BEFORE THE PUBLIC UTILITY COMMISSION OF OREGON

UG 519

OPENING TESTIMONY OF JOHN GARRETT

ON BEHALF OF THE OREGON CITIZENS' UTILITY BOARD

MARCH 5, 2025

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**Avista's $14.2 Million Investment in Aldyl-A Pipe Replacement (AAPR) and Obligation to Examine Non-pipe Alternatives (NPA)**

**Q. Please state your name, occupation, and business address.**

**A.** My name is John Garrett. I am an analyst employed by Oregon Citizens' Utility Board (CUB). My business address is 610 SW Broadway, Ste. 400 Portland, Oregon 97205.

**Q. Please describe your educational background and work experience.**

**A.** My witness qualification statement is provided in CUB/301 Garrett/ 'Witness Qualification Statement.'

**Q. What is the purpose of your testimony?**

**A.** To provide analysis and recommendations for the Oregon Public Utility Commission (PUC) regarding Avista's request for a $14.2 million transfer to plant,[1] with a ~50-year book life,[2] for its investments in replacing Aldyl-A pipe with new gas pipe since its last rate case.

**Q. Are you sponsoring exhibits in this proceeding?**

**A.** Yes, I am sponsoring 18 exhibits. They are as follows, with exhibits containing primary analysis (i.e. from workpapers) in **bold**:

CUB/301 Garrett/ 'Witness Qualification Statement'

CUB/302 Garrett/ 'Avista's Responses to CUB's Discovery Requests'

**CUB/303 Garrett/ 'Aldyl-A Replacement Cost per Customer'**

**CUB/304 Garrett/ 'Aldyl-A Replacement Total Cost and Stranded Investment Risk'**

CUB/305 Garrett/ 'Aldyl-A Slow Crack Growth Evaluation'

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[1] AVISTA/600 Benjamin/Page 18, 'Table No. 6: Mandatory & Compliance Plant Investment.'

[2] CUB/302 Garrett/ 'Avista's Responses to CUB's Discovery Requests,' CUB DR 76.

CUB/306 Garrett/ 'Pacific Gas & Electric and Veteran Pipeline Construction AAPR'

CUB/307 Garrett/ 'Heat Pumps from Vermont Gas Systems'

CUB/308 Garrett/ 'RMI Study on Emergent NPA Opportunities'

CUB/309 Garrett/ 'IEA, Net Zero by 2025'

CUB/310 Garrett/ 'RMI, 8 Benefits of BE for Houses'

CUB/311 Garrett/ 'LBNL, who is participating in residential EE programs?'

**CUB/312 Garrett/ 'Billing Revenue Loss and CPP Benefits of TVE'**

CUB/313 Garrett/ 'CPP Fact Sheet'

CUB/314 Garrett/ 'Findings from a gas-to-induction pilot in low-income housing in NYC'

CUB/315/ Garrett/ 'EPA on NO2 Health Risks'

CUB/316 Garrett/ 'MA DPU Order 20-80-B'

CUB/317 Garrett/ 'Illinois CUB on Gas NPAs'

CUB/318 Garrett/ 'Colorado SB on Reducing the Cost of Use of Natural Gas'

**Q. How is your testimony organized?**

**A.** A table of contents for my testimony is as follows:

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## Table of Contents



## Introduction and Summary

**Q. Please provide a brief overview of Avista's AAPR Program and your approach to examining it.**

**A.** "Aldyl-A" refers to a class of polyethylene compound the DuPont chemical company used in gas distribution system pipe in the 1960's -1990's.[3] Certain earlier vintages of Aldyl-A pipe have proven to be hazardous, because they are vulnerable to embrittlement and sudden rupture.[4] Avista is amidst a 25-year program, the Aldyl-A Pipe Replacement (AAPR) Program, to systematically replace the hazardous Aldyl-

[3] AVISTA/602 Benjamin/Page 117-118 of 687.

[4] AVISTA/602 Benjamin/Page 120-121 and 133 of 687.

A pipe in its distribution system on a priority basis.[5] The Company requests a $14.2 million transfer to plant,[6] with a ~50-year book life,[7] for its investments in replacing Aldyl-A pipe with new gas pipe since its last rate case.

My testimony on the AAPR Program addresses the following key questions, which serve as sections of my testimony (see Table of Contents):

1. What is the cost per customer of replacing Aldyl-A pipe with new gas pipe?
2. How does systematic Aldyl-A pipe replacement stack up against comparable investments in gas distribution infrastructure?
3. What were the Company's regulatory obligations to explore alternatives to systematic Aldyl-A replacement and potentially implement them instead?
4. Did the Company explore any alternatives to systematically replacing Aldyl-A pipe?
5. Was there an alternative that the Company did not explore that is potentially lower cost and lower risk to ratepayers, and would it provide any other notable benefits for ratepayers?
6. Does the Company's investment in systematic Aldyl-A pipe replacement without examining alternatives justify a cost disallowance?
7. What are your recommendations to the Commission?
8. How do your analysis and recommendations fit within the broader context of Oregon state energy utility regulation?

**Q. Please summarize the key findings of your testimony.**

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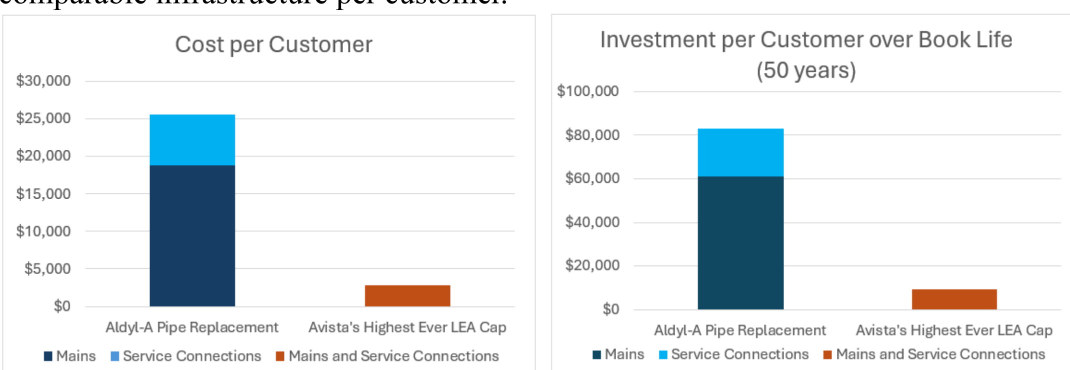
[5] AVISTA/601 Benjamin/Page 6, Lines 2-19.
[6] AVISTA/600 Benjamin/Page 18, 'Table No. 6: Mandatory & Compliance Plant Investment.'
[7] CUB/302 Garrett/ 'Avista's Responses to CUB's Discovery Requests,' DR 76.

**A.** Avista spends about $18.8k per customer (served with replacement pipe) on replacing Aldyl-A distribution main pipes through its AAPR Program, and I estimate that Aldyl-A service connections (pipes that serve individual customers and are not being replaced through the AAPR Program) will cost an additional $6.8k per customer to replace.[8] So altogether, as a solution to the hazards posed by Aldyl-A pipe, I estimate that systematic replacement with new gas pipe costs about $18.8 - $25.6k per customer.[9]

Aldyl-A pipe primarily serves residential customers.[10] At such a high cost per customer, Avista's AAPR Program begets long-term investments in new gas pipe that are much more expensive than its residential line extension allowances (LEA) ever were, along with much higher stranded investment risks as well.[11]

**Figure 1:** Shows Avista's Aldyl-A pipe replacement cost per customer and Avista's highest ever residential LEA cap (left)[12] and the total investment cost per customer over 50 years (right)[13]. Aldyl-A replacement and an LEA cover comparable infrastructure per customer.

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[8] CUB/303 Garrett/ 'Aldyl-A Replacement Cost per Customer.'
[9] *Id.*
[10] *Id.*
[11] CUB/303 Garrett/ 'Aldyl-A Replacement Cost per Customer' and CUB/304 Garrett/ 'Aldyl-A Replacement Total Cost and Stranded Investment Risk.'
[12] CUB/303 Garrett/ 'Aldyl-A Replacement Cost per Customer.'
[13] CUB/304 Garrett/ 'Aldyl-A Replacement Total Cost and Stranded Investment Risk.'

However, since the AAPR Program is a priority safety initiative, it is important to weigh more than the costs and stranded investment risks associated with Aldyl-A pipe replacement. The Company could be justified in spending higher amounts per customer if the expenditure is necessary to ensure the safety of its service, *and no superior alternative is available*.

**Q. What alternatives to Aldyl-A replacement should the company consider?**

One potentially more cost-effective alternative that the Company is required to examine in certain circumstances outlined by the stipulation in UG 461 is non-pipe alternatives (NPA). Avista's NPA obligations under the stipulation in UG 461 apply to "distribution system reinforcements… that exceed a threshold of $1 million for… groups of geographically related projects."[14] The AAPR Program meets these two NPA criteria. The stipulation also states that Avista "include electrification as an NPA" and include "Non-Energy Impacts" as part of the evaluation.[15] Despite these obligations, the Company did not conduct an NPA analysis for its $14.2 million investment in systematic AAPR.[16]

Since the Company did not examine NPAs, I examined NPA opportunities to assess whether any could provide a superior alternative to systematic AAPR. I found that building electrification has *substantial* potential to eliminate the hazards posed by Aldyl-A at lower cost and at lower stranded investment risk than systematic Aldyl-A pipe replacement, in addition to providing numerous other

[14] UG 461, *In the Matter of AVISTA CORPORATION, dba AVISTA UTILITIES, Request for a General Rate Revision.* Order No. 23-384, (Oct. 26, 2023) https://apps.puc.state.or.us/orders/2023ords/23-384.pdf at Appendix B, Page 15 of 27.

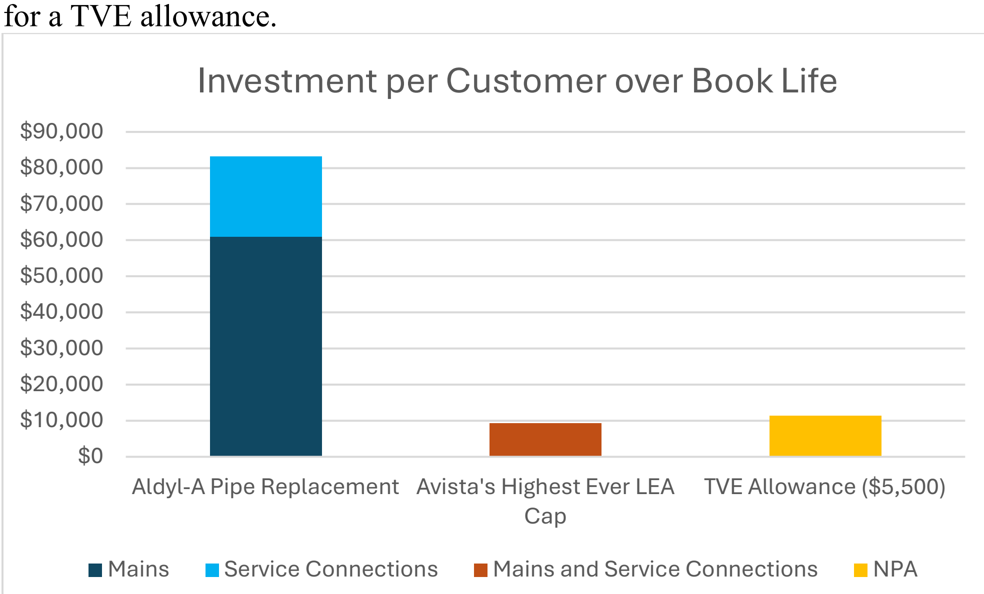
[15] *Id.*

[16] CUB/302 Garrett/ 'Avista's Responses to CUB's Discovery Requests,' DR 105.

benefits. I propose that targeted voluntary electrification (TVE) is compatible with the current regulatory environment and need for an NPA that is compatible with the AAPR Program.

TVE entails the Company offering ratepayers with Aldyl-A pipe a TVE allowance for high efficiency electric appliances (such as a heat pump) to fully electrify. This would unlock capping and pruning Aldyl-A pipe, and avoid costly, long-term investments in gas infrastructure replacement that burden all of Avista's ratepayers. TVE could also provide a cost-effective means of supporting CPP compliance without incurring the high annual costs of alternative fuels, such as renewable natural gas (RNG). Additionally, TVE would help outfit participating ratepayers with brand new, highly efficient, more capable (heat pumps provide AC) and healthier appliances.

**Figure 2:** shows investment costs per customer for Aldyl-A pipe replacement, Avista's highest ever LEA cap for residential customers (a $2,875 allowance), and a $5,500 TVE allowance. The underlying analysis assumes ~50-year book lives for Aldyl-A pipe replacement and Avista's highest ever LEA cap, and a 20-year book life for a TVE allowance.



After extensive research and analysis, I find that the Company's failure to examine NPAs for AAPR delayed what is likely a cost-saving, lower-risk alternative to its AAPR, with many other benefits for its ratepayers as well.

**Q. Please summarize CUB's recommendations to the Commission.**

**A.** CUB recommends:

1. a $710k disallowance from the Company's request of $14.2 million for AAPR since its last rate case;
2. a very deliberate focus on the future, which without a change in course, poses over a decade of $6-9 million investments per year in Oregon[17] in new gas infrastructure to replace Aldyl-A without consideration of superior alternatives;
3. the Commission clarify the Company's obligation to examine NPAs for systematic Aldyl-A replacement, and the specific liabilities for failing to uphold its NPA obligations;
4. the Company provide an NPA analysis that consider TVE at minimum, including the equity components in CUB's testimony;
5. the above NPA analysis would be due with Avista's second IRP update for its 2023 IRP (May 31, 2026), since Avista's next Oregon IRP is not due until April 1, 2027;[18] and
6. the Company adopt specific requirements for tracking discrete investments in gas infrastructure, which are necessary to improve safety planning and the fair allocation of risks associated with long-term investments in gas assets.

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[17] CUB/303 Garrett/ 'Aldyl-A Replacement Cost per Customer.'

[18] LC 81, *In the Matter of AVISTA CORPORATION, dba AVISTA UTILITIES, 2023 Natural Gas Integrated Resource Plan*. Order No. 24-254. (Jul. 29, 2024) https://apps.puc.state.or.us/orders/2024ords/24-254.pdf at 6.

**Q. Please explain how your findings fit within the broader context of Oregon's energy utility sector.**

A. Applying TVE on a small subset of Avista's Oregon gas system through an accessible, equity-informed program offers a key opportunity to understand the impacts of fuel conversions, while supporting Oregon's energy equity and environmental justice policy goals. Given the widely acknowledged importance of electrifying the building sector to achieve decarbonization goals equitably and cost-effectively,[19] piloting TVE on gas customers that are extremely expensive to keep on gas presents a crucial and timely opportunity.[20] My analysis and recommendations support the exploration, and if warranted, timely implementation of an NPA like TVE to offset Avista's planned investments in new gas pipe to replace Aldyl-A pipe.

## Section I. What is the cost per customer of replacing Aldyl-A pipe with new gas pipe?

**Q. How did you calculate the cost per customer of the AAPR Program?**

**A.** CUB/303 Garrett/ 'Aldyl-A Replacement Cost per Customer' details the calculation. I divided the annual costs of the AAPR Program by the annual number of customers served (with replacement pipe necessary to serve them) through the AAPR Program

[19] *See* e.g., CUB/309 Garrett/ 'IEA, Net Zero by 2025' https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf at 61-62; *See* CUB/310 Garrett/ 'RMI, 8 Benefits of BE for Houses' RMI, Eight Benefits of Building Electrification for Households, Communities, and Climate' (Mar. 29, 2021) https://rmi.org/eight-benefits-of-building-electrification-for-households-communities-and-climate/.

[20] By using the term "pilot" CUB is proposing a size-limited, innovative program pursuant to the stipulation requiring the Company to consider NPA, which we expect will be cost effective and will also be highly informative.

each year. I then calculated the 5-year past average cost per customer served of the AAPR Program.

**Q. Why did you use the 5-year past average of the cost per customer?**

**A.** In its "Study of Aldyl-A Pipe Leaks 2022 Update" Avista reported that the cost per foot of pipe replacement has risen and is more expensive than initial installation because "[r]eplacement pipe must be installed in fully developed and occupied areas that consist of numerous below ground facilities, paved streets, sidewalks, arterials, landscaped residential neighborhoods, and hard-surfaced commercial developments teeming with daily traffic and other activity."[21] Furthermore, Avista reported that "pipe replacement costs are higher in Oregon" and that "[t]he major element of the total cost disparity is related to road restoration requirements in Oregon jurisdictions."[22]

Avista's reporting that pipe replacement costs have risen, in addition to recent inflationary pressures, suggest that using a 3-year past average is appropriate for estimating the average cost of replacing Aldyl-A. However, there are other factors to weigh. The AAPR Program covers work on distribution infrastructure across a range of suburban environments, creating noise in the data.[23] A longer period of analysis ought to smooth out the variability in this data and provide a more robust average cost per customer. So although using the 3-year past average results in a significantly

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[21] AVISTA/602 Benjamin/Page 157 of 687.
[22] *Id.*
[23] *Id.* at 157-158 of 687.

higher cost per customer ($21,558/ cust), I opted to use the more conservative, 5-year past average cost per customer ($18,778/ cust).[24]

**Q. What is the cost per customer of the AAPR Program?**

**A.** The cost per customer of the AAPR Program is about $18.8k per customer.[25] The AAPR Program largely impacts residential ratepayers; it impacts residential and commercial customers at a ratio of 10 residential customers to 1 commercial (Sch 420) customers.[26] I attempted to parse out AAPR investments per customer by customer class, so that I could more precisely examine residential-specific costs, but the Company was not able to provide the information required for me to do this.[27]

**Q. What Aldyl-A pipe replacement does the AAPR Program cover and why is it important to also consider Aldyl-A service connections?**

**A.** The AAPR Program covers systematic replacement of Aldyl-A distribution mains, but not Aldyl-A service connections.[28] Distribution mains are typically wider diameter pipes that serve several customers, whereas service connections are typically narrower pipes, which serve single customers. In 2012 the Company reported, "Avista is not planning to systematically replace Aldyl A service pipe as it replaces main pipe and rehabilitates service connections at steel tees. Avista is using the Integrity Management model, however, to track and analyze service leaks going forward to determine if the reliability of Aldyl A service piping changes in ways that warrant a different approach."[29] Figure 3 depicts Avista's priorities for replacing

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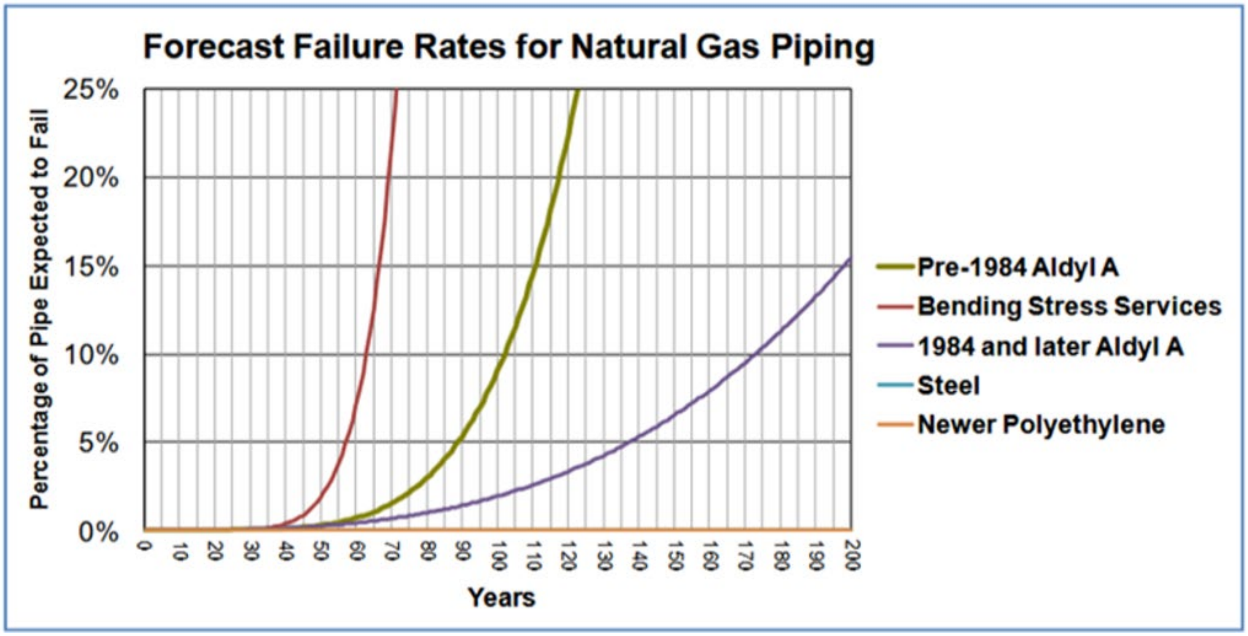
[24] CUB/303 Garrett/ 'Aldyl-A Replacement Cost per Customer.'
[25] *Id.*
[26] *Id.*
[27] CUB/302 Garrett/ 'Avista's Responses to CUB's Discovery Requests,' DR 106.
[28] AVISTA/602 Benjamin/Page 133-138 of 687.
[29] *Id* at 133 of 687.

Aldyl-A pipe based upon the failure modalities for the pipe and when they present unacceptable risks.

**Figure 3** is taken from Avista's "Protocol for Managing Aldyl A Natural Gas Pipe" and shows the "expected failure rates for several classes of pipe in Avista's system, as forecast by Availability Workbench Modeling."[30]




"Bending Stress Services," or "Aldyl A Services Tapped to Steel Mains," pose the earliest spike in critical failure rate at around 50 years after installation. Since the Aldyl-A in Avista's system is 44 years old on average today,[31] it is important that Avista addresses this issue first. The material failure rate of "Pre-1984 Aldyl-A" mains, from hazards like rocks or roots impinging the pipe, pose the next critical failure rate spike at around 75 years after installation.

Avista's workbench modeling and replacement prioritization by failure modality align with a comprehensive, 2017 analysis of the remaining useful life of Aldyl-A, which found that bending stress poses a greater threat than other failure

[30] *Id* at 136 of 687.

[31] *Id* at 137 of 687.

modalities, although other modalities like impingement by a rock or root threaten the integrity of Aldyl-A pipe too.[32]

Beyond the failure rate alone, the Company reported the following regarding the unique hazard posed by Aldyl-A:

> "Looking simply at Aldyl A leaks as part of the aggregate of all system leaks, it could be easy to conclude that Aldyl A pipe failures pose a limited potential for hazard relative to the threat of other system leaks. In fact, while gas equipment leaks are more likely to occur, their potential consequence is often minimal… Through public awareness programs, people have become familiar with the odor of venting gas and tend to quickly call Avista to make repairs; this is especially true if the venting gas can be associated with visible gas valves or meters. By contrast, Aldyl A failures and the associated leaks occur almost entirely underground, out of sight, often in populated areas, and occasionally in the proximity of buildings that are not actually connected to the natural gas system. Without visible facilities, natural gas may have an unexpected presence in the environment that allows people to dismiss slight gas odors. This reduced awareness allows gas from these undetected leaks to have the significant potential to migrate into buildings before it can be identified and reported…**Of the roughly 2,000 equipment leaks reported in the five years of data reviewed, none resulted in gas incidents. By comparison, two of the relatively-small number of Aldyl A material failures resulted in gas migrating into buildings undetected, and upon accidental ignition, resulted in harmful incidents**… The common mode of failure for Aldyl A materials, brittle-like cracking, can also present special problems compared with leaks in other gas piping, such as corrosion in steel gas pipe. **Corrosion leaks tend to begin with the failure of a very minute area in the pipe wall, which then begins to release a very minute amount of natural gas. These leaks then tend to progress very slowly and in a stable and somewhat predicable way over time. These types of leaks, while never positive, are more likely to be detected by modern gas-detection equipment when they are at a stage where the release of gas is relatively minor. By contrast, leaks in Aldyl A piping tend to first appear as substantial (high gas volume) leaks that appear in a very short time period.** This is due to the nature of brittle cracking, where the crack can progress very slowly from the inner wall of the pipe toward the outer wall without any release of gas, until the pipe finally splits open, resulting in a substantial failure. Additionally,

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[32]*See* CUB/305 Garrett/ 'Aldyl-A Slow Crack Growth Evaluation' Lever, Ernest. Slow Crack Growth Evaluation of Vintage Polyethylene Pipes, *Gas Technology Institute* (Oct. 3, 2017).

> unlike the prevention or even suspension of corrosion problems in steel pipe through effective protection methods, there is no way to halt undetected progress of slow crack growth in brittle Aldyl A pipe."[33] (emphasis added in **bold**)

**Q. Do Avista's service connections contain Aldyl-A?**

**A.** Yes, but despite CUB's best efforts, it remains unclear *which* service connections and *how many.* Beyond Avista, Aldyl-A was used for distribution mains and service connections alike and some utilities are replacing thousands of Aldyl-A service connections in addition to the mains.[34] Furthermore, a comprehensive examination of Aldyl-A failure modalities from 2017 examines Aldyl-A pipe of small diameter, which is sized for residential service connections, and says that they are vulnerable to impingement.[35] Avista acknowledges Aldyl-A in its service connections in its Aldyl-A Pipe Management Protocol. [36] However, this ackowledgemetn does not answer which service connections contain Aldyl-A and how many of them are on Avista's system.

To answer these question, I asked the Company through discovery about the number of Aldyl-A service connections it has for each rate class on its system.[37] However, without explanation the Company limited its response to only service connections with wider diameter pipe (greater than 1- ¼ inch), ignoring any service connections with ¾ inch Aldyl-A pipe, which is what I would expect

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[33] AVISTA/602 Benjamin/Page 133-134 of 687.
[34] CUB/306 Garrett/ 'Pacific Gas & Electric and Veteran Pipeline Construction AAPR.'
[35] CUB/305 Garrett/ 'Aldyl-A Slow Crack Growth Evaluation' Lever, Ernest. Slow Crack Growth Evaluation of Vintage Polyethylene Pipes, *Gas Technology Institute* (Oct. 3, 2017) at 103 to 105.
[36] *See* AVISTA/602 Benjamin/Page 133 of 687.
[37] *See* CUB/302 Garrett/ 'Avista's Responses to CUB's Discovery Requests' DRs 115

residential service connections connected to Aldyl-A mains **to** have. Since residential customers make up the bulk of the customers served by the AAPR Program,[38] the Company's response excludes the bulk of potential service connections. From conversation with the Company, it was CUB's understanding that residential customers had Aldyl-A service connections but replacing them was not a component of the AAPR Program. As such, although it appears likely that there is Aldyl-A in service connections connected to Aldyl-A mains, it is still not clear that Aldyl-A service connections were necessarily used for each connection to Avista's distribution mains.

**Q. Please explain your review of replacing service connections.**

**A.** All Aldyl-A pipe, particularly smaller diameter piping with thinner walls, is vulnerable to impingement.[39] Looking beyond Avista's AAPR, some utilities, including Pacific Gas & Electric (PG&E) and utilities served by the Veteran Pipeline Construction (VPC) Company, opted to replace Aldyl-A service connections concurrently with the distribution mains.[40]

While Avista's strategy of prioritizing Aldyl-A distribution mains does not appear unreasonable, it is important to note that doing so leaves the service connections to be dealt with later, whether through a systematic replacement program or piecemeal through Avista's Distribution Integrity Management Program (DIMP).[41] To get a better sense of when this is likely

[38] CUB/303 Garrett/ 'Aldyl-A Replacement Cost per Customer.'
[39] CUB/305 Garrett/ 'Aldyl-A Slow Crack Growth Evaluation' Lever, Ernest. Slow Crack Growth Evaluation of Vintage Polyethylene Pipes, *Gas Technology Institute* (Oct. 3, 2017) at 103 to 105.
[40] CUB/306 Garrett/ 'Pacific Gas & Electric and Veteran Pipeline Construction AAPR.'
[41] As Avista explains "In recent years, PHMSA has moved beyond the enforcement of individual rules to require natural gas utilities to conduct a standardized assessment of risks threatening the

to occur as the service connections age, CUB requested Avista's useful life for Aldyl-A pipe in its system, including service connection pipe, but from the Company's response, it appears that Avista does not have one.[42] CUB also requested information about how many Aldyl-A service connections Avista has in Oregon, but the Company limited its response to only service connections with wider diameter pipe, inexplicably ignoring any service connections that could have ¾ inch Aldyl-A pipe, [43] which is what I would expect residential service connections from the late 1960's to early 1990's to have.

Ultimately, the Company's 50-year investments in Aldyl-A distribution main replacements today, primarily to serve residential customers, are only useful insofar as the gas flowing through them has a safe and regulatorily compliant pathway all the way to the ratepayer, i.e. through service connections. If the service connections connected to the replacement mains are made of a brittle material, Aldyl-A, then it is only reasonable to evaluate whether today's investments in distribution mains will also require service connection replacements within a few decades too, increasing the cost and stranded asset risk per customer of AAPR. Furthermore, if alternatives to Aldyl-A replacement could avoid replacing Aldyl-A mains *and*

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integrity of their pipeline systems. Known as the Distribution Integrity Management Plan (or DIMP) and Transmission Integrity Management Plan (or TIMP), these requirements were enabled by amendments to the Federal Pipeline Safety Regulations on December 4, 2009, and December 15, 2003, respectively." *See* UM 1898, *Avista Utilities 2019 Natural Gas Safety Project Plan* at 4 (Sept. 27, 2019).

[42] CUB/302 Garrett/ 'Avista's Responses to CUB's Discovery Requests,' DRs 7, 8 and 76.

[43] CUB/302 Garrett/ 'Avista's Responses to CUB's Discovery Requests' DRs 115.

service connections, then it is important to understand the avoided cost potential of Aldyl-A service connections too.

**Q. What is the cost per customer of replacing residential service connections and how did you estimate it?**

**A.** CUB/303 Garrett/ 'Aldyl-A Replacement Cost per Customer' shows the calculation. The cost per customer of replacing residential service connections is about $6.8k per customer. To estimate this, I used the same methodology I used for the AAPR Program: a 5-year past average of the cost per customer, except I drew upon a broader dataset (i.e. more than just Aldyl-A replacement work) provided by the Company.[44] Just as with the AAPR Program, the 3-year past average cost per customer ($8,194/ cust) of replacing service connections is significantly higher than the 5-year past average ($6,833/ cust), [45] but I conservatively opted for the 5-year past average in order to draw upon a longer study period and to maintain a consistent methodology across my analyses.

**Q. What is the total cost per customer of systematically replacing Aldyl-A pipe?**

**A.** Together, I estimate that the cost of replacing a customer's Aldyl-A distribution main and service connection is about $25.8k per customer.[46]

**Q. What is the stranded asset risk associated with Aldyl-A distribution main replacements and service connection replacements?**

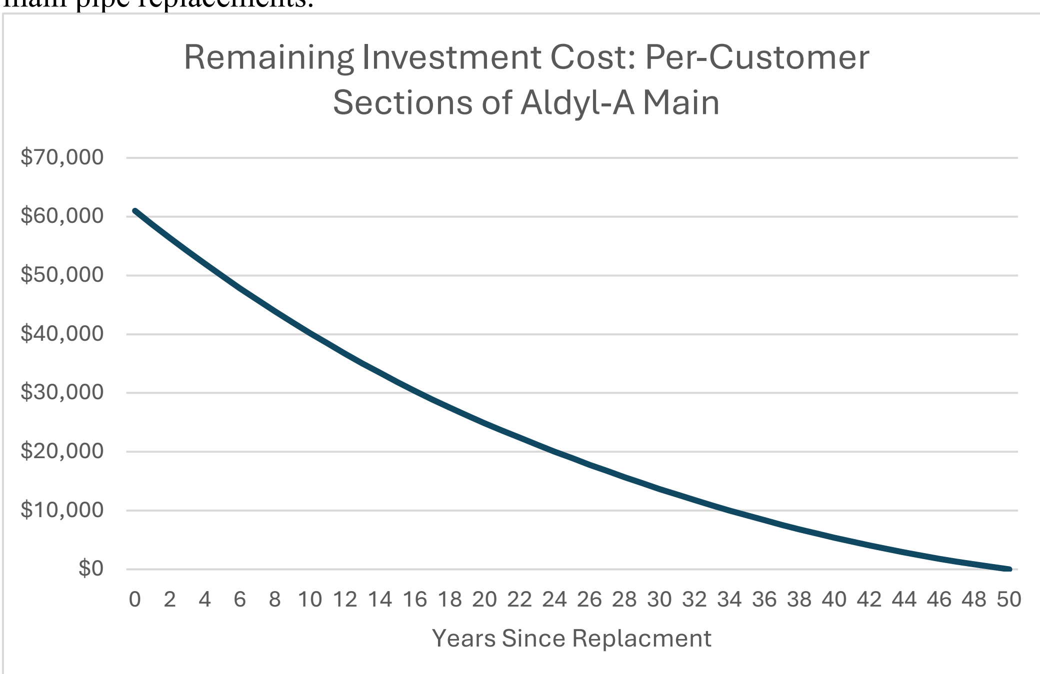
**A.** CUB/304 Garrett/ 'Aldyl-A Replacement Total Cost and Stranded Investment Risk.' examines the stranded investment risks associated with per-ratepayer investments in

[44] CUB/303 Garrett/ 'Aldyl-A Replacement Cost per Customer.'
[45] *Id.*
[46] *Id.*

these assets. The distribution mains and service connections each have ~50-year book lives.[47] I used the Company's current rate of return and capital structure,[48] as opposed to its significantly higher proposed returns,[49] which would drive up the total investment costs and stranded investment risks considerably.

Over the course of its book life, a replacement section of Aldyl-A distribution main pipe for one ratepayer costs $61,005.[50] The high total cost results from rate base financing and taxation costs of the asset over the course of its book life and excludes any incremental O&M for the pipe. Figure 4 shows the investment costs that would remain should one per-customer section of distribution main lose usefulness and become a stranded asset at any point over the course of its book life.

**Figure 4 s**hows the stranded investment risk of per-customer Aldyl-A distribution main pipe replacements.[51]




[47] CUB/302 Garrett/ 'Avista's Responses to CUB's Discovery Requests,' DRs 8 and 76.
[48] CUB/304 Garrett/ 'Aldyl-A Replacement Total Cost and Stranded Investment Risk.'
[49] Avista/100 Rosentrater/Page 20.
[50] CUB/304 Garrett/ 'Aldyl-A Replacement Total Cost and Stranded Investment Risk.'
[51] *Id.*

Over the course of its book life, a replacement service connection for one residential ratepayer costs $22,222.[52] Again, this analysis excludes any incremental O&M costs for the asset. Figure 5 shows the investment costs that would remain should a service connection replacement become a stranded asset at any point over the course of its book life.

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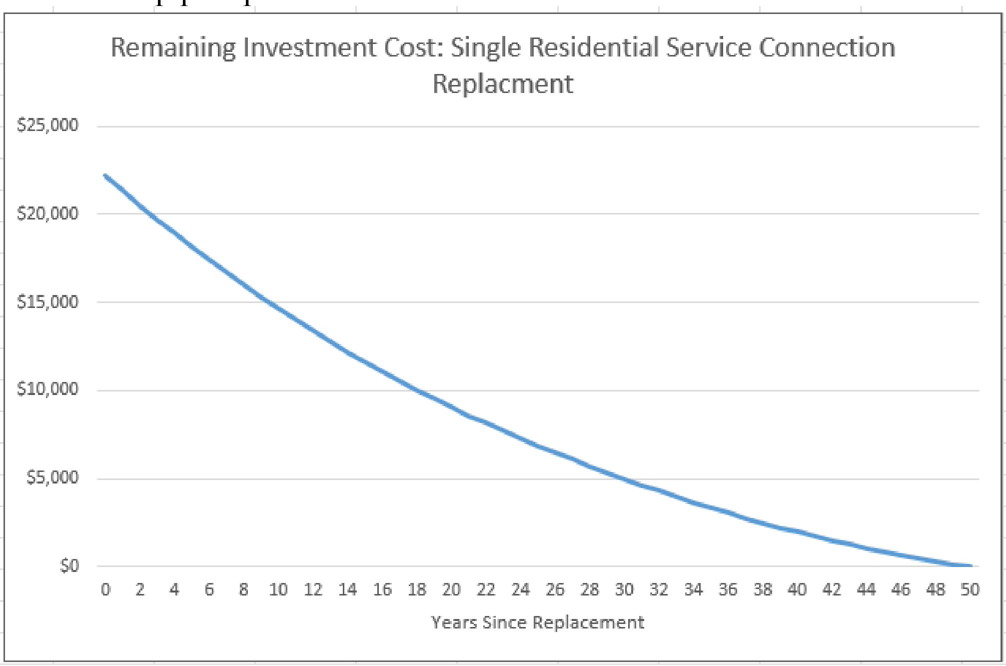
**Figure 5** shows the stranded investment risk of residential Aldyl-A service connection pipe replacements.




[52] *Id.*

## Section II. How does systematic Aldyl-A pipe replacement stack up against comparable investments in gas distribution infrastructure?

**Q. What did you consider in your search for a reasonable comparison?**

**A.** It is important to understand how the Company's significant capital investments in a rate case stack up against comparable investments. Such comparisons are the cornerstone of determining whether otherwise decontextualized cost-drivers are reasonable or not.

The Company's current investments in AAPR cover distribution main replacements and foreshadow service connection replacements over the next few decades that would keep the distribution mains used and useful. Thus, I sought a per-customer investment in distribution mains and service connections to serve as a touchstone, or benchmark to compare Avista's investments in AAPR.

**Q. What is a line extension allowance (LEA)?**

**A.** An LEA is an allowance that a utility provides to a new customer to fully or partially cover the costs of connecting to the utility's system. For instance, for a new customer, a gas utility's LEA policy typically covers up to an established dollar amount to install new pipeline, a meter and cover other connection costs.

Fundamentally, an LEA policy balances the interests of new and existing customers by establishing the maximum LEA the utility will provide a new customer (i.e., the LEA cap).[53] This is necessary because regulated utilities like Avista have a

[53] UG 490, *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision.* CUB/400 Garrett/ Pages 4-7 https://edocs.puc.state.or.us/efdocs/HTB/ug490htb329789032.pdf.

strong inherent incentive to invest in capital projects, because higher investments drive higher rates of return and profits.[54]

If the utility spends too much to connect a new customer, the benefits the new customer brings (like spreading out coverage of the utility's fixed costs) will not outweigh the costs of connecting the new customer.[55] When a utility overspends on interconnection infrastructure for a single new customer, this unfairly drives up the rates of existing customers.[56]

**Q. What was Avista's highest ever LEA cap?**

**A.** The phrase "highest ever LEA cap" refers to Avista's 2021 LEA of $2,875. Avista's LEA policy has evolved to have lower LEA caps since 2021.[57] 2021 was the last year Avista had a residential LEA cap of $2,875 and since then it has gradually decreased. Currently, Avista's residential LEA cap is phasing down to $0 by 2027.[58]

**Q. Why is Avista's highest ever LEA cap an insightful benchmark for comparison to the Company's investments in Aldyl-A pipe replacement?**

**A.** Avista's highest ever LEA cap can be compared to the Company's AAPR costs because it represents the most Avista was ever able to spend cost-effectively on single customer interconnections. Not only do LEAs cover comparable assets to the Aldyl-A pipe in Avista's distribution system, including distribution mains and service

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[54] *Id.*
[55] *Id.*
[56] *Id.*
[57] UG 461, *In the Matter of AVISTA CORPORATION, dba AVISTA UTILITIES, Request for a General Rate Revision.* Opening Testimony CUB/100, Garrett-Jenks/Page 3.
[58] UG 461, *In the Matter of AVISTA CORPORATION, dba AVISTA UTILITIES, Request for a General Rate Revision.* Order No. 23-384, (Oct. 26, 2023) https://apps.puc.state.or.us/orders/2023ords/23-384.pdf at Appendix B Page 11 of 27.

connection pipe, but also by design, an LEA cap represents the maximum amount a gas utility should per customer on this infrastructure if all that mattered was cost-effectiveness. Remember, LEA caps are designed to balance the benefits a single customer adds to the system with the costs to all ratepayers installing new interconnection infrastructure for the new customer. When a gas company spends more than its LEA cap to connect a new customer, it is in theory creating more costs than benefits for its other customers. That said, there are three cautionary considerations to be aware of.

**Q. You mentioned "three cautionary considerations" when comparing the Company's highest ever LEA cap to its investments in Aldyl-A replacement—what are they?**

A. **1.** LEAs do not completely cover service connection and distribution main costs; sometimes a customer contribution is required to cover distribution main extension and service connection costs beyond the LEA cap. As such, the Company's highest ever LEA cap is not a measure of how much distribution mains and service connections together typically cost; instead, it is an indicator of the highest amount that is cost effective for the Company to spend on the infrastructure.

**2.** Avista notes that replacing gas distribution piping is more expensive than initially installing it,[59] so it is reasonable to expect that replacing mains and service connections is more expensive than installing them initially.

**3.** What the Company could reasonably spend on connecting a new customer cost-effectively versus keeping an existing customer's connection safe are two different

[59] AVISTA/602 Benjamin/Page 157 of 687.

things. While an LEA cap limits what a utility spends on connecting a new customer on economic grounds, a regulated utility may consider more than dollars and cents when keeping its system safe and be willing to spend more per customer when necessary, so long as no cheaper and equally effective alternatives are available.

**Q. With these cautionary considerations in mind, why is this a meaningful comparison for your testimony?**

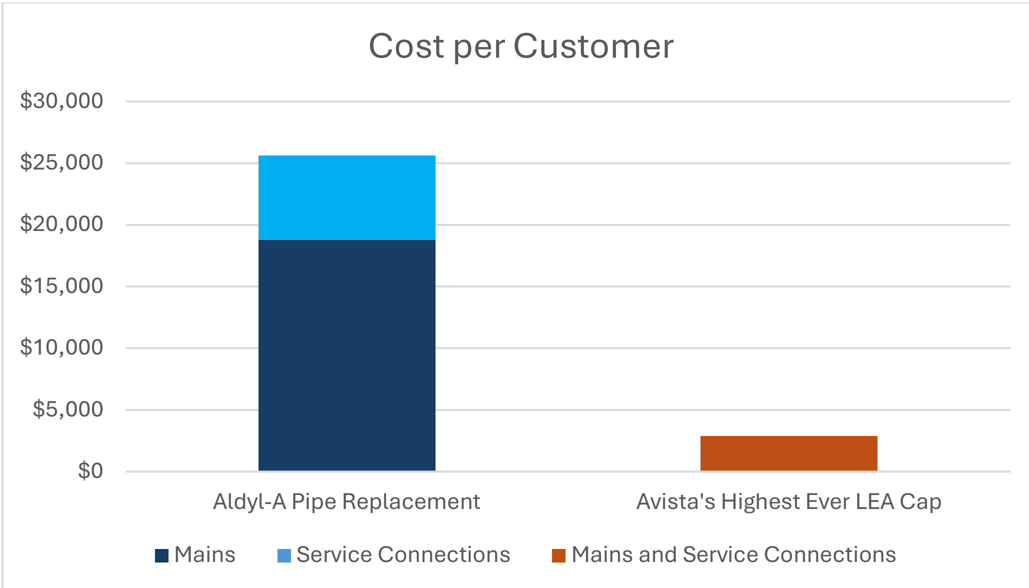
**A.** As I discuss in the remaining sections of my testimony, I am not questioning whether the Aldyl-A hazard must be dealt with on a priority basis or whether the cost per customer could reasonably be higher than Avista's highest ever LEA; instead, I am examining whether the Company's strategy for dealing with Aldyl-A poses burdensome costs and risks, is the most cost-effective means of dealing with Aldyl-A, and whether potential alternatives that the Company is required to explore may be superior. Assessing the cost of Aldyl-A replacement against a cost-effective investment in similar infrastructure offers a good starting point for assessing the urgency with which the Company ought to have sought out more cost-effective alternatives.

**Q. What does the comparison of Aldyl-A pipe replacement against Avista's highest ever LEA cap show?**

**A.** The comparison highlights the extreme cost per customer of the Company's current Aldyl-A hazard mitigation strategy, which is systematic replacement.

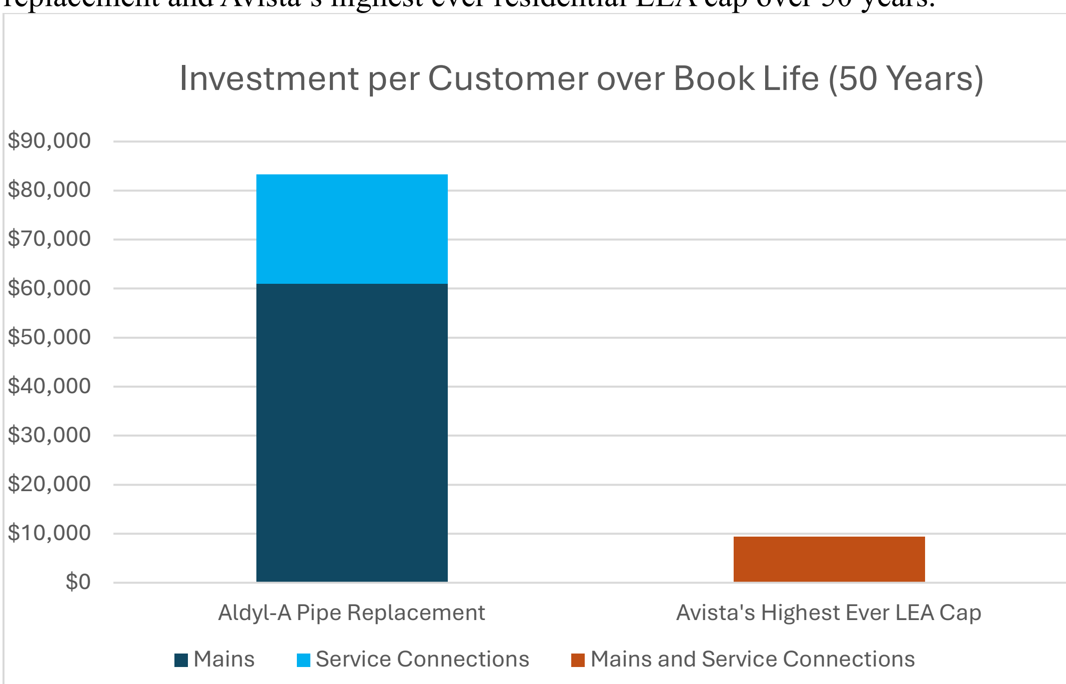
**Figure 6** juxtaposes the Aldyl-A pipe replacement cost per customer and Avista's highest ever residential LEA cap.[60]

[60] CUB/303 Garrett/ 'Aldyl-A Replacement Cost per Customer.'




It is also important to consider the stranded asset risk of Aldyl-A replacement over time. Figure 7 offers this comparison.

**Figure 7:** juxtaposes the total investment cost per customer of Aldyl-A pipe replacement and Avista's highest ever residential LEA cap over 50 years.[61]




[61] CUB/304 Garrett/ 'Aldyl-A Replacement Total Cost and Stranded Investment Risk.'

This comparison has clear implications: while such steep investments and their long-term risks may be justified to keep Avista's service safe sans superior alternatives, these are extremely undesirable investments from cost per customer and stranded asset risk management perspectives. As such, the Company ought to be exploring any alternatives to Aldyl-A pipe replacement that would mitigate Aldyl-A hazards equally well, but at lower cost and stranded investment risk to its ratepayers.

**Q. At the Company's current residential Base Rate (including the Customer Charge and Base Rate per therm), how many years would it take for a ratepayer's billing revenue to offset the total Aldyl-A pipe replacement cost per customer ($83,227)?**

**A.** About 147 years.[62]

## Section III. What were the Company's regulatory obligations to explore alternatives to systematic Aldyl-A replacement and potentially implement them instead?

**Q. What are the Company's general obligations regarding long-term investments in gas infrastructure?**

**A.** Numerous dockets have touched upon the high stranded asset risk associated with long-term investments in gas infrastructure amidst Oregon's climate change

[62] CUB/304 Garrett/ 'Aldyl-A Replacement Total Cost and Stranded Investment Risk.'

mitigation policies, including but not limited to, Commission Order 22-388,[63] the Natural Gas Fact Finding (NGFF) Report,[64] Commission Order 23-281,[65] CUB's Opening Testimony in UG 461, and recently in Commission Order 24-359.[66] These proceedings make clear the importance of seeking out opportunities to avoid risky, long-term investments in new gas infrastructure.

Furthermore, in response to Cascade Natural Gas Company's 2020 IRP update, the Commission stated, "we expect natural gas companies will provide evidence not only that projects are warranted by near-term reliability needs (as distinct from long-term growth projections), but also that the company acted with a sense of urgency in pursuing alternatives, including DSM and energy efficiency, for distribution projects in future IRP analyses. Providing this information early in the IRP review process is critical to our ability to both protect customers from unreasonable costs and risks and respond appropriately to issues of system reliability."[67]

Amidst these clear regulatory signals, the Company ought to have flagged the high cost and stranded investment risk of Aldyl-A replacement and examined

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[63] UG 435*, In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision.* Order No. 22-388 (Oct. 24, 2022) https://apps.puc.state.or.us/orders/2022ords/22-388.pdf at 51.

[64] UM 2178, *In the Matter of OREGON PUBLIC UTILITY COMMISSION STAFF Natural Gas Fact Finding per Executive Order 20-04 PUC Year One Work Plan* Staff Report (Jan. 1, 2023) https://edocs.puc.state.or.us/efdocs/HAU/um2178hau111621.pdf at Appendix F, Page l

[65] LC 79, *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, 2022 Integrated Resource Plan.* Order No. 23-281 (Aug. 2, 2023) https://apps.puc.state.or.us/orders/2023ords/23-281.pdf at 13.

[66] UG 490, *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision* Order No. 24-359 (Oct. 25, 2024) https://apps.puc.state.or.us/orders/2024ords/24-359.pdf at 9 – 11.

[67] LC 76, *In the Matter of CASCADE NATURAL GAS CORPORATION, 2020 Integrated Resource Plan*. Order No. 23-023, (Feb. 6, 2023) https://apps.puc.state.or.us/orders/2023ords/23-023.pdf at 2.

whether less risky alternatives that address Aldyl-A hazard -mitigation equally well were available.

**Q. Does the Company have any firm obligations pertaining to exploring non-pipe alternatives (NPA) specifically?**

**A.** Yes. In the Second Stipulation following the Company's previous rate case (UG 461), which the Commission adopted in Order 23-348, Avista agreed to the following framework for examining NPAs:

> "**21. Non-Pipe Alternatives (NPA):** Avista agrees to implement an NPA framework in Oregon, including the following elements.
>
> i. Upon the rate-effective date, NPA analysis will be performed for supply-side resources and for distribution system reinforcements and expansion projects that exceed a threshold of $1 million for individual projects or groups of geographically related projects. If an NPA is not selected for projects that meet this criteria, Avista will include the NPA analysis as part of the justification when it seeks recovery of the resource addition or distribution system reinforcement or expansion in a rate case.
>
> a. "Supply-side resources" includes but is not limited to all resources upstream of Avista's distribution system and city gates, and supply-side contracts.
>
> b. "Geographically-related projects" means a group of projects that are interdependent or interrelated.
>
> ii. For resources or projects that meet the criteria of (i), Avista will include electrification as an NPA.
>
> iii. Non-Energy Impacts must be included as part of the NPA evaluation."[68]

[68] UG 461, *In the Matter of AVISTA CORPORATION, dba AVISTA UTILITIES, Request for a General Rate Revision.* Order No. 23-384, (Oct. 26, 2023) https://apps.puc.state.or.us/orders/2023ords/23-384.pdf at Appendix B, Page 15 of 27.

Importantly, the Company agreed to conduct NPA analyses on "distribution system reinforcements… that exceed a threshold of $1 million for… groups of geographically related projects." As discussed below, replacing failing pipe is reinforcing the distribution system. Therefore, systematically replacing clusters of Aldyl-A in the Company's distribution system, or reinforcing what would otherwise be inadequate infrastructure, at a cost of $6-9 million/ year, meets the NPA analysis criteria Avista agreed to. Furthermore, Avista agreed to "include electrification as an NPA" and include "Non-Energy Impacts" as part of the evaluation.

## Section IV. Did the Company explore any alternatives to systematically replacing Aldyl-A pipe?

**Q. Did the Company explore any alternatives to systematically replacing Aldyl-A pipe?**

**A.** No, the Company did not explore alternatives to systematically replacing Aldyl-A pipe with new gas pipe.[69] I questioned if the Company explored NPAs for its AAPR Program through discovery, and the Company's complete response is included in CUB/302 Garrett/ 'Avista's Responses to CUB's Discovery Requests,' DR 105.

**Q. Please respond to the Company's response to CUB DR to Avista 105.**

**A.** The Company's NPA obligations require it to examine NPAs for "distribution system reinforcements."[70] In its response to CUB DR to Avista 105, the Company appears to be saying that the AAPR Program does not involve "distribution system

[69] CUB/302 Garrett/ 'Avista's Responses to CUB's Discovery Requests,' DR 105.
[70] *Id.*

reinforcement," because Avista considers distribution system reinforcements to be related to "serv[ing] existing customers where capacity on the system is diminished."[71] Instead of being a distribution system reinforcement, Avista considers the AAPR Program "a safety related program first and foremost," and as such Avista does not believe that the Company's NPA obligations apply.[72]

Despite this, replacing faulty pipeline material with new pipeline would appear to *reinforce* the Company's distribution system. AAPR anticipates and prevents aging assets from failing, distribution system leaks, disruptions to service and safety hazards. If the issue must be couched in terms of serving existing customers with capacity, then without intervention, the faulty Aldyl-A pipe will not be fit to serve customers with *any* capacity soon, unless Avista reinforces this portion of its distribution system with new pipe or pursues an NPA.

**Q. Is the Company's perception of its NPA obligations problematic in other ways?**

**A.** Yes, the Company's perception of its NPA obligations in the stipulation seems to exclude *any* replacement of distribution system piping. Regarding other distribution pipe replacement outside the AAPR, such as replacing Aldyl-A service connections, since the Company does not appear to assign useful lives for distribution system piping,[73] nor does Avista have replacement plans beyond replacing the pipes

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[71] *Id.*
[72] *See Id.*
[73] CUB/302 Garrett/ 'Avista's Responses to CUB's Discovery Requests,' DRs 7, 8 and 76.

piecemeal as they fail,[74] there is no opportunity to anticipate the aging out of pipes and examine NPAs as an alternative to replacement.

So where does this leave NPAs and prudently examining alternatives to \$18.8 - 25.8k per customer pipe replacements? If Avista only replaces distribution pipe through consolidated programs that look ahead for safety, or piecemeal and sporadically through its DIMP as pipes fail, this leaves no space to examine NPAs for costly replacements of gas pipe.

## Section V. Was there an alternative to AAPR that the Company did not explore that is potentially lower cost and lower risk to ratepayers, and would it provide any other notable benefits for ratepayers?

**Q. What alternatives to systematic AAPR did you examine?**

**A.** Since the Company did not provide an analysis of alternatives to systematic Aldyl-A pipe replacement, I examined possible alternatives. One alternative I examined closely was targeted voluntary electrification (TVE), which is offering ratepayers an allowance for installing high efficiency electric appliances. Having a gas company invest in high efficiency electrification is not a new concept; Vermont Gas Systems (VGS) is doing this.[75] VGS's website offers a glimpse of what this could look like for Avista's ratepayers.[76]

[74] AVISTA/602 Benjamin/Page 136 of 687.
[75] CUB/307 Garrett/ 'Heat Pumps from Vermont Gas Systems'
[76] *Id.*

Given the high costs of replacing Aldyl-A pipe with new gas pipe, I examined whether targeted investments in electrification, which could enable capping and pruning Aldyl-A gas distribution infrastructure instead of replacing it, could present a superior alternative to systematic Aldyl-A gas pipe replacement. My focus on targeted and voluntary electrification opportunities, specifically to avoid the replacement of gas infrastructure, is supported by a 2024 whitepaper from the Rocky Mountain Institute (RMI) and National Grid, which provides modern guidance on NPA opportunities for gas systems.[77]

**Q. Please provide an overview of the costs and benefits of TVE as an alternative to AAPR.**

**A.** Table 1 provides an overview of the costs and benefits of TVE as an alternative to AAPR.

**Table 1**. An overview of the costs and benefits of TVE as an alternative to AAPR.

| Benefits | Costs |
|---|---|
| If (TVC Allowance) < (Avoided AAPR Costs) | If (TVC Allowance) > (Avoided AAPR Costs) |
| Negates some Aldyl-A pipe replacement | |
| | Begets Aldyl-A capping and pruning work |
| | Requires TVC program administration |

[77] CUB/308 Garrett/ 'RMI Study on Emergent NPA Opportunities' RMI, National Grid, "Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization" (May 2024) https://www.nationalgridus.com/media/pdfs/other/CM9904-RMI_NG-May-2024.pdf

| | |
|---|---|
| | Could necessitate household and local electric grid distribution upgrades |
| | Reduces gas distribution system linepack capacity |
| Mitigates stranded gas asset risk | |
| Reduces Avista’s CPP compliance costs | |
| | Reduces residential billing revenue |
| Supports EE and decarbonization at household and energy sector scales | |
| Offsets ratepayer appliance replacement costs | |
| Unlocks air conditioning for ratepayers | |
| Could remove harmful pollutants from homes through gas to electric stove replacements | |
| Creates new investing opportunity for Avista | |
| Presents key opportunity to advance Oregon's Energy Equity and Environmental Justice policy goals | |

| | |
|---|---|
| Offers timely opportunity to understand utility impacts from building electrification at manageable scale | |

**Q. How is TVE as an alternative to systematic Aldyl-A replacement "targeted" and "voluntary?"**

**A.** TVE for ratepayers with Aldyl-A pipe is "targeted" because it directs electrification incentives to a subset of Avista's ratepayers that are more expensive to keep on gas.

TVE for ratepayers with Aldyl-A pipe is "voluntary" because ratepayers have the choice to accept a TVE allowance for high efficiency electric appliances in lieu of gas service, or continue receiving the same gas service through replacement piping.

**Q. How did you assess the potential of TVE as an alternative to systematic Aldyl-A pipe replacement?**

**A.** I examined the avoided cost potential per customer of making capital investments in TVE as an alternative to systematic AAPR. I also examined several other tradeoffs of electrifying as well, including changes to Avista's billing revenue and CPP compliance obligations. I examined some non-energy benefits as well, including changes in health, quality of life, and equity that TVE could provide.

**Q. What were the goals of your avoided cost analysis for TVE as an alternative to Aldyl-A pipe replacement?**

**A.** Although I examine TVE as an alternative to AAPR, it is important to note that it was *the Company's* obligation to adequately examine NPAs, including electrification, for its $14.2 million investment in systematic Aldyl-A replacement. As such, this opening testimony provides the potential of one NPA, TVE, to introduce net-beneficial results for Avista's ratepayers by modeling several of the largest tradeoffs. Doing so carries implications for the Company's failure to examine any NPAs itself, and perhaps impetus to promptly commence NPA analyses for systematic AAPR.

Rather than attempt to model the net efficiency and energy sector decarbonization benefits from high-efficiency building electrification, which are already widely acknowledged,[78] my analysis primarily focused on the capital investment tradeoffs and pros and cons to Avista's ratepayers of TVE as an alternative to Aldyl-A pipe replacement. Thus, the tradeoffs I examined would largely stack upon the widely acknowledged efficiency and energy sector decarbonization benefits of high efficiency building electrification.

**Q. What potential does TVE have to avoid capital costs associated with replacing Aldyl-A distribution mains and service connections?**

**A.** If all eligible ratepayers volunteered to electrify in exchange for a TVE allowance to purchase high-efficiency electric appliances, then theoretically all Aldyl-A mains could be capped and pruned, rather than replaced, in addition to the service connections as well. Drawing upon my findings in CUB/303 Garrett/ 'Aldyl-A Replacement Cost per Customer,' this results in a starting point avoided cost per

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[78] CUB/309 Garrett/ 'IEA, Net Zero by 2025' https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf at 61-62; *See* CUB/310 Garrett/ 'RMI, 8 Benefits of BE for Houses' RMI, Eight Benefits of Building Electrification for Households, Communities, and Climate' (Mar. 29, 2021) https://rmi.org/eight-benefits-of-building-electrification-for-households-communities-and-climate/.

customer of about $25.8k. This would suggest any TVE allowance the Company provided that is less than $25.8k per customer would produce a net benefit to Avista's ratepayers.

Although this provides strong initial support for an electrification program to address high AAPR costs, assuming 100% participation in a voluntary electrification program is not realistic; the $25.8k per customer starting point is more applicable to a non-voluntary targeted electrification program. Research conducted by the Lawrence Berkely National Laboratory (LBNL) suggests that incentives for high-efficiency appliance replacement in the Pacific region of the US attract about 10% customer participation.[79] It is important to note that higher incentives, especially ones that would stack upon other federal or state incentives, in addition to growing awareness of the other benefits of building electrification, could increase participation relative to what the LBNL 2021 study found. My examination considered 8, 10, and 12 percent ratepayer participation scenarios.

Partial participation creates a somewhat complex avoided cost modeling challenge: if 8-12% of ratepayers take the TVE allowance, how many sections of Aldyl-A distribution main could be capped and pruned, producing benefits of around $18.8k per customer? Only sections of distribution main that no longer serve any ratepayers could be capped and pruned. While probabilistic and/or stochastic modeling of random groupings of Avista's ratepayers accepting the TVE allowance could address this question, I did not conduct that analysis here because it requires

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[79] CUB/311 Garrett/ 'LBNL, who is participating in residential EE programs?' LBNL, Who is participating in residential energy efficiency programs?' (Nov. 2021) https://eta-publications.lbl.gov/sites/default/files/ee_program_participation.pdf at 17.

mapping Avista's Aldyl-A distribution into a model and this was beyond the scope of opening testimony for a rate case. It is important to note that as an alternative to this modeling, piloting TVE on the small subset of Avista's customers with Aldyl-A pipe could inform this knowledge gap with real, mensurable data.

The potential avoided costs of Aldyl-A service connections are much simpler to model. For each customer that accepts the TVE allowance, an Aldyl-A service connection could be capped and pruned rather than replaced, presenting a starting point avoided cost of about $6.8k per customer.

**Q. What other factors are important to weigh when considering changes to Avista's capital costs that would result from TVE?**

**A.** Many of the costs and benefits included in Table 1 would impact Avista's capital and operating costs. For instance, running a TVE program alongside Avista's AAPR Program would likely bring new administrative costs, perhaps even hiring a new employee. Pruning Aldyl-A pipe rather than replacing it could also reduce Avista's linepack capacity, or gas storage capacity in its pipes, although the Company would also have fewer customers and capacity requirements too. I was not able to assign monetary values to these factors here.

Another important consideration is what new costs capping and pruning Aldyl-A would create. Technically speaking, the removal cost of Aldyl-A ought to be contained within the depreciation revenues the Company already collected for its Aldyl-A pipe over the span of its book life. Within the depreciation expense of gas assets is a line item called "salvage value." Assets with higher decommissioning costs than their scrap value have a negative salvage value. The rising negative salvage value of gas assets was a driving factor in NW Natural's recent request for higher depreciation rates on gas assets that were already in commission.[80]

Going forward, I will continue assessing the avoided cost potential of TVE as an alternative to systematic replacement through discovery and analysis, and possibly in response to other parties testimony and discovery. At this stage, a simplifying assumption would be to assume a TVE allowance of around $6.8k, or the typical cost of a service connection replacement, to be net beneficial. This ignores any benefits from avoiding the replacement of some distribution mains, which cost $18.8k per customer and beget $61,005 investments per customer over 50 years. It also ignores the costs associated with running an additional small program and some costs associated with Avista pruning pieces of its distribution system.

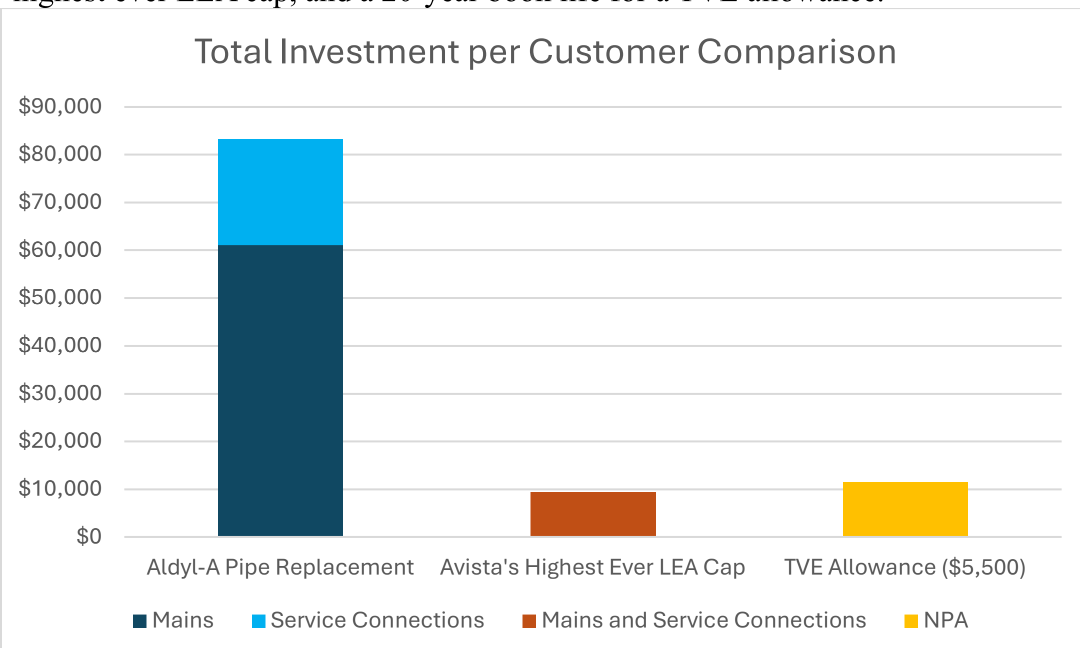
Ultimately, a more granular understanding of the anticipated capital cost tradeoffs of TVE would require more analysis from a range of experts, and ultimately, piloting TVE. This would enable designing a more robust TVE allowance cap and modeling avoided costs more precisely. The TVE cap ought to also consider changes in billing revenue to offset Avista's fixed system costs and the CPP compliance benefits of TVE, in addition to non-energy benefits that participating ratepayers would receive.

[80] *See* UG 490 *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision.* Initial Filing (Dec. 29, 2023) NW Natural/1600 Spanos/Pages 5 – 11.

**Q. Assuming a TVE allowance of $5,500 per participant, what would be the total investment cost per participant and how would this compare to Aldyl-A replacement total costs?**

**A.** Figure 8 illustrates this comparison.

**Figure 68:** shows investments in Aldyl-A pipe replacement, Avista's highest ever LEA Cap for residential customers, and a $5,500 TVE allowance. The underlying analysis assumes ~50-year book lives for Aldyl-A pipe replacement and Avista's highest ever LEA cap, and a 20-year book life for a TVE allowance.[81]



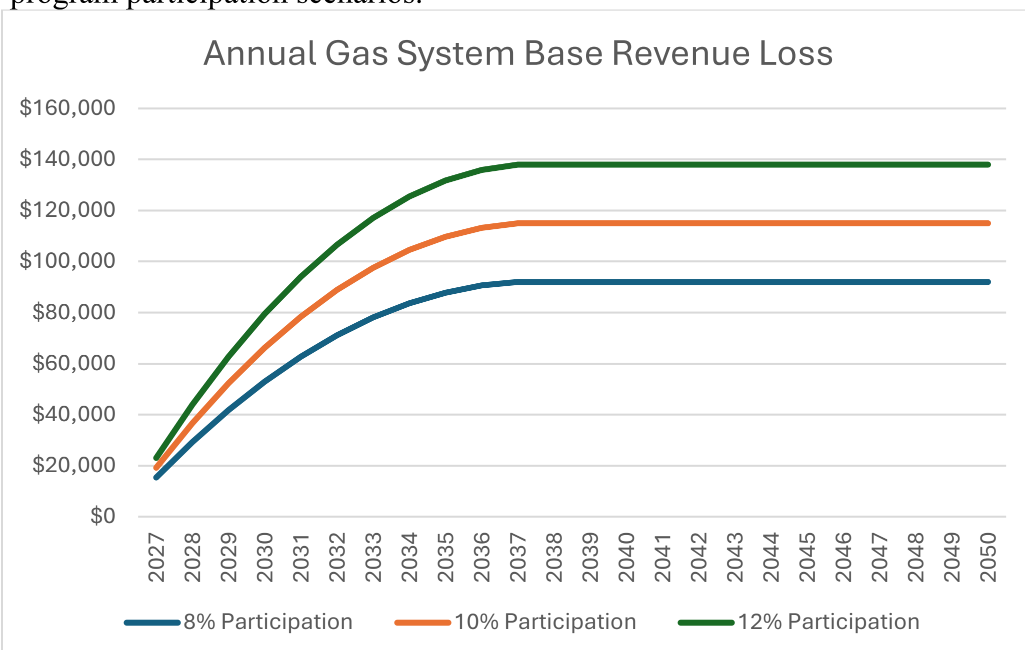

**Q. What billing revenue would you expect Avista to lose as a consequence of offering TVE as an alternative to systematic Aldyl-A replacement?**

**A.** In CUB/312 Garrett/ 'Billing Revenue Loss and CPP Benefits of TVE' I examined the billing revenue loss associated with TVE for residential ratepayers from 2027 to 2037. The analysis considers revenue losses from non-collection of the Avista's current Basic Charge and typical Base Rate per therm of residential ratepayers who

[81] CUB/304 Garrett/ 'Aldyl-A Replacement Total Cost and Stranded Investment Risk.'

take the TVE allowance. I used the Base Rate per them because the electrified ratepayers would no longer create gas fuel requirements or costs, offsetting any lost fuel revenues within their total billing rate. Figure 9 shows the annual reduction in billing revenue Avista would experience by offering TVE as an alternative to Aldyl-A replacement.

**Figure 9:** shows billing revenue loss from TVE under 8, 10, and 12 percent TVE program participation scenarios.[82]




**Q. How would TVE impact Avista's Climate Protection Program (CPP) compliance obligations?**

**A.** In CUB/312 Garrett/ 'Billing Revenue Loss and CPP Benefits of TVE' I examined the CPP compliance benefits of TVE for residential ratepayers from 2027 to 2037. The Oregon Department of Environmental Quality's (DEQ) CPP requires Avista to

[82] CUB/312 Garrett/ 'Billing Revenue Loss and CPP Benefits of TVE'

report $CO_2$ emissions, based upon its fuel deliveries, and offset any $CO_2$ emissions above its declining emissions cap.[83] Each TVE participant's gas fuel use and emissions would drop to zero and be removed from Avista's compliance obligation upon electrifying. Assuming the Company uses Community Climate Incentives (CCIs, which serve as a carbon offset instruments within the CPP[84]) and renewable natural gas (RNG) to achieve its CPP compliance obligations, and that the Company will purchase CCIs first because they are cheaper, then each TVE participant represents annual RNG purchases that the Company will not need to meet its CPP emissions compliance obligations.

To value the avoided RNG purchases, I drew upon NW Natural's ($25/dth)[85] and Staff's ($30/dth)[86] RNG price forecasts that were used in similar modeling for UG 490. In CUB/312 Garrett/ 'Billing Revenue Loss and CPP Benefits of TVE' the cost of RNG ramps up from $25/dth to $30/dth from 2027 to 2037. This is intended to account for the most cost-effective RNG feedstocks becoming saturated, leaving only more expensive options for procuring RNG, which should drive up price.

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[83] CUB/313 Garrett/ 'CPP Fact Sheet.' https://www.oregon.gov/deq/ghgp/Documents/cppOverviewFS.pdf
[84] *Id.*
[85] UG 490, *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision.* Staff/900, Dlouhy/Page 38.
[86] UG 490, *In the Matter of NORTHWEST NATURAL GAS COMPANY, dba NW NATURAL, Request for a General Rate Revision.* NW Natural/2200, Kravitz/Page 23.

**Figure 10:** shows the CPP compliance benefits of TVE under 8, 10, and 12 percent TVE program participation scenarios.[87]

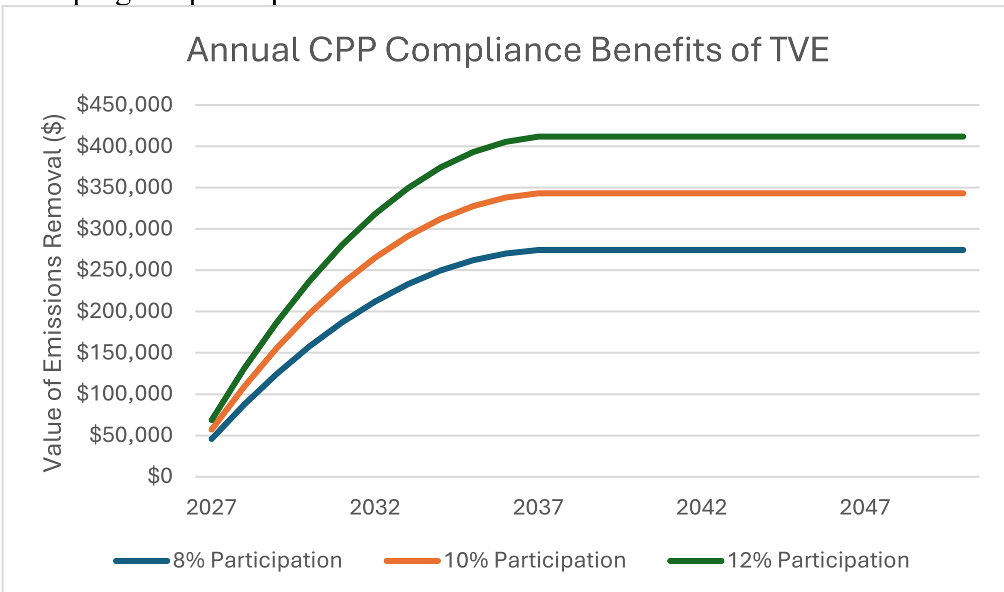


Figure 10 shows the CPP compliance benefits of TVE. Note that the CPP compliance benefits alone more than offset the billing revenue losses (compare to Figure 9) associated with TVE.

**Q. What are the "Non-Energy Impacts" of TVE?**

**A.** Avista's NPA framework obligates it to examine the non-energy impacts of NPAs,[88] so I examined several non-energy impacts of TVE here. TVE offers an opportunity to fill knowledge gaps about electrification, mitigate indoor air pollution and health risks, and meaningfully realize Oregon's Energy Equity and Environmental Justice policy goals.

***Filling Knowledge Gaps about Fuel Conversions***

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[87] CUB/312 Garrett/ 'Billing Revenue Loss and CPP Benefits of TVE'

[88] UG 461, *In the Matter of AVISTA CORPORATION, dba AVISTA UTILITIES, Request for a General Rate Revision.* Order No. 23-384, (Oct. 26, 2023) https://apps.puc.state.or.us/orders/2023ords/23-384.pdf at Appendix B, Page 15 of 27.

Given the widely acknowledged importance of high efficiency building electrification as a tool for achieving decarbonization goals[89], piloting TVE offers a timely opportunity with enormous value for Oregon energy planners. Piloting TVE on ratepayers with Aldyl-A pipe limits the size of the program, presenting a good information-gathering opportunity with limited risk of posing overlarge challenges or consequences.

***Mitigating Health Risks***

A 2024 Columbia University study examining indoor air quality changes from exchanging a gas stove for an electric induction stove found that doing so reduced indoor nitrogen dioxide ($NO_2$) pollution by 56%.[90] The study focused on low-income housing specifically.[91] Reducing exposure to indoor air pollutants such as $NO_2$ is important to human health and wellbeing. According to the US Environmental Protection Agency (EPA), "continued exposure to high $NO_2$ levels can contribute to the development of acute or chronic bronchitis" and "low level $NO_2$ exposure may cause: increased bronchial reactivity in some asthmatics, decreased lung function in patients with chronic obstructive pulmonary disease, and increased risk of respiratory infections, especially in young children."[92]

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[89]CUB/309 Garrett/ 'IEA, Net Zero by 2025' https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf at 61-62; *See* CUB/310 Garrett/ 'RMI, 8 Benefits of BE for Houses' RMI, Eight Benefits of Building Electrification for Households, Communities, and Climate' (Mar. 29, 2021) https://rmi.org/eight-benefits-of-building-electrification-for-households-communities-and-climate/.

[90] CUB/314 Garrett/ 'Findings from a gas-to-induction pilot in low-income housing in NYC' Misbath Daouda, et al., *Out of Gas, In with Justice: Findings from a gas-to-induction pilot in low-income housing in NYC*, Energy Research & Social Science, Vol. 116, 2024. https://lamont.columbia.edu/news/study-finds-switching-gas-electric-stoves-cuts-indoor-air-pollution

[91] *Id.*

[92] CUB/315/ Garrett/ 'EPA on NO2 Health Risks' US EPA, https://www.epa.gov/indoor-air-quality-iaq/nitrogen-dioxides-impact-indoor-air-quality#Health_Effects

Co-author of the stove-transition study, Annie Carforo, offered this key takeaway from the study, "People of color and low-income individuals are more likely to live in smaller, older apartments that have poor ventilation, ineffective or broken range hoods and dated appliances that leak more gas. It is crucial for environmental justice that they are not left behind in [the green energy transition]."[93]

Based on these findings, it appears that an accessible TVE program could help replace gas stoves with electric induction stoves and mitigate detrimental indoor air pollution, alleviating an environmental health hazard that is especially pertinent for low-income people.

***Equity Opportunity***

CUB has carefully considered the equity implications of fuel switching across energy utility planning dockets and we continue to here. We see *significant opportunities* for deliberate TVE program design to Oregon's Energy Equity and Environmental Justice policy goals. One possibility we considered for TVE is scaling the TVE allowances to enable more equitable participation in and benefit from the TVE program. Using Avista's Low Income Rate Assistance Program (LIRAP), Avista could identify income-qualified ratepayers and scale their TVE allowance cap according to the ratepayers' current billing assistance. A higher allowance cap for income-qualified ratepayers would unlock program participation for people that otherwise could not afford to cover any leftover electrification costs. The income-qualified TVE allowance could also be able to cover more than just an

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[93] CUB/314 Garrett/ 'Findings from a gas-to-induction pilot in low-income housing in NYC' Misbath Daouda, et al., *Out of Gas, In with Justice: Findings from a gas-to-induction pilot in low-income housing in NYC*, Energy Research & Social Science, Vol. 116, 2024. https://lamont.columbia.edu/news/study-finds-switching-gas-electric-stoves-cuts-indoor-air-pollution

electric heat pump; it could cover other appliances, such as an induction stove to replace a gas stove.

Drawing upon extant Avista equity programming like the LIRAP would promote regulatory efficiency, which is particularly important here given the shelf life of this NPA opportunity and the need to act swiftly. Ultimately though, how equity goals would be integrated into a TVE program is not a matter for CUB to consider alone, and should TVE see serious consideration and implementation, CUB is adamant that Avista's Equity Advisory Group (EAG) be meaningfully included in designing the program—along with other energy justice advocates, especially those who work directly with low income households on weatherization and energy efficiency. Another important equity consideration, *how could a TVE program be accessible and beneficial to renters and ratepayers residing in multifamily housing?* Considerations around ensuring weatherization along with appliance upgrades are crucial as well. We know that LIRAP participants on the Arrearage Management Program (AMP) are on average using 21% more energy than the average Avista schedule 410 customer, suggesting that their housing is energy inefficient.[94] Again, this would require multi-stakeholder input and intentional program adaptations.

**Q. Do you have any final remarks on TVE as an NPA for Aldyl-A Pipe Replacement?**

**A.** My analysis should not be confused with a net cost-benefit analysis across gas and electric utilities. The efficiency of electric heat pumps relative to gas furnaces is

[94] CUB/302 Garrett/ 'Avista's Responses to CUB's Discovery Requests' DR 60. Note that Avista's response to CUB DR 60 reads "121% more" instead of "21% more." CUB believes this to be a typographical error and that the correct figure is "21% more" based upon the data provided.

beyond the scope of this testimony. My analysis focused on the changes that Avista and its customers would experience as a result of TVE as an alternative to systematic AAPR specifically. My analysis examines many of the primary tradeoffs, although it lacks granularity in some areas. I would expect follow-up analysis of TVE for implementation to address these less explored areas, and probably others that PUC stakeholders with more diverse expertise could identify.

## Section VI. Does the Company's investment in systematic Aldyl-A pipe replacement without examining alternatives justify a cost disallowance?

**Q. Does the Company's investment in systematic Aldyl-A pipe replacement without examining alternatives justify a cost disallowance?**

**A.** Avista dismissed the idea of conducting an NPA analysis because the AAPR Program is related to safety, and due to this dismissal has missed an opportunity to reduce its costs. Delaying the analysis and potential implementation of NPAs poses serious risks and ramifications for residential ratepayers, as my comparison of AAPR and TVE shows. CUB shares the Commission's frustration that after talking about NPAs for several years, we have yet to see good examples of rigorous analysis of implementable alternatives to investments in gas pipelines.[95]

[95] LC 81, *In the Matter of AVISTA CORPORATION, dba AVISTA UTILITIES, 2023 Natural Gas Integrated Resource Plan*. Order No. 24-156 (May 31, 2024) https://apps.puc.state.or.us/orders/2024ords/24-156.pdf at 12.

At the same time, CUB recognizes that the NPA we are proposing would be innovative, and that the Company recently adjusted its AAPR to spread out costs over a longer period in response to COVID hardships.

CUB is therefore proposing a small disallowance of 5% of the AAPR investment costs that Avista is seeking in this case, or $710,000. This allows Avista to earn a return on 95% of its investment, but sends a message that Oregon is serious in its expectation that utilities examine NPAs. Our recommendations build upon this focus on a better future.

## Section VII. What are CUB's recommendations to the Commission?

**Q. What are CUB's recommendations to the Commission?**

**A.** Our recommendations are:

1. A 5% disallowance ($710,000) of Avista's $14.2 million investment in Aldyl-A pipe replacement.
2. Drawing upon Order 20-80-B from the Massachusetts Department of Public Utilities (DPU), clarify that "as part of future cost recovery proposals, LDCs will bear the burden of demonstrating that NPAs were adequately considered and found to be non-viable or cost prohibitive to receive full cost recovery."[96]
3. Direct the Company to examine the following, at minimum, in its AAPR NPA analysis:
    a. Targeted voluntary electrification (TVE), including but not limited to:

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[96] CUB/316 Garrett/ 'MA DPU Order 20-80-B'

i. Using its LIRAP to incorporate equity goals into a TVE program.

1. Incorporate meaningful participation from the Equity Advisory Group (EAG) and other established energy justice stakeholders to inform equity considerations for TVE.

ii. Examine possibility of coordinating with the Energy Trust of Oregon (ETO), and/or other Avista Oregon Low Income Energy Efficiency Program (AOLIEE) partners, to direct energy efficiency investments such as building weatherization to income-qualified TVE participants.

4. Direct Avista to provide an AAPR Program NPA analysis in the second IRP Update to its 2023 IRP, which the Commission directed the Company to file by May 31, 2026.[97] The Commission set this requirement when granting an extension of the due date for Avista's next full IRP to April 1, 2027.[98]

a. The Commission recently stated, "Across gas utility IRPs, we have struggled with this issue of IRPs identifying capital projects too late to avoid an expensive upgrade… we [want to] develop a discipline around NPA analysis to ensure that such analysis is conducted and available before we reach the point that there is no way to avoid a costly capital improvement."[99]

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[97] LC 81, *In the Matter of AVISTA CORPORATION, dba AVISTA UTILITIES, 2023 Natural Gas Integrated Resource Plan*. Order No. 24-254. (Jul. 29, 2024) https://apps.puc.state.or.us/orders/2024ords/24-254.pdf at 6.

[98] *Id.*

[99] LC 81, *In the Matter of AVISTA CORPORATION, dba AVISTA UTILITIES, 2023 Natural Gas Integrated Resource Plan*. Order No. 24-156 (May 31, 2024) https://apps.puc.state.or.us/orders/2024ords/24-156.pdf at 12.

b. Several factors suggest a swift analysis and potentially implementation of an NPA like TVE are achievable:

i. This testimony offers some foundational analysis for economically justifying and designing a TVE program.

ii. A TVE program could draw upon LEA tariff language and structure, in addition to Avista's LIRAP data and input from the recently formed Avista EAG.

iii. Avista already has a contractor dedicated to replacing the Aldyl-A in its service territory, and it is possible that the same contractor is equipped to do Aldyl-A capping and pruning work concurrently with minimal logistical disruptions.

5. Direct the Company to begin tracking in a cohesive database, and regularly reporting to the PUC, the installation date, dollar amount transferred to plant, FERC account, address or GPS location, and initial useful and book lives associated with investments in new gas distribution system piping, which are currently not tracked individually[100] and mixed altogether though group depreciation.

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[100] CUB/302 Garrett/ 'Avista's Responses to CUB's Discovery Requests' DR 76.

## Conclusion: How do your analysis and recommendations fit within the broader context of Oregon state and residential ratepayer advocacy goals?

**Q. How do your analysis and recommendations fit within the broader context of Oregon state and residential ratepayer advocacy goals?**

**A.** My analysis and recommendations support what is already a widely supported decarbonization strategy: building electrification with high efficiency electric appliances.[101] The TVE NPA I examined offers an opportunity to fill knowledge gaps about the utility impacts of this significant decarbonization tool, at a limited scale, and exclusively for ratepayers that are particularly expensive for Avista to keep on gas. TVE also offers continuity of energy choice for ratepayers, energy efficiency benefits, stranded gas asset risk mitigation, air conditioning for TVE participants, health benefits for TVE participants with gas stoves, new investment opportunity for Avista through TVE allowances, and notable opportunity to support ratepayer equity, all of which the status quo, replacing hazardous gas infrastructure with new gas infrastructure, does not. In these regards, my analysis and recommendations are consistent with modern goals the State of Oregon and the PUC.

My recommendations also align with initiatives in other states with decarbonization legislation. Illinois and Colorado are searching for similar

[101] CUB/309 Garrett/ 'IEA, Net Zero by 2025' https://iea.blob.core.windows.net/assets/deebef5d-0c34-4539-9d0c-10b13d840027/NetZeroby2050-ARoadmapfortheGlobalEnergySector_CORR.pdf at 61-62; *See* CUB/310 Garrett/ 'RMI, 8 Benefits of BE for Houses' RMI, Eight Benefits of Building Electrification for Households, Communities, and Climate' (Mar. 29, 2021) https://rmi.org/eight-benefits-of-building-electrification-for-households-communities-and-climate/.

opportunities to pursue NPAs where the replacement of gas infrastructure could be avoided and pilot programs, based upon the same perceived risks of long-term investments in gas infrastructure.[102][103]

While all energy planning must compete with pressing planning priorities—including maintaining safety and reliability and adapting to climate mitigation policy during unstable economic conditions— it is important to note that this opportunity to explore cost-effective, regulatorily compliant beneficial electrification has a shelf life and immediate need. Each year of delay represents an opportunity cost. If the Company is responsible for unwarranted delays, then these costs should fall on the Company, *not ratepayers*. Furthermore, since building electrification is a key component of many decarbonization strategies, from an energy utility planning perspective, we need to understand it *soon*, and implementing TVE as an alternative to systematic AAPR presents favorable circumstances to do so.

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[102] *See* CUB/317 Garrett/ 'Illinois CUB on Gas NPAs' Dorie Seavey et al., Peoples Gas: Escalating business risk in a changing energy landscape, Citizens Utility Board and Groundwork Data, (Oct. 2024) https://www.citizensutilityboard.org/wp-content/uploads/2024/09/PeoplesGasReport_Fall2024.pdf at 72-74.

[103] CUB/318 Garrett/ 'Colorado SB on Reducing the Cost of Use of Natural Gas' https://energyoffice.colorado.gov/gas-planning-pilot-communities "Colorado Senate Bill 24-1370, *Reduce Cost of Use of Natural Gas*, establishes a process for local governments in Xcel Energy gas service territory to explore neighborhood-scale clean heat projects. By using alternative heat sources — such as geothermal, thermal energy networks, or electric heat pumps — these projects will reduce reliance on the natural gas system in new construction and/or existing neighborhoods, saving residents money and lowering building greenhouse gas emissions. These neighborhood-scale clean heat projects can occur in new or existing service areas."

# WITNESS QUALIFICATION STATEMENT

**NAME:** John Garrett

**EMPLOYER:** Oregon Citizens' Utility Board

**TITLE:** Utility Analyst

**ADDRESS:**

610 SW Broadway, Suite 400
Portland, OR 97205

**EDUCATION:**

Master of Public Policy,
Oregon State University,
Corvallis, OR

BA, Molecular Biology and Geography
Colgate University,
Hamilton, NY

**EXPERIENCE:** Provided testimony on behalf of the Oregon Citizens' Utility Board for dockets UG 490 (NWN Rate Case), UE 433 (PAC Rate Case), UG 461 (Avista Rate Case) and UM 1908 (Lumen Price Plan). Provided comments on behalf of the Oregon Citizens' Utility Board for LC 81, LC 83, UE 424, UM 2033 and UM 2056. Worked as a Graduate Researcher for Oregon State University examining the socio-economic impacts of renewable energy development in Oregon. Worked as a Research Assistant for the Archbold Biological Station Agro-ecology Research Ranch examining the socio-economic impacts of conservation polices on Floridian agriculturalists.

**MEMBERSHIP:** National Association of State Utility Consumer Advocates

**AVISTA CORP.**
**RESPONSE TO REQUEST FOR INFORMATION**

| | | | |
|---|---|---|---|
| JURISDICTION: | Oregon | DATE PREPARED: | 01/02/2025 |
| CASE NO: | UG 519 | WITNESS: | Tia Benjamin |
| REQUESTER: | CUB | RESPONDER: | Kaylene Schultz |
| TYPE: | Data Request | DEPT: | Regulatory Affairs |
| REQUEST NO.: | CUB – 003 | TELEPHONE: | (509) 495-2482 |
| | | EMAIL: | Kaylene.Schultz@avistacorp.com |

**REQUEST:**

For all service connection *replacements* in the years 2018 – 2024, for Oregon residential and commercial customers, please provide the following information in an Excel table. Please use the following column headings provided in quotations in "a" – "g".

a. "Customer ID"
b. "Customer Type" – Indicate whether the customer is Residential SF (schedule 410), Residential MF (schedule 411), or Commercial (schedule 420).
c. "Previous Installation Year" – In what year was the service connection being replaced installed?
d. "Replacement Year" – In what year between 2018 – 2024 was the service connection replaced?
e. "Service Connection Length" – How long is the service connection (in feet)?
f. "Cost" – What was the total cost of the service connection replacement in USD?
g. "Aldyl-A Replacement?" – Y/N, was this service connection replaced under Avista's Aldyl-A Replacement Program?

**RESPONSE:**

The Company is the process of reviewing our records and will supplement as soon as possible. The following are some of the Expenditure Requests (ERs) we are reviewing:

ER_3001 - Replace Deteriorating Gas System
ER_3003 - Gas Replace-St&Hwy
ER_3004 - Cathodic Protection-Minor Blanket
ER_3005 - Gas Distribution Non-Revenue Blanket
ER_3006 - Overbuilt Pipe Replacement Blanket
ER_3007 - Isolated Steel Replacement
ER_3008 - Aldyl -A Pipe Replacement

**AVISTA CORP.**
**RESPONSE TO REQUEST FOR INFORMATION**

| | | | |
|---|---|---|---|
| JURISDICTION: | Oregon | DATE PREPARED: | 01/02/2025 |
| CASE NO: | UG 519 | WITNESS: | Tia Benjamin |
| REQUESTER: | CUB | RESPONDER: | Cody Lee |
| TYPE: | Data Request | DEPT: | Natural Gas Dept |
| REQUEST NO.: | CUB – 7 | TELEPHONE: | (509) 495-2129 |
| | | EMAIL: | Cody.Lee@avistacorp.com |

**REQUEST:**

When Avista (or a previous operator of Avista's current gas distribution system in Oregon) initially installed Aldyl-A pipe, what was its assumed useful life?

a. If the useful life varied according to attributes of the pipe (size, purpose, etc.) or its vintage, please provide the useful lives of the pipe for each type and vintage of Aldyl-A pipe.

**RESPONSE:**

It is unknown whether these facilities have reached their initially assumed end-of-life. Due to the age of these facilities and the lack of historical records at the time of installation, Avista is unable to determine or speculate about what the original expectations were around facility end-of-life timeframes.

**AVISTA CORP.**
**RESPONSE TO REQUEST FOR INFORMATION**

| | | | |
|---|---|---|---|
| JURISDICTION: | Oregon | DATE PREPARED: | 01/02/2025 |
| CASE NO: | UG 519 | WITNESS: | Tia Benjamin |
| REQUESTER: | CUB | RESPONDER: | Jason Boni |
| TYPE: | Data Request | DEPT: | Accounting |
| REQUEST NO.: | CUB – 008 | TELEPHONE: | (509) 495-2512 |
| | | EMAIL: | Jason.boni@avistacorp.com |

**REQUEST:**

What is the useful life of each of the assets typically included in a residential service connection, assuming it was installed in 2024?

a. Do the assets and their useful lives vary depending on whether the service connection is a new service connection for a new customer versus a replacement service connection for an existing customer? If so, please provide a narrative explanation and information regarding the differences.

**RESPONSE:**

The Company's depreciation rate for the account associated with service connections is 1.99%, which is equivalent to 50 years. New and existing service connections are included in this account, so there is no distinction between the two.

**AVISTA CORP.**
**RESPONSE TO REQUEST FOR INFORMATION**

| | | | |
|---|---|---|---|
| JURISDICTION: | Oregon | DATE PREPARED: | 01/24/2025 |
| CASE NO: | UG 519 | WITNESS: | Joe Miller |
| REQUESTER: | CUB | RESPONDER: | Jaime Majure |
| TYPE: | Data Request | DEPT: | Regulatory Affairs |
| REQUEST NO.: | CUB – 60 | TELEPHONE: | (509) 495-7839 |
| | | EMAIL: | jaime.majure@avistacorp.com |

**REQUEST:**

Please refer to Avista's response to OPUC DR 264.

a. Is the information presented in Table 2 meant to represent a closed system of accounting of customers in the AMP? In other words, are there customers enrolled in the AMP since October 2022 who can be considered "incomplete" and thus are not accounted for in this table? If so, please explain.
b. For each discount tier, please provide the number of new enrollments into the AMP, the number of cancellations for nonpayment, the number of completions due to more than 85% paid by AMP+EA, and total AMP enrollments, by month, since October 2022.
    i. Please also include how many new enrolling customers opt for Comfort Level Billing at the time of their enrollment, and how many, if any, enroll in Comfort Level Billing during their AMP.
c. For customers who "successfully" complete an AMP matching with Avista, please outline what months those customers began their AMP and what months they ended their AMP. Please also include if any of these customers missed any months which were not two consecutive months.
d. How does the average usage of AMP customers compare to residential customers in general? Does Avista have any insight into how a customer enrolling into the program affects their use?
e. For the 391 and 122 customers (last two columns in Table 2) who "successfully" completed the AMP, what internal indicators, if any, does the Company use to determine the AMP has allowed these customers to continue to stay financially afloat? What proportion of them experience disconnection in the 12 months immediately following completion? Does Avista track bill payment patterns for LIRAP customers who are both enrolled in AMP and not enrolled in AMP? Please explain.
    i. Can Avista compare bill pattern payments of those LIRAP customers enrolled in AMP, with those LIRAP customers not enrolled in AMP, by tier, across a year's time?
    ii. If Avista does not track bill payment patterns, what data would Avista utilize to look at these patterns?
f. For the 644 customers who were removed from the AMP for non-payment, please provide the count of them that experience disconnection in the first month following completion, second month following completion, … and twelfth month following completion.
g. Does Avista have any insight as to why some customers "complete" the AMP by being removed for nonpayment, and others "complete" the program in the more intended

manner? For example, why is Avista considering an AMP "completed" when it was cancelled for non-payment? CUB is curious to know if there are clear reasons why the AMP isn't working for certain customers but is for others.

**RESPONSE:**

Table No. 2, "AMP Closures/Completions by Reason", from Avista's response to OPUC DR 264 is provided again below for ease of reference.

| Discount Tier | Cancellation for Non-Payment | Less than 85% Paid by AMP | More than 85% Paid by AMP | More than 85% Paid by AMP+EA |
|---|---|---|---|---|
| **15%** | 215 | 62 | 147 | 38 |
| **25%** | 429 | 117 | 244 | 84 |
| **Total** | 644 | 179 | 391 | 122 |

a. OPUC DR 264 asks Avista to "provide the number of customers who have, since October 2022, <u>completed</u> an arrearage management program" [Emphasis added], therefore, the response provided (including Table No. 2) only includes data regarding AMPs that have been closed or completed between 10/2022-11/2024. As provided in Avista's response to OPUC DR 264, this includes AMP completion/closure due to not only having completed the 12-month payoff AMP period, but also includes arrangements completed, stopped, or cancelled for reasons such as stopped service, non-payment cancellations, customer requested, or AMP paid in full by additional energy assistance (EA). Since AMP is designed to be a twelve-month payment arrangement, customers whose arrangement is still in "active" status are not included in the table.

b. Please refer to CUB DR 60 Attachment 1. It is worth noting that Table No. 2 above is counting distinct accounts for the entire period (10/2022-11/2024), which does not consider accounts with multiple enrollments during that timeframe, while Attachment 1, in counting distinct accounts by month, may capture multiple enrollments (resulting in a higher customer count).
   i. Customers cannot be enrolled in both the AMP and Comfort Level Billing (CLB) simultaneously, as the two programs are not compatible within Avista's billing system.

c. Please refer to CUB DR 60 Attachment 1. This data shows that while customers who successfully completed the AMP without any missed months had between 340 and 395 days of active participation, there were about 48 customers enrolled in the AMP for 395 or more days. This suggests that these 48 customers had instances of non-compliance with the required payment schedule (i.e., they missed a payment, but then caught up prior to being removed from the program for missing two consecutive payments, allowing them to remain enrolled in the AMP but extending the initial 12-month repayment timeframe).

d. Please refer to CUB DR 60 Attachment 1 for both the data utilized in this response as well as an illustrative chart related to seasonal usage patterns. On average, AMP customers in Oregon use approximately 121% more energy than Schedule 410 residential customers, indicating higher energy needs. Despite this, AMP enrollment does not seem to significantly alter energy usage habits. Both AMP and non-AMP customers exhibit similar seasonal patterns, with increased energy consumption during colder months (December to February) due to heating needs, and decreased usage during warmer months (June to

August). This consistency suggests that weather conditions are the primary driver of energy consumption for both groups. The ratio of increased energy usage during colder months compared to warmer months is similar for both AMP and non-AMP customers.

e. Avista does not have any internal indicators that it tracks on a regular basis to determine if the AMP has allowed customers to "continue to stay financially afloat". As part of its Low-Income Rate Assistance Program (LIRAP) reporting process each year, however, the Company does review AMP participation history in order to identify trends such as customers that may be utilizing the AMP repeatedly. For example, since the AMP is available to customers once per program year, repeated utilization would indicate chronic accumulation of (and need to receive assistance to pay) past due balances – this trend would clearly indicate an inability to "stay financially afloat".

   Of the 513 customers noted in Table No. 2 as having successfully completed the AMP, 3 of these customers had their natural gas service disconnected within 12 months of AMP completion. All of these customers were enrolled in the Company's *My Energy Discount* (MED).

f. Of the 644 customers who did not complete the AMP due to non-payment, 155 of these customers were disconnected for non-payment one or more times in the twelve months following removal from the AMP. The following table illustrates the number of accounts disconnected in each month following AMP removal.

| Number of Months between AMP End Date and Disconnection | Number of Disconnections |
|---|---|
| **1** | 82 |
| **2** | 10 |
| **3** | 27 |
| **4** | 14 |
| **5** | 8 |
| **6** | 8 |
| **7** | 14 |
| **8** | 7 |
| **9** | 2 |
| **10** | 6 |
| **11** | 3 |
| **12** | 1 |
| **Total Disconnections** | **182** |

g. Within Avista's billing system, AMP is established as a payment arrangement service agreement with defined start and end dates. The end date is recorded when a customer discontinues service, fulfills the payment arrangement, or is removed from the program due to non-compliance with program terms. Any AMP enrollment with an end date is considered "completed," indicating the arrangement is no longer active.

Because only one program years' worth of enrollments has been completed in-full, Avista can only speculate the reasons why the AMP is successful for some customers and not others. That said, with this limited available data set, one can speculate there to be a correlation between the duration of active AMPs and the season in which they begin. For the 2022-2023 program year, customers who maintained the longest average participation timeframe typically enrolled in the AMP between April and August, when current bills are generally lower, making compliance easier to achieve.

| Enroll Month | Average Days Actively Enrolled |
|---|---|
| **Oct** | 173 |
| **Nov** | 196 |
| **Dec** | 224 |
| **Jan** | 247 |
| **Feb** | 246 |
| **Mar** | 240 |
| **Apr** | **262** |
| **May** | **260** |
| **Jun** | **280** |
| **Jul** | **270** |
| **Aug** | **259** |
| **Sep** | 239 |
| **Grand Total** | 253 |

# AVISTA CORP.
# RESPONSE TO REQUEST FOR INFORMATION

| | | | |
|---|---|---|---|
| JURISDICTION: | Oregon | DATE PREPARED: | 01/30/2025 |
| CASE NO: | UG 519 | WITNESS: | Tia Benjamin |
| REQUESTER: | CUB | RESPONDER: | Tia Benjamin/Jason Boni |
| TYPE: | Data Request | DEPT: | Regulatory Affairs |
| REQUEST NO.: | CUB – 76 | TELEPHONE: | (509) 495-2225 |
| | | EMAIL: | tia.benjamin@avistacorp.com |

**REQUEST:**

For the new pipe Avista installed to replace Aldyl-A distribution mains as part of the Aldyl-A Pipe Replacement Program in Oregon:

a. What is the useful life of the pipe?
b. What is the book life of the pipe?

**RESPONSE:**

Avista files with the Oregon Commission a request for approval of depreciation rates through a depreciation study every five years. The purpose of having a periodic depreciation study is to modify the depreciation rates as the assets in service adjust; utilities do not track assets individually, as like-assets are grouped with a rate applied. As agreed to in settlement discussions with Oregon Staff, Attachment B of Docket UM 2277 and approved by the Commission in Order No. 23-318, the Company applies a depreciation rate of 1.94% (book life of approx. 51.55 years) to assets in FERC account 376.0 for Mains and a depreciation rate of 1.99% (book life of approx. 50.25 years) to assets in FERC account 380.0 for Services.

The Company completes a depreciation study every five years, consistent with OAR 860-027-0350, and requests modifications to its depreciation rates. Avista hired Gannett Fleming, Inc. to undertake a depreciation study of its depreciable electric, natural gas, and common plant in service as of December 31, 2021.

Avista does not record a separate useful life of individual assets.

**AVISTA CORP.**
**RESPONSE TO REQUEST FOR INFORMATION**

| | | | |
|---|---|---|---|
| JURISDICTION: | Oregon | DATE PREPARED: | 01/30/2025 |
| CASE NO: | UG 519 | WITNESS: | Tia Benjamin |
| REQUESTER: | CUB | RESPONDER: | Cody Lee |
| TYPE: | Data Request | DEPT: | Gas Facilities Replacement Program |
| REQUEST NO.: | CUB – 78 | TELEPHONE: | (509) 495-2129 |
| | | EMAIL: | cody.lee@avistacorp.com |

**REQUEST:**

For the Aldyl-A Pipe Replacement Program, for each of the years 2012 – 2024, please provide the Oregon allocated:

a. Investment in plant.
b. Capital costs (such as pipes, service tees, etc)
c. Total cost, including investment in plant, any additional contracting expenses, O&M, etc.

**RESPONSE:**

Please see UG 519_NONC_AVAtoCUB_DR078R_Attach1_01302025 where the Company is providing on the "CUB 78a (capital TTP)" tab Gas Facilities Replacement Program (GRFP) related transfers to plant (investment in plant) for 2013-2024. Generally, work completed under the GFRP transfer to plant in the same month. In the program's first year (2012), work completed was placed into plant in the following year, therefore 78a (capital TTP) provides data from 2013-2024 while 78 b-c (capital spend) provides data for 2012-2024. After 2013, gas facilities installed by the GFRP transfer to plant in the given month of installation or soon thereafter.

Please see UG 519_NONC_AVAtoCUB_DR078R_Attach1_01302025 where the Company is providing on the "CUB 78 b&c (capital spend)" tab a schedule of annual capital spend including project description and expenditure category classification. In addition to the below descriptions, the project description identifies work on mains vs Service Tee Transitions Remediation (STTR) and expenditure category identifies details such as contractor, materials, in house labor, etc.

**BI_GN106 - Aldyl -A Pipe Replacement:**
At the inception of the program in 2012, this BI included the first major main pipe replacement project, prior to the creation of BI_GN214 - Aldyl A OR - Main Pipe Major Projects in 2013. In subsequent years, this BI has been used for capital costs related to Priority Services and the Company's Cross Boring program. Priority Services includes the replacement of Aldyl A service pipe 1 1/4" and greater serving Schools and Daycare Facilities that do not fall within Major Main Pipe Replacement Project areas. These projects are completed as of 2023. Cross Bore capital costs include pipe sewer camera work not related to major main projects as well as some post construction inspections of major main projects after pipe installation.

**BI_GN214 - Aldyl A OR - Main Pipe Major Projects:**
Large scale, main pipe replacement projects. To meet annual commission commitments, these projects are executed by an external contractor who is exclusively dedicated to

delivering 100% of their assigned work. Over the last 12 years, 76% of all GRFP capital costs are related to these projects.

**BI_GN215 - Aldyl A OR - STTR Major Project:**
Large scale, STTR projects. To meet annual commission commitments, these projects were executed by an external contractor who is exclusively dedicated to delivering 100% of their assigned work. These projects ran from 2013-2018.

**BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts:**
Due to the competing demands of the operational environment and workforce availability, this body of work is less predictable than major project work. This body of work will fluctuate from year to year, and as such, is expected to represent a small portion of the annual workload for the duration of the program. Minor projects have been allocated to Avista's local districts in an effort to leverage local knowledge and resources. Many of these projects are in response to municipal road projects or smaller sections of main pipe replacement that are a part of planned large-scale projects.

**BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts:**
These projects began in 2019 after substantial larger STTR projects were completed. Like minor main work, these STTR minor projects are now completed by local district offices.

Please see UG 519_NONC_AVAtoCUB_DR078R_Attach1_01302025 where the Company is providing on the "CUB 78c (O&M)" tab a schedule of the programs annual O&M costs for 2021-2024. There were no O&M program costs prior to 2021.

**AVISTA CORP.**
**RESPONSE TO REQUEST FOR INFORMATION**

| | | | |
|---|---|---|---|
| JURISDICTION: | Oregon | DATE PREPARED: | 02/14/2025 |
| CASE NO: | UG 519 | WITNESS: | Tia Benjamin |
| REQUESTER: | CUB | RESPONDER: | Kaylene Schultz |
| TYPE: | Data Request | DEPT: | Regulatory Affairs |
| REQUEST NO.: | CUB – 103 | TELEPHONE: | (509) 495-2482 |
| | | EMAIL: | Kaylene.Schultz@avistacorp.com |

**REQUEST:**

Please provide a redacted, non-confidential version of Avista's confidential, supplemental attachment response to CUB DR to Avista 3(UG 519_CONF_AVAtoCUB_DR3R_SuppAttach1 _01232025).

**RESPONSE:**

Please see CUB DR 103 Attachment 1 for a non-confidential version of CUB DR 103C Confidential Supplemental Attachment 1.

**AVISTA CORP.**
**RESPONSE TO REQUEST FOR INFORMATION**

| | | | |
|---|---|---|---|
| JURISDICTION: | Oregon | DATE PREPARED: | 02/14/2025 |
| CASE NO: | UG 519 | WITNESS: | Tia Benjamin |
| REQUESTER: | CUB | RESPONDER: | Patrick Ehrbar |
| TYPE: | Data Request | DEPT: | Regulatory Affairs |
| REQUEST NO.: | CUB – 105 | TELEPHONE: | (509) 495-8620 |
| | | EMAIL: | pat.ehrbar@avistacorp.com |

**REQUEST:**

Has Avista conducted non-pipe alternatives (NPA) analysis, as discussed in Oregon PUC Order NO. 23-384, Appendix B Page 15 of 27 (https://apps.puc.state.or.us/orders/2023ords/23-384.pdf), for its Aldyl-A Pipe Replacement Program?

**RESPONSE:**

The referenced citation is as follows:

> **Non-Pipe Alternatives (NPA):** Avista agrees to implement a NPA framework in Oregon, including the following elements.
>
> i. Upon rate-effective date, NPA analysis will be performed for supply-side resources and for distribution system reinforcements and expansion projects that exceed a threshold of $1 million for individual projects or groups of geographically related projects. If a NPA is not selected for projects that meet this criteria, Avista will include the NPA analysis as part of the justification when it seeks recovery of the resource addition or distribution system reinforcement or expansion in a rate case.
>    1. “Supply-side resources” includes but is not limited to all resources upstream of Avista’s distribution system and city gates, and supply-side contracts.
>    2. “Geographically-related projects” means a group of projects that are interdependent or interrelated.
>
> ii. For resources or projects that meet the criteria of (21)(i), Avista will include electrification as an NPA.
>
> iii. Non-Energy Impacts must be included as part of the NPA evaluation.

There are some important distinctions between what Avista agreed to in its 2023 general rate case, and the ongoing Gas Facility Replacement Program (GFRP or Aldyl-A Pipe Replacement program) developed in 2011, almost 12 years prior. This program is directly related to a natural gas system risk of natural gas pipe that is prone to premature brittle-like cracking. This initiative is part of Avista's broader effort to enhance the safety and reliability of our natural gas distribution system.

Compare that to the NPA agreement from our last general rate case. That agreement is crystal clear in that such a framework is related to “supply-side resources and for distribution system reinforcements and expansion projects”. Such projects driven by a need to serve new customers or continue to serve existing customers where capacity on the system is diminished. In those cases, an NPA might be appropriate to alleviate the demand for natural gas through other methods.

GFRP, on the other hand and as previously mentioned, is a safety related program first and foremost. That information has not only been provided in multiple prior general rate cases, but is also outlined in Avista's "Natural Gas Safety Project Plan – Oregon" filed annually with the Commission (Docket UM 1898).

With all of that stated, no, Avista has not conducted an NPA related to GFRP.

**AVISTA CORP.**
**RESPONSE TO REQUEST FOR INFORMATION**

| | | | |
|---|---|---|---|
| JURISDICTION: | Oregon | DATE PREPARED: | 02/19/2025 |
| CASE NO: | UG 519 | WITNESS: | Tia Benjamin |
| REQUESTER: | CUB | RESPONDER: | Tia Benjamin/Cody Lee |
| TYPE: | Data Request | DEPT: | Regulatory Affairs |
| REQUEST NO.: | CUB – 106 | TELEPHONE: | (509) 495-2225 |
| | | EMAIL: | tia.benjamin@avistacorp.com |

**REQUEST:**

Please provide responses for “a” or “b” (or if practicable both), depending upon what data Avista is better able to compile and provide regarding the Aldyl-A Pipe Replacement Program.

- Refer to Avista’s response to CUB DR 78a, Excel sheet “CUB 78a (Capital TTP)”, cells E1420 – P1420. Of these annual totals for the Aldyl-A Pipe Replacement Program, how much was spent on residential customers, how much was spent on commercial customers (Sch 420), and how much spent on other customers?
- How many feet of replacement pipe was installed for residential customers and how many feet of replacement pipe was installed for commercial customers (Sch 420) through the Aldyl-A Pipe Replacement Program for each of the years 2012 – 2024? CUB is willing to accept footages for distribution mains only, if focusing on these alone would ease the data collection burden on Avista.

**RESPONSE:**

The Gas Facility Replacement Program (GFRP) is focused on replacing 1-1/4" to 4" Aldyl-A pre-1987 pipe, primarily mains. [1] Natural gas main pipe serves all customers and cannot be isolated by customer type or rate schedule. The Company does not track GFRP transfers to plant by rate schedule, nor does the Company track feet of GFRP pipe replacement by rate schedule either.

As discussed in UG 519_NONC_AVAtoCUB_DR114R_02282025, the Company has completed replacements within the part of the program replacing known Priority Services, where Aldyl-A service pipe 1 1/4” and greater serving schools, hospitals, daycare facilities and elderly care facilities that do not fall within Major Main Pipe Replacement Project areas have been replaced, these projects are completed as of 2023. Additionally, please see the Company’s response to CUB DR 115 for information regarding the few customers subject to the objectives of the GFRP with Aldyl-A pipe services outside of the Priority Services portion of the program.

Alternatively, please see UG 519_NONC_AVAtoCUB_DR080R_01302025 where the Company has provided a count of residential and commercial customers served by mains with GFRP Aldyl-A pipe replacements 2013-2024.
Please note, Avista’s goal is to operate a safe, reliable, and cost-effective natural gas distribution system. “As of August 2011, the US Department of Transportation Pipeline and Hazardous

[1] As previously discussed in prior discovery responses, including UG 519_NONC_AVAtoCUB_DR078R_01302025, the Company has completed replacement of it’s Priority Services, where Aldyl-A service pipe 1 1/4” and greater serving Schools and Daycare Facilities that do not fall within Major Main Pipe Replacement Project areas have been replaced, these projects are completed as of 2023. Additionally, please see the Company’s response to CUB DR 115 for information regarding the few customers subject to the objectives of the GFRP with Aldyl-A pipe services. Natural gas main pipe serves all customers and cannot be isolated by customer type or rate schedule.

Materials Safety Administration (PHMSA) mandates gas distribution pipeline operators to implement Integrity Management Plans, or in Avista's case, a Distribution Integrity Management Plan (DIMP) in which pipeline operators are required to identify and mitigate the highest risks within their system. For Avista, aside from third party excavation damage, the highest risks within our natural gas distribution system is Aldyl-A Main Pipe (Manuf. 1964-1984), and the bending stress that occurs on Aldyl-A service pipe where it is connected to steel main pipe," as stated in the Company's Gas Facility Replacement Program (GFRP) Aldyl-A Pipe Replacement Business Case on p. 102 of Company witness Ms. Benjamin's Exhibit 602.

The Company's systematic replacement program (GFRP) was designed and implemented with an optimum timeframe to prudently manage risk, based on highest risks/threats in the natural gas distribution system that have been identified by Avista's DIMP, as well as rate impact to customers. Deferring or terminating the body of work associated with the Company's GFRP would expose Avista to increased operational risks, decreased system reliability, potential harm to the public through damage of life and property, as well as heightened regulatory scrutiny from increasing failures. The Aldyl-A pipe will eventually reach a level of unreliability that is not acceptable due to the tendency for this material to suffer brittle-like cracking leak failures.

**AVISTA CORP.**
**RESPONSE TO REQUEST FOR INFORMATION**

| | | | |
|---|---|---|---|
| JURISDICTION: | Oregon | DATE PREPARED: | 02/19/2025 |
| CASE NO: | UG 519 | WITNESS: | Tia Benjamin |
| REQUESTER: | CUB | RESPONDER: | Cody Lee |
| TYPE: | Data Request | DEPT: | GFRP |
| REQUEST NO.: | CUB – 107 | TELEPHONE: | (509) 495-2129 |
| | | EMAIL: | cody.lee@avistacorp.com |

**REQUEST:**

For the distribution mains replaced through the Aldyl-A Pipe Replacement Program for each of the years 2020 – 2024, what was the average number of residential and average number of commercial customers (Sch 420) per distribution main replaced?

**RESPONSE:**

Please see the Company's response to CUB DR 80, which includes a table for years 2013-2024 (years 2020-2024 re-depicted below for ease of reference) with the number of Avista residential customers on Rate Schedules 410 and 411 and commercial customers on Rate Schedule 420, as well as the number of residential and commercial tees replaced as a result of the Gas Facilities Replacement Program (Aldyl-A pipe replacement). The "# of Residential Customers" and the "# of Commercial Customers" represents customers who had distribution mains serving them replaced.

The average annual number of residential and commercial customers from 2020-2024 who had distribution mains serving them replaced were 338 and 35, respectively, as shown in the table below.

| Year | # of Residential Customers | # of Residential Tees | # of Commercial Customers | # of Commercial Tees |
|---|---|---|---|---|
| 2020 | 364 | 338 | 24 | 24 |
| 2021 | 314 | 298 | 60 | 53 |
| 2022 | 348 | 297 | 32 | 31 |
| 2023 | 362 | 340 | 42 | 37 |
| 2024 | 304 | 274 | 18 | 16 |
| **TOTAL** | **1,692** | **1,547** | **176** | **161** |
| **AVERAGE** | 338 | | 35 | |

**AVISTA CORP.**
**RESPONSE TO REQUEST FOR INFORMATION**

| | | | |
|---|---|---|---|
| JURISDICTION: | Oregon | DATE PREPARED: | 02/28/2025 |
| CASE NO: | UG 519 | WITNESS: | Tia Benjamin |
| REQUESTER: | CUB | RESPONDER: | Tia Benjamin/Cody Lee |
| TYPE: | Data Request | DEPT: | Regulatory Affairs |
| REQUEST NO.: | CUB – 115 | TELEPHONE: | (509) 495-2225 |
| | | EMAIL: | tia.benjamin@avistacorp.com |

**REQUEST:**

For each of the following customer groupings, how many ratepayers have service connections with Aldyl-A pipe?

a. Residential
b. Commercial (Sch 420)
c. All other ratepayers

**RESPONSE:**

The number of customers who have Aldyl-A service lines that are 1-1/4" to 4" Aldyl-A to be replaced by the Gas Facility Replacement Program (GFRP) are:

a. 5 – Residential
b. 79 – Commercial (Sch 420)
c. 1 – All other ratepayers

Data Source: Avista's Response to CUB DR to Avista 103

## SERVICE REPLACEMENTS FOR THE YEAR 2024:

| Year | Average Cost per Replacement | | |
|---|---|---|---|
| 2024 | $8,500.90 | | |
| 2023 | $7,436.34 | | |
| 2022 | $8,643.88 | 3-yr Past Avg | 8,193.71 |
| 2021 | $4,186.99 | | |
| 2020 | $5,399.21 | 5-yr Past Avg | 6,833.46 |
| 2019 | $5,059.28 | | |
| 2018 | $4,473.40 | 7-yr Past Avg | 6,242.86 |

| ID NUMBER | CITY | PIPE SIZE | PIPE LENGTH | INVOICE DATE | INVOICE TOTAL | COMMENTS |
|---|---|---|---|---|---|---|
| 15244549 | MED | 3/4 | 7 | 10/28/2024 | 7161.3 | REPLACEMENT |
| 15244651 | GPS | 3/4 | 29 | 11/12/2024 | 2745.84 | REPLACEMENT |
| 15244482R1 | GPS | 3/4 | 47 | 10/22/2024 | 2787.03 | REPLACEMENT |
| 15244081 | CPT | 3/4 | 131 | 9/3/2024 | 8485.87 | REPLACEMENT |
| 15244079 | CPT | 3/4 | 38 | 9/3/2024 | 5087.69 | REPLACEMENT |
| 15244271 | MED | 3/4 | 35 | 9/19/2024 | 10618.04 | REPLACEMENT |
| 15244227 | MED | 3/4 | 245 | 9/17/2024 | 19442.41 | REPLACEMENT |
| 15243559 | MED | 3/4 | 60 | 6/26/2024 | 6948.32 | REPLACEMENT |
| 15243560 | MED | 3/4 | 114 | 6/26/2024 | 6453.86 | REPLACEMENT |
| 15243639 | GPS | 3/4 | 50 | 7/8/2024 | 9575.27 | REPLACEMENT |
| 15243347 | MED | 3/4 | 140 | 5/31/2024 | 7323.01 | REPLACEMENT |
| 15243534 | GPS | 3/4 | 218 | 6/25/2024 | 3929.72 | REPLACEMENT |
| 15242853 | MED | 3/4 | 105 | 4/10/2024 | 5187.63 | REPLACEMENT |
| 15242935 | MED | 3/4 | 208 | 4/19/2024 | 11962.56 | REPLACEMENT |
| 15242973 | MED | 3/4 | 112 | 4/24/2024 | 1661.4 | REPLACEMENT |
| 15243184 | GPS | 3/4 | 80 | 5/13/2024 | 22111.2 | REPLACEMENT |
| 15243147 | GPS | 3/4 | 48 | 5/8/2024 | 2692.54 | REPLACEMENT |
| 15242732 | GPS | 3/4 | 2 | 3/27/2024 | 6619.61 | REPLACEMENT |
| 15242741 | MED | 3/4 | 140 | 3/28/2024 | 5566.47 | REPLACEMENT |
| 15242878 | GPS | 3/4 | 274 | 4/15/2024 | 5858.79 | REPLACEMENT |
| 15242884 | GPS | 3/4 | 75 | 4/15/2024 | 5965 | REPLACEMENT |
| 15242882 | GPS | 3/4 | 89 | 4/15/2024 | 8603.16 | REPLACEMENT |
| 15242834 | MED | 3/4 | 55 | 4/10/2024 | 3902.42 | REPLACEMENT |
| 15242936 | MED | 3/4 | 120 | 4/19/2024 | 7939.39 | REPLACEMENT |
| 15242223 | GPS | 3/4 | 239 | 1/31/2024 | 13694.53 | REPLACEMENT W 775 FV |
| 15242325 | MED | 3/4 | 82 | 2/9/2024 | 3465.85 | REPLACEMENT |
| 15242432 | MED | 3/4 | 32 | 2/22/2024 | 6798.87 | REPLACEMENT |
| 15242470 | MED | 3/4 | 75 | 2/28/2024 | 3036.53 | REPLACEMENT |
| 15242443 | MED | 3/4 | 32 | 2/23/2024 | 15037.29 | REPLACEMENT |
| 15242544 | GPS | 3/4 | 57 | 3/5/2024 | 2949.65 | REPLACEMENT |
| 15242545 | GPS | 3/4 | 53 | 3/5/2024 | 2111.37 | REPLACEMENT |
| 15242542 | GPS | 3/4 | 55 | 3/4/2024 | 2206.15 | REPLACEMENT |
| 15242096 | MED | 3/4 | 110 | 1/14/2024 | 5435.08 | REPLACEMENT |
| 15242106 | MED | 3/4 | 70 | 1/18/2024 | 2980.13 | REPLACEMENT |
| 15242166 | MED | 3/4 | 32 | 1/29/2024 | 5448.97 | REPLACEMENT |
| 15242185 | MED | 3/4 | 45 | 1/30/2024 | 3366.22 | REPLACEMENT |
| 15242097 | MED | 3/4 | 93 | 1/17/2024 | 17037.21 | REPLACEMENT |
| 15242262 | MED | 3/4 | 82 | 2/5/2024 | 5471.91 | REPLACEMENT |
| 15242259 | MED | 3/4 | 110 | 2/5/2024 | 6364.73 | REPLACEMENT |
| 15242245 | MED | 3/4 | 80 | 2/2/2024 | 7859.41 | REPLACEMENT |
| 14239030 | MED | 3/4 | 112 | 1/5/2024 | 5114.7 | REPLACEMENT |
| 14239028 | MED | 3/4 | 84 | 1/4/2024 | 4098.17 | REPLACEMENT |
| 15242274 | GPS | 3/4 | 37 | 2/6/2024 | 4475 | REPLACEMENT |
| 15242267 | MED | 3/4 | 114 | 2/5/2024 | 8080.83 | REPLACEMENT |
| 14238965 | MED | 3/4 | 57 | 12/29/2024 | 4343.08 | REPLACEMENT |
| 14238959 | MED | 3/4 | 95 | 12/29/2024 | 8089.95 | REPLACEMENT |
| 14238967 | GPS | 3/4 | 98 | 12/29/2024 | 17054.07 | REPLACEMENT |
| 14239007 | MED | 3/4 | 35 | 1/3/2024 | 1911.5 | REPLACEMENT |
| 14238937 | MED | 3/4 | 89 | 12/27/2024 | 4905.4 | REPLACEMENT |
| 14238979 | GPS | 3/4 | 102 | 1/2/2024 | 7576.16 | REPLACEMENT |
| 14238971 | MED | 3/4 | 56 | 12/29/2024 | 4694.5 | REPLACEMENT |
| 14238798 | GPS | 3/4 | 24 | 12/12/2024 | 12,153.87 | ISO REPLACEMENT |
| 14239026 | MED | 3/4 | 80 | 1/4/2024 | 4,796.34 | ISO REPLACEMENT |
| 15242195 | MED | 3/4 | 107 | 1/30/2024 | 5,832.53 | REPLACED SHALLOW SERVICE |
| 15242130 | MED | 3/4 | 57 | 1/23/2024 | 7,015.45 | REPLACED SHALLOW SERVICE |
| 15242687 | MED | 3/4 | 84 | 3/22/2024 | 18,641.77 | ISO REPLACEMENT |
| 15242538 | MED | 3/4 | 50 | 3/5/2024 | 3,376.07 | SHALLOW SERVICE |
| 15242467 | MED | 3/4 | 110 | 2/28/2024 | 72,967.11 | ISO REPLACEMENT |
| 15242471 | GPS | 3/4 | 26 | 2/28/2024 | 1,732.92 | ISO REPLACEMENT |
| 15242469 | GPS | 3/4 | 88 | 2/28/2024 | 3,734.04 | ISO REPLACEMENT |
| 15242430 | GPS | 3/4 | 41 | 2/22/2024 | 2,111.37 | ISO REPLACEMENT |
| 15242429 | GPS | 3/4 | 17 | 2/22/2024 | 1,930.16 | ISO REPLACEMENT |
| 15242225 | GPS | 3/4 | 134 | 1/31/2024 | 5,266.22 | SHALLOW SERVICE |
| 15242433 | GPS | 3/4 | 98 | 2/22/2024 | 7,956.67 | SHALLOW SERVICE |
| 15242938 | MED | 3/4 | 100 | 4/19/2024 | 5,411.00 | ISO REPLACEMENT |
| 15242937 | MED | 3/4 | 32 | 4/19/2024 | 2,569.19 | ISO REPLACEMENT |
| 15242841 | MED | 3/4 | 98 | 4/10/2024 | 4,357.91 | ISO REPLACEMENT |
| 15242961 | GPS | 2 | 45 | 4/24/2024 | 31,844.42 | ISO REPLACEMENT |
| 15242859 | MED | 3/4 | 100 | 4/10/2024 | 16,979.20 | ISO REPLACEMENT |
| 15242966 | GPS | 3/4 | 101 | 4/24/2024 | 5,387.67 | ISO REPLACEMENT |
| 15242754 | MED | 3/4 | 120 | 3/29/2024 | 9,371.70 | ISO REPLACEMENT |
| 15242583 | GPS | 3/4 | 109 | 3/11/2024 | 4,173.23 | ISO REPLACEMENT |
| 15242662 | GPS | 3/4 | 93 | 3/18/2024 | 3,377.18 | ISO REPLACEMENT |
| 15242661 | GPS | 3/4 | 11 | 3/18/2024 | 2,362.96 | ISO REPLACEMENT |
| 15242579 | GPS | 3/4 | 35 | 3/11/2024 | 2,914.35 | ISO REPLACEMENT |
| 15242582 | GPS | 3/4 | 98 | 3/11/2024 | 3,549.48 | ISO REPLACEMENT |
| 15242584 | GPS | 3/4 | 109 | 3/11/2024 | 3,054.35 | REPLACE SHALLOW SERVICE |
| 15242681 | GPS | 3/4 | 75 | 3/20/2024 | 19,509.19 | REPLACED SHALLOW SERVICE |
| 15242898 | MED | 3/4 | 24 | 4/16/2024 | 5,038.72 | ISO REPLACEMENT |
| 15242994 | MED | 3/4 | 861 | 4/25/2024 | 4,353.81 | ISO REPLACEMENT |
| 15242995 | MED | 3/4 | 52 | 4/25/2024 | 4,654.12 | ISO REPLACEMENT |
| 15243345 | MED | 3/4 | 211 | 5/31/2024 | 25,504.14 | ISO REPLACEMENT |
| 15243344 | MED | 2 | 5 | 5/31/2024 | 37,379.20 | ISO REPLACEMENT & VALVE |
| 15244168 | GPS | 3/4 | 87 | 9/12/2024 | 16,233.60 | ISO REPLACEMENT |
| 15244484 | GPS | 3/4 | 168 | 10/22/2024 | 7,897.73 | SHALLOW SVC REPLACEMENT |
| 15242021 | MED | 3/4 | 91 | 1/8/2024 | 6903.42 | REPLACEMENT |
| | | | | | | |
| **TOTAL YEARLY SERVICE REPLACEMENTS= 85** | | | | **TOTAL $ =** | **722,576.88** | |

## SERVICE REPLACEMENTS FOR THE YEAR 2023:

| ID NUMBER | CITY | PIPE SIZE | PIPE LENGTH | INVOICE DATE | INVOICE TOTAL | COMMENTS |
|---|---|---|---|---|---|---|
| 14238567 | GPS | 3/4 | 98 | 11.14.23 | 5,583.18 | REPLACEMENT |
| 14238706 | MED | 3/4 | 55 | 11.30.23 | 4,460.23 | REPLACEMENT |
| 14238398 | GPS | 3/4 | 2 | 10.27.23 | 5,109.79 | REPLACEMENT |
| 1426358 | GPS | 3/4 | 93 | 10.27.23 | 3,557.07 | REPLACEMENT |
| 14238387 | MED | 3/4 | 66 | 10.26.23 | 12069.5 | REPLACEMENT |
| 1426090 | ASH | 3/4 | 90 | 9.26.23 | 8301.6 | REPLACEMENT |
| 1426041 | ASH | 3/4 | 18 | 9.21.23 | 3643.69 | REPLACEMENT |
| 1425946 | MED | 3/4 | 104 | 9.15.23 | 6214.56 | REPLACEMENT |
| 1426212R1 | MED | 3/4 | 70 | 10.4.23 | 5904.88 | REPLACEMENT |
| 1426244 | GPS | 3/4 | 68 | 10.5.23 | 5519.96 | REPLACEMENT |
| 1426207 | GPS | 3/4 | 127 | 10.3.23 | 8478.45 | REPLACEMENT |
| 1426240 | GPS | 3/4 | 145 | 10.5.23 | 7844.22 | REPLACEMENT |
| 1425789 | ASH | 3/4 | 140 | 8.31.23 | 8,297.70 | REPLACEMENT |
| 1425763 | ASH | 3/4 | 140 | 8.30.23 | 8,301.62 | REPLACEMENT |
| 1425788 | ASH | 3/4 | 57 | 8.31.23 | 3,227.21 | REPLACEMENT |
| 1425940 | ASH | 3/4 | 80 | 9.15.23 | 5180.79 | REPLACED S SERVICE |
| 1425812 | GPS | 3/4 | 60 | 8.31.23 | 13043.35 | REPLACEMENT |
| 1425939 | PNX | 3/4 | 80 | 9.15.23 | 7238.44 | REPLACEMENT |
| 1425615 | ASH | 3/4 | 38 | 8.15.23 | 4564.39 | REPLACEMENT |
| 1425557 | GPS | 3/4 | 38 | 8.9.23 | 7121.3 | REPLACEMENT |
| 1425624 | ASH | 3/4 | 12 | 8.16.23 | 2857.84 | REPLACEMENT |
| 1425495 | ASH | 3/4 | 19 | 8.1.23 | 11979.39 | REPLACEMENT |
| 1425524 | RRV | 2 | 150 | 8.3.23 | 11080.71 | REPLACEMENT |
| 1425461 | ASH | 2 | 11 | 7.28.23 | 147.91 | REPLACEMENT |
| 1425357 | ASH | 3/4 | 4 | 7.19.23 | 3416.4 | REPLACEMENT |
| 1425096 | GPS | 3/4 | 48 | 6.23.23 | 2828.64 | REPLACEMENT |
| 1425165 | GPS | 3/4 | 69 | 6.29.23 | 2985.62 | REPLACEMENT |
| 1424665 | ASH | 3/4 | 50 | 5.18.23 | 4776.79 | REPLACEMENT |
| 1424664 | ASH | 3/4 | 71 | 5.18.23 | 4872.28 | REPLACEMENT |
| 1424721 | GPS | 3/4 | 37 | 5.23.23 | 2955.1 | REPLACEMENT |
| 1424770 | MED | 3/4 | 60 | 5.24.23 | 4231.9 | REPLACEMENT |
| 1424769 | MED | 3/4 | 90 | 5.24.23 | 6219.29 | REPLACEMENT |
| 1424768 | MED | 3/4 | 180 | 5.24.23 | 8273.85 | REPLACEMENT |
| 1424835 | ASH | 1/2 | 1 | 6.2.23 | 2912.1 | REPLACEMENT |
| 1424809 | MED | 3/4 | 75 | 5.31.23 | 4948.36 | REPLACEMENT |
| 1424931 | ASH | 3/4 | 20 | 6.8.23 | 3684.23 | REPLACEMENT |
| 1425011 | ASH | 3/4 | 65 | 6.14.23 | 3492.75 | REPLACEMENT |
| 1425013 | ASH | 3/4 | 60 | 6.14.23 | 2687.46 | REPLACEMENT |
| 1424234 | GPS | 3/4 | 18 | 4.13.23 | 16211.04 | REPLACEMENT |
| 1424172 | ASH | 3/4 | 44 | 4.7.23 | 4809.25 | REPLACEMENT |
| 1424176 | ASH | 3/4 | 80 | 4.7.23 | 6355.88 | REPLACEMENT |
| 1424391 | ASH | 3/4 | 33 | 4.26.23 | 5071.07 | REPLACEMENT |
| 1424382 | MED | 3/4 | 15 | 4.25.23 | 1656.8 | REPLACEMENT |
| 1424385 | MED | 3/4 | 100 | 4.25.23 | 4532.19 | REPLACEMENT |
| 1424513 | ASH | 3/4 | 142 | 5.4.23 | 12219.64 | REPLACEMENT |
| 1424159 | MED | 3/4 | 80 | 4.6.23 | 5,417.05 | REPLACEMENT |
| 1424160 | ASH | 3/4 | 65 | 4.6.23 | 5,814.73 | REPLACEMENT |
| 1424162 | MED | 3/4 | 30 | 4.6.23 | 4,497.77 | REPLACEMENT |
| 1424157 | GPS | 3/4 | 64 | 4.6.23 | 4,372.30 | REPLACEMENT |
| 1424065 | GDH | 3/4 | 244 | 3.31.23 | 9,037.26 | REPLACED STEEL SERVICE |
| 1424060 | GPS | 3/4 | 145 | 3.31.23 | 6,843.37 | REPLACEMENT |
| 1424011 | MED | 3/4 | 70 | 3.28.23 | 4,018.32 | REPLACED STEEL SERVICE |
| 1424003 | MED | 3/4 | 27 | 3.28.23 | 5,440.15 | REPLACEMENT |
| 1423995 | MED | 3/4 | 30 | 3.28.23 | 3,321.54 | REPLACEMENT |
| 1423990 | ASH | 3/4 | 154 | 3.28.23 | 8,463.59 | REPLACEMENT |
| 1423991 | MED | 3/4 | 90 | 3.28.23 | 6,338.82 | REPLACEMENT |
| 1423953 | MED | 3/4 | 24 | 3.24.23 | 3,613.12 | REPLACEMENT |
| 1423954 | JVL | 3/4 | 50 | 3.24.23 | 5,585.40 | REPLACEMENT |
| 1423956 | GPS | 3/4 | 85 | 3.24.23 | 7,867.50 | REPLACEMENT |
| 1423953 | MED | 3/4 | 24 | 3.24.23 | 3,613.12 | REPLACEMENT |
| 1423954 | JVL | 3/4 | 50 | 3.24.23 | 5,585.40 | REPLACEMENT |
| 1423947 | MED | 3/4 | 52 | 3.23.23 | 2,302.02 | REPLACEMENT |
| 1423858 | MED | 3/4 | 40 | 3.16.23 | 2,955.26 | REPLACEMENT |
| 1423863 | MED | 3/4 | 75 | 3.16.23 | 4,215.47 | REPLACEMENT |
| 1423843 | GPS | 3/4 | 124 | 3.16.23 | 6,837.12 | REPLACEMENT |
| 1423847 | GPS | 3/4 | 110 | 3.16.23 | 6,638.97 | REPLACEMENT |
| 1423849 | MED | 3/4 | 51 | 3.16.23 | 1,624.60 | REPLACEMENT |

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|---|---|---|---|---|---|---|
| 1423846 | GDH | 3/4 | 156 | 03.16.23 | 22,243.09 | REPLACEMENT |
| 1423790 | GPS | 3/4 | 74 | 03.10.23 | 3,602.81 | REPLACED STEEL SERVICE |
| 1423710 | MED | 3/4 | 115 | 03.02.23 | 3,869.14 | REPLACED STEEL SERVICE |
| 1423712 | MED | 3/4 | 100 | 03.02.23 | 3,468.19 | REPLACED STEEL SERVICE |
| 1423714 | TAL | 3/4 | 43 | 03.02.23 | 6,505.72 | REPLACED STEEL SERVICE |
| 1423675 | GPS | 3/4 | 56 | 02.22.23 | 4139.24 | REPLACED STEEL SERVICE |
| 1423678 | GPS | 3/4 | 235 | 02.22.23 | 14257.85 | REPLACED STEEL SERVICE |
| 1423653 | MED | 3/4 | 100 | 02.21.23 | 6,237.97 | REPLACED STEEL SERVICE |
| 1423649 | MED | 3/4 | 96 | 02.21.23 | 4,989.27 | REPLACED STEEL SERVICE |
| 1423617 | MED | 3/4 | 63 | 02.16.23 | 3,227.69 | REPLACEMENT |
| 1423555 | GPS | 3/4 | 91 | 02.09.23 | 5,348.52 | REPLACEMENT |
| 1423587 | GPS | 3/4 | 91 | 02.14.23 | 26,574.10 | REPLACEMENT |
| 1423588 | GPS | 3/4 | 14 | 02.14.23 | 5,302.02 | REPLACEMENT |
| 1423540 | MED | 3/4 | 75 | 02.08.23 | 4,464.37 | REPLACEMENT |
| 1423453 | MED | 3/4 | 95 | 01.01.23 | 4,366.67 | REPLACEMENT |
| 1423481 | MED | 3/4 | 50 | 02.02.23 | 2,448.96 | REPLACEMENT |
| 1423599 | MED | 3/4 | 105 | 02.15.23 | 14,663.48 | REPLACEMENT |
| 1423595 | ASH | 3/4 | 67 | 02.14.23 | 5,153.79 | REPLACEMENT |
| 1423387 | MED | 3/4 | 83 | 01.24.23 | 5,007.05 | REPLACED STEEL SERVICE |
| 1423232 | MED | 3/4 | 67 | 01.05.23 | 7,233.15 | REPLACED STEEL SERVICE |
| 1423234 | MED | 3/4 | 48 | 01.05.23 | 9,213.34 | REPLACEMENT |
| 1423330 | MED | 3/4 | 80 | 01.18.23 | 6,002.93 | REPLACED STEEL SERVCE |
| 1423473 | GOL | 3/4 | 20 | 2.2.23 | 2,028.00 | REPLACEMENT |
| 1423735 | MED | 3/4 | 101 | 11.23.22 | 6,883.55 | REPLACED STEEL SERVICE |
| 1423138R1 | MED | 3/4 | 62 | 12.29.22 | 5,372.91 | REPLACEMENT |
| 1423296 | CPT | 3/4 | 185 | 01.12.23 | 4,340.71 | REPLACEDS SERVICE |
| 1423195 | ASH | 3/4 | 32 | 12.29.22 | 1,956.16 | REPLACEMENT |
| 1423196 | ASH | 3/4 | 35 | 12.29.22 | 1,975.18 | REPLACEMENT |
| 1423219 | MED | 3/4 | 464 | 01.04.23 | 2,406.22 | REPLACEMENT |
| 1423222 | ASH | 3/4 | 131 | 01.04.23 | 3,668.40 | REPLACED STEEL SERVICE |
| 1423223 | PNX | 3/4 | 22 | 01.04.23 | 4,111.12 | REPLACEMENT |
| 1423228 | CPT | 3/4 | 41 | 01.05.23 | 5,157.71 | REPLACED STEEL SERVICE |
| 1423233 | CPT | 3/4 | 50 | 01.05.23 | 3,671.46 | REPLACEMENT |
| 1423248 | MED | 3/4 | 60 | 01.06.23 | 11,147.10 | REPLACEMENT |
| 1423050 | GPS | 3/4 | 8 | 12.16.22 | 1,556.40 | REPLACEMENT |
| 1422997 | PNX | 3/4 | 92 | 12.13.22 | 3,621.80 | REPLACED STEEL SERVICE |
| 1422884 | MED | 3/4 | 82 | 12.05.22 | 4,632.61 | REPLACED STEEL SERVICE |
| 1422691 | MED | 3/4 | 112 | 11.18.22 | 14,431.37 | REPLACED STEEL SERVICE |
| 1424043 | GPS | 3/4 | 131 | 3.30.23 | 10259.21 | ISO REPLACEMENT |
| 1424300 | GPS | 3/4 | 99 | 4.20.23 | 6951.6 | REPLACED SHALLOW SERVICE |
| 1424723 | GPS | 3/4 | 30 | 5.23.23 | 7298.48 | REPLACED SHALLOW SERVICE |
| 14238528 | MED | 3/4 | 111 | 11.9.23 | 5,424.70 | ISO REPLACEMENT |
| 1426347 | MED | 3/4 | 62 | 10.19.23 | 14,937.12 | ISO REPALCEMENT |
| 14238393 | MED | 3/4 | 114 | 10.26.23 | 11,618.27 | ISO REPLACEMENT |
| 1426353 | WTC | 3/4 | 111 | 10.24.23 | 6,064.02 | SHALLOW SERVICE |
| 14238708 | GPS | 3/4 | 12 | 11.30.23 | 1,652.10 | SHALLOW SERVICE REPLACEMENT |
| 14238710 | GPS | 3/4 | 90 | 11.30.23 | 13,695.76 | REPLACEMENT ISO |
| | | | | | | |
| **TOTAL YEARLY SERVICE REPLACEMENTS= 95** | | | | **TOTAL $ =** | **706,452.61** | |

## SERVICE REPLACEMENTS FOR THE YEAR 2022:

| ID NUMBER | CITY | PIPE SIZE | PIPE LENGTH | INVOICE DATE | INVOICE TOTAL | COMMENTS |
|---|---|---|---|---|---|---|
| 1418206 | ASH | 3/4 | 54 | 10.15.21 | 2,627.01 | REPLACED S SVSC |
| 1418744 | MED | 3/4 | 7 | 12.13.21 | 4,846.02 | REPLACEMENT |
| 1418808 | GPS | 3/4 | 184 | 12.21.21 | 9,721.94 | REPLACED S SVC |
| 1418862 | CPT | 3/4 | 184 | 12.27.21 | 5,299.99 | REPLACEMENT |
| 1418883 | ROG | 3/4 | 101 | 12.28.21 | 9,479.03 | REPLACED S SVC |
| 1418896 | MED | 3/4 | 73 | 12.29.21 | 2,939.12 | REPLACED S SVC |
| 1418959 | GPS | 3/4 | 212 | 01.04.22 | 2,273.27 | REPLACED S SVC |
| 1418967 | GPS | 3/4 | 90 | 01.05.22 | 2,870.83 | REPLACED S SVC |
| 1418989 | GPS | 3/4 | 12 | 01.07.22 | 6,296.13 | REPLACED S SVC |
| 1517479 | ASH | 3/4 | 190 | 08.06.21 | 8,309.30 | REPLACED S SVC |
| 1517481 | MED | 3/4 | 26 | 08.06.21 | 2,822.37 | REPLACED S SVC |
| 1418886R1 | GPS | 3/4 | 40 | 12.29.21 | 8,449.60 | REPLACED S SVC |
| 1418956 | GPS | 3/4 | 46 | 01.04.22 | 9,481.32 | REPLACED S SVC |
| 1419001 | TAL | 3/4 | 95 | 01.07.22 | 2,438.35 | REPLACEMENT |
| 1419016 | GPS | 3/4 | 42 | 01.11.22 | 2,845.00 | REPLACEMENT |
| 1419049 | ASH | 3/4 | 87 | 01.13.22 | 5,366.16 | REPLACEMENT |
| 1419212 | GPS | 3/4 | 34 | 02.01.22 | 2,346.29 | REPLACED S SVC |
| 1419242 | GPS | 3/4 | 15 | 02.02.22 | 1,251.50 | REPLACEMENT |
| 1419243 | GPS | 3/4 | 173 | 02.02.22 | 6,634.75 | REPLACEMENT |
| 1419245 | GPS | 3/4 | 16 | 02.02.22 | 2,166.98 | REPLACEMENT |
| 1419248 | GPS | 3/4 | 8 | 02.02.22 | 5,224.20 | REPLACED S SVC |
| 1419329 | GPS | 3/4 | 21 | 02.09.22 | 5,429.52 | REPLACED S SVC |
| 1418961R4 | ROG | 3/4 | 100 | 01.06.22 | 8,599.11 | REPLACED S SVC |
| 1419012R1 | GPS | 3/4 | 214 | 01.11.22 | 3,279.37 | REPLACED S SVC |
| 1419103R1 | GPS | 3/4 | 212 | 01.20.22 | 10,881.37 | REPLACED S SVC |
| 1419184R1 | GPS | 3/4 | 73 | 01.27.22 | 4,611.76 | REPLACED S SVC |
| 1419397 | MED | 3/4 | 50 | 02.16.22 | 3,480.79 | REPLACEMENT |
| 1419489 | GPS | 3/4 | 89 | 02.24.22 | 2,353.69 | REPLACED S SVC |
| 1419498 | JAC | 3/4 | 80 | 02.24.22 | 2,679.64 | REPLACED S SVC |
| 1419649 | GPS | 3/4 | 93 | 03.11.22 | 3,313.38 | REPLACED S SVC |
| 1419732 | GPS | 3/4 | 10 | 03.22.22 | 1,131.40 | REPLACEMENT |
| 1419848 | MED | 3/4 | 40 | 03.29.22 | 3,606.96 | REPLACEMENT |
| 1419914 | MED | 3/4 | 17 | 04.04.22 | 2,311.79 | REPLACEMENT |
| 1419951 | MED | 3/4 | 30 | 04.06.22 | 2,516.70 | REPLACEMENT |
| 1419965 | GPS | 3/4 | 65 | 04.07.22 | 2,156.48 | REPLACED S SVC |
| 1419968 | GPS | 3/4 | 45 | 04.07.22 | 2,067.48 | REPLACED S SVC |
| 1419978 | CPT | 3/4 | 12 | 04.07.22 | 1,968.92 | REPLACEMENT |
| 1419865 | GPS | 3/4 | 5 | 03.30.22 | 630.40 | REPLACEMENT |
| 1419965 | GPS | 3/4 | 65 | 04.07.22 | 2,156.48 | REPLACED S SVC |
| 1419968 | GPS | 3/4 | 43 | 04.07.22 | 2,067.48 | REPLACED S SVC |
| 1420039 | GPS | 3/4 | 61 | 04.14.22 | 3,342.62 | REPLACED S SVC |
| 1420051 | GPS | 3/4 | 58 | 04.18.22 | 1,526.64 | REPLACED S SVC |
| 1420055 | GPS | 3/4 | 61 | 04.19.22 | 2,440.15 | REPLACED S SVC |
| 1420056 | GPS | 3/4 | 177 | 04.19.22 | 6,177.96 | REPLACED S SVC |
| 1420065 | MED | 3/4 | 41 | 04.19.22 | 4,281.27 | REPLACED S SVC |
| 1420120 | GPS | 3/4 | 95 | 04.20.22 | 2,643.97 | REPLACED S VC |
| 1420122 | GPS | 3/4 | 38 | 04.20.22 | 1,190.14 | REPLACEMENT |
| 1420138 | MED | 3/4 | 15 | 04.26.22 | 765.33 | REPLACEMENT |
| 1420139 | MED | 3/4 | 28 | 04.26.22 | 3,512.60 | REPLACEMENT |
| 1420145 | MED | 3/4 | 80 | 04.26.22 | 3,133.53 | REPLACEMENT |
| 1420211 | GPS | 3/4 | 35 | 05.02.22 | 3,390.60 | REPLACEMENT |
| 1420275 | MED | 3/4 | 26 | 05.05.22 | 2,093.62 | REPLACEMENT |
| 1420277 | MED | 3/4 | 65 | 05.05.22 | 1,138.27 | REPLACED 65' 1/2 P |
| 1420315 | MED | 3/4 | 75 | 05.10.22 | 4,101.12 | REPLACEMENT |
| 1420249 | JAC | 3/4 | 35 | 05.03.22 | 3,708.78 | REPLACEMENT |
| 1420376 | MED | 3/4 | 41 | 05.13.22 | 3,439.09 | REPLACEMENT |
| 1420381 | CPT | 3/4 | 36 | 05.16.22 | 3,753.02 | REPLACEMENT |
| 1420385 | GPS | 3/4 | 88 | 05.16.22 | 16,154.74 | REPLACED S SVC |
| 1420435 | GPS | 3/4 | 162 | 05.18.22 | 6,218.24 | REPLACEMENT |
| 1420490 | MED | 3/4 | 43 | 05.24.22 | 6,912.04 | REPLACEMENT |
| 1420609 | GPS | 3/4 | 59 | 06.03.22 | 3,548.45 | REPLACEMENT |
| 1420498R1 | MED | 3/4 | 92 | 05.24.22 | 5,707.80 | REPLACEMENT |
| 1420301 | GPS | 3/4 | 106 | 05.10.22 | 11,252.79 | REPLACED S SVC |
| 1420302 | GPS | 3/4 | 84 | 05.10.22 | 13,428.07 | REPLACED S SVC |
| 1420303 | GPS | 3/4 | 59 | 05.10.22 | 11,662.53 | REPLACED S SVC |
| 1420434 | GPS | 3/4 | 73 | 05.18.22 | 3,442.26 | REPLACED S SVC |
| 1420475 | GPS | 3/4 | 90 | 05.24.22 | 6,318.83 | REPLACED S SVC |
| 1420544 | MED | 3/4 | 130 | 05.31.22 | 8,072.23 | REPLACED S SVC |
| 1420567 | ASH | 3/4 | 20 | 05.31.22 | 4,336.59 | REPLCAED S SVC |
| 1420569 | MED | 3/4 | 100 | 05.31.22 | 9,133.33 | REPLCAED S SVC |
| 1420570 | CPT | 3/4 | 10 | 05.31.22 | 1,954.84 | REPLACEMENT |
| 1420612 | GPS | 3/4 | 167 | 06.03.22 | 2,149.42 | REPLACEMENT |
| 1420668 | GPS | 3/4 | 66 | 06.09.22 | 3,997.02 | REPLACEMENT |
| 1420691 | MED | 3/4 | 57 | 06.13.22 | 2,689.88 | REPLACED S SVC |
| 1420694 | MED | 3/4 | 15 | 06.13.22 | 4,349.57 | REPLACEMENT |
| 1420724 | GPS | 3/4 | 112 | 06.14.22 | 5,052.83 | REPLACED S SVC |
| 1420728 | MED | 3/4 | 17 | 06.14.22 | 6,478.35 | REPLACED S SVC |
| 1420788 | GPS | 3/4 | 58 | 06.17.22 | 4,198.84 | REPLACED S SVC |
| 1420864 | GPS | 3/4 | 10 | 06.24.22 | 3,587.59 | REPLACED STEEL SERVICE |
| 1420866 | GPS | 3/4 | 268 | 06.24.22 | 8,510.32 | REPLACED S SVC |
| 1420916 | GPS | 3/4 | 13 | 06.30.22 | 1,106.40 | REPLACEMENT |
| 1420936 | MED | 3/4 | 98 | 06.30.22 | 5,108.84 | REPLACED S SVC |
| 1420802 | MED | 3/4 | 422 | 06.22.22 | 27,632.47 | REPLACED SERVICE AND VALVE |
| 1420378R1 | GPS | 3/4 | 158 | 05.16.22 | 12,523.42 | REPLCAED S SVC |
| 1420996 | GPS | 3/4 | 212 | 07.11.22 | 7,185.85 | REPLACEMENT |
| 1421032 | MED | 3/4 | 58 | 07.13.22 | 1,717.75 | REPLACED S SVC |
| 1421105 | CPT | 3/4 | 24 | 07.15.22 | 2,008.58 | REPLACEMENT |
| 1421106 | CPT | 3/4 | 25 | 07.15.22 | 2,590.42 | REPLACEMENT |
| 1421129 | MED | 3/4 | 94 | 07.19.22 | 1,788.99 | REPLACED S SVC |
| 1421130 | MED | 3/4 | 20 | 07.20.22 | 10,427.81 | REPLACED S SVC |
| 1421140 | MED | 3/4 | 20 | 07.20.22 | 1,138.27 | REPLACEMENT |
| 1421153 | GPS | 3/4 | 28 | 07.20.22 | 3,060.92 | REPLACEMENT |
| 1421161 | GPS | 3/4 | 48 | 07.21.22 | 1,473.87 | REPLACEMENT |
| 1421162 | GPS | 3/4 | 26 | 07.21.22 | 1,654.32 | REPLACED SERVICE |
| 1421170 | ASH | 3/4 | 140 | 07.21.22 | 5,597.56 | REPLACED S SVC |
| 1421171 | MED | 3/4 | 50 | 07.21.22 | 2,954.85 | REPLACED S SVC |
| 1421176 | MED | 3/4 | 35 | 07.21.22 | 1,594.90 | REPLACED S SVC |
| 1421215 | GPS | 3/4 | 65 | 07.25.22 | 16,617.67 | REPLACEMENT |
| 1421234 | GPS | 3/4 | 107 | 07.27.22 | 8,521.40 | REPLACED S SVC |
| 1421241 | MED | 3/4 | 69 | 07.27.22 | 4,416.97 | REPLACED S SVC |
| 1421242 | MED | 3/4 | 170 | 07.27.22 | 7,567.99 | REPLACED S SVC |
| 1421244 | CPT | 3/4 | 15 | 07.27.22 | 2,052.93 | REPLACEMENT |
| 1421288 | GPS | 3/4 | 22 | 08.02.22 | 7,960.06 | REPLACED S SVC |
| 1421219R1 | MED | 3/4 | 72 | 07.27.22 | 2,794.04 | REPLACED S SVC |
| 1421348 | GPS | 3/4 | 74 | 08.08.22 | 12,235.15 | REPLACED S SVC |
| 1421391 | JAC | 3/4 | 127 | 08.10.22 | 5,832.02 | REPLACED S SVC |
| 1421462 | ROG | 3/4 | 40 | 08.18.22 | 4,265.69 | REPLACED S SVC |
| 1421513 | MED | 3/4 | 40 | 08.23.22 | 4,583.17 | REPLACED S SVC |
| 1421697 | GPS | 3/4 | 6 | 09.20.22 | 6,570.68 | REPLACED S SVC |
| 1421698 | GPS | 3/4 | 103 | 09.20.22 | 3,952.69 | REPLACED S SVC |
| 1421848 | MED | 3/4 | 70 | 09.26.22 | 5,528.49 | REPLACED S SVC |

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|---|---|---|---|---|---|---|
| 1421875 | MED | 3/4 | 68 | 09.27.22 | 1,956.88 | REPLACED S SVC |
| 1421910 | MED | 3/4 | 40 | 09.29.22 | 2,920.37 | REPLACED S SVC |
| 1421539 | MED | 3/4 | 48 | 08.25.22 | 8,449.74 | REPLACED S SVC |
| 1421715 | GPS | 3/4 | 80 | 09.20.22 | 15,914.99 | REPLACED S SVC |
| 1421847 | ASH | 3/4 | 30 | 09.26.22 | 2,297.19 | REPLACED S SVC |
| 1421860 | CPT | 3/4 | 40 | 09.26.22 | 2,106.45 | REPLACEMENT |
| 1421863 | MED | 3/4 | 45 | 09.26.22 | 3,268.72 | REPLACEMENT |
| 1421901 | GPS | 3/4 | 77 | 09.29.22 | 6,045.03 | REPLACEMENT |
| 1421905 | GPS | 3/4 | 114 | 09.29.22 | 5,065.04 | REPLACED S SVC |
| 1421991 | MED | 3/4 | 100 | 10.03.22 | 6,796.79 | REPLACED S SVC |
| 1422024 | ASH | 3/4 | 25 | 10.04.22 | 6,166.93 | REPLACEMENT |
| 1421720 | GPS | 3/4 | 48 | 09.20.22 | 11,725.28 | REPLACED S SVC |
| 1421741 | CPT | 3/4 | 408 | 09.20.22 | 19,947.02 | REPLACED S SVC |
| 1421745 | GOL | 3/4 | 50 | 09.20.22 | 1,946.12 | REPLACED S SVC |
| 1421747 | CPT | 3/4 | 220 | 09.20.22 | 15,985.35 | REPLACED S SVC |
| 1422055 | GPS | 3/4 | 46 | 10.07.22 | 6,379.41 | REPLACEMENT |
| 1422060 | GPS | 3/4 | 12 | 10.07.22 | 14,520.40 | REPLACED S SVC |
| 1422061 | GPS | 3/4 | 53 | 10.07.22 | 14,962.08 | REPLACED S SVC |
| 1422080 | MED | 3/4 | 118 | 10.10.22 | 11,278.33 | REPLACED S SVC |
| 1422084 | MED | 3/4 | 45 | 10.10.22 | 3,996.63 | REPLACED S SVC |
| 1422085 | TAL | 3/4 | 119 | 10.10.22 | 4,479.93 | REPLACEMENT |
| 1422086 | CPT | 3/4 | 79 | 10.10.22 | 6,796.51 | REPLACED S SVC |
| 1422150 | GPS | 3/4 | 78 | 10.13.22 | 16,339.67 | REPLACED S SVC |
| 1422191 | ASH | 3/4 | 333 | 10.17.22 | 3,918.42 | REPLACEMENT |
| 1422194 | TAL | 3/4 | 52 | 10.17.22 | 4,209.78 | REPLACED S SVC |
| 1422210 | MED | 3/4 | 118 | 10.17.22 | 5,751.12 | REPLACED S SVC |
| 1422232 | MED | 3/4 | 110 | 10.18.22 | 11,819.35 | REPLACED S SVC |
| 1422275 | MED | 3/4 | 55 | 10.20.22 | 9,360.12 | REPLACED S SVC |
| 1422286 | MED | 3/4 | 110 | 10.21.22 | 16,351.89 | REPLACED S SVC |
| 1422287 | GPS | 3/4 | 58 | 10.21.22 | 12,468.08 | REPLACED S SVC |
| 1422295 | MED | 3/4 | 67 | 10.24.22 | 12,988.79 | REPLACED S SVC |
| 1422298 | MED | 3/4 | 74 | 10.24.22 | 8,766.48 | REPLACED S SVC |
| 1422349 | JAC | 3/4 | 105 | 10.26.22 | 17,421.71 | REPLACED S SVC |
| 1422470 | MED | 3/4 | 63 | 11.04.22 | 10,478.91 | REPLACED S SVC |
| 1422527 | MED | 3/4 | 4 | 11.09.22 | 1,026.76 | REPLACEMENT |
| 1422561 | MED | 3/4 | 89 | 11.11.22 | 13,730.59 | REPLACED S SVC |
| 1422289R1 | GPS | 3/4 | 188 | 10.21.22 | 7,804.20 | REPLACED S SVC |
| 1422350 | MED | 3/4 | 100 | 10.26.22 | 17,429.21 | REPLACED S SVC |
| 1422447 | MED | 3/4 | 122 | 11.03.22 | 15,079.15 | REPLACED S SVC |
| 1422449 | MED | 3/4 | 113 | 11.03.22 | 16,406.06 | REPLACED S SVC |
| 1422464 | MED | 3/4 | 322 | 11.04.22 | 20,776.88 | REPLACED S SVC |
| 1422468 | ASH | 3/4 | 90 | 11.04.22 | 24,020.78 | REPLACEMENT |
| 1422503 | MED | 3/4 | 62 | 11.08.22 | 8,971.23 | REPLACEMENT |
| 1422504 | MED | 3/4 | 68 | 11.08.22 | 6,047.73 | REPLACED S SVC |
| 1422510 | JAC | 3/4 | 97 | 11.08.22 | 3,345.30 | REPLACED S SVC |
| 1422525 | MED | 3/4 | 20 | 11.09.22 | 10,848.48 | REPLACED S SVC |
| 1422601 | ASH | 3/4 | 99 | 11.16.22 | 2,735.04 | REPLACEMENT |
| 1422602 | MED | 3/4 | 80 | 11.16.22 | 13,447.61 | REPLACED S SVC |
| 1422606 | MED | 3/4 | 66 | 11.16.22 | 14,032.32 | REPLACED S SVC |
| 1422690 | MED | 3/4 | 111 | 11.18.22 | 12,945.18 | REPLACED S SVC |
| 1422712 | CPT | 3/4 | 78 | 11.21.22 | 7,801.93 | REPLACED S SVC |
| 1422508R1 | MED | 3/4 | 116 | 11.14.22 | 16,791.51 | REPLACED S SVC |
| 1422608R1 | MED | 3/4 | 85 | 11.22.22 | 21,817.73 | REPLACED S SVC |
| | | | | | | |
| **TOTAL YEARLY SERVICE REPLACEMENTS= 126** | | | | **TOTAL $ =** | **1089128.52** | |

## SERVICE REPLACEMENTS FOR THE YEAR 2021:

| ID NUMBER | CITY | PIPE SIZE | PIPE LENGTH | INVOICE DATE | INVOICE TOTAL | COMMENTS |
|---|---|---|---|---|---|---|
| 91972556 | CPT | | | 11/15/20 | 7,461.74 | REPLACEMENT |
| 91975257 | MED | 3/4 | 15 | 11/15/20 | 1,708.35 | REPLACEMENT |
| 91975280 | GPS | 3/4 | 97 | 11/29/20 | 6,224.70 | REPLACEMENT |
| 91975282 | GPS | 3/4 | 72 | 11/29/20 | 2,607.14 | REPLACEMENT |
| 91980368 | GOL | 3/4 | 68 | 11/22/20 | 3,449.95 | REPLACED S SVC |
| 91984974 | MED | 3/4 | 80 | 11/29/20 | 2,610.36 | REPLACEMENT |
| 91984970 | MED | 3/4 | 48 | 11/29/20 | 2,891.93 | REPLACEMENT |
| 91995613 | MED | 3/4 | 106 | 12/13/30 | 9,048.31 | REPLACED S SVC |
| 91995693 | MED | 3/4 | 20 | 12/13/20 | 2,199.03 | REPLACEMENT |
| 91995729 | MED | 3/4 | 12 | 12/13/20 | 3,946.63 | REPLACEMENT |
| 91995763 | GPS | 3/4 | 125 | 12/13/20 | 6,991.17 | REPLACED S SVC |
| 92000482 | MED | 3/4 | 115 | 12/20/20 | 4,351.67 | REPLACED S SVC |
| 92003495 | GPS | 3/4 | 111 | 12/27/20 | 8,187.41 | REPLACED S SVC |
| 92003499 | GPS | 3/4 | 40 | 12/27/20 | 2,871.56 | REPLACEMENT |
| 92003993 | CPT | 3/4 | 120 | 12/27/20 | 4,225.07 | REPLACED S SVC |
| 92006456 | GPS | 3/4 | 6 | 1/3/2021 | 1,937.13 | REPLACEMENT |
| 92009606 | CPT | 3/4 | 72 | 1/10/2021 | 1,374.92 | REPLACED S SVC |
| 92013901 | GPS | 3/4 | 81 | 1/17/2021 | 2,361.07 | REPLACED S SVC |
| 92013976 | GPS | 3/4 | 202 | 1/17/2021 | 6,743.14 | REPLACED S SVC |
| 92013987 | GPS | 3/4 | 7 | 1/17/2021 | 1,647.21 | REPLACED S SVC |
| 92016433 | MED | 3/4 | 36 | 1/24/2021 | 1,505.22 | REPLACEMENT |
| 92016461 | GPS | 3/4 | 54 | 1/24/2021 | 3,974.75 | REPLACED S SVC |
| 92019929 | GPS | 3/4 | 108 | 1/31/2021 | 5,189.01 | REPLACEMENT |
| 92023210 | MED | 3/4 | 53 | 2/7/2021 | 3,394.76 | REPLACEMENT |
| 1516158 | MED | 3/4 | 81 | 4/5/2021 | 2,734.46 | REPLACED S SVC |
| 1516162 | ASH | 3/4 | 68 | 4/5/2021 | 4,617.60 | REPLACEMENT |
| 1516173 | ASH | 3/4 | 59 | 4/6/2021 | 1,716.00 | REPLACED S SVC |
| 1516248 | MED | 3/4 | 238 | 4/8/2021 | 9,457.70 | REPLACED AA |
| 1516293 | MED | 3/4 | 20 | 4/13/2021 | 1,868.61 | REPLACEMENT |
| 1516329 | MED | 3/4 | 90 | 4/15/2021 | 10,549.08 | REPLACED AA |
| 1516330 | MED | 3/4 | 38 | 4/15/2021 | 1,245.44 | REPLACEMENT |
| 1516344 | MED | 3/4 | 10 | 4/15/2021 | 2,572.14 | REPLACED S SVC |
| 1516456 | GPS | 3/4 | 49 | 4/27/2021 | 1,784.69 | REPLACED S SVC |
| 1516289R1 | MED | 3/4 | 68 | 4/13/2021 | 1,904.02 | REPLACED S SVC |
| 1516523 | ASH | 3/4 | 57 | 5/3/2021 | 9,067.75 | REPLACED AA |
| 1516742R1 | CPT | 3/4 | 86 | 5/21/2021 | 2,957.07 | REPLACED S SVC |
| 1516966 | MED | 3/4 | 8 | 6/14/2021 | 1,649.20 | REPLACED AA |
| 1516980 | MED | 3/4 | 49 | 6/14/2021 | 2,967.50 | REPLACED AA |
| 1517100 | ASH | 3/4 | 39 | 6/29/2021 | 12,813.46 | REPLACED S SVC |
| 1517208 | ASH | 3/4 | 39 | 7/14/2021 | 3,849.00 | REPLACED S SVC |
| 1517076 | MED | 3/4 | 9 | 6/24/2021 | 7,061.57 | REPLACEMENT |
| 1517294 | MED | 3/4 | 32 | 7/22/2021 | 3,221.43 | REPLACED AA |
| 1517295 | MED | 3/4 | 28 | 7/22/2021 | 3,315.56 | REPLACED S SVC |
| 1517278 | MED | 3/4 | 93 | 7/21/2021 | 5,409.46 | REPLACED S SVC |
| 1517277 | MED | 3/4 | 103 | 7/21/2021 | 5,353.25 | REPLACED S SVC |
| 1517263 | CPT | 3/4 | 502 | 7/21/2021 | 7,855.00 | REPLACED S SVC |
| 1517032R1 | GPS | 3/4 | 95 | 6/24/2021 | 2,328.04 | REPLACED S SVC |
| 1517069R4 | GOL | 3/4 | 46 | 7/20/2021 | 1,323.68 | REPLACEMENT |
| 1517155R1 | GPS | 3/4 | 3 | 7/12/2021 | 1,323.68 | REPLACEMENT |
| 1517359R1 | MED | 3/4 | 10 | 7/28/2021 | 3,221.46 | REPLACEMENT |
| 1517070 | GPS | 3/4 | 78 | 6/24/2021 | 2,023.37 | REPLACED S SVC |
| 1517346 | CPT | 3/4 | 17 | 7/27/2021 | 5,737.71 | REPLACED S SVC |
| 151355 | CPT | 3/4 | 79 | 7/27/2021 | 6,688.61 | REPLACEMENT |
| 1517643 | ASH | 3/4 | 12 | 8/23/2021 | 1,139.02 | REPLACED AA |
| 1517677 | MED | 3/4 | 29 | 8/26/2021 | 2,619.01 | ISO REPLACEMENT |
| 1517714 | MED | 3/4 | 22 | 8/30/2021 | 1,104.38 | REPLACED AA |
| 1517774 | MED | 3/4 | 25 | 9/7/2021 | 1,986.93 | REPLACED AA |
| 1517780 | MED | 3/4 | 55 | 9/7/2021 | 2,557.04 | REPLACED AA |
| 15177555 | PNX | 3/4 | 99 | 8/17/2021 | 6,124.21 | REPLACEMENT |
| 1516688 | MED | 3/4 | 74 | 5/18/2021 | 7,218.24 | REPLACED AA |
| 1516794 | ASH | 3/4 | 61 | 5/25/2021 | 5,719.95 | REPLACED S SVC |
| 1516806 | GPS | 3/4 | 80 | 6/26/2021 | 3,202.71 | REPLACED S SVC |
| 1516868 | GPS | 3/4 | 32 | 6/2/2021 | 1,137.76 | REPLACED AA |
| 1418002 | GPS | 3/4 | 81 | 9/28/2021 | 9,616.57 | REPLACED S SVC |
| 1418046 | MED | 3/4 | 158 | 9/30/2021 | 2,146.99 | REPLACEMENT |
| 1418077 | MED | 3/4 | 68 | 10/21/2021 | 7,539.30 | REPLACED AA |
| 1418124 | EPT | 3/4 | 72 | 10/11/2021 | 3,049.43 | REPLCAED S SVC |
| 1418125 | EPT | 3/4 | 88 | 10/11/2021 | 4,273.53 | REPLCAED S SVC |
| 1418212 | MED | 3/4 | 19 | 10/15/2021 | 5,854.49 | REPLACEMENT |
| 1418229 | MED | 3/4 | 87 | 10/18/2021 | 9,122.33 | REPLACED ISO |
| 1517587 | GPS | 3/4 | 130 | 8/19/2021 | 2,043.55 | REPLACEMENT |
| 1517817 | CPT | 3/4 | 36 | 9/10/2021 | 3,736.29 | REPLACEMENT |
| 1517918 | MED | 3/4 | 120 | 9/16/2021 | 5,087.25 | REPLACED S SVC |
| 1517984 | MED | 3/4 | 80 | 9/22/2021 | 2,607.19 | REPLACED S SVC |
| 1517985 | ASH | 3/4 | 55 | 9/23/2021 | 1,957.37 | REPLACEMENT |
| 1418089R1 | JAC | 3/4 | 18 | 10/5/2021 | 4,627.41 | REPLACEMENT |
| 1517979R1 | GPS | 3/4 | 70 | 9/15/2021 | 3,134.57 | REPLACEMENT |
| 1418115 | GPS | 3/4 | 121 | 10/8/2021 | 3,105.50 | RPLACED S SVC |
| 1418240 | WHI | 3/4 | 166 | 10/19/2021 | 5,814.87 | REPLACED S SVC |
| 1418380 | MED | 3/4 | 80 | 11/5/2021 | 3,755.77 | REPLACED S SVC |
| 1418529 | JAC | 3/4 | 56 | 11/22/2021 | 1,795.60 | REPLACED S SVC |
| 1418096R1 | ASH | 3/4 | 51 | 10/6/2021 | 2,312.06 | REPLACEMENT |
| 1418230 | MED | 3/4 | 24 | 10/18/2021 | 6,078.62 | REPLACED S SVC |
| 1418453 | MED | 3/4 | 40 | 11/10/2021 | 4,554.02 | REPLACED ISO |
| 1418454 | MED | 3/4 | 54 | 11/10/2021 | 3,160.65 | REPLACED S SVC |
| 1418486 | ASH | 3/4 | 5 | 11/16/2021 | 3,499.59 | REPLACED S SVC |
| 1418524 | WHI | 3/4 | 28 | 11/22/2021 | 11,760.21 | REPLACED S SVC |
| 1418530 | JAC | 3/4 | 104 | 11/21/2021 | 3,009.55 | REPLCAED S SVC |
| 1418679 | GPS | 3/4 | 62 | 12/8/2021 | 1,861.58 | REPLACEMENT |
| 1418680 | GPS | 3/4 | 26 | 12/8/2021 | 1,821.87 | REPLACEMENT |
| 1418681 | GPS | 3/4 | 63 | 12/8/2021 | 1,861.58 | REPLACEMENT |
| 1418682 | GPS | 3/4 | 46 | 12/8/2021 | 1,354.04 | REPLACEMENT |
| 1418685 | GPS | 3/4 | 37 | 12/8/2021 | 1,770.58 | REPLACEMENT |
| 1418686 | GPS | 3/4 | 27 | 12/8/2021 | 1,887.56 | REPLACEMENT |
| 1418687 | GPS | 3/4 | 17 | 12/8/2021 | 1,995.81 | REPLACEMENT |
| 1418690 | GPS | 3/4 | 64 | 12/8/2021 | 1,726.93 | REPLACEMENT |
| 1418691 | GPS | 3/4 | 64 | 12/8/2021 | 1,813.88 | REPLACEMENT |
| 1418692 | GPS | 3/4 | 64 | 12/8/2021 | 1,857.25 | REPLACEMENT |
| 1418693 | GPS | 3/4 | 64 | 12/8/2021 | 1,857.25 | REPLACEMENT |
| 1418694 | GPS | 3/4 | 64 | 12/8/2021 | 1,848.59 | REPLACEMENT |
| 1418696 | GPS | 3/4 | 63 | 12/8/2021 | 1,857.25 | REPLACEMENT |
| 1418756 | GPS | 3/4 | 43 | 12/14/2021 | 1,479.68 | REPLACEMENT |
| 1418759 | GPS | 3/4 | 64 | 12/14/2021 | 1,546.61 | REPLACEMENT |
| 1418766 | GPS | 3/4 | 64 | 12/14/2021 | 1,344.96 | REPLACEMENT |
| 1418768 | GPS | 3/4 | 53 | 12/14/2021 | 1,896.22 | REPLACEMENT |

| | | | | | | |
|---|---|---|---|---|---|---|
| 1418773 | GPS | 3/4 | 53 | 12/14/2021 | 1,805.29 | REPLACEMENT |
| 1418775 | GPS | 3/4 | 60 | 12/14/2021 | 1,896.22 | REPLACEMENT |
| 1418777 | GPS | 3/4 | 56 | 12/14/2021 | 1,900.55 | REPLACEMENT |
| 1418780 | GPS | 3/4 | 51 | 12/14/2021 | 1,736.01 | REPLACEMENT |
| 1418746R1 | GPS | 3/4 | 47 | 12/15/2021 | 7,382.84 | REPLACED S SVC |
| 141877R3 | GPS | 3/4 | 39 | 12/3/2021 | 2,666.00 | REPLACED S SVC |
| 1516732 | MED | 3/4 | 11 | 5/20/2021 | 7,133.42 | REPLCAED S SVC |
| 1516740 | MED | 3/4 | 59 | 5/20/2021 | 2,411.69 | REPLACED S SVC |
| 1516741 | MED | 3/4 | 13 | 5/20/2021 | 3,044.80 | REPLACED S SVC |
| 1516751 | GPS | 3/4 | 130 | 5/21/2021 | 6,272.65 | REPLACED S SVC |
| 1516754 | GOL | 3/4 | 39 | 5/21/2021 | 3,240.81 | REPLACED AA |
| 1517364 | CPT | 3/4 | 17 | 7/28/2021 | 911.60 | REPLACED S SVC |
| 1517388 | JAC | 3/4 | 105 | 7/30/2021 | 3,666.37 | REPLACED S SVC |
| | | | | | | |
| **TOTAL YEARLY REPLACEMENTS = 106** | | | | **TOTAL $ =** | **443,820.62** | |

## SERVICE REPLACEMENTS FOR THE YEAR 2020:

| ID NUMBER | CITY | PIPE SIZE | PIPE LENGTH | INVOICE DATE | INVOICE TOTAL | COMMENTS |
|---|---|---|---|---|---|---|
| 91731598 | CPT | 3/4 | 21 | 11/24/2019 | 1,809.29 | REPLACED SVC |
| 91740290 | ASH | 3/4 | 118 | 12/8/2019 | 5,779.29 | REPLACED S SVC |
| 91740293 | ASH | 3/4 | 12 | 12/8/2019 | 6,791.47 | REPLACED S SVC |
| 91740298 | TAL | 3/4 | 50 | 12/8/2019 | 4,695.41 | REPLACED S SVC |
| 91740584 | GPS | 3/4 | 47 | 12/8/2019 | 2,237.95 | REPLACEMENT |
| 91745507 | ASH | 3/4 | 10 | 12/15/2019 | 3,683.75 | REPLACED S SVC |
| 91745528 | ASH | 3/4 | 20 | 12/15/2019 | 2,035.41 | REPLACED S SVC |
| 91745536 | MED | 3/4 | 56 | 12/15/2019 | 1,617.42 | REPLACED AA |
| 91745540 | MED | 3/4 | 110 | 12/15/2019 | 7,034.69 | REPLACED S SVC |
| 91745573 | GPS | 3/4 | 75 | 12/15/2019 | 4,104.40 | REPLACEMENT |
| 91745575 | GPS | 3/4 | 80 | 12/15/2019 | 3,318.31 | REPLACEMENT |
| 91750857 | PNX | 3/4 | 13 | 12/22/2019 | 2,070.25 | REPLACEMENT |
| 91750871 | MED | 3/4 | 85 | 12/22/2019 | 4,848.35 | REPLACED AA |
| 91750784 | MED | 3/4 | 8 | 12/22/2019 | 2,002.84 | REPLACEMENT |
| 91750875 | MED | 3/4 | 96 | 12/22/2019 | 8,140.94 | REPLACED S SVC |
| 91745530 | MED | 3/4 | 111 | 12/15/2019 | 2,772.42 | REPLACEMENT |
| 91751622 | MED | 3/4 | 25 | 12/29/2019 | 4,218.26 | REPLACEMENT |
| 91762262 | ASH | 3/4 | 29 | 1/19/2020 | 2,320.09 | REPLACED AA |
| 91762299 | CPT | 3/4 | 43 | 1/19/2022 | 5,268.83 | REPLACED S SVC |
| 91771668 | CPT | 3/4 | 16 | 2/2/2020 | 2,964.73 | REPLACEMENT |
| 91786938 | MED | 3/4 | 114 | 3/1/2020 | 12,221.36 | REPLACED S SVC |
| 91791261 | TAL | 3/4 | 8 | 3/8/2020 | 933.95 | REPLACEMENT |
| 91791262 | TAL | 3/4 | 8 | 3/8/2020 | 2,369.47 | REPLACED S SVC |
| 91791263 | TAL | 3/4 | 70 | 3/8/2020 | 2,523.12 | REPLACED S SVC |
| 91791265 | TAL | 3/4 | 38 | 3/8/2020 | 1,800.61 | REPLACED S SVC |
| 91795567 | JAC | 3/4 | 188 | 3/15/2020 | 14,131.10 | REPLACED S SVC |
| 91795586 | MED | 3/4 | 95 | 3/15/2020 | 7,686.81 | REPLACED S SVC |
| 91795587 | TAL | 3/4 | 5 | 3/15/2020 | 1,855.01 | REPLACED S SVC |
| 91795598 | TAL | 3/4 | 62 | 3/15/2020 | 3,284.88 | REPLACED S SVC |
| 91800194 | MED | 3/4 | 85 | 3/22/2020 | 6,304.42 | REPLACED AA |
| 91800211 | MED | 3/4 | 85 | 3/22/2020 | 2,658.62 | REPLACED AA |
| 91800217 | MED | 3/4 | 85 | 3/22/2020 | 2,823.67 | REPLCAED AA |
| 91800250 | MED | 3/4 | 93 | 3/22/2020 | 1,837.87 | REPLACEMENT |
| 91800349 | GPS | 3/4 | 72 | 3/22/2020 | 3,087.09 | REPLACED AA |
| 91805048 | MED | 3/4 | 3 | 3/29/2020 | 3,891.03 | REPLACED AA |
| 91808840 | ASH | 3/4 | 3 | 4/5/2020 | 2,209.61 | REPLACEMENT |
| 91809214 | GPS | 3/4 | 100 | 4/5/2020 | 4,700.16 | REPLACED S SVC |
| 91809210 | GPS | 3/4 | 202 | 4/5/2020 | 12,525.48 | REPLACED S SVC |
| 91812453 | MED | 3/4 | 46 | 4/12/2020 | 5,075.57 | REPLACEMENT |
| 91812482 | GPS | 3/4 | 18 | 4/12/2020 | 2,475.66 | REPLACEMENT |
| 91812648 | GPS | 3/4 | 5 | 4/12/2020 | 2,071.98 | REPLACED AA |
| 91815046 | MED | 3/4 | 5 | 4/12/2020 | 2,935.71 | REPLACEMENT |
| 91825326 | ASH | 3/4 | 66 | 5/3/2020 | 1,764.11 | REPLACEMENT |
| 91840754 | GPS | 3/4 | 48 | 5/24/2020 | 3,439.38 | REPLACED S SVC |
| 91844726 | GOL | 3/4 | 20 | 5/31/2020 | 2,955.07 | REPLACED SHALLOW SVC |
| 91849707 | MED | 3/4 | 70 | 6/7/2020 | 14,209.93 | REPLACEMENT |
| 91849709 | MED | 3/4 | 64 | 6/7/2020 | 8,762.36 | REPLACED S SVC |
| 91849771 | GPS | 3/4 | 188 | 6/7/2020 | 22,283.20 | REPLACED S SVC |
| 91861616 | MED | 3/4 | 50 | 6/21/2020 | 3,127.60 | REPLACEMENT |
| 91861691 | GPS | 3/4 | 98 | 6/21/2020 | 3,654.37 | REPLACED S SVC |
| 91872068 | CPT | 3/4 | 262 | 7/5/2020 | 15,560.89 | REPLACEMENT |
| 91866825 | ASH | 3/4 | 165 | 6/28/2020 | 10,307.09 | REPLACED S SVC |
| 91866874 | ASH | 3/4 | 63 | 6/28/2020 | 3,874.94 | REPLACED S SVC |
| 91872166 | MED | 3/4 | 100 | 7/5/2020 | 7,356.94 | REPLACED S SVC |
| 91872350 | GPS | 3/4 | 8 | 7/5/2020 | 2,598.50 | REPLACEMENT |
| 91876975 | MED | 3/4 | 10 | 7/12/2020 | 1,667.05 | REPLACEMENT |
| 91877077 | MED | 3/4 | 88 | 7/12/2020 | 5,176.42 | REPLACEMENT |
| 91892176 | ASH | 3/4 | 129 | 8/2/2020 | 11,369.11 | REPLACED S SVC |
| 91903452 | MED | 3/4 | 60 | 8/16/2020 | 5,276.94 | REPLACED AA |
| 91908319 | CPT | 3/4 | 97 | 8/23/2020 | 5,786.67 | REPLACED S SVC |
| 91908388 | CPT | 3/4 | 15 | 8/23/2020 | 3,537.84 | REPLACEMENT |
| 91919605 | ASH | 3/4 | 32 | 9/6/2020 | 1,073.04 | REPLACED AA |
| 91919623 | GPS | 3/4 | 44 | 9/6/2020 | 3,277.38 | REPLACED S SVC |
| 91903475 | MED | 3/4 | 188 | 9/16/2020 | 9,829.44 | REPLACEMENT |
| 91908393 | MED | 3/4 | 8 | 8/23/2020 | 3,347.16 | REPLACEMENT |
| 91908394 | MED | 3/4 | 15 | 8/23/2020 | 742.17 | REPLACED AA |
| 91931933 | JAC | 3/4 | 44 | 9/20/2020 | 4,645.44 | REPLACED S SVC |
| 91943602 | MED | 3/4 | 11 | 10/4/2020 | 1,708.35 | REPLACED S SVC |
| 91943603 | CPT | 3/4 | 12 | 10/4/2020 | 761.67 | REPLACED S SVC |
| 91948342 | WHI | 3/4 | 66 | 10/11/2020 | 2,948.99 | REPLACED S SVC |
| 91948403 | ASH | 3/4 | 115 | 10/11/2020 | 6,230.35 | REPLACED S SVC |
| 91948409 | MED | 3/4 | 268 | 10/11/2020 | 6,437.29 | REPLACEMENT |
| 91948558 | MED | 3/4 | 13 | 10/11/2020 | 2,866.33 | REPLACED AA |
| 91953203 | ASH | 3/4 | 45 | 10/18/2020 | 3,081.74 | REPLACED S SVC |
| 91953265 | MED | 3/4 | 30 | 10/18/2020 | 12,310.01 | REPLACED S SVC |
| 91957705 | MED | 3/4 | 58 | 10/25/2020 | 3,998.68 | REPLACMENT |
| 91957708 | MED | 3/4 | 68 | 10/25/2020 | 3,848.74 | REPLACEMENT |
| 91957711 | ASH | 3/4 | 55 | 10/25/2020 | 4,494.47 | REPLACEMENT |
| 91959223 | MED | 3/4 | 50 | 10/25/2020 | 3,936.96 | REPLACED S SVC |
| 91964516 | MED | 3/4 | 8 | 11/1/2020 | 1,348.16 | REPLACEMENT |
| 91957709 | MED | 3/4 | 89 | 10/25/2020 | 3,812.64 | REPLACEMENT |
| 91957726 | GOL | 3/4 | 517 | 10/25/2020 | 47,676.44 | REPLACED AA |
| 91970656 | MED | 3/4 | 44 | 11/8/2020 | 6,089.35 | REPLACED S SVC |
| 91970679 | ASH | 3/4 | 57 | 11/8/2020 | 3,737.18 | REPLACED AA |
| 91970990 | GPS | 3/4 | 140 | 11/8/2020 | 3,573.47 | REPLACED S SVC |
| 91971030 | GPS | 3/4 | 30 | 11/8/2020 | 13,771.24 | REPLACED S SVC |
| 91971047 | GPS | 3/4 | 60 | 11/8/2020 | 1,729.00 | REPLACED S SVC |
| 91975254 | MED | 3/4 | 104 | 11/15/2020 | 6,720.30 | REPLACED S SVC |
| 91980359 | MED | 3/4 | 96 | 11/22/2020 | 11,176.65 | REPLACEMENT |
| 91980363 | MED | 3/4 | 48 | 11/22/2020 | 3,983.48 | REPLACED S SVC |
| 91980443 | GPS | 3/4 | 70 | 11/22/2020 | 5,727.89 | REPLACED S SVC |
| 91995736 | WHI | 3/4 | 16 | 12/13/2020 | 3,183.05 | REPLACEMENT |
| 92000448 | MED | 3/4 | 79 | 12/20/2020 | 4,233.58 | REPLACED S SVC |
| | | | | | | |
| **TOTAL YEARLY REPLACEMENTS = 93** | | | | **TOTAL $ =** | **502,126.33** | |

## SERVICE REPLACEMENTS FOR THE YEAR 2019:

| ID NUMBER | CITY | PIPE SIZE | PIPE LENGTH | INVOICE DATE | INVOICE TOTAL | COMMENTS |
|---|---|---|---|---|---|---|
| 91506320 | GPS | 3/4 | 120 | 12/2/2018 | 9,919.78 | REPLACED S SVC |
| 91506321 | GPS | 3/4 | 18 | 12/2/2018 | 2,015.03 | REPLACED S SVC |
| 91516425 | ASH | 3/4 | 131 | 12/16/2018 | 21,054.82 | REPLACED S SVC |
| 91516503 | MED | 3/4 | 10 | 12/16/2018 | 6,941.05 | REPLACED S SVC |
| 91516537 | GPS | 3/4 | 6 | 12/16/2018 | 3,372.83 | REPLACED S SVC |
| 91520214 | GPS | 3/4 | 150 | 12/23/2018 | 13,756.76 | REPLACED S SVC |
| 91520215 | GPS | 3/4 | 75 | 12/23/2018 | 8,658.28 | REPLACED S SVC |
| 91522420 | JAC | 3/4 | 56 | 12/30/2018 | 2,737.08 | REPLACED S SVC |
| 91522421 | ASH | 3/4 | 41 | 12/30/2018 | 2,594.61 | REPLACED AA |
| 91522427 | MED | 3/4 | 18 | 12/30/2018 | 716.04 | REPLACED AA |
| 91522437 | GPS | 3/4 | 80 | 12/30/2018 | 2,115.11 | REPLACED S SVC |
| 91522783 | CPT | 3/4 | 18 | 1/6/2019 | 3,124.72 | REPLACEMENT |
| 91522968 | ASH | 3/4 | 35 | 1/6/2019 | 2,605.97 | REPLACED S SVC |
| 91522971 | ASH | 3/4 | 18 | 1/6/2019 | 1,732.54 | REPLACED AA |
| 1002285228 | MED | 3/4 | 150 | 12/23/2018 | 2,966.00 | REPLACED SSVC |
| 91526656 | GPS | 3/4 | 100 | 1/13/2019 | 7,745.30 | REPLACED S SVC |
| 91530278 | MED | 3/4 | 160 | 1/20/2019 | 18,058.64 | REPLACEMENT |
| 91530282 | PNX | 3/4 | 62 | 1/20/2019 | 5,935.93 | REPLACED S SVC |
| 91530308 | GPS | 3/4 | 65 | 1/20/2019 | 1,053.91 | REPLACEMENT |
| 91533298 | MED | 3/4 | 90 | 1/27/2019 | 6,696.19 | REPLACED S SVC |
| 91533391 | GPS | 3/4 | 6 | 1/27/2019 | 2,038.80 | REPLACED S SVC |
| 91533415 | MED | 3/4 | 64 | 1/27/2019 | 7,100.63 | REPLACED S SVC |
| 91535696 | MED | 3/4 | 98 | 2/3/2019 | 2,734.14 | REPLACED S SVC |
| 91539074 | TAL | 3/4 | 16 | 2/10/2019 | 4,354.02 | REPLACED S SVC |
| 91535683 | MED | 3/4 | 47 | 2/3/2019 | 3,768.38 | REPLACED S SVC |
| 91535694 | MED | 3/4 | 99 | 2/3/2019 | 6,870.50 | REPLACED S SVC |
| 91539178 | TAL | 3/4 | 11 | 2/10/2019 | 1,261.94 | REPLACED S SVC |
| 91539199 | GPS | 3/4 | 102 | 2/10/2019 | 10,586.89 | REPLACED S SVC |
| 91539202 | ROG | 3/4 | 18 | 2/10/2019 | 2,409.26 | REPLACEMENT |
| 91542710 | TAL | 3/4 | 35 | 2/17/2019 | 2,781.23 | REPLACEMENT |
| 91542741 | MED | 3/4 | 48 | 2/17/2019 | 6,094.16 | REPLACEMENT |
| 91542826 | GPS | 3/4 | 80 | 2/17/2019 | 8,161.66 | REPLACEMENT |
| 91545077 | GPS | 3/4 | 77 | 2/24/2019 | 5,848.37 | REPLACED S SVC |
| 91545117 | CPT | 3/4 | 2 | 2/24/2019 | 2,067.04 | REPLACEMENT |
| 91545118 | MED | 3/4 | 43 | 2/24/2019 | 3,124.93 | REPLACEMENT |
| 91551304 | MED | 3/4 | 55 | 3/3/2019 | 5,109.07 | REPLACED S SVC |
| 91553256 | MED | 3/4 | 10 | 3/10/2019 | 5,022.22 | REPLACED S SVC |
| 91566309 | GPS | 3/4 | 10 | 3/17/2019 | 6,035.53 | REPLACED S SVC |
| 91545107 | MED | 3/4 | 16 | 2/24/2019 | 2,153.19 | REPLACEMENT |
| 91553222 | PNX | 3/4 | 50 | 3/10/2019 | 2,025.43 | REPLACED S SVC |
| 91553240 | ASH | 3/4 | 70 | 3/10/2019 | 3,564.60 | REPLACED S SVC |

| | | | | | | |
|---|---|---|---|---|---|---|
| 91553274 | GPS | 3/4 | 14 | 3/10/2019 | 4,342.76 | REPLACEMENT |
| 91553313 | MED | 3/4 | 17 | 3/10/2019 | 2,704.25 | REPLACED S SVC |
| 91556272 | ASH | 3/4 | 114 | 3/17/2019 | 2,872.28 | REPLACED S SVC |
| 91556552 | ASH | 3/4 | 5 | 3/17/2019 | 3,691.74 | REPLACED S SVC |
| 91556603 | GPS | 3/4 | 73 | 3/17/2019 | 4,123.94 | REPLACED S SVC |
| 91556637 | MED | 3/4 | 74 | 3/17/2019 | 5,333.27 | REPLACED S SVC |
| 91560108 | MED | 3/4 | 50 | 3/24/2019 | 6,303.72 | REPLACED S SVC |
| 91560130 | MED | 3/4 | 25 | 3/24/2019 | 6,007.70 | REPLACED S SVC |
| 91560204 | MED | 3/4 | 58 | 3/24/2019 | 1,907.47 | REPLACED S SVC |
| 91563608 | ASH | 3/4 | 45 | 3/31/2019 | 4,853.03 | REPLACEMENT |
| 91563617 | CPT | 3/4 | 61 | 3/31/2019 | 2,704.29 | REPLACEMENT |
| 91563618 | ASH | 3/4 | 6 | 3/31/2019 | 7,290.39 | REPLACEMENT & VALVE |
| 91563749 | MED | 3/4 | 55 | 3/31/2019 | 1,846.86 | REPLACED S SVC |
| 91568286 | JAC | 3/4 | 6 | 4/7/2019 | 1,954.66 | REPLACEMENT |
| 91568413 | MED | 3/4 | 129 | 4/7/2019 | 6,292.42 | REPLACED S SVC |
| 91568415 | ASH | 3/4 | 150 | 4/7/2019 | 9,471.19 | REPLACED S SVC |
| 91568393 | MED | 3/4 | 48 | 4/7/2019 | 1,976.52 | REPLACED S SVC |
| 91571787 | CPT | 3/4 | 110 | 4/14/2019 | 5,729.17 | REPLACEMENT |
| 91571794 | ASH | 3/4 | 14 | 4/14/2019 | 486.65 | REPLACEMENT |
| 91571818 | GPS | 3/4 | 48 | 4/14/2019 | 4,029.77 | REPLACED S SVC |
| 91576650 | MED | 3/4 | 70 | 4/21/2019 | 5,835.44 | REPLACED S SVC |
| 91576705 | GPS | 3/4 | 138 | 4/21/2019 | 3,923.50 | REPLACED S SVC |
| 91576849 | MED | 3/4 | 17 | 4/21/2019 | 15,240.20 | REPLACED S SVC |
| 91576851 | MED | 3/4 | 79 | 4/21/2019 | 3,923.50 | REPLACED S SVC |
| 91580707 | EPT | 3/4 | 165 | 4/28/2019 | 11,689.55 | REPLACED S SVC |
| 91580784 | TAL | 3/4 | 116 | 4/28/2019 | 7,481.00 | REPLACED S SVC |
| 91580857 | ASH | 3/4 | 50 | 4/18/2019 | 9,154.68 | REPLACEMENT |
| 91580862 | MED | 3/4 | 51 | 4/28/2019 | 4,081.55 | REPLACEMENT |
| 91580893 | ASH | 3/4 | 80 | 4/28/2019 | 5,223.84 | REPLACEMENT |
| 91580932 | ASH | 3/4 | 95 | 4/28/2019 | 3,765.15 | REPLACED AA |
| 91581042 | GPS | 3/4 | 52 | 4/28/2019 | 5,803.00 | REPLACED S SVC |
| 91584750 | MED | 3/4 | 13 | 5/5/2019 | 19,179.88 | REPLACED AA |
| 91588798 | CPT | 3/4 | 123 | 5/12/2019 | 4,904.82 | REPLACED S SVC |
| 9158872 | MED | 3/4 | 30 | 5/12/2019 | 3,890.55 | REPLACED S SVC |
| 91584909 | GPS | 3/4 | 116 | 5/5/2019 | 4,042.87 | REPLACED S SVC |
| 91587925 | GPS | 3/4 | 98 | 5/5/2019 | 2,455.90 | REPLACED S SVC |
| 91584925 | GPS | 3/4 | 98 | 5/5/2019 | 1,910.49 | REPLACED S SVC |
| 91584940 | GPS | 3/4 | 150 | 5/5/2019 | 4,807.56 | REPLACED S SVC |
| 91588823 | ASH | 3/4 | 102 | 5/12/2019 | 2,074.93 | REPLACED S SVC |
| 91588830 | MED | 3/4 | 32 | 5/12/2019 | 1,653.32 | REPLACEMENT |
| 91594438 | CPT | 3/4 | 25 | 5/19/2019 | 2,651.88 | REPLACEMENT |
| 91594566 | ASH | 3/4 | 58 | 5/19/2019 | 10,374.06 | REPLACEMENT |
| 91594631 | GPS | 3/4 | 218 | 5/19/2019 | 10,919.65 | REPLACED S SVC |
| 91598789 | CPT | 3/4 | 120 | 5/26/2019 | 897.37 | REPLACED AA |
| 91598813 | ASH | 3/4 | 60 | 5/26/2019 | 7,650.21 | REPLACEMENT |
| 91599068 | GPS | 3/4 | 75 | 5/26/2019 | 8,173.76 | REPLACEMENT |
| 91602785 | MED | 3/4 | 8 | 6/2/2019 | 1,897.62 | REPLACEMENT |
| 91602956 | MED | 3/4 | 41 | 6/2/2019 | 2,537.02 | REPLACEMENT |
| 91602957 | MED | 3/4 | 27 | 6/2/2019 | 2,716.35 | REPLACEMENT |
| 91563748 | MED | 3/4 | 34 | 3/31/2019 | 5,190.76 | REPLACED S SVC |
| 91602763 | EPT | 3/4 | 10 | 6/2/2019 | 1,636.43 | REPLACEMENT |
| 91602904 | GPS | 3/4 | 5 | 6/2/2019 | 2,765.59 | REPLACEMENT |
| 91608272 | PNX | 3/4 | 28 | 6/9/2019 | 1,724.56 | REPLACEMENT |
| 91613463 | EPT | 3/4 | 105 | 6/16/2019 | 5,464.65 | REPLACEMENT |
| 91613467 | EPT | 3/4 | 57 | 6/16/2019 | 2,432.87 | REPLACEMENT |
| 91613468 | MED | 3/4 | 50 | 6/16/2019 | 3,429.98 | REPLACED S SVC |
| 91613480 | ASH | 3/4 | 75 | 6/16/2019 | 4,745.77 | REPLACED S SVC |
| 91613605 | MED | 3/4 | 70 | 6/16/2019 | 4,747.46 | REPLACED S SVC |
| 91613626 | CPT | 3/4 | 112 | 6/16/2019 | 7,825.67 | REPLACEMENT |
| 91618477 | EPT | 3/4 | 94 | 6/23/2019 | 2,092.03 | REPLACEMENT |
| 91618506 | MED | 3/4 | 60 | 6/23/2019 | 5,612.87 | REPLACED S SVC |
| 91618556 | MED | 3/4 | 90 | 6/23/2019 | 9,393.60 | REPLACEMENT |
| 91618557 | MED | 3/4 | 4 | 6/23/2019 | 3,183.83 | REPLACEMENT |
| 91623115 | TAL | 3/4 | 12 | 6/30/2019 | 4,824.18 | REPLACEMENT |
| 91628202 | MED | 3/4 | 104 | 7/7/2019 | 4,899.61 | REPLACED S SVC |
| 91632216 | CPT | 3/4 | 46 | 7/14/2019 | 8,879.23 | REPLACED AA |
| 91632257 | MED | 3/4 | 79 | 7/14/2019 | 9,402.11 | REPLACED S SVC |
| 91584793 | PNX | 3/4 | | 5/5/2019 | 2,665.89 | REPLACED SHALLOW SVC |
| 91523089 | TAL | 3/4 | 65 | 6/30/2019 | 3,574.31 | REPLACED S SVC |
| 91628239 | GPS | 3/4 | 16 | 7/7/2019 | 1,712.49 | REPLACEMENT |
| 91632215 | MED | 3/4 | 142 | 7/14/2019 | 9,839.97 | REPLACED S SVC |
| 91632229 | MED | 3/4 | 80 | 7/14/2019 | 6,737.29 | REPLACED S SVC |
| 91637145 | ASH | 3/4 | 129 | 7/21/2019 | 9,763.00 | REPLACEMENT |
| 91637253 | ASH | 3/4 | 104 | 7/21/2019 | 1,762.88 | REPLACEMENT |
| 91637344 | MED | 3/4 | 4 | 7/21/2019 | 867.79 | REPLACEMENT |
| 91642464 | MED | 3/4 | 48 | 7/28/2019 | 3,218.17 | REPLACED AA |
| 91642678 | MED | 3/4 | 60 | 7/28/2019 | 2,451.26 | REPLACED S SVC |
| 91642956 | PNX | 3/4 | 12 | 7/28/2019 | 4,949.02 | REPLACED S SVC |
| 91663564 | MED | 3/4 | 2 | 8/25/2019 | 5,826.85 | REPLACEMENT |
| 91667691 | EPT | 3/4 | 201 | 9/1/2019 | 3,108.68 | REPLACED AA |
| 91667721 | MED | 3/4 | 6 | 9/1/2019 | 2,930.69 | REPLACEMENT |
| 91667722 | EPT | 3/4 | 38 | 9/1/2019 | 1,757.06 | REPLACEMENT |
| 91667723 | CPT | 3/4 | 67 | 9/1/2019 | 10,209.37 | REPLACED AA |
| 91672656 | ASH | 3/4 | 85 | 9/8/2019 | 3,227.30 | REPLACEMENT |
| 91672753 | ROG | 3/4 | 129 | 9/8/2019 | 2,998.98 | REPLACED S SVC |
| 91672809 | GPS | 3/4 | 123 | 9/8/2019 | 7,216.63 | REPLACED S SVC |
| 91673157 | GPS | 3/4 | 18 | 9/8/2019 | 11,982.49 | REPLACED S SVC |
| 91677372 | MED | 3/4 | 6 | 9/15/2019 | 1,859.59 | REPLACEMENT |
| 91677584 | JAC | 3/4 | 42 | 9/15/2019 | 1,644.45 | REPLACED S SVC |
| 91677636 | ROG | 3/4 | 138 | 9/15/2019 | 5,763.37 | REPLACED S SVC |
| 91683030 | GPS | 3/4 | 24 | 9/22/2019 | 1,036.20 | REPLACEMENT |
| 91693404 | GPS | 3/4 | 58 | 10/6/2019 | 3,907.06 | REPLACEMENT |
| 91697896 | GPS | 3/4 | 31 | 10/13/2019 | 8,895.85 | REPLACED S SVC |
| 91697897 | WOL | 3/4 | 13 | 10/13/2019 | 4,821.00 | REPLACED S SVC |
| 91704329 | MED | 3/4 | 64 | 10/20/2019 | 2,976.30 | REPLACED S SVC |
| 91709882 | ASH | 3/4 | 65 | 10/27/2019 | 15,212.37 | REPLACEMENT |
| 91709963 | EPT | 3/4 | 80 | 10/27/2019 | 3,928.95 | REPLACEMENT |
| 91709964 | MED | 3/4 | 26 | 10/27/2019 | 3,192.68 | REPLACEMENT |
| 91715583 | MED | 3/4 | 105 | 11/3/2019 | 4,378.76 | REPLACED S SVC |
| 91704361 | GPS | 3/4 | 10 | 10/20/2019 | 6,345.41 | REPLACED S SVC |
| 91715572 | EPT | 3/4 | 23 | 11/3/2019 | 3,514.85 | REPLACEMENT |
| 91720840 | EPT | 3/4 | 100 | 11/10/2019 | 7,625.92 | REPLACED S SVC |
| 91726951 | ASH | 3/4 | 102 | 11/17/2019 | 3,088.15 | REPLACED S SVC |
| 91726998 | WHI | 3/4 | 75 | 11/17/2019 | 7,454.29 | REPLACEMENT |
| 91727117 | GPS | 3/4 | 14 | 11/17/2019 | 2,662.33 | REPLACEMENT |
| 91731563 | ASH | 3/4 | 74 | 11/24/2019 | 5,239.62 | REPLACEMENT |
| 91731674 | GPS | 3/4 | 62 | 11/24/2019 | 7,184.07 | REPLACED S SVC |
| 91750855 | ASH | 3/4 | 24 | 12/22/2019 | 2,345.31 | REPLACED S SVC |
| 91750856 | ASH | 3/4 | 20 | 12/22/2019 | 2,044.40 | REPLACED S SVC |
| 91715668 | MED | 3/4 | 36 | 11/3/2019 | 4,085.30 | REPLACEMENT |
| | | | | | | |
| **TOTAL YEARLY REPLACEMENTS= 151** | | | | **TOTAL $ =** | **763,951.85** | |

## SERVICE REPLACEMENTS FOR THE YEAR 2018:

| ID NUMBER | CITY | PIPE SIZE | PIPE LENGTH | INVOICE DATE | INVOICE TOTAL | COMMENTS |
|---|---|---|---|---|---|---|
| 91284034 | GPS | 3/4 | 50 | 11/19/2017 | 2,506.88 | REPLACED S SVC |
| 91284024 | GPS | 3/4 | 40 | 11/19/2017 | 6,291.36 | REPLACEMENT |
| 91288841 | MED | 3/4 | 411 | 11/26/2017 | 11,781.46 | REPLACED S SVC |
| 91288886 | GPS | 3/4 | 80 | 11/26/2007 | 6,039.08 | REPLACED S SVC |
| 91288838 | MED | 3/4 | 22 | 11/26/2017 | 2,496.70 | REPLACED S SVC |
| 91293001 | GPS | 3/4 | 72 | 12/3/2017 | 6,170.63 | REPLACED S SVC |
| 91296068 | CPT | 3/4 | 85 | 12/10/2017 | 4,936.15 | REPLACED S SVC |
| 91296197 | CPT | 3/4 | 119 | 12/10/2017 | 6,949.81 | REPLACED S SVC |
| 91300792 | MED | 3/4 | 52 | 12/17/2017 | 8,903.91 | REPLACEMENT |
| 91304166 | MED | 3/4 | 159 | 12/24/2017 | 5,235.46 | REPLACED S SVC |
| 91305848 | MED | 3/4 | 67 | 12/31/2017 | 6,498.34 | REPLACED S SVC |
| 91307381 | MED | 3/4 | 256 | 12/31/2017 | 8,826.13 | REPLACED S SVC |
| 91307392 | CPT | 3/4 | 25 | 12/31/2017 | 2,210.55 | REPLACEMENT |
| 91309141 | MED | 3/4 | 90 | 1/7/2018 | 4,141.99 | REPLACED S SVCQ |
| 91309150 | MED | 3/4 | 30 | 1/7/2018 | 2,105.56 | REPLACEMENT |
| 91309161 | PNX | 3/4 | 50 | 1/7/2018 | 2,099.33 | REPLACED S SVC |
| 91309162 | CPT | 3/4 | 66 | 1/7/2018 | 5,136.62 | REPLACED S SVC |
| 91309245 | GPS | 3/4 | 4 | 1/7/2018 | 516.31 | REPLACEMNT |
| 91309244 | GPS | 3/4 | 100 | 1/7/2018 | 5,661.08 | REPLACED S SVC |
| 91309249 | GPS | 3/4 | 6 | 1/7/2018 | 2,756.76 | REPLACED S SVC |
| 91309549 | CPT | 3/4 | 140 | 1/7/2018 | 2,756.76 | REPLACED S SVC |
| 91307389 | GPS | 3/4 | 59 | 12/31/2017 | 4,517.24 | REPLACED S SVC |
| 91311822 | MED | 3/4 | 121 | 1/14/2018 | 1,478.22 | REPLACED S SVC |
| 91311880 | PNX | 3/4 | 20 | 1/14/2018 | 3,768.66 | REPLACEMENT |
| 91314447 | GPS | 3/4 | 120 | 1/21/2018 | 7,007.76 | REPLACED S SVC |
| 91318276 | GPS | 3/4 | 30 | 1/28/2018 | 2,274.74 | REPLACED S SVC |
| 91322121 | ASH | 3/4 | 20 | 2/4/2018 | 3,594.44 | REPLACEMENT |
| 91322122 | ASH | 3/4 | 100 | 2/4/2018 | 4,585.50 | REPLACEMENT |
| 91321963 | CPT | 3/4 | 123 | 2/4/2018 | 2,728.91 | REPLACED S SVC |
| 91322052 | MED | 3/4 | 16 | 2/4/2018 | 2,367.68 | REPLACED S SVC |
| 91322365 | MED | 3/4 | 4 | 2/4/2018 | 1,019.83 | REPLACED S SVC |
| 91325049 | ASH | 3/4 | 70 | 2/11/2018 | 3,292.80 | REPLACEMENT |
| 91325110 | MED | 3/4 | 52 | 2/11/2018 | 2,126.44 | REPLACEMENT |
| 91325122 | MED | 3/4 | 111 | 2/11/2018 | 9,359.83 | REPLACEMENT |
| 91328035 | MED | 3/4 | 94 | 2/18/2018 | 4,841.45 | REPLACEMENT |
| 91328116 | ASH | 3/4 | 16 | 2/18/2019 | 1,278.99 | REPLACEMENT |
| 91328323 | MED | 3/4 | 52 | 2/18/2018 | 4,880.29 | REPLACED S SVC |
| 91334264 | GPS | 3/4 | 64 | 3/4/2018 | 12,928.54 | REPLACEMENT |
| 91338231 | MED | 3/4 | 50 | 3/11/2018 | 4,055.14 | REPLACEMENT |
| 91328108 | ASH | 3/4 | 8 | 2/18/2018 | 3,169.64 | REPLACEMENT |
| 91331660 | MED | 3/4 | 6 | 2/25/2018 | 1,617.20 | REPLACEMENT |
| 91331982 | MED | 3/4 | 60 | 2/25/2018 | 852.66 | REPLACEMENT |
| 91334105 | MED | 3/4 | 50 | 3/4/2018 | 5,353.95 | REPLACED S SVC |
| 91334108 | MED | 3/4 | 16 | 3/4/2018 | 3,628.56 | REPLACED S SVC |
| 91334112 | ASH | 3/4 | 158 | 3/4/2018 | 5,821.38 | REPLACED S SVC |
| 91337979 | MED | 3/4 | 896 | 3/11/2018 | 8,650.09 | REPLACED S SVC |

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|---|---|---|---|---|---|---|
| 91338244 | MED | 3/4 | 150 | 3/11/2018 | 6,980.57 | REPLACEMENT |
| 91338262 | GPS | 3/4 | 32 | 3/11/2018 | 2,684.89 | REPLACEMENT |
| 91343372 | PNX | 3/4 | 63 | 3/18/2018 | 3,823.36 | REPLACED S SVC |
| 91345774 | ASH | 3/4 | 4 | 3/25/2018 | 2,971.62 | REPLACEMENT |
| 91345791 | PNX | 3/4 | 42 | 3/25/2018 | 4,694.79 | REPLACED S SVC |
| 91345802 | CPT | 3/4 | 20 | 3/25/2018 | 1,182.84 | REPLACEMENT |
| 91343343 | MED | 3/4 | 74 | 3/18/2018 | 2,889.96 | REPLACED S SVC |
| 91351211 | ASH | 3/4 | 20 | 4/1/2018 | 895.08 | REPLACED AA |
| 91351229 | MED | 3/4 | 150 | 4/1/2018 | 1,317.59 | REPLACED S SVC |
| 91351230 | MED | 3/4 | 50 | 4/1/2018 | 4,947.88 | REPLACED S SVC |
| 91351245 | CPT | 3/4 | 5 | 4/1/2018 | 1,869.50 | REPLACEMENT |
| 91351246 | CPT | 3/4 | 94 | 4/1/2018 | 4,551.66 | REPLACED S SVC |
| 91351269 | GPS | 3/4 | 80 | 4/1/2018 | 4,418.96 | REPLACED S SVC |
| 91353287 | TAL | 3/4 | 30 | 4/8/2018 | 6,734.58 | REPLACED S SVC |
| 91353288 | TAL | 3/4 | 352 | 4/8/2018 | 826.23 | REPLACEMENT |
| 91353297 | ASH | 3/4 | 96 | 4/8/2018 | 2,964.62 | REPLACEMENT |
| 91353484 | MED | 3/4 | 130 | 4/8/2018 | 817.92 | REPLACEMENT |
| 91353489 | GPS | 3/4 | 86 | 4/8/2018 | 6,958.05 | REPLACED S SVC |
| 91353490 | GPS | 3/4 | 130 | 4/8/2018 | 4,998.44 | REPLACED S SVC |
| 91353491 | GPS | 3/4 | 58 | 4/8/2018 | 3,584.78 | REPLACED S SVC |
| 91353494 | GPS | 3/4 | 31 | 4/8/2018 | 2,682.71 | REPLACED S SVC |
| 91353495 | GPS | 3/4 | 27 | 4/8/2018 | 4,036.46 | REPLACED S SVC |
| 91357376 | MED | 3/4 | 20 | 4/15/2018 | 4,572.90 | REPLACEMENT |
| 91357510 | PNX | 3/4 | 19 | 4/15/2018 | 7,191.14 | REPLACED S SVC |
| 91357514 | ASH | 3/4 | 107 | 4/15/2018 | 2,348.71 | REPLACED S SVC |
| 91357698 | GPS | 3/4 | 178 | 4/15/2018 | 7,041.42 | REPLACED S SVC |
| 91357707 | GPS | 3/4 | 56 | 4/15/2018 | 3,622.13 | REPLACED S SVC |
| 91357709 | GPS | 3/4 | 30 | 4/15/2018 | 1,370.92 | REPLACED S SVC |
| 91362900 | MED | 3/4 | 55 | 4/22/2018 | 6,069.22 | REPLACED S SVC |
| 91362904 | WHI | 3/4 | 90 | 4/22/2018 | 5,563.16 | REPLACED S SVC |
| 91366348 | CPT | 3/4 | 36 | 4/29/2018 | 3,088.97 | REPLACED S SVC |
| 91370087 | MED | 3/4 | 19 | 5/6/2018 | 616.35 | REPLACEMENT |
| 91370099 | TAL | 3/4 | 16 | 5/6/2018 | 2,276.30 | REPLACED S SVC |
| 91370501 | MED | 3/4 | 70 | 5/6/2018 | 6,721.25 | REPLACED AA |
| 91370503 | MED | 3/4 | 32 | 5/6/2018 | 3,492.00 | REPLACEMENT |
| 91375264 | GPS | 3/4 | 80 | 5/13/2018 | 4,629.96 | REPLACEMENT |
| 91375317 | GPS | 3/4 | 78 | 5/13/2018 | 5,081.36 | REPLACED SHALLOW SERVICE |
| 91379620 | MED | 3/4 | 8 | 5/20/2018 | 2,668.11 | REPLACED SHALLOW SERVICE |
| 91379639 | MED | 3/4 | 88 | 5/20/2018 | 11,757.17 | REPLACED S SVC |
| 91379692 | GPS | 3/4 | 160 | 5/20/2018 | 9,178.29 | REPLACED S SVC |
| 91379693 | GPS | 3/4 | 71 | 5/20/2018 | 3,209.87 | REPLACED S SVC |
| 91384421 | MED | 3/4 | 14 | 5/20/2018 | 781.19 | REPLACEMENT |
| 91384600 | MED | 3/4 | 16 | 5/27/2018 | 2,934.88 | REPLACEMENT |
| 91384613 | PNX | 3/4 | 5 | 5/27/2018 | 2,394.92 | REPLACED S SVC |
| 91384753 | GOLD | 3/4 | 8 | 5/27/2018 | 7,946.58 | REPLACED S SVC |
| 91387460 | GPS | 3/4 | 35 | 5/27/2018 | 1,811.69 | REPLACED S SVC |
| 91384807 | GPS | 3/4 | 84 | 5/27/2018 | 11,349.55 | REPLACED S SVC |
| 91385170 | MED | 3/4 | 58 | 5/27/2018 | 4,810.85 | REPLACED S SVC |
| 91388393 | MED | 3/4 | 75 | 6/3/2018 | 2,175.71 | REPLACEMENT |
| 91388511 | GPS | 3/4 | 90 | 6/3/2018 | 4,444.29 | REPLACED S SVC |
| 91392915 | ASH | 3/4 | 35 | 6/10/2018 | 4,604.18 | REPLACED S SVC |
| 91392920 | GPS | 3/4 | 218 | 6/10/2018 | 3,909.10 | REPLACEMENT |
| 91397101 | MED | 3/4 | 81 | 6/17/2018 | 1,337.39 | REPLACED AA |
| 91397109 | MED | 3/4 | 82 | 6/17/2018 | 2,113.68 | REPLACED AA |
| 91397491 | GPS | 3/4 | 72 | 6/17/2018 | 3,406.90 | REPLACED S SVC |
| 91402116 | ASH | 3/4 | 45 | 6/24/2018 | 4,133.33 | REPLACED S SVC |
| 91402170 | ASH | 3/4 | 123 | 6/24/2018 | 8,662.87 | REPLACED S SVC |
| 91407029 | MED | 3/4 | 54 | 7/1/2018 | 1,591.30 | REPLACEMENT |
| 91407067 | MED | 3/4 | 62 | 7/1/2018 | 1,718.21 | REPLACEMENT |
| 91407534 | PNX | 3/4 | 52 | 7/1/2018 | 4,244.22 | REPLACEMENT |
| 91407577 | GPS | 3/4 | 100 | 7/1/2018 | 15,863.26 | REPLACEMENT |
| 91407610 | ASH | 3/4 | 135 | 7/1/2018 | 10,509.25 | REPLACED S SVC |
| 91412447 | ASH | 3/4 | 32 | 7/8/2018 | 1,783.74 | REPLACED AA |
| 91362403 | MED | 3/4 | 60 | 4/22/2018 | 1,342.40 | REPLACEMENT |
| 91378544 | MED | 3/4 | 92 | 6/17/2018 | 11,787.15 | REPLACEMENT |
| 91388357 | ASH | 3/4 | 83 | 6/3/2018 | 4,970.14 | REPLACEMENT |
| 91411832 | MED | 3/4 | 75 | 7/8/2018 | 5,267.24 | REPLACED S SVC |
| 91412429 | ASH | 3/4 | 34 | 7/8/2018 | 3,168.50 | REPLACED S SVC |
| 91412460 | GPS | 3/4 | 150 | 7/8/2018 | 1,808.88 | REPLACEMENT |
| 91412463 | GPS | 3/4 | 22 | 7/8/2018 | 2,112.16 | REPLACEMENT |
| 91415857 | MED | 3/4 | 52 | 7/15/2018 | 4,831.89 | REPLACED AA |
| 91415931 | PNX | 3/4 | 30 | 7/15/2018 | 8,034.81 | REPLACEMENT |
| 91415970 | ASH | 3/4 | 10 | 7/15/2018 | 2,284.84 | REPLACEMENT |
| 91415963 | TAL | 3/4 | 100 | 7/15/2018 | 6,451.33 | REPLACED S SVC |
| 91416080 | GPS | 3/4 | 55 | 7/15/2018 | 2,274.47 | REPLACEMENT |
| 91419444 | MED | 3/4 | 76 | 7/22/2018 | 5,190.43 | REPLACED S SVC |
| 91419446 | MED | 3/4 | 60 | 7/22/2018 | 1,179.62 | REPLACEMENT |
| 91419475 | ASH | 3/4 | 134 | 7/22/2018 | 6,903.51 | REPLACED S SVC |
| 91419477 | ASH | 3/4 | 127 | 7/22/2018 | 5,890.25 | REPLACED S SVC |
| 91419545 | GPS | 3/4 | 70 | 7/22/2018 | 5,525.20 | REPLACED S SVC |
| 91424062 | CPT | 3/4 | 59 | 7/19/2018 | 1,979.67 | REPLACEMENT |
| 91424096 | MED | 3/4 | 2 | 7/29/2018 | 2,687.12 | REPLACEMENT |
| 91424098 | ASH | 3/4 | 50 | 7/29/2018 | 5,064.36 | REPLACED S SVC |
| 91424282 | GPS | 3/4 | 60 | 7/29/2018 | 5,231.47 | REPLACEMENT |
| 91428087 | ASH | 3/4 | 140 | 8/5/2018 | 6,062.43 | REPLACED S SVC |
| 91428098 | MED | 3/4 | 18 | 8/5/2018 | 773.80 | REPLACEMENT |
| 91428099 | ASH | 3/4 | 25 | 8/5/2019 | 3,046.13 | REPLACED S SVC |
| 91407337 | PNX | 3/4 | 37 | 7/1/2018 | 2,480.37 | REPLACEMENT |
| 91424289 | GPS | 3/4 | 348 | 7/29/2018 | 9,897.73 | REPLACED S SVC |
| 91428097 | MED | 3/4 | 62 | 8/5/2018 | 5,216.46 | REPLACED S SVC |
| 91433054 | MED | 3/4 | 200 | 8/12/2018 | 10,288.10 | REPLACED S SVC |
| 91437556 | ASH | 3/4 | 70 | 8/19/2018 | 1,143.43 | REPLACED AA |
| 91433105 | GPS | 3/4 | 4 | 8/12/2018 | 379.83 | REPLACEMENT |
| 91433107 | GPS | 3/4 | 60 | 8/12/2018 | 2,285.71 | REPLACED S SVC |
| 91433117 | MED | 3/4 | 24 | 8/12/2018 | 1,625.59 | REPLACED AA |
| 91437542 | JAC | 3/4 | 12 | 8/19/2018 | 5,169.99 | REPLACEMENT |
| 91437582 | MED | 3/4 | 20 | 8/19/2018 | 1,930.66 | REPLACEMENT |
| 91433070 | ASH | 3/4 | 70 | 8/12/2018 | 11,855.00 | REPLACED S SVC |
| 91437585 | MED | 3/4 | 46 | 8/19/2018 | 4,467.74 | REPLACED S SVC |
| 91437607 | GOLD | 3/4 | 68 | 8/19/2018 | 4,602.98 | REPLACED S SVC |
| 91437704 | MED | 3/4 | 36 | 8/19/2018 | 4,020.69 | REPLACED S SVC |
| 91437704 | MED | 3/4 | 153 | 8/19/2018 | 10,326.42 | REPLACED S SVC |
| 91442216 | ASH | 3/4 | 129 | 8/26/2018 | 4,599.36 | REPLACED S SVC |
| 91442237 | MED | 3/4 | 105 | 8/26/2018 | 6,692.32 | REPLACED S SVC |
| 91442266 | MED | 3/4 | 35 | 8/26/2018 | 4,090.10 | REPLACED S SVC |
| 91447199 | GPS | 3/4 | 139 | 9/2/2018 | 10,924.79 | REPLACED AA |
| 91450962 | MED | 3/4 | 22 | 9/9/2018 | 3,341.65 | REPLACED S SVC |
| 91450967 | MED | 3/4 | 38 | 9/9/2018 | 2,314.45 | REPLACEMENT |
| 91450966 | MED | 3/4 | 3 | 9/9/2018 | 1,509.80 | REPLACEMENT |
| 91407337 | PNX | 3/4 | 37 | 7/1/2018 | 2,480.37 | REPLACEMENT |
| 91424289 | GPS | 3/4 | 38 | 7/29/2018 | 9,894.73 | REPLACED S SVC |
| 91433054 | MED | 3/4 | 200 | 8/12/2018 | 10,288.10 | REPLACED S SVC |
| 91437542 | JAC | 3/4 | 12 | 8/19/2018 | 5,169.99 | REPLACEMENT |
| 91437556 | ASH | 3/4 | 8 | 8/19/2018 | 1,142.43 | REPLACED AA |
| 91437607 | GOLD | 3/4 | 68 | 8/19/2018 | 4,752.50 | REPLACED S SVC |
| 91437608 | GOLD | 3/4 | 20 | 8/19/2018 | 4,602.98 | REPLACED S SVC |
| 91442216 | ASH | 3/4 | 129 | 8/26/2019 | 4,599.36 | REPLACED S SVC |
| 91446934 | PNX | 3/4 | 121 | 9/2/2018 | 1,584.76 | REPLACEMENT |
| 91446935 | MED | 3/4 | 4 | 9/2/2018 | 1,585.81 | REPLACEMENT |
| 91450933 | PNX | 3/4 | 90 | 9/9/2018 | 5,579.70 | REPLACED AA |
| 91450972 | MED | 3/4 | 18 | 9/9/2018 | 1,197.33 | REPLACEMENT |
| 91450980 | MED | 3/4 | 35 | 9/9/2018 | 9,996.22 | REPLACED S SVC |
| 91459890 | MED | 3/4 | 13 | 9/23/2018 | 1,230.00 | REPLACEMENT |
| 91459926 | CPT | 3/4 | 15 | 9/23/2018 | 2,351.67 | REPLACEMENT |
| 91459952 | MED | 3/4 | 42 | 9/23/2018 | 10,545.55 | REPLACEMENT |
| 91465624 | MED | 3/4 | 50 | 9/30/2018 | 6,974.82 | REPLACED S SVC |
| 91465644 | MED | 3/4 | 80 | 9/30/2018 | 7,830.70 | REPLACED S SVC |
| 91450971 | MED | 3/4 | 45 | 9/9/2018 | 4,148.26 | REPLACED AA |
| 91471541 | GPS | 3/4 | 44 | 10/7/2018 | 3,468.35 | REPLACED AA |
| 91471638 | MED | 3/4 | 12 | 10/7/2018 | 3,683.88 | REPLACED S SVC |
| 91479362 | MED | 3/4 | 98 | 10/21/2018 | 5,807.74 | REPLACED S SVC |
| 91484637 | JAC | 3/4 | 130 | 10/28/2018 | 7,287.88 | REPLACEMENT |
| 91484638 | MED | 3/4 | 10 | 10/28/2018 | 1,708.27 | REPLACED AA |
| 91490369 | MED | 3/4 | 100 | 11/4/2018 | 4,251.38 | REPLACED S SVC |
| 91494965 | JAC | 3/4 | 10 | 11/11/2018 | 4,081.06 | REPLACED S SVC |
| 91495009 | JAC | 3/4 | 7 | 11/11/2018 | 3,748.37 | REPLACED S SVC |
| 91495029 | GPS | 3/4 | 6 | 11/11/2018 | 2,451.91 | REPLACEMENT |
| 91490438 | GLE | 3/4 | 15 | 11/4/2018 | 1,916.93 | REPLACED S SVC |
| 91490440 | GPS | 3/4 | 60 | 11/4/2018 | 4,701.67 | REPLACED S SVC |
| 91490447 | GPS | 3/4 | 8 | 11/4/2018 | 5,195.63 | REPLACED S SVC |
| 91494951 | MED | 3/4 | 130 | 11/11/2018 | 8,626.07 | REPLACED AA |
| 91495004 | ASH | 3/4 | 22 | 11/11/2018 | 1,326.90 | REPLACEMENT |
| 91495020 | GPS | 3/4 | 4 | 11/11/2018 | 1,705.17 | REPLACED AA |
| 91495145 | GLE | 3/4 | 36 | 11/11/2018 | 3,664.71 | REPLACED AA |
| 91499123 | GPS | 3/4 | 21 | 11/18/2018 | 3,134.12 | REPLACEMENT |
| 91499128 | MED | 3/4 | 60 | 11/18/2018 | 4,780.74 | REPLACED S SVC |
| 91499130 | MED | 3/4 | 61 | 11/18/2018 | 4,500.92 | REPLACED AA |
| 91499134 | GPS | 3/4 | 4 | 11/18/2018 | 4,722.76 | REPLACEMENT |
| 91499163 | GPS | 3/4 | 50 | 11/18/2018 | 4,283.16 | REPLACED S SVC |
| 91499194 | MED | 3/4 | 45 | 11/18/2018 | 3,634.86 | REPLACED AA |
| 91499197 | MED | 3/4 | 42 | 11/18/2018 | 5,464.23 | REPLACED S SVC |
| 91503768 | MED | 3/4 | 10 | 11/25/2018 | 6,120.25 | REPLACED AA |
| 91503970 | GPS | 3/4 | 12 | 11/25/2018 | 2,963.67 | REPLACED AA |
| 91511820 | GPS | 3/4 | 39 | 12/9/2018 | 4,067.25 | REPLACED S SVC |
| 91511823 | GPS | 3/4 | 40 | 12/8/2018 | 6,646.95 | REPLACEMENT |
| 91511825 | GPS | 3/4 | 10 | 12/9/2018 | 695.89 | REPLACEMENT |
| 91516739 | MED | 3/4 | 13 | 12/16/2018 | 2,568.13 | REPLACED S SVC |
| 91520035 | ASH | 3/4 | 20 | 12/23/2018 | 3,608.36 | REPLACEMENT |
| 91520063 | ASH | 3/4 | 150 | 12/23/2018 | 7,384.93 | REPLACED AA |
| 91520220 | MED | 3/4 | 15 | 12/23/2018 | 3,887.39 | REPLACED S SVC |
| 91520223 | MED | 3/4 | 101 | 12/23/2018 | 5,838.15 | REPLACED S SVC |
| | | | | | | |
| **TOTAL YEARLY REPLACEMENTS = 207** | | | | **TOTAL $ =** | **925,993.55** | |

**Oregon Gas Facilities Replacement Program**
**Transfers-to-Plant**
UG 519. CUB DR - 78a

| | Annual Cost | CPC |
|---|---|---|
| 3-Year Past Average | $8.054.142 | $21.558 |
| 5-Year Past Average | $7.015.452 | $18.778 |
| 7-Year Past Average | $6.941.356 | $18.580 |

| BI Description | Project Number | Project Name | FA Period YYYYMM | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | Grand Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201305 | 438.923 | | | | | | | | | | | | 438.923 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201306 | 69.464 | | | | | | | | | | | | 69.464 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201307 | 27.084 | | | | | | | | | | | | 27.084 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201308 | 24.157 | | | | | | | | | | | | 24.157 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201309 | 27.125 | | | | | | | | | | | | 27.125 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201310 | 53.541 | | | | | | | | | | | | 53.541 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201311 | 141.920 | | | | | | | | | | | | 141.920 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201312 | 284.268 | | | | | | | | | | | | 284.268 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201401 | | 25.052 | | | | | | | | | | | 25.052 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201402 | | 40.890 | | | | | | | | | | | 40.890 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201403 | | (49.102) | | | | | | | | | | | (49.102) |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201404 | | 3.713 | | | | | | | | | | | 3.713 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201405 | | 815 | | | | | | | | | | | 815 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201406 | | 94 | | | | | | | | | | | 94 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201408 | | 72 | | | | | | | | | | | 72 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201411 | | 8.500 | | | | | | | | | | | 8.500 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201412 | | 593 | | | | | | | | | | | 593 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201502 | | | 2.120 | | | | | | | | | | 2.120 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201503 | | | 548 | | | | | | | | | | 548 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201505 | | | 16 | | | | | | | | | | 16 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201508 | | | 30 | | | | | | | | | | 30 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201509 | | | 2.564 | | | | | | | | | | 2.564 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201510 | | | 6.120 | | | | | | | | | | 6.120 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201606 | | | | 535 | | | | | | | | | 535 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201607 | | | | 3.942 | | | | | | | | | 3.942 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201608 | | | | 1.660 | | | | | | | | | 1.660 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201609 | | | | 4.069 | | | | | | | | | 4.069 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201610 | | | | 8.654 | | | | | | | | | 8.654 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201611 | | | | 1.040 | | | | | | | | | 1.040 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201701 | | | | | 11.983 | | | | | | | | 11.983 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201702 | | | | | 3.252 | | | | | | | | 3.252 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201703 | | | | | 1.288 | | | | | | | | 1.288 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201704 | | | | | 20.070 | | | | | | | | 20.070 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201705 | | | | | 24 | | | | | | | | 24 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201706 | | | | | 1.498 | | | | | | | | 1.498 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201707 | | | | | 20.192 | | | | | | | | 20.192 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201708 | | | | | 97.951 | | | | | | | | 97.951 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201709 | | | | | 5.720 | | | | | | | | 5.720 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201710 | | | | | 66.050 | | | | | | | | 66.050 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201711 | | | | | 25.249 | | | | | | | | 25.249 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201712 | | | | | 78.374 | | | | | | | | 78.374 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201801 | | | | | | 128.588 | | | | | | | 128.588 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201802 | | | | | | 19.575 | | | | | | | 19.575 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201803 | | | | | | 680 | | | | | | | 680 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201804 | | | | | | 466 | | | | | | | 466 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201805 | | | | | | 1.148 | | | | | | | 1.148 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201806 | | | | | | 4.555 | | | | | | | 4.555 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201807 | | | | | | 1.274 | | | | | | | 1.274 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201808 | | | | | | 2.479 | | | | | | | 2.479 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201809 | | | | | | 934 | | | | | | | 934 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201810 | | | | | | 1.060 | | | | | | | 1.060 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201811 | | | | | | 1.283 | | | | | | | 1.283 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201812 | | | | | | 1.195 | | | | | | | 1.195 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201901 | | | | | | | 13 | | | | | | 13 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201904 | | | | | | | 507 | | | | | | 507 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201905 | | | | | | | 2.892 | | | | | | 2.892 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201910 | | | | | | | 28.928 | | | | | | 28.928 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201911 | | | | | | | 34.329 | | | | | | 34.329 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 201912 | | | | | | | 24.517 | | | | | | 24.517 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202001 | | | | | | | | (3.703) | | | | | (3.703) |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202003 | | | | | | | | 3.539 | | | | | 3.539 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202004 | | | | | | | | 33.067 | | | | | 33.067 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202005 | | | | | | | | 25.337 | | | | | 25.337 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202006 | | | | | | | | 3.100 | | | | | 3.100 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202007 | | | | | | | | 10.484 | | | | | 10.484 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202008 | | | | | | | | 15.576 | | | | | 15.576 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202009 | | | | | | | | 2.657 | | | | | 2.657 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202010 | | | | | | | | 19.683 | | | | | 19.683 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202011 | | | | | | | | 2.500 | | | | | 2.500 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202012 | | | | | | | | 9.694 | | | | | 9.694 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202101 | | | | | | | | | 27.807 | | | | 27.807 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202102 | | | | | | | | | 30.061 | | | | 30.061 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202103 | | | | | | | | | 45.462 | | | | 45.462 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202104 | | | | | | | | | 14.788 | | | | 14.788 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202105 | | | | | | | | | 8.199 | | | | 8.199 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202106 | | | | | | | | | 7.488 | | | | 7.488 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202107 | | | | | | | | | 780 | | | | 780 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202108 | | | | | | | | | 10.770 | | | | 10.770 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202109 | | | | | | | | | 1.657 | | | | 1.657 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202110 | | | | | | | | | 7.829 | | | | 7.829 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202111 | | | | | | | | | 71.395 | | | | 71.395 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202112 | | | | | | | | | 65.140 | | | | 65.140 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202201 | | | | | | | | | | 5.327 | | | 5.327 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202206 | | | | | | | | | | 183 | | | 183 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202209 | | | | | | | | | | 92 | | | 92 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202210 | | | | | | | | | | 1.009 | | | 1.009 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202212 | | | | | | | | | | 92 | | | 92 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202311 | | | | | | | | | | | 1.826 | | 1.826 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202312 | | | | | | | | | | | 61.545 | | 61.545 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202401 | | | | | | | | | | | | 8.473 | 8.473 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202403 | | | | | | | | | | | | 346 | 346 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202405 | | | | | | | | | | | | 30 | 30 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202406 | | | | | | | | | | | | 447 | 447 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202407 | | | | | | | | | | | | 268 | 268 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202408 | | | | | | | | | | | | 2.849 | 2.849 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202409 | | | | | | | | | | | | 1.753 | 1.753 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202410 | | | | | | | | | | | | 390 | 390 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202411 | | | | | | | | | | | | 176 | 176 |
| BI GN106 - Aldvl -A Pipe Replacement | 06802058 | Aldvl A Pipe Replcmnt OR | 202412 | | | | | | | | | | | | 294 | 294 |
| **BI GN106 - Aldvl -A Pipe Replacement** | **06802058** | **Aldvl A Pipe Replcmnt OR Total** | | **1.066.482** | **30.627** | **11.398** | **19.899** | **331.651** | **163.237** | **91.185** | **121.934** | **291.377** | **6.701** | **63.371** | **15.826** | **2.212.888** |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 201607 | | | | 16.722 | | | | | | | | | 16.722 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 201608 | | | | 22.468 | | | | | | | | | 22.468 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 201609 | | | | 10.113 | | | | | | | | | 10.113 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 201610 | | | | 4.015 | | | | | | | | | 4.015 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 201706 | | | | | 27.749 | | | | | | | | 27.749 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 201709 | | | | | 7.449 | | | | | | | | 7.449 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 201710 | | | | | 1.734 | | | | | | | | 1.734 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 201712 | | | | | 12.155 | | | | | | | | 12.155 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 201801 | | | | | | 49 | | | | | | | 49 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 201803 | | | | | | 2.384 | | | | | | | 2.384 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 201810 | | | | | | 19.803 | | | | | | | 19.803 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 201901 | | | | | | | 636 | | | | | | 636 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 201904 | | | | | | | 38.082 | | | | | | 38.082 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 201905 | | | | | | | 34.891 | | | | | | 34.891 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 201908 | | | | | | | 404 | | | | | | 404 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 201912 | | | | | | | 11.574 | | | | | | 11.574 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202002 | | | | | | | | 493 | | | | | 493 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202003 | | | | | | | | 402 | | | | | 402 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202008 | | | | | | | | 397 | | | | | 397 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202009 | | | | | | | | 200 | | | | | 200 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202010 | | | | | | | | 3.279 | | | | | 3.279 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202011 | | | | | | | | 5.430 | | | | | 5.430 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202101 | | | | | | | | | 189 | | | | 189 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202102 | | | | | | | | | 1.814 | | | | 1.814 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202109 | | | | | | | | | 17.360 | | | | 17.360 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202110 | | | | | | | | | 6.883 | | | | 6.883 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202201 | | | | | | | | | | 654 | | | 654 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202202 | | | | | | | | | | 2.582 | | | 2.582 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202203 | | | | | | | | | | 2 | | | 2 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202205 | | | | | | | | | | 4.429 | | | 4.429 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202206 | | | | | | | | | | 2.704 | | | 2.704 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202207 | | | | | | | | | | 293 | | | 293 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202208 | | | | | | | | | | 9.120 | | | 9.120 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202209 | | | | | | | | | | 206 | | | 206 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202210 | | | | | | | | | | 19.654 | | | 19.654 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202212 | | | | | | | | | | 39.271 | | | 39.271 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202301 | | | | | | | | | | | 15.553 | | 15.553 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202302 | | | | | | | | | | | 2.990 | | 2.990 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202303 | | | | | | | | | | | 51 | | 51 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202306 | | | | | | | | | | | 52 | | 52 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202308 | | | | | | | | | | | 30.641 | | 30.641 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202309 | | | | | | | | | | | 20.409 | | 20.409 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202310 | | | | | | | | | | | 33.237 | | 33.237 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202403 | | | | | | | | | | | | 51 | 51 |
| BI GN106 - Aldvl -A Pipe Replacement | 98401129 | AA OR PRIORITY SERVICES-984 | 202406 | | | | | | | | | | | | 13.439 | 13.439 |
| **BI GN106 - Aldvl -A Pipe Replacement** | **98401129** | **AA OR PRIORITY SERVICES-984 Total** | | | | | **53.318** | **49.087** | **22.236** | **85.587** | **10.201** | **26.245** | **79.415** | **102.933** | **13.490** | **442.512** |
| BI GN106 - Aldvl -A Pipe Replacement | 98405187 | Aldvl A Repl Talent OR | 201302 | 1.209.319 | | | | | | | | | | | | 1.209.319 |
| BI GN106 - Aldvl -A Pipe Replacement | 98405187 | Aldvl A Repl Talent OR | 201303 | (44.364) | | | | | | | | | | | | (44.364) |
| BI GN106 - Aldvl -A Pipe Replacement | 98405187 | Aldvl A Repl Talent OR | 201306 | 107 | | | | | | | | | | | | 107 |
| BI GN106 - Aldvl -A Pipe Replacement | 98405187 | Aldvl A Repl Talent OR | 201308 | 12.700 | | | | | | | | | | | | 12.700 |
| BI GN106 - Aldvl -A Pipe Replacement | 98405187 | Aldvl A Repl Talent OR | 201309 | 36.895 | | | | | | | | | | | | 36.895 |
| BI GN106 - Aldvl -A Pipe Replacement | 98405187 | Aldvl A Repl Talent OR | 201408 | | - | | | | | | | | | | | - |
| **BI GN106 - Aldvl -A Pipe Replacement** | **98405187** | **Aldvl A Repl Talent OR Total** | | **1.214.658** | **-** | | | | | | | | | | | **1.214.658** |
| BI GN106 - Aldvl -A Pipe Replacement | 98601129 | AA OR PRIORITY SERVICES-986 | 201807 | | | | | | 1.504 | | | | | | | 1.504 |
| BI GN106 - Aldvl -A Pipe Replacement | 98601129 | AA OR PRIORITY SERVICES-986 | 201808 | | | | | | 4.140 | | | | | | | 4.140 |
| BI GN106 - Aldvl -A Pipe Replacement | 98601129 | AA OR PRIORITY SERVICES-986 | 201809 | | | | | | 36.059 | | | | | | | 36.059 |
| BI GN106 - Aldvl -A Pipe Replacement | 98601129 | AA OR PRIORITY SERVICES-986 | 201810 | | | | | | 106.187 | | | | | | | 106.187 |
| BI GN106 - Aldvl -A Pipe Replacement | 98601129 | AA OR PRIORITY SERVICES-986 | 202211 | | | | | | | | | | 17.429 | | | 17.429 |
| BI GN106 - Aldvl -A Pipe Replacement | 98601129 | AA OR PRIORITY SERVICES-986 | 202301 | | | | | | | | | | | 28.586 | | 28.586 |
| **BI GN106 - Aldvl -A Pipe Replacement** | **98601129** | **AA OR PRIORITY SERVICES-986 Total** | | | | | | | **147.891** | | | | **17.429** | **28.586** | | **193.906** |
| BI GN106 - Aldvl -A Pipe Replacement | 98701129 | AA OR PRIORITY SERVICES-987 | 201610 | | | | 513 | | | | | | | | | 513 |
| BI GN106 - Aldvl -A Pipe Replacement | 98701129 | AA OR PRIORITY SERVICES-987 | 201611 | | | | 18.911 | | | | | | | | | 18.911 |
| BI GN106 - Aldvl -A Pipe Replacement | 98701129 | AA OR PRIORITY SERVICES-987 | 201701 | | | | | 2.961 | | | | | | | | 2.961 |
| BI GN106 - Aldvl -A Pipe Replacement | 98701129 | AA OR PRIORITY SERVICES-987 | 202203 | | | | | | | | | | 26 | | | 26 |
| BI GN106 - Aldvl -A Pipe Replacement | 98701129 | AA OR PRIORITY SERVICES-987 | 202204 | | | | | | | | | | 347 | | | 347 |
| **BI GN106 - Aldvl -A Pipe Replacement** | **98701129** | **AA OR PRIORITY SERVICES-987 Total** | | | | | **19.424** | **2.961** | | | | | **372** | | | **22.757** |
| **BI GN106 - Aldvl -A Pipe Replacement Total** | | | | **2.281.140** | **30.627** | **11.398** | **92.641** | **383.699** | **333.364** | **176.773** | **132.135** | **317.622** | **103.918** | **194.890** | **28.516** | **4.086.721** |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405218 | AA OR Main Major White City | 201301 | 66 | | | | | | | | | | | | 66 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405218 | AA OR Main Major White City | 201302 | 6.470 | | | | | | | | | | | | 6.470 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405218 | AA OR Main Major White City | 201303 | 6.879 | | | | | | | | | | | | 6.879 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405218 | AA OR Main Major White City | 201304 | 66.646 | | | | | | | | | | | | 66.646 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405218 | AA OR Main Major White City | 201305 | 220.279 | | | | | | | | | | | | 220.279 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405218 | AA OR Main Major White City | 201306 | 186.663 | | | | | | | | | | | | 186.663 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405218 | AA OR Main Major White City | 201307 | 415.877 | | | | | | | | | | | | 415.877 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405218 | AA OR Main Major White City | 201308 | 298.119 | | | | | | | | | | | | 298.119 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405218 | AA OR Main Major White City | 201309 | 233.501 | | | | | | | | | | | | 233.501 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405218 | AA OR Main Major White City | 201310 | 219.953 | | | | | | | | | | | | 219.953 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405218 | AA OR Main Major White City | 201311 | 199.013 | | | | | | | | | | | | 199.013 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405218 | AA OR Main Major White City | 201312 | 271.539 | | | | | | | | | | | | 271.539 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405218 | AA OR Main Major White City | 201401 | | 20.218 | | | | | | | | | | | 20.218 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405218 | AA OR Main Major White City | 201402 | | 11.993 | | | | | | | | | | | 11.993 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405218 | AA OR Main Major White City | 201403 | | (22.419) | | | | | | | | | | | (22.419) |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405218 | AA OR Main Major White City | 201512 | | | - | | | | | | | | | | - |
| **BI GN214 - Aldvl A OR - Main Pipe Major Project** | **98405218** | **AA OR Main Major White City Total** | | **2.125.006** | **9.792** | **-** | | | | | | | | | | **2.134.798** |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405238 | AA OR main major White City W | 201401 | | 27.014 | | | | | | | | | | | 27.014 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405238 | AA OR main major White City W | 201402 | | 34.762 | | | | | | | | | | | 34.762 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405238 | AA OR main major White City W | 201403 | | 187.092 | | | | | | | | | | | 187.092 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405238 | AA OR main major White City W | 201404 | | 256.185 | | | | | | | | | | | 256.185 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405238 | AA OR main major White City W | 201405 | | 180.124 | | | | | | | | | | | 180.124 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405238 | AA OR main major White City W | 201406 | | 173.074 | | | | | | | | | | | 173.074 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405238 | AA OR main major White City W | 201407 | | 164.914 | | | | | | | | | | | 164.914 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405238 | AA OR main major White City W | 201408 | | 316.399 | | | | | | | | | | | 316.399 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405238 | AA OR main major White City W | 201409 | | 631.187 | | | | | | | | | | | 631.187 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405238 | AA OR main major White City W | 201410 | | 107.465 | | | | | | | | | | | 107.465 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405238 | AA OR main major White City W | 201411 | | 504.712 | | | | | | | | | | | 504.712 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405238 | AA OR main major White City W | 201412 | | 223.821 | | | | | | | | | | | 223.821 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405238 | AA OR main major White City W | 201501 | | | 36.570 | | | | | | | | | | 36.570 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405238 | AA OR main major White City W | 201502 | | | 96.175 | | | | | | | | | | 96.175 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405238 | AA OR main major White City W | 201503 | | | 7.131 | | | | | | | | | | 7.131 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405238 | AA OR main major White City W | 201504 | | | 2.143 | | | | | | | | | | 2.143 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405238 | AA OR main major White City W | 201505 | | | 3.346 | | | | | | | | | | 3.346 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405238 | AA OR main major White City W | 201510 | | | 8 | | | | | | | | | | 8 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405238 | AA OR main major White City W | 201512 | | | - | | | | | | | | | | - |

| BI Description | Project Number | Project Name | FA Period YYYYMM | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | Grand Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **BI GN214 - Aldvl A OR - Main Pipe Major Project** | **98405238** | **AA OR main major White City W Total** | | | **2.806.751** | **145.374** | | | | | | | | | | **2.952.125** |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201412 | | 6.830 | | | | | | | | | | | 6.830 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201501 | | | 11.632 | | | | | | | | | | 11.632 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201502 | | | 311.596 | | | | | | | | | | 311.596 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201503 | | | 552.188 | | | | | | | | | | 552.188 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201504 | | | 350.930 | | | | | | | | | | 350.930 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201505 | | | 613.930 | | | | | | | | | | 613.930 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201506 | | | 350.913 | | | | | | | | | | 350.913 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201507 | | | 195.383 | | | | | | | | | | 195.383 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201508 | | | 767.898 | | | | | | | | | | 767.898 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201509 | | | 512.404 | | | | | | | | | | 512.404 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201510 | | | 77.818 | | | | | | | | | | 77.818 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201511 | | | 495.376 | | | | | | | | | | 495.376 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201512 | | | 363.344 | | | | | | | | | | 363.344 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201601 | | | | 41.954 | | | | | | | | | 41.954 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201602 | | | | 162.738 | | | | | | | | | 162.738 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201603 | | | | 121.559 | | | | | | | | | 121.559 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201604 | | | | 257.238 | | | | | | | | | 257.238 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201605 | | | | 122.474 | | | | | | | | | 122.474 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201606 | | | | 130.475 | | | | | | | | | 130.475 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201607 | | | | 16.984 | | | | | | | | | 16.984 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201608 | | | | 1.679 | | | | | | | | | 1.679 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201609 | | | | 3.323 | | | | | | | | | 3.323 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201610 | | | | 2.962 | | | | | | | | | 2.962 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201611 | | | | 3.267 | | | | | | | | | 3.267 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201701 | | | | | 7.610 | | | | | | | | 7.610 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201702 | | | | | 3.352 | | | | | | | | 3.352 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201703 | | | | | 3.334 | | | | | | | | 3.334 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201704 | | | | | 3.334 | | | | | | | | 3.334 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201705 | | | | | 3.334 | | | | | | | | 3.334 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201706 | | | | | 4.670 | | | | | | | | 4.670 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201707 | | | | | 673 | | | | | | | | 673 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405253 | AA OR MainMajor MedfordEast'15 | 201712 | | | | | 419 | | | | | | | | 419 |
| | | | | | | | | | | | | | | | | |
| **BI GN214 - Aldvl A OR - Main Pipe Major Project** | **98405253** | **AA OR MainMajor MedfordEast'15 Total** | | | **6.830** | **4.603.412** | **869.603** | **26.724** | | | | | | | | **5.506.569** |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201511 | | | 426 | | | | | | | | | | 426 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201512 | | | 66 | | | | | | | | | | 66 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201601 | | | | 8.571 | | | | | | | | | 8.571 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201602 | | | | 14.924 | | | | | | | | | 14.924 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201603 | | | | 155.861 | | | | | | | | | 155.861 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201604 | | | | 48.406 | | | | | | | | | 48.406 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201605 | | | | 98.426 | | | | | | | | | 98.426 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201606 | | | | 289.710 | | | | | | | | | 289.710 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201607 | | | | 496.868 | | | | | | | | | 496.868 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201608 | | | | 152.475 | | | | | | | | | 152.475 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201609 | | | | 131.303 | | | | | | | | | 131.303 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201610 | | | | 278.686 | | | | | | | | | 278.686 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201611 | | | | 691.843 | | | | | | | | | 691.843 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201701 | | | | | 640.655 | | | | | | | | 640.655 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201702 | | | | | 1.566 | | | | | | | | 1.566 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201703 | | | | | 2.742 | | | | | | | | 2.742 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201704 | | | | | 1.278 | | | | | | | | 1.278 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201705 | | | | | 1.464 | | | | | | | | 1.464 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201706 | | | | | 6.391 | | | | | | | | 6.391 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201707 | | | | | 78.148 | | | | | | | | 78.148 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201708 | | | | | 6.790 | | | | | | | | 6.790 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201709 | | | | | 9.366 | | | | | | | | 9.366 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201710 | | | | | 51.618 | | | | | | | | 51.618 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201711 | | | | | 11.465 | | | | | | | | 11.465 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201712 | | | | | 138.511 | | | | | | | | 138.511 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201801 | | | | | | (2.927) | | | | | | | (2.927) |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201802 | | | | | | 12.244 | | | | | | | 12.244 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201803 | | | | | | 2.471 | | | | | | | 2.471 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201804 | | | | | | 3.138 | | | | | | | 3.138 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201805 | | | | | | 1.266 | | | | | | | 1.266 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201806 | | | | | | 3.773 | | | | | | | 3.773 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405276 | AA OR MainMajor MedfordE'16 | 201807 | | | | | | 1.527 | | | | | | | 1.527 |
| **BI GN214 - Aldvl A OR - Main Pipe Major Project** | **98405276** | **AA OR MainMajor MedfordE'16 Total** | | | | **492** | **2.367.073** | **949.995** | **16.492** | | | | | | | **3.334.052** |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405295 | AA OR Main Major MedfrdE CO 16 | 201811 | | | | | | 38.903 | | | | | | | 38.903 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405295 | AA OR Main Major MedfrdE CO 16 | 201812 | | | | | | 83.295 | | | | | | | 83.295 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405295 | AA OR Main Major MedfrdE CO 16 | 201901 | | | | | | | 19.114 | | | | | | 19.114 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405295 | AA OR Main Major MedfrdE CO 16 | 201902 | | | | | | | 2.773 | | | | | | 2.773 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405295 | AA OR Main Major MedfrdE CO 16 | 201903 | | | | | | | 30.233 | | | | | | 30.233 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405295 | AA OR Main Major MedfrdE CO 16 | 201904 | | | | | | | (30.233) | | | | | | (30.233) |
| | | | | | | | | | | | | | | | | |
| **BI GN214 - Aldvl A OR - Main Pipe Major Project** | **98405295** | **AA OR Main Major MedfrdE CO 16 Total** | | | | | | | **122.198** | **21.887** | | | | | | **144.085** |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201711 | | | | | 4.550 | | | | | | | | 4.550 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201712 | | | | | 11.882 | | | | | | | | 11.882 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201801 | | | | | | 4.805 | | | | | | | 4.805 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201802 | | | | | | 13.190 | | | | | | | 13.190 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201803 | | | | | | 13.494 | | | | | | | 13.494 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201804 | | | | | | 16.778 | | | | | | | 16.778 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201805 | | | | | | 12.911 | | | | | | | 12.911 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201806 | | | | | | 13.782 | | | | | | | 13.782 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201807 | | | | | | 10.527 | | | | | | | 10.527 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201808 | | | | | | 6.995 | | | | | | | 6.995 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201809 | | | | | | 13.753 | | | | | | | 13.753 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201810 | | | | | | 16.870 | | | | | | | 16.870 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201811 | | | | | | 19.126 | | | | | | | 19.126 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201812 | | | | | | 37.803 | | | | | | | 37.803 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201901 | | | | | | | (769) | | | | | | (769) |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201902 | | | | | | | 208.196 | | | | | | 208.196 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201903 | | | | | | | 491.195 | | | | | | 491.195 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201904 | | | | | | | 309.400 | | | | | | 309.400 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201905 | | | | | | | 386.566 | | | | | | 386.566 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201906 | | | | | | | 383.721 | | | | | | 383.721 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201907 | | | | | | | 136.570 | | | | | | 136.570 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201908 | | | | | | | 278.261 | | | | | | 278.261 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201909 | | | | | | | 133.120 | | | | | | 133.120 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201910 | | | | | | | 120.401 | | | | | | 120.401 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201911 | | | | | | | 65.621 | | | | | | 65.621 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 201912 | | | | | | | 3.524 | | | | | | 3.524 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202001 | | | | | | | | 1.826 | | | | | 1.826 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202002 | | | | | | | | 2.399 | | | | | 2.399 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202003 | | | | | | | | 1.445 | | | | | 1.445 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202004 | | | | | | | | 4.177 | | | | | 4.177 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202005 | | | | | | | | 1.499 | | | | | 1.499 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202011 | | | | | | | | (5.670) | | | | | (5.670) |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202012 | | | | | | | | 1.171 | | | | | 1.171 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202101 | | | | | | | | | (603) | | | | (603) |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202104 | | | | | | | | | 4.665 | | | | 4.665 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202105 | | | | | | | | | 354 | | | | 354 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202106 | | | | | | | | | 5.090 | | | | 5.090 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202107 | | | | | | | | | 567 | | | | 567 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202110 | | | | | | | | | 1.202 | | | | 1.202 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202111 | | | | | | | | | 1.641 | | | | 1.641 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202201 | | | | | | | | | | 38 | | | 38 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202202 | | | | | | | | | | 3.868 | | | 3.868 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202203 | | | | | | | | | | (2.902) | | | (2.902) |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202205 | | | | | | | | | | 3.936 | | | 3.936 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202206 | | | | | | | | | | 358 | | | 358 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202209 | | | | | | | | | | 184 | | | 184 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202210 | | | | | | | | | | 184 | | | 184 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202211 | | | | | | | | | | 727 | | | 727 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202212 | | | | | | | | | | 2.831 | | | 2.831 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202303 | | | | | | | | | | | 355 | | 355 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202307 | | | | | | | | | | | 261 | | 261 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202310 | | | | | | | | | | | 3.902 | | 3.902 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202311 | | | | | | | | | | | 1.551 | | 1.551 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202312 | | | | | | | | | | | 1.316 | | 1.316 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202401 | | | | | | | | | | | | 544 | 544 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202402 | | | | | | | | | | | | 3.385 | 3.385 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202403 | | | | | | | | | | | | 637 | 637 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202404 | | | | | | | | | | | | 503 | 503 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202405 | | | | | | | | | | | | 294 | 294 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202407 | | | | | | | | | | | | 1.877 | 1.877 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405313 | AA OR Main Major S Medford '18 | 202409 | | | | | | | | | | | | 59 | 59 |
| **BI GN214 - Aldvl A OR - Main Pipe Major Project** | **98405313** | **AA OR Main Major S Medford '18 Total** | | | | | | **16.432** | **180.034** | **2.515.855** | **6.846** | **12.917** | **9.224** | **7.386** | **7.300** | **2.755.994** |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 201812 | | | | | | 973 | | | | | | | 973 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 201901 | | | | | | | 17.270 | | | | | | 17.270 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 201902 | | | | | | | 122.310 | | | | | | 122.310 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 201903 | | | | | | | 61.040 | | | | | | 61.040 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 201904 | | | | | | | 63.524 | | | | | | 63.524 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 201905 | | | | | | | 54.617 | | | | | | 54.617 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 201906 | | | | | | | 134.438 | | | | | | 134.438 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 201907 | | | | | | | 92.758 | | | | | | 92.758 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 201908 | | | | | | | 210.684 | | | | | | 210.684 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 201909 | | | | | | | 248.432 | | | | | | 248.432 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 201910 | | | | | | | 201.000 | | | | | | 201.000 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 201911 | | | | | | | 508.452 | | | | | | 508.452 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 201912 | | | | | | | 635.562 | | | | | | 635.562 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202001 | | | | | | | | 131.464 | | | | | 131.464 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202002 | | | | | | | | 250.434 | | | | | 250.434 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202003 | | | | | | | | 505.860 | | | | | 505.860 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202004 | | | | | | | | 289.442 | | | | | 289.442 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202005 | | | | | | | | 394.310 | | | | | 394.310 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202006 | | | | | | | | 568.133 | | | | | 568.133 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202007 | | | | | | | | 129.671 | | | | | 129.671 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202008 | | | | | | | | 34.652 | | | | | 34.652 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202009 | | | | | | | | 153.550 | | | | | 153.550 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202010 | | | | | | | | 48.460 | | | | | 48.460 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202011 | | | | | | | | 24.118 | | | | | 24.118 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202012 | | | | | | | | 33.265 | | | | | 33.265 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202101 | | | | | | | | | 20.676 | | | | 20.676 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202102 | | | | | | | | | 21.764 | | | | 21.764 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202103 | | | | | | | | | 16.330 | | | | 16.330 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202104 | | | | | | | | | 32.180 | | | | 32.180 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202105 | | | | | | | | | 102.554 | | | | 102.554 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202106 | | | | | | | | | 151.834 | | | | 151.834 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202107 | | | | | | | | | 137.046 | | | | 137.046 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202108 | | | | | | | | | 20.267 | | | | 20.267 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202109 | | | | | | | | | 49.192 | | | | 49.192 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202110 | | | | | | | | | 27.729 | | | | 27.729 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202111 | | | | | | | | | 32.617 | | | | 32.617 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202112 | | | | | | | | | 33.306 | | | | 33.306 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202201 | | | | | | | | | | 40.502 | | | 40.502 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202202 | | | | | | | | | | 98.414 | | | 98.414 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202203 | | | | | | | | | | 142.817 | | | 142.817 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202204 | | | | | | | | | | 86.367 | | | 86.367 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202205 | | | | | | | | | | 103.095 | | | 103.095 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202206 | | | | | | | | | | 19.731 | | | 19.731 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202207 | | | | | | | | | | 2.330 | | | 2.330 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202208 | | | | | | | | | | 3.336 | | | 3.336 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202209 | | | | | | | | | | 3.145 | | | 3.145 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202210 | | | | | | | | | | 2.108 | | | 2.108 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202211 | | | | | | | | | | 1.112 | | | 1.112 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202212 | | | | | | | | | | 513 | | | 513 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202301 | | | | | | | | | | | 57 | | 57 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202302 | | | | | | | | | | | 101 | | 101 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202303 | | | | | | | | | | | 491 | | 491 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202304 | | | | | | | | | | | 3.353 | | 3.353 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405324 | AA OR Main Major S Medford '19 | 202403 | | | | | | | | | | | | 421 | 421 |
| **BI GN214 - Aldvl A OR - Main Pipe Major Project** | **98405324** | **AA OR Main Major S Medford '19 Total** | | | | | | | **973** | **2.350.087** | **2.563.359** | **645.496** | **503.469** | **4.003** | **421** | **6.067.808** |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 201907 | | | | | | | 211.175 | | | | | | 211.175 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 201908 | | | | | | | (87) | | | | | | (87) |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 201909 | | | | | | | 486 | | | | | | 486 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 201911 | | | | | | | 536 | | | | | | 536 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 201912 | | | | | | | 50.680 | | | | | | 50.680 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202001 | | | | | | | | 12.849 | | | | | 12.849 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202002 | | | | | | | | 11.248 | | | | | 11.248 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202003 | | | | | | | | 21.374 | | | | | 21.374 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202004 | | | | | | | | 12.111 | | | | | 12.111 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202005 | | | | | | | | 19.368 | | | | | 19.368 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202006 | | | | | | | | 112.181 | | | | | 112.181 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202007 | | | | | | | | 184.160 | | | | | 184.160 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202008 | | | | | | | | 10.391 | | | | | 10.391 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202009 | | | | | | | | 101.115 | | | | | 101.115 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202010 | | | | | | | | 12.615 | | | | | 12.615 |

| Bl Description | Project Number | Project Name | FA Period YYYYMM | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | Grand Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202011 | | | | | | | | 7.555 | | | | | 7.555 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202012 | | | | | | | | 13.081 | | | | | 13.081 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202101 | | | | | | | | | 7.705 | | | | 7.705 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202102 | | | | | | | | | 5.175 | | | | 5.175 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202103 | | | | | | | | | 2.390 | | | | 2.390 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202104 | | | | | | | | | 6.863 | | | | 6.863 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202105 | | | | | | | | | 14.270 | | | | 14.270 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202106 | | | | | | | | | 38.347 | | | | 38.347 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202107 | | | | | | | | | 998 | | | | 998 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202108 | | | | | | | | | 7.434 | | | | 7.434 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202110 | | | | | | | | | 703 | | | | 703 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202111 | | | | | | | | | 110 | | | | 110 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202112 | | | | | | | | | 3.736 | | | | 3.736 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202201 | | | | | | | | | | 9.445 | | | 9.445 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202202 | | | | | | | | | | 115.246 | | | 115.246 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202203 | | | | | | | | | | 279.909 | | | 279.909 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202204 | | | | | | | | | | 170.867 | | | 170.867 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202205 | | | | | | | | | | 185.311 | | | 185.311 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202206 | | | | | | | | | | 103.433 | | | 103.433 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202207 | | | | | | | | | | 4.641 | | | 4.641 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202208 | | | | | | | | | | 28.512 | | | 28.512 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202209 | | | | | | | | | | 24.345 | | | 24.345 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202210 | | | | | | | | | | 10.827 | | | 10.827 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202211 | | | | | | | | | | 3.295 | | | 3.295 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202212 | | | | | | | | | | 3.201 | | | 3.201 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202301 | | | | | | | | | | | 1.874 | | 1.874 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202303 | | | | | | | | | | | 434 | | 434 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202305 | | | | | | | | | | | 4.946 | | 4.946 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202307 | | | | | | | | | | | 6.262 | | 6.262 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202310 | | | | | | | | | | | (2.570) | | (2.570) |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202401 | | | | | | | | | | | | 11.272 | 11.272 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202402 | | | | | | | | | | | | 8.367 | 8.367 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202403 | | | | | | | | | | | | 2.592 | 2.592 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202404 | | | | | | | | | | | | 1.909 | 1.909 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202405 | | | | | | | | | | | | 158 | 158 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202409 | | | | | | | | | | | | 59 | 59 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405333 | AA OR Main Major S Medford '20 | 202411 | | | | | | | | | | | | 59 | 59 |
| **BI GN214 - Aldvl A OR - Main Pipe Major Project** | **98405333** | **AA OR Main Major S Medford '20 Total** | | | | | | | | **262.790** | **518.051** | **87.732** | **939.032** | **10.946** | **24.416** | **1.842.966** |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405339 | AA OR Main Mir Central Pnt '20 | 202111 | | | | | | | | | 271 | | | | 271 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405339 | AA OR Main Mir Central Pnt '20 | 202112 | | | | | | | | | 1.296 | | | | 1.296 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405339 | AA OR Main Mir Central Pnt '20 | 202201 | | | | | | | | | | 128 | | | 128 |
| **BI GN214 - Aldvl A OR - Main Pipe Major Project** | **98405339** | **AA OR Main Mir Central Pnt '20 Total** | | | | | | | | | | **1.567** | **128** | | | **1.695** |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202011 | | | | | | | | 1.654 | | | | | 1.654 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202012 | | | | | | | | 4.091 | | | | | 4.091 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202106 | | | | | | | | | 645 | | | | 645 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202107 | | | | | | | | | 3.976 | | | | 3.976 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202108 | | | | | | | | | 1.289 | | | | 1.289 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202109 | | | | | | | | | 6.990 | | | | 6.990 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202110 | | | | | | | | | 38.350 | | | | 38.350 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202111 | | | | | | | | | 397.352 | | | | 397.352 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202112 | | | | | | | | | 399.389 | | | | 399.389 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202201 | | | | | | | | | | (2.905) | | | (2.905) |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202202 | | | | | | | | | | 84.590 | | | 84.590 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202203 | | | | | | | | | | 123.584 | | | 123.584 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202204 | | | | | | | | | | 54.318 | | | 54.318 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202205 | | | | | | | | | | 39.223 | | | 39.223 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202206 | | | | | | | | | | 4.462 | | | 4.462 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202207 | | | | | | | | | | 6.518 | | | 6.518 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202208 | | | | | | | | | | 5.477 | | | 5.477 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202209 | | | | | | | | | | 43.246 | | | 43.246 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202210 | | | | | | | | | | (18.403) | | | (18.403) |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202211 | | | | | | | | | | 2.012 | | | 2.012 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202212 | | | | | | | | | | 1.383 | | | 1.383 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202301 | | | | | | | | | | | 1.043 | | 1.043 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202302 | | | | | | | | | | | 803 | | 803 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202303 | | | | | | | | | | | 119 | | 119 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202305 | | | | | | | | | | | 618 | | 618 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202307 | | | | | | | | | | | 705 | | 705 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202407 | | | | | | | | | | | | 5.160 | 5.160 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202408 | | | | | | | | | | | | (3.881) | (3.881) |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405359 | AA OR Main Major Eagle Pnt '21 | 202409 | | | | | | | | | | | | 391 | 391 |
| **BI GN214 - Aldvl A OR - Main Pipe Major Project** | **98405359** | **AA OR Main Major Eagle Pnt '21 Total** | | | | | | | | | **5.746** | **847.992** | **343.504** | **3.289** | **1.669** | **1.202.200** |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202107 | | | | | | | | | 684 | | | | 684 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202108 | | | | | | | | | 1.070 | | | | 1.070 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202109 | | | | | | | | | 1.071 | | | | 1.071 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202110 | | | | | | | | | 4.931 | | | | 4.931 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202111 | | | | | | | | | 2.713 | | | | 2.713 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202112 | | | | | | | | | 4.783 | | | | 4.783 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202201 | | | | | | | | | | 1.803 | | | 1.803 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202202 | | | | | | | | | | 3.264 | | | 3.264 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202203 | | | | | | | | | | 28.261 | | | 28.261 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202204 | | | | | | | | | | 9.734 | | | 9.734 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202205 | | | | | | | | | | 24.516 | | | 24.516 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202206 | | | | | | | | | | 152.968 | | | 152.968 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202207 | | | | | | | | | | 18.352 | | | 18.352 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202208 | | | | | | | | | | 72.436 | | | 72.436 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202209 | | | | | | | | | | 86.767 | | | 86.767 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202210 | | | | | | | | | | 135.114 | | | 135.114 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202211 | | | | | | | | | | 106.661 | | | 106.661 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202212 | | | | | | | | | | 781.258 | | | 781.258 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202301 | | | | | | | | | | | 137.923 | | 137.923 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202302 | | | | | | | | | | | 312.264 | | 312.264 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202303 | | | | | | | | | | | 556.500 | | 556.500 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202304 | | | | | | | | | | | 87.290 | | 87.290 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202305 | | | | | | | | | | | 197.421 | | 197.421 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202306 | | | | | | | | | | | 10.440 | | 10.440 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202307 | | | | | | | | | | | 3.415 | | 3.415 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202308 | | | | | | | | | | | 31.908 | | 31.908 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202309 | | | | | | | | | | | 6.442 | | 6.442 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202310 | | | | | | | | | | | 8.337 | | 8.337 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202311 | | | | | | | | | | | 23.708 | | 23.708 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202312 | | | | | | | | | | | 246.713 | | 246.713 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202401 | | | | | | | | | | | | 296.343 | 296.343 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202402 | | | | | | | | | | | | 437.281 | 437.281 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202403 | | | | | | | | | | | | 786.663 | 786.663 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202404 | | | | | | | | | | | | 85.460 | 85.460 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202405 | | | | | | | | | | | | 642.746 | 642.746 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202406 | | | | | | | | | | | | 426.471 | 426.471 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202407 | | | | | | | | | | | | 146.041 | 146.041 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202408 | | | | | | | | | | | | 116.405 | 116.405 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202409 | | | | | | | | | | | | 37.035 | 37.035 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202410 | | | | | | | | | | | | 27.743 | 27.743 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202411 | | | | | | | | | | | | 30.409 | 30.409 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405363 | AA OR Main Mir Medford S E-I5 | 202412 | | | | | | | | | | | | 5.515 | 5.515 |
| **BI GN214 - Aldvl A OR - Main Pipe Major Project** | **98405363** | **AA OR Main Mir Medford S E-I5 Total** | | | | | | | | | | **15.253** | **1.421.133** | **1.622.360** | **3.038.112** | **6.096.858** |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202107 | | | | | | | | | 684 | | | | 684 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202108 | | | | | | | | | 973 | | | | 973 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202109 | | | | | | | | | 286 | | | | 286 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202111 | | | | | | | | | 1.357 | | | | 1.357 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202112 | | | | | | | | | 1.668 | | | | 1.668 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202201 | | | | | | | | | | 2.346 | | | 2.346 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202202 | | | | | | | | | | 3.062 | | | 3.062 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202203 | | | | | | | | | | 3.188 | | | 3.188 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202204 | | | | | | | | | | 4.405 | | | 4.405 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202205 | | | | | | | | | | 4.742 | | | 4.742 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202206 | | | | | | | | | | 10.560 | | | 10.560 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202207 | | | | | | | | | | 5.337 | | | 5.337 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202208 | | | | | | | | | | 93.036 | | | 93.036 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202209 | | | | | | | | | | 82.432 | | | 82.432 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202210 | | | | | | | | | | 20.214 | | | 20.214 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202211 | | | | | | | | | | 1.826 | | | 1.826 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202212 | | | | | | | | | | 1.132 | | | 1.132 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202301 | | | | | | | | | | | 320 | | 320 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202303 | | | | | | | | | | | 192 | | 192 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202306 | | | | | | | | | | | 52 | | 52 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202310 | | | | | | | | | | | 6.242 | | 6.242 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202311 | | | | | | | | | | | 113 | | 113 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202402 | | | | | | | | | | | | 131 | 131 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202403 | | | | | | | | | | | | 1.652 | 1.652 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202404 | | | | | | | | | | | | 2.768 | 2.768 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202405 | | | | | | | | | | | | 126 | 126 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202408 | | | | | | | | | | | | 44 | 44 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202409 | | | | | | | | | | | | 59 | 59 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405364 | AA OR Main Mir Talent | 202410 | | | | | | | | | | | | 59 | 59 |
| **BI GN214 - Aldvl A OR - Main Pipe Major Project** | **98405364** | **AA OR Main Mir Talent Total** | | | | | | | | | | **4.967** | **232.281** | **6.919** | **4.840** | **249.007** |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202107 | | | | | | | | | 410 | | | | 410 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202108 | | | | | | | | | 571 | | | | 571 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202109 | | | | | | | | | 643 | | | | 643 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202110 | | | | | | | | | 572 | | | | 572 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202111 | | | | | | | | | 1.571 | | | | 1.571 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202112 | | | | | | | | | 3.264 | | | | 3.264 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202201 | | | | | | | | | | 3.928 | | | 3.928 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202202 | | | | | | | | | | 3.735 | | | 3.735 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202203 | | | | | | | | | | 4.324 | | | 4.324 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202204 | | | | | | | | | | 5.229 | | | 5.229 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202205 | | | | | | | | | | 11.589 | | | 11.589 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202206 | | | | | | | | | | 46.500 | | | 46.500 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202207 | | | | | | | | | | 26.488 | | | 26.488 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202208 | | | | | | | | | | 139.427 | | | 139.427 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202209 | | | | | | | | | | 291.115 | | | 291.115 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202210 | | | | | | | | | | 112.693 | | | 112.693 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202211 | | | | | | | | | | 148.587 | | | 148.587 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202212 | | | | | | | | | | 61.625 | | | 61.625 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202301 | | | | | | | | | | | 1.496 | | 1.496 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202302 | | | | | | | | | | | 536 | | 536 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202303 | | | | | | | | | | | 1.223 | | 1.223 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202305 | | | | | | | | | | | 412 | | 412 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405365 | AA OR Main Mir Phoenix | 202308 | | | | | | | | | | | 108 | | 108 |
| **BI GN214 - Aldvl A OR - Main Pipe Major Project** | **98405365** | **AA OR Main Mir Phoenix Total** | | | | | | | | | | **7.030** | **855.240** | **3.775** | | **866.045** |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405375 | AA OR Main Mir Medford 1 | 202301 | | | | | | | | | | | 765 | | 765 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405375 | AA OR Main Mir Medford 1 | 202304 | | | | | | | | | | | 1.505 | | 1.505 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405375 | AA OR Main Mir Medford 1 | 202305 | | | | | | | | | | | 180 | | 180 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405375 | AA OR Main Mir Medford 1 | 202306 | | | | | | | | | | | (1.685) | | (1.685) |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405375 | AA OR Main Mir Medford 1 | 202312 | | | | | | | | | | | 806 | | 806 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405375 | AA OR Main Mir Medford 1 | 202401 | | | | | | | | | | | | 3.922 | 3.922 |
| **BI GN214 - Aldvl A OR - Main Pipe Major Project** | **98405375** | **AA OR Main Mir Medford 1 Total** | | | | | | | | | | | | **1.571** | **3.922** | **5.493** |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405382 | AA OR Main Mir Ashland 2024 | 202312 | | | | | | | | | | | 1.428 | | 1.428 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405382 | AA OR Main Mir Ashland 2024 | 202401 | | | | | | | | | | | | 6.395 | 6.395 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405382 | AA OR Main Mir Ashland 2024 | 202402 | | | | | | | | | | | | 34.230 | 34.230 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405382 | AA OR Main Mir Ashland 2024 | 202403 | | | | | | | | | | | | 280.216 | 280.216 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405382 | AA OR Main Mir Ashland 2024 | 202404 | | | | | | | | | | | | 117.908 | 117.908 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405382 | AA OR Main Mir Ashland 2024 | 202405 | | | | | | | | | | | | 120.378 | 120.378 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405382 | AA OR Main Mir Ashland 2024 | 202406 | | | | | | | | | | | | 275.140 | 275.140 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405382 | AA OR Main Mir Ashland 2024 | 202407 | | | | | | | | | | | | 132.532 | 132.532 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405382 | AA OR Main Mir Ashland 2024 | 202408 | | | | | | | | | | | | 168.572 | 168.572 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405382 | AA OR Main Mir Ashland 2024 | 202409 | | | | | | | | | | | | 103.588 | 103.588 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405382 | AA OR Main Mir Ashland 2024 | 202410 | | | | | | | | | | | | 40.232 | 40.232 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405382 | AA OR Main Mir Ashland 2024 | 202411 | | | | | | | | | | | | 24.201 | 24.201 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405382 | AA OR Main Mir Ashland 2024 | 202412 | | | | | | | | | | | | 8.146 | 8.146 |
| **BI GN214 - Aldvl A OR - Main Pipe Major Project** | **98405382** | **AA OR Main Mir Ashland 2024 Total** | | | | | | | | | | | | **1.428** | **1.311.538** | **1.312.966** |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405383 | AA OR Main Mir Cntrl Point '24 | 202312 | | | | | | | | | | | 130 | | 130 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405383 | AA OR Main Mir Cntrl Point '24 | 202401 | | | | | | | | | | | | 2.840 | 2.840 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405383 | AA OR Main Mir Cntrl Point '24 | 202402 | | | | | | | | | | | | 7.756 | 7.756 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405383 | AA OR Main Mir Cntrl Point '24 | 202403 | | | | | | | | | | | | 14.001 | 14.001 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405383 | AA OR Main Mir Cntrl Point '24 | 202404 | | | | | | | | | | | | 9.615 | 9.615 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405383 | AA OR Main Mir Cntrl Point '24 | 202405 | | | | | | | | | | | | 8.425 | 8.425 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405383 | AA OR Main Mir Cntrl Point '24 | 202406 | | | | | | | | | | | | 31.206 | 31.206 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405383 | AA OR Main Mir Cntrl Point '24 | 202407 | | | | | | | | | | | | 200.849 | 200.849 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405383 | AA OR Main Mir Cntrl Point '24 | 202408 | | | | | | | | | | | | 464.600 | 464.600 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405383 | AA OR Main Mir Cntrl Point '24 | 202409 | | | | | | | | | | | | 234.972 | 234.972 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405383 | AA OR Main Mir Cntrl Point '24 | 202410 | | | | | | | | | | | | 65.909 | 65.909 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405383 | AA OR Main Mir Cntrl Point '24 | 202411 | | | | | | | | | | | | 11.113 | 11.113 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98405383 | AA OR Main Mir Cntrl Point '24 | 202412 | | | | | | | | | | | | 11.355 | 11.355 |
| **BI GN214 - Aldvl A OR - Main Pipe Major Project** | **98405383** | **AA OR Main Mir Cntrl Point '24 Total** | | | | | | | | | | | | **130** | **1.062.641** | **1.062.771** |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98605116 | AA OR Main Major Sutherlin '18 | 201801 | | | | | | 2.916 | | | | | | | 2.916 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98605116 | AA OR Main Major Sutherlin '18 | 201802 | | | | | | 4.492 | | | | | | | 4.492 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98605116 | AA OR Main Major Sutherlin '18 | 201803 | | | | | | 10.445 | | | | | | | 10.445 |
| BI GN214 - Aldvl A OR - Main Pipe Major Project | 98605116 | AA OR Main Major Sutherlin '18 | 201804 | | | | | | 106.544 | | | | | | | 106.544 |

| BI_Description | Project Number | Project Name | FA Period YYYYMM | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | Grand Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605116 | AA OR Main Major Sutherlin '18 | 201805 | | | | | | 149.655 | | | | | | | 149.655 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605116 | AA OR Main Major Sutherlin '18 | 201806 | | | | | | 312.450 | | | | | | | 312.450 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605116 | AA OR Main Major Sutherlin '18 | 201807 | | | | | | 395.498 | | | | | | | 395.498 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605116 | AA OR Main Major Sutherlin '18 | 201808 | | | | | | 213.485 | | | | | | | 213.485 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605116 | AA OR Main Major Sutherlin '18 | 201809 | | | | | | 397.083 | | | | | | | 397.083 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605116 | AA OR Main Major Sutherlin '18 | 201810 | | | | | | 196.901 | | | | | | | 196.901 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605116 | AA OR Main Major Sutherlin '18 | 201811 | | | | | | 224.438 | | | | | | | 224.438 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605116 | AA OR Main Major Sutherlin '18 | 201812 | | | | | | 155.235 | | | | | | | 155.235 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605116 | AA OR Main Major Sutherlin '18 | 201901 | | | | | | | 33.423 | | | | | | 33.423 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605116 | AA OR Main Major Sutherlin '18 | 201902 | | | | | | | 586 | | | | | | 586 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605116 | AA OR Main Major Sutherlin '18 | 201904 | | | | | | | 20.123 | | | | | | 20.123 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605116 | AA OR Main Major Sutherlin '18 | 202001 | | | | | | | | 634 | | | | | 634 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605116 | AA OR Main Major Sutherlin '18 | 202207 | | | | | | | | | | 188 | | | 188 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605116 | AA OR Main Major Sutherlin '18 | 202309 | | | | | | | | | | | 153 | | 153 |
| **BI_GN214 - Aldvl A OR - Main Pipe Major Project** | **98605116** | **AA OR Main Major Sutherlin '18 Total** | | | | | | | **2.169.143** | **54.132** | **634** | | **188** | **153** | | **2.224.250** |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605117 | AA OR Main Major Winston 2018 | 201712 | | | | | 642 | | | | | | | | 642 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605117 | AA OR Main Major Winston 2018 | 201801 | | | | | | 9.361 | | | | | | | 9.361 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605117 | AA OR Main Major Winston 2018 | 201802 | | | | | | 17.552 | | | | | | | 17.552 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605117 | AA OR Main Major Winston 2018 | 201803 | | | | | | 59.961 | | | | | | | 59.961 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605117 | AA OR Main Major Winston 2018 | 201804 | | | | | | 1.270.066 | | | | | | | 1.270.066 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605117 | AA OR Main Major Winston 2018 | 201805 | | | | | | 149.028 | | | | | | | 149.028 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605117 | AA OR Main Major Winston 2018 | 201806 | | | | | | 53.742 | | | | | | | 53.742 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605117 | AA OR Main Major Winston 2018 | 201807 | | | | | | 151.584 | | | | | | | 151.584 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605117 | AA OR Main Major Winston 2018 | 201808 | | | | | | 204.854 | | | | | | | 204.854 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605117 | AA OR Main Major Winston 2018 | 201809 | | | | | | 73.039 | | | | | | | 73.039 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605117 | AA OR Main Major Winston 2018 | 201810 | | | | | | 15.716 | | | | | | | 15.716 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605117 | AA OR Main Major Winston 2018 | 201811 | | | | | | 10.621 | | | | | | | 10.621 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605117 | AA OR Main Major Winston 2018 | 201812 | | | | | | 8.893 | | | | | | | 8.893 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605117 | AA OR Main Major Winston 2018 | 201901 | | | | | | | 201 | | | | | | 201 |
| **BI_GN214 - Aldvl A OR - Main Pipe Major Project** | **98605117** | **AA OR Main Major Winston 2018 Total** | | | | | | **642** | **2.024.417** | **201** | | | | | | **2.025.259** |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605139 | AA OR Main Canyonville '20 | 202010 | | | | | | | | 5.539 | | | | | 5.539 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605139 | AA OR Main Canyonville '20 | 202012 | | | | | | | | (5.539) | | | | | (5.539) |
| **BI_GN214 - Aldvl A OR - Main Pipe Major Project** | **98605139** | **AA OR Main Canyonville '20 Total** | | | | | | | | | **-** | | | | | **-** |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605140 | AA OR Main Winston '20 | 202009 | | | | | | | | 39.078 | | | | | 39.078 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605140 | AA OR Main Winston '20 | 202010 | | | | | | | | 1.502 | | | | | 1.502 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605140 | AA OR Main Winston '20 | 202011 | | | | | | | | 115.954 | | | | | 115.954 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605140 | AA OR Main Winston '20 | 202012 | | | | | | | | 3.495 | | | | | 3.495 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605140 | AA OR Main Winston '20 | 202205 | | | | | | | | | | 2.049 | | | 2.049 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605140 | AA OR Main Winston '20 | 202208 | | | | | | | | | | (2.049) | | | (2.049) |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605140 | AA OR Main Winston '20 | 202407 | | | | | | | | | | | | 239 | 239 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605140 | AA OR Main Winston '20 | 202409 | | | | | | | | | | | | 894 | 894 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605140 | AA OR Main Winston '20 | 202410 | | | | | | | | | | | | 2.729 | 2.729 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605140 | AA OR Main Winston '20 | 202411 | | | | | | | | | | | | 3.568 | 3.568 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605140 | AA OR Main Winston '20 | 202412 | | | | | | | | | | | | 2.177 | 2.177 |
| **BI_GN214 - Aldvl A OR - Main Pipe Major Project** | **98605140** | **AA OR Main Winston '20 Total** | | | | | | | | | **160.029** | | **-** | | **9.606** | **169.635** |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202107 | | | | | | | | | 684 | | | | 684 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202109 | | | | | | | | | 797 | | | | 797 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202110 | | | | | | | | | 3.815 | | | | 3.815 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202111 | | | | | | | | | 3.188 | | | | 3.188 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202112 | | | | | | | | | 4.677 | | | | 4.677 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202201 | | | | | | | | | | 4.270 | | | 4.270 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202202 | | | | | | | | | | 4.089 | | | 4.089 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202203 | | | | | | | | | | 4.462 | | | 4.462 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202204 | | | | | | | | | | 40.922 | | | 40.922 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202205 | | | | | | | | | | 196.885 | | | 196.885 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202206 | | | | | | | | | | 185.204 | | | 185.204 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202207 | | | | | | | | | | 101.327 | | | 101.327 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202208 | | | | | | | | | | 247.281 | | | 247.281 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202209 | | | | | | | | | | 569.837 | | | 569.837 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202210 | | | | | | | | | | 303.931 | | | 303.931 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202211 | | | | | | | | | | 185.365 | | | 185.365 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202212 | | | | | | | | | | 40.810 | | | 40.810 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202301 | | | | | | | | | | | 47.466 | | 47.466 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202302 | | | | | | | | | | | 57.405 | | 57.405 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202303 | | | | | | | | | | | 334.017 | | 334.017 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202304 | | | | | | | | | | | 284.255 | | 284.255 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202305 | | | | | | | | | | | 504.913 | | 504.913 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202306 | | | | | | | | | | | 622.874 | | 622.874 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202307 | | | | | | | | | | | 178.096 | | 178.096 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202308 | | | | | | | | | | | 424.402 | | 424.402 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202309 | | | | | | | | | | | 252.174 | | 252.174 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202310 | | | | | | | | | | | 439.086 | | 439.086 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202311 | | | | | | | | | | | 74.634 | | 74.634 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202312 | | | | | | | | | | | 30.098 | | 30.098 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202401 | | | | | | | | | | | | 4.071 | 4.071 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202402 | | | | | | | | | | | | 575 | 575 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202403 | | | | | | | | | | | | 469 | 469 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202404 | | | | | | | | | | | | 22.765 | 22.765 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202405 | | | | | | | | | | | | 3.234 | 3.234 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202406 | | | | | | | | | | | | 2.257 | 2.257 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202407 | | | | | | | | | | | | 10.985 | 10.985 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202409 | | | | | | | | | | | | 262 | 262 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202410 | | | | | | | | | | | | 64 | 64 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605141 | AA OR Main Mir Dillard Winston | 202411 | | | | | | | | | | | | 512 | 512 |
| **BI_GN214 - Aldvl A OR - Main Pipe Major Project** | **98605141** | **AA OR Main Mir Dillard Winston Total** | | | | | | | | | | **13.161** | **1.884.385** | **3.249.421** | **50.194** | **5.197.160** |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202107 | | | | | | | | | 1.176 | | | | 1.176 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202108 | | | | | | | | | 199 | | | | 199 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202109 | | | | | | | | | 629 | | | | 629 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202110 | | | | | | | | | 1.061 | | | | 1.061 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202111 | | | | | | | | | 659 | | | | 659 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202112 | | | | | | | | | 2.734 | | | | 2.734 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202201 | | | | | | | | | | 4.172 | | | 4.172 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202202 | | | | | | | | | | 3.181 | | | 3.181 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202203 | | | | | | | | | | 3.161 | | | 3.161 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202204 | | | | | | | | | | 13.798 | | | 13.798 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202205 | | | | | | | | | | 2.894 | | | 2.894 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202206 | | | | | | | | | | 2.094 | | | 2.094 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202207 | | | | | | | | | | 6.445 | | | 6.445 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202208 | | | | | | | | | | 1.666 | | | 1.666 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202209 | | | | | | | | | | 3.868 | | | 3.868 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202210 | | | | | | | | | | 29.218 | | | 29.218 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202211 | | | | | | | | | | 11.322 | | | 11.322 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202212 | | | | | | | | | | 1.709 | | | 1.709 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202301 | | | | | | | | | | | 4.834 | | 4.834 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202302 | | | | | | | | | | | 77.662 | | 77.662 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202303 | | | | | | | | | | | 102.126 | | 102.126 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202304 | | | | | | | | | | | 94.369 | | 94.369 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202305 | | | | | | | | | | | 146.541 | | 146.541 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202306 | | | | | | | | | | | 19.006 | | 19.006 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202307 | | | | | | | | | | | 1.999 | | 1.999 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202308 | | | | | | | | | | | 3.305 | | 3.305 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202309 | | | | | | | | | | | 3.515 | | 3.515 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202310 | | | | | | | | | | | 2.745 | | 2.745 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202311 | | | | | | | | | | | 106.486 | | 106.486 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202312 | | | | | | | | | | | 48.144 | | 48.144 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202401 | | | | | | | | | | | | 15.017 | 15.017 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202402 | | | | | | | | | | | | 259 | 259 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202403 | | | | | | | | | | | | 64 | 64 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605142 | AA OR Main Mir Canyonville | 202412 | | | | | | | | | | | | 59 | 59 |
| **BI_GN214 - Aldvl A OR - Main Pipe Major Project** | **98605142** | **AA OR Main Mir Canyonville Total** | | | | | | | | | | **6.458** | **83.528** | **610.732** | **15.400** | **716.117** |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202209 | | | | | | | | | | 378 | | | 378 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202210 | | | | | | | | | | 2.895 | | | 2.895 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202211 | | | | | | | | | | 1.068 | | | 1.068 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202212 | | | | | | | | | | 6.475 | | | 6.475 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202301 | | | | | | | | | | | 2.052 | | 2.052 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202302 | | | | | | | | | | | 8.851 | | 8.851 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202303 | | | | | | | | | | | 18.060 | | 18.060 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202304 | | | | | | | | | | | 45.857 | | 45.857 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202305 | | | | | | | | | | | 56.940 | | 56.940 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202306 | | | | | | | | | | | 437.258 | | 437.258 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202307 | | | | | | | | | | | 165.294 | | 165.294 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202308 | | | | | | | | | | | 308.946 | | 308.946 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202309 | | | | | | | | | | | 58.314 | | 58.314 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202310 | | | | | | | | | | | 385.763 | | 385.763 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202311 | | | | | | | | | | | 485.431 | | 485.431 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202312 | | | | | | | | | | | 208.649 | | 208.649 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202401 | | | | | | | | | | | | 4.669 | 4.669 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202402 | | | | | | | | | | | | 13.033 | 13.033 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202403 | | | | | | | | | | | | 64 | 64 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202407 | | | | | | | | | | | | 116 | 116 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202408 | | | | | | | | | | | | 4.925 | 4.925 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202409 | | | | | | | | | | | | 2.986 | 2.986 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98605146 | AA OR Main Mir Roseburg | 202411 | | | | | | | | | | | | 174 | 174 |
| **BI_GN214 - Aldvl A OR - Main Pipe Major Project** | **98605146** | **AA OR Main Mir Roseburg Total** | | | | | | | | | | | **10.816** | **2.181.415** | **25.967** | **2.218.198** |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201512 | | | 6.290 | | | | | | | | | | 6.290 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201601 | | | | 8.829 | | | | | | | | | 8.829 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201602 | | | | 9.436 | | | | | | | | | 9.436 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201603 | | | | 57.141 | | | | | | | | | 57.141 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201604 | | | | 114.978 | | | | | | | | | 114.978 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201605 | | | | 38.441 | | | | | | | | | 38.441 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201606 | | | | 395.721 | | | | | | | | | 395.721 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201607 | | | | 400.966 | | | | | | | | | 400.966 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201608 | | | | 246.993 | | | | | | | | | 246.993 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201609 | | | | 74.830 | | | | | | | | | 74.830 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201610 | | | | 355.601 | | | | | | | | | 355.601 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201611 | | | | 198.228 | | | | | | | | | 198.228 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201701 | | | | | 122.858 | | | | | | | | 122.858 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201702 | | | | | 783 | | | | | | | | 783 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201703 | | | | | 1.814 | | | | | | | | 1.814 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201704 | | | | | 590 | | | | | | | | 590 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201705 | | | | | 1.076 | | | | | | | | 1.076 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201706 | | | | | 47.893 | | | | | | | | 47.893 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201707 | | | | | 55.233 | | | | | | | | 55.233 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201708 | | | | | 11.430 | | | | | | | | 11.430 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201709 | | | | | 99.327 | | | | | | | | 99.327 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201710 | | | | | 839 | | | | | | | | 839 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 201711 | | | | | 678 | | | | | | | | 678 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705085 | AA OR MainMajor NEKlamath '16 | 202002 | | | | | | | | - | | | | | - |
| **BI_GN214 - Aldvl A OR - Main Pipe Major Project** | **98705085** | **AA OR MainMajor NEKlamath '16 Total** | | | | **6.290** | **1.901.164** | **342.520** | | | **-** | | | | | **2.249.974** |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201608 | | | | 2.720 | | | | | | | | | 2.720 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201701 | | | | | 24.227 | | | | | | | | 24.227 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201702 | | | | | 9.262 | | | | | | | | 9.262 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201703 | | | | | 12.010 | | | | | | | | 12.010 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201704 | | | | | 12.196 | | | | | | | | 12.196 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201705 | | | | | 65.186 | | | | | | | | 65.186 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201706 | | | | | 75.433 | | | | | | | | 75.433 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201707 | | | | | 559.572 | | | | | | | | 559.572 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201708 | | | | | 367.317 | | | | | | | | 367.317 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201709 | | | | | 152.266 | | | | | | | | 152.266 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201710 | | | | | 1.190.606 | | | | | | | | 1.190.606 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201711 | | | | | 235.069 | | | | | | | | 235.069 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201712 | | | | | 216.144 | | | | | | | | 216.144 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201801 | | | | | | 31.488 | | | | | | | 31.488 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201802 | | | | | | 5.916 | | | | | | | 5.916 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201803 | | | | | | 7.610 | | | | | | | 7.610 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201804 | | | | | | 38.459 | | | | | | | 38.459 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201805 | | | | | | 242.612 | | | | | | | 242.612 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201806 | | | | | | 245.095 | | | | | | | 245.095 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201807 | | | | | | 441.810 | | | | | | | 441.810 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201808 | | | | | | 496.389 | | | | | | | 496.389 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201809 | | | | | | 399.736 | | | | | | | 399.736 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201810 | | | | | | 265.038 | | | | | | | 265.038 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201811 | | | | | | 312.497 | | | | | | | 312.497 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201812 | | | | | | 129.525 | | | | | | | 129.525 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201901 | | | | | | | 1.176 | | | | | | 1.176 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201902 | | | | | | | 3.235 | | | | | | 3.235 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201906 | | | | | | | 125 | | | | | | 125 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 201909 | | | | | | | 37 | | | | | | 37 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 202010 | | | | | | | | 7.333 | | | | | 7.333 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705089 | AA OR Main Major SE Klmtfls 17 | 202103 | | | | | | | | | 104 | | | | 104 |
| **BI_GN214 - Aldvl A OR - Main Pipe Major Project** | **98705089** | **AA OR Main Major SE Klmtfls 17 Total** | | | | | **2.720** | **2.919.289** | **2.616.174** | **4.573** | **7.333** | **104** | | | | **5.550.192** |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202011 | | | | | | | | 2.253 | | | | | 2.253 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202012 | | | | | | | | 4.258 | | | | | 4.258 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202101 | | | | | | | | | 9.518 | | | | 9.518 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202102 | | | | | | | | | 15.173 | | | | 15.173 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202103 | | | | | | | | | 29.637 | | | | 29.637 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202104 | | | | | | | | | 66.596 | | | | 66.596 |
| BI_GN214 - Aldvl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202105 | | | | | | | | | 185.101 | | | | 185.101 |

| BI Description | Project Number | Project Name | FA Period YYYYMM | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | Grand Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202106 | | | | | | | | | 454.657 | | | | 454.657 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202107 | | | | | | | | | 78.013 | | | | 78.013 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202108 | | | | | | | | | 355.679 | | | | 355.679 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202109 | | | | | | | | | 524.438 | | | | 524.438 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202110 | | | | | | | | | 129.869 | | | | 129.869 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202111 | | | | | | | | | 126.658 | | | | 126.658 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202112 | | | | | | | | | 58.929 | | | | 58.929 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202201 | | | | | | | | | | 7.092 | | | 7.092 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202202 | | | | | | | | | | 4.377 | | | 4.377 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202203 | | | | | | | | | | 3.623 | | | 3.623 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202204 | | | | | | | | | | 2.848 | | | 2.848 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202205 | | | | | | | | | | 1.923 | | | 1.923 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202206 | | | | | | | | | | 27.215 | | | 27.215 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202207 | | | | | | | | | | 71.306 | | | 71.306 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202208 | | | | | | | | | | 88.276 | | | 88.276 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202209 | | | | | | | | | | 29.484 | | | 29.484 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202210 | | | | | | | | | | 4.958 | | | 4.958 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202211 | | | | | | | | | | 705 | | | 705 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202212 | | | | | | | | | | 1.253 | | | 1.253 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202301 | | | | | | | | | | | 57 | | 57 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202305 | | | | | | | | | | | 10.228 | | 10.228 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202306 | | | | | | | | | | | 1.476 | | 1.476 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202307 | | | | | | | | | | | 2.942 | | 2.942 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202310 | | | | | | | | | | | (619) | | (619) |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202312 | | | | | | | | | | | 98 | | 98 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202403 | | | | | | | | | | | | 131 | 131 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202404 | | | | | | | | | | | | 20.734 | 20.734 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202405 | | | | | | | | | | | | 55.287 | 55.287 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202406 | | | | | | | | | | | | 1.567 | 1.567 |
| BI_GN214 - Aldyl A OR - Main Pipe Major Project | 98705110 | Klamath Falls 1 GFRP 2021 | 202407 | | | | | | | | | | | | 239 | 239 |
| **BI_GN214 - Aldyl A OR - Main Pipe Major Project** | **98705110** | **Klamath Falls 1 GFRP 2021 Total** | | | | | | | | | **6.511** | **2.034.268** | **243.058** | **14.183** | **77.959** | **2.375.978** |
| **BI_GN214 - Aldyl A OR - Main Pipe Major Project Total** | | | | **2.125.006** | **2.823.373** | **4.755.568** | **5.140.560** | **4.255.601** | **7.129.432** | **5.209.526** | **3.268.507** | **3.676.944** | **6.525.985** | **7.717.710** | **5.633.985** | **58.262.196** |
| BI_GN215 - Aldyl A OR - STTR Major Project | 06805207 | AA OR STTR CLEAN-UP 2017 | 201712 | | | | | 34.701 | | | | | | | | 34.701 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 06805207 | AA OR STTR CLEAN-UP 2017 | 201801 | | | | | | 26 | | | | | | | 26 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 06805207 | AA OR STTR CLEAN-UP 2017 | 201805 | | | | | | 1.795 | | | | | | | 1.795 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 06805207 | AA OR STTR CLEAN-UP 2017 | 201812 | | | | | | 12.396 | | | | | | | 12.396 |
| **BI_GN215 - Aldyl A OR - STTR Major Project** | **06805207** | **AA OR STTR CLEAN-UP 2017 Total** | | | | | | **34.701** | **14.218** | | | | | | | **48.919** |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405219 | AA OR STTR Major Medford East | 201302 | 209 | | | | | | | | | | | | 209 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405219 | AA OR STTR Major Medford East | 201304 | 4.152 | | | | | | | | | | | | 4.152 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405219 | AA OR STTR Major Medford East | 201305 | 11.840 | | | | | | | | | | | | 11.840 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405219 | AA OR STTR Major Medford East | 201306 | 10.469 | | | | | | | | | | | | 10.469 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405219 | AA OR STTR Major Medford East | 201307 | 43.947 | | | | | | | | | | | | 43.947 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405219 | AA OR STTR Major Medford East | 201308 | 13.673 | | | | | | | | | | | | 13.673 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405219 | AA OR STTR Major Medford East | 201309 | 223.604 | | | | | | | | | | | | 223.604 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405219 | AA OR STTR Major Medford East | 201310 | 110.813 | | | | | | | | | | | | 110.813 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405219 | AA OR STTR Major Medford East | 201311 | 149.943 | | | | | | | | | | | | 149.943 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405219 | AA OR STTR Major Medford East | 201312 | 99.043 | | | | | | | | | | | | 99.043 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405219 | AA OR STTR Major Medford East | 201401 | | 7.879 | | | | | | | | | | | 7.879 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405219 | AA OR STTR Major Medford East | 201403 | | (960) | | | | | | | | | | | (960) |
| **BI_GN215 - Aldyl A OR - STTR Major Project** | **98405219** | **AA OR STTR Major Medford East Total** | | **667.693** | **6.919** | | | | | | | | | | | **674.612** |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405239 | AA OR STTR major Medford West | 201401 | | 35.862 | | | | | | | | | | | 35.862 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405239 | AA OR STTR major Medford West | 201402 | | 34.266 | | | | | | | | | | | 34.266 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405239 | AA OR STTR major Medford West | 201403 | | 196.360 | | | | | | | | | | | 196.360 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405239 | AA OR STTR major Medford West | 201404 | | 152.546 | | | | | | | | | | | 152.546 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405239 | AA OR STTR major Medford West | 201405 | | 155.062 | | | | | | | | | | | 155.062 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405239 | AA OR STTR major Medford West | 201406 | | 263.320 | | | | | | | | | | | 263.320 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405239 | AA OR STTR major Medford West | 201407 | | 119.288 | | | | | | | | | | | 119.288 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405239 | AA OR STTR major Medford West | 201408 | | 225.570 | | | | | | | | | | | 225.570 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405239 | AA OR STTR major Medford West | 201409 | | 179.388 | | | | | | | | | | | 179.388 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405239 | AA OR STTR major Medford West | 201410 | | 76.015 | | | | | | | | | | | 76.015 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405239 | AA OR STTR major Medford West | 201411 | | 72.911 | | | | | | | | | | | 72.911 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405239 | AA OR STTR major Medford West | 201412 | | 14.432 | | | | | | | | | | | 14.432 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405239 | AA OR STTR major Medford West | 201501 | | | 2.651 | | | | | | | | | | 2.651 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405239 | AA OR STTR major Medford West | 201706 | | | | | 54 | | | | | | | | 54 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405239 | AA OR STTR major Medford West | 201707 | | | | | 160 | | | | | | | | 160 |
| **BI_GN215 - Aldyl A OR - STTR Major Project** | **98405239** | **AA OR STTR major Medford West Total** | | | **1.525.020** | **2.651** | | **214** | | | | | | | | **1.527.885** |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405254 | AA OR STTRMajor Medford/Adj'15 | 201501 | | | 8.306 | | | | | | | | | | 8.306 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405254 | AA OR STTRMajor Medford/Adj'15 | 201502 | | | 171.158 | | | | | | | | | | 171.158 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405254 | AA OR STTRMajor Medford/Adj'15 | 201503 | | | 164.821 | | | | | | | | | | 164.821 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405254 | AA OR STTRMajor Medford/Adj'15 | 201504 | | | 192.354 | | | | | | | | | | 192.354 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405254 | AA OR STTRMajor Medford/Adj'15 | 201505 | | | 143.875 | | | | | | | | | | 143.875 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405254 | AA OR STTRMajor Medford/Adj'15 | 201506 | | | 21.929 | | | | | | | | | | 21.929 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405254 | AA OR STTRMajor Medford/Adj'15 | 201507 | | | 10.630 | | | | | | | | | | 10.630 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405254 | AA OR STTRMajor Medford/Adj'15 | 201508 | | | 18.642 | | | | | | | | | | 18.642 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405254 | AA OR STTRMajor Medford/Adj'15 | 201509 | | | 9.079 | | | | | | | | | | 9.079 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405254 | AA OR STTRMajor Medford/Adj'15 | 201510 | | | 17.136 | | | | | | | | | | 17.136 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405254 | AA OR STTRMajor Medford/Adj'15 | 201511 | | | 81.060 | | | | | | | | | | 81.060 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405254 | AA OR STTRMajor Medford/Adj'15 | 201512 | | | 14.588 | | | | | | | | | | 14.588 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405254 | AA OR STTRMajor Medford/Adj'15 | 201601 | | | | 1.641 | | | | | | | | | 1.641 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98405254 | AA OR STTRMajor Medford/Adj'15 | 201602 | | | | (1.226) | | | | | | | | | (1.226) |
| **BI_GN215 - Aldyl A OR - STTR Major Project** | **98405254** | **AA OR STTRMajor Medford/Adj'15 Total** | | | | **853.578** | **415** | | | | | | | | | **853.992** |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98605106 | AA OR STTR Major Rosbrg Adj 17 | 201701 | | | | | 3.273 | | | | | | | | 3.273 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98605106 | AA OR STTR Major Rosbrg Adj 17 | 201702 | | | | | 2.172 | | | | | | | | 2.172 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98605106 | AA OR STTR Major Rosbrg Adj 17 | 201703 | | | | | 22.058 | | | | | | | | 22.058 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98605106 | AA OR STTR Major Rosbrg Adj 17 | 201704 | | | | | 90.160 | | | | | | | | 90.160 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98605106 | AA OR STTR Major Rosbrg Adj 17 | 201705 | | | | | 170.070 | | | | | | | | 170.070 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98605106 | AA OR STTR Major Rosbrg Adj 17 | 201706 | | | | | 64.777 | | | | | | | | 64.777 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98605106 | AA OR STTR Major Rosbrg Adj 17 | 201707 | | | | | 164.528 | | | | | | | | 164.528 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98605106 | AA OR STTR Major Rosbrg Adj 17 | 201708 | | | | | 20.145 | | | | | | | | 20.145 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98605106 | AA OR STTR Major Rosbrg Adj 17 | 201709 | | | | | 3.578 | | | | | | | | 3.578 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98605106 | AA OR STTR Major Rosbrg Adj 17 | 201710 | | | | | 12.498 | | | | | | | | 12.498 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98605106 | AA OR STTR Major Rosbrg Adj 17 | 201711 | | | | | 2.890 | | | | | | | | 2.890 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98605106 | AA OR STTR Major Rosbrg Adj 17 | 201712 | | | | | 8.611 | | | | | | | | 8.611 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98605106 | AA OR STTR Major Rosbrg Adj 17 | 201801 | | | | | | 1.889 | | | | | | | 1.889 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98605106 | AA OR STTR Major Rosbrg Adj 17 | 201802 | | | | | | 2.543 | | | | | | | 2.543 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98605106 | AA OR STTR Major Rosbrg Adj 17 | 201803 | | | | | | 2.162 | | | | | | | 2.162 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98605106 | AA OR STTR Major Rosbrg Adj 17 | 201804 | | | | | | 1.147 | | | | | | | 1.147 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98605106 | AA OR STTR Major Rosbrg Adj 17 | 201806 | | | | | | 313 | | | | | | | 313 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98605106 | AA OR STTR Major Rosbrg Adj 17 | 202305 | | | | | | | | | | | 6.245 | | 6.245 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98605106 | AA OR STTR Major Rosbrg Adj 17 | 202306 | | | | | | | | | | | (6.245) | | (6.245) |
| **BI_GN215 - Aldyl A OR - STTR Major Project** | **98605106** | **AA OR STTR Major Rosbrg Adj 17 Total** | | | | | | **564.760** | **8.054** | | | | | **-** | | **572.814** |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98705086 | AA OR STTRMajor KlamathFls '16 | 201511 | | | 7.055 | | | | | | | | | | 7.055 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98705086 | AA OR STTRMajor KlamathFls '16 | 201601 | | | | 1.619 | | | | | | | | | 1.619 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98705086 | AA OR STTRMajor KlamathFls '16 | 201602 | | | | 13.409 | | | | | | | | | 13.409 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98705086 | AA OR STTRMajor KlamathFls '16 | 201603 | | | | 15.535 | | | | | | | | | 15.535 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98705086 | AA OR STTRMajor KlamathFls '16 | 201604 | | | | 150.410 | | | | | | | | | 150.410 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98705086 | AA OR STTRMajor KlamathFls '16 | 201605 | | | | 58.991 | | | | | | | | | 58.991 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98705086 | AA OR STTRMajor KlamathFls '16 | 201606 | | | | 261.824 | | | | | | | | | 261.824 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98705086 | AA OR STTRMajor KlamathFls '16 | 201607 | | | | 63.222 | | | | | | | | | 63.222 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98705086 | AA OR STTRMajor KlamathFls '16 | 201608 | | | | 8.608 | | | | | | | | | 8.608 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98705086 | AA OR STTRMajor KlamathFls '16 | 201609 | | | | 3.564 | | | | | | | | | 3.564 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98705086 | AA OR STTRMajor KlamathFls '16 | 201610 | | | | 26.216 | | | | | | | | | 26.216 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98705086 | AA OR STTRMajor KlamathFls '16 | 201611 | | | | 9.901 | | | | | | | | | 9.901 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98705086 | AA OR STTRMajor KlamathFls '16 | 201701 | | | | | 4.277 | | | | | | | | 4.277 |
| **BI_GN215 - Aldyl A OR - STTR Major Project** | **98705086** | **AA OR STTRMajor KlamathFls '16 Total** | | | | **7.055** | **613.298** | **4.277** | | | | | | | | **624.631** |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98805081 | AA OR STTR Major LaGrande'15 | 201501 | | | 18.863 | | | | | | | | | | 18.863 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98805081 | AA OR STTR Major LaGrande'15 | 201502 | | | 13.116 | | | | | | | | | | 13.116 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98805081 | AA OR STTR Major LaGrande'15 | 201503 | | | 29.046 | | | | | | | | | | 29.046 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98805081 | AA OR STTR Major LaGrande'15 | 201504 | | | 10.148 | | | | | | | | | | 10.148 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98805081 | AA OR STTR Major LaGrande'15 | 201505 | | | 116.599 | | | | | | | | | | 116.599 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98805081 | AA OR STTR Major LaGrande'15 | 201506 | | | 202.289 | | | | | | | | | | 202.289 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98805081 | AA OR STTR Major LaGrande'15 | 201507 | | | 268.392 | | | | | | | | | | 268.392 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98805081 | AA OR STTR Major LaGrande'15 | 201508 | | | 28.628 | | | | | | | | | | 28.628 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98805081 | AA OR STTR Major LaGrande'15 | 201509 | | | 2.298 | | | | | | | | | | 2.298 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98805081 | AA OR STTR Major LaGrande'15 | 201510 | | | 2.209 | | | | | | | | | | 2.209 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98805081 | AA OR STTR Major LaGrande'15 | 201511 | | | 2.178 | | | | | | | | | | 2.178 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98805081 | AA OR STTR Major LaGrande'15 | 201512 | | | 9.672 | | | | | | | | | | 9.672 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98805081 | AA OR STTR Major LaGrande'15 | 201601 | | | | 395 | | | | | | | | | 395 |
| BI_GN215 - Aldyl A OR - STTR Major Project | 98805081 | AA OR STTR Major LaGrande'15 | 201602 | | | | (395) | | | | | | | | | (395) |
| **BI_GN215 - Aldyl A OR - STTR Major Project** | **98805081** | **AA OR STTR Major LaGrande'15 Total** | | | | **703.437** | **-** | | | | | | | | | **703.437** |
| **BI_GN215 - Aldyl A OR - STTR Major Project Total** | | | | **667.693** | **1.531.939** | **1.566.721** | **613.713** | **603.952** | **22.272** | | | | | **-** | | **5.006.290** |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201403 | | 85.198 | | | | | | | | | | | 85.198 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201404 | | 1.098 | | | | | | | | | | | 1.098 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201405 | | 7.296 | | | | | | | | | | | 7.296 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201406 | | 4.846 | | | | | | | | | | | 4.846 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201407 | | 49.430 | | | | | | | | | | | 49.430 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201408 | | 111.798 | | | | | | | | | | | 111.798 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201409 | | 56.017 | | | | | | | | | | | 56.017 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201410 | | 2.376 | | | | | | | | | | | 2.376 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201411 | | 5.557 | | | | | | | | | | | 5.557 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201412 | | 5.423 | | | | | | | | | | | 5.423 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201501 | | | 3.193 | | | | | | | | | | 3.193 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201502 | | | 1.233 | | | | | | | | | | 1.233 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201503 | | | 153 | | | | | | | | | | 153 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201505 | | | 910 | | | | | | | | | | 910 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201601 | | | | 568 | | | | | | | | | 568 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201602 | | | | 554 | | | | | | | | | 554 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201603 | | | | 4.555 | | | | | | | | | 4.555 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201604 | | | | 6.998 | | | | | | | | | 6.998 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201605 | | | | 9.199 | | | | | | | | | 9.199 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201606 | | | | 8.451 | | | | | | | | | 8.451 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201607 | | | | 7.253 | | | | | | | | | 7.253 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201608 | | | | 8.728 | | | | | | | | | 8.728 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201609 | | | | 8.513 | | | | | | | | | 8.513 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201610 | | | | 4.195 | | | | | | | | | 4.195 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201611 | | | | 811 | | | | | | | | | 811 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201701 | | | | | 3.246 | | | | | | | | 3.246 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201702 | | | | | 41.553 | | | | | | | | 41.553 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201704 | | | | | 13.225 | | | | | | | | 13.225 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201705 | | | | | 13.174 | | | | | | | | 13.174 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201706 | | | | | 16.962 | | | | | | | | 16.962 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201707 | | | | | 17.571 | | | | | | | | 17.571 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201708 | | | | | 94.090 | | | | | | | | 94.090 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201709 | | | | | 80.223 | | | | | | | | 80.223 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201710 | | | | | 37.152 | | | | | | | | 37.152 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201711 | | | | | 4.088 | | | | | | | | 4.088 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201712 | | | | | 75.132 | | | | | | | | 75.132 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201801 | | | | | | 578 | | | | | | | 578 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201802 | | | | | | 225 | | | | | | | 225 |

| BI Description | Project Number | Project Name | FA Period YYYYMM | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | Grand Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201803 | | | | | | 8.650 | | | | | | | 8.650 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201805 | | | | | | 4.684 | | | | | | | 4.684 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201806 | | | | | | 4.044 | | | | | | | 4.044 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201807 | | | | | | 10.993 | | | | | | | 10.993 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201811 | | | | | | 26.441 | | | | | | | 26.441 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201901 | | | | | | | 341 | | | | | | 341 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201904 | | | | | | | 18.008 | | | | | | 18.008 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201905 | | | | | | | 30.527 | | | | | | 30.527 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201906 | | | | | | | 30.915 | | | | | | 30.915 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201907 | | | | | | | 10.608 | | | | | | 10.608 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201908 | | | | | | | 7.716 | | | | | | 7.716 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201910 | | | | | | | 5.596 | | | | | | 5.596 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201911 | | | | | | | 22.293 | | | | | | 22.293 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 201912 | | | | | | | 2.881 | | | | | | 2.881 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202003 | | | | | | | | 5.114 | | | | | 5.114 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202004 | | | | | | | | 19.323 | | | | | 19.323 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202005 | | | | | | | | 8.052 | | | | | 8.052 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202006 | | | | | | | | 14.514 | | | | | 14.514 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202007 | | | | | | | | 5.500 | | | | | 5.500 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202010 | | | | | | | | 1.633 | | | | | 1.633 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202011 | | | | | | | | 59.062 | | | | | 59.062 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202012 | | | | | | | | 36.712 | | | | | 36.712 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202101 | | | | | | | | | 2.232 | | | | 2.232 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202102 | | | | | | | | | 10.393 | | | | 10.393 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202103 | | | | | | | | | 3.247 | | | | 3.247 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202104 | | | | | | | | | 3.456 | | | | 3.456 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202105 | | | | | | | | | 3.160 | | | | 3.160 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202106 | | | | | | | | | 2.969 | | | | 2.969 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202107 | | | | | | | | | 3.197 | | | | 3.197 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202108 | | | | | | | | | 3.784 | | | | 3.784 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202109 | | | | | | | | | 23.053 | | | | 23.053 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202110 | | | | | | | | | 11.644 | | | | 11.644 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202111 | | | | | | | | | 4.394 | | | | 4.394 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202112 | | | | | | | | | 86.519 | | | | 86.519 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202201 | | | | | | | | | | 1.978 | | | 1.978 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202202 | | | | | | | | | | 1.703 | | | 1.703 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202203 | | | | | | | | | | 7.988 | | | 7.988 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202204 | | | | | | | | | | 1.749 | | | 1.749 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202205 | | | | | | | | | | 35.026 | | | 35.026 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202206 | | | | | | | | | | 1.369 | | | 1.369 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202207 | | | | | | | | | | 853 | | | 853 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202208 | | | | | | | | | | 19.313 | | | 19.313 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202209 | | | | | | | | | | 24.736 | | | 24.736 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202210 | | | | | | | | | | 22.454 | | | 22.454 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202211 | | | | | | | | | | 17.461 | | | 17.461 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202212 | | | | | | | | | | 14.449 | | | 14.449 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202301 | | | | | | | | | | | 2.911 | | 2.911 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202302 | | | | | | | | | | | 1.020 | | 1.020 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202303 | | | | | | | | | | | 89.176 | | 89.176 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202304 | | | | | | | | | | | 12.318 | | 12.318 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202305 | | | | | | | | | | | 34.984 | | 34.984 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202306 | | | | | | | | | | | (154) | | (154) |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202307 | | | | | | | | | | | 233.808 | | 233.808 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202308 | | | | | | | | | | | 2.053 | | 2.053 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202309 | | | | | | | | | | | 4.867 | | 4.867 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202310 | | | | | | | | | | | 4.302 | | 4.302 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202311 | | | | | | | | | | | 3.745 | | 3.745 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202312 | | | | | | | | | | | 4.538 | | 4.538 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202401 | | | | | | | | | | | | 6.427 | 6.427 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202402 | | | | | | | | | | | | 10.090 | 10.090 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202403 | | | | | | | | | | | | 14.405 | 14.405 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202404 | | | | | | | | | | | | 11.103 | 11.103 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202405 | | | | | | | | | | | | 85.147 | 85.147 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202406 | | | | | | | | | | | | 175.918 | 175.918 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202407 | | | | | | | | | | | | 59.073 | 59.073 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202408 | | | | | | | | | | | | 65.736 | 65.736 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202409 | | | | | | | | | | | | 11.105 | 11.105 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202410 | | | | | | | | | | | | 9.212 | 9.212 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202411 | | | | | | | | | | | | 8.704 | 8.704 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98401127 | AA OR Main Minor Gas Dist(984) | 202412 | | | | | | | | | | | | 9.340 | 9.340 |
| **BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts** | **98401127** | **AA OR Main Minor Gas Dist(984) Total** | | | **329.039** | **5.489** | **59.826** | **396.416** | **55.615** | **128.884** | **149.910** | **158.046** | **149.080** | **393.568** | **466.258** | **2.292.131** |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98501127 | AA OR Main Minor Gas Dist(985) | 201406 | | 10 | | | | | | | | | | | 10 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98501127 | AA OR Main Minor Gas Dist(985) | 201503 | | | 24 | | | | | | | | | | 24 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98501127 | AA OR Main Minor Gas Dist(985) | 202204 | | | | | | | | | | 2.027 | | | 2.027 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98501127 | AA OR Main Minor Gas Dist(985) | 202209 | | | | | | | | | | (4.819) | | | (4.819) |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98501127 | AA OR Main Minor Gas Dist(985) | 202308 | | | | | | | | | | | 71 | | 71 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98501127 | AA OR Main Minor Gas Dist(985) | 202309 | | | | | | | | | | | 181 | | 181 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98501127 | AA OR Main Minor Gas Dist(985) | 202311 | | | | | | | | | | | 218 | | 218 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98501127 | AA OR Main Minor Gas Dist(985) | 202312 | | | | | | | | | | | 291 | | 291 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98501127 | AA OR Main Minor Gas Dist(985) | 202401 | | | | | | | | | | | | 823 | 823 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98501127 | AA OR Main Minor Gas Dist(985) | 202403 | | | | | | | | | | | | 298 | 298 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98501127 | AA OR Main Minor Gas Dist(985) | 202410 | | | | | | | | | | | | 164 | 164 |
| **BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts** | **98501127** | **AA OR Main Minor Gas Dist(985) Total** | | | **10** | **24** | | | | | | | **(2.792)** | **761** | **1.285** | **(712)** |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201401 | | 794 | | | | | | | | | | | 794 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201403 | | (794) | | | | | | | | | | | (794) |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201405 | | 80 | | | | | | | | | | | 80 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201409 | | 374 | | | | | | | | | | | 374 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201410 | | 222 | | | | | | | | | | | 222 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201411 | | 1.189 | | | | | | | | | | | 1.189 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201412 | | 661 | | | | | | | | | | | 661 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201503 | | | 400 | | | | | | | | | | 400 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201701 | | | | | 43 | | | | | | | | 43 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201702 | | | | | 2.454 | | | | | | | | 2.454 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201703 | | | | | 13.560 | | | | | | | | 13.560 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201704 | | | | | 25.578 | | | | | | | | 25.578 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201705 | | | | | 41.056 | | | | | | | | 41.056 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201706 | | | | | 12.336 | | | | | | | | 12.336 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201707 | | | | | 56.029 | | | | | | | | 56.029 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201708 | | | | | 10.622 | | | | | | | | 10.622 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201710 | | | | | 34.879 | | | | | | | | 34.879 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201711 | | | | | 18.695 | | | | | | | | 18.695 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201712 | | | | | 22.246 | | | | | | | | 22.246 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201804 | | | | | | 664 | | | | | | | 664 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201806 | | | | | | 237 | | | | | | | 237 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201807 | | | | | | 169 | | | | | | | 169 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201906 | | | | | | | 1.970 | | | | | | 1.970 |

| BI_Description | Project Number | Project Name | FA Period YYYYMM | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | Grand Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201907 | | | | | | | 347 | | | | | | 347 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201908 | | | | | | | 1.827 | | | | | | 1.827 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201909 | | | | | | | 34.567 | | | | | | 34.567 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201910 | | | | | | | 24.657 | | | | | | 24.657 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201911 | | | | | | | 7.705 | | | | | | 7.705 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 201912 | | | | | | | 349.680 | | | | | | 349.680 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202001 | | | | | | | | 32.726 | | | | | 32.726 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202002 | | | | | | | | 22.615 | | | | | 22.615 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202003 | | | | | | | | 256.291 | | | | | 256.291 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202004 | | | | | | | | 7.048 | | | | | 7.048 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202005 | | | | | | | | 266.779 | | | | | 266.779 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202006 | | | | | | | | 92.178 | | | | | 92.178 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202007 | | | | | | | | 30.482 | | | | | 30.482 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202008 | | | | | | | | 40.488 | | | | | 40.488 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202009 | | | | | | | | 486.907 | | | | | 486.907 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202010 | | | | | | | | (48.607) | | | | | (48.607) |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202011 | | | | | | | | 451.735 | | | | | 451.735 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202012 | | | | | | | | 684.201 | | | | | 684.201 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202101 | | | | | | | | | 4.210 | | | | 4.210 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202102 | | | | | | | | | 1.252 | | | | 1.252 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202103 | | | | | | | | | 1.467 | | | | 1.467 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202104 | | | | | | | | | 29.315 | | | | 29.315 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202105 | | | | | | | | | 13.922 | | | | 13.922 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202106 | | | | | | | | | 60.718 | | | | 60.718 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202205 | | | | | | | | | | 773 | | | 773 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202206 | | | | | | | | | | 7.468 | | | 7.468 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202207 | | | | | | | | | | 3.101 | | | 3.101 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202208 | | | | | | | | | | 404 | | | 404 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202209 | | | | | | | | | | 3.572 | | | 3.572 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202210 | | | | | | | | | | 311 | | | 311 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202211 | | | | | | | | | | 103 | | | 103 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202212 | | | | | | | | | | 17.454 | | | 17.454 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202301 | | | | | | | | | | | 25.333 | | 25.333 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202302 | | | | | | | | | | | 9.627 | | 9.627 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202303 | | | | | | | | | | | 171 | | 171 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202304 | | | | | | | | | | | 226 | | 226 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202305 | | | | | | | | | | | 2.293 | | 2.293 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202306 | | | | | | | | | | | 30.591 | | 30.591 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202307 | | | | | | | | | | | 9.777 | | 9.777 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202308 | | | | | | | | | | | 12.927 | | 12.927 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202309 | | | | | | | | | | | 68 | | 68 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202310 | | | | | | | | | | | 3.210 | | 3.210 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202311 | | | | | | | | | | | 1.317 | | 1.317 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202402 | | | | | | | | | | | | 1.668 | 1.668 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202403 | | | | | | | | | | | | 132.098 | 132.098 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202404 | | | | | | | | | | | | 26.788 | 26.788 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202406 | | | | | | | | | | | | 11.685 | 11.685 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202407 | | | | | | | | | | | | 14.723 | 14.723 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202408 | | | | | | | | | | | | 10.330 | 10.330 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202410 | | | | | | | | | | | | 1.149 | 1.149 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202411 | | | | | | | | | | | | 3.074 | 3.074 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98601127 | AA OR Main Minor Gas Dist(986) | 202412 | | | | | | | | | | | | 3.466 | 3.466 |
| **BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts** | **98601127** | **AA OR Main Minor Gas Dist(986) Total** | | | **2.525** | **400** | | **237.499** | **1.069** | **420.753** | **2.322.841** | **110.885** | **33.186** | **95.543** | **204.982** | **3.429.683** |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 201402 | | 51.267 | | | | | | | | | | | 51.267 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 201403 | | 8.484 | | | | | | | | | | | 8.484 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 201406 | | 658 | | | | | | | | | | | 658 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 201408 | | 2.676 | | | | | | | | | | | 2.676 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 201409 | | 12.361 | | | | | | | | | | | 12.361 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 201410 | | 31.246 | | | | | | | | | | | 31.246 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 201411 | | 643 | | | | | | | | | | | 643 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 201412 | | (180) | | | | | | | | | | | (180) |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 201501 | | | 643 | | | | | | | | | | 643 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 201502 | | | (643) | | | | | | | | | | (643) |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 201503 | | | 157 | | | | | | | | | | 157 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 201504 | | | 56 | | | | | | | | | | 56 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 201505 | | | 693 | | | | | | | | | | 693 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 201906 | | | | | | | 123 | | | | | | 123 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 202002 | | | | | | | | 1.893 | | | | | 1.893 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 202003 | | | | | | | | 46.351 | | | | | 46.351 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 202004 | | | | | | | | 115.773 | | | | | 115.773 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 202005 | | | | | | | | 249.624 | | | | | 249.624 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 202006 | | | | | | | | 939 | | | | | 939 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 202009 | | | | | | | | 72 | | | | | 72 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 202204 | | | | | | | | | | 1.163 | | | 1.163 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 202208 | | | | | | | | | | 1.418 | | | 1.418 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98701127 | AA OR Main Minor Gas Dist(987) | 202310 | | | | | | | | | | | 1.997 | | 1.997 |
| **BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts** | **98701127** | **AA OR Main Minor Gas Dist(987) Total** | | | **107.156** | **906** | | | | **123** | **414.651** | | **2.581** | **1.997** | | **527.415** |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98801127 | AA OR Main Minor Gas Dist(988) | 201406 | | 3.740 | | | | | | | | | | | 3.740 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98801127 | AA OR Main Minor Gas Dist(988) | 201409 | | 413 | | | | | | | | | | | 413 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98801127 | AA OR Main Minor Gas Dist(988) | 201410 | | 2.058 | | | | | | | | | | | 2.058 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98801127 | AA OR Main Minor Gas Dist(988) | 201412 | | (3.740) | | | | | | | | | | | (3.740) |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98801127 | AA OR Main Minor Gas Dist(988) | 201707 | | | | | 340 | | | | | | | | 340 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98801127 | AA OR Main Minor Gas Dist(988) | 201708 | | | | | 17.951 | | | | | | | | 17.951 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98801127 | AA OR Main Minor Gas Dist(988) | 201709 | | | | | 7.851 | | | | | | | | 7.851 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98801127 | AA OR Main Minor Gas Dist(988) | 201711 | | | | | 2.779 | | | | | | | | 2.779 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98801127 | AA OR Main Minor Gas Dist(988) | 201806 | | | | | | 345 | | | | | | | 345 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98801127 | AA OR Main Minor Gas Dist(988) | 201808 | | | | | | 22.105 | | | | | | | 22.105 |
| BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts | 98801127 | AA OR Main Minor Gas Dist(988) | 201811 | | | | | | 4.970 | | | | | | | 4.970 |
| **BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts** | **98801127** | **AA OR Main Minor Gas Dist(988) Total** | | | **2.471** | | | **28.922** | **27.420** | | | | | | | **58.813** |
| **BI_GN310 - Aldyl A-OR-Main Pipe-Minor Project -Gas Districts Total** | | | | | **441,201** | **6,820** | **59,826** | **662,836** | **84,105** | **549,760** | **2,887,402** | **268,931** | **182,055** | **491,869** | **672,525** | **6,307,330** |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201401 | | 150 | | | | | | | | | | | 150 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201402 | | 148 | | | | | | | | | | | 148 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201403 | | 2.283 | | | | | | | | | | | 2.283 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201404 | | 343 | | | | | | | | | | | 343 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201405 | | 2.205 | | | | | | | | | | | 2.205 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201406 | | 60 | | | | | | | | | | | 60 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201407 | | 19.630 | | | | | | | | | | | 19.630 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201408 | | 700 | | | | | | | | | | | 700 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201409 | | 1.084 | | | | | | | | | | | 1.084 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201411 | | 1.054 | | | | | | | | | | | 1.054 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201501 | | | 1.326 | | | | | | | | | | 1.326 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201502 | | | 381 | | | | | | | | | | 381 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201503 | | | 524 | | | | | | | | | | 524 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201603 | | | | 250 | | | | | | | | | 250 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201604 | | | | 646 | | | | | | | | | 646 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201605 | | | | 535 | | | | | | | | | 535 |

| BI Description | Project Number | Project Name | FA Period YYYYMM | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | Grand Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201606 | | | | 184 | | | | | | | | | 184 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201607 | | | | 1.592 | | | | | | | | | 1.592 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201701 | | | | | 3.552 | | | | | | | | 3.552 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201707 | | | | | 892 | | | | | | | | 892 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201708 | | | | | 3.427 | | | | | | | | 3.427 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201709 | | | | | 1.140 | | | | | | | | 1.140 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201710 | | | | | 2.659 | | | | | | | | 2.659 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201711 | | | | | 96 | | | | | | | | 96 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201801 | | | | | | 225 | | | | | | | 225 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201805 | | | | | | 1.094 | | | | | | | 1.094 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 201903 | | | | | | | 84 | | | | | | 84 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202102 | | | | | | | | | 487 | | | | 487 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202103 | | | | | | | | | 2.484 | | | | 2.484 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202104 | | | | | | | | | 5.226 | | | | 5.226 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202105 | | | | | | | | | 2.652 | | | | 2.652 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202106 | | | | | | | | | 1.062 | | | | 1.062 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202107 | | | | | | | | | 3.314 | | | | 3.314 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202108 | | | | | | | | | 18.191 | | | | 18.191 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202109 | | | | | | | | | 207.085 | | | | 207.085 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202110 | | | | | | | | | 50.360 | | | | 50.360 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202111 | | | | | | | | | 12.634 | | | | 12.634 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202112 | | | | | | | | | 39.396 | | | | 39.396 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202201 | | | | | | | | | | 5.727 | | | 5.727 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202202 | | | | | | | | | | 13.700 | | | 13.700 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202203 | | | | | | | | | | 27.102 | | | 27.102 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202204 | | | | | | | | | | 30.815 | | | 30.815 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202205 | | | | | | | | | | 9.455 | | | 9.455 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202206 | | | | | | | | | | 48.820 | | | 48.820 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202207 | | | | | | | | | | 59.688 | | | 59.688 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202208 | | | | | | | | | | 103.910 | | | 103.910 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202209 | | | | | | | | | | 41.727 | | | 41.727 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202210 | | | | | | | | | | 86.070 | | | 86.070 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202211 | | | | | | | | | | 69.036 | | | 69.036 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202212 | | | | | | | | | | 31.447 | | | 31.447 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202301 | | | | | | | | | | | 63.753 | | 63.753 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202302 | | | | | | | | | | | 39.705 | | 39.705 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202303 | | | | | | | | | | | 75.120 | | 75.120 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202304 | | | | | | | | | | | 42.202 | | 42.202 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202305 | | | | | | | | | | | 22.532 | | 22.532 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202306 | | | | | | | | | | | 30.351 | | 30.351 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202307 | | | | | | | | | | | 5.797 | | 5.797 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202308 | | | | | | | | | | | 21.635 | | 21.635 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202309 | | | | | | | | | | | 11.149 | | 11.149 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202310 | | | | | | | | | | | 38.977 | | 38.977 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202311 | | | | | | | | | | | 27.383 | | 27.383 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202312 | | | | | | | | | | | 20.745 | | 20.745 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202401 | | | | | | | | | | | | 32.751 | 32.751 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202402 | | | | | | | | | | | | 48.202 | 48.202 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202403 | | | | | | | | | | | | 26.411 | 26.411 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202404 | | | | | | | | | | | | 4.758 | 4.758 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202405 | | | | | | | | | | | | 5.829 | 5.829 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202406 | | | | | | | | | | | | 9.173 | 9.173 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202407 | | | | | | | | | | | | 20.015 | 20.015 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202408 | | | | | | | | | | | | 32.802 | 32.802 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202409 | | | | | | | | | | | | 13.473 | 13.473 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202410 | | | | | | | | | | | | 210 | 210 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202411 | | | | | | | | | | | | 119 | 119 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98401128 | AA OR STTR Minor Gas Dist(984) | 202412 | | | | | | | | | | | | 3.498 | 3.498 |
| **BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts** | **98401128** | **AA OR STTR Minor Gas Dist(984) Total** | | | **27.657** | **2.231** | **3.206** | **11.766** | **1.319** | **84** | | **343.092** | **527.496** | **399.348** | **197.243** | **1.513.441** |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98501128 | AA OR STTR Minor Gas Dist(985) | 201502 | | | 183 | | | | | | | | | | 183 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98501128 | AA OR STTR Minor Gas Dist(985) | 201503 | | | 633 | | | | | | | | | | 633 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98501128 | AA OR STTR Minor Gas Dist(985) | 201707 | | | | | 500 | | | | | | | | 500 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98501128 | AA OR STTR Minor Gas Dist(985) | 202109 | | | | | | | | | 5.124 | | | | 5.124 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98501128 | AA OR STTR Minor Gas Dist(985) | 202110 | | | | | | | | | 1.465 | | | | 1.465 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98501128 | AA OR STTR Minor Gas Dist(985) | 202111 | | | | | | | | | 4.204 | | | | 4.204 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98501128 | AA OR STTR Minor Gas Dist(985) | 202112 | | | | | | | | | 3.129 | | | | 3.129 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98501128 | AA OR STTR Minor Gas Dist(985) | 202201 | | | | | | | | | | 322 | | | 322 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98501128 | AA OR STTR Minor Gas Dist(985) | 202202 | | | | | | | | | | 48.608 | | | 48.608 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98501128 | AA OR STTR Minor Gas Dist(985) | 202203 | | | | | | | | | | 253.214 | | | 253.214 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98501128 | AA OR STTR Minor Gas Dist(985) | 202204 | | | | | | | | | | 79.092 | | | 79.092 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98501128 | AA OR STTR Minor Gas Dist(985) | 202205 | | | | | | | | | | 98.187 | | | 98.187 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98501128 | AA OR STTR Minor Gas Dist(985) | 202206 | | | | | | | | | | 106.558 | | | 106.558 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98501128 | AA OR STTR Minor Gas Dist(985) | 202207 | | | | | | | | | | 130.001 | | | 130.001 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98501128 | AA OR STTR Minor Gas Dist(985) | 202208 | | | | | | | | | | 64.067 | | | 64.067 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98501128 | AA OR STTR Minor Gas Dist(985) | 202209 | | | | | | | | | | 57.850 | | | 57.850 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98501128 | AA OR STTR Minor Gas Dist(985) | 202210 | | | | | | | | | | 8.450 | | | 8.450 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98501128 | AA OR STTR Minor Gas Dist(985) | 202211 | | | | | | | | | | 5.766 | | | 5.766 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98501128 | AA OR STTR Minor Gas Dist(985) | 202212 | | | | | | | | | | (8.059) | | | (8.059) |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98501128 | AA OR STTR Minor Gas Dist(985) | 202301 | | | | | | | | | | | 446 | | 446 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98501128 | AA OR STTR Minor Gas Dist(985) | 202304 | | | | | | | | | | | 2.252 | | 2.252 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98501128 | AA OR STTR Minor Gas Dist(985) | 202309 | | | | | | | | | | | 524 | | 524 |
| **BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts** | **98501128** | **AA OR STTR Minor Gas Dist(985) Total** | | | | **816** | | **500** | | | | **13.921** | **844.057** | **3.222** | | **862.516** |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201401 | | 847 | | | | | | | | | | | 847 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201402 | | 9.553 | | | | | | | | | | | 9.553 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201403 | | 3.783 | | | | | | | | | | | 3.783 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201404 | | 8.524 | | | | | | | | | | | 8.524 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201405 | | 32.977 | | | | | | | | | | | 32.977 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201406 | | 28.013 | | | | | | | | | | | 28.013 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201407 | | 26.229 | | | | | | | | | | | 26.229 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201408 | | 33.364 | | | | | | | | | | | 33.364 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201409 | | 30.837 | | | | | | | | | | | 30.837 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201410 | | 42.726 | | | | | | | | | | | 42.726 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201411 | | 28.810 | | | | | | | | | | | 28.810 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201412 | | 17.951 | | | | | | | | | | | 17.951 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201501 | | | 1.245 | | | | | | | | | | 1.245 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201502 | | | (348) | | | | | | | | | | (348) |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201503 | | | 6.259 | | | | | | | | | | 6.259 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201504 | | | 27.743 | | | | | | | | | | 27.743 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201505 | | | 3.794 | | | | | | | | | | 3.794 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201506 | | | 5.444 | | | | | | | | | | 5.444 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201507 | | | 565 | | | | | | | | | | 565 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201512 | | | 1.156 | | | | | | | | | | 1.156 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201606 | | | | 2.189 | | | | | | | | | 2.189 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201609 | | | | 327 | | | | | | | | | 327 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201703 | | | | | 1.074 | | | | | | | | 1.074 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201704 | | | | | 4.467 | | | | | | | | 4.467 |

| BI Description | Project Number | Project Name | FA Period YYYYMM | 2013 | 2014 | 2015 | 2016 | 2017 | 2018 | 2019 | 2020 | 2021 | 2022 | 2023 | 2024 | Grand Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201705 | | | | | 777 | | | | | | | | 777 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201712 | | | | | 740 | | | | | | | | 740 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201801 | | | | | | 2.243 | | | | | | | 2.243 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 201804 | | | | | | 563 | | | | | | | 563 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202010 | | | | | | | | 133 | | | | | 133 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202011 | | | | | | | | 49 | | | | | 49 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202012 | | | | | | | | 97 | | | | | 97 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202204 | | | | | | | | | | 6.362 | | | 6.362 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202205 | | | | | | | | | | 11.894 | | | 11.894 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202206 | | | | | | | | | | 19.285 | | | 19.285 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202207 | | | | | | | | | | 29.254 | | | 29.254 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202208 | | | | | | | | | | 13.563 | | | 13.563 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202209 | | | | | | | | | | 15.020 | | | 15.020 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202210 | | | | | | | | | | 343 | | | 343 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202211 | | | | | | | | | | 25 | | | 25 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202212 | | | | | | | | | | 27.808 | | | 27.808 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202301 | | | | | | | | | | | (18.723) | | (18.723) |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202302 | | | | | | | | | | | 458 | | 458 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202304 | | | | | | | | | | | 4.583 | | 4.583 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202305 | | | | | | | | | | | 7.999 | | 7.999 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202306 | | | | | | | | | | | 9.800 | | 9.800 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202307 | | | | | | | | | | | 1.357 | | 1.357 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202308 | | | | | | | | | | | 2.658 | | 2.658 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202309 | | | | | | | | | | | 15.005 | | 15.005 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202310 | | | | | | | | | | | 64.460 | | 64.460 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202311 | | | | | | | | | | | 14.028 | | 14.028 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202312 | | | | | | | | | | | 14.599 | | 14.599 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202401 | | | | | | | | | | | | 17.578 | 17.578 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202402 | | | | | | | | | | | | 18.408 | 18.408 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202403 | | | | | | | | | | | | 5.760 | 5.760 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202404 | | | | | | | | | | | | 7.089 | 7.089 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202406 | | | | | | | | | | | | 283 | 283 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98601128 | AA OR STTR Minor Gas Dist(986) | 202407 | | | | | | | | | | | | 5.973 | 5.973 |
| **BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts** | **98601128** | **AA OR STTR Minor Gas Dist(986) Total** | | | **263.614** | **45.858** | **2.516** | **7.053** | **2.807** | | **279** | | **123.554** | **116.223** | **55.090** | **616.995** |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 201406 | | 2.817 | | | | | | | | | | | 2.817 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 201407 | | 1.201 | | | | | | | | | | | 1.201 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 201408 | | 34.886 | | | | | | | | | | | 34.886 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 201409 | | 11.673 | | | | | | | | | | | 11.673 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 201410 | | 55.843 | | | | | | | | | | | 55.843 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 201411 | | 25.648 | | | | | | | | | | | 25.648 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 201412 | | 622 | | | | | | | | | | | 622 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 201504 | | | 31 | | | | | | | | | | 31 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 201505 | | | 641 | | | | | | | | | | 641 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 201506 | | | 861 | | | | | | | | | | 861 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 201507 | | | 30.027 | | | | | | | | | | 30.027 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 201508 | | | 38.205 | | | | | | | | | | 38.205 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 201509 | | | 5.129 | | | | | | | | | | 5.129 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 201510 | | | 4.100 | | | | | | | | | | 4.100 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 201512 | | | 7.386 | | | | | | | | | | 7.386 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 201603 | | | | 268 | | | | | | | | | 268 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 201604 | | | | 744 | | | | | | | | | 744 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 201605 | | | | 1.593 | | | | | | | | | 1.593 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 201606 | | | | 629 | | | | | | | | | 629 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 201608 | | | | 2.222 | | | | | | | | | 2.222 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 202004 | | | | | | | | 235 | | | | | 235 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 202111 | | | | | | | | | 833 | | | | 833 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 202112 | | | | | | | | | 4.934 | | | | 4.934 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 202202 | | | | | | | | | | 30.802 | | | 30.802 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 202203 | | | | | | | | | | 29.385 | | | 29.385 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 202204 | | | | | | | | | | 71.248 | | | 71.248 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 202205 | | | | | | | | | | 5.351 | | | 5.351 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 202206 | | | | | | | | | | 156 | | | 156 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 202207 | | | | | | | | | | 9.791 | | | 9.791 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 202208 | | | | | | | | | | 26.173 | | | 26.173 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 202209 | | | | | | | | | | 15.369 | | | 15.369 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 202210 | | | | | | | | | | 19.230 | | | 19.230 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 202211 | | | | | | | | | | 23.327 | | | 23.327 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 202212 | | | | | | | | | | 63.511 | | | 63.511 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 202301 | | | | | | | | | | | 222 | | 222 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 202302 | | | | | | | | | | | 1.290 | | 1.290 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 202303 | | | | | | | | | | | 228 | | 228 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 202305 | | | | | | | | | | | 6.685 | | 6.685 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 202306 | | | | | | | | | | | 1.390 | | 1.390 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98701128 | AA OR STTR Minor Gas Dist(987) | 202403 | | | | | | | | | | | | (300) | (300) |
| **BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts** | **98701128** | **AA OR STTR Minor Gas Dist(987) Total** | | | **132.690** | **86.380** | **5.457** | | | | **235** | **5.768** | **294.344** | **9.815** | **(300)** | **534.390** |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 201405 | | 2.905 | | | | | | | | | | | 2.905 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 201406 | | 284 | | | | | | | | | | | 284 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 201502 | | | 7.887 | | | | | | | | | | 7.887 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 201505 | | | 4.335 | | | | | | | | | | 4.335 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 201506 | | | 7.350 | | | | | | | | | | 7.350 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 201507 | | | 7.547 | | | | | | | | | | 7.547 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 201509 | | | 1.810 | | | | | | | | | | 1.810 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 201510 | | | 70 | | | | | | | | | | 70 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 201603 | | | | 6.064 | | | | | | | | | 6.064 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 201605 | | | | 420 | | | | | | | | | 420 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 201908 | | | | | | | 177 | | | | | | 177 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 201909 | | | | | | | 879 | | | | | | 879 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 201910 | | | | | | | 1.734 | | | | | | 1.734 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 202206 | | | | | | | | | | 130 | | | 130 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 202207 | | | | | | | | | | 3.595 | | | 3.595 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 202208 | | | | | | | | | | 9.331 | | | 9.331 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 202209 | | | | | | | | | | 9.277 | | | 9.277 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 202210 | | | | | | | | | | 8.606 | | | 8.606 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 202211 | | | | | | | | | | 4.512 | | | 4.512 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 202212 | | | | | | | | | | 186 | | | 186 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 202303 | | | | | | | | | | | 171 | | 171 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 202304 | | | | | | | | | | | 3.270 | | 3.270 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 202306 | | | | | | | | | | | 1.703 | | 1.703 |
| BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts | 98801128 | AA OR STTR Minor Gas Dist(988) | 202307 | | | | | | | | | | | 98 | | 98 |
| **BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts** | **98801128** | **AA OR STTR Minor Gas Dist(988) Total** | | | **3.189** | **28.999** | **6.485** | | | **2.790** | | | **35.637** | **5.242** | | **82.342** |
| **BI_GN311 - Aldyl A-OR-STTR-Minor Project -Gas Districts Total** | | | | | **427,149** | **164,284** | **17,663** | **19,320** | **4,126** | **2,874** | **514** | **362,780** | **1,825,088** | **533,851** | **252,033** | **3,609,683** |
| **Grand Total** | | | | **5.073.838** | **5.254.289** | **6.504.790** | **5.924.404** | **5.925.408** | **7.573.298** | **5.938.932** | **6.288.559** | **4.626.278** | **8.637.047** | **8.938.319** | **6.587.059** | **77.272.220** |

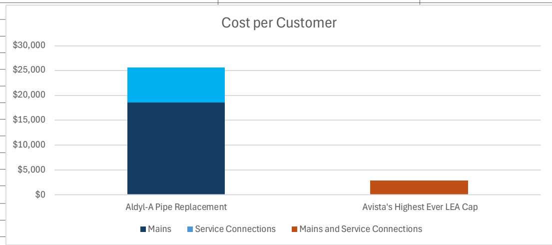
Table Source: Avista's Response to CUB DR to Avista 80

| Year | # of Residential Customers | # of Residential Tees | # of Commercial Customers | # of Commercial Tees |
|---|---|---|---|---|
| **2013 - 2015** | 955 | 849 | 114 | 98 |
| **2016** | 499 | 420 | 16 | 15 |
| **2017** | 553 | 511 | 32 | 31 |
| **2018** | 508 | 470 | 36 | 33 |
| **2019** | 362 | 336 | 26 | 24 |
| **2020** | 364 | 338 | 24 | 24 |
| **2021** | 314 | 298 | 60 | 53 |
| **2022** | 348 | 297 | 32 | 31 |
| **2023** | 362 | 340 | 42 | 37 |
| **2024** | 304 | 274 | 18 | 16 |
| **TOTAL** | **4,569** | **4,133** | **400** | **362** |

| | | | | |
|---|---|---|---|---|
| 5-yr Past Average | 338 | 35 | Customer Ratio | 9.6 |
| Avg Custs/ Year (Both Res and Com), 5-yr Past Avg | 374 | | | |

| | | | |
|---|---|---|---|
| **Aldyl A Pipe Replacement Program** | | | |
| | | **Source:** | |
| Annual Transfer to Plant, 5-yr Past Avg | $7,015,452 | | |
| Annual Customers Served, 5-yr Past Avg | 374 | | |
| Investment/ Cust for Aldyl-A Distribution Mains Replacement | $18,778 | | |
| **Service Connection Cost Est.** | | | |
| Service Connection Replacement, Res Cust, 5-yr Past Avg | $6,833 | | |
| **Total Aldyl-A Replacement Cost / Customer** | $25,611 | | |
| **For Reference** | | | |
| Highest Ever Avista Res LEA Cap | $2,875 | UG 461- Opening Testimony CUB/100, Garrett-Jenks/Page 3 | |
| Ratio (Total Aldyl-A Pipe Replacement: Highest LEA) | 8.9 | | |

| | **Aldyl-A Pipe Replacement** | **Avista's Highest Ever LEA Cap** |
|---|---|---|
| **Mains** | $18,778 | |
| **Service Connections** | $6,833 | |
| **Mains and Service Connections** | | $2,875 |



Determination of Total Cost over Book Life

Input Capital Costs and Rates

| Cost of Capital | % of Captial | Cost | Weighted Cost | |
|---|---|---|---|---|
| Debt | 50% | 4.97% | 2.485% | Source: UG 519- Avista Exhibit 201, Christie/Page 2 of 5, Current Cost of Debt |
| Common Equity | 50% | 9.50% | 4.750% | Source: UG 519- Avista Exhibit 201, Christie/Page 2 of 5, Current Cost of Equity |
| | 100% | | 7.235% | |
| State Tax Rate | | | 7.60% | |
| Federal Tax Rate | | | 21% | |
| Revenue Sensitive Rate | | | 3.08% | Source: UG 519 CUB/302 Garrett/ 'Avista's Responses to CUB's Discovery Requests' DR 108, Line 8 "Total Expense" |
| Deprecation Rate | | | 1.99% | Source: UG 519 CUB/302 Garrett/ 'Avista's Responses to CUB's Discovery Requests' DRs 8 and 76, FERC Account 380 |
| Property Tax Rate | | | 1.28% | Source: UG 519 - Avista/ Garbarino Workpaper "2.05 - PF Property Tax Adjustment" - G-FPT-3, F13 |
| Investment: Aldyl-A Distribution Main Replacment | | | 18788 | Source: UG 519 CUB/303 'Aldyl-A Replacement Cost per Customer' 'AA Replacement Cost per Cust' Cell C8 |

| | | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Deprecation | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 |
| 2 | O&M | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | Property Taxes | 236 | 227 | 219 | 212 | 205 | 198 | 192 | 185 | 179 | 173 | 166 | 160 | 153 | 147 | 141 | 134 | 128 |
| | Taxes on Equity Return | | | | | | | | | | | | | | | | | |
| 4 | State | 92 | 89 | 86 | 83 | 80 | 77 | 75 | 72 | 70 | 67 | 65 | 62 | 60 | 57 | 55 | 53 | 50 |
| 5 | Federal | 234 | 227 | 219 | 212 | 205 | 198 | 191 | 184 | 178 | 172 | 166 | 159 | 153 | 147 | 140 | 134 | 128 |
| 6 | Total Taxes | 326 | 316 | 305 | 295 | 285 | 275 | 266 | 257 | 248 | 239 | 230 | 222 | 213 | 204 | 195 | 187 | 178 |
| | Return on Rate Base | | | | | | | | | | | | | | | | | |
| 7 | Debt | 461 | 447 | 432 | 417 | 403 | 389 | 376 | 363 | 351 | 338 | 326 | 313 | 301 | 289 | 276 | 264 | 251 |
| 8 | Equity | 881 | 855 | 826 | 797 | 770 | 744 | 718 | 694 | 670 | 647 | 623 | 599 | 575 | 552 | 528 | 504 | 481 |
| 9 | Total Return | 1342 | 1303 | 1257 | 1214 | 1172 | 1133 | 1094 | 1057 | 1021 | 985 | 949 | 912 | 876 | 840 | 804 | 768 | 732 |
| 10 | Subtotal Cost of Service | 2279 | 2220 | 2156 | 2095 | 2036 | 1980 | 1925 | 1873 | 1822 | 1770 | 1719 | 1668 | 1617 | 1565 | 1514 | 1463 | 1411 |
| 11 | Revenue Sensitive Items | 72 | 71 | 69 | 67 | 65 | 63 | 61 | 60 | 58 | 56 | 55 | 53 | 51 | 50 | 48 | 46 | 45 |
| 12 | Total Cost of Service | $ 2,351 | $ 2,290 | $ 2,225 | $ 2,161 | $ 2,101 | $ 2,043 | $ 1,987 | $ 1,933 | $ 1,880 | $ 1,827 | $ 1,774 | $ 1,721 | $ 1,668 | $ 1,615 | $ 1,562 | $ 1,509 | $ 1,456 |
| | **Total Cost Over 50 Years** | $ 61,005 | | | | | | | | | | | | | | | | |
| | Rate Base -Net of Deprecation and Def Tax | 18556 | 18005 | 17380 | 16781 | 16206 | 15654 | 15123 | 14612 | 14111 | 13612 | 13112 | 12613 | 12114 | 11615 | 11115 | 10616 | 10117 |
| | Income Taxes | | | | | | | | | | | | | | | | | |
| | Gross up - Equity | 1208 | 1172 | 1131 | 1092 | 1055 | 1019 | 984 | 951 | 918 | 886 | 853 | 821 | 788 | 756 | 723 | 691 | 658 |
| | Less: State Tax | 92 | 89 | 86 | 83 | 80 | 77 | 75 | 72 | 70 | 67 | 65 | 62 | 60 | 57 | 55 | 53 | 50 |
| | Federal Taxable Income | 1116 | 1083 | 1045 | 1009 | 974 | 941 | 909 | 879 | 848 | 818 | 788 | 758 | 728 | 698 | 668 | 638 | 608 |
| | Less: Federal Tax | 234 | 227 | 219 | 212 | 205 | 198 | 191 | 184 | 178 | 172 | 166 | 159 | 153 | 147 | 140 | 134 | 128 |
| | Return | 881 | 855 | 826 | 797 | 770 | 744 | 718 | 694 | 670 | 647 | 623 | 599 | 575 | 552 | 528 | 504 | 481 |
| | Deffered Taxes | | | | | | | | | | | | | | | | | |
| | Book Deprecation | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 |
| | Tax Deprecation | 705 | 1356 | 1254 | 1161 | 1073 | 993 | 918 | 850 | 838 | 838 | 838 | 838 | 838 | 838 | 838 | 838 | 838 |
| | Book-Tax Difference | 331 | 982 | 881 | 787 | 699 | 619 | 544 | 476 | 464 | 464 | 464 | 464 | 464 | 464 | 464 | 464 | 464 |
| | Tax Effect | 89 | 265 | 238 | 212 | 189 | 167 | 147 | 128 | 125 | 125 | 125 | 125 | 125 | 125 | 125 | 125 | 125 |
| | MACRS Deprecation - 20 | 3.75% | 7.22% | 6.68% | 6.18% | 5.71% | 5.29% | 4.89% | 4.52% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% |
| | Property Tax Base | 18467 | 17740 | 17142 | 16568 | 16017 | 15487 | 14976 | 14483 | 13986 | 13486 | 12987 | 12488 | 11988 | 11489 | 10990 | 10491 | 9991 |
| | Tax Calculation Check | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | 27.00400% | | | | | | | | | | | | | | | | |
| | | 0.7300 | | | | | | | | | | | | | | | | |

| | | Year 18 | Year 19 | Year 20 | Year 21 | Year 22 | Year 23 | Year 24 | Year 25 | Year 26 | Year 27 | Year 28 | Year 29 | Year 30 | Year 31 | Year 32 | Year 33 | Year 34 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Deprecation | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 |
| 2 | O&M | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | | | |
| 3 | Property Taxes | 121 | 115 | 109 | 104 | 102 | 98 | 95 | 91 | 88 | 84 | 81 | 77 | 74 | 70 | 67 | 63 | 60 |
| | Taxes on Equity Return | | | | | | | | | | | | | | | | | |
| 4 | State | 48 | 45 | 43 | 40 | 39 | 37 | 36 | 35 | 33 | 32 | 31 | 29 | 28 | 27 | 25 | 24 | 23 |
| 5 | Federal | 121 | 115 | 109 | 103 | 99 | 96 | 92 | 89 | 85 | 82 | 78 | 75 | 72 | 68 | 65 | 61 | 58 |
| 6 | Total Taxes | 169 | 160 | 151 | 144 | 138 | 133 | 128 | 123 | 119 | 114 | 109 | 104 | 100 | 95 | 90 | 85 | 80 |
| | Return on Rate Base | | | | | | | | | | | | | | | | | |
| 7 | Debt | 239 | 227 | 214 | 203 | 195 | 188 | 181 | 175 | 168 | 161 | 154 | 147 | 141 | 134 | 127 | 120 | 114 |
| 8 | Equity | 457 | 433 | 409 | 388 | 373 | 360 | 347 | 334 | 321 | 308 | 295 | 282 | 269 | 256 | 243 | 230 | 217 |
| 9 | Total Return | 696 | 660 | 624 | 592 | 568 | 548 | 528 | 508 | 489 | 469 | 449 | 429 | 410 | 390 | 370 | 350 | 331 |
| 10 | Subtotal Cost of Service | 1360 | 1309 | 1258 | 1214 | 1181 | 1153 | 1125 | 1097 | 1069 | 1041 | 1013 | 985 | 957 | 929 | 901 | 873 | 845 |
| 11 | Revenue Sensitive Items | 43 | 42 | 40 | 39 | 38 | 37 | 36 | 35 | 34 | 33 | 32 | 31 | 30 | 30 | 29 | 28 | 27 |
| 12 | Total Cost of Service | $ 1,403 | $ 1,350 | $ 1,298 | $ 1,252 | $ 1,219 | $ 1,190 | $ 1,161 | $ 1,132 | $ 1,103 | $ 1,074 | $ 1,045 | $ 1,016 | $ 987 | $ 958 | $ 929 | $ 901 | $ 872 |
| | Rate Base -Net of Deprecation and Def Tax | 9617 | 9118 | 8619 | 8176 | 7847 | 7574 | 7301 | 7028 | 6755 | 6482 | 6209 | 5936 | 5663 | 5390 | 5118 | 4845 | 4572 |
| | Income Taxes | | | | | | | | | | | | | | | | | |
| | Gross up - Equity | 626 | 593 | 561 | 532 | 511 | 493 | 475 | 457 | 440 | 422 | 404 | 386 | 369 | 351 | 333 | 315 | 297 |
| | Less: State Tax | 48 | 45 | 43 | 40 | 39 | 37 | 36 | 35 | 33 | 32 | 31 | 29 | 28 | 27 | 25 | 24 | 23 |
| | Federal Taxable Income | 578 | 548 | 518 | 492 | 472 | 455 | 439 | 423 | 406 | 390 | 373 | 357 | 341 | 324 | 308 | 291 | 275 |
| | Less: Federal Tax | 121 | 115 | 109 | 103 | 99 | 96 | 92 | 89 | 85 | 82 | 78 | 75 | 72 | 68 | 65 | 61 | 58 |
| | Return | 457 | 433 | 409 | 388 | 373 | 360 | 347 | 334 | 321 | 308 | 295 | 282 | 269 | 256 | 243 | 230 | 217 |
| | Deffered Taxes | | | | | | | | | | | | | | | | | |
| | Book Deprecation | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 |
| | Tax Deprecation | 838 | 838 | 838 | 419 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Book-Tax Difference | 464 | 464 | 464 | 45 | (374) | (374) | (374) | (374) | (374) | (374) | (374) | (374) | (374) | (374) | (374) | (374) | (374) |
| | Tax Effect | 125 | 125 | 125 | 12 | (101) | (101) | (101) | (101) | (101) | (101) | (101) | (101) | (101) | (101) | (101) | (101) | (101) |
| | MACRS Deprecation - 20 | 4.46% | 4.46% | 4.46% | 2.23% | | | | | | | | | | | | | |
| | Property Tax Base | 9492 | 8993 | 8494 | 8164 | 7948 | 7675 | 7402 | 7129 | 6856 | 6583 | 6310 | 6037 | 5764 | 5491 | 5219 | 4946 | 4673 |
| | Tax Calculation Check | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| | | Year 35 | Year 36 | Year 37 | Year 38 | Year 39 | Year 40 | Year 41 | Year 42 | Year 43 | Year 44 | Year 45 | Year 46 | Year 47 | Year 48 | Year 49 | Year 50 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Deprecation | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 |
| 2 | O&M | | | | | | | | | | | | | | | | |
| 3 | Property Taxes | 56 | 53 | 49 | 46 | 42 | 39 | 35 | 32 | 28 | 25 | 21 | 18 | 14 | 11 | 7 | 4 |
| | Taxes on Equity Return | | | | | | | | | | | | | | | | |
| 4 | State | 21 | 20 | 19 | 17 | 16 | 15 | 13 | 12 | 10 | 9 | 8 | 6 | 5 | 4 | 2 | 1 |
| 5 | Federal | 54 | 51 | 47 | 44 | 40 | 37 | 34 | 30 | 27 | 23 | 20 | 16 | 13 | 9 | 6 | 3 |
| 6 | Total Taxes | 76 | 71 | 66 | 61 | 56 | 52 | 47 | 42 | 37 | 32 | 28 | 23 | 18 | 13 | 8 | 4 |
| | Return on Rate Base | | | | | | | | | | | | | | | | |
| 7 | Debt | 107 | 100 | 93 | 86 | 80 | 73 | 66 | 59 | 53 | 46 | 39 | 32 | 25 | 19 | 12 | 5 |
| 8 | Equity | 204 | 191 | 178 | 165 | 152 | 139 | 126 | 113 | 100 | 88 | 75 | 62 | 49 | 36 | 23 | 10 |
| 9 | Total Return | 311 | 291 | 272 | 252 | 232 | 212 | 193 | 173 | 153 | 133 | 114 | 94 | 74 | 54 | 35 | 15 |
| 10 | Subtotal Cost of Service | 817 | 789 | 761 | 733 | 705 | 677 | 649 | 621 | 592 | 564 | 536 | 508 | 480 | 452 | 424 | 396 |
| 11 | Revenue Sensitive Items | 26 | 25 | 24 | 23 | 22 | 22 | 21 | 20 | 19 | 18 | 17 | 16 | 15 | 14 | 13 | 13 |
| 12 | Total Cost of Service | $ 843 | $ 814 | $ 785 | $ 756 | $ 727 | $ 698 | $ 669 | $ 640 | $ 611 | $ 582 | $ 553 | $ 525 | $ 496 | $ 467 | $ 438 | $ 409 |
| | Rate Base -Net of Deprecation and Def Tax | 4299 | 4026 | 3753 | 3480 | 3207 | 2934 | 2661 | 2388 | 2115 | 1843 | 1570 | 1297 | 1024 | 751 | 478 | 205 |
| | Income Taxes | | | | | | | | | | | | | | | | |
| | Gross up - Equity | 280 | 262 | 244 | 226 | 209 | 191 | 173 | 155 | 138 | 120 | 102 | 84 | 67 | 49 | 31 | 13 |
| | Less: State Tax | 21 | 20 | 19 | 17 | 16 | 15 | 13 | 12 | 10 | 9 | 8 | 6 | 5 | 4 | 2 | 1 |
| | Federal Taxable Income | 258 | 242 | 226 | 209 | 193 | 176 | 160 | 144 | 127 | 111 | 94 | 78 | 62 | 45 | 29 | 12 |
| | Less: Federal Tax | 54 | 51 | 47 | 44 | 40 | 37 | 34 | 30 | 27 | 23 | 20 | 16 | 13 | 9 | 6 | 3 |
| | Return | 204 | 191 | 178 | 165 | 152 | 139 | 126 | 113 | 100 | 88 | 75 | 62 | 49 | 36 | 23 | 10 |
| | Deffered Taxes | | | | | | | | | | | | | | | | |
| | Book Deprecation | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 | 374 |
| | Tax Deprecation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Book-Tax Difference | (374) | (374) | (374) | (374) | (374) | (374) | (374) | (374) | (374) | (374) | (374) | (374) | (374) | (374) | (374) | (374) |
| | Tax Effect | (101) | (101) | (101) | (101) | (101) | (101) | (101) | (101) | (101) | (101) | (101) | (101) | (101) | (101) | (101) | (101) |
| | MACRS Deprecation - 20 | | | | | | | | | | | | | | | | |
| | Property Tax Base | 4400 | 4127 | 3854 | 3581 | 3308 | 3035 | 2762 | 2489 | 2216 | 1944 | 1671 | 1398 | 1125 | 852 | 579 | 306 |
| | Tax Calculation Check | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

Determination of Total Cost over Book Life

Input Capital Costs and Rates

| Cost of Capital | % of Capital | Cost | Weighted Cost | |
|---|---|---|---|---|
| Debt | 50% | 4.97% | 2.485% | Source: UG 519- Avista Exhibit 201, Christie/Page 2 of 5, Current Cost of Debt |
| Common Equity | 50% | 9.50% | 4.750% | Source: UG 519- Avista Exhibit 201, Christie/Page 2 of 5, Current Cost of Equity |
| | 100% | | 7.235% | |
| | | | | |
| State Tax Rate | | | 7.60% | |
| Federal Tax Rate | | | 21% | |
| Revenue Sensitive Rate | | | 3.08% | Source: UG 519 CUB/302 Garrett/ 'Avista's Responses to CUB's Discovery Requests' DR 108, Line 8 "Total Expense" |
| Deprecation Rate | | | 1.99% | Source: UG 519 CUB/302 Garrett/ 'Avista's Responses to CUB's Discovery Requests' DRs 8 and 76, FERC Account 380 |
| Property Tax Rate | | | 1.28% | Source: UG 519 Avista/ Garbarino Workpaper "2.05 - PF Property Tax Adjustment" - G-FPT-3, F13 |
| | | | | |
| Investment: Service Connection Replacement | | | 6844 | Source: UG 519 CUB/303 'Aldyl-A Replacement Cost per Customer' 'AA Replacement Cost per Cust' Cell C12 |

| | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 Deprecation | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 |
| 2 O&M | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 Property Taxes | 86 | 83 | 80 | 77 | 75 | 72 | 70 | 68 | 65 | 63 | 61 | 58 | 56 | 54 | 51 | 49 | 47 |
| Taxes on Equity Return | | | | | | | | | | | | | | | | | |
| 4 State | 33 | 32 | 31 | 30 | 29 | 28 | 27 | 26 | 25 | 25 | 24 | 23 | 22 | 21 | 20 | 19 | 18 |
| 5 Federal | 85 | 83 | 80 | 77 | 75 | 72 | 70 | 67 | 65 | 63 | 60 | 58 | 56 | 53 | 51 | 49 | 47 |
| 6 Total Taxes | 119 | 115 | 111 | 107 | 104 | 100 | 97 | 94 | 90 | 87 | 84 | 81 | 78 | 74 | 71 | 68 | 65 |
| Return on Rate Base | | | | | | | | | | | | | | | | | |
| 7 Debt | 168 | 163 | 157 | 152 | 147 | 142 | 137 | 132 | 128 | 123 | 119 | 114 | 110 | 105 | 101 | 96 | 92 |
| 8 Equity | 321 | 312 | 301 | 290 | 280 | 271 | 262 | 253 | 244 | 236 | 227 | 218 | 210 | 201 | 192 | 184 | 175 |
| 9 Total Return | 489 | 475 | 458 | 442 | 427 | 413 | 399 | 385 | 372 | 359 | 346 | 332 | 319 | 306 | 293 | 280 | 267 |
| 10 Subtotal Cost of Service | 830 | 809 | 785 | 763 | 742 | 721 | 701 | 682 | 664 | 645 | 626 | 608 | 589 | 570 | 552 | 533 | 514 |
| 11 Revenue Sensitive Items | 26 | 26 | 25 | 24 | 24 | 23 | 22 | 22 | 21 | 20 | 20 | 19 | 19 | 18 | 18 | 17 | 16 |
| 12 Total Cost of Service | $ 856 | $ 834 | $ 810 | $ 787 | $ 765 | $ 744 | $ 724 | $ 704 | $ 685 | $ 665 | $ 646 | $ 627 | $ 608 | $ 588 | $ 569 | $ 550 | $ 530 |
| **Total Cost Over 50 Years** | $ 22,222 | | | | | | | | | | | | | | | | |
| Rate Base -Net of Deprecation and Def Tax | 6760 | 6559 | 6331 | 6113 | 5904 | 5702 | 5509 | 5323 | 5140 | 4958 | 4777 | 4595 | 4413 | 4231 | 4049 | 3867 | 3685 |
| Income Taxes | | | | | | | | | | | | | | | | | |
| Gross up - Equity | 440 | 427 | 412 | 398 | 384 | 371 | 358 | 346 | 334 | 323 | 311 | 299 | 287 | 275 | 263 | 252 | 240 |
| Less: State Tax | 33 | 32 | 31 | 30 | 29 | 28 | 27 | 26 | 25 | 25 | 24 | 23 | 22 | 21 | 20 | 19 | 18 |
| Federal Taxable Income | 406 | 394 | 381 | 368 | 355 | 343 | 331 | 320 | 309 | 298 | 287 | 276 | 265 | 254 | 243 | 233 | 222 |
| Less: Federal Tax | 85 | 83 | 80 | 77 | 75 | 72 | 70 | 67 | 65 | 63 | 60 | 58 | 56 | 53 | 51 | 49 | 47 |
| Return | 321 | 312 | 301 | 290 | 280 | 271 | 262 | 253 | 244 | 236 | 227 | 218 | 210 | 201 | 192 | 184 | 175 |
| Differed Taxes | | | | | | | | | | | | | | | | | |
| Book Deprecation | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 |
| Tax Deprecation | 257 | 494 | 457 | 423 | 391 | 362 | 335 | 309 | 305 | 305 | 305 | 305 | 305 | 305 | 305 | 305 | 305 |
| Book-Tax Difference | 120 | 358 | 321 | 287 | 255 | 226 | 198 | 173 | 169 | 169 | 169 | 169 | 169 | 169 | 169 | 169 | 169 |
| Tax Effect | 33 | 97 | 87 | 77 | 69 | 61 | 54 | 47 | 46 | 46 | 46 | 46 | 46 | 46 | 46 | 46 | 46 |
| MACRS Deprecation - 20 | 3.75% | 7.22% | 6.68% | 6.18% | 5.71% | 5.29% | 4.89% | 4.52% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% |
| Property Tax Base | 6727 | 6462 | 6244 | 6035 | 5835 | 5642 | 5456 | 5276 | 5095 | 4913 | 4731 | 4549 | 4367 | 4185 | 4003 | 3821 | 3640 |
| Tax Calculation Check | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | 27.00400% | | | | | | | | | | | | | | | | |
| | 0.7300 | | | | | | | | | | | | | | | | |

| | Year 18 | Year 19 | Year 20 | Year 21 | Year 22 | Year 23 | Year 24 | Year 25 | Year 26 | Year 27 | Year 28 | Year 29 | Year 30 | Year 31 | Year 32 | Year 33 | Year 34 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 Deprecation | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 |
| 2 O&M | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | | | |
| 3 Property Taxes | 44 | 42 | 40 | 38 | 37 | 36 | 35 | 33 | 32 | 31 | 29 | 28 | 27 | 26 | 24 | 23 | 22 |
| Taxes on Equity Return | | | | | | | | | | | | | | | | | |
| 4 State | 17 | 16 | 16 | 15 | 14 | 14 | 13 | 13 | 12 | 12 | 11 | 11 | 10 | 10 | 9 | 9 | 8 |
| 5 Federal | 44 | 42 | 40 | 38 | 36 | 35 | 34 | 32 | 31 | 30 | 29 | 27 | 26 | 25 | 24 | 22 | 21 |
| 6 Total Taxes | 62 | 58 | 55 | 52 | 50 | 48 | 47 | 45 | 43 | 41 | 40 | 38 | 36 | 35 | 33 | 31 | 29 |
| Return on Rate Base | | | | | | | | | | | | | | | | | |
| 7 Debt | 87 | 83 | 78 | 74 | 71 | 69 | 66 | 64 | 61 | 59 | 56 | 54 | 51 | 49 | 46 | 44 | 41 |
| 8 Equity | 166 | 158 | 149 | 141 | 136 | 131 | 126 | 122 | 117 | 112 | 107 | 103 | 98 | 93 | 89 | 84 | 79 |
| 9 Total Return | 253 | 240 | 227 | 215 | 207 | 200 | 192 | 185 | 178 | 171 | 164 | 156 | 149 | 142 | 135 | 128 | 120 |
| 10 Subtotal Cost of Service | 495 | 477 | 458 | 442 | 430 | 420 | 410 | 400 | 389 | 379 | 369 | 359 | 349 | 338 | 328 | 318 | 308 |
| 11 Revenue Sensitive Items | 16 | 15 | 15 | 14 | 14 | 13 | 13 | 13 | 12 | 12 | 12 | 11 | 11 | 11 | 10 | 10 | 10 |
| 12 Total Cost of Service | $ 511 | $ 492 | $ 473 | $ 456 | $ 444 | $ 433 | $ 423 | $ 412 | $ 402 | $ 391 | $ 381 | $ 370 | $ 360 | $ 349 | $ 339 | $ 328 | $ 318 |
| Rate Base -Net of Deprecation and Def Tax | 3503 | 3322 | 3140 | 2978 | 2858 | 2759 | 2660 | 2560 | 2461 | 2361 | 2262 | 2162 | 2063 | 1964 | 1864 | 1765 | 1665 |
| Income Taxes | | | | | | | | | | | | | | | | | |
| Gross up - Equity | 228 | 216 | 204 | 194 | 186 | 180 | 173 | 167 | 160 | 154 | 147 | 141 | 134 | 128 | 121 | 115 | 108 |
| Less: State Tax | 17 | 16 | 16 | 15 | 14 | 14 | 13 | 13 | 12 | 12 | 11 | 11 | 10 | 10 | 9 | 9 | 8 |
| Federal Taxable Income | 211 | 200 | 189 | 179 | 172 | 166 | 160 | 154 | 148 | 142 | 136 | 130 | 124 | 118 | 112 | 106 | 100 |
| Less: Federal Tax | 44 | 42 | 40 | 38 | 36 | 35 | 34 | 32 | 31 | 30 | 29 | 27 | 26 | 25 | 24 | 22 | 21 |
| Return | 166 | 158 | 149 | 141 | 136 | 131 | 126 | 122 | 117 | 112 | 107 | 103 | 98 | 93 | 89 | 84 | 79 |
| Differed Taxes | | | | | | | | | | | | | | | | | |
| Book Deprecation | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 |
| Tax Deprecation | 305 | 305 | 305 | 153 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Book-Tax Difference | 169 | 169 | 169 | 16 | (136) | (136) | (136) | (136) | (136) | (136) | (136) | (136) | (136) | (136) | (136) | (136) | (136) |
| Tax Effect | 46 | 46 | 46 | 4 | (37) | (37) | (37) | (37) | (37) | (37) | (37) | (37) | (37) | (37) | (37) | (37) | (37) |
| MACRS Deprecation - 20 | 4.46% | 4.46% | 4.46% | 2.23% | | | | | | | | | | | | | |
| Property Tax Base | 3458 | 3276 | 3094 | 2974 | 2895 | 2796 | 2696 | 2597 | 2497 | 2398 | 2299 | 2199 | 2100 | 2000 | 1901 | 1802 | 1702 |
| Tax Calculation Check | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| | Year 35 | Year 36 | Year 37 | Year 38 | Year 39 | Year 40 | Year 41 | Year 42 | Year 43 | Year 44 | Year 45 | Year 46 | Year 47 | Year 48 | Year 49 | Year 50 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 Deprecation | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 |
| 2 O&M | | | | | | | | | | | | | | | | |
| 3 Property Taxes | 21 | 19 | 18 | 17 | 15 | 14 | 13 | 12 | 10 | 9 | 8 | 7 | 5 | 4 | 3 | 1 |
| Taxes on Equity Return | | | | | | | | | | | | | | | | |
| 4 State | 8 | 7 | 7 | 6 | 6 | 5 | 5 | 4 | 4 | 3 | 3 | 2 | 2 | 1 | 1 | 0 |
| 5 Federal | 20 | 19 | 17 | 16 | 15 | 13 | 12 | 11 | 10 | 8 | 7 | 6 | 5 | 3 | 2 | 1 |
| 6 Total Taxes | 28 | 26 | 24 | 22 | 21 | 19 | 17 | 15 | 14 | 12 | 10 | 8 | 7 | 5 | 3 | 1 |
| Return on Rate Base | | | | | | | | | | | | | | | | |
| 7 Debt | 39 | 36 | 34 | 31 | 29 | 27 | 24 | 22 | 19 | 17 | 14 | 12 | 9 | 7 | 4 | 2 |
| 8 Equity | 74 | 70 | 65 | 60 | 55 | 51 | 46 | 41 | 37 | 32 | 27 | 22 | 18 | 13 | 8 | 4 |
| 9 Total Return | 113 | 106 | 99 | 92 | 85 | 77 | 70 | 63 | 56 | 49 | 41 | 34 | 27 | 20 | 13 | 5 |
| 10 Subtotal Cost of Service | 298 | 287 | 277 | 267 | 257 | 246 | 236 | 226 | 216 | 206 | 195 | 185 | 175 | 165 | 155 | 144 |
| 11 Revenue Sensitive Items | 9 | 9 | 9 | 8 | 8 | 8 | 8 | 7 | 7 | 7 | 6 | 6 | 6 | 5 | 5 | 5 |
| 12 Total Cost of Service | $ 307 | $ 296 | $ 286 | $ 275 | $ 265 | $ 254 | $ 244 | $ 233 | $ 223 | $ 212 | $ 202 | $ 191 | $ 181 | $ 170 | $ 159 | $ 149 |
| Rate Base -Net of Deprecation and Def Tax | 1566 | 1467 | 1367 | 1268 | 1168 | 1069 | 969 | 870 | 771 | 671 | 572 | 472 | 373 | 274 | 174 | 75 |
| Income Taxes | | | | | | | | | | | | | | | | |
| Gross up - Equity | 102 | 95 | 89 | 82 | 76 | 70 | 63 | 57 | 50 | 44 | 37 | 31 | 24 | 18 | 11 | 5 |
| Less: State Tax | 8 | 7 | 7 | 6 | 6 | 5 | 5 | 4 | 4 | 3 | 3 | 2 | 2 | 1 | 1 | 0 |
| Federal Taxable Income | 94 | 88 | 82 | 76 | 70 | 64 | 58 | 52 | 46 | 40 | 34 | 28 | 22 | 16 | 10 | 4 |
| Less: Federal Tax | 20 | 19 | 17 | 16 | 15 | 13 | 12 | 11 | 10 | 8 | 7 | 6 | 5 | 3 | 2 | 1 |
| Return | 74 | 70 | 65 | 60 | 55 | 51 | 46 | 41 | 37 | 32 | 27 | 22 | 18 | 13 | 8 | 4 |
| Differed Taxes | | | | | | | | | | | | | | | | |
| Book Deprecation | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 | 136 |
| Tax Deprecation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Book-Tax Difference | (136) | (136) | (136) | (136) | (136) | (136) | (136) | (136) | (136) | (136) | (136) | (136) | (136) | (136) | (136) | (136) |
| Tax Effect | (37) | (37) | (37) | (37) | (37) | (37) | (37) | (37) | (37) | (37) | (37) | (37) | (37) | (37) | (37) | (37) |
| MACRS Deprecation - 20 | | | | | | | | | | | | | | | | |
| Property Tax Base | 1603 | 1503 | 1404 | 1304 | 1205 | 1106 | 1006 | 907 | 807 | 708 | 609 | 509 | 410 | 310 | 211 | 111 |
| Tax Calculation Check | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

Determination of Total Cost over Book Life

Input Capital Costs and Rates

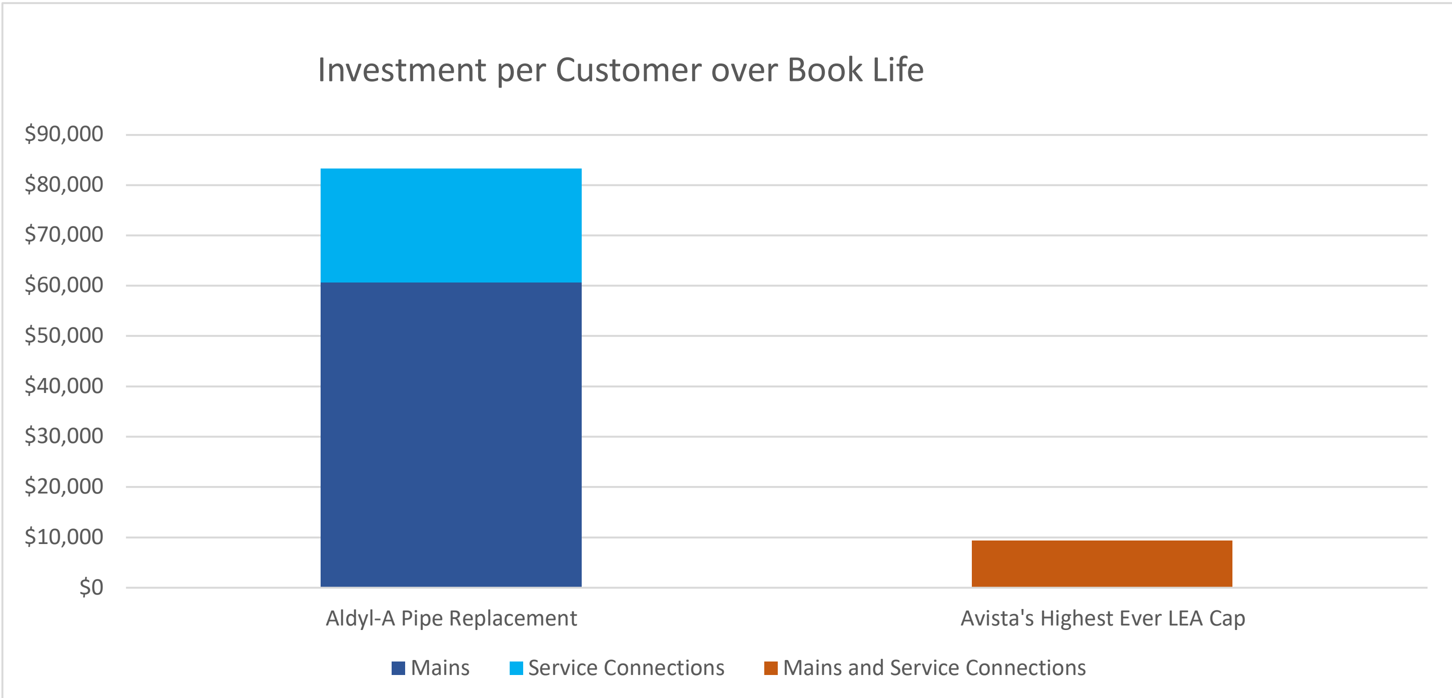
| Cost of Capital | % of Capital | Cost | Weighted Cost | |
|---|---|---|---|---|
| Debt | 50% | 4.97% | 2.485% | Source: UG 519- Avista Exhibit 201, Christie/Page 2 of 5, Current Cost of Debt |
| Common Equity | 50% | 9.50% | 4.750% | Source: UG 519- Avista Exhibit 201, Christie/Page 2 of 5, Current Cost of Equity |
| | 100% | | 7.235% | |
| State Tax Rate | | | 7.60% | |
| Federal Tax Rate | | | 21% | |
| Revenue Sensitive Rate | | | 3.08% | Source: UG 519 CUB/302 Garrett/ 'Avista's Responses to CUB's Discovery Requests' DR 108, Line 8 "Total Expense" |
| Deprecation Rate | | | 1.99% | Source: UG 519 CUB/302 Garrett/ 'Avista's Responses to CUB's Discovery Requests' DRs 8 and 76, FERC Account 380 |
| Property Tax Rate | | | 1.28% | Source: UG 519 - Avista/ Garbarino Workpaper "2.05 - PF Property Tax Adjustment" - G-FPT-3, F13 |
| Investment: Avista's highest ever LEA cap | | | 2875 | Source: UG 461- Opening Testimony CUB/100, Garrett-Jenks/Page 3 |

| | | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Deprecation | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 |
| 2 | O&M | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | Property Taxes | 36 | 35 | 34 | 32 | 31 | 30 | 29 | 28 | 27 | 26 | 25 | 24 | 23 | 23 | 22 | 21 | 20 |
| | Taxes on Equity Return | | | | | | | | | | | | | | | | | |
| 4 | State | 14 | 14 | 13 | 13 | 12 | 12 | 11 | 11 | 11 | 10 | 10 | 10 | 9 | 9 | 8 | 8 | 8 |
| 5 | Federal | 36 | 35 | 34 | 32 | 31 | 30 | 29 | 28 | 27 | 26 | 25 | 24 | 23 | 22 | 21 | 21 | 20 |
| 6 | Total Taxes | 50 | 48 | 47 | 45 | 44 | 42 | 41 | 39 | 38 | 37 | 35 | 34 | 33 | 31 | 30 | 29 | 27 |
| | Return on Rate Base | | | | | | | | | | | | | | | | | |
| 7 | Debt | 71 | 68 | 66 | 64 | 62 | 60 | 57 | 56 | 54 | 52 | 50 | 48 | 46 | 44 | 42 | 40 | 38 |
| 8 | Equity | 135 | 131 | 126 | 122 | 118 | 114 | 110 | 106 | 103 | 99 | 95 | 92 | 88 | 84 | 81 | 77 | 74 |
| 9 | Total Return | 205 | 199 | 192 | 186 | 179 | 173 | 167 | 162 | 156 | 151 | 145 | 140 | 134 | 129 | 123 | 118 | 112 |
| 10 | Subtotal Cost of Service | 349 | 340 | 330 | 321 | 312 | 303 | 295 | 287 | 279 | 271 | 263 | 255 | 247 | 240 | 232 | 224 | 216 |
| 11 | Revenue Sensitive Items | 11 | 11 | 10 | 10 | 10 | 10 | 9 | 9 | 9 | 9 | 8 | 8 | 8 | 8 | 7 | 7 | 7 |
| 12 | Total Cost of Service | $ 360 | $ 350 | $ 340 | $ 331 | $ 321 | $ 313 | $ 304 | $ 296 | $ 288 | $ 280 | $ 271 | $ 263 | $ 255 | $ 247 | $ 239 | $ 231 | $ 223 |
| | **Total Cost Over 50 Years** | $ 9,335 | | | | | | | | | | | | | | | | |
| | Rate Base -Net of Deprecation and Def Tax | 2840 | 2755 | 2660 | 2568 | 2480 | 2395 | 2314 | 2236 | 2159 | 2083 | 2007 | 1930 | 1854 | 1777 | 1701 | 1624 | 1548 |
| | Income Taxes | | | | | | | | | | | | | | | | | |
| | Gross up - Equity | 185 | 179 | 173 | 167 | 161 | 156 | 151 | 145 | 141 | 136 | 131 | 126 | 121 | 116 | 111 | 106 | 101 |
| | Less: State Tax | 14 | 14 | 13 | 13 | 12 | 12 | 11 | 11 | 11 | 10 | 10 | 10 | 9 | 9 | 8 | 8 | 8 |
| | Federal Taxable Income | 171 | 166 | 160 | 154 | 149 | 144 | 139 | 134 | 130 | 125 | 121 | 116 | 111 | 107 | 102 | 98 | 93 |
| | Less: Federal Tax | 36 | 35 | 34 | 32 | 31 | 30 | 29 | 28 | 27 | 26 | 25 | 24 | 23 | 22 | 21 | 21 | 20 |
| | Return | 135 | 131 | 126 | 122 | 118 | 114 | 110 | 106 | 103 | 99 | 95 | 92 | 88 | 84 | 81 | 77 | 74 |
| | Differed Taxes | | | | | | | | | | | | | | | | | |
| | Book Deprecation | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 |
| | Tax Deprecation | 108 | 208 | 192 | 178 | 164 | 152 | 141 | 130 | 128 | 128 | 128 | 128 | 128 | 128 | 128 | 128 | 128 |
| | Book-Tax Difference | 51 | 150 | 135 | 120 | 107 | 95 | 83 | 73 | 71 | 71 | 71 | 71 | 71 | 71 | 71 | 71 | 71 |
| | Tax Effect | 14 | 41 | 36 | 33 | 29 | 26 | 22 | 20 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 | 19 |
| | MACRS Deprecation - 20 | 3.75% | 7.22% | 6.68% | 6.18% | 5.71% | 5.29% | 4.89% | 4.52% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% |
| | Property Tax Base | 2826 | 2715 | 2623 | 2535 | 2451 | 2370 | 2292 | 2216 | 2140 | 2064 | 1987 | 1911 | 1835 | 1758 | 1682 | 1605 | 1529 |
| | Tax Calculation Check | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | 27.00400% | | | | | | | | | | | | | | | | |
| | | 0.7300 | | | | | | | | | | | | | | | | |

| | | Year 18 | Year 19 | Year 20 | Year 21 | Year 22 | Year 23 | Year 24 | Year 25 | Year 26 | Year 27 | Year 28 | Year 29 | Year 30 | Year 31 | Year 32 | Year 33 | Year 34 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Deprecation | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 |
| 2 | O&M | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | | | |
| 3 | Property Taxes | 19 | 18 | 17 | 16 | 16 | 15 | 14 | 14 | 13 | 13 | 12 | 12 | 11 | 11 | 10 | 10 | 9 |
| | Taxes on Equity Return | | | | | | | | | | | | | | | | | |
| 4 | State | 7 | 7 | 7 | 6 | 6 | 6 | 6 | 5 | 5 | 5 | 5 | 4 | 4 | 4 | 4 | 4 | 3 |
| 5 | Federal | 19 | 18 | 17 | 16 | 15 | 15 | 14 | 14 | 13 | 13 | 12 | 11 | 11 | 10 | 10 | 9 | 9 |
| 6 | Total Taxes | 26 | 25 | 23 | 22 | 21 | 20 | 20 | 19 | 18 | 17 | 17 | 16 | 15 | 14 | 14 | 13 | 12 |
| | Return on Rate Base | | | | | | | | | | | | | | | | | |
| 7 | Debt | 37 | 35 | 33 | 31 | 30 | 29 | 28 | 27 | 26 | 25 | 24 | 23 | 22 | 20 | 19 | 18 | 17 |
| 8 | Equity | 70 | 66 | 63 | 59 | 57 | 55 | 53 | 51 | 49 | 47 | 45 | 43 | 41 | 39 | 37 | 35 | 33 |
| 9 | Total Return | 106 | 101 | 95 | 91 | 87 | 84 | 81 | 78 | 75 | 72 | 69 | 66 | 63 | 60 | 57 | 54 | 51 |
| 10 | Subtotal Cost of Service | 208 | 200 | 192 | 186 | 181 | 176 | 172 | 168 | 164 | 159 | 155 | 151 | 146 | 142 | 138 | 134 | 129 |
| 11 | Revenue Sensitive Items | 7 | 6 | 6 | 6 | 6 | 6 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 5 | 4 | 4 | 4 |
| 12 | Total Cost of Service | $ 215 | $ 207 | $ 199 | $ 192 | $ 186 | $ 182 | $ 178 | $ 173 | $ 169 | $ 164 | $ 160 | $ 156 | $ 151 | $ 147 | $ 142 | $ 138 | $ 133 |
| | Rate Base -Net of Deprecation and Def Tax | 1472 | 1395 | 1319 | 1251 | 1201 | 1159 | 1117 | 1075 | 1034 | 992 | 950 | 908 | 867 | 825 | 783 | 741 | 700 |
| | Income Taxes | | | | | | | | | | | | | | | | | |
| | Gross up - Equity | 96 | 91 | 86 | 81 | 78 | 75 | 73 | 70 | 67 | 65 | 62 | 59 | 56 | 54 | 51 | 48 | 46 |
| | Less: State Tax | 7 | 7 | 7 | 6 | 6 | 6 | 6 | 5 | 5 | 5 | 5 | 4 | 4 | 4 | 4 | 4 | 3 |
| | Federal Taxable Income | 88 | 84 | 79 | 75 | 72 | 70 | 67 | 65 | 62 | 60 | 57 | 55 | 52 | 50 | 47 | 45 | 42 |
| | Less: Federal Tax | 19 | 18 | 17 | 16 | 15 | 15 | 14 | 14 | 13 | 13 | 12 | 11 | 11 | 10 | 10 | 9 | 9 |
| | Return | 70 | 66 | 63 | 59 | 57 | 55 | 53 | 51 | 49 | 47 | 45 | 43 | 41 | 39 | 37 | 35 | 33 |
| | Differed Taxes | | | | | | | | | | | | | | | | | |
| | Book Deprecation | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 |
| | Tax Deprecation | 128 | 128 | 128 | 64 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Book-Tax Difference | 71 | 71 | 71 | 7 | (57) | (57) | (57) | (57) | (57) | (57) | (57) | (57) | (57) | (57) | (57) | (57) | (57) |
| | Tax Effect | 19 | 19 | 19 | 2 | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) |
| | MACRS Deprecation - 20 | 4.46% | 4.46% | 4.46% | 2.23% | | | | | | | | | | | | | |
| | Property Tax Base | 1453 | 1376 | 1300 | 1249 | 1216 | 1174 | 1133 | 1091 | 1049 | 1007 | 966 | 924 | 882 | 840 | 799 | 757 | 715 |
| | Tax Calculation Check | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| | | Year 35 | Year 36 | Year 37 | Year 38 | Year 39 | Year 40 | Year 41 | Year 42 | Year 43 | Year 44 | Year 45 | Year 46 | Year 47 | Year 48 | Year 49 | Year 50 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Deprecation | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 |
| 2 | O&M | | | | | | | | | | | | | | | | |
| 3 | Property Taxes | 9 | 8 | 8 | 7 | 6 | 6 | 5 | 5 | 4 | 4 | 3 | 3 | 2 | 2 | 1 | 1 |
| | Taxes on Equity Return | | | | | | | | | | | | | | | | |
| 4 | State | 3 | 3 | 3 | 3 | 2 | 2 | 2 | 2 | 2 | 1 | 1 | 1 | 1 | 1 | 0 | 0 |
| 5 | Federal | 8 | 8 | 7 | 7 | 6 | 6 | 5 | 5 | 4 | 4 | 3 | 3 | 2 | 1 | 1 | 0 |
| 6 | Total Taxes | 12 | 11 | 10 | 9 | 9 | 8 | 7 | 6 | 6 | 5 | 4 | 3 | 3 | 2 | 1 | 1 |
| | Return on Rate Base | | | | | | | | | | | | | | | | |
| 7 | Debt | 16 | 15 | 14 | 13 | 12 | 11 | 10 | 9 | 8 | 7 | 6 | 5 | 4 | 3 | 2 | 1 |
| 8 | Equity | 31 | 29 | 27 | 25 | 23 | 21 | 19 | 17 | 15 | 13 | 11 | 9 | 7 | 5 | 3 | 1 |
| 9 | Total Return | 48 | 45 | 42 | 39 | 36 | 32 | 29 | 26 | 23 | 20 | 17 | 14 | 11 | 8 | 5 | 2 |
| 10 | Subtotal Cost of Service | 125 | 121 | 116 | 112 | 108 | 104 | 99 | 95 | 91 | 86 | 82 | 78 | 74 | 69 | 65 | 61 |
| 11 | Revenue Sensitive Items | 4 | 4 | 4 | 4 | 3 | 3 | 3 | 3 | 3 | 3 | 3 | 2 | 2 | 2 | 2 | 2 |
| 12 | Total Cost of Service | $ 129 | $ 125 | $ 120 | $ 116 | $ 111 | $ 107 | $ 102 | $ 98 | $ 94 | $ 89 | $ 85 | $ 80 | $ 76 | $ 71 | $ 67 | $ 63 |
| | Rate Base -Net of Deprecation and Def Tax | 658 | 616 | 574 | 533 | 491 | 449 | 407 | 365 | 324 | 282 | 240 | 198 | 157 | 115 | 73 | 31 |
| | Income Taxes | | | | | | | | | | | | | | | | |
| | Gross up - Equity | 43 | 40 | 37 | 35 | 32 | 29 | 26 | 24 | 21 | 18 | 16 | 13 | 10 | 7 | 5 | 2 |
| | Less: State Tax | 3 | 3 | 3 | 3 | 2 | 2 | 2 | 2 | 2 | 1 | 1 | 1 | 1 | 1 | 0 | 0 |
| | Federal Taxable Income | 40 | 37 | 35 | 32 | 30 | 27 | 24 | 22 | 19 | 17 | 14 | 12 | 9 | 7 | 4 | 2 |
| | Less: Federal Tax | 8 | 8 | 7 | 7 | 6 | 6 | 5 | 5 | 4 | 4 | 3 | 3 | 2 | 1 | 1 | 0 |
| | Return | 31 | 29 | 27 | 25 | 23 | 21 | 19 | 17 | 15 | 13 | 11 | 9 | 7 | 5 | 3 | 1 |
| | Differed Taxes | | | | | | | | | | | | | | | | |
| | Book Deprecation | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 | 57 |
| | Tax Deprecation | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | Book-Tax Difference | (57) | (57) | (57) | (57) | (57) | (57) | (57) | (57) | (57) | (57) | (57) | (57) | (57) | (57) | (57) | (57) |
| | Tax Effect | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) | (15) |
| | MACRS Deprecation - 20 | | | | | | | | | | | | | | | | |
| | Property Tax Base | 673 | 632 | 590 | 548 | 506 | 464 | 423 | 381 | 339 | 297 | 256 | 214 | 172 | 130 | 89 | 47 |
| | Tax Calculation Check | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |

| | Aldyl-A Pipe Replacement | Avista's Highest Ever LEA Cap |
|---|---|---|
| **Mains** | $61,005 | |
| **Service Connections** | $22,222 | |
| **Mains and Service Connections** | | $ 9,335 |



Determination of Total Cost over Book Life

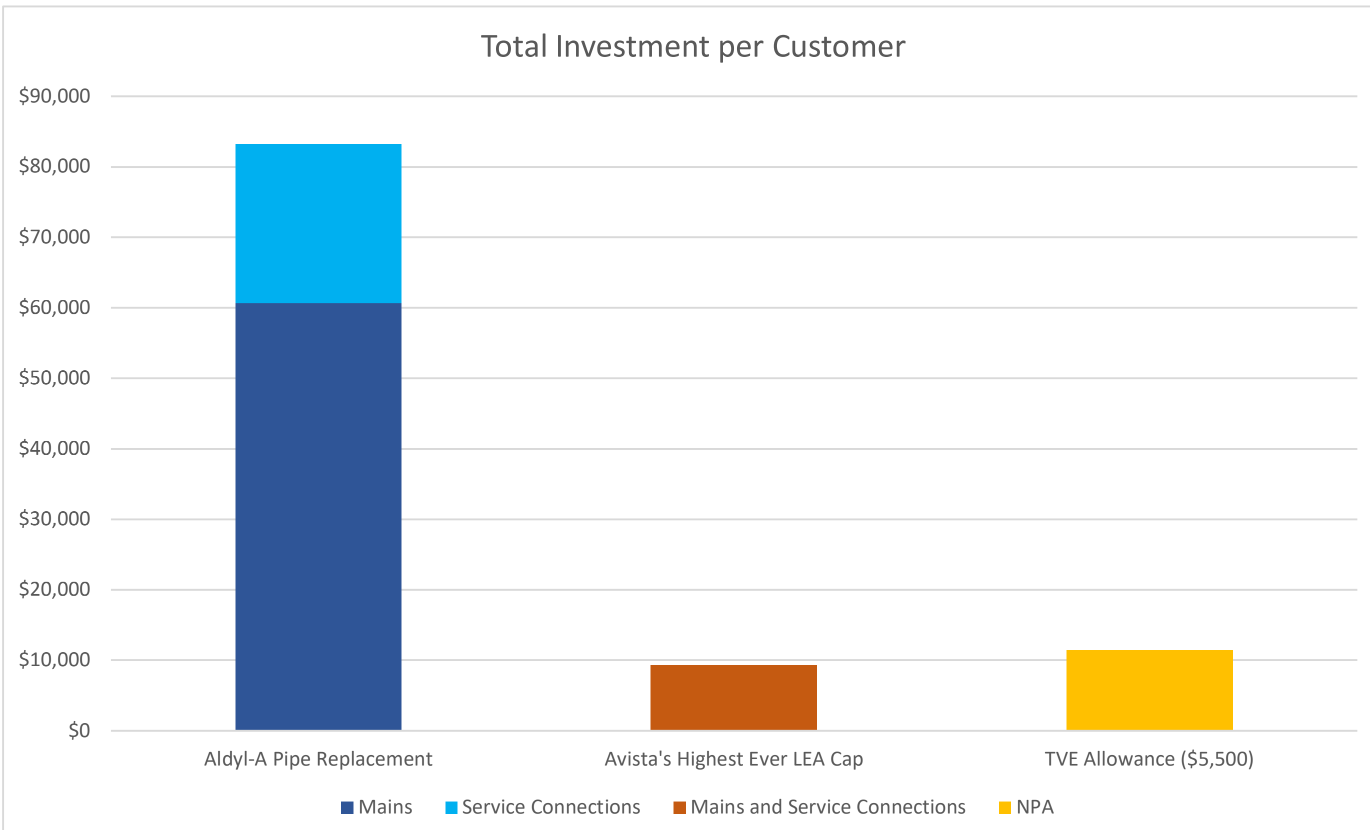
Input Capital Costs and Rates

| Cost of Capital | % of Capital | Cost | Weighted Cost | |
|---|---|---|---|---|
| Debt | 50% | 4.97% | 2.485% | Source: UG 519- Avista Exhibit 201, Christie/Page 2 of 5, Current Cost of Debt |
| Common Equity | 50% | 9.50% | 4.750% | Source: UG 519- Avista Exhibit 201, Christie/Page 2 of 5, Current Cost of Equity |
| | 100% | | 7.235% | |
| State Tax Rate | | | 7.60% | |
| Federal Tax Rate | | | 21% | |
| Revenue Sensitive Rate | | | 3.08% | Source: UG 519 CUB/302 Garrett/ 'Avista's Responses to CUB's Discovery Requests' DR 108, Line 8 "Total Expense" |
| Deprecation Rate | | | 5.00% | Corresponds to a 20-year useful life and book life for an electric heat pump. |
| Property Tax Rate | | | 1.28% | Source: UG 519 - Avista/ Garbarino Workpaper "2.05 - PF Property Tax Adjustment" - G-FPT-3, F13 |
| Investment: TVC Allowance | | | 5500 | |

| | | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 | Year 17 | Year 18 | Year 19 | Year 20 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | Deprecation | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 |
| 2 | O&M | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | Property Taxes | 69 | 65 | 61 | 57 | 54 | 50 | 47 | 43 | 40 | 36 | 33 | 30 | 26 | 23 | 19 | 16 | 12 | 9 | 6 | 2 |
| | Taxes on Equity Return | | | | | | | | | | | | | | | | | | | | |
| 4 | State | 27 | 25 | 24 | 22 | 21 | 19 | 18 | 17 | 15 | 14 | 13 | 11 | 10 | 9 | 7 | 6 | 5 | 3 | 2 | 1 |
| 5 | Federal | 68 | 64 | 60 | 57 | 53 | 49 | 46 | 43 | 39 | 36 | 32 | 29 | 26 | 22 | 19 | 16 | 12 | 9 | 5 | 2 |
| 6 | Total Taxes | 94 | 89 | 84 | 79 | 74 | 69 | 64 | 59 | 55 | 50 | 45 | 40 | 36 | 31 | 26 | 22 | 17 | 12 | 8 | 3 |
| | Return on Rate Base | | | | | | | | | | | | | | | | | | | | |
| 7 | Debt | 133 | 126 | 119 | 112 | 104 | 97 | 90 | 84 | 77 | 70 | 64 | 57 | 51 | 44 | 37 | 31 | 24 | 17 | 11 | 4 |
| 8 | Equity | 255 | 242 | 227 | 213 | 200 | 186 | 173 | 160 | 147 | 135 | 122 | 109 | 97 | 84 | 71 | 59 | 46 | 33 | 21 | 8 |
| 9 | Total Return | 389 | 368 | 346 | 325 | 304 | 283 | 263 | 244 | 225 | 205 | 186 | 167 | 147 | 128 | 109 | 89 | 70 | 51 | 31 | 12 |
| 10 | Subtotal Cost of Service | 827 | 797 | 766 | 736 | 706 | 677 | 649 | 621 | 594 | 566 | 539 | 512 | 484 | 457 | 429 | 402 | 374 | 347 | 320 | 292 |
| 11 | Revenue Sensitive Items | 26 | 25 | 24 | 23 | 22 | 22 | 21 | 20 | 19 | 18 | 17 | 16 | 15 | 15 | 14 | 13 | 12 | 11 | 10 | 9 |
| 12 | Total Cost of Service | $ 853 | $ 823 | $ 791 | $ 759 | $ 729 | $ 699 | $ 670 | $ 641 | $ 613 | $ 584 | $ 556 | $ 528 | $ 500 | $ 471 | $ 443 | $ 415 | $ 386 | $ 358 | $ 330 | $ 302 |
| | **Total Cost Over 20 Years** | $ 11,450 | | | | | | | | | | | | | | | | | | | |
| | Rate Base -Net of Deprecation and Def Tax | 5372 | 5090 | 4786 | 4489 | 4200 | 3918 | 3642 | 3371 | 3104 | 2837 | 2570 | 2303 | 2036 | 1769 | 1502 | 1235 | 968 | 701 | 434 | 167 |
| | Income Taxes | | | | | | | | | | | | | | | | | | | | |
| | Gross up - Equity | 350 | 331 | 311 | 292 | 273 | 255 | 237 | 219 | 202 | 185 | 167 | 150 | 132 | 115 | 98 | 80 | 63 | 46 | 28 | 11 |
| | Less: State Tax | 27 | 25 | 24 | 22 | 21 | 19 | 18 | 17 | 15 | 14 | 13 | 11 | 10 | 9 | 7 | 6 | 5 | 3 | 2 | 1 |
| | Federal Taxable Income | 323 | 306 | 288 | 270 | 253 | 236 | 219 | 203 | 187 | 171 | 155 | 138 | 122 | 106 | 90 | 74 | 58 | 42 | 26 | 10 |
| | Less: Federal Tax | 68 | 64 | 60 | 57 | 53 | 49 | 46 | 43 | 39 | 36 | 32 | 29 | 26 | 22 | 19 | 16 | 12 | 9 | 5 | 2 |
| | Return | 255 | 242 | 227 | 213 | 200 | 186 | 173 | 160 | 147 | 135 | 122 | 109 | 97 | 84 | 71 | 59 | 46 | 33 | 21 | 8 |
| | Differed Taxes | | | | | | | | | | | | | | | | | | | | |
| | Book Deprecation | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 | 275 |
| | Tax Deprecation | 206 | 397 | 367 | 340 | 314 | 291 | 269 | 249 | 245 | 245 | 245 | 245 | 245 | 245 | 245 | 245 | 245 | 245 | 245 | 245 |
| | Book-Tax Difference | (69) | 122 | 92 | 65 | 39 | 16 | (6) | (26) | (30) | (30) | (30) | (30) | (30) | (30) | (30) | (30) | (30) | (30) | (30) | (30) |
| | Tax Effect | (19) | 33 | 25 | 17 | 11 | 4 | (2) | (7) | (8) | (8) | (8) | (8) | (8) | (8) | (8) | (8) | (8) | (8) | (8) | (8) |
| | MACRS Deprecation - 20 | 3.75% | 7.22% | 6.68% | 6.18% | 5.71% | 5.29% | 4.89% | 4.52% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% | 4.46% |
| | Property Tax Base | 5390 | 5057 | 4761 | 4472 | 4190 | 3914 | 3643 | 3378 | 3112 | 2845 | 2578 | 2311 | 2044 | 1777 | 1510 | 1243 | 976 | 709 | 442 | 175 |
| | Tax Calculation Check | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| | | 27.00400% | | | | | | | | | | | | | | | | | | | |
| | | 0.7300 | | | | | | | | | | | | | | | | | | | |

| | Aldyl-A Pipe Replacement | Avista's Highest Ever LEA Cap | TVE Allowance ($5,500) |
|---|---|---|---|
| **Mains** | $61,005 | | |
| **Service Connections** | $22,222 | | |
| **Mains and Service Connections** | | $9,335 | |
| **NPA** | | | $11,450 |
| | | | |
| **Total Cost** | $83,227 | | |
| **Residential Base Billing Revenue ($/yr)** | $567.04 | | |
| **Years to Recover Total Cost** | 147 | | |

Source: UG 519 C

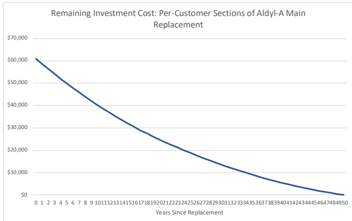


| Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 | Year 13 | Year 14 | Year 15 | Year 16 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $61,005 | $ 58,653 | $56,363 | $54,138 | $51,977 | $49,876 | $47,833 | $45,847 | $43,914 | $42,035 | $40,208 | $38,434 | $36,713 | $35,045 | $33,430 | $31,868 | $30,359 |

| Year 17 | Year 18 | Year 19 | Year 20 | Year 21 | Year 22 | Year 23 | Year 24 | Year 25 | Year 26 | Year 27 | Year 28 | Year 29 | Year 30 | Year 31 | Year 32 | Year 33 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $28,903 | $27,499 | $26,149 | $24,851 | $23,599 | $22,380 | $21,191 | $20,030 | $18,898 | $17,795 | $16,721 | $15,676 | $14,659 | $13,672 | $12,714 | $11,784 | $10,884 |

| Year 34 | Year 35 | Year 36 | Year 37 | Year 38 | Year 39 | Year 40 | Year 41 | Year 42 | Year 43 | Year 44 | Year 45 | Year 46 | Year 47 | Year 48 | Year 49 | Year 50 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $10,012 | $ 9,169 | $ 8,356 | $ 7,571 | $ 6,815 | $ 6,088 | $ 5,390 | $ 4,721 | $ 4,080 | $ 3,469 | $ 2,887 | $ 2,333 | $ 1,809 | $ 1,313 | $ 847 | $ 409 | $ |

| Year | Remaining Investment Cost |
|---|---|
| 0 | $61,005 |
| 1 | $58,653 |
| 2 | $56,363 |
| 3 | $54,138 |
| 4 | $51,977 |
| 5 | $49,876 |
| 6 | $47,833 |
| 7 | $45,847 |
| 8 | $43,914 |
| 9 | $42,035 |
| 10 | $40,208 |
| 11 | $38,434 |
| 12 | $36,713 |
| 13 | $35,045 |
| 14 | $33,430 |
| 15 | $31,868 |
| 16 | $30,359 |
| 17 | $28,903 |
| 18 | $27,499 |
| 19 | $26,149 |
| 20 | $24,851 |
| 21 | $23,599 |
| 22 | $22,380 |
| 23 | $21,191 |
| 24 | $20,030 |
| 25 | $18,898 |
| 26 | $17,795 |
| 27 | $16,721 |
| 28 | $15,676 |
| 29 | $14,659 |
| 30 | $13,672 |
| 31 | $12,714 |
| 32 | $11,784 |
| 33 | $10,884 |
| 34 | $10,012 |
| 35 | $9,169 |
| 36 | $8,356 |
| 37 | $7,571 |
| 38 | $6,815 |
| 39 | $6,088 |
| 40 | $5,390 |
| 41 | $4,721 |
| 42 | $4,080 |
| 43 | $3,469 |
| 44 | $2,887 |
| 45 | $2,333 |
| 46 | $1,809 |
| 47 | $1,313 |
| 48 | $847 |
| 49 | $409 |
| 50 | $0 |



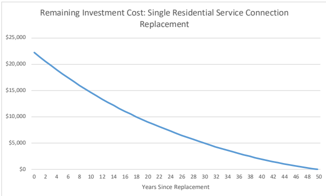
| Year 0 | Year 1 | Year 2 | Year 3 | Year 4 | Year 5 | Year 6 | Year 7 | Year 8 | Year 9 | Year 10 | Year 11 | Year 12 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $22,222 | $ 21,366 | $20,532 | $19,721 | $18,934 | $18,169 | $17,425 | $16,701 | $15,997 | $15,312 | $14,647 | $14,001 | $13,374 |

| Year 13 | Year 14 | Year 15 | Year 16 | Year 17 | Year 18 | Year 19 | Year 20 | Year 21 | Year 22 | Year 23 | Year 24 | Year 25 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $12,766 | $12,178 | $11,609 | $11,059 | $10,529 | $10,017 | $ 9,525 | $ 9,053 | $ 8,597 | $ 8,153 | $ 7,719 | $ 7,296 | $ 6,884 |

| Year 26 | Year 27 | Year 28 | Year 29 | Year 30 | Year 31 | Year 32 | Year 33 | Year 34 | Year 35 | Year 36 | Year 37 | Year 38 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| $ 6,482 | $ 6,091 | $ 5,710 | $ 5,340 | $ 4,980 | $ 4,631 | $ 4,293 | $ 3,965 | $ 3,647 | $ 3,340 | $ 3,044 | $ 2,758 | $ 2,483 |

| Year 39 | Year 40 | Year 41 | Year 42 | Year 43 | Year 44 | Year 45 | Year 46 | Year 47 | Year 48 | Year 49 | Year 50 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| $ 2,218 | $ 1,963 | $ 1,720 | $ 1,486 | $ 1,264 | $ 1,052 | $ 850 | $ 659 | $ 478 | $ 308 | $ 149 | $ |

| Year | Remaining Investment Cost |
|---|---|
| 0 | $22,222 |
| 1 | $21,366 |
| 2 | $20,532 |
| 3 | $19,721 |
| 4 | $18,934 |
| 5 | $18,169 |
| 6 | $17,425 |
| 7 | $16,701 |
| 8 | $15,997 |
| 9 | $15,312 |
| 10 | $14,647 |
| 11 | $14,001 |
| 12 | $13,374 |
| 13 | $12,766 |
| 14 | $12,178 |
| 15 | $11,609 |
| 16 | $11,059 |
| 17 | $10,529 |
| 18 | $10,017 |
| 19 | $9,525 |
| 20 | $9,053 |
| 21 | $8,597 |
| 22 | $8,153 |
| 23 | $7,719 |
| 24 | $7,296 |
| 25 | $6,884 |
| 26 | $6,482 |
| 27 | $6,091 |
| 28 | $5,710 |
| 29 | $5,340 |
| 30 | $4,980 |
| 31 | $4,631 |
| 32 | $4,293 |
| 33 | $3,965 |
| 34 | $3,647 |
| 35 | $3,340 |
| 36 | $3,044 |
| 37 | $2,758 |
| 38 | $2,483 |
| 39 | $2,218 |
| 40 | $1,963 |
| 41 | $1,720 |
| 42 | $1,486 |
| 43 | $1,264 |
| 44 | $1,052 |
| 45 | $850 |
| 46 | $659 |
| 47 | $478 |
| 48 | $308 |
| 49 | $149 |
| 50 | $0 |



the Energy to Lead

**FINAL REPORT**
DOT Project No.: 643
Contract Number: DTPH5615T00007

# Slow Crack Growth Evaluation of Vintage Polyethylene Pipes

**Reporting Period:**
October 1, 2015 through September 24, 2017

**Report Issued:**
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**Prepared for:**
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## Acknowledgements

This project was a large and ambitious project that required close coordination between Gas Technology institute (GTI), Arizona State University (ASU), University of Colorado Denver (UCD)/ Michigan State University (MSU), and other entities. There were many people in each of these organizations that played large and small parts in this effort. Their diligence and dedication to task was very much appreciated and we would be remiss not to mention them by name and offer our sincerest appreciation and thanks for their contributions.

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## Executive Summary

The primary objective of this project was to provide an integrated set of quantitative tools that provide a structured approach to evaluating the latent risk in vintage polyethylene pipes, such as Aldyl-A, that are common in gas distribution systems. Secondary objectives were: first, to provide a fitness for service approach that can support replacement prioritization; second, utilize data from multiple sources such as in ditch condition assessment and leak records; third, to provide a means to access the pipe in a congested urban environment.

The primary objective was realized through the construction of a hybrid causal Bayesian network that allows the synthesis of subject matter expertise with well understood physical causation pathways to failure. These logical structures inherently integrate disparate data sources into a coherent framework for decision support that is readily updated as new information becomes available.

From the outset, the project was structured around developing software agents that are modular and can be integrated into any decision support framework. The framework chosen in this project was a commercially available Artificial Intelligence (AI) platform that has built in ability to deal with any given business logic. The Bayesian networks developed in this project were successfully integrated into the AI framework and used to assess risk dynamically on a synthetic geographical dataset with over 7,000 data elements.

The secondary objectives were realized through several project components that are described next:

- Intelligent data entry forms were developed and integrated into the AI framework to capture disparate data and route the data to the relevant models. Bayesian updating of the model output, after this data was input via the forms, was demonstrated.
- Several variants of prototype endoscopic structured-light cameras were developed to measure pipe geometry from inside the pipe. The cameras developed are small enough to insert into 1” IPS diameter tubing and are suitable for integration into existing keyhole methods for accessing pipelines in congested urban environments. The project demonstrated that these cameras can identify several common geometric features consistent with pipeline anomalies known to introduce significant stress risers that drive pipeline failure via Slow Crack Growth (SCG). Feature recognition and data reduction methods were developed for the massive amounts of data acquired by the endoscopic tool
- A Stress Intensification Factor (SIF) based approach was developed for fitness for purpose determination. Two approaches were developed: reliability based maintenance models based on a fracture mechanics damage propagation approach were used to simulate the cost effectiveness of various repair/replace approaches, and a Bayesian network approach that integrates pipeline configuration, loading

conditions and material models was used to predict expected lifetime for pipeline segments. Both approaches were validated against historic data sets and shown to be equally effective. The material models were used to show that there is no effective pressure test approach to support pipeline replacement prioritization for polyethylene pipe. The lifetime expectancy of components given the available data inputs into the detailed material models developed in this project is the only viable option for enhancing decisions aimed at ensuring system integrity.

### Impact from the Research Results

The insights developed from this body of work were not available to regulators and operators prior to this work, which has provided a structured set of tools for assessing the fitness for service of vintage polyethylene pipelines in gas distribution systems. The models developed in this project are comprehensive probabilistic risk models that can be fully integrated into enterprise decision support systems and used to prioritize replacement programs, provide system integrity reports and assist operators in identifying future integrity related problems in their systems. The prototype endoscopic tools have the potential to fundamentally change how integrity data can be gathered to feed improved risk models for vintage pipeline systems. A detailed list of potential follow-on work is provided in the body of the report. The results of this project will be publicly disseminated through several papers in industry journals and conferences. The scope of the project and interim results were presented at Plastic Pipes XVIII, Berlin, Germany, September 2016 and published in the conference proceedings. A follow-on paper with results will be submitted to Plastic Pipes XIX, Las Vegas, USA, September 2018.

Additional publications related to this body of work include:

1. Yuhao Wang. Yongming Liu, "Probabilistic life prediction and prognostics-based maintenance optimization for gas pipelines". annual conference of the prognostics and health management society 2017, St. Petersburg, Florida, October, 2017. (accepted)
2. Yuhao Wang, Yongming Liu, Tishun Peng, Ernest Lever. "Probabilistic life prediction of plastic pipes using an equivalent crack growth model". 2018 AIAA SciTech conference – nondeterministic approach, Kissimmee, FL, January, 2018. (accepted)
3. Yuhao Wang, Yongming Liu. "A Novel Bayesian Entropy Network for Probabilistic Damage Detection and Classification". 2018 AIAA SciTech conference – nondeterministic approach, Kissimmee, FL, January, 2018. (accepted)
4. Yongming Liu, Yiming Deng "Fast automatic anomaly characterization and risk management in gas pipelines", DOT PHMSA 2016 Research Forum – Invited talk, Cleveland, OH, October, 2016.
5. Yuhao Wang, Yongming Liu. "Reliability-based maintenance optimization for aging gas pipeline system with Bayesian updating". Reliability Engineering and System Safety, 2017. (under preparation)

6. Mohand Alzuhiri, Yiming Deng, "Phase extraction algorithm based fast 3D reconstruction for structured light sensors", to be submitted to Research in Nondestructive Evaluation, 2018 (journal)
7. Peipei Zhu, Mohand Alzuhiri, Yiming Deng, " Data fusion for plastic pipeline damage detection using machine learning algorithms", to be submitted to NDT & E, International, 2017 (journal)
8. Mohand Alzuhiri, Yiming Deng, "Structured Light Based Endoscopic Scanner for Small Diameter Gas Pipelines", 22nd ENDE Workshop, Saclay, France 2017, abstract published in ENDE 2017 proceedings (Sept. 2017)
9. Two published MS theses and one MS thesis to be defended December 2017

## *High Level Detail of Project Components*

1. Stress risers are the most significant driver of failure in plastic gas-distribution pipe
    a. The scope of his project included a comprehensive review of existing data sets
        i. Historic DuPont data
        ii. Reference Rate Process Method (RPM) models were developed for all available data sets
        iii. Comprehensive testing of pipe exhumed after 20 and 40 years in service
    b. Correlations between features observable under a microscope and lifetime expectancy have been developed
    c. Equivalent Stress Intensification Factor (SIF) distributions have been developed for:
        i. Surface morphology
        ii. Low Ductile Inner Wall (LDIW)
        iii. Known loading conditions such as:
            1. Impingement
            2. Bending
            3. Squeeze-off
            4. Soil movement
            5. Ageing
2. It is possible to detect many significant stress risers from inside the pipe by measuring the internal pipe geometry
    a. This is the motivation for the endoscopic structured light tool development undertaken by Michigan State university (MSU)
    b. The method is compatible with keyhole methods already employed
    c. The project was successful in demonstrating that useful information can be gathered from compact structured-light tools and reduced to a useable format
3. A lifetime prediction approach, based on equivalent SIF and the control reference-RPM model for Aldyl-A, that can be applied to any combination of material and loading condition was developed

   a. Bayesian Networks (BN) were developed to capture material and loading combinations and output a predicted lifetime
   b. The BN output was validated against the reference RPM models
4. An alternative lifetime prediction approach utilizing fracture mechanics and damage propagation principles was developed by Arizona State University (ASU)
   a. There are many similarities in the GTI and ASU approaches as far as they both rely on SIF distributions.
      i. GTI utilizes the RPM
      ii. ASU utilizes a damage propagation approach
   b. Both methods provide acceptable predictions when validated against the reference data sets
5. The lifetime prediction models allow the use of Markov Chain Monte Carlo (MCMC) methods to evaluate the impact of various mitigation strategies on the reliability and cost of maintenance of an Aldyl-A gas-distribution system
6. Intelligent data collection approaches were developed to facilitate the capture of pertinent information, from a risk assessment perspective, from disparate data sources
   a. Basic SmartForms were developed for:
      i. First response forms
      ii. Keyhole data collection forms
      iii. Audit forms
   b. The data captured by the SmartForms was connected to the relevant models and Bayesian updating of the predicted risk profile was performed based on the new information
   c. These intelligent data collection forms are necessary for automated compilation of data needed to electronically submit annual and semi-annual pipeline integrity management program performance reports as specified in Advisory Bulletin ADB-07-01

## Report Structure

| Report Section | Topics Covered and Deliverables |
|---|---|
| **Section 1:** Rate Process Models (RPM) for Aldyl-A Piping Systems | **Topics:**<br>1. Rate Process Method<br>  a. Ranking methods<br>  b. Impact of inner wall surface on RPM<br>2. Polyethylene structure and molecular motion<br>3. Bi-directional shift factors |
| | **Deliverables:**<br>1. Reference RPM model for Aldyl A<br>2. Model for correlating surface condition to RPM ranking<br>3. Validated bi-directional shift factors for Aldyl A and other polyethylene materials |
| **Section 2:** Stress Intensification Factors (SIF) for Aldyl-A Piping Systems | **Topics:**<br>1. Failure mechanism of polyethylene<br>2. Variance of stress in polyethylene pipes<br>3. What is a SIF |
| | **Deliverables:**<br>1. SIF for various polyethylene piping configurations<br>2. Probability distributions for SIF in polyethylene piping systems with a quantification of uncertainty for the mean<br>3. Method for combining multiple SIF in a coherent manner |

| Report Section | Topics Covered and Deliverables |
|---|---|
| **Section 3:** Adjusted RPM Models for Use with Aldyl-A SIF | **Topics:**<br>1. Need to adjust the control RPM model to account for distribution of SIF included in the dataset<br>2. Need to calibrate standard SIF distributions for use with the adjusted RPM model<br>3. Validation of the adjusted RPM model and calibrated SIF |
| | **Deliverables:**<br>1. Universal model for SCG failure mode of Aldyl A pipe<br>2. Calibrated SIF for known pipe conditions<br>3. Validation of model and SIF over four independent reference datasets |
| **Section 4:** Bayesian Network Model for Aldyl-A Lifetime Expectancy Systems | **Topics:**<br>1. Causal mechanisms for generating stress fields in Aldyl A pipe<br>2. Methodology for addressing interacting causal factors<br>3. Calibration of Bayesian network to reference datasets |
| | **Deliverables:**<br>1. Comprehensive expert system for Aldyl A piping systems that addresses all interactions<br>2. Calibrated and validated Bayesian network for predicting lifetime expectancy of Aldyl A piping segments |

| Report Section | Topics Covered and Deliverables |
|---|---|
| **Section 5:** Structured Light Method for Internal Inspection of Aldyl-A Pipe | **Topics:**<br>1. Development of endoscopic structured light tool for internal inspection of gas distribution pipe<br>2. Algorithms for detecting and categorizing internal pipeline defects and geometry<br>3. Motion detection and distance measurement<br>4. Data reduction techniques |
| | **Deliverables:**<br>1. Working prototype of endoscopic structured light tool for internal inspection of gas distribution pipe<br>2. Algorithms for damage detection and classification<br>3. Data reduction methods |
| **Section 6:** Damage Detection from Optical Imaging, Creep-Crack Growth Prediction, and Condition-based Maintenance Framework for Aldyl-A Pipes | **Topics:**<br>1. Image reconstruction and damage classification<br>2. Bayesian maximum entropy network<br>3. Creep crack growth prediction<br>4. Maintenance frameworks |
| | **Deliverables:**<br>**1. Algorithms for image reconstruction**<br>**2. Working Bayesian maximum entropy network**<br>**3. Validated creep crack growth model for lifetime prediction for Aldyl A pipe segments**<br>**4. Framework for optimizing maintenance of Aldyl A piping systems i.e. repair/replace balance** |

| Report Section | Topics Covered and Deliverables |
|---|---|
| **Section 7**: Enterprise Decision Support System (EDSS) Framework | **Topics:**<br>1. Semantics of decision support framework for Aldyl A piping systems<br>2. Probabilistic decision support framework<br>3. Data entry<br>4. Simulation<br>5. Insights<br>6. Query<br>7. Communication |
| | **Deliverables:**<br>1. Functioning enterprise decision support framework that incorporates the Bayesian network developed in section 4<br>2. Smart forms for data entry<br>3. Insights and analytics framework<br>4. Data reporting framework |
| **Section 8**: Feasibility of Using a Short-Term Pressure Test to Determine Fitness for Service in the Context of Slow Crack Growth Systems | **Topics:**<br>1. Historic usage of short-term pressure tests in determining fitness for service of gas transmission pipe<br>2. Applicability to plastic gas distribution pipe<br>3. Localized damage propagation in plastic pipe |
| | **Deliverables:**<br>1. Conclusion that short-term testing is not a viable fitness for service test for plastic gas distribution pipe<br>2. Explanation of reasons why the method is not viable |

| Report Section | Topics Covered and Deliverables |
|---|---|
| **Section 9**: Summary and Recommendations | **Topics:**<br>Summarizes technical achievements and recommends utilizing the methods developed in the project to transition to probabilistic, reliability based risk assessment methods.<br><br>Recommends establishing a Joint Industry Program (JIP) to develop guideline for this transition.<br><br>Recommends that the JIP oversee the commercialization and deployment of the structures light scanning tool that can be integrated into existing keyhole technologies |
| **Section 10**: Recommendations for Future Work | **Topics:**<br>Lists future work effort in three areas:<br>1. Fitness for Service<br>2. Decision Support Systems<br>3. Sensing Damage via Internal Inspection<br><br>The future work efforts are designed to enhance the methods developed, address potential weaknesses in the approaches and further integrate disparate efforts that all contribute to system risk and integrity. |

## Technical Achievements of Project

### *Tools for Evaluating Risk*

The primary objective of this project was to provide an integrated set of quantitative tools that provide a structured approach to evaluating the latent risk in vintage polyethylene pipes, such as Aldyl-A, that are common in gas distribution systems.

Polyethylene pipes undergo constant creep due to the nature of the material. The underlying molecular mechanisms that enable creep are called relaxation mechanisms and they are constantly in action. Basic molecular motions occur thousands, or millions of times per second. If there is an external driving for that loads the polymeric structure, stresses will be developed in the material. These stresses give directionality to the random molecular motions that result in creep, and ultimately lead to failure of the polyethylene structure.

A primary deliverable of this project is a set of tools that define:

1. A Rate Process Method (RPM) model that defines the rate at which the polyethylene will creep.
    a. This rate is strongly dependent on temperature
    b. The rate is also dependent on the stress in the polyethylene structure that in turn depends on:
        i. The geometry of the component
        ii. The external loads acting on the component
2. The Stress Intensification Factors (SIF) that provide a simple means of translating the nominal hoop stress of the pipe, which is very easy to calculate, to true stress. Well defined and simple to apply SIF are essential to a workable risk evaluation method that utilizes simple, well-known parameters such as: pipe size, ambient temperature, system operating pressure, component configuration and other measurable installation characteristics to arrive at a true component stress. The SIF developed in this project, together with a single master RPM model underpin the lifetime prediction methods presented in this project.
3. The RPM model and SIF can be used as-is to perform risk assessments given system parameters, or they can be integrated into a tool that is capable of integrating all threat interactions into a composite risk score. A deliverable of this project is a Bayesian network that accomplishes this objective. A fully defined, calibrated and validated Bayesian network is defined in this project.

### Non-Destructive Evaluation in Confined Spaces, Fitness for Service, Replacement Prioritization and Data integration

Secondary objectives of the project were: first, to provide a fitness for service approach that can support replacement prioritization; second, utilize data from multiple sources such as in ditch condition assessment and leak records; third, to provide a means to access the pipe in a congested urban environment. These objectives were technically realized through:

1. A non-destructive tool that is capable of measuring pipeline configuration from inside the pipe was developed and prototyped in this project. This structured light, endoscopic measurement tool is a major breakthrough in assessing gas distribution pipes as it allows the operator to measure pipeline geometry over large lengths of the pipe without excavating the entire pipe. This measurement of pipe geometry from inside the pipe allows identification of several critical defects such as: impingement, squeeze-off, fittings, sudden displacements of the pipe, pipe deformations and other defects that cause stress intensification. This direct measurement of features will allow accurate SIF to be assigned to pipe segments. This will allow proper classification of segment with regard to the anticipated stress fields that when plugged in to the RPM model will provide probability of failure over time. This likelihood of failure is a key component in determining the segments Fitness for Service (FFS).
2. A set of reliability based tools were developed that underpin optimization methods for comparing repair/replace strategies over multi-year timeframes. These methods are based on robust damage propagation methods that were calibrated and validated against historic reference data. It was demonstrated that the Monte Carlo simulations that these tool support are capable of evaluated multiple scenarios and providing guidance as to the most effective risk management strategy over time
3. The tools developed in this project were integrated into a commercially available Artificial Intelligence (AI) platform that is capable of merging multiple disparate data sources, running the various risk assessment tools and providing insights driven be sophisticated data analytics. Intelligent forms that facilitate in-field data gathering and regulatory reporting requirement were also developed and demonstrated and tested as part of this project

### Summary

All of the project deliverables were met and tested via the components described above. A comprehensive set of tools that can be practically applied in multiple approaches, from simpe point applications, to enterprise wide decision support systems has been provided.

## 1. Rate Process Models (RPM) for Aldyl-A Piping Systems

This section discusses the use of the Rate Process Method (RPM) in the context of determining the Fitness for Service (FFS) of Aldyl A gas distribution pipe. The relevance of the RPM in determining FFS of plastic piping is through the usefulness of the method in determining the lifetime expectancy of a pipe under a given load at a given temperature. The typical usage of the RPM correlates hoop stress to time to failure [1, 2]. This normal usage of the RPM is not sufficiently accurate for determining FFS, so we have developed a set of approaches for improving the accuracy of RPM predictions. These approaches will be described in detail in Sections **2** and **3**. The discussion in this section will follow the sequence laid out in **Figure 1-1**.

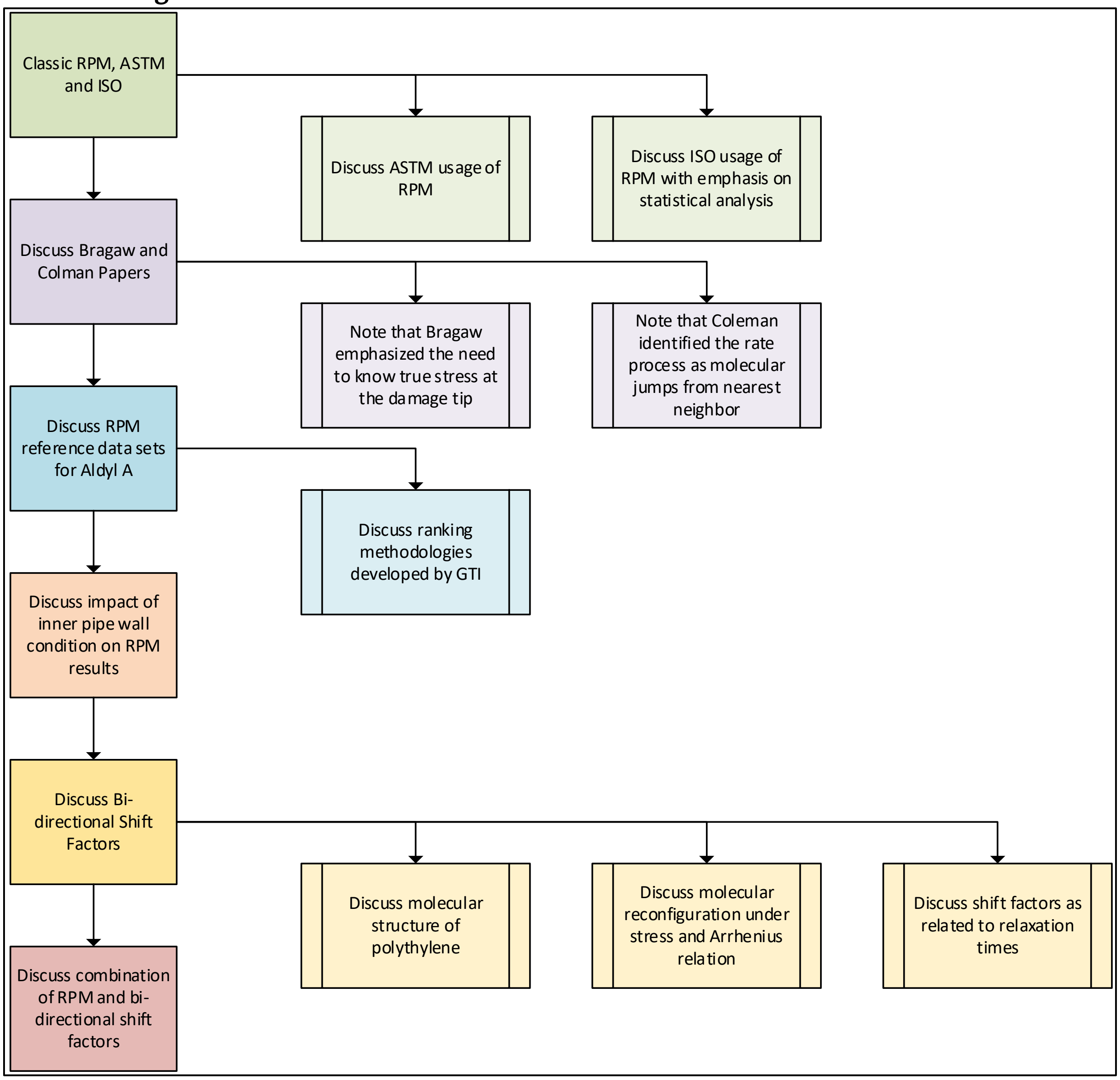


**Figure 1-1. Sequence of topics for discussing the RPM in the context of FFS**

## *Classic RPM, ASTM and ISO*

Kurdziel and Palermo [1] provide a concise overview of the development of the RPM in the United Sates and how it became incorporated into ASTM standards. The insert below reproduces the relevant portion of the paper.

### The Rate Process Method (RPM) [1]

The concept and mathematical basis for using the Rate Process Method for polyethylene (PE) pipe and fitting service projections was originally presented by Bragaw (2) (3). The Plastics Pipe Institute (PPI) Hydrostatic Stress Board (HSB) conducted an extensive evaluation of this and other methods for forecasting the effective long-term performance of PE piping materials. Basically, all these methods require elevated temperature sustained pressure testing of pipe where the type of failure is of the slit or brittle-like mode.
As a result of these studies, HSB determined that the three-coefficient Rate Process Method (RPM) equation provided the best correlation between calculated long-term performance projections and known field performance of several PE piping materials. It also had the best probability for extrapolation of data based on the statistical "lack of fit" test. Further validation of the Rate Process Method was made by comparing RPM projections for PE pipe and fittings obtained at elevated temperatures with actual room temperature laboratory failures for the same pipe and fittings (4).
Rate Process Method testing of pipe or fitting assemblies is conducted in accordance with ASTM D 1598, "Standard Test Method for Time-to-Failure of Plastic Pipe Under Constant Internal Pressure" (5). Fittings are joined to pipe using standard joining procedures. Conducting an RPM experiment requires a minimum of 18 to 20 specimens at various temperature/pressure conditions. As with any test protocol, increasing the number of specimens provides a higher confidence level in the failure mode validation and limits.
Using slit failure mode data points, one calculates the A, B and C coefficients for the following three-coefficient Rate Process Method extrapolation equation:

$$\mathrm{Log}\, t = A + \frac{B}{T} + \frac{C\, \mathrm{Log}\, S}{T}$$

Where:

$t$ = slit mode failure time (hours)
$T$ = absolute temperature (K)
$S$ = stress (psi)

Once the A, B and C coefficients are determined, the RPM equation can be used for various performance projections (average failure time) at typical use temperature (average annual ground temperature) and stress conditions.
The RPM provides the means for not only validating the long-term performance capacity for corrugated HPDE pipe, but it provides a basis for assessing the manufacturer's quality assurance or quality control program. After establishing the RPM coefficients, an appropriate single-point elevated temperature stress rupture test may be established for quality purposes (6).
Mathematically, these RPM projections are sound. They are, however, not absolute and are subject to various experimental errors, unknown deviations and judgment factors. The calculations from the RPM equation are used in conjunction with other known mechanical, performance, and design factors specifically relating to corrugated HDPE pipe to validate the service life projections for these applications.

2. C. G. Bragaw, "Crack Stability Under Load and the Bending Resistance of MDPE Piping Systems", Seventh Plastic Fuel Gas Pipe Symposium, New Orleans, October 1980.
3. C. G. Bragaw, "Service Rating of Polyethylene Systems by the Rate Process Method", Eighth Plastic Fuel Gas Pipe Symposium, New Orleans, November 1983.
4. E. F. Palermo, "Rate Process Method as a Practical Approach to a Quality Control Method for Polyethylene Pipe", Eighth Plastic Fuel Gas Pipe Symposium, New Orleans, November 1983.
5. American Standards Testing and Materials (ASTM), ASTM D 1598, "Standard Test Method for Time-to-Failure of Plastic Pipe Under Constant Internal Pressure," 2004.
6. E. F. Palermo, "Using Laboratory Tests on PE Piping Systems to Solve Gas Distribution Engineering Problems", Tenth Plastic Fuel Gas Pipe Symposium, New Orleans, October 1987.

Kurdziel and Palermo point out that although the method is mathematically sound it is subject to various experimental errors, unknown deviations and judgement factors.
The ISO approach to the RPM is described in "ISO 9080:2012 Plastics piping and ducting systems -- Determination of the long-term hydrostatic strength of thermoplastics materials in pipe form by extrapolation" [2]. The sections covering the principles and use of the method are reproduced in the inserts below.

**Principles [2]**

The suitability for use of a plastics pressure pipe is first of all determined by the performance under stress of its material of construction, taking into account the envisaged service conditions (e.g. temperature). It is conventional to express this by means of the hydrostatic (hoop) stress which a plastics pipe made of the material under consideration is expected to be able to withstand for 50 years at an ambient temperature of 20 °C using water as the internal test medium. The outside environment can be water or air.
In certain cases, it is necessary to determine the value of the hydrostatic strength at either shorter lifetimes or higher temperatures, or on occasion both. The method given in this International Standard is designed to meet the need for both types of estimate. The result obtained will indicate the lower prediction limit (LPL), which is the lower confidence limit of the prediction of the value of the stress that can cause failure in the stated time at a stated temperature (the ultimate stress).
NOTE The MRS value (at 20 °C) is usually based on data obtained using water as the internal and external test medium. It is obvious that indeed all data are used for validation of regression curves at higher temperatures (e.g. 70 °C), including the data obtained with air as the external medium (e.g. at 110 °C).
This International Standard provides a definitive procedure incorporating an extrapolation using test data at different temperatures analysed by multiple linear regression analysis. The results permit the determination of material-specific design values in accordance with the procedures described in the relevant system standards.
This multiple linear regression analysis is based on the rate processes most accurately described by log10(stress) versus log10(time) models.
In order to assess the predictive value of the model used, it has been considered necessary to make use of the estimated 97,5 % lower prediction limit (LPL). The 97,5 % lower prediction limit is equivalent to the lower confidence limit of the 95 % confidence interval of the predicted value. This convention is used in the mathematical calculations to be consistent with the literature. This aspect necessitates the use of statistical techniques.
The method can provide a systematic basis for the interpolation and extrapolation of stress rupture characteristics at operating conditions different from the conventional 50 years at 20 °C. Taking into account the extrapolation factors (see 5.1.4), the extrapolation time limit can go up to 100 years.
It is essential that the medium used for pressurizing the pipe does not have an adverse effect on the pipe. In general, water is considered to be such a medium.
Long consideration was given to deciding which variable should be taken as the independent variable to calculate the long-term hydrostatic strength. The choice was between time and stress.
The basic question the method has to answer can be formulated in two ways as follows.
a) What is the maximum stress (or pressure) that a given pipe system can withstand at a given temperature for a defined time?
b) How long will a pipe system last when subjected to a defined stress (or pressure) at a given temperature?
Both questions are relevant.
If the test data for the pipe under study does not show any scatter and if the pipe material can be described perfectly by the chosen empirical model, the regression with either time independence or stress independence will be identical. This is never the case because the circumstances of testing are never ideal nor will the material be 100 % homogeneous. The observations will therefore always show scatter. The regressions calculated using the two optional independent variables will not be identical and the difference will increase with increasing scatter.
The variable that is assumed to be most affected by the largest variability (scatter) is the time variable and it has to be considered as a dependent variable (random variable) in order to allow a correct statistical treatment of the data set in accordance with this method. However, for practical reasons, the industry prefers to present stress as a function of time as an independent variable.

**Use of the methods [2]**

This extrapolation method is designed to meet the following two requirements:
a) To estimate the lower prediction limit1) (at 97,5 % probability level) of the stress which a pipe made of the material under consideration is able to withstand for 50 years at an ambient temperature of 20 °C using water or air as the test environment.
b) To estimate the value of the lower prediction limit (at 97,5 % probability level) of the stress, either at different lifetimes or at different temperatures, or on occasion both.
There are several extrapolation models in existence, which have different numbers of terms. This SEM will use only models with two, three or four parameters.
Adding more terms could improve the fit but would also increase the uncertainty of the predictions.
The SEM describes a procedure for estimating the lower prediction limit (at 97,5 % probability level) whether a knee (which demonstrates the transition between type A and type B crack behaviour) is found or not (see Annex B).
The materials have to be tested in pipe form for the method to be applicable.
The final result of the SEM for a specific material is the lower prediction limit (at 97,5 % probability level) of the hydrostatic strength, expressed in terms of the hoop stress, at a given time and a given temperature.
1) In various ISO documents, the lower prediction limit (LPL) is referred to as the lower confidence limit (LCL), where LCL is the 97,5 % lower confidence limit for the mean hydrostatic strength.

The ISO document makes it very clear that there will always be scatter in the data due to non-ideal testing circumstances and material inhomogeneity. The ISO method requires the use of a statistically developed Lower Prediction Limit (LPL) in extrapolating from the empirically derived model. We will make extensive use of statistically derived prediction limits in the development of our RPM based model for FFS determination.

### Discussion of Coleman and Bragaw Papers

Bragaw [3, 4] developed the RPM as a tool for predicting the service life of polyethylene pipes and fittings. Bragaw references an earlier work by Coleman [5] in which Coleman noted that the ultimate strain at break of polymeric filaments at a given temperature was invariant with regard to the rate of loading. This suggested to Coleman that a simple superposition principle could be developed for calculating the time to break by creep failure under an arbitrary loading history. The model that he selected was that of rate process theory, where the number of jumps away from their nearest neighbors that elements of the polymer chain take, is the process whose rate we are measuring. In other words, the RPM fundamentally measures the rate of creep of a polymer unit under stress at a given temperature. Coleman developed the mathematical model, performed experiments with multiple fiber constructions, and found that the time to failure is adequately described by a rate process model as shown in **Figure 1-2**.

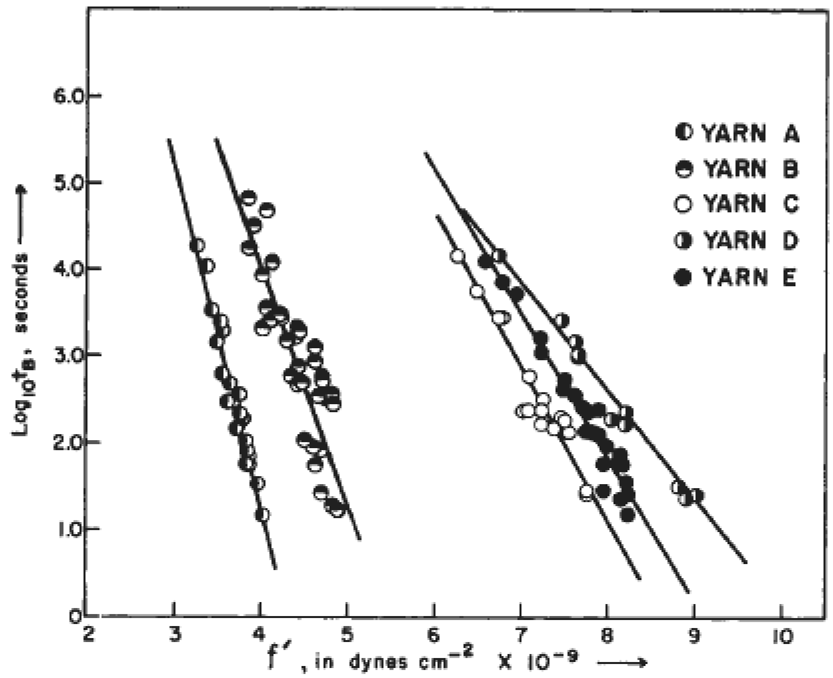


**Fig. 1. Experimental plot of the logarithm of lifetime in seconds** ***versus*** **dead load in dynes cm.$^{-2}$.** Stresses are calculated using the cross-sectional area of the unloaded yarn.

**Figure 1-2. Linear relationship of $\log_{10}$(time to failure) as a function of stress [5]**

Bragaw built upon Coleman's model and developed the RPM model as described by Kurdziel and Palermo [1]. Bragaw notes a key point that is highlighted in the excerpt from his 1982 paper in the insert below: **to correctly model the time to failure we need to know the true stress in the volume in which the failure is propagating through the pipe wall**. He points out the difficulties of determining this stress at the time of publication. At the present time, we have many more tools at our disposal to address the true stress problem and in this project, we have devoted considerable effort to developing Stress Intensification Factors (SIF) that can be used as a linear multiplier for hoop stress in a RPM equation. These methods will be described in detail in subsequent sections, but at this point it is sufficient to note that it is possible to calculate a SIF, or stress riser, that allows us to use a single reference RPM model, together with this SIF, to perform FFS calculations. A SIF (stress riser) of "1" describes a situation where the nominal hoop stress adequately describes the stress state of the pipe. We will use this SIF in the illustrative figures that follow.

Following Coleman(7), rate process theory describes the rate at which a rupture process proceeds by the equation

$$\frac{dc}{dt} = \frac{KT}{\eta} e^{-\left[\frac{\varepsilon-\beta\sigma/2}{KT}\right]} \qquad (1)$$

where $\frac{dc}{dt}$ is fracture rate, t is time, T is absolute temperature, $\sigma$ is true stress at activated sites, $\varepsilon$ is activation energy, and the rest are constants. Coleman simplified this expression to find

$$\log t = A_0 T^{-1} + A_1 T^{-1}\sigma \qquad (2)$$

Two difficulties arise when theoretical Equation 2 is applied to analysis of practical test data obtained on pressurized pipe, fittings, and joints. First, the stress $\sigma$ in Equations 1 and 2 is the true stress in the activated volume near the crack tip. Because overall geometry is very complex, crack tip radius is unknown (and varies during propagation), and crack length varies, true stress $\sigma$ cannot be calculated from system test pressure. Further, $\sigma$ must vary with time under load even though pressure is maintained constant. Second, Equations 1 and 2 describe only a single activated process, and many competing processes may be present. The transition from the ductile failure mechanism to the slit failure mechanism is an example of one of many possible mechanistic transitions. The experimenter must carefully examine specimen failure mode to avoid mixing failures having different mechanisms.

The indeterminacy of true crack tip stress has led us to explore the statistical fit of a number of mathematical models relating temperature and pressure to test or service life of piping components. All mathematical models were closely related to theoretical Equation 1.

Excerpt from Bragaw, C.G. *The Forecast of Polyethylene Pipe and Fitting Burst Life Using Rate Process Theory*. in *5th International Conference on Plastic Pipes, York UK*. 1982.

### Reference RPM Data for Aldyl A

GTI has a database of over 1400 Aldyl-A data points collected over the past decade. This data set includes about 400 reference data points generated by Palermo, working with Bragaw and others, at the DuPont company in their investigation and characterization of the Low Ductile Inner Wall (LDIW) condition that was known to cause premature Slow Crack Growth (SCG) failures of Aldyl A pipe. GTI also has several hundred well documented pipe and fitting failure points generated through long term testing of pipe exhumed from multiple areas after 40-45 years in service. This recent utility data set is consistent with the full data set that spans two decades of testing, indicating that the Aldyl-A pipe in the utility systems is no better than, and no worse than the piping systems evaluated to date.

To illustrate this point a reference temperature of 15°C (59F) has been selected, as it is the upper bound of the ground temperatures in many gas distribution systems. The distribution of the utility data relative to the reference data is the same for all temperatures, but the absolute stress versus time to failure values change from temperature to temperature.
A stress riser of one (1) is used in the following example plots to capture the behavior of pipe subjected to internal pressure alone.

In the charts that follow the diagonal lines depict the performance characteristics of the DuPont control material. The control material is material that performed as originally designed and specified in the official listing of the material. The solid black line is the mean, or nominal performance of the material at the reference temperature for the chart.

The additional lines depict prediction limits at various levels of confidence expressed in natural frequencies of the proportion of data points, sampled from the control pipe, that would be expected to fall below each line (e.g., 1 in 10, 1 in 100 etc.) for the lower prediction bounds, and 9 in 10, 99 in100 etc. for the upper prediction bounds.

The bands between the diagonal lines can be used to assign relative rankings (relative to the expected lifetime at the given stress and temperature) to the points falling in the various bands.

The open grey circles are all of the reference data GTI has collected over the years.
The colored symbols depict various DuPont and Utility Data Sets.

DuPont LDIW reference data was generated by DuPont using pipe known to exhibit the LDIW condition as defined by DuPont.

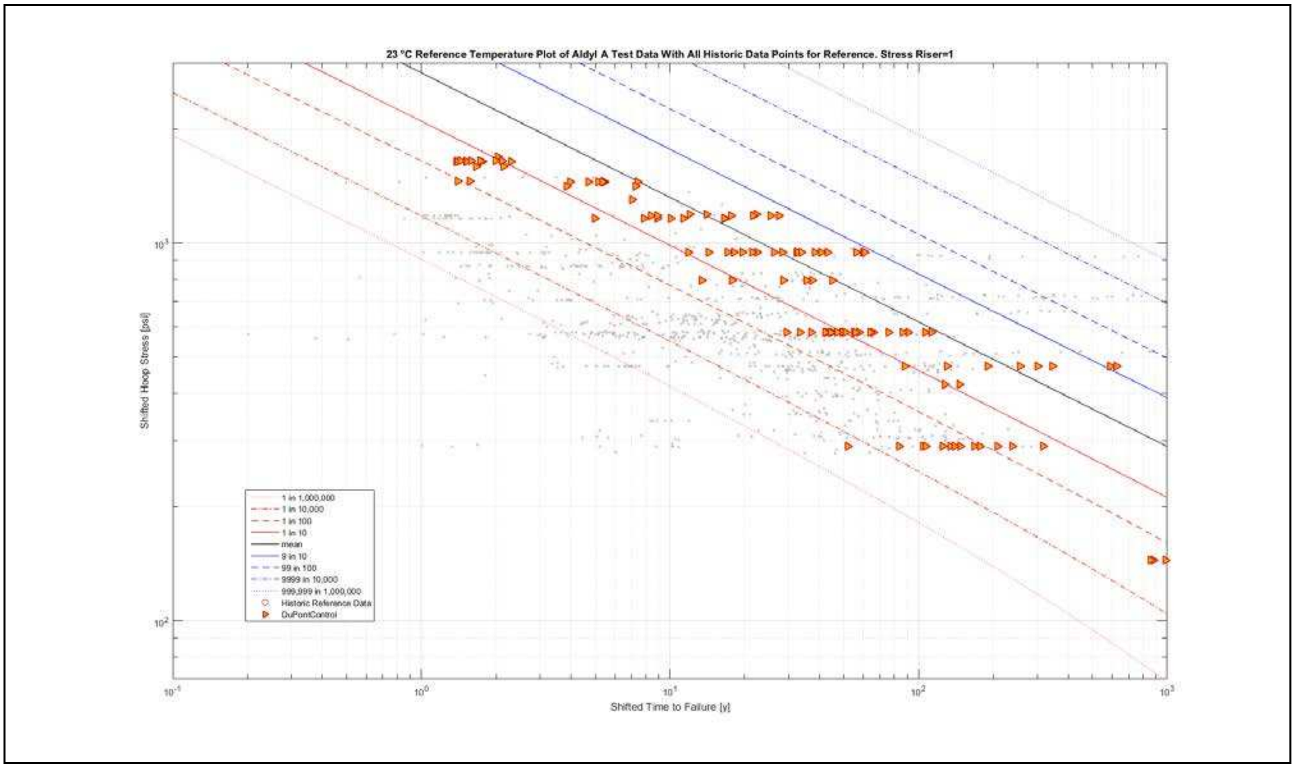


**Figure** 1-3 shows the control data developed by DuPont that will be used to develop the reference RPM model that forms the basis of the FFS calculation method developed in this project. **Figure 1-4** shows the DuPont LDIW data set together with utility data from exhumed pipe relative to the control data set.

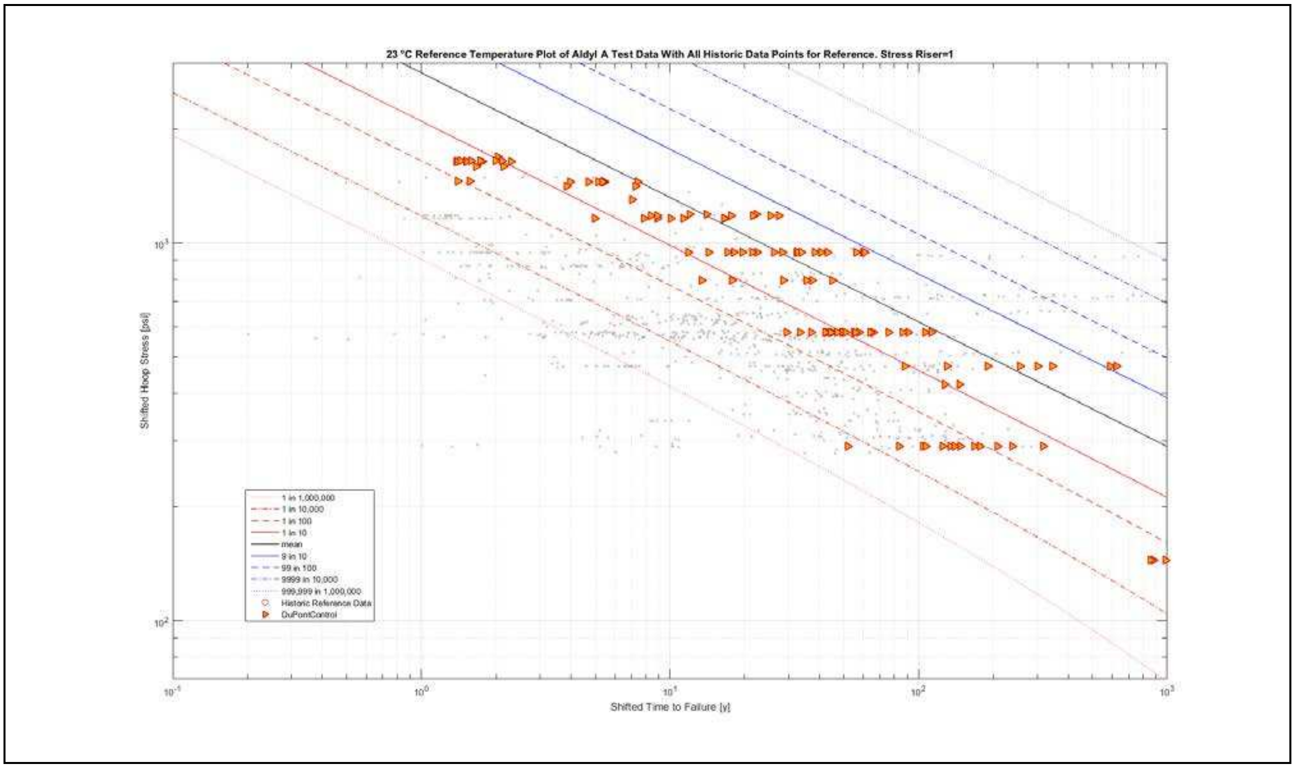


Figure 1-3. DuPont Control Aldyl-A at 23°C (73.4°F) Reference Temperature

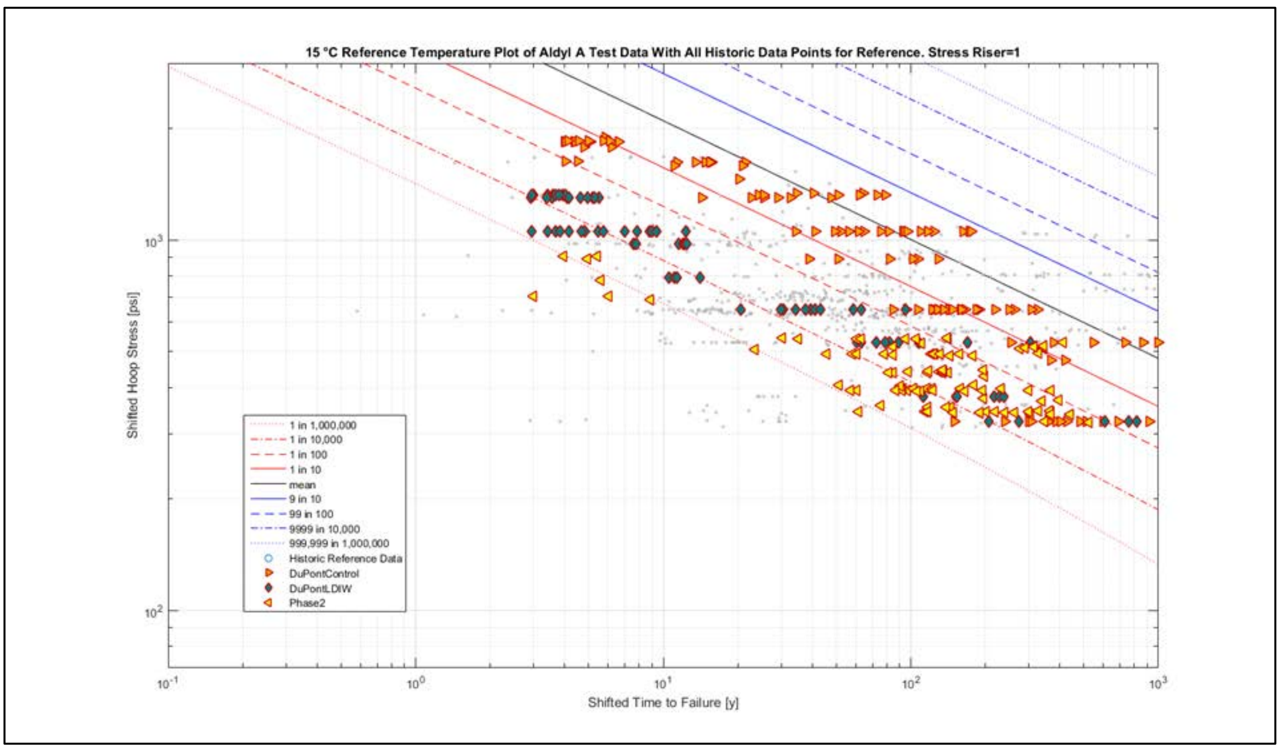


Figure 1-4. Data Set 5 Points at 15°C Showing Correspondence with DuPont LDIW Data

Three simple methods are available to us to assign easily-understood relative rankings to the individual data points generated via RPM testing

## Material Ranking

The "Material Ranking" is based on the prediction limit bands calculated from the RPM model obtained from running multiple linear regression on the DuPont control data set according to ISO 9080 [2].

### 4.1 General model for the regression analysis according to ISO 9080

The general 4-parameter model used in ISO 9080 is the following:

$$Log(t) = C_1 + C_2 \cdot \frac{1}{T} + C_3 \cdot Log(\sigma) + C_4 \cdot \frac{Log(\sigma)}{T} + e$$

*where*

| | | |
|---|---|---|
| $C_1$ *to* $C_4$ | *parameters used in this model* | |
| $t$ | *time to failure* | *[h]* |
| $T$ | *Temperature* | *[K]* |
| $\sigma$ | *Hoop stress* | *[MPa]* |
| $e$ | *error variable* | *Laplace-Gaussian distribution, with zero mean and constant variance (the errors are assumed to be independent)* |

The 4-parameter model shall be reduced to a 3-parameter model if the probability level of $C_3$ is greater than 0.05. i.e. $C_3 = 0$.

**Figure 1-5. The General RPM Model as Described by ISO 9080**

**Table 1-1. DuPont Control Model Parameters for 3 Parameter ISO 9080 Model**

| Parameters | C1 | C2 | C4 | $R^2$ | $R^2_{adj}$ | n | p | $\sigma^2$ |
|---|---|---|---|---|---|---|---|---|
| Value | -17.6172 | 9485.337 | -898.536 | 0.898 | 0.896 | 122 | 3 | 0.080944 |
| Standard Error | 0.703265 | 296.4989 | 33.90417 | | | | | |

| Covariance Matrix | | |
|---|---|---|
| 6.110133978 | -2487.297563 | 152.8993481 |
| -2487.297563 | 1086051.522 | -89681.8456 |
| 152.8993481 | -89681.8456 | 14201.01238 |

The material model fully described in **Table 1-1** enables us to calculate prediction intervals for any desired level of confidence using standard statistical methods as described by Montgomery [6] p468 where the prediction of new observations is discussed:

$$\hat{y}_0 - t_{\frac{\alpha}{2},n-p}\sqrt{\hat{\sigma}^2(1 + x_0'(X'X)^{-1}x_0} \leq Y_0 \leq \hat{y}_0 + t_{\frac{\alpha}{2},n-p}\sqrt{\hat{\sigma}^2(1 + x_0'(X'X)^{-1}x_0} \qquad \textbf{Equation 1-1}$$

$Y_0$ – response variable, in this case the predicted lifetime in hours
$X_0$ – the input vector [1 1/T Log(s)]. Note: Log refers to log base 10 in this equation
$(\mathbf{X'X})^{-1}$ – is the covariance matrix given in **Table 1-1**
T – absolute ambient temperature in Kelvin
s – hoop stress in the pipe at operating pressure in psi
$\sigma^2$ – the variance of the data set
$\alpha$ - the desired confidence level e.g. 0.05 for a 95% two-sided confidence interval
n – the number of samples in the data set
p – the number of parameters being estimated, 3 in this instance
t – the t statistic for the desired confidence and degrees of freedom in the data set

**Equation 1-1** was used to generate the diagonal lower and upper prediction limit lines shown in the plots above. The confidence levels were set to reflect natural frequencies of 1 in 10, 1 in 100, 1 in 10,000 and 1 in 1,000,000 for the lower prediction limits and 9 in 10, 99 in 100, 9,999 in 10,000 and 999,999 in 1,000,000 for the upper prediction limits. Natural frequencies are easier to grasp in this context – they reflect the number of future observations we would expect to fall below each of the prediction limit lines.

The analysis described above is very formal and reflects the confidence we have in the DuPont reference data set. The data set is good as can be seen in low variance and good $R^2$ of the model.

The prediction bands, Figure 1-6. Relative Ranking Bands for Material RPM Performance Relative to DuPont Reference Data**Figure 1-6,** are appropriate for highlighting how the data sets we develop from samples extracted from the field perform in an absolute sense relative to the DuPont data.

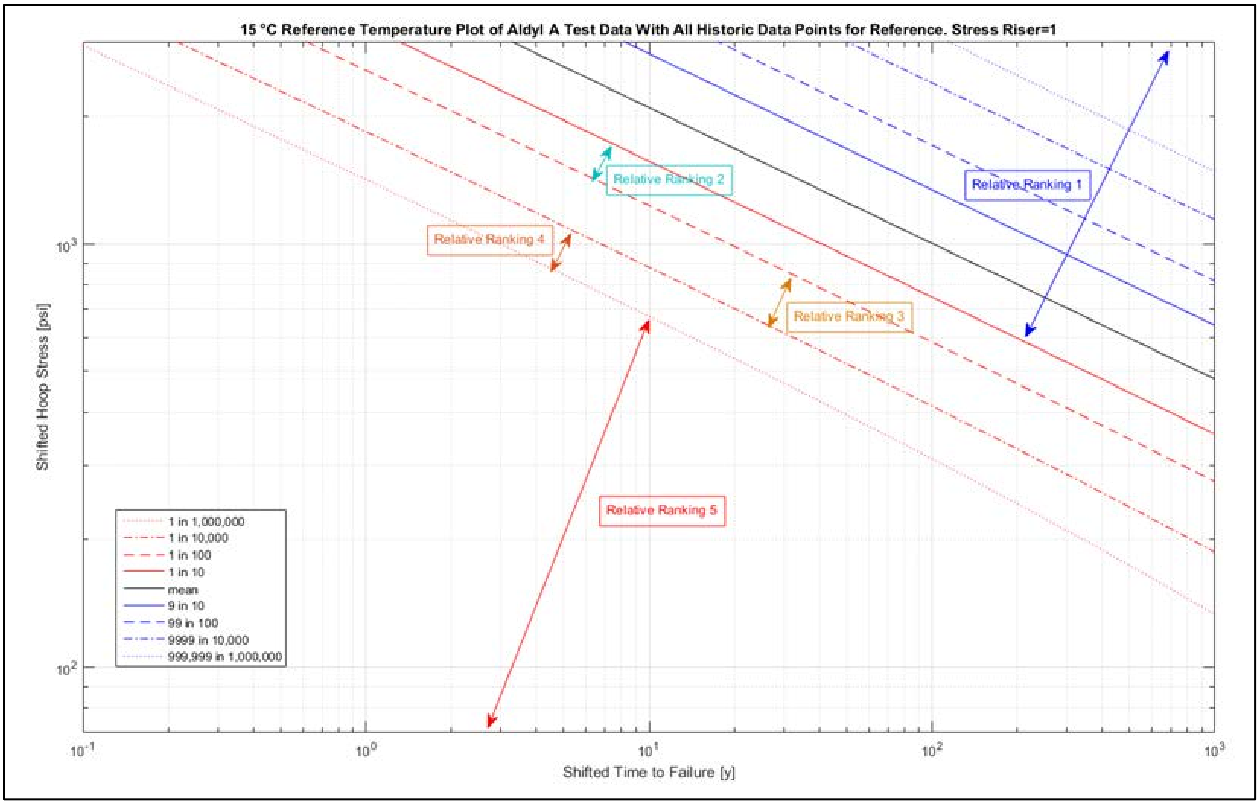


**Figure 1-6. Relative Ranking Bands for Material RPM Performance Relative to DuPont Reference Data**

There is a drawback in looking only at this relative ranking as data can fall in a band that indicates that the buried pipe is performing well below the reference performance. This may be true in an absolute sense, but does not address the operational implications of this below-par material performance.

Two additional reference rankings can be used to address the operational implications:

1. The hoop stress at which the specimen failed
2. The time at which the specimen failed

These two additional rankings can be scaled relative to the operating stress of the pipeline and the desired residual pipe lifetime.

## Failure Stress Ranking

The system in question operates at 45 psig that will cause a hoop stress in SDR 11 pipe of 225 psi. In this report the relative ranking levels were chosen to be 100 psi, 200 psi, 300 psi, and 400 psi for convenience. This choice is arbitrary and subjective and can be changed by subject matter expert consensus at any time. **Figure 1-7**

## Failure Time Ranking

The failure time ranking levels were chosen to be 10 years, 20 years, 30 years, and 40 years. This choice is arbitrary and subjective and can be changed by subject matter expert consensus at any time. **Figure 1-8**

## Operational Relative Ranking

The three rankings described above can be combined into a relative ranking that takes into account the material performance, system operating pressure and the desired residual lifetime of the pipe as follows:

$$\boldsymbol{Operational\ Ranking} = \sqrt[3]{\boldsymbol{Material\ Ranking} * \boldsymbol{Failure\ Stress\ Ranking} * \boldsymbol{Failure\ Time\ Ranking}} \qquad \textbf{Equation 1-2}$$

The relative ranking score obtained by applying **Equation 1-2** scales from 1 to 5. The component scores are integers, but the resultant operation ranking will be a real number.

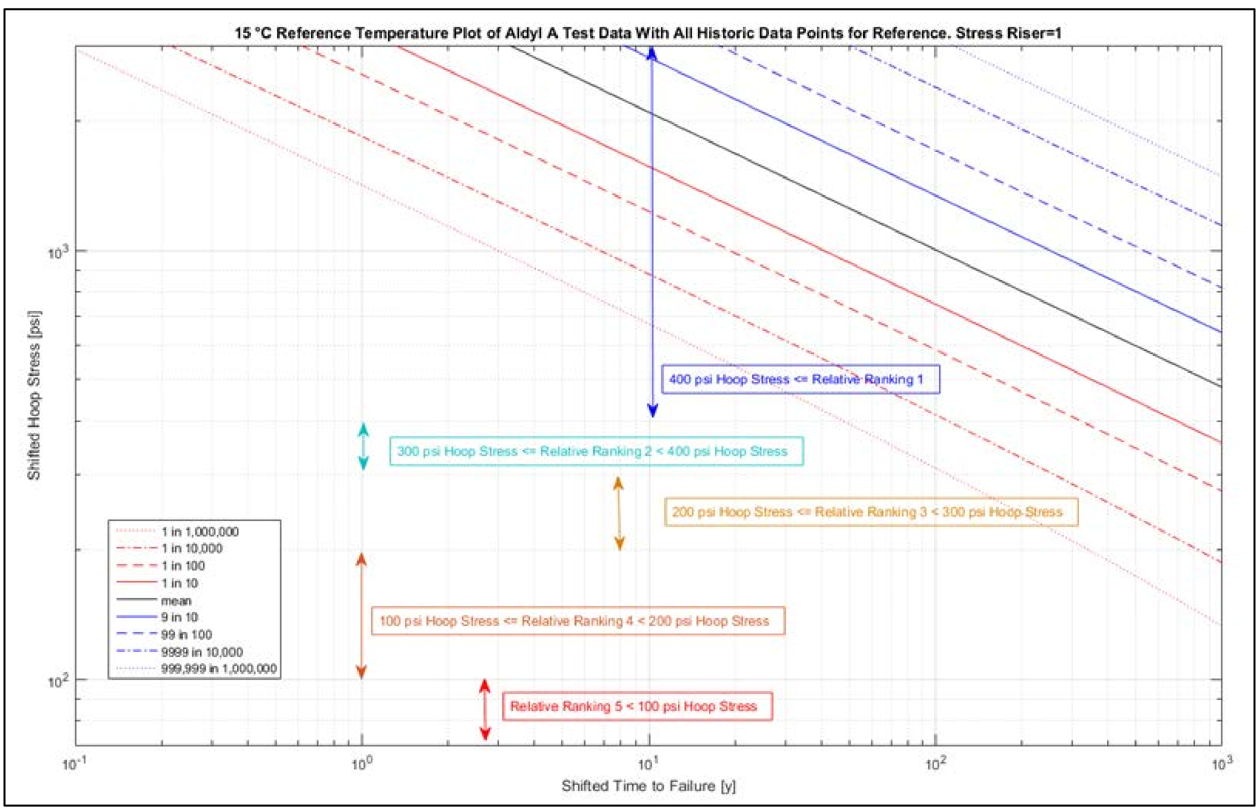


**Figure 1-7. Relative Ranking Bands for Failure Stress Relative to Absolute Hoop Stress in psi**

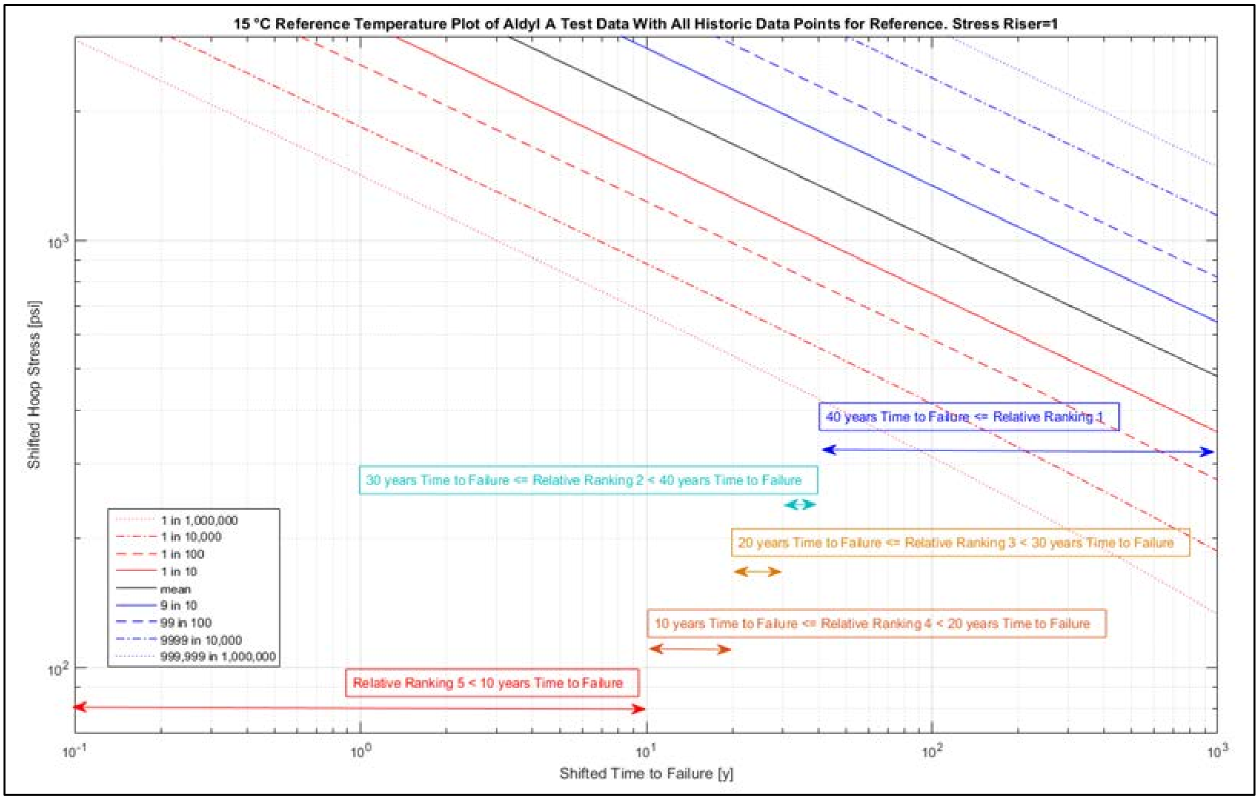


**Figure 1-8. Relative Ranking Bands for Failure Time Relative to Absolute Time to Failure in years**

Some typical output (Data Set 1, 1969 vintage Aldyl A, approximately 45 years in service ) is presented in **Figure 1-9** to **Figure 1-12**. We can see that the materials RPM performance puts it in medium to high risk bands, however the test stresses translate to very high operational pressures at the reference temperature and all of the failure points are in a low operational risk band looking at operating stress alone. Looking at the projected times to failure we see that most of the points are projected to relatively low failure times, placing them in medium to very high risk looking at projected failure times alone. The composite operational risk is low to medium in the absence of fittings, squeeze-offs, or other installation conditions that could introduce a SIF. It is extremely important to have good knowledge of potential SIF to conduct a complete FFS evaluation. We will comprehensively address SIF in later section of the report.

The histograms are a simple count of how many individual data points from the long-term hydrostatic RPM testing fell into each ranking category for the data sub-set being analyzed. A histogram is presented for each of the three rankings described above for a single illustrative example: Data Set 1 (1969), 15°C ground temperature and a stress riser of 1 representing straight pipe under hydrostatic pressure with no fitting or installation condition induced stress risers.

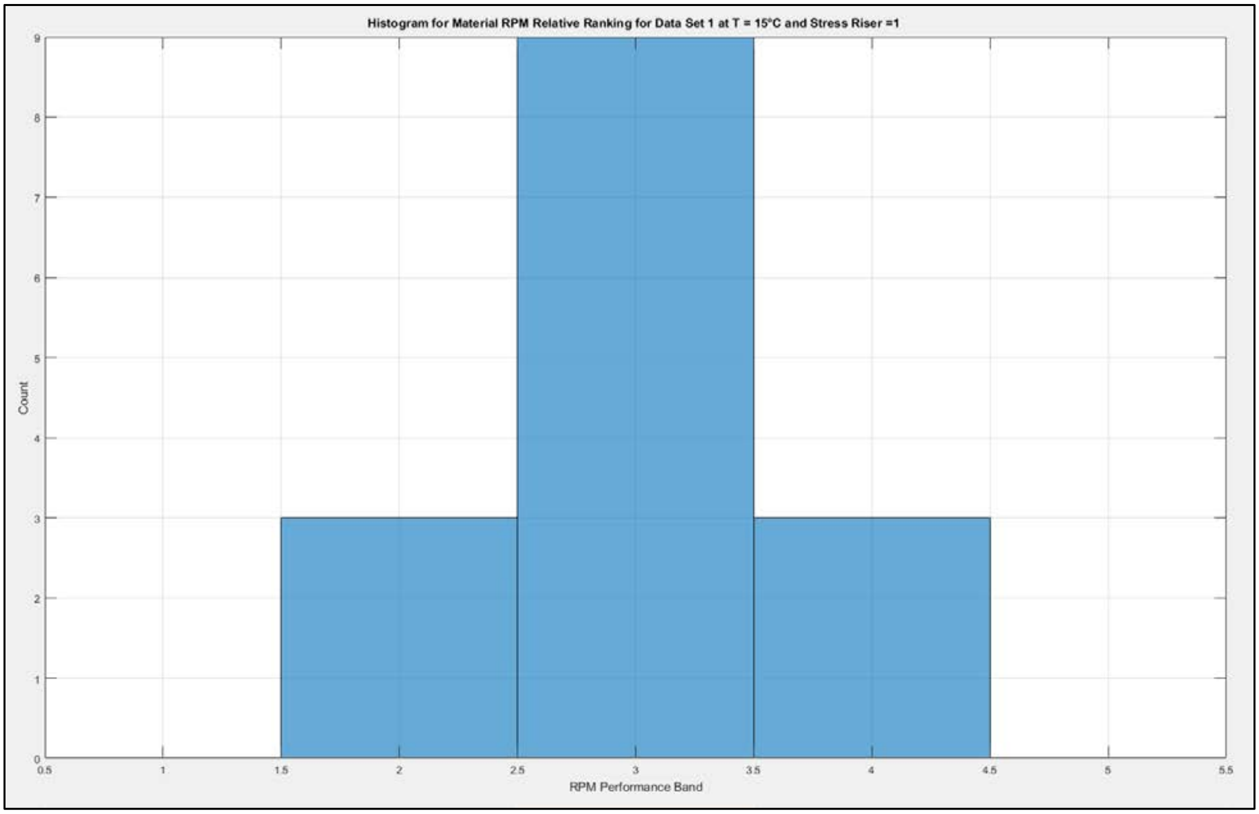


Figure 1-9. Material RPM Relative Ranking for Data Set 1 @ 15°C

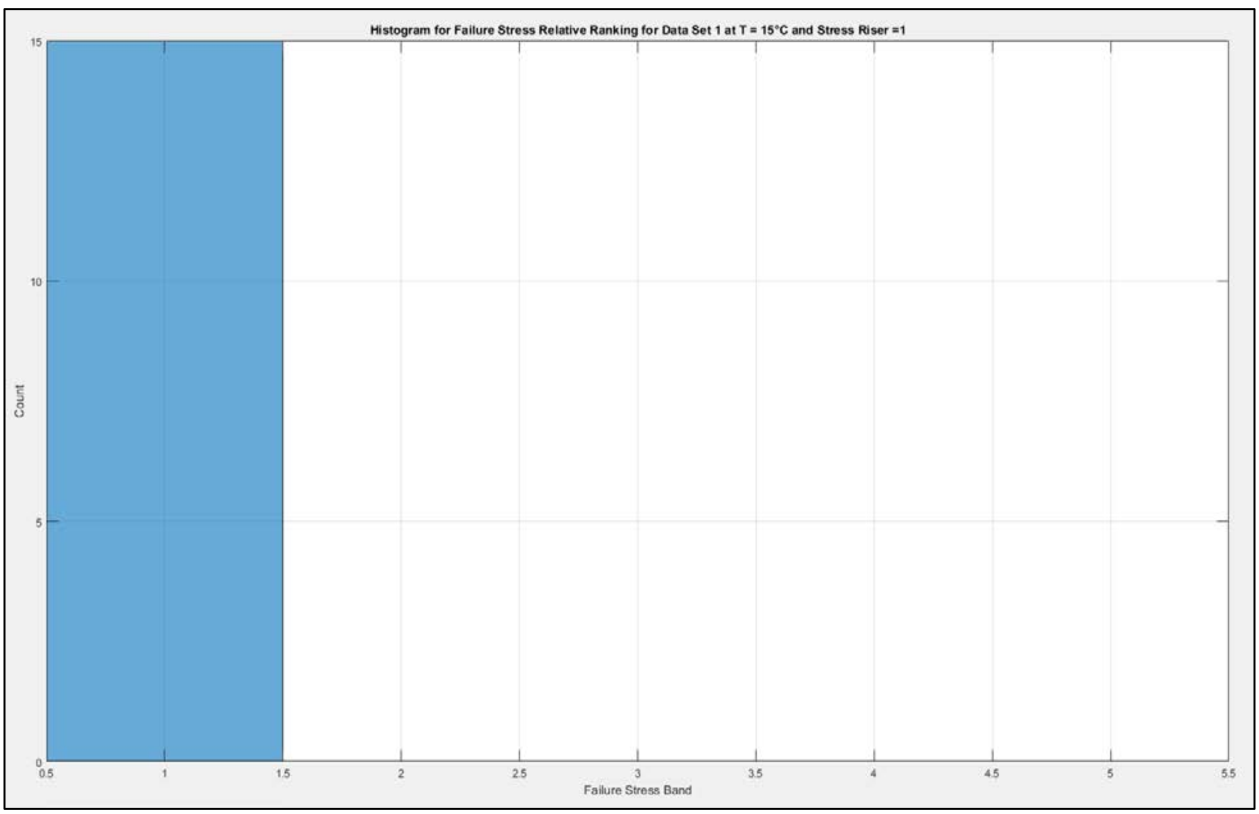


Figure 1-10. Failure Stress Relative Ranking for Data Set 1 @ 15°C

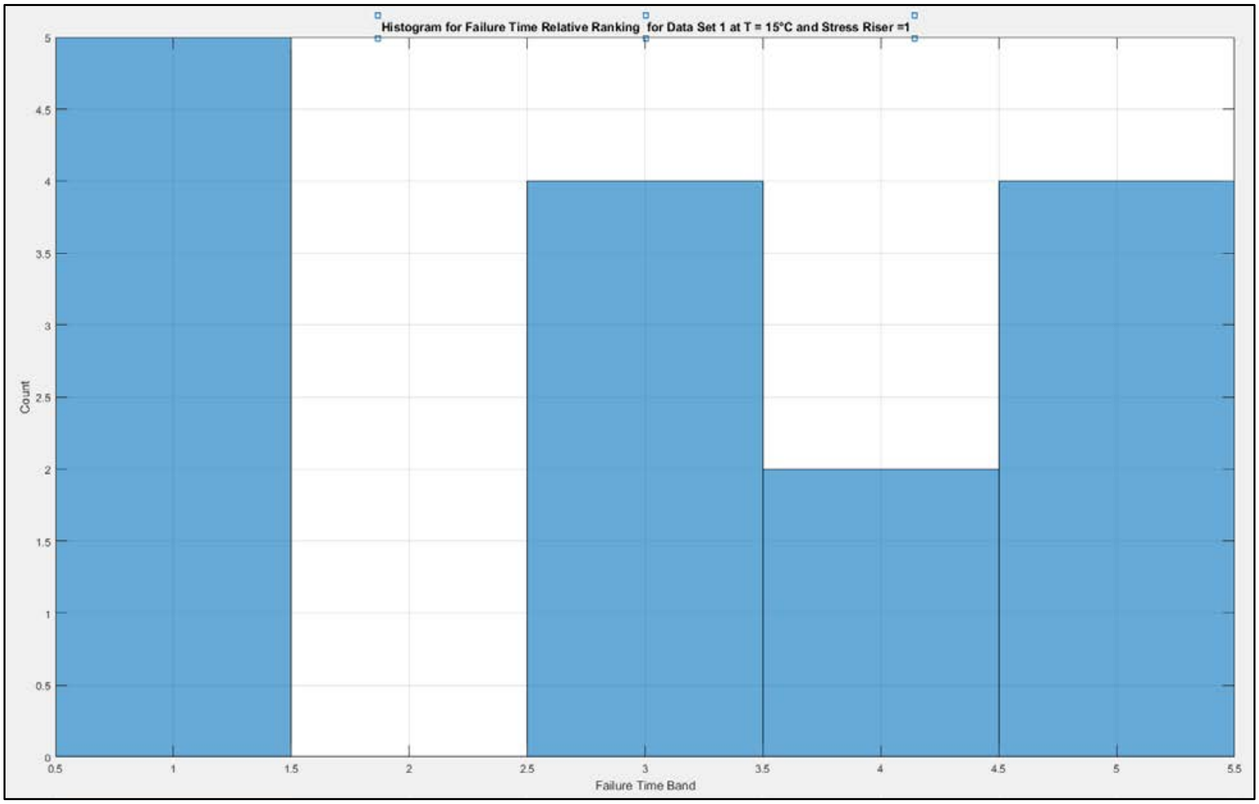


Figure 1-11. Failure Time Relative Ranking for Data Set 1 @ 15°C

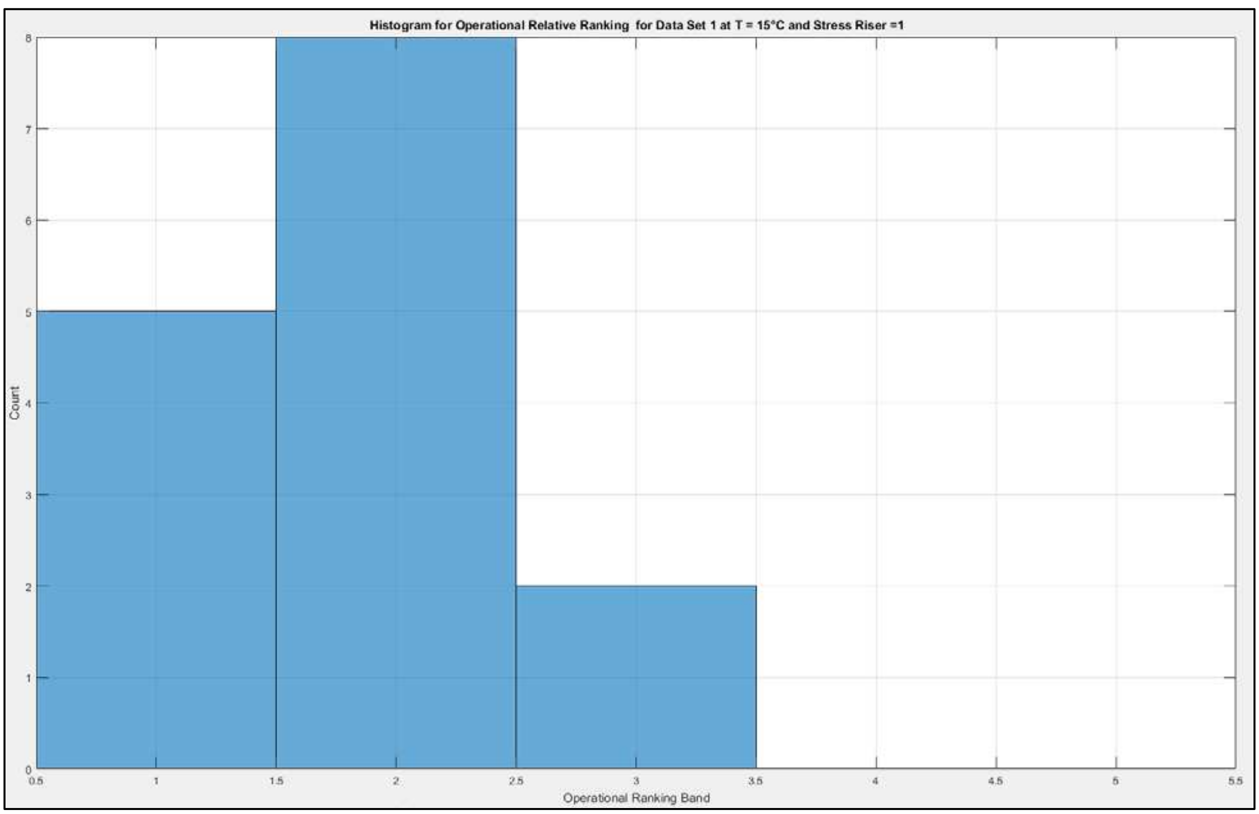


Figure 1-12. Operational Relative Ranking for Data Set 1 @ 15°C

### The Impact of Pipe Inner Wall Surface Condition on Ranking Scores

During the investigations carried out under the Operations Technology Development (OTD) funded project 2.8.d (GTI 20649) that developed risk models for Aldyl A gas distribution piping, it was noted that certain surface features visible in Cross-Polarized Light Microscopy (CPLM) and Scanning Electron Microscopy (SEM) appeared to correlate to times to failure in the RPM testing of pipe specimens. A categorical logistic regression model yielded surprisingly good predictive power as shown in **Figure 1-13**. The results of this study were presented at Plastics Pipes XVII in Chicago, IL September 2014 [7]. In this paper the term "Risk" is used out of context relative to risk assessment where risk is probability of occurrence multiplied by the consequence of the probable event if it occurs. Here the usage of *risk* is: "someone or something that creates or suggests a hazard" e.g. "There is a *risk* of liver damage with this medication", "Pipes with these surface features present have an increased *risk* of reduced lifetime expectancies due to the lower resistance to damage associated with the presence of these features.".

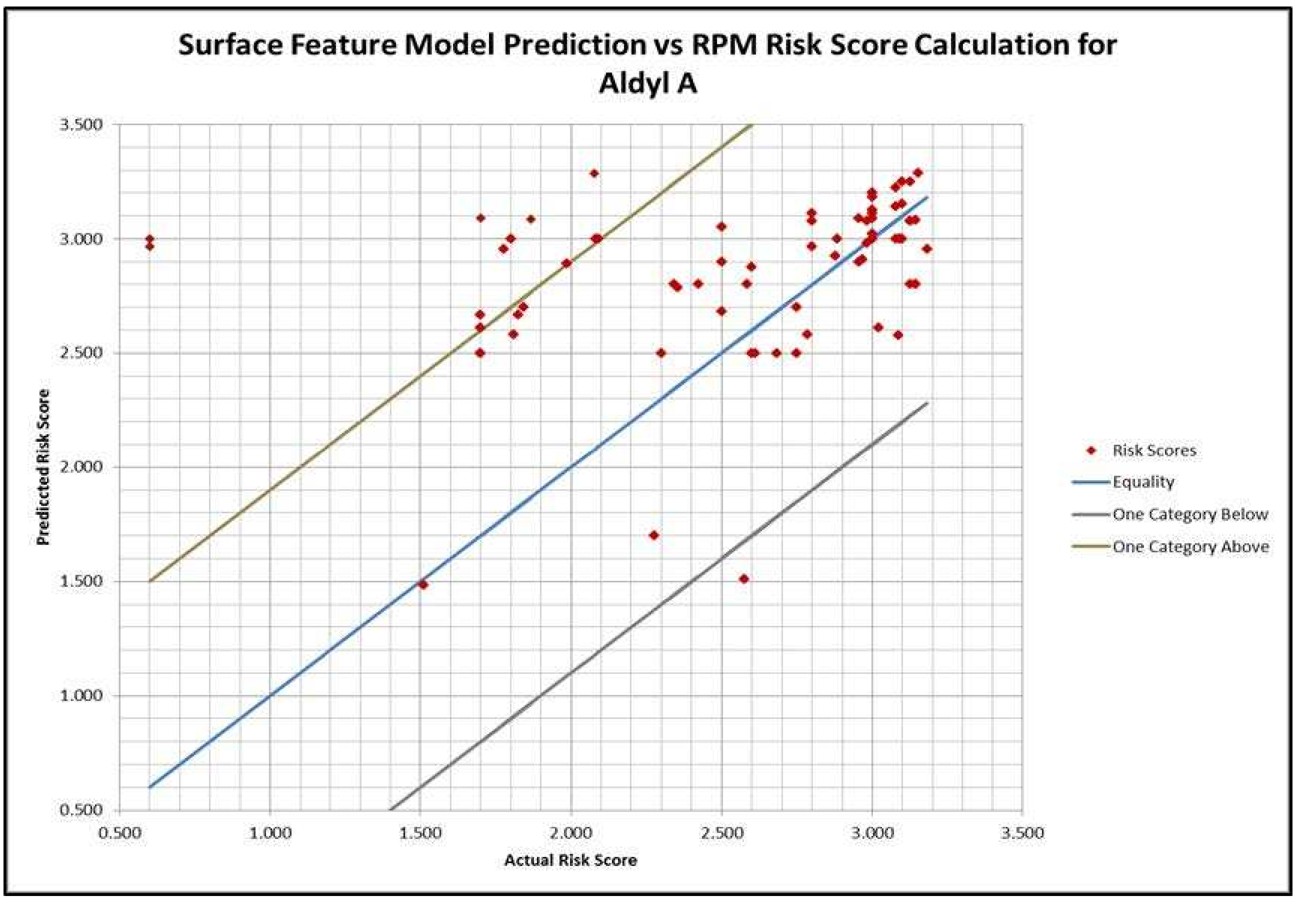


**Figure 1-13. Initial Surface Feature Model for Predicting "Risk" Scores**

This kind of model is extremely useful for pipeline operators in that it can help narrow down the conditional probability estimates of low lifetime expectancy given the presence of these features. **Table 1-2** shows visually how the presence of these features correlates with “Risk” ranking calculated from the DuPont control RPM model and the DuPont LDIW RPM model.

**Table 1-2. Data for Initial Surface Feature Model**

| Risk Rank | Dimple | Micro crack | Crystal | Fiber (rod) | CPLM | Risk Rank | Dimple | Micro crack | Crystal | Fiber (rod) | CPLM |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 0.6 | 1 | 0 | 1 | 0 | 15 | 2.8 | 0 | 0 | 1 | 1 | 10 |
| 0.6 | 1 | 1 | 1 | 1 | 10 | 2.8 | 0 | 0 | 0 | 0 | 10 |
| 1.4 | 0 | 0 | 0 | 0 | 20 | 2.8 | 0 | 0 | 1 | 1 | 10 |
| 1.7 | 1 | 1 | 0 | 0 | 10 | 2.8 | 1 | 1 | 1 | 1 | 10 |
| 1.7 | 1 | 1 | 0 | 1 | 10 | 2.8 | 0 | 0 | 1 | 1 | 10 |
| 1.7 | 1 | 1 | 0 | 1 | 10 | 2.8 | 1 | 1 | 1 | 0 | 15 |
| 1.7 | 1 | 1 | 0 | 0 | 10 | 2.8 | 1 | 1 | 1 | 0 | 20 |
| 1.7 | 0 | 0 | 0 | 0 | 10 | 2.8 | 1 | 0 | 1 | 1 | 10 |
| 1.7 | 0 | 1 | 0 | 0 | 10 | 2.8 | 1 | 0 | 1 | 1 | 15 |
| 1.7 | 0 | 0 | 0 | 0 | 10 | 2.8 | 1 | 1 | 1 | 1 | 15 |
| 1.7 | 0 | 0 | 1 | 0 | 10 | 2.8 | 1 | 0 | 1 | 1 | 15 |
| 1.7 | 0 | 0 | 1 | 0 | 20 | 3.0 | 1 | 1 | 1 | 1 | 20 |
| 1.7 | 0 | 0 | 1 | 1 | 20 | 3.0 | 1 | 1 | 1 | 1 | 20 |
| 1.7 | 0 | 0 | 1 | 1 | 10 | 3.0 | 1 | 1 | 1 | 1 | 20 |
| 1.7 | 0 | 0 | 1 | 0 | 10 | 3.0 | 0 | 0 | 1 | 0 | 20 |
| 2.0 | 1 | 1 | 1 | 0 | 25 | 3.0 | 0 | 0 | 1 | 1 | 20 |
| 2.0 | 1 | 1 | 1 | 1 | 30 | 3.0 | 1 | 1 | 1 | 0 | 25 |
| 2.0 | 0 | 1 | 1 | 0 | 20 | 3.0 | 1 | 1 | 1 | 0 | 25 |
| 2.2 | 0 | 0 | 0 | 0 | 15 | 3.0 | 1 | 1 | 1 | 1 | 25 |
| 2.2 | 1 | 1 | 1 | 1 | 10 | 3.0 | 1 | 1 | 1 | 1 | 20 |
| 2.2 | 1 | 1 | 0 | 1 | 10 | 3.0 | 1 | 0 | 1 | 1 | 20 |
| 2.2 | 1 | 0 | 0 | 0 | 10 | 3.0 | 1 | 1 | 0 | 0 | 25 |
| 2.2 | 1 | 1 | 1 | 1 | 10 | 3.0 | 1 | 1 | 1 | 0 | 25 |
| 2.5 | 1 | 1 | 0 | 0 | 10 | 3.0 | 1 | 1 | 1 | 0 | 10 |
| 2.5 | 1 | 1 | 1 | 1 | 10 | 3.0 | 1 | 1 | 1 | 0 | 25 |
| 2.5 | 1 | 1 | 1 | 0 | 10 | 3.0 | 1 | 0 | 1 | 0 | 10 |
| 2.5 | 0 | 0 | 0 | 0 | 10 | 3.0 | 1 | 1 | 1 | 1 | 30 |
| 2.5 | 0 | 0 | 1 | 0 | 10 | 3.0 | 1 | 1 | 0 | 1 | 25 |
| 2.5 | 1 | 1 | 1 | 1 | 10 | 3.0 | 1 | 1 | 1 | 0 | 25 |
| 2.5 | 0 | 0 | 0 | 0 | 10 | 3.0 | 1 | 1 | 0 | 1 | 25 |
| 2.5 | 0 | 0 | 0 | 0 | 10 | 3.0 | 1 | 1 | 1 | 0 | 10 |
| 2.5 | 1 | 1 | 0 | 0 | 10 | 3.0 | 1 | 1 | 1 | 0 | 25 |
| 2.5 | 0 | 0 | 0 | 0 | 20 | 3.0 | 1 | 1 | 1 | 1 | 30 |
| 2.5 | 0 | 0 | 0 | 0 | 10 | 3.0 | 1 | 1 | 1 | 0 | 30 |
| 2.5 | 0 | 0 | 0 | 0 | 10 | 3.0 | 1 | 1 | 1 | 0 | 30 |
| 2.8 | 0 | 0 | 1 | 0 | 10 | 3.0 | 1 | 1 | 1 | 1 | 10 |
| 2.8 | 0 | 1 | 0 | 0 | 10 | | | | | | |

**Figure 1-14** and **Figure 1-15** show examples of the surface features.

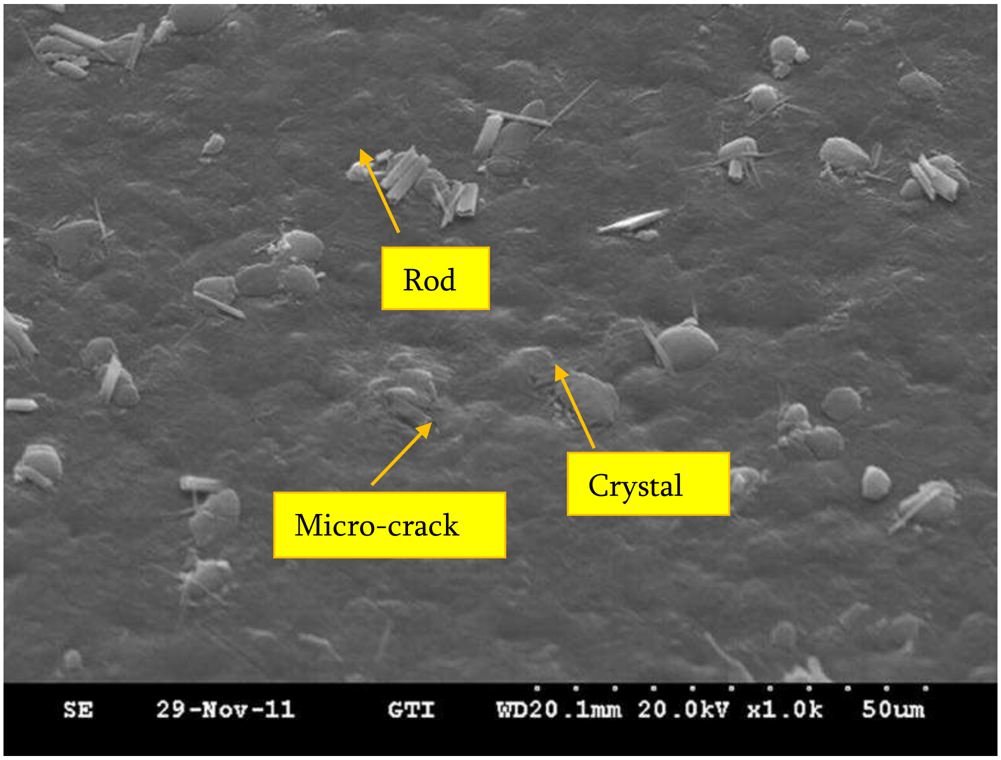


Figure 1-14. SEM image showing Crystals, Rods and Micro-crack

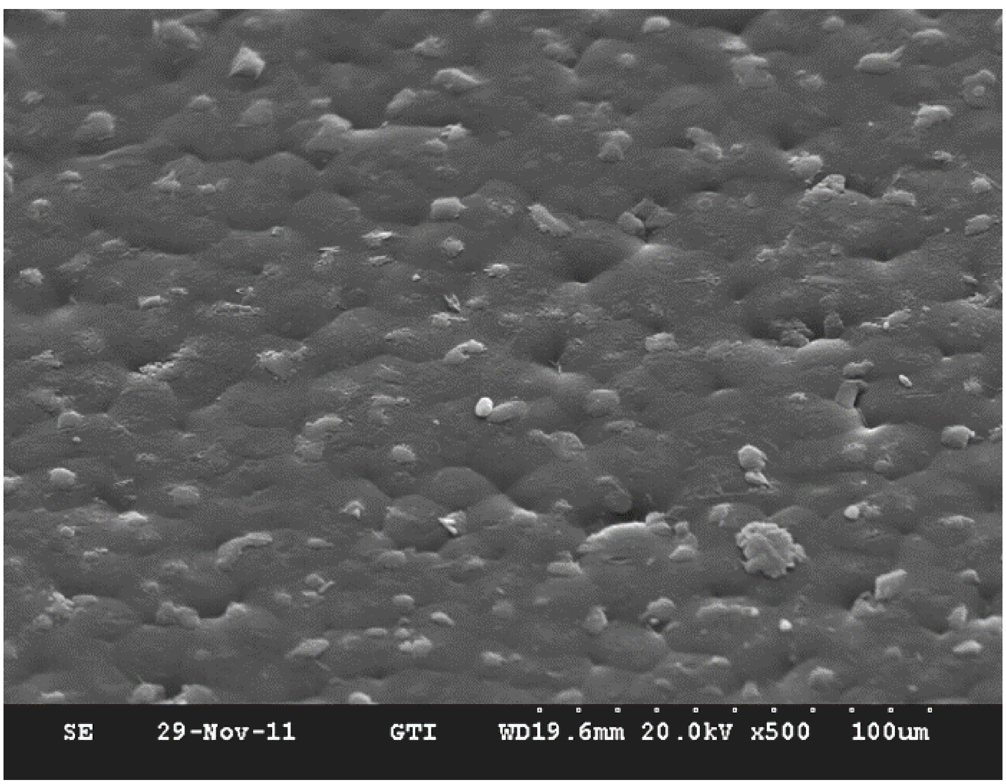


Figure 1-15. SEM Image Showing Dimples

**Table 1-3** shows the data for an improved surface feature model where the initial surface feature model was improved by including relative rankings derived from Oxidation Induction Time (OIT) from thermal testing and Carbonyl Index (CI) from Fourier Transform Infrared (FTIR) testing.

## Table 1-3. Data for Expanded Surface Feature and Thermal Characteristics Model

| LIMSNo | LTHSId | SampleID | OIT SampleID | Dimple | Micro crack | Crystal | Fiber (rod) | CPLM | OIT Risk | FTIR Risk | Risk Score |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 111174-001 | 452 | E1A | E1A | 1 | 1 | 1 | 1 | 10 | 1 | 1 | 0.6 |
| 111174-002 | 455 | E1B | E1AB | 1 | 0 | 1 | 0 | 15 | 1 | 1 | 0.6 |
| 111174-006 | 456 | E5B | E5BC | 1 | 1 | 0 | 1 | 10 | 2 | 1 | 1.1 |
| 111174-012 | 451 | E10B | E10A | 1 | 1 | 0 | 0 | 10 | 3 | | 1.7 |
| 111174-014 | 457 | E12 | E12 | 1 | 1 | 0 | 1 | 10 | 2 | 1 | 1.7 |
| 111174-015 | 458 | E47 | E47 | 1 | 1 | 0 | 0 | 10 | 1 | | 1.7 |
| 111174-018 | 461 | E200C | E200C | 1 | 1 | 1 | 0 | 25 | 3 | 1 | 1.7 |
| 111174-019 | 462 | E207A | E207AB | 1 | 1 | 1 | 1 | 30 | 3 | 1 | 1.7 |
| 111174-029 | 472 | E211C | E211CD | 0 | 0 | 0 | 0 | 10 | 3 | 1 | 1.7 |
| 111174-030 | 473 | E213A | E213A | 0 | 1 | 0 | 0 | 10 | 3 | 1 | 1.7 |
| 111174-031 | 474 | E213B | E213B | 0 | 0 | 0 | 0 | 10 | 3 | 1 | 1.7 |
| 111174-032 | 475 | E217A | E217AB | 0 | 0 | 1 | 0 | 20 | 3 | | 1.7 |
| 111174-034 | 477 | E217C | E217BC | 0 | 0 | 1 | 0 | | 3 | 1 | 1.7 |
| 111174-035 | 478 | E217D | E217CD | 0 | 0 | 1 | 1 | 20 | 3 | | 1.7 |
| 111174-036 | 479 | E224A | E224AB | 0 | 0 | 1 | 1 | 10 | 3 | 1 | 1.7 |
| 111174-037 | 480 | E224B | E224B | 0 | 0 | 1 | 0 | 10 | 3 | 1 | 1.7 |
| 111174-039 | 482 | E224D | E224D | 0 | 0 | 0 | 0 | | 3 | | 1.7 |
| 111174-041 | 484 | E226B | E226B | 0 | 1 | 1 | 0 | 20 | 3 | 1 | 2 |
| 111174-042 | 485 | E230A | E230A | 0 | 0 | 1 | 0 | 10 | 3 | 1 | 2 |
| 111174-043 | 486 | E230B | E230BC | 0 | 0 | 0 | 0 | 15 | 3 | 1 | 2.2 |
| 111174-044 | 487 | E230C | E230CD | 1 | 1 | 0 | 1 | 10 | 2 | 1 | 2.2 |
| 111428-001 | 489 | E401A | E401A | 1 | 1 | 0 | 1 | | 2 | | 2.2 |
| 111428-002 | 490 | E401B | E401BC | 1 | 1 | 0 | 0 | 10 | 1 | | 2.2 |
| 111428-005 | 491 | E401E | E401E | 1 | 1 | 1 | 1 | 10 | 1 | | 2.2 |
| 111428-007 | 492 | E402B | E402AB | 1 | 1 | 1 | 0 | 10 | 1 | | 2.2 |
| 111428-009 | 493 | E402D | E402CD | 0 | 0 | 1 | 0 | 10 | 1 | | 2.2 |
| 111428-010 | 494 | E402E | E402DE | 0 | 0 | 0 | 0 | 10 | 3 | | 2.2 |
| 111428-012 | 496 | E403B | E403CD | 1 | 0 | 1 | 1 | 20 | 3 | | 2.2 |
| 111428-015 | 497 | E403E | E403DE | 1 | 1 | 0 | 1 | 25 | 3 | 1 | 2.2 |
| 111428-016 | 498 | E404A | E404AB | 1 | 1 | 1 | 0 | 10 | 3 | 1 | 2.2 |
| 111428-019 | 499 | E404D | E404DE | 1 | 1 | 1 | 1 | 30 | 3 | 2 | 2.2 |
| 111428-021 | 500 | E405A | E405AB | 1 | 1 | 1 | 0 | 30 | 3 | 1 | 2.2 |
| 111428-023 | 502 | E405C | E405CD | 0 | 0 | 0 | 0 | 20 | 3 | 1 | 2.2 |
| 111428-025 | 504 | E405E | E405DE | 0 | 0 | 1 | 0 | 10 | 3 | 1 | 2.2 |
| 111428-029 | 505 | E406D | E406D | 1 | 1 | 1 | 1 | 10 | 3 | 1 | 2.5 |
| 111428-032 | 506 | E407C | E407CD | 1 | 1 | 1 | 1 | 10 | 1 | 1 | 2.5 |
| 111428-034 | 507 | E407E | E407E | 1 | 1 | 0 | 0 | | 2 | | 2.5 |
| 111428-035 | 508 | E408A | E408A | 0 | 0 | 1 | 1 | 10 | 3 | | 2.5 |
| 111428-041 | 509 | E410A | E410AB | 0 | 0 | 1 | 1 | 10 | 3 | | 2.5 |
| 111428-042 | 510 | E410B | E410BC | 1 | 1 | 1 | 1 | 15 | 3 | 1 | 2.5 |
| 111428-044 | 511 | E410D | E410DE | 1 | 1 | 1 | 1 | 20 | 3 | | 2.5 |
| 111428-046 | 512 | E411A | E411A | 0 | 0 | 1 | 1 | 20 | 3 | | 2.5 |
| 111428-048 | 513 | E411C | E411CD | 1 | 1 | 1 | 0 | 10 | 3 | 1 | 2.5 |

| LIMSNo | LTHSId | SampleID | OIT SampleID | Dimple | Micro crack | Crystal | Fiber (rod) | CPLM | OIT Risk | FTIR Risk | Risk Score |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 111428-048 | 513 | E411C | E411CD | 1 | 1 | 1 | 0 | 10 | 3 | 1 | 2.5 |
| 111428-053 | 514 | E412C | E412BC | 1 | 1 | 1 | 0 | | 3 | 1 | 2.5 |
| 111428-054 | 515 | E412D | E412DE | 1 | 1 | 0 | 1 | 25 | 3 | | 2.5 |
| 111429-001 | 516 | E413A | E413A | 1 | 1 | 1 | 0 | 25 | 3 | | 2.5 |
| 111429-007 | 518 | E414A | E414A | 1 | 1 | 1 | 0 | | 3 | 1 | 2.5 |
| 111429-012 | 519 | E415A | E415A | 1 | 1 | 1 | 0 | 30 | 3 | 2 | 2.5 |
| 111429-018 | 520 | E416B | E416A | 0 | 0 | 0 | 0 | 10 | 3 | 1 | 2.5 |
| 111429-024 | 521 | E417C | E417CD | 1 | 0 | 0 | 0 | 10 | 2 | | 2.8 |
| 111429-026 | 522 | E417E | E417E | 0 | 0 | 0 | 0 | 10 | 3 | 1 | 2.8 |
| 111429-027 | 523 | E418A | E418AB | 0 | 1 | 0 | 0 | 10 | 3 | | 2.8 |
| 111429-031 | 525 | E418E | E418DE | 0 | 0 | 1 | 1 | 10 | 3 | | 2.8 |
| 111429-033 | 526 | E419B | E419A | 1 | 1 | 1 | 0 | 20 | 3 | 1 | 2.8 |
| 111429-035 | 527 | E419D | E419CD | 1 | 0 | 1 | 1 | 15 | 3 | 1 | 2.8 |
| 111429-040 | 528 | E420D | E420E | 1 | 0 | 1 | 1 | 15 | 3 | | 2.8 |
| 111429-042 | 529 | E421A | E421AB | 1 | 1 | 1 | 1 | 20 | 3 | 1 | 2.8 |
| 111429-045 | 530 | E421D | E421DE | 0 | 0 | 1 | 0 | 20 | 3 | | 2.8 |
| 111429-048 | 531 | E422B | E422AB | 1 | 1 | 1 | 0 | 25 | 3 | | 2.8 |
| 111429-049 | 532 | E422C | E422CD | 1 | 1 | 1 | 0 | 25 | 3 | 1 | 2.8 |
| 111429-050 | 533 | E422D | E422E | 1 | 0 | 1 | 0 | 10 | 3 | 1 | 2.8 |
| 131119-012 | 543 | E19 | E2 | 1 | 1 | 1 | 1 | 30 | 3 | 1 | 2.8 |
| 131119-016 | 547 | E21B | E21B | 1 | 1 | 1 | 0 | 25 | 3 | 1 | 2.8 |
| 131119-018 | 549 | E331A | E331AB | 0 | 0 | 0 | 0 | | 3 | 1 | 2.8 |
| 131119-019 | 550 | E331C | E331CD | 1 | 1 | 1 | 1 | 10 | 2 | | 3 |
| 131119-021 | 552 | E332A | E332BC | 1 | 1 | 1 | 1 | 10 | 3 | 1 | 3 |
| 131119-022 | 553 | E332D | E332CD | 1 | 1 | 1 | 1 | 10 | 3 | | 3 |
| 131119-023 | 554 | E333A | E333AB | 1 | 1 | 1 | 0 | 15 | 3 | 1 | 3 |
| 131119-024 | 555 | E333D | E333DE | 1 | 0 | 1 | 1 | 10 | 3 | | 3 |
| 131119-025 | 556 | E334A | E334BC | 1 | 1 | 1 | 1 | 20 | 3 | 1 | 3 |
| 131119-026 | 557 | E334D | E334D | 1 | 1 | 1 | 0 | 25 | 3 | | 3 |
| 131119-027 | 558 | E335A | E335AB | 1 | 1 | 1 | 1 | 25 | 3 | 1 | 3 |
| 131119-028 | 559 | E335B | E335CD | 1 | 1 | 1 | 1 | 20 | 3 | | 3 |
| 131119-029 | 560 | E336A | E336AB | 1 | 1 | 0 | 0 | 25 | 3 | | 3 |
| 131119-030 | 561 | E336C | E336CD | 1 | 1 | 1 | 0 | 25 | 3 | 1 | 3 |
| 131119-031 | 562 | E337A | E337AB | 0 | 0 | 0 | 0 | 20 | 3 | | 3 |
| 131119-032 | 563 | E337C | E337CD | 1 | 1 | 1 | 0 | | 3 | 3 | 3 |
| 131119-033 | 564 | E337D | E337DE | 0 | 0 | 0 | 0 | 10 | 3 | | 3 |
| 131119-035 | 566 | E338C | E338BC | 0 | 0 | 0 | 0 | 10 | 3 | | 3 |
| 131119-036 | 567 | E338D | E338DE | 1 | 1 | 0 | 0 | 10 | 3 | | 3 |
| 131119-037 | 568 | E338E | E338EF | 0 | 0 | 0 | 0 | 10 | 3 | 1 | 3 |

Figure 1-16 shows the performance of the improved model graphically.

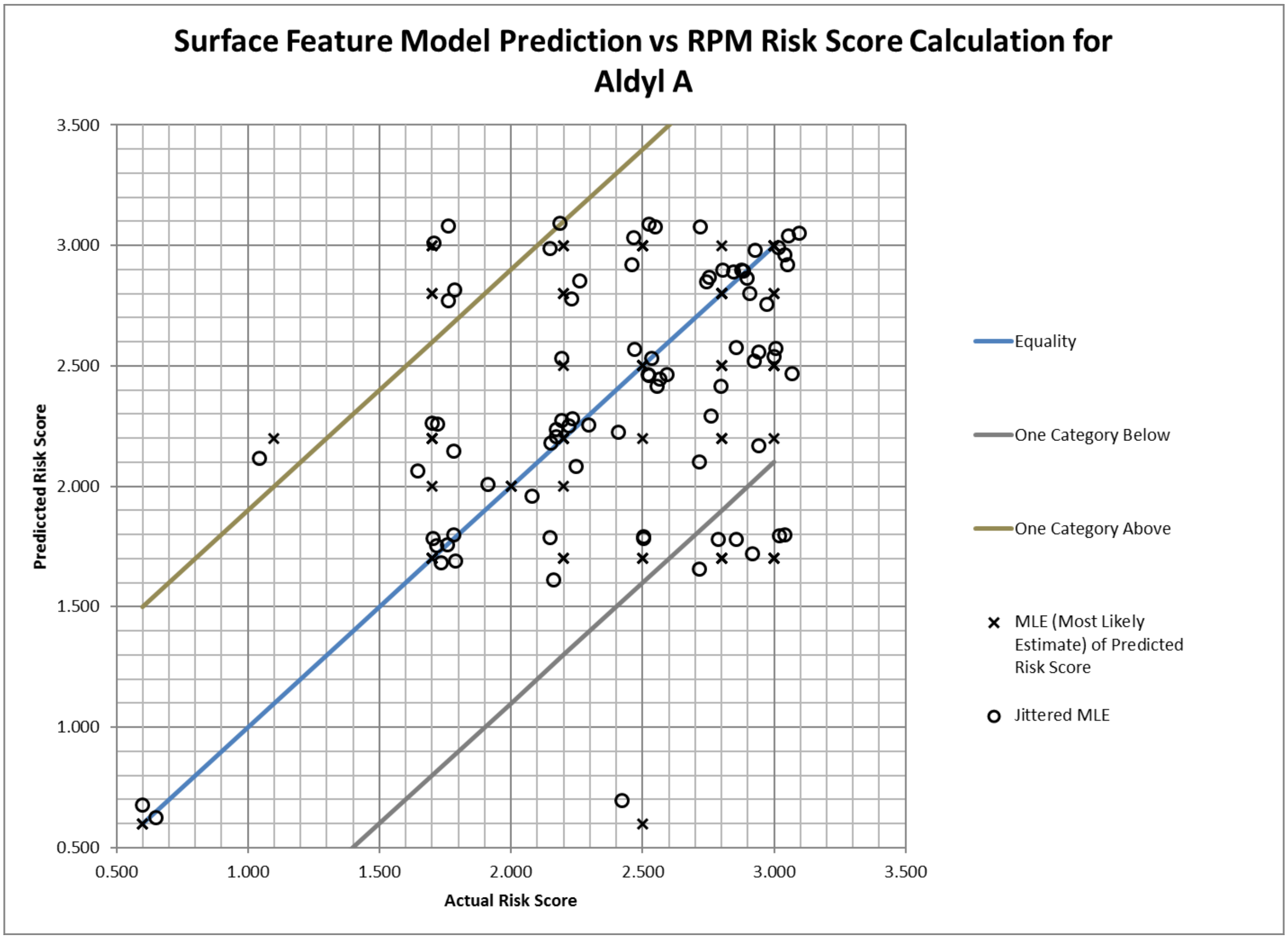


**Figure 1-16. Revised Surface Feature Model**

## Surface Condition Ranking Model V2.0

The early surface correlation model was further refined for this project by rigorously documenting the surface condition and thermal characteristics of 16 long-term hydrostatic test specimens of Aldyl A pipe from a large set of exhumed pipe covering vintages from 1969 to 1974. The data set is presented in **Table 1-4**.

**Table 1-4 – Improved Surface Condition Ranking Model: 14 correct predictions, 2 conservative errors; 87.5% success rate**

| Dimple | Micro Crack | Rod | Boundary Crystals | Surface Crystals | OIT | FTIR - CI | RPM Ranking | | Predicted RPM Ranking |
|---|---|---|---|---|---|---|---|---|---|
| 1 | 1 | 0 | 1 | 2 | 3 | 5 | 3 | ✓ | 3 |
| 1 | 1 | 1 | 1 | 1 | 4 | 4 | 4 | ✓ | 4 |
| 1 | 0 | 1 | 1 | 1 | 2 | 3 | 3 | ✓ | 3 |
| 0 | 1 | 0 | 1 | 1 | 5 | 1 | 2 | ✗ | 3 |
| 1 | 1 | 0 | 1 | 1 | 5 | 1 | 3 | ✓ | 3 |
| 1 | 1 | 0 | 1 | 3 | 5 | 1 | 2 | ✓ | 2 |
| 0 | 1 | 0 | 1 | 1 | 5 | 1 | 3 | ✓ | 3 |
| 1 | 1 | 0 | 4 | 1 | 5 | 1 | 2 | ✓ | 2 |
| 0 | 1 | 1 | 1 | 1 | 3 | 1 | 2 | ✓ | 2 |
| 0 | 1 | 0 | 1 | 1 | 2 | 1 | 2 | ✓ | 2 |
| 1 | 1 | 0 | 3 | 1 | 1 | 2 | 2 | ✗ | 3 |
| 1 | 1 | 1 | 4 | 5 | 2 | 4 | 3 | ✓ | 3 |
| 1 | 1 | 0 | 3 | 2 | 1 | 3 | 3 | ✓ | 3 |
| 1 | 0 | 0 | 3 | 1 | 1 | 3 | 3 | ✓ | 3 |
| 1 | 1 | 0 | 3 | 1 | 1 | 2 | 3 | ✓ | 3 |
| 1 | 1 | 0 | 5 | 2 | 1 | 2 | 2 | ✓ | 2 |

The inputs considered for the model were:

1. Binary for the presence, or absence of:
    a. dimples,
    b. micro-cracks, and
    c. rods.
2. Scaled for the presence of crystals on:
    a. The spherulitic boundaries, and
    b. Across the surface of the spherulites.
3. OIT results, and
4. FTIR results quantified via the Carbonyl Index (CI).

A method for counting the number of crystals per unit length, or area was developed and the count was normalized to a scale of 1 to 5 where 1 reflects the minimum number and 5 the highest number of crystals observed. The OIT and FTIR results were scaled in a similar manner.

A logistic regression model was developed for predicting the Material Ranking Categorization established from the RPM testing described above.

The regression model correctly predicts 14 of the 16 results, with the missed pair of points being conservatively over estimated for severity of ranking. The success rate of the model is 87.5% (14/16) – the results are shown graphically in **Figure 1-17**.

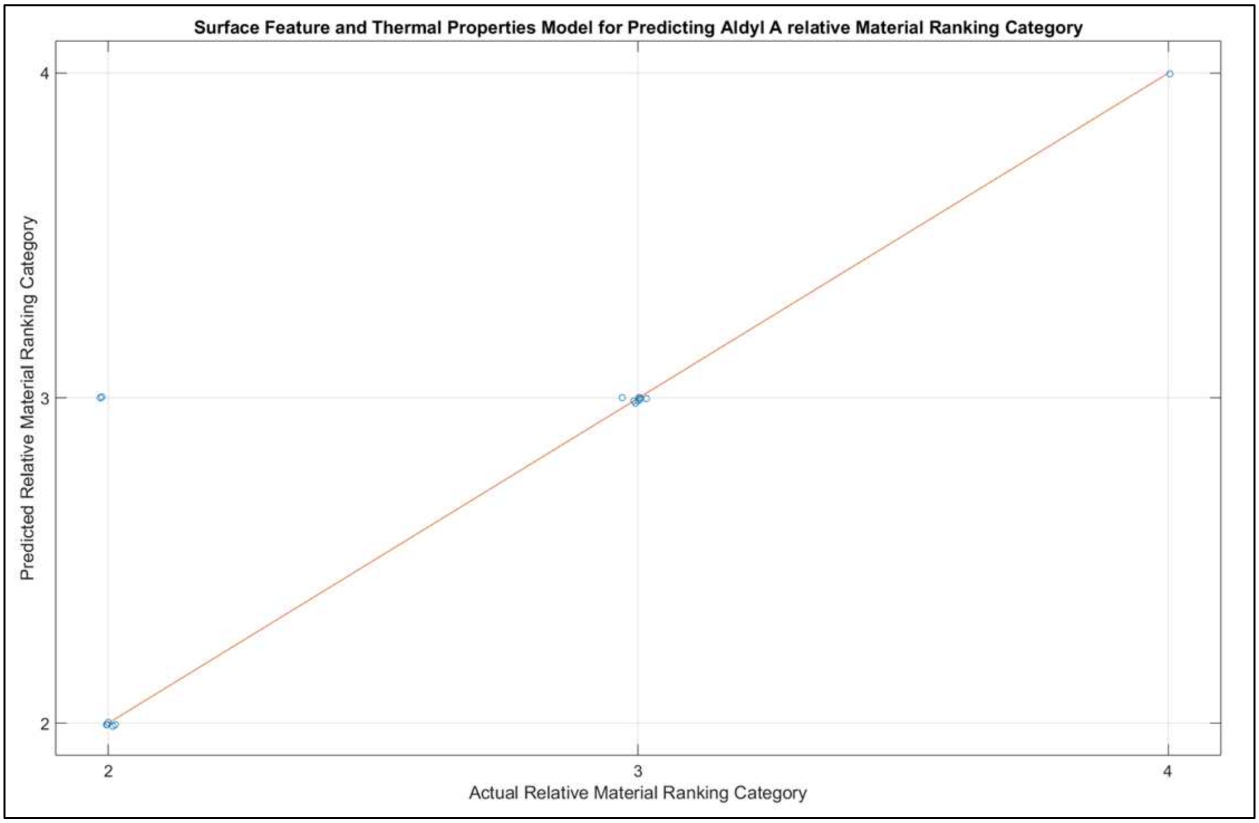


**Figure 1-17. Performance of Surface Feature and Thermal Properties Model for Material Ranking Category Prediction**

In **Figure 1-18** to **Figure 1-33** we show the probabilistic RPM performance band prediction from surface features and thermal characteristics of each specimen. We do this to emphasize that the prediction is probabilistic and that we should select the band with the highest probability (most likely estimate). We can see that for most data points the choice is clear cut, but for some there is close to a 50% likelihood that the point falls in each of two adjacent bands. This was the output for four (4) specimens. The model correctly selected two (2) of these specimens and incorrectly categorized the remaining two. In this case the errors were conservative, but this is likely to be due to random chance and not inherent conservatism in the model.

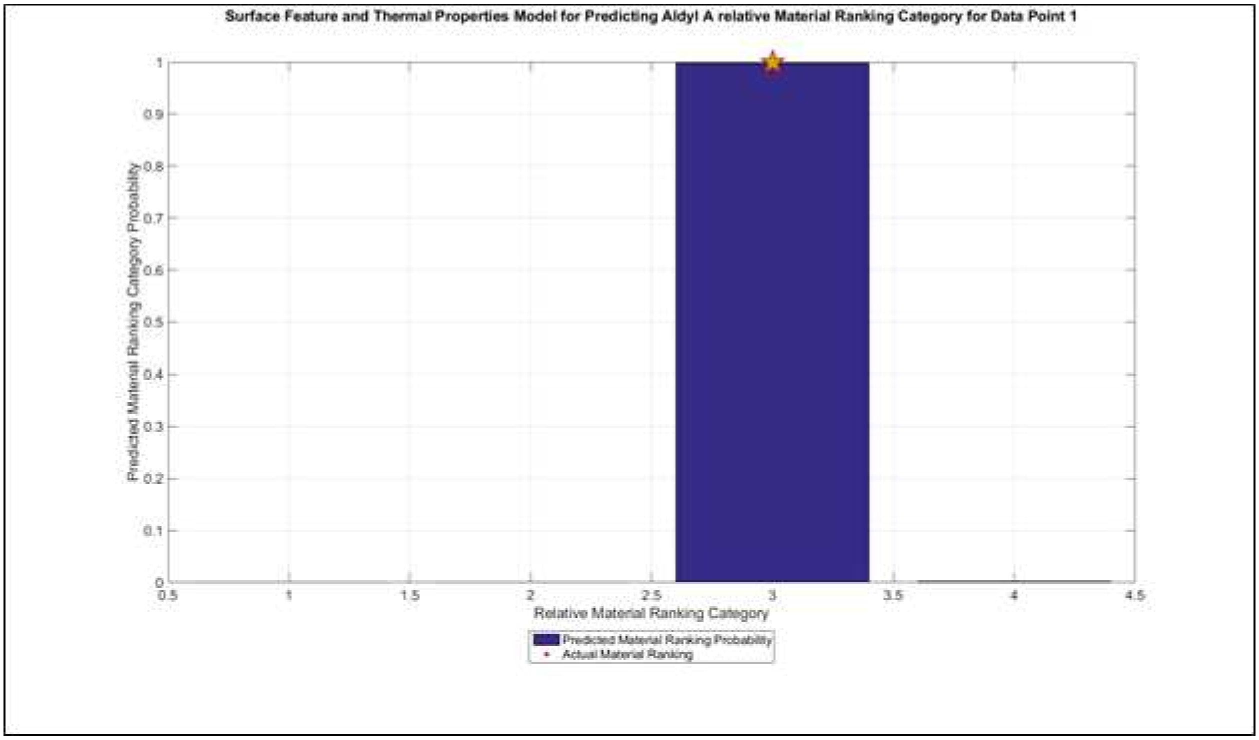


Figure 1-18. Probabilistic prediction of RPM performance band for data point 1

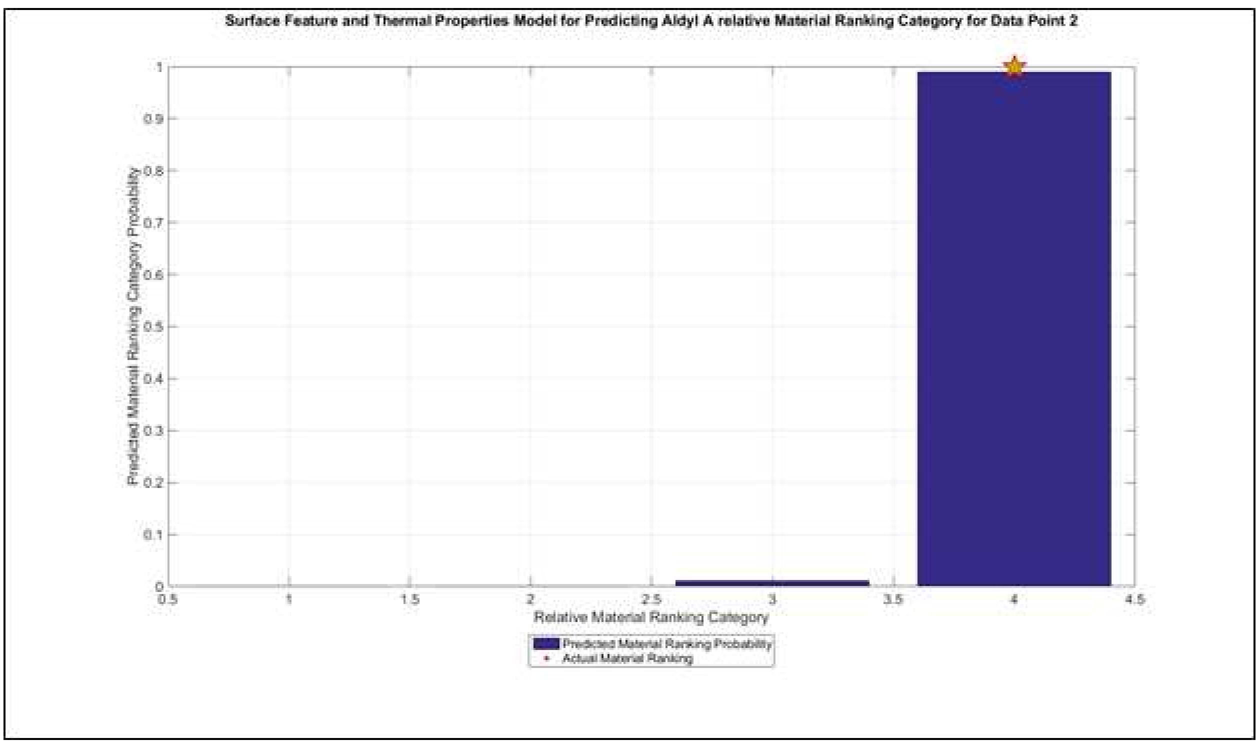


Figure 1-19. Probabilistic prediction of RPM performance band for data point 2

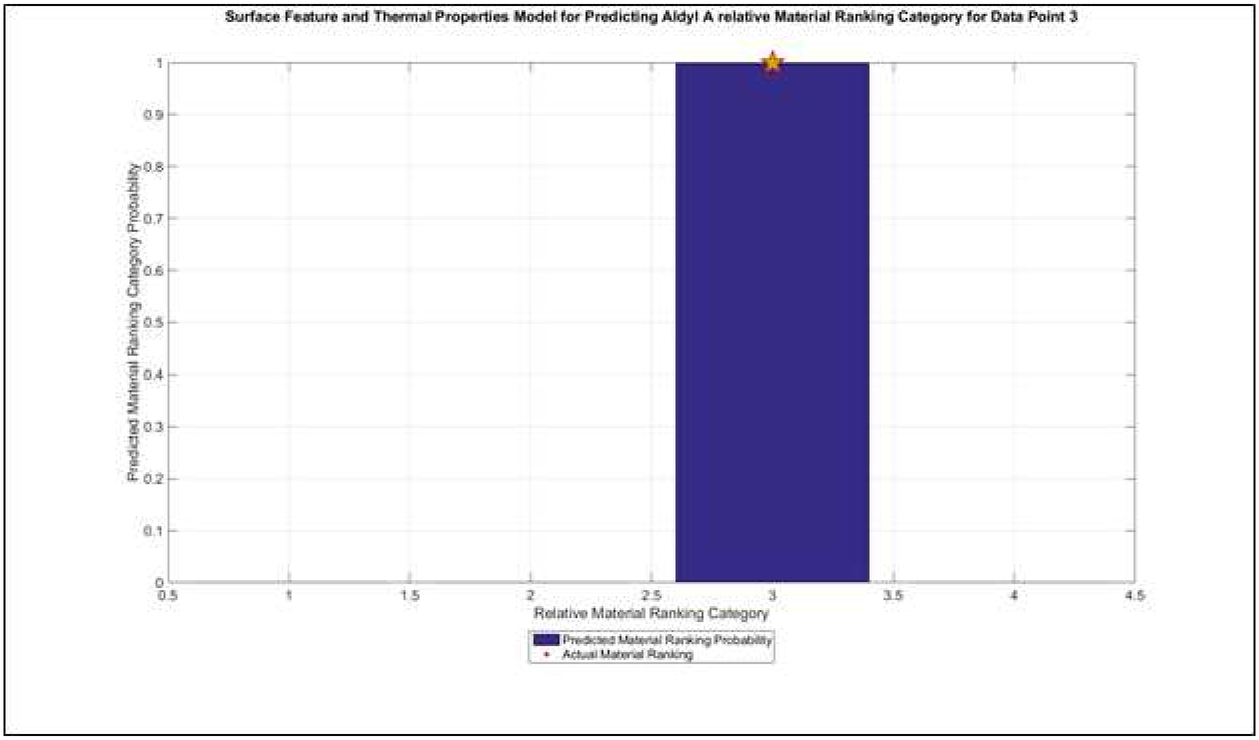


**Figure 1-20. Probabilistic prediction of RPM performance band for data point 3**

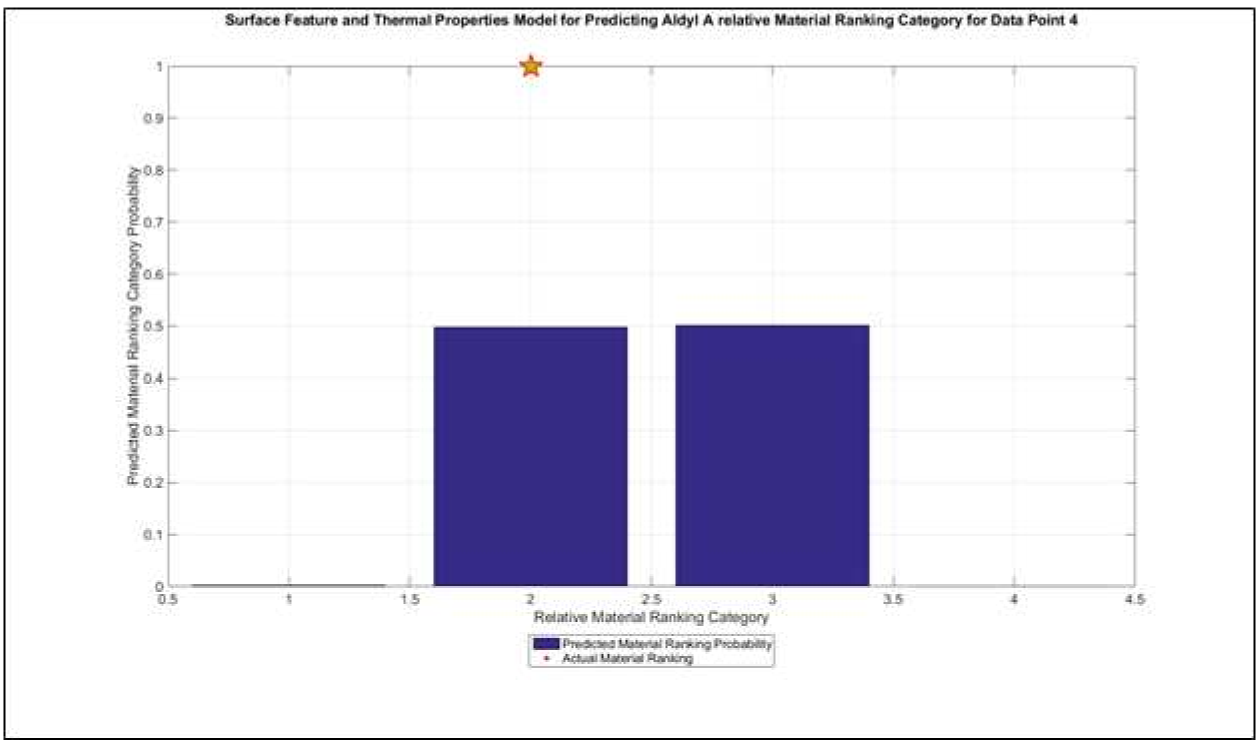


**Figure 1-21 Probabilistic prediction of RPM performance band for data point 4**

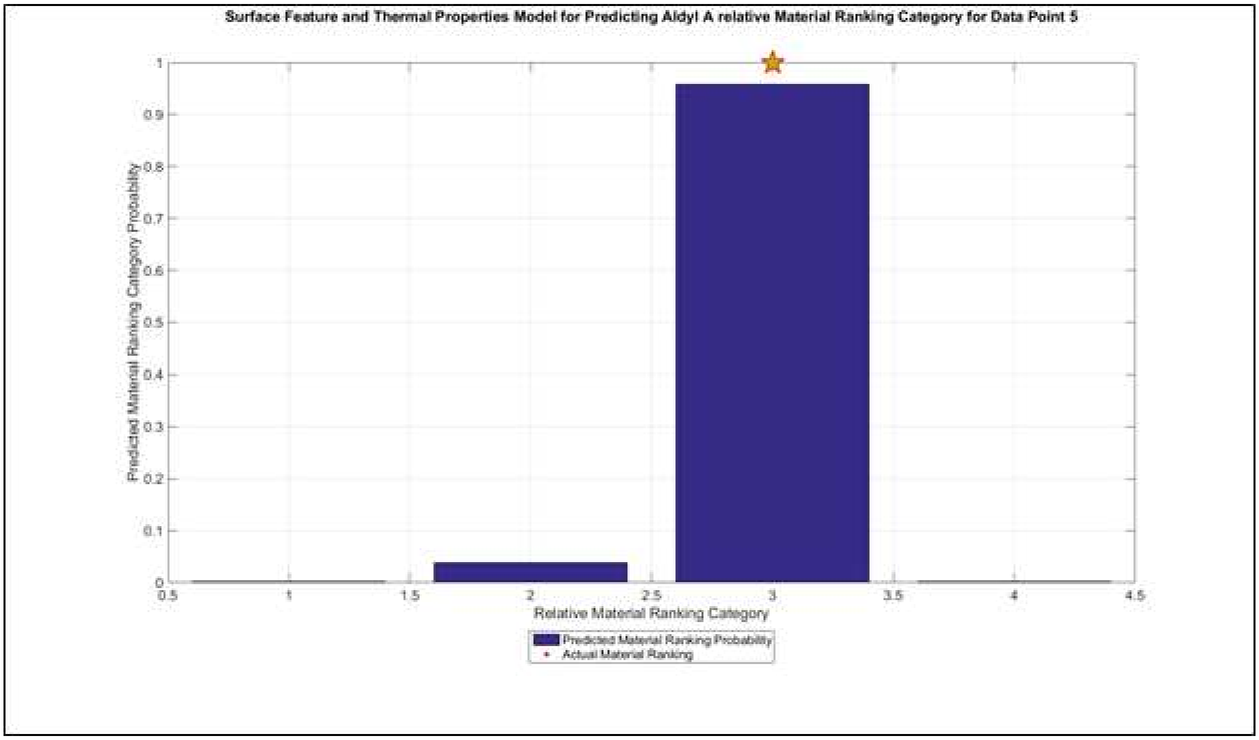


Figure 1-22. Probabilistic prediction of RPM performance band for data point 5

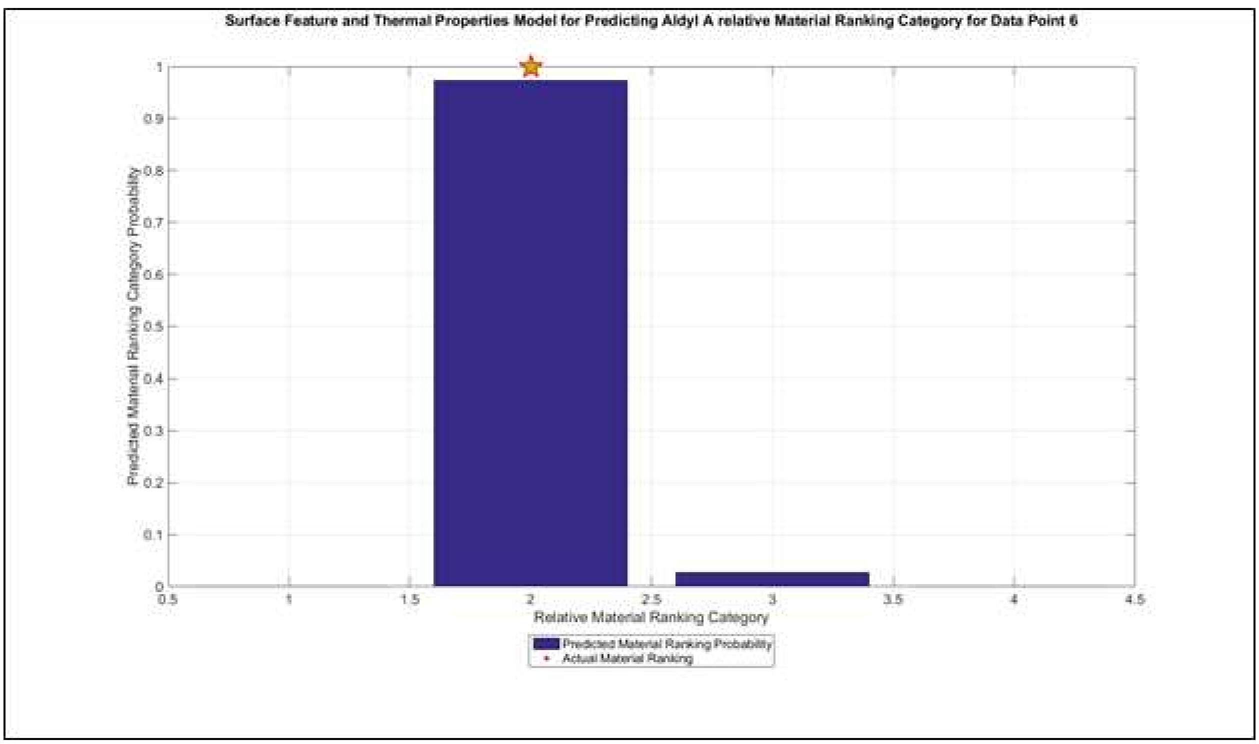


Figure 1-23. Probabilistic prediction of RPM performance band for data point 6

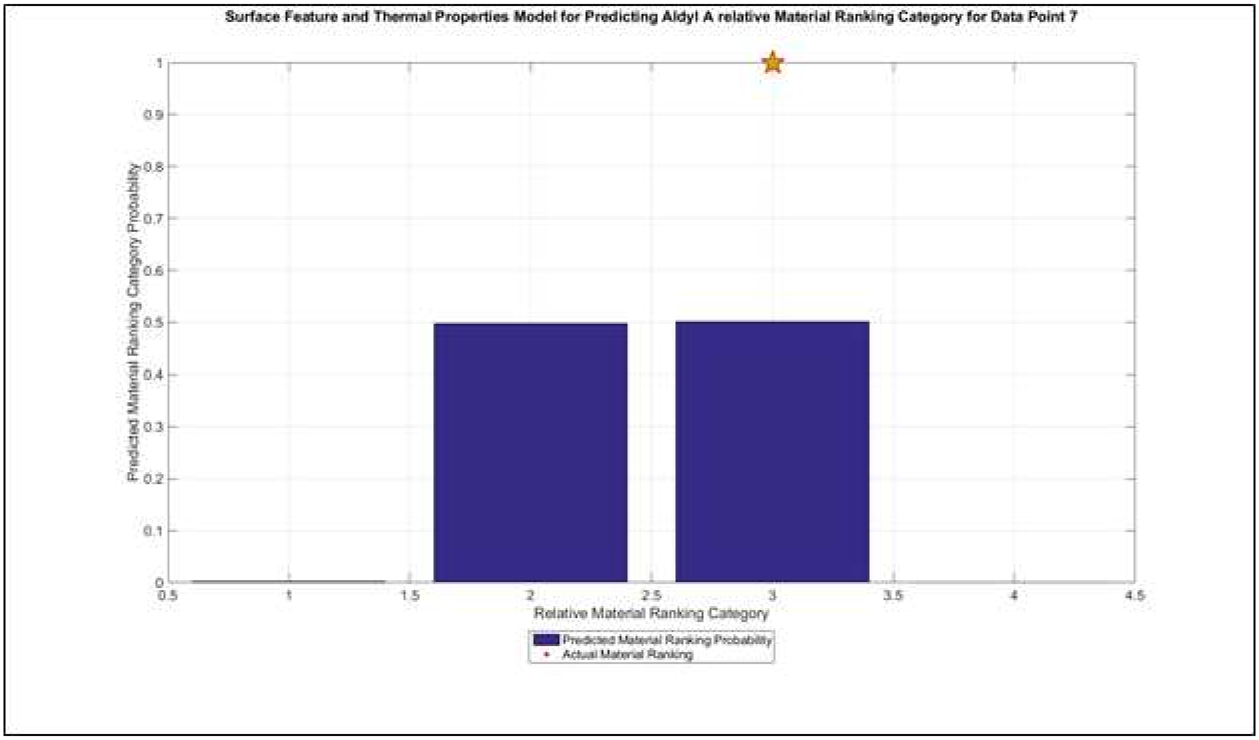


Figure 1-24. Probabilistic prediction of RPM performance band for data point 7

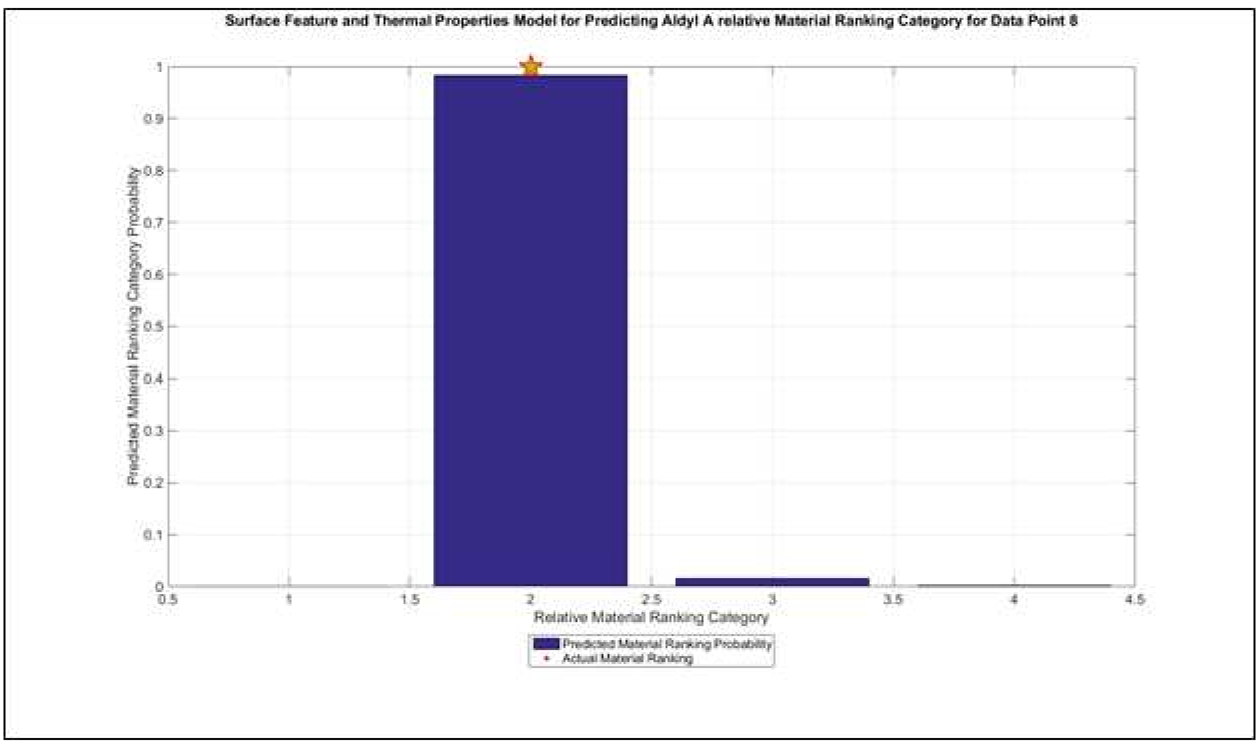


Figure 1-25. Probabilistic prediction of RPM performance band for data point 8

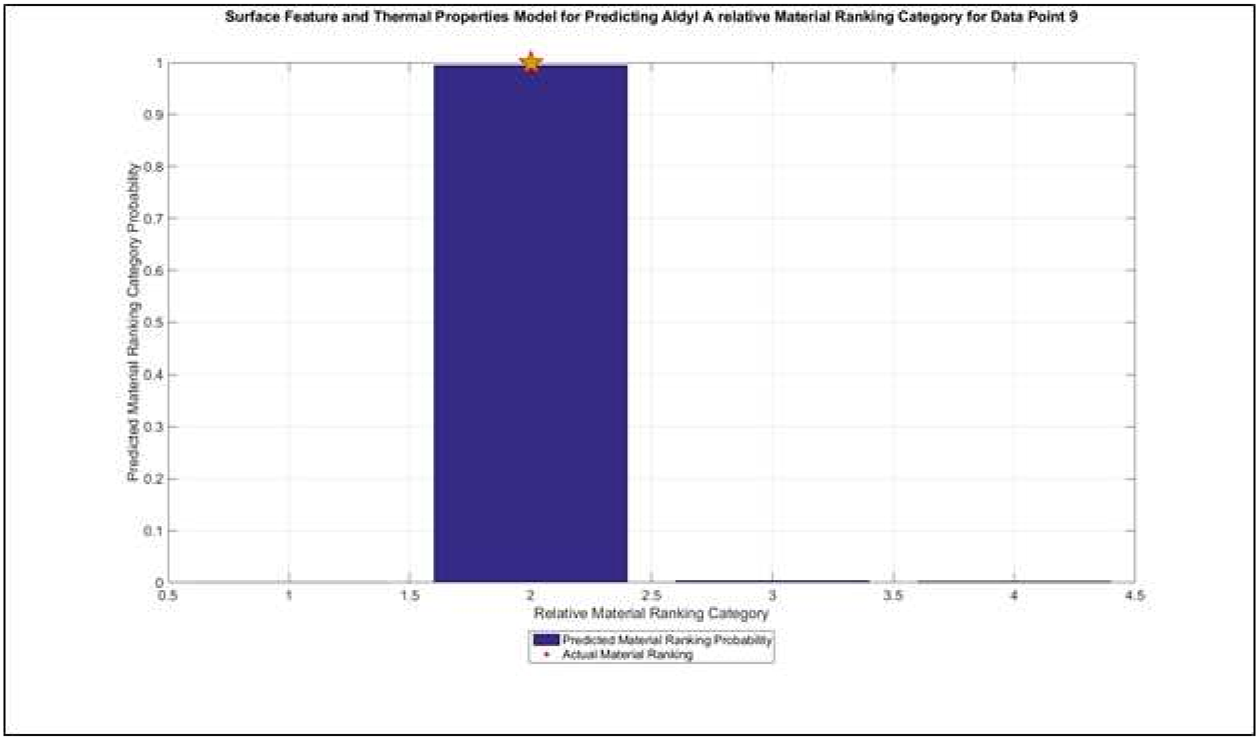


**Figure 1-26. Probabilistic prediction of RPM performance band for data point 9**

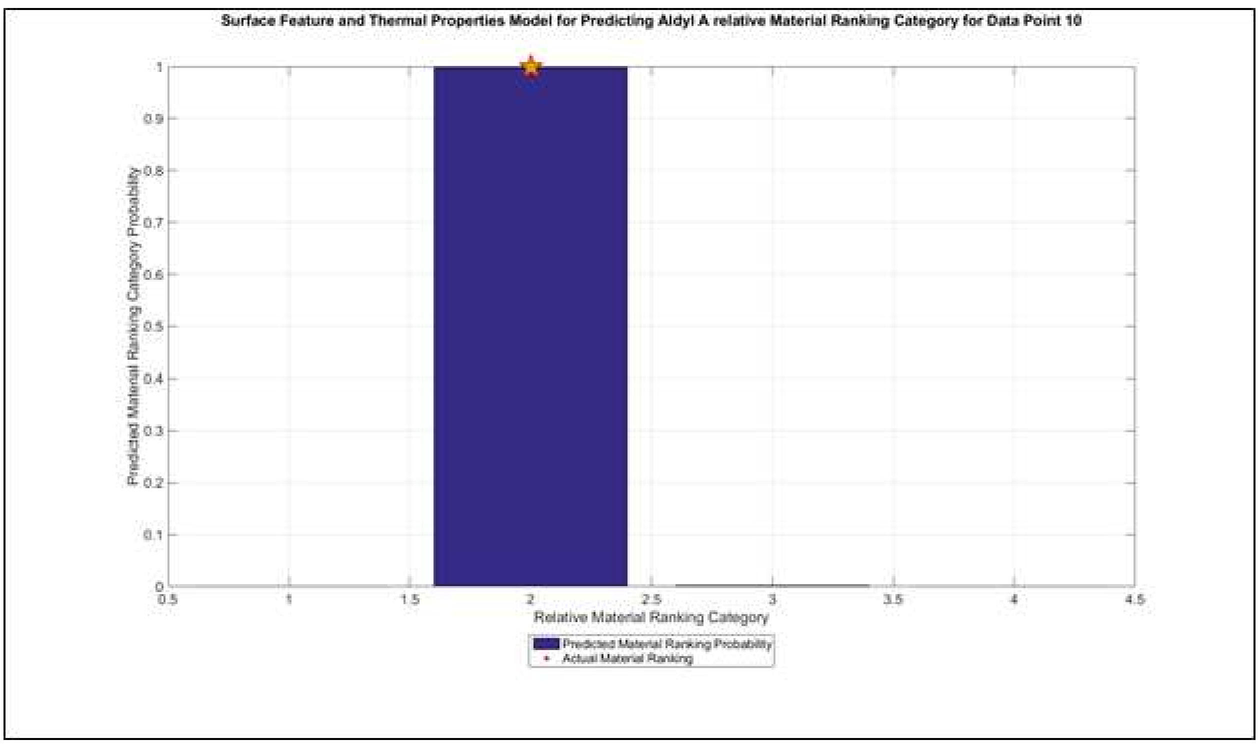


**Figure 1-27. Probabilistic prediction of RPM performance band for data point 10**

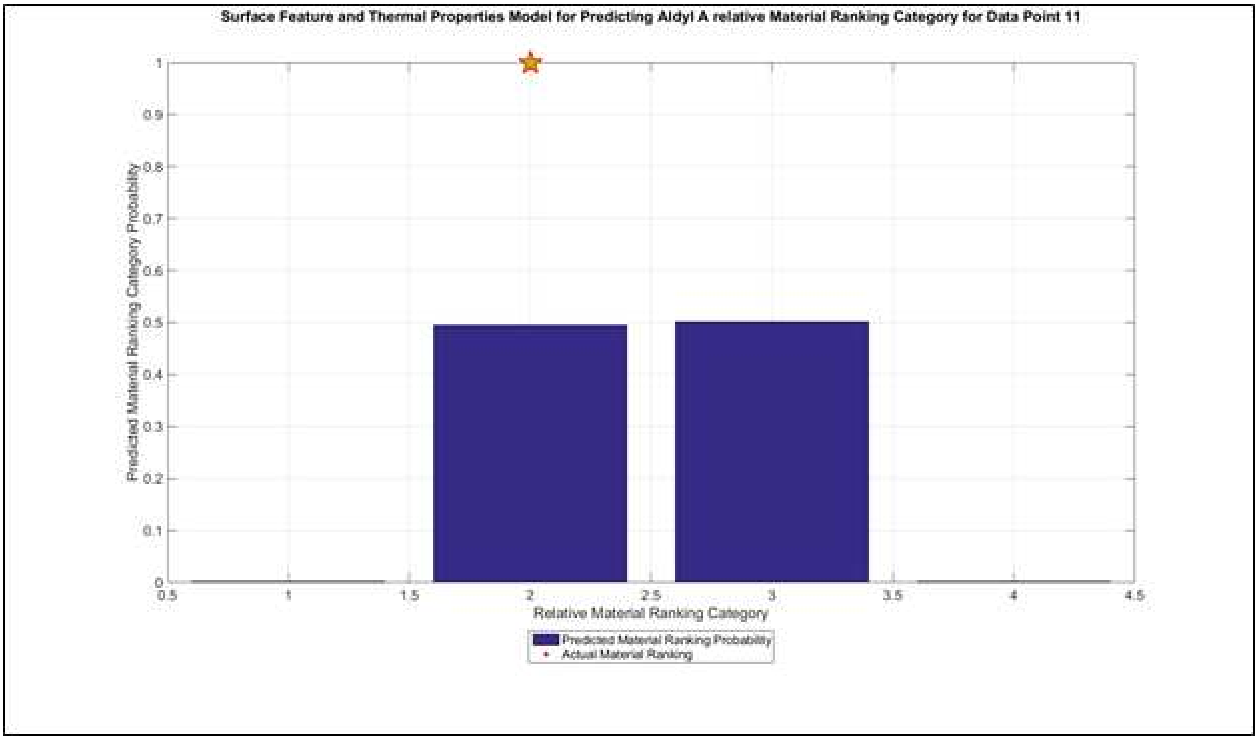


Figure 1-28. Probabilistic prediction of RPM performance band for data point 11

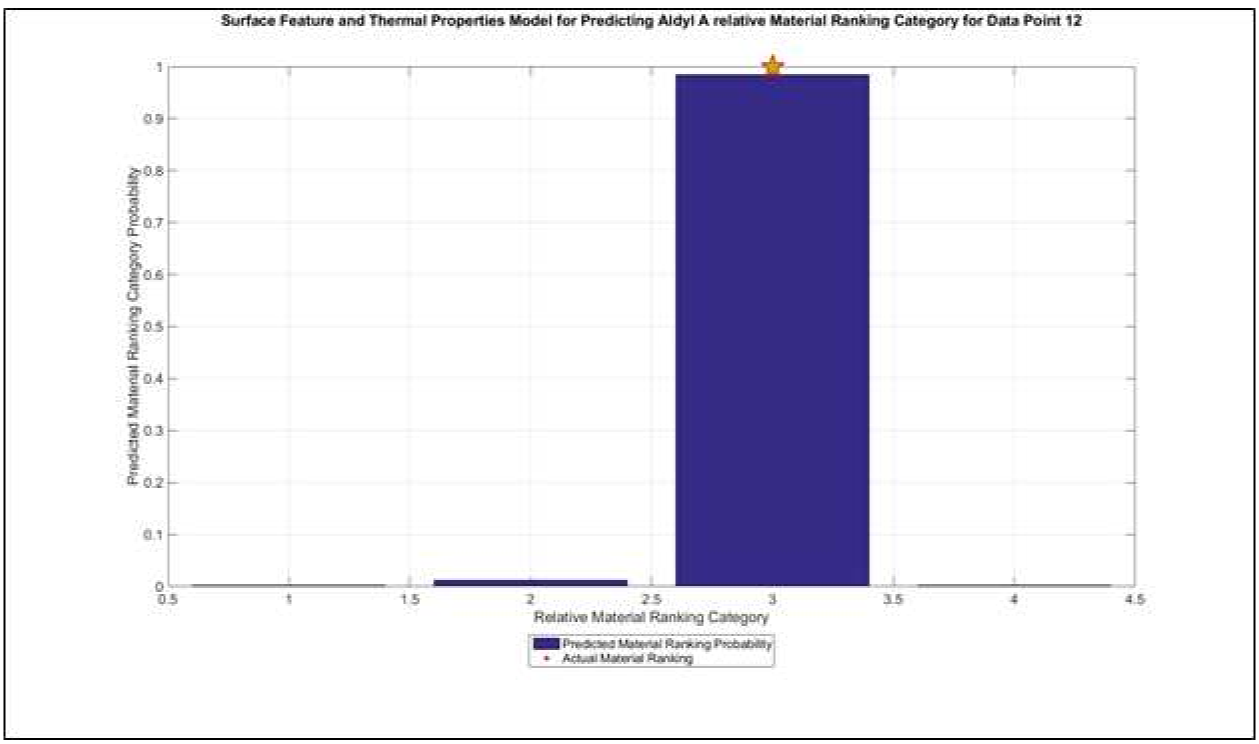


Figure 1-29. Probabilistic prediction of RPM performance band for data point 12

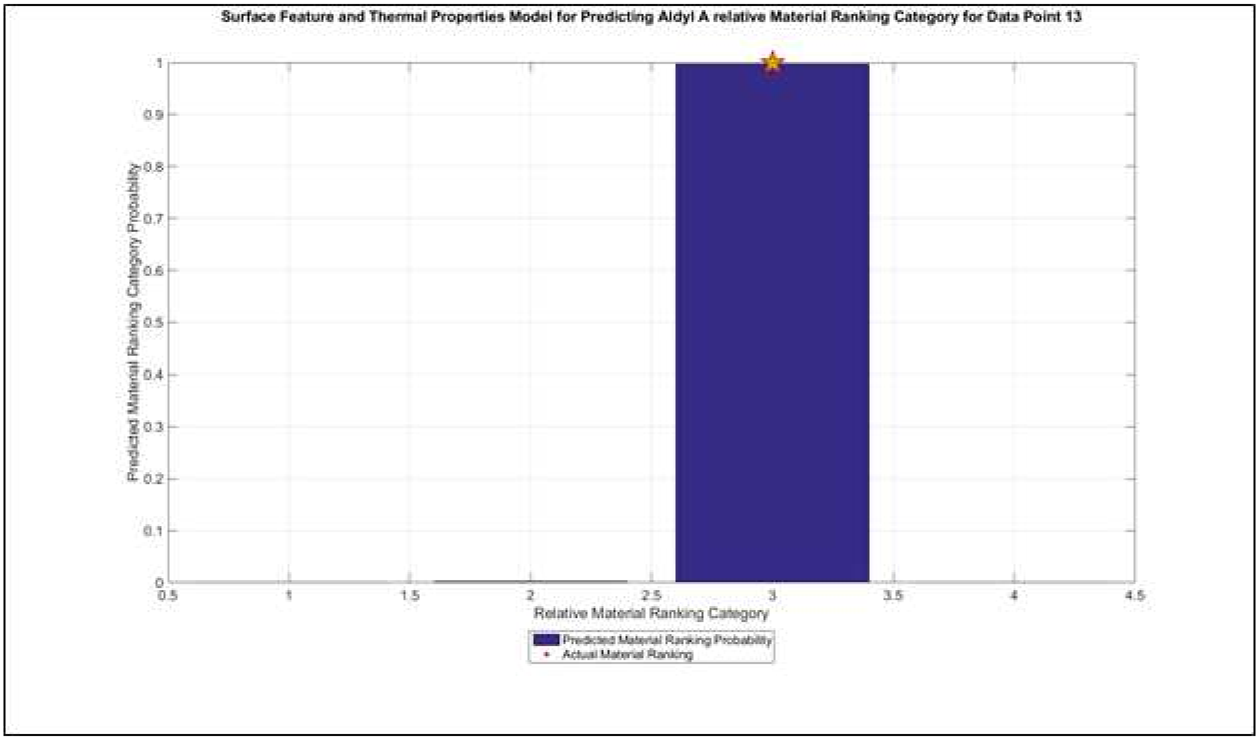


**Figure 1-30. Probabilistic prediction of RPM performance band for data point 13**

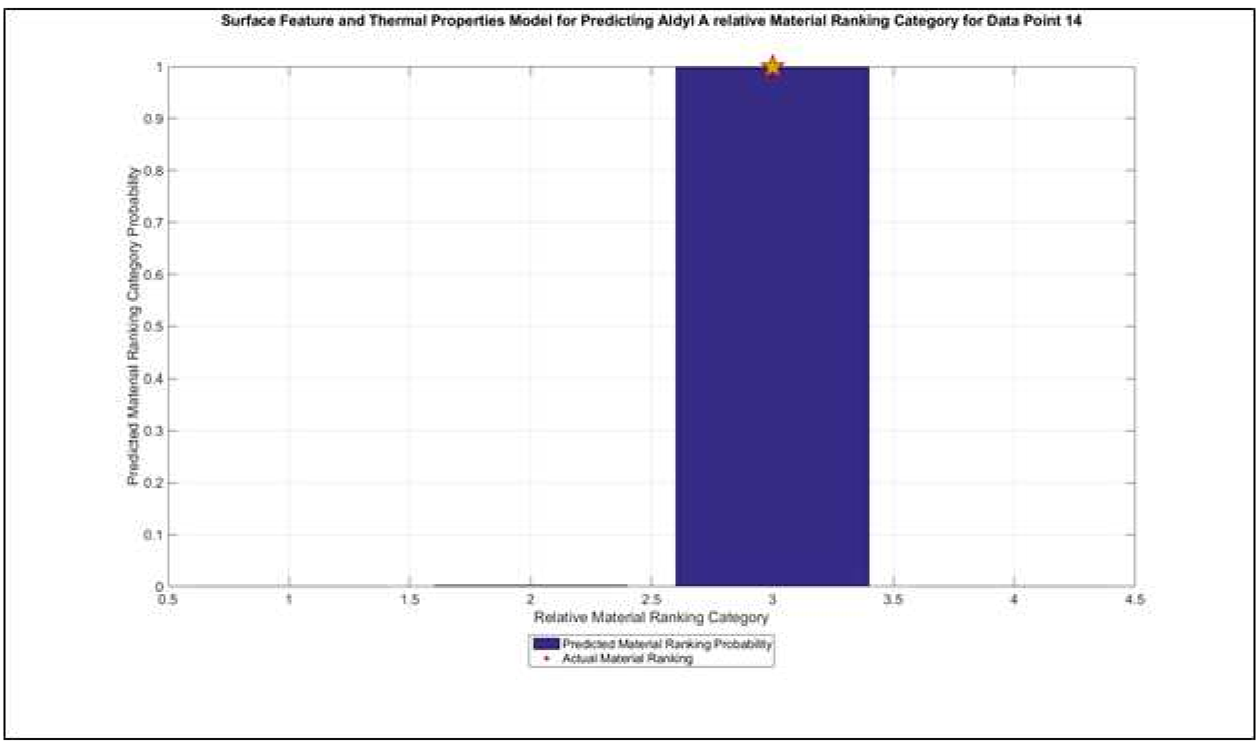


**Figure 1-31. Probabilistic prediction of RPM performance band for data point 14**

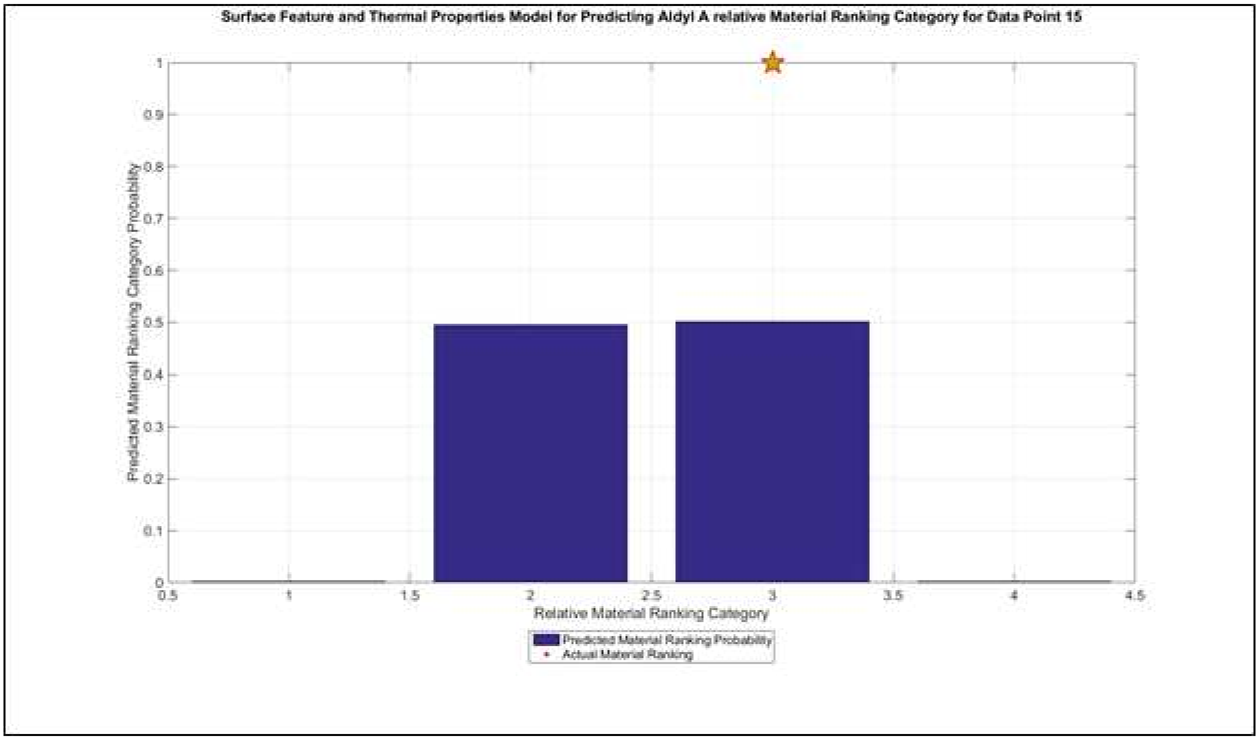


**Figure 1-32. Probabilistic prediction of RPM performance band for data point 15**

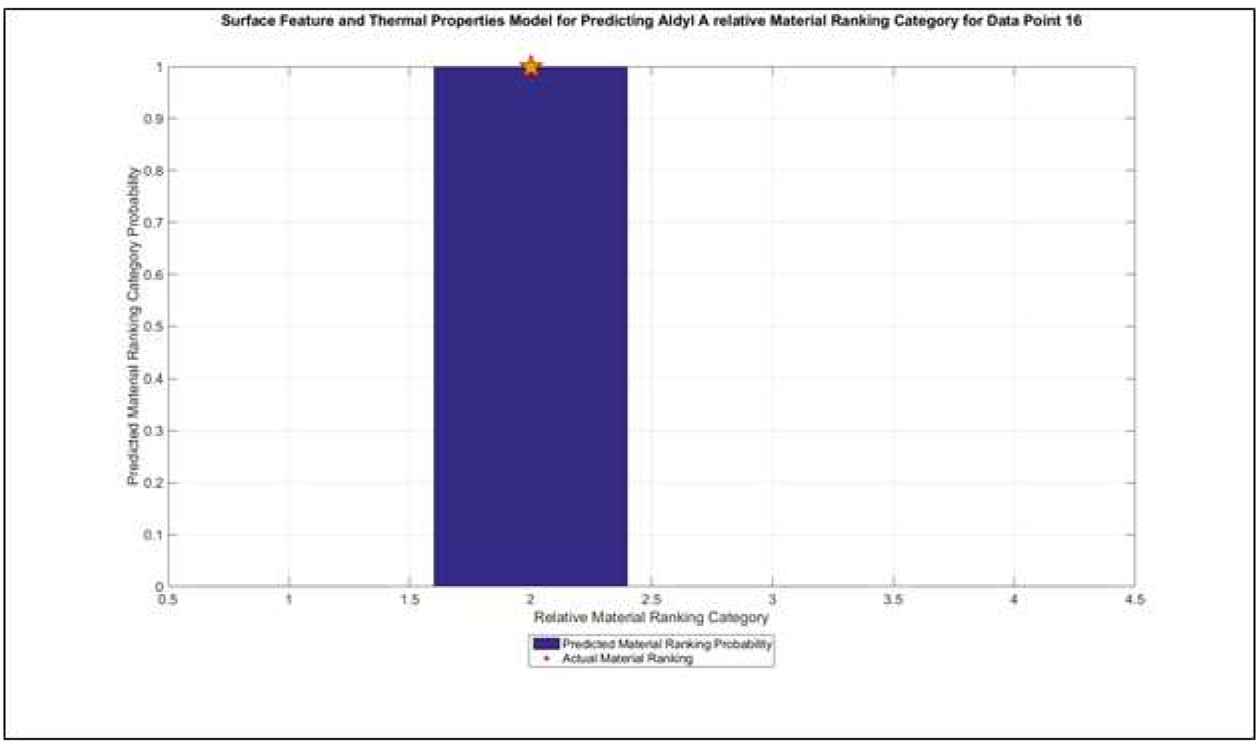


**Figure 1-33. Probabilistic prediction of RPM performance band for data point 16**

## Applying the Surface Correlation Model

The usefulness of the surface correlation model in reducing predictive uncertainty is illustrated in the example presented below. Three data points falling into three different RPM bands as ranked by the long-term testing result were selected. The points are highlighted in **Table 1-5**.

**Table 1-5 – Data for Evaluating Use of the Model (Table sorted by stress)**

| LIMS | Material Ranking | 23°C Stress [psi] | 23°C Time [y] | Location | Vintage |
|---|---|---|---|---|---|
| 152246-014 | 2 | 401 | 134 | Data Set 2 | 1970 |
| 152244-004 | 2 | 410 | 110 | Data Set 4 | 1971 |
| 152243-052 | 4 | 469 | 10 | Data Set 2 | 1970 |
| 152243-053 | 3 | 471 | 16 | Data Set 2 | 1970 |
| 152246-009 | 2 | 507 | 61 | Data Set 2 | 1970 |
| 152244-012 | 2 | 511 | 62 | Data Set 4 | 1971 |
| 152299-013 | 2 | 514 | 39 | Data Set 1 | 1969 |
| 152245-025 | 2 | 514 | 41 | Data Set 3 | 1974 |
| 152299-009 | 3 | 556 | 7 | Data Set 1 | 1969 |
| 152299-003 | 2 | 556 | 27 | Data Set 1 | 1969 |
| 152299-011 | 3 | 605 | 6 | Data Set 1 | 1969 |
| 152244-006 | 3 | 620 | 11 | Data Set 4 | 1971 |
| 152299-010 | 3 | 827 | 6 | Data Set 1 | 1969 |
| 152244-013 | 3 | 963 | 11 | Data Set 4 | 1971 |
| 152299-006 | 3 | 989 | 2 | Data Set 1 | 1969 |
| 152243-004 | 3 | 1164 | 2 | Data Set 2 | 1970 |

The material rankings for the three samples are 2, 3 and 4. The RPM data points for the samples with rankings 2 and 4 fall in the range of test stresses that correspond to pipe operating at 45 psig with stress risers in the 2.2 to 3.1 range (very common in installations).

The reference temperature used in this example is 23°C as it is the standard reference temperature used in many baseline calculations. The same method would be used for any chosen reference temperature (e.g., 15°C, or 10°C). The predicted material rankings are constant across all temperatures – they simply need to be applied to the correct reference temperature graph for the analysis at hand.

The region of the graph being discussed is highlighted with a shaded ellipse in **Figure 1-34.** The RPM test data indicate that the expected lifetimes in this stress range can be anywhere from about 3 years to 70 years.

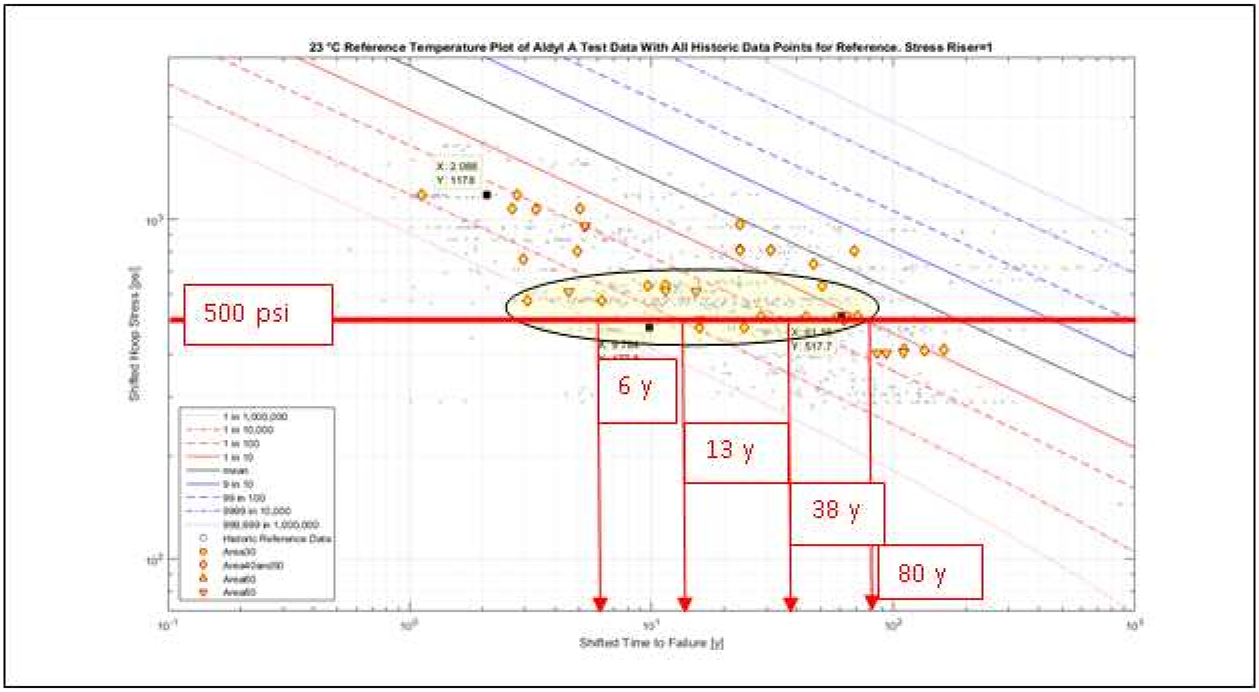


**Figure 1-34. Highlighting Correctly-Predicted Reference Categories for Three Example Points**

If we take advantage of the material ranking prediction the expected residual lifetime ranges are narrowed as follows for the case of a pipeline operating at 45 psig (225 psi hoop stress for DR 11 pipe) and at a stress riser of 2.2 (=500 psi/225 psi):

1. Material Ranking 2: 38-80 years, 42-year range.
2. Material Ranking 3: 13-38 years, 25-year range.
3. Material Ranking 4: 6-13 years, 7-year range.

The expected lifetime prediction is now more precise and gets more specific as the relative material ranking moves towards a higher likelihood of failure. This is due to the power law relationship between stress and time to failure – when plotted on a log-log set of axes we get straight lines, but each decade is an order of magnitude shorter than the decade to the right along the x-axis and the gradations are not linear.

## Surface Correlation Conclusions

1. The revised version of the surface-feature model is a significant improvement over the previous version.
2. The surface feature analysis needs to be expanded to the full RPM data set in future work as well as the retained samples from the OTD 2.8.d (20649) dataset. The combined data sets would give approximately 200 points that can be properly divided into training, check and validation data sets for a "production" model that can be reliably used in system integrity models.

## *Bi-directional Shift Factors*

In the examples above we have presented entire data sets that were generated at multiple temperatures in accordance with the RPM, at single reference temperatures. This is achieved by applying bi-directional shifting to each data point [8-11]. We will now discuss how to develop these bi-directional shift factors, how they relate to the RPM, and creep in polyethylene in general.

### The molecular Structure of Polyethylene

We noted above that the model that Coleman [5] selected was that of rate process theory, where the number of jumps away from their nearest neighbors that elements of the polymer chain take, is the process whose rate we are measuring. We will now explore this concept in a little more detail with respect to polyethylene molecular structure. **Figure 1-35** shows the basic structure of a polyethylene molecules that are an approximately linear chain of ethylene monomers.

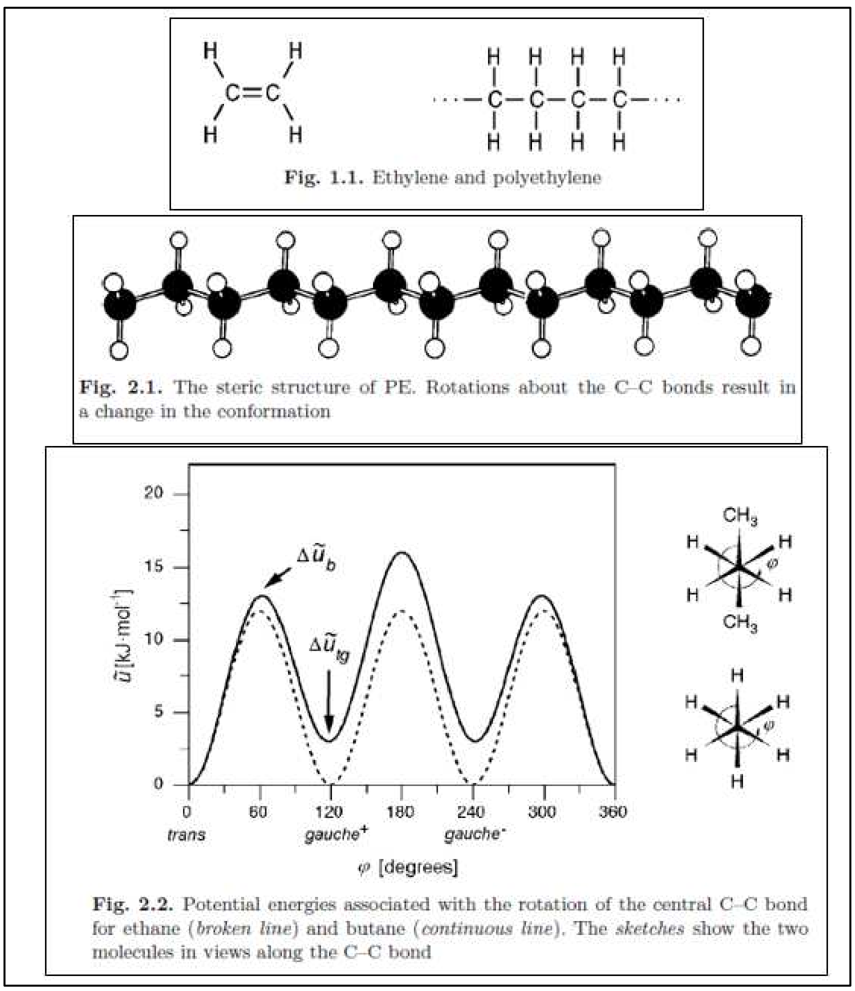


**Fig. 1.1.** Ethylene and polyethylene

**Fig. 2.1.** The steric structure of PE. Rotations about the C–C bonds result in a change in the conformation

**Fig. 2.2.** Potential energies associated with the rotation of the central C–C bond for ethane (*broken line*) and butane (*continuous line*). The *sketches* show the two molecules in views along the C–C bond

**Figure 1-35. Polyethylene Structure and Potential Energies for Rotation of C-C Bond [12]**

It is possible for the C-C elements to rotate about their axis. The lower sub-figure in **Figure 1-35** shows the potential energy associated with each of these rotations. These rotations are one of the basic ways in which we can get "local" reorganization of an individual polyethylene molecule. In the solid-state there are many polyethylene chains in close proximity to one another and many more modes for reorganizing the structure come into effect. **Figure 1-36** and **Figure 1-37** show the unit cell structure and a possible mechanism for long chains to order themselves into the semi-crystalline structure typical of medium and high-density polyethylene used in gas distribution piping systems.

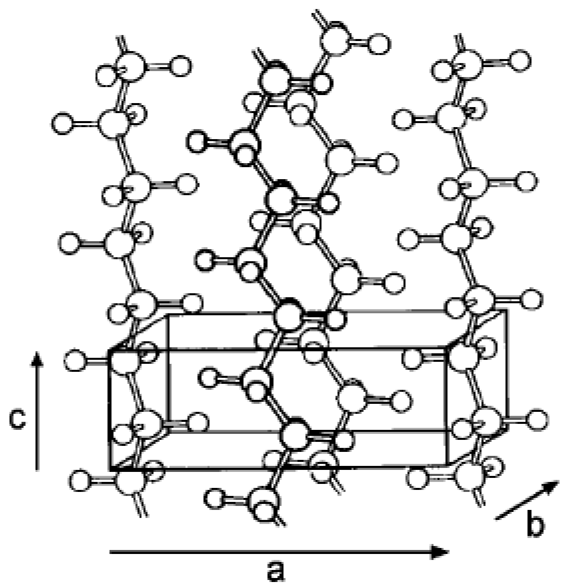


**Fig. 5.12.** Unit cell of PE crystallites: Orthorhombic symmetry, $a = 7.42$ Å, $b = 4.95$ Å, $c = 2.55$ Å. Each cell is occupied by two $C_2H_4$ groups. Structure determination by Bunn [39]

**Figure 1-36. Unit Cell Structure of PE Crystallites** [12]

**Fig. 5.7** The 'solidification model' of the crystallisation process, showing how a chain can be incorporated into a lamellar structure without significant change of overall shape. (Reproduced by permission of IUPAC.)

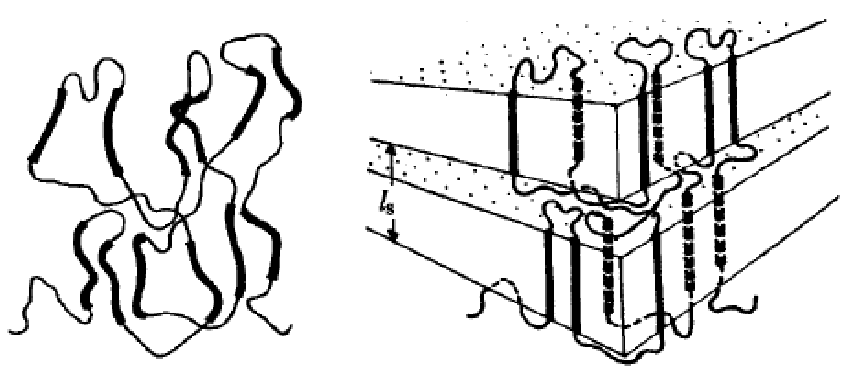


**Figure 1-37. Solidification model of Crystallization Process** [13]

There are several methods available to us for probing the mechanical and electromagnetic responses of polyethylene under cyclic loading. Nuclear Magnetic Resonance (NMR) and Dynamic Thermo-Mechanical Analysis (DTMA) techniques are very effective in measuring the activation energies for various relaxation phenomena in the solid state. **Figure 1-38** shows some results derived from these methods for polyethylene.

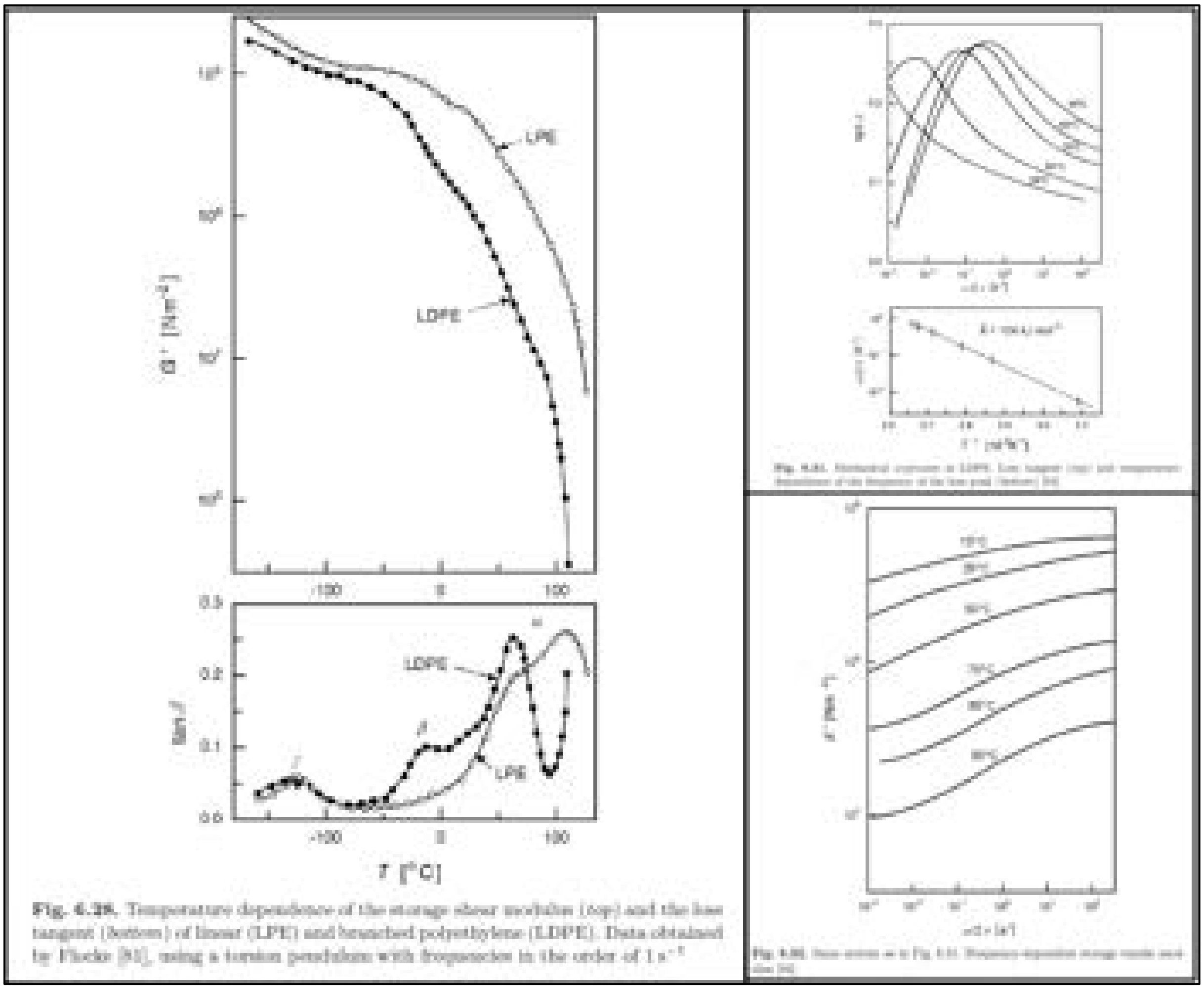


**Figure 1-38. Left-Relaxation Mechanisms in PE, Upper Right – Mechanical α-Process Loss Tangent as a Function of Frequency, Lower Right - Mechanical α-Process Storage Modulus as a Function of Temperature [12]**

The relaxation of interest to us is the α-process. This is the molecular movement process that Coleman [5] was alluding to. Strobl [12] provides an excellent description of this process and the energies (measured by NMR and DTMA) associated with it in the insert below.

The largest changes in the mechanical properties of polyethylenes with moderate to high crystallinity are caused by the α-process. Figures 6.31 and 6.32 present results of frequency-dependent measurements of the tensile modulus of such a sample, conducted at different temperatures between 26°C and 95°C. As can be seen, the loss tangent shows a systematic shift to higher frequencies. The temperature dependence of the loss maximum is indicative of an activated process with an activation energy A = 104 kJ $mol^{-1}$. Figure 6.32 shows that the storage tensile modulus decays with both decreasing frequencies and rising temperatures, whereby the latter effect is caused by the continuous melting.
What is the origin of the α-process? Different observations must be included in the considerations. First, remember the results of the NMR experiment presented in Sect. 5.4.2. ***Here, a longitudinal chain transport through the crystallites was clearly indicated. The chain motion is apparently accomplished by a 180°-twist defect, which is created at a crystal surface and then moves through the crystallite to the other side. As a result, all monomers of a crystalline sequence are rotated by 180° and shifted over the length of one $CH_2$-unit. This screw-motion alone cannot set up the α-process, since it is mechanically inactive. As the crystals remain unchanged, both internally and in their external shape, there is no coupling to a stress field. Furthermore, the high relaxation strength of the α-process suggests a location in the weak amorphous parts of the structure rather than in the crystallites. How can the different observations be cast in one common picture? The answer is that the α-process in polyethylene has a composite nature. The mechanical relaxation indeed originates from an additional shearing of the amorphous regions. However, the prerequisite for this shearing is a chain movement through the crystallites. If such a motion is thermally activated, the pinning of the amorphous sequences onto the crystallite surfaces is no longer permanent. This allows a reorganization of the amorphous regions, which gives rise to a further stress decay. Hence, in the α-process, two relaxation processes, one in the crystallites and the other one located in the amorphous zones, are coupled. As indicated by the broadness of the loss curves, the α-process is based on a larger group of relaxatory modes. Since the temperature variation leaves the shape of the loss curves essentially unchanged, we conclude that all modes employ the same elementary process, to be identified with the step-like longitudinal shifts of the crystalline sequences. NMR experiments and dynamic mechanical measurements indeed yield nearly identical activation energies – A = 105 $kJmol^{-1}$ in Fig. 5.53 and A = 104 $kJmol^{-1}$ in Fig. 6.31. Of interest is a comparison of the rate of elementary steps with the mechanical relaxation rate. The difference amounts to four orders of magnitude, telling us that the reorganization of the chains in the amorphous regions is a complex procedure requiring a huge number of elementary steps.***

*Strobl, G.R., The Physics of Polymers: Concepts for Understanding Their Structures and Behavior. 2013: Springer Berlin Heidelberg.* ***pp280-283 Emphasis added***

Bower [13] has a concise explanation of the site-model theory and a derivation of the rate process formulation for relaxation times described by the Arrhenius equation[1]:

$$k = A\, e^{\frac{-E_a}{R\,T}} \qquad \textbf{Equation 1-3}$$

| | |
|---|---|
| k - | The rate constant |
| T - | The absolute temperature (in kelvins) |
| A - | Pre-exponential factor, a constant for each chemical reaction that defines the rate due to frequency of collisions in the correct orientation |
| $E_a$ - | Activation energy for the reaction (in the same units as R T) |
| R - | Universal gas constant |

In the present context, we are not discussing chemical reactions, but rather the coherent movement of groups of molecular units in a semi-crystalline polymer structure like polyethylene. Site-model theory, in its simplest form, describes two sites, each representing a particular local conformational state of the molecule, separated by an energy barrier as shown in **Figure 1-39**.

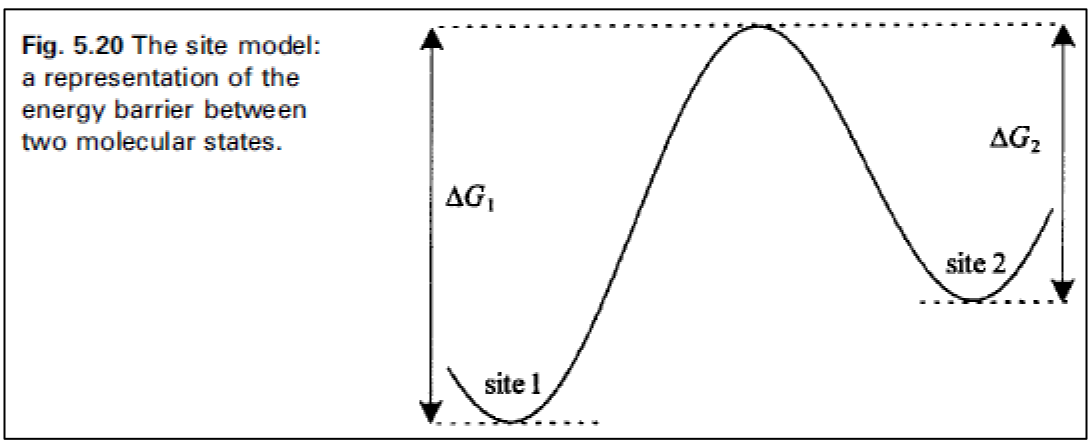


**Figure 1-39. Site-model as described by Bower [13] pp 148**

Bower discusses the number of molecules in each conformational state and the probabilities that they will transition to the alternate state in a time interval. The endpoint of the derivation is that when a semi-crystalline polymer is subjected to a fixed displacement, the

1 Wikipedia contributors, "Arrhenius equation," *Wikipedia, The Free Encyclopedia,* https://en.wikipedia.org/w/index.php?title=Arrhenius_equation&oldid=799107578 (accessed September 15, 2017
The Arrhenius equation is a formula for the temperature dependence of reaction rates

strain will relax to its equilibrium value with a time constant, or relaxation time, "τ"that is temperature dependent and is equal to the average time between jumps over the barrier. The time constant equation is:

$$\tau = \mathrm{A}\exp[\frac{\Delta E}{\mathrm{R\,T}}] \qquad \textbf{Equation 1-4}$$

ΔE is the activation energy, which is equal to the enthalpy difference between the two states.

Bower presents an example where he compares the relaxation times at two different temperatures and develops the following equation:

$$\frac{\tau}{\tau_0} = \exp[\frac{\Delta E}{\mathrm{R}}(\frac{1}{T} - \frac{1}{T_0})] \qquad \textbf{Equation 1-5}$$

**Equation 1-5** is extremely useful as it defines the time-temperature equivalence for a material process that is adequately described by an Arrhenius relationship. The ratio $\tau/\tau_0$ is often called a shift factor as it defines a linear multiplier on a known relaxation time at a reference temperature to arrive at a relaxation time at a different temperature:

$$\tau = \tau_0 * \exp[\frac{\Delta E}{\mathrm{R}}(\frac{1}{T} - \frac{1}{T_0})] = \tau_0 * a_T \qquad \textbf{Equation 1-6}$$

$a_T$ – Shift factor for time/temperature equivalence

Popelar [10, 11, 14] arrived at horizontal and vertical shift factors for polyethylene empirically and published "universal" shift factors that adequately described the time/temperature equivalence of several commercially available polyethylene materials used in natural gas distribution systems at the time he published his work. These shift factors became known in the industry as the Popelar Shift Factors and their application is ubiquitous. The methodology[2] used in the United States for determining the strength ratings of polyethylene resins uses the Popelar shift factors in the validation of regression curves developed for specific application temperatures.
Mavridis [9] addresses the temperature dependence of polyolefin melt rheology and describes a DTMA methodology for extracting the activation energies needed to calculate temperature dependent shift factors. He discusses thermorheological simplicity of melts, where all

2 http://plasticpipe.org/pdf/tr-3-2017a.pdf
TR-3/2017a HDB/HDS/PDB/ SDB/MRS/CRS Policies: Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Hydrostatic Design Stresses (HDS), Pressure Design Basis (PDB), Strength Design Basis (SDB), Minimum Required Strength (MRS) Ratings, and Categorized Required Strength (CRS) for Thermoplastic Piping Materials or Pipe, **Section F.4.1.2**

relaxation processes have the same temperature dependency. He points out that by independently evaluating the temperature dependence of relaxation times and modulus we can derive coherent vertical and horizontal shift factors that fully describe the relaxation behavior of polyolefins as a function of temperature. The method utilized by Mavridis is simply fitting of DTMA data to **Equation 1-5** to extract ΔE for the horizontal and vertical shift factors.

Lever [8] applied the DTMA method described by Mavridis to multiple pipe materials and showed that there is variation in the shift factors amongst materials as well as batch to batch variation. At this point it needs to pointed out that there is a difference in the Mavridis and Popelar approaches in that Popelar [11] used stress relaxation data to fit a non-linear viscoelastic model that captures the essence of the materials relaxation behavior. This viscoelastic model was used to develop horizontal and vertical shift factors that produced a coherent master relaxation curve for a wide array of polyethylene materials in use at that time. The Popelar shift factors are presented in the form:

$$\text{Shift Factor} = \exp(\text{Constant} * (\mathrm{T} - \mathrm{T_{ref}}) \qquad \textbf{Equation 1-7}$$

T – Test Temperature [°C]
$T_{ref}$ – Reference Temperature [°C]

By contrast the Mavridis methodology fits an Arrhenius form yielding:

$$\text{Shift Factor} = \exp(\frac{\text{Activation Energy}}{R} * (\frac{1}{T} - \frac{1}{\mathrm{T_{ref}}}) \qquad \textbf{Equation 1-8}$$

R – Boltzmann's Constant
T - Test Temperature [K]
$T_{ref}$ – Reference Temperature [K]

**Equation 1-7** is dependent on the temperature differential between the test temperature and the reference temperature and is very nearly linear on a log/linear plot. **Equation 1-8** is dependent on the difference between the inverse of the test temperature and the inverse of the reference temperature in degrees Kelvin. This relationship has noticeable curvature on a log/linear plot **Figure 1-40**.

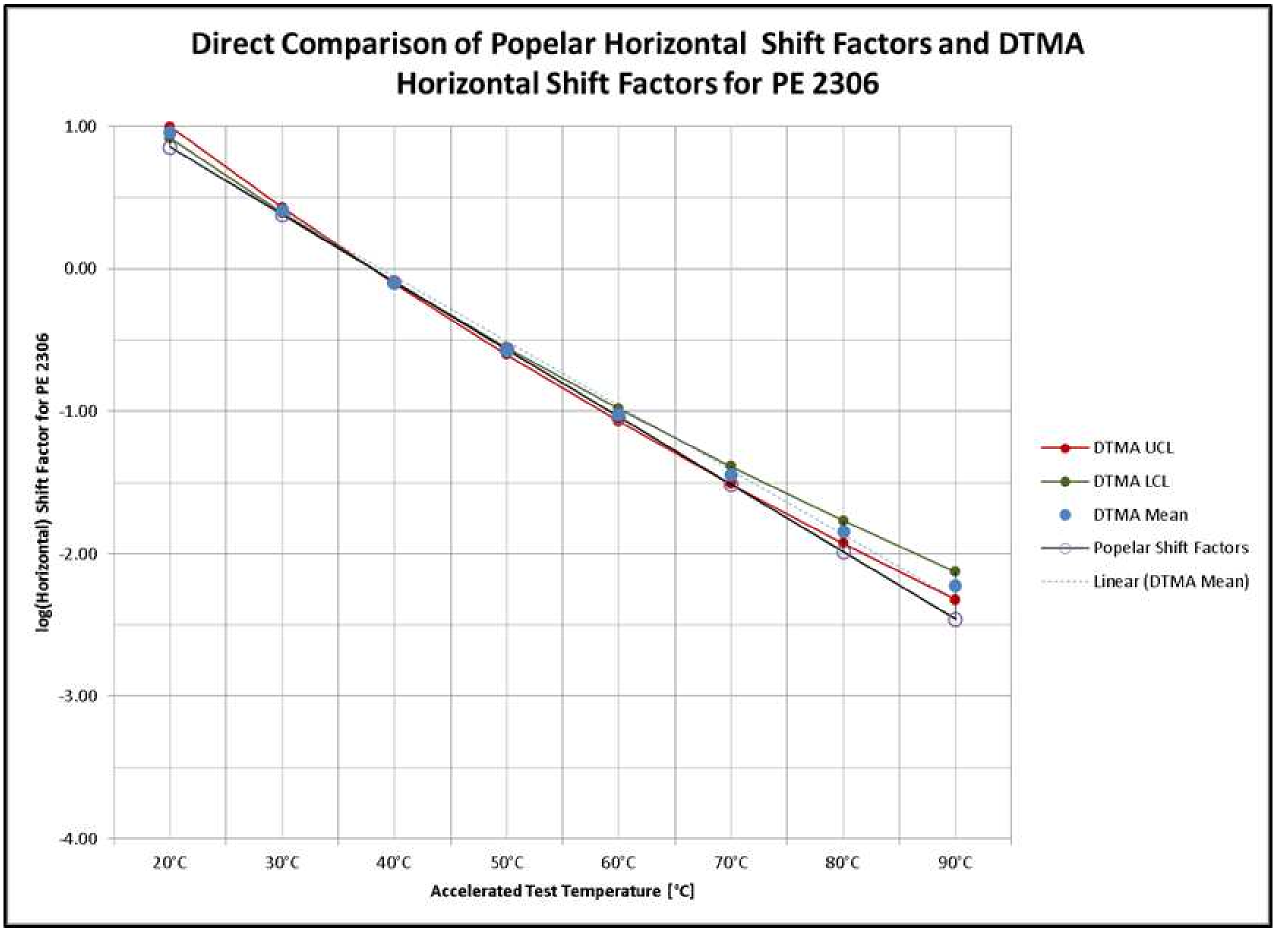


**Figure 1-40. Comparison of DTMA and Popelar Horizontal Shift Factors in Form Presented in [11]**

The results of the DTMA based activation energy determinations are presented in **Figure 1-41** to **Figure 1-44** and **Table 1-6**. The activation energy for the α relaxation process in polyethylene gas distribution pipe compares favorably to the value of 104 kJ/mol Strobl [12] lists for Low Density Polyethylene (LDPE).

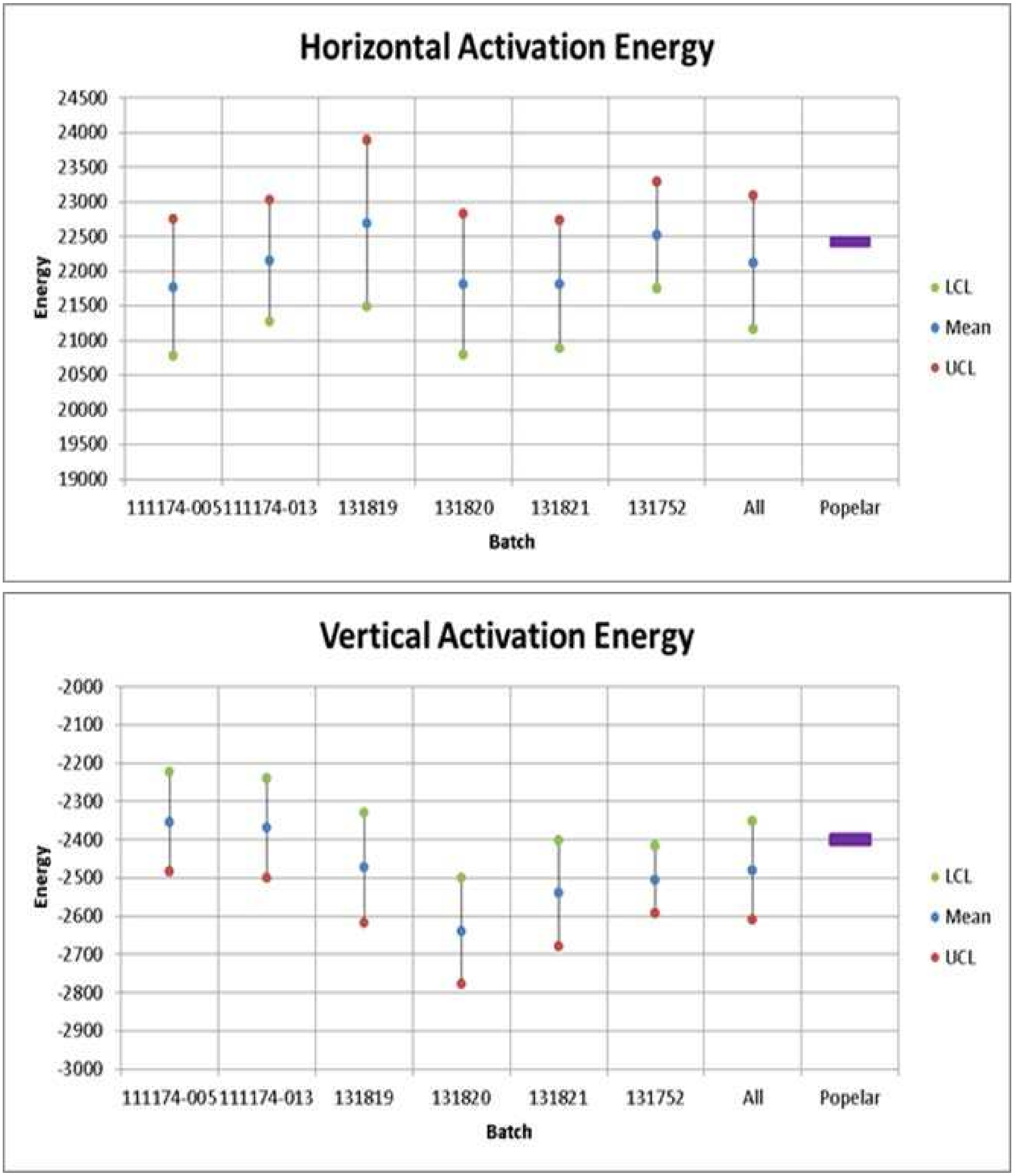


**Figure 1-41. Horizontal and Vertical Activation Energies of Aldyl A (PE2306) Pipe Batches Measured by DTMA. Energy in cal/mol**

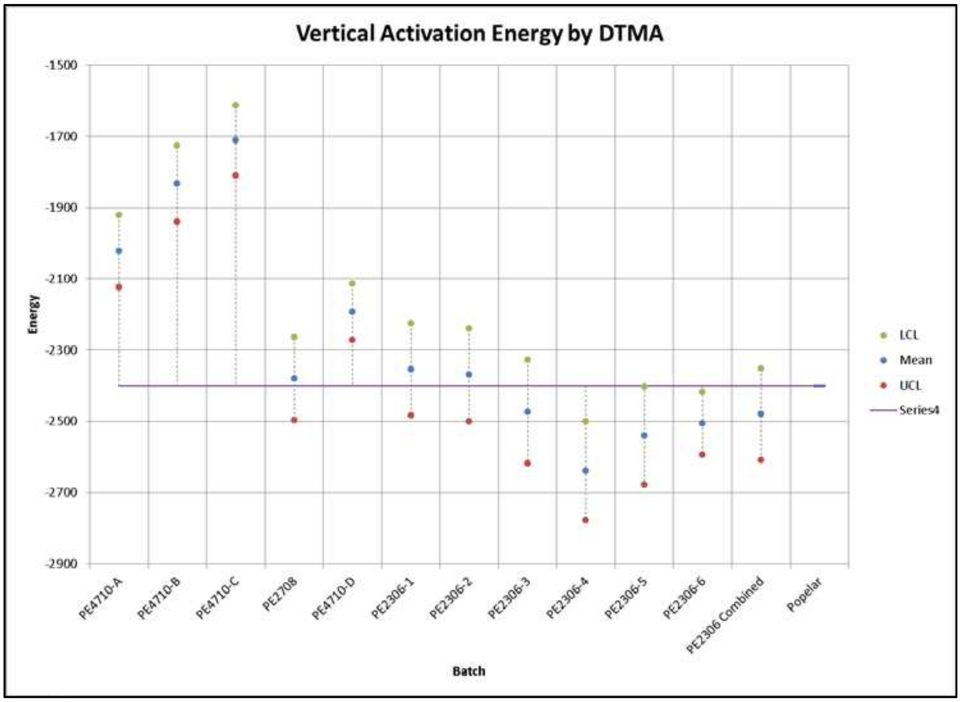


Figure 1-42.Horizontal Activation Energies for Modern and Aldyl A Materials Relative to Equivalent Popelar Activation Energy. Energy in cal/mol

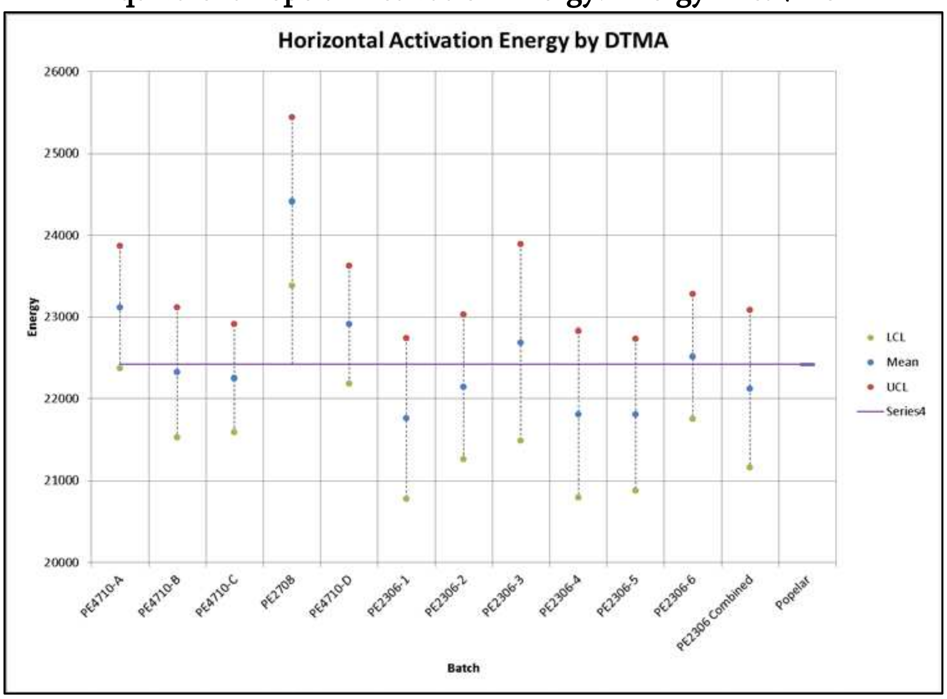


Figure 1-43Vertical Activation Energies for Modern and Aldyl A Materials Relative to Equivalent Popelar Activation Energy. Energy in cal/mol

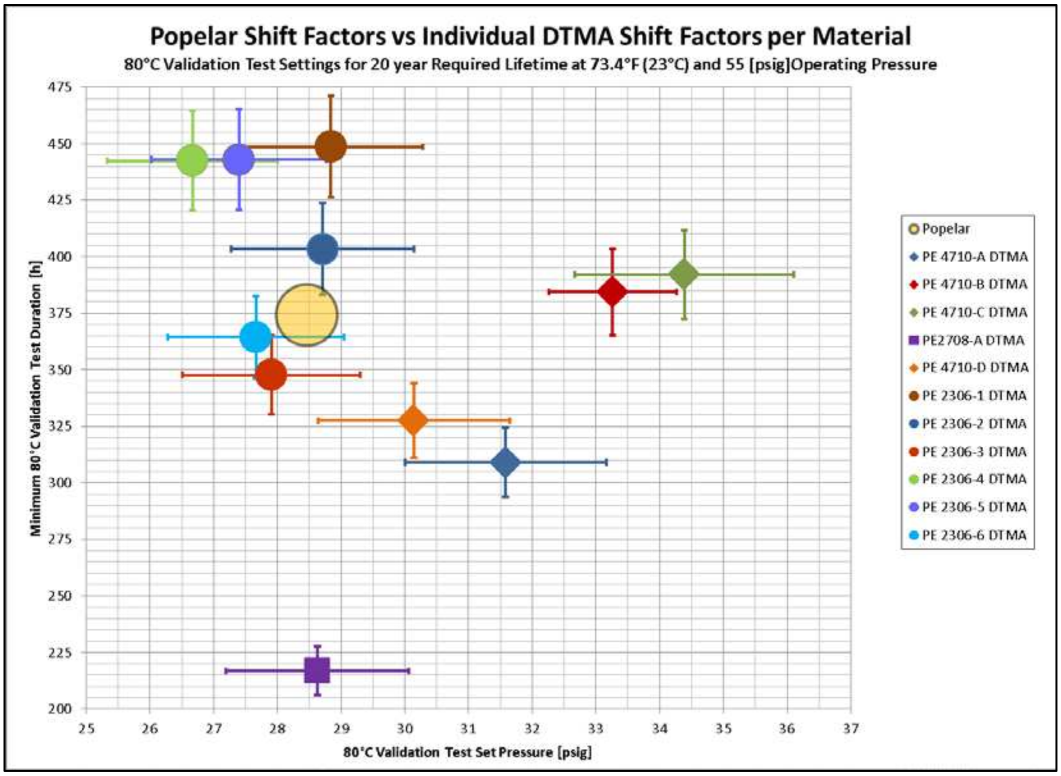


Figure 1-44. 80°C Validation Test time/pressure Combinations for Several Materials to Validate a 20-year Minimum Lifetime at 23°C and an Operating Pressure of 55 psig

Table 1-6. Activation Energies for α relaxation process in polyethylene gas distribution pipe as measured by DTMA

| Aldyl A Batch | Total Activation Energy [ kJ/mol] | | |
|---|---|---|---|
| | UCL | Mean | LCL |
| 111174-005 | 96 | 92 | 87 |
| 111174-013 | 97 | 93 | 89 |
| 131819 | 101 | 95 | 90 |
| 131820 | 96 | 92 | 88 |
| 131821 | 96 | 92 | 88 |
| 131752 | 98 | 95 | 92 |
| **Modern Material** | **Total Activation Energy [kJ/mol]** | | |
| | **UCL** | **Mean** | **LCL** |
| unimodal MDPE A | 114 | 105 | 96 |
| bimodal HDPE C | 102 | 98 | 95 |
| unimodal MDPE B | 100 | 94 | 89 |
| bimodal MDPE D | 104 | 98 | 93 |

Using material specific bi-directional shift factors developed from DTMA measurements allows us to shift data points from tests performed at multiple temperatures to any given reference temperature as shown in **Figure 1-45**. The points in the figure are actual data and the lines reflect the Lower Prediction Limit, Mean and Upper Prediction Limit of the RPM model for the data set. We can see that RPM model and bi-directional shift factors measured for the material tested are coherent. The combination of the two methods is a very powerful data analysis tool.

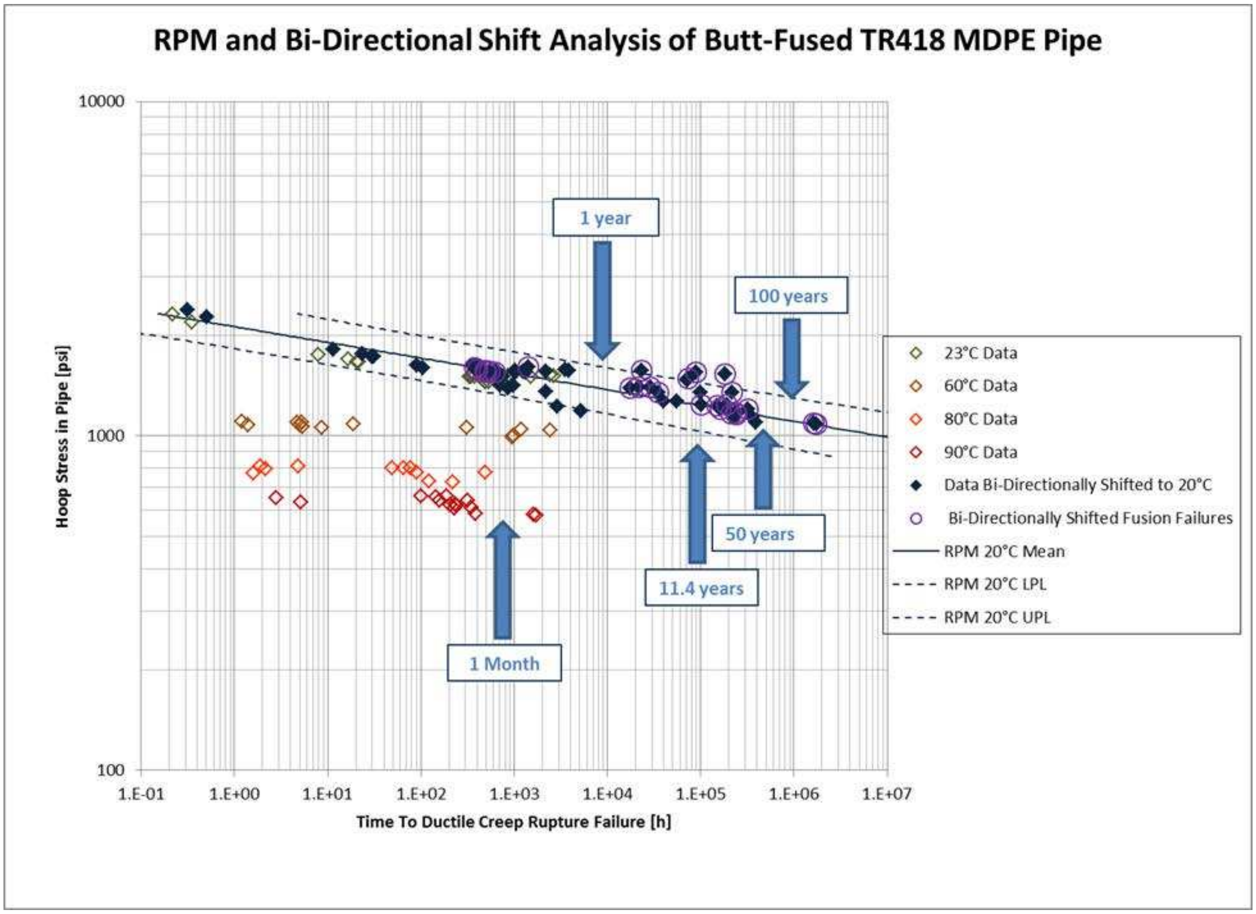


**Figure 1-45. Plot of RPM analysis results**[3]

The bi-directional shift factors allow us to plot master curves at any given reference temperature from data generate at multiple temperatures. The higher the test temperature, the more we accelerate the test.

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3 Figure originally presented in final report for DOT PHMSA contract DTPH56-14-H-00001 project 554 https://primis.phmsa.dot.gov/matrix/PrjHome.rdm?prj=554&s=6D8E1B6104BE4DCEB642A4ACAF14CA84&c=1

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11. Popelar, C., C. Popelar, and V. Kenner, *Viscoelastic material characterization and modeling for polyethylene.* Polymer Engineering & Science, 1990. **30**(10): p. 577-586.
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## 2. Stress Intensification Factors (SIF) for Aldyl-A Piping Systems

### *Brief Literature Review for Current Context*

In **1** we have already seen that at its core, the Rate Process Method is a damage propagation model. Coleman [5] defines a variable, "γ", which he defines as a convenient measure of how much the applied stress has distorted the structure of the fiber at a time t. He is talking about the creep process that is governed by the α-relaxation of the polymer being evaluated. Bragaw [4], in addressing the burst life of polyethylene pipe and fittings, moves on to discuss the rupture process by defining an Arrhenius relationship between the fracture rate, the applied stress and the activation energy of the α-relaxation process in polyethylene. Neither Coleman, nor Bragaw, directly mention the α-relaxation process. However, from the literature [9, 11-13], and the coherence between the shift factors developed from the DTMA measurement of the α-relaxation and the RPM test results that are shifted to a reference temperature, it is clear that the α-relaxation process provides a good explanation of pipe rupture. Bragaw mentions that the Arrhenius equation only identifies a single activation energy, while there must clearly be many activated processes in a typical pipe rupturing process. Strobl [12], Strobl insert, covers this point adequately in noting that the activation energy for the α-relaxation process rolls up a large number of elementary processes. We now need to develop a better understanding of stress as a factor that drives variance in the calculated lifetime expectancy.

### *Failure Modes of Polyethylene*

It is customary to identify three failure modes for polyethylene pipe as illustrated in **Figure 2-1.** In this project, we are interested in Region A and Region B as defined in the figure. The two failure regions are governed by the same α-relaxation process, only the degree of constraint at the damage tip is different in the two regions. The degree of constraint is discussed in detail in **8** below. For now, we can simply note that the magnitude of the parameters C2 and C4 in the RPM models shown in **Table 2-1** define the slope of each curve and reflect the degree of constraint at the damage tip. A cursory inspection of the equations will show that stress has a larger impact in Region A than in Region B. The shallowness of the slope in Region A reflects this. In Region A, the entire pipe wall is subject to the driving stress, whereas in Region B, a small volume at the damage tip is subject to the driving stress (the stress is highly constrained), and only this volume undergoes critical creep phenomena that are governed by the α-relaxation process (damage propagation through the wall – SCG).

**Table 2-1. Aldyl A RPM models for Region A and Region B**

| Parameters | C1 | C2 | C4 |
|---|---|---|---|
| Region B, Quasi-Brittle Failure | -17.6172 | 9485.337 | -898.536 |
| Region A, Ductile Failure | -42.5629 | 37387.00 | -7515.74 |

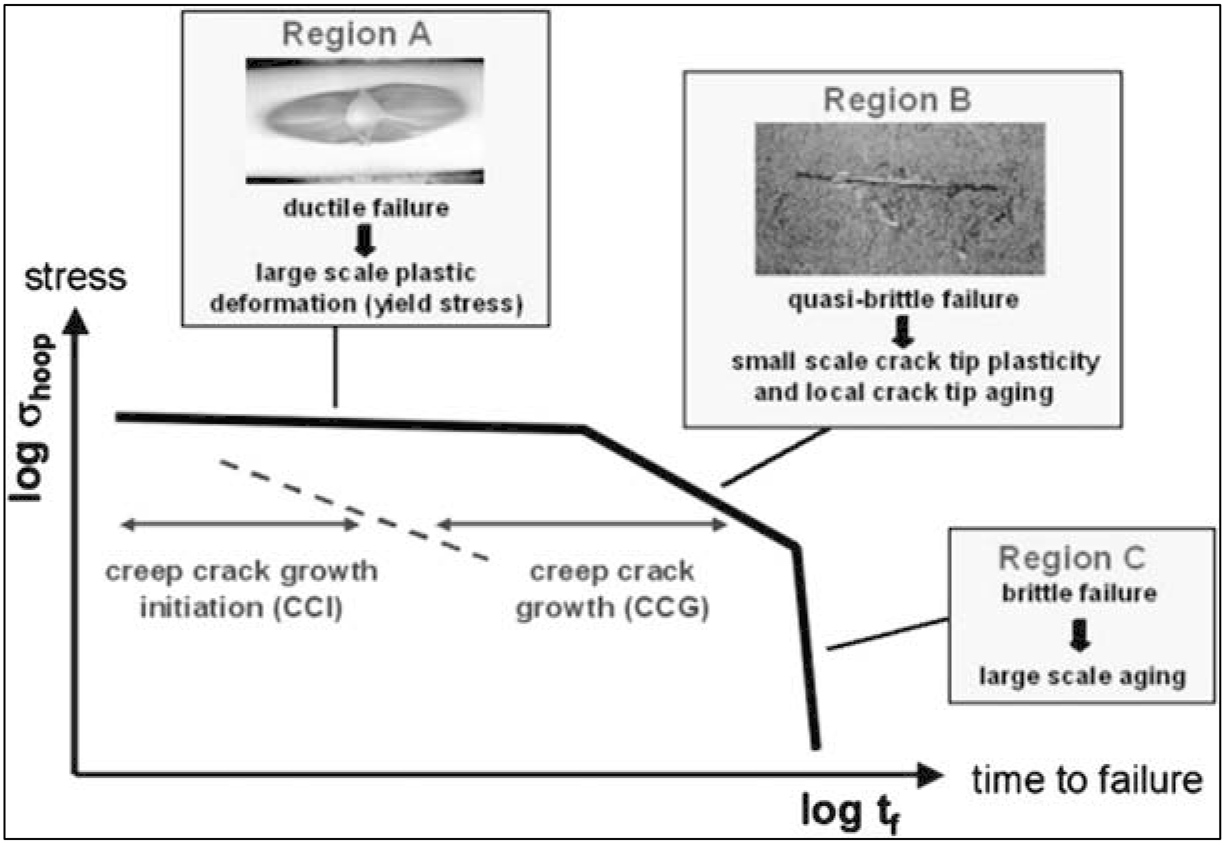



**Figure 2-1. Schematic illustration of the failure behavior of pressurized PE pipes [15]**

## *Variance of Stress in Pipes*

Bragaw [4] begins his analysis from the fracture rate relationship defined in **Equation 2-1.**

$$\frac{dc}{dt} = \frac{KT}{\eta} e^{-\left[\frac{\varepsilon - \frac{\beta\sigma}{2}}{KT}\right]}$$ **Equation 2-1**

| | |
|---|---|
| dc/dt | Fracture rate |
| T | Absolute temperature in Kelvin |
| ε | Activation energy |
| σ | **True stress at activated sites** |

Other symbols are constants

GTI adopts the ISO 9080 [2] formulation of the rate process model as defined in **Equation 2-2**.

$$\log(t) = C_1 + \frac{C_2}{T} + C_3\log(\sigma) + \frac{C_4\log(\sigma)}{T}$$ **Equation 2-2**

| | |
|---|---|
| $C_1$, $C_2$,$C_3$,$C_4$ | Constants determined from data by linear regression (dependent on stress units used) |
| t | Time to failure in hours |
| T | Absolute temperature in Kelvin |
| $\sigma$ | Stress usually in MPa, but can be in any stress unit. In this report psi is used to remain consistent with units commonly used in the industry in the USA. |
| log | Log base 10 |

The stress used in standard RPM analysis is the pipe hoop stress as derived from Barlow's formula that relates the internal pressure that a pipe can withstand to its dimensions and the strength of its material[4]

$$P = \frac{2St}{D}$$ **Equation 2-3**

| | |
|---|---|
| P | Pressure |
| S | Allowable stress |
| T | Wall thickness |
| D | Outside diameter |

For polyethylene pipe the formula is modified to take advantage of the practice of specifying the Dimension Ratio (DR) of the pipe, defined as the ratio between the pipe outside diameter and the wall thickness. If the DR is constrained to be a number from the Renard R10 series[5] it becomes a Standard Dimension Ratio (SDR). Pipe manufactured to a DR results in pipe with the same pressure capacity across all diameters under the assumption that the pipes are not thick-walled cylinders. This assumption holds for pipes of DR larger than 20 (radius/thickness<10), Young [16] § 13.2. We can immediately see that for the majority of

**4** Barlow's formula. (2016, December 1). In Wikipedia, The Free Encyclopedia. Retrieved 11:28, September 20, 2017, from https://en.wikipedia.org/w/index.php?title=Barlow%27s_formula&oldid=752557552

**5** Renard series are a system of preferred numbers dividing an interval from 1 to 10 into 5, 10, 20, or 40 steps. [1] This set of preferred numbers was proposed in the 1870s by French army engineer Colonel Charles Renard.[2] His system was adopted in 1952 as international standard ISO 3. Renard's system of preferred numbers divides the interval from 1 to 10 into 5, 10, 20, or 40 steps. The factor between two consecutive numbers in a Renard series is approximately constant (before rounding), namely the 5th, 10th, 20th, or 40th root of 10 (approximately 1.58, 1.26, 1.12, and 1.06, respectively), which leads to a geometric sequence. This way, the maximum relative error is minimized if an arbitrary number is replaced by the nearest Renard number multiplied by the appropriate power of 10.
Renard series. (2017, June 18). In Wikipedia, The Free Encyclopedia. Retrieved 11:34, September 20, 2017, from https://en.wikipedia.org/w/index.php?title=Renard_series&oldid=786314581

polyethylene piping applications the thin-walled cylinder assumption is not strictly true. The variance is not critical for determining the ductile-rupture boundary of the pipe as defined in PPI TR-3[6], however we should expect to see a significant component of variance in test results associated with the thin-walled assumption. The presence of stress-risers, or stress concentrations[7] will introduce additional variance.

**6** http://plasticpipe.org/pdf/tr-3-2017a.pdf
TR-3/2017a HDB/HDS/PDB/ SDB/MRS/CRS Policies: Policies and Procedures for Developing Hydrostatic Design Basis (HDB), Hydrostatic Design Stresses (HDS), Pressure Design Basis (PDB), Strength Design Basis (SDB), Minimum Required Strength (MRS) Ratings, and Categorized Required Strength (CRS) for Thermoplastic Piping Materials or Pipe, **Section F.4.1.2**

**7** A stress concentration (often called stress raisers or stress risers) is a location in an object where stress is concentrated. An object is stronger when force is evenly distributed over its area, so a reduction in area, e.g., caused by a crack, results in a localized increase in stress. A material can fail, via a propagating crack, when a concentrated stress exceeds the material's theoretical cohesive strength. The real fracture strength of a material is always lower than the theoretical value because most materials contain small cracks or contaminants (especially foreign particles) that concentrate stress. Fatigue cracks always start at stress raisers, so removing such defects increases the fatigue strength.
Stress concentration. (2017, July 1). In Wikipedia, The Free Encyclopedia. Retrieved 12:05, September 20, 2017, from https://en.wikipedia.org/w/index.php?title=Stress_concentration&oldid=788498711

## *Stress Intensification Factors (SIF)*

We will now develop basic SIF for the ductile failure mode of Aldyl A pipe following a process similar to that used in ASME B31.3 as described by Becht [17] §8.4. We do not use fatigue testing to determine the number of cycles to failure and then calculate a ratio to a reference configuration as is done in the ASME context, but do assume that the true stress in the pipe specimen is related to a stress intensification factor as is used in assessing damage tolerance:

> *"The **stress intensity factor**, , is used in fracture mechanics to predict the stress state ("stress intensity") near the tip of a crack caused by a remote load or residual stresses.[1] It is a theoretical construct usually applied to a homogeneous, linear elastic material and is useful for providing a failure criterion for brittle materials, and is a critical technique in the discipline of damage tolerance. The concept can also be applied to materials that exhibit small-scale yielding at a crack tip.*
> *The magnitude of depends on sample geometry, the size and location of the crack, and the magnitude and the modal distribution of loads on the material"*
>
> Stress intensity factor. (2017, September 20). In Wikipedia, The Free Encyclopedia. Retrieved 12:22, September 20, 2017, from https://en.wikipedia.org/w/index.php?title=Stress_intensity_factor&oldid=801550951

We can empirically estimate the SIF associated with each data point in a robust data set i.e. developed using consistent testing methodology and a statistically significant number of results that can be fitted to a model.

**Assumptions:**

1. All the variance in the data set is due to variance in the true stress at the point of failure (data sets with a known material variance can be used to develop an equivalent SIF for the known material condition e.g. LDIW)

**Method:**

1. Fit a regression model to the data set.
2. Find the point with the best relative performance by shifting the mean regression line to pass through each point, observe the new intercept and select the point with the largest intercept as being that with the best relative performance.
3. Define the regression model that passes through the best performing point as the reference model.
4. Calculate the reference model stress for each data point by inserting the actual failure time for the data point into the derived equation for stress given failure time.
5. Divide the reference model stress by the actual failure stress and define this ratio as the individual SIF for the data point

**Figure 2-2** shows the DuPont data sets used to calculate empirical SIF using the above methodology, or variants of the methodology. **Figure 2-3** and **Figure 2-4** show the results for ductile failures.

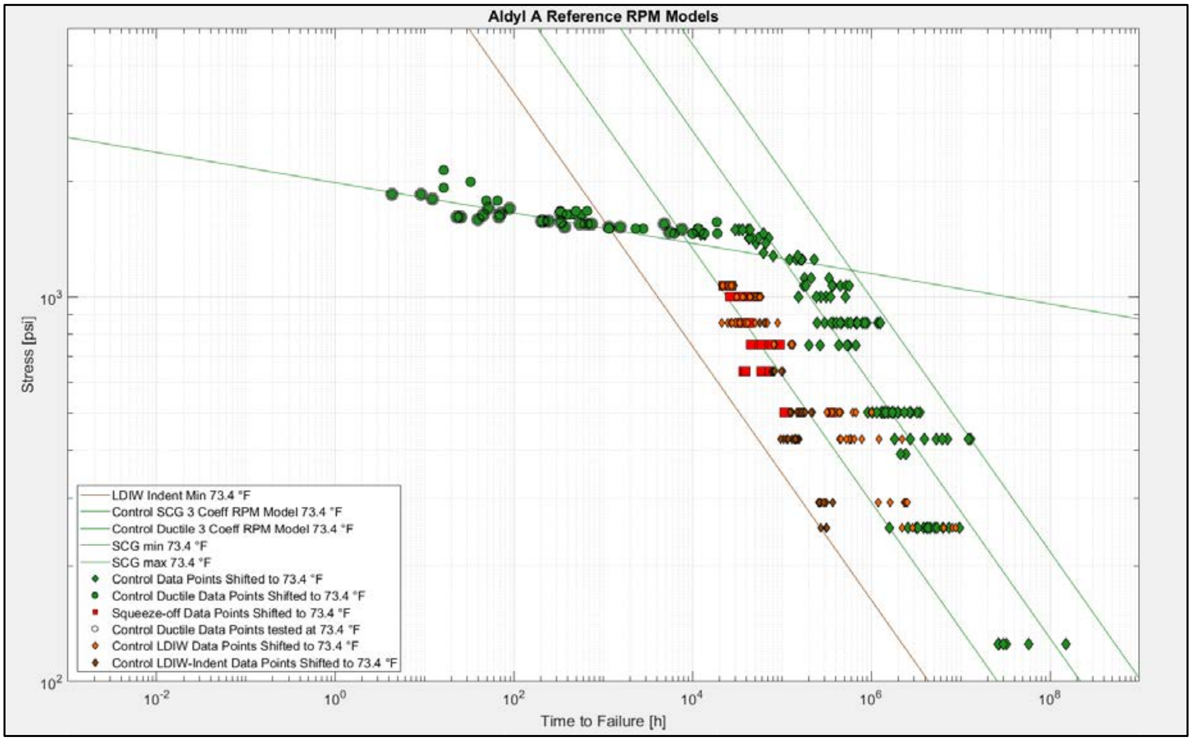



**Figure 2-2. Aldyl A Data Sets for Deriving Empirical SIF**

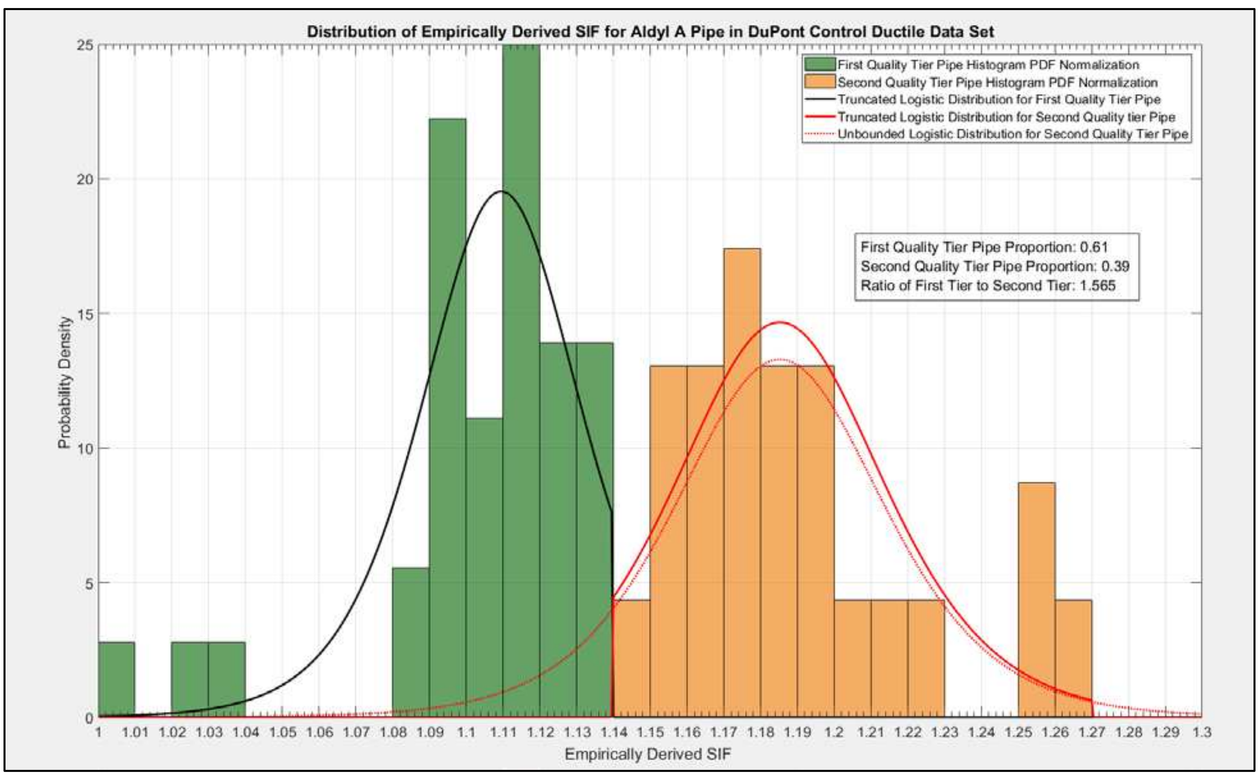



**Figure 2-3. PDF for Empirically Derived SIF for Ductile Failures**

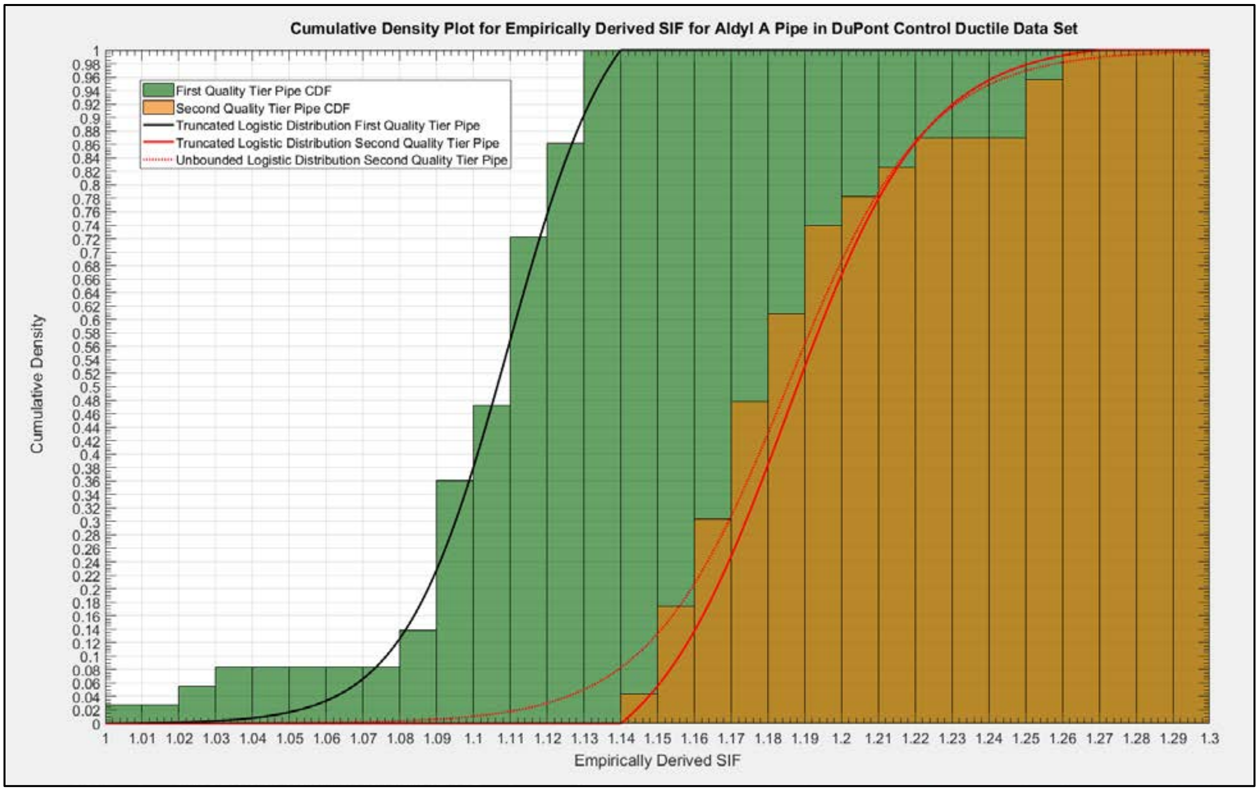



**Figure 2-4. CDF for Empirically Derived SIF for Ductile Failures**

Two distinct distributions of SIF are evident after the application of algorithm described above. It is reasonable to suggest that these two distributions reflect two quality levels of pipe as defined by the wall thickness irregularities, faceted inside diameter and die-lines always present to varying degrees in extruded pipe. To test this idea detailed FEM analyses were run to assess the impact of shallow grooves from die-lines on the SIF for the pipe as described below.

FEM analyses were run to determine the SIF due to sharp and blunt grooves introduced into the pipe internal diameter during extrusion. The assumption is that these SIF "seed" the ductile rupture process and that the ductile stress rupture curves reflect these SIF **Figure 2-5** and **Figure 2-6** show that at internal pressures typical of stress rupture tests the SIF for sharp grooves approaches 3, and for blunt grooves they approach 2.2. The SIF in the ductile data set was calculated as above, with the exception that the maximum SIF was set to 3 to match the maximum SIF from the FEM and the remaining SIF referenced to this value. The resulting distribution of ductile pipe SIF is shown in **Figure 2-7.** The minimum SIF calculates to 2.2, which is in remarkable agreement with the FEM analysis. This result is viewed as validation of the assumption that failure in the ductile regime is seeded by the axial scoring on the pipe ID.

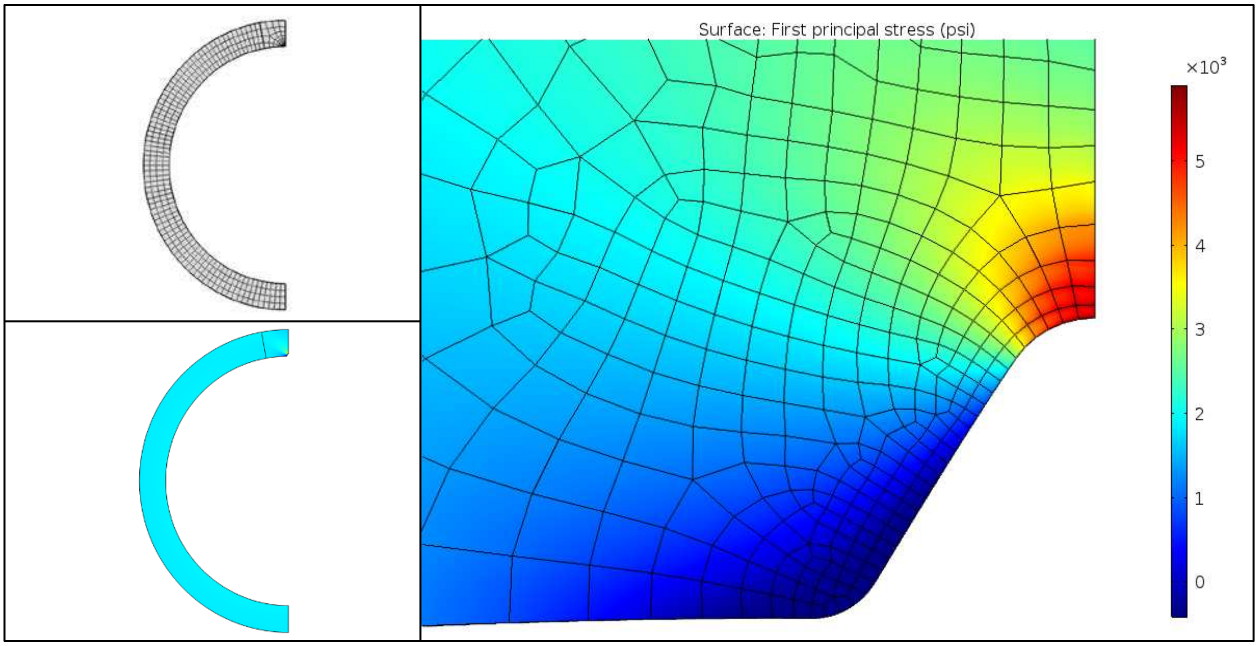



**Figure 2-5. FEM analysis of stress associated with die line grooves on internal diameter of MDPE pipe**

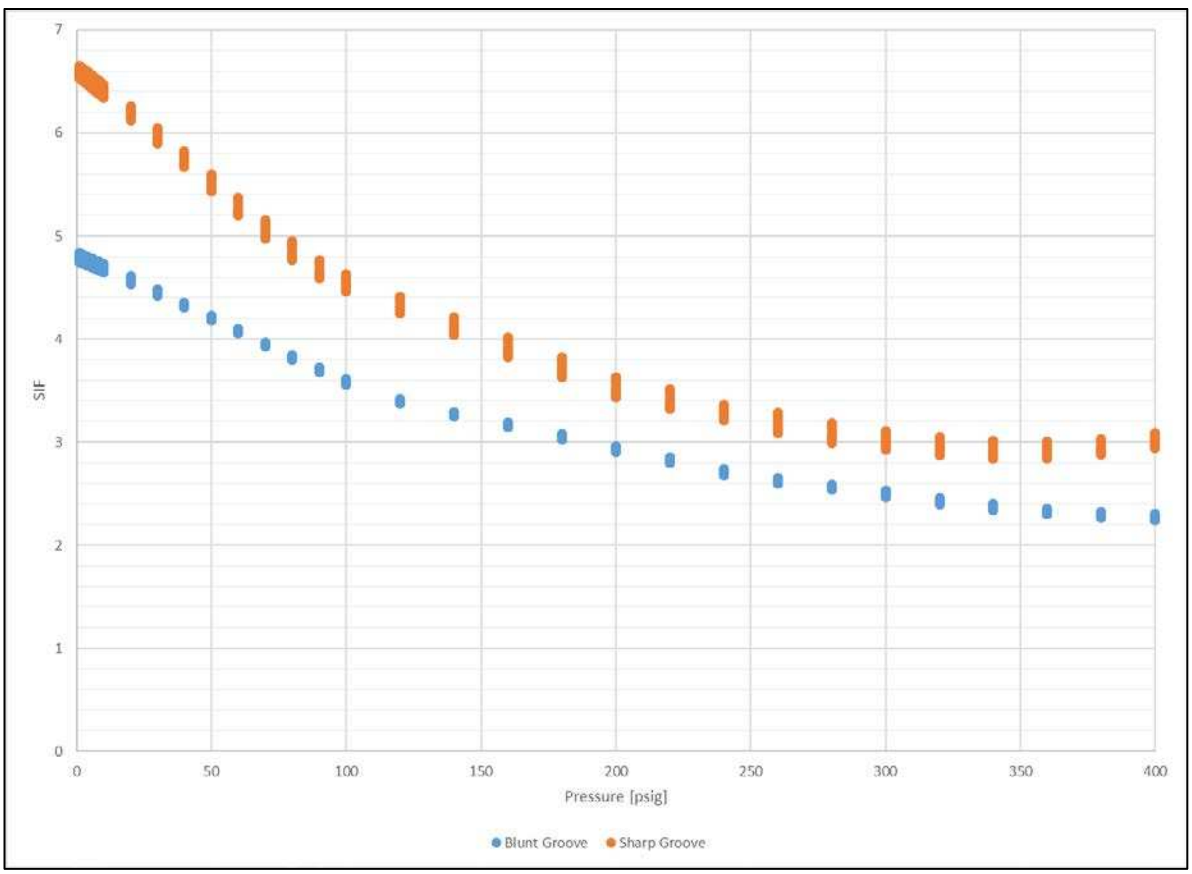



**Figure 2-6. SIF measured in FEM as a function of internal pressure at 73.4°F**

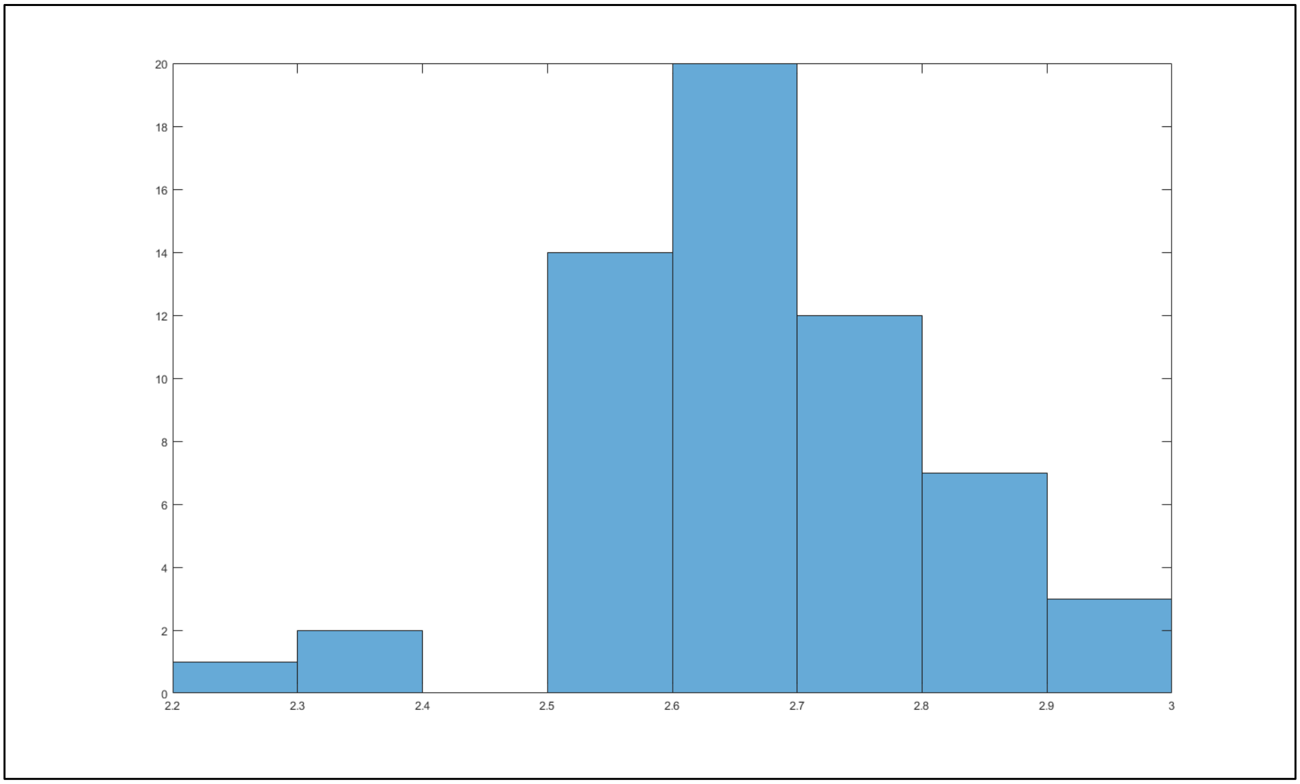



**Figure 2-7. Distribution of ductile failure SIF referenced to FEM results**

**Important Caveat for Ductile Failure SIF**

Actual testing of heavily scored pipe does not result in empirical SIF matching the FEM values, and the failure location does not match the groove locations. This is due to large scale plastic yielding of the pipe wall that reduces the SIF, and potentially the differential creep noted on page **329** that could lead to preferential yielding in the pipe wall resulting in eventual ductile rupture. The SIF distribution shown in **Figure 2-3** shows the effective SIF for different levels of pipe scoring because of the two processes described above playing out. Gas distribution pipe with deep grooves on the ID was extensively tested by GTI using the RPM **Figure 2-9**, and the results were referenced to baseline data from the resin supplier. The resulting SIF distributions are shown in **Figure 2-8**.

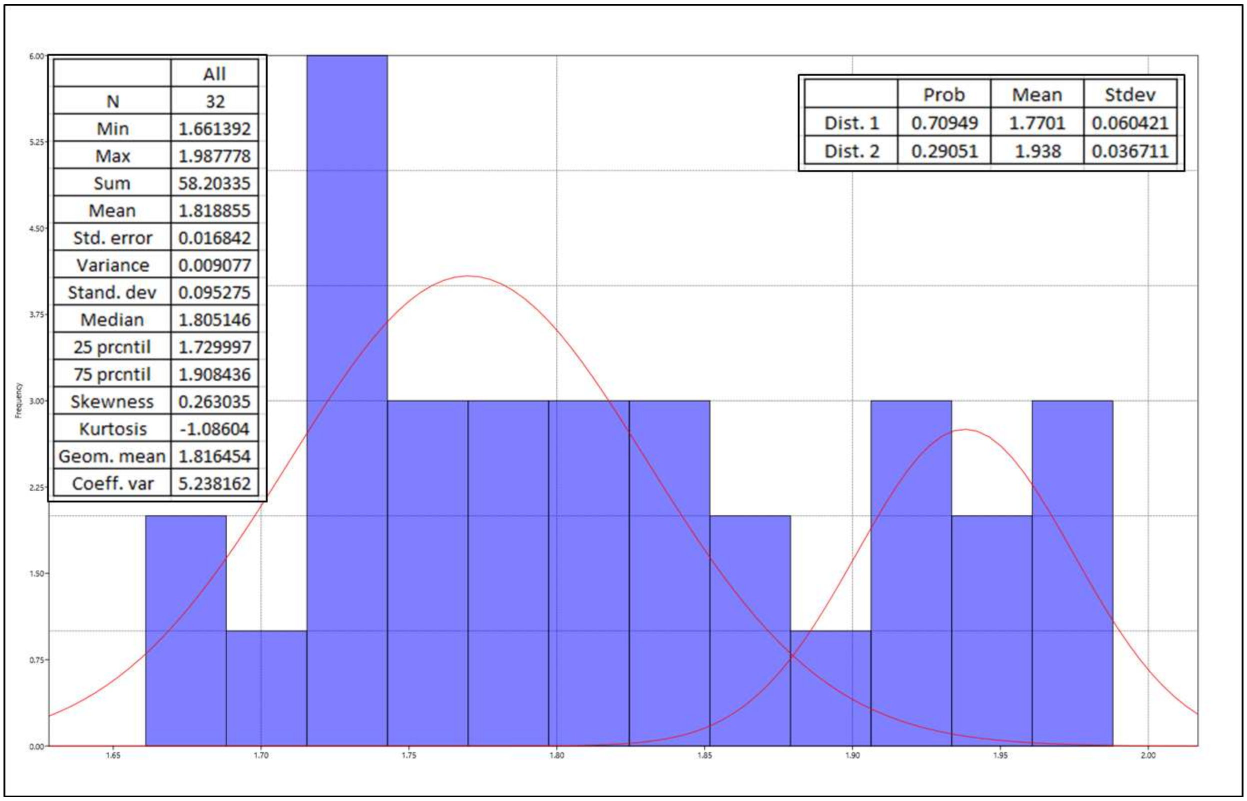



Figure 2-8. Empirical SIF Distributions for Heavily Grooved Gas Distribution Pipe

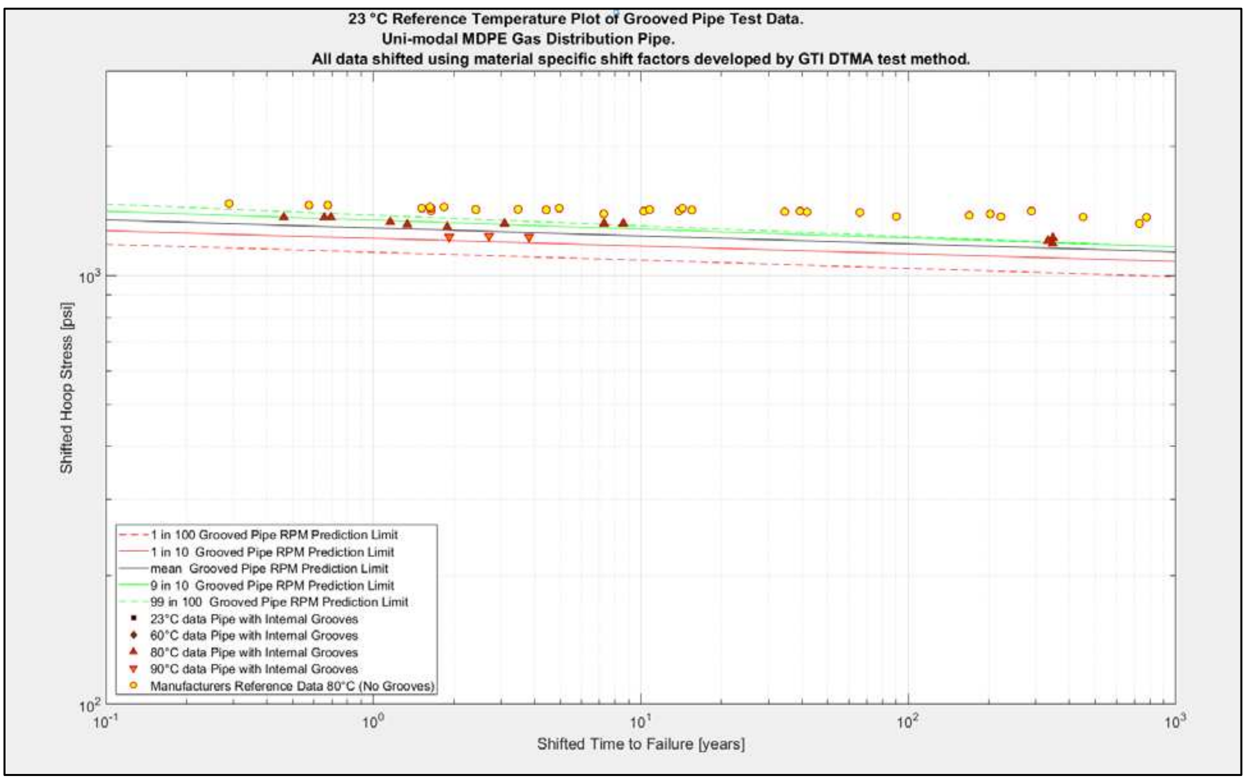



Figure 2-9. RPM Analysis for Empirical SIF Determination

The empirical method was extended to the SCG failures in the DuPont reference data sets and the resulting SIF distributions are shown in **Figure 2-10** together with the FEM adjusted ductile SIF distributions discussed above.

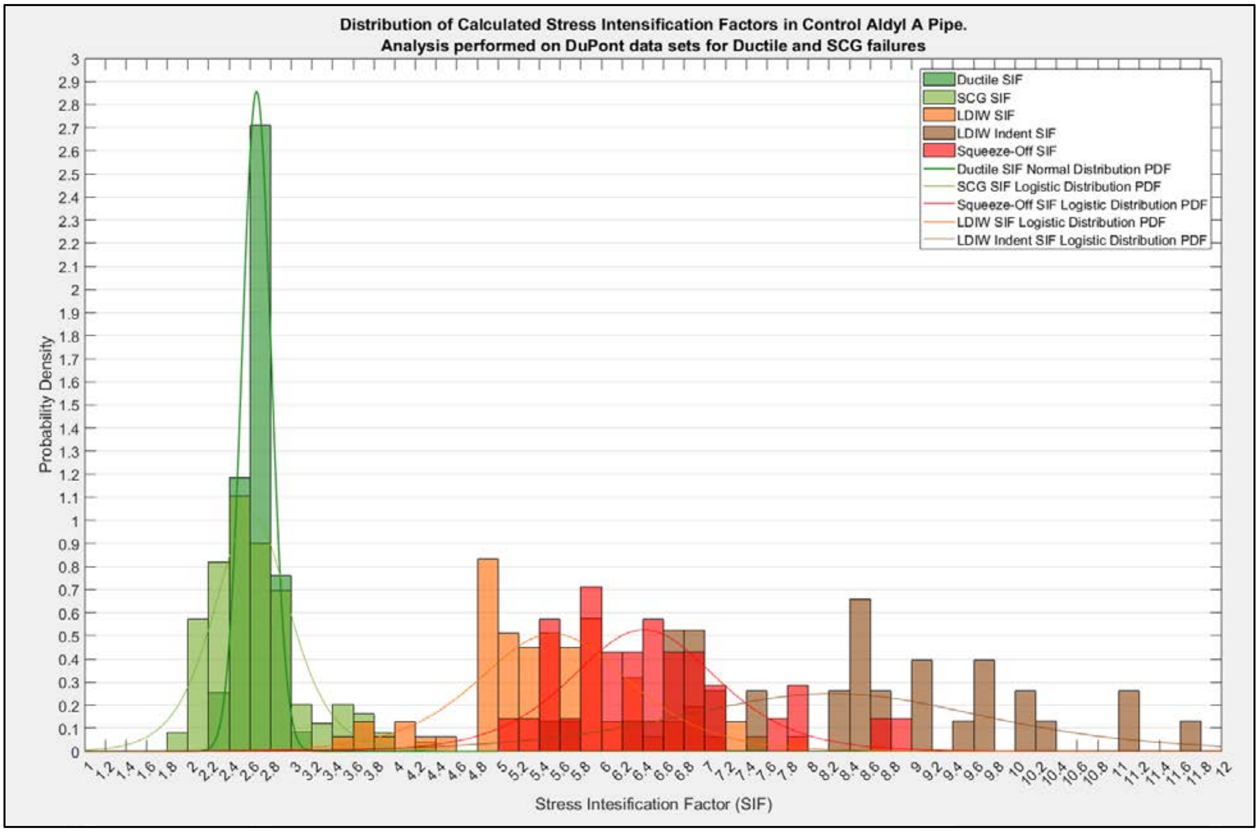



**Figure 2-10. SIF Distributions for Various Aldyl A SCG Data Sets**

The empirically derived SIF were used to predict expected lifetimes for the entire reference data set using the control DuPont SCG model with excellent results as shown in **Figure 2-11,** log-log plot, and **Figure 2-12,** linear-linear plot to emphasize variance. The variance in SCG failure times for a given stress over the performance range in **Figure 2-2** is a factor of 225. The SIF and reference model results yield a variance across the performance range of 2.5 as shown in **Figure 2-13** and **Figure 2-14.** That is, we get a two order of magnitude reduction in variance by addressing the true stress at the damage tip calculation via the empirically derived SIF, and using a single RPM reference model. This is a significant improvement over the simple hoop-stress approach and having to generate multiple RPM reference models.

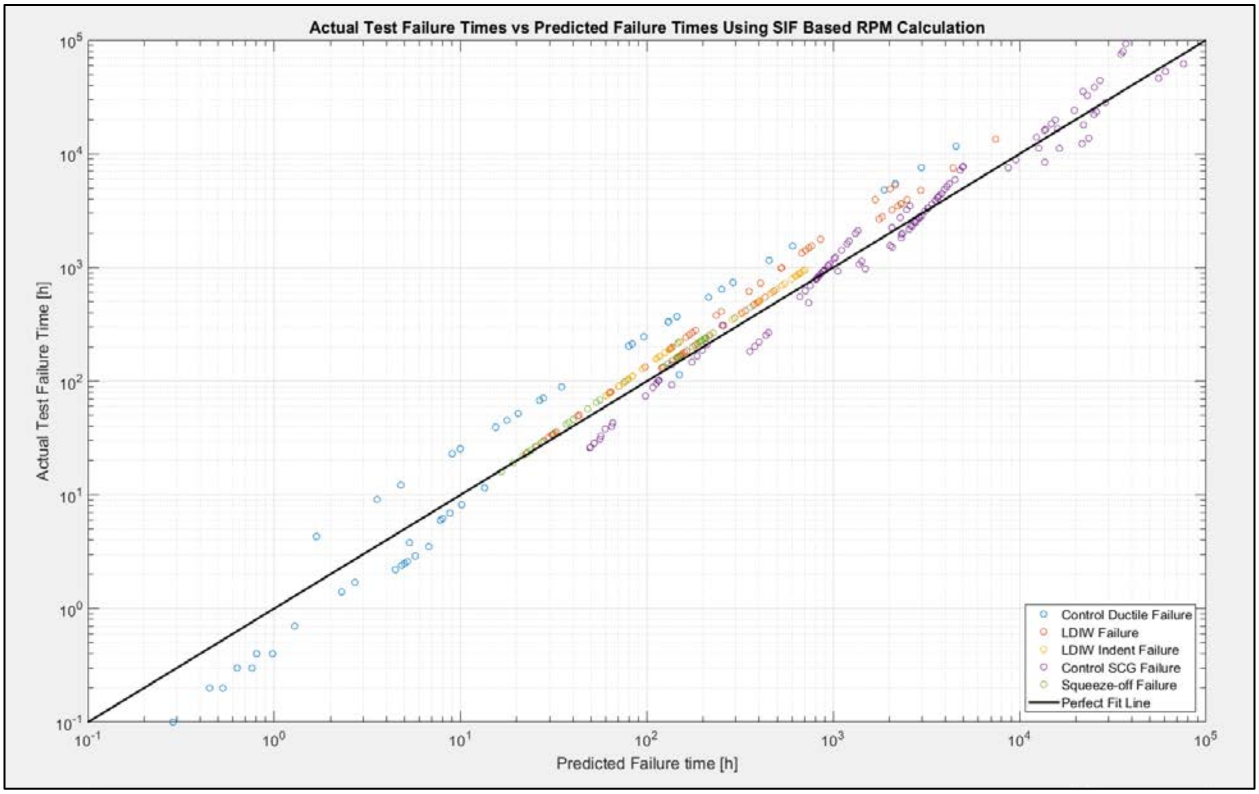



Figure 2-11. Actual vs Predicted Plot for SIF and Reference RPM Model Lifetime Prediction

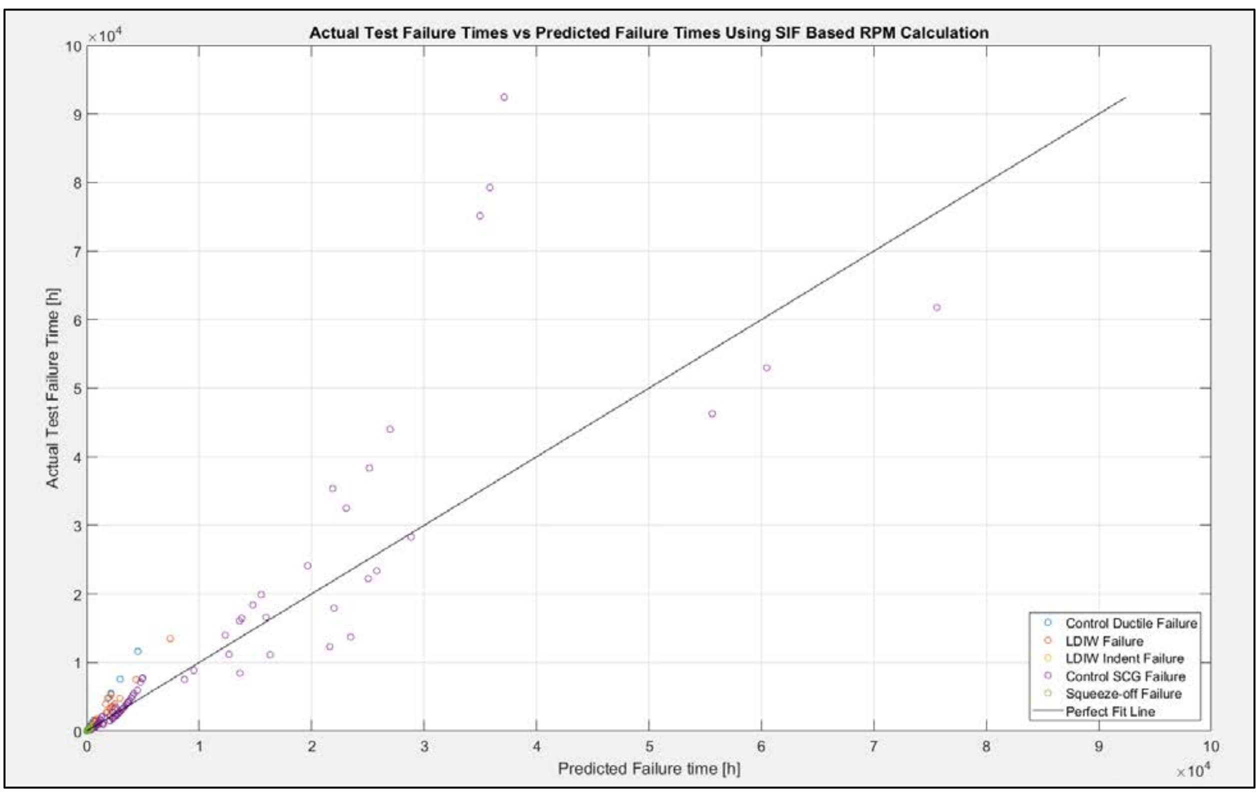



Figure 2-12. Same as Figure 2-11, but Linear Axes

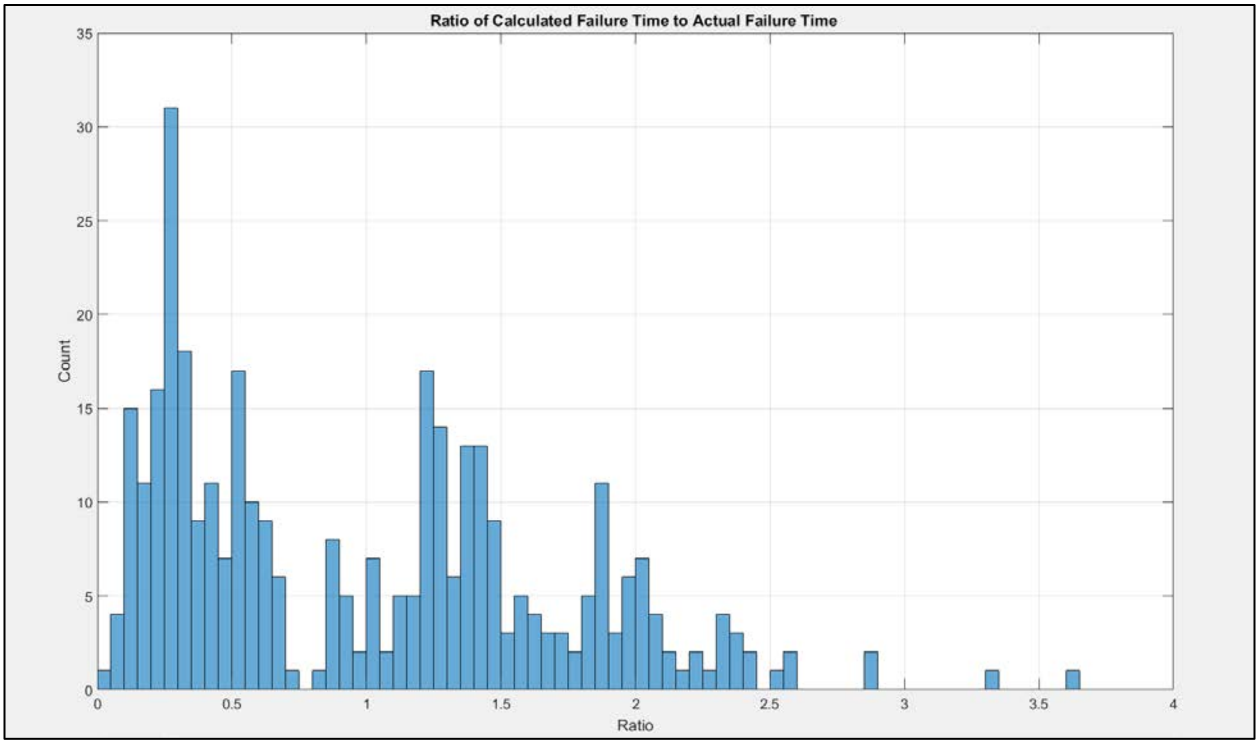



Figure 2-13. Actual to Predicted Failure Time Ratio

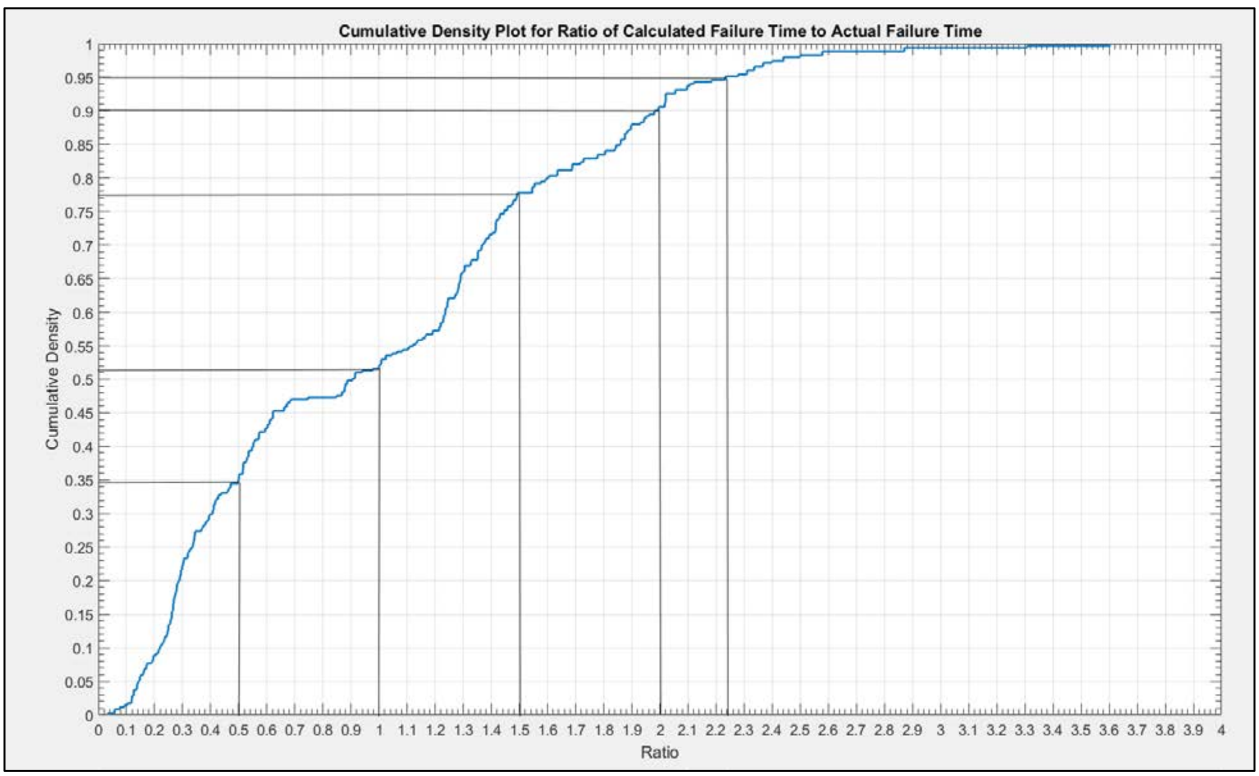



Figure 2-14. CDF for Actual to Predicted Failure Time Ratio

### *SIF for Polyethylene Piping Systems*

In the preceding sections, we focused on extracting effective SIF from reference data sets under the assumption that the variance in performance implied by the results was entirely due to combinations of SIF in the test specimen. We will now look at SIF derived from FEM analyses of pipe and pipe assemblies. The FEM analyses all utilized advanced constitutive models for polyethylene based on extensive mechanical testing of multiple materials. The constitutive models incorporate temperature effects, strain rate effects and relaxation. The SIF listed below are all the SIF associated with initial loading of the assembly and represent the initial static stress state. **Table 2-2** lists some stand-alone SIF for different piping configurations. They are stand-alone because we have not yet addressed how to combine individual SIF into a composite effective SIF that can plugged into a RPM model.

**Table 2-2. Stand-alone SIF for Polyethylene Piping Systems**

| Pipe or Fitting Configuration (All with 45 - 60 psig Internal Pressure, SDR11) | Stress Intensification Factor |
|---|---|
| Socket Coupling – Coupling Edge (FEA Analysis) | 1.25 |
| Soil Loading to 4% Deflection (FEA Analysis) | 1.6 |
| Saddle Tee (FEA Analysis) | 2.7 |
| Socket Coupling – Coupling Center (FEA Analysis) | 1.8 – 2.9 |
| Pipe with Bend Radius of 100 Pipe Diameters (FEA Analysis) | 3.0 |
| Bending (Empirical correlation from RPM testing) | 3.4 |
| Pipe with Bend Radius of 80 Pipe Diameters (FEA Analysis) | 3.6 |
| Pipe with Bend Radius of 50 Pipe Diameters (FEA Analysis) | 4.7 |
| Socket Coupling with Bend Radius of 100 Pipe Diameters (FEA Analysis) | 4.8 |
| Socket Coupling with Bend Radius of 80 Pipe Diameters (FEA Analysis) | 5.8 |
| Impingement (Empirical correlation from RPM testing) | 5 - 7 |
| Socket Coupling with Bend Radius of 50 Pipe Diameters (FEA Analysis) | 7.5 |
| Squeeze-Off at time of squeeze (FEA Analysis) | 8.5 – 10.5 |

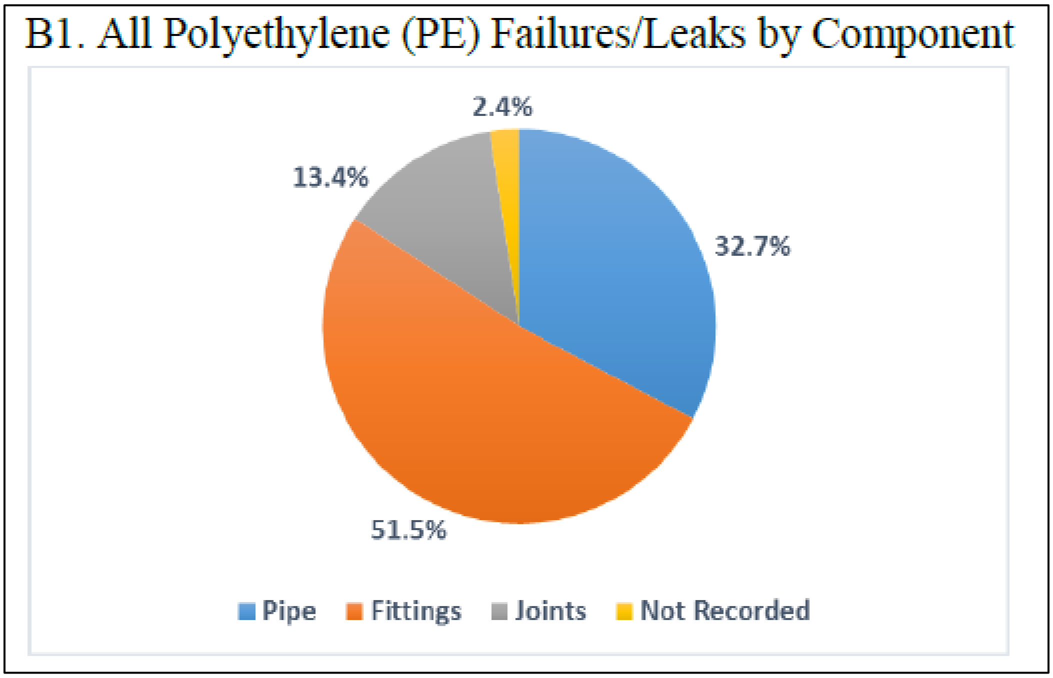
The SIF listed above correlate reasonably well with empirically derived SIF and give a plausible explanation for observed field failures and the proportions of individual causes reported by various sources. There is not much useful failure data in the public domain. Maupin and Mamoun [18] reviewed several hundred data points that included 55 field failures they analyzed, 104 failures in databases they had access to and 162 failure reports from other sources. Their summary of failure categories is presented in **Table 2-3.**

**Table 2-3 Maupin and Mamoun summary of failure categories**

| Failure Type | Number |
|---|---|
| Material Failures | |
| Pipe | |
| Rock Impingement | 9 |
| Squeeze-off | 8 |
| Insert Renewal | 1 |
| Bending/Settlement | 3 |
| Internal Pressure | 1 |
| | |
| Joints | |
| End Caps | 8 |
| Tapping Tee Caps | 9 |
| Tees and Ells | 21 |
| Sockets | 74 |
| Saddles | 118 |
| | |
| Fusion Failures in Joints | |
| Butt Fusion | 29 |
| Socket Fusion | 7 |
| Saddle Fusion | 5 |
| | |
| Quality Control Problems | 6 |
| | |
| Third Party | 14 |
| | |
| Other | 8 |
| | |
| Total | **321** |

Another source of information is the Plastic Pipe Database Collection Initiative (PPDC): "*A group of representatives of federal and state regulatory agencies and the natural gas and plastic pipe industries have come together and formed The Plastic Pipe Data Collection Initiative. Their goal has been to create a national database of information related to the in-service performance of plastic piping materials. Members include the American Gas Association, the American Public Gas Association, the Plastics Pipe Institute (PPI), the National Association of Regulatory Commissioners, the National Association of Pipeline Safety Representatives (NAPSR), the U.S. Department of Transportation and its Office of Pipeline Safety.*"
Source: https://www.aga.org/plastic-pipe-database-collection-initiative , accessed 9/21/2017

The PPDC April 2017 Status Report summarizes the data presented in **Figure 2-15**




All PE Failures/Leaks by Cause

| CAUSE | % of All PE Failures/Leaks | % of All PE Pipe Failures/Leaks | % of All PE Fitting Failures/Leaks | % of All PE Joint Failures/Leaks |
|---|---|---|---|---|
| Excessive Expansion/Contraction | 1.7% | 1.2% | 1.4% | 4.3% |
| Excessive External Earth Loading | 5.7% | 9.0% | 3.6% | 4.8% |
| Installation Error | 28.3% | 12.2% | 31.5% | 56.4% |
| Squeeze Off | 2.0% | 5.7% | 0.1% | 0.1% |
| Point Loading | 6.9% | 16.2% | 2.1% | 3.0% |
| Previous Impact | 1.9% | 5.2% | 0.3% | 0.4% |
| Unknown | 13.3% | 9.1% | 16.0% | 13.6% |
| Other | 14.0% | 16.0% | 14.5% | 2.9% |
| Cap | 4.9% | 0.0% | 9.2% | 0.0% |
| Not Recorded | 3.0% | 2.9% | 2.8% | 3.7% |
| Material Defect | 16.0% | 18.8% | 16.3% | 10.3% |
| Gopher/rodent/worm damage | 0.4% | 1.2% | 0.0% | 0.0% |
| Unknown - Not Excavated, Replaced | 1.2% | 1.4% | 0.6% | 0.4% |
| Unknown - Abandoned | 0.1% | 0.1% | 0.1% | 0.0% |
| Corrosion | 0.8% | 0.8% | 1.4% | 0.1% |
| | | | | |
| | 100.0% | 100.0% | 100.0% | 100.0% |

**Figure 2-15. PPDC April 2017 Data for Polyethylene**

The only useful information we can glean from the PPDC data is that fittings dominate the failures, point loading, squeeze-off and earth loading appear as prominent causes. This information supports the relative severity of SIF presented in **Table 2-2.**

A more detailed FEM analysis of fittings subjected to bending was undertaken and it was found that saddle fittings represent one of the most severe combination of SIF for fittings in a polyethylene piping system. Studies, shown in **Figure 2-16,** were performed on three sizes of pipe 1.25'',2'',4'', with and without tees. For each pipe configuration, the stress intensity factor (SIF) was calculated by taking the maximum von Mises stress in each load case and dividing it by the nominal pipe hoop stress calculated from the internal pressure of the respective load case. After comprehensive analysis, it is found that the calculated SIF is size independent, as expected, and all the regression models can be generalized to a single power law function that correlates the SIF with input configuration parameters, such as internal pressure (P) and bending radius factor (BRF) Equation **2-4**.

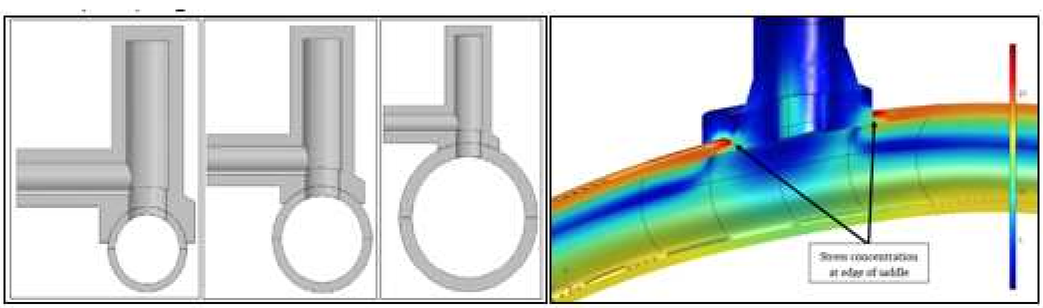


**Figure 2-16. FEM models for saddle tee SIF evaluation**

$$SIF = aP^bBRF^c$$ **Equation 2-4**

SIF – Stress Intensity Factor

$P$ – Pressure[psi]

BRF – Bend Radius Factor expressed as multiples of the pipe diameter

a, b, c – Regression Coefficients

The FEM models were extended to consider the direction of the pipe bending relative to the fitting placement for saddle tees, which are not symmetric in this context. Socket couplings are symmetric and the direction of bending is immaterial. The bending moment sign convention used in this analysis is defined in **Figure 2-18.** The tee will be on the concave up portion of the pipe for positive bending, and on the convex up portion of the pipe for negative bending. The correlation coefficients for the key configurations are presented in **Table 2-4.** A plot of the SIF for a pipe without saddle tee is illustrated in **Figure 2-17**

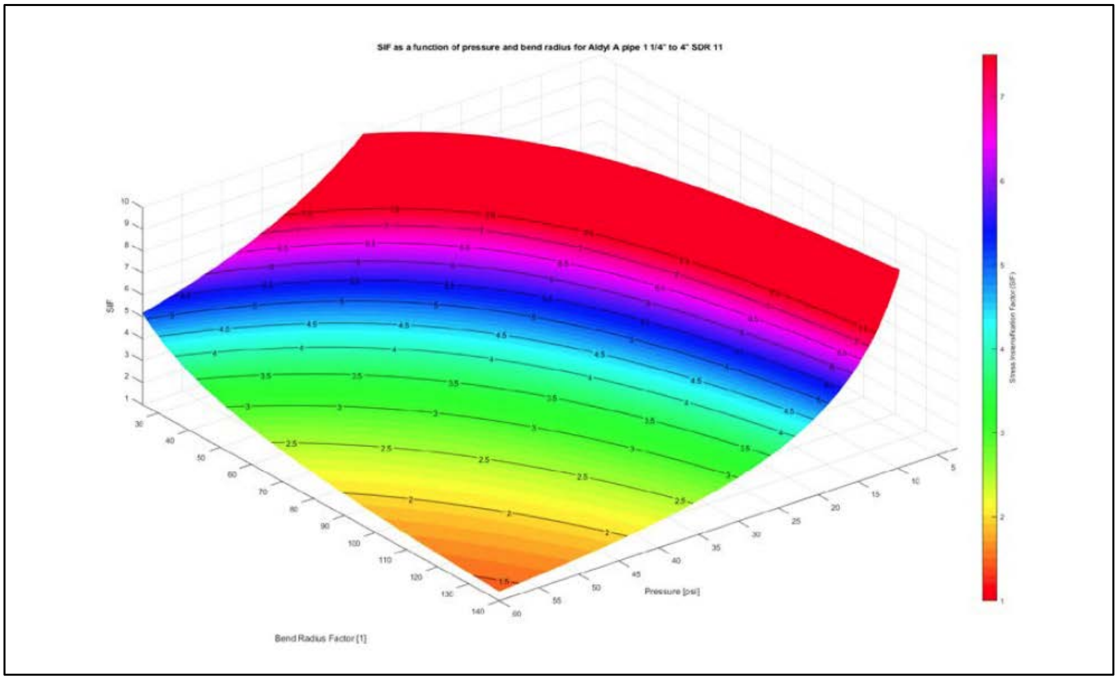



**Figure 2-17. SIF for pipe as a function of BRF and P**

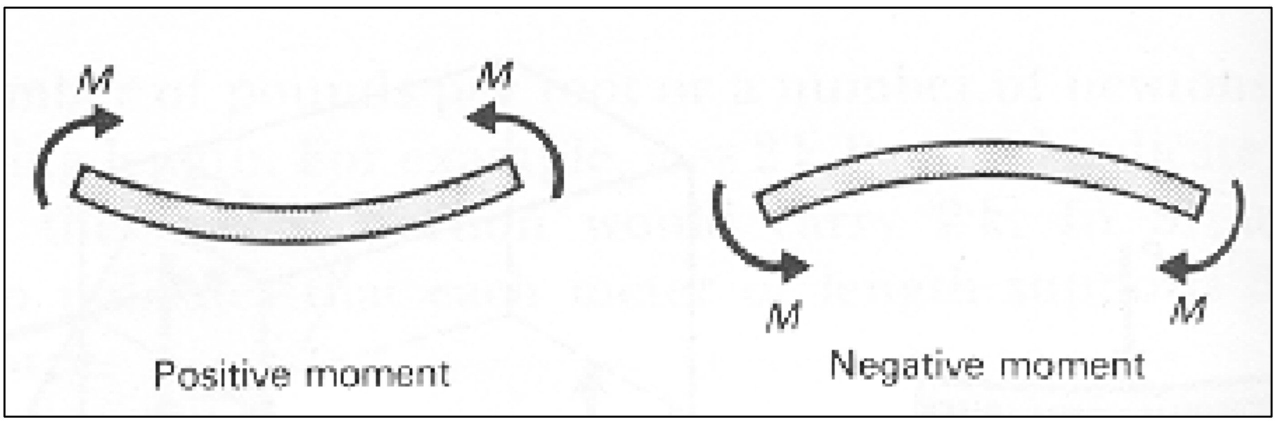



**Figure 2-18. Bending moment sign convention-positive concave up, negative concave down**

**Table 2-4. Correlation coefficients for pipe under bending with and without fittings**

| Configuration | a | b | c |
|---|---|---|---|
| Pipe without Saddle Tee | 4453.0 | -1.0657 | -0.744 |
| Pipe with Saddle Tee Positive Bending | 5310.7 | -0.9654 | -0.7251 |
| Pipe with Saddle Tee Negative Bending | 9364.1 | -1.0757 | -0.7789 |
| Pipe with Saddle Tee Lateral | 3476.7 | -1.0059 | -0.5593 |
| Pipe with Coupling | 4285.0 | -0.676 | -0.9252 |

The relative effect of the different bending configurations on saddle tee assemblies is presented in **Figure 2-19** and the SIF for pipe, tee and couplings in **Figure 2-20.**

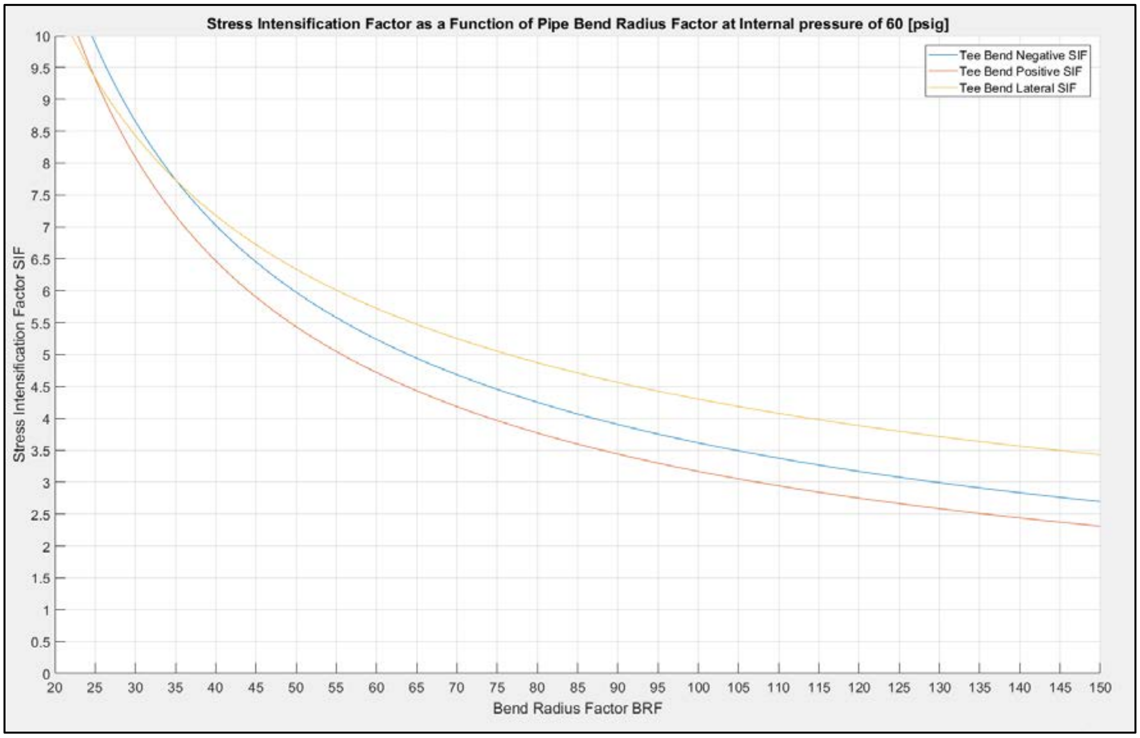



**Figure 2-19. Relative effect of bending configurations on saddle tee assemblies**

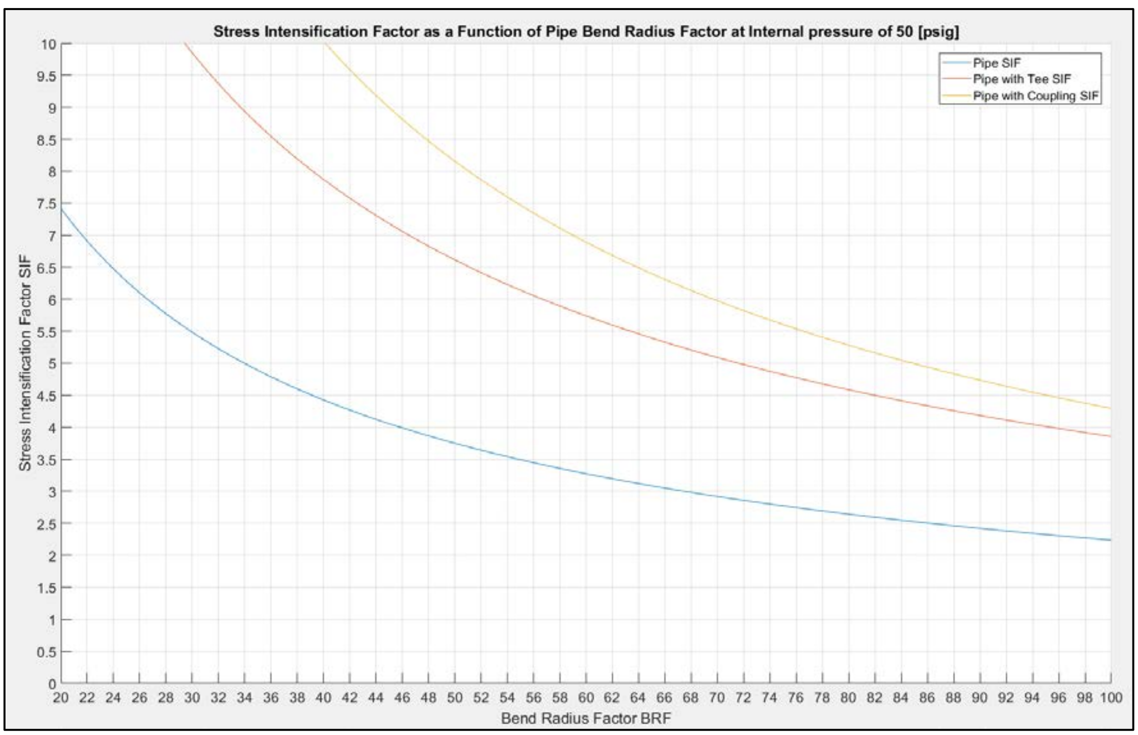



**Figure 2-20. SIF for pipe, tee and coupling under bending**

### Combining SIF Distributions for Polyethylene Piping systems

In the sections above we have presented several SIF distributions extracted empirically from actual test data. Through inspection of many of these data sets, it was found that a Logistic Distribution provides the best fit for the data. The logistic distribution is a two-parameter distribution with a location parameter that is the mean of the variable being modeled and a shape factor that reflects the variance of the variable **Figure 2-21**.

| | |
|---|---|
| Parameters | $\mu$ location (real)<br>$s > 0$ scale (real) |
| Support | $x \in (-\infty, \infty)$ |
| PDF | $\dfrac{e^{-\frac{x-\mu}{s}}}{s\left(1+e^{-\frac{x-\mu}{s}}\right)^2}$ |
| CDF | $\dfrac{1}{1+e^{-\frac{x-\mu}{s}}}$ |
| Mean | $\mu$ |
| Median | $\mu$ |
| Mode | $\mu$ |
| Variance | $\frac{s^2\pi^2}{3}$ |
| Skewness | 0 |
| Ex. kurtosis | 1.2 |
| Entropy | $\ln(s) + 2 = \ln(\sigma) + 1.40457$<br>where $\sigma$ is the standard deviation |
| MGF | $e^{\mu t}\,\mathrm{B}(1-st, 1+st)$<br>for $st \in (-1, 1)$ Beta function |
| CF | $e^{it\mu}\dfrac{\pi st}{\sinh(\pi st)}$ |

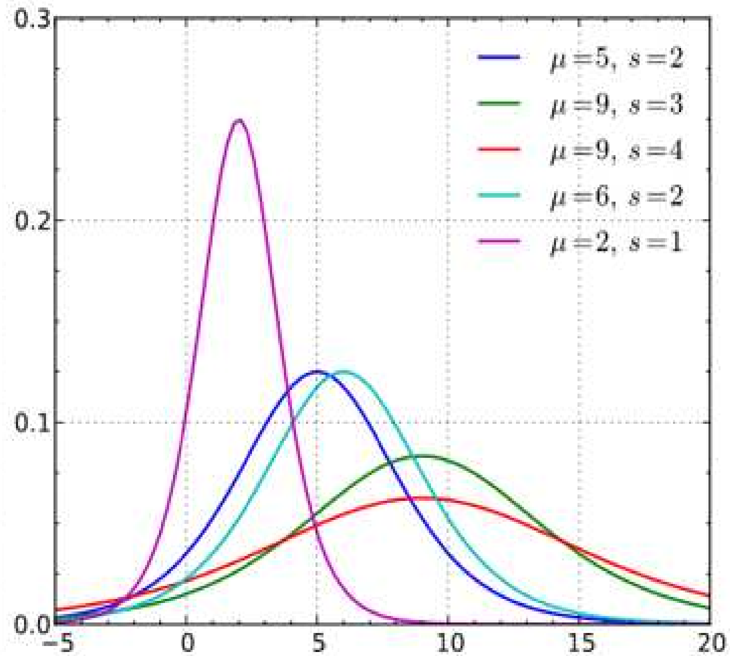



**Figure 2-21. Wikipedia contributors. "Logistic distribution."** ***Wikipedia, The Free Encyclopedia*****. Wikipedia, The Free Encyclopedia, 15 Jul. 2017. Web.**

The logistic distribution resembles the normal distribution, but has heavier tails making it better suited to simulation techniques where there is uncertainty as to the actual values of the parameters.

Inspection of several empirically derived logistic distributions for SIF in polyethylene pipe systems leads to the "rule of thumb" that setting the shape factor "s" to 6 percent of the mean value is a reasonable first approximation that can be updated as more data is gathered. It was also found that a convenient approach to combining multiple SIF acting on a single piping component is to use the Euclidean, or L2 norm to sum them. We can represent "n" independent SIF as a vector:

$$\mathrm{SIF} = (\mathrm{SIF1}, \mathrm{SIF2}, \ldots.\mathrm{SIFn})$$

The magnitude of the composite SIF is given by **Equation 2-5**

$$||\mathrm{SIF}||_2 = \sqrt{\mathrm{SIF}_1^2 + \cdots + \mathrm{SIF}_n^2} \qquad \textbf{Equation 2-5}$$

We can use Equation 2-5 to reference all SIF to a baseline SIF that we define as Pipe Quality Tier 1 as discussed above and shown in **Figure 2-3** by requiring the L2 norm of every pair of SIF that includes the baseline SIF to be equal to the standalone value of the second SIF. The same method can be applied to the shape factors. **Table 2-5** presents a collection of SIF for both the ductile and SCG failure modes, each group being referenced to the Pipe Quality Tier 1 SIF for the relevant failure mode. SIF for Ductile and SCG failure modes need to be treated separately. For the most part we are only interested in the SCG failure mode.

**Table 2-5. SIF Distributions for Polyethylene Piping systems**

| SIF for Ductile Failure: Logistic Distribution Parameters | Standalone SIF | | Referenced to baseline pipe SIF | |
|---|---|---|---|---|
| | Mu | sigma | Mu | sigma |
| Pipe Quality Tier 1 – Baseline SIF | 1.110 | 0.014 | 1.110 | 0.014 |
| Use standalone SIF value for single SIF. Develop composite SIF by adding SIF referenced to baseline using Equation 2-5 for each independent SIF component acting on pipe component to the baseline SIF | | | | |
| Pipe Quality Tier 2 | 1.185 | 0.018 | 0.417 | 0.011 |
| Pipe Quality Tier 3 Severe Grooves | 1.819 | 0.109 | 1.441 | 0.109 |
| **SIF for SCG Failure: Logistic Distribution Parameters** | **Standalone SIF** | | **Relative to baseline pipe SIF** | |
| | **Mu** | **sigma** | **Mu** | **sigma** |
| Pipe Quality Tier 1 SCG – Baseline SIF | 2.000 | 0.120 | 2.000 | 0.120 |
| Use standalone SIF value for single SIF. Develop composite SIF by adding SIF referenced to baseline using Equation 2-5 for each independent SIF component acting on pipe component to the baseline SIF | | | | |
| Pipe Quality Tier 2 SCG | 2.200 | 0.132 | 0.917 | 0.055 |
| Pipe Quality Tier 3 Severe Grooves SCG | 3.000 | 0.180 | 2.236 | 0.134 |
| Pipe Quality Tier 4 LDIW SCG | 5.780 | 0.347 | 5.423 | 0.326 |
| LDIW Squeeze-off SCG | 6.696 | 0.402 | 6.390 | 0.384 |
| LDIW Impingement SCG | 8.598 | 0.516 | 8.362 | 0.502 |

### *SIF Summary*

- We have discussed the failure mechanism of polyethylene in some detail
- We have discussed the variance of stress in polyethylene pipes
- We have defined our usage of the term SIF
- We have developed SIF for various polyethylene piping configurations
- We have shown how to develop a probability distribution for SIF using a mean value and a quantification of our uncertainty for the mean
- We have presented a method for combining multiple SIF in a coherent manner

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## 3. Adjusted RPM Models for Use with Aldyl-A SIF

So far, we have established a sound reference RPM model for Aldyl A that can be used to predicted the lifetime of a piping component, provided we have an accurate representation of the stress driving the mode of failure. We have developed SIF to represent the driving stress, provided a means for combining SIF and are left with the task of reconciling the RPM model with the SIF.

The complicating issue is that the RPM models were developed with test specimens having a wide variance of actual effective-SIF during their evaluation. In the section **Stress Intensification Factors (SIF)** above, we presented a method for estimating the distribution of these SIF in a dataset under the assumption that the variance in test results is due solely to the distribution of effective SIF. We showed that the standalone SIF we developed match SIF determined by various other methods quite closely.

### *Adjusting the RPM Model for Internal SIF*

We will now adjust the RPM model for SCG in Aldyl A to account for the SIF that were present in the test specimens, normalize the standalone SIF accordingly, and demonstrate the validity of the method using several independent datasets.

**Figure 3-1** shows the distribution of SIF in the DuPont control dataset for SCG failures. It is interesting to note that the mean SIF value is very close to that shown in **Figure 2-6** for blunt grooves, and that there is peak around SIF=3 that would correspond to sharp grooves. We would expect to realize the full effect of SIF in SCG type failures. **Figure 3-2** shows the true stress in the test specimens, obtained by multiplying the hoop stress by the SIF developed from assuming that the variance in results is solely due to differences in the true stress.

On substituting the true-stress values into a RPM analyses we find that 94 of the 122 data points closely follow the expected Arrhenius behavior as evidenced by a straight line on a log-log plot. Twenty-nine data points deviate markedly from this behavior. This is shown in **Figure 3-3.** In selecting data points to include in the model the 94 well behaved points were selected by default and a further 5 points were added to ensure that the mean line of the RPM model closely matched the slope of the 94 points on the log-log plot. The justification for this step is that the slope of the model lines reflects a combination of the activation energy for the α-relaxation process and the degree of constraint at the damage tip. The data points that deviate from this behavior may have been mixed mode failures where the degree of constraint at the damage tip was greatly reduced, or they could reflect data recording or other experimental errors. The resulting adjusted RPM model is presented in **Table 3-1**.

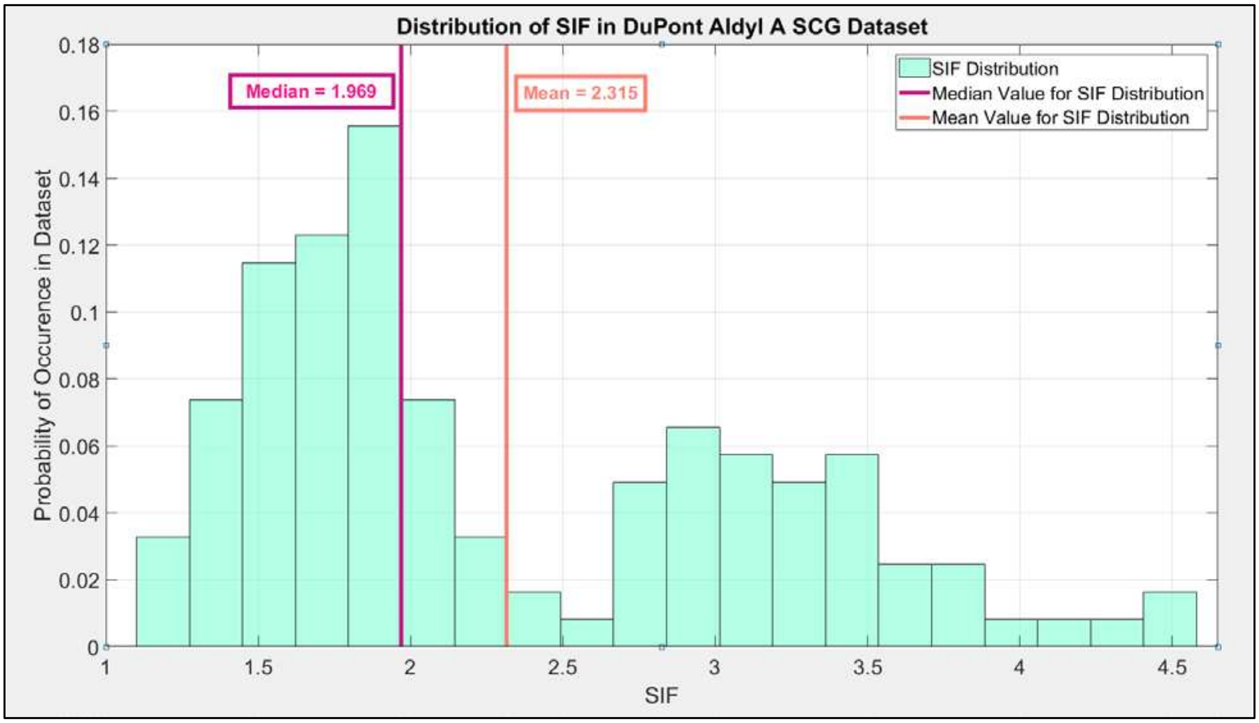



Figure 3-1. Distribution of SIF in DuPont SCG Reference Dataset

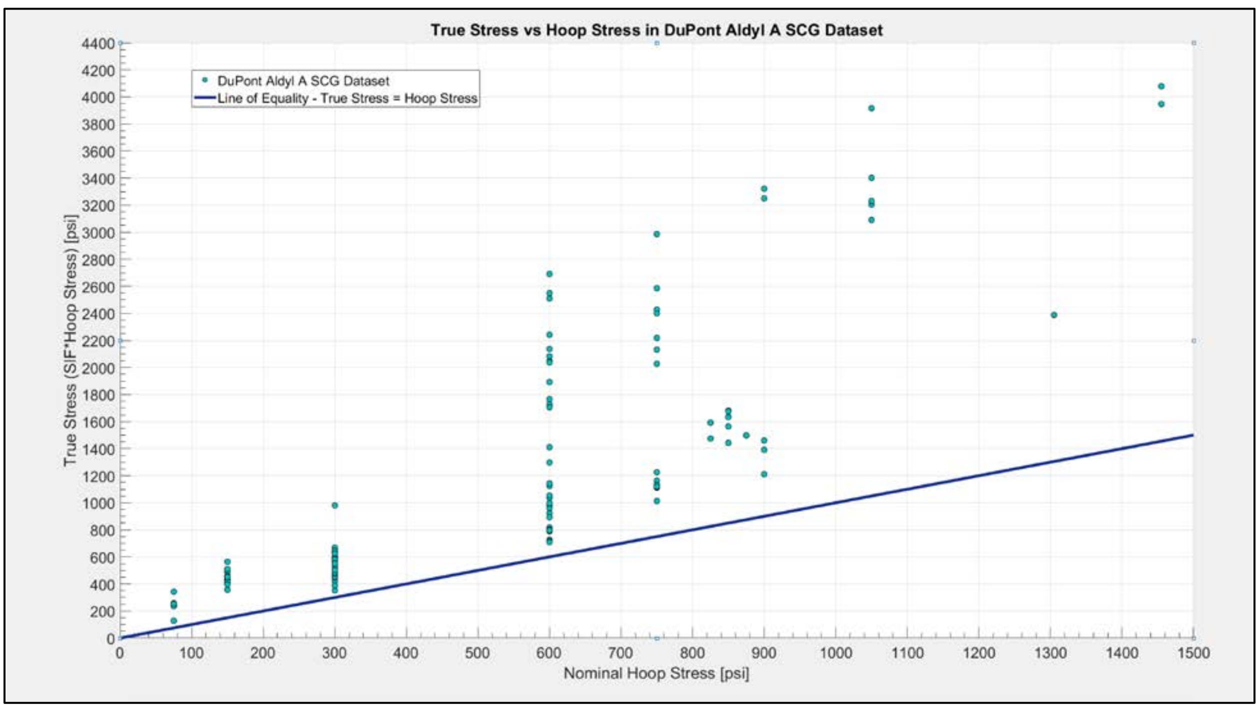



Figure 3-2. True Stress vs Hoop Stress in DuPont SCG Reference Set

**Table 3-1. SIF Adjusted DuPont SCG Control Model Parameters for 3 Parameter ISO 9080 Model**

| Parameters | C1 | C2 | C4 | $R^2$ | $R^2_{adj}$ | n | p | $\sigma^2$ |
|---|---|---|---|---|---|---|---|---|
| Value | -18.051 | 10268.4 | -1030.7 | 0.954 | 0.953 | 99 | 3 | 0.0429 |
| Standard Error | 0.52565 | 232.21 | 28.0683 | | | | | |

| Covariance Matrix | | |
|---|---|---|
| 0.276312393 | -116.2678638 | 7.443808708 |
| -116.2678638 | 53921.28778 | -4836.675907 |
| 7.443808708 | -4836.675907 | 787.830244 |

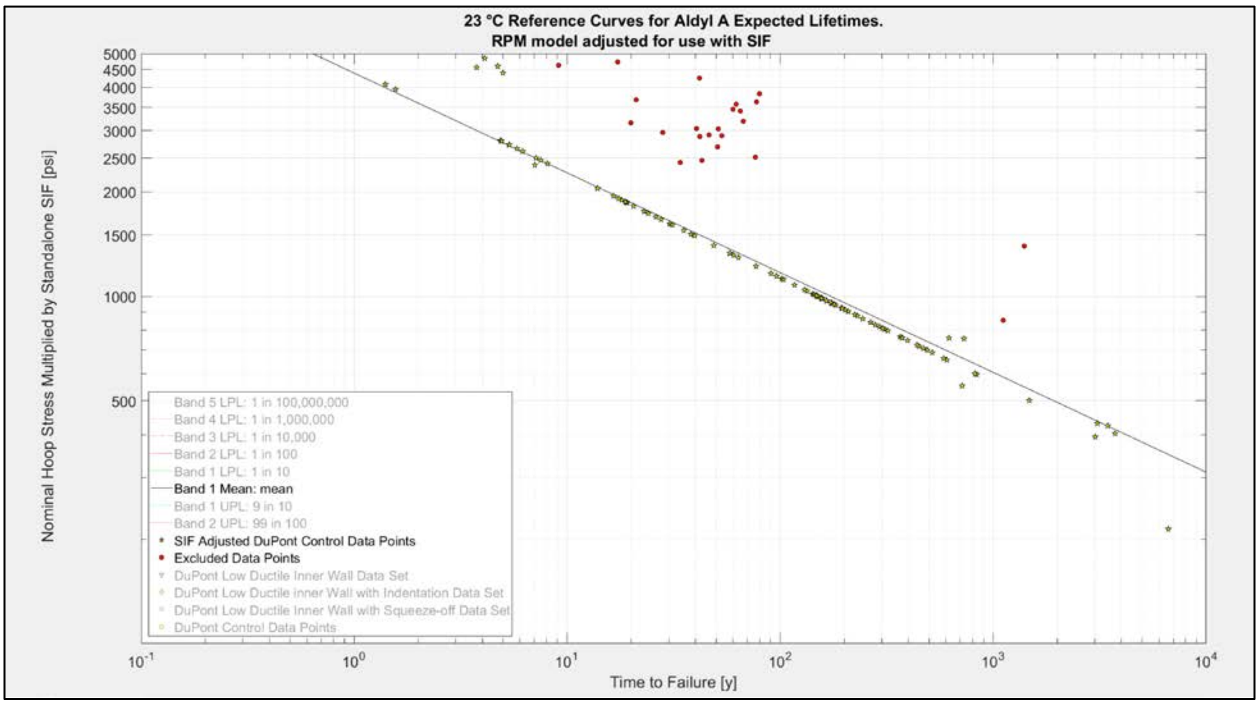



**Figure 3-3. SIF Adjusted RPM model for DuPont Control SCG Dataset**

The prediction limit bands for the adjusted RPM model are shown in **Figure 3-4**. There is no intrinsic significance to the prediction bands as they do not reflect true variance in a dataset, they simply give a convenient measure of distance from the mean for when we plot actual data sets for comparison.

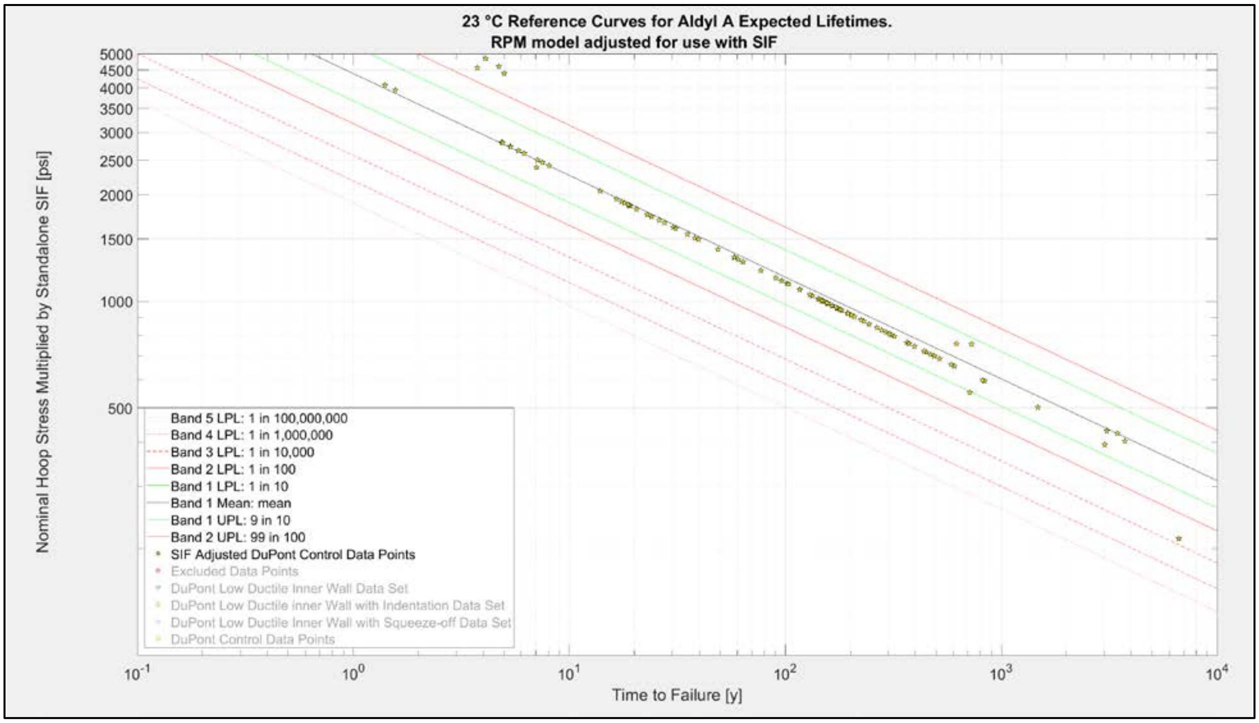



**Figure 3-4. Adjusted RPM Model with Prediction Limit Bands**

In addition to the control SCG dataset GTI has DuPont reference datasets for Aldyl A pipe with LDIW, LDIW with Squeeze-off, and LDIW with indentation. These four datasets are independent and reflect varying levels of intrinsic defect and material condition. The hoop stress for each data set was multiplied by the standalone SIF presented in **Table 3-2**. The SIF adjusted for use with adjusted RPM model are normalized to the median of the SIF for the control SCG dataset.

**Table 3-2. Adjusted SIF for use with Adjusted RPM Model**

| Adjusted SIF for SCG Failure: Logistic Distribution Parameters for use with adjusted RPM model given in Table 3-1 | Standalone SIF | | Relative to baseline pipe SIF | |
|---|---|---|---|---|
| | Mu | sigma | Mu | sigma |
| Pipe Quality Tier 1 SCG – Baseline SIF | 1.016 | 0.061 | 1.016 | 0.061 |
| Use standalone SIF value for single SIF. Develop composite SIF by adding SIF referenced to baseline using Equation 2-5 for each independent SIF component acting on pipe component to the baseline SIF | | | | |
| Pipe Quality Tier 2 SCG | 1.117 | 0.067 | 0.461 | 0.028 |
| Pipe Quality Tier 3 Severe Grooves SCG | 1.524 | 0.091 | 1.136 | 0.068 |
| Pipe Quality Tier 4 LDIW SCG | 2.936 | 0.176 | 2.755 | 0.165 |
| LDIW Squeeze-off SCG | 3.401 | 0.204 | 3.246 | 0.195 |
| LDIW Impingement SCG | 4.367 | 0.262 | 4.247 | 0.255 |

The SIF adjusted data points for the four datasets are overlaid on the adjusted RPM model in **Figure 3-5**.

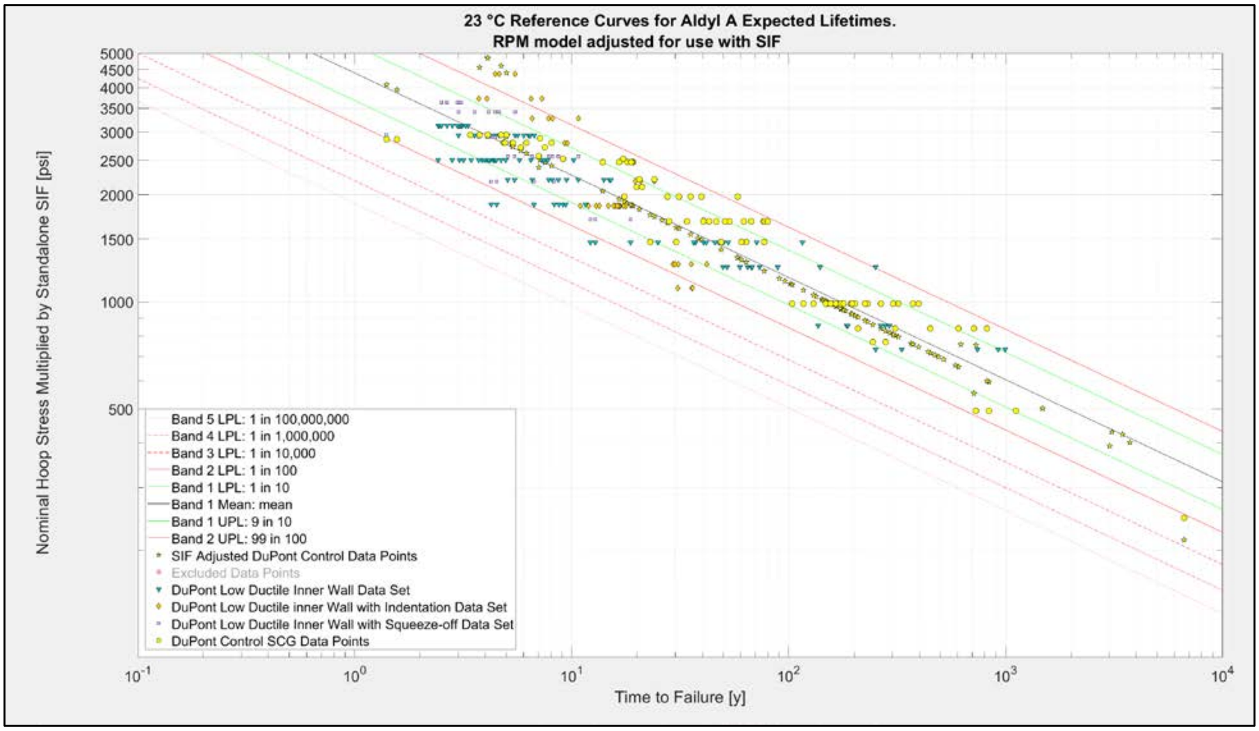



**Figure 3-5. Validation of Adjusted RPM Model and Standalone SIF Approach for 4 Independent Datasets with Different Intrinsic Defects and Loading Conditions**

All four of the datasets overlap in the same region and capture the same slope as the model indicating the adjusted model is a true material behavior model calibrated to the true stress at the damage tip. There are 7 points out of 351 above the Band 2 UPL, or 1.02% and 8 points below the Band 2 LPL, or 1.17%. We would be expecting to find 1% of data points above and a further 1% of data points below these two prediction bounds respectively. Given this excellent agreement we can say that the proposed methodology gives us 98% certainty in our predictions.

### *Summary*

1. We have developed a RPM prediction model for Aldyl A that captures the SCG behavior if we know the true stress at the damage tip
2. We have developed SIF for many known material conditions and loading configurations that are calibrated to the RPM model
3. We have demonstrated the validity of the RPM model and SIF with four independent datasets containing 351 validation points.
4. We have demonstrated that the prediction limits of the RPM model match the reference data to the expected confidence level.

## 4. Bayesian Network Model for Aldyl-A Lifetime Expectancy

### Introduction

In this section, the roots causes for pipe risk assessment are identified and an ontology describing the interactions between them is proposed, which primarily includes the current knowledge base of the subject matter experts. Upon that, a directed acyclic graph (DAC) approach, i.e. Bayesian network is employed to express the causal relationship between the root causes. Different from the classical index-based risk model, the probabilistic Bayesian network model can inherently incorporate the historic data, subject matter expert's opinions, as well as the belief about the collected data. Those characteristics allow for continuous refinement of the network structure and node probability table when additional knowledge is available. The risk prognosis and context condition diagnosis are achieved by propagating the information in forward and backward directions, which means the causal network can not only calculate the pipeline segment risk given the context conditions, but also recommend the optimal mitigation approaches taken to achieve certain operation goals. The network developed in this section acts as the engine for the enterprise decision support system. The detailed description of the overall development process is discussed below.

### Bayesian Network Theory

Bayesian networks are causal probabilistic models that combine data and subject matter expert knowledge to quantify certainty, providing the most rigorous and rational basis for critical decision making process. Specifically, a Bayesian network is a directed acyclic graph where the nodes represent a set of random variables $X = \{X_1, X_2, X_3, \dots, X_n\}$, and the edges connecting any two nodes represent direct dependency between them[19]. The strength of an edge is given by conditional probability distribution of the nodes associated with the edge. **Figure 4-1** shows a Bayesian network model of five nodes.

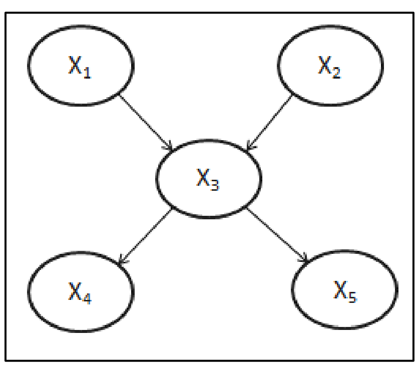



**Figure 4-1. Example of Bayesian network with five nodes**

Mathematically, a Bayesian network of a set of $n$ random variables $X = \{X_1, X_2, X_3, \dots, X_n\}$ is represented by its joint probability distribution $P(X_1 = x_1, X_2 = x_2, X_3 = x_3, \dots, X_n = x_n)$ or $P(x_1, x_2, x_3, \dots, x_n)$, where $x_1, x_2, x_3, \dots, x_n$ are the values of the variables $X_1, X_2, X_3, \dots, X_n$, respectively. The probability distribution for each variable $X_i$ is computed by taking the marginal integration of all the other variables. Based on the direction of information propagation, the Bayesian network can be used for prognosis and diagnosis.

$$\begin{aligned} &P(x_1, x_2, x_3, \dots, x_n) \\ &= P(x_1)P(x_2|x_1)P(x_3|x_1, x_2) \dots P(x_n|x_1, x_2, x_3, \dots, x_{n-1}) \\ &= \prod_{i=1}^{n} P(x_i|x_1, x_2, x_3, \dots, x_{i-1}) \end{aligned}$$ **Equation 4-1**

## *Pipeline Risk Modeling*

It has been stated before that the failure of pipeline results from the interaction of multiple causes. The capabilities of Bayesian network enable the calculation of threat interaction levels and severity of risks in vintage gas pipelines. To improve the analysis accuracy, the subject matter expert's opinions, historic data, and concurrent inspection data are integrated in the developed Bayesian network model.

### Graphical Analysis for Risk Factors

Initially, 32 factors, identified by SMEs were considered to have critical impact on the performance of vintage gas pipelines. Those factors are illustrated in **Figure 4-2** and they represent the nodes of the developed Bayesian network.

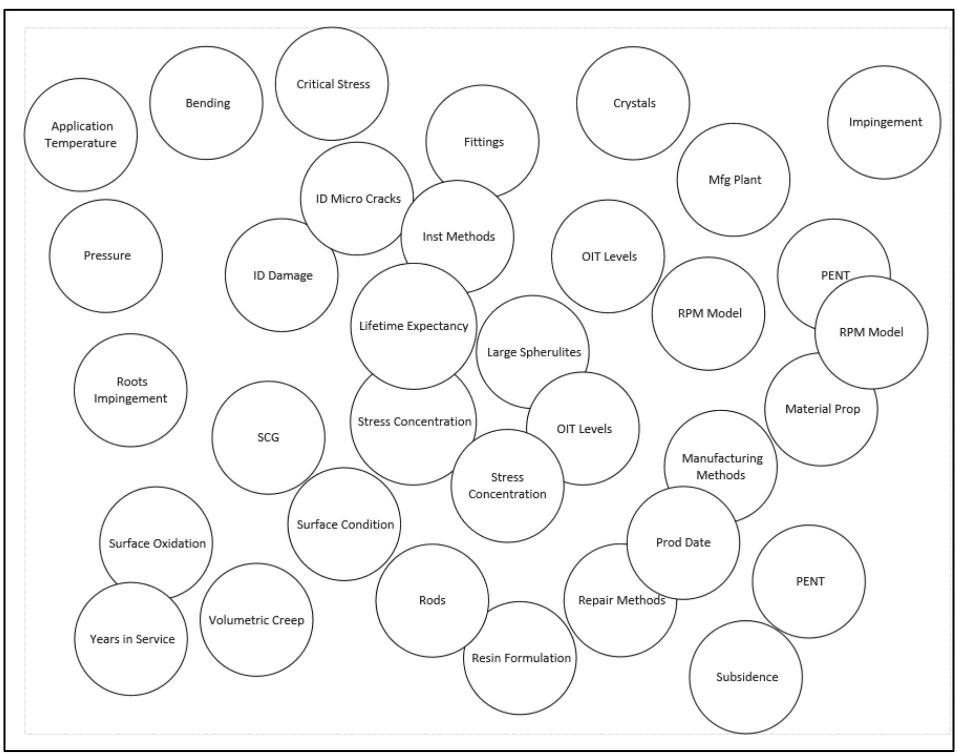



**Figure 4-2. Factors selected by SMEs**

The second step is to determine the interaction between every two nodes. Out of a theoretical possible combination of 4,294,967,296 interactions between the 32 factors, SMEs then selected 65 plausible interactions to construct the edges of the initial Bayesian network as shown in **Figure 4-3**. Two simple graphical analyses were then run. First, betweenness centrality, which is equal to the number of shortest paths from all vertices to all others that pass through that node, was calculated for every node. It is shown in **Figure 4-4**. Second, degree centrality, which is the number of ties a node has to other nodes, was calculated for each node as shown in **Figure 4-5**. Larger red dot denotes higher centrality value in both **Figure 4-4** and **Figure 4-5**. The product of degree centrality and betweenness centrality gives a composite ranking, which then helps to identify the most important factors. **Figure 4-6** and **Figure 4-7** show the composite ranking of nodes in the Bayesian network. As expected, the top five factors with the highest composite rankings in decreasing order are Stress concentration, Manufacturing methods, Bending, RPM model, and Surface condition.

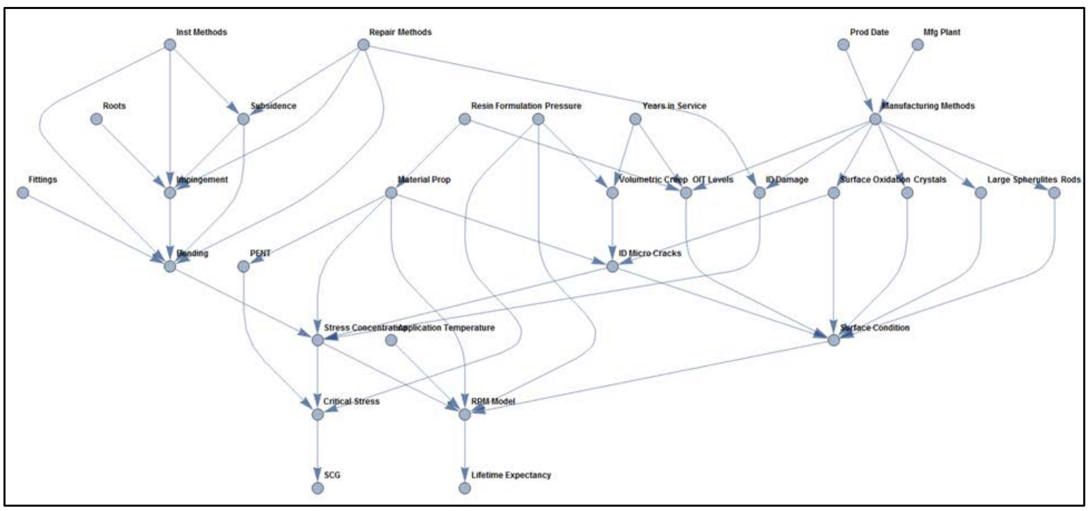



**Figure 4-3. Initial Bayesian network graph selected by SMEs**

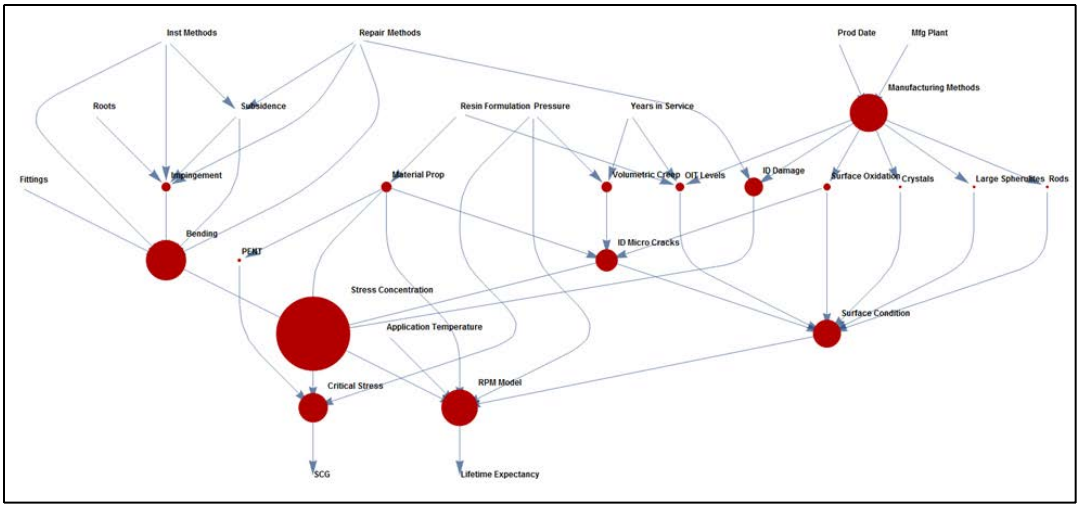



Figure 4-4. Betweenness centrality of the Bayesian network graph

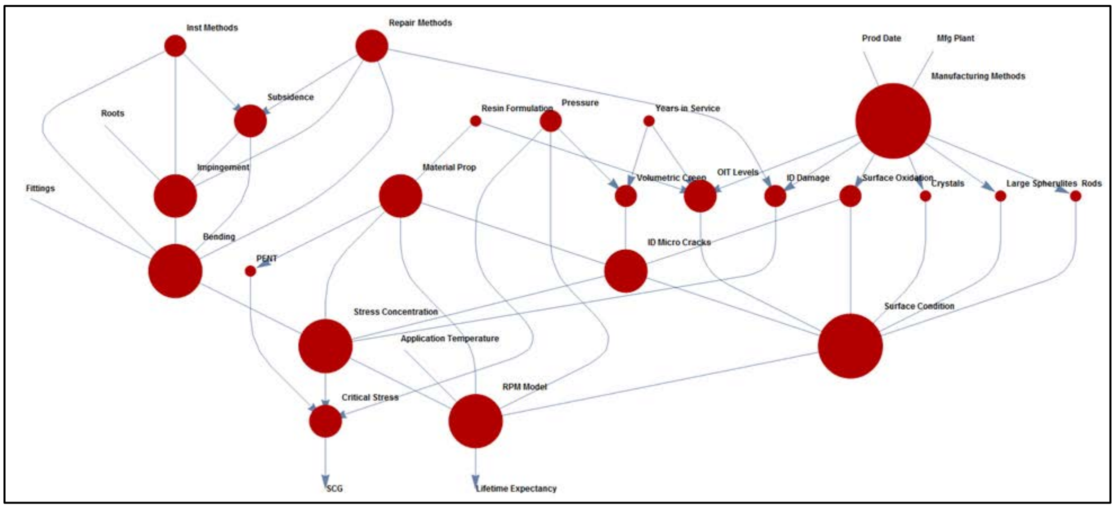



Figure 4-5. Degree centrality of the Bayesian network graph

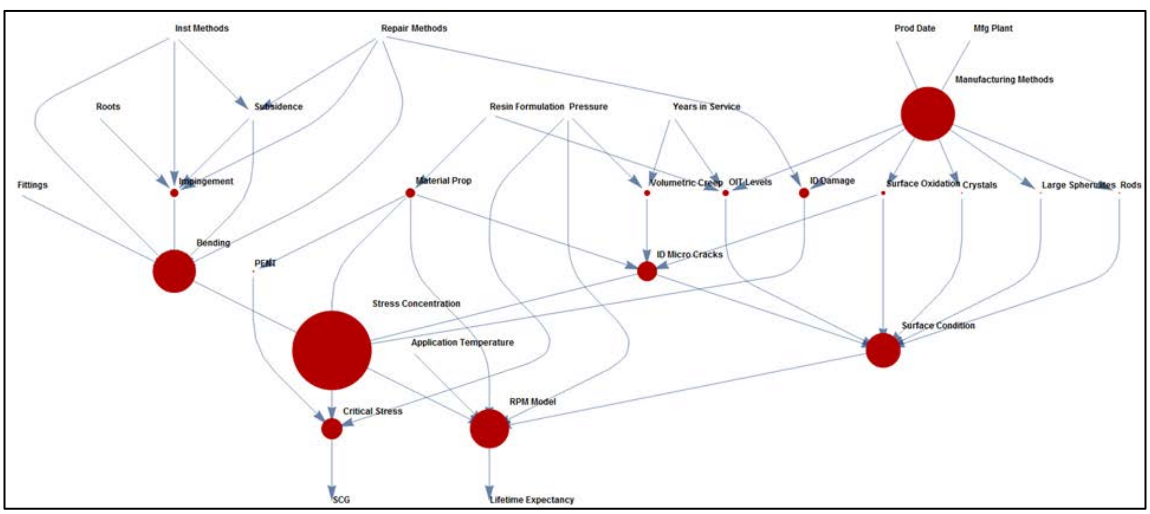



Figure 4-6. Composite ranking of the Bayesian network graph

| | |
|---|---|
| Stress Concentration | 51. |
| Bending | 27.5 |
| Manufacturing Methods | 26. |
| RPM Model | 25. |
| Critical Stress | 20. |
| Surface Condition | 19. |
| ID Micro Cracks | 15. |
| ID Damage | 12.5 |
| Volumetric Creep | 7. |
| Material Prop | 7. |
| Impingement | 6. |
| OIT Levels | 5.6 |
| Surface Oxidation | 4.6 |
| PENT | 2. |
| Rods | 1.6 |
| Large Spherulites | 1.6 |
| Crystals | 1.6 |
| Years in Service | 0. |
| Subsidence | 0. |
| SCG | 0. |
| Roots | 0. |
| Resin Formulation | 0. |
| Repair Methods | 0. |
| Prod Date | 0. |
| Pressure | 0. |
| Mfg Plant | 0. |
| Lifetime Expectancy | 0. |
| Inst Methods | 0. |
| Fittings | 0. |
| Application Temperature | 0. |

Betweenness Centrality

| | |
|---|---|
| Manufacturing Methods | 8 |
| Surface Condition | 7 |
| Stress Concentration | 6 |
| RPM Model | 6 |
| Bending | 6 |
| Material Prop | 5 |
| Impingement | 5 |
| ID Micro Cracks | 5 |
| Subsidence | 4 |
| Repair Methods | 4 |
| OIT Levels | 4 |
| Critical Stress | 4 |
| Volumetric Creep | 3 |
| Surface Oxidation | 3 |
| Pressure | 3 |
| Inst Methods | 3 |
| ID Damage | 3 |
| Years in Service | 2 |
| Rods | 2 |
| Resin Formulation | 2 |
| PENT | 2 |
| Large Spherulites | 2 |
| Crystals | 2 |
| SCG | 1 |
| Roots | 1 |
| Prod Date | 1 |
| Mfg Plant | 1 |
| Lifetime Expectancy | 1 |
| Fittings | 1 |
| Application Temperature | 1 |

Degree Centrality

| | |
|---|---|
| Stress Concentration | 306. |
| Manufacturing Methods | 208. |
| Bending | 165. |
| RPM Model | 150. |
| Surface Condition | 133. |
| Critical Stress | 80. |
| ID Micro Cracks | 75. |
| ID Damage | 37.5 |
| Material Prop | 35. |
| Impingement | 30. |
| OIT Levels | 22.4 |
| Volumetric Creep | 21. |
| Surface Oxidation | 13.8 |
| PENT | 4. |
| Rods | 3.2 |
| Large Spherulites | 3.2 |
| Crystals | 3.2 |
| Years in Service | 0. |
| Subsidence | 0. |
| SCG | 0. |
| Roots | 0. |
| Resin Formulation | 0. |
| Repair Methods | 0. |
| Prod Date | 0. |
| Pressure | 0. |
| Mfg Plant | 0. |
| Lifetime Expectancy | 0. |
| Inst Methods | 0. |
| Fittings | 0. |
| Application Temperature | 0. |

Composite Ranking =
Betweenness Centrality * Degree Centrality

**Figure 4-7. Composite ranking of the nodes in Bayesian network graph**

The third step is to construct conditional probability tables for the factors in the Bayesian network. Three methods were identified for the purpose: FEM analysis, Data collection and analysis, and Experimentation and observation as shown in **Figure 4-8**. We used an extensive historic hydrostatic test data covering all vintage pipelines to construct the preliminary conditional probability table. **Figure 4-9** demonstrates the preliminary analysis results. The initial study was conducted on a set of 105 slow crack growth failures in pipe that were not associated with fittings or other known stress risers. The pipes were all extracted from a gas distribution system in 2010 -2011. They had been in service since 1972, 1973 and 1974. A combination of simpler statistical models, subject matter expertise and historical observations was used to estimate initial graphical structure and probabilistic distribution of a Bayesian network model. This process is represented in ontology illustrated by **Figure 4-10**. Statistical models help to understand various levels of threat interactions between factors of interest that may lead to failure. Some of the modeling methods, evaluated in this preliminary work, are rate process method, fault tree analysis, event tree analysis, surface feature model, finite element method, risk score model, etc. The following sections will demonstrate the continuous refinement of the developed Bayesian network when additional data or knowledge are collected.

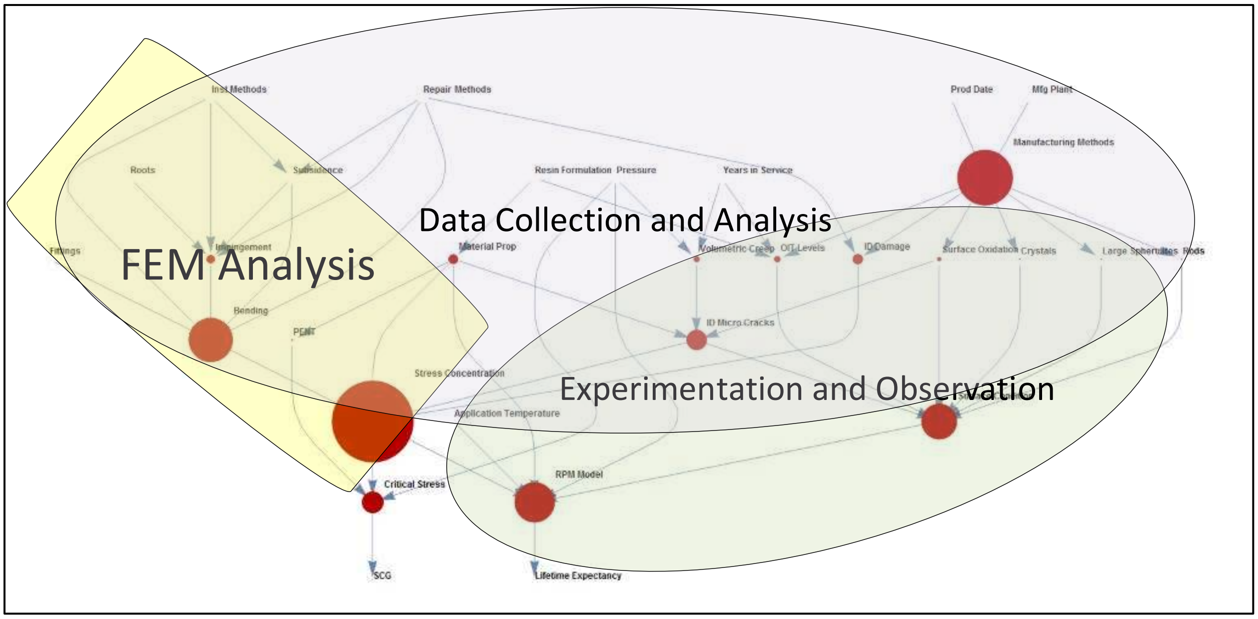



Figure 4-8. Methods to derive the conditional probability tables in the Bayesian network

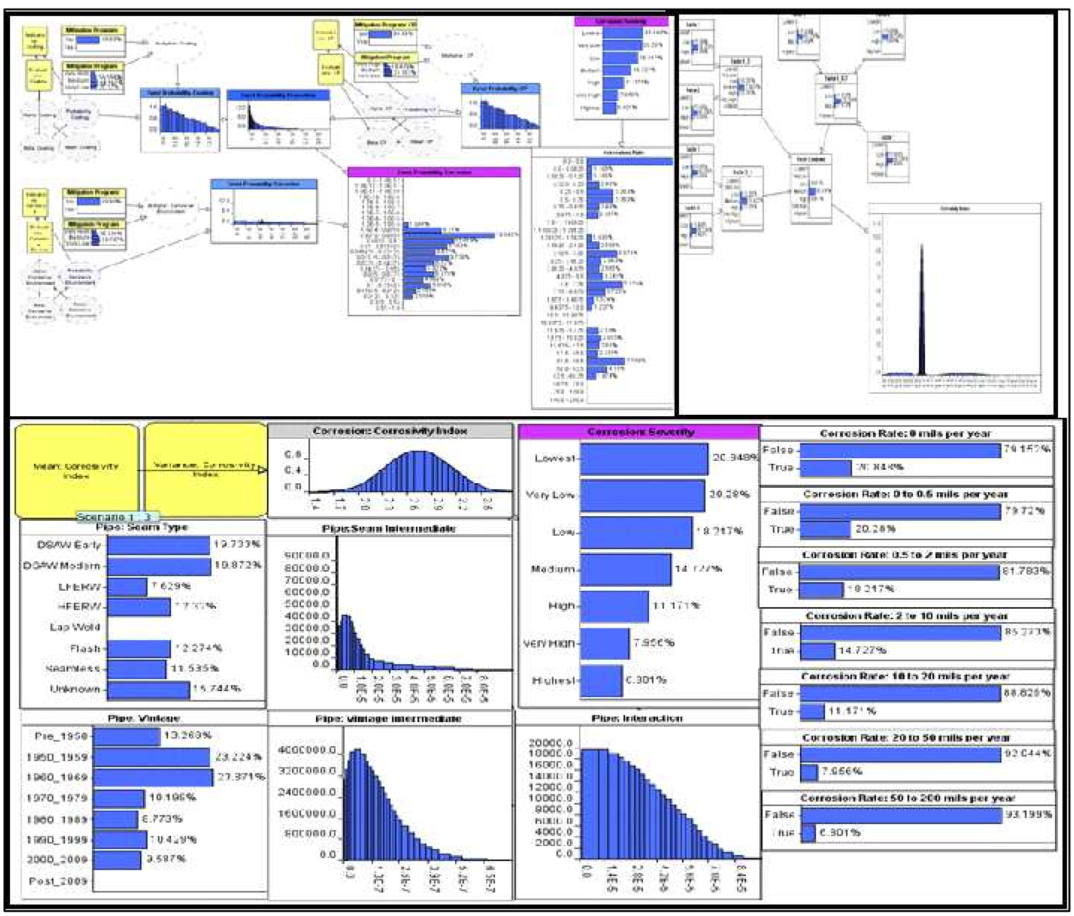



Figure 4-9. Preliminary conditional probability distributions

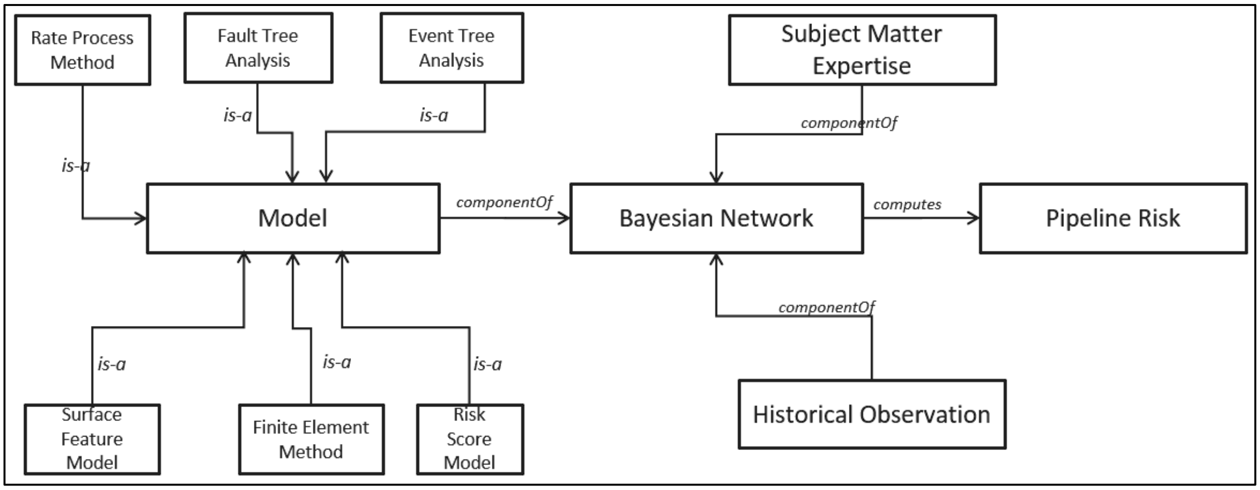



**Figure 4-10. Ontology describing the models, subject matter expert's knowledge, historical observation, and Bayesian network**

## Bayesian Network Quantification for Aldyl A Risk Assessment

Under the normal operation pressure, pipelines will experience the slow crack growth (SCG) failure pattern, because the applied stress is too low to cause ductile failure. Three factors were identified to have the greatest impact on the pipe SCG lifetime expectancy - pipe inner wall surface condition, stress state, and ground temperature. The pipe inner surface condition depends on a number of factors notably the presence of surface oxidation, surface crystals, boundary crystals, large Spherulites, rods, inside diameter micro cracks (IDMC), and dimple. The pipe stress state is the result of any stress risers acting on the pipe such as material properties, impingement, bending, etc. Ground temperature is directly associated with the creep behavior of a pipe, and thus affects its lifetime expectancy.

In this project, AgenaRisk[20], a popular risk analysis and decision support software, is used to develop the causal network, which is then deployed to the developed Enterprise Decision Support System. The JavaScript Object Notation (JSON) messaging format from the previous quarter is also updated with new features for sensitivity analysis, initialization, update and query operation in the Bayesian network model. Given the SCG failure pattern described above, the initially constructed Bayesian network in **Figure 4-3** is updated and illustrated in **Figure 4-11**. In this updated network, volumetric creep node is eliminated because through extensive studies, available volumetric creep models could not provide satisfactory prediction for the initiation of inner diameter micro cracks (IDMC) as well as the total lifetime expectancy. An alternative approach is proposed in the following section to incorporate the effect of years in service. Apart from that, some intermediate nodes, such as "OD_ID_ratio", "Resultant Movement", and "Risk Score" are introduced here to alleviate computational efforts.

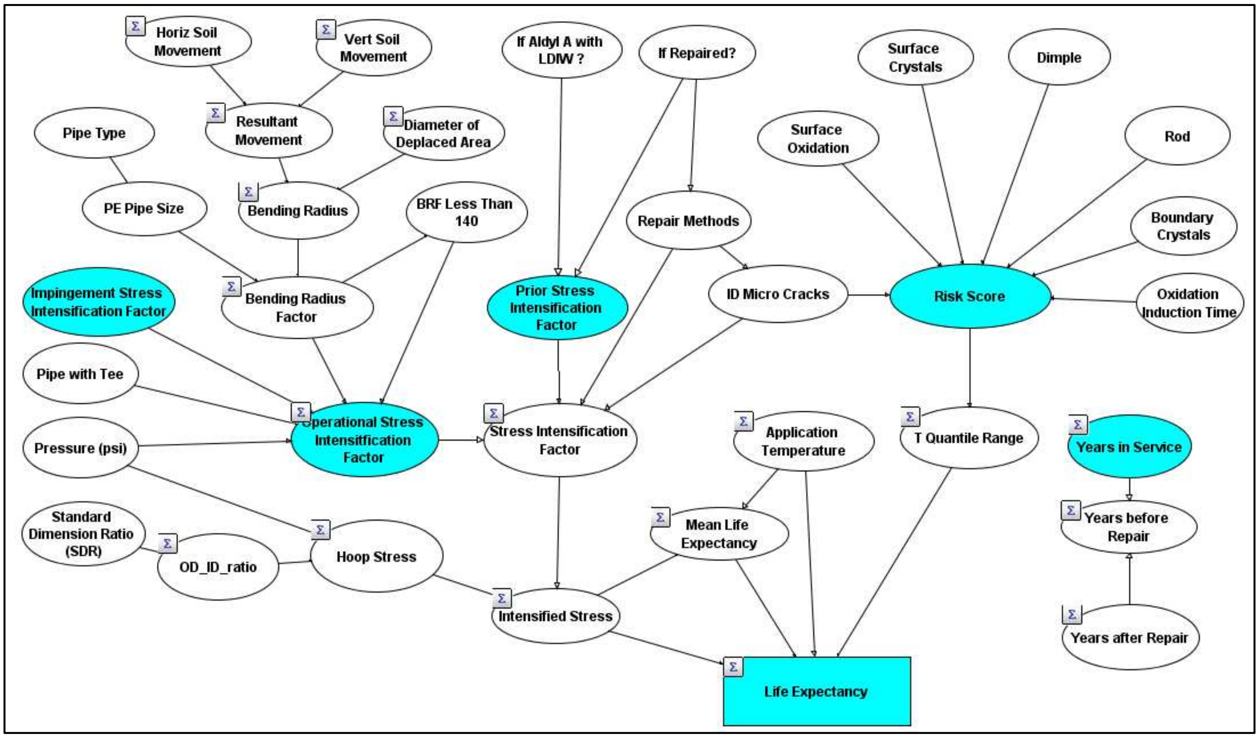



**Figure 4-11. The modified overall Bayesian network**

### *Prior Stress Intensification Factor (PSIF)*

In this section, the effect of years in service is considered by introducing the prior stress intensification factor (PSIF) node. The stress concentration node in the initial design is modified as operational stress intensification factor (OSIF), which represents the stress intensification factor (SIF) caused by factors related to pipeline operations, such as soil movement, impingement, pipe type, operational pressure, etc. Analogous to previous discussion, the network is partitioned into several sub-networks according to the nodes highlighted in **Figure 4-11**. The node "Impingement Stress Intensification Factor" is the output from a separate Bayesian network model, which will be discussed in detail below. The node types and states are determined with the best knowledge of the investigator and they are summarized in **Table 4-1**.

**Table 4-1. The summary for node types and states**

| Node Name | Node Type | States/Distribution | Unit | Explanation |
|---|---|---|---|---|
| Years in Service | Continuous | N (40, 400, 5, 70)* | Year | From Installation Time to Now |
| Years after Repair | Continuous | U (0, 50)** | Year | From Repair Time to Now |
| Years before Repair | Continuous | | Year | Years-YaftRep |
| If Aldyl A with LDIW | Boolean | (False, True) | | Check If the Aldyl a Pipe Has Low Ductile Inner Wall (LDIW) |

| Node Name | Node Type | States/Distribution | Unit | Explanation |
|---|---|---|---|---|
| If Repaired | Boolean | (False, True) | | Check If the Pipe Has Been Repaired |
| Repair Methods | Labelled | (Mechanical Coupling, Butt Fusion, NA) | | Repair Methods |
| Prior Stress Intensification Factor (PSIF) | Continuous | | | Prior Stress Intensification Factor based on Historic AldylA Data |
| Horiz Soil Movement | Continuous | N(12, 36, 0, 120) | Ft | Soil Movement along Horizontal Direction |
| Vert Soil Movement | Continuous | N(24, 36, 0, 120) | Ft | Soil Movement along Vertical Direction |
| Resultant Movement | Continuous | | Ft | Resultant Soil Movement |
| Diameter of Displace Area | Continuous | N(50,100, 0, 100) | Ft | Diameter of the Area with Soil Movement |
| Bending Radius | Continuous | | | Pipe Bending Radius |
| Pipe Type | Boolean | (Service Lines, Mains) | | Pipe Function Type |
| PE Pipe Size | Labelled | (<=1 inch, <=2inch, <=4 inch, <= 6 inch ) | | Pipe Outside Diameter |
| Bending Radius Factor | Continuous | | | Bending Radius/Pipe Size |
| BRF Less Than 140 | Boolean | (False, True) | | Check if the Bending Radius Factor is Less Than 140 |
| Pipe with Tee (PWT) | Boolean | (False, True) | | Check if the AldylA Pipe has a Tee |
| Operational Stress Intensification Factor (OSIF) | Continuous | | | SIF Caused by Root, Rock, Impingement, and Bending |
| Stress Intensity Factor (SIF) | Continuous | | | Combination Between PSIF and OSIF |
| ID Micro Cracks | Discrete Real | (0.0, 1.0) | | Existence of Micro Cracks on Inside Diameter |
| Surface Oxidation | Discrete Real | (0.0, 1.0, 2.0, 3.0, 4.0, 5.0) | | Surface Oxidation on Inside Diameter |
| Surface Crystal | Discrete Real | (0.0, 1.0, 2.0, 3.0, 4.0, 5.0) | | Surface Crystal on inside diameter |
| Dimple | Discrete Real | (0.0, 1.0) | | Existence of Dimple on Inside Diameter |
| Rod | Discrete Real | (0.0, 1.0) | | Existence of Rod on Inside Diameter |
| Boundary Crystal | Discrete Real | (0.0, 1.0, 2.0, 3.0, 4.0, 5.0) | | Boundary Crystal on Inside diameter |
| Risk Score | Labelled | (1, 2, 3, 4) | | Relative Risk Score Determined by Pipe Micro Surface Features |
| T Quantile Range | Continuous | ([-1.29,6.50],[-2.36,-1.29], [-3.84,-2.36],[-5.00,-3.84]) | | Quantile Range from t Distribution |
| Application Temperature | Continuous | 23 | Celsius | Average Operation Temperature of the Pipe |
| Pressure | Continuous | N(50, 400, 1, 100) | Psi | Operation Pressure |
| Standard Dimension Ratio (SDR) | Discrete Real | (9, 11, 13) | | Outside Diameter/Wall Thickness |

| Node Name | Node Type | States/Distribution | Unit | Explanation |
|---|---|---|---|---|
| OD_ID_Ratio | Continuous | (1.6531, 1.4938, 1.3967) | | SDR^2/(SDR-2)^2 |
| Hoop Stress | Continuous | | Psi | Hoop Stress Caused by Internal Pressure |
| Intensified Stress | Continuous | | Psi | Hoop Stress Intensified by SIF |
| Mean Life Expectancy | Continuous | | Log(hrs) | Mean Life Prediction using Control SCG Model |
| Life Expectancy | Continuous | | Log(hrs) | Life Prediction Considering Risk Score of the Pipe |
| Impingement SIF | Continuous | | | SIF Caused by Impingement |
| * Represents truncated normal distribution $N(\mu, \sigma^2, Lower\ Bound, Upper\ Bound)$<br>**Represents uniform distribution $U(Lower\ Bound, Upper\ Bound)$ | | | | |

The Dupont Company has performed hydrostatic testing of Aldyl A in accordance with the industry accepted Rate Process Model (RPM). The times of failure of the specimens under different conditions overlay the Dupont control reference data at all stress levels. The hydrostatic pressure testing data sets for Aldyl A are depicted in **Figure 4-12**, in which it can be seen that the pipes have different failure time distributions for different geometry/loading conditions such as low ductile inner wall (LDIW), indentation/impingement, and squeeze-off. LDIW is the inner surface feature defects induced by manufacturing process for Aldyl A in 1970s. Since indentation has similar effect with the impingement, its effect is considered in the impingement node. Generally, squeeze-off is a common method for stopping the gas flow for plastic pipe repair. Therefore, it is assumed that the pipe will be under squeeze-off loading condition if the pipe has been repaired.

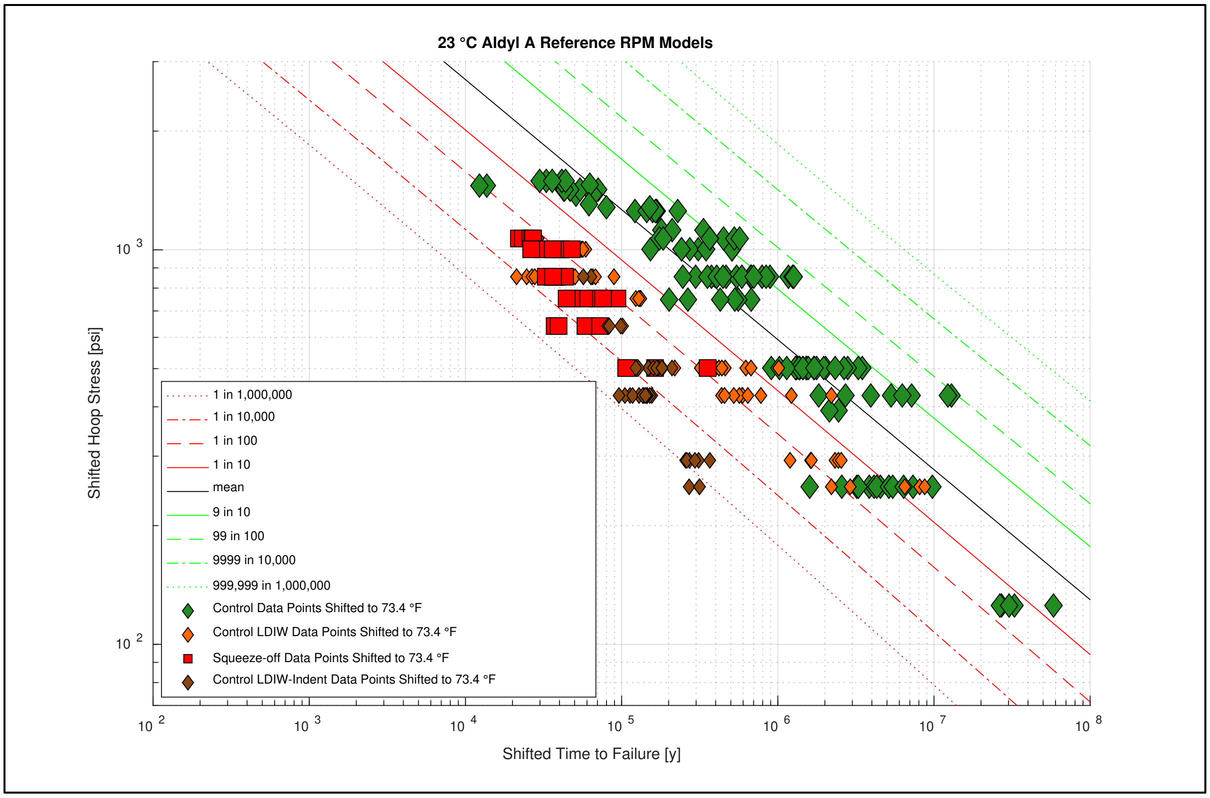



**Figure 4-12. Data sets for SCG control, LDIW control, LDIW with indentation and LDIW with squeeze-off shifted to 73.4°F**

In pressure testing guidelines, stress intensification factor (SIF) originating from the extrusion process seeds the ductile failure mode, which was consistent with the results from finite element analysis (FEA). Bearing the idea that the distribution of SIF on the inside diameter will not vary between different testing methods, the mean SIF value for the SCG data should be identical with that of the Ductile data. To compute the life under different loading conditions, the data sets for control LDIW, LDIW with Indentation, and LDIW with squeeze-off were mapped to the SCG control curve with an equivalent SIF value for each data point. The mapping process is discussed in **8** below. The prior distributions for SIF under different loading conditions are depicted in **Figure 4-13**. Before substituting the computed SIF distribution into the RPM, the values need to be normalized with respect to its mean SIF value of the control SCG data and the normalized SIF is represented as SIFN below.

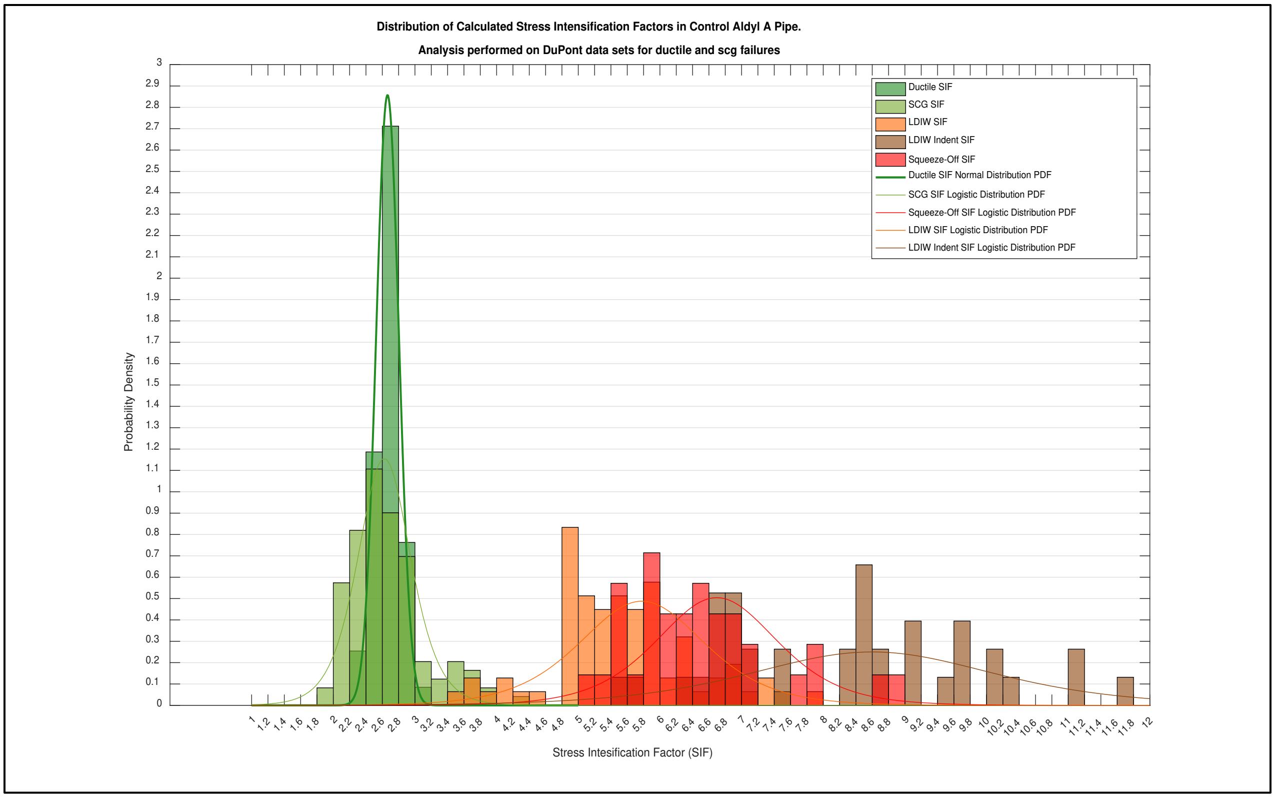



**Figure 4-13. The SIF distributions under different loading conditions**

To accurately quantify the remaining useful life (RUL) of pipes, it is critical to consider the effect of years in service. The schematics for computing the relative stress intensification factor (SIFR) are illustrated in **Figure 4-14**. Plugging these two data points into SCG reference rate process model (RPM), we can get

$$\log(t_0) = C_1 + \frac{C_2}{T} + \frac{C_4}{T}\log(\sigma_0) \quad \textbf{Equation 4-2}$$

$$\log(t_0 - \Delta t) = C_1 + \frac{C_2}{T} + \frac{C_4}{T}\log(\sigma_1) \quad \textbf{Equation 4-3}$$

Combining Equation **4-2** and **Equation 4-3**, the relative SIF can be computes as

$$SIFR = \frac{\sigma_1}{\sigma_0} = \left(\frac{t_0 - \Delta t}{t_0}\right)^{\frac{T}{C_4}} \quad \textbf{Equation 4-4}$$

Thus, the total SIF (SIFT) after $\Delta t$ years in service is expressed as

$$SIFT = SIFR \times SIFN \qquad \textbf{Equation 4-5}$$

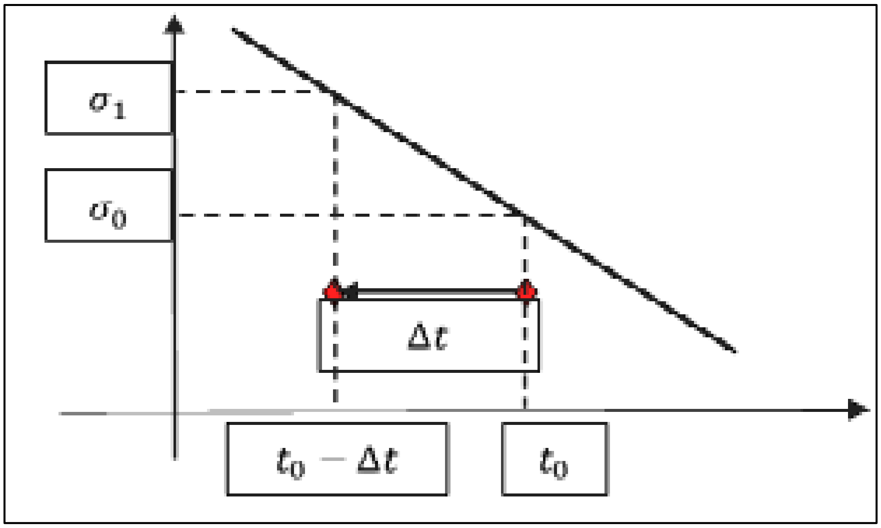



**Figure 4-14. The schematics for computing the relative SIF (SIFR)**

Given the years in service, the total failure life of the pipe is the summation of years in service and the predicted RUL. Taking the LDIW data as an example, **Figure 4-15** illustrates the procedures for computing the RUL and total failure time after certain years in service. The LDIW is shifted to the left by $\Delta t$ years as shown in **Figure 4-16**. Conceptually, the predicted total failure time after certain years in service should be identical to the control LDIW data without considering other material degradation factors. The predicted total failure time considering different years in service is given in **Figure 4-17**.

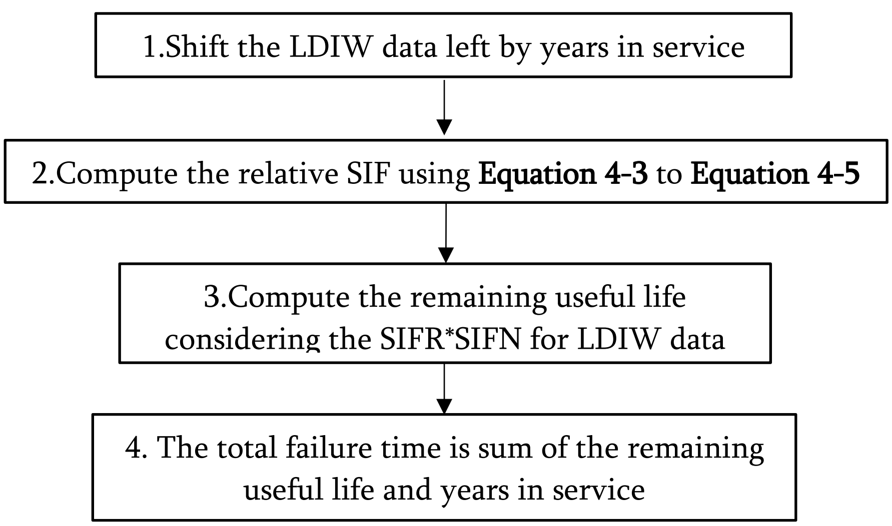



**Figure 4-15. The procedures for computing the RUL and total failure time**

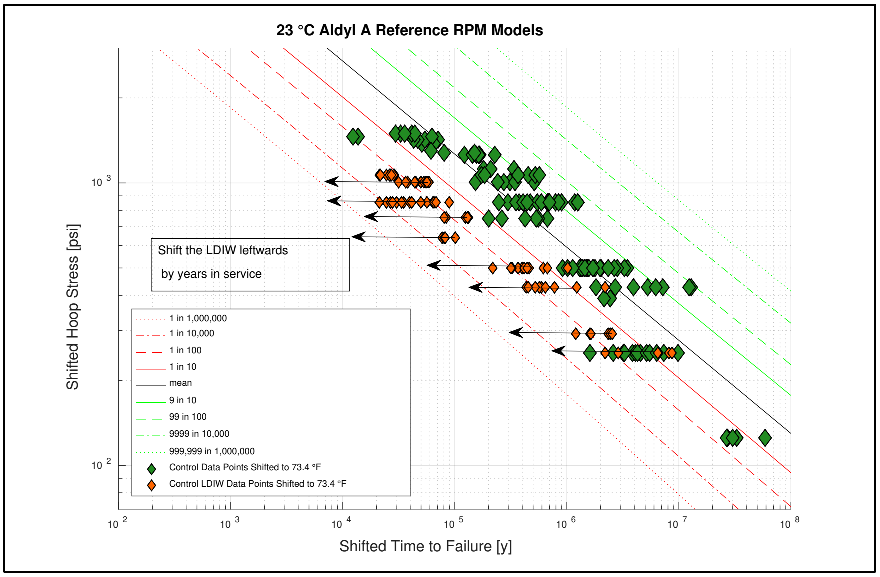



**Figure 4-16. Shift the LDIW data leftwards by $\Delta t$**

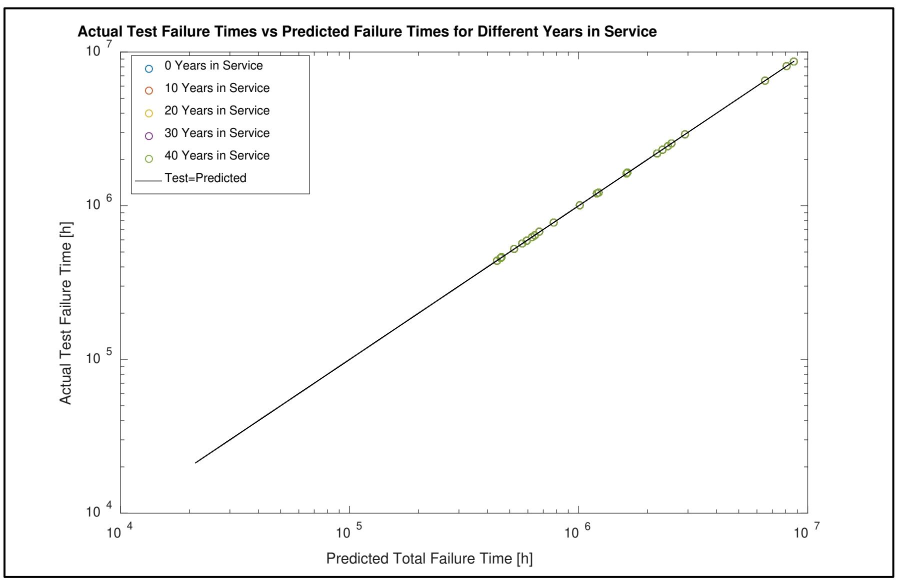



**Figure 4-17. The validation of predicted total failure time after different years in service**

For pipes in service, their loading conditions may change due to the change of pipe inner wall surface features, such as LDIW or internal damage caused by squeeze-off. In the developed Bayesian network, different loading conditions generated by different combinations of repair or inner diameter surface features are summarized in **Table 4-2**. That means different data sets will be used for computing the SIFT in **Equation 4-5** for each individual case. The SIFT are proportionally combined by the ratio of the years under a specific loading condition and the total years in service. For example, the pipe has been in service for $\Delta t$ years under the loading condition 1 and loading condition 2 for $\Delta t_1$ and $\Delta t_2$ years, respectively. The final SIFT can be calculated as

$$SIFT = SIFT_1 \frac{\Delta t_1}{\Delta t} + SIFT_2 \frac{\Delta t_2}{\Delta t}$$ **Equation 4-6**

The sub-network for computing the prior SIF distribution is shown in **Table 4-2**, in which the prior SIF distribution is computed considering the years in service as well as the years after repair by means of AgenaRisk application programming interface (API)

**Table 4-2. Different combinations of loading conditions**

| If LDIW? / If Repaired? | True | False |
|---|---|---|
| True | LDIW + Squeeze off | Control SCG + Squeeze off |
| False | LIDW | Control SCG |

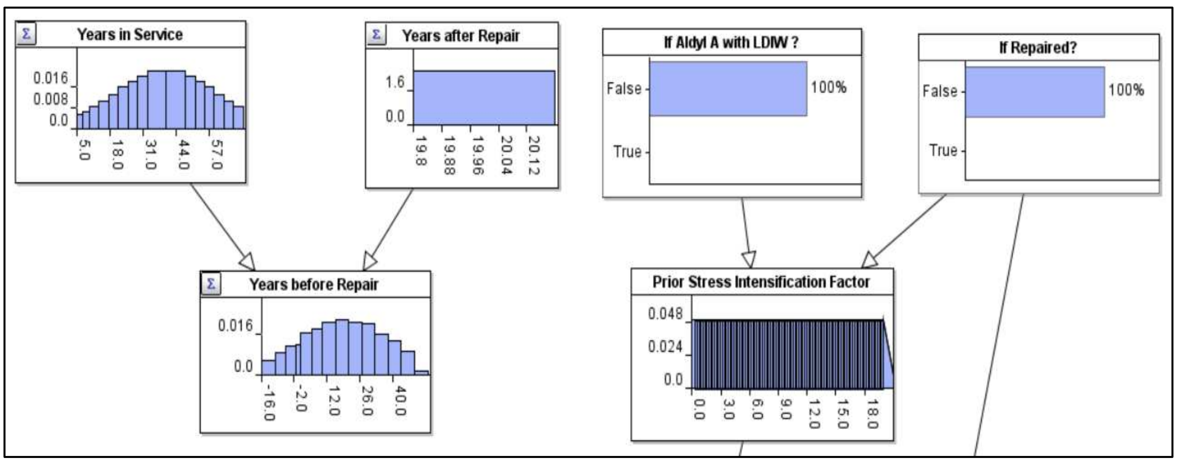



**Figure 4-18. The sub-network for computing the prior SIF distribution**

***Impingement Stress Intensification Factor (ImpSIF)***

Since the deformation caused by indentation and impingement are similar, they are generally considered as impingement in this developed Bayesian network. In 1982, Dupont issued a letter urging its customers to realize the risk of pipes subject to rock/root impingement. According the report published in 2014[21], the stress concentration introduced by impingement occurs more often than that caused by squeeze-off.  Additionally, impingement is of particular concern because it would accelerate pipe failures by around 12 years from the time when the pipe was initially impinged.

Extensive studies have been performed to quantify the stress or strain caused by indentation/impingement[22, 23]. In[24], the author applied the equivalent load approach to study the stress distribution around imperfection in thin-walled structures. The latest version of ASME B31.8 standard recommends the equations for calculating the effective strain in dents. Based on the theory of plates, the strain components are estimated considering the geometry of the deformation, which includes the dent length and dent depth along the circumferential and axial directions.

$$\varepsilon_1 = \frac{t}{2}\left(\frac{1}{R_o} - \frac{1}{R_1}\right) \qquad \textbf{Equation 4-7}$$

$$\varepsilon_2 = -\frac{1}{2}\frac{t}{R_2} \qquad \textbf{Equation 4-8}$$

$$\varepsilon_3 = \frac{1}{2}\left(\frac{d}{L}\right)^2 \qquad \textbf{Equation 4-9}$$

where $\varepsilon_1$, $\varepsilon_2$, $\varepsilon_3$ stand for the circumferential bending strain, longitudinal bending strain, and extensional membrane strain. The values for $R_1$ and $R_2$ are negative for reentrant impingement. The symbols in above equations illustrated by plotting them in **Figure 4-19** below,

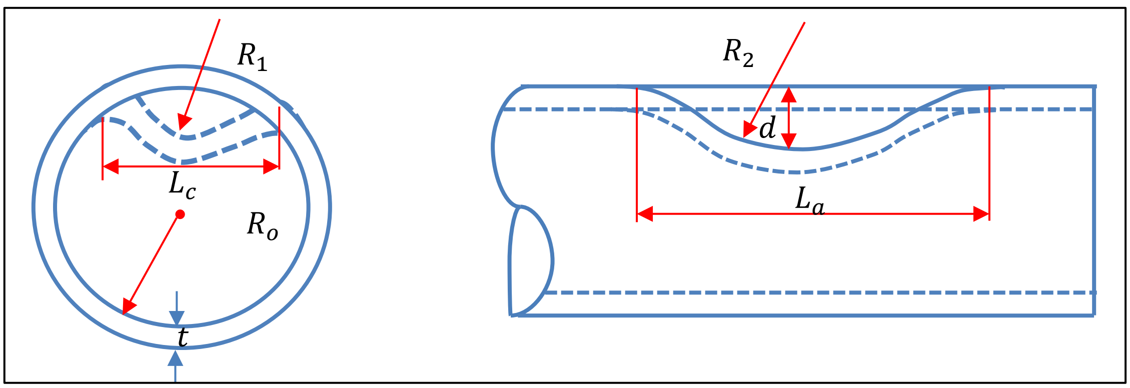



**Figure 4-19. The geometry of indentation/impingement**

As stated in[25], the pipe material will experience severe plastic deformation due to indentation, therefore the elasto-plastic characteristic of the polyethylene material should be used to avoid overestimating the stress concentration. GTI has generated the stress strain curves for medium density polyethylene and Aldyl A materials, which was successfully implemented to simulate the nonlinearity of the squeeze-off process. The stress strain curve for Aldyl A material is illustrated in **Figure 4-20**.

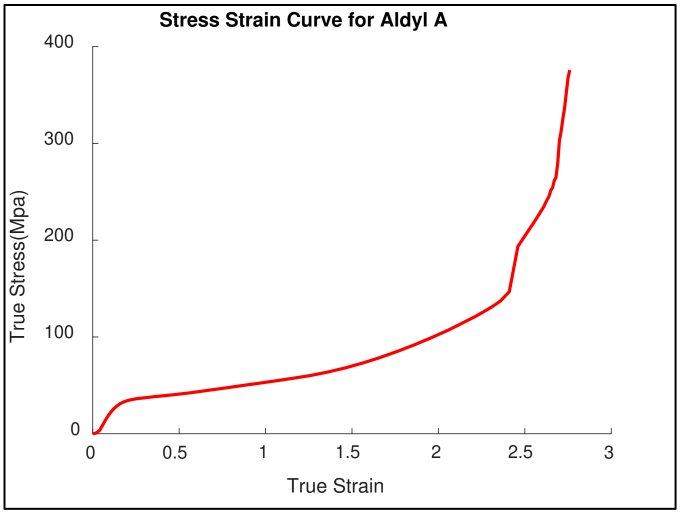



**Figure 4-20. The stress strain curve for Aldyl A**

Since the pipe is not undergoing uniaxial stress state, the strain components along tri-axial directions are combined to calculate the effective strain in the inside diameter,

$$\varepsilon_{eff} = \frac{\sqrt{2}}{3}\sqrt{(e_1 - e_2)^2 + (e_1 - e_3)^2 + (e_2 - e_3)^2} \qquad \textbf{Equation 4-10}$$

where $e_1$, $e_2$, $e_3$ stand for the total strain along circumferential, axial, and radial directions, respectively and $\varepsilon_{eff}$ is the combined effective strain. For polyethylene, the Poisson's ratio is very close to 0.5, Equation 4-10 can be simplified as $\varepsilon_{eff} = e_1$ under uniaxial loading. Generally, the stress along radial direction can be neglected in comparison with the other two directions and Equation 4-10 is rearranged as

$$\varepsilon_{eff} = \frac{2}{3}\sqrt{{e_1}^2 - e_1 e_2 + {e_2}^2} \qquad \textbf{Equation 4-11}$$

where $e_1$=$\varepsilon_1$ and $e_2 = \varepsilon_2 + \varepsilon_3$. Using the effective strain, the effective stress induced by impingement can be computed by substituting the effective strain in the stress strain curve.

Empirically, for a specific pipe diameter, the geometrical parameters shown in **Figure 4-19** are bounded. For example, the dent depth $d$ should be less than the pipe radius $R_o$. It is defined in  that dents are considered to be injurious if the depth $d$ is greater than 6%. The circumferential dent length $L_c$ should not be greater than the pipe outside diameter. Based on the geometric relationship, the bend radius along the circumferential and axial directions can be estimated as

$$R_1 = \frac{L_c^2}{8d} + \frac{d}{2} \qquad \textbf{Equation 4-12}$$

$$R_2 = \frac{L_a^2}{8d} + \frac{d}{2}$$ **Equation 4-13**

Thus, the sub-network for computing strain components is shown in **Figure 4-21**. It is explicitly demonstrated that the circumferential strain is much higher in comparison with the other two components, which can be explained by the restrained dent length along the circumferential direction. If impingement information is unknown to the operator, the induced SIF severity can be empirically estimated using linear combination of root and rock density. Given the prior distributions, the distribution of impingement induced stress concentration can be calculated and shown in **Figure 4-22**(a). **Figure 4-22**(b) plots the SIF distribution by processing the reference Aldyl A hydrostatic testing data.

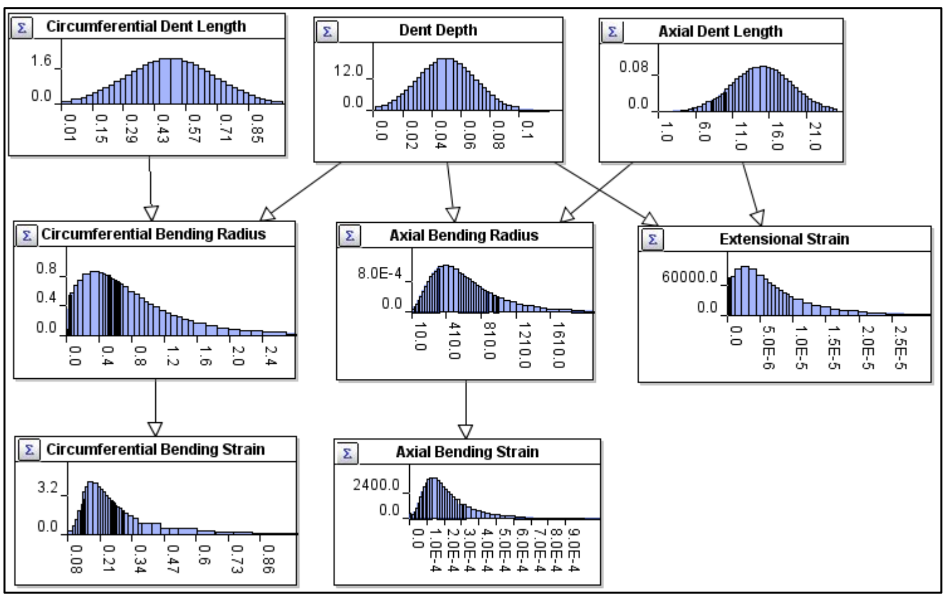
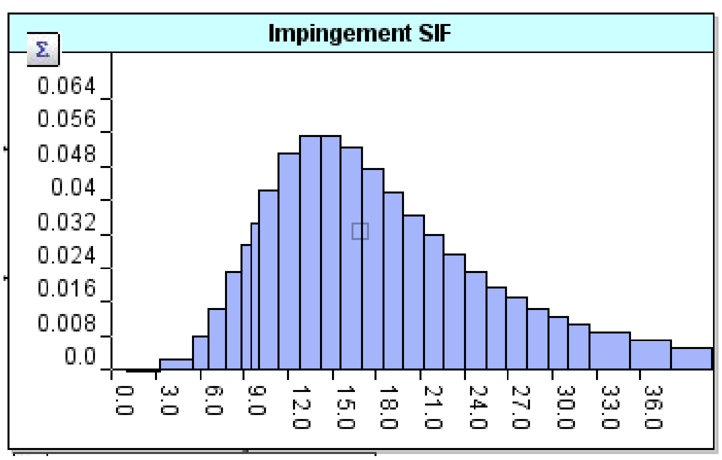
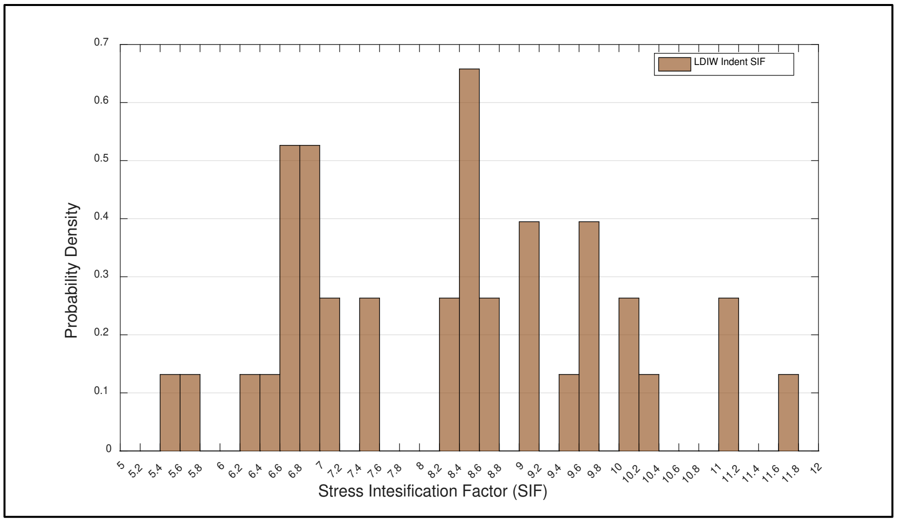



**Figure 4-21. The Bayesian network for strain components**




(a)




(b)

**Figure 4-22. The distributions of SIF from Bayesian network (a) and experiment (b)**

From the above plots, it can be observed that the estimation from the Bayesian network is much higher than the experimental results. The discrepancy may originate from the accuracy for the bending radius estimation and the true stress strain curve difference for the pipe under hydrostatic testing. For simplicity, a correction factor 0.5 is introduced here in the Bayesian network to make it consistent with the experimental testing. After calibration, the Bayesian network for computing the impingement SIF is depicted in **Figure 4-23**.

**Table** 4-3 summarizes the type and states for each node.

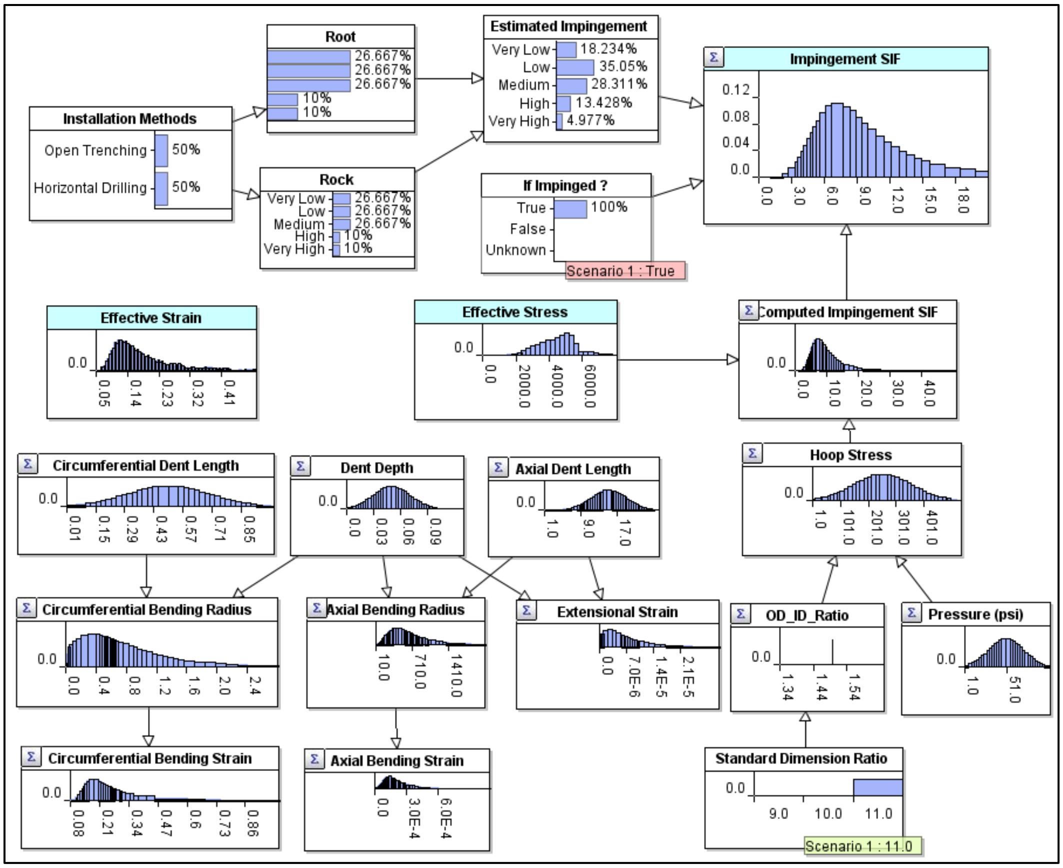



**Figure 4-23. The Bayesian network model for computing impingement SIF**

**Table 4-3. The type and states for each node**

| Node Name | Node Type | States/Distribution | Unit | Explanation |
|---|---|---|---|---|
| Circumferential Dent Length | Continuous | N(0.5, 0.04, 0, 1) | In | Dent Length along Circumferential Direction |
| Dent Depth | Continuous | N(0.05, 0.0004, 0.00001, 0.14) | In | Depth of the Dent |
| Axial Dent Length | Continuous | N(15, 16, 0.5, 25) | In | Dent Length along Axial Direction |
| Circumferential Bending Radius | Continuous | | In | $\|R_1\|$ |
| Axial Bending Radius | Continuous | | In | $\|R_2\|$ |
| Circumferential Bend Strain | Continuous | | | $\varepsilon_1$ |
| Axial Bending Strain | Continuous | | | $\varepsilon_2$ |
| Extensional Strain | Continuous | | | $\varepsilon_3$ |
| Effective Strain | Continuous | | | $\varepsilon_{eff}$ |
| Effective Stress | Continuous | | Psi | Stress on Corresponding to $\varepsilon_{eff}$ on the Stress Strain Curve |

| Node Name | Node Type | States/Distribution | Unit | Explanation |
| --- | --- | --- | --- | --- |
| Computed Impingement SIF | Continuous | | | Effective Stress/Hoop Stress |
| Installation Methods | Labelled | (Open Trenching, Horizontal Drilling) | | The Methods of Installation |
| Root | Ranked | (Very Low, Low, Medium, High, Very High) | | Root Density |
| Rock | Ranked | (Very Low, Low, Medium, High, Very High) | | Rock Density |
| Estimated Impingement | Ranked | (Very Low, Low, Medium, High, Very High) | | Estimated Impingement Severity |
| If Impinged ? | Labelled | (Yes, No, Unknown) | | Check if the Pipe is Impinged |
| Impingement SIF | Continuous | | | SIF Caused by Impingement |

As seen above, the distribution for "Impingement SIF" node overlays the distribution from experimental testing after introducing the correction factor. The advantage of this network is it can provide relatively accurate SIF prediction for different impingement configurations, which is more informative than the extracted SIF distribution for the decision making process.

### *Operational Stress Intensification Factor (OSIF)*

Operational stress intensification factor (OSIF) represents the SIF introduced by real operational conditions, such as impingement, soil movement or bending. As stated previously, prior stress intensification factor (PSIF) represents the SIF introduced by primary loading conditions caused by years in service or repair methods. The superposition of these two sources of SIF is the total stress intensification factor (SIF).

A FEA model was created to investigate the SIF caused by bending, with or without fitting tees. Then, the model was extended to consider the relative angle between fitting tees and bending curvature. **Figure 4-24** shows the definition of bending sign convention used in this report. The tee will be on the concave up portion of the pipe for positive bending and on the convex up portion of the pipe for negative bending. For each pipe configuration, the SIF was calculated by taking the maximum von Mises stress in each load case and dividing it by the nominal pipe hoop stress calculated from the internal pressure of the respective load case. After that, a power law regression model was constructed to correlate the SIF with input configuration parameters, such as internal pressure (P) and bending radius factor (BRF).

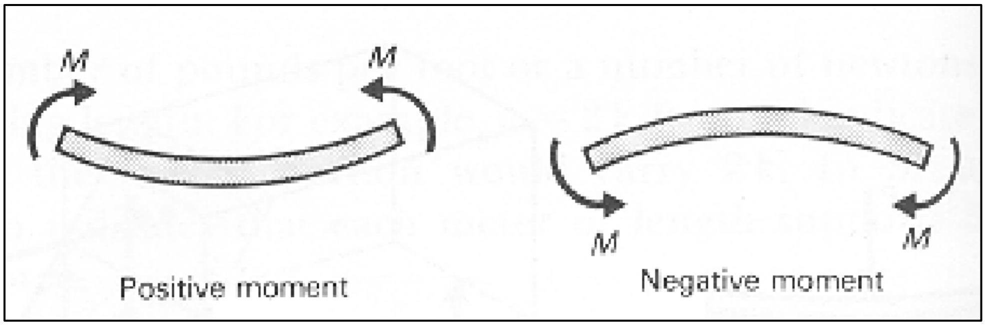



**Figure 4-24. Bending moment sign convention-positive concave up, negative concave down**

Through comprehensive analysis, it is found that the calculated SIF is independent of pipe size, as expected, and all the regression models can be generalized to a single power law function. The generic equation for the fitting is shown in Equation 4-14 and the regression coefficients are listed in **Table 4-4**.

$$SIF = aP^b BRF^c$$ **Equation 4-14**

where SIF – Stress Intensification Factor

$P$ – Pressure[psi]

BRF – Bend Radius Factor expressed as multiples of the pipe diameter

a, b, c – Regression Coefficients

**Table 4-4. Regression coefficients for each configuration**

| Configuration | a | b | c |
|---|---|---|---|
| Pipe without Tee | 4453.0 | -1.0657 | -0.744 |
| Pipe with Tee Positive Bending | 5310.7 | -0.9654 | -0.7251 |
| Pipe with Tee Negative Bending | 9364.1 | -1.0757 | -0.7789 |
| Pipe with Tee Lateral Bending | 3476.7 | -1.0059 | -0.5593 |

**Figure 4-25** shows the relative severity of the bending configurations at an internal pressure of 45 psig. The maximum stress is the greatest for a lateral bend > positive vertical bending> negative vertical bending > pipe with no tee. To simplify the computation and application of the developed network, the regression coefficients for pipes with the tee under lateral bending are chosen to represent all three configurations, which can provide relatively conservative life prediction for Aldyl A pipes.

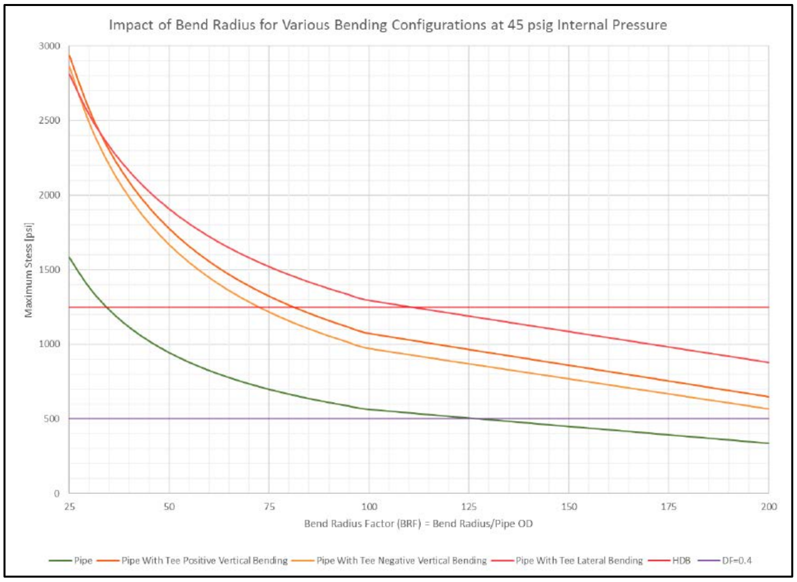
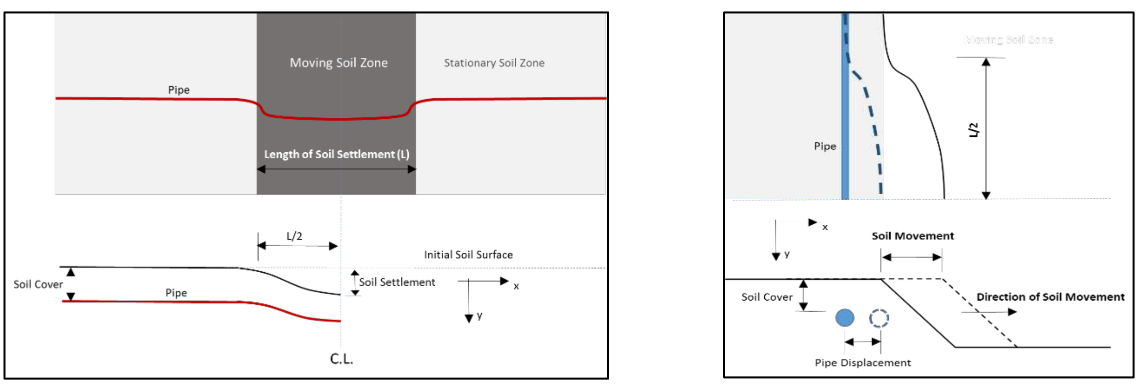



**Figure 4-25. The relative severity of bending configurations at 45 psig internal pressure, SDR 11 pipe**

The investigation of the soil movement effect on the pipeline has been performed in GTI project 21559 and 21584 Mobile Hybrid LiDAR & Infrared Sensing for Natural Gas Pipeline Monitoring. Gas distribution pipeline may experience high longitudinal strains in the events of soil movement resulting from external force, seismic activity, slope instability, flooding, and soil subsidence. The deformation of the pipeline may be either along the vertical direction because of soil settlement or along the horizontal direction because of landslides. The schematic representation of pipe deformation under vertical or horizontal soil movement is shown in **Figure 4-26**. It can be easily concluded that bending will be introduced on the pipe due to the combinatory effect of the vertical and horizontal soil movement. The rough estimation of the bending radius can be computed using the fundamental knowledge of solid geometry. The schematics of the resultant pipeline deformation are demonstrated in **Figure 4-27**.




(a) (b)

**Figure 4-26. The schematic representation of pipeline bending undervertical soil movement (a) and horizontal soil movement (b)**

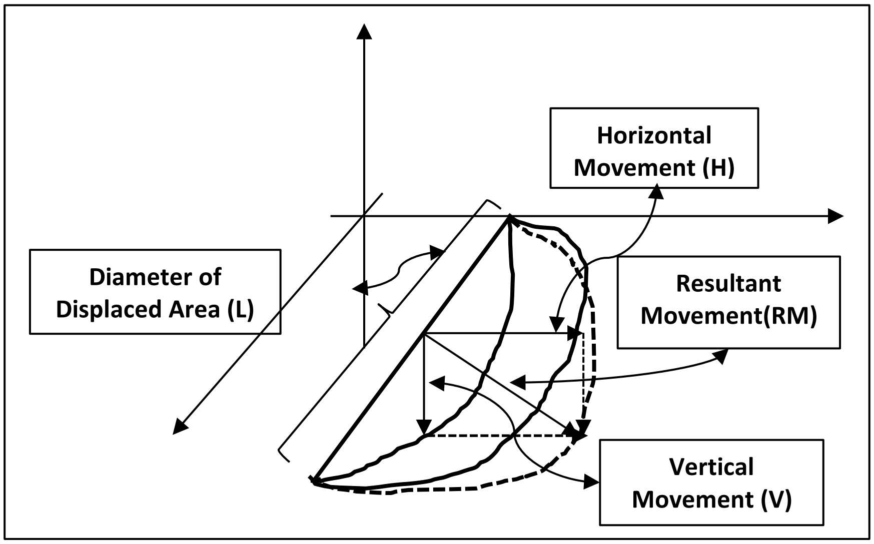



**Figure 4-27. The resultant deformation of pipeline bending due to soil movement**

As seen above, the bending radius (BR) can be calculated as

$$RM = \sqrt{V^2 + H^2} \quad \textbf{Equation 4-15}$$

$$BR^2 = (BR - RM)^2 + \frac{L^2}{4} \quad \textbf{Equation 4-16}$$

$$BR = \frac{RM}{2} + \frac{L^2}{4RM} \quad \textbf{Equation 4-17}$$

From the expression in Equation 4-14, it is trivial to find that the bending radius caused by soil movement can be easily incorporated in this formula. Considering the impingement, soil movement, and bending discussed above, the Bayesian network for operational SIF is shown in **Figure 4-28**.

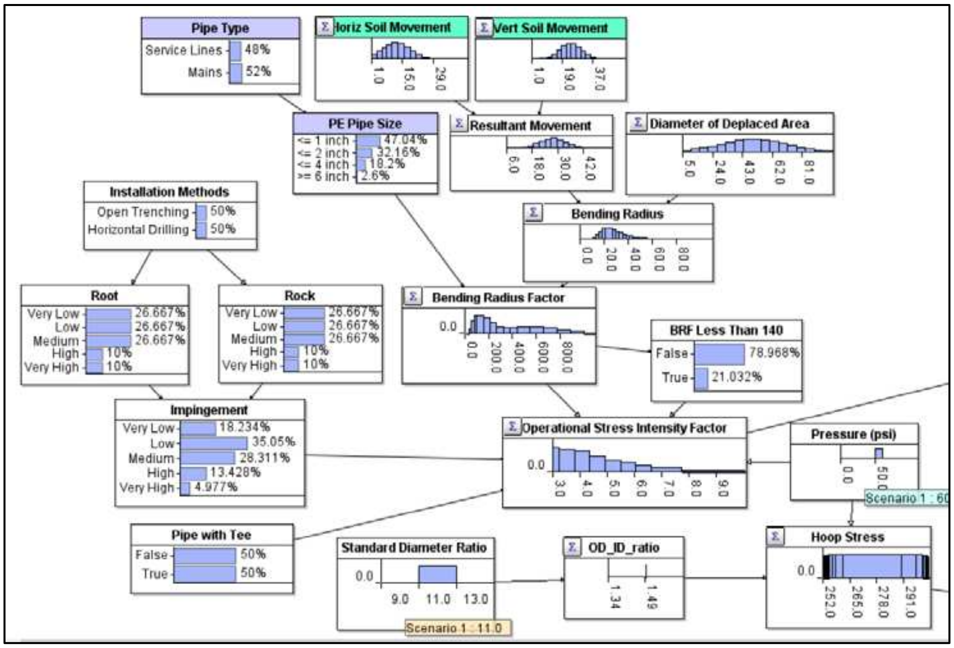


**Figure 4-28. The Bayesian network for node "Operational SIF"**

***Risk Score***

During the investigations carried out under the OTD 2.8.d (20649) project, it was noted that certain surface features visible in Cross-Polarized Light Microscopy (CPLM) and Scanning Electron Microscopy (SEM) appeared to correlate to times to failure in the RPM testing of pipe specimens. A categorical (multinomial) logistic regression model yielded surprisingly good predictive power. The model was later improved by incorporating relative ranking derived from Oxidation Induction Time (OIT) from thermal testing and Carbonyl Index (CI) from Fourier Transform Infrared (FTIR) testing. The developed logistic regression model was implemented in the Bayesian network to create the node probability table given the fitted model coefficients. Details for computing the probability of each state (i.e. outcome) are discussed below.

The multinomial logistic regression is a classification method that generalizes logistic regression to solve problems with more than two possible discrete outcomes[26]. Assume there are $K$ possible outcomes, the multinomial logit model is to regress the $K - 1$ outcomes against the pivot outcome, such as outcome K. The logit regression can be expressed as

$$ln(Pr(Y_i = 1)/Pr(Y_i = K)) = \beta_1 X_i \qquad \textbf{Equation 4-18}$$

$$ln(Pr(Y_i = 2)/Pr(Y_i = K)) = \beta_2 X_i \qquad \textbf{Equation 4-19}$$

$$ln(Pr(Y_i = K - 1)/Pr(Y_i = K)) = \beta_{K-1} X_i \qquad \textbf{Equation 4-20}$$

where $\beta_1, \beta_2, \ldots, \beta_{K-1}$ are the model coefficient vectors corresponding to 1, 2, …. , $K-1$ outcomes, $X_i$ is a vector representing the surface condition attributes of a pipe. Since the sum of the probabilities for $K$ outcomes is one, the probability for each outcome can be computed as

$$Pr(Y_i = K) = 1 \Big/ (1 + \sum_{k=1}^{K-1} exp(\beta_k X_i)) \quad \textbf{Equation 4-21}$$

$$Pr(Y_i = 1) = exp(\beta_1 X_i) \Big/ (1 + \sum_{k=1}^{K-1} exp(\beta_k X_i)) \quad \textbf{Equation 4-22}$$

$$Pr(Y_i = 2) = exp(\beta_2 X_i) \Big/ (1 + \sum_{k=1}^{K-1} exp(\beta_k X_i)) \quad \textbf{Equation 4-23}$$

$$Pr(Y_i = K-1) = exp(\beta_{K-1} X_i) \Big/ (1 + \sum_{k=1}^{K-1} exp(\beta_k X_i)) \quad \textbf{Equation 4-24}$$

Given the derivation above, the node probability table of the "Risk Score" node can be constructed using the AgenaRisk API. The completed subnetwork is illustrated in **Figure 4-29**.

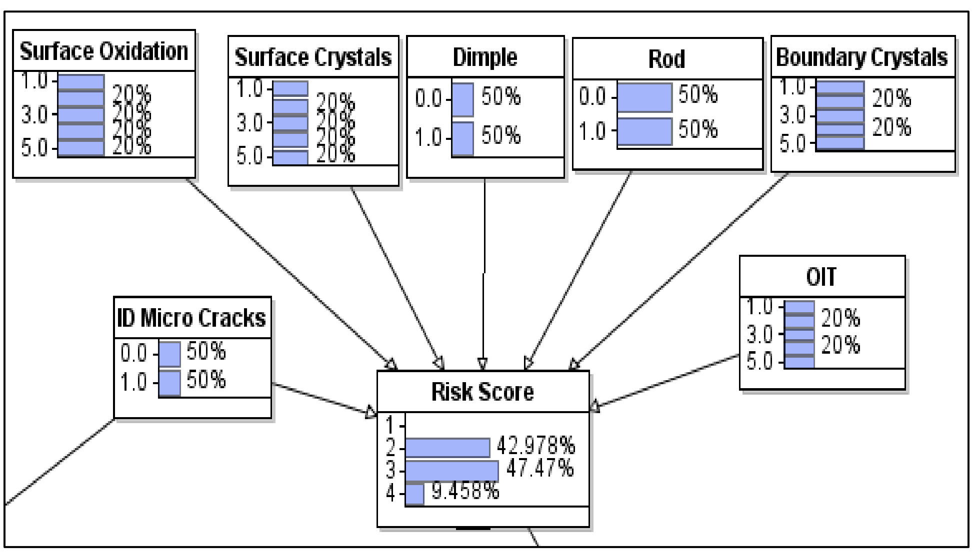



**Figure 4-29. The Bayesian network for node "Risk Score"**

### *Sub-networks Assembly*

In this part, the sub-networks developed above are integrated as an overall Bayesian network as shown **Figure 4-30**. Using the developed network, on the one hand, the remaining useful life (RUL) of pipelines can be predicted given context conditions, such as buried environment, application temperature, and pipe inner diameter surface features. On the other hand, the context conditions can be diagnosed based on the evidence for pipeline RUL. The forward and backward reasoning process will be provided later to validate the integrity of the developed risk assessment network.

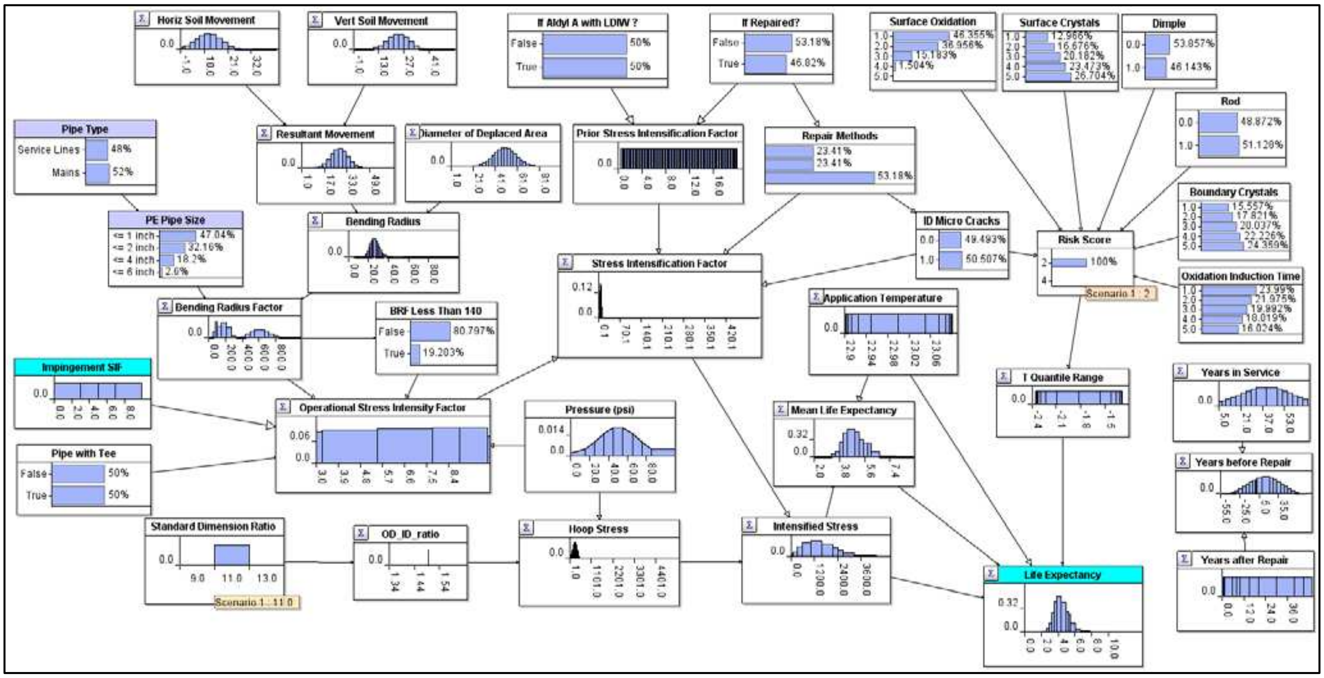



**Figure 4-30. The integrated Bayesian network for pipeline risk assessment**

## Bayesian Network Testing and Validation

### *Risk Score Validation*

For Bayesian network, one node is independent of the others if the evidences for all of its parent nodes are provided. Analogously, in the developed overall network, the risk score can be computed given its parent nodes representing the inside diameter surface features.  In the OTD project (4.12-GTI 21301), different combinations of surface features and the predicted risk score from logistic regression were listed. Plugging these data into the developed network, the risk score for each scenario should be replicated. The risk scores from the original regression model and Bayesian network are compared in **Table 4-5**.

**Table 4-5. The risk score comparison between logistic regression and Bayesian network**

| Risk Score from Regression | Probability of Each Category | | | | Risk Score from network |
|---|---|---|---|---|---|
| | 1 | 2 | 3 | 4 | |
| **3** | 7.40E-05 | 0 | 0.998062 | 0.001864 | **3** |
| **4** | 0.000179 | 0 | 0.010156 | 0.989665 | **4** |
| **3** | 0.000707 | 5.00E-06 | 0.998109 | 0.001179 | **3** |
| **3** | 0.001328 | 0.496864 | 0.501255 | 0.000553 | **3** |

| | | | | | |
|---|---|---|---|---|---|
| 3 | 0.001982 | 0.03762 | 0.958174 | 0.002224 | 3 |
| 2 | 6.00E-06 | 0.972903 | 0.027091 | 0 | 2 |
| 3 | 0.001328 | 0.496864 | 0.501255 | 0.000553 | 3 |
| 2 | 0.000366 | 0.982811 | 0.015212 | 0.00161 | 2 |
| 2 | 0.00032 | 0.993946 | 0.003589 | 0.002146 | 2 |
| 2 | 4.00E-06 | 0.997916 | 0.00208 | 0 | 2 |
| 3 | 0.002037 | 0.494501 | 0.501623 | 0.00184 | 3 |
| 3 | 0.001875 | 0.012431 | 0.984085 | 0.001609 | 3 |
| 3 | 0.000811 | 0.00141 | 0.997339 | 0.00044 | 3 |
| 3 | 7.60E-05 | 0.001317 | 0.998605 | 2.00E-06 | 3 |
| 3 | 0.002037 | 0.494501 | 0.501623 | 0.00184 | 3 |
| 2 | 2.00E-06 | 0.999757 | 0.000241 | 0 | 2 |

From **Table 4-5**, it can be seen that the developed network can completely reproduce the results from the original logistic regression model when the category is determined by the maximum predicted probability. In the developed Bayesian network, the probability for each category will be considered for risk assessment, which will minimize the information loss from the logistic regression model.

### *Rate Process Model Validation*

In this Bayesian network, the pipes are undergoing slow crack growth failure pattern under the normal service condition. The risk score computed above was initially generated relative to the reference SCG model. Different scores mean different levels of risk for SCG failure. In order to validate the reference SCG model, the Bayesian network is run multiple times with different stress and risk scores. The prediction limits (PL) from the SCG reference model and the Bayesian network are plotted in **Figure 4-31**.

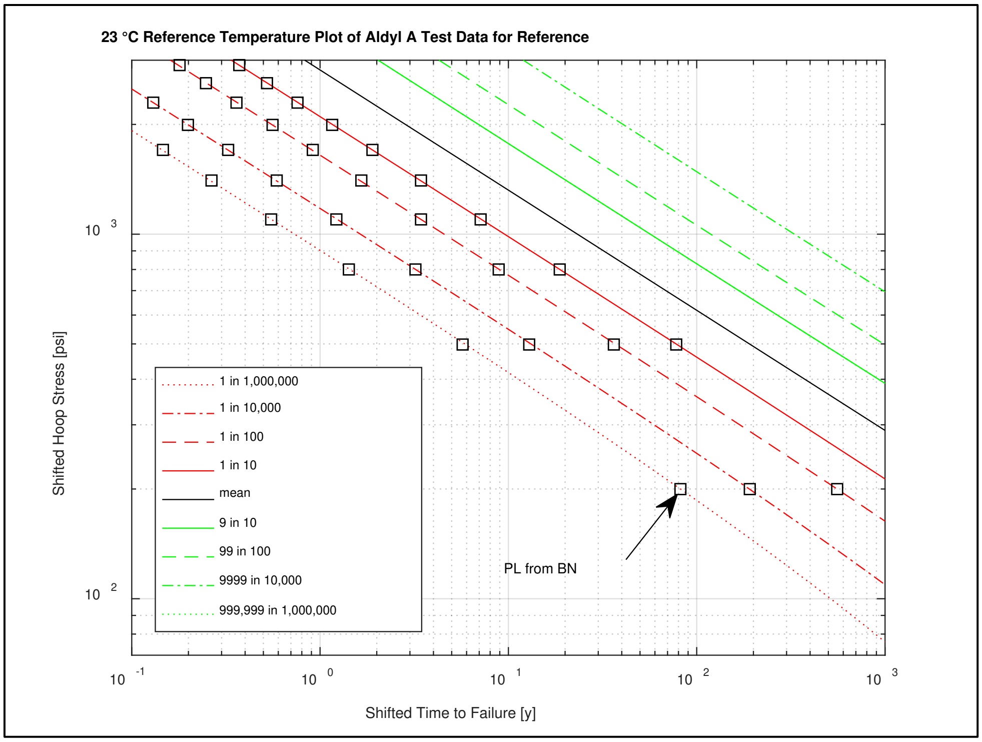


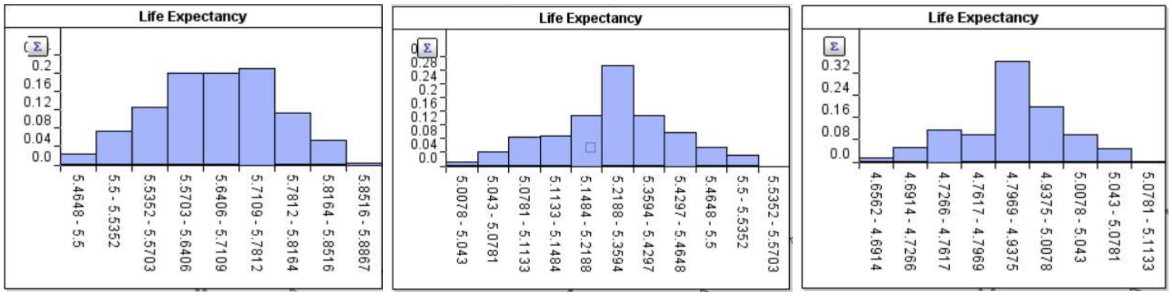

**Figure 4-31. The reproduced prediction limits using Bayesian network**

***Remaining Useful Life Prediction***

The critical application for this network is to assess the risk of the pipe by predicting its RUL given specific context conditions, such as temperature, buried environment, inner diameter surface features, and so on. If the pipe is under the same internal pressure, the RUL will be decreasing with higher risk score. To validate this conceptual understanding, three scenarios are generated and listed in
**Table 4-6.**

**Table 4-6. The context conditions for 3 scenarios**

| Scenarios | Intensified Stress (psi) | Temperature (Celsius) | Dimple | ID Micro Cracks | Rod | Boundary Crystal | Surface Crystal | Oxidation Induction Time | Surface Oxidation | Risk Score |
|---|---|---|---|---|---|---|---|---|---|---|
| 3 | 500 | 23 | 1 | 1 | 1 | 1 | 1 | 4 | 4 | 1 |
| 1 | 500 | 23 | 1 | 1 | 0 | 5 | 2 | 1 | 2 | 2 |
| 2 | 500 | 23 | 1 | 1 | 0 | 1 | 2 | 3 | 5 | 3 |




(a) Risk Score=1 (b) Risk Score=2 (c) Risk Score=3

**Figure 4-32. The final distributions for the log of the life expectancy (hrs) Mean life=53.1 years, (b) Mean life=21.7 years, (c) Mean life=8.7 years**

To investigate the effect of prior SIF, 10 scenarios are generated by changing the evidence for nodes "If Aldyl A with LDIW", "If Repaired", "Repair Methods", "Years in Service" and "Years after Repair". Using the network, their corresponding median and quantile life prediction can be easily computed. It should be noted that the life prediction may not represent the true life for the pipe, because the overall Bayesian network has not been calibrated using true testing data for pipes undergoing the combination of different loading conditions. However, the trend for the life prediction should be consistent with the conceptual understanding of the pipeline failure mechanism. Those assumed 10 scenarios are summarized in **Table 4-7**, in which the first row listed the node names. The life prediction results are summarized in **Table 4-8.**

**Table 4-7. The context conditions for 10 scenarios**

| Scenarios | If Aldyl A with LDIW | If Repaired | Repair Methods | Years after Repair | Years | Temperature | Pressure | Bending Radius Factor |
|---|---|---|---|---|---|---|---|---|
| 1 | False | False | NA | 0 | 40 | 23 | 60 | 150 |
| 2 | False | True | Butt Fusion | 10 | 40 | 23 | 60 | 150 |
| 3 | False | True | Butt Fusion | 20 | 40 | 23 | 60 | 150 |
| 4 | False | True | Butt Fusion | 30 | 40 | 23 | 60 | 150 |
| 5 | False | True | Mechanical Coupling | 30 | 40 | 23 | 60 | 150 |
| 6 | True | False | NA | 0 | 40 | 23 | 60 | 150 |
| 7 | True | True | Butt Fusion | 5 | 40 | 23 | 60 | 150 |
| 8 | True | True | Butt Fusion | 10 | 40 | 23 | 60 | 150 |
| 9 | True | True | Butt Fusion | 15 | 40 | 23 | 60 | 150 |
| 10 | True | True | Mechanical Coupling | 15 | 40 | 23 | 60 | 150 |

**Table 4-8. The median and quantile life prediction for those 10 scenarios (years)**

| Scenarios | Median | Upper Quantile | Lower Quantile |
|---|---|---|---|
| 1 | 35.54 | 89.92 | 15.22 |
| 2 | 22.17 | 41.27 | 8.21 |
| 3 | 21.50 | 39.40 | 7.99 |
| 4 | 17.16 | 39.15 | 7.70 |
| 5 | 13.34 | 28.95 | 6.14 |
| 6 | 23.41 | 43.76 | 9.11 |
| 7 | 10.48 | 24.05 | 4.77 |
| 8 | 10.15 | 22.01 | 4.65 |
| 9 | 10.69 | 24.25 | 4.96 |
| 10 | 8.52 | 17.86 | 4.01 |

From above table, it can be seen that the predicted life will be shorter for the pipe that has been repaired longer time back. The reason is because it is assumed that the plastic pipe will be squeezed once it is repaired. The mechanical coupling may also decrease the life time and the reason is the localized bending will be introduced around the coupling edge. Those preliminary assumptions can be updated once additional knowledge is acquired.

### *Conclusions and discussions*

This section presents the procedures of designing, developing, and validating the probabilistic risk assessment model. Bayesian network is proven to be a good candidate for expressing the semantic ontology of pipeline risk phenomenon. The inherent causal relationship could greatly reduce the complexity and scale of the network model. By processing the Aldyl A hydrostatic testing data sets, the effects of years in service, squeeze-off and LDIW are successfully taken into account as the prior SIF distribution. Impingement induced SIF is modelled by combining the theory of plates and stress strain curve considering large plastic deformation, the sub-network developed from which is also calibrated and corrected using the hydrostatic testing results. Each sub-network can be continuously refined with additional data acquisition. Then, they are assembled to compute the life expectancy of pipeline segments given different context conditions. The risk model can be combined with smart data collection, pipeline inspection, and mitigation practice to provide informative guidance for integrity management and concurrent situation awareness.

It should be noted that the contribution of each sub-network to the final failure time is determined by the investigator's best knowledge. Additional research is needed for the interactive nature of different sources of SIF. The accuracy of each part of the network may also be further updated if more reliable data is collected.

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## 5. Structured Light Method for Internal Inspection of Aldyl-A Pipe

### Introduction

Identification and classification of the current vintage pipeline inner wall damage precursor are of critical importance. However, there is a limited success in sensing and characterizing the long lengths of deteriorating plastic pipelines with a high probability of detection (POD), and the capability of the currently available accelerometers and imaging technologies that can be miniaturized and integrated into smaller CTS size pipes for a fast scan is questionable and needs a systematic assessment. There are several known inner pipe wall surface conditions that increase the probability of premature failure due to slow crack growth. The major drivers of premature failure due to slow crack growth are bending stresses due to tight bend radii, impingement, and fittings. Damage is also introduced by pipe squeeze-off during maintenance operations. These conditions identification has been investigated by various nondestructive evaluation (NDE) techniques, such as direct visual/optical methods using CCD cameras, ultrasonic testing, liquid-coupled acoustic measurement (e.g. sonar) and laser based surface inspection approaches including light detection and ranging (LiDAR) and laser topography[27-29]. However, these currently available technologies suffer either from low-sensitivity and resolution for small damage precursors, or complex settings and large system footprint that makes it incapable for plastic gas distribution pipes with much smaller diameters. In this task, led by the PI at MSU, we developed a multi-spectral and miniaturized optical sensing platform for imaging the smaller CTS size pipe inner walls with high sensitivity and specificity of damage identification. The literature review and progress in the 1st quarter are presented in the following sections.

### Principle of 3D optical inspection system

3D profiling has been widely used and has a lot of applications in manufacturing and medical field. The principle of capturing 3D image is mathematically based on the triangulation. This technique depends on two basic and critical components in the system, which are camera and projector. The optical projector/source sends structured light to the object, where a typical structure light pattern is shown in **Figure 5-1**. The benefit of using this light is to computationally capture the depth information from the 3D object from a relatively simple light projection. In the literature, a pinhole model is used to capture the light that reflected from the object.

$$\widetilde{m}^c \propto K^c[R^c\ t^c]\widetilde{M}^w \qquad \textbf{Equation 5-1}$$

where $\propto$ stands for the equality up to scale factor, $[R^c\ t^c]$ is extrinsic parameters matrix and $K^c$ is the camera parameters whose matrix form is shown in eqn. **Equation 5-2**:

$$K^c = \begin{bmatrix} \propto & \gamma & u_0 \\ 0 & \beta & v_0 \\ 0 & 0 & 1 \end{bmatrix}$$ **Equation 5-2**

$u_0$ *and* $v_0$ are coordinates of the principle point, while $\propto$ *and* $\beta$ are the focal lengths.

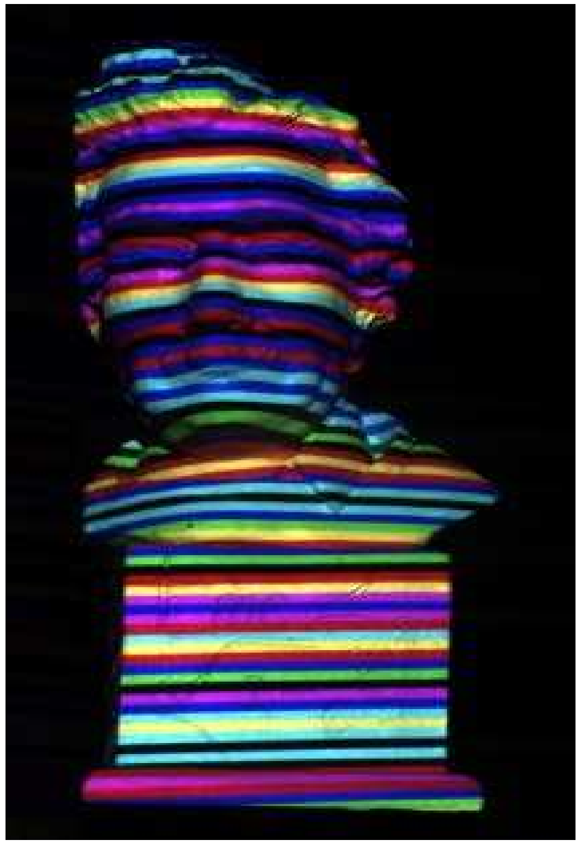


**Figure 5-1. Example of a structured light pattern projected onto an object [30]**

By using the structured light illumination, the collected images by the camera will be reconstructed into 3D data. Figure 5-2 illustrates the triangulation system by a camera and light source. In this task, by taking advantage of the endoscope technique, the innovative imaging principle of using the multicolor multi-ring is considered to increase the resolution and sensing speed for possible in-line inspection (ILI) integration. Although there are many kinds of structured light methods, Single Shot (SS) technique is one of the most used techniques, and we will adopt it for the first prototype development. Since the single shot just needs one image of the scene to reconstruct 3D data, it will simplify the sensor hardware design as well as reduce the image processing load. In other literature in the medical field, one design of structured light endoscope needs a camera and a slide projector to collect the 3D data, which will also be investigated in this task. Figure 5-3 shows the endoscope technique using for clinical applications at the diameter of 3.8mm.

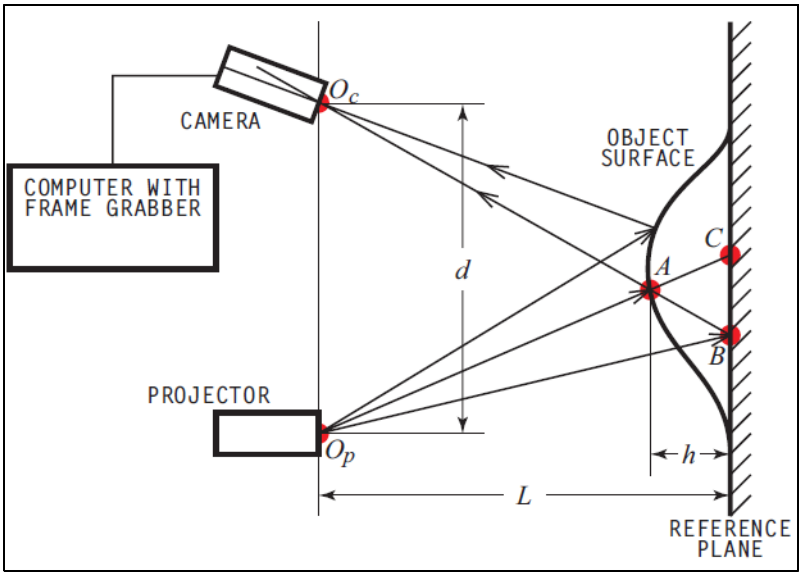



**Figure 5-2: Illustration of a 3D structured light measurement** [31]

Optical sensing is one of the NDE techniques that have been improved significantly in the past few years. There are several ways under optical sensing to produce a 3D image. However, two different techniques will be the main categories which are passive acquisition and active acquisition, in which laser and structured light will be classified under active acquisition. The following chart shown in **Figure 5-3** illustrates the main categories of the optical sensors.

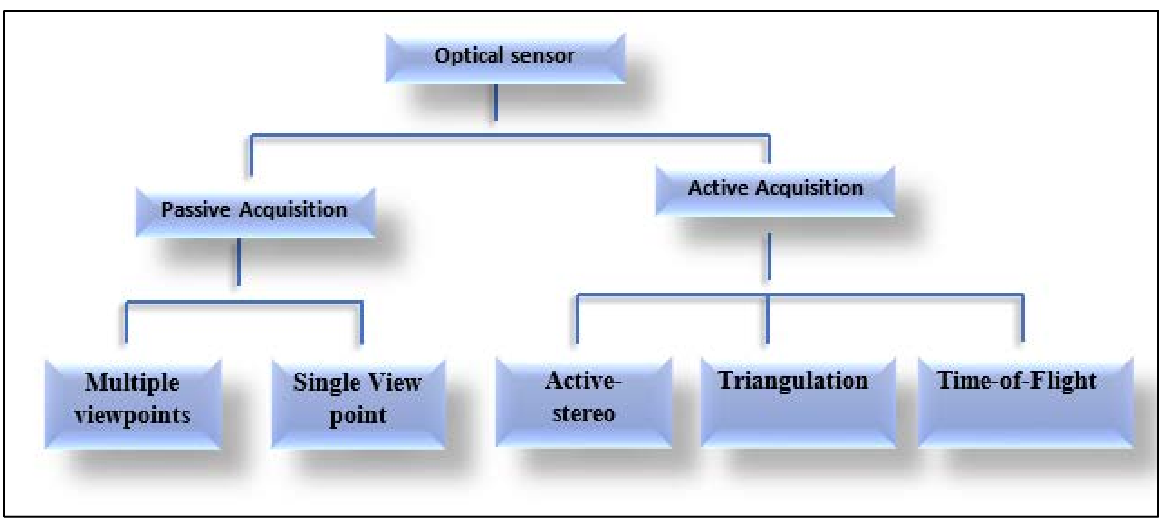



**Figure 5-3. Classification of the optical sensors category**

## Passive Acquisition

Passive Acquisition is one of the methods that can be used to obtain 3D optical images. This technique is called passive because the data is collected by using the camera without using any active source, such as lasers to provide strip line or by using structured lights. Multiple viewpoints and single view point techniques are classified to be the main methods for the passive acquisition

*Multiple viewpoints*

This technique is used to take the image from different viewpoints/angles. Two cameras or more can be used to collect the data from different angles. By using multiple cameras, the technique will be called stereo vision. There are different kinds of stereo with a different number of the cameras that have been used. For example: if two cameras have been used to capture the image the technique, is called binocular stereo. Similarly, trinocular stereo is when three cameras have been used to capture the image. Also, if a single camera has been used to take the image for the same point but from different locations and time, this technique is called structure from motion. By processing the images that have been taken from the different locations or different cameras, the 3D rays will be determined. Finally, from the 3D rays, the 3D position of the point in the scene can be determined. One illustration of the multiple viewpoints is shown in **Figure 5-4.**

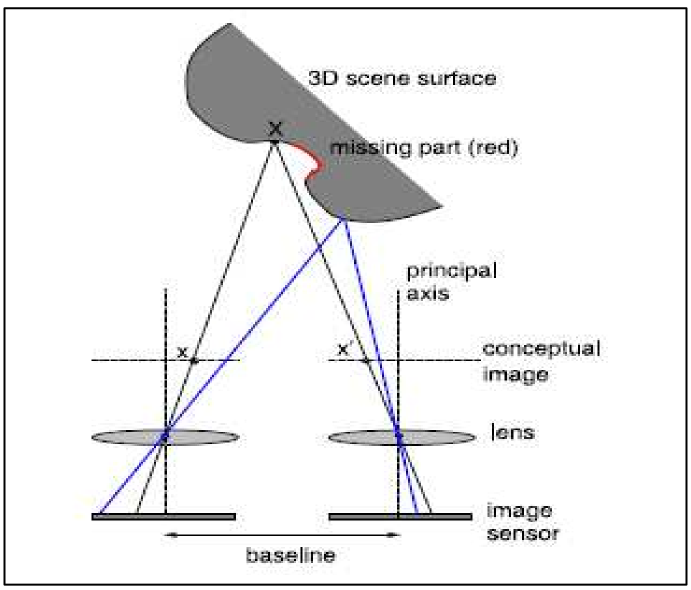



**Figure 5-4. Illustration of multiple viewpoints technique** [31]

*Single view points*

In this technique, the captured image does not come from multiple cameras or the camera motion. The captured image, in this case, will be taken by using the object details, for example, the texture of the object, shading, or focus, etc. **Figure 5-5** shows that the 3D image has been generated by shape from shading. This technique depends on the reflection from the object. The pixels in the reconstructed image illustrate the intensity of the reflection that comes from the object shade, and by using regularized surface fitting, the 3D image can be reconstructed. Overall, the multiple viewpoints method is more accurate and more efficient

than single view point method. This technique's limitations and the enhancement of the reconstructed image are described in [32]. Shape from shading technique is known as Photometric stereo. Main steps to generate a 3D image by using this technique is that taking more than one image for the same point but the illuminations for the scenes are different. The other technique is called shape from focus. Taking two images from different depths of field is the main idea of processing 3D image, and the approach is described in [33].
In summary, single view technique is not as good as multiple viewpoints technique in terms of speed and regulation. Therefore, multiple viewpoints technique is more commonly used. However, the passive acquisition is not suitable for this project. The active acquisition will be the tool for making the 3D imaging which will be reviewed and discussed in the following section.

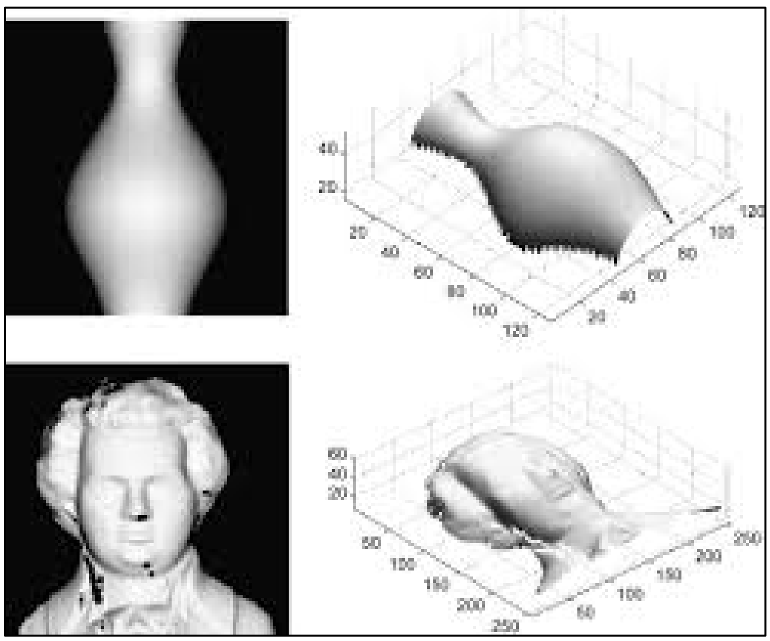


**Figure 5-5. Illustration of generating 3D image by using shape from shading [28]**

### Active Acquisition

Active Acquisition has different techniques to capture the viewpoints comparing with passive techniques. As illustrated in the passive techniques, captured image does not need structured light or laser stripe to collect the data. However, in Active Acquisition, optical detectors such as camera need to be used to detect the point. In addition, the active sources such as laser source or structure light should be considered to complete the imaging process.

#### *Active-stereo*

Active stereo has a similar concept with multiple viewpoints. In this technique, a light source with special features is used to replace the function one of the cameras in the multiple viewpoints method. **Figure 5-6** illustrates the principle of the Active-stereo method with laser scanning. The light source has been focused on the scene; then the camera captures the view. There are different kinds of the light sources. Structured light and laser are two of the most known sources. These techniques will be discussed in the following sections. Active stereo is more common than passive techniques because of the high resolution, and the data that have been taken by the laser or structured light are more accurate. However, to generate a 3D image by using a camera and light source, the triangulation should be considered to calculate the depth of the scene, which makes the method mathematically rigorous and challenging.

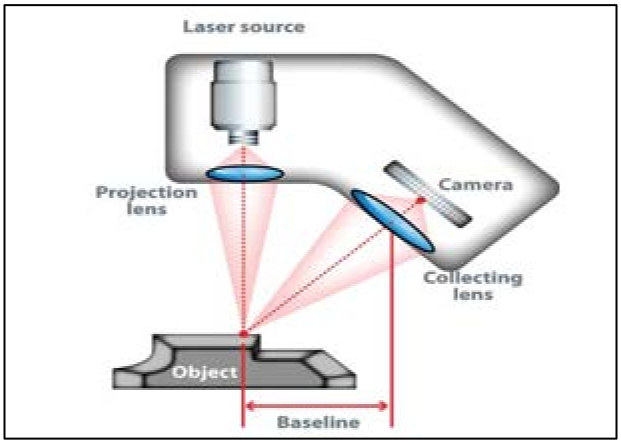



**Figure 5-6. Illustration of active stereo with laser scanning technique** [31]

**Laser Scanning**

A lot of applications have used laser scanning to get a 3D image. Laser scanning is using a strip of laser light, or it can be a circle-shaped source to scan the inner surface of an object, (e.g. pipelines in this project, which will be discussed in detail later). Basically, a camera with high resolution has been used as a sensor to capture the scene. Both the camera and the laser source work as one unit to produce a 3D image. **Figure 5-7** illustrates how the laser and camera work together. The distance between the camera and the laser source and the illumination is calculated by using triangulation to create the 3D images. When the laser projects the light on the object, the laser light will capture the object shape. Then by knowing the camera and laser positions, the depth of the object can be easily calculated.

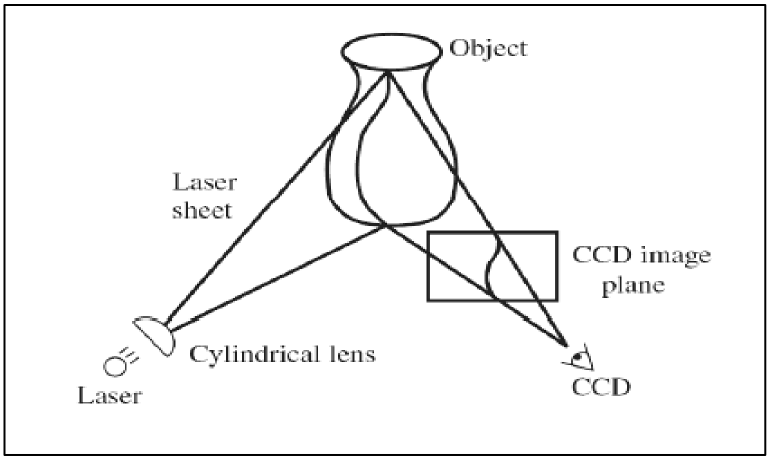



**Figure 5-7. Laser scanning technique using CCD camera and laser source [34]**

**Structured Light**

As discussed in the laser scanning section, structured light is similar to the laser technique in setup, however, a structured light projector is used in this technique instead of the laser source. The structured light technique has been used for a lot of applications in industrial and medical testing. The principle of structured light is shown in Figure 5-8, which depends on the relative positions of the camera and projector. In this system, the projector is connected to the computer and is controlled to generate pre-designed patterns. There are different kinds of patterns that are used for structured light such as: Spatial patterns, Temporal patterns, Colored patterns.

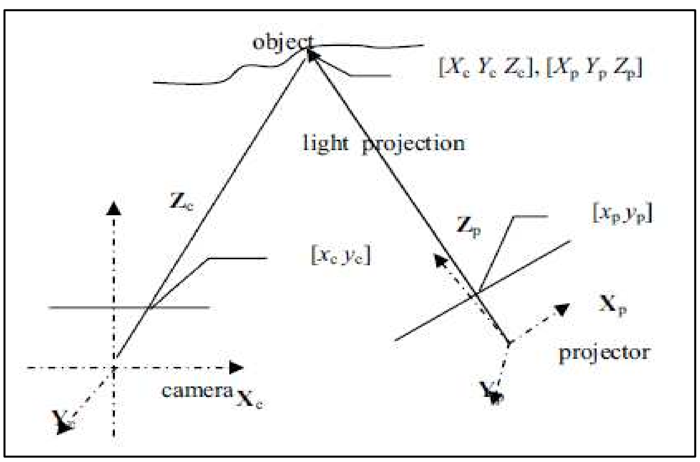



**Figure 5-8. structured light technique with a light projector and camera [35]**

## Multi colors multi rings approach:

Laser ring approach is a robust technique to scan surfaces, but the main drawback is its long scanning time due to the small number of 3D points acquired from each single frame. Another factor is the limitation of the spatial resolution due to the width of projected laser ring. In this section, we present a multi rings approach to increase the number of acquired 3D point from each recorded frame and to increase the resolution of the acquisition system. In this scenario, a 1D stripes sequence or a 2D grid is projected to the object to be scanned. The projection of multiple scanning lines leads to the rise of the correspondence problem (i.e. the correspondence between the projected and imaged scanning lines). Different methods are used to solve this problem. It varies from shifting of binary patterns to the use of frequency domain methods. Experiments show that the methods that are implemented with multiple projections provide dense 3D acquisitions but with the cost of processing time while single shot techniques provide nearly real-time results but provide a more sparse 3D grid that depends on the number of projected stripes in each single frame[36, 37]. In the case of the pipe internal surface scanner, the camera is moving inside the pipe which eliminates the possibility of using multi images technique due to the difficulty of acquiring these images for the same scene during the camera movement along the pipe. Thus, a single shot system is employed to account for the effect of scanner movement.

*Colored single shot patterns:*

In this method, multiple lines with different colors are projected to the surface with special sequences in order to acquire them uniquely[38, 39]. This method requires only one frame to perceive the depth of the scanned object. The method produces surfaces with less resolution due to the limitations on the number of projected lines, but it is considered fast and can be adapted to suit real-time systems and the imaging of moving objects [30].

**Projector pattern**

Single shot techniques require the projection of special patterns where each set of sub-patterns are unique within the projected color sequence to retrieve the actual location of the projected colored lines. For this purpose, the sequence is required to have a set of words that are uncorrelated with their entire projected sequence. De Bruijn sequences offer such capability by providing a set of uncorrelated sets of numbers. Each set is governed by two factors $k$ and $n$. Where $k$ represents the number of values that can be chosen for sequence elements, and $n$ represents the length of each sub-pattern. These factors also govern the total length of the sequence where the total length equals $k^n$.

*Reconstruction algorithm*

The reconstruction algorithm is executed in the following sequence:

**Image enhancement**

The recorded images are passed through a number of steps that may include noise reduction, color correction and transformation to another color spaces, etc. these steps enhance the image quality and improve the image segmentation of the projected rings.

***Segmentation:***

One of the main operations in the line detection is the segmentation. Each layer is segmented by taking the gradient of the image with Sobel filter. A 2D filter is used because the lines are circular and the color change happens in both the vertical and horizontal axes. After finding the gradient in each channel, they are combined by using an ***or*** operator:

$$final\ edge = edge_r | edge_g | edge_b$$

The gradient is thresholded to separate the foreground from the background.

**Color sequence detection:**

In this step, the algorithm compares the sequence of the projected and detected pattern by comparing the values along the projection axis. In the case of rectangular pattern projection, the comparison is made by exciting a raster scan along the horizontal or vertical axis. In the case of the pipe scanner, the color change detection is done along the radial axis as explained by the direction of the arrows in **Figure 5-9**.

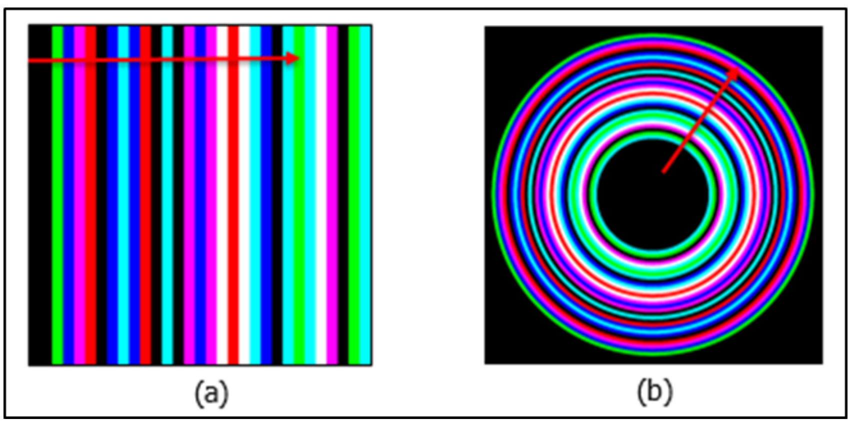


**Figure 5-9. Projection patterns: a) rectangular, b) circular**

The algorithm is utilized to check the color difference instead of checking the absolute value of the color because it is more robust to noise due the luminance differences [30]. The algorithm checks the detected sequence for any potential matching with projected sub patterns. For example, if the word length is four, then the algorithm starts matching the first four detected edges with the first four projected colors. If there is no match, the algorithm shifts the detected sequence and repeats the comparison process. If there is no match the projected colors windows is shifted and the comparison process is repeated. If a match is found, the four detected edges are registered as true edges, and the depth is extracted. Figure 5-10 shows the comparison process between the two hypothetical channels where the first one is the projected channel while the second is the received channel. The algorithm selects four elements from the projected sequence and starts shifting through the received channel until it finds a match as shown with the sequence [-1 0 0 1]. In our case, the matching is executed through the 3 RGB channels at the same time.

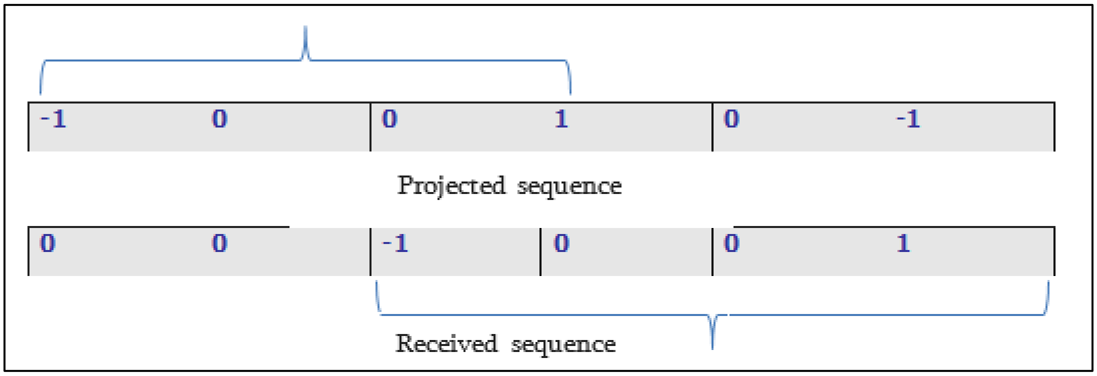



**Figure 5-10: Matching process**

## *Experimental*

### Defects and cracks in the pipes

In the beginning, 3 inch diameter pipes are considered as the specimen. Figure 5-11 shows the pipes that have been used in the experimental work.

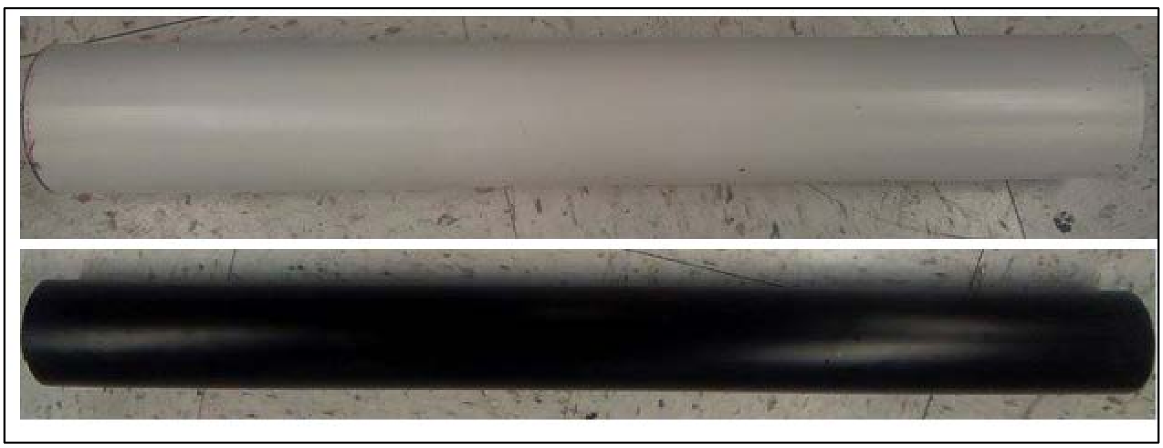


**Figure 5-11. Pipes for the experimental work**

Then some defects were introduced into the pipe as illustrated in Figure 5-12. Through hole defects with different diameters were introduced. In the white pipe specimen, the smallest hole in the pipe has the diameter of 0.0787 inches, and the biggest hole is 0.314 inches. Also, there are additional holes with 0.157 and 0.197 inch diameters. Moreover, some screws were installed to mimic different defect types. In the black pipe specimen, some damage was introduced to simulate different kinds of defects. **Figure 5-13** shows cracks with different directions on the pipe wall with a crack width 0.039 inches.

**Figure 5-12: The holes that have been introduced as defects**

**Figure 5-13. The linear cracks in the spacemen**

Because our focus is to minimize the sensing system to fit the specimen smaller than 1 inch, a smaller pipe provided by GTI with different kind of defects was shipped to LEAP and tested in Q2. The diameter of this pipe is 1.85 inches. **Figure 5-14** shows the second type of pipe that has been used in the experimental work in Q2.

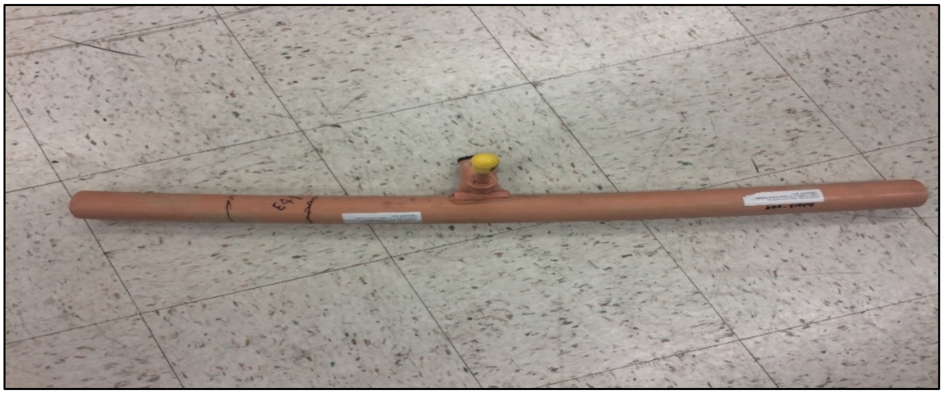
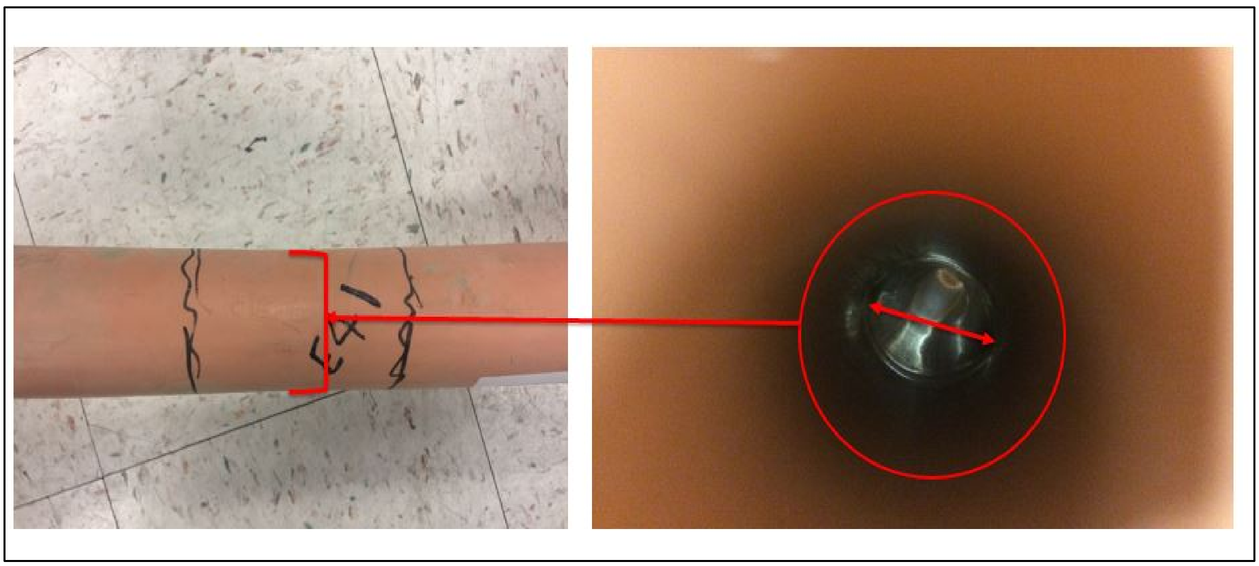


**Figure 5-14. Pipe with a small diameter (1.85 inches) and damage section**

The damaged section of this pipe is explained in **Figure 5-15** with **Figure 5-15.a** showing the outer section of the damaged area while **Figure 5-15.b** is showing an internal view that was taken by an endoscopic camera.



(a) (b)

**Figure 5-15. Optical outer and inner view of the E41 damage of GTI pipe sample damaged area**

## Scanning without light source

Before performing the laser scanning or structured light scanning, passive scanning is considered to show the defects without any light source. Two different cameras were used to scan the inner side of the pipes as shown in **Figure 5-16**. These cameras have different diameters. The diameter of the smallest camera is 0.23 inches, and the diameter of the largest camera is 0.62 inches. The camera is installed in a special prototype that was produced by 3D printing. After installing the camera and moving it inside the pipe, a video is recorded to capture all inner surfaces in the pipe. **Figure 5-17 a** illustrates the cracks that have been captured by using the two camera. Also, **Figure 5-17 b** shows the holes that were introduced into the pipe.

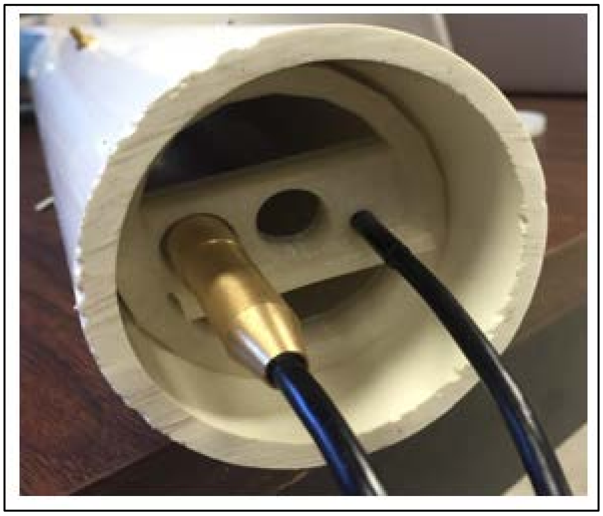
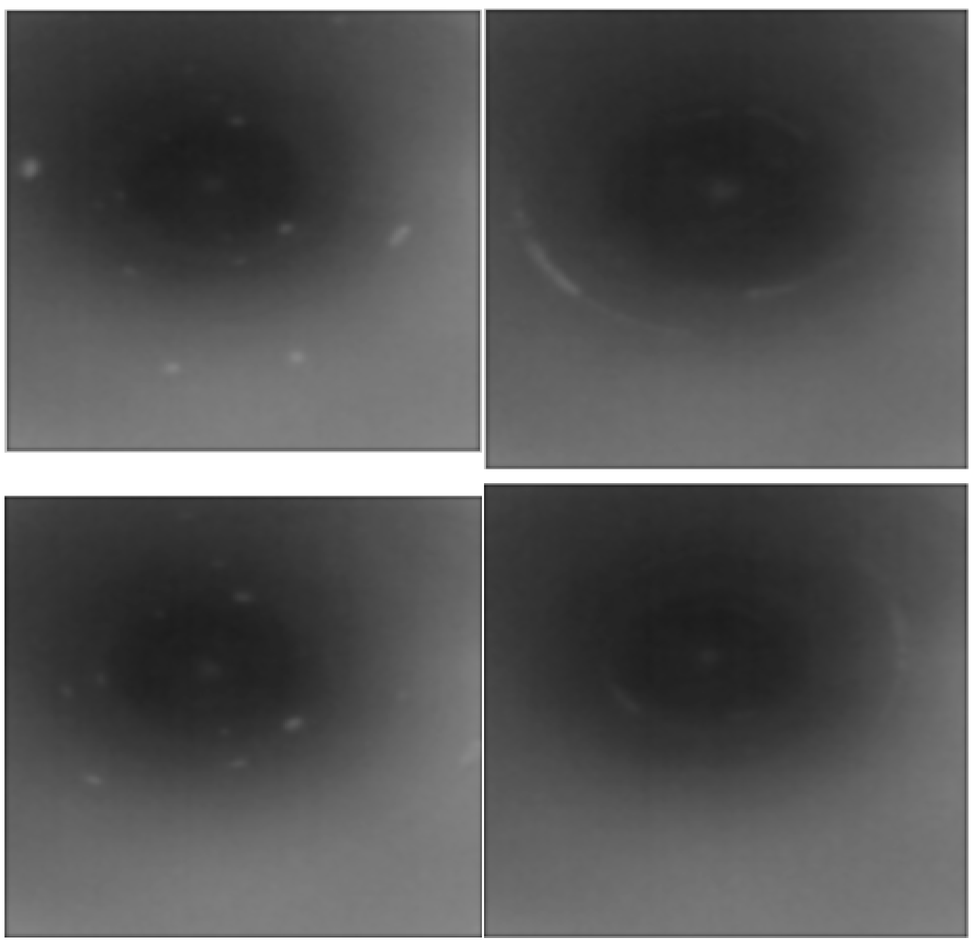


**Figure 5-16. Two different cameras installed inside the pipe**



(a) (b)

**Figure 5-17. The different defect types captured by using the camera**

Using a single passive camera gives an initial indication about the existence of damage on the pipe's surface but it doesn't provide enough information about the size and the shape of the damaged area. This is due to the lack of any depth information in the recorded camera frames.

*Single ring scanning*

In this part of the research, a single ring laser is considered to be the light source of the scanner. Laser source with a specific red ring was used to detect the cracks and the deformation. An image of the laser source and the projected red laser ring is shown in **Figure 5-18**. The relation between the diameter of the ring and the distance between the ring and the laser source is (1:1). This means that if the distance between the laser and the scene is 1 meter, then the diameter of the ring on the scene will be 1 meter.

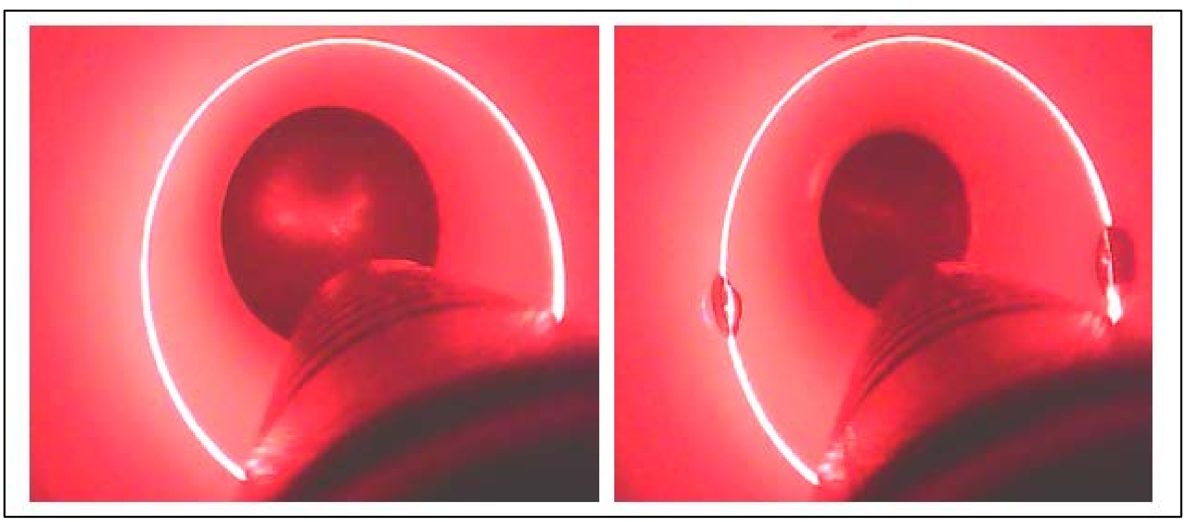
**Figure 5-18. The laser source used in the sensor prototype**

*Scanning with small view angle camera*

One of the cameras that was shown in **Figure 5-18** was used with the laser source to scan the pipe. **Figure 5-19** illustrates the prototype that has been used for scanning. The camera in this prototype is attached to the cover of the laser source and two centimeters to the back to provide a better view angle due the small view angle of the camera (65 degrees). Therefore this shifting is needed to let the camera capture the maximum amount of the laser ring. By moving the prototype with constant speed, the camera collects the data and saves it to an external computer.

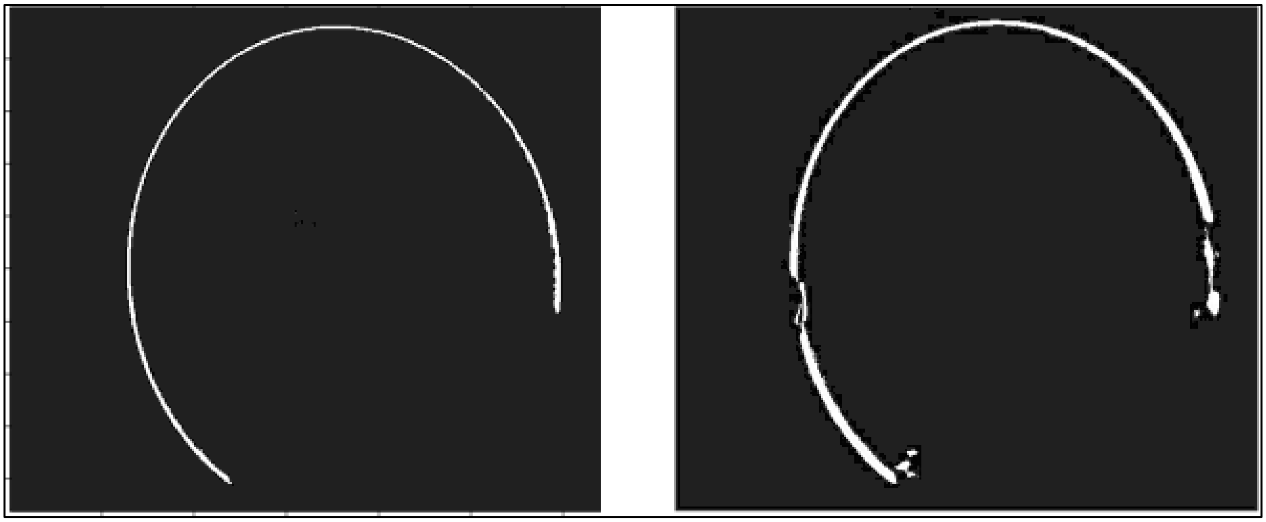
**Figure 5-19. Simple camera and source bundle prototype**

As shown in **Figure 5-20**, the laser ring is not complete because the camera captures only a partial part of the projected laser ring. Thus, part of the scene is blocked. This kind of missing ring parts is called shadowing. This shadow area blocks about 25% of the whole scene while the other parts can be reconstructed successfully. Therefore, this kind of missing information is one of the limitations that should be considered to solve in the next sections. **Figure 5-21a** shows that the laser ring does not have any deformation. On the other hand, **Figure 5-21b** shows some deformation in the segmented laser ring. The changes in the laser ring shape are indications of the existence of deformation on the pipe's wall which is decoded later to form the damage 3D profile.



(a) (b)

**Figure 5-20. Some frames form the collected data: a) with no defects and b) with defect**



(a) (b)

**Figure 5-21. Results after applying the thresholding**

### *3D image reconstruction*

As mentioned before, the reconstruction process depends on the triangulation between the camera and the projector. To determine the shifted location of the projected lines, some intermediate image processing steps are implemented. The complexity of the required steps depends on the type of the used structured light methodology and the amount of noise and artifacts that corrupt the camera image. For this project, two types of implementations are considered. The first one is the single laser ring, and the other is the multi-ring multi-color method which will be implemented in later sections.

For the single laser ring, the reconstruction algorithm is applied to either one of the RGB layers that has the maximum intensity for the laser ring or the gray scale version of the image. In the case of the red laser scanner, the green layer is chosen because it contained minimum amount of noise from the red light. The extraction process starts with applying a weighted threshold to the image to reduce the noise. After that, a two-dimensional Sobel filter is applied to extract the edges the ring from the image. To enhance the laser line detection, a multiple morphological operation is applied to fill and connect the discontinuities of the laser ring [40]. The laser ring is then extracted, and the deformation depth is calculated. **Figure 5-22** shows a brief description of the implemented algorithm.

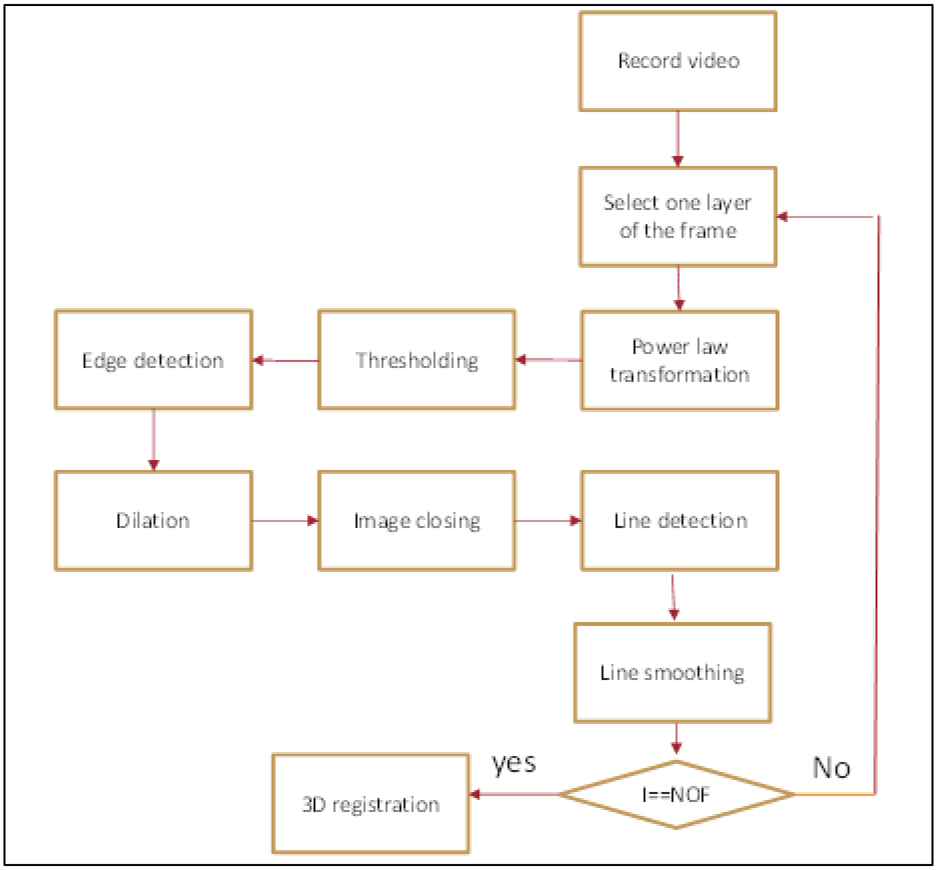



**Figure 5-22. Reconstruction algorithm for single laser ring**

The Multi rings patterns are proposed to increase the resolution and the speed of the 3D acquisition. With the introduction of multiple rings in the image, the problem of the ring correspondence arises. One of the proposed solutions to solve this problem is the use of colored rings. The colors of the rings are coded with a special code to create sets of unique sequences that can be identified correctly in any location inside the image. Many methods are proposed to decode those patterns. One of the methods is to use graph based reconstruction to decode the pattern [41, 42]. In this method, the image is segmented with watershed transformation. Then a graph diagram is created for the segmented image, and the edges are extracted per this graph diagram. For both described methods, after processing each frame, the depth information is collected and registered to form the final 3D shape. One of the registration methods is performed by using the location of the camera as a reference for the registration process. The other method is to use special image registration algorithm to estimate the location and register the frame. Multiple registration algorithms are proposed to solve this problem, one of the popular algorithms depends on Iterated Closest Point [41]. The problem with those algorithms is that they fail to deal with flat smooth surfaces due to the lack of any distinctive features [42]. For this reason, a combination of both position data and registration algorithms need to be applied to achieve the accurate results.

Preliminary results of the 3D reconstruction for the single laser ring can be seen in Figure 5-23. The results show that about 75 percent of the pipe's surface is reconstructed correctly, and the defect are represented as a bumps or holes on the pipe's walls. The surface reconstruction can be enhanced by using a more advanced setup for the camera and the projector to reduce the amount of the shadows. The results also show some defects due to the instability of the camera holder. A more stable holder and a correction algorithm are required to reduce those defects. The projector and camera setup and the required algorithms for the multi ring methodology are shown in the next sections.

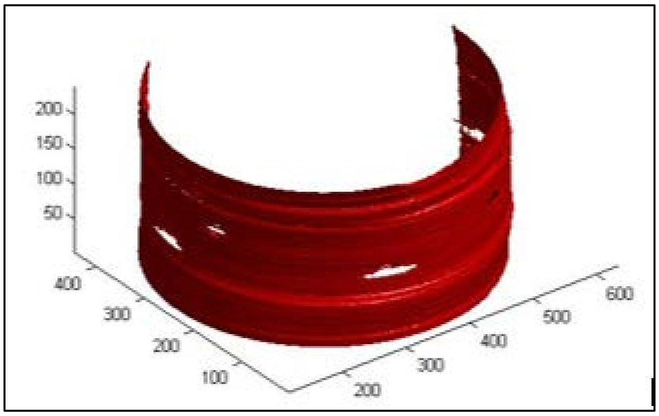



**Figure 5-23. 3D reconstruction of the internal surface of the pipe**

*Scanning with large view angle camera*

In this section, we repeated the same 3D reconstruction but with a different prototype. The missing part in the previous 3D image causes some problems. For example, if there are any defects or cracks in the missing area, the 3D reconstructed image will not show these defects. Therefore, some enhancement needed to be made to avoid this kind of problems.
Using a large view angle camera is one of the solutions that make the reconstructed image better. The difference between this camera and the previous one is the view angle. In the old one the view angle is about 65 degrees, but in the new one it is 180 degree that allows the whole scene to be detected by putting the camera and the laser source on the same base line. This wide angle is achieved by using a convex mirror or using a fisheye lens. In our setup, we opted to use a fisheye camera to simplify the setup and make it more robust and practical. **Figure 5-24** shows the fisheye camera that is used in this experimental work.


**Figure 5-24. Fish-eye camera**

In the previous prototype the camera was attached to the laser source but in the new prototype the camera and the laser source are separated, and they are on the same base line. Because the camera has 180-degree view angles, all the ring will be captured without missing any part. The new prototype can be illustrated in **Figure 5-25**. The prototype will be inserted into the specimen to collect the data. However, the scanning will be performed by human hand so, some misalignment will be introduced. After that, the same 3D reconstruction process will be repeated. Then taking a few frames from the recorded video, the laser light inside the pipe will be as shown in **Figure 5-26** a and b. In **Figure 5-26 a**, the ring is complete and the laser light does not have any deformation. This indicates that the areas that have been covered by this light are still without any defects. On the other hand, **Figure 5-26 b** shows the small deformation in the laser light.

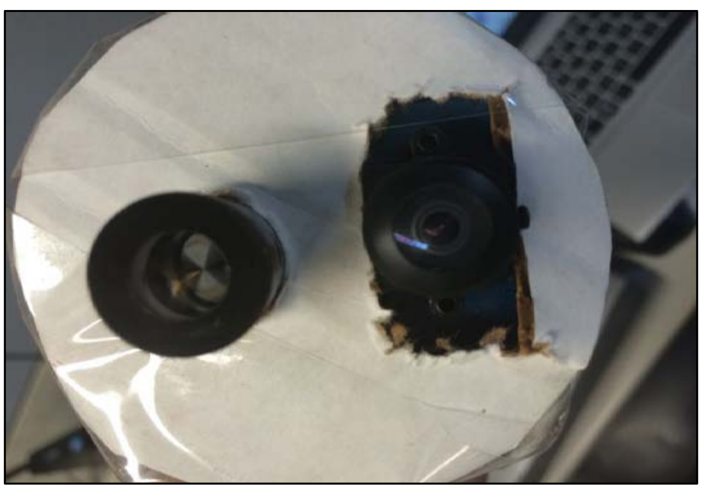
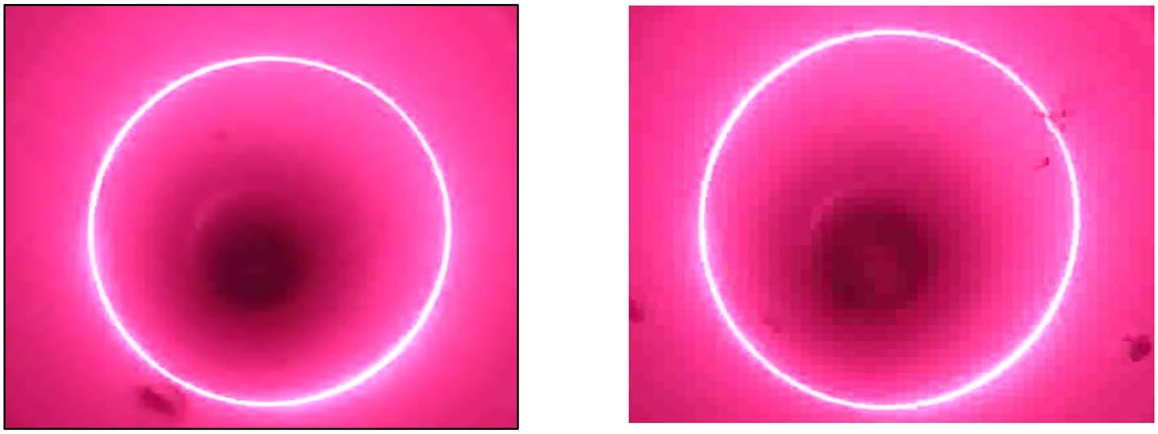


**Figure 5-25. The camera and the laser source installed in temporary prototype**



(a) (b)

**Figure 5-26. Complete ring images, a) full ring. b) ring with some deformation**

Per this deformation, this frame will represent the area that has the defect in the pipe. Likewise, by stacking all the frames and generating the 3D image, the defects will clearly appear in the final image **Figure 5-27**. The laser and camera take up a large space inside the pipe making the minimization of the prototype more complicated. Different prototypes are being developed to minimize the size of the sensor and will be reported in next sections.

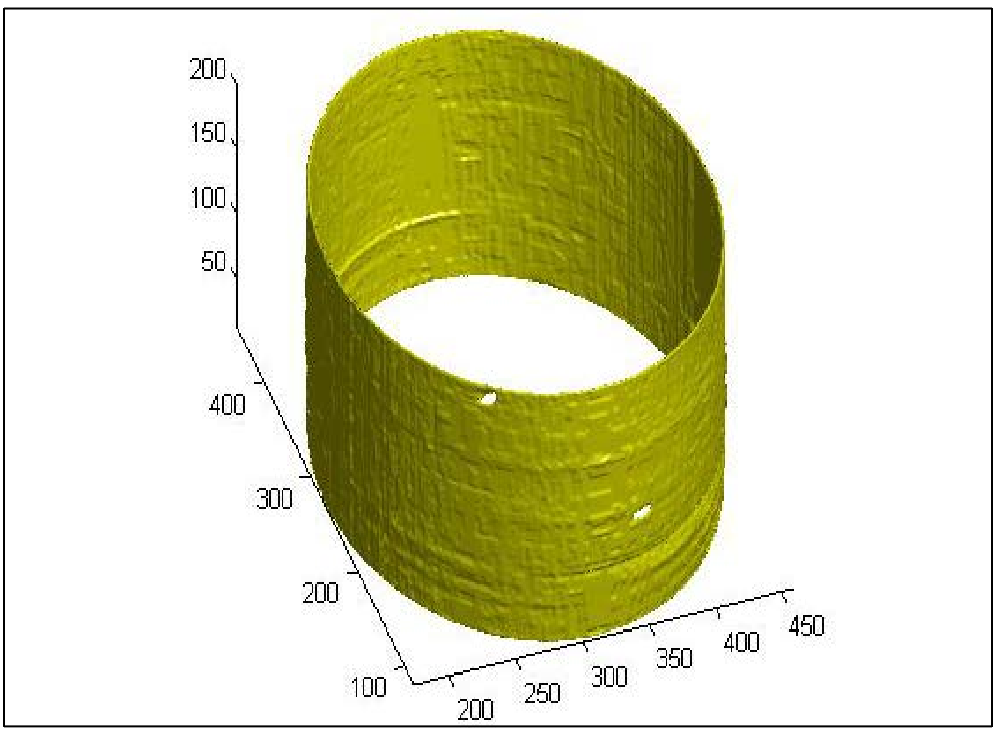



**Figure 5-27. The 3D reconstructed image with complete FOV**

### *Scanner and the Sensor in Opposite Direction*

As mentioned in the previous section, the laser source and the camera take more space if they are installed in the same baseline. Therefore, in this section different prototype will be illustrated. Although this prototype will reduce the size of the scanner, the image will not be a full ring. Some missing part will be shown in the collected data because of the metal that has been used to connect the laser source and the camera. A part of the light will be blocked and will not be recorded by connecting the prototype as shown in **Figure 5-28**. Therefore, when moving the prototype inside the pipe, the scene will be as shown in **Figure 5-29**.

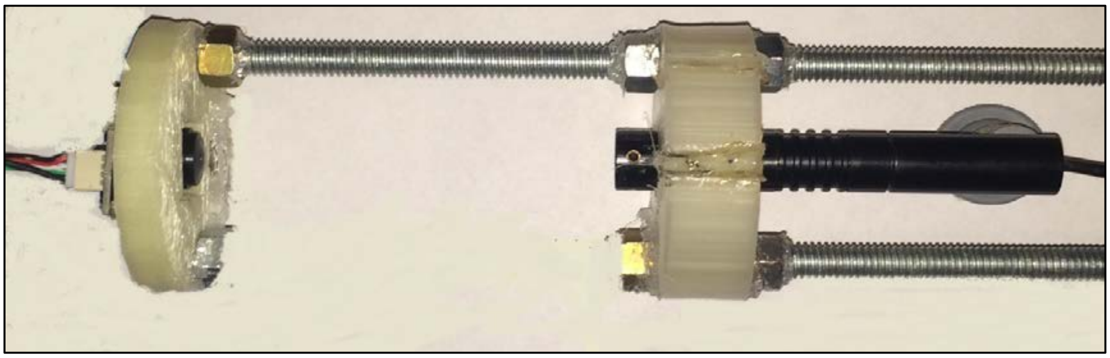


**Figure 5-28. The prototype that has been used in this section**

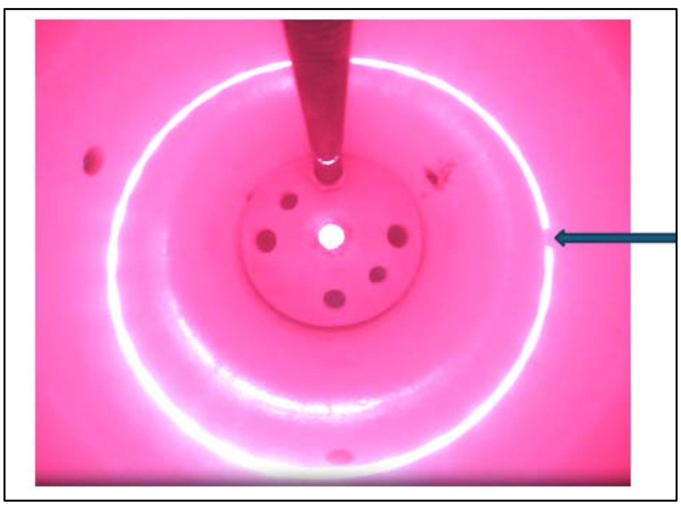


**Figure 5-29. Illustration of one frame that has defects**

Clearly, the defects can be illustrated as missing points in the laser beam. Thus, after processing all the frames, the final 3D reconstructed image will be as shown in **Figure 5-30.**

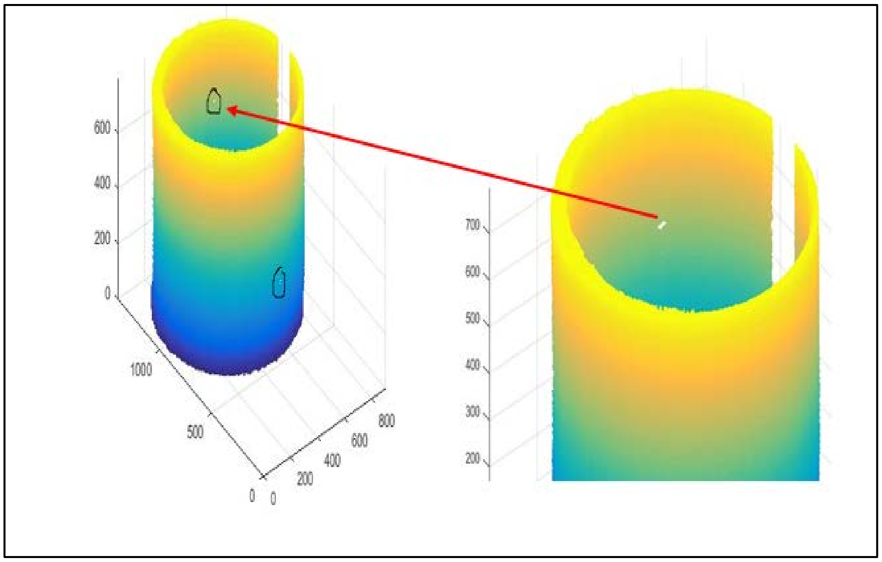


**Figure 5-30. 3D reconstruction**

## Deformation Detection

3 D visualization is an efficient method to emphasize the deformation in the pipes. The circularity of the pipe can be checked by performing eccentricity calculations from the data. In this section, the eccentricity is calculated, quantitative analysis is performed, and the misalignment correction is provided to minimize the camera misalignment.

### *Eccentricity Calculation*

As known, a circle has a fixed diameter or radius in all directions as shown in **Figure 5-31.** This radius is measured from the center of the circle to the edge. Therefore, the distance (a) equals to distance (b). On the other hand, in the case of the ellipse, the (a) and (b) are not equal.

The ellipse has two different radii which are called semi-major and semi-minor. Semi-major denoted as (a) and indicates to the larger radius, and the other radius (semi-minor) denoted as (b). As shown in **Figure 5-32,** there are two focal points which are F1 and F2, and the distance between the focal point and the center is called linear eccentricity. Then by choosing any point on the ellipse (p) and calculating the distance between it and the focal points, we can get the semi-major axes as follows:

$$PF_1 + PF_2 = 2a \qquad \textbf{Equation 5-3}$$

$$f^2 = a^2 - b^2 \qquad \textbf{Equation 5-4}$$

Then by knowing a, b and f, another term can be calculated which is called eccentricity and denoted by e. In case of ellipse, e will be between 0 and 1 (0 < e > 1).

$$e = \frac{f}{a}$$ **Equation 5-5**

$$e = \frac{\sqrt{a^2 - b^2}}{a}$$ **Equation 5-6**

$$e = \sqrt{\frac{a^2 - b^2}{a^2}}$$ **Equation 5-7**

$$e = \sqrt{1 - \left(\frac{b}{a}\right)^2}$$ **Equation 5-8**

For example, if we have a=2.5 and b=2, then $e = 0.6$, Which is less than 1. Also, if a=b=2.5 $e$, is equal to zero, which is the case of the circle. Thus, by calculating the eccentricity for each frame, we can define if the frame is normal or defective.

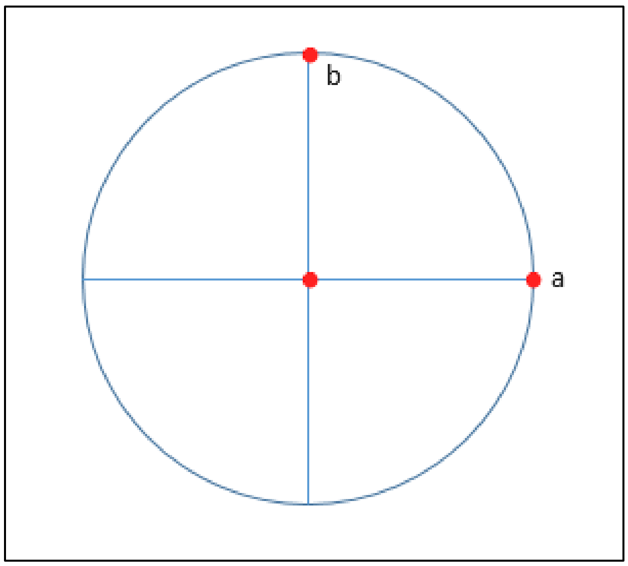



**Figure 5-31: Illustration of the circle which has fixed radius**

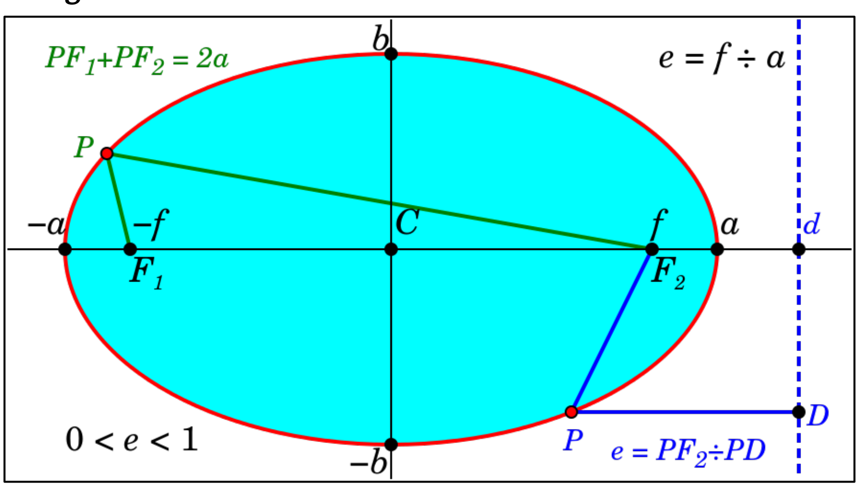



**Figure 5-32. Illustration of the ellipse [43]**

*Eccentricity of a deformation free area*

In this section, the eccentricity formula will be applied for some frames that do not have a deformation to emphasize whether if it has a circle shape or not. Because of some other effects, the eccentricity may not be zeros in the case of free deformation area. This issue is due to the scanner misalignment and will be discussed later. However, let's consider that the misalignment is negligible in the current section, and just focus on the large variation of the sequence. Then the defects can be easily illustrated. **Figure 5-33** illustrates the eccentricity of 20 frames without defects, and the variation is not significant. The eccentricity in **Figure 5-33** varies between 0.26 and 0.32. By taking a special case to check the eccentricity. And frame number 60 has been chosen for that, then the semi-major radius is 200 (number of pixels). And semi-minor radius is 193 pixels then the eccentricity will be equal to 0.26622. It is still not zero, but this result will be compared with the results in the following section.

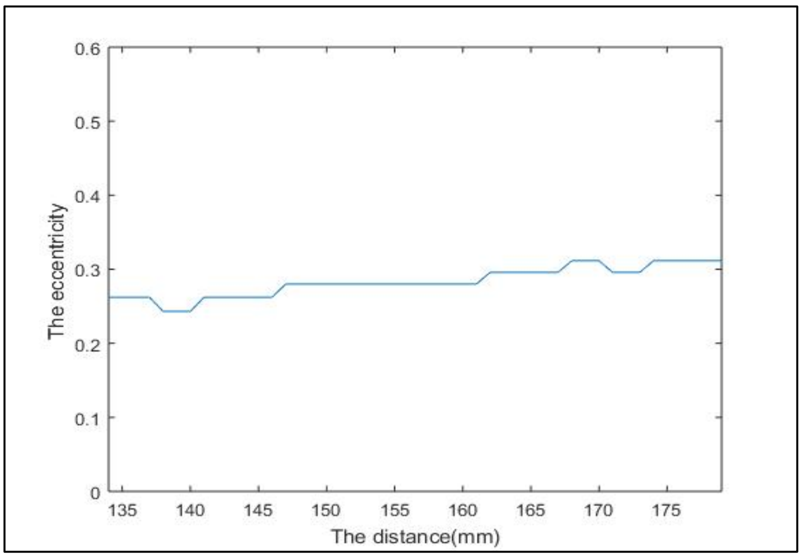
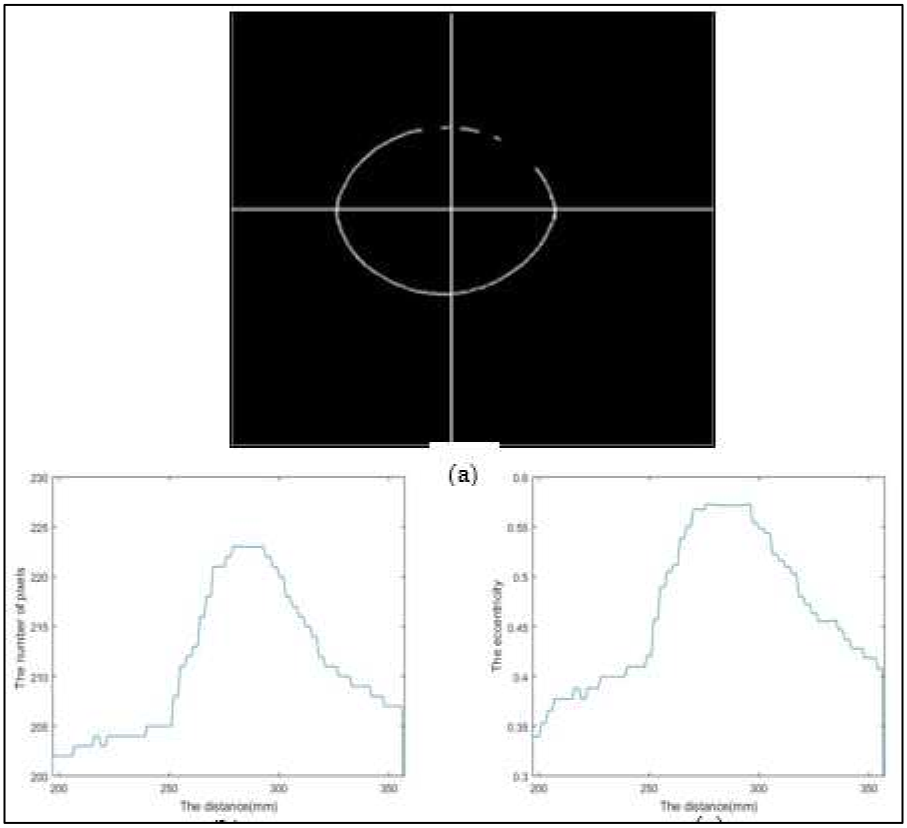



**Figure 5-33. Illustration of 20 frames (4.4 cm) from collected data**

*Eccentricity of the Area with Squeezed Parts*

For the frames that have defects, the eccentricity will be much bigger than the other that were illustrated in the previous section. Therefore, by picking some frames that have defects, and let's say ten frames (120-130). One of the frames is shown in **Figure 5-34.a**. Vertical and horizontal lines are added to the image to illustrate the center of the ring. However, the eccentricity will be calculated for frame number 125. Then by calculating semi-major radius which is 217 and the semi-minor radius will be 185 and the eccentricity is equal to 0.5227. The eccentricity is increased when compared with the previous result. To emphasize the difference between the deformation free area and squeezed part the eccentricity will be calculated for all the frames as shown in **Figure 5-34.b**. Initially, the eccentricity will be fluctuating around small value then suddenly will start increasing until reaching the pick value (0.58) after that it will decrease until starts fluctuating around small value again. These analyses show that the deformation can be easily discovered by using the eccentricity.




b c

**Figure 5-34. a) Illustration of one frame with a defect and there are two lines to emphasize the ring center, b) Final result of the eccentricity has been calculated for 71 frames (17.6 cm), c) Illustration of the semi-major radius of all 71 frames (17.6 cm)**

### *Misalignment Correction*

The misalignment is one of the problems that are faced when the data is analyzed. This issue makes the reconstructed image not clear enough to emphasize the defects, therefore, in this section, the misalignment correction will be applied to one of the data sets that does not have defects **Figure 5-35**, but the eccentricity is large because of the misalignment.

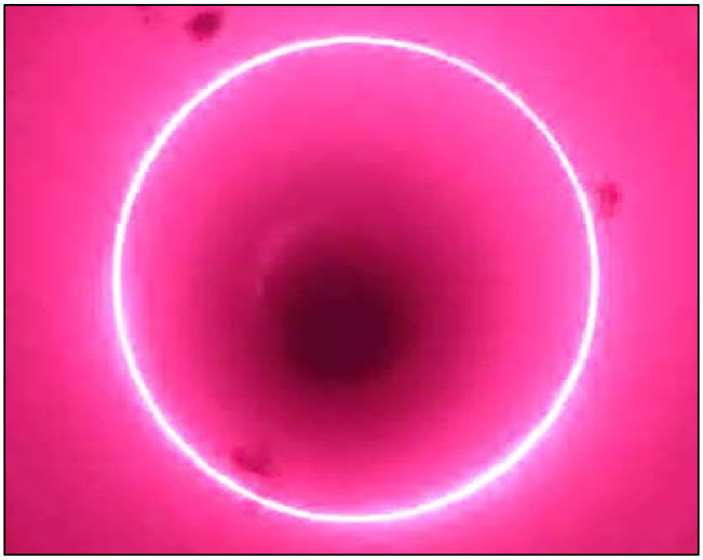


**Figure 5-35. The region without defects but the shape is not circle**

Moreover, if the eccentricity algorithm was applied to a couple of frames, the output will not be zero as mentioned previously, the eccentricity will be around (0.6359) as shown in **Figure 5-36.** (a). Also, the 3D reconstructed image will be as shown in**Figure 5-36.b**. Thus, the correction should be applied to decrease the eccentricity to be close to zero for deformation free images. This correction depends on the semi-major radius, semi-minor radius, and the orientation of the ring. These parameters are used to determine the (tform) matrix by using an affine transformation, then the image is reshaped and squeezed to a circular shape as shown in Figure 5-37.b.

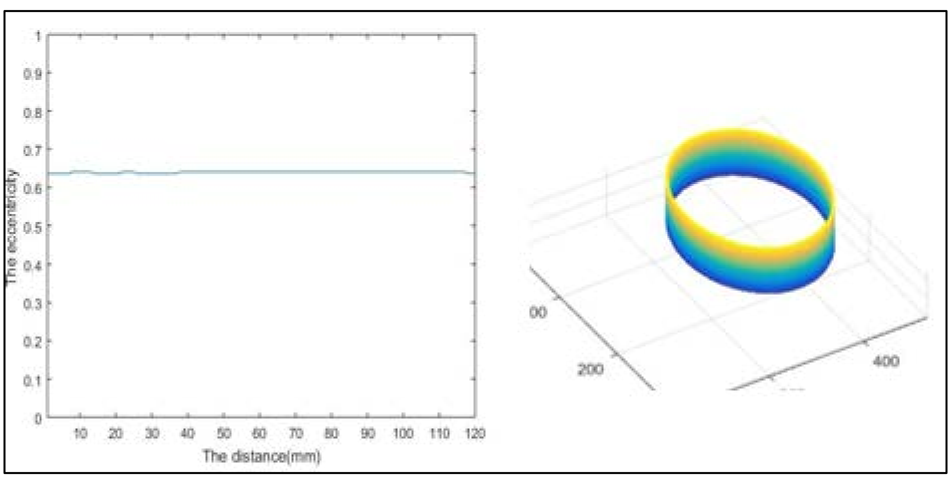



**Figure 5-36. a) The eccentricity of multi frames without misalignment correction, b) 3D reconstructed image of number of frames without applying misalignment correction**

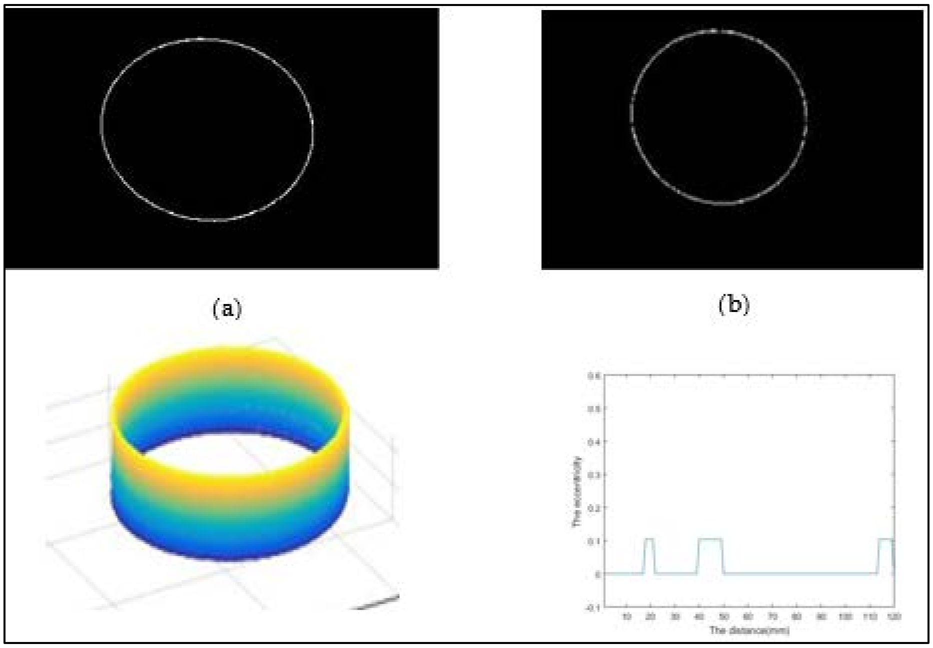



**Figure 5-37. a) illustration of one frame that effected by misalignment and the shape is not a circle. b) The same frame after applying misalignment correction and the shape is closer to circle. c) 3D reconstructed image after applying misalignment correction, d) The eccentricity after applying misalignment correction**

Finally, the eccentricity of the same frames after applying misalignment correction will be around (zero) which is what we expected to have and Figure 5-37.d illustrates the eccentricity after misalignment correction.

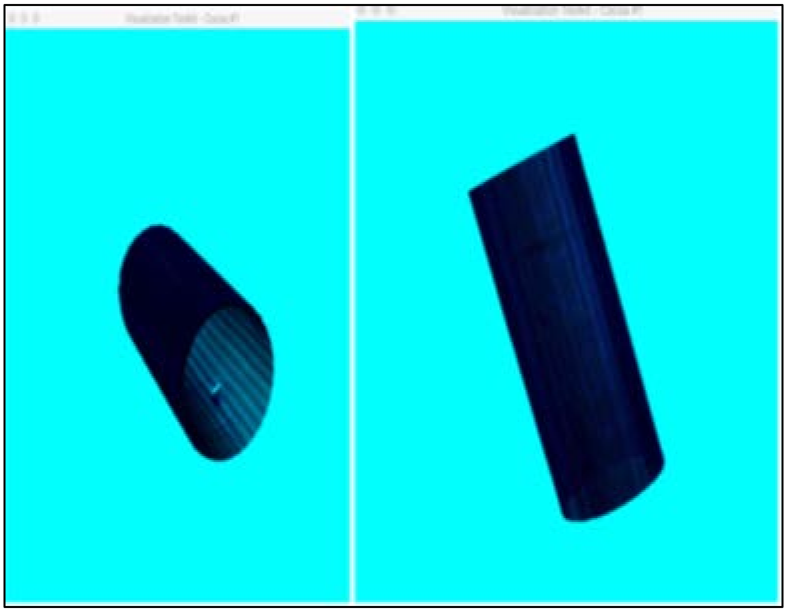
***Raspberry Pi based scanner:***

Outdoor field deployment of the scanner makes the mobility of the system a crucial factor to increase its efficiency and flexibility. In this section, a brief description is given about the use of a small size single board computer as the processing unit for the scanning system. This will enable the integration of the system to build a battery-powered handheld device that has a light weight, small form factor, and low power consumption.

The Raspberry Pi 2 model B, was released in February 2015 as the latest Raspberry Pi model with updated hardware. The Raspberry Pi 2 model B, has a quad-core ARM Cortex-A7 CPU processor running at 900MHz with 1024 Megabytes of onboard memory with four USB-ports with one 10/100 Megabit/s Ethernet port, and one micro-SD card slot for storage on board [44]. The Raspberry Pi 2 model B, is faster and has twice the amount of memory compared to its predecessor, the Raspberry Pi Model B+. It now has a quad-core processor, which is speculated to make the Raspberry Pi 2 model B up to six times faster than the previous models. Arch Linux ARM is an ARM-based Linux distribution ported from the x86 based Linux distribution Arch Linux. The Arch Linux philosophy is that users should be in total control over the operating system, which allows the users to implement it in any way they like. Therefore, Arch Linux can be used for simple tasks and as well as more advanced scenarios. Arch Linux ARM is based directly on Arch Linux, and they share almost all the code, which makes Arch Linux ARM a very fast, Unix-like and flexible Linux distribution. Arch Linux ARM has adopted the rolling-release update function from the x86-version. This means that small iterations are made available to the users as soon as they are ready, instead of the releasing larger updates every few months [44]. The crack detection program is laid out to run on top of an operating system, so installing one on the Raspberry Pi is the first thing to do. The preferred system for this task is NOOBS, as there is a distribution available, which is optimized for the Raspberry Pi. For this project the NOOBS:v:1:7:0:zip distribution was used. The operating system always runs from an SD card, which was found to be reasonable during the development of the Raspberry Pi. SD cards deliver high capacity, are cheap and fast, easily writable and easily changeable in case of damage. The size of the used card should amount to at least 4 GB, as it will contain the operating system (about 2 GB) and should still provide some additional space. We used 32 GB SD card since we were dealing with High-Resolution images. The file system used for the first setup during the integration of the Raspberry Pi into the WSI system was ext4. It is recommended to continue working with ext4 or at least another journaling file system, as journaling provides higher security in case of a power failure or a system crash. After unpacking the downloaded NOOBS image, it can be copied onto the SD card. If connected to a monitor, booting the Raspberry Pi with its new operating system for the first time should display a configuration menu. In the case of not using an extra monitor for the Raspberry Pi the configuration menu can be accessed with the help of the command raspiconfig (as root). One should at least expand the file system on the SD card to be able to use all its space. On top of the operating system, we install OpenCV libraries and Visualization Tool Kit with Python interface. OpenCV libraries provide a set of instructions to perform morphological operations. Visualization Tool Kit installed on this machine helps rendering system for analyzing the cracks. Since Raspberry Pi has a lot of resources available on the system, it provides support for a vast variety of libraries on it. But all the resources available on the system provides only limited processing capability for the current real-time implementation. Onboard memory is very limited about 1GB of RAM due to which we experience a limited Image processing capabilities.

### Motion detection and distance estimation:

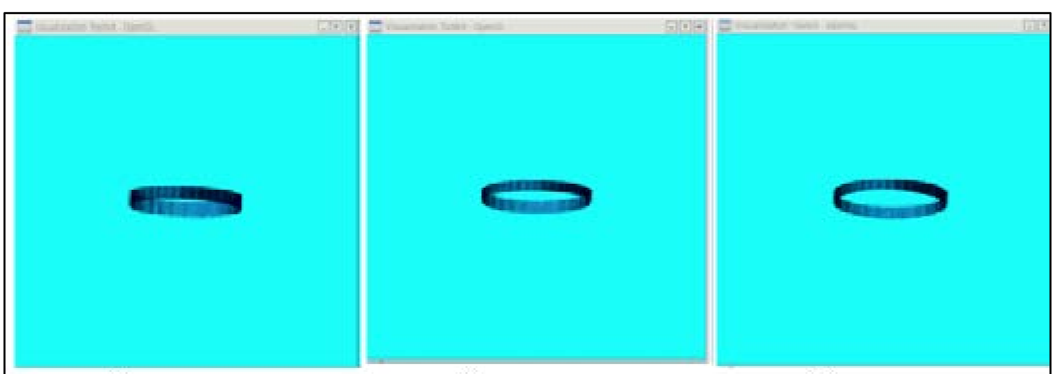
In this section, the small, low-cost device is used to reconstruct the frames from the camera, with a processing time of 0.35 seconds per frame. The reconstruction results by using raspberry pi are shown below in **Figure 5-38** (a) and (b). As the number of images for processing increases the performance of raspberry pi decreases and the memory available on the raspberry pi is not sufficient.



(a) (b)

**Figure 5-38. a and b Represents the Reconstruction Results on Raspberry Pi**

To avoid running out of memory, we split the scanning into equal sized slices and store them in individual files. Figure 5-39 shows the slices for certain scanning section. When we split the data, we avoided the memory issue with the raspberry pi, but we were unable to know the distance of scan range. Therefore, to avoid this problem, we calculated the scan distance of each scan sample and also we calculated the distance of defect from the starting point. Since we are moving with the hand, we assumed the scanning speed to be constant and assumed that our sensing module captures ten frames for every 1cm distance. Scan Distance equals to the Number of Frames Captured divided by the Number of Frames Per Centimeter with assumption that the Speed is constant. Then we captured 210 frames, i.e.; we moved 21 cm from the starting point. Then we split the data based on the equal sized slices each of 7cm as in Figure 5-39 (a), (b) and (c).



(a) (b) (c)

**Figure 5-39. Equal Sized Slices 28cm long a) 0-7 cm b) 7-14cm c) 14-21cm**

The other experiment was to detect the crack and its position from the starting point. We used our test specimen that is shown **Figure 5-40.** (a) for this experiment and performed some tests. We marked our cracks as shown in **Figure 5-40.** (a). We determined with a measuring scale that the first crack is at a distance of 18 cm, second at a distance of 20 cm and third at 23 cm from the starting position. The rendered results are shown in **Figure 5-40**.(b). The cracks are detected by the principle of motion sensing. At the beginning we capture two images and find the difference between them. If the difference is not null then the motion is detected, and we assume that it is due to some deformation or crack inside the pipe at that point. The distance from the starting point is calculated according to the block diagram in **Figure 5-41.**(a) .

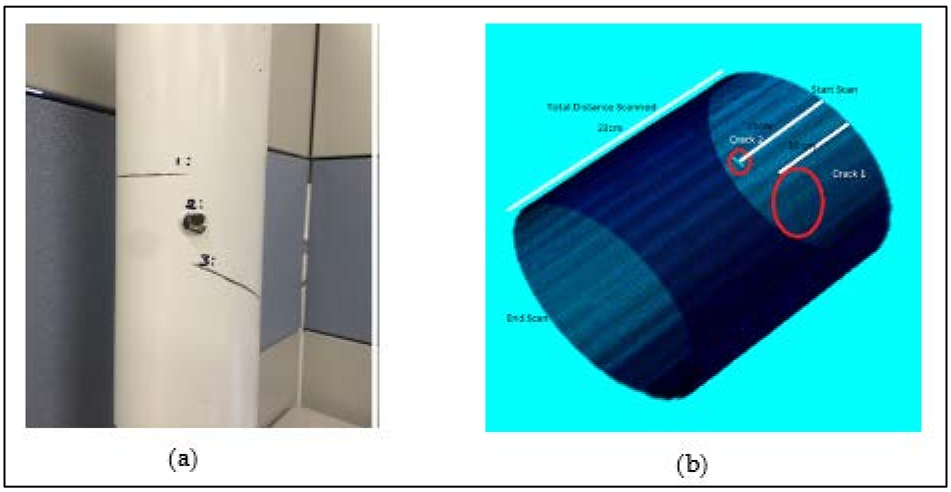



**Figure 5-40. a) Object under test for distance calculation, b) 3D Rendered Scan with Crack Detection**

**Figure 5-41.** (b) shows a comparison between the actual and estimated positions of defects. From the figure, we observed that the crack one and two were accurately matching with the original measurements, but few points were not overlapping this was due to the movement of the prototype. Our experiment requires the prototype to be moved at a constant speed manually which is not an easy task.

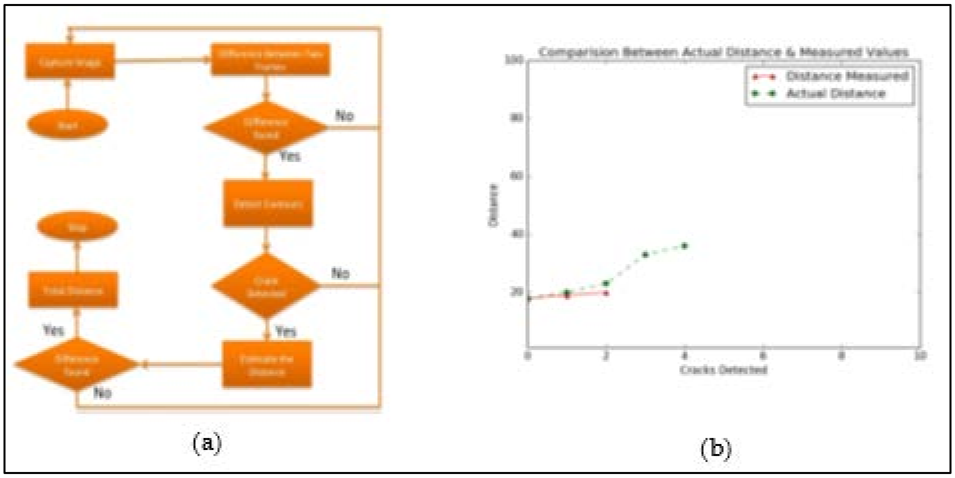



**Figure 5-41. a) Experimental flow for distance calibration, b) Comparison between the actual distance and measured distance**

## Multi-Rings Multi-Colors Scanning

As discussed in previous sections, structured light is one of the methods that have been used to generate a 3D image by using a camera and an active light source. To produce a pattern that is needed to illuminate the scene, a projector is required to do this step. In typical 3D imaging by using structured light, the projector will be like one that is shown in Figure 5-42. However, this kind of projectors will not be sufficient inside the small pipes. An alternative to using a DLP projectors, is design small slide projector to provide the wanted pattern.


**Figure 5-42. Structured light with a projector used to generate the [45]**

***Simulation environment:***

A simulation geometry is created by using an open source software (POV-ray) to simulate the structured light scanning process. The simulation helps developing the algorithm in parallel with developing the hardware. It also provides a controlled testing environment to test the robustness of the algorithm against different noise and interference conditions. The simulation environment provides a light source and a camera that are modifiable to perform different scanning tasks for different targets shapes.

Two geometries were simulated, the first one is a simple rectangular geometry to test the performance of the algorithm then the geometry is modified to simulate the pipe scanner.

1. Simulation with rectangular geometry:
   A 3D object (Stanford bunny [46]) is used as the target to be scanned. In the simulation, the camera and the projector are aligned at different angles with reference to the target. The target is illuminated with a colored sequence that generated with De Bruijn algorithm. As De Bruijn consists of some repeated colors and as the camera cannot differentiate between repeated colors, XOR operator is used to removing any color repetition [30]. A sequence with K=5 and n=3 is shown in **Figure 43.** (a). The image captured by the camera is shown in **Figure 43.** (b), and it is obvious that the projected stripes are deformed by the object surface. After that, the image is segmented as shown in **Figure 43.** (c). The segmentation results show that the area near the tail couldn't be segmented correctly due to the poor illumination because the projector is projecting from the opposite side. The final results after post-processing are shown in **Figure 44**. The results show that the object has been successfully constructed and the depth is retrieved. The 3D acquisition of the object suffers from some small missing parts due to some segmentation problem related to the scene illumination.

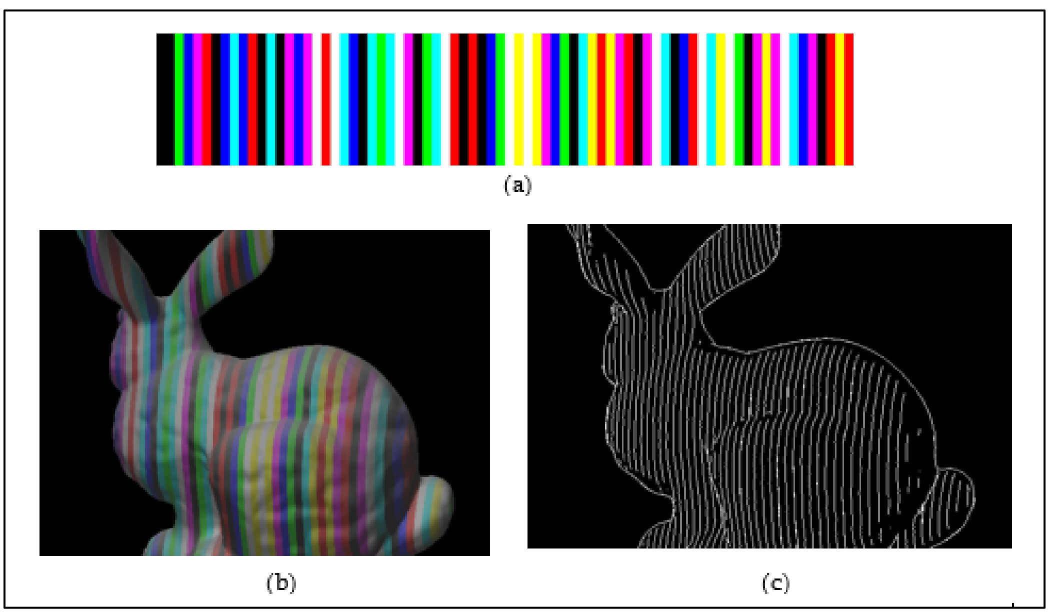



**Figure 5-43. a) Illumination pattern, b) Geometry after illumination, c) Segmented image**

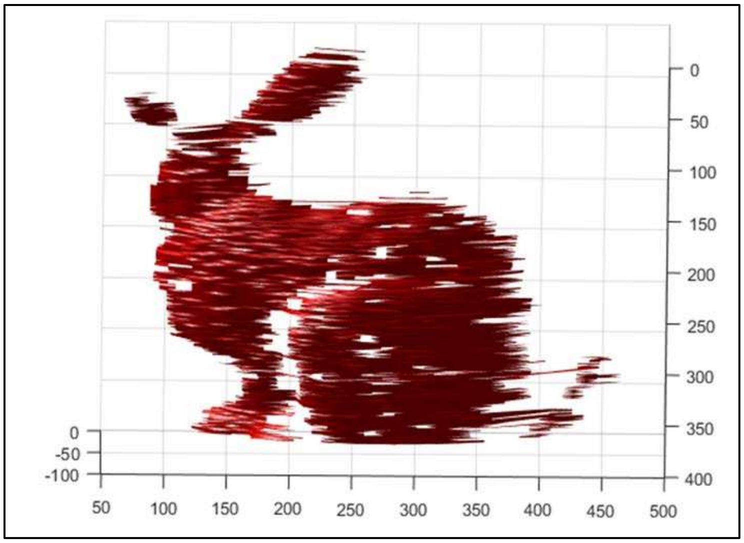



**Figure 5-44. 3D reconstruction results**

2. Simulation with circular geometry :
The simulation is repeated with circular geometry with the camera and projector orientation shown in **Figure 5-45**. The camera is placed in front of the projector to collect all the reflected light from the pipe walls. The scanner is placed inside a cylindrical tube that was created by using CAD software.

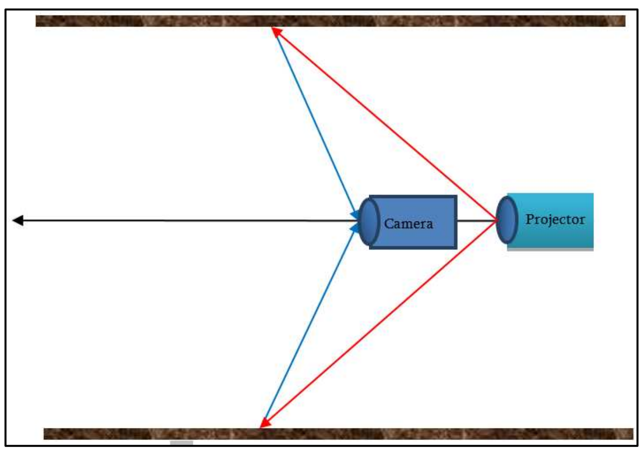



**Figure 5-45. Circular geometry of the simulation**

The projector illumination pattern is the same as the one shown in **Figure 5-9 b**. It is created by converting the pattern in **Figure 5-9.a** to circular geometry. The first simulated geometry is normal defect free pipe to act as a reference model. The simulation results are shown in **Figure 5-46**. It shows the simulation geometry, simulated pipe surface, reconstructed 3D points from 16 consecutive frames, and interpolated and rendered final profile. The reconstructed 3D geometry shows good agreement with the smooth circular pipe internal surface therefore we decided to move forward and started to introduce defects to the pipe wall to test the algorithm performance. The first geometry is a bent pipe, and it is shown in

**Figure 5-47 a.** The acquired camera image is shown in **Figure 5-47 b.** It is clear that the projected circular lines are deformed due to the existence of the bend inside the pipe. The reconstructed 3D points are shown **Figure 5-47 c**. The 3D profile of the bend is accurately reconstructed with some missing data on the edges of the bend due to the sudden change in the surface. The interpolated 3D frame is shown in **Figure 5-47 d** in which the missing points have been interpolated. A simpler type of bends is simulated in **Figure 5-48** where it is simulating a flattened upper surface of the pipe due to an external load. The reconstruction is ideal in this case due to the smooth transitions. The second defect geometry type is shown in **Figure 5-49.** It showins the simulation of reconstructing a sudden bump on the pipe wall. From the simulation results it is obvious that the projected rings are deformed by the shape of the bump. But it also shows that the bump is blocking the camera from seeing any detail behind the bump. This is the reason for the partial reconstruction of the bump surface. The algorithm is able to reconstruct on the frontal surface of this bump while the rear part appears as a hole in the 3D reconstruction due to the shadowing effect.

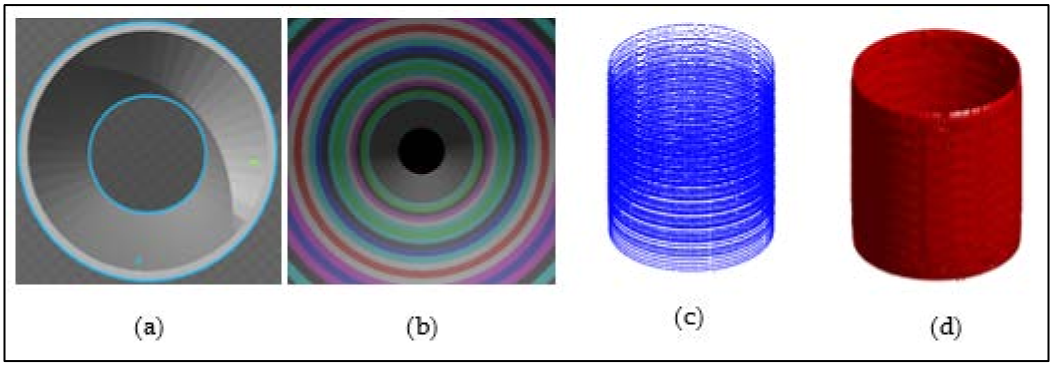



**Figure 5-46. Simulation of a normal defect free pipe**

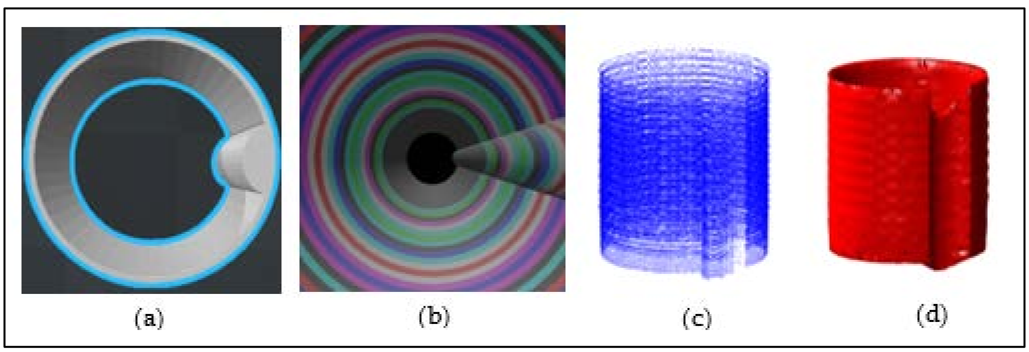



**Figure 5-47. Simulation with a bend along the pipe**

2. <u>Simulation with a hole</u>:

The 3D sample is modified to have a hole on its internal surface in order to simulate the case of the existence of a hole on the pipe surface. In a similar manner to the previous simulations, the scanner is moved inside the pipe. The simulated geometry and the reconstruction results are shown in **Figure 5-50.** The simulation starts with the hole on the edge of the projected pattern, where it has no effect on the reconstruction.

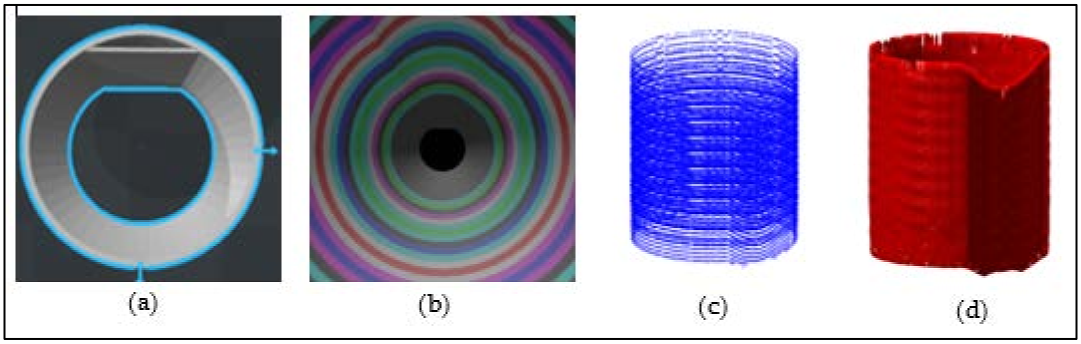



**Figure 5-48. Simulation of deformation along the pipe wall**

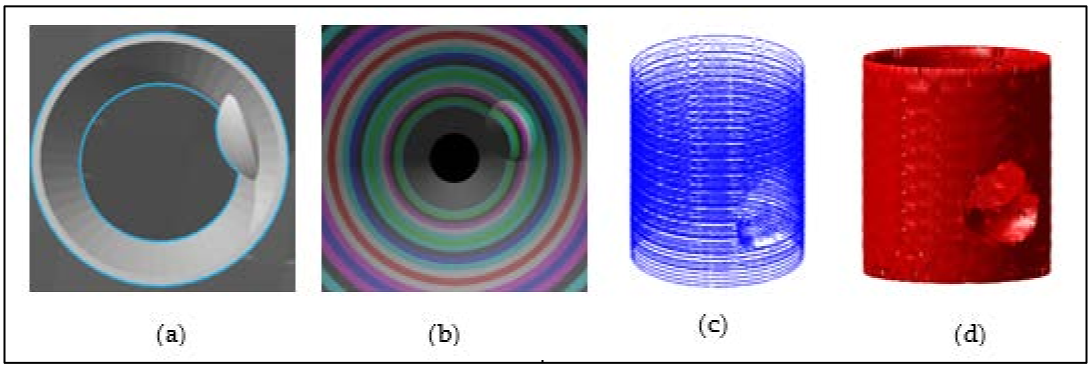



**Figure 5-49. Simulation of bump in the pipe wall**

After that, it is moved more and more toward the end of the pattern until it exits. The reconstruction results show that at the beginning the hole has no effect, then it starts to create a big hole inside the reconstructed surface (larger than its size) then this effect starts to disappear until it diminishes completely. The reason for this effect is that the hole size is smaller than the size of the projected code. To reduce this effect, shorter codes and thinner stripes are preferred. But for our scanner inside the pipe this effect is not severe, because the final profile is a combination of all the frames in the scanned video. Therefore, the hole boundaries will be reconstructed successfully but with a lower density of 3D points near the hole region.

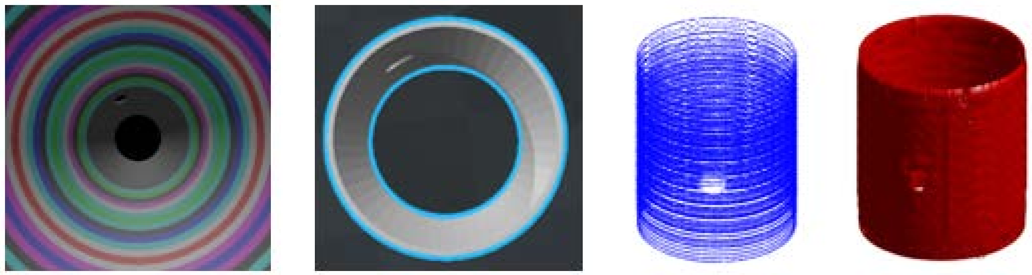
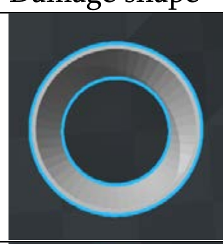
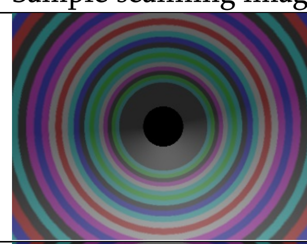
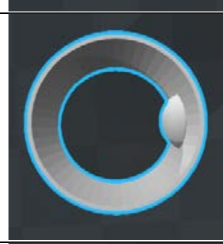
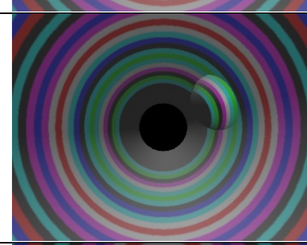
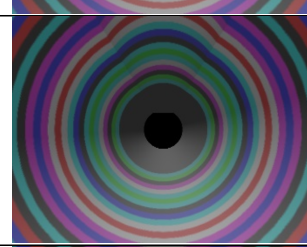
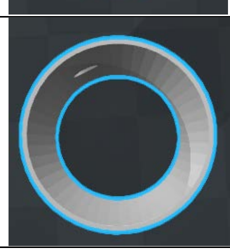
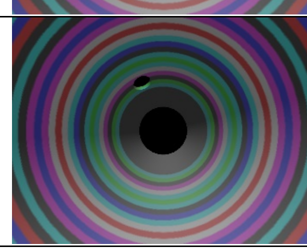


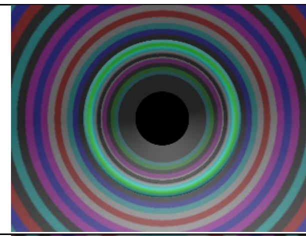
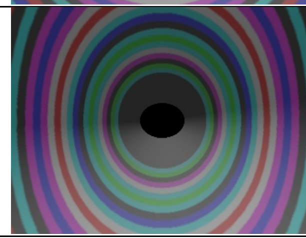
**Figure 5-50. Simulation of a hole in the pipe wall**

***Defects database:***

Data reduction and classification tools require a large number of images with different defects types and projected patterns. Therefore, a dataset is created to provide a reference training and validation dataset for our current and future data analysis. The dataset is designed to have a diverse defects types with different view angles and different sizes. The defects types that are simulated in the dataset is explained in **Table 5-1**.

**Table 5-1. Database defects types**

| Damage type | Damage shape | Sample scanning image |
|---|---|---|
| No damage |  |  |
| Impact damage(bump) |  |  |
| Dent |  |  |
| Hole |  |  |

| | | |
|---|---|---|
| Split |  |  |
| Squeeze |  |  |

Currently, five defects types have been simulated within the same simulation environment that is described in the simulation environment section, and a defect free pipe is also simulated to take it as a reference. The first defect type simulates an impact damage that is caused by an external tapered object. The second defect simulates a dented pipe by an external load from above. The third defect shows a hole through the pipe wall. The fourth defect represents a split defect on the pipe wall. The fifth defect represents a squeezed pipe by an external load. The images in the data set are created by simulating the scanning process along the pipe which gives different view angles for each different frame in the scanning video. The same defect is then simulated with different sizes to simulate different scenarios. Then the resulted dataset is increased by using image rotation to produce the defects at different locations for each rotation angle.  Therefore, the data set will provide a set with different shapes, sizes, location and rotation angles. Noise is added to the dataset to make it more flexible and give the user the ability to control the amount of the noise in the reconstruction or training process. The current data set is a synthetic dataset. Experimental scanning samples will be added later to the give more the depth for the user about experimental effects during the data analysis.

*Projector prototype III:*

The main idea of using the slide projector is to emit a pattern with different colors of the object to obtain different illumination areas. As a result, a small slide projector has been designed to generate the colors instead of using the regular projector. Moreover, to create this projector, some lenses are needed. The lenses that have been chosen for this step have a diameter (1.5 inches). Therefore, the size of the projector will suite the small diameter pipes that we need to scan. Then, these lenses will be stacked with a certain way inside a prototype that has been designed by using the 3D printer. One achromatic lens, two double convex lenses, and two convex lenses are used as shown in **Figure 5-51**. Every lens has a focal length that should be considered when the designer stacks the lenses together. The main idea of using the Achromatic lens is to reduce effects of chromatic and spherical aberration. The other lenses are used to magnify the image and increase the resolution. The slide that is used in this prototype has multiple rings as illustrates in **Figure 5-52**. Moreover, the power of the light source is strong enough to generate the light that is needed to emit the pattern.

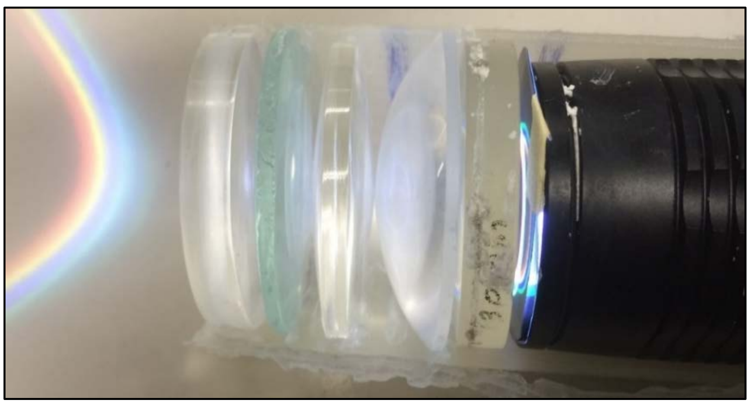
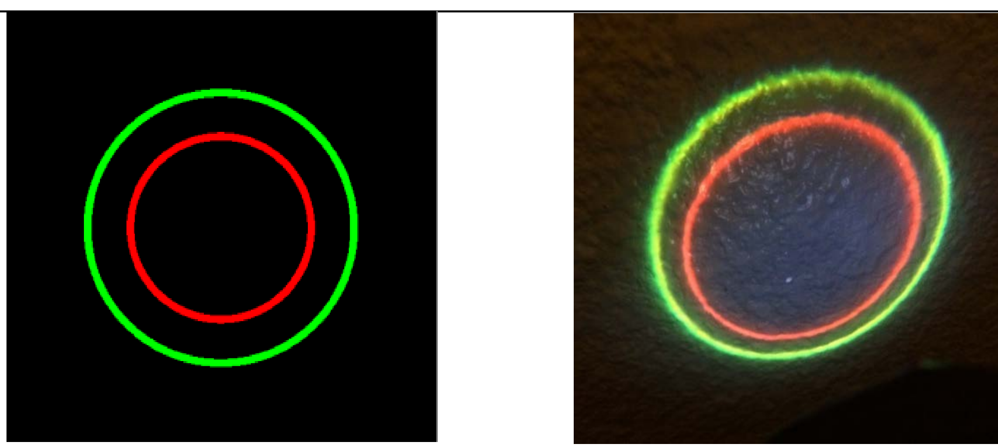


**Figure 5-51. The lenses stacked inside the prototype**



(a) (b)

**Figure 5-52. a) The slide for the projector, b) Projected pattern**

However, the slide has two different colors (red and green) as shown in **Figure 5-52.a**. There is a black area between the two rings just to separate the edges. This separation can be removed in the future after increasing the resolution. **Figure 5-52.b** shows the pattern on the rough surface to clarify the edges. The length of the projector is 7.87 inches, and the largest diameter is 1.77 inches which can be used to scan the pipe that has 1.85 inches. Also, the distance between the light source and the rings when are projected inside the pipe is 1.02 inches. Then the next step is to connect the prototype and the camera as shown in **Figure 5-53.**

**Figure 5-53. Projector and the camera connected to each other**

The camera that has been used in this step is the one that has small view angle. Because the pipe has a small diameter, small view angle camera can be used instead to the large view angle camera. As shown in the figure the distance between the light source and the camera is 5.51 inches. By moving the prototype inside the pipe, the data will be collected by using the camera. Each frame has some features that came from the structure of the pipe. Figure **5-55** (a) illustrates some frames that have been taken from the data. Clearly, the shape of the rings has been changed as shown in **Figure 5-55 (b)**. This change shows the squeezed parts in the pipe. As a result, the reconstructed image will have the same shape of the corrupted image. But in this case, there is some illumination that has been generated from the extra light that comes from the lenses. To block the extra light, a black tape has been used to cover the edge of the lens as shown in **Figure 5-54 (b)**. The difference can be easily illustrated in **Figure 5-56,** and the colors clearer after blocking the white light. Then, the algorithm will process each frame in order to generate the 3D reconstructed image as shown in **Figure 5-57**.

Figure 5-54. a) the projection on the smooth surface. b) the prototype with blocked edges

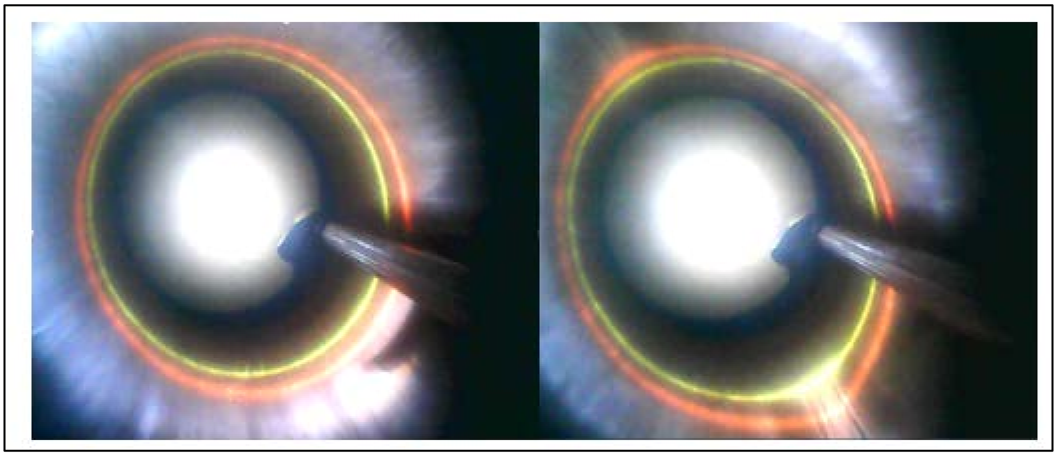


Figure 5-55. a) Illustration of one frame without defects.  b) Illustration of a frame with squeezed part

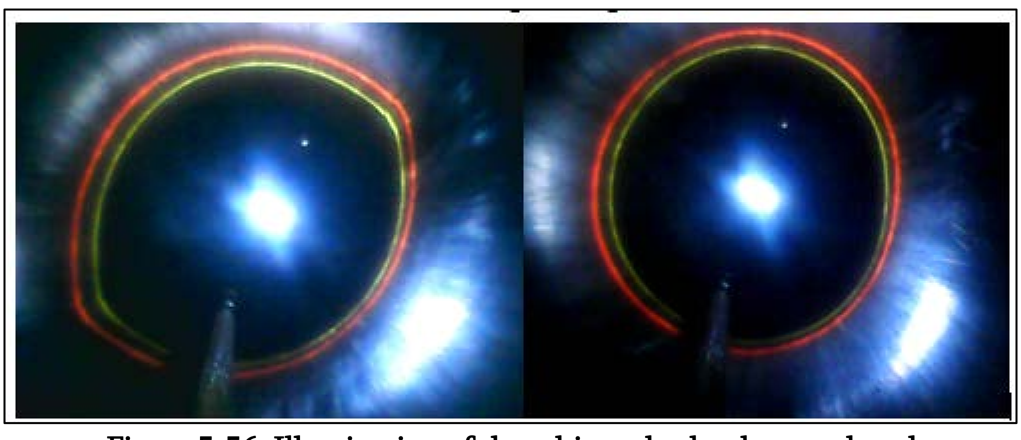


Figure 5-56. Illumination of the white color has been reduced

A color segmentation is done as a first step in the algorithm to generate the 3D image. The red color is segmented and reconstructed as shown in **Figure 5-57**. It can be seen that one of the reconstructed images is not a regular ring shape, but it is twisted. The twisted area in the image illustrates the squeezed part inside the pipe. Moreover, **Figure 5-58** shows just a few number of frames that show the pressed area.

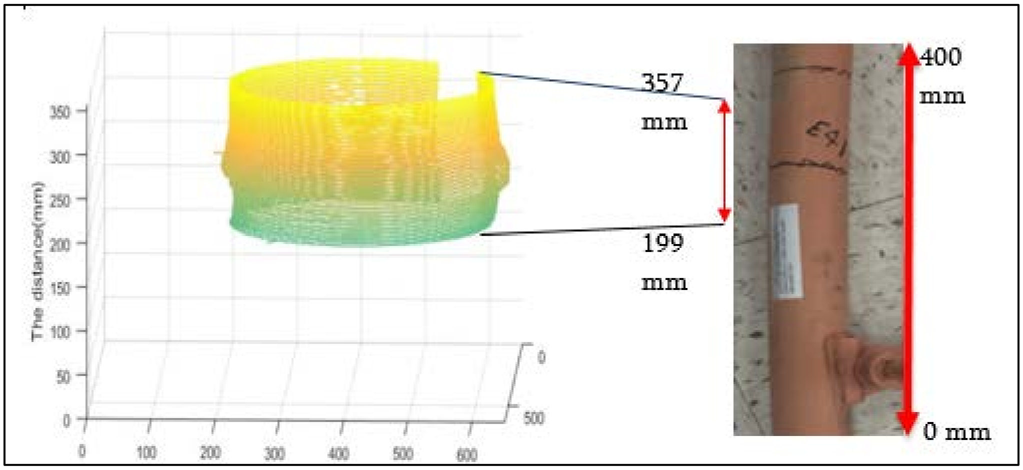



**Figure 5-57. 3D reconstructed image with and without the defects.**

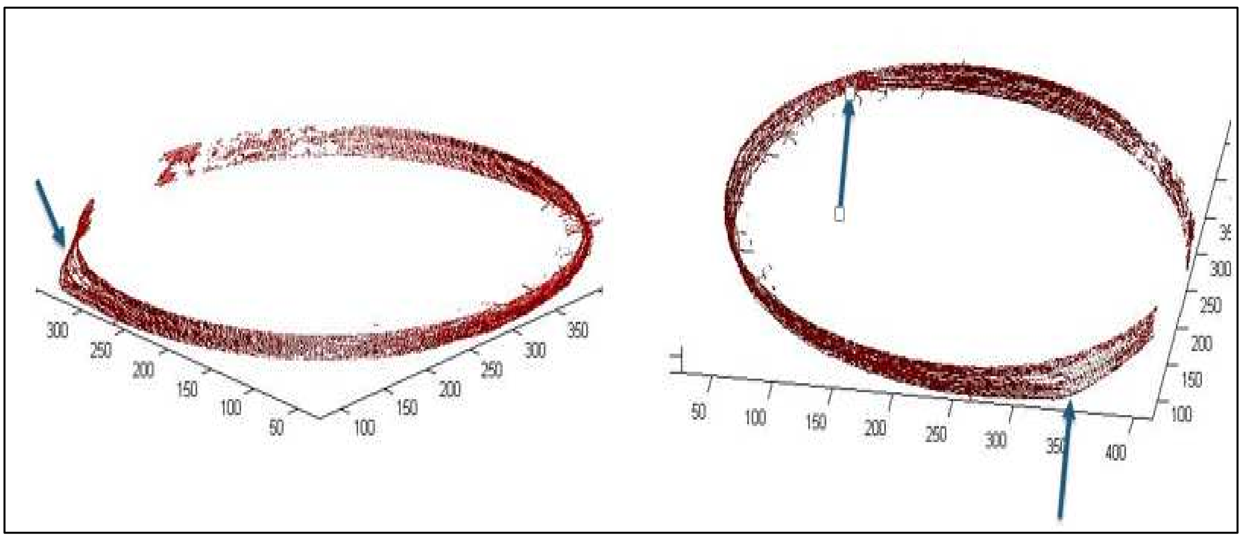


**Figure 5-58. Reconstructed frames that show the squeezed parts inside the pipe**

*Miniaturized sensor (Prototype IV):*

Structured light sensors adopt the same stereo concept of using two cameras to extract the 3D information, but use a different path to collect the correspondence points. To solve the problem of finding correspondence points that are found in the passive stereo sensors, the structured light uses an active light source that projects a pattern that has well-defined points. These points can be easily matched when comparing the projected and captured images. The number of reconstructed 3D points is proportional to the number of the matched points between the projected and captured images. Therefore, the design of the sensor plays an important role in the reconstruction process because enhancing the quality of the projected and captured image increases the number of acquired 3D data proportionally. In this section, we are focusing on designing a new miniaturized sensor that provides a high-resolution projected image, wide projection angle, and a small size to inspect 0.75-inch pipes. The structured light sensor consists of a light module that projects a highly-textured pattern and a camera that captures the deformations in the projected pattern. Three main schematics were considered for the sensor design as shown in **Figure 5-59**. Schematic (a) employs a projector and a camera that are facing each other. In this scheme, both the projector and the camera are required to have a wide view angle to shorten the length of the sensor. In schematic (b), the light module is put in series with a camera that is pointing in the same direction. In this scheme, only the camera is required to have a wider angle than the projector. In schematic (c), the light module and the camera are aligned in a parallel scheme. In this scheme, the camera, and the light source can have similar focal length because both are pointing to the same direction and lies at approximately the same distance from the pipe internal surface.

For a fixed diameter pipe, both designs (a) and (b) could have the same characteristics, but as the diameter of the pipe changes the drawbacks of the first design starts to appear. By increasing the diameter of the pipe, the rays from the camera and projector will no longer intersect at the same area on the pipe internal surface. To solve this problem, the distance between the camera and the light module needs to be increased and thus increase the overall sensor size as well. In schematic (b), the rays from the camera and the projector are propagating in the same direction, which means that the intersection points will only diverge slightly with the increase of the diameter size. The third scheme doesn’t suffer from the problem of changing the pipe diameter as both the camera and the light source are aligned in the same direction and is also shorter that the other schemes, but aligning the sensor components beside each other’s will increase in the overall sensor diameter. For the reasons above, we opted to go with testing schematic (b) and (c).

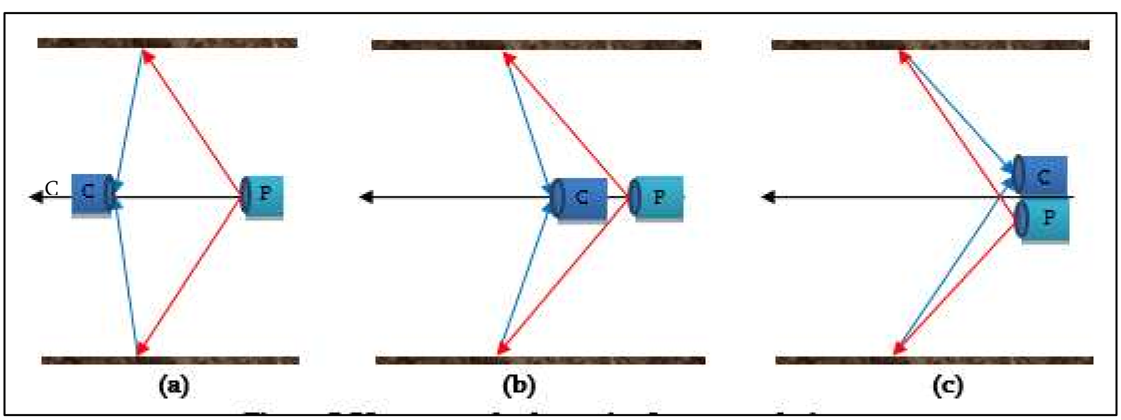



**Figure 5-59. proposed schematics for sensor design**

As mentioned before the sensor consists of two main components, the camera, and the light source module. The bellow sections give a detailed description of the sensor components, the camera, and the light source module and give a brief description of the fabrication process.

***Structured light module:***

As the size of the inspected pipes can go down to 1 inch, the diameter of the new light source module is reduced to be less than 0.6 inches. The current digital light projectors in the market are not a good candidate for this task due to their large size (larger than one inch diameter) and the difficulty of customizing these projectors to be embedded in our sensor. Our team chose to go with designing a new small slide projector light module. This type of projectors can be scaled to be in the range of 4 millimeters in diameters [47], and can also provide high flexibility in changing the optical properties of the projector.
This type of projectors adopts powerful white light source to illuminate a colored slide to produce the required image. The resulted image from then projected by using projection optics. The overall structure of the structured light module is shown in **Figure 5-60**. It consists of the following parts

1. Main light source: The structured light module requires a strong light source to produce high contrast images and it should also have a small form factor to reduce the sensor size. There are two main options for this task, either using an external light source and transfer the light to the projector through an optical fiber or using a high-quality light emitting diode. Each one of the options has its strengths and weaknesses. The external light source provides a high amount of power but adds more complexity to the system with an additional external unit and an optical fiber for light transmission. On the other hand, LEDs provide simple and easy to implement a solution but produce a high amount of heat in the sensor head when high illumination is required. Our current prototype is tested with LED light source (Cree XHP50) which can provide a maximum of 149 lm/W while having a maximum output light intensity of 2546 lm under ideal conditions. To enhance the heat convection from the module and to reduce the LED teperature, a high-quality copper heat sink is attached to the LED while maintaining low current at 100 mA.

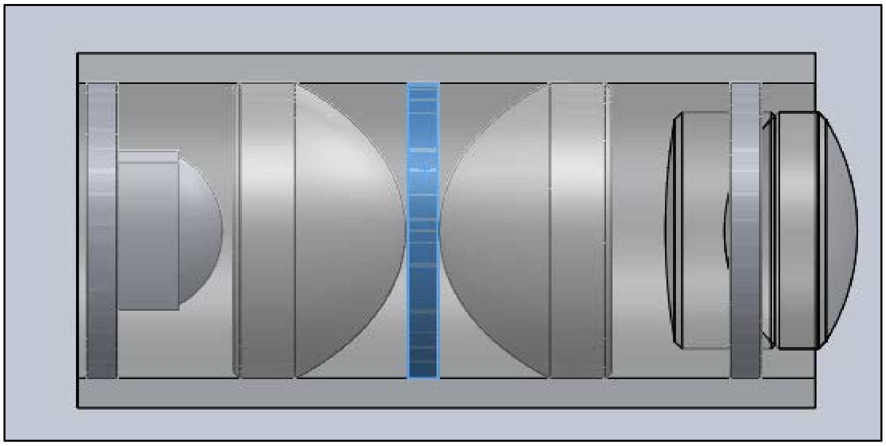


**Figure 5-60. 3D schematic of the light module**

Condenser lenses: Two condenser lenses with a diameter of 10 mm and a focal length if 8mm is used in the light module. The lens is shown in **Figure 5-62.a**. The first lens is placed directly after the light source to collimate the diverging light rays from the LED and focus them on the colored slide. The second lens is placed before the objective lens to increase the projection angle of the light module. **Figure 5-61** shows the effect of adding the second condenser lens on the view angle of the projector.

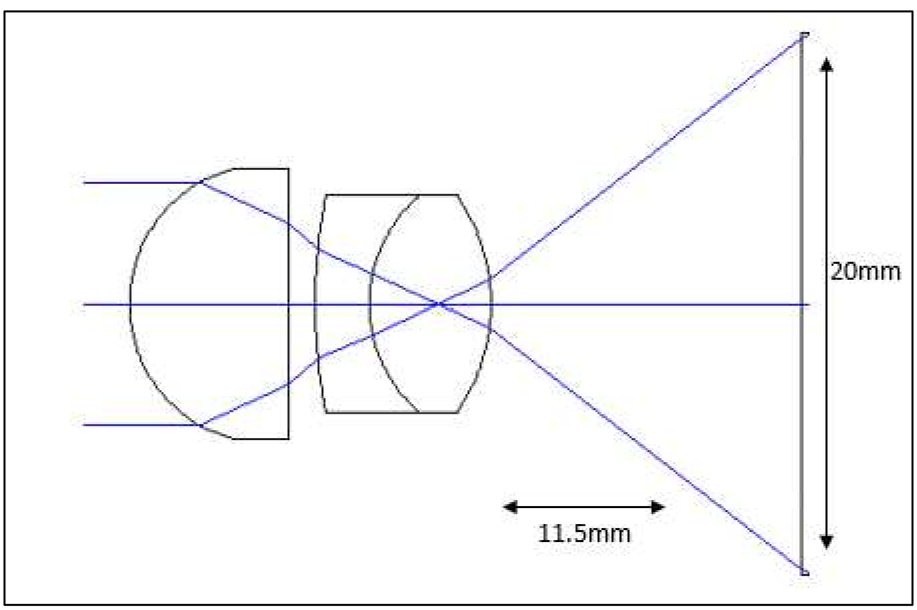



**Figure 5-61. Ray tracing of the lenses**

2. Objective lens: The image that is produced by the photo slide is passed through the objective lens to project it to the pipe internal surface. An Achromatic doublet that is shown in Figure 5-62.b is used instead of the normal biconvex lens to reduce the

amount of chromatic and spherical aberration. The doublet lens has a diameter of 8 mm and a focal length if 10mm.

3. Photo slide: The photo slide acts as a filter that passes the colors that are printed on the film surface and block all other light components. The photo slide is currently fabricated by using heat resistive transparency film and printed with an inkjet printer. A glass photo filter is considered for future prototypes.


**Figure 5-62. a) Condenser lens, b) Objective lens**

**Camera:**

For the camera, we are using small size(10*10*15mm) fish eye camera. This is an analog camera that is connected to the computer by using an analog to digital convertor. The final assembly of the camera and the light module for schematic b is shown in Figure 5-63. The camera and the light module are assembled by using a transparent glass holder to allow the transmission of light through the holder. Schematic c does not require a special component and can be setup directly with the simple fixture to hold the camera and the light module together in parallel.

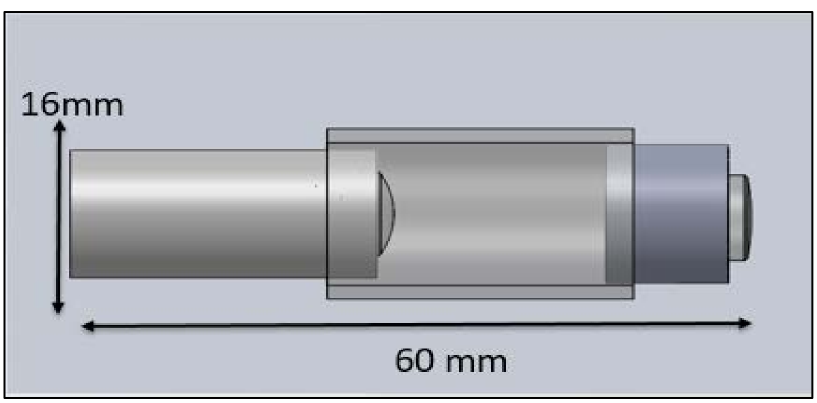



**Figure 5-63. Assembly of camera and light module**

*Triangulation in the scanner*

The triangulation process in the geometry at a specific angle $\theta$, is explained in Figure 5-64. ***c*** is the camera, p is the projector, P is the intersection point, f is the focal length, d is the distance between the projector and camera, and r is the position of the point on the image plane. For a general camera model, it is defined by the following two equations

$$\frac{f_p}{Z} = \frac{r_p}{X}, \qquad \frac{f_c}{z-d} = \frac{r_c}{X}$$ **Equation 5-9**

By combining the two equations, Z and X are given by:

$$Z = \frac{d}{1 - \frac{f_c\, r_p}{f_p r_c}} \quad , \quad X = \frac{r_p\, Z}{f_p}$$ **Equation 5-10**

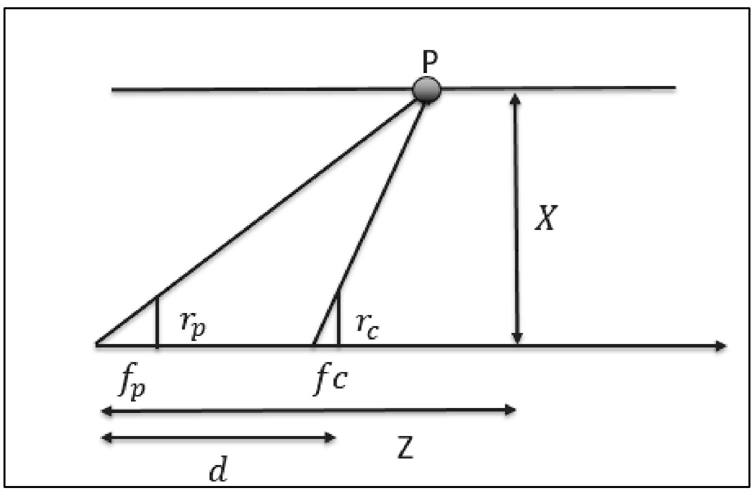



**Figure 5-64. Triangulation of the system inside the pipe**

## Camera Calibration

To reduce the effect of using a fisheye camera and in order to calculate the internal camera parameter for the use in the triangulation process, camera calibration is performed. In this process, a simplified 2D camera calibration scheme that was suggested by [48] is used to calibrate the camera with a 2D checkerboard.

$$S \begin{bmatrix} u \\ v \\ 1 \end{bmatrix} = K \begin{bmatrix} r_{11} & r_{12} & t_1 \\ r_{21} & r_{22} & t_2 \\ r_{31} & r_{32} & t_3 \end{bmatrix} \begin{bmatrix} x \\ y \\ 1 \end{bmatrix}$$

$\boldsymbol{u}$, $\boldsymbol{v}$ are the coordinates of the corresponding image point, $\boldsymbol{x}, \boldsymbol{y}$ are the world coordinate of the points, $\boldsymbol{r_{ij}}$ are the rotation parameters for the checkerboard image, $\boldsymbol{t_i}$ are the translation parameters for the checkerboard image. ***S*** is a scaling factor. The focal length of the camera is calculated and the lens parameters are then used to correct the effect of the wide lens distortion to the image. The fish eye distortion cause the straight lines in the image to be bent. This effect can be removed by calculating the original lens parameters then use an inverse transformation to remove this effects. An explanation of the effect is shown in **Figure 5-65** where the lines of the checker board is straightened after applying the inverse transformation.

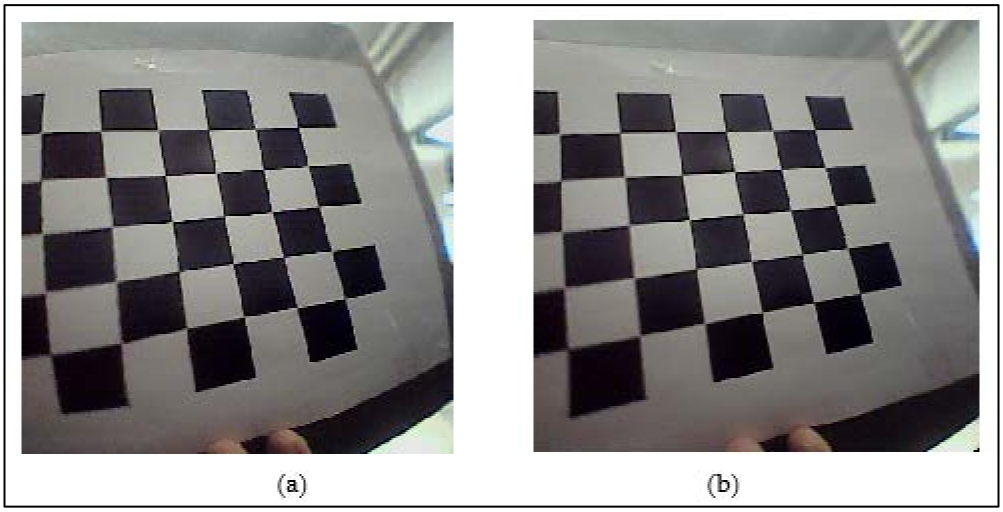



**Figure 5-65. Lens distortion removal, a) Before, b) After**

**Experimental results**

In this section, we will explain the structured light module. The integration of the camera will be explained in the next section. To fabricate the light module cover, we are using 3D printing for rapid fabrication and testing before building the final prototype. The cover was printed as two pieces that can be combined to form the final lens assembly. **Figure 5-66** shows one side of the cover. The cover is designed to have 1mm thickness which means that the final light module design will have a diameter of 12 mm (13mm for the final 3D assembled prototype).

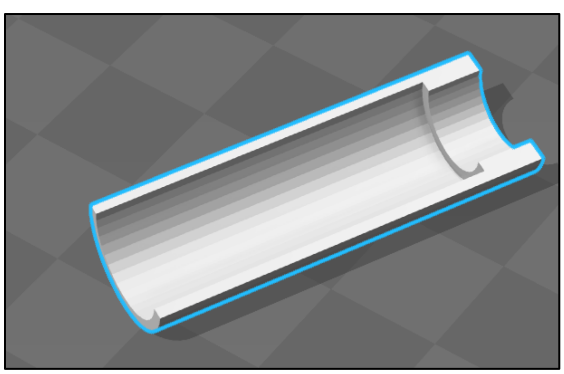


**Figure 5-66. One side of the light module cover**

The assembly of the components is shown in **Figure 5-67**. Currently, the projector components are assembled and fixed inside the cover by using a glue gun. The glue is used at this stage to facilitate the modification of internal components location in the testing stage. In the future version, the components will be fixed with mechanical fixture after finishing the calibration of the light module. The shape of the final fabricated prototype is shown

**Figure 5-67.Light module internal components**

The LED source is excited with a voltage of 5.28 volts and a current of 100milliamps. Different slides were tested to evaluate the performance of the light module. In the beginning, a slide that has four colors (blue, yellow, red, blue) is placed in the light module. The projected colored pattern is shown in **Figure 5-68.**b. The projected image is displayed with high resolution, and color contrast and the edges between the different rings can be identified correctly. After that, we tried to implement a larger number of colored rings to examine the maximum resolution of the projector, but we were limited by the resolution of the printer. The quality of the printer also affects the saturation of the projected colors; the blue rings are projected with purple color.

(a) (b)

**Figure 5-68. a) Projector final assembly, b) Projection of multiple rings**

In the design of the final pattern that is used in the scanning, only a combination of red, green, blue is used. This step facilitates the image segmentation on the reconstruction side by providing an image that can be segmented by using the hue channel only [47]. For this type of patterns, the segmentation is performed as follows. In the first step, the image is converted from the RGB to HSV space and only the hue channel is extracted. In the second step, a median filter is applied to reduce the noise from the camera sensor while preserving the edges of the rings. In the final step, a multi-level thresholding is performed to isolate each different color; then the edges are extracted by taking the image gradient. The final assembly of the structured light module with the camera is shown in **Figure 5-69.** In this prototype, the slide projector is integrated with the wide-angle camera and connected with a transparent glass tube.

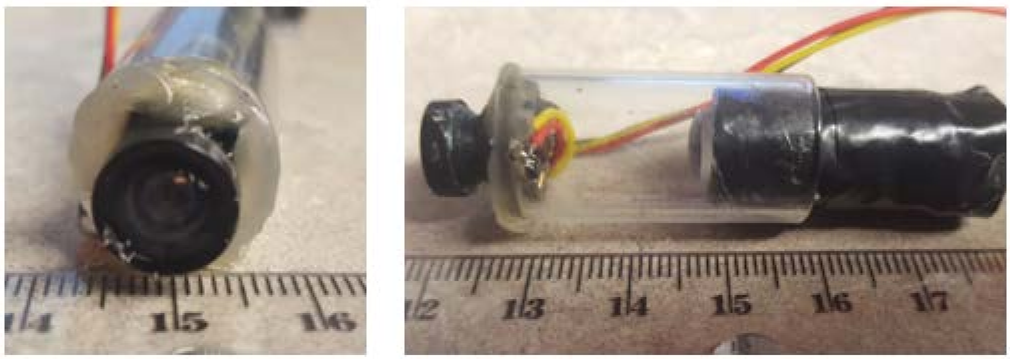


**Figure 5-69. Scanner final assembly**

In order to perform a controlled scans with a constant speed and orientation, the scanner is mounted into a horizontal scanner as shown in **Figure 5-70 a**, and a single frame of the recorded video is shown in **Figure 5-70 b**. The recorded frame is showing three complete colored rings with the effect of the connection wires appearing as a dark shadow on the upper side of the image. The scanned object is a black PVC tube with a surface texture that is appearing as horizontal lines along the pipe surface.

(a) (b)

**Figure 5-70. a) Prototype IV scanning system, b) a single frame from the system**

The segmentation is performed on the image, and the location of each color is decoded by matching it with the color change in the projected sequence as explained chapter one. The conversion from RGB to HSV highly reduces the effect the surface texture and eliminates its effect on the final reconstruction. The results of decoding one frame are shown in **Figure 5-71.**

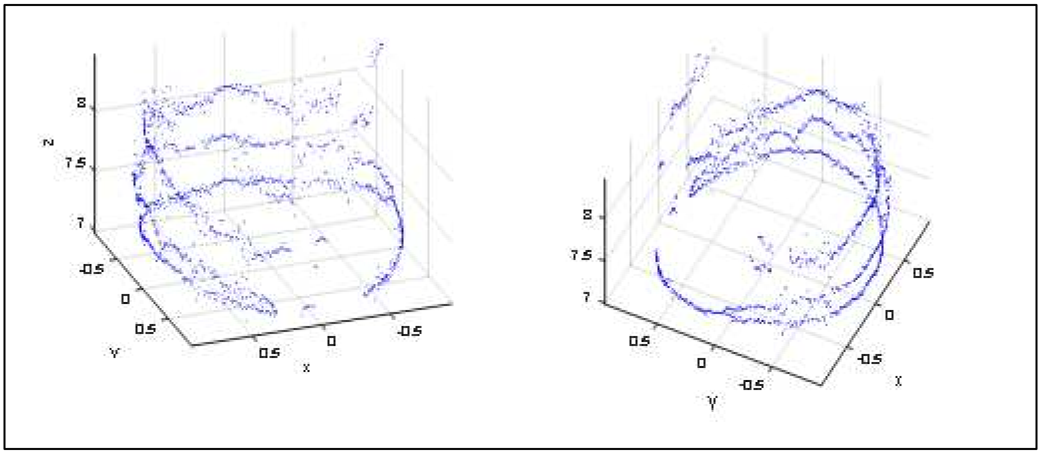


**Figure 5-71. Reconstruction of a single frame**

The final reconstruction of this single frame is showing the results from the three color transitions. The circular shape of the pipe is reconstructed successfully although the algorithm has failed to reconstruct the complete set of edges from the second and third projected circle. Currently, one of the factors that are affecting the reconstruction process is the spatial resolution of the projected rings on the walls of the pipe. The registration of the consecutive frames is another factor that's is under study because currently, the scanner needs to be moved at a constant speed to assume that the distance between each two consecutive frames is constant. An interpolated result of stacking all the consecutive frames while assuming equidistance between them (which is partially true in our case) is shown in **Figure 5-72.** The current results show that the profile of the scanned pipe is reconstructed successfully but there are holes in the reconstructed profile and there is shifting between the consecutive frames due to the shaking in the platform. Another factor is the existence of outliers from the wrongly decoded edges.

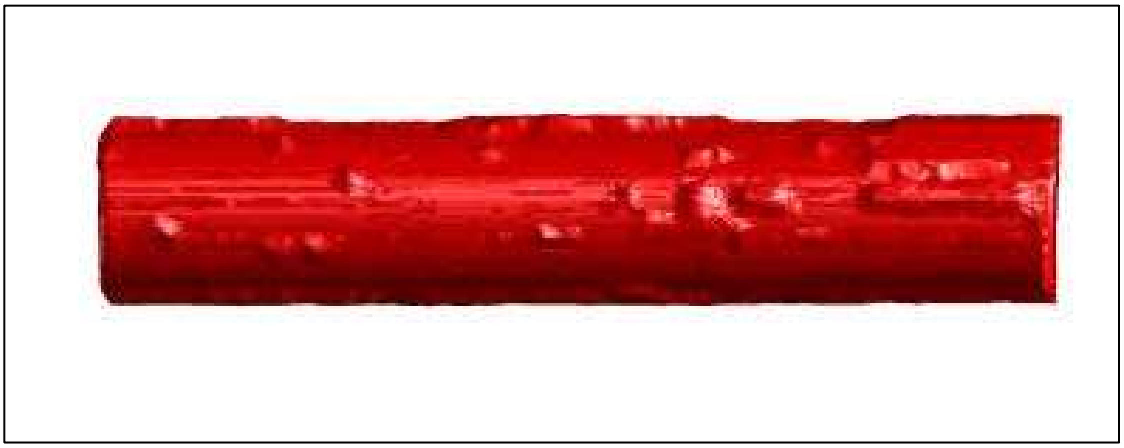
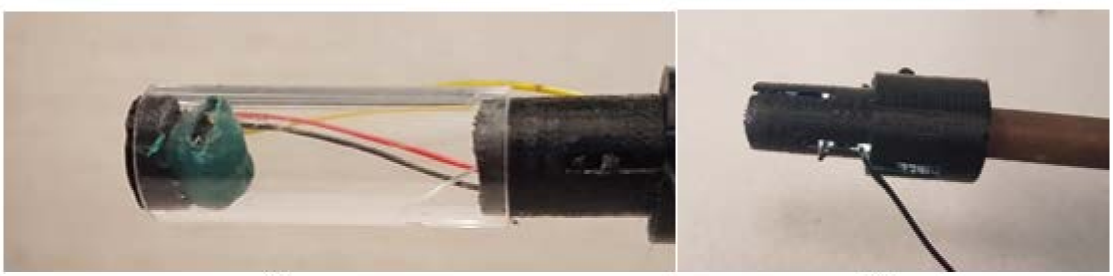


Figure 5-72. 3D reconstruction of pipe surface from multiple frames

A more efficient design of the projector is shown in **Figure 5-73** where all the components are integrated into a compact 3D printed case. In this prototype, all the lenses and slides have been put inside frames that can be moved along a rail so that the components can be inserted and removed easily. This new design offers a better way to easily change the projected pattern without the need to reassemble the whole light module



(a) (b)

Figure 5-73: The final version of the scanning tool and a separate image of the light module

## Damage classification and data reduction

The proposed structured light scanning platform creates high-quality inner wall optical images. These images record the specific condition of the pipeline. How to analyze these images will influence the accuracy and the efficiency of the detection platform. Developing a proper pipe data analysis algorithm is necessary. However, the large amount of the images brings challenges to extract defect features efficiently. Thus, data reduction should be done to reduce data dimensionality and choose significant features firstly. In order to extract pipeline inner wall damage-sensitive features, the histogram of oriented gradients (HOG) descriptor [49] is utilized to reserve image edge information which can represent the deformation features of the structured light. This HOG descriptor is based on calculating well-normalized local histograms of image gradient orientations in a dense grid. The calculation of the HOG descriptor can be summarized as follows:

1: Compute the pixel-level gradient image for each image. Record every gradient's amplitude and orientation. The most common method is to apply the 1-D centered, point discrete derivative mask in one or both of the horizontal and vertical directions. Specifically, this method requires filtering the color or intensity data of the image with the following filter kernels:

$$[-1,0,1] \text{ and } [-1,0,1]^T$$

2: Divide the image into small connected regions called cells, and for each cell compute a histogram of gradient directions or edge orientations for the pixels within the cell. Each pixel within the cell casts a weighted vote for an orientation-based histogram channel based on the values found in the gradient computation. The cells themselves can either be rectangular or radial in shape, and the histogram channels are evenly spread over 0 to 180 degrees or 0 to 360 degrees, depending on whether the gradient is "unsigned" or "signed".

3: Groups of adjacent cells are called blocks. Normalized group of histograms represents the block histogram. In block normalization, L2-norm is used in this report:

$$f = \frac{v}{\sqrt{\|v\|_2^2 + e^2}}$$

v denotes the non-normalized vector containing all histograms in a given block. The set of these block histograms represents the descriptor. **Figure 5-74** demonstrates the HOG descriptor implementation scheme. The 'cells' can characterize defect appearance and shape. The normalized 'blocks' is for better invariance to illumination, shadowing, etc. HOG descriptor reduces the initial data dimensionality by mapping gradients into angular bins in step 2.

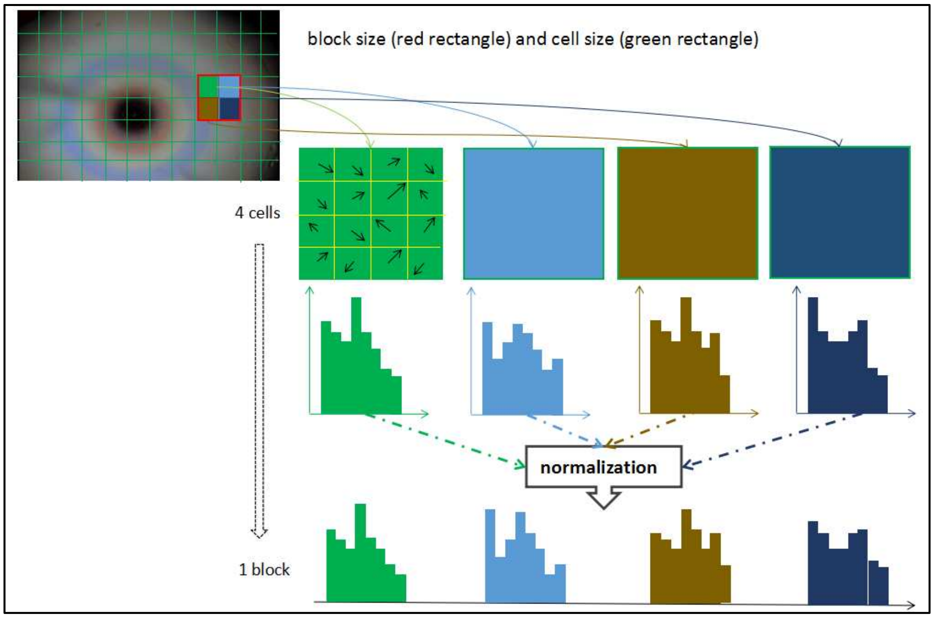



**Figure 5-74. HOG descriptor implementation scheme**

Moreover, so as to test whether HOG descriptors is appropriate in structured light data feature extraction, linear support vector machines (SVM) algorithm is used to classify the computed HOG descriptors. An SVM model is a representation of the samples as points in space, mapped so that the samples of the separate categories are divided by a clear gap that is as wide as possible. New samples are then mapped into that same space and predicted to belong to a category based on which side of the gap they fall. Define a training data set of N HOG descriptors $\hat{x}_i$ (i=1,...,N) of the form ($\hat{x}_1, y_1$),...,($\hat{x}_N, y_N$)

Where $y_i$ are labels. In this report, $y_i$=1 means $\hat{x}_i$ contains defects and $y_i$=-1 means $\hat{x}_i$ contains non-defects. In binary classification problem, linear SVM algorithm is trained by the minimization of the error function:

$$\begin{aligned} &\frac{1}{2} w^T w + T\sum_{i=1}^{N} \upsilon_i , \\ &s.t.\, w^T x_i y_i + b \geq 1 - \upsilon_i , \\ &\upsilon_i \geq 0, \mathrm{i} = 1,..., \mathrm{N} \end{aligned} \qquad \textbf{Equation 5-11}$$

Where $\upsilon_i$ are slack variables which penalizes samples which violate the margin requirements. In order to judge the classification results, the accuracy $\alpha$ is defined as follows:

$$\alpha = \frac{CP + CN}{P + N} \qquad \textbf{Equation 5-12}$$

where CP denotes number of images which include defects correctly classified, CN represents number of images which have no defects correctly classified, P is a number of defect images and N is the number of non-defect images.

*Classification results based on HOG descriptor*

**(1) Simulation pipe data classification**

Four types of damages include bump, dent, hole and squeezing defect were simulated in the form of a video (**Figure 5-75**). The size of each frame is 768*1024. Define the size of the cell as 8*8, and then four cells concatenate one block. Nine bins which are spaced over 0◦–180◦ map the pixel-level gradients into nine directions. After these definitions, every image can get their corresponding HOG descriptors. Figure 5-76 illustrates four normalized histograms which separately correspond to four adjacent cells in one block. The HOG descriptor of one image can be evaluated by cascading all blocks. Based on this data set, we can see that the size of each data feature-HOG descriptor is reduced to 36*12065=434340 when the initial image dimensionality is 768*1024=786432. The row number 36 is the product of 9 bins and four cells in one block. 12065 is computed by the step size and the block size because the block scans the whole image. That's to say; the original data has been reduced. Then the SVM classifier is used to test whether the HOG features are meaningful to classify the damages.

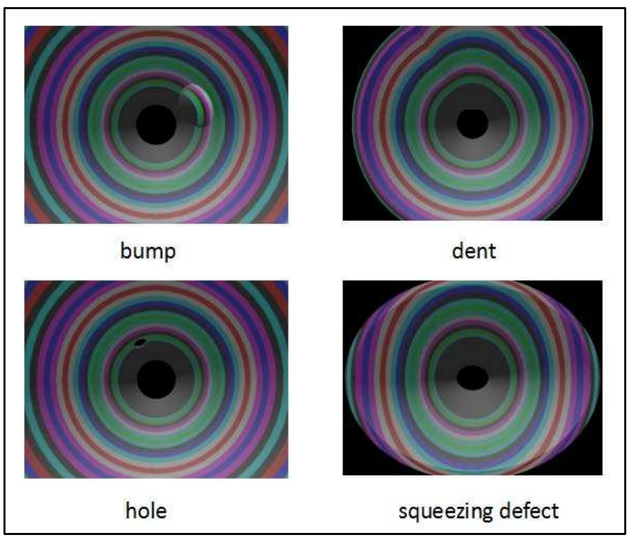



**Figure 5-75. Four types of damages**

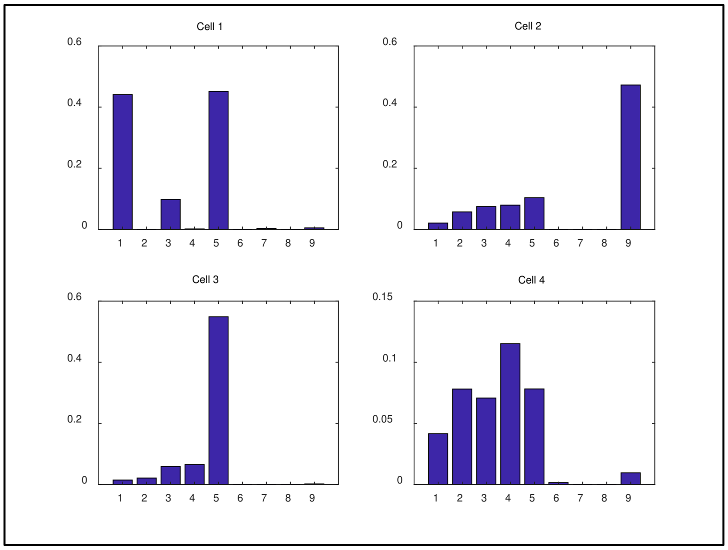



**Figure 5-76. Four normalized histograms in one block of one simulation pipe image**

Firstly, the SVM classifier is a supervised learning algorithm. One training set with labels should be prepared. Label 1 denotes the defect frame and label -1 means the non-defect sample. In this report, 50 labeled frames with 4 types of damages are used to train the SVM classifier. After training, 26 frames with different types of damages are tested. From the testing results in **Figure 5-77**, 26 samples have been successfully classified. According to the definition of accuracy, the classification results achieve 100% accuracy. That's to say, the HOG descriptors can be used to extract structured light data features.

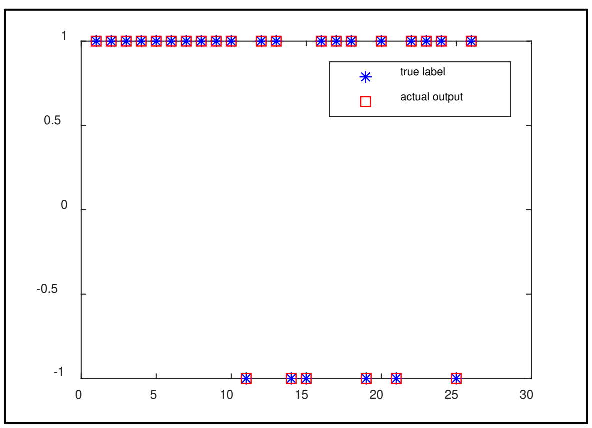



**Figure 5-77. The classification results of the test simulation samples**

**(2) Experimental pipe data classification**

The experimental pipe data (480*720) which contains several hole damages are recorded by the Prototype IV scanning system (Multi-Rings multi-Colors scanning sensor). In the same way, all the frames can be represented by their corresponding HOG features. **Figure 5-78** shows four normalized histograms in one block. The size of each HOG descriptor is

36*5251=189036 which is less than 480*720=345600. Separate all frames into one training data set (80 samples) and one test data set (25 samples). From the classification results in **Figure 5-79**, we can see that all test samples have been classified correctly. Combined with the simulation results, it can be summarized that the HOG feature can be utilized to do the structured light data reduction and feature extraction.

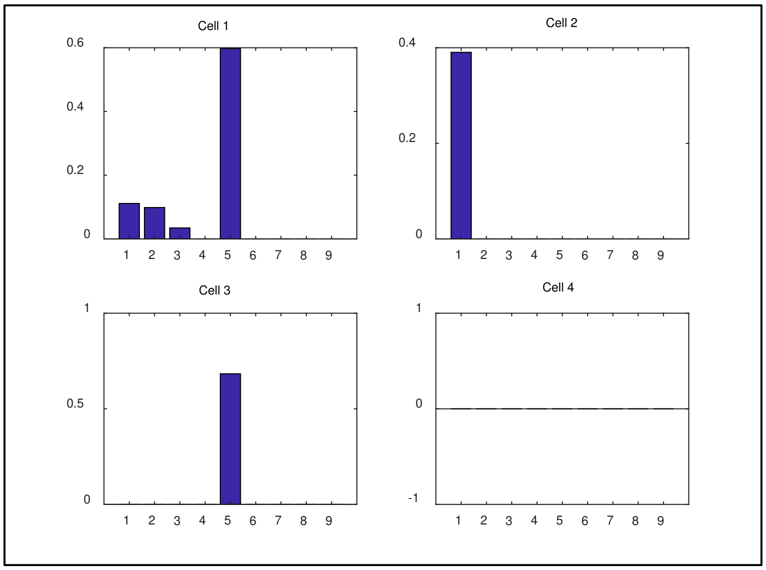



**Figure 5-78. four normalized histograms in one block of one experimental pipe image**

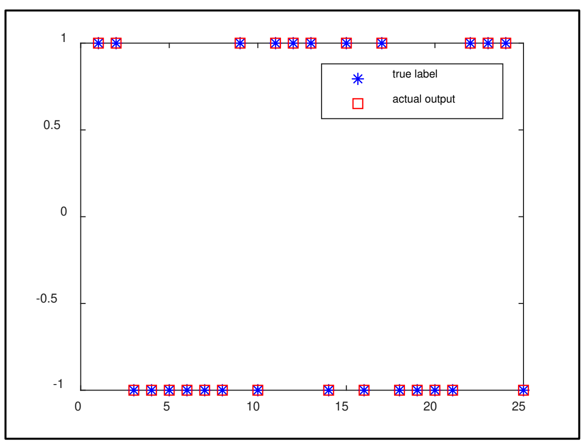



**Figure 5-79. classification results of the experimental samples**

### *Pipe data convolutional neural network (CNN) classification model*

Data reduction extracts useful features from the initial data which can train the classification model more easily. One deep learning approach - convolutional neural network can learn data features by itself without manual intervention. In order to develop more data processing method to meet the different demands of practical application, another classification model based on CNN is researched.

## Background

The inverse problem in NDE about evaluating defect information $\Omega(i)(i=1,2,...,I)$ from observed signals $\Theta(i)(i=1,2,...,I)$ can be denoted as:

$$\Omega(i)=\{M^{-1}\}\Theta(i); \qquad i=1,2,...,I \qquad \textbf{Equation 5-13}$$

where $M^{-1}$ is the inverse operator. The solution of the inverse problem is an estimation $\hat{\Omega}(i)(i=1,2,...,I)$ of defect information $\Omega(i)(i=1,2,...,I)$. One classical CNN structure is developed to solve the evaluation of $\hat{\Omega}(i)(i=1,2,...,I)$.

A whole CNN is comprised of one input layer, one or more convolutional layers, several pooling layers and one output layer. The convolutional layers are feature extraction layers which can compute input's convolutional features without artificial definition and operation. In this layer, weight sharing is applied to increase learning efficiency by reducing the number of free weights being learnt. The pooling layers can reduce the spatial size of the input representation to make the CNN easier to train. Besides these layers, dropout method can be used to prevent CNN from overfitting. In the training phase, the output of the l+1 convolutional layer $\Theta_{m,n}^{labeled,l+1}(i)$ can calculate by the following equation:

$$\Theta_{m,n}^{labeled,l+1}(i)=\sum_a\sum_b w_{a,b}^{l+1}\sigma(\Theta_{m-a,n-b}^{labeled,l}(i))+b_{m,n}^{l+1} \qquad \textbf{Equation 5-14}$$

where m and n are pixel's coordinate. $w_{a,b}^{l+1}$ is the weight of the l+1 convolutional filter on coordinate (a, b). $\sigma$ is the activation. $b_{m,n}^{l+1}$ is the bias. Back propagation based on loss function such as mean squared error, categorical cross entropy is a method to calculate the gradient of the loss function with respect to the weights $w_{a,b}^{l+1}$ and bias $b_{m,n}^{l+1}$ in a CNN. The computed gradient of loss function is used to adjust the weights $w_{a,b}^{l+1}$ and the bias.

### *Pipe data preprocessing procedure*

In the designed laser scan and structured light detection system, the deformation of the laser or the structured light which is caused by the defects in the pipe has been recorded in the video. Separate the video into the images and then preprocess them for improving the CNN performance. In order to pay attention to the deformation, one strategy is used to prepare the inputs of the CNN.

One threshold $\chi$ is defined to suppress the background (the region that is outside of laser ring or structured light). The inputs of the CNN in the training phase should contain defect features and non-defect features. These features should help training a CNN model which has the invariance like scale invariance and direction invariance. In this prediction model, the local features which is captured by a window Win with fixed size (W_r, W_c) are utilized (red line in Figure 1). The fixed window can guarantee the inputs with the same size and scale. Moreover, because the laser ring or structured light detection system use circular light, image rotation is utilized to make the CNN prediction model be direction invariance (**Figure 5-80**).

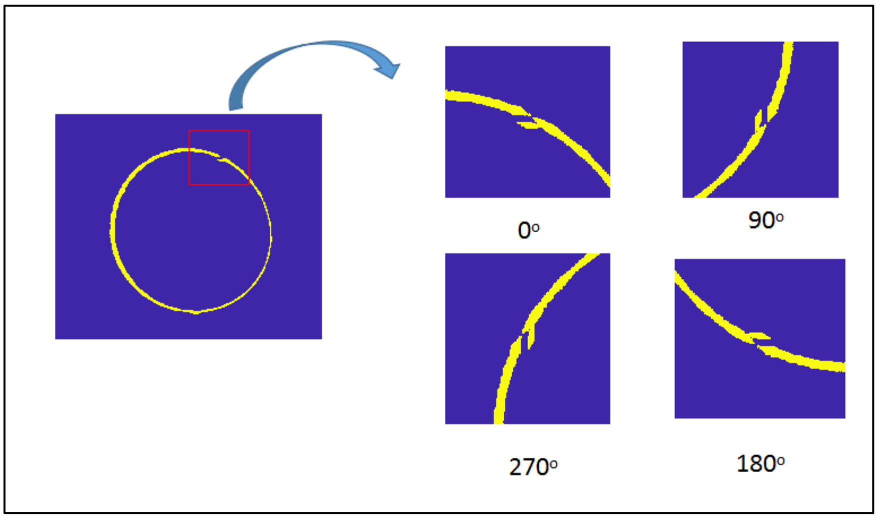



**Figure 5-80. image rotation**

### *Pipe data classification results*

After data preprocessing, one classical CNN structure which contains four convolutional layers and two pooling layers has been used (**Figure 5-81**). The size of convolutional filters is 3*3. 3 filters utilized in the first convolutional layer and 6 filters in the second convolutional layer. Dropout method is used to prevent the overfit of the CNN model. The output layer is a softmax layer which can map the outputs of samples into the probabilities.

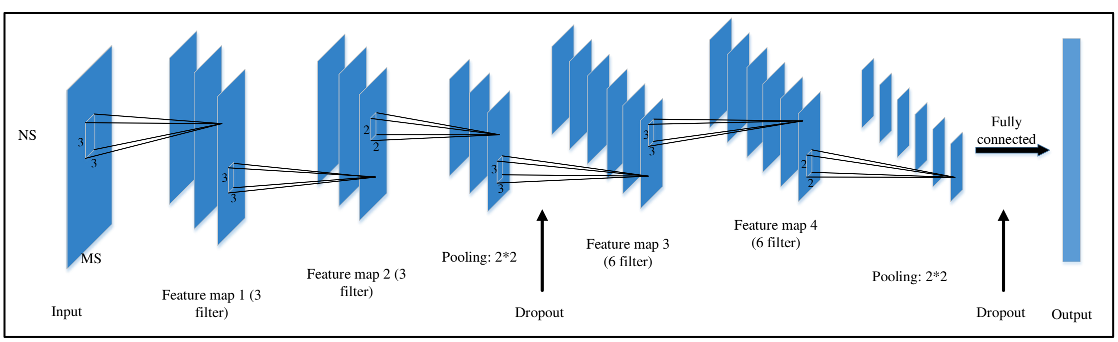



**Figure 5-81: CNN structure**

Specifically, in this qualitative classification problem (defect or non-defect), defect information $\Omega(i)(i=1,2,\dots,I)$ can be regarded as an indicator set like [0, 1] that indicates whether defects exist or not. In general, the outputs of the designed model are their inputs' corresponding labels:

$$\Omega(i)=\begin{cases} 1,\ defect \\ 0,\ non\text{-}defect \end{cases}, \qquad i=1,2,\dots,I \qquad \textbf{Equation 5-15}$$

After the SoftMax layer, these labels will be mapped into values between 0 and 1. If the output is close to 1, it means this sample contains defect. One threshold $\tau$ is needed to determine which class they belong to:

$$\Omega(i)=\begin{cases} \geq \tau,\ defect \\ < \tau,\ non\text{-}defect \end{cases}, \qquad i=1,2,\dots,I \qquad \textbf{Equation 5-16}$$

The laser ring data is used to test the performance of the CNN model. Thirteen hole defects on the plastic pipe is used to train the CNN model. The laser scans the plastic pipe continuously. So, one defect information will be recorded in a consecutive sequence. **Figure 5-82** shows an example of one testing frame. Define W_r=200, W_c=200. The fixed window Win segments this image (after background suppressing: $\chi$ =240) into 16 parts. Record the rank of every part (as shown in Figure 5-82 ), the region of defect can be known approximately after the testing. Figure 5-83 displays the classification results of the testing samples. A consecutive sequence of 7 frames have been put into the trained CNN model to test the performance of the CNN model. This sequence has recorded the same defect. As shown in **Figure 5-83**, only part 3 in every image contains defects. The output of the CNN model is a softmax function, so the output of each sample is a probability. Combined with the labels we defined as below, if the output of one sample is close to 1, it indicates that this is a defect sample, vice versa. Compared this information with the probability results in **Figure 5-83** , it is obvious that all defect areas have been identified. Define $\tau=0.5$. All part 3 of 7 frames have larger probabilities than 0.5. Other parts are smaller than 0.5 which means they have non-defects. All defect regions have been successfully identified without false calls.

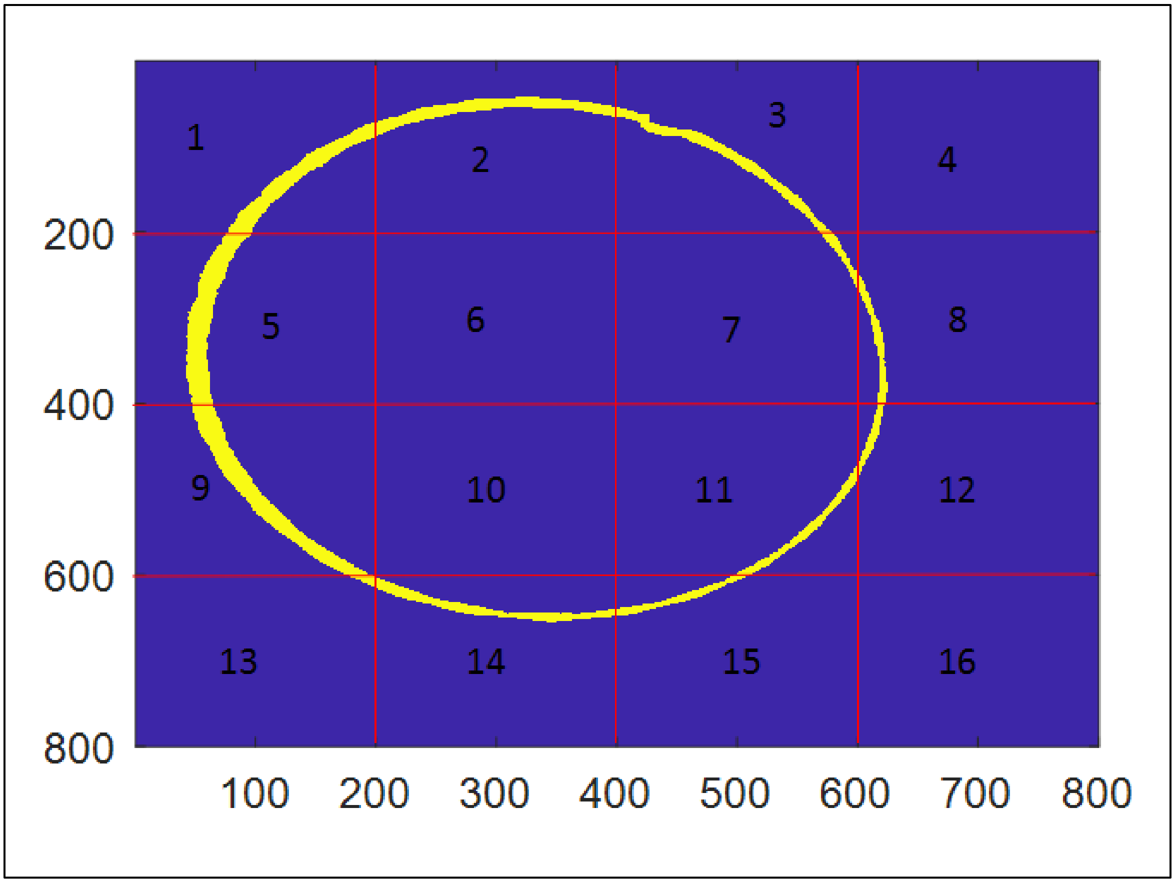
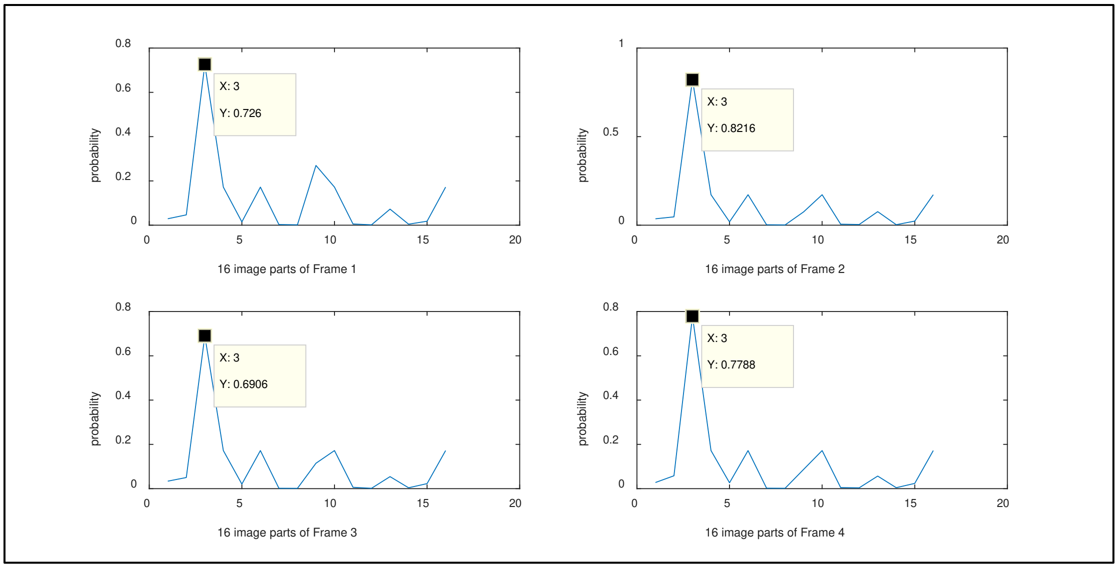
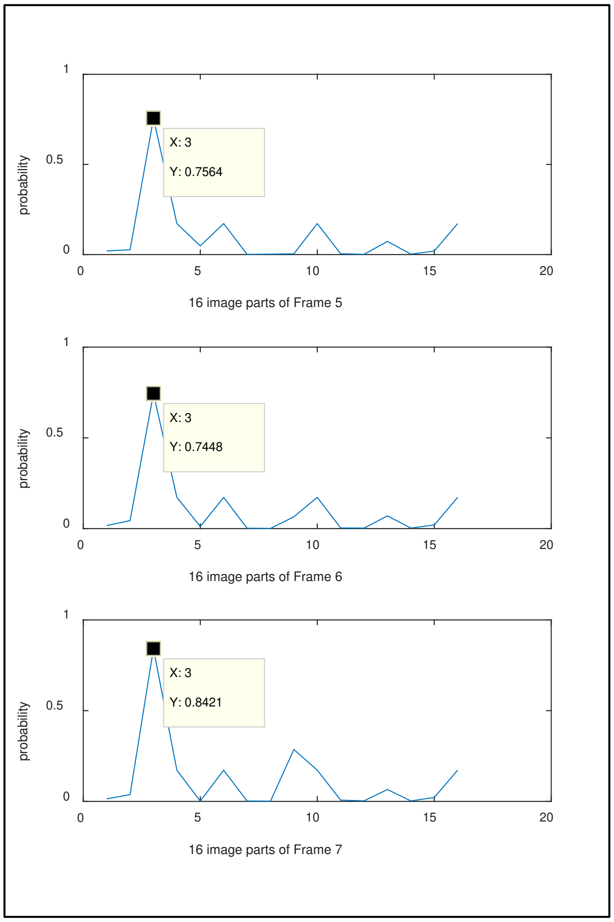



Figure 5-82. segment result of one image




**(a)**




**(b)**

**Figure 5-83. classification results of a consecutive sequence of frames**

## Conclusions

The project aims to develop an integrated set of quantitative tools that provides an approach to reducing operational risk in vintage plastic distribution systems susceptible to Slow Crack Growth (SCG) failures. The tool is an optical device that can reconstruct the profiles of the internal pipe surface and able to detect the existence of deformations and defects that can be visually detected on the pipe wall. For this task, structures light endoscopes are proposed due their robustness and simplicity. In this project, the experimental work is divided into two parts. The first part is used to develop and test the performance of laser profiling based scanners while the second part is specified to develop and test a multicolor multi ring structured light scanners. Four prototypes have been successfully developed for the high resolution and sensitivity pipe inner-wall imaging. The first design is developed with an initial capability to give a partial image about the pipe surface. This initial prototype is used to help developing the reconstruction algorithm and became the base for the next generations of the prototypes. The reconstruction algorithm is developed and tested on simulation data and then used for the reconstruction of the images from the actual laser scanner. In order to enhance the quality of the device and increase the amount of the reconstructed surface area, prototype II is developed. This prototype is 3D printed and has employed a new fishery camera to provide the required wide angle to capture the full laser ring. This prototype provides a more stable scanning platform that can reconstruct 100% of the pipe surface. In order to further improve the quality of the scanner, multicolor multi-ring approach is used to increase the number of reconstructed points from each frame and enhance the spatial resolution by providing sharper edges. In order to project colored rings into the pipe a small slide projector, prototype III is developed. The projector is built to project two-color rings. Prototype IV is developed to reduce the size of the scanner in order to be fitted inside a 1-inch pipe and to increase the number of projected rings. The prototype has been built and tested, and a simulation environment is created to develop the reconstruction algorithm. Experimental scans have been performed and the data is used to create the accurate profile of the pipe inner wall. The performance of the algorithm has been tested against different defect types by using simulations. Smooth deformations and shape changes were reconstructed correctly and precisely. Sudden discontinuities in the surface introduce non reconstructable shadows behind the defect and also create difficulties in the matching between the projected and received sequences. The code discontinuities are not a severe factor because as the scanning platform is moving along the object, it can collect all the missing points. The shadow problem is dependent on the view angle of the scanner (larger view angle creates less shadows) and the smoothness of the deformation. A synthetic database is created to act as a reference for our data analysis algorithms. The database includes five defects types with different shapes and sizes and it is mainly used for the data reduction analysis. A data reduction framework is created and followed by a classification network. The network model works as a binary classifier that test each set of camera frames for the presence or absence of defects. From the classification results, it can be seen that the classification model performs excellent in the defect prediction problem and the defined local feature can reserve the characteristics of the initial data. The data reduction model is also helpful to improve the performance of the classification network.

### Future work

The delivered work meets the goal and proposed research objectives. Some additional research and hardware development can be done to enhance the ESLiST sensing system.
1. The current system provides a high quality and fast surface profile reconstruction, but the spatial resolution can be further increased by improving the hardware design, better system calibration, and more efficient reconstruction algorithm. Currently, a fixed structured light pattern was applied, which might not be optimal for all damage types and different field testing conditions. With the successful demonstration of the Prototype, I to Prototype IV and their feasibility of extracting damage dimensional information at MSU, extensive involvement of GTI in collecting real data should be expected. Additional work on feeding updated stress concentration factor derived from ESLiST image and ESLiST assisted decision information back to the sensing system should be carried out to complete the development loop and further optimize the novel structured light sensors design.
2. The proposed prototype works very well in a controlled lab environment by assuming the sensor is moving in a controlled straight path that is along the pipe's center axis. This assumption might be violated in actual field testing and inspection due to mechanical vibration of the sensing platform moving inside the pipe with complex geometries. An inertial measurement unit (IMU) can be integrated into the system to provide an estimation of the device orientation and positioning. Real-time compensation algorithms are needed to correct any distortion and misalignment induced error in data reconstruction to achieve same imaging resolution in a field environment.
3. Static structured light patterns have been studied and implemented as we proposed. However, the potential of the structured light approach will be maximized by introducing dynamic light patterns and data structures to adapt to various damage types and sizes under different light conditions. This could be better understood through both numerical simulations and experimental studies by collaborating with GTI and industry partners. An optimization of the current static structure light patterns to study the relationship between the smallest detectable damage feature and the parameters of the static light pattern will also be beneficial.
4. Further improvement of the current data reduction and reconstruction will lead to faster and more accurate damage detection. The current framework only focuses on the SCG failure mode, so supervised multispectral data dimensionality reduction and defect classification methods would be sufficient and are successfully demonstrated. However, additional work should be done to realize the unsupervised damage recognition and information fusion while multiple failure modes are considered. Integration of advanced sensors from MSU and the intelligent decision support system from GTI and ASU would be more critical to achieving an optimal diagnostic and prognostic framework for gas pipeline industries.

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# 6. Damage Detection from Optical Imaging, Creep-Crack Growth Prediction, and Condition-based Maintenance Framework for Aldyl-A Pipes

This section will summarize all work done by ASU during the project. A novel damage detection method based on optical imaging were developed. Damage classification was done using a Naïve Bayes (NB) classifier. The classification result was compared with the neural network (NN) and showed little difference. In searching for an algorithm to build a new classifier that could encode empirical information (expert opinion) into the classifier, a novel Bayesian/maximum entropy network (BEN) classifier were developed based on the maximum entropy concept. The BEN classifier can handle extra information such as moment constraints. Given the available information, the classifier can achieve faster learning and behaves better than NB when the training size is small.

An equivalent creep crack growth (CCG) prediction model using a power law equation was calibrated and validated using the experimental data from GTI. With the proper assumptions, the model prediction matches the experimental data reasonably well. Uncertainty was introduced into the model parameters and Monte Carlo (MC) simulation was used to calculate the failure probability. The model will be later applied into the maintenance framework.

A condition-based maintenance framework was formulated for the maintenance scheduling of the pipeline system. In the proposed framework, the conditions of the pipes were categorized into several condition stages according to their crack length. The conditions of the pipes can be iteratively calculated via a condition transition matrix. The condition transition matrix can be calculated using the predicted crack growth curve. The overall maintenance plan is optimized by minimizing the maintenance cost under the constraint of failure probability. The maintenance was done using genetic algorithm.

The model parameter in the CCG prediction model can be updated by observations via Bayesian updating. The updating process would reduce the uncertainty within the model parameters and hence reduce the variances. The updated CCG curve would change the values in the probability transition matrix in the maintenance framework and hence change the maintenance decision. It is shown that, comparing with non-updating results, the cost for maintenance was reduced.

## *Introduction*

Damage diagnosis and remaining life prediction of pipeline infrastructure systems is still a challenging problem despite tremendous progress made during the past several decades in understanding damage accumulation in plastic gas distribution pipes. Historically, two entirely different approaches are used for structural system performance prediction (i.e. data-driven or physics-based predictive models). Data-driven approaches used nondestructive inspection technique (optical images, ultrasound, acoustic measurement, etc.) and experts' justification (personal experience on trending function, normal range of operations, etc.) to extrapolate system future behaviors. Physics-based models use underlying mechanisms (crack initiation and propagation model, chemical diffusion functions, oxidization rate, etc.) to predict system future behaviors. Information fusion between two approaches will enable accurate risk assessment and mitigation planning.

Bayesian networks are graphic probabilistic models that are based on Bayes' theorem [50]. Bayesian networks describe the dependence between variables through a direct acyclic graph (DAG). Bayes' theorem states that the posterior probability is proportional to the product of the likelihood and the prior [51]. Bayesian networks are widely used in inference due to the ability to update the posterior distribution with observations. A lot of work has been done on pattern recognition [52, 53], image classification [54] and automatic image segmentation [55]. There are different kinds of algorithms for Bayesian network classifiers, such as Naïve Bayes, Tree Augmented Naïve Bayes (TAN) [56] and Selective Naïve Bayesian Networks [57]. The Naïve Bayes classifier is a simple and fast algorithm with a surprisingly good accuracy despite the unrealistic assumption about the independence of the features [56]. In this project, a device to reconstruct pipe inner surfaces in 3D using video frames was built. The device comprised an endoscope camera and a patterned projector. Video was recoded as the device move along the pipe. Reconstruction was done by the analysis of the video frames and triangulation of the patterned light in each frame. The idea was presented in some medical researches [42]. The device building and reconstruction algorithm was mainly done by the MSU. Based on the reconstruction result, the geometric features such as the length, area of the damage can be isolated and calculated. These features were put into a Bayesian classifier. The classification result was compared with more advanced algorithms like the Neural Network (NN) and showed no big difference in our case.

To further enhance the accuracy of the algorithm based on the Naïve Bayes (NB) classifier, various methods have been developed. The selective Naïve Bayes classifier method uses a forward search to select features that does not decrease the accuracy. An approach of combining the Naïve Bayes with decision tree method was proposed in [58] and showed significant improvements. TAN adds additional edges between features to capture their correlations and releases the strong independence assumption of Nave , but does not significantly increase the computational cost. Although tremendous progress has been achieved in machine learning and artificial intelligent over the decades, a classifier would still need a large dataset to be trained and would only take point data (instances). It is hard however, to encode empirical information (constraints over a feature) into the classifier. In this research, we presented that by introducing an additional term to the Bayesian equation, we can handle extra information in the form of constraint in the proposed Bayesian/maximum entropy network (BEN). The added term was derived using the maximum entropy (ME) method [59, 60] by maximizing the entropy of the posterior distribution under constraints. It was shown that Bayes' theorem is a special case of ME [61]. A demonstration example showed that the BEN classifier behaves better than traditional NB when the training size is small.

Since the working condition of the pipe is under static pressure, creep failure is the dominant failure mode in the pipeline system. Many existing models have been proposed and developed to analyze the creep deformation and life prediction. The characteristic of a creep crack is that in polymeric materials is that there is craze formed at the crack tip, which is fibrils that are bridging the edges of the crack. Schapery's [62] model uses viscoelastic fracture mechanics approach to determine the crack growth rate as a function of stress intensity factor (SIF). Williams and Marshall's model [63] considers the Young's modulus as a time dependent function. In [64, 65], cohesive zone model is used to model the creep cracking process as a one-dimensional zone at the crack tip, which grows and ruptures as the time increases. The above studies indicate that SIF is the key for the creep failure prediction. This work used a power law equation to describe the crack growth rate. The model assumed a semi-circular surface crack in the longitudinal direction and the SIF solution were adopted from [65] and an asymptotic solution [66] to consider the notch effect. Model parameter uncertainty were considered to predict life in a probabilistic sense. The model was calibrated and validated by the experimental data from GTI. The probability transition matrix was calculated using Monte Carlo (MC) simulation.

In the search for state-of-the-art method of developing a maintenance frame work, the most discussed method is a condition-based maintenance(CBM). This method is constituted by 3 parts, data acquisition, data handling and decision making. Data acquisition is a step to collect useful data from the object, including event data and condition monitoring data. The event data include information of jobs or operations the object has been through, like loading, temperature change etc. Condition monitoring data are physical measurements of the object that can identify its health state. Both types of data are equally important [67]. There are numerous ways of data acquisition for the condition monitoring data, like microwave or ultrasonic sensor etc. In our case, the condition data would be the image reconstruction. Data handling is how the acquired raw data can be transformed into useful understandable and easy-to-process data. In our case, the acquired reconstruction data was classified into types of damages. The last step is the maintenance decision making, basically diagnostics and prognostics. Prognostics predict faults before it occurs while diagnostics is important when the prognostics failed and a fault occurred. There exist large quantities of literature regarding the subject, some researchers use hypothesis testing [68] and cluster analysis [69] for fault diagnosis and some uses machine learning techniques [70] but due to the lack of training data, the real application of machine learning technique is not easy. Other researchers use model based approaches with explicit physical and mathematical model, some models for bearings [71] and gearboxes [72] are already applied in diagnosis. The prognostics mostly predicts the remaining useful life (RUL) of a subject under the current condition and past and future jobs or operations. Some methods predict failure if the condition reaches a threshold value and others uses a model based on failure mechanism. Two statistical models called proportional-hazards model [73] and proportional intensity model [74] has become a useful tool in remaining life predictions. A hidden Markov model can calculate the transition probability from known experimental data [75]. Some also tried to apply artificial intelligence to RUL in [76]. Model-based approaches are presented in [77]. For the maintenance decision making, most researches focus on minimizing the costs, although there are some other papers that discuss the optimization of inspection intervals [78]. This project presents a maintenance framework based on probabilistic models. From the pipe imaging section, we can have the types of damages and its corresponding size (can be regarded as a deterioration stage). Depending on its future operation condition, a transition probability matrix can be formed and used to iteratively calculate the probability of the condition of the pipes. A maintenance decision can be made for minimizing the cost while constraining the failure probability of the system. Or if the budget is fixed, a maintenance schedule can be made for maximizing performance.

Bayesian network updating has been extensively used for damage diagnosis and prognosis of metallic and composite materials [79, 80]. The information fusion between diagnostics and prognostics can achieve a more accurate risk assessment and maintenance planning. To achieve a dynamic maintenance network, the model parameters will be continuously updated through the on-field observation. The updating process is achieved by Bayesian updating. This algorithm has been proved in many studies to improve the prognosis using the observation data from the condition monitoring [77][33]. The Bayesian updating is based on Bayes' theorem to update the hypothesis probability distribution (prior) with new information (likelihood). With the continuous updates, the variance of the distribution would reduce, indicating the uncertainty of the parameter would decrease.

### *Imaging reconstruction and damage classification*

This part will discuss the performed work and results related to the pipe 3D surface reconstruction and the damage classifications. First, the algorithm of a Bayesian classifier will be introduced. Before the prototype reconstruction device was available, simulated pipe imaging data were used to test the classifier and showed promising result. Despite the difficulty using the prototype camera to get good pipe imaging, we tested a small set of real data recorded in lab with the classifier and showed good result.

## Naïve Bayes classifier

The Bayesian network classifier is based on a simple Bayes theorem:

$$P(A \mid B) = \frac{P(B \mid A)P(A)}{P(B)} \qquad \textbf{Equation 6-1}$$

where A and B are events, and P(A), P(B) are the probability of event A and B without regard to each other. P(A|B) is a conditional probability describing the probability of event A given that B is true, also called posterior. P(B|A) is the likelihood term describing the probability of observing B given that A is true. During the classification, a set of training data is required to train the Bayesian network. For each class, the network treats each feature as random variables and find a certain distribution from the data. For a Naïve Bayes classifier, he classification is done by:

$$c^* = \arg\max_{i=1...m} P(c_j)\prod_{i=1}^{n} P(A_i = a_i \mid c_j) \qquad \textbf{Equation 6-2}$$

It means that given a new data, for each feature $A_i$, the classifier will calculate the probability that it belongs to class j (j=1…m). And assign the class that has the highest posterior probability for this data. The posterior probability is calculated by the product of the probability for each feature since the Naïve Bayes assume independence among all features. A graphical illustration of a Naïve Bayes network is shown in **Figure 6-1**

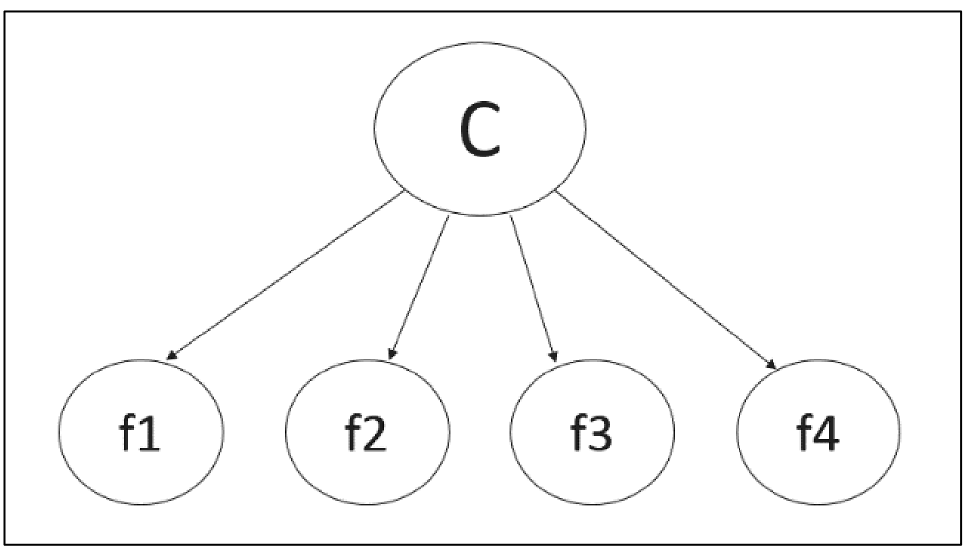


**Figure 6-1. Graphic model for a Naïve Bayes classifier with one class node and four feature nodes**

The Bayes classifier was widely used since its simplicity in structure and computation.

## Pipe imaging data simulation and classification

### *Pipe simulation*

In the pipeline system, common damages include dent, slit, rock impingement and squeeze-off **Figure 6-2**. These 4 types of damage were simulated in a 3D binary array with dimension 640*480*200, where 0 represents the void and 1 is the pipe wall. The damages were generated frame by frame with gradual change in the shape of the circle. The dent and impingement was simulated as an indent on the circle, while dent has a larger deformation and impingement being shaper. The squeeze-off was simulated as a gradual change in the diameter of the cross section of the pipe.

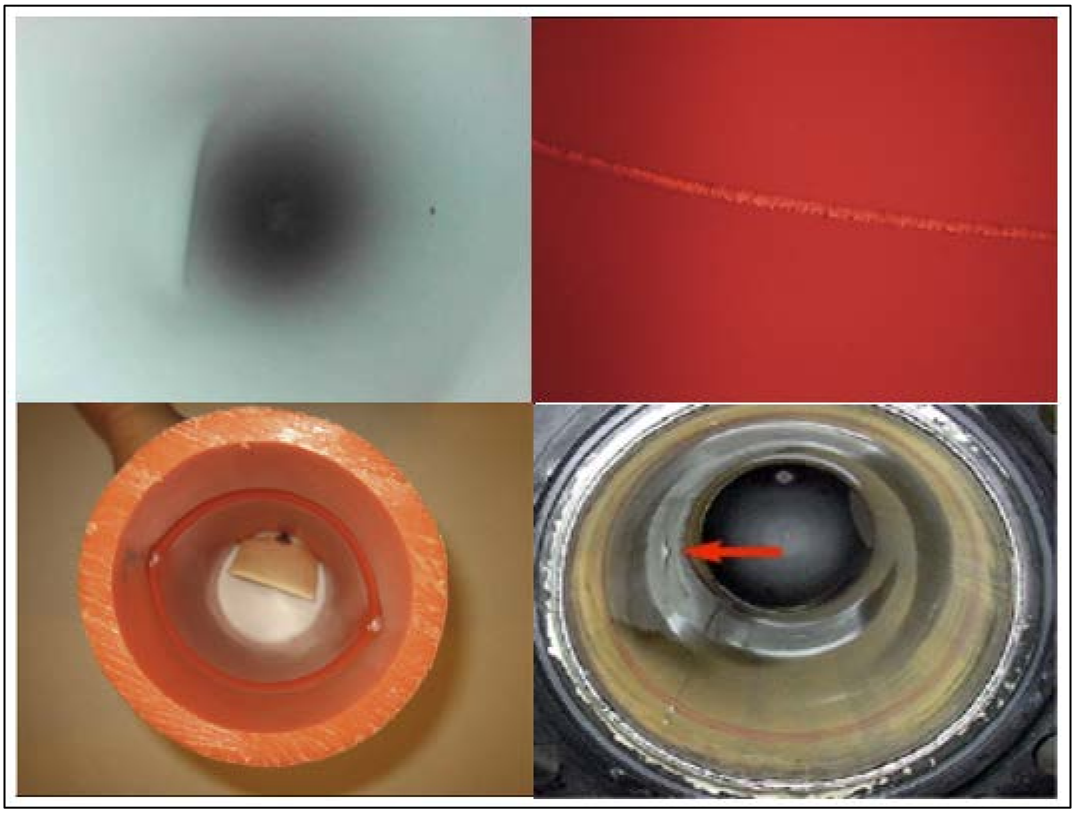

**Figure 6-2. Four types of common damage in pipe: dent (top left), slit (top right), squeeze-off (bottom left) and impingement (bottom right)**

The four types of damage can be randomly generated with different size and position. This can provide us with great amount of data since the real data is limited. **Figure 6-3** shows a visualization of the 3D array for samples of each damage type. Comparing with the ones in **Figure 6-2**, the simulation can have a good representation of the real damage.

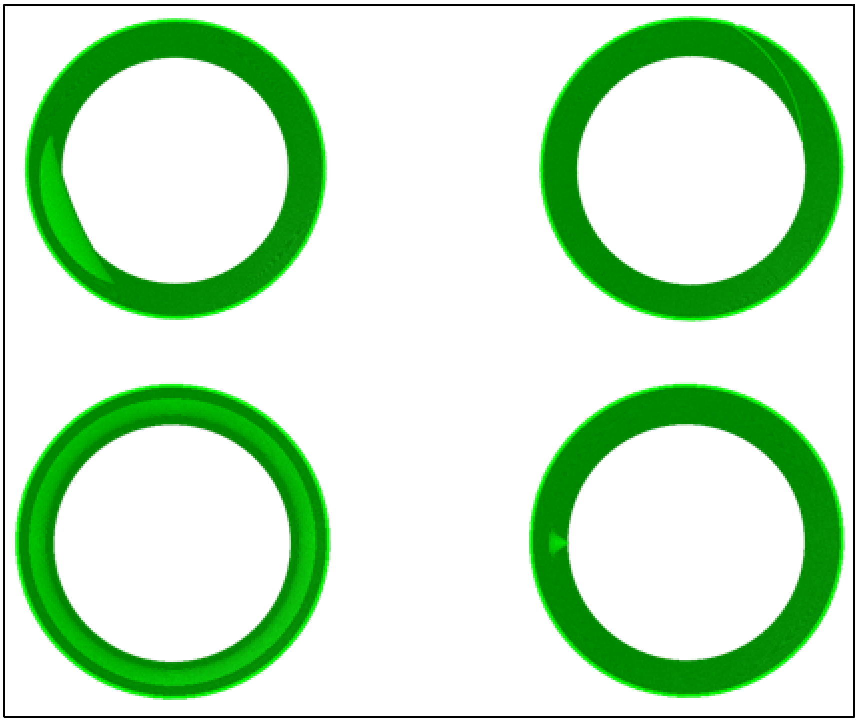

**Figure 6-3. . Sample of the four types of damage: dent (top left), slit (top right), squeeze-off (bottom left) and impingement (bottom right)**

Random noises were added to the 3D array to simulate the potential noise in a camera sensor.

*Feature calculation and classification*

Geometric features were extracted based on the simulated pipe. A few methods were tried to isolate the damage in a 3D pipe model. The first method used was a frame differencing method, it regards the previous frame as the background of the current frame. Such method works fine only with idealized data, i.e. the one without noise. A frame averaging method [81] take the average of a few numbers of the previous frames as the background of the current frame. This method would compensate a small amount of noise. But since the camera needs to fit in small pipelines, the size of the sensor would be small and a large amount of noise is expected. A more advanced method of foreground detection using Gaussian mixture model [82] were tried. After comparison, the frame averaging algorithm is chosen as the denoise method in our case due to its low computational cost as well as its good effects on the data.

Based on the isolated 3D structure (damage), a few geometric features can be calculated. In the demonstration example, four features were proposed, namely the surface area of the isolated damage, the maximum cross section (x-y plane) area, the length in z direction and the ratio of x-y plane projection to z direction length, respectively. 400 simulated damaged pipe sections (100 of each kind of damage) were randomly generated for the feature data. Using these feature, a NB classifier can achieve an accuracy of 89%. Figure 6-4 shows the accuracy of the classifier vs. the training size. The drop of the accuracy at 300 training data size is caused by overfitting.

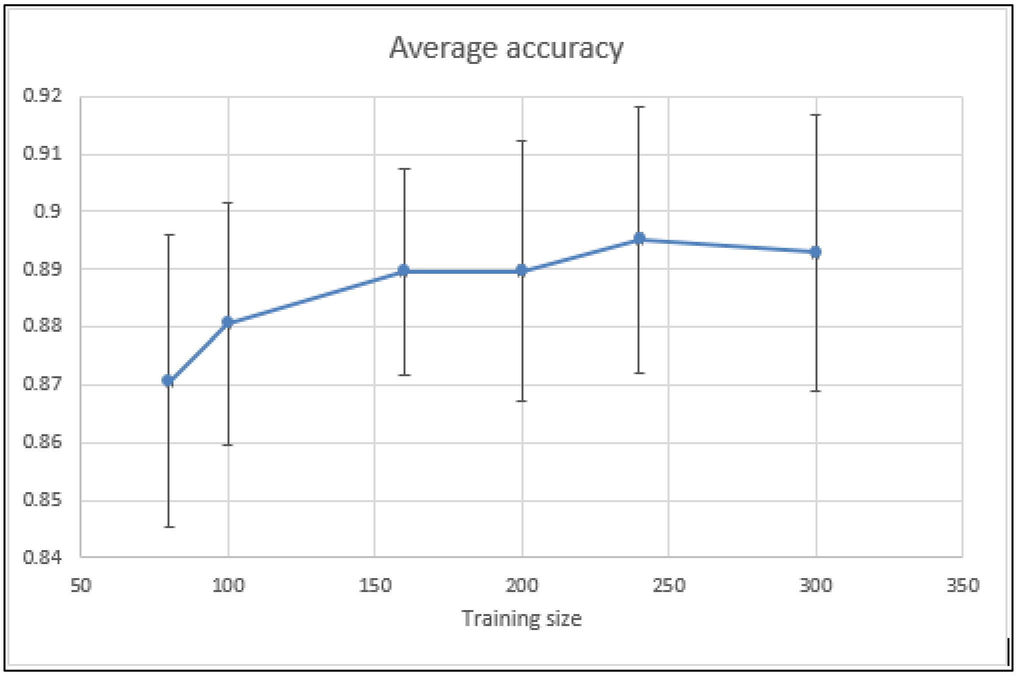


**Figure 6-4. Average accuracy vs. training data size with simulated feature data**

## Comparison with neural network (NN)

The previous section discussed the behavior of the simple naïve Bayes classifier. It can be considered that it achieved plausible results. In this section, a comparison was done using the same data set by classification using Neural Network (NN) in MATLAB [83]. Since NN classifier can directly take image as input, another method of using 2D image as input was introduced and compared among Neural Network and NB.

### *Neural Network with extracted feature data*

Since NN has an additional validation step, the training and testing is a bit different then the NB. The network used in this case has 10 hidden neurons, the training set is set to be 30% to 80% of the data, and the test and evaluation set are set to be equal. The detailed algorithm of NN is beyond the scope of this study. The comparison of the classification result is shown in Figure 6-5. As we can see, the Neural Network has a similar accuracy as NB. And NN also suffers the overfitting effect.

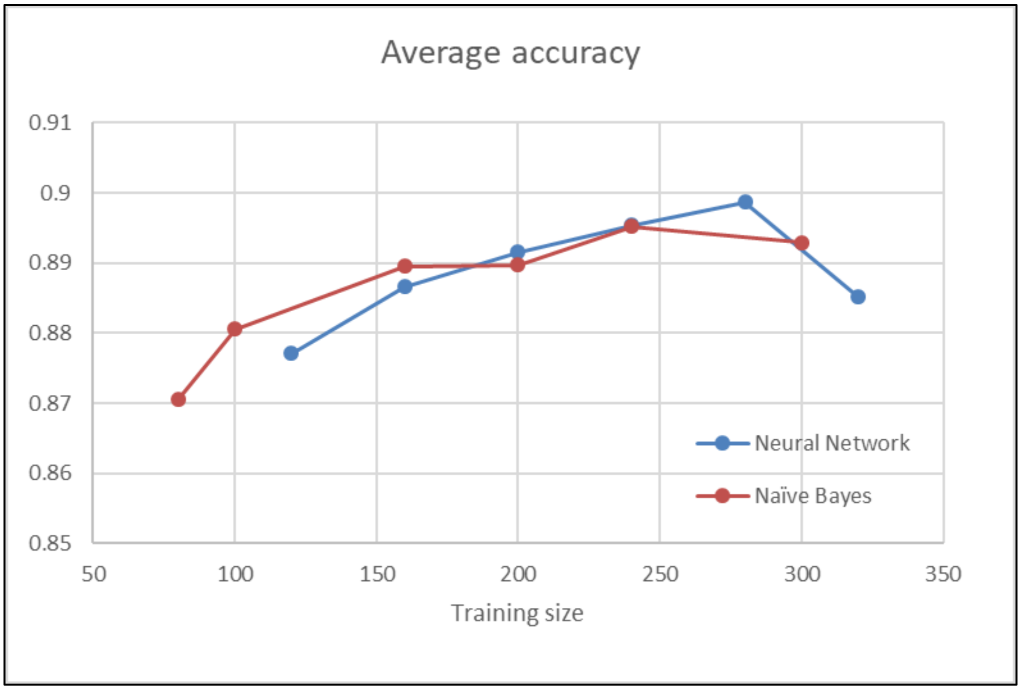


**Figure 6-5. Average accuracy for Neural Network using simulated data**

*2D feature image as input*

Although to the benefit that NN can take image as input, the original frames are too large, which would take longer training and testing time, and have too much useless data (both the inside and outside the pipe cross section have black area that is the same no matter the damage). A method of dimension reduction is considered. And a sequence of five steps of image processing is designed to get a feature image with a much lower resolution, which will then act as input images for NN and NB. The targeting image is each frame for the simulated pipe structure with noise. The five steps are dilation, filling, subtraction, rotation and pooling, as shown in **Figure 6-6**. Details will be introduced bellow.

The first step is to dilate the white pixels. This will let the noisy edge of the pipe form a closed contour of the cross section. In the second step the closed section is filled with white pixels, as shown in **Figure 6-6** (c). Then the filled cross section is subtracted from a perfect cross section of the pipe. This step isolates the damage. Since the damages from each frame is at a different angle, a rotation helps align them in the same direction. **Figure 6-6(**e) shows an example of 50 dent section that were aligned in the same direction. Then a pooling zooms in at the damage, forming a 60 by 60 feature image for each frame, further reduce useless information.

Since this method uses only 2D image frames instead of 3D structure, it is able to get much more data set from the simulated pipes. In total, one thousand images were processed with 200 for each damage and 200 for non-damaged pipe section.

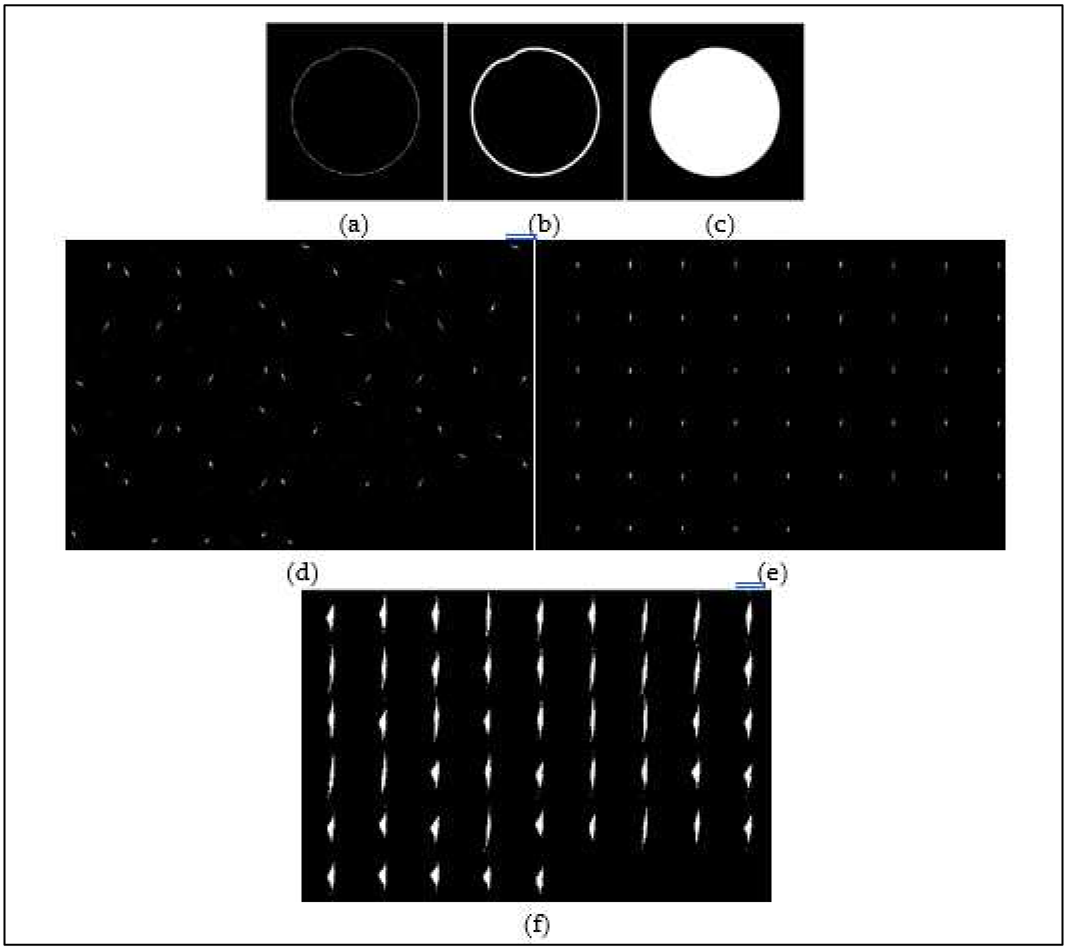


**Figure 6-6. Image processing steps for extracting feature image. (a) the original frame for an impingement, (b) the dilation helps form a closed contour, (c) the closed circle is filled, (d) extracting the filled graphs from a round, (e) rotating the isolated damage into the same direction and (f) pooling to enlarge the damage and eliminate useless data**

Using the feature image, the neural network can almost achieve no error in classification. It can be understood that a 2D image contains much more information than the simple 4 features data extracted from 3D model.

How would a Naïve Bayes behave with the same amount of information? A network with 3,600 nodes (one node for each pixel) were created in this case, each node corresponds to a pixel in the 60 by 60 feature images. Since the value of the pixels takes only 0 and 1, and we only need to differentiate the magnitude of probability, the probability distribution for each node is model as a Gaussian distribution with fixed variance. The average of the pixel value was taken as the mean and the variance was set to a certain value for each likelihood function. It is found that when choosing the variance to be 0.4, the network can achieve the highest performance. It can be seen from Figure 6-7, with this formulation, the Naïve Bayes Classifier can also achieve an almost perfect result.

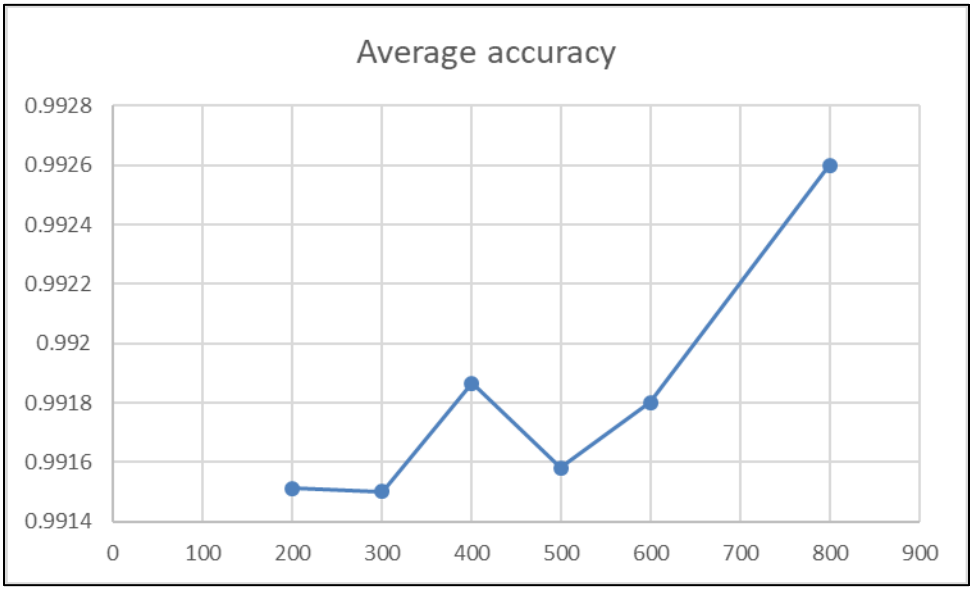


**Figure 6-7. The accuracy vs. training data size using a refined Gaussian node**

The above results indicated that a Naïve Bayes classifier is sufficient for the damage classification in our case.

### Classification using real image

The real data was recorded using the prototype device received from the cooperating institute (Figure 6-8). It has a fisheye camera aligned with a laser ring projector. The two white plates are 3D printed and it can fit into a 3-inch pipe. The camera connects to a computer via USB port and the laser projector needs an additional power supply.

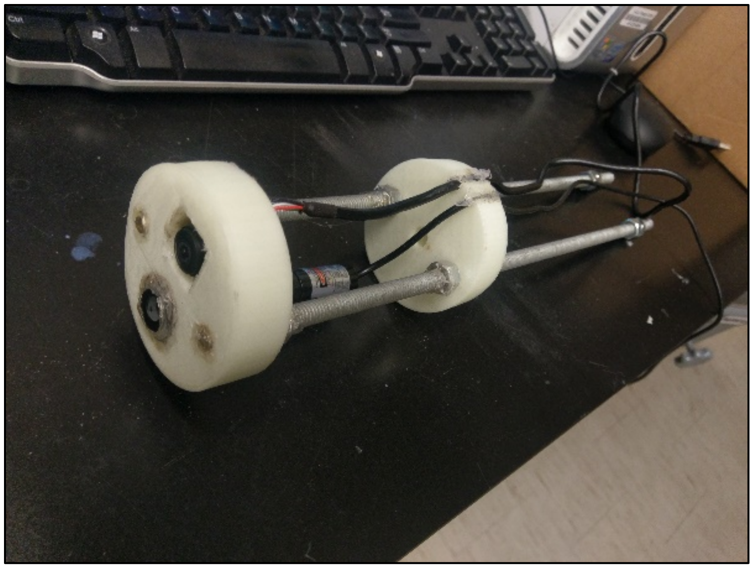

**Figure 6-8. The prototype camera**

To conduct the experiment, we bought a few PVC pipes from local hardware store and manually created/simulated some damage. **Figure 6-9** shows the manually created damages. A slit was cut using a saw on the pipe wall. Some pastes were stuck on the pipe wall to simulate dent and impingement.

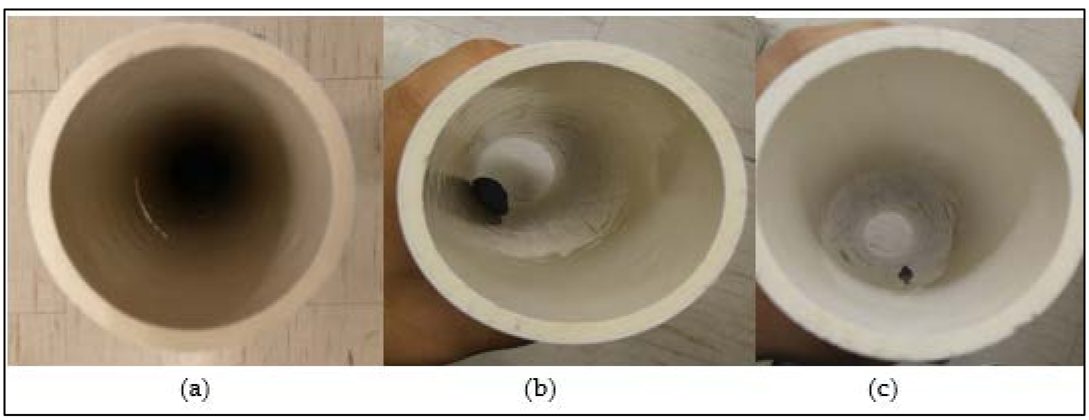


**Figure 6-9. Damaged pipes with slit (left), dent (middle) and impingement (right)**

But the reconstruction algorithm provided is very sensitive to the vibration of the camera. As we investigate the code, the algorithm simply stacks up all the black and white frames to form the 3D model. And this would lead to various bad visualization of the reconstructed pipe. To overcome these issues, photo shots, instead of videos, were taken when the camera is moving along the pipe. By doing this we could effectively reduce the vibration effect. Photo groups were taken with the damage set at different angle and paste for dent and impingement with different shape. The process of collecting data is a long and verbose process. After the data collection, each group of pictures were taken to the MATLAB code to reconstruct the 3D pipe model. Some good results can be seen in Figure 6-10. And the 3D pipe model (essentially a 3D binary matrix) were processed using the denoise and frame averaging algorithm to isolate the damage. And based on the isolated damage, geometric features, such as length, volume, surface area, can be calculated.

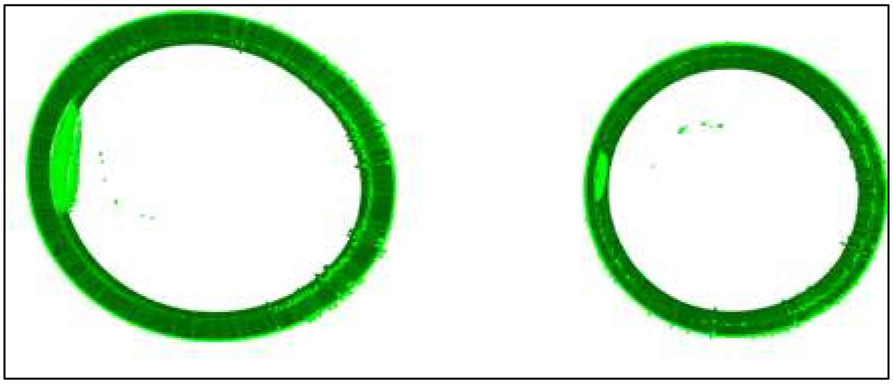

**Figure 6-10. Two good reconstruction results**

Due to the nature of the algorithm, out of all the tests only 90 sets of data, 30 sets for each kind of damage, can be selected to do classification. Naïve Bayes classifier were used to classify the data. By varying the size of the training data, the average accuracy is around 77%. Figure 6-11 shows the trend of average accuracy in relation to training data size.

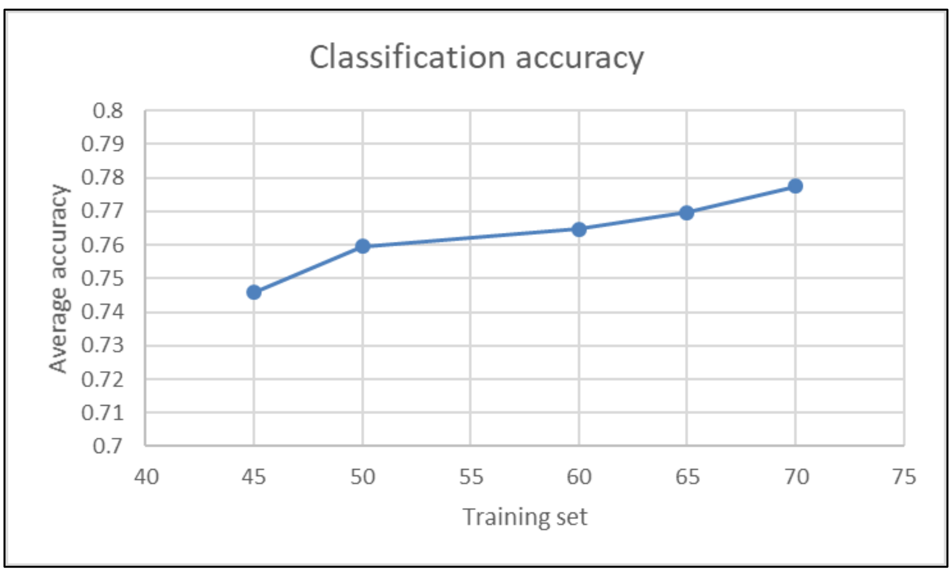


**Figure 6-11. The average classification accuracy vs. training size using real data**

## Image reconstruction and damage classification conclusion

A simple Naïve Bayes classifier is applied in the damage detection and classification task. The method showed promising result with simulated pipe imaging. Its performance can be comparative to more advanced method, such as Neural Network. This is probably due to that our case is not complicate in nature. The classification results using real imaging data was disappointing. This was mainly due to the prototype reconstruction device. The algorithm for the reconstruction needed to be revised.

### *Bayesian/maximum entropy network*

The proposed maximum entropy (ME) network could introduce extra constraint on the features in a Bayesian network. In this section, we first introduce the concept of the maximum entropy. The detailed derivation of how the ME can be applied into a Bayesian classifier. A toy example is given to demonstrate the advantage of the proposed BEN network comparing to that of Naïve Bayes.

#### Introduction to maximum entropy

The Maximum relative Entropy (ME) method was originally used to assign probabilities using information as constraints [59]. Giffin [84] used the ME method to update probability with moment constraints. Caticha [61] found the relationship between the ME method and Bayes' theorem and showed that the Bayes' rule is a special case of ME. Guan [85] applied the ME updating into fatigue damage prognosis in a single updating scheme.

For an uncertain parameter $\theta \in \Theta$ and the corresponding response variable $x \in X$ , let $\mu(x,\theta)$ be the prior of the joint probability distribution and $p(x,\theta)$ the posterior of the joint probability. According to maximum entropy axioms [86], the desired $p(x,\theta)$ would maximizes the relative entropy:

$$S[P,P_{\text{old}}] = -\int dx d\theta P(x,\theta) \log \frac{P(x,\theta)}{P_{\text{old}}(x,\theta)} \quad \textbf{Equation 6-3}$$

The constraints with observation data *x'*, which is the case in a Bayesian updating scheme can be expressed as a delta function at *x'*:

$$P(x) = \int d\theta P(x,\theta) = \delta(x - x') \quad \textbf{Equation 6-4}$$

And the moment constraint for a given function *f(θ)* is given as:

$$\int dx d\theta P(x,\theta) f(\theta) = F \quad \textbf{Equation 6-5}$$

After forming a Lagrangian function including the constraint in Eq. (4) and (5), the updated function $P$ is expressed in the form:

$$P_{\text{new}}(\theta) = P_{\text{old}}(\theta)\frac{P_{\text{old}}(x'|\theta)}{P_{\text{old}}(x')}\frac{e^{\beta f(\theta)}}{Z}$$ **Equation 6-6**

where $x'$ is the observation data and $Z$ is a normalizing constant. The term $\beta$ is determined by $\frac{\partial \log Z}{\partial \beta} = F$. This additional exponential term serve as a shifting factor from the old distribution. It is clear that the result when $\beta = 0$ will recover the Bayes' rule.

## Maximum entropy in Bayesian network classifier

When applying the ME method into classification, the constraint information would be different than the above introductions. Recall a basic Naïve Bayes network as shown in **Figure 6-1** the class node C is a discrete node, the value of which is the class label. And the corresponding feature nodes $f_1$ to $f_2$ could be either continuous or discrete depending on specific setup. Each node contains its prior distribution and the edge contains the likelihood function between the two nodes. The constraint would be given on the likelihood function, since the prior knowledge would usually be the information about a feature given a certain class. For example, when distinguishing an orange to an apple, the information we know is that if it is an orange, it must have a rough surface and the color is orange. Detailed derivation will be shown as follows.

The constraint on the likelihood function given a known moment information is:

$$\int df_j p(f_j \mid C = c_i) g(f_j) = G_i$$ **Equation 6-7**

(7)

where $f_j$ is the jth feature in the network and $c_i$ is the ith class label. The equation states that the expected value of some function $g(f_j)$ is $G_i$. The constraint is enforced on $f_j$ corresponding to $C = c_i$. Additionally, we have the two normalization constraints for the likelihood function and the joint pdf:

$$\int df_j p(f_j \mid C = c_i) = 1$$
$$\int df_j dC p(f_j, C) = 1$$ **Equation 6-8**

Forming the Lagrangian function regarding the three constraint in Eq. (7) and (8) we have:

$$\begin{aligned}\mathcal{L} = &-\int df_j dC p(f_j, C)\log\frac{p(f_j, C)}{\mu(f_j, C)} + \alpha[\int df_j dC p(f_j, C) - 1] \\ &+\int dC\beta(C)[\int df_j p(f_j, C) g(f_j) - G_i p(C)] \\ &+\int dC\gamma(C)[\int df_j p(f_j, C) - p(C)]\end{aligned}$$ **Equation 6-9**

$\alpha$ , $\beta(C)$ and $\gamma(C)$ are Lagrangian multipliers. Note that Eq. (7) and the first equation in Eq. (8) were multiplied with $p(C=c_i)$ on both sides and that $p(f_j, C=c_i) = p(f_j \mid C=c_i)p(C=c_i)$. Since the class label C is a discrete variable, the integral can be regarded as a summation. To find the optimal posterior $p(f_j, C)$, the variation of the Lagrangian function is se to be 0, i.e. $\delta\mathcal{L} = 0$. This yields $\partial\mathcal{L} / \partial p = 0$:

$$\frac{\partial\mathcal{L}}{\partial p} = \int df_j dC[-\log\frac{p(f_j,C)}{\mu(f_j,C)} - 1 + \alpha + \beta(C)g(f_j) + \gamma(C)] = 0$$ **Equation 6-10**

The above equation satisfies for any $p(f_j, C)$ which means:

$$-\log\frac{p(f_j,C)}{\mu(f_j,C)} - 1 + \alpha + \beta(C)g(f_j) + \gamma(C) = 0$$ **Equation 6-11**

Hence:

$$p(f_j,C) = \mu(f_j,C)e^{-1+\alpha}e^{\beta(C)g(f_j)}e^{\gamma(C)} = \frac{\mu(f_j,C)e^{\beta(C)g(f_j)}e^{\gamma(C)}}{z}$$ **Equation 6-12**

With

$$z = 1/e^{-1+\alpha} = \int df_j dC\mu(f_j,C)e^{\beta(C)g(f_j)+\gamma(C)} = \sum_C \int df_j \mu(f_j,C)e^{\beta(C)g(f_j)+\gamma(C)}$$ **Equation 6-13**

By assuming the prior does not change, i.e. $p(C) = \mu(C)$, we can solve for the likelihood function:

$$p(f_j \mid C) = \frac{\mu(f_j \mid C)e^{\beta(C)g(f_j)+\gamma(C)}}{z}$$ **Equation 6-14**

Back substitute into the constraints in Eq. (7) and the first equation in Eq. (8):

$$\frac{\int df_j \mu(f_j \mid C)e^{\beta(C)g(f_j)}e^{\gamma(C)}g(f_j)}{z} = G_i$$ **Equation 6-15**

$$\frac{\int df_j \mu(f_j \mid C)e^{\beta(C)g(f_j)}e^{\gamma(C)}}{z} = 1$$ **Equation 6-16**

Given the above two equations, for a fixed value of $C = c_i$ we can solve for the corresponding unknown $\beta(C = c_i)$ and $\gamma(C = c_i)$. Since the term $e^{\gamma(C)} / z$ can be regarded as a normalizing constant for a fixed ci, we can eliminate this term by the ratio of Eq. (15) and (16):

$$\frac{e^{\gamma(C)} \int df_j \mu(f_j \mid C) e^{\beta(C) g(f_j)} g(f_j)}{e^{\gamma(C)} \int df_j \mu(f_j \mid C) e^{\beta(C) g(f_j)}} = G \qquad \textbf{Equation 6-17}$$

Now let us focus on a specific case where the constraint on likelihood function is a first order moment, i.e. $g(f_j) = f_j$. And the likelihood function is a normal distribution $\mu(f_j \mid C) = \frac{1}{\sqrt{2\pi\sigma^2}} e^{-\frac{(f_j - \mu)^2}{2\sigma^2}}$. Substitute into Eq. (17) and eliminate the common term:

$$\frac{\int_{-\infty}^{\infty} e^{-\frac{1}{2\sigma^2} f^2 + (\frac{\mu}{\sigma^2} + \beta) f} f df}{\int_{-\infty}^{\infty} e^{-\frac{1}{2\sigma^2} f^2 + (\frac{\mu}{\sigma^2} + \beta) f} df} = G_i \qquad \textbf{Equation 6-18}$$

From basic calculus, we have: $\int_{-\infty}^{\infty} e^{-ax^2 - bx} dx = \sqrt{\frac{\pi}{a}} e^{b^2/4a}$

$$\int_{-\infty}^{\infty} x e^{-ax^2 - bx} dx = -\frac{\sqrt{\pi}}{2a^{3/2}} e^{b^2/4a} \qquad \textbf{Equation 6-19}$$

Let: $a = \frac{1}{2\sigma^2}, b = -(\frac{\mu}{\sigma^2} + \beta)$

Substitute into (18):

$$\frac{-\frac{\sqrt{\pi} b}{2a^{3/2}} e^{\frac{b^2}{4a^2}}}{\sqrt{\frac{\pi}{a}} e^{\frac{b^2}{4a^2}}} = -\frac{b}{2a} = G_i \qquad \textbf{Equation 6-20}$$

Solve for $\beta$:

$$\beta = \frac{G_i - \mu}{\sigma^2} \qquad \textbf{Equation 6-21}$$

Substitute $\beta$ into (16):

$$\frac{e^{\gamma(C)}}{z} = \frac{1}{\int df_j \mu(f_j \mid C) e^{\beta(C) g(f_j)}} \quad \textbf{Equation 6-22}$$

Let:

$$I = \int df_j \mu(f_j \mid C) e^{\beta(C) g(f_j)} = \frac{e^{-\frac{\mu^2}{2\sigma^2}}}{\sqrt{2\pi\sigma^2}} \int_{-\infty}^{\infty} e^{-\frac{1}{2\sigma^2} f^2 + (\frac{\mu}{\sigma^2} + \beta) f} df \quad \textbf{Equation 6-23}$$

Again, we let: $a = \dfrac{1}{2\sigma^2}, b = -(\dfrac{\mu}{\sigma^2} + \beta) = -\dfrac{G_i}{\sigma^2}$

So:

$$I = \frac{e^{-\frac{\mu^2}{2\sigma^2}}}{\sqrt{2\pi\sigma^2}} \sqrt{\frac{\pi}{a}} e^{\frac{b^2}{4a^2}} = e^{\frac{G_i^2 - \mu^2}{2\sigma^2}} \quad \textbf{Equation 6-24}$$

Hence:

$$\frac{e^{\gamma(C)}}{z} = I^{-1} = e^{\frac{\mu^2 - G_i^2}{2\sigma^2}} \quad \textbf{Equation 6-25}$$

The new updated joint distribution can be written as:

$$p(f_j, C) = \mu(C) \mu(f_j \mid C) e^{\frac{G_i - \mu}{\sigma^2} f_j} e^{\frac{\mu^2 - G_i^2}{2\sigma^2}} \quad \textbf{Equation 6-26}$$

The result shows that after the updating with moment information, there would be 2 more exponential term. Which is similar to the result found in [84, 85].

## Demonstration example for Bayesian/maximum entropy network

Using the above derivation, a maximum entropy network is formed and can be trained. Following is a simple example to illustrate the behavior of a BEN classifier against the NB classifier.

Assume a dataset of two types (classes) of damaged pipes, namely slit (class 1) and impingement (class 2). Two measurements were taken: the length is measured as the longest dimension for the damage and the volume of the damage. The data were randomly generated according to four independent normal distributions as listed in **Table 6-1**:

**Table 6-1. Random generator for demonstration data**

| Damage type | Length | Volume |
|---|---|---|

| | | |
|---|---|---|
| Slit | $N(175,5^2)$ | $N(100,15^2)$ |
| Impingement | $N(165,5^2)$ | $N(150,20^2)$ |

A total of 200 data were randomly generated. Assume that we know by experience that the length of a slit is typically 100 unit. So the constraint can be mathematically expressed as:

$$\int df_2 p(f_2 \mid C = C_1) f_2 = 100 \qquad \textbf{Equation 6-27}$$

Substituting into the results from the above derivation, a BEN classifier is formed and can be trained. The classification with the example data can be seen in **Figure 6-12**. The comparison is the result from Naïve Bayes, i.e. no additional constraint. As we can see, due to the additional constraint information, the accuracy of the entropy network is significantly higher than that of a Naïve Bayes when there are less training data. When the training size increases, the accuracy from the two network converges.

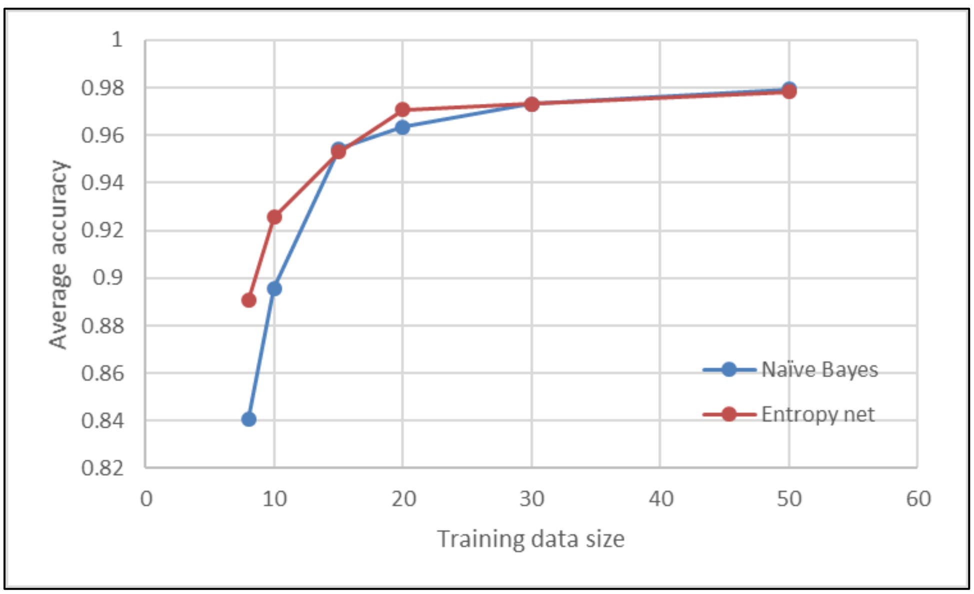


**Figure 6-12. Average accuracy for NB and BEN**

When we look at the probability distribution of the likelihood function for $p(f_2 \mid C = C_1)$ in both cases, in **Figure 6-13**, the additional constraint helps enforce that the mean of the variable is 100.

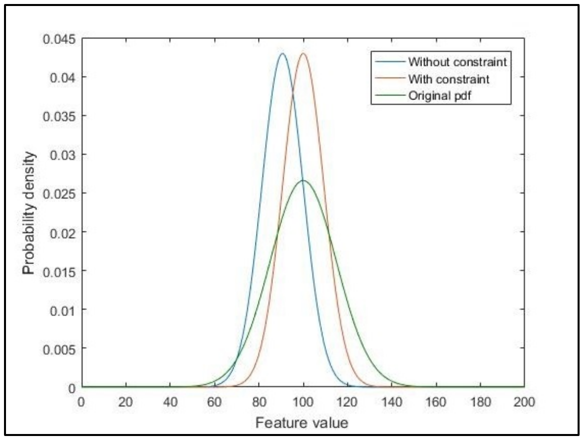


**Figure 6-13. The comparison of the updated probability distribution with and without constraint**

It can be concluded that the entropy network does improved classification accuracy when training data is small. Which is often the case for some engineering problems. Such a method could benefit classification tasks where experimental data is hard to get.

### Bayesian/maximum entropy network conclusion

In this section, the maximum entropy method was applied in the Bayesian network and used as a classifier. Detailed derivation showed that it was possible to accept any order of moment constraint. An analytical solution was given for a special case where the nodes are modeled as Gaussian and the constraint as a first order moment. Theoretically, any constraint that could be expressed in the form of an equality of the probability function could be encoded into the classifier. A toy example was given to show that the BEN indeed performs better when the training data is small. Since the empirical information on the pipe imaging data is not available, the method was not tested against real data.

## *Creep crack growth prediction*

In this section, an equivalent crack growth model for creep life prediction of polymers is discussed. The equivalent crack growth rate is modeled using a Paris' law like equation. The model was calibrated and validated using the data provided by GTI. The experimental data was done on Aldyl-A pipes under various loading condition and different damage types. This enabled the study of the effect of damage on the life of the pipe materials. The damage is considered as stress risers in the pipe. The results showed that the method has a good prediction comparing to the experimental data. The prediction results was then applied to the maintenance framework.

### Model development

The proposed method expressed the crack growth rate as a Paris' type function as:

$$\frac{da}{dt} = C \cdot K^m$$ **Equation 6-28**

where $C$ and $m$ are material properties that will be calibrated using the control data group. $K$ is the stress intensity factor (SIF). The crack is assumed to be a semi-circular crack at the inner surface in the longitudinal direction. The SIF solution is given in [65] as:

$$K = \sigma\sqrt{\frac{\pi}{Q}aF}$$ **Equation 6-29**

where $a$ is the crack length, $\sigma$ is the hoop stress, $Q$ is the shape factor, in this case is given a fixed value of $Q$=2.464 and $F$ is the boundary correction factor. An asymptotic SIF solution considering the notch effect is proposed in [66]. The expression for the SIF is modified as:

$$K = \sigma\sqrt{\frac{\pi}{Q}(a + d\{1 - \exp[-\frac{a}{d}(K_t^2 - 1)]\})F}$$ **Equation 6-30**

where $K_t$ is the stress concentration factor, $d$ is a geometric measurement of the notch size. A schematic illustration is shown in Figure 6-14. $t$ is the thickness of the pipe. The boundary correction factor is fitted as a function that is related to the geometry of the crack. In this specific case, $F$ is calculated as [65]:

$$F = (1.04 + 0.2017\times(\frac{a}{t})^2 - 0.1061\times(\frac{a}{t})^4)\times(6.05 - 0.5\sqrt{\frac{a}{t}})$$ **Equation 6-31**

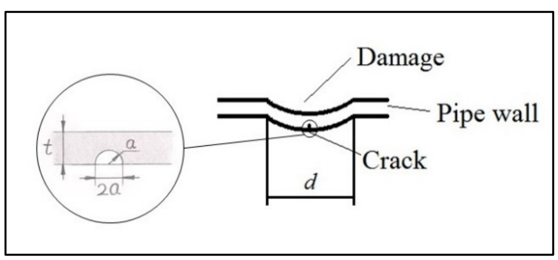


**Figure 6-14. Schematic plot of the crack at a notch root and the semi-circular geometry of a crack**

Integrating the crack growth rate equation from initial crack length $a_i$ to critical crack length $a_c$, the failure time $T_f$ can be expressed as a function of the hoop stress $\sigma$ as

$$T_f = C^{-1}\int_{a_i}^{a_c} K^{-m}da = C^{-1}(\sqrt{\frac{\pi}{Q}})^{-m}\sigma^{-m}\int_{a_i}^{a_c} F\sqrt{a + d\{1 - \exp[-\frac{a}{d}(K_t^{\ 2} - 1)]\}}$$ **Equation 6-32**

Taking the logarithm on both side of the equation gives a linear relationship between the failure time and stress as:

$$\log T_f = -m * \log \sigma + \log(C^{-1}(\sqrt{\frac{\pi}{Q}})^{-m} I) \qquad \textbf{Equation 6-33}$$

where $I = \int_{a_i}^{a_c} F\sqrt{a + d\{1 - \exp[-\frac{a}{d}(K_t^{\,2} - 1)]\}}\,da$. Eq. (33) is the proposed life prediction model for the slow crack growth (SCG) of polymers.

To predict the crack growth as a function of time, the upper limit of the integral in $I$ can be changed to an arbitrary crack length $a_t$. And the corresponding time on the left-hand side can be calculated. This gives an implicit equation for the crack length as a function of time and stress level with five model parameters. It can be solved by numerical method and the crack length vs. time can be plotted.

$$t = C^{-1}(\sqrt{\frac{\pi}{Q}})^{-m} \sigma^{-m} \int_{a_i}^{a_t} F\sqrt{a + d\{1 - \exp[-\frac{a}{d}(K_t^{\,2} - 1)]\}}\,da \qquad \textbf{Equation 6-34}$$

### Calibration and validation

The data set from GTI was done using Aldyl-A pipe. It consists of 5 groups, namely the ductile control group, SCG (slow crack growth) control group, LDIW (low ductile inner wall) control group, LDIW with indentation and LDIW with squeeze-off. The ductile group is tested in high stress level and failure is dominated by ductile deformation. There is a total of 450 data points in this data set. The hoop stress and the failure time were recorded and shifted to 23°C (73.4°F), which is the normal operating temperature. The test used Rate Process Method (RPM) to evaluate the long-term performance of the pipe and used bi-directional shift factors to shift the test results to a common reference temperature. The properties of the polymeric material are governed by the activation energy of the molecular rearrangement. It is measured using Dynamic Thermo-Mechanical Analysis techniques. The activation energy can help determining the Time Temperature Superposition characteristics of the material [40][2], which are the basis of the RPM calculations. GTI employed DTMA to measure the activation energy and use the measurement to develop the bi-directional shift factors [8]. By using these information, the test results at an elevated temperature can be shifted to the reference temperature. The stress concentration factors in the data set are estimated by dividing the actual shifted time by the mean time calculated from control SCG model. Since the study focuses on the creep behavior, the ductile control group will not be used. The SCG data will be used to calibrate the material properties in the proposed model, and the other groups will be used to validate the prediction result of the model. The data are plotted in **Figure 6-15** in double log scale. The log-log plot for the stress vs. life of the data showed a linear tendency.

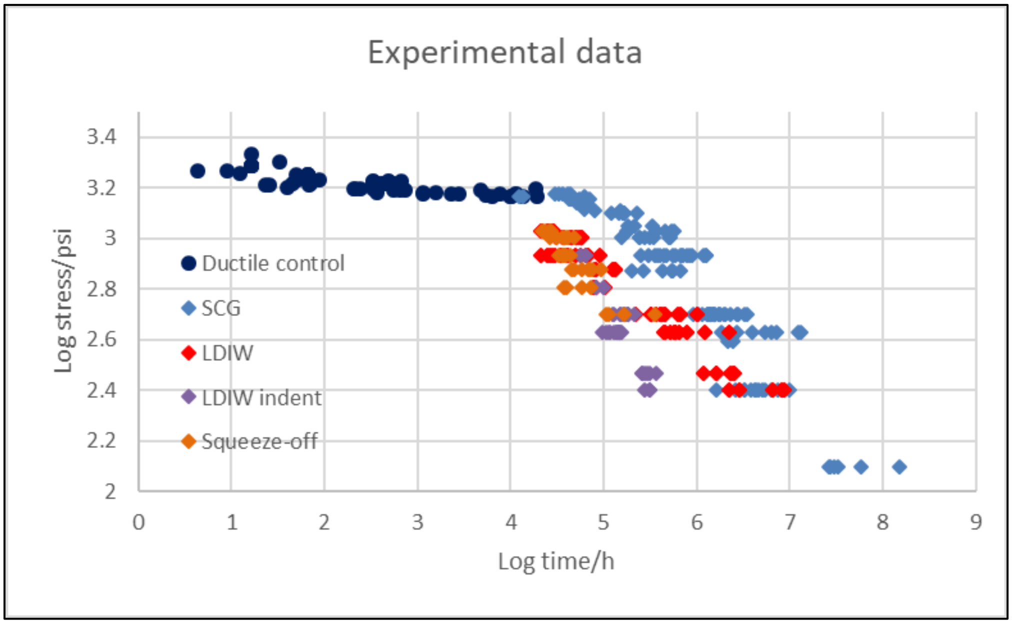


**Figure 6-15. Experimental data shifted to 23°C (73.4°F)**

**Figure 6-16** shows the geometry of the pipe. The outer diameter is 2.375 in. And the SDR value is 11, which means the ratio of outer diameter and pipe thickness is 11.

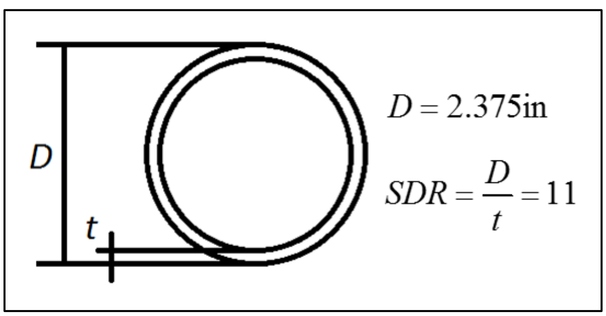


**Figure 6-16. The geometry of the pipe**

The initial crack length can be observed through SEM image in **Figure 6-4,** the micro-crack measures about 25 µm. In this case, the initial crack length is set as $a_i = 10^{-3}$ in . The critical crack length is assumed to be $a_c = 0.1$ in . The measurement for the critical crack length is not important because the crack growth rate will be extremely fast when closing to rupture. A typical damage size is around 1 inch, the value for $d$ is chosen to be $d = 1$ in .

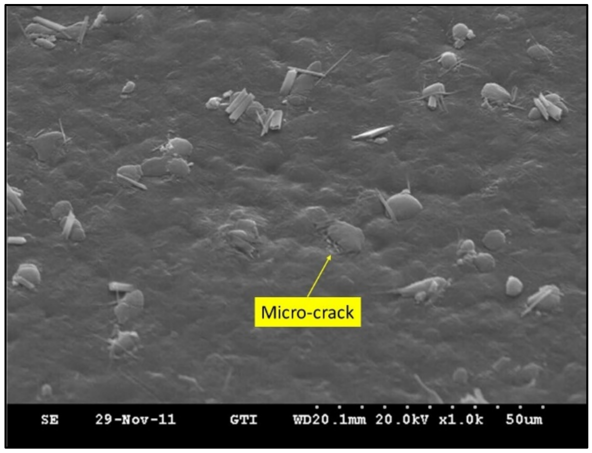


**Figure 6-17. The SEM image showing an initial crack**

The data in SCG group is used as reference data, a linear relation between the logarithm of stress and time is calculated by linear regression. The linear regression gives the stress as a function of time as: $\log T_f = -2.5632 \log \sigma + 13.0796$, indicating $m = 2.5632$. The mean of the stress concentration factor is used as the value for $K_t$ to evaluate the integral $I$. And the value for $C$ is calculated as: $\log C = -13.3442$. Here, the value of $C$ is considered as a random variable. Assume that the slope of the log linear curve, $m$, is fixed. By back substituting the experimental data points into the equation, we could get an array of $\log C$. The value for the logarithm of C can be fitted into a normal distribution. For the SCG data, $\log C$ follows a normal distribution with mean -13.3442 and variance 0.2960. Using these data, we could plot the regressed stress vs. life curve for SCG data in **Figure 6-18**.

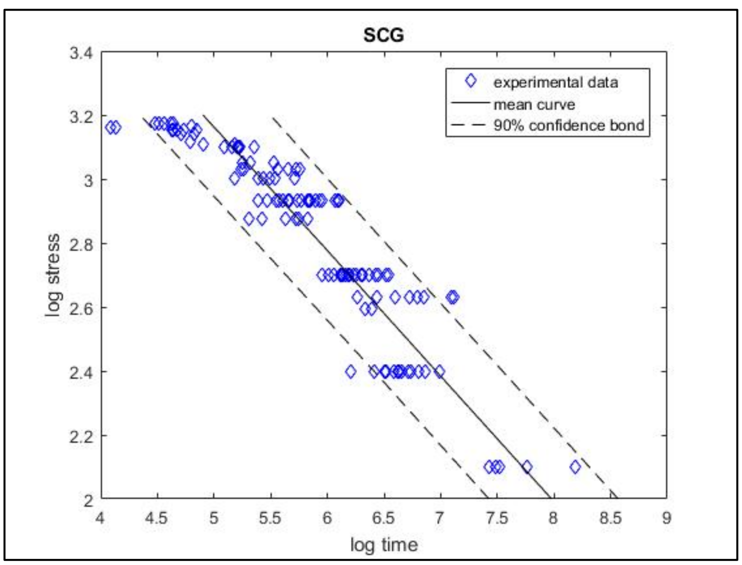


**Figure 6-18. Stress-Life curve for SCG data and its confidence bond against the lab data**

By substituting the $K_t$ with the mean value from other groups, the stress vs. life can be predicted for other damage types. The results of the prediction versus the experimental data for LDIW, indentation and squeeze-off are plotted in **Figure 6-19**. The predictions agree with the data closely.

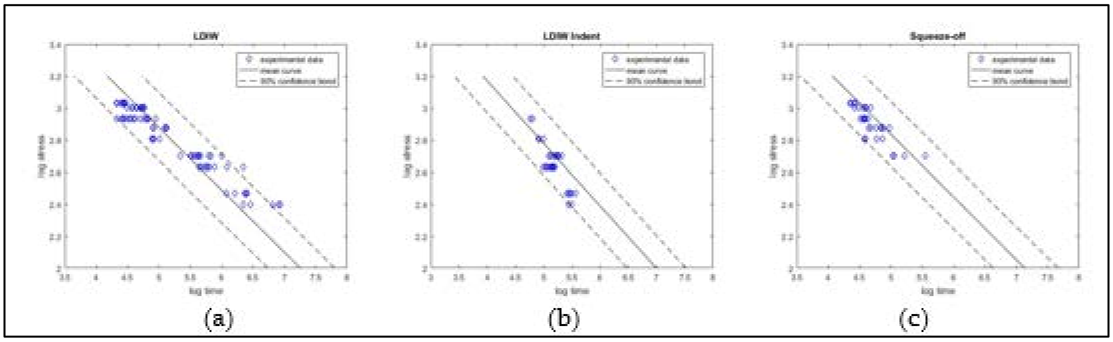


**Figure 6-19. The prediction of stress-life curve for (a) LDIW, (b) LDIW indent and (c) Squeeze-off**

## Uncertainty and reliability prediction

The value of $C$ and $Kt$ in the prediction model can be regarded as random variables. The distribution of $\log C$ can be found by fixing $m$ and substitute the experimental data and is calculated above to follow a normal distribution with mean -13.3442 and variance 0.2960. The stress concentration factor $K_t$ in each group was tested against various types of distribution by KS test [87] and is found that a logistic distribution can best describe the measured data. The uncertainty quantification of the model parameter for SCG group is listed in **Table 6-2**.

**Table 6-2. Uncertainty quantification of the model parameters for SCG group**

| Parameter name | Distribution | Distribution parameter | |
|---|---|---|---|
| | | Mu | sigma |
| $a_i$ | Constant | 0.001 | |
| $a_c$ | Constant | 0.1 | |
| $d$ | Constant | 1 | |
| $\log C$ | Normal | -13.3442 | 0.2960 |
| $m$ | Constant | 2.5632 | |
| $K_t$ | Logistic | 2.6192 | 0.2445 |

The crack growth prediction is achieved by numerically evaluating the integral $I$ at continuous values of crack length $a_t$ given a pair of random sample of $C$ and $K_t$. Hence, the implicit function of $a_t$ as a function of time can be plotted. **Figure 6-20** shows the crack growth curve for SCG at $\sigma = 1000$ psi along the 90% confidence bond. It shows that the crack growth process is quite slow in the beginning and gradually speeds up. This plot could be used to calculate the failure probability at a given time.

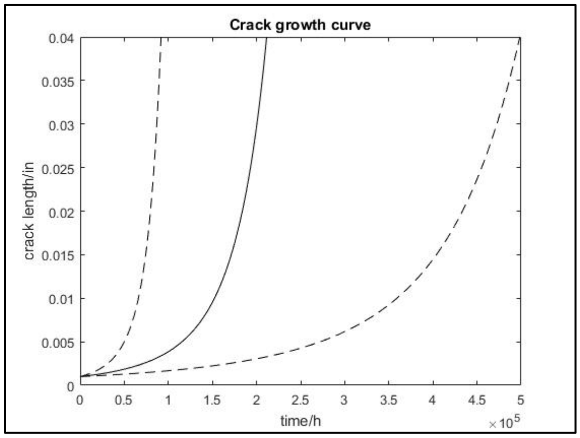


**Figure 6-20. The crack growth curve for SCG and its confidence bond at 1000 psi**

The probability of failure is studied at $\sigma = 1000$ psi and $t = 2\times10^5$ h. The mean curve in Figure 6-20 indicates that the crack length at $t = 2\times10^5$ h is around 0.03 inch, which is still far from failure. While the MC method simulation of crack length at $t = 2\times10^5$ h indicates that it is possible for the crack length to exceed the critical crack length. Figure 6-21 shows the empirical cumulative density function (CDF) and probability density function (PDF) generated from 10,000 MC samples. As we can see in the CDF plot, only a little over 60% of the simulated MC sample is beneath the critical crack length. The shaded area in **Figure 6-21** (b) gives the failure probability. For a deterministic model, a crack length of 0.03 inch would not be considered as failure. But according to the probability analysis, the failure probability at $t = 2\times10^5$ h is 37.85%, which is not negligible. The failure probability model would be significant in reliability analysis.

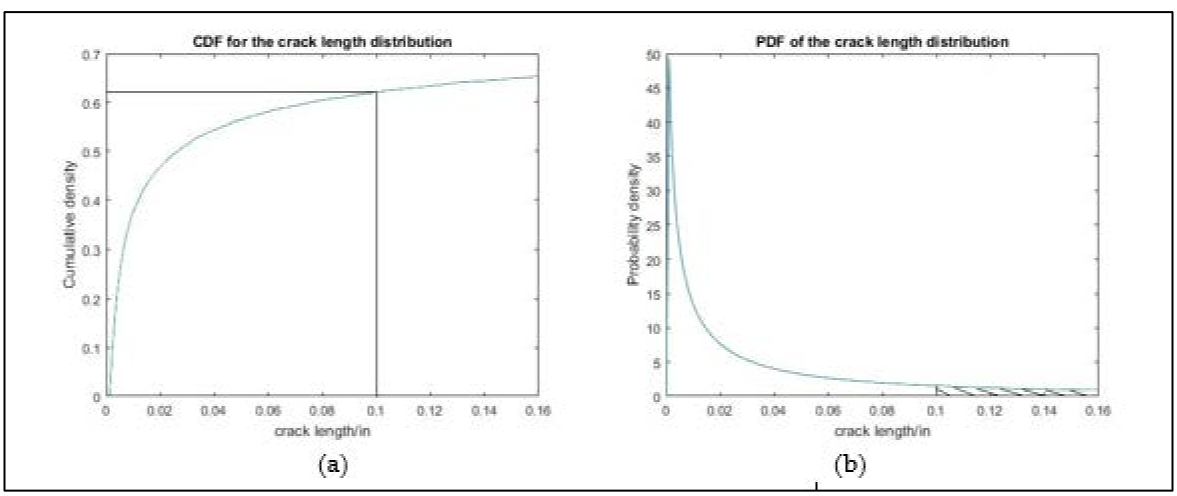


**Figure 6-21. The empirical CDF and (b) PDF of the crack length distribution**

## Approximated creep crack growth prediction conclusion

The prediction model used a simple power law equation to predict the crack growth in polymer pipes. The novelty of the method is that it considered the effect of damage on the life prediction. The error analysis was done by taking the difference in failure time of the lab data against the predicted mean. For each data points, the error is calculated as the actual life from test minus the predicted mean failure time at the corresponding stress. The errors were collected and plotted as an empirical CDF in **Figure 6-22** compared with the MC sample errors. The MC sample error represents a standard distribution of the failure time.

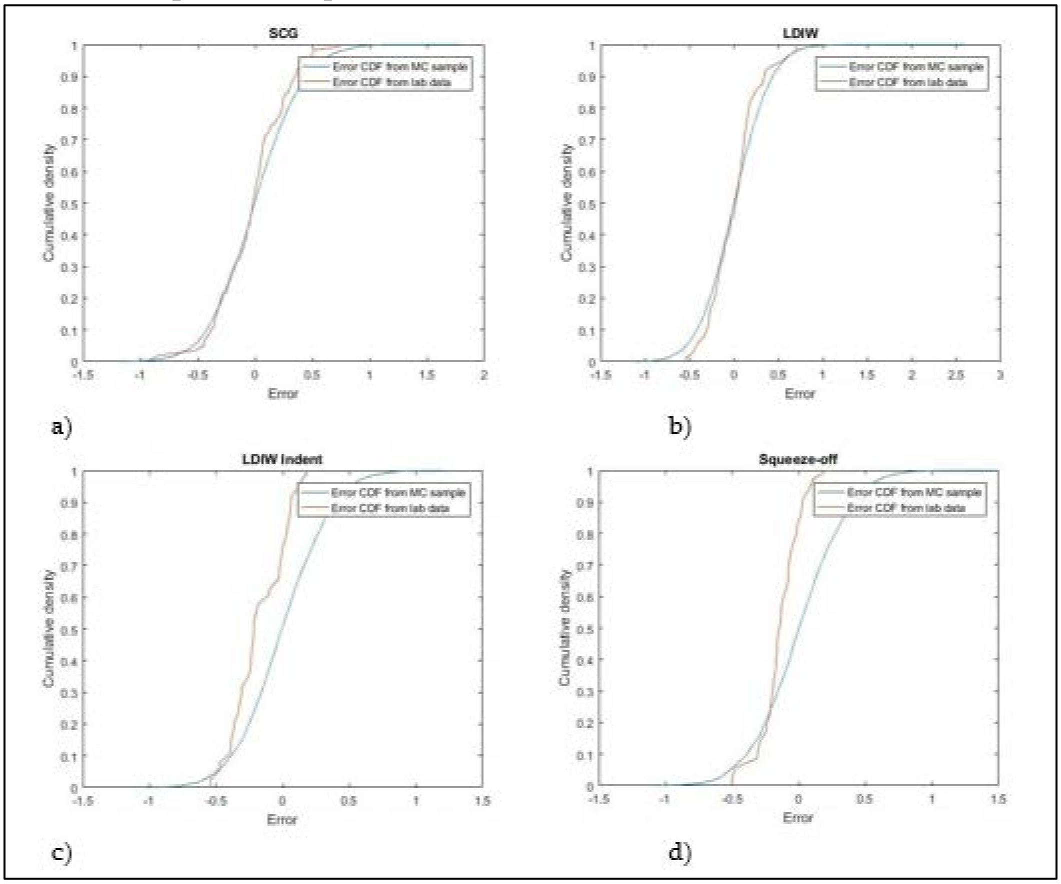


**Figure 6-22. The empirical CDF of the error comparing with the CDF of the MC sample error for a) SCG, b) LDIW, c) LDIW indent and d) Squeeze-off**

Within the margin of error, the experimental data agrees well with the predicted data from the proposed model. The group with indentation and squeeze-off deviates from the MC data, one possible explanation is that the assumed damage size $d$ is different regarding these two types of damage.

## *Maintenance framework*

In this section, a condition-based maintenance framework was formulated. The method categorizes the pipes into different condition stages. Based on the current condition and the future working condition of the pipe, the condition vector and the cost for maintenance can be iteratively calculated. Minimizing the overall cost would give the optimal maintenance plan.

### Maintenance framework formulation

**Table 6-3** the list of symbols used in the formulation.

**Table 6-3. Nomenclature for the maintenance decision framework**

| Name | Meaning |
|---|---|
| $Q$ | The total quantity of pipes |
| $S$ | Number of deterioration stage |
| $M$ | Number of possible maintenance method |
| **D** | Condition vector with dimension 1×S |
| **P** | Deterioration matrix, S×S |
| $\mathbf{M}_m$ | Maintenance transition matrix, S×S |
| **X** | Decision matrix, M×S |
| **C** | Cost matrix, M×S |

Each term in the condition vector D represents the percentage of samples in each stage. The elements in the vector should sum up to 1. The degradation matrix is the probability transition matrix for a certain time step Δt. The term **P**(i,j) means the probability of transition from condition i to condition j. For example if **P**(2,5)=0.1, it means a sample that is now in condition 2 has a 10% probability of transiting to stage 5 after time period Δt, without any repair. The elements in each row of the degradation matrix should sum up to 1.

The maintenance matrix is the probability transition matrix for a maintenance method. The term $\mathbf{M}_m$(i,j) means the percentage of pipes that transit from condition i to condition j right after the maintenance method m. For example, $\mathbf{M}_2$(3,1)=0.1 means that 10% of the pipes that is in condition stage 3 will transit to condition 1 after maintenance method 2. The elements in each row should sum up to 1. The maintenance matrix for doing no maintenance is an identity matrix.

The decision matrix is the object of the optimization. The term **X**(i,j) means the percentage of pipes that is in condition j has maintenance i done. For example, **X**(2,4)=0.1 means that maintenance method 2 is applied to 10% of the pipes in condition stage 3. The elements in each column should sum up to 1.

The element **C**(i,j) in the cost matrix corresponds to the expense of applying a maintenance i for a pipe that is in condition stage j. For example, the element **C**(3,5)=5000 means it takes $5,000 to do a maintenance 3 to a pipe that is in condition stage 5.

When calculating the new condition vector after a time period Δt, the following equation is used:

$$\mathbf{D}_{new} = \sum_m \mathbf{D} \cdot\times \mathbf{X}(m,:) \times \mathbf{M}_m \times \mathbf{P} \qquad \textbf{Equation 6-35}$$

where the term $\mathbf{X}(m,:)$ is the $m^{th}$ row of the decision matrix, meaning the decision vector for maintenance m. The sign $\cdot\times$ is an element wise operator. The dot product of **D** and $\mathbf{X}(m,:)$ gives a $1\times S$ vector, which means the percentage of samples in each condition that will have maintenance m applied. The vector is then multiplied by the maintenance matrix, which would result in another $1\times S$ vector, means the condition vector right after maintenance m being applied. The condition after maintenance times the degradation matrix gives us the new predicted condition vector ($1\times S$) for the group of pipes that had maintenance m done. The sum over m adds up all the condition vector for different maintenance group.

The corresponding cost is calculated by:

$$\text{Budget} = \sum_m Q \times \mathbf{D} \cdot\times \mathbf{X}(m,:) \times \mathbf{C}(m,:) \qquad \textbf{Equation 6-36}$$

The dot product of **D** and $\mathbf{X}(m,:)$ times $Q$ gives a quantity vector with dimension $1\times S$. Each value means the number of pipes in the corresponding condition that had maintenance m done. The quantity vector times the cost vector, with is the $m^{th}$ row of the cost matrix, yields the cost for doing maintenance m. The sum over all maintenance method gives us the total cost.

## Generating probability transition matrix

In the previous section, we have predicted the approximated creep crack growth curve in a probabilistic sense, as in **Figure 6-20**. In this section, we will calculate the probability transition matrix for the maintenance frame work based on the crack growth curve.

In the following example, we are getting the probability transition matrix for a time steo of Δt=1500 h and for the stress level of $\Delta\sigma = 1000\text{psi}$. The deterioration stage is categorized into 5 stages from initial crack length to failure, listed in **Table 6-4**. We assume that the observation of the crack length is a uniform distribution, which means the observation of a crack length $a$ is equally possible in the range of 0.001 to 0.1 in.

**Table 6-4. The condition stage**

| Condition | Excellent | Good | Fair | Poor | Failure |
|---|---|---|---|---|---|
| Crack length/in | $10^{-3}$ – $2*10^{-3}$ | $10^{-3}$ – $6*10^{-3}$ | $6*10^{-3}$ – $2*10^{-2}$ | $2*10^{-2=}$ -- 0.1 | 0.1< |

Monte Carlo simulation were used in this case. We evenly sampled around 2000 points from 0.001 to 0.1 in as the observed crack length in current stage. Each sample point has a corresponding pair of *C* and *Kt* from the creep crack growth model. And the life after Δt is calculated by letting the current point evolve along the specified curve. **Figure 6-23** may help better understand the process of the MC simulation. As we can see in the picture, for an arbitrary initial crack observation $a_i$, we can find the corresponding life $t_1$ from the red curve. The crack length after time step Δt, regarding the same red curve, would be the crack length $a_t$ corresponding to the life of $t_1$+Δt on the red curve. The blue curve is another possible curve with a different pair of *C* and *Kt*, and there is a corresponding life $t_1$' for the initial observation. The prediction of the crack length after time step Δt, according to the blue curve, is $a_t$' as shown. As we can see that the initial observation falls in condition stage 2, and the prediction according to the red curve would be in condition 3, while the prediction according to the blue curve would be in condition 4. Thus, for this initial observation, the term **P**(2,3)=0.5 and **P**(2,4)=0.5 since they have equal chances of transitioning to condition 3 and 4 after time Δt.

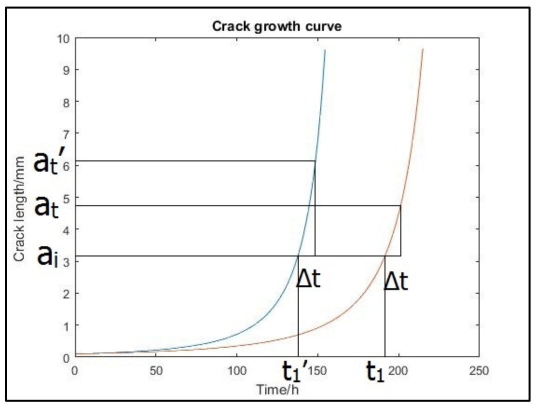


**Figure 6-23. Illustration of the crack growth evolvement.**

This process was done for all the curves in the cluster and the 2000 samples of observation. And the elements in the degradation matrix were calculated as the percentage of pipes that falls in each condition. For this example, the resulting degradation matrix is:

$$\mathbf{P} = \begin{bmatrix} 0.7945 & 0.2051 & 0.0003 & 0.0001 & 0 \\ 0 & 0.8121 & 0.1875 & 0.0003 & 0 \\ 0 & 0 & 0.8085 & 0.1914 & 9.34\text{e-}05 \\ 0 & 0 & 0 & 0.8999 & 0.1001 \\ 0 & 0 & 0 & 0 & 1 \end{bmatrix} \qquad \textbf{Equation 6-37}$$

## Illustrative example

This section will go over the maintenance optimization problem through a demonstrative example, hoping that the reader can have a clear understanding of the proposed framework.

*Maintenance decision optimization*

As a demonstration example, we assume three type of maintenance: do nothing (a natural degradation process), repair and replacement. Still, we consider the pipes as in SCG condition and under a constant pressure of 1000 psi. The maintenance transition matrix for doing nothing is an identity and the one for repair and replace were assumed:

$$\mathbf{M}_2 = \begin{bmatrix} 1 & 0 & 0 & 0 & 0 \\ 0.5000 & 0.5000 & 0 & 0 & 0 \\ 0.1000 & 0.3000 & 0.6000 & 0 & 0 \\ 0.0100 & 0.0400 & 0.2500 & 0.7000 & 0 \\ 0 & 0.0100 & 0.0400 & 0.1500 & 0.8000 \end{bmatrix}$$ **Equation 6-38**

$$\mathbf{M}_3 = \begin{bmatrix} 0.99 & 0.01 & 0 & 0 & 0 \\ 0.99 & 0.01 & 0 & 0 & 0 \\ 0.99 & 0.01 & 0 & 0 & 0 \\ 0.99 & 0.01 & 0 & 0 & 0 \\ 0.99 & 0.01 & 0 & 0 & 0 \end{bmatrix}$$

respectively. The cost matrix is assumed as:

$$\mathbf{C} = \begin{bmatrix} 0 & 0 & 0 & 0 & 0 \\ 30 & 30 & 50 & 100 & 200 \\ 1600 & 1600 & 1600 & 2500 & 3000 \end{bmatrix}$$ **Equation 6-39**

The initial conditions were set as:

$$\mathbf{D} = \begin{bmatrix} 0.10 & 0.20 & 0.50 & 0.15 & 0.05 \end{bmatrix}$$ **Equation 6-40**

The problem is that we are trying to minimize the cost under the reliability constraint: The failure probability should not exceed 0.05. The failure probability is the last term in the condition vector. The problem is transformed as to minimize the budget given the constraint of the last element in **D** should be less than 0.05. Due to the property of the maintenance decision matrix, the number of unknowns are 10.

Since the problem has 10 degree of freedom (DOF), genetic algorithm (GA) [88] was chosen to calculate the optimal maintenance planning. GA is inspired by bio-processes such as mutation and gene selection, and is commonly used in optimization problems. The method has advantages when dealing with high dimensional problems. Since GA is a nondeterministic algorithm, the result for every run would be different. And the solution may not be the best solution. It is an efficient algorithm and has a MATLAB built in function.

The objective function for the maintenance problem is the total cost for maintenance as in **Equation 6-36**. The constraint is the last term in the condition vector.

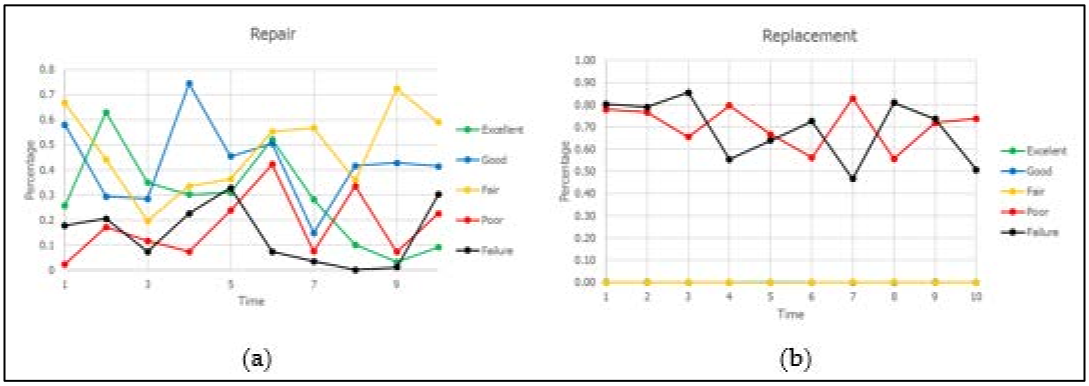


Figure 6-24. **Figure 6-24** shows the optimized results for 10 consecutive time steps. As we can see from the figure, more effort will be put in the replacements of pipes in poor and failure conditions and repair with the ones in good and fair conditions. Note that the result for the maintenance decision would differ from different runs, but the overall trend would be the same.

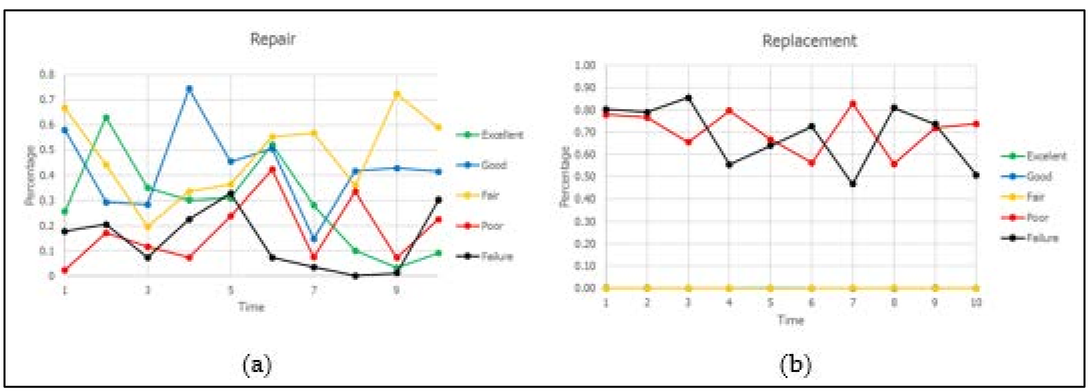


**Figure 6-24. The visualization of maintenance plan for (a) repair and (b) replacement**

***Consequence cost***

In general situations, the damage caused by failure is more severe in some cases while in other cases not. For example, an explosion caused by failure of gas pipe would be hazardous if it happened in a hospital, but not so if it were a rural area. So, per different circumstances, the importance of failure might be different. In regard of this, we add the consequence cost and different groups into the maintenance framework.

The idea is as simple as adding an extra dimension regarding the groups. We use $G$ to represent the total number of groups. The condition vector now becomes a condition matrix with dimension $G \times S$. The quantity becomes a quantity vector of size $G \times 1$ with each term representing the quantity of pipes in each group. An additional weighting vector **W** of dimension $1 \times G$ was created, which is the weight (the severity of consequence) assigned to different group. The reliability objective function is:

$$reliability = \mathbf{W} \cdot \mathbf{D}_{new}(:, S) \qquad \textbf{Equation 6-41}$$

The term $\mathbf{D}_{new}(:, S)$ is the last column of the new predictive condition matrix, which represents the failure probability in each group. The product gives a scaler value.

Following the same example in the previous section, we assumed 3 groups of pipes ($G$=3), each represents a business center area, residential area and rural area. The three groups have the same initial observation of the condition vector as in the previous example. The quantity vector $\mathbf{Q} = [100 \quad 100 \quad 100]$, meaning 100 pipes in each group. We assume that the consequence cost of the three area is from high to low, and the weighting vector $\mathbf{W} = [10 \quad 5 \quad 1]$. The decision matrix now becomes a 3-dimensional matrix ($M \times S \times G$). The number of DOF increased to (($M$-1)$\times S \times G$=) 30.

**Figure 6-6** shows the total cost for each group. We can see that there will be more money spent in the group with higher consequence cost to reduce the probability of failure. This makes sense since if we wanted to avoid failure in one area it is reasonable to spend more money in maintain the pipes are in good working conditions.

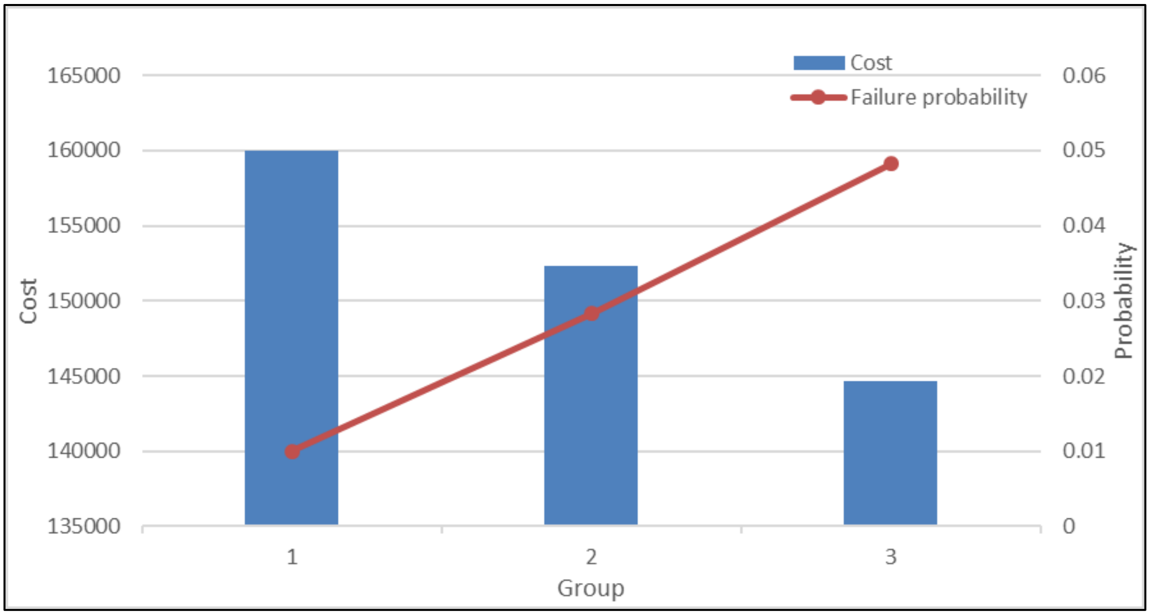


**Figure 6-25. The cost and failure probability prediction for each group**

***Dynamic maintenance framework***

The dynamic updating of the transition matrix can increase the prediction accuracy of the crack length. Hence help the maintenance planning to avoid unwanted failure or the unnecessary cost. The updating is achieved through the observation of *Kt* parameters. With a calibrated camera that reconstruct the pipe in 3D, the actual dimension of the damage can be measured. The stress concentration factor can hence be calculated using finite element model.

Bayesian updating is widely used in probability related studies. It is used to update the belief of existing knowledge (prior) through new information (observation). The updated posterior of a Bayesian updating network is:

$$P(\theta \mid x^{'}) \propto P(x^{'} \mid \theta) P(\theta) \qquad \textbf{Equation 6-42}$$

P(θ) is the prior, which, in our case, is the distribution of *Kt* fitted by the lab data. P(x'| θ) is the likelihood function through observation.

Suppose a few observations of the Kt were made through the field data. And is used to update the Kt distribution. The observation is assumed to follow a normal distribution with mean of 4.2 and variance of 0.35. Markov Chain Monte Carlo (MCMC) method is used to generate the updated distribution samples. **Figure 6-26** shows the updated probability compared with the original one. We can see that the updated value of *Kt* has smaller mean and variance.

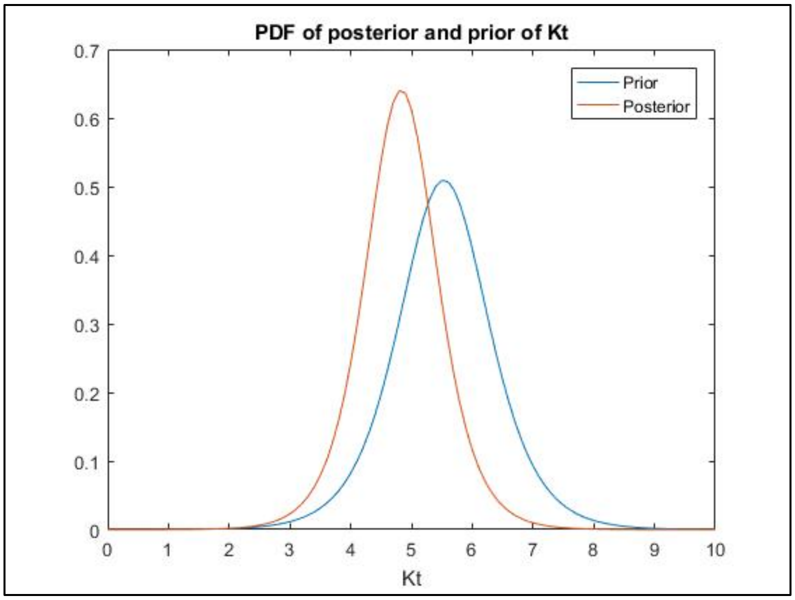


**Figure 6-26. The original and updated probability of Kt**

The updated distribution of Kt is then used into the MC method to generate an updated transition matrix the same way as in the previous section. The updated transition matrix is:

$$\mathbf{P}' = \begin{bmatrix} 0.6068 & 0.3922 & 0.0010 & 0 & 0 \\ 0 & 0.5072 & 0.4726 & 0.0184 & 0.0017 \\ 0 & 0 & 0.3764 & 0.5882 & 0.0354 \\ 0 & 0 & 0 & 0.4098 & 0.5902 \\ 0 & 0 & 0 & 0 & 1 \end{bmatrix}$$ **Equation 6-43**

We assume that the observation was made at the end of the $4^{th}$ time step and the optimized results are shown in Figure 6-27.

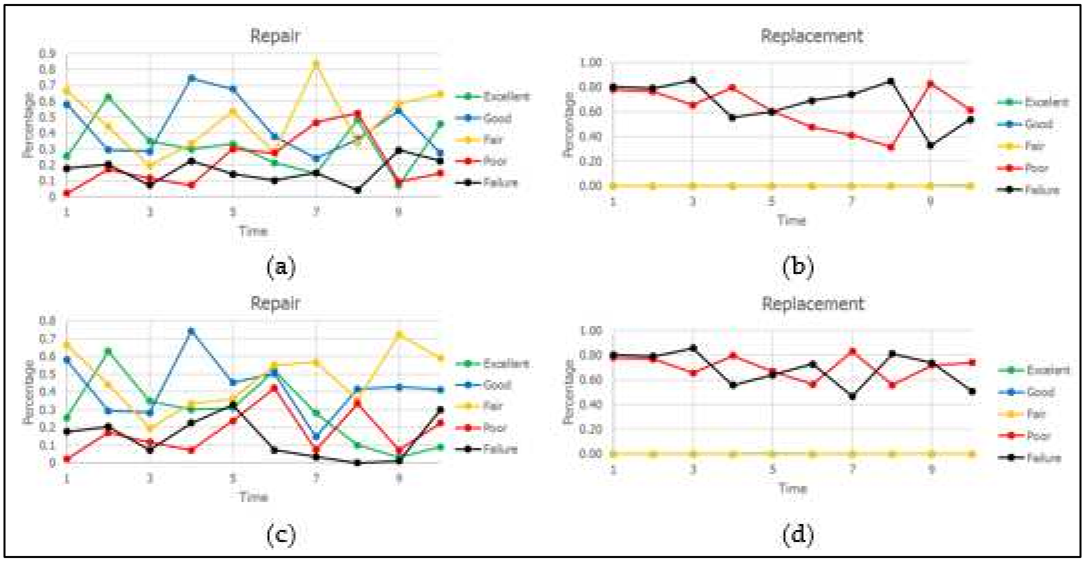


**Figure 6-27. The maintenance plan with updating at the end of the 4th time step (a) and (b), comparing with the plan without updating (c) and (d)**

Figure 6-28 shows the comparison of cost for maintenance with and without updating. As we can see, the cost after updating is reduced. This is due to the reduced uncertainty via the Bayesian updating.

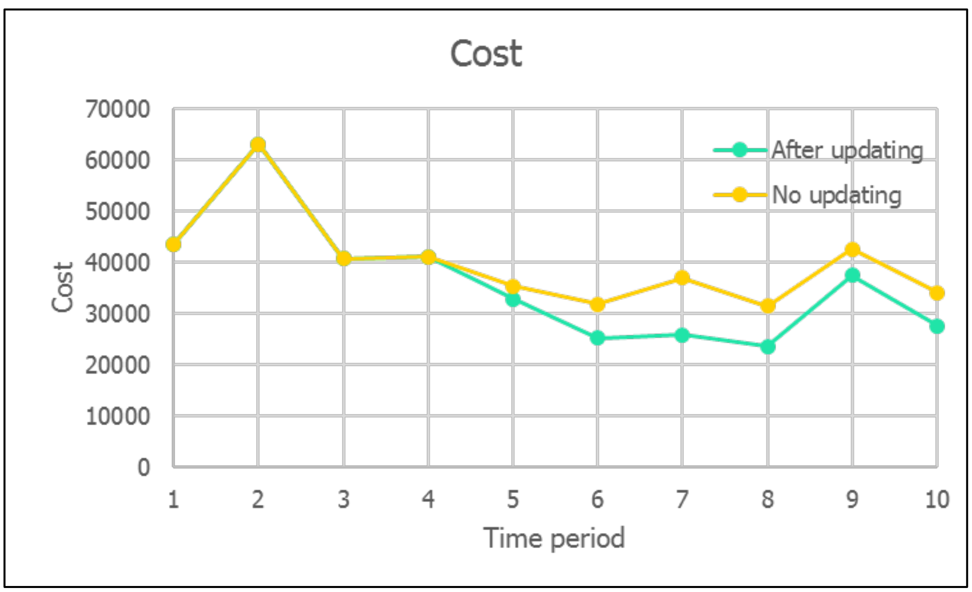


**Figure 6-28. Comparison of cost for maintenance for each period**

Assume that over the 10 maintenance periods, observation was made to continuously update the model parameter *Kt*. Figure 6-29 shows the change in the distribution of *Kt* after each update. As shown in the graph, the variance of the distribution decreased after each update. After each update, the probability transition matrix can be recalculated for the next iteration.

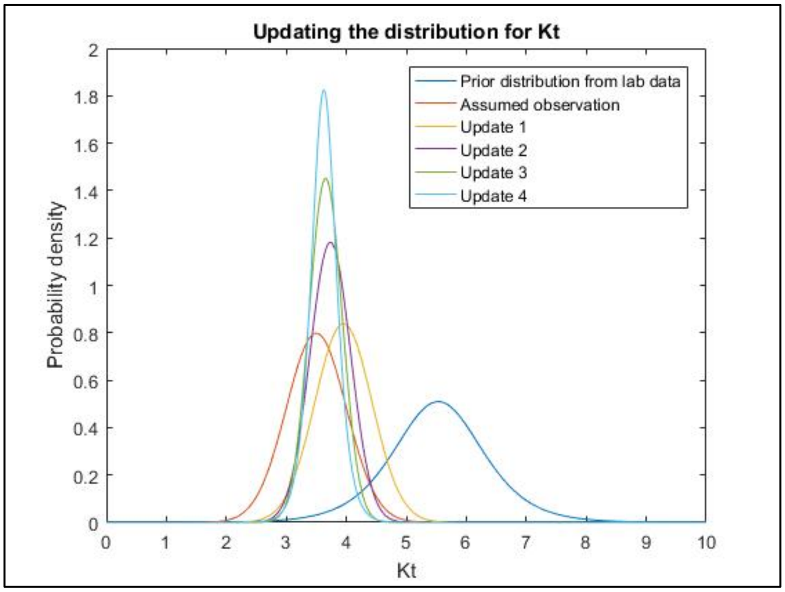


**Figure 6-29. Continuous updating for parameter Kt**

Following the previous example, the effect of continuous updates can be studied. Assume that the updating was done every 2 maintenance periods. Figure 6-30 shows the optimized cost for each period. According to the simulation, it is showing a trend in decrease of cost as more updating were done. The total cost for the 10 maintenance period as the number of updates was shown in Figure 6-31. The curve showed a converging trend was the number of updates increases. This is true because the variance of the parameter Kt is also converging to a very small number according to the Bayesian updating scheme.

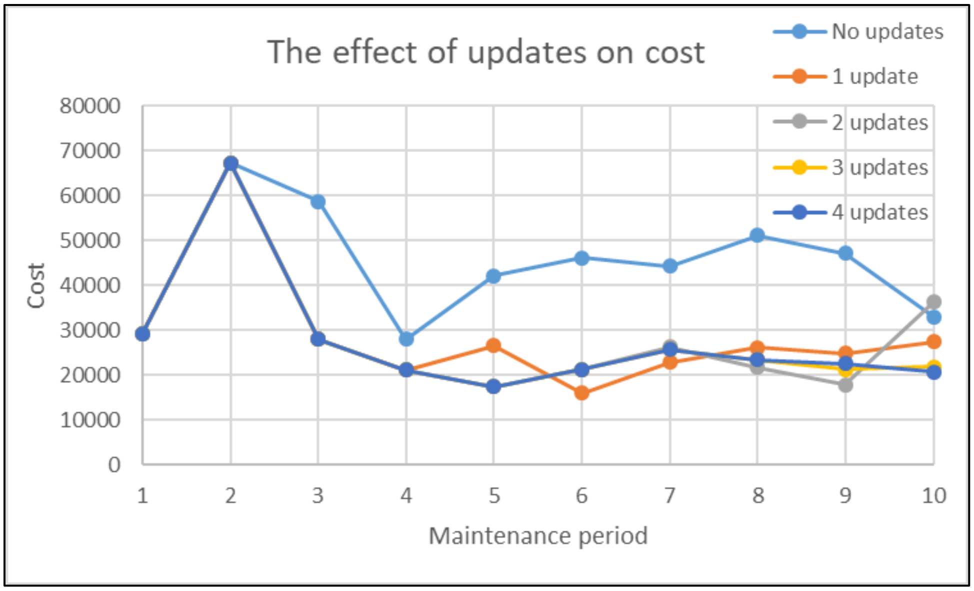


**Figure 6-30. The effect of continuous updates on periodical maintenance cost**

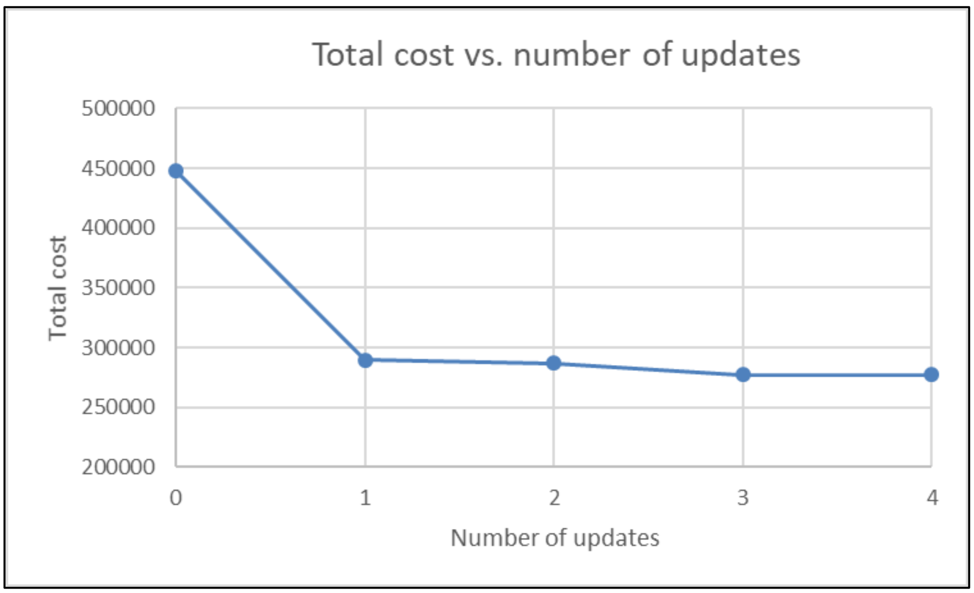


**Figure 6-31. Total cost for maintenance in 10 period vs the number of updates.**

The Bayesian updating framework fused the diagnostic result from the classification with the prognostic model. Dynamic reliability-based maintenance optimization can be achieved with the proposed maintenance framework.

## Maintenance framework conclusion

A condition based maintenance framework were formulated for the maintenance planning of the gas pipeline system. The proposed method categorizes the pipes into different condition stages according to the crack length. The iteration of the condition vector was calculated using the degradation matrix. Given a load and a maintenance period, the degradation matrix can be calculated from the crack growth curve. The optimization was done by limiting the value of the last element in the new condition vector, which indicates the failure probability. The fusion of prognosis with diagnosis is achieved by the real-time Bayesian updating of the model parameters with diagnostic results. The effect of the Bayesian updating reduced the uncertainty in the model parameter. The maintenance framework can also consider the consequence cost according to the location of the system.

### *Conclusions and future work*

Accurate damage detection and classification as well as the remaining useful life prediction of infrastructure such as gas pipelines is important in maintaining the system functionality. A good maintenance plan can reduce the failure probability and ensure the infrastructure is always in working condition.

The study proposed a non-destructive damage detection method based on optical image. A device with an endoscope camera and a structured light projector was used to recode video/photo frames along the pipe. The inner surface of the pipe can be reconstructed in 3D via the video. Then, the defects in the pipe can be isolated and geometric features can be calculated. These features were put into a Naïve Bayes classifier for classification. The accuracy can be as high as 90% for the simulated data, which is comparable to more advanced machine learning algorithms such as Neural Network. The actual test was performed with the prototype device from cooperating institute. Due to the disadvantage of the prototype device and algorithm, the classification result was around 77%.

A novel BEN as a classifier was proposed to enhance the classification accuracy. It combines the maximum entropy method with Bayes' theorem to encode additional information into the network. The extra knowledge about a feature would enable a fast learning for the network. The presented work showed detailed derivation for extra knowledge given in the form of moment constraint. A special case for a Gaussian node with first order moment constraint were analytically derived. A simple example showed that the BEN classifier performs better than the NB when the training size is small and the accuracies converged as the training size increased. This is because that when large number of data is available, the trained network will be closer to the ground truth, hence the effect of the constraint may become negligible.

A simple model for the creep crack growth prediction in polymer materials were developed. The model used a power law equation and considered the damage in pipes as stress risers. The model was calibrated and validated with the lab data provided by GTI. With some proper assumptions, the model prediction agrees with the data well. Due to the stochastic nature of the crack growth process, uncertainties were introduced as the random distribution for the model parameters. The RUL of the material can be analyzed in a probabilistic sense. Monte Carlo method is used for the calculation of failure probability given a stress level and current stage.

A condition based maintenance framework were formulated for the maintenance planning of the gas pipeline system. The proposed method categorizes the pipes into different condition stages according to the crack length. The iteration of the condition vector was calculated using the degradation matrix. Given a load and a maintenance period, the degradation matrix can be calculated from the crack growth curve predicted. The optimization was done via genetic algorithm by limiting the value of the last element in the new condition vector, which indicates the failure probability, and minimizing the overall cost. A weighing factor were added to consider the consequence of failure in different location. The result showed that more money will be spent in maintaining the functionality in areas with high consequence costs.

The fusion of prognosis with diagnosis is achieved by the real-time Bayesian updating of the model parameters with diagnostic results. According to the image analysis, the damage type and the dimension measurement of the damage can be possible. This information is used to update the parameters' distributions in the creep crack growth prediction model. The updating process can reduce the uncertainty in the model, hence change the degradation matrix in the maintenance framework. A demonstration example showed that the updating process can decrease the uncertainty in the model, hence increase the prediction accuracy of the crack growth behavior. This could help the maintenance planning to reduce the unnecessary costs or avoid unwanted failure. The information fusion between diagnostics and prognostics can achieve a more accurate risk assessment and maintenance planning.

### Future work

The presented work meets the goal in the proposal statement. Some additional work can be done to enhance and further develop the results in this study:

1) The algorithm for the image reconstruction can be adjusted. The camera needs to be calibrated so that it can calculate the coordinate of the patterned light relative to the camera. With a calibrated camera, the size of the damage can also be known which is useful in the proposed dynamic maintenance framework. The dimensional information could be used to update the stress concentration factor and hence update the maintenance plan.
2) Although the proposed creep prediction model agrees well with the experimental data, there still exists some bias from the lab data. Further demonstration is needed if there were additional data available from GTI.
   The ductile group in the data set was not used, but a trend of smooth transition can be observed in the data point plot (Figure 6-15) from ductile data to SCG data. An

asymptotic function regarding yield strength of the material can be modeled for the slope of the regression curve. This would need further research and justification.

3) The maintenance framework is flexible in solving the maintenance planning given different conditions (minimize cost given reliability constraint and optimize reliability given budget constraint). The computational cost would be enormous when applied in large scale systems with various groups of pipes. The underlying principle when dealing with large scale optimization is to be studied. The maintenance framework may need to be adjusted for the high dimensional problem.
4) The proposed Bayesian entropy network (BEN) as a classifier can achieve fast learning with the extra information. The BEN concept can also be used in updating probabilities. The first step is applying the network in the updating of the parameters in the creep crack prediction model. The BEN can also be applied into large scale systems. In a large network, the update of one parameter would affect the nodes in the whole system. Sometimes this effect is not wanted. With the additional constraint, the BEN updating can be more accurate and efficient than traditional Bayesian network updating.

   Sometimes, there could be a bias between the expert opinion (empirical information) and the ground truth. Once the wrong information were coded into the network, instead of increasing the inference accuracy, it would degrade the performance of the network and even damage the whole system. Since the constraint in a BEN framework is strong, an adaptive BEN is needed to compensate this situation. The adaptive network would use the given constraint when there is not enough data to update the belief. But would change to the truth from data when more observation become available. This could be understood as when there is limited information, the network chooses to believe experience, but shifts its belief to the truth brought by data when more evidence become available.
5) The current framework focuses on one failure mode of plastic pipelines (slow crack growth). Information fusion and big data analytics with multiple failure modes and large systems that can integrate with the ongoing development of GTI framework needs further development. The “agent” serving for different failure types will need to automatically fused together for a consistent risk assessment. Recent advancement in artificial intelligence (AI) such as deep network learning has the potential for diagnostics and prognostics for gas pipeline industries.

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## 7. Enterprise Decision Support System (EDSS) Framework

Natural gas distribution companies with significant mileage of vintage plastic piping (specifically Aldyl A) in their distribution systems are faced with challenges in identifying segments of pipe that are at high risk of failure. This is due to several interacting factors that increase the likelihood of Slow Crack Growth (SCG) occurring. It is essential to correctly assess the fitness for service of the system as a whole, and locally where risk factors may be higher than the system's average. A holistic approach to identifying interacting factors through pipeline inspection and the development of risk models to integrate the effects of interactions and provide meaningful input into fitness for service determinations and potential mitigative strategies is needed.

In this project, an integrated set of quantitative tools were developed to support enterprise decision making process to reducing operational risk in vintage plastic distribution systems susceptible to SCG failure. The toolset allows operators, regulators and utilities to apply science and engineering methods on a variety of data sources related to pipeline distribution for fitness of service evaluation, calculate threat severity levels, and continuously monitor threat interactions and flag concerns at trigger points. The data sources may contain available system information including external conditions, inspection and leak records, historic data, customer data, and subject matter expertise.

The enterprise decision support system consists of risk models developed with Bayesian network and semantic ontology, and smart forms for field data collection. Ontology describes domain knowledge and is designed by subject matter expert to model the threat interactions. Bayesian network is ideally suited for evaluating interacting threats, investigating root causes, and predicting the effect of mitigation strategies based on conditional probabilities calculated from available data. It calculates of the probability of failures of plastic pipes and classifies them into various risk levels. The risk assessment also includes a probabilistic estimate of the remaining effective lifetime of individual segments of vintage plastic pipe. Smart forms are mobile based data collection forms that ask operators "smart" questions needed to gather relevant information for improved threat identification and risk assessment process. Specifically, a smart form captures detailed and quality data required for more granular risk analysis, such as the identification of vintage plastic pipelines with higher risks.

## Introduction

Many pipeline incidents are the result of multiple, interacting causes, not a single threat. Individual threats can each be at "acceptable" levels but when overlaid result in a significant threat to the pipeline or even a failure. In this project, we are developing an enterprise decision support system platform powered by Bayesian network and semantic ontology that models the interactions between factors leading to threats or failures. Ontology describes domain knowledge and is designed by subject matter expert. Bayesian network allows calculation of the probability of failures and classification of them into various categories based on risk levels. It is ideally suited for evaluating interacting threats, investigating root causes, and predicting the effect of mitigation strategies based on conditional probabilities calculated from available data. This assessment will include a probabilistic estimate of the remaining effective lifetime of individual segments of vintage plastic pipe and a yes/no determination of whether a short-term pressure test is capable of validating the maximum defect size in the system.

## *Probabilistic Decision Support System Design*

### Semantic Ontology

Semantic Ontology provides a formal, explicit specification of a shared conceptualization of a domain. It defines the concepts and entities involved, as well as the relationships between them in an application. It also facilitates knowledge sharing over heterogeneous applications. A subject matter expert may initially guide the development of ontology that provides the domain knowledge to combine the data from different sources. Ontologies serve as vocabulary in a complex environment.

In this work, we have represented subject matter expertise of pipeline threats in ontological format. **Figure 7-1** illustrates an example of such an ontology describing interactions between factors contributing to threats in vintage pipelines. Some of the factors are residual stress, wrinkle bends/miter bend, fabrication/weld quality, third party damage, external corrosion, internal corrosion, stress corrosion cracking, soil and other superimposed stresses, and unknown, hidden, incorrect operations threats.

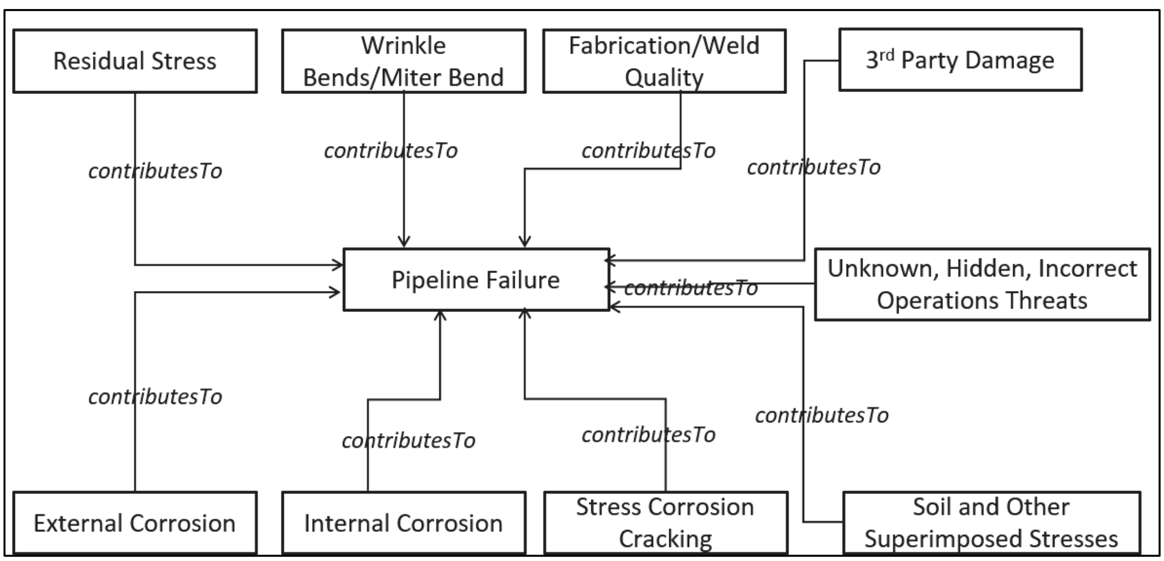



**Figure 7-1. Example of ontology representing threats leading to pipeline failure**

We followed an ontology design standard called *Event-Model-F* which gives a formal model of events. Event describes an action at a certain time and location. The model is based on the foundational principles of ontology and provides comprehensive support to represent time and space, objects and persons, as well as causal and correlative relationships between events. **Figure 7-2** is an ontology of failure events described by using a combination of causality and observation patterns. It represents cracked gas pipeline event leading to the gas leakage event which is reported by an operator.

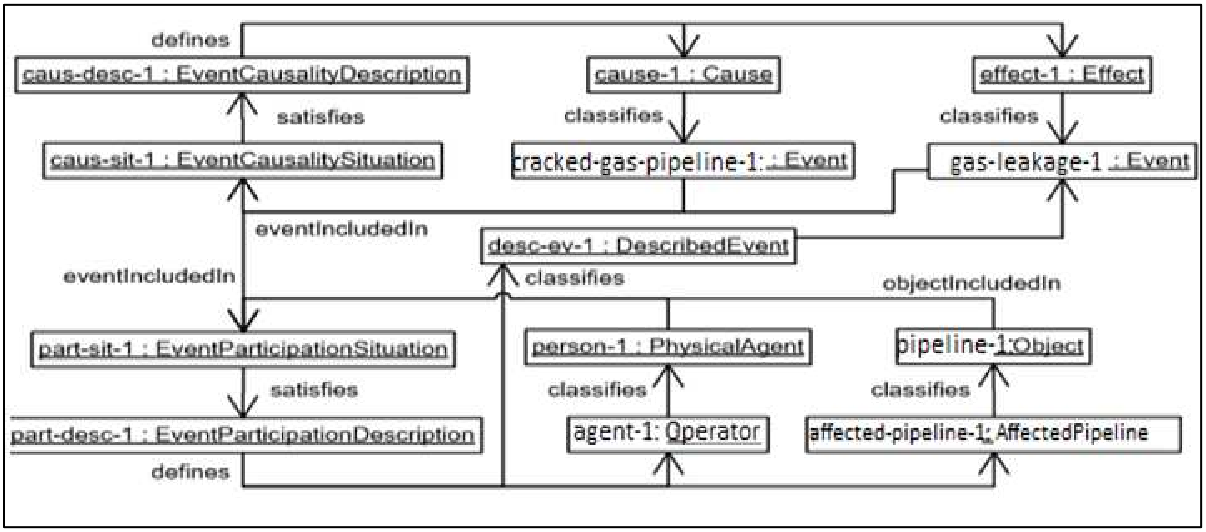



**Figure 7-2. Illustration of ontology describing causality in gas distribution pipeline**

**Figure 7-3** is an example ontology modeling the pipeline risk computation using statistical model, subject matter expertise, historical observations, and Bayesian network.

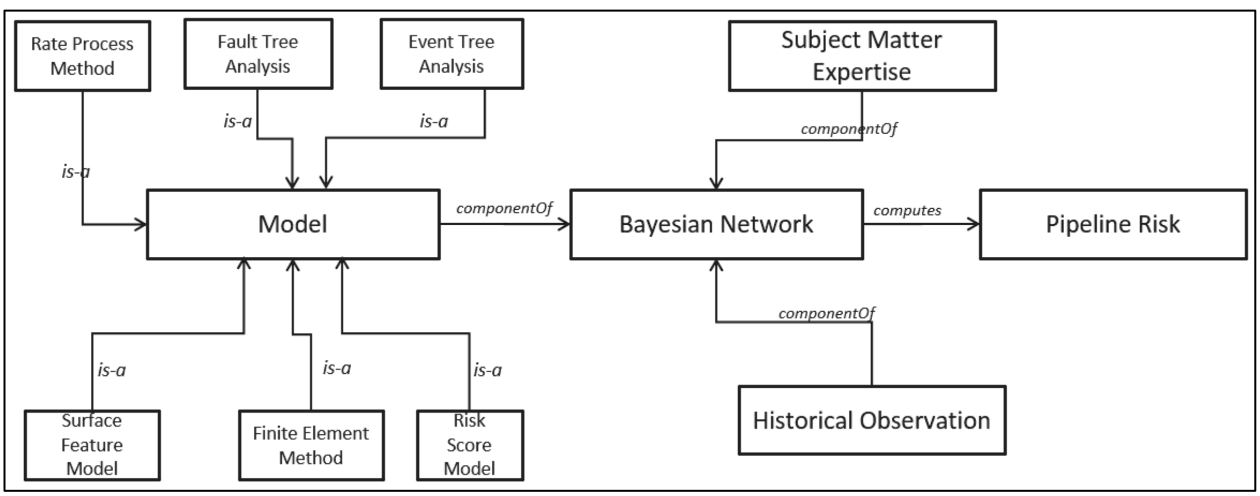



**Figure 7-3. Ontology describing the models, subject matter expert's knowledge, historical observation, and Bayesian network**

Bayesian foundational ontology framework was developed in collaboration with SmartCloud, Inc. to provide a probabilistic modeling approach to build domain and application knowledge. It is difficult to express incomplete, partial or uncertain knowledge in a traditional ontology. The concepts of Bayesian network model were added to the conventional ontology standard. The extended ontology follows the foundational principles of ontology and provides comprehensive support to represent time and space, objects and persons, as well as causal and correlation relationships between events. Bayesian foundational ontology incorporates the notion of nodes, edges, states, and node probability tables as illustrated by **Figure 7-4.**

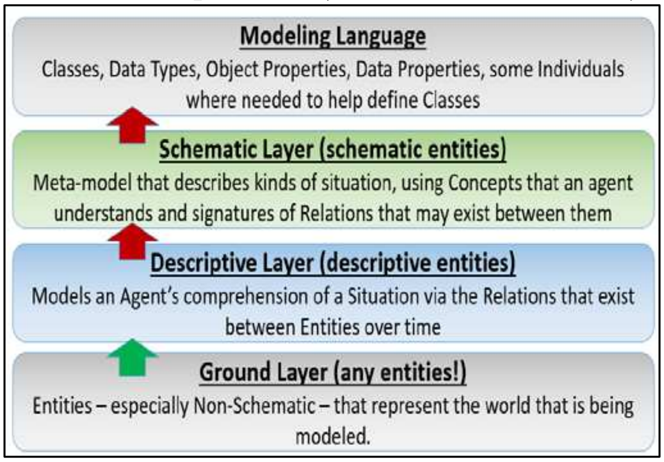



**Figure 7-4. Bayesian foundational ontology**

A conventional ontological approach such as in **Figure 7-5,** on the other hand, lacks the concepts needed for a Bayesian network model.

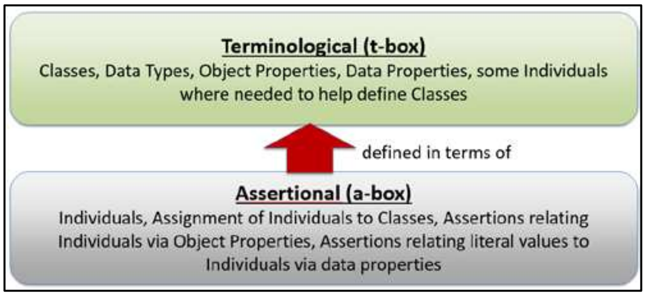



**Figure 7-5. Conventional ontology**

## Probabilistic Enterprise Decision Support System

Probabilistic Enterprise Decision Support system (EDSS) enables operators, regulators and utilities to apply science and engineering methods on heterogeneous data sources related to pipeline distribution for fitness of service evaluation. The data sources may contain available system information including external conditions, inspection and leak records, historic data, customer data, and subject matter expertise. EDSS has models that calculate threat interaction levels and their severity. It provides a method to continuously monitor threat interactions and flag concerns at trigger points.

The conceptual design of EDSS is given below in **Figure 7-6** and **Figure 7-7**.

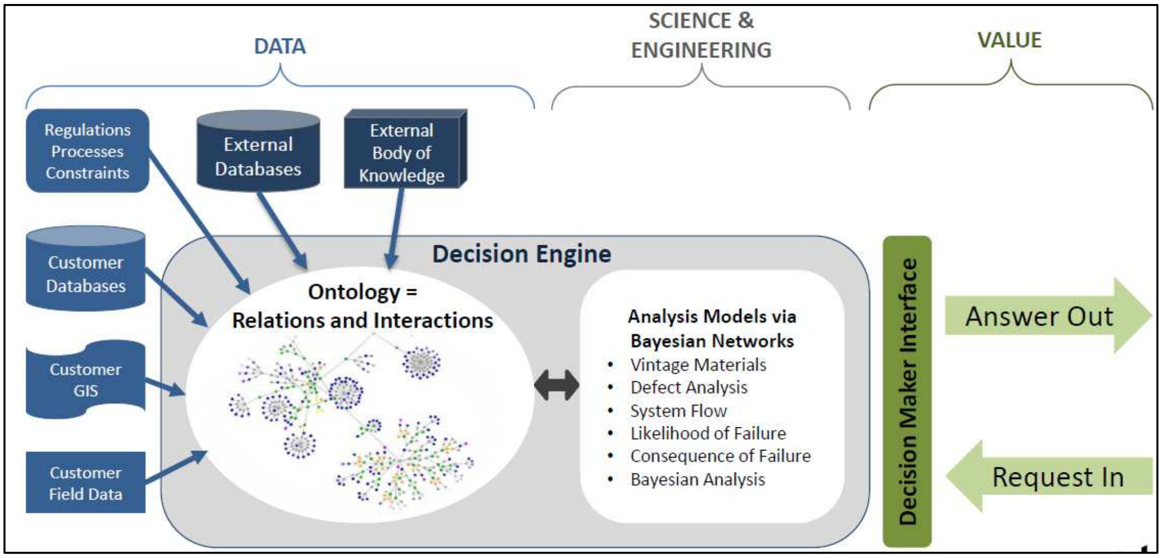



Figure 7-6. Conceptual design of Enterprise Decision Support System

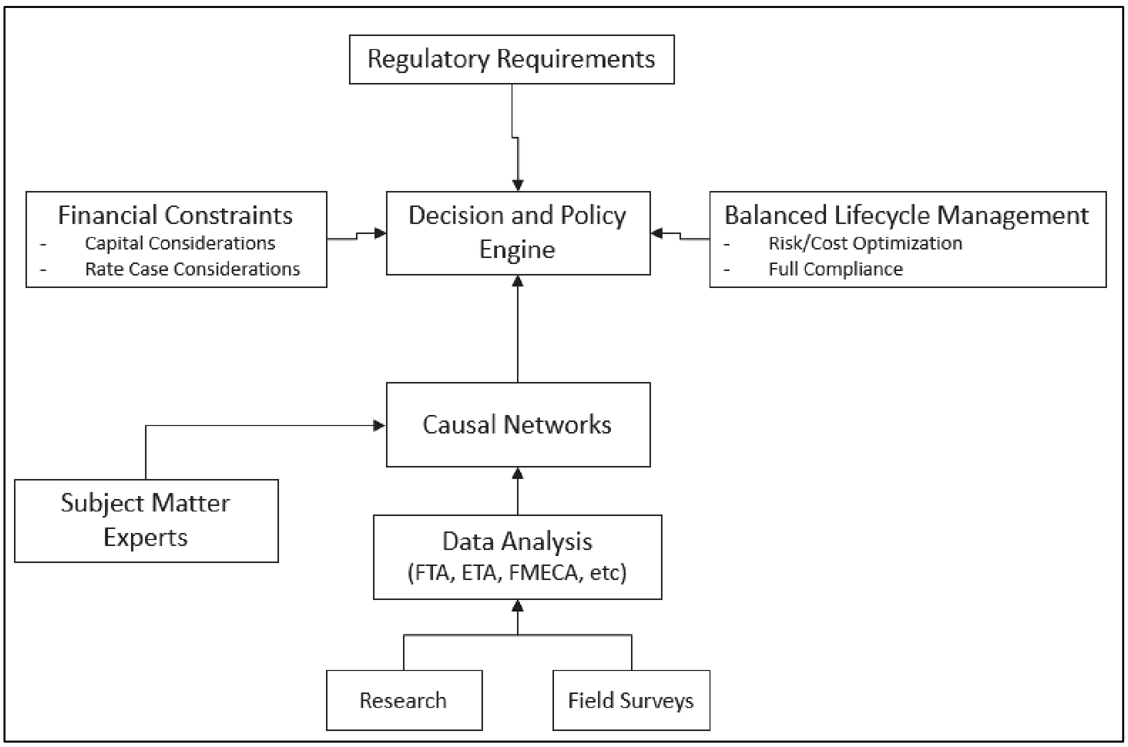



Figure 7-7. Regulations and Standards guiding decision making process in EDSS

The UML use case diagram of the EDSS is given in **Figure 7-8.** Operators, Regulators, Utilities and Subject matter experts are the stakeholders in EDSS.

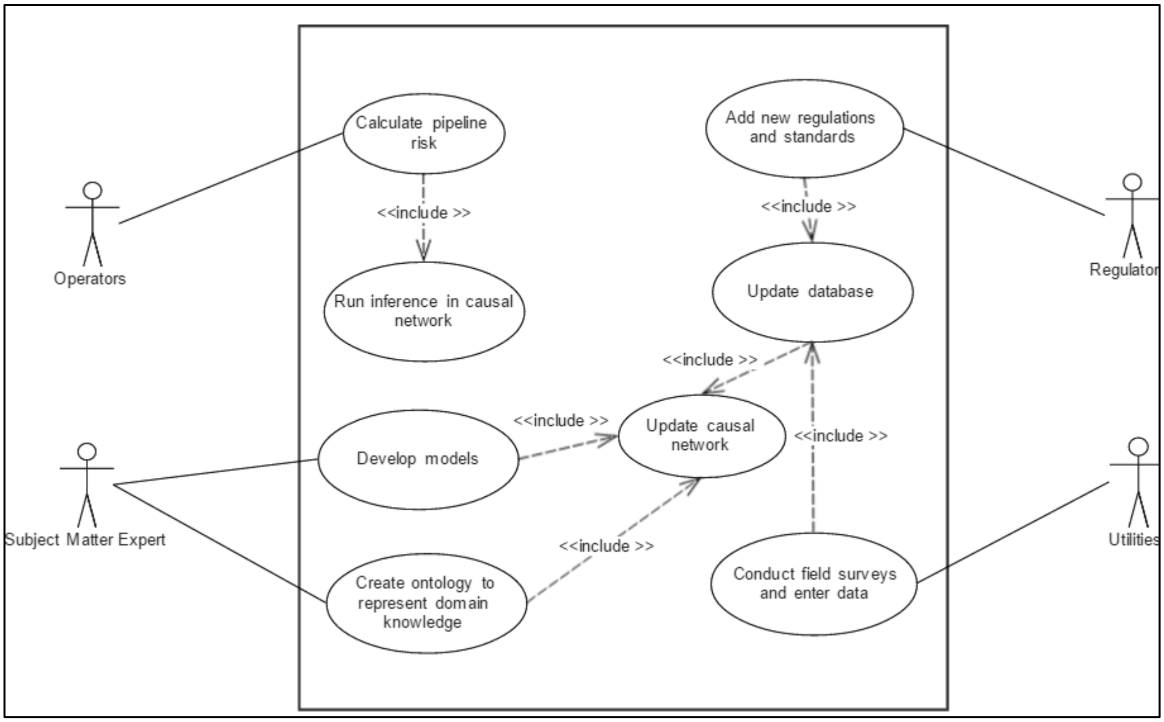



**Figure 7-8. Use case diagram of EDSS**

We now show the Software-as-a-Service architecture of the EDSS platform in **Figure 7-9** and **Figure 7-10**. It is a real-time, cloud-based scalable system hosted in Microsoft Azure. The heterogeneous dispersed data are stored in its big data source and semantically enabled models are deployed into the EDSS platform. EDSS is being built with open-source technologies mostly licensed under Apache 2.0 license. Two open standards have been identified for data communication in and out of EDSS: resource description framework (RDF) and JSON-LD (JavaScript Object Notation for Linked Data).

- RDF is a language for representing semantic information about objects in the World Wide Web. It is a graph based data model which provides grammar for its syntax and supports query against the model. Several design tools, including Protégé, are available for designing RDF ontology. Due to the availability of design tools and ease of usage, we have selected RDF as an ontological standard to represent subject matter experts' knowledge.
- JSON-LD is a specialized RDF syntax. As JSON-LD is also JSON document that represents an instance of an RDF data model, it fits well with the schema- less NoSQL database. Therefore, we have selected JSON-LD as communication standard between applications or models.

ISO 19465/AMQP 1.0 has been identified as an appropriate open standard messaging protocol for EDSS to efficiently transfer information within and between utilities or government agencies. It enables cross-platform applications to be built using brokers, libraries and frameworks from different vendors. AMQP 1.0 is supported in Microsoft Windows Azure and Redhat Linux operating systems. Some of its early backers are US Department of Homeland Security, Microsoft Corporation, VMware Inc, Cisco Systems, Mitre Corporation, Bank of America, Goldman Sachs, etc.

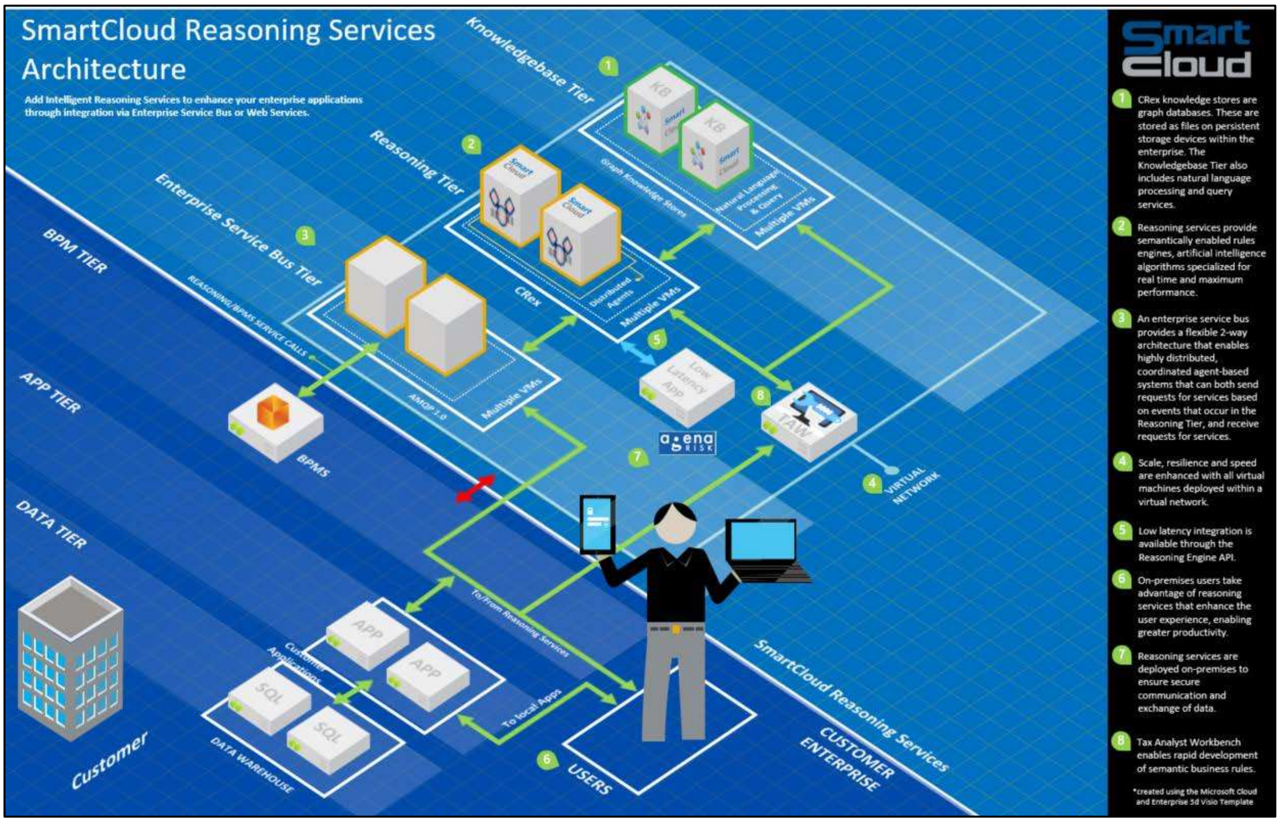



**Figure 7-9. 3rd party integration of EDSS platform in their services**

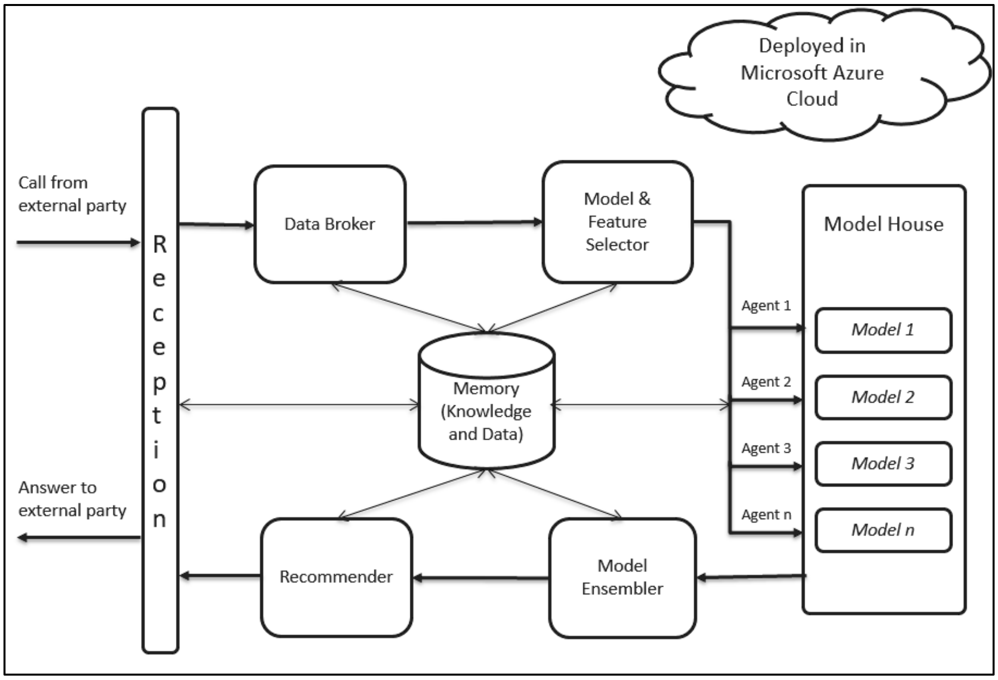



**Figure 7-10. Architecture of Enterprise Decision Support System**

There are nine components of EDSS platform.

*Reception*: It is ISO 19464/AMQP 1.0 standard communication bus which interacts with external services. It accepts queries and data as input and returns the result of causal Bayesian inference.

*Data broker*: It fetches information from the database. An ontological method will facilitate such data fetch.

*Database/Memory*: Big database technologies such as NoSQL, Graph database and Apache Hadoop are used as the database technology. NoSQL and graph database overcome the limitation of structured relational database systems by allowing schema-less data. Consequently, a variety of data in any form such as customer GIS, customer database, regulatory requirements, standards, constraints, events, sensor logs, etc are supported within the same data store. Apache Hadoop will be used as a data warehouse to ultimately store the data which may be used for analytics in future.

*Model and feature selector:* It performs two tasks. First, relevant single or multiple models are selected based on the query and data. Second, it identifies the important features and selects them from data by performing statistical analysis.

*Model:* A model is a description of the system using mathematical concepts and language. Examples of models are Bayesian network, neural network, fault tree analysis, event tree analysis, surface feature model and finite element method, etc. Models developed with any of the programming languages such as JAVA, R, MATLAB and Python are supported.

*Model House*: It stores a collection of models. Graphical processing unit and central processing unit provides scalable and distributed cloud computing power to the models as required, thus supporting simple mathematical model to compute intensive image processing models.

*Agent*: An agent is an autonomous entity which observes events in an environment and directs its activity towards achieving goals. Each model has its own dedicated agent. The agents execute models asynchronously in parallel. In addition, it prepares data in specific format for the selected model and pulls parameter values for models from memory.

*Model Ensembler*: It uses multiple learning algorithms to obtain better result than could be obtained from any of the constituent models. It decides the best solution from the results of multiple models.

*Recommender*: It formats the final result in an appropriate format and logs that information in memory.

The design of EDSS platform as a Software-as-a-Service (SaaS) enables it to communicate with other enterprise or government applications, thereby increasing its usability and a value addition to utilities, operators, regulators and public.

### Data Entry

"Smart form" was designed and developed for data entry purpose. Smart form is an electronic form with capability beyond a traditional data entry interface with a fixed schema. The fields in the form are generated dynamically based on the content and context of the data entered so far. Subject matter expertise, represented as ontology, guides the process of data entry. It will guide the operator through the relevant data gathering stages and ensure only valid and relevant data is fed directly into the appropriate models. It is designed to overcome human data entry errors, which are the most common source of bad data, and to collect as much complete data as possible.

### Simulation

EDSS platform provides a set of toolsets for simulation and modeling **Figure 7-11**. It has access to heterogeneous big data sources including simulated test data, manufacturers' data, field failure data, research reports, academic literature, standards and regulations, and subject matter expertise. Operators or analysts may run simulation with models that include application specific handbook models, probabilistic risk models, and calculators. Multiple competing models may be deployed and run in parallel to evaluate the results.

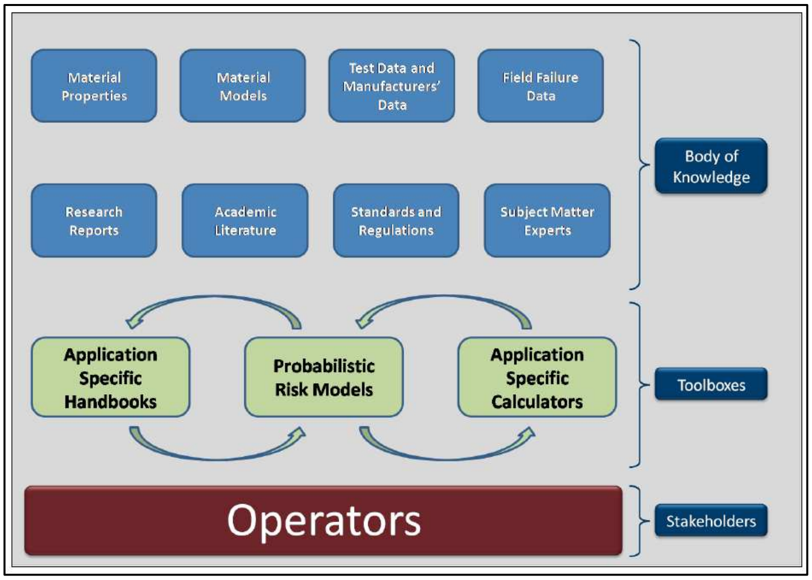



**Figure 7-11. Simulation model toolboxes with access to heterogeneous data sources**

## Insights Interface

Insights interface **Figure 7-12** is designed as a web-based dashboard that operators or regulators can configure to gain key insights into the information they want including vital details about the data, regulations and standards. Furthermore, it allows users to select multiple risk models, enter parameters, and run them in parallel to display the comparative results as graphs and visuals.

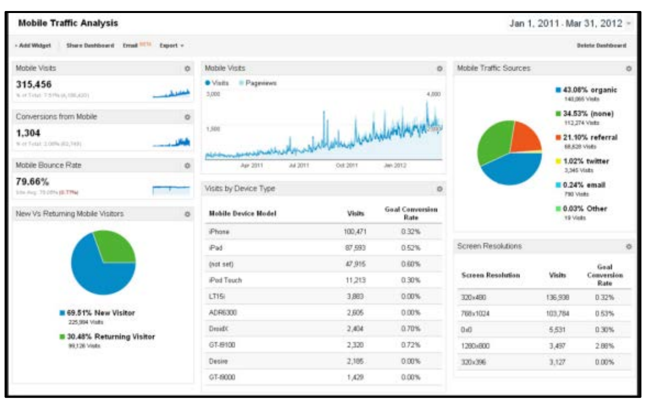



**Figure 7-12. Mockup version of insights interface dashboard**

## Query

A query is a request for information from the EDSS system. In this work, four different types of queries are supported – diagnostic query, predictive query, inter-causal query, and combined query. **Figure 7-13** illustrates these four types of query.

a. *Diagnostic query* performs reasoning from effects to cause. For instance, the questions such as - determine the stress concentration and temperature that reduces the pipeline life expectancy by ten years – may be answered with diagnostic query.
b. *Predictive query* performs reasoning from cause to its effects such as "what is the change in pipeline life expectancy for an increase in stress concentration by 50 psi?"
c. *Inter-causal query* involves reasoning about the mutual causes of a common effect.
d. *Combined query* provides a flexible reasoning to find intermediate results of diagnostic and predictive query.

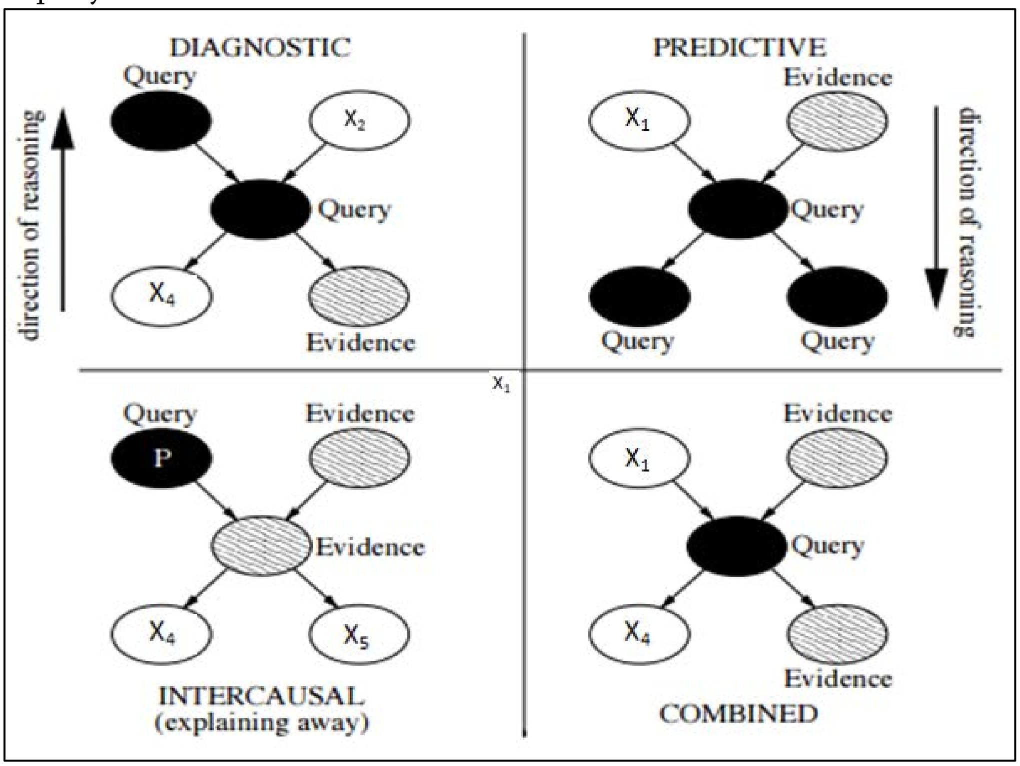



**Figure 7-13. Supported Query Types**

## Data Communication

**Figure 7-14** illustrates the data flow between user interface, database, and model modules. The data is communicated between these modules in a JavaScript Object Notation (JSON) format. JSON is a lightweight data-interchange format that is built on two structures:

- A collection of key/value pairs, similar to a dictionary entry.
- An ordered list of values

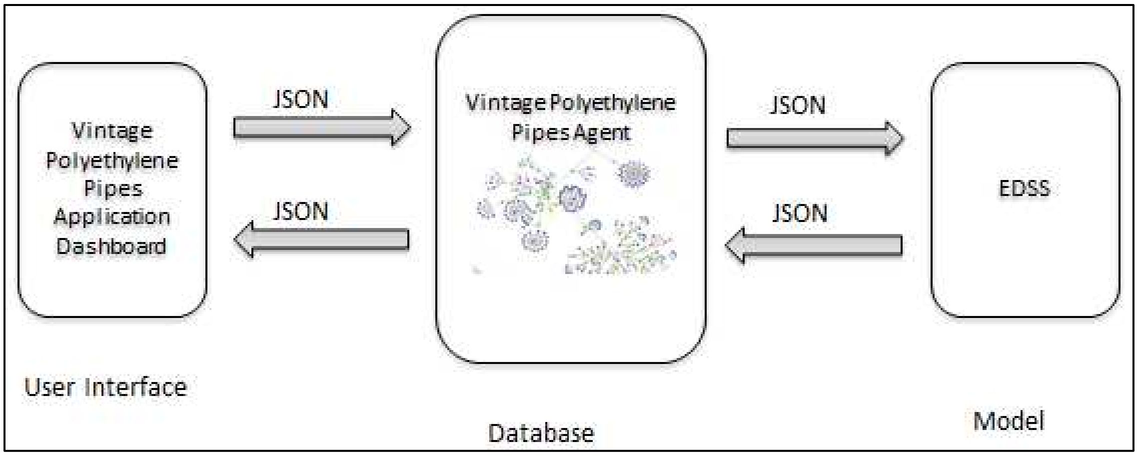



**Figure 7-14. Data flow between user interface, database, and model modules in EDSS**

The template of a generic JSON message developed is given below. It is used to initialize, update, and query the Bayesian network in the EDSS.

*JSON message* = {

```
                    “app”: “”,
                    “operation”: “”,
                   “bNodes”:[
                       //categorical ranked/unranked; Boolean; discrete node
                       {
                           “bName”: “”,
                           “bType”: “”,
                           “bNPTType”:””,
                           “bParents”: [],
                           “bNPT”: {
                               “bNPTValue”:[
                                       {
                                               “bNPTState”:””,
                                               “bNPTStateValue”:0.0
                                       }
                               ]
                           },
                           “bStates”: []
                       },
                       //continuous interval node with expression representation of NPT
                       {
                           “bName”: “”,
                           “bType”: “”,
                           “bNPTType”:””,
                           “bParents”:[],
```

“bNPT”:{
“bNPTExpressionType”:””,
“bNPTValue”:[{
“bNPTMean”:0.0,
“bNPTVariance”:0.0
}]
},
“bLower”:0.0,
“bUpper”:0.0
},
//continuous interval node with partitioned expression representation of NPT
{
“bName”: “”,
“bType”:””,
“bNPTType”:””,
“bParents”:[””,””],
“bNPT”:{
“bNPTExpressionType”:””,
“bNPTValue”:
[
{
“bNPTParentState”: {“bNPTParent”:””, “bNPTState”:””},
“bNPTArithmenticEquation”:””
},
{
“bNPTParentState”: {“bNPTParent”:””, “bNPTState”:””},
“bNPTArithmenticEquation”:””
}
]
},
“bLower”:0.0,
“bUpper”:0.0
}
]
}


The fields in the JSON message are -

1. app - Name of the application

*Type*: String
*Required*: True

2. operation – Operation type

   *Type*: String
   - INITIALIZE
   - QUERY
   - UPDATE

   *Required*: True

3. bNodes – List of nodes

   *Type*: JSON
   *Required*: True

4. bName – Name of node

   *Type*: String
   *Required*: True

5. bType – Type of node

   *Type*: String
   - *BOOLEAN*
   - *CONTINUOUS*
   - *DISCRETE*
   - *INTEGER-INTERVAL*
   - *CATEGORICAL-RANKED*
   - *CATEGORICAL-UNRANKED*

   *Required*: True

6. bParents – Parents of a node

   *Type: String array*
   *Required*: True

7. bNPTType – Type of node probability table

   *Type*: String
   - *NUMERIC*
   - *EXPRESSION*
   - *PARTITIONED*

*Required*: True

8. bNPT – Node probability table

   *Type:* JSON

   *Required*: True

   //categorical ranked/unranked;  boolean; discrete node

```
"bNPT": {
        "bNPTValue":[
        {
                "bNPTState":"",
                "bNPTStateValue":0.0
            }
    ]
}
```

   //continuous interval node with expression representation of NPT

```
"bNPT":{
        "bNPTExpressionType":"",
        "bNPTValue":[{
            "bNPTMean":0.0,
            "bNPTVariance":0.0
        }]
    }
```

   //continuous interval node with partitioned expression representation of NPT

```
"bNPT":{
        "bNPTExpressionType":"",
      "bNPTValue":
    [
            {
                "bNPTParentState": {"bNPTParent":"", "bNPTState":""},
                    "bNPTArithmenticEquation":""
            },
            {
                "bNPTParentState": {"bNPTParent":"", "bNPTState":""},
                    "bNPTArithmenticEquation":""
            }
        ]
}
```

9. bStates – States of a node

   *Type: String array*

*Required*: No (except in categorical and Boolean node types)

10. bLower – Lower range of a node

    *Type:* Decimal
    *Required*: No (required in Continuous, Discrete, Integer interval node types)

11. bUpper – Upper range of a node

    *Type:* Decimal
    *Required*: No (except in Continuous, Discrete, Integer interval node types)

## Probabilistic Decision Support System Development

### Smart Form

Smart forms are the data acquisition forms generated automatically from ontologies, and are useful in aggregation of the semantically enriched input gathered through these forms to feed into EDSS. The smart forms developed in this project are keyhole data gathering form, first response form and audit form. The architecture of smart forms is shown in **Figure 7-15**.

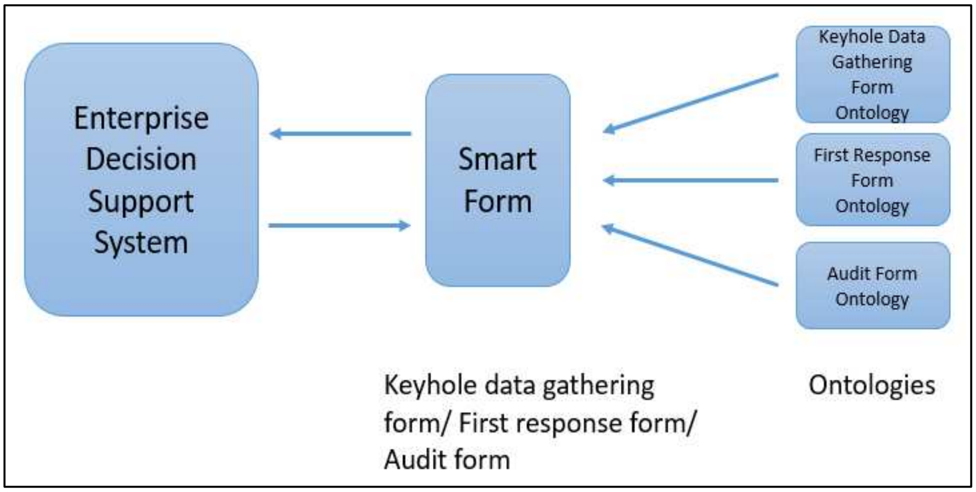



**Figure 7-15. Basic Workflow Architecture of Smart Forms**

Smart forms has inbuilt logic to improve the data collection process and identification of the root cause during the pipeline repair process. The logic provides "smart" questions and answer options to guide the user through the process of determining the root cause to ensure that the correct root cause is identified and appropriate supporting information is provided. The smart form logic and definitions can be integrate into utilities existing field data collection forms. A smart form improves the quality of data collected during the repair process and leads to improved threat identification and risk assessment for DIMP. Further, a smart form allows more detailed information to be captured to allow more granular analysis performed, such as the identification of key threat trends.

The use of "other" or "Not Available" during leak root cause investigations limits the ability of operators to understand trends, threats, and risk. Data collection programs such as CGA's DIRT, Plastic Pipe Data Committee, and PHMSA routinely publish reports with between 10% and 60% of root causes listed as "other" or "Not Available". The developed approach improves the data quality and ultimately the ability of the industry to identify and respond to threats in a timely manner.

## Methodology

### *Root Cause Analysis Process*

#### Fault Tree Analysis

FTA[8] is an ideal method for breaking the data gathering process into logical steps **Figure 7-16** and . The top gate is the fault condition and a series of and/or gates define the sequence of conditions that lead up to the fault condition. The lowest level gates can be viewed as the root cause at the desired level of granularity (the root cause may not be fully resolved).

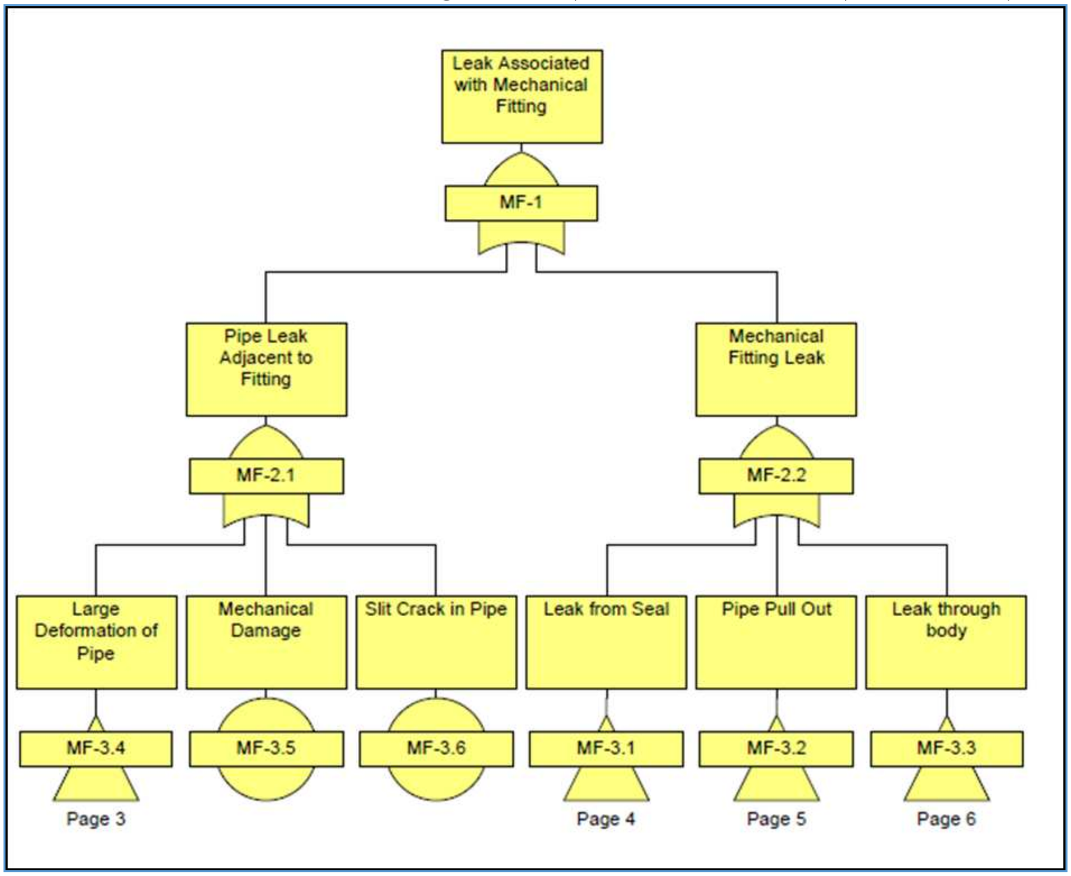



**Figure 7-16. Example of a fault tree**

A complete fault tree analysis, as depicted in **Figure 7-17**, can be very large.

---

8 A concise history of the FTA methodology, how it can be used and the advantages of the method is presented in Wikipedia: "http://en.wikipedia.org/w/index.php?title=Fault_tree_analysis&oldid=628258471"

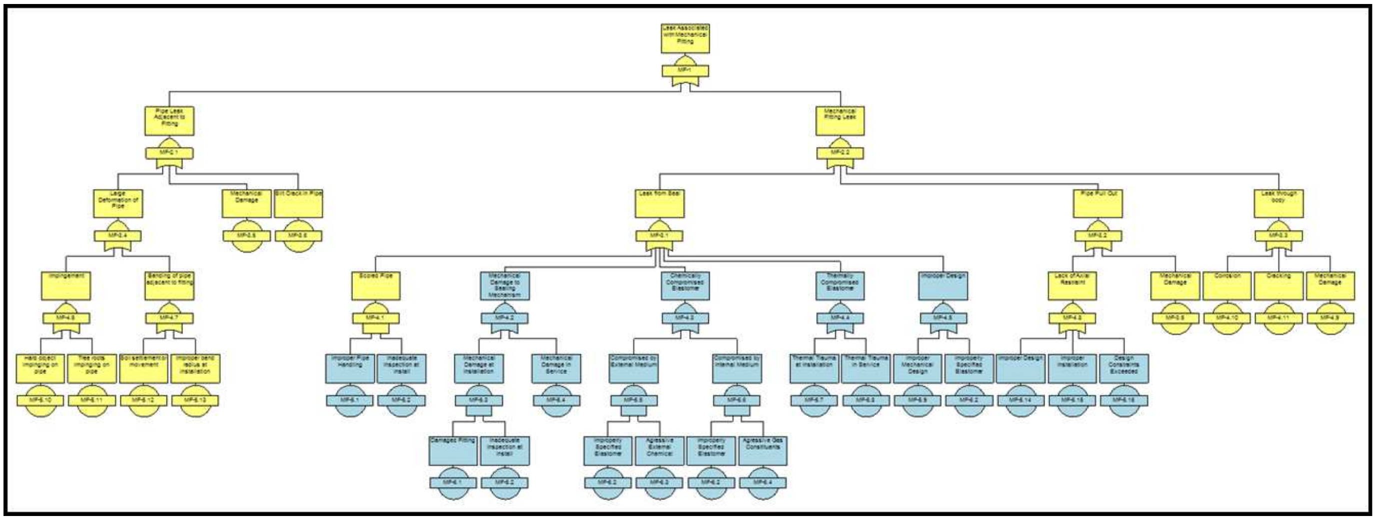


**Figure 7-17. Full FTA for leaks associated with mechanical fittings**

Some portions can be readily diagnosed and resolved in the field (those nodes depicted in yellow in Figure 7-17). The nodes depicted in blue will likely need a separate and more expert investigation to be properly resolved.

In order for the RCA process not to become an unwieldy, we need to come up with methods to break analysis into digestible portions. This is easily accomplished by converting the fault tree into a Decision Tree.

## Decision Tree

A Decision Tree[9] is a very convenient flowchart like graphical depiction of an algorithm where the pathways from root to leaf depict classification rules **Figure 7-18** and **Figure 7-19** .

9 A concise description of Decision Tree is presented in Wikipedia: http://en.wikipedia.org/wiki/Decision_tree

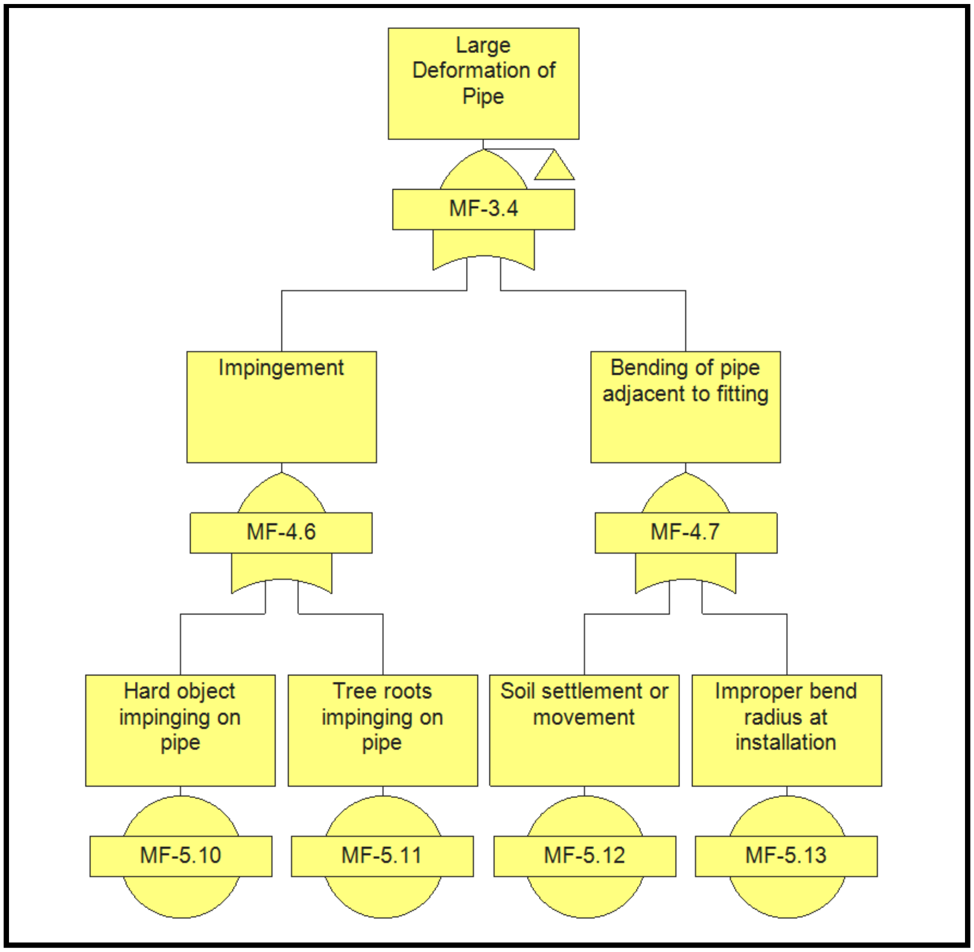



Figure 7-18. Fault Tree depiction of Decision Tree

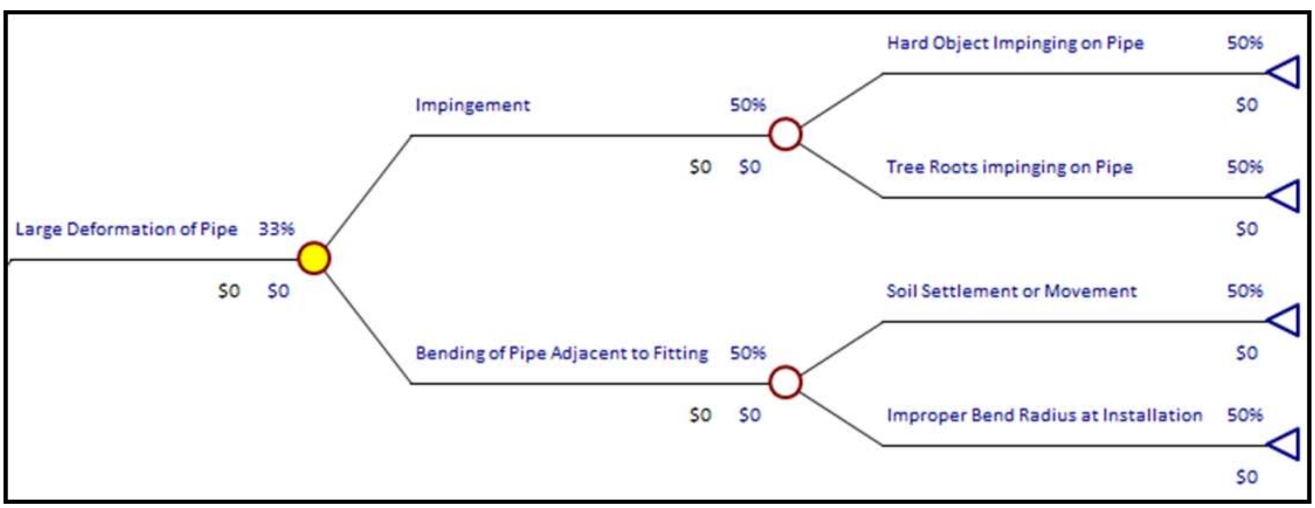



Figure 7-19. Decision Tree depiction of the FTA

A fault tree can be traversed in either direction – top level event to causes, or cause to possible top level events. The decision tree depiction is better for moving from the observed event to the root cause through a series of binary questions – the next pathway is either activated, or it is not.

A decision tree consists of 3 types of nodes:

1. Decision nodes - commonly represented by squares
2. Chance nodes - represented by circles
3. End nodes - represented by triangles

In this application we are not making actual decisions, we are simply traversing a logical pathway, so the nodes utilized are chance nodes and end nodes. A chance node, or circle in the diagrams presented, simply indicates that there are several alternate pathways to choose from. The operator is presented with enough information to enable a quick choice as to which pathway is correct. The pathway terminates at an end node (triangle), which is the point that the subject matter experts have determined to be the best point of termination for the particular investigation for which we are gathering information.

Each branch in the **Figure 7-20** is a set of questions on the electronic form. Depending on the option that is clicked **Figure 7-21** the next screen will display the relevant choices. Relevant and useful pictorial or textual guidance can be displayed in association with each question.

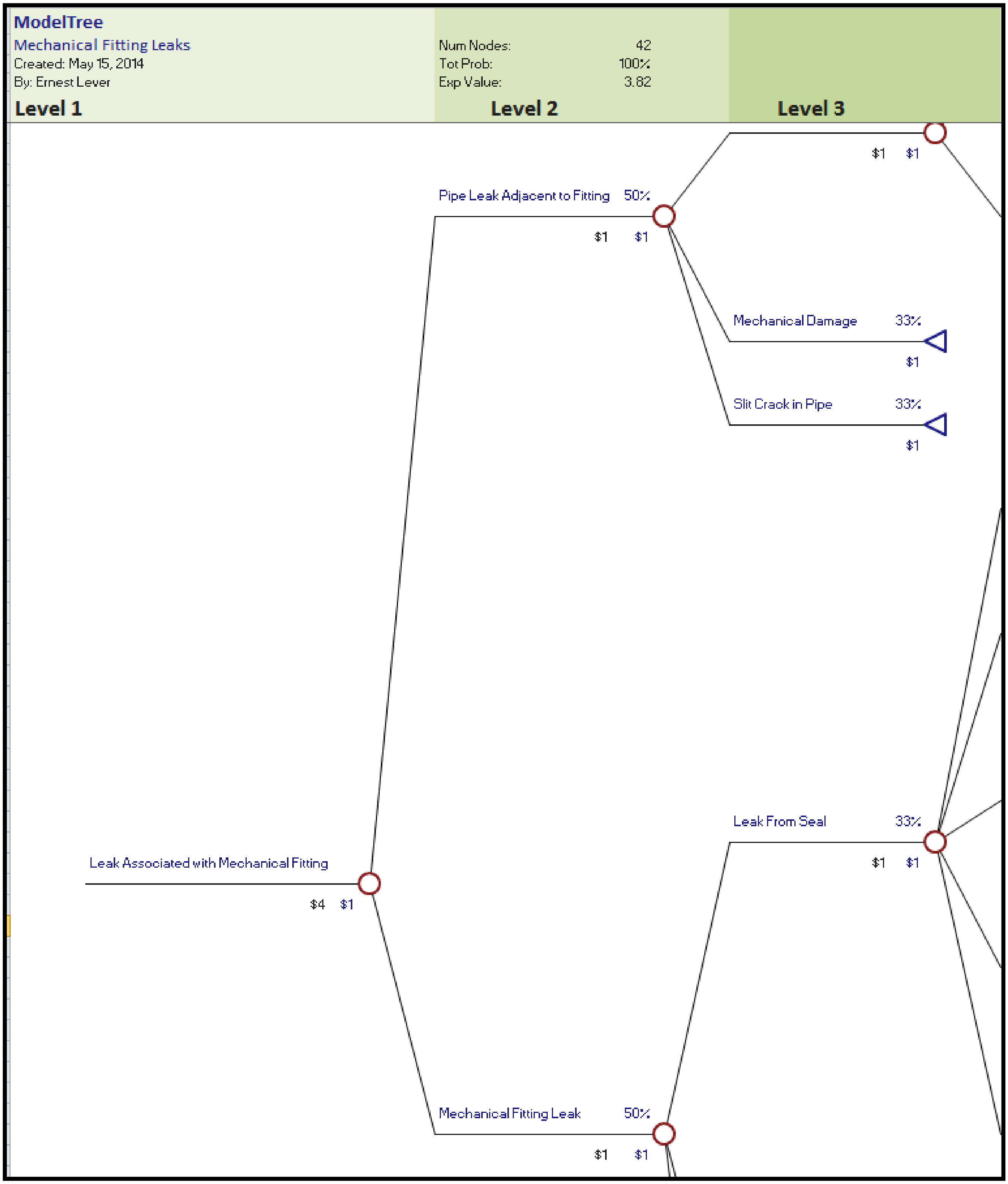



Figure 7-20. Entry level for the "Leak Associated with Mechanical Fitting" decision tree

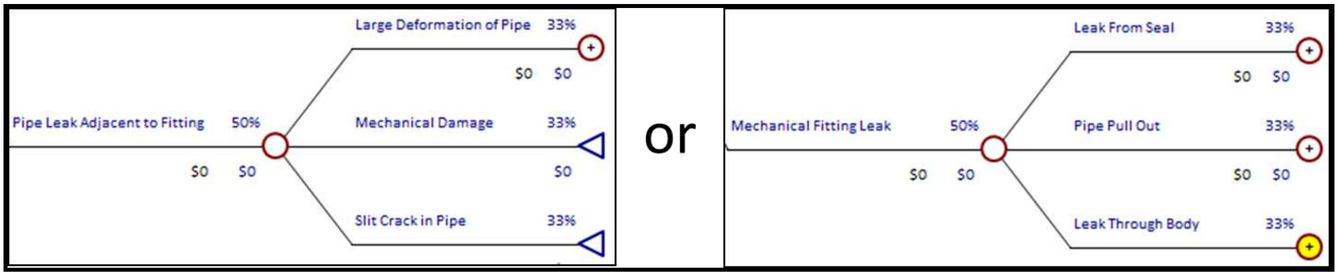



**Figure 7-21. Moving along the decision tree towards the root cause**

## Gathering Context Sensitive Information for Risk Models

Working through the decision tree that was defined by the original fault tree we will eventually arrive at a root cause. Some nodes may require extensive investigation for the correct follow on path to be identified, but the fact that the form is derived from well-defined fault tree analyses, developed by subject matter experts, allows simply structured assistance to be provided to the operator at each node of the decision tree.
The application can prompt the operator to gather useful meta-data related to the particular investigative pathway, such as detailed photographs, videos captured at the site or any additional that is known to be helpful in a determining the implications to the rest of the system due to the incident that occurred. This information gathering prompts is driven by the collected knowledge of analyzing many similar incidents that is embedded in the fault trees and is only be provided in the proper context so as to avoid overloading the operator with reams of information that he or she has to evaluate on the fly. The prompts take the form of simple, clear instructions with pictorial assists, provided in the proper sequence to ensure efficiency of the information gathering process.

## Eliminating the "Other" Category

The operator is presented with clear choices between alternate pathways at every point in the field investigation. If there is insufficient information to answer a set of questions the investigation is stopped at that point with a simple note "insufficient information available to continue". We then have a very clear record of what was available to the field crew and where they were unable to continue due to lack of resources or information. If the incident warrants further investigation the subject matter experts called in to continue the investigation have a well-defined start point for their detailed investigative work.
The application can associate a belief score for each node in a pathway that is a function of:

- How many subsequent nodes are resolved,
- How much supporting evidence for each pathway is stored in the meta-data.

### Data Driven Risk and Consequence Models

The decision tree underlying the form is essentially a risk and consequence model:

- Field data for each node can be directly used to assign probability of occurrence for each pathway, and
- Operator data for associated costs can be directly input into the decision tree yielding an expected cost for all possible system faults as well as each particular branch.

This functionality will not be exposed in the smart form application, but the data gathered can be directly input into an associated risk and consequence model. Because the form structure is derived directly from a fault tree analysis the data gathered is perfectly structured to feed into risk and consequence models.

### Involving Standards Organizations

An industry standard can be developed to define the accepted fault trees for all common field failure modes. The standard can define:

- The appropriate questions to be asked at each level of the process:
    - Filling out the form
    - Conducting ancillary root cause investigations
- The appropriate methods for developing supporting data
- The consensus root causes for each field failure mechanism

### Benefits of Proposed Smart Form

The major benefits are:

- Well-defined, consistent and coherent logic,
- "Other" category avoided,
- Potential for industry standard,
- Readily implemented in electronic format,
- Integrate with mobile data apps,
- GIS integration possible,
- Tracking and Traceability integration possible, and
- Data collected can be fed directly into risk and consequence models (consistent structure).

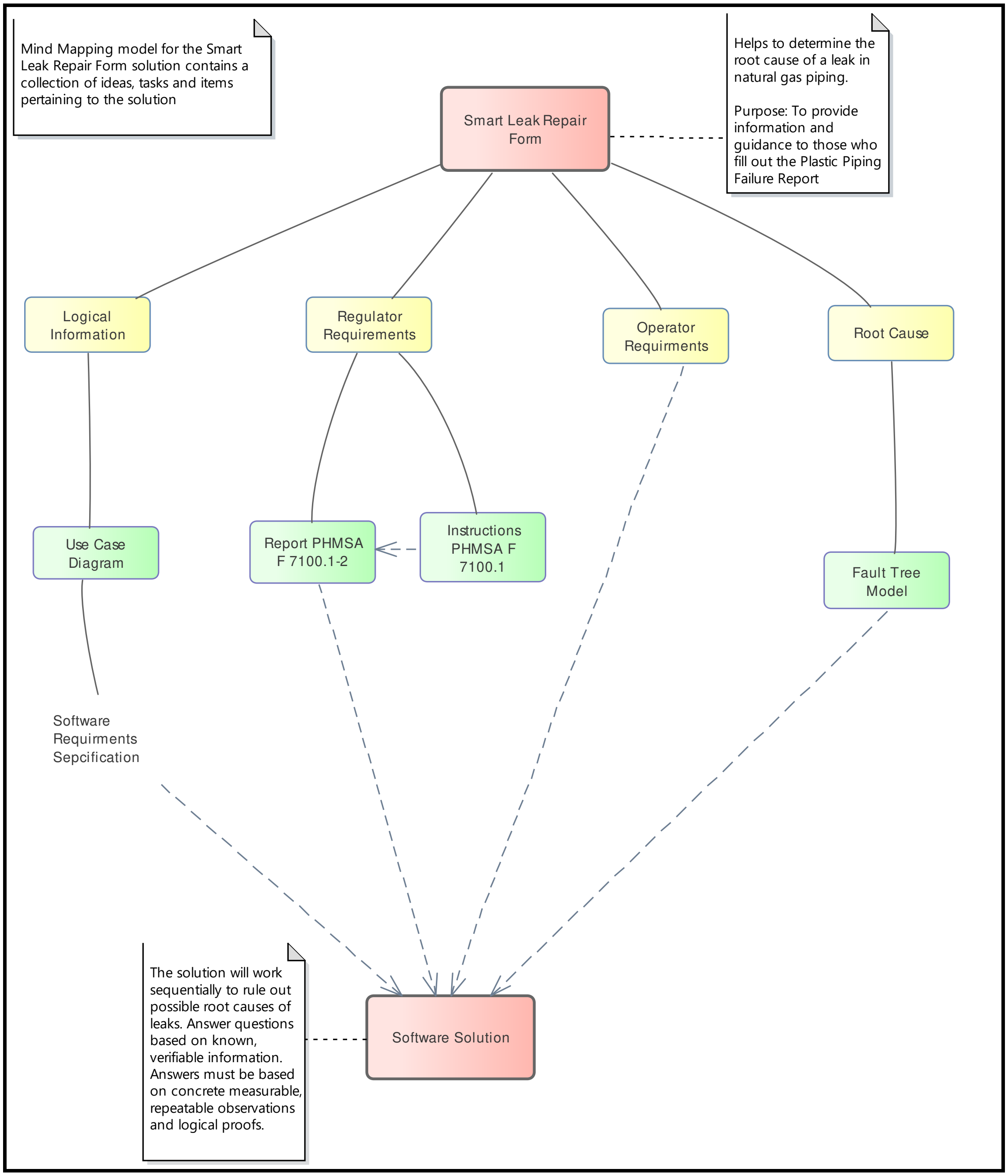



**Figure 7-22. Mind Mapping Diagram of Smart Form Application**

### Development

The smart form application improves the data collection process by guiding operators through a series of relevant questions about the system being inspected. High-level requirements that are supported by the developed application include the following:

- Runs on an Android smart (mobile) device.
- Supports disconnected data collection in cases of no internet access.
- Supports syncing of disconnected data once internet access is restored.
- Supports flexible data entry so that any non-standard data can be captured.
- Support the auto-generation of a point location, this should represent the GNSS point where the user created the record. The point feature should be inserted into Esri Geodatabase.
- Supports taking a geotagged photo that is retained and related to the record of interest.
- Supports User Authentication including “organization” or “domain”
- Support Deployment Configurations
- Manage Data Connection
- The Smart Forms Platform enables configuration of decision-driven workflows using graphical editors that map specific workflows to forms. The architecture for this platform is shown in **Figure 7-23** Architectural and software selection is based on flexibility and agility through maximizing application embedded intelligence and creating interfaces that are intuitive to field users.

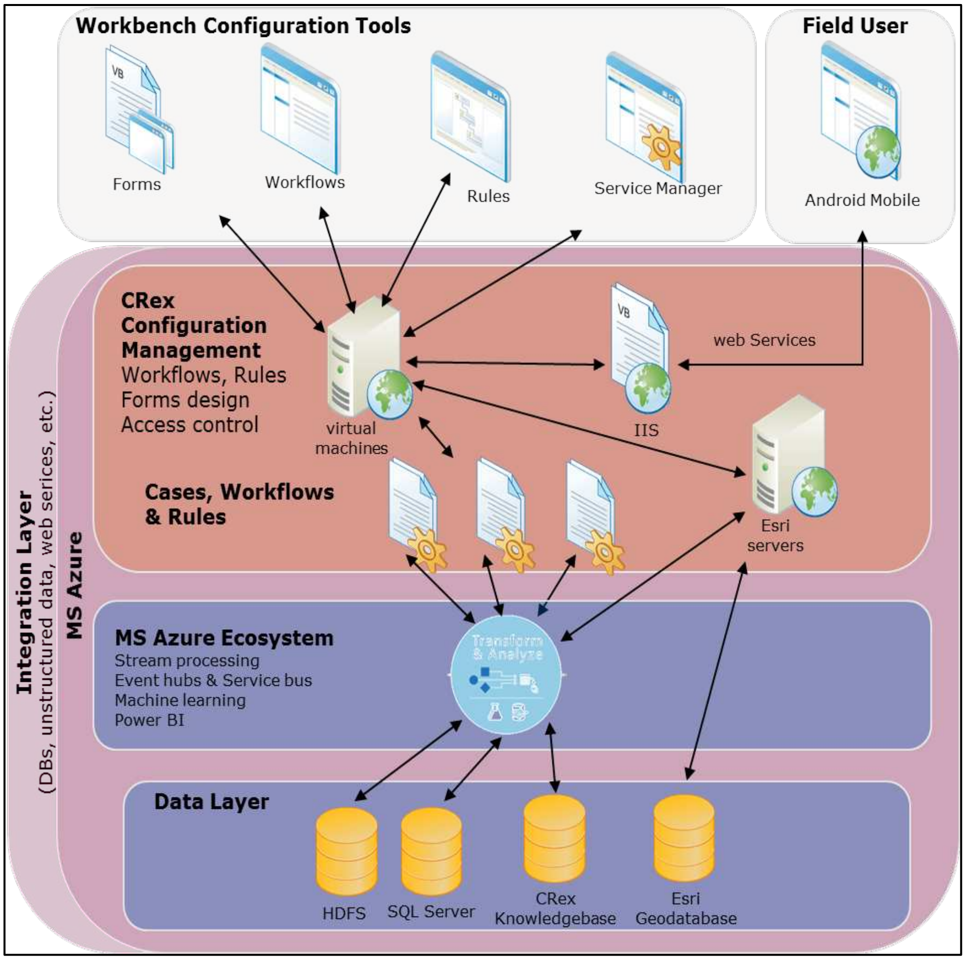



**Figure 7-23. High level systems architecture developed for the Smart Forms Platform**

The implementation is a modern, robust and fully-configurable Smart Forms creation platform for Android mobile devices. The platform is provided as a cloud-based service with developer, configuration and end-user (field user) access to different features. Central to the platform is a Configuration Manager application that enables use case configuration for new forms-driven applications through graphical editing of displayed forms as well as the workflows that drive the deployed smart forms. The platform takes advantage of the ability of the platform to map individual forms to tasks or activities within rules-driven workflows. A case management feature, essentially a workflow that manages other workflows, is provided to manually or automatically select from among a number of workflows to implement in the mobile application and that drive display of forms. Workflows are constructed visually within a Workbench and specific tasks within a workflow direct the display of forms in an intelligent way using rules entered through structured natural language editors, also within the Workbench. Other methods can be employed to make the decisions required by smart forms. For example, a Bayesian network might be evaluated in a task within a workflow and the results used to decide which additional forms to display or the data to display within a form. The capabilities are generalized in such a way that it is not necessary to upgrade, recompile or redeploy the Smart Form application in order to release new use case configurations into production. Only the configuration needs to be changed, and if new intelligent services are provided in the future, these can be accessed through standard connectors. A Service Manager is provided for user authentication based on organization or domain and configuration management **Figure 7-24**.

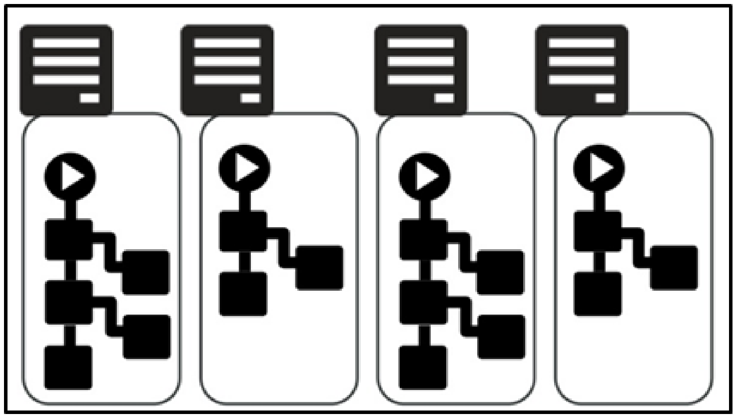


**Figure 7-24. Configuration of forms to specific workflows**

Development and deployment within Microsoft Azure allows access to other services within the Azure Transform & Analyze ecosystem, including Stream processing, Event Hubs, Service Bus, machine learning, Hadoop and Power BI. Of these services Service Bus and Power BI is used in this project. Future efforts can take advantage of all Microsoft services, and others created by Microsoft or 3rd-party vendors in the future. The semantically-enabled Bayesian network engine developed with GTI in an effort parallel to this project, is provided within this layer. The architecture is designed to meet the immediate Smart Forms project needs, while allowing for future expansion and eliminating obsolescence.

The data layer includes the CRex semantic knowledgebase and SQL Server for raw or unstructured data storage. CRex is also able to use SQL Server to store semantically-represented knowledge, typically historical information for archival. An Esri geodatabase in this layer provides for storage of geospatial information, obtained from the Android smart device, or other external services through the integration layer.

An integration layer is provided for programmatic interface to the Smart Forms Platform. There is one primary connection technology to support for this integration; AMQP 1.0, an enterprise service bus standard with connectors available to a large number of structured and unstructured data sources and targets.

*Components*

SmartForms improves both the collection and analysis of pipeline network integrity data through the development of a proof of concept (POC) server/mobile device application. The SmartForms POC consists of two applications, a locally installed mobile device app for field use and a host server application that stores knowledge, enable analysis, and intelligently drive field data collection.

The mobile device application will be used by field personnel. The mobile app uses a series of workflow-driven forms to guide field technicians through the collection of data. The mobile app supports both connected and off-line operation. When connected, data collection is context sensitive, in that a data gathered during a collection step can influence follow-on data collection requirements. When off-line, data collection is saved on the mobile device and asynchronously uploaded to the server database when a connection is subsequently established.

The server application will used by business managers and analysts. The server application provides a semantic database for the collected data and performs pipeline segment risk analysis. The risk analyses results is presented to the user through tabular displays and geographical visualizations.

The SmartForms Platform includes an environment for configuration of forms displayed on mobile devices, workflows and rules that used the data collection context to drive the sequence of forms or data displayed. Developers use the configuration environment to implement the use cases described in this document. Developers are familiar with proper use of tools in the configuration environment and create services that can be deployed in the SmartForms server, connect to necessary data sources and targets, and display the SmartForms in multiple field devices.

*User Personas*

Three user personas are identified for the SmartForms application; the field technician, the configuration developer, and the manager/business analyst.

a. Field Technician

The field technician is responsible for the collection of field data for a variety of field activities. Each field activity has a unique set of information that needs to be collected and stored into a central database.

The field technician needs to confirm that they have gathered all of the appropriate field information for a field activity, which may vary depending on the intermediate data gathering. For the POC application, it is assumed that the field technician is:

- Already trained and qualified for data collection for the defined field activities.

- Already familiar with the basics of using an Android smartphone app.

b. Manager/Business Analyst

The manager/business analyst is responsible for determining and prioritizing field activities and pipeline network maintenance based upon historical and current field data. They are also responsible for developing and maintaining the SmartForm work flows used by the field technicians for collecting field activity data.

The manager/business analyst wants to be sure that all required data for a field activity is gathered and that the new information gets uploading into the central database for analysis. Further, if a field technician gathers new information that warrants extra data collection, the manager/business analyst would like to interactively guide the field technician while they are still in the field.

The manager/business analyst want to be able to focus their maintenance and improvement capital on the pipeline network segment that are at the highest risk of failure. They will use the SmartForms application to perform analysis queries of the central database to produce ranked risk-based assessments of pipeline segments within pipeline network. For the POC application, it is assumed that the manager/business analyst is:

- Knowledgeable about how to interpret field data to determine risk of failure
- Knowledgeable about the process(es) that field technicians should use to collect data
- Minimal experience with creating programmatic process workflows

c. Configuration Developer

The configuration developer creates and updates the data collection workflows used by the field data collection mobile app. The developer uses business modelling tools to define and test data collection processes. For the POC application, it is assumed that the workflow developer is:

- Knowledgeable about the process(es) that field technicians should use to collect data
- Has experience with creating programmatic process workflows
- Knowledgeable about the relations and dependencies that influence risk of failure to a pipeline network
- Understands how to build and interpret Bayesian network models and apply them within the workflow

*Specifications*

**Functionality**

High-level requirements that are supported by the SmartForms applications include the following.

- Runs on an Android smart (mobile) device.
- Supports disconnected data collection in cases of no internet access.

- Supports syncing of disconnected data once internet access is restored.
- Supports flexible data entry so that any non-standard data can be captured.
- Support the auto-generation of a point location, this should represent the GNSS point where the user created the record. The point feature should be inserted into ESRI Geodatabase.
- Supports taking a geotagged photo that is retained and related to the record of interest.
- Supports User Authentication including "organization" or "domain"
- Support Deployment Configurations
- Manage Data Connection
- Requirement details to be elicited by the vendor as part of the project's execution.

User Interfaces

The field user interface does the following:

- Support basic Android style and functionality conventions.
- Support different screen sizes, different screen densities
- Implement adaptive UI flows
- Follow Android icon guidelines
- Use proper margins and padding
- Handle device orientation changes
- Use large, obvious tap targets (buttons, list items)

The application monitoring user interface has the following:

- Display:
    - o The number of active sessions (devices that have connected to the server and have not disconnected)
    - o The number of mobile devices currently connected to the central server
    - o The number of mobile devices that connected to the server but are not currently connected (have become decoupled but have an active session)
- Display for each connected device
    - o A visualization showing the state of the application on the mobile device. For example, if the application defines 5 screens/forms, which are displayed in some order (dependent on the application logic), then a visual that shows the form that was last displayed to the user on the mobile device.
    - o Provide a historical record of device connectivity

The business manager/analyst user interface does the following:
- web-based
- Present a gains chart for the pipeline network
- Present a color-coded geospatial view of the network segment risks

The configuration developer user interface has the following features:
- web-based
- Provide graphical tools for viewing and modifying the field data collection forms and workflows
- Push updated and approved forms and workflows to field mobile devices.

**Performance**

Application simultaneously supports, without significant response time impact:
- 25 mobile device users
- 1 administrative (configuration) user
- 2 management/business analyst users

Application responds to mobile device user requests within:
- 5 seconds for requests requiring on-line connectivity
- 3 seconds for off-line mode requests

Application availability is:
- During normal business hours as specified for the use cases
- Field device geographic coverage is to limited to area(s) specified by detailed design use cases

The deployed POC application uses local mobile devices loosely-coupled to a central, cloud-based server. The POC demonstrates mechanics that permit the mobile device application to operate properly when the server connection is unavailable, and for synchronization to occur when connectivity to the server is restored.

The mobile application must run within the available RAM and flash memory on the mobile device. The mobile application must function in both on-line (connected to a remote server) and off-line (disconnected from remote server) modes. When off-line, the application provides local (on-device) functions as defined in the use cases. Whenever an off-line device reestablishes a connection to the remove server, local data is automatically synchronized with the remote.

The application must accommodate as much as possible network latencies that limit responsiveness of distant servers providing information to the mobile application.

### Operations & Maintenance

Users must download and regularly update the mobile application. Data stored locally on the mobile device must be backed up by the user using 3rd party backup software that is supported by the SmartForms application.
SmartForms application sessions that remain open on the server for more than 1 hour after connectivity is lost is automatically closed and users must re-start the application to begin a new session. Sessions that become disconnected from the server (decoupled) for any period of time less than 1 hour must be synchronized with the server upon reconnection. No provision for re-initializing cancelled sessions is supported.

### *Systems Integration*

The SmartForms application requires two systems interfaces; a web services interface to support communication between the SmartForms remote, mobile device application and Microsoft Internet Information Services (IIS) web server, and an Azure Service Bus messaging interface between all database servers, and Microsoft Azure ecosystem services/applications, including GIS.
All communication between the remote SmartForms application on Android and the SmartForms server application must use web services protocols. Details on IIS Web Development can be found at https://msdn.microsoft.com/en-us/library/ms525945(v=vs.90).aspx
All communications between ESRI servers, Azure ecosystems services/applications, database applications and the SmartForms server application is via JSON-LD messages across an Azure Service Bus.
Details on use of the Azure Service Bus can be found at https://azure.microsoft.com/en-us/documentation/services/service-bus/
JSON-LD information can be found at http://json-ld.org/

### *Security*

The SmartForms applications must support communication protocols and provide suitable monitoring functions for protecting against malicious or accidental access, modification, disclosure, destruction, or misuse. Security functionality includes:

- Session password-based sign-on & authentication with configurable authorizations/permissions based on user role
- Single factor authentication (SFA) is used. Future versions are expected to require improvements in authentication. Therefore, the SFA implementation must not limit conversion to improved authentication functions in the future.
- Use of https for web services calls
- Support for existing mobile device security systems and softwares
- Server-side components uses suitable firewall software together with activity logging that enables forensic analysis of security issues

### *Data Management*

The SmartForms application supports persistent storage of:

- Use case configurations
    - Activities and rules
    - Use case templates
- GIS data
- Collected field data

SmartForms data management functionality includes, as required for the use cases defined in this document:

- predefined OWL 2.0 ontologies for classes, attributes (data properties) and relations (object properties)
- temporal (time stamp) management at the required level of time granularity for
    - data collection
    - data history
- database assertion and access rates is lower than network and application latencies such that database activity does limit application performance

### *Use Cases*

**Network Risk Assessment**

| *Goal* | **Perform Bayesian risk assessment for a pipeline network using current knowledge base** |
|---|---|
| *Pre-Conditions* | Link to SmartForms host server<br>User authentication with analyst access |
| *Successful End* | Risk report and gains risk chart generated for selected network |
| *Abnormal End* | Unable to generate report due to programmatic exception or missing information |
| *Agent(s)* | Business Manager/Analyst<br>SmartForms host server |
| *Trigger* | Ad hoc request by a Business Manager/Analyst |

| Use Case: Network Risk Assessment | | |
|---|---|---|
| **Pre-Conditions** | **Step** | **Outcomes** |
| Link established to host server | 1 **Open Application** | Application authentication screen appears |
| Analyst enters identifying credentials | 2 **User Authentication** | User ID, organization, and role has been validated for Analyst access |
| Analyst access authorized Report selection UI | 3 **Report Selection** | Selected report query |
| Selected report query Bayesian Network (BN) model | 4 **Gains Chart Generation** | Gains risk chart generated from BN results |

## Cognitive Field Data Collection

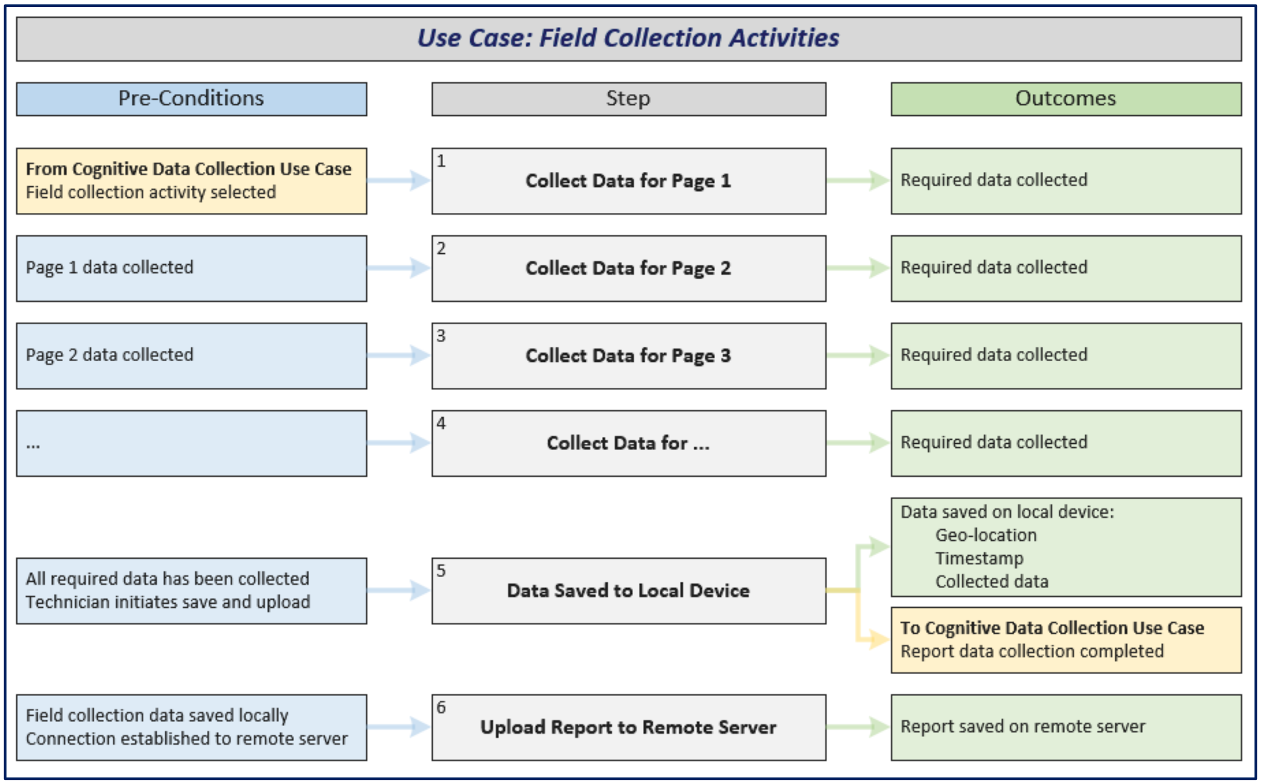
| *Goal* | Provided guided pipeline network field data collection via an Android mobile device |
|---|---|
| *Pre-Conditions* | Android mobile device with SmartForms application loaded<br>Qualified Field Technician with user authentication for technician access |
| *Successful End* | Completed activity report uploaded to host server |
| *Abnormal End* | Activity report information not received by host server<br>Incorrect and/or incomplete information collected and saved for selected activity |
| *Agent(s)* | Qualified Field Technician<br>SmartForms mobile application<br>SmartForms host server |
| *Trigger* | Ad hoc initiation by Qualified Field Technician |

### *Use Case: Cognitive Field Data Collection*

| Pre-Conditions | Step | Outcomes |
|---|---|---|
| Android mobile devices pre-loaded with SmartForms application | 1 **Open Application** | Application authentication screen appears |
| User enters identifying credentials | 2 **User Authentication** | User ID, organization, and role has been validated for field data entry |
| Distribution network database<br>Component selection form | 3 **Component Selection** | Selected component |
| Activities selection form for selected component | 4 **Activity Selection** | Selected activity |
| Workflow for selected activity | 5 **Guided Field Data Collection** | Initiate data collection Use Case for selected activity |
| Recently uploaded activity report | 6 **Follow-up Data Collection** | One or more screen forms presented for recording additional activity field data |
| Field technician has entered all required field data for the additional activity | 7 **Save Additional Activity Field Data** | Save performed to local device, including:<br>Field data<br>Timestamp<br>Geo-location |
| One or more saved activity reports<br>Connected established to remote server | 8 **Activity Data Posted to Remote Server** | Locally saved activity reports uploaded to remote server |

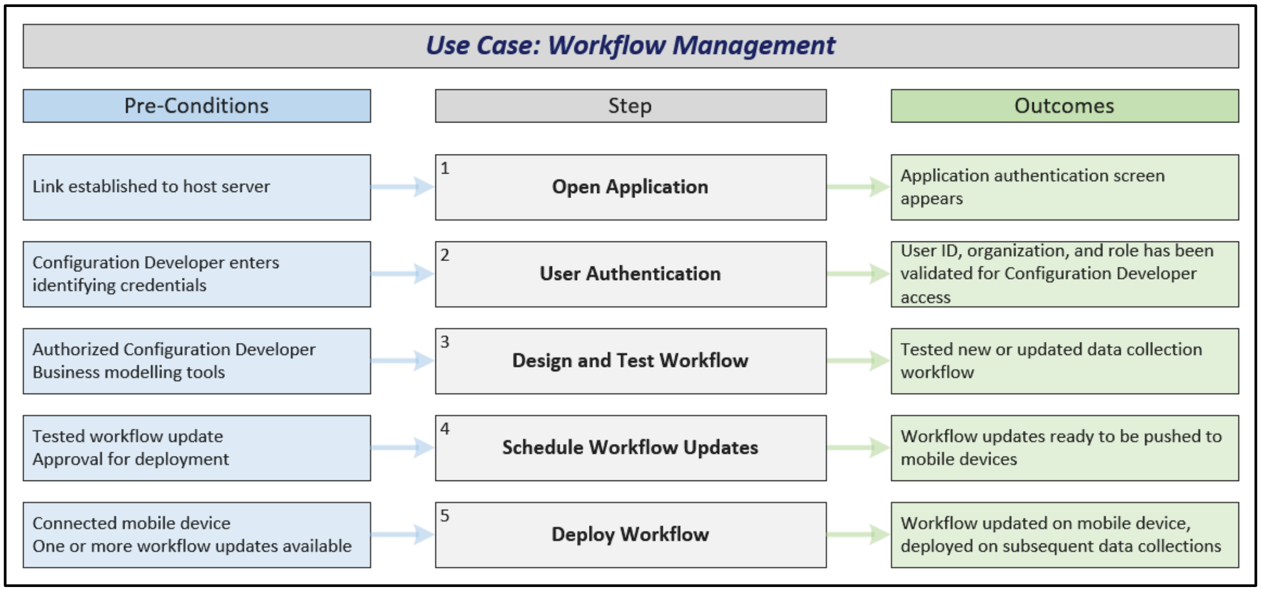
**Field Collection Activities Use Case**

| | |
|---|---|
| *Goal* | Collect specific field data for a field activity, including:<br>• Manual entries<br>• Scanned barcodes<br>• Photographs |
| *Pre-Conditions* | Qualified Field Technician has selected a field activity in the SmartForms mobile application |
| *Successful End* | Completed collection of field data |
| *Abnormal End* | Application fails to present appropriate forms<br>Application collects incorrect data for activity<br>Application fails to record governance data |
| *Agent(s)* | Qualified Field Technician<br>SmartForms mobile application<br>SmartForms host server |
| *Trigger* | Selection of a field activity within the SmartForm mobile application |




## Workflow Management

| *Goal* | Create or update field data collection process workflow in the mobile app |
|---|---|
| *Pre-Conditions* | Link to SmartForms host server<br>User authentication with Configuration Developer access |
| *Successful End* | Workflow created or updated and available to SmartForm mobile app as an update |
| *Abnormal End* | Unable to create or update workflow successfully<br>Unable to download the latest workflow into mobile app |
| *Agent(s)* | Configuration Developer<br>SmartForms host server |
| *Trigger* | Ad-hoc by a Configuration Developer |




### *Design*

This section describes the design of a proof-of-concept (POC) SmartForms application, sufficient to enable developers to plan and begin work on creating the POC application. The design comprises two sections that follow this introduction;

1. the Configuration Management section, describing the design of the environment that is used to manage the lifecycle of the SmartForms specified in the 7 required and, by extension other, use cases, and
2. the Situational Reasoning section, describing how intelligence needed to drive SmartForms displays in mobile devices is implemented;
    a. interface with, baseline and store SmartForm component, activity and geospatial data in a knowledgebase,
    b. manage multiple models used in reasoning, and
    c. make data available to a user interface capability for visualization.

This document is updated as the project proceeds to include the latest understanding of the SmartForms application design. The version record contains the document version number, authors, publish date and notes for each version.

### *Configuration Management*

This section describes the design of a Configuration Manager that enables definition of;

1. Forms or screens, implemented as HTML5 web pages, that contain user interface fields;
2. Workflows comprising a sequence of tasks and decision points that direct the display of Forms based on data entered into the user interface fields.

The capabilities of the Configuration Manager implement a generic ability to define a finite state machine[10] that determines the states and sequence in which a specific series of Forms are displayed during a field data collection session **Figure 7-25**. In creating Forms, Developers effectively specify States, Data Items, Methods and Workflows that implement the Form state transitions in the 7 required project use cases, or new use cases defined in the future.

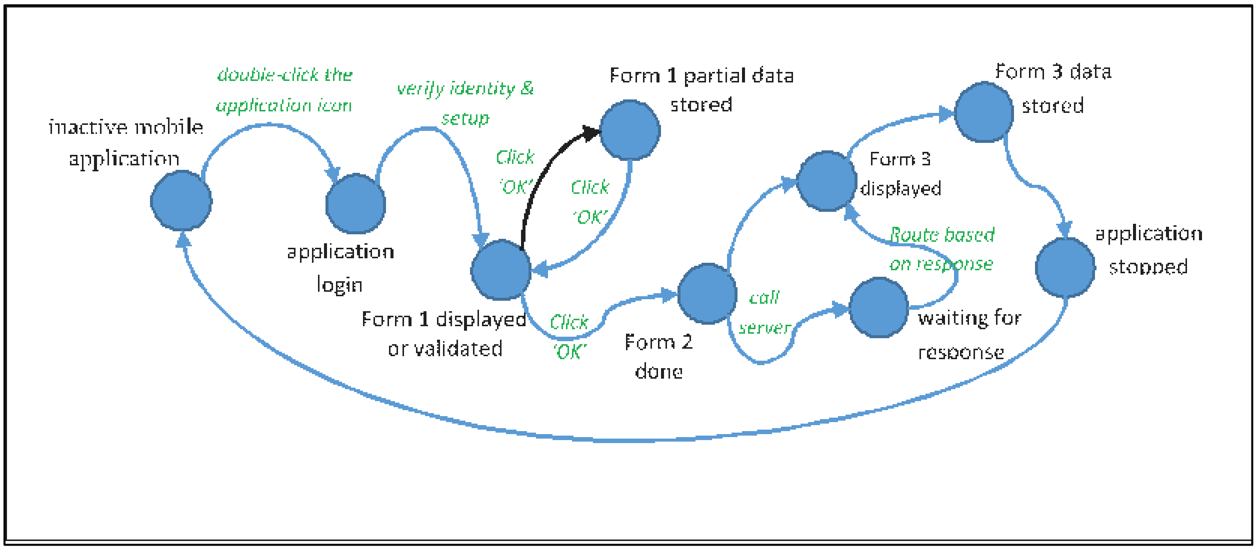



**Figure 7-25. Example sequence of states in a SmartForms application, effectively configured in the Configuration Manager**

### *Situational Reasoning*

This section describes design of the SmartForm manager-based services for;

1. Representing situations that describe relevant states or conditions that may exist in data collected by the SmartForms mobile application used by Field Technicians;
2. Representing Bayesian network structure and data and relations to situational representation in order to allow for Bayesian network node values to inform situational determination;
3. Representing situation action networks that define the way in which goals are achieved by SmartForm manager agents.

SmartForm manager provides situation centric cognitive- and knowledge-based ontological services involving a variety of numeric and logical reasoning techniques. These capabilities can be packaged in a variety of ways ranging from small components deployed within Azure functions up to large systems distributed over an elastic pool of virtual machines.

10 The states and their transitions can be represented in a state chart diagram.

Composability is a strong theme throughout the architecture, allowing packaging decisions to be made based on what scalability requirements are required for different parts of the solution.

In this application, SmartForm manager is primarily a consumer of data generated by the SmartForms workflows. The data is important to support the continuous improvement of models from which risk-based decisions are made. Activity logging supports the provenance of SmartForm manager data, so with this in mind the primary objectives for SmartForm manager are as follows:

1) To be the system of record for provenance data, including activity logging records.
2) To manage an interface with an ESRI system so that geographical visualization of data is possible. This data is a mixture of slowly changing master data (configuration of the gas network) and day-to-day information (including photographs) from the field data collection sessions.

To provide an interface with business intelligence software so that gains charts and other data visualizations can be produced.

### *Component Architecture*

**Figure 7-26** illustrates the principal components and the relationships between them. The opportunities to use communication techniques described above are shown:

- Enterprise Service Bus messaging is used to convey information from the K2 Workflow environment to SmartForm manager.
- SmartForm manager injects data into the ESRI ArcGIS system using a RESTful API
- ArcGIS can also request extra web content from SmartForm manager as needed.

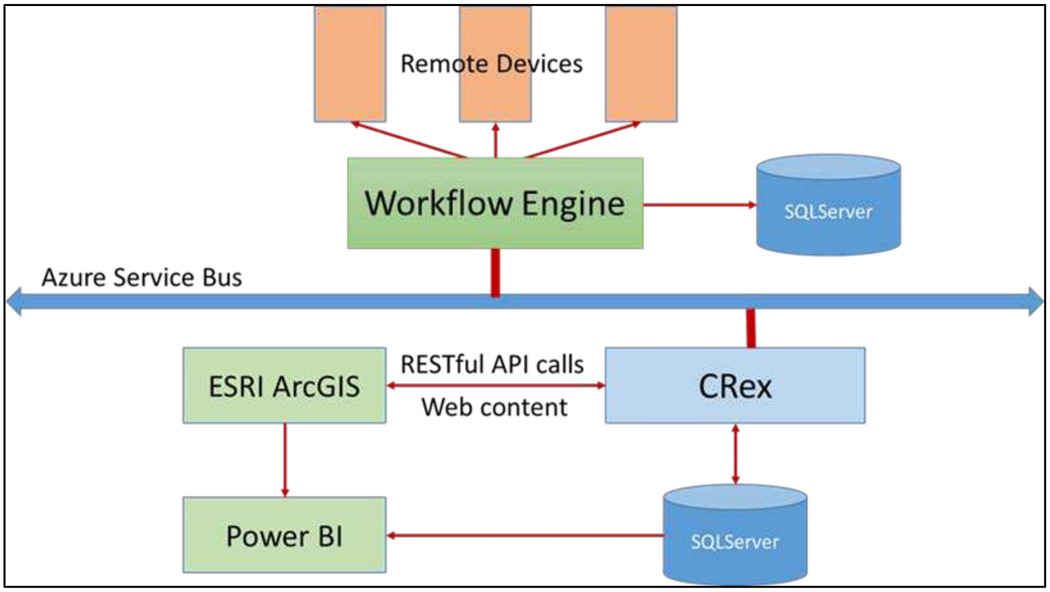



**Figure 7-26. Example sequence of states in a SmartForms application, effectively configured in the Configuration Manager.**

### *Model Management Techniques*

Anything that has information associated with it can be represented as an Entity in SmartForm manager. Elements of models can be entities, as can real-world objects, events, people, other agents and the activities they perform. All entities have unique identifiers. Simple entities can be composed into more complex entities, so a model composed of model elements can be an entity, as can departments composed of people, roles and responsibilities, and plans and workflows can be entities composed of activities. A situation is an entity composed of objects, people and agents plus a narrative of events and activities that involve them as time passes.

If the information about an entity changes over time, SmartForm manager tracks those changes by maintaining a version history of each entity. Versions of entities are identified by a combination of the entity identifier and the identifier of the activity that created the new version. Some entities are expected to remain the same across time; the main examples of these are entities that represent events and entities that represent messages exchanged between parts of the system.

Sometimes, SmartForm manager needs to reason about different ways in which the world might change. To keep track of different possible futures, the version history can have branches. Each branch is also given an identifier.

Activity Logging and Provenance

To keep an accurate record of activities within the system, an activity model is required. In addition to activities, the primary entities in this model are agents (software agents, organizations, and people) and the data entities that are produced and consumed by the

activities. This combination of entity types not only serves as an activity log, but also provides rigorous provenance for data entities produced by the system.
Auditability of activity logs is achieved by maintaining two kinds of model in SmartForm manager.

1) A model derived from designed workflows that captures how a data collection should proceed.
2) A model of what actually happened during a field data collection session.

It is then possible to assist the auditing process by identifying significant differences between the desired and actual data collection.
Each of these models is represented by a situation. The setting of the situation's narrative includes a gas network segment, a field technician along with a location and a time interval over which data collection occurs. In the desired model, these are represented by place-holders whereas in the model of actual data collection these are replaced by references to real pipes, people etc. This allows the same model elements to be used for both models.

### *Data Management*

Data managed by the SmartForms application includes;

- Workflow configurations & templates
- Form configurations & templates
- Pipe networks data including;
    - ID = Unique id for each AldylA distribution mains
    - End1_Longitude, End1_Latitude = Longitude and latitude of one end of the mains
    - End2_Longitude, End2_Latitude = Longitude and latitude of other end of the mains
    - Area_Code = 1 to 5
    - Year_Installed = Year In which the mains was installed (1969 - 1980)
    - Years_In_Service = Current year - Year_Installed
    - Probability_of_Failure_5yrs = Probability of failure in 5 years
    - Probability_of_Failure_10yrs = Probability of failure in 10 years
- Collected field data
- For each of the above, a timestamp and validity interval

Predefined OWL 2.0 ontologies are provided for classes of objects, their attributes (data properties) and relations (object properties), and elements required for situational and Bayesian network concepts.
The storage technology is Microsoft Azure SQL Server.

### *Aldyl-A Pipeline Network Model*

Information about the gas network is represented as a composable, layered model. The most basic layer contains the geographic representation of each network segment. Other layers add more data so that views combining several kinds of data can be composed easily **Figure 7-27**. The unit of composability is the amount of knowledge for one network segment for one layer, and these is represented as versioned entities in SmartForm manager.
The set of layers required for this model are as follows:

1) Geographic layer. Provides the geographical point data needed to locate the network segment. This layer also contains details of features near the pipeline segment that combine with risk-of-failure to generate a risk metric.
2) Physical composition layer. Provides data on the dimensions and material of the pipe used in the network segment, along with estimates of replacement cost for the segment.
3) Physical provenance layer. Provides details of the manufacturer, data of manufacture and date of deployment of the pipe. It also provides a maintenance history of the pipe since deployment that includes maintenance techniques used.
4) Risk analysis layer. Contains the results of Bayesian analysis of risk using the Aldyl-A model.
5) Custom layers. As needed to support the kinds of information made available from field collection workflows.

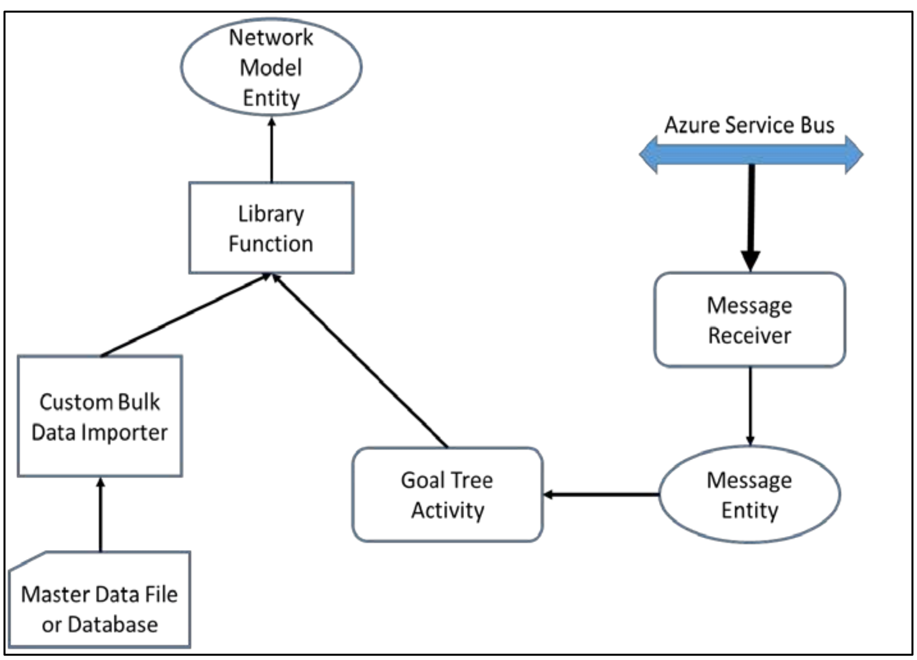



**Figure 7-27. Layer population techniques**

The two main pathways for data to arrive in the network model are the bulk import of master data from external resources (data files, databases etc.) and the translation of messages that arrive in SmartForm manager. Noting that revisions to master data records may result from messages delivered to SmartForm manager, it makes sense that there is a library of functions for creating master data elements that are used by both techniques as shown below. The primary difference between the information that is stored in each case is in the provenance data that is created.

### *User Interface and Integration with ESRI/ArcGIS*

SmartForm manager data can be made available in ArcGIS through the RESTful API for the product. The required steps are as follows:

1) Data is made available in records. A schema for the records must be declared. Once this has been done, the schema is used for all records of that type.
2) A target for a new data record is created or chosen in the ArcGIS data. A target might be a geographical point created in ArcGIS to represent the location of a field engineer during data collection, a geographical point created to represent the location a photograph was taken, or an extended geometric feature such as the representation of the pipe segment.
3) A data record is created and populated using data values extracted from one (or more) levels in the network model, typically for a single network segment.
4) The data record is associated with the selected target in ArcGIS.

New records created in this way become viewable through the ArcGIS user interfaces and the data is available for queries made against ArcGIS data stores.

Not all data that is accessible through the ArcGIS user interfaces must be copied into the ArcGIS database. Data can also be made available by storing a URL in an ArcGIS record. This is the method used to associate photographs with geographical points since the images are stored in Azure Blob Storage and the URL supplied to SmartForm manager. URLs can also be used to address knowledge in SmartForm manager, reducing the amount of data that must be replicated between the systems.

The primary means for a business analyst to interact with the system is through Microsoft Power BI.

Geospatial View

This solution takes advantage of standard components that already exist for projecting ArcGIS data into Power BI.

### *Gains Chart*

A gains chart component looking like the following has been proposed **Figure 7-28**

| Probability of Failure within 5 years | Number of Segments | Percent of Segments | Cumulative % | Average Years in Service | Linear Feet | Replacement Cost | Cumulative Replacement Cost |
|---|---|---|---|---|---|---|---|
| 90%+ | 183 | 2.38% | 2.38% | 51.8 | 12,426 | $2,795,756 | $2,795,756 |
| 80-90% | 975 | 12.66% | 15.03% | 44.1 | 82,997 | $18,674,363 | $21,470,118 |
| 70-80% | 985 | 12.79% | 27.82% | 44.0 | 81,316 | $18,296,065 | $39,766,183 |
| 60-70% | 993 | 12.89% | 40.71% | 44.1 | 88,431 | $19,896,967 | $59,663,150 |
| 50-60% | 398 | 5.17% | 45.88% | 40.4 | 31,286 | $7,039,312 | $66,702,463 |
| 40-50% | 218 | 2.83% | 48.71% | 44.1 | 16,707 | $3,759,120 | $70,461,583 |
| 30-40% | 64 | 0.83% | 49.54% | 43.9 | 4,141 | $931,670 | $71,393,253 |
| 20-30% | 1,162 | 15.09% | 64.62% | 45.3 | 121,652 | $27,371,634 | $98,764,887 |
| 10-20% | 1,494 | 19.40% | 84.02% | 37.0 | 131,774 | $29,649,092 | $128,413,979 |
| <10% | 1,262 | 16.38% | 100.40% | 40.7 | 123,825 | $27,860,680 | $156,274,660 |

**Figure 7-28. Example of a Gains Chart**

The aggregate data in this table can be computed by Power BI based on a view of data extracted from various layers of the network for each segment of the network **Table 7-1**

**Table 7-1. Data for creation of gains charts**

| Field | Source |
|---|---|
| Probability of Failure | Produced during Bayesian analysis with the Aldyl-A model; stored in the risk analysis layer of the network model. |
| Years in Service | Stored in the physical provenance layer of the network model. |
| Linear Feet | Stored in the geographic layer of the network model |
| Replacement Cost | Stored in the physical composition layer of the network model. |

***SmartForm Ontologies***

*Foundation* - The foundation ontology is a SmartCloud ontology® defining the modeling elements for composing settings and narratives using Situation Theory.
*Provenance* - This is a small SmartCloud ontology® that places the design patterns from PROV-O (see below) within the context of situations as represented using the foundation ontology.

Standard and 3rd Party Ontologies
*Units of Measure* - The OM-1 ontology focuses on units of measure, their dimensionality and the quantities and measurements that use them. (see http://www.wurvoc.org/vocabularies/om-1.6/)
*Organization* - The Organization Ontology is a W3C Recommendation since 16th January 2014. It is centered on terminology that allows the modeling of organizational structures with important connections to the Roles and Agents required by the PROV-O ontology. (see http://www.w3.org/TR/vocab-org/)

*People* - The Friend-of-a-Friend (foaf) ontology provides terminology about people, connections between people, and knowledge related to people. (see http://xmlns.com/foaf/spec/)
*Media* - The Dublin Core ontology is a small, frequently used ontology for describing media items in the semantic web. (see http://wiki.dublincore.org/index.php/User_Guide)
*Provenance* - The PROV-O ontology is a W3C recommended ontology for representing the use and production of data entities during activities performed by agents. It is widely used within the semantic web community and represents state-of-the-art for activity logging and provenance. (see http://www.w3.org/TR/prov-o/)

### *Keyhole Inspection Form, First Response Form, Audit Report Form*

The Keyhole Inspection or First Response form improves data collection process by guiding operators through a series of relevant questions during inspection of the pipeline segment being inspected. The questionnaire is intelligently generated through decision-driven workflows where the data entered by operators determines the next question for data entry. The SmartForm runs on an android mobile device and supports flexible data entry so that any non-standard data may be captured. The geolocation of the inspection is automatically captured along with other details. **Table 7-2** lists the details of Keyhole Inspection and First Response forms.

**Table 7-2. Keyhole Inspection Form and First Response Form**

| Smart Form type | Keyhole Inspection Form or First Response Form |
|---|---|
| Goal in Context | Create, view and edit a record for keyhole data gathering |
| Scope & Level | Scope = Intelligence Field Data Collection. Level = User Goal |
| Preconditions | The user should be familiar with the procedures and recommended practices to collect keyhole or first response data. |
| Success End Situation | The user successfully enters the keyhole or first response information (the mobile application works even when the internet connectivity is lost). The mobile application posts the data collected to the remote server (if there was no internet during data collection process, the data is posted to the remote server once the application is online). |
| Failed End Situation | Inability to operate in offline mode. Inability to save and post the data collected to remote server. |
| Primary Agent<br><br>Secondary Agent | Field Operator<br><br>Qualified Field Personnel |
| Trigger | A Field Operator (or any qualified field personnel) is out in the field to gather pipeline data. |

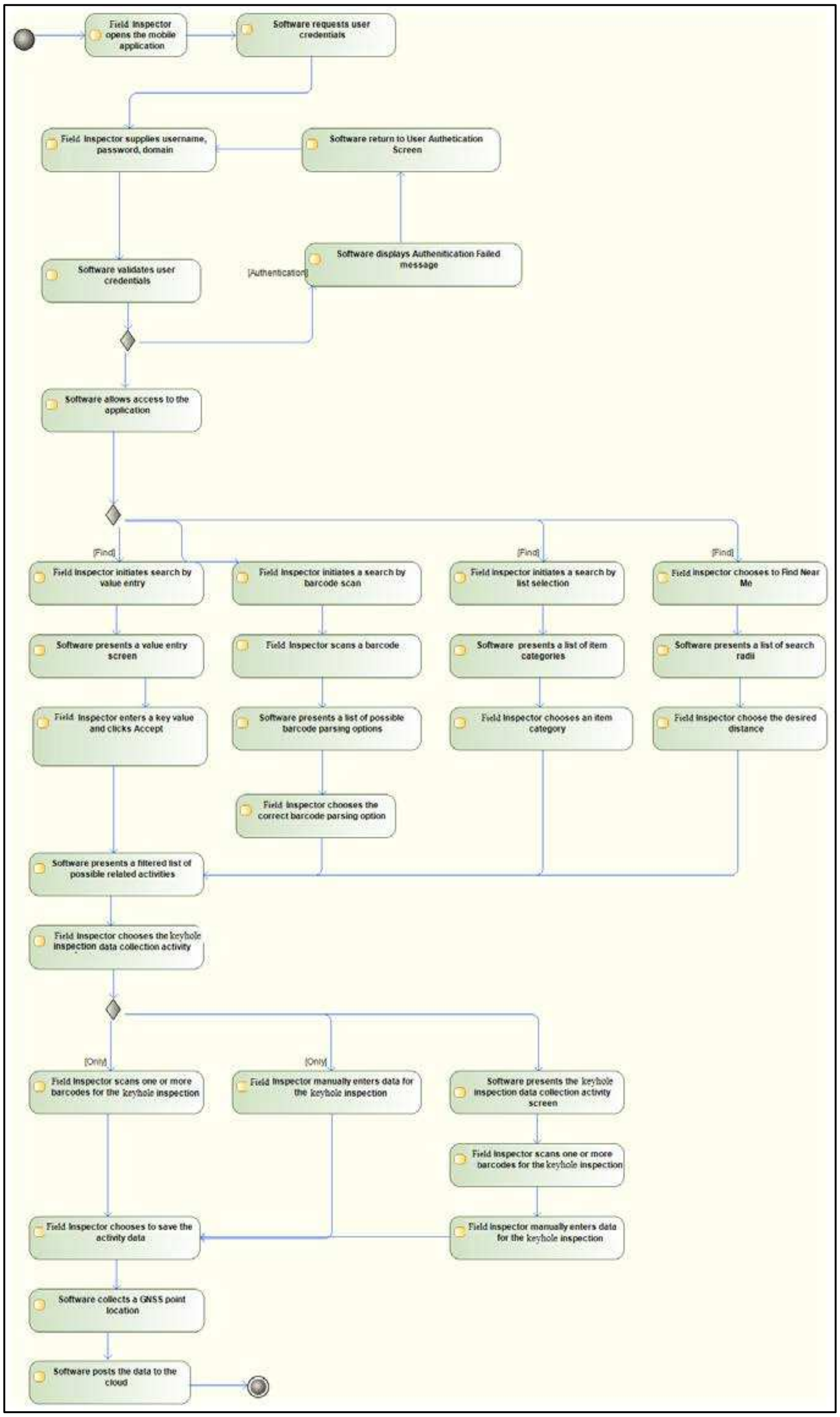
| Smart Form type | Keyhole Inspection Form or First Response Form | |
|---|---|---|
| DESCRIPTION | Step | Actions Leading to the Successful Goal |
| | 1. | Field Operator opens the mobile application |
| | 2. | Field Operator enters user credentials in the login screen |
| | 3. | Field Operator initiates search of the gas components (e.g., pipeline, valves, etc) by:<br><br>- Value entry<br>- Barcode scan<br>- List selection<br>- Find near me (based on location) |
| | 4. | The mobile application presents a filtered list of possible related activities. |
| | 5. | Field Operator chooses the keyhole data gathering or first response activity. |
| | 6. | Field Operator navigates through a sequence of data entry screens to collect all relevant information. Each step/screen has one or more of the following:<br><br>- Scans one or more barcodes<br>- Manually enters data<br>- Takes photos |
| | 7. | Field Operator saves the activity data. The mobile application adds time and geo-location point information to the activity data. |
| | 8. | The mobile application posts the data to remote data server. |

| | |
|---|---|
| RELATED INFORMATION | Keyhole Data Gathering; First Response |
| Priority: | 1 |
| Performance | Normal mobile application responsiveness is sufficient. |
| Communication channels between agents | Keyhole data/First response records on Android mobile phone. |
| Superordinates | Create, View, Edit records |

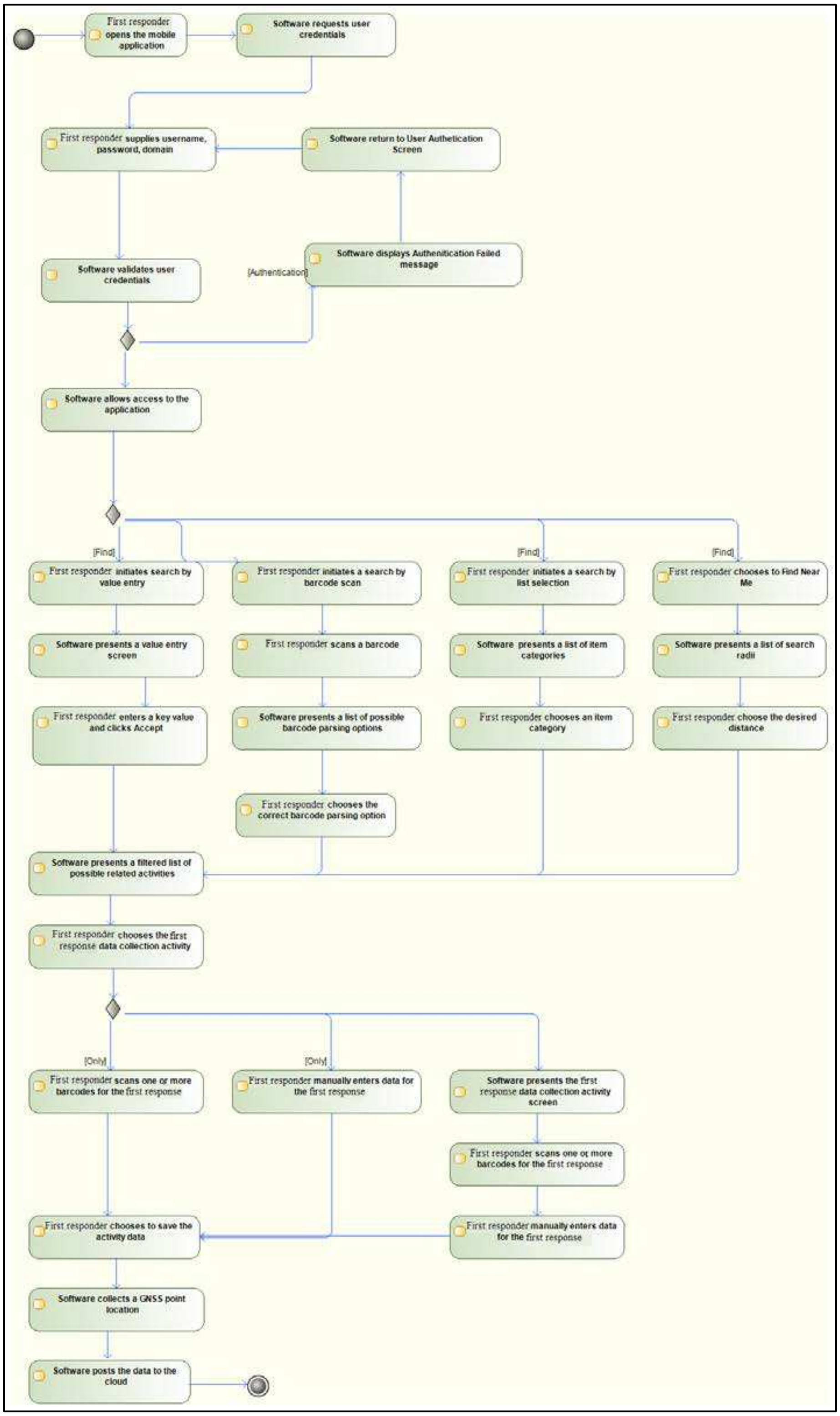
Gas operators are required to submit annual audit reports and incident reports to PHMSA. It takes quite an effort to collect all required information in one place to fill up the forms. One of the goals of SmartForm is to replace the current manual report filing process and to automate the audit report generation by pulling together information from databases distributed across different business units. The audit report form helps to complete PHMSA F 7100.1-1 annual report form and the process audit prescribed in ASME B31.8S standard.

## *Activity Diagrams*

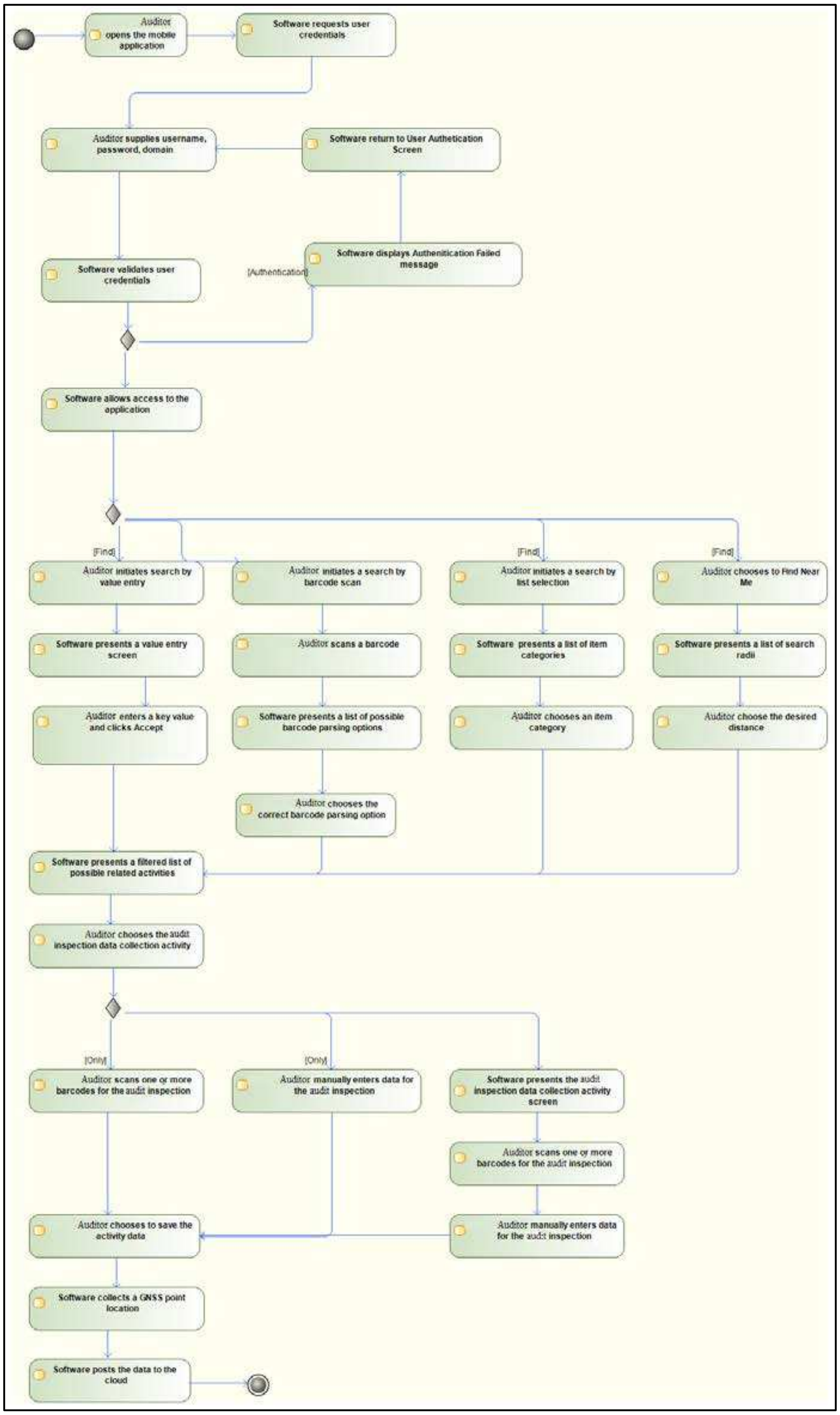
### Activity Diagram – Create a tracking record for keyhole data gathering inspections



## Activity Diagram – Create a tracking record for first response data gathering



## Activity Diagram – Create a tracking record for audit event data gathering



## *Appendix A- Use Case: EDSS with SmartForms Demo*

| Pre-Conditions | Step | Outcomes |
|---|---|---|
| Laptop with server application started<br>Server application loaded with demo network<br>Mobile device with loaded app and connection to laptop server<br>Demo BA logon credentials | 1 **Business Analyst Logon** | User logged on and role authenticated<br>?Option menu displayed? |
| BN trained for demo pipeline network in developer UI | 2 **Present Bayesian Network (BN)** | Viewer understands how BN is used to determine pipeline segment risk |
| User logged on with BA authentication<br>Network Risk Analysis requested | 3 **Display Network Risk Analysis Table** | Prioritized risk analysis table (gains chart) |
| Geographical Network Risk display requested | 4 **Display ARCGIS Risk Visualization** | ARCGIS network visualization of pipeline segment risk generated |
| ARCGIS risk display | 5 **Zoom to Demo Pipe Segments** | Pipe segments “scheduled” for field reports displayed |
| BPMN diagram for activity report that requires risk-based branching of the field data collection workflow | 6 **Present Risk-Based Collection Design** | Viewer understands how risk-based data collection is to be implemented |
| Implemented activity report workflow that uses risk-based field data collection workflow branching | 7 **Present Risk-Based Collection Workflow** | Viewer understands how risk-based data collection has been implemented on mobile device |
| Mobile device with loaded app and connection to laptop server | 8 **Field Tech Logon** | User logged on and role authenticated<br>Component query menu displayed |
| User logged on with Field Tech authentication | 9 **Component Selection by List** | Demo component selected<br>Report activity menu displayed |
| Demo component selected | 10 **Activity Selection** | Activity report selected |
| Demo component selected<br>Activity report selected | 11 **High Risk Component Assessment** | Risk information for workflow guidance downloaded to mobile app<br>Form 1 of report workflow displayed |
| Form 1 of selected activity displayed | 12 **SmartForm-Led Data Collection** | TO BE EXPANDED<br>All data collected for selected report |
| Completed Activity Report | 13 **Data Uploaded to Host Server** | Report received and store by host server application |
| User logged on with Field Tech authentication | 14 **Component Selection by List** | Demo component selected<br>Report activity menu displayed |
| Demo component selected | 15 **Activity Selection** | Activity report selected |
| Demo component selected<br>Activity report selected | 16 **Low Risk Component Assessment** | Risk information for workflow guidance downloaded to mobile app<br>Form 1 of report workflow displayed |
| Form 1 of selected activity displayed | 17 **SmartForm-Led Data Collection** | TO BE EXPANDED<br>All data collected for selected report |
| Completed Activity Report | 18 **Data Uploaded to Host Server** | Report received and store by host server application |
| New Activity Report(s) received by host server application | 19 **Situational Evaluation** | New information is available for risk analysis queries<br>Situational HCA level report issued |
| User logged on with BA authentication<br>Network Risk Analysis requested<br>New activity report information | 20 **Display Network Risk Analysis Table** | Prioritized risk analysis table (gains chart) |
| Geographical Network Risk display requested | 21 **Display ARCGIS Risk Visualization** | ARCGIS network visualization of pipeline segment risk generated |
| ARCGIS risk display | 22 **Zoom to Demo Pipe Segments** | Pipe segment that received new field report data displayed<br>Status updated based on latest data |

## *Deployment and Testing*

In this section, we describe our deployment and testing methodology, test data, test cases, and the various types of testing performed on Keyhole inspection form, first response form, audit form, and Bayesian network.

**Table 7-3. Technical Specification of the Deployment Environment**

| | Details |
|---|---|
| Vendor | Microsoft Azure |
| Operating System | Microsoft Windows 10 Virtual Machine |
| Virtual Machine Hardware | 2.4 GHz Intel Xeon® E5-2673 v3 (Haswell) processor |
| Processor | 2 cores |
| RAM | 14 GB |
| Disk Space | 100 GB |

### Test Data Preparation

To test the system, a synthetic virtual gas pipeline network of Aldyl-A plastic pipes was prepared in GIS system. The pipe network consists of 7706 piping segments divided into five regions. Each segment was characterized with lab and synthetic data describing various pipe attributes such as pressure, material, installation date, repair date, associated leaks, etc. **Figure 7-29** shows the map of the test pipeline network.

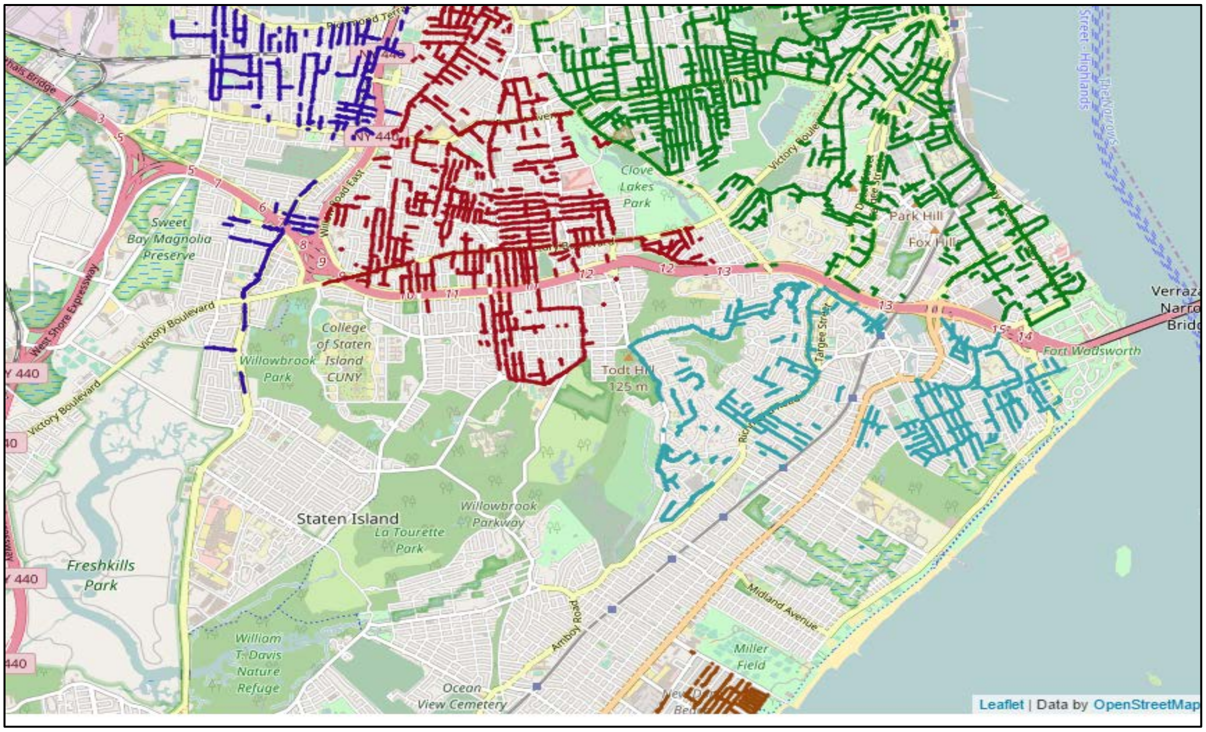



**Figure 7-29. Test gas distribution network**

SmartForms such as keyhole inspection and first response are connected to the test gas network and serve as a field data collection tool for individual pipe segment. The Bayesian network is also connected to the test gas distribution network and is used to calculate the mean life prediction and the risk of failure for every pipe segment. The testing of risk analysis can be conducted at segment level or region level.

## Test Case Preparation

Test cases are essential tools for systematic planning and execution of testing scenarios. In this project, a number of test cases were prepared to list a set of conditions to determine whether the deployed probabilistic decision support system and SmartForms satisfies the requirements and functions correctly. The system was tested and refined until all test cases were passed. The specification format for test cases used in this project is listed in the table below.

| Attributes | Definition |
|---|---|
| Test Case ID | Unique ID of the test case |
| Test Case Summary | Goal of the test case |
| Prerequisites | Any pre-condition that must be met before executing the test |
| Test Procedure | Detailed steps to execute the test |
| Test Data | Data to use for testing |

| | |
|---|---|
| Expected Result | Expected result of the test |
| Actual Result | Actual result from the test |
| Status | Pass/Fail to indicate the test result |
| Remarks | Additional comments about the test |
| Created By | Person who created the test case |
| Date of Creation | Date of test case creation |
| Executed By | Person who ran the test |
| Date of Execution | Date of test execution |
| Test Environment | Hardware and software environment in which the test was performed |

## Testing of Keyhole Inspection Form

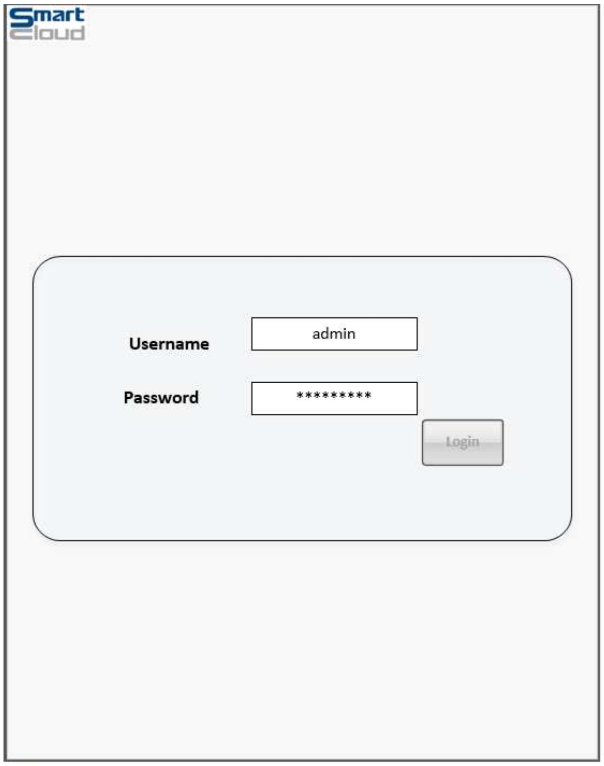
### *Functional Testing*

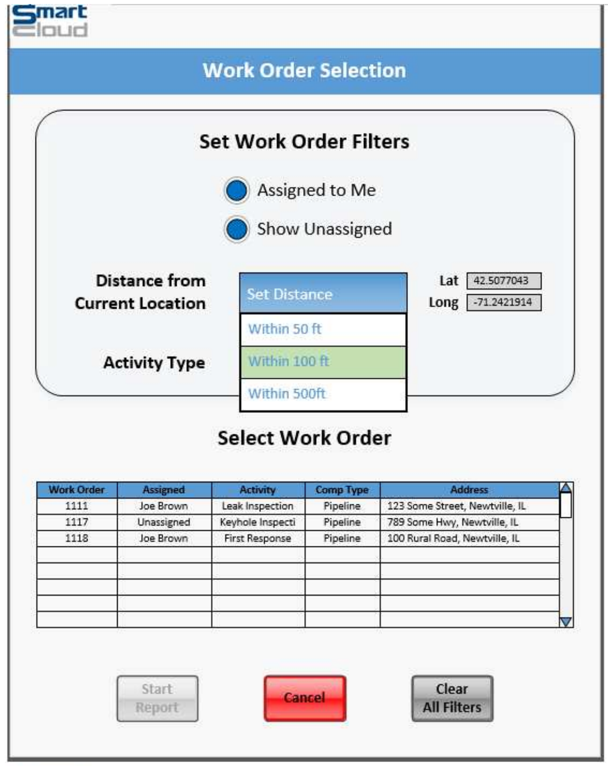
Each functionality of the Keyhole inspection form was tested to verify that it meets the requirement specification. An appropriate input is entered in the system and the output is verified by comparing the actual result with the expected result. The table below illustrates the steps taken for functional testing and lists the pass/fail grade for each testing step.

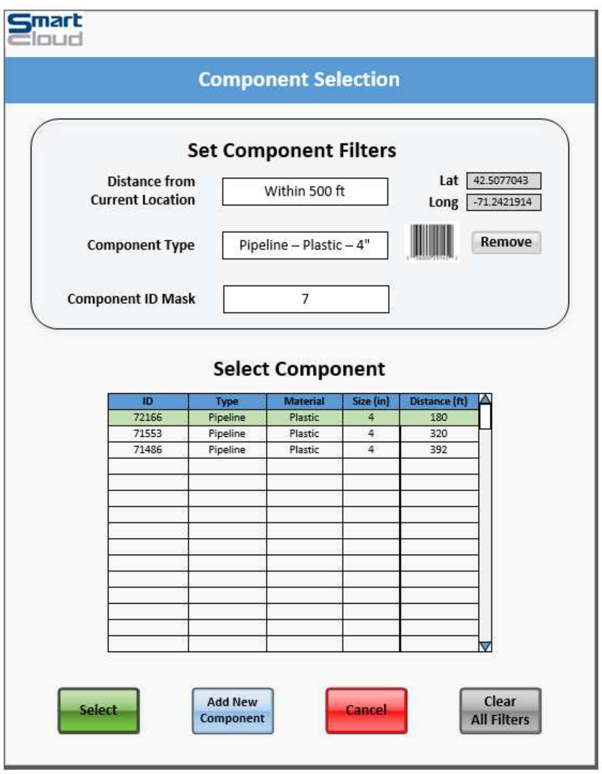
| Step # | Step Description | Test Data | Expected Results | Test Pass/Fail |
|---|---|---|---|---|
| 1 | Enter login information | username: *admin* password: *Admin12248* | Show keyhole inspection form main page | Pass |
| 2.a | Filter existing pipelines by barcode | ASTM F2897 barcode | List pipelines matching information in barcode | Pass |
| 2.b | Filter existing pipelines by distance | 100 feet | List pipelines within 100 feet of current location | Pass |
| 2.c | Filter existing pipelines by type | Aldyl-A plastic pipe | List all Aldyl-A pipelines | Pass |
| 3.a | Select existing pipeline from filtered list of pipelines | Pipeline with ID 72166 | Show next screen to view historical data of the pipeline selected | Pass |

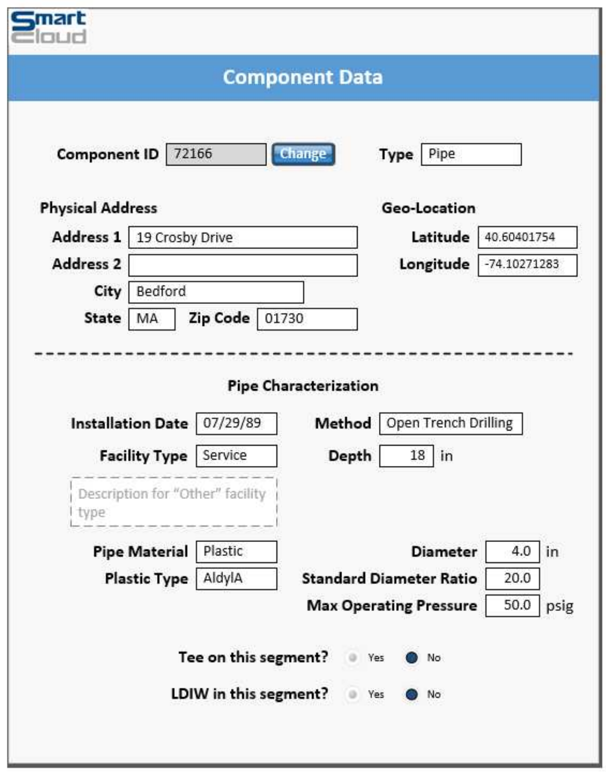
| | | | | |
|---|---|---|---|---|
| 3.b | Add new pipeline information | Pipeline with ID 77667 | Save new pipeline information and show screen to enter data | Pass |
| 4 | View historical pipeline data | | Show past data and allow updates | Pass |
| 5 | Enter new keyhole inspection data | | Collects all keyhole inspection data. As a next step, enable Save button | Pass |
| 6 | Save the entered keyhole inspection data | Press Save button | Save the data in cloud database | Pass |

Sample screen shots of the functional testing are shown in figures below.


Smart Cloud
Username
admin
Password
*********
Login


Smart Cloud
Work Order Selection
Set Work Order Filters
Assigned to Me
Show Unassigned
Distance from Current Location
Set Distance
Within 50 ft
Within 100 ft
Within 500ft
Lat 42.5077043
Long -71.2421914
Activity Type
Select Work Order
Work Order | Assigned | Activity | Comp Type | Address
1111 | Joe Brown | Leak Inspection | Pipeline | 123 Some Street, Newtville, IL
1117 | Unassigned | Keyhole Inspecti | Pipeline | 789 Some Hwy, Newtville, IL
1118 | Joe Brown | First Response | Pipeline | 100 Rural Road, Newtville, IL
Start Report
Cancel
Clear All Filters


Smart Cloud
Component Selection
Set Component Filters
Distance from Current Location
Within 500 ft
Lat 42.5077043
Long -71.2421914
Component Type
Pipeline – Plastic – 4"
Remove
Component ID Mask
7
Select Component
ID | Type | Material | Size (in) | Distance (ft)
72166 | Pipeline | Plastic | 4 | 180
71553 | Pipeline | Plastic | 4 | 320
71486 | Pipeline | Plastic | 4 | 392
Select
Add New Component
Cancel
Clear All Filters


Smart Cloud
Component Data
Component ID 72166
Change
Type Pipe
Physical Address
Address 1 19 Crosby Drive
Address 2
City Bedford
State MA
Zip Code 01730
Geo-Location
Latitude 40.60401754
Longitude -74.10271283
Pipe Characterization
Installation Date 07/29/89
Method Open Trench Drilling
Facility Type Service
Depth 18 in
Description for "Other" facility type
Pipe Material Plastic
Plastic Type AldylA
Diameter 4.0 in
Standard Diameter Ratio 20.0
Max Operating Pressure 50.0 psig
Tee on this segment? Yes No
LDIW in this segment? Yes No

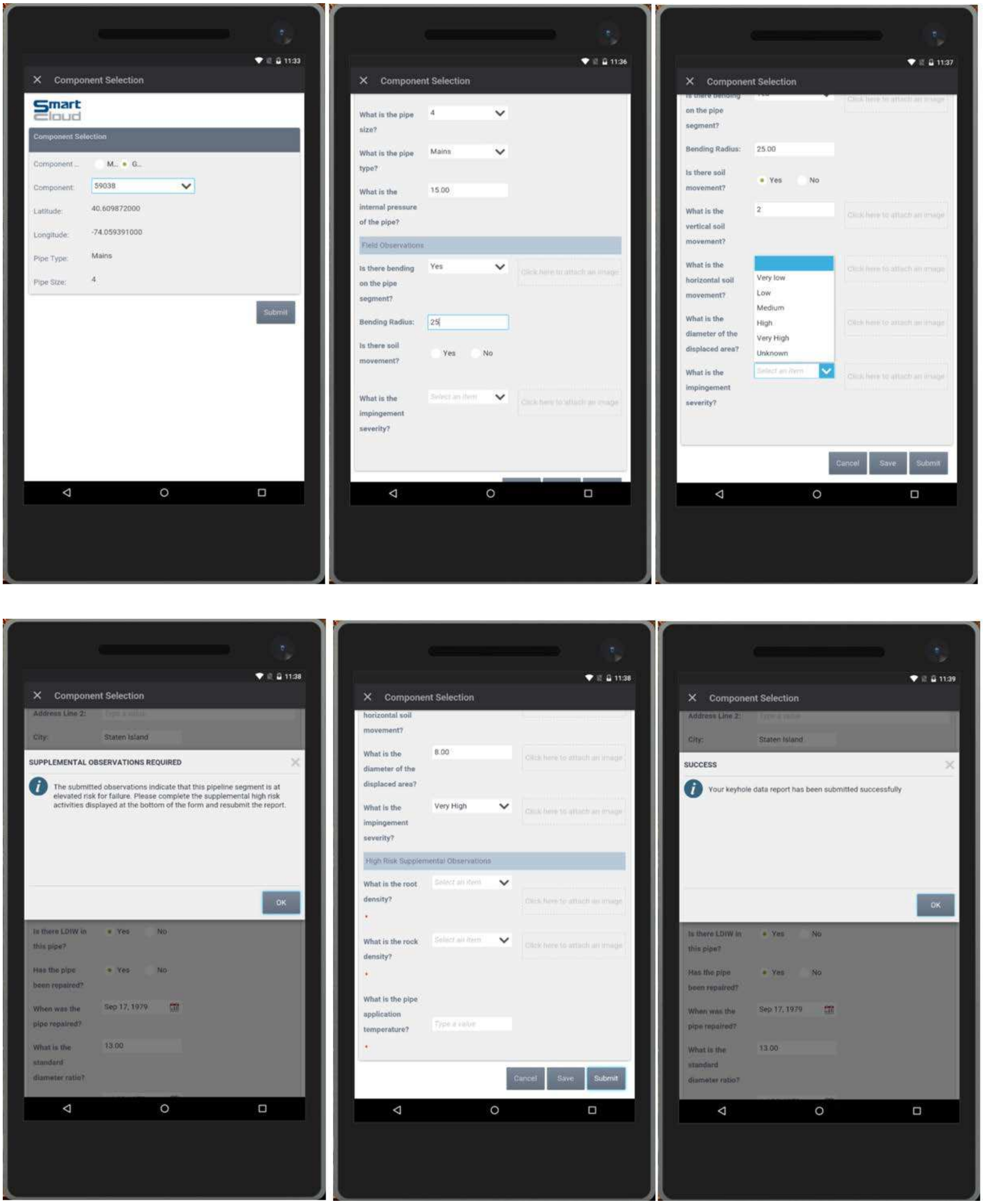



Figure 7-30. Screen captures of Keyhole Inspection Form mobile application

### *System Integration Testing*

In system integration testing, keyhole inspection form was combined with database and Bayesian network in the server and tested as a single system. Table below describes the steps taken during the integration testing and lists the pass/fail grade for each step.

| Step # | Step Description | Test | Expected Results | Test Pass/Fail |
|---|---|---|---|---|
| 1 | Deploy the latest Keyhole Inspection Form in cloud server | Run unit test for integrity checks | Provides latest version of the application for installation in mobile devices | Pass |
| 2 | Create database table to store the keyhole inspection data | Run unit test queries | Stores data collected from Keyhole inspection form | Pass |
| 3 | Install the SmartForms application in mobile that includes keyhole leak inspection form | Install/update the application in android phone | Pulls latest version of the application from server and installs it in the mobile device | Pass |
| 4 | Open mobile application and enter keyhole inspection data | Enter keyhole inspection data through the mobile application and press save button in the application | Updates database table in the server with new information | Pass |

### *Validation Testing*

Validation testing verifies in detail that the keyhole inspection form meets requirement specification and each data collection field works as intended. The table below lists the data fields that were tested and the pass/fail result of the tests.

| Screen | Test Field | Entry | Branching | Attachments | Test Pass/Fail |
|---|---|---|---|---|---|
| 1 | Report Provenance Tab | | | | Pass |
| | | Form: Report Provenance | | | |
| 2 | Pipeline Component Tab | | | | Pass |
| | | Form: Pipeline Component | | | |
| 3 | Type of Job on Site | | | | Pass |

| | | | | | |
|---|---|---|---|---|---|
| | *(Options: Abandon Services, Cathodic Protection, Valve Maintenance, CI Joint Repair, Test Hole, Other)* | Pulldown text | | Notes | |
| 3 | Number of Core(s) | | | | Pass |
| | | Numeric | | Notes | |
| 3 | Core Diameter | | | | Pass |
| | *(Options: 18", 24")* | Pulldown text | | Notes | |
| 3 | Core Thickness | | | | Pass |
| | | Numeric, inches | | Notes | |
| 3 | Vacuum Only | | | | Pass |
| | *(Options: Yes, No)* | Button selection | | Notes | |
| 3 | Depth of Facility | | | | Pass |
| | | Numeric, inches | | Notes | |
| 3 | Operating Pressure | | | | Pass |
| | | Numeric, psig<br>Not Available | | Notes | |
| 3 | Maximum Operating Pressure | | | | Pass |
| | | Numeric, psig | | | |
| 3 | Soil Temperature | | | | Pass |
| | Converted to C for BN | Numeric, °F<br>Not Available | | Notes | |
| 3 | Pipe Condition | | | | Pass |
| | *(Options: Good, Break, Damage, Light Corrosion, Heavy Corrosion, Thru Corrosion, Joint Flaw, Other)* | Pulldown text | | Picture, Notes | |
| 3 | External Coating | | | | Pass |
| | *(Options: X-tru coat, Coal tar enamel, Tape wrap, FBE, Powder Coating, Mastic, Wax tape, Not Available)* | Pulldown text - Any Known Type | Expose: Coating Condition<br><br>Expose: Adhesion Status | Picture, Notes | |
| | | Pulldown text - Not Available | | | |
| 3 | Coating Condition | | Conditional | | Pass |
| | *(Options: Good, Bare, Damage, Poor Joint, Deteriorated)* | Pulldown text | | Picture, Notes | |
| 3 | Coating Adhesion | | Conditional | | Pass |
| | *(Options: Bonded, Disbonded)* | Button selection | | Notes | |
| 3 | External Coating | | | | Pass |
| | *(Options: X-tru coat, Coal tar enamel, Tape wrap, FBE, Powder Coating, Mastic, Wax Tape, Not Available)* | Pulldown text | | Picture, Notes | |
| 3 | Coating Condition | | | | Pass |
| | *(Options: Good, Bare, Damage, Poor Joint, Deteriorated)* | Pulldown text | | Picture, Notes | |
| 3 | Impingement Depth | | | | Pass |

| | | | | | |
|---|---|---|---|---|---|
| | Convert to impingement ratio for classification<br>BN Classifications ([0-0.2],[0.2-0.4],[0.4-0.6],[0.6-0.8],[0.8+] | Numeric, inches | | Picture, Notes | |
| 3 | Bending on Pipe Segment? | | | | Pass |
| | *(Options: Yes, No, Not Available)* | Pulldown - Yes | Expose: Bending Radius | Picture, Notes | |
| | | Pulldown - No | | | |
| | | Pulldown – Not Available | | | |
| 3 | Bending Radius | | Conditional | | Pass |
| | | Numeric, feet | | | |
| 4 | Soil Type | | | | Pass |
| | *(Options: Standard, Clay, Gravel, Sand, Peat)* | Pulldown text | | Picture, Notes | |
| 4 | Root Density | | | | Pass |
| | *(Options: Very Low, Low, Medium, High, Very High, Not Available)* | Pulldown selection | | Picture, Notes | |
| 4 | Rock Density | | | | Pass |
| | *(Options: Very Low, Low, Medium, High, Very High, Not Available)* | Pulldown selection | | Picture, Notes | |
| 4 | Soil Movement | | | | Pass |
| | *(Options: Yes, No)* | Button selection - Yes | Expose: Vertical Soil Movement<br>Expose: Horizontal Soil Movement<br>Expose: Diameter of Displaced Area | Picture, Notes | |
| | | Button selection - No | | | |
| 4 | Vertical Soil Movement | | Conditional | | Pass |
| | | Numeric, feet | | Picture, Notes | |
| 4 | Horizontal Soil Movement | | Conditional | | Pass |
| | | Numeric, feet | | Picture, Notes | |
| 4 | Diameter of Displaced Soil Area | | Conditional | | Pass |
| | | Numeric, feet | | Picture, Notes | |
| 4 | Prior Leak Repair? | | | | Pass |
| | *(Leak Repair Report ID, if found<br>"No Repair Recorded", if no prior report<br>"Not Available" if no CRex connectivity)* | Report ID | Expose: Repair Date | | |
| | | "No Repair Recorded" | | | |
| | | "Not Available" | | | |
| 4 | Repair Date | | Conditional | | Pass |
| | | Date (YYMMDD) | | | |
| 5 | Leak Found? | | | | Pass |

| | | | | | |
|---|---|---|---|---|---|
| | *(Options: Yes, No)* | Button selection | Expose: Leak Grade<br>Expose: Leak Size Characterization | Notes | |
| 5 | Equipment Used | | | | Pass |
| | *(Options: Flame Ionization, Remote Methane Leak Detection, Other)* | Pulldown text - Flame Ionization | | Notes | |
| | | Pulldown text - Remote Methane Leak Detection | | | |
| | | Pulldown text - Other | Expose: Other Equip Type Description | | |
| 5 | Wind Speed | | | | Pass |
| | | Numeric, m/s<br>Not Available | | Notes | |
| 5 | Wind Direction | | | | Pass |
| | *(Options: N, NE, E, SE, S, SW, W, NW, Not Available)* | Pulldown text | | Notes | |
| 5 | Leak Grade | | Conditional | | Pass |
| | *(Options: Grade 1, Grade 2, Grade 3)* | Pulldown text | | Notes | |
| 5 | Leak Size Characterization | | Conditional | | Pass |
| | *(Options: Diameter, Length)* | Button selection - Diameter | Expose: Leak Size - Diameter | Notes | |
| | | Button selection - Length | Expose: Leak Size - Length | | |
| 5 | Leak Size - Diameter | | Conditional | | Pass |
| | | Numeric, in | | Picture, Notes | |
| 5 | Leak Size - Length | | Conditional | | Pass |
| | | Numeric, in | | Picture, Notes | |

### *Risk Calculation Testing*

To demonstrate how keyhole inspection form helps to refine the risk profiles of the gas distribution network with latest data, we selected five pipeline segments randomly and calculated mean life expectancy and risk score before and after the new data was collected with keyhole inspection form. **Table 7-4** and **Table 7-5** show the data before and after the data is collected. Then, the original and updated data are given as input for the developed Bayesian network, which estimates the life expectancy for each pipe segment. The mean life expectancy is the direct measure for the pipe failure likelihood, while the consequence of the failure is determined by the type of buildings or facilities. Given the likelihood and consequence, the risk is simply the product of those two measures. The computed risk for the original and update data is shown in **Table 7-6**.

Table 7-4. Data before Keyhole inspection collects new information

| ID | Years after Repair | Root | Rock | Horiz Soil_ Mov | Vert_Soil _Mov | Diameter of Displaced Area | Pipe Size | Pressure | If LDW | If Repaired | Leak Type |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 30 | Med | Med | 8 | 11 | 25 | <= 2 inch | 45 | True | True | Type 3 |
| 2 | 31 | Med | Very High | 0 | 5 | 8 | <= 2 inch | 45 | True | True | Type 3 |
| 3 | 26 | Med | Low | 8 | 7 | 8 | <= 1 inch | 45 | True | True | Type 3 |
| 4 | 32 | Med | Very Low | 1 | 6 | 2 | <= 1 inch | 55 | True | True | Type 3 |
| 5 | 31 | Med | Med | 3 | 6 | 25 | <= 4 inch | 55 | True | True | Type 3 |

Table 7-5. Latest data from Keyhole inspection

| ID | Years after Repair | Root | Rock | Horiz Soil_ Mov | Vert_ Soil_ Mov | Diameter of Displaced Area | Pipe Size | Pressure | If LDW | If Repaired | Leak Type |
|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | 33 | Med | Med | 9 | 11 | 26 | <= 2 inch | 45 | True | True | Type 3 |
| 2 | 34 | Med | Very High | 1 | 5 | 8.7 | <= 2 inch | 45 | True | True | Type 1 |
| 3 | 29 | Med | High | 8 | 7 | 8 | <= 1 inch | 45 | True | True | Type 1 |
| 4 | 35 | Med | Low | 1 | 9 | 2.2 | <= 1 inch | 55 | True | True | Type 2 |
| 5 | 34 | Med | Med | 3 | 9 | 27.5 | <= 4 inch | 55 | True | True | Type 2 |

Table 7-6. Mean life prediction of pipeline segments before and after data is collected with keyhole inspection form

| ID | Mean life prediction before data is collected | Mean life prediction after data is collected |
|---|---|---|
| 1 | 0.615875 | 0.740329 |
| 2 | 0.799914 | 0.799998 |
| 3 | 0.282651 | 0.357131 |
| 4 | 0.799711 | 0.79999 |
| 5 | 0.799999 | 0.8 |

From **Table 7-7**, the mean life expectancy is decreasing when the data are updated three years later. However, the change in life expectancy is relatively small compared with the original values. Therefore, the updated risks for those 3 segments are not affected by the newly gathered data. Practically, effective prevention or mitigation measures should be taken if the risks are higher than a threshold value (i.e. risk tolerance).

**Table 7-7. Risk after a number of years**

| | ID | 1 yr | 2 yrs | 3 yrs | 4 yrs | 5 yrs | 10 yrs | 15 yrs | 20 yrs | 30 yrs |
|---|---|---|---|---|---|---|---|---|---|---|
| *Before data is collected with Keyhole Inspection Form* | 1 | 3.22E-06 | 0.000445 | 0.004234 | 0.015893 | 0.038045 | 0.256674 | 0.475484 | 0.615875 | 0.740329 |
| | 2 | 0.002101 | 0.078987 | 0.272732 | 0.467648 | 0.605736 | 0.788866 | 0.799168 | 0.799914 | 0.799998 |
| | 3 | 6.12E-08 | 1.04E-05 | 0.000129 | 0.000621 | 0.001868 | 0.029596 | 0.09568 | 0.182651 | 0.357131 |
| | 4 | 0.002505 | 0.074884 | 0.249289 | 0.430559 | 0.567443 | 0.780286 | 0.797916 | 0.799711 | 0.79999 |
| | 5 | 0.026625 | 0.296322 | 0.566769 | 0.703688 | 0.761005 | 0.799371 | 0.799979 | 0.799999 | 0.8 |
| *After data is collected with Keyhole Inspection Form* | 1 | 4.43E-06 | 0.000611 | 0.005669 | 0.02074248 | 0.048468 | 0.298187 | 0.522008 | 0.652887 | 0.75768 |
| | 2 | 0.003519 | 0.100391 | 0.309649 | 0.5015927 | 0.629989 | 0.790707 | 0.799302 | 0.799927 | 0.799998 |
| | 3 | 1.08E-07 | 1.6E-05 | 0.000186 | 0.00085565 | 0.002484 | 0.035684 | 0.109744 | 0.202996 | 0.382059 |
| | 4 | 0.001216 | 0.039984 | 0.152908 | 0.29763093 | 0.431237 | 0.737363 | 0.788531 | 0.797506 | 0.799818 |
| | 5 | 0.037506 | 0.345769 | 0.60884 | 0.72716615 | 0.772429 | 0.799645 | 0.79999 | 0.799999 | 0.8 |

## Testing of First Response Form

### *Functional Testing*

Each functionality of the First Response Form was tested to verify that it meets the requirement specification. An appropriate input is entered in the system and the output is verified by comparing the actual result with the expected result. The table below illustrates the steps taken for functional testing and lists the pass/fail grade for each testing step.

| Step # | Step Description | Test Data | Expected Results | Test Pass/Fail |
|---|---|---|---|---|
| 1 | Enter login information | username: *admin*<br>password: *Admin12248* | Show first response form main page | Pass |
| 2.a | Filter existing pipelines by barcode | ASTM F2897 barcode | List pipelines matching information in barcode | Pass |
| 2.b | Filter existing pipelines by distance | 100 feet | List pipelines within 100 feet of current location | Pass |
| 2.c | Filter existing pipelines by type | Aldyl-A plastic pipe | List all Aldyl-A pipelines | Pass |
| 3.a | Select existing pipeline from filtered list of pipelines | Pipeline with ID '72166' | Show next screen to view historical data of the pipeline selected | Pass |
| 3.b | Add new pipeline information | Pipeline with ID '77667' | Save new pipeline information and show screen to enter data | Pass |
| 4 | View historical pipeline data | | Show past data and allow updates | Pass |
| 5 | Enter new first response data | **Please refer to:** | Collects all first response data. As a next step, enable Save button | Pass |
| 6 | Save the entered first response data | Press Save button | Save the data in cloud database | Pass |

### *System Integration Testing*

In the system integration testing, First Response Form was combined with database and Bayesian network in the server and tested as a single system. Table below describes the steps taken during the integration testing and lists the pass/fail grade for each step.

| Step # | Step Description | Test | Expected Results | Test Pass/Fail |
|---|---|---|---|---|
| 1 | Deploy the latest First Response Form in cloud server | Run unit test for integrity checks | Provides latest version of the application for installation in mobile devices | Pass |
| 2 | Create database table to store the first response data | Run unit test queries | Stores data collected from first response form | Pass |
| 3 | Install the SmartForms application in mobile that includes first response form | Install/update the application in android phone | Pulls latest version of the application from server and installs it in the mobile device | Pass |
| 4 | Open mobile application and enter first response data | Enter first response data through the mobile application and press save button in the application | Updates database table in the server with new information | Pass |

### *Validation Testing*

Validation testing verifies in detail that the First Response Form meets requirement specification and each data collection field works as intended. The table below lists the data fields that were tested and the pass/fail result of the tests. First response form is divided into different tabs in android application for ease of usage.

*Tab: First Response Header*

| Screen | Field | Entry | Branching | Attachments | Test Pass/Fail |
|---|---|---|---|---|---|
| Hdr | First Response No. | | | | |
| | | FSTR-000000 | | | Pass |
| Hdr | Work Order No. | | | | |
| | | Text, from WO selection | | | Pass |
| Hdr | Component ID | | | | |
| | | Text, from Component tab | | | Pass |

*Tab: First Response Footer*

| Screen | Field | Entry | Branching | Attachments | Test Pass/Fail |
|---|---|---|---|---|---|
| Hdr | First Response No. | | | | |
| | | FSTR-000000 | | | Pass |
| Hdr | Work Order No. | | | | |
| | | Text, from WO selection | | | Pass |
| Hdr | Component ID | | | | |
| | | Text, from Component tab | | | Pass |

*Tab: First Response*

| Screen | Field | Entry | Branching | Attachments | Test Pass/Fail |
|---|---|---|---|---|---|
| 1 | Report Provenance Tab | | | | |
| | | Form: Report Provenance | | | Pass |
| 2 | Component Tab | | | | |
| | | Form: Basic Info (top half)<br>Based on Component Type (bottom half):<br>Form: Pipeline, Ind Meter, or Res Meter | Based on type, Expose:<br>Pipeline, Industrial Meter,<br>or Residential Meter tab | | Pass |
| 3 | Report Type | | | | |
| | *(Options: Leak Response, Exposed Metal Pipe)* | Button selection - Leak Response | Expose: Leak Response tab | | Pass |
| | | Button selection - Exposed Metal Pipe | Expose: Exposed Pipe tab | | |
| 4a | Leak Response Tab | | Conditional | | |
| | | Form: Leak Response | | | Pass |
| 4b | Exposed Pipe Tab | | Conditional | | |
| | | Form: Exposed Pipe | | | Pass |

## *Tab: Leak Response*

| Screen | Field | Entry | Branching | Attachments | Test Pass/Fail |
|---|---|---|---|---|---|
| 1 | Leak Grade | | | | |
| | *(Options: Grade 1, Grade 2, Grade 3)* | Pulldown text | | Notes | Pass |
| 1 | Wind Speed | Not Available | | | |
| | | Numeric, m/s | | Notes | Pass |
| 1 | Wind Direction | | | | |
| | *(Options: N, NE, E, SE, S, SW, W, NW, Not Available)* | Pulldown text | | Notes | Pass |
| 1 | Ambient Temperature | Not Available | | | |
| | *Converted to C for Bayesian Network* | Numeric, °F | | Notes | Pass |
| 1 | Equipment ID | | | | |
| | | Text | | Notes | Pass |
| 1 | Inside Investigation Needed | | | | |
| | *(Options: Yes, No)* | Button selection - Yes | Expose: Inside Investigation Performed | Notes | Pass |
| | | Button selection - No | | | |
| 1 | Inside Investigation Performed | | Conditional | | |
| | *(Options: Yes, No, No Access)* | Button selection | | Picture, Notes | Pass |
| 1 | Soap Test | | | | |
| | *(Options: Yes, No)* | Button selection - Yes | Expose: Test Type<br>Expose: Start Time<br>Expose: End Time<br>Expose: Pressure<br>Expose: Results<br>Expose: Length of Pipe | Notes | Pass |
| | | Button selection - No | | | |
| 1 | Test Type | | Conditional | | |
| | *(Options: Air, Gas, Water, Nitrogen)* | Pulldown text | | Picture, Notes | Pass |
| 1 | Start Time | | Conditional | | |
| | | Timestamp | | | Pass |
| 1 | End Time | | Conditional | | |
| | | Timestamp | | | Pass |
| 1 | Pressure | | Conditional | | |
| | | Numeric, psig<br>Not Applicable | | Notes | Pass |
| 1 | Test Result | | Conditional | | |
| | *(Options: Pass, Fail)* | Button selection | | Notes | Pass |
| 1 | Length of Pipe | | Conditional | | |
| | | Numeric, ft<br>Not applicable | | Picture, Notes | Pass |

*Tab: Exposed Pipe*

| *Screen* | *Field* | *Answers* | *Branching* | *Attachments* | *Test Pass/Fail* |
|---|---|---|---|---|---|
| 1 | Length of Pipe Inspected | | | | |
| | | Numeric, ft | | | Pass |
| 1 | Exposed Pipe Accessibility | | | | |
| | *(Options: Accessible, Inaccessible)* | Button selection | | Picture, Notes | Pass |
| 1 | First PSP Reading | | | | |
| | | Numeric, volts | | | Pass |
| 1 | First PSP Read Latitude | | | | |
| | | Numeric<br>Use Current Location | | | Pass |
| 1 | First PSP Read Longitude | | | | |
| | | Numeric<br>Use Current Location | | | Pass |
| 1 | First PSP Outside Limit? | | | | |
| | *(Options: Outside Limits, Within Limits)* | Text - "Outside Limits" | Expose: Tech Called<br>Expose: Tech Callout Time | | Pass |
| | | Text- "Within Limits" | | | |
| 1 | Tech Called (per GOS 2575.2800) | | Conditional | | |
| | | Text | | | Pass |
| 1 | Tech Callout Time | | Conditional | | |
| | | Timestamp | | | Pass |
| 2 | External Coating | | | | |
| | *(Options: X-tru coat, Coal tar enamel, Tape wrap, FBE, Powder Coating, Mastic, Wax tape, Not Available)* | Pulldown text - Any Known Type | Expose: Coating Condition<br>Expose: Adhesion Status | Picture, Notes | Pass |
| | | Pulldown text - Not Available | | | |
| 2 | Coating Condition | | Conditional | | |
| | *(Options: Good, Bare, Damage, Poor Joint, Deteriorated)* | Pulldown text | | Picture, Notes | Pass |
| 2 | Coating Adhesion | | Conditional | | |
| | *(Options: Bonded, Disbonded)* | Button selection | | Notes | Pass |
| 2 | Pipe Damage | | | | |
| | *(Options: Damaged, Not Damaged)* | Button selection - Damaged | Expose: Damage Requires Remediation<br>Expose: Describe Damage | Picture, Notes | Pass |
| | | Button selection - Not Damaged | | | |
| 2 | Damage Requires Remediation? (per GOS 2575.1700) | | Conditional | | |
| | *(Options: Yes, No)* | Button selection | | Notes | Pass |
| 2 | Describe Pipe Damage | | Conditional | | |
| | | Text | | | Pass |

| | | | | | |
|---|---|---|---|---|---|
| 3 | External Corrosion? | | | | |
| | *(Options: Corrosion, No Corrosion)* | Button selection - Corrosion | Expose: External Corrosion Type<br>Expose: Corrosion Requires Remediation | Picture, Notes | Pass |
| | | Button selection - No Corrosion | | | |
| 3 | External Corrosion Type | | Conditional | | |
| | *(Options: Surface Rust, Isolated Pit, Multiple Pits, General Corrosion, Not Available)* | Pulldown text - Isolated Pit<br>- Multiple Pits | Expose: Maximum Pit Depth<br>Expose: Pit Circumference<br>Expose: Pit Position | Picture, Notes | Pass |
| | | Pulldown text - Multiple Pits | Expose: Distance between Pits<br>Expose: Length of Pitting | | |
| | | Pulldown text - all others | | | |
| 3 | Maximum Pit Depth | | Conditional | | |
| | | Numeric, in | | Picture, Notes | Pass |
| 3 | Pit Circumference | | Conditional | | |
| | | Numeric, in | | Picture, Notes | Pass |
| 3 | Distance between Pits | | Conditional | | |
| | | Numeric, ft | | Picture, Notes | Pass |
| 3 | Length of Pitting on Pipe | | Conditional | | |
| | | Numeric, ft | | Picture, Notes | Pass |
| 3 | Position of Pitting | | Conditional | | |
| | | Text box | | Picture | Pass |
| 3 | Corrosion Requires Remediation? (per GOS 2600.1900) | | Conditional | | |
| | *(Options: Yes, No)* | Button selection | | Notes | Pass |
| 4 | Pipe Interior Visible? | | | | |
| | *(Options: Visible, Not Visible* | Button selection - Visible | Expose: Retired Pipe<br>Expose: Coupon<br>Expose: Internal Corrosion | Picture, Notes | Pass |
| | | Button selection - Not Visible | | | |
| 4 | Retired Pipe | | Conditional | | |
| | *(Options: Yes, No)* | Button selection | | Notes | Pass |
| 4 | Coupon | | Conditional | | |
| | *(Options: Yes, No)* | Button selection - Yes | Expose: Coupon ID | Picture, Notes | Pass |
| | | Button selection - No | | | |
| 4 | Coupon ID | | Conditional | | |
| | | Text | | | Pass |
| 4 | Internal Corrosion? | | | | |
| | *(Options: Corrosion, No Corrosion, Not Available)* | Button selection - Corrosion | Expose: Internal Corrosion Type | Picture, Notes | Pass |

| | | | | | |
|---|---|---|---|---|---|
| | | | Expose: Corrosion Requires Remediation | | |
| | | Button selection - No Corrosion | | | |
| | | Button selection - Not Available | Expose: Not Available Explanation | | |
| 4 | Not Available Explanation | | Conditional | | |
| | | Text box | | | Pass |
| 4 | Internal Corrosion Type | | Conditional | | |
| | *(Options: Surface Rust, Isolated Pit, Multiple Pits, General Corrosion)* | Pulldown text - Isolated Pit - Multiple Pits | Expose: Maximum Pit Depth<br>Expose: Pit Circumference<br>Expose: Pit Position | Picture, Notes | Pass |
| | | Pulldown text - Multiple Pits | Expose: Distance between Pits<br>Expose: Length of Pitting | | |
| | | Pulldown text - all others | | | |
| 4 | Maximum Pit Depth | | Conditional | | |
| | | Numeric, in | | Picture, Notes | Pass |
| 4 | Pit Circumference | | Conditional | | |
| | | Numeric, in | | Picture, Notes | Pass |
| 4 | Distance between Pits | | Conditional | | |
| | | Numeric, ft | | Picture, Notes | Pass |
| 4 | Length of Pitting on Pipe | | Conditional | | |
| | | Numeric, ft | | Picture, Notes | Pass |
| 4 | Position of Pitting | | Conditional | | |
| | | Text box | | Picture | Pass |
| 4 | Corrosion Requires Remediation? (per GOS 2600.1900) | | Conditional | | |
| | *(Options: Yes, No)* | Button selection | | Notes | Pass |
| 5 | Cast Iron Graphitization? | | Conditional Tab: Pipe Material: Cast Iron | | |
| | *(Options: Yes, No)* | Button selection - Yes | Expose: Graphitization Location<br>Expose: Extent of Graphitization | Picture, Notes | Pass |
| | | Button selection - No | | | |
| 5 | Graphitization Location | | Conditional | | |
| | | Text | | | Pass |
| 5 | Extent of Graphitization | | Conditional | | |
| | | Text | | | Pass |
| 6 | Second PSP Reading | | | | |
| | | Numeric, volts | | | Pass |
| 6 | Second PSP Read Latitude | | | | |
| | | Numeric<br>Use Current Location | | | Pass |

| | | | | | |
|---|---|---|---|---|---|
| 6 | Second PSP Read Longitude | | | | |
| | | Numeric<br>Use Current Location | | | Pass |
| 6 | Second PSP Outside Limit? | | | | |
| | *(Options: Outside Limits, Within Limits)* | Text - Outside Limits | Expose: Tech Called<br>Expose: Tech Callout Time | | Pass |
| | | Text- Within Limits | | | |
| 6 | Tech Called (per GOS 2575.2800) | | Conditional | | |
| | | Text | | | Pass |
| 6 | Tech Callout Time | | Conditional | | |
| | | Timestamp | | | Pass |

## Testing of Audit Report Form

### *Functional Testing*

Each functionality of the Audit Report Form was tested to verify that it meets the requirement specification. An appropriate input is entered in the system and the output is verified by comparing the actual result with the expected result. The table below illustrates the steps taken for functional testing and lists the pass/fail grade for each testing step.

| Step # | Step Description | Test Data | Expected Results | Test Pass/Fail |
|---|---|---|---|---|
| 1 | Enter login information | username: *admin*<br>password: *Admin12248* | Show audit report main page | Pass |
| 2 | View annual report data | | Show gas distribution system data from past year | Pass |
| 3 | Enter data for any empty fields | **Please refer to:** | **Collects.** As a next step, enable Save button | Pass |
| 4 | Save the completed audit report form | Press Save button | Save the data in cloud database | Pass |

**Figure 7-31** shows the screenshot of Annual Report Form design.

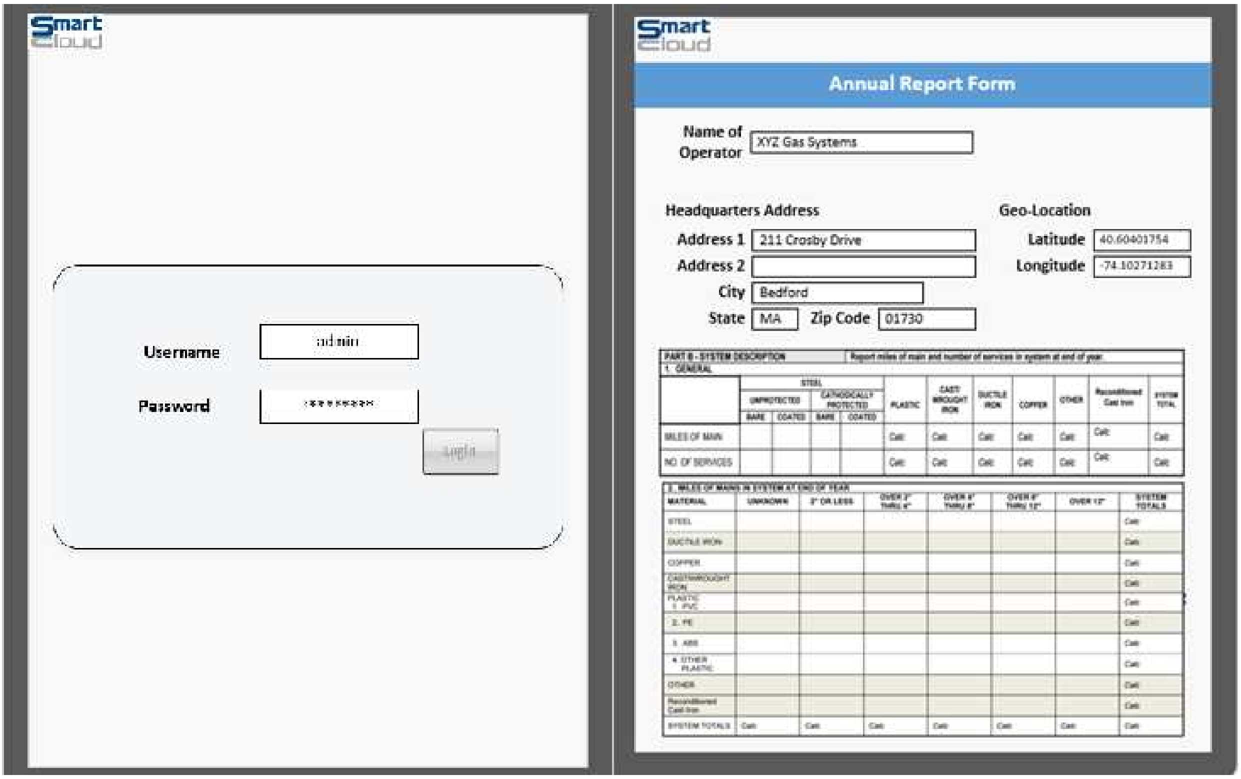



Figure 7-31. Annual Report Form login page and main section

### *System Integration Testing*

In the system integration testing, Audit Report Form was connected to the database in the server and tested as a single system. Table below describes the steps taken during the integration testing and lists the pass/fail grade for each step.

| Step # | Step Description | Test | Expected Results | Test Pass/Fail |
|---|---|---|---|---|
| 1 | Deploy the latest annual report form in cloud server | Run unit test for integrity checks | Provides latest version of the application for report generation | Pass |
| 2 | Create database table to store the annual report data | Run unit test queries | Stores data derived from the main database of gas distribution system | Pass |
| 3 | Open and complete Audit report form | Verify data displayed in the audit form, complete any remaining empty fields, and press save button in the application | Updates database table in the server with new information | Pass |

### *Validation Testing*

Validation testing verifies in detail that the Audit Report Form meets requirement specification and each data collection field works as intended. The table below lists the data fields that were tested and the pass/fail result of the tests.

Audit for Integrity Management Program (Process, Inspection, Mitigation, and Prevention) as prescribed in ASME B31.8S standard

| Integrity Management Program Area | Audit Questions | Test Pass/Fail |
|---|---|---|
| Pipe Segmentation | Has the whole pipeline system been segmented?<br>• How many miles of pipeline were investigated?<br>• Was it different from the value specified by the requirements?<br>What were the company specific integrity management goals/objectives?<br>Did the operator consider those goals when applying the process?<br>Was there a new pipeline becoming a part of an integrity management program?<br>• If so, were the functional requirements, including prevention, detection, and mitigation considered?<br>Is the risk assessment results applicable to the pipe within the segment?<br>• If not, what was the reason for limiting its application? | Pass |
| Threat Identification | Did the operator identify/evaluate all the threats?<br>• If not, which one(s) of following was the reason for excluding the threat/threats?<br>• There is no history of a threat impacting the particular segment or pipeline system<br>• The threat is not supported by applicable industry data or experience<br>• The threat is not implied by related data elements<br>• The threat is not supported by like/similar analyses<br>• The threat is not applicable to system or segment operating conditions<br>Were there multiple threats occurring on the pipe segment?<br>• If so, was the interaction considered? | Pass |
| Data Collection and Integration | Did the operator have a comprehensive plan for collecting, reviewing, and analyzing all data sets?<br>Did the operator include all possible data sources specified in ASME B31.8S?<br>• If not, what was the reason for excluding the specific data source?<br>Did the operator check the quality and deficiency of the collected data? | Pass |

| | | |
|---|---|---|
| | • Did the operator follow the ASCE, PHMSA ADB, ASTM GARP, and ISO standards when checking the quality?<br>• Did the operator follow the prescriptive process when the data quality and sufficiency was below requirement? | |
| Risk Assessment | Did the operator consider all the consequence factors specified in ASME B31.8S when doing risk assessment?<br>• If not, what was the reason for excluding the specific factor?<br>Did the risk assessment possess the following characteristics?<br>a. Attributes(Defined logic and be structured)<br>b. Resources(Adequate personnel and time)<br>c. Operating/mitigation history(Consider the frequency and consequence of past events)<br>d. Predictive capability(Identify threats not considered)<br>e. Risk confidence (All data verified and checked)<br>f. Feedback(Continuous improvement)<br>g. Documentation(Thoroughly documented)<br>h. What if (Structure necessary to perform "what if" calculation)<br>i. Weighting factors (All threats and consequences weighted)<br>j. Structure (Compare, rank risk results to prioritize integrity management decision making)<br>k. Segmentation(Incorporate sufficient resolution of pipe pipeline segment size)<br>Was the result from risk assessment consistent with the industry's experience?<br>Was the result from risk assessment used to prioritize initial integrity assessment? | Pass |
| Integrity Assessment | Did the operator follow the standard ASME B31.8S for the selecting of integrity inspection tool for each threat type?<br>Were the techniques used not published by consensus standard?<br>• If so, did the operator follow the performance requirements of ASME B31.8S code and confirm the validity of this approach?<br>Were indications of defects discovered during inspection? | Pass |

| | | |
|---|---|---|
| | • If so, was the indication examined and evaluated to determine if they are actually defects or not?<br>Was any abnormality discovered using the inspection method?<br>• What was the number of anomalies found during inspection?<br>• Were these anomalies addressed properly?<br>Was the information updated periodically?<br>• If so, what is the frequency/interval for the information updating?<br>Was the plan flexible enough to incorporate new information acquired during integrity management?<br>Was the risk reassessment conducted periodically?<br>• If so, what is the frequency/interval for the reassessment?<br>Were the results from risk and integrity assessment considered when prioritizing inspections and mitigation activities? | |
| Response to Integrity Assessment | Was the repair activity made in accordance with ASME B31.8S?<br>Did the operator evaluate prevention techniques that prevent future deterioration of the pipeline?<br>Was the information obtained from risk and integrity assessment, mitigation activities added to database?<br>Was the plan or program updated when additional information was acquired and incorporated? | Pass |
| Performance Measures | Was enough time given to collect the data for measures selection?<br>Did the selected performance measures possess the general characteristics, including simple, measurable, attainable, relevant, permit timely evaluation?<br>• If not, which one(s) the following characteristics was missing?<br>o Simple<br>o Measurable<br>o Attainable<br>o Relevant<br>o Permit timely evaluation<br>Did the operator evaluate the performance measures periodically? | Pass |

| | | |
|---|---|---|
| | • If yes, what is the frequency/interval of the evaluation? (At least annually)<br>Did the operator conduct internal benchmarking and audit conducted on the selected measures?<br>Were the results from performance measures utilized to improve the integrity management process? | |
| Change of Plan | Were there operational changes for significant pressure, pressure cycles, and pressure fluctuation on the pipe segment?<br>• If yes, did the operator consider the fatigue failure mechanism?<br>Have the changes on technology, physical, process, organization been addressed?<br>Have the changes been incorporated into future risk assessment?<br>Has the plan change been monitored to ensure the performance measures effective?<br>Was benchmarking with other gas pipeline operators used?<br>• If so, was the performance measure derived from it carefully evaluated to ensure the comparisons are valid?<br>Were recommendations for changes based on the analysis of performance measures and audits? | Pass |
| Communication Plan | Did the operator keep the public, emergency responder, location official, jurisdictional authorities, and stakeholder informed during the process?<br>Did the communications take place periodically?<br>Was there a written procedure for the change of plan?<br>Were the system changes listed below reflected in the integrity management program?<br>a. Change in land use<br>b. Changes to the MAOP<br>c. Daily changes in operating pressure<br>Were changes identified and reviewed before implementation?<br>Did the personnel understand the whole plan change procedures?<br>Did the operator investigate the effectiveness of the plan?<br>Did the operator refresh the training for personnel after the change of plan? | Pass |

| | | |
|---|---|---|
| | Were the appropriate stakeholders given the opportunity to participate the risk assessment process?<br>Have the operator documented the changes, new technologies, and public awareness? | |
| Quality Control Plan | Were there quality control activities listed below in the integrity management plan?<br>a. Identify the processes that will be included in the quality program<br>b. Determine the sequence and interaction of these process<br>c. Determine the criteria and methods needed to ensure that both the operation and control of these processes are effective<br>d. Provide the resources and information necessary to support the operation and monitoring of these processes<br>e. Monitor, measure, and analyze these processes<br>f. implement actions necessary to achieve planned results and continued improvement of these processes<br>Were the relevant documents controlled and maintained at appropriate locations for the duration of the program?<br>Were the responsibilities and authorities clearly, formally defined?<br>Were results of the quality control plan reviewed at predetermined intervals?<br>Were the personnel involved in the program competent and qualified to execute the activities within the program?<br>Did the operator monitor the program to show it was being implemented according to plan?<br>Were control points, criteria, and/or performance metrics defined?<br>Were corrective actions to improve quality plan documented and their implementation monitored?<br>Were outside resources used to conduct any process that affected the quality of the program?<br>• If so, did the operator ensure control of such processes and document them within the quality program? | Pass |

### *Query Testing*

In this test, queries developed to fill PHMSA annual audit report for gas distribution pipeline titled "PHMSA F 7100.1-1 (Annual report form)" were tested. Sections A, B and C of the form was automatically filled with the aggregated data from the database.

## Conclusions

The tasks outlined in this section show that it is feasible to integrate the risk assessment tools developed in this project into a commercially available artificial intelligence platform designed to provide enterprise level decision support. The tasks discussed above addressed data flows and the provision of intelligent feedback to the operators given the data inputs and the analyses run on the inputs. We have demonstrated the system components necessary to arrive at system wide, and individual segment fitness for service information needed to drive rate cases, replacement programs and asset maintenance programs.

## 8. Feasibility of Using a Short-Term Pressure Test to Determine Fitness for Service in the Context of Slow Crack Growth

Kiefner and Maxey, 2000, published a report, "The Benefits and Limitations of Hydrostatic Testing", that gives a good overview of the motivation behind using a short-term pressure test to determine fitness for service of steel pipelines [89]. Some select portions of this report are presented in the inserts and **Figure 8-1** below:

> Both field experience and full-scale laboratory tests have revealed much about the benefits and limitations of hydrostatic testing. Among the things learned were the following:
>
> - Longitudinally oriented defects in pipe materials have unique failure pressure levels that are predictable on the basis of the axial lengths and maximum depths of the defects and the geometry of the pipe and its material properties(2).
> - The higher the test pressure, the smaller will be the defects, if any, that survive the test.
> - With increasing pressure, defects in a typical line-pipe material begin to grow by ductile tearing prior to failure. If the defect is close enough to failure, the ductile tearing that occurs prior to failure will continue even if pressurization is stopped and the pressure is held constant. The damage created by this tearing when the defect is about ready to fail can be severe enough that if pressurization is stopped and the pressure is released, the defect may fail upon a second or subsequent pressurization at a pressure level below the level reached on the first pressurization. This phenomenon is referred to as a pressure reversal(3, 4).
> - Testing a pipeline to its actual yield strength can cause some pipe to expand plastically, but the number of pipes affected and the amount of expansion will be small if a pressure-volume plot is made during testing and the test is terminated with an acceptably small offset volume or reduction in the pressure-volume slope(5).

## TEST-PRESSURE-TO-OPERATING-PRESSURE RATIO

The hypothesis that "the higher the test-pressure-to-operating-pressure ratio, the more effective the test", is validated by Figure 1. Figure 1 presents a set of failure-pressure-versus-defect-size relationships for a specific diameter, wall thickness, and grade of pipe. A great deal of testing of line-pipe materials over the years has validated these curves[(2)]. Each curve represents a flaw with a uniform depth-to-wall-thickness ratio. Nine such curves are given (d/t ranging from 0.1 to 0.9).

Consider the maximum operating pressure for the pipeline (the pressure level corresponding to 72 percent of SMYS). That pressure level is represented in Figure 1 by the horizontal line labeled MOP. At the MOP, no defect longer than 10 inches and deeper than 50 percent of the wall thickness can exist. Any such defect would have failed in service. Similarly, no defect longer than 4 inches and deeper than 70 percent of the wall thickness can exist, nor can one that is longer than 16 inches and deeper than 40 percent of the wall thickness.

By raising the pressure level above the MOP in a hydrostatic test, the pipeline's operator can assure the absence of defects smaller than those that would fail at the MOP. For example, at a test pressure level equivalent to 90 percent of SMYS, the largest surviving defects are determined in Figure 1 by the horizontal line labeled 90 percent of SMYS. At that level, the longest surviving defect that is 50 percent through the wall can be only about 4.5 inches. Compare that length to the length of the longest possible 50-percent-through flaw at the MOP; it was 10 inches. Alternatively, consider the minimum survivable depth at 90 percent SMYS for a 10-inch-long defect (the size that fails at the MOP if it is 50 percent through the wall). The survivable depth is only about 32 percent through the wall. By a similar process of reasoning, one can show that even smaller flaws are assured by tests to 100 or 110 percent of SMYS (the horizontal lines drawn at those pressure levels on Figure 1).

The point is that the higher the test pressure (above MOP), the smaller will be the possible surviving flaws. This fact means a larger size margin between flaw sizes left after the test and the sizes of flaws that would cause a failure at the MOP. If surviving flaws can be extended by operating pressure cycles, the higher test pressure will assure that it takes a longer time for these smaller flaws to grow to a size that will fail at the MOP. Thus, Figure 1 provides proof of the validity of the hypothesis (i.e., the higher the test-pressure-to-operating-pressure ratio, the more effective the test).

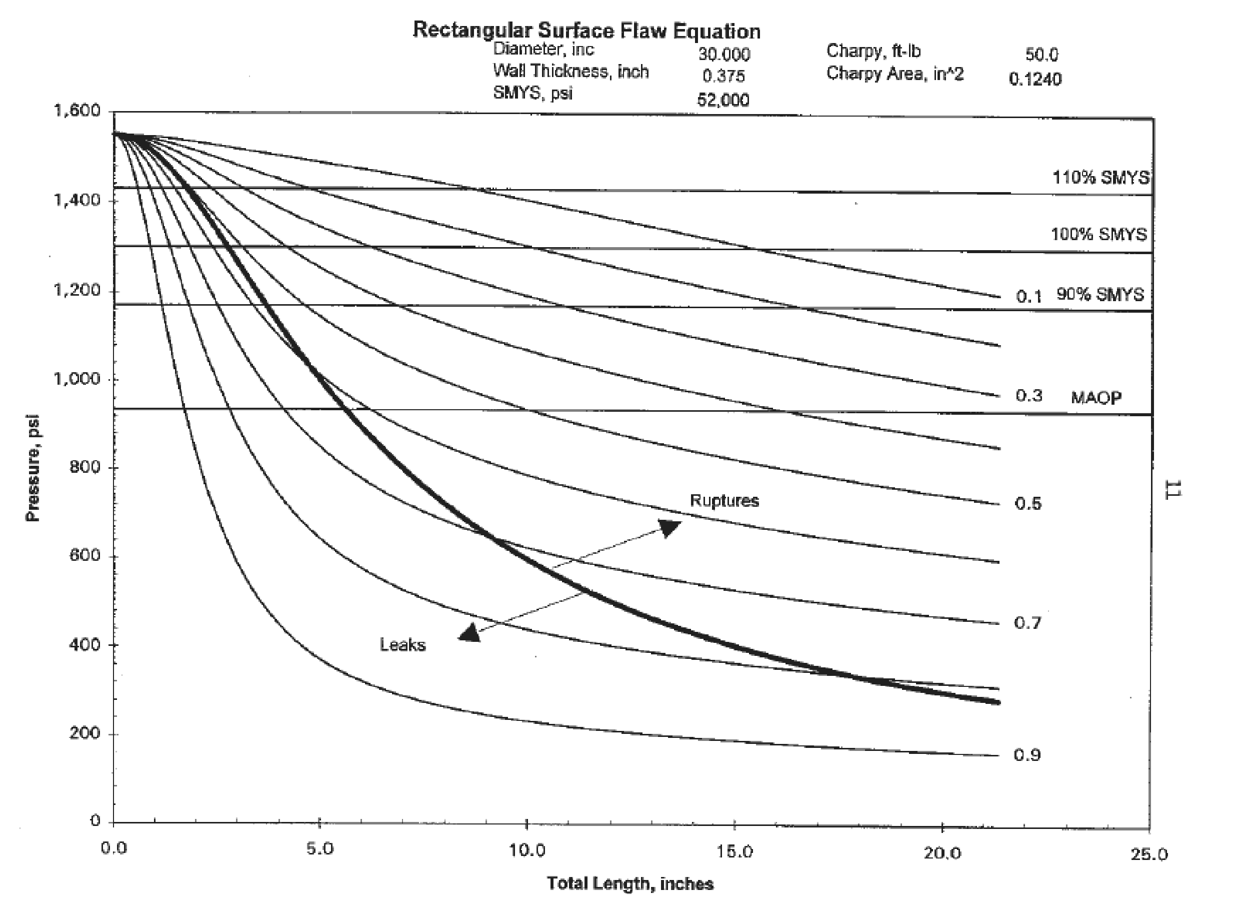


Figure 1. Impact of Test Pressure Levels on Margin of Safety

Figure 8-1. Kiefner [89] Figure 1.

The feasibility of the approach is clearly based on how defects propagate in typical pipeline steels, i.e. cracks will propagate a small distance into the pipe wall under load, and arrest (remain stable) until the rupture boundary for the pipeline steel is reached. In **Figure 8-1** Kiefner and Maxey show an illustrative example for a steel with known yield strength and toughness. There is a well understood relationship between the crack length, the ratio of crack depth to wall thickness and the rupture boundary for each combination of pipe diameter, wall thickness, yield strength and toughness that can be used to calculate the leak rupture boundary for steel pipe[11].

11 http://www.ttoolboxes.com/documents/OTD_TOC/13-0002_4_TOC.pdf

**Leak Rupture Boundary Calculator and Training Manual, and Final Report**
OTD Project Number: 4.9.a
Document Number: OTD-13/0002 and OTD-13/0004
Daniel Ersoy, Ernest Lever

We will now investigate whether a similar approach is feasible for vintage polyethylene pipelines.

### *Understanding Highly Localized Ductile Creep Failure (SCG)*

GTI has worked on several projects designed to test the impact of different fluid media on the ductile and SCG failure modes of various polyethylene materials. To accomplish this in an effective and consistent manner a unique Universal Test Vessel (UTV) was designed and specialized test rigs were built to carefully data log the tests. The basic UTV design is shown in **Figure 8-2**.

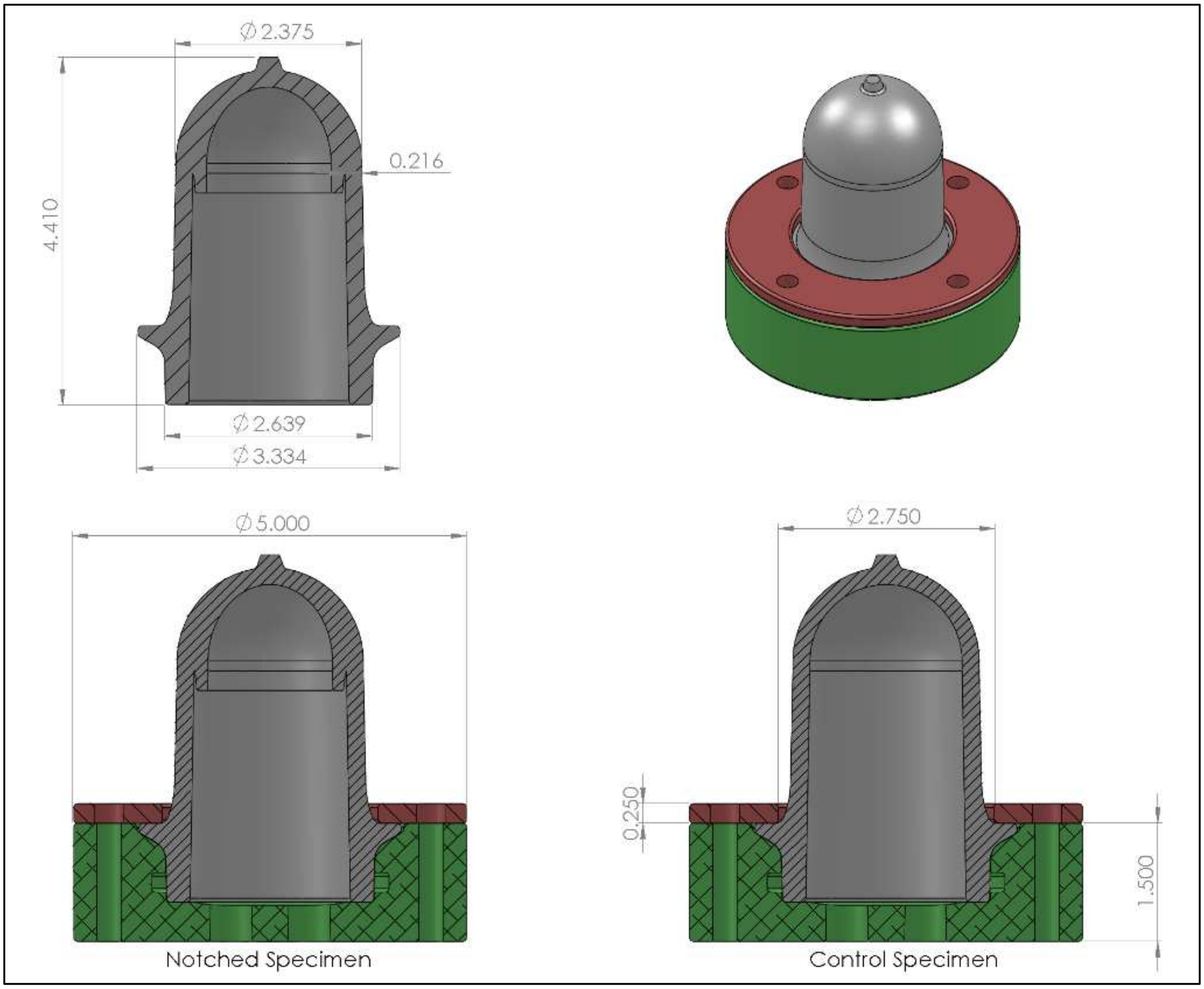



**Figure 8-2. Design of Universal Test Vessell (UTV), with and without SIF notch**

The UTV has two configurations:

1. *A hemispherical domed version designed to replicate the hoop stress condition in pipe*

2. *A version with a thickened dome and razor sharp molded notch designed to introduce a severe SIF to encourage SCG.*

Specimens can be molded from pellets, or reground pipe exhumed from service. Both methods were used in different projects with good success.
Ductile failure in a UTV with no stress riser notch is shown in **Figure 8-3**, and ductile failure from a stress riser notch is shown in **Figure 8-4.**

**Figure 8-3. Ductile failure in un-notched UTV**

The ductile failure originating at the stress riser notch shown in **Figure 8-4** is similar to the ductile and mixed-mode failures seen in the CPF testing shown cyclic pressure testing of notched pipe specimens

**Figure 8-4. Ductile failure initiated at the stress riser notch**

True SCG failures were induced in notched UTV molded from first generation MDPE reground from pipe that had been in service for 40 years. The sensitivity of the test equipment and the leak detection approach used allowed very early identification of wall breach. Wall breaches in the range of 200 – 300 microns were routinely detected as shown in **Figure 8-5.**

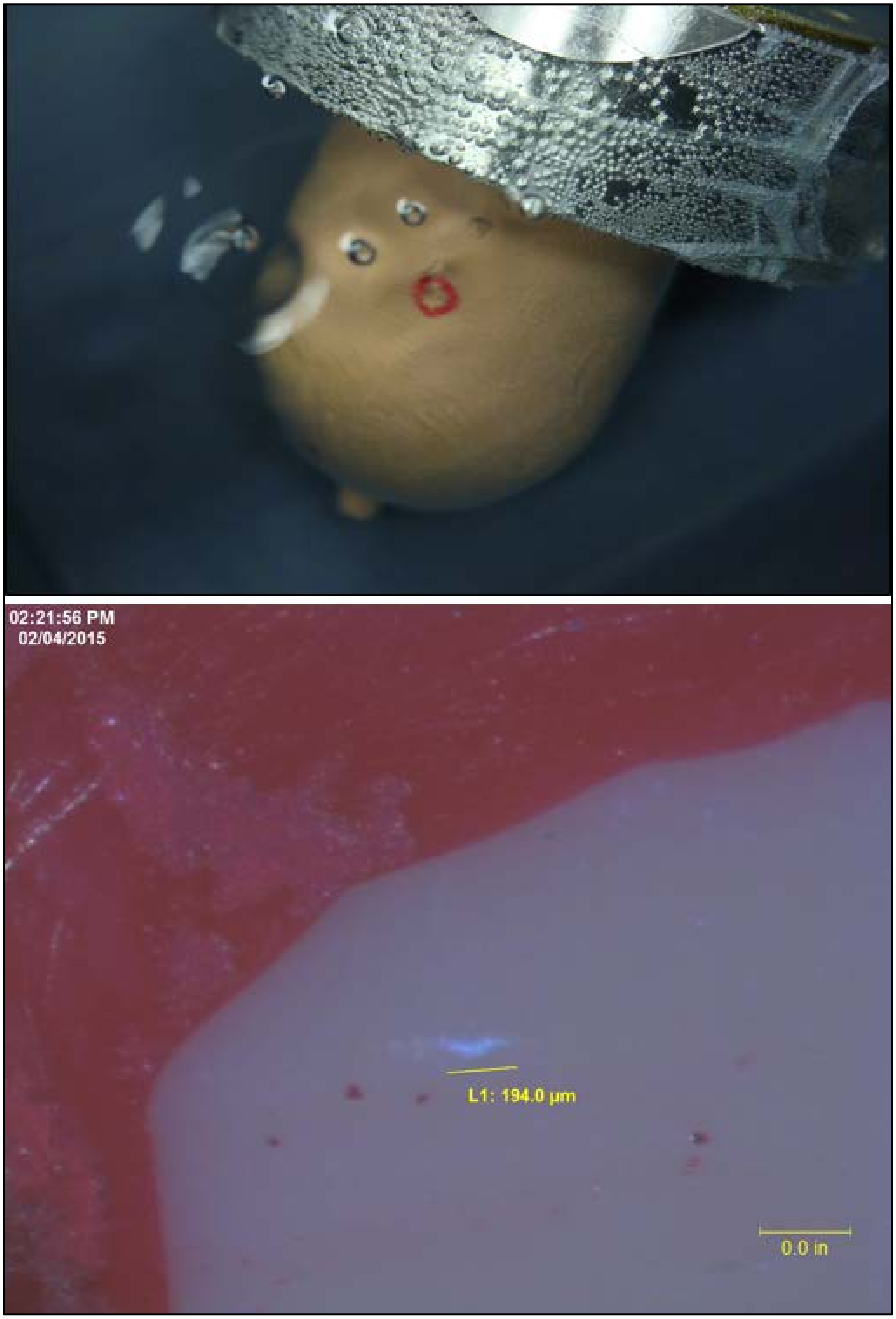



Figure 8-5. Early detection of wall breach due to SCG

Detailed FEM analysis of the stress regime around the notch tip was carried out using a proprietary and highly detailed constitutive model for polyethylene materials. The constitutive model is full viscoelastic-plastic, captures strain rate dependency, temperature dependency and relaxation. **Figure 8-6** shows the capability of the model to capture large plastic deformation, necking and drawing.

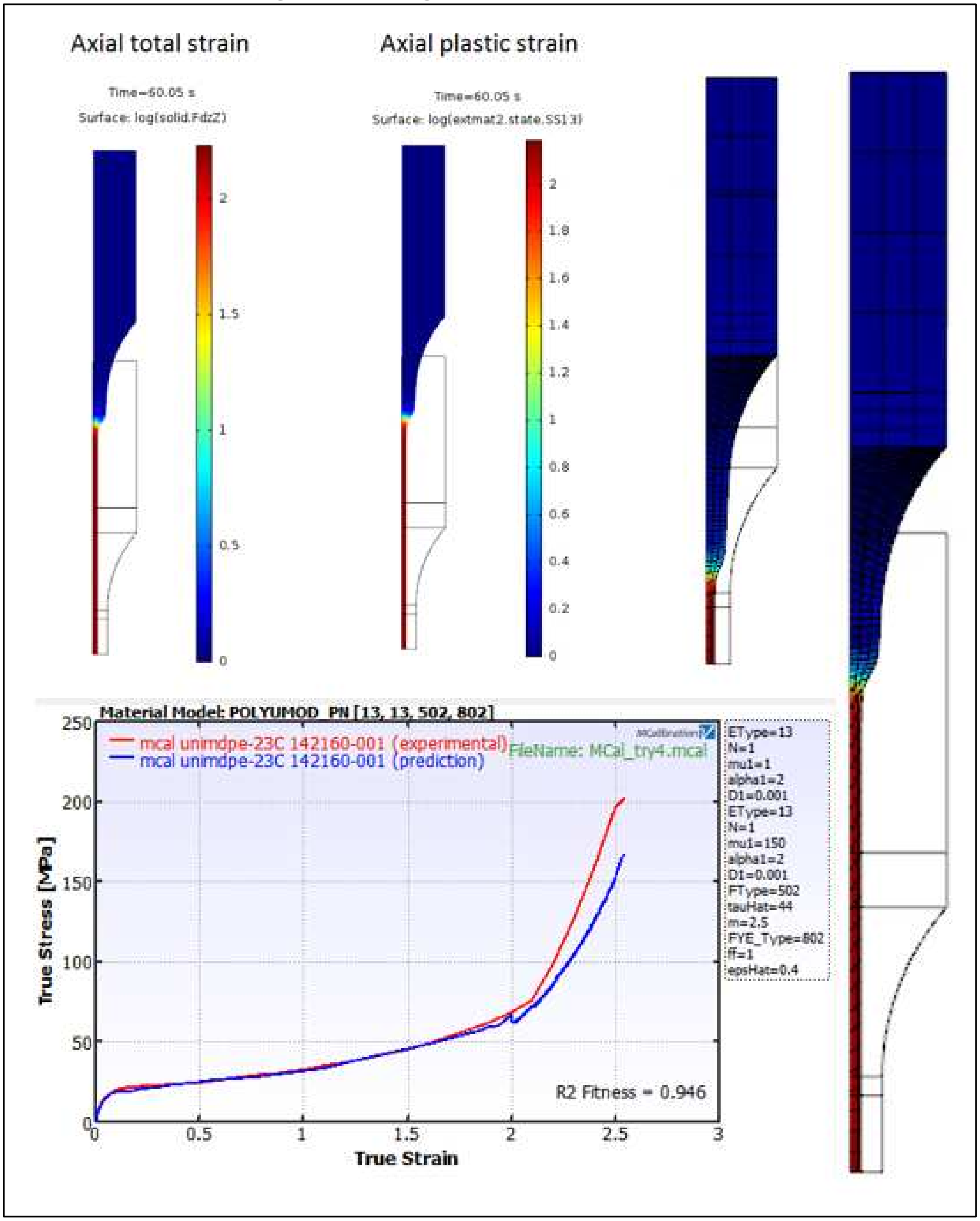



**Figure 8-6. Constitutive model for FEM analysis of unimodal MDPE**

**Figure 8-7** shows the true stress / true strain and engineering stress / strain curves output by the constitutive model. In the engineering stress-strain curve we see strain hardening from about 800% engineering strain. In **Figure 8-8** we show how to identify the onset of strain hardening on the true stress strain curve.

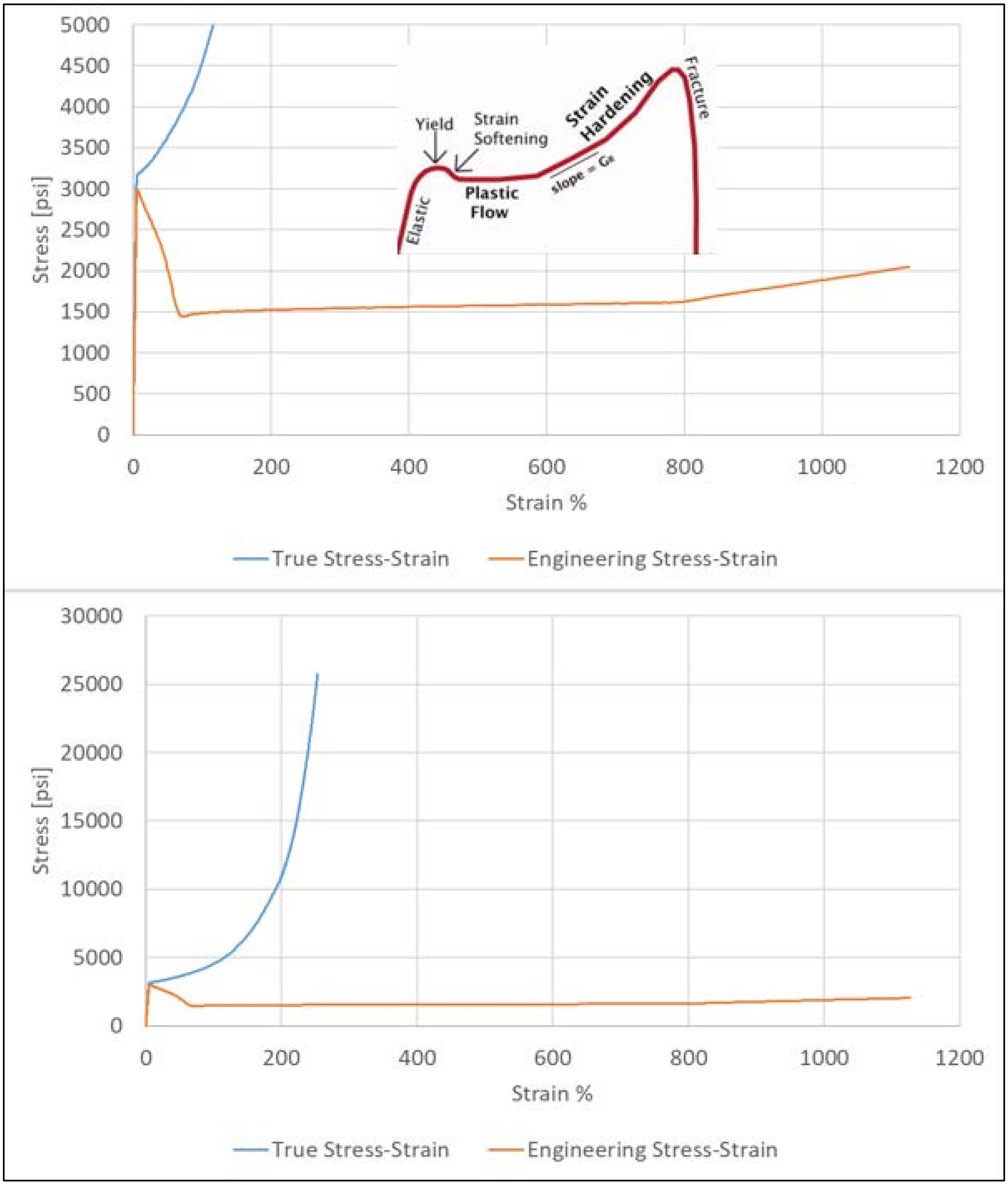



**Figure 8-7. Engineering and True Stress / True Strain curves from the constitutive model**

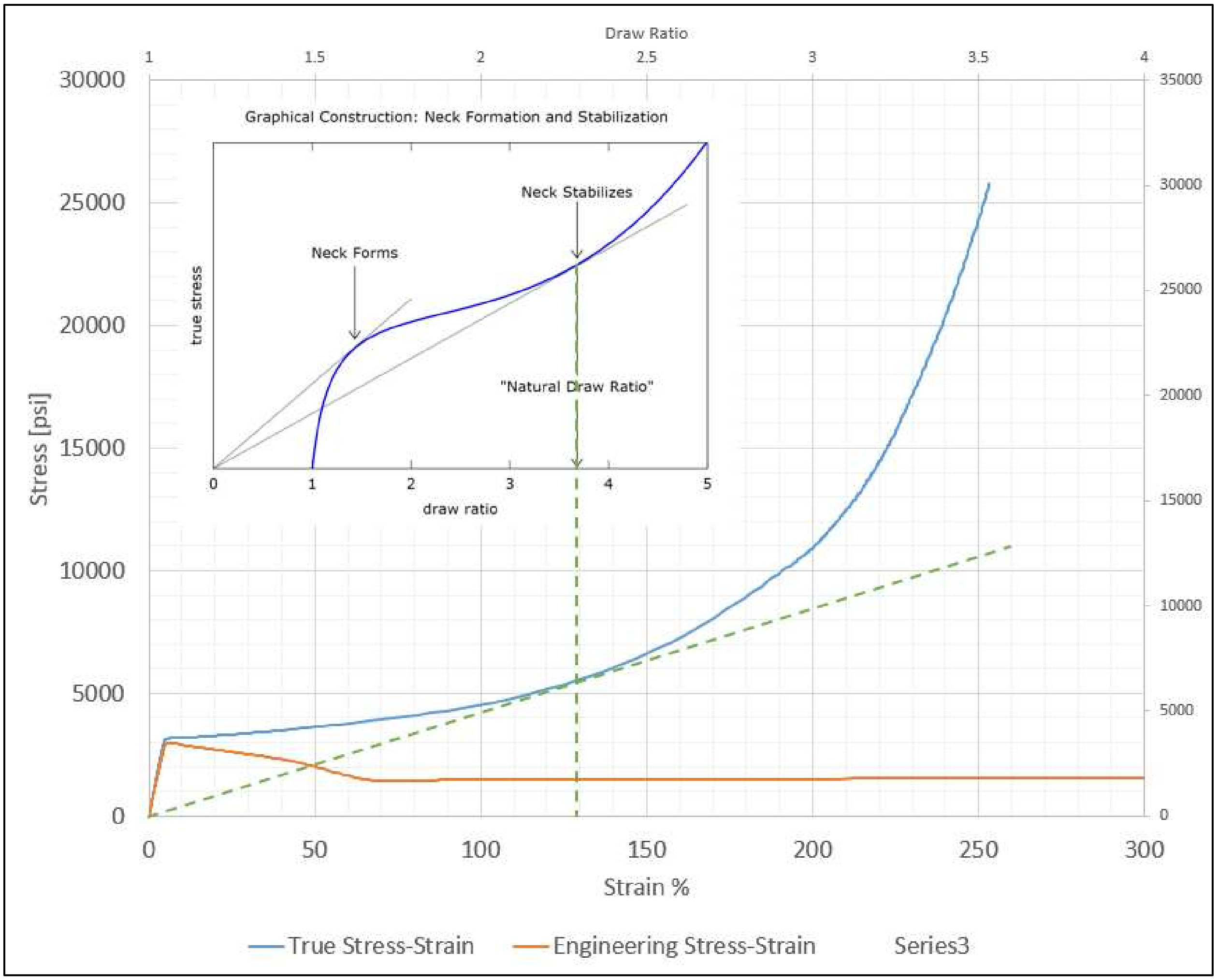



**Figure 8-8. Draw ratio and onset of strain hardening**

The damage propagation resistance of different materials will be strongly dependent on the strain hardening characteristics of the material and the dependence of the critical break strain as a function of stress triaxiality. There are advanced damage propagation models that address these concepts [90-94]. Detailed discussion of these approaches is beyond the scope of this project, but GTI is actively exploring ways to calibrate these models to polyethylene materials and how to incorporate them into time to failure simulations for various damage propagation regimes.

**Figure 8-9** shows the first principal stress that can barely be seen at the image scale and the stress triaxiality contours. The stress triaxiality is a measure of the 2-D constraint. At higher stress triaxiality more plasticity will be experienced and damage will propagate faster.

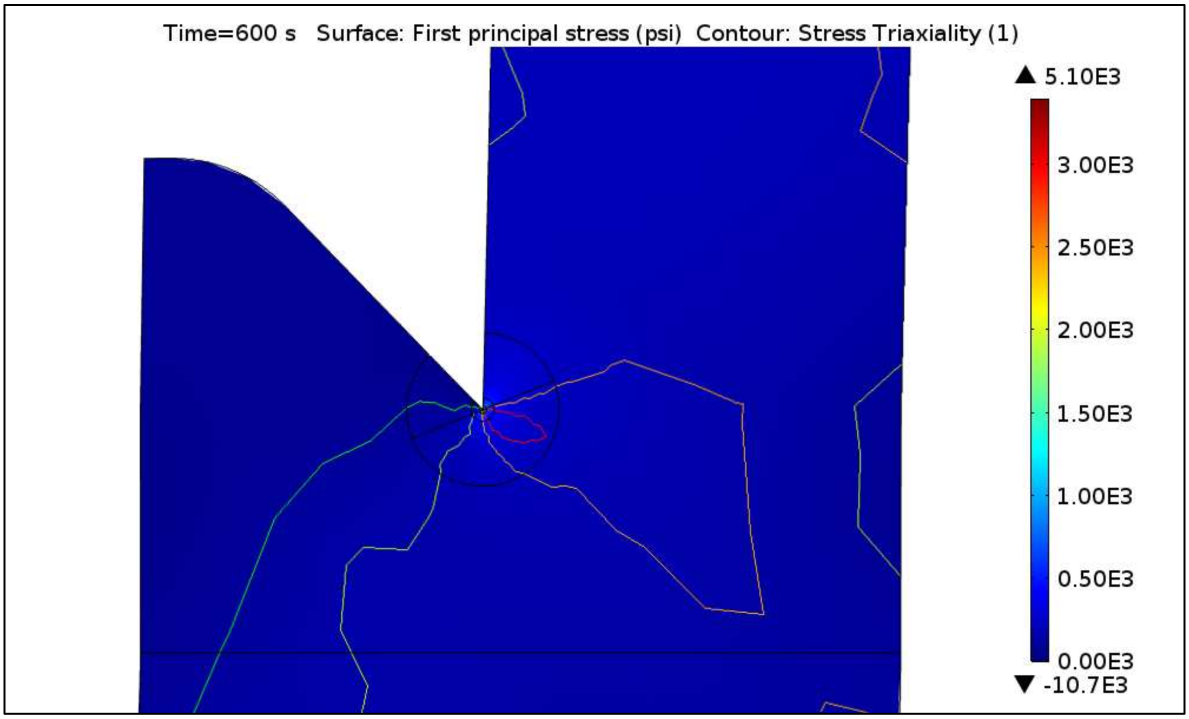



**Figure 8-9. FEM analysis of the stress regime at the UTV notch tip**

Stress triaxiality is defined as the ratio of hydrostatic pressure, or mean stress, to the von Mises equivalent stress.

$$\frac{\sigma_h}{\sigma_{eqv}} = TF = \frac{1/3\left(\sigma_1+\sigma_2+\sigma_3\right)}{\frac{1}{\sqrt{2}}\sqrt{\left(\sigma_1-\sigma_2\right)^2+\left(\sigma_2-\sigma_3\right)^2+\left(\sigma_3-\sigma_1\right)^2}}$$

where $\sigma_1$, $\sigma_2$ and $\sigma_3$ are the first, second and third principal stresses and

$$\frac{\sigma_1+\sigma_2+\sigma_3}{3} = \text{Hydrostatic stress}$$

$$\frac{1}{\sqrt{2}}\sqrt{\left(\sigma_1-\sigma_2\right)^2+\left(\sigma_2-\sigma_3\right)^2+\left(\sigma_3-\sigma_1\right)^2} = \text{Equivalent von Mises stress}$$

https://www.quora.com/What-is-stress-triaxiality accessed 6/25/2017

The principal direction of the stress triaxiality indicates the direction in which the crack or damage will propagate. **Figure 8-10** gives a better feel for the degree of constraint at the notch tip. The actual stress field exists in a small volume, while the stress triaxiality field exists at larger scale and dictates the direction of propagation.

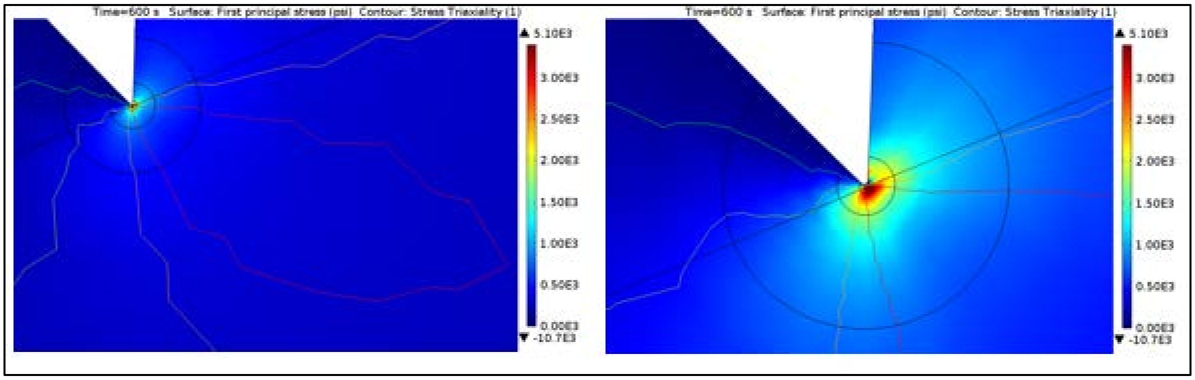



**Figure 8-10. Zooming in to better visualize the notch tip stress field**

Intact UTV specimens that failed by suspected SCG from the notch tip were examined by high resolution 3D X-Ray Computed Tomography capable of resolving volumes around one cubic micron. **Figure 8-11** shows an image of a cross-section through the UTV that closely matches the FEM output shown in .

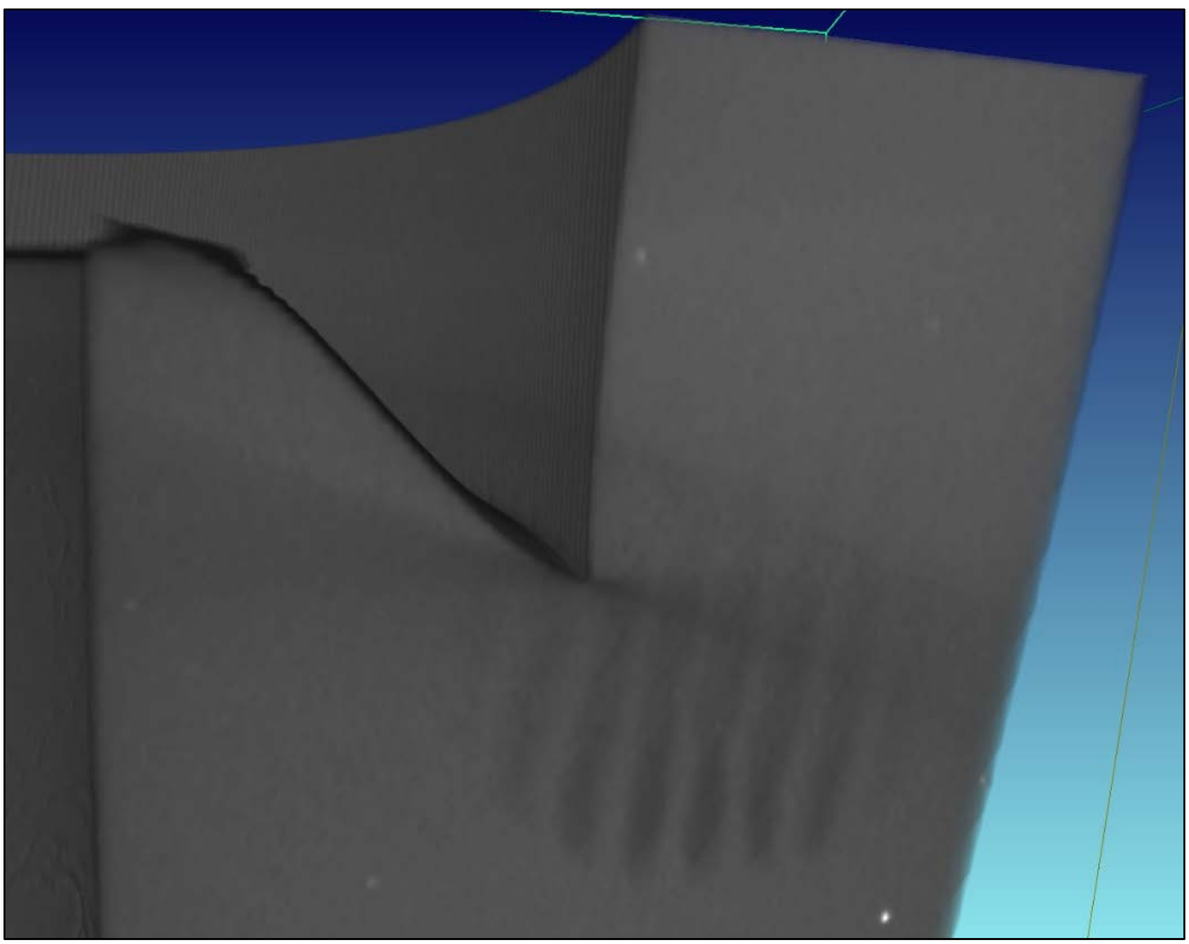


**Figure 8-11. Computerized X-Ray Tomography image of damage propagation from the notch tip in a first generation unimodal MDPE UTV**

**Figure 8-12** shows a view, orthogonal to the previous view, where we can clearly the consistency of the molded stress riser in the UTV. There is consistent and symmetric damage propagation into the specimen wall from the notch tip.

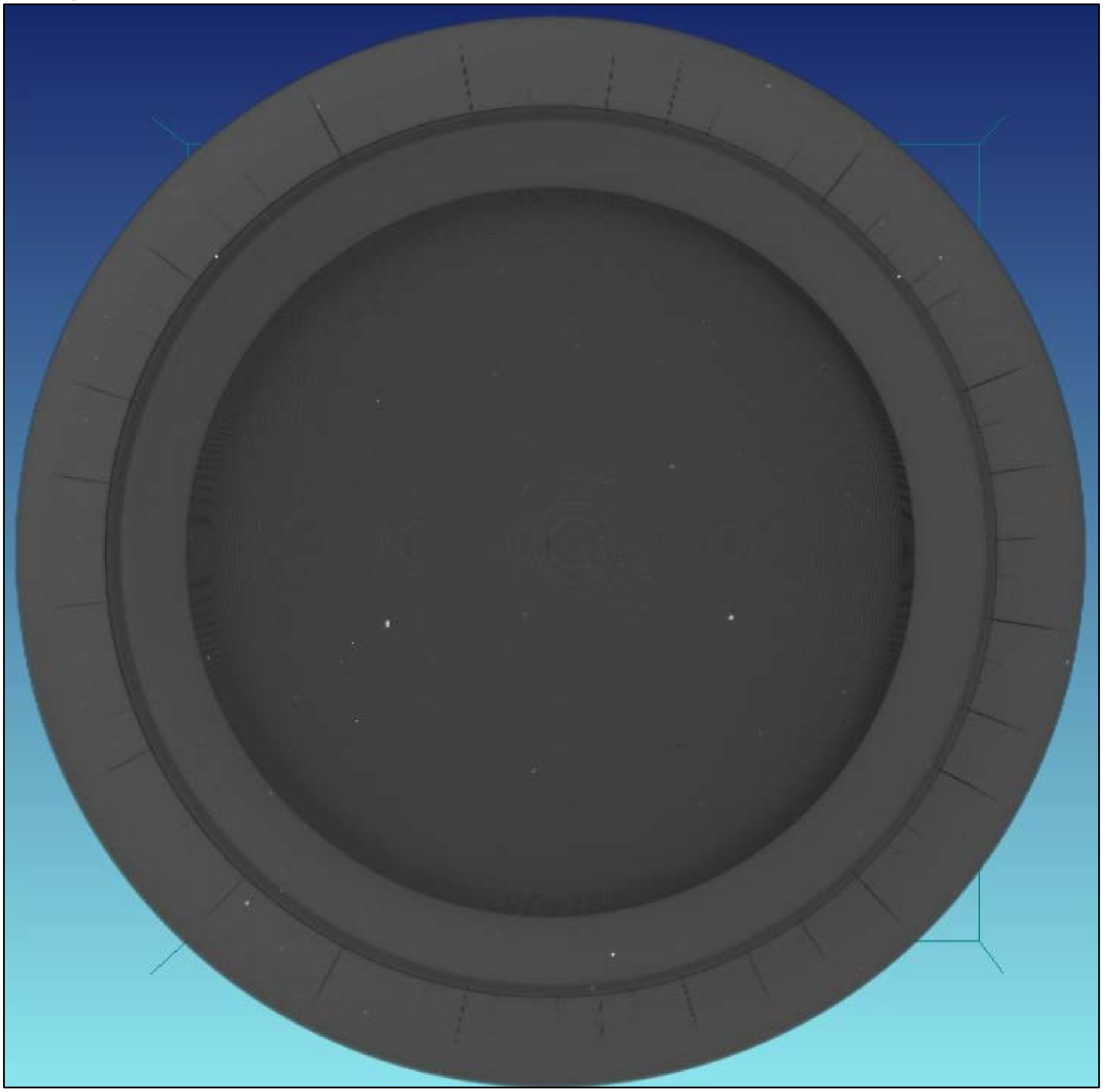


**Figure 8-12. Computerized X-Ray Tomography section through UTV showing multiple damage fronts propagating radially outwards from the notch tip**

We have now seen that we can clearly predict the locus and direction of damage propagation in polyethylene bodies. We will now look at fracture surfaces from damage propagation in a UTV with no stress riser, i.e. the damage propagated from an intrinsic defect in the wall of the specimen **Figure 8-13** to **Figure 8-19**.

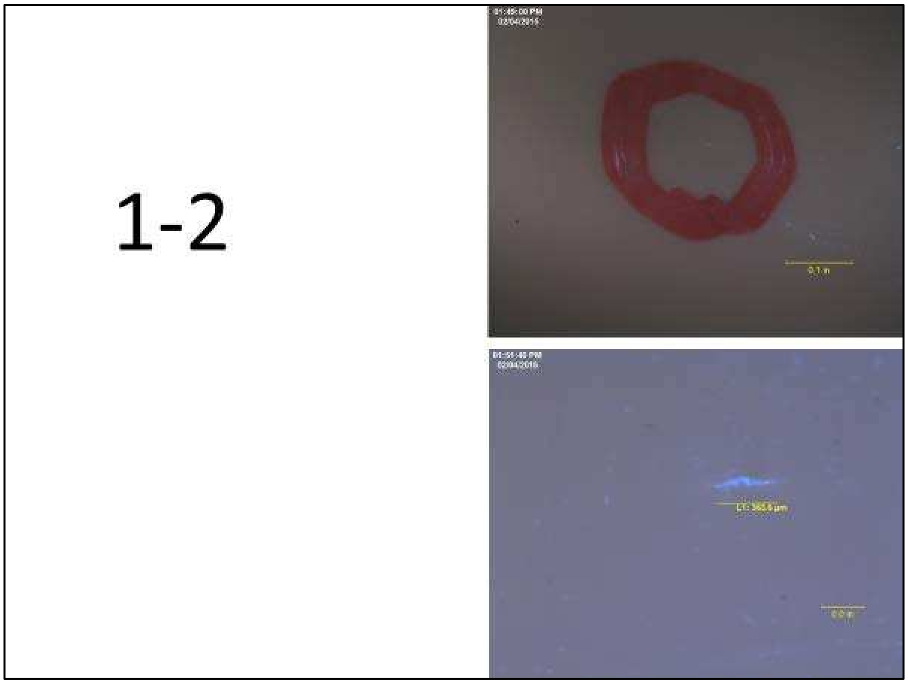



Figure 8-13. Specimen outer wall showing breach

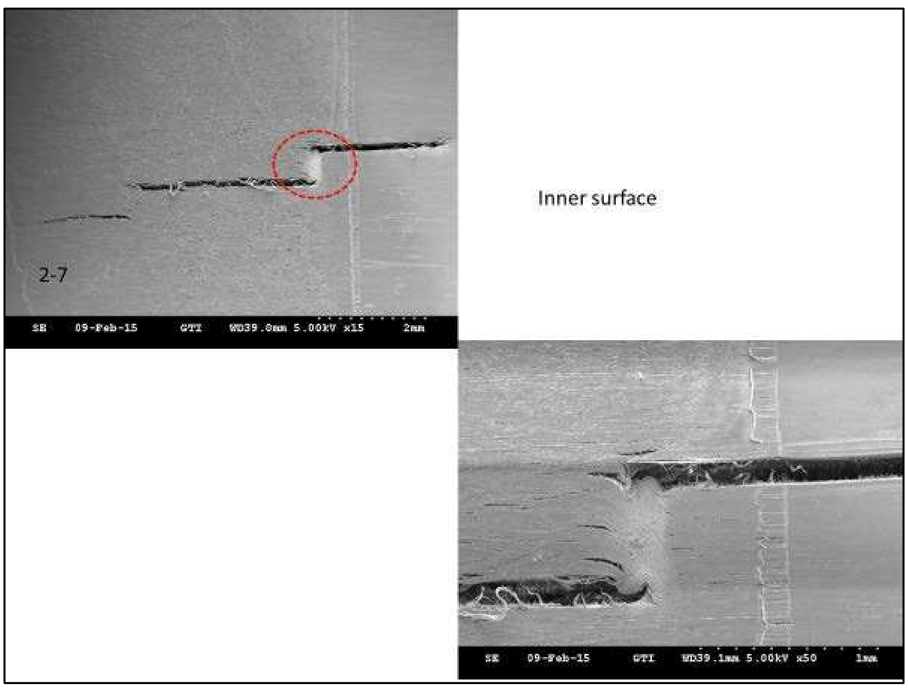



Figure 8-14. Inner surface showing stress cracking

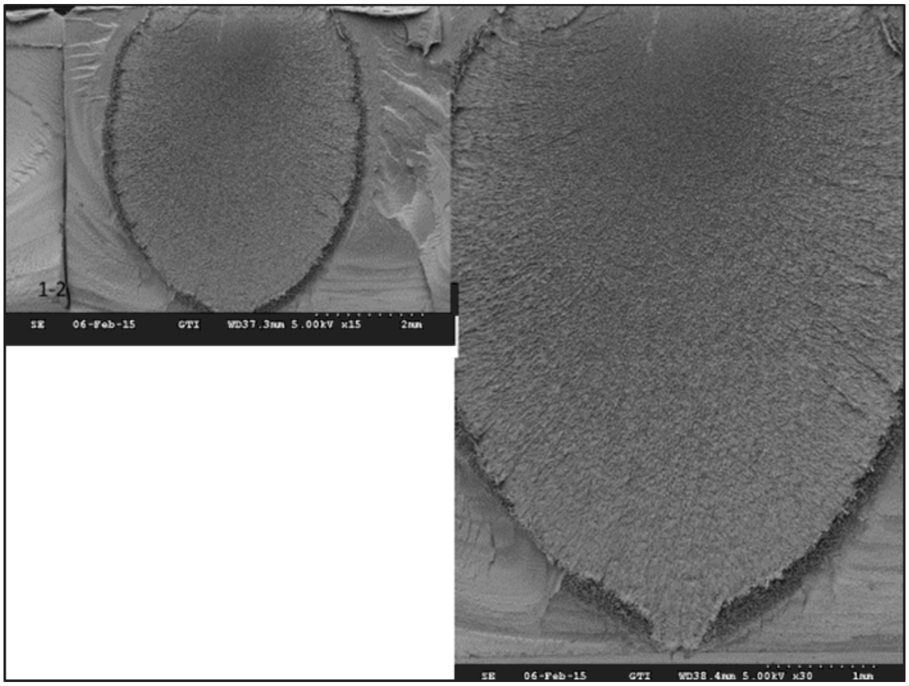



**Figure 8-15. Fracture surface showing inner wall at top and outer wall at bottom**

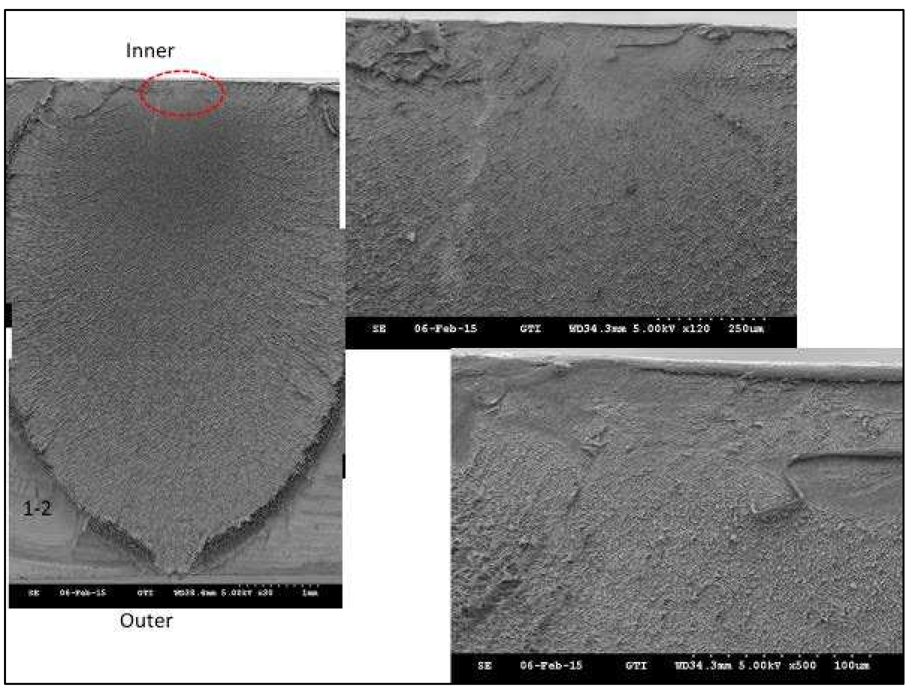



**Figure 8-16. Detail of fracture surface – inner region**

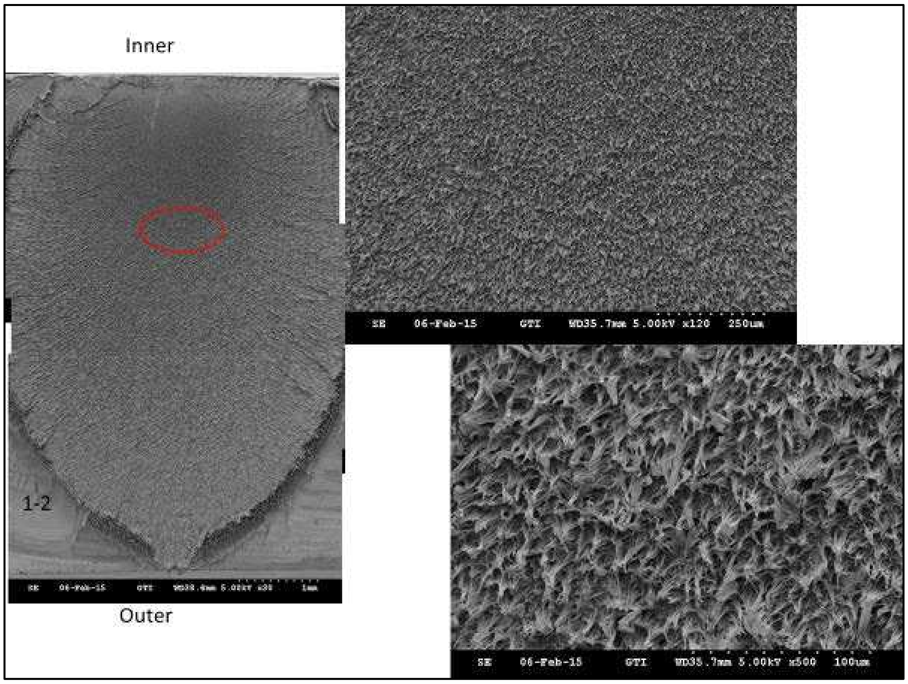



Figure 8-17. Detail of fracture surface – inner third region

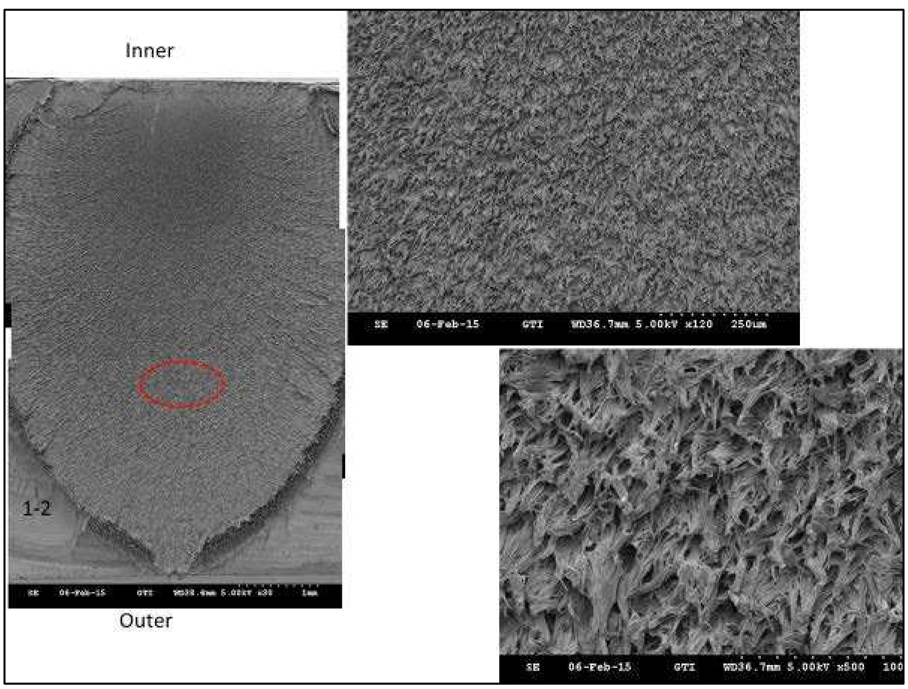



Figure 8-18. Detail of fracture surface – outer third region

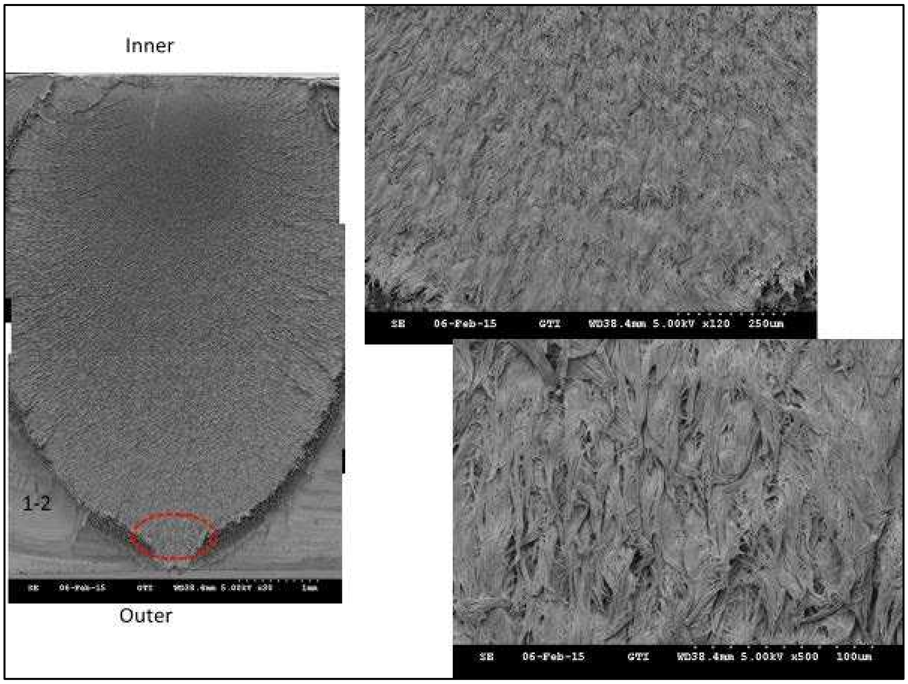



**Figure 8-19. Detail of fracture surface – wall breach region**

In reviewing **Figure 8-13** to **Figure 8-19** we note first that on the inner surface we see cracks with a large opening on the surface and cracks with a narrower opening on the surface. The size of this opening is a function of how far into the wall the crack has progressed. From simple geometry, we can understand that the further the crack front progresses into the wall, the less constrained it is geometrically. When we look at the fracture morphology we see a transition from a relatively smooth fracture surface with short, finer fibrils to increasingly larger and longer fibrils. As we move into the wall-breach region we see relatively large volumes that have been "torn" with "smeared" looking "leaves" that have clearly undergone large ductile deformation.

There are two factors at play in this progression:

1. The SIF increases with increasing crack depth
2. Geometric constraint is lost as the crack depth increases
3.

These two phenomena are graphically illustrated in **Figure 8-20** and **Figure 8-21** that show results of an FEM analysis using a simple constitutive model on an <u>externally notched</u> pipe conforming to the CPF test specimen geometry. We see that as the depth of damage penetration into the pipe wall increases the tip stress increases dramatically and triaxiality decreases sharply until it reaches a lower bound a little less than 0.4. A state of uniaxial tension has a stress triaxiality of 1/3. We can use **Figure 8-21** to determine, as a function of internal pressure, at what depth of damage propagation we achieve ligament stress (triaxiality approaching 1/3) at the damage tip.

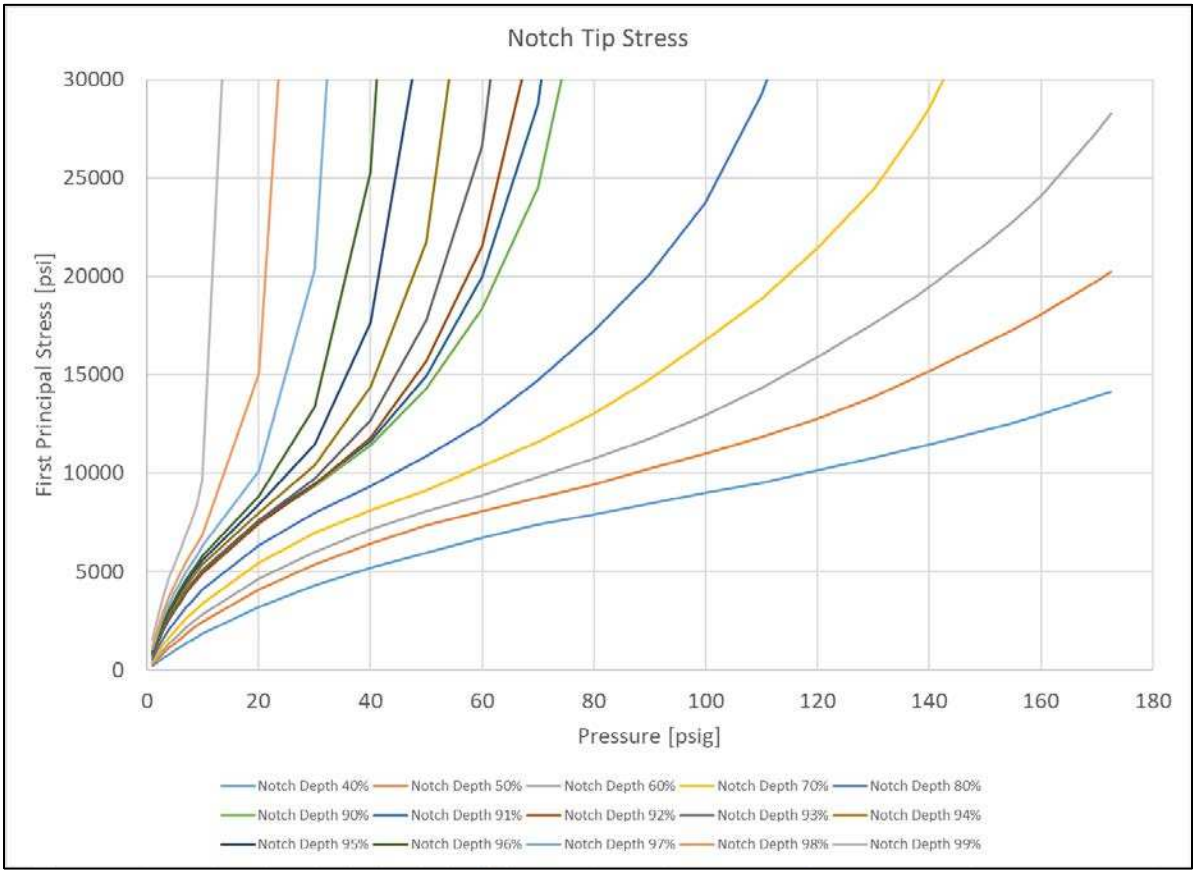



**Figure 8-20. Increasing damage tip stress as a function of test pressure and depth of damage in an externally notched pipe**

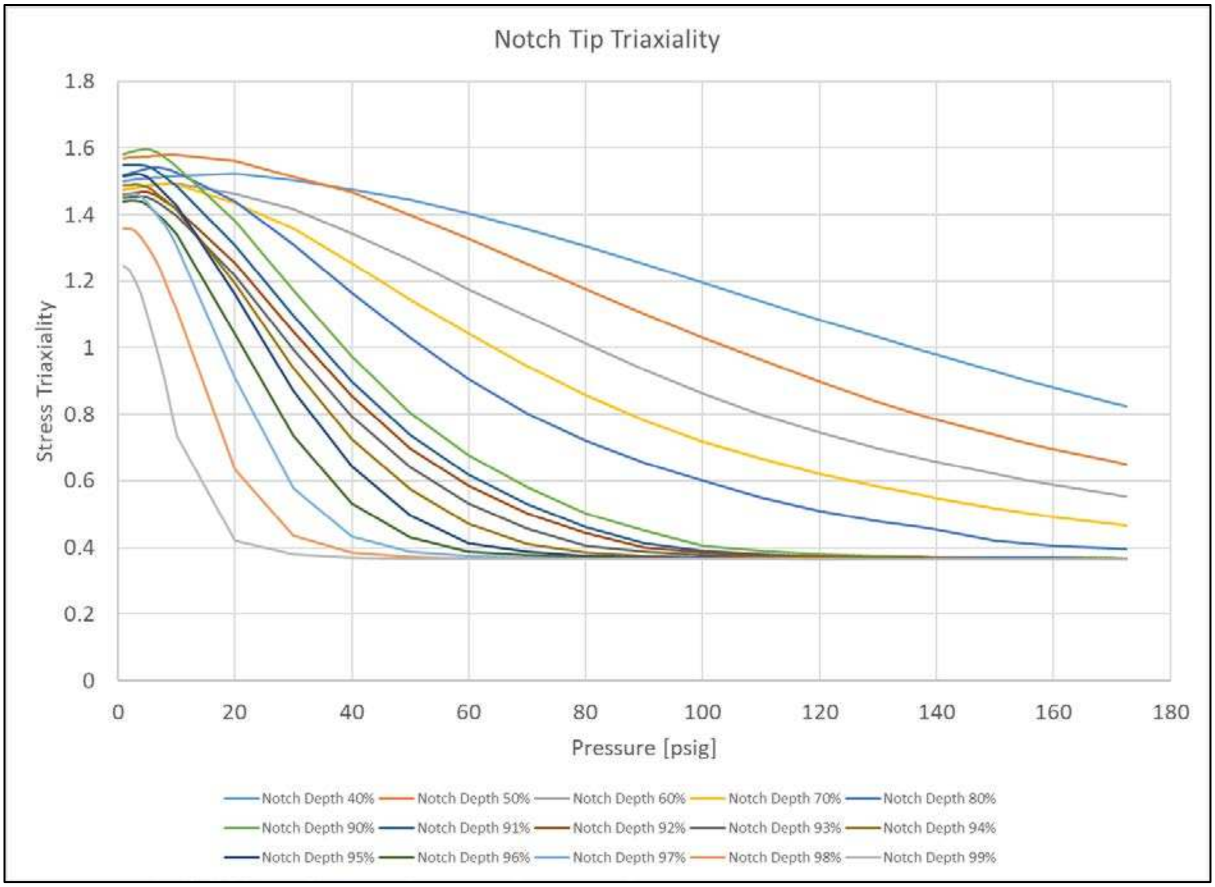



**Figure 8-21. Decreasing triaxiality (loss of constraint) at the damage tip as a function of test pressure and depth of damage in an externally notched pipe**

We will now address, in some detail, void formation ahead of the damage zone that occurs at high stress triaxiality (these voids give rise to fibrils). Voids form at stress triaxiality levels greater than 1 as shown in **Figure 8-22** and **Figure 8-23**.

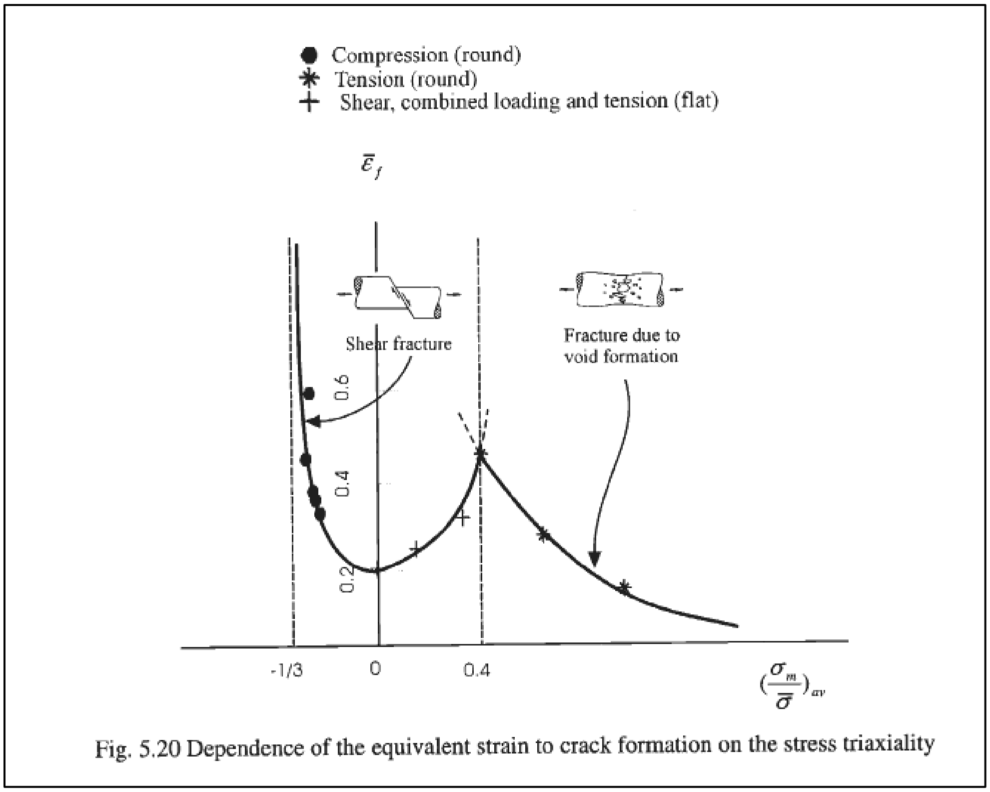



**Figure 8-22. Dependence of critical strain at break and fracture mode of stress triaxiality per Bao [90] (PhD Thesis, MIT 2003)**

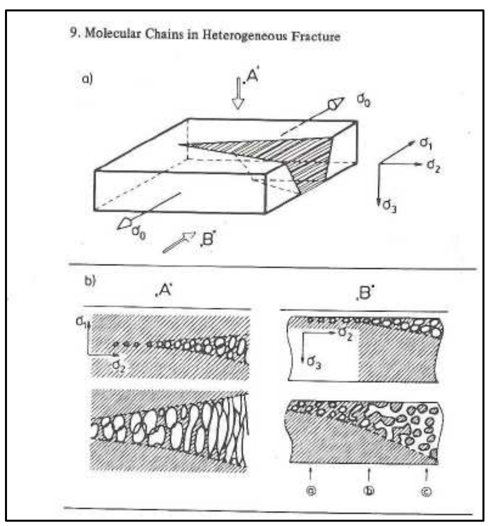



**Figure 8-23. Void and fibril formation in polymers under stress triaxiality. Kausch, Polymer Fracture, Fig 9.17 a, p 340 [95]**

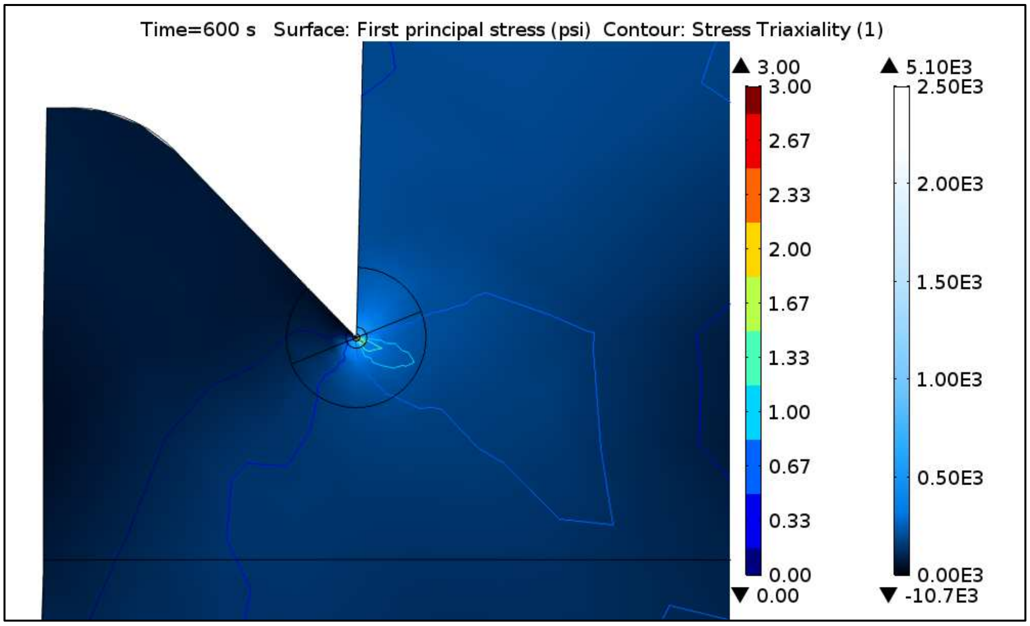



**Figure 8-24. Stress triaxiality contours around UTV notch. Outer closed contour is for triaxiality = 1/3, and demarks the region where hoop stress dominates (outside the closed contour).**

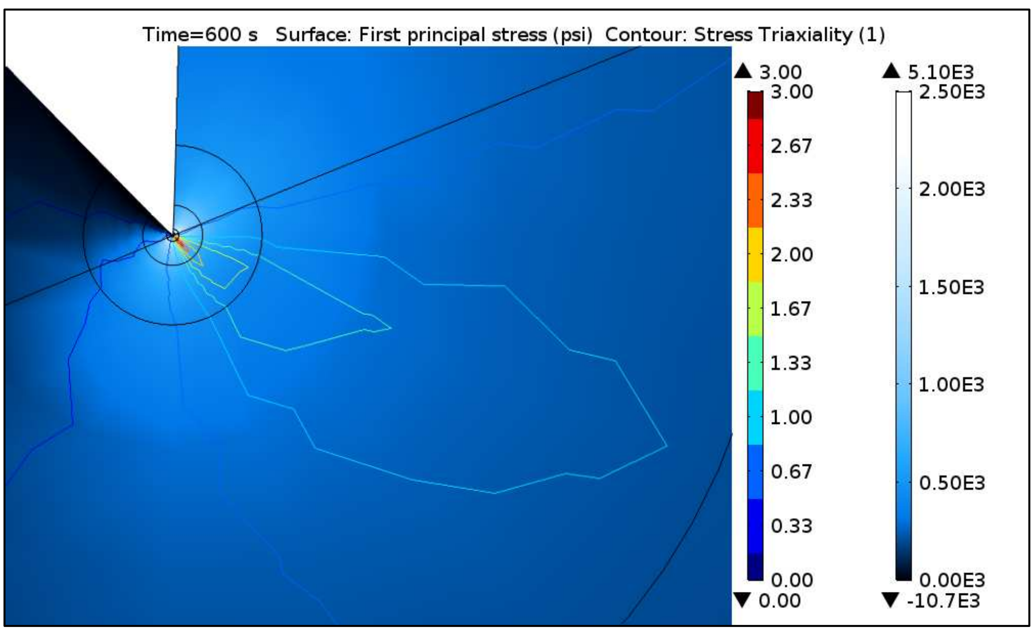



**Figure 8-25. Stress triaxiality contours around UTV notch. Outer closed contour is for triaxiality = 1, and demarks the region where void formation is possible (inside the closed contour).**

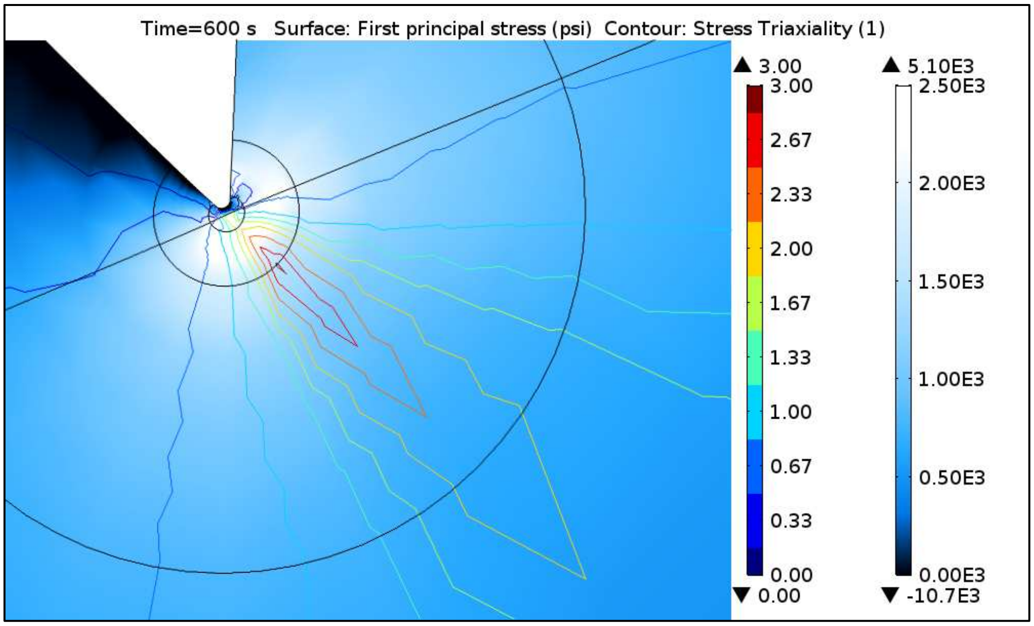



**Figure 8-26. Stress triaxiality contours around UTV notch. innermost closed contour is for triaxiality = 3, and demarks the region where void formation is highly likely to occur (inside the closed contour).**

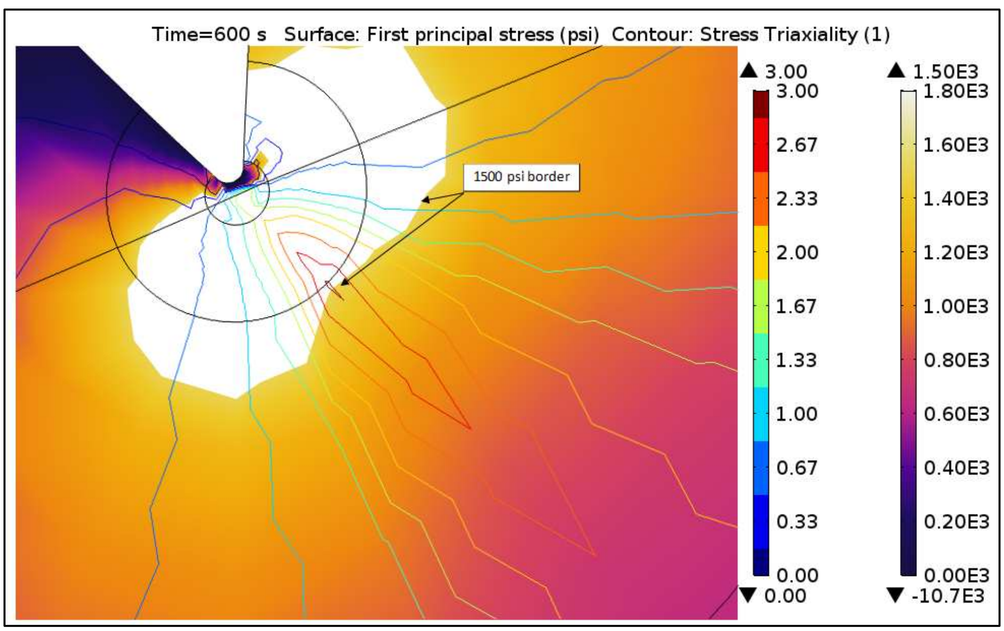



**Figure 8-27. Same as Figure 8-26 – accentuating the stress levels at the maximum triaxiality region**

Running a viscoelastic/plastic FEM analysis on the externally notched pipe specimens used in overpressure testing conducted by GTI we see in **Figure 8-28** to **Figure 8-30** that we have potential for SCG at a damage penetration depth of 40% and 550 psi hoop stress. At a damage penetration depth of 70% there is already little likelihood of SCG.

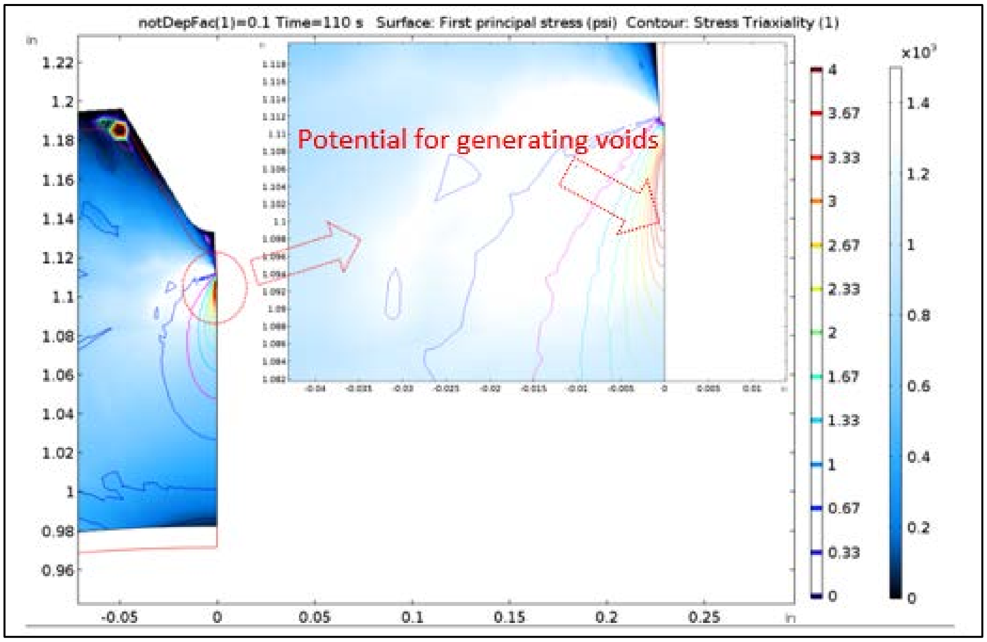



Figure 8-28. External Notch, 40% depth, 110 psig internal pressure (550 psi hoop stress)

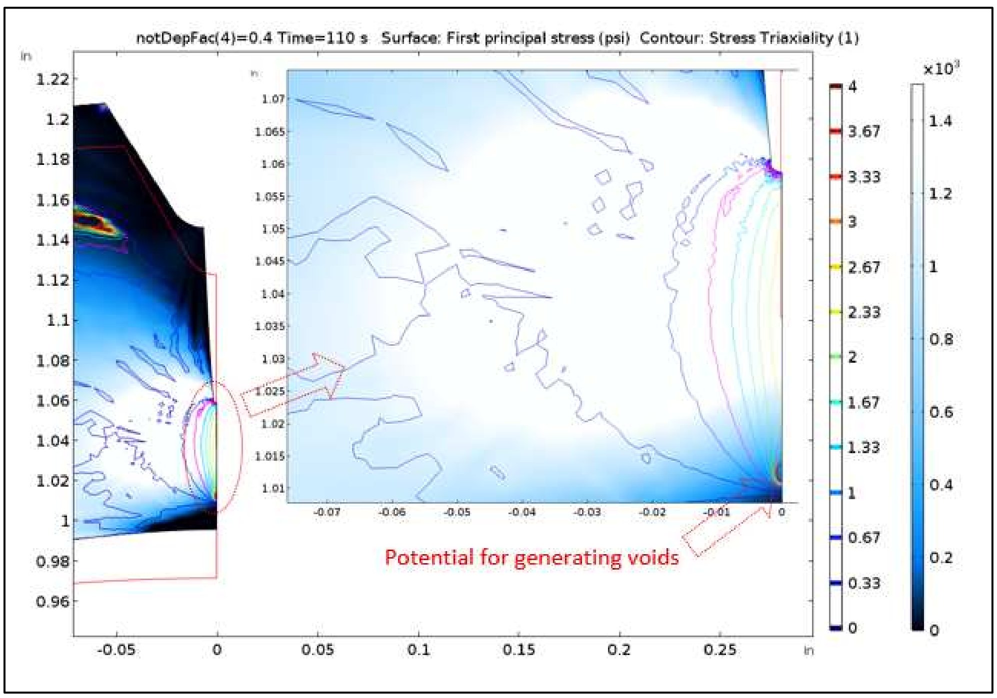



Figure 8-29. External Notch, 70% depth, 110 psig internal pressure (550 psi hoop stress)

All the FEM analyses were run for polyethylene at 23°C (73°F).

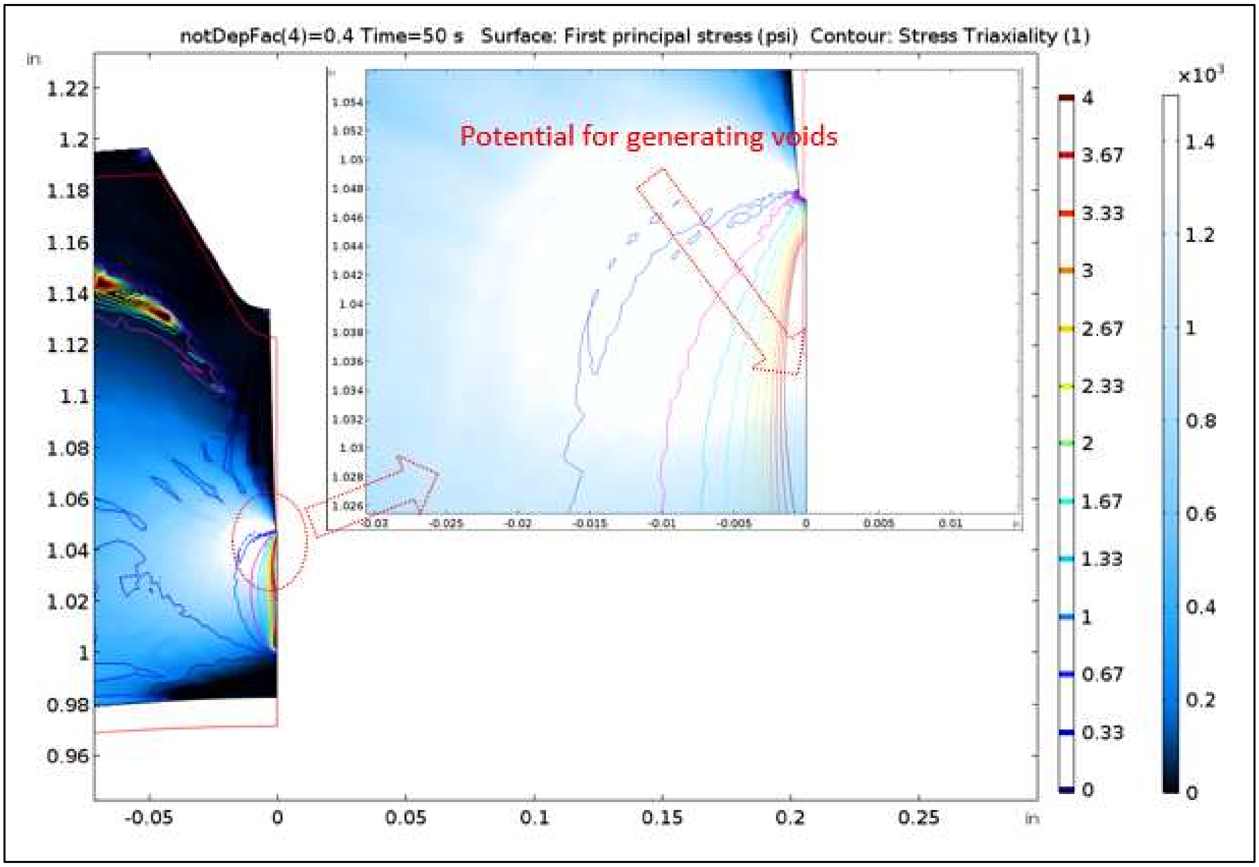



**Figure 8-30. External Notch, 70% depth, 50 psig internal pressure (250 psi hoop stress)**

Now that we have a rudimentary understanding of why voids and fibrils form ahead of the notch tip, we need to recognize that the behavior of the individual fibrils will exhibit some stochastic variation due to random variations in material properties in each fibril.

We will first look at variation in ultimate strain at break under displacement controlled yielding.

In **Figure 8-31** we see actual variation in strain at break in similar specimens cut from pipe. In **Figure 8-32** we show the energy density for each of the tensile specimens. These two plots make the connection between critical strain at break and the toughness of the material i.e. how much energy it absorbs before fracture. The fibrils in SCG and the remaining ligament in the final ductile rupture will follow these curves on their path to rupture.

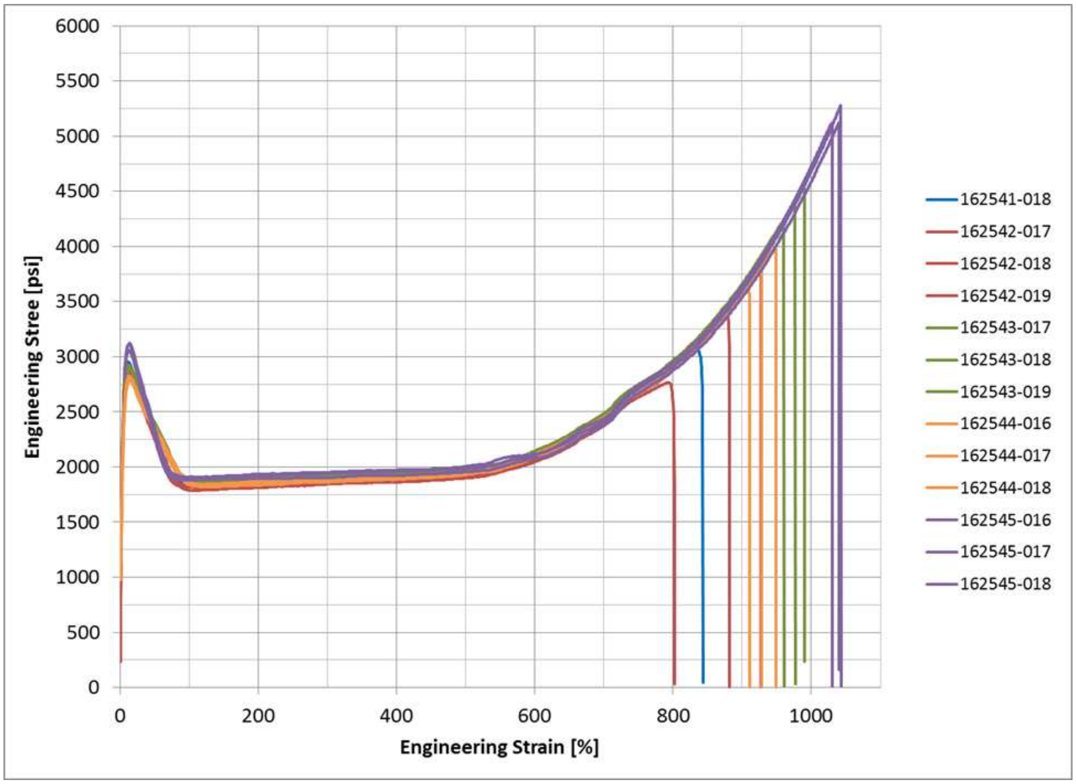



Figure 8-31. Variations in critical strain at break in multiple unimodal MDPE specimens, cut from the same pipe, under the same nominal tensile test conditions

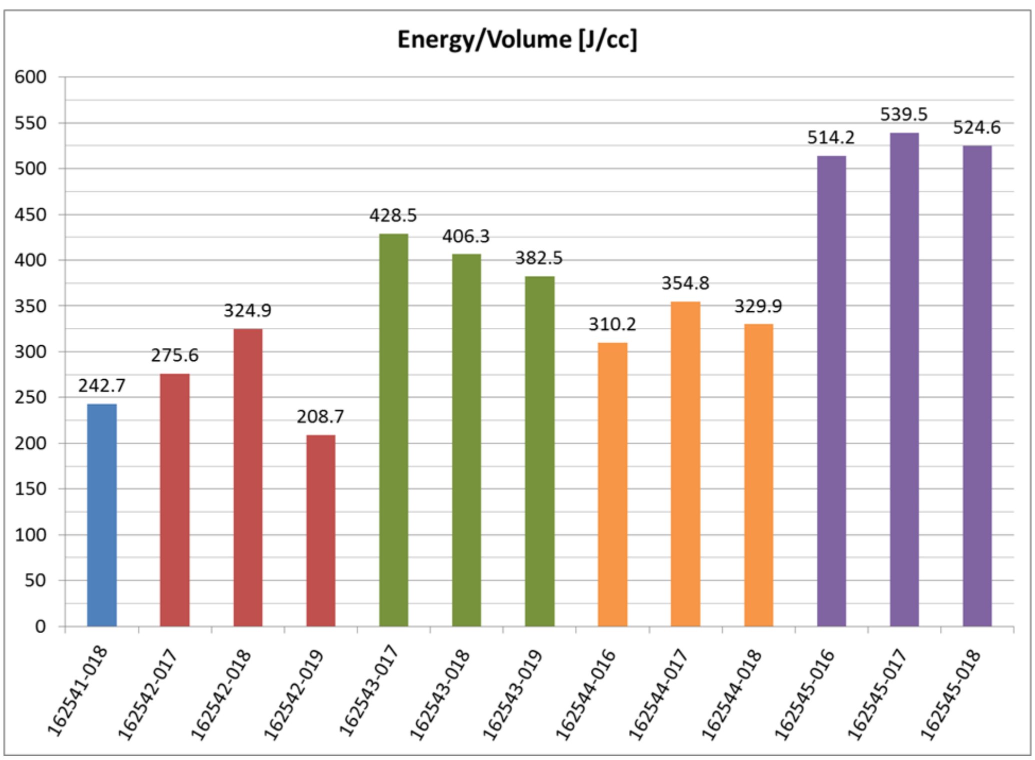



Figure 8-32. Variation in the energy density for the tensile tests shown in Figure 8-31

**Figure 8-33** and **Figure 8-34** show load controlled creep results at 90°C and 5 MPa (725 psi) nominal stress. The ASTM D638 Type V dog bones, punched from the same pipe were left on test for 4313 hours (equivalent to > 400 years and > 10 MPa (1450 psi) stress @ 20°C. The remarkable result is the spread in creep rates where there is an order of magnitude difference between the highest and lowest extensions over this time. Upon displacement controlled pull to break after 4313 hours of force controlled creep, both specimens converged to the same force displacement curve and failed at peak loads and displacements within 3% of their average value.

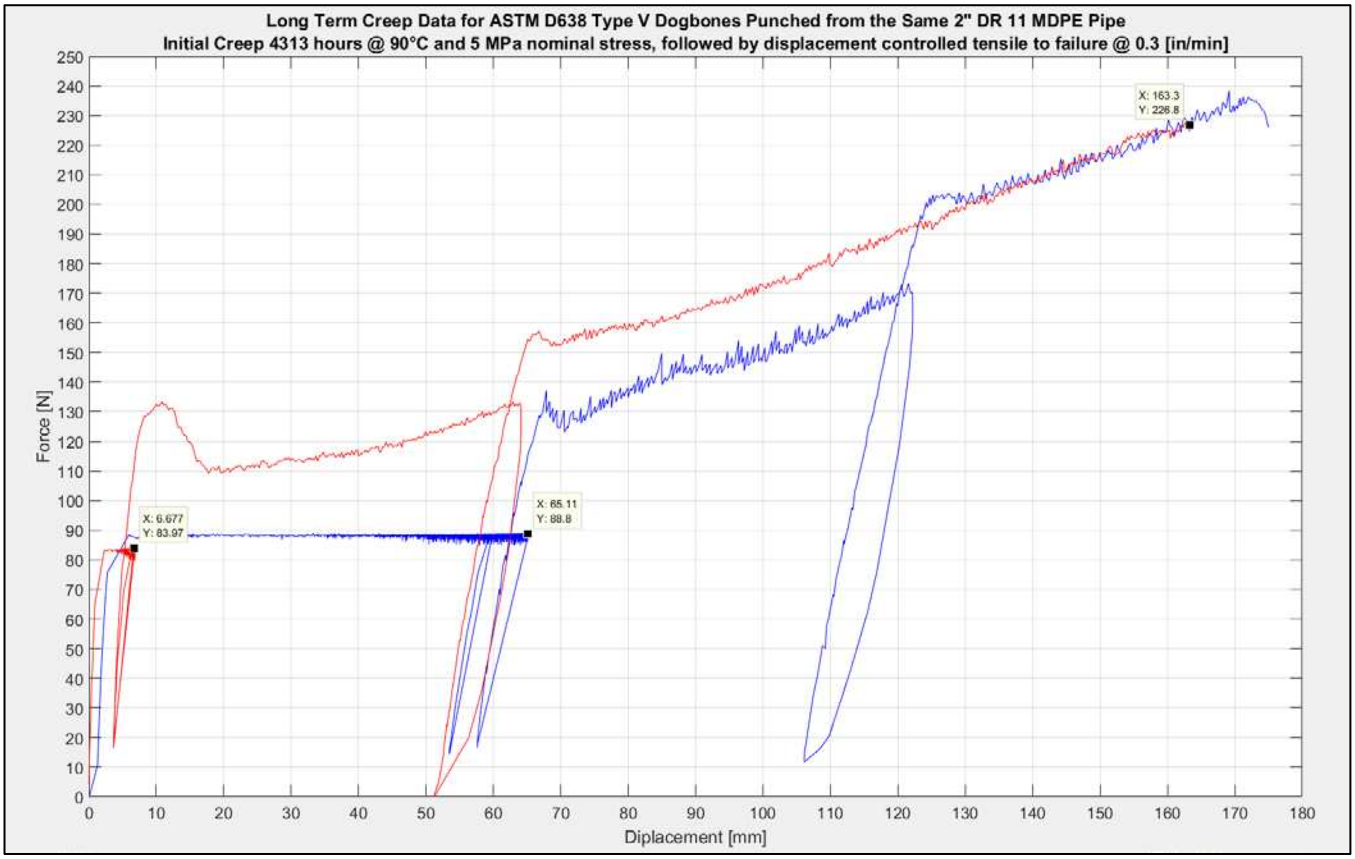



**Figure 8-33. MDPE - comparison of creep rates under load controlled long-term tensile creep @ 90°C, 5 MPa**

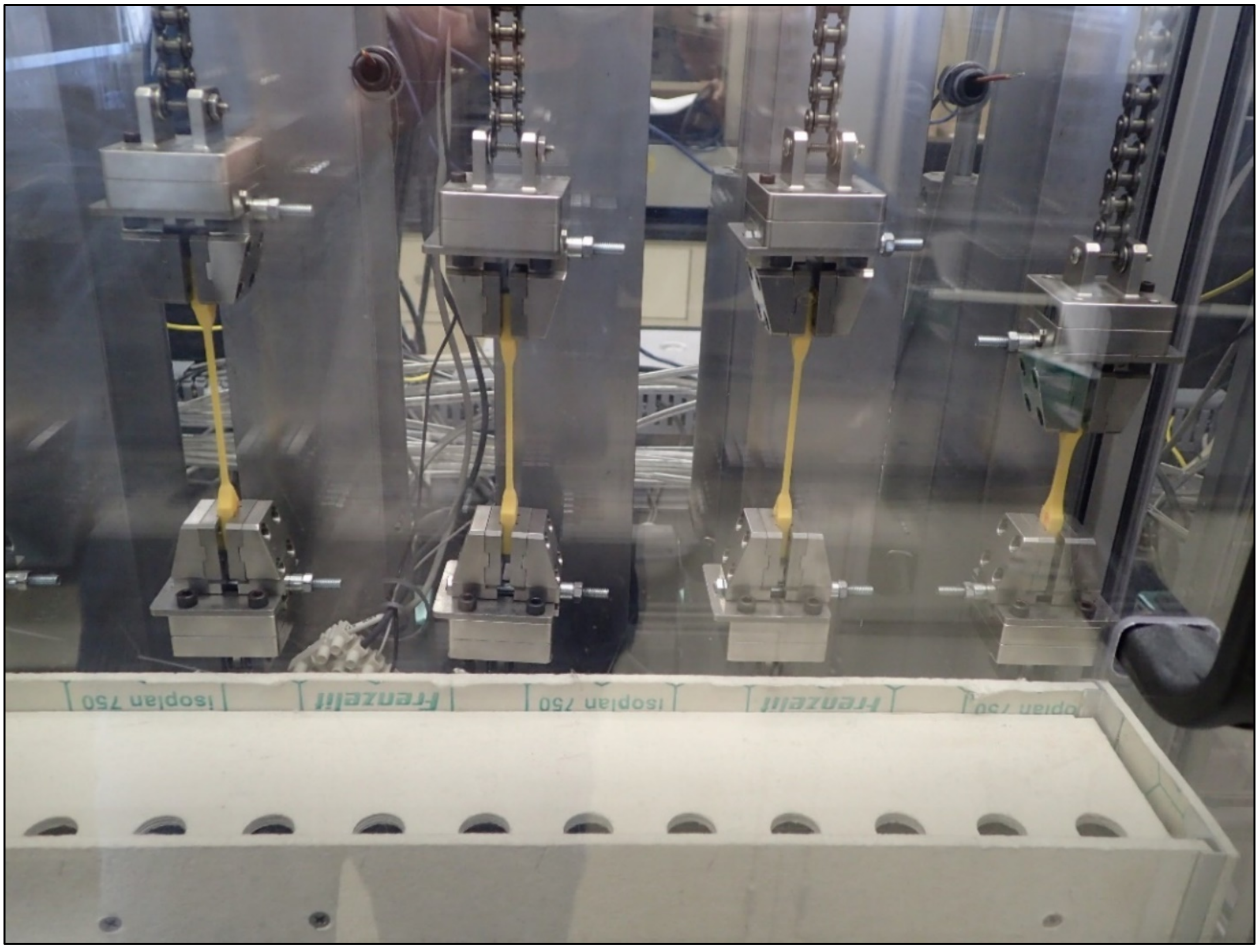



**Figure 8-34. Left specimen blue curve above, Right specimen red curve above**

The creep data from 27 ASTM D638 Type V dog bone specimens punched from 3 similar pipes, exhumed from service in a gas distribution system is presented in **Table 8-1**. The data is color coded per pipe. The sixth digit of the LIMS number identifies the pipe and the last three digits the specimen number punched from the pipe.

**Table 8-1. Creep Data for 2" SDR 11 MDPE Gas Distribution Pipe. Color Coded Per Pipe (3 pipes with multiple specimens from each)**

| Station | LIMS | State | TempdegC | AvgTdegC | AvgTK | AvgStressMPa | ReferenceStrain | EnergyVolJcc |
|---|---|---|---|---|---|---|---|---|
| '1-1' | '162541-025' | 'Creep @ 4313 h' | 90 | 89.8 | 363.0 | 5.0 | 90.4 | 5653.6 |
| '1-2' | '162541-026' | 'Creep @ 4313 h' | 90 | 89.8 | 363.0 | 5.0 | 75.4 | 5293.3 |
| '1-3' | '162541-027' | 'Creep @ 4313 h' | 90 | 89.8 | 363.0 | 5.0 | 756.3 | 39202.8 |
| '1-4' | '162542-026' | 'Creep @ 4313 h' | 90 | 89.8 | 363.0 | 4.7 | 721.5 | 35648.9 |
| '1-5' | '162542-027' | 'Creep @ 4313 h' | 90 | 89.8 | 363.0 | 4.7 | 345.5 | 18145.4 |
| '1-6' | '162542-028' | 'Creep @ 4313 h' | 90 | 89.8 | 363.0 | 4.7 | 569.0 | 28329.2 |
| '1-7' | '162543-026' | 'Creep @ 4313 h' | 90 | 89.8 | 363.0 | 4.8 | 66.6 | 3695.5 |
| '1-8' | '162543-027' | 'Creep @ 4313 h' | 90 | 89.8 | 363.0 | 4.8 | 64.4 | 3829.2 |

| Station | LIMS | State | TempdegC | AvgTdegC | AvgTK | AvgStressMPa | ReferenceStrain | EnergyVolJcc |
|---|---|---|---|---|---|---|---|---|
| '1-9' | '162543-028' | 'Creep @ 4313 h' | 90 | 89.8 | 363.0 | 4.8 | 49.2 | 3086.4 |
| '1-1' | '162541-025' | 'Break' | 90 | 89.8 | 363.0 | | 1049.7 | 69666.0 |
| '1-2' | '162541-026' | 'Break' | 90 | 89.8 | 363.0 | | 2426.0 | 241034.1 |
| '1-3' | '162541-027' | 'Break' | 90 | 89.8 | 363.0 | | 2300.8 | 197375.2 |
| '1-4' | '162542-026' | 'Break' | 90 | 89.8 | 363.0 | | 2444.2 | 212809.8 |
| '1-5' | '162542-027' | 'Break' | 90 | 89.8 | 363.0 | | 2580.6 | 234933.0 |
| '1-6' | '162542-028' | 'Break' | 90 | 89.8 | 363.0 | | 1967.2 | 158845.9 |
| '1-7' | '162543-026' | 'Break' | 90 | 89.8 | 363.0 | | 2156.1 | 210488.4 |
| '1-8' | '162543-027' | 'Break' | 90 | 89.8 | 363.0 | | 2219.9 | 217476.7 |
| '1-9' | '162543-028' | 'Break' | 90 | 89.8 | 363.0 | | 2150.9 | 202415.3 |
| '2-1' | '162541-022' | 'Creep @ 4313 h' | 60 | 66.1 | 339.2 | 6.7 | 654.3 | 47106.5 |
| '2-2' | '162541-023' | 'Creep @ 4313 h' | 60 | 66.1 | 339.2 | 6.7 | 507.9 | 38271.9 |
| '4-1' | '162541-024' | 'Creep @ 4313 h' | 60 | 60.7 | 333.9 | 6.7 | 656.3 | 46530.7 |
| '2-4' | '162542-023' | 'Creep @ 4313 h' | 60 | 66.1 | 339.2 | 6.3 | 606.2 | 41137.5 |
| '2-5' | '162542-024' | 'Creep @ 4313 h' | 60 | 66.1 | 339.2 | 6.3 | 249.5 | 18745.6 |
| '2-6' | '162542-025' | 'Creep @ 4313 h' | 60 | 66.1 | 339.2 | 6.3 | 647.1 | 43584.3 |
| '2-7' | '162543-023' | 'Creep @ 4313 h' | 60 | 66.1 | 339.2 | 6.4 | 514.0 | 36334.1 |
| '2-8' | '162543-024' | 'Creep @ 4313 h' | 60 | 66.1 | 339.2 | 6.4 | 666.7 | 43371.4 |
| '2-9' | '162543-025' | 'Creep @ 4313 h' | 60 | 66.1 | 339.2 | 6.4 | 82.3 | 7995.2 |
| '2-1' | '162541-022' | 'Break' | 60 | 66.1 | 339.2 | | 2216.2 | 255104.6 |
| '2-2' | '162541-023' | 'Break' | 60 | 66.1 | 339.2 | | 2254.4 | 269912.4 |
| '4-1' | '162541-024' | 'Break' | 60 | 60.7 | 333.9 | | 2112.6 | 236216.8 |
| '2-4' | '162542-023' | 'Break' | 60 | 66.1 | 339.2 | | 2436.1 | 280357.0 |
| '2-5' | '162542-024' | 'Break' | 60 | 66.1 | 339.2 | | 2431.0 | 285827.6 |
| '2-6' | '162542-025' | 'Break' | 60 | 66.1 | 339.2 | | 2649.6 | 318821.3 |
| '2-7' | '162543-023' | 'Break' | 60 | 66.1 | 339.2 | | 2206.9 | 245982.6 |
| '2-8' | '162543-024' | 'Break' | 60 | 66.1 | 339.2 | | 2256.8 | 252660.1 |
| '2-9' | '162543-025' | 'Break' | 60 | 66.1 | 339.2 | | 1933.9 | 209075.6 |
| '3-1' | '162541-019' | 'Creep @ 4313 h' | 40 | 40.3 | 313.5 | 8.9 | 891.4 | 79999.9 |
| '3-2' | '162541-020' | 'Creep @ 4313 h' | 40 | 40.3 | 313.5 | 8.9 | 794.3 | 75752.7 |
| '3-3' | '162541-021' | 'Creep @ 4313 h' | 40 | 40.3 | 313.5 | 8.9 | 771.6 | 73467.3 |
| '3-4' | '162542-020' | 'Creep @ 4313 h' | 40 | 40.3 | 313.5 | 8.3 | 684.4 | 62038.7 |
| '3-5' | '162542-021' | 'Creep @ 4313 h' | 40 | 40.3 | 313.5 | 8.3 | 659.4 | 59518.0 |
| '3-6' | '162542-022' | 'Creep @ 4313 h' | 40 | 40.3 | 313.5 | 8.3 | 670.0 | 61012.3 |
| '3-7' | '162543-020' | 'Creep @ 4313 h' | 40 | 40.3 | 313.5 | 8.5 | 67.0 | 10128.0 |
| '3-8' | '162543-021' | 'Creep @ 4313 h' | 40 | 40.3 | 313.5 | 8.5 | 594.6 | 55776.2 |
| '3-9' | '162543-022' | 'Creep @ 4313 h' | 40 | 40.3 | 313.5 | 8.5 | 53.6 | 7909.8 |
| '3-1' | '162541-019' | 'Break' | 40 | 40.3 | 313.5 | | 1688.0 | 218607.7 |
| '3-2' | '162541-020' | 'Break' | 40 | 40.3 | 313.5 | | 2201.1 | 325433.9 |
| '3-3' | '162541-021' | 'Break' | 40 | 40.3 | 313.5 | | 2234.2 | 333458.5 |

| Station | LIMS | State | TempdegC | AvgTdegC | AvgTK | AvgStressMPa | ReferenceStrain | EnergyVolJcc |
|---|---|---|---|---|---|---|---|---|
| '3-4' | '162542-020' | 'Break' | 40 | 40.3 | 313.5 | | 2367.2 | 360672.5 |
| '3-5' | '162542-021' | 'Break' | 40 | 40.3 | 313.5 | | 2369.7 | 380312.8 |
| '3-6' | '162542-022' | 'Break' | 40 | 40.3 | 313.5 | | 2164.5 | 311021.4 |
| '3-7' | '162543-020' | 'Break' | 40 | 40.3 | 313.5 | | 1718.4 | 241020.1 |
| '3-8' | '162543-021' | 'Break' | 40 | 40.3 | 313.5 | | 1639.9 | 215169.2 |
| '3-9' | '162543-022' | 'Break' | 40 | 40.3 | 313.5 | | 1699.8 | 238104.4 |

In **Figure 8-35** we plot the response surface for the creep data where Temperature [K] and Strain [%] are the fixed variables and energy per unit volume [J/cc] is the response. The energy per unit volume is calculated from the integral of the force displacement trace and the specimen geometry. We can clearly see that this surface is a material characteristic governed by the material density (ultimate break strength). The internal variation under force controlled creep are likely due to distributions in the rheological properties of the various molecular weight components of the resin formulation.

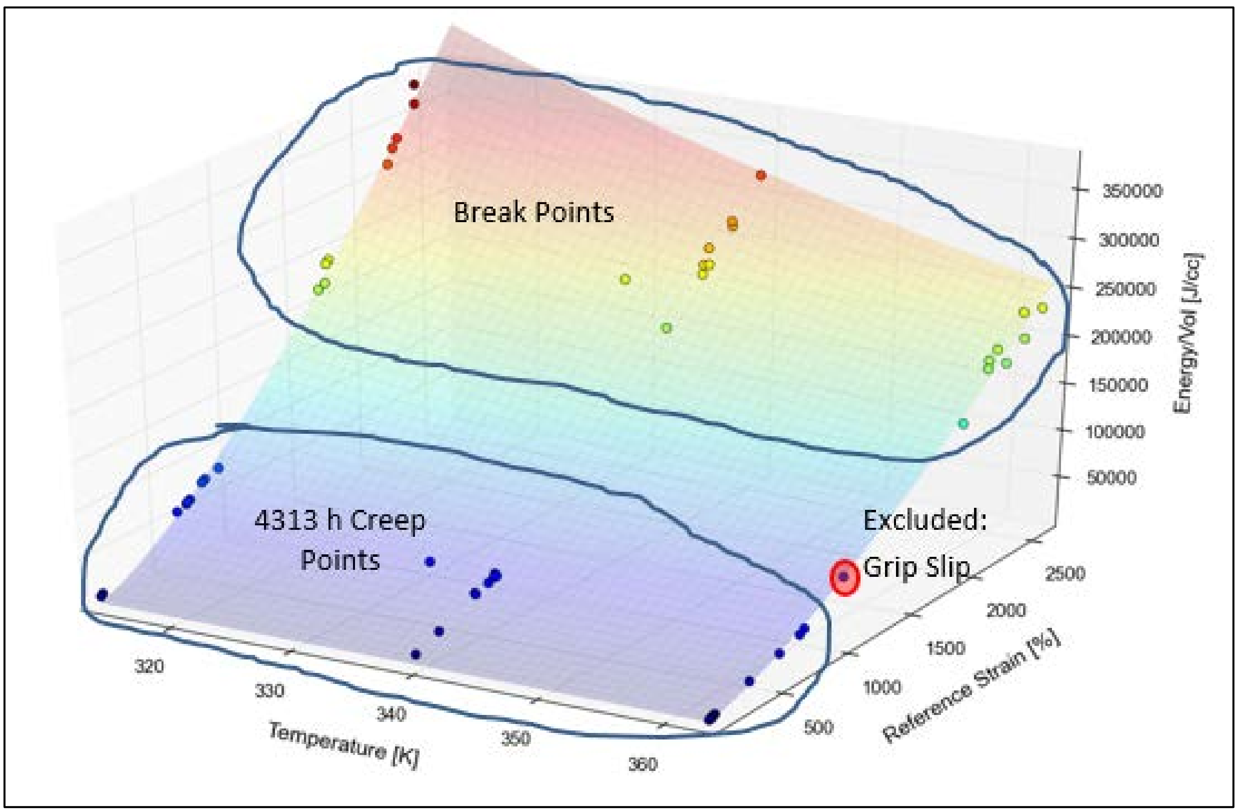



**Figure 8-35. Creep Surface for MDPE**

In **Figure 8-36** and **Figure 8-37** we present a graphical breakdown of the data in **Table 8-1**.

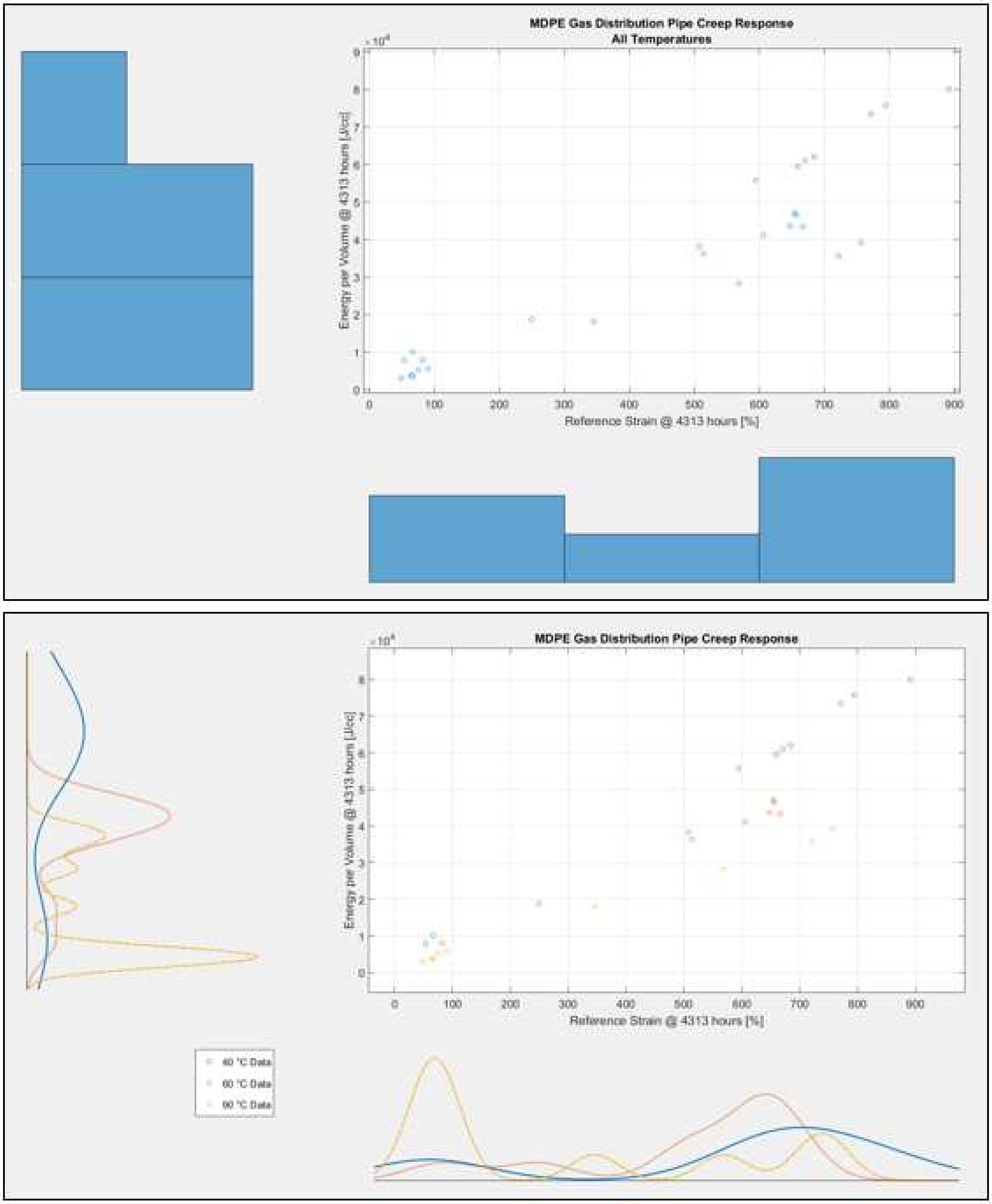



**Figure 8-36. Creep Response of MDPE Pipe at 4313 h of Load Controlled Creep @ 90°C.**

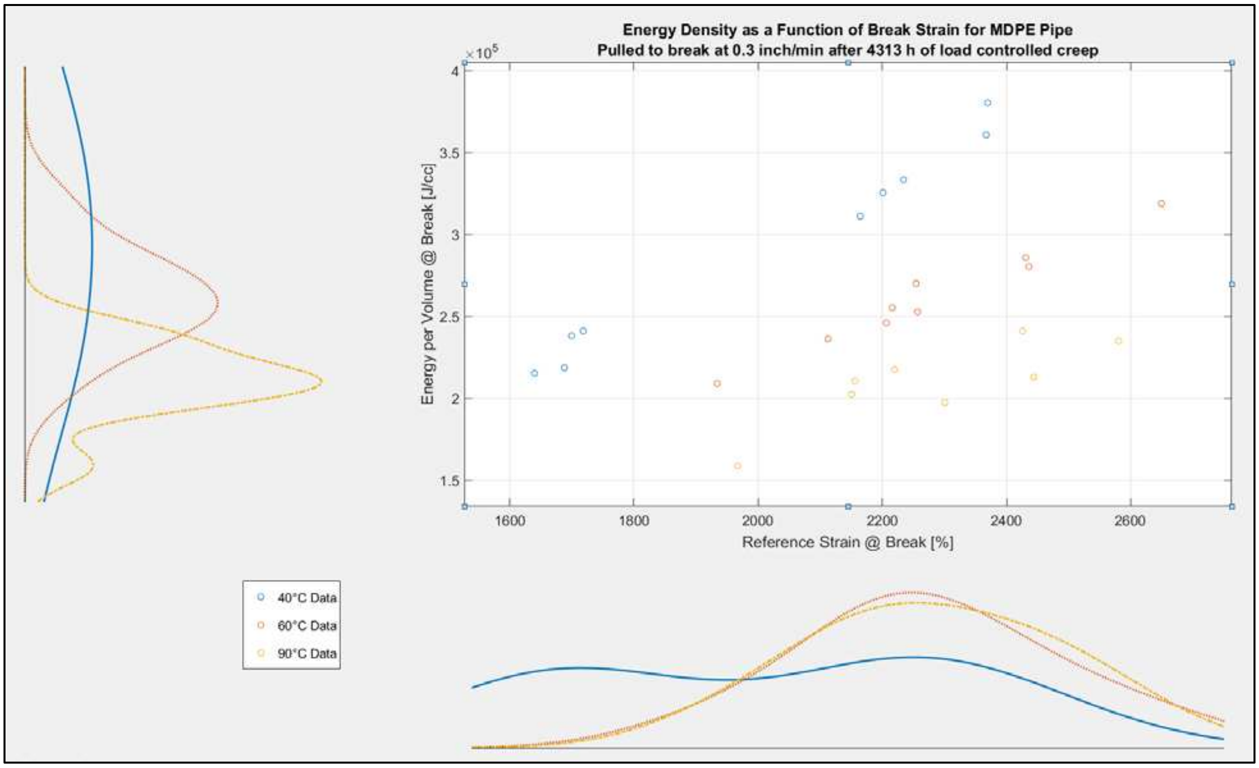



**Figure 8-37. Energy Density and Strain at Break for MDPE Pipe**

## SCG Summary

Introducing a notch into a polyethylene pipe creates a complex situation around the notch tip that will have dependencies on geometry and material properties. Review of the stress triaxiality distribution under various geometries and internal pressure clearly indicates that SCG will only occur under relatively low nominal hoop-stress conditions. The occurrence of SCG does not indicate a new mode of failure, it is still ductile creep, but occurs in a small local volume under high geometric constraint.

## Ductile Tearing Summary

GTI was able to induce ductile tearing, in polyethylene pipe, from a significant notch (30% wall thickness) during accelerated testing. Failure times of 1-10 hours were achievable at 90°C and test pressures of 150-200 psig. This would equate to test pressures of 350 – 450 psig at 68°F and failures would occur at test-times in the range 1,500-15,000 hours[12]. This is clearly impractical as field test and appears to indicate that a short-term pressure test to determine fitness for service is unlikely to succeed.

12 Using standard shift factors for polyethylene

8. Lever, E., *Bi-Directional Shift Factors Revisited*, in *Plastic Pipes XVII*. 2014: Chicago, IL.

In the following section, we will attempt to develop pressure test guidelines purely through analyzing reference SCG data sets. We will then review the results and check for consistency with the accelerated testing and FEM driven conclusion we reached above.

### *Pressure Test Guidelines*

**Figure 8-38** shows the process used for establishing pressure test guidelines. The basic premise is that a pressure test needs to be capable of causing damage that will breach the wall in a specified time frame under normal operating conditions to fail within the time of the over pressure test. The models needed to carry out this process are fully developed at this point. Actual guidelines will be provided in the next monthly report.
The results of steps 1, 2 and 3 are shown in **Figure 8-39** below. The data sets are for Ductile control, SCG control, LDIW control, LDIW with Indentation and LDIW with squeeze-off. There were 450 reference data points in total used in this analysis.

1. Determine vertical shift factors by aligning control ductile data to RPM mean line
2. Determine horizontal shift factors by aligning control SCG data to RPM mean line
3. Shift all data sets to reference temperature of 73.4°F using adjusted shift factors
4. Calculate intercepts for lines of slope equal to control ductile model that pass through all control ductile points
5. Calculate nominal ductile SIF by dividing actual shifted hoop stress by mean stress calculated from model
6. Calculate adjSIF ductile relative to the worst performing point – the point with smallest intercept calculated above
7. SIF3=3*SIFadj to peg worst point to FEM SIF for pipe with sharp scoring from extrusion process that asymptotically tends to 3
8. Calculate instantaneous ductile yield stress from RPM model adjusted to pass through best performing data point
9. Calculate nominal SCG SIF by dividing actual shifted time by mean time calculated from control SCG model
10. Calculate adjSIF SCG relative to the best performing SCG data point
11. Adjust the mean of the SCG adjSIF distribution to be equal to the mean of the ductile adjSIF distribution by adding the difference between means
12. Multiply the shifted hoop stress the adjSIF and divide the result by the ductile yield to identify points with immediate damage propagation
13. Use the points with immediate damage propagation to fit a propagation time as a function of SIF and Hoop Stress (near and far field stress)
14. Use the points without immediate damage propagation to fit a crack initiation time as a function of near and far field stress model
15. Use the propagation time model to identify what circumstances can be identified in a short term over pressure test

**Figure 8-38. Process for establishing pressure test guidelines**

FEM analyses were run to determine the SIF due to sharp and blunt grooves introduced into the pipe internal diameter during extrusion. The assumption is that these SIF "seed" the ductile rupture process and that the ductile stress rupture curves reflect these SIF. **Figure 8-40** and **Figure 8-41** show that at internal pressures typical of stress rupture tests the SIF for sharp grooves approaches 3 and for blunt grooves they approach 2.2. In steps 4, 5, 6 and 7 the distribution of the SIF in the ductile data set was calculated and is shown in **Figure 8-42.**

Fixing the maximum SIF to 3 per the FEM analysis results in a minimum SIF of 2.2, which is in remarkable agreement with the FEM analysis. This result is viewed as validation of the assumption that failure in the ductile regime is driven by the axial scoring on the pipe ID. In steps 9, 10 and 11 the SIF for the SCG data were calculated with an intermediate step of adjusting the control SCG calculated mean for the SIF distribution to match that of the ductile data points. The logic is that these are the same pipe population put into testing regimes that ensure ductile or SCG failures. The distribution of stress risers on the internal diameter of the pipes does not vary between tests. The ductile rupture process will ensure that sharp defects will blunt under plastic flow and we will see a narrow distribution of effective stress risers as reflected by the FEM results and the SIF distribution calculated from the data. In the SCG testing the far field stress is well below the ductile rupture boundary and we would expect to see a broader distribution of SIF due to less blunting of sharp notches and lower SIF also generating crack growth. This turns out to be a correct assumption. **Figure 8-43** shows the distribution of SIF in all of the reference data sets. Two parameter probability distributions have been fitted to all these results and will be used as priors in the Bayesian network models.

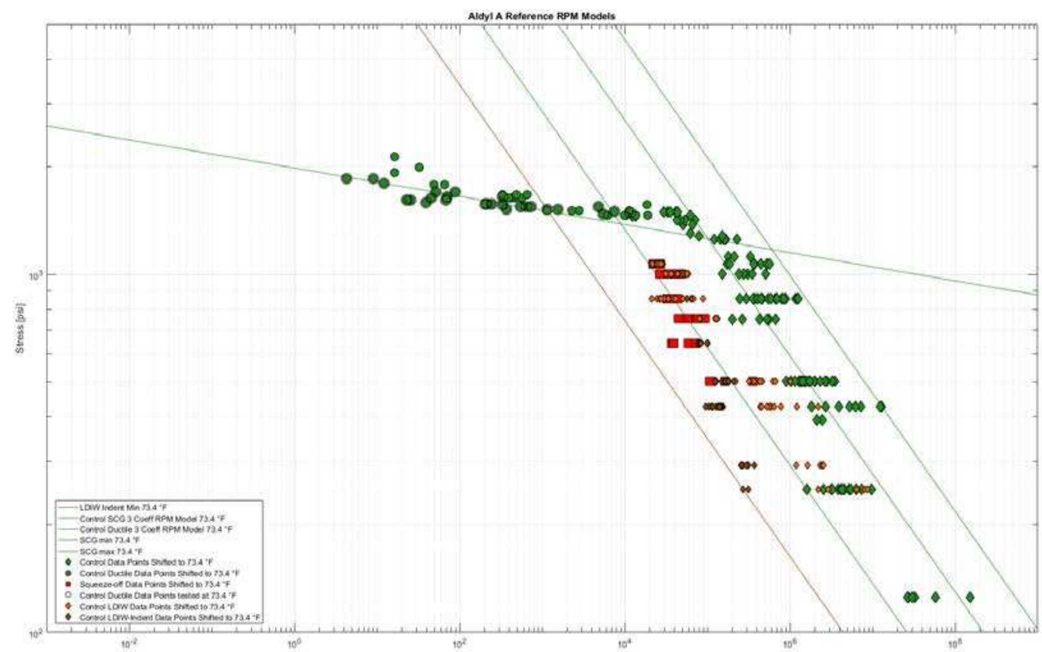



**Figure 8-39. Reference data sets shifted to 73.4°F per steps 1,2 and 3 of the process for determining pressure test guidelines**

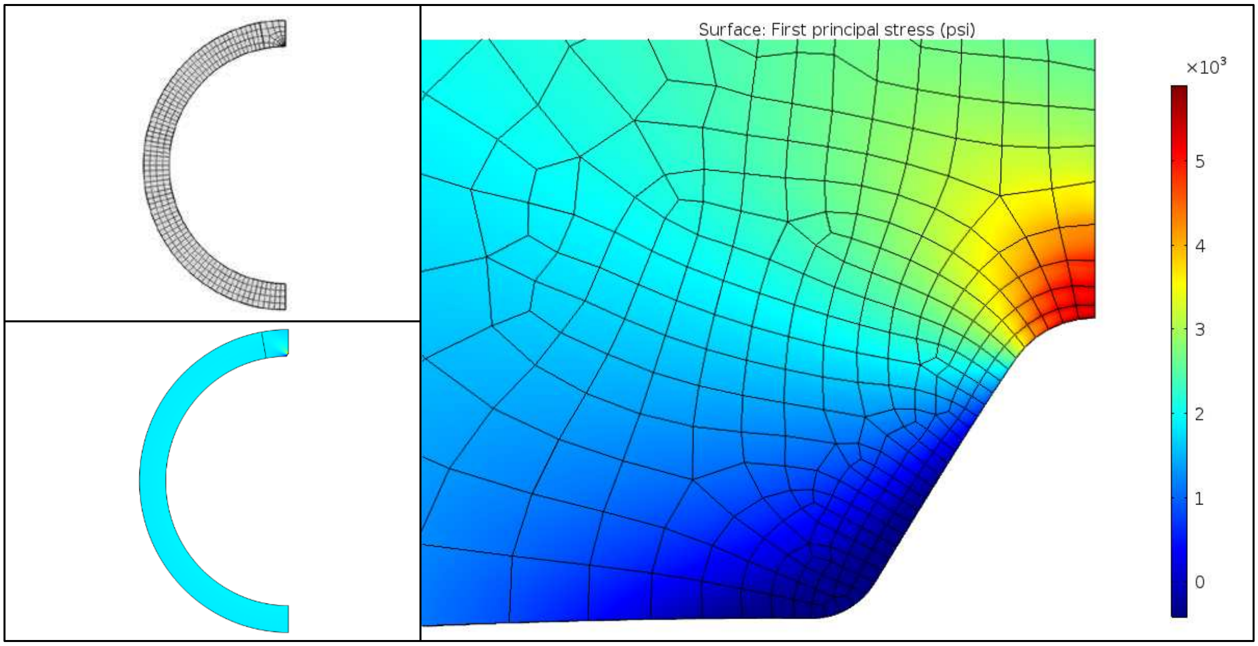



**Figure 8-40. FEM analysis of stress associated with die line grooves on internal diameter of MDPE pipe**

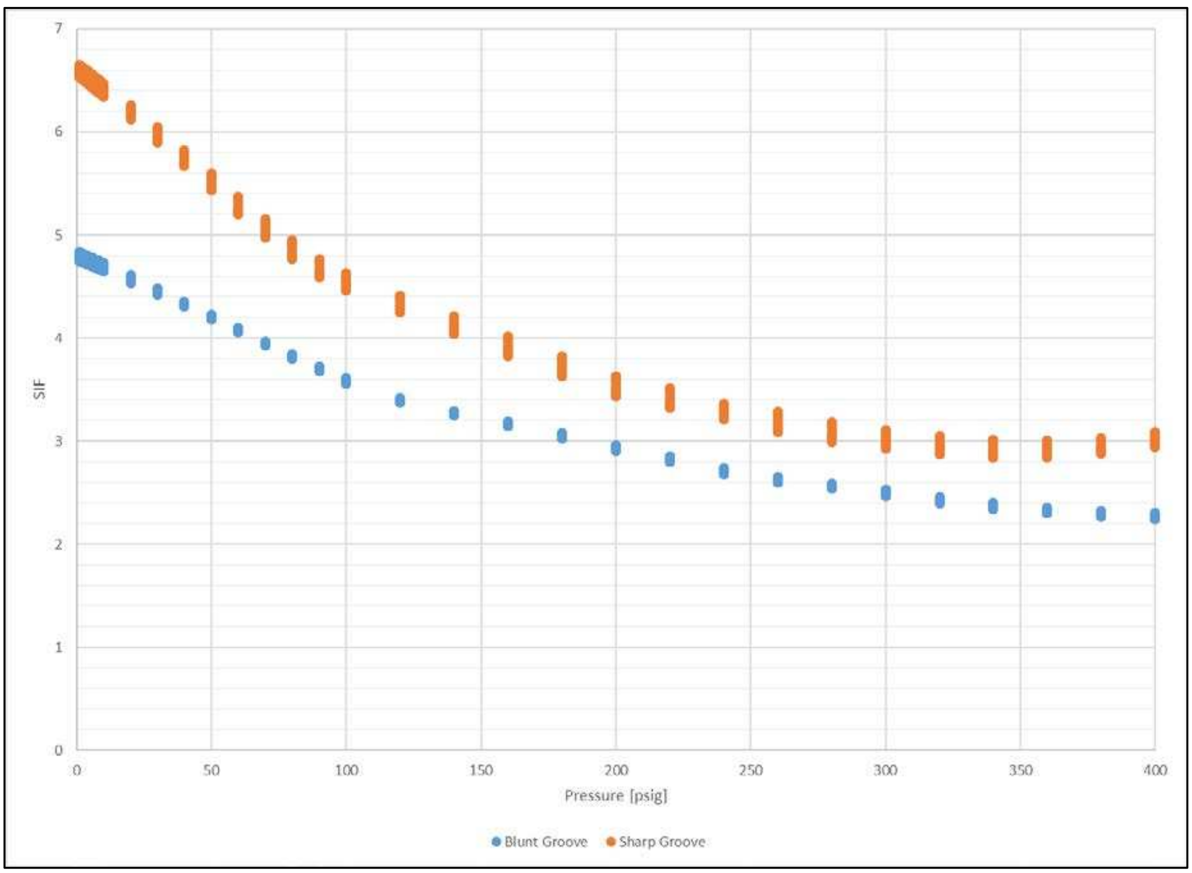



**Figure 8-41. SIF measured in FEM as a function of internal pressure at 73.4°F**

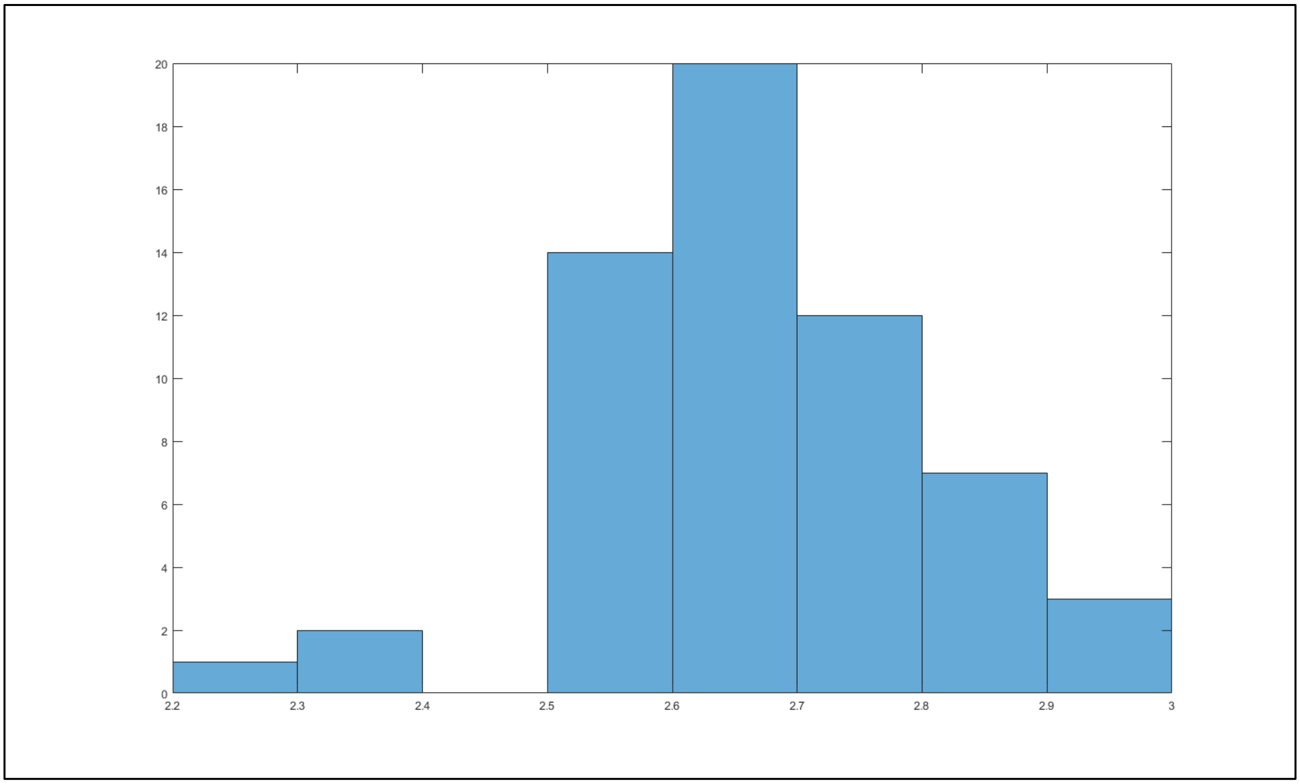



Figure 8-42. Distribution of SIF calculated in steps 4,5,6 and 7 of the process

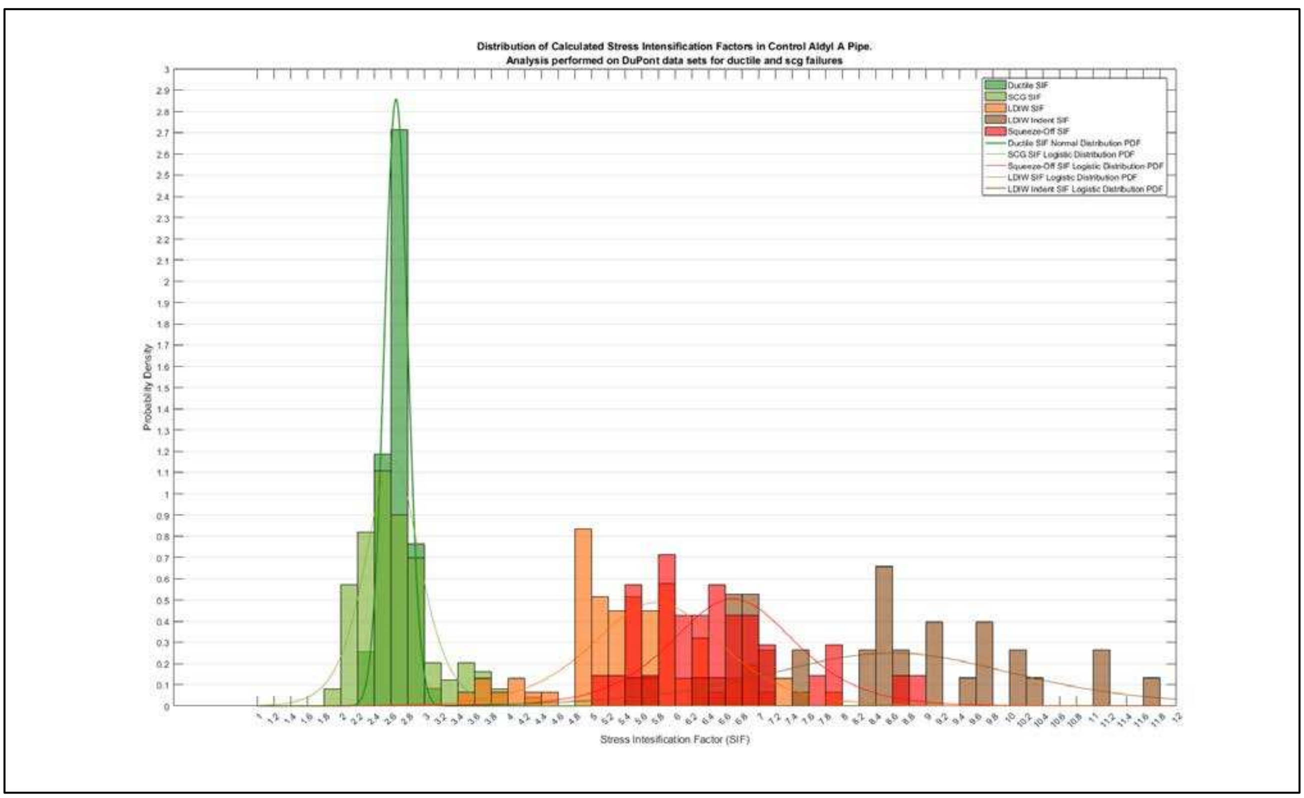



Figure 8-43. Distribution of SIF in SCG data set

The calculated SIF normalized to the mean of the ductile SIF were used to calculate the expected failure time for all data points where the nominal hoop stress multiplied by the SIF was input together with the test temperature into the control SCG RPM model. The results are shown in **Figure 8-44** with the 10 non-conservative results highlighted in red. There were 351 validation points with 2.8% of results non-conservative predictions, therefore we can conservatively state that we have 95% confidence that the model predictions will result in a conservative lifetime prediction. **Figure 8-45** shows the actual correlation estimate distribution with mean value of 0.9.

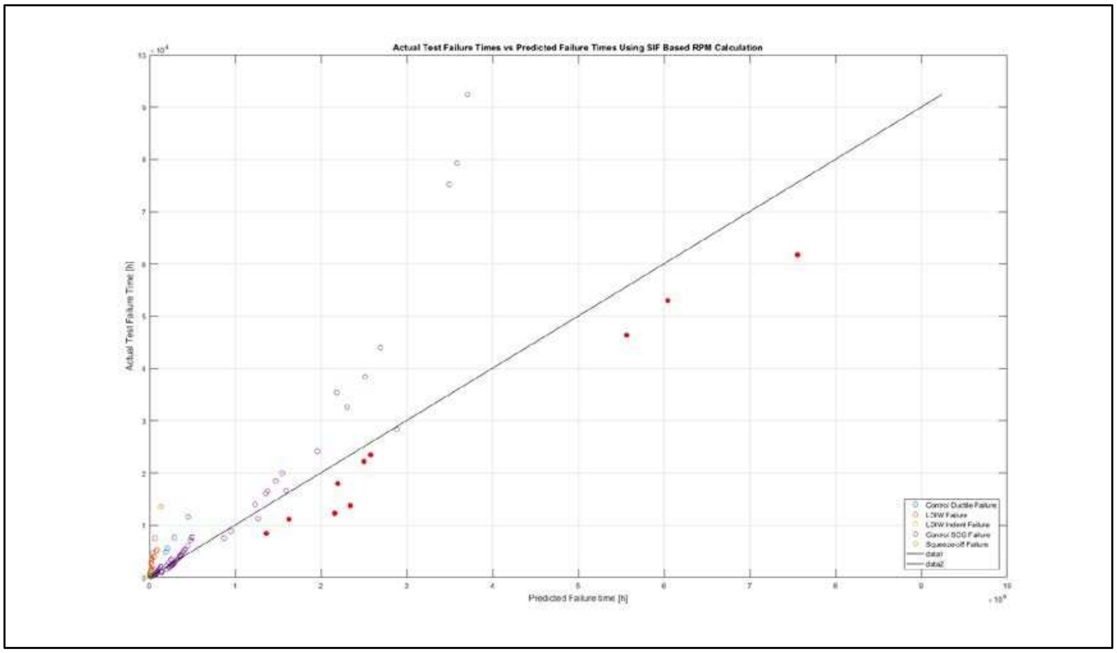



**Figure 8-44. Actual failure times vs predicted failure times, red points non-conservative**

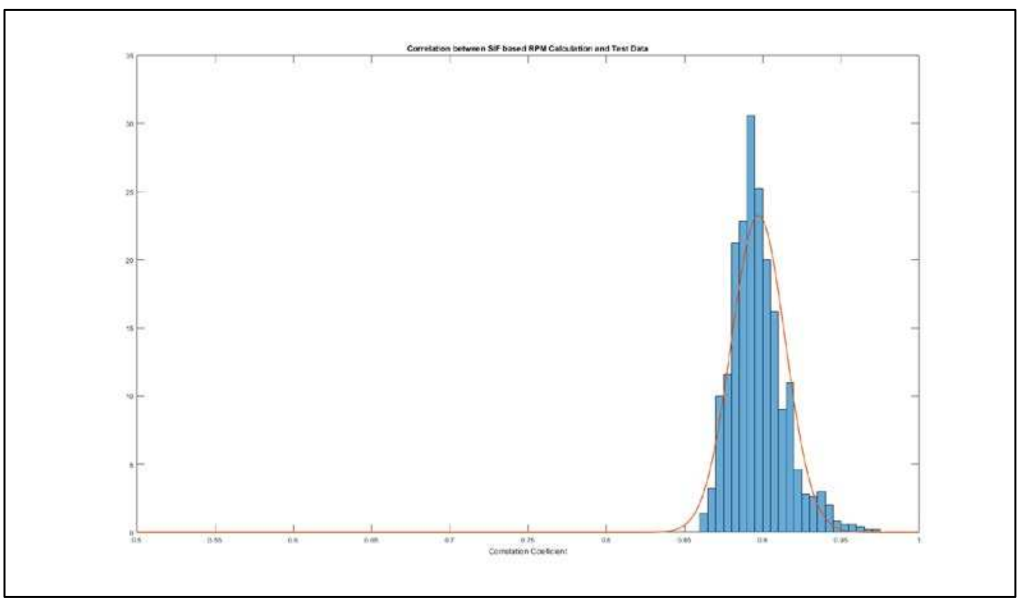



**Figure 8-45. Correlation of model results to actual results mean=0.9**

This result is encouraging as it validates the general approach used in the risk models employed in this project, where SIF are widely used as linear multipliers on the nominal hoop stress in conjunction with reference RPM model.

Steps 8, 12, 13 and 14 were used to extract propagation and initiation times from the data. In step 8 the instantaneous yield stress of the MDPE was determined to be 3,025 psi, which is very good agreement with mechanical testing data. This value was used to sort the SCG data into two categories:

1. Data points where the nominal hoop stress multiplied by the SIF exceeded the instantaneous yield stress, and
2. Data points where the nominal hoop stress multiplied by the SIF was less than the instantaneous yield stress.

The first group were assumed to have immediate damage propagation and the failure time was assumed to represent only propagation time. These points were used to fit a model relating the propagation time to the near field stress represented by the SIF and the far field stress represented by the nominal hoop stress. A good statistical model was found:

```
General model for Propagation Time:
   PropagationTime= a*SIF^b*HoopStress^c
Coefficients (with 95% confidence bounds):
     a =   2.233e+11 (-1.081e+11, 5.548e+11)
     b =      -1.232 (-1.459, -1.005)
     c =      -1.915 (-2.086, -1.743)
Goodness of fit:
 SSE: 5.04e+10
 R-square: 0.8644
 Adjusted R-square: 0.8628
 RMSE: 1.712e+04
```

The second group were assumed to have a crack initiation time followed by a propagation time. The propagation time for each data point was calculated from the propagation time model and subtracted from the failure time to yield the crack initiation time. The resulting data were fitted to a general model of the same form as the propagation time model:

General model for Initiation Time:
InitiationTime= a*SIF^b*HoopStress^c
Coefficients (with 95% confidence bounds):
a = 2.573e+11 (5.041e+10, 4.643e+11)
b = -0.8051 (-1.106, -0.5043)
c = -1.76 (-1.891, -1.628)
Goodness of fit:
SSE: 4.532e+14
R-square: 0.827
Adjusted R-square: 0.8249
RMSE: 1.652e+06

The initiation time and propagation time models were applied to all SCG data points to estimate total time to failure using hoop stress and normalized SIF as inputs.
The initiation time to total time ratio for all points was calculated. The mean was found to be 0.85, which is in good agreement with the rule of thumb that initiation time is 80-90% of the total time to failure. The distribution of results is shown in **Figure 8-46**.

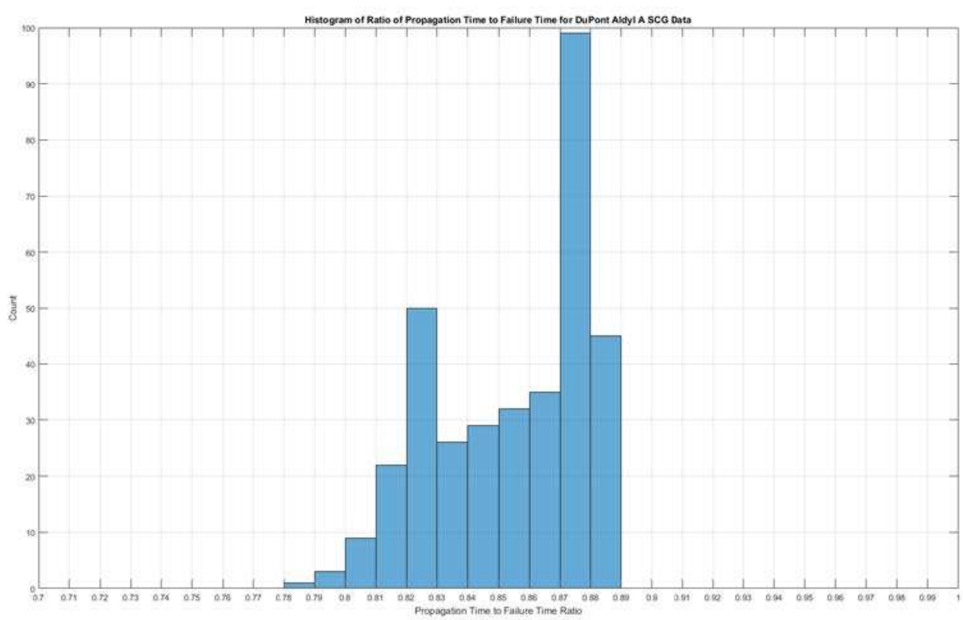



**Figure 8-46. Distribution of propagation time to fail time ratio**

The ratio of calculated failure time to actual failure times is shown in **Figure 8-47**.

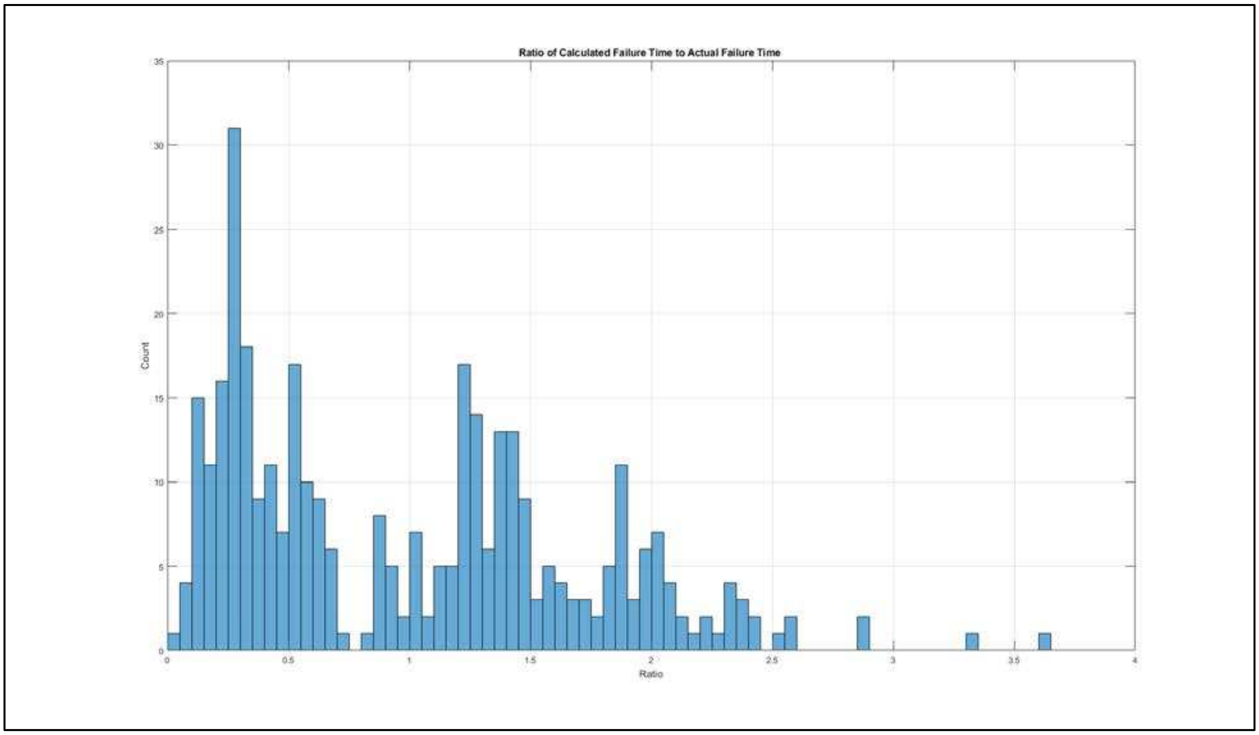



**Figure 8-47. Distribution of calculated failure times to actual failure times ratio**

The proper context for reviewing this result is to examine **Figure 8-39** and measure the ratio between the best performing SCG points and the worst performing points at a given hoop stress. The ratio is 50:1. If we include the problematic loading and material data this ratio grows to 250:1. For the validation shown in **Figure 8-44** all data points were included and the maximum ratio is about 3.6:1. The cumulative density plot of this distribution is shown in **Figure 8-48**. From this plot, we can see that 95% of results yield a ratio of less than 2.25 and 90% a ratio less than 2.

**This result shows us that knowledge of the SIF and material condition reduces our uncertainty in lifetime prediction by up to 2 orders of magnitude.**

This is a remarkable result that can be used to develop value of information statement to justify the gathering of more detailed information on the system.

Step 15, the development of pressure test guidelines is the next step in the process.

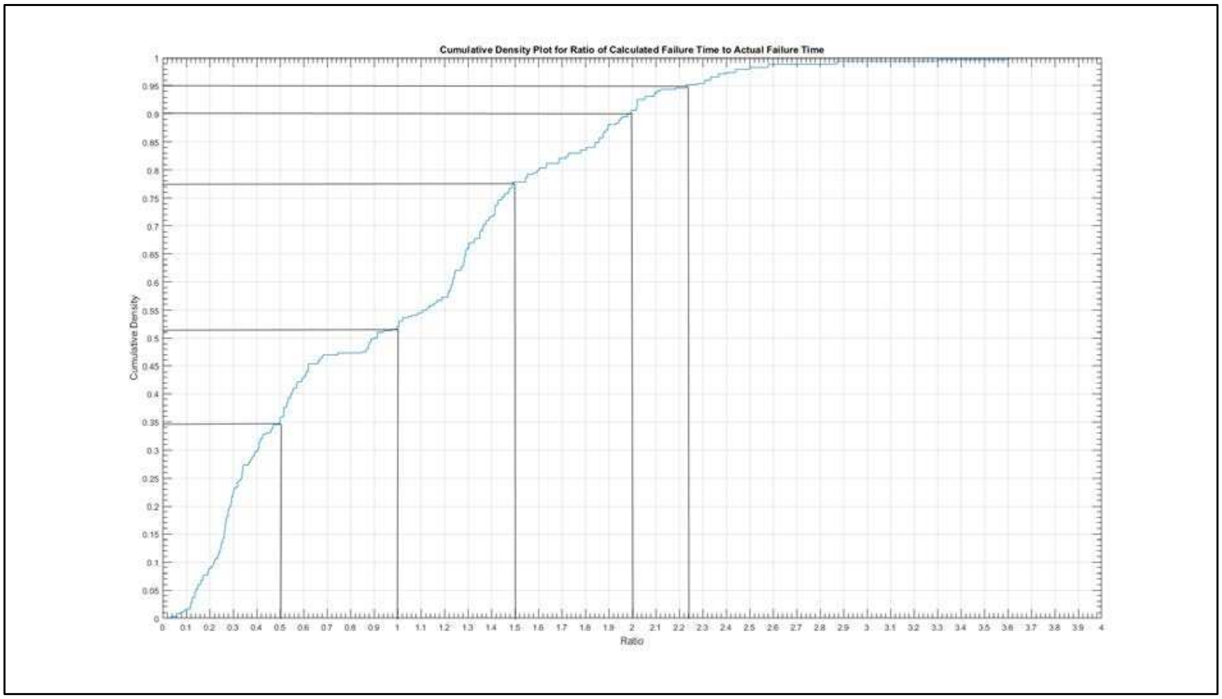



**Figure 8-48. Cumulative Density Plot for ratio of calculated failure times to actual failure time**

Using the model for propagation time above we can calculate the expected time to failure in an over-pressure test at 68°F where we raise the internal pressure to 1.5 * Maximum operating Pressure. The results are shown in **Figure 8-49.**

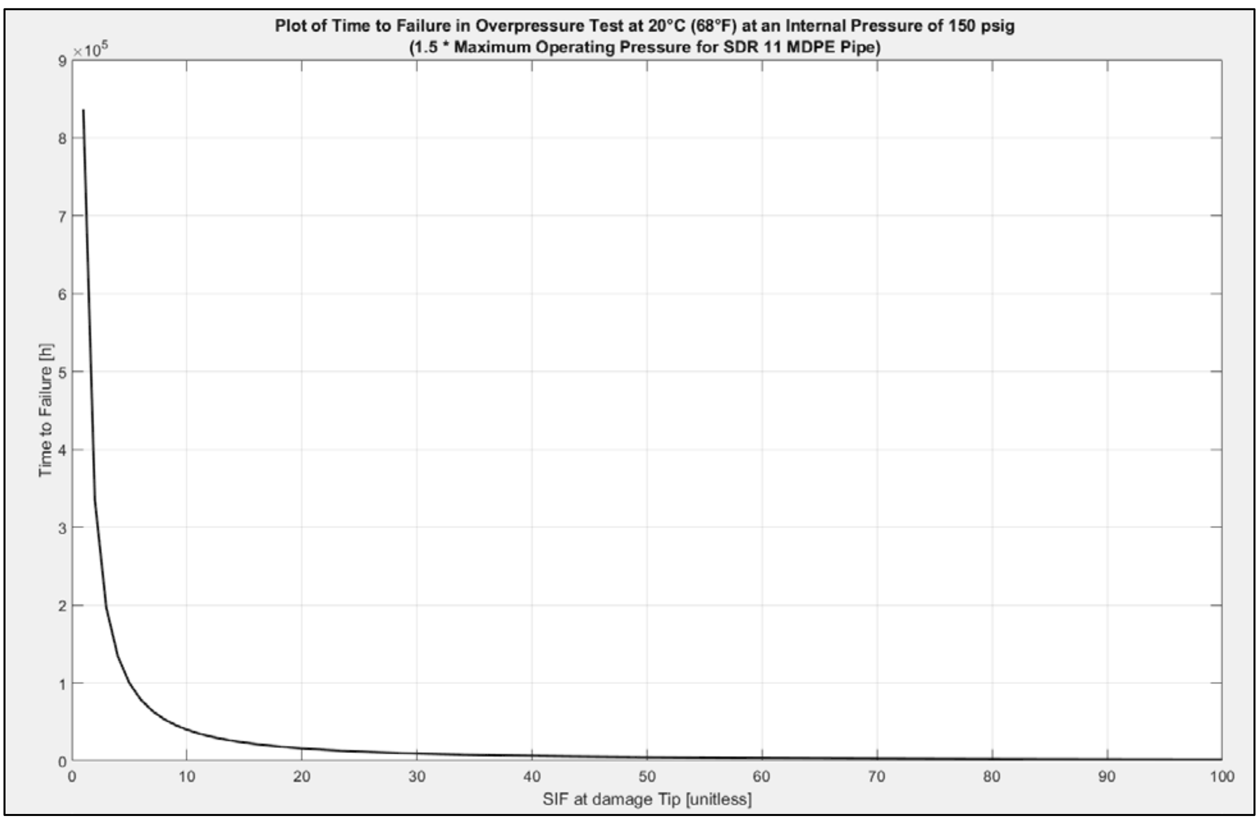


**Figure 8-49. Over-pressure test @ 68°F and 150 psig internal pressure**

As expected the results are absurd with failure times more than 50,000 hours at SIF <10.

Increasing the internal pressure to 400 psig per the example in the ductile tearing discussion above yields failure times in the 6,000 – 15,000-hour range for 5< SIF < 10 (**Figure 8-50**).

The maximum possible SIF for polyethylene at 400 psig internal pressure is about 11. This result is in the same ballpark as the expected time to failure derived from accelerated testing of multiple classes of polyethylene resin.

The times to failure are calibrated to the full wall thickness of SDR 11 pipe. Propagation times for fractions of the wall thickness would have to be calculated based on several assumptions about the rate of acceleration as the crack depth increases. This is beyond the scope of the present project.

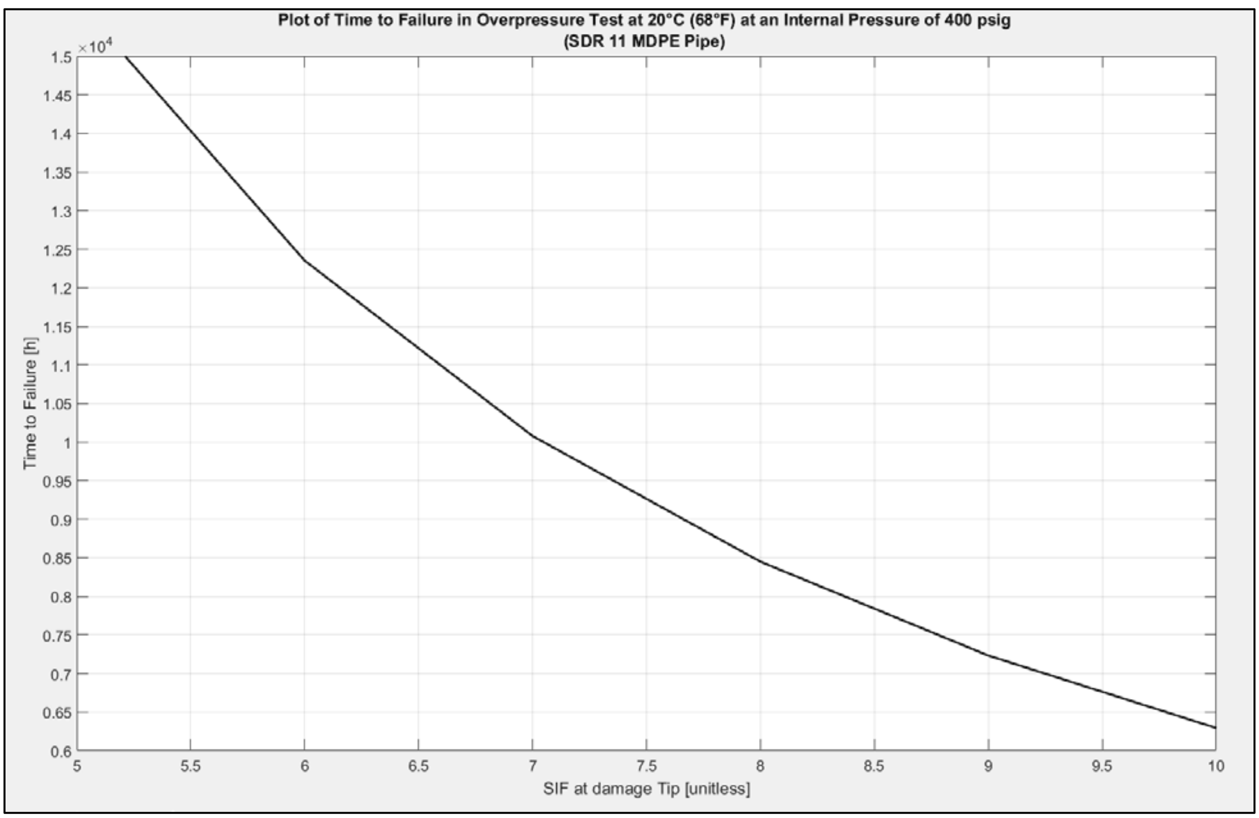



**Figure 8-50. Over-pressure test @ 68°F and 400 psig internal pressure**

### Short-term Pressure Test Conclusion

- Polyethylene constantly creeps under load and therefore does not react in a similar manner to steel at a crack tip.
- In polyethylene damage propagates per classic ductile material models as described by Bao [2].
- At crack tip fibrils form and undergo creep at rates that depend on the local strain
- The times to failure follow a strong power law relationship to both stress and temperature
- Two approaches to estimating damage propagation times lead to similar results:
    - Propagating damage from a razor notch through 30% of the wall in accelerated testing
    - Backing propagation times out from multiple SCG reference data sets
- A short-term over pressure test will not be effective in eliminating cracks of a given size from consideration with any acceptable level of certainty.

## Section 8 Bibliography

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## 9. Summary and Recommendations

### Tools for Evaluating Risk

The primary objective of this project was to provide an integrated set of quantitative tools that provide a structured approach to evaluating the latent risk in vintage polyethylene pipes, such as Aldyl-A, that are common in gas distribution systems.

Polyethylene pipes undergo constant creep due to the nature of the material. The underlying molecular mechanisms that enable creep are called relaxation mechanisms and they are constantly in action. Basic molecular motions occur thousands, or millions of times per second. If there is an external driving for that loads the polymeric structure, stresses will be developed in the material. These stresses give directionality to the random molecular motions that result in creep, and ultimately lead to failure of the polyethylene structure.

A primary deliverable of this project is a set of tools that define:

4. A Rate Process Method (RPM) model that defines the rate at which the polyethylene will creep.
    a. This rate is strongly dependent on temperature
    b. The rate is also dependent on the stress in the polyethylene structure that in turn depends on:
        i. The geometry of the component
        ii. The external loads acting on the component
5. The Stress Intensification Factors (SIF) that provide a simple means of translating the nominal hoop stress of the pipe, which is very easy to calculate, to true stress. Well defined and simple to apply SIF are essential to a workable risk evaluation method that utilizes simple, well-known parameters such as: pipe size, ambient temperature, system operating pressure, component configuration and other measurable installation characteristics to arrive at a true component stress. The SIF developed in this project, together with a single master RPM model underpin the lifetime prediction methods presented in this project.
6. The RPM model and SIF can be used as-is to perform risk assessments given system parameters, or they can be integrated into a tool that is capable of integrating all threat interactions into a composite risk score. A deliverable of this project is a Bayesian network that accomplishes this objective. A fully defined, calibrated and validated Bayesian network is defined in this project.

### Non-Destructive Evaluation in Confined Spaces, Fitness for Service, Replacement Prioritization and Data integration

Secondary objectives of the project were: first, to provide a fitness for service approach that can support replacement prioritization; second, utilize data from multiple sources such as in ditch condition assessment and leak records; third, to provide a means to access the pipe in a congested urban environment. These objectives were technically realized through:

4. A non-destructive tool that is capable of measuring pipeline configuration from inside the pipe was developed and prototyped in this project. This structured light, endoscopic measurement tool is a major breakthrough in assessing gas distribution pipes as it allows the operator to measure pipeline geometry over large lengths of the pipe without excavating the entire pipe. This measurement of pipe geometry from inside the pipe allows identification of several critical defects such as: impingement, squeeze-off, fittings, sudden displacements of the pipe, pipe deformations and other defects that cause stress intensification. This direct measurement of features will allow accurate SIF to be assigned to pipe segments. This will allow proper classification of segment with regard to the anticipated stress fields that when plugged in to the RPM model will provide probability of failure over time. This likelihood of failure is a key component in determining the segments Fitness for Service (FFS).
5. A set of reliability based tools were developed that underpin optimization methods for comparing repair/replace strategies over multi-year timeframes. These methods are based on robust damage propagation methods that were calibrated and validated against historic reference data. It was demonstrated that the Monte Carlo simulations that these tool support are capable of evaluated multiple scenarios and providing guidance as to the most effective risk management strategy over time
6. The tools developed in this project were integrated into a commercially available Artificial Intelligence (AI) platform that is capable of merging multiple disparate data sources, running the various risk assessment tools and providing insights driven be sophisticated data analytics. Intelligent forms that facilitate in-field data gathering and regulatory reporting requirement were also developed and demonstrated and tested as part of this project

### Summary

All of the project deliverables were met and tested via the components described above. A comprehensive set of tools that can be practically applied in multiple approaches, from simpe point applications, to enterprise wide decision support systems has been provided.

### Recommendations

The RPM and SIF based methods developed in this project can be immediately applied in:

1. Relative risk models
2. Quantitative risk models
3. Probabilistic risk models

They can be applied to point problems, as well as system wide problems. However, to address system wide problems in a coherent manner it is advisable to transition to probabilistic decision support systems. This is not a simple task. A Joint Industry Program (JIP) involving all stakeholders i.e. regulators, operators, material suppliers, manufacturers should be established to develop a roadmap that provides guidelines to the industry on how to improve all risk assessment methods outlined above through adoption of the tools provided by this project. The roadmap should include transition pathways between each of the risk assessment methodologies.

A key first effort should be to provide clear guidelines on how to improve data collection methods to support probabilistic reasoning and reliability based risk assessment methods. Efficient data collection will be greatly enhanced by the structured light scanning method developed in this project. The JIP should be tasked with shepherding the commercial development and deployment of this exciting technology that can be integrated into existing keyhole technologies.

The JIP can provide useful guidance on how to use the methods developed inn this project to support transitioning from prescriptive regulation to performance based regulation that will have reliability based maintenance frameworks as a key underpinning.

## 10. Future Work

The results presented in this report are a synthesis of five discreet efforts performed by three institutions GTI, ASU and MSU. GTI defined the architecture of the project and supervised the collaborative effort. GTI developed the adjusted RPM model and SIF distributions essential for performing fitness for service calculations, a Bayesian network for synthesizing complete system information, and integrated the above into a commercially available AI system together with developing an intelligent field data collection framework. MSU developed the structured light damage detection prototypes and associated algorithms. ASU developed methods for recognizing damage from the structured light data stream, and developed a maintenance optimization framework based on damage propagation and reliability methods that can be integrated into an enterprise decision support framework.

At the end of this collaborative effort considerable thought was put into identifying future research efforts that will enhance the methods presented. Some of the suggestions are presented below for consideration by interested parties.

### *Fitness for Service*

The presented work provides an excellent baseline that will enable operators to immediately apply the methods to point problems as they are identified in their systems. Several method improvements are needed to facilitate the transition to probabilistic risk assessment in the context of enterprise decision support systems:

1. Work needs to be done to extend the concepts presented into simulation the SCG process in polyethylene materials.
   a) The strain dependency of bidirectional shift factors needs to be investigated in the strain hardening portion of the stress/strain curve
   b) Creep rate experiments need to be conducted in the strain hardening portion of the stress/strain curve
   c) Bao-Wierzbicki models need to be developed to describe the critical strain at break of polyethylene fibrils
2. Implementation projects need to be carried out to develop the intelligent field data collection concepts presented in this project. These projects will develop the sampling plans and data categories needed to support probabilistic reasoning in system wide fitness for service determinations.
3. Work should be performed to integrate the decision support methods outlined in this project into enterprise risk governance frameworks i.e. risk tolerance and objective setting frameworks need to be developed to facilitate progressing beyond compliance towards true risk management that can inform the risk governance efforts of the organization.

### *Decision Support systems*

The presented work meets the goal in the proposal statement. Some additional work can be done to enhance and further develop the maintenance framework presented in this study:

1. The algorithm for the image reconstruction can be adjusted. The camera needs to be calibrated so that it can calculate the coordinate of the patterned light relative to the camera. With a calibrated camera, the size of the damage can also be known which is useful in the proposed dynamic maintenance framework. The dimensional information could be used to update the stress concentration factor and hence update the maintenance plan.
2. Although the proposed creep prediction model agrees well with the experimental data, there still exists some bias from the lab data. Further demonstration is needed if there were additional data available from GTI.
3. The ductile group in the data set was not used, but a trend of smooth transition can be observed in the data point plot (Figure 6-15) from ductile data to SCG data. An asymptotic function regarding yield strength of the material can be modeled for the slope of the regression curve. This would need further research and justification.
4. The maintenance framework is flexible in solving the maintenance planning given different conditions (minimize cost given reliability constraint and optimize reliability given budget constraint). The computational cost would be enormous when applied in large scale systems with various groups of pipes. The underlying principle when dealing with large scale optimization is to be studied. The maintenance framework may need to be adjusted for the high dimensional problem.
5. The proposed Bayesian entropy network (BEN) as a classifier can achieve fast learning with the extra information. The BEN concept can also be used in updating probabilities. The first step is applying the network in the updating of the parameters in the creep crack prediction model. The BEN can also be applied into large scale systems. In a large network, the update of one parameter would affect the nodes in the whole system. Sometimes this effect is not wanted. With the additional constraint, the BEN updating can be more accurate and efficient than traditional Bayesian network updating.
6. Sometimes, there could be a bias between the expert opinion (empirical information) and the ground truth. Once the wrong information were coded into the network, instead of increasing the inference accuracy, it would degrade the performance of the network and even damage the whole system. Since the constraint in a BEN framework is strong, an adaptive BEN is needed to compensate this situation. The adaptive network would use the given constraint when there is not enough data to update the belief. But would change to the truth from data when more observation become available. This could be understood as when there is limited information, the

network chooses to believe experience, but shifts its belief to the truth brought by data when more evidence become available.

7. The current framework focuses on one failure mode of plastic pipelines (slow crack growth). Information fusion and big data analytics with multiple failure modes and large systems that can integrate with the ongoing development of GTI framework needs further development. The "agent" serving for different failure types will need to automatically fused together for a consistent risk assessment. Recent advancement in artificial intelligence (AI) such as deep network learning has the potential for diagnostics and prognostics for gas pipeline industries.

### *Sensing Damage via Internal Inspection*

The delivered work meets the goal and proposed research objectives. Some additional research and hardware development can be done to enhance the ESLiST sensing system:

1. The current system provides a high quality and fast surface profile reconstruction, but the spatial resolution can be further increased by improving the hardware design, better system calibration, and more efficient reconstruction algorithm. Currently, a fixed structured light pattern was applied, which might not be optimal for all damage types and different field testing conditions. With the successful demonstration of the Prototype, I to Prototype IV and their feasibility of extracting damage dimensional information at MSU, extensive involvement of GTI in collecting real data should be expected. Additional work on feeding updated stress concentration factor derived from ESLiST image and ESLiST assisted decision information back to the sensing system should be carried out to complete the development loop and further optimize the novel structured light sensors design.
2. The proposed prototype works very well in a controlled lab environment by assuming the sensor is moving in a controlled straight path that is along the pipe's center axis. This assumption might be violated in actual field testing and inspection due to mechanical vibration of the sensing platform moving inside the pipe with complex geometries. An inertial measurement unit (IMU) can be integrated into the system to provide an estimation of the device orientation and positioning. Real-time compensation algorithms are needed to correct any distortion and misalignment induced error in data reconstruction to achieve same imaging resolution in a field environment.
3. Static structured light patterns have been studied and implemented as we proposed. However, the potential of the structured light approach will be maximized by introducing dynamic light patterns and data structures to adapt to various damage types and sizes under different light conditions. This could be better understood through both numerical simulations and experimental studies by collaborating with GTI and industry partners. An optimization of the current static structure light patterns to study the

relationship between the smallest detectable damage feature and the parameters of the static light pattern will also be beneficial.

4. Further improvement of the current data reduction and reconstruction will lead to faster and more accurate damage detection. The current framework only focuses on the SCG failure mode, so supervised multispectral data dimensionality reduction and defect classification methods would be sufficient and are successfully demonstrated. However, additional work should be done to realize the unsupervised damage recognition and information fusion while multiple failure modes are considered. Integration of advanced sensors from MSU and the intelligent decision support system from GTI and ASU would be more critical to achieving an optimal diagnostic and prognostic framework for gas pipeline industries.

## List of Acronyms

| Acronym | Description |
|---|---|
| ALM | Augmented LaGrange multiplier |
| BEN | Bayesian/maximum Entropy Network |
| CAD | Computer aided design |
| CBM | Condition-Based Maintenance |
| CCD | Charge coupled device |
| CCG | Creep Crack Growth |
| CDF | Cumulative Density Function |
| CNN | Convolutional neural network |
| CTS | Copper tube size |
| DLP | Digital light processing |
| DOF | Degree of Freedom |
| EDSS | Enterprise Decision Support System |
| ESLIST | Endoscopic structured light scanning tool |
| FEM | Finite Element Method |
| FFS | Fitness for Service |
| FOV | Field of view |
| GA | Genetic Algorithm |
| GTI | Gas Technology Institute |
| HSV | Hue, Saturation, Value |
| ILI | In-line inspection |
| IMU | Inertial measurement unit |
| LDIW | Low Ductile Inner Wall |
| LEAP | Laboratory of Electromagnetic and Acoustic Imaging and Prognostics |
| LED | Light emitting diode |
| LIDAR | Light detection and ranging |
| MC | Monte Carlo |
| MCMC | Markov Chain Monte Carlo |
| ME | Maximum Entropy |
| NB | Naïve Bayes |

| Acronym | Description |
|---|---|
| NDE | Nondestructive evaluation |
| NN | Neural Network |
| PDF | Probability Density Function |
| PI | Project investigator |
| POD | Probability of detection |
| POD | Probability of detection |
| PVC | Polyvinyl Chloride |
| RGB | Red green blue |
| RPM | Rate Process Model/Method |
| RUL | Remaining Useful Life |
| SCG | Slow crack growth |
| SCG | Slow crack growth |
| SEM | Scanning Electron Microscope |
| SIF | Stress intensity factor |
| SS | Single shot |
| TAN | Tree Augmented Naïve Bayes |

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# PG&E UPGRADING NATURAL GAS LINES IN BLUE LAKE STARTING TOMORROW

Sunday, 6 February 2022, 1:00 pm | Oliver Cory | Leave a comment

**This is a press release from Pacific Gas and Electric Company:**

Pacific Gas and Electric Company

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Pacific Gas and Electric Company (PG&E) is enhancing the safety and reliability of its natural gas system in Humboldt County. As part of PG&E's Pipeline Replacement Program, the company is replacing gas distribution lines and main services lines that run throughout the downtown areas of Blue Lake. The work will be done in phases and in small areas at a time.

PG&E will be replacing a total of 31,315 feet of Aldyl-A plastic gas distribution lines with high density polyethylene (HDPE) plastic. In total, 428 service lines to residents and businesses will also be replaced.

The first phase will begin on February 7 in which PG&E and contract gas crews with Teichert will be working within the area of Blue Lake that is west of G. Street and south of Powers Creek.

For the safety of the public and workers, there will be condensed

SEARCH

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Search Continues for Missing Whale Gulch Resident Dave Taylor

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lanes throughout the duration of the project, but no road closures are expected.  To aid drivers through the construction zone, there will be signage and PG&E has hired contractors for traffic management in the form of flaggers.

Traffic control crews will start setting up Monday, February 7 at 6:30 a.m. and all workers will be cleared out of the road by 6:30 p.m.  Construction will take place Monday through Friday. If there is a need, some work may take place on Saturdays in coordination with the City of Blue Lake.

Residents and businesses in the area received letters and automated phone calls about the work last year and will be notified again. If the need to shut off gas service arises, customers will be notified.

Throughout the process, PG&E may need to release natural gas from the pipeline and will follow all necessary safety

Humboldt County Jail Reports: Daily Booking Sheet – February 24, 2025

City of Arcata Wants Your Input on the Valley West Community Center Survey

Garberville Optometry Brings Mobile Eye Care to Southern Humboldt

Life from the Stacks: Painting a Path to a More Visible Library

Hope Sack Chosen as Eureka Natural Foods' Change 4 Change Recipient

Friends of the Arcata Marsh Sponsoring Lecture on Fish Research with Lily Olmo on March 5th

Covelo Man Arrested for Firearm and Probation Violations

requirements. This is also called venting the line. As PG&E purges gas from the line, the smell of natural gas and the sound of venting may be noticeable. The natural gas released during venting will quickly dissipate into the atmosphere and will not be harmful. However, PG&E encourages anyone who has concerns about natural gas odors in or around their home or business to call PG&E at 1-800-743-5000.

The second phase of work will begin in April and includes the areas of Blue Lake east of G. Street and south of Power Creek. Both phases of the project are expected to be complete by June 2023, barring unforeseen circumstances such as inclement weather.

We appreciate everyone's patience while we do this important safety work, as much of the gas system was originally installed in this area in the 1970's.  For more information on PG&E's gas safety programs,

Humboldt County to Begin Revoking Cannabis Permits Over Unpaid Measure S Taxes

Access Humboldt's 'Ray of Sunshine Award' Presentation is March 20th

Driver in Custody After Crashing Into Pole on Harris Street

Friends of the Arcata Marsh Hosting Five Tours in March

Celtic Celebration: Good Company Brings Traditional Tunes to Arts Alive

HappyDay: 'As the Woodstove Ticks'

Search Underway for Missing Southern Humboldt Senior

Greater Eureka Chamber Recognizes 2024 Business Awards Winners at Fashion-

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visit www.pge.com/gassafety and click on “Safety Initiatives”.

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# ALDYL-A REPLACEMENT PROGRAM

## Multiple locations throughout California

VPC is actively replacing gas mains and service lines around California as part of an ongoing effort to upgrade plastic and steel pipelines with modern materials. Through 2020, crews have completed 63 projects ranging from $150K to $2M in size, installing 171,400 LF of main and replacing more than 3,250 services.

| | |
|---|---|
| **Business Line:** | Gas |
| **Performed By:** | Veteran Pipeline Construction (VPC), a Charge company |
| **Delivery Method:** | Construction services/Project management |
| **Size:** | Approx. 30 miles of main and 3,200 services |

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### Project Highlights

- Completed 63 projects (through 2020)
- Installed 171,400 linear feet of mainline
- Replaced 3,253 services
- Te-ins to existing gas lines

### Project Services

- Directional Drilling
- Open Trench
- Houseline Plumbing
- Restoration
- Pipe Splitting

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CANARY MEDIA
Clean energy journalism for a cooler tomorrow

# This Vermont gas utility is getting into the electric heat pump business

The state's climate mandates are pushing Vermont Gas Systems to adapt and diversify its business, ramping up energy efficiency, renewable natural gas, and now heat pump offerings.

By **Lisa Prevost**
15 May 2023


A heat pump. Credit: Santeri Viinamäki / Creative Commons

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a broader portfolio of thermal systems that will help both the business and its customers make the transition to a decarbonized future, said Richard Donnelly, the company's director of energy innovation.

"We offer natural gas, energy-efficient products, weatherization, renewable natural gas, heat pump water heaters, and now heat pumps," he said.

Expanding its offerings also puts the company in a good position to comply with the state's new Clean Heat Standard, which became law last week after the legislature overrode a veto by Republican Gov. Phil Scott. Once implemented in 2025, the law will require fuel dealers to reduce the amount of fossil fuel they sell over time, or earn "clean heat credits" by doing things that offset building emissions, such as weatherization services and installing heat pumps.

Under the new heat pump program launched this month, the state's only natural gas utility will use its in-house service technicians to install centrally ducted, cold-climate heat pumps in qualifying homes. The highly efficient systems use electricity, rather than fossil fuels, to heat and cool homes.

Customers will be able to either buy or lease the systems at rates that factor in the heat pump rebates available through the state's utilities in partnership with Efficiency Vermont.

"We'll process that rebate up front for a purchase, and bake it into our lease prices as well," Donnelly said.

Each system will use the home's existing ductwork, and be integrated with the

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system, adding in the benefits of resiliency," Donnelly said. "This is also an opportunity to reduce their carbon footprint."

In order to qualify, homes must already have ductwork that delivers heat through vents. They must also have a fairly efficient furnace.

An estimated 14,000 of the utility's 55,000 customers could be eligible. Most homes in the company's service area have hydronic heating systems with radiators or baseboard radiators; Donnelly said the company will begin offering heat pump solutions for those customers in the future.

The new program comes just over a year after Vermont Gas announced it would begin installing electric heat pump water heaters for its customers. The company is also looking for a site to test its first fossil fuel-free networked geothermal project, another possible business to branch into as the state moves away from fossil fuels.

"As a distribution utility, energy efficiency utility, and integrated energy services provider, Vermont Gas is uniquely positioned to help its customers take advantage of the latest and most cost-effective technology," said Dylan Giambatista, the company's public affairs director.

Vermont's climate mandates call for reducing greenhouse gas emissions by 26% from 2005 levels by 2025, 40% from 1990 levels by 2030, and 80% by 2050.

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Gas heating customers switching to electric heat pumps won't necessarily save money, at least for now. While the heat pumps are more efficient, gas is currently the cheaper source for heating, Donnelly said.

But the company is developing an online calculator that will allow customers to see how setting the system to swap over to the furnace at 20 degrees versus, say, 25 degrees will compare in terms of carbon reduction and heating costs. They will also be able to measure the carbon and cost impact of adding in renewable natural gas.

"A lot of our customers are motivated by carbon reduction, but they don't know how much a heat pump would help in terms of their overall consumption," Donnelly said. "We're taking that role to educate."

Giambatista said he installed a heat pump in his 1945 house last fall. He set the smart thermometer to swap over to his gas furnace when temperatures dropped to 25 degrees. Over the winter his gas usage dropped by about 60% compared to previous years, he said.

To date, about 45,000 ducted and ductless heat pumps have been installed in Vermont under the state's rebate program, according to Phil Bickel, HVAC and refrigeration program manager at Efficiency Vermont.

They are primarily in homes that heat with fuel oil, the majority of homes in the state.

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Efficiency Vermont does recommend that homeowners maintain a backup source for heat. The heat pumps work well down to about -15 degrees, "but in Vermont, there are those times when we are going to have a long cold snap," Bickel said.

ENN Northeast Vermont

Lisa Prevost is a journalist based in Connecticut.

# Heat Pumps from VGS

VGS offers several heat pump models to fit your energy goals. We have options to warm and cool spaces, and heat water. These systems have multiple benefits. In many cases heat pumps are more efficient than fossil fuel combustion systems. If you currently heat with propane or fuel oil, heat pumps could help you lower your energy bill.[1]

As with all VGS services, you can count on our team of experts to help you identify the best fit for your home, your budget, and your energy objectives. Our goal is to make the process user-friendly. And, thanks to flexible options to purchase or lease, you have options to buy, install, and service these systems.

When you buy or lease heat pump equipment from VGS, you're getting a whole lot more than just a great way to heat and cool your home or heat your hot water. You'll get affordable lease and purchase options, a service team that is a phone call away, and an integrated approach to help you reliably keep your home comfortable all year long, while also cutting carbon.

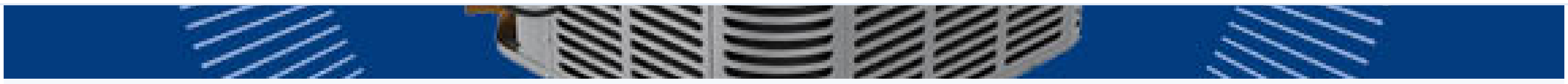
VGS makes it easy for you by incorporating qualified utility rebates from Efficiency Vermont and your electric distribution utility into the sale and lease prices. Burlington Electric Department[2] customers are entitled to an enhanced rebate, which VGS incorporates into the sale and lease prices. We also include service plans in leases[3], so you get peace of mind along with an easy monthly payment.[4]

## Ductless Mini-Split Heat Pumps

A Ductless Mini-Split Heat Pump will keep you comfy all year long. These systems work for both heating and cooling. We configure the ductless mini-split heat pump with a smart thermostat to make it easy to use. Our team will help you understand options to achieve your energy goals. As an added bonus, adopting a heat pump eliminates the need for difficult installation and removal of window air conditioners.

VGS offers this program to both existing customers and new customers who reside within a 5-mile radius of our distribution system. This includes those who are not connected to natural gas service. View our Interactive Map to see if your address qualifies for the program.

Compare Heating Costs



## Centrally Ducted Heat Pumps

Centrally Ducted Heat Pumps are an energy-efficient, low-carbon way to heat and cool your home. We integrate a heat pump with your existing hot-air furnace and ductwork to send warm and cool air throughout your home. Our team configures the system with a smart thermostat to make it easy to use.

VGS currently only offers these systems to VGS customers connected to gas service.

**Calculate Estimated Carbon & Cost**

## Heat Pump Water Heaters

Heat Pump Hot Water Heaters warm the water in your home. These appliances are up to three times more energy efficient than traditional electric resistance water heaters and the system's heat pump will help dehumidify your space. Switching to an electric heat pump hot water heater could save you money. Income qualified households may also qualify for a free or low-cost hot water heater through the "Switch & Save" program.

VGS offers this program to both existing customers and new customers who reside within a 5-mile radius of our distribution system. This includes those who are not connected to natural gas service. View our Interactive Map to see if your address qualifies for the program.

**Compare Water Heating Costs**

### Equipment Interest Form

Interested in VGS's heat pump program? Click here to complete an equipment interest form.

**Submit Online**

### View Coverage Map

Not a natural gas customer but interested in our programs? See if your home is within our territory for a Ductless Mini-Split Heat Pump or Heat Pump Water Heater.

**View Map**

More Ways to Switch
View Options →

Heat Pump Loan Application
View Document →

## Frequently Asked Questions

How does a Heat Pump work?

What is the difference between a Ductless Mini-Split Heat Pump and a Centrally Ducted Heat Pump?

Will a Heat Pump save me money?

Will a Heat Pump save carbon?

Is a Heat Pump able to heat my home in a cold climate like Vermont?

Are Heat Pumps eligible for state rebates?

Are Heat Pumps eligible for tax incentives/credits?

What kind of maintenance is required on a Heat Pump?

Are service plans available?

What is the term for leasing a heat pump?

1. Source: National Renewable Energy Laboratory, New release: Benefits of heat pumps detailed in new NREL report. February 2024. ↩
2. Limit (1) one BED rebate per household or business. Households or businesses that previously received a BED rebate for a ductless (mini-split) system are not eligible for the centrally ducted rebate. ↩
3. Leasing equipment from VGS is subject to VGS review and qualification. ↩
4. Please note: Service plans are currently only available for leased systems. VGS anticipates it will offer service plans for heat pumps sold and installed by VGS in the near future. ↩

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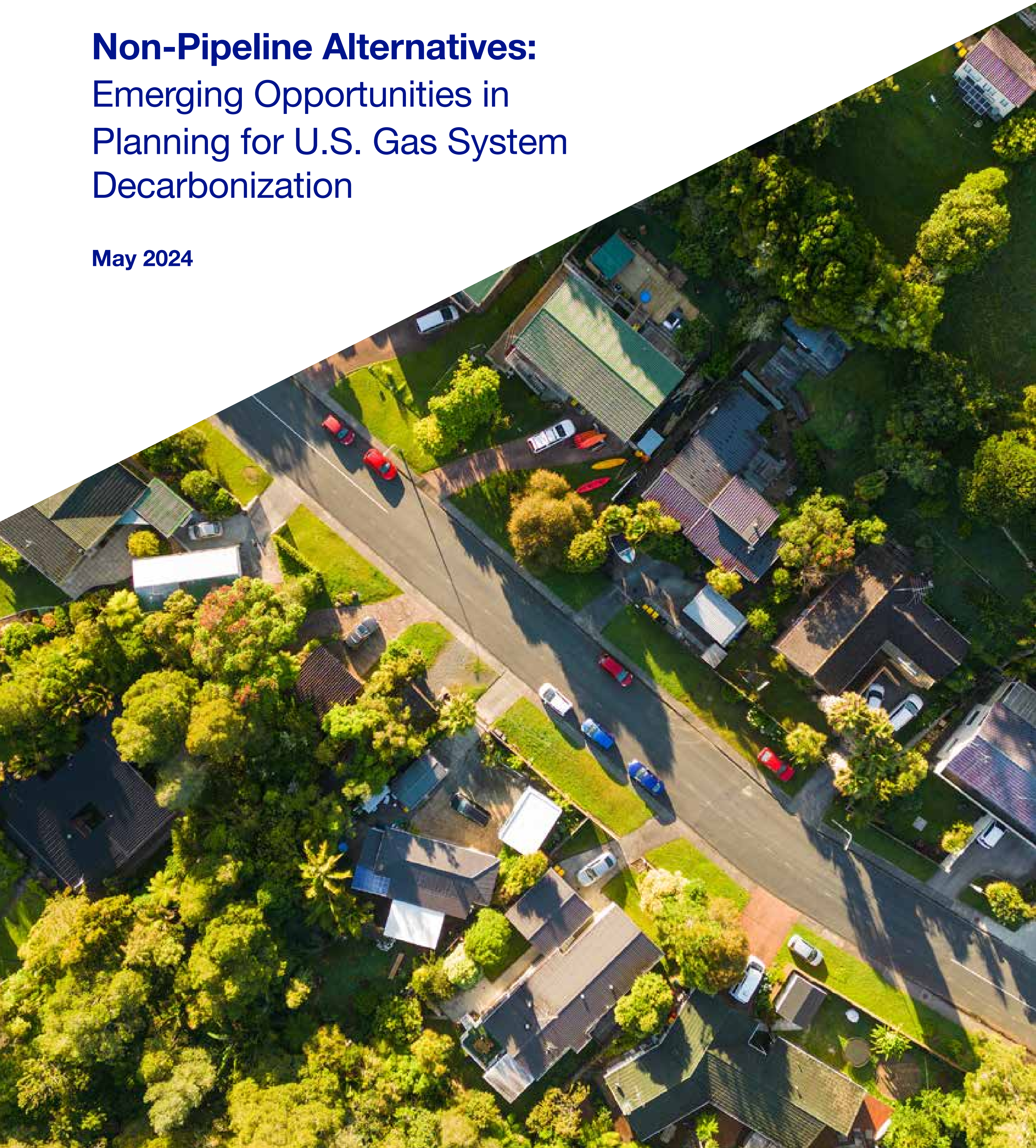
# Non-Pipeline Alternatives: Emerging Opportunities in Planning for U.S. Gas System Decarbonization

**May 2024**



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# Executive Summary

Multiple states in the U.S. have adopted ambitious climate targets requiring the achievement of net-zero greenhouse gas (GHG) emissions. To meet these climate targets and utility net-zero goals, utilities, regulators, and other stakeholders have begun planning for a future that is less reliant on fossil gas and more dependent on clean energy resources. Progress towards this future can be significantly advanced through integrated energy planning and adoption of non-pipeline alternative solutions.

**Integrated energy planning (IEP)** is the practice of incorporating critical interactions between gas, electric, and customer energy systems into utility and energy planning processes in the context of long-term climate goals. By recognizing the interdependent nature of today's energy systems, integrated energy planning can aid in assessing the infrastructure and customer impacts of potential transition strategies. This serves to advance net-zero goals most cost-effectively and equitably, while ensuring the safety and reliability of the systems customers rely on.

**Non-pipeline alternatives (NPAs)** are projects or initiatives intended to simultaneously reduce GHG emissions and defer, reduce, or avoid the need to construct or upgrade components of the natural gas system through customers' installation of all-electric equipment or connection to other lower-carbon infrastructure, including thermal energy networks. NPAs are an emerging area of opportunity for gas system decarbonization in the U.S., with the potential to achieve ratepayer savings across three categories of gas network investment: replacement of existing infrastructure, capacity expansion of existing system, and system extension to new customers.

National Grid U.S. is working to advance its own planning processes in accordance with the goals of the jurisdictions in which it operates, Massachusetts and New York. In order to better understand the landscape of non-pipeline alternatives and integrated energy planning in the gas industry today, National Grid and RMI worked together to identify case studies where NPAs and integrated energy planning have been implemented or developed. This research included interviewing utilities, non-governmental organizations (NGOs), consultants, and others working to deploy NPAs and integrated energy planning in diverse jurisdictions across the U.S. and Europe.

**This whitepaper is divided into two parts:**

First, we present nine case studies describing the current state of NPA initiatives and integrated energy planning in the U.S. and Europe. These case studies include projects that have moved toward implementation in both the U.S. and Europe, including the decommissioning of specific gas infrastructure.

For example:

- Pacific Gas & Electric (PG&E) in California has completed 88 NPA projects, converting a total of 105 customers from gas. Other U.S. utilities advancing projects include National Grid, Con Edison, Rochester Gas and Electric, and Xcel.
- In Europe, municipal clean heat planning is prevalent or required in multiple countries including the Netherlands and Switzerland. While Zurich is the only example of a city that has completed neighborhood-scale decommissioning to date, other cities in Switzerland and elsewhere are working to follow suit.
- Combination utilities in the U.S. such as National Grid and Xcel are working to integrate internal gas and electric planning teams and develop new tools and processes for integrated energy planning. An early example of cross-utility planning can also be found in Québec, where the gas and electric utilities received regulatory approval for a joint decarbonization strategy that accounts for the benefits each system provides the other.

Then, based on our research and learnings, National Grid and RMI offer the following eight insights for further exploration by U.S. utilities, regulators, policymakers, and other stakeholders to advance the deployment of NPAs and integrated energy planning:

**NPA projects underway today reflect diverse energy policy goals and energy system characteristics across different jurisdictions.** Clean heat planning is generally motivated by environmental and economic concerns, while some jurisdictions are also motivated by geopolitical and equity concerns. This diversity will necessarily shape the solutions that meet each jurisdiction's goals and needs.

**NPA projects can identify value in cost savings on the gas system, emissions reduction, or other societal benefits.** Utilities looking to develop cost tests for NPA projects should start by identifying the key costs and benefits, which may vary by jurisdiction and emissions valuation structure.

**Prioritization of NPA projects should weigh a broad set of criteria, including gas asset risk and hydraulic feasibility, electric capacity, benefit-cost criteria, customer propensity for new technology adoption, and community factors.** Some near-term areas of opportunity for NPAs are high-cost gas asset replacements where there is electric headroom and fewer than five customers on a segment.

**NPA projects can be funded from a series of different sources while protecting ratepayers' long-term affordability.** To date, NPA projects have been funded by gas ratepayers. However, to help mitigate upward rate pressure for gas customers as gas demand declines, consideration should be given to alternative funding sources, including federal, state or local taxpayer funding, as well as electric ratepayer funding.

**Integrated gas and electric network planning offers the opportunity to achieve net-zero goals as cost-effectively and equitably as possible.** Regulatory support will be required to enable cross-utility data sharing and decision-making, and to invest in new tools and capabilities.

**Utility and municipality partnership may be a key element of NPA projects and localized integrated energy planning.** Partnering at the municipal level is a valuable way to ensure alignment, build community support, and incorporate local priorities in project planning.

*In presenting this work, we hope the case studies and insights detailed herein will serve as a catalyst for advancing the implementation of NPAs and integrated energy planning across the U.S.*

**Individual customer persuasion to reach 100% participation is not a scalable NPA approach for avoided replacement projects.** Under the current regulatory framework, NPAs that avoid infrastructure replacement require voluntary and coordinated conversion of 100% of customers on the segment from gas to all-electric equipment. To date, no U.S. utility has successfully completed this type of NPA under the existing regulatory framework for projects serving greater than five customers.

**Policy change will be needed to evolve the utility business model and obligation to serve, while retaining the opportunity for cost recovery in a transition away from the use of gas.** State regulators will have a critical role in overseeing substantial changes to the provision of utility service that enable NPA projects to scale.

In presenting this work, we hope the case studies and insights detailed herein will serve as a catalyst for advancing the implementation of NPAs and integrated energy planning across the U.S.

# Introduction

### What are non-pipeline alternatives and integrated energy planning?

**Non-pipeline alternatives (NPAs)** are projects or initiatives intended to simultaneously reduce GHG emissions and defer, reduce, or avoid the need to construct or upgrade components of the natural gas system. NPAs are an emerging tool providing an opportunity to reduce emissions, gas system costs, and customer risk by avoiding unnecessary gas infrastructure spending. This is achieved through the electrification of potential new or existing gas customers or connection to other carbon-free infrastructure, including thermal energy networks such as networked geothermal systems. NPA projects fall under one of three categories of avoided incremental infrastructure investment:

- **Avoided replacement** projects avoid the risk-driven replacement of an asset, including retiring the asset and converting affected customers from gas. Avoided replacement projects require targeted electrification of all gas uses by all customers connected to a given segment of pipe, in order for the investment in new infrastructure to be avoided and the asset disconnected and retired. In practice, avoided replacement projects tend to see greater success under existing regulatory frameworks when the number of customers per project is fewer than five.
- **Avoided capacity expansion** projects avoid investments driven by forecasted load growth. These projects typically do not require 100% of affected customers to participate in demand reduction measures.
- **Avoided system extension** projects avoid the extension of the gas system to new customers. Several jurisdictions address system extensions through avenues other than utility policy.

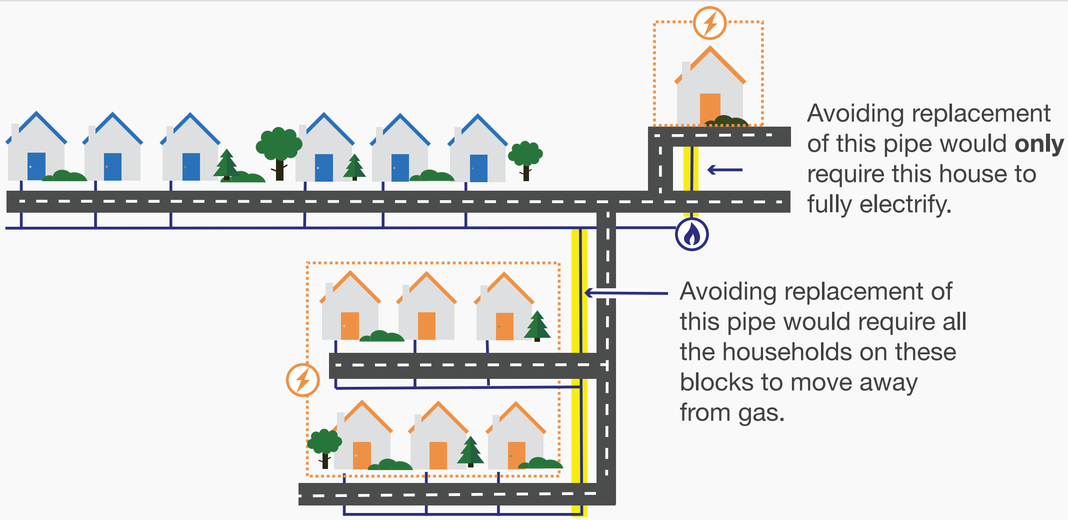
In this paper, our research primarily focuses on deploying NPAs to avoid gas infrastructure replacement or capacity expansion, including projects that involve decommissioning specific gas infrastructure. These three categories can be seen in Exhibit 1.

**Integrated energy planning (IEP)** is the practice of considering and incorporating critical interactions between gas, electric, and customer energy systems into utility and energy planning processes in the context of long-term climate goals, to achieve net-zero goals most cost-effectively and equitably for customers. While recognizing that IEP can provide broad value beyond NPAs, this paper focuses on the ways IEP can facilitate NPA identification and development.

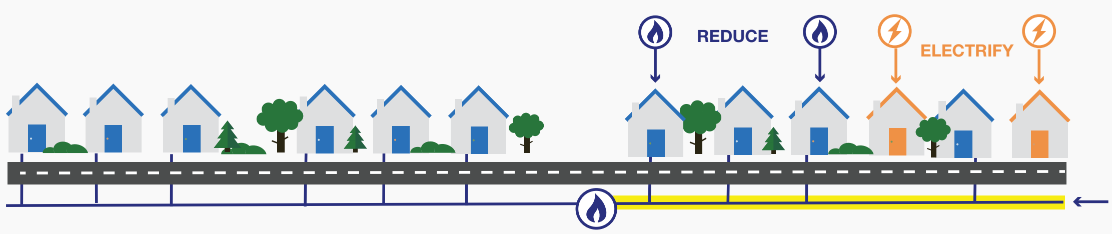
***NPAs are an emerging tool providing an opportunity to reduce emissions, gas system costs, and customer risk by avoiding unnecessary gas infrastructure spending.***

*Exhibit 1: NPA projects fall under one of three categories of avoided incremental infrastructure investment.*

### Avoided replacement

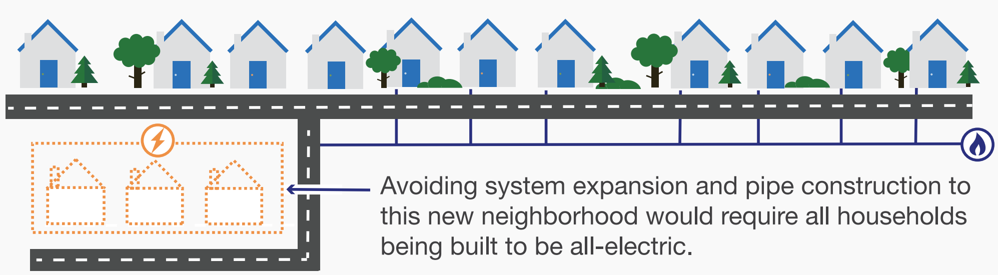



### Avoided capacity expansion




To avoid a capacity upgrade for this pipe, buildings beyond this pipe segment would need to reduce their overall gas demand – this could be through incremental reductions across the group, or full electrification of some customers. This reduction would not require 100% participation of all households.

### Avoided system extension



### Why are these topics important?

Natural gas utilities serve over 77 million customers in the U.S. These utilities maintain and operate more than one million miles of local distribution lines and invest over $20 billion per year in distribution systems.[1] State and federal climate and energy planning processes are increasingly cognizant of significant GHG emissions from the use of natural gas and thus identify a range of strategies aimed at reducing the use of gas over time.[2] In addition, policymakers in several states have begun to grapple with potential policy issues raised by a long-term reduction in the utilization of natural gas infrastructure (referred to in this paper as "gas transition").

***State and federal climate and energy planning processes are increasingly cognizant of significant GHG emissions from the use of natural gas and thus identify a range of strategies aimed at reducing the use of gas over time. In addition, policymakers in several states have begun to grapple with potential policy issues raised by a long-term reduction in the utilization of natural gas infrastructure.***

### Relevant Context for Non-Pipeline Alternatives in MA, NY and other U.S. States

In December 2022, New York and Massachusetts, the states in which National Grid operates, published net-zero plans calling for long-range reductions in the use of gas and new planning for gas transition policy issues. In New York, the Climate Action Council's Final Scoping Plan found that "achievement of the emission limits will entail a substantial reduction of fossil natural gas use and strategic downsizing and decarbonization of the gas system."[3] The Scoping Plan called for the "identification of strategic opportunities to retire existing pipelines as demand declines," including "seeking to move whole streets or neighborhoods at a time from gas infrastructure" to an electrified alternative.[4] The Scoping Plan further recognized the need for "integrated planning with the decarbonization of the power generation sector and buildout of local electric transmission and distribution systems" to meet increased demand and ensure equity and cost-effectiveness for customers.[5]

In Massachusetts, the Clean Energy and Climate Plan for 2050 (CECP) determined that "necessary reductions in natural gas throughput will require changes in how the gas system is operated and regulated and may require decommissioning significant parts of the gas system."[6] The CECP also found that gas distribution utilities may need to "manage customers' departure from the gas system to enable the retirement of some selected parts of the system to save some ongoing avoidable operating and/or capital investment costs."[7]

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[1] This figure from 2022 (the latest year with available data) represents a four-fold increase in annual spending since 2011. "Gas Utility Construction Expenditures by Type of Facility 1972-2022," American Gas Association, 2023, https://www.aga.org/wp-content/uploads/2023/01/Table12-1.pdf.

[2] More than ten states, including Massachusetts and New York, have opened regulatory proceedings to consider how gas utility planning should evolve in line with state emissions reduction targets.

[3] New York State Climate Action Council, "New York State Climate Action Council Scoping Plan," 2022, https://climate.ny.gov/resources/scoping-plan/, at p.350.

[4] Ibid at p.351.

[5] Ibid at p.350.

[6] Massachusetts Executive Office of Energy and Environmental Affairs, "Clean Energy and Climate Plan for 2050," 2022, https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2050, at p.62.

[7] Ibid at p.83.

Additionally, the December 6, 2023 order in Massachusetts Department of Public Utilities (DPU) Future of Heat Proceeding 20-80 affirms the value of targeted electrification and integrated energy planning as key strategies for managing the long-term costs of the gas system.[8] The DPU emphasizes the importance of rate recovery for existing, prudently made infrastructure investments and indicates in this order that the DPU will increase its scrutiny of new investments on the gas system, including an expectation that utilities will regularly assess NPAs to projected infrastructure needs. In the Climate Compliance Plan process established by the order, gas utilities must file plans every five years detailing their alignment with emissions reduction targets. The DPU also highlights the need for better integration of gas and electric system planning and requires electric utilities to partner in the development of overlapping gas utilities' Climate Compliance Plans.

Beyond the Northeast, there are other examples of regulators and utilities evolving gas infrastructure planning to manage ratepayer costs while achieving needed emissions reductions. California and Colorado have eliminated gas line extension allowances statewide, an indication that expansion of the gas system is no longer seen as a net benefit to existing gas ratepayers.[9] Both states now also require utilities to seek approval for and evaluate alternatives to certain gas infrastructure investments above a specific cost threshold.[10] Colorado's gas planning rules, similar to the new Massachusetts DPU Climate Compliance Plans, also require utilities to regularly file plans for meeting emissions targets and managing gas system costs.[11]

In this evolving policy landscape, gas utilities should prepare for changes on their systems and find new ways to manage capital investments. Utilities need to balance the imperatives of safe and reliable service, GHG emissions reduction, and long-term customer affordability in a future with reduced gas use. In this context, IEP and NPA solutions to avoid gas system investments present important opportunities to achieve this balance.

This whitepaper aims to describe the current state of NPA solutions and gas transition planning in North America and Europe and identify projects that have moved toward implementation, including decommissioning of gas infrastructure. We further explore the potential for the expanded use of NPAs and integrated energy planning in the U.S., including the potential role of municipalities in helping coordinate planning at the neighborhood or city scale.

***Gas utilities should prepare for changes on their systems and find new ways to manage capital investments. Utilities need to balance the imperatives of safe and reliable service, GHG emissions reduction, and long-term customer affordability in a future with reduced gas use.***

[8] Massachusetts Department of Public Utilities, "Order on Regulatory Principles and Framework," D.P.U 20-80-B, December 6, 2023, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18297602.

[9] California Public Utilities Commission, "Phase III Decision Eliminating Gas Line Extension Allowances, Ten-Year Refundable Payment Option, and Fifty Percent Discount Payment Option under Gas Line Extension Rules, Decision 22-09-026," Rulemaking 19-01-011, September 15, 2022, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M496/K987/496987290.PDF. S.B. 23-291, 74th Leg., (CO 2023), https://leg.colorado.gov/sites/default/files/2023a_291_signed.pdf.

[10] California Public Utilities Commission, "Decision Adopting Gas Infrastructure General Order," Rulemaking 20-01-007, November 30, 2022, https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M499/K396/499396103.PDF.

[11] Colorado Public Utilities Commission, "Commission Decision Adopting Rules," Proceeding No. 21R-0449G, December 1, 2022, https://www.dora.state.co.us/pls/efi/EFI_Search_UI.Show_Decision?p_session_id=&p_dec=29605.

## Case Studies

This section provides illustrations of non-pipeline alternatives and integrated energy planning from leading jurisdictions in North America and Europe. This section begins with a description of National Grid's initiatives in this area, then identifies other notable U.S. utilities advancing NPAs and IEP, and then details the most developed European examples.

### National Grid US

In April 2022, National Grid published its Clean Energy Vision, which calls for achieving net-zero GHG emissions by 2050 by focusing on four pillars: energy efficiency in buildings; 100% fossil-free gas network; hybrid electric-gas heating systems; and targeted electrification and networked geothermal.[12] This vision recognizes the need for electrification of many existing gas customer end uses to achieve net-zero GHG emissions through full electrification as well as partial or hybrid electrification.

National Grid has been evaluating potential non-pipeline alternative projects in New York for several years and working with peer utilities, regulators, and stakeholders to develop supporting regulatory frameworks.[13]

More recently, in Massachusetts, National Grid has been developing networked geothermal demonstrations which could also have potential as NPAs.[14]

***National Grid has been evaluating potential non-pipeline alternative projects in New York for several years, and working with peer utilities, regulators, and stakeholders to develop supporting regulatory frameworks.***

#### NPAs for Avoiding the Replacement of Existing Infrastructure

Over the last two years in New York, National Grid has been working to identify planned gas capital projects that could potentially be avoided through targeted electrification and decommissioning of specific segments of aging gas infrastructure rather than replacement.[15] In that time, National Grid has identified 27 of these projects in its New York territory. Of the 398 customers initially contacted about these 27 potential NPA projects, 149 customers have responded (37%) and 18 have expressed interest (5%).

One of the key barriers to implementing NPA solutions that retire leak-prone pipe is the fact that 100% of affected customers must participate in the program in order to decommission the asset. In communicating with customers about the benefits of NPAs, National Grid has identified a lack of broad customer familiarity with heat pump technologies,

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[12] National Grid, "Our Clean Energy Vision," April 2022, https://www.nationalgrid.com/us/fossilfree.

[13] This work has included National Grid's NPA Screening and Suitability Criteria proposal as well as the Joint Local Distribution Companies NPA Incentives and Cost Recovery proposals, filed with NYS Public Service Commission on August 10, 2022. "Joint Local Distribution Companies' Proposals for Non-Pipe Alternative Incentive Mechanism and Cost Recovery Procedures," New York Public Service Commission Case 20-G-0131, August 10, 2022, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={EBD3BFE2-6AC6-4A28-B98A-09E6A7CB75A4}. National Grid, "National Grid's Proposals for Non-Pipe Alternative Screening and Suitability Criteria," New York Public Service Commission Case 20-G-0131, August 10, 2022, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={2EC93238-1BA2-4AE6-B390-0436B198391B}.

[14] The company is developing a networked geothermal demonstration project at the Boston Housing Authority's (BHA) Franklin Field in Dorchester, MA. This geothermal project will replace an aging gas boiler loop that currently serves 129 BHA units. Construction is expected to begin in 2025.

[15] These efforts have focused on specific planned gas main replacement projects that are part of ongoing capital programs to replace Leak Prone Pipe, or 'LPP,' a term used in several Northeast states to refer to infrastructure that is assessed as a leak risk, based on vintage, material, or other factors. Utilities in other regions of the U.S. may refer to this type of pipe by its 'DIMP' score, based on the federal Distribution Integrity Management Program administered by the Pipeline and Hazardous Materials Safety Administration ('PHMSA').

customer concerns about the impacts of electrification on their energy bills, customers' preferences for some gas appliances, and challenges aligning the gas infrastructure replacement timelines with timelines for customers' own equipment turnover.[16]

However, National Grid has had three successful NPAs in rural upstate NY, where it identified 19 homes that are each directly served by a connection to gas transmission infrastructure, or "farm tap," that requires replacing gas regulator equipment. National Grid proposed covering the full cost of installing geothermal heating systems for each of these 19 homes, in lieu of investment in new regulators. Of these customers, five have expressed interest and three have moved forward with full electrification, with geothermal heating system installation complete.[17] Their gas service will be terminated, and any gas appliances replaced with electric appliances, paid for by the gas utility's program. Together, the electrification of these three customers will retire 586 feet of gas pipe and avoid the need for three new regulators.

### NPAs for Avoiding Capacity Expansion Projects

National Grid has released three requests for proposals to date across six sites in the New York Cityand Long Island gas territories, seeking third-party vendors to offer NPA solutions to permanently reduce peak demand to help avoid future capacity investments planned to meet growing gas demand.[18] [19] The company is currently evaluating requests for proposal responses and considering the cost-effectiveness and deployment feasibility of proposed solutions.

Electrification, weatherization, and energy efficiency are among the solutions that National Grid and the third-party vendors have identified to permanently reduce peak demand. Unlike avoided replacement projects, these projects do not always require 100% of affected customers to participate. The number of participating customers needed to avoid the capacity expansion project will depend on the specific project and how much demand reduction is necessary.

### NPAs for Avoiding New Customer Connections

When five or more potential new customers request to connect to National Grid's New York gas system, requiring the addition of more than 500 feet of gas main, National Grid has begun reaching out to these customers with information about NPA incentives for electrification in lieu of connection to the gas system. In these cases, the NPA incentives offered are equivalent to the value of the avoided pipeline installation. National Grid is considering expanding this offering to all potential new customers seeking to add more than 100 feet of gas main.

[16] To date, National Grid has reached customers via phone calls to inform them about NPA incentive opportunities for their property. In 2024, National Grid plans to expand its customer outreach to include email, postcards, and a website for customers to learn and engage further about NPA programs. National Grid is also considering resource requirements for door-to-door outreach.

[17] Of the five customers that initially expressed interest, one project didn't move forward as it was disqualified by the contractor and one customer opted out.

[18] KeySpan Energy Delivery New York (KEDNY) service territory.

[19] KeySpan Energy Delivery Long Island (KEDLI) service territory.

### Integrated Energy Planning Analyses

In response to stakeholder and utility commission interest, National Grid electric and gas planning and asset management teams began in 2022 to jointly explore how to conduct IEP.

To better understand the methodology, assumptions, data and capabilities required to enable IEP, a team conducted an analysis that evaluated the electric network impacts of fully electrifying residential gas heating load in two Massachusetts towns with both National Grid electric and gas service. The team also identified segments of leak prone pipe that could be candidates for targeted electrification if customers could be fully electrified and the leak prone pipe segment decommissioned in lieu of replacement.

The preliminary analysis found that the cost of electric grid upgrades to support community-wide heating electrification for all residential customers in the two cities outweighed the costs of avoided gas infrastructure replacement. However, the analysis found some segments of leak-prone pipe that could be good NPA candidates, where the benefits of avoided gas infrastructure replacement outweighed the costs of electric grid upgrades to support the incremental electric demand.

The analysis also identified additional learnings. First, there is a wide range of potential peak load impacts from the electrification of heat depending on many factors, including the type, size and efficiency of the heat pump adopted, the energy efficiency of the premise, and whether electric resistance back-up heating is used. In addition, further analysis and sensitivities are needed to understand the implications of the electrification of transport, which could lead to higher cost of electric upgrades, as well as potential opportunities for load optimization or demand response that could help mitigate peak impacts.

***The team also identified segments of leak prone pipe that could be candidates for targeted electrification if customers could be fully electrified and the leak prone pipe segment decommissioned in lieu of replacement.***

The exercise also made it clear that new tools and resources would be needed to scale the analysis and to consider multiple scenarios and sensitivities, such as collaborative modeling between gas and electric planning systems and locational forecasting of customer propensity in heating technologies. Since that preliminary analysis, National Grid has explored and begun piloting new software tools that could enable more sophisticated and scalable IEP.

# Other U.S. Case Studies: Utilities Advancing NPA Projects

Highlighted below are notable NPA efforts from three utilities in the U.S.: Pacific Gas & Electric, Con Edison, and Xcel Energy. As of early 2024, National Grid and RMI are also aware of ongoing NPA efforts at other New York utilities such as Rochester Gas and Electric and New York State Electric and Gas.[20]

## Pacific Gas & Electric

Pacific Gas & Electric (PG&E) has successfully completed 88 targeted electrification projects, including decommissioning 22 miles of transmission pipe and converting 105 customers from gas. Each project has required high-touch customer outreach and in most cases, PG&E has offered to pay the full cost of customer conversion from gas service. PG&E has so far successfully executed projects affecting fewer than five customers at a time, reflecting the challenge of persuading larger clusters of customers to reach unanimous agreement on electrification. PG&E has also proposed a much larger project at California State University Monterey, where the university is the sole decision-maker for campus facilities.[21]

The requirement for voluntary participation from 100% of affected customers is an identified barrier to PG&E's pursuit of larger projects at scale. This requirement derives from the statutory 'obligation to serve,' which broadly obliges utilities to provide utility service upon request. In practice, this obligation prevents utilities from permanently ceasing service to a customer as part of a targeted electrification project so long as that customer wishes to continue to receive gas.[22] PG&E is considering support for legislative changes which could enable larger-scale targeted electrification initiatives.[23]

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PG&E has developed a Geospatial Electrification tool which the utility uses to identify candidate sites for NPAs across its system. PG&E has also provided a version of this gas asset analysis tool under NDA to some cities in its service territory to aid in their decarbonization planning. Additionally, the California Energy Commission has funded a "Targeted Building Electrification and Gas System Decommissioning Pilot Project" in Northern California which leverages PG&E's gas asset analysis tool to develop a framework to identify high-potential NPA projects. The project's interim report, "Strategic Pathways and Analytics for Tactical Decommissioning of Portions of Gas Infrastructure in Northern California," highlights questions essential to integrated energy planning, including what information about energy

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[20] "Avangrid Subsidiaries NYSEG and RG&E Advance Their First Whole Home Electrification Project in New York," AP News, February 2024, https://apnews.com/press-release/business-wire/avangrid-inc-new-york-construction-and-engineering-government-programs-246e3fbad6da4b0aaca71e79aa82ace9.

[21] Pacific Gas and Electric, "Application of Pacific Gas and Electric Company (U 39 G) for Approval of Zonal Electrification Pilot Project and Request for Expedited Schedule," California Public Utilities Commission Application No. 22-08-003, August 10, 2022, https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M496/K451/496451495.PDF.

[22] While exact language can vary, statute in most states includes a definition of utilities' obligation to serve customers as part of the public utilities code.

[23] For example, CA Senate Bill 527 did not pass in 2023 but would have allowed a limited number of pilot targeted electrification projects to proceed with less than 100% customer opt-in, subject to PUC oversight and approval. S.B. 23-527, (CA 2023), https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=202320240SB527.

infrastructure and population demographics is needed to make near-term investment decisions that advance long-term utility, customer, and state policy goals.[24]

### Con Edison

In November 2023, Con Edison released a Non-Pipes Alternatives Implementation Plan, detailing their NPA efforts to date. Con Edison operates two NPA programs: the Area Load Relief Program, which works to address capacity constraints across a broad area, and the Electric Advantage Program, which aims to avoid gas main replacements, such as those removing leak-prone pipe.

The Area Load Relief Program has one active project with expected efficiency investments beginning in 2024, which aims to achieve the necessary demand reduction by November 2025. Since its launch in 2023, the Electric Advantage Program has identified over 300 candidate projects, conducted customer outreach for 65 projects, and confirmed implementation plans for 3 projects that will convert a total of 5 customers from gas. Additional projects are anticipated to progress in 2024. The Electric Advantage Program has so far targeted only pipe segments serving fewer than 5 customers each. Con Edison's early experience emphasizes the importance of high-touch customer contact and face-to-face engagement for these projects.

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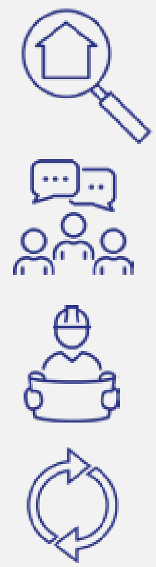

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**3**
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### Xcel Energy

Under new gas planning rules established by the Colorado Public Utilities Commission in 2022, Xcel Colorado assessed NPA portfolios as potential alternatives to seven anticipated infrastructure investment projects. Of these, two NPA projects have been proposed for Commission approval.[25] One project impacts over 25,000 customers and aims to reduce peak gas demand by aggregating customer electrification to avoid the need for a gas capacity expansion project. The second project aims to avoid the replacement of high-risk mains and services, and thus requires full electrification of the 66 primarily commercial customers served by this infrastructure.

[24] Energy and Environmental Economics, Inc., Gridworks Organization, and East Bay Community Energy, "Strategic Pathways and Analytics for Tactical Decommissioning of Portions of Gas Infrastructure in Northern California," June 2023, https://gridworks.org/wp-content/uploads/2023/06/Evaluation-Framework-for-Strategic-Gas-Decommissioning-in-Northern-California-Interim-Report-for-CEC-PIR-20-009.pdf.

[25] Of the remaining five projects assessed, two were too far in the future (five years from filing, approximately six years from initial identification) to perform effective cost estimates and cost-benefit analyses, though these will continue to be assessed for NPAs in future filings. The remaining three projects will proceed with the gas infrastructure option, as the net economic benefit for the NPA option was less than the infrastructure option for one project, and the last two were required in-service by the 2024-2025 heating season. Public Service Company of Colorado, "PSCo Initial 2023-2028 Gas Infrastructure Plan, Attachments B.1-B.4 and B.6-B.8," Colorado Public Utilities Commission Proceeding No. 23M-0234G, May 18, 2023, https://www.dora.state.co.us/pls/efi/EFI.Show_Filing?p_fil=G_804257&p_session_id=.

# European Case Studies: Examples of Targeted Electrification and Clean Heat Planning

As of early 2024, National Grid and RMI are aware of several European countries actively advancing targeted electrification and clean heat planning. These examples focus on planned solutions at the municipal and neighborhood level.

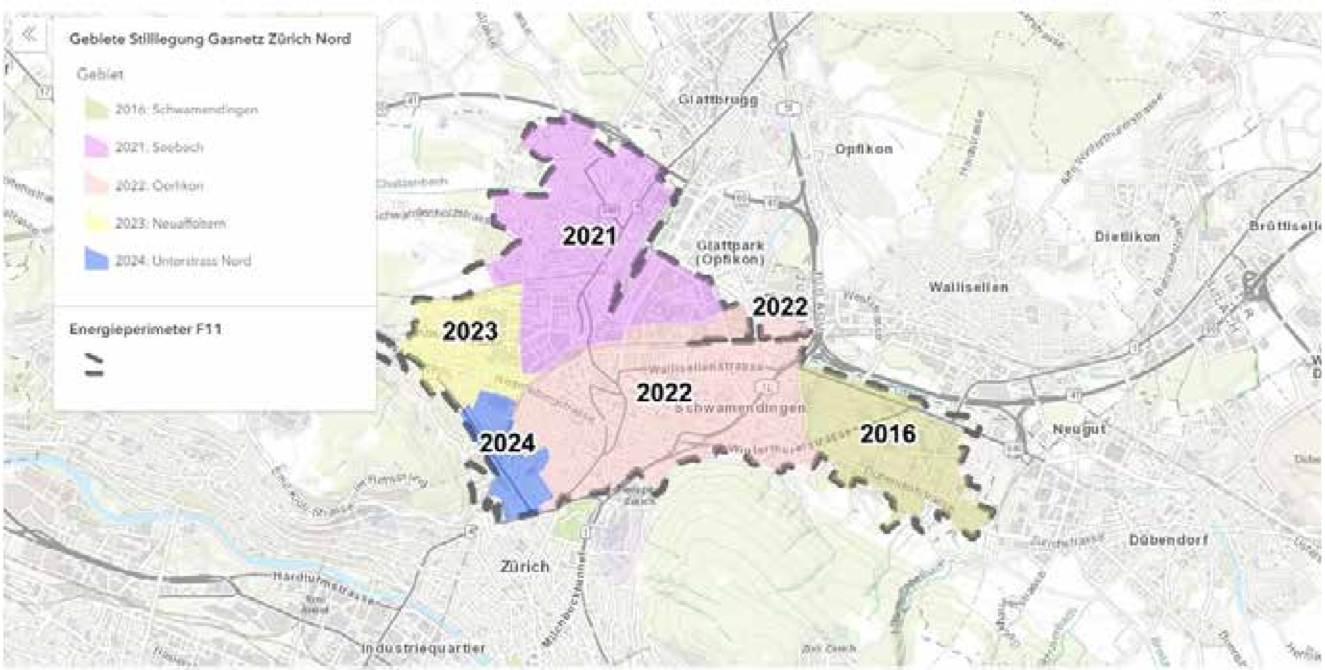
### Switzerland

Two cities in Switzerland – Zurich and Winterthur – have initiated plans to decommission some or all of their cities' natural gas distribution infrastructure. In both cases, utilities have informed residents in specific neighborhoods that gas service will be discontinued on a set timeline, typically 10 years in advance. The city of Basel is also planning neighborhood scale decommissioning for the whole city, with a targeted end date of 2037. To date, Zurich is the only city that has completed the decommissioning of segments of the gas system.

Zurich's gas utility, Energie360, initially pursued decommissioning in the North Zurich district based on the poor economics of maintaining the gas system in parallel with a district heating system, given that many customers had already converted from gas to district heat, and gas system utilization was low. Customer communications began in the early 2010s, and many of the affected customers have now seen gas service discontinued. Planning for additional decommissioning by neighborhood is currently underway, led by the City of Zurich in pursuit of GHG reduction goals. The city and utility are discussing plans for the city to compensate the utility for lost future earnings from gas sales, stemming from the next round of decommissioning projects.

***Two cities in Switzerland – Zurich and Winterthur – have initiated plans to decommission some or all of their cities' natural gas distribution infrastructure. In both cases, utilities have informed residents in specific neighborhoods that gas service will be discontinued on a set timeline, typically 10 years in advance.***

***North Zurich neighborhood gas system decommissioning by year.[26]***




[26] Energie 360, "Gas network closure in Zurich North," https://www.energie360.ch/de/kundenservice/gas-stilllegung

As part of the gas decommissioning process, the utility offers customers compensation based on the estimated remaining life of their gas equipment and the timeline between notification and gas shutoff. After first communicating a 5-year timeline for early projects, the utility extended the timeline to 10 years based on customer feedback.

In some cases, utilities have informed customers that district heating systems are being expanded to their neighborhoods as alternatives to gas. One identified challenge emerges when a customer's equipment reaches end-of-life before the district heating system is available. Parallels in the U.S. might include streets or neighborhoods where avoiding the gas infrastructure replacement requires additional electric investment that cannot be completed before the new heating systems are needed. This scenario will require special attention from implementers to ensure customers' energy needs continue to be met throughout the conversion.

### Denmark

Denmark has a high penetration of district heating — 56% — whereas only 20% of households rely on gas for space heating.[27] The number of gas customers across Denmark is in decline, falling roughly 2% in 2021 and 8% in 2022 as both gas economics and European efforts to reduce reliance on Russian gas imports took hold. The state has a goal that no households are heated by gas after 2035. Industry and district heating are expected to continue receiving gas service but convert from fossil gas to biogas. As of fall 2023, there have been no examples yet of decommissioned gas pipe segments in Denmark.

The national gas distribution system operator, Evida, recently published a study of their system that screens for areas where decommissioning is feasible and would support the economic viability of the system.[28] Evida points to the fact that they must reduce their asset base to avoid significant rate increases as customer count falls. By their estimate, 28% of the subnetworks on the Danish gas system are not recovering revenue equal to their costs. Evida recommends these subnetworks as priorities for decommissioning but notes that shutting down a subnetwork currently requires gas customers to choose a different form of energy on their own initiative. Accordingly, the study highlights the need for legal changes to allow the utility to proactively designate gas subnetworks for decommissioning, with adequate customer notification and support.

### Netherlands

The Netherlands has established a target that no households are heated with natural gas by 2050. Currently, 90% of buildings use gas for primary heating. Since 2018, most new construction has been prohibited from connecting to the gas distribution system. Measures to encourage electrification of existing buildings include a gradual reduction of taxes on electricity use and a corresponding increase in taxes on gas use, in addition to heat pump incentives.[29] Depreciation of existing gas infrastructure has been accelerated. In the past, customers disconnecting from the gas system were required to pay an "exit fee," but this cost is now socialized among all gas customers.

***Currently, 90% of buildings in the Netherlands use gas for primary heating. Since 2018, most new construction has been prohibited from connecting to the gas distribution system.***

[27] Katinka Johansen, Sven Werner, "Something is sustainable in the state of Denmark: A review of the Danish district heating sector," Renewable and Sustainable Energy Reviews, Volume 158, 2022, 112117, ISSN 1364-0321, https://doi.org/10.1016/j.rser.2022.112117.

[27] Evida, "Smart Conversion of Gas Consumption Must Transform the Gas System," June 27, 2023, https://evida.dk/media/4w2b1xdx/evidas-kortl%C3%A6gning-af-gasdistributionssystemet.pdf.

[29] Emma Koster, Katja Kruit, Marianne Teng, and Florian Hesselink, "The Natural Gas Phase-Out in the Netherlands," CE Delft, February 2022, https://cedelft.eu/wp-content/uploads/sites/2/2022/03/CE_Delft_210381_The_natural_gas_phase-out_in_the_Netherlands_DEF.pdf

Currently, municipalities are required to conduct local heat planning in consultation with utilities. However, when this planning process has identified neighborhoods for electrification and discontinued gas service, neither the municipality nor the utility has had a practical pathway to implement this plan.[30] Pending legislation would authorize municipalities to designate specific areas where gas service will be discontinued, with a minimum of eight years' notice.[31]

### Germany

In Germany, municipalities are required to develop clean heat plans. Gas distribution systems in Germany are already "largely depreciated"—that is, the remaining net book value of existing assets is less than 20% of their initial cost. This is due in part to the advanced age of many gas assets currently in service.[32] A study by Agora Energiewende, a non-profit think tank, found that efficient planning of gas infrastructure could halve the total increase in gas bills through 2044, relative to the bill increases incurred in an unplanned scenario. While there are not yet specific policies or programs to plan and execute targeted electrification in Germany, there is an increasing focus on questions around gas transition, including emerging research and thought leadership on how to address new gas connections, decommissioning plans, and the potential role of accelerated depreciation.[33]

### Austria

The City of Vienna published a climate neutral heating and cooling strategy statement on the building sector implications of the state's 2040 climate neutrality goal.[34] The policy explicitly centers on phasing out gas use. A current barrier to both utility gas system planning and municipal regulation of heating systems in existing buildings is the lack of policy clarity at the federal level. A potential federal law that would authorize municipalities to regulate existing buildings recently failed to reach consensus, and uncertainty about what level of government will hold the decision-making authority for decarbonizing the buildings sector has stalled action on this front.

[30] Ibid.
[31] Municipal Instruments Heat Transition Act, Dutch Parliament, 2023, https://www-tweedekamer-nl.translate.goog/kamerstukken/wetsvoorstellen/detail?cfg=wetsvoorsteldetails&qry=wetsvoorstel:36387&_x_tr_sl=auto&_x_tr_tl=en&_x_tr_hl=en&_x_tr_pto=wapp.
[32] Mareike Herrndorff, et. al., "A New Regulatory Framework for Natural Gas Distribution Networks," April 18, 2023, https://www-agora--energiewende-de.translate.goog/publikationen/ein-neuer-ordnungsrahmen-fuer-erdgasverteilnetze?_x_tr_sl=auto&_x_tr_tl=en&_x_tr_hl=en&_x_tr_pto=wapp.
[33] Bundesministerium für WIrstchaft und Klimaschutz. "Green Paper Transformation Gags-/Wasserstoff-Verteilernetze," 2024, https://www.bmwk.de/Redaktion/DE/Downloads/G/green-paper-transformation-gas-wasserstoff-verteilernetze.pdf?__blob=publicationFile&v=4
[34] City of Vienna, "Phasing Out Gas: Heating and Cooling Vienna 2040," 2023, https://www.wien.gv.at/stadtentwicklung/energie/pdf/phasing-out-gas.pdf.

## Insights for Exploration in the U.S. Context

Across multiple jurisdictions with varied approaches to gas transition planning, these case studies encompass a significant body of experience. While examples of completed NPA projects in the U.S. are still limited, we develop several key insights below worth exploring further in the U.S. context.

### 1) NPA projects underway today reflect diverse energy policy goals and energy system characteristics across different jurisdictions.

In the U.S., low-cost domestic natural gas supply has led to widespread adoption of natural gas for heating and other purposes over many decades, with the associated expansion of gas distribution networks. Many stakeholders have recognized that continued gas system expansion is no longer consistent with climate policy; however, related policy and planning processes are still in their early stages. As described in the earlier sections, a handful of U.S. gas utilities have begun evaluating and pursuing NPAs as part of their gas planning processes.

In Europe, many jurisdictions have sought to reduce reliance on gas for some time, motivated by economic, geopolitical, and environmental concerns. As discussed earlier, recent developments such as the Russian invasion of Ukraine and related increases in the price of gas, put additional weight behind Europe's policy shift away from gas. At the national level, several jurisdictions have established policies to fully transition away from the use of natural gas. There are also a number of municipal planning processes underway in European cities to support more localized planning of future customer heating technologies and enable long-term infrastructure transitions.

Additional European jurisdictions, such as Germany, have further recognized the value of planning for the management of infrastructure transition costs. For jurisdictions or gas systems in the U.S. with significant undepreciated balances, there is an even higher incentive to act now to find ways to lower the overall costs of the transition to clean energy.

While it is important to recognize the successful and ongoing examples of NPAs and targeted electrification that have been explored in North America and Europe, it is also important to understand the distinctions among the jurisdictions where these projects are proceeding. Jurisdictions can vary significantly in geography, climate, customer composition, policy and regulatory preferences, the availability of other energy infrastructure, supply capacity, and the role that gas systems play in meeting today's energy demand. This diversity will necessarily shape the solutions that meet each jurisdiction's goals and needs.

### 2) NPA projects can identify value in cost savings on the gas system, emissions reduction, or other societal benefits.

Different jurisdictions and utilities have used varied terms and frameworks to distinguish among specific types of targeted electrification. For example, PG&E's efforts to date differentiate between 'targeted electrification', indicating projects motivated by cost savings on the gas system, and 'zonal electrification', indicating projects motivated by societal benefits, such as providing clean energy to disadvantaged communities or achieving significant greenhouse gas emissions reductions. In Europe, a common distinction is between heat planning, focused on the solutions that will provide clean heat to customers, and gas infrastructure planning, focused on the costs and timelines associated with maintaining, repairing, or retiring gas infrastructure. Broadly, these distinctions reflect the unique considerations for projects that are driven by infrastructure cost savings relative to those driven by other societal benefits.

Infrastructure-driven planning is characterized by a focus on economically driven projects that have a specific timeline – that is, where there is a quantifiable gas investment to be avoided. Common examples in the U.S. include areas of leak-prone pipe or pipe otherwise in need of safety remediation, gas assets at the end of their useful life, or infrastructure in need of capacity expansion to meet increased demand. Attractive NPA projects in lieu of such investments could accrue net savings to gas ratepayers, and early experience from the U.S. demonstrates that utilities have been able to identify such projects where the avoided cost is substantial and investments in NPA projects would be cost-effective.

Notably, certain types of infrastructure-driven projects allow for and require different approaches in order to avoid the anticipated gas system investment. For example, as discussed in the earlier case studies, solutions for capacity expansion projects can be targeted to a broad area and do not usually require 100% customer participation within that area, whereas leak-prone pipe in need of replacement would require all affected customers to adopt alternatives to natural gas service.

While capacity-related projects avoid this specific challenge, they face uncertainty in the permanence of the demand reduction as they cannot guarantee new loads won't appear in the future. Similar to replacement projects, capacity projects still require a minimum threshold of customer participation to ensure the gas investment can be avoided. This complicates the process of funding increased incentives for participating customers, as this funding is premised on avoiding the gas investment, which in turn is premised on a certain number of customers opting in, as well as the location and usage pattern of those customers relative to the capacity project.

Factors other than cost might motivate a utility, regulator, or municipality to prioritize an NPA even if the avoided gas investment alone is not sufficient to fully fund the project. 'Societally' driven projects thus comprise a broad category of projects not solely motivated by infrastructure costs. These could include projects motivated by their impact on reducing greenhouse gas emissions or projects motivated by providing benefits to disadvantaged communities. This category could also include specific communities that seek to exit the gas system regardless of the age of infrastructure serving them, such as through a municipal heat planning process driven by emissions reduction or other concerns. In the Swiss examples, the earliest projects were motivated primarily by cost savings for underutilized infrastructure, but more recent municipally driven projects are motivated by GHG reduction goals.

These categories can and do overlap. Some projects may have a quantifiable infrastructure investment to be avoided in a disadvantaged community, while other projects' avoided investment only covers a portion of the cost, with the remainder covered by funding intended for climate mitigation. The implications of these distinct categories impact how decision-makers might consider how to allocate costs for different projects, as well as how projects might be identified through energy or community planning processes.

### 3) Prioritization of NPA projects should weigh a broad set of criteria.

For utilities seeking to identify and pursue NPA opportunities within their existing capital or system planning processes (or via newer integrated energy planning processes), there are several key criteria to consider, many of which impact the overall economics of a given NPA project. These criteria include:

- **Gas asset risk and investment timeline:** For many projects, if the investment is needed urgently for safety or reliability, for instance in less than two years, it may not be feasible to implement an NPA before the need must be addressed. One notable exception is the success PG&E has found in executing small-scale (e.g., fewer than five impacted customers) projects in the range of 18-24 months. As illustrated in early experience in Zurich, longer

timelines are more important for larger, neighborhood-scale projects. Longer timelines of five or more years give stakeholders more time to design and implement appropriate solutions, particularly where NPAs and targeted electrification are nascent concepts. Timelines of up to five years may be workable but could be challenging for first-of-a-kind efforts impacting larger groups of customers.

- **Hydraulic feasibility:** Segments with a one-way flow or terminal branches can typically be removed without impacting the remaining system. Meanwhile, assets that provide reliability to other parts of the system may be difficult to retire. In some cases, the hydraulic impact of removing a segment of pipe can be mitigated through limited reinforcement elsewhere.
- **The outlook for local electric capacity, or headroom:** The simplest NPA projects will have ample local electric capacity that can accommodate added load from targeted electrification without costly electric upgrades. Other attractive projects could maintain peak demand below the local capacity threshold through demand-side measures such as load shifting or energy efficiency. Some NPA projects will require upgrades in electric capacity that could be costly. Even in these instances, it may be the case that organic load growth would have required capacity upgrades regardless of the NPA project, and it might not necessarily be appropriate to allocate all electric upgrade costs to the NPA project itself.
- **The types of customers:** Different customer types (residential, commercial, or industrial) or building types (single-family homes vs. large apartment buildings) may involve different levels of cost, difficulty, or NPA project scope.
- **The number of customers:** If each impacted customer must agree to participate for an NPA to proceed, projects with 1-5 customers may be more feasible than projects impacting a larger group, under current regulatory frameworks. Additionally, if the avoided infrastructure cost is divided across the impacted customers, each customer can receive a larger NPA incentive when the project affects fewer customers.
- **The presence of community support:** Partnership with community-based organizations, local governments, or interested individuals can facilitate productive customer engagement. A local government with high climate ambition or additional motivations to reduce the presence of gas infrastructure in their community may be able to provide additional support through data sharing and staff capacity.
- **Customer propensity:** The likelihood of customers to adopt electric technologies and opt to participate in an NPA project could be an indicator of project success, as NPA projects are dependent on voluntary participation under the current regulatory framework. Indicators of customer propensity could include building stock and energy usage data (such as the age and energy intensity of buildings), customer participation in utility programs, awareness and adoption of heat pumps, and other demographic data.
- **Equity:** Equity criteria, such as location in a disadvantaged community and enrollment in bill discount rates, are also important to consider in site prioritization. Cost effectiveness and customer propensity criteria may be at odds with equity criteria, so it is important to assess these criteria holistically to balance a utility's cost and equity goals.

The relative weight of each criterion may vary depending on the goals and authority of the decision-maker, whether the utility, the state utility commission, or a municipality.

In prioritizing projects and crafting implementation plans, utilities will need to weigh gas system, electric system, and customers' system considerations and economics together. One approach seen in Winterthur mapped the city according to the type of clean heating solution each neighborhood would transition to; these maps index predominantly on customer density to determine suitability for extension of existing network heating or construction of new heat networks. While district heating is much less prevalent in the U.S., thermal energy networks are increasingly of interest to utilities, regulators, and stakeholders, particularly in urban areas with colder climates. Where appropriate, NPA planning could assess feasibility for thermal energy networks, as these provide an opportunity for utility business model evolution and can mitigate peak electric network infrastructure requirements and costs, if deployed at scale.

### 4) NPA projects can be funded from a series of different sources while protecting ratepayers' long-term affordability.

NPA projects can involve multiple distinct categories of cost, including:

- front-of meter gas system costs, including the cost of decommissioning the gas asset,
- front-of-meter electric system costs (e.g., distribution capacity upgrades),
- behind-the-meter costs (e.g., the cost of electrification retrofits), and
- programmatic or administrative costs.

In the context of long-term declining gas demand, NPA projects should aim to mitigate upward rate pressure on customers remaining on the gas system. Not only will managing system costs improve customer equity and long-term affordability, but it will also contribute to utilities' long-term cost recovery and financial health via reasonable rates.

Some existing regulatory mechanisms, such as accelerated depreciation, are available to aid with financially sustainable and equitable cost recovery. However, additional policy mechanisms may be needed to help manage gas transition costs, including the potential flow of funding across the electric and gas customer bases, as demonstrated by the Québec gas and electric utilities discussed on page 23.

Cost-effectiveness evaluations are a key method of determining the amount of funding appropriate for ratepayers to pay into a targeted electrification or NPA program. Due to the broad set of benefits these projects provide, these tests may include societal costs and benefits, including carbon reduction benefits. Appropriately accounting for the societal and customer value of the investment efficiencies enabled through IEP and NPAs will require updating cost-effectiveness tests as these solutions scale.

Below we lay out the major potential sources of funding for NPA projects, with the rationale for using each.

#### Federal and state funding (taxpayers)

Where federal or state funding is available, these sources should be pursued to maximize ratepayer savings whenever possible. For example, the Infrastructure Investment and Jobs Act and the Inflation Reduction Act make available significant funding for programs that help to reduce the costs of NPA projects. Many states including Massachusetts and New York also offer rebates and incentives for energy efficiency upgrades, heat pumps, and more efficient appliances. To the extent targeted electrification initiatives are a priority for a given jurisdiction, legislators may appropriate funds specifically to support these projects.

#### Gas ratepayers

NPA projects present an opportunity to avoid costs on the gas system, thereby achieving savings for gas ratepayers. This forms the primary rationale for recovering NPA funding from gas ratepayers. These projects also provide a direct opportunity to reduce GHG emissions. Because NPAs are premised on the ability to avoid a future investment in gas infrastructure, there is a strong justification for gas ratepayers to provide funding for these projects. At the same time, it may be appropriate to limit gas ratepayer funding to some threshold below the full avoided cost, so that some avoided spending can be returned as savings for gas ratepayers.

In certain cases, paying more than the avoided infrastructure cost may be justified based on project benefits, though the allocation of these costs between gas and electric customers should be determined by regulators. These benefits could include the innovation value of early project demonstrations, quantified GHG benefits, or support for income-qualified customers' participation in targeted electrification and NPA projects. In the long term, particularly as rate pressures on a declining gas customer base increase, decision-makers may wish to reconsider whether it continues to make sense to seek NPA funding from gas ratepayers.

### Electric ratepayers

Funding from electric customers is premised on the benefits that NPA projects provide via load growth and additional future revenue on the electric system. Electric ratepayers could also be responsible for incentives for equipment upgrades that may be needed, after any state and federal energy efficiency incentives are exhausted. One model of funding could draw a “bright line” between the two rate bases, allocating electric ratepayer funding only to associated costs on the electric system, and gas ratepayer funding only to costs on the gas system. This model’s simplicity may be particularly attractive for early or pilot projects. Alternately, regulators could determine what amount of funding is justified on either side of the “bright line,” while allowing for the potential combination of funding for any remaining costs.

### Local taxpayer funding

Local funding from a county, city, or town may be a particularly relevant resource where the municipality is conducting clean heat planning that might pursue more NPA projects than could be funded through traditional pathways.

### Individual customers

Most customers will bear some costs within the home, as they would during normal equipment replacement. Offering a sufficient timeline from initial notice to gas decommissioning could allow a reasonable period for homeowners and building owners to plan for proactive equipment replacement in lieu of short term or emergency replacements.

In the Swiss case studies identified above, customers are typically given 10 years' notice and offered supportive incentives and programming but are responsible for costs in excess of the incentives they receive. For low- and moderate-income customers, additional support for equipment replacement and supplemental upgrades such as energy efficiency will be needed.

### 5) Integrated gas and electric network planning offers an opportunity to achieve net-zero goals as cost-effectively and equitably as possible.

An orderly transition to net-zero emissions requires gas and electric coordination and collaboration on system planning, as well as involvement of customers

***An orderly transition to net-zero emissions requires gas and electric coordination and collaboration on system planning, as well as involvement of customers and communities in decision-making.***

and communities in decision-making. Coordinated planning offers several opportunities to ensure affordability and reliability, including:

- Prudently building out the electric system in the right locations at the right time to prepare for conversion of fossil fuel-based heating (including delivered fuels as well as natural gas) to electric heating;
- Making calculated decisions about where on the gas system to prioritize investment (e.g. leak-prone pipe repair or replacement) and/or planning to decommission sections of the gas network in favor of electric heating or thermal networks; and
- Leveraging energy efficiency and load control to help optimize demand and avoid the highest-cost infrastructure scenarios.

*Coordination between and within utilities to optimize long-range investment plans is critical to ensure a cost-effective energy transition for all customers.*

Optimized investment of this kind requires a significant, long-term exchange of geographically specific data between planning teams within or across utilities. For example, coordinated planning could ensure electric capacity is available or built out in time to support NPA projects. However, a process for information exchange between utilities at this level of specificity does not yet exist. While some utilities serving both gas and electricity have voluntarily embarked on intra-utility integration of their gas and electric teams, the scalability of these efforts is constrained by limited levels of territorial overlap, especially in the Northeast U.S. Regulatory action is thus needed to enable data sharing and decision making between utilities in a more comprehensive way. Absent regulatory support, it is unlikely that integrated energy planning will achieve the scale needed to realize cross-system savings.

*Regulatory support is needed to invest in new tools and capabilities that enable integrated energy planning to achieve a cost-optimized transition.*

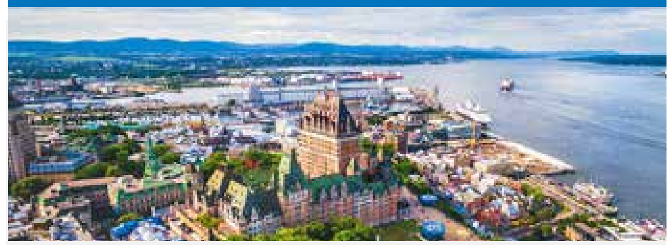
Key tools could include software that translates geographic gas demand scenarios into impacts on electric system load, and vice versa. These gas and electric load scenarios would then inform geographically specific distribution planning for both systems, and aid in the identification of high priority, or most cost-effective, NPA projects. These tools should also be used to generate versions of distribution system maps that could be shared with municipal or local government planners to support local clean heat planning.

PG&E has already developed an asset screening tool, featuring an integrated mapping of gas and electric systems with customer data. This tool has aided in early research on potential NPA frameworks for California. Indeed, such an integrated system mapping and planning tool empowers the utility and partners to identify potential projects along multiple prioritization criteria. PG&E's mapping tool has also helped cities gain insight for localized decarbonization planning.

*Targeted electrification and NPA pilots should leverage integrated planning to inform the development of regulatory frameworks for deploying these solutions at scale.*

Regulators should encourage pilots to test innovative approaches to scaling NPAs, including through novel cost recovery and allocation structures. Pilots could also be used to test deployment under alternate structures of the utilities' obligation to serve, though this model may require legislative authorization. Where customers' gas and electric providers differ, pilots should also seek to inform new protocols for cross-utility coordination. Development of these pilots will enable testing of new data-sharing, planning, and cost-recovery structures across utilities.

### Québec Example of Cross-Utility Funding



Énergir and Hydro-Québec, respectively the primary gas and electric utilities serving Québec, have signed an agreement for a joint decarbonization strategy. This strategy, approved by the regulatory authority, centers on partial (70%) electrification of building heating systems with gas backup. The strategy includes compensation payments from the electric utility to the gas utility based on avoided electric peak capacity investments enabled by maintaining gas backup. Participating gas customers are estimated to see modest annual bill savings, while the gas utility anticipates preserving a substantial share of distribution revenues despite a significant reduction in gas throughout.

This approach provides an early example of integrated energy planning, including the concept of funding flowing between gas and electric rate bases contingent on the value that each system contributes through decarbonization-focused programs. In the near term, funding across rate bases could be applicable to thermal energy networks where capital investments cannot be reasonably recovered from thermal network customers alone. In the longer term, regulators may consider models of cross-rate base funding that account for the value each system provides the other, in service of broader policy goals such as the reduction of GHG emissions.

### 6) Utility and municipality partnership may be a key element of NPA projects and localized integrated energy planning.

As seen in the European case studies highlighted above, local energy planning achieves the level of granularity needed to plan for and meet local needs. Policymakers and regulators should find ways to empower local energy planning that identifies a long-term portfolio of heat solutions for a community or municipality. It will be important for utilities to partner with municipal governments conducting local energy planning, both to share system maps and to provide technical partnership in municipal decision-making based on system data. Potential benefits of local energy planning include the opportunity for residents and local leaders to design and champion locally tailored solutions.

The early examples of successful European targeted electrification projects come from the Swiss cities in which municipal government has become more involved in making community-specific heating transition decisions. Pending new legislation, communities in the Netherlands are poised for similar progress, having already coordinated between municipal governments and utilities on community-wide heating plans.

Applying a similar model in the U.S. could entail supporting municipalities to partner with the utilities that serve them to conduct clean heat planning, including identifying segments of the gas network for NPA and thermal heating projects. This approach could allow municipalities with ambitious climate policies to pursue NPAs at a faster pace than others, and to reflect local priorities in identifying projects.

This kind of partnership can be effective if it produces proposed NPA projects rooted both in utility analysis and community priorities. To make it effective in the U.S., utilities, municipalities, regulators, and policymakers will need to take several new actions:

- Utilities will need to develop improved tools and capabilities for evaluating NPA opportunities at the local level, building on data across the gas system, electric system, and their customer base, as described above.
- Utilities and municipal staff will need to learn how to conduct this collaborative planning most effectively. Utilities generally have little precedent for such detailed planning with local government, and cities may lack the staff capacity or expertise to partner fully.
- Regulators may need to provide guidance to streamline such planning and make it consistent across their state. Regulators can also set clear expectations for how the outputs of this planning will be evaluated – for instance, how they will evaluate proposed NPA projects resulting from utility-municipal joint planning.
- Regulators must provide clear guidance on cost allocation and cost recovery, recognizing the need for a clear framework to advance proposed NPA projects, while also protecting ratepayers outside first mover communities and ensuring less well-resourced communities are not burdened by early NPA projects.
- Policymakers will need to give clear direction regarding how the utility's obligation to serve will be treated for projects resulting from joint utility-municipal planning, to ensure promising projects can advance, as described further below.
- In cases where a community is served by separate gas and electric utilities, this planning will be more complex. In this case, new guidance will be needed regarding how data will be shared across both systems and the responsibilities of each utility. New policy direction may be needed, including for the case in which an investor-owned utility provides one service, and a municipal or cooperative utility provides another.

### 7) Individual customer persuasion to reach 100% participation is not a scalable NPA approach for avoided replacement projects.

Several U.S. utilities are currently pursuing individual customer persuasion to implement NPAs, with notable but limited success. In order for avoided replacement NPA projects to be successful, 100% of affected customers need to transition all gas heating equipment and appliances, including water heaters and stoves, to electric and transition off of the gas system. As discussed, it is very difficult to get all customers to participate and disconnect from the gas system in projects with more than 5 customers.

Early experience makes clear that, under a voluntary model, any one customer can derail a potential project that is otherwise economically attractive and well-received by other customers, thereby limiting the prospects for this approach.

These approaches continue to have value, and new customer engagement strategies may expand success. However, it is unlikely they will readily scale to be a substantial portion of projects that could be attractive on economic and climate terms. There may be more scalable success in the near term pursuing this approach in projects not requiring 100% participation, such as capacity expansion projects.

**8) Policy change will be needed to evolve the utility business model and obligation to serve, while still retaining the opportunity for cost recovery in a transition away from the use of gas.**

In many jurisdictions, gas utilities are obligated by statute or regulation to connect new customers upon request and/or to continue providing service to existing customers (i.e. indefinitely). Such obligations have implications for targeted electrification projects. Utilities' obligation to connect new gas customers upon request will require the construction of new gas infrastructure regardless of whether the expansion is economically viable. Utilities' obligation to continue serving gas to existing customers poses a different challenge – that even where an NPA solution is economically attractive, if even one customer wishes to continue receiving gas service, the utility may still be required to install new infrastructure to maintain service.

***This policy challenge requires designing a new process to enable projects driven by community needs or system economics rather than individual customer opt-in. Addressing this challenge will entail new and substantial policy shifts that also ensure reliable and affordable energy for customers.***

This policy challenge requires designing a new process to enable projects driven by community needs or system economics rather than individual customer opt-in. Addressing this challenge will entail new and substantial policy shifts that also ensure reliable and affordable energy for customers.

In many cases in the U.S., legislative change is needed at the state level to enable regulators to work with stakeholders to develop a new paradigm for equitable access to essential energy services. The simplest change would remove the statutory obligation for utilities to continue serving gas to existing customers and empower regulators to enable or establish alternative plans or programs whereby customers are still provided with affordable and equitable access to energy.

Another model, as illustrated by the Swiss and Dutch case studies, would empower motivated municipalities to conduct heat planning that includes the retirement of gas infrastructure. In the Swiss case, community willingness to be an 'early adopter' of clean heat and infrastructure planning enabled cities like Zurich and Winterthur to proactively designate which neighborhoods would transition from the gas system on specific timelines. This approach also enabled these cities to plan the expansion of existing and construction of new district heating systems to align with geographically specific heat infrastructure plans. Such an approach would similarly require utility regulators to play an active role in project approval and the establishment of guardrails to ensure that reliability is maintained, excessive costs are not put onto ratepayers, and utilities have the opportunity to recover prudent investments in gas infrastructure even as NPA projects scale.

*State regulators have a critical role in overseeing changes to the provision of utility service.*

In the U.S., relevant authorities for infrastructure investment and service provision are provided by statute to public utility commissions. These commissions are charged with setting utility rates and policy in accordance with the regulatory compact that provides utilities with an opportunity to earn a reasonable return on investment in exchange for providing safe and reliable service at reasonable cost to all customers who request it.

***Utility regulators have a critical role to play in implementing any changes to the utilities' obligation to serve and advancing NPAs.***

As such, state regulators have a critical role to play in overseeing infrastructure planning and changes to the provision of utility service. The regulatory process to establish guardrails in any model of a reformed obligation to serve could include determinations of the minimum years of notice given to customers who would no longer receive gas, guidance on incentives and customer compensation, design of programs to support customers in transitioning behind-the-meter equipment, and preconditions tying the termination of service to municipal heat plans or other forms of municipal support. Regardless of the method of reform, utility regulators have a critical role to play in implementing any changes to the utilities' obligation to serve and advancing NPAs. Regulatory guidance is necessary to require the identification and analysis of NPAs, shape cost-effectiveness assessments, direct deeper analyses of utilities' investments, update rate mechanisms and depreciation methodologies that provide the opportunity to recover prudent investments, create data-sharing protocols across utilities with overlapping territory and with interested municipalities, conduct robust stakeholder processes, and set requirements for both broad and targeted customer education.

# Conclusion

The insights laid out in this paper are a starting point for further exploration in the U.S. context. Our hope in presenting this work is for the findings to serve as a jumping-off point for future work across the country.

Below are some suggested starting points for decision-makers and stakeholders seeking to advance this work.

- Regulators should develop specific guidance to clarify the path to identify, propose, receive approval for, implement, and recover costs for NPAs in their state.
- Utilities should advance efforts to pursue the most achievable NPAs under existing frameworks (e.g., projects serving 1-5 customers, under the 100% persuasion model, and projects to avoid capacity expansions).
- Decision-makers should find ways to encourage increased utility-municipal engagement, data sharing, and cooperation for integrated energy planning in support of jurisdictional climate policy goals.
- Regulators should also support utilities' development of integrated system mapping tools to facilitate cross-utility coordinated planning and cooperation with interested municipalities.
- Stakeholders should develop an understanding of the ways utilities' obligation to serve may need to evolve, and what guardrails are necessary, in their state.
- Regulators should update rate mechanisms and depreciation methodologies that address the opportunity to recover prudent investments and protect future ratepayers, in light of anticipated changes in long-run gas system utilization.

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RMI | nationalgrid

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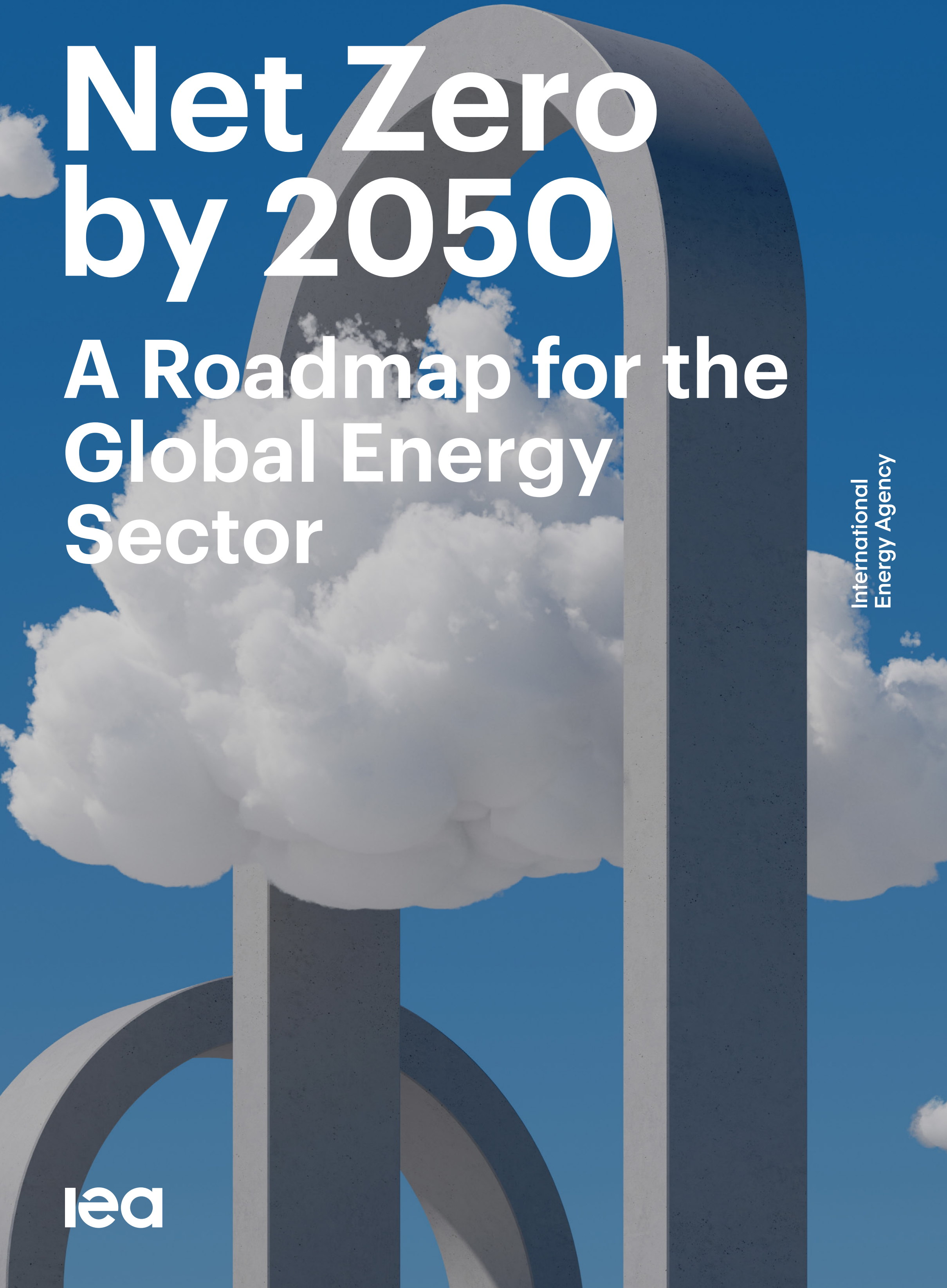
# Net Zero by 2050

## A Roadmap for the Global Energy Sector

International Energy Agency



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# Net Zero by 2050

## A Roadmap for the Global Energy Sector

Net Zero by 2050 Interactive
iea.li/nzeroadmap

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# INTERNATIONAL ENERGY AGENCY

The IEA examines the full spectrum of energy issues including oil, gas and coal supply and demand, renewable energy technologies, electricity markets, energy efficiency, access to energy, demand side management and much more. Through its work, the IEA advocates policies that will enhance the reliability, affordability and sustainability of energy in its 30 member countries, 8 association countries and beyond.

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We are approaching a decisive moment for international efforts to tackle the climate crisis – a great challenge of our times. The number of countries that have pledged to reach net-zero emissions by mid-century or soon after continues to grow, but so do global greenhouse gas emissions. This gap between rhetoric and action needs to close if we are to have a fighting chance of reaching net zero by 2050 and limiting the rise in global temperatures to 1.5 °C.

Doing so requires nothing short of a total transformation of the energy systems that underpin our economies. We are in a critical year at the start of a critical decade for these efforts. The 26th Conference of the Parties (COP26) of the United Nations Framework Convention on Climate Change in November is the focal point for strengthening global ambitions and action on climate by building on the foundations of the 2015 Paris Agreement. The International Energy Agency (IEA) has been working hard to support the UK government's COP26 Presidency to help make it the success the world needs. I was delighted to co-host the IEA-COP26 Net Zero Summit with COP26 President Alok Sharma in March, where top energy and climate leaders from more than 40 countries highlighted the global momentum behind clean energy transitions.

The discussions at that event fed into this special report, notably through the Seven Key Principles for Implementing Net Zero that the IEA presented at the Summit, which have been backed by 22 of our member governments to date. This report maps out how the global energy sector can reach net zero by 2050. I believe the report – *Net Zero by 2050: A roadmap for the global energy system* – is one of the most important and challenging undertakings in the IEA's history. The Roadmap is the culmination of the IEA's pioneering work on energy data modelling, combining for the first time the complex models of our two flagship series, the *World Energy Outlook* and *Energy Technology Perspectives*. It will guide the IEA's work and will be an integral part of both those series going forward.

Despite the current gap between rhetoric and reality on emissions, our Roadmap shows that there are still pathways to reach net zero by 2050. The one on which we focus is – in our analysis – the most technically feasible, cost-effective and socially acceptable. Even so, that pathway remains narrow and extremely challenging, requiring all stakeholders – governments, businesses, investors and citizens – to take action this year and every year after so that the goal does not slip out of reach.

This report sets out clear milestones – more than 400 in total, spanning all sectors and technologies – for what needs to happen, and when, to transform the global economy from one dominated by fossil fuels into one powered predominantly by renewable energy like solar and wind. Our pathway requires vast amounts of investment, innovation, skilful policy design and implementation, technology deployment, infrastructure building, international co-operation and efforts across many other areas.

Since the IEA's founding in 1974, one of its core missions has been to promote secure and affordable energy supplies to foster economic growth. This has remained a key concern of our Roadmap, drawing on special analysis carried out with the International Monetary Fund and the International Institute for Applied Systems Analysis. It shows that the enormous challenge of transforming our energy systems is also a huge opportunity for our economies, with the potential to create millions of new jobs and boost economic growth.

Another guiding principle of the Roadmap is that clean energy transitions must be fair and inclusive, leaving nobody behind. We have to ensure that developing economies receive the financing and technological know-how they need to continue building their energy systems to meet the needs of their expanding populations and economies in a sustainable way. It is a moral imperative to bring electricity to the hundreds of millions of people who currently are deprived of access to it, the majority in of them in Africa.

The transition to net zero is for and about people. It is paramount to remain aware that not every worker in the fossil fuel industry can ease into a clean energy job, so governments need to promote training and devote resources to facilitating new opportunities. Citizens must be active participants in the entire process, making them feel part of the transition and not simply subject to it. These themes are among those being explored by the Global Commission on People-Centred Clean Energy Transitions, which I convened at the start of 2021 to examine how to enable citizens to benefit from the opportunities and navigate the disruptions of the shift to a clean energy economy. Headed by Prime Minister Mette Frederiksen of Denmark and composed of government leaders, ministers and prominent thinkers, the Global Commission will make public its key recommendations ahead of COP26 in November.

The pathway laid out in our Roadmap is global in scope, but each country will need to design its own strategy, taking into account its specific circumstances. There is no one-size-fits-all approach to clean energy transitions. Plans need to reflect countries' differing stages of economic development: in our pathway, advanced economies reach net zero before developing economies do. As the world's leading energy authority, the IEA stands ready to provide governments with support and advice as they design and implement their own roadmaps, and to encourage the international co-operation across sectors that is so essential to reaching net zero by 2050.

This landmark report would not have been possible without the extraordinary dedication of the IEA colleagues who have worked so tirelessly and rigorously on it. I would like to thank the entire team under the outstanding leadership of my colleagues Laura Cozzi and Timur Gül.

The world has a huge challenge ahead of it to move net zero by 2050 from a narrow possibility to a practical reality. Global carbon dioxide emissions are already rebounding sharply as economies recover from last year's pandemic-induced shock. It is past time for governments to act, and act decisively to accelerate the clean energy transformation.

As this report shows, we at the IEA are fully committed to leading those efforts.

**Dr Fatih Birol**
**Executive Director**
**International Energy Agency**

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**The energy sector is the source of around three-quarters of greenhouse gas emissions today and holds the key to averting the worst effects of climate change, perhaps the greatest challenge humankind has faced.** Reducing global carbon dioxide ($CO_2$) emissions to net zero by 2050 is consistent with efforts to limit the long-term increase in average global temperatures to 1.5 °C. This calls for nothing less than a complete transformation of how we produce, transport and consume energy. The growing political consensus on reaching net zero is cause for considerable optimism about the progress the world can make, but the changes required to reach net-zero emissions globally by 2050 are poorly understood. A huge amount of work is needed to turn today's impressive ambitions into reality, especially given the range of different situations among countries and their differing capacities to make the necessary changes. This special IEA report sets out a pathway for achieving this goal, resulting in a clean and resilient energy system that would bring major benefits for human prosperity and well-being.

**The global pathway to net-zero emissions by 2050 detailed in this report requires all governments to significantly strengthen and then successfully implement their energy and climate policies.** Commitments made to date fall far short of what is required by that pathway. The number of countries that have pledged to achieve net-zero emissions has grown rapidly over the last year and now covers around 70% of global emissions of $CO_2$. This is a huge step forward. However, most pledges are not yet underpinned by near-term policies and measures. Moreover, even if successfully fulfilled, the pledges to date would still leave around 22 billion tonnes of $CO_2$ emissions worldwide in 2050. The continuation of that trend would be consistent with a temperature rise in 2100 of around 2.1 °C. Global emissions fell in 2020 because of the Covid-19 crisis but are already rebounding strongly as economies recover. Further delay in acting to reverse that trend will put net zero by 2050 out of reach.

**In this Summary for Policy Makers, we outline the essential conditions for the global energy sector to reach net-zero $CO_2$ emissions by 2050.** The pathway described in depth in this report achieves this objective with no offsets from outside the energy sector, and with low reliance on negative emissions technologies. It is designed to maximise technical feasibility, cost-effectiveness and social acceptance while ensuring continued economic growth and secure energy supplies. We highlight the priority actions that are needed today to ensure the opportunity of net zero by 2050 – narrow but still achievable – is not lost. The report provides a global view, but countries do not start in the same place or finish at the same time: advanced economies have to reach net zero before emerging markets and developing economies, and assist others in getting there. We also recognise that the route mapped out here is a path, not necessarily the path, and so we examine some key uncertainties, notably concerning the roles played by bioenergy, carbon capture and behavioural changes. Getting to net zero will involve countless decisions by people across the world, but our primary aim is to inform the decisions made by policy makers, who have the greatest scope to move the world closer to its climate goals.

## *Net zero by 2050 hinges on an unprecedented clean technology push to 2030*

**The path to net-zero emissions is narrow: staying on it requires immediate and massive deployment of all available clean and efficient energy technologies.** In the net-zero emissions pathway presented in this report, the world economy in 2030 is some 40% larger than today but uses 7% less energy. A major worldwide push to increase energy efficiency is an essential part of these efforts, resulting in the annual rate of energy intensity improvements averaging 4% to 2030 – about three-times the average rate achieved over the last two decades. Emissions reductions from the energy sector are not limited to $CO_2$: in our pathway, methane emissions from fossil fuel supply fall by 75% over the next ten years as a result of a global, concerted effort to deploy all available abatement measures and technologies.

**Ever-cheaper renewable energy technologies give electricity the edge in the race to zero.** Our pathway calls for scaling up solar and wind rapidly this decade, reaching annual additions of 630 gigawatts (GW) of solar photovoltaics (PV) and 390 GW of wind by 2030, four-times the record levels set in 2020. For solar PV, this is equivalent to installing the world's current largest solar park roughly every day. Hydropower and nuclear, the two largest sources of low-carbon electricity today, provide an essential foundation for transitions. As the electricity sector becomes cleaner, electrification emerges as a crucial economy-wide tool for reducing emissions. Electric vehicles (EVs) go from around 5% of global car sales to more than 60% by 2030.

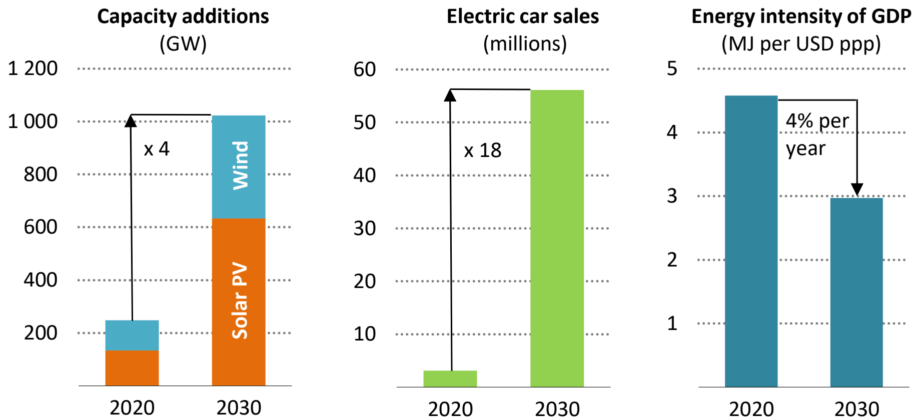
### PRIORITY ACTION

### Make the 2020s the decade of massive clean energy expansion

**All the technologies needed to achieve the necessary deep cuts in global emissions by 2030 already exist, and the policies that can drive their deployment are already proven.**

As the world continues to grapple with the impacts of the Covid-19 pandemic, it is essential that the resulting wave of investment and spending to support economic recovery is aligned with the net zero pathway. Policies should be strengthened to speed the deployment of clean and efficient energy technologies. Mandates and standards are vital to drive consumer spending and industry investment into the most efficient technologies. Targets and competitive auctions can enable wind and solar to accelerate the electricity sector transition. Fossil fuel subsidy phase-outs, carbon pricing and other market reforms can ensure appropriate price signals. Policies should limit or provide disincentives for the use of certain fuels and technologies, such as unabated coal-fired power stations, gas boilers and conventional internal combustion engine vehicles. Governments must lead the planning and incentivising of the massive infrastructure investment, including in smart transmission and distribution grids.

**Key clean technologies ramp up by 2030 in the net zero pathway**




Note: MJ = megajoules; GDP = gross domestic product in purchasing power parity.

## *Net zero by 2050 requires huge leaps in clean energy innovation*

**Reaching net zero by 2050 requires further rapid deployment of available technologies as well as widespread use of technologies that are not on the market yet.** Major innovation efforts must occur over this decade in order to bring these new technologies to market in time. Most of the global reductions in $CO_2$ emissions through 2030 in our pathway come from technologies readily available today. But in 2050, almost half the reductions come from technologies that are currently at the demonstration or prototype phase. In heavy industry and long-distance transport, the share of emissions reductions from technologies that are still under development today is even higher.

**The biggest innovation opportunities concern advanced batteries, hydrogen electrolysers, and direct air capture and storage.** Together, these three technology areas make vital contributions the reductions in $CO_2$ emissions between 2030 and 2050 in our pathway. Innovation over the next ten years – not only through research and development (R&D) and demonstration but also through deployment – needs to be accompanied by the large-scale construction of the infrastructure the technologies will need. This includes new pipelines to transport captured $CO_2$ emissions and systems to move hydrogen around and between ports and industrial zones.

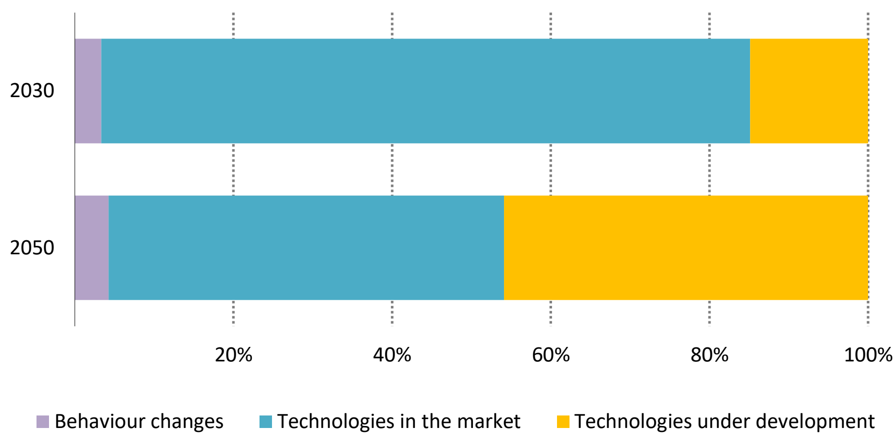
PRIORITY ACTION

## Prepare for the next phase of the transition by boosting innovation

**Clean energy innovation must accelerate rapidly, with governments putting R&D, demonstration and deployment at the core of energy and climate policy.**

Government R&D spending needs to be increased and reprioritised. Critical areas such as electrification, hydrogen, bioenergy and carbon capture, utilisation and storage (CCUS) today receive only around one-third of the level of public R&D funding of the more established low-carbon electricity generation and energy efficiency technologies. Support is also needed to accelerate the roll-out of demonstration projects, to leverage private investment in R&D, and to boost overall deployment levels to help reduce costs. Around USD 90 billion of public money needs to be mobilised globally as soon as possible to complete a portfolio of demonstration projects before 2030. Currently, only roughly USD 25 billion is budgeted for that period. Developing and deploying these technologies would create major new industries, as well as commercial and employment opportunities.

**Annual $CO_2$ emissions savings in the net zero pathway, relative to 2020**



## *The transition to net zero is for and about people*

**A transition of the scale and speed described by the net zero pathway cannot be achieved without sustained support and participation from citizens.** The changes will affect multiple aspects of people's lives – from transport, heating and cooking to urban planning and jobs. We estimate that around 55% of the cumulative emissions reductions in the pathway are linked to consumer choices such as purchasing an EV, retrofitting a house with energy-efficient technologies or installing a heat pump. Behavioural changes, particularly in advanced economies – such as replacing car trips with walking, cycling or public transport, or foregoing a long-haul flight – also provide around 4% of the cumulative emissions reductions.

**Providing electricity to around 785 million people that have no access and clean cooking solutions to 2.6 billion people that lack those options is an integral part of our pathway.** Emissions reductions have to go hand-in-hand with efforts to ensure energy access for all by 2030. This costs around USD 40 billion a year, equal to around 1% of average annual energy sector investment, while also bringing major co-benefits from reduced indoor air pollution.

**Some of the changes brought by the clean energy transformation may be challenging to implement, so decisions must be transparent, just and cost-effective.** Governments need to ensure that clean energy transitions are people-centred and inclusive. Household energy expenditure as a share of disposable income – including purchases of efficient appliances and fuel bills – rises modestly in emerging market and developing economies in our net zero pathway as more people gain access to energy and demand for modern energy services increases rapidly. Ensuring the affordability of energy for households demands close attention: policy tools that can direct support to the poorest include tax credits, loans and targeted subsidies.

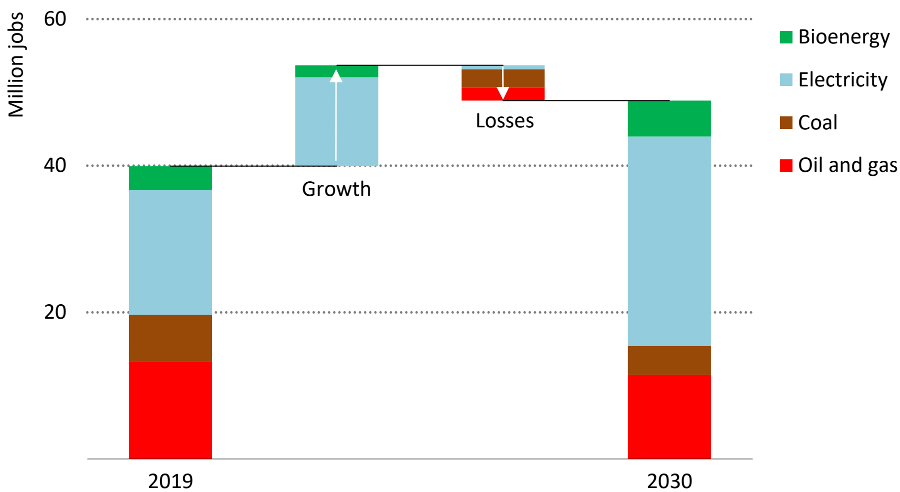
P R I O R I T Y   A C T I O N

### Clean energy jobs will grow strongly but must be spread widely

**Energy transitions have to take account of the social and economic impacts on individuals and communities, and treat people as active participants.**

The transition to net zero brings substantial new opportunities for employment, with 14 million jobs created by 2030 in our pathway thanks to new activities and investment in clean energy. Spending on more efficient appliances, electric and fuel cell vehicles, and building retrofits and energy-efficient construction would require a further 16 million workers. But these opportunities are often in different locations, skill sets and sectors than the jobs that will be lost as fossil fuels decline. In our pathway, around 5 million jobs are lost. Most of those jobs are located close to fossil fuel resources, and many are well paid, meaning structural changes can cause shocks for communities with impacts that persist over time. This requires careful policy attention to address the employment losses. It will be vital to minimise hardships associated with these disruptions, such as by retraining workers, locating new clean energy facilities in heavily affected areas wherever possible, and providing regional aid.

**Global employment in energy supply in the net zero pathway, 2019-2030**




## *An energy sector dominated by renewables*

**In the net zero pathway, global energy demand in 2050 is around 8% smaller than today, but it serves an economy more than twice as big and a population with 2 billion more people.** More efficient use of energy, resource efficiency and behavioural changes combine to offset increases in demand for energy services as the world economy grows and access to energy is extended to all.

**Instead of fossil fuels, the energy sector is based largely on renewable energy.** Two-thirds of total energy supply in 2050 is from wind, solar, bioenergy, geothermal and hydro energy. Solar becomes the largest source, accounting for one-fifth of energy supplies. Solar PV capacity increases 20-fold between now and 2050, and wind power 11-fold.

**Net zero means a huge decline in the use of fossil fuels.** They fall from almost four-fifths of total energy supply today to slightly over one-fifth by 2050. Fossil fuels that remain in 2050 are used in goods where the carbon is embodied in the product such as plastics, in facilities fitted with CCUS, and in sectors where low-emissions technology options are scarce.

**Electricity accounts for almost 50% of total energy consumption in 2050.** It plays a key role across all sectors – from transport and buildings to industry – and is essential to produce low-emissions fuels such as hydrogen. To achieve this, total electricity generation increases over two-and-a-half-times between today and 2050. At the same time, no additional new final investment decisions should be taken for new unabated coal plants, the least efficient coal plants are phased out by 2030, and the remaining coal plants still in use by 2040 are retrofitted. By 2050, almost 90% of electricity generation comes from renewable sources, with wind and solar PV together accounting for nearly 70%. Most of the remainder comes from nuclear.

**Emissions from industry, transport and buildings take longer to reduce. Cutting industry emissions by 95% by 2050 involves major efforts to build new infrastructure.** After rapid innovation progress through R&D, demonstration and initial deployment between now and 2030 to bring new clean technologies to market, the world then has to put them into action. Every month from 2030 onwards, ten heavy industrial plants are equipped with CCUS, three new hydrogen-based industrial plants are built, and 2 GW of electrolyser capacity are added at industrial sites. Policies that end sales of new internal combustion engine cars by 2035 and boost electrification underpin the massive reduction in transport emissions. In 2050, cars on the road worldwide run on electricity or fuel cells. Low-emissions fuels are essential where energy needs cannot easily or economically be met by electricity. For example, aviation relies largely on biofuels and synthetic fuels, and ammonia is vital for shipping. In buildings, bans on new fossil fuel boilers need to start being introduced globally in 2025, driving up sales of electric heat pumps. Most old buildings and all new ones comply with zero-carbon-ready building energy codes.[1]

PRIORITY ACTION

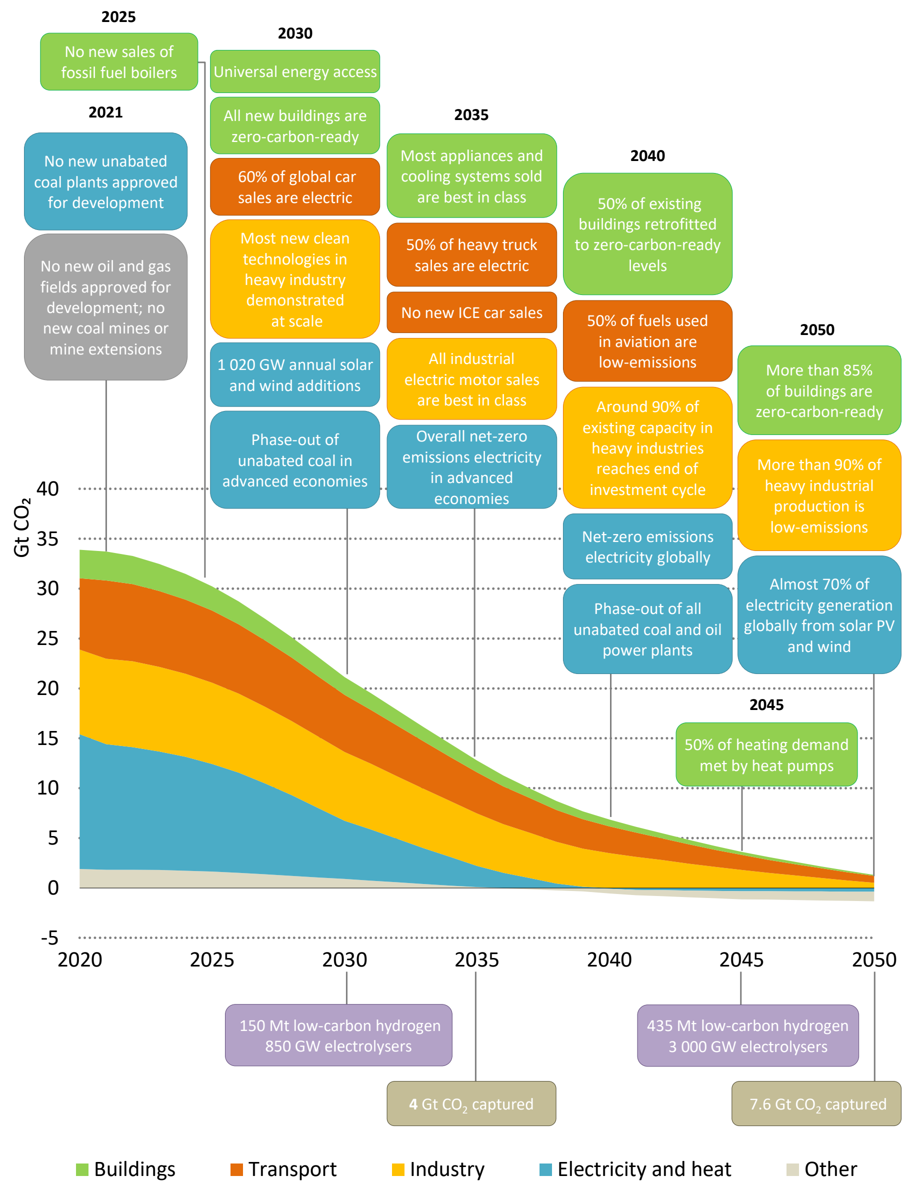
### Set near-term milestones to get on track for long-term targets

**Governments need to provide credible step-by-step plans to reach their net zero goals, building confidence among investors, industry, citizens and other countries.**

Governments must put in place long-term policy frameworks to allow all branches of government and stakeholders to plan for change and facilitate an orderly transition. Long-term national low-emissions strategies, called for by the Paris Agreement, can set out a vision for national transitions, as this report has done on a global level. These long-term objectives need to be linked to measurable short-term targets and policies. Our pathway details more than 400 sectoral and technology milestones to guide the global journey to net zero by 2050.

[1] A zero-carbon-ready building is highly energy efficient and either uses renewable energy directly or uses an energy supply that will be fully decarbonised by 2050, such as electricity or district heat.

## Key milestones in the pathway to net zero



## *There is no need for investment in new fossil fuel supply in our net zero pathway*

**Beyond projects already committed as of 2021, there are no new oil and gas fields approved for development in our pathway, and no new coal mines or mine extensions are required.** The unwavering policy focus on climate change in the net zero pathway results in a sharp decline in fossil fuel demand, meaning that the focus for oil and gas producers switches entirely to output – and emissions reductions – from the operation of existing assets. Unabated coal demand declines by 98% to just less than 1% of total energy use in 2050. Gas demand declines by 55% to 1 750 billion cubic metres and oil declines by 75% to 24 million barrels per day (mb/d), from around 90 mb/d in 2020.

**Clean electricity generation, network infrastructure and end-use sectors are key areas for increased investment.** Enabling infrastructure and technologies are vital for transforming the energy system. Annual investment in transmission and distribution grids expands from USD 260 billion today to USD 820 billion in 2030. The number of public charging points for EVs rises from around 1 million today to 40 million in 2030, requiring annual investment of almost USD 90 billion in 2030. Annual battery production for EVs leaps from 160 gigawatt-hours (GWh) today to 6 600 GWh in 2030 – the equivalent of adding almost 20 gigafactories[2] each year for the next ten years. And the required roll-out of hydrogen and CCUS after 2030 means laying the groundwork now: annual investment in $CO_2$ pipelines and hydrogen-enabling infrastructure increases from USD 1 billion today to around USD 40 billion in 2030.

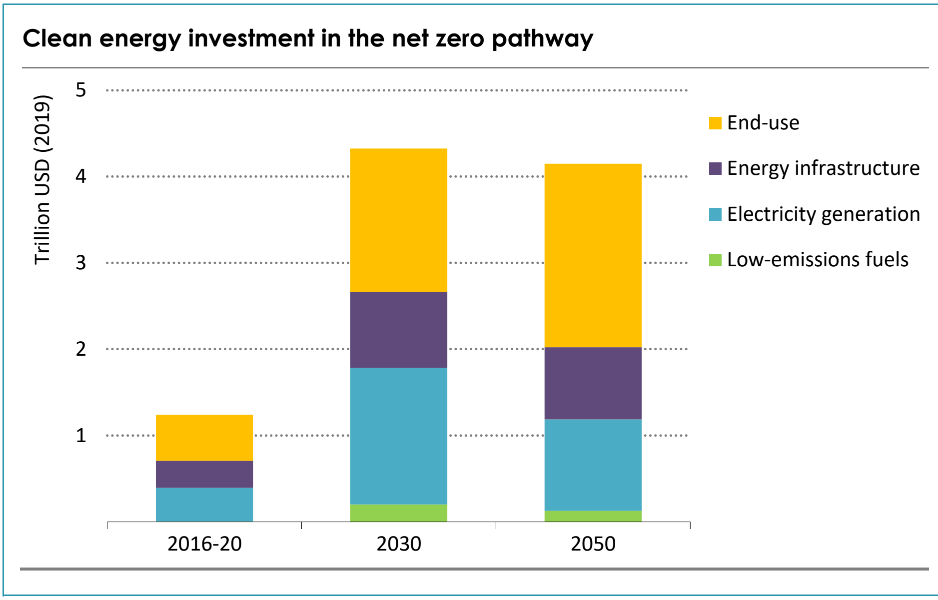
### PRIORITY ACTION

### Drive a historic surge in clean energy investment

**Policies need to be designed to send market signals that unlock new business models and mobilise private spending, especially in emerging economies.**

Accelerated delivery of international public finance will be critical to energy transitions, especially in developing economies, but ultimately the private sector will need to finance most of the extra investment required. Mobilising the capital for large-scale infrastructure calls for closer co-operation between developers, investors, public financial institutions and governments. Reducing risks for investors will be essential to ensure successful and affordable clean energy transitions. Many emerging market and developing economies, which rely mainly on public funding for new energy projects and industrial facilities, will need to reform their policy and regulatory frameworks to attract more private finance. International flows of long-term capital to these economies will be needed to support the development of both existing and emerging clean energy technologies.

[2] Battery gigafactory capacity assumption = 35 gigawatt-hours per year.




## *An unparalleled clean energy investment boom lifts global economic growth*

**Total annual energy investment surges to USD 5 trillion by 2030, adding an extra 0.4 percentage point a year to annual global GDP growth, based on our joint analysis with the International Monetary Fund.** This unparalleled increase – with investment in clean energy and energy infrastructure more than tripling already by 2030 – brings significant economic benefits as the world emerges from the Covid-19 crisis. The jump in private and government spending creates millions of jobs in clean energy, including energy efficiency, as well as in the engineering, manufacturing and construction industries. All of this puts global GDP 4% higher in 2030 than it would be based on current trends.

**Governments have a key role in enabling investment-led growth and ensuring that the benefits are shared by all.** There are large differences in macroeconomic impacts between regions. But government investment and public policies are essential to attract large amounts of private capital and to help offset the declines in fossil fuel income that many countries will experience. The major innovation efforts needed to bring new clean energy technologies to market could boost productivity and create entirely new industries, providing opportunities to locate them in areas that see job losses in incumbent industries. Improvements in air quality provide major health benefits, with 2 million fewer premature deaths globally from air pollution in 2030 than today in our net zero pathway. Achieving universal energy access by 2030 would provide a major boost to well-being and productivity in developing economies.

## *New energy security concerns emerge, and old ones remain*

**The contraction of oil and natural gas production will have far-reaching implications for all the countries and companies that produce these fuels.** No new oil and natural gas fields are needed in our pathway, and oil and natural gas supplies become increasingly concentrated in a small number of low-cost producers. For oil, the OPEC share of a much-reduced global oil supply increases from around 37% in recent years to 52% in 2050, a level higher than at any point in the history of oil markets. Yet annual per capita income from oil and natural gas in producer economies falls by about 75%, from USD 1 800 in recent years to USD 450 by the 2030s, which could have knock-on societal effects. Structural reforms and new sources of revenue are needed, even though these are unlikely to compensate fully for the drop in oil and gas income. While traditional supply activities decline, the expertise of the oil and natural gas industry fits well with technologies such as hydrogen, CCUS and offshore wind that are needed to tackle emissions in sectors where reductions are likely to be most challenging.

**The energy transition requires substantial quantities of critical minerals, and their supply emerges as a significant growth area.** The total market size of critical minerals like copper, cobalt, manganese and various rare earth metals grows almost sevenfold between 2020 and 2030 in the net zero pathway. Revenues from those minerals are larger than revenues from coal well before 2030. This creates substantial new opportunities for mining companies. It also creates new energy security concerns, including price volatility and additional costs for transitions, if supply cannot keep up with burgeoning demand.

**The rapid electrification of all sectors makes electricity even more central to energy security around the world than it is today.** Electricity system flexibility – needed to balance wind and solar with evolving demand patterns – quadruples by 2050 even as retirements of fossil fuel capacity reduce conventional sources of flexibility. The transition calls for major increases in all sources of flexibility: batteries, demand response and low-carbon flexible power plants, supported by smarter and more digital electricity networks. The resilience of electricity systems to cyberattacks and other emerging threats needs to be enhanced.

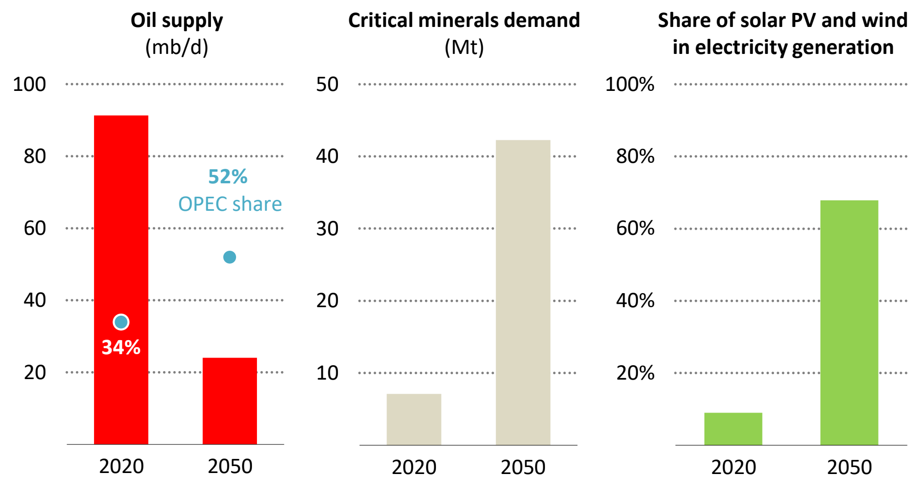
### P R I O R I T Y   A C T I O N

### Address emerging energy security risks now

**Ensuring uninterrupted and reliable supplies of energy and critical energy-related commodities at affordable prices will only rise in importance on the way to net zero.**

The focus of energy security will evolve as reliance on renewable electricity grows and the role of oil and gas diminishes. Potential vulnerabilities from the increasing importance of electricity include the variability of supply and cybersecurity risks. Governments need to create markets for investment in batteries, digital solutions and electricity grids that reward flexibility and enable adequate and reliable supplies of electricity. The growing dependence on critical minerals required for key clean energy technologies calls for new international mechanisms to ensure both the timely availability of supplies and sustainable production. At the same time, traditional energy security concerns will not disappear, as oil production will become more concentrated.

**Global energy security indicators in the net zero pathway**




Note: mb/d = million barrels per day; Mt = million tonnes.

## *International co-operation is pivotal for achieving net-zero emissions by 2050*

**Making net-zero emissions a reality hinges on a singular, unwavering focus from all governments – working together with one another, and with businesses, investors and citizens.** All stakeholders need to play their part. The wide-ranging measures adopted by governments at all levels in the net zero pathway help to frame, influence and incentivise the purchase by consumers and investment by businesses. This includes how energy companies invest in new ways of producing and supplying energy services, how businesses invest in equipment, and how consumers cool and heat their homes, power their devices and travel.

**Underpinning all these changes are policy decisions made by governments.** Devising cost-effective national and regional net zero roadmaps demands co-operation among all parts of government that breaks down silos and integrates energy into every country's policy making on finance, labour, taxation, transport and industry. Energy or environment ministries alone cannot carry out the policy actions needed to reach net zero by 2050.

**Changes in energy consumption result in a significant decline in fossil fuel tax revenues.** In many countries today, taxes on diesel, gasoline and other fossil fuel consumption are an important source of public revenues, providing as much as 10% in some cases. In the net zero pathway, tax revenue from oil and gas retail sales falls by about 40% between 2020 and 2030. Managing this decline will require long-term fiscal planning and budget reforms.

**The net zero pathway relies on unprecedented international co-operation among governments, especially on innovation and investment.** The IEA stands ready to support governments in preparing national and regional net zero roadmaps, to provide guidance and assistance in implementing them, and to promote international co-operation to accelerate the energy transition worldwide.

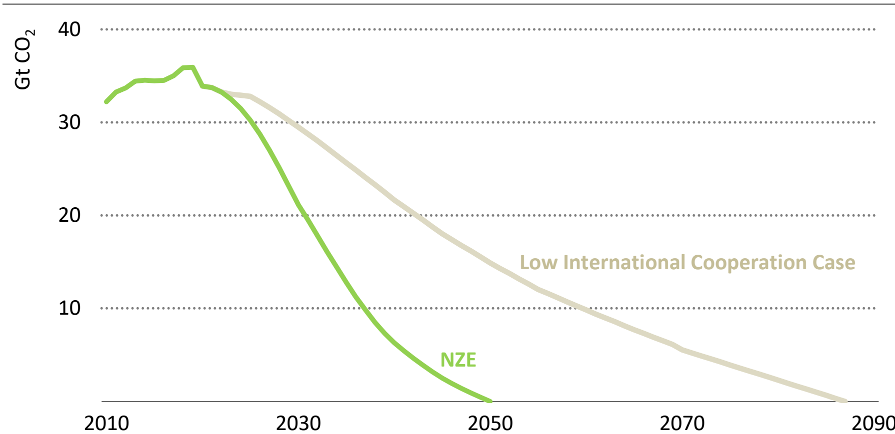
P R I O R I T Y   A C T I O N

## Take international co-operation to new heights

**This is not simply a matter of all governments seeking to bring their national emissions to net zero – it means tackling global challenges through co-ordinated actions.**

Governments must work together in an effective and mutually beneficial manner to implement coherent measures that cross borders. This includes carefully managing domestic job creation and local commercial advantages with the collective global need for clean energy technology deployment. Accelerating innovation, developing international standards and co-ordinating to scale up clean technologies needs to be done in a way that links national markets. Co-operation must recognise differences in the stages of development of different countries and the varying situations of different parts of society. For many rich countries, achieving net-zero emissions will be more difficult and costly without international co-operation. For many developing countries, the pathway to net zero without international assistance is not clear. Technical and financial support is needed to ensure deployment of key technologies and infrastructure. Without greater international co-operation, global $CO_2$ emissions will not fall to net zero by 2050.

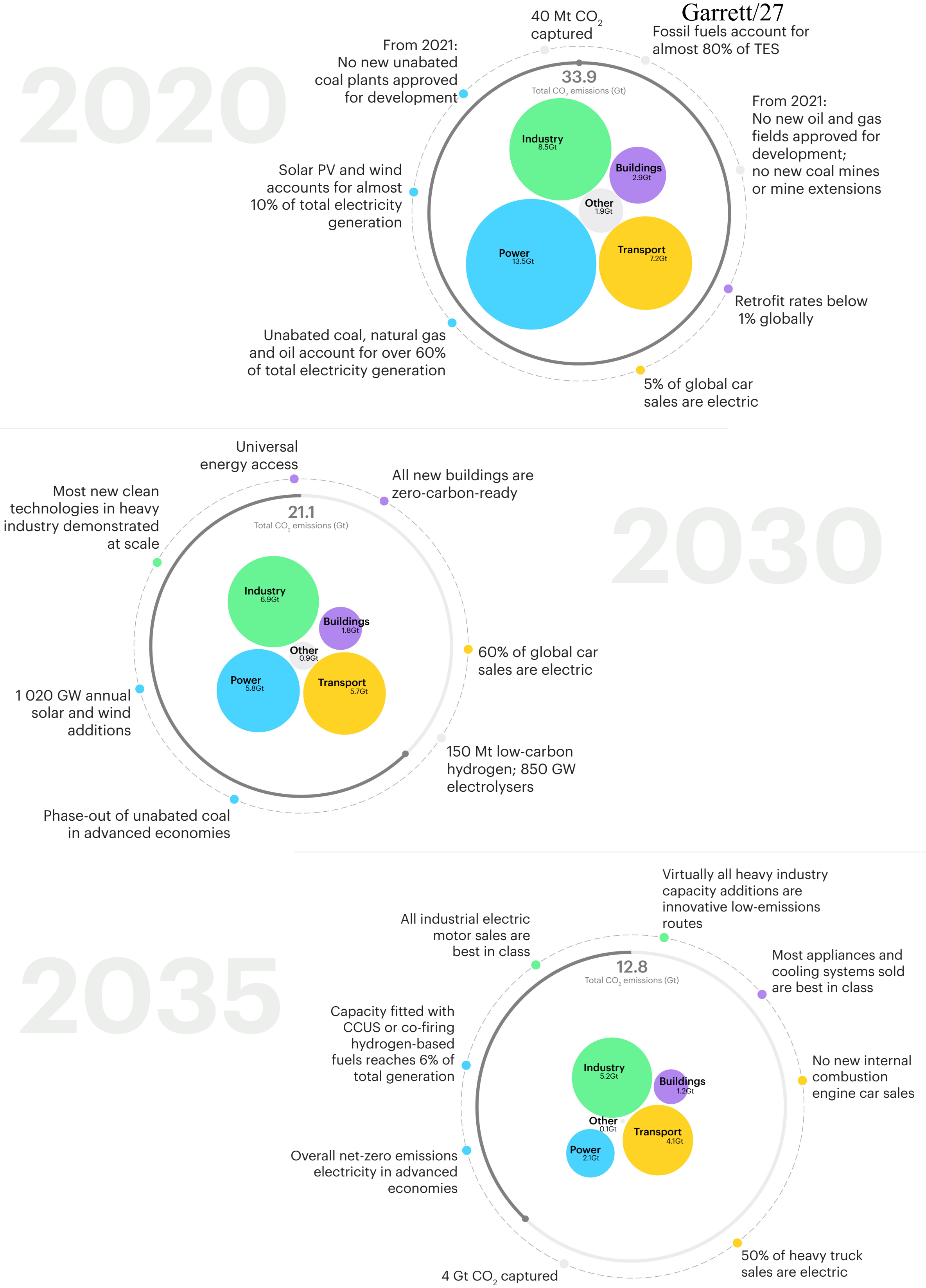
**Global energy-related $CO_2$ emissions in the net zero pathway and Low International Co-operation Case**

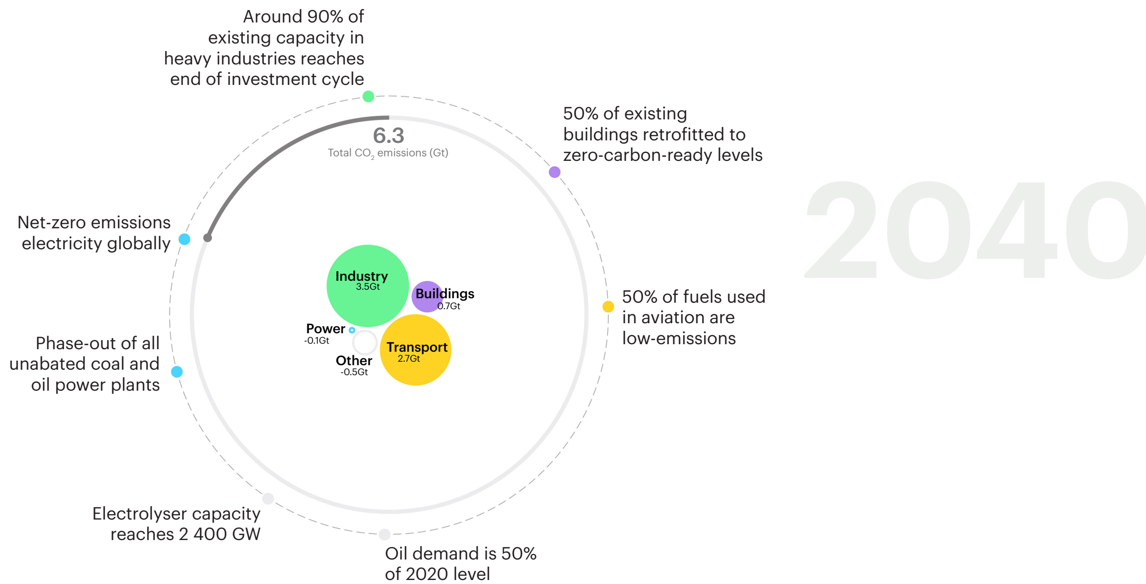


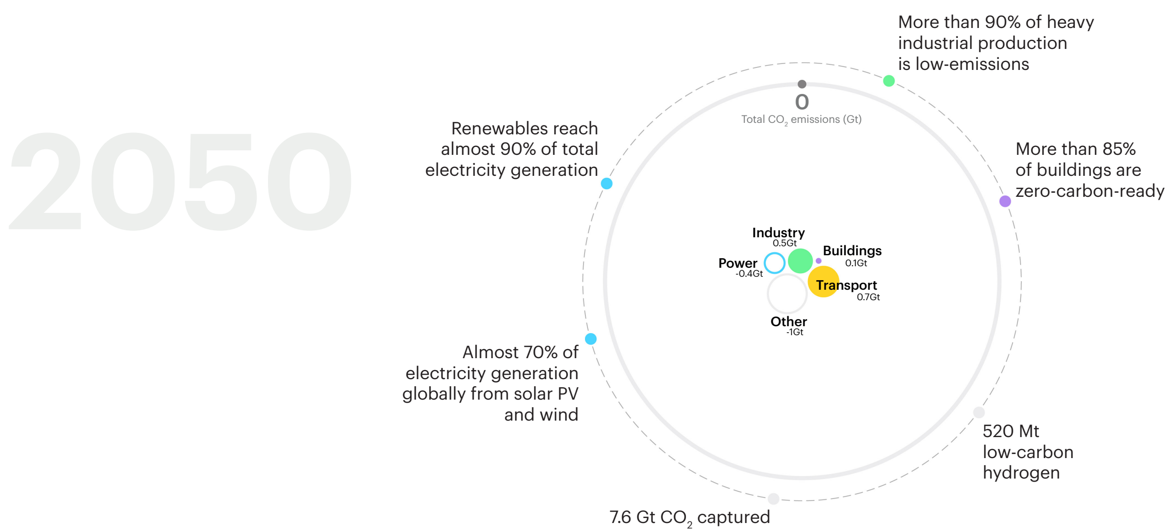

Note: Gt = gigatonnes.

Net Zero Emissions by 2050 Interactive iea.li/nzeroadmap






Around 90% of
existing capacity in
heavy industries reaches
end of investment cycle
50% of existing
buildings retrofitted to
zero-carbon-ready levels
2040
6.3
Total $CO_2$ emissions (Gt)
Net-zero emissions
electricity globally
Industry
3.5Gt
Buildings
0.7Gt
Power
-0.1Gt
Transport
2.7Gt
Other
-0.5Gt
50% of fuels used
in aviation are
low-emissions
Phase-out of all
unabated coal and
oil power plants
Electrolyser capacity
reaches 2 400 GW
Oil demand is 50%
of 2020 level


2050
More than 90% of heavy
industrial production
is low-emissions
0
Total $CO_2$ emissions (Gt)
Renewables reach
almost 90% of total
electricity generation
More than 85%
of buildings are
zero-carbon-ready
Industry
0.5Gt
Buildings
0.1Gt
Power
-0.4Gt
Transport
0.7Gt
Other
-1Gt
Almost 70% of
electricity generation
globally from solar PV
and wind
520 Mt
low-carbon
hydrogen
7.6 Gt $CO_2$ captured

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# Announced net zero pledges and the energy sector


## SUMMARY

- There has been a rapid increase over the last year in the number of governments pledging to reduce greenhouse gas emissions to net zero. Net zero pledges to date cover around 70% of global GDP and $CO_2$ emissions. However, fewer than a quarter of announced net zero pledges are fixed in domestic legislation and few are yet underpinned by specific measures or policies to deliver them in full and on time.
- The Stated Policies Scenario (STEPS) takes account only of specific policies that are in place or have been announced by governments. Annual energy-related and industrial process $CO_2$ emissions rise from 34 Gt in 2020 to 36 Gt in 2030 and remain around this level until 2050. If emissions continue on this trajectory, with similar changes in non-energy-related GHG emissions, this would lead to a temperature rise of around 2.7 °C by 2100 (with a 50% probability). Renewables provide almost 55% of global electricity generation in 2050 (up from 29% in 2020), but clean energy transitions lag in other sectors. Global coal use falls by 15% between 2020 and 2050; oil use in 2050 is 15% higher than in 2020; and natural gas use is almost 50% higher.
- The Announced Pledges Case (APC) assumes that all announced national net zero pledges are achieved in full and on time, whether or not they are currently underpinned by specific policies. Global energy-related and industrial process $CO_2$ emissions fall to 30 Gt in 2030 and 22 Gt in 2050. Extending this trajectory, with similar action on non-energy-related GHG emissions, would lead to a temperature rise in 2100 of around 2.1 °C (with a 50% probability). Global electricity generation nearly doubles to exceed 50 000 TWh in 2050. The share of renewables in electricity generation rises to nearly 70% in 2050. Oil demand does not return to its 2019 peak and falls about 10% from 2020 to 80 mb/d in 2050. Coal use drops by 50% to 2 600 Mtce in 2050, while natural gas use expands by 10% to 4 350 bcm in 2025 and remains about that level to 2050.
- Efficiency, electrification and the replacement of coal by low-emissions sources in electricity generation play a central role in achieving net zero goals in the APC, especially over the period to 2030. The relative contributions of nuclear, hydrogen, bioenergy and CCUS vary across countries, depending on their circumstances.
- The divergence in trends between the APC and the STEPS shows the difference that current net zero pledges could make, while underlining at the same time the need for concrete policies and short-term plans that are consistent with long-term net zero pledges. However, the APC also starkly highlights that existing net zero pledges, even if delivered in full, fall well short of what is necessary to reach global net-zero emissions by 2050.

## 1.1 Introduction

November 2021 will see the most important UN Framework Convention on Climate Change (UNFCCC) Conference of the Parties (COP 26) since the Paris Agreement was signed in 2015. As COP 26 approaches, an increasing number of countries have announced long-term goals to achieve net-zero greenhouse gas (GHG) emissions over the coming decades. On 31 March 2021, the International Energy Agency (IEA) hosted a Net Zero Summit to take stock of the growing list of commitments from countries and companies to reach the goals of the Paris Agreement, and to focus on the actions necessary to start turning those net zero goals into reality.

Achieving those goals will be demanding. The Covid-19 pandemic delivered a major shock to the world economy, resulting in an unprecedented 5.8% decline in $CO_2$ emissions in 2020. However, our monthly data show that global energy-related $CO_2$ emissions started to climb again in December 2020, and we estimate that they will rebound to around 33 gigatonnes of carbon dioxide (Gt $CO_2$) in 2021, only 1.2% below the level in 2019 (IEA, 2021). Sustainable economic recovery packages offered a unique opportunity to make 2019 the definitive peak in global emissions, but the evidence so far points to a rebound in emissions in parallel with renewed economic growth, at least in the near term (IEA, 2020a).

Recent IEA analyses examined the technologies and policies needed for countries and regions to achieve net-zero emissions energy systems. The *World Energy Outlook 2020* examined what would be needed over the period to 2030 to put the world on a path towards net-zero emissions by 2050 in the context of the pandemic-related economic recovery (IEA, 2020b). The Faster Innovation Case in *Energy Technology Perspectives 2020* explored whether net-zero emissions could be achieved globally by 2050 through accelerated energy technology development and deployment alone: it showed that, relative to baseline trends, almost half of the emissions savings needed in 2050 to reach net-zero emissions rely on technologies that are not yet commercially available (IEA, 2020c).

This special report, prepared at the request of the UK President of the COP 26, incorporates the insights and lessons learned from both reports to create a comprehensive and detailed pathway, or roadmap, to achieve net-zero energy-related and industrial process $CO_2$ emissions globally by 2050. It assesses the costs of achieving this goal, the likely impacts on employment and the economy, and the wider implications for the world. It also highlights the key milestones for technologies, infrastructure, investment and policy that are needed along the road to 2050.

This report is set out in four chapters:

- **Chapter 1** explores the outlook for global $CO_2$ emissions and energy supply and use based on existing policies and pledges. It sets out projections of global energy use and emissions based on the **Stated Policies Scenario (STEPS)**, which includes only the firm policies that are in place or have been announced by countries, including Nationally

Determined Contributions. It also examines the **Announced Pledges Case (APC)**, a variant of the STEPS that assumes that all of the net zero targets announced by countries around the world to date are met in full.



- **Chapter 2** presents the **Net-Zero Emissions by 2050 Scenario (NZE)**, which describes how energy demand and the energy mix will need to evolve if the world is to achieve net-zero emissions by 2050. It also assesses the corresponding investment needs and explores key uncertainties surrounding technology and consumer behaviour.
- **Chapter 3** examines the implications of the NZE for various sectors, covering fossil fuel supply, the supply of low-emissions fuels (such as hydrogen, ammonia, biofuels, synthetic fuels and biomethane) and the electricity, transport, industry and buildings sectors. It highlights the key changes required to achieve net-zero emissions in the NZE and the major milestones that are needed along the way.
- **Chapter 4** explores the implications of the NZE for the economy, the energy industry, citizens and governments.

## 1.2 Emissions reduction targets and net zero pledges

### *1.2.1 Nationally Determined Contributions*

Under the Paris Agreement, Parties [1] are required to submit Nationally Determined Contributions (NDCs) to the UNFCCC and to implement policies with the aim of achieving their stated objectives. The process is dynamic; it requires Parties to update their NDCs every five years in a progressive manner to reflect the highest possible ambition. The first round of NDCs, submitted by 191 countries, covers more than 90% of global energy-related and industrial process $CO_2$ emissions. [2] The first NDCs included some targets that were unconditional and others that were conditional on international support for finance, technology and other means of implementation.

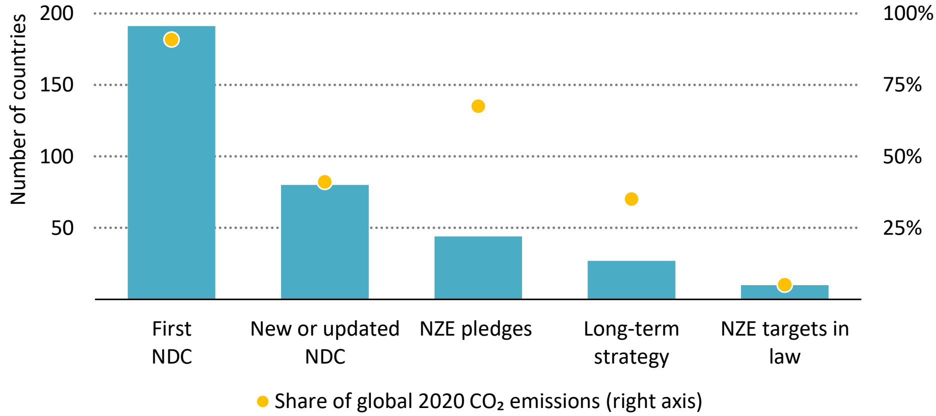
As of 23 April 2021, 80 countries have submitted new or updated NDCs to the UNFCCC, covering just over 40% of global $CO_2$ emissions (Figure 1.1).[3] Many of the updated NDCs include more stringent targets than in the initial round of NDCs, or targets for a larger number of sectors or for a broader coverage of GHGs. In addition, 27 countries and the European Union have communicated long-term low GHG emissions development strategies to the UNFCCC, as requested by the Paris Agreement. Some of these strategies incorporate a net zero pledge.

[1] Parties refers to the 197 members of the UNFCCC which includes all United Nations member states, United Nations General Assembly Observer State of Palestine, UN non-member states Niue and the Cook Islands and the European Union.

[2] Unless otherwise stated, $CO_2$ emissions in this report refer to energy-related and industrial process $CO_2$ emissions.

[3] Several countries have indicated that they intend to submit new or updated NDCs later in 2021 or in 2022.

**Figure 1.1 ▷ Number of countries with NDCs, long-term strategies and net zero pledges, and their shares of 2020 global $CO_2$ emissions**






*Around 40% of countries that have ratified the Paris Agreement have updated their NDCs, but net zero pledges cover around 70% of global $CO_2$ emissions*

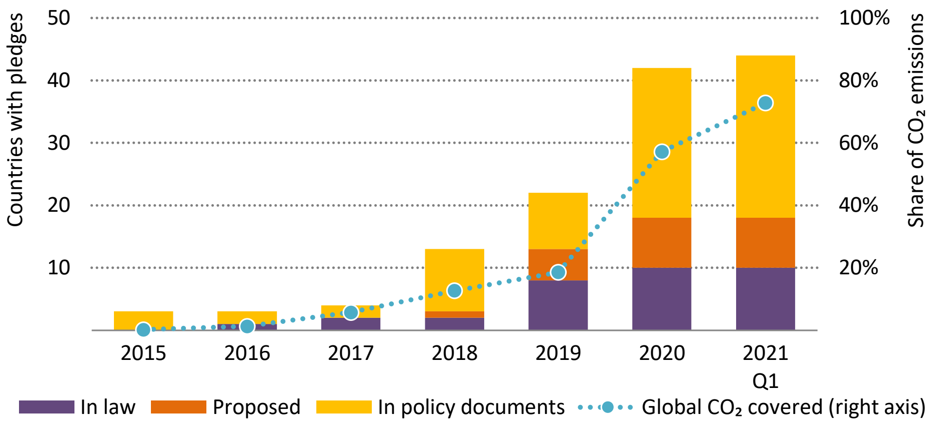
### *1.2.2 Net-zero emissions pledges*

There has been a rapid increase in the number of governments making pledges to reduce GHG emissions to net zero (Figure 1.2). In the Paris Agreement, countries agreed to "achieve a balance between anthropogenic emissions by sources and removals by sinks of greenhouse gases in the second-half of the century". The Intergovernmental Panel on Climate Change (IPCC) *Special Report on Global Warming of 1.5 °C* highlighted the importance of reaching net-zero $CO_2$ emissions globally by mid-century or sooner to avoid the worst impacts of climate change (IPCC, 2018).

Net-zero emissions pledges have been announced by national governments, subnational jurisdictions, coalitions[4] and a large number of corporate entities (see Spotlight). As of 23 April 2021, 44 countries and the European Union have pledged to meet a net-zero emissions target: in total they account for around 70% of global $CO_2$ emissions and GDP (Figure 1.3). Of these, ten countries have made meeting their net zero target a legal obligation, eight are proposing to make it a legal obligation, and the remainder have made their pledges in official policy documents.

[4] Examples include: the UN-led Climate Ambition Alliance in which signatories signal they are working towards achieving net-zero emissions by 2050; and the Carbon Neutrality Coalition launched at the UN Climate Summit in 2017, in which signatories commit to develop long-term low GHG emissions strategies in line with limiting temperature rises to 1.5 °C.

**Figure 1.2 ▻** **Number of national net zero pledges and share of global $CO_2$ emissions covered**

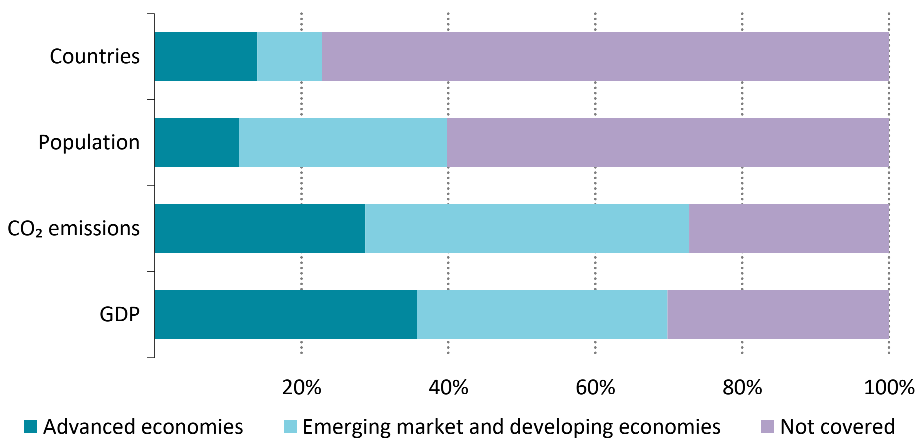





*There has been a significant acceleration in net-zero emissions pledges announced by governments, with an increasing number enshrined in law*

Notes: In law = a net zero pledge has been approved by parliament and is legally binding. Proposed = a net zero pledge has been proposed to parliament to be voted into law. In policy document = a net zero pledge has been proposed but does not have legally binding status.

**Figure 1.3 ▻** **Coverage of announced national net zero pledges**






*Countries accounting for around 70% of global $CO_2$ emissions and GDP have set net zero pledges in law, or proposed legislation or in an official policy document*

Note: GDP = gross domestic product at purchasing power parity.

In contrast to some of the shorter term commitments contained within NDCs, few net zero pledges are supported by detailed policies and firm routes to implementation. Net-zero emissions pledges also vary considerably in their timescale and scope. Some key differences include:

- **GHG coverage.** Most pledges cover all GHG emissions, but some include exemptions or different rules for certain types of emissions. For example, New Zealand's net zero pledge covers all GHGs except biogenic methane, which has a separate reduction target.
- **Sectoral boundaries**. Some pledges exclude emissions from specific sectors or activities. For example, the Netherlands aims to achieve net-zero GHG emissions only in its electricity sector (as part of an overall aim to reduce total GHG emissions by 95%), and some countries, including France, Portugal and Sweden, exclude international aviation and shipping.
- **Use of carbon dioxide removal (CDR)**. Pledges take varying approaches to account for CDR within a country's sovereign territory. CDR options include natural $CO_2$ sinks, such as forests and soils, as well as technological solutions, such as direct air capture or bioenergy with carbon capture and storage. For example, Uruguay has stated that natural $CO_2$ sinks will be used to help it reach net-zero emissions, while Switzerland plans to use CDR technologies to balance a part of its residual emissions in 2050.
- **Use of international mitigation transfers**. Some pledges allow GHG mitigation that occurs outside a country's borders to be counted towards the net zero target, such as through the transfer of carbon credits, while others do not. For example, Norway allows the potential use of international transfers, while France explicitly rules them out. Some countries, such as Sweden, allow such transfers but specify an upper limit to their use.
- **Timeframe**. The majority of pledges, covering 35% of global $CO_2$ emissions in 2020, target net-zero emissions by 2050, but Finland aims to reach that goal by 2035, Austria and Iceland by 2040 and Sweden by 2045. Among others, the People's Republic of China (hereafter China) and Ukraine have set a target date after 2050.

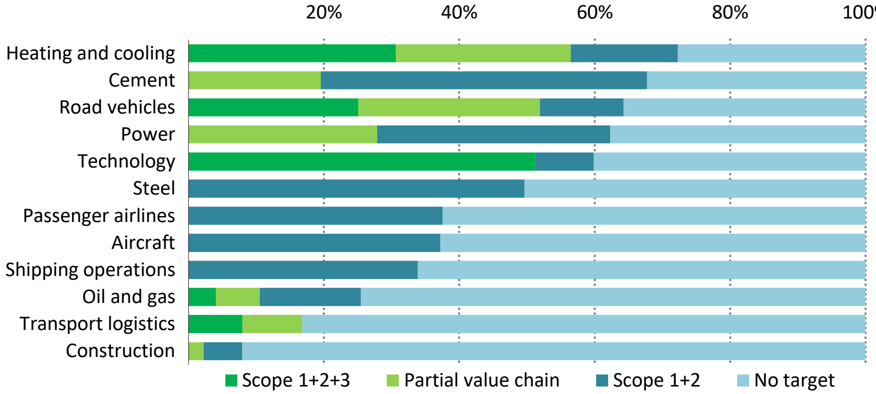
S P O T L I G H T

## How are businesses responding to the need to reach net-zero emissions?

There has been a rapid rise in net-zero emissions announcements from companies in recent years: as of February 2021, around 110 companies that consume large amounts of energy directly or produce energy-consuming goods have announced net-zero emissions goals or targets.

Around 60-70% of global production of heating and cooling equipment, road vehicles, electricity and cement is from companies that have announced net-zero emissions targets (Figure 1.4). Nearly 60% of gross revenue in the technology sector is also generated by companies with net-zero emission targets. In other sectors, net zero pledges cover 30-40% of air and shipping operations, 15% of transport logistics and 10% of construction. All these shares are likely to keep growing as more companies make pledges.

**Figure 1.4 ▷ Sectoral activity of large energy-related companies with announced pledges to reach net-zero emissions by 2050**






*Some sectors are more advanced in terms of the extent of net zero targets by companies active in the sector*

Notes: Scope 1 = direct emissions from energy and other sources owned or controlled. Scope 2 = indirect emissions from the production of electricity and heat, and fuels purchased and used. Scope 3 = indirect emissions from sources not owned or directly controlled but related to their activities (such as employee travel, extraction, transport and production of purchased materials and fuels, and end-use of fuels, products and services). Partial value chain includes Scope 1 and 2 emissions and Scope 3 emissions in specific geographic locations or sections of a company's value chain.

Source: IEA analysis based on company reports from the largest 10-25 companies within each sector.

Company pledges may not be readily comparable. Most companies account for emissions and set net zero pledges based on the GHG Protocol (WRI, WBCSD, 2004), but the coverage and timeframe of these pledges varies widely. Some cover only their own emissions, for example by shifting to the use of zero-emissions electricity in offices and production facilities, and by eliminating the use of oil in transport or industrial operations, e.g. FedEx, ArcelorMittal and Maersk. Others also cover wider emissions from certain parts of their values chains, e.g. Renault in Europe, or all indirect emissions related to their activities, e.g. Daikin, Toyota, Shell, Eni and Heidelberg. Around 60% of pledges aim to achieve net-zero emissions by 2050, but several companies have set an earlier deadline of 2030 or 2040.

Around 40% of companies that have announced net zero pledges have yet to set out how they aim to achieve them. For those with detailed plans, the main options include direct emissions reductions, use of $CO_2$ removal technologies, such as afforestation, bioenergy with carbon capture, utilisation and storage (CCUS), or direct air capture with $CO_2$ storage, and purchasing emissions (credits generated through emissions reductions that occur elsewhere). The use of offsets could be a cost-effective mechanism to eliminate emissions from parts of value chains where emissions reductions are most challenging, provided that schemes to generate emissions credits result in permanent, additional and verified emissions reductions. However, there is likely to be a limited supply of emissions credits consistent with net-zero emissions globally and the use of such credits could divert investment from options that enable direct emissions reductions.

## 1.3 Outlook for emissions and energy in the STEPS

The IEA Stated Policies Scenario (STEPS) illustrates the consequences of existing and stated policies for the energy sector. It draws on the latest information regarding national energy and climate plans and the policies that underpin them. It takes account of all policies that are backed by robust implementing legislation or regulatory measures, including the NDCs that countries have put forward under the Paris Agreement up to September 2020 and the energy components of announced economic stimulus and recovery packages. So far, few net-zero emissions pledges have been backed up by detailed policies, implementation plans or interim targets: most net zero pledges therefore are not included in the STEPS.

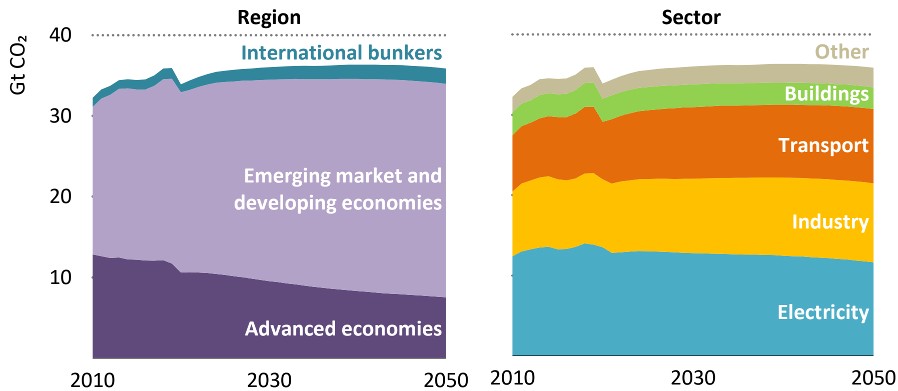
### *1.3.1 $CO_2$ emissions*

Global $CO_2$ emissions in the STEPS bring about only a marginal overall improvement in recent trends. Switching to renewables leads to an early peak in emissions in the electricity sector, but reductions across all sectors fall far short of what is required for net-zero emissions in 2050. Annual $CO_2$ emissions rebound quickly from the dip caused by the Covid-19 pandemic in 2020: they increase from 34 Gt in 2020 to 36 Gt in 2030 and then remain around this level until 2050 (Figure 1.5). If emissions trends were to continue along the same trajectory after 2050, and with commensurate changes in other sources of GHG emissions, the global average surface temperature rise would be around 2.7 °C in 2100 (with a 50% probability).

There is strong divergence between the outlook for emissions in advanced economies on one hand and the emerging market and developing economies on the other. In advanced economies, despite a small rebound in the early 2020s, $CO_2$ emissions decline by about a third between 2020 and 2050, thanks to the impact of policies and technological progress in reducing energy demand and switching to cleaner fuels. In emerging market and developing economies, energy demand continues to grow strongly because of increased population, brisk economic growth, urbanisation and the expansion of infrastructure: these effects outweigh improvements in energy efficiency and the deployment of clean technologies, causing $CO_2$ emissions to grow by almost 20% by the mid-2040s, before declining marginally to 2050.

**Figure 1.5 ▹ Energy-related and industrial process $CO_2$ emissions by region and sector in the STEPS**








*Global $CO_2$ emissions rebound quickly after 2020 and then plateau, with declines in advanced economies offset by increases elsewhere*

Note: Other = agriculture and own use in the energy sector.

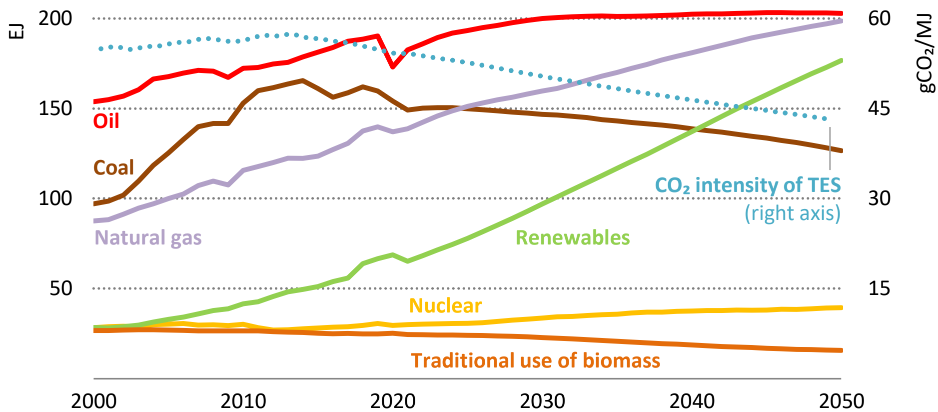
### 1.3.2 Total energy supply, total final consumption and electricity generation

The projected trends in $CO_2$ emissions in the STEPS result from changes in the amount of energy used and the mix of fuels and technologies. Total energy supply (TES)[5] worldwide rises by just over 30% between 2020 and 2050 in the STEPS (Figure 1.6). Without a projected annual average reduction of 2.2% in energy intensity, i.e. energy use per unit of GDP, TES in 2050 would be around 85% higher. In advanced economies, energy use falls by around 5% to 2050, despite a 75% increase in economic activity over the period. In emerging market and developing economies, energy use increases by 50% to 2050, reflecting a tripling of economic output between 2020 and 2050. Despite the increase in GDP and energy use in emerging market and developing economies, 750 million people still have no access to electricity in 2050, more than 95% of them in sub-Saharan Africa, and 1.5 billion people continue to rely on the traditional use of bioenergy for cooking.

The global fuel mix changes significantly between 2020 and 2050. Coal use, which peaked in 2014, falls by around 15%. Having fallen sharply in 2020 due to the pandemic, oil demand rebounds quickly, returning to the 2019 level of 98 million barrels per day (mb/d) by 2023 and reaching a plateau of around 104 mb/d shortly after 2030. Natural gas demand increases from 3 900 billion cubic metres (bcm) in 2020 to 4 600 bcm in 2030 and 5 700 bcm in 2050. Nuclear energy grows by 15% between 2020 and 2030, mainly reflecting expansions in China.

[5] Total primary energy supply (or total primary energy demand) has been renamed total energy supply in accordance with the International Recommendations for Energy Statistics (IEA, 2020d).

**Figure 1.6 ▻** **Total energy supply and $CO_2$ emissions intensity in the STEPS**



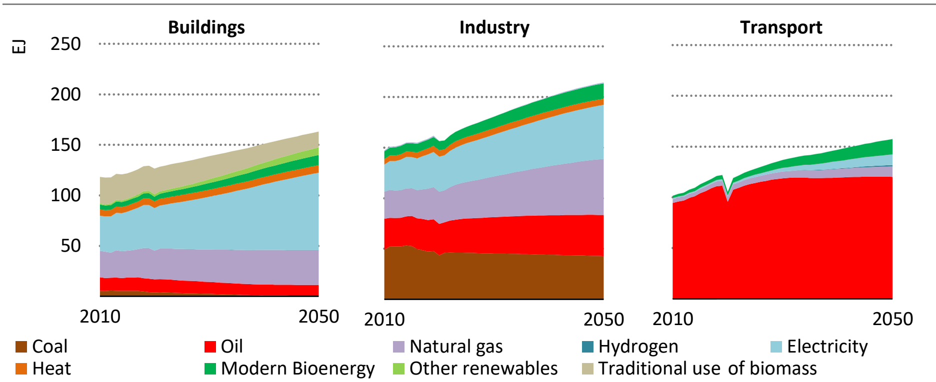



*Coal use declines, oil plateaus and renewables and natural gas grow substantially to 2050*

Note: EJ = exajoule; MJ = megajoule; TES = total energy supply.

Total final consumption increases in all sectors in the STEPS, led by electricity and natural gas (Figure 1.7). All the growth is in emerging market and developing economies. The biggest change in energy use is in the electricity sector (Figure 1.8). Global electricity demand increases by 80% between 2020 and 2050, around double the overall rate of growth in final energy consumption. More than 85% of the growth in global electricity demand comes from emerging market and developing economies. Coal continues to play an important role in electricity generation in those economies to 2050, despite strong growth in renewables: in advanced economies, the use of coal for electricity generation drops sharply.

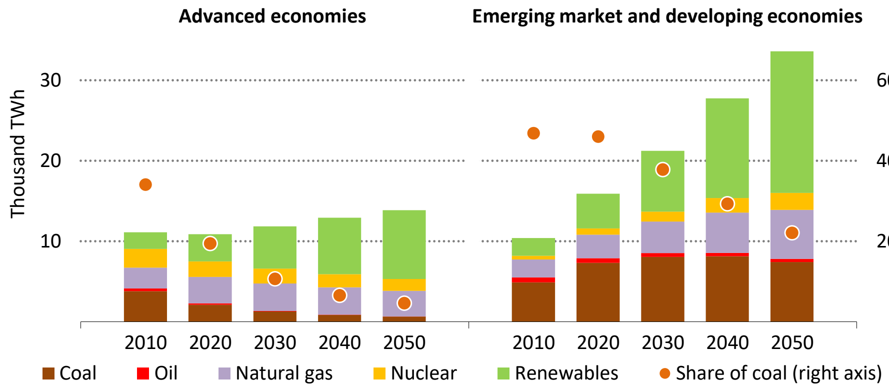
**Figure 1.7 ▻** **Total final consumption by sector and fuel in the STEPS**






*Final energy consumption grows on average by 1% per year between 2020 and 2050, with electricity and natural gas meeting most of the increase*

**Figure 1.8 ▷ Electricity generation by fuel and share of coal in the STEPS**






*Emerging market and developing economies drive most of the increase in global electricity demand, met mainly by renewables and gas, though coal remains important*



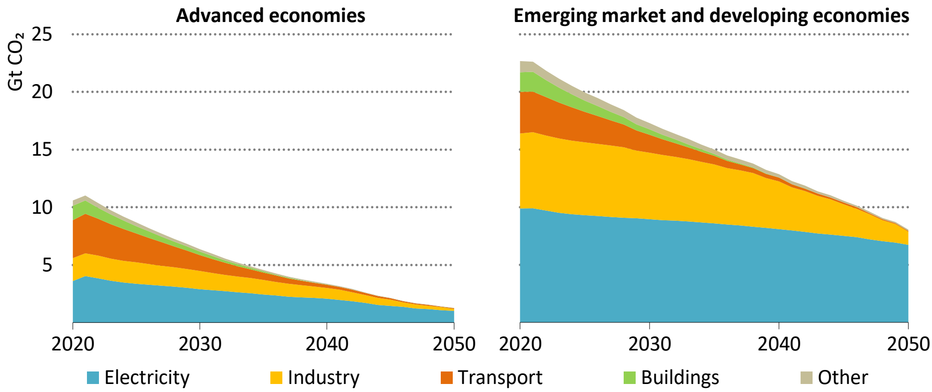
### *1.3.3 Emissions from existing assets*

The energy sector contains a large number of long-lived and capital-intensive assets. Urban infrastructure, pipelines, refineries, coal-fired power plants, heavy industrial facilities, buildings and large hydro power plants can have technical and economic lifetimes of well over 50 years. If today's energy infrastructure was to be operated until the end of the typical lifetime in a manner similar to the past, we estimate that this would lead to cumulative energy-related and industrial process $CO_2$ emissions between 2020 and 2050 of just under 650 Gt $CO_2$. This is around 30% more than the remaining total $CO_2$ budget consistent with limiting global warming to 1.5 °C with a 50% probability (see Chapter 2).

The electricity sector accounts for more than 50% of the total emissions that would come from existing assets; 40% of total emissions would come from coal-fired power plants alone. Industry is the next largest sector, with steel, cement, chemicals and other industry accounting for around 30% total emissions from existing assets. The long lifetime of production facilities in these sub-sectors (typically 30-40 years for a blast furnace or cement kiln) and the relatively young age of the global capital stock explain their large contribution. Transport accounts for just over 10% of emissions from existing assets and the buildings sector accounts for just under 5%. The lifetime of vehicles and equipment in the transport and buildings sectors is generally much shorter than is the case in electricity and industry – passenger cars, for example, are generally assumed to have a lifetime of around 17 years – but associated infrastructure networks such as roads, electricity networks and gas grids have very long lifetimes.

There are some large regional differences in emissions levels from existing assets (Figure 1.9). Advanced economies tend to have much older capital stocks than emerging market and developing economies, particularly in the electricity sector, and existing assets will reach the end of their lifetimes earlier. For example, the average age of coal-fired power plants in China is 13 years and 16 years in the rest of Asia, compared to around 35 years in Europe and 40 years in the United States (IEA, 2020e).

**Figure 1.9 ▷ Emissions from existing infrastructure by sector and region**






*Emerging market and developing economies account for three-quarters of cumulative emissions from existing infrastructure through to 2050*

## 1.4 Announced Pledges Case

The Announced Pledges Case (APC) assumes that all national net-zero emissions pledges are realised in full and on time. It therefore goes beyond the policy commitments incorporated in the STEPS. The aim of the APC is to see how far full implementation of the national net-zero emissions pledges would take the world towards reaching net-zero emissions, and to examine the scale of the transformation of the energy sector that such a path would require.

The way these pledges are assumed to be implemented in the APC has important implications for the energy system. A net zero pledge for all GHG emissions does not necessarily mean that $CO_2$ emissions from the energy sector need to reach net zero. For example, a country's net zero plans may envisage some remaining energy-related emissions are offset by the absorption of emissions from forestry or land use, or by negative emissions arising from the use of bioenergy or direct capture of $CO_2$ from the air (DAC) with CCUS.[6] It is not possible to know exactly how net zero pledges will be implemented, but the design of the APC, particularly with respect to the details of the energy system pathway, has been informed by the pathways that a number of national bodies have developed to support net zero pledges (Box 1.1). Policies in countries that have not yet made a net zero pledge are assumed to be the same as in the STEPS. Non policy assumptions, including population and economic growth, are the same as in the STEPS.

[6] For example, in recent economy-wide net zero mitigation pathways for the European Union, around 140-210 million tonnes $CO_2$ of emissions from the energy sector remain in 2050, which are offset by CDR from managed land-use sinks, and bioenergy and DAC with CCUS (European Commission, 2018).

**Box 1.1 ▹ Consultations with national bodies on achieving national net-zero emissions goals**

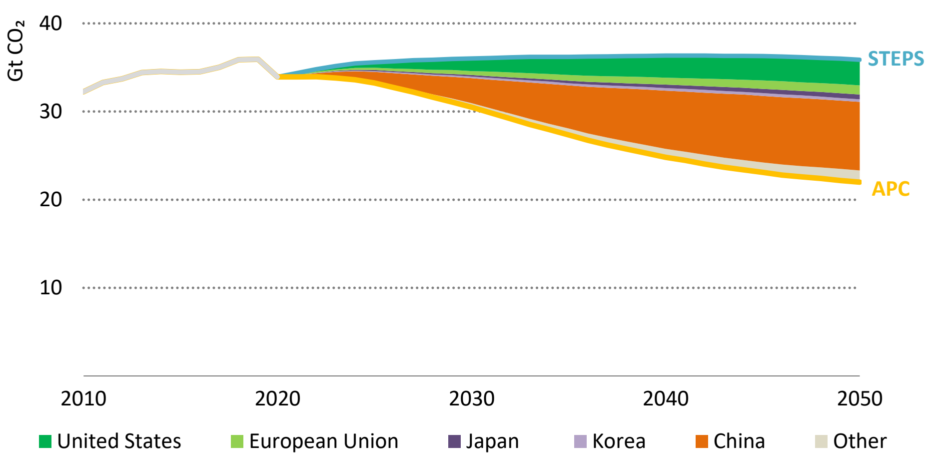
To help inform its work on net zero pathways, the IEA engaged in extensive consultations with experts in academia and national bodies that have developed pathways to support net zero pledges made by governments. This includes groups that have developed net-zero emissions pathways for several countries including China, European Union, Japan, United Kingdom and United States, as well as the IPCC. These pathways were not used directly as input for the APC, but the discussions informed our modelling of national preferences and constraints within each jurisdiction and to benchmark the overall level of energy-related $CO_2$ emissions reductions that are commensurate with economy-wide net zero goals.



### 1.4.1 $CO_2$ emissions

In the APC, there is a small rebound in emissions to 2023, although this is much smaller than the increase that immediately followed the financial crisis in 2008-09. Emissions never reach the previous peak of 36 Gt $CO_2$. Global $CO_2$ emissions fall around 10% to 30 Gt in 2030 and to 22 Gt in 2050. This is around 35% below the level in 2020 and 14 Gt $CO_2$ lower than in the STEPS (Figure 1.10). If emissions continue this trend after 2050, and with a similar level of changes in non-energy-related GHG emissions, the global average surface temperature rise in 2100 would be around 2.1 °C (with a 50% probability).

**Figure 1.10 ▹ Global energy-related and industrial process $CO_2$ emissions by scenario and reductions by region, 2010-2050**



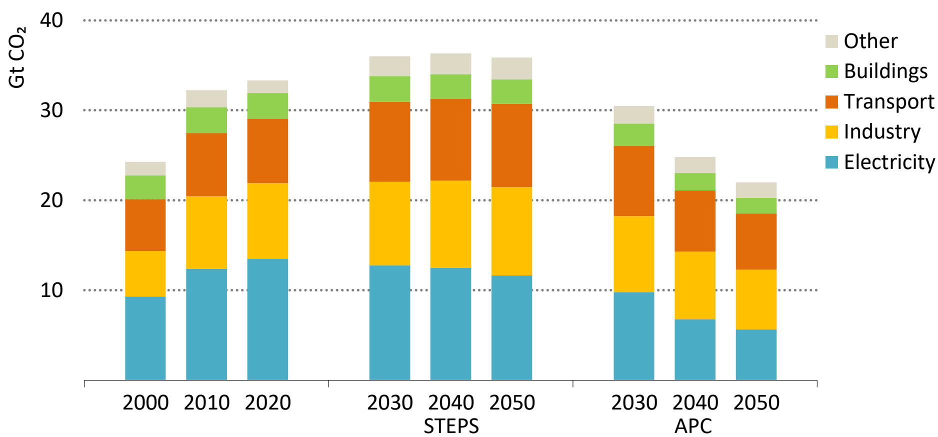



***Achieving existing net zero pledges would reduce emissions globally to 22 Gt $CO_2$ in 2050, a major reduction compared with current policies but still far from net-zero emissions***

The net zero pledges that have been made to date therefore make a major difference to the current trajectory for $CO_2$ emissions. Equally, however, existing net zero pledges fall well short of what is necessary to reach net-zero emissions globally by 2050. This highlights the importance of concrete policies and plans to deliver in full long-term net zero pledges. It also underlines the value of other countries making (and delivering on) net zero pledges: the more countries that do so, and the more ambitious those pledges are, the more the gap will narrow with what is needed to reach net-zero emissions by 2050.

The largest drop in $CO_2$ emissions is in the APC is in the electricity sector with global emissions falling by nearly 60% between 2020 and 2050. This occurs despite a near-doubling of electricity demand as energy end-uses are increasingly electrified, notably in transport and buildings (Figure 1.11). This compares with a fall in emissions of less than 15% in the STEPS.

**Figure 1.11 ▷ Global $CO_2$ emissions by sector in the STEPS and APC**






*Announced net zero pledges would cut emissions in 2050 by 60% in the electricity sector, 40% in buildings, 25% in industry and just over 10% in transport*

The transport and industry sectors see a less marked fall in $CO_2$ emissions to 2050 in the APC, with increases in energy demand in regions without net zero pledges partially offsetting emissions reduction efforts in other regions. Emissions from the buildings sector decline by around 40% between 2020 and 2050, compared with around 5% in the STEPS: fossil fuel use in buildings is mostly to provide heating, and countries that have made pledges account for a relatively high proportion of global heating demand.

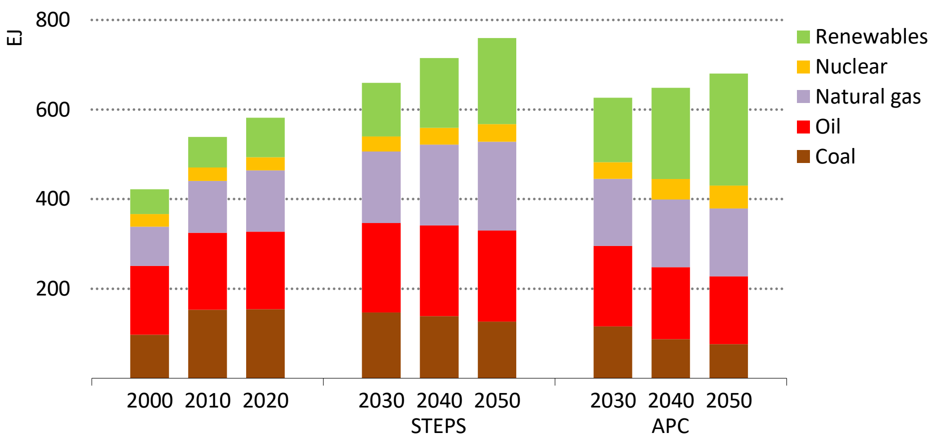
Even in regions with net zero pledges, there are some residual emissions in 2050, mainly in industry and transport. This reflects the scarcity of commercially available options to eliminate all emissions from heavy-duty trucks, aviation, shipping and heavy industry.

### *1.4.2 Total energy supply*



Global total energy supply increases by more than 15% between 2020 and 2050 in the APC, compared with a third in the STEPS (Figure 1.12). Energy intensity falls on average by around 2.6% per year to 2050 compared with 2.2% in the STEPS. There is a substantial increase in energy demand in emerging market and developing economies, where economic and population growth is fastest and where there are fewer net zero pledges, which outweighs the reductions in energy demand in the countries with net zero pledges.

**Figure 1.12 ⊳ Total energy supply by source in STEPS and APC**






***Announced net zero pledges lift renewables in the APC from 12% of total energy supply in 2020 to 35% in 2050, mainly at the expense of coal and oil***

The global increase in energy supply in the APC is led by renewables, which increase their share in the energy mix from 12% in 2020 to 35% by 2050 (compared with 25% in 2050 in the STEPS). Solar photovoltaics (PV) and wind in the electricity sector together contribute about 50% of the growth in renewables supply, and bioenergy contributes around 30%. Bioenergy use doubles in industry, triples in electricity generation and grows by a factor of four in transport: it plays an important role in reducing emissions from heat supply and removing $CO_2$ from the atmosphere when it is combined with CCUS. Nuclear maintains its share of the energy mix, its output rising by a quarter to 2030 (compared with a 15% increase in the STEPS), driven by lifetime extensions at existing plants and new reactors in some countries.

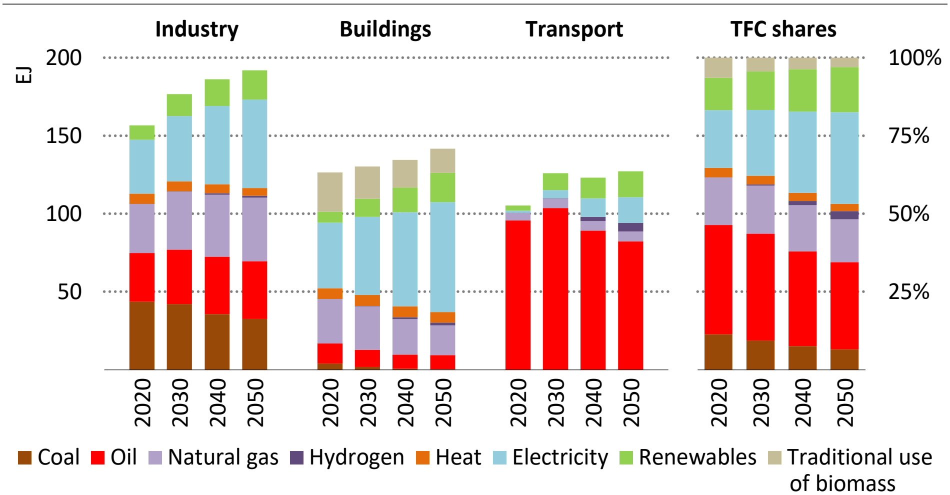
Global coal use falls significantly more rapidly in the APC than in the STEPS. It drops from 5 250 million tonnes of coal equivalent (Mtce) in 2020 to 4 000 Mtce in 2030 and 2 600 Mtce in 2050 (compared with 4 300 Mtce in the STEPS in 2050). Most of this decline is due to reduced coal-fired electricity generation in countries with net zero pledges as plants are repurposed, retrofitted or retired. In advanced economies, unabated coal-fired power plants are generally phased out over the next 10-15 years. China's coal consumption for electricity declines by 85% between 2020 and 2050 on its path towards carbon neutrality in 2060. These declines more than offset continued growth for coal in countries without net zero pledges. Globally, coal use in industry falls by 25% between 2020 and 2050, compared with a 5% decline in the STEPS.

Oil demand recovers slightly in the early 2020s but never again reaches its historic peak in 2019. It declines to 90 mb/d in the early 2030s and to 80 mb/d in 2050, around 25 mb/d lower than in the STEPS, thanks to a strong push to electrify transport and shifts to biofuels and hydrogen, especially in regions with pledges. Natural gas demand increases from about 3 900 bcm in 2020 to around 4 350 bcm in 2025, but is then broadly flat to 2050 (it continues to grow to around 5 700 bcm in the STEPS).

### *1.4.3 Total final consumption*

Global energy use continues to grow in all major end-use sectors in the APC, albeit substantially more slowly than in the STEPS (Figure 1.13). Total final consumption (TFC) increases by around 20% in 2020-50, compared with a 35% increase globally in the STEPS. Measures to improve energy efficiency play a major role in the APC in reducing demand growth in countries with net zero pledges. Without those efficiency gains, electricity demand growth would make it much harder for renewables to displace fossil fuels in electricity generation. The biggest reduction in energy demand relative to the STEPS is in transport, thanks to an accelerated shift to electric vehicles (EVs), which are around three-times as energy efficient as conventional internal combustion engine vehicles.

**Figure 1.13 ⊳ Total final consumption in the APC**






***Announced net zero pledges lead to a shift away from fossil fuels globally to electricity, renewables and hydrogen. Electricity's share rises from 20% to 30% in 2050***

The fuel mix in final energy use shifts substantially in the APC. By 2050, electricity is the largest single fuel used in all sectors except transport, where oil remains dominant. The persistence of oil in transport stems partly from the extent of its continued use in countries without net zero pledges, and partly from the difficulty of electrifying substantial parts of the transport sector, notably trucking and aviation. Electricity does make inroads into transport, however, and rapid growth in the uptake of EVs puts oil use into decline after 2030, with EVs accounting for around 35% of global passenger car sales by 2030 and nearly 50% in 2050 in the APC (versus around 25% in the STEPS in 2050). Electrification in the buildings sector is also much faster in the APC than in the STEPS.

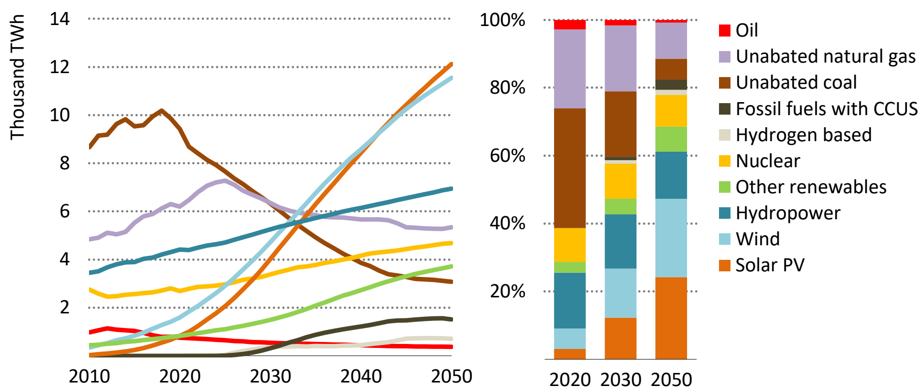
The direct use of renewables expands in all end-use sectors globally through to 2050. Modern bioenergy accounts for the bulk of this growth, predominantly through the blending of biomethane into natural gas networks and liquid biofuels in transport. This occurs mainly in regions with net zero pledges. Hydrogen and hydrogen-based fuels play a larger role in the APC than in the STEPS, reaching almost 15 exajoules (EJ) in 2050, though they still account for only 3% of total final consumption worldwide in 2050. Transport accounts for more than two-thirds of all hydrogen consumption in 2050. In parallel, on-site hydrogen production in the industry and refining sectors gradually shifts towards low-carbon technologies.

### 1.4.4 Electricity generation

Global electricity generation nearly doubles during the next three decades in the APC, rising from about 26 800 terawatt-hours (TWh) in 2020 to over 50 000 TWh in 2050, some 4 000 TWh higher than in the STEPS. Low-emissions energy sources provide all the increase. The share of renewables in electricity generation rises from 29% in 2020 to nearly 70% in 2050, compared with about 55% in the STEPS, as solar PV and wind race ahead of all other sources of generation (Figure 1.14). By 2050, solar PV and wind together account for almost half of electricity supply. Hydropower also continues to expand, emerging as the third-largest energy source in the electricity mix by 2050. Nuclear power increases steadily too, maintaining its global market share of about 10%, led by increases in China. Natural gas use in electricity increases slightly to the mid-2020s before starting to fall back, while coal's share of electricity generation falls from around 35% in 2020 to below 10% in 2050. At that point, 20% of the remaining coal-fired output comes from plants equipped with CCUS.

Hydrogen and ammonia start to emerge as fuel inputs to electricity generation by around 2030, used largely in combination with natural gas in gas turbines and with coal in coal-fired power plants. This extends the life of existing assets, contributes to electricity system adequacy and reduces the overall costs of transforming the electricity sectors in many countries. Total battery capacity also rises substantially, reaching 1 600 gigawatts (GW) in 2050, 70% more than in the STEPS.

**Figure 1.14 ▷** **Global electricity generation by source in the APC**






*Renewables reach new heights in the APC, rising from just under 30% of electricity supply in 2020 to nearly 70% in 2050, while coal-fired generation steadily declines*

Note: Other renewables = geothermal, solar thermal and marine.

# A global pathway to net-zero $CO_2$ emissions in 2050


## SUMMARY

- The Net-Zero Emissions by 2050 Scenario (NZE) shows what is needed for the global energy sector to achieve net-zero $CO_2$ emissions by 2050. Alongside corresponding reductions in GHG emissions from outside the energy sector, this is consistent with limiting the global temperature rise to 1.5 °C without a temperature overshoot (with a 50% probability). Achieving this would require all governments to increase ambitions from current Nationally Determined Contributions and net zero pledges.
- In the NZE, global energy-related and industrial process $CO_2$ emissions fall by nearly 40% between 2020 and 2030 and to net zero in 2050. Universal access to sustainable energy is achieved by 2030. There is a 75% reduction in methane emissions from fossil fuel use by 2030. These changes take place while the global economy more than doubles through to 2050 and the global population increases by 2 billion.
- Total energy supply falls by 7% between 2020 and 2030 in the NZE and remains at around this level to 2050. Solar PV and wind become the leading sources of electricity globally before 2030 and together they provide nearly 70% of global generation in 2050. The traditional use of bioenergy is phased out by 2030.
- Coal demand declines by 90% to less than 600 Mtce in 2050, oil declines by 75% to 24 mb/d, and natural gas declines by 55% to 1 750 bcm. The fossil fuels that remain in 2050 are used in the production of non-energy goods where the carbon is embodied in the product (like plastics), in plants with carbon capture, utilisation and storage (CCUS), and in sectors where low-emissions technology options are scarce.
- Energy efficiency, wind and solar provide around half of emissions savings to 2030 in the NZE. They continue to deliver emissions reductions beyond 2030, but the period to 2050 sees increasing electrification, hydrogen use and CCUS deployment, for which not all technologies are available on the market today, and these provide more than half of emissions savings between 2030 and 2050. In 2050, there is 1.9 Gt of $CO_2$ removal in the NZE and 520 million tonnes of low-carbon hydrogen demand. Behavioural changes by citizens and businesses avoid 1.7 Gt $CO_2$ emissions in 2030, curb energy demand growth, and facilitate clean energy transitions.
- Annual energy sector investment, which averaged USD 2.3 trillion globally in recent years, jumps to USD 5 trillion by 2030 in the NZE. As a share of global GDP, average annual energy investment to 2050 in the NZE is around 1% higher than in recent years.
- The NZE taps into all opportunities to decarbonise the energy sector, across all fuels and all technologies. But the path to 2050 has many uncertainties. If behavioural changes were to be more limited than envisaged in the NZE, or sustainable bioenergy less available, then the energy transition would be more expensive. A failure to develop CCUS for fossil fuels could delay or prevent the development of CCUS for process emissions from cement production and carbon removal technologies, making it much harder to achieve net-zero emissions by 2050.

## 2.1 Introduction

Achieving a global energy transition that is compatible with the world's climate goals is unquestionably a formidable task. As highlighted in Chapter 1, current pledges by governments to reduce emissions to net zero collectively cover around 70% of today's global economic activity and global $CO_2$ emissions. The Announced Pledges Case shows that, if all those pledges were met in full, it would narrow the gap between where we are heading and where we need to be to achieve net-zero emissions by 2050 worldwide. But it also shows that the gap would remain large. Meeting all existing net zero pledges in full would still leave 22 gigatonnes (Gt) of energy-related and industrial process $CO_2$ emissions globally in 2050, consistent with a temperature rise in 2100 of around 2.1 °C (with a 50% probability).

In this chapter, we examine the energy sector transformation which is embodied in our Net-Zero Emissions by 2050 Scenario. First, it provides an overview of the key assumptions and market dynamics underlying the projections, including projected fossil fuel and $CO_2$ prices. It discusses trends in global $CO_2$ emissions, energy use and investment, including the key roles played by efficiency measures, behavioural change, electrification, renewables, hydrogen and hydrogen-based fuels, bioenergy, and carbon capture, utilisation and storage (CCUS). Further, it discusses some of the key uncertainties surrounding the global pathway towards net-zero emissions related to behavioural change, the availability of sustainable bioenergy, and the deployment of CCUS for fossil fuels. The transformation of specific energy sectors is assessed and discussed in detail in Chapter 3.

## 2.2 Scenario design

The Net-Zero Emissions by 2050 Scenario (NZE) is designed to show what is needed across the main sectors by various actors, and by when, for the world to achieve net-zero energy-related and industrial process $CO_2$ emissions by 2050.[1] It also aims to minimise methane emissions from the energy sector. In recent years, the energy sector was responsible for around three-quarters of global greenhouse gas (GHG) emissions. Achieving net-zero energy-related and industrial process $CO_2$ emissions by 2050 in the NZE does not rely on action in areas other than the energy sector, but limiting climate change does require such action. We therefore additionally examine the reductions in $CO_2$ emissions from land use that would be commensurate with the transformation of the energy sector in the NZE, working in co-operation with the International Institute for Applied Systems Analysis (IIASA). In parallel with action on reducing all other sources of GHG emissions, achieving net-zero $CO_2$ emissions from the energy sector by 2050 is consistent with around a 50% chance of limiting the long-term average global temperature rise to 1.5 °C without a temperature overshoot (IPCC, 2018).

[1] Unless otherwise stated, carbon dioxide ($CO_2$) emissions in this chapter refer to energy-related and industrial process $CO_2$ emissions. Net-zero $CO_2$ emissions refers to zero $CO_2$ emissions to the atmosphere, or with any residual $CO_2$ emissions offset by $CO_2$ removal from direct air capture or bioenergy with carbon capture and storage.

The NZE aims to ensure that energy-related and industrial process $CO_2$ emissions to 2030 are in line with reductions in 1.5 °C scenarios with no or low or limited temperature overshoot assessed in the IPCC in its Special Report on Global Warming of 1.5 °C.[2] In addition, the NZE incorporates concrete action on the energy-related United Nations Sustainable Development Goals related to achieving universal energy access by 2030 and delivering a major reduction in air pollution. The projections in the NZE were generated by a hybrid model that combines components of the IEA's World Energy Model (WEM), which is used to produce the projections in the annual *World Energy Outlook,* and the Energy Technology Perspectives (ETP) model.



### Box 2.1 ▷ International Energy Agency modelling approach for the NZE

A new, hybrid modelling approach was adopted to develop the NZE and combines the relative strengths of the WEM and the ETP model. The WEM is a large-scale simulation model designed to replicate how competitive energy markets function and to examine the implications of policies on a detailed sector-by-sector and region-by-region basis. The ETP model is a large-scale partial-optimisation model with detailed technology descriptions of more than 800 individual technologies across the energy conversion, industry, transport and buildings sectors.

This is the first time this modelling approach has been implemented. The combination of the two models allows for a unique set of insights on energy markets, investment, technologies, and the level and detail of policies that would be needed to bring about the energy sector transformation in the NZE.

Results from the WEM and ETP model have been coupled with the Greenhouse Gas - Air Pollution Interactions and Synergies (GAINS) model developed by IIASA (Amann et al., 2011). The GAINS model is used to evaluate air pollutant emissions and resultant health impacts linked to air pollution. For the first time, IEA model results have also been coupled with the IIASA's Global Biosphere Management Model (GLOBIOM) to provide data on land use and net emissions impacts of bioenergy demand.

The impacts of changes in investment and spending on global GDP in the NZE have been estimated by the International Monetary Fund (IMF) using the Global Integrated Monetary and Fiscal (GIMF) model. GIMF is a multi-country dynamic stochastic general equilibrium model used by the IMF for policy and risk analysis (Laxton et al., 2010; Anderson et al., 2013). It has been used to produce the IMF's World Economic Outlook scenario analyses since 2008.

There are many possible paths to achieve net-zero $CO_2$ emissions globally by 2050 and many uncertainties that could affect any of them; the NZE is therefore *a* path, not *the* path to net-zero emissions. Much depends, for example, on the pace of innovation in new and emerging

[2] The IPCC classifies scenarios as "no or limited temperature overshoot", if temperatures exceed 1.5 °C by less than 0.1 °C but return to less than 1.5 °C in 2100, and as "higher overshoot", if temperatures exceed 1.5 °C by 0.1-0.4 °C but return to less than 1.5 °C in 2100.

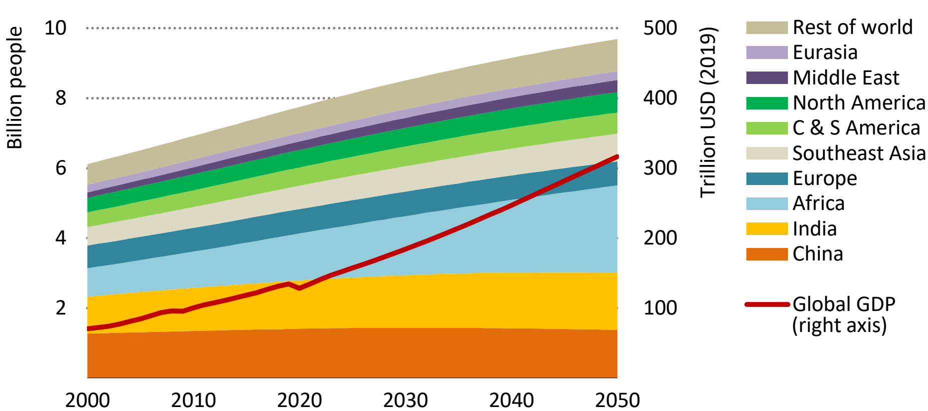
technologies, the extent to which citizens are able or willing to change behaviour, the availability of sustainable bioenergy and the extent and effectiveness of international collaboration. We investigate some of the key alternatives and uncertainties here and in Chapter 3. The Net-Zero Emissions by 2050 Scenario is built on the following principles.

- The uptake of all the available technologies and emissions reduction options is dictated by costs, technology maturity, policy preferences, and market and country conditions.
- All countries co-operate towards achieving net-zero emissions worldwide. This involves all countries participating in efforts to meet the net zero goal, working together in an effective and mutually beneficial way, and recognising the different stages of economic development of countries and regions, and the importance of ensuring a just transition.
- An orderly transition across the energy sector. This includes ensuring the security of fuel and electricity supplies at all times, minimising stranded assets where possible and aiming to avoid volatility in energy markets.

### 2.2.1 Population and GDP

The energy sector transformation in the NZE occurs against the backdrop of large increases in the world's population and economy (Figure 2.1). In 2020, there were around 7.8 billion people in the world; this is projected to increase by around 750 million by 2030 and by nearly 2 billion people by 2050 in line with the median variant of the United Nations projections (UNDESA, 2019). Nearly all of the population increase is in emerging market and developing economies: the population of Africa alone increases by more than 1.1 billion between 2020 and 2050.

**Figure 2.1 ▷ World population by region and global GDP in the NZE**






*By 2050, the world's population expands to 9.7 billion people and the global economy is more than twice as large as in 2020*

Notes: GDP = gross domestic product in purchasing power parity; C & S America = Central and South America.

Sources: IEA analysis based on UNDESA (2019); Oxford Economics (2020); IMF (2020a, 2020b).

The world's economy is assumed to recover rapidly from the impact of the Covid-19 pandemic. Its size returns to pre-crisis levels in 2021. From 2022, the GDP growth trend is close to the pre-pandemic rate of around 3% per year on average, in line with assessments from the IMF. The response to the pandemic leads to a large increase in government debt, but resumed growth, along with low interest rates in many countries, make this manageable in the long term. By 2030, the world's economy is around 45% larger than in 2020, and by 2050 it is more than twice as large.



### 2.2.2 Energy and $CO_2$ prices

Projections of future energy prices are inevitably subject to a high degree of uncertainty. In IEA scenarios, they are designed to maintain an equilibrium between supply and demand. The rapid drop in oil and natural gas demand in the NZE means that no fossil fuel exploration is required and no new oil and natural gas fields are required beyond those that have already been approved for development. No new coal mines or mine extensions are required either. Prices are increasingly set by the operating costs of the marginal project required to meet demand, and this results in significantly lower fossil fuel prices than in recent years. The oil price drops to around USD 35/barrel by 2030 and then drifts down slowly towards USD 25/barrel in 2050.

**Table 2.1 ▷ Fossil fuel prices in the NZE**

| **Real terms** (USD 2019) | 2010 | 2020 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|
| **IEA crude oil** (USD/barrel) | 91 | 37 | 35 | 28 | 24 |
| **Natural gas** (USD/MBtu) | | | | | |
| United States | 5.1 | 2.1 | 1.9 | 2.0 | 2.0 |
| European Union | 8.7 | 2.0 | 3.8 | 3.8 | 3.5 |
| China | 7.8 | 5.7 | 5.2 | 4.8 | 4.6 |
| Japan | 12.9 | 5.7 | 4.4 | 4.2 | 4.1 |
| **Steam coal** (USD/tonne) | | | | | |
| United States | 60 | 45 | 24 | 24 | 22 |
| European Union | 108 | 56 | 51 | 48 | 43 |
| Japan | 125 | 75 | 57 | 53 | 49 |
| Coastal China | 135 | 81 | 60 | 54 | 50 |

Notes: MBtu = million British thermal units. The IEA crude oil prices are a weighted average import price among IEA member countries. Natural gas prices are weighted averages expressed on a gross calorific-value basis. US natural gas prices reflect the wholesale price prevailing on the domestic market. The European Union and China gas prices reflect a balance of pipeline and liquefied natural gas (LNG) imports, while Japan gas prices solely reflect LNG imports. LNG prices used are those at the customs border, prior to regasification. Steam coal prices are weighted averages adjusted to 6 000 kilocalories per kilogramme. US steam coal prices reflect mine-mouth price plus transport and handling cost. Coastal China steam coal price reflects a balance of imports and domestic sales, while the European Union and Japanese steam coal prices are solely for imports.

In line with the principle of orderly transitions governing the NZE, the trajectory for oil markets and prices avoids excessive volatility. What happens depends to a large degree on the strategies adopted by resource-rich governments and their national oil companies. In the NZE it is assumed that, despite having lower cost resources at their disposal, they restrict investment in new fields. This limits the need for the shutting in and closure of higher cost production. The market share of major resource-rich countries nevertheless still rises in the NZE due to the large size and slow decline rates of their existing fields.

Producer economies could pursue alternative approaches. Faced with rapidly falling oil and gas demand, they could, for example, opt to increase production so as to capture an even larger share of the market. In this event, the combination of falling demand and increased availability of low cost oil would undoubtedly lead to even lower – and probably much more volatile – prices. In practice, the options open to particular producer countries would depend on their resilience to lower oil prices and on the extent to which export markets have developed for low-emissions fuels that could be produced from their natural resources.

Anticipating and mitigating feedbacks from the supply side is a central element of the discussion about orderly energy transitions. A drop in prices usually results in some rebound in demand, and policies and regulations would be essential to avoid this leading to any increase in the unabated use of fossil fuels, which would undermine wider emissions reduction efforts.

As the energy sector transforms, more fuels are traded globally, such as hydrogen-based fuels and biofuels. The prices of these commodities are assumed to be set by the marginal cost of domestic production or imports within each region.

A broad range of energy policies and accompanying measures are introduced across all regions to reduce emissions in the NZE. This includes: renewable fuel mandates; efficiency standards; market reforms; research, development and deployment; and the elimination of inefficient fossil fuel subsidies. Direct emissions reduction regulations are also needed in some cases. In the transport sector, for example, regulations are implemented to reduce sales of internal combustion engine vehicles and increase the use of liquid biofuels and synthetic fuels in aviation and shipping, as well as measures to ensure that low oil prices do not lead to an increase in consumption.

$CO_2$ prices are introduced across all regions in the NZE (Table 2.2). They are assumed to be introduced in the immediate future across all advanced economies for the electricity generation, industry and energy production sectors, and to rise on average to USD 130 per tonne ($tCO_2$) by 2030 and to USD 250/$tCO_2$ by 2050. In a number of other major economies – including China, Brazil, Russia and South Africa – $CO_2$ prices in these sectors are assumed to rise to around USD 200/$tCO_2$ in 2050. $CO_2$ prices are introduced in all other emerging market and developing economies, although it is assumed that they pursue more direct policies to adapt and transform their energy systems and so the level of $CO_2$ prices is lower than elsewhere.

**Table 2.2 ▹ $CO_2$ prices for electricity, industry and energy production in the NZE**

| USD (2019) per tonne of $CO_2$ | 2025 | 2030 | 2040 | 2050 |
|---|---|---|---|---|
| Advanced economies | 75 | 130 | 205 | 250 |
| Selected emerging market and developing economies* | 45 | 90 | 160 | 200 |
| Other emerging market and developing economies | 3 | 15 | 35 | 55 |

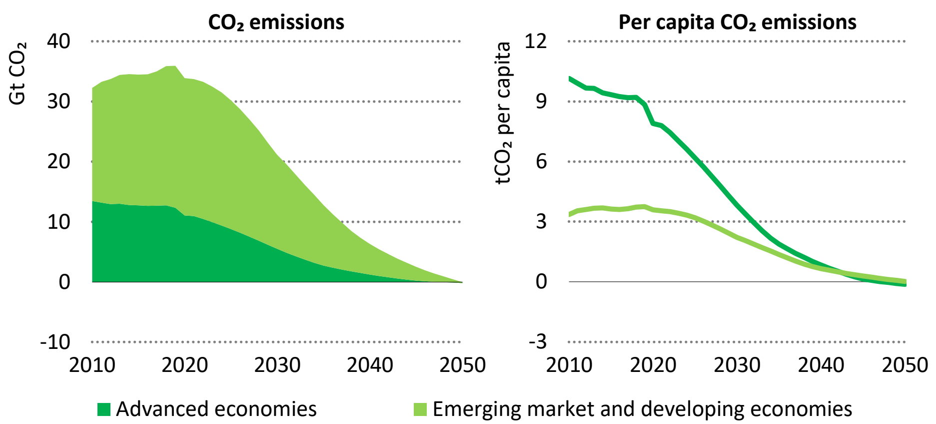
* Includes China, Russia, Brazil and South Africa.



## 2.3 $CO_2$ emissions

Global energy-related and industrial process $CO_2$ emissions in the NZE fall to around 21 Gt $CO_2$ in 2030 and to net-zero in 2050 (Figure 2.2).[3] $CO_2$ emissions in advanced economies as a whole fall to net zero by around 2045 and these countries collectively remove around 0.2 Gt $CO_2$ from the atmosphere in 2050. Emissions in several individual emerging market and developing economies also fall to net zero well before 2050, but in aggregate there are around 0.2 Gt $CO_2$ of remaining emissions in this group of countries in 2050. These are offset by $CO_2$ removal in advanced economies to provide net-zero $CO_2$ emissions at the global level.

**Figure 2.2 ▹ Global net $CO_2$ emissions in the NZE**






***$CO_2$ emissions fall to net zero in advanced economies around 2045 and globally by 2050. Per capita emissions globally are similar by the early-2040s.***

Note: Includes $CO_2$ emissions from international aviation and shipping.

[3] In the period to 2030, $CO_2$ emissions in the NZE fall at a broadly similar rate to the P2 illustrative pathway in the IPCC SR 1.5 (IPCC, 2018). The P2 scenario is described as "a scenario with … shifts towards sustainable and healthy consumption patterns, low-carbon technology innovation, and well-managed land systems with limited societal acceptability for BECCS [bioenergy with carbon capture and storage]". After 2030, emissions in the NZE fall at a much faster pace than in the P2 scenario, which has 5.6 Gt $CO_2$ of residual energy sector and industrial process $CO_2$ emissions remaining in 2050.

Several emerging market and developing economies with a very large potential for producing renewables-based electricity and bioenergy are also a key source of carbon dioxide removal (CDR). This includes making use of renewable electricity sources to produce large quantities of biofuels with CCUS, some of which is exported, and to carry out direct air capture with carbon capture and storage (DACCS).

Per capita $CO_2$ emissions in advanced economies drop from around 8 $tCO_2$ per person in 2020 to around 3.5 $tCO_2$ in 2030, a level close to the average in emerging market and developing economies in 2020. Per capita emissions also fall in emerging market and developing economies, but from a much lower starting point. By the early 2040s, per capita emissions in both regions are broadly similar at around 0.5 $tCO_2$ per person.

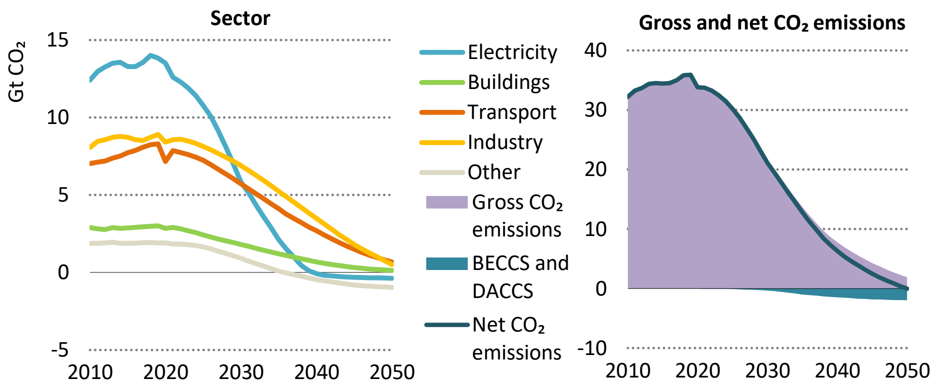
Cumulative global energy-related and industrial process $CO_2$ emissions between 2020 and 2050 amount to just over 460 Gt in the NZE. Assuming parallel action to address $CO_2$ emissions from agriculture, forestry and other land use (AFOLU) over the period to 2050 would result in around 40 Gt $CO_2$ from AFOLU (see section 2.7.2). This means that total $CO_2$ emissions from all sources – some 500 Gt $CO_2$ – are in line with the $CO_2$ budgets included in the IPCC SR1.5, which indicated that the total $CO_2$ budget from 2020 consistent with providing a 50% chance of limiting warming to 1.5 °C is 500 Gt $CO_2$ (IPCC, 2018).[4] As well as reducing $CO_2$ emissions to net-zero, the NZE seeks to reduce non-$CO_2$ emissions from the energy sector. Methane emissions from fossil fuel production and use, for example, fall from 115 million tonnes (Mt) methane in 2020 (3.5 Gt $CO_2$-equivalent [$CO_2$-eq])[5] to 30 Mt in 2030 and 10 Mt in 2050.

The fastest and largest reductions in global emissions in the NZE are initially seen in the electricity sector (Figure 2.3). Electricity generation was the largest source of emissions in 2020, but emissions drop by nearly 60% in the period to 2030, mainly due to major reductions from coal-fired power plants, and the electricity sector becomes a small net negative source of emissions around 2040. Emissions from the buildings sector fall by 40% between 2020 and 2030 thanks to a shift away from the use of fossil fuel boilers, and retrofitting the existing building stock to improve its energy performance. Emissions from industry and transport both fall by around 20% over this period, and their pace of emissions reductions accelerates during the 2030s as the roll-out of low-emissions fuels and other emissions reduction options is scaled up. Nonetheless, there are a number of areas in transport and industry in which it is difficult to eliminate emissions entirely – such as aviation and heavy industry – and both sectors have a small level of residual emissions in 2050. These residual emissions are offset with applications of BECCS and DACCS.

[4] This budget is based on Table 2.2 of the IPCC SR1.5 (IPCC, 2018). It assumes 0.53 °C additional warming from the 2006-2015 period to give a remaining $CO_2$ budget from 2018 of 580 Gt $CO_2$. There were around 80 Gt $CO_2$ emissions emitted from 2018 to 2020.

[5] Non-$CO_2$ gases are converted to $CO_2$-equivalents based on the 100-year global warming potentials reported by the IPCC 5th Assessment Report (IPCC, 2014). One tonne of methane is equivalent to 30 tonnes of $CO_2$.

**Figure 2.3 ▷ Global net-$CO_2$ emissions by sector, and gross and net $CO_2$ emissions in the NZE**






***Emissions from electricity fall fastest, with declines in industry and transport accelerating in the 2030s. Around 1.9 Gt $CO_2$ are removed in 2050 via BECCS and DACCS.***

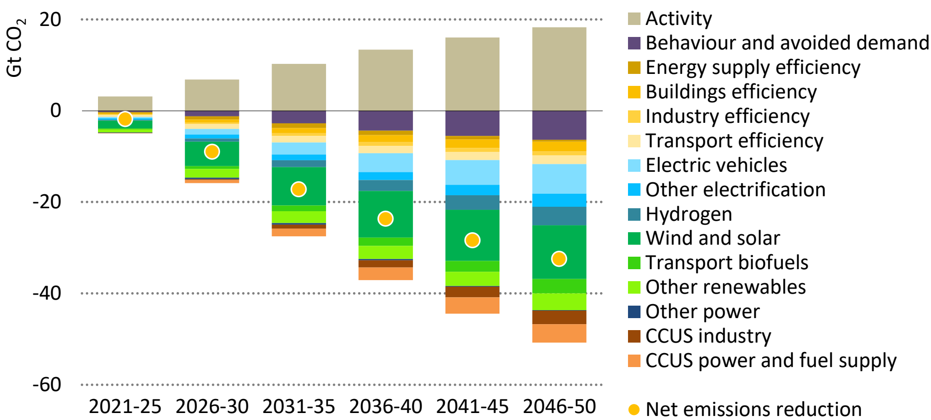
Notes: Other = agriculture, fuel production, transformation and related process emissions, and direct air capture. BECCS = bioenergy with carbon capture and storage; DACCS = direct air capture with carbon capture and storage. BECCS and DACCS includes $CO_2$ emissions captured and permanently stored.

The NZE includes a systematic preference for all new assets and infrastructure to be as sustainable and efficient as possible, and this accounts for 50% of total emissions reductions in 2050. Tackling emissions from existing infrastructure accounts for another 35% of reductions in 2050, while behavioural changes and avoided demand, including materials efficiency[6] gains and modal shifts in the transport sector, provide the remaining 15% of emissions reductions (see section 2.5.2). A wide range of technologies and measures are deployed in the NZE to reduce emissions from existing infrastructure such as power plants, industrial facilities, buildings, networks, equipment and appliances. The NZE is designed to minimise stranded capital where possible, i.e. cases where the initial investment is not recouped, but in many cases early retirements or lower utilisation lead to stranded value, i.e. a reduction in revenue.

The rapid deployment of more energy-efficient technologies, electrification of end-uses and swift growth of renewables all play a central part in reducing emissions across all sectors in the NZE (Figure 2.4). By 2050, nearly 90% of all electricity generation is from renewables, as is around 25% of non-electric energy use in industry and buildings. There is also a major role for emerging fuels and technologies, notably hydrogen and hydrogen-based fuels, bioenergy and CCUS, especially in sectors where emissions are often most challenging to reduce.

[6] Materials efficiency includes strategies that reduce material demand, or shift to the use of lower emissions materials or lower emissions production routes. Examples include lightweighting and recycling.

**Figure 2.4 ⊳ Average annual $CO_2$ reductions from 2020 in the NZE**






***Renewables and electrification make the largest contribution to emissions reductions, but a wide range of measures and technologies are needed to achieve net-zero emissions***

Notes: Activity = changes in energy service demand from economic and population growth. Behaviour = change in energy service demand from user decisions, e.g. changing heating temperatures. Avoided demand = change in energy service demand from technology developments, e.g. digitalisation.

## 2.4 Total energy supply and final energy consumption

### *2.4.1 Total energy supply[7]*

Total energy supply falls to 550 exajoules (EJ) in 2030, 7% lower than in 2020 (Figure 2.5). This occurs despite significant increases in the global population and economy because of a fall in energy intensity (the amount of energy used to generate a unit of GDP). Energy intensity falls by 4% on average each year between 2020 and 2030. This is achieved through a combination of electrification, a push to pursue all energy and materials efficiency opportunities, behavioural changes that reduce demand for energy services, and a major shift away from the traditional use of bioenergy.[8] This level of improvement in energy intensity is much greater than has been achieved in recent years: between 2010 and 2020, average annual energy intensity fell by less then 2% each year.

After 2030, continuing electrification of end-use sectors helps to reduce energy intensity further, but the emphasis on maximising energy efficiency improvements in the years up to

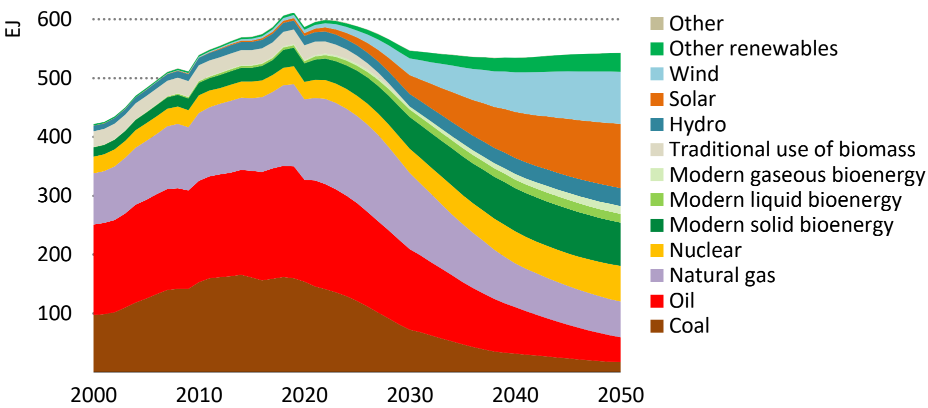
[7] The terms total primary energy supply (TPES) or total primary energy demand (TPED) have been renamed as total energy supply (TES) in accordance with the International Recommendations for Energy Statistics (IEA, 2020a).

[8] Modern forms of cooking require much less energy than the traditional use of biomass in inefficient stoves. For example, cooking with a liquefied petroleum gas stove uses around five-times less energy than the traditional use of biomass.

2030 limits the available opportunities in later years. At the same time, increasing production of new fuels, such as advanced biofuels, hydrogen and synthetic fuels, tends to push up energy use. As a result, the rate of decline in energy intensity between 2030 and 2050 slows to 2.7% per year. With continued economic and population growth, this means that total energy supply falls slightly between 2030 and 2040 but then remains broadly flat to 2050. Total energy supply in 2050 in the NZE is close to the level in 2010, despite a global population that is nearly 3 billion people higher and a global economy that is over three-times larger.



**Figure 2.5 ▷ Total energy supply in the NZE**





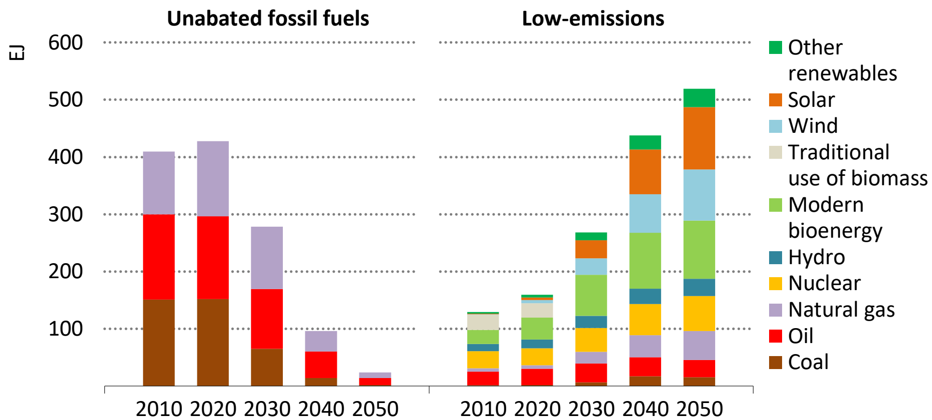

*Renewables and nuclear power displace most fossil fuel use in the NZE, and the share of fossil fuels falls from 80% in 2020 to just over 20% in 2050*

The energy mix in 2050 in the NZE is much more diverse than today. In 2020, oil provided 30% of total energy supply, while coal supplied 26% and natural gas 23%. In 2050, renewables provide two-thirds of energy use, split between bioenergy, wind, solar, hydroelectricity and geothermal (Figure 2.6). There is also a large increase in energy supply from nuclear power, which nearly doubles between 2020 and 2050.

There are large reductions in the use of fossil fuels in the NZE. As a share of total energy supply, they fall from 80% in 2020 to just over 20% in 2050. However, their use does not fall to zero in 2050: significant amounts are still used in producing non-energy goods, in plants with CCUS, and in sectors where emissions are especially hard to abate such as heavy industry and long-distance transport. All remaining emissions in 2050 are offset by negative emissions elsewhere (Box 2.2). Coal use falls from 5 250 million tonnes of coal equivalent (Mtce) in 2020 to 2 500 Mtce in 2030 and to less than 600 Mtce in 2050 – an average annual decline of 7% each year from 2020 to 2050. Oil demand dropped below 90 million barrels per day (mb/d) in 2020 and demand does not return to its 2019 peak: it falls to 72 mb/d in 2030 and 24 mb/d in 2050 – an annual average decline of more than 4% from 2020 to 2050. Natural gas use dropped to 3 900 billion cubic metres (bcm) in 2020, but exceeds its previous

2019 peak in the mid-2020s before starting to decline as it is phased out in the electricity sector. Natural gas use declines to 3 700 bcm in 2030 and 1 750 bcm in 2050 – an annual average decline of just under 3% from 2020 to 2050.

**Figure 2.6 ▷ Total energy supply of unabated fossil fuels and low-emissions energy sources in the NZE**






*Some fossil fuels are still used in 2050 in the production of non-energy goods, in plants equipped with CCUS, and in sectors where emissions are hard to abate*

Note: Low-emissions includes the use of fossil fuels with CCUS and in non-energy uses.

**Box 2.2 ▷ Why does fossil fuel use not fall to zero in 2050 in the NZE?**

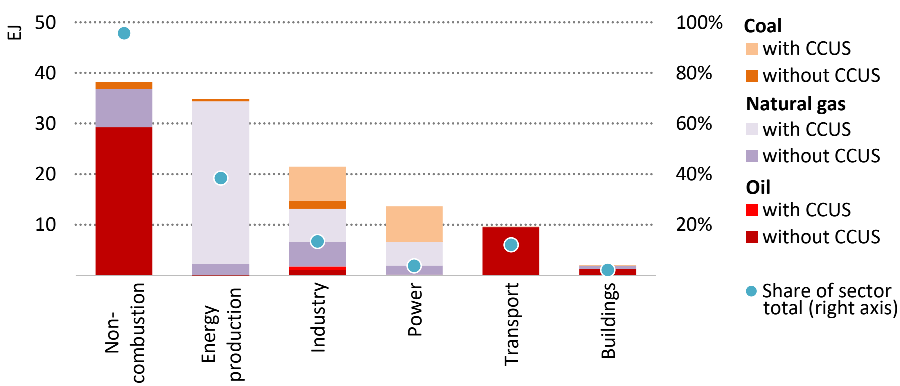
In total, around 120 EJ of fossil fuels is consumed in 2050 in the NZE relative to 460 EJ in 2020. Three main reasons underlie why fossil fuel use does not fall to zero in 2050, even though the energy sector emits no $CO_2$ on a net basis:

- **Use for non-energy purposes**. More than 30% of total fossil fuel use in 2050 in the NZE – including 70% of oil use – is in applications where the fuels are not combusted and so do not result in any direct $CO_2$ emissions (Figure 2.7). Examples include use as chemical feedstocks and in lubricants, paraffin waxes and asphalt. There are major efforts to limit fossil fuel use in these applications in the NZE, for instance global plastic collection rates for recycling rising from 15% in 2020 to 55% in 2050, but fossil fuel use in non-energy applications still rises slightly to 2050.
- **Use with CCUS.** Around half of fossil fuel use in 2050 is in plants equipped with CCUS (around 3.5 Gt $CO_2$ emissions are captured from fossil fuels in 2050). Around 925 bcm of natural gas is converted to hydrogen with CCUS. In addition, around 470 Mtce of coal and 225 bcm of natural gas are used with CCUS in the electricity and industrial sectors, mainly to extend the operations of young facilities and reduce stranded assets.

- **Use in sectors where technology options are scarce.** The remaining 20% of fossil fuel use in 2050 in the NZE is in sectors where the complete elimination of emissions is particularly challenging. Mostly this is oil, as it continues to fuel aviation in particular. A small amount of unabated coal and natural gas are used in industry and in the production of energy. The unabated use of fossil fuel results in around 1.7 Gt $CO_2$ emissions in 2050, which are fully offset by BECCS and DACCS.



**Figure 2.7 ▷ Fossil fuel use and share by sector in 2050 in the NZE**



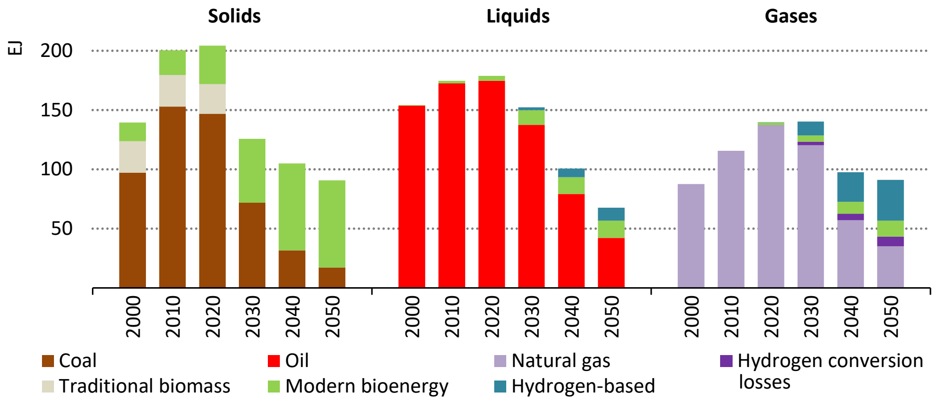



*More than 30% of fossil fuel use in 2050 is not combusted and so does not result in direct $CO_2$ emissions, around 50% is paired with CCUS*

Notes: Non-combustion includes use for non-emitting, non-energy purposes such as petrochemical feedstocks, lubricants and asphalt. Energy production includes fuel use for direct air capture.

Solid, liquid and gaseous fuels continue to play an important role in the NZE, which sees large increases in bioenergy and hydrogen (Figure 2.8). Around 40% of bioenergy used today is for the traditional use of biomass in cooking: this is rapidly phased out in the NZE. Modern forms of solid biomass, which can be used to reduce emissions in both the electricity and industry sectors, rise from 32 EJ in 2020 to 55 EJ in 2030 and 75 EJ in 2050, offsetting a large portion of a drop in coal demand. The use of low-emissions liquid fuels, such as ammonia, synthetic fuels and liquid biofuels, increases from 3.5 EJ (1.6 million barrels of oil equivalent per day [mboe/d]) in 2020 to just above 25 EJ (12.5 mboe/d) in 2050. The supply of low-emissions gases, such as hydrogen, synthetic methane, biogas and biomethane rises from 2 EJ in 2020 to 17 EJ in 2030 and 50 EJ in 2050. The increase in gaseous hydrogen production between 2020 and 2030 in the NZE is twice as fast as the fastest ten-year increase in shale gas production in the United States.

**Figure 2.8 ⊳** **Solid, liquid and gaseous fuels in the NZE**






***Increases in low-emissions solids, liquids and gases from bioenergy, hydrogen and hydrogen-based fuels offset some of the declines in coal, oil and natural gas***

Notes: Hydrogen conversion losses = consumption of natural gas when producing low-carbon merchant hydrogen using steam methane reforming. Hydrogen-based includes hydrogen, ammonia and synthetic fuels.

### *2.4.2 Total final consumption*

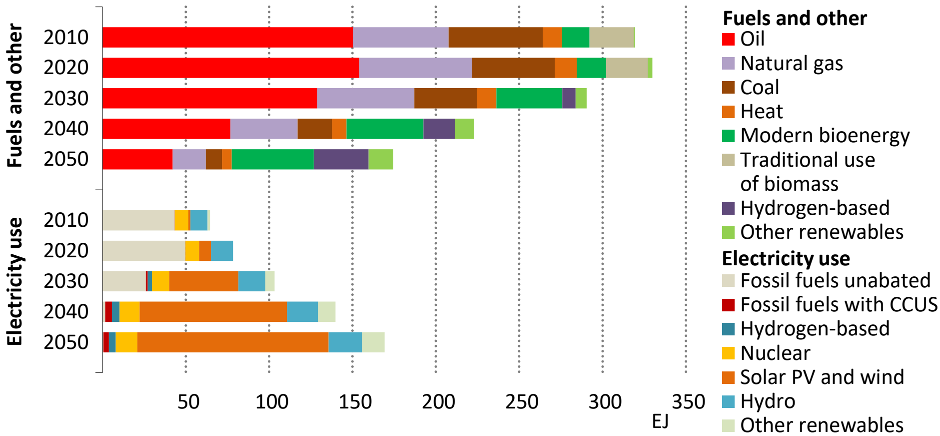
Total final consumption worldwide rebounds marginally following its 5% drop in 2020, but it never returns to 2019 levels in the NZE (435 EJ). It falls by just under 1% each year on average between 2025 and 2050 to 340 EJ. Energy efficiency measures and electrification are the two main contributing factors, with behavioural changes and materials efficiency also playing a role. Without these improvements, final energy consumption in 2050 would be around 640 EJ, around 90% higher than the level in the NZE. Final consumption of electricity increases by 25% from 2020 to 2030, and by 2050 it is more than double the level in 2020. The increase in electricity consumption from end-uses sectors and from hydrogen production means that overall annual electricity demand growth is equivalent to adding an electricity market the size of India every year in the NZE. The share of electricity in global final energy consumption jumps from 20% in 2020 to 26% in 2030 and to around 50% in 2050 (Figure 2.9). The direct use of renewables in buildings and industry together with low-emissions fuels such as bioenergy and hydrogen-based fuels provide a further 28% of final energy consumption in 2050; fossil fuels comprise the remainder, most of which are used in non-emitting processes or in facilities equipped with CCUS.

In industry, most of the global emissions reductions in the NZE during the period to 2030 are delivered through energy and materials efficiency improvements, electrification of heat, and fuel switching to solar thermal, geothermal and bioenergy. Thereafter, CCUS and hydrogen play an increasingly important role in reducing $CO_2$ emissions, especially in heavy industries such as steel, cement and chemicals. Electricity consumption in industry more than doubles between 2020 and 2050, providing 45% of total industrial energy needs in 2050 (Figure 2.10).

The demand for merchant hydrogen in industry increases from less than 1 Mt today to around 40 Mt in 2050. A further 10% of industrial energy demand in 2050 is met by fossil fuels used in plants equipped with CCUS.

**Figure 2.9 ▷ Global total final consumption by fuel in the NZE**







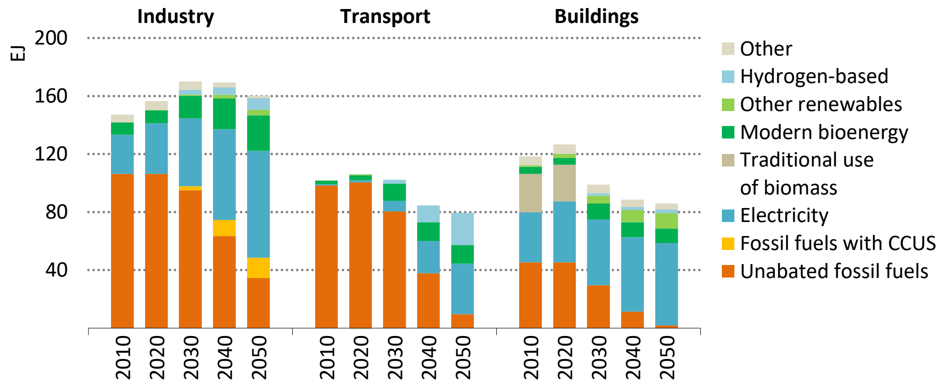

*The share of electricity in final energy use jumps from 20% in 2020 to 50% in 2050*

Note: Hydrogen-based includes hydrogen, ammonia and synthetic fuels.

In transport, there is a rapid transition away from oil worldwide, which provided more than 90% of fuel use in 2020. In road transport, electricity comes to dominate the sector, providing more than 60% of energy use in 2050, while hydrogen and hydrogen-based fuels play a smaller role, mainly in fuelling long-haul heavy-duty trucks. In shipping, energy efficiency improvements significantly reduce energy needs (especially up to 2030), while advanced biofuels and hydrogen-based fuels, such as ammonia, increasingly displace oil. In aviation, the use of synthetic liquids and advanced biofuels grows rapidly, and their share of total energy demand rises from almost zero today to almost 80% in 2050. Overall, electricity becomes the dominant fuel in the transport sector globally by the early 2040s, and it accounts for around 45% of energy consumption in the sector in 2050 (compared with 1.5% in 2020). Hydrogen and hydrogen-based fuels account for nearly 30% of consumption (almost zero in 2020) and bioenergy for a further 15% (around 4% in 2020).

In buildings, the electrification of end-uses including heating leads to demand for electricity increasing by around 35% between 2020 and 2050: it becomes the dominant fuel, reaching 16 000 terawatt-hours (TWh) in 2050, and accounting for two-thirds of total buildings sector energy consumption. By 2050, two-thirds of residential buildings in advanced economies and around 40% of residential buildings in emerging market and developing economies are fitted with a heat pump. Onsite renewables-based energy systems such as solar water heaters and biomass boilers provide a further quarter of final energy use in the buildings sector in 2050 (up from 6% in 2020). Low-emissions district heating and hydrogen provide only 7% of energy use, but play a significant role in some regions.

**Figure 2.10 ▷ Global final energy consumption by sector and fuel in the NZE**






*There is a wholesale shift away from unabated fossil fuel use to electricity, renewables, hydrogen and hydrogen-based fuels, modern bioenergy and CCUS in end-use sectors*

Note: Hydrogen-based includes hydrogen, ammonia and synthetic fuels.

Buildings energy consumption falls by 25% between 2020 and 2030, largely as a result of a major push to improve efficiency and to phase out the traditional use of solid biomass for cooking: it is replaced by liquefied petroleum gas (LPG), biogas, electric cookers and improved bioenergy stoves. Universal access to electricity is achieved by 2030, and this adds less than 1% to global electricity demand in 2030. Energy consumption in the buildings sector contracts by around 15% between 2030 and 2050 given continued efficiency improvements and electrification. By 2050, energy use in buildings is 35% lower than in 2020. Energy efficiency measures – including improving building envelopes and ensuring that all new appliances brought to market are the most efficient models available – play a key role in limiting the rise in electricity demand in the NZE. Without these measures, electricity demand in buildings would be around 10 000 TWh higher in 2050, or around 70% higher than the level in the NZE.

**S P O T L I G H T**

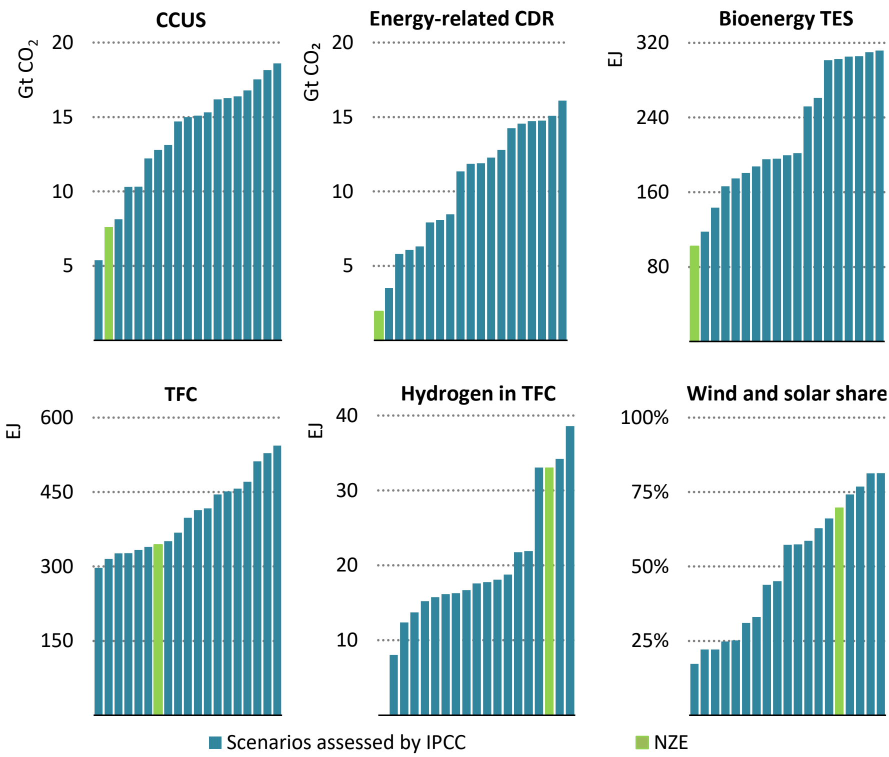
## How does the NZE compare with similar 1.5 °C scenarios assessed by the IPCC?

The IPCC SR1.5 includes 90 individual scenarios that have at least a 50% chance of limiting warming in 2100 to 1.5 °C (IPCC, 2018).[9] Only 18 of these scenarios have net-zero $CO_2$ energy sector and industrial process emissions in 2050. In other words, only one-in-five of the 1.5 °C scenarios assessed by the IPCC have the same level of emissions reduction

[9] Includes 53 scenarios with no or limited temperature overshoot and 37 scenarios with a higher temperature overshoot.

ambition for the energy and industrial process sectors to 2050 as the NZE.[10] Some comparisons between these 18 scenarios and the NZE in 2050 (Figure 2.11):

**Figure 2.11 ▷ Comparison of selected indicators of the IPCC scenarios and the NZE in 2050**






*The NZE has the lowest level of energy-related CDR and bioenergy of any scenario that achieves net-zero energy sector and industrial process $CO_2$ emissions in 2050*

Notes: CCUS = carbon capture, utilisation and storage; CDR = carbon direct removal; TES = total energy supply; TFC = total final consumption. Energy-related CDR includes $CO_2$ captured through bioenergy with CCUS and direct air capture with CCUS and put into permanent storage. Wind and solar share are given as a percentage of total electricity generation. Only 17 of the 18 scenarios assessed by the IPCC report hydrogen use in TFC.

- **Use of CCUS.** The scenarios assessed by the IPCC have a median of around 15 Gt $CO_2$ captured using CCUS in 2050, more than double the level in the NZE.
- **Use of CDR.** $CO_2$ emissions captured and stored from BECCS and DACCS in the IPCC scenarios range from 3.5-16 Gt $CO_2$ in 2050, compared with 1.9 Gt $CO_2$ in the NZE.

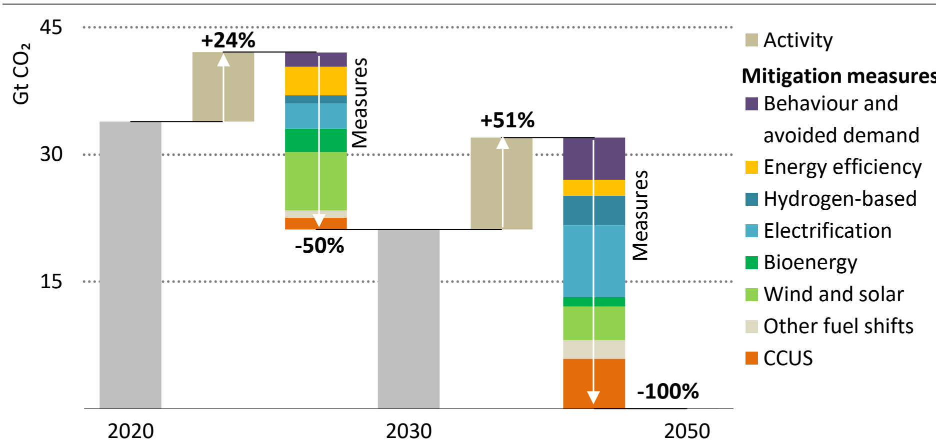
[10] The low-energy demand scenario has around 4.5 Gt $CO_2$ energy sector and industrial process emissions in 2050 and is not included in this comparison.

- **Bioenergy.** The IPCC scenarios use a median of 200 EJ of primary bioenergy in 2050 (compared with 63 EJ today) and a number use more than 300 EJ. The NZE uses 100 EJ of primary bioenergy in 2050.
- **Energy efficiency.** Total final consumption in the IPCC scenarios range from 300-550 EJ in 2050 (compared with around 410 EJ in 2020). The NZE has final energy consumption of 340 EJ in 2050.
- **Hydrogen.** The IPCC scenarios have a median of 18 EJ hydrogen in total final consumption in 2050, compared with 33 EJ in the NZE.[11]
- **Electricity generation.** The shares of wind and solar in total electricity generation in 2050 in the IPCC scenarios range from around 15-80% with a median value of 50%. In the NZE, wind and solar provide 70% of total generation in 2050.

## 2.5 Key pillars of decarbonisation

Achieving the rapid reduction in $CO_2$ emissions over the next 30 years in the NZE requires a broad range of policy approaches and technologies (Figure 2.12). The key pillars of decarbonisation of the global energy system are energy efficiency, behavioural changes, electrification, renewables, hydrogen and hydrogen-based fuels, bioenergy and CCUS.

**Figure 2.12 ▷ Emissions reductions by mitigation measure in the NZE, 2020-2050**






*Solar, wind and energy efficiency deliver around half of emissions reductions to 2030 in the NZE, while electrification, CCUS and hydrogen ramp up thereafter*

Notes: Activity = energy service demand changes from economic and population growth. Behaviour = energy service demand changes from user decisions, e.g. changing heating temperatures. Avoided demand = energy service demand changes from technology developments, e.g. digitalisation. Other fuel shifts = switching from coal and oil to natural gas, nuclear, hydropower, geothermal, concentrating solar power or marine.

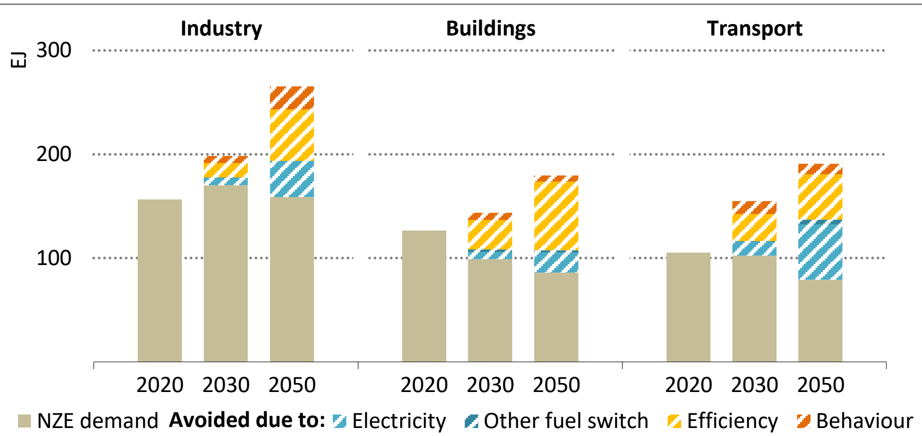
[11] The NZE value for hydrogen includes the total energy content of hydrogen and hydrogen-based fuels consumed in final energy consumption.

### 2.5.1 Energy efficiency

Minimising energy demand growth through improvements in energy efficiency makes a critical contribution in the NZE. Many efficiency measures in industry, buildings, appliances and transport can be put into effect and scaled up very quickly. As a result, energy efficiency measures are front-loaded in the NZE, and they play their largest role in curbing energy demand and emissions in the period to 2030. Although energy efficiency improves further after 2030, its contribution to overall emissions reductions falls as other mitigation measures play an expanding role. Without the energy efficiency, behavioural changes and electrification measures deployed in the NZE, final energy consumption would be around 300 EJ higher in 2050, almost 90% above the 2050 level in the NZE (Figure 2.13). Efficiency improvements also help reduce the vulnerability of businesses and consumers to potential disruptions to electricity supplies.



**Figure 2.13 ▷ Total final consumption and demand avoided by mitigation measure in the NZE**






*Energy efficiency plays a key role in reducing energy consumption across end-use sectors*

Notes: Other fuel switch includes switching to hydrogen-related fuels, bioenergy, solar thermal, geothermal, or district heat.

In the buildings sector, many efficiency measures yield financial savings as well as reducing energy use and emissions. In the NZE, there are immediate and rapid improvements in energy efficiency in buildings, mainly from large-scale retrofit programmes. Around 2.5% of existing residential buildings in advanced economies are retrofitted each year to 2050 in the NZE to comply with zero-carbon-ready building standards[12] (compared with a current retrofit rate of less than 1%). In emerging market and developing economies, building replacement

[12] A zero-carbon-ready building is highly energy efficient and uses either renewable energy directly or from an energy supply that will be fully decarbonised by 2050 in the NZE (such as electricity or district heat). A zero-carbon-ready building will become a zero-carbon building by 2050, without further changes to the building or its equipment (see Chapter 3).

rates are higher and the annual rate of retrofits is around 2% through to 2050. By 2050, the vast majority of existing residential buildings are retrofitted to be zero-carbon buildings. Energy-related building codes are introduced in all regions by 2030 to ensure that virtually all new buildings constructed are zero-carbon-ready. Minimum energy performance standards and replacement schemes for low-efficiency appliances are introduced or strengthened in the 2020s in all countries. By the mid-2030s, nearly all household appliances sold worldwide are as efficient as the most efficient models available today.

In the transport sector, stringent fuel-economy standards and ensuring no new passenger cars running on internal combustion engines (ICEs) are sold globally from 2035 result in a rapid shift in vehicle sales toward much more efficient electric vehicles (EVs).[13] The impact on efficiency is seen in the 2030s, as the composition of the vehicle stock changes: electric cars make up 20% of all cars on the road in 2030 and 60% in 2040 (compared with 1% today). Continuous improvements in the fuel economy of heavy road vehicles take place through to 2050 as they switch to electricity or fuel cells, while efficiency in shipping and aviation improves as more efficient planes and ships replace existing stock.

In the industry sector, most manufacturing stock is already quite efficient, but there are still opportunities for energy efficiency improvements. Energy management systems, best-in-class industrial equipment such as electric motors, variable speed drives, heaters and grinders are installed, and process integration options such as waste heat recovery are exploited to their maximum economic potentials in the period to 2030 in the NZE. After 2030, the rate of efficiency improvement slows because many of the technologies needed to reduce emissions in industry in the NZE require more energy than their equivalent conventional technologies. The use of CCUS, for example, increases energy consumption to operate the capture equipment, and producing electrolytic hydrogen on-site requires additional energy than that needed for the main manufacturing process.

**Table 2.3 ▷ Key global milestones for energy efficiency in the NZE**

| Sector | 2020 | 2030 | 2050 |
|---|---|---|---|
| **Total energy supply** | *2010-20* | *2020-30* | *2030-50* |
| Annual energy intensity improvement (MJ per USD GDP) | -1.6% | -4.2% | -2.7% |
| **Industry** | | | |
| Energy intensity of direct reduced iron from natural gas (GJ per tonne) | 12 | 11 | 10 |
| Process energy intensity of primary chemicals (GJ per tonne) | 17 | 16 | 15 |
| **Transport** | | | |
| Average fuel consumption of ICE heavy trucks fleet (index 2020=100) | 100 | 81 | 63 |
| **Buildings** | | | |
| Share of zero-carbon-ready buildings in total stock | <1% | 25% | >85% |
| New buildings: heating & cooling energy consumption (index 2020=100) | 100 | 50 | 20 |
| Appliances: unit energy consumption (index 2020=100) | 100 | 75 | 60 |

Notes: ICE = internal combustion engine; zero-carbon-ready buildings = see description in section 3.7.

[13] In 2020, the average battery electric car required around 30% of the energy of the average ICE car to provide the same level of activity.

### 2.5.2 Behavioural change

The wholescale transformation of the energy sector demonstrated in the NZE cannot be achieved without the active and willing participation of citizens. It is ultimately people who drive demand for energy-related goods and services, and societal norms and personal choices will play a pivotal role in steering the energy system onto a sustainable path. Just under 40% of emissions reductions in the NZE result from the adoption of low-carbon technologies that require massive policy support and investment but little direct engagement from citizens or consumers, e.g. technologies in electricity generation or steel production. A further 55% of emissions reductions require a mixture of the deployment of low-carbon technologies and the active involvement or engagement of citizens and consumers, e.g. installing a solar water heater or buying an EV. A final 8% of emissions reductions stem from behavioural changes and materials efficiency gains that reduce energy demand, e.g. flying less for business purposes (Figure 2.14). Consumer attitudes can also impact investment decisions by businesses concerned about public image.



In the NZE, behavioural change refers to changes in ongoing or repeated behaviour on the part of consumers which impact energy service demand or the energy intensity of an energy-related activity.[14] Reductions in energy service demand in the NZE also come from advances in technology, but these are not counted as behavioural changes. For example, increased digitalisation and a growing market share of smart appliances, such as smart thermostats or space-differentiated thermal controls reduce the necessity for people to play an active role in energy saving in homes over time in the NZE.

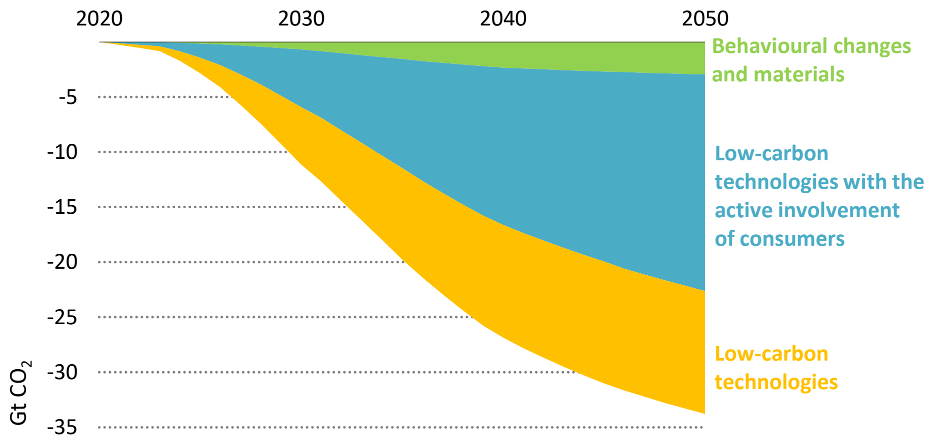
There are three main types of behavioural change included in the NZE. A wide range of government interventions could be used to motivate these changes (see section 2.7.1).

- **Reducing excessive or wasteful energy use.** This includes reducing energy use in buildings and on roads, e.g. by reducing indoor temperature settings, adopting energy saving practices in homes and limiting driving speeds on motorways to 100 kilometres per hour.
- **Transport mode switching.** This includes a shift to cycling, walking, ridesharing or taking buses for trips in cities that would otherwise be made by car, as well as replacing regional air travel by high-speed rail in regions where this is feasible. Many of these types of behavioural changes would represent a break in familiar or habitual ways of life and as such would require a degree of public acceptance and even enthusiasm. Many would also require new infrastructure, such as cycle lanes and high-speed rail networks, clear policy support and high quality urban planning.
- **Materials efficiency gains.** This includes reduced demand for materials, e.g. higher rates of recycling, and improved design and construction of buildings and vehicles. The scope for gains to some extent reflects societal preferences. For instance, in some places there

[14] This means, for example, that purchasing an electric heat pump instead of a gas boiler is not considered as a behavioural change, as it is both an infrequent event and does not necessarily impact energy service demand.

has been a shift away from the use of single-use plastics in recent years, a trend that accelerates in the NZE. Gains in materials efficiency depend on a mixture of technical innovation in manufacturing and buildings construction, standards and regulations to support best-practice and ensure universal adoption of these innovations, and increased recycling in society at large.

**Figure 2.14 ▷ Role of technology and behavioural change in emissions reductions in the NZE**






*Around 8% of emissions reductions stem from behavioural changes and materials efficiency*

Notes: Low-carbon technologies include low-carbon electricity generation, low-carbon gases in end-uses and biofuels. Low-carbon technologies with the active involvement of citizens includes fuel switching, electrification and efficiency gains in end-uses. Behavioural changes and materials efficiency includes transport mode switching, curbing excessive or wasteful energy use, and materials efficiency measures.

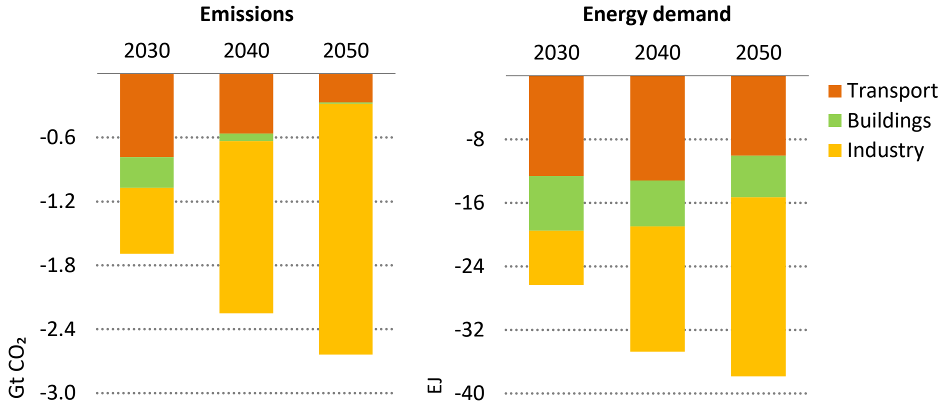
Three-quarters of the emissions reductions from behavioural changes in the NZE are achieved through targeted government policies supported by infrastructure development, e.g. a shift to rail travel supported by high-speed railways. The remainder come from adopting voluntary changes in energy saving habits, mainly in homes. Even in this case, public awareness campaigns can help shape day-to-day choices about how consumers use energy. (Details of what governments can do to help bring about behavioural changes are discussed in Chapter 4).

Behavioural changes reduce energy-related activity by around 10-15% on average over the period to 2050 in the NZE, reducing overall global energy demand by over 37 EJ in 2050 (Figure 2.15). In 2030, around 1.7 Gt $CO_2$ emissions are avoided, 45% of which come from transport, notably through measures to phase out car use in cities and to improve fuel economy. For example, reducing speed limits on motorways to 100 km/h reduces emissions from road transport by 3% or 140 Mt $CO_2$ in 2030. A shift away from single occupancy car use towards ridesharing or cycling and walking in large cities saves a further 185 Mt $CO_2$. Around

40% of emissions savings in 2030 occur in industry because of improvements in materials efficiency and increased recycling, with the biggest impacts coming from reducing waste and improving the design and construction of buildings. The remainder of emissions savings in 2030 are from behavioural changes in buildings, for example adjusting space heating and cooling temperatures.



**Figure 2.15 ▷ $CO_2$ emissions and energy demand reductions from behavioural changes and materials efficiency in the NZE**






*By 2030, behaviour changes and materials efficiency gains reduce emissions by 1.7 Gt $CO_2$, and energy demand by 27 EJ; reductions increase further through to 2050*

In 2050, the growing importance of low-emissions electricity and fuels in transport and buildings means that 90% of emissions reductions are in industry, predominantly in those sectors where it is most challenging to tackle emissions directly. Material efficiency alone reduces demand for cement and steel by 20%, saving around 1 700 Mt $CO_2$. Of the emissions reductions in transport in 2050, nearly 80% come from measures to reduce passenger aviation demand, with the remainder from road transport.

The scope, scale and speed of adoption of the behavioural changes in the NZE varies widely between regions, depending on several factors including the ability of existing infrastructure to support such changes and differences in geography, climate, urbanisation, social norms and cultural values. For example, regions with high levels of private car use today see a more gradual shift than others towards public transport, shared car use, walking and cycling; air travel is assumed to switch to high-speed rail on existing or potential routes only where trains could offer a similar journey time; and the potential for moderating air conditioning in buildings and vehicles takes into account seasonal effects and humidity. Wealthier regions generally have higher levels of per capita energy-related activity, and behavioural changes play an especially important role in these regions in reducing excessive or wasteful energy consumption.

Most of the behavioural changes in the NZE would have some effect on nearly everyone's daily life, but none represents a radical departure from energy-reducing practices already experienced in many parts of the world today. For example, in Japan an awareness campaign has successfully reduced cooling demand in line with the reductions assumed in many regions in the NZE by 2040; legislation to limit urban car use has been introduced in many large cities; and speed limit reductions to around 100 km/h (the level adopted globally in the NZE by 2030) have been tested in the United Kingdom and Spain to reduce air pollution and improve safety.

**Table 2.4 ▷ Key global milestones for behavioural change in the NZE**

| Sector | Year | Milestone |
|---|---|---|
| **Industry** | 2020 | • Global average plastics collection rate = 17%. |
| | 2030 | • Global average plastics collection rate = 27%.<br>• Lightweighting reduces the weight of an average passenger car by 10%. |
| | 2050 | • Global average plastics collection rate = 54%.<br>• Efficiency of fertiliser use improved by 10%. |
| **Transport** | 2030 | • Eco-driving and motorway speed limits of 100 km/h introduced.<br>• Use of ICE cars phased out in large cities. |
| | 2050 | • Regional flights are shifted to high-speed rail where feasible.<br>• Business and long-haul leisure air travel does not exceed 2019 levels. |
| **Buildings** | 2030 | • Space heating temperatures moderated to 19-20 °C on average.<br>• Space cooling temperatures moderated to 24-25°C on average.<br>• Excessive hot-water temperatures reduced. |
| | 2050 | • Use of energy-intensive materials per unit of floor area decreases by 30%.<br>• Building lifetime extended by 20% on average. |

Note: Eco-driving involves pre-emptive stopping and starting; ICE = internal combustion engine.

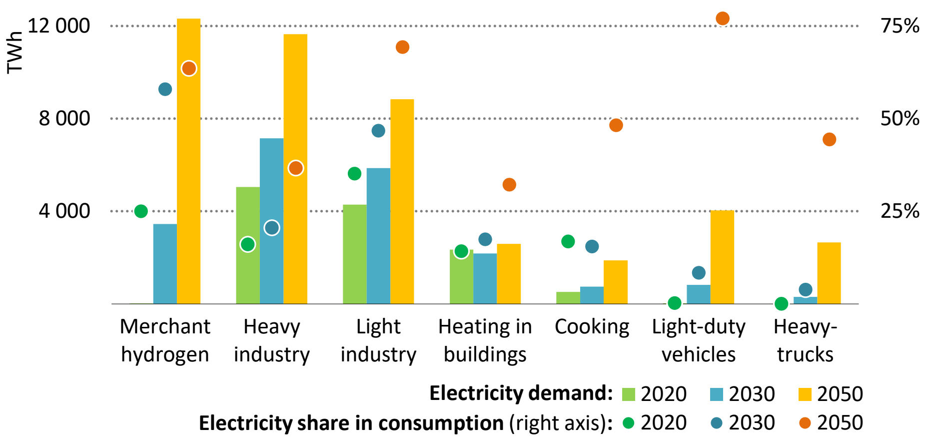
## *2.5.3 Electrification*

The direct use of low-emissions electricity in place of fossil fuels is one of the most important drivers of emissions reductions in the NZE, accounting for around 20% of the total reduction achieved by 2050. Global electricity demand more than doubles between 2020 and 2050, with the largest absolute rise in electricity use in end-use sectors taking place in industry, which registers an increase of more than 11 000 TWh between 2020 and 2050. Much of this is due to the increasing use of electricity for low- and medium-temperature heat and in secondary scrap-based steel production (Figure 2.16).

In transport, the share of electricity increases from less than 2% in 2020 to around 45% in 2050 in the NZE. More than 60% of total passenger car sales globally are EVs by 2030 (compared with 5% of sales in 2020), and the car fleet is almost fully electrified worldwide by 2050 (the remainder are hydrogen-powered cars). The increase in electric passenger car sales globally over the next ten years is over twenty-times higher than the increase in ICE car sales over the last decade. Electrification is slower for trucks because it depends on higher density batteries than those currently available on the market, especially for long-haul trucking, and on new high-power charging infrastructure: electric trucks nevertheless account for around 25% of total heavy truck sales globally by 2030 and around two-thirds in 2050. The electrification of shipping and aviation is much more limited and only gets under way after large improvements in battery energy density (see section 3.6) (Figure 2.17). In the NZE, demand for batteries for transport reaches around 14 TWh in 2050, 90-times more than in 2020. Growth in battery demand translates into an increasing demand for critical minerals. For example, demand for lithium for use in batteries grows 30-fold to 2030 and is more than 100-times higher in 2050 than in 2020 (IEA, 2021).



**Figure 2.16 ▷ Global electricity demand and share of electricity in energy consumption in selected applications in the NZE**





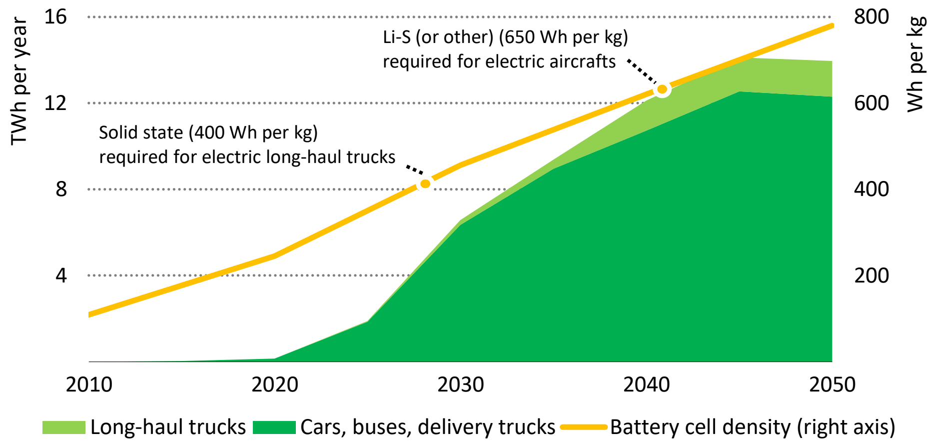

*Global electricity demand more than doubles in the period to 2050, with the largest rises to produce hydrogen and in industry*

Notes: Merchant hydrogen = hydrogen produced by one company to sell to others. Light-duty vehicles = passenger cars and vans. Heavy trucks = medium-freight trucks and heavy-freight trucks.

In buildings, electricity demand is moderated in the NZE by a huge push to improve the efficiency of appliances, cooling, lighting and building envelopes. But a large increase in activity, along with the widespread electrification of heating through the use of heat pumps, means that electricity demand in buildings still rises steadily over the period reaching 66% of total energy consumption in buildings in 2050.

Alongside the growth in the direct use of electricity in end-use sectors, there is also a huge increase in the use of electricity for hydrogen production. Merchant hydrogen produced using electrolysis requires around 12 000 TWh in 2050 in the NZE, which is greater than current total annual electricity demand of China and the United States combined.

**Figure 2.17 ▹ Battery demand growth in transport and battery energy density in the NZE**






*Nearly 20 battery giga-factories open every year to 2030 to satisfy battery demand for electric cars in the NZE; higher density batteries are needed to electrify long-haul trucks*

Notes: Li-S = lithium-sulphur battery; Wh per kg = Watt hours per kilogramme.

The acceleration of electricity demand growth from 2% per year over the past decade to 3% per year through to 2050, together with a significantly increased share of variable renewable electricity generation, means that annual electricity sector investment in the NZE is three-times higher on average than in recent years. The rise in electricity demand also calls for extensive efforts to ensure the stability and flexibility of electricity supply through demand-side management, the operation of flexible low-emissions sources of generation including hydropower and bioenergy, and battery storage.

**Table 2.5 ▹ Key global milestones for electrification in the NZE**

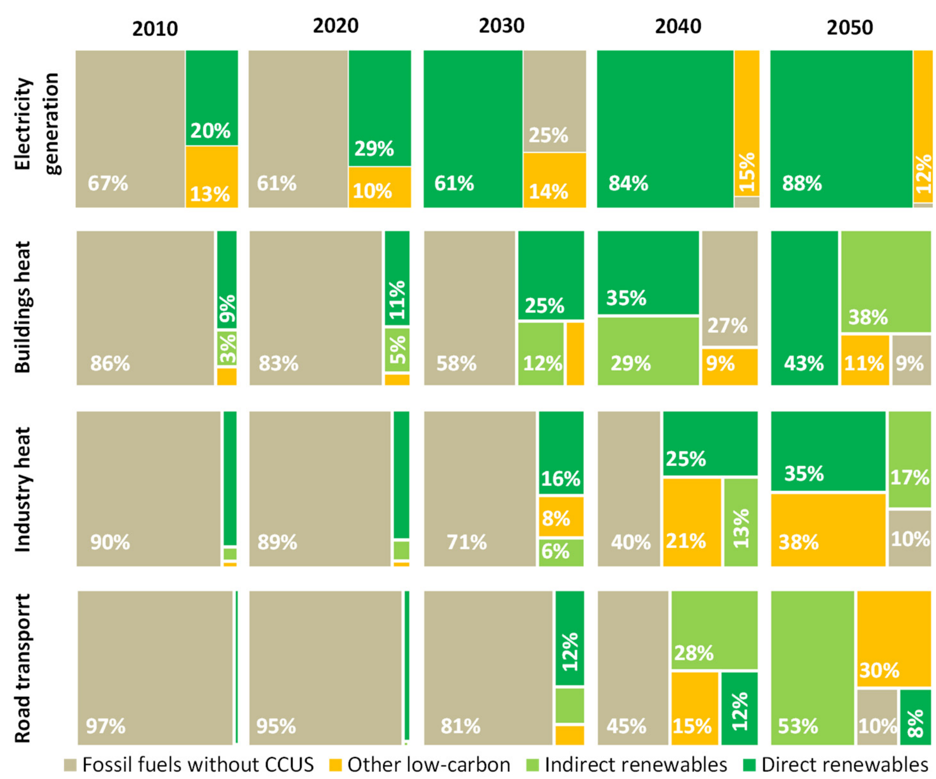
| Sector | | 2020 | 2030 | 2050 |
|---|---|---|---|---|
| **Share of electricity in total final consumption** | | 20% | 26% | 49% |
| **Industry** | | | | |
| Share of steel production using electric arc furnace | | 24% | 37% | 53% |
| Electricity share of light industry | | 43% | 53% | 76% |
| **Transport** | | | | |
| Share of electric vehicles in stock: | cars | 1% | 20% | 86% |
| | two/three-wheelers | 26% | 54% | 100% |
| | bus | 2% | 23% | 79% |
| | vans | 0% | 22% | 84% |
| | heavy trucks | 0% | 8% | 59% |
| Annual battery demand for electric vehicles (TWh) | | 0.16 | 6.6 | 14 |
| **Buildings** | | | | |
| Heat pumps installed (millions) | | 180 | 600 | 1 800 |
| Share of heat pumps in energy demand for heating | | 7% | 20% | 55% |
| Million people without access to electricity | | 786 | 0 | 0 |

### 2.5.4 Renewables

At a global level, renewable energy technologies are the key to reducing emissions from electricity supply. Hydropower has been a leading low-emission source for many decades, but it is mainly the expansion of wind and solar that triples renewables generation by 2030 and increases it more than eightfold by 2050 in the NZE. The share of renewables in total electricity generation globally increases from 29% in 2020 to over 60% in 2030 and to nearly 90% in 2050 (Figure 2.18). To achieve this, annual capacity additions of wind and solar between 2020 and 2050 are five-times higher than the average over the last three years. Dispatchable renewables are critical to maintain electricity security, together with other low-carbon generation, energy storage and robust electricity networks. In the NZE, the main dispatchable renewables globally in 2050 are hydropower (12% of generation), bioenergy (5%), concentrating solar power (2%) and geothermal (1%).



**Figure 2.18 ▻ Fuel shares in total energy use in selected applications in the NZE**






*Renewables are central to emissions reductions in electricity, and they make major contributions to cut emissions in buildings, industry and transport both directly and indirectly*

Notes: Indirect renewables = use of electricity and district heat produced by renewables. Other low-carbon = nuclear power, facilities equipped with CCUS, and low-carbon hydrogen and hydrogen-based fuels.

Renewables also play an important role in reducing emissions in buildings, industry and transport. Renewables can be used either indirectly, via the consumption of electricity or district heating that was produced by renewables, or directly, mainly to produce heat.

In transport, renewables play an important indirect role in reducing emissions by generating the electricity to power electric vehicles. They also contribute to direct emissions reductions through the use of liquid biofuels and biomethane.

In buildings, renewable energy is mainly used for water and space heating. The direct use of renewable energy rises from about 10% of heating demand globally in 2020 to 40% in 2050, about three-quarters of the increase is in the form of solar thermal and geothermal. Deep retrofits and energy-related building codes are paired with renewables whenever possible: almost all buildings with available roof space and sufficient solar insolation are equipped with solar thermal water heaters by 2050, as they are more productive per square metre than solar PV and as heat storage in water tanks is generally more cost-effective than storage of electricity. Rooftop solar PV, which produces renewable electricity onsite, is currently installed on around 25 million rooftops worldwide; the number increases to 100 million rooftops by 2030 and 240 million by 2050. A further 15% of heating in buildings in 2030 comes indirectly from renewables in the form of electricity, and this rises to almost 40% in 2050.

In industry, bioenergy is the most important direct renewable energy source for low- and medium-temperature needs in the NZE. Solar thermal and geothermal also produce low temperature heat for use in non-energy-intensive industries and ancillary or downstream processes in heavy industries. Bioenergy, solar thermal and geothermal together provide about 15% of industry heat demand in 2030, roughly double their share in 2010, and this increases to 40% in 2050. The indirect use of renewable energy via electricity adds 15% to the contribution that renewables make to total industry energy use in 2050.

**Table 2.6 ▷ Key deployment milestones for renewables**

| Sector | | 2020 | 2030 | 2050 |
|---|---|---|---|---|
| **Electricity sector** | | | | |
| Renewables share in generation | | 29% | 61% | 88% |
| Annual capacity additions (GW): | Total solar PV | 134 | 630 | 630 |
| | Total wind | 114 | 390 | 350 |
| | *– of which: Offshore wind* | 5 | 80 | 70 |
| | Dispatchable renewables | 31 | 120 | 90 |
| **End-uses sectors** | | | | |
| Renewable share in TFC | | 5% | 12% | 19% |
| Households with rooftop solar PV (million) | | 25 | 100 | 240 |
| Share of solar thermal and geothermal in buildings | | 2% | 5% | 12% |
| Share of solar thermal and geothermal in industry final consumption | | 0% | 1% | 2% |

Note: TFC = total final consumption.

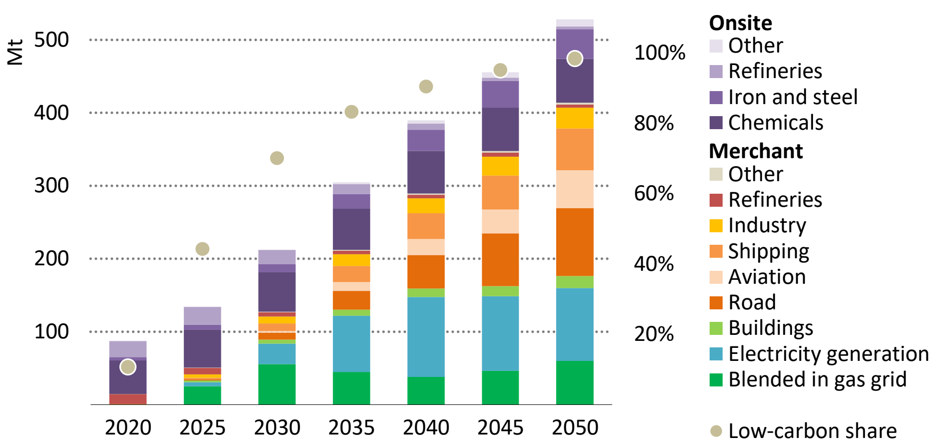
### 2.5.5 Hydrogen and hydrogen-based fuels

The initial focus for hydrogen use in the NZE is the conversion of existing uses of fossil energy to low-carbon hydrogen in ways that do not immediately require new transmission and distribution infrastructure. This includes hydrogen use in industry and in refineries and power plants, and the blending of hydrogen into natural gas for distribution to end-users.



Global hydrogen use expands from less than 90 Mt in 2020 to more than 200 Mt in 2030; the proportion of low-carbon hydrogen rises from 10% in 2020 to 70% in 2030 (Figure 2.19). Around half of low-carbon hydrogen produced globally in 2030 comes from electrolysis and the remainder from coal and natural gas with CCUS, although this ratio varies substantially between regions. Hydrogen is also blended with natural gas in gas networks: the global average blend in 2030 includes 15% of hydrogen in volumetric terms, reducing $CO_2$ emissions from gas consumption by around 6%.

**Figure 2.19 ▷ Global hydrogen and hydrogen-based fuel use in the NZE**






*The initial focus for hydrogen is to convert existing uses to low-carbon hydrogen; hydrogen and hydrogen-based fuels then expand across all end-uses*

Note: Includes hydrogen and hydrogen contained in ammonia and synthetic fuels.

These developments facilitate a rapid scaling up of electrolyser manufacturing capacity and the parallel development of new hydrogen transport infrastructure. This leads to rapid cost reductions for electrolysers and for hydrogen storage, notably in salt caverns. Stored hydrogen is used to help balance both seasonal fluctuations in electricity demand and imbalances that may arise between the demand for hydrogen and its supply by off-grid renewable systems. During the 2020s, there is also a large increase in the installation of end-use equipment for hydrogen, including more than 15 million hydrogen fuel cell vehicles on the road by 2030.

After 2030, low-carbon hydrogen use expands rapidly in all sectors in the NZE. In the electricity sector, hydrogen and hydrogen-based fuels provide an important low-carbon source of electricity system flexibility, mainly through retrofitting existing gas-fired capacity to co-fire with hydrogen, together with some retrofitting of coal-fired power plants to co-fire with ammonia. Although these fuels provide only around 2% of overall electricity generation in 2050, this translates into very large volumes of hydrogen and makes the electricity sector an important driver of hydrogen demand. In transport, hydrogen provides around one-third of fuel use in trucks in 2050 in the NZE: this is contingent on policy makers taking decisions that enable the development of the necessary infrastructure by 2030. By 2050, hydrogen-based fuels also provide more than 60% of total fuel consumption in shipping.

Of the 530 Mt of hydrogen produced in 2050, around 25% is produced within industrial facilities (including refineries), and the remainder is merchant hydrogen (hydrogen produced by one company to sell to others). Almost 30% of the low-carbon hydrogen used in 2050 takes the form of hydrogen-based fuels, which include ammonia and synthetic liquids and gases. An increasing share of hydrogen production comes from electrolysers, which account for 60% of total production in 2050. Electrolysers are powered by grid electricity, dedicated renewables in regions with excellent renewable resources and other low-carbon sources such as nuclear power. Rolling out electrolysers at the pace required in the NZE is a key challenge given the lack of manufacturing capacity today, as is ensuring the availability of sufficient electricity generation capacity. Global trade in hydrogen develops over time in the NZE, with large volumes exported from gas and renewables-rich areas in the Middle East, Central and South America and Australia to demand centres in Asia and Europe.

**Table 2.7 ▷ Key deployment milestones for hydrogen and hydrogen-based fuels**

| Sector | 2020 | 2030 | 2050 |
|---|---|---|---|
| **Total production hydrogen-based fuels** (Mt) | **87** | **212** | **528** |
| Low-carbon hydrogen production | 9 | 150 | 520 |
| *share of fossil-based with CCUS* | *95%* | *46%* | *38%* |
| *share of electrolysis-based* | *5%* | *54%* | *62%* |
| Merchant production | 15 | 127 | 414 |
| Onsite production | 73 | 85 | 114 |
| **Total consumption hydrogen-based fuels** (Mt) | **87** | **212** | **528** |
| Electricity | 0 | 52 | 102 |
| of which hydrogen | 0 | 43 | 88 |
| of which ammonia | 0 | 8 | 13 |
| Refineries | 36 | 25 | 8 |
| Buildings and agriculture | 0 | 17 | 23 |
| Transport | 0 | 25 | 207 |
| of which hydrogen | 0 | 11 | 106 |
| of which ammonia | 0 | 8 | 44 |
| of which synthetic fuels | 0 | 5 | 56 |
| Industry | 51 | 93 | 187 |

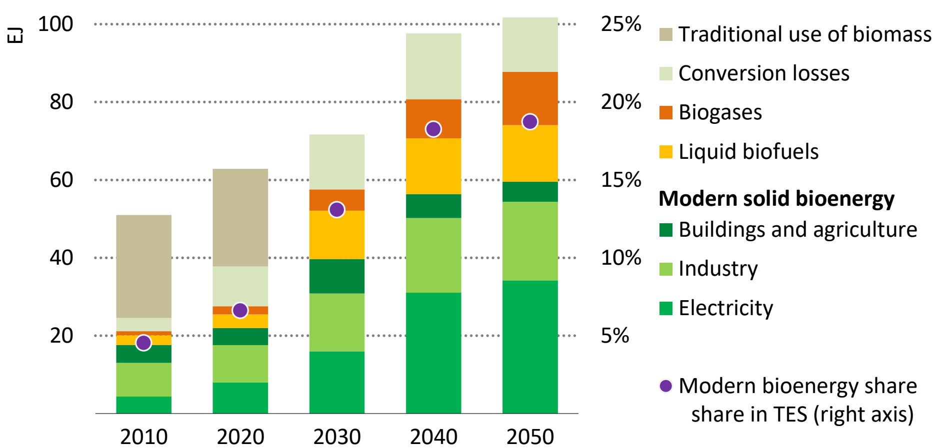
Note: Hydrogen-based fuels are reported in million tonnes of hydrogen required to produce them.

### 2.5.6 Bioenergy



Global primary demand for bioenergy was almost 65 EJ in 2020, of which about 90% was solid biomass. Some 40% of the solid biomass was used in traditional cooking methods which is unsustainable, inefficient and polluting, and was linked to 2.5 million premature deaths in 2020. The use of solid biomass in this manner falls to zero by 2030 in the NZE, to achieve the UN Sustainable Development Goal 7. Increases in all forms of modern bioenergy more than offset this, with production rising from less than 40 EJ in 2020 to around 100 EJ in 2050 (Figure 2.20).[15] All bioenergy in 2050 comes from sustainable sources and the figures in the NZE for total bioenergy use are well below estimates of global sustainable bioenergy potential, thus avoiding the risk of negative impacts on biodiversity, fresh water systems, and food prices and availability (see section 2.7.2).

**Figure 2.20 ▷ Total bioenergy supply in the NZE**






*Modern bioenergy use rises to 100 EJ in 2050, meeting almost 20% of total energy needs. Global demand in 2050 is well below the assessed sustainable potential*

Notes: TES = Total energy supply. Conversion losses occur during the production of biofuels and biogases.

Modern solid bioenergy use rises by about 3% each year on average to 2050. In the electricity sector, where demand reaches 35 EJ in 2050, solid bioenergy provides flexible low-emissions generation to complement generation from solar PV and wind, and it removes $CO_2$ from the atmosphere when equipped with CCUS. In 2050, electricity generation using bioenergy fuels reaches 3 300 TWh, or 5% of total generation. Bioenergy also provides around 50% of district heat production. In industry, where demand reaches 20 EJ in 2050, solid bioenergy provides high temperature heat and can be co-fired with coal to reduce the emissions intensity of

15 Modern bioenergy includes biogases, liquid biofuels and modern solid biomass harvested from sustainable sources. It excludes the traditional use of biomass.

existing generation assets. Demand is highest for paper and cement production: in 2050, bioenergy meets 60% of energy demand in the paper sector and 30% of energy demand for cement production. Modern solid bioenergy demand in buildings increases to nearly 10 EJ in 2030, most of it for use in improved cookstoves as unsustainable traditional uses of biomass disappear. Bioenergy is also increasingly used for space and water heating in advanced economies.

Household and village biogas digesters in rural areas provide a source of renewable energy and clean cooking for nearly 500 million households by 2030 in the NZE and total biogas use rises to 5.5 EJ in 2050 (from under 2 EJ in 2020).[16] Biomethane demand grows to 8.5 EJ, thanks to blending mandates for gas networks, with average blending rates increasing to above 80% in many regions by 2050. Half of total biomethane use is in the industry sector, where biomethane replaces natural gas as a source of process heat. The buildings and transport sectors each account for around a further 20% of biomethane consumption in 2050.

One of the key advantages of bioenergy is that it can use existing infrastructure. For example, biomethane can use existing natural gas pipelines and end-user equipment, while many drop-in liquid biofuels can use existing oil distribution networks and be used in vehicles with only minor or limited alterations. BioLPG – LPG derived from renewable feedstocks – is identical to conventional LPG and so can be blended and distributed in the same way. Sustainable bioenergy also provides a valuable source of employment and income for rural communities, reduces undue burdens on women often tasked with fuel collection, brings health benefits from reduced air pollution and proper waste management, and reduces methane emissions from inefficient combustion and the decomposition of waste.

Liquid biofuel consumption rises from 1.6 mboe/d in 2020 to 6 mboe/d in 2030 in the NZE, mainly used in road transport. After 2030, liquid biofuels grow more slowly to around 7 mboe/d in 2050 and their use shifts to shipping and aviation as electricity increasingly dominates road transport. Almost half of liquid biofuel use in 2050 is for aviation, where bio-kerosene accounts for around 45% of total fuel use in aircraft.

Bioenergy with carbon capture and storage (BECCS) plays a critical role in the NZE in offsetting emissions from sectors where the full elimination of emissions is very difficult to achieve. In 2050, around 10% of total bioenergy is used in facilities equipped with CCUS and around 1.3 Gt $CO_2$ is captured using BECCS. Around 45% of this $CO_2$ is captured in biofuels production, 40% in the electricity sector and the rest in heavy industry, notably cement production.

[16] Biogas is a mixture of methane, $CO_2$ and small quantities of other gases produced by anaerobic digestion of organic matter in an oxygen free environment. Biomethane is a near pure source of methane produced either by removing $CO_2$ and other contaminants from biogas or through the gasification of solid biomass (IEA, 2020b).

**Table 2.8 ▷ Key deployment milestones for bioenergy**

| | 2020 | 2030 | 2050 |
|---|---|---|---|
| **Total energy supply** (EJ) | **63** | **72** | **102** |
| Share of advanced biomass feedstock | 27% | 85% | 97% |
| **Modern gaseous bioenergy** (EJ) | **2.1** | **5.4** | **13.7** |
| Biomethane | 0.3 | 2.3 | 8.3 |
| **Modern liquid bioenergy** (mboe/d) | **1.6** | **6.0** | **7.0** |
| Advanced biofuels | 0.1 | 2.7 | 6.2 |
| **Modern solid bioenergy** (EJ) | **32** | **54** | **74** |
| **Traditional use of solid biomass** (EJ) | **25** | **0** | **0** |
| Million people using traditional biomass for cooking | 2 340 | 0 | 0 |

Notes: mboe/d = million barrels of oil equivalent per day. Bioenergy from forest plantings is considered advanced when forests are sustainably managed (see section 2.7.2).



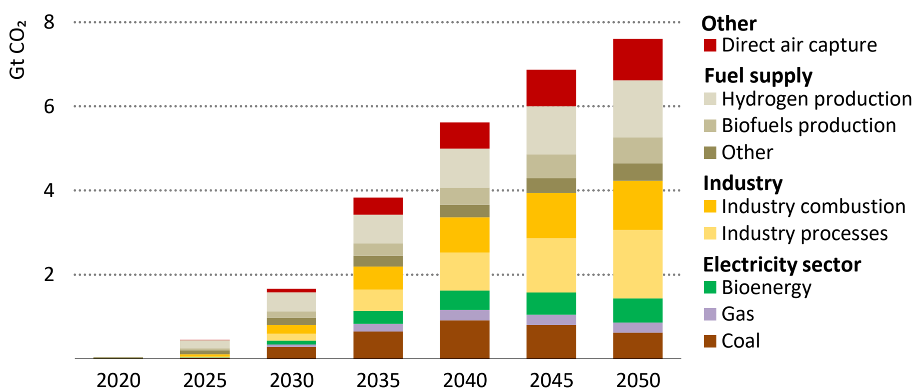
### 2.5.7 Carbon capture, utilisation and storage

CCUS can facilitate the transition to net-zero $CO_2$ emissions by: tackling emissions from existing assets; providing a way to address emissions from some of the most challenging sectors; providing a cost-effective pathway to scale up low-carbon hydrogen production rapidly; and allowing for $CO_2$ removal from the atmosphere through BECCS and DACCS.

In the NZE, policies support a range of measures to establish markets for CCUS investment and to encourage use of shared $CO_2$ transport and storage infrastructure by those involved in the production of hydrogen and biofuels, the operation of industrial hubs, and retrofitting of existing coal-fired power plants. Capture volumes in the NZE increase marginally over the next five years from the current level of around 40 Mt $CO_2$ per year, reflecting projects currently under development, but there is a rapid expansion over the following 25 years as policy action bears fruit. By 2030, 1.6 Gt $CO_2$ per year is captured globally, rising to 7.6 Gt $CO_2$ in 2050 (Figure 2.21). Around 95% of total $CO_2$ captured in 2050 is stored in permanent geological storage and 5% is used to provide synthetic fuels. Estimates of global geological storage capacity are considerably above what is necessary to store the cumulative $CO_2$ captured and stored in the NZE. A total of 2.4 Gt $CO_2$ is captured in 2050 from the atmosphere through bioenergy with $CO_2$ capture and direct air capture, of which 1.9 Gt $CO_2$ is permanently stored and 0.5 Gt $CO_2$ is used to provide synthetic fuels in particular for aviation.

Energy-related and process $CO_2$ emissions in industry account for almost 40% of the $CO_2$ captured in 2050 in the NZE. CCUS is particularly important for cement manufacturing. Although efforts are pursued in the NZE to produce cement more efficiently, CCUS remains central to efforts to limit the process emissions that occur during cement manufacturing. The electricity sector accounts for almost 20% of the $CO_2$ captured in 2050 (of which around 45% is from coal-fired plants, 40% from bioenergy plants and 15% from gas-fired plants). CCUS-equipped power plants contribute just 3% of total electricity generation in 2050 but the volumes of $CO_2$ captured are comparatively large. In emerging market and developing economies, where large numbers of coal power plants have been built relatively recently, retrofits play an important role where there are storage opportunities. In advanced economies, gas-fired plants with CCUS play a bigger role, providing dispatchable electricity at relatively low cost in regions with cheap natural gas and existing networks. In 2030, around 50 GW of coal-fired power plants (4% of the total at that time) and 30 GW of natural gas power plants (1% of the total) are equipped with CCUS, and this rises to 220 GW of coal (almost half of the total) and 170 GW of natural gas (7% of the total) capacity in 2050. A further 30% of $CO_2$ captured in 2050 comes from fuel transformation, including hydrogen and biofuels production as well as oil refining. The remaining 10% is from DAC, which is rapidly scaled up from several of pilot projects today to 90 Mt $CO_2$ per year in 2030 and just under 1 Gt $CO_2$ per year by 2050.

**Figure 2.21 ▹ Global $CO_2$ capture by source in the NZE**






*By 2050, 7.6 Gt of $CO_2$ is captured per year from a diverse range of sources. A total of 2.4 Gt $CO_2$ is captured from bioenergy use and DAC, of which 1.9 Gt $CO_2$ is permanently stored.*

**Table 2.9 ▹ Key global milestones for CCUS**

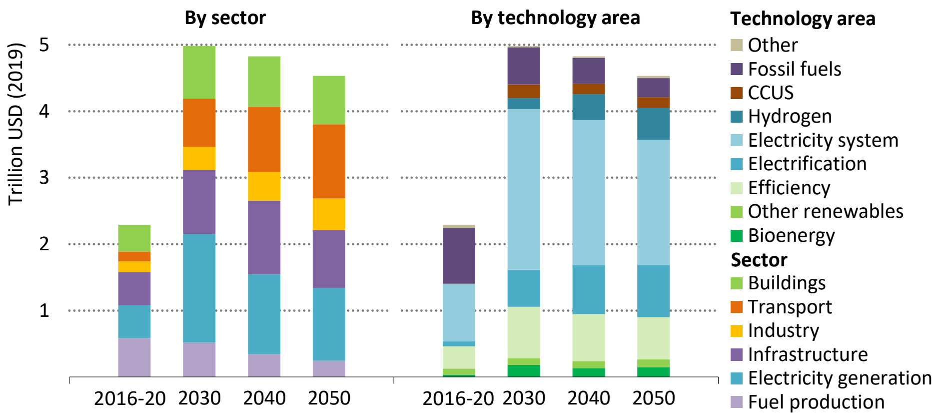
| | 2020 | 2030 | 2050 |
|---|---|---|---|
| **Total $CO_2$ captured (Mt $CO_2$)** | **40** | **1 670** | **7 600** |
| $CO_2$ captured from fossil fuels and processes | 39 | 1 325 | 5 245 |
| Power | 3 | 340 | 860 |
| Industry | 3 | 360 | 2 620 |
| Merchant hydrogen production | 3 | 455 | 1 355 |
| Non-biofuels production | 30 | 170 | 410 |
| $CO_2$ captured from bioenergy | 1 | 255 | 1 380 |
| Power | 0 | 90 | 570 |
| Industry | 0 | 15 | 180 |
| Biofuels production | 1 | 150 | 625 |
| Direct air capture | 0 | 90 | 985 |
| Removal | 0 | 70 | 630 |

## 2.6 Investment



The radical transformation of the global energy system required to achieve net-zero $CO_2$ emissions in 2050 hinges on a big expansion in investment and a big shift in what capital is spent on. The NZE expands annual investment in energy from just over USD 2 trillion globally on average over the last five years to almost USD 5 trillion by 2030 and to USD 4.5 trillion by 2050 (Figure 2.22).[17] Total annual capital investment in energy in the NZE rises from around 2.5% of global GDP in recent years to about 4.5% in 2030 before falling back to 2.5% by 2050.

**Figure 2.22 ▷ Annual average capital investment in the NZE**






*Capital investment in energy rises from 2.5% of GDP in recent years to 4.5% by 2030; the majority is spent on electricity generation, networks and electric end-user equipment*

Notes: Infrastructure includes electricity networks, public EV charging, $CO_2$ pipelines and storage facilities, direct air capture and storage facilities, hydrogen refuelling stations, and import and export terminals for hydrogen, fossil fuels pipelines and terminals. End-use efficiency investments are the incremental cost of improving the energy performance of equipment relative to a conventional design. Electricity systems include electricity generation, storage and distribution, and public EV charging. Electrification investments include spending in batteries for vehicles, heat pumps and industrial equipment for electricity-based material production routes.

The shift in what capital is spent on leads to annual investment in electricity generation rising from just over USD 500 billion over the last five years to more than USD 1 600 billion in 2030, before falling back as the cost of renewable energy technologies continues to decline. Annual nuclear investment rises too: it more than doubles by 2050 compared with current levels. Annual investment in fuel supply however drops from about USD 575 billion on average over

[17] Investment levels presented in this report include a broader accounting of efficiency improvements in buildings than reported in the IEA World Energy Investment (IEA, 2020c) and so differ from the numbers presented there.

the last half-decade to USD 315 billion in 2030 and USD 110 billion in 2050. The share of fossil fuel supply in total energy sector investment drops from its 25% level in recent years to just 7% by 2050: this is partly offset by the rise in spending on low-emissions fuel supply, such as hydrogen, hydrogen-based fuels and bioenergy. Annual investment in these fuels increases to nearly USD 140 billion in 2050. Investment in transport increases significantly in the NZE from USD 150 per year in recent years to more than USD 1 100 billion in 2050: this stems mainly from the upfront cost of electric cars compared with conventional vehicles despite the decline in the cost of batteries.

By technology area, electrification is the dominant focus in the NZE. In addition to more investment in electricity generation, there is a huge increase in investment in expansion and modernisation of electricity networks. Annual investment rises from USD 260 billion on average in recent years to around USD 800 billion in 2030 and remains about that level to 2050. Such investment is needed to ensure electricity security in the face of rising electricity demand and the proportion of variable generation in the power mix. There is also a large increase in investment in the electrification of end-use sectors, which includes spending on EV batteries, heat pumps and electricity-based industrial equipment. In addition to investment in electrification, there is a moderate increase in investment in hydrogen to 2030 as production facilities are scaled up, and larger increases after as hydrogen use in transport expands: annual investment in hydrogen, including production facilities, refuelling stations and end-user equipment, reaches USD 165 billion in 2030 and over USD 470 billion in 2050. There is also an increase in global investment in CCUS (annual investment exceeds USD 160 billion by 2050 and in efficiency (around USD 640 billion annual investment by 2050, mostly for deep building retrofits and efficient appliances in the industry and buildings sectors).

Financing the investment needed in the NZE involves redirecting existing capital towards clean energy technologies and substantially increasing the overall level of investment in energy. Most of this increase in investment comes from private sources, mobilised by public policies that create incentives, set appropriate regulatory frameworks and reform energy taxes. However, direct government financing is also needed to boost the development of new infrastructure projects and to accelerate innovation in technologies that are in the demonstration or prototype phase today. Projects in many emerging market and developing economies are often relatively reliant on public financing, and policies that ensure a predictable flow of bankable projects have an important role in boosting private investment in these economies, as does the scaling up of concessional debt financing and the use of development finance. There are extensive cross-country co-operation efforts in the NZE to facilitate the international flow of capital.

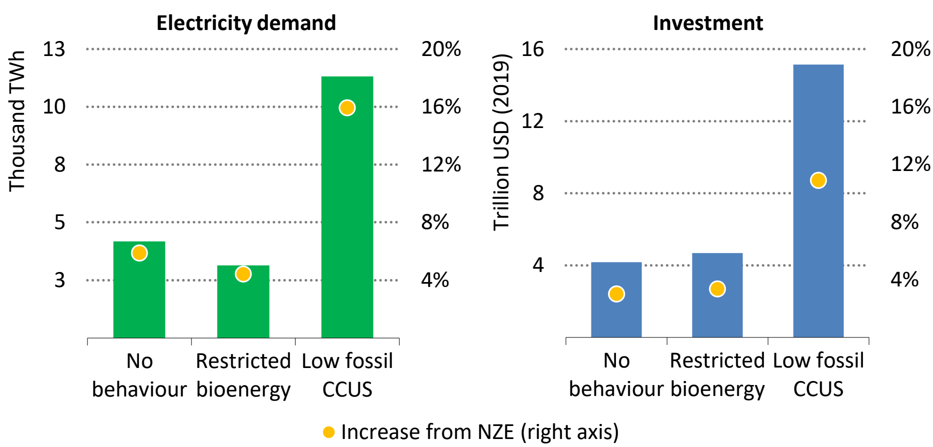
The large increase in capital investment in the NZE is partly compensated for by lower operating expenditure. Operating costs account today for a large share of the total cost of upstream fuel supply projects and fossil fuel generation projects: the clean technologies that play an increasing role in the NZE are characterised by much lower operating costs.

## 2.7 Key uncertainties

The road to net-zero emissions is uncertain for many reasons: we cannot be sure how underlying economic conditions will change, which policies will be most effective, how people and businesses will respond to market and policy signals, or how technologies and their costs will evolve from within or outside the energy sector. The NZE therefore is just one possible pathway to achieve net-zero emissions by 2050. Against this background, this section looks at what the implications would be if the assumptions in the NZE turn out to be off the mark with respect to behavioural change, bioenergy and CCUS for fossil fuels. These three areas were selected because the assumptions made about them involve a high degree of uncertainty and because of their critical contributions to achieve net-zero emissions by 2050.



**Figure 2.23 ▷ Additional electricity demand in 2050 and additional investment between 2021-2050 for selected areas of uncertainty**






*The absence of behaviour change, restrictions on bioenergy use and failure to develop fossil fuel CCUS would each raise investment to meet net-zero emissions by USD 4-15 trillion*

Notes: No behaviour assumes none of the behavioural changes included in the NZE. Restricted bioenergy assumes no increase in land use for bioenergy production. Low fossil CCUS assumes no increase in fossil fuel-based CCUS apart from projects already approved or under construction.

Our analysis clearly highlights that more pessimistic assumptions would add considerably to both the costs and difficulty of achieving net-zero emissions by 2050 (Figure 2.23).

- Behavioural changes are important in reducing energy demand in transport, buildings and industry. If the changes in behaviour assumed in the NZE were not attainable, emissions would be around 2.6 Gt $CO_2$ higher in 2050. Avoiding these emissions through the use of additional low-carbon electricity and hydrogen would cost an additional USD 4 trillion.

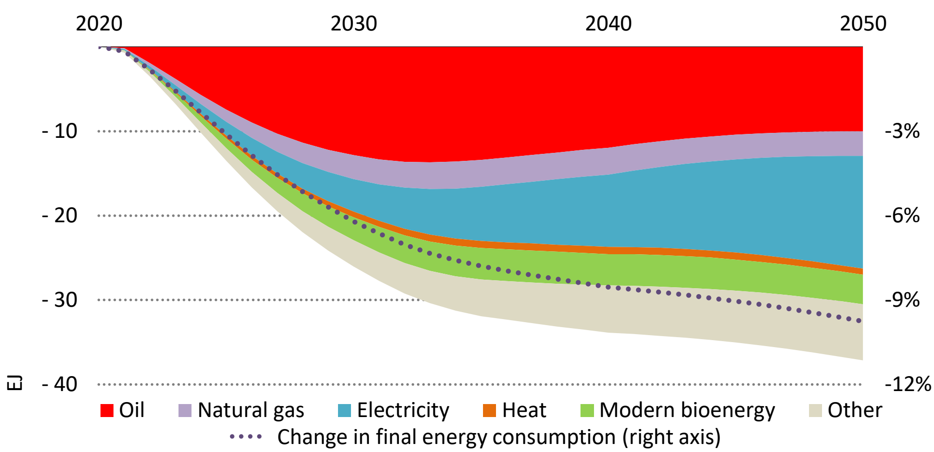
- Bioenergy use grows by 60% between 2020 and 2050 in the NZE and land use for its propagation increases by around 25%. Bioenergy use in 2050 in the NZE is well below current best estimates of global sustainable bioenergy potential, but there is a high degree of uncertainty concerning this level. If land use for bioenergy remains at today's level, bioenergy use in 2050 would be around 10% lower, and achieving net-zero emissions in 2050 would require USD 4.5 trillion extra investment.
- A failure to develop CCUS for fossil fuels would substantially increase the risk of stranded assets and would require around USD 15 trillion of additional investment in wind, solar and electrolyser capacity to achieve the same level of emissions reductions. It could also critically delay progress on BECCS and DACCS: if these cannot be deployed at scale, then achieving net-zero emissions by 2050 would be very much harder.

### 2.7.1 Behavioural change

*Impact of behavioural changes in selected sectors in the NZE*

Changes in the behaviour of energy consumers play an important role in cutting $CO_2$ emissions and energy demand growth in the NZE. Behavioural changes reduce global energy demand by 37 EJ in 2050, a 10% reduction in energy demand at that time, and without them cumulative emissions between 2021 and 2050 would be around 10% higher (Figure 2.24). Behavioural change plays a particularly important role in the transport sector.

**Figure 2.24 ▹ Reduction in total final consumption due to behavioural changes by fuel in the NZE**






*The impact of behaviour changes and materials efficiency on final energy consumption increases over time*

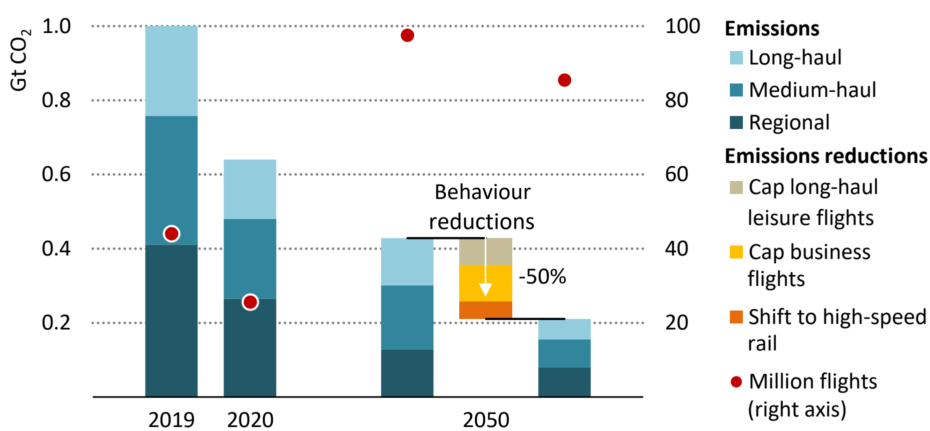
Note: Other includes coal, hydrogen, geothermal, solar thermal, synthetic oil and synthetic gas.

**Passenger aviation.** Demand would grow more than threefold globally between 2020 and 2050 in the absence of the assumed changes in behaviour in the NZE. About 60% of this growth would occur in emerging market and developing economies. In the NZE, three changes lead to a 50% reduction in emissions from aviation in 2050, while reducing the number of flights by only 12% (Figure 2.25).

- Keeping air travel for business purposes at 2019 levels. Although business trips fell to almost zero in 2020, they accounted for just over one-quarter of air travel before the pandemic. This avoids around 110 Mt $CO_2$ in 2050 in the NZE.
- Keeping long-haul flights (more than six hours) for leisure purposes at 2019 levels. Emissions from an average long-haul flight are 35-times greater than from a regional flight (less than one hour). This affects less than 2% of flights but avoids 70 Mt $CO_2$ in 2050.
- A shift to high-speed rail. The opportunities for shifting regional flights to high-speed rail vary by region. Globally, we estimate that around 15% of regional flights in 2019 could have been shifted given existing rail infrastructure; future high-speed rail lines ensure that by 2050 around 17% could be shifted (IEA, 2019).[18] This would reduce emissions by around 45 Mt $CO_2$ in 2050 (high-speed trains generate no emissions in 2050 in the NZE).



**Figure 2.25 ⊳ Global $CO_2$ emissions from aviation and impact of behavioural changes in the NZE**





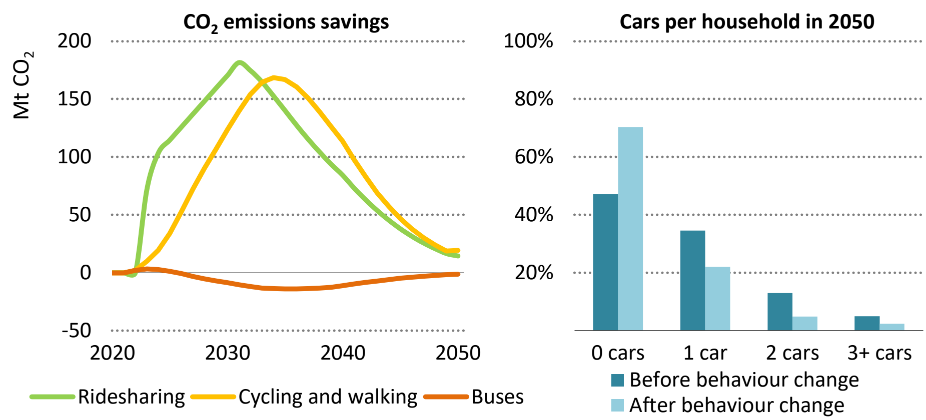

*Demand for passenger aviation is set to grow significantly by 2050, but behavioural changes reduce emissions by 50% in 2050 despite reducing flights by only 12%*

Notes: Long-haul = more than 6 hour flight; medium-haul = 1-6 hour flight; regional = less than 1 hour. Business flights = trips for work purposes; leisure flights = trips for leisure purposes. Average speeds vary by flight distance and range from 680-750 km/h.

[18] This assumes that: new rail routes avoid water bodies and tunnelling through elevated terrain; travel times are similar to aviation; and centres of demand are sufficiently large to ensure that high-speed rail is economically viable.

**Car use.** A variety of new measures that aim to reduce the use of cars in cities and overall car ownership levels are assumed in the NZE. They lead to rapid growth in the rideshare market in urban areas, as well as phasing out polluting cars in large cities and replacing them with cycling, walking and public transport. The timing of these changes in the NZE depends on cities having the necessary infrastructure and public support to ensure a shift away from private car use. Between 20-50% of car trips are shifted to buses, depending on the city in question, with the remainder replaced by cycling, walking and public transport. These changes reduce emissions from cars in cities by more than 320 Mt $CO_2$ in total in the mid-2030s (Figure 2.26). Their impact on emissions fades over time as cars are increasingly electrified, but they still have a significant impact on curbing energy use in 2050.

**Figure 2.26 ▷ Global $CO_2$ emissions savings and car ownership per household due to behavioural change in the NZE**






*Policies discouraging car use in cities lead to rapid reductions in $CO_2$ emissions and lower car ownership levels, though the impact diminishes over time as cars are electrified*

The gradual move away from cars in cities also has an impact on car ownership levels. Survey data indicates that car-share schemes and the provision of public transport reduces car ownership by up to 35%, with the biggest changes taking place in multiple car households (Jochem et al., 2020; Martin, Shaheen and Lidiker, 2010). Without behavioural changes, 35% of households would have a car in 2050; with behavioural changes this share falls to around 20% in the NZE, and two-car households fall from 13% of the total to less than 5%.

The changing patterns of mobility in cities in NZE have implications for materials demand. Reduced car ownership leads to a small drop in steel demand in 2050, saving around 40 Mt $CO_2$ in steel production. Increased cycling would need to be supported by building an estimated 80 000 km of new cycle lanes globally over the period to 2050, generating increased demand for cement and bitumen. This effect is small, however: the extra emissions associated with this would be less than 5% of the emissions avoided by lower car use.

*How to bring about the behavioural changes in NZE*

**Regulations and mandates** could enable roughly 70% of the emissions saved by behavioural changes in the NZE. Examples include:

- Upper speed limits, which are reduced over time in the NZE from their current levels to 100 km/h, cutting emissions from road vehicles by 3% in 2050.
- Appliance standards, which maximise energy efficiency in the buildings sector.
- Regulations covering heating temperatures in offices and default cooling temperatures for air conditioning units, which reduce excessive thermal demand.
- Changes initially tackled by market-based mechanisms, e.g. swapping regional flights for high-speed rail,[19] which can be addressed by regulation over time to mirror changes in public sentiment and consumer norms.

**Market-based instruments** use a mix of financial incentives and disincentives to influence decision making. They could enable around two-thirds of the emissions saved by behavioural changes in the NZE. Examples include:

- Congestion pricing and targeted interventions differentiated by vehicle type,[20] such as charges aimed at the most polluting vehicles, or preferential parking for clean cars.
- Transport demand measures that reduce travel, such as fuel taxes and distance-based vehicle insurance and registration fees (Byars, Wei and Handy, 2017).
- Information measures that help consumers to drive change, such as mandatory labelling of embodied or lifecycle emissions in manufacturing and a requirement for companies to disclose their carbon emissions.

**Information and awareness measures** could enable around 30% of the emissions saved by behavioural changes in the NZE. Examples include:

- Personalised and real-time travel planning information, which facilitates a switch to walking, cycling and public transport.
- Product labelling and public awareness campaigns in combination, which help make recycling widespread and habitual.
- Comparisons with consumption patterns of similar households, which can reduce wasteful energy use by up to 20% (Aydin, Brounen and Kok, 2018).

Not all the behavioural changes in the NZE would be equally easy to achieve everywhere, and policy interventions would need to draw on insights from behavioural science and take into account existing behavioural norms and cultural preferences. Some behavioural changes may be more socially acceptable than others. Citizen assemblies in the United Kingdom and

[19] A law banning domestic flights where a rail alternative of under two-and-a-half hours exists has been proposed in France (Assemblee Nationale, 2021).

[20] Congestion charging is currently used in 11 major cities and has been shown to reduce traffic volumes by up to 27%. Low-emissions zones charge vehicles to enter urban zones based vehicle type and currently exist in 15 countries (TFL, 2021; Tools of Change, 2014; European Commission, 2021).

France indicate a large level of support for taxes on frequent and long-distance flyers and for banning polluting vehicles from city centres; conversely, measures that limit car ownership or reduce speed limits have gained less acceptance (Convention Citoyenne pour le Climat, 2021; Climate Assembly UK, 2020). Behavioural changes which reduce energy use in homes may be particularly well supported: a recent survey showed 85% support for line-drying clothes and switching off appliances, and only 20% of people felt that reducing temperature settings in homes was undesirable (Newgate Research and Cambridge Zero, 2021).

**Table 2.10 ▹ Key behavioural changes in the NZE**

| | Policy options | Related policy-goals | Cost-effectiveness | Timeliness | Social acceptability | $CO_2$ emissions impact |
|---|---|---|---|---|---|---|
| **Low-car cities**<br>• Phase out ICE cars from large cities.<br>• Rideshare all urban car trips. | • Low-emissions zones.<br>• Access restrictions.<br>• Parking restrictions.<br>• Registration caps.<br>• Parking pricing.<br>• Congestion charges.<br>• Investment in cycling lanes and public transportation. | • Air pollution mitigation.<br>• Public health.<br>• Reduced congestion.<br>• Urban space.<br>• Beautification and liveability. | neutral match | neutral match | neutral match | good match |
| **Fuel-efficient driving**<br>• Reduce motorway speeds to less than 100 km/h.<br>• Eco-driving.<br>• Raise air conditioning temperature in cars by 3 °C. | • Speed limits.<br>• Real-time fuel efficiency displays.<br>• Awareness campaigns. | • Road safety.<br>• Reduced noise pollution. | good match | good match | neutral match | good match |
| **Reduce regional flights**<br>• Replace all flights <1h where high-speed rail is a feasible alternative. | • High-speed rail investment.<br>• Subsidies for high-speed rail travel.<br>• Price premiums. | • Lower air pollution.<br>• Lower noise pollution. | poor match | poor match | neutral match | neutral match |
| **Reduce international flights**<br>• Keep air travel for business purposes at 2019 levels.<br>• Keep long-haul flights for leisure at 2019 levels. | • Awareness campaigns.<br>• Price premiums.<br>• Corporate targets.<br>• Frequent-flyer levies. | • Lower air pollution.<br>• Lower noise pollution. | good match | good match | neutral match | good match |
| **Space heating**<br>• Target average set-point temperatures of 19-20 °C. | • Awareness campaigns.<br>• Consumption feedback.<br>• Corporate targets. | • Public health.<br>• Energy affordability. | good match | good match | good match | good match |
| **Space cooling**<br>• Target average set-point temperatures of 24-25 °C. | • Awareness campaigns.<br>• Consumption feedback.<br>• Corporate targets. | • Public health.<br>• Energy affordability. | good match | good match | good match | poor match |

= poor match = neutral match = good match

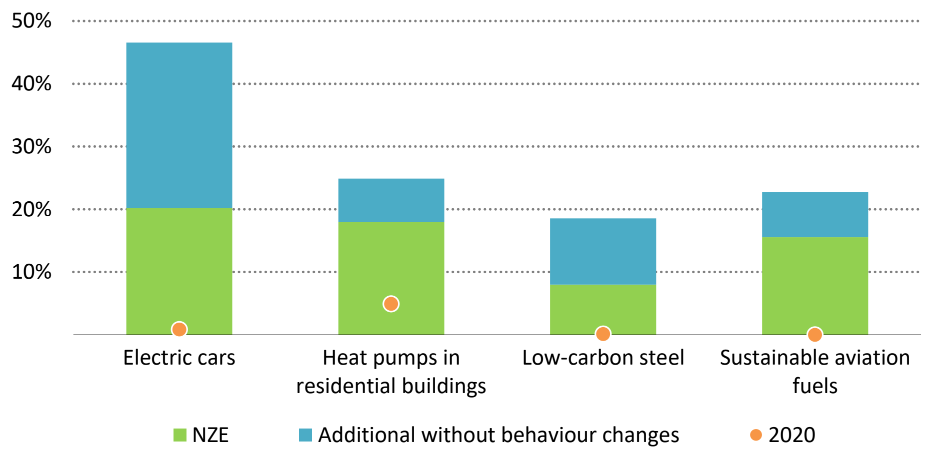
Notes: Large cities = cities over 1 million inhabitants. ICE = internal combustion engine. $CO_2$ emissions impact = cumulative reductions 2020-2050. Eco-driving = early upshifting as well as avoiding sudden acceleration, stops or idling. The number of jobs that can be done at home varies considerably by region, globally, an average of 20% of jobs can be done at home.

The behavioural changes in the NZE would bring wider benefits in terms of air pollution in cities, road safety, noise pollution, congestion and health. Attitudes to policy interventions can change quickly when co-benefits become apparent. For example, support for congestion charging in Stockholm jumped from less than 40% when the scheme was introduced to around 70% three years later; a similar trend was seen in Singapore, London and other cities, all of which experienced declines in air pollution after the introduction of charging (Tools of Change, 2014; DEFRA, 2012).

### *Are net-zero emissions by 2050 still possible without behavioural change?*

If the behavioural changes described in the NZE were not to materialise, final energy use would be 27 EJ and emissions 1.7 Gt $CO_2$ higher in 2030, and they would be 37 EJ and 2.6 Gt $CO_2$ higher in 2050. This would further increase the already unprecedented ramp-up needed in low-carbon technologies. The share of EVs in the global car fleet would need to increase from around 20% in 2030 to 45% to ensure the same level of emissions reductions (Figure 2.27). Achieving the same reduction in emissions in homes would require electric heat pumps sales to reach 680 million in 2030 (compared with 440 million in the NZE). Without gains in materials efficiency, the share of low-carbon primary steel production would need to be more than twice as high in 2030 as in the NZE. In 2050, the use of sustainable aviation fuels would also need to rise to 7 mboe/d (compared with 5 mboe/d in the NZE). Emissions from cement and steel production would be 1.7 Gt $CO_2$ higher in 2050 than in the NZE, and so require increased deployment of CCUS in industry, deployment of electric arc furnaces and more use of low-carbon hydrogen.

**Figure 2.27 ▷ Share of low-carbon technologies and fuels with and without behavioural change in 2030 in the NZE**






***In the absence of behavioural changes, the share of low-emissions technologies in end-uses in 2030 would need to be much larger to achieve the same emissions as in the NZE***

Notes: Electric cars = share of electric cars on the road globally. Sustainable aviation fuels = biojet kerosene and synthetic jet kerosene. Low-carbon steel refers to primary steel production.

### *2.7.2 Bioenergy and land-use change*

Modern forms of bioenergy play a key role in achieving net-zero emissions in the NZE. Bioenergy is a versatile renewable energy source that can be used in all sectors, and it can often make use of existing transmission and distribution infrastructure and end-user equipment. But there are constraints on expanding the supply of bioenergy: with finite potential for bioenergy production from waste streams, there are possible trade-offs between expanding bioenergy production, achieving sustainable development goals and avoiding conflicts with other land uses, notably food production.

The level of bioenergy use in the NZE takes account of these constraints: bioenergy demand in 2050 is around 100 EJ. The global sustainable bioenergy potential in 2050 has been assessed to be at least 100 EJ (Creutzig, 2015) and recent assessments estimate a potential between 150-170 EJ when integrating relevant UN Sustainable Development Goals (Frank, 2021; IPCC, 2019; IPCC, 2014; Wu, 2019). However, there is a high degree of uncertainty over the precise levels of this potential. Using modelling developed in co-operation with IIASA, here we examine the implications for achieving net-zero $CO_2$ emissions by 2050 if the available levels of sustainable bioenergy were to be lower. We also examine what would need to be done to achieve large reductions in emissions from agriculture, forestry and other land use (AFOLU).

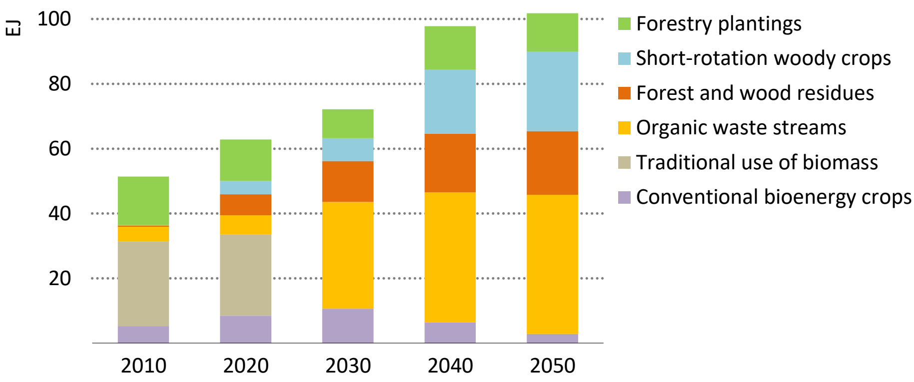
#### *Ensuring a sustainable supply of bioenergy*

Most liquid biofuels produced today come from dedicated bioenergy crops such as sugarcane, corn or oil crops, often known as conventional biofuels. The expanded use of feedstocks and arable land to produce these biofuels can conflict with food production. In the NZE, there is a shift towards the use of sustainable, certified agricultural products and wood. Biofuel production processes in the NZE use advanced conversion technologies coupled with CCUS where possible (see section 3.3.2). The emphasis is also on advanced bioenergy feedstocks, including waste streams from other processes, short-rotation woody crops and feedstocks that do not require the use of arable land. Advanced bioenergy accounts for the vast majority of bioenergy supply in the NZE by 2050. The use of conventional energy crops for biofuel production grows from around 9 EJ in 2020 to around 11 EJ in 2030, but then falls by 70% to 3 EJ in 2050 (including feedstocks consumed in the biofuel production processes).

Advanced bioenergy feedstocks that do not require land include organic waste streams from agriculture and industry, and woody residues from forest harvesting and wood processing. Investment in comprehensive waste collection and sorting in the NZE unlocks around 45 EJ of bioenergy supply from various organic waste streams which is primarily used to produce biogases and advanced biofuels (Figure 2.28). Woody residues from wood processing and forest harvesting provide a further 20 EJ of bioenergy in 2050 in the NZE – less than half of current best estimates of the total sustainable potential. Bioenergy can also be produced from dedicated short-rotation woody crops (25 EJ of bioenergy supply in 2050).[21] Sustainably managed forestry fuelwood or plantations[22] and tree plantings integrated with agricultural production via agroforestry systems that do not conflict with food production or biodiversity provide just over 10 EJ of bioenergy in 2050.



**Figure 2.28 ▷ Global bioenergy supply by source in the NZE**






***Bioenergy use increases by around 60% between 2020 and 2050, while shifting away from conventional feedstocks and the traditional use of biomass***

Note: Organic waste streams include agricultural residues, food processing, industrial and municipal organic waste streams; they do not require land area.

Source: IEA analysis based on IIASA data.

The total land area dedicated to bioenergy production in the NZE increases from 330 million hectares (Mha) in 2020 to 410 Mha in 2050. In 2050, around 270 Mha is forest, representing around one-quarter of the total area of global managed forests, and around 5% of total forest area. There is 130 Mha of land used for short-rotation advanced bioenergy crops in 2050 and 10 Mha for conventional bioenergy crops. There is no overall increase in cropland use for bioenergy production in the NZE from today's level and no bioenergy crops are developed on forested land in the NZE.[23] As well as allowing a much greater level of bioenergy crop production on marginal lands, woody energy crops can produce twice as much bioenergy per hectare as conventional bioenergy crops.

[21] Woody short-rotation coppice crops grown on crop land, pasture land or marginal lands not suited to food crops.

[22] Sustainable forestry management ensures that the carbon stock and carbon absorption capability of the forest is expanded or remains unchanged.

[23] Of the 140 Mha land used for bioenergy crops in 2050, 70 Mha are marginal lands or land currently used for livestock grazing and 70 Mha are cropland. There is a 60 Mha increase in cropland use for woody crops to 2050 in the NZE but this is offset by a reduction in cropland use for producing conventional biofuel feedstocks.

Total land use for bioenergy in the NZE is well below estimated ranges of potential land availability that take full account of sustainability constraints, including the need to protect biodiversity hotspots and to meet the UN Sustainable Development Goal 15 on biodiversity and land use. The certification of bioenergy products and strict control of what land can be converted to expand forestry plantations and woody energy crops nevertheless is critical to avoid land-use conflict issues. Certification is also critical to ensure the integrity of $CO_2$ offsets (see Chapter 1), the use of which should be carefully managed and restricted to sectors that lack alternative mitigation options. A related land-use issue is how to tackle emissions that arise from outside the energy sector (Box 2.3).

### Box 2.3 ▷ Balancing emissions from land use, agriculture and forestry

To limit the global temperature rise, all sources of GHG emissions need to decline to close to zero or to be offset with CDR. The energy sector accounted for around three quarters of total GHG emissions in recent years. The largest source of GHG emissions other than the energy sector is agriculture, forestry and other land use (AFOLU), which produced between 10-12 Gt $CO_2$-eq net GHG emissions in recent years.[24] $CO_2$ emissions from AFOLU were around 5-6 Gt $CO_2$, and nitrous oxide and methane emissions were around 5-6 Gt $CO_2$-eq (IPCC, 2019).

Options to reduce emissions from AFOLU and enhance removals include: halting deforestation; improving forest management practices; instituting farming practices that increase soil carbon levels; and afforestation. A number of companies have recently expressed interest in these sorts of nature-based solutions to offset emissions from their operations (see Chapter 1). For afforestation, converting around 170 Mha (roughly half the size of India) to forests would sequester around 1 Gt $CO_2$ annually by 2050.

Achieving net-zero energy-related and industrial process $CO_2$ emissions by 2050 in the NZE does not rely on any offsets from outside the energy sector. But commensurate action on AFOLU would help limit climate change. The energy-sector transformation in the NZE would reduce $CO_2$ emissions from AFLOU in 2050 by around 150 Mt $CO_2$ given the switch away from conventional crops and the increase in short rotation advanced-bioenergy crop production on marginal lands and pasture land. To reduce emissions from AFOLU further would require reducing deforestation by two-thirds by 2050, instituting improved forest management practices and planting around 250 Mha of new forests. The combined impact of these changes would reduce $CO_2$ emissions from AFOLU to zero by 2040 and absorb 1.3 Gt $CO_2$ annually by 2050. In this case, cumulative AFOLU $CO_2$ emissions between 2020 and 2050 would be around 40 Gt $CO_2$.

Non-$CO_2$ emissions from livestock, as well as other agricultural emissions, may be more difficult to mitigate given the link between livestock production and nitrous oxide and methane emissions. Changes to farming practices and technology improvements,

[24] AFOLU emissions are emissions from anthropogenic activities and do not include $CO_2$ emissions removal from the atmosphere by natural land sinks.

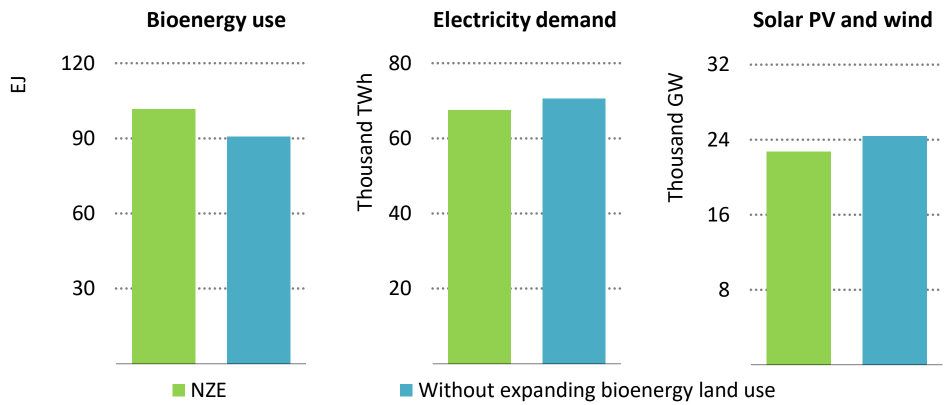
including changes to animal feed, could help to reduce these emissions, but it may be necessary to use afforestation to offset these emissions entirely. An alternative could be to reduce these emissions by reducing the demand for livestock products. For example, we estimate that reducing meat consumption in households with the highest levels of per capita consumption today to the global average level would reduce GHG emissions by more than 1 Gt $CO_2$-eq in 2050. Lower demand for livestock products would reduce the pasture needed globally for livestock by close to 200 Mha and the cropland that is used to grow feed for livestock by a further 80 Mha.



### *Are net-zero emissions by 2050 possible without expanding land use for bioenergy?*

Estimates of the global sustainable bioenergy potential are subject to a high degree of uncertainty, in particular over the extent to which new land area could sustainably be converted to bioenergy production. As a result, the NZE takes a cautious approach to bioenergy use, with consumption in 2050 (100 EJ) well below the latest estimates that integrate relevant SDGs, which suggest a potential between 150-170 EJ. But it is possible that the land available to provide sustainable bioenergy is even more limited. Here we explore the implications for emissions of restricting land use for dedicated bioenergy crops and forestry plantations to around 330 Mha, which is what is used today.

**Figure 2.29 ▹ Impact on electricity demand and ability to achieve net-zero emissions by 2050 without expanded bioenergy land use**






***Achieving net-zero emissions without expanding bioenergy land use would require a further 3 200 TWh from solar PV and wind, increasing capacity in the NZE by nearly 10%***

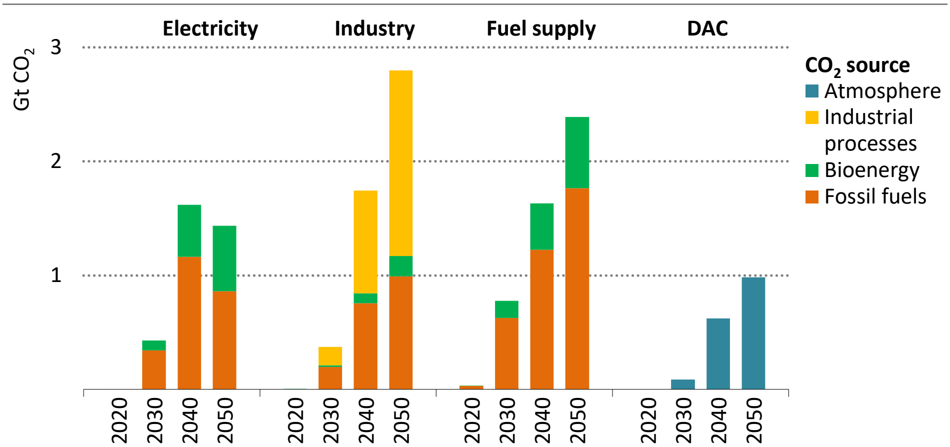
Limiting land use to 330 Mha would reduce available bioenergy supply in 2050 by more than 10 EJ. This would mostly take the form of a reduction in the availability of short-rotation woody energy crops, which are mainly used in the NZE in place of fossil fuels to provide high temperature heat for industrial processes and for electricity generation. Without bioenergy, it is likely that hydrogen and synthetic methane would be used instead, and their production would require around 70 Mt of hydrogen in 2050 (15% more than in the NZE). If this were to be produced through the use of electrolysis it would require around 750 GW of electrolyser capacity and increase electricity demand in 2050 by around 3 200 TWh (Figure 2.29).

The additional electricity that would be needed could be produced using renewables, which would require an additional 1 700 GW of wind and solar PV capacity and almost 350 GW of additional battery capacity in 2050. Annual capacity additions during the 2030s would need to be 160 GW higher than in the NZE. The additional wind, solar, battery and electrolyser capacity, together with the electricity networks and storage needed to support this higher level of deployment would cost more than USD 5 trillion by 2050. This is USD 4.5 trillion more than would be needed if the use of bioenergy were to be expanded as envisaged in the NZE, and would increase the total investment needed in the NZE by 3%. While it might therefore be possible still to achieve net-zero emissions in 2050 without expanding land use for bioenergy, this would make the energy transition significantly more expensive.

### *2.7.3 CCUS applied to emissions from fossil fuels*

A total of 7.6 Gt $CO_2$ is captured in 2050 in the NZE, almost 50% of which is from fossil fuel combustion, 20% is from industrial processes, and around 30% is from bioenergy use with $CO_2$ capture and DAC (Figure 2.30). The use of CCUS with fossil fuels provides almost 70% of the total growth in CCUS to 2030 in the NZE. Yet the prospects for the rapid scaling up of CCUS are very uncertain for economic, political and technical reasons. Here we look at the implications for reaching net-zero emissions in 2050 if fossil fuel CCUS does not expand beyond existing and planned projects.

**Figure 2.30 ▷ CCUS by sector and emissions source in the NZE**






*Fossil fuel emissions account for almost 70% of total $CO_2$ capture in 2030 and almost 50% in 2050*

Note: DAC = direct air capture.

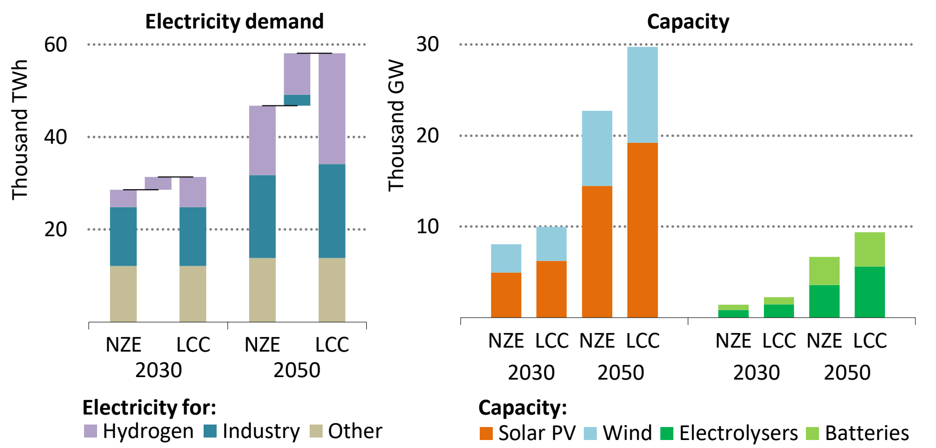
*Are net-zero emissions by 2050 possible without fossil fuel-based CCUS?*

Fossil fuel-based CCUS applications comprise most of the CCUS projects added to 2030 in the NZE. These projects help to reduce risks for other non-fossil fuel CCUS applications that are essential to reach net zero. In view of the challenges that fossil fuel-based CCUS projects face, we have constructed a *Low CCUS Case (LCC)* in which no new fossil fuel CCUS projects are developed beyond those already under construction or approved for development. In the LCC, $CO_2$ emissions captured from fossil fuels are only around 150 Mt in 2050, compared with 3 600 Mt in 2050 in the NZE.



In industry, the lack of new fossil fuel CCUS projects leads in the LCC to 1.2 Gt of additional $CO_2$ emissions compared with the NZE in 2050. It would be necessary to use alternative technologies to eliminate these emissions in order to achieve net zero by 2050. A number of technologies that are at the prototype stage of development would be needed, such as electric cement kilns or electric steam crackers for high-value chemicals production (see Box 2.4). Assuming that these technologies could be demonstrated and deployed at scale, this would increase electricity demand by around 2 400 TWh and hydrogen demand in industry by around 45 Mt in 2050. It would also be necessary to replace the 145 Mt of hydrogen that is produced in the NZE from fossil fuels equipped with CCUS. Provision of this 190 Mt of hydrogen through electrolysis would require an additional 2 000 GW capacity of electrolysers in 2050 (almost 60% more than in the NZE) and an additional 9 000 TWh of electricity (Figure 2.31).

**Figure 2.31 ▷ Impacts of achieving net-zero emissions by 2050 without expanded fossil fuel-based CCUS**






***Failure to deploy fossil fuel-based CCUS would significantly increase electricity demand and require much more solar, wind and electrolyser capacity***

Note: LCC = Low CCUS Case where CCUS applied to fossil fuels is restricted to projects under construction or approved for development today.

### Box 2.4 ▷ Technology innovation in the NZE

Innovation is key to developing new clean energy technologies and advancing existing ones. The importance of innovation increases as we get closer to 2050 because existing technologies will not be able to get us all the way along the path to net-zero emissions. Almost 50% of the emissions reductions needed in 2050 in the NZE depend on technologies that are at the prototype or demonstration stage, i.e. are not yet available on the market (see Chapter 4).

After a new idea makes its way from the drawing board to the laboratory and out into the world, there are four key stages in the clean energy innovation pipeline (IEA, 2020d). But the pathway to maturity can be long and success is not guaranteed.

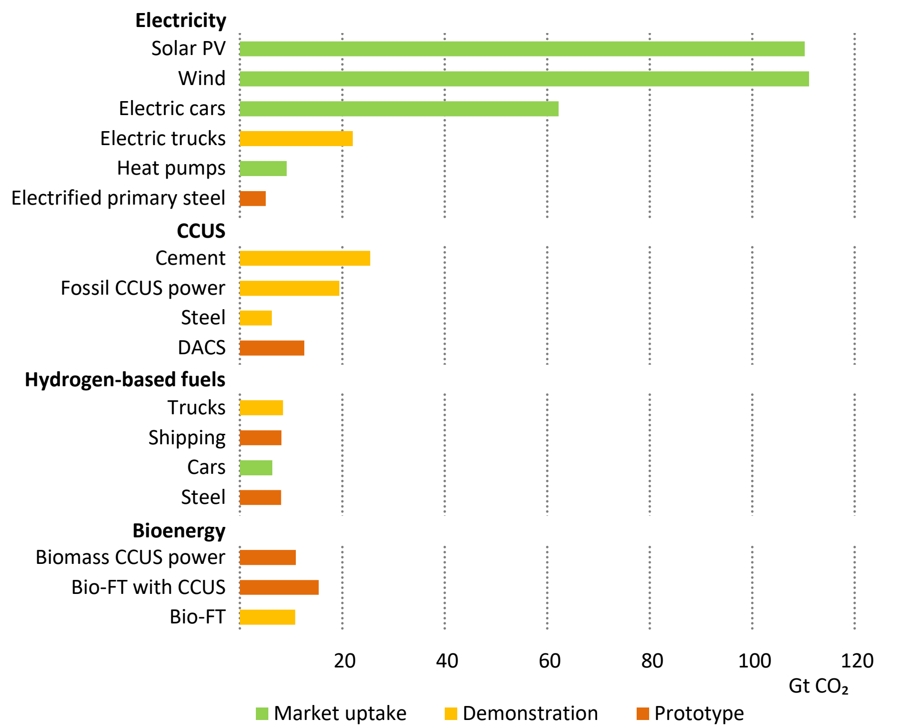
- **Prototype.** A concept is developed into a design and then into a prototype for a new device, e.g. a furnace that produces steel with pure hydrogen instead of coal.
- **Demonstration.** The first examples of a new technology are introduced at the size of a full-scale commercial unit, e.g. a system that captures $CO_2$ emissions from cement plants.
- **Market uptake.** The technology is being deployed in a number of markets. However, it either has a cost and performance gap with established technologies (e.g. electrolysers for hydrogen production) or it is competitive but there are still barriers, such as integration with existing infrastructure or consumer preferences, to reaching its full market potential (e.g. heat pumps). Policy attention is needed in both cases to stimulate wider diffusion to reduce costs and to overcome existing barriers, with more of the costs and risks being borne gradually by the private sector.
- **Maturity.** The technology has reached market stability, and new purchases or installations are constant or even declining in some environments as newer technologies start to compete with the stock of existing assets, e.g. hydropower turbines.

Innovation is critical in the NZE to bring new technologies to market and to improve emerging technologies, including for electrification, CCUS, hydrogen and sustainable bioenergy. The degree of reliance on innovation in the NZE varies across sectors and along the various steps of the value chains involved (Figure 2.32).

- **Electrification.** Almost 30% of the 170 Gt $CO_2$ cumulative emissions reductions from the use of low-emissions electricity in the NZE comes from technologies that are currently at prototype or demonstration stage, such as electricity-based primary steel production or electric trucks.
- **Hydrogen.** Not all steps of the low-carbon hydrogen value chain are available on the market today. The majority of demand technologies, such as hydrogen-based steel production, are only at the demonstration or prototype stage. These deliver more than 75% of the cumulative emissions reductions in the NZE related to hydrogen.

- **CCUS.** Around 55% of the cumulative emissions reductions that come from CCUS in the NZE are from technologies that are at the demonstration or prototype stage today. While $CO_2$ capture has been in use for decades in certain industrial and fuel transformation processes, such as ammonia production and natural gas processing, it is still being demonstrated at a large scale in many of the other possible applications.
- **Bioenergy.** Around 45% of the cumulative emissions reductions in the NZE related to sustainable bioenergy come from technologies that are at the demonstration or prototype stage today, mainly for the production of biofuels.

**Figure 2.32 ▷ Cumulative $CO_2$ emissions reductions for selected technologies by maturity category in the NZE**






***CCUS, hydrogen and bioenergy technologies are less mature than electrification. Most technologies for heavy industry and trucks are at early stages of development.***

Notes: Bio-FT = Biomass gasification with Fischer-Tropsch synthesis. Maturity levels are the technology design at the most advanced stage.

In the electricity sector, it would be necessary to produce an additional 11 300 TWh of electricity for industry and fuel transformation and to replace virtually all of the electricity generated from fossil fuel powered plants equipped with CCUS in 2050 in the NZE. Using renewables, this would require an additional 7 000 GW of wind and solar PV capacity in 2050. This is around 30% more than in the NZE, and would mean that annual capacity additions of solar PV and wind during the 2030s would need to reach 1 300 GW (300 GW more than in the NZE). To accommodate this additional level of variable renewables and to provide the flexibility that is available from fossil fuel CCUS equipped plants in the NZE, around 660 GW more battery capacity would be needed in 2050 (20% more than in the NZE in in 2050), together with additional 110 GW of other dispatchable capacity.

Reducing the rate of adding CCUS at existing coal- and gas-fired generation plants in the LCC would also raise the risk of stranded assets. We estimate that up to USD 90 billion of existing coal- and gas-fired capacity could be stranded in 2030 and up to USD 400 billion by 2050. Investment in fossil fuel-based CCUS in the NZE to 2050 is around USD 650 billion, which would be avoided in the LCC. But additional investment is required in the LCC for extra wind, solar and electrolyser capacity, for electricity-based routes in heavy industry, and for expanded electricity networks and storage to support this higher level of deployment. As a result, the additional cumulative investment to reach net-zero emissions in 2050 in the LCC is USD 15 trillion higher than in the NZE.

Failure to develop CCUS for fossil fuels would also be likely to delay or prevent the development of other CCUS applications. Without fossil fuel-based CCUS, the number of users and the volumes of the $CO_2$ transport and storage infrastructure deployed around industrial clusters would be reduced. Fewer actors and more limited pools of capital would be available to incur the high upfront costs of infrastructure, as well as other risks associated with the initial roll-out of CCUS infrastructure clusters. In addition, there would be fewer spill-over learning and cost-reduction benefits from developing fossil fuel-based CCUS, making the successful demonstration and scale up of more nascent CCUS technologies much less likely. A delay in the development of other CCUS technologies would have a major impact on the prospect of getting to net-zero emissions in 2050. For example, CCUS is the only scalable low-emissions option to remove $CO_2$ from the atmosphere and to almost eliminate emissions from cement production. If progress in these technologies were delayed and could not be deployed at scale, then achieving net-zero emissions by 2050 would be vastly more difficult.

# Sectoral pathways to net-zero emissions by 2050

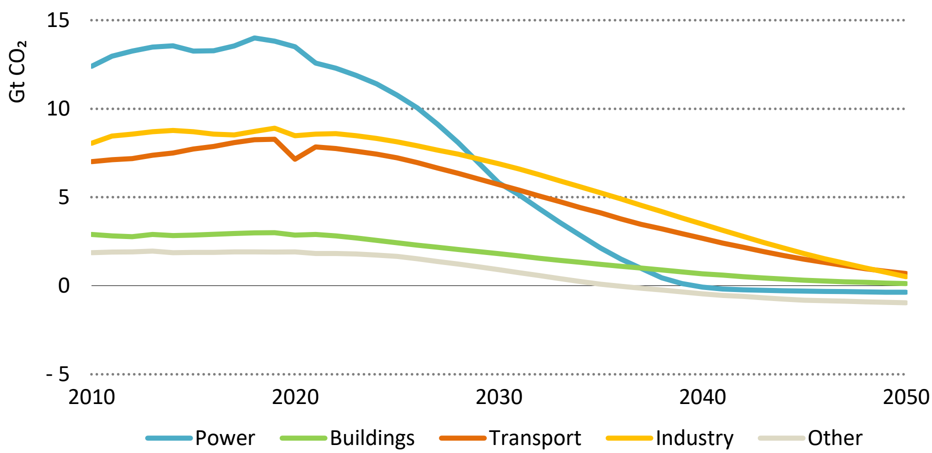

## SUMMARY

- Fossil fuel use falls drastically in the Net-Zero Emissions Scenario (NZE) by 2050, and no new oil and natural gas fields are required beyond those that have already been approved for development. No new coal mines or mine extensions are required. Low-emissions fuels – biogases, hydrogen and hydrogen-based fuels – see rapid growth. They account for almost 20% of global final energy in 2050, compared with 1% in 2020. More than 500 Mt of low-carbon hydrogen is produced in 2050, of which about 60% is produced using electrolysis that accounts for 20% of global electricity generation in 2050. Liquid biofuels provide 45% of global aviation fuel in 2050.
- Electricity demand grows rapidly in the NZE, rising 40% from today to 2030 and more than two-and-a-half-times to 2050, while emissions from generation fall to net-zero in aggregate in advanced economies by 2035 and globally by 2040. Renewables drive the transformation, up from 29% of generation in 2020 to 60% in 2030 and nearly 90% in 2050. From 2030 to 2050, 600 GW of solar PV and 340 GW of wind are added each year. The least-efficient coal plants are phased out by 2030 and all unabated coal by 2040. Investment in electricity grids triples to 2030 and remains elevated to 2050.
- In industry**,** emissions drop by 20% to 2030 and 90% to 2050. Around 60% of heavy industry emissions reductions in 2050 in the NZE come from technologies that are not ready for market today: many of these use hydrogen or CCUS. From 2030, all new industry capacity additions are near-zero emissions. Each month from 2030, the world equips 10 new and existing heavy industry plants with CCUS, adds 3 new hydrogen-based industrial plants and adds 2 GW of electrolyser capacity at industrial sites.
- In transport, emissions drop by 20% to 2030 and 90% to 2050. The initial focus is on increasing the operational and technical efficiency of transport systems, modal shifts, and the electrification of road transport. By 2030, electric cars account for over 60% of car sales (4.6% in 2020) and fuel cell or electric vehicles are 30% of heavy truck sales (less than 0.1% in 2020). By 2035, nearly all cars sold globally are electric, and by 2050 nearly all heavy trucks sold are fuel cell or electric. Low-emissions fuels and behavioural changes help to reduce emissions in long-distance transport, but aviation and shipping remain challenging and account for 330 Mt $CO_2$ emissions in 2050.
- In buildings**,** emissions drop by 40% to 2030 and more than 95% to 2050. By 2030, around 20% of the existing building stock worldwide is retrofitted and all new buildings comply with zero-carbon-ready building standards. Over 80% of the appliances sold are the most efficient models available by 2025 in advanced economies and by the mid-2030s worldwide. There are no new fossil fuel boilers sold from 2025, except where they are compatible with hydrogen, and sales of heat pumps soar. By 2050, electricity provides 66% of energy use in buildings (33% in 2020). Natural gas use for heating drops by 98% in the period to 2050.

## 3.1 Introduction

The Net-Zero Emissions by 2050 Scenario (NZE) involves a global energy system transformation that is unparalleled in its speed and scope. This chapter looks at how the main sectors are transformed, as well as the specific challenges and opportunities this involves (Figure 3.1). It covers the supply of fossil and low-emissions fuels, electricity generation and the three main end-use sectors – industry, transport and buildings. For each sector, we set out some key technology and infrastructure milestones on which the NZE depends for its successful delivery. Further we discuss what key policy decisions are needed, and by when, to achieve these milestones. Recognising that there is no single pathway to achieve net-zero emissions by 2050 and that there are many uncertainties related to clean energy transitions, in this chapter we also explore the implications of choosing not to rely on certain fuels, technologies or emissions reduction options across the transformation and end-use sectors.

**Figure 3.1 ▷ $CO_2$ emissions by sector in the NZE**






*Emissions fall fastest in the power sector, with transport, buildings and industry seeing steady declines to 2050. Reductions are aided by the increased availability of low-emissions fuels*

Note: Other = agriculture, fuel production, transformation and related process emissions, and direct air capture.

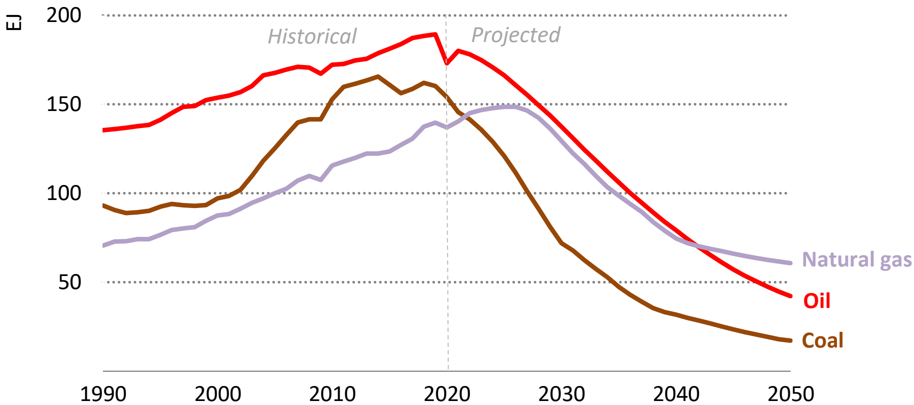
## 3.2 Fossil fuel supply

### 3.2.1 Energy trends in the Net-Zero Emissions Scenario

Coal use declines from 5 250 million tonnes of coal equivalent (Mtce) in 2020 to 2 500 Mtce in 2030 and to less than 600 Mtce in 2050. Even with increasing deployment of carbon capture, utilisation and storage (CCUS), coal use in 2050 is 90% lower than in 2020

(Figure 3.2). Oil demand never returns to its 2019 peak and it declines from 88 million barrels per day (mb/d) in 2020 to 72 mb/d in 2030 and to 24 mb/d in 2050, a fall of almost 75% between 2020 and 2050. Natural gas quickly rebounds from the dip in demand in 2020 and rises through to the mid-2020s, reaching a peak of around 4 300 billion cubic metres (bcm), before dropping to 3 700 bcm in 2030 and to 1 750 bcm in 2050. By 2050, natural gas use is 55% lower than in 2020.

**Figure 3.2 ▹ Coal, oil and natural gas production in the NZE**






***Between 2020 and 2050, demand for coal falls by 90%, oil by 75%, and natural gas by 55%***

### *Oil*

The trajectory of oil demand in the NZE means that no exploration for new resources is required and, other than fields already approved for development, no new oil fields are necessary. However, continued investment in existing sources of oil production are needed. On average oil demand in the NZE falls by more than 4% per year between 2020 and 2050. If all capital investment in producing oil fields were to cease immediately, this would lead to a loss of over 8% of supply each year. If investment were to continue in producing fields but no new fields were developed, then the average annual loss of supply would be around 4.5% (Figure 3.3). The difference is made up by fields that are already approved for development.

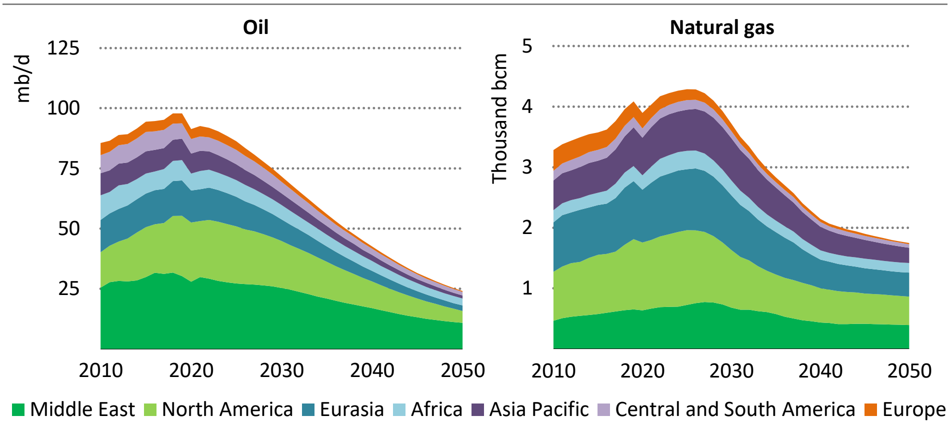
These dynamics are reflected in the oil price in the NZE, which drops to around USD 35/barrel in 2030 and USD 25/barrel in 2050. This price trajectory is largely determined by the operating costs for fields currently in operation, and only a very small volume of existing production would need to be shut in. However, income from oil production in all countries is much lower in the NZE than in recent years,[1] and the NZE projects significant stranded

[1] Governments may also reduce or eliminate upstream taxes to ensure that production costs are below the oil price to maintain domestic production.

capital and stranded value.[2] The oil price in the NZE would be sufficient in principle to cover the cost of developing new fields for the lowest cost producers, including those in the Middle East, but it is assumed that major resource holders do not proceed with investment in new fields because doing so would create significant additional downward pressure on prices.

The refining sector also faces major challenges in the NZE. Refinery throughput drops considerably and there are significant changes in product demand. With rapid electrification of the vehicle fleet, there is a major drop in demand for traditional refined products such as gasoline and diesel, while demand for non-combusted products such as petrochemicals increases. In recent years, around 55% of oil demand was for gasoline and diesel, but this drops to less than 15% in 2050, while the share of ethane, naphtha and liquefied petroleum gas (LPG) rises from 20% in recent years to almost 60% in 2050. This shift accentuates the drop in oil demand for refiners, and refinery runs fall by 85% between 2020 and 2050. Refiners are used to coping with changing demand patterns, but the scale of the changes in the NZE would inevitably lead to refinery closures, especially for refineries not able to concentrate primarily on petrochemical operations or the production of biofuels.

**Figure 3.3 ▷ Oil and natural gas production in the NZE**






*No new oil and natural gas fields are required beyond those already approved for development. Supply is increasingly concentrated in a few major producing countries*

## *Natural gas*

No new natural gas fields are needed in the NZE beyond those already under development. Also not needed are many of the liquefied natural gas (LNG) liquefaction facilities currently under construction or at the planning stage. Between 2020 and 2050, natural gas traded as

[2] Stranded capital is capital investment in fossil fuel infrastructure that is not recovered over the operating lifetime of the asset because of reduced demand or reduced prices resulting from climate policies. Stranded value is a reduction in the future revenue generated by an asset or asset owner assessed at a given point in time because of reduced demand or reduced prices resulting from climate policies (IEA, 2020a).

LNG falls by 60% and trade by pipeline falls by 65%. During the 2030s, global natural gas demand declines by more than 5% per year on average, meaning that some fields may be closed prematurely or shut in temporarily. Declines in natural gas demand slow after 2040, and more than half of natural gas use globally in 2050 is to produce hydrogen in facilities with CCUS. The large level of hydrogen, also produced using electrolysis, and biomethane in the NZE, means that the decline in total gaseous fuels is more muted than the decline in natural gas. This has important implications for the future of the gas industry (see Chapter 4).



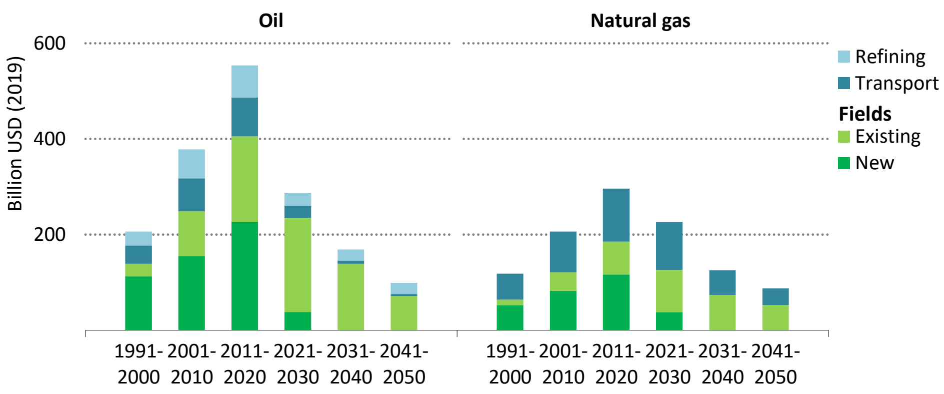
*Coal*

No new coal mines or extensions of existing ones are needed in the NZE as coal demand declines precipitously. Demand for coking coal falls at a slightly slower rate than for steam coal, but existing sources of production are sufficient to cover demand through to 2050. Such a decline in coal demand would have major consequences for employment in coal mining regions (see Chapter 4). There is a slowdown in the rate of decline in the 2040s as coal production facilities are increasingly equipped with CCUS: in the NZE, around 80% of coal produced in 2050 applies CCUS.

### 3.2.2 Investment in oil and gas

Upstream oil and gas investment averages about USD 350 billion each year from 2021 to 2030 in the NZE (Figure 3.4). This is similar to the level in 2020, but around 30% lower than average levels during the previous five years. Once fields under development start production, all of the upstream investment in the NZE is to support operations in existing fields; after 2030, total annual upstream investment is around USD 170 billion each year.

**Figure 3.4 ⊳ Investment in oil and natural gas supply in the NZE**






***Once fields under development start production, all upstream oil and gas investment is spent on maintaining production at existing fields***

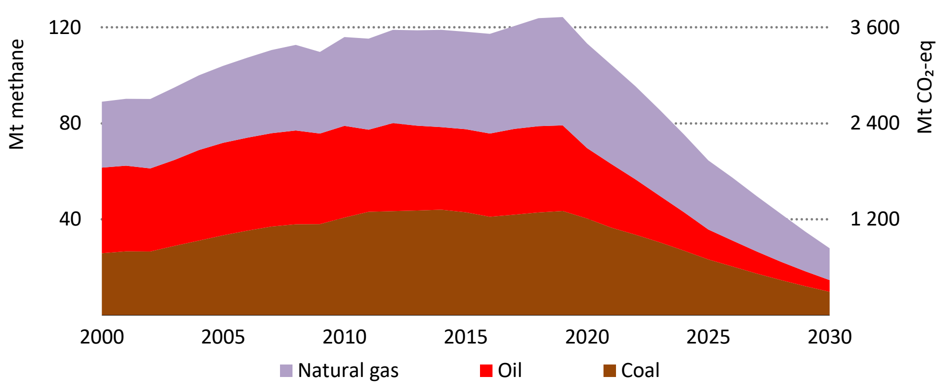
Note: Investment in new fields in the 2021-2030 period is for projects that are already under construction or have been approved.

### 3.2.3 Emissions from fossil fuel production

Emissions from the supply chains of coal, oil and natural gas fall dramatically in the NZE. The global average greenhouse gas (GHG) emissions intensity of oil production today is just under 100 kilogrammes of carbon-dioxide equivalent (kg $CO_2$-eq) per barrel. Without changes, a large proportion of global production would become uneconomic, as $CO_2$ prices are applied to the full value chains of fossil fuels. For example, by 2030 the $CO_2$ price in advanced economies in the NZE is USD 100 per tonne of $CO_2$ ($tCO_2$), which would add USD 10 to the cost of producing each barrel at today's average level of emissions intensity.

Methane constitutes about 60% of emissions from the coal and natural gas supply chains and about 35% of emissions from the oil supply chain. In the NZE, total methane emissions from fossil fuels fall by around 75% between 2020 and 2030, equivalent to a 2.5 gigatonne of carbon-dioxide equivalent (Gt $CO_2$-eq) reduction in GHG emissions (Figure 3.5). Around one-third of this decline is a result of an overall reduction in fossil fuel consumption, but the larger share comes from a huge increase in the deployment of emissions reduction measures and technologies, which leads to the elimination of all technically avoidable methane emissions by 2030 (IEA, 2020a).

**Figure 3.5 ▹ Methane emissions from coal, oil and natural gas in the NZE**






*Methane emissions from fossil fuels fall by 75% between 2020 and 2030 as result of a concerted global effort to deploy all available reduction measures and technologies*

Note: Mt = million tonnes.

Actions to reduce the emissions intensity of existing oil and gas operations in the NZE leads to: the end of all flaring; the use of CCUS with centralised sources of emissions (including to capture natural sources of $CO_2$ that are often extracted with natural gas); and significant electrification of upstream operations (often making use of off-grid renewable energy sources).

The NZE inevitably brings significant challenges for fossil fuel industries and those who work in them, but it also brings opportunities. Coal mining declines dramatically in the NZE, but the mining of minerals needed for clean energy transitions increases very rapidly, and mining expertise is likely to be highly valued in this context. The oil and gas industry could play a key role in helping to develop at scale a number of clean energy technologies such as CCUS, low-carbon hydrogen, biofuels and offshore wind. Scaling up these technologies and bringing down their costs will rely on large-scale engineering and project management capabilities, qualities that are a good match to those of large oil and gas companies. These issues, including the question of how to help those affected by the major changes implied by the NZE, are discussed in more detail in Chapter 4.



## 3.3 Low-emissions fuel supply

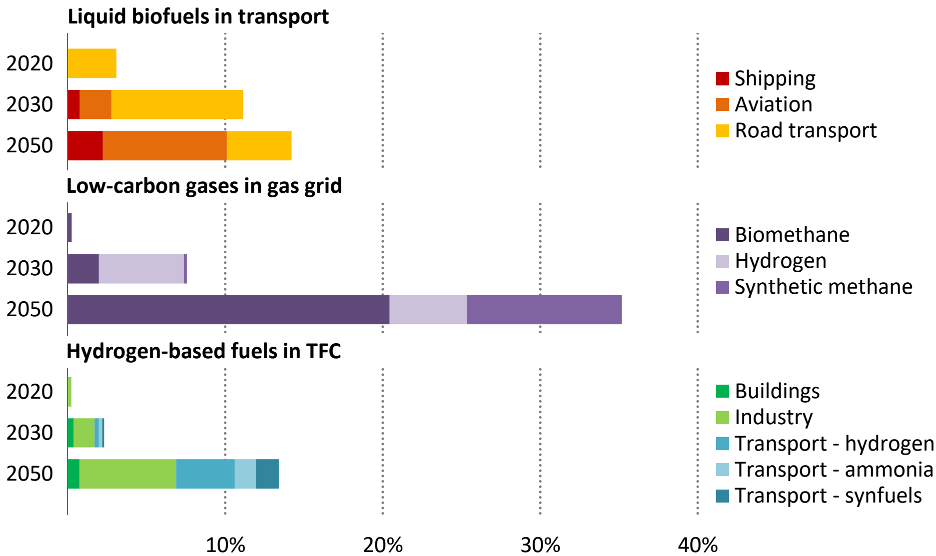
### *3.3.1 Energy trends in the Net-Zero Emissions Scenario*

Reaching net-zero emissions will require low-emissions fuels[3] where energy needs cannot easily or economically be met by electricity (Figure 3.6). This is likely to be the case for some modes of long-distance transport (trucks, aviation and shipping) and of heat and feedstock supply in heavy industry. Some low-emissions fuels are effectively drop-in, i.e. they are compatible with the existing fossil fuel distribution infrastructure and end-use technologies, and require few if any modifications to equipment or vehicles.

Low-emissions fuels today account for just 1% of global final energy demand, a share that increases to 20% in 2050 in the NZE. Liquid biofuels meet 14% of global transport energy demand in 2050, up from 4% in 2020; hydrogen-based fuels meet a further 28% of transport energy needs by 2050. Low-carbon gases (biomethane, synthetic methane and hydrogen) meet 35% of global demand for gas supplied through networks in 2050, up from almost zero today. The combined share of low-carbon hydrogen and hydrogen-based fuels in total final energy use worldwide reaches 13% in 2050. Hydrogen and ammonia also provide important low-emissions sources of power system flexibility and contribute 2% of overall electricity generation in 2050, which is enough to make the electricity sector an important driver of hydrogen demand.

[3] Low-emissions fuels refer to liquid biofuels, biogas and biomethane, and hydrogen-based fuels (hydrogen, ammonia and synthetic hydrocarbon fuels) that do not emit $CO_2$ from fossil fuels directly when used and also emit very little when being produced. For example, hydrogen produced from natural gas with CCUS and high capture rates (90% or higher) is considered a low-emissions fuel, but not if produced without CCUS.

**Figure 3.6 ▹ Global supply of low-emissions fuels by sector in the NZE**






*Low-emissions fuels in the form of liquid biofuels, biomethane, hydrogen-based fuels help to decarbonise sectors where direct electrification is challenging*

Notes: TFC = total final consumption. Low-carbon gases in the gas grid refers to the blending of biomethane, hydrogen and synthetic methane with natural gas in a gas network for use in buildings, industry, transport and electricity generation. Synfuels refer to synthetic hydrocarbon fuels produced from hydrogen and $CO_2$. Final energy consumption of hydrogen includes, in addition to the final energy consumption of hydrogen, ammonia and synthetic hydrocarbon fuels, the on-site hydrogen production in the industry sector.

### 3.3.2 Biofuels[4]

Around 10% of the global primary supply of modern bioenergy (biomass excluding traditional uses for cooking) was consumed as liquid biofuels for road transport and 6% was consumed as biogases (biogas and biomethane) to provide power and heat in 2020, with the rest directly used for electricity generation and heating in the residential sector. Supply accelerates sharply in the NZE with liquid biofuels expanding by a factor of almost four and biogases increasing by a factor of six by 2050.

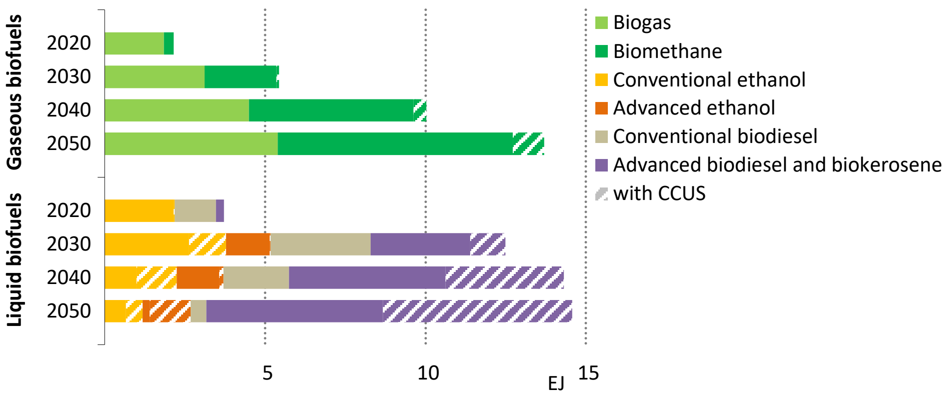
All but about 7% of liquid biofuels for transport are currently produced from conventional crops such as sugarcane, corn and soybeans. Such crops directly compete with arable land that can be used for food production, which limits the scope for expanding output. So most of the growth in biofuels in the NZE comes from advanced feedstocks such as wastes and residues and woody energy crops grown on marginal lands and cropland not suitable for food

[4] Liquids and gases produced from bioenergy.

production (see section 2.7.2). Advanced liquid biofuel production technology using woody feedstock expands rapidly over the next decade in the NZE, and its contribution to liquid biofuels jumps from less than 1% in 2020 to almost 45% in 2030 and 90% in 2050 (Figure 3.7). By 2030, production reaches 2.7 million barrels of oil equivalent per day (mboe/d) by 2030, underpinned by biomass gasification using the Fischer-Tropsch process (bio-FT) and cellulosic ethanol, mostly to produce drop-in substitutes for diesel and jet kerosene. Advanced liquid biofuel production increases by an additional 130% to more than 6 mboe/d in 2050, the bulk of which is biokerosene.



**Figure 3.7 ▻ Global biofuels production by type and technology in the NZE**






***Liquid biofuel production quadruples while that of biogases expands sixfold between 2020 and 2050, underpinned by the development of sustainable biomass supply chains***

Notes: EJ = exajoules; CCUS = carbon capture, utilisation and storage. Conventional ethanol refers to production using food energy crops. Advanced ethanol refers to production using wastes and residues and non-food energy crops grown on marginal and non-arable land. Conventional biodiesel includes fatty acid and methyl esters (FAME) route using food energy crops. Advanced biodiesel includes biomass-based Fischer-Tropsch and HEFA routes using wastes, residues and non-food energy crops grown on marginal and non-arable land. Biomethane includes biogas upgrading and biomass gasification-based routes.

Production using these feedstocks is mostly under development today. Current output capacity, principally cellulosic ethanol, is about 2.5 thousand barrels of oil equivalent per day (kboe/d). The NZE assumes that projects currently in the pipeline in Japan, the United Kingdom and the United States will bring these technologies to the market within the next few years. The scale up required for all advanced liquid biofuels (including from waste oils) over the next decade is equivalent to building one 55 kboe/d biorefinery every ten weeks (the world's largest biorefinery has capacity of 28 kboe/d).

The supply of these biofuels after 2030 shifts rapidly in the NZE from passenger vehicles and light trucks, where electrification is increasingly the order of the day, to heavy road freight, shipping and aviation. Ammonia makes inroads into shipping. Advanced liquid biofuels increase their share of the global aviation fuel market from 15% in 2030 to 45% in 2050.

Advanced biofuels such as hydrogenated esters and fatty acids (HEFA) and bio-FT are able to adjust their product slates (up to a point) from renewable diesel to biokerosene, and existing ethanol plants, especially those that can be retrofitted with CCUS or integrated with cellulosic feedstock, also make a contribution.

The supply of biogases increases even more than liquid biofuels. Injection into gas networks expands from under 1% of total gas volume in 2020 to almost 20% in 2050, reducing the emissions intensity of the network-based gas. Biomethane is mostly produced by upgrading biogas produced from anaerobic digestion of feedstocks such as agricultural residues like manure and biogenic municipal solid waste, thereby avoiding methane emissions that would otherwise be released. Due to the dispersed nature of these feedstocks, this assumes the construction of thousands of injection sites and associated distribution lines every year. Biogas and biomethane are also used as clean cooking fuels and in electricity generation in the NZE.

The production of biofuels can be combined with CCUS at a relatively low cost in some biofuel production routes (ethanol, bio-FT, biogas upgrading) because the processes involved release very pure streams of $CO_2$. In the NZE, the use of biofuels with CCUS results in annual carbon dioxide removal (CDR) of 0.6 Gt $CO_2$ in 2050, which offset residual emissions in transport and industry.

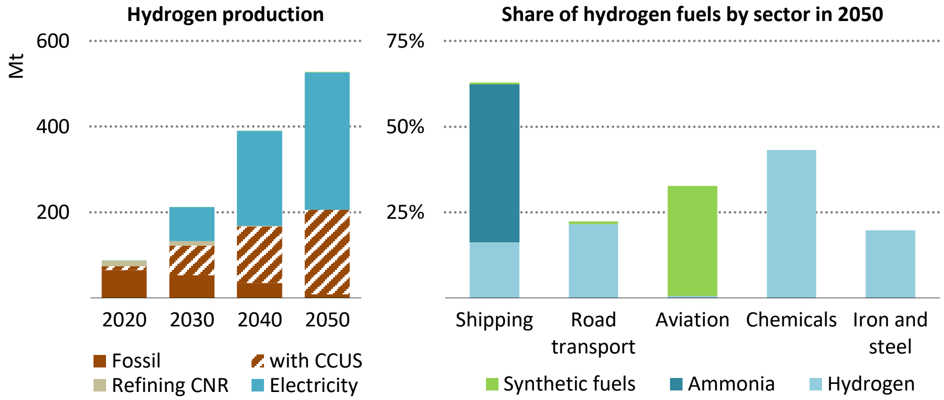
### *3.3.3 Hydrogen and hydrogen-based fuels*

Hydrogen use in the energy sector today is largely confined to oil refining and the production of ammonia and methanol in the chemicals industry. Global hydrogen demand was around 90 million tonnes (Mt) in 2020, mainly produced from fossil fuels (mostly natural gas) and emitting close to 900 Mt $CO_2$. Both the amount needed and the production route of hydrogen change radically in the NZE. Demand increases almost sixfold to 530 Mt in 2050, of which half is used in heavy industry (mainly steel and chemicals production) and in the transport sector; 30% is converted into other hydrogen-based fuels, mainly ammonia for shipping and electricity generation, synthetic kerosene for aviation and synthetic methane blended into gas networks; and 17% is used in gas-fired power plants to balance increasing electricity generation from solar PV and wind and to provide seasonal storage. Overall, hydrogen-based fuels[5] account for 13% of global final energy demand in 2050 (Figure 3.8).

Ammonia is used today as feedstock in the chemical industry, but in the NZE it is also used as fuel in various energy applications, benefitting from its lower transport cost and higher energy density than hydrogen. Ammonia accounts for around 45% of global energy demand for shipping in 2050 in the NZE. Co-firing with ammonia is also a potential early option to reduce $CO_2$ emissions in existing coal-fired power plants. The toxicity of ammonia means that its handling is likely to be limited to professionally trained operators, which could restrict its potential.

[5] Hydrogen-based fuels are defined as hydrogen, ammonia as well as synthetic hydrocarbon fuels produced from hydrogen and $CO_2$.

**Figure 3.8 ▷ Global production of hydrogen by fuel and hydrogen demand by sector in the NZE**






*Hydrogen production jumps sixfold by 2050, driven by water electrolysis and natural gas with CCUS, to meet rising demand in shipping, road transport and heavy industry*

Note: Refining CNR = hydrogen by-product from catalytic naphtha reforming at refineries.

Synthetic kerosene meets around one-third of global aviation fuel demand in 2050 in the NZE. Its manufacture at bioenergy-fired power or biofuel production plants requires $CO_2$ captured from the atmosphere. $CO_2$ from these sources can be considered carbon neutral, as it results in no net emissions when the fuel is used. There is scope for the co-production of advanced liquid biofuels and synthetic liquid fuels from hydrogen and $CO_2$, with the integration of the two processes reducing the overall liquid fuel production costs. Alongside synthetic liquid fuels, enough synthetic methane is produced from hydrogen and $CO_2$ in 2050 to meet 10% of demand for network supplied gas in the buildings, industry and transport sectors.

By 2050, hydrogen production in the NZE is almost entirely based on low-carbon technologies: water electrolysis accounts for more than 60% of global production, and natural gas in combination with CCUS for almost 40%. Global electrolyser capacity reaches 850 gigawatts (GW) by 2030 and 3 600 GW by 2050, up from around 0.3 GW today. Electrolysis absorbs close to 15 000 terawatt-hours (TWh), or 20% of global electricity supply in 2050, largely from renewable resources (95%), but also from nuclear power (3%) and fossil fuels with CCUS (2%). Natural gas use for hydrogen production with CCUS is 925 bcm in 2050, or around 50% of global natural gas demand, with 1.8 Gt $CO_2$ being captured.

Scaling up deployment of technologies and related manufacturing capacity will be critical to reducing costs. Water electrolysers are available on the market today and hydrogen production from natural gas with CCUS has been demonstrated at a commercial scale (there are seven plants in operation around the world). The choice between the two depends on economic factors, mainly the cost of natural gas and electricity, and on whether $CO_2$ storage is available. For natural gas with CCUS, production costs in the NZE are around USD 1-2 per kilogramme (kg) of hydrogen in 2050, with gas costs typically accounting for 15-55% of total production costs. For water electrolysis, learning effects and economies of scale result in CAPEX cost reductions of 60% in the NZE by 2030 compared to 2020. Production cost reductions hinge on lowering the cost of low-carbon electricity, as electricity accounts for 50-85% of total production costs, depending on the electricity source and region. The average cost of producing hydrogen from renewables drops in the NZE from USD 3.5-7.5/kg today to around USD 1.5-3.5/kg in 2030 and USD 1-2.5/kg in 2050 – essentially about the same as the cost of producing with natural gas with CCUS.

Converting hydrogen into other energy carriers, such as ammonia or synthetic hydrocarbon fuels, involves even higher costs. But it results in fuels that can be more easily transported and stored, and which are also often compatible with existing infrastructure or end-use technologies (as in the case of ammonia for shipping or synthetic kerosene for aviation). For ammonia, the additional synthesis step increases the production costs by around 15% compared with hydrogen (mainly due to additional conversion losses and equipment costs).

The relatively high cost of synthetic hydrocarbon fuels explains why their use is largely restricted to aviation in the NZE, where alternative low-carbon options are limited. Synthetic kerosene costs were USD 300-700/barrel in 2020: although these costs fall to USD 130-300/barrel by 2050 in the NZE as the costs of electricity from renewables and $CO_2$ feedstocks decline, the cost of synthetic kerosene remains far higher than the projected USD 25/barrel cost of conventional kerosene in 2050 in the NZE. The supply of $CO_2$, captured from bioenergy equipped with CCUS or direct air capture (DAC), needed to make these fuels is a relevant cost factor, accounting for USD 15-70/barrel of the cost of synthetic hydrocarbon fuels in 2050. Closing these cost gaps implies penalties for fossil kerosene or support measures for synthetic kerosene corresponding to a $CO_2$ price of USD 250-400/tonne.

Increasing global demand for low-carbon hydrogen in the NZE provides a means for countries to export renewable electricity resources that could not otherwise be exploited. For example, Chile and Australia announced ambitions to become major exporters in their national hydrogen strategies. With declining demand for natural gas in the NZE, gas-producing countries could join this market by exporting hydrogen produced from natural gas with CCUS. Long-distance transport of hydrogen, however, is difficult and costly because of its low energy density, and can add around USD 1-3/kg of hydrogen to its price. This means that, depending on each country's own circumstances, producing hydrogen domestically may be cheaper than importing it, even if domestic production costs from low-carbon electricity or natural gas with CCUS are relatively high. International trade nevertheless becomes increasingly important in the NZE: around half of global ammonia and a third of synthetic liquid fuels are traded in 2050.

### 3.3.4 Key milestones and decision points

**Table 3.1 ▷ Key milestones in transforming low-emissions fuels**

| Sector | 2020 | 2030 | 2050 |
|---|---|---|---|
| **Bioenergy** | | | |
| Share of modern biofuels in modern bioenergy (excluding conversion losses) | 20% | 45% | 48% |
| Advanced liquid biofuels (mboe/d) | 0.1 | 2.7 | 6.2 |
| Share of biomethane in total gas networks | <1% | 2% | 20% |
| $CO_2$ captured and stored from biofuels production (Mt $CO_2$) | 1 | 150 | 625 |
| **Hydrogen** | | | |
| Production (Mt $H_2$) | 87 | 212 | 528 |
| *of which:* low-carbon (Mt $H_2$) | 9 | 150 | 520 |
| Electrolyser capacity (GW) | <1 | 850 | 3 585 |
| Electricity demand for hydrogen-related production (TWh) | 1 | 3 850 | 14 500 |
| $CO_2$ captured from hydrogen production (Mt $CO_2$) | 135 | 680 | 1 800 |
| Number of export terminals at ports for hydrogen and ammonia trade | 0 | 60 | 150 |

Note: mboe/d = million barrels of oil equivalent per day; Mt = million tonnes; $H_2$ = hydrogen.

#### *Biofuels*

Several sustainability frameworks considering net lifecycle GHG emissions and other sustainability indicators exist in different regions, e.g. the Renewable Energy Directive II in the European Union, RenovaBio in Brazil and the Low-C Fuel Standards in California. However, the scope, methodology and sustainability metrics of these frameworks differ. Global consensus on a sustainability framework and indicators within the next few years would help stimulate investment; this should be a priority. Such a framework should cover all forms of bioenergy (liquid, gaseous and solid) and other low-emissions fuels, and should strive for continuous environmental performance improvement. Certification schemes ideally should be developed in parallel.

Another early priority is for governments to assess national sustainable biomass feedstock potential as soon as possible to establish the quantities and types of wastes, residues and marginal lands suitable for energy crops. Assessments should provide the basis for national roadmaps for all liquid and gaseous biofuels, and strategies for low-emissions fuels. Early decisions will be needed in this context about how to support the sustainable collection of wastes and residues from the forestry, agriculture, animal and food industries and from advanced municipal solid waste sorting systems: in the NZE, support measures are in place by 2025. Measures might usefully include low-emissions fuels standards that incentivise the use of biofuels as feedstock. International knowledge-sharing would help with the design of such measures and assist efficient dissemination of best practices from regions with existing collection systems, e.g. for forestry residues in Nordic countries and used cooking oil collection in Europe, China and Southeast Asia countries.

Governments will also need to decide how best to support biogas installations and distribution in order to move away from traditional uses of biomass for cooking and heating by 2030. Such practices remain widespread in some developing countries. They are best tackled as part of broader programmes to promote clean cooking alongside improving access to electricity and LPG.

Decisions will be needed by 2025 on how best to create markets for sustainable biofuels and close the cost gap between biofuels and fossil fuels. Measures will need to incentivise the rapid development and deployment of advanced liquid biofuel technologies in end-use sectors (particularly heavy-duty trucking, shipping and aviation), using mechanisms such as low-carbon fuel standards, biofuel mandates and $CO_2$ removal credits. Measures that could boost the scaling up of advanced biofuels production in the next four years include: incentives for co-processing bio-oil in existing oil refineries or fully converting oil refineries to biorefineries; retrofitting ethanol plants with CCUS; and integrating cellulosic ethanol production with existing ethanol plants.

New infrastructure will be needed to provide for the injection of more biomethane into gas networks and to transport and store the $CO_2$ captured from ethanol and bio-FT biofuel plants. Governments should prioritise the co-development of biogas upgrading facilities and biomethane injection sites by 2030, ensuring that particular attention is paid to minimising fugitive biomethane emissions from the supply chain. Where biomass availability allows, governments may see value in encouraging the deployment of biofuel plants with CCUS near existing industrial hubs where integrated CCUS projects are planned, such as the Humber region in the United Kingdom.

### *Hydrogen-based fuels*

An immediate priority should be for governments to assess the opportunities and challenges of developing a low-carbon hydrogen industry as part of national hydrogen strategies or roadmaps. Decisions will be needed on whether to produce hydrogen domestically from low-carbon electricity via water electrolysis or from gas with CCUS or a combination of both, or whether to rely on imported hydrogen-based fuels. Building technology leadership along the hydrogen supply chain could help create jobs and stimulate economic growth.

Decisions will be needed during the next decade on how best to bring down the costs of low-carbon hydrogen production. Switching existing hydrogen production in industry and oil refining from unabated fossil fuels to low-carbon hydrogen is one possible way to ramp up low-carbon hydrogen production in applications that have large demand already available. Financial support instruments, such as contracts for differences, could help to reduce the current cost gap of low-carbon hydrogen production compared to existing unabated production from fossil fuels.

Decisions will also be needed on how best to scale up hydrogen. Industrial ports could be a good starting point, since they may provide access to low-carbon hydrogen supply in the form of offshore wind or $CO_2$ storage. They also offer scope to promote new port-related uses for hydrogen, e.g. shipping and delivery trucks, and they could become the first nodes of an international hydrogen trade network. The establishment of hydrogen trade will require the development of methodologies to determine the carbon footprint of the different hydrogen production routes and the adoption of guarantees of origin and certification schemes for low-carbon hydrogen (and hydrogen-based fuels).

Blending hydrogen into existing gas networks offers another early avenue to scale up low-carbon hydrogen production and trigger cost reductions. International harmonisation of safety standards and national regulations on allowed concentrations of hydrogen in gas grids would help with this, as would the adoption of blending quotas or low-emissions fuel standards.



Repurposing existing gas pipelines, where technically feasible, with declining natural gas demand and connecting large hydrogen demand hubs to transport hydrogen could result in low cost and low regret opportunities to kick-start the development of new hydrogen infrastructure. Developing the infrastructure for hydrogen at the pace required in the NZE would involve considerable investment risks along the value chain of production, transport and demand ranging from hydrogen production technologies through to low-emissions electricity generation and $CO_2$ transport and storage. Governments and local authorities could play an important role by co-ordinating the planning processes among the various stakeholders; direct public investment or public-private partnerships could help to develop necessary shared infrastructure for hydrogen; and international co-operation and cross-border initiatives could help to share investment burdens and risks and so facilitate large-scale deployments, as in the EU Important Projects of Common European Interest.

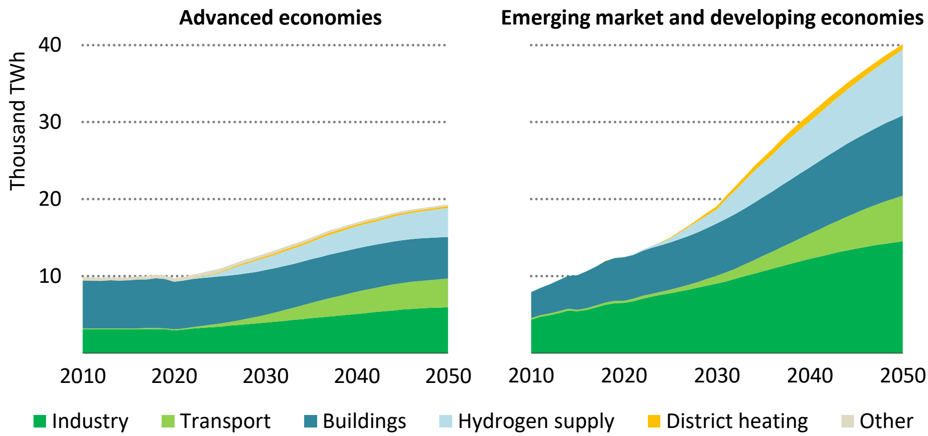
## 3.4 Electricity sector

### *3.4.1 Energy and emissions trends in the Net-Zero Emissions Scenario*

The NZE involves both a significant increase in electricity needs – the result of an increase in economic activity, rapid electrification of end-uses and expansion of hydrogen production by electrolysis – and a radical transformation in the way electricity is generated. Global electricity demand was 23 230 TWh in 2020 with an average growth rate of 2.3% per year over the previous decade. It climbs to 60 000 TWh in 2050 in the NZE, an average increase of 3.2% per year.

Emerging market and developing economies account for 75% of the projected global increase in electricity demand to 2050 (Figure 3.9). Their demand increases by half by 2030 and triples by 2050, driven by expanding population and rising incomes and living standards, as well new sources of demand linked to decarbonisation. In advanced economies, electricity demand returns to growth after a decade-long lull, nearly doubling between 2020 and 2050, driven mostly by end-use electrification and hydrogen production.

**Figure 3.9 ▷ Electricity demand by sector and regional grouping in the NZE**



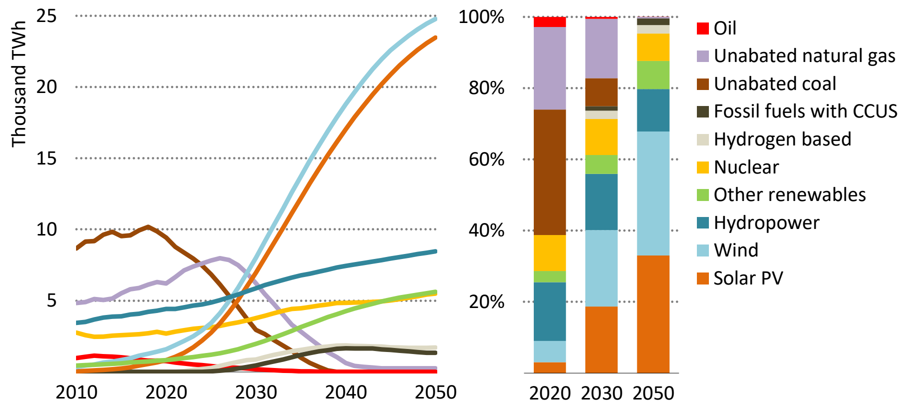



*Electrification of end-uses and hydrogen production raise electricity demand worldwide, with a further boost to expand services in emerging market and developing economies*

The transformation of the electricity sector is central to achieving net-zero emissions in 2050. Electricity generation is the single largest source of energy-related $CO_2$ emissions today, accounting for 36% of total energy-related emissions. $CO_2$ emissions from electricity generation worldwide totalled 12.3 Gt in 2020, of which 9.1 Gt was from coal-fired generation, 2.7 Gt from gas-fired plants and 0.6 Gt from oil-fired plants. In the NZE, $CO_2$ emissions from electricity generation fall to zero in aggregate in advanced economies in the 2030s. They fall to zero in emerging market and developing economies around 2040.

Renewables contribute most to decarbonising electricity in the NZE: global generation from renewables nearly triples by 2030 and grows eightfold by 2050 (Figure 3.10). This raises the share of renewables in total output from 29% in 2020 to over 60% in 2030 and nearly 90% in 2050. Solar PV and wind race ahead, becoming the leading sources of electricity globally before 2030: each generates over 23 000 TWh by 2050, equivalent to about 90% of all electricity produced in the world in 2020. Pairing battery storage systems with solar PV and wind to improve power system flexibility and maintain electricity security becomes commonplace in the late 2020s, complemented by demand response for short duration flexibility and hydropower or hydrogen for flexibility across days or even seasons. Hydropower is the largest low-carbon source of electricity today and steadily grows in the NZE, doubling by 2050. Generation using bioenergy – in dedicated plants and as biomethane delivered through gas networks – doubles to 2030 and increases nearly fivefold by 2050.

**Figure 3.10 ▷ Global electricity generation by source in the NZE**






***Solar and wind power race ahead, raising the share of renewables in total generation from 29% in 2020 to nearly 90% in 2050, complemented by nuclear, hydrogen and CCUS***

Nuclear power also makes a significant contribution in the NZE, its output rising steadily by 40% to 2030 and doubling by 2050, though its overall share of generation is below 10% in 2050. At its peak in the early 2030s, global nuclear capacity additions reach 30 GW per year, five-times the rate of the past decade. In advanced economies, lifetime extensions for existing reactors are pursued in many countries as they are one of the most cost-effective sources of low-carbon electricity (IEA, 2019), while new construction expands to about 4.5 GW per year on average from 2021 to 2035, with an increasing emphasis on small modular reactors. Despite these efforts, the nuclear share of total generation in advanced economies falls from 18% in 2020 to 10% in 2050. Two-thirds of new nuclear power capacity in the NZE is built in emerging market and developing economies mainly in the form of large-scale reactors, where the fleet of reactors quadruples to 2050. This raises the share of nuclear in electricity generation in those countries from 5% in 2020 to 7% in 2050 (as well as nuclear meeting 4% of commercial heat demand in 2050).

Nuclear power technologies have advanced in recent years, with several first-of-a-kind large-scale reactors completed that include enhanced safety features. While projects have been completed on schedule in China, Russia and the United Arab Emirates, there have been substantial delays and cost overruns in Europe and the United States. Small modular reactors and other advanced reactor designs are moving towards full-scale demonstration, with scalable designs, lower upfront costs and the potential to improve the flexibility of nuclear power in terms of both operations and outputs, e.g. electricity, heat or hydrogen.

Retrofitting coal- and gas-fired capacity with CCUS or co-firing with hydrogen-based fuels enables existing assets to contribute to the transition while cutting emissions and supporting electricity security. The best opportunities for CCUS are at large, young facilities with available space to add capture equipment and in locations with $CO_2$ storage options or demand for use. Opportunities are concentrated in China for coal-fired power plants and the United States for gas-fired capacity. While they provide just 2% of total generation from 2030 to 2050 in the NZE, retrofitted plants capture a total of 15 Gt $CO_2$ emissions over the period.

Carbon capture technologies remain at an early stage of commercialisation. Two commercial power plants have been equipped with CCUS over the past five years, and there are currently 18 CCUS power projects in development worldwide. Completing these projects in a timely manner and driving down costs through learning-by-doing will be critical to further expansion. An alternative would be to retrofit existing coal- and gas-fired power plants to co-fire high shares of hydrogen-based fuels. In the NZE, hydrogen-based fuels generate 900 TWh of electricity in 2030 and 1 700 TWh in 2050 in this way (about 2.5% of global generation in both years). A large-scale (1 GW) demonstration project to co-fire with 20% ammonia is underway in 2021, with aims to move towards ammonia-only combustion. Manufacturers have signalled that future gas turbine designs will be capable of co-firing high shares of hydrogen. While the investment needed to co-fire hydrogen-based fuels looks to be modest, relatively high fuel costs point to targeted applications to support power system stability and flexibility rather than bulk power.

The global use of unabated fossil fuels in electricity generation is sharply reduced in the NZE. Unabated coal-fired generation is cut by 70% by 2030, including the phase-out of unabated coal in advanced economies, and phased out in all other regions by 2040. Large-scale oil-fired generation is phased out in the 2030s. Generation using natural gas without carbon capture rises in the near term, replacing coal, but starts falling by 2030 and is 90% lower by 2040 compared with 2020.

The electricity sector is the first to achieve net-zero emissions mainly because of the low costs, widespread policy support and maturity of an array of renewable energy technologies. Solar PV is first among them: it is the cheapest new source of electricity in most markets and has policy support in more than 130 countries. Onshore wind is also a market-ready low cost technology that is widely supported and can be scaled up quickly, rivalling the low costs of solar PV where conditions are good, though it faces public opposition and extensive permitting and licensing processes in several markets. Offshore wind technology has been maturing rapidly in recent years; its deployment is poised to accelerate in the near term. The current focus is on fixed-bottom installations, but floating offshore wind starts to make a major contribution from around 2030 in the NZE, helping to unlock the enormous potential that exists around the world. Hydropower, bioenergy and geothermal technologies are well established, mature and flexible renewable energy sources. As dispatchable generating options, they will be critical to electricity security, complemented by batteries, which have seen sharp cost reductions, have proven their ability to provide high-value grid services and can be built in a matter of months in most locations. Concentrating solar and marine power are less mature technologies, but innovation could see them make important contributions in the long term.

### 3.4.2 Key milestones and decision points

**Table 3.2 ▷ Key milestones in transforming global electricity generation**

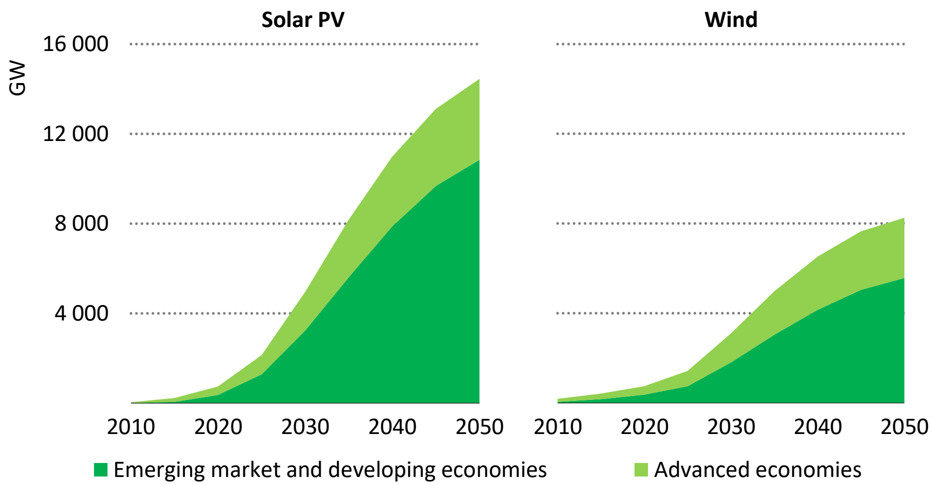
| Category | |
|---|---|
| **Decarbonisation of electricity sector** | • Advanced economies in aggregate: 2035.<br>• Emerging market and developing economies: 2040. |
| **Hydrogen-based fuels** | • Start retrofitting coal-fired power plants to co-fire with ammonia and gas turbines to co-fire with hydrogen by 2025. |
| **Unabated fossil fuel** | • Phase out all subcritical coal-fired power plants by 2030 (870 GW existing plants and 14 GW under construction).<br>• Phase out all unabated coal-fired plants by 2040.<br>• Phase out large oil-fired power plants in the 2030s.<br>• Unabated natural gas-fired generation peaks by 2030 and is 90% lower by 2040. |

| Category | 2020 | 2030 | 2050 |
|---|---|---|---|
| **Total electricity generation** (TWh) | 26 800 | 37 300 | 71 200 |
| **Renewables** | | | |
| Installed capacity (GW) | 2 990 | 10 300 | 26 600 |
| Share in total generation | 29% | 61% | 88% |
| Share of solar PV and wind in total generation | 9% | 40% | 68% |
| **Carbon capture, utilisation and storage (CCUS) generation** (TWh) | | | |
| Coal and gas plants equipped with CCUS | 4 | 460 | 1 330 |
| Bioenergy plants with CCUS | 0 | 130 | 840 |
| **Hydrogen and ammonia** | | | |
| Average blending in global coal-fired generation (without CCUS) | 0% | 3% | 100% |
| Average blending in global gas-fired generation (without CCUS) | 0% | 9% | 85% |
| **Unabated fossil fuels** | | | |
| Share of unabated coal in total electricity generation | 35% | 8% | 0.0% |
| Share of unabated natural gas in total electricity generation | 23% | 17% | 0.4% |
| **Nuclear power** | *2016-20* | *2021-30* | *2031-50* |
| Average annual capacity additions (GW) | 7 | 17 | 24 |
| **Infrastructure** | | | |
| Electricity networks investment in USD billion (2019) | 260 | 820 | 800 |
| Substations capacity (GVA) | 55 900 | 113 000 | 290 400 |
| Battery storage (GW) | 18 | 590 | 3 100 |
| Public EV charging (GW) | 46 | 1 780 | 12 400 |

Note: GW = gigawatts; GVA = gigavolt amperes.

Transforming the electricity sector in the way envisioned in the NZE involves large capacity additions for all low-emissions fuels and technologies. Global renewables capacity more than triples to 2030 and increases ninefold to 2050. From 2030 to 2050, this means adding more than 600 GW of solar PV capacity per year on average and 340 GW of wind capacity per year including replacements (Figure 3.11), while offshore wind becomes increasingly important over time (over 20% of total wind additions from 2021 to 2050, compared with 7% in 2020). The annual deployment of battery capacity in the electricity sector needs to scale up in parallel, from 3 GW in 2019 to 120 GW in 2030 and over 240 GW in 2040. Retrofitting existing coal- and gas-fired power plants also needs to get underway.

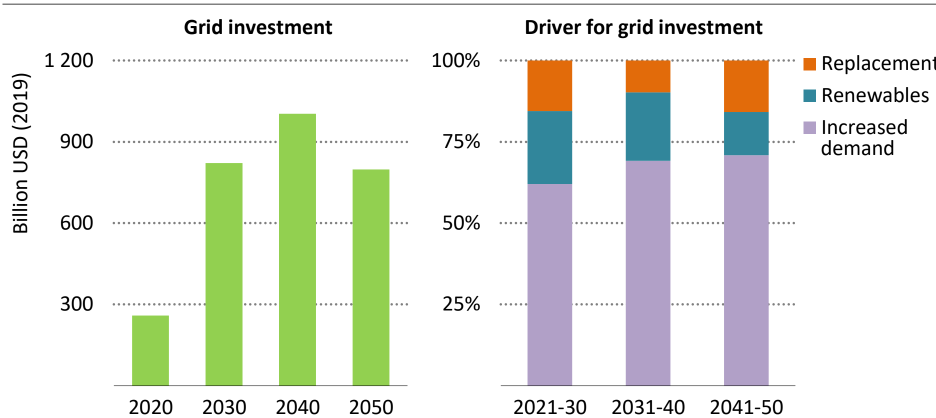
**Figure 3.11 ▹ Solar PV and wind installed capacity in the NZE**






*Solar PV and wind need to scale up rapidly to decarbonise electricity, with total solar PV capacity growing 20-fold and wind 11-fold by 2050*

**Figure 3.12 ▹ Global investment in electricity networks in the NZE**





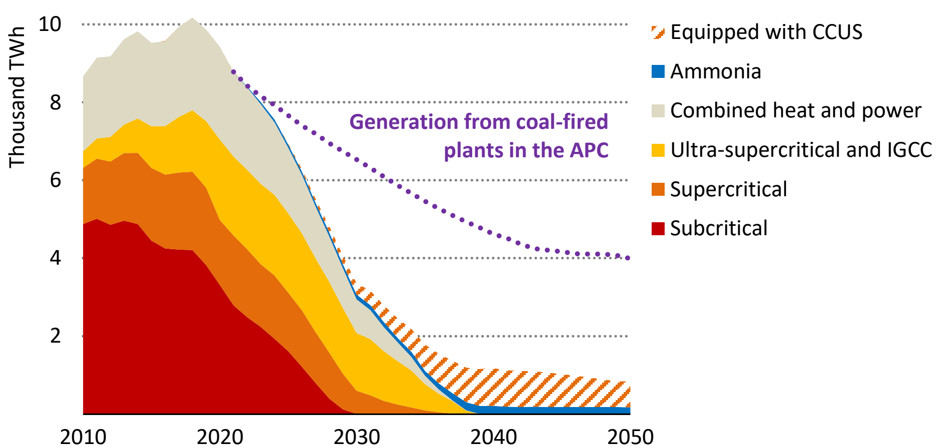

*Electricity network investment triples to 2030 and remains elevated to 2050, meeting new demand, replacing ageing infrastructure and integrating more renewables*

Investment in electricity networks will be crucial to achieving this transformation. Global electricity networks that took over 130 years to build need to more than double in total length by 2040 and increase by another 25% by 2050. Total grid investment needs to rise to USD 820 billion by 2030, and USD 1 trillion in 2040, before falling back after electricity is fully decarbonised and the growth of renewables slows to match demand growth (Figure 3.12). Replacing ageing infrastructure is an important part of network investment through to 2050 in the NZE.



Governments face several key decisions in the electricity sector if they are to follow the pathway to net-zero emissions by 2050 envisioned in the NZE particularly about how to best use existing power plants. For retrofits of coal- or gas-fired capacity, either with carbon capture or co-firing with hydrogen-based fuels (or full conversion), decisions are needed to support first-of-a-kind projects before 2030 before widespread retirement of unabated plants becomes necessary. For other fossil fuel power stations, decisions about phase outs are needed. Coal-fired power plants should be phased out completely by 2040 unless retrofitted, starting with the least-efficient designs by 2030 (Figure 3.13). This would require shutting 870 GW of existing subcritical coal capacity globally (11% of all power capacity) and international collaboration to facilitate substitutes. By 2040, all large-scale oil-fired power plants should be phased out. Natural gas-fired generation remains an important part of electricity supply through to 2050, but strong government support will be needed to ensure that CCUS is deployed soon and on a large scale.

**Figure 3.13 ▹ Coal-fired electricity generation by technology in the NZE**





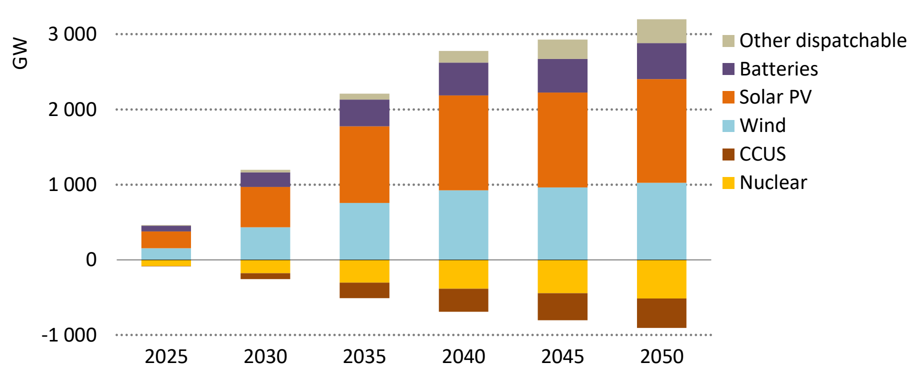

*Coal-fired power accounted for 27% of global energy $CO_2$ emissions in 2020, and in the NZE, all subcritical plants are phased out by 2030 and all plants without CCUS by 2040*

Notes: APC = Announced Pledges Case; IGCC = integrated gasification combined-cycle. Ammonia includes co-firing and full conversion of coal plants.

The path to net-zero emissions could be facilitated by early government action to help move several technologies that provide power system flexibility through the demonstration phases and bring them to market. Expanding the set of energy storage technologies to complement batteries and addressing emerging needs for longer duration seasonal storage would be of particular value. Technical solutions to support the stability of power grids with high shares of solar and wind would also benefit from research and development (R&D) support.

There are three important sets of decisions to be made concerning nuclear power: lifetime extensions; pace of new construction; and advances in nuclear power technology. In advanced economies, decisions need to be made about new construction and the large number of nuclear power plants that may be retired over the next decade absent action to extend their lifetimes and make the required investment. Without further lifetime extensions and new projects beyond those already under construction, nuclear power output in advanced economies will decline by two-thirds over the next two decades (IEA, 2019). In emerging market and developing economies, there are decisions to be made about the pace of new nuclear power construction. From 2011 to 2020, an average of 6 GW of new nuclear capacity came online each year. By 2030, the rate of new construction increases to 24 GW per year in the NZE. The third set of decisions concerns the extent of government support for advanced nuclear technologies, particularly those related to small modular reactors and high-temperature gas reactors, both of which can expand markets for nuclear power beyond electricity.

**Figure 3.14 ▷ Additional global alternative capacity needed in a Low Nuclear and CCUS Case**






***Sharply reducing the roles of nuclear power and carbon capture would require even faster growth in solar PV and wind, making achieving the net zero goal more costly and less likely***

Note: The Low Nuclear and CCUS Case assumes that global nuclear power output is about 60% lower in 2050 than in the NZE due to no additional lifetime extensions or new nuclear projects in advanced economies and no expansion of the current pace of construction in emerging market and developing economies, and that the amount of coal- and gas-fired capacity equipped with CCUS is 99% lower than in the NZE.

Failing to take timely decisions on nuclear power and CCUS would raise the costs of a net-zero emissions pathway and add to the risk of not meeting the goal by placing an additional burden on wind and solar to scale up even more quickly than in the NZE (Figure 3.14). In a *Low Nuclear and CCUS Case*, we assume that global nuclear power output is 60% lower in 2050 than in the NZE as a result of no additional nuclear lifetime extensions or new projects in advanced economies and no expansion of the current pace of construction in emerging market and developing economies, and that only the announced CCUS projects are completed (representing 1% of the CCUS capacity added in the NZE).



Our analysis indicates that the burden of replacing those sources of low-carbon generation would fall mainly on solar PV and wind power, calling for 2 400 GW more capacity than in the NZE – an amount far exceeding their combined global capacity in operation in 2020 (Figure 3.14). There would also be a need for about 480 GW of battery capacity above and beyond the 3 100 GW deployed in the NZE, plus more than 300 GW of other dispatchable capacity to meet demand in all seasons and ensure system adequacy. This would call for an additional USD 2 trillion investment in power plants and related grid assets (net of lower investment in nuclear and CCUS). Taking account of avoided fuel costs, the estimated total additional cost of electricity to consumers between 2021 and 2050 is USD 260 billion.

## 3.5 Industry

### *3.5.1 Energy and emission trends in the Net-Zero Emissions Scenario*

As the second-largest global source of energy sector $CO_2$ emissions, industry has a vital contribution to make in achieving the net zero goal. Industrial $CO_2$ emissions[6] (including from energy use and production processes) totalled about 8.4 Gt in 2020. Advanced economies accounted for around 20% and emerging market and developing economies for around 80%, although complex global supply chains for the production of materials and manufacturing mean that advanced economies generally consume far more finished goods than they produce.

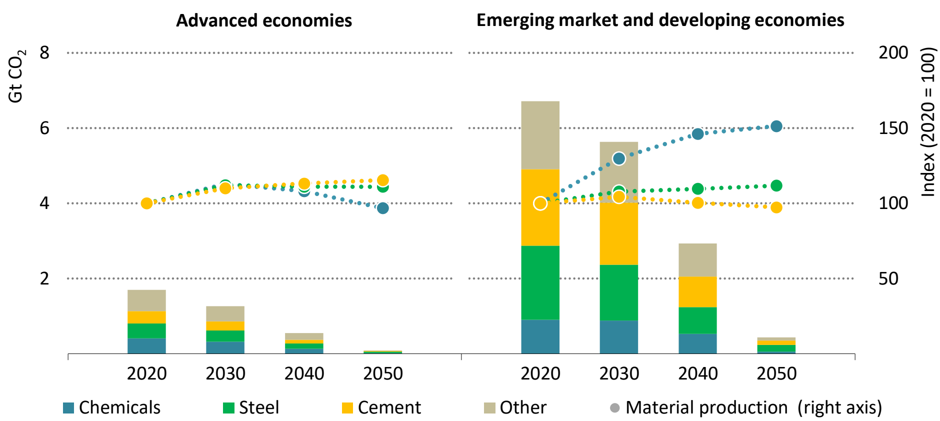
Three heavy industries – chemicals, steel and cement – account for nearly 60% of all industrial energy consumption and around 70% of $CO_2$ emissions from the industry sector. Production is highly concentrated in emerging market and developing economies, which account for 70-90% of the combined output of these commodities (Figure 3.15). China alone was responsible for almost 60% of both steel and cement production in 2020. These bulk materials are essential inputs to our modern way of life, with few cost-competitive substitutes; the challenge is to carry on producing these materials without emitting $CO_2$.

The outlook for global materials demand in the NZE is one of plateaus and small increases. This is in stark contrast with the growth seen during the last two decades when global steel

[6] All $CO_2$ emissions in this section refer to direct $CO_2$ emissions from the industry sector unless otherwise specified.

demand rose by 2.1-times, cement by 2.4-times and plastics (a key group of material outputs from the chemical sector) by 1.9-times in response to global economic and population expansion. When economies are developing, per capita material demand tends to rise rapidly to build up stocks of goods and infrastructure. As economies mature, future demand stems primarily from the need to refurbish and replace these stocks, the levels of which tend to saturate. In the NZE, flattening or even declining demand in many countries around the world leads to slower global demand growth. Some countries such as India see higher growth in steel and cement production, while production in China declines considerably following its industrial boom period after the turn of the millennium.

**Figure 3.15 ▷ Global $CO_2$ emissions from industry by sub-sector in the NZE**





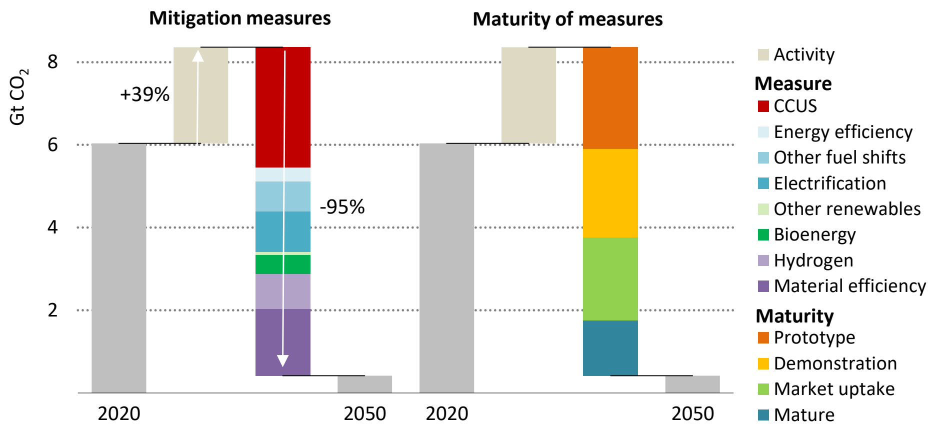

*The majority of residual emissions in industry in 2050 come from heavy industries in emerging market and developing economies*

Note: Other includes the production of aluminium, paper, other non-metallic minerals and other non-ferrous metals, and a series of light industries.

Certain segments of material demand increase rapidly to support the required expansion of energy-related infrastructure in the NZE, notably renewable electricity generation and transport infrastructure. The additional infrastructure required for these two segments by 2050 relative to today alone contributes roughly 10% of steel demand in 2050. But co-ordinated cross-sectoral strategies, including modal shifts in transport and building renovation, as well as other changes in design, manufacturing methods, construction practices and consumer behaviour, more than offset this increase. Overall, global demand for steel in 2050 is 12% higher than today, primary chemicals is 30% higher and cement demand is broadly flat.

$CO_2$ emissions from heavy industry decline by 20% by 2030 and 93% by 2050 in the NZE. Optimising the operational efficiency of equipment, adopting the best available technologies for new capacity additions and measures to improve material efficiency play an important part in this. However, there are limits to how much emissions can be reduced by these measures. Almost 60% of emissions reductions in 2050 in the NZE are achieved using technologies that are under development today (large prototype or demonstration scale) (Figure 3.16).

**Figure 3.16 ▷ Global $CO_2$ emissions in heavy industry and reductions by mitigation measure and technology maturity category in the NZE**






*An array of measures reduces emissions in heavy industry, with innovative technologies like CCUS and hydrogen playing a critical role*

Hydrogen and CCUS technologies together contribute around 50% of the emissions reductions in heavy industry in 2050 in the NZE. These technologies enable the provision of large amounts of high-temperature heat, which in many cases cannot be easily provided by electricity with current technologies, and help to reduce process emissions from the chemical reactions inherent in some industrial production. Bioenergy also makes a contribution in a wide array of industrial applications.

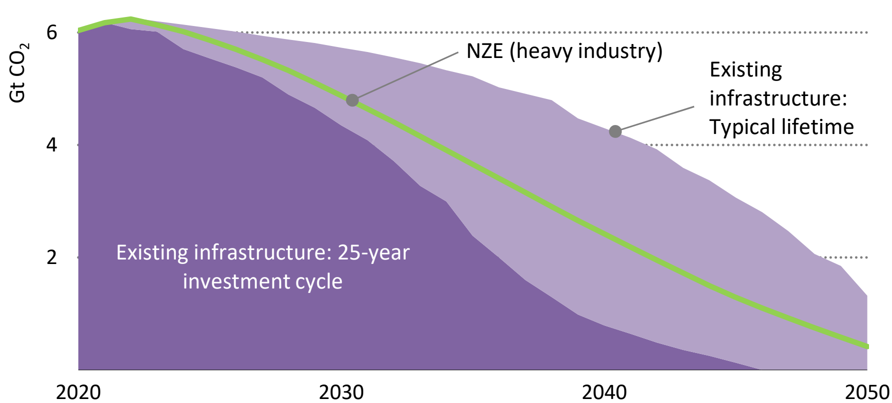
Aside from the need for high-temperature heat and process emissions, two factors explain the slower pace of emissions reductions in heavy industries relative to other areas of the energy system. First, the ease with which many industrial materials and products can be traded globally means that markets are competitive and margins are low. This leaves little room to absorb additional costs stemming from the adoption of more expensive production pathways. It will take time to develop robust global co-operation and technology transfer frameworks or domestic solutions to enable a level playing field for these technologies. Second, heavy industries use capital-intensive and long-lived equipment, which slows the deployment of innovative low-emission technologies. Capacity additions in the period to 2030 – before a large-scale roll-out of innovative processes can take place – largely explain the persistence of industrial emissions in 2050, more than 80% of which are in emerging market and developing economies. Strategically timed investment in low-carbon technologies could help minimise early retirements (Box 3.1).

**Box 3.1 ▷ Investment cycles in heavy industry**

For heavy industry, the year 2050 is just one investment cycle away. Average lifetimes of emissions-intensive assets such as blast furnaces and cement kilns are around 40 years. After about 25 years of operation, however, plants often undergo a major refurbishment to extend their lifetimes.

The challenge is to ensure that innovative near-zero emissions industrial technologies that are at large prototype and demonstration stage today reach markets within the next decade, when around 30% of existing assets will have reached 25 years of age and thus face an investment decision. If these innovative technologies are not ready, or not used even if ready, this would have a major negative impact on the pace of emissions reductions or risk an increase in stranded assets (Figure 3.17). Conversely, if they are ready, and if existing plants are retrofit or replaced with them at the 25-year investment decision point, this could reduce projected cumulative emissions to 2050 from existing heavy industry assets by around 40%. The critical window of opportunity from now to 2030 should not be missed.

**Figure 3.17 ▷ $CO_2$ emissions from existing heavy industrial assets in the NZE**

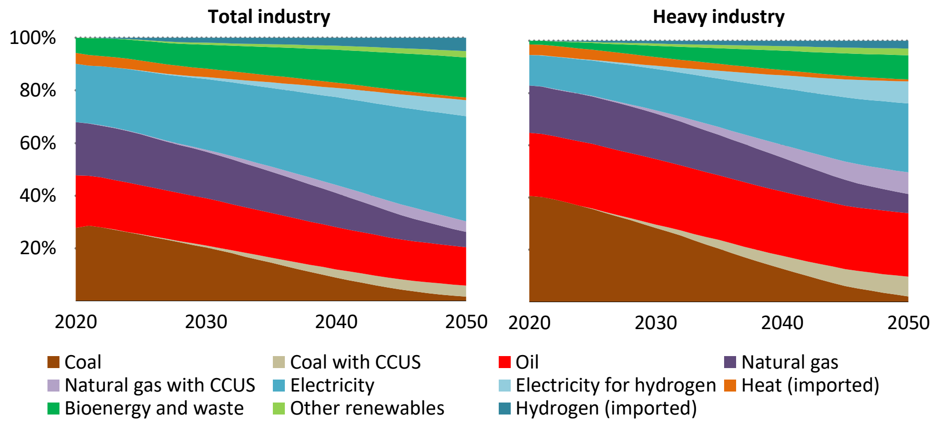





*Intervening at the end of the next 25-year investment cycle could help unlock 60 Gt $CO_2$, around 40% of projected emissions from existing heavy industry assets*

The energy mix in industry changes radically in the NZE. The share of fossil fuels in total energy use declines from around 70% today to 30% in 2050. The vast majority of fossil fuels still being used then are in heavy industries, mainly as chemical feedstock (50%) or in plants equipped with CCUS (around 30%). Electricity is the dominant fuel in industrial energy demand growth, with its share of total industrial energy consumption rising from 20% in 2020 to 45% in 2050. Some 15% of this electricity is used to produce hydrogen. Bioenergy plays an important role, contributing 15% of total energy use in 2050, but sustainable supplies are limited, and it is also in high demand in the power and transport sectors. Renewable solar and geothermal technologies to provide heat make a small but fast growing contribution (Figure 3.18).

**Figure 3.18 ▷ Global final industrial energy demand by fuel in the NZE**






*Fossil fuel use in industry is halved by 2050, replaced primarily by electricity and bioenergy*

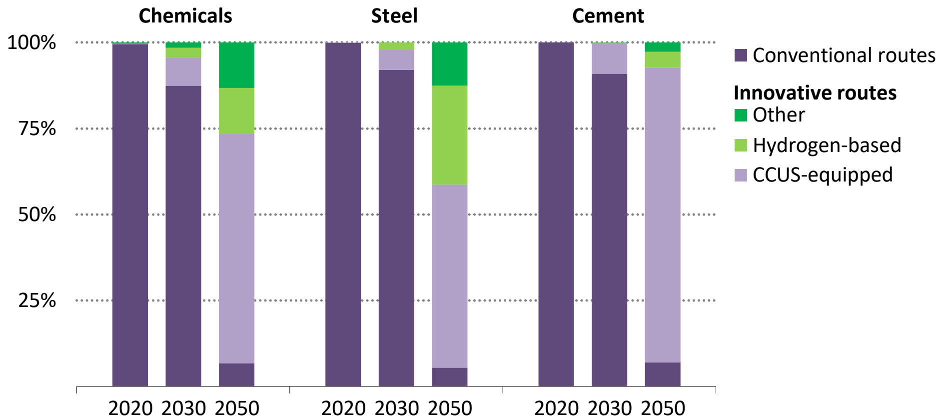
Notes: Industrial energy consumption includes chemical feedstock and energy consumed in blast furnaces and coke ovens. Hydrogen refers to imported hydrogen and excludes captive hydrogen generation. Electricity for hydrogen refers to electricity used in the production of captive hydrogen via electrolysis.

### Chemicals production

In the NZE, emissions from the chemicals sub-sector fall from 1.3 Gt in 2020 to 1.2 Gt in 2030 and around 65 Mt in 2050. The share of fossil fuels in total energy use falls from 83% in 2020 (mostly oil and natural gas), to 76% in 2030 and 61% in 2050. Oil remains the largest fuel used in primary chemicals production by 2050 in the NZE, along with smaller quantities of gas and coal.

Technologies that are currently available on the market account for almost 80% of the emissions savings achieved globally in the chemical industry by 2030 in the NZE relative to today. They include recycling and re-use of plastics and more efficient use of nitrogen fertilisers, which reduce the demand for primary chemicals, and measures to increase energy efficiency. Beyond 2030, the bulk of emissions reductions result from the use of technologies whose integration in chemical processes is under development today, including certain CCUS applications and electrolytic hydrogen generated directly from variable renewable electricity (Figure 3.19). CCUS-equipped conventional routes and pyrolysis technologies are most competitive in regions with access to low cost natural gas, while electrolysis is the favoured option in regions where the deployment of CCUS is impeded by a lack of infrastructure or public acceptance.

**Figure 3.19 ▷ Global industrial production of bulk materials by production route in the NZE**






***Near-zero emissions routes dominate cement, primary steel and chemicals production by 2050, with key roles for CCUS and hydrogen-based technologies***

Notes: CCUS = carbon capture, utilisation and storage. Chemicals refers to the production of primary chemicals (ethylene, propylene, benzene, toluene, mixed xylenes, ammonia and methanol). Steel refers to primary steel production. Other includes innovative processes that utilise bioenergy and directly electrify production. Hydrogen-based refers to electrolytic hydrogen. Fossil fuel-based hydrogen with CCUS is included in the CCUS-equipped category.

### *Iron and steel production*

In the NZE, global $CO_2$ emissions from the iron and steel sub-sector fall from 2.4 Gt in 2020 to 1.8 Gt in 2030 and 0.2 Gt in 2050, as the unabated use of fossil fuels falls sharply. Their share of the overall fuel mix drops from 85% today to just over 30% in 2050. The steel industry remains one of the last sectors using significant amounts of coal in 2050, primarily due to its importance as a chemical reduction agent, albeit mostly in conjunction with CCUS.

The NZE sees a radical technological transformation of the iron and steel sub-sector based largely on a major shift from coal to electricity. By 2050, electricity and other non-fossil fuels account for nearly 70% of final energy demand in the sector, up from just 15% in 2020. This shift is driven by technologies such as scrap-based electric arc furnaces (EAF), hydrogen-based direct reduced iron (DRI) facilities, iron ore electrolysis and the electrification of ancillary equipment. The share of coal in total energy use drops from 75% in 2020 to 22% by 2050 in the NZE, of which 90% is used in conjunction with CCUS.

Technologies that are currently on the market deliver around 85% of emissions savings in steel production to 2030. They include material and energy efficiency measures and a major increase in scrap-based production – which requires only around one-tenth of the energy of primary steel production – driven primarily by increased scrap availability as more products reach their end-of-life. Partial hydrogen injection into commercial blast furnaces and DRI furnaces gain pace in the mid-2020s, building on pilot projects testing the practice today. After 2030, the bulk of emission reductions come from the use of technologies that are under development, including hydrogen-based DRI and iron ore electrolysis. Several CCUS-equipped process technologies are deployed in parallel, including innovative smelting reduction, natural gas-based DRI production (particularly in regions with low natural gas prices) and innovative blast furnace retrofit arrangements in regions with relatively young plants.



### *Cement production*

Producing a tonne of cement today generates around 0.6 tonnes $CO_2$ on average, two-thirds of which are process emissions generated from carbon released from the raw materials used. Fossil fuels – mostly coal plus some petroleum coke – account for 90% of thermal energy needs.

Increased blending of alternative materials into cement to replace a portion of clinker (the active and most emissions-intensive ingredient), lower demand for cement and energy efficiency measures deliver around 40% of the emissions savings in 2030 compared with 2020. Through use of blended cements, the global clinker-to-cement ratio declines from 0.71 in 2020 to 0.65 in 2030. The ratio continues to decline after 2030, but more slowly, reaching 0.57 in 2050 (blended cements could reach a clinker-to-cement ratio as low as 0.5, but market application potential depends on regional contexts). Limestone and calcined clay are the main alternative materials used in blended cements by 2050. Since 0.5 is the lowest technically achievable clinker-to-cement ratio, other measures are needed to achieve deeper emission reductions.

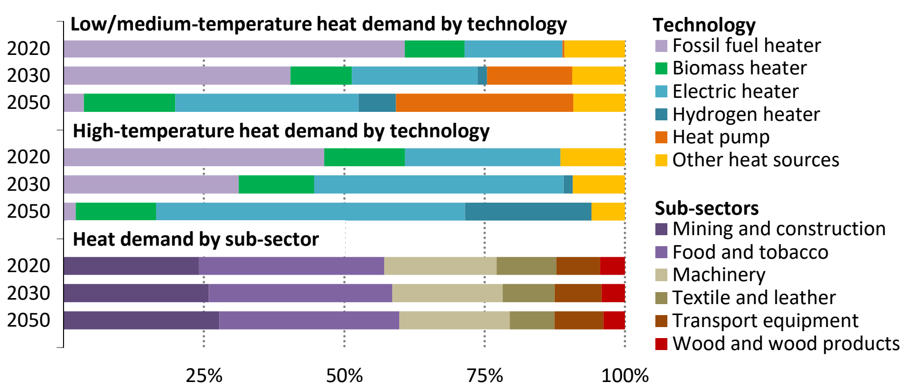
After 2030 in the NZE, the bulk of emissions reductions come from the use of technologies that are under development today. CCUS is the most important, accounting for 55% of reductions in 2050 relative to today. In many cases, it is more cost-effective in the NZE to apply CCUS to fossil fuel combustion emissions than to switch to zero-emissions energy sources. Coal use is eliminated from cement production by 2050, when natural gas accounts for about 40% of thermal energy (up from 15% today), biomass and renewable waste for a further 35% (up from less than 5% today), hydrogen and direct electrification for just about 15%, and oil products and non-renewable waste for the remainder. Constraints on the availability of sustainable biomass supplies prevent it from claiming a higher share. Direct electrification of cement kilns is at the small prototype stage today, and so only starts to be deployed after 2040 on a small scale. From the 2040s, hydrogen provides around 10% of thermal energy needs in cement kilns, although blending of small amounts begins earlier. Innovative types of cement based on alternative binding materials that limit or avoid the generation of process emissions, and even enable $CO_2$ capture during the curing process, are either still at much earlier stages of development relative to other options like CCUS, or have limited applicability.

### Box 3.2 ▷ What about other industry sub-sectors?

Steel, cement and chemicals are not the only outputs from the industry sector. It also includes other energy-intensive sub-sectors such as aluminium, paper, other non-metallic minerals and non-ferrous metals, as well as light industries that produce vehicles, machinery, food, timber, textiles and other consumer goods, together with the energy consumed in construction and mining operations.

Emissions from the light industries decline by around 30% by 2030 and around 95% by 2050 in the NZE. In contrast to the heavy industries, most of the technologies required for deep emission reductions in these sub-sectors are available on the market and ready to deploy. This is in part because more than 90% of total heat demand is low/medium-temperature, which can be more readily and efficiently electrified.

**Figure 3.20 ▷ Share of heating technology by temperature level in light industries in the NZE**






*The share of electricty in satisfying heat demand for light industries rises from less than 20% today to around 40% in 2030 and about 65% in 2050*

Notes: Light industries excludes non-specified industrial energy consumption. Low/medium-temperature heat corresponds to 0-400 °C and high-temperature heat to >400 °C. Other heat sources includes solar thermal and geothermal heaters, as well as imported heat from the power and fuel transformation sector.

Electricity accounts for around 40% of heat demand by 2030 and about 65% by 2050. For low- (<100 °C) and some medium- (100-400 °C) temperature heat, electrification includes an important role for heat pumps (accounting for about 30% of total heat demand in 2050). In the NZE, around 500 MW of heat pumps need to be installed every month over the next 30 years. Along with electrification, there are smaller roles for hydrogen and bioenergy for high-temperature heat (>400 °C), accounting for around 20% and around 15% respectively of total energy demand in 2050 (Figure 3.20). The rate of electrolyser capacity deployment is much lower than heavy industries, but the unit sizes will also be much smaller. About 5% of heat demand is satisfied by direct use of renewables, including solar thermal and geothermal heating technologies.

Energy efficiency also plays a critical role in these manufacturing industries, notably through increased efficiency in electric motors (conveyers, pumps and other driven systems). By 2030, 90% of the motor sales in other industries are Class 3 or above.



### 3.5.2 Key milestones and decision points

**Table 3.3 ▷ Key milestones in transforming global heavy industry sub-sectors**

| Category | |
|---|---|
| **Heavy industry** | • 2035: virtually, all capacity additions are innovative low-emissions routes. |
| **Industrial motors** | • 2035: all electric motors sales are best in class. |

| Category | 2020 | 2030 | 2050 |
|---|---|---|---|
| **Total industry** | | | |
| Share of electricity in total final consumption | 21% | 28% | 46% |
| Hydrogen demand (Mt $H_2$) | 51 | 93 | 187 |
| $CO_2$ captured (Mt $CO_2$) | 3 | 375 | 2 800 |
| **Chemicals** | | | |
| Share of recycling: reuse in plastics collection | 17% | 27% | 54% |
| reuse in secondary production | 8% | 14% | 35% |
| Hydrogen demand (Mt $H_2$) | 46 | 63 | 83 |
| with on-site electrolyser capacity (GW) | 0 | 38 | 210 |
| Share of production via innovative routes | 1% | 13% | 93% |
| $CO_2$ captured (Mt $CO_2$) | 2 | 70 | 540 |
| **Steel** | | | |
| Recycling, re-use: scrap as share of input | 32% | 38% | 46% |
| Hydrogen demand (Mt $H_2$) | 5 | 19 | 54 |
| with on-site electrolyser capacity (GW) | 0 | 36 | 295 |
| Share of primary steel production: hydrogen-based DRI-EAF | 0% | 2% | 29% |
| iron ore electrolysis-EAF | 0% | 0% | 13% |
| CCUS-equipped processes | 0% | 6% | 53% |
| $CO_2$ captured | 1 | 70 | 670 |
| **Cement** | | | |
| Clinker to cement ratio | 0.71 | 0.65 | 0.57 |
| Hydrogen demand (Mt $H_2$) | 0 | 2 | 12 |
| Share of production via innovative routes | 0% | 9% | 93% |
| $CO_2$ captured (Mt $CO_2$) | 0 | 215 | 1 355 |

Note: DRI = direct reduced iron; EAF = electric arc furnace.

From 2030 onwards, all new capacity additions in industry in the NZE feature near-zero emissions technologies. Much of the heavy industry capacity that will be added and replaced in the coming years is in emerging market and developing economies; they may expect financial support from advanced economies. Each month from 2030 to 2050, the NZE implies an additional 10 industrial plants equipped with CCUS, three additional fully hydrogen-based industrial plants and 2 GW of extra electrolyser capacity at industrial sites. While challenging, this is achievable. For comparison, about 12 heavy industrial facilities were built from scratch on average per month in China alone from 2000 to 2015. By 2050, nearly all production in heavy industry is with near-zero emissions technologies.

Decisive action from governments is imperative to achieve clean energy transitions in heavy industry at the scale and pace envisioned in the NZE. Within the next two years, governments in advanced economies will need to take decisions about funding for R&D for critical near-zero emissions industrial technologies and for mitigating the investment risks associated with demonstrating them at scale. This should lead to at least two or three commercial demonstration projects for each technology in different regions, and to market deployment by the mid-2020s. International co-ordination and co-operation would facilitate better use of resources and help prevent gaps in funding.

Governments also need to take early decisions on large-scale deployment of near-zero emissions technologies. By 2024 in advanced economies and 2026 in emerging market and developing economies, governments should have in place a strategy for incorporating near-zero emissions technologies into the next series of capacity additions and replacements for steel and chemical plants, which should include decisions about whether to pursue CCUS, hydrogen or a combination of both. If they are to succeed, those strategies need to include concrete plans for developing and financing the necessary infrastructure for CCUS and/or hydrogen, together with clean electricity generation for hydrogen production. The construction of the required infrastructure should begin as soon as possible given the long lead-times involved.

Within a similar timeframe, governments of countries that produce cement should decide how to develop the necessary CCUS infrastructure for that sub-sector, including the necessary legal and regulatory frameworks. Importing countries should make plans to move progressively to exclusive use of low-emissions cement, which may involve the need to support the development of CCUS-equipped facilities elsewhere in order to ensure supplies and to avoid a disproportionate burden being placed on other countries.

Strategies must be underpinned by specific policies. By 2025, all countries should have a long-term $CO_2$ emissions reduction policy framework in place to provide certainty that the next wave of investment in capacity additions will feature near-zero emissions technologies. Successful strategies are likely to require initial measures such as carbon contracts for difference, public procurement and incentives to encourage private sector procurement. As new technologies are deployed and costs decline, there is likely to be a strong case by about 2030 for replacing these initial measures with others such as $CO_2$ taxes, emissions trading systems and emissions performance standards. Financing support for near-zero emissions capacity additions may also have an important role to play through measures such as low interest and concessional loans and blended finance, as well as through contributions by advanced economies to funds that support projects in emerging market and developing economies. Strategies should also include measures to reduce industrial emissions through material efficiency, for example by revising design regulations, adopting incentives to promote longer product and building lifetimes, and improving systems for collecting and sorting materials for recycling.

There is a strong case for an international agreement on the transition to near-zero emissions for globally traded products by the mid-2020s so as to establish a level playing field. Alternatively, countries may need to resort to measures to shield domestic near-zero emissions production from competition from products that create emissions. Any such policy would need to be designed to respect the regulatory frameworks governing international trade, such as those of the World Trade Organization.



Even with accelerated innovation timelines and strong policies in place, some high-emitting capacity additions will be needed to meet demand in the next decade before near-zero emissions technologies are available. It would make sense for governments to require any new capacity to incorporate retrofit-ready designs so that unabated capacity added in the next few years has the technical capacity and space requirement to integrate near-zero emissions technologies in coming years. Beyond 2030, investment in the NZE is confined to innovative near-zero emissions process routes.

Governments should not overlook the need for measures to spur deployment of already available near-zero emissions technologies in light manufacturing industries. Adopting a carbon price and then sufficiently increasing the price over time – through carbon taxes or emissions trading systems for larger manufacturers – may be the simplest way to achieve that objective. Other regulatory measures such as tradeable low-carbon fuel and emissions standards could yield the same outcome, but may involve greater administrative complexity. Technology mandates are likely to be needed to achieve the energy efficiency savings in the NZE, such as minimum energy performance standards for new motors and boilers. Tailored programmes and incentives for small and medium enterprises could also play a helpful role.

## 3.6 Transport

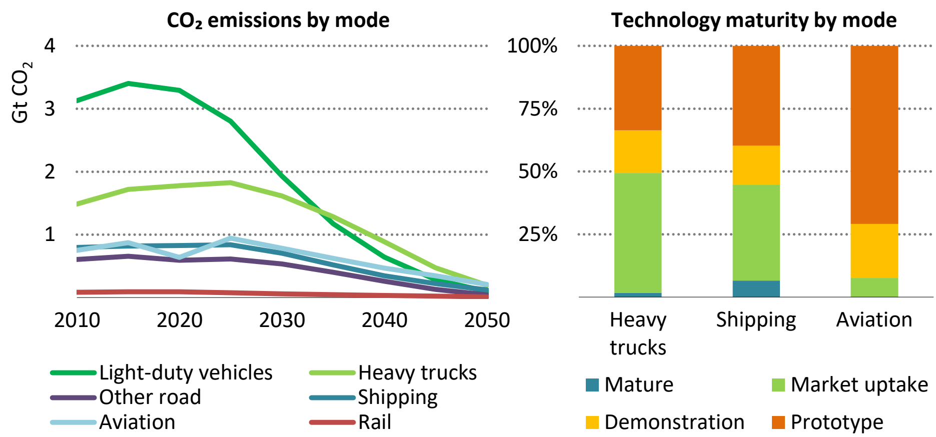
### *3.6.1 Energy and emission trends in the Net-Zero Emissions Scenario*

The global transport sector emitted over 7 Gt $CO_2$ in 2020, and nearly 8.5 Gt in 2019 before the Covid-19 pandemic.[7] In the NZE, transport sector $CO_2$ emissions are slightly over 5.5 Gt in 2030. By 2050 they are around 0.7 Gt – a 90% drop relative to 2020 levels. $CO_2$ emissions decline even with rapidly rising passenger travel, which nearly doubles by 2050, and rising freight activity, which increases by two-and-a-half-times from current levels, and an increase in the global passenger car fleet from 1.2 billion vehicles in 2020 to close to 2 billion in 2050.

[7] Unless otherwise noted, $CO_2$ emissions reported here are direct emissions from fossil fuel combusted during the operation of vehicles.

The transport modes do not decarbonise at the same rate because technology maturity varies markedly between them (Figure 3.21). $CO_2$ emissions from two/three-wheelers almost cease by 2040, followed by cars, vans and rail in the late 2040s. Emissions from heavy trucks, shipping and aviation fall by an annual average of 6% between 2020 and 2050, but still collectively amount to more than 0.5 Gt $CO_2$ in 2050. This reflects projected activity growth and that many of the technologies needed to reduce $CO_2$ emissions in long distance transport are currently under development and do not start to make substantial inroads into the market in the coming decade.

**Figure 3.21 ▷ Global $CO_2$ transport emissions by mode and share of emissions reductions to 2050 by technology maturity in the NZE**






*Passenger cars can make use of low-emissions technologies on the market, but major advances are needed for heavy trucks, shipping and aviation to reduce their emissions*

Notes: Other road = two/three wheelers and buses. Shipping and aviation include both domestic and international operations. See Box 2.4 for details on the maturity categories.

Decarbonisation of the transport sector in the NZE relies on policies to promote modal shifts and more efficient operations across passenger transport modes (see sections 2.5.7 and 4.4.3),[8] as well as improvements in energy efficiency. It also depends on two major technology transitions: shifts towards electric mobility (electric vehicles [EVs] and fuel cell electric vehicles [FCEVs])[9] and shifts towards higher fuel blending ratios and direct use of

[8] Examples of efficient operations include: seamless integration of various modes (inter-modality) and "Mobility as a Service" in passenger transport; logistics measures in road freight, e.g. backhauling, night-time deliveries, real-time routing; slow steaming in shipping; and air traffic management, e.g. landing and take-off scheduling in aviation.

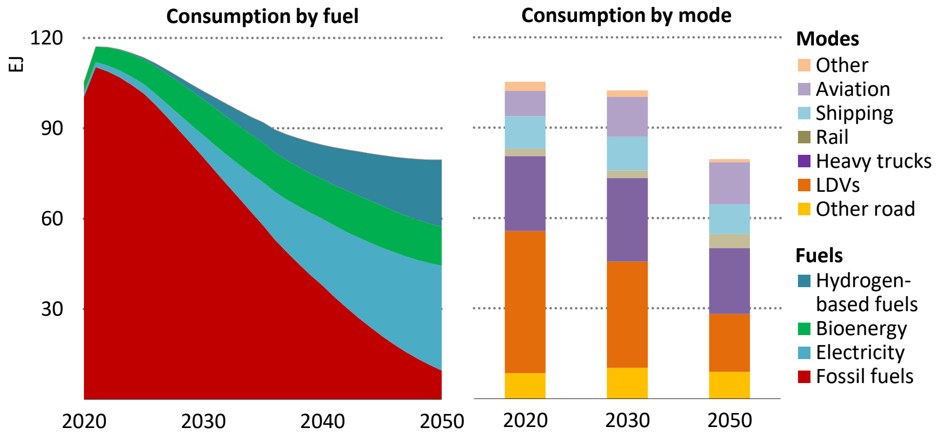
[9] EVs include battery electric vehicles, plug-in hybrid electric-gasoline vehicles and plug-in hybrid electric-diesel vehicles. FCEVs contain a battery and electric motor and are capable of operating without tailpipe emissions.

low-carbon fuels (biofuels and hydrogen-based fuels). These shifts are likely to require interventions to stimulate investment in supply infrastructure and to incentivise consumer uptake.

Transport has traditionally been heavily reliant on oil products, which accounted for more than 90% of transport sector energy needs in 2020 despite inroads from biofuels and electricity (Figure 3.22). In the NZE, the share of oil drops to less than 75% in 2030 and slightly over 10% by 2050. By the early 2040s, electricity becomes the dominant fuel in the transport sector worldwide in the NZE: it accounts for nearly 45% of total final consumption in 2050, followed by hydrogen-based fuels (28%) and bioenergy (16%). Biofuels almost reach a 15% blending share in oil products by 2030 in road transport, which reduces oil needs by around 4.5 million barrels of oil equivalent per day (mboe/d). Beyond 2030, biofuels are increasingly used for aviation and shipping, where the scope for using electricity and hydrogen is more limited. Hydrogen carriers (such as ammonia) and low-emissions synthetic fuels also supply increasing shares of energy demand in these modes.



**Figure 3.22 ⊳ Global transport final consumption by fuel type and mode in the NZE**





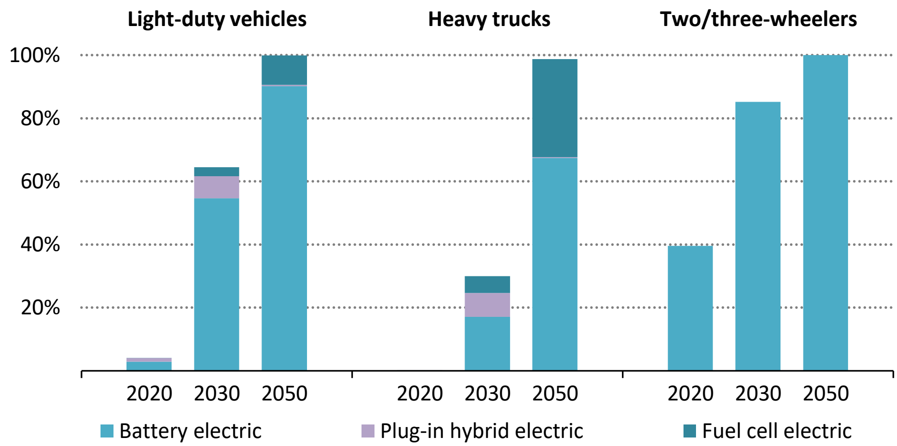

*Electricity and hydrogen-based fuels account for more than 70% of transport energy demand by 2050*

Note: LDVs = Light-duty vehicles; Other road = two/three wheelers and buses.

### *Road vehicles*

Electrification plays a central role in decarbonising road vehicles in the NZE. Battery cost declines of almost 90% in a decade have boosted sales of electric passenger cars by 40% on average over the past five years. Battery technology is already relatively commercially competitive. FCEVs start to make inroads in the 2020s in the NZE. The electrification of heavy trucks moves more slowly due to the weight of the batteries, high energy and power requirements required for charging, and limits on driving ranges. But fuel cell heavy trucks make significant progress, mainly after 2030 (Figure 3.23). The number of battery electric, plug-in hybrid and fuel cell electric light-duty vehicles (cars and vans) on the world's roads reaches 350 million in 2030 and almost 2 billion in 2050, up from 11 million in 2020. The number of electric two/three-wheelers also rises rapidly, from just under 300 million today to 600 million in 2030 and 1.2 billion in 2050. The electric bus fleet expands from 0.5 million in 2020 to 8 million in 2030 and 50 million in 2050.

**Figure 3.23 ▷ Global share of battery electric, plug-in hybrid and fuel cell electric vehicles in total sales by vehicle type in the NZE**





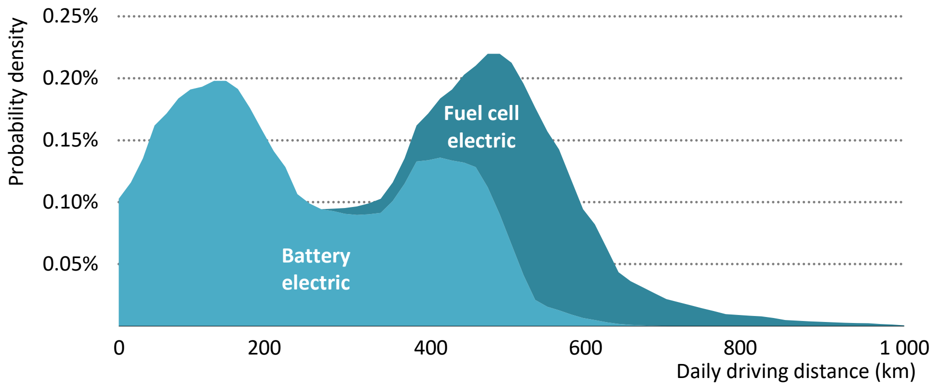

*Sales of battery electric, plug-in hybrid and fuel cell electric vehicles soar globally*

Note: Light-duty vehicles = passenger cars and vans; Heavy trucks = medium- and heavy-freight trucks.

Light-duty vehicles are electrified faster in advanced economies over the medium term and account for around 75% of sales by 2030. In emerging and developing economies, they account for about 50% of sales. Almost all light-duty vehicle sales in advanced economies are battery electric, plug-in hybrid or fuel cell electric by the early 2030s and in emerging and developing economies by the mid-2030s.

For heavy trucks that operate over long distances, currently biofuels are the main viable commercial alternative to diesel, and they play an important role in lowering emissions from heavy-duty trucks over the 2020s. Beyond 2030, the number of electric and hydrogen-powered heavy trucks increases in the NZE as supporting infrastructure is built and as costs decline (lower battery costs, energy density improvements and lower costs to produce and deliver hydrogen) (IEA, 2020b). This coincides with a reduction in the availability of sustainable bioenergy, as limited supplies increasingly go to hard-to-abate segments such as aviation and shipping, though biofuels still meet about 10% of fuel needs for heavy-duty trucks in 2050 (see Chapter 2). Advanced economies have a higher market share of battery electric and fuel cell electric heavy-duty trucks sales in 2030, more than twice the level in emerging market and developing economies, although this gap closes towards 2050.

**Figure 3.24 ▷ Heavy trucks distribution by daily driving distance, 2050**






*Driving distance is the key factor affecting powertrain choice for trucks*

Realising the objectives of the NZE depends on rapid scaling up of battery manufacturing (current announced production capacity for 2030 would cover only 50% of required demand in that year), and on the rapid introduction on the market of next generation battery technology (solid state batteries) between 2025 and 2030. Electrified road systems using conductive or inductive power transfer to provide electricity to trucks offer an alternative for battery electric and fuel cell electric trucks on long-distance operations, but these systems too would need rapid development and deployment.

### *Aviation*[10]

The NZE assumes that air travel, measured in revenue-passenger kilometres, increases by only around 3% per year to 2050 relative to 2020. This compares with about around 6% over the 2010-19 period. The NZE assumes that aviation growth is constrained by comprehensive government policies that promote a shift towards high-speed rail and rein in expansion of long-haul business travel, e.g. through taxes on commercial passenger flights (see section 2.5.2).

Global $CO_2$ emissions from aviation rise in the NZE from about 640 Mt in 2020 (down from around 1 Gt in 2019) to a peak of 950 Mt by around 2025. Emissions then fall to 210 Mt in 2050 as the use of low-emissions fuels grows. Emissions are hard to abate because aviation

[10] Aviation considered here includes both domestic and international flights. While the focus here is on commercial passenger aviation, dedicated freight and general (military and private) aviation, which collectively account for more than 10% of fuel use and emissions, are also included in the energy and emissions accounting.

requires fuel with a high energy density. Emissions in aviation comprise just over 10% of unabated $CO_2$ emissions from fossil fuels and industrial processes in 2050.

In the NZE, the global use of jet kerosene declines to about 3 EJ in 2050 from 9 EJ in 2020 (and around 14.5 EJ in 2019 before the Covid-19 crisis), and its share of total energy use falls from almost 100% to just over 20%. The use of sustainable aviation fuel (SAF) starts to increase significantly in the late-2020s. In 2030, around 15% of total fuel consumption in aviation is SAF, most of which is biojet kerosene (a type of liquid biofuel). This is estimated to increase the ticket price for a mid-haul flight (1 200 km) by about USD 3 per passenger. By 2050, biojet kerosene meets 45% of total fuel consumption in aviation and synthetic hydrogen-based fuels meet about 30%. This is estimated to increase the ticket price for a mid-haul flight in 2050 by about USD 10 per passenger. The NZE also sees the adoption of commercial battery electric and hydrogen aircraft from 2035, but they account for less than 2% of fuel consumption in 2050.

Operational improvements, together with fuel efficiency technologies for airframes and engines, also help to reduce $CO_2$ emissions by curbing the pace of fuel demand growth in the NZE. These improvements are incremental, but revolutionary technologies such as open rotors, blended wing-body airframes and hybridisation could bring further gains and enable the industry to meet the International Civil Aviation Organization's (ICAO) ambitious 2050 efficiency targets (IEA, 2020b).

### *Maritime shipping*[11]

Maritime shipping was responsible for around 830 Mt $CO_2$ emissions worldwide in 2020 (880 Mt $CO_2$ in 2019), which is around 2.5% of total energy sector emissions. Due to a lack of available low-carbon options on the market and the long lifetime of vessels (typically 25-35 years), shipping is one of the few transport modes that does not achieve zero emissions by 2050 in the NZE. Nevertheless, emissions from shipping decline by 6% annually to 120 Mt $CO_2$ in 2050.

In the short term, there is considerable potential for curbing fuel consumption in shipping through measures to optimise operational efficiency and improve energy efficiency. Such approaches include slow steaming and the use of wind-assistance technologies (IEA, 2020b). In the medium to long term, significant emissions reductions are achieved in the NZE by switching to low-carbon fuels such as biofuels, hydrogen and ammonia. Ammonia looks likely to be a particularly good candidate for scaling up, and a critical fuel for long-range transoceanic journeys that need fuel with high energy density.

Ammonia and hydrogen are the main low-carbon fuels for shipping adopted over the next three decades in the NZE, their combined share of total energy consumption in shipping reaching around 60% in 2050. The 20 largest ports in the world account for more than half of global cargo (UNCTAD, 2018); they could become industrial hubs to produce hydrogen and

[11] Maritime shipping here includes both domestic and international operations.

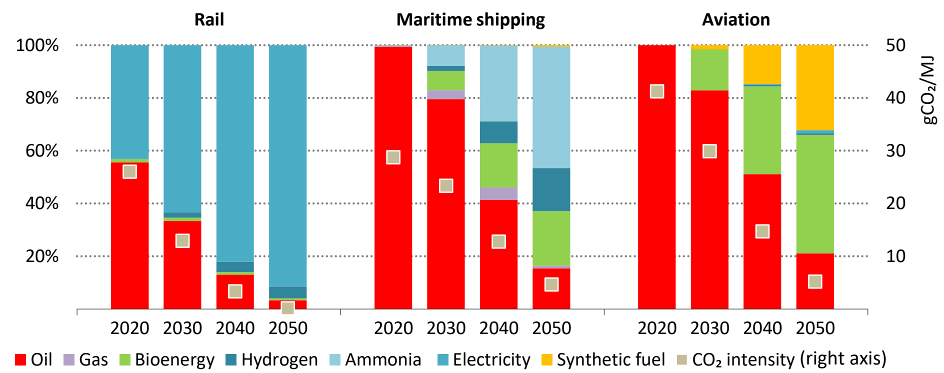
ammonia for use in both chemical and refining industries, as well as for refuelling ships. Internal combustion engines for ammonia-fuelled vessels are currently being developed by two of the largest manufacturers of maritime engines and are expected to become available on the market by 2024. Sustainable biofuels provide almost 20% of total shipping energy needs in 2050. Electricity plays a very minor role, as the relatively low energy density of batteries compared with liquid fuels makes it suitable only for shipping routes of up to 200 km. Even with an 85% increase in battery energy density in the NZE as solid state batteries come to market, only short-distance shipping routes can be electrified.



### *Rail*

Rail transport is the most energy-efficient and least carbon-intensive way to move people and second only to shipping for carrying goods. Passenger rail almost doubles its share of total transport activity to 20% by 2050 in the NZE, with particularly rapid growth in urban and high-speed rail (HSR), the latter of which contributes to curbing growth in air travel. Global $CO_2$ emissions from the rail sector fall from 95 Mt $CO_2$ in 2020 (100 Mt $CO_2$ in 2019) to almost zero by 2050 in the NZE, driven primarily by rapid electrification.

**Figure 3.25 ⊳ Global energy consumption by fuel and $CO_2$ intensity in non-road sectors in the NZE**






*Railways rely heavily on electricity to decarbonise, while shipping and aviation curb emissions mainly by switching to low-emissions fuels*

Note: Synthetic fuel = low-emissions synthetic hydrogen-based fuels.

In the NZE, all new tracks on high-throughput corridors are electrified from now on, while hydrogen and battery electric trains, which have recently been demonstrated in Europe, are adopted on rail lines where throughput is too low to make electrification economically viable. Oil use, which accounted for 55% of total energy consumption in the rail sector in 2020, falls to almost zero in 2050: it is replaced by electricity, which provides over 90% of rail energy needs and by hydrogen which provides another 5%.

### 3.6.2 Key milestones and decision points

**Table 3.4 ▷ Key milestones in transforming the global transport sector**

| Category | |
|---|---|
| **Road transport** | • 2035: no new passenger internal combustion engine car sales globally |
| **Aviation and shipping** | • Implementation of strict carbon emissions intensity reduction targets as soon as possible. |

| Category | | 2020 | 2030 | 2050 |
|---|---|---|---|---|
| **Road transport** | | | | |
| Share of PHEV, BEV and FCEV in sales: | cars | 5% | 64% | 100% |
| | two/three-wheelers | 40% | 85% | 100% |
| | bus | 3% | 60% | 100% |
| | vans | 0% | 72% | 100% |
| | heavy trucks | 0% | 30% | 99% |
| Biofuel blending in oil products | | 5% | 13% | 41% |
| **Rail** | | | | |
| Share of electricity and hydrogen in total energy consumption | | 43% | 65% | 96% |
| Activity increase due to modal shift (index 2020=100) | | 100 | 100 | 130 |
| **Aviation** | | | | |
| Synthetic hydrogen-based fuels share in total aviation energy consumption | | 0% | 2% | 33% |
| Biofuels share in total aviation energy consumption | | 0% | 16% | 45% |
| Avoided demand from behaviour measures (index 2020=100) | | 0 | 20 | 38 |
| **Shipping** | | | | |
| Share in total shipping energy consumption: | Ammonia | 0% | 8% | 46% |
| | Hydrogen | 0% | 2% | 17% |
| | Bioenergy | 0% | 7% | 21% |
| **Infrastructure** | | | | |
| EV public charging (million units) | | 1.3 | 40 | 200 |
| Hydrogen refuelling units | | 540 | 18 000 | 90 000 |
| Share of electrified rail lines | | 34% | 47% | 65% |

Note: PHEV = plug-in hybrid electric vehicles; BEV = battery electric vehicles; FCEV = fuel cell electric vehicles.

Electrification is the main option to reduce $CO_2$ emissions from road and rail modes, the technologies are already on the market and should be accelerated immediately, together with the roll-out of recharging infrastructure for EVs. Deep emission reductions in the hard-to-abate sectors (heavy trucks, shipping and aviation) require a massive scale up of the required technologies over the next decade, which today are largely at the prototype and demonstration stages, together with plans for the development of associated infrastructure, including hydrogen refuelling stations.

The transformation of transport required to be on track to reduce emissions in line with the NZE calls for a range of government decisions over the next decade. In the next few years, all governments need to eliminate fossil fuel subsidies and encourage switching to low-carbon technologies and fuels across the entire transport sector. Before 2025, governments need to define clear R&D priorities for all the technologies that can contribute to decarbonise transport in line with their strategic priorities and needs. Ideally this would be informed by international dialogue and collaboration. R&D is critical in particular for battery technology, which should be an immediate priority.



To achieve the emissions reductions required by the NZE, governments also need to move quickly to signal the end of sales of new internal combustion engine cars. Early commitments would help the private sector to make the necessary investment in new powertrains, relative supply chains and refuelling infrastructure (see section 4.3.4). This is particularly important for the supply of battery metals, which require long-term planning (IEA, 2021a).

By 2025, the large-scale deployment of EV public charging infrastructure in urban areas needs to be sufficiently advanced to allow households without access to private chargers to opt for EVs. Governments should ensure sustainable business models for companies installing chargers, remove barriers to planning and construction, and put in place regulatory, fiscal and technological measures to enable and encourage smart charging, and to ensure that EVs support electricity grid stability and stimulate the adoption of variable renewables (IEA, 2021b).

For heavy trucks, battery electric trucks are just beginning to become available on the market, and fuel cell electric technologies are expected to come to market in the next few years. Working in collaboration with truck manufacturers, governments should take steps in the near term to prioritise the rapid commercial adoption of battery electric and fuel cell electric trucks. By 2030, they should take stock of the competitive prospects for these technologies, so as to focus R&D on the most important challenges and allow adequate time for strategic infrastructure deployment, thus paving the way for large-scale adoption during the 2030s.

Governments need to define their strategies for low-carbon fuels in shipping and aviation by 2025 at the latest, given the slow turnover rate of the fleets, after which they should rapidly implement them. International co-operation and collaboration will be crucial to success. Priority action should target the most heavily used ports and airports so as to maximise the impact of initial investment. Harbours near industrial areas are ideally placed to become low-carbon fuel hubs.

**Box 3.3 ▷ What would be the implications of an all-electric approach to emissions reductions in the road transport sector?**

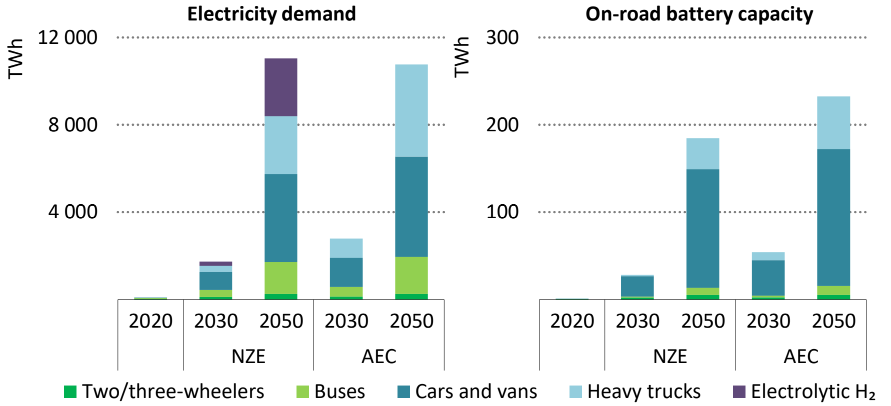
The use of a variety of fuels in road transport is a core component of the NZE. However, governments might want to consider an all-electric route to eliminate $CO_2$ emissions from transport, especially if other technologies such as FCEVs and advanced biofuels fail to develop as projected. We have therefore developed an *All-Electric Case* which looks at the implications of electrifying all road vehicle modes. In the NZE, decarbonisation of road transport occurs primarily via the adoption of plug-in hybrid electric vehicles (PHEVs), battery electric vehicles (BEVs), fuel cell electric vehicles (FCEVs) and advanced biofuels. The All-Electric Case assumes the same rate of road transport decarbonisation as the NZE, but achieved via battery electric vehicles alone.

The All-Electric Case depends on even further advances in battery technologies than the NZE that lead to energy densities of at least 400 Watt hours per kilogramme (Wh/kg) by the 2030s at costs that would make BEV trucks preferable to FCEV trucks in long-haul operations. This would mean 30% more BEVs (an additional 350 million) on the road in 2030 than in the NZE. Over sixty five million public chargers would be needed to support the vehicles, requiring a cumulative investment of around USD 300 billion, 35% higher than the NZE. This would require faster expansion of battery manufacturing. The annual global battery capacity additions for BEVs in 2030 would be almost 9 TWh, requiring 80 giga-factories (assuming 35 GWh per year output) more than in the NZE, or an average of over two per month from now to 2030.

The increased use of electricity for road transport would also create additional challenges for the electricity sector. The total electricity demand for road transport (11 000 TWh or 15% of total electricity consumption in 2050), would be roughly the same in both cases, when account is taken of demand for electrolytic hydrogen. However, the electrolytic hydrogen in the NZE can be produced flexibly, in regions and at times with surplus renewables-based capacity and from dedicated (off-grid) renewable power. Peak power demand in the All-Electric Case, taking into consideration the flexibility that enables smart charging of cars, is about one-third (2 000 GW) higher than in the NZE, mainly due to the additional evening/overnight charging of buses and trucks. If not coupled with energy storage devices, ultra-fast chargers for heavy-duty vehicles could cause additional spikes in demand, putting even more strain on electricity grids.

While full electrification of road transport is possible, it could involve additional challenges and undesirable side effects. For example, it could increase pressure on electricity grids, requiring significant additional investment, and increasing the vulnerability of the transport system to power disruptions. Fuel diversification could bring benefits in terms of resilience and energy security.

**Figure 3.26 ▷ Global electricity demand and battery capacity for road transport in the NZE and the All-Electric Case**






*Both direct electricity consumption and vehicle battery capacity in 2050 increase by about a quarter in the All-Electric Case relative to the NZE*

Note: AEC = All-Electric Case.

## 3.7 Buildings

### 3.7.1 Energy and emission trends in the Net-Zero Emissions Scenario

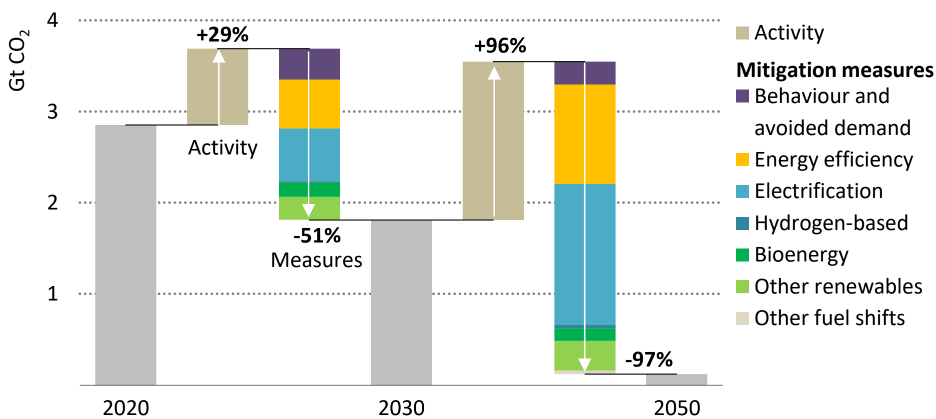
Floor area in the buildings sector worldwide is expected to increase 75% between 2020 and 2050, of which 80% is in emerging market and developing economies. Globally, floor area equivalent to the surface of the city of Paris is added every week through to 2050. Moreover, buildings in many advanced economies have long lifetimes and around half of the existing buildings stock will still be standing in 2050. Demand for appliances and cooling equipment continues to grow, especially in emerging market and developing economies where 650 million air conditioners are added by 2030 and another 2 billion by 2050 in the NZE. Despite this demand growth, total $CO_2$ emissions from the buildings sector decline by more than 95% from almost 3 Gt in 2020 to around 120 Mt in 2050 in the NZE.[12]

Energy efficiency and electrification are the two main drivers of decarbonisation of the buildings sector in the NZE (Figure 3.27). That transformation relies primarily on technologies

[12] All $CO_2$ emissions in this section refer to direct $CO_2$ emissions unless otherwise specified. The NZE also pursues reductions in emissions linked to construction materials used in buildings. These embodied emissions are cut by 40% per square metre of new floor area by 2030, with material efficiency strategies cutting cement and steel use by 50% by 2050 relative to today through measures at the design, construction, use and end-of-life phases.

already available on the market, including improved envelopes for new and existing buildings, heat pumps, energy-efficient appliances, and bioclimatic and material-efficient building design. Digitalisation and smart controls enable efficiency gains that reduce emissions from the buildings sector by 350 Mt $CO_2$ by 2050. Behaviour changes are also important in the NZE, with a reduction of almost 250 Mt $CO_2$ in 2030 reflecting changes in temperature settings for space heating or reducing excessive hot water temperatures. Additional behaviour changes such as greater use of cold temperature clothes washing and line drying, facilitate the decarbonisation of electricity supply. There is scope for these reductions to be achieved rapidly and at no cost.

**Figure 3.27 ▷ Global direct $CO_2$ emissions reductions by mitigation measure in buildings in the NZE**



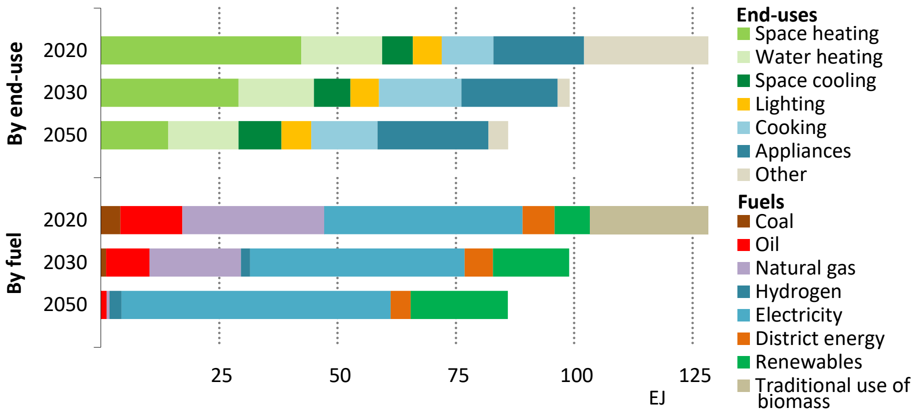



*Electrification and energy efficiency account for nearly 70% of buildings-related emissions reductions through to 2050, followed by solar thermal, bioenergy and behaviour*

Notes: Activity = change in energy service demand related to rising population, increased floor area and income per capita. Behaviour = change in energy service demand from user decisions, e.g. changing heating temperatures. Avoided demand = change in energy service demand from technology developments, e.g. digitalisation.

Rapid shifts to zero-carbon-ready technologies see the share of fossil fuels in energy demand in the buildings sector drop to 30% by 2030, and to 2% by 2050 in the NZE. The share of electricity in the energy mix reaches almost 50% by 2030 and 66% by 2050, up from 33% in 2020 (Figure 3.28). All end-uses today dominated by fossil fuels are increasingly electrified in the NZE, with the share of electricity in space heating, water heating and cooking increasing from less than 20% today to more than 40% in 2050. District energy networks and low-carbon gases, including hydrogen-based fuels, remain significant in 2050 in regions with high heating needs, dense urban populations and existing gas or district heat networks. Bioenergy meets nearly one-quarter of overall heat demand in the NZE by 2050, over 50% of bioenergy use is for cooking, nearly all in emerging market and developing economies, where 2.7 billion people gain access to clean cooking by 2030 in the NZE. Space heating demand drops by two-thirds between 2020 and 2050, driven by improvement in energy efficiency and behavioural changes such as the adjustment of temperature set points.

**Figure 3.28 ▷ Global final energy consumption by fuel and end-use application in buildings in the NZE**






*Fossil fuel use in the buildings sector declines by 96% and space heating energy needs by two-thirds to 2050, thanks mainly to energy efficiency gains*

Note: Other includes desalination and traditional use of solid biomass which is not allocated to a specific end-use.

### *Zero-carbon-ready buildings*

The NZE pathway for the buildings sector requires a step change improvement in the energy efficiency and flexibility of the stock and a complete shift away from fossil fuels. To achieve this, more than 85% of buildings need to comply with zero-carbon-ready building energy codes by 2050 (Box 3.4). This means that mandatory zero-carbon-ready building energy codes for all new buildings need to be introduced in all regions by 2030, and that retrofits need to be carried out in most existing buildings by 2050 to enable them to meet zero-carbon-ready building energy codes.

Retrofit rates increase from less than 1% per year today to about 2.5% per year by 2030 in advanced economies: this means that around 10 million dwellings are retrofitted every year. In emerging market and developing economies, building lifetimes are typically lower than in advanced economies, meaning that retrofit rates by 2030 in the NZE are lower, at around 2% per year. This requires the retrofitting of 20 million dwellings per year on average to 2030. To achieve savings at the lowest cost and to minimise disruption, retrofits need to be comprehensive and one-off.

**Box 3.4 ▷ Towards zero-carbon-ready buildings**

Achieving decarbonisation of energy use in the sector requires almost all existing buildings to undergo a single in-depth retrofit by 2050, and new construction to meet stringent efficiency standards. Building energy codes covering new and existing buildings are the fundamental policy instrument to drive such changes. Building energy codes currently exist or are under development in only 75 countries, and codes in around 40 of these countries are mandatory for both the residential and services sub-sectors. In the NZE, comprehensive zero-carbon-ready building codes are implemented in all countries by 2030 at the latest.

*What is a zero-carbon-ready building?*

A zero-carbon-ready building is highly energy efficient and either uses renewable energy directly, or uses an energy supply that will be fully decarbonised by 2050, such as electricity or district heat. This means that a zero-carbon-ready building will become a zero-carbon building by 2050, without any further changes to the building or its equipment.

Zero-carbon-ready buildings should adjust to user needs and maximise the efficient and smart use of energy, materials and space to facilitate the decarbonisation of other sectors. Key considerations include:

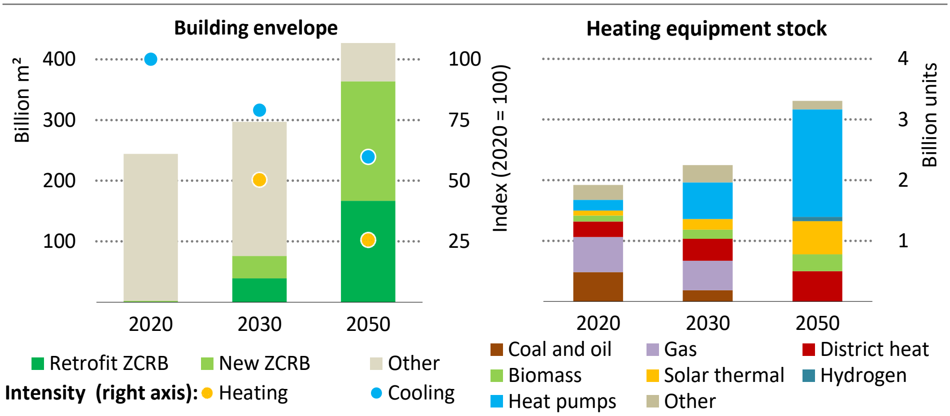
- **Scope.** Zero-carbon-ready building energy codes should cover building operations (scope 1 and 2) as well as emissions from the manufacturing of building construction materials and components (scope 3 or embodied carbon emissions).
- **Energy use.** Zero-carbon-ready energy codes should recognise the important part that passive design features, building envelope improvements and high energy performance equipment play in lowering energy demand, reducing both the operating cost of buildings and the costs of decarbonising the energy supply.
- **Energy supply.** Whenever possible, new and existing zero-carbon-ready buildings should integrate locally available renewable resources, e.g. solar thermal, solar PV, PV thermal and geothermal, to reduce the need for utility-scale energy supply. Thermal or battery energy storage may be needed to support local energy generation.
- **Integration with power systems.** Zero-carbon-ready building energy codes need buildings to become a flexible resource for the energy system, using connectivity and automation to manage building electricity demand and the operation of energy storage devices, including EVs.
- **Buildings and construction value chain.** Zero-carbon-ready building energy codes should also target net-zero emissions from material use in buildings. Material efficiency strategies can cut cement and steel demand in the buildings sector by more than a third relative to baseline trends, and embodied emissions can be further reduced by more robust uptake of bio-sourced and innovative construction materials.

### *Heating and cooling*

Building envelope improvements in zero-carbon-ready retrofit and new buildings account for the majority of heating and cooling energy intensity reductions in the NZE, but heating and cooling technology also makes a significant contribution. Space heating is transformed in the NZE, with homes heated by natural gas falling from nearly 30% of the total today to less than 0.5% in 2050, while homes using electricity for heating rise from nearly 20% of the total today to 35% in 2030 and about 55% in 2050 (Figure 3.29). High efficiency electric heat pumps become the primary technology choice for space heating in the NZE, with worldwide heat pump installations per month rising from 1.5 million today to around 5 million by 2030 and 10 million by 2050. Hybrid heat pumps are also used in some of the coldest climates, but meet no more than 5% of heating demand in 2050.



**Figure 3.29 ▷ Global building and heating equipment stock by type and useful space heating and cooling demand intensity changes in the NZE**






***By 2050, over 85% of buildings are zero-carbon-ready, reducing average useful heating intensity by 75%, with heat pumps meeting over half of heating needs***

Notes: ZCRB refers to buildings meeting zero-carbon-ready building energy codes. Other for building envelope refers to envelopes that do not meet zero-carbon-ready building energy codes. Other for heating equipment stock includes resistive heaters, and hybrid and gas heat pumps.

Not all buildings are best decarbonised with heat pumps, however, and bioenergy boilers, solar thermal, district heat, low-carbon gases in gas networks and hydrogen fuel cells all play a role in making the global building stock zero-carbon-ready by 2050. Bioenergy meets 10% of space heating needs by 2030 and more than 20% by 2050. Solar thermal is the preferred renewable technology for water heating, especially where heat demand is low; in the NZE it meets 35% of demand by 2050, up from 7% today. District heat networks remain an attractive option for many compact urban centres where heat pump installation is impractical, in the NZE they provide more than 20% of final energy demand for space heating in 2050, up from a little over 10% today.

There are no new coal and oil boilers sold globally from 2025 in the NZE. Sales of gas boilers fall by more than 40% from current levels by 2030 and by 90% by 2050. By 2025 in the NZE, any gas boilers that are sold are capable of burning 100% hydrogen and therefore are zero-carbon-ready. The share of low-carbon gases (hydrogen, biomethane, synthetic methane) in gas distributed to buildings rises from almost zero to 10% by 2030 to above 75% by 2050.

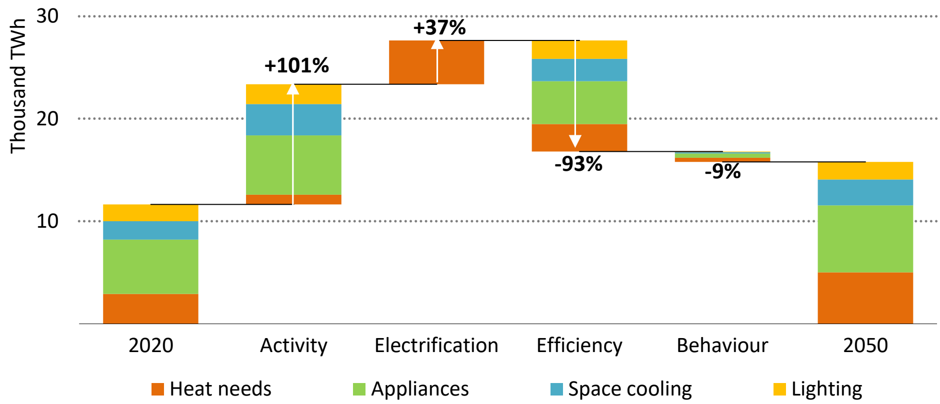
Buildings that meet the standards of zero-carbon-ready building energy codes drive down the need not only for space heating but also for space cooling – the fastest growing end-use in buildings since 2000. Space cooling represented only 5% of total buildings energy consumption worldwide in 2020, but demand for cooling is likely to grow strongly in the coming decades with rising incomes and a hotter climate. In the NZE, 60% of households have an air conditioner in 2050, up from 35% in 2020. High-performance building envelopes, including bioclimatic designs and insulation, can reduce the demand for space cooling by 30-50%, while providing greater resilience during extreme heat events. In the NZE, electricity demand for space cooling grows annually by 1% to reach 2 500 TWh in 2050. Without 2 000 TWh of savings from residential building envelope improvements and higher efficiency equipment, space cooling demand would be almost twice as high.

### *Appliances and lighting*

Electric appliances and lighting become much more efficient over the next three decades in the NZE thanks to policy measures and technical advances. By 2025 in the NZE, over 80% of all appliances and air conditioners sold in advanced economies are the best available technologies today in these markets, and this share increases to 100% by the mid-2030s. In emerging market and developing economies, which account for over half of appliances and air conditioners by 2050, the NZE assumes a wave of policy action over the next decade which leads to 80% of equipment sold in these markets in 2030 being as efficient as the best available technologies in advanced economies today, increasing to close to 100% by 2050 (Figure 3.30). The share of light-emitting diode (LED) lamps in total lightbulb sales reaches 100% by 2025 in all regions. Minimum energy performance standards are complemented by requirements for smart control of appliances to facilitate demand-side response in all regions.

Energy use in buildings will be increasingly focused on electric, electronic and connected equipment and appliances. The share of electricity in energy consumption in buildings rises from 33% in 2020 to around two-thirds in 2050 in the NZE, with many buildings incorporating decentralised electricity generation using local solar PV panels, battery storage and EV chargers. The number of residential buildings with solar PV panels increases from 25 million to 240 million over the same period. In the NZE, smart control systems shift flexible uses of electricity in time to correspond with generation from local renewables, or to provide flexibility services to the power system, while optimised home battery and EV charging allow households to interact with the grid. These developments help improve electricity supply security and lower the cost of the energy transition by making it easier and cheaper to integrate renewables into the system.

**Figure 3.30 ⊳ Global change in electricity demand by end-use in the buildings sector**






*Energy efficiency is critical to mitigate electricity demand growth for appliances and air conditioning, with savings more than offsetting the impact of electrifying heat*



## 3.7.2 Key milestones and decision points

**Table 3.5 ⊳ Key milestones in transforming global buildings sector**

| Category | |
|---|---|
| New buildings | • From 2030: all new buildings are zero-carbon-ready. |
| Existing buildings | • From 2030: 2.5% of buildings are retrofitted to be zero-carbon-ready each year. |

| Category | 2020 | 2030 | 2050 |
|---|---|---|---|
| **Buildings** | | | |
| Share of existing buildings retrofitted to the zero-carbon-ready level | <1% | 20% | >85% |
| Share of zero-carbon-ready new buildings construction | 5% | 100% | 100% |
| **Heating and cooling** | | | |
| Stock of heat pumps (million units) | 180 | 600 | 1 800 |
| Million dwellings using solar thermal | 250 | 400 | 1 200 |
| Avoided residential energy demand from behaviour | n.a. | 12% | 14% |
| **Appliances and lighting** | | | |
| Appliances: unit energy consumption (index 2020=100) | 100 | 75 | 60 |
| Lighting: share of LED in sales | 50% | 100% | 100% |
| **Energy access** | | | |
| Population with access to electricity (billion people) | 7.0 | 8.5 | 9.7 |
| Population with access to clean cooking (billion people) | 5.1 | 8.5 | 9.7 |
| **Energy infrastructure in buildings** | | | |
| Distributed solar PV generation (TWh) | 320 | 2 200 | 7 500 |
| EV private chargers (million units) | 270 | 1 400 | 3 500 |

Near-term government decisions are required for energy codes and standards for buildings, fossil fuel phase out, use of low-carbon gases, acceleration of retrofits and financial incentives to encourage investment in building sector energy transitions. Decisions will be most effective if they focus on decarbonising the entire value chain, taking into account not only buildings but also the energy and infrastructure networks that supply them, as well as wider considerations including the role of the construction sector and urban planning. Such decisions are likely to bring wider benefits, notably in reducing fuel poverty.

Near-term government action is needed to ensure that zero-carbon-ready buildings become the new norm across the world before 2030 for both new construction and retrofits. This requires governments to act before 2025 to ensure that zero-carbon-ready compliant building energy codes are implemented by 2030 at the latest. While this goal applies to all regions, ways to achieve zero-carbon-ready buildings vary significantly across regions and climate zones, and the same is true for heating and cooling technology strategies. Governments should consider paving the way by making public buildings zero-carbon-ready in the coming decade.

Governments will need to find ways to make new zero-carbon-ready buildings and retrofits affordable and attractive to owners and occupants by overcoming financial barriers, addressing split incentive barriers and minimising disruption to building use. Building energy performance certificates, green lease agreements, green bond financing and pay-as-you save models could all play a part.

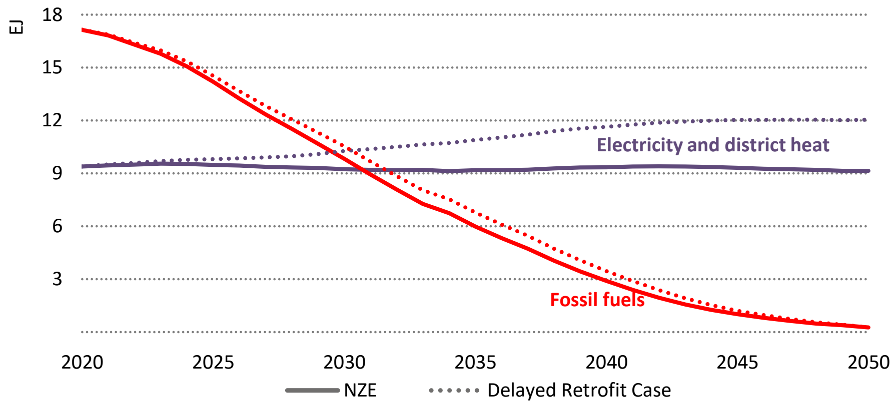
Making zero-carbon-ready building retrofits a central pillar of economic recovery strategies in the early 2020s is a no-regrets action to jumpstart progress towards a zero-emissions building sector. Foregoing the opportunity to make energy use in buildings more efficient would drive up electricity demand linked to electrification of energy use in the buildings sector and make decarbonising the energy system significantly more difficult and more costly (Box 3.5).

### Box 3.5 ▹ What would be the impact of global retrofit rates not rising to 2.5%?

Decarbonising heating in existing buildings in the NZE rests upon a deep retrofit of the majority of the existing building stock. Having almost all buildings meet zero-carbon-ready building energy codes by 2050 would require retrofit rates of 2.5% each year by 2030, up from less than 1% today. Retrofits can be disruptive for occupants, require high upfront investment and may face permitting difficulties. These issues make achieving the required pace and depth of retrofits in the coming years the biggest challenge facing the buildings sector.

Any delay in reaching 2.5% of annual retrofits by 2030 would require such a steep subsequent ramp up as to make retrofitting the vast majority of buildings by 2050 virtually impossible. Modelling indicates that a delay of ten years in the acceleration of retrofitting, would increase residential space heating energy demand by 25% and space cooling demand by more than 20%, translating to a 20% increase in electricity demand in 2050 relative to the NZE (Figure 3.31). This would put more strain on the power sector, which would need to install more low-carbon generation capacity. Policies and fuel switching would still drive down fossil fuel demand in the *Delayed Retrofit Case*, but an additional 15 EJ of fossil fuels would be burned by 2050, emitting 1 Gt of $CO_2$.

**Figure 3.31 ▷ Global residential space heating and cooling energy demand in the NZE and Delayed Retrofit Case**






***Delays in the ramp up of retrofit rates and depth would be almost impossible to catch up, placing further strain on the power sector and pushing up fossil fuel demand***

Governments need to establish policies for coal and oil boilers and furnaces for space and water heating, which in the NZE are no longer available for sale from 2025. They also need to take action to ensure that new gas boilers are able to operate with low-carbon gases (hydrogen ready) in decarbonised gas networks. This puts a premium on the availability of compelling alternatives to the types of boilers being phased out, including the use of heat pumps, efficient wood stoves (using sustainable supplies of wood), district energy, solar PV, solar thermal and other renewable energy technologies. Which alternatives are best will depend to some extent on local conditions, but electrification will be the most energy-efficient and cost-effective low-carbon option in most cases, and decarbonising and expanding district energy networks is likely to make sense where densities allow. The use of biomethane or hydrogen in existing or upgraded gas networks may be the best option in areas where more efficient alternatives are not possible.

Governments also face decisions on minimum energy performance standards (MEPS). The NZE sees all countries introduce MEPS for all main appliance categories set at the most stringent levels prevailing in advanced economies by 2025 at the latest. Among others, this would mean ending the sale of incandescent, halogen and compact fluorescent lamps by that time. Setting MEPS at the right level will require careful planning; international collaboration to align standards and objectives could play a helpful role in keeping costs down.

The systemic nature of the NZE means that strategies and policies for buildings will work best if they are aligned with those being adopted for power systems, urban planning and mobility. This would help to ensure the successful scaling up of building-integrated PV technologies, battery storage and smart controls to make buildings active service providers to grids. It would also help to foster the deployment of smart EV charging infrastructure. Policies incentivising dense and mixed-use urban planning coupled with easy access to local services and public transport could reduce reliance on personal vehicles (see Chapter 2). There are also links between buildings strategies and measures to reduce the embodied carbon emissions of new construction, which falls by 95% by 2050 in the NZE.

# Wider implications of achieving net-zero emissions

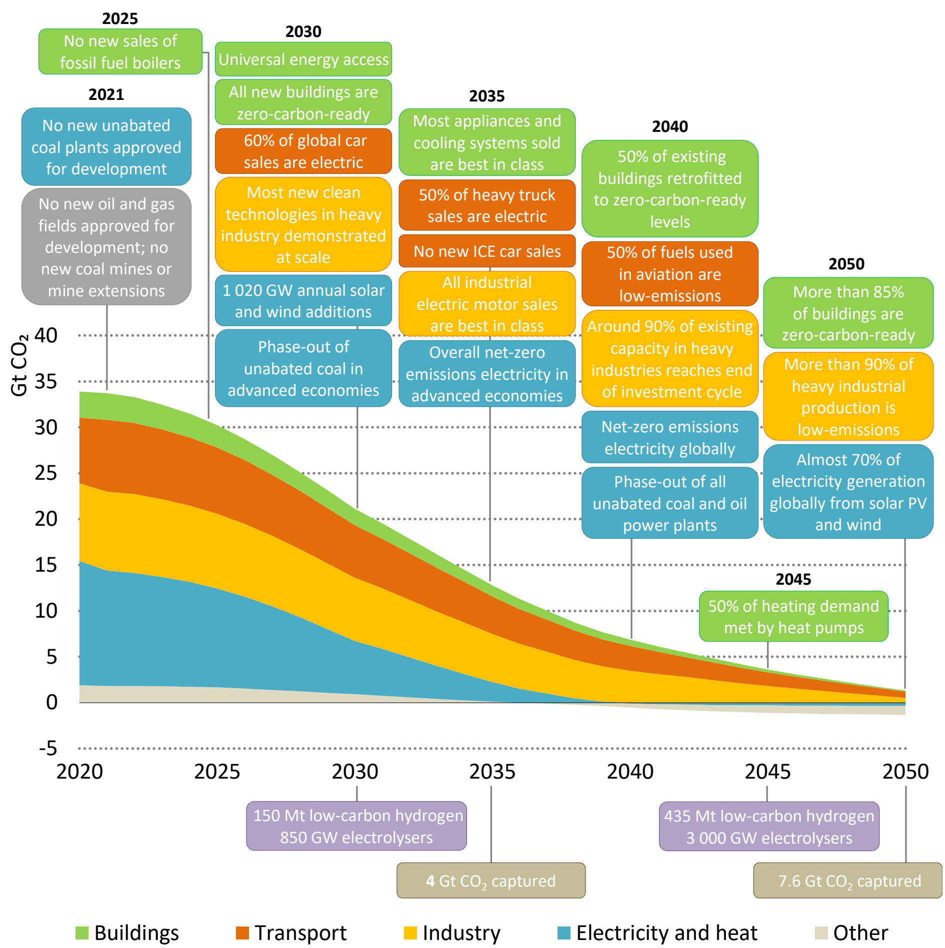
## SUMMARY


- **Economy:** In our Net-Zero Emissions by 2050 Scenario (NZE), global $CO_2$ emissions reach net zero by 2050 and investment rises across electricity, low-emissions fuels, infrastructure and end-use sectors. Clean energy employment increases by 14 million to 2030, but employment in oil, gas and coal declines by around 5 million. There are varying results for different regions, with job gains not always occurring in the same place, or matching the same skill set, as job losses. The increase in jobs and investment stimulates economic output, resulting in a net increase in global GDP to 2030. But oil and gas revenues in producer economies are 80% lower in 2050 than in recent years and tax revenues from retail oil and gas sales in importing countries are 90% lower.
- **Energy industry:** There is a major contraction in fossil fuel production, but companies that produce these fuels have skills and resources that could play a key role in developing new low-emissions fuels and technologies. The electricity industry scales up to meet demand rising over two-and-a-half-fold to 2050 and becomes more capital intensive, focusing on renewables, sources of flexibility and grids. Large energy-consuming companies, vehicle manufacturers and their suppliers adjust designs and retool factories while improving efficiency and switching to alternative fuel supplies.
- For **citizens** who lack access to electricity and clean cooking, the NZE delivers universal access by 2030. This costs around USD 40 billion a year over the next decade and adds less than 0.2% to $CO_2$ emissions. For citizens the world over, the NZE brings profound changes, and their active support is essential if it is to succeed. Around three-quarters of behavioural changes in the NZE can be directly influenced or mandated by government policies. The cost of energy is also an important issue for citizens, and the proportion of disposable household income spent on energy over the period to 2050 remains stable in emerging market and developing economies, despite a large increase in demand for modern energy services.
- **Government** action is central to achieve net-zero emissions globally by 2050; it underpins the decisions made by all other actors. Four particular points are worth stressing. First, the NZE depends on actions that go far beyond the remit of energy ministers, and requires a co-ordinated cross-government approach. Second, the fall in oil and gas demand in the NZE may reduce some traditional energy security risks, but they do not disappear, while potential new vulnerabilities emerge from increasing reliance on electricity systems and critical minerals. Third, accelerated innovation is needed. The emissions cuts to 2030 in the NZE can be mostly achieved with technologies on the market today, but almost half of the reductions in 2050 depend on technologies that are currently under development. Fourth, an unprecedented level of international co-operation is needed. This helps to accelerate innovation, develop international standards and facilitate new infrastructure to link national markets. Without the co-operation assumed in the NZE, the transition to net-zero emissions would be delayed by decades.

## 4.1 Introduction

Achieving net-zero emissions by 2050 is a monumental task, especially against a backdrop of increasing economic and population growth. It calls for an unwavering focus from all governments, working together with industries and citizens, to ensure that the transition to global net-zero emissions proceeds in a co-ordinated way without delay. In this chapter, we look at what the changes that deliver net-zero emissions globally by 2050 in the NZE would mean for the economy, the energy industry, citizens and governments.

**Figure 4.1 ▷ Selected global milestones for policies, infrastructure and technology deployment in the NZE**






*There are multiple milestones on the way to global net-zero emissions by 2050. If any sector lags, it may prove impossible to make up the difference elsewhere.*

Wide-ranging measures and regulations in the NZE help to influence or change the purchases that individuals make, the way they heat and cool their homes, and their means of transport. Many industries, especially those that are currently involved in the production of energy or are large-scale users of energy, also face change. Some of the shifts for individuals and industries may be unpopular, underscoring the fact that it is essential to ensure that the energy transition is transparent, just and cost-effective, and to persuade citizens of the need for reform. These changes deliver significant benefits. There are around 790 million people who do not have access to electricity today and 2.6 billion people who do not have access to clean cooking options. The NZE shows how emissions reductions can go hand-in-hand with efforts to provide universal access to electricity and clean cooking, and to improve air quality. It provides significant opportunities too, with clean energy technologies providing many new business opportunities and jobs, and with innovations that stimulate new industrial capacities.



Underpinning all of these changes are decisions taken by governments. This will require wholehearted buy-in from all levels of government and from all countries. The magnitude of the changes required to reach global net-zero emissions by 2050 are not within the power of government energy or environment departments alone to deliver, nor within the power of individual countries. It will involve an unprecedented level of global collaboration, with recognition of and sensitivity to differences in the stages of development of individual countries, and an appreciation of the difficulties faced by particular communities and members of society, especially those who may be negatively affected by the transition to net-zero emissions. In the NZE, governments start by setting unequivocal long-term targets, ensuring that these are fully supported from the outset by explicit, near-term targets and policy measures that clearly set out the pathway, and that recognise each country's unique starting conditions, to support the deployment of new infrastructure and technologies (Figure 4.1).

## 4.2 Economy

### *4.2.1 Investment and financing*

The transition to net-zero emissions by 2050 requires a substantial ramp up in the investment of electricity, infrastructure and the end-use sectors. The largest increase over the next decade is in electricity generation: annual investment increases from about USD 0.5 trillion over the past five years to USD 1.6 trillion in 2030 (Figure 4.2). By 2030, annual investment in renewables in the electricity sector is around USD 1.3 trillion, slightly more than the highest level ever spent on fossil fuel supply (USD 1.2 trillion in 2014). Annual investment in clean energy infrastructure increases from around USD 290 billion over the past five years to about USD 880 billion in 2030. This is for electricity networks, public electric vehicle (EV) charging stations, hydrogen refuelling stations and import and export terminals, direct air capture and $CO_2$ pipelines and storage facilities. Annual investment in low-carbon technologies in end-use sectors rises from USD 530 billion in recent years to USD 1.7 trillion in 2030.[1] This includes spending on deep retrofitting of buildings, transformation of industrial processes, and the purchase of new low-emissions vehicles and more efficient appliances.

After 2030, annual electricity generation investment falls by one-third to 2050. A lot of infrastructure for a low-emissions electricity sector is established within the first decade of the NZE, and the cost of renewables continues to decline after 2030. In end-use sectors, there are continued increases in investment in EVs, carbon capture, utilisation and storage (CCUS) and hydrogen use in industry and transport, and more efficient buildings and appliances.

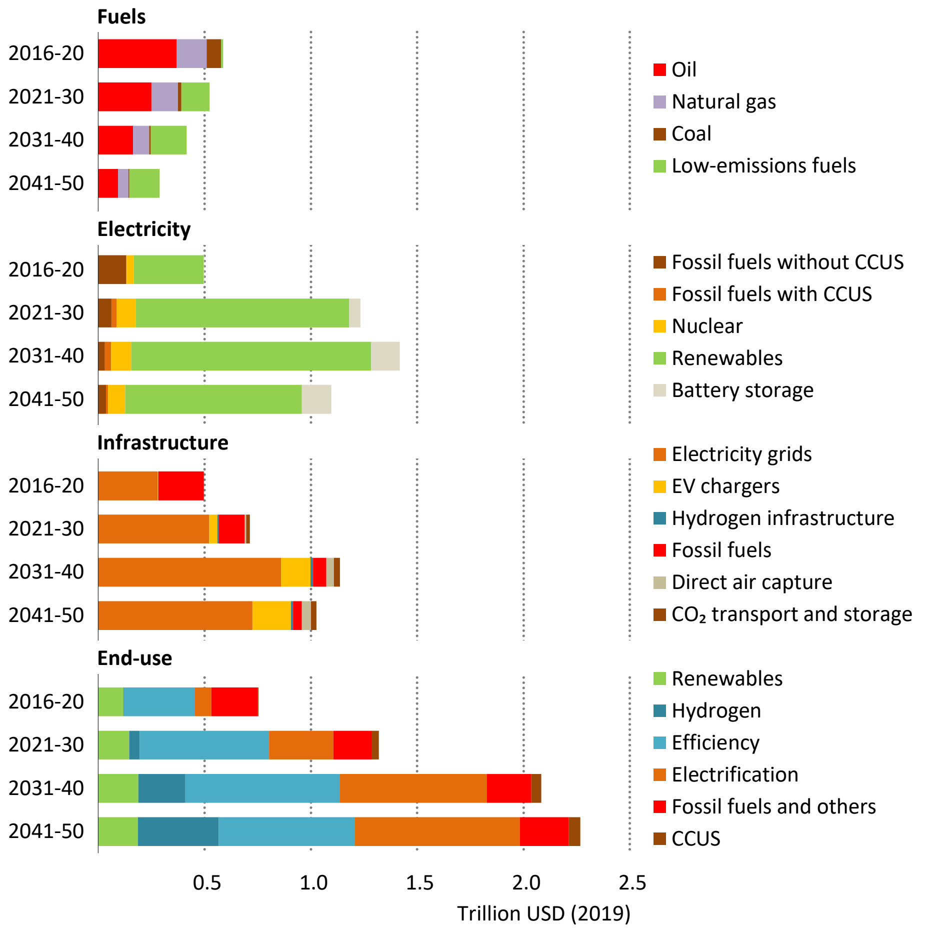
Global investment in fossil fuel supply falls steadily from about USD 575 billion on average over the past five years to USD 110 billion in 2050 in the NZE, with upstream fossil fuel investment restricted to maintaining production at existing oil and natural gas fields. This investment reflects the fact that fossil fuels are still used in 2050 in the NZE in processes where they are paired with CCUS, in non-emitting processes (such as petrochemical manufacturing), and in sectors where emissions reductions are most challenging (with emissions offset by carbon dioxide removal). Investment in low-emissions fuels increases more than thirty-fold between 2020 and 2050, reaching about USD 135 billion in 2050. This is split roughly equally between the production of hydrogen and hydrogen-based fuels, and the production of biofuels.

Over the 2021-50 period in the NZE, annual average total energy sector investment as a share of gross domestic product (GDP) is around 1% higher than over the past five years. The private sector is central to finance higher investment needs. It requires enhanced collaboration between developers, investors, public financial institutions and governments. Collaboration will be especially important over the next five to ten years for the development of large infrastructure projects and for technologies in the demonstration or prototype phase today such as some hydrogen and CCUS applications. Companies and investors have declared strong interest to invest in clean energy technologies, but turning interest into actual investment at the levels required in the NZE also depends on public policies.

Some obstacles to investment need to be tackled. Many emerging market and developing economies are reliant on public sources to finance energy projects and new industrial facilities. In some cases, improvements in regulatory and policy frameworks would facilitate the international flow of long-term capital to support the development of both new and existing clean energy technologies. The rapid growth in investment in transport and buildings in the NZE presents a different kind of challenge for policy makers. In many cases, an increase in capital spending for an efficient appliance or low-emissions vehicle would be more than offset by lower expenditure on fuels and electricity over the product lifetime, but some low-income households and small and medium enterprises may not be able to afford the upfront capital required.

[1] Investment levels presented in this report include a broader accounting of efficiency improvements in buildings and differ from that reported in the IEA World Energy Investment report (IEA, 2020a). End-use efficiency investments are the incremental cost of improving the energy performance of equipment relative to a conventional design.

**Figure 4.2 ▻ Global average annual energy investment needs by sector and technology in the NZE**





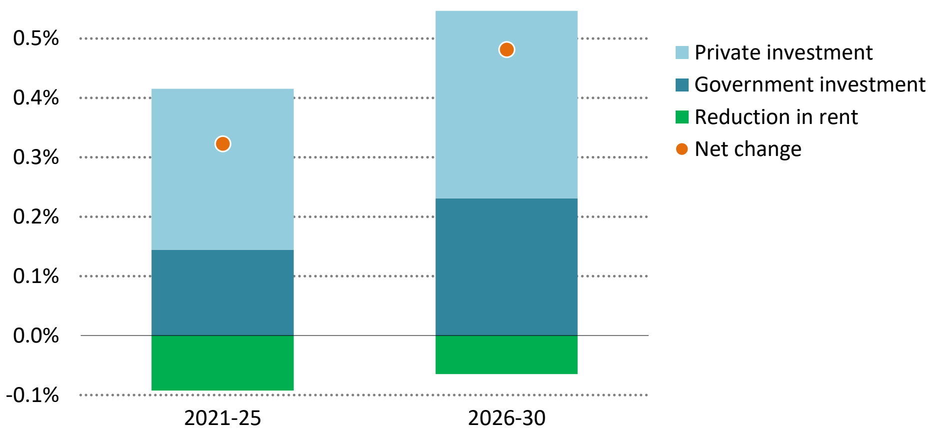

***Investment increases rapidly in electricity generation, infrastructure and end-use sectors. Fossil fuel investment drops sharply, partly offset by a rise in low-emissions fuels.***

Notes: CCUS = carbon capture, utilisation and storage; EV = electric vehicle. Infrastructure includes electricity networks, public EV charging, $CO_2$ pipelines and storage facilities, direct air capture and storage facilities, hydrogen refuelling stations, and import and export terminals for hydrogen and fossil fuels pipelines and terminals. End-use efficiency investments are the incremental cost of improving the energy performance of equipment relative to a conventional design.

## 4.2.2 Economic activity

The energy transition required for net-zero emissions by 2050 will affect all economic activities directly or indirectly. In co-ordination with the International Monetary Fund, we have modelled the medium-term global macroeconomic impact of the changes in the energy sector that occur in the NZE. This analysis shows that the surge in private and government spending on clean energy technologies in the NZE creates a large number of jobs and stimulates economic output in the engineering, manufacturing and construction industries. This results in annual GDP growth that is nearly 0.5% higher than the levels in the Stated Policies Scenario (STEPS)[2] during latter half of the 2020s (Figure 4.3).[3]

**Figure 4.3 ▷ Change in annual growth rate of global GDP in the NZE relative to the STEPS**






***The surge in government and private investment in the NZE has a positive impact on global GDP, but there are large differences between regions***

Notes: GDP = gross domestic product. Reduction in rents stem mainly from lower fossil fuel income.

Source: IEA analysis based on IMF.

There are large differences in macroeconomic impacts between regions. The decline in fossil fuel use and prices results in a fall in GDP in the producer economies,[4] where revenues from oil and gas sales often cover a large share of public spending on education, health care and other public services. The drop in oil and gas demand, and the consequent fall in international prices for oil and gas, cause net income in producer economies to drop to historic lows (Figure 4.4). Some countries with the lowest cost oil resources (including members of the

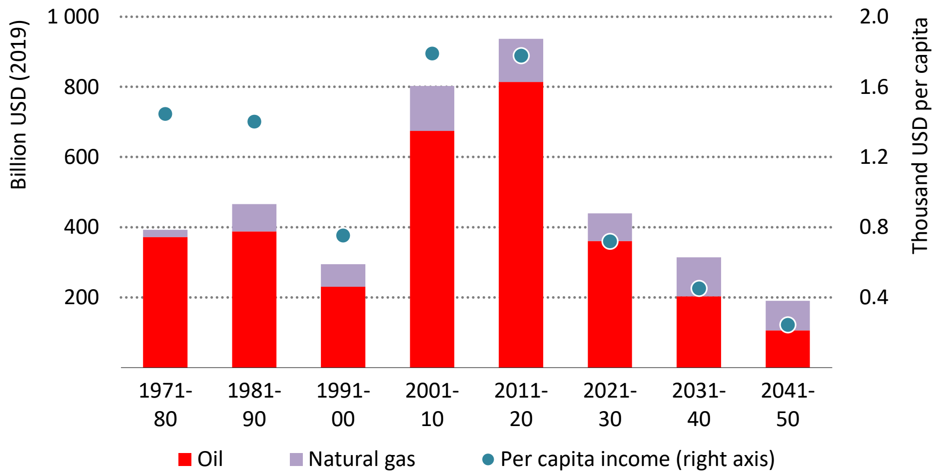
[2] The IEA Stated Policies Scenario is the projection for the global energy system based on the policies and measures that governments around the world have already put in place and on announced policies as expressed in official targets and plans, such as Nationally Determined Contributions put forward under the Paris Agreement (see Chapter 1).

[3] The estimated general equilibrium macroeconomic impact of the increase in public and private investment and the reduction in oil-related revenue contained in the NZE has been provided by the International Monetary Fund using its Global Integrated Monetary and Fiscal Model (GIMF).

[4] Producer economies are large oil and gas exporters that rely on hydrocarbon revenues to finance a significant proportion of their national budgets, including countries in the Middle East, Russia and the Caspian region.

Organization of the Petroleum Exporting Countries [OPEC]) gain market share in these circumstances, but even they would see large falls in revenues. Structural reforms would be needed to address the societal challenges, including those to accelerate the process of reforming inefficient fossil fuel subsidies and to speed up moves to use hydrocarbon resources to produce low-emissions fuels, e.g. hydrogen and hydrogen-based fuels (see section 4.3.1).

**Figure 4.4 ▻ Income from oil and gas sales in producer economies in the NZE**





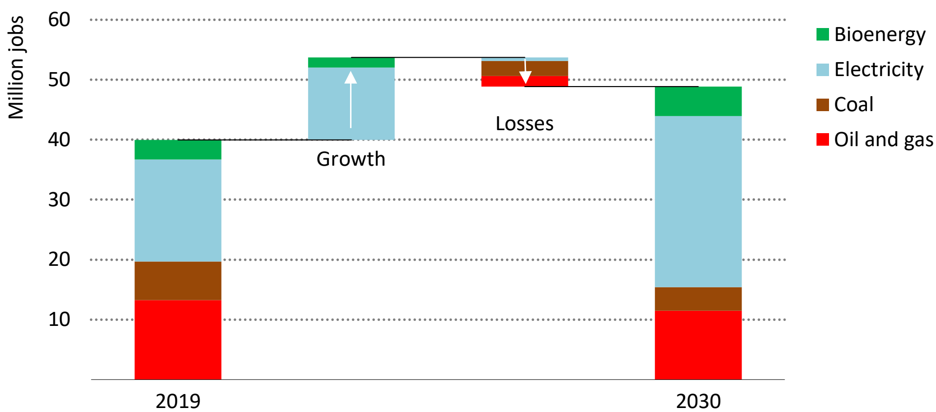

***Structural reforms and new sources of revenue are needed in producer economies, but these are unlikely to compensate fully for a large drop in oil and gas income***

The macroeconomic effects of the NZE are very uncertain. They depend on a host of factors including: how government expenditure is financed; benefits from improvements to health; changes in consumer bills; broad impact of changes in consumer behaviour; and potential for productivity spill-overs from accelerated energy innovation. Nonetheless, impacts are likely to be lower than assessments of the cost of climate change damages (OECD, 2015). It is also likely that a co-ordinated, orderly transition can be executed without major global systemic financial impacts, but this will require close attention from governments, financial regulators and the corporate sector.

### 4.2.3 Employment

Employment in the energy sector shifts markedly in the NZE in response to changes in investment and spending on energy. We estimate that today roughly 40 million people around the world work directly in the oil, gas, coal, renewables, bioenergy and energy network industries (IEA, 2020b). In the NZE, clean energy employment increases by 14 million to 2030, while employment in oil, gas and coal fuel supply and power plants declines by around 5 million, leading to a net increase of nearly 9 million jobs (Figure 4.5).

**Figure 4.5 ▷ Global energy sector employment in the NZE, 2019-2030**






*Overall employment in the energy sector increases by almost 9 million to 2030 as jobs created in clean energy sectors outpace losses in fossil fuels*

Jobs created would not necessarily be in the same area where jobs are lost, plus the skill sets required for the clean energy jobs may not be directly transferable. Job losses would be most pronounced in communities that are heavily dependent on fossil energy production or transformation activities. Even where the number of direct energy jobs lost is small, the impact on the local economy may be significant. Government support would almost certainly be needed to manage these transitions in a just, people-centred way. In preparation, a better understanding of current energy industry employment is needed. A useful action would be for governments to adopt more detailed surveying approaches for energy industry employment, such as those used in the *US Energy & Employment Report* (NASEO and Energy Futures Initiative, 2021).

In addition to the 14 million new clean energy jobs created in the NZE, other new jobs are created by changes in spending on more efficient appliances, electric and fuel cell vehicles, and building retrofits and energy-efficient construction. These changes would require a further 16 million workers, meaning that there would be 30 million more people working in clean energy, efficiency and low-emissions technologies by 2030 in the NZE (Figure 4.6).[5] Investment in electricity generation, electricity networks, EV manufacturing and energy efficiency are among the areas that will open up new employment opportunities. For example, jobs in solar and wind more than quadruple in the NZE over current levels. Nearly two-thirds of workers in these sectors by 2030 in the NZE would be highly skilled and the

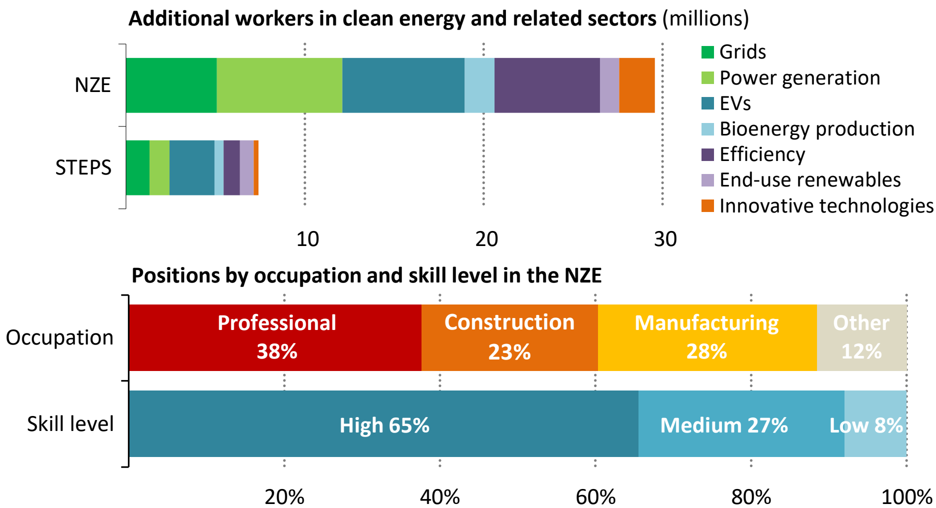
[5] This includes new jobs and jobs filled by moving current employment from one type of production to another.

majority require substantial training. In addition, with the more than doubling of total energy investment, new employment opportunities will arise in associated areas such as wholesale trading, financial and legal services.

In many cases it may be possible to shift workers to new product lines within the same company, for example in vehicle manufacturing as production reconfigures to EVs. However, there would be larger risks for specialised supply chain companies that provide products and services, e.g. internal combustion engines that are replaced by new components such as batteries.



**Figure 4.6 ▷ New workers in clean energy and related sectors and shares by skill level and occupation in the NZE and the STEPS in 2030**






*About 30 million new workers are needed by 2030 to meet increased demand for clean energy, efficiency, and low-emissions technologies; over half are highly skilled positions*

Note: EVs = electric vehicles.

The new jobs created in the NZE tend to have more geographic flexibility and a wider distribution than is the case today. Around 40% are jobs located close to where the work is being done, e.g. building efficiency improvements or wind turbine installation, and the remaining are jobs tied to manufacturing sites. Today the manufacturing capacity for a number of clean energy technologies, such as batteries and solar photovoltaic panels, is concentrated in particular areas, notably China. The rapid increase in demand for clean energy technologies in the NZE requires new production capacity to come online that could be located in any region. Those countries and companies that move first may enjoy strategic advantages in capturing burgeoning demand.

## 4.3 Energy industry

### *4.3.1 Oil and gas*

The energy transition envisioned in the NZE involves a major contraction of oil and gas production with far-reaching implications for all the companies that produce these fuels. Oil demand falls from around 90 million barrels per day (mb/d) in 2020 to 24 mb/d in 2050, while natural gas demand falls from 3 900 billion cubic metres (bcm) to around 1 700 bcm. No fossil fuel exploration is required in the NZE as no new oil and natural gas fields are required beyond those that have already been approved for development. This represents a clear threat to company earnings, but there are also opportunities. The resources and skills of the oil and gas industry are a good match with some of the new technologies needed to tackle emissions in sectors where reductions are likely to be most challenging, and to produce some of the low-emissions liquids and gases for which there is a rapid increase in demand in the NZE (see Chapter 2). By partnering with governments and other stakeholders, the oil and gas industry could play a leading role in developing these fuels and technologies at scale, and in establishing new business models.

The oil and gas industry is highly diverse, and various companies could pursue very different strategies in the transition to net-zero emissions. Minimising emissions from core oil and gas operations however should be a first-order priority for all oil and gas companies. This includes tackling methane emissions that occur during operations (they fall by 75% between 2020 and 2030 in the NZE) and eliminating flaring. Companies should also electrify operations using renewable electricity wherever possible, either by purchasing electricity from the grid or by integrating off-grid renewable energy sources into upstream facilities or transport infrastructure. Producers that can demonstrate strong and effective action to reduce emissions can credibly argue that their oil and gas resources should be preferred over higher emissions options.

Some oil and gas companies may choose to become "energy companies" focused on low-emissions technologies and fuels, including renewable electricity, electricity distribution, EV charging and batteries. Several technologies that are critical to the achievement of net-zero emissions, such as CCUS, hydrogen, bioenergy and offshore wind, look especially well-suited to some of the existing skills, competencies and resources of oil and gas companies.

- **Carbon capture, utilisation and storage**. The oil and gas industry is already the global leader in developing and deploying CCUS. Of the 40 million tonnes (Mt) of $CO_2$ captured today at large-scale facilities, around three-quarters is captured from oil and gas operations, which often produce concentrated streams of $CO_2$ that are relatively easy and cost effective to capture (IEA, 2020c). The oil and gas industry also has the large-scale engineering, pipeline, sub-surface and project management skills and capabilities to handle large volumes of $CO_2$ and to help scale up the deployment of CCUS.

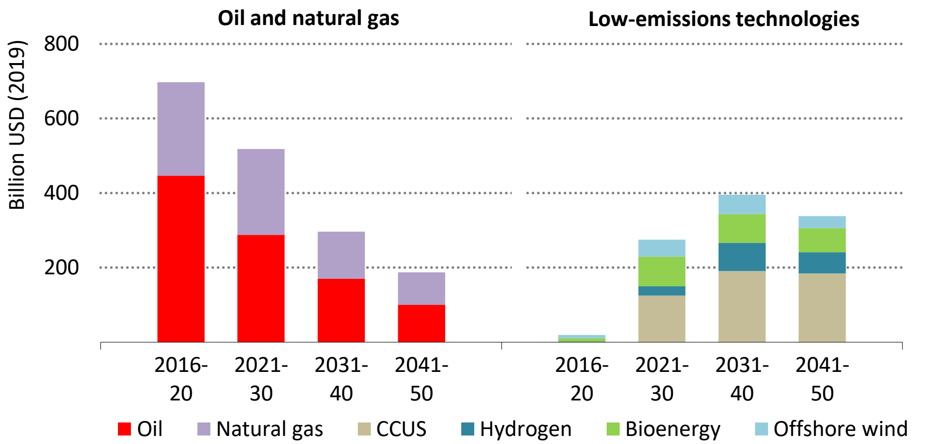
- **Low-emissions hydrogen and hydrogen-based fuels**. Oil and gas companies could contribute to developing and deploying low-emissions hydrogen in several ways (IEA, 2019a). Nearly 40% of hydrogen production in 2050 in the NZE is from natural gas in facilities equipped with CCUS, providing an important opportunity for companies and countries to utilise their natural gas resources in a way that is consistent with net-zero emissions. Of the total output of 530 Mt of hydrogen in 2050, about 30% is processed into ammonia and synthetic fuels (equivalent to around 7.5 mboe/d). The transformation processes involved have many potential synergies with the skills and equipment used in oil and gas processing and refining. Oil and gas companies also have long experience of transporting liquids and gases by pipeline and ships.
- **Advanced biofuels and biomethane**. The production of advanced biofuels grows substantially in the NZE, but this depends critically on continued technological innovation. Many oil and gas companies have active R&D programmes in these areas and could become leading producers. Biomethane – a low-emissions alternative to natural gas – can be produced in large centralised facilities, which could be a good fit with the knowledge and technical expertise of existing gas producers (IEA, 2020d).
- **Offshore wind**. About 40% of the lifetime costs of a standard offshore wind project involve significant synergies with the offshore oil and gas sector (IEA, 2019b). The oil and gas industry has considerable experience of working in offshore locations, which could be of value in the construction of foundations and subsea structures for offshore wind farms, especially when using vessels during installation and operation. The experience of maintaining safety standards in oil and gas companies could also be helpful during maintenance and inspection of offshore wind farms once they are in operation.



Oil and gas companies are well-placed to accelerate the pace of development and deployment of these technologies, and to gain a commercial edge over other companies. In the NZE, investment in low-emissions technologies suited to the skills and expertise of oil and gas companies exceeds that in traditional oil and gas operations by 2030. Total capital spending on these technologies and on traditional oil and gas operations averages USD 650 billion per year over 2021-50, just less than annual investment in oil and gas projects between 2016 and 2020 (Figure 4.7).

Not all oil and gas companies will choose to follow a strategy of diversifying into other types of energy. For example, it is far from certain that national oil companies will be charged by their state owners to diversify and develop low-emissions energy sources outside their core area of activity; other companies may decide simply to concentrate on supplying oil and natural gas as cleanly and efficiently as possible, and to return income to shareholders. What is clear, however, is that no oil and gas company would be unaffected by the NZE and that all parts of the industry need to decide how to respond (IEA, 2020e).

**Figure 4.7 ▷ Annual average investment in oil and gas and low-emissions technologies with synergies for the oil and gas industry in the NZE**






*Investment in low-emissions technologies suited to the skills and expertise of oil and gas companies exceeds investment in traditional operations by 2030*

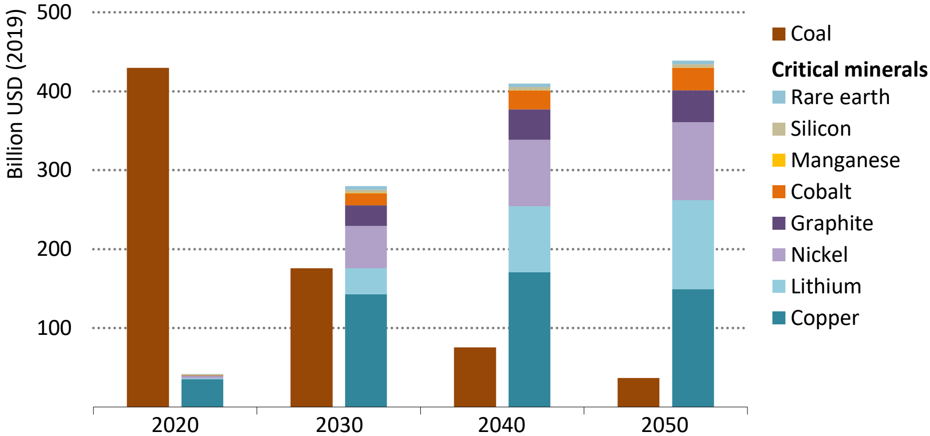
Note: CCUS = carbon capture, utilisation and storage.

### 4.3.2 Coal

The precipitous decline in coal use projected in the NZE would have major implications for the future of mining companies and countries with large existing production capacities. Around 470 million tonnes of coal equivalent (Mtce) of coal used in the NZE in 2050 is in facilities equipped with CCUS (80% of global coal demand in 2050), which prevents an even sharper decline in demand. But no new coal mines or mine extensions are needed in the NZE. Retraining and regional revitalisation programmes would be essential to reduce the social impact of job losses at the local level and to enable workers and communities to find alternative livelihoods. There could also be opportunities to locate new clean energy facilities, including the new processing facilities that are needed for critical minerals, in the areas most affected by mine closures.

For mining companies, however, the contraction in coal demand in the NZE could be offset by the need to increase mining of other raw minerals, including those vital to many clean energy technologies, such as copper, lithium and nickel (IEA, 2021a). Global demand for these critical minerals rises rapidly in the NZE (Figure 4.8). For example, demand for lithium for use in batteries expands by a factor of 30 by 2030, while demand for rare earths, primarily used for making EV motors and wind turbines, increases by a factor of ten by 2030. Critical mineral resources are not always located in the same locations or countries as existing coal mines, but the skills and experience of mining companies will be essential to ensure that the supply of these minerals is able to match demand at reasonable prices. By the 2040s, the size of the global market for these minerals approaches that for coal today.

**Figure 4.8 ⊳ Global value of coal and selected critical minerals in the NZE**






*The market for critical minerals approaches that of coal today in the 2040s*

Notes: Includes total revenue for coal and for selected critical minerals used in clean energy technologies. The prices of critical minerals are based on conservative assumptions about cost increases (around a 10%-20% increase from current levels to 2050).

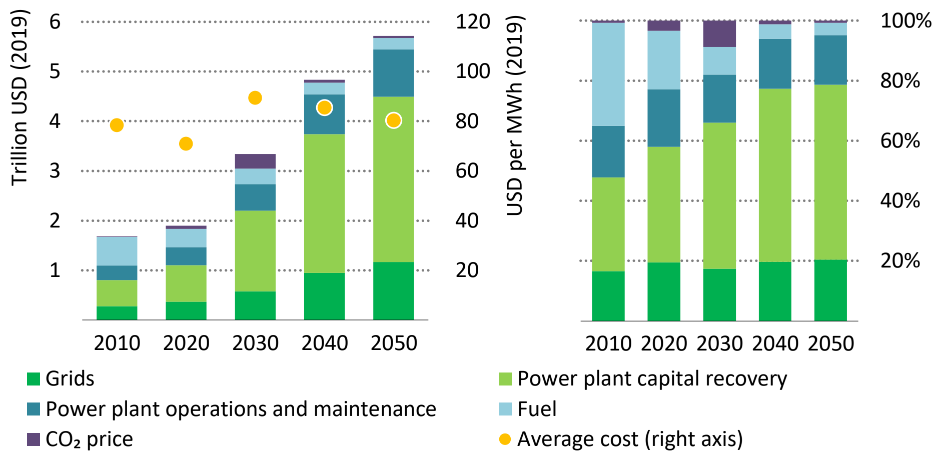
### *4.3.3 Electricity*

Getting to net-zero emissions calls for a massive expansion of the electricity sector to power the needs of a growing global economy, the electrification of end-uses that previously used fossil fuels, and the production of hydrogen from electrolysis. While electricity demand increases more than two-and-a-half times, the rapid transformation of the industry means that total electricity supply costs triple from 2020 to 2050 in the NZE, raising average costs per unit of electricity generation modestly (Figure 4.9).

The electricity supply industry also becomes much more capital intensive, accelerating a recent trend. The share of capital in total costs rises from less than 60% in 2020 (already ten percentage points higher than in 2010) to about 80% in 2050. This is largely due to a massive increase in renewable energy and the corresponding need for more network capacity and sources of flexibility, including battery storage. In the late 2020s and 2030s, the upgrading and replacement of existing solar and wind capacity as they come to the end of their operating lives also boosts capital needs.[6] New nuclear power capacity additions add further capital spending in the NZE. The rising capital intensity of the electricity industry increases the importance of limiting risk for new investment and ensuring sufficient revenues in all years for grid operators to fund rising investment needs – a point underlined by the financial difficulties experienced by some network companies in 2020 due to depressed electricity demand resulting from the Covid-19 crisis (IEA, 2020f).

[6] They typically need replacing after 25-30 years of operation, whereas many conventional hydropower, nuclear and coal plants operate far longer albeit with periodic additional investment.

**Figure 4.9 ⊳ Global electricity supply costs by component in the NZE**






***Electricity system costs triple to 2050, raising average supply costs modestly; the massive growth of renewables makes the industry more capital intensive***

Notes: Electricity supply costs include all the direct costs to produce and transmit electricity to consumers. Battery storage systems are included in power plant capital recovery.

The rising share of renewables in the electricity generation mix has important implications for the design of electricity markets. When the shares of solar, wind, other variable renewables and nuclear power reach high levels, available electricity supply at no marginal cost is often above electricity demand, resulting in a wholesale price of electricity that is zero or even negative. By 2050, without changes in electricity market design, about 7% of wind and solar output in the NZE would be above and beyond what can be integrated (and so curtailed), and the share of zero-price hours in the year would increase to around 30% in major markets from close to zero today, despite the active use of demand response. If the share of renewables in the electricity generation mix is to rise as envisioned in the NZE, it would therefore be highly desirable to effect significant changes in the design of electricity markets so as to provide signals for investment, including investment in sources of flexibility such as battery storage and dispatchable power plants.

The increase in electricity use inevitably raises associated costs. Operating and maintaining power plants worldwide costs close to USD 1 trillion in 2050 in the NZE, two-and-a-half times the level in 2020. In 2020, upkeep at fossil fuel power plants accounted for USD 150 billion, and renewables required nearly as much, mostly for hydropower. By 2050, the cost of operating and maintaining renewables reaches USD 780 billion, most it needed for wind and solar photovoltaics (PV) as a result of their massive scaling up: offshore wind alone accounts for USD 90 billion.

The sharp reduction of fossil fuel use in the electricity industry and lower fuel prices mean that costs related to fuel and $CO_2$ prices are significantly reduced. This continues a recent trend driven by near record-low natural gas prices in many markets. Even with rising $CO_2$ prices over time, the rapid decarbonisation of electricity means that fuel and $CO_2$ make up a declining share of total costs, falling from about one-quarter in 2020 to 5% in 2050. The balance of fuel costs shifts towards low-emissions sources, mainly nuclear power and bioenergy (including with CCUS), though some still remains related to natural gas and coal used in power plants equipped with CCUS.

One challenge in this context is what to do about the coal-fired power plants in operation. In 2020, over 2 100 gigawatts (GW) of power plants worldwide used coal to produce electricity and heat, and they emitted nearly 30% of all energy-related $CO_2$ emissions. Options include retrofitting coal-fired power plants with CCUS technologies, co-firing with biomass or ammonia; repurposing coal plants to focus on providing flexibility; and, where feasible, phasing them out. In the NZE, all unabated coal-fired power plants are phased out in advanced economies by 2030 and in emerging market and developing economies by 2040. As a result, emissions from coal-fired power plants fall from 9.8 gigatonnes (Gt) in 2020 to 3.0 Gt in 2030 and to just 0.1 Gt by 2040 (residual emissions from coal with CCUS plants).[7]



Another challenge is related to the scale of capacity retirements envisaged and associated site rehabilitation, starting with coal. The pace of retirement of coal-fired power plants over 2020-50 is nearly triple that of the past decade. Decommissioning at each site can often last a decade and entail significant cost, and may involve closing a mine as well. In some cases, it may be financially attractive to build a renewable energy project on the same site, taking advantage of the grid connection and limiting the cost of rehabilitation. Thousands of natural gas-fired and oil-fired power plants are also retired by 2050, though these sites are often strategically located on the grid and many are likely to be replaced directly with battery storage systems.

The large fleet of ageing nuclear reactors in advanced economies means their decommissioning increases, despite many reactor lifetime extensions. In the NZE, annual average nuclear retirements globally are 60% higher over the next 30 years than in the last decade. Each nuclear decommissioning project can span decades, with costs ranging from several hundred million dollars to well over USD 1 billion for large reactors (NEA, 2016).

### 4.3.4 Energy-consuming industries

The changes in the NZE would have an enormous impact on industries that manufacture vehicles and their material and component suppliers. Around 95% of all the cars and nearly all of the trucks sold worldwide in 2020 were conventional vehicles with an internal combustion engine. In the NZE, about 60% of global car sales in 2030 are EVs, and 85% of

[7] A $CO_2$ capture rate of 90% is assumed, though higher rates are technically possible with reduced efficiencies and additional costs (IEA, 2020g).

heavy-duty trucks sold in 2040 are EVs or fuel cell vehicles. In the NZE, vehicle component suppliers and vehicle manufacturers alike retool factories, change designs to incorporate batteries and fuel cells, and adjust supply chains to minimise the lifecycle emissions intensities of vehicles. This provides opportunities to redesign existing parts and manufacturing processes to improve efficiency and lower costs.

The rapid increase in EV sales in the NZE requires an immediate scale up of new supply chains for batteries as well as recharging and low-emissions refuelling infrastructure. In the NZE, battery production capacity increases to more than 6.5 terawatt-hours (TWh) by 2030, compared with less than 0.2 TWh in 2020. Any delay in expanding battery manufacturing capacity would have a detrimental impact on the roll-out of EVs and slow cost reductions for other clean energy technologies that benefit in the NZE from having similar manufacturing processes and know-how (such as fuel cell vehicles and electrolysers).

In aviation and shipping, liquid low-emissions fuels are central to cut emissions. Switching to some of these would have little impact on vessel design: the use of hydrogen-based fuels or biofuels in shipping would only require changes to the motor and fuel system, and bio-kerosene or synthetic kerosene can operate with existing aircraft. New bunkering and refuelling infrastructure are needed in the NZE, however, and the use of these low-emissions fuels also requires new safety and standardisation standards, protocols for permitting, construction and design, as well as international regulation, monitoring, reporting and verification of their production and use.

In heavy industrial sectors – steel, cement and chemicals – most deep emissions reduction technologies are not available on the market today. In the NZE, material producers soon demonstrate near-zero emission processes, aided by government risk-sharing mechanisms, and start to adapt their existing production assets. For multinational companies, this includes developing technology transfer strategies to roll-out processes across plants. International co-operation would help to ensure a level playing field for all. Within countries, efforts focus on industrial hubs in order to accelerate emissions reductions across multiple industrial sectors by promoting economies of scale for new infrastructure (such as $CO_2$ transport and storage) and supplies of low-emissions energy.

Materials producers work with governments in the NZE to create an international certification system for near-zero emission materials to differentiate them from conventional ones. This would enable buyers of materials such as vehicle manufacturers and construction companies to enter into commercial agreements to purchase near-zero emissions materials at a price premium. In most cases, the premium would result in only a modest impact on the final price of the product price given that materials generally account for a small portion of manufacturing costs (Material Economics, 2019).

## 4.4 Citizens

### *4.4.1 Energy-related Sustainable Development Goals*

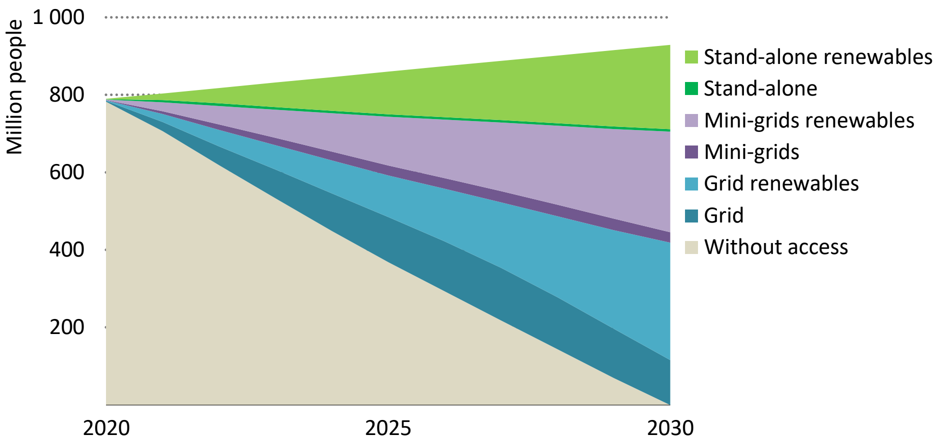
An inclusive and people-centred transition is key to the world moving rapidly, collectively and consistently toward net-zero emissions by mid-century. The NZE achieves the United Nations energy-related Sustainable Development Goals (SDGs) of universal access to clean modern energy by 2030 (SDG 7.1) and reducing premature deaths caused by air pollution (SDG 3.9). The technologies, options and measures used to achieve full access to low-emissions electricity and clean cooking solutions by 2030 in the NZE also help to reduce greenhouse gas (GHG) emissions from household energy use.



*Energy access*

About 790 million people worldwide did not have access to electricity in 2020, most of them living in sub-Saharan Africa and developing Asia. Around 2.6 billion people did not have access to clean cooking options: 35% of them were in sub-Saharan Africa, 25% in India and 15% in China. A lack of access to energy not only impedes economic development, but also causes serious harm to health and is a barrier to progress on gender equality and education.[8]

**Figure 4.10 ▹ People gaining access to electricity by type of connection in emerging market and developing economies in the NZE**





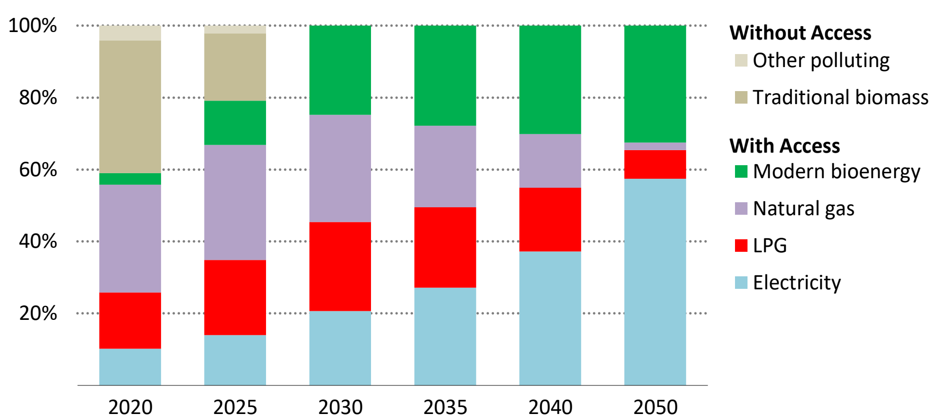

*More than 80% of people gaining access to electricity by 2030 are supplied renewable power and just over half via off-grid systems*

[8] Households relying on the traditional use of biomass for cooking dedicate around 1.4 hours each day collecting firewood and several hours cooking with inefficient stoves, a burden largely borne by women (IEA, 2017).

Around 45% of those who lack access to electricity by 2030 gain it via a connection to a main grid, while the rest are served by mini-grids (30%) and stand-alone solutions (25%) (Figure 4.10). Almost all off-grid or mini-grid solutions are 100% renewable. Decentralised systems that rely on diesel generators, which are also deployed in some grid-connected systems to compensate for low reliability, are phased out later and replaced with solar storage systems. Achieving full access does not lead to a significant increase in global emissions: in 2030 it adds less than 0.2% to $CO_2$ emissions. Achieving full access to electricity also brings efficiency gains and accelerates the electrification of appliances, which become critical to emissions reductions in buildings after 2030 in emerging market and developing economies.

For clean cooking, 55% of those gaining access by 2030 in the NZE do so through improved biomass cookstoves (ICS) fuelled by modern biomass, biogas or ethanol, 25% through the use of liquefied petroleum gas (LPG) and 20% via electric cooking solutions (Figure 4.11). LPG is the main fuel adopted in urban areas and ICS is the main option in rural areas. The use of LPG results in a slight increase in $CO_2$ emissions in 2030 but a net reduction in overall GHG emissions due to reduced methane, nitrous oxides and black carbon emissions from the traditional use of biomass. In addition, LPG is increasingly decarbonised after 2030 using bio-sourced butane and propane (bioLPG) produced sustainably from municipal solid waste (MSW) and other renewable feedstocks. The technical potential of bioLPG production from MSW in 2050 in Africa could be enough to satisfy the cooking needs of more than 750 million people (GLPGP, 2020; Liquid Gas Europe, 2021).

**Figure 4.11 ▻ Primary cooking fuel by share of population in emerging market and developing economies in the NZE**






*Traditional biomass is entirely replaced with modern energy by 2030, mainly in the form of bioenergy and LPG; by 2050, electricity, bioenergy and bioLPG meet most cooking needs*

Notes: Modern bioenergy includes improved cook stoves, biogas and ethanol. Liquefied petroleum gas (LPG) includes fossil and renewable fuel.

The achievement of universal access to clean energy by 2030 requires governments and donors to put expanding access at the heart of recovery plans and programmes. There would be multiple benefits: investing heavily in energy access would provide an immediate economic boost, create local jobs and bring durable improvements to social well-being by modernising health services and food chains. In the NZE, around USD 35 billion is spent each year improving access to electricity and almost USD 7 billion each year on clean cooking solutions for people in low-income countries from now to 2030.

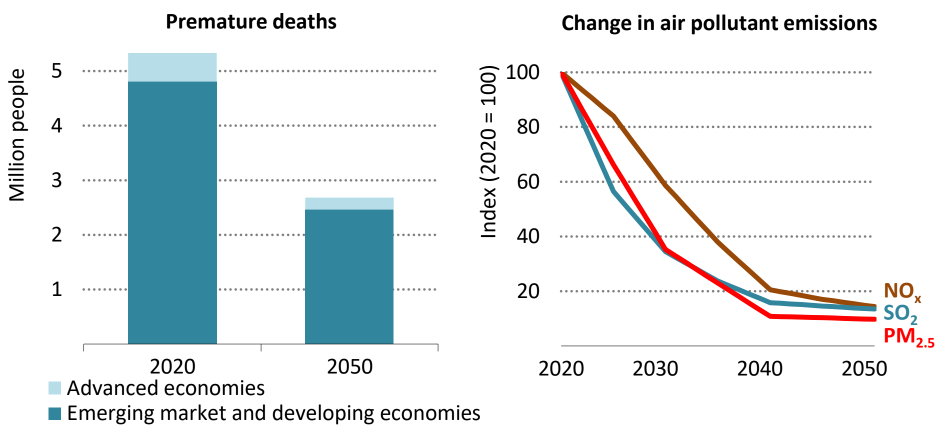
### *Air pollution and health*

More than 90% of people around the world are exposed to polluted air today. Such pollution led to around 5.4 million premature deaths in 2020, undermining economic productivity and placing extra stress on healthcare systems. Most of these deaths were in emerging market and developing economies. Just over half were caused by exposure to outdoor air pollution; the remainder resulted from breathing polluted air indoors, caused mainly by the traditional use of biomass for cooking and heating.



Energy-related emissions of the three major air pollutants – sulphur dioxide ($SO_2$), nitrogen oxides ($NO_X$) and fine particulate matter ($PM_{2.5}$) – fall rapidly in the NZE. $SO_2$ emissions fall by 85% between 2020 and 2050, mainly as a result of the large-scale phase-out of coal-fired power plants and industrial facilities. $NO_X$ emissions also drop by around 85% as a result of the increased use of electricity, hydrogen and ammonia in the transport sector. The increased uptake of clean cooking fuels in developing countries, together with air pollution control measures in industry and transport, results in a 90% drop in $PM_{2.5}$ emissions (Figure 4.12). The reduction in air pollution in the NZE leads to roughly a halving in premature deaths in 2050 compared with 2020, saving the lives of about 2 million people per year, around 85% of them in emerging market and developing economies.

**Figure 4.12 ▷ Global premature deaths and air pollutant emissions in the NZE**






*Reductions in major air pollutants mean 2 million fewer premature deaths per year*

Sources: IEA analysis based on IIASA.

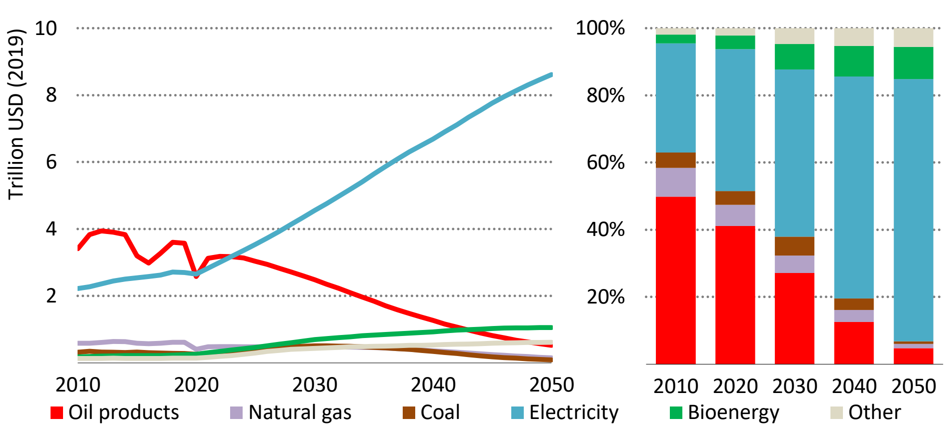
### 4.4.2 Affordability

*Total spending on energy*

Energy affordability is a key concern for governments, businesses and households. Global direct spending on energy, i.e. the total fuel bills paid by all end users, which totalled USD 6.3 trillion in 2020, increases by 45% to 2030 and 75% to 2050, in large part reflecting population and GDP growth over this period. As a share of global GDP, the figures look rather different: total direct spending on energy holds steady at around 8% out to 2030 (similar to the average over the last five years), but then declines to 6% in 2050. This decline offsets a significant share of the higher cost of buying new, more efficient energy-consuming equipment.

A portion of the increase in energy spending in the NZE is related to rising $CO_2$ prices and the removal of consumption subsidies for fossil fuels and electricity. $CO_2$ pricing (taxes and trading schemes) paid by end users at its peak generates global revenues in the NZE of close to USD 700 billion each year between 2030 and 2035, before declining steadily due to declining overall emissions: these revenues could be recycled into economies or otherwise used to improve consumer welfare, particularly for low-income households. The NZE also sees the progressive removal of consumption subsidies for fossil fuels, many of which disproportionally benefit wealthier segments of the population that use more of the subsidised fuel. Phasing out the subsidies would provide more efficient price signals for consumers, and spur more energy conservation and measures to improve energy efficiency. The impact of phasing out subsidies on lower income households could be offset through direct payment schemes or other means at lower overall costs to the economy.

**Figure 4.13 ▷ Global energy spending by fuel in the NZE**






*Total energy spending increases by 75% to 2050, mainly on electricity*

Note: Other = hydrogen-based and synthetic fuels, and district heating.

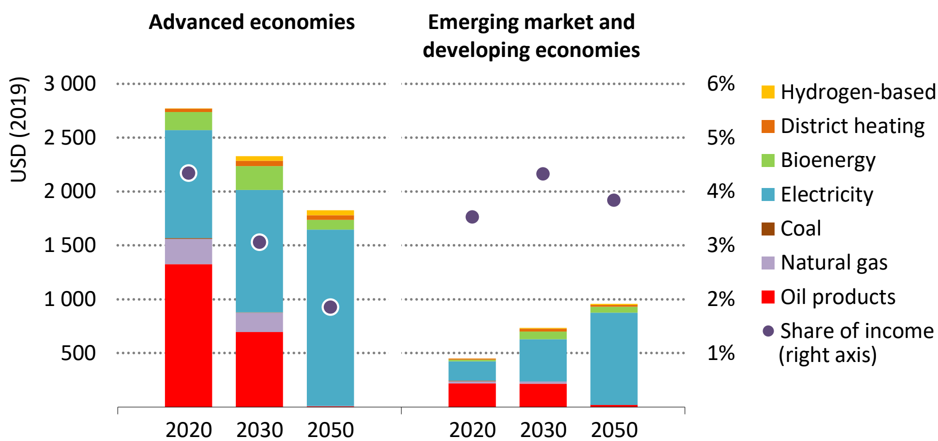
The transformation of the global energy system in the NZE drives a major shift in the composition of energy spending. Spending on electricity at USD 2.7 trillion in 2020 (45% of total energy spending) exceeded spending on oil products for the first time and it rises to over USD 8.5 trillion in 2050 (80% of total energy spending) (Figure 4.13). Retail electricity prices increase by 50% on average, contributing to the total increase. Spending on oil, which has dominated overall energy spending for decades, goes into long-term decline in the 2020s, its share of spending falling from 40% in 2020 to just 5% in 2050. Spending on natural gas and coal also declines in the long term, offset by higher spending on low-emissions fuels. Spending on bioenergy reaches about USD 900 billion per year by 2040, while other low-emissions fuels, including hydrogen-based products, gain a foothold and establish a market worth of around USD 600 billion per year by 2050.



### *Household spending on energy*

Direct spending by households on energy, including for heating, cooling, electricity and fuel for passenger cars, falls as a share of disposable income in the NZE, though there are large differences between countries (Figure 4.14).

**Figure 4.14 ▷ Average annual household energy bill in the NZE**





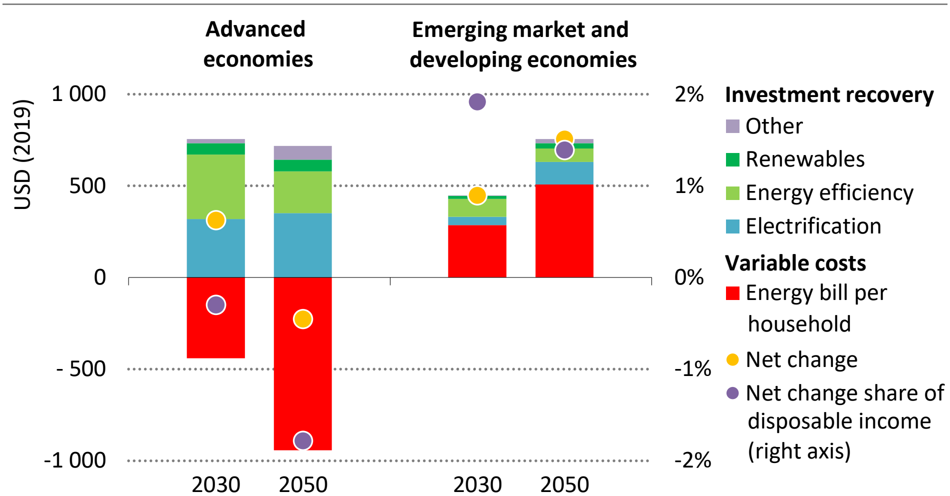

***The proportion of disposable household income spent on energy is stable in emerging market and developing economies, and drops substantially in advanced economies***

Note: Hydrogen-based includes hydrogen, ammonia and synthetic fuels.

In advanced economies, the average annual bill declines from about USD 2 800 in 2020 to USD 2 300 in 2030, thanks to a strong push on energy efficiency and cost-effective electrification. Oil products make up close to half of household energy bills in 2020, but this falls to 30% in 2030 and almost zero in 2050, due to a rapid shift to EVs and to downward pressure on oil prices. Natural gas bills, which make up almost 10% of the total today, also fall to almost zero in 2050 with the electrification of heating and cooking. Electricity rises from about 35% of household fuel bills in 2020 to 90% in 2050, increasing the sensitivity of households to electricity prices and consumption. Increasing incomes mean that household spending on energy as a share of disposable income drops from 4% in 2020 to 2% in 2050.

In emerging market and developing economies, there is a huge increase in demand for modern energy services linked to expanding populations, economic growth, rising incomes and universal access to electricity and clean cooking options. As in advanced economies, electricity accounts for the vast majority of energy bills in 2050. The use of more efficient appliances and equipment curbs some of the increase in demand, but household bills still increase in the NZE by over 60% to 2030 and more than double by 2050. As a percentage of disposable income, however, bills in emerging market and developing economies remain around 4%, and there are large social and economic benefits from increased energy use.

**Figure 4.15 ⊳ Change in household spending on energy plus energy-related investment in the NZE relative to 2020**






*Total household spending on energy increases modestly in emerging market and developing economies, leaving over 90% of additional income available for other uses*

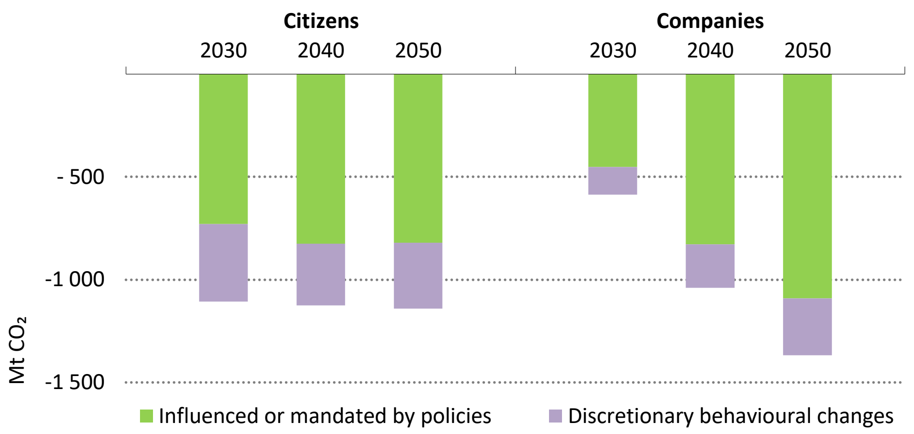
Taking into account additional investment in electricity-consuming equipment such as efficient appliances and electric vehicles, spending on energy plus related investment is USD 1.30 higher per day per household globally in 2050 than in 2020 in the NZE. This modest increase means that expenditure on energy makes up a smaller share of disposable income in 2050 than it does today, though the impacts vary by country. In advanced economies, additional investment in electrification, energy efficiency and renewable energy costs about USD 750 per household by 2030 and USD 720 in 2050, which is fully offset by reductions in the level of energy bills (Figure 4.15). In emerging market and developing economies, a growing basket of energy services means increased use of energy, and total energy-related household spending increases. Additional investment moderates the change in energy bills, with the result that total energy-related spending takes 2 percentage points more of household disposable income in 2030 and 1 percentage point more in 2050 than today.

### *4.4.3 Behavioural changes*

Behavioural changes play an important part in reducing energy demand and emissions in the NZE, especially in sectors where technical options for cutting emissions are limited in 2050. While it is citizens and companies that modify their behaviour, the changes are mostly enabled by the policies and investments made by governments, and in some instances, they are required by laws or regulations. The Covid-19 pandemic has increased general awareness of the potential effectiveness of behavioural changes, such as mask-wearing, and working and schooling at home. The crisis demonstrated that people can make behavioural changes at significant speed and scale if they understand the changes to be justified, and that it is necessary for governments to explain convincingly and to provide clear guidance about what changes are needed and why they are needed.

4

**Figure 4.16 ▷ Emissions reductions from policy-driven and discretionary behavioural changes by citizens and companies in the NZE**






***Three-quarters of the emissions saved by behavioural changes could be directly influenced or mandated by government policies***

Around three-quarters of the emissions saved by behavioural changes between 2020 and 2050 in the NZE could be directly influenced or mandated by government policy (Figure 4.16). They include mitigation measures such as phasing out polluting cars from large cities and reducing speed limits on motorways. The other one-quarter involves more discretionary behavioural changes, such as reducing wasteful energy use in homes and offices, though even these types of changes could be promoted through awareness campaigns and other means. Around 10% of emissions savings directly influenced or mandated by government policy would require new or redirected investment in infrastructure. For example, the shift in the NZE from regional flights to high-speed rail would necessitate building around 170 000 kilometres of new track globally by 2050 (a tripling of 2020 levels).

Behavioural changes made by citizens and companies play a roughly equal role in reducing emissions in the NZE. Most changes in road transport and energy-saving in homes would depend on individuals, whereas the private sector has the primary role in reducing energy demand in commercial buildings and pursuing materials efficiency in manufacturing. Companies can also influence behavioural changes indirectly, for example, by promoting the use of public transport by employees that commute or encouraging working from home. However, a simple distinction between the role for individuals and companies masks a complex underlying dynamic: it is ultimately citizens as consumers of energy-related goods and services who shape corporate strategies, but at the same time companies do much to influence and generate consumer demand through marketing and advertising. In the NZE, consumers and companies move together in adopting behavioural changes, with governments setting the direction of those changes and facilitating them via effective and sustained policy support.

The behavioural changes in the NZE happen to different extents in different regions, and reflect a range of geographical and infrastructure constraints, as well as existing behavioural norms and cultural preferences. In countries with low rates of car ownership or energy service demand in buildings, many of the behavioural changes in advanced economies in NZE would not be relevant or appropriate. As a result, around half of the emissions savings from behavioural changes are in emerging market and developing economies, despite around 95% of activity growth in buildings and road transport between 2020 and 2050 occurring there. Nevertheless, there are significant opportunities in emerging market and developing economies for materials efficiency and urban design to decouple growth in economic prosperity and energy services from increases in emissions. For example, around 85% of $CO_2$ emissions reductions from cement and steel making in 2050 are due to gains in materials efficiency in emerging market and developing economies.

Cities are important to the behavioural changes in the NZE. Urban design can reduce the average city dweller's carbon footprint by up to 60% by shaping lifestyle choices and influencing day-to-day behaviour. For example, compact cities with clustered amenities can shorten average trip lengths; digitalisation can help shared private mobility to become the de facto option to accommodate much of the growth in service demand; and urban green infrastructure can reduce cooling demand (Feyisa, Dons & Meilby, 2014).

## 4.5 Governments

### 4.5.1 Energy security

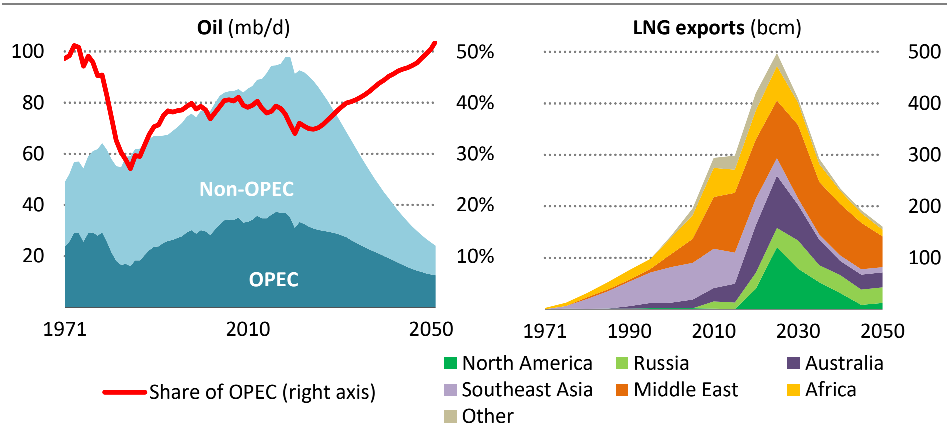
Energy security is an important consideration for governments and those they serve, and the pathway to net-zero emissions must take account of it. Concerns about energy security have traditionally been associated with oil and natural gas supplies. The drop in oil and gas demand and the increased diversity of the energy sources used in the NZE may reduce some risks, but they do not disappear. There are also new potential vulnerabilities associated with the need to maintain reliable, flexible and secure electricity systems, and with the increase in demand for raw minerals for clean energy technologies. Improving energy efficiency remains the central measure for increasing energy security – even with rapid growth in low-emissions electricity generation, the safest energy supplies are those that are not needed.



*Oil and gas security*

No new oil and natural gas fields are required in the NZE beyond those already approved for development, and supplies become increasingly concentrated in a small number of low-cost producers. For oil, OPEC's share of global oil supply grows from around 37% in recent years to 52% in 2050, a level higher than at any point in the history of oil markets (Figure 4.17). For natural gas, inter-regional liquefied natural gas (LNG) trade increases from 420 bcm in 2020 over the next five years but it then falls to around 160 bcm in 2050. Nearly all exports in 2050 come from the lowest cost and lowest emissions producers. This means that the importance of ensuring adequate supplies of oil and natural gas to the smooth functioning of the global energy system would be quantitatively lower in 2050 than today, but it does not suggest that the risk of a shortfall in supply or sudden price rise is necessarily going to diminish, and a shortfall or sudden price rise would still have large repercussions for a number of sectors.

**Figure 4.17 ▷ Global oil supply and LNG exports by region in the NZE**






*Increased reliance on OPEC and other producer economies suffering from falling oil and gas revenues could pose a risk to supply security in consuming countries*

Even if the timing and ambition of emission reduction policies are clear, the changes in the NZE clearly have implications for producers and consumers alike. Many producer economies would see oil and gas revenues drop to some of the lowest ever levels (see section 4.2.2). Even if these producers increase their market share, and diversify their economies and sources of tax revenue, they are likely to struggle to finance essential spending at current levels. This could have knock-on effects for social stability, and that in turn could potentially threaten the smooth delivery of oil and gas to consuming countries. Moves on the part of producer economies to gain market share or a failure to maintain upstream operations while managing the extreme strains that would be placed on their fiscal balances could lead to turbulent and volatile markets, greatly complicating the task facing policy makers.

### *Electricity security*

The rapid electrification of all sectors in the NZE, and the associated increase in electricity's share of total final consumption from 20% in 2020 to nearly 50% in 2050, puts electricity even more at the heart of energy security across the world than it already is (IEA, 2020h). Greater reliance on electricity has both positive and negative implications for overall energy security. One advantage for energy-importing countries is that they become more self-sufficient, since a much higher share of electricity supply is based on domestic sources in the NZE than is the case for other fuels. However the increased importance of electricity means that any electricity system disruption would have larger impacts. Electricity infrastructure is often more vulnerable to physical shocks such as extreme weather events than pipelines and underground storage facilities, and climate change is likely to put increasing pressure on electricity systems, for example through more frequent droughts that might decrease the availability of water for hydropower and for cooling at thermal power plants. The resilience of electricity systems needs to be enhanced to mitigate these risks and maintain electricity security, including through more robust contingency planning, with solutions based on digital technologies and physical system hardening (IEA, 2021b).

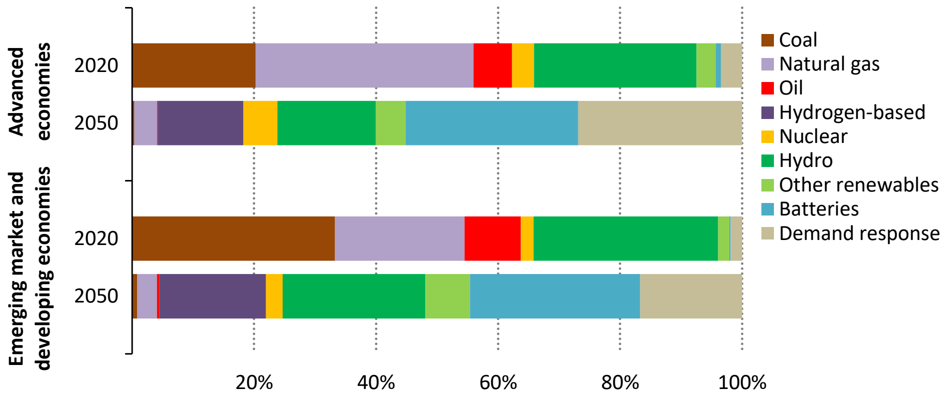
Cybersecurity could pose an even greater risk to electricity security as systems incorporate more digitalised monitoring and controls in a growing number of power plants, electricity network assets and storage facilities. Policy makers have a central part to play in ensuring that the cyber resilience of electricity is enhanced, and there are a number of ways in which they can pursue this (IEA, 2021c).

Maintaining electricity security also requires a range of measures to ensure flexibility, adequacy and reliability at all times. Enhanced electricity system flexibility is of particular importance as the share of variable renewables in the generation mix rises. As a consequence, electricity system flexibility quadruples globally in the NZE in parallel with a more than two-and-a half-fold increase in electricity supply.[9] A portfolio of flexibility sources – including power plants, energy storage and demand response supported by electricity

[9] Electricity system flexibility is quantified here based on hour-to-hour ramping needs, which is only one aspect of flexibility that also includes actions on much shorter time scales to maintain frequency and other ancillary services.

networks – is used to match supply and demand at all times of the year, under varying weather conditions and levels of demand. There is a significant shift in the NZE from using coal- and gas-fired power plants for the provision of flexibility to the use of renewables, hydrogen, battery storage, and demand-side response (Figure 4.18).

**Figure 4.18 ▹ Electricity system flexibility by source in the NZE**






*To meet four-times the amount of hour-to-hour flexibility needs, batteries and demand response step up to become the primary sources of flexibility*

Electricity demand also becomes much more flexible as a result of the use of demand response measures, e.g. to shift consumption to times when renewable energy is plentiful. Conventional sources of demand response such as moderating industry activities remain important, but new areas of demand response such as smart charging of EVs unlock valuable new ways of supplementing them.[10] As the EV fleet expands in the NZE, EVs provide a significant portion of total electricity system flexibility. Although the technology already exists, the roll-out of smart charging has been slow to date due to institutional and regulatory barriers; these hurdles are overcome in the NZE. Measures are also implemented to ensure that the digitalisation of charging and other sources of flexibility does not compromise cybersecurity, and that potential social acceptance issues are addressed.

Energy storage also plays an important role in the provision of flexibility in the NZE. The deployment of battery storage systems is already starting to accelerate and to contribute to the management of short-duration flexibility needs, but the massive scale up to 3 100 GW of storage in 2050 (with four hour duration on average) envisaged in the NZE hinges on overcoming current regulatory and market design barriers. Pumped hydropower offers an attractive means of providing flexibility over a matter of hours and days, while hydrogen has

[10] Smart chargers share real-time data with a centralised platform to allow system operators to optimise charging profiles based on how much energy the vehicle needs over a specified span of time, how much is available, the price of wholesale electricity, grid congestion and other parameters.

the potential to play an important part in longer term seasonal storage since it can be stored in converted gas storage facilities that have several orders of magnitude more capacity than battery storage projects.

Dispatchable power is essential to the secure transition of electricity systems, and in the NZE this comes increasingly from low-emissions sources. Hydropower provides a significant part of flexibility in many electricity systems today, and this continues in the future, with particular emphasis on expanding pumped hydro facilities. Nuclear power and geothermal plants, though designed for baseload generation, also provide a degree of flexibility in the NZE, but there are constraints on how much these sources can be expanded. This leaves an important role for thermal power plants that are equipped with carbon capture or use low-emissions fuels. For example, the use of sustainable biomass or low-emissions ammonia in existing coal plants offers a way of allowing these facilities to continue to contribute to flexibility and capacity adequacy, while at the same time reducing $CO_2$ emissions. Additional measures will also be necessary to maintain power system stability (Box 4.1).

### Box 4.1 ▹ Power system stability with high shares of variable renewables

Stability is a key feature of electricity security, allowing systems to remain in balance and withstand disturbances such as sudden generator or grid outages. Historically, conventional generators such as nuclear, hydro and fossil fuels have been central to electricity system stability, providing inertia with rotating machines that allow stored kinetic energy to be instantly converted into power in case of a system disturbance, and generating a voltage signal that helps all generators remain synchronous.

In contrast, newer technologies such as solar PV, wind and batteries are connected to the system through converters. They generally do not contribute to system inertia and are configured as "grid-following" units, synchronising to conventional generators. Maintaining system stability will call for new approaches as the share of converter based resources, and in particular variable renewables, rises much higher in electricity systems.

There is a growing body of knowledge and studies on stability in systems with high shares of variable renewables. For example, a recent joint study by the IEA and RTE, the transmission system operator in France, analyses the conditions under which it would be technically feasible to integrate high shares of variable renewables in France (IEA, 2021d). Based on the findings of this study:

- One option to ensure stability for a net zero power system is to maintain a minimum amount of conventional generation from low-carbon technologies during hours of high shares VRE output. This approach to maintain stability comes at the cost of solar and wind curtailment at high shares.
- Updated grid codes can be used to call for variable renewables and batteries to provide fast frequency response services, which can help reduce the amount of conventional generation needed for stability.

- Synchronous condensers are able to provide inertia without generating electricity. The technology is already proven at GW-scale in Denmark and also in South Australia, but experience needs to be expanded at larger scale.
- Grid-forming converters can allow variable renewables and batteries to generate a voltage signal, though experience with this approach needs to move beyond micro-grids and small islands to large interconnected systems.

Demonstration projects, stakeholder consultations and international collaboration will be critical to fully understand the merits of each of these four approaches and the scope for a portfolio of options that would most cost-effectively achieve net zero emissions while maintaining electricity security.



Electricity networks support and enable the use of all sources of flexibility, balancing demand and supply over large areas. Timely investment in grids to minimise congestion and expand the size of the areas where supply and demand are balanced will be critical to making the best use of solar PV and wind projects, and ensuring affordable and reliable supplies of electricity. Expanding long-distance transmission also makes a key contribution in the NZE, since a lack of available land near demand centres and other factors mean new sources of generation are often located in remote areas. It is important that new transmission systems are built with variable, bidirectional operation in mind in order to maximise the use of available flexibility sources, and that regulatory and market arrangements support flexible connections between systems. The key value of interconnections comes from complementary electricity demand and wind patterns: solar PV output is more highly correlated than wind over large areas.

The NZE sees a major increase in demand for critical minerals such as copper, lithium, nickel, cobalt and rare earth elements that are essential for many clean energy technologies. There are several potential vulnerabilities that could hinder the adequate supply of these minerals and lead to price volatility (IEA, 2021a). Today's production and processing operations for many minerals are highly concentrated in a small number of countries, making supplies vulnerable to political instability, geopolitical risks and possible export restrictions. In many cases, there are also concerns about land-use changes, competition for scarce water resources, corruption and misuse of government resources, fatalities and injuries to workers, and human rights abuses, including the use of child labour. New critical mineral projects can have long lead times, so the rapid increase in demand in the NZE could lead to a mismatch in timing between supply and demand. The international trade and investment regime is key to maintaining reliable mineral supplies, but policy support and international co-ordination will be needed to ensure the application of rigorous environmental and social regulations.

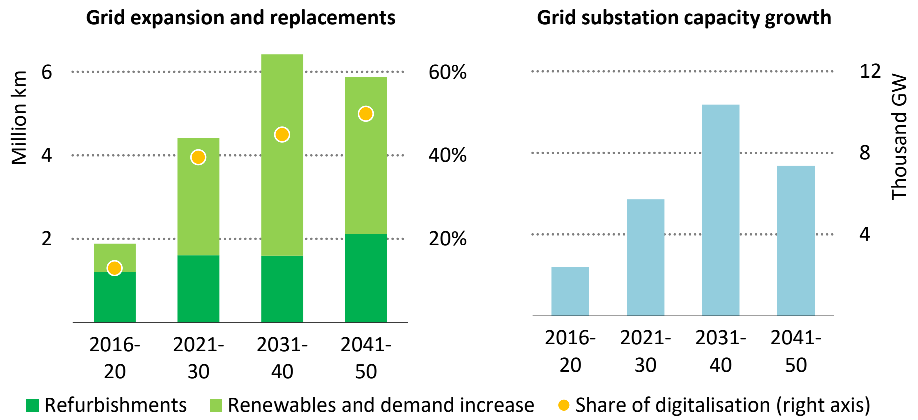
### 4.5.2 Infrastructure

Getting to net-zero emissions will require huge amounts of new infrastructure and lots of modifications to existing assets. Energy infrastructure is transformed in the NZE as all countries and regions move from systems supporting the use of fossil fuels and the distribution of conventionally generated electricity to systems based largely on renewable electricity and low-emissions fuels. In many emerging market and developing economies, the provision of large amounts of infrastructure would be necessary in the coming decades in any case, creating a window of opportunity to support the transition to a net-zero emissions economy. In all countries, governments will play a central role in planning, financing and regulating the development of infrastructure. Some of the main infrastructure components – electricity networks and EV charging, pipelines systems for low-emissions fuels and $CO_2$, and transport infrastructure – are discussed below.

The rapid increase in electricity demand in the NZE and the transition to renewable energy call for an expansion and modernisation of electricity networks (Figure 4.19). This would require a sharp reversal in the recent trend of declining investment: failure to achieve this would almost certainly make the energy transition for net-zero emissions impossible. Tariff design and permitting procedures also need to be revised to reflect fundamental changes in the provision and uses of electricity. Some of the main considerations include:

- **Long-distance transmission**. Most of the growth in renewables in the NZE comes from centralised sources. Yet the best solar and wind resources are often in remote regions, requiring new transmission connections. Ultra high-voltage direct current systems are likely to play an important role in supporting transmission over long distances.
- **Local distribution**. Energy efficiency gains in households and wider use of rooftop solar PV mean surplus electricity will be available more often, while electric heat pumps and residential EV charging points will require electricity to be more widely available. Together these developments point to the need for substantial increases in distribution network capacity.
- **Grid substations**. The massive expansion of solar PV and wind requires new grid substations: their capacity expands by more than 57 000 GW in the NZE by 2030, doubling current capacity globally.
- **EV charging**. Major new public charging networks are built in the NZE, including in work places, highway service stations and residential complexes, to support EV expansion and long-distance driving on highways.
- **Digitalisation of networks**. With a large increase in the use of connected devices, the digitalisation of grid assets supports more flexible grid operations, better management of variable renewables and more efficient demand response.

**Figure 4.19 ▷ Annual average electricity grid expansion, replacement and substation capacity growth in the NZE**





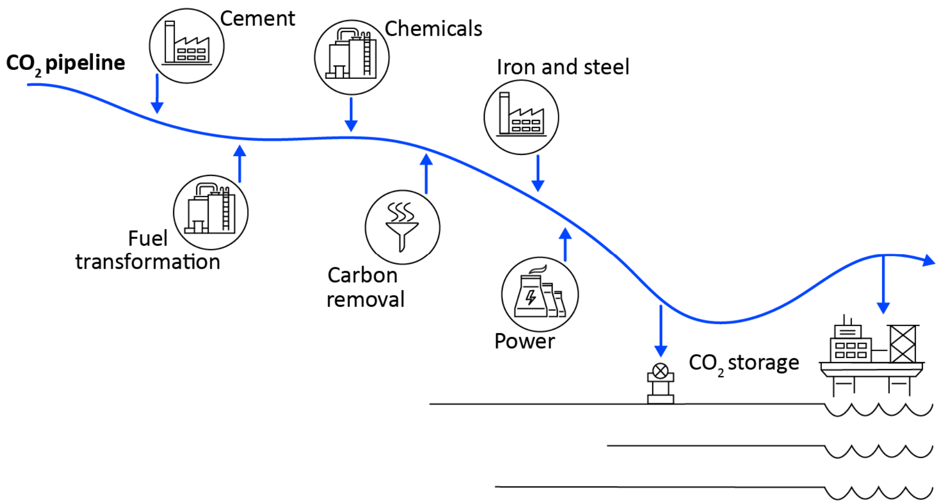

***Grid and substation expansion is driven largely by the massive deployment of renewables and electrification of end-uses, with a rising digital share of infrastructure***

Note: Substation capacity here assumes active electricity is equal to apparent electricity.

Pipelines continue to play a key role in the transmission and distribution of energy in the NZE:

- Given the rapid decline of fossil fuels, significant investment in new oil and gas pipelines are not needed in the NZE. However investment is needed to link the production of low-emissions liquids and gases with consumption centres, and to convert existing pipelines and associated distribution infrastructure for the use of these low-emissions fuels. Some low-emissions fuels, such as biomethane and synthetic hydrogen-based fuels, can make use of existing infrastructure without any modifications, but pure hydrogen requires a retrofit of existing pipelines. New dedicated hydrogen infrastructure is also needed in the NZE, for example to move hydrogen produced in remote areas with excellent renewable resources to demand centres.
- The expansion of CCUS in the NZE requires investment in $CO_2$ transport and storage capacity. By 2050, 7.6 Gt of $CO_2$ is captured worldwide, requiring a large amount of pipeline and shipping infrastructure linking the facilities where $CO_2$ is captured with storage sites. Industrial clusters, including ports, may offer the best near-term opportunities to build $CO_2$ pipeline and hydrogen infrastructure, as the various industries in those clusters using the new infrastructure would be able to share the upfront investment needs (Figure 4.20).

**Figure 4.20** ▷ **Illustrative example of a shared $CO_2$ pipeline in an industrial cluster**






***Deployment of technologies like CCUS and hydrogen and their enabling infrastructure would benefit strongly from a cross-sectoral approach in industrial clusters***

Transforming transport infrastructure represents both a challenge and an opportunity. The challenge arises from the potential increase in the energy and carbon intensity of economic growth during the infrastructure development phase.[11] Steel and cement are the two main components of virtually all infrastructure projects, but they are also among the most challenging sectors to decarbonise. The opportunity comes from the scope that exists in some countries to develop infrastructure from scratch in a way that is compatible with the net zero goal. Countries undergoing rapid urbanisation today can design and steer new infrastructure development towards higher urban density and high-capacity mass transit in tandem with EV charging and low-emissions fuelling systems.

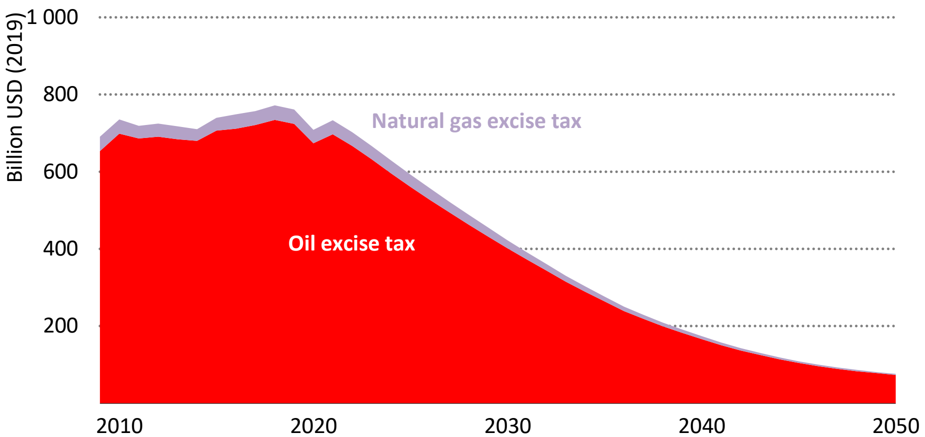
Rail has an important part to play as transport infrastructure is developed. The NZE sees large-scale investment in all regions in high-speed trains to replace both long-distance car driving and short-haul aviation. It also sees large-scale investment in all regions in track, control systems, rolling stock modernisation and combined freight facilities to improve speed and flexibility for just-in-time logistical operations and thus support a shift of freight from road to rail, especially for container traffic.

[11] The modelling for the NZE incorporates the increase in steel and cement that is required to build additional transport infrastructure (roads, cars and trucks) and energy infrastructure, e.g. power plants and wind turbines.

### 4.5.3 Tax revenues from retail energy sales

The slump in the consumption of fossil fuels required to get to net-zero emissions would result in the loss of a large amount of tax revenue in many countries, given that fuels such as oil-based transport fuels and natural gas are often subject to high excise or other special taxes. In recent years, energy-related taxes accounted for around 4% of total government tax revenues in advanced economies on average and 3.5% in emerging market and developing economies, but they provided as much as 10% in some countries (OECD, 2020).

**Figure 4.21 ▷ Global revenues from taxes on retail sales of oil and gas in the NZE**






*Tax revenues slump from retail sales of oil and gas*

Tax revenue from oil and natural gas retail sales falls by close to 90% between 2020 and 2050 in the NZE (Figure 4.21). Governments are likely to need to rely on some combination of other tax revenues and public spending reforms to compensate. Some taxation measures focused on the energy sector could be useful. However, any such taxes would need to be carefully designed to minimise their impact on low-income households, as poorer households spend a higher percentage of their disposable income on electricity and heating. Options for energy-related taxes include:

- **$CO_2$ prices**. These are introduced in all regions in the NZE, albeit at different levels for countries and sectors, which provide additional revenue streams. The reduction in oil and natural gas excise taxes is more than compensated over the next 15 years by higher revenues from $CO_2$ prices related to these fuels paid by end users and other sectors, but these too fall as the global energy system moves towards net-zero emissions.
- **Road fees and congestion charges**. These would have the added benefit of discouraging driving and encouraging switching to other less carbon-intensive modes of transport.

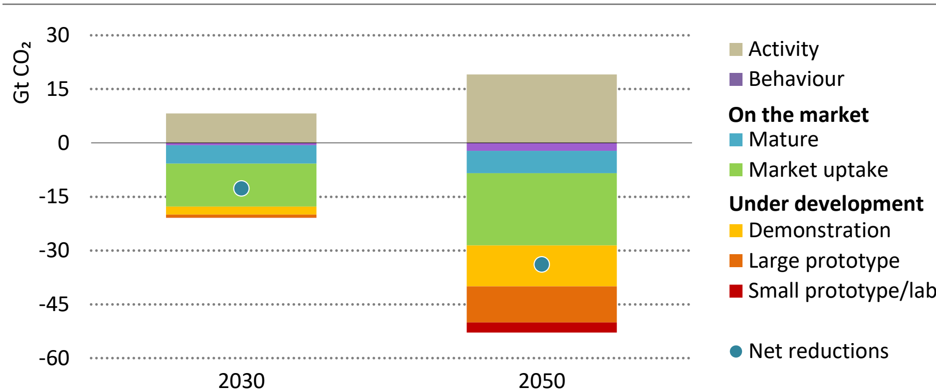
- **Increasing taxation on electricity**. Higher taxes on all electricity sales could generate substantial revenues, especially since large increases in price often have little effect on consumption. This might be counterproductive, however, as it would reduce the cost-effectiveness of both EVs and heat pumps, which could slow their adoption, although this risk could be mitigated by the introduction of $CO_2$ prices.

Natural gas is currently less taxed than transport fuels in most countries. Introducing and raising $CO_2$ prices for natural gas used in buildings, mostly for heating, would accelerate energy efficiency improvements and boost government revenues, although care would be needed to avoid disproportionately impacting low-income households. Taxing natural gas used in industry would improve the competitiveness of less carbon-intensive fuels and technologies such as hydrogen, but would run the risk of undermining the international competitiveness of energy-intensive sectors and carbon leakage in the absence of co-ordinated global action or border carbon-tax adjustments.

### *4.5.4 Innovation*

Without a major acceleration in clean energy innovation, reaching net-zero emissions by 2050 will not be achievable. Technologies that are available on the market today provide nearly all of the emissions reductions required to 2030 in the NZE to put the world on track for net-zero emissions by 2050. However, reaching net-zero emissions will require the widespread use after 2030 of technologies that are still under development today. In 2050, almost 50% of $CO_2$ emissions reductions in the NZE come from technologies currently at demonstration or prototype stage (Figure 4.22). This share is even higher in sectors such as heavy industry and long-distance transport. Major innovation efforts are vital in this decade so that the technologies necessary for net-zero emissions reach markets as soon as possible.

**Figure 4.22 ▷ Global $CO_2$ emissions changes by technology maturity category in the NZE**



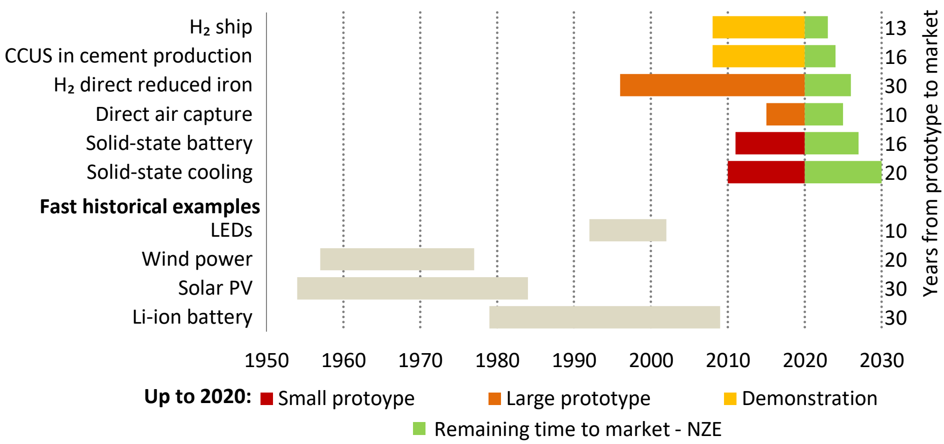



***While the emissions reductions in 2030 mostly rely on technologies on the market, those under development today account for almost half of the emissions reductions in 2050***

Innovation cycles for early stage clean energy technologies are much more rapid in the NZE than what has typically been achieved historically, and most clean energy technologies that have not been demonstrated at scale today reach markets by 2030 at the latest. This means the time from first prototype to market introduction is on average 20% faster than the fastest energy technology developments in the past, and around 40% faster than was the case for solar PV (Figure 4.23). Technologies at the demonstration stage, such as CCUS in cement production or low-emissions ammonia-fuelled ships, are brought into the market in the next three to four years. Hydrogen-based steel production, direct air capture (DAC) and other technologies at the large prototype stage reach the market in about six years, while most technologies at small prototype stage – such as solid state refrigerant-free cooling or solid state batteries – do so within the coming nine years.



**Figure 4.23 ▷ Time from first prototype to market introduction for selected technologies in the NZE and historical examples**






*Technology development cycles are cut by around 20% from the fastest developments seen in the past*

Note: $H_2$ = hydrogen; CCUS = carbon capture, utilisation and storage; LED = light-emitting diode; Li-ion = lithium-ion.

Sources: IEA analysis based on Carbon Engineering, 2021; Greco, 2019; Tenova, 2018; Gross, 2018; European Cement Research Academy, 2012; Kamaya, 2011; Zemships, 2008.

An acceleration of this magnitude is clearly ambitious. It requires technologies that are not yet available on the market to be demonstrated very quickly at scale in multiple configurations and in various regional contexts. In most cases, these demonstrations are run in parallel in the NZE. This is in stark contrast with typical practice in technology development: learning is usually transferred across consecutive demonstration projects in different contexts to build confidence before widespread deployment commences.

The acceleration that is needed also requires a large increase in investment in demonstration projects. In the NZE, USD 90 billion is mobilised as soon as possible to complete a portfolio of demonstration projects before 2030: this is much more than the roughly USD 25 billion budgeted by governments to 2030. Most of these projects are concerned with the electrification of end-uses, CCUS, hydrogen and sustainable bioenergy, mainly for long-distance transport and heavy industrial applications.

Increased public funding helps to manage the risks of such first-of-a-kind projects and to leverage private investment in research and development (R&D) in the NZE. This represents a reversal of recent trends: government spending on energy R&D worldwide, including demonstration projects, has fallen as a share of GDP from a peak of almost 0.1% in 1980 to just 0.03% in 2019. Public funding also becomes better aligned with the innovations needed to reach net-zero emissions. In the NZE, electrification, CCUS, hydrogen and sustainable bioenergy account for nearly half of the cumulative emissions reductions to 2050. Just three technologies are critical in enabling around 15% of the cumulative emissions reductions in the NZE between 2030 and 2050: advanced high-energy density batteries, hydrogen electrolysers and DAC.

### *Governments drive innovation in the NZE*

Bringing new energy technologies to market can often take several decades, but the imperative of reaching net-zero emissions globally by 2050 means that progress has to be much faster. Experience has shown that the role of government is crucial in shortening the time needed to bring new technology to market and to diffuse it widely (IEA, 2020i). The government role includes educating people, funding R&D, providing networks for knowledge exchange, protecting intellectual property, using public procurement to boost deployment, helping companies innovate, investing in enabling infrastructure and setting regulatory frameworks for markets and finance.

Knowledge transfer from first-mover countries can also help in the acceleration needed, and is particularly important in the early phases of adoption when new technologies are typically not competitive with incumbent technologies. For example, in the case of solar PV, national laboratories played a key role in the early development phase in the United States, projects supported directly by government in Japan created market niches for initial deployment and government procurement and incentive policies in Germany, Italy, Spain, United States, China, Australia and India fostered a global market. Lithium-ion (Li-ion) batteries were initially developed through public and private research that took place mostly in Japan, their first energy-related commercial operation was made possible in the United States, and mass manufacturing today is primarily in China.

Many of the biggest clean energy technology challenges could benefit from a more targeted approach to speed up progress (Diaz Anadon, 2012; Mazzucato, 2018). In the NZE, concerted government action leverages private sector investment and leads to advances in clean energy technologies that are currently at different stages of development.

- To 2030, the focus of government action is on bringing new zero- or low-emissions technologies to market. For example, in the NZE, steel starts to be produced using low-emissions hydrogen at the scale of a conventional steel plant, large ships start to be fuelled by low-emissions ammonia and electric trucks begin operating on solid state batteries. In parallel, there is rapid acceleration in the deployment of low-emissions technologies that are already available on the market but that have not yet reached mass market scale, bringing down the costs of manufacturing, construction and operating such technologies due to learning-by-doing and economies of scale.

- From 2030 to 2040, technology advances are consolidated to scale up nascent low-emissions technologies and expand clean energy infrastructure. Clean energy technologies that are in the laboratory or at small prototype stage today become commercial. For example, fuels are replaced by electricity in cement kilns and steam crackers for high value chemicals production.
- From 2040 to 2050, technologies at a very early stage of development today are adopted in promising niche markets. By 2050, clean energy technologies that are at demonstration or large prototype stage today become mainstream for purchases and new installations, and they compete with present conventional technologies in all regions. For example, ultra high-energy density batteries are used in aircraft for short flights.



### *4.5.5 International co-operation*

The pathway to net-zero emissions by 2050 will require an unprecedented level of international co-operation between governments. This is not only a matter of all countries participating in efforts to meet the net zero goal, but also of all countries working together in an effective and mutually beneficial manner. Achieving net-zero emissions will be extremely challenging for all countries, but the challenges are toughest and the solutions least easy to deliver in lower income countries, and technical and financial support will be essential to ensure the early stage deployment of key mitigation technologies and infrastructure in many of these countries. Without international co-operation, emissions will not fall to net zero by 2050.

There are four aspects of international co-operation that are particularly important (Victor, Geels and Sharpe, 2019).

- **International demand signals and economies of scale**. International co-operation has been critical to the cost reductions seen in the past for many key energy technologies. It can accelerate knowledge transfer and promote economies of scale. It can also help align the creation of new demand for clean energy technologies and fuels in one region with the development of supply in other regions. These benefits need to be weighed against the importance of creating domestic jobs and industrial capacities, and of ensuring supply chain resilience.
- **Managing trade and competitiveness**. Industries that operate in a number of countries need standardisation to ensure inter-operability. Progress on innovation and clean energy technology deployment in sectors such as heavy industry has been inhibited in the past by uncoordinated national policies and a lack of internationally agreed

standards. The development of such standards could accelerate energy technology development and deployment.

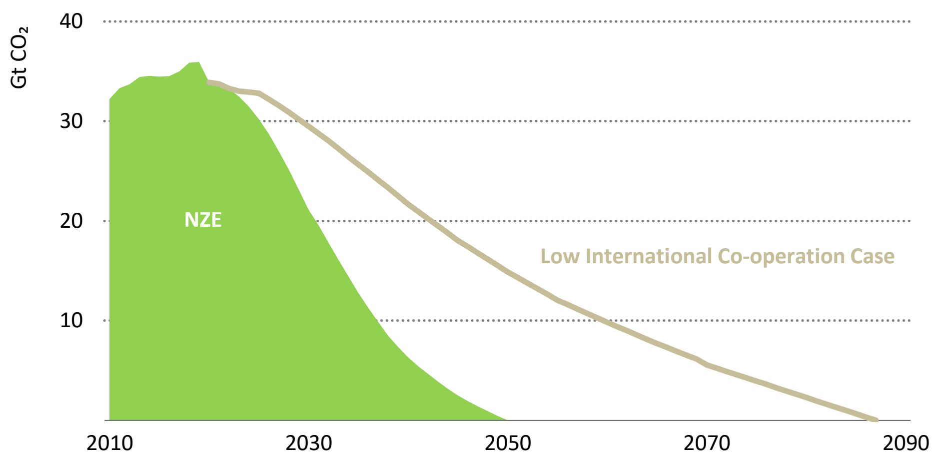
- **Innovation, demonstration and diffusion**. Clean energy R&D and patenting is currently concentrated in a handful of places: United States, Europe, Japan, Korea and China accounted for more than 90% of clean energy patents in 2014-18. Progress towards net-zero emissions would be increased by moving swiftly to extend experience and knowledge of clean energy technologies in countries that are not involved in their initial development, and by funding first-of-a-kind demonstration projects in emerging market and developing economies. International programmes to fund demonstration projects, especially in sectors where technologies are large and complex, would accelerate the innovation process (IEA, 2020i).
- **Carbon dioxide removal (CDR) programmes**. CDR technologies such as bioenergy and DAC equipped with CCUS are essential to provide emissions reductions at a global level. International co-operation is needed to fund and certify these programmes, so as to make the most of suitable land, renewable energy potential and storage resources, wherever they may be. International emissions trading mechanisms could play a role in offsetting emissions in some sectors or areas with negative emissions, though any such mechanisms would require a high degree of co-ordination to ensure market functioning and integrity.

The NZE assumes that international co-operation policies, measures and efforts are introduced to overcome these hurdles. To explore the potential implications of a failure to do so, we have devised a *Low International Co-operation Case* (Box 4.2). This examines what would happen if national efforts to mitigate climate change ramp up in line with the level of effort in the NZE but co-operation frameworks are not developed at the same speed. It shows that the lack of international co-operation has a major impact on innovation, technology demonstration, market co-ordination and ultimately on the emissions pathway.

### Box 4.2 ▻ Framing the Low International Co-operation Case

To develop the *Low International Co-operation Case*, technologies and mitigation options were assessed and grouped based on their current degree of maturity and the importance of international co-operation to their deployment. Mature technologies in markets that are firmly established and that have a low exposure to international co-operation are assumed to have the same deployment pathways as in the NZE. Technologies and mitigation options where co-operation is needed to achieve scale and avoid duplication, that have a large exposure to international trade and competitiveness, that depend on large and very capital-intensive demonstration programmes, or that require support to create market pull and standardisation to ensure inter-operability, are assumed to be deployed more slowly (Malhotra and Schmidt, 2020). Compared with the NZE, these technologies are delayed by 5-10 years in their initial deployment in advanced economies and by 10-15 years in emerging market and developing economies.

**Figure 4.24 ▷ $CO_2$ emissions in the Low International Co-operation Case and the NZE**



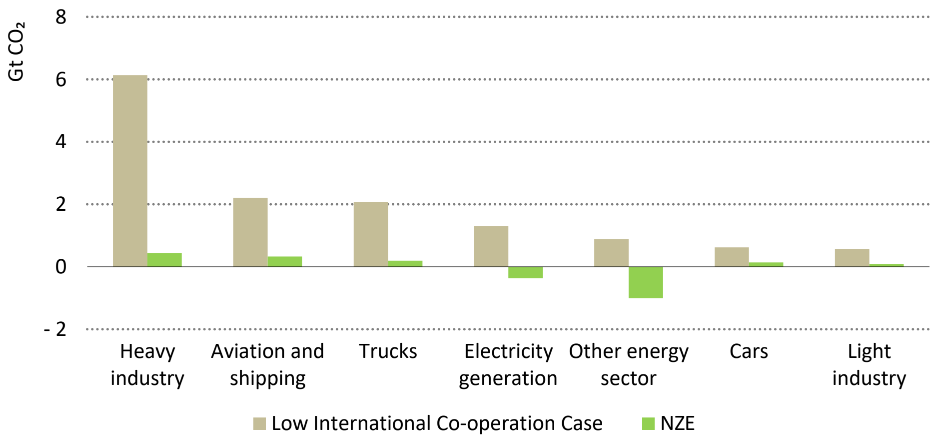



***Without international co-operation, the transition to net zero would be delayed by decades***

Weak international co-operation slows the deployment of mitigation options that are currently in the demonstration phase (Figure 4.24). This includes emissions reductions in heavy industry, trucks, aviation, shipping and CDR. The energy transition proceeds unevenly as a result. Over the next 20 years in the Low International Co-operation Case, emissions decline at a rapid but still slower pace than in the NZE in electricity generation, cars, light industry and buildings. However, emissions reductions are much slower in other areas. After the mid-2030s, the pace of emissions reductions worldwide slows markedly relative to the NZE, and the transition to net zero is delayed by decades. Just over 40% of the 15 Gt $CO_2$ of emissions remaining in 2050 are in heavy industry, where the slower pace of demonstration and diffusion of mitigation technologies is particularly significant (Figure 4.25). A further one-third of the residual emissions in 2050 are from aviation, shipping and trucks. Here the slower scale up and diffusion of advanced biofuels, hydrogen-based fuels and high-energy density batteries hinders progress. The absence of co-operation to support the deployment of new projects in emerging market and developing economies means that emissions reductions there are much slower than in the NZE.

These results highlight the importance for governments of strengthening international co-operation. A strong push is needed to accelerate innovation and the demonstration of key technologies, especially for complex technologies in emerging market and developing economies where costs for first-of-a-kind projects are generally higher, and to address concerns about international trade and competitiveness so as to ensure a just transition for all.

**Figure 4.25** ▷ **$CO_2$ emissions in the Low International Co-operation Case and the NZE in selected sectors in 2050**






***$CO_2$ emissions in 2050 in the Low International Co-operation Case are concentrated in the industry and transport sectors***

Note: Other energy sector = fuel production and direct air capture.

# ANNEXES

# Tables for scenario projections

## *General note to the tables*

This annex includes global historical and projected data for the Net-Zero Emissions by 2050 scenario for the following data sets: energy supply, energy demand, gross electricity generation and electrical capacity, carbon dioxide ($CO_2$) emissions from fossil fuel combustion and industrial processes, and selected economic and activity indicators.

The definitions for fuels and sectors are in Annex C. Common abbreviations used in the tables include: EJ = exajoules; CAAGR = compound average annual growth rate; CCUS = carbon capture, utilisation and storage. Consumption of fossil fuels in facilities without CCUS are classified as "unabated".

Both in the text of this report and in the tables, rounding may lead to minor differences between totals and the sum of their individual components. Growth rates are calculated on a compound average annual basis and are marked "n.a." when the base year is zero or the value exceeds 200%. Nil values are marked "-".

To download the tables in Excel format go to: **iea.li/nzedata**.

## *Data sources*

The formal base year for the scenario projections is 2019, as this is the last year for which a complete picture of energy demand and production is available. However, we have used more recent data when available, and we include our 2020 estimates for energy production and demand in this annex. Estimates for the year 2020 are based on updates of the IEA's Global Energy Review reports which are derived from a number of sources, including the latest monthly data submissions to the IEA's Energy Data Centre, other statistical releases from national administrations, and recent market data from the IEA Market Report Series that cover coal, oil, natural gas, renewables and power.

Historical data for gross electrical capacity are drawn from the S&P Global Market Intelligence World Electric Power Plants Database (March 2020 version) and the International Atomic Energy Agency PRIS database.

## *Definitional note: A.1. Energy supply and transformation table*

Total energy supply (TES) is equivalent to electricity and heat generation plus "other energy sector" excluding electricity and heat, plus total final consumption (TFC) excluding electricity and heat. TES does not include ambient heat from heat pumps or electricity trade. Solar in TES includes solar PV generation, concentrating solar power and final consumption of solar thermal. Other renewables in TES include geothermal, and marine (tide and wave) energy for electricity and heat generation. Hydrogen production and biofuels production in the other energy sector account for the energy input required to produce merchant hydrogen (mainly natural gas and electricity) and for the conversion losses to produce biofuels (mainly primary solid biomass) used in the energy sector. While not itemised separately, non-renewable waste and other sources are included in TES.

### *Definitional note: A.2. Energy demand table*

Sectors comprising total final consumption (TFC) include industry (energy use and feedstock), transport, buildings (residential, services and non-specified other) and other (agriculture and other non-energy use). Energy demand from international marine and aviation bunkers are included in transport totals.

### *Definitional note: A.3. Electricity tables*

Electricity generation expressed in terawatt-hours (TWh) and installed electrical capacity data expressed in gigawatts (GW) are both provided on a gross basis (i.e. includes own use by the generator). Projected gross electrical capacity is the sum of existing capacity and additions, less retirements. While not itemised separately, other sources are included in total electricity generation.

### *Definitional note: A.4. $CO_2$ emissions table*

Total $CO_2$ includes carbon dioxide emissions from the combustion of fossil fuels and non-renewable wastes, from industrial and fuel transformation processes (process emissions) as well as $CO_2$ removals. Three types of $CO_2$ removals are presented:

- Captured and stored emissions from the combustion of bioenergy and renewable wastes (typically electricity generation).
- Captured and stored process emissions from biofuels production.
- Captured and stored carbon dioxide from the atmosphere, which is reported as direct air carbon capture and storage (DACCS).

The first two entries are often reported as bioenergy with carbon capture and storage (BECCS). Note that some of the $CO_2$ captured from biofuels production and direct air capture is used to produce synthetic fuels, which is not included as $CO_2$ removal.

Total $CO_2$ captured includes the carbon dioxide captured from CCUS facilities (such as electricity generation or industry) and atmospheric $CO_2$ captured through direct air capture but excludes that captured and used for urea production.

### *Definitional note: A.5. Economic and activity indicators*

The emission intensity expressed in kilogrammes of carbon dioxide per kilowatt-hour (kg $CO_2$/kWh) is calculated based on electricity-only plants and the electricity component of combined heat and power (CHP) plants. [1]

Other abbreviations used include: PPP = purchasing power parity; GJ = gigajoules; Mt = million tonnes; pkm = passenger-kilometres; tkm = tonnes-kilometres; $m^2$ = square metres.

[1] To derive the associated electricity-only emissions from CHP plants, we assume that the heat production of a CHP plant is 90% efficient and the remainder of the fuel input is allocated to electricity generation.

## Table A.1: Energy supply and transformation

| | Energy supply (EJ) | | | | | Shares (%) | | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2019 | 2020 | 2030 | 2040 | 2050 | 2020 | 2030 | 2050 | 2020-2030 | 2020-2050 |
| **Total energy supply** | **612** | **587** | **547** | **535** | **543** | **100** | **100** | **100** | **-0.7** | **-0.3** |
| Renewables | 67 | 69 | 167 | 295 | 362 | 12 | 30 | 67 | 9.3 | 5.7 |
| Solar | 4 | 5 | 32 | 78 | 109 | 1 | 6 | 20 | 21 | 11 |
| Wind | 5 | 6 | 29 | 67 | 89 | 1 | 5 | 16 | 17 | 9.6 |
| Hydro | 15 | 16 | 21 | 27 | 30 | 3 | 4 | 6 | 2.9 | 2.2 |
| Modern solid bioenergy | 31 | 32 | 54 | 73 | 73 | 5 | 10 | 14 | 5.3 | 2.8 |
| Modern liquid bioenergy | 4 | 3 | 12 | 14 | 15 | 1 | 2 | 3 | 14 | 4.9 |
| Modern gaseous bioenergy | 2 | 2 | 5 | 10 | 14 | 0 | 1 | 3 | 10 | 6.4 |
| Other renewables | 4 | 5 | 13 | 24 | 32 | 1 | 2 | 6 | 11 | 6.7 |
| Traditional use of biomass | 25 | 25 | - | - | - | 4 | - | - | n.a. | n.a. |
| Nuclear | 30 | 29 | 41 | 54 | 61 | 5 | 8 | 11 | 3.5 | 2.4 |
| Unabated natural gas | 139 | 136 | 116 | 44 | 17 | 23 | 21 | 3 | -1.6 | -6.6 |
| Natural gas with CCUS | 0 | 1 | 13 | 31 | 43 | 0 | 2 | 8 | 37 | 16 |
| Oil | 190 | 173 | 137 | 79 | 42 | 29 | 25 | 8 | -2.3 | -4.6 |
| of which non-energy use | 28 | 27 | 32 | 31 | 29 | 5 | 6 | 5 | 1.4 | 0.2 |
| Unabated coal | 160 | 154 | 68 | 16 | 3 | 26 | 12 | 1 | -7.9 | -12 |
| Coal with CCUS | 0 | 0 | 4 | 16 | 14 | 0 | 1 | 3 | 60 | 22 |
| **Electricity and heat sectors** | **233** | **230** | **240** | **308** | **371** | **100** | **100** | **100** | **0.4** | **1.6** |
| Renewables | 36 | 38 | 107 | 220 | 284 | 17 | 44 | 77 | 11 | 6.9 |
| Solar PV | 2 | 3 | 25 | 61 | 84 | 1 | 10 | 23 | 24 | 12 |
| Wind | 5 | 6 | 29 | 67 | 89 | 2 | 12 | 24 | 17 | 9.6 |
| Hydro | 15 | 16 | 21 | 27 | 30 | 7 | 9 | 8 | 2.9 | 2.2 |
| Bioenergy | 9 | 10 | 18 | 35 | 39 | 4 | 8 | 10 | 6.3 | 4.6 |
| Other renewables | 4 | 4 | 14 | 30 | 42 | 2 | 6 | 11 | 14 | 8.5 |
| Hydrogen | - | - | 5 | 11 | 11 | - | 2 | 3 | n.a. | n.a. |
| Ammonia | - | - | 1 | 2 | 2 | - | 0 | 0 | n.a. | n.a. |
| Nuclear | 30 | 29 | 41 | 54 | 61 | 13 | 17 | 16 | 3.5 | 2.4 |
| Unabated natural gas | 56 | 55 | 49 | 4 | 2 | 24 | 21 | 0 | -1.1 | -11 |
| Natural gas with CCUS | - | - | 1 | 5 | 5 | - | 1 | 1 | n.a. | n.a. |
| Oil | 9 | 8 | 2 | 0 | 0 | 4 | 1 | 0 | -12 | -14 |
| Unabated coal | 102 | 100 | 30 | 0 | 0 | 43 | 12 | 0 | -11 | -34 |
| Coal with CCUS | 0 | 0 | 3 | 10 | 7 | 0 | 1 | 2 | 55 | 19 |
| **Other energy sector** | **57** | **57** | **61** | **76** | **91** | **100** | **100** | **100** | **0.7** | **1.5** |
| Hydrogen production | - | 0 | 21 | 49 | 70 | 0 | 35 | 77 | 66 | 23 |
| Biofuels production | 5 | 6 | 12 | 15 | 12 | 10 | 20 | 13 | 8 | 2.7 |

## Table A.2: Energy demand

| | Energy demand (EJ) | | | | | Shares (%) | | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2019 | 2020 | 2030 | 2040 | 2050 | 2020 | 2030 | 2050 | 2020-2030 | 2020-2050 |
| **Total final consumption** | **435** | **412** | **394** | **363** | **344** | **100** | **100** | **100** | **-0.4** | **-0.6** |
| Electricity | 82 | 81 | 103 | 140 | 169 | 20 | 26 | 49 | 2.4 | 2.5 |
| Liquid fuels | 175 | 158 | 143 | 96 | 66 | 38 | 36 | 19 | -1.0 | -2.9 |
| Biofuels | 4 | 3 | 12 | 14 | 15 | 1 | 3 | 4 | 14 | 4.9 |
| Ammonia | - | - | 1 | 3 | 5 | - | 0 | 1 | n.a. | n.a. |
| Synthetic oil | - | - | 0 | 2 | 5 | - | 0 | 1 | n.a. | n.a. |
| Oil | 171 | 154 | 129 | 77 | 42 | 37 | 33 | 12 | -1.8 | -4.2 |
| Gaseous fuels | 70 | 68 | 68 | 60 | 53 | 16 | 17 | 15 | 0.1 | -0.8 |
| Biomethane | 0 | 0 | 2 | 5 | 8 | 0 | 1 | 2 | 25 | 13 |
| Hydrogen | 0 | 0 | 6 | 12 | 20 | 0 | 2 | 6 | 54 | 20 |
| Synthetic methane | - | - | 0 | 1 | 4 | - | 0 | 1 | n.a. | n.a. |
| Natural gas | 70 | 67 | 58 | 40 | 20 | 16 | 15 | 6 | -1.4 | -4.0 |
| Solid fuels | 92 | 89 | 61 | 46 | 35 | 22 | 16 | 10 | -3.6 | -3.0 |
| Biomass | 39 | 39 | 24 | 25 | 25 | 9 | 6 | 7 | -4.8 | -1.4 |
| Coal | 53 | 50 | 38 | 21 | 10 | 12 | 10 | 3 | -2.8 | -5.3 |
| Heat | 13 | 13 | 12 | 9 | 6 | 3 | 3 | 2 | -1.2 | -2.7 |
| Other | 3 | 3 | 7 | 11 | 15 | 1 | 2 | 4 | 8.2 | 5.2 |
| **Industry** | **162** | **157** | **170** | **169** | **160** | **100** | **100** | **100** | **0.8** | **0.1** |
| Electricity | 35 | 35 | 47 | 62 | 74 | 22 | 28 | 46 | 3.0 | 2.5 |
| Liquid fuels | 31 | 31 | 31 | 27 | 23 | 20 | 18 | 15 | -0.2 | -0.9 |
| Oil | 31 | 31 | 31 | 27 | 23 | 20 | 18 | 15 | -0.2 | -0.9 |
| Gaseous fuels | 32 | 32 | 35 | 34 | 28 | 20 | 21 | 18 | 1.0 | -0.4 |
| Biomethane | 0 | 0 | 1 | 2 | 4 | 0 | 0 | 3 | 22 | 15 |
| Hydrogen | - | 0 | 3 | 4 | 5 | 0 | 2 | 3 | 44 | 15 |
| Unabated natural gas | 32 | 32 | 30 | 22 | 9 | 20 | 18 | 6 | -0.5 | -4.0 |
| Natural gas with CCUS | 0 | 0 | 1 | 5 | 7 | 0 | 1 | 4 | 38 | 18 |
| Solid fuels | 58 | 52 | 51 | 40 | 30 | 34 | 30 | 18 | -0.3 | -1.9 |
| Biomass | 10 | 9 | 15 | 19 | 20 | 6 | 9 | 13 | 5.2 | 2.8 |
| Unabated coal | 48 | 44 | 35 | 15 | 3 | 28 | 20 | 2 | -2.3 | -9.0 |
| Coal with CCUS | 0 | 0 | 1 | 5 | 7 | 0 | 1 | 4 | 91 | 31 |
| Heat | 6 | 6 | 6 | 3 | 2 | 4 | 3 | 1 | -1.2 | -4.5 |
| Other | 0 | 0 | 1 | 3 | 4 | 0 | 1 | 2 | 33 | 14 |
| Iron and steel | 36 | 33 | 37 | 36 | 32 | 21 | 22 | 20 | 1.1 | -0.2 |
| Chemicals | 22 | 20 | 26 | 26 | 25 | 13 | 15 | 15 | 2.7 | 0.7 |
| Cement | 12 | 16 | 11 | 11 | 10 | 10 | 7 | 7 | -3.3 | -1.3 |

## Table A.2: Energy demand

| | Energy demand (EJ) | | | | | Shares (%) | | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2019 | 2020 | 2030 | 2040 | 2050 | 2020 | 2030 | 2050 | 2020-2030 | 2020-2050 |
| **Transport** | **122** | **105** | **102** | **85** | **80** | **100** | **100** | **100** | **-0.3** | **-0.9** |
| Electricity | 1 | 1 | 7 | 22 | 35 | 1 | 7 | 44 | 17 | 11 |
| Liquid fuels | 115 | 99 | 89 | 53 | 30 | 94 | 87 | 38 | -1.0 | -3.9 |
| Biofuels | 4 | 3 | 11 | 12 | 11 | 3 | 11 | 14 | 14 | 4.3 |
| Oil | 111 | 96 | 76 | 35 | 9 | 91 | 74 | 12 | -2.2 | -7.4 |
| Gaseous fuels | 5 | 5 | 6 | 10 | 15 | 5 | 6 | 18 | 2.1 | 3.7 |
| Biomethane | 0 | 0 | 1 | 1 | 2 | 0 | 0 | 2 | 23 | 11 |
| Hydrogen | 0 | 0 | 1 | 6 | 13 | 0 | 1 | 16 | 92 | 34 |
| Natural gas | 5 | 5 | 4 | 2 | 0 | 5 | 4 | 0 | -1.5 | -11 |
| Road | 90 | 81 | 73 | 57 | 50 | 77 | 72 | 63 | -0.9 | -1.6 |
| Passenger cars | 47 | 41 | 30 | 19 | 17 | 39 | 29 | 21 | -3.1 | -2.9 |
| Trucks | 27 | 25 | 28 | 24 | 22 | 24 | 27 | 28 | 1.1 | -0.4 |
| Aviation | 14 | 8 | 13 | 13 | 14 | 8 | 13 | 18 | 4.6 | 1.7 |
| Shipping | 12 | 11 | 11 | 10 | 10 | 10 | 11 | 12 | 0.4 | -0.3 |
| **Buildings** | **129** | **127** | **99** | **89** | **86** | **100** | **100** | **100** | **-2.4** | **-1.3** |
| Electricity | 43 | 42 | 45 | 51 | 57 | 33 | 46 | 66 | 0.7 | 1.0 |
| Liquid fuels | 13 | 13 | 9 | 4 | 2 | 10 | 10 | 2 | -3.2 | -6.0 |
| Biofuels | 0 | 0 | 0 | 1 | 1 | 0 | 0 | 1 | 26 | 12 |
| Oil | 13 | 13 | 9 | 4 | 1 | 10 | 9 | 1 | -3.4 | -7.7 |
| Gaseous fuels | 30 | 28 | 23 | 13 | 6 | 22 | 23 | 7 | -2.1 | -4.9 |
| Biomethane | 0 | 0 | 1 | 2 | 2 | 0 | 1 | 2 | 29 | 11 |
| Hydrogen | - | 0 | 2 | 2 | 2 | 0 | 2 | 2 | 103 | 27 |
| Natural gas | 30 | 28 | 19 | 7 | 1 | 22 | 20 | 1 | -3.8 | -12 |
| Solid fuels | 34 | 34 | 10 | 7 | 6 | 27 | 10 | 7 | -11 | -5.5 |
| Modern biomass | 5 | 5 | 9 | 7 | 6 | 4 | 9 | 7 | 6.9 | 0.9 |
| Traditional use of biomass | 25 | 25 | - | - | - | 20 | - | - | n.a. | n.a. |
| Coal | 4 | 4 | 1 | 0 | 0 | 3 | 1 | 0 | -12 | -21 |
| Heat | 7 | 7 | 6 | 5 | 4 | 5 | 6 | 5 | -1.2 | -1.6 |
| Other | 2 | 3 | 5 | 8 | 11 | 2 | 5 | 12 | 7.1 | 4.8 |
| Residential | 91 | 90 | 67 | 59 | 58 | 71 | 67 | 67 | -3.0 | -1.5 |
| Services | 38 | 36 | 32 | 30 | 28 | 29 | 33 | 33 | -1.2 | -0.9 |
| **Other** | **22** | **23** | **22** | **20** | **18** | **100** | **100** | **100** | **-0.5** | **-0.9** |

## Table A.3: Electricity

| | Electricity Generation (TWh) | | | | | Shares (%) | | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2019 | 2020 | 2030 | 2040 | 2050 | 2020 | 2030 | 2050 | 2020-2030 | 2020-2050 |
| **Total generation** | **26 922** | **26 778** | **37 316** | **56 553** | **71 164** | **100** | **100** | **100** | **3.4** | **3.3** |
| Renewables | 7 153 | 7 660 | 22 817 | 47 521 | 62 333 | 29 | 61 | 88 | 12 | 7.2 |
| Solar PV | 665 | 821 | 6 970 | 17 031 | 23 469 | 3 | 19 | 33 | 24 | 12 |
| Wind | 1 423 | 1 592 | 8 008 | 18 787 | 24 785 | 6 | 21 | 35 | 18 | 9.6 |
| Hydro | 4 294 | 4 418 | 5 870 | 7 445 | 8 461 | 17 | 16 | 12 | 2.9 | 2.2 |
| Bioenergy | 665 | 718 | 1 407 | 2 676 | 3 279 | 3 | 4 | 5 | 7.0 | 5.2 |
| *of which BECCS* | *-* | *-* | *129* | *673* | *842* | *-* | *0* | *1* | *n.a.* | *n.a.* |
| CSP | 14 | 14 | 204 | 880 | 1 386 | 0 | 1 | 2 | 31 | 17 |
| Geothermal | 92 | 94 | 330 | 625 | 821 | 0 | 1 | 1 | 13 | 7.5 |
| Marine | 1 | 2 | 27 | 77 | 132 | 0 | 0 | 0 | 28 | 14 |
| Nuclear | 2 792 | 2 698 | 3 777 | 4 855 | 5 497 | 10 | 10 | 8 | 3.4 | 2.4 |
| Hydrogen-based | - | - | 875 | 1 857 | 1 713 | - | 2 | 2 | n.a. | n.a. |
| Fossil fuels with CCUS | 1 | 4 | 459 | 1 659 | 1 332 | 0 | 1 | 2 | 61 | 21 |
| Coal with CCUS | 1 | 4 | 289 | 966 | 663 | 0 | 1 | 1 | 54 | 19 |
| Natural gas with CCUS | - | - | 170 | 694 | 669 | - | 0 | 1 | n.a. | n.a. |
| Unabated fossil fuels | 16 941 | 16 382 | 9 358 | 632 | 259 | 61 | 25 | 0 | -5.4 | -13 |
| Coal | 9 832 | 9 426 | 2 947 | 0 | 0 | 35 | 8 | 0 | -11 | -40 |
| Natural gas | 6 314 | 6 200 | 6 222 | 626 | 253 | 23 | 17 | 0 | 0.0 | -10 |
| Oil | 795 | 756 | 189 | 6 | 6 | 3 | 1 | 0 | -13 | -15 |

| | Electrical Capacity (GW) | | | | | Shares (%) | | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | 2019 | 2020 | 2030 | 2040 | 2050 | 2020 | 2030 | 2050 | 2020-2030 | 2020-2050 |
| **Total capacity** | **7 484** | **7 795** | **14 933** | **26 384** | **33 415** | **100** | **100** | **100** | **6.7** | **5.0** |
| Renewables | 2 707 | 2 994 | 10 293 | 20 732 | 26 568 | 38 | 69 | 80 | 13 | 7.5 |
| Solar PV | 603 | 737 | 4 956 | 10 980 | 14 458 | 9 | 33 | 43 | 21 | 10 |
| Wind | 623 | 737 | 3 101 | 6 525 | 8 265 | 9 | 21 | 25 | 15 | 8.4 |
| Hydro | 1 306 | 1 327 | 1 804 | 2 282 | 2 599 | 17 | 12 | 8 | 3.1 | 2.3 |
| Bioenergy | 153 | 171 | 297 | 534 | 640 | 2 | 2 | 2 | 5.7 | 4.5 |
| *of which BECCS* | *-* | *-* | *28* | *125* | *152* | *-* | *0* | *0* | *n.a.* | *n.a.* |
| CSP | 6 | 6 | 73 | 281 | 426 | 0 | 0 | 1 | 28 | 15 |
| Geothermal | 15 | 15 | 52 | 98 | 126 | 0 | 0 | 0 | 13 | 7.4 |
| Marine | 1 | 1 | 11 | 32 | 55 | 0 | 0 | 0 | 34 | 16 |
| Nuclear | 415 | 415 | 515 | 730 | 812 | 5 | 3 | 2 | 2.2 | 2.3 |
| Hydrogen-based | - | - | 139 | 1 455 | 1 867 | - | 1 | 6 | n.a. | n.a. |
| Fossil fuels with CCUS | 0 | 1 | 81 | 312 | 394 | 0 | 1 | 1 | 66 | 25 |
| Coal with CCUS | 0 | 1 | 53 | 182 | 222 | 0 | 0 | 1 | 59 | 22 |
| Natural gas with CCUS | - | - | 28 | 130 | 171 | - | 0 | 1 | n.a. | n.a. |
| Unabated fossil fuels | 4 351 | 4 368 | 3 320 | 1 151 | 677 | 56 | 22 | 2 | -2.7 | -6.0 |
| Coal | 2 124 | 2 117 | 1 192 | 432 | 158 | 27 | 8 | 0 | -5.6 | -8.3 |
| Natural gas | 1 788 | 1 829 | 1 950 | 679 | 495 | 23 | 13 | 1 | 0.6 | -4.3 |
| Oil | 440 | 422 | 178 | 39 | 25 | 5 | 1 | 0 | -8.3 | -9.0 |
| Battery storage | 11 | 18 | 585 | 2 005 | 3 097 | 0 | 4 | 9 | 42 | 19 |

# Table A.4: $CO_2$ emissions

| | $CO_2$ emissions (Mt $CO_2$) | | | | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|
| | 2019 | 2020 | 2030 | 2040 | 2050 | 2020-2030 | 2020-2050 |
| **Total $CO_2$*** | **35 926** | **33 903** | **21 147** | **6 316** | **0** | **-4.6** | **n.a.** |
| **Combustion activities (+)** | **33 499** | **31 582** | **19 254** | **6 030** | **940** | **-4.8** | **-11** |
| Coal | 14 660 | 14 110 | 5 915 | 1 299 | 195 | -8.3 | -13 |
| Oil | 11 505 | 10 264 | 7 426 | 3 329 | 928 | -3.2 | -7.7 |
| Natural gas | 7 259 | 7 138 | 5 960 | 1 929 | 566 | -1.8 | -8.1 |
| Bioenergy and waste | 75 | 71 | - 48 | - 528 | - 748 | n.a. | n.a. |
| **Industry removals (-)** | **1** | **1** | **214** | **914** | **1 186** | **75** | **28** |
| Biofuels production | 1 | 1 | 142 | 385 | 553 | 68 | 24 |
| Direct air capture | - | - | 71 | 528 | 633 | n.a. | n.a. |
| **Electricity and heat sectors** | **13 821** | **13 504** | **5 816** | **- 81** | **- 369** | **-8.1** | **n.a.** |
| Coal | 10 035 | 9 786 | 2 950 | 102 | 69 | -11 | -15 |
| Oil | 655 | 628 | 173 | 6 | 6 | -12 | -14 |
| Natural gas | 3 131 | 3 089 | 2 781 | 268 | 128 | -1.0 | -10 |
| Bioenergy and waste | - | - | - 87 | - 457 | - 572 | n.a. | n.a. |
| **Other energy sector*** | **1 457** | **1 472** | **679** | **- 85** | **- 368** | **-7.4** | **n.a.** |
| **Final consumption*** | **20 647** | **18 928** | **14 723** | **7 011** | **1 370** | **-2.5** | **-8.4** |
| Coal | 4 486 | 4 171 | 2 935 | 1 186 | 117 | -3.5 | -11 |
| Oil | 10 272 | 9 077 | 6 973 | 3 242 | 880 | -2.6 | -7.5 |
| Natural gas | 3 451 | 3 332 | 2 668 | 1 453 | 303 | -2.2 | -7.7 |
| Bioenergy and waste | 75 | 71 | 40 | - 70 | - 176 | -5.6 | n.a. |
| Industry* | 8 903 | 8 478 | 6 892 | 3 485 | 519 | -2.0 | -8.9 |
| Iron and steel | 2 507 | 2 349 | 1 778 | 859 | 220 | -2.7 | -7.6 |
| Chemicals | 1 344 | 1 296 | 1 199 | 654 | 66 | -0.8 | -9.5 |
| Cement | 2 461 | 2 334 | 1 899 | 906 | 133 | -2.0 | -9.1 |
| Transport | 8 290 | 7 153 | 5 719 | 2 686 | 689 | -2.2 | -7.5 |
| Road | 6 116 | 5 483 | 4 077 | 1 793 | 340 | -2.9 | -8.9 |
| Passenger cars | 3 121 | 2 746 | 1 626 | 547 | 85 | -5.1 | -11 |
| Trucks | 1 835 | 1 721 | 1 614 | 890 | 198 | -0.6 | -6.9 |
| Aviation | 1 019 | 621 | 783 | 469 | 210 | 2.4 | -3.5 |
| Shipping | 883 | 800 | 705 | 348 | 122 | -1.3 | -6.1 |
| Buildings | 3 007 | 2 860 | 1 809 | 685 | 122 | -4.5 | -10 |
| Residential | 2 030 | 1 968 | 1 377 | 541 | 108 | -3.5 | -9.2 |
| Services | 977 | 892 | 432 | 144 | 14 | -7.0 | -13 |
| **Total $CO_2$ removals** | **1** | **1** | **317** | **1 457** | **1 936** | **79** | **29** |
| **Total $CO_2$ captured** | **40** | **40** | **1 665** | **5 619** | **7 602** | **45** | **19** |

**Includes industrial process emissions.*

## Table A.5: Economic and Activity Indicators

| | Indicator | | | | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|
| | 2019 | 2020 | 2030 | 2040 | 2050 | 2020-2030 | 2020-2050 |
| Population (million) | 7 672 | 7 753 | 8 505 | 9 155 | 9 692 | 0.9 | 0.7 |
| GDP (USD 2019 billion, PPP) | 134 710 | 128 276 | 184 037 | 246 960 | 316 411 | 3.7 | 3.1 |
| GDP per capita (USD 2019, PPP) | 17 558 | 16 545 | 21 638 | 26 975 | 32 648 | 2.7 | 2.3 |
| TES/GDP (GJ per USD 1 000, PPP) | 4.543 | 4.578 | 2.973 | 2.164 | 1.716 | -4.2 | -3.2 |
| TFC/GDP (GJ per USD 1 000, PPP) | 3.231 | 3.208 | 2.139 | 1.468 | 1.086 | -4.0 | -3.5 |
| TES per capita (GJ) | 79.77 | 75.74 | 64.33 | 58.38 | 56.03 | -1.6 | -1.0 |
| $CO_2$ intensity of electricity generation (kg $CO_2$ per kWh) | 0.468 | 0.438 | 0.138 | -0.001 | -0.005 | -11 | n.a. |

| | Activity | | | | | CAAGR (%) | |
|---|---|---|---|---|---|---|---|
| | 2019 | 2020 | 2030 | 2040 | 2050 | 2020-2030 | 2020-2050 |
| **Industrial production** | | | | | | | |
| Primary chemicals (Mt) | 538 | 529 | 641 | 686 | 688 | 1.9 | 0.9 |
| Steel (Mt) | 1 869 | 1 781 | 1 937 | 1 958 | 1 987 | 0.8 | 0.4 |
| Cement (Mt) | 4 215 | 4 054 | 4 258 | 4 129 | 4 032 | 0.5 | -0.0 |
| **Transport** | | | | | | | |
| Passenger cars (billion vkm) | 15 300 | 14 261 | 15 775 | 19 159 | 24 517 | 1.0 | 1.8 |
| Trucks (billion tkm) | 26 646 | 25 761 | 38 072 | 49 756 | 59 990 | 4.0 | 2.9 |
| Aviation (billion pkm) | 8 506 | 5 474 | 10 271 | 11 573 | 14 566 | 6.5 | 3.3 |
| Shipping (billion tkm) | 107 225 | 109 153 | 155 621 | 209 905 | 291 032 | 3.6 | 3.3 |
| **Buildings** | | | | | | | |
| Services floor area (million $m^2$) | 49 670 | 49 825 | 58 867 | 68 576 | 78 157 | 1.7 | 1.5 |
| Residential floor area (million $m^2$) | 190 062 | 192 558 | 235 745 | 290 696 | 345 183 | 2.0 | 2.0 |
| Million households | 2 095 | 2 116 | 2 435 | 2 765 | 3 051 | 1.4 | 1.2 |

# Technology costs

## *Electricity generation*

**Table B.1 ▷ Electricity generation technology costs by selected region in the NZE**

| | Financing rate (%) | Capital costs ($/kW) | | | Capacity factor (%) | | | Fuel, $CO_2$ and O&M ($/MWh) | | | LCOE ($/MWh) | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | All | 2020 | 2030 | 2050 | 2020 | 2030 | 2050 | 2020 | 2030 | 2050 | 2020 | 2030 | 2050 |
| **United States** | | | | | | | | | | | | | |
| Nuclear | 8.0 | 5 000 | 4 800 | 4 500 | 90 | 80 | 75 | 30 | 30 | 30 | 105 | 110 | 110 |
| Coal | 8.0 | 2 100 | 2 100 | 2 100 | 20 | *n.a.* | *n.a.* | 90 | 170 | 235 | 220 | *n.a.* | *n.a.* |
| Gas CCGT | 8.0 | 1 000 | 1 000 | 1 000 | 55 | 25 | *n.a.* | 50 | 80 | 105 | 70 | 125 | *n.a.* |
| Solar PV | 3.7 | 1 140 | 620 | 420 | 21 | 22 | 23 | 10 | 10 | 10 | 50 | 30 | 20 |
| Wind onshore | 3.7 | 1 540 | 1 420 | 1 320 | 42 | 43 | 44 | 10 | 10 | 10 | 35 | 35 | 30 |
| Wind offshore | 4.5 | 4 040 | 2 080 | 1 480 | 42 | 46 | 48 | 35 | 20 | 15 | 115 | 60 | 40 |
| **European Union** | | | | | | | | | | | | | |
| Nuclear | 8.0 | 6 600 | 5 100 | 4 500 | 75 | 75 | 70 | 35 | 35 | 35 | 150 | 120 | 115 |
| Coal | 8.0 | 2 000 | 2 000 | 2 000 | 20 | *n.a.* | *n.a.* | 120 | 205 | 275 | 250 | *n.a.* | *n.a.* |
| Gas CCGT | 8.0 | 1 000 | 1 000 | 1 000 | 40 | 20 | *n.a.* | 65 | 95 | 120 | 100 | 150 | *n.a.* |
| Solar PV | 3.2 | 790 | 460 | 340 | 13 | 14 | 14 | 10 | 10 | 10 | 55 | 35 | 25 |
| Wind onshore | 3.2 | 1 540 | 1 420 | 1 300 | 29 | 30 | 31 | 15 | 15 | 15 | 55 | 45 | 40 |
| Wind offshore | 4.0 | 3 600 | 2 020 | 1 420 | 51 | 56 | 59 | 15 | 10 | 5 | 75 | 40 | 25 |
| **China** | | | | | | | | | | | | | |
| Nuclear | 7.0 | 2 800 | 2 800 | 2 500 | 80 | 80 | 80 | 25 | 25 | 25 | 65 | 65 | 60 |
| Coal | 7.0 | 800 | 800 | 800 | 60 | *n.a.* | *n.a.* | 75 | 135 | 195 | 90 | *n.a.* | *n.a.* |
| Gas CCGT | 7.0 | 560 | 560 | 560 | 45 | 35 | *n.a.* | 75 | 100 | 120 | 90 | 115 | *n.a.* |
| Solar PV | 3.5 | 750 | 400 | 280 | 17 | 18 | 19 | 10 | 5 | 5 | 40 | 25 | 15 |
| Wind onshore | 3.5 | 1 220 | 1 120 | 1 040 | 26 | 27 | 27 | 15 | 10 | 10 | 45 | 40 | 40 |
| Wind offshore | 4.3 | 2 840 | 1 560 | 1 000 | 34 | 41 | 43 | 25 | 15 | 10 | 95 | 45 | 30 |
| **India** | | | | | | | | | | | | | |
| Nuclear | 7.0 | 2 800 | 2 800 | 2 800 | 70 | 70 | 70 | 30 | 30 | 30 | 75 | 75 | 75 |
| Coal | 7.0 | 1 200 | 1 200 | 1 200 | 50 | *n.a.* | *n.a.* | 35 | 50 | 75 | 65 | *n.a.* | *n.a.* |
| Gas CCGT | 7.0 | 700 | 700 | 700 | 55 | 50 | *n.a.* | 45 | 45 | 50 | 55 | 60 | *n.a.* |
| Solar PV | 5.8 | 580 | 310 | 220 | 20 | 21 | 21 | 5 | 5 | 5 | 35 | 20 | 15 |
| Wind onshore | 5.8 | 1 040 | 980 | 940 | 26 | 28 | 29 | 10 | 10 | 10 | 50 | 45 | 40 |
| Wind offshore | 6.6 | 2 980 | 1 680 | 1 180 | 32 | 37 | 38 | 25 | 15 | 10 | 130 | 70 | 45 |

Notes: O&M = operation and maintenance; LCOE = levelised cost of electricity; kW = kilowatt; MWh = megawatt-hour; CCGT = combined-cycle gas turbine; n.a. = not applicable. Cost components and LCOE figures are rounded.

Sources: IEA analysis; IRENA Renewable Costing Alliance; IRENA (2020).

- Major contributors to the LCOE include: overnight capital costs; capacity factor that describes the average output over the year relative to the maximum rated capacity (typical values provided); the cost of fuel inputs; plus operation and maintenance. Economic lifetime assumptions are 25 years for solar PV, onshore and offshore wind.
- Weighted average costs of capital (WACC) reflect analysis for utility-scale solar PV in the *World Energy Outlook 2020* (IEA, 2020) and for offshore wind from the *Offshore Wind Outlook 2019* (IEA, 2019). Onshore wind was assumed to have the same WACC as utility-scale solar PV. A standard WACC was assumed for nuclear power, coal- and gas-fired power plants (7-8% based on the stage of economic development).
- Fuel, $CO_2$ and O&M costs reflect the average over the ten years following the indicated date in the projections.
- The capital costs for nuclear power represent the "nth-of-a-kind" costs for new reactor designs, with substantial cost reductions from the first-of-a-kind projects.

### *Batteries and hydrogen*

**Table B.2 ▷ Capital costs for batteries and hydrogen production technologies in the NZE**

| | 2020 | 2030 | 2050 |
|---|---|---|---|
| Battery packs for transport applications (USD/kWh) | 130 - 155 | 75 - 90 | 55 - 80 |
| Low-temperature electrolysers (USD/$kW_e$) | 835 - 1 300 | 255 - 515 | 200 - 390 |
| Natural gas with CCUS (USD/kW $H_2$) | 1 155 - 2 010 | 990 - 1 725 | 935 - 1 625 |

Notes: kWh = kilowatt-hour; $kW_e$ = kilowatt electric; CCUS = carbon capture, utilisation and storage; $H_2$ = hydrogen. Capital costs for electrolysers and hydrogen production from natural gas with CCUS are overnight costs.

Source: IEA analysis.

# Definitions

This annex provides general information on terminology used throughout this report including: units and general conversion factors; definitions of fuels, processes and sectors; regional and country groupings; and abbreviations and acronyms.

## Units

| | | |
|---|---|---|
| **Area** | $km^2$ | square kilometre |
| | Mha | million hectares |
| **Batteries** | Wh/kg | Watt hours per kilogramme |
| **Coal** | Mtce | million tonnes of coal equivalent (equals 0.7 Mtoe) |
| **Distance** | km | kilometre |
| **Emissions** | ppm | parts per million (by volume) |
| | $tCO_2$ | tonnes of carbon dioxide |
| | Gt $CO_2$-eq | gigatonnes of carbon-dioxide equivalent (using 100-year global warming potentials for different greenhouse gases) |
| | kg $CO_2$-eq | kilogrammes of carbon-dioxide equivalent |
| | g $CO_2$/km | grammes of carbon dioxide per kilometre |
| | kg $CO_2$/kWh | kilogrammes of carbon dioxide per kilowatt-hour |
| **Energy** | EJ | exajoule |
| | PJ | petajoule |
| | TJ | terajoule |
| | GJ | gigajoule |
| | MJ | megajoule |
| | boe | barrel of oil equivalent |
| | toe | tonne of oil equivalent |
| | ktoe | thousand tonnes of oil equivalent |
| | Mtoe | million tonnes of oil equivalent |
| | MBtu | million British thermal units |
| | kWh | kilowatt-hour |
| | MWh | megawatt-hour |
| | GWh | gigawatt-hour |
| | TWh | terawatt-hour |
| **Gas** | bcm | billion cubic metres |
| | tcm | trillion cubic metres |
| **Mass** | kg | kilogramme (1 000 kg = 1 tonne) |
| | kt | kilotonnes (1 tonne x $10^3$) |
| | Mt | million tonnes (1 tonne x $10^6$) |
| | Gt | gigatonnes (1 tonne x $10^9$) |

| | | |
|---|---|---|
| **Monetary** | USD million | 1 US dollar x $10^6$ |
| | USD billion | 1 US dollar x $10^9$ |
| | USD trillion | 1 US dollar x $10^{12}$ |
| | USD/$tCO_2$ | US dollars per tonne of carbon dioxide |
| **Oil** | kb/d | thousand barrels per day |
| | mb/d | million barrels per day |
| | mboe/d | million barrels of oil equivalent per day |
| **Power** | W | watt (1 joule per second) |
| | kW | kilowatt (1 watt x $10^3$) |
| | MW | megawatt (1 watt x $10^6$) |
| | GW | gigawatt (1 watt x $10^9$) |
| | TW | terawatt (1 watt x $10^{12}$) |

## *General conversion factors for energy*

| | | Multiplier to convert to: | | | | |
|---|---|---|---|---|---|---|
| | | **EJ** | **Gcal** | **Mtoe** | **MBtu** | **GWh** |
| *Convert from:* | **EJ** | 1 | 238.8 x $10^6$ | 23.88 | 9.47.8 x $10^3$ | 2.778 x $10^5$ |
| | **Gcal** | 4.1868 x $10^{-9}$ | 1 | $10^{-7}$ | 3.968 | 1.163 x $10^{-3}$ |
| | **Mtoe** | 4.1868 x $10^{-2}$ | $10^7$ | 1 | 3.968 x $10^7$ | 11 630 |
| | **MBtu** | 1.0551 x $10^{-9}$ | 0.252 | 2.52 x $10^{-8}$ | 1 | 2.931 x $10^{-4}$ |
| | **GWh** | 3.6 x $10^{-6}$ | 860 | 8.6 x $10^{-5}$ | 3 412 | 1 |

Note: There is no generally accepted definition of boe; typically the conversion factors used vary from 7.15 to 7.40 boe per toe.

## *Currency conversions*

| **Exchange rates** *(2019 annual average)* | **1 US dollar (USD) equals:** |
|---|---|
| British Pound | 0.78 |
| Chinese Yuan Renminbi | 6.91 |
| Euro | 0.89 |
| Indian Rupee | 70.42 |
| Indonesian Rupiah | 14 147.67 |
| Japanese Yen | 109.01 |
| Russian Ruble | 64.74 |
| South African Rand | 14.45 |

Source: OECD National Accounts Statistics: purchasing power parities and exchange rates dataset, July 2020.

## *Definitions*

**Advanced bioenergy:** Sustainable fuels produced from non-food crop feedstocks, which are capable of delivering significant lifecycle greenhouse gas emissions savings compared with fossil fuel alternatives, and which do not directly compete with food and feed crops for agricultural land or cause adverse sustainability impacts. This definition differs from the one used for "advanced biofuels" in US legislation, which is based on a minimum 50% lifecycle greenhouse gas reduction and which, therefore, includes sugar cane ethanol.

**Agriculture:** Includes all energy used on farms, in forestry and for fishing.

**Agriculture, forestry and other land use (AFOLU) emissions:** Includes greenhouse gas emissions from agriculture, forestry and other land use.

**Ammonia ($NH_3$):** Is a compound of nitrogen and hydrogen. It can be used directly as a fuel in direct combustion process, and in fuel cells or as a hydrogen carrier. To be a low-carbon fuel, ammonia must be produced from low-carbon hydrogen, the nitrogen separated via the Haber process, and electricity needs are met by low-carbon electricity.

**Aviation:** This transport mode includes both domestic and international flights and their use of aviation fuels. Domestic aviation covers flights that depart and land in the same country; flights for military purposes are also included. International aviation includes flights that land in a country other than the departure location.

**Back-up generation capacity:** Households and businesses connected to a main power grid may also have back-up electricity generation capacity that, in the event of disruption, can provide electricity. Back-up generators are typically fuelled with diesel or gasoline and capacity can be as little as a few kilowatts. Such capacity is distinct from mini-grid and off-grid systems that are not connected to a main power grid.

**Biodiesel:** Diesel-equivalent, processed fuel made from the transesterification (a chemical process that converts triglycerides in oils) of vegetable oils and animal fats.

**Bioenergy:** Energy content in solid, liquid and gaseous products derived from biomass feedstocks and biogas. It includes solid biomass, liquid biofuels and biogases.

**Biogas:** A mixture of methane, carbon dioxide and small quantities of other gases produced by anaerobic digestion of organic matter in an oxygen-free environment.

**Biogases:** Include biogas and biomethane.

**Biomethane:** Biomethane is a near-pure source of methane produced either by upgrading biogas (a process that removes any $CO_2$ and other contaminants present in the biogas) or through the gasification of solid biomass followed by methanation. It is also known as renewable natural gas.

**Buildings:** The buildings sector includes energy used in residential, commercial and institutional buildings and non-specified other. Building energy use includes space heating and cooling, water heating, lighting, appliances and cooking equipment.

**Bunkers:** Includes both international marine bunkers and international aviation bunkers.

**Capacity credit:** Proportion of the capacity that can be reliably expected to generate electricity during times of peak demand in the grid to which it is connected.

**Carbon capture, utilisation and storage (CCUS):** The process of capturing $CO_2$ emissions from fuel combustion, industrial processes or directly from the atmosphere. Captured $CO_2$ emissions can be stored in underground geological formations, onshore or offshore or used as an input or feedstock to create products.

**Clean energy:** Includes renewables, energy efficiency, low-carbon fuels, nuclear power, battery storage and carbon capture, utilisation and storage.

**Clean cooking facilities:** Cooking facilities that are considered safer, more efficient and more environmentally sustainable than the traditional facilities that make use of solid biomass (such as a three-stone fire). This refers primarily to improved solid biomass cookstoves, biogas systems, liquefied petroleum gas stoves, ethanol and solar stoves.

**Coal:** Includes both primary coal (including lignite, coking and steam coal) and derived fuels (including patent fuel, brown-coal briquettes, coke-oven coke, gas coke, gas-works gas, coke-oven gas, blast furnace gas and oxygen steel furnace gas). Peat is also included.

**Concentrating solar power (CSP):** Solar thermal power/electric generation systems that collect and concentrate sunlight to produce high temperature heat to generate electricity.

**Conventional liquid biofuels:** Fuels produced from food crop feedstocks. These liquid biofuels are commonly referred to as first generation and include sugar cane ethanol, starch-based ethanol, fatty acid methyl esther (FAME) and straight vegetable oil (SVO).

**Decomposition analysis:** Statistical approach that decomposes an aggregate indicator to quantify the relative contribution of a set of pre-defined factors leading to a change in the aggregate indicator. This report uses an additive index decomposition of the type Logarithmic Mean Divisia Index (LMDI).

**Demand-side integration (DSI):** Consists of two types of measures: actions that influence load shape such as energy efficiency and electrification; and actions that manage load such as demand-side response.

**Demand-side response (DSR):** Describes actions which can influence the load profile such as shifting the load curve in time without affecting the total electricity demand, or load shedding such as interrupting demand for short duration or adjusting the intensity of demand for a certain amount of time.

**Dispatchable generation:** Refers to technologies whose power output can be readily controlled - increased to maximum rated capacity or decreased to zero - in order to match supply with demand.

**Electricity demand:** Defined as total gross electricity generation less own use generation, plus net trade (imports less exports), less transmissions and distribution losses.

**Electricity generation:** Defined as the total amount of electricity generated by power only or combined heat and power plants including generation required for own use. This is also referred to as gross generation.

**Energy sector $CO_2$ emissions:** Carbon dioxide emissions from fuel combustion (excluding non-renewable waste). Note that this does not include fugitive emissions from fuels, $CO_2$ from transport, storage emissions or industrial process emissions.

**Energy sector GHG emissions:** $CO_2$ emissions from fuel combustion plus fugitive and vented methane, and nitrous oxide ($N_2O$) emissions from the energy and industry sectors.

**Energy services:** See useful energy.

**Ethanol:** Refers to bio-ethanol only. Ethanol is produced from fermenting any biomass high in carbohydrates. Today, ethanol is made from starches and sugars, but second-generation technologies will allow it to be made from cellulose and hemicellulose, the fibrous material that makes up the bulk of most plant matter.

**Fischer-Tropsch synthesis:** Catalytic production process for the production of synthetic fuels. Natural gas, coal and biomass feedstocks can be used.

**Gases:** Includes natural gas, biogases, synthetic methane and hydrogen.

**Geothermal:** Geothermal energy is heat derived from the sub-surface of the earth. Water and/or steam carry the geothermal energy to the surface. Depending on its characteristics, geothermal energy can be used for heating and cooling purposes or be harnessed to generate clean electricity if the temperature is adequate.

**Heat (end-use):** Can be obtained from the combustion of fossil or renewable fuels, direct geothermal or solar heat systems, exothermic chemical processes and electricity (through resistance heating or heat pumps which can extract it from ambient air and liquids). This category refers to the wide range of end-uses, including space and water heating, and cooking in buildings, desalination and process applications in industry. It does not include cooling applications.

**Heat (supply):** Obtained from the combustion of fuels, nuclear reactors, geothermal resources and the capture of sunlight. It may be used for heating or cooling, or converted into mechanical energy for transport or electricity generation. Commercial heat sold is reported under total final consumption with the fuel inputs allocated under electricity and heat sectors.

**Hydrogen:** Hydrogen is used in the energy system to refine hydrocarbon fuels and as an energy carrier in its own right. It is also produced from other energy products for use in chemicals production. As an energy carrier it can be produced from hydrocarbon fuels or from the electrolysis of water with electricity, and can be burned or used in fuel cells for electricity and heat in a wide variety of applications. To be low-carbon hydrogen, either the emissions associated with fossil-based hydrogen production must be prevented (for example by carbon capture, utilisation and storage) or the electricity input to hydrogen produced from water must be low-carbon electricity. In this report, final consumption of hydrogen includes demand for pure hydrogen and excludes hydrogen produced and consumed onsite by the same entity. Demand for hydrogen-based fuels such as ammonia or synthetic hydrocarbons are considered separately.

**Hydrogen-based fuels:** Include ammonia and synthetic hydrocarbons (gases and liquids). Hydrogen-based is used in figures to refer to hydrogen and hydrogen-based fuels.

**Hydropower:** The energy content of the electricity produced in hydropower plants, assuming 100% efficiency. It excludes output from pumped storage and marine (tide and wave) plants.

**Industry:** The sector includes fuel used within the manufacturing and construction industries. Key industry branches include iron and steel, chemicals and petrochemicals, cement, and pulp and paper. Consumption of fuels for the transport of goods is reported as part of the transport sector, while consumption by off-road vehicles is reported under industry.

**International aviation bunkers:** Includes the deliveries of aviation fuels to aircraft for international aviation. Fuels used by airlines for their road vehicles are excluded. The domestic/international split is determined on the basis of departure and landing locations and not by the nationality of the airline. For many countries this incorrectly excludes fuels used by domestically owned carriers for their international departures.

**International marine bunkers:** Covers fuels delivered to ships of all flags that are engaged in international navigation. The international navigation may take place at sea, on inland lakes and waterways, and in coastal waters. Consumption by ships engaged in domestic navigation is excluded. The domestic/international split is determined on the basis of port of departure and port of arrival, and not by the flag or nationality of the ship. Consumption by fishing vessels and by military forces is excluded and included in residential, services and agriculture.

**Investment:** All investment data and projections reflect spending across the lifecycle of a project, i.e. the capital spent is assigned to the year when it is incurred. Investments for oil, gas and coal include production, transformation and transportation; those for the power sector include refurbishments, uprates, new builds and replacements for all fuels and technologies for on-grid, mini-grid and off-grid generation, as well as investment in transmission and distribution, and battery storage. Investment data are presented in real terms in year-2019 US dollars unless otherwise stated.

**Light-duty vehicles** (LDV)**:** include passenger cars and light commercial vehicles (gross vehicle weight <3.5 tonnes).

**Liquid biofuels:** Liquid fuels derived from biomass or waste feedstocks and include ethanol and biodiesel. They can be classified as conventional and advanced liquid biofuels according to the bioenergy feedstocks and technologies used to produce them and their respective maturity. Unless otherwise stated, liquid biofuels are expressed in energy-equivalent volumes of gasoline and diesel.

**Liquids:** Includes oil, liquid biofuels (expressed in energy-equivalent volumes of gasoline and diesel), synthetic oil and ammonia.

**Low-carbon electricity:** Includes renewable energy technologies, hydrogen-based generation, nuclear power and fossil fuel power plants equipped with carbon capture, utilisation and storage.

**Low-emissions fuels:** Include liquid biofuels, biogas and biomethane, hydrogen, and hydrogen-based fuels that do not emit any $CO_2$ from fossil fuels directly when used and also emit very little when being produced.

**Marine:** Represents the mechanical energy derived from tidal movement, wave motion or ocean current and exploited for electricity generation.

**Merchant hydrogen:** Hydrogen produced by one company to sell to others; equivalent to hydrogen reported in total final consumption.

**Mini-grids:** Small grid systems linking a number of households or other consumers.

**Modern bioenergy:** Includes modern solid biomass, liquid biofuels and biogases harvested from sustainable sources. It excludes the traditional use of biomass.

**Modern energy access:** Includes household access to a minimum level of electricity; household access to safer and more sustainable cooking and heating fuels, and stoves; access that enables productive economic activity; and access for public services.

**Modern renewables:** Includes all uses of renewable energy with the exception of traditional use of solid biomass.

**Modern solid biomass:** Refers to the use of solid biomass in improved cookstoves and modern technologies using processed biomass such as pellets.

**Natural gas:** Comprises gases occurring in deposits, whether liquefied or gaseous, consisting mainly of methane. It includes both "non-associated" gas originating from fields producing hydrocarbons only in gaseous form, and "associated" gas produced in association with crude oil as well as methane recovered from coal mines (colliery gas). Natural gas liquids (NGLs), manufactured gas (produced from municipal or industrial waste, or sewage) and quantities vented or flared are not included. Gas data in cubic metres are expressed on a gross calorific value basis and are measured at 15 °C and at 760 mm Hg ("Standard Conditions"). Gas data expressed in tonnes of oil equivalent, mainly for comparison reasons with other fuels, are on a net calorific basis. The difference between the net and the gross calorific value is the latent heat of vaporisation of the water vapour produced during combustion of the fuel (for gas the net calorific value is 10% lower than the gross calorific value).

**Natural gas liquids** (NGLs)**:** Liquid or liquefied hydrocarbons produced in the manufacture, purification and stabilisation of natural gas. These are those portions of natural gas which are recovered as liquids in separators, field facilities or gas processing plants. NGLs include but are not limited to ethane (when it is removed from the natural gas stream), propane, butane, pentane, natural gasoline and condensates.

**Network gases:** Includes natural gas, biomethane, synthetic methane and hydrogen blended in a gas network.

**Non-energy use:** Fuels used for chemical feedstocks and non-energy products. Examples of non-energy products include lubricants, paraffin waxes, asphalt, bitumen, coal tars and oils as timber preservatives.

**Nuclear:** Refers to the primary energy equivalent of the electricity produced by a nuclear plant, assuming an average conversion efficiency of 33%.

**Off-grid systems:** Stand-alone systems for individual households or groups of consumers.

**Offshore wind:** Refers to electricity produced by wind turbines that are installed in open water, usually in the ocean.

**Oil:** Oil production includes both conventional and unconventional oil. Petroleum products include refinery gas, ethane, liquid petroleum gas, aviation gasoline, motor gasoline, jet fuels, kerosene, gas/diesel oil, heavy fuel oil, naphtha, white spirit, lubricants, bitumen, paraffin, waxes and petroleum coke.

**Other energy sector:** Covers the use of energy by transformation industries and the energy losses in converting primary energy into a form that can be used in the final consuming sectors. It includes losses by gas works, petroleum refineries, coal and gas transformation and liquefaction, biofuels production and the production of hydrogen and hydrogen-based fuels. It also includes energy own use in coal mines, in oil and gas extraction, in direct air capture, in biofuels production and in electricity and heat production. Transfers and statistical differences are also included in this category.

**Power generation:** Refers to fuel use in electricity plants, heat plants and combined heat and power (CHP) plants. Both main activity producer plants and small plants that produce fuel for their own use (auto-producers) are included.

**Productive uses:** Energy used towards an economic purpose: agriculture, industry, services and non-energy use. Some energy demand from the transport sector, e.g. freight, could also be considered as productive, but is treated separately.

**Renewables:** Includes bioenergy, geothermal, hydropower, solar photovoltaics (PV), concentrating solar power (CSP), wind and marine (tide and wave) energy for electricity and heat generation.

**Residential:** Energy used by households including space heating and cooling, water heating, lighting, appliances, electronic devices and cooking equipment.

**Services:** Energy used in commercial facilities, e.g. hotels, offices, catering, shops, and institutional buildings, e.g. schools, hospitals, offices. Energy use in services includes space heating and cooling, water heating, lighting, equipment, appliances and cooking equipment.

**Shale gas:** Natural gas contained within a commonly occurring rock classified as shale. Shale formations are characterised by low permeability, with more limited ability of gas to flow through the rock than is the case with a conventional reservoir. Shale gas is generally produced using hydraulic fracturing.

**Shipping/navigation:** This transport sub-sector includes both domestic and international navigation and their use of marine fuels. Domestic navigation covers the transport of goods or persons on inland waterways and for national sea voyages (starts and ends in the same country without any intermediate foreign port). International navigation includes quantities of fuels delivered to merchant ships (including passenger ships) of any nationality for consumption during international voyages transporting goods or passengers.

**Solar photovoltaic** (PV)**:** Electricity produced from solar photovoltaic cells.

**Solid biomass:** Includes charcoal, fuelwood, dung, agricultural residues, wood waste and other solid wastes.

**Steam coal:** Type of coal that is mainly used for heat production or steam-raising in power plants and, to a lesser extent, in industry. Typically, steam coal is not of sufficient quality for steel making. Coal of this quality is also commonly known as thermal coal.

**Synthetic methane:** Low-carbon synthetic methane is produced through the methanation of low-carbon hydrogen and carbon dioxide from a biogenic or atmospheric source.

**Synthetic oil:** Low-carbon synthetic oil produced through Fischer Tropsch conversion or methanol synthesis from syngas, a mixture of hydrogen ($H_2$) and carbon monoxide (CO).

**Total energy supply** (TES)**:** Represents domestic demand only and is broken down into electricity and heat generation, other energy sector and total final consumption.

**Total final consumption** (TFC)**:** Is the sum of consumption by the various end-use sectors. TFC is broken down into energy demand in the following sectors: industry (including manufacturing and mining), transport, buildings (including residential and services) and other (including agriculture and non-energy use). It excludes international marine and aviation bunkers, except at world level where it is included in the transport sector.

**Total final energy consumption** (TFEC)**:** Is a variable defined primarily for tracking progress towards target 7.2 of the UN Sustainable Development Goals. It incorporates total final consumption (TFC) by end-use sectors but excludes non-energy use. It excludes international marine and aviation bunkers, except at world level. Typically this is used in the context of calculating the renewable energy share in total final energy consumption (Indicator 7.2.1 of the Sustainable Development Goals), where TFEC is the denominator.

**Total primary energy demand** (TPED)**:** See total energy supply

**Traditional use of solid biomass:** Refers to the use of solid biomass with basic technologies, such as a three-stone fire, often with no or poorly operating chimneys.

**Transport:** Fuels and electricity used in the transport of goods or people within the national territory irrespective of the economic sector within which the activity occurs. This includes fuel and electricity delivered to vehicles using public roads or for use in rail vehicles; fuel delivered to vessels for domestic navigation; fuel delivered to aircraft for domestic aviation; and energy consumed in the delivery of fuels through pipelines. Fuel delivered to international marine and aviation bunkers is presented only at the world level and is excluded from the transport sector at a domestic level.

**Trucks:** Includes medium trucks (gross vehicle weight 3.5-15 tonnes) and heavy trucks (>15 tonnes).

**Useful energy:** Refers to the energy that is available to end-users to satisfy their needs. This is also referred to as energy services demand. As result of transformation losses at the point of use, the amount of useful energy is lower than the corresponding final energy demand for most technologies. Equipment using electricity often has higher conversion efficiency than equipment using other fuels, meaning that for a unit of energy consumed electricity can provide more energy services.

**Wind:** electricity produced by wind turbines from the kinetic energy of wind.

**Woody energy crops:** Short-rotation plantings of woody biomass for bioenergy production, such as coppiced willow and miscanthus.

**Variable renewable energy** (VRE)**:** Refers to technologies whose maximum output at any time depends on the availability of fluctuating renewable energy resources. VRE includes a broad array of technologies such as wind power, solar PV, run-of-river hydro, concentrating solar power (where no thermal storage is included) and marine (tidal and wave).

**Zero-carbon-ready buildings:** A zero-carbon-ready building is highly energy efficient and either uses renewable energy directly, or an energy supply that can be fully decarbonised, such as electricity or district heat.

**Zero-emissions vehicles** (ZEVs)**:** Vehicles which are capable of operating without tailpipe $CO_2$ emissions (battery electric vehicles and fuel cell vehicles).

## *Regional and country groupings*

**Advanced economies:** OECD regional grouping and Bulgaria, Croatia, Cyprus[1,2], Malta and Romania.

**Africa:** North Africa and sub-Saharan Africa regional groupings.

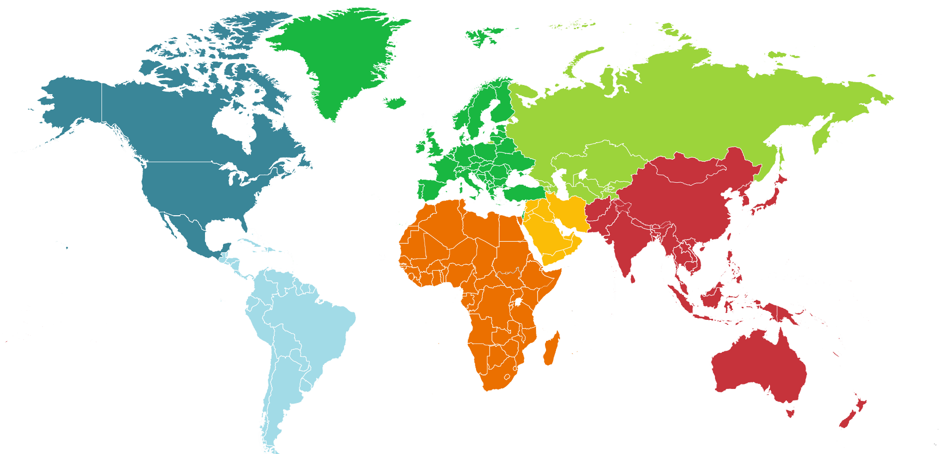
**Asia Pacific:** Southeast Asia regional grouping and Australia, Bangladesh, China, India, Japan, Korea, Democratic People's Republic of Korea, Mongolia, Nepal, New Zealand, Pakistan, Sri Lanka, Chinese Taipei, and other Asia Pacific countries and territories.[3]

**Caspian:** Armenia, Azerbaijan, Georgia, Kazakhstan, Kyrgyzstan, Tajikistan, Turkmenistan and Uzbekistan.

**Central and South America:** Argentina, Plurinational State of Bolivia (Bolivia), Brazil, Chile, Colombia, Costa Rica, Cuba, Curaçao, Dominican Republic, Ecuador, El Salvador, Guatemala, Haiti, Honduras, Jamaica, Nicaragua, Panama, Paraguay, Peru, Suriname, Trinidad and Tobago, Uruguay, Bolivarian Republic of Venezuela (Venezuela), and other Central and South American countries and territories.[4]

**China:** Includes the (People's Republic of) China and Hong Kong, China.

**Figure C.1 ▷ Main country groupings**




Note: This map is without prejudice to the status of or sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area.

**Developing Asia:** Asia Pacific regional grouping excluding Australia, Japan, Korea and New Zealand.

**Emerging market and developing economies:** All other countries not included in the advanced economies regional grouping.

**Eurasia:** Caspian regional grouping and the Russian Federation (Russia).

**Europe:** European Union regional grouping and Albania, Belarus, Bosnia and Herzegovina, North Macedonia, Gibraltar, Iceland, Israel[5], Kosovo, Montenegro, Norway, Serbia, Switzerland, Republic of Moldova, Turkey, Ukraine and United Kingdom.

**European Union:** Austria, Belgium, Bulgaria, Croatia, Cyprus[1,2], Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Ireland, Italy, Latvia, Lithuania, Luxembourg, Malta, Netherlands, Poland, Portugal, Romania, Slovak Republic, Slovenia, Spain and Sweden.

**IEA (International Energy Agency):** OECD regional grouping excluding Chile, Colombia, Iceland, Israel, Latvia, Lithuania and Slovenia.

**Latin America:** Central and South America regional grouping and Mexico.

**Middle East:** Bahrain, Islamic Republic of Iran (Iran), Iraq, Jordan, Kuwait, Lebanon, Oman, Qatar, Saudi Arabia, Syrian Arab Republic (Syria), United Arab Emirates and Yemen.

**Non-OECD:** All other countries not included in the OECD regional grouping.

**Non-OPEC:** All other countries not included in the OPEC regional grouping.

**North Africa:** Algeria, Egypt, Libya, Morocco and Tunisia.

**North America:** Canada, Mexico and United States.

**OECD** (Organisation for Economic Co-operation and Development)**:** Australia, Austria, Belgium, Canada, Chile, Colombia, Czech Republic, Denmark, Estonia, Finland, France, Germany, Greece, Hungary, Iceland, Ireland, Israel, Italy, Japan, Korea, Latvia, Lithuania, Luxembourg, Mexico, Netherlands, New Zealand, Norway, Poland, Portugal, Slovak Republic, Slovenia, Spain, Sweden, Switzerland, Turkey, United Kingdom and United States.

**OPEC** (Organisation of the Petroleum Exporting Countries)**:** Algeria, Angola, Republic of the Congo (Congo), Equatorial Guinea, Gabon, the Islamic Republic of Iran (Iran), Iraq, Kuwait, Libya, Nigeria, Saudi Arabia, United Arab Emirates and Bolivarian Republic of Venezuela (Venezuela).

**Southeast Asia:** Brunei Darussalam, Cambodia, Indonesia, Lao People's Democratic Republic (Lao PDR), Malaysia, Myanmar, Philippines, Singapore, Thailand and Viet Nam. These countries are all members of the Association of Southeast Asian Nations (ASEAN).

**Sub-Saharan Africa:** Angola, Benin, Botswana, Cameroon, Republic of the Congo (Congo), Côte d'Ivoire, Democratic Republic of the Congo, Eritrea, Ethiopia, Gabon, Ghana, Kenya, Mauritius, Mozambique, Namibia, Niger, Nigeria, Senegal, South Africa, South Sudan, Sudan, United Republic of Tanzania (Tanzania), Togo, Zambia, Zimbabwe and other African countries and territories.[6]

### *Country notes*

[1] Note by Turkey: The information in this document with reference to "Cyprus" relates to the southern part of the island. There is no single authority representing both Turkish and Greek Cypriot people on the island. Turkey recognises the Turkish Republic of Northern Cyprus (TRNC). Until a lasting and equitable solution is found within the context of the United Nations, Turkey shall preserve its position concerning the "Cyprus issue".

[2] Note by all the European Union Member States of the OECD and the European Union: The Republic of Cyprus is recognised by all members of the United Nations with the exception of Turkey. The information in this document relates to the area under the effective control of the Government of the Republic of Cyprus.

[3] Individual data are not available and are estimated in aggregate for: Afghanistan, Bhutan, Cook Islands, Fiji, French Polynesia, Kiribati, Macau (China), Maldives, New Caledonia, Palau, Papua New Guinea, Samoa, Solomon Islands, Timor-Leste and Tonga and Vanuatu.

[4] Individual data are not available and are estimated in aggregate for: Anguilla, Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, Bermuda, Bonaire, British Virgin Islands, Cayman Islands, Dominica, Falkland Islands (Malvinas), French Guiana, Grenada, Guadeloupe, Guyana, Martinique, Montserrat, Saba, Saint Eustatius, Saint Kitts and Nevis, Saint Lucia, Saint Pierre and Miquelon, Saint Vincent and Grenadines, Saint Maarten, Turks and Caicos Islands.

[5] The statistical data for Israel are supplied by and under the responsibility of the relevant Israeli authorities. The use of such data by the OECD and/or the IEA is without prejudice to the status of the Golan Heights, East Jerusalem and Israeli settlements in the West Bank under the terms of international law.

[6] Individual data are not available and are estimated in aggregate for: Burkina Faso, Burundi, Cabo Verde, Central African Republic, Chad, Comoros, Djibouti, Kingdom of Eswatini, Gambia, Guinea, Guinea-Bissau, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Réunion, Rwanda, Sao Tome and Principe, Seychelles, Sierra Leone, Somalia and Uganda.

## *Abbreviations and Acronyms*

| | |
|---|---|
| **AFOLU** | agriculture forestry and other land use |
| **APC** | Announced Pledges Case |
| **ASEAN** | Association of Southeast Asian Nations |
| **BECCS** | bioenergy equipped with CCUS |
| **BEV** | battery electric vehicles |
| **CCUS** | carbon capture, utilisation and storage |
| **CDR** | carbon dioxide removal |
| **CFL** | compact fluorescent lamp |
| **$CH_4$** | methane |
| **CHP** | combined heat and power; the term co-generation is sometimes used |
| **CNG** | compressed natural gas |
| **CO** | carbon monoxide |
| **$CO_2$** | carbon dioxide |
| **$CO_2$-eq** | carbon-dioxide equivalent |
| **COP** | Conference of Parties (UNFCCC) |
| **CSP** | concentrating solar power |
| **DAC** | direct air capture |
| **DACCS** | direct air capture with carbon capture and storage |
| **DER** | distributed energy resources |
| **DSI** | demand-side integration |
| **DSO** | distribution system operator |
| **DSR** | demand-side response |
| **EAF** | electric arc furnaces |
| **EHOB** | extra-heavy oil and bitumen |
| **ETP** | Energy Technology Perspectives |
| **EU** | European Union |
| **EV** | electric vehicle |
| **FCEV** | fuel cell electric vehicle |
| **GDP** | gross domestic product |
| **GHG** | greenhouse gases |
| **GTL** | gas-to-liquids |
| **HEFA** | hydrogenated esters and fatty acids |
| **ICE** | internal combustion engine |
| **IEA** | International Energy Agency |
| **IIASA** | International Institute for Applied Systems Analysis |
| **IMF** | International Monetary Fund |
| **IOC** | international oil company |
| **IPCC** | Intergovernmental Panel on Climate Change |
| **LCC** | Low CCUS Case |
| **LDVs** | light-duty vehicles |
| **LCV** | light-commercial vehicle |
| **LED** | light-emitting diode |

| | |
|---|---|
| **LNG** | liquefied natural gas |
| **LPG** | liquefied petroleum gas |
| **MEPS** | minimum energy performance standards |
| **NDCs** | Nationally Determined Contributions |
| **NEA** | Nuclear Energy Agency (an agency within the OECD) |
| **NGLs** | natural gas liquids |
| **NGV** | natural gas vehicle |
| **NOC** | national oil company |
| **$NO_X$** | nitrogen oxides |
| **$N_2O$** | nitrous oxide |
| **NZE** | Net-Zero Emissions Scenario |
| **OECD** | Organisation for Economic Co-operation and Development |
| **OPEC** | Organization of the Petroleum Exporting Countries |
| **PHEV** | plug-in hybrid electric vehicles |
| **PLDV** | passenger light-duty vehicle |
| **PM** | particulate matter |
| **$PM_{2.5}$** | fine particulate matter |
| **PPP** | purchasing power parity |
| **PV** | photovoltaics |
| **R&D** | research and development |
| **RD&D** | research, development and demonstration |
| **SAF** | sustainable aviation fuel |
| **SDG** | Sustainable Development Goals (United Nations) |
| **$SO_2$** | sulphur dioxide |
| **SR1.5** | IPCC Special Report on the impacts of global warming of 1.5°C above pre-industrial levels |
| **STEPS** | Stated Policies Scenario |
| **T&D** | transmission and distribution |
| **TES** | total energy supply |
| **TFC** | total final consumption |
| **TFEC** | total final energy consumption |
| **TPED** | total primary energy demand |
| **UEC** | unit energy consumption |
| **UN** | United Nations |
| **UNDP** | United Nations Development Programme |
| **UNEP** | United Nations Environment Programme |
| **UNFCCC** | United Nations Framework Convention on Climate Change |
| **UK** | United Kingdom |
| **US** | United States |
| **VRE** | variable renewable energy |
| **WEO** | *World Energy Outlook* |
| **WHO** | World Health Organization |
| **ZEV** | Zero-emissions vehicle |

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# Eight Benefits of Building Electrification for Households, Communities, and Climate

March 29, 2021

By Mina Lee, Sherri Billimoria

Buildings account for 28 percent of the United States' energy use and greenhouse gas emissions—and we need to halve our emissions in a decade and eliminate them completely by 2050 in order to meet the Paris Agreement goal to limit global warming to 1.5°C. But more than half of American homes rely on gas or other fossil fuels as their primary heating or cooking fuel, which produces carbon dioxide ($CO_2$), carbon monoxide (CO), sulfur dioxide ($SO_2$), nitrogen oxides ($NO_x$), methane, and many other harmful compounds.

Building electrification is the movement to shift away from fossil fuels—like gas—toward clean electricity for heating and cooking. All-electric homes deliver climate, health, and economic benefits to Americans and are a crucial component of the clean energy future that should not be overlooked.

Below are eight facts about building electrification that can help move cities, states, and the country away from burning fossil fuels in buildings:

1. **Building Electrification Is a Key Part of the Solution for Climate Change and Reducing Emissions**

Seventy million American homes and businesses burn gas, oil, and propane for heating space and water and cooking food, generating 600 million tons of $CO_2$ each year. Factoring in the latest estimates of methane leakage, that number rises to nearly 1 billion tons of $CO_2$ equivalent—a significant chunk of the emissions that drive the climate crisis. To avoid the worst consequences of climate change and for US states and cities to meet their "deep decarbonization" climate goals, we must eliminate carbon pollution from gas furnaces, water heaters, and other fossil fuel-powered appliances in homes. Electrification is the only established way to accomplish this.

2. **Building Electrification Creates Healthy Homes and Living Environments**

More than half of all US households have gas appliances, which emit a wide range of air pollutants. As a result, the air indoors—where people spend nearly 90 percent of their time—is often more polluted than outdoor air. In fact, homes with gas stoves have nitrogen dioxide ($NO_2$) concentrations that are 50 percent to over 400 percent higher than in homes with electric stoves.

Additional pollutants such as CO, particulate matter, and formaldehyde from gas appliances can all cause negative health effects, often exacerbating respiratory conditions like asthma and allergies. Children living in homes with gas stoves are 42 percent more likely to suffer asthma symptoms than those living in homes with electric stoves. Furthermore, exposure to $NO_2$ pollution can exacerbate susceptibility to severe health outcomes during public health incidents, like the current COVID-19 pandemic.

3. **Building All-Electric Homes Is Less Expensive Than Building Homes with Fossil Fuel Appliances**

RMI research has shown that building a new all-electric, single-family home is less expensive than a new mixed-fuel home that relies on gas, regardless of location. This is because mixed-fuel homes have gas furnaces, water heaters, air conditioning, and new gas connections (which carry a median price tag of nearly $9,000). The all-electric home, by comparison, uses a single heat pump system for both heating and cooling, as well as a heat pump water heater. Heat pumps also provide significant carbon and energy savings

Commercial Buildings
e-Lab: Electricity Innovation Lab
Electricity
Energy Efficiency
Finance
General
General Energy
Global South
Hydrogen
India
Industry
Islands
Oil and Gas Solutions
Residential Buildings
RMI
South East Asia
Spark Chart
Strategic Insights
Supply Chain Emissions
Transportation
Trucking
US Policy

over gas appliances, resulting in a lower annual utility cost for the all-electric home.

### 4. Electrifying Buildings Can Create Thousands of Good, Family-Supporting Middle-Class Jobs

An all-electric transition that includes electric vehicles and solar panel installation can create up to 25 million jobs in the near term and an estimated 5 million jobs sustained over time—roughly double the number of jobs supported by today's energy industry.

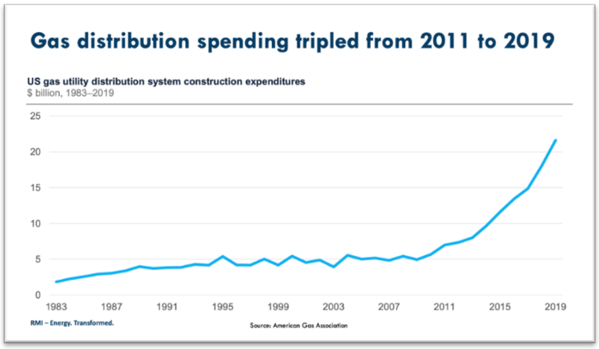
A report released by UCLA's Luskin Center for Innovation found that building electrification in California alone will boost employment in the construction, energy, and manufacturing industries, supporting more than 100,000 jobs—eight times as many jobs as would be lost in the gas sector as it is phased out. The right electrification policies can build a just transition for these gas workers as well. Furthermore, three out of every five jobs required to meet building electrification goals would be in "high-road" sectors, where firms compete on the basis of skill, experience, and qualifications, and where worker pay tends to be higher.

### 5. Building Electrification Can Be a Transformative, Positive Force for Low-Income Residents and Communities of Color

Air pollution disproportionately impacts low-income communities and communities of color. Because buildings contribute to this dangerous air pollution, building electrification can help improve indoor and outdoor air quality for these communities. Furthermore, low-income, African American, and Latino households bear disproportionate energy cost burdens—three times as high as other homes. Equitable building electrification—through programs that offer electric appliances at low or no cost, energy efficiency programs, and building upgrades—can reduce this energy burden.

Building electrification will bring cleaner air, healthier homes, good jobs, and empowered workers. It also expands access to affordable clean energy and energy efficiency to reduce monthly energy bills for pollution-burdened communities—all while helping states meet their climate goals.

### 6. Gas Infrastructure Costs Are Soaring




While the cost of highly efficient electric appliances like heat pumps is projected to continue declining, the cost of maintaining the aging US gas infrastructure is **increasing**. These gas infrastructure costs are passed directly on to customers, who are expected to pay them off over the next 50-plus years—long past the point at which we know we need to have eliminated emissions. It's not only that heat pumps are cheaper—continuing to invest in gas creates a big financial and equity problem down the road. By phasing out gas, states can invest more financial resources into expanding their electricity grid and renewable energy sources, rather than pouring billions into maintaining gas pipelines.

Additionally, many states are rethinking the role of gas in their energy mix—especially gas that is burned on-site for heating and cooling in homes. **Last year**, states representing roughly **a quarter** of the nation's direct gas usage began processes to manage a transition off of their gas systems, and even major utilities and financial institutions have announced that they no longer view gas as a long-term part of the energy mix.

### 7. Gas Alternatives Are Not Sufficient

"Renewable" natural gas (RNG) usually refers to biomethane that is created from sources such as wastewater, landfill methane, or agricultural waste and then pumped into the existing natural gas grid. RNG is expensive to develop, and at best it can only meet a small fraction of gas demand. **Research** overwhelmingly shows that RNG is likely to remain too limited and costly to decarbonize the buildings sector. It could only replace **3 to 12 percent** of the existing demand for gas and is **4 to 17 times** more expensive than fossil gas. Furthermore, because RNG supplies are limited, the best use of RNG will likely be in hard-to-decarbonize sectors such as industrial processes that cannot be easily electrified.

Other alternatives, like hydrogen or synthetic methane, have also been touted by the gas industry as alternatives for decarbonizing buildings. These technologies face steep cost and infrastructure challenges to scale up, and they would ultimately require more electricity generation to produce than would be needed for an all-electric buildings sector.

### 8. Building Electrification Is Gaining Momentum across the United States

In less than two years, 40 cities and counties across California have passed local building electrification policies to phase out gas and ensure that new homes and buildings are equipped with highly efficient electric appliances for heating, cooling, and cooking. Other **cities** are considering similar electrification policies, and states—including **Colorado**, **Massachusetts**, **New Jersey**, and **California**—feature electrification as a key component of their decarbonization plans.

All-electric construction is already the standard in many US states. Nearly **60 percent** of new homes nationwide are built all-electric, and more new homes use heat pumps than any other technology. Moreover, the latest polls show that Americans **strongly support** transitioning the United States to clean sources of energy, and they believe that moving away from natural gas will benefit their communities.

As these facts show, building electrification is the most cost-effective and lowest-risk solution to phase fossil fuels out of buildings. Electrifying homes and businesses eliminates emissions—a crucial step toward a 1.5°C future—and brings an array of additional health and economic benefits. With electrification gaining momentum across the United States and cost-effective, efficient technologies like heat pumps already widely available, the future of all-electric buildings looks increasingly bright.

Electricity Markets & Policy
Energy Analysis & Environmental Impacts Division
Lawrence Berkeley National Laboratory

# Who is participating in residential energy efficiency programs?

## Exploring demographic and other household characteristics of participants in utility customer-funded energy efficiency programs

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November 2021

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# Acronyms and Abbreviations

| | |
|---|---|
| ACS | American Community Survey |
| CBG | Census block group |
| DI | Direct install |
| HVAC | Heating, ventilation, and air conditioning |
| IQ | Income qualified |
| LEAD | Low-Income Energy Affordability Data |
| RECS | Residential Energy Consumption Survey |

# Executive Summary

Utility customer-funded energy efficiency programs benefit all customers by reducing the total electric system cost and also provide direct benefits to the participants. We study the relationships between participation rates in residential programs and demographic and other household characteristics. Understanding the current state of these relationships will help us assess the extent of current inequities in program participation and figure out what characteristics we need to target to achieve equitable outcomes.

We review previous work on this topic and compare it to our own primary analysis of four datasets. Using as consistent a methodology as possible, we study the impact of 11 demographic and household characteristics – income, education, race and ethnicity, limited English, energy poverty, tenure, householder age, homeownership, building vintage, building type, and urbanization. Our datasets have different scopes, strengths, and levels of detail, including one with household-level data at a national scale, two from New England at the zip code level, and one from a Midwestern state at the census block group level.

We employ both single-variable and multivariable models to study the relationships between these factors and program participation. The single-variable models describe the relationship between each factor and program participation, while the multivariable models seek to disentangle the effects of individual factors from other factors they are correlated with (e.g., income and education). Parsing these factors suggests specific opportunities for programmatic intervention.

Table ES-1 shows a high-level summary of results from our analysis and previous work. Overall, the table suggests there is room to improve equity of program participation. The clearest associations with energy efficiency program participation were with education and building type – higher education households and households in single-family homes were more likely to participate, and these relationships remained strong in multivariable analyses. The single-family results are in part structural – many programs are only available to single-family households – though our results suggest that these structural factors should be examined. The very clear impact of education on participation across program types suggests that program administrators may wish to explore strategies to better engage households and locations with lower educational attainment.

Results for race and income were somewhat less consistent, both in our analysis and in the existing literature. They depended on the statistical model, the individual program, and the particular racial and ethnic group being considered. Still, patterns emerged that suggest inequities regarding these factors that program administrators may wish to address. In single-variable models, income and participation were positively correlated except in income-qualified programs, although it was not always significant in multivariable models. The patterns were similar for Black heads of household but varied for other racial and ethnic groups.

One of our datasets allows us to compare two different participation rates for the same income-qualified program – the *overall* participation rate, or the share of *total* households in the geographic area who participated, and the *eligible* participation rate, or the share of *eligible* households in the geographic area who participated. We find that the results of the analysis depend on which rate is chosen. For example, higher income areas had a lower overall participation rate but a higher eligible participation rate for the income-qualified program – indicating that within the eligible low-income population, households in higher-income areas participated more.

Additional work could improve our understanding of equity in program participation and how to improve it. Possibilities include extending the analysis to more places with a wider variety of programs and demographics, closely considering the implications of using particular participation and equity metrics (including place-based vs. household-level metrics), and identifying design and delivery characteristics of particular programs that are successful at attaining equitable outcomes for replication elsewhere.

**Table ES-1. Simplified summary of results**

| | Household income | | Householder education | | Black householder | | Latino White householder | | Other race / ethnicity | | Limited English | | Energy poverty | | Householder age | | Ownership | | Tenure | | Number of units | | Vintage | | Urbanization | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential Energy Consumption Survey (RECS) | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Any assistance | — | — | ▲ | ▲ | — | — | ▼ | — | ▼ — | ▼ — | | | — | — | ▲ | — | | | ▼ | — | ▼ | ▼ | ▼ | ▼ | — | — |
| Lights | ▼ | ▼ | — | — | ▲ | — | — | — | — | ▼ — | | | ▲ — | — | — | — | | | — | — | ▼ | — | ▼ | ▼ | — | — |
| Audit | ▼ | — | ▲ | ▲ | — | — | — | — | — | ▼ — | | | — | ▼ | — | — | | | — | — | ▼ | ▼ | — | — | — | — |
| Appliance rebate | ▲ | — | — | — | — | — | ▼ | ▼ | — | — | | | — | — | — | — | | | — | — | — | ▼ | — | — | ▼ — | — |
| Appliance recycling | ▲ | — | — | — | ▼ | — | ▼ | — | — | — | | | ▼ — | — | ▲ | — | | | ▼ | ▼ | ▼ | — | ▼ | ▼ | — | ▲ ▼ |
| Mass Save | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Electric | ▲ | — | ▲ | ▲ | ▼ | — | — | ▼ | ▼ | ▼ — | ▼ | — | ▲ | ▲ | ▲ | — | — | — | ▲ | — | ▼ | ▼ | ▲ ▼ | — | ▼ | ▲ |
| National Grid Rhode Island | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Market rate | ▲ | | ▲ | | * | | * | | * | | ▼ | | ▼ | | — | | ▲ | | — | | ▼ | | — | | — | |
| Income qualified — eligible | ▲ | | — | | * | | * | | * | | ▼ | | ▼ | | — | | ▲ | | — | | ▼ | | — | | ▼ | |
| Income qualified — overall | ▼ | | ▼ | | * | | * | | * | | — | | ▲ | | — | | ▼ | | — | | — | | — | | ▼ | |
| Utility A (Midwest) | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Any program | ▲ | ▲ | ▲ | ▲ | — | ▲ | — | ▲ | ▲ ▼ | — | ▼ | — | ▼ | ▼ | ▲ | ▲ | — | — | ▲ | ▲ | ▼ | ▼ | ▼ | — | ▲ | ▲ |
| Any market-rate program | ▲ | ▲ | ▲ | ▲ | ▼ | ▼ | — | ▲ | ▲ ▼ | — | ▼ | — | ▼ | ▼ | ▲ | ▲ | ▲ | ▲ | ▲ | ▲ | ▼ | ▼ | ▼ | ▲ | ▲ | ▲ |
| Income qualified audit & direct install | ▼ | ▼ | ▲ | ▲ | ▲ | ▲ | ▼ | — | ▲ ▼ | ▲ | — | ▼ | ▲ | — | — | ▲ | — | — | ▲ | — | ▼ | ▼ | ▲ | ▼ | ▲ | ▲ |
| Audit & direct install | ▲ | — | ▲ | ▲ | ▲ | ▲ | — | — | ▼ — | — | — | — | ▼ | ▼ | ▲ | ▲ | — | — | ▲ | — | ▼ | ▼ | — | — | ▲ | ▲ |
| HVAC rebate | ▲ | ▲ | ▲ | ▲ | ▼ | ▼ | — | — | ▲ ▼ | — | ▼ | — | ▼ | ▼ | ▲ | ▲ | — | — | ▲ | ▲ | ▼ | ▼ | ▼ | ▲ | ▲ | ▲ |
| Appliance recycling | ▲ | — | ▲ | ▲ | ▼ | ▼ | ▲ | ▲ | ▲ ▼ | ▲ | — | — | ▼ | ▼ | ▲ | — | — | — | ▲ | — | ▼ | — | ▼ | — | ▲ | ▲ |
| Literature | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | ▲ 7<br>— 3 | ▲ 2 | ▲ 3 | ▲ 1 | — 2<br>▼ 1 | ▲ 1 | ▲ 1<br>— 2<br>▼ 1 | ▲ 1 | ▲ 2<br>— 2<br>▼ 2 | ▲ 1 | ▲ 1 | ▲ 1 | | ▲ 1 | — 1<br>▼ 2 | — 1 | ▲ 4 | ▲ 2 | | ▼ 2 | ▼ 1 | ▲ 1<br>▼ 2 | ▲ 1<br>▼ 1 | — 1 | ▲ 1 | ▲ 1 |

**Key:**

▲ participation increased as the variable increased, or was higher for households with the characteristic

▼ participation decreased as the variable increased, or was lower for households with the characteristic

— participation did not change based on the variable

blank : variable was not studied

gray columns contain single-variable results

unshaded (white) columns contain multivariable results

Multiple symbols indicate that the relationship varied depending on the subgroup or exact metric considered.

Numbers in the "Literature" rows indicate the count of studies that found a particular result.

* Racial and ethnic groups were not compared individually to the share of non-Latino White householders because of sample size. The share of non-Latino White heads of household in the zip code was positively correlated with the market-rate and *eligible* income-qualified participation rates but negatively correlated with the *overall* income-qualified participation rate.

# 1. Introduction

Utility customer-funded energy efficiency programs are a major delivery mechanism for residential energy efficiency investment in the United States, and therefore a key component of climate investment. These energy efficiency programs benefit all utility customers by reducing the total cost of electricity and gas delivery services. Households that participate receive additional direct benefits, which can include lower energy bills, improved home comfort, and better indoor air quality (IEA, 2019; Pigg et al., 2021). This motivates identifying which types of utility customers are currently accessing these programs, and which types are not, in pursuit of equitable outcomes.

In this report, we examine how participation rates in residential utility customer-funded energy efficiency programs vary by demographic and other household characteristics. First we review and summarize some previous research addressing this question. The methodologies and demographic factors vary widely across studies, and most studies only consider one factor (e.g., income or building type) at a time. Second we analyze four distinct datasets with a relatively consistent methodology, using multivariable models when we can to parse the effects of different factors.[1] We document how program participation in our data differs by these demographic and physical factors and compare our results to findings from previous studies.

Section 2 identifies a number of factors that might influence energy efficiency program participation and reviews prior research on these factors. Section 3 describes our data and methodology for the primary research we conduct in this report. Section 4 presents our results for each studied dataset. Section 5 brings our results together across our datasets and joins them with the prior literature. Section 6 offers conclusions for program administrators to consider, and Section 7 identifies additional research efforts that could further improve our understanding of the determinants of program participation and move towards more equitable program implementation.

# 2. Previous Work on Characteristics Influencing Participation in Energy Efficiency Programs

This section describes the demographic and physical characteristics that we study and the relationships previous studies have found between these characteristics and program participation. There are many pathways through which these characteristics might influence participation. For example, higher-income households may be more likely to have the capital required for investment (or be better able to access a loan with favorable terms). Products or services may be easier to access in a particular area. In some cases there are plausible reasons that a characteristic could either decrease or increase participation. For example, low-income households may participate less because they may be unable to afford to

[1] Single variable or univariate models reveal the relationship between a single factor and the outcome of interest, for example income and participation. However, there are many other factors related to income, such as education and race, which might affect participation. Multivariable or multivariate models reveal the relationship between a factor and the outcome when the other factors are held constant. This is sometimes referred to as “controlling” for the other variables.

replace broken or inefficient equipment, conduct deep retrofits, cover upfront costs in advance of receiving a program rebate, or pay a premium for efficiency. Conversely, these households may participate more because bill reductions and improvements in comfort and air quality may have a larger impact. Also, they may be eligible for federal and utility-sponsored income-qualified weatherization and efficiency programs. However, because these programs have higher costs for program administrators than market-rate programs, they are not funded in proportion to the share of low-income households in the area (Frick et al., 2021; Reames et al., 2019).

Table 1 summarizes findings from the studies described in the remainder of this section, categorized by data source.

**Table 1. Summary of select previous work**

| Source | Place | Years covered | HH† income | HoH educa-tion | Black HoH† | Latino White HoH | Other race / ethnicity | Limited English | Energy poverty | HoH age | Owner-ship | Tenure | Number of units | Vintage | Urbani-zation |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Survey data (household-level demographics) | | | | | | | | | | | | | | | |
| Burke & Cooper, 2013 | National | 2009-2011 | | | | | | | | | | | | | |
| market rate | | | ▲ | | | | | | | ▼ | ▲ | | | | |
| weatherization | | | — | | | | | | | ▼ | ▲ | | | | |
| Cohn, 2015 | National | 2015 | | | — | ▲ | ▲ | | | | | | | | |
| DNV-GL, 2017 | NY | 2016-2017 | ▲ | ▲ | | | | | | ▼ | ▲ | | | | |
| Frank & Nowak, 2016 | CA | 2010-2012 | ▲ | ▲ | ▼ — | ▼ — | ▼ — | ▲ | | | | | | ▲ ▼ | |
| Illume et al., 2020 | IN | 2019 | ▲ | | | | | | | | | | | | |
| Navigant et al., 2020 * | MA | 2013-2017 | ▲ | ▲ | | | | ▲ | ▲ | | ▲ | ▼ | ▼ ▲ | — | |
| Research Into Action, 2019 | OR | 2018 | — | ▲ | — | — | — | | | — | ▲ | | ▼ | | |
| Wemple et al., 2016 * | National | 2013-2015 | | | | | | | | | | | | | |
| market rate | | | | | ▲ | ▲ | ▲ | | | | | | | | |
| weatherization | | | | | ▲ | ▲ | ▲ | | | | | | | | |
| Utility data (place-based demographics) | | | | | | | | | | | | | | | |
| DNV-GL, 2019 | MA | 2013-2017 | ▲ | | | | | | | | ▲ | | | | |
| Navigant, 2017 * | RI | 2009-2015 | | | | | | | | | | | | | |
| market rate | | | ▲ | | | | | | | — | ▲ | ▼ | ▼ | | ▲ |
| income qualified | | | — | | | | | | | — | — | ▼ | ▼ | | ▲ |
| Rubado et al., 2018 | OR | 2013-2017 | | | | | | | | | | | | | |
| capital investment | | | ▲ | | | | ▲ ▼ | | | | | | | | ▲ |
| free to participant | | | — | | | | ▲ ▼ | | | | | | | | ▲ |

**Key:**

▲ participation increased as the variable increased, or was higher for households with the characteristic

▼ participation decreased as the variable increased, or was lower for households with the characteristic

— participation did not change based on the variable

blank: variable was not studied

* included multivariable analysis

† HH is household; HoH is head of household

Multiple symbols indicate that the relationship varied depending on the subgroup or program considered.

Except where the results are split into two lines in the table, studies did not distinguish between market-rate and income-qualified programs.

## 2.1 Household Characteristics

### 2.1.1 Income

Multiple studies have examined the relationship between income and program participation. Some studies are based on self-reported program participation from surveys; others are based on program participation data from program administrators. In most cases they found that participation rates in energy efficiency programs tend to increase as household income goes up. Burke and Cooper (2013) conducted single variable analysis based on a national survey of 32,000 households on behaviors and attitudes related to energy use. They showed that higher-income households were more likely to report participating in utility-sponsored programs than low-income ones, with the exception of weatherization programs (which are most often available only to low-income households). A Navigant (2017) study of participation rates in market-rate and income-qualified whole-building efficiency programs found that their income metric was in the top five most influential factors (out of fourteen factors tested) for market-rate electric accounts but not for gas or income-qualified accounts. Among market-rate electric accounts, participation increased with income, as measured by the percent of area median income (AMI). Frank and Nowak (2016) found that low- and middle-income households were underrepresented among program participants relative to their share of total households, based on analysis of 16 program evaluations in California for the 2010-2012 program period. DNV-GL (2017) surveyed customers about Rochester Gas & Electric's online marketplace for discounted energy efficient products and found that higher income households were more likely to have made purchases there. In a single variable analysis based on surveys and interviews in Massachusetts, Navigant et al. (2020) found that non-participants were more likely to be low and moderate income. However, when they added other variables to the analysis, income was no longer a consistent predictor of participation.

Rubado et al. (2018) found that participation tended to be higher in census tracts with higher incomes for 5 years of program participation data from Energy Trust of Oregon, except for programs that are provided at no cost to the participant. Similarly, DNV-GL (2019) found higher electric and gas savings in census block groups with lower shares of low-income households.

In other studies, income was not a significant factor influencing participation. Research Into Action (2019) found no significant difference in the income of participants and non-participants in Energy Trust of Oregon programs based on a telephone survey. Illume Advising et al. (2020) surveyed customers of Northern Indiana Public Service Company (NIPSCO) who did not participate in their home audit programs. The surveyed non-participants had a slightly higher proportion of households with incomes over $75,000 than in the service territory at large; the result was not tested for statistical significance.

Overall, although there were some instances where income was not associated with participation, in most cases higher-income households participated more. None of the studies found that participation increased as incomes declined.

### 2.1.2 Education

Four studies that compared the educational attainment of participants of energy efficiency programs found that post-secondary education is associated with higher participation. These studies cover 14 evaluations of California efficiency programs (Frank and Nowak, 2016), customers of Energy Trust of Oregon (Research Into Action, 2019), people who bought from Rochester Gas & Electric's online marketplace (DNV-GL, 2017), and Massachusetts residents (Navigant et al., 2020). Only Navigant et al. conducted a multivariable analysis, and their finding that non-participants were more likely than participants to only have a high school education held up in both their single- and multivariable analyses. The research findings were consistent – participation increased with educational attainment in all cases.

### 2.1.3 Race and Ethnicity

Previous studies of the impact of race and ethnicity on program participation have shown mixed results. In some cases, they have shown higher participation among non-White groups. In a multivariable regression analysis by Wemple et al. (2016) of a national survey of 32,000 households on behaviors and attitudes related to energy use, non-White groups were 1.38-2.52 times more likely to report participating in a variety of general and income-qualified efficiency programs than Whites. For most programs, the Asian and Pacific Islander group had the highest propensity to participate. The analysis controlled for 10 variables including homeownership, income, and household type. A marketing poll of 1,345 homeowners in five regions of the US (Cohn, 2015) indicated that Latinos were the most likely group to be interested in energy efficiency and to have made energy efficiency improvements in their houses within the last year. Also, Latinos and Asians were more likely to have participated in a utility-sponsored rebate program than Blacks or Whites (25-26% vs. 17-19%).

In other cases, the patterns varied between non-White groups. An analysis of 5 years of program participation data from Energy Trust of Oregon found that census tracts with a high proportion of Asians were the most likely to participate, while tracts with a high proportion of Native Americans were the least likely (Rubado et al., 2018). Tracts with higher racial and ethnic diversity tended to have more variation in participation rates than affluent White ones, perhaps because of differences in behavior among different racial and ethnic groups. Overall, though, those high diversity tracts had higher participation rates in programs with a cost to the participant. However, another study for Energy Trust of Oregon, this time based on survey results, found that there was no statistically significant difference in reported program participation based on race (Research Into Action, 2019).

Frank and Nowak (2016) found that Whites were overrepresented in California's whole-home retrofit and online/mail energy audit programs compared to their share of both the overall population and single-family homeowners. However, the proportion of participants in various racial and ethnic groups for the appliance and refrigerator recycling programs were consistent with the California population.

Overall, race and ethnicity were inconsistently associated with program participation. Non-White groups, particularly Latinos and Asians, often participated more than non-Latino Whites, although there were some cases where the relationship was reversed. In other cases, race and ethnicity had no impact on participation. Native Americans were only considered separately in one instance, but in that study they were the racial and ethnic group least likely to have participated (Rubado et al., 2018).

### 2.1.4 Limited English

Although it is often related to race and ethnicity, limited English presents another set of barriers. For example, program materials may be available only in a few languages (Cadmus, 2013).

Two studies that investigated the effect of language found that households with limited English were underrepresented in participant populations (Frank and Nowak, 2016; Navigant et al., 2020). However, partnering with community organizations and offering information in languages other than English can successfully engage these households. When Southern California Edison offered seminars in Chinese, Korean, and Spanish, three quarters of attendees who were surveyed afterwards reported installing some kind of energy efficiency equipment, and another three quarters reported changing their behavior (Cadmus, 2013).

### 2.1.5 Energy Poverty

Customers who spend a large portion of their income on or have trouble paying their utility bills have a greater incentive to reduce their energy consumption, which might increase participation. However, they are less likely to have funds to spend on efficiency upgrades, so we expect to see their participation concentrated in income-qualified programs.

Massachusetts residents who agreed or completely agreed with the statement that they worry about having enough money to pay their energy bills were more likely to have participated in a Mass Save program (Navigant et al., 2020). This was the only study we found that directly tested the impact of energy poverty on program participation.

### 2.1.6 Householder Age

None of the studies that looked at the influence of the age of the head of household found that older householders were more likely to participate; either younger householders were more likely to participate or age did not have an effect. Single variable analysis by Burke and Cooper (2013), based on a national survey of 32,000 households on behaviors and attitudes related to energy use, showed that younger heads of household were more likely to report participating in utility-sponsored efficiency programs. Similarly, a survey in Rochester Electric & Gas territory found that younger customers were more likely to have bought an efficient product from the online marketplace (DNV-GL, 2017). However, householder age, size of household, and marital status were not in the top five of fourteen variables with the most influence on participation in National Grid Rhode Island's whole-building retrofit programs, whether market rate or income qualified (Navigant, 2017). An analysis of phone surveys found no statistically significant difference in people who did and did not participate in Energy Trust of Oregon's programs based on age, household size, or the presence of a child in the house (Research Into Action, 2019).

### 2.1.7 Homeownership

Evidence both from customer surveys and data directly from the program administrator paired with the census indicates that homeowners are more likely to participate in efficiency programs than renters. Homeowners are more likely than renters to buy efficient products from Rochester Gas & Electric's online marketplace (DNV-GL, 2017). The increase in participation in Energy Trust of Oregon's programs for homeowners is statistically significant (Research Into Action, 2019). Participants in efficiency programs in Massachusetts are more likely to be homeowners than renters, although adding educational attainment to the analysis shows that there is no difference for renters with a college degree (Navigant et al., 2020). In a national survey of 32,000 households, respondents who were homeowners reported higher participation rates than respondents who were renters (Burke and Cooper, 2013). DNV-GL (2019) looked at the relationship between savings and the share of owner-occupied households in a census block group and found an overall increasing trend in savings as homeownership share increased.

Homeownership was not one of the top variables explaining participation in National Grid Rhode Island whole-house retrofit programs, but for both the market-rate and income-qualified programs homeowners were more likely to participate (Navigant, 2017).

While the strength of the relationship varied across the reviewed studies, they all found that homeowners were more likely to participate.

### 2.1.8 Tenure

Two analyses of the impact of the length of time someone has lived in their current unit found that long-time residents were less likely to participate. A multivariable analysis of participation rates in National Grid Rhode Island's whole-house retrofit programs showed that tenure was one of the top five most influential variables of the 14 variables they considered (Navigant, 2017). In the market-rate program, homeowners who had lived 3-15 years in their home were most likely to have participated. In the income-qualified program, participation by electric-account holders declined after 8 years of residence. A single variable analysis comparing the characteristics of participants and non-participants found that survey respondents who had moved in within the last 5 years were most likely to report that they had participated in one of Massachusetts's programs (Navigant et al., 2020).

### 2.1.9 Trust

Interviews and discussions in multiple studies raised the idea that trust in the utility or program administrator can impact participation. This can range from mistrust of government agencies and other entities that are part of the "system", to caution around opportunities that seem too good to be true and might be scams, to wariness of organizations who are seen as having broken promises (Navigant et al., 2020; Active Efficiency Collaborative, 2020; Cadmus, 2013). But trust can be built up through successive positive interactions. Once someone has participated in one efficiency program, they are more likely to participate in another one (Burke and Cooper, 2013; Wemple et al., 2016; Illume Advising et al., 2020).

## 2.2 Physical Characteristics of the Dwelling

### 2.2.1 Building Type

Overall, studies found that participation rates were higher in single-family homes. Although homes with up to 4 units were eligible for the single-family programs in Rhode Island, Navigant (2017) found that participants in the electric and gas market-rate programs were more likely to live in single-family homes than nonparticipants were. In fact, the number of units in the building was one of the top two variables linked to participation. Similarly, participants in efficiency programs in Oregon were statistically significantly more likely to live in single-family homes than non-participants were (RIA, 2019). A study in Massachusetts found that households living in small multifamily buildings (3-9 units) were underrepresented as program participants compared to single-family homes or large multifamily buildings (10+ units) (Navigant et al., 2020). Some of these findings may be related to the different ownership rates of the building types, as single-family homes are more often owned than other building types.

### 2.2.2 Vintage

Previous studies do not point to a clear relationship between building vintage and program participation. Age of the building was in the top five most influential variables for predicting participation in National Grid Rhode Island's whole-building retrofit programs (Navigant, 2017). For both the market-rate and income-qualified programs, participants were more likely to live in buildings built between 1930 and 2000 than nonparticipants. This finding was particularly pronounced for the gas accounts in the income-qualified program. On the other hand, in Massachusetts Navigant et al. (2020) did not find any substantial differences in participation based on vintage. In their overview of program assessments in California, Frank and Nowak (2016) found that there was a higher proportion of houses built before 1970 among participants in the whole home retrofit program than in the building stock overall. On the other hand, houses built after 2000 were overrepresented among people who participated in an online energy audit. These findings may suggest that vintage effects depend on program type.

### 2.2.3 Urbanization

Studies in both Oregon and Rhode Island found that participation rates were lower in rural areas than urban ones. In Oregon, the urban/rural divide was particularly strong for programs that required a capital investment (Rubado et al., 2018) but the result may have been confounded by differences in program offerings across service territories. In Rhode Island, the result held up in the multivariable analysis and was conducted in a single utility's service territory (Navigant, 2017).

## 2.3 Program Characteristics

Different efficiency programs require differing participation commitments. For example, rebate programs for heating, ventilation, and air conditioning (HVAC) equipment can leave a high up-front cost to the consumer and require hiring a contractor for installation. This may make these programs more easily available to higher income households. On the other hand, direct installation of efficient lights is accessible across income levels.

In their survey of 33 program evaluations in California, Frank and Nowak (2020) saw differences in participant characteristics based on the cost or time buy-in required for the program. Programs with higher buy-in tended to have participants who had higher incomes, had a college degree, had good English skills, and were White. While Rubado et al. (2018) found that households with higher incomes participated more in Oregon efficiency programs, the trend was more pronounced for programs that required a financial investment from the participant than those that did not.

# 3. Research Approach, Data and Methods

This section describes several datasets we leverage in our own analysis of the determinants of participation and methods we employ.

## 3.1 Data Sources

For our analysis in this report, we leverage efficiency program participation data from four sources:

- The 2015 Residential Energy Consumption Survey (RECS)
- Mass Save programs from 2013–2018
- National Grid Rhode Island programs from 2015–2017
- Programs offered by a Midwestern utility, here called Utility A, from 2017–2019

Table 2 provides a summary of these data sources. The remainder of this section describes each dataset in more detail.

The RECS data include demographic and household information, but our other datasets do not. In those cases we use demographic and household information from the American Community Survey (ACS) and Low-Income Energy Affordability Data (LEAD), as described in Section 3.1.4.

**Table 2. Summary of participation data sources**

| Dataset | Geographic extent and specificity | Years covered | Demographics source | Participation variable | Program breakdown | Sample size |
|---|---|---|---|---|---|---|
| RECS | National – 10 census divisions | Data collected 2015–2016 | Household survey | Whether household received assistance, yes/no | 4 types of assistance | 3,928 owner-occupied units |
| Mass Save | Part of Massachusetts – zip code | 2013–2018 | ACS, LEAD | Participant incentives ($) by zip code | None | 472 zip codes over 6 years |
| Rhode Island | Rhode Island – zip code | 2015–2017 | ACS, LEAD | Eligible and overall participation rates by zip code[2] | 2 programs | 76 zip codes |
| Utility A | Portion of a Midwestern state – census block group (CBG) | 2017–2019 | ACS, LEAD | Count of participating addresses by CBG | 4 programs | 1,750 CBGs |

### 3.1.1 Residential Energy Consumption Survey (RECS)

The RECS is a periodic effort by the Department of Energy to understand residential energy consumption by surveying a nationally representative sample of households.[3] Questions cover characteristics of the physical space as well as demographic and behavioral information about the occupants. We use the public microdata from the 2015 RECS in this analysis, which is presented at the census division level (Figure 1).[4] For the full text of all the questions used in the analysis, see Appendix A.1.

The 3,928 participating homeowners were asked about four types of energy efficiency assistance that we are able to study[5]:

Has your household received any of the following energy-related benefits or assistance for this home?

- Free or subsidized energy-efficient light bulbs
- Free or subsidized home energy audit
- Utility or energy supplier rebate for new appliance or equipment
- Recycling of an old appliance or equipment (e.g., a refrigerator)

[2] See Section 3.1.2.2 for the distinction between eligible and overall participation rates.
[3] https://www.eia.gov/consumption/residential/
[4] There are nine census divisions, but the RECS splits the Mountain division in two and reports the data in ten geographic bins.
[5] They were also asked about other types of energy-related assistance, but the number of households that reported receiving them was very small, so they were not included in the public microdata.

The biggest strengths of the RECS data for our analysis are that they are nationally representative and reported at the household level. This means that we know the demographic and housing characteristics of the respondents themselves; none of our other datasets define characteristics at the household level.

At the same time, there are several limitations to the RECS data. First, the question about energy assistance does not explicitly address utility customer-funded programs, so it is possible that the reported assistance did not come from such programs. That said, utility customer-funded programs are the dominant delivery mechanism for these types of assistance in the United States, so we suspect most reported assistance did come from such programs. Second, the data are reported at a high level of geographic aggregation. We do not have any specifics about the energy assistance available to the responding households; some of the households in the dataset may not have been able to access some types of assistance, for example due to lack of program availability or eligibility restrictions. Finally, the RECS survey only asked homeowners about receiving energy efficiency assistance, so we do not have insight into the behavior of renters.

### 3.1.2 Data at the Zip Code Level

We use three data sets from specific utilities or groups of utilities. Because none of these datasets provide demographic or physical characteristics at the household level, we use place-based Census data for our household and demographic characteristics. See Section 3.1.4 for more information on our use of Census data.

#### *3.1.2.1 Mass Save*

Mass Save is a consortium of six investor-owned utilities in Massachusetts that coordinates energy efficiency programs and reporting. They publish electricity and gas consumption, savings, and participant incentive data at the town and zip code level starting in 2013.[6] These data are from its member utilities and cover most of the efficiency programs in the state and 465 of Massachusetts' zip codes. We use data from 2013-2018. Programs run by municipal utilities are not included.

Based on regulatory reporting, income-qualified programs account for about a quarter of utility residential electric and gas program spending in Massachusetts. The other program types that account for large portions of the budget are whole-building audits and retrofits for both electricity and gas, lighting programs for electricity, and water and space heating programs for gas.[7]

These data come with three limitations related to their level of aggregation. First, they are not broken down by program; all residential reporting, including for income-qualified programs, is combined.[8] Second, the data are not broken down by utility service territory even though the programs are run by individual utilities and vary slightly among them. Third, the data are reported at the zip code level, so we

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[6] https://www.masssavedata.com/Public/GeographicSavings?view=U
[7] E Source DSM Insights, Program Benchmarking, https://dsmi.esource.com/program-benchmarking/
[8] In Massachusetts, the Low-Income Energy Affordability Network (LEAN) offers no-cost programs to low-income households. The funding comes from multiple sources, including the utilities, state government, and the federal Weatherization Assistance Program (WAP). The Mass Save data only include the utility-funded savings and incentives.

do not know the characteristics of the households that received the participant incentives. We use place-based Census data for our household and demographic characteristics.

Another limitation of these data is that participation is not reported directly. Instead we use participant incentives[9] as a proxy.

As we investigated the Mass Save data, we realized that the variation in natural gas service availability across the participating utilities' territories was a significant driver of our results and confounded the relationships we were attempting to study. For that reason, we only present results for the Mass Save electricity programs.

#### 3.1.2.2 National Grid Rhode Island

National Grid Rhode Island offers market-rate and income-qualified programs that both include free energy audits and direct installation of simple measures such as lighting, low flow showerheads, and smart power strips. The market-rate program provides targeted recommendations for further efficiency measures along with information about rebates and loan opportunities. The income-qualified program will weatherize the house and replace inefficient appliances and heating systems at no cost to the customer (Navigant, 2017).

Navigant studied the factors that are associated with participation in these programs for 2015 through 2017 in their report "Energy Efficiency Program Customer Participation Study" (Navigant, 2017). They used account- and household-level participation data, building characteristics, and demographic information. Due to data availability, the analysis covered the single-family programs (which apply to buildings with up to four units). Many of the insights from that analysis are included in Section 2 above.

While Navigant analyzed many of the factors that we are interested in, they did not look at education or race. However, Appendix A of their report contains cumulative participant counts and participation rates for each of Rhode Island's 76 zip codes broken out by program and fuel. We use those participation data in conjunction with data from the Census to analyze the associations with race and education.

We look at two different participation rates. The first rate is the "eligible participation rate" or the share of eligible customers that participated in the program. In this case, each customer in a building with up to four units is classified as being eligible for either the income-qualified or the market-rate program. Navigant did this classification and included the eligible participation rates in their report.[10] The second rate is the "overall participation rate" or the share of total households that participated. In this case, the total number of households is taken from the Census and does not vary based on whether or not they are eligible for the particular program whose participation rate is being calculated. This is the method

[9] Participant incentives are defined as a "budget category that includes funds paid by the reporting Program Administrator to or on behalf of customers or trade allies as rebates or in other forms." https://www.masssavedata.com/Public/Glossary

[10] Customers were classified as eligible for the income-qualified program if they were on one of the low-income rates or had participated in the income-qualified program (more recently than the market-rate program). Other factors were not considered when determining eligibility.

we use for our other datasets because we do not have information about the number of eligible customers. As discussed in Section 4.3, these two participation rates show differences in the way they relate to some studied factors – such as income – that are important to account for when interpreting results in other datasets.

The main strength of this dataset is that we can compare results based on the eligible and overall participation rates. The main limitation is that there are only 76 zip codes in Rhode Island, so the sample size is relatively small. In addition, we do not have household-level demographic data and use place-based data instead.

#### 3.1.3 Data at the Census Block Group Level: Utility A

Utility A serves gas and electricity customers in the Midwest. Utility A's electricity and gas service territories are not identical. The data consist of counts of unique participating customers by program for 2017–2019 at the census block group (CBG) level. We analyze following residential efficiency programs:

- An appliance recycling program that picks up working refrigerators and freezers and gives participants a rebate.
- A HVAC rebate program that offers mail-in rebates for high efficiency heating and cooling equipment including furnaces, air conditioners, boilers, and smart thermostats.
- Two programs, one market rate and one income qualified, offering a free energy audit with recommended savings measures. Based on the fuels served by the utility, the customer may have any or all of the following installed during the audit: LEDs, water efficiency measures, and water heater pipe insulation. Duct sealing may also be improved, and low-income customers may receive a programmable thermostat.

In addition to program-level analysis, we look at aggregated program participation in any program or any market-rate program. The Any Program and Any Market-Rate Program categories include participation in three other residential programs without enough participants to analyze on their own.

A significant strength of this dataset is that participation is broken down by program. The data are also relatively disaggregated, being at the level of a census block group instead of a zip code. The main limitation is that there is no household-level demographic data, so we must use place-based data instead.

#### 3.1.4 American Community Survey (ACS) and Low-Income Energy Affordability Data (LEAD)

Except for the RECS, we do not have household-level building characteristics or demographic information. In order to conduct analysis of these factors, we use data from the American Community Survey (ACS), which is conducted each year by the Census Bureau. We collect ACS data on both building characteristics (type, vintage, urban or rural location) and household characteristics (annual income, educational attainment, race and ethnicity, limited English, age of the head of household, tenure in the living space, and homeownership). See Appendix A.2 for a summary of the specific variables used.

We use data from the ACS at two geographic levels: census tracts and census block groups (CBGs). A census tract is a portion of a county with between 1,200 and 8,000 people, with a target size of 4,000 people. A block group is a portion of a tract with 600 to 3,000 people.[11] Utility A provided data at the block group level, so we use the ACS data without aggregation. However, the Mass Save and Rhode Island participation data are at the zip code level, so we aggregate ACS tract-level data to the zip code level. See Appendix A.2 for information about how we do the aggregation.

We also draw data from the Department of Energy's Low-Income Energy Affordability Data (LEAD) Tool.[12] This tool calculates mean energy burden, or the share of income that is spent on energy, at the tract level based on ACS data. All Utility A block groups in a given tract therefore receive the same LEAD mean energy burden in our data; we aggregate and calculate zip code means for MA and RI zip codes. The RECS contains household-level data related to energy burden, which we use (rather than LEAD data) when analyzing that dataset.

## 3.2 Methodology

We use descriptive statistics and regression models to illustrate and interrogate the dependence of the participation metrics on eleven demographic and physical factors:

- Income – household income
- Education – highest level of education achieved
- Race and ethnicity – self-identified race and ethnicity into the Census categories[13]
- Limited English[14]
- Tenure – number of years in the current dwelling
- Age – age of head of household
- Homeownership – occupied by the owner or renters
- Vintage – year the dwelling was built
- Building type – number of dwelling units in the building
- Urbanization – being in an urban or rural area
- Energy poverty[15]

We estimate relationships between these factors and our participation metrics using both single-variable and multivariable regression models. Conceptually, these models tell us somewhat different things. The single variable models we view as descriptive: they tell us whether there is a relationship

[11] https://www.census.gov/programs-surveys/geography/about/glossary.html
[12] https://www.energy.gov/eere/slsc/maps/lead-tool
[13] Unless otherwise noted, we combine the race and ethnicity variables into four categories: White alone, not Hispanic or Latino ("non-Latino White"); White alone, Hispanic or Latino ("Latino White"); Black alone ("Black"); Other ("Other").
[14] The Census defines a limited-English-speaking household as one in which no one over the age of 14 speaks only English or speaks English "very well." https://www.census.gov/topics/population/language-use/about/faqs.html
[15] The metric of energy poverty depends on the dataset. For the RECS, we use questions such as "In the last year, how many months did your household reduce or forego expenses for basic household necessities, such as medicine or food, in order to pay an energy bill?" See Appendix A.1 for more information. For Mass Save and Utility A, we use energy burden, or the percent of income spent on energy.

between each factor and program participation that is robust enough to likely not be due to chance. The multivariable models are somewhat more diagnostic: they explore whether the descriptive results may be explained in part by other factors. Some of the factors are correlated (e.g., income and education), so including them both in multivariable models helps distinguish which one is more influential. The single-variable results may in some ways be more important to an equity analysis: if certain households are participating more than others, these outcomes may be inequitable regardless of whether they are driven in part by some other factor. Still, we feel both analyses are important, and our multivariable models (which are not common in the literature) suggest targets for programmatic intervention.

Because we have household-level data for the RECS, making our participation outcome binary (yes or no), we use a logistic model. For our other datasets, where our participation outcomes are rates (such as the share of households in a census block group that participated), we use linear probability models. See Appendix A.3 for more details.

# 4. Results

This section provides a visual and narrative description of our analysis results, stepping through each dataset one at a time. See Appendix B for correlation matrices of the explanatory variables and Appendix C for the full regression tables. Section 5 is organized by household characteristic and relates our results to the existing literature reviewed in Section 2.

## 4.1 RECS

Table 3 summarizes the rates at which all RECS homeowners reported that they received the four types of energy-related assistance we study. 23% of the 56,670 homeowners who responded to the survey reported receiving at least one of the studied types of assistance.

**Table 3. RECS energy-related assistance rates.** "Any of the above" is not the sum of the "Participants" column because some households received multiple kinds of assistance. The values in the "Total responses" columns vary by type of assistance because not all homeowners answered every question.

| | Participants | Non-participants | Total responses | Participation rate |
|---|---|---|---|---|
| Free or subsidized energy-efficient light bulbs | 4,635 | 51,975 | 56,610 | 8% |
| Free recycling of old appliance or equipment | 5,235 | 51,255 | 56,490 | 9% |
| Utility or energy supplier rebate for new appliance or equipment | 3,600 | 52,950 | 56,550 | 6% |
| Free or subsidized home energy audit | 1,800 | 54,420 | 56,220 | 3% |
| *Any of the above* | *13,125* | *43,545* | *56,670* | *23%* |

In our regression analysis, household location had a significant association with receipt of energy assistance for all four types we study, individually as well as overall. Households in the South census region (all divisions) and the West North Central census region received statistically significantly lower levels of overall energy efficiency assistance than those in the Northeast census region, which had the highest rate (Figure 1, Figure 2). The differences were substantial: when controlling for other relevant factors, households in these areas were 10-20 percentage points less likely to have received at least one kind of assistance. Other regions and divisions are not statistically significantly different from the Northeast overall. These relative participation rates were broadly similar to the levels of utility customer-funded spending on energy efficiency in the regions during the period of RECS data collection (Gilleo et al., 2015).

These findings were similar for the individual types of assistance, although the differences were typically larger. For example, households in the West South Central division were 12 percentage points less likely on average to have received free or subsidized efficient light bulbs than those in New England. The notable exception is appliance recycling, which appears to be relatively rare in New England. Households in the Middle Atlantic division, the Midwest region, and the Mountain South and Pacific divisions all show statistically significantly *higher* rates of receipt of appliance recycling assistance than households in New England.

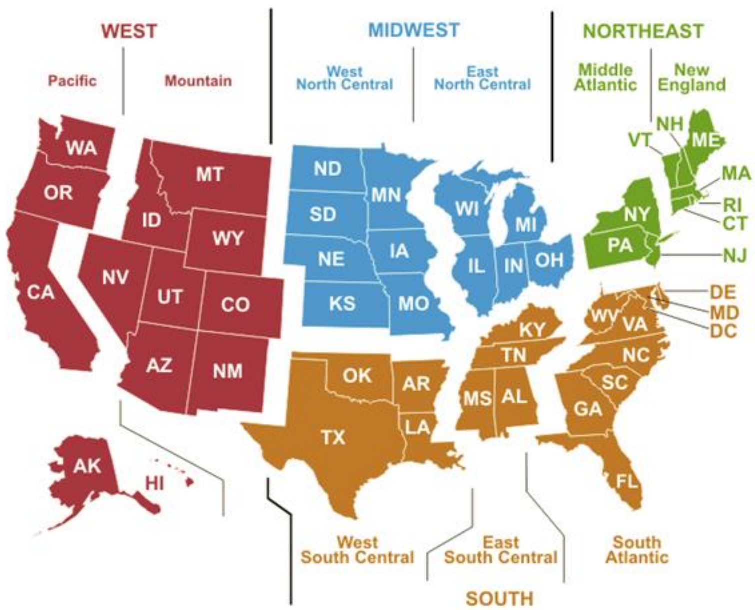


**Figure 1: Census regions and divisions.** The RECS further breaks down the Mountain census division into Mountain South (Arizona, New Mexico, and Nevada) and Mountain North (Colorado, Idaho, Montana, Utah, and Wyoming). Source: https://www.eia.gov/consumption/commercial/maps.php#census.

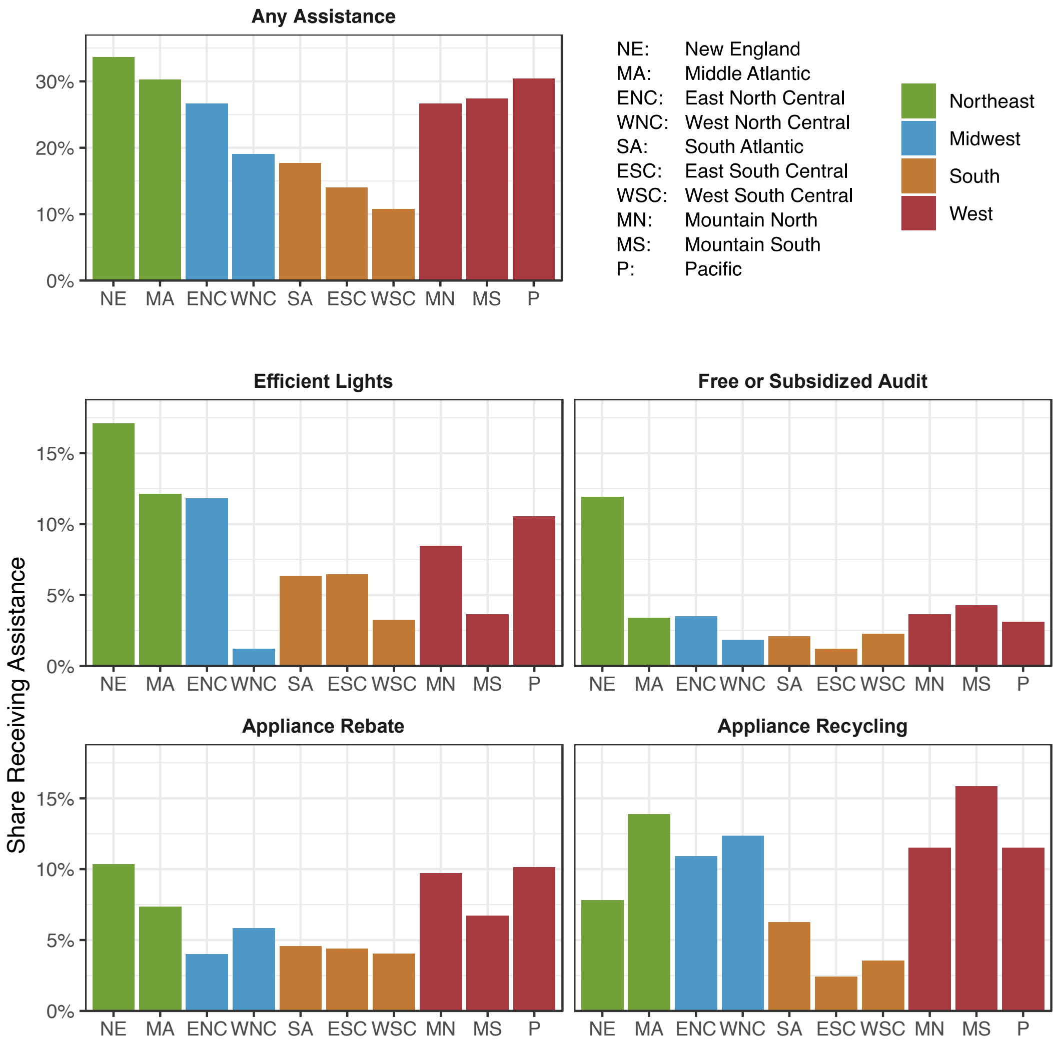


**Figure 2: RECS share receiving assistance by Census division**

Table 4 shows a high-level summary of the relationships between the demographic and household characteristics we study with the receipt of energy efficiency assistance.

**Table 4. RECS summary of results**

| | Household income | | Householder education | | Black householder | | White, Latino householder | | Other race / ethnicity householder | | Energy poverty | | Bill or repair assistance | | Householder age | | Tenure | | Number of units | | Vintage | | Urbanization | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Any assistance | — | — | ▲ | ▲ | — | — | ▼ | — | ▼ — | ▼ — | — | — | ▲ | ▲ | ▲ | — | ▼ | — | ▼ | ▼ | ▼ | ▼ | — | — |
| Lights | ▼ | ▼ | — | — | ▲ | — | — | — | — | ▼ — | ▲ — | — | ▲ | ▲ | — | — | — | — | ▼ | — | ▼ | ▼ | — | — |
| Audit | ▼ | — | ▲ | ▲ | — | — | — | — | — | ▼ — | — | ▼ | ▲ | ▲ | — | — | — | — | ▼ | ▼ | — | — | — | — |
| Appliance rebate | ▲ | — | — | — | — | — | ▼ | ▼ | — | — | — | — | ▲ | ▲ | — | — | — | — | — | ▼ | — | — | ▼ — | — |
| Appliance recycling | ▲ | — | — | — | ▼ | — | ▼ | — | — | — | ▼ — | — | ▲ | ▲ | ▲ | — | ▼ | ▼ | ▼ | — | ▼ | ▼ | — | ▲ ▼ |

**Key:**

▲ receipt of assistance was higher for households with the characteristic or a higher value of the factor

▼ receipt of assistance was lower for households with the characteristic or a lower value of the factor

— participation did not change based on the characteristic

Multiple symbols indicate that the relationship varied depending on the subgroup.

■ gray columns contain single-variable results

□ unshaded (white) columns contain multivariable results

In addition to Census division, another factor that was significantly associated with receipt of all four types of *energy efficiency* assistance we study was receipt of assistance with *bill payments or appliance repairs* (Figure 3). Our multivariable regression analysis indicates that households that received assistance paying for energy bills or repairing appliances were 20 percentage points more likely on average to receive at least one type of energy efficiency assistance than otherwise equivalent households that did not. This finding presumably reflects efforts by program administrators to target programs to these households.

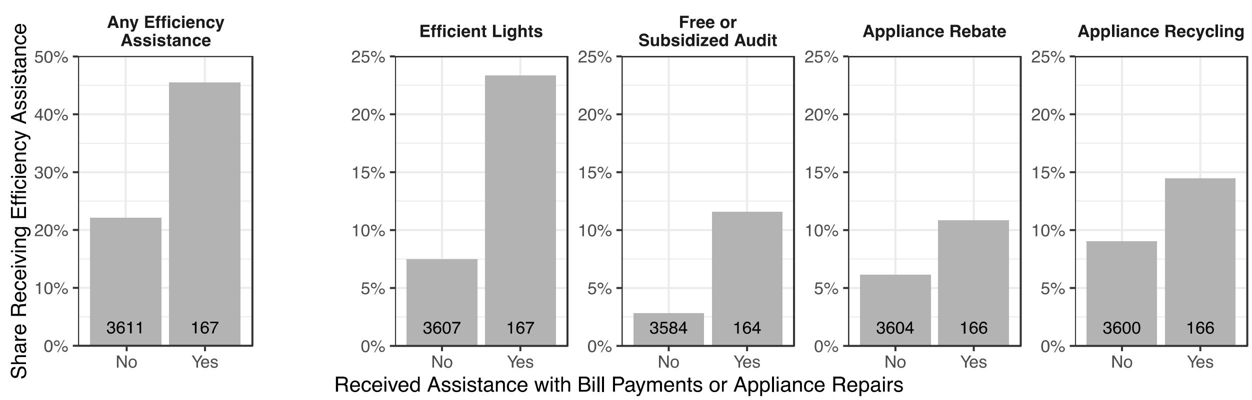


**Figure 3: RECS share of households receiving efficiency assistance by receipt of assistance with bill payments or appliance repairs.** Numbers indicate count of respondents.

Household income did not show any statistically significant relationship with overall receipt of energy efficiency assistance, either on its own or when controlling for other variables (Figure 4). When we look at the different forms of assistance separately, however, we see that some efficient lighting assistance and audit assistance was likely targeted at lower-income households. Compared to households with a self-reported annual income less than $20k, households making at least $80k were about 5 percentage points less likely on average to receive assistance with efficient lighting when controlling for other factors. For appliance rebate and recycling assistance, higher-income households were more likely to receive assistance. These differences are statistically significant in single-variable models, but not in multivariable models, indicating that factors correlated with income – such as education, homeownership, etc. – may help explain the results. We discuss this issue further in Section 5 below.

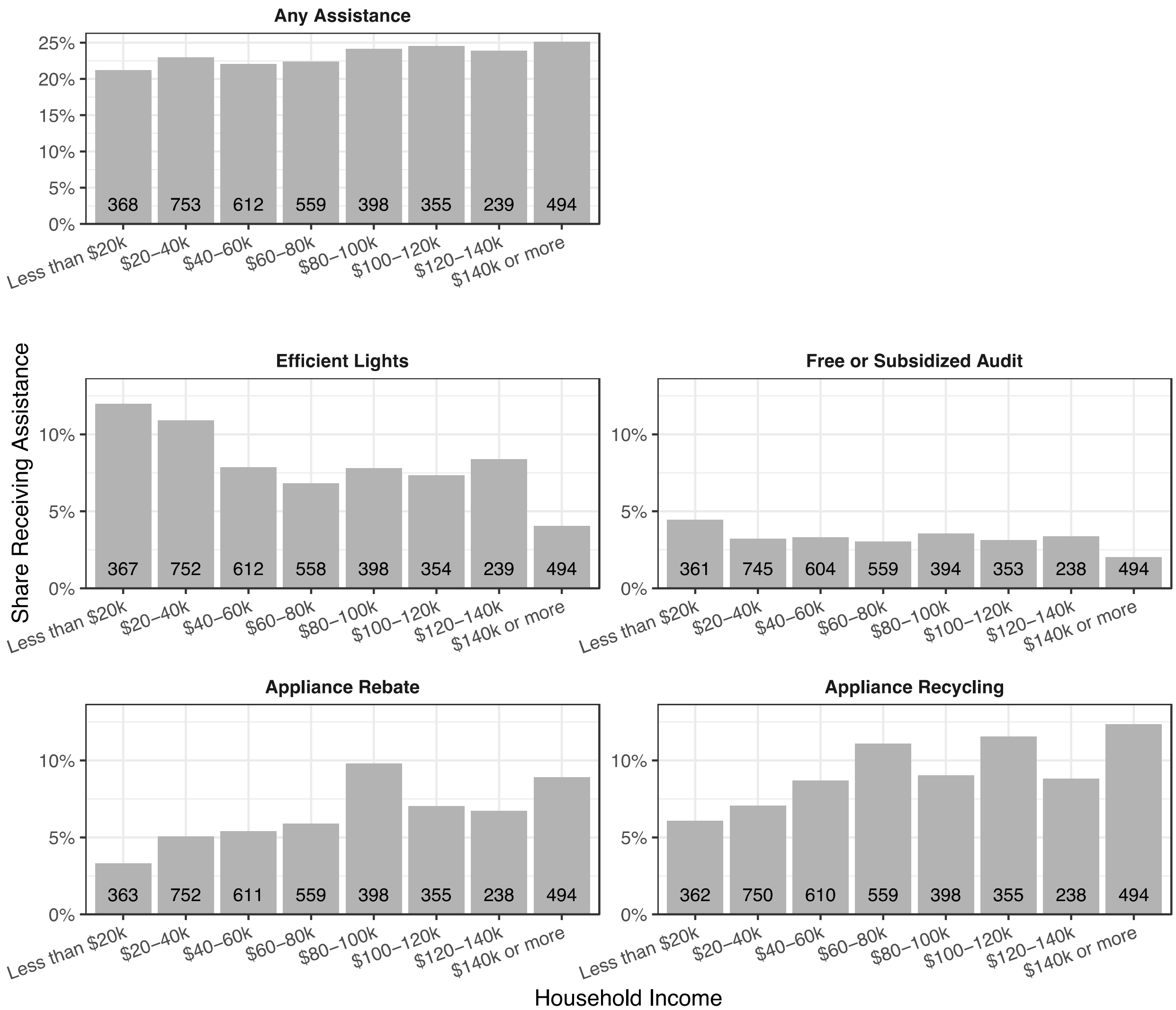


**Figure 4: RECS share of households receiving assistance by annual household income.** Numbers indicate count of respondents in the income bin.

Households whose heads of household had more years of education were more likely to receive energy efficiency assistance, both overall and for each individual program type other than efficient lighting. When controlling for other factors, heads of household with at least a Bachelor's degree were 8 percentage points more likely to receive some type of assistance than those without a high school degree. Households with Internet access also received energy efficiency assistance at higher rates than those without, all else equal. Both of these variables may relate to a household's means to find and evaluate information about the availability and benefits of energy efficiency assistance.

The relationship between energy assistance and race and ethnicity depended on the particular racial and ethnic group as well as the presence of control variables. When controlling for the other factors, Black heads of household and those who selected two or more races did not show statistically significantly different rates of energy efficiency assistance receipt than non-Latino White heads of household. However, most other racial and ethnic groups were less likely to receive some type of energy assistance than non-Latino White heads of household. American Indian or Alaska Native and Asian heads of household were less likely to receive assistance overall. American Indian or Alaska Native heads of household were less likely to receive efficient lights or audit assistance; Native Hawaiian or Other Pacific Islander heads of household were less likely to receive audit assistance; and Latino White heads of household were less likely to receive appliance rebates.

Beyond income, we investigate three variables related to energy poverty: frequency of keeping the home at an unhealthy temperature, reducing or forgoing basic necessities due to home energy bills, and receiving a disconnect notice. In most cases these variables are not statistically significant, especially in multivariable models.

Households in multifamily buildings of 5 or more units and households in mobile homes received statistically significantly lower levels of overall energy efficiency assistance than those in single-family detached buildings in most cases.[16] The reflexive explanation for this finding is the challenge of reaching renters with programs due to split incentives. However, that explanation does not apply here, since the survey responses we study are homeowner-only; our results indicate that *owners* of units in larger buildings and mobile homes accessed less energy efficiency assistance. The pattern only holds for free and subsidized audits and appliance rebates; there was no statistically significant difference in receipt of assistance for efficient lighting or appliance recycling based on building type.
Households in new buildings (those built after 2010) received less energy efficiency-related assistance than those in old buildings (those built before 1950), both overall and for lighting and appliance recycling programs specifically. It is no surprise that there would be more demand for energy efficiency assistance in old homes, which are more likely to lack efficient lighting and to need to upgrade appliances.

While census division was one of the most influential variables tied to receipt of efficiency assistance, the other locational characteristic we consider, urban vs rural, was generally not associated with receipt of assistance in a statistically significant fashion.

[16] Because only homeowners were asked about their participation in energy efficiency programs, more than 80% of the respondents lived in single-family detached homes. This means that the sample sizes in the other categories are relatively small and therefore that results are less likely to be statistically significant.

## 4.2 Mass Save

Table 5 shows a high-level summary of the relationships between the demographic and household characteristics we study with electric incentive payments.

**Table 5. Mass Save summary of results**

| | Household income | | Householder education | | Black householder | | Latino White householder | | Other race / ethnicity householder | | Limited English | | Energy burden | | Householder age | | Ownership | | Tenure | | Number of units | | Vintage | | Urbanization | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Electric incentives | ▲ | — | ▲ | ▲ | ▼ | — | — | ▼ | ▼ | ▼ — | ▼ | — | ▲ | ▲ | ▲ | — | — | — | ▲ | — | ▼ | ▼ | ▲ | — | ▼ | ▲ |

**Key:**

▲ per household incentives increased as the percentage of households in the zip code with the characteristic increased

▼ per household incentives decreased as the percentage of households in the zip code with the characteristic decreased

— participation did not change based on the variable

Multiple symbols indicate that the relationship varied depending on the subgroup.

▉ gray cells contain single-variable results

▢ unshaded (white) cells contain multivariable results

In a single-variable model, income was significantly correlated with zip code mean income, with higher-income zip codes receiving higher incentives per household (Figure 5). However, when controlling for the other demographic and physical characteristics we study, income had no statistically significant relationship with incentives.

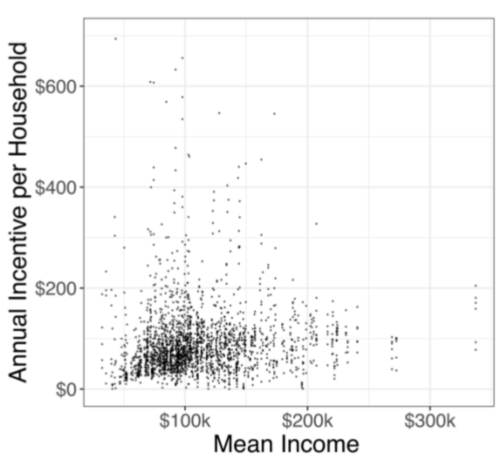


**Figure 5: Mass Save annual incentives per household by zip code mean income**

Education, on the other hand, was significantly correlated with incentives in both single- and multivariable models. In both cases, zip codes with a greater percentage of heads of household with a Bachelor's or graduate degree received higher incentives per household (Figure 6).

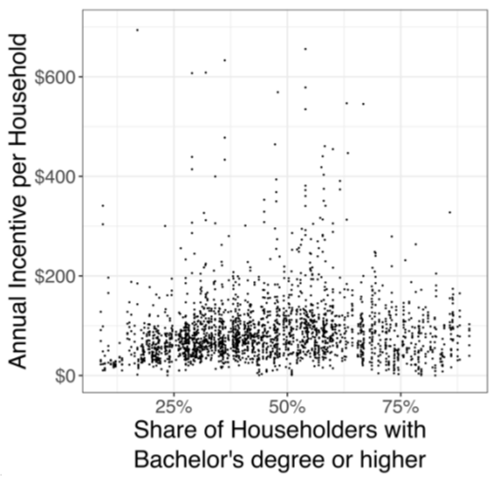


**Figure 6: Mass Save average annual incentives per household by share of householders in the zip code with a Bachelor's degree or higher**

A higher percentage of non-Latino White heads of household in a zip code was associated with higher incentives in both single- and multivariable models. While zip codes with a higher percentage of Black heads of household received lower incentives on average, the relationship was not significant in the multivariable model, indicating that other factors accounted for the difference. However, the percentage of Latino White heads of household in the zip code was only significant in the multivariable model, indicating that zip codes with a higher percentage of Latino White heads of household received lower incentives than average given the other characteristics of the zip codes.
In terms of energy burden, zip codes with a higher burden received higher electric incentives – an increase of 1 percentage point in energy burden was associated with a $20/household/year increase in electric incentives. Because zip codes with lower mean incomes did not receive higher incentives, this result may indicate that participation was particularly strong in zip codes that consumed more energy than otherwise similar zip codes.

We consider several factors related to the house itself: building type, vintage, and urbanization. The only factor with a consistent relationship with household incentives was building type; zip codes with higher percentages of single-family homes received higher incentives on average.

## 4.3 National Grid Rhode Island

Table 6 shows the eligible and overall participation rates for National Grid Rhode Island. Because only a fraction of the total households qualify for any particular program, the overall participation rates are lower than the eligible participation rates, particularly for income-qualified programs.

**Table 6. National Grid Rhode Island eligible and overall participation rates**

| Program | Participants | Eligible accounts | Eligible participation rate | Overall participation rate |
|---|---|---|---|---|
| Market-rate electric | 33,544 | 324,491 | 10.3% | 8.1% |
| Market-rate gas | 7,992 | 186,934 | 4.3% | 1.9% |
| Income-qualified electric | 9,202 | 27,908 | 33.0% | 2.2% |
| Income-qualified gas | 1,446 | 14,462 | 10.0% | 0.4% |

The sample size of 76 zip codes was too small for the multivariable analysis we conduct for the other datasets, so we only present single variable results for Rhode Island (Table 7). Because the analysis is single variable, we cannot disentangle the individual effects of the variables. In Rhode Island, education and race/ethnicity are both highly correlated with income (Table B - 2), and our analysis will not reveal how much a result is driven by one variable versus the other.

**Table 7. National Grid Rhode Island summary of single-variable results**

| | Household income | Householder education | Non-Latino White householder | Limited English | Energy burden | Householder age | Ownership | Tenure | Number of units | Vintage | Urbanization |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Market rate | ▲ | ▲ | ▲ | ▼ | ▼ | — | ▲ | — | ▼ | — | — |
| Income qualified — eligible | ▲ | — | ▲ | ▼ | ▼ | — | ▲ | — | ▼ | — | ▼ |
| Income qualified — overall | ▼ | ▼ | ▼ | — | ▲ | — | ▼ | — | — | — | ▼ |

**Key:**

▲ participation increased as the percentage of households in the zip code with the characteristic increased

▼ participation decreased as the percentage of households in the zip code with the characteristic decreased

— participation did not change based on the variable

Figure 7 shows that the overall participation rate was positively correlated with mean income in the zip code for the market-rate program and negatively correlated for the income-qualified program. This is to be expected because not as many households qualify for the income-qualified program in zip codes with higher mean incomes. On the other hand, the *eligible* participation rate was positively correlated with the mean income for both the market-rate and income-qualified programs: a higher share of eligible households participated in the income-qualified program in zip codes with higher mean incomes. This difference may imply that the behavior of low-income households depended on the characteristics of their higher-income neighbors. Or it may imply that among eligible households, higher-income households were more likely to participate.

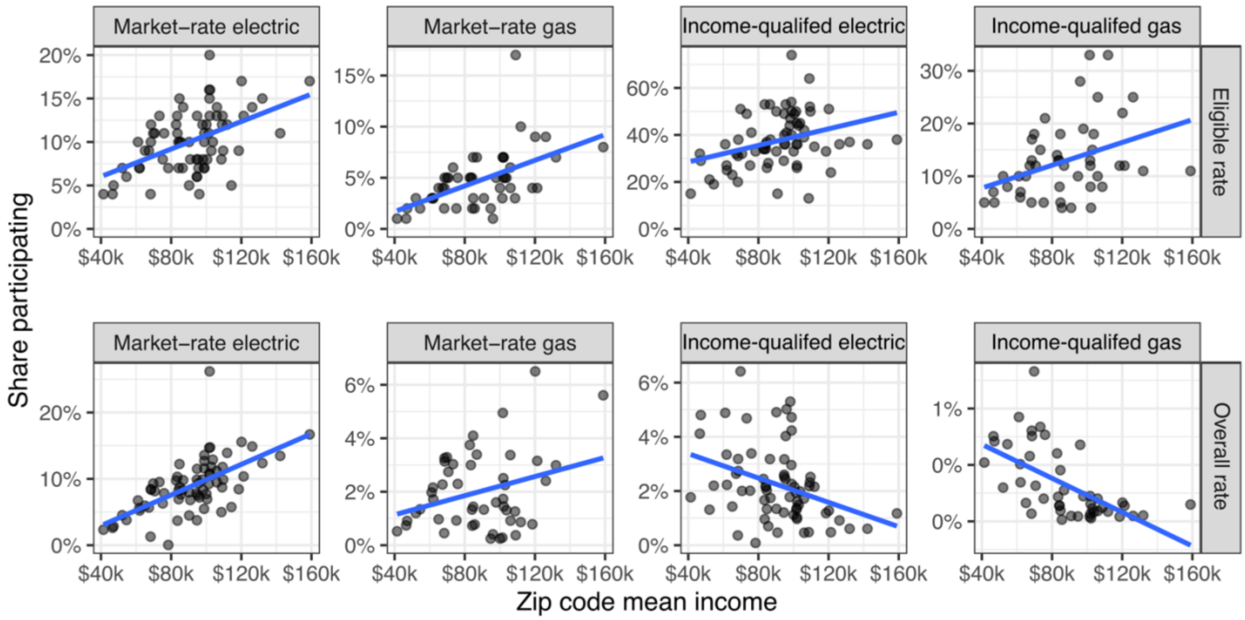


**Figure 7: National Grid Rhode Island program participation by zip code mean household income**

The relationship between eligible and overall participation rates and the share of heads of households in the zip code with a Bachelor's degree or higher was analogous to what we find for mean income (Figure 8). Education and income are strongly related in general (see Appendix B), so it is not surprising that the patterns closely track each other.

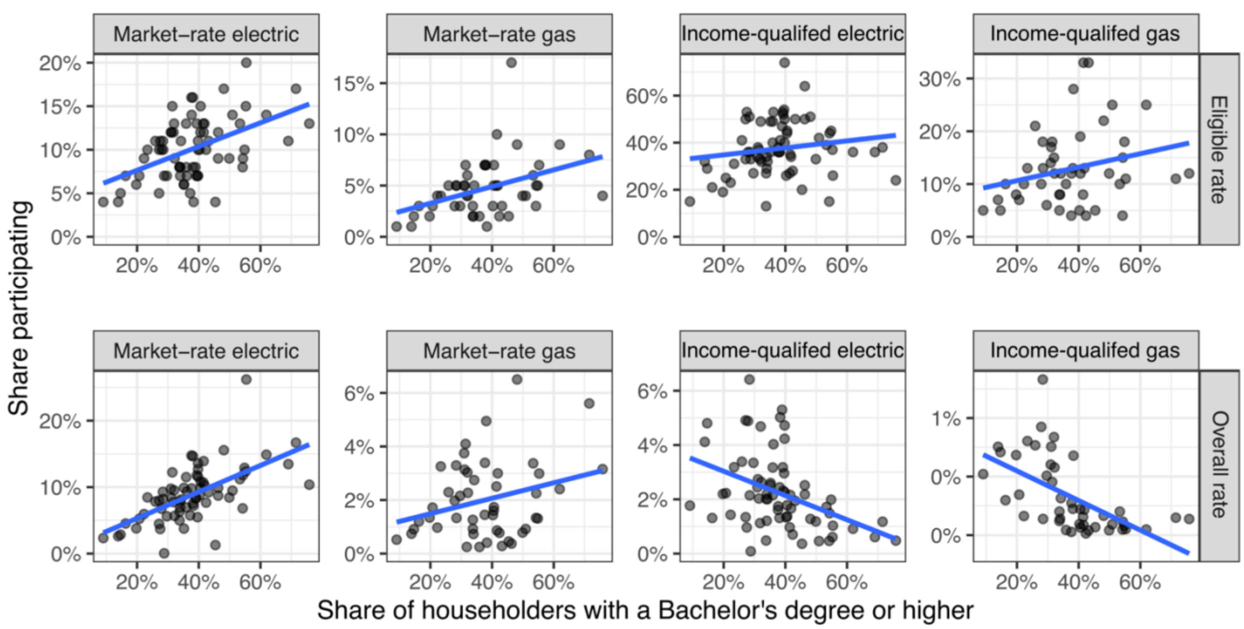


**Figure 8: National Grid Rhode Island program participation by share of householders with a Bachelor's degree or higher**

Figure 9 shows the relationship between program participation and the share of households in the zip code headed by a non-Latino White person. More than half of the zip codes have at least 90% non-Latino White householders, so none of the other racial or ethnic groups had a statistically significant relationship with participation rate on their own. However, taken as a binary variable, market-rate participation and eligible income-qualified participation were higher in zip codes with a greater share of non-Latino White heads of household. The direction of the relationship was reversed for the overall participation rate in the income-qualified program, in similar fashion to the reversals observed for income and education.

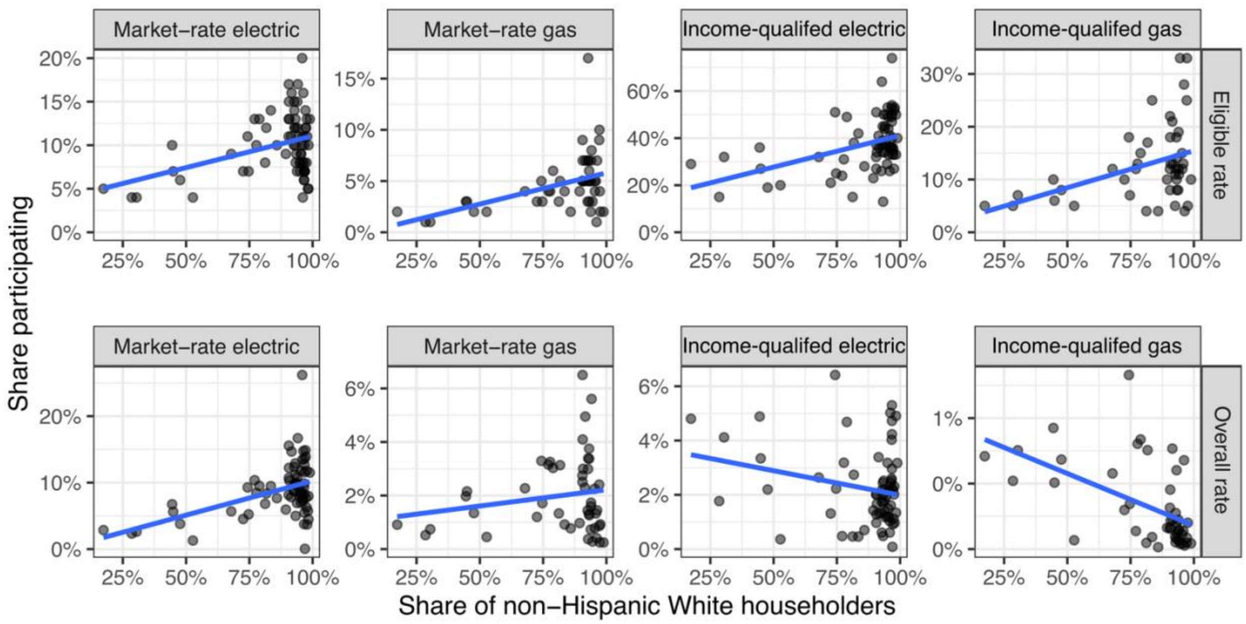


**Figure 9: National Grid Rhode Island program participation by share of non-Latino White householders**

As shown in Table 7 we also observe reversals in the relationships between participation and both energy burden and homeownership. Lower energy burden and higher homeownership rate were associated with lower overall participation rates but higher eligible participation rates.

## 4.4 Utility A

Table 8 shows the number of participants and participation rates for Utility A's four largest residential programs for 2017–2019. The HVAC rebate program was by far the largest, so results for this program are generally very similar to those for Any Market-Rate Program and for Any Program.

**Table 8. Utility A program participation rates**

| Program | Participants | Rate |
|---|---|---|
| HVAC Rebate | 22,251 | 2.51% |
| Appliance Recycling[17] | 5,985 | 0.80% |
| Audit & direct install (DI) | 2,309 | 0.26% |
| Income-qualified (IQ) audit & direct install (DI)[18] | 2,500 | 0.28% |
| *Any Market-Rate Program* | *30,532* | *3.44%* |
| *Any Program* | *32,900* | *3.71%* |

Table 9 shows a high-level summary of the results for Utility A. Relationships between block group demographics and program participation were broadly similar across the programs. Factors correlated with higher participation were a higher proportion of the population over 25 years old with some postsecondary education; a lower mean energy burden; and being in a metropolitan area. CBGs with a higher proportion of householders 55 years or older and living in buildings with less than 5 units also had higher participation rates on average.

**Table 9. Utility A summary of results**

| | Household income | | Householder education | | Black householder | | Latino White householder | | Other race / ethnicity householder | | Limited English | | Energy burden | | Householder age | | Ownership | | Tenure | | Number of units | | Vintage | | Urbanization | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Any program | ▲ | ▲ | ▲ | ▲ | — | ▲ | — | ▲ | ▲ ▼ | — | ▼ | — | ▼ | ▼ | ▲ | ▲ | — | — | ▲ | ▲ | ▼ | ▼ | ▼ | — | ▲ | ▲ |
| Any market-rate program | ▲ | ▲ | ▲ | ▲ | ▼ | ▼ | — | ▲ | ▲ ▼ | — | ▼ | — | ▼ | ▼ | ▲ | ▲ | ▲ | ▲ | ▲ | ▲ | ▼ | ▼ | ▼ | ▲ | ▲ | ▲ |
| IQ audit & DI | ▼ | ▼ | ▲ | ▲ | ▲ | ▲ | ▼ | — | ▲ ▼ | ▲ | — | ▼ | ▲ | — | — | ▲ | — | — | ▲ | — | ▼ | ▼ | ▲ | ▼ | ▲ | ▲ |
| Audit & DI | ▲ | — | ▲ | ▲ | ▲ | ▲ | — | — | ▼ — | — | — | — | ▼ | ▼ | ▲ | ▲ | — | — | ▲ | — | ▼ | ▼ | — | — | ▲ | ▲ |
| HVAC rebate | ▲ | ▲ | ▲ | ▲ | ▼ | ▼ | — | — | ▲ ▼ | — | ▼ | — | ▼ | ▼ | ▲ | ▲ | — | — | ▲ | ▲ | ▼ | ▼ | ▼ | ▲ | ▲ | ▲ |
| Appliance recycling | ▲ | — | ▲ | ▲ | ▼ | ▼ | ▲ | ▲ | ▲ ▼ | ▲ | — | — | ▼ | ▼ | ▲ | — | — | — | ▲ | — | ▼ | — | ▼ | — | ▲ | ▲ |

**Key:**

▲ participation increased as the percentage of households in the CBG with the characteristic increased

▼ participation decreased as the percentage of households in the CBG with the characteristic decreased

— participation did not change based on the variable

Multiple symbols indicate that the relationship varied depending on the subgroup.

■ gray cells contain single-variable results

□ unshaded (white) cells contain multivariable results

However, there were some factors whose associations varied across programs, most prominently race and income. CBGs with lower median household incomes had statistically significantly higher participation rates in the income-qualified (IQ) program. However, lower income was associated with a statistically significant *decrease* in Any Market-Rate Program and Any Program participation. Median

[17] Appliance Recycling was an all-electric program, so we use only households in Utility A's electric territory to calculate participation rate.
[18] Because we do not have eligible participant counts, we use overall participation rates. We calculate the IQ audit & DI participation rate based on the number of households in the CBG even though not all of the households are eligible.

income was significantly associated with participation in the market-rate audit & direct install or appliance recycling programs only in single-variable models. Most of these results are not surprising given the single variable relationships seen in Figure 10.[19]

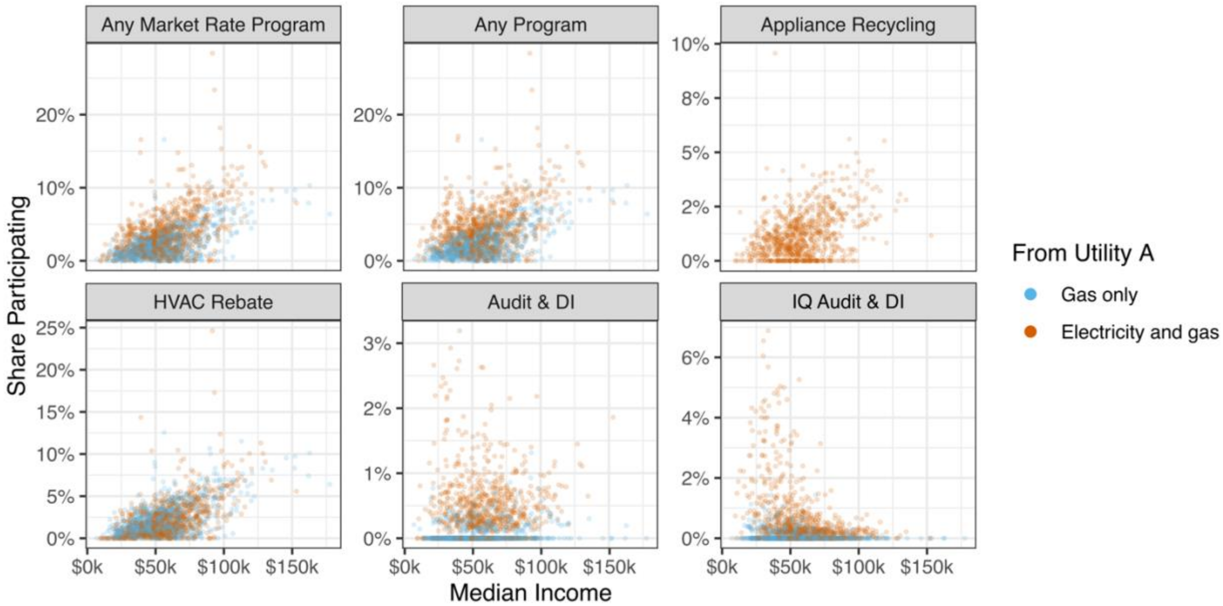


**Figure 10: Utility A program participation by CBG median income**

Figure 11 shows the relationship between program participation and the share of the households in the CBG with a non-Latino White head. Although it only considers that single variable, the general patterns that emerge visually are consistent with the statistical analysis that controls for our other demographic and household characteristics.

CBGs with a higher proportion of Black heads of household had higher participation in the audit & direct install programs (both the income-qualified and the market-rate programs). The relationship was reversed for appliance recycling, HVAC rebates, and Any Market-Rate Program. For every increase of one percentage point in the proportion of Black heads of household in the CBG, participation in the IQ direct install program rose by 2.4% and participation in the HVAC rebate program dropped by 1%; the changes were smaller for the other programs. In the Any Program results, the former effect dominated the latter: households with Black heads of household showed higher overall participation than those with non-Latino White heads of household, all else equal.

CBGs with a higher proportion of Latino White heads of households did not show statistically significantly different participation than non-Latino-White-headed households in the IQ program. However, they did have higher participation rates in both Any Market-Rate Program and Any Program categories. Again, all of these effects emerge from a model that controls for income and other factors, so they appear to be specifically related to race and ethnicity.

[19] In the case of the appliance recycling program, the multivariable statistical analysis shows that the positive visual association between median income and can be accounted for by other demographic and housing characteristics.

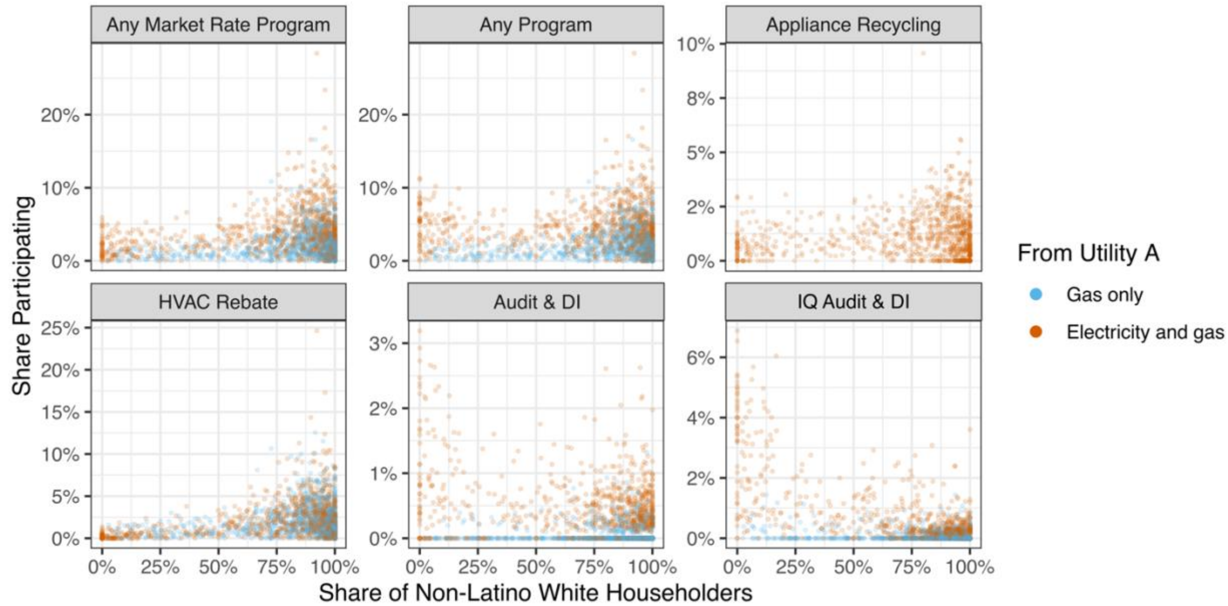


**Figure 11: Utility A program participation by share of non-Latino White householders**

The share of limited-English households had substantially different relationships with participation in the single- and multivariable models. When considered on its own, the share of limited-English households was negatively correlated with participation in the HVAC rebate program, Any Program, and Any Market-Rate Program. However, when controlling for other factors these relationships were no longer significant. Instead these CBGs with more limited-English households had lower participation in the IQ program in a statistically significant fashion.

Except for the IQ program, higher mean energy burden was negatively correlated with participation. Because this was true in single- as well as multivariable models, the effect of energy burden was in addition to the effect of income. For the IQ program, mean energy burden was positively associated with participation in the single variable but not multivariable model, indicating that mean energy burden itself did not have a direct effect on participation.

CBGs with higher shares of owner-occupied units had higher rates of Any Program participation, and this relationship was statistically significant.

# 5. Comparison of Findings Across Datasets and With Existing Literature

While there is a lot of variation in the relationships between the demographic and housing factors that we consider and the receipt of energy efficiency assistance, some general patterns do emerge from the analysis.[20] Table 10 shows a high-level summary.

[20] In Section 4 we are careful to use precise language to refer to the variables and the different ways they are defined in our datasets. In this section we are describing overall patterns and use words such as “participation” and “income” in more general ways that can apply to all of the analyses.

**Table 10. Simplified summary of results**

| | Household income | | Householder education | | Black householder | | Latino White householder | | Other race / ethnicity | | Limited English | | Energy poverty | | Householder age | | Ownership | | Tenure | | Number of units | | Vintage | | Urbanization | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Residential Energy Consumption Survey (RECS) | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Any assistance | — | — | ▲ | ▲ | — | — | ▼ | — | ▼ — | ▼ — | | | — | — | ▲ | — | | | ▼ | — | ▼ | ▼ | ▼ | ▼ | — | — |
| Lights | ▼ | ▼ | — | — | ▲ | — | — | — | — | ▼ — | | | ▲ — | — | — | — | | | — | — | ▼ | — | ▼ | ▼ | — | — |
| Audit | ▼ | — | ▲ | ▲ | — | — | — | — | — | ▼ — | | | — | ▼ | — | — | | | — | — | ▼ | ▼ | — | — | — | — |
| Appliance rebate | ▲ | — | — | — | — | — | ▼ | ▼ | — | — | | | — | — | — | — | | | — | — | — | ▼ | — | — | ▼ — | — |
| Appliance recycling | ▲ | — | — | — | ▼ | — | ▼ | — | — | — | | | ▼ — | — | ▲ | — | | | ▼ | ▼ | ▼ | — | ▼ | ▼ | — | ▲ ▼ |
| Mass Save | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Electric | ▲ | — | ▲ | ▲ | ▼ | — | — | ▼ | ▼ | ▼ — | ▼ | — | ▲ | ▲ | ▲ | — | — | — | ▲ | — | ▼ | ▼ | ▲ ▼ | — | ▼ | ▲ |
| National Grid Rhode Island | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Market rate | ▲ | | ▲ | | * | | * | | * | | ▼ | | ▼ | | — | | ▲ | | — | | ▼ | | — | | — | |
| Income qualified — eligible | ▲ | | — | | * | | * | | * | | ▼ | | ▼ | | — | | ▲ | | — | | ▼ | | — | | ▼ | |
| Income qualified — overall | ▼ | | ▼ | | * | | * | | * | | — | | ▲ | | — | | ▼ | | — | | — | | — | | ▼ | |
| Utility A (Midwest) | | | | | | | | | | | | | | | | | | | | | | | | | | |
| Any program | ▲ | ▲ | ▲ | ▲ | — | ▲ | — | ▲ | ▲ ▼ | — | ▼ | — | ▼ | ▼ | ▲ | ▲ | — | — | ▲ | ▲ | ▼ | ▼ | ▼ | — | ▲ | ▲ |
| Any market-rate program | ▲ | ▲ | ▲ | ▲ | ▼ | ▼ | — | ▲ | ▲ ▼ | — | ▼ | — | ▼ | ▼ | ▲ | ▲ | ▲ | ▲ | ▲ | ▲ | ▼ | ▼ | ▼ | ▲ | ▲ | ▲ |
| Income qualified audit & direct install | ▼ | ▼ | ▲ | ▲ | ▲ | ▲ | ▼ | — | ▲ ▼ | ▲ | — | ▼ | ▲ | — | — | ▲ | — | — | ▲ | — | ▼ | ▼ | ▲ | ▼ | ▲ | ▲ |
| Audit & direct install | ▲ | — | ▲ | ▲ | ▲ | ▲ | — | — | ▼ — | — | — | — | ▼ | ▼ | ▲ | ▲ | — | — | ▲ | — | ▼ | ▼ | — | — | ▲ | ▲ |
| HVAC rebate | ▲ | ▲ | ▲ | ▲ | ▼ | ▼ | — | — | ▲ ▼ | — | ▼ | — | ▼ | ▼ | ▲ | ▲ | — | — | ▲ | ▲ | ▼ | ▼ | ▼ | ▲ | ▲ | ▲ |
| Appliance recycling | ▲ | — | ▲ | ▲ | ▼ | ▼ | ▲ | ▲ | ▲ ▼ | ▲ | — | — | ▼ | ▼ | ▲ | — | — | — | ▲ | — | ▼ | — | ▼ | — | ▲ | ▲ |
| Literature | | | | | | | | | | | | | | | | | | | | | | | | | | |
| | ▲ 7<br>— 3 | ▲ 2 | ▲ 3 | ▲ 1 | — 2<br>▼ 1 | ▲ 1 | ▲ 1<br>— 2<br>▼ 1 | ▲ 1 | ▲ 2<br>— 2<br>▼ 2 | ▲ 1 | ▲ 1 | ▲ 1 | | ▲ 1 | — 1<br>▼ 2 | — 1 | ▲ 4 | ▲ 2 | | ▼ 2 | ▼ 1 | ▲ 1<br>▼ 2 | ▲ 1<br>▼ 1 | — 1 | ▲ 1 | ▲ 1 |

**Key:**

▲ participation increased as the variable increased, or was higher for households with the characteristic

▼ participation decreased as the variable increased, or was lower for households with the characteristic

— participation did not change based on the variable

blank : variable was not studied

gray columns contain single-variable results

unshaded (white) columns contain multivariable results

Multiple symbols indicate that the relationship varied depending on the subgroup or exact metric considered.

Numbers in the "Literature" rows indicate the count of studies that found a particular result.

* Racial and ethnic groups were not compared individually to the share of non-Latino White householders because of sample size. The share of non-Latino White heads of household in the zip code was positively correlated with the market-rate and *eligible* income-qualified participation rates but negatively correlated with the *overall* income-qualified participation rate.

When considering market-rate programs, in general participation was higher among higher-income households, more educated households, households without limited English, older heads of household, homeowners, and buildings with fewer units. Black heads of household tended to participate less in market-rate programs than non-Latino White heads of household. All these patterns also emerged in the reviewed literature, with the exception of age (which few reviewed studies addressed). It appears there is opportunity to improve equity of participation in these programs.

Income-qualified programs showed very different patterns. When looking at overall participation rates, lower-income households and Black heads of household participated more in these programs, although households in multi-unit buildings still participated less. However, the method of calculating participation rates can have a large impact on the results. For the National Grid Rhode Island data we are able to compare the share of total households in the zip code who participated (overall participation) with the share of eligible households in the zip code who participated (eligible participation). In the case of income-qualified programs, we see a different relationship between *overall* and *eligible* participation and the variables tested. Specifically, a higher share of eligible low-income households in higher-income, more highly educated, and more White areas participated in income-qualified programs. This implies that the same types of inequities that arise in market-rate programs may appear within the eligible populations of income-qualified programs or that the characteristics of the neighborhood affected the participation rate of low-income households.

Because of the importance of participation metric for income-qualified results, we are cautious about interpreting results for income-qualified programs from our other three datasets where we do not have eligibility information. A similar pattern might also be observed if eligibility based on living in a single- versus multi-family or owned versus rented home were taken into account.

Many of the factors we study are correlated with each other[21], and our multivariable models attempt to isolate their individual impacts. When we do so, education stands out as a consistent predictor of program participation. In almost every case, increased education was associated with increased receipt of efficiency assistance, and in no case was it associated with decreased receipt in a multivariable model. Indeed, in certain cases (e.g., income-qualified programs), the effect of education became clearer in a multivariable model. These findings are consistent with the four studies discussed in Section 2.1.2 that investigated education. Income and race/ethnicity, conversely, were less well correlated with participation, though the relationships outlined in the paragraphs above did remain statistically significant in some cases. Massachusetts, Rhode Island, and the Midwestern state all have a higher proportion of householders who are non-Latino Whites than the country as a whole, so evidence from more racially and ethnically diverse locations would be valuable.

While efficiency can be an important strategy for reducing energy burden, our results suggest that efficiency programs were not reaching households with the highest burdens in many cases. In the RECS data, our most direct proxies for energy burden were not statistically significant except for receiving a

[21] See Appendix B for correlation matrices.

free or subsidized energy audit, in which case the more burdened households received less assistance. However, assistance with bill payments and appliance repairs was strongly positively correlated with all of the forms of efficiency assistance. For Utility A, participation in the market-rate programs and Any Program was not only lower in CBGs with lower median incomes, but also negatively correlated with the Census tract's mean energy burden – meaning that households with higher energy burdens participated *less*, all else equal. The only instance in which participation and energy burden were positively correlated was for Mass Save electric incentives. This last finding is consistent with the survey-based study of Mass Save programs that found that people who worry about having enough money to pay their energy bills were more likely to have participated in an efficiency program (Navigant et al., 2020). We do not study energy burden directly in the National Grid Rhode Island data, but the fact that eligible participation rates declined based on the zip code's mean income implies that the households with the lowest incomes (and likely highest energy burdens) were not participating.

Along with education, the factor with the most consistent relationship with receipt of efficiency assistance was building type. It was statistically significant in most multivariate models, and households in single-family homes or apartment buildings with less than 5 units were more likely to receive assistance than households in larger buildings or those in mobile homes. This is consistent with previous studies.

The relationship between homeownership and program participation in our multivariable models was much weaker than when considering this factor on its own.

# 6. Conclusion

As Table 10 shows, certain types of utility customers participated more than others in energy efficiency programs. These findings may point program administrators toward program design or delivery changes in pursuit of more equitable participation outcomes.

Education stands out as a consistent predictor of participation, with more educated heads of household – or households in higher-educated areas – participating more. Education is reliably associated with greater participation in all types of studied programs when controlling for other factors – more so than other factors such as income and race/ethnicity. This finding suggests that programs may need to make specific efforts to target low-education households or locations to improve equity in program participation.

Income and race/ethnicity may be the first factors that spring to mind when considering equity in program participation. Our results, and those in the literature, are not as clear for these factors as for education, but do suggest reason to attend to them in program delivery.

Regarding income, in many cases higher-income households or those from higher-income areas participated more in market-rate programs. This finding often, though not always, held up when controlling for other factors such as education. In several cases our results suggested that households in lower-income areas participate more in income-qualified programs, which of course we would expect to be true. However, in the one dataset that allowed us to consider the share of *eligible* households that participate in these programs, eligible low-income households that lived in high-income areas participated more than those that lived in low-income areas. So, even among income-qualified programs there is reason for concern about reaching eligible customers equitably with respect to income.

Our results were more variable with respect to race and ethnicity. Individual programs showed different associations between participation and specific racial or ethnic groups. Even just looking at the two studied income-qualified programs (National Grid Rhode Island's and Utility A's), the association between race and participation depended on the participation metric used and the particular racial group. Different program outreach strategies may be particularly important to the participation rates of different racial and ethnic groups. The results from the literature regarding these factors are also varied.

One common goal of energy efficiency programs is reducing energy costs for households that struggle to pay those costs. However, our results and those in the literature do not necessarily show that programs in general are effectively targeting households with high energy burdens. Indeed, in several cases these households participated *less* than households with lower energy burdens. This finding suggests a clear opportunity for program administrators to modify their targeting, especially as program administrators can directly observe which customers are behind in their bill payments or have their service cut.

When considering potential modifications to program design or delivery in the interest of creating equitable outcomes, program administrators must first define what outcomes they are seeking, and consider what outcomes they can directly act on. As an example, our and others' results suggest that households in very newly built homes participated less, but this finding may not raise equity concerns: homes with new appliances and equipment, and in most cases built to more stringent building energy codes, often have less reason to participate in an energy efficiency program. We also find considerable regional variation in program participation: households in the South census region participated less and those in the Northeast participated more. This is likely due to differences in program availability and funding, rather than differences in participation rates among eligible households. Such regional differences are more difficult for individual program administrators to address, as they relate to differences in state-level decisions about the allocation of resources and regulation. However, program administrators can more directly act on many other differences in participation rates identified here.

Our findings highlight the importance of carefully choosing the metrics for studying equity in program participation and whether they will allow the desired question to be answered. As our Rhode Island data analysis emphasizes, outcomes can be quite different when considering eligible participation rates vs. overall participation rates, reversing the direction of the association in some of our results.

To assess equity in program participation, a researcher or program administrator must first decide which participant characteristics are relevant for equity and should be examined. Income, race and ethnicity, and energy burden are among those most commonly discussed. Our findings suggest that education be considered as well, because it was the characteristic most consistently associated with participation. Urbanization and building type, particularly single- versus multi-family homes, were also consistently associated with participation. Differences in participation based on these factors may or may not raise equity concerns, but it might be beneficial to intentionally decide whether or not to consider them.

Our findings also point to the importance of carefully considering program eligibility, in two ways. First, program eligibility influences the demographic characteristics of who can participate. Program administrators have been offering free and expanded programs for low-income households, for example, as a means of addressing concerns that those who need assistance might not receive it. Programs seeking equitable outcomes will very likely employ this and other eligibility tests going forward.

Second, as our results in Section 4.3 demonstrate, eligibility tests can complicate the analysis of who is participating, particularly when using place-based demographic data. For example, participation will be higher in low-income areas for programs with income eligibility requirements, but participation may still be higher among the highest-income households who are eligible. This dynamic can also obscure the association between participation and variables associated with the eligibility requirement, such as race and ethnicity, education, or housing type in the case of income. Many programs and interventions use place-based metrics for targeting their activities,[22] so program administrators will need to carefully define equity metrics, and carefully interpret outcomes.

While this report draws directly on data from four different datasets, and indirectly on the findings of a dozen other studies, readers should be cautious about generalizing the results. In some cases only a handful of studies speak to a particular factor, and in some cases results diverged across different program administrators and program settings. Additional research would have high value. Moreover, this report says little about *how* to change program design and delivery to achieve different participation outcomes. More effort to identify potential strategies and test their effectiveness is warranted, and should be a priority as program administrators, regulators, and policymakers devote increasing attention to this topic. Section 7 goes into more detail on future work that would provide additional value.

# 7. Future Work

This report provides the most comprehensive overview of the determinants of energy efficiency program participation that we are aware of. Nevertheless, the evidence base for answering this question is fragmented and results are at times contradictory. Considerable additional work could be devoted to this topic. Specific possibilities include:

[22] Two examples are the Community Reinvestment Act (https://www.federalreserve.gov/consumerscommunities/cra_about.htm), which evaluates banks based on the credit they extend to low- and moderate-income neighborhoods, and the Department of Housing and Urban Development's income limits (https://www.huduser.gov/portal/datasets/il.html), which determine place-based eligibility for various housing programs.

- Evidence from additional settings. Table 10 reflects results from thirteen studies (including ours). Only four of these studies (including ours) conducted any multivariable analysis. Hundreds of utilities and program administrators run energy efficiency programs across the country, with different types of programs serving different populations. Additional evidence, particularly multivariable analysis of programs in a variety of parts of the country, would be very helpful to supplement our conclusions here and to begin to parse some of the additional questions below. In addition, the locations that we study have a higher proportion of non-Latino Whites than the country overall, so it would be especially useful to study settings with more racial and ethnic diversity.
- Closer assessment of program eligibility when studying determinants of participation. Since we got distinctly different results from the National Grid Rhode Island data depending on whether program eligibility is taken into account, household-level data that include program eligibility would be very valuable for understanding the determinants of participation among eligible households. These data are particularly important for income-qualified programs since the demographics of the eligible households may not be the same as the CBG or zip code they live in.
- Design of place-based metrics to assess equity in participation (or other outcomes). The gold standard dataset for equity assessment would include household-level data with program eligibility information, but this is difficult to find and collect. This project would look for combinations of data and analysis methods using place-based data that yield the same associations between demographics and participation as the gold standard, and could be employed in other settings where household-level data are not available. Approaches could include multivariable analysis of place-based demographics and univariate analysis of place-based demographics with eligibility information.
- Effects of program design and delivery. In this report we illustrate the relationships between factors and program participation, but we generally could not identify the reasons for those relationships – though we have suggested explanations where they arise. However, some of the relationships are not universal. Examining Table 10 reveals several factors – such as race and energy burden – that have different relationships with participation in different settings. Presumably, additional studies could reveal other factors that merit similar scrutiny. By examining the targeting practices and delivery mechanisms of programs that achieve different results, we may come to better understand how to achieve desired program participation outcomes.
- Greater leveraging of EM&V reports. Utilities and program administrators often conduct surveys of their customers, which can include household-level demographic information, for their EM&V reports. We found and discussed findings from several such studies, but our search was not exhaustive. Although the demographic data collected and analysis methods vary widely, the geographic spread and number of programs covered may allow us to start grouping different directional results into categories. For example, race might tend to be associated with program participation differently for whole home and lighting programs.

- Implementation and analysis of pilot program approaches specifically targeted to achieve desired participation outcomes. As opposed to the previous bullets – which would leverage existing variation in program delivery to understand how that variation influences participation – this approach would explicitly test the impact of a change in program design or delivery to understand its impact on participation. Such approaches would allow clearer attribution of causality to particular approaches – especially where pilots employed randomized control trials or related approaches that facilitate causal inference. Analysis of novel approaches depends on program administrators implementing such approaches in a fashion that can be readily analyzed.
- Studying the distribution of benefits directly (as opposed to participation, as we do here). The Justice40 Initiative (and, likely, other similar initiatives at other levels of government) is considering appropriate ways to define and measure the benefits of energy efficiency and clean energy interventions. With these definitions and metrics in hand we can build on the approaches used here to study the demographic characteristics of the CBGs that are receiving more and less of those benefits. For example, energy savings and incentive dollars are available for some utilities and programs to facilitate the analysis.

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# Appendix A. Methodological Details

## A.1 RECS Survey Questions and Variables

The RECS questions used in the analysis are:

- Which best describes your home?
  - Mobile home
  - Single-family house detached from any other house
  - Single-family house attached to one or more other houses (for example: duplex, row house, or townhome)
  - Apartment in a building with 2 to 4 units
  - Apartment in a building with 5 or more units
- Is your home owned by you or someone in your household, rented, or occupied without payment of rent?
- When was your home built?
- When did your household move in?
- How often do you or other members of your household find your home too drafty?
- In your home, do you or any members of your household access the Internet?
- What is your age?
- Are you Hispanic or Latino?
- What is your race? Please select all that apply.
- What is the highest degree or level of school you have completed?
- Including all income sources, which category best describes the total combined income of all household members for the last year, before taxes and deductions?
- In the last year, how many months did your household reduce or forego expenses for basic household necessities, such as medicine or food, in order to pay an energy bill?
- In the last year, how many months did your household keep your home at a temperature that you felt was unsafe or unhealthy?
- In the last year, how many months did your household receive a disconnection notice, shut off notice, or nondelivery notice for an energy bill?
- Has your household participated in a home energy assistance program that helps pay energy bills or fix broken equipment?
- Has your household received any of the following energy-related benefits or assistance for this home?
  - Free or subsidized energy-efficient light bulbs
  - Free or subsidized home energy audit
  - Utility or energy supplier rebate for new appliance or equipment
  - Recycling of an old appliance or equipment (for example: a refrigerator)
  - Tax credit for new appliance or equipment
  - Other (please specify)

The other RECS variables included in the analysis are geographic. The Census Bureau divides the country into 4 regions and 9 divisions (Figure 1). It also defines an urbanized area as a territory with densely populated tracts totaling at least 50,000 inhabitants; if the total population is between 2,500 and

50,000, it qualifies as an urban cluster.[23] Metropolitan and micropolitan statistical areas are similar, with the former organized around an urbanized area and the latter around an urban cluster.[24]

## A.2 Data Preparation

### A.2.1 American Community Survey

While the ACS is conducted every year, the Census Bureau also publishes results that are representative of 5 year periods. Because the utility-specific data covers multiple years, we used these 5 year estimates unless otherwise noted. Table A - 1 lists the source census tables and summary files used for the analysis variables. Unless otherwise noted they refer to occupied housing units or the head of household, rather than total population or residential building stock.

**Table A-1. ACS tables and sequences**

| Characteristic | Tract | Block group |
|---|---|---|
| Income | S1902 | 58 |
| Education | S2502 | 4225 |
| Race and ethnicity | S2502 | 111 |
| Language – limited English | S1602 | 44 |
| Tenure | S2502 | 113 |
| Householder age | S2502 | 111 |
| Homeownership | S2504 | 111 |
| Vintage | S2504 | 113 |
| Building type | S2504 | 112 |
| Urbanization | HCT1[26] | Delineation File[27] |

Most of these variables are reported as the number of households in a particular bin, for example structures built 1939 or earlier, 1940 to 1959, etc. For the analysis we maintained most of this granularity of the data and normalized them to the total number of households in the appropriate geographic area.

### A.2.2 Zip Code Aggregation

ACS data is not reported at the zip code level, so we used the tract-to-zip-code crosswalk published by the Department of Housing and Urban Development.[28] Zip codes can be made up of portions of census tracts as well as multiple tracts. If a tract is divided between zip codes, we assume that the

[23] https://www.census.gov/programs-surveys/geography/guidance/geo-areas/urban-rural/2010-urban-rural.html
[24] https://www.census.gov/programs-surveys/metro-micro.html
[25] Educational attainment for the population 25 or older.
[26] From the last decennial census, in 2010.
[27] Delineation of metropolitan and micropolitan counties. https://www.census.gov/geographies/reference-files/time-series/demo/metro-micro/delineation-files.html
[28] https://www.huduser.gov/portal/datasets/usps_crosswalk.html

demographics are equally distributed. For example, if Tract A has 100 owner-occupied housing units and 75% of the tract's addresses are in Zip 1 and 25% in Zip 2, we assign 75 owner-occupied units to Zip 1 and 25 to Zip 2. Because medians cannot be allocated in this way, we used mean and binned variables for the zip-code-level data in cases where we used medians for the CBGs.

## A.3 Statistical Modeling

### A.3.1 Regression Analysis

Logistic regression is used to model binary outcomes. The result of the model is the predicted probability of achieving one of the two outcomes at any combination of the predictor variables. Because the RECS data are at the household level, we have a binary outcome – whether or not the household received the particular kind of assistance. So a logistic model is appropriate for this circumstance.

The regression coefficients for logistic models are difficult to interpret, so we report average marginal effects (AMEs) to convey the magnitude of the relationship between the particular independent variable and the outcome variable. Conceptually, a marginal effect is the slope of the logistic curve with respect to a single variable. The AME is the average of that slope when the other independent variables take on the values of every data point in the dataset. Thus, they indicate the average impact of a unit change in each dependent variable, and can be interpreted in the same manner as the coefficients from a linear regression.

While logistic regression is sometimes used on shares, which vary continuously from 0 to 1, it is not appropriate for our place-based data. The participation rates are clustered very close to zero, which makes the error bands for logistic models very large in regions of the logistic curve where there is very little data. A linear probability model, where the dependent variable is the share of households that participate, is more appropriate in this case.

In both cases we specify our models as a linear combination of all of the explanatory variables. We considered alternate specifications with only a subset of variables, but they did not change the conclusions from the models.

### A.3.2 RECS Weighting

The RECS used a multistage area probability sample design to randomly select progressively smaller geographic areas to survey while making sure to get a representative sample.[29] Then they extrapolated from the sample to the whole population with sample weights. The usual standard error calculation is not appropriate with this kind of survey design that employs sample weights because depends on the observations being independent of each other. Consequently we followed the guidance provided with the data and used the survey package[30] in R to take the replicate weights into account when calculating the standard error.

[29] US Energy Information Administration.
https://www.eia.gov/consumption/residential/reports/2015/methodology/index.php
[30] https://cran.r-project.org/web/packages/survey/survey.pdf

### A.3.3 Mass Save Details

Rather than aggregating all of the incentives in each zip code over the 6 years of our study period, we use 1 zip code-year as our unit of analysis. This means that each zip code contributes up to 6 data points to the modeling dataset and allows us to include the 69 zip codes that do not have data reported from all 6 years. Because year was a significant variable in our regression models, we do not account for missing data by creating an average incentive value per year in the zip code.

However, there are still two reasons why data from a particular zip code-year may not be included in the analysis. First, we dropped zip-code years with incentives that were clear outliers based on gaps in incentives. On the electric side our cutoff was $700 per household per year, and for gas it was $400 per household per year. Second, 28 zip codes have Mass Save data but are not allocated any residential addresses from HUD's tract-to-zip-code crosswalk.

# Appendix B. Correlation Coefficients

Many of the household and physical characteristics we consider are related to each other. Tables B - 1 through B - 4 show the correlation coefficients between these factors for the RECS, Mass Save, National Grid Rhode Island, and Utility A.

**Table B-1. RECS correlation matrix**

| | Income[31] | Bachelor's degree or higher | Non-Latino White | Black | Latino White | Reduce or forego basic necessities due to energy bill at least 1 month | Keep home at unhealthy temperature at least 1 month | Receive disconnect notice at least 1 month | Householder age | Single-family home | Urban area or cluster |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Income | 1 | 0.45 | 0.08 | -0.11 | -0.05 | -0.26 | -0.16 | -0.17 | -0.23 | 0.18 | 0.08 |
| Bachelor's degree or higher | 0.45 | 1 | 0.05 | -0.05 | -0.08 | -0.17 | -0.09 | -0.14 | -0.12 | 0.09 | 0.13 |
| Non-Latino White | 0.08 | 0.05 | 1 | | | -0.16 | -0.10 | -0.15 | 0.14 | 0.06 | -0.12 |
| Black | -0.11 | -0.05 | | 1 | | 0.13 | 0.06 | 0.15 | 0.00 | -0.01 | 0.00 |
| Latino White | -0.05 | -0.08 | | | 1 | 0.08 | 0.09 | 0.07 | -0.12 | -0.03 | 0.12 |
| Reduce or forego basic necessities due to energy bill at least 1 month | -0.26 | -0.17 | -0.16 | 0.13 | 0.08 | 1 | 0.41 | 0.40 | -0.10 | -0.11 | -0.03 |
| Keep home at unhealthy temperature at least 1 month | -0.16 | -0.09 | -0.10 | 0.06 | 0.09 | 0.41 | 1 | 0.21 | -0.01 | -0.08 | 0.00 |
| Receive disconnect notice at least 1 month | -0.17 | -0.14 | -0.15 | 0.15 | 0.07 | 0.40 | 0.21 | 1 | -0.14 | -0.08 | -0.04 |
| Householder age | -0.23 | -0.12 | 0.14 | 0.00 | -0.12 | -0.10 | -0.01 | -0.14 | 1 | 0.01 | -0.03 |
| Single-family home | 0.18 | 0.09 | 0.06 | -0.01 | -0.03 | -0.11 | -0.08 | -0.08 | 0.01 | 1 | 0.06 |
| Urban area or cluster | 0.08 | 0.13 | -0.12 | 0.00 | 0.12 | -0.03 | 0.00 | -0.04 | -0.03 | 0.06 | 1 |

[31] In the RECS income is divided into 8 bins, 7 of which are of equal width ($20k). The remaining bin is unbounded: "$140k and up".

**Table B-2. Mass Save correlation matrix**

| | Mean income | Bachelor's degree or higher | Non-Latino White | Black | Latino White | Limited English | Mean energy burden | Mean householder age[32] | Owner-occupied | Single-family home | Urban zip code |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Mean income | 1 | 0.83 | 0.28 | -0.28 | -0.34 | -0.32 | -0.64 | 0.19 | 0.41 | 0.32 | 0.05 |
| Bachelor's degree or higher | 0.83 | 1 | 0.24 | -0.29 | -0.33 | -0.30 | -0.63 | 0.10 | 0.23 | 0.14 | 0.09 |
| Non-Latino White | 0.28 | 0.24 | 1 | | | -0.86 | -0.07 | 0.57 | 0.76 | 0.73 | -0.40 |
| Black | -0.28 | -0.29 | | 1 | | 0.49 | 0.19 | -0.34 | -0.48 | -0.45 | 0.26 |
| Latino White | -0.34 | -0.33 | | | 1 | 0.73 | 0.21 | -0.41 | -0.60 | -0.53 | 0.26 |
| Limited English | -0.32 | -0.30 | -0.86 | 0.49 | 0.73 | 1 | 0.05 | -0.48 | -0.75 | -0.73 | 0.32 |
| Mean energy burden | -0.64 | -0.63 | -0.07 | 0.19 | 0.21 | 0.05 | 1 | 0.20 | -0.02 | 0.12 | -0.30 |
| Mean householder age | 0.19 | 0.10 | 0.57 | -0.34 | -0.41 | -0.48 | 0.20 | 1 | 0.68 | 0.67 | -0.25 |
| Owner-occupied | 0.41 | 0.23 | 0.76 | -0.48 | -0.60 | -0.75 | -0.02 | 0.68 | 1 | 0.94 | -0.43 |
| Single-family home | 0.32 | 0.14 | 0.73 | -0.45 | -0.53 | -0.73 | 0.12 | 0.67 | 0.94 | 1 | -0.45 |
| Urban zip code | 0.05 | 0.09 | -0.40 | 0.26 | 0.26 | 0.32 | -0.30 | -0.25 | -0.43 | -0.45 | 1 |

[32] The ACS reports householder age in bins of 10 years, starting at 35 and ending at 85; the bins on either side are unbounded (i.e. under 35 years and 80 years and above). To calculate the mean age for the geographic area (zip code or CBG), we take the midpoint of each bounded bin and 30 and 90 for the unbounded ones.

**Table B-3. National Grid Rhode Island correlation matrix**

| | Mean income | Bachelor's degree or higher | Non-Latino White | Black | Latino White | Limited English | Mean energy burden | Mean householder age | Owner-occupied | Single-family home | Urban zip code |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Mean income | 1 | 0.80 | 0.71 | -0.71 | -0.71 | -0.69 | -0.67 | 0.51 | 0.73 | 0.74 | -0.32 |
| Bachelor's degree or higher | 0.80 | 1 | 0.47 | -0.52 | -0.52 | -0.47 | -0.79 | 0.39 | 0.37 | 0.44 | -0.09 |
| Non-Latino White | 0.71 | 0.47 | 1 | | | -0.91 | -0.45 | 0.67 | 0.84 | 0.84 | -0.41 |
| Black | -0.71 | -0.52 | | 1 | | 0.76 | 0.53 | -0.65 | -0.74 | -0.74 | 0.38 |
| Latino White | -0.71 | -0.52 | | | 1 | 0.88 | 0.56 | -0.60 | -0.78 | -0.78 | 0.39 |
| Limited English | -0.69 | -0.47 | -0.91 | 0.76 | 0.88 | 1 | 0.40 | -0.49 | -0.82 | -0.82 | 0.36 |
| Mean energy burden | -0.67 | -0.79 | -0.45 | 0.53 | 0.56 | 0.40 | 1 | -0.19 | -0.29 | -0.31 | 0.10 |
| Mean householder age | 0.51 | 0.39 | 0.67 | -0.65 | -0.60 | -0.49 | -0.19 | 1 | 0.62 | 0.68 | -0.25 |
| Owner-occupied | 0.73 | 0.37 | 0.84 | -0.74 | -0.78 | -0.82 | -0.29 | 0.62 | 1 | 0.97 | -0.62 |
| Single-family home | 0.74 | 0.44 | 0.84 | -0.74 | -0.78 | -0.82 | -0.31 | 0.68 | 0.97 | 1 | -0.62 |
| Urban zip code | -0.32 | -0.09 | -0.41 | 0.38 | 0.39 | 0.36 | 0.10 | -0.25 | -0.62 | -0.62 | 1 |

**Table B-4. Utility A correlation matrix**

| | Median income | Bachelor's degree or higher | Non-Latino White | Black | Latino White | Limited English | Mean energy burden | Mean householder age | Owner-occupied | Single-family home | Metropolitan CBG |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Median income | 1 | 0.58 | 0.45 | -0.42 | -0.18 | -0.19 | -0.45 | 0.22 | 0.66 | 0.46 | 0.02 |
| Bachelor's degree or higher | 0.58 | 1 | 0.28 | -0.22 | -0.19 | -0.18 | -0.52 | 0.13 | 0.30 | 0.13 | 0.18 |
| Non-Latino White | 0.45 | 0.28 | 1 | | | -0.36 | -0.31 | 0.22 | 0.52 | 0.24 | -0.33 |
| Black | -0.42 | -0.22 | | 1 | | 0.11 | 0.29 | -0.10 | -0.46 | -0.19 | 0.29 |
| Latino White | -0.18 | -0.19 | | | 1 | 0.48 | 0.08 | -0.24 | -0.20 | -0.09 | 0.16 |
| Limited English | -0.19 | -0.18 | -0.36 | 0.11 | 0.48 | 1 | 0.07 | -0.19 | -0.23 | -0.14 | 0.04 |
| Mean energy burden | -0.45 | -0.52 | -0.31 | 0.29 | 0.08 | 0.07 | 1 | 0.01 | -0.23 | -0.07 | -0.29 |
| Mean householder age | 0.22 | 0.13 | 0.22 | -0.10 | -0.24 | -0.19 | 0.01 | 1 | 0.44 | 0.25 | -0.11 |
| Owner-occupied | 0.66 | 0.30 | 0.52 | -0.46 | -0.20 | -0.23 | -0.23 | 0.44 | 1 | 0.73 | -0.12 |
| Single-family home | 0.46 | 0.13 | 0.24 | -0.19 | -0.09 | -0.14 | -0.07 | 0.25 | 0.73 | 1 | -0.02 |
| Metropolitan CBG | 0.02 | 0.18 | -0.33 | 0.29 | 0.16 | 0.04 | -0.29 | -0.11 | -0.12 | -0.02 | 1 |

# Appendix C. Multivariable Regression Results

Tables C - 1 through C - 3 contain the results of the multivariable regression models for the RECS, Mass Save, and Utility A. Single-variable regression results are available on request.

## C.1 RECS

**Table C-1. RECS regression results – logistic model**

| | *Dependent variable:* | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Efficient Lights | | Free or Subsidized Audit | | Appliance Rebate | | Appliance Recycling | | Any Assistance | |
| | (1) | | (2) | | (3) | | (4) | | (5) | |
| | Coefficient & SE | AME | Coefficient & SE | AME | Coefficient & SE | AME | Coefficient & SE | AME | Coefficient & SE | AME |
| **Census division (compared to "New England")** | | | | | | | | | | |
| Middle Atlantic | -0.411 | -0.044 | -1.393 | -0.058 | -0.268 | -0.018 | 0.776** | 0.061 | -0.149 | -0.029 |
| | (-0.349) | | (-0.781) | | (-0.352) | | (-0.253) | | (-0.266) | |
| East North Central | -0.372 | -0.04 | -1.253 | -0.055 | -0.860* | -0.046 | 0.590* | 0.043 | -0.219 | -0.043 |
| | (-0.325) | | (-0.767) | | (-0.33) | | (-0.237) | | (-0.228) | |
| West North Central | -2.475*** | -0.137 | -1.597 | -0.063 | -0.223 | -0.015 | 0.679* | 0.052 | -0.655* | -0.116 |
| | (-0.552) | | (-0.897) | | (-0.362) | | (-0.26) | | (-0.283) | |
| South Atlantic | -1.122** | -0.094 | -1.495 | -0.061 | -0.744* | -0.042 | 0.014 | 0.001 | -0.840** | -0.143 |
| | (-0.349) | | (-0.757) | | (-0.345) | | (-0.236) | | (-0.246) | |
| East South Central | -1.465* | -0.11 | -2.548 | -0.077 | -0.835* | -0.045 | -0.869 | -0.035 | -1.265*** | -0.193 |
| | (-0.648) | | (-1.283) | | (-0.346) | | (-0.52) | | (-0.328) | |
| West South Central | -1.839*** | -0.123 | -0.96 | -0.046 | -0.690* | -0.039 | -0.461 | -0.022 | -1.231*** | -0.189 |
| | (-0.426) | | (-0.809) | | (-0.32) | | (-0.365) | | (-0.233) | |

| | Efficient Lights | | Free or Subsidized Audit | | Appliance Rebate | | Appliance Recycling | | Any Assistance | |
|---|---|---|---|---|---|---|---|---|---|---|
| Mountain North | -0.643 | -0.063 | -1.364 | -0.058 | -0.107 | -0.008 | 0.722 | 0.056 | -0.153 | -0.03 |
| | (-0.349) | | (-0.833) | | (-0.404) | | (-0.418) | | (-0.298) | |
| Mountain South | -1.727** | -0.119 | -0.575 | -0.031 | -0.18 | -0.013 | 0.978** | 0.084 | -0.215 | -0.042 |
| | (-0.6) | | (-0.938) | | (-0.474) | | (-0.305) | | (-0.281) | |
| Pacific | -0.523 | -0.053 | -1.427 | -0.059 | 0.095 | 0.007 | 0.639* | 0.048 | -0.037 | -0.007 |
| | (-0.29) | | (-0.811) | | (-0.322) | | (-0.249) | | (-0.223) | |
| **Educational attainment (compared to "Less than high school diploma")** | | | | | | | | | | |
| High school diploma or GED | 0.234 | 0.014 | 2.027 | 0.024 | 0.007 | 0 | 0.151 | 0.008 | 0.058 | 0.008 |
| | (-0.33) | | (-1.226) | | (-0.579) | | (-0.414) | | (-0.217) | |
| Some college or Associate's degree | 0.242 | 0.015 | 2.194 | 0.028 | 0.4 | 0.018 | 0.563 | 0.037 | 0.352 | 0.052 |
| | (-0.365) | | (-1.214) | | (-0.57) | | (-0.376) | | (-0.218) | |
| Bachelor's degree | 0.078 | 0.004 | 2.337 | 0.032 | 0.761 | 0.039 | 0.672 | 0.046 | 0.51 | 0.079 |
| | (-0.37) | | (-1.259) | | (-0.576) | | (-0.403) | | (-0.253) | |
| Graduate degree | 0.391 | 0.025 | 2.870* | 0.051 | 0.539 | 0.025 | 0.768 | 0.054 | 0.629* | 0.1 |
| | (-0.376) | | (-1.26) | | (-0.603) | | (-0.404) | | (-0.245) | |
| **Income (compared to "Less than $20k")** | | | | | | | | | | |
| $20- 40k | -0.229 | -0.021 | -0.867 | -0.026 | 0.25 | 0.012 | -0.018 | -0.001 | -0.147 | -0.025 |
| | (-0.316) | | (-0.456) | | (-0.49) | | (-0.34) | | (-0.223) | |

| | Efficient Lights | | Free or Subsidized Audit | | Appliance Rebate | | Appliance Recycling | | Any Assistance | |
|---|---|---|---|---|---|---|---|---|---|---|
| $40 - 60k | -0.506 | -0.041 | -0.448 | -0.016 | 0.142 | 0.006 | 0.311 | 0.023 | -0.202 | -0.034 |
| | (-0.275) | | (-0.461) | | (-0.449) | | (-0.323) | | (-0.192) | |
| $60 - 80k | -0.662 | -0.051 | -0.633 | -0.021 | 0.305 | 0.014 | 0.444 | 0.034 | -0.201 | -0.034 |
| | (-0.332) | | (-0.44) | | (-0.457) | | (-0.343) | | (-0.183) | |
| $80 - 100k | -0.693* | -0.053 | -0.407 | -0.014 | 0.641 | 0.035 | 0.04 | 0.003 | -0.239 | -0.04 |
| | (-0.33) | | (-0.448) | | (-0.459) | | (-0.364) | | (-0.236) | |
| $100 - 120k | -0.758 | -0.057 | -0.561 | -0.019 | 0.081 | 0.003 | 0.444 | 0.034 | -0.23 | -0.038 |
| | (-0.378) | | (-0.545) | | (-0.516) | | (-0.361) | | (-0.249) | |
| $120 - 140k | -0.63 | -0.049 | -0.732 | -0.023 | 0.438 | 0.022 | 0.112 | 0.007 | -0.244 | -0.041 |
| | (-0.394) | | (-0.546) | | (-0.513) | | (-0.382) | | (-0.259) | |
| $140k or more | -1.228*** | -0.079 | -0.817 | -0.025 | 0.387 | 0.019 | 0.5 | 0.039 | -0.195 | -0.033 |
| | (-0.334) | | (-0.55) | | (-0.498) | | (-0.352) | | (-0.243) | |
| **Frequency of reducing or forgoing basic necessities due to home energy bill (compared to "Never")** | | | | | | | | | | |
| 1-2 months | -0.559 | -0.03 | 0.885* | 0.031 | 0.489 | 0.031 | -0.659 | -0.042 | -0.172 | -0.027 |
| | (-0.398) | | (-0.435) | | (-0.396) | | (-0.352) | | (-0.278) | |
| Some months | 0.048 | 0.003 | 0.448 | 0.013 | 0.298 | 0.017 | -0.434 | -0.03 | 0.061 | 0.01 |
| | (-0.221) | | (-0.385) | | (-0.375) | | (-0.303) | | (-0.178) | |
| Almost every month | -0.127 | -0.008 | 0.882 | 0.031 | 0.274 | 0.016 | -0.314 | -0.023 | 0.015 | 0.002 |
| | (-0.432) | | (-0.53) | | (-0.468) | | (-0.456) | | (-0.288) | |

| | Efficient Lights | | Free or Subsidized Audit | | Appliance Rebate | | Appliance Recycling | | Any Assistance | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Frequency of keeping home at unhealthy temperature (compared to "Never")** | | | | | | | | | | |
| 1-2 months | 0.608<br>(-0.527) | 0.05 | 0.256<br>(-0.777) | 0.008 | -0.436<br>(-0.796) | -0.019 | 0.825<br>(-0.531) | 0.084 | 0.822<br>(-0.424) | 0.156 |
| Some months | -0.188<br>(-0.446) | -0.012 | 0.303<br>(-0.51) | 0.009 | -0.382<br>(-0.604) | -0.017 | 0.244<br>(-0.353) | 0.02 | 0.071<br>(-0.262) | 0.012 |
| Almost every month | -0.493<br>(-0.384) | -0.027 | 0.018<br>(-0.695) | 0 | 0.303<br>(-0.484) | 0.018 | -0.084<br>(-0.316) | -0.006 | -0.281<br>(-0.22) | -0.042 |
| **Frequency of receiving disconnect notice (compared to "Never")** | | | | | | | | | | |
| 1-2 months | 0.101<br>(-0.414) | 0.007 | -0.261<br>(-0.657) | -0.007 | 0.041<br>(-0.343) | 0.002 | 0.06<br>(-0.324) | 0.005 | -0.009<br>(-0.227) | -0.001 |
| Some months | 0.225<br>(-0.399) | 0.016 | 0.08<br>(-0.51) | 0.002 | 0.209<br>(-0.432) | 0.012 | -0.029<br>(-0.47) | -0.002 | 0.059<br>(-0.289) | 0.01 |
| Almost every month | 0.704<br>(-0.601) | 0.059 | -17.065*<br>(-7.861) | -0.036 | -1.287<br>(-1.165) | -0.041 | -0.546<br>(-1.116) | -0.035 | -0.209<br>(-0.471) | -0.032 |
| **Frequency of draft (compared to "Never")** | | | | | | | | | | |
| Some of the time | 0.034<br>(-0.149) | 0.002 | 0.411<br>(-0.275) | 0.011 | -0.277<br>(-0.15) | -0.015 | -0.063<br>(-0.12) | -0.005 | -0.08<br>(-0.089) | -0.013 |

| | Efficient Lights | | Free or Subsidized Audit | | Appliance Rebate | | Appliance Recycling | | Any Assistance | |
|---|---|---|---|---|---|---|---|---|---|---|
| Most of the time | 0.062 | 0.004 | 0.293 | 0.008 | -0.611 | -0.029 | 0.301 | 0.026 | 0.014 | 0.002 |
| | (-0.329) | | (-0.516) | | (-0.426) | | (-0.267) | | (-0.176) | |
| All the time | 0.483 | 0.037 | 0.248 | 0.006 | -0.319 | -0.017 | -0.448 | -0.03 | 0.081 | 0.014 |
| | (-0.36) | | (-0.722) | | (-0.545) | | (-0.709) | | (-0.266) | |
| **Race and ethnicity (compared to "Non-Latino White")** | | | | | | | | | | |
| Black or African/American Alone | 0.391 | 0.029 | -0.086 | -0.002 | -0.356 | -0.018 | -0.43 | -0.03 | 0.137 | 0.023 |
| | (-0.261) | | (-0.568) | | (-0.418) | | (-0.327) | | (-0.214) | |
| American Indian or Alaska Native Alone | -1.675* | -0.058 | -16.099* | -0.037 | -1.155 | -0.042 | -1.098 | -0.061 | -1.302* | -0.152 |
| | (-0.772) | | (-7.84) | | (-0.858) | | (-0.765) | | (-0.558) | |
| Asian Alone | -0.291 | -0.017 | -0.022 | -0.001 | -0.276 | -0.014 | -0.619 | -0.041 | -0.575* | -0.082 |
| | (-0.324) | | (-0.592) | | (-0.384) | | (-0.413) | | (-0.229) | |
| Native Hawaiian or Other Pacific Islander Alone | 0.648 | 0.052 | -16.469* | -0.037 | -12.151 | -0.064 | -11.994 | -0.097 | -0.895 | -0.118 |
| | (-1.157) | | (-7.97) | | (-7.957) | | (-7.959) | | (-0.995) | |
| 2 or More Races | -0.107 | -0.006 | 0.488 | 0.017 | -0.676 | -0.03 | 0.246 | 0.022 | 0.085 | 0.014 |
| | (-0.647) | | (-0.901) | | (-0.774) | | (-0.479) | | (-0.306) | |
| White Alone and Hispanic or Latino | 0.401 | 0.03 | -0.764 | -0.017 | -0.684* | -0.03 | -0.396 | -0.028 | -0.295 | -0.046 |
| | (-0.203) | | (-0.46) | | (-0.317) | | (-0.286) | | (-0.164) | |

| | Efficient Lights | | Free or Subsidized Audit | | Appliance Rebate | | Appliance Recycling | | Any Assistance | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Householder age** | | | | | | | | | | |
| Householder age | 0.004<br>(-0.006) | 0 | 0.005<br>(-0.008) | 0 | -0.003<br>(-0.007) | 0 | 0.005<br>(-0.005) | 0 | 0.005<br>(-0.004) | 0.001 |
| **Tenure (compared to "Moved in before 1980")** | | | | | | | | | | |
| Moved in 1980-1989 | 0.528<br>(-0.292) | 0.035 | 0.045<br>(-0.45) | 0.001 | 0.189<br>(-0.382) | 0.011 | -0.155<br>(-0.24) | -0.014 | 0.093<br>(-0.172) | 0.016 |
| Moved in 1990-1999 | 0.111<br>(-0.288) | 0.006 | -0.033<br>(-0.345) | -0.001 | 0.234<br>(-0.334) | 0.014 | 0.14<br>(-0.187) | 0.014 | 0.146<br>(-0.158) | 0.026 |
| Moved in 2000-2009 | 0.457<br>(-0.311) | 0.03 | 0.112<br>(-0.369) | 0.003 | -0.08<br>(-0.338) | -0.004 | -0.444<br>(-0.221) | -0.037 | -0.103<br>(-0.195) | -0.017 |
| Moved in 2010-2015 | 0.058<br>(-0.344) | 0.003 | -0.262<br>(-0.414) | -0.007 | -0.259<br>(-0.412) | -0.013 | -0.830**<br>(-0.25) | -0.06 | -0.428<br>(-0.239) | -0.066 |
| **Vintage (compared to "Built before 1950")** | | | | | | | | | | |
| Built 1950-1959 | -0.398<br>(-0.308) | -0.029 | 0.084<br>(-0.413) | 0.002 | 0.483<br>(-0.359) | 0.025 | 0.256<br>(-0.204) | 0.02 | 0.03<br>(-0.178) | 0.005 |
| Built 1960-1969 | -0.662*<br>(-0.291) | -0.045 | 0.238<br>(-0.452) | 0.007 | 0.399<br>(-0.311) | 0.02 | 0.630*<br>(-0.252) | 0.056 | 0.135<br>(-0.163) | 0.023 |

| | Efficient Lights | | Free or Subsidized Audit | | Appliance Rebate | | Appliance Recycling | | Any Assistance | |
|---|---|---|---|---|---|---|---|---|---|---|
| Built 1970-1979 | -0.288 | -0.022 | -0.318 | -0.008 | 0.393 | 0.019 | 0.111 | 0.008 | -0.073 | -0.012 |
| | (-0.249) | | (-0.449) | | (-0.331) | | (-0.222) | | (-0.147) | |
| Built 1980-1989 | -0.601 | -0.041 | 0.154 | 0.005 | 0.307 | 0.014 | 0.076 | 0.005 | -0.155 | -0.025 |
| | (-0.307) | | (-0.469) | | (-0.296) | | (-0.235) | | (-0.185) | |
| Built 1990-1999 | -0.222 | -0.017 | 0.229 | 0.007 | 0.157 | 0.007 | 0.016 | 0.001 | -0.106 | -0.017 |
| | (-0.318) | | (-0.368) | | (-0.318) | | (-0.226) | | (-0.178) | |
| Built 2000-2009 | -0.55 | -0.039 | -0.619 | -0.014 | 0.393 | 0.019 | 0.2 | 0.015 | -0.143 | -0.023 |
| | (-0.31) | | (-0.494) | | (-0.264) | | (-0.276) | | (-0.171) | |
| Built 2010-2015 | -0.599 | -0.041 | -15.817 | -0.036 | 0.473 | 0.024 | -1.594*** | -0.062 | -0.698* | -0.098 |
| | (-0.565) | | (-7.821) | | (-0.42) | | (-0.431) | | (-0.321) | |
| **Building type (compared to "Single-family detached house")** | | | | | | | | | | |
| Single-family attached house | -0.237 | -0.015 | -0.261 | -0.007 | -0.651 | -0.028 | 0.391 | 0.035 | -0.011 | -0.002 |
| | (-0.256) | | (-0.362) | | (-0.398) | | (-0.204) | | (-0.161) | |
| Apartment in a building with 2-4 units | -0.345 | -0.021 | -0.751 | -0.017 | 0.411 | 0.027 | 0.428 | 0.039 | -0.145 | -0.024 |
| | (-0.696) | | (-1.097) | | (-0.562) | | (-0.497) | | (-0.402) | |
| Apartment in a building with 5 or more units | -0.611 | -0.033 | -16.651* | -0.037 | -1.409*** | -0.045 | -0.832 | -0.048 | -1.032*** | -0.131 |
| | (-0.482) | | (-7.707) | | (-0.228) | | (-0.431) | | (-0.279) | |

| | Efficient Lights | | Free or Subsidized Audit | | Appliance Rebate | | Appliance Recycling | | Any Assistance | |
|---|---|---|---|---|---|---|---|---|---|---|
| Mobile home | -0.344 | -0.021 | -1.034 | -0.021 | -0.409 | -0.019 | -0.366 | -0.025 | -0.621* | -0.089 |
| | (-0.343) | | (-0.578) | | (-0.443) | | (-0.42) | | (-0.247) | |
| **Urbanization (compared to "Rural")** | | | | | | | | | | |
| Urban cluster | 0.092 | 0.006 | 0.514 | 0.017 | -0.879* | -0.038 | -0.16 | -0.012 | -0.264 | -0.041 |
| | (-0.223) | | (-0.367) | | (-0.332) | | (-0.245) | | (-0.19) | |
| Urban area | -0.006 | 0 | -0.086 | -0.002 | -0.181 | -0.01 | 0.036 | 0.003 | -0.061 | -0.01 |
| | (-0.21) | | (-0.304) | | (-0.171) | | (-0.187) | | (-0.128) | |
| **Internet (compared to "No internet at home")** | | | | | | | | | | |
| Internet at home | 0.066 | 0.004 | 0.812 | 0.018 | 0.314 | 0.015 | 0.198 | 0.014 | 0.366* | 0.055 |
| | (-0.235) | | (-0.577) | | (-0.424) | | (-0.254) | | (-0.173) | |
| **Assistance types (compared to not receiving the assistance)** | | | | | | | | | | |
| Bill or appliance repair assistance | 0.563 | 0.045 | 1.111 | 0.043 | 0.763* | 0.054 | 1.084*** | 0.118 | 1.002*** | 0.194 |
| | (-0.282) | | (-0.557) | | (-0.347) | | (-0.287) | | (-0.2) | |
| Free or subsidized audit | -0.291*** | -0.019 | | | -0.047 | -0.003 | 0.074* | 0.006 | | |
| | (-0.064) | | | | (-0.076) | | (-0.034) | | | |
| Efficient lights | | | 2.750*** | 0.075 | 0.583* | 0.031 | -0.197* | -0.015 | | |
| | | | (-0.274) | | (-0.251) | | (-0.086) | | | |

| | Efficient Lights | | Free or Subsidized Audit | | Appliance Rebate | | Appliance Recycling | | Any Assistance | |
|---|---|---|---|---|---|---|---|---|---|---|
| Appliance rebate | 0.672** | 0.044 | -0.468 | -0.013 | 0 | | 0.131 | 0.01 | | |
| | (-0.212) | | (-0.295) | | () | | (-0.22) | | | |
| Appliance recycling | -0.066 | -0.004 | -0.074 | -0.002 | 0.156 | 0.008 | | | | |
| | (-0.139) | | (-0.132) | | (-0.183) | | | | | |
| **Constant** | | | | | | | | | | |
| Constant | -1.695* | | -5.630** | | -3.174** | | -3.748*** | | -1.290* | |
| | (-0.714) | | (-1.71) | | (-0.98) | | (-0.643) | | (-0.49) | |
| Observations | 3,774 | | 3,748 | | 3,770 | | 3,766 | | 3,771 | |
| Log Likelihood | -988.412 | | -449.451 | | -853.211 | | -1,105.64 | | -2,011.07 | |
| Akaike Inf. Crit. | 2,100.83 | | 1,022.90 | | 1,830.42 | | 2,335.28 | | 4,140.14 | |

*Notes:* AME is "average marginal effect". See Section A.3.1 for more details. $^{*}$p<0.05; $^{**}$p<0.01; $^{***}$p<0.001

## C.2 Mass Save

**Table C-2. Mass Save regression results – linear model**

| | *Dependent variable:* |
|---|---|
| | **Electric Incentives** |
| **Educational attainment (compared to "Less than high school graduate")** | |
| High school graduate | 79.133* (30.873) |
| Some college or associate's degree | 22.347 (29.706) |
| Bachelor's degree or higher | 166.120*** (25.560) |
| **Income** | |
| Mean income | 0.00004 (0.00004) |
| **Energy burden** | |
| Mean energy burden | 2,029.328*** (115.555) |
| **Race and ethnicity (compared to "Non-Latino White")** | |
| Black | 0.657 (10.064) |
| White, Hispanic or Latino | -115.474*** (18.375) |
| Asian | -131.388*** (18.208) |
| Other | -87.335*** (23.416) |
| **Limited English (compared to "Not limited English")** | |
| Limited English | 412.048*** (35.721) |

| | |
|---|---|
| **Householder age (compared to "Less than 35 years")** | |
| 35 to 44 years | -75.182* (29.878) |
| 45 to 54 years | -59.544* (25.281) |
| 55 to 64 years | 155.720*** (24.902) |
| 65 to 74 years | -55.365* (26.706) |
| 75 to 84 years | 315.877*** (37.368) |
| 85 years and over | -112.606** (38.316) |
| **Tenure (compared to "Moved in before 1990")** | |
| Moved in 2015 or later | 118.768*** (32.228) |
| Moved in 2010 to 2014 | 35.685 (25.129) |
| Moved in 2000 to 2009 | 140.133*** (24.440) |
| Moved in 1990 to 1999 | -12.779 (30.698) |
| **Building type (compared to "Single-family home")** | |
| 2-4 units | -94.953*** (15.954) |
| 5-9 units | -136.826*** (24.671) |
| 10+ units | -59.956*** (14.954) |
| Other | -147.863*** (30.291) |

| | |
|---|---|
| **Vintage (compared to "Built before 1940")** | |
| Built 2010 or later | 83.093* (36.352) |
| Built 2000-2009 | 25.244 (20.265) |
| Built 1980-1999 | 26.389* (11.017) |
| Built 1960-1979 | 5.708 (10.083) |
| Built 1940-1959 | -88.173*** (13.884) |
| **Occupancy (compared to "Renter occupied")** | |
| Owner occupied | -0.484 (18.114) |
| **Urbanization (compared to "Rural")** | |
| Urban | 14.637*** (3.094) |
| **Incentive year (compared to "2013")** | |
| 2014 | 14.186*** (2.127) |
| 2015 | 28.402*** (2.128) |
| 2016 | 31.076*** (2.127) |
| 2017 | 41.863*** (2.124) |
| 2018 | 51.811*** (2.127) |
| **Constant** | |
| Constant | -179.211*** (38.160) |
| Observations | 9,392 |
| $R^2$ | 0.299 |

| | |
|---|---|
| Adjusted $R^2$ | 0.297 |
| Residual Std. Error | 58.066 (df = 9355) |
| F Statistic | 111.052$^{***}$ (df = 36; 9355) |
| *Note:* | $^{*}$p<0.05; $^{**}$p<0.01; $^{***}$p<0.001 |

## C.3 Utility A

**Table C-3. Utility A regression results – linear model**

| | Any Program | Any Market-Rate Program | IQ Audit & DI | Audit & DI | HVAC Rebate | Appliance Recycling |
|---|---|---|---|---|---|---|
| | (1) | (2) | (3) | (4) | (5) | (6) |
| **Educational attainment (compared to "Less than high school graduate")** | | | | | | |
| High school graduate | 0.003 | -0.003 | 0.005$^{*}$ | 0.001 | -0.006 | 0.002 |
| | (0.008) | (0.007) | (0.002) | (0.001) | (0.006) | (0.003) |
| Some college or associate's degree | 0.017$^{*}$ | 0.015$^{*}$ | 0.002 | 0.001 | 0.008 | 0.004 |
| | (0.008) | (0.007) | (0.002) | (0.001) | (0.006) | (0.003) |
| Bachelor's degree or higher | 0.066$^{***}$ | 0.061$^{***}$ | 0.005$^{*}$ | 0.008$^{***}$ | 0.047$^{***}$ | 0.009$^{***}$ |
| | (0.007) | (0.007) | (0.002) | (0.001) | (0.005) | (0.003) |
| **Income** | | | | | | |
| Median income | 1.007e-07$^{*}$ | 1.258e-07$^{**}$ | -2.465e-08$^{*}$ | -1.151e-08 | 1.264e-07$^{***}$ | 8.876e-09 |
| | (4.230e-08) | (4.061e-08) | (1.140e-08) | (6.808e-09) | (3.181e-08) | (1.494e-08) |
| **Energy burden** | | | | | | |
| Mean energy burden | -0.416$^{***}$ | -0.407$^{***}$ | -0.01 | -0.034$^{***}$ | -0.277$^{***}$ | -0.099$^{***}$ |
| | (0.058) | (0.056) | (0.016) | (0.009) | (0.044) | (0.021) |
| **Race and ethnicity (compared to "Non-Latino White")** | | | | | | |
| Black | 0.017$^{***}$ | -0.006$^{*}$ | 0.024$^{***}$ | 0.007$^{***}$ | -0.01$^{***}$ | -0.003$^{**}$ |
| | (0.003) | (0.003) | (8.502e-04) | (5.076e-04) | (0.002) | (0.001) |
| White, Hispanic or Latino | 0.027$^{**}$ | 0.026$^{**}$ | 7.895e-04 | 4.676e-04 | 0.017$^{*}$ | 0.011$^{**}$ |
| | (0.01) | (0.009) | (0.003) | (0.002) | (0.007) | (0.003) |
| Asian | 0.018 | 0.018 | -6.975e-04 | -0.003 | 0.016 | 0.002 |
| | (0.019) | (0.018) | (0.005) | (0.003) | (0.014) | (0.007) |
| Other | 0.001 | -0.01 | 0.011$^{***}$ | 3.811e-04 | -0.01 | -0.003 |
| | (0.008) | (0.008) | (0.002) | (0.001) | (0.006) | (0.003) |

| | Any Program | Any Market-Rate Program | IQ Audit & DI | Audit & DI | HVAC Rebate | Appliance Recycling |
|---|---|---|---|---|---|---|
| **Limited English (compared to "Not limited English")** | | | | | | |
| Limited English | -0.011 | 0.002 | -0.012* | 0.004 | -0.005 | 0.006 |
| | (0.018) | (0.017) | (0.005) | (0.003) | (0.013) | (0.006) |
| **Householder age (compared to "Less than 35 years")** | | | | | | |
| 35 to 44 years | -0.002 | 4.207e-04 | -0.002 | -0.001 | -4.264e-04 | 8.548e-04 |
| | (0.008) | (0.008) | (0.002) | (0.001) | (0.006) | (0.003) |
| 45 to 54 years | 0.006 | 0.006 | 1.135e-04 | 5.618e-04 | 0.004 | 0.001 |
| | (0.008) | (0.008) | (0.002) | (0.001) | (0.006) | (0.003) |
| 55 to 64 years | 0.023** | 0.021* | 0.003 | 0.002 | 0.019** | 1.513e-04 |
| | (0.008) | (0.008) | (0.002) | (0.001) | (0.006) | (0.003) |
| 65 to 74 years | 0.035*** | 0.029*** | 0.007** | 0.004* | 0.025*** | -1.855e-04 |
| | (0.009) | (0.009) | (0.002) | (0.001) | (0.007) | (0.003) |
| 75 to 84 years | 0.044*** | 0.044*** | 0.001 | 0.008*** | 0.034*** | 0.004 |
| | (0.011) | (0.011) | (0.003) | (0.002) | (0.008) | (0.004) |
| 85 years and over | 0.064*** | 0.054*** | 0.009* | 0.006** | 0.042*** | 0.009 |
| | (0.014) | (0.014) | (0.004) | (0.002) | (0.011) | (0.005) |
| **Tenure** | | | | | | |
| Median year moved in | 4.680e-04** | 5.265e-04** | -5.103e-05 | 6.523e-06 | 5.589e-04*** | -1.032e-04 |
| | (1.671e-04) | (1.604e-04) | (4.506e-05) | (2.690e-05) | (1.257e-04) | (5.902e-05) |
| **Vintage** | | | | | | |
| Median year structure built | 7.497e-05 | 9.788e-05* | -2.830e-05* | 2.571e-06 | 1.154e-04*** | -3.061e-05 |
| | (4.479e-05) | (4.300e-05) | (1.208e-05) | (7.210e-06) | (3.369e-05) | (1.582e-05) |
| **Building type (compared to "Single-family home")** | | | | | | |
| 2-4 units | 5.948e-04 | 0.004 | -0.003 | -0.001 | 0.001 | 0.003 |
| | (0.009) | (0.008) | (0.002) | (0.001) | (0.007) | (0.003) |
| 5-9 units | -0.028** | -0.02* | -0.008** | -0.002 | -0.014 | -0.002 |
| | (0.01) | (0.009) | (0.003) | (0.002) | (0.007) | (0.003) |
| 10+ units | -0.041*** | -0.03*** | -0.011*** | -0.006*** | -0.023*** | -0.002 |
| | (0.007) | (0.006) | (0.002) | (0.001) | (0.005) | (0.002) |
| Other | -0.025*** | -0.025*** | 8.403e-04 | -4.958e-04 | -0.02*** | -0.004 |
| | (0.006) | (0.006) | (0.002) | (0.001) | (0.005) | (0.002) |
| **Occupancy (compared to "Renter occupied")** | | | | | | |
| Owner occupied | 0.011 | 0.012* | -8.490e-04 | -2.767e-04 | 0.009 | 0.002 |
| | (0.006) | (0.006) | (0.002) | (9.817e-04) | (0.005) | (0.002) |

| | Any Program | Any Market-Rate Program | IQ Audit & DI | Audit & DI | HVAC Rebate | Appliance Recycling |
|---|---|---|---|---|---|---|
| **Urbanization (compared to "Metropolitan area")** | | | | | | |
| Micropolitan area | -0.012*** | -0.012*** | -4.958e-04 | -8.451e-04*** | -0.008*** | -0.003*** |
| | (0.002) | (0.001) | (4.150e-04) | (2.478e-04) | (0.001) | (5.437e-04) |
| Rural | -0.017*** | -0.016*** | -0.001 | -0.001** | -0.01*** | -0.005*** |
| | (0.002) | (0.002) | (5.899e-04) | (3.522e-04) | (0.002) | (7.728e-04) |
| **Electric territory (compared to "Electric service not from Utility A")** | | | | | | |
| Electric service from Utility A | 0.023*** | 0.02*** | 0.004*** | 0.004*** | 0.004*** | 0.013*** |
| | (0.001) | (0.001) | (2.998e-04) | (1.790e-04) | (8.362e-04) | (3.927e-04) |
| **Constant** | | | | | | |
| Constant | -1.096*** | -1.256*** | 0.155 | -0.02 | -1.35*** | 0.264* |
| | (0.332) | (0.319) | (0.09) | (0.053) | (0.25) | (0.117) |
| Observations | 1496 | 1496 | 1496 | 1496 | 1496 | 1496 |
| Log Likelihood | 3.767e+03 | 3.828e+03 | 5.728e+03 | 6.499e+03 | 4.193e+03 | 5.324e+03 |
| Akaike Inf. Crit. | -7.480e+03 | -7.602e+03 | -1.140e+04 | -1.294e+04 | -8.332e+03 | -1.059e+04 |
| *Note:* | | | | | | *p<0.05; **p<0.01; ***p<0.001 |

**Targeted Voluntary Conversion CPP Emissions Compliance Offset Analysis**

**Inputs:**

| | | **Source** |
|---|---|---|
| Metric Tons CO2 Per Therm of Pipeline Natural Gas Combustion (tons CO2/ therm) | 0.0053 | US EPA: https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator-calculations-and-references |
| Average Avista Use Per OR Residential Customer (therms/yr) | 564 | UG 519 Avista Exh 903 'Exh C-Brief' Cell F14*12 months |
| Emissions Removed From Avista's Portfolio per Voluntary Residential NPA Participant | 3.0 | |
| Residential Customer Participation in NPA: Technical Potential (customers/yr) | 338 | UG 519 CUB/303 Garrett/ 'Aldyl-A Replacement Cost per Customer' 'Customers Served AAPR' Cell C17 |
| Total Remaining Residential Customers Eligible From 2027-2037 | 3718 | |
| Remaining Program Period 2027-2037 (yrs) | 11 | |
| Program Participation | 0.10 | CUB/311 Garrett/ 'LBNL, who is participating in residential EE programs?' LBNL, Who is participating in residential energy efficiency programs?' (Nov. 2021) https://eta-publications.lbl.gov/sites/default/files/ee_program_participation.pdf at 17. |
| Present Residential Customer Base Rate ($/the) | $0.76603 | UG 519 Avista Exh 903 'Exh C-Brief' Cell D6 |
| Present Residential Customer Basic Charge ($/mo) | $11.25 | UG 519 Avista Exh 903 'Exh C-Brief' Cell D4 |
| Avg Residential Base Revenue ($/yr) | $567.04 | |

| **Year** | **Eligible Participants Remaining** | **New NPA Participation (customers/yr)** | **Total Customers Converted Through NPA to Date** | **CPP Compliance Emissions Removed per Year (tons CO2/ yr)** | **Value in Avoided RNG ($/yr)** | **Gas System Base Revenue Lost ($/yr)** |
|---|---|---|---|---|---|---|
| 2027 | 3718 | 34 | 34 | 101 | $47,658 | $19,165.98 |
| 2028 | 3380 | 31 | 65 | 193 | $92,803 | $36,589.60 |
| 2029 | 3042 | 28 | 92 | 276 | $135,175 | $52,270.86 |
| 2030 | 2704 | 25 | 117 | 349 | $174,515 | $66,209.76 |
| 2031 | 2366 | 22 | 138 | 413 | $210,562 | $78,406.29 |
| 2032 | 2028 | 18 | 157 | 468 | $243,056 | $88,860.47 |
| 2033 | 1690 | 15 | 172 | 514 | $271,737 | $97,572.28 |
| 2034 | 1352 | 12 | 184 | 551 | $296,346 | $104,541.73 |
| 2035 | 1014 | 9 | 194 | 579 | $316,622 | $109,768.81 |
| 2036 | 676 | 6 | 200 | 597 | $332,306 | $113,253.54 |
| 2037 | 338 | 3 | 203 | 606 | $343,138 | $114,995.90 |
| 2038 | 0 | 0 | 203 | 606 | $343,138 | $114,995.90 |
| 2039 | 0 | 0 | 203 | 606 | $343,138 | $114,995.90 |
| 2040 | 0 | 0 | 203 | 606 | $343,138 | $114,995.90 |
| 2041 | 0 | 0 | 203 | 606 | $343,138 | $114,995.90 |
| 2042 | 0 | 0 | 203 | 606 | $343,138 | $114,995.90 |
| 2043 | 0 | 0 | 203 | 606 | $343,138 | $114,995.90 |
| 2044 | 0 | 0 | 203 | 606 | $343,138 | $114,995.90 |
| 2045 | 0 | 0 | 203 | 606 | $343,138 | $114,995.90 |
| 2046 | 0 | 0 | 203 | 606 | $343,138 | $114,995.90 |
| 2047 | 0 | 0 | 203 | 606 | $343,138 | $114,995.90 |
| 2048 | 0 | 0 | 203 | 606 | $343,138 | $114,995.90 |
| 2049 | 0 | 0 | 203 | 606 | $343,138 | $114,995.90 |
| 2050 | 0 | 0 | 203 | 606 | $343,138 | $114,995.90 |

**Targeted Voluntary Conversion CPP Emissions Compliance Offset Analysis**

**Inputs:**

| | | Source |
|---|---|---|
| Metric Tons CO2 Per Therm of Pipeline Natural Gas Combustion (tons CO2/ therm) | 0.0053 | US EPA: https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator-calculations-and-references |
| Average Avista Use Per OR Residential Customer (therms/yr) | 564 | UG 519 Avista Exh 903 'Exh C-Brief' Cell F14*12 months |
| Emissions Removed From Avista's Portfolio per Voluntary Residential NPA Participant | 3.0 | |
| Residential Customer Participation in NPA: Technical Potential (customers/yr) | 338 | UG 519 CUB/303 Garrett/ 'Aldyl-A Replacement Cost per Customer' 'Customers Served AAPR' Cell C17 |
| Total Remaining Residential Customers Eligible From 2027-2037 | 3718 | |
| Remaining Program Period 2027-2037 (yrs) | 11 | |
| Program Participation | 0.10 | CUB/311 Garrett/ 'LBNL, who is participating in residential EE programs?' LBNL, Who is participating in residential energy efficiency programs?' (Nov. 2021) https://eta-publications.lbl.gov/sites/default/files/ee_program_participation.pdf at 17. |
| Present Residential Customer Base Rate ($/the) | $0.76603 | UG 519 Avista Exh 903 'Exh C-Brief' Cell D6 |
| Present Residential Customer Basic Charge ($/mo) | $11.25 | UG 519 Avista Exh 903 'Exh C-Brief' Cell D4 |
| Avg Present Residential Base Revenue ($/yr) | $567.04 | |

| Year | Eligible Participants Remaining | New NPA Participation (customers/yr) | Total Customers Converted Through NPA to Date | CPP Compliance Emissions Removed per Year (tons CO2/ yr) | Value in Avoided RNG ($/yr) | Gas System Base Revenue Lost ($/yr) |
|---|---|---|---|---|---|---|
| 2027 | 3718 | 27 | 27 | 81 | $38,126 | $15,332.79 |
| 2028 | 3380 | 25 | 52 | 154 | $74,242 | $29,271.68 |
| 2029 | 3042 | 22 | 74 | 220 | $108,140 | $41,816.69 |
| 2030 | 2704 | 20 | 93 | 279 | $139,612 | $52,967.81 |
| 2031 | 2366 | 17 | 111 | 331 | $168,449 | $62,725.04 |
| 2032 | 2028 | 15 | 125 | 375 | $194,445 | $71,088.37 |
| 2033 | 1690 | 12 | 138 | 411 | $217,390 | $78,057.82 |
| 2034 | 1352 | 10 | 147 | 441 | $237,077 | $83,633.38 |
| 2035 | 1014 | 7 | 155 | 463 | $253,298 | $87,815.05 |
| 2036 | 676 | 5 | 160 | 478 | $265,845 | $90,602.83 |
| 2037 | 338 | 2 | 162 | 485 | $274,510 | $91,996.72 |
| 2038 | 0 | 0 | 162 | 485 | $274,510 | $91,996.72 |
| 2039 | 0 | 0 | 162 | 485 | $274,510 | $91,996.72 |
| 2040 | 0 | 0 | 162 | 485 | $274,510 | $91,996.72 |
| 2041 | 0 | 0 | 162 | 485 | $274,510 | $91,996.72 |
| 2042 | 0 | 0 | 162 | 485 | $274,510 | $91,996.72 |
| 2043 | 0 | 0 | 162 | 485 | $274,510 | $91,996.72 |
| 2044 | 0 | 0 | 162 | 485 | $274,510 | $91,996.72 |
| 2045 | 0 | 0 | 162 | 485 | $274,510 | $91,996.72 |
| 2046 | 0 | 0 | 162 | 485 | $274,510 | $91,996.72 |
| 2047 | 0 | 0 | 162 | 485 | $274,510 | $91,996.72 |
| 2048 | 0 | 0 | 162 | 485 | $274,510 | $91,996.72 |
| 2049 | 0 | 0 | 162 | 485 | $274,510 | $91,996.72 |
| 2050 | 0 | 0 | 162 | 485 | $274,510 | $91,996.72 |

**Targeted Voluntary Conversion CPP Emissions Compliance Offset Analysis**

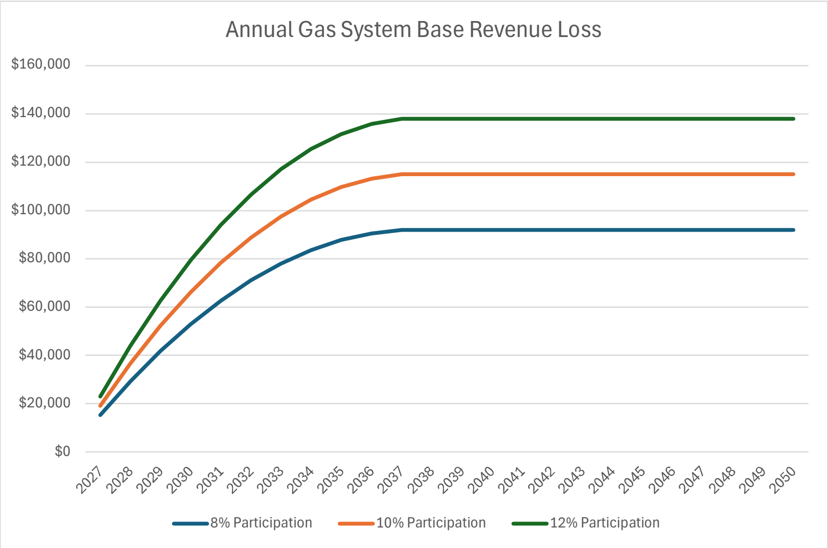
**Inputs:**

| | | **Source** |
|---|---|---|
| Metric Tons CO2 Per Therm of Pipeline Natural Gas Combustion (tons CO2/ therm) | 0.0053 | US EPA: https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator-calculations-and-references |
| Average Avista Use Per OR Residential Customer (therms/yr) | 564 | UG 519 Avista Exh 903 'Exh C-Brief' Cell F14*12 months |
| Emissions Removed From Avista's Portfolio per Voluntary Residential NPA Participant ( | 3.0 | |
| Residential Customer Participation in NPA: Technical Potential (customers/yr) | 338 | UG 519 CUB/303 Garrett/ 'Aldyl-A Replacement Cost per Customer' 'Customers Served AAPR' Cell C17 |
| Total Remaining Residential Customers Eligible From 2027-2037 | 3718 | |
| Remaining Program Period 2027-2037 (yrs) | 11 | |
| Program Participation | 0.10 | CUB/311 Garrett/ 'LBNL, who is participating in residential EE programs?' LBNL, Who is participating in residential energy efficiency programs?' (Nov. 2021) https://eta-publications.lbl.gov/sites/default/files/ee_program_participation.pdf at 17. |
| Present Residential Customer Base Rate ($/the) | $0.76603 | UG 519 Avista Exh 903 'Exh C-Brief' Cell D6 |
| Present Residential Customer Basic Charge ($/mo) | $11.25 | UG 519 Avista Exh 903 'Exh C-Brief' Cell D4 |
| Avg Residential Base Revenue ($/yr) | $567.04 | |

| **Year** | **Eligible Participants Remaining** | **New NPA Participation (customers/yr)** | **Total Customers Converted Through NPA to Date** | **CPP Compliance Emissions Removed per Year (tons CO2/ yr)** | **Value in Avoided RNG ($/yr)** | **Gas System Base Revenue Lost ($/yr)** |
|---|---|---|---|---|---|---|
| 2027 | 3718 | 41 | 41 | 121 | $57,190 | $22,999.18 |
| 2028 | 3380 | 37 | 77 | 231 | $111,364 | $43,907.52 |
| 2029 | 3042 | 33 | 111 | 331 | $162,211 | $62,725.04 |
| 2030 | 2704 | 29 | 140 | 419 | $209,418 | $79,451.71 |
| 2031 | 2366 | 26 | 166 | 496 | $252,674 | $94,087.55 |
| 2032 | 2028 | 22 | 188 | 562 | $291,667 | $106,632.56 |
| 2033 | 1690 | 18 | 206 | 617 | $326,085 | $117,086.73 |
| 2034 | 1352 | 15 | 221 | 661 | $355,615 | $125,450.07 |
| 2035 | 1014 | 11 | 232 | 694 | $379,947 | $131,722.57 |
| 2036 | 676 | 7 | 240 | 716 | $398,767 | $135,904.24 |
| 2037 | 338 | 4 | 243 | 727 | $411,765 | $137,995.08 |
| 2038 | 0 | 0 | 243 | 727 | $411,765 | $137,995.08 |
| 2039 | 0 | 0 | 243 | 727 | $411,765 | $137,995.08 |
| 2040 | 0 | 0 | 243 | 727 | $411,765 | $137,995.08 |
| 2041 | 0 | 0 | 243 | 727 | $411,765 | $137,995.08 |
| 2042 | 0 | 0 | 243 | 727 | $411,765 | $137,995.08 |
| 2043 | 0 | 0 | 243 | 727 | $411,765 | $137,995.08 |
| 2044 | 0 | 0 | 243 | 727 | $411,765 | $137,995.08 |
| 2045 | 0 | 0 | 243 | 727 | $411,765 | $137,995.08 |
| 2046 | 0 | 0 | 243 | 727 | $411,765 | $137,995.08 |
| 2047 | 0 | 0 | 243 | 727 | $411,765 | $137,995.08 |
| 2048 | 0 | 0 | 243 | 727 | $411,765 | $137,995.08 |
| 2049 | 0 | 0 | 243 | 727 | $411,765 | $137,995.08 |
| 2050 | 0 | 0 | 243 | 727 | $411,765 | $137,995.08 |

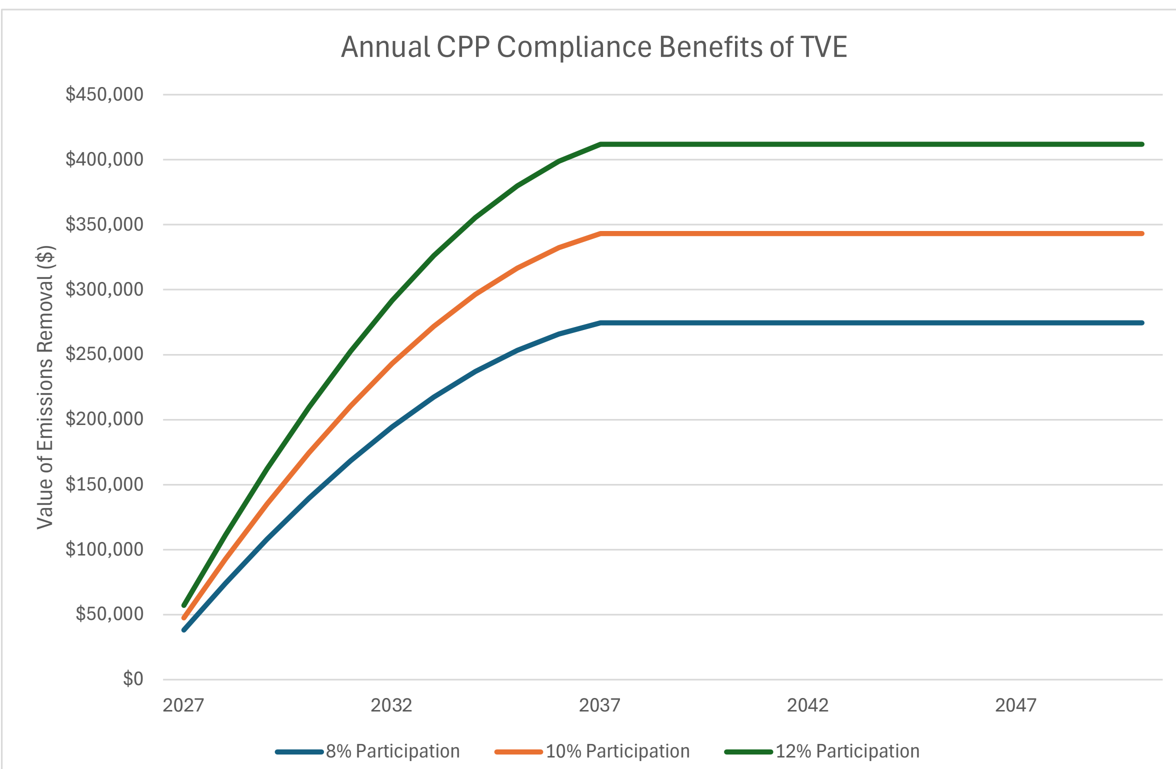
**Annual Gas System Base Revenue Loss**

| Year | 8% Participation | 10% Participation | 12% Participation |
|---|---|---|---|
| 2027 | $15,333 | $19,166 | $22,999 |
| 2028 | $29,272 | $36,590 | $43,908 |
| 2029 | $41,817 | $52,271 | $62,725 |
| 2030 | $52,968 | $66,210 | $79,452 |
| 2031 | $62,725 | $78,406 | $94,088 |
| 2032 | $71,088 | $88,860 | $106,633 |
| 2033 | $78,058 | $97,572 | $117,087 |
| 2034 | $83,633 | $104,542 | $125,450 |
| 2035 | $87,815 | $109,769 | $131,723 |
| 2036 | $90,603 | $113,254 | $135,904 |
| 2037 | $91,997 | $114,996 | $137,995 |
| 2038 | $91,997 | $114,996 | $137,995 |
| 2039 | $91,997 | $114,996 | $137,995 |
| 2040 | $91,997 | $114,996 | $137,995 |
| 2041 | $91,997 | $114,996 | $137,995 |
| 2042 | $91,997 | $114,996 | $137,995 |
| 2043 | $91,997 | $114,996 | $137,995 |
| 2044 | $91,997 | $114,996 | $137,995 |
| 2045 | $91,997 | $114,996 | $137,995 |
| 2046 | $91,997 | $114,996 | $137,995 |
| 2047 | $91,997 | $114,996 | $137,995 |
| 2048 | $91,997 | $114,996 | $137,995 |
| 2049 | $91,997 | $114,996 | $137,995 |
| 2050 | $91,997 | $114,996 | $137,995 |



**Annual Avoided CPP Compliance Costs**

| Year | 8% Participation | 10% Participation | 12% Participation |
|---|---|---|---|
| 2027 | $38,126 | $47,658 | $57,190 |
| 2028 | $74,242 | $92,803 | $111,364 |
| 2029 | $108,140 | $135,175 | $162,211 |
| 2030 | $139,612 | $174,515 | $209,418 |
| 2031 | $168,449 | $210,562 | $252,674 |
| 2032 | $194,445 | $243,056 | $291,667 |
| 2033 | $217,390 | $271,737 | $326,085 |
| 2034 | $237,077 | $296,346 | $355,615 |
| 2035 | $253,298 | $316,622 | $379,947 |
| 2036 | $265,845 | $332,306 | $398,767 |
| 2037 | $274,510 | $343,138 | $411,765 |
| 2038 | $274,510 | $343,138 | $411,765 |
| 2039 | $274,510 | $343,138 | $411,765 |
| 2040 | $274,510 | $343,138 | $411,765 |
| 2041 | $274,510 | $343,138 | $411,765 |
| 2042 | $274,510 | $343,138 | $411,765 |
| 2043 | $274,510 | $343,138 | $411,765 |
| 2044 | $274,510 | $343,138 | $411,765 |
| 2045 | $274,510 | $343,138 | $411,765 |
| 2046 | $274,510 | $343,138 | $411,765 |
| 2047 | $274,510 | $343,138 | $411,765 |
| 2048 | $274,510 | $343,138 | $411,765 |
| 2049 | $274,510 | $343,138 | $411,765 |
| 2050 | $274,510 | $343,138 | $411,765 |



| RNG ($/dth) | Source |
|---|---|
| $30 | UG 490 Opening Testimony Staff/900, Dlouhy/Page 38 |
| $25 | UG 490 Reply Testimony NW Natural/2200, Kravitz/Page 23 |

| Year | RNG ($/dth) |
|---|---|
| 2027 | 25 |
| 2028 | 25.5 |
| 2029 | 26 |
| 2030 | 26.5 |
| 2031 | 27 |
| 2032 | 27.5 |
| 2033 | 28 |
| 2034 | 28.5 |
| 2035 | 29 |
| 2036 | 29.5 |
| 2037 | 30 |
| 2038 | 30 |
| 2039 | 30 |
| 2040 | 30 |
| 2041 | 30 |
| 2042 | 30 |
| 2043 | 30 |
| 2044 | 30 |
| 2045 | 30 |
| 2046 | 30 |
| 2047 | 30 |
| 2048 | 30 |
| 2049 | 30 |
| 2050 | 30 |


# Climate Protection Program: Overview

This document provides a plain language overview of Oregon's Climate Protection Program. DEQ is providing this overview for information purposes only. See Oregon Administrative Rules (OAR) chapter 340, division 273 for the Climate Protection Program rules.

## Purposes of the Climate Protection Program

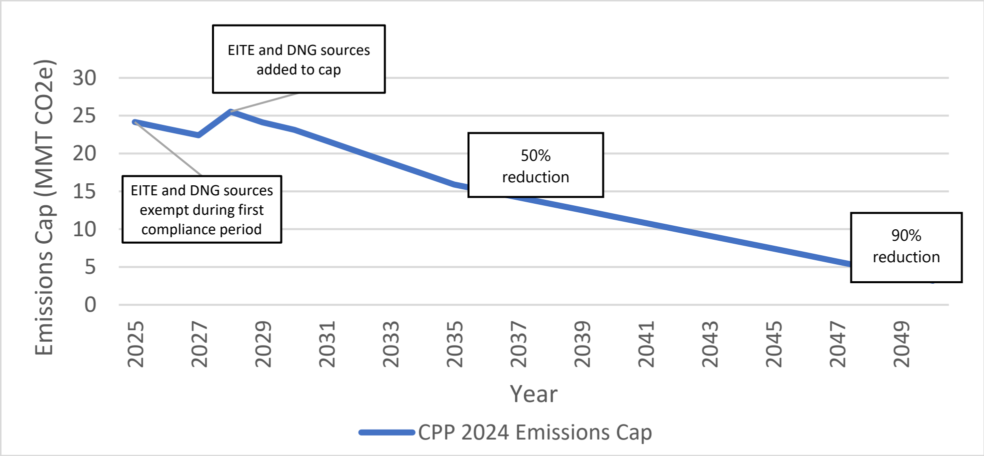
- To reduce greenhouse gas emissions,
- To achieve co-benefits from other air contaminant reductions,
- To support a strong statewide economy, and
- To enhance public welfare for Oregon communities, particularly environmental justice communities, including communities of color, communities experiencing low-income, tribal, and rural communities.

**To support these purposes, the CPP:**

- Requires that regulated entities reduce greenhouse gas emissions,
- Supports reduction of other types of air pollution
- Prioritizes reduction of greenhouse gas emissions and other air pollutants in environmental justice communities disproportionately burdened by pollution
- Provides regulated entities with compliance options to minimize business and consumer economic impacts,
- Incentivizes the reduction of emissions from industries in Oregon, and
- Allows regulated entities to comply in part with Community Climate Investments

### Regulating greenhouse gas emissions

The CPP has a declining and enforceable limit, or cap, on greenhouse gas emissions from the use of fossil fuels. The cap is lowered over time reaching a 50% percent reduction by 2035 and 90% reduction in emissions by 2050 from a baseline of average 2017-2019 emissions.

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800-452-4011 | TTY: 711 | deqinfo@deq.oregon.gov

State of Oregon
DEQ Department of Environmental Quality

### How do regulated companies comply?

Each year, DEQ distributes a set number of free compliance instruments to regulated companies. The program gives regulated companies the option to bank compliance instruments if they emit less than what they were allowed, trade compliance instruments with other regulated companies, or earn additional credits by contributing funds to DEQ-approved entities through the community climate investments program. The total number of compliance instruments distributed by DEQ each year is equal to that year's emissions cap, except for 2025. In 2025, for one time only, DEQ will also distribute early reduction compliance instruments.

For every metric ton of greenhouse gas emissions a company is responsible for, it must submit a compliance instrument or a Community Climate Investment credit to DEQ. The first compliance period starts Jan. 1, 2025, and covers emissions through the end of 2027. During the first compliance period regulated companies can choose to use Community Climate Investment credits to meet up to 15% of their compliance. The first demonstration of compliance will be in December 2028 for the years 2025-2027. All subsequent compliance periods will be two years.

The Climate Protection Program is one of many complementary policies and programs in Oregon, such as elective vehicle rebates, the Clean Fuels Program, and utility planning, to reduce climate pollution. The CPP drive emissions reductions as well as leverage reductions achieved through other incentives, which will further support compliance.

## Who is a regulated entity?

### Fuel suppliers

- Natural gas utilities (local distribution companies), and
- Suppliers of gasoline, diesel, kerosene, and propane with emissions that meet or exceed a threshold for inclusion. Over time, the threshold declines to cover a wider scope of emissions and suppliers, and the program will capture approximately 99% of in-scope combustion emissions from liquid fuels and propane used in Oregon.

### Energy-intensive trade-exposed industry sources

- Stationary sources in trade-exposed industry sectors with annual covered emissions that meet or exceed a threshold of 15,000 metric tons of carbon dioxide equivalent (MT $CO_2e$).

### Direct natural gas sources

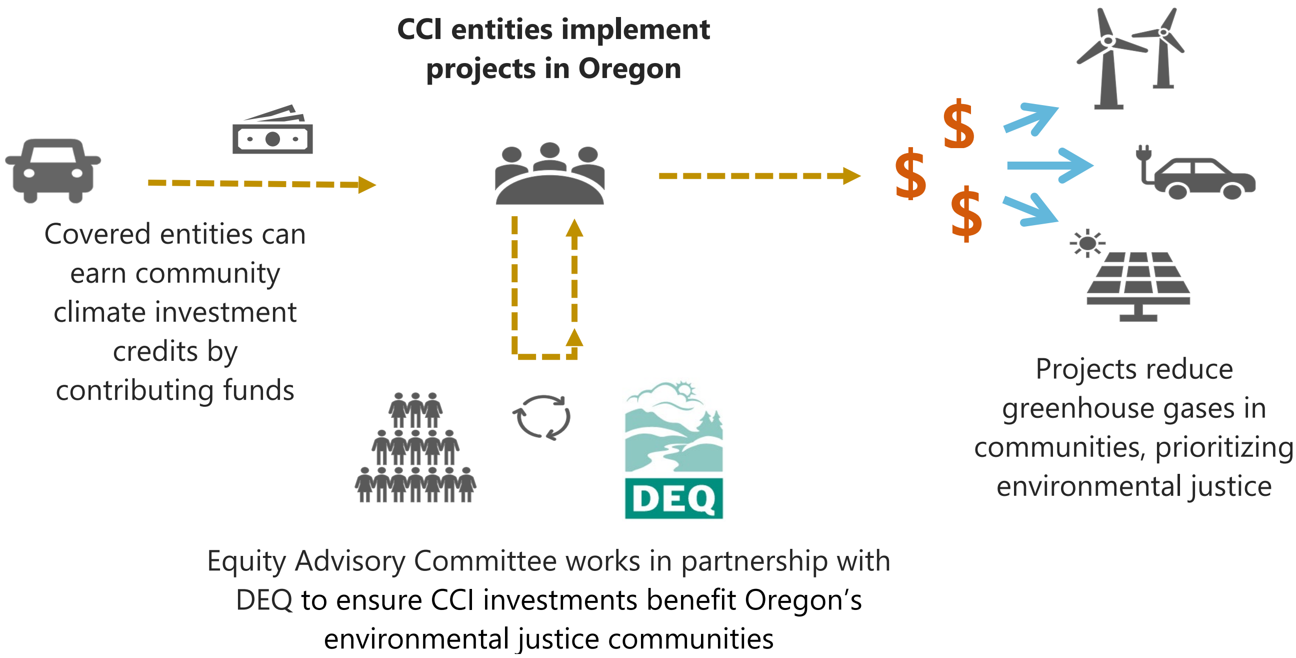
- Stationary sources in non-EITE industry sectors that use natural gas distributed to the source by an entity other than a local distribution company and that meet or exceed a threshold of 15,000 metric tons of carbon dioxide equivalent (MT $CO_2e$).

### Note on regulated entities

EITE and DNG sources are exempt for the first compliance period (2025-2027) and will not receive compliance instruments for this period. During this time, DEQ will conduct a rulemaking to determine carbon emissions intensity targets for EITE and DNG sources before the second compliance period (2028-2029).

# What are Community Climate Investments?

Covered entities can choose to earn Community Climate Investment credits by contributing funds to third-party entities that will implement projects that reduce greenhouse gas emissions in Oregon. The starting contribution amount to receive a CCI credit is $129.




# What are environmental justice communities in Oregon?

Environmental justice communities mean communities of color, communities experiencing lower incomes, communities experiencing health inequalities, tribal communities, rural communities, remote communities, coastal communities, communities with limited infrastructure and other communities traditionally underrepresented in public processes and adversely harmed by environmental and health hazards, including seniors, youth and persons with disabilities.

# What kinds of projects will be supported by CCI funds?

Eligible projects include actions that reduce greenhouse gas emissions in Oregon resulting from:

- Transportation of people, freight, or both
- An existing or new residential use or structure
- An existing or new industrial process or structure
- An existing or new commercial use or structure

# More Information

Visit the Climate Protection Program web page.

# Non-discrimination statement

DEQ does not discriminate on the basis of race, color, national origin, disability, age, sex, religion, sexual orientation, gender identity, or marital status in the administration of its programs and activities. Visit DEQ's Civil Rights and Environmental Justice page.

HEALTH

# Study Finds Switching From Gas to Electric Stoves Cuts Indoor Air Pollution

New research evaluated the feasibility and benefits of transitioning from gas to induction stoves in affordable housing.

By Columbia Climate School
July 26, 2024

Switching from a gas stove to an electric induction stove can reduce indoor nitrogen dioxide air pollution, a known health hazard, by more than 50 percent according to new research led by scientists at Columbia University Mailman School of Public Health and the Columbia Climate School.

**Photo: Ivan Radic via wikimedia Commons**

The study was carried out as part of a pilot project titled "Out of Gas, In with Justice" led by Northern Manhattan-based nonprofit WE ACT for Environmental Justice . The pilot is the first to evaluate the feasibility and benefits of transitioning from gas to induction stoves in affordable housing. It is also the first study to evaluate the effects of residential cooking electrification in a public housing setting in the U.S.

This research comes as New York City passed a law in 2023 that will ban gas-powered heaters, cooking stoves and water boilers in all new buildings to meet climate goals. Similarly, in 2022, California adopted an electric-friendly statewide building code requiring buildings to be "all-electric ready." Gas stoves are used in about 38 percent of U.S. homes but their prevalence varies significantly by state, reaching 62 percent in New York.

Twenty low-income households in a public housing building in the Bronx were recruited and randomized to have their gas stove replaced with an induction stove or serve as a control group. Between October 2021 and July 2022, homes were monitored continuously over three seven-day periods to assess indoor air quality ($NO_2$, CO, $PM_{2.5}$) and stove use before and after the intervention. The impact of cooking on indoor air quality was also evaluated during controlled cooking tests. Participants were invited to take part in a focus group.

Researchers found a 56 percent reduction in average daily $NO_2$ concentrations in the induction stove group compared with the control group using gas stoves.

"We have seen these high pollution numbers in most apartments with [gas stoves and] inadequate ventilation. Unless a vent moves air outside an apartment, then it is just mixing the pollution around your apartment," said study co-author Roisin Commane , an atmospheric chemist at Lamont-Doherty Earth Observatory, which is part of the Columbia Climate School. In many New York City kitchens that use gas stoves, she added, it's important to open the window when cooking or you may see similar levels of pollution in your apartment.

During focus group discussions, participants using the new stoves unanimously reported being pleased with the transition. None of the participants opted to switch back to gas cooking despite having the option to do so at zero cost.

While the study did not measure the climate benefits of the intervention, there is ample research on the negative effects of gas stoves . Residential gas use accounts for 15 percent of the country's gas consumption. Gas is composed primarily of methane, a greenhouse gas with more than 80 times the global warming potential of CO2 over a 20-year timeframe.

"A green energy transition should prioritize electric stoves, which both reduce greenhouse gas emissions and improve the health of vulnerable populations," said senior author Darby Jack , professor of environmental health sciences at Columbia's Mailman School of Public Health.

"People of color and low-income individuals are more likely to live in smaller, older apartments that have poor ventilation, ineffective or broken range hoods and dated appliances that leak more gas. It is crucial for environmental justice that they are not left behind in this transition," said study co-author Annie Carforo, climate justice campaigns manager at WE ACT .

*This story was adapted from a post originally published by Columbia University Mailman School of Public Health.*

# Nitrogen Dioxide's Impact on Indoor Air Quality

The two most prevalent oxides of nitrogen are nitrogen dioxide ($NO_2$) and nitric oxide (NO). Both are toxic gases with $NO_2$ being a highly reactive oxidant and corrosive.

**On this page:**



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## Sources of Nitrogen Dioxide

The primary sources indoors are combustion processes, such as:

- unvented combustion appliances, e.g. gas stoves
- vented appliances with defective installations
- welding
- tobacco smoke
- kerosene heaters.

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# Health Effects Associated with Nitrogen Dioxide

EPA's Integrated Risk Information System Profile for Nitrogen Dioxide
<http://cfpub.epa.gov/ncea/iris/iris_documents/documents/subst/0080_summary.pdf>.

- $NO_2$ acts mainly as an irritant affecting the mucosa of the eyes, nose, throat and respiratory tract.
- Extremely high-dose exposure (as in a building fire) to $NO_2$ may result in pulmonary edema and diffuse lung injury.
- Continued exposure to high $NO_2$ levels can contribute to the development of acute or chronic bronchitis.
- Low level $NO_2$ exposure may cause:
    - increased bronchial reactivity in some asthmatics
    - decreased lung function in patients with chronic obstructive pulmonary disease
    - increased risk of respiratory infections, especially in young children

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# Levels in Homes

Average level in homes without combustion appliances is about half that of outdoors. In homes with gas stoves, kerosene heaters or un-vented gas space heaters, indoor levels often exceed outdoor levels.

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# Steps to Reduce Exposure

Venting the $NO_2$ sources to the outdoors, and assuring that combustion appliances are correctly installed, used and maintained are the most effective measures to reduce exposures.

(These are the same steps as those used to reduce exposure to carbon monoxide).

- Keep gas appliances properly adjusted.

- Consider purchasing a vented space heater when replacing an un-vented one.
- Use proper fuel in kerosene space heaters.
- Install and use an exhaust fan vented to outdoors over gas stoves.
- Open flues when fireplaces are in use.
- Choose properly sized wood stoves that are certified to meet EPA emission standards. Make certain that doors on all wood stoves fit tightly.
- Have a trained professional inspect, clean and tune-up central heating system (furnaces, flues and chimneys) annually. Repair any leaks promptly.
- Do not idle the car inside garage.

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# Standards or Guidelines

No standards have been agreed upon for nitrogen oxides in indoor air. ASHRAE and the US. EPA National Ambient Air Quality Standards list 0.053 ppm as the average annual limit for $NO_2$ in outdoor air.

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# Additional Resources

Nitrogen Dioxide "Criteria Air Pollutants" <https://epa.gov/criteria-air-pollutants> from the Office of Air and Radiation.

Last updated on March 5, 2024

# The Commonwealth of Massachusetts

## DEPARTMENT OF PUBLIC UTILITIES

D.P.U. 20-80-B December 6, 2023

Investigation by the Department of Public Utilities on its own Motion into the role of gas local distribution companies as the Commonwealth achieves its target 2050 climate goals.

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ORDER ON REGULATORY PRINCIPLES AND FRAMEWORK

TABLE OF CONTENTS

## SUMMARY

The Department of Public Utilities ("Department") announces a regulatory framework intended to set forth its role and that of the Massachusetts gas local distribution companies ("LDCs") in helping the Commonwealth achieve its target of net-zero greenhouse gas ("GHG") emissions by 2050. Global Warming Solutions Act, St. 2008, c. 298 ("GWSA"); Executive Office of Energy and Environmental Affairs Determination of Statewide Emissions Limit for 2050 (April 22, 2020). The Department seeks to enable the Commonwealth to move into its clean energy future while simultaneously safeguarding ratepayer interests and maintaining affordability for customers; ensuring safe, reliable, and cost-effective natural gas service; minimizing the burden on low- and moderate-income households as the transition proceeds; and facilitating a just workforce and energy infrastructure transition.

In this proceeding, the Department reviewed eight potential decarbonization "pathways" to achieving the target of a 90 percent gross reduction in GHG emissions by 2050 as compared to 1990 levels, as well as interim GHG emissions reductions targets of 50 percent by 2030 and 75 percent by 2040. The decarbonization pathways are designed to reflect different futures for the LDCs and their customers, ranging from ongoing use of the LDCs' distribution networks to 100-percent decommissioning of gas distribution infrastructure in the Commonwealth. The Department makes no findings as to a preferred pathway or technology; rather, our aim is to create and promote a regulatory framework that is flexible, protects consumers, promotes equity, and provides for fair consideration of the current and future technologies and commercial applications required to meet the Commonwealth's clean energy objectives.

The Department considered six regulatory design recommendations intended to facilitate the Commonwealth's transition: (1) support customer adoption of and conversion to electrified and decarbonized heating technologies; (2) blend renewable gas supply into gas-resource portfolios; (3) pilot and deploy innovative electrification and decarbonized technologies; (4) manage gas embedded infrastructure investments and cost recovery; (5) evaluate and enable customer affordability; and (6) develop LDC transition plans and chart future progress. The Department makes specific findings about each of these regulatory design recommendations as detailed in the Order.

As to supporting customer adoption of and conversion to electrified and decarbonized heating technologies, the Department finds that to achieve the Commonwealth's climate targets, there must be a significant increase in the use of electrified and decarbonized heating technologies. The Department and LDCs can play a pivotal role by enhancing incentives and expanding the Mass Save energy efficiency programs to facilitate customer use of heat pumps. The Department also addresses the critical need to minimize costs for customers, including through pursuit of outside funding sources, and prioritizing workforce development to enable a just transition framework for gas industry workers as well as customers.

The Department rejects the recommendation to change its current gas supply procurement policy to support the addition of renewable natural gas ("RNG") to LDC supply portfolios due to concerns regarding the costs and availability of RNG as well as its uncertain

status as zero-emissions fuel. The Department does support the option for customers to be able to purchase RNG from their LDC or a supplier at full cost to the customer.

Given the critical importance of significantly decarbonizing the heating sector, the Department considered the proposal that the LDCs pilot and deploy the following four technologies: (1) networked geothermal; (2) targeted electrification; (3) hybrid heating systems; and (4) renewable hydrogen. As detailed in the Order, the Department views networked geothermal projects as those with the most potential to reduce GHG emissions, and expresses support for targeted electrification as well.

The Department seeks to dissuade gas customer expansion and to align rate design with the Commonwealth's climate objectives. To achieve this, the Department instructs gas utilities to revise their per-customer revenue decoupling mechanism to a decoupling approach based on total revenues. Removing the incentive to add new customers aligns the LDCs' rate design with climate objectives and GHG emissions reductions targets. The Department finds it must examine the issue of depreciation, i.e., the period of time over which a capital investment is recovered, and stranded assets. As an initial step, the Department directs all LDCs to conduct a comprehensive review that includes a forecast of the potential magnitude of stranded investments, and to identify the impacts of accelerated depreciation proposals, as well as potential alternatives to accelerated depreciation.

The Department finds that consideration of non-gas pipeline alternatives ("NPAs"), defined broadly to include electrification, thermal networked systems, targeted energy efficiency and demand response, and behavior change and market transformation, is necessary to minimize investments in the gas pipeline system that may be stranded costs in the future as decarbonization measures are implemented. Going forward, the Department states that as part of future cost recovery proposals, LDCs will bear the burden of demonstrating that NPAs were adequately considered and found to be non-viable or cost prohibitive to receive full cost recovery.

The Department agrees with suggestions that the standards for investments to serve new customers be examined. The Department therefore directs the LDCs to begin reviewing existing tariffs, policies, and practices related to new service connections to determine: (1) the number of *de facto* free extension allowances; (2) whether current models and policies accurately reflect the anticipated income and timeframe over which the capital investments will be recovered; and (3) whether existing state policies are inconsistent with current practices by incentivizing new customers to join the gas distribution system and allowing LDCs to extend their systems through plant additions. Further, in reviewing future applications for new service, the Department will examine the appropriateness of the existing standard—that there be no adverse impacts on existing natural gas customers—in the context of a broader climate mandate.

The Department observes that there are numerous concerns regarding affordability for customers, including the upfront costs required for customers to convert appliances and heating systems from natural gas to electricity, and also higher rates for customers who remain on the system. Cost shifting between migrating and non-migrating customers and between rate classes, and potential disproportionate impacts on low-income customers and customers from environmental justice populations, present equity challenges as well.

Finally, the Department finds that the clean energy transition will require coordinated planning between LDCs and electric distribution companies, monitoring progress through LDC reporting, and aligning existing Department practices with climate targets. To that end, the Department orders LDCs to submit individual Climate Compliance Plans to the Department every five years beginning in 2025, and to propose climate compliance performance metrics in their upcoming performance-based regulation filings, ensuring a proactive approach to achieving climate targets.

## I. INTRODUCTION

The Department of Public Utilities ("Department") opened this inquiry on October 29, 2020, to examine the role of Massachusetts gas local distribution companies ("LDCs") in helping the Commonwealth achieve its 2050 climate targets, and to identify strategies for enabling the Commonwealth to move into its net zero greenhouse gas ("GHG") emissions energy future while simultaneously safeguarding ratepayer interests; ensuring safe, reliable, and cost-effective natural gas service; and potentially recasting the role of LDCs in the Commonwealth. Investigation by the Department of Public Utilities on its own Motion into the Role of Gas Local Distribution Companies as the Commonwealth Achieves its Target 2050 Climate Goals, D.P.U. 20-80, Vote and Order Opening Investigation at 1 (2020) ("Vote and Order"). The Department specifically sought to develop a regulatory and policy framework to guide the evolution of the gas distribution industry in the context of a clean energy transition that requires the Department to consider new policies and structures to protect ratepayers as the Commonwealth reduces its reliance on natural gas. D.P.U. 20-80, at 4. This proceeding is necessarily one step—not the first and certainly not the last—as we endeavor to chart a path forward that enables the Commonwealth to achieve its target of net zero GHG emissions by 2050. Global Warming Solutions Act, St. 2008, c. 298 ("GWSA"); Executive Office of Energy and Environmental Affairs Determination of Statewide Emissions Limit for 2050 (April 22, 2020), available at https://www.mass.gov/doc/final-signed-letter-of-determination-for-2050-emissions-limit/download (last visited November 29, 2023). The Department docketed this matter as D.P.U. 20-80.

Through this investigation, the Department has gathered a significant body of information from the LDCs and a wide range of institutional and individual stakeholders, evincing the need for an evolving, multifaceted, broadly coalitional, and responsive process as we seek to define and meet the significant challenges and potential opportunities that are presented not only by the Commonwealth's climate targets, but also by the threat and reality of the climate crisis itself. The Department acknowledges and appreciates the time, commitment, and thoughtful contributions provided by many stakeholders throughout this proceeding. In this Order, we first enunciate a set of regulatory principles that will guide our decision-making in this and future dockets. We then address in more detail the reports and analyses produced by the LDCs and their consultants, as well the comments and analyses submitted by stakeholders. Our purpose here never has been to dictate one path forward, but to gather information and identify existing and potential means within our authority to remove barriers to the clean energy transition and find ways for the Department to facilitate and accelerate pursuit of our 2050 climate targets. To that end, in this Order we identify future areas of inquiry that will be explored and note those future proceedings (including technical conferences, adjudications, and additional investigations) where we will investigate and implement the issues and principles identified herein.

In enunciating regulatory principles, our intent is that these foundational propositions will inform many of the Department's processes and proceedings through a "whole of DPU" approach, not limited to those matters such as this where climate and GHG-reduction policies explicitly are at issue, but also inform rate design and other more traditional Department functions within our authority. We also note areas in which the Department cannot (or cannot yet) act unilaterally, observing where legislative change or other agency action is required as we seek to pursue vigorously our role in a "whole of government" response to the climate crisis. The Department is one governmental actor working toward the clean energy transition, and we anticipate necessary future legislative action, as well as implementation from the Executive Office of Energy and Environmental Affairs ("EEA"), Massachusetts Department of Energy Resources ("DOER"), Massachusetts Department of Environmental Protection ("MassDEP"), and the Massachusetts Clean Energy Center ("MassCEC"), among others. Finally, in establishing these guiding principles we take care to emphasize the role of communities, neighborhoods, and individuals within the clean energy transition, as we seek to facilitate active participation in a "whole of society" approach to electrification, decarbonization, a just and equitable workforce transition, and equitable investment in communities in pursuit of our 2050 climate targets. While the Department cannot dictate the choices of individual consumers, we can and will seek to maintain a safe, reliable, and affordable system while encouraging and facilitating the thousands of small transitions that must occur on household, neighborhood, and community levels for the Commonwealth as a whole to move into its clean energy future.

## II. PROCEDURAL HISTORY

On October 29, 2020, the Department voted to open an investigation into potential policies that will enable the Commonwealth to reach its target of net zero GHG emissions by

2050 and the role of Massachusetts gas LDCs[1] in achieving that goal.[2] D.P.U. 20-80, at 1. The Department stated its intent to solicit utility and stakeholder input in this investigation, noting that EEA was (1) developing in consultation with MassDEP and DOER an evaluation of potential pathways to achieving the Commonwealth's 2050 GWSA statewide net zero emissions limit; and (2) preparing a Clean Energy and Climate Plan ("CECP")[3] for 2030. D.P.U. 20-80, at 3, citing Executive Office of Energy and Environmental Affairs Determination of Statewide Emissions Limit for 2050 (April 22, 2020); G.L. c. 21N, §§ 3, 4; Massachusetts 2050 Decarbonization Roadmap (December 2020), available at

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1 The gas LDCs subject to the Department's jurisdiction are: The Berkshire Gas Company ("Berkshire Gas"); Boston Gas Company d/b/a National Grid ("National Grid (gas)"); Eversource Gas Company of Massachusetts ("EGMA") and NSTAR Gas Company ("NSTAR Gas"), each d/b/a Eversource Energy (together, "Eversource"); Fitchburg Gas and Electric Light Company d/b/a Unitil ("Unitil"); and Liberty Utilities (New England Natural Gas Company) Corp. d/b/a Liberty ("Liberty").

2 Prior to the Department's issuance of the Order, the Attorney General of the Commonwealth of Massachusetts ("Attorney General") filed a petition ("Petition") requesting that the Department open an investigation to assess the future of the LDCs' operations and planning in light of the Commonwealth's target of net zero GHG emissions by 2050 (Attorney General Petition at 1 (June 4, 2020), citing GWSA; Executive Office of Energy and Environmental Affairs Determination of Statewide Emissions Limit for 2050 (April 22, 2020); State of the State Address (January 21, 2020)). The Attorney General's request has been incorporated into this docket.

3 EEA prepares a CECP every five years, beginning in 2010. The CECP sets forth a policy/roadmap for the Commonwealth to meet the GHG emissions limits by 2050. The Interim 2030 CECP developed by EEA was released in December 2020. The final CECP for 2025 and 2030 was released in June 2022 ("2025/2030 CECP") and can be found at https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030 (last visited November 29, 2023).

https://www.mass.gov/doc/ma-2050-decarbonization-roadmap/download (last visited November 29, 2023). The Department stated its anticipation that the 2050 Decarbonization Roadmap ("2050 Roadmap") and 2030 CECP (together, the "Roadmaps") would set forth policies affecting ratepayers, LDCs, and the gas industry as a whole. D.P.U. 20-80, at 3. The Department therefore directed the LDCs to: (1) initiate a joint request for proposals ("RFP") for an independent consultant to conduct a detailed study of each LDC and analyze the feasibility of all pathways identified in the Roadmaps, as well as any additional strategies identified by the independent consultant, to help the Commonwealth achieve its goal of net zero GHG emissions by 2050; (2) submit a report prepared by the independent consultant that integrates the individual analyses of each LDC into one, collective report containing comparisons among the LDCs; and (3) submit individual proposals to the Department that includes each LDC's recommendations and plans for helping the Commonwealth achieve its 2050 climate targets, supported by the independent consultant's report, along with all analyses and supporting data. The Vote and Order further directed that the LDCs engage in a stakeholder process to solicit feedback and advice on the independent consultant's report and the LDCs' individual proposals prior to submitting these documents to the Department. D.P.U. 20-80, at 4-5.

On November 6, 2020, the Attorney General filed a motion requesting clarification ("Motion for Clarification") of the Department's Vote and Order with respect to its directives for stakeholder participation in (1) the development of the RFP to hire an independent consultant; and (2) the Massachusetts gas LDCs' development of the report and proposals

(Attorney General Motion for Clarification at 1). The Department received several responses to the Attorney General's Motion for Clarification from interested stakeholders.[4] On February 10, 2021, the Department issued an order on the Attorney General's request. Investigation by the Department of Public Utilities on its own Motion into the Role of Gas Local Distribution Companies as the Commonwealth Achieves its Target 2050 Climate Goals, D.P.U. 20-80-A (2021).

On March 1, 2021, the Attorney General filed a notice of retention of experts and consultants in this investigation at funding not to exceed $150,000, filed pursuant to G.L. c. 12, § 11E(b) ("Notice of Retention"). On May 21, 2021, the Attorney General filed a revised notice to retain experts and consultants seeking an amended funding at an amount not to exceed $350,000 ("Revised Notice of Retention"). The Department received no comments on the Attorney General's Notice of Retention or Revised Notice of Retention[5] and on June 29, 2021, the Department issued an order approving the Attorney General's Revised

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4 The following stakeholders submitted responses to the Attorney General's Motion for Clarification: Conservation Law Foundation ("CLF"); the Sierra Club; Environmental Defense Fund ("EDF"); joint response by the gas LDCs; the Town of Hopkinton; the Gas Leaks Allies; and Mothers Out Front.

5 Pursuant to G.L. c. 12, § 11E(b), the Department must allow all full parties to a proceeding the opportunity to comment on the Attorney General's Notice of Retention. The only full party to this proceeding is the Attorney General. Nevertheless, the Attorney General served her Notice of Retention on the LDCs and the LDCs did not comment. It is unclear whether the Attorney General served her Revised Notice of Retention on the LDCs, but it was not required.

Notice of Retention. D.P.U. 20-80, Order on Attorney General's Revised Notice of Retention of Experts and Consultants (June 29, 2021).

On March 1, 2021, and September 1, 2021, and in accordance with the Department's directives, the LDCs provided status updates regarding the progress with respect to the RFP and stated that, through the RFP, the LDCs selected Energy & Environmental Economics ("E3"), with ScottMadden as subcontractor (together, "Consultants"), to be the independent consultant for the pathways analysis, and the retention of Environmental Resources Management ("ERM") to develop and facilitate the stakeholder process.

On March 18, 2022, pursuant to the Department's Vote and Order, each LDC submitted: (1) the company's individual proposals and plans for helping the Commonwealth achieve its 2050 climate targets within reports entitled "net zero enablement plan[s]" ("Net Zero Enablement Plan," or collectively, "Net Zero Enablement Plans"); and (2) a report on the technical analysis of decarbonization pathways ("Pathways Report") as well as a report on considerations and alternatives for regulatory designs to support transition plans ("Regulatory Designs Report") (collectively, the "Reports").[6] In addition, on this same date the LDCs submitted: (1) a stakeholder engagement report ("Stakeholder Engagement Report") prepared by ERM to develop and facilitate the stakeholder engagement process; (2) the gas LDCs' common regulatory framework and overview of the Net Zero Enablement

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[6] The Reports were prepared by the LDCs' Consultants.

Plans ("Framework and Overview"); and (3) a proposed Net Zero Enablement Plan model tariff ("Model Tariff").

On March 23, 2022, the Department issued a Notice of Filing, Public Hearing, and Request for Comments ("Notice") along with an Order of Notice ("Order of Notice").[7] The

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[7] On February 14, 2022, the Attorney General and DOER submitted correspondence outlining procedural recommendations, including a proposed procedural schedule for this matter, for which CLF, National Consumer Law Center ("NCLC"), Low-Income Energy Affordability Network ("LEAN"), and Home Energy Efficiency Team ("HEET") expressed support. In consideration of the recommendations submitted by the Attorney General and DOER, the Department set a procedural schedule in this matter on March 24, 2022.

On March 28, 2022, CLF, Acadia Center, EDF, HEET, and Sierra Club jointly filed a motion for reconsideration of the Department's Order of Notice issued on March 23, 2022 ("Joint Motion for Reconsideration"). The Joint Motion for Reconsideration requested that the Department: (1) rescind its March 23, 2022 Order of Notice; (2) extend the procedural schedule set forth by the Department on March 24, 2022; and (3) allow for additional process in this docket, including the opportunity to intervene or otherwise obtain party status, participate in discovery, present expert testimony, and to cross-examine witnesses (Joint Motion for Reconsideration at 11-12).

On April 4, 2022, the Department received a jointly filed response by the gas LDCs ("LDCs' Response to Joint Motion for Reconsideration") objecting to the Joint Motion for Reconsideration on the grounds that (1) the Joint Motion for Reconsideration is improper and contradictory to the purposes of this proceeding and (2) the process outlined in the Department's Notice and procedural schedule is consistent with both Department precedent for similar proceedings and the Attorney General's Petition in this matter (LDCs' Response to Joint Motion for Reconsideration at 3-4).

On April 15, 2022, the Department issued a Hearing Officer Memorandum noting that pursuant to the Notice of Filing and Public Hearing issued in this matter, the deadline for submitting written comments was May 6, 2022. The Department encouraged stakeholders to submit comments identifying issues with the consultants' reports and the LDCs' individual proposals and suggestions and recommendations of alternative

Department held technical sessions on the Reports and Net Zero Enablement Plans on March 30, 2022, and April 15, 2022. On May 3, 2022, and May 5, 2022, the Department held public hearings to receive comments on the Reports and Net Zero Enablement Plans.

The Department received more than 230 initial comments from various stakeholders and members of the public ("Initial Comments"). The Department directed the gas LDCs to respond to the Initial Comments, and the LDCs submitted their response on July 29, 2022 ("LDC Joint Comments"). On September 8, 2022, the Department requested all final comments from stakeholders in response to the LDCs' Joint Comments by October 14, 2022 ("Final Comments").[8, 9]

The Department issued seven sets of common information requests to the gas LDCs, one set of information requests each to Berkshire Gas and Unitil, and two sets of information

proposals, particularly alternative regulatory framework proposals (Hearing Officer Memorandum at 2 (April 15, 2022)). The Department stated that its goal is to develop an overall regulatory framework that will be used to guide statewide and company-specific proposals, so the Department specifically sought alternative proposals that will inform the Department's analysis on the regulatory framework. The Department further stated its intent to schedule additional technical conferences to explore regulatory framework proposals after the May 6, 2022 comment deadline (Hearing Officer Memorandum at 2 (April 15, 2022)).

8 The substance of the Initial Comments, LDC Joint Comments, and Final Comments is discussed further below in Sections V and VI.

9 DOER submitted late-filed Final Stakeholder Comments on October 17, 2022, pursuant to its request to submit its final comments one business day late. The Department herein accepts DOER's late-filed Final Stakeholder Comments.

requests each to Eversource, Liberty, and National Grid (gas). In total, the Department issued 113 information requests to the LDCs.

## III. BEYOND GAS: A SUMMARY OF REGULATORY PRINCIPLES

Massachusetts has long been a national leader in adopting state policies to address climate change. Through our actions in this proceeding, we continue in that leadership role by tackling the challenging issues associated with developing a pathway for the transition in the natural gas industry that will be necessary for the Commonwealth to achieve its target of net-zero GHG emissions by 2050, as set forth in the GWSA, and to achieve the sector-specific emissions reductions established in the CECP for 2025 and 2030.[10]

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10 In addition to the GWSA, the Commonwealth has enacted An Act Creating a Next-Generation Roadmap for Massachusetts Climate Policy, St. 2021, c. 8 ("2021 Climate Act"), and An Act Driving Clean Energy and Offshore Wind, St. 2022, c. 179 ("2022 Clean Energy Act"). The GWSA, as amended by the 2021 Climate Act and implemented by the Secretary of EEA, requires the Commonwealth to reduce GHG emissions between 10 and 25 percent from 1990 levels by 2020, at least 50 percent from 1990 levels by 2030, at least 75 percent from 1990 levels by 2040, and achieve net-zero emissions by 2050 with a gross reduction in emissions of 85 percent from 1990 levels. G.L. c. 21N § 4; Executive Office of Energy and Environmental Affairs Determination of Statewide Emissions Limit for 2050 (April 22, 2020) (setting a legally binding statewide limit of net-zero GHG emissions by 2050, defined as 85 percent below 1990 levels); State of the State Address (January 2021) (Governor commits to achieving net zero greenhouse gas emissions by 2050), available at https://archives.lib.state.ma.us/handle/2452/816469 (last visited November 29, 2023). The CECP for 2025 and 2030 set sector-specific emissions reduction targets, as mandated by the 2021 Climate Act, setting an emissions reduction target for residential heating and cooling of 29 percent by 2025 and 49 percent by 2030 and an emission reduction target for commercial and industrial heating and cooling of 35 percent by 2025 and 49 percent by 2030 (2025/2030 CECP at 23). The 2025/2030 CECP and supporting information including sublimits is available at https://www.mass.gov/info-details/massachusetts-clean-energy-and-climate-plan-for-2025-and-2030 (last visited November 29, 2023).

As we chart the path for this transition, we emphasize that nothing we do here is intended to jeopardize the rate recovery of the billions of dollars of existing investments in natural gas infrastructure by the LDCs operating within the Commonwealth. Traditional notions of the regulatory compact continue to apply to those investments and, accordingly, there generally must be some demonstration of imprudence before recovery of existing investments can be challenged. At the same time, however, it is fair to say that a different lens will be applied to gas infrastructure investments going forward. The Department will be examining more closely whether such additional investments are in the public interest, given the now-codified commitment toward achieving Commonwealth's target of achieving net-zero GHG emissions by 2050 and the urgent need to address climate change. In this "beyond gas" future, we will be exploring and implementing policies that are geared toward minimizing additional investment in pipeline and distribution mains and achieving decarbonization in the residential, commercial, and industrial sectors.

The ambitious mandates established by the Commonwealth require gas LDCs to move beyond "business as usual" in their gas system planning, whether involving proposed expansion of service to new areas or investments necessary to maintain the safety of existing natural gas infrastructure. As discussed in subsequent sections of this Order, we are acting, within our existing statutory authority, to discourage further expansion of the natural gas distribution system. We will do so by revisiting the "public interest" standard we apply in evaluating proposed expansions, by examining the line extension policies followed by LDCs that may be inconsistent with the broader public policy of achieving necessary GHG reductions, and by encouraging consideration of zero-carbon alternatives, such as electrification and thermal networked systems, to traditional gas system capital investments.

With respect to maintenance of the existing natural gas infrastructure, our "beyond gas" future will similarly involve close scrutiny of the extent to which additional investment is necessary, with an eye toward minimization of costs that may be stranded in the future as decarbonization measures are implemented in the natural gas industry. In particular, we will generally require the examination of non-gas pipeline alternatives ("NPAs"), defined broadly to include electrification, thermal networked systems, targeted energy efficiency and demand response, and behavior change and market transformation.[11] Going forward, LDCs will have the burden to demonstrate the consideration of NPAs as a condition of recovering additional investment in pipeline and distribution mains. As discussed in later sections of this Order, we will continue to explore opportunities for strategic and targeted decommissioning of portions of LDC service territories, through demonstration projects deploying both electrification and thermal network technologies.

As in the case of the transition to clean energy in the electricity sector, the decarbonization of the natural gas industry may result in higher costs being imposed on ratepayers. Given the urgency of addressing the climate crisis, however, we are reluctant to slow the pace at which the transition must occur due to concerns about affordability for

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11 The comprehensive analysis of NPAs that we envision incorporates many of the elements identified in the Attorney General's proposed "investment alternatives calculator" and the "geographic marginal cost analysis" proposed by DOER, both of which are discussed later in this Order.

low- and moderate-income utility customers. Rather, the Department will address these issues in a separate proceeding, to be commenced later this year, dedicated toward examining innovative solutions to address the energy burden and affordability, such as capping energy bills by percentage of income or offering varying levels of low-income discounts, that have been implemented in other jurisdictions. We are confident that we can develop a solution—which likely will require a change in our statutory authority—that will allow us to address affordability issues in an effective manner and still enable us to achieve the necessary progress toward the Commonwealth's GHG emission reduction limits.

The transition of the natural gas industry involves other important considerations that we will need to address in a thoughtful and deliberate manner. As the Commonwealth accomplishes greater penetration of building electrification and distributed energy resources, we need to prioritize opportunities for residents of environmental justice populations[12] to benefit from moving beyond gas. This includes electrification and thermal network projects as well as workforce development and employment prospects for people historically left out

[12] In Massachusetts, an environmental justice population is a neighborhood where one or more of the following criteria are true: (1) the annual median household income is 65 percent or less of the statewide annual median household income; (2) people of color make up 40 percent or more of the population; (3) 25 percent or more of households identify as speaking English less than "very well"; (4) people of color make up 25 percent or more of the population and the annual median household income of the municipality in which the neighborhood is located does not exceed 150 percent of the statewide annual median household income. Executive Office of Energy and Environmental Affairs Environmental Justice Policy at 4 (2021). <u>See</u> https://www.mass.gov/info-details/environmental-justice-populations-in-massachusetts (last visited November 29, 2023).

of the clean energy transition (e.g., women, people of color, Indigenous Peoples, veterans, people living with disabilities, immigrants, people who were formerly incarcerated). We also will work with the LDCs to encourage workforce development training and employment opportunities for gas workers and steelworkers to participate in a just transition away from fossil fuels. Thermal network projects, for example, offer attractive opportunities for workers in the gas industry to perform similar work in the installation of the infrastructure to deliver decarbonized heating and cooling solutions to residential and commercial customers.

Finally, as is apparent from the vast number of issues addressed in this Order, developing a regulatory framework to guide the transition of the natural gas industry in Massachusetts is an exceedingly complex undertaking. It involves fundamental ratemaking issues regarding the continued financial viability of LDCs and preserving their ability to raise capital on reasonable terms, as well as developing an orderly means of recovering in rates the billions of dollars in existing investment in natural gas infrastructure while maintaining the safety of the gas distribution system so long as natural gas continues to be delivered through it. It involves maintaining the affordability of energy services, and being particularly mindful to avoid burdening low- to moderate-income households that may be left behind—and potentially bearing a greater burden of the fixed costs of maintaining existing natural gas infrastructure—as more affluent households transition away from natural gas appliances. It involves recognizing the potential for the disproportionate distribution of the negative impacts associated with building, operating, and maintaining gas infrastructure. And it involves addressing the workforce issues associated with a gradual decommissioning of the existing natural gas distribution system. As we continue to develop the regulatory framework in subsequent proceedings following the issuance of this Order, we emphasize the importance of the continued involvement of all relevant stakeholders in the process. It is important, for example, for LDCs to move beyond "business as usual" practices toward active participation in developing innovative solutions to achieving the clean energy future codified in the Commonwealth's GHG emissions reduction targets. These exceedingly complex issues can be addressed effectively only with the broad participation of all the constituencies affected by this transition. We look forward to exploring these issues collectively in future proceedings.

## IV. SCOPE AND AUTHORITY

The Department has broad authority to supervise gas companies pursuant to G.L. c. 164, § 76; Massachusetts Electric Company v. Department of Public Utilities, 419 Mass. 239, 245 (1994). It is well established, however, that the Department's general supervisory authority cannot arise from a vacuum. Massachusetts Oilheat Council, Inc., D.T.E. 00-57, at 6-7 (2001) citing Massachusetts Electric Company, 419 Mass. at 246.

The Legislature has taken steps to focus the Department's regulatory mandate on GHG emissions reductions in addition to its traditional concerns of ensuring safety, security, reliability, equity, and affordability. Both the 2021 Climate Act and 2022 Clean Energy Act include changes to the Department's regulatory authority over gas companies. In the 2021 Climate Act, the Legislature added Section 1A to G.L. c. 25, which provides:

> In discharging its responsibilities under [chapter 25] and chapter 164, the department shall, with respect to itself and the entities it regulates, prioritize safety, security, reliability of service, affordability, equity and reductions in

> greenhouse gas emissions to meet statewide greenhouse gas emission limits and sublimits established pursuant to chapter 21N.

The 2021 Climate Act also revised G.L. c. 21N, § 6, to charge the Secretary of EEA with establishing programs to meet GHG emissions limits and sublimits and implement the roadmap plans established by G.L. c. 21N. In addition, the 2022 Clean Energy Act amended G.L. c. 164, § 141, which now directs the Department, in all decisions or actions regarding rate designs, to consider, among other things, the impact of such decisions or actions on the reduction of GHG emissions as mandated by G.L. c. 21N to reduce energy use.

Recent legislation has not, however, amended or repealed other statutes that govern the Department's regulation of the natural gas industry. As we note in this Order, the Department may revisit its own precedent and standards of review in certain areas, and in other areas, legislative action may be required for the Department to be able to implement change or pursue particular pathways for achieving the Commonwealth's 2050 targets. For example, G.L. c. 164, § 30, establishes Department review of an LDC's petition to expand its service territory, which the Department has evaluated under a public interest standard. An Act Relative to Gas Leaks, St. 2014, c. 149, was enacted on June 26, 2014 ("Gas Leaks Act") and codified the uniform gas leaks classifications at G.L. c. 164, § 144; gas system enhancement plans ("GSEPs") at G.L. c. 164, § 145; and required the Department to, on or before January 1, 2015, authorize gas companies "to design and offer programs to customers which increase the availability, affordability, and feasibility of natural gas service for new customers." St. 2014, c. 149, § 3. In addition, the 2022 Clean Energy Act mandates that DOER establish a demonstration project in which up to ten municipalities may adopt zoning ordinances that restrict fossil fuel use in the construction sector. St. 2022, c. 179, § 84(b). As part of the demonstration project, DOER must collect data from the participants and submit reports to the Legislature every two years that include recommendations for the continuation or termination of the demonstration project. St. 2022, c. 179, § 84(e).

Finally and most specifically to our consideration of the Reports, Net Zero Enablement Plans, and other submissions in this proceeding, Section 77 of the 2022 Clean Energy Act provides:

> Notwithstanding any general or special law or rule, regulation or order to the contrary, the department of public utilities shall not approve any company-specific plan filed pursuant to the DPU Docket No. 20-80, Investigation by the Department of Public Utilities on its own Motion into the Role of Gas Local Distribution Companies as the Commonwealth Achieves its Target 2050 Climate Goals, prior to conducting an adjudicatory proceeding with respect to such plan.

St. 2022, c. 179, § 77. Based on this clear directive, the Department will not approve the Net Zero Enablement Plans and/or the Model Tariff submitted by the LDCs in this investigation but will identify future adjudicatory proceedings and filings where we may properly consider company-specific plans.

The Department does not cite the above statutes as obstacles to the regulatory principles articulated in this Order. Rather, we do so only to acknowledge that our authority as a regulatory agency is bound by the limits established by law. Where pathways or proposals are inconsistent with existing statutes, the Department will note where additional legislative change or authority is necessary.

## V. DECARBONIZATION REPORTS

### A. Pathways to Net Zero

At the direction of the Department, the LDCs retained the Consultants to perform a detailed study for each LDC, analyzing the feasibility of each decarbonization pathway identified by the Roadmaps. D.P.U. 20-80, at 3-5. In an effort to allow for meaningful comparisons among the LDCs and to ensure the consideration of all decarbonization strategies, the Department required the Consultants to identify any pathways not examined in the Roadmaps and employ consistent methods and considerations to analyze decarbonization opportunities for each individual LDC. D.P.U. 20-80, at 5. The Department instructed the Consultants to combine the individual analyses into a single, collective report presenting: (1) a quantification of the costs and actual economy-wide GHG emissions reductions involved in transitioning the natural gas system; and (2) a discussion of qualitative factors such as impacts on public safety, reliability, economic development, equity, emissions reductions, and timing for each identified pathway, among other requirements. D.P.U. 20-80, at 5-6.

To fulfill this requirement, the LDCs submitted the Pathways Report, which provides eight pathways designed to reflect different futures[13] for the LDCs and their customers

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13 The eight pathways are not forecasts, but rather narratives that allow for the identification and comparison of the relative costs, risks, and feasibility of different futures (Pathways Report at 11, 34). The Pathways Report further notes that analyzing decarbonization pathways out to 2050 involves a multi-decade horizon that is inherently assumption-driven and uncertain across several factors, including cost, consumer behavior, technology development, deployment, and other factors (Pathways Report at 27).

(Pathways Report at 11). Each of the eight pathways achieves the Commonwealth's goals of 90 percent gross GHG emissions reductions and net-zero GHG emissions by 2050 compared to 1990 levels, as well as the interim statutory GHG emissions reduction goals of 50 percent by 2030 and 75 percent by 2040 (Pathways Report at 11, 48). Similar to the 2050 Roadmap, all pathways have approximately 4.5 million metric tons of gross economy-wide, non-energy emissions[14] remaining in 2050 (Pathways Report at 48).

The eight pathways include the deployment of seven space-heating technologies,[15] and leverage various levels of renewable fuels, energy efficiency,[16] and building electrification technologies (Pathways Report at 31, 49-57). The eight decarbonization pathways impute a range of uses and roles for the gas system over time, spanning from 100 percent decommissioning of the system to large amounts of renewable gases being supplied to high-efficiency gas appliances (Pathways Report at 11, 63-75). In parallel, the Pathways

14 A more detailed description of GHG accounting (i.e., direct, electric sector, non-energy, and renewable fuels emission accounting methods) can be found in the Pathways Report, Appendix 1, at 21-28. Further information on common baseline economy-wide assumptions such as population growth and electrification of the transportation sector can be found in the Pathways Report, Appendix 1, at 8-9.

15 The seven identified space-heating technologies include: (1) air source heat pumps; (2) ground source heat pumps; (3) hybrid heat pumps; (4) networked geothermal; (5) standard gas furnaces; (6) high efficiency gas furnaces; and (7) gas heat pumps (Pathways Report at 31).

16 The Pathways Report states that energy efficiency is a foundational strategy to enable decarbonization of heating across all scenarios, reducing challenges associated with both electrification and decarbonized fuel-based strategies (Pathways Report at 47, 52-53, 110).

Report considers impacts on the electric system due to electrification-driven peaks and increased generation capacity (Pathways Report at 57-63).

The Pathways Report notes several key uncertainties across the pathways and develops sensitivity analyses to better capture assumptions in its modeling (Pathways Report at 34-35). Informed by a literature review,[17] the Pathways Report provides both optimistic and conservative views for the following six uncertainties: (1) incremental costs of cold-climate air source heat pumps ("cold-climate ASHPs"); (2) technical performance of cold-climate ASHPs; (3) incremental electric sector distribution system costs; (4) networked geothermal system installation costs; (5) cost and availability of renewable fuels;[18] and (6) opportunities for gas system cost avoidance (Pathways Report at 35). Additionally, the Pathways Report projects three pathways that would involve gas system departures through a geographically planned approach,[19] resulting in potential reductions in operation and maintenance expenses,

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17 The Consultants conducted a literature review of decarbonization strategies studied and implemented in the U.S. and internationally (Pathways Report at 28-29; App. 2).

18 The Pathways Report defines renewable fuels as an umbrella term for renewably produced alternatives to fossil fuels, inclusive of renewable gases in the distribution system and renewable fuels in the transportation sector (Pathways Report at 9). The Report designates the following gases as renewable and having a net–zero GHG impact according to the Massachusetts GHG Inventory: (1) biomethane produced through anaerobic digestion or gasification; (2) hydrogen produced from electrolysis powered by renewable energy; and (3) synthetic natural gas produced from renewable hydrogen and a climate-neutral source of carbon (Pathways Report at 9, 52, 110; App. 1, at 21-22). The Department does not necessarily consider biomethane, hydrogen, or synthetic natural gas to be renewable fuels.

19 The Department further discusses geographically planned approaches and customer choice topics below in Section VI.B and Section VI.D.

GSEP expenditures,[20] and capital replacement costs (Pathways Report at 68-69). The Pathways Report further explores the cost and equity implications of combining the revenue requirement for the LDCs to maintain and operate both the gas and a networked geothermal system (Pathways Report at 72-75).[21]

The Pathways Report states that three pathways were modified from the Roadmaps: (1) high electrification, in which greater than 90 percent of the building sector electrifies primarily through the adoption of cold-climate ASHPs; (2) low electrification, in which 65 percent of the building sector electrifies with cold-climate ASHPs and gas customer count declines by 40 percent compared to today; and (3) interim 2030 CECP, in which the building sector electrifies at an accelerated pace, following the goals outlined in the Interim 2030 CECP (Pathways Report at 29-31). The 100 percent gas decommissioning pathway assumes that the building and industrial sectors fully electrify by 2050, with roughly 25 percent of the building sector converting to networked geothermal (Pathways Report at 31). The targeted electrification pathway assumes that greater than 90 percent of buildings electrify, with LDC customers converting to cold-climate ASHPs in a targeted approach (Pathways Report at 31). The networked geothermal pathway considers roughly 25 percent of the building sector

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20 The Department allows LDCs to recover certain costs associated with the replacement of leak-prone pipeline infrastructure, pursuant to G.L. c. 164, § 145.

21 The Pathways Report posits that a combined rate base would exhibit increased system costs, but theoretically would mitigate costs per customer as a larger portion of the customers remain that may share in the recovery of the combined system costs (Pathways Report at 73-75).

converting to networked geothermal systems, with remaining LDC customers using renewable gas[22] (Pathways Report at 31). The hybrid electrification[23] pathway assumes that greater than 90 percent of buildings electrify through cold-climate ASHPs paired with RNG (Pathways Report at 31). Lastly, the efficient gas equipment scenario assumes that the building sector largely adopts high-efficiency gas appliances supplied by a combination of renewable gas, with the industrial sector converting to dedicated hydrogen pipelines (Pathways Report at 31). Table 1 below contains a summary of each decarbonization pathway.

**Table 1: Key Narratives by Decarbonization Pathway (Pathways Report at 29-32)**

| Pathway | Overview |
|---|---|
| Low Electrification (inspired by 2050 Decarbonization Roadmap "Pipeline Gas") | High electrification in the transportation sector. Buildings partly electrify. Building sector electrifies 65 percent of buildings through the adoption of ASHPs. Gas customer count declines by 40 percent compared to today. |
| High Electrification (inspired by 2050 Decarbonization Roadmap "All Options") | High electrification in both buildings and transportation sector. Building sector electrifies more than 90 percent primarily through the adoption of ASHPs. |
| Interim 2030 CECP | Accelerated electrification and building shell measures based on the interim 2030 building sector target. |

22 The Pathways Report defines "renewable gas" as "an umbrella term referring to renewably produced alternatives to natural gas that can be blended into the distribution pipeline system" (Pathways Report at 9, App. 1, at 15). Under this definition, renewable gases include biomethane produced through anaerobic digestion or gasification, renewable hydrogen, and synthetic natural gas ("SNG"), further defined and discussed in Section VI.C of this Order (Pathways Report at 9, App. 1, at 15).

23 The Pathways Report describes hybrid electrification as a space heating strategy that combines electric heat pumps with a gas or fuel oil backup that can be powered by renewable fuels (Pathways Report at 8).

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|---|---|
| Hybrid Electrification | Heat pumps are paired with gas or fuel oil backup to mitigate electric sector impacts. More than 90 percent of buildings electrify through ASHPs paired with renewable gas back-up (hybrid heat pumps) that supply heating in cold hours of the year. |
| Networked Geothermal | Part of the gas system is strategically replaced by networked geothermal systems. LDCs evolve their business model and convert +/- 25 percent of the building sector to networked geothermal systems. Remaining gas customers use renewable gas as their main source of heating by 2050. |
| Targeted Electrification | Part of the gas system is strategically decommissioned with customers adopting ASHPs. More than 90 percent of buildings are electrified through a combination of technologies. LDC customers converting to ASHPs do so in a "targeted" approach. |
| Efficient Gas Equipment | Building sector will adopt increasingly efficient gas appliances supplied by decarbonized gas. The industrial sector converts to dedicated hydrogen pipelines. |
| 100 Percent Gas Decommissioning | Building sector and industry will fully electrify allowing for 100 percent decommissioning of the gas distribution system. Building and industrial sectors fully electrify by 2050. +/- 25 percent of the building sector converts to networked geothermal systems. |

Developed with input from both LDCs and stakeholders, the eight pathways and their associated projected cumulative energy system costs (in 2020 dollars)[24] are calculated as follows: (1) high electrification, $87 billion to $111 billion; (2) low electrification, $73 billion to $95 billion; (3) interim 2030 CECP, $93 billion to $121 billion; (4) 100 percent gas decommissioning, $94 billion to $135 billion; (5) targeted electrification,

24 The Pathways Report calculates costs on a levelized basis, including a society-wide discount factor of 3.6 percent, noting that the study does not quantitatively consider the social costs of carbon or avoided costs related to potential health or environmental damages resulting from climate change (Pathways Report, App. 1, at 62).

$73 billion to $109 billion; (6) networked geothermal, $81 billion to $124 billion; (7) hybrid electrification, $63 billion to $92 billion; and (8) efficient gas equipment, $66 billion to $105 billion (Pathways Report, App. 1, at 62-65). The Pathways Report further presents cumulative energy system costs both annually and by decade relative to a reference scenario that does not meet the Commonwealth's 2050 climate targets, delineating the following cost components: (1) demand-side capital; (2) electricity supply; (3) gas system; (4) natural gas commodity costs; (5) liquid renewable fuels commodity costs; (6) renewable gas commodity costs; and (7) networked geothermal installation costs (Pathways Report at 13-14, 26-27, 79-82; App. 1, at 62, 65-66).

Further, the Pathways Report offers an evaluation of the feasibility and level of challenge[25] expected for each pathway across the following criteria: (1) cumulative energy system costs; (2) technology readiness; (3) air quality; (4) workforce transition; (5) customer practicality; (6) near-term customer affordability; (7) long-term customer affordability; and (8) customer equity (Pathways Report at 11-12, 76-79, 84-108). The Pathways Report states that all pathways were assumed to comply with Department and industry standards for safety and reliability (Pathways Report at 11-12, 77, 87-91).

Lastly, the Pathways Report presents several low-regret strategies and commonalities across the LDCs, while highlighting the need for further research and development ("R&D")

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[25] The Pathways Report defines challenge as the magnitude of change from current industry or customers practices and/or amount of policy intervention required (Pathways Report at 76).

and key distinctions among the LDCs (Pathways Report at 109-115). In conclusion, the Pathways Report finds that all pathways imply transformational changes for the Commonwealth, the LDCs, and their customers, and that strategies that use both the gas and electric systems to deliver low-carbon heat to a portion of the buildings in Massachusetts show a lower level of challenge across a range of evaluation criteria (Pathways Report at 11, 109).

B. Stakeholder Comments Concerning the Pathways Report

Many commenters disagree with the Pathways Report's conclusion that pathways utilizing both the gas and electric systems actually would present a lower level of challenge to the Commonwealth in reaching its climate commitments. For example, the Attorney General contends that the lower overall costs reported for the hybrid electrification pathway rest on unsound and unproven assumptions, arguing that the beneficial impacts of hybrid electrification on electric system infrastructure additions could be attained by focusing on building electrification in the near term. (Attorney General Technical Comments[26] at 6-8, 19-21 (May 6, 2022)). Although DOER acknowledges significant alignment between the Pathways Report and the 2050 Roadmap, DOER calls on the Department to acknowledge that electrification is the dominant strategy specified in the 2025/2030 CECP, and to find that the LDCs' proposed plans and framework are not sufficient to achieve decarbonization (DOER

[26] The Office of the Attorney General's Initial Stakeholder Comments on Consultants' Technical Analysis of Decarbonization Pathways Report (May 6, 2022).

Comments at 6-7 (May 6, 2022) ("DOER Initial Comments"); DOER Comments at 6-8 (October 17, 2022) ("DOER Final Comments")).

Other commenters opine that electrification should not be the Commonwealth's sole decarbonization strategy, arguing that hybrid pathways are necessary for preserving optionality as renewable generation increasingly comes online (see, e.g., Associated Industries of Massachusetts ("AIM") Comments at 2 (June 17, 2022); Shell USA, Inc. Comments at 4-5 (May 6, 2022); Tufts Medicine Lowell General Hospital Comments at 1 (July 22, 2022); Lahey Hospital and Medical Center Comments at 1 (July 15, 2022); SFE Energy Massachusetts, Inc. ("SFE Energy") Comments at 3 (May 6, 2022)). Similarly, the National Fuel Cell Research Center calls for further quantification of the value of the increased reliability and resilience that could be provided by decarbonized gas and electric systems (National Fuel Cell Research Center Comments at 2 (May 6, 2022)).

Numerous commenters criticize the Pathways Report's assumptions regarding the availability, pricing, and emissions of renewable fuels (see, e.g., Attorney General Technical Comments at 8-19; Sierra Club Comments at 8-9 (May 6, 2022) ("Sierra Club Initial Comments"); Acadia Center Comments at 7-15 (May 6, 2022) ("Acadia Center Initial Comments")). The Attorney General notes that the annual volumes of RNG needed in Massachusetts by 2050 under a hybrid electrification pathway is roughly 70 trillion British thermal units ("TBtu"), whereas the total available RNG output nationwide as of 2020 was only 50 TBtu (Attorney General Technical Comments at 9). The Attorney General argues that both the exponential growth in RNG volumes and the practicality of Massachusetts securing a population-weighted "fair share" of 3.7 percent of all RNG volumes east of the Mississippi River are unrealistic (Attorney General Technical Comments at 9-12; Attorney General Final Comments at 20-21 (October 14, 2022)). Several other commenters question the availability and market clearing price of RNG modeled under the hybrid electrification pathway (see, e.g., Sierra Club Initial Comments at 10-12; Acadia Center Initial Comments at 10-15).

Relatedly, several commenters argue that the Pathways Report repeats known flaws in Massachusetts GHG Inventory[27] accounting, questioning whether renewable fuels are truly carbon neutral when combusted, and if upstream emissions related to the extraction and transmission of fuels should be counted (see, e.g., Acadia Center Initial Comments at 4-10; Sierra Club Initial Comments at 8; LexCAN Advocacy Committee Comments at 1 (May 9, 2022)). Some commenters question the leakage rates associated with the existing gas system, demanding greater transparency regarding leakage rates and lost and unaccounted for gas volumes (see, e.g., "Interested Persons"[28] Comments at 2-4; CLF Comments at 11, 27-31

[27] Information about the Massachusetts GHG Inventory is available at https://www.mass.gov/lists/massdep-emissions-inventories (last visited November 29, 2023).

[28] On October 14, 2022, individuals associated with the following organizations filed a joint set of comments as "interested persons": Greater Boston Physicians for Social Responsibility; Climate Reality Project Boston Metro Chapter; Gas Leaks Allies; Pipe Line Awareness Network for the Northeast; Fore River Residents Against the Compressor Station; Mothers Out Front; Ashland Sustainability Committee; Sierra Club; Acadia Center; Gas Transition Allies; Brookline GreenSpace Alliance; Emerald Necklace Conservancy; Elders Climate Action Massachusetts; and No Pipeline Westborough.

(May 6, 2022) ("CLF Initial Comments"); CLF Final Comments at 4 (October 14, 2022) ("CLF Final Comments"); Acadia Center Comments at 7). Finally, several commenters call for the use of a 20-year global warming potential ("GWP") value for methane, consistent with the most recent Intergovernmental Panel on Climate Change Fifth Assessment Report (see, e.g., CLF Initial Comments at 28; Acadia Center Initial Comments at 6-7).

Additionally, numerous commenters argue that the Pathways Report fails to vigorously pursue potential gas infrastructure cost savings, such as reduced GSEP spending and more optimistic networked geothermal cost assumptions (see, e.g., Attorney General Technical Comments at 21-23; CLF Initial Comments at 12, 51-53; Sierra Club Initial Comments at 20-21). Several commenters criticize the hybrid electrification pathway as being potentially skewed toward lower system-wide costs, noting that the Pathways Report's lower level of building shell retrofits and inclusion of residential hybrid fuel oil/ASHPs does not allow for an apples-to-apples comparison across pathways (see, e.g., Acadia Center Initial Comments at 19-21; Sierra Club Initial Comments at 5). Lastly, several commenters criticize the Pathways Report's consideration of health and air quality impacts, arguing that combining indoor and outdoor air quality into a single metric masks the risk of maintaining gas appliances in homes to the health of children, the elderly, environmental justice populations, and people with underlying health conditions (see, e.g., Greater Boston Physicians for Social Responsibility Comments at 7-9 (May 2, 2022); Massachusetts Medical Society Comments at 2-3 (May 3, 2022)).

C. LDCs Response to Stakeholder Comments

The LDCs reject the notion that the Pathways Report picks a preferred pathway, arguing that other pathways compare favorably to the hybrid electrification pathway, and that differences in the application of building shells and discount rates do not impact the Pathways Report's conclusions (LDC Joint Comments at 9, 40, 45-47). The LDCs contend the finding that decarbonization pathways that "strategically use the state's gas infrastructure alongside and in support of electrification are likely to carry lower levels of challenge" is not unique to this study, and that similar findings have been identified in both the U.S. and abroad (LDC Joint Comments at 9, 42-45). The LDCs maintain that the Pathways Report is a product of a significant amount of discussion and feedback from stakeholders, and that it is imperative for the Department and key stakeholders to approve the Net Zero Enablement Plans and Model Tariff (LDC Joint Comments at 13, 96).

The LDCs argue that the Consultants' recommendations draw from common strategies identified across all pathways and that suggestions that the benefits of hybrid electrification can be captured by balancing all-electric and conventional gas heat demands are at odds with a targeted electrification strategy that substantially reduces gas infrastructure investment (LDC Joint Comments at 9, 47-49). The LDCs maintain that the Pathways Report considers the potential for substantial avoided reinvestment in gas infrastructure, including reductions in GSEP spending and detailed consideration of networked geothermal potential (LDC Joint Comments at 8, 32-37). The LDCs assert that the alternative gas infrastructure cost comparisons provided by stakeholders are not comparable to those in the Pathways Report (LDC Joint Comments at 8, 37-38).

With respect to the availability and pricing of renewable fuels, the LDCs insist that the Pathways Report includes both optimistic and conservative ranges that are heavily derated to assess potential availability to Massachusetts and are based on the best available literature (LDC Joint Comments at 8, 19-26). The LDCs maintain that the Pathways Report's approach to pricing renewable fuels is consistent with similar industry studies in the Northeast, including the 2050 Roadmap (LDC Joint Comments at 8, 26-29). Additionally, the LDCs state that the Pathways Report's approach to emissions accounting is consistent with the Massachusetts GHG Inventory, 2050 Roadmap, and international reporting standards, and that the use of a 20-year GWP value for methane would require a reevaluation of the Commonwealth's 1990 emissions baseline (LDC Joint Comments at 9, 30, 49-53). Lastly, the LDCs argue that the Pathways Report's modeling of leakage rates is consistent with the official accounting framework used in the Massachusetts GHG Inventory and 2050 Roadmap, and that the Pathways Report sufficiently addresses qualitative health and air quality impacts (LDC Joint Comments at 9-10, 53-59).

D. Analysis and Conclusions

Consistent with the directives of the Department, the LDCs retained the Consultants to perform a detailed study for each LDC analyzing: (1) the feasibility of each decarbonization pathway identified by the Roadmaps; and (2) any pathways not examined in the Roadmaps, among other requirements. D.P.U. 20-80, at 3-5. The Department required the Consultants to combine the individual analyses into a single, collective report presenting: (1) a quantification of the costs and actual economy-wide GHG emissions reductions involved in transitioning the natural gas system; and (2) a discussion of qualitative factors such as impacts on public safety, reliability, economic development, equity, emissions reductions, and timing, for each identified pathway. D.P.U. 20-80, at 5-6.

To fulfill these directives, the LDCs submitted the Pathways Report, which identifies and discusses eight decarbonization pathways designed to allow for the comparison of the relative costs, risks, and feasibility of different futures (Pathways Report at 11, 34). The Department commends the LDCs and their Consultants for their comprehensive effort in estimating the costs and economy-wide GHG emissions reductions[29] involved in transitioning the natural gas system. The Department fully recognizes the difficulty in assessing these multidimensional challenges and expresses its appreciation for the comprehensive Pathways Report.

DOER notes significant alignment between the Pathways Report and the 2050 Roadmap, stating that the two documents demonstrate several common assumptions and outcomes (DOER Initial Comments at 6-8). However, commenters predominantly disagree over the Pathways Report's finding that strategically using the state's gas infrastructure

29 For each pathway involving electrification strategies, the Consultants were directed to provide a transparent depiction of key assumptions used in the analysis and a calculation of GHG emissions reductions, inclusive of GHG emissions from generation source. D.P.U. 20-80, at 5. The Department finds that the Pathways Report appropriately addressed this request (Pathways Report at 48; App. 1, at 21-28).

alongside and in support of electrification is likely to carry lower levels of challenge, most typified by the hybrid electrification pathway (see, e.g., Attorney General Final Comments at 6-19; DOER Initial Comments at 8-10; LDC Joint Comments at 40-48). Any further attempt to quantify alternative fuels, electrification technologies, and their associated GHG emissions reductions in a generic sense, is beyond the scope of the current investigation. The Department makes no findings related to a preferred pathway or technology here, as such considerations need to be made in the context of the distinct service territories of each LDC.[30] The Commonwealth's dominant building decarbonization strategy, however, is electrification as noted in the 2025/2030 CECP.[31] Our aim is to create and promote a regulatory framework that is flexible, protects consumers, promotes equity, and provides for fair consideration of the current and future technologies and commercial applications required to meet the Commonwealth's clean energy mandates and comply with the 2025/2030 CECP.

In doing so, the Department acknowledges that there is potential for further refinement to capture more fully the intricacies and granularity needed to achieve the Commonwealth's 2050 climate targets. Ultimately, the transition toward the Commonwealth's net zero targets will be one that is driven by the willingness and ability of residential, commercial, and industrial customers to support the Commonwealth's

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30 As noted above in Section IV, the Department must review LDC-specific plans in adjudicatory proceedings before approving any individual plan. St. 2022, c. 179, § 77.

31 2025/2030 CECP at 27, available at https://www.mass.gov/doc/clean-energy-and-climate-plan-for-2025-and-2030/download (last visited November 29, 2023).

environmental goals and climate targets through investments in their homes, businesses, and transportation infrastructure. The Department seeks to expeditiously attain the GHG emissions reductions necessary to achieve these targets and will begin by more thoroughly addressing the six regulatory design recommendations below. Indeed, as we discuss in more detail in the next section, we recognize that new regulatory support strategies will be needed to minimize customer cost impacts regardless of which pathway, or combination of pathways, is pursued. After due consideration of the record, we find that the Pathways Report satisfies the Department's directives in opening this investigation in D.P.U. 20-80.

## VI. REGULATORY DESIGN RECOMMENDATIONS

### A. Introduction

The Consultants identify six regulatory design recommendations: (1) support customer adoption of and conversion to electrified/decarbonized heating technologies; (2) blend renewable gas supply into gas-resource portfolios; (3) pilot and deploy innovative electrification and decarbonized technologies; (4) manage gas embedded infrastructure investments and cost recovery; (5) evaluate and enable customer affordability; and (6) develop LDC transition plans and chart future progress. The Department here analyzes the merits of the various regulatory pathways proposed by the Consultants, and also uses this framework as a vehicle for identifying areas where we intend to pursue future investigation.

## B. Support Customer Adoption of and Conversion to Electrified/Decarbonized Heating Technologies

### 1. Introduction and Summary

To meet the Commonwealth's climate targets, the decarbonization pathways will require significant levels of customer adoption of electrification and decarbonization heating technologies (Regulatory Designs Report at 19). The Regulatory Designs Report explains that certain pathways, such as high electrification, will require swift and early action to increase customer utilization (Regulatory Designs Report at 19). The Consultants recommend the following regulatory approaches to support customer use of electrification and decarbonization heating technologies: enhance and increase funding of energy efficiency programs; restructure electric and gas distribution rates; and revise customer service standards and procedures (Regulatory Designs Report at 20-24). These recommendations are discussed in detail below.

#### a. Energy Efficiency

To support customer adoption of electrification and decarbonization technologies identified in the pathways analysis, the Consultants recommend increasing energy efficiency program budgets, enhancing the programs to include new measures and strategies, and finding additional sources of funding (Regulatory Designs Report at 21). The Regulatory Designs Report emphasizes that the decarbonization pathways will require the deployment of new strategies and technologies (Regulatory Designs Report at 21). Since some decarbonization pathways target entire customer groups rather than individual customers to convert from natural gas to full electric service, energy efficiency programs will need to expand to support new incentive offerings and targeted electrification of entire customer blocks (Regulatory Designs Report at 21). The Consultants recommend evaluating the potential benefits of avoiding gas system infrastructure costs as part of targeted electrification or geothermal demonstration projects in the calculation of cost-effectiveness (Regulatory Designs Report at 21). The Regulatory Designs Report further explains that other enhancements may be necessary, including customer education and awareness, adoption of decarbonization strategies and technologies, and market transformation initiatives targeted at contractors, distributors, and manufacturers (Regulatory Designs Report at 21).

In addition, the Regulatory Designs Report states that the pathways will require larger energy efficiency budgets to support the enhanced initiatives discussed above (Regulatory Designs Report at 21). Since the current energy efficiency programs already are funded by ratepayers through the energy efficiency surcharge ("EES"),[32] the Consultants recommend evaluating additional funding sources to increase budgets and better align the benefits and cost responsibilities for certain programs between gas and electric companies (Regulatory Designs Report at 21-22). Specifically, the Consultants suggest offsetting some costs through a financial transfer from electric to gas utilities under a dual energy agreement (Regulatory Designs Report at 21-22).[33] A dual energy agreement involves a benefit-sharing mechanism

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32 The EES is included in the Local Distribution Adjustment Factor ("LDAF") of a customer's bill (Regulatory Designs Report at 21).

33 The Consultants cite a "dual energy" agreement between a Canadian electric company, Hydro-Quebec, and Energir, a gas company, in which gas customers in targeted market areas are converted to electricity to operate on electric heat during

that allows for a financial transfer from the electric company to the LDC as compensation for its role in electrification (Regulatory Designs Report at 22). The Consultants claim that a financial transfer reflects the economic and reliability benefits of maintaining the gas system to support electrification for hybrid heating customers (Regulatory Designs Report at 22).

b. Restructuring of Electric and Gas Rates

To support customer adoption of electrification and decarbonization technologies identified in the pathways analysis, the Consultants recommend examining electric and gas distribution rate policies to reflect the changing demand and infrastructure requirements of electrification (Regulatory Designs Report at 22-23). For example, the pathways analysis shows that increased use of electric heating shifts peak electric demand from summer to winter and, therefore, presents an opportunity to evaluate price signals associated with electric rates to reflect changing demand (Regulatory Designs Report at 22).

For electric distribution rates, the Consultants recommend exploring: (1) the potential of time-variant rates to reflect the cost of serving electricity demands during peak periods; and (2) critical peak-pricing rates that reflect the cost of serving higher electricity demands under extreme weather conditions (Regulatory Designs Report at 22). The Consultants explain that critical peak-pricing rates could be used to reflect the substantially higher cost of electricity generation, transmission, and distribution to meet demand during extreme weather

non-winter peak periods while operating on gas heat during winter peak periods (Regulatory Designs Report at 22).

conditions, and provide customers with an incentive to reduce electricity use during those weather conditions (Regulatory Designs Report at 22).

For gas distribution rates, the Consultants observe that the adoption of hybrid heating systems may change gas demand characteristics because these customers would be using the system only during peak winter periods (Regulatory Designs Report at 23). Because of this change, the Consultants suggest creating a rate class for customers with hybrid heating systems (Regulatory Designs Report at 23). The Consultants state that a hybrid rate class would establish rates to better reflect the costs associated with providing gas service exclusively during peak winter periods (Regulatory Designs Report at 23).

In addition to creating another rate class, the Consultants recommend changing the revenue decoupling mechanism ("RDM") (Regulatory Designs Report at 23-34). The current gas RDM is designed on a per-customer basis, which allows the LDCs to retain the incremental revenues associated with serving new gas customers to offset the incremental costs associated with those customers until distribution rates are reset (Regulatory Designs Report at 23-24). The Consultants explain that this mechanism has worked well with the historical increase in gas customers; most of the decarbonization pathways, however, anticipate a decrease in the number of gas customers over time (Regulatory Designs Report at 24). The Consultants recommend transitioning away from a revenues-per-customer approach to a reconciliation of total revenues (Regulatory Designs Report at 24). Under this approach, the LDCs would reconcile actual revenues and Department-authorized or target revenues rather than revenues per customer, and that reconciliation would include revenue from new customers (Regulatory Designs Report at 24).

c. Customer Service Standards and Procedures

The Consultants explain that certain decarbonization pathways will require updated customer service standards and procedures to support adoption of electrification and decarbonization technologies identified in the pathways analysis (Regulatory Designs Report at 24). Geographically targeted electrification, for example, would require all customers within a specific geographic area or neighborhood to convert from gas to electric or another alternative (Regulatory Designs Report at 24). The Consultants caution that such strategies may raise concerns over customer choice, cost, the LDCs' obligation to serve, and customer service protections (Regulatory Designs Report at 24). The Consultants recommend comprehensive measures to address various issues, including enhancing customer communication and education processes, expanding customer options for gas and electric services, providing financial support for customers, and fostering stronger relationships with contractors (Regulatory Designs Report at 24-25). These recommendations are aimed at facilitating and promoting the widespread adoption of electrification and decarbonization technologies among customers (Regulatory Designs Report at 24-25).

2. Summary of Comments

a. Energy Efficiency

Commenters agreed with increasing incentives and exploring new energy efficiency strategies to better support customer adoption of electrification and decarbonization heating technologies (see, e.g., Acadia Center Initial Comments at 21-22; OPOWER Comments at 3 (May 6, 2022)). Other commenters argue that energy efficiency incentives for gas appliances should be phased out (Sierra Club Comments at 21; CLF Initial Comments at 9). The Attorney General notes that the Department-approved 2022-2024 Three-Year Energy Efficiency Plans ("2022-2024 Three-Year Plans") include significant investments to promote the adoption of heat pumps, while also observing that the most recent plans already come with significant budget and bill impacts for customers (Attorney General Initial Comments,[34] App. C at 7). The Attorney General and Acadia Center support enhanced energy efficiency investment but encourage the LDCs to explore other funding sources beyond the EES to minimize customer bill impacts (Attorney General Initial Comments, App. C at 7; Acadia Center Initial Comments at 22-23). In addition to funding, commenters say workforce development needs further support to facilitate customer adoption (Attorney General Initial Comments at 54; Acadia Center Initial Comments at 22; HEET Comments at 7 (May 6, 2022) ("HEET Comments")). The Attorney General states that the Department should engage regularly with workforce stakeholders, through working groups or other means, to better inform the transition of gas distribution services (Attorney General Initial Comments at 54).

[34] Regulating Uncertainty: The Office of the Attorney General's Regulatory Recommendations to Guide the Commonwealth's Gas Transition to a Net Zero Future (May 6, 2022).

The LDCs maintain that the Pathways Report does not adopt one pathway, but recommends energy efficiency as a low-regret strategy (LDC Joint Comments at 40-41). The LDCs reiterate that energy efficiency measures may decrease the impacts of electrification on the electric system and reduce demands for natural gas (LDC Joint Comments at 40-41). According to the LDCs, additional investment in energy efficiency will play a critical role in meeting the needs of an electrified economy (LDC Joint Comments at 6).

b. Rate Restructuring

Many commenters agree with the Consultants' recommendation to investigate changes to gas distribution rates and revenue decoupling (see, e.g., Attorney General Initial Comments at 38-39; Acadia Center Initial Comments at 23; and DOER Final Comments at 2). The Attorney General argues that the Department should conclude its investigation in Investigation to Review and Revise the Standard of Review and the Filing Requirements for Gas Special Contracts Filed Pursuant to G.L. c. 164, § 94, D.P.U. 18-152, and limit gas special contracts to only unique and novel public interest circumstances (Attorney General Initial Comments at 41). According to the Attorney General, gas special contracts[35] should demonstrate net benefits to customers, and that the customer's use of natural gas is no more harmful in terms of GHG and air pollutant emissions than the customer's alternative energy resource(s) (Attorney General Initial Comments at 41-43). The Attorney General also

35 Gas special contracts allow LDCs to provide firm transportation service to customers at individually negotiated, off-tariff distribution rates. D.P.U. 18-152, Vote and Order Opening Investigation at 1 (2018).

recommends that the Department not permit LDCs to recover costs for marketing related to promoting gas service because these costs are not aligned with the Commonwealth's decarbonization goals (Attorney General Initial Comments at 41). Furthermore, the Attorney General asserts that any modifications to the current cost recovery mechanisms should consider equity, affordability, and preservation of customer choice (Attorney General Final Comments at 4).

Commenter RMI[36] posits that a hybrid heating scenario requires that customers do three things: electrify with heat pumps, retain utility gas backup, and use that gas backup sparingly (RMI Comments at 3 (May 6, 2022) ("RMI Initial Comments")). As a result, RMI argues, crafting an effective rate design for hybrid heating customers will be challenging given that to reduce emissions and remain economically viable, a hybrid rate design must both (1) recover the costs of the gas system without encouraging customers to use gas as their primary heating fuel, and (2) avoid customer departure from the gas system (RMI Initial Comments at 3). RMI argues that as gas demand declines and non-fossil gas is substituted for fossil gas, rising gas rates will become inevitable and may lead to significant cost recovery and equity challenges under a hybrid heating rate design (RMI Initial Comments at 3).

The LDCs maintain that there is still interest in natural gas service despite the momentum toward full electrification (LDC Joint Comments at 10). The LDCs acknowledge

[36] Formerly "Rocky Mountain Institute" (RMI Initial Comments at 1).

concerns over increasing costs but reaffirm that the Regulatory Designs Report proposes potential rate designs to align equitably the benefits[37] and cost of hybrid heating (LDC Joint Comments at 75). Specifically, the LDCs contend that rate designs, such as a new hybrid rate class and critical peak pricing, will help incentivize customers to adopt and remain on hybrid heating systems (LDC Joint Comments at 75). The LDCs explain that a combination of customer education, financial support, and supportive policy initiatives will be necessary to spur the level of conversion needed for electrification modeled in each pathway (LDC Joint Comments at 10).

Additionally, the LDCs state that the potential of financial transfers from electric to gas utilities would help reflect the economic and reliability benefits of maintaining the gas system to aid the electric system during peak weather events (LDC Joint Comments at 75). The Sierra Club, however, opposes the sharing of costs between electric and gas customers (Sierra Club Initial Comments at 19; Sierra Club Comments at 12-13 (October 14, 2022) ("Sierra Club Final Comments")). The Sierra Club argues that electric customers subsidizing the decarbonization of the gas sector would constitute an inappropriate cross-subsidization given that the electric sector already has "borne its share of decarbonization costs" (Sierra Club Initial Comments at 19; Sierra Club Final Comments at 12-13).

[37] The LDCs explain that hybrid electrification is beneficial because it allows customers to leverage their existing equipment as a backup heating system (LDC Joint Comments at 74).

The LDCs reaffirm that most of the decarbonization pathways will result in service to fewer gas customers over time (LDC Joint Comments at 90). The LDCs recommend revising the RDM from a per-customer basis reconciliation of actual and authorized revenues to a reconciliation of total revenues (LDC Joint Comments at 90, citing Regulatory Designs Report at 23-24). The LDCs agree that replacing the RDM per customer with a total revenues or revenue cap decoupling is better aligned with the Commonwealth's decarbonization goals (LDC Joint Comments at 90-91). The Attorney General likewise agrees with revising the RDM (Attorney General Initial Comments at 39).

c. Affordability and Customer Choice

Several commenters also expressed affordability concerns, particularly for low- and moderate-income ("LMI") customers. Many commenters called for the prioritization of LMI customers to ensure an equitable transition and protect them from bearing the increased energy burden associated with electrification (see, e.g., NCLC Comments at 32 (May 6, 2022) ("NCLC Initial Comments"); LEAN Comments at 2-3 (May 6, 2022) ("LEAN Initial Comments"); Sierra Club Final Comments at 12). Some commenters, such as Acadia Center, disagree with charging customers exit fees[38] to leave the gas system because it may hinder electrification affordability (see, e.g., Acadia Center Initial Comments at 24; RMI Initial Comments at 3). LEAN recommends increasing low-income discounts and offering an exemption from the bill impacts of accelerated deprecation for LMI customers (LEAN Initial

[38] An "exit fee" or "migration charge" which would be charged to customers leaving the natural gas system is defined and discussed further in Section VI.F.

Comments at 17). In sum, numerous commenters express concerns that the LDC transition plans may impose an unfair burden on LMI customers in the absence of regulatory intervention.

The Attorney General confirms that, absent regulatory reform, remaining gas customers will experience significant rate increases as other customers leave the system (Attorney General Initial Comments at 46). Many commenters agree that LMI customers are less likely to leave the gas system and, therefore, may be disproportionately impacted by higher energy bills (see, e.g., HEET Comments at 7; LEAN Initial Comments at 17). The Attorney General explains that LMI customers currently spend a higher percentage of their income on utility bills than any other income group (Attorney General Initial Comments at 48). The Attorney General recommends that the Department consider adopting a rate mechanism to protect LMI customers from high energy burdens and potential rate increases (Attorney General Initial Comments at 50). Specifically, the Attorney General states that there should be a cap on the amount an LMI customer is billed (Attorney General Initial Comments at 52). Other commenters agree that the LDCs should consider rate mechanisms to help protect LMI ratepayers from high energy burdens and potential rate increases (see, e.g., DOER Initial Comments at 15; LEAN Initial Comments at 18).

Regarding customer choice, many commenters support a full transition away from fossil fuels via electrification. A handful of commenters do not (see, e.g., Tufts Medicine Lowell General Hospital Comments at 1; Inovis Energy, Inc. Comments at 1-2 (July 13, 2022); Mass Coalition for Sustainable Energy Comments at 1 (October 6, 2022)). One commenter noted that full electrification should be contingent on adequate renewable energy production (Shell USA, Inc. Comments at 4). Other commenters support electrification alongside geothermal and other low-carbon heating options (see, e.g., CLF Initial Comments at 12; Martin Comment at 1 (May 6, 2022)). Commenters acknowledge the LDCs' obligation to serve current gas customers but suggest revising the obligation to serve standards (see, e.g., Pipeline Awareness Network for the Northeast, Inc. ("PLAN") Comments at 4 (May 6, 2022) ("PLAN Initial Comments"); CLF Initial Comments at 21). PLAN states that the obligation to serve criteria apply only to existing customers (PLAN Comments at 5 (October 14, 2022) ("PLAN Final Comments").

The LDCs reiterate that customer choice will drive the acceptance of electrification but maintain that there is public support for preserving the natural gas system (LDC Joint Comments at 93-94, citing Exh. DPU-Comm 2-13, Att.). The LDCs highlight the substantial upfront costs for electrification as a barrier to conversion (LDC Joint Comments at 95, citing Pathways Report, Figure 4, at 17). The LDCs state that the Net Zero Enablement Plans contain strategies to help educate customers around their energy options (LDC Joint Comments at 94). Furthermore, the LDCs assert that achieving the levels of electrification modeled in each pathway will hinge not only on customer education, but also on supportive policy initiatives and market transformation activities that help customers overcome the upfront cost barriers to electrification (LDC Joint Comments at 94-95). The LDCs view current and future pilot projects as an opportunity to test and evaluate different market transformation approaches, including various incentive strategies to facilitate customer implementation of electrification and decarbonization heating technologies (LDC Joint Comments at 96, citing Exh. DPU-Comm 5-6).

3. Analysis and Conclusions

a. Introduction

The Department recognizes that significant levels of customer acceptance of electrification and decarbonization technologies will be needed for the Commonwealth to achieve its climate targets. While LDCs already have begun to increase the level of customer implementation of energy efficiency and decarbonized technologies through their 2022-2024 Three-Year Plans, more will need to be done inside and outside of the energy efficiency rubric to prioritize electrification, equity, and workforce development (Regulatory Designs Report at 20). See also 2022-2024 Three-Year Energy Efficiency Plans, D.P.U. 21-120 through D.P.U. 21-129, at 42, 46-47, 51 (2022) ("2022-2024 Three-Year Plans Order"). The Consultants recommend enhancing energy efficiency programs and funding to incentivize customer participation; restructuring gas and electric distribution rates to reflect the changing demand and infrastructure requirements of electrification; and establishing new customer service standards and procedures to facilitate and promote the widespread use of electrification and decarbonization technologies among customers (Regulatory Designs Report at 20-21). Commenters offer a range of perspectives on the transition to cleaner energy sources, with a focus on mitigating the impact on customers, especially those with lower incomes, and the role of incentives, rate structures, and policy initiatives in shaping the energy landscape. We address these recommendations below.

b. Energy Efficiency

The Department recognizes the importance of programs with effective participant incentives to help facilitate increased electrification and use of decarbonization technologies. The LDCs have strategies to leverage their cost-effective energy efficiency plans and strategies to encourage electrification through heat pumps and other measures. 2022-2024 Three-Year Plans Order at 51-52. In addition, under the Green Communities Act,[39] three-year plans must achieve all cost-effective energy efficiency, pass the cost-effectiveness analysis using the total resource cost test,[40] direct 20 percent of budgets to low-income energy efficiency, minimize administrative costs, maximize competitive procurement, and be mindful of bill impacts on gas ratepayers. G.L. c. 25, § 21(b)(1). In addition, beginning with the 2025-2027 three-year energy efficiency plans, there shall be "no spending on incentives, programs or support for systems, equipment, workforce development or training as they relate to new fossil fuel equipment unless such spending is for low-income households, emergency facilities, hospitals, a backup thermal energy source for a heat pump, or hard to electrify uses, such as industrial processes." G.L. c. 25, § 21(b)(2)(xi). Further, the Department already must consider whether these plans are constructed to meet or exceed the GHG emissions reduction mandates set by the EEA Secretary pursuant to G.L. c. 21N,

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39 An Act Relative to Green Communities, Acts of 2008, chapter 69, section 11.

40 In determining cost-effectiveness, the calculation of benefits shall include the social value of GHG reductions, except in the cases of conversions from fossil fuel heating and cooling to fossil fuel heating and cooling. G.L. c. 25, § 21(b)(1).

§ 3B. Finally, the Department considers whether the proposed plans adequately prioritize safety, reliability, security, affordability, and equity. 2022-2024 Three-Year Plans Order at 84.

The 2022-2024 Three-Year Plans have made significant steps in promoting both energy efficiency and electrification through customer incentives and performance incentives. See 2022 Energy Efficiency Annual Reports, D.P.U. 23-60, Berkshire Gas Company, App. 1, at 2-3 (June 1, 2023). The Department expects the LDCs to continue expanding the scope of ambition in their three-year plans to promote reductions in overall energy usage that result in cost-effective programs, while balancing increased electrification to meet GHG emissions reduction targets.

At the same time, the Department remains concerned about customer bill increases associated with enhancing the Commonwealth's energy efficiency programs. The Regulatory Designs Report recommends minimizing the potential bill impacts of these program enhancements by using other funding sources, such as government funding, gas system exit fees, and financial transfers from electric to gas utilities (Regulatory Designs Report at 44 n.57; Exh. DPU-Comm 3-3). Since 2010, the Department has required gas three-year plans to include all other sources of funding that program administrators have pursued to help fund the energy efficiency programs.[41] Investigation by the Department of Public Utilities on

41 In approving an energy efficiency funding mechanism for the electric program administrators, the Department must consider the availability of other private or public funds. G.L. c. 25, § 19(a)(3)(ii).

its own Motion into Updating its Energy Efficiency Guidelines, D.P.U. 20-150-A, App. A, § 3.2.2.1 (2021), ("Guidelines"). The Department reminds program administrators that this requirement to pursue non-ratepayer sources of funding is more important now than ever, especially for residential and small-business customers who disproportionately bear the burden of higher energy efficiency surcharges as compared to other rate classes. The Department, however, declines to implement exit fees or financial transfers as viable outside funding sources to offset the cost of expanding energy efficiency budgets. As discussed in Section VI.F below, the Department is concerned that charging an additional fee to exit the gas system may disincentivize customers from fully electrifying. At the same time, in the absence of a gas exit fee, residential and small business customers who are not able to leave the system may bear even higher energy bills. The Department is open to reviewing any alternative funding sources so long as they help facilitate a safe, reliable, and equitable transition for all ratepayers.

Lastly, in response to the Attorney General's recommendation to engage with workforce stakeholders, the Department recognizes that the utility and energy contractor workforce will play an integral role in customer acceptance of electrification and decarbonization technologies. Workforce development is essential to safe and reliable gas operations and will be at the forefront of the industry transition. As required by G.L. c. 25, § 19(d), the annual workforce development program budget of $12 million is explicitly allocated from the 2022-2024 Three-Year Plans to MassCEC to grow and diversify a clean energy equity workforce and market development program in the Commonwealth.[42] 2022-2024 Three-Year Plans Order at 42. The Department accepts that significant efforts will be required to develop strategies to train and ensure family-sustaining wages for a workforce to support the energy transition. It is critical to train current gas system workers for employment opportunities in the clean energy sector. It is also important that jobs are available in the clean energy sector to support workers who are women, people of color, Indigenous Peoples, veterans, people living with disabilities, immigrants, and people who were formerly incarcerated. A comprehensive workforce strategy requires solutions that ensure the well-being of workers and communities, create jobs, and contribute to a thriving and sustainable economy. This strategy should be viewed as part of a just transition framework.

The Department, therefore, strongly encourages the LDCs to engage with other stakeholders, including labor unions, MassCEC, and existing workforce development programs, to establish a just transition framework for gas industry workers and people who have largely been left out of the clean energy workforce to start training for jobs that support

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[42] General Laws c. 25, § 19(d), added by the 2021 Climate Act, requires the Department to annually collect and transfer not less than $12 million to MassCEC for the clean energy equity workforce and market development program established pursuant to G.L. c. 23J, § 13. MassCEC states that this funding will be used for assisting environmental justice populations to plan and develop career training programs for employment in high demand clean energy occupations, and to provide support for expansion and creation of minority- and women-owned business enterprises in business categories critical to state climate targets. Massachusetts Clean Energy Center Request for Fiscal Year 2023 Funding Pursuant to G.L. c. 25, § 19(d), D.P.U. 22-75, Letter Order at 1 (June 27, 2022).

electrification and decarbonization. The LDCs shall provide an update on this just transition framework in their future Climate Compliance Plans, which the Department details in Section VI.G below.

c. Rate Restructuring

The LDCs propose evaluating alternative rate designs to better reflect the changing demand and infrastructure requirements of electrification and agree with the recommendation to change the RDM structure (Regulatory Designs Report at 22-23). The Department supports the alignment of LDC rate designs with climate objectives and GHG reduction compliance pathways.[43] In particular, the Department agrees with the recommendation to replace the current per-customer RDM with a total revenues or revenue cap decoupling mechanism. The Department finds that a revenue cap approach, which subsequently disincentivizes LDCs to expand their gas customer base, better aligns with the policies of the Commonwealth expressed in current climate laws. The Department directs each of the LDCs to propose an RDM that implements this approach in its next rate case. The Department also encourages the LDCs to evaluate and propose alternative rate resigns and other cost recovery mechanisms that are consistent with the direction provided in this Order.

The Department acknowledges that the LDCs and Consultants identify hybrid heating systems as a low-regret strategy toward decarbonization and takes notice of the significant

43 When considering new rate designs, the Department is required to take into consideration the reduction of GHG emissions pursuant to the 2022 Clean Energy Act. G.L. c 164, § 141.

uptick in utilization of heat pumps under the current three-year plans.[44] As we discuss in Section VI.D, however, the Department is not persuaded that pursuit of a broad hybrid heating strategy that would necessitate maintenance of the natural gas system to support backup heating systems is a viable path forward. Given improvements in technology, the Department expects that cold-climate heat pumps generally will eliminate the need for backup heating systems. During this transition period, however, the Department accepts that customers may elect to retain their previous backup heating systems, such as gas-fired boilers, to support heat pumps, as discussed further in Section VI.D. The LDCs shall continue to track customer heat pump installations. Further, the LDCs must work with their energy contractors and vendors to provide sufficient information to customers about the capabilities of heat pumps so they may reach a more informed conclusion about the true need for backup heating systems. If the LDCs propose a new rate design for hybrid heating customers, then they must strike a balance between recovering the costs of the gas system without encouraging customers to use gas as their primary heating fuel, thereby enabling

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44 To date, three gas program administrators have filed mid-term modification requests in 2023 for additional funding partially due to a higher-than-expected demand for heat pumps (see Berkshire Gas Company, D.P.U. 23-93, Pre-Filed Testimony of Hammad Chaudhry and Jillian Winterkorn at 3-4; Liberty Utilities, D.P.U. 23-91, Pre-Filed Testimony of Kimberly Gragoo, Stephanie Terach, and Autumn R. Snyder at 6-7; Fitchburg Gas and Electric Light Company, D.P.U. 23-70, Pre-Filed Testimony of Cindy L. Carroll and Mary A. Downes at 6).

GHG emissions reductions while maintaining low operating costs to retain customers.[45] The Department will consider all other rate restructuring proposals on a case-by-case basis.

With respect to special gas contracts, we acknowledge the Attorney General's suggestion that the Department conclude its investigation in D.P.U. 18-152 and limit gas special contracts to only unique and novel public interest circumstances (Attorney General Initial Comments at 41). The Department agrees that the requirements for gas special contracts should be improved and refined, and that the ongoing investigation in D.P.U. 18-152 is the proper vehicle for the pursuit of any such changes. Given that D.P.U. 18-152 remains an open proceeding, we decline to address the specifics or potential outcomes here other than to acknowledge that a re-examination of gas special contracts is part of the portfolio of actions we are taking to facilitate the necessary transition of the natural gas industry.

Finally, we agree with the Attorney General that LDCs should not be permitted to include in rates any costs associated with marketing geared toward the promotion or expansion of gas service. As noted by the Attorney General, these costs are not aligned with the Commonwealth's decarbonization targets and any continued funding of such advertising or marketing by ratepayers is the type of "business as usual" operations of LDCs that must

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45 In the context of hybrid heating and a hybrid heating rate design, the importance of customer retention via low operating costs is so that increasing costs do not incent those customers most able to afford full electrification to pursue that option (or delivered fuels) while leaving lower-income customers on a rate that potentially would rapidly increase to account for fewer customers supporting the system (RMI Initial Comments at 2-3). This is inconsistent with an equitable transition.

cease. Moreover, this prohibition on ratepayer funding of gas marketing extends not only to initiatives undertaken directly by LDCs, but includes indirect efforts to promote either natural gas expansion or policies geared toward promoting natural gas expansion. If and to the extent LDCs wish to continue participating in such efforts, the associated costs will be borne entirely by shareholders.

d. Affordability and Customer Choice

The pace of customer transition to alternatives to natural gas is a significant uncertainty facing gas industry sales and revenue projections. Many commenters argued for the prioritization of LMI customers to ensure an equitable transition (see, e.g., NCLC Initial Comments at 32; LEAN Final Comments at 2-3; Sierra Club Final Comments at 12). The Attorney General contends that that the Department should consider adopting a rate mechanism to protect LMI customers from high energy burdens and potential rate increases (Attorney General Initial Comments at 50).

The Department agrees that the pace of customer transition to gas alternatives will depend on a suite of available incentives, education, legislative change, and market transformation activities. Ensuring an affordable and equitable transition will be among the most potentially challenging aspects of this undertaking. A mass exodus of gas customers has the potential to shock rates to the detriment of remaining ratepayers and reduce utility revenues, jeopardizing the LDCs' continued provision of safe and reliable service to remaining customers, as well as posing a potential general safety risk to the public at large. Conversely, less competition from alternatives may result in a slower pace of transition and delay the necessary achievement of the climate targets. The Department and LDCs will need to take steps to minimize the impacts of long-term competitive losses. The Department will address the practicality of such strategies through the remainder of this Order, including modification of line extension policies that assume long-term sales revenue, shifting revenue from traditional rate base to performance-based mechanisms that incent reduced emissions, and rate structures that protect LMI customers.

As to preserving customer choice, it is not clear that the Department has the statutory authority to prohibit the addition of new gas customers. It is the Department's long-standing policy, however, that an LDC need not serve new customers in circumstances in which the addition of new customers would raise the cost of gas service for existing firm ratepayers. Boston Gas Company, D.P.U. 88-67 (Phase I) at 282-284 (1988). An LDC must therefore first ensure that the incremental costs to expand its distribution network do not exceed the incremental revenues from such expansion to include the cost of expanding its distribution network in rates. Bay State Gas Company, D.P.U. 12-25, at 379 (2012); Boston Gas Company, D.T.E. 03-40, at 48 (2003). LDCs determine whether a main or service extension is economically feasible using a model to compare the estimated cost of the project to the estimated revenues over the expected useful life of the plant investment to ensure the internal rate of return exceeds the rate of return allowed in the Company's most recent base distribution rate case. See, e.g., NSTAR Gas Company, D.P.U. 19-120, at 456-457 (2020) (reviewing the company's main extension policy in the course of analyzing a surcharge proposal pursuant to St. 2014, c. 149, § 3); Boston Gas Company, D.P.U. 89-180, at 16-17

(1990). When an investment needed to serve a new customer does not pass the internal rate of return test, the gas company may require the customer to pay a contribution in aid of construction ("CIAC") to make up the deficit. D.P.U. 19-120, at 456-457.[46] It thus appears that there is an opportunity to revise the process of making this cost determination, reviewing tariff provisions, and current LDC practices to disincentivize further customer expansion while still preserving customer choice to the extent necessary. These changes are further discussed in Section VI.E below.

### C. Blend Renewable Gas Supply Into Gas-Resource Portfolios

#### 1. Introduction and Summary

The Regulatory Designs Report recommends that the LDCs develop a procurement strategy to add renewable gas options to their resource portfolios (Regulatory Designs Report at 25). As used by the Consultants, "renewable gas supply" is an umbrella term that refers to renewably produced alternatives to natural gas that includes biomethane produced through anaerobic digestion or gasification, renewable hydrogen, and SNG produced from renewable hydrogen and a climate-neutral source of carbon (Pathways Report at 9; Regulatory Designs Report at 6, 25). The Consultants note that blending limited amounts of renewable gases into the pipeline could result in a reduction of GHG emissions without a corresponding substantial increase in overall gas costs (Regulatory Designs Report at 25). The Consultants recommend

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[46] Property that has been contributed to a utility is not included in rate base. D.P.U. 12-25, at 380 n.220, citing Milford Water Company, D.P.U. 771, at 21 (1982); Oxford Water Company, D.P.U. 18595, at 18 (1976); Commonwealth Gas Company, D.P.U. 18545, at 2 (1976).

that the LDCs investigate the deliverability of biomethane, hydrogen, and synthetic gases from a broader range of resources and regions to clarify further their role in supporting the state's decarbonization goals and ensure that these fuels in fact can meet the requirements of the pathways (Regulatory Designs Report at 25). Finally, the Regulatory Designs Report recognizes that renewable gas does not meet the Department's least-cost standard (Regulatory Designs Report at 25). The Consultants make three specific recommendations intended to enable LDCs to incorporate renewable gas supply into the system: (1) update the forecast and supply planning standards to add renewable gas; (2) provide customers with an option to purchase renewable gas from the LDC; and (3) provide customers with an option to purchase renewable gas from third-party suppliers (Regulatory Designs Report at 25-26).

According to the Regulatory Designs Report, the Department should update its forecast and supply planning[47] standards to require a minimum level of renewable gas and

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47 Pursuant to G.L. c. 164, § 69*I*, every gas company shall file for the Department's approval a long-range forecast with respect to the gas requirements of its market area for the ensuing five-year period, consisting of the gas sendout necessary to serve projected firm customers and the available supplies necessary to meet the projected demand. Further, the Department reviews a gas company's five-year supply plan to determine whether the plan is adequate to meet projected normal-year, design-year, design-day, and cold-snap firm sendout requirements. Fitchburg Gas and Electric Light Company, D.P.U. 21-10, at 3 (2022).

Under its current standards, the Department determines if a company's projection method is reasonable based on whether the method is: (a) reviewable, that is, contains enough information to allow a full understanding of the forecast method;
(b) appropriate, that is, technically suitable to the size and nature of the particular gas company; and (c) reliable, that is, provides a measure of confidence that the gas company's assumptions, judgments, and data will forecast what is most likely to

incorporate the cost of carbon in the LDCs' supply plan economic analysis (Regulatory Designs Report at 25). The Consultants posit that either a Renewable Heating Fuel Standard ("RHFS") or a Renewable Portfolio Standard ("RPS") could establish a minimum level of RNG, similar to the electric industry (Regulatory Designs Report at 25). The Consultants suggest that either the Legislature or the Department via a generic proceeding could authorize an RHFS or RPS, and that the minimum level of renewable gas could be set low initially to address concerns with availability and cost, with subsequent increases subject to these considerations (Regulatory Designs Report at 25-26). A second approach to updating the forecast and supply standards discussed by the Consultants is the addition of a cost of carbon to the supply planning economic analysis, which would provide an economic advantage to low-carbon supplies (Regulatory Designs Report at 26). As in the context of the RHFS and RPS option, the Consultants assert the cost of carbon initially could be set low to address supply availability, cost, or customer affordability considerations and then increased gradually subject to these considerations (Regulatory Designs Report at 26).

The Consultants' second recommendation for incorporating renewable gas into the system is to provide LDC customers who want to reduce their carbon emissions the option to purchase renewable gas directly from the LDC (Regulatory Designs Report at 26). In this scenario, the Department would approve a tariff through either an LDC-specific rate-setting

occur. D.P.U. 21-10, at 3, <u>citing</u> <u>Bay State Gas Company</u>, D.T.E. 02-75, at 2 (2004); <u>The Berkshire Gas Company</u>, D.T.E. 02-17, at 2 (2003).

proceeding or through a generic proceeding applicable to all LDCs (Regulatory Designs Report at 26).

With respect to the third recommendation to facilitate use of renewable gas, the Regulatory Designs Report recommends that the Department provide customers with an option to purchase renewable gas from third-party suppliers via each LDC's delivery service (Regulatory Designs Report at 26). The Consultants posit that this approach may be appealing to customers, especially large commercial and industrial customers, seeking to purchase directly from a third-party supplier. The Regulatory Designs Report recognizes that a special tariff may be required to address interconnection requirements (Regulatory Designs Report at 26).

Finally, and applicable to all three design approaches discussed above, the Consultants recommend a procurement strategy that includes customer education, marketing, and incentives that promote the integration of renewable gas into the gas system. This would facilitate customer understanding of the benefits and cost implications of renewable gas and their options to incorporate it into their fuel mix (Regulatory Designs Report at 27).

2. Summary of Comments

Generally, commenters agree in their objections to the recommendations in the Regulatory Designs Report regarding renewable gas.[48] Numerous commenters raised issues

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48 While the Pathways Report refers to "renewable gas," commenters also refer to renewable natural gas or "RNG," which along with SNG and hydrogen, may also be referred to as "decarbonized gas" (Attorney General Initial Comments at 11-12). The

and concerns related to emissions, system upgrades and related costs, and the availability of alternatives.

The Attorney General argues that the Pathways Report overstates the availability of RNG and understates RNG's costs (Attorney General Technical Comments at 8-16; Attorney General Final Comments at 20). The Attorney General asserts that there is no credible basis to assume that RNG can be made available in Massachusetts at the volumes needed to support the gas use in 2050 assumed under the hybrid electrification scenario, and further that the Consultants significantly understate the costs of obtaining RNG (Attorney General Technical Comments at 8-16). The Attorney General argues that, in developing their price projections for RNG, the Consultants developed a weighted average price for RNG instead of pricing it at the incremental price of the marginal unit of supply (Attorney General Final Comments at 21). Moreover, the Attorney General asserts that the continued use of biomethane is inconsistent with the Commonwealth's policy as set forth in EEA's 2025/2030 CECP (Attorney General Final Comments at 21-22). The Attorney General also questions the Consultants' assumption that RNG is carbon neutral (Attorney General Technical Comments at 16-19). Further, the Attorney General notes that RNG and hydrogen, although emerging, are unproven and uncertain technologies that carry significant investment risks (Attorney General Initial Comments at 32). The Attorney General therefore recommends that

Attorney General and others assert, however, that the term "decarbonized gas" is a misnomer (Attorney General Initial Comments at 11 n.48).

the Department ensure that investments in unproven or uncertain technologies are borne entirely by utility shareholders (Attorney General Initial Comments at 32).

DOER suggests that the Department consider R&D proposals intended to increase the supply of RNG and hydrogen (DOER Initial Comments at 11). DOER also proposes that the Department disallow long-term contracts that would lock customers into high-risk and high-cost resources for long periods (DOER Initial Comments at 16). Finally, DOER proposes that the Department should require the LDCs to complete R&D projects using RNG to demonstrate emissions reductions consistent with the GWSA methodology before it approves any long-term contracts for renewable gas or hydrogen (DOER Final Comments at 15).

Acadia Center argues that the proposals involving RNG: (1) fail to account for out-of-state emissions occurring during the productions and transmission of the fuels; (2) dramatically underestimate the level of methane leaks from the natural gas systems in Massachusetts; (3) assume that biofuels are GHG-neutral; and (4) underestimate the availability and price of RNG and hydrogen (Acadia Center Initial Comments at 5-15).

Similar to Acadia Center, Sierra Club asserts that the Consultants underestimate the levels of GHG emissions from RNG and SNG, and also underestimate the availability of and clearing prices for renewable gas (Sierra Club Initial Comments at 8-11). In addition, Sierra Club argues that hydrogen is an inefficient and unfeasible strategy to decarbonize buildings (Sierra Club Initial Comments at 14-17). Finally, Sierra Club argues that even if the LDCs' treatment of biofuels as zero-GHG emitting is consistent with both the Commonwealth's current GHG accounting methodologies and its 2050 Roadmap, that is an inadequate basis for assessing the relative merits of biofuel investments as part of a decarbonization strategy (Sierra Club Final Comments at 6-8).

CLF argues that there is insufficient evidence to support the claim that biomethane is a zero-emissions fuel over the course of its lifecycle (CLF Final Comments at 4). Regarding hydrogen, CLF argues that it is highly volatile and will have to be limited to applications and sectors that cannot be electrified (CLF Final Comments at 4). CLF contends that LDCs would have to prove that biomethane is a zero-carbon fuel before forecast and supply plan standards should be allowed to include RNG, or before customers should be given the option to purchase RNG from LDCs or from third parties (CLF Initial Comments at 14). CLF maintains that the Consultants' technical analyses around the impact of biomethane were based on assumptions not grounded in science or reality (CLF Initial Comments at 14). In addition, EDF contends that there is a good understanding of the climate and safety impacts of renewable fuels, noting that hydrogen emissions have global warming potential (EDF Comments at 6–8 (October 13, 2022) ("EDF Final Comments")).

Dozens of individual and group commenters raised concerns similar to those recited above, specifically arguing against the mandated use of RNG and/or hydrogen based on issues related to supply availability, GHG emissions, safety, and cost (see, e.g., Interested Persons Comments at 2-3; Elders Climate Action Massachusetts Comments at 1-3 (May 6, 2022); Callaway Comments at 1 (May 4, 2022); Fortuin Comments at 1-2 (May 6, 2022); Phillips Comments at 1 (May 6, 2022)).

The LDCs argue that RNG and other alternative fuel sources are a necessary component of any decarbonization future and that the path to net zero does not need to be a binary decision between fuel sources and a fully electrified system (LDC Joint Comments at 60). The LDCs contend that adding RNG to the supply portfolio will produce environmental benefits, contributing to achievement of the Commonwealth's objectives, and will improve supply availability and diversity, both critical gas supply planning considerations (LDC Joint Comments at 60-61). Further, the LDCs point out that to fully electrify, a significant overbuild of renewables will be required to ensure peak demand can be met by the electric network (LDC Joint Comments at 62). The LDCs assert RNG can complement electrification by supporting the intermittent nature of renewable generation resources like solar and wind (LDC Joint Comments at 62).

Regarding the various comments expressing skepticism that RNG can be scaled to the level needed and purchased at a reasonable cost, the LDCs state that they expect the availability of RNG to continue to grow as technologies to develop RNG continue to advance (LDC Joint Comments at 63). Finally, regarding the criticism that the Consultants treat renewable gases as carbon neutral, the LDCs assert that this approach is consistent with both the official GHG accounting methodology of the Commonwealth and the 2050 Roadmap (LDC Joint Comments at 30).

3. Analysis and Conclusions

The Consultants recommend that the LDCs develop a procurement strategy to add RNG supply to the resource portfolio. The Department has been presented with three specific means of enabling the LDCs to incorporate RNG supply into their gas system: (1) update the forecast and supply planning standards to incorporate RNG through either a RHFS/RPS or the addition of a cost of carbon; (2) provide customers with an option to purchase RNG from the LDC; and (3) provide customers with an option to purchase RNG from third-party suppliers (Regulatory Designs Report at 25-26).

Most commenters did not address directly the suggestion that the Department update the forecast and supply planning standards to incorporate RNG. Numerous comments did note, however, that RNG does not provide measurable benefits in terms of costs and emissions reductions.

Our policy regarding the LDCs' procurement of gas resources is well established. The Department first articulated its standard for commodity and capacity acquisitions in Commonwealth Gas Company, D.P.U. 94-174-A (1996), where the Department determined that to demonstrate that the proposed acquisition of a resource that provides commodity and/or incremental resources is consistent with the public interest, an LDC must show that the acquisition is (1) consistent with the company's portfolio objectives; and (2) compares favorably to the range of alternative options reasonably available to the company at the time of the acquisition or contract renegotiation. D.P.U. 94-174-A at 27. In Liberty Utilities (New England Natural Gas Company) Corp., D.P.U. 22-32-C at 36 (2022), the Department also noted that we must consider whether the proposed acquisition is consistent with the GWSA and any applicable emissions limit or sublimit set by the Secretary of EEA. G.L. c. 25, § 1A. At this time, as we discuss below, we have been presented with no evidence convincing us to alter this gas procurement policy. On the contrary, we share the concerns raised by various stakeholders regarding costs, availability, and the treatment of renewable fuels as carbon neutral.

As the LDCs acknowledge, RNG currently does not meet the Department's least-cost supply planning standards given the higher cost of RNG relative to pipeline gas. Given this, the inclusion of RNG supplies in an LDC's resource portfolio would violate our goal of providing gas service at the lowest possible cost. Indeed, the higher cost of RNG raises customer affordability concerns as LDC rates will be higher than they otherwise would be if pipeline gas continued to be used.

We recognize that RNG and the use of hydrogen as a fuel are emerging technologies that have not yet been proven to lead to a net reduction in GHG emissions. The Consultants assume that RNG's emissions are carbon neutral under the Commonwealth's current GHG accounting framework (Regulatory Designs Report at 8 n.7). They acknowledge that if the GHG emissions accounting conventions change, however, the potential of RNG as a carbon-neutral fuel diminishes and its value in terms of decarbonization would be overstated (Pathways Report at 18 n.12). In our view, more studies are required in this area to support the claim that RNG is a zero-emissions fuel. For example, a full life-cycle analysis that considers all of the emissions profiles and captures emissions gains and losses throughout the entire production process may be necessary to determine the total carbon intensity of RNG.

Regarding the availability of RNG, we are not convinced that sufficient RNG stocks will be available to ensure the alleged potential environmental benefits. Record evidence shows that there is significant uncertainty regarding the availability of RNG (Pathways Report, App. 1, at 16). Indeed, the Consultants note that biomass resource availability in New England is relatively low compared to other regions in the United States. New England has an estimated 0.63 dry tons of feedstocks available per person per year, whereas the average availability of feedstocks for the U.S. as a whole, is 2.47 dry tons per person per year (Pathways Report, App. 1, at 15). According to the Coalition for Renewable Natural Gas, of the 300 RNG facilities in the U.S., only eight are located in New England.[49] In the long run, RNG supply shortages may lead to higher costs. For these reasons, we have no basis in the existing record for altering our existing gas procurement policy as established in D.P.U. 94-174-A to allow for the acquisition of RNG and or the imposition of a RHFS or cost of carbon in the LDCs' supply plan economic analyses. We recognize, however, that the technology is evolving and the process to produce RNG may possibly lead to measurable benefits in the future, particularly for hard-to-electrify industrial processes. We encourage LDCs to investigate all options that will lead to a reduction in their GHG footprint, including lifecycle emissions associated with system operations, and we will review any proposals that are consistent with existing standards as well as with the Commonwealth's GWSA and the 2021 Climate Act.

49 See https://www.rngcoalition.com/?gad=1&gclid=Cj0KCQjwpc-oBhCGARIsAH6ote-K_4nSXK5AbiPbzM5IqeZD-AfyAg7WWyM5sfivAv_6_Q3Uvs9i4sYaAgadEALw_wcB (last visited November 29, 2023).

As the Commonwealth strives to achieve its 2050 climate targets, we envision that the long-term use of the natural gas distribution system generally will be limited to strategic circumstances where electrification is not feasible for all natural gas applications. For example, we recognize that some C&I customers require natural gas for process heat applications for which there are currently no electric-driven alternatives. It would therefore be necessary to make RNG and/or hydrogen available to this category of end-use customers.

Regarding the recommendation that gas customers be provided with the option to purchase RNG from their LDC or a third-party supplier, the Department has endeavored to develop a competitive natural gas supply market that would allow customers the broadest possible choice and provide all customers with an opportunity to share in the benefits of increased competition. See Natural Gas Unbundling, D.T.E. 98-32-B at 3, 4 (1999). We anticipate that there may be situations where customers would like to purchase RNG from their gas company or directly from a third-party supplier. We encourage LDCs to begin assessing customer interest in RNG and, if so, determine the associated demand load and begin developing educational and marketing material. While we support customer choice as it relates to RNG, we recognize that due to its nature and current technology, RNG is more expensive than conventional natural gas (Regulatory Designs Report at 25, 41). The inclusion of RNG-related costs in an LDC's supply portfolio costs—i.e., costs currently recovered under an LDC's seasonal cost of gas adjustment clause—would therefore increase the average cost of gas. To avoid any cross-subsidization issues, participation in such a program must be voluntary with all associated costs, including program administration costs, allocated and recovered solely from the participants. As we will not authorize a mechanism that would socialize the higher commodity cost of RNG, the Department expects that customers selecting RNG, regardless of whether it was procured from the LDC or a third-party supplier, will be responsible for the costs. We expect that the LDCs will inform potential customers of the cost of RNG, its lifecycle GHG emissions, and the likely bill impacts associated with their participation. To ensure that no costs associated with such a voluntary option are assigned to non-participants, the LDCs must keep a separate accounting of RNG costs and develop a voluntary RNG opt-in sales tariff outlining the provisions for service for Department review and approval. In summary, subject to the conditions above, we will allow the option for consumers to purchase RNG from an LDC or a third-party supplier.

The Department cautions, however, that RNG and hydrogen may require system upgrades due to the density of the fuels. If the LDCs need to upgrade their systems or incur additional interconnection and metering equipment costs to make these fuels available, all of the relevant system-upgrade costs, in addition to traditional costs borne by gas ratepayers, must be assumed by those who will take RNG supply and not by all customers. In summary, all costs associated with RNG are to be borne solely by utility shareholders or program participants.

The Department may review proposals for RNG or hydrogen pilot programs, as discussed below in Section VI.D. However, we agree with the Attorney General that RNG and hydrogen blending are new, unproven, and uncertain technologies. LDCs may research and assess these technologies, but until they prove to be a viable alternative to the business-as-usual model and support the Commonwealth's climate targets, any infrastructure costs associated with RNG and hydrogen will be the sole responsibility of the utility shareholders and not their customers.

### D. Pilot and Deploy Innovative Electrification and Decarbonized Technologies

#### 1. Introduction and Summary

The Regulatory Designs Report recommends that the LDCs pilot and deploy the following four technologies: (1) networked geothermal; (2) targeted electrification; (3) hybrid heating systems; and (4) renewable hydrogen (Regulatory Designs Report at 27-29). Further, the Regulatory Designs Report recommends that the Department develop guidance for review and approval of pilot projects and R&D programs, design additional cost recovery mechanisms, and track and report on performance metrics (Regulatory Designs Report at 29-30).

The Regulatory Designs Report explains that pilot opportunities for networked geothermal systems potentially could serve as strategic replacements for planned capital spending and be consistent with networked geothermal pilots approved for NSTAR Gas[50] and National Grid (gas);[51] however, the Regulatory Designs Report notes outstanding questions

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50 On October 30, 2020, the Department approved a networked geothermal demonstration project proposed by NSTAR Gas to evaluate the technology in a mixed-use, dense urban environment. D.P.U. 19-120, at 138-156.

51 On December 15, 2021, the Department approved a networked geothermal demonstration proposal from National Grid (gas). Boston Gas Company,

exist regarding the technical implementation, financing, and role of networked geothermal in avoiding gas infrastructure investments (Regulatory Designs Report at 27). The Regulatory Designs Report also recommends an investigation into the most optimal operation of hybrid heating systems to support both the gas and electric systems and potentially lower annual customer bills, avoid electric infrastructure costs necessary to meet heating demands, and lower GHG emissions through reliance on dispatchable winter peak generation resources (Regulatory Designs Report at 28). Finally, the Regulatory Designs Report recommends that LDCs pursue pilot opportunities to investigate the extent to which hydrogen can be added to their systems without the need for customer equipment or pipeline upgrades, engage in R&D opportunities related to the commercialization of synthetic gases, and explore certified natural gas, which may have lower upstream emission intensity (Regulatory Designs Report at 28-29).

The Regulatory Designs Report posits that an updated process for approval of pilot and R&D programs could facilitate the timely evaluation and deployment of decarbonized technologies better than a project-by-project approach (Regulatory Designs Report at 29).

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D.P.U. 21-24, at 32-33 (2021). National Grid (gas) will prioritize the installation of networked geothermal systems that evaluate one or more of the following concepts: (1) the thermal performance and economics of shared loops serving a larger number of customers with more diverse load profiles than a networked geothermal project completed by its New York affiliate; (2) switching gas customers to geothermal energy as an alternative to leak-prone pipe replacement; (3) installing shared loops to manage local gas system constraints and peaks; and (4) installing shared loops to lower operating costs and GHG emissions for low-income customers and environmental justice populations. D.P.U. 21-24, at 3-4.

The Regulatory Designs Report explains that pilot and R&D programs could establish a process to track and report on performance metrics of interest, such as achievement of defined objectives; installation and service provider participation; customer education, interest and adoption experience; and role of the project in achieving decarbonization goals (Regulatory Designs Report at 30). The Regulatory Designs Report states that LDCs could recover the costs associated with additional pilots and R&D either through the local distribution adjustment clause or a new fully reconciling funding mechanism (Regulatory Designs Report at 30).

In this Order, we evaluate the potential of the four specific technologies recommended by the Consultants, both in the context of this proceeding and future potential investigations, pilot programs, and targeted deployments, and we address the regulatory framework that exists and that will evolve for the review and approval of pilot programs to examine emerging decarbonization technologies.

2. Summary of Comments

Commenters generally agree with the recommendation that the Department should streamline its review of pilot opportunities to facilitate more timely evaluation and deployment of electrification and decarbonized technologies (see, e.g., DOER Initial Comments at 16; CLF Initial Comments at 60; Acadia Center Initial Comments at 25). However, commenters disagree about which technologies, fuels, and end uses merit ratepayer-funded R&D (see, e.g., Attorney General Final Comments at 11-12; AIM Comments at 2; RMI Final Comments at 4; EDF Initial Comments at 1-3). To that end, the

Attorney General urges the Department to acknowledge the technical uncertainty of decarbonizing the building heating sector, calling for a framework that provides for fair consideration of the current and future technologies and commercial applications required to meet the Commonwealth's clean energy mandates (Attorney General Final Comments at 3-4).

Several commenters express support for the LDCs' approved networked geothermal pilots, arguing for the accelerated deployment of this technology (see, e.g., Sierra Club Final Comments at 11-12; CLF Initial Comments at 12; Climate Action Now Western Mass Comments at 2 (May 5, 2022); Mothers Out Front Massachusetts Comments at 1, 4 (May 2, 2022)). The Attorney General calls on the Department to open an investigation into the regulatory treatment of geothermal heat districts and alternative thermal technologies to examine possible regulation and ownership frameworks as the Department continues to learn about the costs, feasibility, and scalability of networked geothermal (Attorney General Initial Comments at 45-46). Similarly, HEET proposes a framework for the evolution of LDCs into thermal utilities, positing that pilots involving 100 customers or fewer could be approved by the Department within a month of filing (HEET Comments at 17, 22-32). The LDCs state that they consider networked geothermal to be a type of targeted electrification and would like the flexibility to pursue or expand their networked geothermal offerings, pending the receipt of successful pilot data (LDC Joint Comments at 67).

Numerous commenters call for R&D into other types of targeted electrification, including decommissioning of the gas system, that may demonstrate cost savings (see, e.g., CLF Initial Comments at 9, 55; DOER Final Comments at 16-17). The Attorney General calls for the adoption of comprehensive geographic distribution system and customer mapping,[52] in addition to an investment alternatives calculator to assist in reviewing traditional gas system capital investments (Attorney General Initial Comments at 22-24, 33-35; Attorney General Final Comments at 10-11). Similarly, DOER recommends that the Department require the LDCs to complete geographic mapping and marginal cost analyses before moving forward with any additional R&D proposals so that the LDCs can use these results in determining the appropriateness of any such projects (DOER Initial Comments at 14-15; DOER Final Comments at 7-10, 19-20).

Numerous commenters object to LDCs piloting alternative fuel blends (i.e., RNG, hydrogen, SNG) into their distribution systems, raising concerns about safety, affordability, GHG emissions, and leakage (see, e.g., Attorney General Initial Comments at 11-14; Acadia Center Initial Comments at 21; Sierra Club Initial Comments at 17; Massachusetts Medical Society Comments at 1-2). Other commenters acknowledge that alternative fuels may be necessary for the Commonwealth to reach its clean energy commitments, calling for R&D in various hard-to-electrify end uses including certain industrial processes (see, e.g., CLF Initial Comments at 61; Sierra Club Initial Comments at 15; City of Boston Initial Comments[53] at 1; Medical Area Total Energy Plant Comments at 1 (July 28, 2022)). The Attorney General

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[52] The Department further discusses geographically planned approaches and gas/electric coordination topics below in Section VI.D and Section VI.G.

[53] Comments of the Rev. Mariama White-Hammond, Chief of Environment, Energy, and Open Space, City of Boston (May 5, 2022).

recommends that any investment in unproven technologies such as RNG and hydrogen be viewed as imprudent today with the associated costs being borne entirely by utility shareholders (Attorney General Initial Comments at 32-33). Regarding proposals for new technologies or fuels, DOER argues that the LDCs must identify "go/no go benchmarks," including when to abandon a project or program if the results show that longer-term implementation would not be cost effective for ratepayers and/or achieve net-zero emissions in the most cost-effective manner (DOER Final Comments at 12).

### 3. Analysis and Conclusions

#### a. Introduction

Demonstration projects or pilots are well-established and evaluated vehicles for the introduction of emerging technologies into the existing framework of broadly deployed programs such as energy efficiency. In Investigation by the Department of Public Utilities on its own Motion into Updating its Energy Efficiency Guidelines, D.P.U. 20-150-A, updating its energy efficiency guidelines, the Department compiled directives from recent orders that addressed the appropriate process and standard of review for approval and changes to demonstration project proposals. D.P.U. 20-150-A at 22. The Department described a demonstration project as "a relatively small, self-contained endeavor, such as a pilot, that may transition to a core initiative or program," and further clarified demonstration project evaluation, budgetary, and cost-effectiveness considerations. D.P.U. 20-150-A at 24-25; Guidelines § 3.9.[54]

In this proceeding, numerous commenters agree that the Department should develop additional guidance for its review and approval of pilot projects and R&D programs in an effort to study and deploy innovative electrification and decarbonized technologies (see, e.g., Regulatory Designs Report at 27-30; DOER Initial Comments at 16; Attorney General Initial Comments at 24, 33). The Department strives to foster the innovation necessary to ensure the safe and reliable delivery of low-carbon energy in an equitable manner; at the same time, the Department must consider the potential customer bill impacts of any additional cost recovery mechanisms for pilots, as ratepayers in the Commonwealth already experience significant energy supply and programming costs. See, e.g., 2022-2024 Three-Year Plans Order at 220, 223. The Department maintains that pilots are valuable because they are small in scale and allow for the collection of distinct data and insights that will advance knowledge in a specific field. See, e.g., D.P.U. 21-24, at 26; Fitchburg Gas and Electric Light Company, D.P.U. 16-184, at 10-12 (2017).

The Regulatory Designs Report recommends that the LDCs pilot and deploy four specific technologies (Regulatory Designs Report at 27-29). As discussed below, the

54 The Department defines a demonstration project as a hard-to-measure offering, including pilots, limited in term and scope designed to provide the information required to assess its potential for measurable, cost-effective savings and benefits that can be scaled to be included in programs. Guidelines § 2.3. Demonstration projects are hard-to-measure offerings initially but are anticipated to have measurable savings and benefits at scale. Guidelines § 3.9.1.1.

Department welcomes networked geothermal and other targeted electrification technologies[55] in particular as promising decarbonization strategies and will require each LDC to identify pertinent demonstration projects in each of its service territories. In contrast, the Department is uncertain about the viability of hybrid heating and hydrogen technologies and their potential as economical long-term solutions for ratepayers, for the reasons we discuss below.

b. Hybrid Heating Systems

The Regulatory Designs Report recommends investigation into the optimal operation of hybrid heating systems, in support of both the gas and electric distribution systems (Regulatory Designs Report at 28). Specifically, the Consultants recommend further investigation of certain design elements for hybrid heating systems, such as the installation of integrated controls (Regulatory Designs Report at 28).[56]

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55 The Department emphasizes that pilot projects, including those for networked geothermal and other targeted electrification technologies, funded by gas ratepayers must benefit those ratepayers and not constitute cross-subsidization. See D.P.U. 19-120, at 147-148 (networked geothermal project must be designed in a manner to provide direct benefits to ratepayers whether through participation or in a manner that will generate findings to inform the scalability of networked geothermal for its existing gas customers).

56 The Consultants note that during the 2019-2021 Three-Year Plan term, program administrators created initial integrated controls specifications and requirements to ensure that heat pumps installed to augment existing systems operate efficiently, and that additional studies were proposed in the 2022-2024 Three-Year Plan term (Regulatory Designs Report at 28). “Program Administrators” are the LDCs as well as electric distribution companies and approved municipal aggregators who develop and administer energy efficiency programs under the Green Communities Act. St. 2008, c. 169. D.P.U. 20-150-A at 1.

Several commenters express skepticism about hybrid heating systems, urging the Department to reject the hybrid electrification scenario completely (see, e.g., Attorney General Technical Comments at 3, 19, 21; Acadia Center Initial Comments at 19-21; Sierra Club Initial Comments at 5).[57] As mentioned above, the Attorney General argues that the Pathways Report's promotion of a hybrid electrification pathway rests on unsound and unproven assumptions, and that the benefits of hybrid electrification on electric infrastructure additions can be attained by focusing on building electrification in the near term (Attorney General Technical Comments at 6-21).

The LDCs maintain that hybrid electrification is a practical and relatively low-challenge strategy and opportunity to achieve the Commonwealth's decarbonization objectives (LDC Joint Comments at 70). The LDCs argue that hybrid electrification technologies: (1) reduce the need for electric system build out; (2) mitigate costs and winter peaking; and (3) provide energy security benefits as a cold-climate backup system (LDC Joint Comments at 70-75). Other commenters argue that a hybrid electrification approach to decarbonization preserves optionality and elements of customer choice as renewable generation increasingly comes online (see, e.g., AIM Comments at 2; Shell USA, Inc.

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57 As noted above, Section 77 of the 2022 Clean Energy Act explicitly prohibits the Department from approving any company-specific plan pursuant to D.P.U. 20-80 prior to conducting an adjudicatory proceeding with respect to such plan. St. 2022, c. 179, § 77. Therefore, at present, the Department will not endorse or reject any specific pathway or space heating technology.

Comments at 4-5; Tufts Medicine Lowell General Hospital Comments at 1; Lahey Hospital and Medical Center Comments at 1; SFE Energy Comments at 3).

The Department cannot reject or prohibit hybrid heating systems as an option for customers. It is, after all, the customer who chooses the type of heating system to install in the home or building. The Department shares the concerns expressed by numerous commenters, however, that a customer's retention of a gas furnace or boiler to serve exclusively as a cold-climate backup may not be necessary.[58] In the short term, hybrid heating could be used to support both the gas and electric systems and potentially lower annual customer bills, avoid electric infrastructure costs to meet heating demands, and lower GHG emissions through reliance on dispatchable winter peak generation resources (Regulatory Designs Report at 28). In the long term, however, it will be impractical to maintain the gas distribution system solely for backup furnaces in cold weather. The Department will therefore not approve the use of additional ratepayer dollars for hybrid heating system pilots and, as stated below, we expect LDCs to focus on targeted electrification and—pending the outcome of current pilots—networked geothermal projects to meet the long-term climate targets of the Commonwealth.

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58 The Department notes that research priorities for the LDCs as Program Administrators of the 2022-2024 Energy Efficiency Plan include studying residential hybrid heat pump controls, optimization, and metering impacts, in addition to requiring integrated controls for certain residential and income-eligible applications (See D.P.U. 21-120 through D.P.U. 21-129, Exh. 1, at 77; Exh. 1, App. H at 21, 57-60).

Nevertheless, the Department must ensure that the information contractors relay to customers who are deciding between hybrid and full-electrification technologies is both informative and correct. Therefore, the Department will require the LDCs to report on hybrid heating switchover practices in their first Climate Compliance Plan filings. This first Climate Compliance Plan report must include a discussion of the technical resources provided to contractors in the Mass Save heat pump installer network such as heat pump capacity and temperature point heuristics, and address any service area specific guidance that differs from cold-climate sizing and design trainings offered by common manufacturers. The Department fully expects that the LDCs as Program Administrators will continue to explore hybrid heat pump shared benefit and incentive structures, particularly related to LMI participants.

c. Renewable Hydrogen and RNG

The Regulatory Designs Report recommends that the LDCs pursue pilot opportunities to investigate the extent to which hydrogen and RNG can be blended safely into the LDC distribution system without the need for customer equipment or pipeline upgrades (Regulatory Designs Report at 28). The Consultants further note R&D opportunities related to the commercialization of synthetic gases and recommend investigating certified natural gas which may have reduced upstream emissions from the production of gas (Regulatory Designs Report at 28-29).[59]

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[59] The Department discusses synthetic and certified gas commodity above in Section VI.C.

Numerous commenters express concern with potential emissions and leakage issues associated with hydrogen blending, with the Attorney General arguing for all investments in hydrogen to be viewed as imprudent, and borne entirely by shareholders (see, e.g., Attorney General Initial Comments at 32-33; EDF Initial Comments at 1-3). Other commenters note that alternative fuels such as hydrogen may be necessary for the Commonwealth to reach its clean energy commitments, calling for R&D in certain hard-to-electrify end uses such as industrial processes (see, e.g., CLF Initial Comments at 61; Sierra Club Initial Comments at 15; City of Boston Initial Comments at 1; Medical Area Total Energy Plant Comments at 1). The LDCs acknowledge that the GHG effects of leaked, non-combusted hydrogen are not well understood, and that very few studies are available on its global warming potential (LDC Joint Comments at 56, citing Pathways Report at 113).

The Department agrees that significant research is necessary before hydrogen feasibly could be injected into an LDC's distribution system. The Department notes that the states of New York, New Jersey, Maine, Rhode Island, Connecticut, and Vermont along with the Commonwealth of Massachusetts announced the submission of a proposal for a Northeast Regional Clean Hydrogen Hub[60] to the U.S. Department of Energy ("DOE") to compete for a $1.25 billion share of the $8 billion in federal hydrogen hub funding available as part of the Infrastructure Investment and Jobs Act, Pub. L. No. 117-58 (2021). In an announcement on October 13, 2023, DOE announced the first regional hydrogen hubs and the Northeast

60 See https://www.masscec.com/press/seven-states-northeast-regional-clean-hydrogen-hub-announce-submission-362-billion-proposal (last visited November 29, 2023).

Hydrogen Hub was not selected for funding.[61] The Department is optimistic that future funding opportunities may allow for the exploration of hydrogen R&D in the region without requiring additional ratepayer funds.

The Department also acknowledges, however, that there may be certain end uses, such as high-temperature industrial processes, that require a combustible molecule of a lower GHG emissions profile. In the short term, the Department will entertain hydrogen demonstration proposals for targeted end uses. Any proposals for hydrogen or RNG pilots, however, should include cost-effectiveness screening, and in the absence of cost-effectiveness screening, an appropriate analysis must support the potential of the proposal to deliver net benefits in the future. Guidelines § 3.9. Further, hydrogen and RNG demonstration project proposals must thoroughly explain how the targeted application is "hard to decarbonize," in addition to explaining electrification alternatives and alignment with the GWSA and the 2021 Climate Act. Further, RNG and hydrogen pilot proposals must take into consideration environmental justice populations and ensure that any such projects do not contribute to a decline of indoor air quality.

d. Networked Geothermal

Networked geothermal technology connects multiple, energy-efficient ground-source heat pumps ("GSHPs") to a loop system designed to provide heating and cooling to multiple buildings in a geographic area. The Department has found that: (1) geothermal networks

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61 See https://www.energy.gov/articles/biden-harris-administration-announces-7-billion-americas-first-clean-hydrogen-hubs-driving (last visited November 29, 2023).

have the potential to significantly reduce GHG emissions; and (2) geothermal demonstration projects designed to test the effectiveness and scalability of utility-owned geothermal networks have the potential to reduce current barriers to widespread adoption in furtherance of the Commonwealth's climate policies. D.P.U. 19-120, at 139.

Several commenters express support for networked geothermal technologies and their expedited deployment (see, e.g., Attorney General Initial Comments at 45-46; DOER Final Comments at 9, 15-16). The LDCs acknowledge that they consider networked geothermal to be a type of targeted electrification and would like the flexibility to pursue or expand their networked geothermal offerings, pending the receipt of successful pilot data (LDC Joint Comments at 67).

The Department commends the LDCs for exploring an innovative technology that has the potential to reduce GHG emissions and barriers to widespread deployment of clean heating technologies in furtherance of the Commonwealth's climate laws and policies. The Department notes the substantial progress in the construction of the Commonwealth's first utility-owned networked geothermal demonstration project in Framingham, with NSTAR Gas planning for the loop to be in operation prior to the 2023 heating season. See NSTAR Gas Company, D.P.U. 23-86, Exh. EVER-ANB/NLB-1, at 11.

Regarding the Attorney General's request to open an investigation into the regulatory treatment of geothermal heat districts and alternative thermal technologies, the Department concludes that opening an investigation at this time is premature. The Department shares the optimism expressed by stakeholders concerning the operation and management of the approved networked geothermal demonstrations, and eagerly awaits successful evaluation data concerning their costs, feasibility, and potential scalability.[62] Depending upon the results of that evaluation, the Department can be expected to move expeditiously to develop broader guidance for networked geothermal, which may require specific performance metrics and strategies to target benefits toward environmental justice populations.

e. Targeted Electrification

Several commenters support additional targeted electrification demonstration projects, in which a participant would disconnect from the gas distribution system and fully electrify space heating and appliance loads (see, e.g., CLF Initial Comments at 9; RMI Final Comments at 3). To that end, numerous commenters recommend that the LDCs complete comprehensive geographic system and customer mapping, in addition to marginal cost analyses to explore cost-effective alternatives to traditional gas investment (see, e.g., Attorney General Final Comments at 14-15; DOER Initial Comments at 14-15).[63]

The LDCs respond to this proposition by citing several factors that require evaluation before targeted electrification is undertaken on parts of their systems (LDC Joint Comments at 68). The LDCs indicate, for example, that removing gas service from certain parts of

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62 In addition, the Department has approved a settlement agreement in Eversource Energy/Bay State Gas Company, D.P.U. 20-59/19-140/19-141 at 61 (2020), that provided funding for the Attorney General and DOER to administer a geothermal microgrid pilot in the Merrimack Valley.

63 The Department further discusses comprehensive geographic distribution system and customer mapping below in Section VI.G below.

their systems may result in operational concerns regarding system pressures and flows elsewhere on their systems (LDC Joint Comments at 68). The LDCs also argue that decommissioning the gas distribution system would require greater education efforts, as removing gas service as an option for any of a customer's building needs will affect the viability of proposed targeted electrification options (LDC Joint Comments at 68). Generally, the LDCs raise concerns about the process, standards, and policies surrounding targeted electrification, while ensuring the safety and reliability of customers who choose to remain on the system (LDC Joint Comments at 68-69).

The Department is optimistic that targeted electrification through decommissioning parts of the gas system may serve as a promising approach to reaching the Commonwealth's GHG emissions targets; the Department also recognizes, however, that there are several operational constraints and unknowns as raised by the LDCs. To better understand these opportunities and constraints, the Department directs each LDC to work with the relevant electric distribution company to study the feasibility of piloting a targeted electrification project in its service territory. Each LDC, in coordination with the applicable electric distribution company, shall propose at least one demonstration project in its service territory for decommissioning an area of its system through targeted electrification. The LDC should target a portion of its system that suffers from pressure/reliability issues, leak-prone pipe, and/or that targets environmental justice populations that have borne the burden of hosting energy infrastructure. The Department expects the LDCs to engage with elected and appointed officials in the community, community-based organizations that work on energy, environment, labor, or ending poverty, and other interested residents. The Department directs each LDC to file its project proposal by March 1, 2026, for inclusion in its 2030 Climate Compliance Plan, working with its relevant electric distribution company and Program Administrator as necessary.[64]

f. Demonstration Project Process

In reviewing a proposed demonstration project, the Department considers the: (1) reasonableness of the size, scope, and scale of the proposed project in relation to the likely benefits to be achieved; (2) adequacy of the evaluation plan; (3) extent to which there is appropriate coordination among Program Administrators; and (4) bill impacts to customers, among other things. Guidelines § 3.9.1. Demonstration projects are not required to be cost effective at the initial testing and evaluation stage; however, an evaluation report at a demonstration project's conclusion requires detailed analyses of actual project costs and benefits, in addition to projected costs and benefits were the project to be delivered as a program at scale. Guidelines §§ 3.9.1.1, 3.9.2. In absence of cost-effectiveness screening,

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64 The Department has found that, while pursuing energy and demand savings through strategic electrification, the Program Administrators must seek to reduce GHG emissions and minimize ratepayer costs. 2022-2024 Three-Year Plans Order at 84. Splitting incentives between gas and electric Program Administrators may mitigate bill impacts and produce a more equitable sharing of costs and benefits between gas and electric ratepayers. The Department notes that Program Administrators already are required to address fully how they considered a split incentive for both large traditional custom projects and large strategic electrification projects that involve offsetting natural gas consumption in its three-year energy efficiency plan, term report, and any applicable mid-term modification proposals. Liberty Utilities (New England Natural Gas Company Corp., D.P.U. 22-94, at 14 (2022).

detailed program descriptions and appropriate analysis must support the potential of a demonstration project to deliver net benefits in the future. Guidelines § 3.9.1.2.

The Department recognizes that both geothermal demonstration projects that have come before us required multiple proceedings, such as separate proposal, implementation, and cost-recovery filings, in addition to project-level evaluation studies.[65] See, e.g., Boston Gas Company, D.P.U. 20-120, Interlocutory Order on Proposed Demonstration Projects (December 11, 2020); NSTAR Gas Company, D.P.U. 21-53, Order on Phase I NSTAR Gas Company's Implementation Plan (January 4, 2022); NSTAR Gas Company, D.P.U. 22-125, Stamp Approval (December 5, 2022). Inasmuch as the Department had not reviewed a geothermal network proposal prior to 2020, however, such a proposal was considered a matter of first impression. The Department determined that these additional proceedings were therefore necessary to protect participating consumers, set the appropriate budgets, and maintain general oversight as the LDCs use ratepayer dollars to explore innovative solutions in support of Massachusetts' GHG emissions reductions targets. D.P.U. 19-120, at 138, 141, 148-149, 154; D.P.U. 21-53, at 8-9.

The Department has general supervisory authority over gas and electric companies, and must make all necessary examination and inquiries to keep itself informed as to the

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65 The Department acknowledges that multiple proceedings may serve as a barrier to meaningful engagement and participation by the public, and, to that end, the Department opened an investigation into procedures for enhancing public awareness of and participation in its proceedings. Notice of Inquiry by the Department of Public Utilities on its own Motion into Procedures for Enhancing Public Awareness of and Participation in its Proceedings, D.P.U. 21-50 (2021).

condition of the respective properties owned by such corporations, and the manner in which they are conducted with reference to the safety and convenience of the public. G.L. c. 164, § 76. The Department anticipates that the desired streamlining will occur as demonstration projects in support of the Commonwealth's GHG emissions reductions targets become more routine and as the LDCs understand what is expected of them in meeting the Department's standard of review.

Accordingly, the Department concludes that no further "streamlining" of its demonstration project review is required at this time, and that the LDCs have received sufficient guidance and cost-recovery avenues for researching and deploying innovative electrification and decarbonization technologies. The Department fully recognizes the financial and technological uncertainties that LDCs face in reaching the Commonwealth's mandated decarbonization targets; to minimize ratepayer costs, however, we continue to require that innovative technologies be rooted in cost-effectiveness and be offered in a cost-efficient manner.

Any demonstration project proposals related to innovative technologies must include detailed implementation plans and terms and conditions that are acceptable to and protective of participants. Each LDC seeking to demonstrate a new technology must propose novel objectives that will reasonably result in quantifiable GHG emissions reductions, and each LDC will be required to provide updates in its Climate Compliance Plan reports. As circumstances change, the Department may consider an alternative framework to incentivize the deployment of decarbonization technologies, as necessary.

E. Manage Gas Embedded Infrastructure Investments and Cost Recovery

1. Introduction and Summary

As discussed above in Section V.A, most of the pathways modeled predict declines in the number of LDC customers and system utilization over time (Regulatory Designs Report at 31-32). The Consultants raise two main concerns surrounding the issue of declining customers and throughput, namely the resulting higher costs for customers remaining on the natural gas system, and a mismatch between how infrastructure costs are currently recovered and the predicted system utilization (Regulatory Designs Report at 31-32). To mitigate the potential impacts associated with the recovery of embedded infrastructure costs and declining system usage, the Consultants recommend finding ways to minimize or avoid gas infrastructure investments where possible, pre-approval of non-GSEP investments, revisions to existing line extension policies, and accelerated depreciation (Regulatory Designs Report at 32-40).

a. Minimize Capital Investments

The Consultants recommend that the Department and LDCs develop a framework to examine opportunities to minimize or avoid gas infrastructure projects, while continuing to maintain safe and reliable service (Regulatory Designs Report at 32-33). The Regulatory Designs Report encourages geographically targeted electrification where possible as a way to address embedded infrastructure cost issues, as well as investigating various NPAs to replace non-cathodically protected steel, cast-iron, and wrought iron, and other aged pipe with new pipe (Regulatory Designs Report at 33). The Consultants acknowledge that these options are not without barriers, as targeted electrification requires all customers in an area to agree to terminate gas service and switch to electric service, and there are costs associated with switching (Regulatory Designs Report at 33). NPAs discussed include energy efficiency measures, demand response solutions, electrification, and networked geothermal systems (Regulatory Designs Report at 33-34).

b. Pre-Approval

The Consultants recommend the Department establish a process to review and pre-approve LDC capital investment plans relating to non-GSEP investments (Regulatory Designs Report at 34). They suggest conducting holistic, long-term capital planning that aligns safety and reliability investments with the Commonwealth's decarbonization targets (Regulatory Designs Report at 34). The Consultants propose reviewing LDC capital plans every three years—similar to the review process for energy efficiency plans—and that the process should evaluate changes in forecasted demand driven by decarbonization goals (Regulatory Designs Report at 34).

c. Line Extensions

Another recommendation for managing the concerns around embedded infrastructure is to revise the standards associated with line extensions and investments to serve new customers (Regulatory Designs Report at 34-36). The Consultants note that currently the standard for serving new customers is that existing customers must not subsidize the cost to serve new customers, and that to the extent the incremental revenues of the customer addition are not equal to or greater than the associated costs, the difference must be paid by the customer in the form of a CIAC (Regulatory Design Report at 36). The Consultants identify four potential changes to the current line extension policy: (1) shortening the investment payback period; (2) reducing customer revenues supporting the new investments; (3) increasing the target rate of return on the investments; and (4) requiring customers to guarantee the revenues supporting the incremental costs (Regulatory Designs Report at 36).

d. Accelerated Depreciation

Rather than the current practice of utilizing straight-line depreciation, the Consultants recommend accelerated forms of depreciation, such as the Units of Production method or implementing shorter service lives, to better align the recovery of infrastructure costs with the anticipated utilization and anticipated customer migration (Regulatory Designs Report at 37-40). The Consultants suggest that while accelerated forms of depreciation increase costs in the short term, the associated depreciation costs should remain stable compared to continued use of the straight-line method, which will result in increased future costs if system utilization declines (Regulatory Designs Report at 37-38). Accelerated deprecation is presented as not only a means of mitigating affordability and equity concerns, but also a way to mitigate concerns related to unrecovered rate base as customers leave the gas system by recovering costs in an accelerated fashion (Regulatory Designs Report at 38-39).

2. Summary of Comments

A number of commenters specifically argue that line extensions and new customer additions should cease as soon as possible, citing health concerns, the potential for stranded assets, and the ability to achieve net-zero emissions (see, e.g., McCord Comments at 3

(May 6, 2022); Muzzy Comments at 1 (May 6, 2022) ("Muzzy Comments"); PLAN Final Comments at 6; RMI Initial Comments at 12-13; Robinson Comments at 1 (May 4, 2022)). Other commenters express general concerns regarding stranded assets associated with increased capital investments, and some urge a transition away from investments in fossil fuels (see, e.g., Archbald Comments at 1 (May 6, 2022); Armstrong Comments at 1 (May 4, 2022); Boston Common Asset Management Comments at 2 (May 6, 2022); Burdick Comments at 1 (May 6, 2022); C. Rose Comments at 1 (May 4, 2022); Royce Comments at 1 (May 2, 2022)). Several commenters support implementing opportunities to minimize or avoid gas infrastructure projects generally (see, e.g., Acadia Center Initial Comments at 24); CLF Initial Comments at 9).

LEAN contends that furthering capital investments and any proposals to accelerate cost recovery will only increase financial risks and create affordability issues for low-income customers in particular (LEAN Initial Comments at 10, 18). Alternatively, the Attorney General suggests that the Department conduct a review of existing tariff provisions and line extension policies, as there is no current uniform model or costing matrix to assess the cost-benefit analysis of line extensions (Attorney General Initial Comments at 32); Attorney General Final Comments at 16). More specifically, the Attorney General states the Department should determine whether the current CIAC model is consistent with state policies and goals, reflects anticipated investment recovery, and results in mostly free extensions for new customers (Attorney General Initial Comments at 32). The LDCs acknowledge that not all utilities handle line extensions in a uniform way and do not oppose a collaborative review of the current models or the development of a common framework as proposed by the Attorney General (LDC Joint Comments at 93).

In addition to the suggested review of CIAC models and line extension policies, the Attorney General recommends that the Department retain consultants or work with utilities to develop an "investment alternatives calculator" that would review and compare the expected costs of new gas system investments with the short- and long-term costs of alternative solutions (Attorney General Initial Comments at 33-35; Attorney General Final Comments at 11). The Attorney General contends that a properly designed investment alternatives calculator would provide a set of prescribed assumptions for the cost of carbon, a range of values for the cost of gas commodity, the cost of avoided GHG emissions, and the cost of alternative technologies (Attorney General Initial Comments at 33-34)

Regarding depreciation, Acadia Center, CLF, and others argue that accelerated depreciation is worth investigating, and DOER contends that a geographic marginal cost analysis to address decommissioning plans should be required before accelerated depreciation is allowed (see, e.g., Acadia Center Initial Comments at 24; CLF Initial Comments at 54; DOER Initial Comments at 17; RMI Initial Comments at 13). CLF also suggests that investigations into any depreciation changes should begin promptly, as any delays could increase the risk of rate shock when changes are implemented, and that depreciation rates should reflect the utilization of different assets with different lifetimes (CLF Initial Comments at 49, 53).

The Attorney General asserts that accelerated depreciation inappropriately shifts market and climate policy risk from utilities to ratepayers while increasing the cost of gas service (Attorney General Initial Comments at 35-36). She suggests it is unrealistic for utilities to continue to invest in gas infrastructure without regard to market risks and decarbonization goals, and that the Department may choose to treat future infrastructure investments differently from those made historically (Attorney General Initial Comments at 36). The Attorney General contends the Department should order LDCs to file information on the magnitude of potential stranded costs and work to establish clear cost recovery timelines or guidelines to balance the costs and responsibilities of possible stranded assets (Attorney General Initial Comments at 35-37; Attorney General Final Comments at 16). The Town of Hopkinton opposes the adoption of accelerated depreciation, arguing that it shifts cost recovery to taxpayers from the LDCs and ratepayers (Town of Hopkinton Comments at 3-4 (May 6, 2022)). The LDCs disagree with the Attorney General's assessment regarding the shifting of risks, and instead argue that accelerated depreciation addresses affordability concerns for current and future customers while maintaining a safe and reliable system (LDC Joint Comments at 86). The LDCs argue that they must continue to make investments to maintain the gas system, and that the regulatory compact entitles utilities to an opportunity to earn a reasonable return on, and a return of, their prudent investments (LDC Joint Comments at 87). The LDCs also disagree with DOER's assertion that consideration of accelerated depreciation should be delayed until the completion of a marginal cost analysis addressing decommissioning plans, arguing that it would be subject to significant uncertainty and complexities (LDC Joint Comments at 87-88).

3. Analysis and Conclusions

a. Pre-Approval and Capital Investments

The Regulatory Designs Report recommends that the Department review and pre-approve certain future LDC capital investments as part of the reporting and planning process going forward in order to continue providing safe and reliable gas service (Regulatory Designs Report at 46). In the instant proceeding, the Department is not persuaded that pre-approval of investments is appropriate at this time. We observe that there are extensive federal and state regulations intended to ensure the safe maintenance and operation of the natural gas pipeline system, which include safety standards and mandated program improvements. The Department will not interfere with the mandates of the federal and state regulations. See, e.g., 49 C.F.R. §§ 192.907, 911, 1005, 1007; 220 CMR 101.00. The Department does, however, recognize that achieving state climate change goals necessarily requires the minimization of stranded investments to the extent possible. The Consultants recommend encouraging NPAs as alternatives to replacing aged pipes and/or installing new mains. The Attorney General argues that the Department should adopt a robust alternatives analysis or an "investment alternatives calculator" to ensure that any investments made represent the best alternative available at the time (Attorney General Initial Comments at 33; Attorney General Final Comments at 11). The Department agrees that consideration of NPAs will be an essential part of the regulatory landscape, and that companies should begin examining opportunities to minimize investments that may contribute to future stranded costs. As described in Section III above, the recoverability of additional investment in natural gas infrastructure will require an analysis of whether such investments are consistent with state emissions reduction targets and the thorough evaluation of NPAs. As part of any future cost recovery proposals, LDCs will bear the burden of demonstrating that NPAs were adequately considered and found to be non-viable or cost prohibitive in order to receive full cost recovery.[66]

b. Line Extensions

As discussed in Section III, the Commonwealth's climate laws, which include a 2050 GHG emissions reduction mandate and interim targets, require LDCs and the Department to move beyond a "business as usual" approach to system planning and expansion. Accordingly, the Department agrees with the Consultant and commentor suggestions that the standards for investments to serve new customers be examined and revised. The Attorney General specifically recommends that the Department address the standard for line extensions, along with other ratemaking policies, as part of a gas ratemaking regulatory reform in a separate proceeding or working group (Attorney General Final

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66 The Attorney General suggests the use of a "investment alternatives calculator" to evaluate NPAs. The Department agrees that stakeholders should have the opportunity to review not only individual NPA analysis but the underlying assumptions and inputs. The Department therefore directs that in conducting the cost-benefit analysis underlying the consideration and evaluation of NPAs, the LDCs consult with stakeholders prior to submitting an NPA analysis for Department review and adjudication.

Comments at 16). The LDCs express a willingness to develop collaboratively a common framework for evaluating new service connections and a review of existing CIAC and internal rate of return ("IRR") models (LDC Joint Comments at 92-93). The Department directs all LDCs to begin reviewing existing tariffs, policies, and practices related to new service connections to determine: (1) the number of *de facto* free extension allowances; (2) whether current models and policies accurately reflect the anticipated income and timeframe over which the capital investments will be recovered; and (3) whether existing state policies are inconsistent with current practices by incentivizing new customers to join the gas distribution system and allowing LDCs to extend their systems through plant additions.

The Department recognizes that certain statutory and legislative changes may be necessary going forward. In NSTAR Gas Company, D.P.U. 22-107 (2022), in the context of a proposed extension of natural gas service to the Town of Douglas, several parties and participants expressed concern that Section 3 of the Gas Leaks Act, which mandates that the Department review and approve proposals designed to increase the availability, affordability, and feasibility of natural gas service for new customers, is inconsistent with the Commonwealth's GHG emissions reduction targets and climate policies. D.P.U. 22-107, at 6-9, 12. Section 3 was enacted by the Legislature in 2014. D.P.U. 19-120, at 464. Prior to any approval and implementation of a program proposed under Section 3, the Department must review the company's determination that a main or service extension is economically feasible and review the gas company's CIAC policy and methodology. St. 2014, c. 149,

§ 3(a); D.P.U. 19-120, at 456. In D.P.U. 22-107, the Department found that the state's recent climate legislation neither repealed nor amended Section 3; however, we recognize the inherent conflict between the express goals of these statutes given that Section 3 encourages investments in new main and service extensions and increased use of natural gas, while climate legislation mandates a reduction in GHG emissions. See D.P.U. 19-120, at 464. For the Department to pursue fully its mandate to prioritize reductions in GHG emissions along with safety, security, reliability of service, affordability, and equity as directed by the Legislature in the 2021 Climate Act, we recommend that the Legislature repeal Section 3 of the Gas Leaks Act to eliminate any potential conflict of laws.

With respect to line extensions and applications specifically pursuant to G.L. c. 164, Section 30,[67] the Department determines whether a proposal is reasonable. As discussed in D.P.U. 22-107, we have found this includes the overarching consideration of the public interest, defined generally as requiring that there be no adverse impacts on existing natural gas customers. D.P.U. 22-107, at 3-4. In reviewing future applications, the Department will examine the public interest in the context of our broader climate mandates. In doing so,

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67 The Department reviews petitions for authorization to expand a gas distribution company's service territory pursuant to G.L. c. 164, § 30, which states:

> The [D]epartment may, after notice and a public hearing, authorize a gas or electric company to carry on its business in any town in the commonwealth other than the town named in its agreement of association or charter, subject to sections eighty-six to eighty-eight, inclusive, and it may purchase, hold and convey real and personal estate in such other town necessary for carrying on its business therein.

we note that Section 30 does not require that the Department grant petitions in those circumstances where such a grant would not adversely impact existing customers. See D.P.U. 22-107, at 4. We also note that in D.P.U. 22-107, the Department found that the company had demonstrated that an alternative electrification approach was economically unviable, and that the expansion of services into the Town of Douglas was reasonable and consistent with the public interest. D.P.U. 22-107, at 15. While Section 30 does not expressly require a company to evaluate alternatives to expanding its gas system, going forward the Department will take the evaluation of alternatives into consideration along with any impact on achieving the state's climate targets. D.P.U. 22-107, at 15. Finally, although the adjudication of a specific standard of review is outside the scope of this proceeding, the Department anticipates that its consideration of a petition pursuant to Section 30 will presume a requirement of consistency with an LDC's Climate Compliance Plan, as discussed in Section VI.G.

c. Accelerated Depreciation

There is general consensus among the LDCs and stakeholders that the issue of depreciation and stranded assets must be examined. While stakeholders differ as to the exact approach to deal with the issue, the Department agrees that the matter is important and must be investigated. As an initial step, the Department directs all LDCs to conduct a comprehensive review that includes a forecast of the potential magnitude of stranded investments. As part of this review, the LDCs must identify the impacts of accelerated depreciation proposals and identify potential alternatives to accelerated depreciation.

The Consultants and LDCs specifically reference the "Units of Production" method of accelerated depreciation as a way of aligning cost recovery of capital investments with system utilization, noting that it is a method recognized by the National Association of Regulatory Utility Commissioners ("NARUC"), as well as the option of implementing shorter asset service lives (Regulatory Designs Report at 38). The Department notes there are various options to consider with respect to accelerated depreciation, and the LDCs should not limit their review to any one method such as the Units of Production method, as each has its own inherent benefits and limitations (see, e.g., Regulatory Designs Report at 38; NARUC Depreciation Manual at 52-53; 57-61). Accelerated depreciation methods currently are not used for regulatory purposes, with the straight-line method primarily utilized in utility depreciation studies (NARUC Depreciation Manual at 61). The Department previously has recognized, however, that there is a fundamental transition underway in the gas industry in Massachusetts, and further investigation of cost recovery of existing infrastructure investment is required. The goal of the review should be not only assessing the magnitude of stranded costs, but also to investigate ways to address cost recovery while balancing ratepayer and shareholder risk going forward in a way that adequately reflects system costs, shareholder awareness of risk, and realistic expectations of the future, while addressing customer affordability and equity concerns.

### F. Evaluate and Enable Customer Affordability

#### 1. Introduction and Summary

The fifth regulatory recommendation focuses on evaluating and enabling customer affordability as customers transition away from reliance on the gas system to decarbonized technologies. The Consultants caution that each of the identified decarbonization pathways raise cost considerations for customers as well as associated equity challenges, which will require regulatory and policy interventions to mitigate impacts on customers (Regulatory Designs Report at 40). In particular, the Consultants explain that given the magnitude of potential cost impacts, and the rate and equity implications associated with progress toward electrification, there is a need to expand the scope of the current cost recovery mechanisms for LDCs (Regulatory Designs Report at 41). The Consultants therefore recommend a specific set of regulatory designs and policy changes to address these concerns, which we discuss below (Pathways Report at 100-108; Regulatory Designs Report at 40-45).

##### a. Cost and Equity Implications of the Pathways

The Consultants highlight that the upfront costs required for customers to convert appliances and heating systems from natural gas to electricity are a significant barrier for customers to migrate off the gas system (Pathways Report at 105-106). The Consultants further state that when a growing number of customers transition off the gas system, customers who remain on the system will experience increasing energy costs that they must absorb (Regulatory Designs Report at 40; Pathways Report at 106). Absent regulatory changes, the Consultants conclude the remaining customers will see higher rates due to varying increases in commodity or delivery costs[68] (Regulatory Designs Report at 41). The Consultants maintain that by 2050, some of the higher electrification pathways may result in unrealistic costs imposed on customers from $30,000 to more than $70,000 per customer per year (Pathways Report at 107). Pathways with more moderate levels of electrification result in less significant cost shifting, yet still yield costs per customer expected to be 40 percent to 50 percent above the reference case by 2050 (Pathways Report at 107).

In addition to affordability challenges, the pathways present equity challenges, including cost shifting between migrating and non-migrating customers and between rate classes, and potential disproportionate impacts on low-income customers and customers designated as environmental justice populations (Regulatory Designs Report at 40; Pathways Report at 106). The Consultants explain that customers who are unable to fund the high upfront costs of switching to decarbonized technology (especially non-migrating customers who qualify for low income-rates and those who are designated as environmental justice populations) or otherwise face challenges in adopting clean technologies (i.e., the hard-to-electrify commercial sector) are more likely to remain stranded on the gas system and shoulder the growing costs (Pathways Report at 29, 106-109). The Consultants state that

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[68] According to the Consultants' projections, certain pathways that allow for higher continued gas system utilization (i.e., "Efficient Gas Equipment" and "Low Electrification") will experience increased commodity cost of renewable gas in the system, while others that allow for lower gas system utilization (i.e., "High Electrification") will see increases in delivery costs due to customers departing the gas system and leaving behind uncollected embedded gas infrastructure costs to be recovered over fewer customers and/or therms (Pathways Report at 101; Regulatory Designs Report at 41).

low-income customers remaining on the gas system likely will spend an increasingly higher share of their income on energy, from approximately seven percent to more than 15 percent in 2050 (Pathways Report at 101-102).

In addition, the Consultants caution that the pathways present various equity considerations with respect to existing infrastructure retirements, new energy infrastructure construction, and the decommissioning of LDC infrastructure, including municipal tax base impacts, service interruptions and road closures associated with prolonged and significant electric industry or alternative technology construction, and decommissioning of LDC infrastructure (Pathways Report at 108). The Consultants explain that policies will need to address and mitigate, to the extent possible, impacts on environmental justice and low-income populations associated with siting and construction of energy infrastructure as well as potential decommissioning of any LDC facilities. The Consultants state that these mitigation policies are particularly important for environmental justice populations, which generally are concentrated in communities already hosting energy infrastructure (Pathways Report at 108).

b. Recommended Regulatory and Policy Interventions

The Consultants propose to address affordability and equity concerns through a set of specific regulatory design recommendations, which focus on understanding and minimizing the impacts of decarbonization on customers (Regulatory Designs Report at 42). These regulatory design recommendations include identifying and quantifying transition costs, evaluating the impacts of transition costs on customers, and exploring alternative cost recovery mechanisms and securitization as methods for mitigating affordability issues

(Regulatory Designs Report at 42, 45). In addition, the Consultants suggest that policy interventions such as targeted incentives aimed at promoting a more equitable transition to clean technologies are warranted (Regulatory Designs Report at 20, Pathways Report at 108). Ultimately, the Consultants conclude that the magnitude and pace of electrification associated with a particular pathway will impact LDCs and the Department's ability to develop and implement regulatory policies that mitigate potential cost shifts and associated equity issues (Pathways Report at 108).

First, the Consultants recommend developing a framework to identity and quantify transition costs (i.e., uncollected costs from customers who have departed the gas system, costs associated with design and implementation of the regulatory reforms,[69] workforce transition costs, and costs associated with restructuring or realignment of gas supply portfolios) (Regulatory Designs Report at 42). The next step should be to evaluate the impact of those transition costs on customers under the various pathways (Regulatory Designs Report at 42).[70]

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69 These proposed regulatory reforms include geographically targeted electrification, non-pipeline solutions, coordinated planning efforts between electric and gas utilities, and accelerated depreciation (Regulatory Designs Report at 42).

70 The Consultants explain that under some pathways, such as 100 percent gas decommissioning, the transition costs grow quickly and have a substantial impact on customer rates much earlier in the decarbonization pathway, while under other pathways, such as hybrid electrification, the transition costs grow more slowly and have a substantial impact on rates later in the decarbonization pathway (Regulatory Designs Report at 42).

The Consultants next recommend mitigating transition costs by evaluating alternative approaches to cost recovery, such as charging customers leaving the gas system an exit fee or migration fee ("migration charge"),[71] and a statewide recovery mechanism through electric surcharges ("transition charge") (Regulatory Designs Report at 42). The first approach suggests a migration charge for customers leaving the gas system to cover costs that were incurred to serve them but not collected (Regulatory Designs Report at 42-43).[72] According to the Consultants, this would minimize the cost shift to customers remaining on the system as well as minimizing the potential for non-recovery of embedded costs (Regulatory Designs Report at 43). The second approach of charging transition charges seeks to align the benefits of decarbonization with the transition costs through sharing the transition costs more broadly with those who benefit from the transition (Regulatory Designs Report at 43). The Consultants acknowledge that the mechanism underlying this approach requires considerable review and evaluation, including its implications on LDC customers and, more broadly, on those who would pay for the transition costs, but they suggest that the process could start with establishing a fund and continue with attempts to identify other funding sources (Regulatory Designs Report at 43). The Consultants assert that the substantial transition costs

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[71] The Consultants refer to this fee as a "migration fee," while some commenters refer to the charge as an "exit fee." The Department uses the term migration charge, which has the same meaning as migration fee and exit fee, and references the terms used by commenters when summarizing comments.

[72] The Consultants posit that this option likely would require legislative approval given the charge would be based on LDC costs charged to non-LDC customers (Regulatory Designs Report at 42).

associated with each pathway require a cost recovery mechanism consistent with the scope and scale of such costs (Regulatory Designs Report at 42).

The Consultants' final recommendation is to evaluate the use of securitization as a method to finance transition costs and lower a utility's borrowing costs, which, in turn, decreases the amount customers will have to repay, and allows both parties to benefit directly from the bond market (Regulatory Designs Report at 45).[73] The Consultants acknowledge that securitization poses the challenge of requiring a secure revenue stream, whereas the revenue stream under the decarbonization pathways is subject to significant uncertainty (Regulatory Designs Report at 45). The Consultants suggest that a possible, albeit untested, solution to this uncertainty would be through charges on both gas and electric bills (Regulatory Designs Report at 45).

In addition to the above set of regulatory design recommendations, the Consultants introduce a few policy interventions they claim are needed to address affordability and regulatory concerns. First, to address the burden of upfront capital costs of appliances, as well as the costs associated with decarbonization in the building sector (e.g., implementing building shell retrofits), the Consultants suggest that expanded policies aimed at providing additional customer incentives should be established (Pathways Report at 102, 106-107; App. 1, at 57).

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73 The Consultants state that securitization has been used in the utility industry to finance the recovery of extraordinary costs (e.g., wildfire mitigation costs in California, coal plant decommissioning costs in New Mexico, and storm costs in Texas), serving to minimize the impacts on customer rates (Regulatory Designs Report at 45).

Next, the Consultants suggest that a means of mitigating the unintended consequences of inequitable cost shifting is to provide incremental incentives to low-income and environmental justice populations to promote decarbonization (Pathways Report at 108). In addition, the Consultants suggest that incentives designed to benefit both landlords and renters would help address the current misalignment of interests between these parties, especially for pathways with higher levels of customer transitions (Pathways Report at 108). Further, the Consultants caution that the pathways present various equity issues related to both existing infrastructure retirements and new energy infrastructure construction, including municipal tax base impacts, service interruptions and road closures associated with prolonged and significant electric industry or alternative technology construction, and decommissioning of gas infrastructure (Pathways Report at 108). Importantly, environmental justice populations are generally over-represented in communities already hosting energy infrastructure (e.g., LDC on-system LNG and propane assets). Given that each pathway has a significant level of energy infrastructure construction, the Consultants suggest that policies will need to specifically address and mitigate the disproportionate impacts on environmental justice and low-income populations associated with siting and constructing energy infrastructure as well as the decommissioning any LDC facilities (Pathways Report at 108).

2. Summary of Comments

Several commentors expressed affordability concerns, particularly for LMI customers (see, e.g., Attorney General Initial Comments at 50; DOER Initial Comments at 15; LEAN Initial Comments at 18; NCLC Initial Comments at 32; HEET Comments at 7). Several stakeholders call for the prioritization of LMI customers to ensure an equitable transition and protect those customers from bearing the increased energy burden associated with electrification (see, e.g., NCLC Initial Comments at 32; LEAN Final Comments at 2-3; Sierra Club Final Comments at 12). Stakeholders generally agree that LMI customers are less likely to leave the gas system and, therefore, may be disproportionately impacted by higher energy bills (see, e.g., Acadia Center Initial Comments at 22; LEAN Initial Comments at 17). To that end, several commentors suggest that the LDCs should consider rate mechanisms to help protect LMI ratepayers from high energy burdens and potential rate increases (see, e.g., Attorney General Initial Comments at 52; DOER Initial Comments at 15; LEAN Initial Comments at 18).

The Attorney General argues that the current gas regulatory framework does not protect LMI customers and customers in environmental justice populations from the increasingly high energy burdens that will disproportionately impact these customers as more ratepayers leave the gas system in the transition to a net-zero future (Attorney General Initial Comments at 46-47, 52; Attorney General Final Comments at 3-4). The Attorney General asserts that the high upfront investment required to transition to alternatives, such as heat pumps, creates inequities for LMI customers as these households often lack savings, disposable income, and access to credit, which prevents them from affording clean energy alternatives (Attorney General Initial Comments at 47-48). The Attorney General adds that likewise renters may be poorly positioned to participate in and benefit from the energy transition as renters often are responsible for heating bills yet have no control over the heating system and a landlord may not be motivated to make necessary upfront investments (Attorney General Initial Comments at 48; Attorney General Final Comments at 3-4). The Attorney General further observes there is a disproportionate impact to health and safety experienced in certain communities (e.g., due to pollution or the siting of energy infrastructure), including environmental justice populations (Attorney General Initial Comments at 50).

The Attorney General argues that protection for LMI ratepayers must be directionally consistent with reducing dependence on natural gas and should minimize the risk that customers unable to migrate end up with a disproportionate share of transition, embedded, or stranded costs (Attorney General Initial Comments at 52). To this end, the Attorney General recommends that the Department consider adopting a rate mechanism to protect LMI ratepayers from high energy burdens and from potential rate increases related to climate investments by both the gas and electric distribution companies, such as implementing a cap on the amount an LMI ratepayer is billed (Attorney General Initial Comments at 52). The Attorney General further recommends that the Department provide targeted support to LMI customers and customers in environmental justice populations when programs are designed to facilitate opportunities for residents to access cleaner energy alternatives (Attorney General Initial Comments at 52; Attorney General Final Comments at 17).

Several commenters disagree with implementing a migration charge as suggested by the Consultants (see, e.g., Acadia Center Initial Comments at 24-25; RMI Initial Comments at 3; Sierra Club Initial Comments at 18-19; CLF Final Comments at 6). Acadia Center agrees that customer affordability issues should be addressed through a Department investigation of various cost recovery options, but does not believe exit fees are the appropriate approach (Acadia Initial Comments at 24-25).

Sierra Club argues that a migration charge is unfair and undermines the Commonwealth's GHG emissions reduction goals by contradicting incentives to leave the gas system (Sierra Club Initial Comments at 18-19). Sierra Club further contends that this approach fails to account for system costs to which customers contributed but from which they did not benefit (e.g., system expansions and system upgrades to deal with growing demand in certain geographic areas), and questions whether customers would be compensated for those excess contributions when they leave the gas system as well (Sierra Club Initial Comments at 19). Sierra Club also argues that electric ratepayers should not be burdened with gas system transition costs (Sierra Club Initial Comments at 19). Sierra Club suggests that this approach would make the cost of electrification relatively more expensive and would affect not only the customer economics of electrifying from gas, but also of electrifying fuel oil and propane use (Sierra Club Initial Comments at 19).

According to Sierra Club, the best way to minimize low-income energy burdens is to fully electrify low-income housing as part of a high electrification strategy given that the Pathways Report shows that energy burdens of low-income customers would be lowest for those who fully electrify (Sierra Club Initial Comments at 22; Sierra Club Final Comments at 12). Sierra Club states that while it is important to implement policies such as low-income rates to mitigate impacts on those low-income customers left on the gas system, the priority should be implementing policies and funding programs to support low-income electrification to ensure low-income customers are not left behind in the transition to clean energy (Sierra Club Initial Comments at 22; Sierra Club Final Comments at 12). LEAN also supports protection of low-income customers from rate increases under the pathways and advocates for an increase to low-income discounts (LEAN Initial Comments at 17; LEAN Final Comments at 2-3).

CLF also argues against imposing a migration charge or transition fee on customers leaving the gas system (CLF Final Comments at 6). CLF contends that doing so would essentially serve as a penalty for transitioning to decarbonized technologies (CLF Final Comments at 6). Further, according to CLF, such a framework would ensure that only those who can afford to pay the fee will be able to make the choice to use clean energy options, leaving the most vulnerable residents who are unable to afford the costs to transition to clean energy stranded on an increasingly high-cost gas system (CLF Final Comments at 6). In addition, CLF submitted a “Scoping a Future of Gas Study,” which recommends that utility analyses must account for the differences between customer classes and reflect the impact of each scenario on customers in each category, including low-income ratepayers, moderate-income ratepayers, and renters within the residential class, as well as different types of commercial buildings and industrial consumption (CLF Initial Comments at 38). CLF suggests that LDCs must track the rate and bill impacts of each energy transition scenario on customers with reduced ability to make infrastructure choices in their homes, such as LMI households and renters, and find ways to mitigate the effects of any inequitable outcomes (CLF Initial Comments at 38). The analyses for customer affordability must compare overall costs associated with the use of gas as a "bridge" fuel versus direct transition to electricity (CLF Initial Comments at 39). CLF recommends that LDCs also should consider that customers might switch from pipeline gas to delivered fuels if pipeline service becomes uneconomic, and include recommendations to mitigate any negative effects resulting from such choices (CLF Initial Comments at 39).

DOER agrees with the Consultants that it is necessary to protect customers, particularly low-income customers and those in environmental justice populations, from rate shocks by evaluating decarbonization-specific rate structures (DOER Initial Comments at 9, 11). DOER argues that the Department should require the LDCs to conduct a geographic marginal cost analysis to identify where transitioning to cleaner technologies provides significant benefits, which includes recommendations for mechanisms (e.g., new rate structure proposals for future tariff proceedings or for future legislative or regulatory action) to help protect low-income residents (DOER Initial Comments at 15). DOER asserts that LDCs must balance affordability concerns for customers against continuing to make necessary investments in the gas system to ensure safety and reliability (DOER Final Comments at 19).

The LDCs indicate support for the Commonwealth's climate goals and contend that customer choice should be at the center of any strategy to meet those goals as individual decisions about when and how to adopt electrification and efficiency measures will affect the nature, scale, and magnitude of electric and gas system transformations (LDC Joint

Comments at 93-94, citing Pathways Report at 15). The LDCs support the hybrid electrification pathway because it results in lower energy system costs, providing an incentive for customers to adopt hybrid heating systems (LDC Joint Comments at 75). The LDCs support the Consultants' suggestions for potential rate designs, such as a new hybrid heating rate class and critical peak pricing, to incentivize customers to adopt or remain on hybrid heating systems (LDC Joint Comments at 75). To ensure customer equity, LDCs are considering potential financial transfers from electric utilities to gas utilities as an approach to fund transition costs (LDC Joint Comments at 75). The LDCs assert this arrangement recognizes the multiple benefits of maintaining gas system functionality, including better utilization of the electrical system, avoidance of significant electrical system upgrade costs, and the maintenance of an alternative energy source in the event of blackouts (LDC Joint Comments at 75). The LDCs argue that achieving the levels of electrification modeled in each pathway will require significant customer education efforts, as well as development of supportive policy initiatives and market transformation activities that help customers overcome the upfront cost barriers to electrification (LDC Joint Comments at 94-95).

### 3. Analysis and Conclusions

#### a. Introduction and Summary

In opening this investigation, the Department sought to examine strategies to enable the Commonwealth to move into its net zero GHG emissions energy future while simultaneously safeguarding ratepayer interests. As detailed by the Consultants and LDCs and reinforced by several stakeholder comments, customers are expected to see considerable impacts through the affordability and equity implications of the transition to clean energy alternatives. Namely, customers will face challenges with respect to the upfront costs necessary to invest in clean technologies, rate increases for a declining number of customers remaining on the gas system, and resultant equity impacts, especially for LMI ratepayers and environmental justice populations.

In discharging our responsibilities under G.L. c. 25, the Department must prioritize affordability and equity in addition to safety, security, reliability of service, and reductions in GHG emissions to meet statewide emissions limits and sublimits. G.L. c. 25, § 1A. As electrification efforts expand, ensuring affordability and equity is of particular importance to avoid overburdening customers financially, particularly those who already bear higher burdens in terms of not only costs but other cumulative impacts. The Department acknowledges that the ability to meet these goals will depend on a variety of factors, including the magnitude and pace of customer transition, and legislative and regulatory changes. The Department remains committed to ensuring that its future regulatory policies are aimed at addressing barriers to expeditious customer transition to decarbonized energy options, while mitigating challenges with affordability and equity.

Throughout this proceeding, numerous stakeholders and individuals raised concerns regarding the ability of customers to afford the costs of the transition away from gas, as well the potential inequitable impacts to customers, especially those most vulnerable. The Consultants, as well as several stakeholders, propose a host of solutions to address these issues. Upon examination of the challenges and proposed strategies related to affordability identified during this proceeding, the Department has determined that further investigation is necessary and herein sets forth several areas for future evaluation that will focus on informing the strategies and any necessary regulatory changes to balance affordability and equity with the need to transition into a clean energy future as quickly and aggressively as is practicable. We discuss these areas of future investigation below.

b. Transition Costs

With respect to transition cost considerations, the Department recognizes that the increasing number of gas customers leaving the gas system likely will result in higher rates for those customers remaining on the system. The Department shares commenters' concerns regarding barriers preventing LMI customers from transitioning away from gas, while those same customers would bear a disproportionate energy burden by remaining on the gas system. We agree that new regulatory support and strategies will be needed to minimize the negative implications of this potential cost shifting and to maximize affordability.

The Department supports the Consultants' suggestion that an appropriate starting point is the development of a framework to identify transition costs and quantify these costs to understand the full scope of the cost impacts associated with the various decarbonization strategies, and then to evaluate the impact of those costs on ratepayers. The Department envisions that this framework should, at minimum, include identifying and quantifying the following transition costs: (1) uncollected costs from customers who have departed the gas system; (2) costs associated with design and implementation of regulatory reforms, including geographically targeted electrification, NPAs, coordinated planning efforts between electric and gas utilities, and accelerated depreciation; (3) workforce transition and training costs; and (4) costs associated with restructuring or realigning of gas supply portfolios (Regulatory Designs Report at 42).

Once quantified, the impact of transition costs on ratepayers, particularly LMI customers and environmental justice populations, should be evaluated fully. Importantly, this evaluation should encompass a broad range of considerations, including but not limited to: (1) bill impacts by customer class (short and long term as well as percentage of cost increase relative to household income); (2) GHG emissions reductions; (3) public health and safety; and (4) equity[74] under the various pathways. The Department is interested in DOER's recommendation that the LDCs conduct a geographic marginal cost analysis to identify where transitioning to cleaner technologies provides significant benefits, including potential mechanisms (e.g., new rate structure proposals for future tariff proceedings or for future legislative or regulatory action) to help protect LMI ratepayers. As discussed in Section VI.E above, the Department favors a robust alternatives analysis, and we see a geographical marginal cost analysis to be a potentially valuable and informative part of that process. As suggested by the Attorney General, the Department will prioritize consideration

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74 In this context, evaluation of equity considerations should include impacts on LMI customers, environmental justice populations, renters, and people of color, both in terms of energy burden and energy-related health and safety impacts. An equity analysis should consider the disproportionate and inequitable distribution of burdens and benefits that currently exist as well as future projections.

of any impacts that result in disproportionate and inequitable distribution of burdens and benefits when making any future regulatory decisions.

c. Alternative Cost Recovery

The Department agrees that we should evaluate and consider alternative cost recovery mechanisms. The Consultants suggest implementing migration and transition charges, along with financing transition costs through securitization, as potential cost recovery mechanisms to alleviate the increasing burdens on customers as more and more leave the gas system. Several commenters express support for types of mechanisms that help mitigate cost and equity impacts to customers, but also argue that implementing the Consultants' proposed mechanisms is inappropriate.

While the Department acknowledges the potential benefits of implementing a migration charge or exit fee for migrating off the gas system—such as reducing the costs that will shift to the remaining gas customers and minimizing the potential for non-recovery of embedded costs—the potential burdens and impacts on those customers and their decision to adopt clean alternatives remain unknown and untested. The Department is concerned that charging a fee to exit the gas system may disincentivize some customers from pursuing electrification. Similarly, while the Department acknowledges the potential benefit that securitization methods could yield (i.e., in terms of lowering borrowing costs and reducing customer rate shocks), the full scope of the impacts on customers and the gas and electric systems remains to be seen.[75] For these reasons, the Department declines to adopt the proposed alternative cost recovery mechanisms at this time and we will examine other cost recovery mechanisms in a future investigation.

Lastly, the Department agrees with several commenters that there is a need to adopt a rate mechanism aimed at protecting LMI customers from high energy burdens and potential rate increases as they transition from gas to electricity. As mentioned in Section VI.B above, the Green Communities Act directs that 20 percent of three-year energy efficiency plan budgets be allocated to low-income energy efficiency. G.L. c. 25, § 21(b)(1). We determine that there should be additional policies and programs to support low-income electrification to ensure low-income customers are not left behind in the transition to clean energy and, in fact, benefit in the near-term from electrification opportunities. The Department encourages the LDCs to work with the Energy Efficiency Advisory Council, including LEAN, to explore strategies to better reach underserved populations and hard-to-reach customers, including renters and landlords, LMI customers, and environmental justice populations. The Department also previously directed the LDCs to weatherize prior to or as part of an electrification project to ensure that overall energy consumption will decrease, while minimizing ratepayer bill impacts, particularly for LMI customers, for purposes of acquiring all cost-effective energy efficiency under the Green Communities Act. 2022-2024

75 The Department notes that while G.L. c. 164, §1H, provides that the Department shall approve an electric company's securitization plan that maximizes rate affordability to ratepayers, the statute does not explicitly apply to LDCs.

Three-Year Plans Order at 107-108. An enhanced incentive structure that includes weatherization for low-income and environmental justice population customers in addition to incentives for heat pump conversions will ensure a reduction in energy consumption and minimize bill impacts. The LDCs should encourage, through education and enhanced incentives, proper weatherization of all customer homes in advance of heat pump installation. LDCs should also ensure that contractors properly size heat pumps prior to installation. Failing to do so potentially increases energy costs for customers. 2022-2024 Three-Year Plans Order at 107-108.

Further, we acknowledge the Recommendations of the Climate Chief, Melissa Hoffer, developed pursuant to Executive Order No. 604, §3(b), which recommends that the Department "prioritize any rate reform necessary to ensure that electric bills will be affordable for all households, particularly those with low and moderate incomes."[76] As noted in Section III above, the Department will investigate this issue further as we evaluate methods to ensure affordability and equity in light of higher energy burdens on LMI customers.

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76 Hoffer, Melissa, Office of Climate Innovation and Resilience, "Recommendations of the Climate Chief pursuant to Section 3(b) of Executive Order No. 604," pages 40-43 (October 23, 2023), available at: https://www.mass.gov/doc/recommendations-of-the-climate-chief-october-25-2023/download (last visited November 29, 2023).

G. Develop LDC Transition Plans and Chart Future Progress

1. Introduction and Summary

The sixth regulatory recommendation includes developing transition plans and evaluating progress toward the Commonwealth's climate targets. The Consultants state that the transition toward achieving climate targets will require (1) periodic reporting and (2) an iterative planning process that reflects lessons learned and new developments (Regulatory Designs Report at 46). The Consultants identify the following reporting and planning processes for inclusion in the new LDC transition plans:

1) Evaluation of LDC transition plan progress toward achievement of climate goals and addressing challenges;

2) Review and pre-approval of future LDC capital investments with a focus on necessary gas system replacements and identification of strategic opportunities to avoid new gas infrastructure through electrification and alternative options;

3) Establish a framework to review and optimize cross-coordination planning between gas and electric utilities;

4) Establish a framework for review and approval of cost recovery mechanisms for LDC capital investments and pilot projects;

5) Evaluation of customer affordability metrics;

6) Evaluation of key initiative data such as number of renewable natural gas customers, GHG emissions calculations, rates and bill impacts, and impacts on environmental justice populations with each plan filing; and

7) Incorporation of performance metrics and incentives to align LDCs' financial incentives with the goals of the Commonwealth (Regulatory Designs Report at 46-47).

Each LDC filed a Net Zero Enablement Plan, an initial transition plan for meeting the Commonwealth's 2050 goals (Framework and Overview at 17). The LDC Net Zero

Enablement Plans are designed to continue energy efficiency efforts consistent with the three-year energy efficiency plans, and to advance decarbonization and the Consultants' recommended regulatory designs in the short term. (Framework and Overview at 17). Included in the LDC transition plans is a proposed Model Tariff that would allow the LDCs to recover costs associated with their respective Net Zero Enablement Plans (Framework and Overview at 18-19). The LDCs seek Department approval of a framework for future iterations of the Net Zero Enablement Reports and the Model Tariff (Framework and Overview at 18-19). Each LDC proposes to file a Net Zero Enablement Plan on a three-year cycle, to align with the three-year energy efficiency cycle, using a five-year and ten-year planning horizon (Framework and Overview at 18). The Consultants note that GSEP capital investments would not be included in the transition plans because there is a process in place for Department review and approval for such expenditures (Regulatory Designs Report at 46). The LDCs propose that the Department review their initial and future three-year transition plans pursuant to the following standard of review: "The LDC's transition portfolio is reasonably designed to contribute to the reduction of GHG emissions to meet net-zero emissions by 2050, without compromising the safety, reliability and affordability of service offered to current customers" (Framework and Overview at 18).

2. Summary of Comments

a. Comprehensive and Coordinated Planning

Most commenters agree that comprehensive planning is needed to guide future investments and meet decarbonization objectives. The Attorney General recommends that the

Department take several steps to support LDC comprehensive planning such as: (1) requiring LDCs to file a comprehensive geographic distribution system mapping report; (2) implementing an investment alternatives calculator;[77] (3) mandating an alternatives analysis for approval of LDC proposals for alternative sources of methane or combustible gas; (4) directing LDCs to file plans that demonstrate the achievement of required GHG emissions reductions; and (5) reviewing LDC forecast and supply planning to better align GHG emissions reduction requirements (Attorney General Final Comments at 10-13). The Attorney General explains that without a full map of the gas system, the regulatory framework would continue to perpetuate piecemeal planning and siloed decision making which may impact the cost-effective achievement of net zero emissions by 2050 (Attorney General Final Comments at 10). The Attorney General maintains that such a map could help identify areas that are best suited for targeted electrification (Attorney General Final Comments at 14). DOER also supports requiring LDCs to submit a geographic distribution system map (DOER Final Comments at 10).

In addition, commenters agree that coordinated planning between gas and electric distribution system companies is necessary. The Attorney General recommends that the Department require electric distribution company participation in gas system investment proceedings (Attorney General Final Comments at 15). The Attorney General contends that the Department cannot adequately evaluate any proposed investment without joint electric and

[77] We address the suggestion of an investment alternatives calculator in Section VI.E.

gas planning (Attorney General Final Comments at 15). Other commenters such as Acadia Center and CLF oppose having LDCs lead the transition plans (Acadia Center Final Comments at 2; and CLF Final Comments at 7). Acadia Center and CLF argue that the LDCs have a financial interest in maintaining the gas system, which creates a conflict of interest in leading the transition plans (Acadia Center Final Comments at 2; CLF Final Comments at 7). CLF avers that LDCs should be treated as stakeholder participants in the "future of gas," while Acadia Center recommends implementing an independent planning authority to lead coordinated planning (CLF Final Comments at 7; Acadia Center Final Comments at 1; Acadia Center Initial Comments at 27-28). Public commenters conveyed support for developing transition plans, but many expressed concerns with the proposal that the LDCs lead the transition.

The LDCs disagree with Acadia Center's recommendation to create a third-party planning authority to oversee the transition plans (LDC Joint Comments at 78). The LDCs argue that creating a new third-party planning authority would conflict with prior Department precedent and the rights and obligations conferred upon utility companies by law and statute (LDC Joint Comments at 78). In particular, the LDCs posit that the Department has long deferred to the judgment and expertise of regulated utility companies when it comes to operating and maintaining their systems (LDC Joint Comments at 80, citing Boston Gas Company and Colonial Gas Company, D.P.U. 13-78, at 13 (2014)). Moreover, the LDCs maintain that it is appropriate for utilities to develop their own investment plans because they bear the responsibility of maintaining a safe and reliable service that is compliant with all federal and state regulatory and statutory requirements (LDCs Joint Comments at 81). Regarding specific analytical constructs for evaluating potential gas network investments proposed by the Attorney General and DOER (e.g., investment alternatives calculator or geographic mapping and marginal cost analysis), the LDCs argue such tools would reduce network planning to consideration of selected quantifiable parameters and, therefore, would be unable to capture the broad range of considerations that are required to make coordinated investment decisions (LDC Joint Comments at 82, citing Exh. DPU-Comm 7-2).

b. Limiting Incentives for Gas System Growth

Several commenters propose recommendations regarding GSEPs. The Attorney General asserts that the Department should consider climate objectives as part of GSEP review and require LDCs to demonstrate that the proposed investment is the least-cost alternative to improve safety and reduce leaks (Attorney General Initial Comments at 30). Additionally, the Attorney General proposes that the Department form a working group to make recommendations for potential changes to GSEPs (Attorney General Attorney General Initial Comments at 44). Similarly, DOER contends that LDCs should be required to address how specific GSEP investments correlate with a parallel geographical marginal cost analysis (DOER Final Comments at 18). DOER, Sierra Club, and CLF agree with revising the current GSEP process so investments in gas infrastructure can be minimized to the greatest extent practicable (DOER Final Comments at 17; CLF Initial Comments at 8; Sierra Club Initial Comments at 20). Several commenters echoed the importance of minimizing further gas system investments (see, e.g., HEET Comments at 8; LEAN Initial Comments at 10-11;

Muzzey Comments at 1). Commenters cited concerns regarding stranded assets and perpetuating the use of fossil fuel gas through gas system investments (see, e.g., RMI Initial Comments at 11; Werlin Comments at 1 (May 6, 2022); Lipke Comments at 1 (May 6, 2022)). Other commenters called for the end of both gas line extensions and the addition of new gas customers to the system (see, e.g., HEET Comments at 33; McCord Comments at 3; PLAN Initial Comments at 4).

The LDCs reiterate that the proposed transition plans exclude GSEP-related investments because there already is a process in place for Department gas system review and approval (LDCs Joint Comments at 81, citing Regulatory Designs Report at 46). The LDCs maintain that their respective GSEPs are consistent with the Gas Leaks Act and note that the Department consistently has found that the replacement of aging infrastructure under GSEPs achieves the goals of improvements in public safety, infrastructure reliability, and the reduction of lost and unaccounted for ("LAUF") natural gas. (LDC Joint Comments at 85, citing Fitchburg Gas and Electric Light Company, D.P.U. 20-GSEP-01, at 9 (2021)). Additionally, the LDCs note that they already are required to show that their respective GSEPs reduce emissions through annual filings with MassDEP (LDC Joint Comments at 85). The LDCs do not object to evaluating possible modifications to GSEPs as part of a working group provided they have adequate representation (LDC Joint Comments at 85).

Other recommendations are intended to further disincentivize gas system growth. For example, the Attorney General avers that LDCs should no longer be permitted to recover costs for marketing related to promoting gas service (Attorney General Initial Comments at 41). The Attorney General argues that these costs are not aligned with the Commonwealth's decarbonization goals and therefore expansion advertising should no longer be funded by ratepayers (Attorney General Initial Comments at 41). Similarly, the Sierra Club argues that incentives for gas appliances should be phased out (Sierra Club Initial Comments at 21). The Attorney General makes an additional recommendation to revise existing performance-based ratemaking ("PBR") mechanisms to establish incentives and disincentives designed around the gas utilities' progress in compliance with the Climate Act mandates (Attorney General Initial Comments at 40-41). The Attorney General states the Department should consider directing each LDC to submit revised PBR plans instead of waiting for the LDC to file its next base rate case (Attorney General Initial Comments at 40-41).

The LDCs disagree with the Attorney General's recommendation to revise the PBR mechanism (LDC Joint Comments at 88). The LDCs explain that PBR generates a level of revenue for a company to run its business, similar to an annual allowance to cover business operations, which enables the company to make system investments and attain operational and capital efficiencies (LDC Joint Comments at 89). According to the LDCs, these efficiencies create savings which are passed on to customers (LDC Joint Comments at 89). Additionally, the LDCs maintain that the existing PBR framework is not inherently inconsistent with progress toward decarbonization (LDC Joint Comments at 89). The LDCs argue that it is not necessary to revise the existing PBR because a new framework that aligns incentives with decarbonization still would apply with or without the current PBR framework (LDC Joint Comments at 89).

c. Net Zero Enablement Plans

Many commenters request that the Department reject the LDCs' individual Net Zero Enablement Plans and associated Model Tariff (see, e.g., Sierra Club Final Comments at 4; NCLC Initial Comments at 20; CLF Final Comments at 6). Some commenters express concerns that the proposed Net Zero Enablement Plans are biased, inaccurate, profit-driven, and ineffective to adequately transform energy use (Donaldson Comments at 1 (May 6, 2022); NCLC Initial Comments at 14-16; Sierra Club Final Comments at 13-14). In addition, other commenters contend that the Model Tariff is premature and that it is unfair for utilities to offer a product, such as RNG, as a tariffed utility service (see, e.g., Attorney General Initial Comments, App. C at 3-4; SFE Energy Comments at 3-4 (May 6, 2022)). The Attorney General criticizes the Net Zero Enablement Plans, contending that the LDCs are resisting change by seeking to maintain gas infrastructure (Attorney General Initial Comments, App. C at 2). The Attorney General proposes that the Department open a planning docket for the purpose of ensuring LDC compliance with climate mandates before considering the proposed Net Zero Enablement Plans (Attorney General Initial Comments, App. C at 3).

DOER recommends that the Department require the LDCs to develop more detailed three-year plans that propose decarbonization regulatory actions, evaluation of previous metrics, and recommendations for future plans (DOER Initial Comments at 13). DOER proposes that the Net Zero Enablement Plans should include the following: (1) a geographic mapping and marginal cost analysis to demonstrate the interaction of multiple strategies; (2) a demonstration of cost considerations; (3) enhanced proposals for regulatory actions to support decarbonization; and (4) metrics as a tool to evaluate successful strategies (DOER Initial Comments at 14). The LDCs maintain that each proposed Net Zero Enablement Plan pursues a portfolio of the various decarbonization pathways analyzed by the Consultants in an effort to meet the Commonwealth's targets while maintaining safety and reliability (LDC Joint Comments at 17). The LDCs request that the Department review and approve the individual Net Zero Enablement Plans and Model Tariff (LDC Joint Comments at 17).

### 3. Analysis and Conclusions

#### a. Introduction

The LDCs developed individual transition plans that articulate their role in supporting the Commonwealth's achievement of its climate mandates. The LDCs specifically propose to implement transition plans that include: (1) joint gas and electric planning; (2) periodic reporting; and (3) a Model Tariff to facilitate recovery of costs associated with the Net Zero Enablement Plans (Regulatory Designs Report at 46-47). The LDCs maintain that it is appropriate for utilities to develop their own transition plans and oppose recommendations to implement an investment alternatives calculator or geographic mapping report (LDC Joint Comments at 81-82). As we have stated from the beginning of this investigation, rather than selecting a single pathway for decarbonization, the Department will focus on creating a regulatory planning framework that is flexible, protects customers, and considers a suite of electrification and decarbonization technologies to facilitate the transition. Here we identify certain strategies and processes that will allow the Department and stakeholders to collect and evaluate information, establish common metrics and assumptions, and refine reporting review procedures to maintain and accelerate momentum toward achievement of the Commonwealth's climate targets. Consistent with our "whole of DPU" approach, these will include LDC reporting requirements, utilization of existing working groups and other forums, convening of technical conferences and additional working groups as necessary, and further investigation and adjudicatory proceedings within the Department.

b. Comprehensive and Coordinated Planning

The LDCs propose to establish a process for coordinated planning between gas and electric utilities (Regulatory Designs Report at 46). The Department agrees that coordinated and comprehensive planning between electric and gas utilities is needed to facilitate the energy transition. Gas and electric infrastructure planning will be necessary as consumers transition from using fossil fuel-based heating systems to electric heat pumps. We note that going forward, evaluation of any proposed investments will have to take place in the context of joint electric and gas system planning. The Department emphasizes that joint electric and gas utility planning must occur in a broad stakeholder context so that the LDCs and electric distribution companies exclusively are not defining the process and outcome. The LDCs and electric distribution companies should consult with stakeholders regarding such a joint planning process that, while it is not Department led, may lead to proposals for Department review. We will continue to monitor and define these processes in future proceedings, as necessary.

Next, the Department addresses the practicality of requiring a comprehensive map of the gas distribution network. The Attorney General asserts that a map of all gas system infrastructure will better enable the Department to evaluate proposed gas system investment and alternatives (Attorney General Initial Comments at 23-24). The Department in Section III and Section VI.E above expressed its support of a robust alternatives analysis, for the first time mandating that LDCs must include and demonstrate analysis of alternatives as a prerequisite for cost recovery of infrastructure investments. As to the requirement of a gas system infrastructure map, the Department seeks to balance the need for comprehensive and useable information with the nature of the extensive critical energy infrastructure information ("CEII") inherent in such an undertaking, which is required by public records law to be protected from public disclosure.[78] We therefore decline to order public filing of such mapping with the Department in a Climate Compliance Plan or otherwise. We will, however, explore appropriate means of facilitating such information sharing without compromising CEII.

The Department finds that it would be inappropriate to issue any further directives that could impact potential changes to GSEPs here. The 2022 Clean Energy Act required the Department to convene a stakeholder working group to develop recommendations and

[78] G.L. c. 66, § 6A(e); G.L. c. 4, § 7(26)(n).

legislative changes to align the gas system with statewide emissions limits, as well as encourage the development of geothermal systems. St. 2022, c. 179, § 68. The GSEP working group has met several times since its initial meeting in April 2023.[79] Each of the LDCs, as well as many of the parties to this proceeding, is participating in the GSEP working group process, and most of the topics raised by the Attorney General and other stakeholders are being explored in that forum. The GSEP working group is expected to produce its findings and recommendations to the Legislature by the end of the year.

c. Climate Compliance Plans

The Department appreciates the LDCs' efforts to design the initial Net Zero Enablement Plans. As a threshold matter, Section 77 of the 2022 Clean Energy Act dictates that the Department shall not approve any company-specific plan in this investigation prior to conducting an adjudicatory proceeding with respect to such plan. St. 2022, c. 179, § 77. Therefore, while the LDCs' Net Zero Enablement Plans lay out the companies' strategies to achieve compliance with climate objectives mandates,[80] which may inform the regulatory framework we seek to establish here, we cannot approve such a plan or a Model Tariff

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79 See https://www.mass.gov/info-details/gseps-pursuant-to-2014-gas-leaks-act (last visited November 29, 2023).

80 The LDCs explain that certain pathways evaluated in the Net Zero Enablement Plans, such as efficient gas equipment installation, may build on the three-year plan activities by offering additional incentives, complementary measures, or implementation practices that further advance efficient gas equipment installations, but that do not fall within the parameters of the Department's precedent for cost-effectiveness applicable to energy efficiency sectors, programs, or core initiatives (Exh. DPU-Comm 1-11).

without full adjudication. This proceeding is an investigation and not an adjudicatory proceeding. Consistent with the legislative directive, the Department will review and approve company-specific plans in subsequent adjudicatory proceedings.

To that end, the Department directs each LDC to file individual Climate Compliance Plans every five years, with the first such Plan being due on or before April 1, 2025.[81] Each Climate Compliance Plan should expand on previous Net Zero Enablement Plans by demonstrating how each LDC proposes to: (1) contribute to the prescribed GHG emissions reduction sublimits set by EEA for both Scope 1[82] and Scope 3[83] emissions; (2) satisfy customer demand safely, reliably, affordably, and equitably using known and market-ready technology available at the time of the filing; (3) use pilot or demonstration projects to assist

81 Subsequent Climate Compliance Plans would be due in 2030, 2035, and 2040. The plans should include a five- and ten-year planning horizon.

82 The U.S. Environmental Protection Agency ("EPA") defines Scope 1 emissions as "direct greenhouse emissions that occur from sources that are controlled or owned by an organization." Scope 1 and Scope 2 Inventory Guidance, available at https://www.epa.gov/climateleadership/scope-1-and-scope-2-inventory-guidance (last visited November 29, 2023).

83 The EPA defines Scope 3 emissions as emissions that "result of activities from assets not owned or controlled by the reporting organization, but that the organization indirectly impacts in its value chain." Scope 3 Inventory Guidance, available at https://www.epa.gov/climateleadership/scope-3-inventory-guidance (last visited November 29, 2023).

in identifying investment alternatives; (4) incorporate the evaluation of previous metrics[84]; and (5) implement recommendations for future plans.

Each electric distribution company operating in an LDC's service area will be required to participate in the Climate Compliance Plan gas planning process.[85] Each Climate Compliance Plan should detail the total investment required and should also include a description of at least one alternative method to meet the required emissions reductions, providing the estimated costs for the considered alternative, and a demonstration that the proposed plan is superior to the alternative. To track compliance with the Commonwealth's interim emissions reduction deadlines, each LDC will be required to file an informational Climate Act Compliance Term Report Filing nine months after each interim deadline (i.e., 2025, 2030, 2035, 2040) indicating whether or not the LDC achieved the required emissions reductions.

d. Climate Compliance Incentives

The LDCs state that the planning and evaluation process could be used to design performance metrics and incentives to align the LDCs' financial incentives with the Commonwealth's goals (Regulatory Designs Report at 47). A PBR mechanism can provide such an incentive for an LDC to take actions aligned with the Commonwealth's climate

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[84] Evaluation of previous metrics would not be applicable to the first Climate Compliance Plan filed.

[85] The Climate Compliance Plans should also include customer, stakeholder, and community input where practicable.

policy and mandates to reduce its sales of methane gas through a series of measures to encourage gas efficiency, demand response, and electrification, as well as reducing LDC system and customer emissions of methane and carbon dioxide. In recent Orders, the Department has approved a PBR framework for LDCs, recognizing that there is a fundamental evolution taking place in the natural gas local distribution industry in Massachusetts.[86] Currently, the Department requires a utility seeking approval of an incentive proposal like PBR to "demonstrate that its approach is more likely than current regulation to advance the Department's traditional goals of safe, reliable, and least-cost energy service and to promote the objectives of economic efficiency, cost control, lower rates and reduced administrative burden in regulation."[87] To better align gas PBRs with the Commonwealth's long-term future of the gas system in a net-zero 2050 economy, the Department finds that it should amend the existing PBR framework to establish incentives and disincentives reflecting the gas utilities' progress toward compliance with the Climate Act mandates, and achievement of their approved Climate Compliance Plans. Accordingly, the Department directs the LDCs to propose climate compliance performance metrics in their next PBR filings.

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86 See, e.g., NSTAR Gas Company, D.P.U. 19-120, at 56; Boston Gas Company, D.P.U. 20-120, at 66-67 (2021).

87 See NSTAR Gas Company, D.P.U. 19-120, at 59.

## VII. CONCLUSION

The Department herein has set forth a regulatory strategy for pursuing an energy future that begins to move the Commonwealth beyond gas and toward its climate objectives. As we have detailed, this will include new reporting and analysis requirements, utilization of existing working groups and other forums, convening of technical conferences and additional working groups as necessary, and further investigation and adjudicatory proceedings within the Department. Going forward, the Department will seek to facilitate a safe, orderly, and equitable transition for the LDCs and their customers through these processes while pursuing the Commonwealth's 2050 GHG emissions reductions mandate and interim targets.

## VIII. ORDER

Accordingly, after due consideration, it is

ORDERED: That the Massachusetts gas local distribution companies shall comply with the directives contained in this Order.

By Order of the Department,

James M. Van Nostrand, Chair

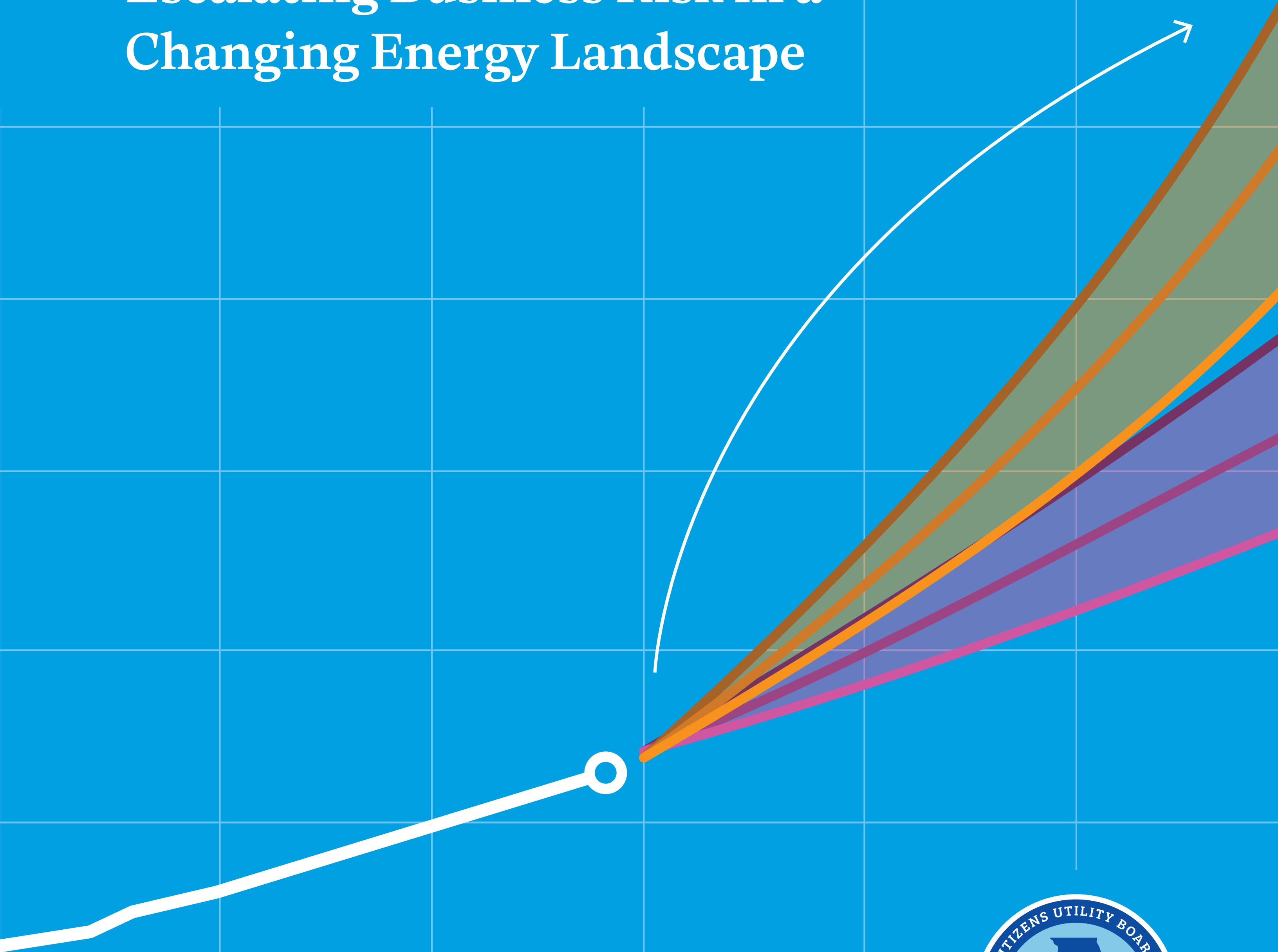
Cecile M. Fraser
Cecile M. Fraser, Commissioner

Staci Rubin, Commissioner

UG 519/CUB/317
Garrett/1

# Peoples Gas

## Escalating Business Risk in a Changing Energy Landscape



October 2024

Groundwork Data

# Acknowledgements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# Contents

# Executive Summary

**Peoples Gas Light and Coke Company ("Peoples Gas" or "PGL")**, one of the oldest natural gas delivery systems in the United States, has been a cornerstone of Chicago's energy infrastructure for over 150 years. It has evolved alongside the city's shift from wood and coal to manufactured gas, and eventually to natural gas by the mid-20th century. Today, Peoples Gas – a subsidiary of the $44 billion energy holding company, WEC Energy Group, Inc. (WEC Energy) – serves nearly 900,000 customers, providing gas for heating, cooking, and industrial uses.

Since its acquisition by WEC Energy in 2015, Peoples Gas has delivered five consecutive years of record financial returns, with dividend payments to WEC Energy increasing more than fivefold, totaling $335 million in 2023. Central to these profits has been the company's **System Modernization Program (SMP)**, a multi-decade, multibillion-dollar initiative to replace much of the city's gas distribution network and upgrade the system's pressure. However, despite this strong record of profitability, the SMP has also introduced significant financial and regulatory risks. In November 2023, the Illinois Commerce Commission (ICC) paused the SMP, initiated an investigation into its reasonableness and prudence, disallowed recovery of $177 million in previously incurred capital costs, and initiated a multi-phased Future of Gas proceeding. These actions, alongside Illinois' broader push toward clean energy, highlight the increasing regulatory scrutiny facing gas utilities in a rapidly changing energy landscape.

Today, as a gas-only utility, Peoples Gas is particularly vulnerable to the financial risks posed by shifting customer preferences and decarbonization efforts that increasingly favor electrification. Notwithstanding its historical significance and critical role in the city's development, Peoples Gas now faces business threats that jeopardize the sustainability of its long-standing business model.

# A. Scope of this report

This report examines the risks and uncertainties facing Peoples Gas, its investors, and its customers. It provides a comprehensive analysis that includes:

- **PGL's corporate and regulatory history.** We chart the evolution of Peoples Gas, the regulatory model set by the ICC, and the significant scrutiny the SMP has faced from numerous audits and investigations.
- **Evaluation of key business threats.** We evaluate the impact of three major threats:
  1. **Escalating delivery costs.** The increasing costs associated with replacing aging infrastructure, particularly in an industry now in the mature phase of its life cycle.
  2. **Clean energy policies.** Mandates and incentives from the city of Chicago, Illinois, and the federal government related to reducing reliance on fossil fuels and encouraging the adoption of cleaner, more efficient energy systems.
  3. **Competition from clean energy alternatives.** The growing shift toward efficient electric appliances, which threatens to reduce the demand for natural gas.

  Using Groundwork Data's Gas Delivery Cost Model, we conduct a modeling analysis to assess the likely future levels of revenue and customer payments needed to sustain PGL's operations under the assumption that a full-scope SMP is approved by the ICC. We also examine the impact of gas customer departures as households and businesses chose to switch to electric alternatives for space and water heating, air conditioning, and other functionalities such as cooking.
- **Critical assessment of PGL's strategy.** We critically assess PGL's assertion that reinstating the full SMP is the most viable and cost-effective solution for addressing safety, reliability, and emissions concerns. We also evaluate PGL and WEC Energy's claims that electrification is infeasible and alternative gases offer a viable building decarbonization path for Chicago.

- **Regulatory and financial challenges.** We examine PGL's evolving regulatory landscape, including recent decisions that have negatively impacted Peoples Gas and the ICC's commitment to re-evaluate the role of gas utilities in Illinois' energy future in light of the state's climate goals. Given this heightened regulatory scrutiny, we examine what the impact would be of reducing capital spending on the Peoples Gas system.

## B. Main findings

The extensive modeling analysis conducted for this report investigates the total costs of resuming PGL's SMP at both full-funding and restricted levels (75% and 50% of full funding). We also evaluate the impact of gas customer departures on these scenarios. Our main findings are as follows:

1. **Unsustainable rate increases.** Restarting the SMP at full scale would necessitate historically unprecedented rate hikes, even assuming a stable gas customer base. By 2040, the average annual per-customer delivery charge would need to essentially double, increasing from $1,206 to $2,424. Year-over-year rate increases of roughly 7% would be required. This compares with a 4.7% rate of annual increase in actual per customer delivery costs for the recent 2015 to 2024 period.

2. **Impact of a shrinking customer base.** With a moderately declining gas customer base, average delivery costs per remaining customer rise significantly because cost recovery for PGL's escalating rate base must be spread over a shrinking pool of ratepayers. Under a full-scope SMP, customer attrition of 50% by 2050 results in annualized rate increases of 12%, 2.5 times the year-over-year increases from 2015 to 2024 (4.7%).[1] Such a level of escalation – resulting in a 185% increase in per customer delivery charges by 2040 to $3,437 – would raise serious concerns about long-term affordability and customer retention, both of which are critical to maintaining stable PGL revenue streams. In addition, these levels of rate increases would undoubtedly accelerate customer departure from the gas system.

3. **Limited potential for rate-increase moderation through reduced capital expenditures.** Lower SMP spending will moderate upward pressure on customer rates; however, this effect may be overwhelmed by the impact of a shrinking gas customer base. Even with reduced SMP spending, a declining customer base would still require annual delivery cost increases of 8% to 10%. This suggests that merely scaling back capital investments will not be sufficient to alleviate the financial pressures facing Peoples Gas should customer departures accelerate.

4. **Escalating cost recovery risks.** Continuing the capital expenditures required by a full-scope SMP would expose WEC Energy to significant cost recovery risks (15% of the parent company's asset base is currently attributable to Peoples Gas). Assuming that a full SMP resumes, PGL's unrecovered balances would surge by 127%, reaching approximately $12 billion by 2040. Complete cost recovery would not occur until after the year 2100. This sharp rise in stranded asset risk over the next 15 years increases the likelihood of significant financial write-downs, especially if regulators take steps to protect taxpayers from bearing the costs of decommissioning the gas network.

5. **Capital costs that significantly exceed previous annual spending levels.** Given the extensive work remaining, PGL and WEC Energy will need to spend much more annually on the SMP than they previously have or project to spend. To complete the SMP by 2040, annual capital spending would need to increase to $547 million beginning in 2025 compared to the historical annual average SMP spending level of $280 million.

6. **Heightened regulatory intervention.** Recent actions by the ICC, coupled with the sunsetting of the QIP Rider, have introduced new regulatory challenges for Peoples Gas that have begun to alter the company's investment risk profile. Peoples Gas has been adversely impacted by

1 By "rate increase" we refer to increases in average delivery costs per customer (or the increase in revenue requirement per customer not including charges for actual therms of gas consumed). Assuming the commodity price of gas remains stable, then these delivery cost increases are a reasonable approximation of increases in average customer gas rates.

these regulatory decisions, including a negative credit review from Moody's Ratings, a subsequent decline in WEC Energy's stock price, and capital spending disallowances. While the outcomes of two critical dockets are pending (the 2024 SMP Investigation and ICC's Future of Gas proceeding), it is clear that Peoples Gas must now operate in a regulatory environment predicated on heightened scrutiny, a focus on decarbonization, and concern about the rising costs of system modernization.

7 **Inadequate strategic response.** Peoples Gas and WEC Energy's current plans do not adequately address the looming threats to their gas utility business model and, therefore, do not adequately allow investors to assess the financial and operational risks associated with a shrinking customer base, escalating infrastructure costs, and regulatory pressures. PGL states that it has not conducted an analysis of Chicago's future energy consumption patterns. Such an analysis is essential and would ideally be coordinated with the city's electric utility, Commonwealth Edison, allowing for the modeling of reasonable scenarios for the uptake of efficient, non-gas technologies by the building sector. In addition, while PGL asserts that a critical role of the SMP is to carry alternative fuels, PGL has not provided feasibility and/or cost/benefit analyses related to decarbonizing the city's gas system by blending in RNG and/or hydrogen.

8 **Future infrastructure challenges.** The scope of system modernization planning put forward by Peoples Gas is confined to the next 15 years and excludes the substantial amounts of pipeline that will be in need of replacement after the SMP concludes. For example, by the 2050s, an additional 1,000 miles of distribution mains installed in the 1980s and 1990s will be queuing up for replacement. If the Peoples Gas system is to be continued indefinitely, then the Chicago gas territory needs a comprehensive, viable plan for the future of gas not just for the duration of the SMP but through the end of the century.

## C. Investor risks and strategic implications

PGL's current trajectory raises significant strategic concerns for WEC Energy and its investors, given the financial and operational challenges outlined above. While Peoples Gas has historically delivered strong financial results, mounting risks threaten to negatively impact its financial performance. The long-term sustainability of PGL's operations in Chicago is in question, with potential repercussions that extend beyond Peoples Gas to the broader financial health and creditworthiness of the parent company, requiring investors to carefully assess how evolving regulatory, financial, and market risks might impact WEC Energy's future stability and profitability.

### Regulatory risks

- **Sunsetting of the regulatory mechanism allowing for accelerated cost recovery.** Accelerated cost recovery played a pivotal role in sustaining PGL's earnings but it expired in December 2023. As a result, future cost recovery efforts will likely take place in more frequent and potentially contentious rate cases, introducing greater financial uncertainty for Peoples Gas. Longer lag times for cost recovery may negatively impact PGL's future cash flows.
- **Potential reductions in earnings.** Any curtailment of the SMP by the ICC, so as to limit rate increases or curb stranded asset risk, would reduce PGL's earnings. We estimate that a 50% reduction in a fully-funded SMP would result in a 33% decrease in the company's earnings before interest and taxes (EBIT) by 2040.
- **Frequent rate increases.** Chicago's gas delivery rates are already among the highest in the nation and substantial PGL rate hikes could exacerbate affordability issues, particularly for low-income and energy-burdened customers. The need for rate increases that significantly exceed historical trends is likely to lead to regulatory and possibly legislative intervention, developments that would present risks for investors.

- **Additional regulatory intervention.** With limited relief achievable through reduced capital expenditures alone, additional regulatory actions, such as more stringent prudency reviews, are more likely.

## Market risks

- **Shrinking customer base.** As gas delivery costs rise and the competitiveness of electric alternatives improves, gas customer attrition is likely to accelerate. This could trigger a negative feedback loop where further departures increase the financial burden on remaining ratepayers and undermine cost recovery efforts. For Peoples Gas, a shrinking customer base will increase cash flow uncertainty and put downward pressure on profitability, potentially adversely affecting net present value.
- **Elevated cost recovery and stranded asset risk.** Continuation of a full-scope SMP could see unrecovered balances in PGL's rate base reach approximately $12 billion by 2040. Coupled with the potential for customer departures and uncertainty about the magnitude of PGL's obligations for retiring or decommissioning gas assets, Peoples Gas faces enhanced risk of not recovering the capital it has invested in the gas system.

## Credit Risks

- **Potential credit downgrades.** Unstable rating outlooks for Peoples Gas have already begun. Actual credit downgrades are a serious possibility given the combined pressures of pending regulatory dockets and decisions, high gas system infrastructure costs, and declining gas demand. These would put pressure on WEC Energy's credit rating risk, likely increasing the parent company's cost of capital and eroding investor confidence.

## Strategic misalignment with climate goals and policies

- **Conflict with climate policies.** PGL's strategy of expanding and modernizing fossil fuel infrastructure increasingly conflicts with the aggressive climate goals of the city of Chicago and Illinois. This misalignment exacerbates the risks of regulatory and market pressures as policies may increasingly prioritize the transition away from natural gas for Chicago's building sector.
- **Threat to "solvency" of low-income discount rate (LIDR) structure.** The state's signature climate law, CEJA, mandated the ICC to study how bill impacts for low-income utility customers could be mitigated and gave the ICC authority to file tariffs establishing LIDRs. In October 2024, Peoples Gas will begin implementing a LIDR that caps gas charges at 3% of household income, providing a credit to energy-burdened customers offset by a rider applied to other ratepayers. However, if gas rate increases accelerate due to SMP spending and/or customer departures, LIDR's cross-subsidization of rate classes could become strained, potentially rendering the structure unworkable if it further incentivizes customer departure and attracts financial and political attention.

# D. Conclusion

Peoples Gas and WEC Energy stand at a critical juncture. The risks and uncertainties highlighted in this report underscore the growing challenges of sustaining the financial health and viability of traditional gas utility operations during the energy transition. As regulatory scrutiny intensifies, and as market dynamics evolve in response to shifting consumer preferences and technological advancements, the business model that has underpinned Peoples Gas for over a century is becoming increasingly vulnerable.

The situation that Peoples Gas faces is emblematic of pressures across the nation that mature, incumbent gas-only utilities may encounter as they grapple with rising infrastructure costs, regulatory changes, and competitive threats from disruptive technologies. Decisions made in the near future regarding the financial path of Peoples Gas will provide important lessons for other energy companies confronting similar risks.

For investors, the evolving challenges confronting Peoples Gas serve as a critical reminder of the complexities involved in the ongoing energy transition and the future of gas. It is essential to monitor these developments closely as they could have significant implications not just for WEC Energy but for the broader utility sector.

# Section 1

# Introduction

**Peoples Gas Light and Coke Company ("Peoples Gas" or "PGL") operates one of the oldest natural gas delivery systems in the United States, serving Chicago, Illinois, the nation's third-largest city.** The gas system expanded in parallel with the industrialization of Chicago during the 19th and 20th centuries. Today, it provides nearly 900,000 customers with gas for heating, cooking, industrial uses, and more. Once an exemplar of technological advancement and modernization with a lengthy waiting list for service, Peoples Gas – a subsidiary since 2015 of Wisconsin-based WEC Energy Group, Inc. ("WEC Energy") – faces an uncertain future, challenged by its aging gas infrastructure in an era of climate change and growing scrutiny of the health and safety implications of gas use.

Since 2018, Peoples Gas has delivered five consecutive years of record financial returns to its parent company. Dividend payments increased more than fivefold and totaled $335 million in 2023. Central to these profits has been the company's **System Modernization Program (SMP)** – a multi-decade, multi-billion dollar initiative to replace much of the city's gas distribution network and upgrade system pressure.[2] However, in November 2023, the Illinois Commerce Commission (ICC) paused the SMP, launched a new investigation to determine the reasonableness and prudence of the program going forward, and disallowed recovery of $177 million for previously incurred capital costs. These actions, along with the ICC's initiation of a Future of Gas proceeding, highlight the increasing regulatory scrutiny facing gas-only utilities in a changing energy landscape.

This report examines the risks and uncertainties facing Peoples Gas, its investors, and customers.

In **Section 2**, we trace the evolution of the company's business model and operations from the early 1900s to today, demonstrating the transition from expansion to replacement and modernization of the company's aging gas infrastructure. We chart the historical relationship between Peoples Gas and the ICC, showing how their intertwined actions brought about record profits for Peoples Gas and its parent company as PGL's rate base grew. Finally, we review the history and current status of the SMP, including PGL's most recent proposal to the ICC as part of the ICC-initiated 2024 SMP Investigation.

**Section 3** introduces and evaluates the financial impacts on the company and its customers of three key business threats: the increasing costs of replacing aging infrastructure; mandates and incentives related to climate change, health, and safety; and growing competition from non-gas alternatives. Detailed modeling results for two scenarios are presented that forecast the revenue requirement increases necessary to reinstate a full-scope SMP, along with the resulting increases in average ratepayer delivery costs. The first scenario provides for a continued stable gas customer base and the second for a declining customer base due to customers defecting to take up efficient electric appliances and/or in response to increasing gas charges. We also model the mounting stranded asset risk that is emerging as the future of the PGL gas system becomes increasingly uncertain.

**Section 4** critically evaluates PGL's assertion that the gas system must prepare for the eventual integration of alternative gases (such as renewable natural gas (RNG) and hydrogen) as well as the company's claim that reinstating the full SMP is the most viable and cost-effective solution for addressing safety, reliability, and emissions concerns. We critically evaluate each of these positions on their own merits in light of emerging alternatives such as building electrification and a managed decline of the gas system.

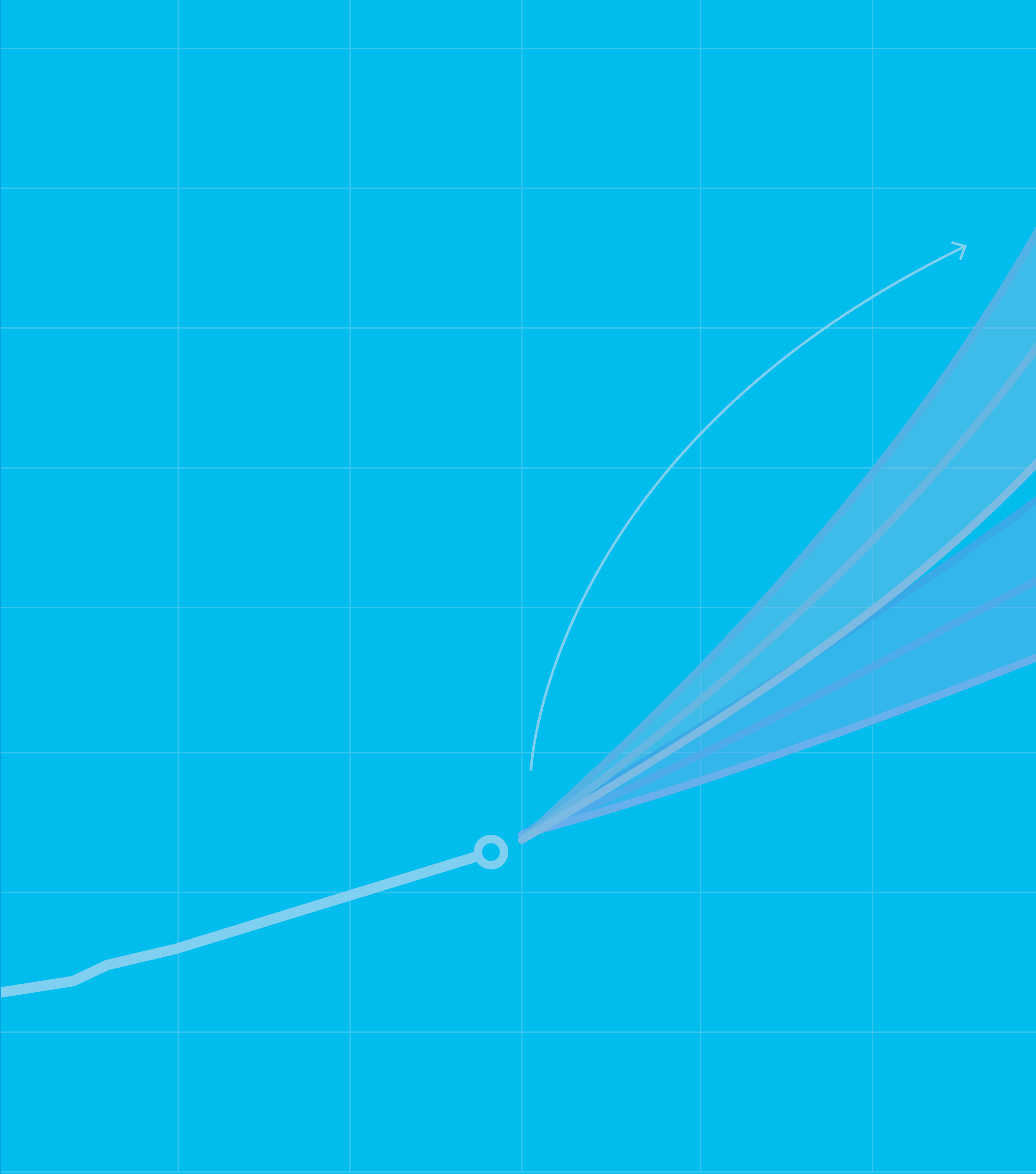
2 Peoples Gas (PGL) now refers to the SMP as the "Safety Modernization Program." The Illinois Commerce Commission (ICC) generally refers to the "System Modernization Program" (see, for example, ICC Docket No. 24-0081).

In **Section 5** we consider the challenges to Peoples Gas from the evolving regulatory landscape within Illinois. While Peoples Gas historically has benefited from regulatory support for aggressive infrastructure replacement, recent decisions by the ICC indicate a shift toward greater scrutiny and a potential reevaluation of the role of gas utilities in Illinois in order to achieve alignment with the state's clean energy goals. This shift was underscored by ICC Chairman Scott's statement upon the announcement of the SMP pause: "As the State embarks on a journey toward a 100 percent clean energy economy, the gas system's operations will not continue to exist in their current form."[3] In consideration of these regulatory changes, we model two reduced-spending SMP scenarios and analyze the implications for PGL's revenue requirement, average ratepayer delivery costs, stranded asset risk, and the company's annual operating income.

**Section 6** summarizes our main findings regarding resuming a full SMP that concludes in 2040. We find that Peoples Gas faces elevated business risk on several fronts – regulatory, market, and credit – and that the sustainability of the company's Chicago operations is increasingly uncertain and risky, with potential repercussions that extend beyond PGL to affect the broader financial health and creditworthiness of the parent company, WEC Energy. While Peoples Gas thus far has delivered strong financial results for WEC Energy, the mounting pressures on PGL suggest that investors should be increasingly concerned not only with securing a profitable return but also about fully recovering their initial investments in the gas distribution system.

**"The sustainability of WEC Energy's gas utility operations in Chicago is increasingly uncertain and risky, with potential repercussions that extend beyond PGL to affect the broader financial health and creditworthiness of the parent company."**

3 Illinois Commerce Commission (ICC), Press Release (November 16, 2023), https://ltgov.illinois.gov/news/press-release.27313.html.



Section

2

# The Peoples Gas business model: From expansion to "modernization"

**For over a century, Peoples Gas has been a cornerstone of energy provision for the residents of Chicago.** As a regulated monopoly utility, its business model has been shaped by judicial interpretation, state legislation, and the operational norms and regulations set by the ICC. This framework has evolved to encompass not just safety, reliability, cost-effectiveness, and conservation, but also equity and the reduction of greenhouse gas emissions.[4]

In this section, we examine the coevolution of PGL's business model and the regulatory framework in which Peoples Gas operates, tracing the progression of the company's business model from the early 1900s to today. While the company's operations have evolved over the decades, the foundation of how Peoples Gas generates revenue has not. The company operates under rate-of-return regulation whereby it earns an allowed rate of return on the equity-financed portion of its capital investments in the gas system. What has changed over the years is the justification for those capital investments, from the early 20th century *expansion* efforts to bring gas to every street and building to the current *modernization* efforts that have led to substantial investments and record earnings for PGL's parent company, WEC Energy. This section highlights PGL's dependence on its modernization plan for earnings growth and the evolution of the SMP program, including the company's most recent SMP proposal to the ICC.

## A. Evolution of the Peoples Gas business model and operations

For illustrative purposes, we divide the history of PGL's operations and business model evolution into three distinct periods: expansion (c. 1913 - late 1970s), transition (c. 1980 - c. 2010), and modernization (c. 2010 - c. 2023).

4 Illinois Public Utilities Act, 220 ILCS 5/1-102 (from Ch. 111 2/3, par. 1-102).

**Figure 2.1: Rate-of-return regulation - Key variables**

**Rate base.** The rate base is the value of the utility's gas plant used to provide gas services that is approved by regulators as constituting the investment on which a fair rate of return is to be based. Gas plant (also referred to as "gas infrastructure") includes distribution mains, meters, and services; transmission mains; storage facilities; and other structures, property, and equipment. The rate base is calculated by adding up the original cost of the assets and adjusting for depreciation and other factors. The rate base grows when utilities invest above the rate of depreciation.

**Rate of return.** Investor-owned utilities engage in approved capital spending to maintain and upgrade their infrastructure, and they earn a regulator-authorized rate of return on their investments known as the "weighted average cost of capital." That blended rate of return includes the profit rate that utilities are allowed to earn on their capital spending. This rate is then multiplied by the rate base to determine the amount of revenue needed to compensate utilities for the equity their shareholders invest, the cost of bond capital, whether it is short, medium, or long-term debt, and income taxes.

**Revenue requirement.** The basis for setting a utility's rates is known as the "revenue requirement." The revenue requirement refers to the total funds that an investor-owned utility needs to collect from its customers in order to pay for the gas system expenses it expects to incur in a given year (i.e., total "delivery costs"). These expenses include the utility's profit on its capital spending, operations and maintenance, depreciation, taxes, customer service, and administration. Dividing the revenue requirement by the total customer base yields a key metric used in this analysis: *average delivery cost per gas customer*.

## 1. Expansion (c.1913 to late-1970s)

Throughout the first three-quarters of the 20th century, Peoples Gas operated in a regulatory environment that encouraged significant capital investment to build out both the supply and delivery components of gas service. Under rate-of-return regulation, Peoples Gas earned a percentage return on capital expenditures deemed prudent by the Commission. The most significant investment in the first half of the century was the construction of a pipeline in 1931 to transport natural gas from the Texas Panhandle to Chicago. This enabled the mixing of natural gas with locally derived coal gas, significantly increasing both the supply and energy density of pipeline gas, which in turn fueled a surge in demand primarily to replace coal for space heating. The $75 million investment (of which Peoples Gas paid approximately one quarter)[5] is equivalent to nearly $1.5 billion today. In addition to the cost of the pipeline, accommodating the new fuel required burner adjustments to all gas-operating appliances – nearly 9 million burners for 820,000 customers.[6] Despite these high capital investments, the introduction of natural gas enabled a rate reduction for customers. A temporary spike in prices to $1.26 per thousand cubic feet in 1941 remained the highest average gas cost to Illinois residential customers until 1974 (see Figure 2.2).

In conjunction with increased investment and stable customer prices, Peoples Gas provided steady returns to its shareholders. Dividends were raised eight times during the 1960s, with earnings-per-share routinely surpassing $3.00.[7] The expansionary period for the gas system came to a close by the mid-1970s as a global energy crisis and the saturation of Chicago's customer base coincided.

5 Peoples Gas Light and Coke Company, *1932 Year Book*, p. 11 (accessed via Mergent Archives).
6 Ibid., p. 14.
7 Peoples Gas Company and Subsidiary Companies, *1970 Annual Report*, p. 2 (accessed via Mergent Archives).

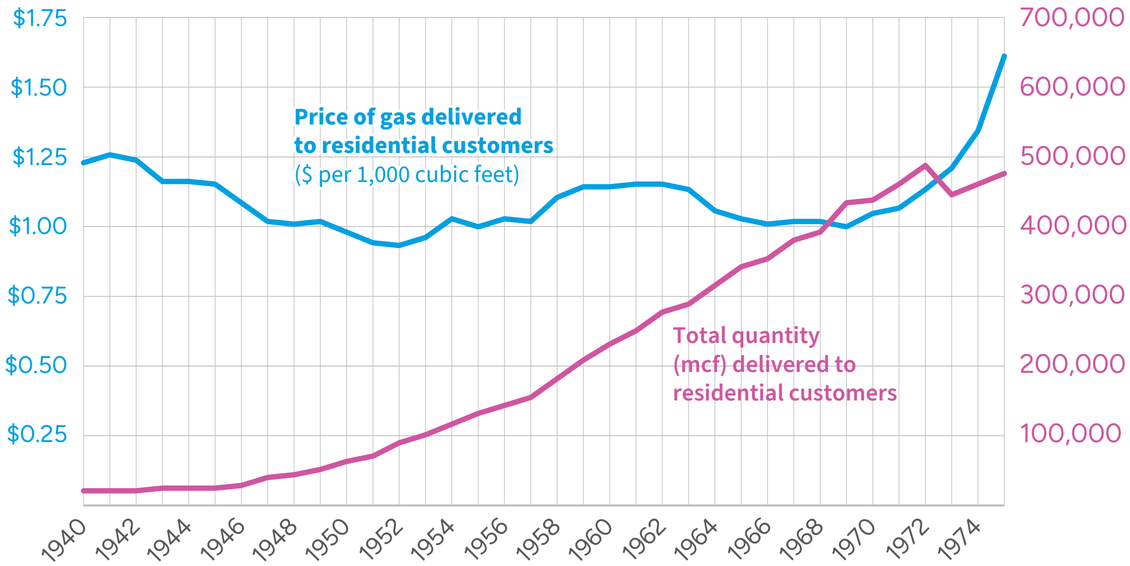
## 2. Transition from expansion to replacement (late 1970s to c. 2007)

By 1980, the Peoples Gas gas distribution system was "essentially mature," according to company management.[8] Customer growth and consumption had plateaued as the distribution system expanded to reach nearly every dwelling in Chicago, providing heating to over 82% of residents and by the mid-1970s, cooking, water heating, and clothes drying for 90%. That same year, Peoples Gas underwent a major restructuring, spinning off its highly profitable generation and transmission assets into a new company, MidCon Corp. This spin-off marked a significant shift as these assets had been crucial for the growth and profitability of PGL's parent company at the time, Peoples Energy Corporation (PEC). After the spin-off, PEC focused exclusively on its regulated businesses, of which Peoples Gas constituted the main holding.[9]

In 1981, an engineering study of Peoples Gas conducted by Zinder Engineering, Inc. (ZEI) recommended a 50-year program to accelerate the replacement of a subset of at-risk, leak-prone cast iron pipes (small-diameter cast iron pipes in clay soils).[10] Peoples Gas began replacing cast iron pipes at a pace of approximately 40 miles per year. This shift marked the transition from expansion to replacement as the company's dominant operational focus. Accordingly, the company's source of profit generation transitioned from capital spending on expanding the delivery system to capital spending on replacing aging, leak-prone mains. In 1994, the scope of the replacement program expanded to include all cast-iron pipes rather than just a subset. This expansion increased the target main replacement goal from 1,679 miles in 50 years (by 2030) to 3,450 miles by 2050.[11]

8 Peoples Energy Corporation, *1980 Annual Report*, p. 15 (accessed via Mergent Archives).
9 Peoples Energy Corporation, *1982 Annual Report*, p. 1 (accessed via Mergent Archives).
10 Zinder Engineering. Inc., *Cast Iron Pipe Replacement Study for Peoples Gas LIght and Coke Company*, Volume 1 (1981, Engineering Report No. ER-048), pp. 5-12 (filed as PGL Ex. 2.01 in Docket No. 24-0081).
11 Abraham Scarr and Jeff Orcutt, *Tragedy of Errors: The Peoples Gas Pipe Replacement Program is a Poorly Designed, Mismanaged, Bad Investment for Chicago* (June 2019, Illinois PIRG Education Fund), p.16, https://publicinterestnetwork.org/wp-content/uploads/2022/07/Tragedy-oferrors_scrn-5.pdf.

**Figure 2.2:** Price and total quantity of natural gas delivered to Illinois residential customers, 1940-1975




Source: Data compiled from U.S. Bureau of Mines, *Minerals Yearbook* (various issues from 1941-1976, chapter on natural gas), https://search.library.wisc.edu/digital/APPYAWXJZXOESO8L.

From the early 1980s through the end of the 1990s, Peoples Gas was able to invest in capital projects without significantly increasing customer rates, thanks in large part to declining gas supply prices. While customer bills stayed largely level, the portion of customer revenue that went to fuel vs. delivery charges changed drastically. As shown in Table 2.1, in 1984, the passthrough cost of gas accounted for two thirds of PGL revenue; by 1999, this portion had declined to just 38%. Over the same period, Peoples Gas averaged over $65 million in net income each year.

> "While customer bills stayed largely level, the portion of customer revenue that went to fuel vs. delivery charges changed drastically."

**Table 2.1:** Declining citygate gas prices enabled level PGL customer gas bills

| Year | Illinois citygate fuel price (per 1,000 cu ft) | Fuel cost as % of PGL operating revenues | PGL net income (millions) |
|---|---|---|---|
| **1984** | $3.44 | 0.66 | $62,134 |
| **1985** | 3.43 | 0.63 | $69,383 |
| **1986** | 3.02 | 0.60 | $66,456 |
| **1987** | 2.81 | 0.57 | $47,170 |
| **1988** | 2.74 | 0.56 | $66,306 |
| **1989** | 2.99 | 0.59 | $77,881 |
| **1990** | 3.09 | 0.59 | $60,156 |
| **1991** | 2.91 | 0.57 | $61,763 |
| **1992** | 3.2 | 0.56 | $58,946 |
| **1993** | 3.3 | 0.57 | $64,355 |
| **1994** | 3.02 | 0.57 | $63,825 |
| **1995** | 2.59 | 0.50 | $53,660 |
| **1996** | 3.27 | 0.49 | $88,752 |
| **1997** | 3.28 | 0.54 | $85,098 |
| **1998** | 2.77 | 0.42 | $68,378 |
| **1999** | 3.00 | 0.38 | $78,217 |

Source: Data compiled from U.S. Energy Information Administration, Natural Gas Data, https://www.eia.gov/dnav/ng/hist/n3050il3A.htm, and PGL, Income statements from PGL Annual Reports, 1984–1996.

## QIP Rider annual reconciliations

QIP costs are subject to an annual reconciliation that examines the costs for accuracy and prudency. Reconciliations from 2017 through 2023 are pending and the possibility of future write-downs for past expenditures exists. In its 2023 annual report, WEC Energy wrote: "As of December 31, 2023, there can be no assurance that all costs incurred under PGL's QIP rider during the open reconciliation years...will be deemed recoverable by the ICC. Disallowances by the ICC, if any, could be material and have a material adverse effect on our results of operations."[1]

1 WEC Energy, 2023 Annual Report (March 2024), p. F-98, https://www.annualreports.com/HostedData/AnnualReports/PDF/NYSE_WEC_2023.pdf.

## 3. The shift to "modernization" (c. 2007 to c. 2023)

Over the course of the past 15 years, which has included two corporate acquisitions, Peoples Gas has significantly transformed its capital spending and infrastructure strategy. Initially focused on replacing 40 miles of leaking cast iron and ductile iron mains per year, the utility's approach evolved after the 2007 merger of its parent company, Peoples Energy Corporation, with WPS Resources Corporation to form Integrys Energy Group, Inc.[12] This merger signaled a shift towards more ambitious "comprehensive overhaul" and "system modernization," as WPS committed to doubling the annual capital investment in the company's main replacement program.[13]

In 2011, Peoples Gas launched its Accelerated Main Replacement Program (AMRP), installing a record 155 miles of new gas mains that year (only 19 miles were due to retiring cast and ductile iron main).[14] The year prior, the ICC approved the Infrastructure Cost Recovery (ICR) Rider, allowing cost recovery for AMRP expenditures outside of formal rate case proceedings in order to provide concurrent recovery of the revenue requirement associated with pipeline replacement. Later that year, however, the Illinois Appellate Court reversed this approval, ruling that the ICC had overstepped its legal bounds in approving the rider and that the utility should instead recover its accelerated pipeline replacement costs through traditional ratemaking procedures.[15]

In 2013, the Illinois General Assembly reinstated accelerated recovery with Public Act 98-57, formally authorizing a new rider called the Qualifying Infrastructure Plant (QIP) Rider. This rider significantly expanded the scope of infrastructure eligible for accelerated cost recovery beyond the replacement of distribution mains, services, and meters to include: transmission pipe replacement, changing the pressure of pipe networks from low to medium, and replacing or installing transmission and distribution regulation stations, regulators, valves, and associated facilities to establish over-pressure protection. Notably, the QIP Rider provided for its own sunset date of December 31, 2023.

QIP played a pivotal role in the finances of Peoples Gas, significantly contributing to steady profitability. In general, accelerated cost recovery riders (also called capital trackers) are attractive regulatory mechanisms for investors because they allow for faster and more predictable returns on investment. Annual cost recovery under QIP ranged from $192 million to $348 million.[16]

In 2015, Integrys Energy Group was acquired by Wisconsin Energy Corporation, forming WEC Energy Group and creating the largest electric and natural gas utility holding in the Midwest and a top ten

12 SEC Archive, "New Release: WPS Resources Corporation and Peoples Energy Corporation Merger Completed, WPS Resources Changes Name to Integrys Energy Group, Inc." (February 21, 2007), https://www.sec.gov/Archives/edgar/data/107833/000091686307000103/exh991press.htm.

13 ICC, Reorganization Application, Docket No. 06-0540, Testimony of James F. Schott, WI Public Service Corporation, p.8, https://www.icc.illinois.gov/docket/P2006-0540/documents/99154/files/178643.pdf.

14 The Liberty Consulting Group, *Executive Summary of a Final Report on Phase One of an Investigation of Peoples Gas LIght and Coke Company's AMRP* (May 5, 2015, ICC14GAS0002), https://icc.illinois.gov/api/web-management/documents/downloads/public/FinalReportTheLibertyConsultingGroupPhaseOneAMRP.pdf.

15 Steve Daniels, "Peoples Gas infrastructure surcharge rejected by Appeals Court," *Crain's Chicago Business* (October 3, 2011), https://www.chicagobusiness.com/article/20111003/NEWS11/110939981/peoples-gas-infrastructure-surcharge-rejected-by-appeals-court.

16 WEC Energy, *2023 Annual Report* (March 2024), p. F-31, https://www.annualreports.com/HostedData/AnnualReports/PDF/NYSE_WEC_2023.pdf.

gas distribution company.[17] In 2023, WEC Energy's asset base totaled $29.4 billion, encompassing a diversified portfolio of regulated and unregulated subsidiaries, including renewable energy facilities.[18] WEC Energy promised investors 5-7% growth in earnings per share and strong dividends. As a condition of the ICC's approval of the WEC Energy acquisition of Peoples Gas and North Shore Gas, the ICC required PGL to file a "Cost Plan Model and Scheduling Master Plan" for the AMRP. PGL's new management agreed that better project administration was needed and extended the program's terminal date from 2030 to a new target end date of 2035-2040. WEC Energy also committed to investing at least $1 billion in Peoples Gas from 2015 to 2017 for infrastructure projects. That commitment was exceeded by nearly 20%, with $1.178 billion spent on infrastructure projects over that period.[19]

In 2016, the AMRP was essentially rebranded as the System Modernization Program (SMP).[20] The stated goal of the two programs remained the same, namely, "to maintain the safety and reliability of PGL's distribution system while systematically addressing risks attributable to aging main by removing that main from the system…"[21] In practice, "modernization" has been a better descriptor of the wider work scope put forward by Peoples Gas, inclusive of system-wide pressurization upgrades. While the AMRP began with a focus on cast iron and ductile iron replacement, the SMP today has a broader, more complex scope and consists of five different subprograms: Neighborhood, Public Improvement, System Improvement, Emergency, and High Pressure. This multifaceted structure has created ambiguity about the intersection of three types of work, each of which PGL treats as falling under the SMP: at-risk pipe replacement, work that PGL is already doing or is required to do (such as pipeline replacements dictated by third parties), and work it wants to do (converting its entire system from low to medium pressure).[22]

## B. SMP's profitability for Peoples Gas and cost to ratepayers

Despite challenges encountered throughout the implementation of the SMP, Peoples Gas has consistently been profitable. Capital spending on replacing and upgrading its gas distribution infrastructure have substantially increased the company's rate base, boosting earnings through a regulated rate of return. However, this profitability has required steady increases in customer delivery charges.

### 1. Corporate profitability

Under WEC Energy's ownership, PGL's net income has increased significantly, rising by 137% through 2022 and averaging 20% year-over-year growth since 2015 (see Figure 2.3). This increase is closely linked to gross revenue that Peoples Gas received via the QIP surcharge.

In 2023, Peoples Gas reported a decline in net income to $120.1 million because it recorded the ICC's rate-case related disallowance of $177.2 million as an impairment, thus reducing operating income.[23]

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17 Wisconsin Energy Corporation and Integrys, Wisconsin Energy To Acquire Integry Energy Group: Presentation (September 2014), Slide 23, https://www.wecenergygroup.com/invest/wec-teg_transaction_sep2014.pdf.

18 WEC Energy, *September 2024 Investor Book* (September 3, 2024), p. 38, https://s22.q4cdn.com/994559668/files/doc_presentations/2024/Sep/03/09-2024-september.pdf.

19 ICC, 2023 Rate Case for PGL, Docket No. 23-0068, Request No. ICC 1.02, p. 1, https://www.icc.illinois.gov/docket/P2023-0069/documents/337765/files/588769.pdf.

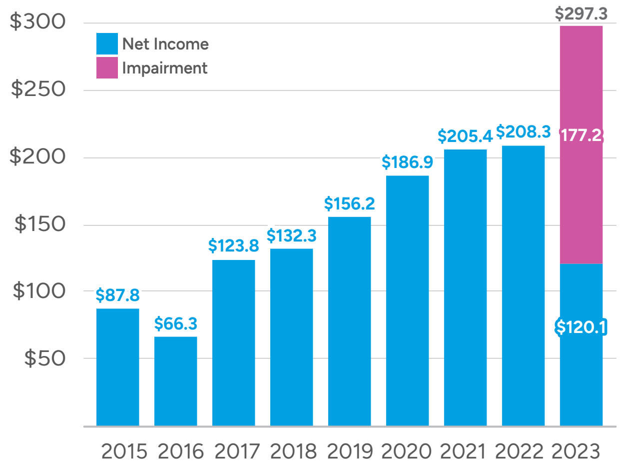
20 ICC, Bureau of Public Utilities, Staff Report to the Commission Regarding Workshops Held to Evaluate and Assess the Peoples Gas Light and Coke Company Gas System Modernization Program (May 31, 2016), https://icc.illinois.gov/docket/P2016-0376/documents/244379/files/431018.pdf.

21 ICC, 2024 SMP Investigation, Docket No. 24-0081, *Peoples Gas and the SMP: History, Current State, and Alternatives*, PGL Exhibit 2.0, p. 16, https://www.icc.illinois.gov/docket/P2024-0081/documents/348897/files/609896.pdf.

22 Abraham Scarr and Jeff Orcutt, *Tragedy of Errors: The Peoples Gas Pipe Replacement Program is a Poorly Designed, Mismanaged, Bad Investment for Chicago* (June 2019, Illinois PIRG Education Fund), p. 9, https://publicinterestnetwork.org/wp-content/uploads/2022/07/Tragedy-oferrors_scrn-5.pdf.

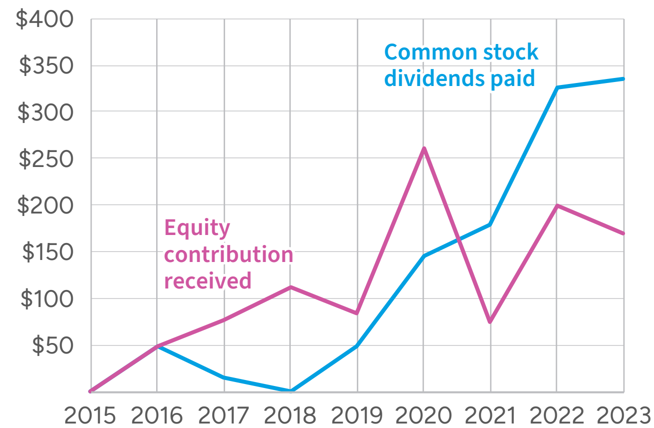
23 PGL, Form 21 ILCC for 2023 (April 2024), pdf p.134, https://www.icc.illinois.gov/downloads/public/filing/2/2/2/372732.pdf. PGL writes: "As the ICC did not grant a rehearing on the disallowance of our capital costs, we recorded a $177.2 million non-cash impairment of our property, plant, and equipment in 2023. This amount includes the previously incurred disallowed costs related to our shops and facilities. The remaining disallowance of capital costs related to our expected future spend. We anticipate appealing the ICC's disallowance of our capital costs to the Illinois Appellate Court after the rehearing process is completed."

**Figure 2.3: Peoples Gas net income, 2015-2023 ($ millions)**




Source: PGL Annual Reports, Consolidated Income Statement (various years), https://investor.wecenergygroup.com/investors/financial-info/subsidiary-financial-statements/default.aspx.

**Figure 2.4: Dividends paid by PGL to WEC Energy & WEC Energy equity invested in PGL ($ millions)**




Source: PGL Annual Reports, Consolidated Equity Statement (various years), https://investor.wecenergygroup.com/investors/financial-info/subsidiary-financial-statements/default.aspx.

Absent this impairment, net income would have totaled $297.3 million.

In addition to significant growth in net income, Figure 2.4 illustrates the annual dividends paid by Peoples Gas to WEC Energy and the capital contributions received by PGL from its parent company. In 2023, Peoples Gas paid a record $335 million dividend to WEC Energy, marking more than a fivefold increase in annual dividends since 2018. From 2018 to 2023, WEC Energy's capital contributions to Peoples Gas totaled $1.029 billion, or an annual average contribution of $150 million (see Figure 2.4).

WEC Energy's dividend payouts to shareholders have also seen substantial increases, largely fueled by the profitability of its subsidiaries. According to WEC Energy's 2023 10-K filings with the U.S. Securities and Exchange Commission (SEC), the company's dividends have more than doubled since 2015, averaging a 15% annual growth rate and totaling $984 million in 2023.[24] Notably, the contribution from Peoples Gas has increased substantially: PGL's share of WEC Energy's total dividends increased from 7% in 2019 to 34% in 2023.

WEC Energy's net income and earnings per share today are at record levels. In 2023, the company raised its dividend for the 20th consecutive year and revised its long-term earnings growth projections upward.[25] According to WEC Energy, "investment opportunities support long-term EPS growth of 6.5%-7%."[26]

## 2. Rising QIP charges to ratepayers

While the SMP and the QIP rider have been highly lucrative for WEC Energy, driving substantial profits and earnings, these gains have come at a significant cost to gas ratepayers. As shown in Figure 2.5, annual QIP charges for the average Chicago residential customer surged from $75 in 2018 to $183 in 2023, representing an average annual increase of nearly 30%.[27]

These rising charges have relegated the PGL gas system to among the most expensive in the nation. Because a high percentage of Chicago's households are energy-burdened, these escalating costs are

24 WEC Energy Group, *10-K Annual Report to the Securities & Exchange Commission* (February 16, 2024), Statements of Cash Flows (various years), p. 167, https://investor.wecenergygroup.com/investors/financial-info/sec-filings/sec-filings-details/default.aspx?FilingId=17296303.

25 WEC Energy Group, *2023 Annual Report* (March 2024), p. 2, https://www.annualreports.com/HostedData/AnnualReports/PDF/NYSE_WEC_2023.pdf.

26 WEC Energy Group, *2022 Corporate Responsibility Report*, p. 14, https://www.wecenergygroup.com/csr/cr2022/wec-corporate-responsibility-report-2022.pdf.

27 The QIP rider has now terminated and PGL proposes to continue SMP cost recovery through its rate cases. QIP charges were percentage multipliers applied to fixed monthly charges and a range of variable charges including the distribution charge, storage service charge, volume balancing charge, invested capital tax adjustment, and other cost adjustments.

fueling affordability concerns and increasing the likelihood of regulatory scrutiny. Future scenarios for these rising delivery costs are modeled in Sections 3 and 5 of this report.

## C. SMP scrutiny and PGL's latest proposal

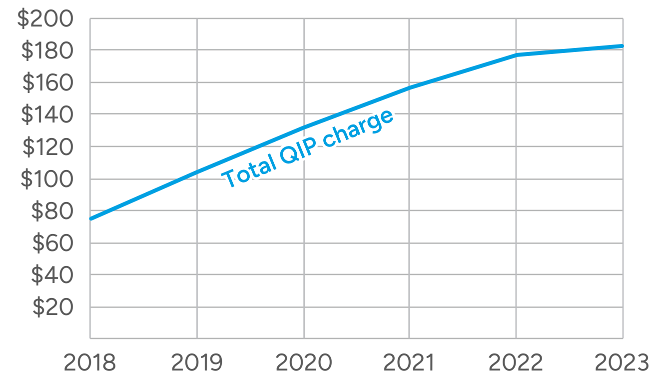
Over the years, PGL's AMRP/SMP plans and outcomes have attracted considerable scrutiny (see Figure 2.8 for audits and investigations from 2007 to 2020). Multiple official investigations and audits have in turn led to revised program priorities, shifting capital spending plans, and evolving milestones. The chief concerns raised by the various audits and investigations have included:

- Project mismanagement and inadequate planning
- Lagging timeline and unrealistic termination date
- Scope creep and ambiguity
- Underemphasis on targeting and replacing the highest-risk pipe; overemphasis on medium-pressure upgrades
- Significant cost overruns

Figure 2.6 summarizes basic SMP outcomes and spending. As of the end of 2023, Peoples Gas had replaced 865 miles of distribution mains or 37% of the total it wishes to replace. Approximately 1,500 miles are still slated for replacement with a target completion date of 2040.[28] Since being acquired by WEC Energy, Peoples Gas has spent $2.6 billion on the SMP or an average of $294 million per year. Figure 2.7 shows annual AMRP/SMP spending over the last decade. The highest annual spending occurred in 2018 ($313 million) and has generally declined since that time.

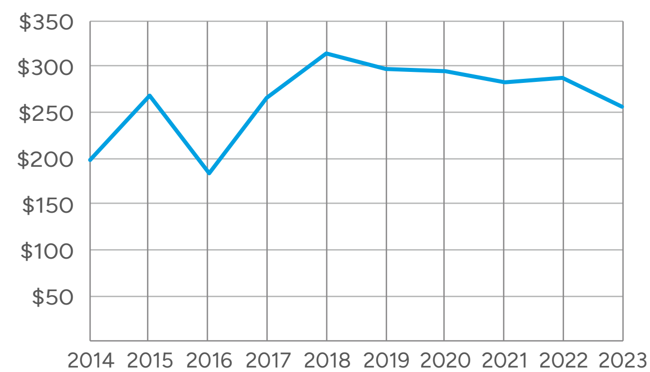
According to PGL's April 2024 filing, an additional $7.5 billion is required to complete the program.[29] (Note: This capital expenditure forecast does not account for inflation or any escalation factors.)

**Figure 2.5: Annual QIP Rider charges for average residential heating customer, 2018-2023**




Source: SMP Quarterly Reports, "Average residential heating customer's monthly bill" (Q4 various years), https://www.icc.illinois.gov/programs/natural-gas-investigations.

**Figure 2.7: AMRP/SMP spending, 2014-2023 ($ millions)**




Source: ICC, 2024 SMP Investigation, Docket No. 24-0081, *Peoples Gas and the SMP: History, Current State, and Alternatives*, PGL Exhibit 2.0, p. 18, https://www.icc.illinois.gov/docket/P2024-0081/documents/348897/files/609896.pdf.

Intervenors across several SMP investigations have questioned PGL's ability to accurately forecast and/or express overall program costs.[30]

28 ICC, 2024 SMP Investigation, Docket No. 24-0081, *Peoples Gas and the SMP: History, Current State, and Alternatives*, PGL Exhibit 2.0, p. 29, https://www.icc.illinois.gov/docket/P2024-0081/documents/348897/files/609896.pdf.

29 Ibid.

30 See, for example, ICC, 2024 SMP Investigation, Docket No. 24-0081, Direct Testimony of AG Gas Technical Panel (June 18, 2024), p. 15, https://www.icc.illinois.gov/docket/P2024-0081/documents/351860/files/615460.pdf.

**Figure 2.6: Basic SMP facts as of Q4 2023**

- **Five subprograms:** Neighborhood, Public Improvement, System Improvement, Emergency, and High Pressure.[1]
- **Distribution mains replaced since 2011:** 865 miles of mains (cast iron and ductile iron, and low pressure) or 37% of the total as of 2011 (2,371 miles).[2]
- **SMP spending from 2014-2023:** $2.6 billion[3] or $294 million per year.
- **2023 unit costs per mile of main replacement in Neighborhood and Public & Service Improvement Programs, respectively (including main install, main retirement, service replacement, and meter moves):** $4 million and $5.1 million.[4]
- **Main miles remaining to be replaced:** 1,499 miles of mains, of which 1,112 are cast and ductile iron (CI/DI) and 385 are low-pressure plastic or steel main.[5] Assuming double decking is used, these replacements would result in the installation of 2,120 miles of main. Of the cast and ductile iron mains, 983 are low pressure.
- **Additional new high-pressure main to be installed:** 30 miles.[6]
- **Services to be replaced:** 202,779 (including leak-prone services and other services connected to CI/DI main).[7]
- **Meters to be moved outside:** 346,912 meters.[8]
- **Stated target investment levels for 2023-2025:** $280-$300 million per year.[9] (See Section 3.A.1 of this report for our analysis of investment levels needed to complete the SMP.)
- **Future capex requirement:** PGL estimates $7.2 billion to $13 billion (PGL says the higher figure corresponds to a focus on at-risk pipeline only).[10] Multiple intervenors in the 2024 SMP Investigation find that PGL has not accurately forecast SMP costs and that its estimates should be disregarded.[11]
- **Target completion date:** 2035-2040 based on prior regulatory approval; 2040 based on SMP Quarterly Report for Q4 2023;[12] 2045 per PGL "if the Commission concludes that annual affordability should play a greater role in the analysis";[13] 2049 per ICC estimates in 2023 Rate Case for PGL.[14]

1 For descriptions of each subprogram and an explanation of PGL's risk analysis and prioritization methods, see ICC, 2024 SMP Investigation, Docket No. 24-0081, *Peoples Gas and the SMP: History, Current State, and Alternatives*, PGL Exhibit 2.0, pp. 39-49, https://www.icc.illinois.gov/docket/P2024-0081/documents/348897/files/609896.pdf.
2 See the "Work Draw-down Curve" presented in PGL, *Safety Modernization Program Quarterly Report*, Q4 2023 (revised April 24, 2024), p. 5, https://icc.illinois.gov/api/web-management/documents/downloads/public/gas/2023%20-%20Q4%20SMP%20Report.pdf.
3 ICC, 2024 SMP Investigation, Docket No. 24-0081, *Peoples Gas and the SMP: History, Current State, and Alternatives*, PGL Exhibit 2.0, p. 18, https://www.icc.illinois.gov/docket/P2024-0081/documents/348897/files/609896.pdf.
4 PGL, *Safety Modernization Program Quarterly Report*, Q4 2023 (February 14, 2024), p. 6 and 9, https://icc.illinois.gov/api/web-management/documents/downloads/public/gas/2023%20-%20Q4%20SMP%20Report.pdf.
5 ICC, 2024 SMP Investigation, Docket No. 24-0081, *Peoples Gas and the SMP: History, Current State, and Alternatives*, PGL Exhibit 2.0, p. 42, https://www.icc.illinois.gov/docket/P2024-0081/documents/348897/files/609896.pdf.
6 Ibid., p. 61.
7 Ibid.
8 Ibid.
9 PGL, *Safety Modernization Program Quarterly Report*, Q4 2023 (February 14, 2024), p. 5 (figure), https://icc.illinois.gov/api/web-management/documents/downloads/public/gas/2023%20-%20Q4%20SMP%20Report.pdf and WEC Energy Group, *2022 Corporate Responsibility Report*, p. 13, https://www.wecenergygroup.com/csr/cr2022/wec-corporate-responsibility-report-2022.pdf.
10 PGL states that the cost figures presented in its April 2024 filing are "not meant to provide the Commission with a new cost estimate for the SMP." ICC, 2024 SMP Investigation, Docket No. 24-0081, *Peoples Gas and the SMP: History, Current State, and Alternatives*, PGL Exhibit 2.0, pp. 63-64, https://www.icc.illinois.gov/docket/P2024-0081/documents/348897/files/609896.pdf.
11 ICC, 2024 SMP Investigation, Docket No. 24-0081, AG Exhibit 1.0, p. 46 (June 18, 2024), https://www.icc.illinois.gov/docket/P2024-0081/documents/351860.
12 PGL, *Safety Modernization Program Quarterly Report*, Q4 2023 (February 14, 2024), Appendix A - Neighborhood Metrics ("End Year" column), https://icc.illinois.gov/api/web-management/documents/downloads/public/gas/2023%20-%20Q4%20SMP%20Report.pdf.
13 ICC, 2024 SMP Investigation, Docket No. 24-0081, *Peoples Gas and the SMP: History, Current State, and Alternatives*, PGL Exhibit 2.0, p. 75, https://www.icc.illinois.gov/docket/P2024-0081/documents/348897/files/609896.pdf.
14 ICC, 2023 Rate Case for PGL, Docket No. 23-0069, Final Order (November 16, 2023), p. 28, https://www.icc.illinois.gov/docket/P2023-0069/documents/344306.

**Figure 2.8: Audits and investigations, 2007-2020**[1]

- **1st Liberty Audit.** In May 2007, the ICC ordered that an audit of PGL's cast iron replacement program be conducted. This audit, completed in August 2008, recommended that within six months, "Peoples Gas should document a well-defined plan for the *systematic* replacement of vulnerable service lines."[2]
- **2nd Liberty Audit.** In 2013, because of concern that the SMP/AMRP "lacked detail," the ICC ordered a two-phase audit of the program (the "Liberty Audit") which concluded in December 2017. The audit resulted in PGL adopting numerous recommendations regarding planning and execution plus two years of monitoring.
- **ICC-initiated Docket No.** 15-0608. This investigation sought to determine whether PGL, Integrys, or WEC Energy knowingly misled or withheld information about ballooning SMP/AMRP cost estimates from the ICC. The two resulting settlement agreements included PGL fines and refunds totalling $18.5 million.
- **ICC-initiated Docket No.** 16-0376. This proceeding investigated the SMP/AMRP costs, schedule, scope, and other issues. PGL proposed a "neighborhood approach" with three-year rolling plans. The proceeding was contested, but in 2019 the IL Appellate Court affirmed the ICC's decision. Pursuant to the proceeding, PGL is required to file quarterly reports and report specific monitoring metrics.
- **Second Kiefner Study.** In its final order for Docket 16-0376, the ICC ordered a new SMP engineering (the "Second Kiefner Study" filed in January 2020). The study found that "most of PGL's CI mains average over 90 years old and most of PGL's DI mains average over 50 years old" and that "83% of the remaining CI and DI pipes have an average remaining life of less than 15 years."[3] The study recommended greater acceleration of the SMP, specifically that "all CI and DI pipes should be replaced by 2030, 10 years earlier than the current plan of completion by 2040."

1 For further detail, see ICC, "The Peoples Gas Light and Coke Company Gas Main Replacement Program: A [sic] Historical Narrative" (not dated), https://icc.illinois.gov/api/web-management/documents/downloads/public/gas/Final%20Historical%20Narrative.pdf.

2 ICC, *Final Report on an Investigation of Peoples Gas Pipeline Safety Program*, The Liberty Consulting Group (August 2008), p. 16, https://icc.illinois.gov/api/web-management/documents/downloads/public/ng/Final%20Report%20Pipeline%20Safety%20Investigation%20-%20Public%20Version.pdf.

3 Keifner and Associates, Inc., *Engineering Study of the Cast Iron and Ductile Iron Pipeline System*, Final Report No. 20-001 presented to PGL (January 2020), p.(i), https://www.icc.illinois.gov/docket/P2018-1092/documents/295819/files/515921.pdf.

> **"In November 2023, the ICC issued a rate case order that paused PGL's multi-decade SMP for a year"**

In November 2023, the ICC issued a rate case order that paused PGL's multi-decade SMP for a year, launching a new investigation ("2024 SMP Investigation") "to determine the reasonableness and prudence of the Company's next iteration of the SMP."[31] The ICC's decision was driven by concerns over cost overruns, doubts about the program's effectiveness in mitigating risks from aging infrastructure, and questions about whether the most vulnerable neighborhoods were being prioritized.[32] The launching of a new investigation was strongly supported by the Attorney General, the city of Chicago, and public interest groups. In addition to halting the SMP, the ICC disallowed $177 million in prior capital spending by Peoples Gas, along with an additional $59 million related to "expected future spend."[33]

These actions by the ICC had immediate financial consequences for PGL and parent company WEC Energy (see Section 5). During WEC Energy's Q4 Earnings Call, Gale Klappa, then-Chairman of WEC Energy, defended the company's position stating, "We firmly believe that the investments were necessary and prudent, and at the appropriate time, we will appeal the decision in court." Klappa added, "We had planned to invest approximately $265 million in these safety upgrades during 2024. Given the Commission's order, we will not be carrying out the program as envisioned. We honestly do not believe that stopping the work is in the best interests of our Chicago customers."[34] WEC Energy characterized the ICC's disallowance of previously incurred capital "highly unusual and not indicative of WEC Energy Group's operating performance."[35]

In response to the ICC's investigation, Peoples Gas submitted a detailed filing in April 2024, outlining three alternative scenarios for the continuation of the SMP, with estimated costs ranging from $7.2 billion to $13 billion:[36]

- **Program Option 1:** Addressing *only* leak-prone mains and services (no medium pressure upgrades) at a cost of $13 billion.
- **Program Option 2:** Addressing leak-prone mains *and* upgrading to medium pressure at a cost of $7.5 billion.
- **Program Option 3:** Upgrading to medium pressure and addressing small- and medium-diameter leak-prone material (excludes replacing 49 miles of cast iron/ductile iron that are already medium pressure and 36 inches or greater with a remaining asset life of more than 50 years) at a cost of $7.2 billion.

In its filing, Peoples Gas advocates for the reinstatement of the SMP, specifically Program Option 3.[37] This plan involves replacing all remaining cast iron and ductile iron pipes and upgrading the system to medium pressure but, compared to Option 2, excludes 49 miles of main that would instead be addressed "on a more reactive basis."[38] Peoples Gas contends that this scope is crucial for ensuring safety, reliability, operational efficiency, and enabling the potential use of "future fuels," such as hydrogen blending and renewable natural gas (RNG)."[39] Cost recovery for these investments would be pursued through traditional rate cases, although no schedule has been established for these proceedings.

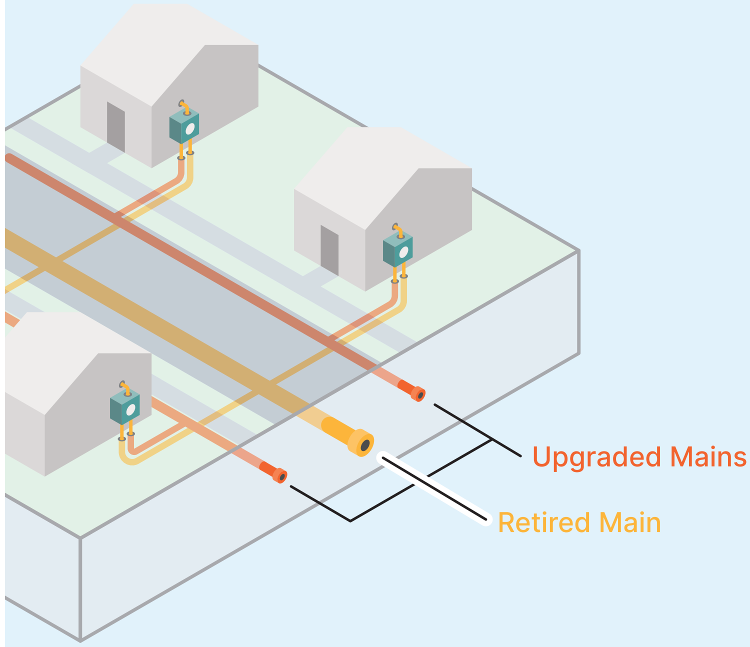
31 ICC, 2023 Rate Case for PGL, Docket No. 23-0069, Final Order (November 16, 2023), p. 30, https://www.icc.illinois.gov/docket/P2023-0069/documents/344306/files/601245.pdf.
32 Ibid., pp. 29-30.
33 A small amount of the disallowance was restored in a Partial Rehearing Proceeding that concluded in May 2024. See Section 5 for more detail.
34 WEC Energy Group, Q4 2023 Earnings Call, https://finance.yahoo.com/news/wec-energy-group-inc-nyse-150702538.html.
35 WEC Energy Group, *2023 Annual Report* (March 2024), p. P-48, https://www.annualreports.com/HostedData/AnnualReports/PDF/NYSE_WEC_2023.pdf.
36 ICC, 2024 SMP Investigation, Docket No. 24-0081, *Peoples Gas and the SMP: History, Current State, and Alternatives*, PGL Exhibit 2.0, p. 61 & 64, https://www.icc.illinois.gov/docket/P2024-0081/documents/348897/files/609896.pdf. PGL states that these cost estimates do not allow for inflation or other escalation or discount factors, and are not meant to be used as formal revised cost estimates. PGL also provides an alternative to its neighborhood-based approach (High Risk Zone Approach (HZRA)) which would further focus on the riskiest pipe segments as opposed to neighborhood-based geographic boundaries. Ibid., p. 80.
37 Ibid., p. 64.
38 Ibid.
39 ICC, 2023 Rate Case for PGL, Docket No. 23-0069, Final Order (November 16, 2023), p. 70, https://www.icc.illinois.gov/docket/P2023-0069/documents/344306/files/601245.pdf.

Critics have long urged that the SMP be scaled back to focus solely on the most critical leak-prone mains and services.[40] However, Peoples Gas maintains that such a limited approach would ultimately be more costly than Program Options 2 or 3. The company claims that considerable cost savings – over $5 billion – would be achieved by bundling material replacement with system pressure upgrades. This strategy, the utility contends, reduces the required diameter of the mains and allows for less expensive construction methods such as double decking and directional boring versus open cutting. Peoples Gas reports that the average cost of replacing a mile of CI/DI low pressure main without using double decking, directional boring, and lower diameter pipelines is $10.7 million per mile. According to the Attorney General, "this wildly expensive forecast is unlikely to be accurate" because PGL based it on a sample of projects that are "short cycle" (i.e., "emergency" projects) and have unit costs in excess of 300% that of other projects.[41]

The SMP remains central to Peoples Gas's business model, driving significant revenue growth for its parent company through increased capital expenditures. The QIP accelerated cost recovery mechanism was pivotal in sustaining these earnings and its recent expiration means that future cost recovery will likely occur through more frequent and potentially contentious rate cases, introducing greater financial uncertainty for the utility. In addition, reflecting broader trends in the gas utility sector, the SMP generally faces an uphill course as Peoples Gas grapples with the high costs and risks of replacing aging infrastructure in a regulatory environment increasingly focused on decarbonization and emission reductions. Three key disruptors of the traditional gas utility model play a core role in these shifting trends and are analyzed in the next section.

40 See, for example: ICC, 2016 SMP Investigation, Docket No.16-0376, AG Exhibit 1.0 (October 11, 2016), https://www.icc.illinois.gov/docket/P2016-0376/documents/246901/files/435644.pdf ; and Abraham Scarr and Jeff Orcutt, *Tragedy of Errors: The Peoples Gas Pipe Replacement Program is a Poorly Designed, Mismanaged, Bad Investment for Chicago* (June 2019, Illinois PIRG Education Fund), p. 9, https://publicinterestnetwork.org/wp-content/uploads/2022/07/Tragedyoferrors_scrn-5.pdf.

41 ICC, 2024 SMP Investigation, Docket No. 24-0081, AG Exhibit 1.0, p. 46 (June 18, 2024), https://www.icc.illinois.gov/docket/P2024-0081/documents/351860.




## Double Decking

Double decking refers to the practice of installing new main on both sides of the street to replace the existing run of main under the street. Each main serves customers on that side of the street. Since more main is installed than retired, double decking results in the use of more materials and involves moving to new medium-pressure pipe. While it requires more materials, double decking typically allows for lower-cost installation techniques such as directional drilling. Furthermore, it can reduce the risk of third-party damage by locating the mains away from other underground utilities. As a result, double decking can be cost effective depending on local restoration and trenching requirements and the location of the street's utility corridor containing other utilities such as sewer, water, and electric.[1]

1 For more information, see ICC, 2024 SMP Investigation, PGL Ex. 3.03, Request No. COC 1.36, https://www.icc.illinois.gov/docket/P2024-0081/documents/352843/files/617447.pdf.

Section

3

# Systemic threats to Peoples Gas

**Peoples Gas began in the 1880s on a competitive playing field and evolved over the following 150 years into the monopoly provider of gas services for nearly every building in Chicago.** Today, the company is entrenched in a costly and prolonged infrastructure replacement phase that is driving rate base expansion and fueling record earnings growth. But, at the same time, Peoples Gas faces an emerging set of systemic challenges that threaten the company's risk profile and financial stability, and undermine the long-term viability of its business model and operations.

This section examines three emerging business threats to Peoples Gas: escalating gas delivery costs, increasing regulatory pressure to reduce greenhouse gas emissions, and growing competition from alternative energy technologies. The first challenge is largely tied to the fact that the gas distribution industry is now in the mature phase of its life cycle with plateaued customer growth due to market saturation. The second and third threats directly relate to the energy transition, that is, America's shift to clean energy in order to reduce greenhouse gas emissions and meet urgent climate goals.

To examine the financial implications of these threats to Peoples Gas, we use Groundwork Data's Gas Delivery Cost Model to forecast future revenue requirement and customer delivery costs for two scenarios. Both provide for the completion of all outstanding SMP projects identified by Peoples Gas, assuming historic PGL unit costs. The first scenario assumes a stable gas customer base while the second models a declining base in line with the expectation that customers will leave the gas system as the energy transition progresses.

## A. Threat 1: Escalating delivery costs

PGL's customers face the highest delivery costs of any gas utility in Illinois[42] and these costs rank among the most expensive in the nation.[43] Before factoring in the cost of the gas itself, the average PGL customer pays approximately $1,000 annually just for the delivery of gas. These significant per-customer delivery costs are driven by three primary factors:

1. **High capital spending.** Substantial investments have been made in PGL's gas infrastructure, particularly for the replacement of high-cost, long-lived assets like pipeline mains.
2. **Operations and maintenance expenses.** The company incurs significant operations and maintenance costs – around $300 million annually – including uncollectible account expenses which totaled $54 million in 2023.[44]
3. **Stagnant customer base.** Growth in PGL's customer base has leveled off; therefore, increasing delivery system costs must be distributed across a relatively constant number of users. Notably, Peoples Gas had more residential customers in 1990 (789,604) than it does today (773,427).[45]

42 PGL's per customer delivery cost is more than a third higher than the next most expensive utility in the state. See: Dorie Seavey et al., *The Future of Gas in Illinois* (May 2024, Building Decarbonization and Groundwork Data), Section 5, https://buildingdecarb.org/resource/the-future-of-gas-in-illinois.

43 Delivery costs are the main charge on gas customer bills and refer to all expenses associated with the reliable and safe transportation of gas to customers, including the costs of system operation, maintenance, repair, customer service, administration, taxes, and repaying utilities for their capital investments (capital spending is paid back over many years).

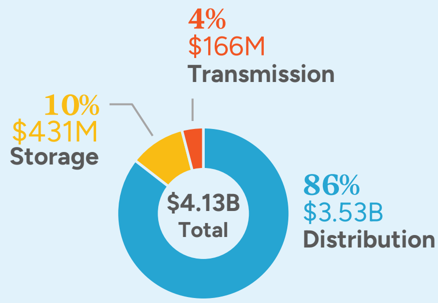
44 For more on PGL's bad debt expenses, see Section 5.E.2 of this report.

45 For the 1990 figure, see PGL, Annual Report on Form 10-K for fiscal year ended September 30, 1994, Item 6, p. 11, https://www.sec.gov/Archives/edgar/data/77388/0000912057-94-004271.txt. For the 2023 figure, see ICC, *Comparison of Gas Sales Statistics for 2022 and 2023* (July 2024), Table 4, p. 4, https://www.icc.illinois.gov/downloads/public/ng/23-22Comparison%20of%20Gas%20Sales%20Statistics.pdf.

# Highlights of PGL and WEC Energy's gas system investments in Chicago

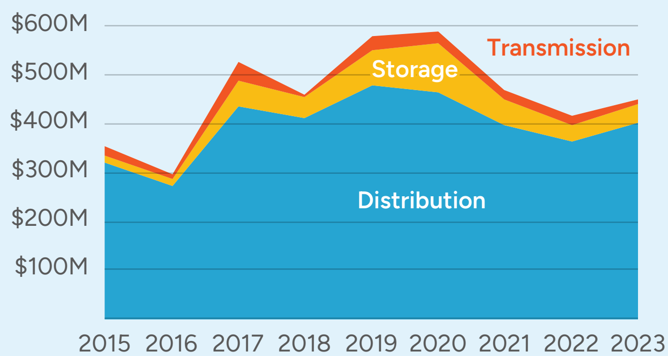
- From 2015 through 2023, the two companies invested $4.1 billion in distribution, transmission, and storage infrastructure, or $459 million per year.[1]
- The vast majority of this investment (86%) has been in distribution plant and approximately half that amount has been in pipeline mains which have a lengthy cost recovery period of approximately 65 years.[2]
- PGL's gas-plant-in-service balance for distribution, transmission, and storage assets ballooned by 80% from the end of 2014 to the end of 2023, increasing from $3.6 billion to $6.5 billion.[3]

**Figure 3.1: Total spending on PGL gas system by category, 2015-2023**



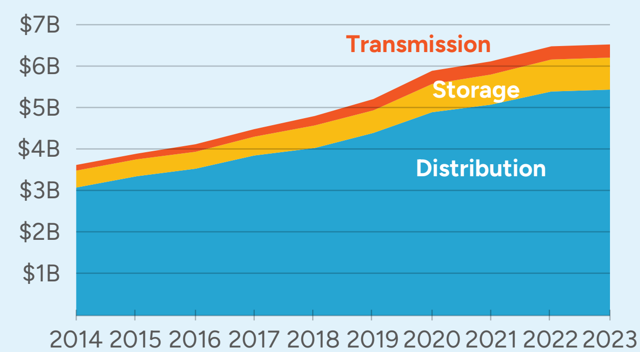

Source: GWD analysis of ICC, 2023 PGL Rate Case, Docket No. 23-0069, PIO Ex. 1.2, pp. 3-4.

**Figure 3.2: Trends in spending on PGL gas system by category, 2015-2023**




Source: GWD analysis of ICC, 2023 PGL Rate Case, Docket No. 23-0069, PIO Ex. 1.2, pp. 3-4.

**Figure 3.3: Growth in PGL's gas plant in service, 2014 (EOY) - 2023 (EOY)**




Source: GWD analysis of "Gas Plant in Service" Schedule, PGL ICC Form 21 ILCC (various years)

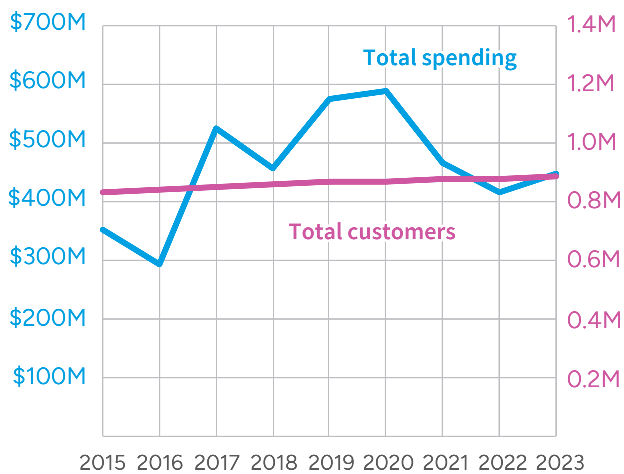
1 Calculated from ICC, 2023 Rate Case for PGL, Docket No. 23-0069, PIO Exhibit 1.2, pp. 3-4. https://www.icc.illinois.gov/docket/P2023-0069/documents/337548/files/588151.pdf. Note: Calculations exclude intangible plant and plant related to manufactured gas and land rights. They also exclude capital spending on general plant and information technology which totaled another $339 million over this period. 2023 figures are estimates.

2 ICC, 2023 Rate Case for Peoples Gas, Docket No. 23-0069, PGL Ex. 9.1: "Summary of the depreciation study," Table 1, Survivor Curve entry for plastic mains, https://drive.google.com/file/d/10X3MsrkN5ZDybC6g-d7hzYUqnvr9CT8CQ/view?usp=drive_link.

3 PGL, Form 21 ILCC for 2023 (various years), "Gas Plant in Service" Schedule, https://www.icc.illinois.gov/downloads/public/filing/2/2/2/372732.pdf. Figures show end-of-year balances after retirements, adjustments, and transfers.

As shown in Figure 3.4, from 2015 to 2023, PGL's customer base increased by 0.7% while average annual gas system spending increased considerably through 2020 and then declined during the Covid pandemic. To continue the substantial remaining SMP work – 63% of which remains to be completed – system costs must be spread over a customer base that has shown little growth for several decades. This strongly suggests that gas delivery charges for Peoples Gas customers will continue to rise *independently* of climate policies.

**Figure 3.4: Total distribution, transmission, and storage capital spending versus customer counts**




Source: GWD analysis of ICC, 2023 PGL Rate Case, Docket No. 23-0069, PIO Ex. 1.2, pp. 3-4 and ICC, *Comparison of Gas Sales Statistics* (various years), https://www.icc.illinois.gov/icc-reports/report/comparison-of-gas-sales-statistics.

## 1. Modeling results for "Full SMP" scenario with a stable gas customer base

We apply our Gas Delivery Cost Model to assess a resumed "Full SMP" scenario. We define Full SMP as having the following scope as of the end of 2023:[46]

- Replace 1,506 miles of cast iron and ductile iron and low-pressure mains
- Reconnect and/or replace 202,779 services
- Relocate 346,912 meters
- Install 30 miles of high-pressure main

The scope of Full SMP reflects the complete set of items that Peoples Gas has identified as constituting its "historical approach to upgrading its gas distribution system."[47]

For our modeling input values, we rely on data submitted by Peoples Gas to the ICC during its 2023 rate case, information found in PGL's SMP Quarterly Reports (particularly the Q4 2023 report), and information provided in PGL's major report filed at the beginning of the company's 2024 SMP Investigation (Docket No. 24-0081). Our major assumptions are as follows:[48]

- Peoples Gas restarts its Full SMP in 2025.
- All work is completed by 2040 and is spread evenly across the 15-year period (2025-2040).
- The company's gas customer base remains stable (we explore a declining customer base in Section 3.C.2).
- Historic unit cost rates for SMP work (e.g., $ per retirement mile, $ per service line) remain stable.
- An annual inflation adjustment of 2.5%.
- Non-SMP spending continues in line with prior years at a rate of $116 million per year for the remainder of SMP.[49]

Our key modeling findings for this scenario (Full SMP with a stable customer base) are as follows (see Table 3.1 and Figures 3.5 and 3.6 for further detail):

1. **Revenue requirement impact.** Under the Full SMP Scenario, by 2030, Peoples Gas's revenue requirement would need to increase by nearly a third to fund capital spending for both SMP and non-SMP projects. By SMP's projected 2040 end date, the annual revenue requirement roughly

46 See the Appendix on Modeling for further description of Full SMP scope, data sources, and a description of Groundwork Data's Gas Delivery Cost Model. "Full SMP" scope includes all the scope items presented by PGL in ICC, 2024 SMP Investigation, Docket No. 24-0081, *Peoples Gas and the SMP: History, Current State, and Alternatives*, PGL Exhibit 2.0, p. 61, https://www.icc.illinois.gov/docket/P2024-0081/documents/348897/files/609896.pdf.

47 See Program Option 2 in ICC, 2024 SMP Investigation, Docket No. 24-0081, *Peoples Gas and the SMP: History, Current State, and Alternatives*, PGL Exhibit 2.0, p. 61, https://www.icc.illinois.gov/docket/P2024-0081/documents/348897/files/609896.pdf.

48 See the Appendix for further details.

49 Non-SMP capital spending includes capital spending on storage, transmission, and non-SMP distribution infrastructure. The latter consists largely of spending on new line extensions. We have excluded spending on General Plant and Information Technology. See the Appendix for detailed notes and sources.

> **"Managing the increasing costs of the gas system under Full SMP spending would require the ICC to place Peoples Gas customers on a steep trajectory of rising gas delivery costs. By 2040, the average annual per-customer delivery charge would need to double, increasing from $1,260 to $2,424 – requiring a year-over-year increase of 6.7%."**

doubles from its 2025 level (peaking at $2.1 billion in 2040, up from $1.1 billion in 2025).

2. **Customer impact.** Managing the increasing costs of the gas system under Full SMP spending would require the ICC to place Peoples Gas customers on a steep trajectory of rising gas delivery costs. By 2040, the average annual per-customer delivery charge would need to double, increasing from $1,260 to $2,424 (see Figure 3.5). This would require year-over-year rate increases of 6.7%.

3. **Unrecovered balances.** Committing to Full SMP spending would significantly increase PGL's asset recovery risk profile. Currently, the company has about $5 billion in unrecovered gas plant assets in its approved rate base.[50] Under the Full SMP scenario, PGL's unrecovered assets would increase by 128% from 2025 to by 2040, rising from $5.2 billion ($5,846 per customer) to nearly $12 billion ($13,298 per customer) (see Figure 3.6). Complete SMP cost recovery would not conclude until around 2100, assuming an average depreciation rate of 65 years for the last SMP main installed in 2040.[51]

4. **Total capital costs.** Given the extensive work remaining, PGL and WEC Energy will need to spend much more annually on the SMP than they previously have or project to. To complete the SMP by 2040, our analysis finds that SMP spending would need to increase to $547 million beginning in 2025. The historical annual average spend for the SMP has been $280 million (as of Dec. 31, 2023).[52]

**Table 3.1: Modeling results for Full SMP scenario with a stable customer base (2.5% annual inflation factor assumed)**

| | 2025 | 2030 | 2040 |
|---|---|---|---|
| **Total cumulative capex** | $663M | $4,234M | $12,847M |
| **Cumulative capex - SMP only** | $547M | $3,711M | $12,668M |
| **Revenue requirement** | $1,069M | $1,408M | $2,149M |
| **Cumulative revenue requirement** | $1,069M | $7,427M | $25,497M |
| **Average annual delivery cost per customer** | $1,206 | $1,588 | $2,424 |
| **Unrecovered balances** | $5.18B | $7.38B | $11.79B |

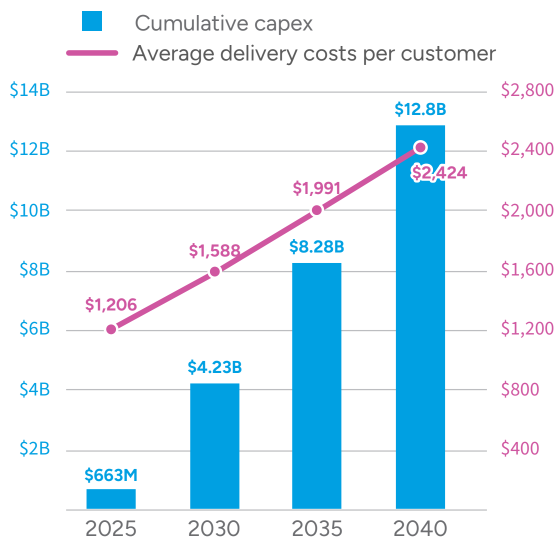
Source: GWD modeling results.

50 Unrecovered gas plant assets refer to gas plant assets that have been put into service but which have not yet been fully paid back by ratepayers. We measure these as the difference between original cost and accumulated depreciation.

51 ICC, 2023 Rate Case for PGL, Docket No. 23-0069, PGL Ex. 9.1: "Summary of the depreciation study," Table 1, Survivor Curve entry for plastic mains, https://drive.google.com/file/d/10X3MsrkN5ZDybC6g-d7hzYUqnvr9CT8CQ/view?usp=drive_link.

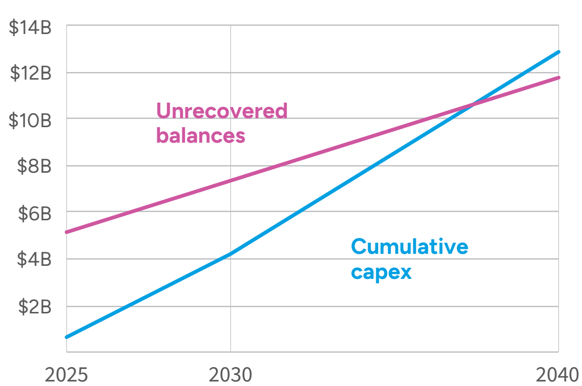
52 According to WEC Energy, SMP historical annual average spend as of Dec. 31, 2023 was $280 million. WEC Energy, *September 2024 Investor Book*, p. 35, https://s22.q4cdn.com/994559668/files/doc_presentations/2024/Sep/03/09-2024-september.pdf.

**Figure 3.5: Cumulative capex & average delivery costs per customer under Full SMP with a stable customer base, 2025-2040**




Source: GWD modeling results.

**Figure 3.6: Cumulative capex & unrecovered balances under Full SMP with a stable customer base (millions)**




Source: GWD modeling results.

## 2. Challenges and considerations for Peoples Gas beyond 2040

The financial and operational implications of the SMP through 2040 are critical but it is equally important to address four key concerns that will persist beyond this timeline and require attention today: the infeasibility of the 2040 completion SMP timeline, PGL's mounting stranded asset risk, the impact of uncertainty about PGL's asset retirement obligations (AROs), and the need for replacement programs beyond the SMP.

### PGL's current SMP timeline is not feasible

Given Peoples Gas's historical replacement rate of 58 miles of main per year (2018-2023), it is improbable that the SMP will be completed by the projected 2040 end date. At its current pace the program would extend to 2051. For the program to meet the 2040 deadline, PGL would need to significantly increase its annual replacement rate to 94 miles per year.[53] Concern regarding the feasibility of the SMP timeline has also been expressed by the ICC.[54]

Additionally, the SMP quarterly reports indicate a substantial backlog of projects slated to begin in 2040. If not addressed proactively, this backloading could lead to coordination challenges across multiple neighborhoods, thereby potentially complicating project management and leading to increased costs.

53 In PGL's April 2024 filing (https://www.icc.illinois.gov/docket/P2024-0081/documents/348897/files/609896.pdf), PGL states that 983 miles of CI/DI low-pressure main and 80 miles of CI/DI medium-pressure main remain to be replaced under SMP, or 1,063 miles of leak-prone main. The company's quarterly reports to the ICC refer to retiring 1,506 miles of main, a total that includes additional miles of main related to medium-pressure upgrade projects. Assuming SMP recommences in 2025, that leaves 16 years to complete SMP, requiring a replacement rate of 1,506 divided by 16, or 94 miles per year, a rate that is 62% higher than its historic replacement rate.

54 ICC, 2023 Rate Case for PGL, Docket No. 23-0069, Final Order, p. 28, https://www.icc.illinois.gov/docket/P2023-0069/documents/344306/files/601245.pdf.

> "assuming an average useful life of 65 years, approximately 71.5 miles [of distribution mains] would need to be replaced each year in perpetuity."

## Stranded asset risk from unrecovered balances is accelerating

This analysis shows that Peoples Gas faces growing stranded asset risk. The company's undepreciated balances are already substantial ($5 billion) and could rise to nearly $12 billion by 2040 if Full SMP resumes, with cost recovery extending into the 22nd century.

The current regulatory model assumes gas mains and services will remain used and useful throughout their expected physical lives. However, emissions-related policies and the prospect of declining gas demand – issues addressed later in this section – may shorten the useful lives of pipelines, reduce capacity utilization, and/or lower the profitability of gas infrastructure. Any of these shifts would heighten the risk of unrecoverable gas investments (i.e., undepreciated balances) with negative consequences for PGL's market valuation.

Managing stranded asset risk is a critical task for regulators nationwide, who are increasingly focused on reducing the creation of long-lived gas assets. The ICC has flagged stranded gas assets as a key issue to be considered in its Future of Gas proceeding. In Section 5, we show that lower spending levels today can reduce the risk of unrecovered costs. (See Figure 5.1 for how other states are tackling stranded gas assets.)

## The obligation to retire gas infrastructure assets

An asset retirement obligation (ARO) is a liability recorded on a gas utility's balance sheet, arising from the legal requirement to retire or decommission assets like distribution mains or services.[55] Peoples Gas collects for these eventual retirement costs through negative net salvage values in its depreciation rates, spreading the expected cost over time.

If gas asset service lives are shortened due to planned transitions or customer attrition, the company's ARO liability would increase accordingly. Peoples Gas would likely request a revised depreciation schedule to recover these costs over a shorter period. If accelerated depreciation is not approved, Peoples Gas could face financial risk, potentially drawing on reserves to cover retirement costs, which may increase financial exposure and lead to higher costs for ratepayers.

## Replacement programs beyond SMP will be needed to address additional aging pipeline

The Peoples Gas distribution system consists of approximately 4,700 main miles installed at different points in time.[56] If installations had occurred at a relatively even pace across the years, then, assuming an average useful life of 65 years, approximately 71.5 miles would need to be replaced each year in perpetuity. This means that after the SMP concludes, whether in 2040 or the early 2050s, Peoples Gas will face the ongoing challenge of replacing gas mains as they age. By the late 2040s and 2050s, many distribution mains installed in the 1980s and 1990s – roughly 1,100 miles – will be approaching the end of their useful lives, a substantial next-up cohort of pipeline in line for replacement. (See Figure 3.7 for the decadal age distribution of the company's distribution mains as of 2023.)

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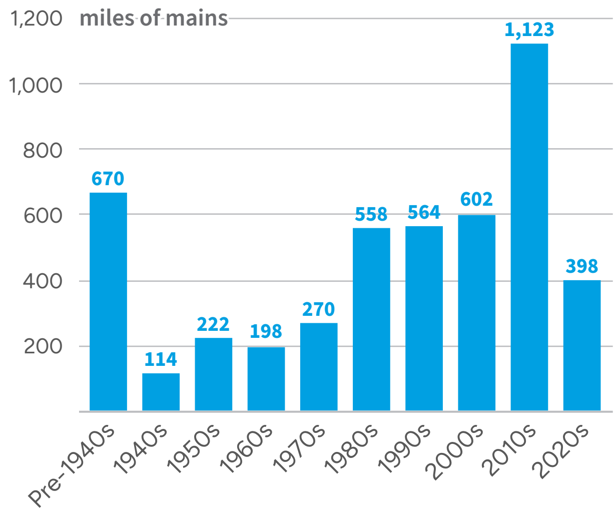
55 U.S. Federal Energy Regulatory Commission (FERC), Docket No. RM02-7-000, Order No. 631 Accounting, Financial Reporting, and Rate Filing Requirements for Asset Retirement Obligations (April 9, 2003), p. 6, https://www.ferc.gov/sites/default/files/2020-05/RM02-7-04-09-03.pdf.

56 ICC, 2024 SMP Investigation, Docket No. 24-0081, *Peoples Gas and the SMP: History, Current State, and Alternatives*, PGL Exhibit 2.0, p. 8, https://www.icc.illinois.gov/docket/P2024-0081/documents/348897/files/609896.pdf.

**Figure 3.7: PGL distribution mains installed by decade**




Source: PHMSA, Gas Distribution Annual Data: 2010 to present (ZIP extracted for 2023), https://www.phmsa.dot.gov/data-and-statistics/pipeline/gas-distribution-gas-gathering-gas-transmission-hazardous-liquids.

The above four findings are critical to the ICC's consideration of the SMP's future feasibility. They underscore the growing problem of stranded asset risk and the likelihood that, beyond 2040, the need for capital expenditures to replace aging gas mains is unlikely to meaningfully decline. They also highlight the massive nature of the proposed "modernization" of Chicago's gas delivery system and the fact that the SMP – today only 37% complete – would constitute only a downpayment on an overhaul that would last well beyond 2040, continuing indefinitely as long as the system is in service.

## B. Threat 2: Clean energy policies

The increasing adoption of clean energy policies poses a significant threat to the traditional natural gas utility business model. Federal, state, and local governments are implementing mandates and incentives that promote renewable energy and drive the decarbonization of the energy sector. These policies aim to reduce reliance on fossil fuels and encourage the adoption of cleaner, more efficient energy systems, reshaping the energy market and exerting both regulatory and competitive pressures on gas utilities.

Here we examine how these evolving clean energy policies are impacting the operations and financial stability of Peoples Gas.

### 1. State policy

In 2019, Governor Pritzker signed an executive order committing the state to the principles of the Paris Climate Agreement.[57] Two years later, Illinois instituted its most prominent energy legislation, the 2021 Clean and Equitable Jobs Act (CEJA). CEJA's key provisions relevant to this analysis include:

- **Phasing out fossil fuels.** The state commits to phasing out coal and gas electricity by 2045 and increasing renewable energy to 40% by 2030 and 50% by 2040.
- **Beneficial electrification plans.** The two largest electric utilities must develop plans and on-bill financing programs to support clean energy technology adoption.[58]
- **Energy affordability study.** The ICC must study energy affordability for low-income households and develop a new low-income discount rate (LIDR) structure that limits gas and electric charges for low-income households to no more than 6% of their income. The study was completed in December 2022 and gas utilities are on track to roll out their LIDRs by October 2024, with electric utilities to follow thereafter.[59]
- **Stretch Energy Code.** Illinois must develop a Stretch Energy Code for greater building efficiency. The now-finalized draft code incentivizes, but does not mandate, electric over gas in new construction.[60]

57 Illinois Executive Order Number 06-19 (January 23, 2019), https://www.illinois.gov/government/executive-orders/executive-order.executive-order-number-6.2019.html
58 For a fuller treatment of Illinois' energy transition legislation and orders, see Figure 2.2 of Dorie Seavey et al., *The Future of Gas in Illinois* (May 2024, Building Decarbonization and Groundwork Data), https://buildingdecarb.org/resource/the-future-of-gas-in-illinois.
59 ICC, Bureau of Public Utilities, *Low-Income Discount Rate Study Report to the Illinois General Assembly* (December 2022), 8, https://icc.illinois.gov/downloads/public/icc-reports/low-income-discount-rate-study-report-2022-12-15.pdf.
60 CEJA required the establishment of a Stretch Energy Code that would be available for municipalities to adopt (or opt into) beginning June 2024. The code is based on the International Energy Conservation Code (IECC) with some modifications. Despite calls for the stretch

CEJA did not specifically address the role of the gas system in the energy transition nor did it establish decarbonization targets for the building sector or specify greenhouse gas (GHG) emissions targets for the gas distribution industry. In an effort to address this gap, the ICC's Future of Gas proceeding is designed to investigate the decarbonization of the gas distribution system. According to the ICC, "the main goal of the proceedings is to explore issues tied to decarbonization of the gas distribution system, including how the gas systems may need to adapt. Additionally, the proceedings aim to develop recommendations for future Commission actions and any necessary legislative changes."[61]

In March 2024, the Illinois Environmental Protection Agency released its 2024 Priority Climate Action Plan (PCAP), a major planning document providing guidance and coordination for the state's climate planning, including assisting Illinois with applying for federal climate-related funding. Consistent with the state's decarbonization objectives, the PCAP sets two key goals for the building sector:[62]

- Reaching a 33% reduction in energy use in buildings by 2050.
- Accelerating the use of efficient, all-electric heating and appliances in buildings, increasing their share of new sales to 50%-90% by 2050.

The PCAP finds that "by 2050, Illinois will need to improve efficiency and install electric appliances in millions of homes and buildings to meet its commitment to the Paris Agreement."[63]

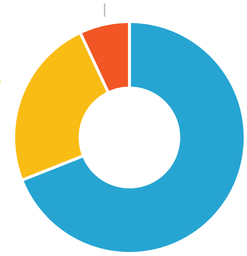
## 2. City of Chicago policy

Over the past five years, the city of Chicago – home to 23% of Illinois' population and the third-largest city in the U.S. – has significantly increased its climate commitments, setting aggressive GHG targets as detailed below. The city is actively pursuing policies that suggest a gradual but significant transition away from natural gas in its building sector, although the timeline for this transition remains uncertain.

In 2019, the Chicago City Council enacted a resolution to transition to 100% clean, renewable energy community-wide by 2035. This resolution also committed the city to use 100% clean, renewable energy for municipal operations by 2025 and for the Chicago Transit Authority to fully electrify its bus fleet by 2040.

The 2022 Climate Action Plan set a target of a 62% reduction in all emissions by 2040 relative to a 2017 baseline. An addendum in 2023 estimated a possible 67% reduction through additional programs and standards. Finally, in 2023, the city released its first citywide plan in half a century – We Will Chicago – which includes a number of ambitious clean energy goals.[64]

**Figure 3.8: Buildings' share of greenhouse gas emissions in Chicago, 2017**




Source: City of Chicago Greenhouse Gas Inventory Report (December 2019), p. ix, https://www.chicago.gov/content/dam/city/progs/env/GHG_Inventory/Chicago-2017-GHG-Report_Final.pdf

The building sector is central to the city's clean energy planning as it is responsible for nearly 70% of Chicago's emissions (see Figure 3.8).[65] In summer 2023, Mayor Brandon Johnson's transition team recommended:[66]

code to require all-electric buildings, the code still allows for the use of fossil fuels. However, buildings that use fossil fuels will be required to implement additional energy efficiency measures, such as high efficiency furnaces, lower air exchange rates, and greater efficiency applications. The stretch code also requires new construction buildings to be electric-ready. https://cdb.illinois.gov/business/codes/illinois-energy-codes/illinois-stretch-energy-code.html.

61 ICC, Future of Gas Proceedings, https://www.icc.illinois.gov/programs/Future-of-Gas-Workshop.

62 Illinois Environmental Protection Agency, *Priority Climate Action Plan* (March 1, 2024), pp. 22-23, https://epa.illinois.gov/content/dam/soi/en/web/epa/topics/climate/documents/Illinois%20Priority%20Climate%20Action%20Plan.pdf.

63 Ibid.

64 City of Chicago, We Will Chicago, https://wewillchicago.com/plan.

65 Louise Sharrow et al., *Building Electrification Helps Illinois Achieve Climate Goals*, RMI (September 2020) https://rmi.org/insight/building-electrification-helps-illinois and City of Chicago, *2022 Climate Action Plan*, https://www.chicago.gov/city/en/sites/climate-action-plan/home.html.

66 City of Chicago, *A Blueprint for Creating a More Just and Vibrant City for All: Transition Team Report to Mayor Brandon Johnson* (July

- Requiring all new buildings and major renovations to use efficient, all-electric equipment and build rooftop solar-ready infrastructure plus incentivize the adoption of heat pumps, all-electric equipment, and renewable energy technologies.
- Developing policies to retrofit existing buildings, including measures to address indoor air pollution by transitioning away from fossil fuel heating, cooling, and cooking.

Community pressure to speed up emissions control and building decarbonization in Chicago is increasing. Beyond broad GHG emission reduction goals, prior policy has focused on measuring and reporting carbon emissions but without specific requirements for reducing emissions. That has begun to change. In January 2024, Mayor Johnson proposed a Clean and Affordable Buildings Ordinance (CABO) that would require zero-to-low emission energy systems in new construction. Over fifty other municipalities across the country, including New York City, Los Angeles, and San Francisco, have passed similar ordinances promoting the design of buildings without gas connections. WEC Energy reported that "PGL's future natural gas operations could be materially adversely impacted if the CABO is passed."[67]

In March 2024, the Urban Land Institute Chicago released a report calling on the city to take bolder steps to reduce GHG from existing buildings and accelerate building decarbonization,[68] including adopting building performance decarbonization standards policy for the city that require switching to clean, renewable energy sources over specific periods of time, ultimately reaching net zero. This report has the support of a wide swath of industry experts, civic and community leaders, and public sector officials.

Leading examples of city policy actions related to building decarbonization are detailed in Figure 3.9.

Chicago has put in place several funding programs to support building upgrades and adoption of alternate technologies (see Figure 3.10). In addition, $263 million in funding has been allocated to Illinois under the Inflation Reduction Act (IRA) for two home energy rebate programs (HOMES and HEERA).[69] The funds are administered by the Illinois Environmental Protection Agency (EPA) and have not yet been processed or released. According to the IL EPA, "Illinois plans to allocate 100% of rebate funds to low-income households (i.e., households with less than 80% of the area median income)"; a minimum of 10% is to be allocated to low-income multifamily buildings.[70] Approximately 26% of the state's low-income households are located in the city of Chicago. Illinois also recently received $172 million in additional funds from the IRA's Climate Pollution Reduction Grant program to assist localities in decarbonizing their building sectors.

Finally, Peoples Gas and Commonwealth Edison (ComEd) – Chicago's electricity utility – have ratepayer-funded energy efficiency programs that together provide approximately $448 million in funds annually. While these programs support the general goal of energy efficiency, they may lack alignment with state and local building decarbonization and electrification goals. For example, PGL's program provides rebates for the purchase of new gas appliances and furnaces.

The various federal, state, and local funding streams described in Figure 3.10 together leverage significant sources of funding to support Chicago's building decarbonization efforts. Effort is focused on coordinating initiatives across state and local agencies and energy utilities, identifying delivery approaches that braid together available incentives and promote greater awareness of decarbonization programs.

2023), p. 80, https://www.chicago.gov/City/en/depts/Mayor/supp_info/transition-report.html.

67 WEC Energy Group, *2023 Annual Report*, p. F-32, https://www.wecenergygroup.com/invest/annualreports/wec2023-annual-report.pdf.

68 "Chicago has an extensive stock of older buildings. According to an analysis by the National Trust, in 2015, Chicago had more than 500,000 buildings and more than half were nearly 100 years old. Swasti Shah, *Climate Ready Chicago: Strategies for Accelerating Building Decarbonization* (March 2024, Urban Land Institute), p. 14, https://chicago.uli.org/report-released-climate-ready-chicago/.

69 Illinois Environmental Protection Agency, Office of Energy, Energy Rebates, https://epa.illinois.gov/topics/energy/energy-rebates.html.

70 Ibid.

**Figure 3.9: Chicago building decarbonization policies**

**Building retrofit and electrification targets from the 2022 Climate Action Plan.** These provide for a) retrofitting 20% of 5-plus unit residential buildings by 2030 and 50% by 2040; 20% of commercial buildings by 2035; and b) electrifying 30% of existing residential buildings by 2035, 10% of existing commercial buildings by 2035, and 90% of existing city-owned buildings by 2035.

**Building and energy codes and other housing development requirements.** All-electric construction and advanced decarbonization are supported by the *Chicago Energy Transformation Code*, effective November 2022. Residences must be built with electrical capacity and wiring necessary to support full electrification without disallowing gas appliances.[1] In addition, as of 2023, all affordable housing developed with city support must be all-electric.[2] The strengthened 2024 *Sustainable Development Policy* (SDP) promotes sustainable building methods and materials for city-assisted construction and rehab projects requiring certain types of funding and zoning approvals. The *Chicago Energy Benchmarking Ordinance* requires commercial, institutional, and residential buildings over 50,000 square feet to report their energy consumption annually and verify their data every 3 years.

**Proposed Clean and Affordable Buildings Ordinance (CABO).** CABO would set an indoor emissions limit banning the combustion of fuels that emit more than 25 kg/btu, effectively requiring all new construction to use clean power sources.[3] The ordinance was introduced to the City Council in January 2024. Exceptions are provided for commercial cooking, emergency backups, among others.

**100% renewable energy for city government buildings and operations.** In August 2022, the city announced an agreement to purchase 100% renewable energy starting in 2025 for all city facilities and operations.[4] This makes Chicago one of the largest cities to make this commitment; one of IL's largest solar projects to date will supply the clean energy.

1 The CETC regulates minimum energy conservation requirements for all aspects of energy uses in both new construction and building renovations. This code exceeds the latest edition of the International Energy Conservation Code (IECC). https://www.chicago.gov/City/en/depts/bldgs/provdrs/bldg_code/alerts/2022/october/energycode.html.

2 City of Chicago, Department of Housing, *2023 Architectural Technical Standards Manual* (effective April 4, 2023), p. 35, https://www.chicago.gov/content/dam/City/depts/doh/qap/qap_2023/ATS-2023-8.2.23.pdf.

3 City of Chicago, Proposed Clean & Affordable Buildings Ordinance (January 2024), https://news.wttw.com/sites/default/files/article/file-attachments/cd502415-4ff4-440a-8f92-7cdf53888b00.pdf. Peoples Gas issued a statement saying "We believe this proposed ordinance is a terrible idea for Chicago. It would increase costs and risk reliability for everyone, especially during the coldest days of the year like we are seeing this week." Ysabelle Kempe, "Chicago mayor proposes natural gas ban in new ComEd-buildings," *Smart Cities Dive* (January 25, 2024), https://www.smartcitiesdive.com/news/chicago-mayor-natural-gas-ban-new-buildings-electrification-decarbonization-emissions/705580/.

4 City of Chicago, Office of the Mayor, "Mayor Lightfoot Announces Agreement to Purchase 100% Clean, Renewable Energy Starting in 2025," Press Release (August 8, 2022), https://www.chicago.gov/city/en/depts/mayor/press_room/press_releases/2022/august/Purchase100Percent-CleanRenewableEnergy2025.html.

**Figure 3.10: Public funding streams supporting clean-energy for Chicago's building sector**

### City of Chicago

**Green Homes Chicago.** This program provides income-eligible homeowners with up to $50,000 in comprehensive retrofit services plus new insulation, heat pump HVAC systems, induction stoves, heat pump water heaters and clothes dryers, and other energy saving measures.[1] The program is delivered by the nonprofit Elevate and Zero Homes. With 2023 funding of $21 million, this program aims to accelerate the decarbonization of 1-6 unit residential buildings owned by low- and moderate-income homeowners and also larger multi-family buildings.

**Climate Infrastructure Fund.**[2] Proceeds from a 2021 City of Chicago Bond issue fund yearly grants to accelerate Chicago's green economy transition by seeding energy efficiency/renewable energy projects by small businesses and nonprofits. In 2024, $3.7 million is to be dispersed, including grants for EVs, charging stations, and green stormwater management.[3]

**Illinois Solar For All.** Created in 2017, this program provides incentives for distributed generation and community solar projects in low-income and environmental justice communities. With a 2024-2025 budget of $66.5 million,[4] the program is administered by the nonprofit Elevate and is funded by the federal government, the state's renewable portfolio standard, and various utility tariffs.[5] Over the last 5 years, the program has supported 545 projects in ComEd territory.[6] An additional pilot supports repairs and upgrades required for on-premise solar photovoltaic installation, such as roof repairs and electrical work.

**PGL and ComEd energy efficiency and demand reduction programs.** PGL and ComEd annually budget about $24.4 million and $423.9 million, respectively, to assist their customers with energy efficiency.[7] These programs are statutorily mandated and overseen by the ICC. The two utilities have joint or coordinated programs for income-eligible, single-family and multifamily upgrades and for building envelope improvements for non-income-eligible homes. In addition, rebates on the gas side support new gas appliances and furnaces; on the electric side, rebates assist with upgrading from electric resistance heating to heat pumps.

### Inflation Reduction Act (IRA) and Illinois

**HEERA (High Efficiency Electric Home Rebate Act) and HOMES (Home Owner Managing Energy Savings) rebates for low-income households.** $263 million in funding has been allocated to Illinois under the Inflation Reduction Act (IRA) for two home energy rebate programs, HOMES and HEERA.[8] Administered by the IL EPA, 100% of the funding is to be directed to low-income residences.

**Energy-Efficient Commercial Buildings Tax Deduction (Section 179D).** This federal tax credit provides an estimated cash value of roughly 25% for energy efficiency upgrades to multifamily residential buildings (4+ stories).

**Climate Pollution Reduction Grant.** CPRG is allocating $172 million to the IL EPA to distribute to state and local governments for comprehensive GHG and air pollution reduction plans via building electrification.[9]

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1 City of Chicago, Office of the Mayor, Press Release (July 20, 2023), https://www.chicago.gov/City/en/depts/Mayor/press_room/press_releases/2023/july/ResidentialDecarbonizationRetrofitProgram.html. See also: https://www.chicago.gov/City/en/depts/doh/supp_info/residential-housing-decarbonization-and-retrofits.html.

2 City of Chicago, Climate Infrastructure Projects, https://www.chicago.gov/City/en/sites/dpd-recovery-plan/home/climate-infrastructure-projects.html.

3 City of Chicago, Office of the Mayor, Press Release (January 30, 2024), https://www.chicago.gov/city/en/depts/mayor/press_room/press_releases/2024/january/climate-infrastructure-fund-grants-will-support-solar-arrays--el.html.

4 Illinois Power Agency, *2024 Long-Term Renewable Resources Procurement Plan* (April 2024), Table 8-2, p. 255, https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/final-2024-long-term-renewable-resources-procurement-plan-19-apr-2024.pdf.

5 The program recently received an additional $156 million in federal funding. https://www.epa.gov/newsreleases/epa-announces-illinois-finance-authority-receive-more-156-million-deliver-residential.

6 Illinois Power Agency, *2024 Long-Term Renewable Resources Procurement Plan* (April 2024), Figure 8-1, p. 248, https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/final-2024-long-term-renewable-resources-procurement-plan-19-apr-2024.pdf.

7 PGL, Energy Efficiency Plan 4 for January 1, 2022 - December 31, 2025, p. 7, https://www.ilsag.info/wp-content/uploads/Peoples-Gas-2022-2025-EE-Plan_filed-March-2021.pdf; ComEd, Commonwealth Edison Company's Revised Energy Efficiency and Demand Response Plan 2022-2025, ICC Docket No. 21-0155, ComEd Ex. 1.01R - Corr., p. 7, https://icc.illinois.gov/api/web-management/documents/downloads/public/future-of-gas/ComEd%202022-25%20Energy%20Efficiency%20Plan.pdf.

8 Illinois Environmental Protection Agency, Office of Energy, Energy Rebates, https://epa.illinois.gov/topics/energy/energy-rebates.html.

9 U.S. Environmental Protection Agency, Inflation Reduction Act, https://www.epa.gov/inflation-reduction-act/state-illinois.

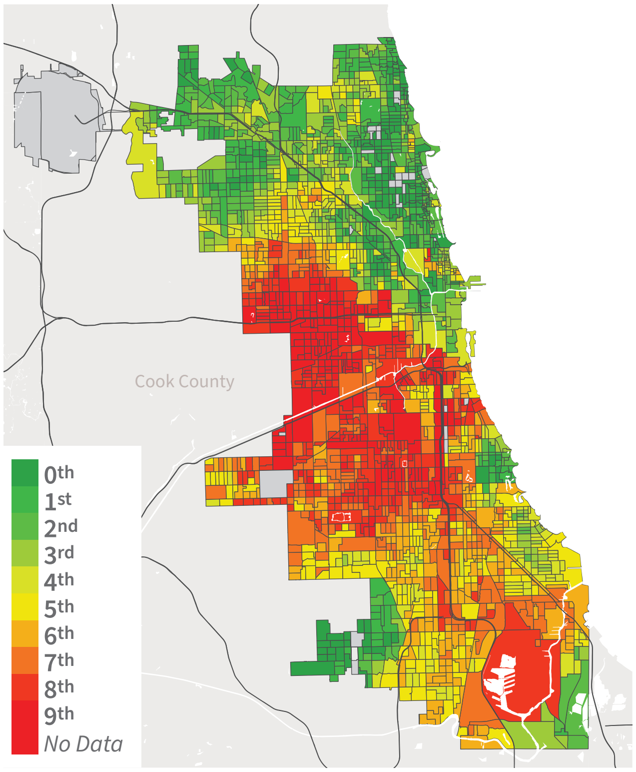


**Figure 3.11: Air quality and health index, Chicago 2020**

Source: City of Chicago, Air Quality and Health Report (2020), p. 7, https://www.chicago.gov/content/dam/city/depts/cdph/statistics_and_reports/Air_Quality_Health_doc_FINALv4.pdf.

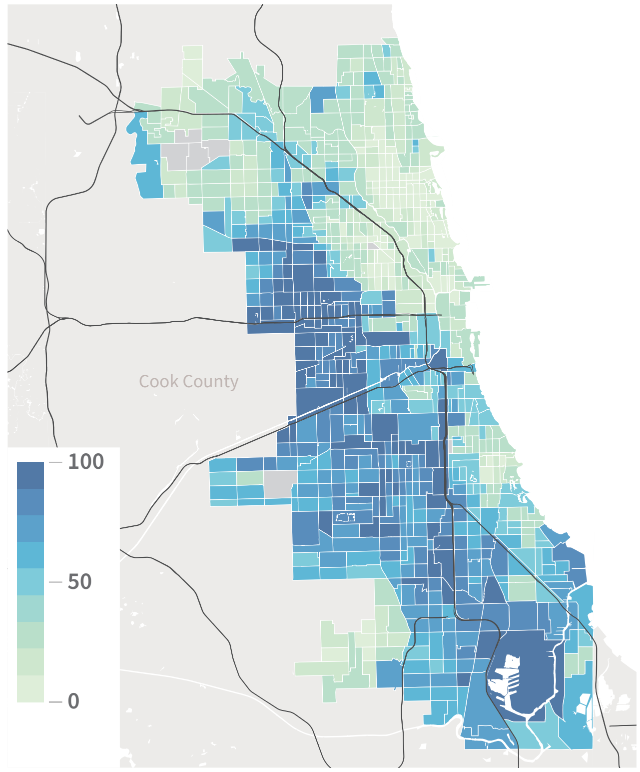


**Figure 3.12: Environmental justice index, Chicago 2023**

Source: Chicago Department of Health, Chicago Health Atlas, https://chicagohealthatlas.org/indicators/CHAIXYP?topic=chicago-environmental-justice-index.

Note: Chicago's environmental justice index shows the communities in Chicago most burdened by pollution and most vulnerable to its effects. The index utilizes a composite score based on 28 indicators representative of environmental conditions and exposures, sensitive populations, and socioeconomic factors that contribute to environmental stressors or community vulnerability.

## Public Health, Climate and Safety Considerations

The Chicago metro area has the second highest energy-burdened population in the country (second only to New York City)[71] and nearly 30 percent of Chicago census tracts are designated environmental justice neighborhoods (see Figures 3.11 and 3.12). Health and public safety issues resulting from the impact of climate change and GHG emissions are adding to the pressure to move forward with more aggressive building decarbonization strategies as well as stricter building codes and green infrastructure projects, with particular attention to environmental justice and lower-income communities.

For Chicago, leaked and combusted natural gas are key drivers of these health-damaging emissions:

- **Scientific research has established that methane leaks from gas distribution systems around the U.S.** – including Chicago – are significantly underestimated. A study by Floerchinger et al. found that official emission inventories in Chicago currently underestimate the contribution of natural gas to methane emissions by about 50%.[72] Furthermore, studies find that methane leaks from Chicago's gas distribution system tend to be concentrated in the metro region's lower-income communities, producing "disturbing inequalities": leak density increases with both the

71 Ariel Brehobl, Lauren Ross, and Roxana Ayala, *How High Are Household Energy Burdens: An Assessment of National and Metropolitan Energy Burden across the United States*, American Council for an Energy-Efficient Economy (ACEEE) (September 2020), Table B3.2, p. 57, https://www.aceee.org/sites/default/files/pdfs/u2006.pdf. The ACEEE study also finds that in 2020 "[a] quarter of low-income households have an energy burden above 15% in the Chicago metropolitan area, which is more than 5.5 times higher than the median energy burden." See: "Energy Burdens in Chicago," https://www.aceee.org/sites/default/files/pdfs/aceee-01_energy_burden_-_chicago.pdf.

72 Cody Floerchinger et al., "Relative flux measurements of biogenic and natural gas-derived methane for seven U.S. cities," *Elementa Science of the Anthropocene* (February 2021, 9:1), DOI:10.1525/elementa.2021.000119.

percent of people of color in the census tract and decreasing income.[73]

- **Research from cities with older gas infrastructure like Chicago's also show that behind-the-meter leaks are a significant contributor to fugitive methane emissions,[74] including from stoves even when they are turned off.[75]** When gas is combusted inside homes, harmful compounds known to cause cancer and other health problems are released.[76] Still a further source of air pollution for Illinois more generally is fossil fuel pollution from upwind gas fracking fields and oil extraction facilities in Texas, Oklahoma, and Pennsylvania.[77]

The climate, health, and safety consequences of leaked and combusted natural gas are many. A warming climate is increasing flooding and extreme heat events for Chicago. Chicago is at risk from increasing extreme precipitation and greater volatility of Lake Michigan's water level which may pose challenges to underground infrastructure.[78] A study by the Center for Neighborhood Technology found that nearly three-quarters of Chicago's flood damage claims in recent years occurred in 13 zip codes where 62% of households have an income of less than $50,000, and over a quarter are below the poverty line. Furthermore, Chicago has the seventh-highest average heat index, weighted for its area, in the U.S. The city's asphalt and concrete density contributes to a heat island effect: Chicago is one of six cities that had more than 1 million people living under an urban heat island effect over 8 degrees.[79] A heavy concentration of the affected population lives in the city's southwest side, one of the city's poorest areas.

On the health front, emissions from gas systems elevate mortality and other health burdens such as asthma and heart attacks.[80] According to recent peer-reviewed analysis, 21% of childhood asthma cases in Illinois are attributable to indoor natural gas combustion for residential cooking. In response, legislation at the state level in Illinois has been filed that would require health warnings to be placed on gas stoves for sale (HB 5063 "Gas Stove Labeling Act").[81]

Finally, gas leaks can be extremely dangerous to local public safety and property. Even a small leak or a rupture in a gas line can lead to an explosion, killing or harming people and destroying or damaging property. Most reported incidents are caused by excavation that ruptures a gas line, but pipelines can corrode and fail due to their material, age, and condition.[82] Gas appliances can also leak gas and present an explosion risk.

## Regulatory involvement by the City

The strong positions taken by the city of Chicago during the course of its intervenor status during PGL's 2023 rate case deserve mention. According to the city, PGL provided "an unacceptable response to an inevitable energy transition" by failing to plan, ignoring state and city decarbonization targets, and "continuing to heavily invest in gas infrastructure without due regard for affordability and stranded assets."[83] The city emphasized the need for reevaluating the SMP and requiring it to evolve given

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73 Zachary D. Weller et al., "Environmental injustices of leaks from urban natural gas distribution systems; Patterns among and within 13 U.S. metro areas," *Environmental Science & Technology* (2022, 56:12), pp. 8599-8609, https://pubs.acs.org/doi/10.1021/acs.est.2c00097.

74 Maryann R. Sargent et al., "Majority of US urban natural gas emissions unaccounted for in inventories," *Proceedings of the National Academy of Sciences of the United States of America* (2021, 118), https://www.pnas.org/doi/10.1073/pnas.2105804118. In response, the U.S. Environmental Protection Agency (EPA) has now adjusted its inventory of GHG to include methane emissions from residential and commercial appliances as well as other sources. U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990-2020: Updates Under Consideration for Post-Meter Emissions* (September 2021), https://www.epa.gov/system/files/documents/2021-09/2022-ghgi-update-post-meter_sept-2021.pdf.

75 Eric D. Lebel et al., "Methane and NOx Emissions from Natural Gas Stoves, Cooktops, and Ovens in Residential Homes," *Environmental Science & Technology* (January 2022, 56:4), pp. 2529-2539, https://doi.org/10.1021/acs.est.1c04707.

76 When combusted, gas releases a number of harmful compounds, including benzene, NOx, fine inhalable particles (PM2.5), and formaldehyde. Yifang Zhu et al., *Effects of Residential Gas Appliances on Indoor and Outdoor Air Quality and Public Health in California*, UCLA Fielding School of Public Health Department of Environmental Health Sciences (2020), https://coeh.ph.ucla.edu/wp-content/uploads/2023/01/Effects-of-Residential-Gas-Appliances-on-Indoor-and-Outdoor-Air-Quality-and-Public-Health-in-California.pdf.

77 Jonathan J. Buonocore et al., "Air pollution and health impacts of oil & gas production in the United States, *Environmental Research & Health* (2023, 1), https://doi.org/10.1088/2752-5309/acc886.

78 Dan Egan, "The climate crisis haunts Chicago's future. A Battle Between a Great City and a Great Lake," *New York Times* (July 7, 2021), https://www.nytimes.com/interactive/2021/07/07/climate/chicago-river-lake-michigan.html.

79 Alix Martichoux, "Chicago is an 'urban heat island.' So what does that mean?" WGN9 (July 13, 2024),

80 Ibid.

81 Illinois General Assembly, HB5063 (introduced February 8, 2024), https://www.ilga.gov/legislation/103/HB/PDF/10300HB5063lv.pdf; and https://www.canarymedia.com/articles/fossil-fuels/gas-stove-health-warning-labels-health-california-new-york-illinois-ge#.

82 For an analysis of Illinois' pipeline safety track record, see https://pstrust.org/state-of-safety-illinois/.

83 Ibid., p. 110.

the fundamentally altered "energy environment" and "trajectory of the city's energy future as provided for in the city's Climate Action Plan."[84]

The city underscores that, in response to requests to provide analyses assessing the impact of decarbonization policies on future throughput and infrastructure needs, PGL stated that "[n]o specific studies have been conducted of how, when or where to do [infrastructure upgrades] to accommodate lower carbon fuels, in part because there has been no Illinois 'Future of Gas' proceeding to clarify the scope of possibilities and the regulatory policies that will accompany them."[85] The city also expressed concern about unrealistic backloading of many SMP projects such that many substantial projects are not slated to begin for over a decade, presenting significant financial challenges for residents to transition to cleaner alternatives.

The city specifically asked that Peoples Gas be required to work with the city and other interested and affected stakeholders to assess the "potential for strategic electrification and retirement of leak-prone pipe" and to develop a pilot that allows the Commission to assess the impact of the pilot on advancing equity and reducing GHG emissions.

## C. Threat 3: Growing demand substitution due to unprecedented competition from clean energy alternatives

Rapid technological change is producing new equipment and appliances for space and water heating, as well as cooking and clothes drying, that offer higher efficiency as well as attractive alternative value propositions, such as more comfortable homes, more precise cooking, and improved indoor air quality (see Figure 3.13 for a review of some of these technologies). These technologies are also increasingly cost competitive with their fossil-fuel analogues, particularly over a ten-year payback period. Their adoption is further enhanced by unprecedented federal subsidies and tax credits reviewed in Section 3.B and the fact that they may reduce long-term energy bills compared to the expensive future of gas.

We review here the information available on adoption of clean heating and cooling technologies in Chicago and then present modeling results for a scenario that fully reinstates the SMP but allows for a moderately contracting Chicago gas customer base.

### 1. Adoption of clean space and water heating technologies in Chicago

The Midwest's adoption rate for clean-energy space and water heating technologies has lagged behind that of other areas in the country.[86] But gas heating in Chicago has been slowly losing market share to electric over the past decade. The percentage of Chicago's housing dependent on utility gas has steadily fallen since 2010, from 85.5% to 76.5% in 2022, (an average annual decline of 0.75 points). Electricity's share of heating, on the other hand, has grown from 12% to 19%.[87]

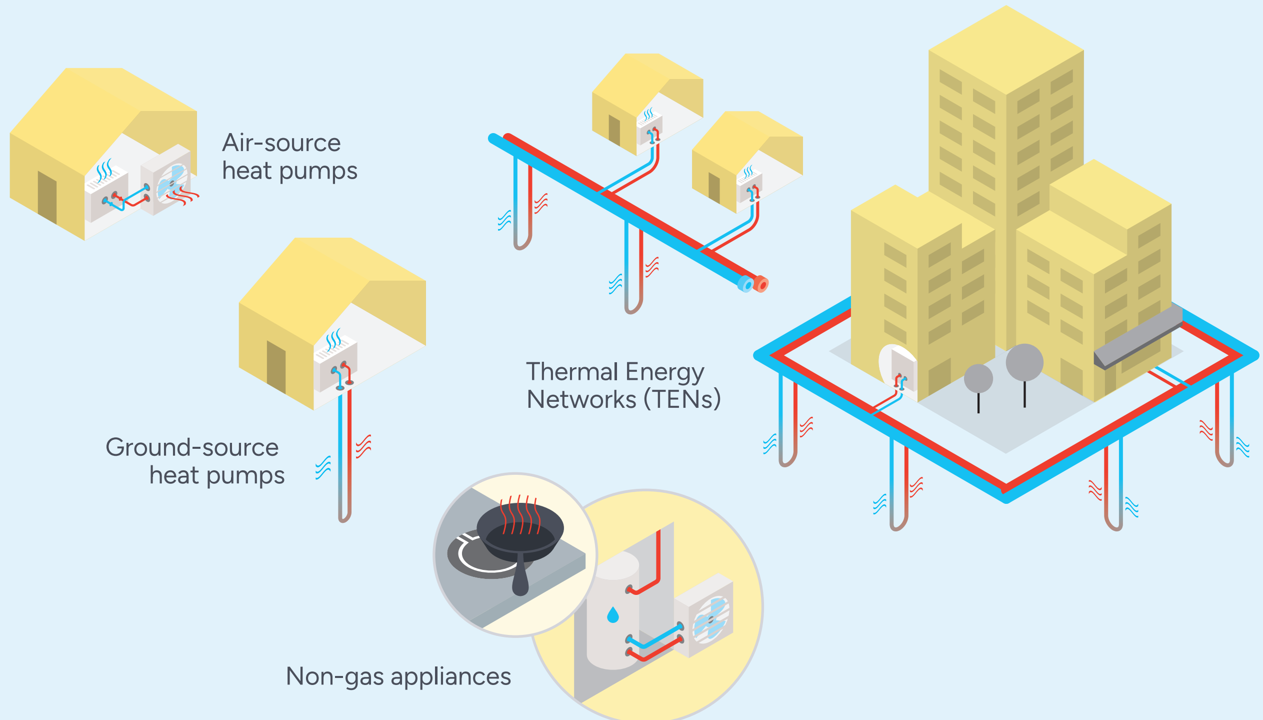
These broad market share statistics likely understate actual heat pump adoption in the Chicago area. While the HVAC industry does not release state or regional sales data, Mitsubishi Electric Trane HVAC U.S., a major heat-pump supplier, reports that heat pump sales in the Chicago area market have increased by double digits year-over-year for the past ten years. In 2023, for example, the supplier's heat pump sales in the Chicago area increased by more than 25% over 2022.[88]

Multi-building strategies will also play a role in curtailing gas demand. Thermal energy networks

84 ICC, 2023 Rate Case for PGL, Docket No. 23-0069, Final Order (November 16, 2023), pp. 20-21, 109-110, https://www.icc.illinois.gov/docket/P2023-0069/documents/344306/files/601245.pdf.
85 Ibid., p. 112.

86 Katherine Shok, "Electrifying the Midwest" (October 17, 2023), https://atlasbuildingshub.com/2023/10/17/electrifying-the-midwest.
87 U.S. Census Bureau, American Community Survey, S2504 Physical Housing Characteristics for Occupied Housing Units, 1-year estimates (various years), https://data.census.gov/table/ACSST1Y2022.S2504?q=S2504&g=040XX00US17_160XX00US1714000.
88 Nara Schoenberg, "Concerned about climate change, more Chicagoans are buying all-electric home heating systems, *Chicago Tribune* (January 31, 2024), https://www.chicagotribune.com/2024/01/31/concerned-about-climate-change-more-chicagoans-are-buying-all-electric-home-heating-systems/.

**Figure 3.13: Technologies displacing gas consumption in buildings**



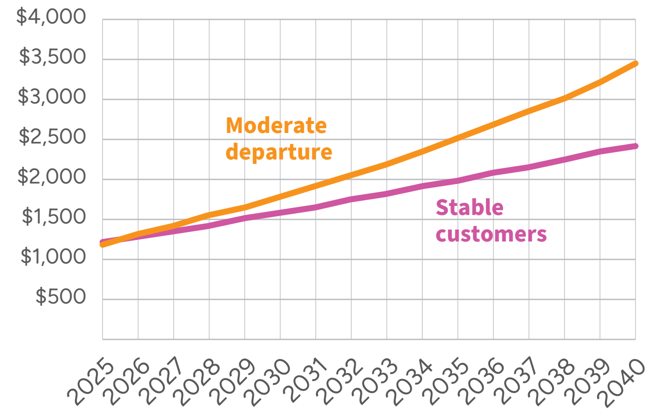

- **Air-source heat pumps.** ASHPs provide electric heating and cooling to a building in a single unit that exchanges energy with the ambient outdoor air. ASHPs were traditionally reserved for milder climates and are prevalent in much of the southern United States, but adoption is growing in colder climates in response to heat pump efficiency improvements and increased customer awareness of the technology. These advancements plus government incentive programs resulted in U.S. annual ASHP sales outpacing annual gas furnace sales for the first time in 2022.
- **Ground-source heat pumps.** GSHPs are quite similar to ASHPs except that they exchange energy with the earth. Because ground temperatures are relatively stable throughout the year, this configuration results in higher efficiencies for GSHPs compared to ASHPs. This lowers operating costs and also reduces the need for costly upgrades to the electric grid system to provide more energy. The increased efficiency comes at a higher cost than ASHPs, mainly due to the cost of digging.
- **Thermal energy networks.** TENs are made up of underground interconnected pipes that exchange thermal energy (heated or cooled water) between connected buildings. The connected ambient loops can harness thermal reservoirs, such as the temperature of bedrock or local bodies of water, and waste heat from data centers or wastewater treatment facilities.
- **Non-gas appliances, deep energy efficiency, and demand flexibility.** Energy-efficient appliances such as induction stoves and heat pump water heaters along with retrofits that promote energy efficiency can also help in reduce demand for gas and enable buildings to transition to electricity. Advanced controls that enable demand management and bidirectional energy transfers are also reduce energy demand and promoting more efficient, grid-interactive buildings.

(TENs) are a next-generation district energy solution that primarily use electricity to provide heating and cooling services by leveraging waste heat, ground, and waterbodies as thermal resources. Such systems are poised to best provide campus or district-scale services and could serve as an avenue for reducing large blocks of gas load. While approaches vary, such systems have been demonstrated across the country.[89] Of note is the Centrio Chicago District Cooling System, the largest carbon-free ice storage chilled-water system in the U.S.[90] In operation since 1995, Centrio provides sustainable district cooling service to 38% of the downtown area (115 buildings).

A recent state-level effort has advanced the consideration of TENs in Illinois. The ICC led a series of workshops on TENs and in March 2024 submitted a final report with recommendations on the role of TENs in Illinois' clean energy future to the Governor and General Assembly.[91] The report notes that the Chicago area has considerable promise for developing TENs because it is both home to the Centrio system and is one of the top data center markets in the country (data centers produce large amounts of heat waste).[92] This creates an opportunity for connecting the two thermal energy resources.

Also featured in the state report is the Chicago Sustainable Square Mile project piloted by the local environmental justice organization, Blacks In Green. Encompassing four city blocks containing more than 100 multi- and single-family residential buildings, this project seeks to develop a non-utility, community ownership model for thermal energy networks to be located in the West Woodlawn community of the city's south side. In 2023, the project received funding from the U.S. Department of Energy.[93]

**Figure 3.14: Impact of moderate customer departures on average delivery costs per customer under Full SMP, 2025-2040**




Source: GWD modeling

## 2. Modeling results for "Full SMP" scenario with a declining gas customer base

As gas demand in Chicago's building sector declines due to increased electrification and customer exits from the gas system, understanding the financial implications for Peoples Gas becomes essential. To quantify these impacts, we apply our Gas Delivery Cost Model under the assumption that Full SMP spending resumes while the PGL customer base contracts by 2% annually, resulting in a 50% decrease by 2050.

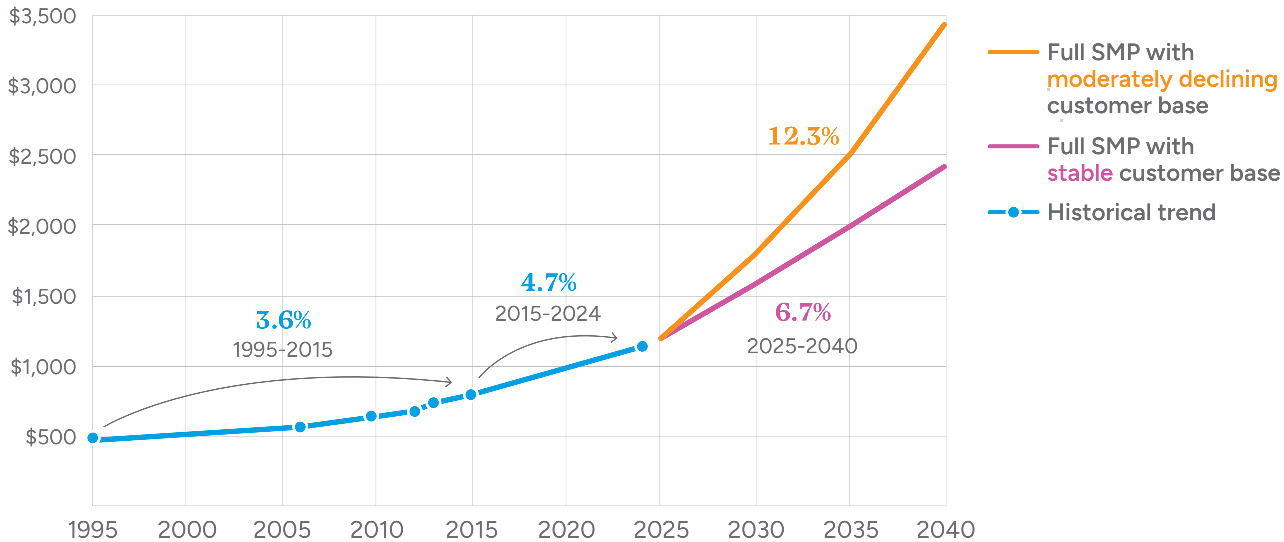
Our modeling results show that, as the number of gas customers decreases, average delivery costs per remaining customer rise significantly. This is because cost recovery for PGL's escalating rate base must be spread over a shrinking pool of ratepayers, thereby intensifying the financial burden on those remaining.

Figure 3.14 illustrates these findings. By 2030, per customer delivery charges increase by 50% from current levels, compared to a 32% increase for a

89 Hyunjun Oh and Koenraad Beckers, *Cost and Performance Analysis for Five Existing Geothermal Heat Pump-Based District Energy Systems in the United States* (July 2023, National Renewable Energy Laboratory), https://www.osti.gov/servlets/purl/1992646/.
90 Centrio, "Largest Carbon-Zero District Cooling System in the U.S.," https://www.centrioenergy.com/our-districts/chicago/. CenTrio's district cooling system in Chicago draws on the largest ice-battery in North America, creating ice at night while energy demand and prices are lowest which then cools the water during the day. Three of the district's cooling plants tap into the Chicago River. See also: https://www.enelnorthamerica.com/solutions/case-studies/centrio-energy-maximizes-demand-response.
91 ICC, *Thermal Energy Network Report* (February 2024), https://icc.illinois.gov/api/web-management/documents/downloads/public/TEN/Thermal%20Energy%20Network%20Report%202024.pdf.
92 Ibid., pp. 11-12.

93 The Blacks in Green project is using the BETTER HEAT model and is being administered by The Accelerate Group. See: Juanpablo Ramirez-Franco, "A Geothermal Energy Boom Could Be Coming to Chicago's South Side," *Grist* (February 23, 2024), https://grist.org/cities/black-communities-south-side-chicago-geothermal-heat/.

**Figure 3.15: Historical trends in PGL delivery cost per customer vs. future increases required for Full SMP with & without customer decline**




Sources: For 1995-2024, ICC final rate case orders (Appendix A or B) for Docket Nos. 95-0032, 07-0242, 09-0167, 11-0281,12-0512, 14-0225, 23-0069 and ICC, Comparison of Gas Sales Statistics (various years); for 2025-2040, GWD modeling. Note: Percentages refer to average year-over-year increases in delivery costs per customer.

stable customer base. By the SMP's projected 2040 termination date, delivery charges per customer surge by 185%, reaching $3,437, up from $1,206 in 2025. If the resulting rate increases were evenly distributed over the next 15 years (2025-2040), a 12.3% increase in annual delivery charges per customer would be required. Such a rate trajectory would likely accelerate the departure of additional gas customers, creating a negative feedback loop of spiraling rates and declining customers.

## 3. Comparing historical trends in PGL's per customer delivery costs with projected future increases

Our modeling results indicate that resuming Full SMP would necessitate substantial increases in per customer delivery costs, leading to higher customer bills. These costs would escalate further as customers leave the gas system. To assess these projected increases against historical trends, we use the approved revenue requirements in prior PGL rate cases to calculate per customer delivery costs.

Figure 3.15 illustrates the resulting trends from 1995 to 2024; it also shows our projections for these costs assuming that Full SMP resumes in 2024. The blue line represents historical increases in per customer delivery costs, with each dot corresponding to the test year of the relevant rate case. The red line shows the cost increases required to reinstitute Full SMP, assuming a stable customer base. The green line reflects the same capital spending assumptions but with a moderately contracting customer base.

This analysis makes clear that the rates of increase in per customer delivery costs required by Full SMP would be historically unprecedented and likely untenable. Compared to the past three decades – where rates first increased 3.6% per year from 1995 to 2015 and then by 4.7% more recently – Full SMP with a stable customer base would increase annual customer delivery charges by 6.7% from 2025 on. With a shrinking customer base, Full SMP would require yearly rate increases of 12.3%, or 2.5 times the rate of increase from 2015 to 2024.

## D. Business risk implications for Peoples Gas

This section has analyzed three critical threats to PGL's traditional business model: rising infrastructure costs, climate policies and programs, and increasing competition from alternative technologies. Due to the maturity of Chicago's gas system, infrastructure costs are on an upward trajectory, independent of climate policy and demand substitution. With aging infrastructure in need of repair or replacement and a level customer base, the burden of these costs is intensifying for ratepayers. Furthermore, PGL's customer base is expected to decline in response to state and local GHG emission and decarbonization policies as well as the growing availability of cost-effective alternatives to gas-dependent space and water heating.

Next, we explored the future costs of Chicago's gas system under the assumption that Full SMP is resumed. We presented two sets of modeling results: one assuming a stable gas customer base and the other assuming a steady decline in the customer base to half of its current level by 2050. The delivery costs of the gas system are driven in large part by PGL's substantial existing approved rate base of $4.2 billion (cost recovery for this base is outstanding) and the continuing multibillion-dollar costs of the SMP. These fixed infrastructure costs will not decrease with reduced gas consumption or a declining customer base. Our findings indicate that gas delivery costs in Chicago will face steady upward pressure in both scenarios. From 2025 to 2040, customer delivery charges would need to escalate by nearly 7% annually under the stable customer scenario and by 12% under the declining customer scenario. Under the latter scenario, Chicago gas customers can expect their average delivery costs to increase nearly 50% just 6 years from now (by 2030).

Figure 3.16 illustrates the dynamic of these interacting factors and captures the possibility of a spiraling rate crisis in which higher charges would push more ratepayers to leave the gas system, leaving system costs to be spread over a declining number of ratepayers. Such a situation would inevitably attract regulatory and legislative attention.

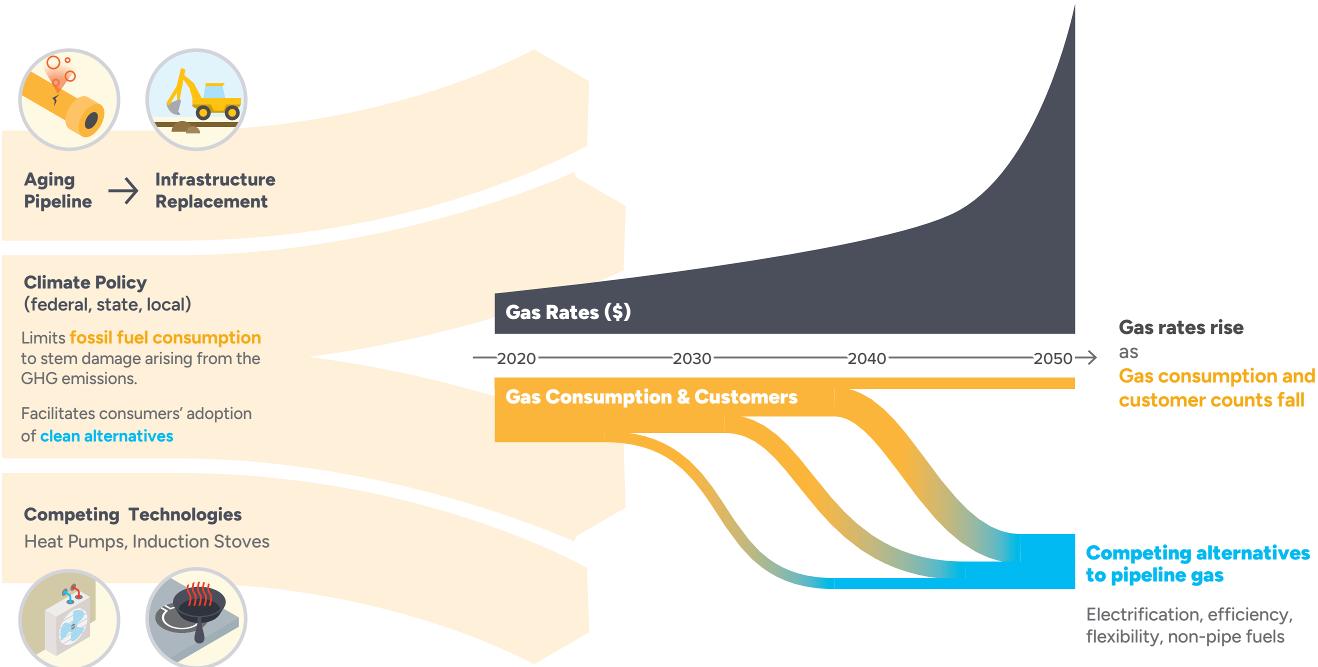
An unmanaged gas transition in which these factors play out without overarching policy and regulatory direction would present substantial challenges to PGL's operational and financial stability. As these challenges intensify, several major business and investor risks for PGL are likely to emerge:

- **Lower gas demand.** Decreased demand will negatively impact PGL's earnings, cash flow, and dividends payable to WEC Energy, potentially affecting WEC Energy's share price as well.
- **Rate fatigue.** The need for rate increases that significantly exceed historical trends is likely to lead to regulatory and legislative intervention, presenting risk for investors. Chicago's gas delivery rates are already among the highest in the nation and substantial rate hikes could exacerbate affordability issues, particularly for low-income and energy-burdened customers.
- **Adverse regulatory decisions.** Any decision to curtail the SMP would negatively impact PGL's cash flow and earnings and also WEC Energy's share price. Recent evidence of these kinds of impacts are presented in Section 5.B.
- **Elevated cost recovery and stranded asset risk, and financial pressures related to decommissioning liabilities.** Increasing concerns over cost recovery and decommissioning liabilities (i.e., asset retirement obligations) could negatively affect PGL's credit rating and potentially also WEC Energy's rating, leading to higher borrowing costs.

PGL plays an important role in WEC Energy's portfolio, constituting roughly 30% of the holding company's total gas distribution customers, 15% of its total assets, and 34% of its recent shareholder dividends.[94] As a result, business risks to Peoples Gas have potential upstream implications for WEC Energy. As detailed in Section 5.B, WEC Energy has already experienced negative financial impacts due

94 For customer figure, see WEC Energy, *2023 Corporate Responsibility Report*, pp. 7, https://www.wecenergygroup.com/csr/cr2023/wec-corporate-responsibility-report-2023.pdf#pagemode=bookmarks. For asset figure, see WEC Energy Group, *September 2024 Investor Book* (September 3, 2024), p. 38, https://s22.q4cdn.com/994559668/files/doc_presentations/2024/Sep/03/09-2024-september.pdf.

**Figure 3.16:** Causes and effects of an unmanaged gas transition




Source: GWD.

to recent PGL regulatory decisions, including the ICC's pause of the SMP. As a result, WEC Energy is reallocating investments from Peoples Gas to unregulated, renewable energy projects. As the risks of an unmanaged gas transition mount, PGL is likely to place a growing strain on WEC Energy's overall financial performance.

> "As the risks of an unmanaged gas transition mount, PGL is likely to place a growing strain on WEC Energy's overall financial performance."

Section

# 4

# The response of Peoples Gas and WEC Energy to energy transition risk

**Peoples Gas faces a challenging set of circumstances on both the demand and supply side of its operations.** Rising infrastructure costs, building pressure from state and municipal clean energy and GHG policies, and competition from alternative technologies present fundamental challenges to continuing a business-as-usual approach to its operations as these disruptors over the next five to 25 years can be expected to significantly alter residential and business energy consumption patterns, appliance choices, and overall gas usage.

In response to these pressures, Peoples Gas has chosen to continue its accelerated investment in gas infrastructure. The company justifies this multi-decade capital spending program by citing four primary objectives: maintaining the safety and reliability of the gas system, reducing methane emissions, ensuring energy affordability for the city's consumers, and preparing the gas system for the eventual integration of alternative gases, such as renewable natural gas (RNG) and hydrogen.

To assess the validity of Peoples Gas's strategy, it is essential to critically evaluate each of these objectives on its individual merits:

## A. Safety and reliability

PGL asserts that "it is essential to replace at-risk cast iron and ductile iron pipe in PGL's distribution system and that it should be done on an accelerated basis in the interest of safety."[95] Despite more than four decades of investment, substantial amounts of at-risk pipeline – some over 50 years old – remain a significant safety concern for Peoples Gas, as documented in the 2020 Kiefner study.[96]

In its 2023 rate case orders, the ICC made clear that it no longer supports granting approval for capital spending projects on the basis of generalized appeals to safety, reliability, and reduced emissions.[97] Consequently, the ICC is expected to increase its scrutiny of PGL's pipeline evaluations and the criteria used to determine whether replacements are necessary. The Commission may also consider alternatives to full replacement, such as repair, relining, or pipeline retirement, to meet safety goals.

Repairing pipeline is not a perfect substitute for replacing pipeline and there are circumstances where replacing an at-risk section of pipe is required for public safety purposes and/or is the most cost effective option. However, when feasible, repairing a pipe with advanced leak repair technologies can be a far less expensive option than pipeline replacement.[98] Some repair technologies – for example, cured-in-place (CIP) systems – constitute de facto "pipeline renewal" that extends the life of some types of pipeline by several decades.[99] In sum, pipeline retirement, pipeline renewal, and other advanced leak repair approaches may "eliminate leaks and their associated environmental and risks – a retired pipe does not leak – while reducing emissions at a faster rate, reducing stranded asset risk, lowering energy bills, and improving public health, comfort and air quality."[100]

The deployment of state-of-the art repair technologies is hindered by the fact that the regulatory cost recovery system typically rewards replacement rather than repair. The economic literature on leak repair vs. pipeline replacement makes clear that gas utilities have an incentive to over-invest in replacement because they are allowed to earn a rate of return on capital investments

95 ICC, 2024 SMP Investigation, Docket No. 24-0081, *Peoples Gas and the SMP: History, Current State, and Alternatives*, PGL Exhibit 2.0, p. 66, https://www.icc.illinois.gov/docket/P2024-0081/documents/348897/files/609896.pdf.

96 According to the 2020 Kiefner study, most of PGL's cast iron (CI) mains average over 90 years old and most of its ductile iron mains are over 50 years old. Furthermore, "83% of the remaining CI and DI pipes have an average remaining life of less than 15 years." Keifner and Associates, Inc., *Engineering Study of the Cast Iron and Ductile Iron Pipeline System*, Final Report No. 20-001 presented to PGL (January 2020), p.(i), https://www.icc.illinois.gov/docket/P2018-1092/documents/295819/files/515921.pdf.

97 ICC, 2023 Rate Case for Ameren Illinois Company, Docket No. P2023-0067, Final Order (November 16, 2023), p. 90, https://www.icc.illinois.gov/docket/P2023-0067/documents/344282/files/601209.pdf.

98 For an example from National Grid's Boston territory, see: Dorie Seavey, *Leak and Combusted: Strategies for reducing the hidden costs of methane emissions and transitioning off gas* (March 2024, HEET), p. 50, https://tinyurl.com/4dd9ru3d.

99 Ibid., p. 49.

100 NY Public Service Commission, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service, Case 22-E-0064 and Case 22-G-0065, Direct Testimony of Alice Napoleon and Asa Hopkins PhD on behalf of Natural Resources Defense Council (May 20, 2022), p. 35, https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B3F43993F-8776-4CBC-8571-677B40CD7476%7D.

## How Peoples Gas and WEC Energy view the SMP

### Peoples Gas

"While various parties have challenged various aspects of the SMP over the years, from the earliest ZEI studies to today there has never been any serious dispute that it is essential to replace at-risk cast iron and ductile iron pipe in PGL's distribution system and that it should be done on an accelerated basis in the interest of safety. Doing so is not just an obvious safety and reliability imperative, but also has environmental benefits and enhances compatibility with future fuels."[1]

### WEC Energy

*"Peoples Gas expects to continue investing between $280 million and $300 million annually in a program to to replace more than 2,000 miles of Chicago's deteriorating natural gas pipes — many of which were installed in the 1800s. We are replacing dated cast and ductile iron pipes and facilities in the natural gas delivery system with polyethylene pipes for longterm system safety, improved reliability and greatly reduced methane emissions. Safety enhancements include upgrading the system from low-pressure to medium-pressure operation. In addition, the modernization positions Chicago for a clean energy future in which renewable natural gas and hydrogen may someday heat customer homes and fuel the economy. Work on the program, overall, is more than 35% complete."*[2]

1 ICC, 2024 SMP Investigation, Docket No. 24-0081, *Peoples Gas and the SMP: History, Current State, and Alternatives*, PGL Exhibit 2.0, p. 66, https://www.icc.illinois.gov/docket/P2024-0081/documents/348897/files/609896.pdf.

2 WEC Energy Group, *2022 Corporate Responsibility Report*, p. 13, https://www.wecenergygroup.com/csr/cr2022/wec-corporate-responsibility-report-2022.pdf.

> "The economic literature on leak repair vs. pipeline replacement makes clear that gas utilities have an incentive to over-invest in replacement..."

but not on leak detection and repair, which are treated as operational expenses.[101] In addition, gas companies lack the financial incentive to repair leaks in order to stop the waste of their primary product. They have regulatory approval to pass on the cost of the lost gas to their customers as a "normal" cost of doing business, and – at least for their distribution systems – they are not financially responsible for the climate and health costs caused by gas leaks.

In terms of comparing the relative efficacy and cost effectiveness of non-pipeline alternatives vs. pipeline replacement projects, Peoples Gas readily proffers the opinion that electrification is too expensive (see Section 4.B), but it is silent on the question of the rate increases required to pay for continuing its accelerated investments in Chicago's gas system for another 15 to 25 years, including under varying assumptions regarding customer base attrition. Additionally, Peoples Gas states that its new risk model (JANA) for scoring and prioritizing projects will not be used to evaluate the cost-effectiveness of "risk mitigation" projects (including projects that presumably deploy alternatives to pipeline replacement), but only to compare potential risk reduction between projects prior to their implementation.[102]

101 Dorie Seavey, *Leak and Combusted: Strategies for reducing the hidden costs of methane emissions and transitioning off gas* (March 2024, HEET), pp. 42-43, https://tinyurl.com/4dd9ru3d.

102 ICC, 2024 SMP Investigation, Docket No. 24-0081, PIRG Exhibit 2.4, p. 17, https://www.icc.illinois.gov/docket/P2024-0081/documents/351917/files/615647.pdf.

## B. Feasibility of electrification

PGL's position is that electrification is not a feasible alternative for gas consumers in Chicago for three reasons: it is too expensive, it would lead to unreliable energy supplies, and it is not clean.[103] Before addressing these arguments, we note that Peoples Gas has yet to study the likely effects of plausible electrification scenarios on gas demand and put in place robust demand forecasts to guide its planning and inform regulators. Expert testimony presented in PGL's 2023 rate case concluded that the company "has conducted no analysis of how implementation of the Climate Action Plan could impact PGL customer count, usage volume, and the required capacity and maintenance of PGL's gas distribution system"[104] and has done little to consider a future where demand shrinks.[105] In addition, the company states that it "has not conducted any studies or other activities regarding the identification of "non-pipeline solutions/ alternatives" that could mitigate the scope and cost of future projects.[106] In the current SMP Investigation, Peoples Gas offers that it is only required to consider and study NPAs as part of its new bi-annual Integrated Resource Plan (IRP) proceeding[107] and, therefore, it would be duplicative and inefficient to assess them as part of the SMP proceeding.[108]

## Non-pipe alternatives

Non-pipeline alternatives (NPAs) refer to targeted activities or investments that delay, reduce, or avoid the need to build or upgrade traditional natural gas infrastructure such as pipelines, storage, and peaking resources. Many of these solutions involve transitioning the current system – where buildings are heated by fossil fuels or other combustible gases that are hazardous to health, safety, and climate – to one where buildings are heated by non-combustible, renewable sources of thermal energy via air- and ground-source heat pump technologies. Examples of alternative solutions include: paired pipeline retirement and electrification of corresponding customer loads, thermal energy networks, and advanced leak repair (including pipeline renewal systems) and enhanced leak monitoring.

> "the company has conducted no analysis of how implementation of the Climate Action Plan could impact PGL customer count, usage volume, and the required capacity and maintenance of PGL's gas distribution system"

103 These positions were laid out in PGL's response to an ICC interrogatory in the company's 2023 Rate Case. ICC, 2023 Rate Case for PGL, Docket No. 23-0069, ICC Request No. ICC 1.04 (May 16, 2023), https://www.icc.illinois.gov/docket/P2023-0069/documents/337765/files/588776.pdf.

104 ICC, 2023 Rate Case for PGL, Docket No. 23-0069, Direct Testimony by Dr. Sol deLeon, COC Ex. 1.0, p. 27, https://www.icc.illinois.gov/docket/P2023-0069/documents/337552/files/588163.pdf.

105 In contrast, Ameren Illinois has provided such an analysis, conducted by the Electric Power Research Institute (EPRI). For a description, see p. Section 4.B.1.

106 ICC, 2023 Rate Case for PGL, Docket No. 23-0069, Request No. COC 4.27, https://www.icc.illinois.gov/docket/P2023-0069/documents/337552/files/588191.pdf.

107 The IRP refers to a new long-term planning requirement ordered by the ICC in its four gas utility 2023 rate case orders. Beginning in 2025, gas utilities must present a 5-year action plan of investments with a longer-term planning horizon where applicable, describing the lowest societal cost gas distribution investments necessary to meet customer demand and comply with public policy objectives.

108 ICC, 2024 SMP Investigation, Docket No. 24-0081, PGL Exhibit 3.0, p. 43, https://www.icc.illinois.gov/docket/P2024-0081/documents/352840/files/617402.pdf.

## 1. Economics of electrification in Chicago

Peoples Gas argues that electrification is currently excessively expensive. In its 2023 rate case, the company stated that "forcing electrification on PGL customers on an aggressive time table would be massively expensive. Requiring all electric homes could double customers' heating costs."[109] Similarly, WEC Energy states that electrification is not cost competitive: "conventional electric heat pumps are significantly more costly than natural gas heating in our region."[110]

These claims do not appear to take into account the findings of recent studies examining the growing cost effectiveness of electrification for Illinois and Chicago specifically and the impact of rising gas prices:

- **Illinois Decarbonization Study by Energy and Environmental Economics, Inc.** (E3) (December 2022).[111] This study – prepared for ComEd – models various scenarios to "determine the impact that CEJA and the IRA will have on GHG emissions in Illinois." It separately models scenarios for ComEd's service territory (which includes Chicago), finding similar results. It finds that "customers with natural gas heating in buildings...see their costs increase as more customers transition to...all electric homes." Total customer costs (appliance upfront costs plus monthly bills) are lower today for customers who electrify, particularly due to incentive programs like the IRA. Annual bills are lower for electrified customers in the future because of the rising cost of gas: "Gas rates escalate as the fixed costs of the gas system are spread across fewer remaining customers."[112] The study also finds that gas backup for home heating can reduce the need for electric system upgrades and further lower electric costs. Finally, the study finds that despite the "substantial support" available through the IRA, many customers will still face "prohibitive" upfront costs to electrify.
- **Electrification scenarios for Ameren Illinois by Electric Power Research Institute (EPRI).**[113] EPRI's study projects a decrease in gas consumption in the Ameren gas territory of 18% to 40% by 2050 due to electrification. Specifically within the building sector, EPRI projects a gas consumption decline of 38% to 56% by 2050 due to gains in market share for both residential heat pump space heating and heat pump water heating.
- **Feasibility of advanced retrofits and heat pumps for Chicago by the National Renewable Energy Laboratory (NREL) and Elevate (2022).**[114] NREL and Elevate model 75% of Chicago's residential building stock to simulate possible energy savings and utility costs. They find that "advanced retrofits with energy efficiency upgrades and electrification with heat pumps can reduce utility costs and produce >50% energy savings in older vintage homes in Chicago, reduce CO2 emissions, add necessary cooling, and remove indoor air quality hazards like NOx pollutants." In addition to the high efficiency of modern heat pumps, utility bill savings from full electrification are realized "by eliminating the monthly fixed gas fees for natural gas in Chicago." Many older homes in the study also benefit from the addition of central cooling provided by heat pumps. The study finds that "advanced retrofit packages with heat pumps have the potential to reduce Chicago's CO2 emissions by 2.5 million metric tons per year – the equivalent of 500,000 cars taken off the road."

Meeting the growing electricity demand of increasingly electrified transportation and building loads will require significant investment in electric generation and distribution infrastructure.

109 ICC, 2023 Rate Case for PGL, Docket No. 23-0069, ICC Request No. ICC 1.04 (May 16, 2023), p. 1, https://www.icc.illinois.gov/docket/P2023-0069/documents/337765/files/588776.pdf.
110 WEC Energy Group, *2022 Corporate Responsibility Report*, p. 41, https://www.wecenergygroup.com/csr/cr2022/wec-corporate-responsibility-report-2022.pdf.
111 Energy and Environmental Economics, Inc., *Illinois Decarbonization Study: Climate and Equitable Jobs Act and Net Zero by 2050* (December 2022), https://www.ethree.com/wp-content/uploads/2022/12/E3-Commonwealth-Edison-Decarbonization-Report.-December-2022.pdf.
112 E3's modeling assumes a 1% annual increase in revenue requirement for each IL gas utility. Our study shows PGL's revenue requirement growing at 3%-6% per year due to the relatively higher costs of the SMP (Full SMP, stable customer base). Therefore, we can expect the cost reduction for electrification relative to continued gas use to be even greater than what E3 shows for the state.
113 ICC, 2023 Rate Case for Ameren Illinois, Docket 23-0067, PIO 7.04R Attach 1, Electric Power Research Institute, "Electrification Scenarios for Ameren Illinois' Energy Future," Executive Summary, p. 11.
114 NREL and Elevate, *Achieving 50% Energy Savings in Chicago Homes: A Case Study for Advancing Equity and Climate Goals* (November 2022), https://www.elevatenp.org/wp-content/uploads/Achieving-50-Energy-Savings-in-Chicago-Homes-1.pdf.

However, that cost will be spread across growing consumption, and electricity use will be increasingly managed by technologies that allow for more optimal use of electricity resources, such as batteries, flexible loads, and load control systems. The ComEd Illinois Decarbonization Study shows that, in the near term before loads started to increase, heating and transportation electrification lead to greater grid utilization factors and lower average per kWh costs. Smart rate design, such as that being implemented in several states, can be used to lower the operational cost burden for early adopters.[115] Over the long term, even assuming the buildout costs of new electric infrastructure, greater demand for electricity will moderate average costs; in contrast, the future of gas is on course to deliver steep increases in average delivery costs even as demand is decreasing.

The upfront costs of electrification do pose a barrier to fuel switching from gas to electricity, but electrification generates consumer value in ways that gas does not. Upfront costs need not be cheaper for consumers to electrify. In contrast with the "forced electrification" scenario painted by Peoples Gas, the real challenge is that, as customers voluntarily depart the gas system in response to that enhanced value, the increasing costs of the gas system will be concentrated on a population less able to afford increasing rates.

If anything, Chicago is an ideal candidate for electrification given the high costs of PGL's gas delivery charges which are among the highest in the country. PGL's residential and small commercial customers will be *pulled* by the value offered by efficient electric alternatives, including their superior health properties for indoor spaces, and *pushed* by higher gas delivery charges. It is useful to remember that, during the first part of the 20th century, gas service was more expensive than wood, coal, and heating oil. Its growth was driven by consumer preference and made possible by policymakers and regulators who crafted new rules and regulations to support the fledgling industry. Ultimately, clean energy technologies for space heating threaten the foundation of Chicago's widespread gas service.

115 See Andrew DeBenedictis et al., *Interagency Rates Working Group Study*, Energy & Environmental Economics (August 12, 2024), https://www.mass.gov/doc/near-term-rate-strategy-draft-report-for-public-comment/download; and Central Maine Power, "Statement on Unanimous Approval of CMP Rate Plan," (June 6, 2023), https://www.cmpco.com/w/statement-on-unanimous-approval-of-cmp-rate-plan#.

## 2. Reliability of gas vs. electricity

Ensuring that homes can be reliably heated is an important consideration for a large-scale shift to electric heat. According to Peoples Gas, electrifying current gas customers would lead to peak shortages and unreliable energy supplies. The company asserts that "today's electric grid was not built for the strain of millions of new electric vehicles and appliances from policy-driven electrification,"[116] and, furthermore, that "the electrification of vehicles and buildings switching from gas to electric-powered heating could lead to shortages during normal peak times as the decade proceeds."[117]

In contrast, ComEd recently reported that, at current heat pump adoption rates for its territory,"it looks like there is enough capacity.[118] In large part, this reflects the excess supply of ComEd's grid: ComEd currently exports nearly a third of its generating power.[119] In winter 2023, for example, 32 TWh of generation were available to serve 22 TWh of load.[120] Further, "when compared to the all-time system peak, there is 7 GW excess capacity; when compared to total available generation, there is 12 GW."[121] ComEd estimates that a 50% heat pump adoption rate through 2040 would require the installation of 1.5 million heat pumps in its territory and 12GW of additional capacity, which already exists in its grid.[122] While it is undeniable that increased investments will be necessary to expand Illinois' electrical grid, it appears that current excess capacity is adequate to make considerable progress on heat pump adoption without straining the system and harming energy reliability.

Peoples Gas also ignores other strategies for managing loads and reducing electric heating peaks,

116 ICC, 2023 Rate Case for PGL, Docket No. 23-0069, Request No. ICC 1.04, p. 1, https://icc.illinois.gov/docket/P2023-0068/documents/337765/files/588776.pdf.
117 Ibid, p. 2.
118 ICC, Future of Gas Proceeding, ComEd Presentation: "Introduction to Electric Utility Considerations: ComEd" (May 20, 2024), remarks by Jason Decker, VP Regulatory Policy & Strategy, https://icc.illinois.gov/api/web-management/documents/downloads/public/future-of-gas/ComEd%20Presentation_ICC%20Future%20of%20Gas_5-20-2024.pdf.
119 Ibid., Slide 5.
120 Ibid., Slide 6.
121 Ibid., Slide 7.
122 Ibid., Slide 11.

> "ComEd estimates that a 50% heat pump adoption rate through 2040 would require the installation of 1.5 million heat pumps in its territory and 12GW of additional capacity, which already exists in its grid."

thereby protecting customers from energy outages. These include improved software controls,[123] more resilient building envelopes due to thermal improvements, and greater use of distributed energy resources that leverage growing renewable energy production. ComEd points favorably to the impact of solar generation (rooftop and community) on Chicago's electricity supply. Its most recent solar forecast shows a near quadrupling of residential solar and a 250% increase in small commercial and industry solar for the period 2023 to 2029.[124] ComEd also underscores the potential for bringing down the electric load using TENs that tap into Lake Michigan.[125]

Finally, Peoples Gas fails to consider the role that tank-based fuels could play for some types of housing in order to provide backup and resiliency services in situations where full electrification may be too costly or impractical. While tank-based fuels today cost more than delivered gas, the costs of a low-utilization gas delivery system on a per MMBtu basis would likely exceed the delivered costs of such fuels.

123 Elias N. Pergantis et al., "Field demonstration of predictive heating control for an all-electric house in a cold climate," *Applied Energy* (2024, 360:122820), https://doi.org/10.1016/j.apenergy.2024.122820.
124 ComEd, *Load Forecast for Five-Year Planning Period June 2024 - May 2029* (July 15, 2023) Table II-5(a), p. 23, https://ipa.illinois.gov/content/dam/soi/en/web/ipa/documents/procurement-plans/2024/appendix-c-comed-submittal-2024-electricity-plan.pdf.
125 Comment by Jason Decker, ComEd VP of Regulatory Policy and Strategy, during ComEd Presentation: "Introduction to Electric Utility Considerations: ComEd" (May 20, 2024), https://icc.illinois.gov/api/web-management/documents/downloads/public/future-of-gas/ComEd%20Presentation_ICC%20Future%20of%20Gas_5-20-2024.pdf.

## 3. Relative emissions from electricity and gas

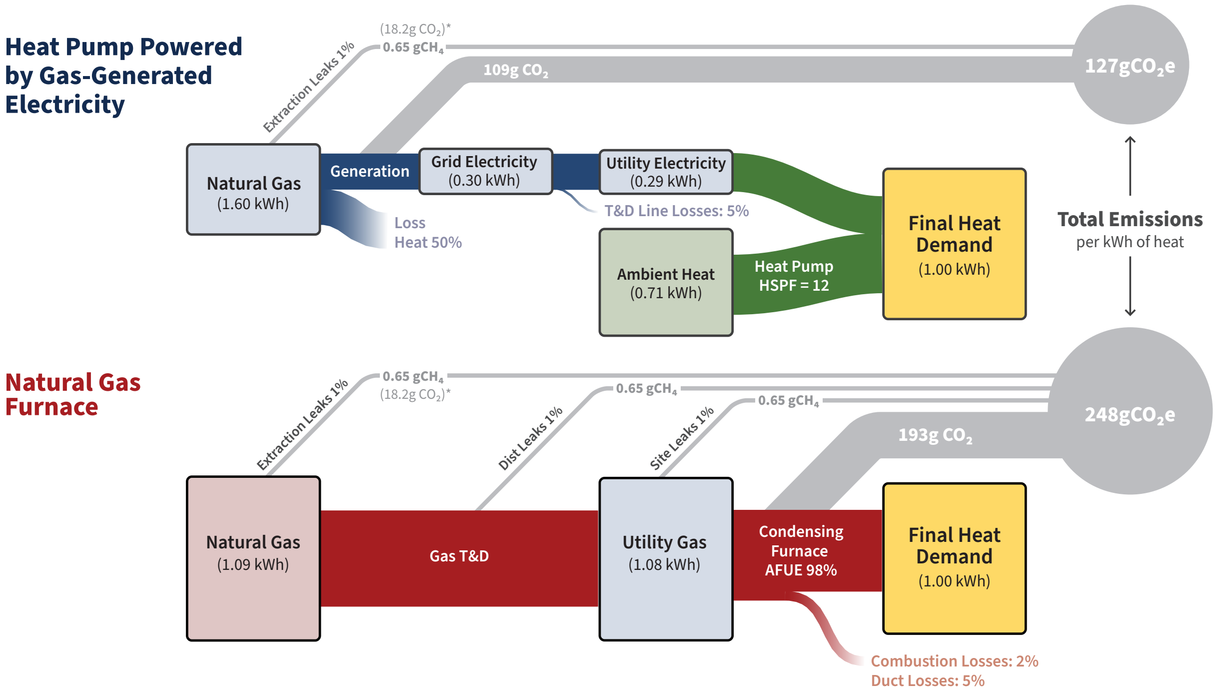
Peoples Gas and WEC Energy position electricity as a dirtier energy source than gas in the short to near term. WEC Energy asserts that "[f]ull-home electrification is significantly more costly than natural gas heating in our region, and currently appears to demonstrate no net reduction in methane consumption due to seasonal demands for power generation."[126] In its April 2024 presentation to the Illinois Future of Gas proceeding, PGL presented its summary analysis of the relative emissions of an "efficient gas furnace" and two types of heat pumps, concluding that far fewer emissions result from the gas furnace.[127]

While the assumptions behind WEC Energy and PGL's analyses have not been provided, both appear to assume that seasonal demands for electric heating and any required non-baseload generation rely on a resource mix heavily weighted toward coal. This is a questionable, worst-case assumption that is out of step with the excess generation reported by ComEd as well as the fact that Illinois has made substantial strides in making its grid less carbon intensive, including being on track to completely phase out coal by 2030.[128] ComEd indicates that over 75% of its current generation is carbon-free.[129]

Numerous studies have established that heat pumps reduce emissions for the average household in every state when compared to the highest efficiency gas-fired equipment available.[130] Most notably, a high-resolution national scale study from

126 WEC Energy Group, *2023 Corporate Responsibility Report*, p. 34, https://www.wecenergygroup.com/csr/cr2023/wec-corporate-responsibility-report-2023.pdf.
127 PGL and North Shore Gas, "Role of Gas Utilities in the Clean Energy Transition and Impacts of Electrification," Presentation to the IL Future of Gas Proceeding (April 22, 2024), pdf slide 10, https://icc.illinois.gov/api/web-management/documents/downloads/public/future-of-gas/PGL%20NSG%20Future%20of%20Gas%20Presentation%2004-22-24.pdf. See also: ICC, 2023 Rate Case for PGL, Docket No. 23-0069, ICC Request No. ICC 1.04 (May 16, 2023), p. 2, https://www.icc.illinois.gov/docket/P2023-0069/documents/337765/files/588776.pdf.
128 Sources of ComEd's electricity for the 12 months ending September 30, 2023 are presented in ComEd's environmental disclosure statement, https://www.icc.illinois.gov/downloads/public/filing/2/12/13/350333.pdf.
129 ICC, Future of Gas Proceeding, ComEd Presentation: "Introduction to Electric Utility Considerations: ComEd" (May 20, 2024), slide 5, https://icc.illinois.gov/api/web-management/documents/downloads/public/future-of-gas/ComEd%20Presentation_ICC%20Future%20of%20Gas_5-20-2024.pdf.
130 Sam Calisch, "Heat Pumps emit less than high efficiency gas appliances in nearly every household in America," Rewiring America (April 20, 2022), https://www.rewiringamerica.org/circuit-breakers/heat-pumps.

**Figure 4.1: Comparison of energy flows and emissions from a gas furnace and a heat pump powered by electricity from gas generation**




Source: GWD.

the National Renewable Energy Laboratory (NREL) demonstrated near-universal emissions reductions when coupling building energy simulations with various grid forecasts.[131] Modern heat pumps consume less energy than they deliver. As shown in Figure 4.1, even when a heat pump runs with electricity generated from gas, it reduces emissions relative to combusting gas directly for heat in the home. In addition, statements regarding the carbon intensity of electricity are often overestimated when the pace of grid decarbonization is not accounted for and when analyses are based on older, less efficient heat pumps.[132]

> "even when a heat pump runs with electricity generated from gas, it reduces emissions relative to combusting gas directly for heat in the home."

131 E.J.H. Wilson et al., "Heat pumps for all? Distributions of the costs and benefits of residential air-source heat pumps in the United States," *Joule* (2024, 8 (4), 1000–1035), https://doi.org/10.1016/j.joule.2024.01.022.

132 Sam Calisch, "Heat Pumps emit less than high efficiency gas appliances in nearly every household in America," Rewiring America (April 20, 2022), https://www.rewiringamerica.org/circuit-breakers/heat-pumps.

# C. Emissions

Reducing greenhouse gas emissions is a major goal of the SMP. PGL's position is that leak-prone pipeline replacement will solve the problem of downstream methane emissions as more mains are replaced and as RNG is increasingly utilized.[133] The company reports that "from 2016 through 2021, the SMP reduced methane emissions by 1,100 metric tons, equivalent to the greenhouse gas emissions of 71 million miles driven by the average gasoline-powered car."[134]

PGL and WEC Energy's position fails to address two important dimensions of the emissions problem:

- **Official methane leak rates significantly underestimate the contribution of PGL's gas network to Chicago's GHG emissions.** This is for two reasons. First, methane leaked from storage facilities, gas mains and services, and meters is underestimated for the Chicago territory.[135] Second, WEC Energy and PGL do not take into account Scope 3 emissions which broadly include behind-the meter (i.e., indoor) emissions attributable to both gas leaks and the combustion of gas in household equipment and appliances.
- **Pipeline replacement generally is a high-cost approach to reducing GHG emissions from gas distribution systems.** Replacing gas mains in many circumstances is unlikely to be the most cost-effective solution to controlling and reducing emissions. In fact, pipeline replacement can compare "very unfavorably with electrification on the basis of dollars per ton of CO2 saved,"[136] particularly when pipe replacement costs are high, as they are in the Peoples Gas territory.[137]

It should be noted that, assuming that recent proposed PHMSA revisions to gas pipeline leak detection and repair (LDAR) regulations take effect as proposed in March 2025, PGL is likely to face significant repercussions.[138] This is because the regulations will require gas utilities to conduct more frequent leak surveys, expand the definition of hazardous leaks, increase their focus on Grade 3 leaks, accelerate repairs, and conduct enhanced leak monitoring.[139] PGL expects that the enhanced regulations will result in an increase in detected leaks and associated leak repair and maintenance costs.[140] The ICC Safety and Reliability Division finds that the potential LDAR rule "could result in Peoples Gas spending significantly more money to fix leaks in the near future."[141]

In its April 2024 filing in the 2024 SMP Investigation, PGL argues that this looming PHMSA-related cost of compliance issue is a further reason to "promptly resume a proactive pipe replacement program."[142] Over the last four years (2020 to 2023), PGL's

133 WEC Energy Group, CDP Climate Change Questionnaire for 2023, p. 65, https://www.wecenergygroup.com/csr/cdp2023-climate-change.pdf; and ICC, 2023 Rate Case for PGL, Docket No. 23-0069, ICC Request No. ICC 1.04 (May 16, 2023), p. 3, https://www.icc.illinois.gov/docket/P2023-0069/documents/337765/files/588776.pdf.

134 ICC, 2023 Rate Case for PGL, Docket No. 23-0069, Request No. ICC 1.04 (May 16, 2023), p. 3 of 4, https://www.icc.illinois.gov/docket/P2023-0069/documents/337765/files/588776.pdf.

135 Cody Floerchinger et al., "Relative flux measurements of biogenic and natural gas-derived methane for seven U.S. cities," *Elementa Science of the Anthropocene* (February 2021, 9:1), DOI:10.1525/elementa.2021.000119.

136 NY Public Service Commission, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Brooklyn Union Gas Company and KeySpan Gas d/b/a National Grid, Case 23-G-0225 & 0226, Direct Testimony of Alice Napoleon on behalf of the Natural Resources Defense Council (September 1, 2023), p. 45, https://www.synapse-energy.com/sites/default/files/Direct%20Testimony%20of%20Alice%20Napoleon%20on%20behalf%20of%20NRDC%20KEDNY%20KEDLI%2022-017.pdf.

137 In testimony for a recent ConEd rate case in New York, Napoleon and Hopkins estimate that "an approach based on building retrofits, electrification, and pipeline retirement could reduce emissions at a cost per ton that is 77 percent less expensive than the cost per ton of the MRP [main replacement pipe], while delivering co-benefits of lower energy bills and increased public health and comfort for building residents." NY Public Service Commission, Proceeding on Motion of the Commission as to the Rates, Charges, Rules and Regulations of Consolidated Edison Company of New York, Inc. for Gas Service, Case 22-E-0064 and Case 22-G-0065, Direct Testimony of Alice Napoleon and Asa Hopkins PhD on behalf of Natural Resource Defense Council (May 20, 2022), p. 6, https://www.synapse-energy.com/sites/default/files/Synapse-Panel-Testimony-Exhibits-NRDC-22-017.pdf.

138 ICC, 2024 SMP Investigation, Docket No. 24-0081, Staff Exhibit 2.0, https://www.icc.illinois.gov/docket/P2024-0081/documents/351871/files/615569.pdf.

139 Dorie Seavey, *Leaked & Combusted* (May 2024, HEET), pp. 43-45, https://assets-global.website-files.com/649aeb5aaa8188e00cea66bb/663a27270c0fa4fffcfe447d_Leaked-and-Combusted-May-2024.pdf.

140 ICC, 2024 SMP Investigation, Docket No. 24-0081, *Peoples Gas and the SMP: History, Current State, and Alternatives*, PGL Exhibit 2.0, p. 35, https://www.icc.illinois.gov/docket/P2024-0081/documents/348897/files/609896.pdf. ICC staff estimates that improved leak detection will result in identifying many more Grade 3 leaks involving "somewhere between 366,960 to 489,280 [joint] locations" which if leaking will have to be treated within 3 to 7 years (a common leakage spot on cast and ductile iron pipes are the connection joints). See: ICC, 2024 SMP Investigation, Docket No. 24-0081, Staff Exhibit 2.0, p. 5, https://www.icc.illinois.gov/docket/P2024-0081/documents/351871/files/615569.pdf.

141 ICC, 2024 SMP Investigation, Docket No. 24-0081, Staff Exhibit 2.0, p. 7, https://www.icc.illinois.gov/docket/P2024-0081/documents/351871/files/615569.pdf.

142 ICC, 2024 SMP Investigation, Docket No. 24-0081, *Peoples Gas and the SMP: History, Current State, and Alternatives*, PGL Exhibit 2.0, p. 35, https://www.icc.illinois.gov/docket/P2024-0081/documents/348897/files/609896.pdf.

annual leak repair and maintenance costs averaged $27.1 million, or about 8% of its total operations and maintenance expenses.[143] Any increase in PGL's operations and maintenance expenses would lower the company's net income until the next rate case when rate increases could be pursued to cover the added expenses. An additional motivation for Peoples Gas to resume the SMP is that having a pipeline replacement program in place can greatly extend the PHMSA compliance dates to address detected leaks if the specific material at issue is scheduled for replacement.[144]

## D. Role and feasibility of RNG and hydrogen

PGL's position is that it is essential for Chicago to continue to use the SMP to create a "modern distribution infrastructure system" that can carry lower carbon fuels. According to the company, to do otherwise would be to foreclose "beneficial opportunities"[145] and jeopardize the preservation of "customer choice" such that customers can "choose the decarbonization strategies that work best for them."[146] As it stands, PGL's system is a poor candidate for transporting and delivering these fuels because its cast iron mains are leak prone, have limited remaining service lives, and provide limited pressurization capabilities.[147]

Groundwork Data recently conducted an analysis of the potential role that alternative gases could play in Illinois' energy transition.[148] Our key conclusions are these:

- **RNG is an exceptionally expensive decarbonization pathway that does not create any new value for gas customers.** At scale, energy customers would incur burdensome costs, further incentivizing customers to leave the gas system. Additionally, scaling RNG for heat will likely be constrained by new federal incentives for transportation biofuels and carbon sequestration.
- **The highest and best use of Illinois' vast potential bioenergy resources is not RNG for building heating.** These resources would have far greater economic value if allocated to harder-to-electrify sectors, such as sustainable aviation fuel and carbon dioxide removal. Additionally, scaling RNG for heat will likely be further constrained by new federal incentives for transportation biofuels and carbon sequestration.
- **Like RNG, hydrogen for heating is neither a scalable decarbonization solution nor cost effective.** The preponderance of scientific literature finds that hydrogen is not cost-optimal for building decarbonization.[149] Beyond cost and efficiency, other problems include: hydrogen's significant GHG and environmental impacts (hydrogen has recently been determined to have a larger global warming potential than previously understood);[150] pipeline materials compatibility (hydrogen is known to have a degrading effect on pipes, fittings, valves, joints and welds);[151] safety issues (hydrogen is more hazardous than fossil gas); hydrogen's questionable impact on end-use appliances (appliances and furnaces are not certified to burn hydrogen and as the percentage of hydrogen blends increases, end-use appliances may require modifications);[152] leakage rates (because hydrogen is a small molecule, leak rates from distribution pipes will increase); and the need to increase operating pressures which in turn will increase leak flow rates (hydrogen has only one-third the energy content of methane;

143 PGL, *Safety Modernization Program Quarterly Report*, Q4 2023 (February 14, 2024), p. 24, https://icc.illinois.gov/api/web-management/documents/downloads/public/gas/2023%20-%20Q4%20SMP%20Report.pdf
144 For example, under the new LDAR rule, Class 2 leaks must be repaired within 1 year unless scheduled for replacement, in which case the operator has 2 years. Class 3 leaks have a 3-year repair timeline unless the operator is under a replacement program in which case the operator has 7 years to replace the pipe. See ICC, 2024 SMP Investigation, Docket No. 24-0081, Staff Exhibit 2.0, p. 5, https://www.icc.illinois.gov/docket/P2024-0081/documents/351871/files/615569.pdf.
145 Ibid., p. 2.
146 Ibid., p. 3.
147 Ibid., p. 11.
148 Dorie Seavey et al., *The Future of Gas in Illinois* (May 2024, Building Decarbonization and Groundwork Data), Section 5, https://buildingdecarb.org/resource/the-future-of-gas-in-illinois.

149 Jan Rosenow, "A meta-review of 54 studies on hydrogen heating," *Cell Reports Sustainability* (December 14, 2023), https://doi.org/10.1016/j.crsus.2023.100010.
150 Maria Sand et al., "A multi-model assessment of the Global Warming Potential of hydrogen," *Communications Earth & Environment* (June 7, 2023, 4:203), https://doi.org/10.1038/s43247-023-00857-8.
151 Kevin Topolski et al., *Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology* (2022, National Renewable Energy Laboratory), https://www.osti.gov/biblio/1893355.
152 Ibid.

> **"Procuring RNG for heat means paying for high production costs and clearing the higher cost of these credits. Ultimately, these financing mechanisms will push up rates for customers and make electrification more affordable."**

therefore, greater pressure is required to deliver the same amount of energy).[153]

Like many investor-owned gas utilities, PGL has adopted a bullish position toward RNG and hydrogen but without detail on how and over what time frame pilots can be scaled up to create affordable gas rates.[154] In addition, PGL has not provided feasibility and/or cost/benefit analyses related to decarbonizing the city's gas system by blending in RNG and/or hydrogen.

WEC Energy, for its part, has stated that it is looking at RNG blends from dairy farms as an alternative to electrification and is "taking steps to implement this method as we work toward our methane reduction goal."[155] However, the parent company has not explained how it seeks to overcome the barriers posed by federal and state fuel standards that provide significant subsidies for fuels used solely for transportation end-uses.

An RNG interconnection pilot is currently underway to connect PGL's high-pressure distribution system and an RNG project involving anaerobic digesters for local food waste diverted from landfills.[156] The pilot is part of the urban farming Green Era Campus on Chicago's Southside. The $32 million project has received international attention for its efforts to prioritize local community needs as part of its development. The total cost of the interconnection is reported to be $1.7 million and the pilot is designed to produce up to 1,152 Mcg of gas per day (48 Mcf/hour) with multiple testing protocols to ensure that the RNG produced meets pipeline quality and safety standards.[157] The cost of the interconnection is to be recovered via a recently approved rider.[158]

According to Groundwork Data's analysis, the cost of RNG produced by the Green Era project is likely to total over $25 per MMBtu (food waste) – far exceeding the $3-$6 range of fossil gas in recent years.[159] The project is likely only financially feasible due to the availability of Renewable Fuel Standard (RFS) and Low Carbon Fuel Standard (LCFS) credits for the production of RNG for use in vehicles only. Procuring RNG for heat means paying for high production costs and clearing the higher cost of these credits. Ultimately, these financing mechanisms will push up rates for customers and make electrification more affordable.

Regarding hydrogen, WEC Energy has stated that "there is potential for hydrogen to be produced with zero-emission energy resources and blended with conventional natural gas. If this technology becomes a viable option for our natural gas business, we expect our modernized distribution system could be modified slightly to carry hydrogen fuel."[160] Yet as of 2023, Peoples reports that it "has not conducted a study on hydrogen's use in the new SMP facilities

153 Ibid.
154 ICC, 2023 Rate Case for PGL, Docket No. 23-0069, Request No. ICC 1.04, https://icc.illinois.gov/docket/P2023-0068/documents/337765/files/588776.pdf.
155 WEC Energy, *2022 Corporate Responsibility Report*, https://www.wecenergygroup.com/csr/cr2022/wec-corporate-responsibility-report-2022.pdf#pagemode=bookmarks.
156 Corli Jay, "The South Side is getting a facility to turn food waste into natural gas," *Crain's Chicago Business* (May 19, 2022), https://www.chicagobusiness.com/utilities/auburn-gresham-getting-renewable-natural-gas-facility.
157 ICC, Verified Petition of PGL for Certain Regulatory Findings re: Proposed RNG Connection, Docket No. 22-0323, PGL Exhibit 4.0 (April 26, 2022), https://icc.illinois.gov/docket/P2022-0323/documents/323226/files/562662.pdf.
158 Effective April 2023, the ICC approved the implementation of a new PGL rider called "Rider PRG: Producer of Renewable Gas Transportation Service." See: PGL, "Rider PRG," ILL. C.C. NO. 28, Sixth Revised Sheet No. 147 (March 2023), https://www.icc.illinois.gov/downloads/public/filing/4/344699.pdf.
159 Dorie Seavey et al.,*The Future of Gas in Illinois* (May 2024, Building Decarbonization and Groundwork Data), Section 5, https://buildingdecarb.org/resource/the-future-of-gas-in-illinois.
160 WEC Energy Group, *2022 Climate Report: Pathway to a Clean Energy Future*, p. 25, https://www.wecenergygroup.com/csr/climate-report2022.pdf.

being deployed."[161] The most successful and longest-running hydrogen blending project in the U.S. is by Hawaii Gas. Recent hydrogen-blending efforts by other gas utilities both in the U.S. and the United Kingdom have fizzled.[162]

## E. Key takeaways and strategic implications

Peoples Gas and its parent company, WEC Energy, have opted for a strategy of aggressive investment in the SMP with the expectation of securing greater financial returns while maintaining system reliability and preparing for potential use of "future fuels." This approach is built on several high-risk assumptions that warrant close scrutiny.

First, the company's strategy rests on the assumption that large-scale investments in traditional gas infrastructure will continue to be justified by safety, reliability, and environmental considerations. This assumption may overlook the rapidly changing regulatory, policy, and market environment where increasing pressure to decarbonize could undermine the long-term viability of these investments.

Second, the expectation that emerging technologies such as RNG and hydrogen will provide a reliable and cost-effective pathway for decarbonization is far from guaranteed. These technologies face significant technical, economic, and regulatory hurdles, and their widespread adoption remains uncertain. This high-risk assumption exposes Peoples Gas to the possibility that these technologies may not materialize at scale or within projected timeframes.

Finally, the failure to thoroughly evaluate and consider non-pipeline alternatives, such as advanced leak detection and repair technologies, electrification, and thermal energy networks, is a significant oversight. By not exploring these options, Peoples Gas may be missing opportunities to adapt to the evolving energy landscape and mitigate the risks associated with continued reliance on fossil fuel infrastructure. For investors, this lack of comprehensive risk assessment should be a point of concern as it could lead to unforeseen challenges and impact the company's long-term financial stability.

161 ICC, 2023 PGL Rate Case, Docket No. 23-0069, COC Exhibit 1.05, p. 3, https://www.icc.illinois.gov/docket/P2023-0069/documents/337552/files/588187.pdf.

162 See Sam Brasch,"Xcel Energy backs off plan to blend hydrogen into the natural gas system serving a neighborhood near Hudson," *Colorado Public Radio* (March 5, 2024), https://www.cpr.org/2024/03/05/xcel-energy-pauses-plan-to-blend-hydrogen-into-natural-gas-system-near-hudson/; and BBC, "Ellesmere Port hydrogen heating trial scrapped after protests" (July 11, 2023), https://www.bbc.com/news/uk-england-merseyside-66165484.

Section

# 5

# Managing risk in a changing regulatory environment

**Recent actions by the ICC coupled with the sunsetting of the QIP Rider, have introduced new financial challenges for Peoples Gas and arguably have begun to alter the company's risk profile for investors.** The ICC's actions are part of a broader reassessment of the role of gas utilities within the context of Illinois' climate commitments. The Commission has stated that to meet the state's climate law, "the gas distribution system as currently operated will need to change."[163] Further underscoring this shift is the recent launch of the ICC Future of Gas proceeding which aims to address the decarbonization of the gas system and develop recommendations for regulatory and legislative changes.[164]

This section surveys this evolving regulatory landscape and examines the financial repercussions for Peoples Gas. Given a future regulatory environment predicated on heightened scrutiny, a focus on decarbonization, and concern about the rising costs of system modernization, we present modeling results for two scenarios that require reduced – rather than Full – SMP spending. In the first scenario, SMP capital spending is lowered by 25%; in the second, it is reduced by 50%. We explore how reduced spending would affect PGL's financial stability and long-term viability in a rapidly evolving energy landscape.

163 ICC, 2023 Rate Case for PGL, Docket No. 23-0069, Final Order (November 16, 2023), p. 121, https://www.icc.illinois.gov/docket/P2023-0069/documents/344306/files/601245.pdf.

164 ICC, Initiation of proceeding to examine the Future of Natural Gas and issues associated with decarbonization of the gas distribution system, Docket No. 24-0158, https://www.icc.illinois.gov/docket/P2024-0158/documents/347887.

# A. Recent regulatory decisions

From November 2023 through Q2 2024, the ICC took several noteworthy steps consistent with a tightened regulatory regime for investor-owned gas utilities. For Peoples Gas, these actions largely stemmed from the Commission's 2023 rate case order and included the following:

- **Pause of the SMP Program.** The ICC's year-long "pause" of the SMP has halted planned capital expenditures.[165] The accompanying new SMP investigation (Docket No. 24-0081) was strongly advocated for by the Attorney General, the City of Chicago, and public interest intervenors. In its 2023 rate case order, the ICC found that Peoples Gas had failed to adequately justify the SMP and cited concerns with SMP cost overruns, insufficient risk reduction for aging pipes, and lack of prioritization of neighborhoods with the highest levels of risk.[166]
- **Capital expenditure disallowances.** The ICC disallowed $177.2 million related to spending on PGL's service centers and an additional $59 million for "expected future spend."[167]
- **Biennial long-term gas infrastructure plan.** Beginning in 2025, Illinois' four largest gas utilities, including Peoples Gas, will be required to publicly disclose a five-year action plan for investments. This plan must describe the lowest societal cost gas distribution investments necessary to meet customer demand and comply with public policy objectives.[168]
- **Annual leak reporting requirement.** As part of its 2023 rate case orders, the ICC adopted recommendations to enhance utility leak reporting in order to provide greater transparency and to enable the Commission to assess the

165 ICC, 2023 Rate Case for PGL, Docket 23-0069, Final Order (November 16, 2023), p. 30, https://www.icc.illinois.gov/docket/P2023-0069/documents/344306/files/601245.pdf.

166 Ibid., pp. 29-30.

167 WEC Energy Group, *2023 Annual Report*, Note 26, p. F-98, https://www.wecenergygroup.com/invest/annualreports/wec2023-annual-report.pdf.

168 ICC, 2023 Rate Case for PGL, Docket No. 23-0069, Final Order (November 16, 2023), pp. 119-120, https://www.icc.illinois.gov/docket/P2023-0069/documents/344306/files/601245.pdf

scope of system leaks and the effectiveness of utility efforts to identify, target, and remedy them. Beginning July 1, 2024, each gas utility must annually report leaks by grade, cause, and facility type (material type and infrastructure type).[169]

- **ICC order on PGL's rehearing petition.** Peoples Gas requested that the ICC add back $145 million in capital spending related to work-in-progress and "emergency" projects, thereby exempting these from the SMP pause. In a June 2024 order, the ICC agreed to reinstate only $28.5 million, increasing PGL's revenue requirement by $1.6 million instead of nearly $8 million.[170] Peoples Gas is contesting this rehearing order in the Illinois Appellate Court.
- **Inadequate justification for CI/DI pipeline replacement.** In its 2023 rate case order, the ICC determined that Peoples Gas failed to provide sufficient detail regarding the replacement of cast iron and ductile iron (CI/DI) pipelines; therefore, it was unable to conclude that the 2024 SMP test year investments were "prudent and reasonable." The Commission noted that "between the end of 2018 and the end of 2022, PGL retired and replaced 237 miles or 59 miles per year. At this rate, it will take 26 years – until 2049 – to replace the existing at-risk pipe. PGL makes no attempt in this record to explain the steps they will take to complete retirement within or close to the Kiefner Study's specified timeline [of 2030]."[171] The Commission found that PGL "offered inadequate record justification for maintaining a $265 million spending level [for SMP]."[172] This scrutiny could lead to further disallowances or stricter oversight, potentially reducing future investment returns.

In its 2023 rate case orders for Illinois' four largest investor-owned utilities, the ICC articulated a firm guiding principle: "the question is not whether pipeline replacements generally improve safety and reliability, but what types of pipes are to be replaced, to what degree safety and reliability are affected, at what pace, and at what cost."[173] This suggests a higher threshold for justifying SMP investments such that it is no longer sufficient to claim that an investment improves safety, reliability, or reduces emissions; instead, going forward, PGL's proposed spending plans must meet the ICC's detailed criteria.

## B. Financial impacts

The regulatory actions outlined above have had immediate material effects on Peoples Gas and the shareholders of its parent company, with both entities describing the regulatory environment shift as "adverse" and a "deterioration."

To date, the financial consequences – all negative – have included:

- **Increased operating expenses due to non-cash impairment.** Peoples Gas expensed $177.2 million related to the ICC's disallowances of previously incurred capital costs as a non-cash "impairment."[174] The impairment was also reflected in WEC Energy's consolidated income statements.[175]
- **Decline in WEC Energy net income from Illinois.** WEC Energy recorded an $86.9 million, or 38.3%, decrease in net income to common shareholders due to its Illinois segment.[176] This decline in net income was the first to occur in five years.
- **WEC Energy decision to shift capex away from PGL.** During its Q4 2023 earnings call and

169 Ibid., p. 65. For PGL's first annual leak report, see: PGL, *Annual Leak Report for Calendar Year 2023*, https://www.icc.illinois.gov/docket/P2023-0069/documents/352355/files/616633.pdf.
170 ICC, 2023 Rate Case for PGL, Docket No. 23-0069, Order on Rehearing (May 30, 2024), https://www.icc.illinois.gov/docket/P2023-0069/documents/351184/files/614334.pdf.
171 ICC, 2023 Rate Case for PGL, Docket 23-0069, Final Order (November 16, 2023), p. 28, https://www.icc.illinois.gov/docket/P2023-0069/documents/344306/files/601245.pdf.
172 Ibid., p. 29.
173 ICC, 2023 Rate Case for Ameren Illinois Company, Docket No. P2023-0067 (November 16, 2023), p. 90, https://www.icc.illinois.gov/docket/P2023-0067/documents/344282.
174 Note: An impairment loss is recognized when the carrying amount of an asset is not recoverable and exceeds its fair value. PGL, *2023 Annual Report*, Consolidated Income Statement, p. 37 and 43, http://q4live.s22.clientfiles.s3-website-us-east-1.amazonaws.com/994559668/files/doc_financials/2023/q4/2023-PGL-Annual-Report.pdf.
175 WEC Energy Group, *2023 Annual Report*, p. F-40, https://www.wecenergygroup.com/invest/annualreports/wec2023-annual-report.pdf.
176 According to WEC Energy, the decrease was "driven by higher operating expenses, primarily due to an impairment associated with the ICC's disallowance of certain incurred capital costs in its 2023 rate orders for PGL and NSG [North Shore Gas]" but offset by lower operation and maintenance costs, rate increases for the two Illinois gas utilities, and continued capital investment in the SMP project in 2023. Ibid., p. F-13.

in response to what it called a "disappointing" conclusion to the 2023 rate case, WEC Energy announced that it had lowered its planned five-year investment in Illinois' gas delivery system by $800 million for 2024-2028, compared to 2023-2027. The capex is to be redirected to non-regulated, renewable power operating subsidiaries, indicating a "diminished role for gas utilities in [its] business mix."[177]

- **Decrease in unadjusted WEC Energy earnings per share (EPS).** The negative impact of the ICC's disallowance decreased EPS on an unadjusted basis by $0.41. The resulting EPS for 2023 was $4.22 versus $4.45 in 2022.[178] (The adjusted EPS for 2023 was $4.63).
- **Negative credit review from Moody's Ratings.** Following the ICC's June 2024 order on PGL's rehearing request, Moody's changed PGL's outlook from stable to negative, although it did not change PGL's current A-level ratings. According to Moody's, "the negative outlook on PGL's financial performance for the next few years reflects a deterioration in the Illinois regulatory environment, uncertainty about future capital expenditures, increased likelihood that PGL's cash flows will be subject to regulatory lag in terms of cost recovery (including prudency reviews of amounts previously collected through riders), and the probability of an adverse outcome of the pending SMP investigation."[179]
- **Subsequent fall in WEC Energy's stock price.** Upon the announcement of the ICC's 2023 rate case decision, WEC Energy's stock price declined 4.6%. It declined again at the time of the rehearing order and the announcement of Moody's negative credit review in June 2024. However, as of early September 2024, the stock had rebounded to reach a 52-week high.

177 Tom DiChristopher, "Future of gas, pipe safety probes cloud outlook for WEC Energy's Chicago Utility," *S&P Capital IQ* (February 6, 2024). WEC Energy indicates that in 2028 it expects gas assets to make up 30% of its total asset base, down from 35% at the end of 2023. See WEC Energy, *September 2024 Investor Report* (September 4, 2024), p. 13, https://s22.q4cdn.com/994559668/files/doc_presentations/2024/Sep/03/09-2024-september.pdf.
178 WEC Energy Group, *2023 Annual Report*, p. P-43, https://www.wecenergygroup.com/invest/annualreports/wec2023-annual-report.pdf.
179 Moody's Ratings, Rating Action: Moody's Ratings changes outlook of Peoples Gas Light and Coke to negative; affirms ratings" (June 3, 2024), https://ratings.moodys.com/ratings-news/422391.

"the negative outlook on PGL's financial performance for the next few years reflects a deterioration in the Illinois regulatory environment, uncertainty about future capital expenditures, increased likelihood that PGL's cash flows will be subject to regulatory lag in terms of cost recovery (including prudency reviews of amounts previously collected through riders), and the probability of an adverse outcome of the pending SMP investigation."

— Moody's

## C. Future of Gas deliberations in Illinois

To address systemic decarbonization issues and develop recommendations for regulatory actions and legislation, the ICC initiated a Future of Gas proceeding in March 2024.[180] According to WEC Energy Group's 2023 annual report, while the ultimate outcome of this proceeding remains uncertain, "future natural

180 The proceeding begins with two workshop series. See ICC, Future of Gas Proceedings, https://www.icc.illinois.gov/programs/Future-of-Gas-Workshop.

> **"The considerable cost savings from avoided gas pipeline replacement could effectively be redirected towards investment in building electrification."**

gas investment opportunities in Illinois could be negatively impacted."[181]

With the launch of this Future of Gas proceeding, Illinois joined 11 other states where utility commissions have undertaken similar initiatives. These proceedings generally focus on addressing long-term gas planning, pathways for emissions reductions, clean energy infrastructure, workforce transitions, and protections for low-income ratepayers[182] (see Figure 5.1 for future-of-gas-related activity across the country).

An important framework to emerge from these efforts is that of a "managed gas transition" – that is, a comprehensive strategy involving regulatory oversight and stakeholder collaboration to phase out pipeline-delivered gas in favor of clean energy while ensuring safety, reliability, and affordability. A managed gas transition has three key building blocks:[183]

1. **Halting gas system expansion** (e.g., limiting or removing pipeline line extension allowances and instituting all-electric building codes)
2. **Limiting reinvestment in the gas distribution system** by restricting or reducing capital spending on the replacement of existing gas infrastructure
3. **Strategically downsizing the gas distribution system** by creating detailed, phased plans for decommissioning the gas system over time

Implementing such a strategy requires developing rigorous frameworks for identifying and evaluating non-pipeline alternatives (NPAs), such as advanced leak repair, pipeline decommissioning, targeted or zonal electrification, and thermal energy networks.

A key factor driving some states to explore policies supporting a managed transition is the body of analysis indicating that the cost of building electrification is comparable to, and potentially lower than, the cost of pipeline replacement over the long term.[184] The considerable cost savings from avoided gas pipeline replacement could effectively be redirected towards investment in building electrification. Should the ICC implement elements of a managed transition, the financial implications for Peoples Gas under its current operating model could be substantial, particularly given that Chicago's electric system is owned and operated by a separate utility, ComEd.

181 WEC Energy Group, *2023 Annual Report*, p. F-32, https://www.wecenergygroup.com/invest/annualreports/wec2023-annual-report.pdf.

182 See BDC's summary of active Future of Gas proceedings as well as their tracker: https://buildingdecarb.org/decarbnation-issue-2.

183 Dorie Seavey et al., *The Future of Gas in Illinois* (May 2024, Building Decarbonization and Groundwork Data), Section 6, https://buildingdecarb.org/resource/the-future-of-gas-in-illinois.

184 See, for example, Aryeh Gold-Parker et al., *Benefit-Cost Analysis of Targeted Electrification and Gas Decommissioning in California: Evaluation of 11 Candidate Sites in the San Francisco Bay Area*, California Energy Commission (December 2023), https://www.ethree.com/wp-content/uploads/2023/12/E3_Benefit-Cost-Analysis-of-Targeted-Electrification-and-Gas-Decommissioning-in-California.pdf; and UMass Amherst Energy Transition Institute, *Equitable Energy Transition Planning in Holyoke Massachusetts: A Technical Analysis for Strategic Gas Decommissioning and Grid Resiliency* (December 2023, prepared by Groundwork Data), https://doi.org/10.7275/enzr-5311.

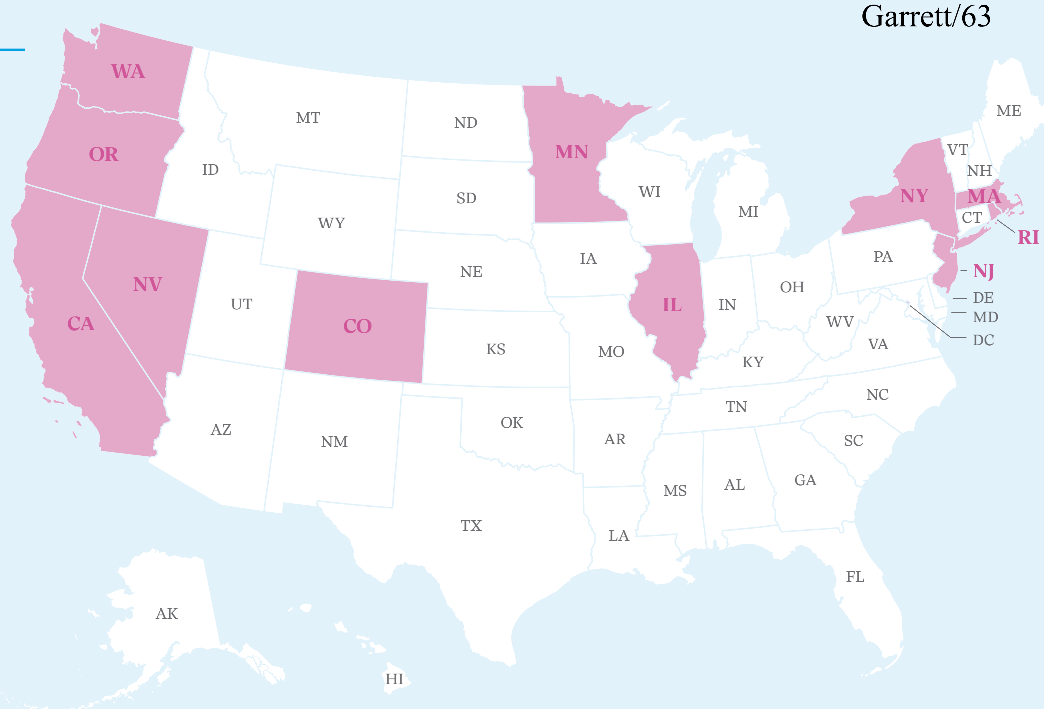



**Figure 5.1: Future-of-gas activity across the states**

**Future-of Gas-Proceedings.** Proceedings have occurred or are underway in 12 states: California, Colorado, Illinois, Massachusetts, Minnesota, Nevada, New Jersey, New York, Oregon, Rhode Island, and Washington. Among the main issues under consideration are: aligning utility planning with climate goals, equitably financing existing gas assets, halting gas system expansion, transitioning away from the gas system while maintaining safe, reliable, and affordable energy access, and providing a just transition for gas workers.[1]

**Non-pipeline alternative (NPAs) frameworks.** NPAs are intended to delay, reduce, or avoid the need to build up or upgrade traditional gas infrastructure such as pipelines, storage, and peaking resources (see page 47 for a description). California, Colorado, Massachusetts, New York, Oregon, and Rhode Island now require local gas utilities to evaluate and consider NPAs as a substitute for pipeline replacement.

**Thermal energy network (TEN) pilots.** Several utility-sponsored thermal energy network projects are under development across the country. In Massachusetts, Eversource and National Grid are leading  3 projects. In New York, plans for 13 utility TEN projects have been proposed as required under the Utility Thermal Energy Network and Jobs Act. To encourage TEN pilots, Colorado and Minnesota have each taken steps to expand their definitions of clean heat resources to include thermal energy and/or to provide that gas utilities can sell thermal energy. In Chicago, the environmental justice organization, Blacks In Green, is piloting non-utility TEN ownership models. In 2023, the organization received funding from the Department of Energy "to design and develop a community geothermal heating and cooling district…across four city blocks containing more than 100 multi-family and single-family homes."[2] At the state level, the ICC held a workshop on thermal energy networks in 2023 and submitted a report with recommendations on the role of TENs in Illinois' clean energy future to the Governor and General Assembly.[3]

1 Kristin George Bagdanov, "The Future of Gas: A Summary of Regulatory Proceedings on the Methane Gas System," DecarbNation Blog (December 15, 2022, revised May 31, 2024, Building Decarbonization Coalition), https://buildingdecarb.org/decarbnation-issue-2#scope.

2 Juanpablo Ramirez-Franco, "A Geothermal Energy Boom Could Be Coming to Chicago's South Side," *Grist* (February 23, 2024), https://grist.org/cities/black-communities-south-side-chicago-geothermal-heat/.

3 The workshop covered a variety of issues, including: different ownership models for TENs; synergies with existing weatherization and energy efficiency programs; contributions to climate justice and equitable building electrification; and the role of TENs in creating a just transition for utility workers. The final report recommended exploring utility and non-utility ownership models, necessary regulatory and legislative changes, consumer protections, and other recommendations. ICC, *Thermal Energy Network Report* (February 2024),  https://icc.illinois.gov/api/web-man-

**Decommissioning with targeted electrification.** Several states are advancing or encouraging targeted or zonal electrification projects and pilots that provide for retiring gas pipeline segments. The CA Energy Commission's Tactical Gas Decommissioning Project is identifying 3 pilot sites for gas decommissioning and Pacific Gas and Electric (PG&E) has independently instituted a number of small-scale decommissioning projects.[4] The District of Columbia has released a detailed roadmap for strategically electrifying buildings and transportation in the District.[5] In Massachusetts, the Department of Public Utilities has ordered that each gas utility coordinate with the relevant electric company to propose at least one demonstration project for "decommissioning an area of its system through targeted electrification."[6] In Minnesota, gas companies can sell electric heating technologies such as ASHPs and geothermal or aquifer thermal applications, and gas utilities are encouraged to undertake decarbonization pilots.[7]

**Analytic tools for decommissioning.** CA Energy Commission's Tactical Gas Decommissioning Project is developing a decommissioning tool to identify cost-effective gas segments for retirement. PG&E has developed an internal Gas Asset Analysis Tool to identify locations where zonal electrification and/or targeted decommissioning of the methane gas system may reduce gas system costs.[8] Federal and state funding has also begun supporting the development of technical frameworks and tools that use longer planning horizons, integrate planning between gas and electric systems, and assess alternative strategies for gas network sections slated for pipeline replacement.[9]

**Accelerated gas asset depreciation for dual utilities.** In Washington, a newly adopted law (HB 1589) provides for accelerated depreciation by 2050 for Puget Sound Energy (PSE) gas assets put in service by July 2024; it also allows for gas/electric rate base merging.[10]

**Stranded assets.** In Massachusetts, the Department of Public Utilities has directed gas utilities to forecast "the potential magnitude of stranded investments" and identify the impacts of accelerated depreciation proposals and other alternatives.[11] In California, the Public Utilities Commission (CPUC) has also adopted a new framework to comprehensively review utility gas infrastructure investments in order to help the state transition away from gas-fueled technologies and avoid stranded assets in the gas system.[12] Utilities must now seek CPUC approval of gas infrastructure projects of $75 million or more or those with significant air quality impacts. Previously, all gas infrastructure projects were considered in utility general rate cases.

agement/documents/downloads/public/TEN/Thermal%20Energy%20 Network%20Report%202024.pdf

4 Gridworks, "Site Prioritization: Identifying Three Proposed Gas Decommissioning Pilot Locations" (August 17, 2023), https://gridworks.org/2023/08/site-prioritization-identifying-three-proposed-gas-decommissioning-pilot-locations/

5 Government of the District of Columbia, Department of Energy and Environment, *The Strategic Electrification Roadmap for Buildings and Transportation in the District of Columbia* (April 2023), https://doee.dc.gov/sites/default/files/dc/sites/ddoe/page_content/attachments/Strategic%20Electrification%20Roadmap-reducedsize.pdf.

6 MA Department of Public Utilities, Order on Regulatory Principles and Framework, DPU 20-80-B (December 6, 2023), p. 87, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18297602.

7 Frank Jossi, "Under new law, Minnesota gas utilities could play a role in electrification," *Energy News Network* (July 21, 2021), https://energynews.us/2021/07/21/under-new-law-minnesota-gas-utilities-could-play-a-role-in-electrification/

8 CA Energy Commission, PG&E Comments on the Draft 2021 Integrated Energy Policy Report (IEPR), Volume III Decarbonizing the State's Gas System, Docket 21-IEPR-01 (January 28, 2022), https://efiling.energy.ca.gov/GetDocument.aspx?tn=241334.

9 An example of the latter is the Local Energy Asset Planning (LEAP) tool developed by Groundwork Data with support from the U.S. Department of Energy and the MA Department of Energy Resources. UMass Amherst Energy Transition Institute, *Equitable Energy Transition Planning in Holyoke Massachusetts: A Technical Analysis for Strategic Gas Decommissioning and Grid Resiliency* (December 2023, prepared by Groundwork Data), https://doi.org/10.7275/enzr-5311.

10 Matt Joyce, "The path for gas utility decarbonization in Washington state" (May 28, 2024, NW Energy Coalition), https://nwenergy.org/featured/path-for-gas-utility-decarbonization-in-washington-state/ and Puget Sound Energy, "Facts about HB 1589," Press Release (March 29, 2024), https://www.pse.com/en/press-release/details/Facts-about-HB-1589.

11 MA Department of Public Utilities, Order on Regulatory Principles and Framework, DPU 20-80-B (December 6, 2023), p. 101, https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/18297602.

12 CA Public Utilities Commission, "CPUC creates new framework to advance California's transition away from natural gas," News and Updates (December 1, 2022), https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-creates-new-framework-to-advance-california-transition-away-from-natural-gas.

# D. Modeling the impact of SMP curtailment

There is a strong possibility that the current SMP investigation will result in limitations on the SMP's scope and spending. This would be consistent with the ICC's heightened regulatory scrutiny and concerns about the rising costs of system modernization, mounting stranded asset risk, and the prospect of historically unprecedented rate hikes. Any reductions in capital spending for gas infrastructure would have financial implications for Peoples Gas and its parent company.

To assess the implications of curtailed SMP spending, we model two possible capex reduction scenarios. These could be achieved by implementing some or all of the following strategies:

- Prioritizing and managing the replacement of the highest-risk mains and service lines.
- Strategic decommissioning, starting with the end nodes of the distribution system and progressing to additional segments as needed.
- Scaling up of specific non-pipeline alternatives, such as thermal energy networks or targeted electrification.
- Targeted pipeline repairs using advanced technologies such as liners that can extend the life of some pipes by decades.

The first scenario – SMP@75% – models a 25% reduction in the PGL's proposed Full SMP spending. We assume the reduction occurs in 2025 and the reduced capex level is then held constant through 2040. The second scenario – SMP@50% – models a 50% reduction in SMP spending levels that is then held steady through 2040. As in our Full SMP modeling, we assume a constant annual rate of non-SMP capital spending of $116 million. We model each scenario under both a stable and declining customer base (2% annual decline).

## 1. Curtailed SMP with a stable customer base

Table 5.1 and Figure 5.2 summarize the key modeling results for the two restricted spending scenarios, assuming a stable customer base, and also provide a comparison with the corresponding Full SMP results.

Our key modeling findings are as follows:

- **Average delivery costs and revenue requirement.** Curtailed SMP spending reduces PGL's revenue requirement and, therefore, average delivery costs per customer. Compared to Full SMP, 25% and 50% SMP reductions over the period 2025 to 2040 reduce the increase in average delivery costs per customer from 100% to 77% and 53%, respectively. SMP@50% would require a 3.6% year-over-year increase in revenue requirement (and therefore customer rates) whereas SMP@75% would require a 5.2% increase, compared to a 6.7% increase for the Full SMP option.
- **Cumulative capital expenditures.** By 2040, Full SMP would require capital expenditures of nearly $13 billion whereas the 75% and 50% scenarios would require $10 billion and $7.6 billion, respectively.
- **Unrecovered balances.** Curtailed SMP spending results in lower levels of unrecovered balances by 2040: $7.9 billion and $9.8 billion for the 50% and 75% SMP scenarios, respectively, compared to $11.8 billion for Full SMP.
- **Annual operating income.** As SMP spending is curtailed, PGL's annual operating income or earnings before interest and taxes (EBIT) necessarily declines. Under Full SMP, PGL's operating income increases by an average of 8% per year between 2025 and 2040, reaching $741 million in the last year. Under the 75% and 50% capex scenarios, annual increases in operating income decline to 6% and 3.5%, respectively. Compared to Full SMP in 2040, operating income is 17% lower in the 75% capex scenario and 33% lower in the 50% capex scenario ($741 million vs. $618 million and $497 million, respectively).

**Table 5.1: Modeling results for restricted SMP scenarios compared to Full SMP with a stable customer base ( 2.5% annual inflation factor assumed)**

| | | 2025* | 2030 | 2040 |
|---|---|---|---|---|
| **Cumulative capex** | **Full SMP** | $663M | $4,234M | $12,847M |
| | **SMP @ 75%** | $526M | $3,361M | $10,199M |
| | **SMP @ 50%** | $390M | $2,488M | $7,550M |
| **Annual revenue requirement*** | **Full SMP** | $1,069M | $1,408M | $2,149M |
| | **SMP @ 75%** | | $1,322M | $1,895M |
| | **SMP @ 50%** | | $1,236M | $1,640M |
| **Cumulative revenue requirement*** | **Full SMP** | $1,069M | $7,427M | $25,497M |
| | **SMP @ 75%** | | $7,171M | $23,500M |
| | **SMP @ 50%** | | $6,914M | $21,493M |
| **Average delivery cost per customer*** | **Full SMP** | $1,206 | $1,588 | $2,424 |
| | **SMP @ 75%** | | $1,491 | $2,138 |
| | **SMP @ 50%** | | $1,394 | $1,849 |
| **Unrecovered balances** | **Full SMP** | $5,183M | $7,379M | $11,789M |
| | **SMP @ 75%** | | $6,720M | $9,839M |
| | **SMP @ 50%** | | $6,062M | $7,900M |
| **PGL projected annual operating income (EBIT)**** | **Full SMP** | $326M | $464M | $741M |
| | **SMP @ 75%** | | $422M | $618M |
| | **SMP @ 50%** | | $381M | $497M |

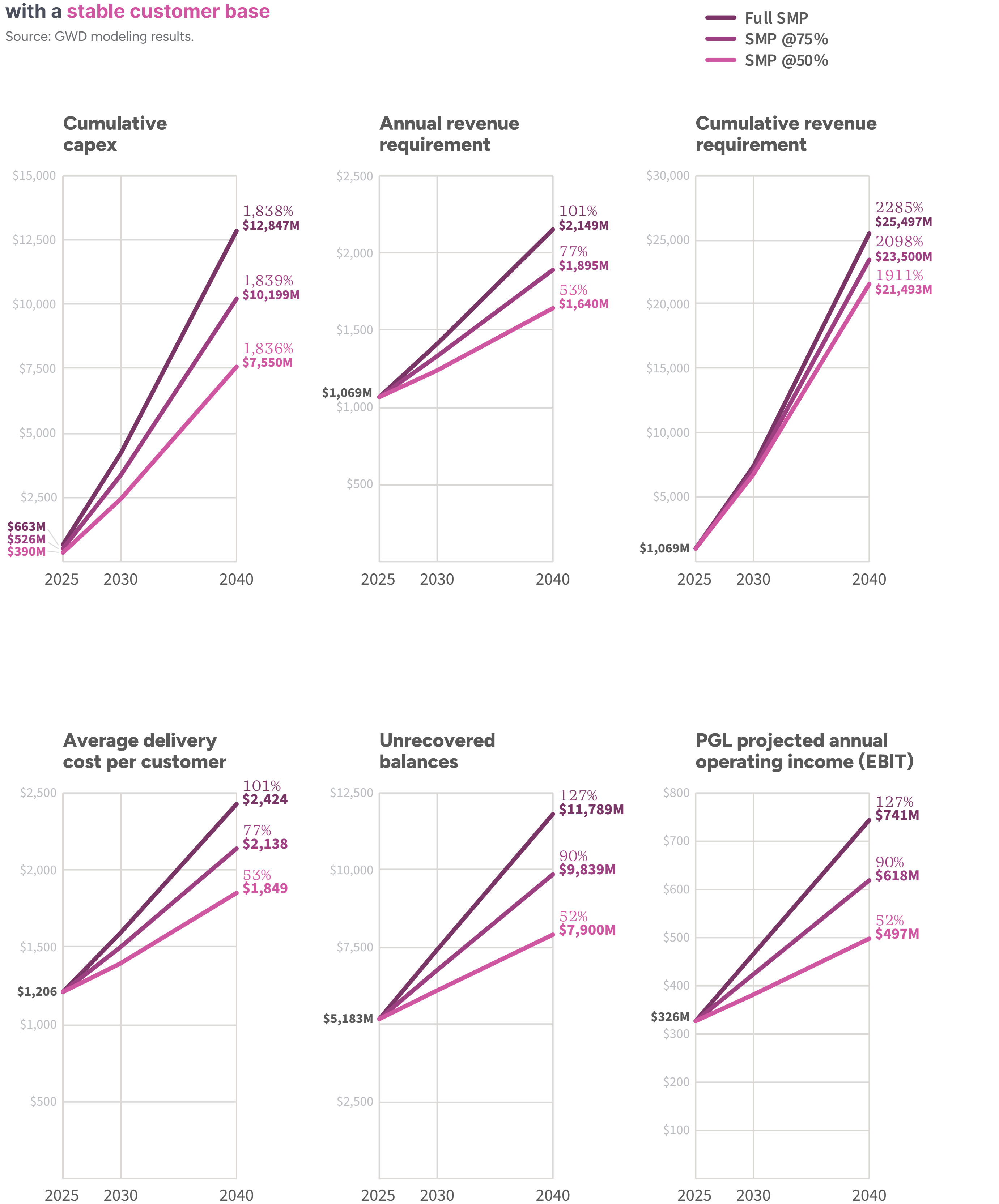
* For 2025, with the exception of cumulative capex, the differences in the starting values for each variable are sufficiently minimal that they can be presented as the same value.

** We treat annual operating income and Earnings Before Interest and Taxes (EBIT) as equivalent. This is because, in the context of utility financial statements, operating income is typically defined as total revenue minus operating expenses, excluding non-operating income, interest expenses, and taxes. EBIT, by definition, also represents earnings before the deduction of interest and taxes, aligning it with operating income in the case of a regulated utility. Therefore, for the purposes of our analysis, these two metrics are interchangeable and provide a consistent measure of the company's profitability from core operations.

Source: GWD modeling results.

**Figure 5.2:** **Modeling results for restricted SMP scenarios compared to Full SMP with a stable customer base**

Source: GWD modeling results.

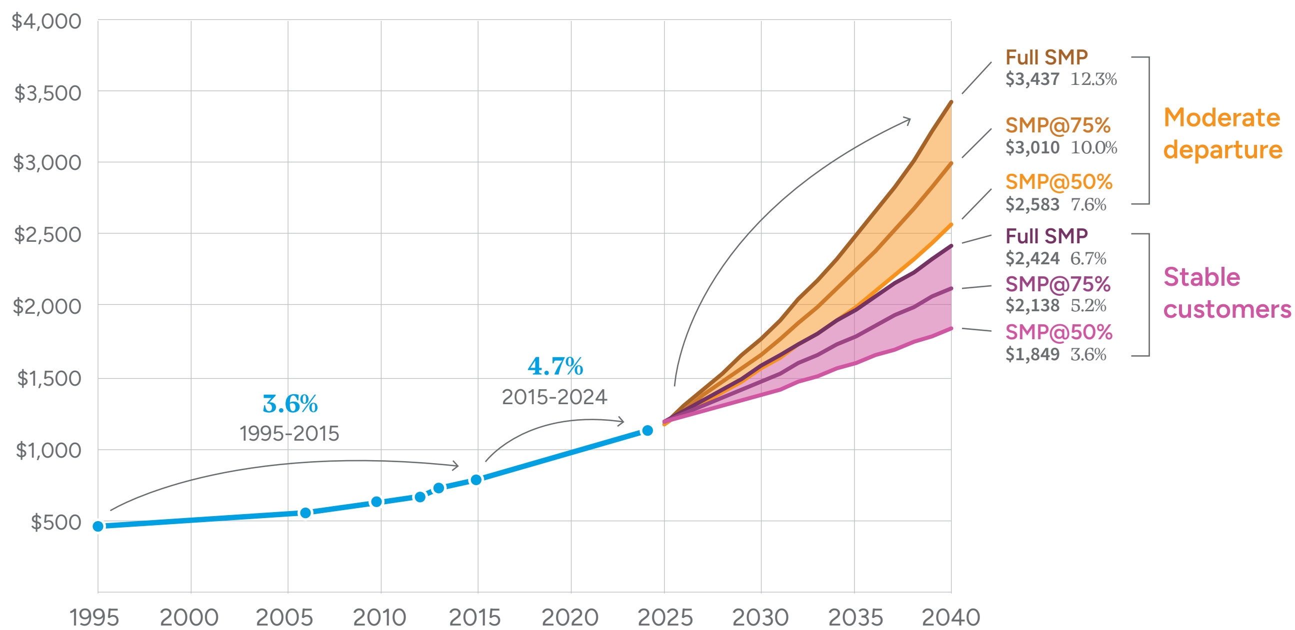


## 2. Curtailed SMP with a moderately declining customer base

The last step in our modeling is to investigate the impact of a moderate rate of gas customer decline. As for the Full SMP scenario, we assume a 2% year-over-year decline resulting in a 50% contraction in PGL's gas customer base by 2050. Under moderate customer decline, curtailed SMP spending (ranging from 25% to 50% reduced capex) increases annual average delivery costs per customer by 4-5 percentage points from 2025 to 2040, compared to a stable customer base.

Under SMP@75%, average delivery costs per customer would rise by 150% over the period 2025 to 2040. Under SMP@50%, they would increase by 114%. These accelerating delivery costs would require year-over-year increases in delivery charges of 10.0% and 7.6%, respectively. While these rate increases would not be as steep as those required under Full SMP with a declining customer base, they would still far exceed the recent historical trend rate of 4.7% for the period 2015-2024 (see Figure 5.3 and Table 5.2).

**Figure 5.3: Average delivery costs per customer: historical trends vs. future scenarios**




Source: GWD modeling results. Note: Percentages refer to average year-over-year increases in delivery costs per customer.

**Table 5.2: Annual delivery charge increases required by Full SMP vs. restricted SMP with moderate customer decline**

| | | 2025 | 2030 | 2040 | % change 2025 - 2040 |
|---|---|---|---|---|---|
| **Average delivery cost per customer** | **Full SMP** | $1,206 | $1,789 | $3,437 | 185% or 12.3% per year |
| | **SMP @ 75%** | $1,206 | $1,679 | $3,010 | 150% or 10.0% per year |
| | **SMP @ 50%** | $1,206 | $1,570 | $2,583 | 114% or 7.6% per year |

Source: GWD modeling results.

# E. Other key findings

Two other findings from our analysis deserve mention.

## 1. PGL's significant O&M expenses

Regardless of whether and how SMP spending is curtailed, PGL's operations and maintenance (O&M) expenses are a significant driver of the company's future revenue requirement needs.[185] In its 2023 rate case decision, the ICC approved annual O&M expenses of $359 million[186] and we carry those forward in our modeling with a conservative escalation factor of 2.5%. Actual increases could be higher, particularly given the operational impact of the new PHMSA LDAR regulations expected to take effect in 2025 (see Section 4.C for more on PHMSA's proposal for revised LDAR regulations). In addition, O&M may increase if reduced SMP capex is offset by expenditures on non-pipe alternatives that are treated as O&M (e.g., pipeline repairs and renewal) as opposed to capital spending. (Note: our modeling does provide for a decrease in O&M as customers exit the system.)

## 2. Unaffordability and uncollectibles

In its 2023 rate case order decision, the ICC stated that "the evidence in the record shows that Peoples Gas' and North Shore Gas' current and proposed rates are unaffordable for substantial numbers of financially struggling customers…" and that a significant portion of NS-PGL customers have considerable energy burdens.[187] The ICC maintains an online credit, collections, and arrearages dashboard that consistently shows high numbers of PGL customers who are behind on their bills and assessed late fees.[188]

The exposure of PGL and its parent company to "credit losses" is attenuated, if not eliminated, by regulatory mechanisms that allow the company to "socialize" written-off revenues due to uncollectibles. WEC Energy states that "at December 31, 2023, $914.6 million, or 60.8%, of our net accounts receivable and unbilled revenues balance had regulatory protections in place to mitigate the exposure to credit losses."[189] In 2023, PGL's uncollectibles totaled $54.2 million and constituted 5% of the company's total gas service revenues. The company recoups these uncollectibles via base rate payments that include rate recovery for uncollectibles plus a specific rider – the Uncollectible Expense Adjustment (UEA) Rider – that recovers the difference between actual uncollectible write-offs and the amounts recovered in rates. These cost recovery regulatory protections for uncollectibles bolster PGL revenue and increase cash flow.

In addition, PGL receives payments from the federal bill assistance LIHEAP program. These totaled $51 million during 2021-22.[190] These public bill assistance subsidies help significant numbers of low-income gas customers stay on the gas system and afford their bills but they also implicitly support PGL throughput.

In October 2024, a new five-tier discounted low-income rate (LIDR) structure will be implemented by PGL that provides a credit to qualifying low-income customers such that their gas payments (supply and delivery) constitute no more than 3% of their income.[191] The credit is to be paid for by an offsetting rider – Rider LIDA – levied on other ratepayers which is expected to lower uncollectibles and, therefore, customer charges for

185 It is noteworthy that the total costs of the three scenarios through 2040 – as measured by their cumulative revenue requirement – are not wildly different, differing by 16%. The minimum cost is $21.5 billion (for SMP@50%) while the maximum is $25.5 billion (for Full SMP).

186 ICC, 2023 Rate Case for PGL, Consolidated Revised Appendix B to Rehearing Order, Docket No. 23-0069 (May 30, 2024), https://www.icc.illinois.gov/docket/P2023-0069/documents/351184/files/614335.pdf.

187 ICC, 2023 Rate Case for PGL, Docket No. 23-0069, Final Order (November 16, 2023), p. 266, https://www.icc.illinois.gov/docket/P2023-0069/documents/344306/files/601245.pdf.

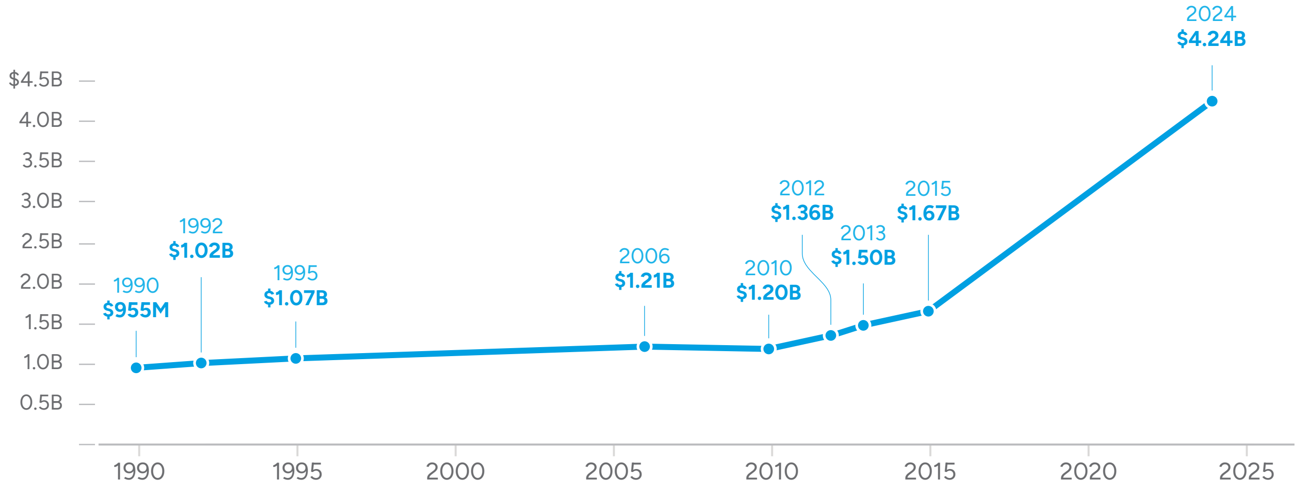
188 During 2023, PGL assessed late fees each month for an average 28% of its residential customers. As of the end of July 2024, residential arrearages with a past due amount greater than 30 days totaled $89.4 million. ICC, Credit, Collections, and Arrearages Reports Monthly Dashboard, https://www.icc.illinois.gov/industry-reports/credit-collections-and-arrearages-reports/monthly-dashboard.

189 WEC Energy Group, *10-K Annual Report to the Securities & Exchange Commission* (February 16, 2024), p. 109, https://investor.wecenergygroup.com/investors/financial-info/sec-filings/sec-filings-details/default.aspx?FilingId=17296303.

190 LIHEAP (Low-Income Home Energy Assistance Program) helps low-income households pay for heat, gas, and electric utilities. Payments are made directly to the energy service providers on behalf of qualifying households. For further description, see ICC, Bureau of Public Utilities, *Low-Income Discount Rate Study Report to the Illinois General Assembly*, (December 2022), p. 22, https://icc.illinois.gov/downloads/public/icc-reports/low-income-discount-rate-study-report-2022-12-15.pdf.

191 ICC, 2023 Rate Case for PGL, Docket No. 23-0069, Final Order (November 16, 2023), p. 265, https://www.icc.illinois.gov/docket/P2023-0069/documents/344306.

**Figure 5.4:** **PGL's approved rate base, 1990-2024**




Source: ICC, Financial Analysis Division, Rate Case Histories, "Gas," (revised July 2024), https://www.icc.illinois.gov/downloads/public/RateCaseHistory.xlsx.
Note: Each dot corresponds to a PGL rate case. The approved rate base includes approved adjustments.

> "At some point, the additional payments levied on non-low-income gas customers in order to socialize the gas system's energy burdens may alter the economics of household electrification and push even more gas customers to leave the gas system."

the uncollectibles rider. Both LIDR and the UEA are examples of rate-class cross subsidization designed to mitigate bill impacts for low-income customers.

Socializing the arrearages revenue deficit via a cap on household energy burden provides an important social protection for low-income households. However, it is unclear how LIDR will fare under the pressures of increasing gas rates due to higher levels of SMP spending, a contracting gas customer base, and declining throughput. At some point, the additional payments levied on non-low-income gas customers in order to socialize the gas system's energy burdens may alter the economics of household electrification and push even more gas customers to leave the gas system.

# F. Modeling implications

The outcome of the 2024 SMP Investigation could be a restricted-scope SMP with lower spending. That possibility is modeled in this section in order to assess its financial and regulatory implications relative to the Full SMP scenario modeled in Section 3. A comparison of the two sets of results leads to the following observations:

1. **Reduced SMP capital spending (modeled as 25% and 50% reductions) is impactful in lowering revenue requirement, cumulative capex, and unrecovered balances.** Looking across the two lower spending scenarios, a smaller revenue requirement decreases the needed increase in gas delivery rates from roughly a quarter to a half. Depending on the scenario, over the 15-year period reduced capital spending avoids $2.6 billion to $5.3 billion in new gas infrastructure assets and avoids $2 billion to $4 billion in unrecovered balances.

2. **Substantial recent increases in PGL's rate base temper the "power" of a circumscribed SMP to have greater impact on the company's revenue requirement and, therefore, on customer rates.** By 2040, a 50% decline in Full SMP results in only a 31% decline in revenue requirement. Figure 5.6 shows the ICC-approved rate base additions that have occurred over the last 30 years. During the recent 2023 rate case – the first since WEC Energy's acquisition of Peoples Gas in 2015 – over $2 billion in SMP spending that occurred outside the rate base under the QIP Rider was moved into PGL's rate base. The financial consequences of completing cost recovery for those new gas plant assets will persist for decades to come and essentially drive cost recovery needs. As underscored in our recent statewide report on the future of gas in Illinois, that capex reductions do not have a greater impact on revenue requirement "reflects the strong "undertow" effect of high levels of capital spending that have been baked into the rate bases of each utility, reflecting prior cost recovery decisions."[192]

3. **PGL's annual operating income and EBIT are positively correlated with SMP spending.** Rate base increases over the last 7 years have pushed up PGL's operating income to new levels. A 50% reduction in SMP spending by 2040 would cause operating income/EBIT to fall by a third.

4. **The moderating effect of significant reductions in SMP spending on customer rates would likely be overwhelmed by the impact of a shrinking gas customer base.** Annual Increases of 8% to 10% in average delivery costs per customer (and therefore rates) would be needed under the scenario of a moderately contracting customer base.

Our modeling of future SMP scenarios shows that, even with significant curtailment of capital expenditures, Peoples Gas customers would face steep annual rate increases in response to customer departures. The magnitude of projected rate hikes even in a reduced-SMP spending paradigm should be a serious concern for the ICC and would constitute a significant business risk for Peoples Gas.

192 Dorie Seavey et al., *The Future of Gas in Illinois* (May 2024, Building Decarbonization and Groundwork Data), p. 9, https://buildingdecarb.org/resource/the-future-of-gas-in-illinois.

# Section 6

# Conclusions

> **"Our analysis finds that resuming the SMP at full funding levels puts Peoples Gas on an unsustainable trajectory with respect to revenue requirements and customer rate increases. In addition, on this path, billions of dollars of additional capital spending on natural gas infrastructure will be subject to cost recovery risk as alternative energy sources gain ground and gas demand inevitably declines."**

**Peoples Gas, one of the oldest continuously operating gas utilities in the United States, has been a cornerstone of Chicago's energy infrastructure for over 150 years, evolving as the city transitioned from wood and coal to manufactured gas, and eventually to natural gas by the mid-20th century.** Today, as a gas-only utility, Peoples Gas is particularly vulnerable to the financial risks posed by shifting customer preferences and decarbonization efforts that increasingly favor electrification. Notwithstanding its historical significance and critical role in the city's development, the company now faces business threats that jeopardize the sustainability of its long-standing business model. These threats include the escalating costs of replacing aging infrastructure; state and city of Chicago mandates and policies related to climate change, health, and safety; and increasing competition from non-gas alternatives.

Peoples Gas and its parent company, WEC Energy, view the indefinite continuation of the gas distribution system as essential to serving their Chicago customers. This belief underpins their commitment to the System Modernization Program (SMP), which aims to replace an additional 1,500 miles of main infrastructure and raise pressure levels in order to "modernize" the system and prepare for the introduction of alternative fuels, which the companies view as having strong potential to decarbonize the city's gas system. Peoples Gas and WEC Energy also assert that their operations will soon be net-zero in terms of methane emissions. Finally, they dismiss electrification as not yet being cost effective or an efficient solution for space and water heating in the Midwest.

This report locates Peoples Gas in a different economic and regulatory reality – one that is both urgent and complex, and subject to growing risk and uncertainty. Our analysis establishes that Peoples Gas has entered a challenging period of mounting competition from clean, non-gas technologies for heating and cooling buildings and for ancillary activities such as cooking and water heating. We do not find scientific or economic support for the proposition that alternative fuels have favorable prospects for heating Chicago's building sector. Instead, Chicago's building sector offers strong prospects for significant "load" shifting from gas to electricity, particularly given the relatively high gas delivery costs of the Peoples Gas system. PGL's territory should be planning for declining gas demand and underutilized infrastructure over the coming decades.

Our analysis finds that resuming the SMP at full funding levels puts Peoples Gas on an unsustainable trajectory with respect to revenue requirements and customer rate increases. In addition, on this path, billions of dollars of additional capital spending on natural gas infrastructure will be subject to cost recovery risk as alternative energy sources gain ground and gas demand inevitably declines.

# A. Main findings

The in-depth modeling analysis conducted for this report investigates the total costs of resuming PGL's SMP at both full-funding and restricted levels (75% and 50% of full funding). We also evaluate the impact gas customer departures on these scenarios. Our main findings are as follows:

1. **Unsustainable rate increases.** Restarting the SMP at full scale would necessitate historically unprecedented rate hikes, even assuming a stable gas customer base. By 2040, the average annual per-customer delivery charge would need to essentially double, increasing from $1,206 to $2,424. Year-over-year rate increases of roughly 7% would be required. This compares with a 4.7% rate of annual increase in actual per customer delivery costs for the recent 2015 to 2024 period.

2. **Impact of a shrinking customer base.** With a moderately declining gas customer base, average delivery costs per remaining customer rise significantly because cost recovery for PGL's escalating rate base must be spread over a shrinking pool of ratepayers. Under Full SMP, customer attrition of 50% by 2050 results in annualized future rate increases of 12%, roughly 2.5 times the year-over-year increases from 2015 to 2024 (4.7%). Such a level of escalation – resulting in a 185% increase in per customer delivery charges by 2040 to $3,437 – would raise serious concerns about long-term affordability and customer retention, both of which are critical to maintaining stable PGL revenue streams. In addition, these levels of rate increases would undoubtedly accelerate customer departure from the gas system.

3. **Limited potential for rate-increase moderation through reduced capital expenditures.** Lower SMP spending will moderate upward pressure on customer rates; however, this effect may be overwhelmed by the impact of a shrinking gas customer base. Even with reduced SMP spending, a declining customer base would still require annual delivery cost increases of 8% to 10%. This suggests that merely scaling back capital investments will not be sufficient to alleviate the financial pressures facing Peoples Gas should customer departures accelerate.

4. **Escalating cost recovery risks.** Continuing Full SMP capital expenditures would expose WEC Energy to significant cost recovery risks (15% of the parent company's asset base is currently attributable to Peoples Gas). Assuming that Full SMP resumes, PGL's unrecovered balances would surge by 127%, reaching approximately $12 billion by 2040. Complete cost recovery would not occur until after the year 2100. This sharp rise in stranded asset risk over the next 15 years increases the likelihood of significant financial write-downs, especially if regulators take steps to protect taxpayers from bearing the costs of decommissioning the gas network.

5. **Capital costs that significantly exceed previous annual spending levels.** Given the extensive work remaining, PGL and WEC Energy will need to spend much more annually on the SMP than they previously have or project to spend. To complete the SMP by 2040, annual capital spending would need to increase to $547 million beginning in 2025 compared to the historical annual average SMP spending level of $280 million.

6. **Heightened regulatory intervention.** Recent actions by the ICC, coupled with the sunsetting of the QIP Rider, have introduced new regulatory challenges for Peoples Gas that have begun to alter the company's investment risk profile. Peoples Gas has been adversely impacted by these regulatory decisions, including a negative credit review from Moody's Ratings, a subsequent decline in WEC Energy's stock price, and capital spending disallowances. While the outcomes of two critical dockets are pending (the 2024 SMP Investigation and ICC's Future of Gas proceeding), it is clear that Peoples Gas must now operate in a regulatory environment predicated on heightened scrutiny, a focus on decarbonization, and concern about the rising costs of system modernization.

7 **Inadequate strategic response.** Peoples Gas and WEC Energy's current plans do not adequately address the looming threats to their gas utility business model and, therefore, do not adequately allow investors to assess the financial and operational risks associated with a shrinking customer base, escalating infrastructure costs, and regulatory pressures. PGL states that it has not conducted an analysis of Chicago's future energy consumption patterns. Such an analysis is essential and would ideally be coordinated with the city's electric utility, Commonwealth Edison, allowing for the modeling of reasonable scenarios for the uptake of efficient, non-gas technologies by the building sector. In addition, while PGL asserts that a critical role of the SMP is to carry alternative fuels, PGL has not provided feasibility and/or cost/benefit analyses related to decarbonizing the city's gas system by blending in RNG and/or hydrogen.

8 **Future infrastructure challenges.** The scope of system modernization planning put forward by Peoples Gas is confined to the next 15 years and excludes the substantial amounts of pipeline that will be in need of replacement after the SMP concludes. For example, by the 2050s, an additional 1,000 miles of distribution mains installed in the 1980s and 1990s will be queuing up for replacement. If the Peoples Gas system is to be continued indefinitely, then the Chicago gas territory needs a comprehensive, viable plan for the future of gas not just for the duration of the SMP but through the end of the century.

# B. Investor risks and strategic implications

PGL's current trajectory raises significant strategic concerns for WEC Energy and its investors, given the financial and operational challenges outlined in this report. While Peoples Gas has historically delivered strong financial results, mounting risks threaten to negatively impact its financial performance. The long-term sustainability of PGL's operations in Chicago is in question, with potential repercussions that extend beyond Peoples Gas to the broader financial health and creditworthiness of the parent company, requiring investors to carefully assess how evolving regulatory, financial, and market risks might impact WEC Energy's future stability and profitability.

## Regulatory risks

- **Sunsetting of the regulatory mechanism allowing for accelerated cost recovery.** Accelerated cost recovery played a pivotal role in sustaining PGL's earnings but it expired in December 2023. As a result, future cost recovery efforts will likely take place in more frequent and potentially contentious rate cases, introducing greater financial uncertainty for Peoples Gas. Longer lag times for cost recovery may negatively impact PGL's future cash flows.
- **Potential reductions in earnings.** Any curtailment of the SMP by the ICC, so as to limit rate increases or curb stranded asset risk, would reduce PGL's earnings. We estimate that a 50% reduction in a fully-funded SMP would result in a 33% decrease in the company's EBIT by 2040.
- **Frequent rate increases.** Chicago's gas delivery rates are already among the highest in the nation and substantial PGL rate hikes could exacerbate affordability issues, particularly for low-income and energy-burdened customers. The need for rate increases that significantly exceed historical trends is likely to lead to regulatory and possibly legislative intervention which would present risk for investors.

- **Additional regulatory intervention.** With limited relief achievable through reduced capital expenditures alone, additional regulatory actions, such as more stringent prudency reviews, are more likely.

## Market risks

- **Shrinking customer base.** As gas delivery costs rise and the competitiveness of electric alternatives improves, gas customer attrition is likely to accelerate. This could trigger a negative feedback loop where further departures increase the financial burden on remaining ratepayers and undermine cost recovery efforts. For Peoples Gas, a shrinking customer base will increase cash flow uncertainty and put downward pressure on profitability, potentially adversely affecting net present value.
- **Elevated cost recovery and stranded asset risk.** Continuation of a full-scope SMP could see unrecovered balances in PGL's rate base reach approximately $12 billion by 2040. Coupled with the potential for customer departures and uncertainty about the magnitude of PGL's obligations for retiring or decommissioning gas assets, Peoples Gas faces enhanced risk of not recovering the capital it has invested in the gas system.

## Credit Risks

- **Potential credit downgrades.** Unstable rating outlooks for Peoples Gas have already begun. Actual credit downgrades are a serious possibility given the combined pressures of pending regulatory dockets and decisions, high gas system infrastructure costs, and declining gas demand. These would put pressure on WEC Energy's credit rating risk, likely increasing the parent company's cost of capital and eroding investor confidence.

## Strategic misalignment with climate goals and policies

- **Conflict with climate policies.** PGL's strategy of expanding and modernizing fossil fuel infrastructure increasingly conflicts with the aggressive climate goals of the city of Chicago and Illinois. This misalignment exacerbates the risks of regulatory and market pressures as policies may increasingly prioritize the transition away from natural gas for Chicago's building sector.
- **Threat to "solvency" of low-income discount rate (LIDR) structure.** The state's signature climate law, CEJA, mandated the ICC to study how bill impacts for low-income utility customers could be mitigated and gave the ICC authority to file tariffs establishing LIDRs. In October 2024, Peoples Gas will begin implementing a LIDR that caps gas charges at 3% of household income, providing a credit to energy-burdened customers offset by a rider applied to other ratepayers. However, if gas rate increases accelerate due to SMP spending and/or customer departures, LIDR's cross-subsidization of rate classes could become strained, potentially rendering the structure unworkable if it further incentivizes customer departure and attracts financial and political attention.

## C. Final reflection

Peoples Gas and WEC Energy stand at a critical juncture. The risks and uncertainties highlighted in this report underscore the growing challenges of sustaining the financial health and viability of traditional gas utility operations during the energy transition. As regulatory scrutiny intensifies, and as market dynamics evolve in response to shifting consumer preferences and technological advancements, the business model that has underpinned Peoples Gas for over a century is becoming increasingly vulnerable.

The situation that Peoples Gas faces is emblematic of pressures across the nation that mature, incumbent gas-only utilities may encounter as they grapple with rising infrastructure costs, regulatory changes, and competitive threats from disruptive technologies. Decisions made in the near future regarding the financial path of Peoples Gas will provide important lessons for other energy companies confronting similar risks.

For investors, the evolving challenges confronting Peoples Gas serve as a critical reminder of the complexities involved in the ongoing energy transition and the future of gas. It is essential to monitor these developments closely as they could have significant implications not just for WEC Energy but for the broader utility sector.

Section

# 7

# Appendix on Modeling Methodology

**This appendix describes Groundwork Data's Gas Delivery Cost Model and the approach we took to estimating the cost of Full SMP.** Our model allows us to project the annual revenue requirements of Peoples Gas. It also allows us to examine the sensitivity of revenue requirement to changes in both capital spending on gas plant and the size of the company's customer base. In addition, we evaluate the bill impact on ratepayers by calculating the average per customer revenue requirement and then tracking that variable over time.

## Methodology and analytical approach

Groundwork Data's Gas Delivery Cost Model uses a revenue requirement modeling approach that includes both the capital-related costs of utilities and operations-related costs – in other words, we project a full revenue requirement that includes the sum of total return on the utility's gas plant rate base, depreciation, operations and maintenance, and property taxes.

We include the following capital cost components of the revenue requirement:

- Allowed rate of return on rate base (weighted average cost of capital (WACC) for debt and equity)
- Depreciation rates (constructed as a weighted average for the main types of gas plant assets)
- Retirement rates (constructed as a weighted average for the main types of gas plant assets)
- Net salvage rates (constructed as a weighted average for the main types of gas plant assets)
- Property taxes
- Gross-up for state and federal income taxes and bad debt

Gas asset depreciation is determined by three main components: asset service life, net salvage value, and the method of depreciation. Asset service life refers to the period over which an asset is expected to be available for use by the gas utility (its "useful life"). An asset's useful life may be shorter than its physical life. Gas plant investments such as pipeline mains have depreciation schedules that extend about 60 years. Net salvage represents the expected cost recovery needed to remove the pipeline at the end of its service life. (For pipeline mains, net salvage is typically a negative value because the cost of removing the pipe at the end of its useful life exceeds the scrap or "salvage value" that the utility can recover.) This study assumes a straight-line depreciation method which is the standard method for the gas industry. The longer the depreciation schedule, the higher the total rate of return to be collected.

The cost of capital is equal to the return on the rate base, adjusted for the gross-ups and property taxes, multiplied by the rate base, which is the original cost of the utility's gas plant net of accumulated depreciation, retirements, and net salvage value.

Operations and maintenance expenses (O&M) include expenses such as conducting leak surveys, repairing pipelines and meters, right of way surveys, emergency responses to gas odor calls, and general and administrative expenses. They also include supplies and labor not used for plant construction. After conducting a trend analysis of these expenses, we did not observe significant increases in annual O&M spending outside of increases due to inflation. Therefore, we assume O&M expenses track our assumed inflation rate of 2.5%. Note that our model does provide for a decrease in O&M as customers exit the system.

Capital expenditures include spending on four types of gas plant (distribution, transmission, storage, and general plant) across two sources: the System Modernization Program (SMP) and non-SMP capital spending. See the next section for a detailed description of our calculations.

# Estimating capital expenditures for SMP and non-SMP spending

## Baseline SMP annual spending

For the baseline scenario, this analysis assumes that the SMP resumes in 2025 to accomplish what we term "Full SMP. " We define Full SMP as covering the following four-pronged scope of work: a) replacing 1,506 miles of cast iron, ductile iron, and low-pressure mains; b) reconnecting and/or replacing 202,779 services; c) relocating 346,912 meters; and d) installing 30 miles of high-pressure mains. Quantities for (a) come from PGL's 2023 Q4 SMP Quarterly Report, while quantities for (b), (c), and (d) come from PGL's "Peoples Gas and the SMP" report to the ICC.[193]

To estimate the total cost of Full SMP, we use the company's SMP Quarterly Reports to calculate the average unit costs for each of the four Full SMP components over the period for which we have the most detailed data, 2018 to 2023.[194] These calculations average the unit costs found in the relevant SMP subprograms (Neighborhood, Public Improvement, System Improvement, and High Pressure). We discounted data from all SMP Quarterly Reports to 2024$s and calculated the average cost to replace a mile of main ($3,933,793 / mile), the average cost per service ($6,246 / service), the average cost per meter ($2,432 / meter), and the average cost per mile of high-pressure main ($16,643,427 / mile). We then multiply those unit costs by the total units for each of the scope components and then sum to arrive at the grand total. To arrive at an estimate of annual capital expenditures for the full SMP, we divide the grand total by the number of years remaining to complete SMP by the target deadline of 2040 (15 years, inclusive of 2040). This was then escalated to 2025 dollars assuming 2.5% inflation.

## Baseline non-SMP annual spending

Non-SMP spending refers to other capital expenditures made by Peoples Gas on the following types of assets: storage, transmission, and non-SMP distribution infrastructure. For our calculations, we exclude capital spending on intangible plant, plant related to manufactured gas and land rights, general plant, and information technology. Our initial year values for storage and transmission are tied to median spending on these categories for the period 2013 to 2023. The historical values were sourced from PIO Exhibit 1.2 filed in the company's 2023 rate case (the exhibit provides PGL's response to an interrogatory from the Attorney General, Request No. AG 5.03).[195] The source for our baseline estimate of non-SMP distribution spending is a set of estimates for 2024 non-QIP distribution spending provided by Peoples Gas in response to an ICC information request made in the company's 2023 rate case.[196]

These analyses yielded estimates for storage spending of $51,782,176 and transmission spending of $21,296,290. Non-QIP distribution spending was forecast in the interrogatory response to be $40,300,000. The sum of these provides an estimate of $113,378,466 for total non-SMP spending in 2024$s. This was then escalated to 2025 dollars assuming 2.5% inflation.

# Analytical approach

Our analytical approach relies on five steps:

1. **Develop capital cost and rate base projections.** As described above, we used multiple sources to develop a projection of capital spending from 2025 to 2040 for completion of Full SMP, breaking out SMP and non-SMP spending.
2. **Estimate the annual revenue requirement needed to cover PGL's capital spending plus related capital costs and operating expenses.**

193 ICC, 2024 SMP Investigation, Docket No. 24-0081, *Peoples Gas and the SMP: History, Current State, and Alternatives*, PGL Exhibit 2.0, p. 61 & 64, https://www.icc.illinois.gov/docket/P2024-0081/documents/348897/files/609896.pdf.

194 PGL, SMP Quarterly Reports, https://www.icc.illinois.gov/programs/natural-gas-investigations.

195 ICC, 2023 Rate Case for PGL, Docket No. 23-0069, PIO Exhibit 1.2, pp. 3-4. https://www.icc.illinois.gov/docket/P2023-0069/documents/337548/files/588151.pdf.

196 ICC, 2023 Rate Case for PGL, Docket No. 23-0069, Response to REQUEST NO. ICC 1.02, https://www.icc.illinois.gov/docket/P2023-0069/documents/337765/files/588769.pdf.

We rely on the Commission's 2023 rate case orders and related rate case filings to determine our initial base year variables.

3. **Estimate the average utility delivery cost per customer served under various capital investment and customer base scenarios.** Using our annual revenue requirement projections, we calculate the estimated per customer revenue requirement (i.e., the total revenue requirement in each year divided by the total customer base). Our estimates of per customer revenue requirements serve as a consistent, normalized metric for assessing the bill impact to ratepayers.[197]

4. **Calculate the value of unrecovered gas plant balances ("book value").** An unrecovered balance refers to gas assets that have been put into service but have not yet been fully recovered through rates. This balance consists of investments that are still being "recovered" through rates and therefore are not yet fully depreciated. This variable serves as our metric for capital asset risk exposure.

5. **Estimate annual operating income or earnings before interest and taxes (EBIT).** In this report, we use annual operating income as a proxy for EBIT, as it represents the primary component of EBIT and because non-operating contributions, such as income from investments or asset sales, are minimal and infrequent. We derive estimated annual operating income as PGL's return on its rate base before gross ups for federal and state income tax rates and the company's uncollectible expense rate.

We use 2025 as the initial year for our modeling (updating prior-year values to 2025 using a 2.5% inflation factor) and then project the annual revenue requirement in future years. All future values are expressed in nominal dollars and assume a 2.5% inflation rate. It should be noted that our modeling approach implicitly assumes that steady rate increases occur but, in reality, rate increases occur at intervals coinciding with rate case proceedings before the ICC.

**Table 7.1: Data sources and initial values**

| Variable* | Source |
|---|---|
| **Rate base** | 2023 ICC Rate Case Rehearing Order - Appendices |
| **Capital expenditures for SMP and non-SMP** | See section above on "Estimating capital expenditures" |
| **Accumulated depreciation** | 2023 ICC Rate Case Rehearing Order - Appendices |
| **Depreciation, retirement, and net salvage rates** | Gas utility depreciation studies filed in 2023 rate case for PGL |
| **O&M net of production expenses** | 2023 ICC Rate Case Rehearing Order - Appendices |
| **Property/real estate taxes** | 2023 ICC Rate Case Rehearing Order - Appendices |
| **Capital structure** | 2023 ICC Rate Case Final Orders (section on Cost of Capital) |
| **Weighted average cost of capital** | 2023 ICC Rate Case Final Orders (section on Cost of Capital) |
| **Gross revenue conversion factor** | 2023 ICC Rate Case Final Orders - Appendices |
| **Number of customers** | 2023 Rate Case filing Schedule E-5 (Jurisdictional Operating Revenue) |
| **Inflationary factor** | 2.5% applied annually |

*all for 2025 unless otherwise noted

197 An alternative approach is to estimate the future typical customer bills (gas supply charge plus fixed and variable delivery charges) that will be developed through the regulatory ratemaking process.

COLORADO
Energy Office
(/)

# Gas Planning Pilot Community Request for Information

## Background

Colorado **Senate Bill 24-1370 (https://leg.colorado.gov/bills/hb24-1370)**, *Reduce Cost of Use of Natural Gas*, establishes a process for local governments in Xcel Energy gas service territory to explore neighborhood-scale clean heat projects. By using alternative heat sources — such as geothermal, thermal energy networks, or electric heat pumps — these projects will reduce reliance on the natural gas system in new construction and/or existing neighborhoods, saving residents money and lowering building greenhouse gas emissions. These neighborhood-scale clean heat projects can occur in new or existing service areas.

**Contact Information:**
**gov_ceo_policy@state.co.us (mailto:gov_ceo_policy@state.co.us)**

**AVISTA CORP.**
**RESPONSE TO REQUEST FOR INFORMATION**

| | | | |
|---|---|---|---|
| JURISDICTION: | Oregon | DATE PREPARED: | 01/02/2025 |
| CASE NO: | UG 519 | WITNESS: | Tia Benjamin |
| REQUESTER: | CUB | RESPONDER: | Cody Lee |
| TYPE: | Data Request | DEPT: | Natural Gas Dept |
| REQUEST NO.: | CUB – 7 | TELEPHONE: | (509) 495-2129 |
| | | EMAIL: | Cody.Lee@avistacorp.com |

**REQUEST:**

When Avista (or a previous operator of Avista's current gas distribution system in Oregon) initially installed Aldyl-A pipe, what was its assumed useful life?

a. If the useful life varied according to attributes of the pipe (size, purpose, etc.) or its vintage, please provide the useful lives of the pipe for each type and vintage of Aldyl-A pipe.

**RESPONSE:**

It is unknown whether these facilities have reached their initially assumed end-of-life. Due to the age of these facilities and the lack of historical records at the time of installation, Avista is unable to determine or speculate about what the original expectations were around facility end-of-life timeframes.

**UG 519 – CERTIFICATE OF SERVICE**

I hereby certify that, on this 5th day of March 2025, I served the foregoing **CUB OPENING TESTIMONY 300** in UG 519 upon the Commission and each party.

| | |
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Respectfully submitted,

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