

GREEN ENERGY
INSTITUTE
Lewis & Clark Law School

Cole Souder, Staff Attorney
10101 S. Terwilliger Boulevard
Portland, Oregon 97219
Phone: (503)768-6955
E-Mail: csouder@lclark.edu

November 7, 2025

VIA ELECTRONIC FILING TO: PUC.FilingCenter@puc.oregon.gov

Public Utility Commission of Oregon
Attn: Filing Center
201 High St. SE, Suite 100
Salem, OR 97301

RE: UM 2377 – PUC Investigation of Rule C and I, Marginal Cost Study Treatment: Rebuttal and Cross-Answering Testimony and Sponsored Exhibits of Intervenors Climate Solutions, Columbia Riverkeeper, Community Energy Project, Green Energy Institute at Lewis & Clark Law School, and Oregon Environmental Council (“Coalition”).

Dear Filing Center:

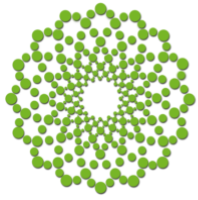
Attached for filing, please find the Coalition’s Rebuttal and Cross-Answering Testimony and sponsored exhibits for the above-referenced proceeding. The consolidated PDF for filing includes testimony and exhibits of Cole Souder (Exhibit Coalition/300–310).

Please feel free to reach out to me directly with any questions about this filing.

Sincerely,

/s/ Cole Souder

Cole Souder
OSB No. 243874
Green Energy Institute at
Lewis & Clark Law School
10101 S. Terwilliger Blvd.
Portland, OR 97219
(503) 768-6955
csouder@lclark.edu



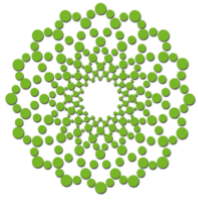
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CERTIFICATE OF SERVICE
UM 2377

I hereby certify that on November 7, 2025, I served CLIMATE SOLUTIONS, COLUMBIA RIVERKEEPER, COMMUNITY ENERGY PROJECT, GREEN ENERGY INSTITUTE AT LEWIS & CLARK LAW SCHOOL, AND OREGON ENVIRONMENTAL COUNCIL'S REBUTTAL AND CROSS-ANSWERING TESTIMONY AND SPONSORED EXHIBITS upon the Commission and each party's representative(s) designated to receive service.

PUC FILING CENTER Filing Center, Public Utility Commission of Oregon P.O. Box 1088 Salem, OR 97308-1088 P.U.C.FilingCenter@state.or.us	PORTLAND GENERAL ELECTRIC JAKI FERCHLAND (C) (HC) 121 SW SALMON ST. 1WTC0306 PORTLAND OR 97204 jacquelyn.ferchland@pgn.com DAVID F WHITE (C) (HC) 121 SW SALMON ST., 1WTC1301 PORTLAND OR 97204 david.white@pgn.com pge.opuc.filings@pgn.com
AWEC ANNA CONGON (C) PEPPLE MOSER PC 107 SE WASHINGTON ST., SUITE 430 PORTLAND, OR 97214 jlb@dvclaw.com CORRINE OLSON (C) (HC) PEPPLE MOSER PC 1750 SW HARBOR WAY, STE. 450 PORTLAND OR 97201 coo@dvclaw.com TYLER C PEPPLE (C) (HC) PEPPLE MOSER PC 107 SE WASHINGTON ST., SUITE 430 PORTLAND, OR 97214 tcp@dvclaw.com	CRITFC ELIJAH CETAS (C) er.cetas@gmail.com ANNETTE CRUZ CRITFC acruz@critfc.org CHRISTINE GOLIGHTLY (C) 700 NE MULTNOMAH STE 1200 PORTLAND OR 97232 golc@critfc.org PATRICK OSHIE Patri50931@aol.com

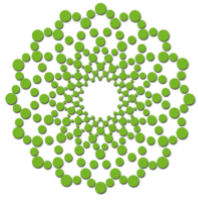


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Lewis & Clark Law School

Cole Souder, Staff Attorney
10101 S. Terwilliger Boulevard
Portland, Oregon 97219
Phone: (503)768-6955
E-Mail: csouder@lclark.edu

STAFF STEPHANIE S ANDRUS (C) OREGON DEPARTMENT OF JUSTICE BUSINESS ACTIVITIES SECTION 1162 COURT ST NE SALEM OR 97301-4096 stephanie.andrus@doj.oregon.gov BRET STEVENS (C) (HC) PUBLIC UTILITY COMMISSION OF OREGON PO BOX 1088 SALEM OR 97308-1088 bret.stevens@puc.oregon.gov	CLIMATE SOLUTIONS, ET AL. CARRA SAHLER (C) GREEN ENERGY INSTITUTE LEWIS & CLARK LAW SCHOOL 10101 S TERWILLIGER BLVD PORTLAND OR 97219 sahler@lclark.edu COLE SOUDER (C) GREEN ENERGY INSTITUTE LEWIS & CLARK LAW SCHOOL 10101 S TERWILLIGER BOULEVARD PORTLAND OR 97219 csouder@lclark.edu
OREGON CITIZEN'S UTILITY BOARD ROBERT JENKS 610 SW BROADWAY STE 400 PORTLAND OR 97205 robert@oregoncub.org dockets@oregoncub.org CLAIRE VALENTINE-FOSSUM (C) (HC) 610 SW BROADWAY STE 400 PORTLAND OR 97205 claire@oregoncub.org RYAN TRAN (C) (HC) 610 SW BROADWAY STE 400 PORTLAND OR 97205 ryan@oregoncub.org	NIPPC SPENCER GRAY sgray@nippc.org MAX GREENE SANGER GREENE PC 4031 SE HAWTHORNE BLVD PORTLAND OR 97214 max@sanger-law.com IRION SANGER SANGER GREENE PC 4031 SE HAWTHORNE BLVD PORTLAND OR 97214 irion@sanger-law.com



**GREEN ENERGY
INSTITUTE**
Lewis & Clark Law School

Cole Souder, Staff Attorney
10101 S. Terwilliger Boulevard
Portland, Oregon 97219
Phone: (503)768-6955
E-Mail: csouder@lclark.edu

DATA CENTER COALITION LUCAS FYKES (C) 525-K EAST MARKET STREET #253 LEESBURG VA 20176 lucas@datacentercoalition.org SIDNEY VILLANUEVA BLUE SKIES LAW LLC 1255 BAYBERRY RD LAKE OSWEGO OR 97034 sidney@blueskieslaw.com	VERRUS LLC JEFF BLADEN VERRUS LLC 918 N RENGSDORF AVE MOUNTAIN VIEW CA 94043 bladen@verrusdata.com SOMMER MOSER PEPPLE MOSER PC 107 SE WASHINGTON ST., STE 403 PORTLAND, OR 97214 sommer@pepplemoser.com
AMAZON DATA SERVICES CAROLINE CILEK DAVIS WRIGHT TREMAINE LLP 560 SW 10TH AVE., SUITE 700 PORTLAND OR 97205 carolinecilek@dwt.com DEREK D GREEN DAVIS WRIGHT TREMAINE LLP 1300 SW FIFTH AVE STE 2400 PORTLAND OR 97201 derekgreen@dwt.com BRITTANY ILES 410 TERRY AVENUE NORTH SEATTLE WA 98109 beiles@amazon.com	

/s/ Cole Souder

Cole Souder

OSB No. 243874

Green Energy Institute

at Lewis and Clark Law School

10101 S. Terwilliger Blvd.

Portland, OR, 97219

(503) 768-6955

csouder@lclark.edu

BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 2377

In the Matter of

PUBLIC UTILITY COMMISSION OF
OREGON

Investigation into Marginal Cost Study
Treatment and Costs for Large Customers and
Further Modifications to Portland General
Electric Company's Rule C and Rule I

CLIMATE SOLUTIONS, COLUMBIA
RIVERKEEPER, COMMUNITY ENERGY
PROJECT, GREEN ENERGY INSTITUTE
AT LEWIS & CLARK LAW SCHOOL, AND
OREGON ENVIRONMENTAL COUNCIL'S
OPENING TESTIMONY

REBUTTAL AND CROSS-ANSWERING TESTIMONY

OF

CLIMATE SOLUTIONS, COLUMBIA RIVERKEEPER, COMMUNITY ENERGY PROJECT,
GREEN ENERGY INSTITUTE AT LEWIS & CLARK LAW SCHOOL, AND OREGON
ENVIRONMENTAL COUNCIL

November 7, 2025

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BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON

UM 2377

In the Matter of

PUBLIC UTILITY COMMISSION OF
OREGON

Investigation into Marginal Cost Study
Treatment and Costs for Large Customers
and Further Modifications to Portland
General Electric Company's Rule C and
Rule I

REBUTTAL AND CROSS-ANSWERING TESTIMONY

OF COLE SOUDER

ON BEHALF OF CLIMATE SOLUTIONS, COLUMBIA RIVERKEEPER, COMMUNITY
ENERGY PROJECT, GREEN ENERGY INSTITUTE AT LEWIS & CLARK LAW
SCHOOL, AND OREGON ENVIRONMENTAL COUNCIL

(Non-Confidential)

November 7, 2025

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I. Introduction

Q. Are you the same Cole Souder who provided Opening Testimony in this proceeding for the Coalition?

A. Yes, I am.

Q. What is the purpose of your Rebuttal Testimony?

A. In this testimony, I respond to the Opening Testimony of the other parties in this docket and provide additional information and evidence in support of the Coalition's recommendations. I also explain adjustments to our recommendations.

Q. Please summarize your Opening Testimony.

A. In my Opening Testimony I first addressed the reasons why residential and commercial customers need protection from new data center load growth and the broader risks data centers present to Oregonians. I discussed my recommendations for PGE's Rules I and C, advocating for a more protective set of policies than the ones PGE proposed in UE 430. I then wrote about the complicated nature of performing energy efficiency at data centers, particularly after a data center has been energized. Finally, I discussed potential pathways to ensure that new data center loads do not prevent PGE from meeting its HB 2021 obligations.

Q. Please describe the structure of your testimony.

A. My testimony is structured into the following sections

- Section I: Introduction
- Section II: Summary of Recommendations
- Section III: Underlying Policy Concerns of Data Centers
- Section IV: Rule I

- Section V: Cost Allocation
- Section VI: Energy Efficiency
- Section VII: HB 2021 Compliance, Green Tariffs, and Special Contracts
- Section VIII: Load Following Credit

II. Summary of Recommendations

I recommend the Commission adopt the following recommendations:

- Section IV: Rule I
 - Minimum Generation Demand
 - 90% of Allocated System Capacity
 - Minimum Transmission Demand
 - 90% of Allocated System Capacity
 - Billed Distribution Demand
 - Keep proposal, except allow for Contributions in Aid of Construction for 100 percent of Cost of Work
 - Exit Fee: The sum of
 - The greater of 1) the remaining Minimum Generation Demand and Minimum Transmission Demand charges for the remainder of the contract, and 2) three years' worth of Minimum Generation Demand and Minimum Transmission Demand payments for the highest Allocated System Capacity during the course of the Customer Service Contract
 - Net book value of the incremental distribution assets caused by the customer
 - Customer Deposit:
 - Amount: 2 years' worth of Minimum Generation Demand and Minimum Transmission Demand payments based on the highest Allocated System Capacity over the course of the contract.
 - Refundable at the end of an LLCA if the customer has exceeded minimum demand for 80 percent of billing periods over the course of the contract and is not in arrears for any payments.
 - Minimum Contract Length
 - 20 MW to 30 MW: 10 years
 - 30 MW+ to 70MW: 15 years
 - 70MW+: 20 years
 - Exceedance Penalty
 - Amount: 4x transmission charge and 1.5x generation charge
 - No Buffer: Exceedance Penalty applies for any exceedance over Allocated System Capacity.
- Section V: Cost Allocation

- Reject PGE’s “primary purpose” methodology for determining if an investment is growth or non-growth related
- Require PGE to apportion an investment’s cost as growth or non-growth depending on the percent of the investment’s cost serving each purpose.
- Require the Company to perform “but-for” analyses in planning documents as a part of determining whether one of the purposes of an investment is to serve load growth.
- Section VI: Energy Efficiency
 - Include a charge of 1 cent/kWh on the tariff for data centers, paid to ETO, to fund non-cost-effective energy efficiency upgrades and “enabling repairs” for ETO’s “priority customers.”
 - Amend Schedule 109 to require all data center customers subject to the POWER Act (Schedule 96 customers) to pay the maximum contribution allowable under HB 3141 between cost-effective energy efficiency under ORS 757.054 and the public purpose charge under ORS 757.612.
 - Require Schedule 96 customers to make filings outlining their monthly energy and water usage for the purpose of allowing ETO, Staff, and Stakeholders to better understand the available pathways towards achieving greater efficiency in existing data centers.
- Section VII: HB 2021 Compliance, Green Tariffs, and Special Contracts
 - If the Commission approves PGE’s special contract proposal
 - Require that any energy sources acquired through a special contract be non-emitting.
 - Require that PGE verify that the energy sources acquired via special contract would not have been resources available via RFP for other customers.
 - The Commission should require, as a term in contracts signed with Schedule 96 customers, that those customers only utilize renewable energy resources and batteries for backup power.
- Section VIII: Load Following Credit
 - The Commission should not allow the Load Following Credit to be extended to any new customers.

III. Underlying Policy Concerns of Data Centers

Q. In your Opening Testimony, you wrote about some of the risks related to data centers. Do you reiterate that testimony here?

A. Yes. Absent policies that protect against cost-shifting, PGE’s other customers will unfairly pay tens of millions of dollars for costs the Company incurs to serve data centers. A recent report showed that about \$4.4 billion in costs related to the transmission needs of data

1 centers were passed along to other customers in PJM territory.¹ These added costs can be
2 debilitating for customers who have already stretched their wallets to pay for rate increases in
3 recent years along with other cost of living increases.

4 **Q. Aren't data centers a necessary component of our technological age?**

5 A. To some extent, yes. Many data centers provide the backbone of the internet, storing
6 the necessary information that allows for the modern technologies we all use like email, file
7 sharing, and webpages. For example, if you have ever streamed a show or movie, the
8 necessary data that allows you to do so is stored in data centers around the world. To that
9 end, the Coalition is not opposed to data centers writ large or their presence in PGE territory.
10 The Coalition's concerns are rooted both in the near term spreading of costs data centers
11 impose on PGE's other customers, and the longer term risk that the data center buildout will
12 leave the utility with tens or hundreds of millions of dollars of stranded assets. Relatedly, on
13 a subject that I address more fully in Section VII on HB 2021, the Coalition is concerned
14 about the sheer scale of load growth PGE is projecting from data centers and the stress that
15 will put on the Company's ability to meet its other goals and obligations.

16 **Q. Why are you particularly worried that data centers will leave customers with**
17 **stranded assets?**

18 A. The scale of the planned investments as well as the fundamental technological and
19 economic underpinning of data centers specifically built to service AI worry me from a
20 stranded asset perspective.

¹ Peter Behr, *Data center boom sparks sticker shock for PJM ratepayers*, E&E NEWS, (Oct. 3, 2025), available at <https://www.eenews.net/articles/data-center-boom-sparks-sticker-shock-for-pjm-ratepayers/>; Ethan Howland, *Customers in 7 PJM states paid \$4.4 billion for data center transmission in 2024: report*, UTIL. DRIVE, (Oct. 1, 2025), available at <https://www.utilitydive.com/news/pjm-data-center-transmission-costs-ratepayers/761579/>.

1 **Q. What will the scale of data center buildout look like?**

2 A. No one knows, and indeed that very question is at the heart of this docket. PGE says
3 it expects to connect 600 MW by 2030 and an additional gigawatt by 2040, but those
4 estimates rise with every load forecast the Company performs.² OpenAI says that it plans to
5 build 30 GW worth of data centers.³ Sam Altman, OpenAI's CEO, stated he would like to
6 begin adding 1 GW of data center capacity a week.⁴ Meta is currently building what it says
7 will be a 5 GW data center in Louisiana.⁵ Previously, Mark Zuckerberg announced Meta's
8 intention to invest \$600 billion dollars on data centers in the U.S. by 2028.⁶

9 Talk is cheap, and there is good reason to think that growth at this scale is not going
10 to happen. Altman is delusional if he thinks OpenAI will be adding 1 GW of data center
11 capacity a week, and a hot mic revealed that Zuckerberg's \$600 billion number was made up
12 to impress President Trump.⁷ This raises an important question, though: If at least some of
13 the public statements of the people driving the data center buildout for AI are clearly bunk,
14 where do the falsehoods end and reality begin? And, more specifically to this docket, what

² Coalition/301, Souder/18.

³ Deepa Seetharaman and Krystal Hu, *Altman touts trillion-dollar AI vision as OpenAI restructures to chase scale*, REUTERS, (Oct. 29, 2025), available at <https://www.reuters.com/sustainability/land-use-biodiversity/altman-touts-trillion-dollar-ai-vision-openai-restructures-chase-scale-2025-10-29/>.

⁴ Matteo Wong and Charlie Warzel, *Here's How the AI Crash Happens*, THE ATLANTIC, (Oct. 30, 2025), available at https://www.theatlantic.com/technology/2025/10/data-centers-ai-crash/684765/?gift=nwn-guseqS6cY1kVeEKZAdaSthtnZy-pwftXDjsd3E&utm_source=copy-link&utm_medium=social&utm_campaign=share.

⁵ Maxwell Zeff, *Mark Zuckerberg says Meta is building a 5 GW AI data center*, TECHCRUNCH, (Jul. 14, 2025), available at <https://techcrunch.com/2025/07/14/mark-zuckerberg-says-meta-is-building-a-5gw-ai-data-center/>.

⁶ Frank Landymore, *Hot Mic Catches Mark Zuckerberg Groveling to Trump*, YAHOO!, (Sept. 8, 2025), available at <https://www.yahoo.com/news/articles/hot-mic-catches-mark-zuckerberg-170531448.html>.

⁷ *Id.*

1 role does PGE have to protect its other customers from the speculation that is occurring at an
2 alarming rate in the attempt to “win” the AI race?

3 **Q. What is the traditional narrative about the risk of stranded assets that data**
4 **centers present for a utility?**

5 A. Traditionally, data centers are thought to present a risk of stranded assets due to their
6 ability to move operations relatively easily. Unlike other forms of industry, data centers don’t
7 rely on complicated supply lines or large specialized equipment. The equipment consists of
8 relatively small chip racks, connected together into an integrated network of computers. But
9 the chips can live anywhere. The fear is that facilities might chase lower energy rates (or
10 available water) into new jurisdictions only a few years after setting up shop in a particular
11 locale, leaving remaining customers on the hook for the infrastructure built to serve their
12 large power needs.

13 **Q. Do you share that concern?**

14 A. Yes, but I am more concerned with a different matter.

15 **Q. What is your main concern that would drive stranded assets related to data**
16 **centers?**

17 A. My main concern relates to the economics of data centers built to serve AI, or
18 “hyperscalers.” Over the past few months, the drumbeat of reports, prognostications, and
19 outright warnings about a data center bubble have shown that the underlying economics of
20 AI call into question the efficacy of throwing hundreds of billions of dollars into the industry.
21 One back-of-the-envelope calculation by hedge fund manager Harris Kupperman estimates
22 that, as an industry, AI will need to bring in about \$400 billion in revenues just to break even
23 on the capital expenditures (capex) made in 2025 alone, and \$1 trillion to break even on the

1 expected capex between 2025 and 2026.⁸ Actually turning a profit might take “many trillions
2 more.”⁹ He notes that Netflix, with its 300 million subscribers, has revenues of about \$39
3 billion, and, if one wants a more business-oriented comparison, Microsoft Office has
4 revenues of about \$95 billion.¹⁰

5 The reason AI requires such astronomical revenues just to break even is the rapid
6 depreciation of its assets. Graphics Processing Units (GPUs) used in AI have, at best, a
7 technological lifespan of about five years.¹¹ One refrigerator-size computing rack of Nvidia
8 chips can cost a few million dollars.¹² Filling a data center with chips can cost over a billion
9 dollars. Even the buildings themselves appear to depreciate quickly because of “changes to
10 cooling systems, chip and racking designs, power systems, and even overall layouts.”¹³ In
11 China, the arrival of DeepSeek, a more efficient form of ChatGPT, stopped a massive AI
12 buildout supported by the Chinese Government in its tracks because the type of data center
13 optimized for model learning are not optimized for inference.¹⁴ And AI products, despite
14 being shoved into nearly every consumer product imaginable, are not being met with

⁸ Harris Kupperman, *An AI Addendum*, PRAETORIAN CAPITAL: KUPPY’S KORNER, (Oct. 5, 2025), available at <https://pracap.com/an-ai-addendum/>.

⁹ *Id.*

¹⁰ Harris Kupperman, *Global Crossing Is Reborn...*, PRAETORIAN CAPITAL: KUPPY’S KORNER, (Aug. 20, 2025), available at <https://pracap.com/global-crossing-reborn/>.

¹¹ *Id.* (stating the depreciation life of a GPU is three to five years); Ed Zitron, *The Case Against Generative AI*, WHERE’S YOUR ED AT, (Sept. 29, 2025), available at <https://www.wheresyoured.at/the-case-against-generative-ai/> (stating lifespan of a GPU is at most five years)

¹² Stephen Witt, *Inside the Data Centers that Train A.I. and Drain the Electric Grid*, NEW YORKER, (Oct. 27, 2025), available at <https://www.newyorker.com/magazine/2025/11/03/inside-the-data-centers-that-train-ai-and-drain-the-electrical-grid>.

¹³ Harris Kupperman, *An AI Addendum*, PRAETORIAN CAPITAL: KUPPY’S KORNER, (Oct. 5, 2025), available at <https://pracap.com/an-ai-addendum/>.

¹⁴ Caiwei Chen, *China built hundreds of AI data centers to catch the AI bom. Now many stand unused*, MIT TECH. R. (Mar. 26, 2025), available at <https://www.technologyreview.com/2025/03/26/1113802/china-ai-data-centers-unused/>.

1 demand. For example, one might expect that, if AI would succeed anywhere, it would be as
2 an add-on to tools businesses already pay for, but that isn't the case: Microsoft 365 Copilot is
3 only being taken up by about 1.8 to 2.7% of customers.¹⁵ A now well-circulated MIT study
4 found that 95 percent of AI pilots developed for businesses are abandoned because they fail
5 to provide benefits for customers.¹⁶

6 The rapid depreciation of facilities presents a unique risk for utilities that spend
7 hundreds of millions of dollars to build facilities with depreciation schedules lasting more
8 than half a century. Put succinctly in the Economist:

9 Data centers are usually financed over decades, but those on the cutting edge of
10 AI may become obsolete far quicker . . . This is partly due to technology: Nvidia,
11 the dominant maker of AI-related graphics processing units (GPUs), relentlessly
12 improves the efficiency of its chips, which may require regular data-centre [sic]
13 upgrades, such as new cooling systems. With land so readily available, a rival
14 data-centre builder with a better, cheaper design can easily set up elsewhere. That
15 raises the likelihood of stranded assets.¹⁷

16 Because of the pace of innovation, at least at the infrastructure and chip level, the actual data
17 centers may become obsolete much more quickly than the energy infrastructure built to
18 power them. One of the myriad ways one can differentiate between a hyperscaler and a
19 traditional cloud-based data center is simply the novelty of the technology (let alone the
20 profitability). Cloud-based data centers have been around since the early days of the internet
21 and have shown that they can be viable customers for decades. We are still in the first wave

¹⁵ Ed Zitron, *The Case Against Generative AI*, WHERE'S YOUR ED AT, (Sept. 29, 2025), available at <https://www.wheresyoured.at/the-case-against-generative-ai/>.

¹⁶ Aditya Challapally, et al., *The GenAI Divide: State of AI in Business 2025*, MIT NANDA, (2025), available at https://mlq.ai/media/quarterly_decks/v0.1_State_of_AI_in_Business_2025_Report.pdf.

¹⁷ *The murky economics of the data-centre investment boom*, ECONOMIST (Sept. 30, 2025), available at <https://www.economist.com/business/2025/09/30/the-murky-economics-of-the-data-centre-investment-boom>.

1 of hyperscalers built for the purpose of AI, with no evidence that these facilities are designed
2 to last longer than a decade.

3 The evidence from China shows the present risk of betting big on the current
4 hyperscaler buildout. It appears that when DeepSeek launched its efficient large language
5 model (LLM), the core AI task that was needed shifted from learning to inquiry, a
6 completely different task with different computational needs. As a result, about 80 percent of
7 China's newly built computing resources are sitting unused.¹⁸ Should we expect the same
8 result here? Probably not, at least not to the same degree, but the underlying concern is
9 directionally true—in ten years, all the data centers built to perform learning will not be well-
10 suited to perform inference, and the ones that are well-suited to perform inference-based
11 tasks today will be outcompeted by newer facilities built with newer GPUs, more efficient
12 cooling technology, and optimized floorplans. Perhaps I am wrong, and on some level I hope
13 that I am, but the evidence we have today is that the hyperscaled data centers built before the
14 end of the decade will not be the ones in use by the end of 2040.

15 But AI succeeding is not, in my opinion, necessarily a better outcome. Matteo Wong
16 and Charlie Warzel, writing for *The Atlantic*, summarized my feelings well:

17 Boom and bust can feel like two sides of the of the same coin: Consider also that
18 if AI companies deliver on their massive investments, it would likely mean
19 producing a technology so capable and revolutionary that it wipes out countless
20 jobs and sends an unprecedented shock wave through the global economy before
21 humans have time to adapt. (Perhaps we will be unable to adapt at all.) If they
22 fail, there will likely be unprecedented financial turmoil as well.¹⁹

¹⁸ Caiwei Chen, *China built hundreds of AI data centers to catch the AI boom. Now many stand unused*, MIT TECH. R. (Mar. 26, 2025), available at

<https://www.technologyreview.com/2025/03/26/1113802/china-ai-data-centers-unused/>.

¹⁹ Matteo Wong and Charlie Warzel, *Here's How the AI Crash Happens*, THE ATLANTIC, (Oct. 30, 2025), available at https://www.theatlantic.com/technology/2025/10/data-centers-ai-crash/684765/?gift=nwn-guseqS6cY1kVeEKZAdaSthtnZy-pwftXDjsd3E&utm_source=copy-link&utm_medium=social&utm_campaign=share.

1 The sentiment is not unique to Wong and Warzel. Here's Eric Lutz writing for *Vanity Fair*:

2 If the frenzied investment in artificial intelligence is overheated, as even
 3 OpenAI's Sam Altman has warned, the markets could be hit hard enough to shake
 4 the economy as a whole . . . But if the gamble pays off, it'll mean a boom for a
 5 technology that could bring about widespread unemployment and social
 6 disruption.²⁰

7 And here is Brian Phillips for *The Ringer*:

8 A sharp contraction in tech would put tens of thousands of people out of work,
 9 vaporize trillions in investment dollars, torpedo retirement and education funds,
 10 obliterate life savings, and ruin lives. It would be a violent shock to a system
 11 that's already under strain. Of course, one of the reasons the economy is under
 12 strain is the massive concentration of wealth in the hands of a small number of
 13 oligarchs, and those same oligarchs would like to use AI to replace the human
 14 labor force—likely putting tens of thousands of people out of work, vaporizing
 15 non-oligarchic wealth, obliterating savings, etc. It may be better for the world for
 16 the bubble to pop, whatever damage is done.²¹

17 **Q. How does this skepticism influence your recommendations?**

18 A. The Commission has repeatedly spoken about its focus on pursuing “least regrets”
 19 pathways to meet our collective goals of safety, reliability, affordability, and emissions
 20 reductions. I see the least regrets path as one that is comparatively protective of customers
 21 and willing to pump the brakes (to the extent allowable under the regulatory compact) on the
 22 rush to build hyperscaled data centers in PGE territory. I do not see a scenario where the
 23 Commission will regret approving more protective policies for PGE's other customers to
 24 minimize the risk that new data center customers, with their unprecedented demand for
 25 electricity to power an unprofitable new technology, will not be around in 30 years to pay for

²⁰ Eric Lutz, *The Double Bind of the AI Bubble Means We're Screwed Whether the Tech Succeeds or Fails*, VANITY FAIR, (Nov. 3, 2025), available at <https://www.vanityfair.com/news/story/ai-bubble-double-bind>.

²¹ Brian Phillips, *How Catastrophic Is It If the AI Bubble Bursts? An FAQ*, THE RINGER (Nov. 4, 2025), available at <https://www.theringer.com/2025/11/04/tech/ai-bubble-burst-popping-explained-collapse-or-not-chatgpt>.

the resources PGE builds in the next decade. As a matter of public policy, the Commission should approach these new loads with caution and skepticism.

IV. Rule I

Q. Summarize your recommendations related to Rule I and Rule C?

A. The Coalition makes the following recommendations regarding PGE's Rule I:

- Minimum Generation Demand
 - 90% of Allocated System Capacity
- Minimum Transmission Demand
 - 90% of Allocated System Capacity
- Billed Distribution Demand
 - Keep proposal, except allow for Contributions in Aid of Construction for 100 percent of Cost of Work
- Exit Fee: The sum of
 - The greater of 1) the remaining Minimum Generation Demand and Minimum Transmission Demand charges for the remainder of the contract, and 2) three years' worth of Minimum Generation Demand and Minimum Transmission Demand payments for the highest Allocated System Capacity during the course of the Customer Service Contract
 - Net book value of the incremental distribution assets caused by the customer
- Customer Deposit:

- 2 years' worth of Minimum Generation Demand and Minimum Transmission Demand payments at the highest Allocated System Capacity over the course of the contract.
- Refundable at the end of an LLCA if the customer has exceeded minimum demand for 80 percent of billing periods over the course of the contract and is not in arrears for any payments.

- Minimum Contract Length

- 20 MW to 30 MW: 10 years
- 30 MW+ to 70MW: 15 years
- 70MW+: 20 years

- Exceedance Penalty

- Amount: 4x transmission charge and 1.5x generation charge
- No Buffer: Exceedance Penalty applies for any exceedance over Allocated System Capacity.

Q. Why have you updated your recommendation to set the minimum demand charge for generation at 90% of allocated capacity?

A. In Opening Testimony, I advocated for a Minimum Generation Demand charge for at 80% of Allocated System Capacity until 2040. Here, I update that recommendation to simply set the Minimum Generation Demand at 90% of Allocated System Capacity.

Staff correctly pointed out in Opening Testimony that the level at which to set a minimum billed demand is subjective.²² Contrary to the Data Center Coalition's (DCC)

²² Staff/100, Stevens/45.

1 request that PGE should “undertake quantitative analyses”²³ to set its minimum demand
2 percentage, the percent the Commission sets will be reflective not of an objective metric but
3 rather a subjective desire to be more or less protective of other rate classes. Tellingly, the
4 DCC didn’t provide any indication of what quantitative factors PGE should look at to
5 determine a proper minimum demand level.

6 Looking at PGE’s attempt to tether its 80% threshold to a quantitative factor (the
7 Company’s minimum load factor for Schedule 90 customers) shows why quantitative
8 analyses would not help the Commission set a proper minimum billed demand threshold.
9 PGE’s methodology assumes that there is a relationship between a proper minimum billed
10 demand and the load factor of a customer (or customer class). But the concept of a minimum
11 billed demand exists to ensure that, despite a company’s actual usage, a certain amount of
12 cost-recovery is guaranteed so that other customers aren’t stuck paying for equipment built to
13 serve a specific customer or class of customers. It protects against the potential problem of
14 overestimated load. Take two hypothetical customers, each allocated 100 MW. Customer A
15 has a load factor of 100%, and in fact uses exactly 100 MW 24/7/365. Customer B has a load
16 factor of 70% and a peak demand that fluctuates wildly between 50 MW and 100MW. Under
17 PGE’s assumptions, Customer A (and customers like it) should have a minimum billed
18 demand of 100%, and Customer B should have a minimum billed demand of 70%. But, as far
19 as the purpose of a minimum billed demand goes, Customer A presents no problem from a
20 cost-shifting perspective—the customer has correctly identified its need and would pay the
21 same amount regardless of the existence of a minimum billed demand charge. Customer B,
22 on the other hand, is exactly the type of customer that requires a minimum billed demand

²³ DCC/100, Fykes/6.

1 provision. This example shows that basing the minimum billed demand on load factor does
2 not actually tether the terms of the policy itself to the purpose of the policy.

3 In theory, a proper minimum billed demand would simply be 100%. As PGE has
4 noted, it plans to have available transmission, distribution, and generation resources beyond
5 the level allocated to a specific customer to allow for fluctuations in a customer's usage.²⁴ If
6 customers are causing PGE to have at the ready the resources to not just meet allocated
7 capacity, but exceed that capacity, then those customers should be responsible for paying for
8 the full cost of those resources. Recognizing, however, that "forecasts will never be perfect,
9 and some amount of buffer is necessary to ensure that very large customers are not
10 unreasonably penalized for deviations from the forecast," a ten percent buffer (i.e., a
11 minimum billed demand of 90%) strikes an appropriate balance between the practical
12 realities of large loads and the needs of other customers.²⁵

13 Given that no "percentage" is inherently correct, the Commission should err on the
14 side of a higher minimum billed demand for two reasons. First, the Commission should be
15 more protective of PGE's other customers from large loads like data centers. The risks data
16 centers present to customers are myriad, and not just limited to the risk of a higher electric
17 bill, as noted previously. Second, as outlined in my Opening Testimony, a higher minimum
18 billed demand will offer a stronger incentive for new customers to properly estimate their
19 capacity needs and reduce the risk of overestimated load.²⁶ Load growth in PGE's territory
20 makes not just the job of rote utility service more complicated, but also the task of

²⁴ Coalition/108, Souder/1.

²⁵ *In the Matter of PACIFICORP, dba PACIFIC POWER, Request for a General Rate Revision*,
Docket No. UE 433, Order No. 24-447, at 100 (Dec. 19, 2024), available at
<https://apps.puc.state.or.us/orders/2024ords/24-447.pdf>.

²⁶ Coalition/100, Souder/15–16.

1 compliance with HB 2021. Overestimated load will make PGE's work even more
2 complicated and costly. The Commission should take every opportunity to discourage new
3 customers from further burdening the Company and other customers with speculative load
4 requests.

5 **Q. Staff stated that it is considering a scaling minimum demand for customers.²⁷**
6 **What do you think of that potential policy?**

7 A. The Coalition is open to the concept of a scaling minimum demand. As the Coalition
8 has noted earlier, hyperscalers present additional risks that are more concerning than smaller
9 cloud-service data centers. Although a minimum demand charge is a necessary component
10 for all customers subject to the POWER Act, arguably the impetus to have a higher minimum
11 is greater as data centers get larger.

12 Compare Customer A (20 MW), Customer B (150 MW), and Customer C (300 MW),
13 all with a minimum demand set at 85 percent. The load variance of the customers before
14 dipping below their minimum demand level would be 3 MW for Customer A, 22.5 MW for
15 Customer B, and 45 MW for Customer C. Larger hyperscaler customers, then, could
16 overestimate their load by an amount equal to the size of a full customer subject to the
17 POWER Act. Even a 150 MW customer, could face essentially no penalty while consistently
18 using 130 MW, leaving other customers to bear the costs of the 20 MW deficit—equivalent
19 to an entire facility subject to the POWER Act. Determining the ideal minimum billed
20 demand in terms of the MWs below a customer's Allocated System Capacity rather than as a
21 percent of its Allocated System Capacity may be more equitable between Schedule 96
22 customers and more adequately protective of PGE's other customers.

²⁷ Staff/100, Stevens/48.

1 **Q. What are potential methods of having a variable or scaling minimum demand?**

2 A. The Commission could set a scaling minimum demand in a variety of ways. Staff
3 noted in Opening Testimony that the level could be raised linearly or logarithmically with a
4 maximum at or below 100 percent.²⁸ Under either of these two options, the Commission
5 would likely need to increase the minimum demand on a piecemeal basis to avoid customers
6 having minimum demands of, say, 92.143 percent. Under any scaling system, the first steps
7 should include 1) determining the range of minimum demand levels (the minimum and the
8 maximum minimum demand) and 2) determining at what allocated capacity to apply the
9 maximum minimum demand level. For example, a framework could have minimum billed
10 demands set between 80 and 100 percent of allocated capacity, with 100 percent applying to
11 all customers 100 MW and above. Perhaps obviously, customers at 20 MW would have a
12 minimum demand set at 80 percent of allocated capacity. Then, we would determine the
13 number of scales or steps to take—for this example, four steps, increasing linearly. Under
14 that system, there would be five tranches:

- 15 • Tranche 1: 20 MW to 40 MW, minimum billed demand: 80 percent
- 16 • Tranche 2: 40 MW to 60 MW, minimum billed demand: 85 percent
- 17 • Tranche 3: 60 MW to 80 MW, minimum billed demand: 90 percent
- 18 • Tranche 4: 80 MW to 100 MW, minimum billed demand: 95 percent
- 19 • Tranche 5: Over 100MW, minimum billed demand: 100 percent.

20 Alternatively, the Commission could use something similar to the buffer that PGE
21 proposes as a part of its Exceedance Penalty provision, which sets the buffer at ten percent of
22 Allocated System Capacity up to a buffer of 5 MW. For example, the policy could set the

²⁸ *Id.*

1 minimum demand charge at 90 percent of allocated capacity, not to exceed a difference of 10
2 MW from a customer's Allocated System Capacity. So, customers between 20 MW and 100
3 MW would have a minimum demand set at 90% of allocated capacity and customers over
4 100 MW would have a minimum demand set at 10 MW below their Allocated System
5 Capacity.

6 The Coalition is not currently recommending a scaled approach, but it remains open
7 to it and may have a specific recommendation in future testimony. In any event, if the
8 Commission does adopt a scaling approach, the same methodology should be applied for
9 both Minimum Generation Demand and Minimum Transmission Demand.

10 **Q. You have also updated your proposal regarding the minimum contract length.**
11 **Please explain that proposal.**

12 A. The Coalition recommends that the minimum contract length depend on the size of
13 the data center customer. The Commission should adopt the following set of minimum
14 contract lengths for the following customer groups:

- 15 • 20 MW to 30 MW: 10 years
- 16 • 30 MW+ to 70MW: 15 years
- 17 • 70MW+: 20 years

18 **Q. Why should different customers have different contract lengths?**

19 A. As noted above, the Coalition looks at strategies that address the differences between
20 the relatively smaller customers that are subject to the POWER Act and hyperscalers. To be
21 clear, even a 20 MW facility presents substantial risks of cost-shifting and stranded assets,
22 especially as a class if a half dozen such facilities are connected. But hyperscalers warrant

1 additional protections due to their, well, scale, as well as the fact that those facilities have not
2 proven that they can have useful lives beyond 10 years.

3 In my opinion, the Commission’s decision on the minimum contract length should
4 focus on the likelihood a customer will sign a new contract when its first one ends. Imagine a
5 customer that PGE knew with 100 percent certainty would remain on its system utilizing
6 exactly its Allocated System Capacity for the next 70 years. A minimum contract length
7 would be unnecessary for that customer because it would remain on PGE’s system for the
8 depreciable life of the infrastructure built to serve it and would not leave other customers
9 with stranded assets. On the other hand, a customer that PGE knew with 100 percent
10 certainty would not be signing a second contract would warrant a contract with a very long
11 term because the Company would know that whenever the contract ended, the assets built to
12 serve the customer would be stranded unless a new customer could step into the place of the
13 original customer.

14 As I noted above, those analyzing the economics of data centers have begun to point
15 out that facilities built to serve AI have depreciable lives of around ten years (on the long
16 end) due to the rapid changes to the chips that perform computations and the optimal layouts
17 for operating AI.²⁹ As the experience in China mentioned earlier in this testimony shows,
18 hyperscalers built to serve the “learning” functions of an AI tool may not be well-positioned
19 to serve the inference functions that will become prevalent once (if) AI becomes more

²⁹ Harris Kupperman, *An AI Addendum*, PRAETORIAN CAPITAL: KUPPY’S KORNER, (Oct. 5, 2025), available at <https://pracap.com/an-ai-addendum/>; *The murky economics of the data-centre investment boom*, ECONOMIST (Sept. 30, 2025), available at <https://www.economist.com/business/2025/09/30/the-murky-economics-of-the-data-centre-investment-boom>.

1 prevalent, meaning the centers built in the next five years are unlikely to be the dominant
2 facilities in 20 years.

3 Cloud-based data center businesses have a more proven track record of profitability
4 and relative stability. Amazon Web Services (AWS) famously propped up the company's
5 unprofitable Amazon Prime enterprise for years. In fact, the only thing that seems capable of
6 slowing AWS's profitability is AI.³⁰ Without downplaying the risks that cloud-based data
7 centers also present for other customers, they are at least safer bets to remain on PGE's
8 system beyond the completion of an initial ten-year contract than their larger counterparts.

9 Until hyperscaled data centers have shown that they can withstand competition and
10 market evolutions to remain in place for several decades, the Commission should require
11 longer minimum contract lengths to protect customers from the heightened risk of stranded
12 assets as compared to other, smaller data centers. A ten-year contract does not offer PGE's
13 other customers enough assurance that data centers in the hundreds of megawatts in size will
14 actually pay back a substantial portion of the costs they impose on PGE. Furthermore, the
15 larger the facility, the less likely it is that another customer will be able to assume the
16 abandoned capacity, raising the likelihood that, if a larger customer does not renew its
17 contract, the assets built to serve it will become stranded. I therefore recommend a scaled
18 approach with the following minimum contract lengths:

- 19 • 20MW to 30MW: 10 years
- 20 • 30MW+ to 70MW: 15 years
- 21 • 70MW+: 20 years.

³⁰ Todd Bishop, "Amazon Web Services profits squeezed as AI arms race drives spending surge," GEEKWIRE, (July 31, 2025), available at <https://www.geekwire.com/2025/amazon-web-services-profits-squeezed-as-ai-arms-race-drives-spending-surge/>.

1 **Q. What is PGE’s deposit proposal?**

2 A. PGE proposes a refundable System Capacity Allocation Deposit set at two-years’
3 worth of minimum transmission demand charges.³¹ Customers that have kept up with their
4 bills are refunded half the amount after two years and the remainder after year three.³²

5 **Q. What do you propose regarding the system allocation deposit?**

6 A. The Commission should require the deposit to include two-years’ worth of both
7 minimum transmission demand charges as well as minimum generation demand charges. The
8 Commission should also make the deposit repayable only at the end of a customer’s contract
9 if the customer has met the following two conditions: 1) the customer has achieved at least its
10 minimum demand during at least 80 percent of its billing cycles over the course of its LLCA,
11 and 2) the customer is not in arrears. Finally, the Commission should ensure that the System
12 Capacity Allocation Deposit is based on the largest Allocated System Capacity over the
13 course of the Customer Service Contract.

14 **Q. What is the purpose of the customer deposit?**

15 A. PGE states that the customer deposit is in place to “reduce speculative load requests
16 and encourage customers to make thoughtful, realistic assessments.”³³ Much like the
17 minimum demand provisions, then, the system allocation deposit aims to prevent a customer
18 from overestimating its demand.

19 **Q. Does the refundable nature of the deposit negate the purpose of the deposit?**

20 A. Not necessarily. As long as the deposit is only refundable if a customer meets certain
21 criteria that, if met, would mean the customer did not in fact overestimate its capacity

³¹ PGE/105, Ferchland-Barrow/17.

³² *Id.*

³³ PGE/100, Ferchland-Barrow/35

1 request, the refundability of the deposit would not stifle the deposit's purpose. PGE's
2 testimony indicates there is no need to retain the customer deposit "if a customer meets their
3 minimum demand requirements."³⁴ PGE's proposed Rule I terms, however, state that a
4 customer will lose the deposit only if it has arrearages.³⁵

5 I agree that whether a customer is in arrears is an important metric. But that serves a
6 slightly different purpose, or at least additional, to the one PGE stated in testimony as the
7 basis for the System Capacity Allocation Deposit. Denying a refund because of the existence
8 of an arrearage seems less about ensuring that a customer meets its minimum demand than it
9 is about having a portion of funds available to fill the gap if a customer proves unable to pay
10 its bills. Indeed, a customer could be in arrears even if it has consistently met its minimum
11 demand from a usage standpoint. To be sure, I agree that this is a valid purpose for the
12 deposit, as indicated by my recommendation that the System Capacity Allocation Deposit
13 only be refundable if the customer is not in arrears at the end of its contract.

14 But PGE's Rule I, as proposed in its Opening Testimony, does not sufficiently
15 achieve the stated goal of the System Capacity Allocation Deposit—to avoid speculative load
16 requests. As PGE's Rule I is written, a customer could consistently use less than its Allocated
17 System Capacity, and in fact could use no power at all but still have its deposit refunded so
18 long as it pays its bill. A customer that consistently uses below its minimum demand but pays
19 its bills is not a policy success. While a minimum demand level below 100 percent of
20 allocated capacity recognizes that predicting load with absolute certainty is impossible,
21 consistently collecting payment based only on minimum demand would mean the Company

³⁴ *Id.*

³⁵ PGE/105, Ferchland-Barrow/17.

1 is repeatedly under-collecting from large customers. Put another way, if a customer has only
2 had to make payments based on its minimum demand, it did not “make a thoughtful, realistic
3 assessment[] of [its] capacity needs.”³⁶ It overestimated its demand, likely by a substantial
4 amount, causing PGE to incur additional costs that would then be spread to other customers.

5 **Q. Under what conditions should the system capacity deposit be refunded?**

6 A. A customer should have to meet two conditions before it is refunded its deposit. First,
7 as is currently the case in PGE’s proposed Rule I, the customer cannot be in arrears. Second,
8 the customer should have to have exceeded its minimum demand for some percentage (the
9 Coalition proposes 80 percent) of the billing periods during its contract. The Coalition is
10 open to other suggestions from parties on the proper percentage for that provision. I will
11 note, however, that optimal percentage will depend in part on the level at which the
12 Commission sets minimum demand. A lower minimum demand should warrant a higher
13 threshold to earn a refund of the deposit, and vice versa.

14 **Q. Why should the system allocation deposit include generation charges?**

15 A. Limiting the deposit to only minimum transmission demand charges is a remnant of
16 PGE’s proposal in UE 430, which included a minimum transmission demand charge but not
17 a minimum generation demand charge.³⁷ Now that the parties generally agree that a
18 minimum generation demand charge should be included in the LLCA, any deposit should
19 include both transmission and generation components. As noted above, according to PGE the
20 purpose of the deposit is to “reduce speculative load requests and encourage customers to

³⁶ PGE/100, Ferchland-Barrow/35.

³⁷ See, In the Matter of PORTLAND GENERAL ELECTRIC, Investigation into New Load Connection Costs, Docket No. UE 430, PGE/100, Fagen-Frayer/46 (Dec. 20, 2024), available at <https://edocs.puc.state.or.us/efdocs/HTB/ue430htb333702025.pdf>.

1 make thoughtful, realistic assessments of their capacity.”³⁸ But, as I also argue, the deposit
2 serves an additional purpose to provide other customers with a certain amount of protection if
3 a data center customer consistently fails to meet its Allocated System Capacity. A customer
4 that fails to meet its allocated capacity (i.e., one that consistently pays only the minimum
5 billed demand charges) will saddle other customers with the costs associated with the
6 infrastructure built for its service. The deposit provides some level of additional cost
7 recovery in that scenario, further protecting other customers from the risk of cost-shifting.
8 Thus, a proper deposit would include both a transmission and generation component to
9 account for the fact that a new large customer will impose both transmission and generation
10 costs on the Company.

11 **Q. Why should the deposit only be repayable at the end of the contract?**

12 A. The deposit should only be repayable at the end of the contract to ensure that a
13 customer continues to meet its Allocated System Capacity through the end of the contract
14 term. Under PGE’s scheme, a customer is paid back the deposit by the end of year three of its
15 contract, assuming the customer is not in arrears. But a customer that signs a 10- or 15- or
16 20-year contract may meet its demand requirements in the first few years of a contract, but
17 then dip below that minimum demand in future years.

18 The issue relates back to the disconnect between the length of contracts being
19 proposed in this docket and the depreciation schedules of the infrastructure that will serve the
20 large loads at issue here. As PGE has stated, the purpose of the deposit is to reduce and
21 protect against speculative loads, those that do not consistently use the level of power that
22 PGE has allocated. Under PGE’s deposit proposal, a load is no longer “speculative” so long

³⁸ PGE/100, Ferchland-Barrow/35.

1 as it meets its minimum demand requirements (which, again, the Company seems to define
2 simply as not being in arrears) in the first three years of a contract.³⁹ I disagree. Given that
3 much of the infrastructure built to serve new large loads like data centers will have useful
4 lives spanning six decades, a load that meets its minimum demand requirement for three
5 years has not yet proven that it was not “speculative.”

6 From a long-term investment standpoint, even a load that completes a 10-year
7 contract but then does not contract for power beyond that point should not be refunded its
8 deposit because the load turned out to be speculative. While the Coalition does not take that
9 position at this time, it will continue to consider what the proper refund period should be for
10 a customer deposit.

11 **Q. Please explain your proposal to require that the System Capacity Allocation**
12 **Deposit be based on the higher Allocated System Capacity over the course of the**
13 **contract.**

14 A. The Commission should ensure that customers are paying a deposit based on the
15 maximum Allocated System Capacity allotted over the course of their contract. According to
16 PGE, its proposal allows for ramping Allocated System Capacity, where a customer is
17 allocated more capacity over the course of the contract until they reach some highest level of
18 Allocated System Capacity.⁴⁰ As PGE states: “PGE will prepare a Large Load Customer
19 Agreement for a customer’s requested peak demand. This may include a ramp of allocated
20 system capacity due to availability of capacity (ex. 10 MW in year 1, 20 MW in year 2,
21 etc.).”⁴¹ PGE’s proposed Rule I defines Allocated System Capacity as “the capacity on the

³⁹ *Id.*; PGE/105, Ferchland-Barrow/17.

⁴⁰ Coalition/302, Souder/1.

⁴¹ *Id.*

1 Company's transmission system that is available to reliably serve an Applicant or Customer
2 and that the Company allocates as a result of the system capacity allocation process, which is
3 reflected in the Customer Service Contract."⁴² Rule I section on the System Allocation
4 Deposit states that applicants will only have to make a one-time deposit based on their
5 Allocated System Capacity.⁴³

6 These three components, taken together, create a vague standard that could result in
7 the deposit a customer pays being far too small. As I understand it, a customer only ever pays
8 one deposit based on its Allocated System Capacity at the start of an LLCA. The Allocated
9 System Capacity is the amount of capacity available to serve a customer that PGE has
10 allocated to the customer. So if a customer has a 15-year contract where, over the first 5
11 years, the Allocated System Capacity ramps up from 10 MW to 50 MW, what is the
12 Allocated System Capacity for the purposes of determining the level of the customer deposit?
13 Given that the deposit is two years' worth of minimum demand charges, it stands to reason
14 that the deposit could be based on the customer's allocation in the first two years of the
15 contract. Or it could just be based on the allocation in the first year of the contract. Or it
16 could be based on the maximum allocation over the course of the contract. As it stands, any
17 of those interpretations seem to be reasonable interpretations of the Company's Rule I
18 language.

19 My fear is the fact that the largest potential customers are unlikely to be able to
20 connect to their full capacity in the first year of an LLCA, and therefore will have allocation
21 ramps built into their contracts. The allocations in the early years of the contract may only

⁴² PGE/105, Ferchland-Barrow/1.

⁴³ *Id.*, Ferchland-Barrow/17.

1 account for 25 percent of their final allocation. If that's the case, and customers are only
2 paying deposits that account for a quarter of their actual capacity, PGE will have failed to
3 adequately protect customers from speculative loads and overestimated capacity even by its
4 own stated standards. PGE needs to clarify the customer deposit policy to ensure that
5 customers are paying deposits based on the maximum Allocated System Capacity over the
6 course of a contract.

7 **Q. Has your proposal for the exceedance penalty changed?**

8 A. No. I continue to recommend an Exceedance Penalty of 4x the transmission charge
9 and 1.5x the generation charge. I also recommend that there be no buffer above the
10 customer's allocated capacity before the exceedance penalty applies.

11 **V. Cost Allocation**

12 **Q. What did PGE propose regarding cost allocation for generation and**
13 **transmission?**

14 A. PGE offered essentially the same cost allocation proposal for both generation and
15 transmission. PGE proposes splitting new investments into two buckets: investments to serve
16 load growth and investments that are not serving load growth. Non-growth investments
17 would have no change to their allocation methodology. For growth-based investments,
18 however, PGE proposed a new cost allocation methodology, its Peak Growth Modifier
19 (PGM), rooted in each class's contribution to load growth as opposed to the class's
20 contribution to peak load. PGE recommends a three-year, backward-looking window for
21 determining both revenue-requirement investments (i.e., whether to sort the investment as
22 growth or non-growth) and the PGM components.

1 **Q. What did Staff propose regarding cost allocation for generation and**
2 **transmission?**

3 A. Staff proposed a similar framework for cost allocation for generation and
4 transmission. Like PGE, Staff proposed a preferred framework that splits growth and non-
5 growth investments and then allocated the costs for growth investments on the basis of each
6 class's contributions to load growth. Staff stated that the load growth "could be calculated as
7 the growth since the previous rate case or over a certain period of time, say 5 years and that it
8 could also be inclusive of the Test Year load forecast."⁴⁴

9 To perform the task of separating out growth-related and non-growth related
10 investments, Staff recommended that the Commission require PGE to perform a "but-for"
11 analysis in future planning documents to better understand the impact of new large loads on
12 any preferred portfolio of resources.⁴⁵

13 **Q. Does the Coalition support the proposals of other parties regarding cost**
14 **allocation for generation and transmission?**

15 A. In general, the Coalition is supportive of a cost allocation methodology, or at least the
16 underlying concept of the methodology, that Staff and PGE proposed. Separating growth and
17 non-growth investments and then applying a growth-based cost allocation methodology to
18 growth-based investments does a better job of assigning costs to the rate classes that cause
19 them than the current methodology. As PGE's testimony showed, adopting its new
20 methodology would result in savings for other customer classes, including residential
21 customers, by shifting the costs of new resources onto its (proposed) Schedule 96 customers.

⁴⁴ Staff/100, Stevens/27.

⁴⁵ *Id.*, Stevens/28–29.

1 **Q. Do you have concerns about PGE’s proposal?**

2 A. Yes. I am concerned about the lack of detail in PGE’s proposal. Clearly identifying
3 the factors that the Company and stakeholders will consider in determining whether an
4 investment is growth-related or non-growth related is an important step that should occur in
5 this docket. I understand PGE’s proposal to require that resources be categorized as growth
6 or non-growth related depending on the “primary purpose” of the investment.⁴⁶ According to
7 PGE, the primary purpose determination will be “fact specific and depend upon the
8 individual facts and circumstances.”⁴⁷

9 What worries me is that PGE has not been forthcoming on what factors the Company
10 will use to make its determination. When asked what factors the Company would use to
11 determine if an investment is “growth-motivated,” PGE stated that it “will classify the
12 investment as growth-motivated if the primary driver of the investment is to increase
13 capacity or serve new loads.”⁴⁸ PGE also pointed to a portion of its Opening Testimony that
14 merely reiterates that investments that serve growth will be classified as growth-related and
15 investments that serve other purposes will be classified as non-growth related.⁴⁹

16 The Commission should require PGE to disclose ahead of time its methodological
17 process for determining whether an asset is categorized as growth or non-growth related. The
18 Commission should also require PGE to establish criteria for defining “primary purpose.” As
19 noted above, the Coalition is supportive of the core-concept of the Peak Growth Modifier and
20 the similar proposal Staff put forward, but to be effective the process of making those

⁴⁶ Coalition/303, Souder/1.

⁴⁷ *Id.*

⁴⁸ Coalition/304, Souder/1.

⁴⁹ *Id.*; PGE/100, Ferchland-Barrow/22, lines 4–7.

1 determinations must be transparent, allowing for meaningful engagement from Staff and
2 stakeholders.

3 **Q. What would make the allocation process more transparent?**

4 A. The Coalition supports Staff recommendation that the Company perform “but for”
5 analyses in planning documents in order to “give the Commission and stakeholders a
6 qualitative understanding of the impact of large load customers on the Company’s generation
7 and transmission planning decisions and related costs.”⁵⁰ Beyond the evidentiary
8 transparency that such analyses can foster, beginning the work of categorization during the
9 planning process will give stakeholders a longer timeframe to consider investments and
10 scrutinize PGE’s determinations. Because of the information asymmetry present in utility
11 processes, allowing stakeholders to engage on the question of categorization from the IRP
12 through the RFP and into ratemaking proceedings will help produce more equitable
13 outcomes.

14 I reiterate that any transparent process will rely on establishing the metrics that PGE
15 (and others) will consider in making determinations for investments. The Coalition agrees
16 that the ultimate determination should and will be “fact specific,” but that does not mean that
17 we cannot begin to develop the types of facts and circumstances that the Company plans to
18 look at and how they might influence a future decision.

19 **Q. Do you agree with PGE’s “primary purpose” approach to determining if an**
20 **investment is growth or non-growth related?**

21 A. No. If the purpose of changing the cost allocation methodology is to ensure that costs
22 associated with serving new large loads are not passed to other customers, why would we

⁵⁰ Staff/100, Stevens/28–29.

1 adopt a system that would still allow for costs associated with serving new loads to be spread
2 to other customers? If PGE invests in a new solar field and 60 percent of the purpose of the
3 investment is to reduce emissions for HB 2021 purposes and 40 percent is to serve new load,
4 why should PGE's other customers be saddled with the costs of that 40 percent? Isn't that
5 exactly what we are trying to avoid in this docket?

6 **Q. Wouldn't it be easier to simply determine a project's primary purpose than to**
7 **apportion the costs with some level of specificity between growth and non-growth**
8 **purposes?**

9 A. Not necessarily, or at least not to a meaningful extent. To determine the primary
10 purpose, PGE would first have to determine (to some reasonable estimation) the portion of
11 the project that serves each purpose. Once that's done, PGE could then just take the portion
12 serving new load and put that into the Peak Growth Modifier. We don't have to let the
13 perfect be the enemy of the good in apportioning a resource between its growth and non-
14 growth components—even roughly estimating to the nearest factor of 5 or 10 percent would
15 do a much better job of accurately assigning costs to the causal customers than a primary
16 purpose test.

17 In its Opening Testimony, PGE left unanswered basic questions about how the
18 primary purpose test would work in practice. Take, for example, a transmission project that
19 PGE determined was needed for the following purposes: 30 percent to help connect resources
20 for HB 2021 purpose, 30 percent for system hardening, and 40 percent to serve new load.
21 PGE's proposal does not specify whether the project would be considered growth-related
22 because the plurality purpose of the project is to serve new load, or non-growth related
23 because most of the project is serving a collection of non-growth purposes. Putting aside that

1 PGE has not stated how it imagines its primary purpose test would work in practice, the
2 much bigger question is how *it should* work in practice. And there may not be a great answer
3 to that question, because the design of primary purpose test will result in inequitable results
4 unless every investment is solely either growth or non-growth related. So long as investments
5 have both growth and non-growth purposes, the primary purpose test will result in
6 inequitable cost-shifting.

7 Thus, PGE should apportion an investment's costs as either growth or non-growth
8 related based on the contribution of each purpose to the resource's acquisition. This may
9 seem burdensome, but PGE will have to perform most of the work already if it sticks with the
10 primary purpose approach. To determine the primary purpose, PGE should have to perform
11 an analysis of the relative contribution of the various purposes of an investment to determine
12 the "primary purpose" of an investment. At a minimum, it will have to be able to track with
13 some specificity the amount of an investment that is going towards serving load growth. It
14 appears from the proceedings in UM 2273 that it will also have to track the amount of each
15 investment going towards compliance with HB 2021 to determine the implications for the
16 cost cap.⁵¹ At this point, the Company should have the necessary information to be able to
17 apportion the investment's cost as growth or non-growth. Thus, using the less precise
18 primary purpose test will hardly save the Company any time or effort, but could expose
19 customers to inequitable cost shifting. Determining the share of each purpose of an
20 investment and allocating the costs accordingly is a better method of achieving equitable cost
21 allocation.

⁵¹ ORS 469A.445.

1 **Q. What period should be used to determine the level of load growth in the Peak**
2 **Growth Modifier?**

3 A. PGE suggested a three-year, backward-looking approach. Staff did not recommend a
4 specific timeframe, but mentioned that a five-year backward-looking approach could be used,
5 and that it could also include the Test Year forecast. The Coalition does not necessarily
6 recommend one model or the other, but does note that the use of some forward-looking
7 approach like the Test Year forecast may be helpful. Load growth from large customers is
8 different from growth caused by other customer classes in that it grows in chunks.
9 Residential load growth occurs smoothly over time as new homes are connected to the
10 system. Large customers connect relatively infrequently, but when they do, they can cause a
11 sizable jump all by themselves in a rate class's growth. While some form of line-drawing
12 must be done, the optimal outcome would allow the PGM calculation to have some
13 flexibility to account for large customers that are going to connect in the near future,
14 especially if the load growth will be particularly large.

15 **Q. What else should be considered in allocating costs to serve growing load?**

16 A. As Staff highlighted in testimony, the load profiles of large loads are very different
17 from the profiles of other customers, in particular residential and commercial customers.⁵² As
18 a result, the resources necessary to serve load growth from data centers may not be the same
19 resources most effective for serving load growth from residential customers electrifying. For
20 example, CUB pointed out that the marginal energy resource for a residential customer is
21 energy efficiency, which can be acquired at a much lower cost than other resources.⁵³

⁵² Staff/100, Stevens/16–17.

⁵³ CUB/100, Jenks/39.

1 **Q. Given the differences in load profile and growth rate of large customers, would it**
2 **be easiest to just directly assign the costs of resources to large load customers?**

3 A. Perhaps, although many of the same problems associated with the other
4 methodologies would persist. Given PGE's scope of work over the next decade-plus—
5 reducing existing emissions, meeting data center load growth, meeting load growth due to
6 electrification, wildfire hardening, ensuring reliability and resiliency—the Company will
7 likely be acquiring generation, distribution, and transmission resources concurrently that
8 serve multiple purposes. The core issue of how PGE determines whether a resource is fit to
9 be directly assigned to future Schedule 96 customers or not is not solved by using a direct-
10 assignment cost allocation model. Whether resources should be fully assigned to a customer
11 or split up between the varying purposes of a project, and what methodology to use or factors
12 to consider in making those determinations, must be thought through to ensure the system
13 maintains equitable cost allocation.

14 With that said, a direct access model has at least one major benefit. Under the PGM
15 approach that PGE proposes, residential customers are likely to be saddled with costs related
16 to investments that data centers require. PGE showed that Schedule 7 and future Schedule 96
17 customers drove peak growth between 2022 and 2025, meaning that those two customer
18 classes will bear the lion's share of the costs under the PGM model.⁵⁴ That will change as
19 Schedule 96's growth accelerates over the next decade, but residential load growth will still
20 mean that Schedule 7 customers are being assigned costs associated with resources built to
21 serve data centers. If the resources needed to serve data centers have a higher incremental
22 cost than the resources PGE can acquire to serve residential customers, the PGM model will

⁵⁴ PGE/100, Ferchland-Barrow/26.

1 cause some amount of cost shifting from data centers to residential customers. Directly
2 assigning costs can avoid mixing higher-cost data center-serving resources with lower-cost
3 residential-serving resources.

4 **Q. Do you have any other input regarding PGE's proposed PGM?**

5 A. Yes, I have one more concern. PGE stated that customers with negative growth will
6 receive a credit for their allocation of costs for non-growth resources.⁵⁵ As PGE explains: "a
7 class with negative growth that is allocated \$1,000,000 in non-growth fixed generation costs
8 and -\$100,000 in growth-motivated fixed generation costs would be allocated a net \$900,000
9 in fixed generation costs."⁵⁶ Customer classes with negative growth should not receive an
10 offsetting charge for non-growth costs because negative growth does not result in negative
11 costs. Put another way, imagine all customer classes reduced load by one percent over the
12 relevant time period. Growth-related costs in that scenario would be \$0, not some negative
13 number. Providing customer classes that do not grow (or have negative growth) with a credit
14 will inequitably shift some costs towards growing rate classes.

15 **VI. Energy Efficiency**

16 **Q. Did you make recommendations related to energy efficiency in your Opening**
17 **Testimony?**

18 A. No. In my Opening Testimony, I outlined how energy efficiency can be measured in
19 data centers before detailing why it might be difficult to set up standards that consistently
20 encourage the adoption of more efficient technologies over time.

21 **Q. Do you have any recommendations related to energy efficiency now?**

⁵⁵ Coalition/305, Souder/1.

⁵⁶ *Id.*

1 A. Yes. The Coalition agrees with Columbia River Inter-Tribal Fish Commission's
2 (CRITFC) recommendation in its Opening Testimony that the data center tariff should
3 include a charge that funds energy efficiency measures for other customers, specifically
4 low-income and environmental justice communities in PGE's territory. I recommend a
5 charge of 1 cent/kWh that funds ETO programs that provide non-cost-effective energy
6 efficiency offerings for "priority customers" as well as "enabling repairs" for those same
7 customers so they can access cost-effective offerings. Additionally, the Commission should
8 require PGE to amend Schedule 109 such that customers under the proposed Schedule 96
9 make the maximum contribution allowable under HB 3141.

10 **Q. Why does it make sense to have data centers pay for the energy efficiency of**
11 **other customers?**

12 A. As I noted in my Opening Testimony, setting objective metrics for the energy
13 efficiency of data centers is complicated by the fact that the main efficiency metrics used are
14 inverse to each other. When a data center that installs more efficient chips and improves its
15 IT-related efficiency, it simultaneously makes its Power Usage Effectiveness (PUE)—the
16 measure of efficiency for non-IT equipment like air conditions—worse. Making matters
17 more complicated is the fact that data centers are often disinclined to share any information
18 related to their power usage, framing it as a trade secret. A final issue is the relationship
19 between efficiency and water usage—generally, more efficient data centers will have higher
20 water usage, its own negative externality. I also noted in my previous testimony the
21 problematic relationship between increased efficiency after a data center is connected and
22 some of the cost-protection policies at the center of this docket, including minimum billed
23 demand provisions.

1 The Commission should therefore require new data centers to fund additional
2 efficiency measures for other customers, where efficiency is more clearly a positive both for
3 the individual customer and the system writ large.

4 **Q. What is the potential for data centers to fund the energy efficiency of other**
5 **customers?**

6 A. Tremendous potential exists for data centers to fund energy efficiency and DERs in
7 residential and commercial buildings to offset their capacity additions to PGE's system. A
8 recent report from Rewiring America argues that data centers could more than cover their
9 capacity additions to the electric system by paying for heat pumps to replace inefficient
10 resistance heating and covering a portion of the cost of installing solar panels with batteries
11 in residences.⁵⁷ That report found that, in Oregon, simply replacing resistance heating with
12 heat pumps could cover essentially all the capacity needs of new data center customers in the
13 near term.⁵⁸ Covering 1/3 the cost of new rooftop solar installations with a battery backup
14 could also make up for the capacity additions of new planned data centers as well.⁵⁹

15 While fully displacing a data center's capacity additions is not necessarily the target
16 that the Commission should aim for, the Rewiring America study shows that funding energy
17 efficiency and DERs can reduce the impact of new data centers. Funding programs in low-
18 income and environmental justice communities can provide an array of benefits for those
19 who traditionally have borne the brunt of the negative impacts from industrial customers.
20 Replacing electric resistance heating with heat pumps, for example, will lower customer
21 bills, provide what can be lifesaving cooling in homes that do not already have air

⁵⁷ Coalition/306, Souder/5.

⁵⁸ *Id.*, Souder/6.

⁵⁹ *Id.*, Souder/9.

1 conditioning, and produce better indoor air quality. But, because heat pumps are relatively
2 expensive, low-income customers and many moderate-income customers cannot afford to
3 replace their inefficient equipment without substantial subsidization of the upfront
4 installation cost.

5 **Q. Does Energy Trust of Oregon ever engage in non-cost-effective programs?**

6 A. Yes. Energy Trust of Oregon has consistently received exceptions to its general
7 requirement to acquire cost-effective energy efficiency for the sake of providing incentives
8 for heat pumps. For example, in Order 25-071, the Commission approved a cost-
9 effectiveness exception for two heat pump measures.⁶⁰ That ETO has repeatedly asked for,
10 and the Commission has repeatedly approved, cost-effectiveness exceptions for heat pump
11 programs is indicative of the fact that heat pumps provide substantial benefits to customers
12 not traditionally captured in a cost-effectiveness analysis.

13 **Q. Is the cost of energy efficiency changing?**

14 A. Yes, energy efficiency is becoming more expensive. ETO has recognized that the
15 costs of further energy efficiency are going up because it “has already captured the lowest-
16 cost energy efficiency.”⁶¹ To deliver deeper efficiency gains, ETO plans to “focus on
17 engaging customers on larger, more complex energy-savings projects, and engaging
18 customers our programs have historically underserved—including people of color, people in
19 rural areas and people with low-incomes.”⁶² Those gains will continue to offset the need for

⁶⁰ *In the Matter of ENERGY TRUST OF OREGON, Cost Effectiveness Exception Request for Electric Measures*, Docket No. UM 1696, Order 25-071, at 1, 4 (Feb. 19, 2025), available at <https://apps.puc.state.or.us/orders/2025ords/25-071.pdf>.

⁶¹ *In the Matter of ENERGY TRUST OF OREGON, 2026-2030 Multiyear Plan*, Docket No. ETO 1, Draft 2026-2030 Multiyear Plan, at 3 (Aug. 15, 2025), available at <https://edocs.puc.state.or.us/efdocs/HAA/haa339117027.pdf>.

⁶² *Id.*

1 utilities to make costly expenditures that customers must pay for. ETO expects its efficiency
2 measures will avoid \$4.2 billion in utility costs from 2026 to 2030.

3 **Q. Could a program be operated outside of ETO?**

4 A. Yes. Theoretically, another option would be to set up a program similar to NW
5 Natural's Oregon Low-Income Energy Efficiency Program (OLIEE), which is administered
6 by CAP agencies. CAP agencies have closer bonds to low-income communities because they
7 are generally the administrators of low-income emergency funds, such the Low-Income
8 Home Energy Assistance Program (LIHEAP), the Oregon Low Income Gas Assistance
9 Program (OLGA), and the Oregon Energy Assistance Program (OEAP).

10 Under OLIEE,⁶³ customers can access funding for home weatherization and other
11 efficiency measures like replacing aging equipment with efficient upgrades. These upgrades
12 are generally made at no-cost to the customers, although CAP agencies and OHCS will often
13 cobble together funding from multiple sources to perform a given home's retrofits. However,
14 as discussed below, operating a program like OLIEE is likely precluded by statute.

15 **Q. Has ETO identified a need for additional funding to support programs for low-**
16 **income customers?**

17 A. Yes. In its Multi-year plan, ETO identified a handful of future needs and priorities,
18 which included funding for "priority customers," those with low incomes, customers of
19 color, and rural customers.⁶⁴ ETO noted that serving low-income customers generally costs
20 more than serving medium- and high-income customers because the incentive must cover
21 most or all of the cost for new equipment rather than just a portion of the cost and because

⁶³ Avista offers a similar program called AOLIEE (Avista's Oregon Low-Income Energy Efficiency), as does Cascade under its Weatherization Assistance program.

⁶⁴ *Id.*, at 57–58; 90.

1 ETO often has to make additional administrative investments in identifying and targeting
2 communities with offers. In practice, this means fewer programs exist to serve low-income
3 customers because “investments in low-income offers put pressure on the cost-effectiveness
4 of some of” ETO’s programs.⁶⁵

5 ETO also identified the need to fund “critical home repairs,” which are repairs
6 necessary to receive other energy upgrades.⁶⁶ These types of upgrades are often called
7 “enabling repairs” as they are not directly tied to energy efficiency but enable a home to
8 receive upgrades like weatherization. As mentioned below, similar dockets in other states
9 have resulted (through settlement) in data center customers funding enabling repairs for low-
10 income customers to maximize weatherization efforts. Creating a pool of special funding that
11 allows either ETO or other entities to perform these enabling repairs could allow ETO to
12 achieve greater energy efficiency in the homes that need it most. ETO works with other
13 entities to access complementary funding sources like the Portland Clean Energy Benefits
14 Fund or the Home Energy Rebates Program to reach a broader range of homes with
15 efficiency measures than otherwise would be possible. Creating an additional pool of funding
16 for this specific purpose can help accelerate that work and deliver deeper bill reductions for
17 the communities that need it most.

18 **Q. What benefits would customers receive if data centers funded energy efficiency**
19 **measures in low-income and environmental justice communities?**

20 A. Drawing funds for residential energy efficiency from a data center tariff would have
21 several benefits that go beyond even the typical benefits of energy efficiency. As noted

⁶⁵ *Id.*, at 91.

⁶⁶ *Id.*, at 58.

1 above, paying for the energy efficiency of other customers can help to offset a large load's
2 contribution to load growth without disrupting the customer-protection policies contemplated
3 by parties in this docket. Furthermore, providing additional sources of funding for residential
4 energy efficiency programs can help fill a portion of the "complementary funding" gap left
5 by federal policies that have removed incentives for technologies that ETO encourages.⁶⁷
6 Finally, ETO would be able to more fully serve a group of customers that has not
7 traditionally benefitted equitably from ETO's offerings.

8 **Q. Are there any examples from other states where data centers fund energy**
9 **efficiency or similar programs for other customers?**

10 A. Yes. The Indiana Utility Regulatory Commission approved a settlement on several
11 data center-related issues (those mirroring the Rule I and Rule C issues present in this
12 docket) earlier in 2025.⁶⁸ Under that settlement, Amazon, Google, and Microsoft agreed to
13 pay \$500,000 per year for five years to the Indiana Community Action Association
14 (INCAA), totaling \$7.5 million in funding, to support health and safety measures to enhance
15 weatherization opportunities.⁶⁹ Funding health and safety components allows the income-
16 qualified customers that utilize INCAA's program to move forward with weatherization
17 projects that wouldn't be able to proceed otherwise, giving them "access to a greater range of
18 services than before."⁷⁰ The health and safety components are essentially the "enabling
19 repairs" ETO identified in its Multiyear Plan.

⁶⁷ See, *id.*, at 16–17.

⁶⁸ Coalition/109, Souder/46.

⁶⁹ *Id.*

⁷⁰ *Id.*

1 **Q. You are asking for data centers to be charged the maximum possible**
2 **contribution to the public purpose charge and cost-effective energy efficiency. Can the**
3 **Commission require an additional contribution from data centers to fund non-cost-**
4 **effective energy efficiency?**

5 A. Yes. HB 3141’s contribution cap only applies to charges under ORS 757.054 and
6 ORS 757.612.⁷¹ Although ORS 757.612 states that the public purpose charge it allows is the
7 only such charge the Commission can impose,⁷² no such restriction is placed on the
8 Commission’s ability to impose an additional charge for ETO to administer to support non-
9 cost-effective energy efficiency upgrades or “enabling” upgrades discussed above. To my
10 knowledge, no statutes prevent the Commission from assessing a separate charge to support
11 ETO programs outside the scope of ORS 757.054.

12 Of course, the Commission must ensure that rates are fair and reasonable.⁷³ Imposing
13 an additional charge to data center customers to fund deeper energy efficiency improvements
14 than those available through traditional cost-effective funding is reasonable and fair for three
15 reasons. First, as explained above, funding residential energy efficiency can reduce the
16 overall impact of data centers on PGE’s load, and in particular shave peak load, avoiding
17 additional expenditures that PGE may have to make beyond serving new data centers and
18 complying with HB 2021. Second, as ETO pointed out in its Multiyear Plan, a need exists to
19 fund enabling repairs and offers for low-income customers. Finally, the POWER Act directs
20 the Commission, in reviewing the tariff PGE creates for data center customers, to consider

⁷¹ HB 3141, 81st Leg. Assemb., 2021 Reg. Sess., sec. 3(4)(a), (Or. 2021).

⁷² ORS 757.612(3)(h).

⁷³ ORS 756.040(1).

1 whether it provides for equitable contributions to grid efficiency.⁷⁴ An additional charge
2 would be equitable for the reasons cited above—it would offset at least some of the
3 substantial burden these companies are imposing on PGE and its other customers, is needed
4 for ETO to be able to achieve its mission to the fullest extent, and will help lower bills for
5 PGE’s customers with lower incomes. The POWER Act also gives the Commission the
6 broad power to include in the tariff any conditions it feels would be in the public interest.⁷⁵
7 For all the reasons above, a requirement that large load customers contribute to energy
8 efficiency funding as proposed here is in the public interest.

9 **Q. What would the impact be of a 1 cent/kWh charge?**

10 A. At one cent per kilowatt-hour, millions of dollars could be generated for residential
11 energy efficiency. Here’s a quick back-of-the-envelope estimate. PGE has stated that it
12 currently has just under 400 MW of data center load currently connected to its system.⁷⁶
13 Assuming a load factor of 80 percent across the data centers, that would amount to about 2.8
14 billion kWh of usage in a year.⁷⁷ Applying a charge of 1 cent/kWh would yield about \$28
15 million per year at current usage levels.

16 **Q. Could the money generated fund purposes other than energy efficiency and**
17 **enabling repairs?**

18 A. Yes. ETO also highlighted a desire to provide additional funding for distributed
19 energy resources like solar and batteries for residential customers. If the Commission
20 approved a sufficient charge, ETO could also use the funds generated to deliver great

⁷⁴ HB 3546, 83rd Or. Leg. Assemb., 2025 Reg. Sess., Section 2(3)(b) (Or. 2025).

⁷⁵ *Id.*, Section 2(3)(e).

⁷⁶ Coalition/301, Souder/18.

⁷⁷ $400 \text{ MW} * 1000 \text{ kW/MW} * 24 \text{ hours/day} * 365 \text{ days/year} * 0.8 \text{ (load factor)} = 2,803,200,000 \text{ kWh/year.}$

1 resilience for customers and PGE's system by installing DERs in the homes of priority
2 customers.

3 **Q. Have you developed further recommendations as it relates to energy efficiency at**
4 **data centers themselves?**

5 A. In a sense. As I wrote in my Opening Testimony, encouraging energy efficiency in
6 data centers once the facility is energized is complicated by several factors, including the
7 context-dependent metrics by which data center efficiency is measured, the fact that driving
8 down usage may frustrate other cost-collection-focused policies, and the more fundamental
9 problem that data centers are extremely reluctant to let third-parties learn about the function
10 of their facilities. To the last point, a recent article in the New Yorker pointed out that, as a
11 condition of receiving a tour of a Microsoft data center, the reporter agreed to take no photos,
12 limit the description of the interior, and not reveal where in the United States the facility was
13 located.⁷⁸

14 Analyzing and developing solutions to encourage energy efficiency in data centers
15 will require more transparency into the technology and operations of these facilities. As both
16 the Coalition and CRITFC highlighted in Opening Testimony, there is direct relationship
17 between water usage and energy efficiency at data centers because the most efficient cooling
18 technologies use more water than other options. This creates a point of tension between two
19 main concerns related to data centers—should we support a reduction in energy at the
20 expense of higher water usage, or should we allow for higher energy usage to preserve water
21 for surrounding communities?

⁷⁸ Stephen Witt, *Inside the Data Centers that Train A.I. and Drain the Electric Grid*, NEW YORKER, (Oct. 27, 2025), available at <https://www.newyorker.com/magazine/2025/11/03/inside-the-data-centers-that-train-ai-and-drain-the-electrical-grid>.

1 Understanding the energy efficiency potential at a data center, and the policy
2 implications of pursuing marginally more energy efficiency, requires transparent information
3 about, among other things, data center water usage. Utilizing this information will help the
4 Commission and stakeholders to continue our work to ensure that, if data centers connect in
5 IOU territories, they do so in a manner than minimally impacts other ratepayers and the
6 surrounding community. I therefore recommend that the Commission require Schedule 96
7 customers to make simple filings, available to the public, that outline total energy and water
8 usage on a monthly basis as a condition of receiving service.

9 **VII. HB 2021 Compliance, Green Tariffs, and Special Contracts**

10 **Q. You wrote previously about the risk that new data center loads present to the**
11 **Company meeting its HB 2021 obligations. Are you still concerned about the way new**
12 **load increases will make the task of HB 2021 compliance more complicated?**

13 A. Yes, very much so. In its most recent CEP/IRP Roundtable on October 22, 2025, PGE
14 displayed its preliminary load growth forecast. The results were striking. The September
15 2025 forecast showed 12% higher load in 2044 than PGE's May 2024 forecast had
16 previously predicted, driven entirely by an increase in the Company's predicted load growth
17 from the industrial sector.⁷⁹ Residential load growth was slightly down from 2.3% annual
18 growth to 2.2% annual growth, and commercial growth dropped from 2.3% annual growth to
19 0.3% annual growth.⁸⁰ But annual industrial growth jumped from 5.2% in the May 2024
20 reference case to 7.2% in the September 2025 reference case.⁸¹

⁷⁹ Coalition/301, Souder/20.

⁸⁰ *Id.*

⁸¹ *Id.*

1 PGE noted that it expects industrial customers to become the largest share of energy
2 deliveries “in the next few years,” and by 2044 industrial load appears to make up more than
3 half of all energy deliveries.⁸² PGE currently has 393 MW of existing, energized “large
4 loads” and already has another 442 MWs worth under construction.⁸³ But that’s nothing
5 compared to the over 3 GW of large loads “In Study” which it describes as studies that are
6 underway with initial contracting.⁸⁴ As noted previously, PGE expects to have 1 GW of data
7 center load connected by 2030, and another GW connected by 2040.⁸⁵

8 Data center load growth on this scale will jeopardize PGE’s ability to meet HB 2021.
9 The high load factor of these loads means an additional 600 MW of power to serve data
10 center growth by 2030 is likely to translate to something around 480 MWa of energy. PGE’s
11 last RFP acquired a paltry 82 MWa of energy.

12 In my Opening Testimony, I noted that the federal landscape had soured toward
13 renewable energy, making the task of acquiring sufficient resources to meet HB 2021 while
14 also serving load growth more complicated than it already had been. Since Opening
15 Testimony, the Trump Administration’s war on renewable energy has continued apace. The
16 Administration’s approach has targeted “blue” states, canceling U.S. Department of Energy
17 funding for 321 projects largely in states that voted for Kamala Harris in the 2024 election,
18 and entirely targeting companies based in Democrat-led states.⁸⁶ Included in the cancelations
19 are 19 Oregon projects worth \$405 million, including the \$87 million the state was set to

⁸² *Id.*, Souder/9, 20.

⁸³ *Id.*, Souder/18.

⁸⁴ *Id.*

⁸⁵ *Id.*

⁸⁶ Maeve Allsup, *Scoop: These are the 321 awards DOE is canceling*, LATITUDE MEDIA (Oct. 2, 2025), available at <https://www.latitudemedia.com/news/scoop-these-are-the-321-awards-doe-is-canceling/>.

1 receive to stand up its Solar for All program.⁸⁷ As I noted in my Opening Testimony, the
2 Trump Administration is also slowing down, if not outright preventing, renewable projects
3 on federal land. Federal opposition to renewable energy will make building new renewable
4 facilities more difficult, limiting the availability of new renewable energy for PGE to acquire
5 and driving up costs for everyone. It is against these headwinds that PGE must work.

6 **Q. Why is it important that the Commission take proactive steps to address the**
7 **threat data centers present to the state’s decarbonization goals?**

8 A. The Oregon Climate Action Commission, with the assistance of ODOE, released its
9 Transformational Integrated Greenhouse Gas Emissions Reduction Project (TIGHGER)
10 report in October of this year and found that the state is no longer on track to reach its 2035
11 reduction goal and is even further behind meeting its 2050 goal.⁸⁸ One of the two primary
12 drivers in putting the state behind is “increasing data center load growth,” half of which is
13 expected to occur in IOU territories over which the Commission has authority.⁸⁹ The
14 Commission can and must take the necessary steps to prevent unrestrained load growth from
15 overwhelming our energy system’s ability to decarbonize on the scientifically required
16 timeframe.

17 **Q. Do you maintain the same recommendations you supported in Opening**
18 **Testimony?**

⁸⁷ Monica Samayoa, *Oregon to lose an additional \$400 million in federal climate grants*, OR. PUB. BROADCASTING, (Oct. 2, 2025), available at <https://www.opb.org/article/2025/10/02/oregon-lose-additional-400-million-federal-climate-grants/>.

⁸⁸ Coalition/307, Souder/30.

⁸⁹ *Id.*

1 A. Yes. The Commission should take a multi-pronged approach that utilizes the study
2 process as well as innovative tariff designs that only allow data centers to energize once PGE
3 can serve the new load with renewable resources, while also allowing data center companies
4 to pursue non-emitting resources that may not be affordable for other customers, like
5 geothermal power.

6 In Opening Testimony, I suggested a queueing system that would allow customers to
7 connect to PGE's system only once sufficient renewable resources were available to serve
8 those customers. New customers could jump the queue if they brought their own renewable
9 resources to the system. Several intervenors brought up the possibility of raising the direct
10 access cap to allow data center customers to utilize the existing framework to contract for
11 resources, and PGE proposed "special contracts" that "allow large customers to meet their
12 specific procurement goals while enabling PGE to maintain load visibility, ensure planning
13 alignment, and assign all appropriate costs and risks to the contracting customer."⁹⁰

14 **Q. PGE favored special contracts over direct access. Do you believe that special**
15 **contracts are a better alternative than the Cost of Service option?**

16 PGE raised a theoretically reasonable concern about utilizing the direct access
17 system; it fears it would remain the Provider of Last Resort, requiring it to plan for the
18 potential to have the load become its responsibility.⁹¹ However, the Company has also stated
19 elsewhere that it would remain that provider of last resort for special contract customers.⁹²
20 PGE should clarify whether it would or would not remain the provider of last resort under its
21 special contract proposal. The Coalition also has several concerns with PGE's special

⁹⁰ PGE/100, Ferchland-Barrow/47.

⁹¹ *Id.*

⁹² Coalition/308, Souder/1.

1 contracting structure, namely with the emissions associated with the delivery of these
2 resources and the possibility that these special contracts allow data centers to buy the
3 cheapest renewable resources on the market, leaving PGE's other customers to pay for more
4 expensive resources acquired in an RFP process.

5 PGE states that the special contracts are desirable because they can be designed to
6 suit the preferences of the customer, including their "emissions goals."⁹³ But, if PGE wants
7 to have a chance to comply with HB 2021, the "emissions goals" of any new resources
8 should simply be zero emissions. At a minimum, the Commission should require that any
9 special contracts must be for entirely non-emitting resources, otherwise large loads will be
10 further burdening other customers by requiring existing customers to decarbonize even more
11 than HB 2021 requires to make up for those marginal emissions. This would also increase the
12 likelihood of PGE hitting HB 2021's cost cap, at which point it may not need to comply with
13 HB 2021 (noting, however, that the dynamics of the cost cap are currently being litigated in
14 UM 2273).

15 PGE also notes that the special contracts pathway can "allow customers to receive
16 service quicker than they may otherwise through [Cost of Service]. Formal RFP processes
17 not only take additional time to acquire and contract for resources, but resources that will be
18 acquired through RFPs will be allocated to all customers."⁹⁴ I understand (but disagree with)
19 the allure to PGE to create a structure that speeds up the procurement process for data
20 centers. As the Company notes, "these customers have aggressive development schedules,"⁹⁵
21 and the ability of a utility to offer shorter connection timelines can attract future large

⁹³ PGE/100, Ferchland-Barrow/45.

⁹⁴ *Id.*

⁹⁵ *Id.*

1 customers.⁹⁶ The potential pitfall of this approach is the ability of these large loads to acquire
2 the cheapest resources before PGE is able to acquire such resources for other customers
3 through an RFP process, leaving only relatively more expensive resources for residential and
4 commercial customers. If data centers can use special contracts to acquire utility grade solar,
5 wind, and batteries, and can do so on a quicker timeline than an RFP process allows, it seems
6 inevitable that the result will be cheaper power for data centers and more expensive power
7 for PGE's other customers. PGE cannot allow the dollar signs in its eyes to blind it to the fact
8 that it has a duty to provide affordable service to all its customers, and its current special
9 contracts process does nothing to protect residential and commercial customers from
10 exposure to marginally higher costs associated with compliance with HB 2021.

11 PGE notes that the special contract process could allow a data center to "pursue a
12 generation option—such as nuclear—that does not currently align with PGE's RFP eligibility
13 criteria."⁹⁷ Members of the Coalition are wary of additional nuclear energy development and
14 remind the Commission of the continued moratorium against building new nuclear facilities
15 in Oregon. If data center companies utilize this function to pursue non-emitting, firm
16 resources like geothermal, which can meet their needs without crowding out resources best
17 suited for PGE's other customers, the special contract system could be beneficial for all. If
18 the Commission approves PGE's special contract proposal, it should require that any
19 contracts signed include a yearly charge based on the amount of capacity acquired that funds
20 energy efficiency for low-income residential customers, ideally targeting programs that

⁹⁶ As indicated by my earlier testimony, I disagree with PGE's desire to court additional new large loads because doing so exposes the Company's other customers to an ever-increasing risk of inequitable cost shifting, makes the task of complying with HB 2021 more complicated, and has not been shown to provide offsetting benefits for other customers.

⁹⁷ PGE/100, Ferchland-Barrow/48.

1 replace resistance heating with heat pumps to maximize the usage reduction benefits as a
2 means of further aiding PGE's need to meet both load growth and HB 2021.

3 **Q. Do you prefer Staff's voluntary renewable energy tariff (VRET) concept?**

4 A. In many ways, yes. PGE stated that its Green Tariff (to which Staff analogizes its
5 VRET concept) would not be effective in serving data centers because it "is not intended to
6 be a load-serving product but is intended to provide claims to renewable energy credits."⁹⁸
7 Data centers "require a more flexible and tailored approach," according to PGE. Staff's
8 VRET concept seems to provide that flexibility, while also creating the types of safeguards
9 necessary to ensure that the resources data centers acquire are "additional" to those that could
10 go to serve other customers.

11 For example, Staff noted that customers "could identify a resource to procure that
12 has not already been included in the final shortlist of PGE's All-Source Request for
13 Proposal."⁹⁹ Staff explain that, because these resources did not make the final shortlist, they
14 "would likely cost more than the bids on the RFP shortlist and not be part of PGE's resource
15 strategy."¹⁰⁰ This is an important component of any special contract or VRET model, that the
16 resources acquired are not simply the least cost resources that may bid into an RFP. While
17 Staff identifies the possibility of accessing resources that have already not been selected in an
18 RFP, other possibilities include, as PGE hinted, resources that would not bid into an RFP,
19 like geothermal resources.

20 Another possibility is the customer protection provision that exists in NV Energy's
21 Clean Transition Tariff (CTT), which specifically directs the Public Utility Commission of

⁹⁸ *Id.*, Ferchland-Barrow/49.

⁹⁹ Staff/100, Bolton/5.

¹⁰⁰ *Id.*

1 Nevada to “consider whether non-participating customers of the utility experience increased
2 costs for electric service or forgo the benefit of a reduction of costs for electric service” as a
3 result of a contract signed pursuant to the CTT.¹⁰¹ Any similar provision governing the
4 signing of special contracts in PGE’s tariff could require a showing that the resources
5 acquired under the contract were not likely to be made available to residential customers in
6 PGE’s territory.

7 The Coalition does not have a specific recommendation currently between a VRET
8 model as Staff hinted at or PGE’s special contracts model. More important is the customer
9 protections built into whichever model the Commission approves to ensure: 1) that the other
10 terms discussed in this docket are fully accounted for in any non-COS contract, 2) that the
11 resources customers acquire are additional to the resources the Company would acquire for
12 customers in an RFP, 3) that the contract maintains equitable contributions to energy
13 efficiency and other public purposes, and 4) that the resources acquired do not shift the
14 burden of additional decarbonization onto other customers for HB 2021 purposes.

15 **Q. Does the backup generation at a data center count towards HB 2021?**

16 A. No, generally it does not. Of course, the purpose of HB 2021 is to reduce emissions
17 related to the generation of electricity. Data centers often utilize diesel generators as backup
18 energy either in times of stress on the grid or as a means of reducing the capacity the
19 company asks for from their utility. Allowing data centers to operate diesel backup will result
20 in higher statewide emissions that evade our attempts to reduce overall emissions.

21 **Q. What should the Commission require of backup power?**

¹⁰¹ Coalition/309, Souder/6.

1 A. The Commission should consider requiring, as a part of contracts that Schedule 96
2 customers sign, that customers utilize batteries connected to renewable resources for backup
3 power. Requiring batteries connected to non-emitting resources will reduce greenhouse gas
4 and other emissions associated with these very large customers, helping to achieve the
5 purpose of HB 2021. PGE relies on the idea that data centers can provide myriad benefits for
6 other customers namely by citing to the use of battery electric storage systems in the
7 Company's Distributed Standby Generation program.¹⁰² The Coalition is appreciative of the
8 fact that PGE is already working with data center customers to include battery backups to
9 provide grid flexibility during peak loads, at least in some cases.¹⁰³ To help maximize the
10 grid benefits data center customers may present for other customers, and to reduce the overall
11 emissions of customers PGE serves, the Commission should require, as a term in contracts
12 signed with Schedule 96 customers, that those customers only utilize renewable energy
13 resources and batteries for backup power.

14 **VIII. Load Following Credit**

15 **Q. Did you make a recommendation regarding the Load Following Credit in your**
16 **Opening Testimony.**

17 A. No, I did not, but the Coalition's other expert, Andy Eiden, did. Mr. Eiden
18 recommended that the Load Following Credit (LFC) not be extended to new large loads.

19 **Q. What did other parties recommend for the Load Following Credit?**

¹⁰² Coalition/310, Souder/1.

¹⁰³ Jeff St. John, *Oregon utility tries out a faster, cheaper way to power data centers*, CANARY MEDIA, (Nov. 4, 2025), available at <https://www.canarymedia.com/articles/data-centers/oregon-utility-tries-out-a-faster-cheaper-way-to-power-data-centers> (PGE worked with a new customer in Hillsboro that will be building 31 MW of 2-hr batteries adjacent to the facility to provide grid flexibility).

1 A. PGE did not recommend extending the LFC to new data center customers.¹⁰⁴ Staff
2 recommended not extending the LFC to new data center customers and that the LFC should
3 be eliminated entirely in a phased approach, reducing it by half in this case and then
4 removing the remainder in PGE's next general rate case.¹⁰⁵ CUB recommended not
5 extending the load following credit to new customers.¹⁰⁶ AWEC stated that the LFC issue
6 should only be considered in relation to its applicability to data centers because this is not a
7 general rate case.¹⁰⁷ Whether AWEC supports applying the load following credit to loads that
8 qualify for Schedule 96 that meet the LFC's criteria is not clear.

9 **Q. Do you support the position of Andy Eiden that the Load Following Credit**
10 **should not be extended to new customers?**

11 A. Yes. PGE justified the LFC on the grounds that the "benefits of volume and load
12 factor are significant for the remainder of PGE's customer base" because applicable large
13 loads do not need PGE to operate a peaker plant or buy short-term market power to serve
14 customer load.¹⁰⁸ CUB pointed out, however, that the logic may have switched now that load
15 must largely be served with intermittent rather than firm resources, meaning PGE must build
16 out greater resources to serve the loads that might qualify for the LFC than an equivalent
17 level of more intermittent (lower load factor) loads like residential customers.¹⁰⁹ Mr. Eiden
18 also provided evidence that data center loads, particularly AI-rated data centers, experience

¹⁰⁴ PGE/100, Ferchland-Barrow/52.

¹⁰⁵ Staff/100, Stevens/66.

¹⁰⁶ CUB/100, Jenks/33.

¹⁰⁷ AWEC/100, Kaufman/5–6.

¹⁰⁸ PGE/100, Ferchland-Barrow/51.

¹⁰⁹ CUB/100, Jenks/32.

1 wide fluctuations in power, indicating they are not stable enough to justify the load following
2 credit.¹¹⁰

3 **Q. Do you agree with Staff's proposal to begin a phased elimination of the Load**
4 **Following Credit?**

5 A. The Coalition does not take a position at this time on the application of the credit to
6 current customers. With that said, Staff contends that PGE has not provided evidence to
7 support the existence of the credit and that the benefits of a high load factor customer are
8 already embedded in the lower per-kWh rate schedule 90 customers currently pay. Staff
9 argues that it is discriminatory to grant certain large customers the LFC for simply using load
10 in the way they would use it otherwise when other customer classes are not given a financial
11 benefit for using load in a particular manner that could be less costly than other usage
12 patterns. Staff makes a convincing argument that the continued existence of the LFC results
13 in discriminatory rates, and because of that should be eliminated immediately. A phased
14 elimination is a reasonable approach to remove the discriminatory rate structure elements in a
15 way that allows the affected customer(s) to not face rate shock.

16 **Q. Does that conclude your testimony?**

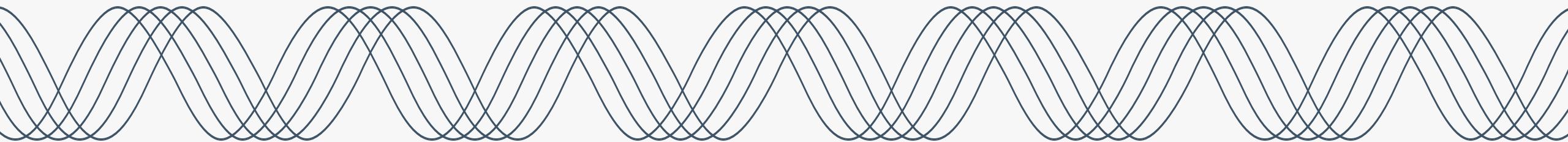
17 A. Yes.

¹¹⁰ Coalition/200, Eiden/21–23.



PGE CEP & IRP Roundtable 25-5

Oct 22nd 2025



Meeting Details



Electronic version of presentation

<https://portlandgeneral.com/about/who-we-are/resource-planning/combined-cep-and-irp/combined-cep-irp-public-meetings>



Zoom meeting details

- Join Zoom Meeting
<https://us06web.zoom.us/j/9291862450?pwd=xVXQl4jljt7FdetDzWD0G35FFvayF8.1&omn=84372774388>
- Meeting ID: 929 186 2459
- Passcode: 108198



Participation

- Use the raise the hand feature to let us know you have a question
- Unmute with microphone icon or *6

Meeting Logistics



Focus on Learning & Understanding

- There will be no chat feature during the meeting to streamline taking feedback
- Team members will take clarifying questions during the presentation, substantive questions will be saved for the end (time permitting)
- Attendees are encouraged to 'raise' their hand to ask questions

Follow Up

If we don't have time to cover all questions, we will rely on the CEP/IRP feedback form



October 22, 2025 – Agenda

9:00 | Welcome

9:05 | Corporate Load Forecast - Methodology & Trends

9:55 | Draft AdapDER Forecast

10:35 | Existing Resources & Resource Topology

11:10 | Futures/ Markets

11:55 | Closing Remarks - Next Steps

Upcoming Roundtable Schedule for the 2026 CEP/IRP

Wednesdays from 9 to 12 pm, Online Via Zoom

October 22, 2025

Corporate load forecast, existing resources - resources topology, Future Markets.

December 03, 2025

Transmission options, role of VPP, EE/DR integrations, ETO EE Forecast, drivers of capacity need.

January 14, 2026

Resource options, related economics, CBLs, RFP proxies, CEP emissions reductions

February 25, 2026

Portfolio/scenarios designs, flexibility study results

April 08, 2026

Draft portfolio analysis results

May 20, 2026

Updates prior to filing

July 01, 2026

Office Hours after filing

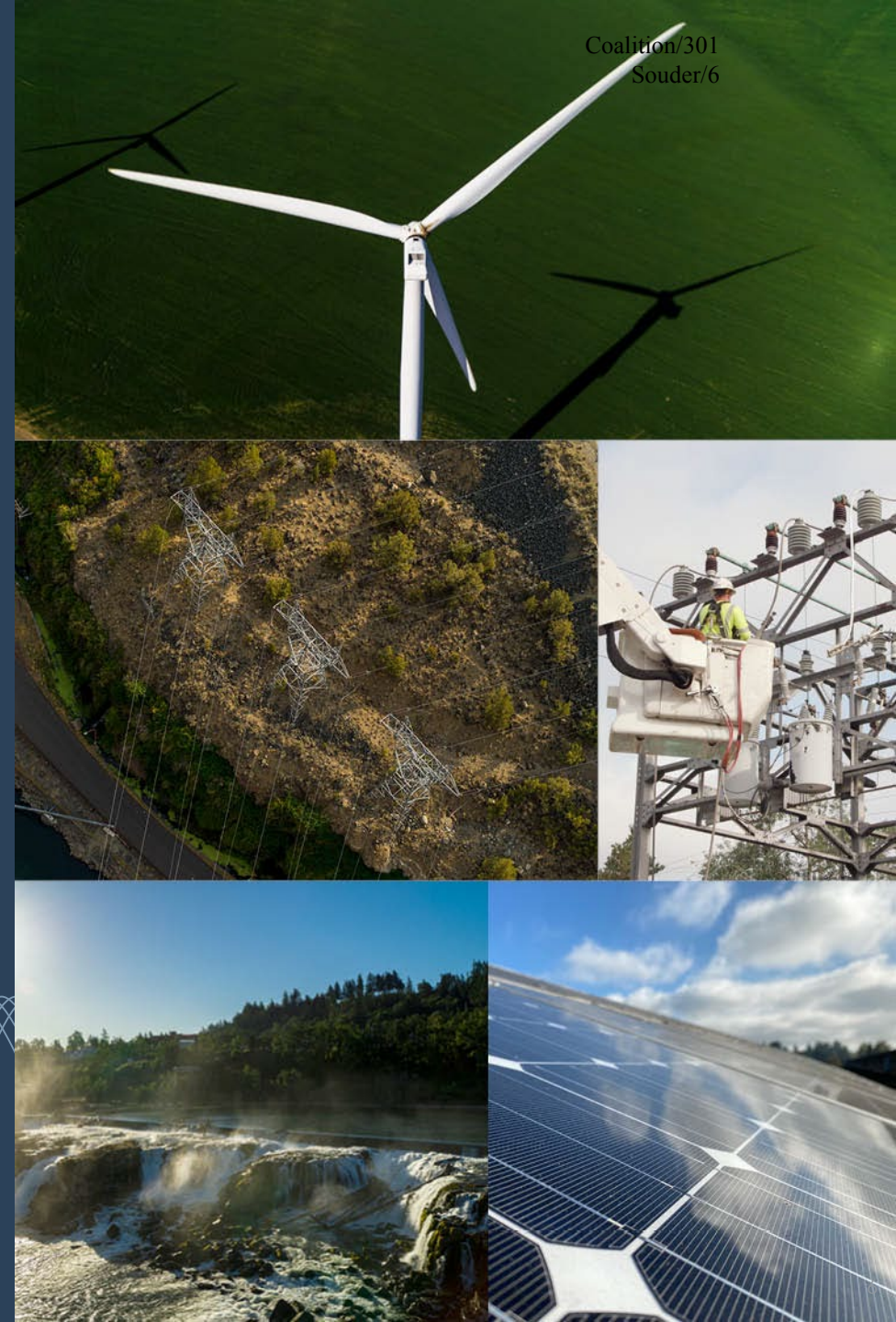
8 Workshops

Topics noted here are subject to change

Sep 2025 – Corporate Load Forecast Methodology & Trends

Amber Riter, PGE
Senior Principal Financial Risk Analyst

Shannon Greene, PGE
Senior Financial Analyst



Load Forecast Topics

PGE's load breakout and growth trends

Review of PGE's load forecast model methodology

Preliminary forecast results

Design load scenarios

PGE's 2024 Load – Energy And Demand



PGE's 2024 energy deliveries were roughly equal across the customer classes (residential, commercial, industrial)

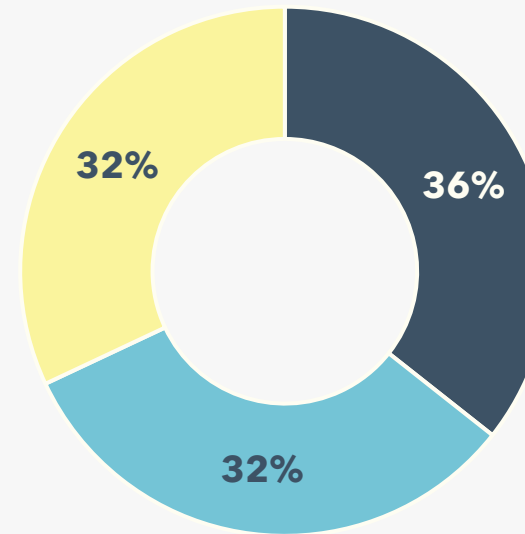
We expect industrial to be the largest share of energy deliveries in the next few years

PGE's system peak demand is more heavily weighted towards the residential class

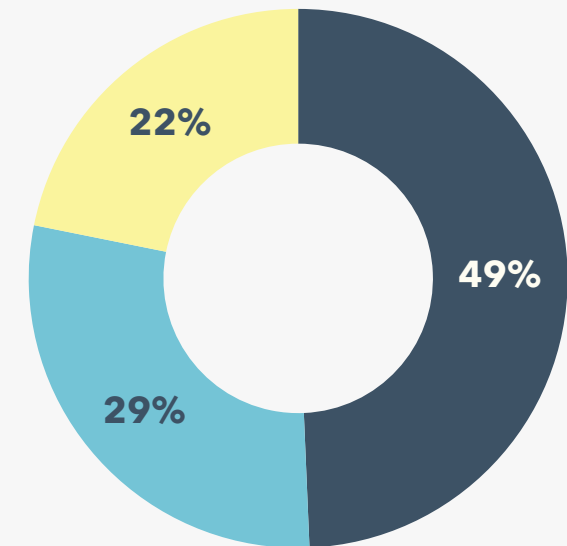
While the growth rate of industrial load is expected to outpace commercial and residential, residential continues to outsize industrial contribution to peak

Share of 2024 Load by Class

Energy Deliveries



Peak Demand (4CP)



■ Residential ■ Commercial ■ Industrial

PGE's Load Growth

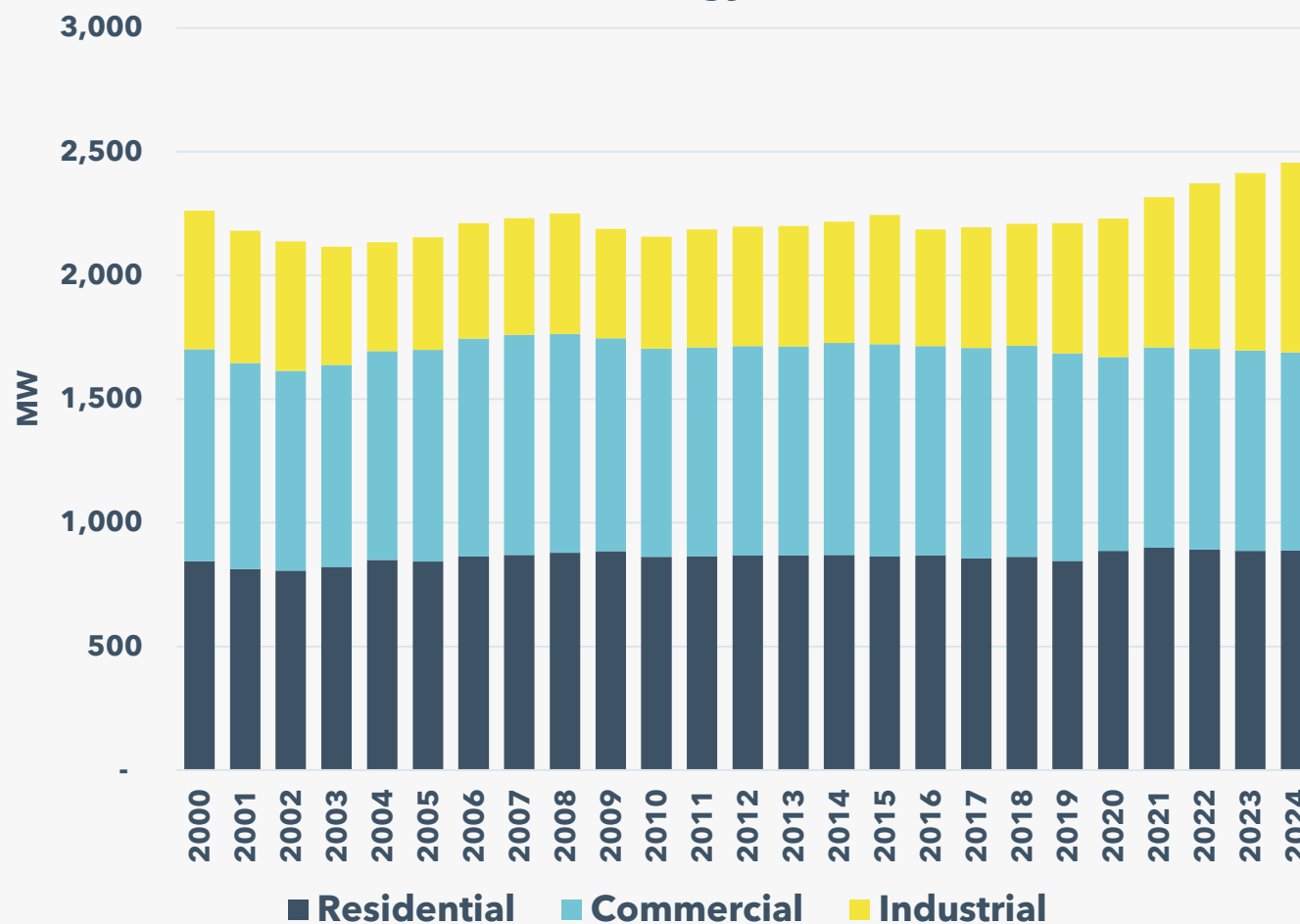
Lasting COVID-19 impact on residential and commercial

While the initial scale of impact has been offset, residential loads shifted higher and commercial loads lower

Acceleration of industrial growth continues

This is expected to continue as data center demand from cloud and AI uses expands

PGE Annual Energy Deliveries



PGE's 2024 Load by Class

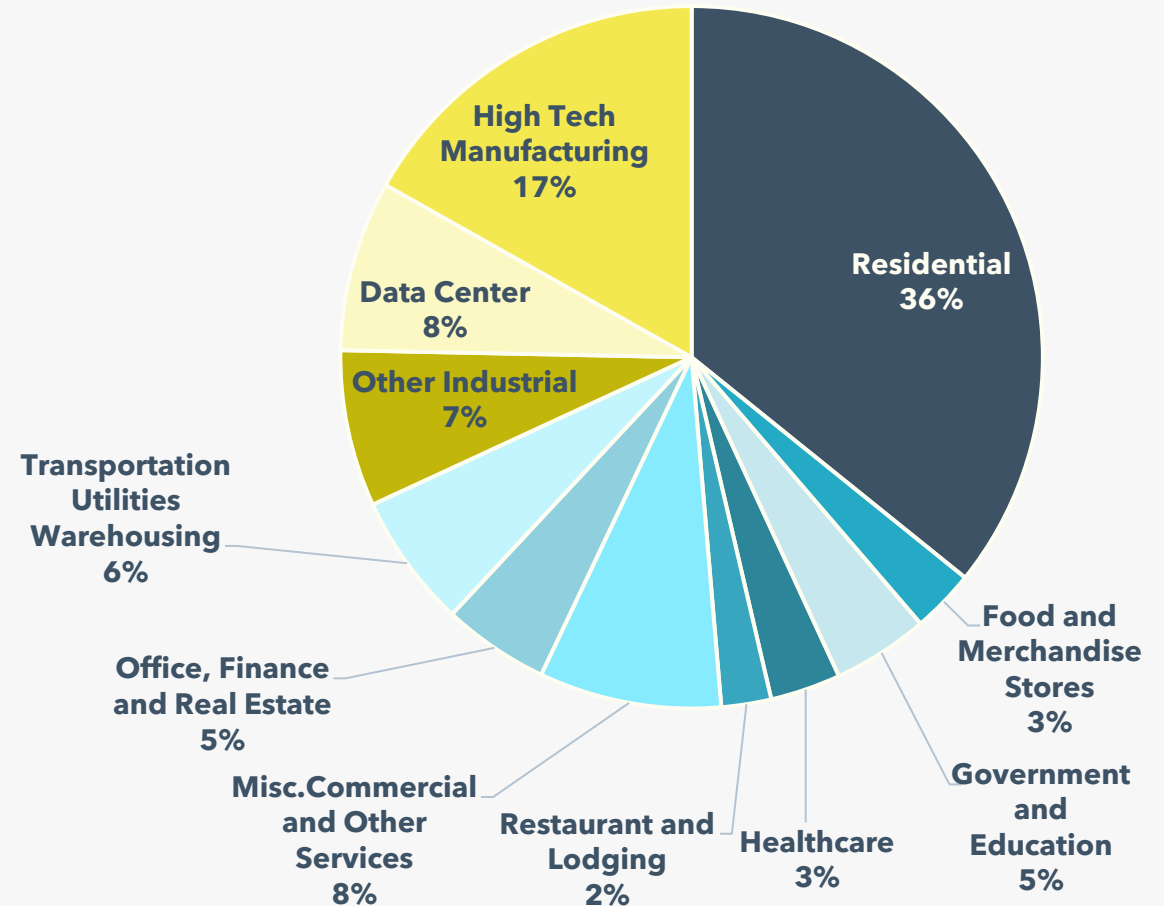
PGE's industrial load growth is fueled by rapid development in the Data Center segment

PGE's data center energy deliveries have expanded from under 50 aMW in Q2 2020 to over 300 aMW in Q2 2025

High-Tech manufacturing remains PGE's largest non-residential segment

Share of 2024 Energy Deliveries by Class

Coalition/301
Souder/11



Load Growth Trends

A load factor is the ratio of average to peak load, representing the 'peakiness' of a system or class load

Residential customers have a lower load factor as they are more sensitive to changes in temperature

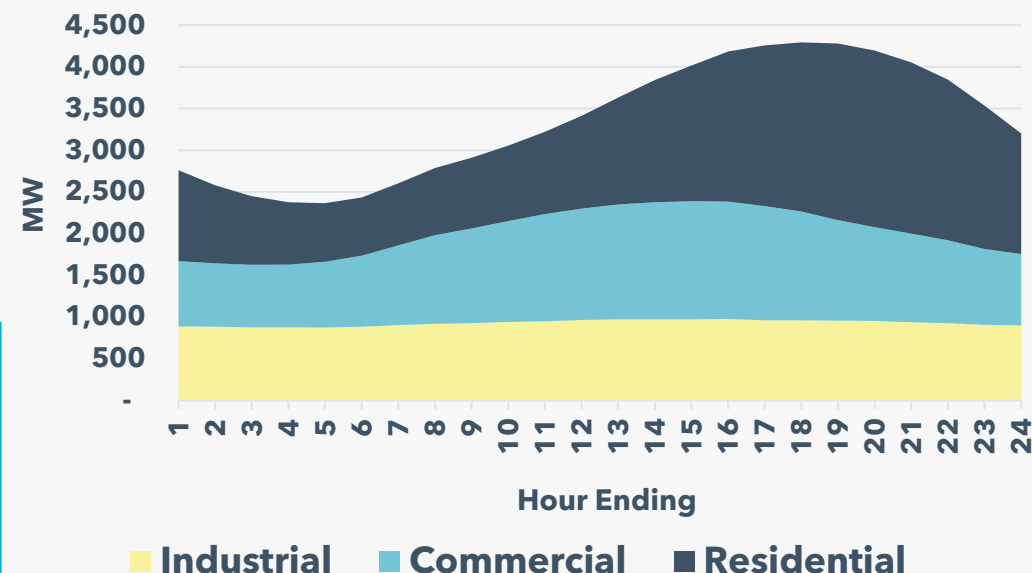
In recent years, increased saturation and utilization of air conditioning has **led to a lower system load factor**

Industrial customers have a higher load factor due to a more stable load shape

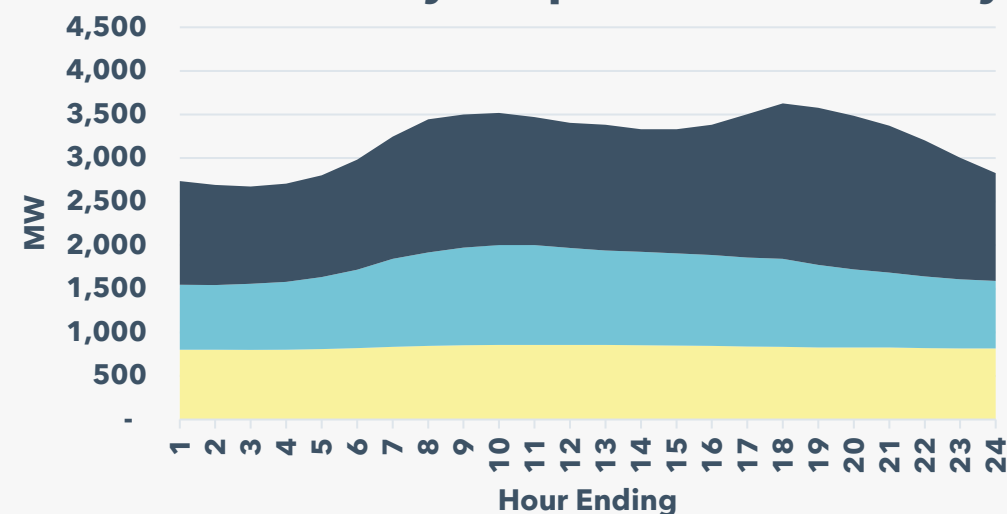
In the future, we expect the **system load factor to increase** as the share of industrial load increases

Our hourly model methodology allow for us to capture these changes

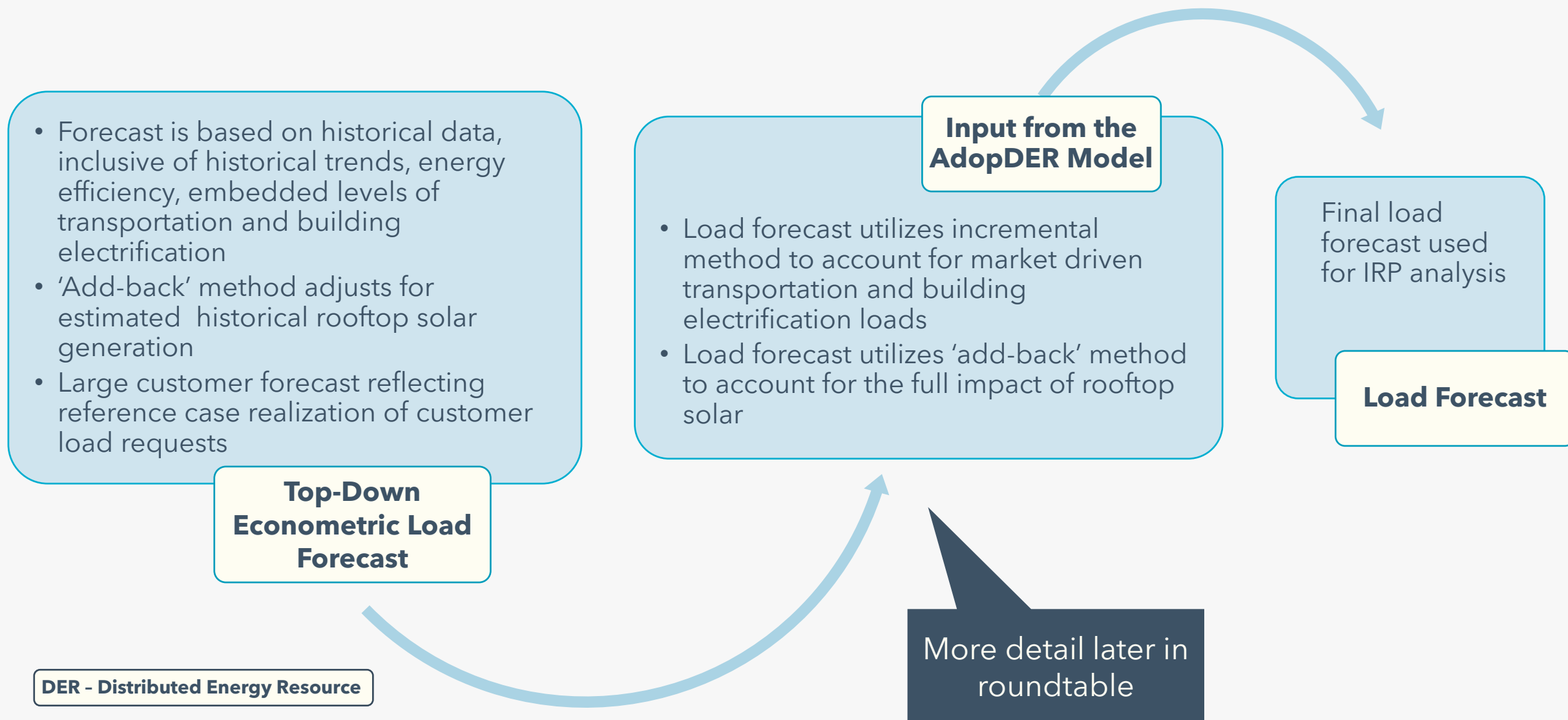
2024 Daily Shape Summer Peak Day



2024 Daily Shape Winter Peak Day



PGE's Load Forecasting Model



DER - Distributed Energy Resource

Energy Deliveries Model

Overview

Based on historical, monthly billing data

- Updated 2-4 times per year
- 3 sets of residential equations based on average usage and customer count
- 6 regression equations based on monthly energy deliveries by rate schedule
- Individual forecasts for large customers

Changes in Method

“Add-back” impact of rooftop solar to regression timeseries

+ accounts for rapid increase in rooftop solar adoption

Energy Deliveries Model

Residential Models

Estimation Period: UPC 2011-2025, Count 2000-2025,
Building Permits 2010-2025

Data Frequency and Source: Monthly, billing data

Grouping: Dwelling type

Model Type: ARIMA

Input Assumptions: Normal weather, including warming trend

UPC_s = fn (HDD, CDD, wind, energy efficiency, monthly indicators, COVID indicator)

Count = fn (Building Permits, monthly indicators, control indicators)

Building Permits = fn (Housing starts, construction employment, monthly indicators, control indicators)

Independent right-hand side variables

Heating and
cooling degree
days

Housing Starts

Energy
Efficiency
Forecast

Indicator
Variables
(COVID,
monthly)

Solar Add-back -
Single Family

ARIMA: Autoregressive Integrated Moving Average
CDD: Cooling Degree Day
HDD: Heating Degree Day
UPC: Usage Per Customer

Energy Deliveries Model

Non-Residential Rate Schedule Models

Estimation Period: 2011-2025

Data Frequency and Source: Monthly, billing data

Grouping: Rate Schedule

Model Type: ARIMA

Input Assumptions: Normal weather, including warming trend

Usage_s = fn (HDD, CDD, energy efficiency, employment, monthly indicators, control indicators)

Independent right-hand side variables

**Heating and
cooling degree
days**

**Oregon
Employment**

**Energy
Efficiency
Forecast**

**Indicator
Variables
(COVID,
monthly)**

**Solar Add-back -
(Rates 32, 83, &
85)**

ARIMA: Autoregressive Integrated Moving Average

CDD: Cooling Degree Day

HDD: Heating Degree Day

Energy Deliveries Model

Non-Residential Large Load

Individual customer forecasts for approximately 30 large customers, 26% of 2024 system deliveries

- Focus on large sites with high energy intensity
- Usage is less dependent on regional economic indicators
- Can experience sudden or drastic changes in operations

Customers may be eligible for direct contracting through UM 2377

More on how new large loads will be considered in IRP analysis in future roundtables

Independent right-hand side variables

Customer requests

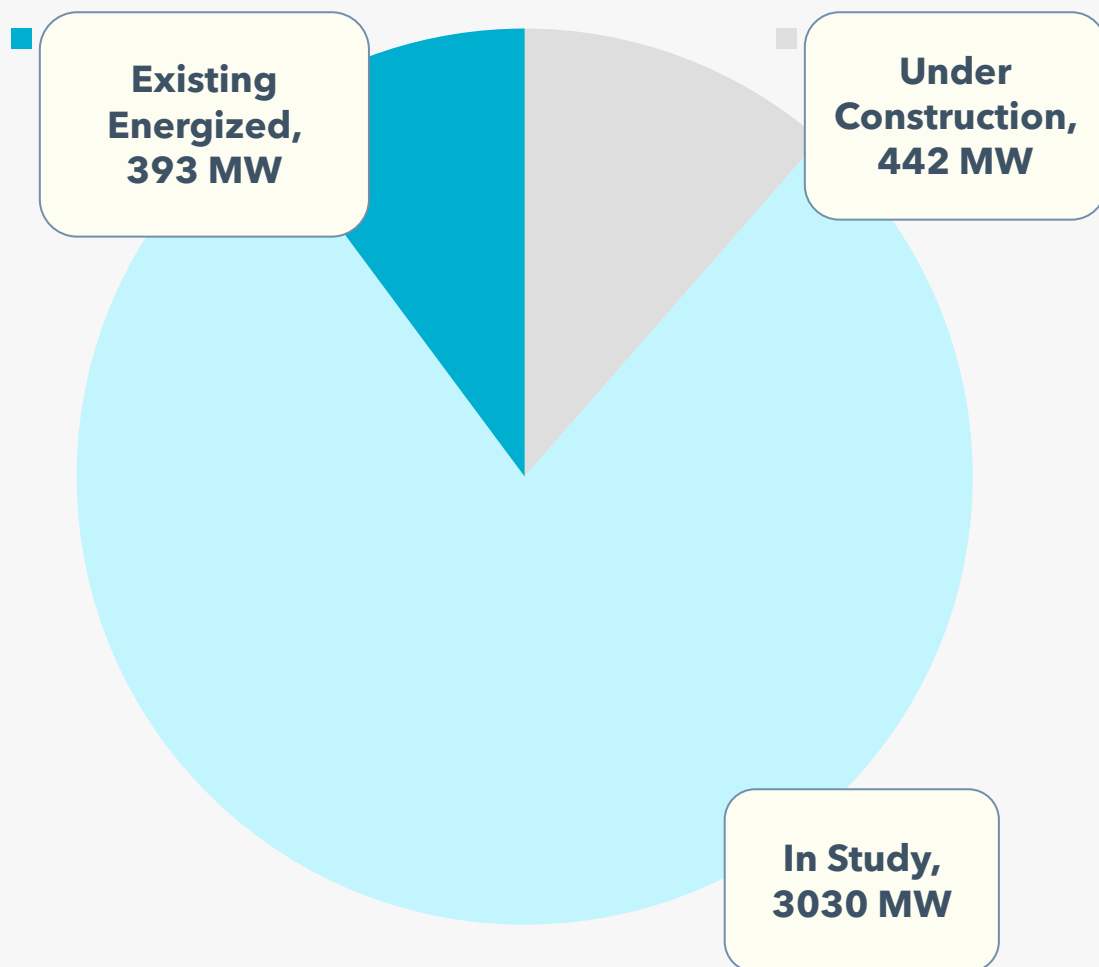
Historic load ramp and comparison to like customer

Segment level industry reports

Company credit review

Energy Deliveries Model

Capacity Request Pipeline Informs the Large Load Forecast



Robust pipeline informs the load forecast

Uncertainty in project realization rate and load ramp timing remain key risks to the outlook

Reference case forecast assumes large load of 1 GW by 2030 and 2 GW by 2040



Existing and Energized

393 MW of capacity from existing and fully energized customers continuing to ramp between 2025 and 2030



Under Construction

442 MW of capacity under construction with energization and ramping occurring in the next several years



In Study

3030 MW from data center applications
Studies underway with initial contracting in Q4

Preliminary Energy Deliveries Forecast

Long term growth rates

Average 20 Year Growth Rate: 3.8%

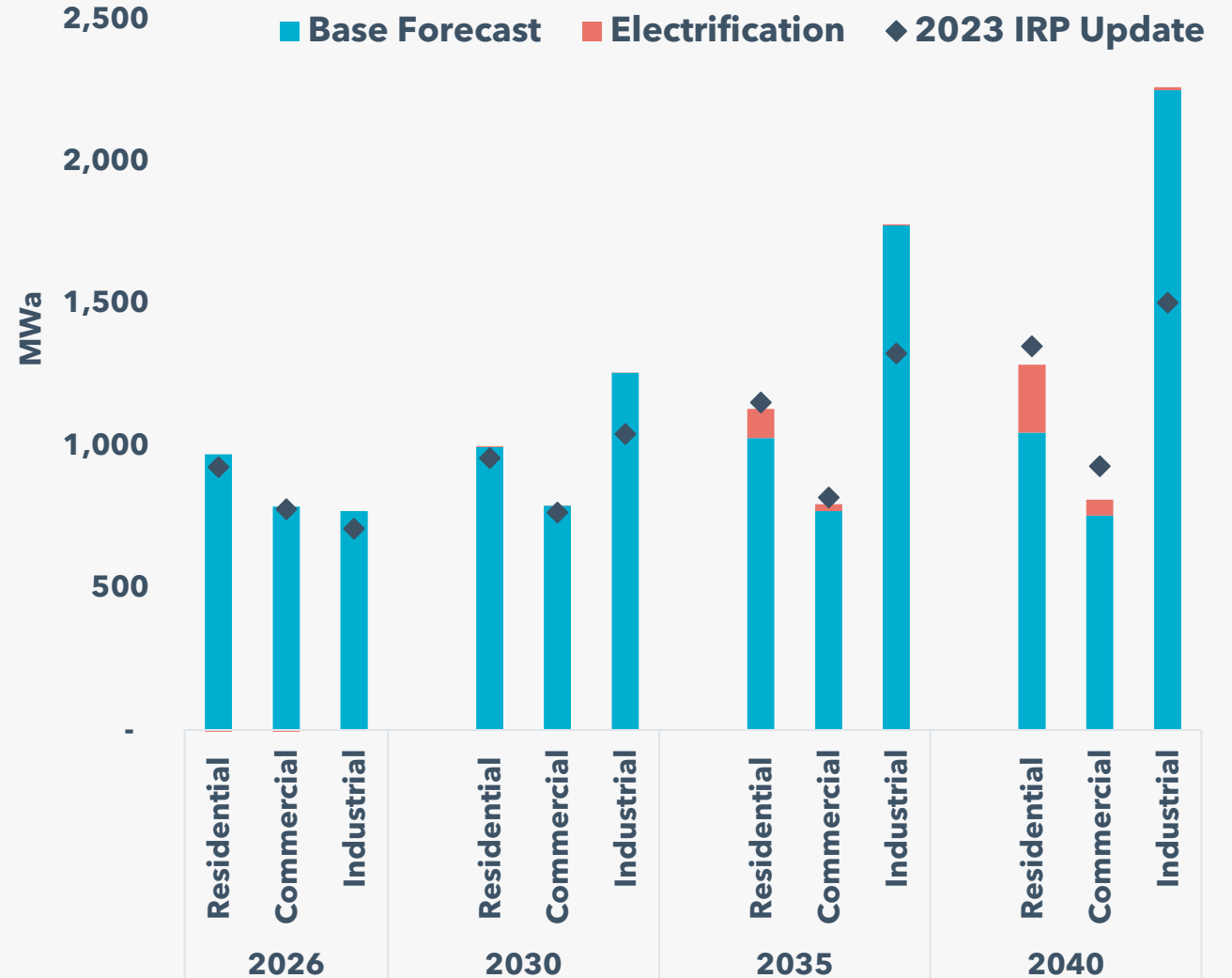
Including the impact of Rooftop Solar, Transportation and Building Electrification

The **residential and commercial** sectors show only modest growth on the five-year horizon. Growth accelerates when electrification begins to outpace rooftop solar

The **industrial** sector is expected to continue to **grow rapidly**, driven primarily by data centers

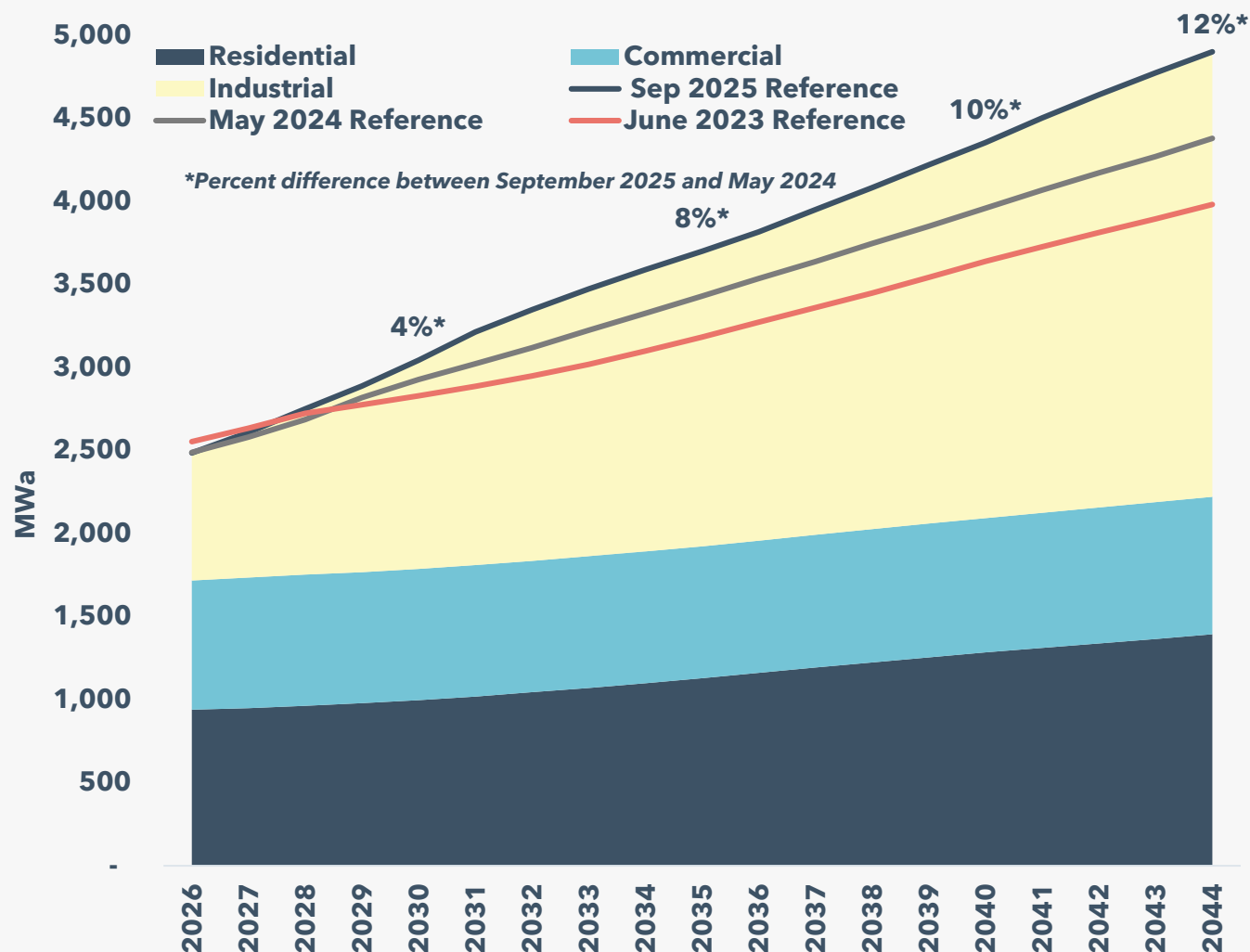
Significant uncertainty remains in the long-term realization of new load requests

The industrial segment **quickly outsizes** residential and commercial segments



Preliminary Energy Deliveries Forecast

Comparison to Prior Vintages



20 Year Average Annual Growth Rates

	June 2023 Reference	May 2024 Reference	September 2025 Reference
Total Energy	2.6%	3.2%	3.8%
Residential	2.2%	2.3%	2.2%
Commercial	2.3%	2.3%	0.3%
Industrial	3.4%	5.2%	7.2%

Decreased electrification forecast, specifically for the commercial sector, is more than offset by increased large customer growth

Hourly Load Simulations

Overview

Key output: Hourly Load Simulations over 210 draws and Peak Demand forecast

- Based on historical, hourly load research data
- Updated once per year
- 3 sets of hourly equations by customer class – residential, commercial, industrial
- Simulations using 30 historical weather years * 7 day of week start
- Scaled to align with average energy from the energy deliveries model

Changes in Method

“Add-back” impact of rooftop solar to regression timeseries

+ accounts for rapid increase in rooftop solar adoption

Hourly Load Simulations Specification

Estimation Period: 2019-2024

Data Frequency and Source: hourly, load research

Grouping: Customer Class

Model Type: Fixed Effect

Input Assumptions: Average usage across simulation compared to monthly forecast to create scale factor

Output: 210 Simulations based on 30 weather years and seven day of week adjustments

Hourly Usage_{SD} = fn (CDD, CDD build up, HDD, HDD build up, wind, trend, indicator variables)

Independent right-hand side variables

Heating and
cooling degree
days, and other
weather

Solar Addback

Demand Response
Addback

Trend

Indicator Variables
(COVID, monthly,
DOW, extreme
events)

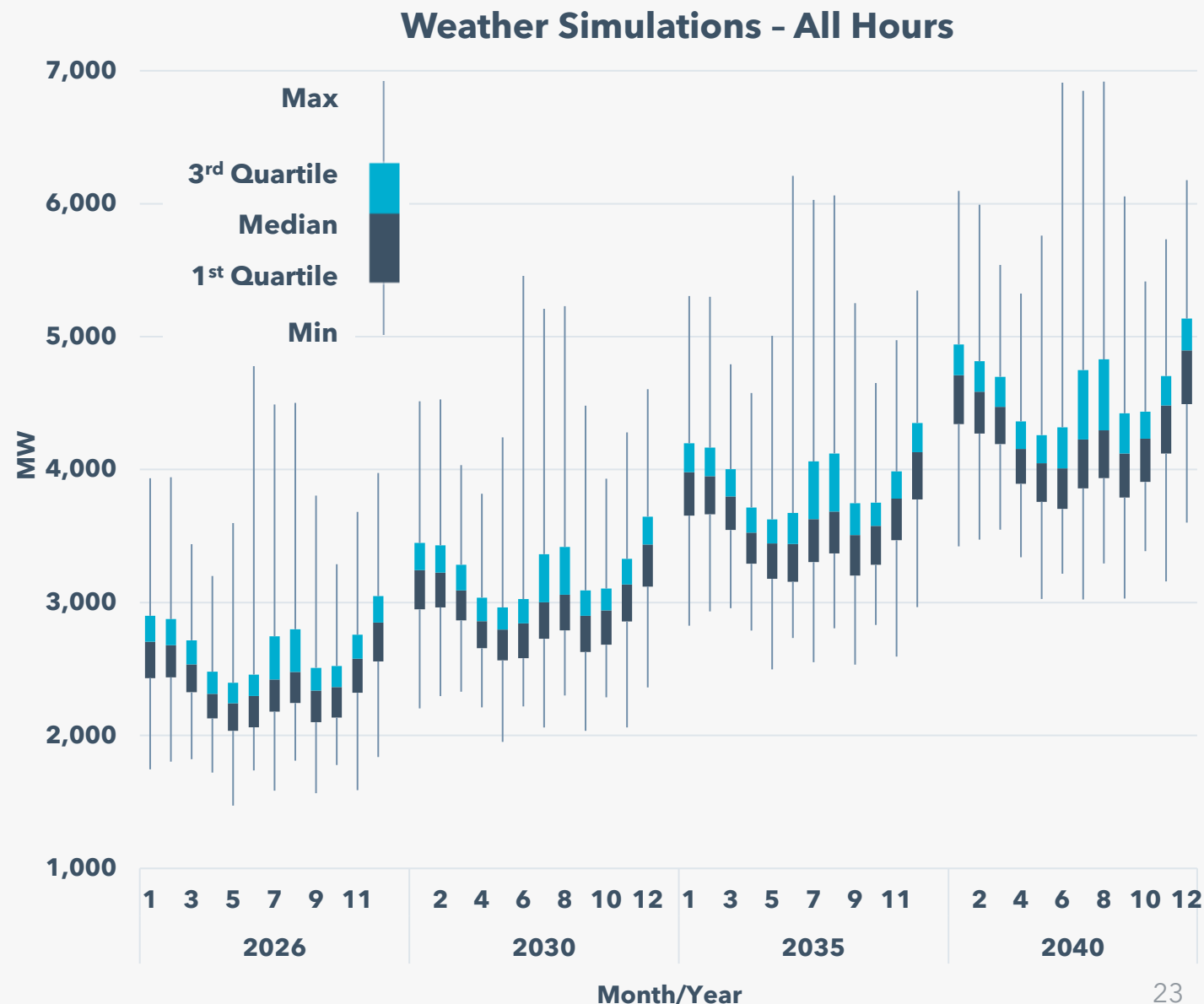
CDD: Cooling Degree Day
HDD: Heating Degree Day

Preliminary Hourly Load Simulations

Results

Simulations create 210 future scenarios used to match supply with demand and assess capacity need under different weather conditions

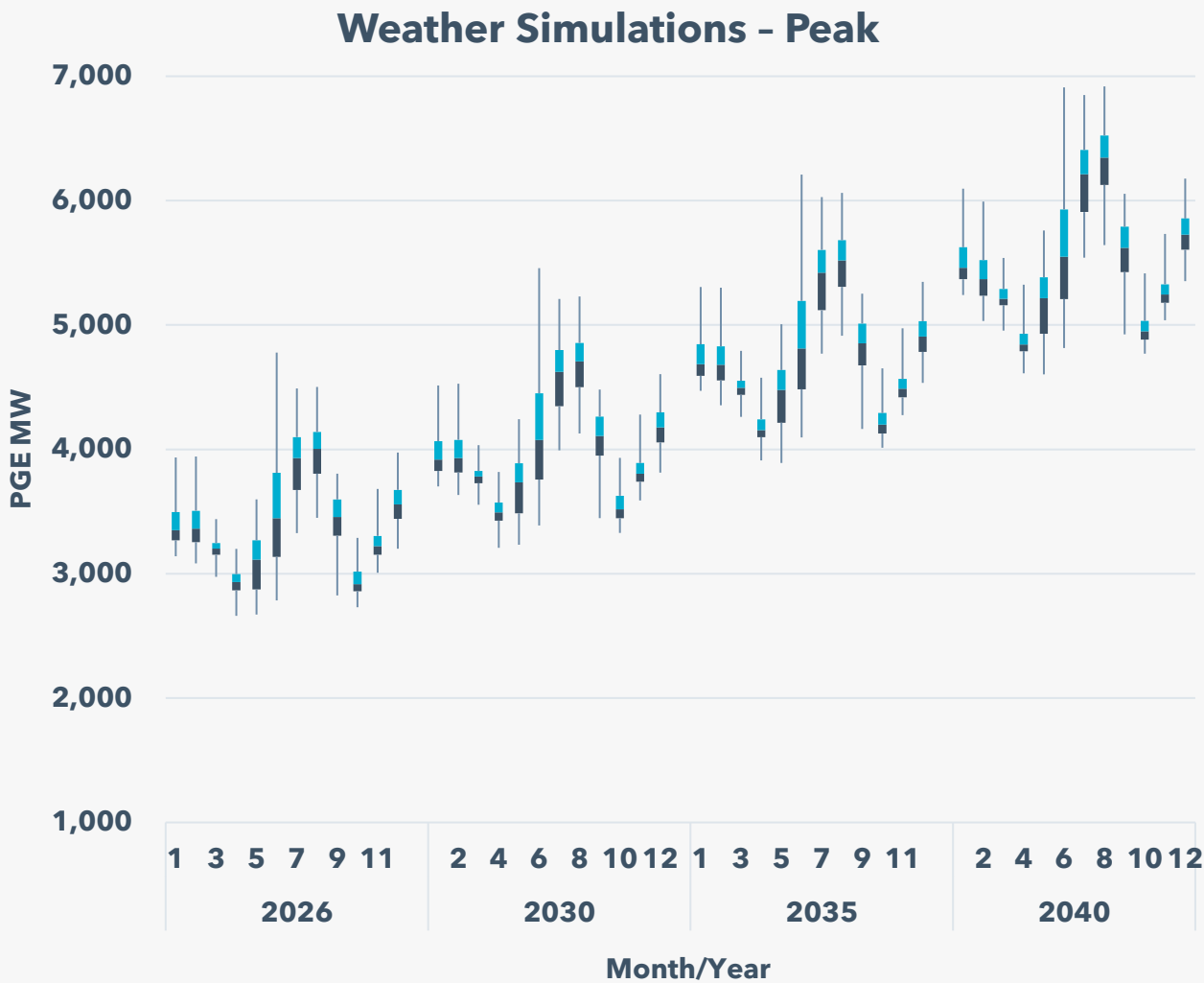
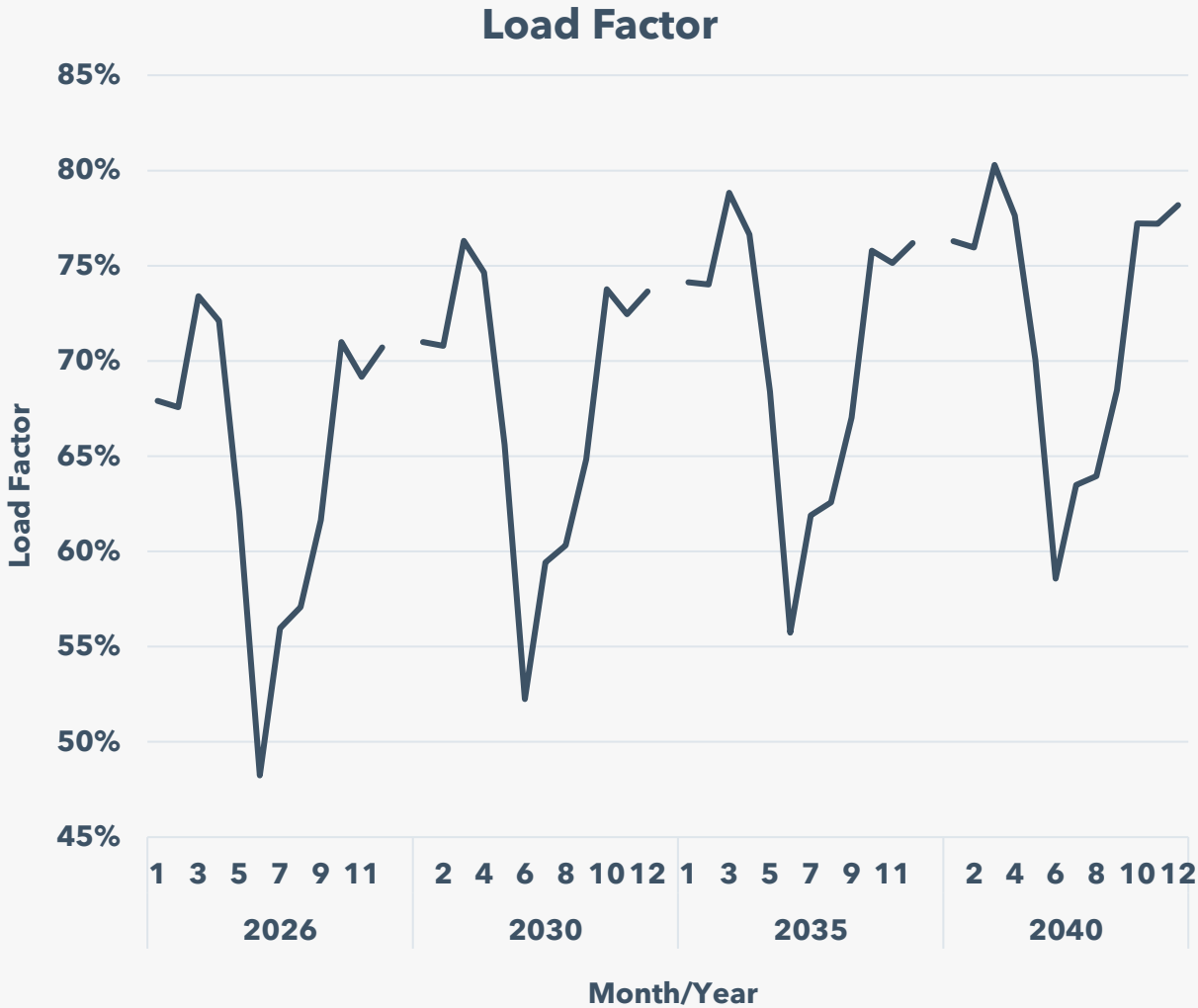
Load factor increases over time driven by increased industrial deliveries flattening total load shapes





Preliminary Hourly Load Simulations

Results

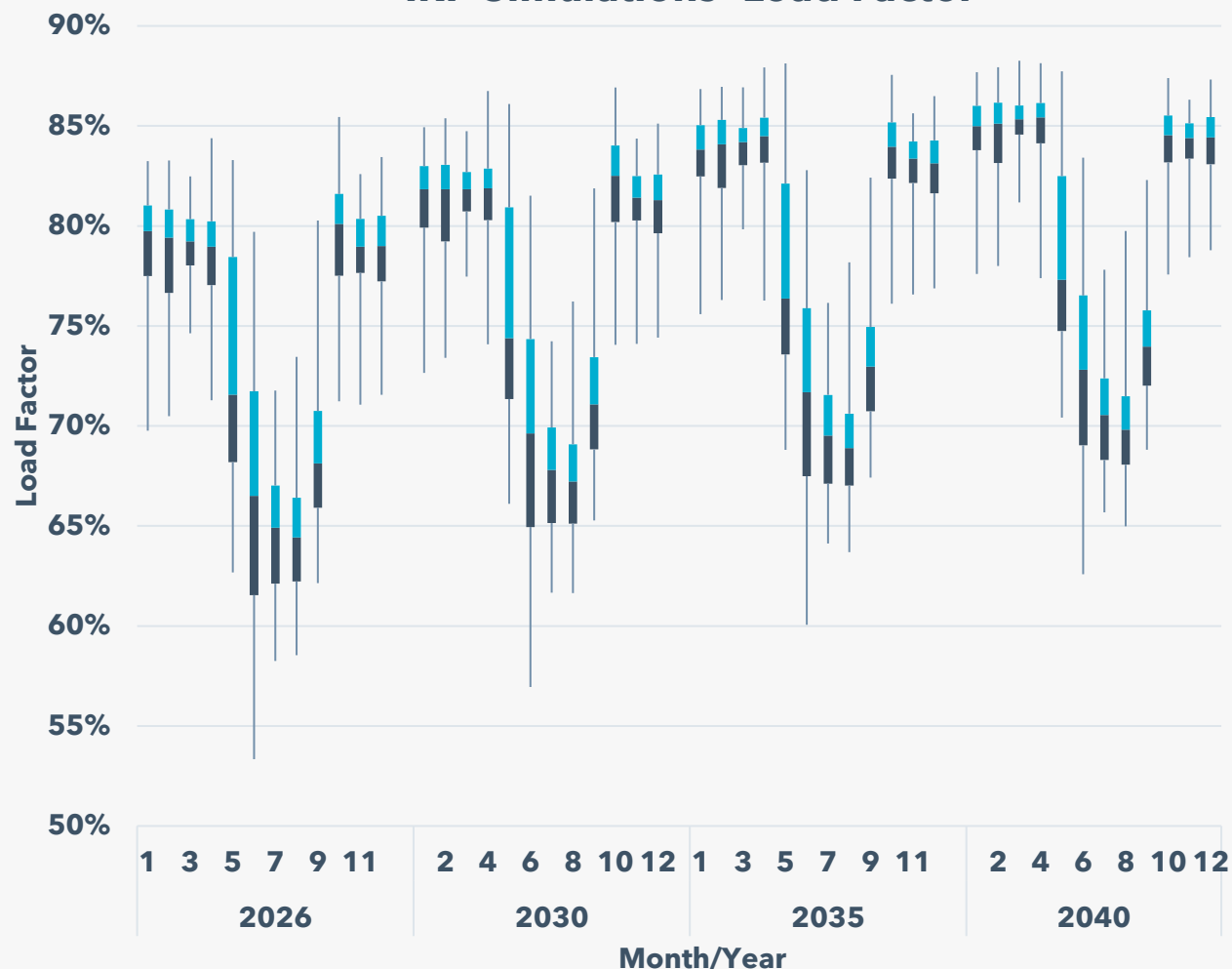




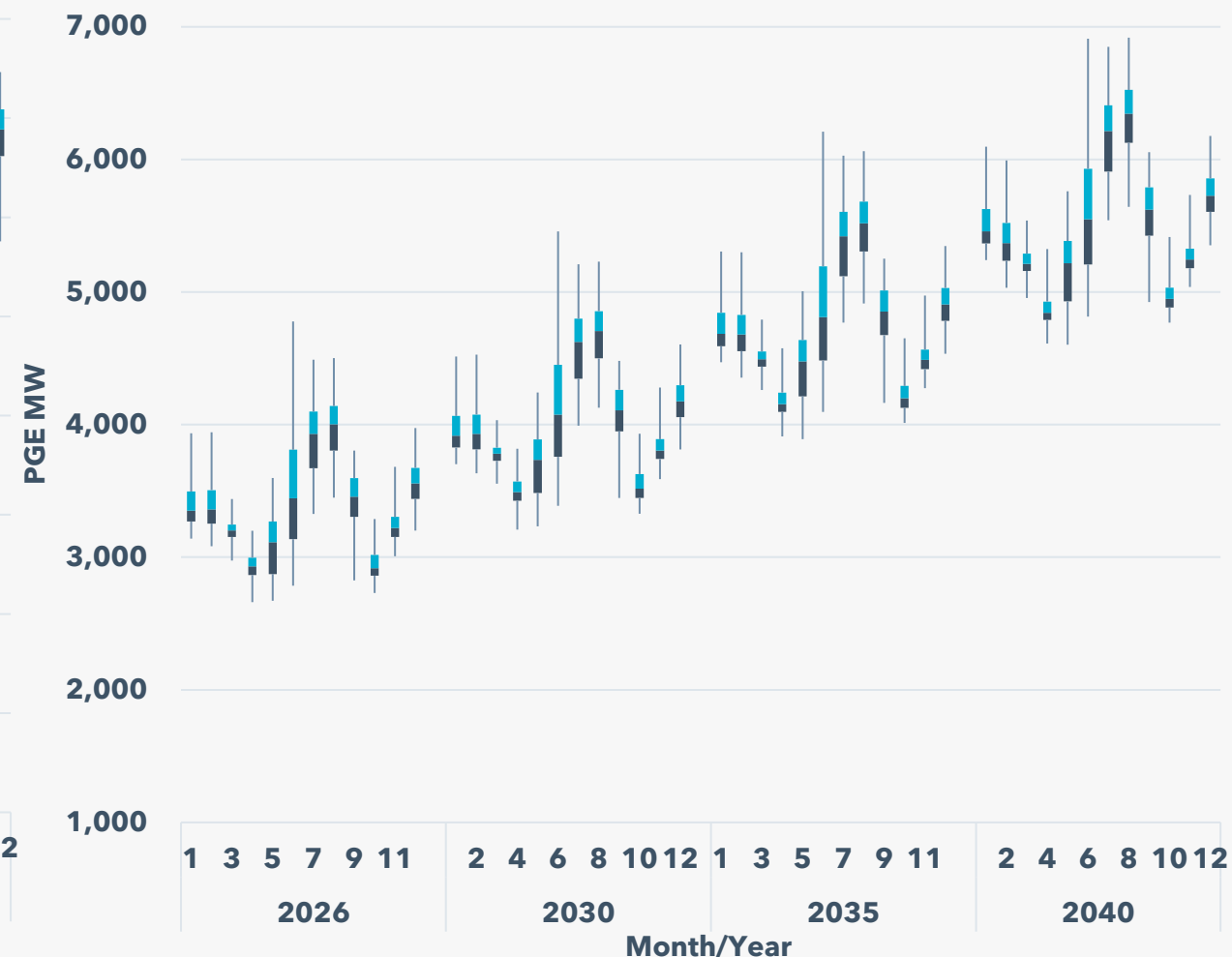
Preliminary Hourly Load Simulations

Results

IRP Simulations -Load Factor



Weather Simulations - Peak



Addressing Uncertainty

The load forecast centers around a reference case point estimate. However, the IRP process considers uncertainty associated with load in several ways

- Forecast updates to account for new information
- High and Low load forecasts are developed based on varying economic inputs
- Weather uncertainty is considered within the resource adequacy model Sequoia

Scenario Development

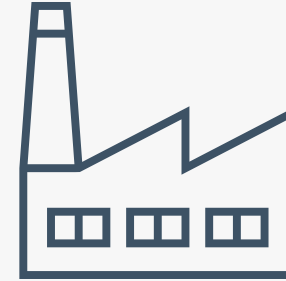
Key Inputs



Customer Growth



Economic Conditions



Data Center Expansion



DER Adoption

Reference Case

September 2025 forecast from Oregon's Office of Economic Analysis. 10-year avg customer count growth 1.1%

September 2025 forecast from Oregon's Office of Economic Analysis. 10-year AAGR of 0.5%

Existing segment of approx. 400 MW increases to 1 GW in 2030 and 2 GW in 2040

Alignment with today's reference case AdoptER forecast. Current Federal and State policy assumptions

High Case

Policy steps are successful at encouraging increased building. Growth in customer count is 0.5% higher.

Optimistic case, employment in Oregon posts modest gains in the near term 10-year AAGR of 1.0%

Rapid expansion, segment increases to 2 GW in 2030 and 3 GW in 2040

Scenarios to be built out in future sessions

Low Case

Economic conditions weigh on housing. Growth in customer count is 0.5% lower.

Near term recession case, employment growth continues to fall in Oregon before a slow recovery. 10-year AAGR of -0.1%

Constrained growth, 500 MW in 2030 and 600 MW in 2040

Primary driver of residential usage per customer in the forecast period

Summary / Highlights / Next Steps

Preliminary load forecast shows increased total energy outlook, driven by large customer growth

The load forecast that will inform the 2026 IRP will be finalized to include final AdopDER results and Energy Efficiency forecasts from the Energy Trust this Fall

This forecast will inform the 2026 IRP resource need and portfolio/scenario analysis

Details on these topics to be discussed at future roundtables



Guided Feedback – Corporate Load Forecast

- What do you see as the biggest risks to PGE's load forecast?



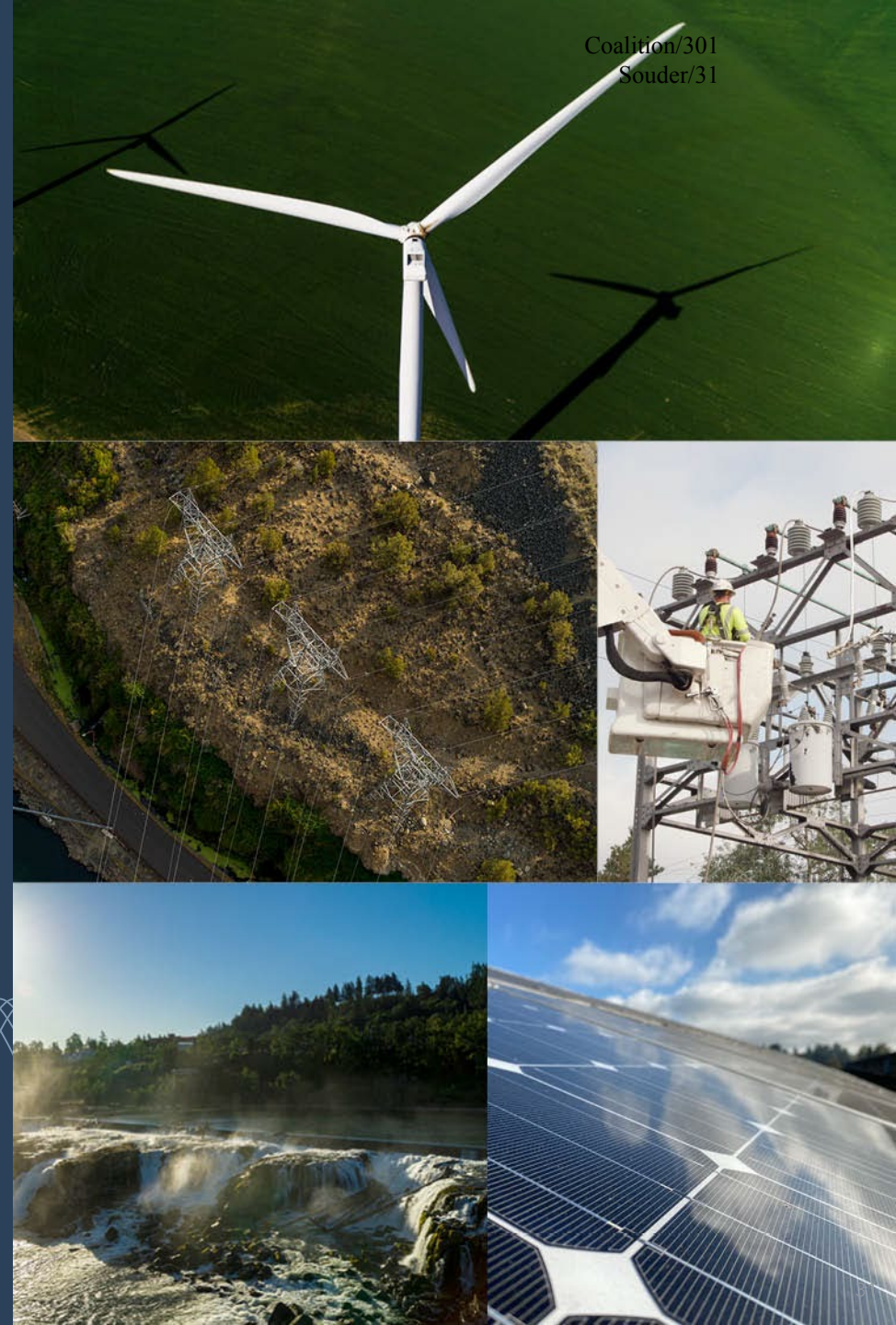
Questions



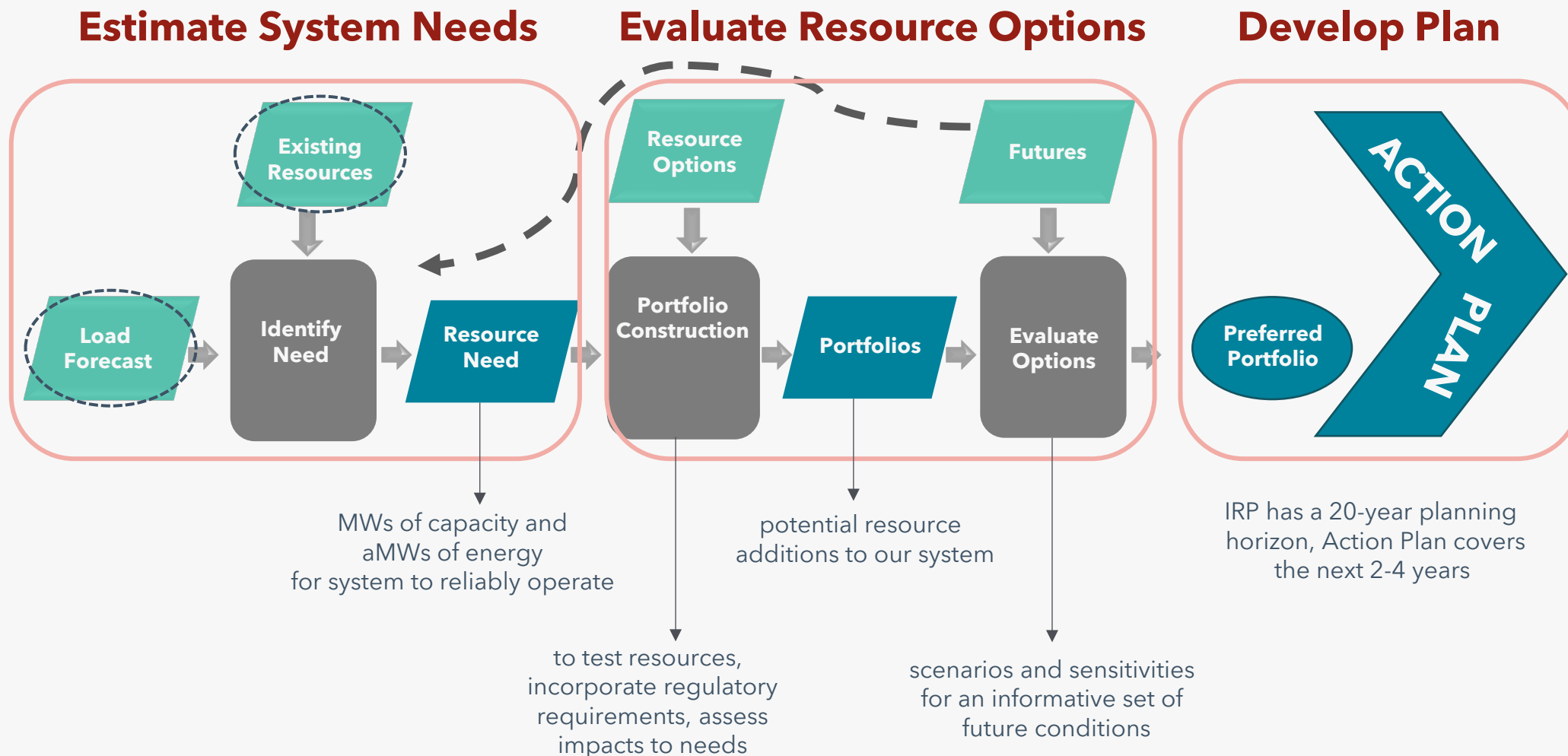
Draft AdopDER Forecast

Kyle Billeci, PGE

Principal Strategy & Planning Analyst



High-Level IRP Analysis Process



DER Forecast Topics

AdopDER Overview

Recalibration of Inputs & Assumptions

Results by Scenario

Comparison to 2023 IRP Update

AdopDER is...

Python-based site-level simulation model

Forecasts the adoption of **50+ distributed energy resources (DER)**

Simulates **locational, 8760 hourly load impacts** from co-adoption of DERs and electrification

Supports resource planning and distribution planning processes



**Full methodology & technical details documented in [DSP Part 2](#) (Chapter 3).*

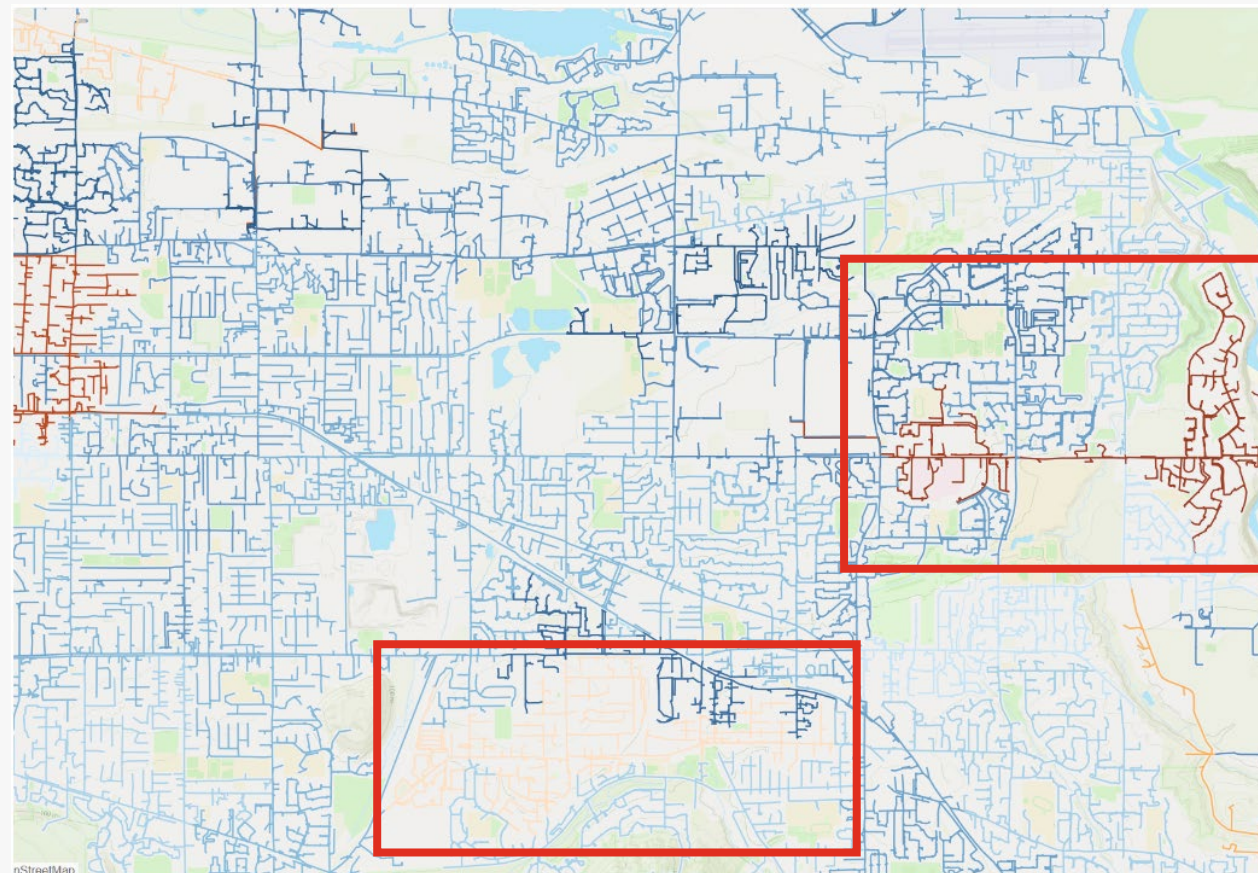
AdopDER's Purpose

- 1) Estimate future **total** DER adoption & impacts
- 2) Forecast **where** DERs will be most impactful

Future load growth is not spread evenly across the distribution system and AdopDER forecasts where those expected trends of DERs will be

DERs included in PGE's forecast include:

- Building Electrification
- Transportation Electrification
- Solar & Battery Storage
- Demand Response/Flex Programs

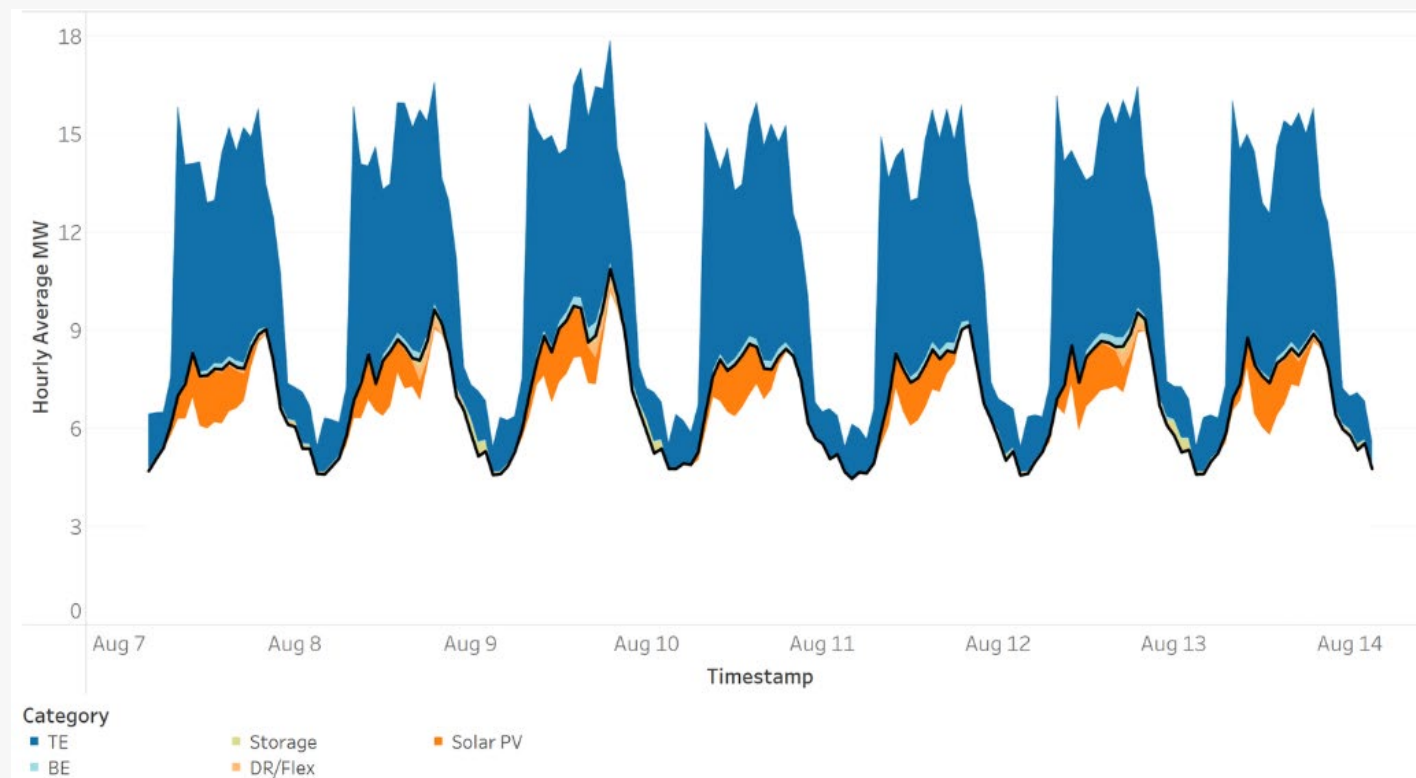


Feeder-level map of constrained feeders

AdopDER's Output

AdopDER produces estimated **8760 hourly load impacts for 20 years** to:

- Estimate feeder-level load growth
- Estimate available resources PGE can implement to mitigate load growth
 - VPP (DSP)
 - Customer Programs (MYP)
- Evaluate the cost effectiveness of individual DER measures and measure bundles
- IRP forecast will cover 2026-2045



Example of feeder-level load profile of DERs during a given week

**Black line is baseline load shape of feeder without DERs*

How AdopDER Informs PGE

Integrated Resource Plan (IRP)

- DER capacity and energy impacts included in load forecasts and resource adequacy

Transportation Electrification Plan (TEP)

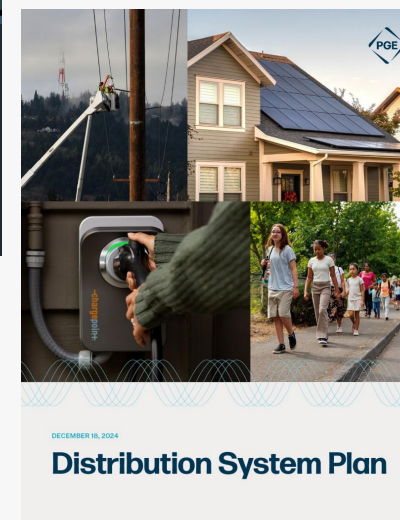
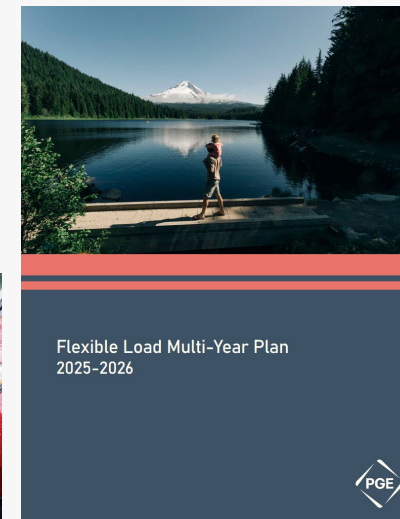
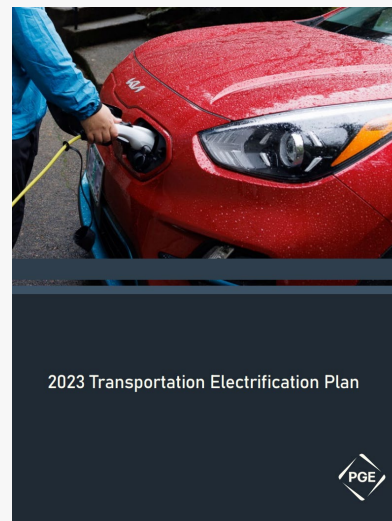
- Forecast of EV adoption and charging load by segment to inform infrastructure needs and program design

Distribution System Plan (DSP)

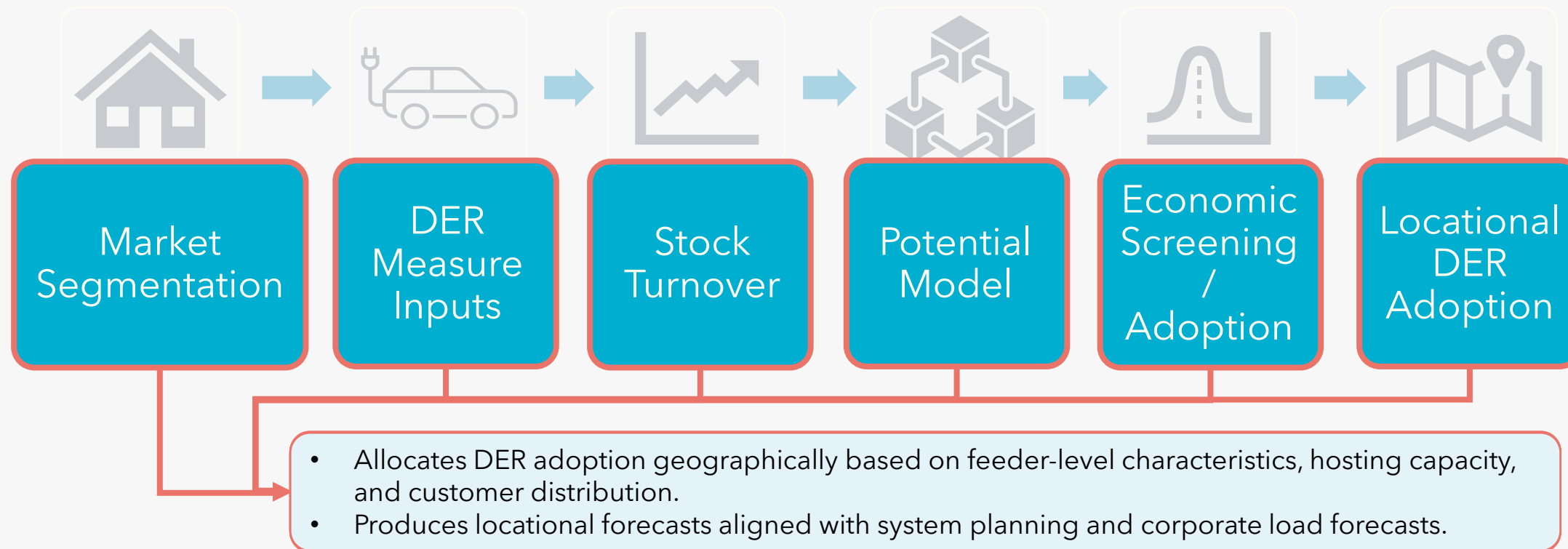
- Locational DER capacity potential and adoption to assess hosting capacity, grid needs, and non-wire solutions

Multi-Year Plan (MYP)

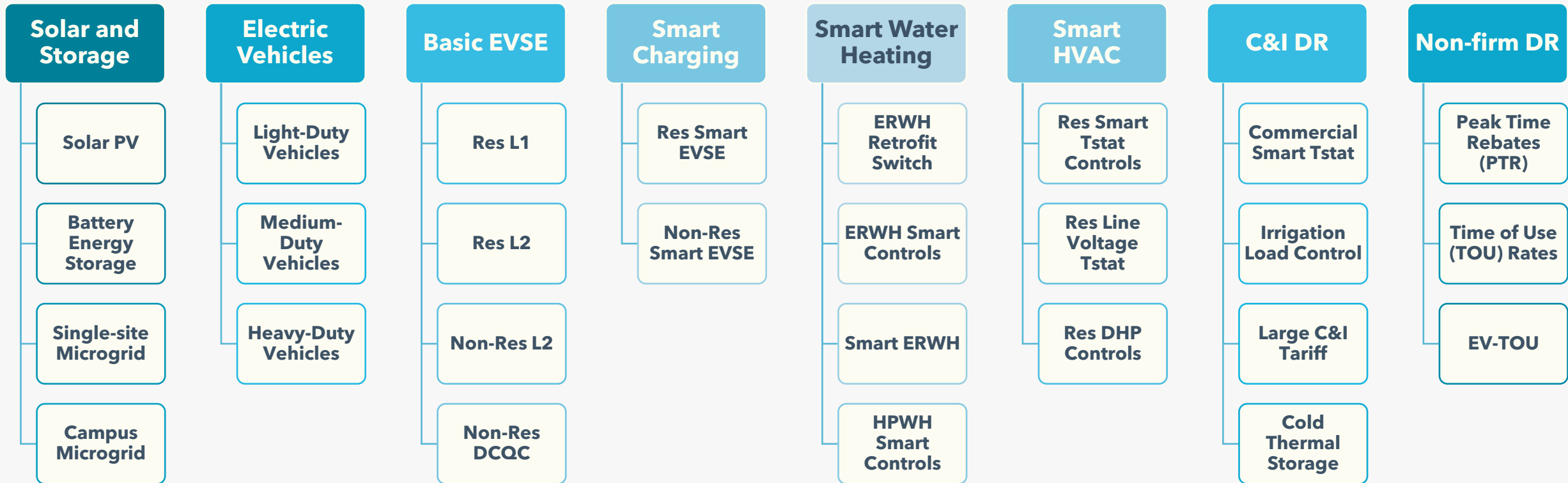
- Inform corporate load forecast and expected system demand trends to reflect net system load after DER growth



AdopDER Simplified



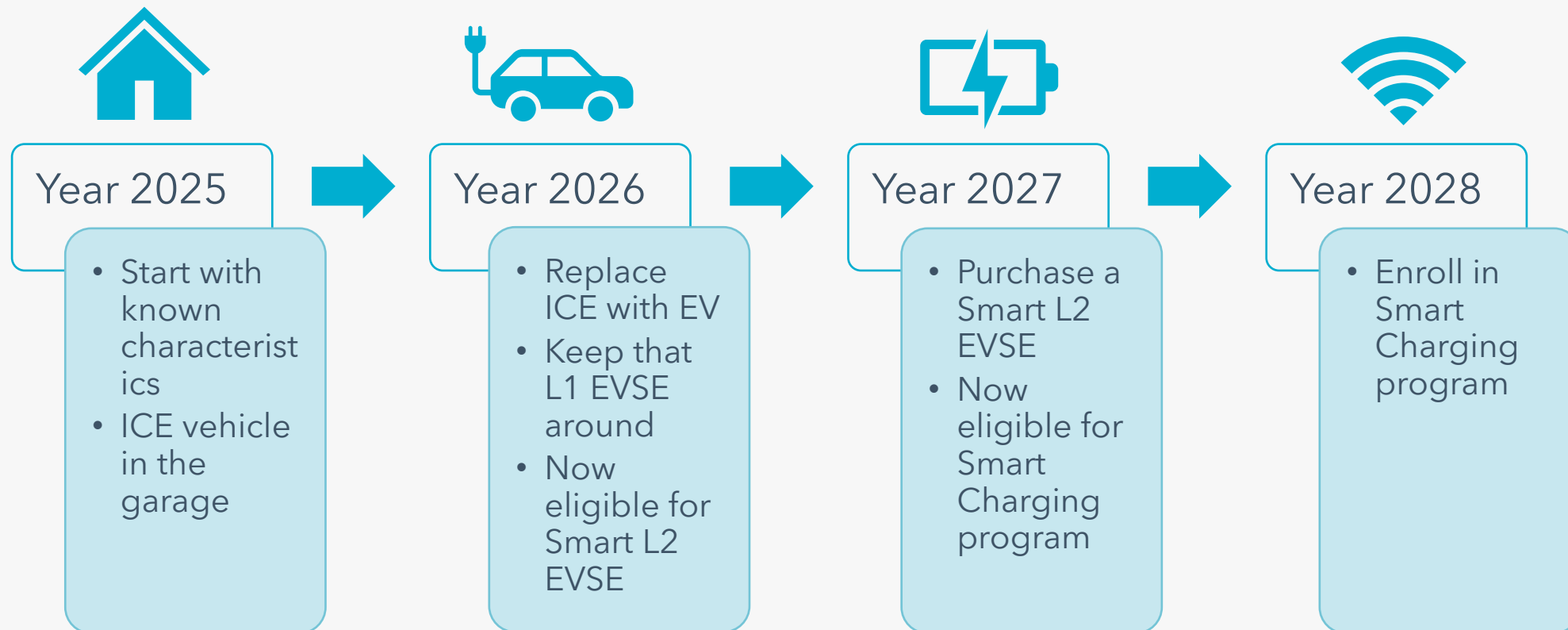
DER Measure Inputs



DER Customer Journey

Step 1: Adoption

Hypothetical Example of DER Adoption



ICE: Internal Combustion Engine
EV: Electrical Vehicle
EVSE: Electric Vehicle Supply Equipment (Charger)
L1: Level 1 Charger
L2: Level 2 Charger

Apply DER Load Impacts

Step 2: Load Impacts

Feeder-Level load, no
DER adoption

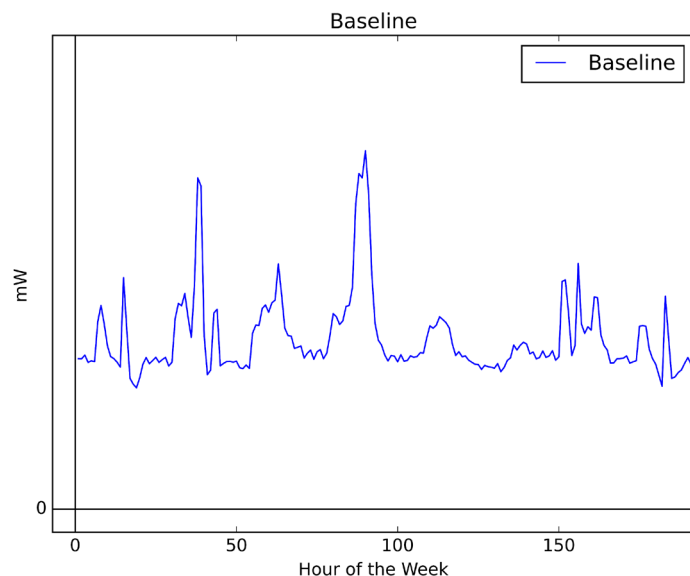


Apply load impacts for
each DER measure

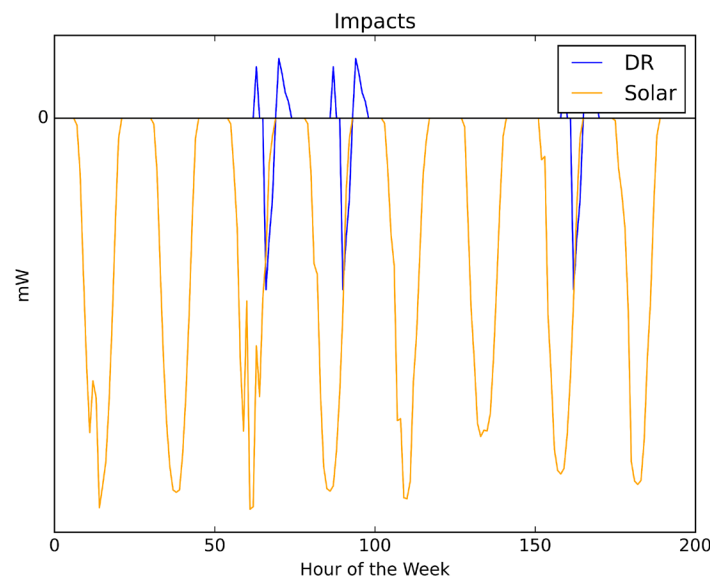


Feeder-level load with
DER adoption

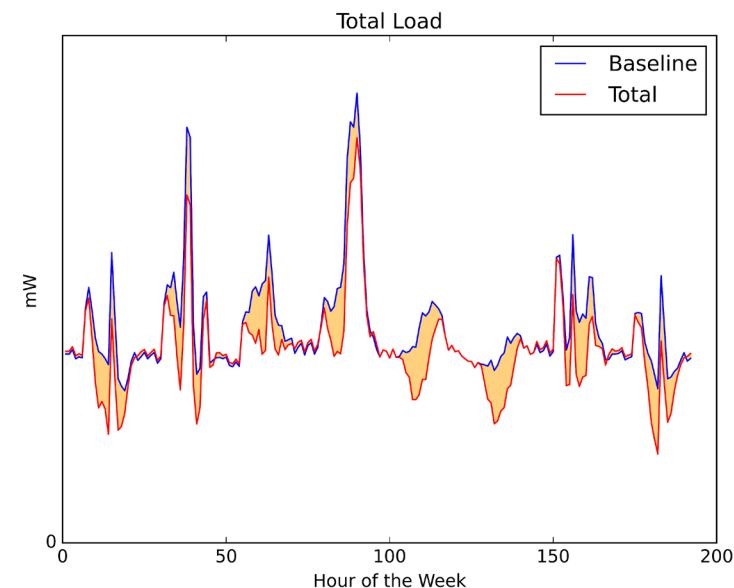
Predicted Hourly Feeder Load (MW, Aug 2030)



Predicted DER Load Impacts (MW, Aug 2030)



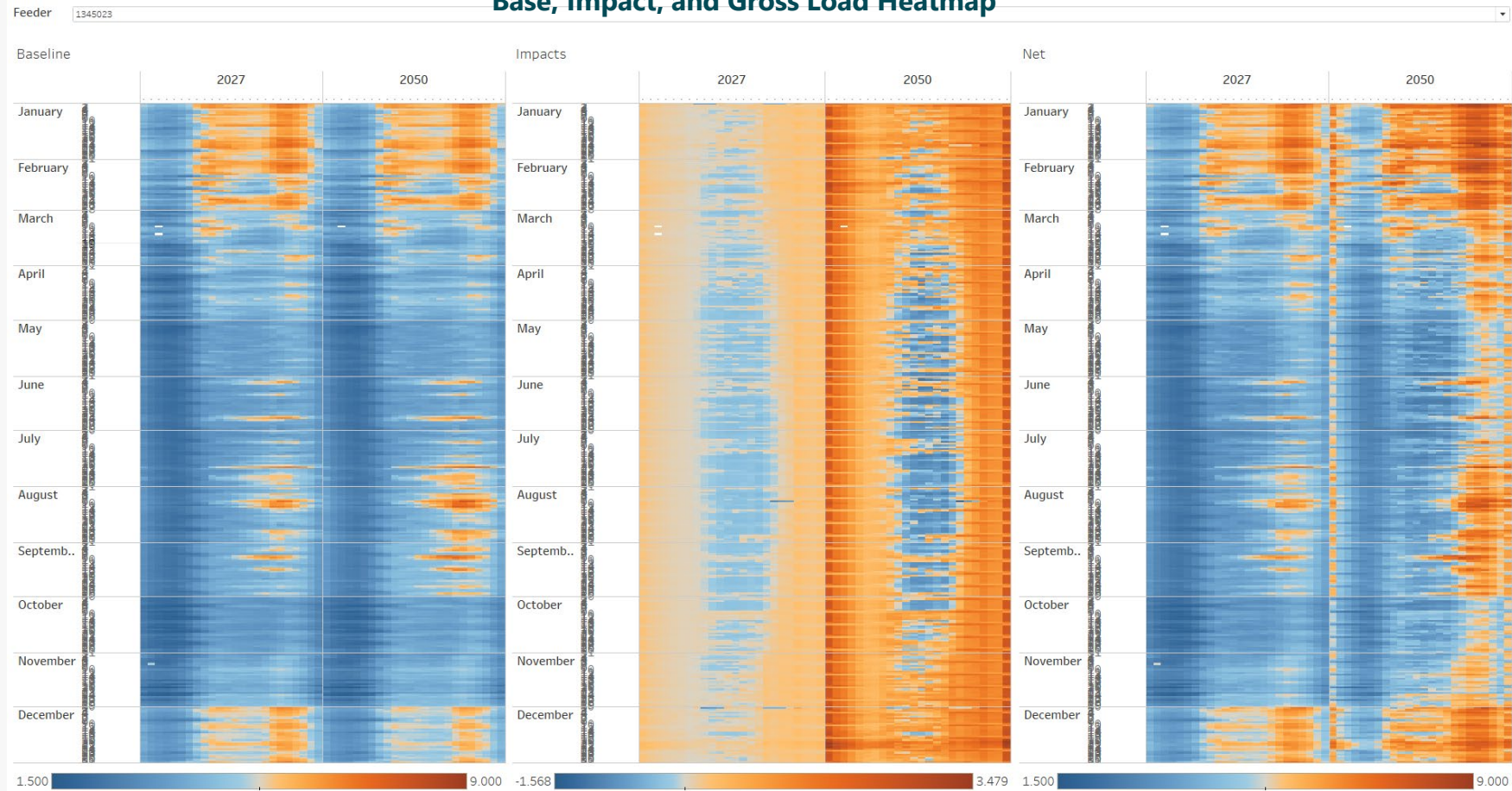
Predicted Hourly Feeder Load (MW, Aug 2030)



Produce Hourly Load Impacts

Step 3: Reporting

Island Substation, Feeder 1345023 Base, Impact, and Gross Load Heatmap



Assumption Updates

(since 2023 IRP Update)

- Refreshed DMV LDV registrations and MDV/HDV counts and locations
- Refreshed public/private EVSE charging infrastructure
- Refreshed solar and storage project additions and corrections
- Updated PGE Flex Program Participants
- Updated known large load additions
- Updated 2024 AMI data
- Updated 2025 corporate load forecast
- Updated light-duty vehicle, rooftop solar, and battery storage adoption curves
- Recalibration of EVSE charging impacts per vehicle
- Adjustment to NREL ATB pricing based on tariffs
- Implementation of "Big Beautiful Bill" impacts on federal incentives

Electric Vehicles



Oregon's ZEV Adoption Targets: SB 1044

In 2019, [Senate Bill 1044](#) outlined new Zero Emission Vehicle adoption targets for Oregon:

- 50,000 registered ZEVs on Oregon roads by 2020
- 250,000 registered ZEVs on Oregon roads by 2025
- At least 25 percent of registered vehicles and at least half of the new vehicles sold annually are ZEVs by 2030
- At least 90 percent of new vehicles sold annually are ZEVs by 2035.

[SB 1044](#) (Page 2)

ZEVs by Type as of June 2025

BEV	PHEV
85,507	35,467

Total ZEVs

120,974

[ODOT EV Dashboard](#) (June 2025)

- AdopDER was previously calibrated with aggressive adoption curves given availability of incentives, previous historical success, and state goals.

PGE-Specific Impacts

ZEVs by Type as of June 2025

BEV	PHEV
62,175	12,685

Total ZEVs

74,860

Press Release · August 7, 2025

Oregon DEQ to suspend EV Standard Rebate as of Tuesday, Sept. 9

Electric vehicle shoppers race to claim \$7,500 tax credit before September 30

- Recalibrated adoption curves and level-set with currently registered/operating EVs in PGE territory and available incentives:
 - Removal of any federal EV credits in 2026+
 - Removed \$2,500 Oregon Clean Vehicle Rebate for non-low income
 - Recalibrated adoption based on historical trends vs. policy timelines/goals
 - Delay of Advanced Clean Trucks (no enforcement until 2027)

Assumption Updates

(since 2023 IRP Update)

- Refreshed DMV LDV registrations and MDV/HDV counts and locations
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- Refreshed solar and storage project additions and corrections
- Updated PGE Flex Program Participants
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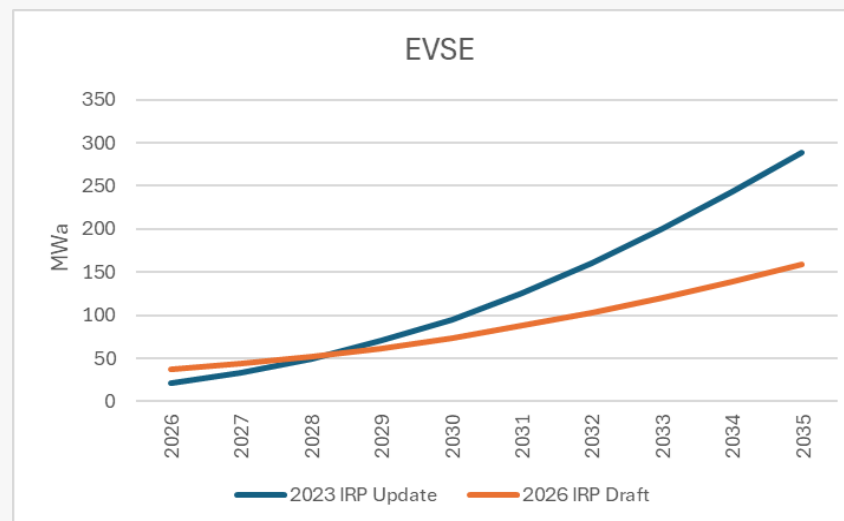
Electric Vehicle Chargers (EVSE)



- Refreshed Alternative Fuels Data Center charger location/type/ports data
 - Now includes locational and charger counts for program and non-program enrolled PGE customers not captured in AFDC

EVSE Charging Impacts Calibration

- Misrepresentation of EV driving patterns and charging trends were causing lower than expected EVSE charging impacts.
- **Goal:** Simplify the process by breaking down the analysis into pieces:
 - Average vehicle miles travelled by weight class
 - kWh charging need per mile
 - Mileage criteria for PHEVs (45% electric)
 - Home vs. Public/Workplace Charging (80% home vs. 20% public)



$$aMW = \frac{kWh \text{ per mile} * VMT}{\text{hours per year}}$$

Assumption Updates

(since 2023 IRP Update)

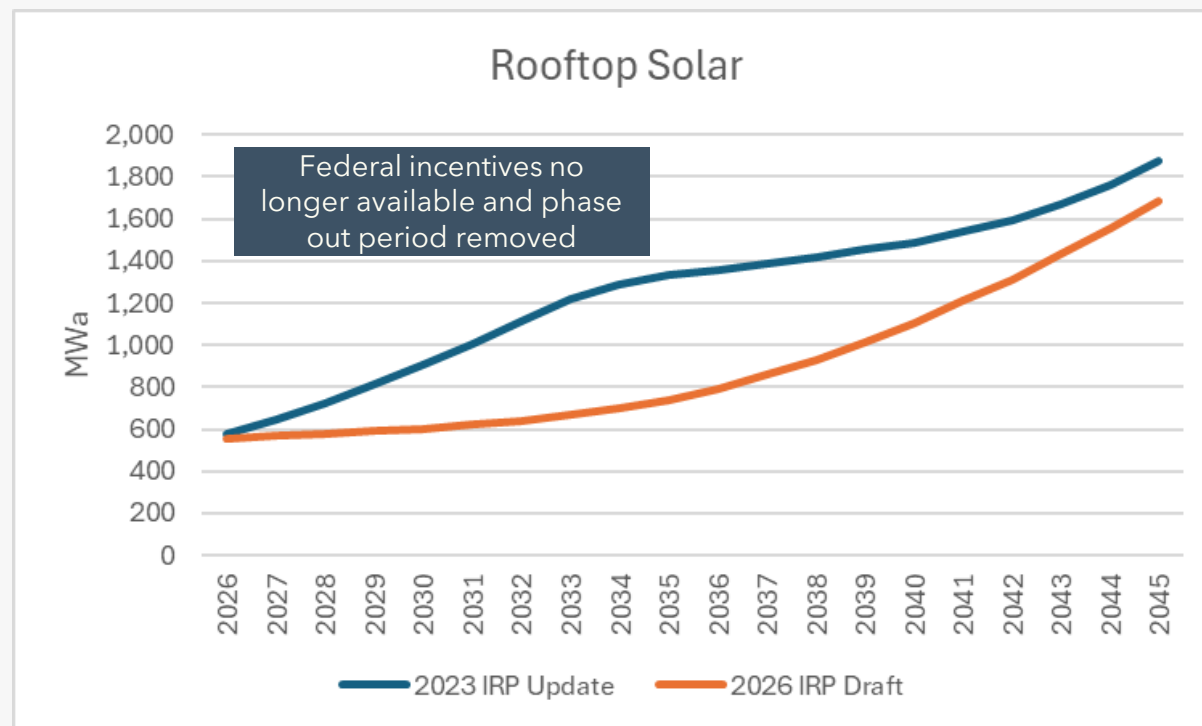
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- Recalibration of EVSE charging impacts per vehicle
- Adjustment to NREL ATB pricing based on tariffs
- Implementation of "Big Beautiful Bill" impacts on federal incentives

Solar & Storage

- Updated solar and storage projects via PGE's internal data in accordance with OPUC's Order 24-068
 - AC to DC nameplate capacities corrected
 - Accurate project accounting of legacy data

Adoption Impacts via Federal Incentives

- With removal of federal incentives, adoption curves have shifted



*Similar curve adjustment for storage

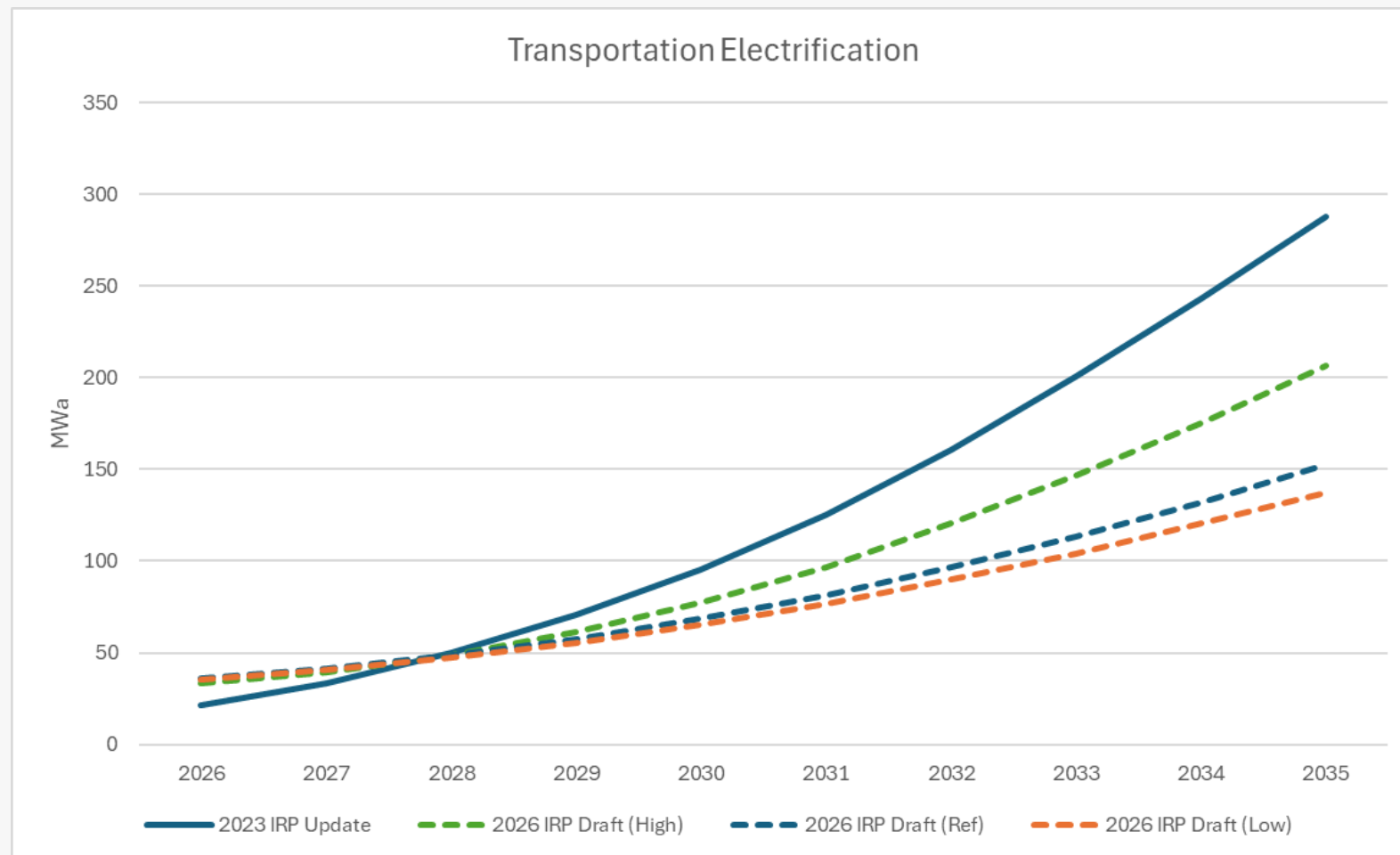
Draft DER Forecast Results



EVSE

Updates:

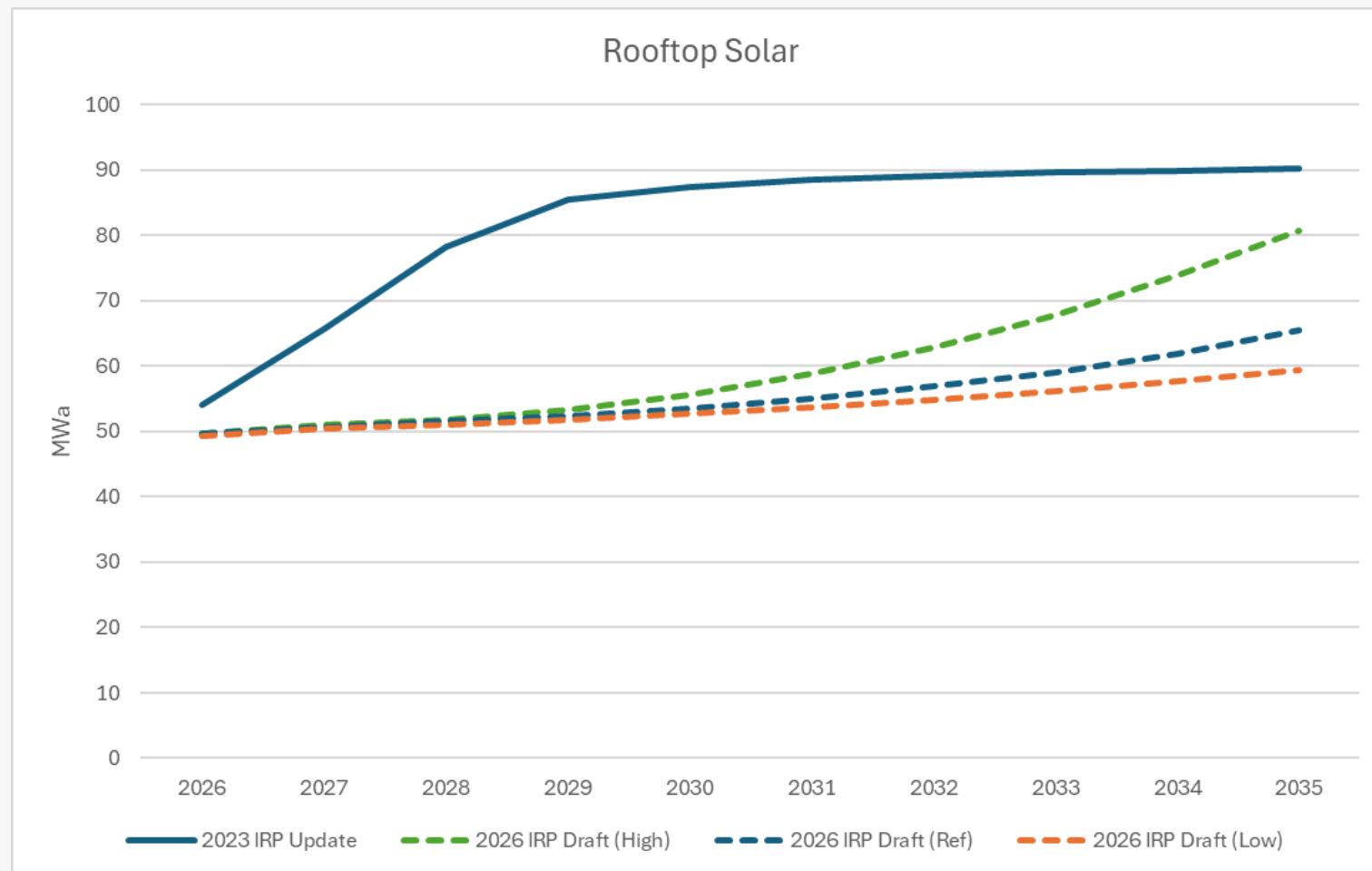
- Refined charging behavior methodology – *early years impact*
- Slower EV/PHEV adoption adjusts market projection & load impacts
- Better alignment with historical adoption trends and removal of federal EV tax credit



Solar

Updates:

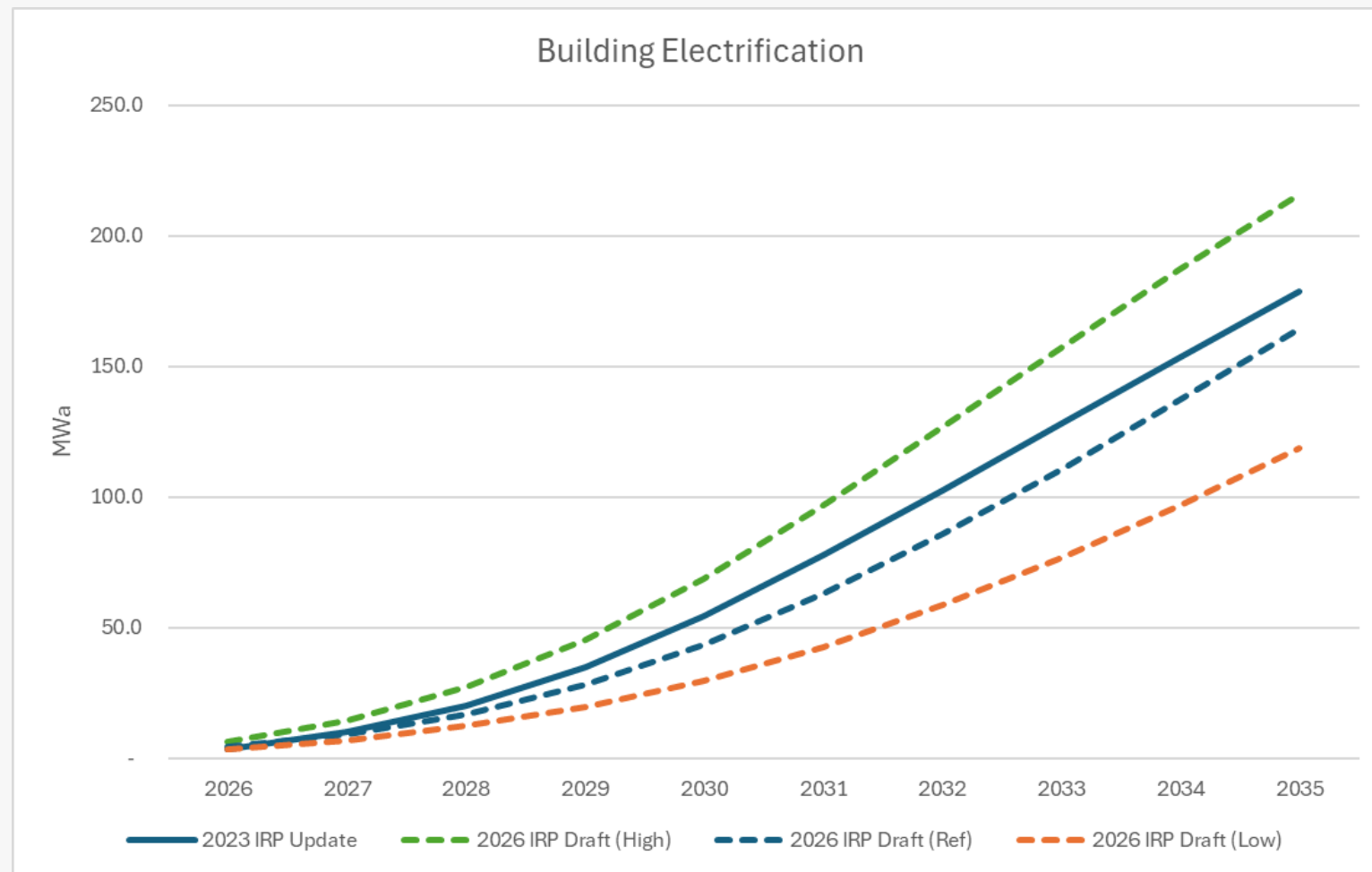
- Removal of duplicative projects and corrected project categorizations via Order 24-068
- Adjusted legacy AC & DC values from prior IRP via Order 24-068
- Forecast no longer includes the federal Investment Tax Credit (ITC) for solar installations



Building Electrification

Updates:

- Reflects current adoption of PGE programs and electrification measures
- Slight reduction of adoption due to removal of Energy Efficiency Home Improvement Credit supporting qualified heat pump installations



Guided Feedback – AdoptER Forecast

- What other data, scenarios, and considerations would help ensure AdoptER continues to serve long-term DER planning?
- Are there specific updated datasets that you think should be included in the AdoptER analysis?
 - Examples such as: NEEA's 2025 CBSA, EIA's most recent Residential Consumption Survey (RECS), etc.



Questions



Existing Resources

Rob Campbell, PGE
Principal Integrated Resource Planning

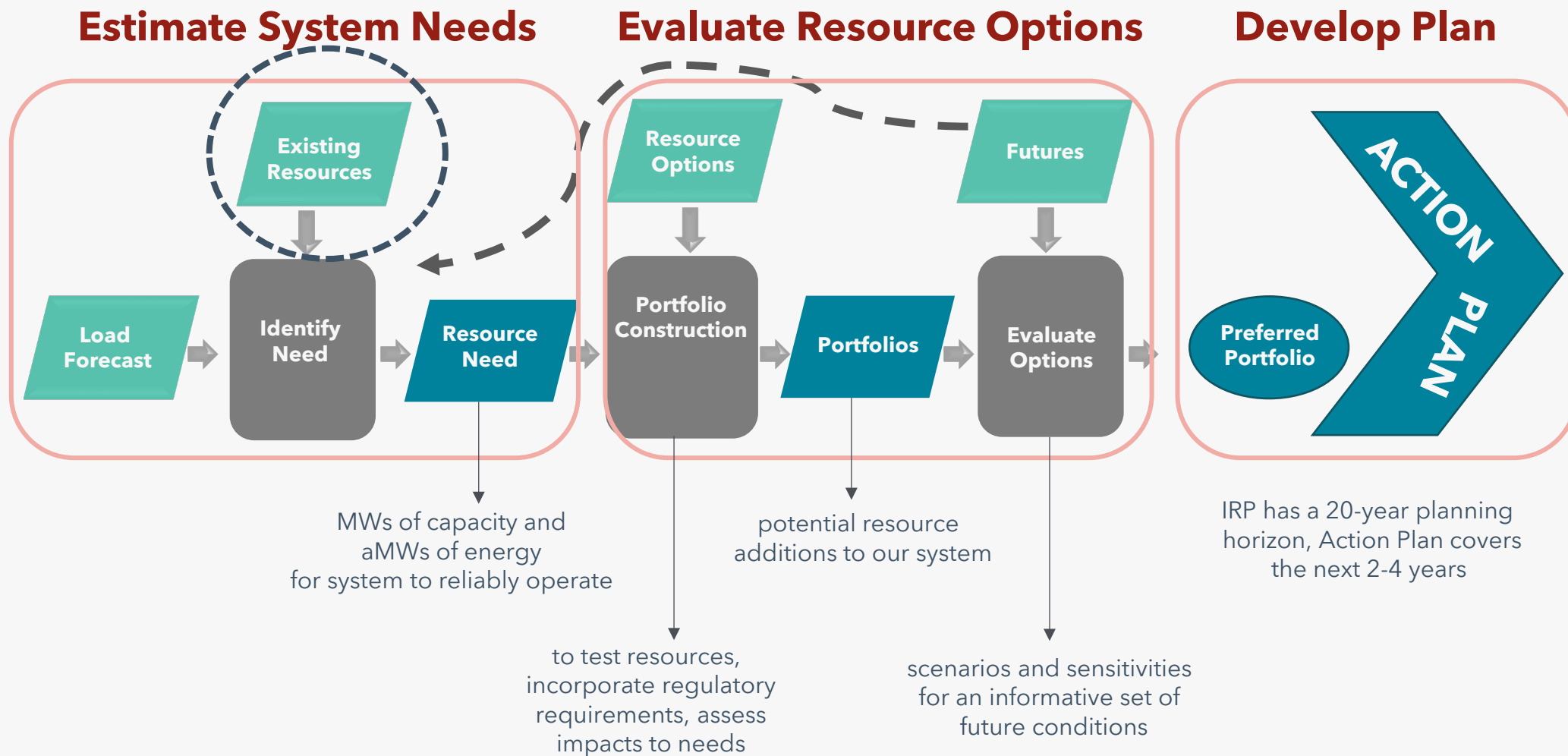
Jarek Oliver, PGE
Principal Integrated Resource Planning

Resource Topology

Robert Brown, PGE
Senior Principal Integrated Resource Planning



High-Level IRP Analysis Process



Topics

Overview of PGE's existing generating resources

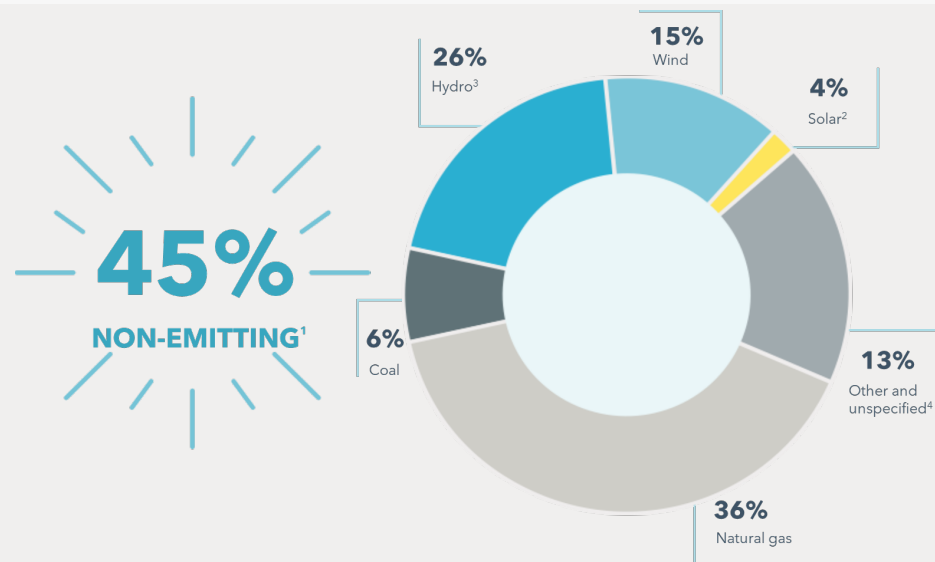
Considerations for representing existing resources in modeling

Planned existing resource verification/modification for this IRP

Aurora topology enhancements for resource representation in modeling

PGE's HB 2021 Progress

2024 Resources for PGE's Total System Load



1. Percentages represent 2024 resource mix from PGE's total system load, inclusive of wholesale volumes. The percentage of 2024 retail load, excluding wholesale sales, served by non-emitting resources is 40%.
2. Represents utility-scale solar generated, does not include 279,957 MWh of customer rooftop solar resources.
3. Hydro amounts include purchases from Bonneville Power Administration, which may have an immaterial amount of emissions associated with them, per ODEQ rules.
4. Unspecified is purchased power for which a specific generating resource is not defined and could be any of the generation types (e.g., wind, hydro, gas).

Clean Energy Additions Since 2021*

Achieving emissions reductions requires steadily adding renewable energy, battery storage, energy efficiency and demand response to our portfolio, so we can reliably and affordably reduce fossil fuel generation.

Since PGE implemented its emission targets in 2021, PGE and its customers have committed to adding 2,300+ MW of clean energy.

Wind:

- Clearwater 2024: 311 MW

Utility Scale Solar:

- Wheatridge 2022: 50 MW
- Patchwayit 2023: 162 MW
- Tower 2026: 120 MW
- Daybreak 2026: 140 MW
- Bakeoven 2026: 60 MW

Small-Scale Solar:

- Community Solar & QFs: 99
- Rooftop Solar: 165

Batteries

- Wheatridge 2022: 30 MW
- Constable 2024: 75 MW
- Sundial 2024: 200 MW
- Coffee Creek 2024: 17 MW
- Seaside 2025: 200 MW
- Other BESS: 8 MW

Hydro Contracts

- Mid-C PPA 2023 (2024-2025): 76 MW
- Mid-C PPA 2023 (2024-2026): 434 MW
- Douglas PUD 2024 (2026-2030): 79 MW

Customer Programs:

- Energy Efficiency: 122 aMW

* Through ownership, PPA, contract, or customer programs.

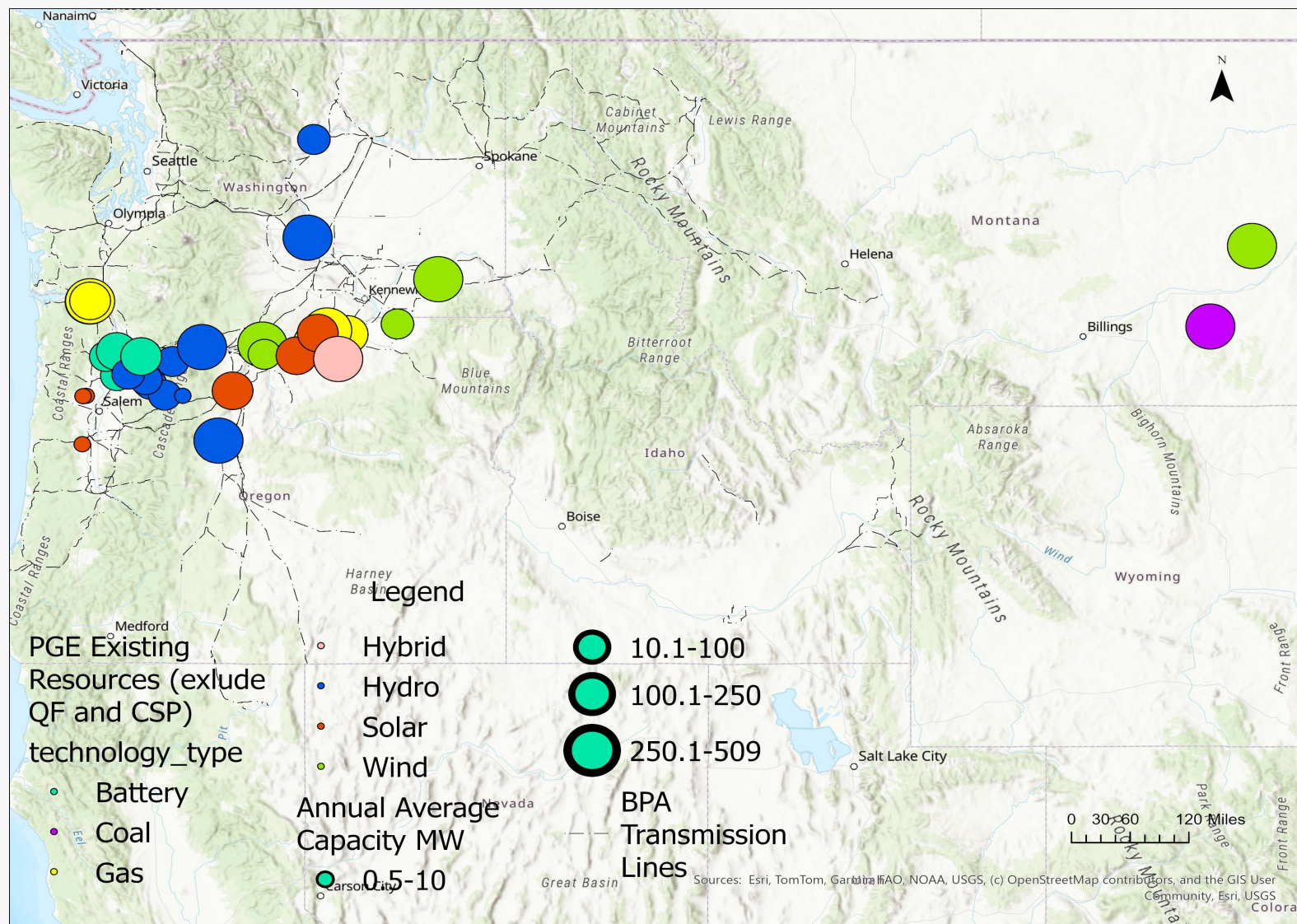
Existing Resources

Utility-Scale

3,868 MW of generating capacity through sole or joint ownership

2,830 MW through long-term utility-scale power purchase agreements including customer driven GFI facilities

Most generating resources are located near our service territory



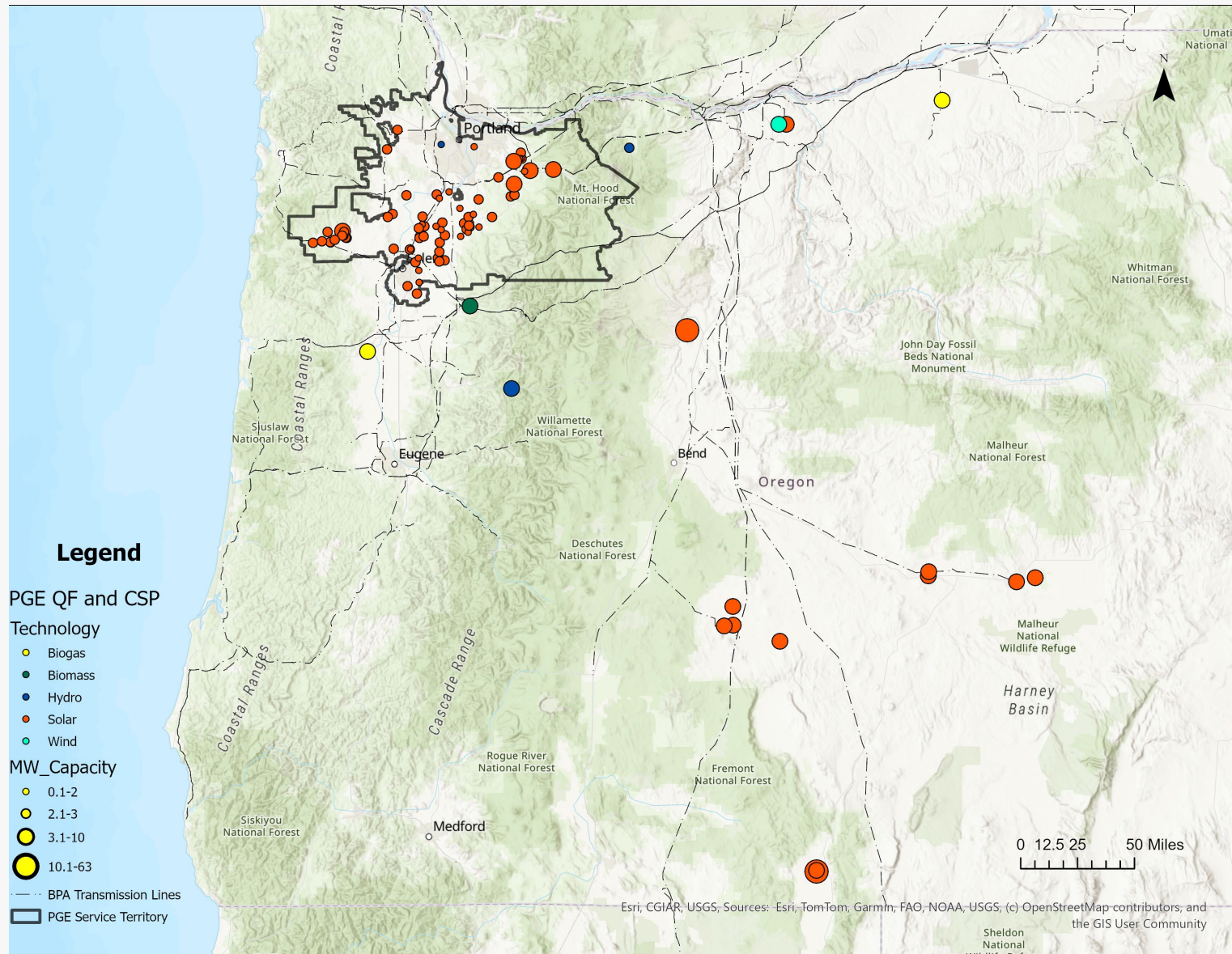
Existing Resources

QF and CSP

528 MW of online and expected Qualifying facilities (QFs) and Community Solar Projects (CSP)

QFs include small, non-utility resources that meet federal Public Utility Regulatory Policies Act (PURPA) requirements from which we purchase power

CSP allow customers to subscribe to a portion of a local project



Existing Resources

Hydro

Real-World Considerations

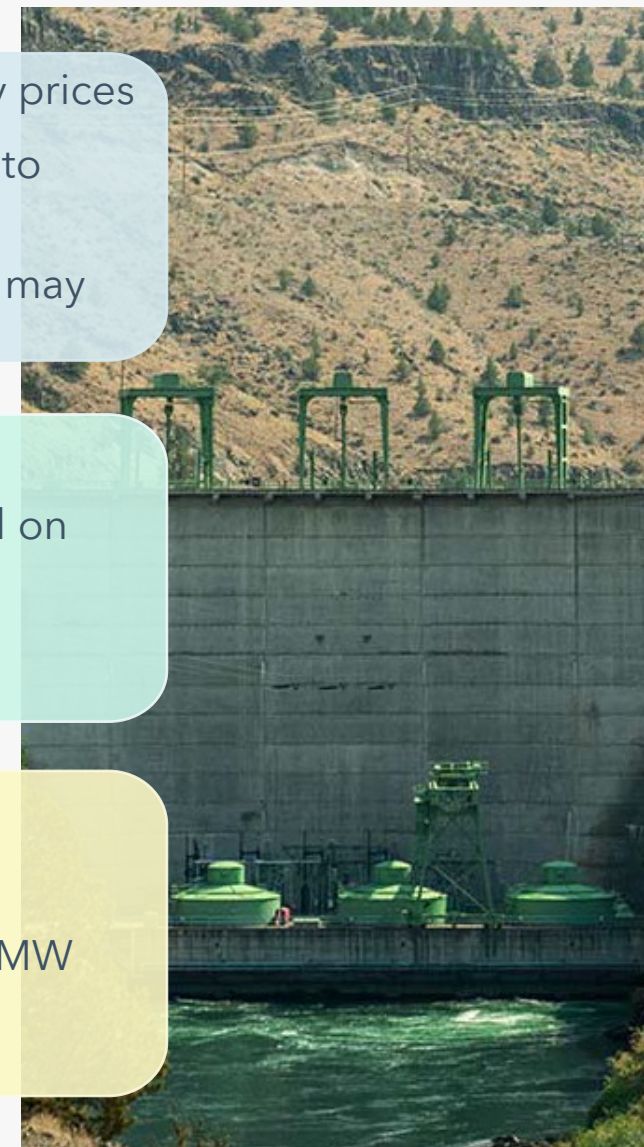
- Generation in the PNW can strongly influence electricity prices
- Uncertainties in water availability from year-to-year due to weather/climate variations
- Changing environment, fish, wildlife, other policies that may impact operations

Treatment in Modeling

- **Aurora:** "Average" hydro year, with condition variations
- **Sequoia:** dispatches weekly energy and capacity based on random hydro draws from 30 years of historical data
- **ROSE-E:** informed by above

Upcoming Expirations

- Douglas AMA (-> 12/31/25); Contract Size: ~57 aMW
- Wells Legacy (-> 9/30/28); Contract Size: ~39 aMW
- PR/Wanapum 20% (-> 12/31/26); Contract Size: ~200 aMW
- **Total Hydro Retirements by 2029: ~296 aMW**



Existing Resources

Thermals

Real-World Considerations

- Baseload electricity resource essential for reliable service, esp. at peak demand times
- Natural gas prices and demand needs drive operations
- Fuel availability and storage constraints

Treatment in Modeling

- **Aurora:** Economic dispatch
- **Sequoia:** dispatches weekly energy and capacity based on random draws from recent historical data plus explicit hourly representation of spin & non-spin reserves by resource based on capability
- **ROSE-E:** informed by above

Upcoming Expirations

- Approximately 500 MWs currently exiting the portfolio by 2030 (245 MW of Colstrip and 250 MW Calpine HRCO)
- Revisiting forward-looking operational parameters impacting availability and dispatch, e.g. constraints at Beaver/PW2



Existing Resources

VERs and Storage

Real-World Considerations

- Variable energy resources (VERs) are intermittent by nature, i.e., only available when the wind blows or sun shines
- Increasing deployment of clean energy resources requires continued analysis of resource capabilities for system reliability

Treatment in Modeling

- **Aurora:** Economic dispatch
- **Sequoia:** dispatches weekly energy and capacity based on random draws from recent historical data; storage not limited to one cycle per day
- **ROSE-E:** informed by above

Upcoming Expirations

- By 2030, 35 MWs of small VERs and other QFs expected to exit the portfolio, along with 200 MW of BPA capacity contracts in 2025
- Revisiting forward-looking operational parameters impacting availability and dispatch, e.g. capacity factors, hourly generation shapes for wind and solar, etc.



Aurora

Modeling tool PGE used for production cost modeling in the IRP

Aurora Prior uses

1 Market price simulations

- WECC-wide dispatch

2 Resource energy valuation

- "PZM" - PGE Zonal Model
- Simulated prices are inputs

3 Portfolio energy and emissions evaluation

- "iGHG" - spreadsheet model to forecast emissions
- "mPZM" - modified version of PZM incorporating emissions forecast and composition of incremental portfolio

Aurora Topology Enhancement

Expanding the PZM topology could allow for prior uses #2 and #3 to take place in a single model

The purpose of this enhancement is to address three needs:

1

Estimate and forecast portfolio CO₂ emissions within Aurora

- Consider CO₂ emissions constraints

2

Simulate the interaction of resource portfolios with PGE's load and market(s)

- Differentiate energy delivered to retail load vs. wholesale sales

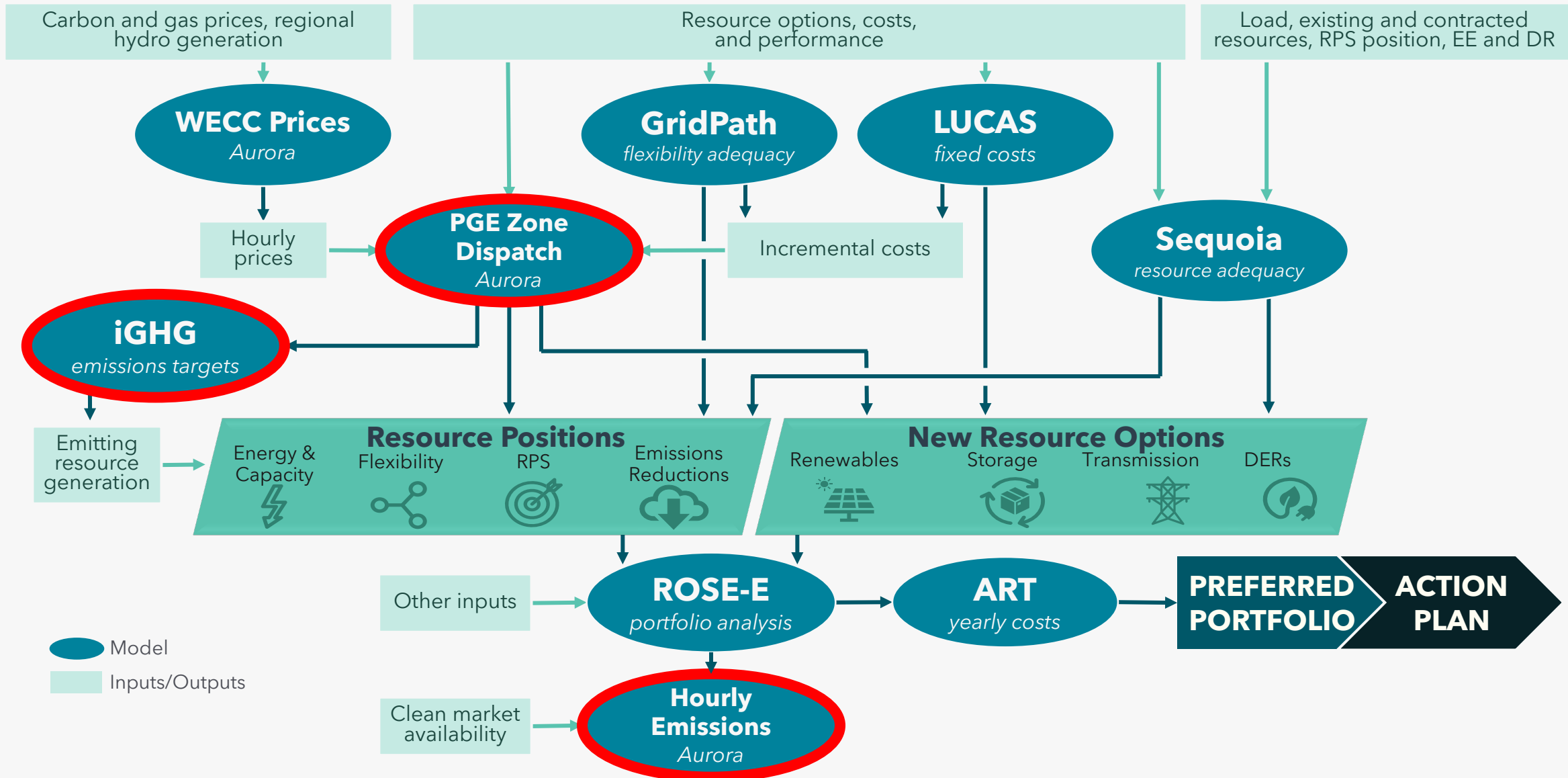
3

Consider the potential effects of CO₂ emissions pricing

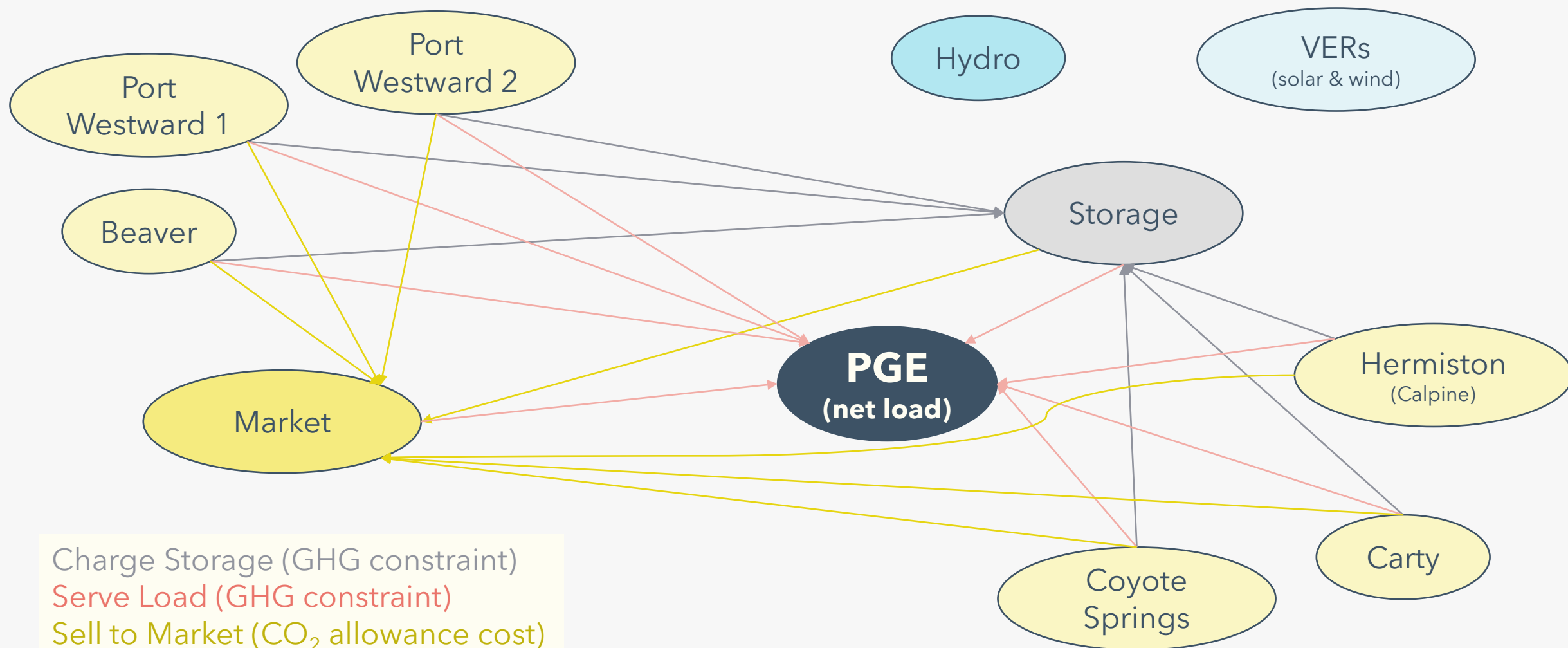
Topology refers to the connection of elements in the system

- Zones contain resources and/or loads
- Links represent the ability for energy to move between Zones

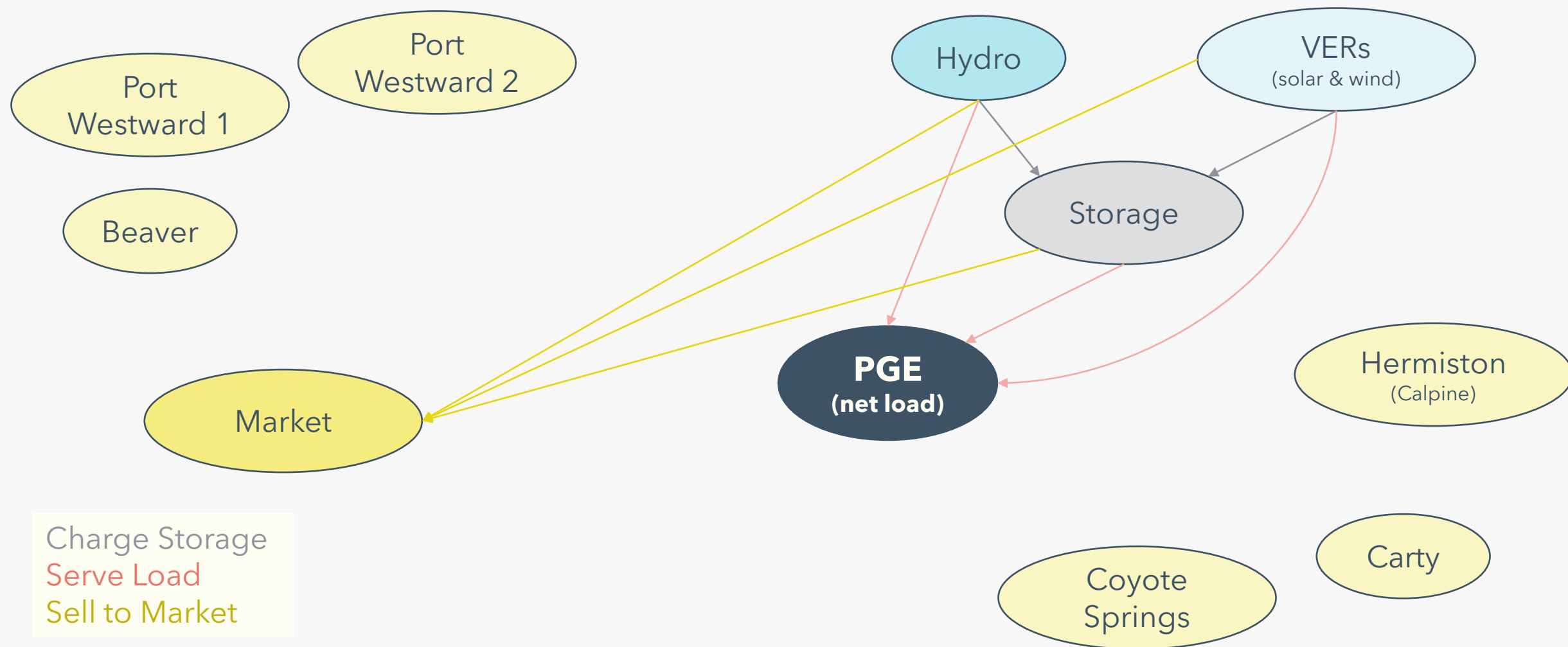
Current IRP Modeling Flow



Aurora Topology: Emitting Resources



Aurora Topology: Non-emitting Resources



Guided Feedback – Resource Topology

- Aurora topology: Are the modeling refinements we've described clear to you, and do they make sense?



Questions



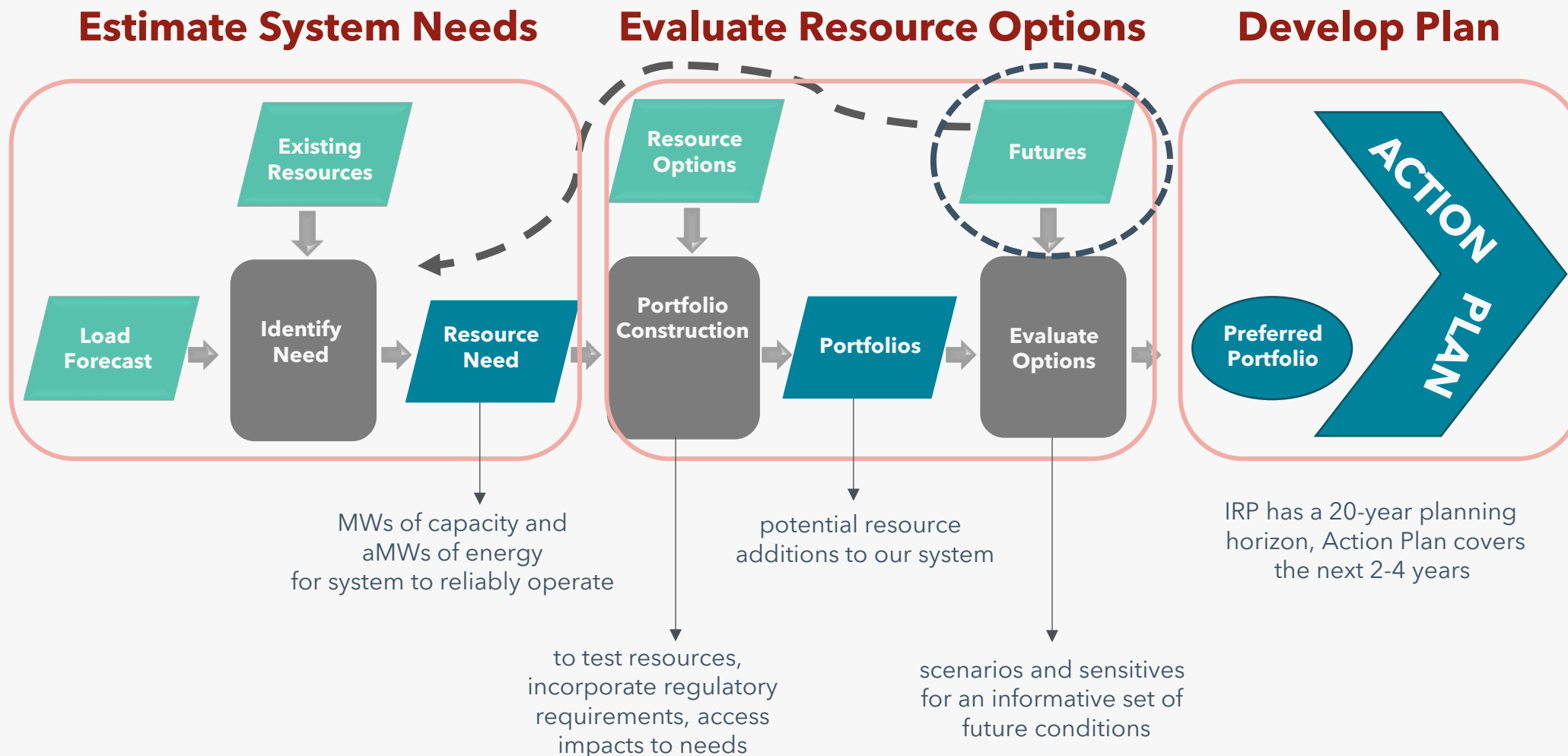
Futures/Markets

Chris White, PGE

Principal Integrated Resource Planning



High-Level IRP Analysis Process



Topics

Updating WECC Model Inputs

WECC Supply & Demand Assumptions

Preview IRP Price Forecast in anticipation of 2026 CEP/IRP

Discussion of Price Futures for 2026 CEP/IRP

Updating WECC Model Inputs

PGE generates its **IRP fundamentals price forecast** using the WECC Model. The underlying input data employed in the WECC model is furnished by Wood-Mackenzie Consulting.

These new inputs represent an updated *worldview of future supply and demand conditions*.

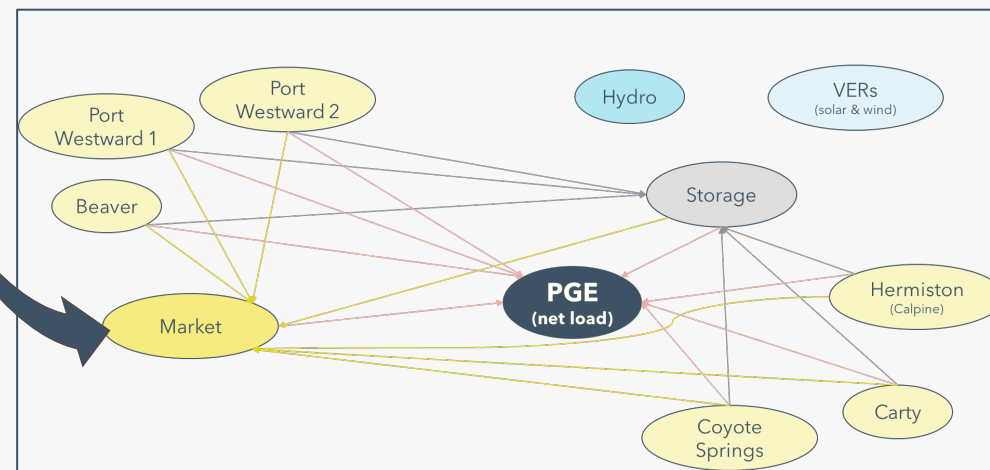
Model inputs change over time relative to macroeconomic conditions, load expectations, resource procurement costs, fuel prices, government policy, etc.

* Note that this discussion is limited to the IRP fundamentals price forecast and does not incorporate information regarding the electric forward price curve. A discussion of the change in methodology to the IRP price forecast is available in the October 2024 roundtable presentation.

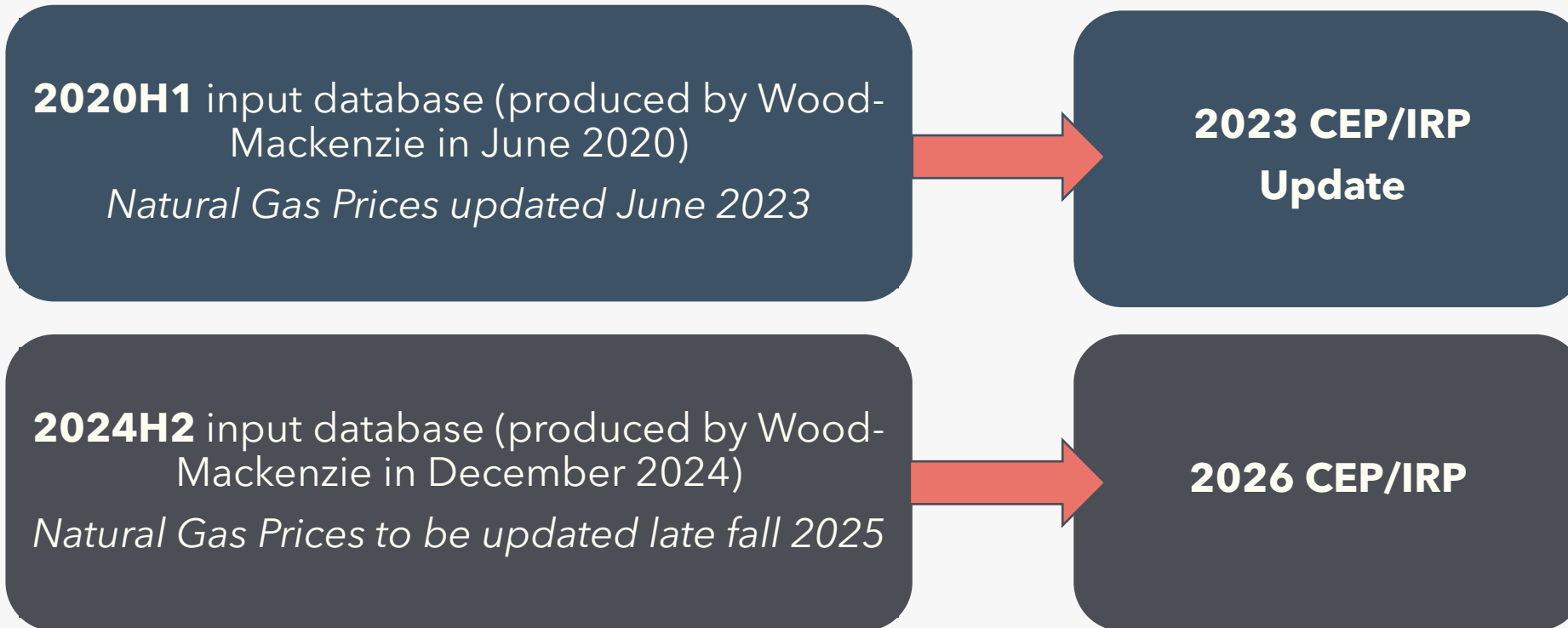
WECC Model

Price forecasts used to populate market prices for **economic** dispatch model

PGE-Zonal Model (PZM)



Updating WECC Model Inputs

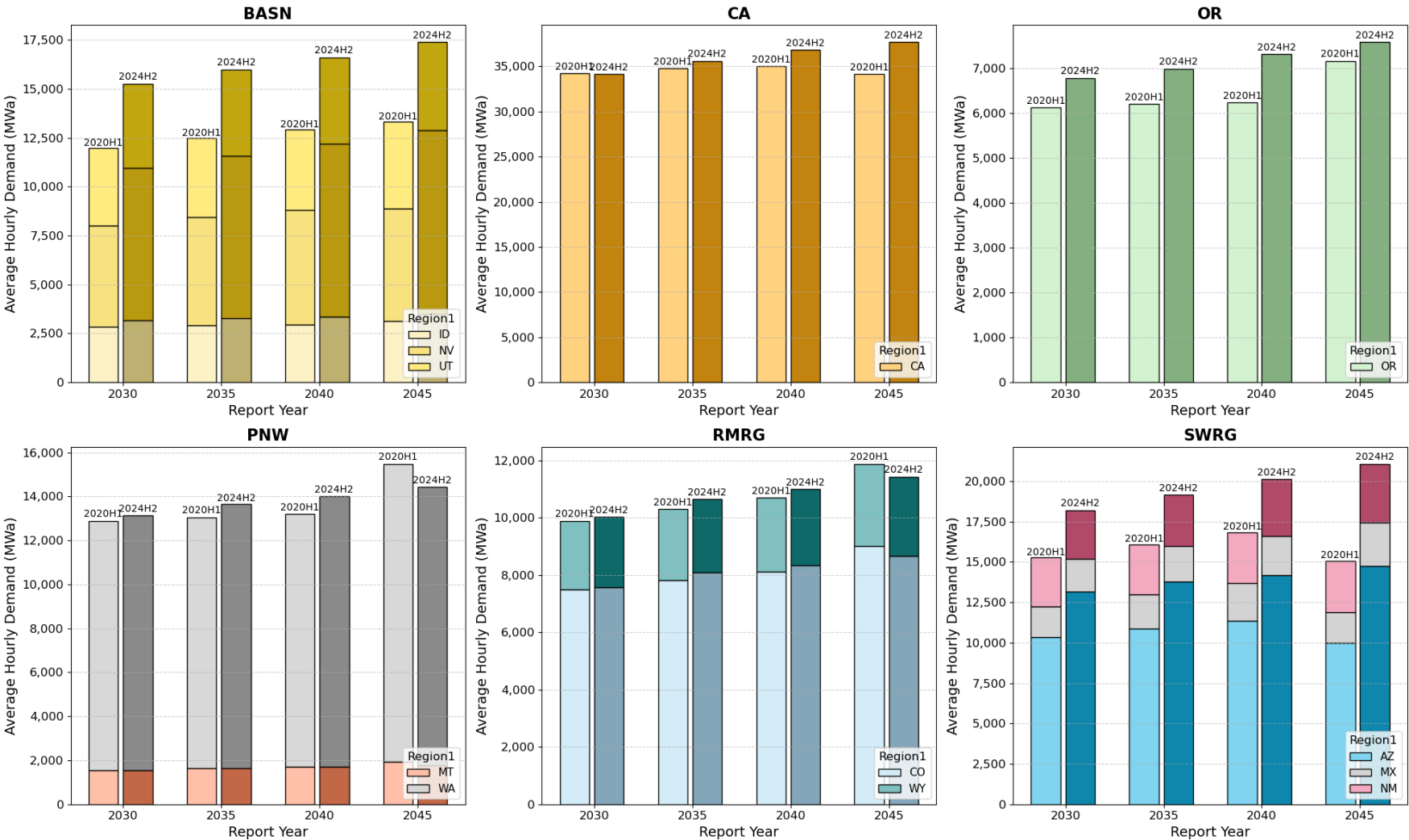


* PGE regularly updates the natural gas price assumptions in the WECC input database.



Changes to Demand in WECC Model

Demand/Load Comparison by State/Region



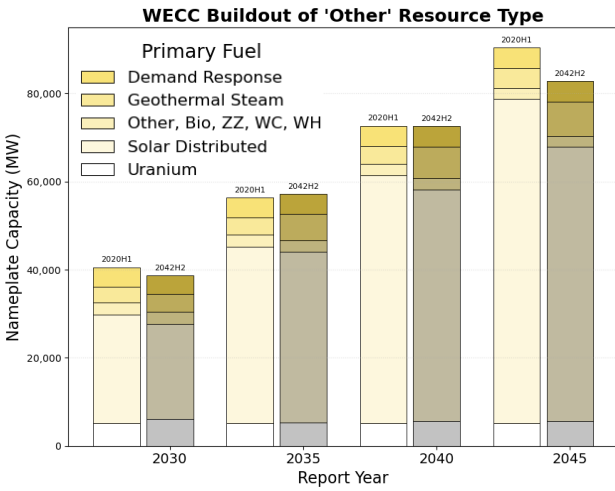
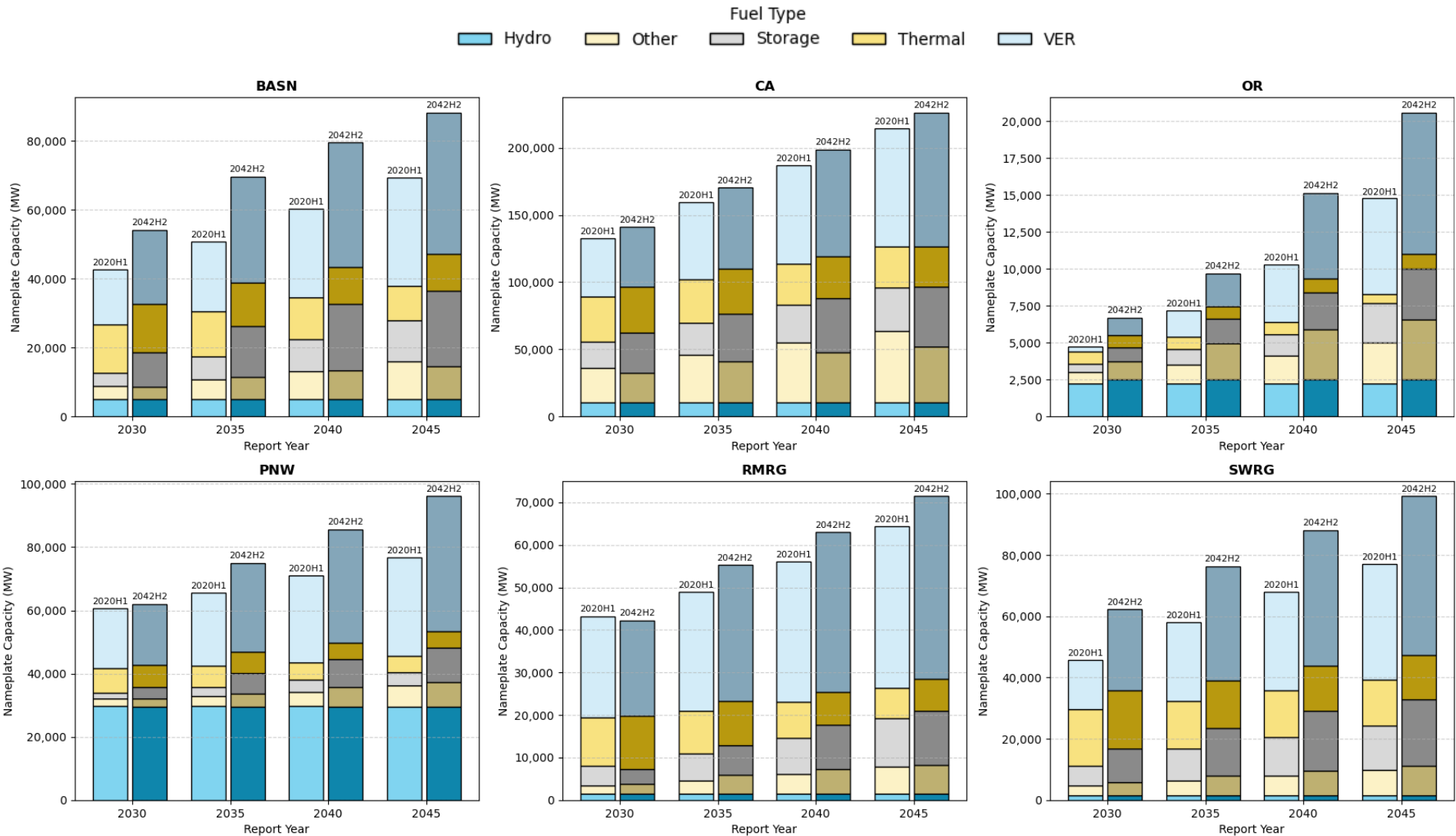
State to Region Mapping

State	Abbrev	Region
Idaho	ID	BASN
Nevada	NV	BASN
Utah	UT	BASN
California	CA	CA
Oregon	OR	OR
Montana	MT	PNW
Washington	WA	PNW
Colorado	CO	RMRG
Wyoming	WY	RMRG
Arizona	AZ	SWRG
Mexico	MX	SWRG
New Mexico	NM	SWRG



Changes to Supply in WECC Model

Resource Buildout Comparison by Region by Fuel Type



State to Region Mapping

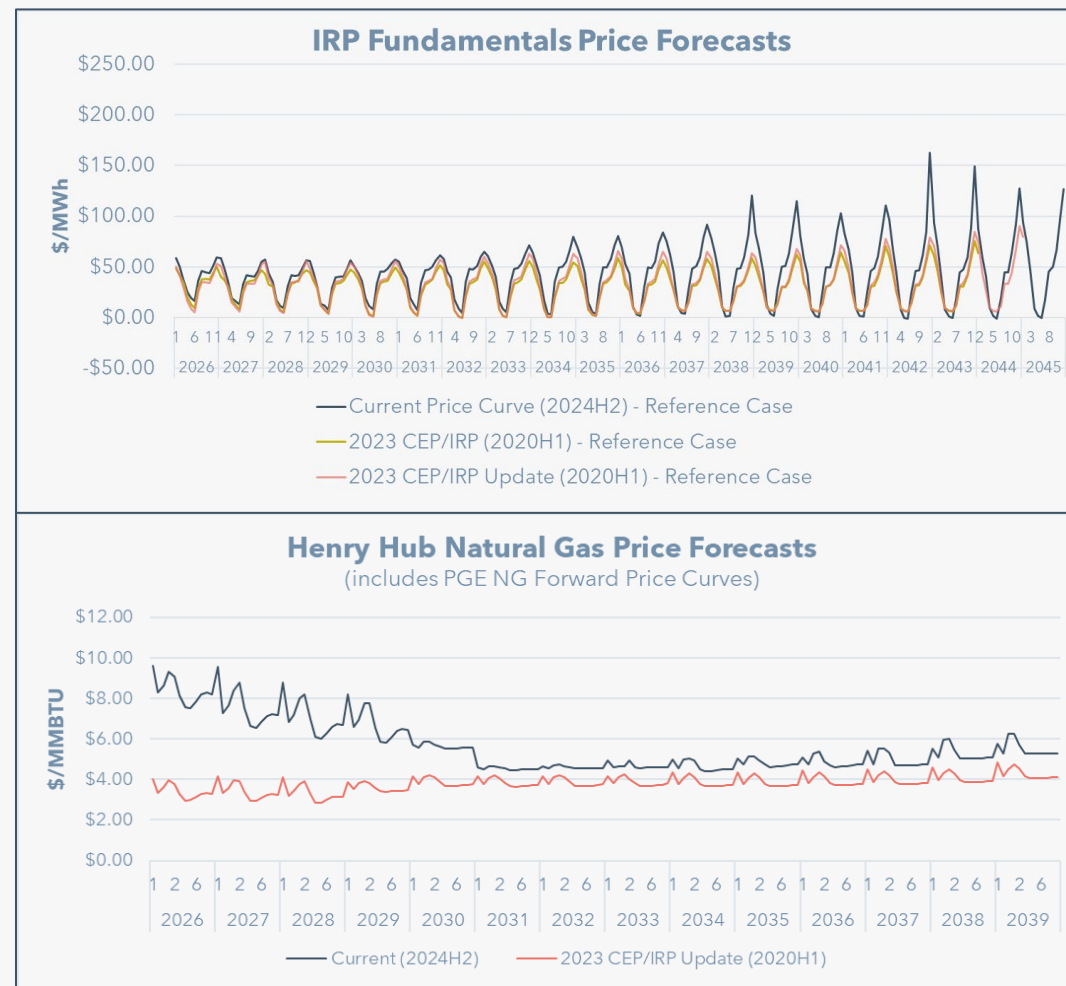
State	Region
Idaho	BASN
Nevada	BASN
Utah	BASN
California	CA
Oregon	OR
Montana	PNW
Washington	PNW
Colorado	RMRG
Wyoming	RMRG
Arizona	SWRG
Mexico	SWRG
New Mexico	SWRG

Preview Changes to IRP Price Forecast

The 2024H2 input database was updated to reflect NG price forecasts produced in June 2025. The revised IRP fundamentals price curve is shown in dark blue.

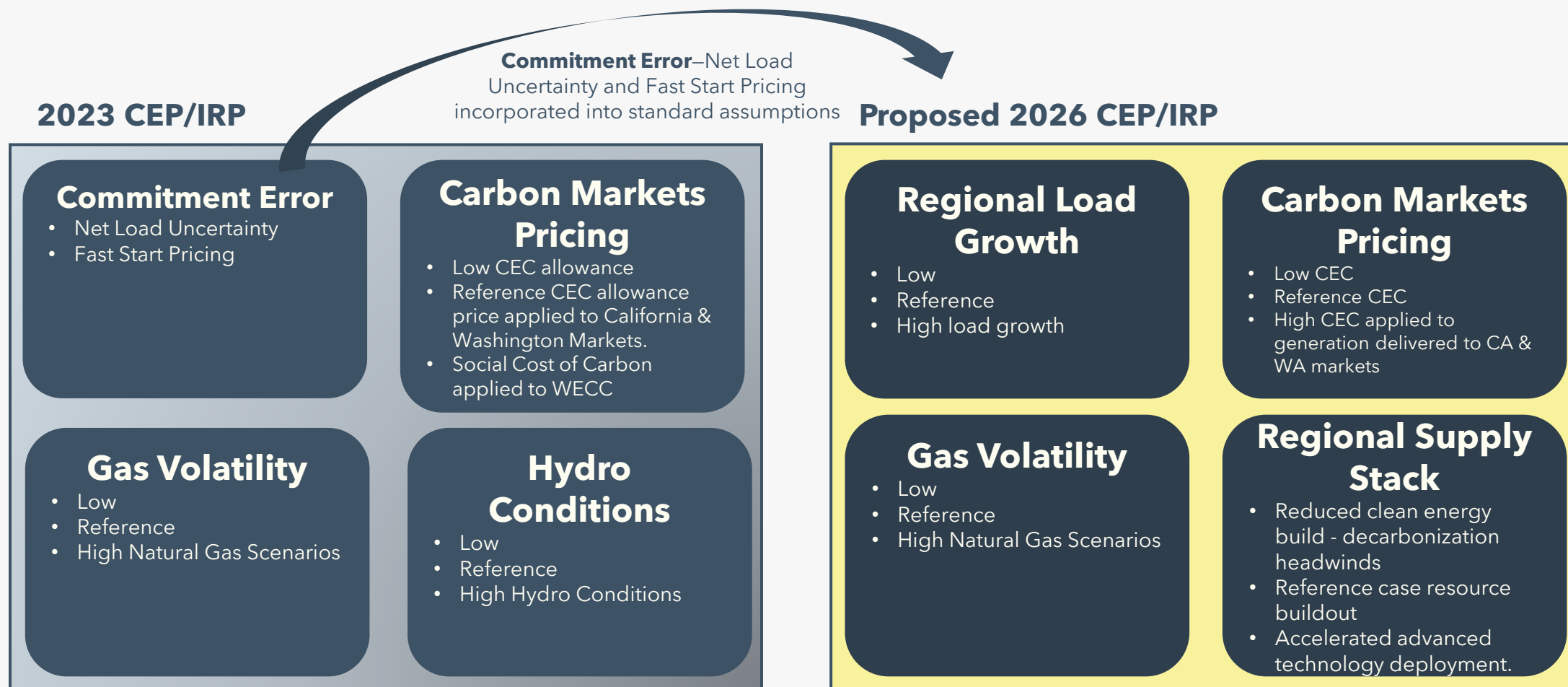
In comparing the current IRP fundamental price forecast from the 2024H2 input database to prior IRP vintages, we observe:

- Higher average prices due to larger load growth.
- Higher natural gas prices due to increased domestic and international demand.
- Increasing average winter prices due to decreasing proportion of thermal resources to meet to load in winter months.
- Increasing reliance on storage resources to replace other dispatchable resources.



* Note that the reference natural gas and electricity price curves will be updated prior to the 2026 IRP to adapt price forecasts to new price futures (see next slide).

Price Futures – WECC Model Scenarios





Guided Feedback – Price Futures/Market Assumptions

- What questions do you have about the differences between the use of PGE Zonal Model and the WECC model
- What are your reactions about PGE's proposed WECC price future concepts? What type of information would you like IRP to share and what alternatives would you suggest?



Questions



NEXT STEPS

A recording from today's webinar will be available on our website in one week

Upcoming Roundtable: December 3rd, 2025



Thank you

Contact us at
IRP.CEP@PGN.COM

An

Oreannon
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Oreannon
Oregon

kind of energy



ACRONYMS

ARIMA: autoregressive integrated moving average

ART: annual revenue-requirement tool

ATC available transfer capability

BPA: Bonneville Power Administration

C&I: commercial and industrial

CBI: community benefit indicators

CBIAG: community benefits and impacts advisory group

CBRE: community based renewable energy

CDD: cooling degree day

CEC: California energy commission

CEP: clean energy plan

CF conditional firm

DC: direct current

DER: distributed energy resource

DR: demand response

DSP: distribution system plan

EE: energy efficiency

ELCC: effective load carrying capacity

EJ: environmental justice

ETO: energy trust of Oregon

EUI: energy use intensity

GHG: greenhouse gas

HB2021: House Bill 2021

HDD: heating degree day

HVDC: high-voltage direct current

IE: independent evaluator

IOU: investor-owned utilities

ITE: information technology equipment

ITC: investment tax credit

kW: kilowatt

LOLH: loss of load hours

LT/ST: long term/ short term

LTF long-term firm

MW: megawatt

MW_a: mega watt average

NAICS: North American industry classification system

NCE: non-cost effective

NG: natural gas

NPVRR: net present value revenue requirement

OASIS Open Access Same Time Information System

ODOE: Oregon department of energy

PPA: power purchase agreement

PSH: pumped storage hydro

PUC: public utility commission

PURPA: Public Utility Regulatory Policies Act

PV: photovoltaic

REC: renewable energy credit

RLRR: low carbon price future

ROSE-E: resource option strategy engine

RPS: renewable portfolio standard

RRRR: reference case price future

RTO: regional transmission organization

SoA: South of Allston

T&D: transmission and distribution

TSR: transmission service request

TSEP: TSR study and expansion process

Tx: transmission

UPC: usage per customer

UPS: uninterruptible power supply

VER: variable energy resources

VPP: virtual power plant

WECC: western electricity coordinating council

October 6, 2025

To: Cole Souder
Green Energy Institute

From: Jaki Ferchland
Senior Manager, Rates & Regulatory Affairs

Portland General Electric Company
UM 2377
PGE Response to OPUC Data Request 24
Dated September 22, 2025

Request:

PGE proposes a system allocated period of three years. Is it possible that customers will be allocated more capacity than originally allocated for the first allocation period? For example, could a customer be allocated 50 MW in its first period, then 75 MW in its second period, then 90 MW in its third allocation period?

Response:

PGE will prepare a Large Load Customer Agreement for a customer's requested peak demand. This may include a ramp of allocated system capacity due to availability of capacity (ex. 10 MW in year 1, 20 MW in year 2, etc.) This will be determined as part of the study process and defined in the signed contract.

If a customer wishes to increase their total demand more than 1,000kW beyond the original allocated capacity amount then the customer would need to submit a request into PGE's Prospective Large Load Request process. This may result in a new or amended contract and may be subject to new Distribution costs, etc.

October 6, 2025

To: Cole Souder
Green Energy Institute

From: Jaki Ferchland
Senior Manager, Rates & Regulatory Affairs

Portland General Electric Company
UM 2377
PGE Response to OPUC Data Request 18
Dated September 22, 2025

Request:

Under PGE's proposal to split investments into growth-motivated and non-growth motivated, how would the Company handle investments that partially serve growth and partially serve existing load?

Response:

PGE objects to this request on the grounds that it calls for speculation. Subject to and without waiving its objection, PGE responds as follows:

PGE will classify investments based on their primary purpose. These determinations will be fact specific and depend upon the individual facts and circumstances. They will be implemented in order to fairly allocate and recover costs to those driving them.

October 6, 2025

To: Cole Souder
Green Energy Institute

From: Jaki Ferchland
Senior Manager, Rates & Regulatory Affairs

Portland General Electric Company
UM 2377
PGE Response to OPUC Data Request 15
Dated September 22, 2025

Request:

For the purposes of applying the Peak Growth Modifier to a resource, what factors will PGE use to determine if an investment is "growth-motivated"?

Response:

PGE will classify the investment as growth-motivated if the primary driver of the investment is to increase capacity or serve new loads. PGE further addresses this topic in PGE Exhibit 100, page 22 beginning at line 4.

October 6, 2025

To: Cole Souder
Green Energy Institute

From: Jaki Ferchland
Senior Manager, Rates & Regulatory Affairs

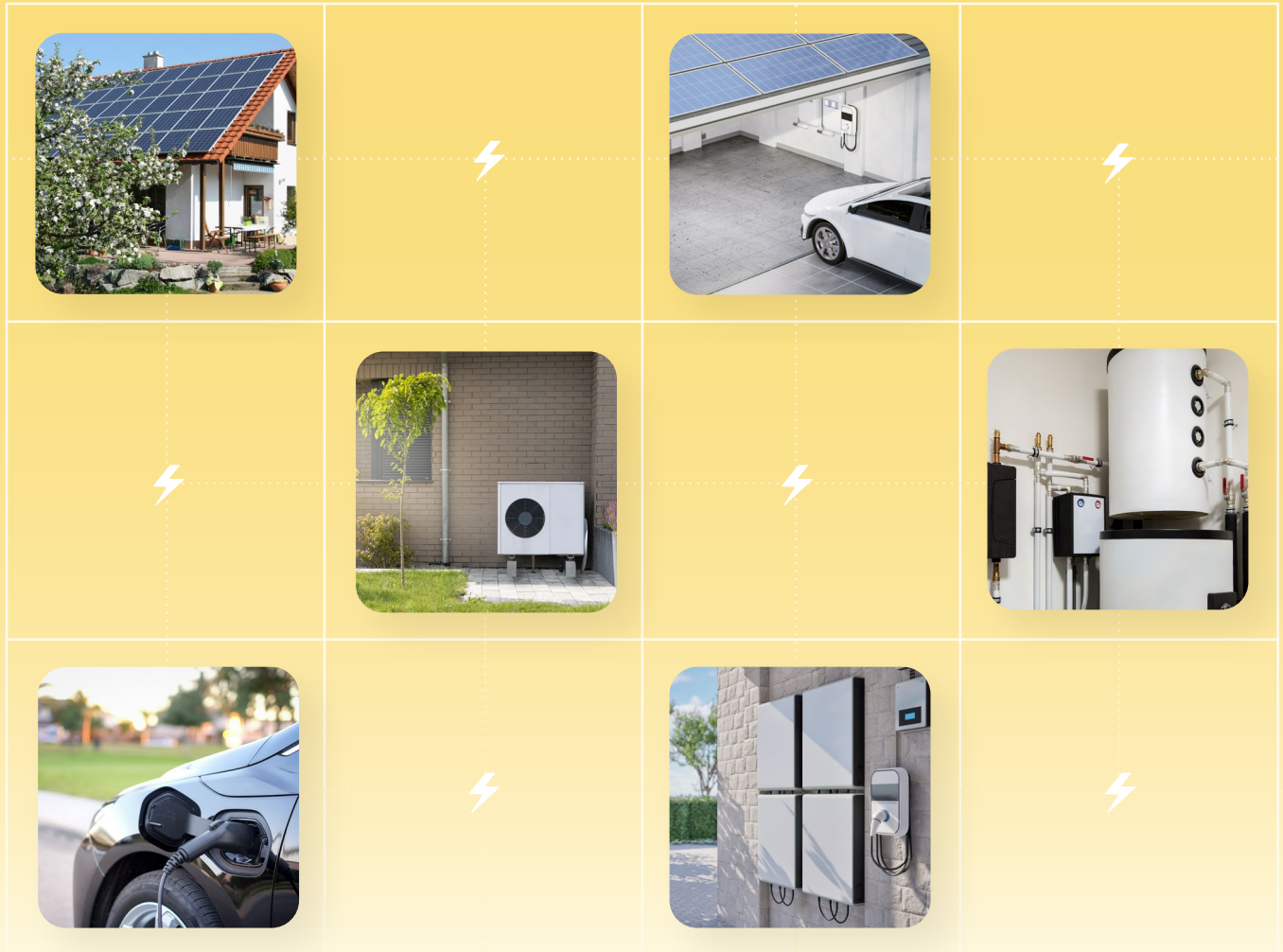
Portland General Electric Company
UM 2377
PGE Response to OPUC Data Request 22
Dated September 22, 2025

Request:

Under PGE's Peak Growth Modifier proposal, how will costs be allocated to classes with negative growth?

Response:

Rate classes with negative growth during the 3-year window will receive an offsetting credit against the non-growth costs that are allocated on the basis of the relevant generation or transmission marginal cost study. For example, using fictitious dollar values, a class with negative growth that is allocated \$1,000,000 in non-growth fixed generation costs and -\$100,000 in growth-motivated fixed generation costs would be allocated a net \$900,000 in fixed generation costs.



Homegrown energy

How household upgrades can meet 100 percent of data center demand growth

⚡ **AUTHORS:** Cora Wyent, Miki Verma, and Wael Kanj

Hyperscalers should pay for heat pumps, rooftop solar, and storage to get the capacity they need on the grid now, while setting us up for an affordable, reliable, and clean energy future.

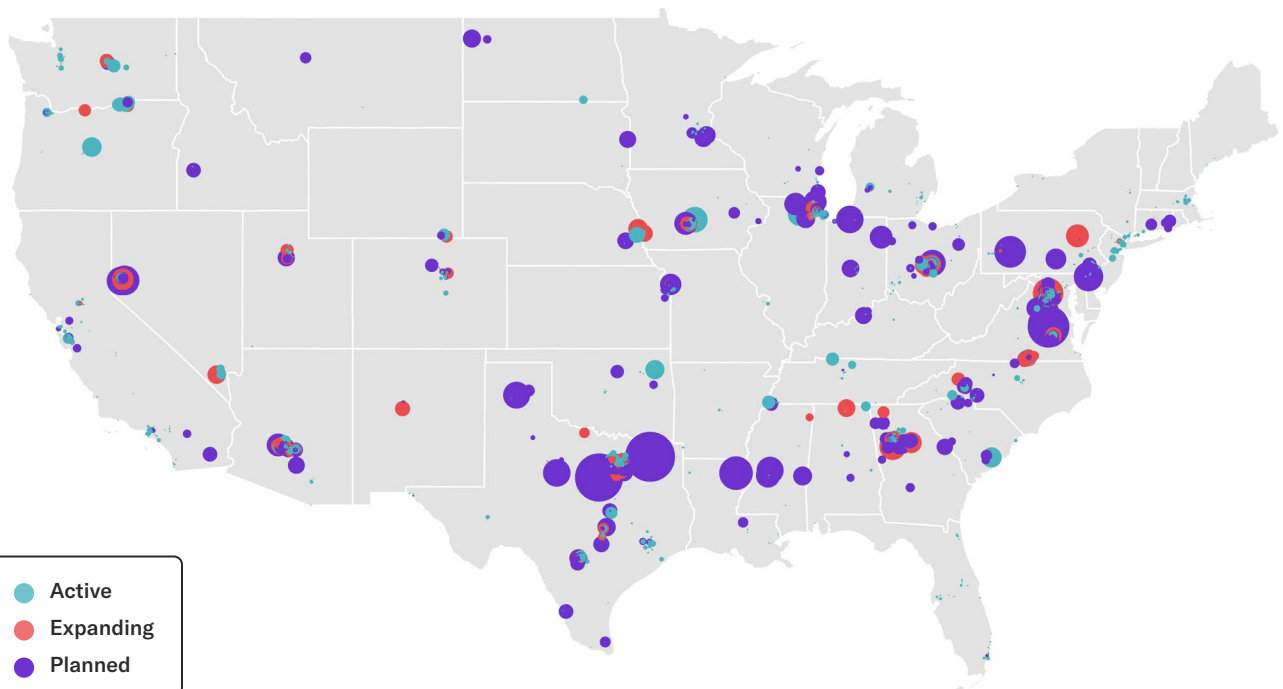
⚡ Increased demand from data centers is straining our electricity grid and driving up costs for everyone

Over the next five years, U.S. electricity demand is projected to grow by 128 GW.¹ This is an increase of 16 percent over today's national peak demand (the most electricity we use in the country at a given time) and marks a sharp departure from more than two decades of flat electricity demand. The primary drivers for this increase are hyperscalers, the tech companies building energy-intensive AI data centers at a rapid pace. **The data centers currently planned or already under construction across the country would add a total of 93 GW of electricity demand to the grid by 2029.**²

93 GW:
That's more than the current generation capacity of California.

ON THE HORIZON

Active and planned data centers projected to be built through 2029³



This new demand, plus constrained supply, is driving up costs. Across the country, households have been opening their mail and discovering soaring monthly electricity bills. **Electricity prices have risen twice as fast as inflation over the last year,⁴ and they are expected to keep rising.** Utilities have requested \$29 billion in rate hikes so far this year alone.⁵



Electricity prices are expected to keep rising.

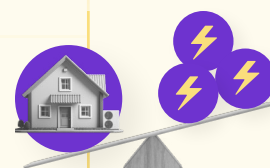
Rising electricity prices are squeezing American households at the worst possible time, with wages lagging behind inflation⁶ and federal incentives for money-saving home upgrades disappearing. But this doesn't have to be a zero-sum game where households must compete with data centers and industry for limited power. Instead, households could serve as the foundation of an energy system that powers prosperity for families and a competitive, electric-powered economy.



Households can be the hero of this story

In response to this new era of demand growth, hyperscalers and utilities are currently looking to centralized, utility-scale solutions, like building fossil fuel or nuclear power plants.⁷ However, there is an overlooked solution that has the potential to provide sweeping benefits: investing in the household as energy infrastructure.

Households have historically been seen as passive energy consumers, subject to rising prices. This is an outdated view. The world is moving toward a future where every household can be its own power plant or smart grid asset, generating clean electricity from rooftop solar and storing it to shift the loads from electric appliances and meet the needs of the grid. For example, heat pump water heaters can pre-heat water in the middle of the day, then supply ample hot water to a household during peak hours without drawing electricity from the grid. Electric vehicles can be programmed to charge overnight when there is less demand for electricity on the grid. Home batteries can send electricity back to the grid when our system needs it the most, and recent tests show that they can be incredibly effective at this.⁸ Far from being passive consumers, households are now essential energy infrastructure that can be leveraged to solve our energy challenges.



Households are now essential energy infrastructure that can be leveraged to solve our energy challenges.

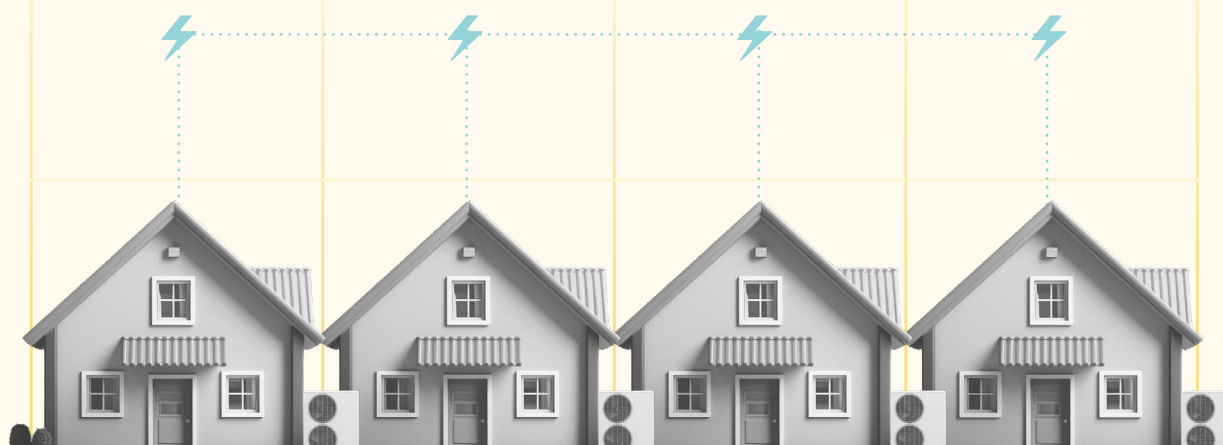
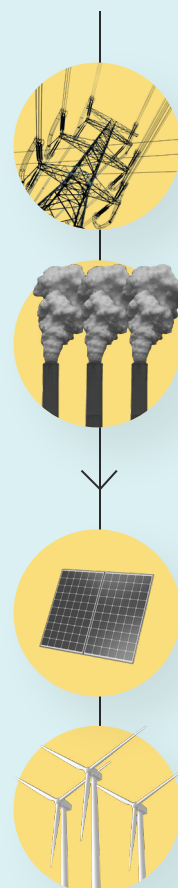
The connection between peak demand and electricity prices



The electrical grid is built with enough capacity to accommodate peak demand, which is the maximum amount of power used simultaneously by customers on the grid. This typically occurs on the hottest summer afternoon or coldest winter morning. Most of the year, we have excess grid capacity: meaning the total electricity we need is lower than the maximum electricity the grid can generate and distribute. However, if electricity demand at peak hours increases and exceeds the grid capacity, we need new infrastructure to avoid power outages and blackouts.

Infrastructure costs include the costs to build and maintain the poles, wires, and power plants we need to support peak demand. Customers are on the hook for paying off the cost of adding those new power plants or electrical poles to prepare for peak demand, all year round.⁹ These fixed costs get passed down to us regardless of how much energy we use, through the electricity rate that we pay on our bills.

Therefore, one way to minimize infrastructure costs is to **reduce peak demand**, which is equivalent to **creating capacity** on the grid. The household upgrades described in this report achieve that by either directly reducing electricity demand during peak times with more efficient electric appliances, or by generating electricity from solar panels and storing it in batteries to be discharged during peak periods, so that it doesn't have to be supplied by the grid.



If we shift our perspective to see households as energy infrastructure, households can be the hero of our energy story.

In the following sections, we provide a three-part roadmap for how hyperscalers and utilities can create capacity on the grid and pave the way to a better energy future by investing in U.S. households:

- 1 **Hyperscalers could meet one third of their projected additional capacity needs** by paying for heat pumps in select households that currently use inefficient electric heating, cooling, and water heating, thereby creating capacity on the grid from a subset of households.
- 2 **Hyperscalers could more than meet their total planned capacity needs** by paying for battery storage as well as rooftop solar for homes well suited for it. This will create new generation capacity on the grid.
- 3 **Hyperscalers' immediate investments in these solutions will forge the technological and economic pathways that transform America's entire energy system.** What starts as an urgent solution to AI's power hunger becomes the foundation for an all-electric economy — efficient, resilient, affordable for households, and perfectly suited to position the U.S. as a global leader in the industries that will define this century.



The first two solutions demonstrate that we can more than meet the projected hyperscaler capacity needs by upgrading households. If hyperscalers pay to upgrade households with heat pumps, rooftop solar, and storage, it will lower electricity costs for households, improve resilience to power outages, and drive down upfront costs by maturing the growing market for home energy upgrades. It is a true win-win.

This approach will also buy us time to invest in the grid to meet growing demand from electrification, and to conduct a managed transition from two energy systems — the gas system and the electric grid — to one. In this way, even though hyperscalers would only pay for upgrades in a subset of homes, these investments will facilitate the broader transition to a modern, all-electric energy system.

In the following sections, we expand upon and prove out each of these household solutions.¹⁰ Ultimately, we show that the solution to our current energy challenges lies in investing in households — to unlock significant energy bill savings, improve health, and ensure grid reliability for our communities for decades to come.

We can more than meet the projected hyperscaler capacity needs by upgrading households.

Hyperscalers could meet 33 percent of their capacity needs by paying for residential heat pumps

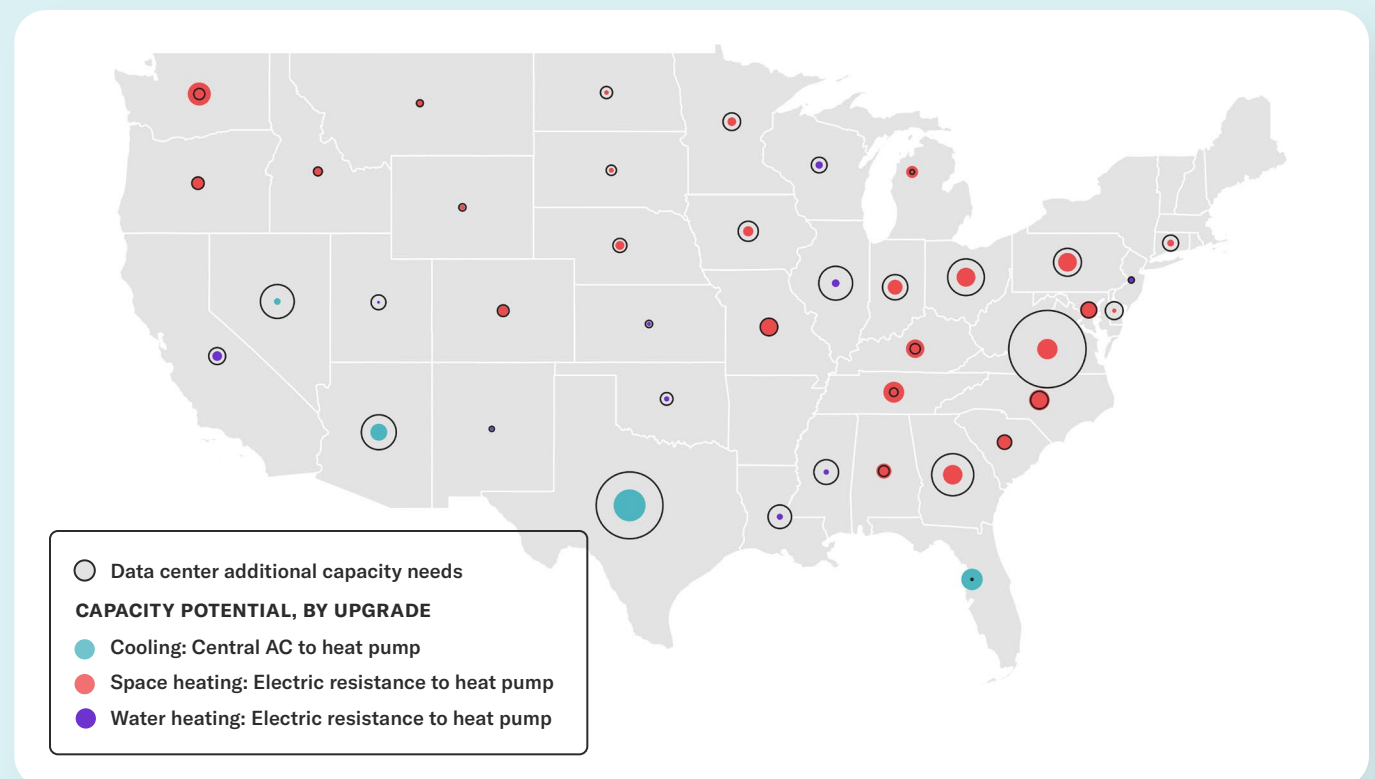


From load flexibility (adjusting, reducing, or shifting peak electricity usage outside of peak times)¹¹ to building new power plants, there are many possible utility-scale solutions for lowering or meeting peak demand. But an immediate, win-win solution to rising demand has largely been overlooked: installing heat pumps in the tens of millions of U.S. households that currently use inefficient electric heating, cooling, and water heating.

In every state, installing heat pumps can meet a significant portion of the expected increase in demand from data centers. In states that currently experience peak electricity demand in the winter, either due to cooler temperatures or high rates of electric resistance heating, we can upgrade inefficient electric resistance heating to heat pumps. In warmer states that currently experience peak electricity demand in the summer, we can create the most capacity by upgrading inefficient air conditioners to efficient heat pumps that both heat and cool homes. In states where the other two solutions are less viable, often in cases where the summer and winter demand are similar, converting inefficient electric resistance water heaters to heat pump water heaters becomes the best option, delivering a smaller yet still meaningful amount of capacity.

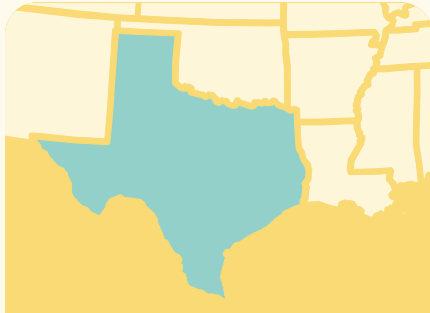
HEAT PUMP CAPACITY

Projected additional data center capacity needs (through 2029) compared to household heat pump capacity potential by state.¹²

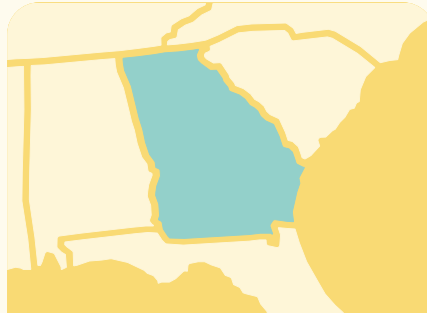


Across the country, these upgrades would create a total of 30 GW of capacity, approximately equal to 33 percent of projected additional data center capacity needs. The map above shows that there is broad alignment between states with high projected data center growth and states with high expected peak reduction from heat pump upgrades.

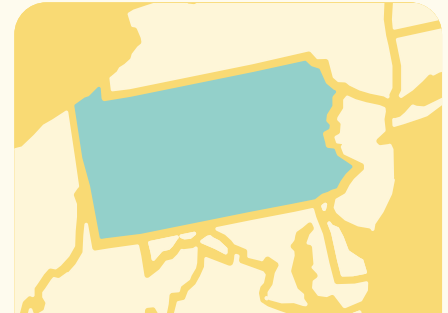
STATE EXAMPLES



→ **Texas** expects to see 17 GW of data center demand growth over the next five years, almost a fifth of all new national data center demand. But by upgrading the 4.5 million households in the state that use central air conditioners to heat pumps, we can create **3.9 GW** of capacity on the grid, about **23 percent** of the expected new data center capacity needs in the state.

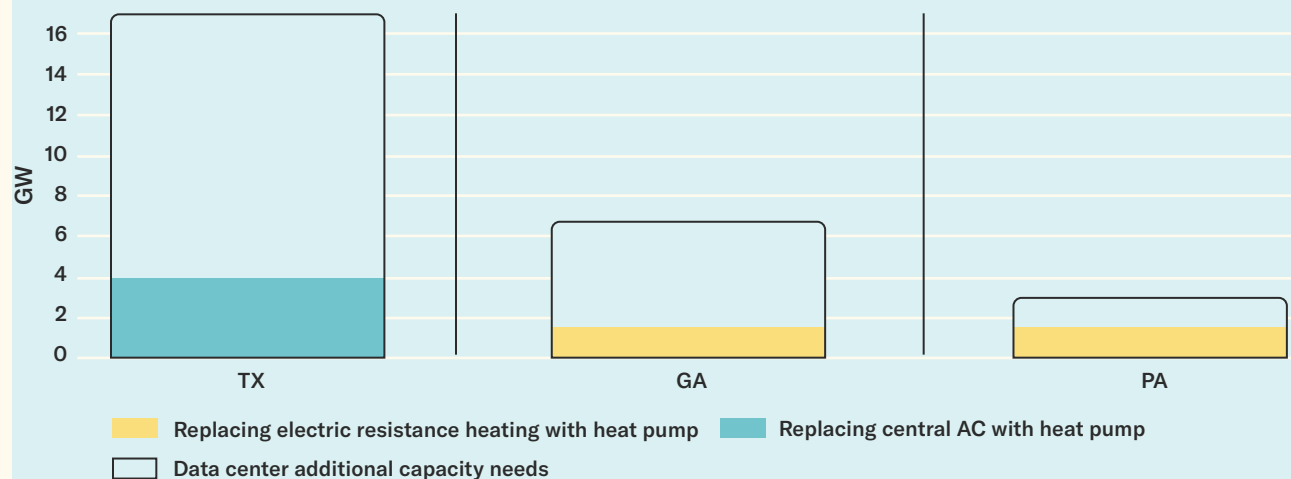


→ **Georgia** is projected to have **6.7 GW** of new demand from data centers over the next five years. By upgrading the almost half a million homes in the state that use inefficient electric resistance heating to heat pumps, we could unlock **1.5 GW** of capacity, about **22 percent** of the projected capacity needs.



→ In **Pennsylvania**, data centers will add about **3 GW** of new demand to the grid, and we have the opportunity to reduce current residential peaks by about **1.3 GW**, or **45 percent** of new demand, just by upgrading inefficient electric resistance heating to heat pumps.

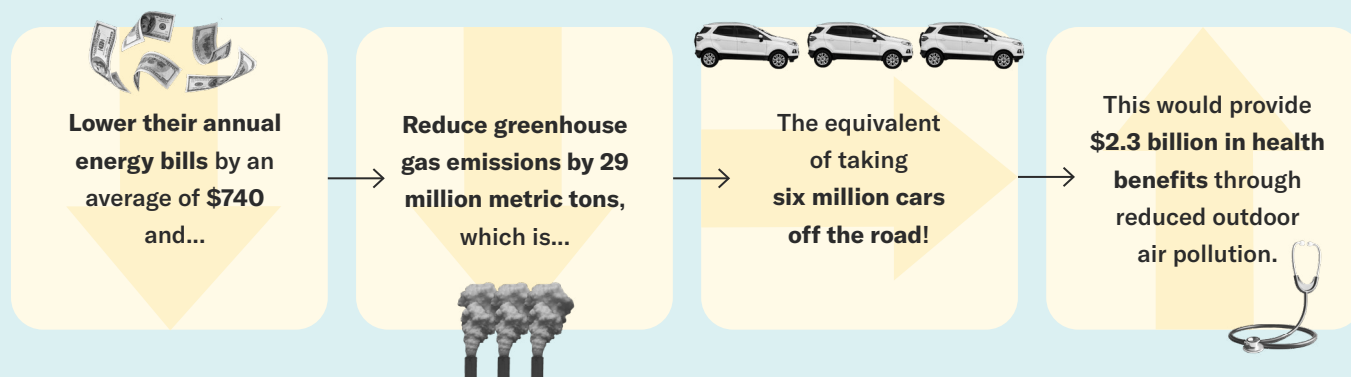
Potential for heat pump upgrades to fulfill new data center demand, by state.



Converting electric resistance households to heat pumps is particularly well matched with regions that are expected to see high data center growth, including the Southeast and the Pacific Northwest. This solution alone would create 24 GW of capacity nationally. If hyperscalers paid for 50 percent of the upfront cost of installing heat pumps in homes with electric resistance heating, they could get capacity on the grid at a price of about \$344/kW-year — a similar cost to building and operating a new gas power plant, which currently costs about \$315/kW-year.¹³

Purely comparing the upfront cost of heat pumps to the upfront cost of a new gas power plant doesn't capture the significant immediate benefits that heat pumps bring to households. The upgraded households (select households currently using inefficient electric heating, cooling, and water heating) would lower their annual energy bills by an average of \$740. Across these 21 million households, each year, heat pump upgrades would reduce greenhouse gas emissions by 29 million metric tons. That's the equivalent of taking 6 million cars off the road.¹⁴ The switch would also provide \$2.3 billion in health benefits through reduced outdoor air pollution.¹⁵

If select households currently using inefficient electric heating, cooling, and water heating upgraded to heat pumps, they would...



From a household's perspective, a 50 percent hyperscaler discount on the upfront cost would enable them to get a heat pump for around \$9,000. This brings the heat pump cost below the cost of a like-for-like alternative, such as an electric resistance furnace and a central air conditioner. It also makes the decision to upgrade to a heat pump an easy choice, and lets the household start saving money on Day 1. Pairing these investments with additional negotiated discounts or standardized installs that achieve economies of scale will create a virtuous feedback cycle that further lowers upfront costs for households and makes existing local incentives more efficient and effective.

Hyperscalers seeking capacity on the grid should first pay for home heat pump upgrades. This is faster than building new power plants. Since many of the power plants proposed for new construction or repowering burn coal or gas, it is significantly cleaner, and more insulated from future volatility in fuel prices. This is a win-win solution for hyperscalers, utilities, and households.



2 Hyperscalers could more than meet their capacity needs by paying for rooftop solar and storage

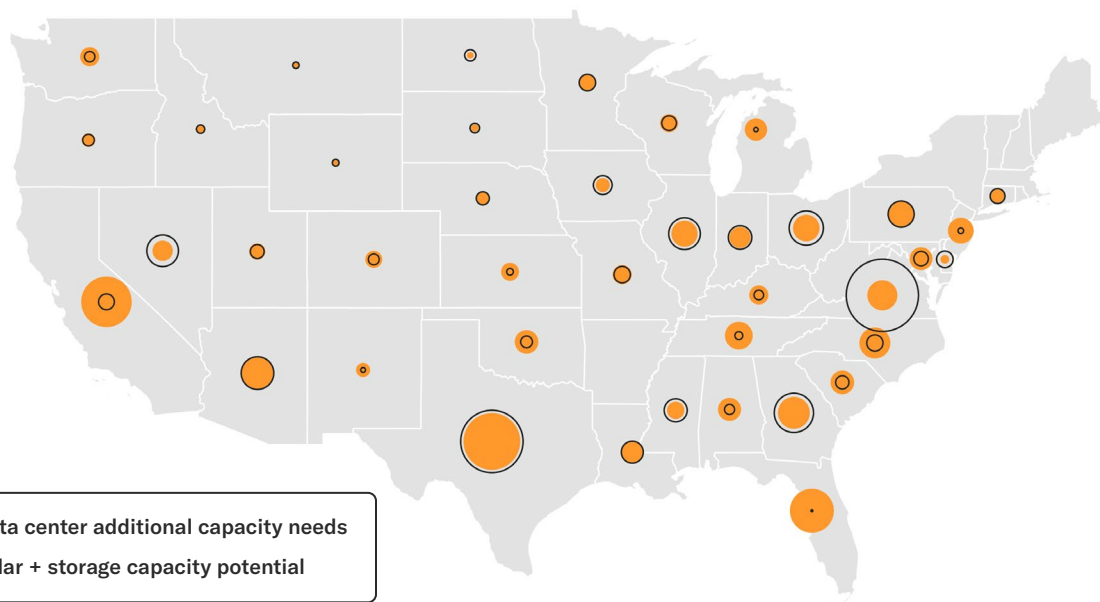
We have multiple options for adding electric generating capacity to meet growing peak demand. We can build new power plants, but the timeline to bring a new gas plant online is currently seven years, and the timeline for a new nuclear plant is even longer and more uncertain. We can invest in utility-scale renewables, which will be needed, but are currently bottlenecked by long interconnection queues. Or, we can leverage the household as energy infrastructure and invest in installing rooftop solar and storage in U.S. households to meet our needs quickly.

If every single-family household in the U.S. installed a home battery, and those with a suitable roof¹⁶ installed a 5 kW solar system (about 11 solar panels), they could collectively generate 109 GW of increased capacity on the grid. We assume that households charge the battery off-peak, either from the grid or from rooftop solar, and they discharge the battery during peak periods to reduce the household's contribution to peak demand.

That would free up significant space on the grid — and total more than the 93 GW in projected additional capacity needs from data centers through 2029. With solar installations sized to meet a home's post-electrification load, or home batteries sized to provide multi-day backup during power outages, the peak demand reduction could be even higher.

SOLAR + STORAGE CAPACITY

Projected data center additional capacity needs (through 2029) compared to rooftop solar and storage capacity potential by state.



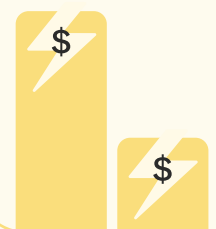


By analyzing the potential for cost compression in the U.S. rooftop solar and storage market, researchers estimate that installations at this scale, paired with targeted interventions to lower costs, would reduce the cost of rooftop solar and storage by at least 40 percent. These targeted interventions include streamlining the permitting process and reducing customer acquisition costs.¹⁷ At this reduced cost, hyperscalers could pay for 30 percent of the cost of rooftop solar and a home battery and get capacity on the grid at costs comparable to building a gas power plant.¹⁸ However, the advantages of investing in the household extend far beyond just cost. First, it could be implemented on a much quicker timeline, on the order of months rather than years. Second, rather than building a polluting power plant, hyperscalers would provide community benefits directly by helping households install rooftop solar and a battery at a significant discount. When states and utilities invest in household electrification and streamline interconnection processes, they build trust in communities while creating an environment that invites business investment.

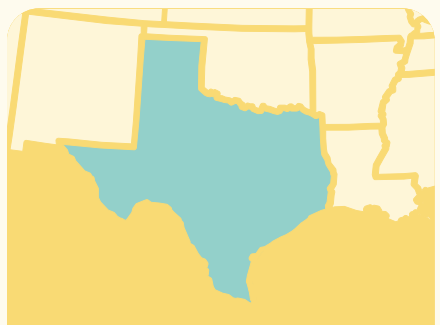
Finally, this arrangement provides significant financial benefits for the household. Households would pay about \$11,000 for the solar plus storage system up front, then get free or discounted electricity for the lifetime of those systems. After 40 percent cost compression, and with a 30 percent hyperscaler investment in solar and storage, we estimate that households could effectively pay about \$0.11/kWh for electricity, about 30 percent lower than today's average prices. This locks in low electricity prices for households for decades to come, shielding households from volatility in fuel prices.

While hyperscalers could pay for home batteries alone, pairing them with rooftop solar is far more advantageous. The two solutions work together to more effectively create capacity by both producing and storing energy. Rooftop solar also provides a unique economic benefit to households while ensuring the battery is charged with clean energy, preventing potential increased emissions related to grid charging.

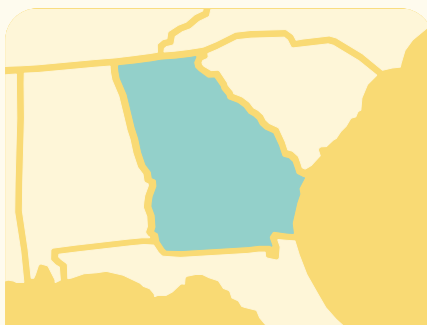
We estimate that households could effectively pay about **\$0.11/kWh** for electricity, about **30 percent lower** than today's average prices.



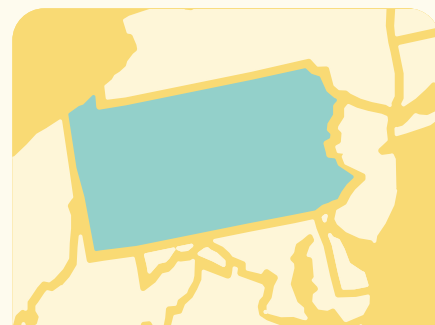
STATE FOCUS



→ In **Texas**, alongside the **3.9 GW** of capacity created by upgrading central air conditioners to heat pumps, solar and storage could unlock another **10 GW** of capacity. That means these residential solutions alone would total about **80 percent** of projected new data center demand in the state.

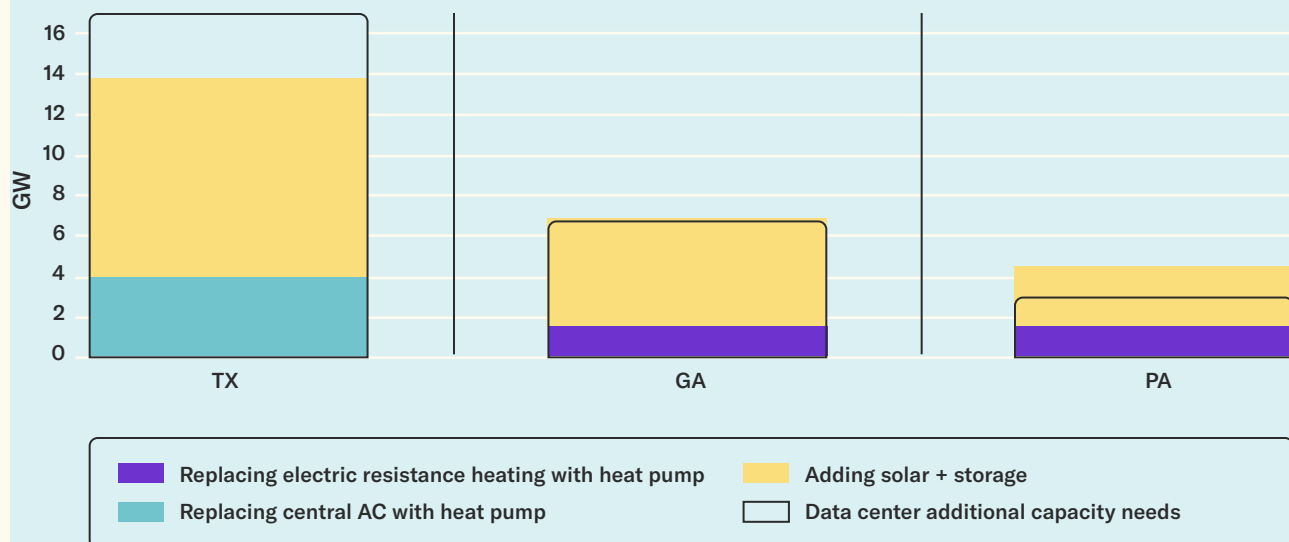


→ In **Georgia**, if we can unlock **1.5 GW** of peak demand capacity by upgrading inefficient electric resistance heating to heat pumps, rooftop solar and storage could provide an additional **5.4 GW** of peak demand capacity. This would total **more than the 6.7 GW of new demand** from data centers over the next five years.



→ Finally, in **Pennsylvania**, in addition to the **1.3 GW** of capacity created by upgrading electric resistance heating to heat pumps, solar and storage can offer another **3.2 GW** of capacity. This will total more than **150 percent** of the expected **3 GW** in new data center demand.

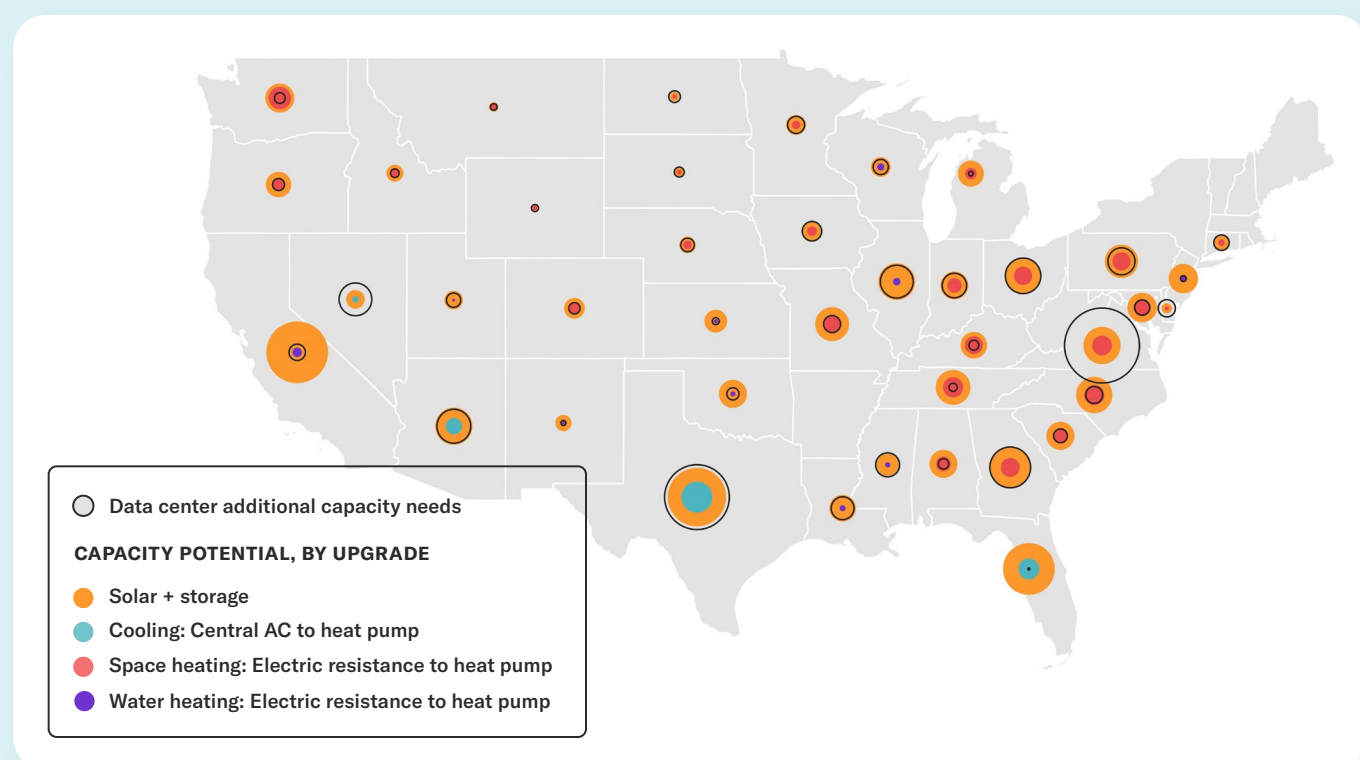
Potential for heat pump, solar, and storage upgrades to fulfill new data center demand, by state.



Pairing rooftop solar and storage also improves the long-term economic benefits for the household. Some states have reduced or eliminated credits for households that send electricity generated by their panels back to the grid. As a result, households now have an incentive to store electricity generated by their solar panels during the day for use in the evening.¹⁹ Installing rooftop solar and storage together ensures that households will see the economic benefits of rooftop solar long into the future, regardless of how their state decides to compensate for solar credits.

COMBINED UPGRADE CAPACITY

Projected data center additional capacity needs (through 2029) compared to capacity potential from heat pump upgrades paired with rooftop solar and storage by state.²⁰



States, utilities, and hyperscalers should be looking to households as a critical part of the strategy needed for the U.S. to lead on AI. In many states, the potential capacity created from targeted residential heat pump installation, solar, and storage more than meets expected additional data center capacity needs. In all of those places, homes can be more than the hero of the data center demand growth story; they can also power further affordable electrification of homes and businesses. With the combined efforts of hyperscalers, utilities, regulators, policymakers, and advocates, we can harness the power of the household to stabilize runaway electricity rates, and prevent the expansion of costly new fossil fuel plants. Household electrification can provide a faster and more cost-effective solution to our energy challenges, while providing immediate benefits and economic relief to Americans. This approach should be on the “do now” and “do first” lists for hyperscaler and utility investment.



3

Hyperscaler investments in heat pumps, solar, and storage pave the way to a modern, all-electric energy future

Meeting the capacity demands of new data centers in the coming years is a challenge, but it is also an opportunity to build for an economic future that will require abundant and affordable energy. Other economies are choosing to build out all-electric energy systems powered by renewable energy, and the U.S. must do the same to remain a global leader.²¹ American households can be the hero of the current moment, meeting the capacity that new data centers require on the grid. In addition, investing in households will make it possible for us to shift to this modern future by completely electrifying home energy use, upgrading our grid, and managing the phase-out of the duplicative gas system. **Hyperscaler investments in household upgrades lay the groundwork for this larger transformation to an all-electric energy future.**

Household upgrades lay the groundwork for an all-electric energy future.

Initial investments in residential heat pumps, solar, and storage catalyze further changes in several ways. First, as discussed above, rooftop solar and storage will provide electricity to households at an effective cost of \$0.11/kWh. Access to electricity at a fixed and affordable rate relative to gas prices will ensure that households save money on their energy bills when they switch from fossil fuel to electric appliances.

Second, home solar and storage will overcome concerns about household resilience to power outages after widespread electrification. All-electric homes powered by solar and storage will be able to operate their appliances, staying comfortable and livable, even when the power goes out.²²

Third, by installing a high volume of heat pumps in homes currently using inefficient electric heating, cooling, and water heating, we will mature the already-growing market for heat pump installations. We will grow the workforce and increase contractor comfort with heat pump installs, driving upfront costs down and making heat pumps more affordable for everyone.



Finally, installing residential capacity now will make it easier to meet continued load growth — both by extending our timeline and freeing up resources to make the transition possible. We will certainly need new utility-scale generation alongside rooftop solar and battery storage to support this increased demand. But in contrast to the current surge in demand from data centers, this increase in demand will not happen overnight. We have decades to plan for this transition and build out the grid. At the same time, we can transition from two energy systems to one. We are currently paying to build and maintain two increasingly redundant systems: the gas system and the electric grid. Utilities are pouring more than \$20 billion each year into aging gas distribution infrastructure, and costs are increasing.²³ If these trends continue, utilities will have to spend more than \$1 trillion over the next 25 years just replacing aging gas distribution pipes. We can avoid this costly future. Instead, to provide the capacity required to electrify everything, we can invest the \$1 trillion that would otherwise be invested in the gas system into upgrading the electric grid and electrifying households.



Utilities are pouring more than **\$20 billion** each year into aging gas distribution infrastructure, and costs are increasing.

There are many exciting solutions that we have not analyzed in depth in this report that would help keep electricity prices stable and avoid ongoing increases in peak demand. In brief, some of these include:



Charging electric vehicles at off-peak times, which has already driven down electricity prices by increasing the amount of electricity we use without increasing peak demand, thereby spreading grid costs over more kilowatt-hours of electricity.²⁴



Load shifting, or rescheduling electricity use from high-demand (peak) periods to low-demand (off-peak) times, which can also improve grid efficiency and drive down electricity prices.



Curtailment, or turning off less essential loads during peak periods or emergencies, which can limit growth in peak demand.



Installing more power-efficient appliances, like heat pump water heaters that plug into a standard 120-volt wall outlet, which can limit growth in peak demand.

The impact of these solutions on peak demand and electricity prices in an all-electric future will be the subject of future work.



Invest in households first

We urge hyperscalers, utilities, and other decision makers to **first look to the household** when they are solving the energy system challenges of our time. Leveraging households as energy infrastructure rather than passive or competing consumers is the fastest, cleanest, and most beneficial way to meet surging electricity demand.

Between installing heat pumps in homes with inefficient heating and cooling, and installing rooftop solar and storage, we can more than meet the projected load growth from data centers. This sets us up for a more affordable energy future, where our economy is powered by a single resilient and clean energy system, and we are no longer spreading money between both the electricity grid and the gas system.

When we invest in home upgrades to meet surging demand, everyone wins. Hyperscalers get the power that they desperately need to build new data centers. Policymakers and utilities can meet demand and keep the lights on — with a flexible, resilient, and cost-effective grid resource that can be deployed much faster than alternatives. Most importantly, households get to experience the win-win of affordable, reliable, and clean energy.

Leveraging households as energy infrastructure rather than passive or competing consumers is the fastest, cleanest, and most beneficial way to meet surging electricity demand.

ENDNOTES

- 1 “Strategic Industries Surging: Driving US Power Demand.” Grid Strategies, December 2024. <https://gridstrategiesllc.com/wp-content/uploads/National-Load-Growth-Report-2024.pdf>
- 2 Based on data from Aterio (<https://www.aterio.io/>). For full details, refer to technical methodology.
- 3 Active campuses are those already operational. Planned campuses are those either announced or under construction. Expanding campuses are those with a mix of active and planned data centers.
- 4 Horsley, Scott. “Electricity prices are climbing more than twice as fast as inflation.” NPR, 16 August 2025. <https://www.npr.org/2025/08/16/nx-s1-5502671/electricity-bill-high-inflation-ai>
- 5 “Utilities Have Requested \$29 Billion in Rate Hikes for 2025, Surpassing 2024.” Powerlines, 10 July 2025. <https://powerlines.org/utilities-have-requested-29-billion-in-rate-hikes-for-2025-surpassing-2024/>
- 6 Foster, Sarah “Four years after inflation first spiked, Americans’ wages are still falling behind — and a slower job market isn’t helping.” Bankrate, 18 August 2025. <https://www.bankrate.com/banking/federal-reserve/wage-to-inflation-index/>
- 7 Baddour, Dylan and Arcelia Martin. “Data centers are building their own gas power plants in Texas.” The Texas Tribune, 5 June 2025. <https://www.texastribune.org/2025/06/05/texas-data-centers-gas-power-plants-ai/>
- 8 Allsup, Maeve. “Running the numbers on Tesla and Sunrun’s massive California VPP test.” Latitude Media, 19 August 2025. <https://www.latitudemedia.com/news/running-the-numbers-on-tesla-and-sunruns-massive-california-vpp-test/>
- 9 Chandramowli, Shankar et al. “Power surge: Navigating US electricity demand growth.” ICF, 22 October 2024. <https://www.icf.com/-/media/files/icf/reports/2024/utility-flagship-report-icf-2024.pdf>
- 10 All analysis is done on single-family occupied households. For more details, see the technical methodology.
- 11 Zeitlin, Matthew. “One Weird Trick to Build New Data Centers Without Breaking the Grid.” Heatmap News, 14 August, 2025. <https://heatmap.news/energy/ai-flexible-loads>
- 12 Household capacity potential is reported for the single heat pump solution that delivers the most capacity for each state (converting electric resistance heating to heat pumps, converting central air conditioners to heat pumps, or converting electric resistance water heaters to heat pump water heaters).
- 13 Based on current costs from Cohen, Jesse et al. “Gas Turbine Supply Constraints Threaten Grid Reliability; More Affordable Near-Term Solutions Can Help.” RMI, 18 June 2025. <https://rmi.org/gas-turbine-supply-constraints-threaten-grid-reliability-more-affordable-near-term-solutions-can-help/>. For more details, refer to technical methodology.
- 14 Based on the Environmental Protection Agency estimate from “Greenhouse Gas Emissions from a Typical Passenger Vehicle.” Environmental Protection Agency, 12 June 2025. <https://www.epa.gov/greenvehicles/greenhouse-gas-emissions-typical-passenger-vehicle>
- 15 Rewiring America internal modeling. For more details, refer to the technical methodology.
- 16 Battery is represented by a Tesla Powerwall 3. Solar suitability derived from modeling done by the National Renewable Energy Laboratory. About 81% of single-family homes nationally are considered suitable for solar, varying by location. For full methodology, refer to the technical methodology.
- 17 Hastings, Colby et al. “Tesla Energy: Breaking the Cost Barrier in Residential Energy.” Tesla, August 2025. https://energylibrary.tesla.com/docs/Public/Solar/Retrofit/WhitePaper/en/Tesla_Energy_Breaking_the_Cost_Barrier_in_Residential_Energy.pdf
- 18 Cost of capacity from rooftop solar and storage under this arrangement are around \$365/kW-year, compared to \$315/kW-year for a gas power plant.
- 19 “How California’s new net metering policies have made solar energy storage more valuable.” Vox, 20 June 2023. <https://www.vox.com/ad/23727390/california-new-net-metering-policies>
- 20 Adding capacity reductions from household electrification with rooftop solar and storage may differ from analyzing each in isolation because of how residential peak consumption shifts with different upgrades. For more details, refer to the technical methodology.
- 21 McCarthy, Dan. “Chart: Which countries get the most power from solar and wind?” Canary Media, 27 June 2025. <https://www.canarymedia.com/articles/solar/chart-countries-most-renewable-energy>
- 22 Sun, Tao et al. “Solar and battery can reduce energy costs and provide affordable outage backup for US households.” Nature Energy, 1 August 2025. <https://www.nature.com/articles/s41560-025-01821-w>
- 23 “Gas Utility Construction Capital Expenditure.” American Gas Association, 2025. <https://www.aga.org/research-policy/resource-library/gas-utility-construction-capital-expenditure/>
- 24 Hammon, Beth. “The Truth About Electric Vehicles and the Grid: Strengthening—Not Straining—Our Energy Future.” NRDC, 28 February 2025. <https://www.nrdc.org/bio/beth-hammon/truth-about-electric-vehicles-and-grid-strengthening-not-straining-our-energy>

See technical methodology [here](#).

Homegrown energy: How household upgrades can meet 100 percent of data center demand growth

Hyperscalers should pay for heat pumps, rooftop solar, and storage to get the capacity they need on the grid now, while setting us up for an affordable, reliable, and clean energy future.

⚡ **AUTHORS:** Cora Wyent, Miki Verma, and Wael Kanj



YEARS of SERVICE

OREGON
DEPARTMENT OF
ENERGY

Transformational Integrated Greenhouse Gas Emissions Reduction Project (TIGHGER)

GHG Emission Reduction Forecast Update
OCAC – October 10, 2025

Transformational Integrated Greenhouse Gas Emissions Reduction (TIGHGER) Project

TIGHGER 1.0 - Goal: Develop and analyze actions across the economy to achieve Oregon's sector-based greenhouse gas emissions reduction goal of at least 45 percent below 1990 levels by 2035, while continuing to grow Oregon's economy and enhancing equity and quality of life for all Oregonians.

Phases of the Project:

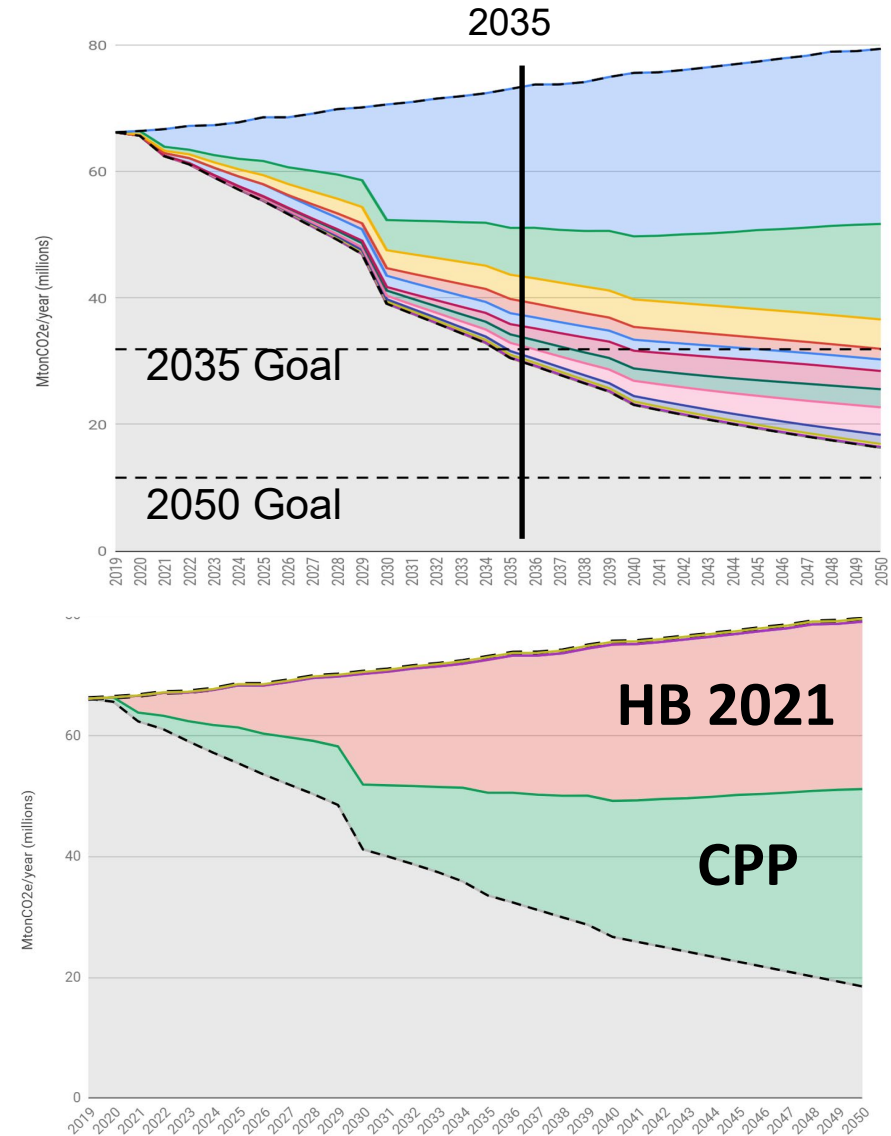
1. Forecast GHG emissions
2. Assess the impact of existing programs and regulations (through 2035)
3. Assess additional opportunities to reduce GHG emissions

TIGHER 1.0 Process Overview

- Multi-Year Process
- US Climate Alliance Grant of \$252,000
- ODOE Project Manager (~1.5 FTE) plus 1 modeling consultant (SSG)
- OGWC (OCAC) Review and Public Engagement Committee
- Engagement of over 95 people in 3 Public Meetings, 100 public comments, and 9 state agencies
- Focus of over 15 Commission & Subcommittee meetings with public comments

TIGHGER 1.0 Findings

- The state's 15 existing policies and programs already adopted (and the federal CAFE standards), would enable the state to reach its 2035 emissions reduction goal if they are all implemented as planned and fully funded
- There are two Big Lever Programs that Reduce 97% of the emissions we need to meet our 2035 goal – HB 2021 and the Climate Protection Program (CPP)



Programs and Regulations Adopted

DEQ Programs and Rules:

1. Advanced Clean Cars 1 (2009)
2. Clean Fuels Program (2016)
3. Advanced Clean Trucks (CPP)
4. Climate Protection Program (CPP)
5. Advanced Clean Cars II (CPP)
6. Clean Fuels Program Expansion (CPP)
7. Landfill Program
8. Recycling Modernization Act

Federal Programs:

- CAFÉ standards

Other Programs and Rules:

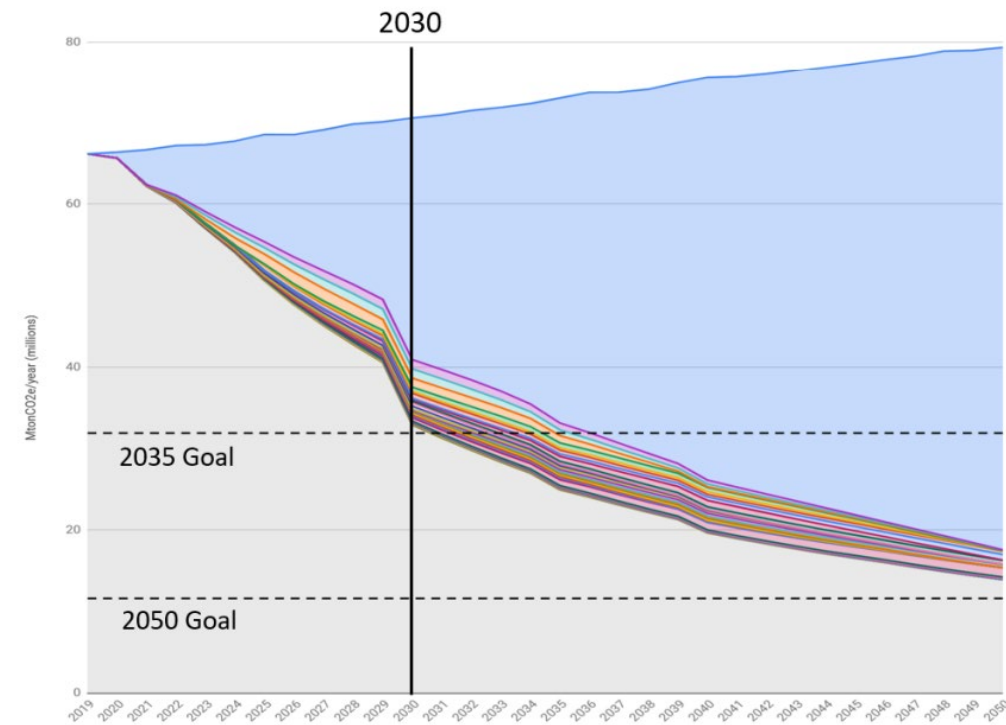
9. HB 2021 (100% Clean Electricity)
10. Energy Efficiency Appliances (ODOE)
11. Solar + Storage Rebate Program (ODOE)
12. Heat Pump Rebate Programs (ODOE)
13. Community Renewable Energy Program (ODOE)
14. Manufactured Home Replacement (OHCS)
15. Healthy Homes Grant Program (OHCS)

Non-Quantifiable Programs:

- Every Mile Counts
- Climate Friendly and Equitable Communities

TIGHGER 1.0 Findings

- TIGHGER also analyzed an additional 35 climate actions that could accelerate meeting the 2035 goal by 2030 (the "TIGHGER Actions")
- The results show significant financial and co-benefits from the TIGHGER Actions
- Results from TIGHGER 1.0 informed the Commission's [Roadmap to 2030](#) and recommendations to the Legislature



Why TIGHGER 2.0?

(Technical Analysis/Update)

- Respond to legislative directive (HB 3409) to periodically prepare a detailed forecast of GHG emissions reductions
- **Phase 1** - Update the GHG emissions assumptions and forecast through 2050
 - Include new inputs (e.g., data center loads)
 - Impacts from federal changes (e.g., CAFÉ)
 - Impacts of new state programs
 - Assess progress to date
- **Phase 2** - Evaluate additional actions to meet our goals
- Inform future policy and program actions

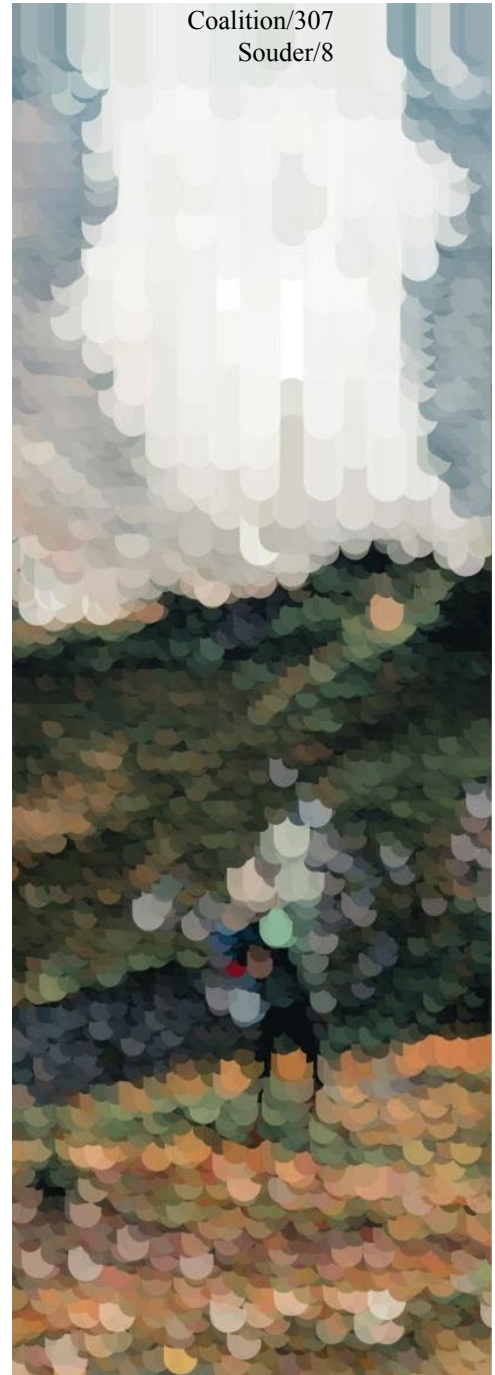
MODEL FORECAST RESULTS BUSINESS AS PLANNED

October 10, 2025

Transformational Integrated Greenhouse
Gas Emissions Reduction Project
(TIGHGER 2.0)

Sustainability
Solutions Group

Coalition/307
Souder/8



Bottom-up



Transformational



Transparency



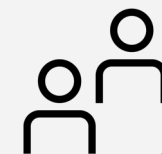
Economic impacts



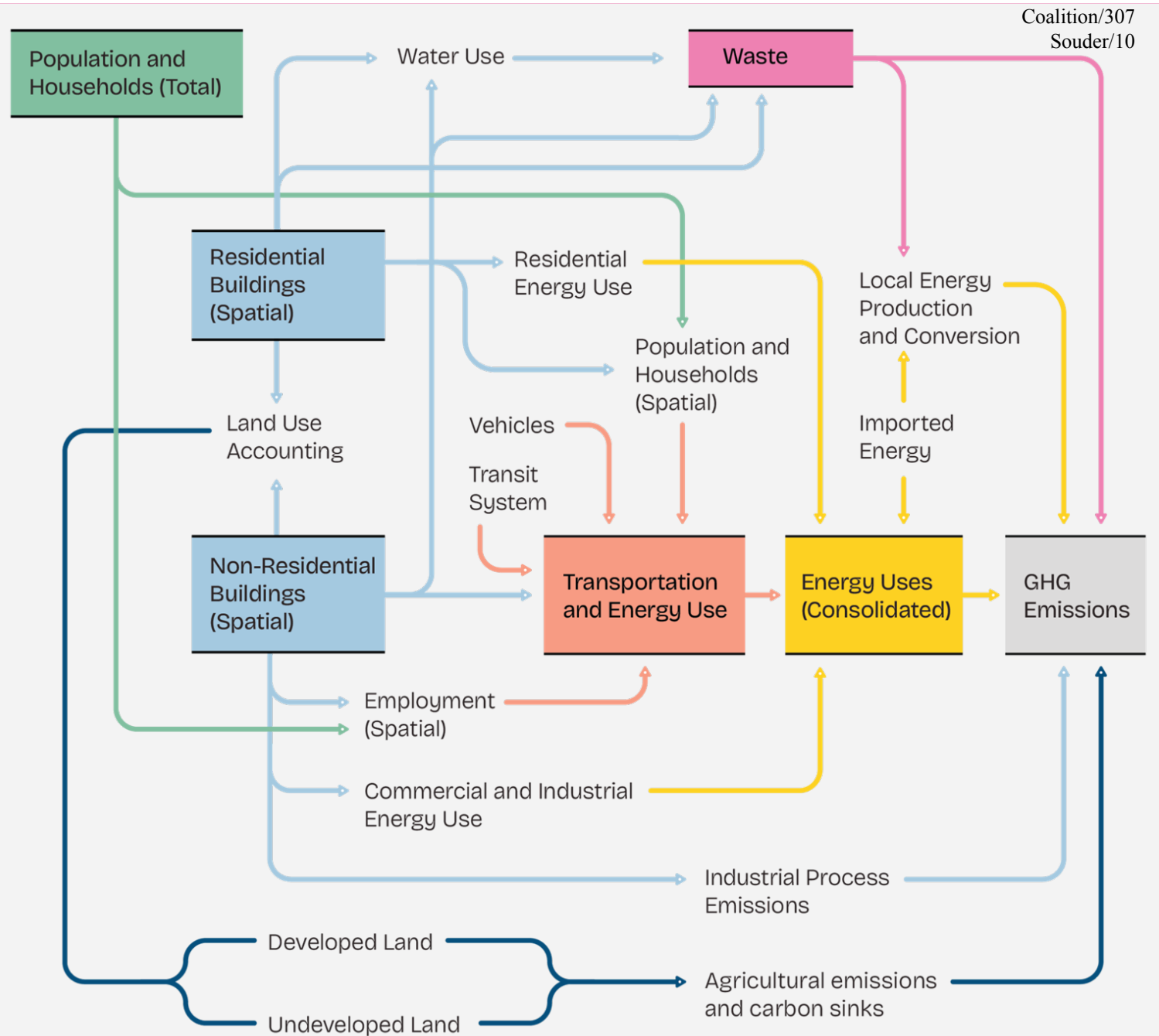
Public health impacts



Equity impacts



Model Structure Integrated



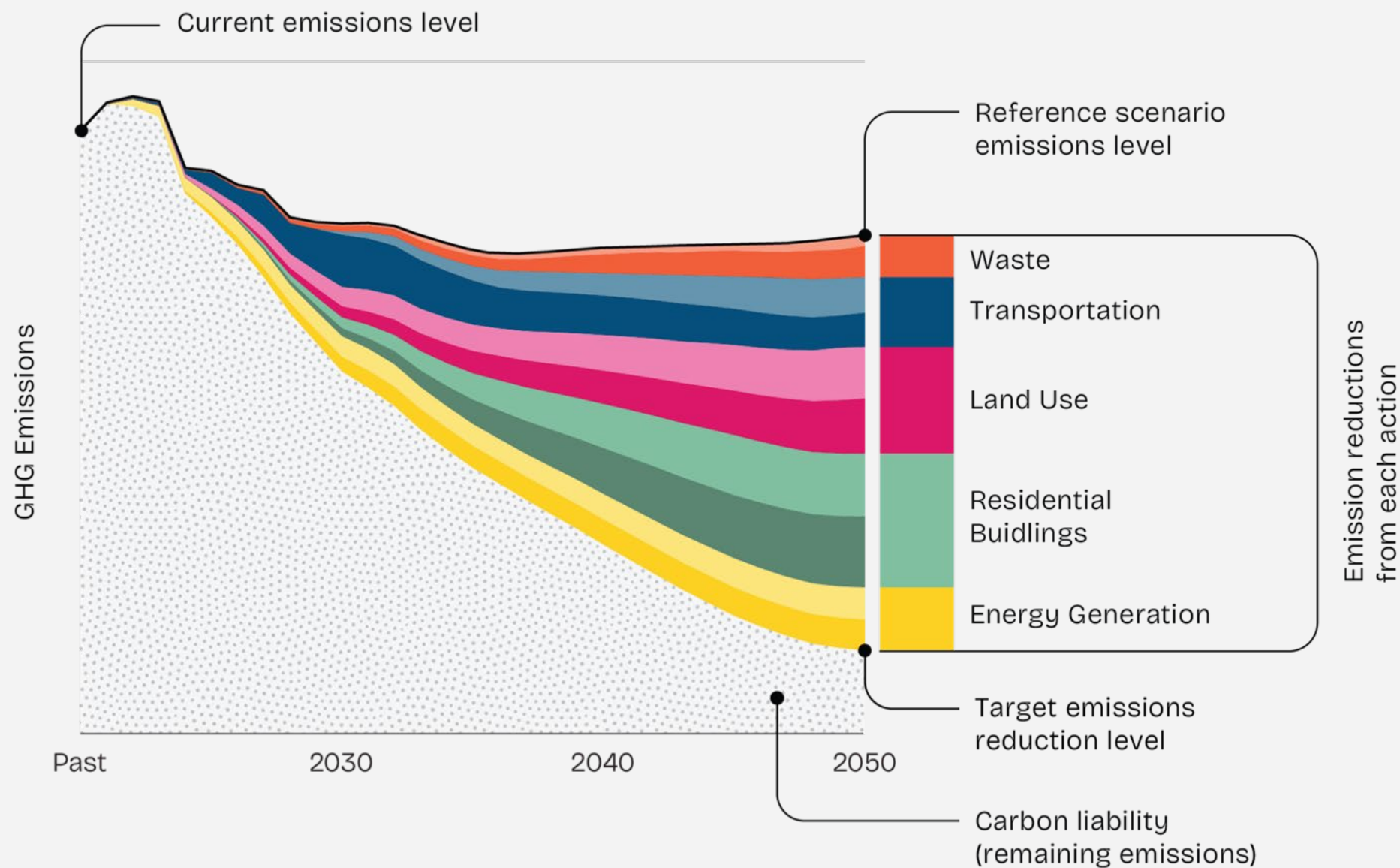
Capabilities....

- ..of representing non-linear behaviour
- ..of representing diversity and heterogeneity
- ..of incorporating uncertainties or contingencies

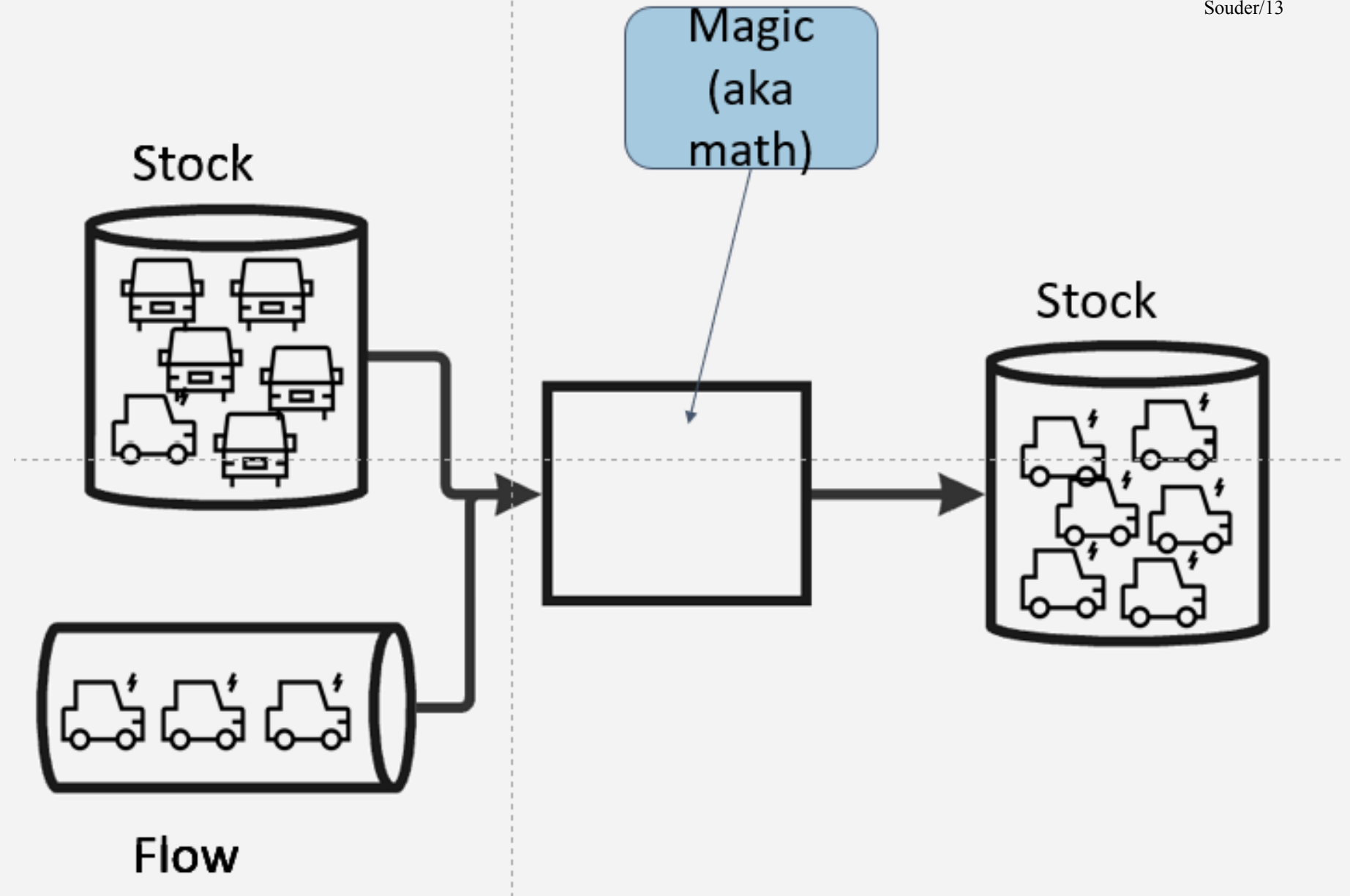
Köhler, J., De Haan, F., Holtz, G., Kubeczko, K., Moallemi, E., Papachristos, G., & Chappin, E. (2018). Modelling sustainability transitions: An assessment of approaches and challenges. *Journal of Artificial Societies and Social Simulation*, 21(1)

Scenarios

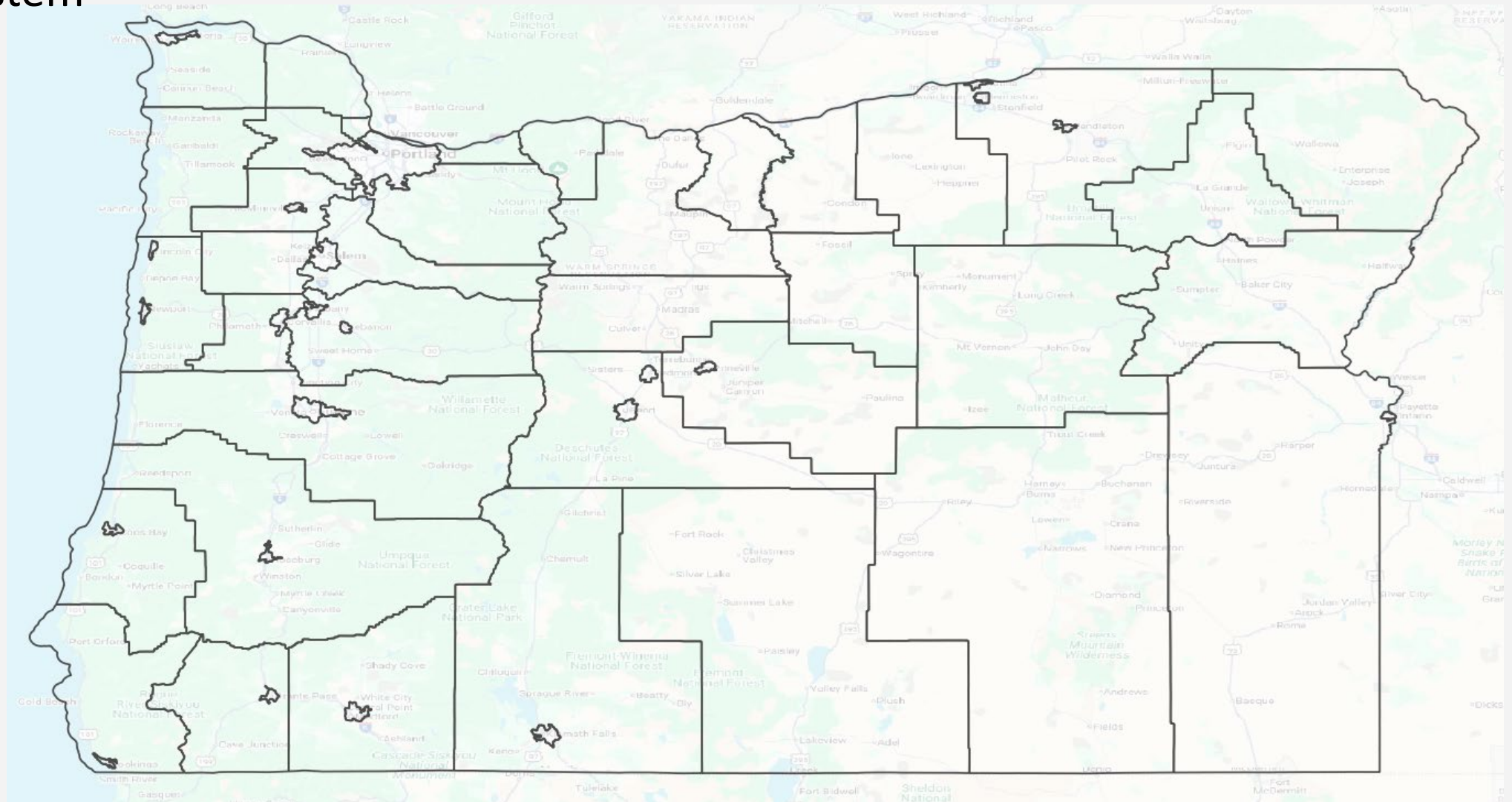
Stories about the future



Stocks & Flows



Spatial Zone system



Scenarios

BAU

Business as Usual

Scenario that involves no new/future policy interventions

BAP

Business as Planned

Scenario that represents impact of current policies

BAP Criteria

Funded

Regulations

**Clear
enforceable
mechanisms**

**Adopted by
state**

High certainty

**Consistent with
Energy Strategy**

Coalition/307
Souder/16

BAU

Assumptions

Population projection by County

PSU population
forecasts by county

Employment projection County

State of Oregon
Employment
Department

Coalition/307
Souder/17

Heating and cooling degree days by county

U.S. Climate
Resilience Toolkit
Climate Explore
(Version 3.1)

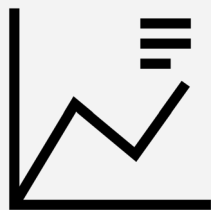
Data Centers

NWPCC load growth
forecast:

2030: 2.54GW

2046: 3.42GW

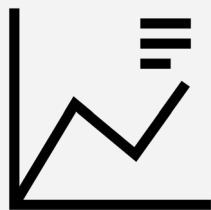
Programs and Regulations Adopted



DEQ

- **Climate Protection Program (CPP)**
- Clean Fuels Program (CFP)
- Advanced Clean Cars II (ACC II)
- Advanced Clean Trucks (ACT)
- Plastic Pollution and Recycling Modernization Act (RMA)
- Landfill Program
- **Food Waste Reduction Strategy**
- **Heavy-Duty Engine and Vehicle Omnibus Rule**

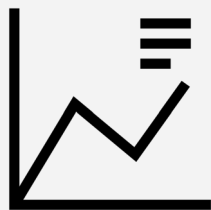
Programs and Regulations Adopted



ODOE

- Energy Efficiency Standards for Appliances
- **Heat Pump Purchase Program**
- Community Heat Pump Deployment Program
- Oregon Rental Home Heat Pump Program
- Community Renewable Energy Grant Program
- Solar + Storage Rebate Program
- Community Renewable Energy Grant Program
- 1.5% for Green Energy Technology (GET) Program
- State Energy Efficient Design (SEED) Program
- Public Purchase Charge Schools Program
- **Building Energy Performance Standards**
- **Home Efficiency Rebate Program (HOMES)**
- **Home Electrification and Appliance Rebate Program (HEAR)**
- **Energy Efficiency and Conservation Block Grant**
- **Energy Efficient Wildfire Rebuilding Incentive**

Programs and Regulations Adopted



Additional Programs

- Clean Electricity Law HB 2021
- Manufactured Home Replacement (OHCS)
- Healthy Homes Grant Program (OHA)
- **Multifamily Energy Program (OHCS)**
- **Climate-Friendly and Equitable Communities (DLCD)**
- **Middle Housing (HB 2001) (DLCD)**
- **Statewide Transportation Strategy Programs (ODOT)**
- **Oregon Clean Vehicle & Charge Ahead Rebate Program (ODOT)**
- **Low Emission Vehicle Program (ODOT)**
- **West Coast Electric Highway**
- **National EV Infrastructure (NEVI) Program (ODOT)**
- **Community EV Charging Rebate Program (ODOT)**

Federal Programs

- *CAFÉ Standards (canceled)*

Programs and Regulations Adopted



Additional Programs

- Electric Vehicle Reliability Accessibility Accelerator Program (ODOT)
- Carbon Reduction Program (ODOT)
- Diesel Emissions Mitigation Grant Program (ODOT)
- Oregon Zero-Emission Fueling Infrastructure Grant Program (ODOT)
- Medium-and Heavy Duty Emissions Vehicle Rebate (ODOT)
- Charging and Fueling Infrastructure Grant Program (ODOT)
- Energy Efficiency Specialty Code (DCBS)
- Oregon Commercial Energy Efficiency Specialty Code (DCBS)
- Oregon Residential Energy Efficiency Specialty Code (DCBS)
- Climate Equity and Resilience Through Action (CERTA) Measures – Climate Pollution Reduction Grant

Actions

BAP



Construct new energy efficient buildings

- Construct new commercial buildings according to Energy Efficiency Specialty Code and ANSI/ASHRAE/IES Standard 90.1 – 2022 (as modified)*
- Implement Climate Equity and Resilience Through Action "CERTA" Buildings Measure #6 - New Multifamily Construction
- SEED - Increase energy efficiency of new state facilities (20% better than building code)
- Construct new residential buildings according to Energy Efficiency Specialty Code and ANSI/ASHRAE/IES Standard 90.1 – 2022 (as modified)
- Increase rate of production of "missing middle" housing (duplexes, etc. from HB 2001)
- Implement CERTA Measure #10 - Building reuse and space efficient housing

***IES**: Illuminating Engineering Society.

***ANSI**: American National Standards Institute.

***ASHRAE**: American Society of Heating, Refrigerating, and Air- Conditioning Engineers.



Actions

BAP



Retrofit existing buildings

- Retrofit large commercial buildings by 2030 (Building Performance Standard)
- Implement CERTA Buildings Measure #7 - Building Performance Standard incentives
- Retrofit residences with insulation and electric appliances via the Home Electrification and Appliance Rebate Program (HEAR)
- Improve energy efficiency of residences via the Home Efficiency Rebate Program (HOMES)
- Implement CERTA Buildings Measure #6 - Increase energy efficiency of existing and new multifamily buildings in PGE/Pacific Corp service areas
- Implement CERTA Measure #9 - Residential retrofits/weatherization
- Implement CERTA Buildings Measure #8 - New & Existing residential heat pumps
- Install heat pumps in existing residential buildings (single family and multifamily) (2023-2025)
- Install heat pumps in rebuilt residences after Labor Day wildfires (2023-2025)
- Replace 10,000 manufactured homes with energy efficient models (2025-2036)
- Implement Healthy Homes Repair Fund
- Increase energy efficiency of public school buildings (Public Purchase Charge) in PGE/Pacific Corp service areas



Actions

BAP



Transition to electric vehicles

- Implement Advanced Clean Cars II
- Implement the Advanced Clean Truck Rules
- Implement CERTA Measure #1 - Expand Oregon Clean Vehicle Rebate
- Implement CERTA Measure #5 - Medium-and Heavy-Duty Charging Infrastructure Grant
- Energy Efficiency and Conservation Block Grant to reduce energy use
- Reduce emissions (NOx and PM2.5) from new medium- and heavy-duty vehicles sold in Oregon



Actions

BAP



Reduce industrial emissions

- Climate Protection Program - Industrial
- RMA - Reduce emissions from in-state producers of pulp and paper
- RMA & CERTA - Reduce emissions from production and transport of materials (in OR) used to construct buildings and infrastructure
- RMA & CERTA - Reduce emissions from producers of packaging/paper/foodware producers



Actions

BAP



Reduce waste emissions

- Implement Recycling Modernization Act (waste-related actions)
- Reduce methane emissions from landfills
- Implement CERTA Measure #11 - Increase capacity to compost/digest organic waste
- Implement CERTA Measure #12 - Landfill Methane
- Increase recycling collection and processing
- Prevent food waste via the Pacific Coast Food Waste Commitment



Actions

BAP



Implement HB 2021 (and related actions)

- HB 2021 100% Clean Energy Standard
 - Increase distributed energy resources
 - Implement community renewable energy grant program through 2027
 - Implement Renewable Portfolio Standards
 - Install solar + storage on residential buildings via rebate program



Actions

(stand alone)

BAP



Implement energy
efficiency standards
for appliances



Implement Climate-
Friendly and
Equitable
Communities CFEC

reduce VMT

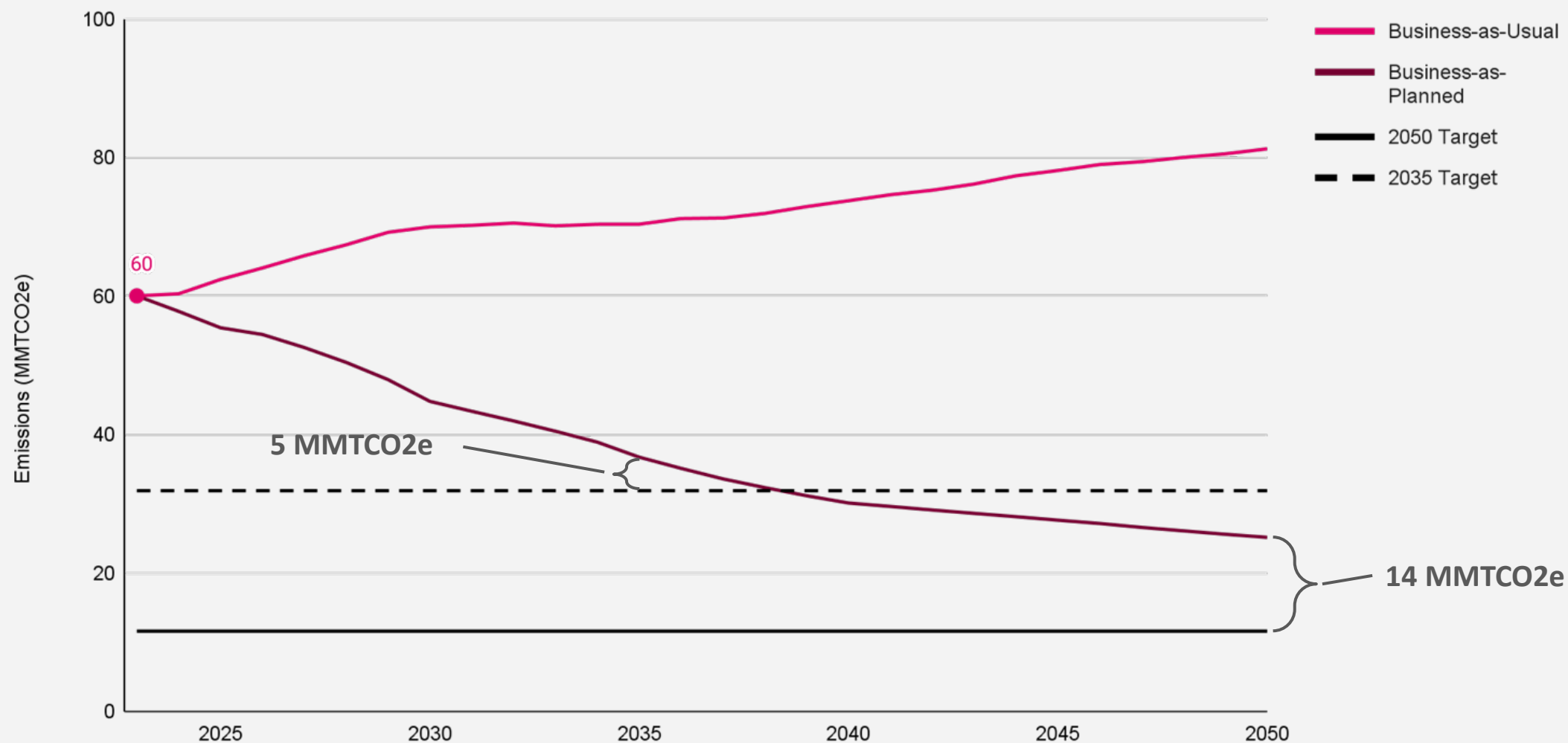


Implement the
Climate Protection
Program

reduce emissions
from fossil fuels not
addressed by other
programs or policies



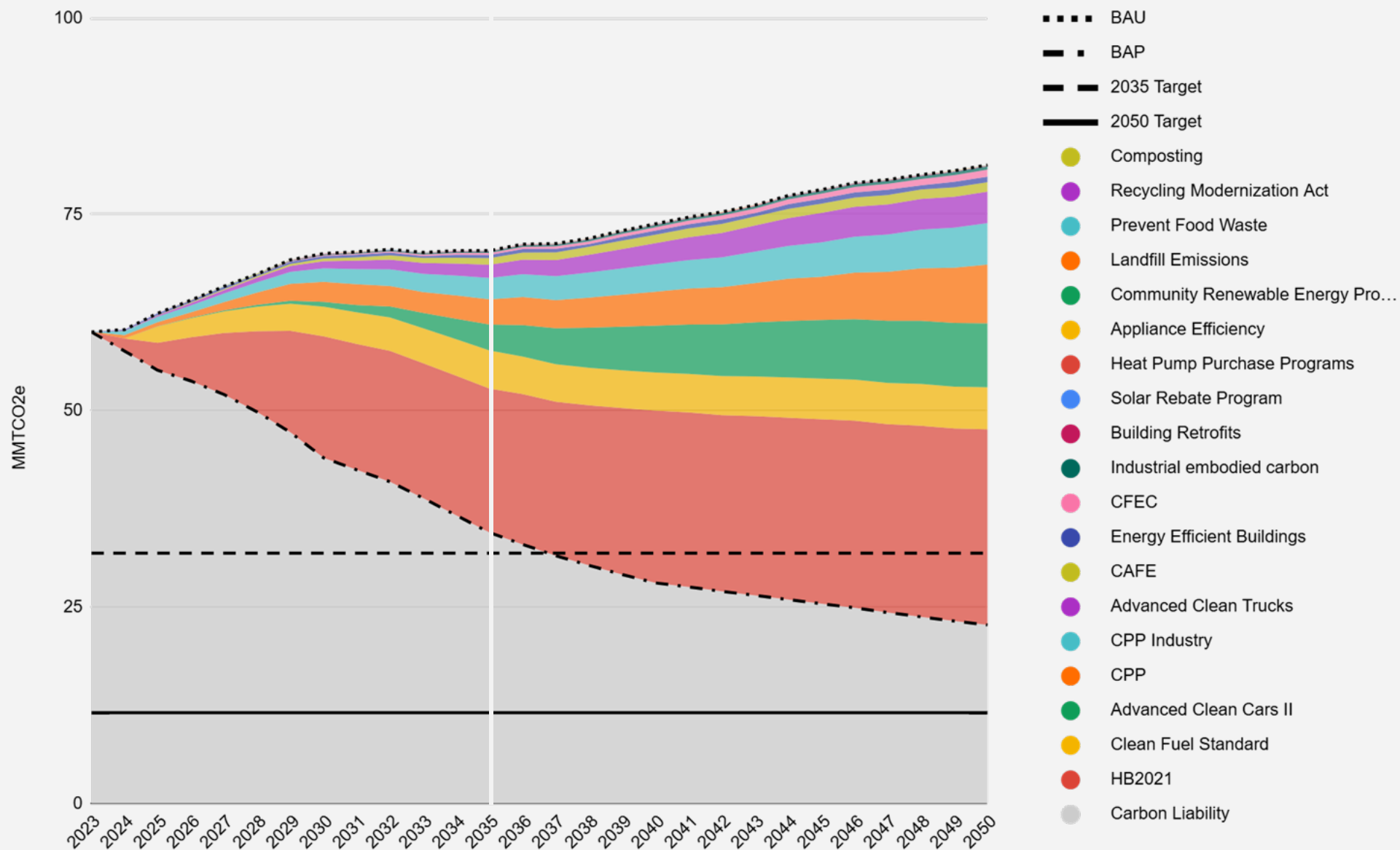
Emissions Overview



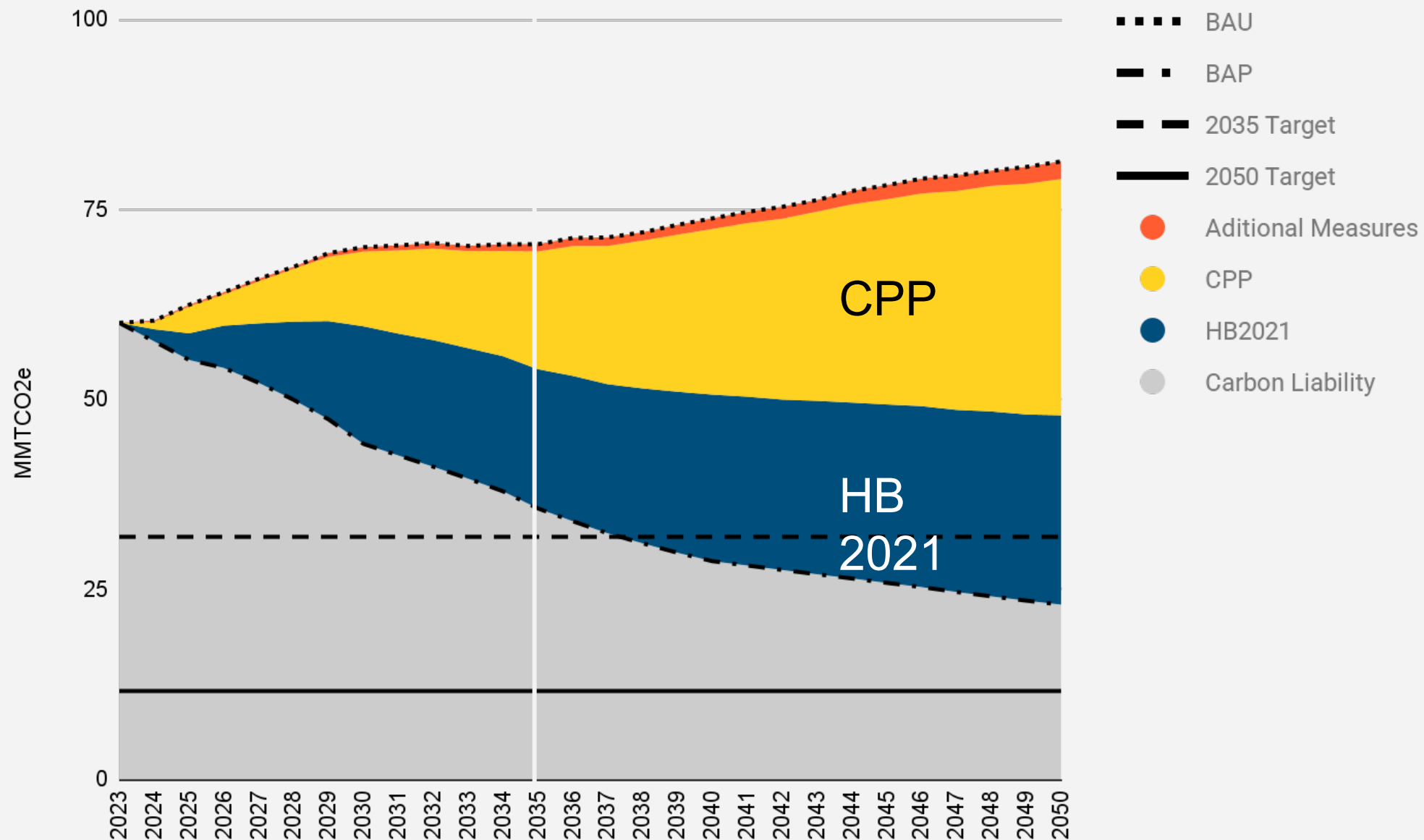
Key Takeaways - Major Changes from TIGHGER 1.0

- Oregon is no longer on target to reach its 2035 reduction goal (meet it in 2037) creating a 2035 gap
- Larger gap to meet the 2050 goal
- Primary drivers:
 - Increasing data center load growth (with half in Consumer-Owned Utility service territory not subject to clean energy requirements of HB 2021, conservative assumption of emission factor for market purchases)
 - Feds cancel CAFE standards (assume no future increases in MPG)

Emissions by Policy



Emissions by Big Lever Programs

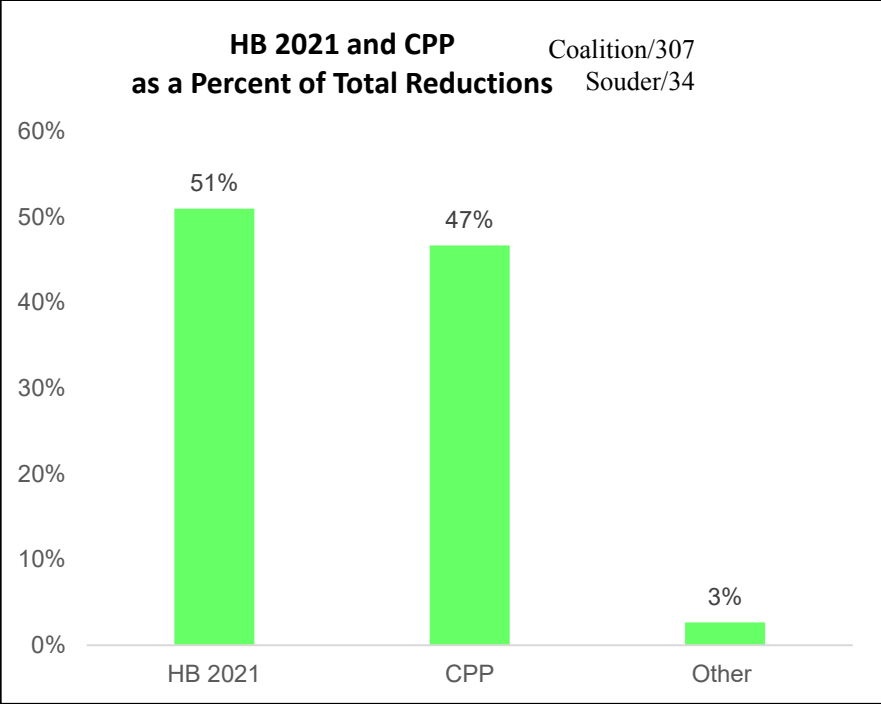
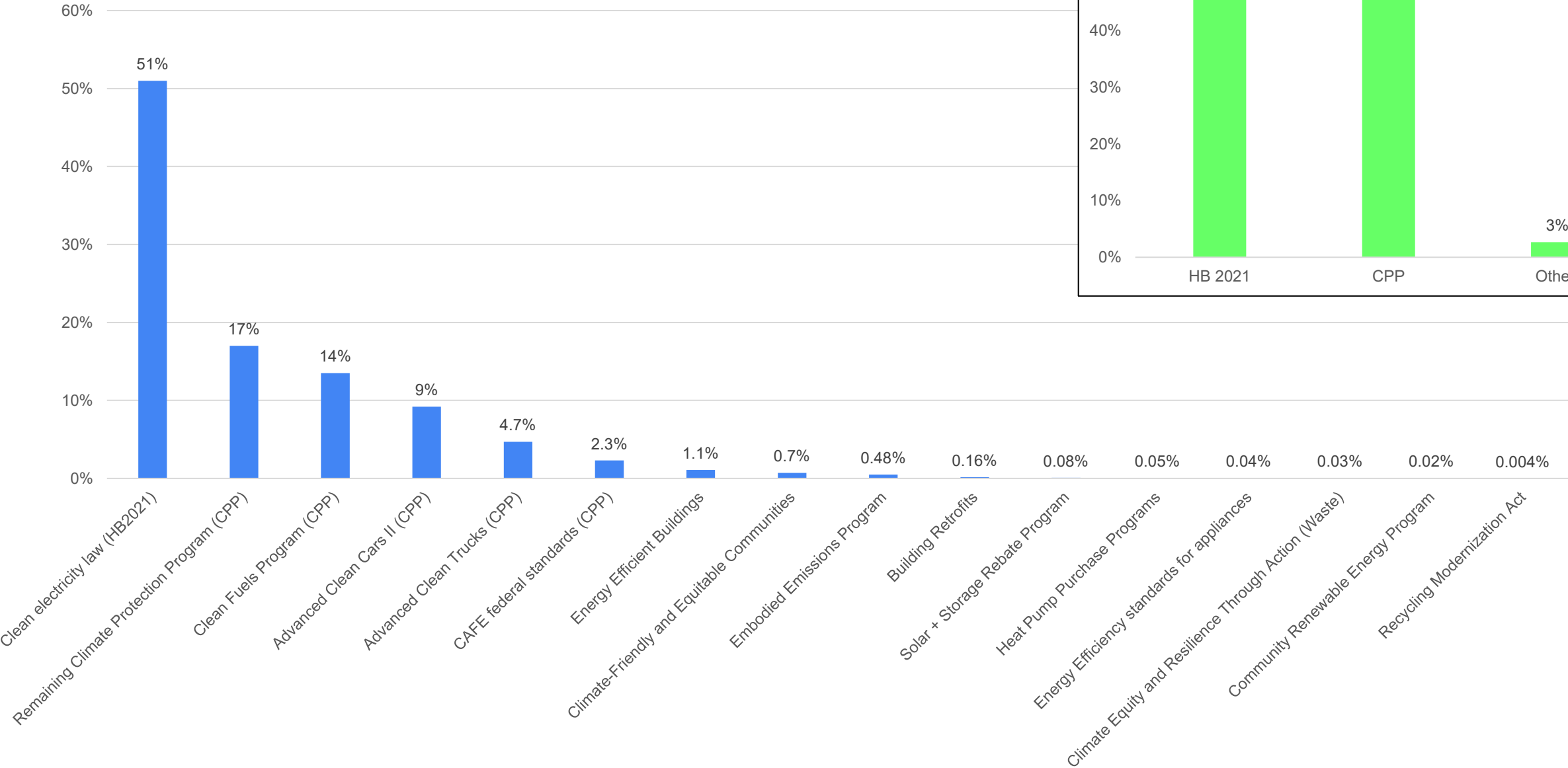


Emissions by Policy

2035

Rank	Action Title	Annual Emissions Reduced (MMTCO2e)	Percent of Total	Cumulative Percent of Total
1	Clean electricity law (HB2021)	18.32	51%	51%
2	Remaining Climate Protection Program (CPP)	5.93	17%	68%
3	Clean Fuels Program (CPP)	4.84	13.5%	81%
4	Advanced Clean Cars II (CPP)	3.32	9.2%	90%
5	Advanced Clean Trucks (CPP)	1.67	4.7%	95%
6	CAFE federal standards (CPP)	0.83	2.3%	97%
7	Energy Efficient Buildings	0.40	1.1%	98%
8	Climate-Friendly and Equitable Communities	0.25	0.70%	99%
9	Embodied Emissions Program	0.17	0.48%	100%
10	Building Retrofits	0.06	0.16%	100%
11	Solar + Storage Rebate Program	0.03	0.08%	100%
12	Heat Pump Purchase Programs	0.02	0.05%	100%
13	Energy Efficiency standards for appliances	0.01	0.04%	100%
14	Climate Equity and Resilience Through Action (Waste)	0.01	0.03%	100%
15	Community Renewable Energy Program	0.01	0.02%	100%
16	Recycling Modernization Act	0.00	0.004%	100%
	Total	35.88	100%	100%

Programs and Regulations Adopted GHG Emission Reduction Contribution

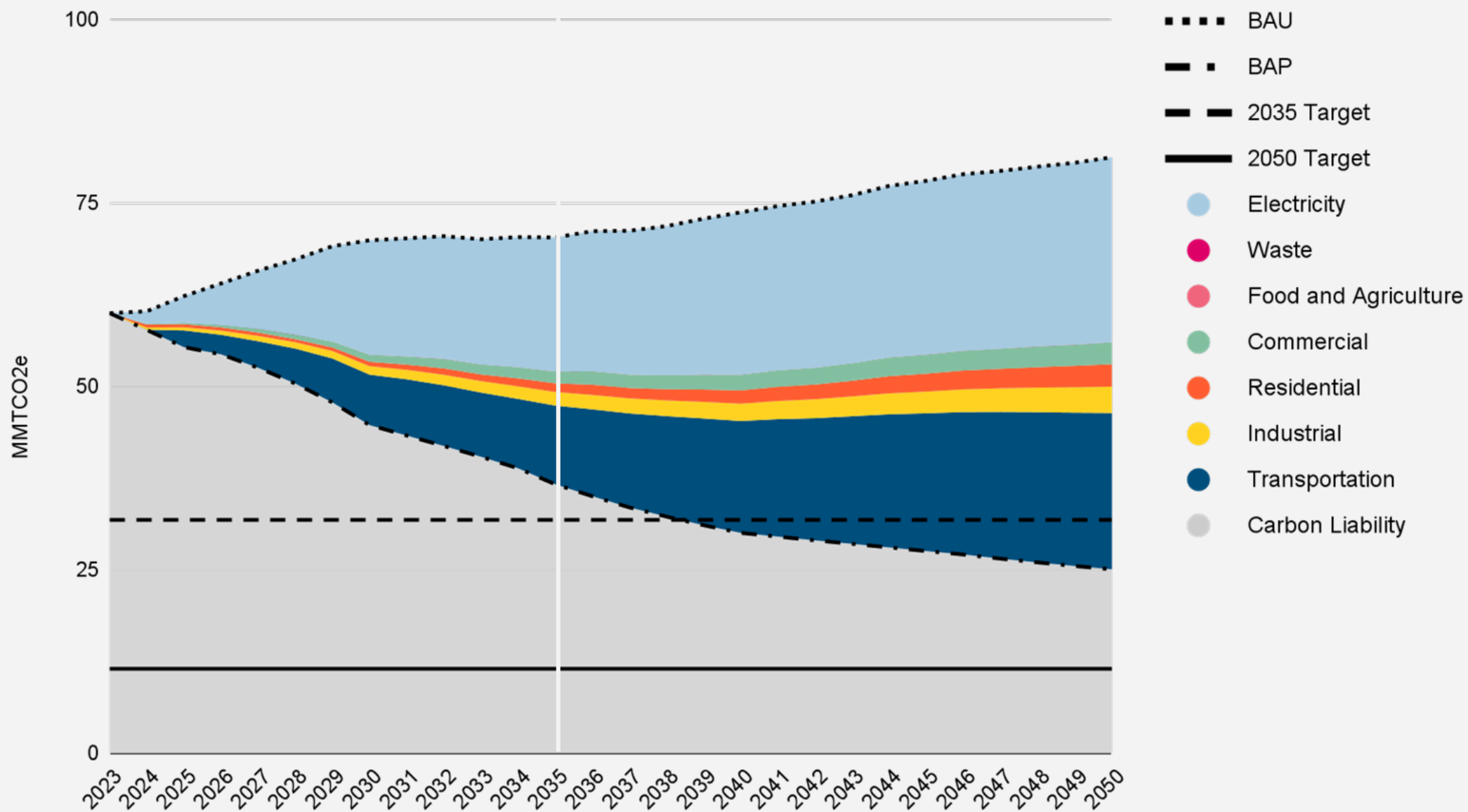


Emissions by Policy

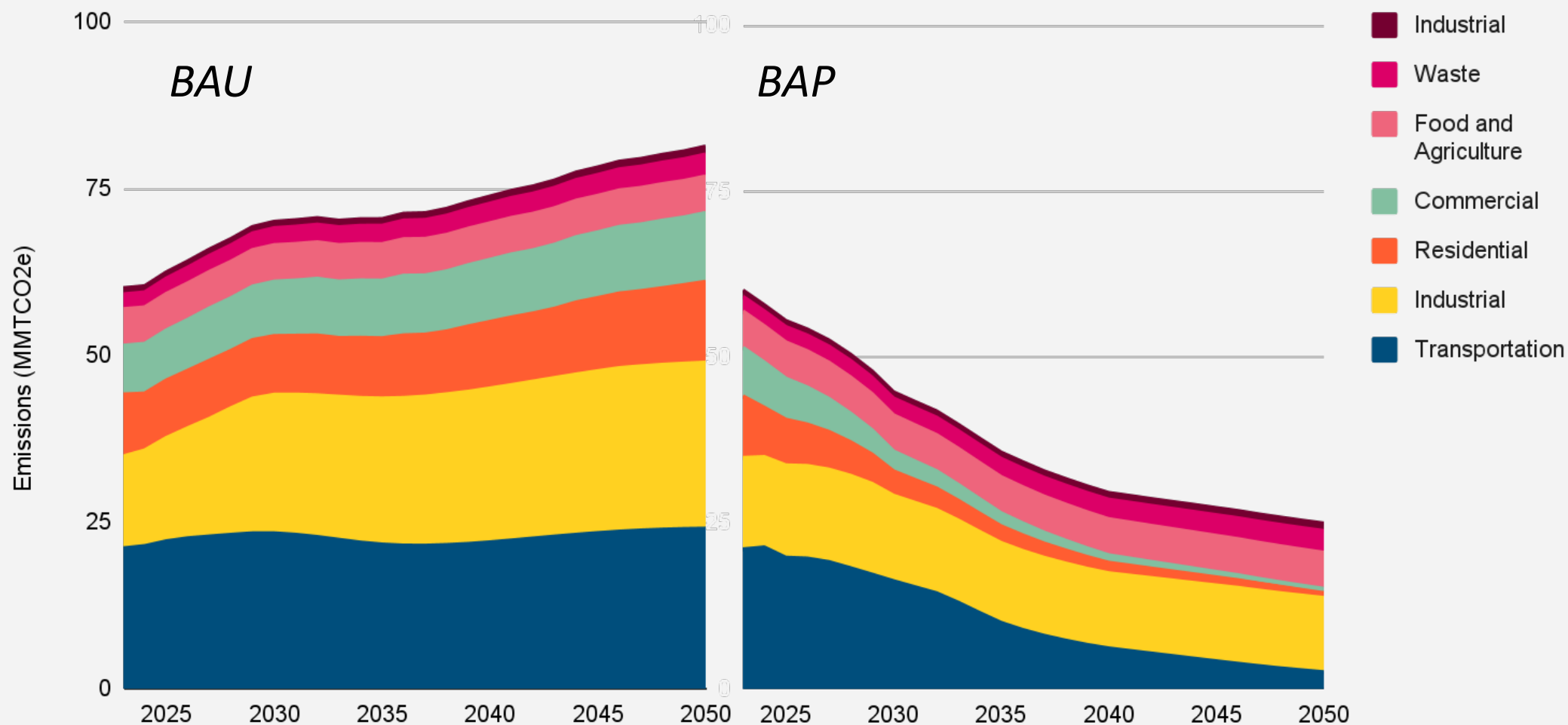
2050

Rank	Action Title	Annual Emissions Reduced (MMTCO2e)	Percent of Total	Cumulative Percent of Total
1	Clean electricity law (HB2021)	24.90	43%	43%
2	Remaining Climate Protection Program (CPP)	12.76	22%	64%
3	Advanced Clean Cars II (CPP)	8.14	14%	78%
4	Clean Fuels Program (CPP)	5.34	9.1%	87%
5	Advanced Clean Trucks (CPP)	3.99	6.8%	94%
6	CAFE federal standards (CPP)	1.20	2.1%	96%
7	Climate-Friendly and Equitable Communities	0.89	1.5%	98%
8	Energy Efficient Buildings	0.72	1.2%	99%
9	Embodied Emissions Program	0.42	0.7%	100%
10	Building Retrofits	0.06	0.1%	100%
11	Heat Pump Purchase Programs	0.04	0.1%	100%
12	Solar + Storage Rebate Program	0.03	0.0%	100%
13	Climate Equity and Resilience Through Action (Waste)	0.01	0.02%	100%
14	Energy Efficiency standards for appliances	0.01	0.02%	100%
15	Community Renewable Energy Program	0.01	0.01%	100%
16	Recycling Modernization Act	0.00	0.006%	100%
	Total	58.53	100%	100%

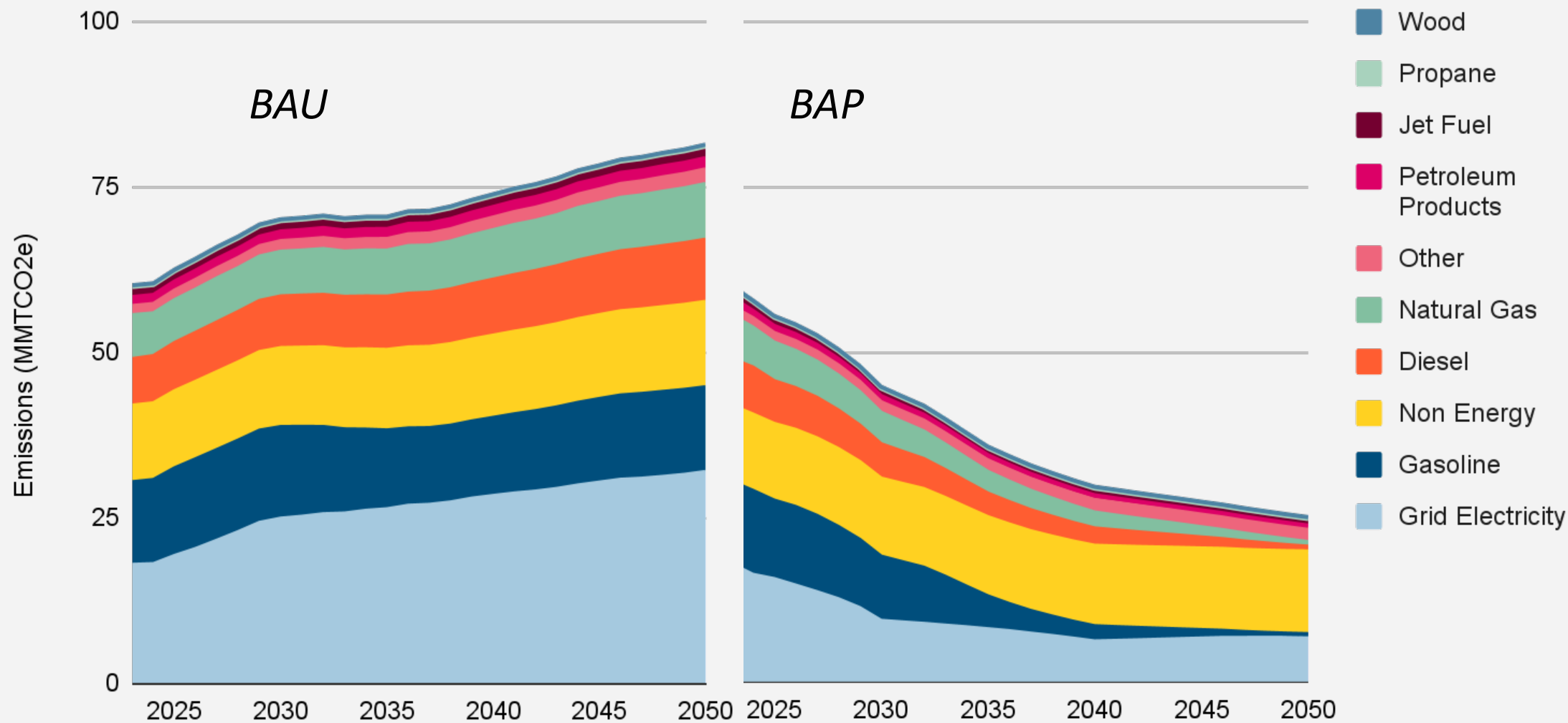
Emissions by Sector



Emissions by Sector



Emissions by Fuel



TIGHGER 2.0 Next Steps

Phase 1 - Model Forecast – Fall 2025

- Public comment period open
- Materials available on the OCAC's [October 10 Meeting website](#)
- Submit comments by October 31, 2025 to OCAC@energy.oregon.gov

Phase 2 - Gaps Analysis and Additional Measures - Spring 2026

- Public comment opportunity to be scheduled

October 7, 2025

To: Bob Jenks
Oregon Citizens' Utility Board

From: Jaki Ferchland
Senior Manager, Rates & Regulatory Affairs

Portland General Electric Company
UM 2377
PGE Response to CUB Data Request 26
Dated September 19, 2025

Request:

Does PGE serve as the provider of last resort for a special contract customer?

Response:

Commission Order in UE 115. Order No 01-777 states:

"[b]ecause PGE remains the provider of last resort within its service territory, Staff notes that the company is obligated to provide safe and adequate service to all customers within its service area regardless of whether the customer is returning to utility service or has remained as a PGE customer."

Assuming the special contract customers reside in PGE's service territory, then PGE would be the provider of last resort for such customers.

-
-
-

24-05023

Public Utilities Commission of Nevada
Electronic Filing

Submitted: 6/11/2025 4:39:43 PM

Reference: 2d9a4c00-ece9-4426-b60d-705cadfccd88

Payment Reference: 26-b60d-705cadfccd88

Filed For: SPPC

In accordance with NRS Chapter 719,
this filing has been electronically signed and filed
by: /s Lynn DIInnocenti

By electronically filing the document(s),
the filer attests to the authenticity of the electronic signature(s) contained therein.

This filing has been electronically filed and deemed to be signed by an authorized
agent or
representative of the signer(s) and
SPPC



FILED WITH THE PUBLIC UTILITIES COMMISSION OF NEVADA - 6/11/2025

June 11, 2025

Ms. Trisha Osborne
Assistant Commission Secretary
Public Utilities Commission of Nevada
1150 East William Street
Carson City, Nevada 89701-3109

RE: **Docket No. 24-05023** – Application of Sierra Pacific Power Company d/b/a NV Energy, filed under Advice Letter No. 674-E, to implement Clean Transition Tariff Schedule No. CTT to allow eligible customers to receive bundled electric service from new clean energy resources.

Dear Ms. Osborne:

Sierra Pacific Power Company d/b/a NV Energy (“Sierra”) hereby submit for filing the enclosed compliance per the Order dated March 11, 2025 requiring Sierra to file revised tariffs as outlined in the Stipulation filed in this docket.

Should you have any questions regarding this filing, please do not hesitate to contact me at 775-834-5696 or deborah.bone@nvenergy.com.

Respectfully submitted,

/s/ Deborah Bone

Deborah Bone
Deputy General Counsel

SIERRA PACIFIC POWER COMPANY dba NV ENERGY

6100 Neil Road, Reno, Nevada

Tariff No. **Electric No. 1**21st RevisedCancelling 20th RevisedPUCN Sheet No. **62A**PUCN Sheet No. **62A**

Table of Contents
ELECTRIC RATES
(Continued)

<u>SCHEDULE</u>	<u>TYPE OF SERVICE</u>	<u>SHEET NO.</u>
EVCCR-TOU	Electric Vehicle Commercial Charging Rider	79E – 79H
GS-4	Large Transmission Service	80 – 80C
IP	Incremental Price Tariff	80G – 80J
GS-4-NG	GS-4 New Generation	80L – 80P
MPE	Market Price Energy	80Q(1) – 80Q(4)
LCMPE	Large Customer Market Price Energy	80Q(6) – 80Q(9)
NDPP	Natural Disaster Protection Plan	80S
NMR-B	Net Metering Rider-B – Non-Residential and Non-Small General Service	81D(3)(h) - 81D(3)(q)
NMR-G	Net Metering Rider-G – Residential and Small General Service – Grandfathered	81D(3)(r) - 81D(3)(aa)
NMR 405	Net Metering Rider 405	81D(3)(ab)–81D(3)al
SSR	Small Standby Service Rider-1	81D(4) – 81D(15)
LSR	Large Standby Service Rider	81D(16) – 81D(31)
DOS	Distribution-Only Service Rider	81E – 81P(5)
OFF	Optional Flexible Payment	81P(6) – 81P(8)
SSE	Shared Savings-Electric	81Q
PV-1	Photovoltaic Service	81R – 81S
WCS	Wireless Communication Service	81AE – 81AG
NGR	NV GreenEnergy Rider	81AH – 81AK(1)
CPST	Customer Price Stability Tariff	81AK(2) – 81AK(5)
EDRR	Economic Development Rate Rider	81AL – 81AY
ESER	Expanded Solar Energy Rate	81AZ – 81AZ(1)
ESAP	Expanded Solar Access Program Rate	81AZ(2)
ESB-V2G	Electric School Bus Vehicle-to-Grid Trial	81AZ(3) – 81AZ(5)
NVEVCN	NV Energy Electric Vehicle Charging Network	81AZ(6) – 81AZ(8)
CTT	Clean Transition Tariff	81AZ(9)- 81AZ(13)

(N)

Issued: **06-11-25**

Effective:

Advice No.: **674-E**

Issued By:

Timothy Clausen

Vice President, Regulatory

SIERRA PACIFIC POWER COMPANY dba NV Energy

6100 Neil Road, Reno, Nevada

Tariff No. **Electric No. 1**

Original

Cancelling

PUCN Sheet No. **81AZ(09)**

PUCN Sheet No.

Schedule No. CTT
CLEAN TRANSITION TARIFF

APPLICABLE

This clean transition tariff rate schedule is applicable to all non-Residential Service Customers demonstrating that they will have an average annual hourly load of five megawatts or more based on a consecutive twelve-month rolling average. To reach the five megawatt eligibility threshold, governmental entity customers may aggregate facilities that will be served pursuant to this schedule provided such facilities are operated by the eligible customer under a common budget and common control. A non-governmental Customer may use an aggregated load to meet the five megawatt threshold for this schedule with Commission approval, which shall be determined by the Commission on a case-by-case basis, provided that each facility that the customer proposes to aggregate has an average annual hourly load of 1 MW or more based on a consecutive twelve-month rolling average.

TERRITORY

Entire Nevada service territory, as specified.

RATES

- A. A Customer receiving service under this schedule that has achieved the five megawatt load threshold will pay the following rates and charges:
1. The BTGR of the otherwise applicable rate schedule of the Customer, with the cost of generation capacity and energy supply removed through bill credits.
 2. A demand charge(s), if applicable, under the otherwise applicable rate schedule.
 3. A facilities charge(s), if applicable, under the otherwise applicable rate schedule.
 4. The BSC of the otherwise applicable rate schedule.
 5. The UEC as described in Special Condition 1.
 6. Franchise Fees, Taxes and Mill Assessment that are assessed under the otherwise applicable rate schedule.

Issued: **06-11-25**

Effective:

Advice No.: **674-E-R**

Issued By:

Timothy Clausen

Vice President, Regulatory

(N)

(N)

SIERRA PACIFIC POWER COMPANY dba NV Energy

6100 Neil Road, Reno, Nevada

Tariff No. **Electric No. 1**

Original

Cancelling

PUCN Sheet No. **81AZ(10)**

PUCN Sheet No. _____

Schedule No. CTT
CLEAN TRANSITION TARIFF
(Continued)

RATES (continued)

7. Public Program Costs unless exempted by any applicable law or order of the PUCN.
8. An energy charge as specified in an Energy Supply Agreement between the Utility and the Customer.
- B. A Customer receiving service under this schedule that has achieved the five megawatt load threshold will not pay the following rates and charges:
 1. A Customer taking service under this schedule shall not be subject to the Net-BTER, DEAA unless specified in the Energy Supply Agreement.
- C. A Customer receiving service under this schedule that subsequently falls below the five megawatt load threshold, based on a twelve-month rolling average, shall pay the otherwise applicable rate schedule of the Customer until the Customer's twelve-month rolling average once again achieves a five megawatt load threshold or as otherwise determined in its Energy Supply Agreement.

SPECIAL CONDITIONS

1. **UEC**. The Universal Energy Charge (UEC), pursuant to NAC 702.150 through 702.450, will go to fund the Nevada fund for energy assistance and conservation. Under certain circumstances, Customers will be refunded amounts paid in excess of \$25,000 per calendar quarter. The Commission will administer the collection of the UEC, certify exemptions, and administer refunds. Exemptions are generally kWh sold to:
 - a) Any governmental agency, including the State of Nevada and any political subdivision thereof, and
 - b) Any Customer using electrolytic-manufacturing processes.

Except as provided above, all kWh sold are subject to the charge. The UEC is not subject to the charges applicable under the Special Supplementary Tariff.

2. **Rights and Obligations**. The rights and obligations of the parties with respect to the supply of energy will be specified in an Energy Supply Agreement.

(Continued)

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Timothy Clausen

Vice President, Regulatory

(N)

(N)

SIERRA PACIFIC POWER COMPANY dba NV Energy

6100 Neil Road, Reno, Nevada

Tariff No. **Electric No. 1**

Original

Cancelling

PUCN Sheet No. **81AZ(11)**

PUCN Sheet No. _____

Schedule No. CTT
CLEAN TRANSITION TARIFF
(Continued)

SPECIAL CONDITIONS (continued)

3. **Energy Supply Agreement.** The Energy Supply Agreement must be approved by the Commission.

- a. An Energy Supply Agreement shall be filed within, or contemporaneously with, an Integrated Resource Plan or Integrated Resource Plan Amendment that includes a renewable resource(s) not previously approved by the Commission that will serve as the resource(s) for supply to the Energy Supply Agreement counterparty.
- b. A request for approval of an amended Energy Supply Agreement is not required to be filed within an Integrated Resource Plan or Integrated Resource Plan Amendment unless the resource(s) or a portion of the resource(s) planned to serve the Energy Supply Agreement changes from the original application.
- c. If an approved Energy Supply Agreement is amended, and such amendment changes a material term (i.e., price, resource, load), the amended Energy Supply Agreement must be filed with the Commission and served on all parties to the underlying Energy Supply Agreement approval docket. Parties to the underlying approval docket will have an opportunity to object to the amendment.

In considering whether the Energy Supply Agreement is in the public interest, the Commission will consider whether non-participating customers of the utility experience increased costs for electric service or forgo the benefit of a reduction of costs for electric service as a result of the Energy Supply Agreement.

The Energy Supply Agreement shall:

- a. Be in the public interest;
- b. Provide for payment by the Customer of the Utility's cost in procuring the energy for the Customer;
- c. Provide for a payment by the Customer for its portion of the Utility's transmission and distribution costs;
- d. Not impair the reliability of the Utility's system or the Utility's ability to provide electric service to its other customers;
- e. Include other terms and conditions related to the respective rights and obligations of the Utility and Customer to take service under this schedule;
- f. Identify the basis for the calculation of the price of energy;
- g. Have a term length that is the same term as the life of the CTT Facility(s), unless otherwise specified and explained in the Application;
- h. Contain sufficient information to determine the Customer's hourly annual load requirements;

(Continued)

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SIERRA PACIFIC POWER COMPANY dba NV Energy

6100 Neil Road, Reno, Nevada

Tariff No. Electric No. 1

Original

Cancelling _____

PUCN Sheet No. 81AZ(12)

PUCN Sheet No. _____

Schedule No. CTT
CLEAN TRANSITION TARIFF
(Continued)

SPECIAL CONDITIONS (continued)

3. **Energy Supply Agreement.** (continued)

- i. Be attached to an Application that Identifies system and/or non-participant benefits that will result from the Energy Supply Agreement and provide supporting information;
- j. Include a provision for an early termination fee, in the event the Customer terminates the Energy Supply Agreement prior to the end of the Energy Supply Agreement;
- k. Be attached to an Application that explains and supports how the CTT ESA Rate was calculated.

4. **Termination.** The termination rights of the Customer and the Utility are governed by the terms of the applicable Energy Supply Agreement.

5. **Renewable Portfolio Standard (RPS) Compliance.** For every Customer that takes service under this schedule, the Utility shall retire or transfer to the Customer to retire portfolio energy credits in compliance with the RPS. The Utility shall retain the difference between the amount of portfolio energy credits procured pursuant to the Energy Supply Agreement and the RPS, unless as specified otherwise under the terms and conditions of the Energy Supply Agreement between the Customer and the Utility.

6. **Customer Load.** A Customer may take service under this schedule for all or a portion of its total load as set forth in the terms and conditions of the Energy Supply Agreement between the Customer and the Utility.

DEFINITIONS

For purposes of this Schedule No. CTE, the following definitions apply.

- A. BSC: The Basic Service Charge, which is approved by the Commission.
- B. BTER: A rate consisting of the base tariff energy rate which is approved by the Commission.
- C. BTGR: A rate consisting of the base tariff general rate approved by the Commission.
- D. DEAA: A rate consisting of the deferred energy accounting adjustment, which is approved by the Commission.

(Continued)

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(N)

(N)

SIERRA PACIFIC POWER COMPANY dba NV Energy

6100 Neil Road, Reno, Nevada

Tariff No. **Electric No. 1**

Original

Cancelling

PUCN Sheet No. **81AZ(13)**

PUCN Sheet No. _____

Schedule No. CTT
CLEAN TRANSITION TARIFF
(Continued)

DEFINITIONS (continued)

- E. Energy Supply Agreement: Is the contract approved by the Commission that is executed by the Customer and Utility pursuant to terms of Schedule No. CTT.
- F. Net-BTER: A rate consisting of the BTER less the cost of the out-of-the-money long-term renewable energy contracts that the Utility has entered.
- G. Public Program Costs: Are all costs, either legislatively mandated or PUCN approved, that the Utility incurs in implementing legislatively mandated and PUCN approved programs.
- H. PUCN: Is the Public Utilities Commission of Nevada.
- I. RPS: As defined in NRS 704.7805, Portfolio Standard means a portfolio standard for Renewable Energy and energy from a qualified energy recovery process established by the Commission pursuant to NRS 704.7821. The Portfolio Standard provides for increasing minimum amounts of Renewable Energy to be added annually to the Utility's mix of resources required to meet its load requirements.
- J. UEC: A rate consisting of the universal energy charge, which is approved by the Commission.
- K. CTT ESA Rate: The fixed MWh rate for the energy delivered from the CTT Facility to the Customer under the Energy Supply Agreement.
- L. CTT Facility: One or more clean energy resource(s), such as renewable energy resources listed in NRS 704.7811, from which NV Energy will procure or generate energy for Customer that is approved by the PUCN. Such facility(s) shall be identified by name in the Energy Supply Agreement.

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Issued By:

Timothy Clausen

Vice President, Regulatory

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(N)

CERTIFICATE OF SERVICE

I hereby certify that I have served the foregoing filing of **SIERRA PACIFIC POWER COMPANY D/B/A NV ENERGY** in Docket No. 24-05023 upon the persons listed below by electronic mail:

Don Lomoljo
Public Utilities Comm. of Nevada
1150 E. William Street
Carson City, NV 89701-3109
dlomoljo@puc.nv.gov

Staff Counsel Division
Public Utilities Comm. of Nevada
9075 West Diablo, Suite 250
Las Vegas, NV 89148
pucn.sc@puc.nv.gov

Attorney General's Office
Bureau of Consumer Protection
100 N. Carson St.
Carson City, NV 89701
bcpserv@ag.nv.gov

Michael Saunders
Attorney General's Office
Bureau of Consumer Protection
8945 W. Russell Road, Suite 204
Las Vegas, NV 89148
bcpserv@ag.nv.gov
msaunders@ag.nv.gov

Hunter Holman
Interwest Energy Alliance
400 Gold Ave SW Ste 700
Albuquerque, NM 87102
hunter@interwest.org

Dallas Harris (IEA)
Davison Van Cleve, P.C.
4675 W. Teco Ave., Suite 230
Las Vegas, NV 89118
dah@dvclaw.com

Rikki Seguin
Interwest Energy Alliance
400 Gold Ave SW Ste 700
Albuquerque, NM 87102
rikki@interwest.org

Samuel Johnston
Interwest Energy Alliance
35 E 100 S Apt 608
Salt Lake City, UT 84111
sam@interwest.org

Patrick Woolsey
Sierra Club
2101 Webster St., Suite 1300
Oakland, CA 94612
patrick.woolsey@sierraclub.org

Maddie Lipscomb
Sierra Club
2101 Webster St., Suite 1300
Oakland, CA 94612
maddie.lipscomb@sierraclub.org

1 Justina Caviglia (Google)
Ellen Zuckerman
2 Roni Shaffer
Parsons Behle & Latimer
3 50 West Liberty St., Ste. 750
4 Reno, NV 89501
jcaviglia@parsonsbehle.com
5 ezuckerman@google.com
rshaffer@parsonsbehle.com
6

Carolyn Berry (Google)
Bates White LLC
2001 K Street NW North Bldg Suite 500
Washington, DC 20006
carolyn.berry@bateswhite.com

7 Lucas Foletta (SNGG)
Carole Davis
8 McDonald Carano, LLP
100 West Liberty Street, 10th Floor
9 Reno, NV 89501
lfoletta@mcdonaldcarano.com
10 cdavis@mcdondcarano.com
11

Katherine Ramsey
Nihal Shrinath
Sierra Club Environmental Las Program
2101 Webster Street, Suite 1300
Oakland, CA 94612
Katherine.ramsey@sierraclub.org
Nihal.shrinath@sierraclub.org

12 DATED this 11th day of June, 2025.
13

/s/Lynn D'Innocenti

14 Lynn D'Innocenti
15 Paralegal
Nevada Power Company d/b/a NV Energy
16 Sierra Pacific Power Company d/b/a NV Energy
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July 15, 2025

To: Cole Souder
Green Energy Institute

From: Jaki Ferchland
Senior Manager, Rates & Regulatory Affairs

Portland General Electric Company
UM 2377
PGE Response to OPUC Data Request 012
Dated July 1, 2025

Request:

Please refer to PGE's 2023 CEP/IRP Update, page 35, which states: "Additional benefits may accrue to all customers should large industrial backup generation or other resources tied to these customers be made available for grid reliability and flexibility." Please explain under what circumstances a large industrial customer's backup generation could be used for broader grid reliability and flexibility and the value of that reliability and flexibility for other customers.

Response:

Currently, PGE works with large customers to incorporate their backup generation and BESS systems into PGE's Distributed Standby Generation (DSG) program. The DSG program allows PGE to hold non-spinning contingency reserves on the backup generation and BESS within the program, which aids PGE in fulfilling our North American Electric Reliability (NERC) contingency reserve requirements.

The value to other customers comes from these resources serving as non-spinning contingency reserves and providing frequency response capabilities required by NERC. By using DSG resources as contingency reserves (typically dispatched only 7-10 hours annually), PGE can free up hydro and natural gas resources to serve load, enhancing system flexibility and reliability while meeting capacity needs.

Additional benefits accrue when BESS systems enrolled in the DSG program are used for demand response. Large customers have demonstrated willingness to partner on DSG enrollment, including upgrading to cleaner Tier 4 generators and incorporating BESS into their facilities.