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July 17, 2024

VIA E-MAIL TO

Public Utility Commission of Oregon
Filing Center
201 High Street SE, Suite 100
Salem, Oregon 97301-3398

**Re: Docket No. PCN 6 - In the Matter of Portland General Electric Company, Petition
of Public Convenience and Necessity**

Attention Filing Center:

Attached for filing in the above-referenced docket, please find Portland General Electric Company's Motion for Leave to File Supplemental Testimony.

Please contact this office with any questions.

Sincerely,

A handwritten signature in blue ink that reads "Cole Albee".

Cole Albee
Paralegal
McDowell Rackner Gibson PC

Attachments

**BEFORE THE PUBLIC UTILITY COMMISSION
OF OREGON**

PCN 6

In the Matter of

PORTLAND GENERAL ELECTRIC
COMPANY

Petition for Certificate of Public
Convenience and Necessity.

**PORTLAND GENERAL ELECTRIC
COMPANY'S MOTION FOR LEAVE
TO FILE SUPPLEMENTAL
TESTIMONY**

1 Pursuant to OAR 860-001-0420, Portland General Electric Company (PGE or the
2 Company) hereby submits to the Public Utility Commission of Oregon (Commission) this
3 Motion for Leave to File Supplemental Testimony.

4 The Company's Supplemental Direct Testimony of Dr. Ian Beil, which is attached to this
5 Motion, provides additional analysis under OAR 860-025-0030(2)(n) and explains why
6 conservation measures, non-wires alternatives, and construction of one or more lower-voltage
7 single or multi-circuit lines are not reasonably available alternative solutions to constructing the
8 Rosemont to Wilsonville 115-kilovolt transmission line.¹ Since the Company filed its Petition
9 for a Certificate of Public Convenience and Necessity (CPCN) and associated direct testimony
10 on April 17, 2024, Save Stafford Road (SSR) has raised the concern that PGE's Petition for
11 CPCN is incomplete based on the Company's analysis under OAR 860-025-0030(2)(n).² While
12 the Company does not agree with SSR's interpretation of OAR 860-025-0030(2)(n) to require
13 PGE to evaluate non-feasible alternatives, in the spirit of cooperation, the Company is providing
14 further explanation as to why conservation measures, non-wires alternatives, and construction
15 of one or more lower-voltage single or multi-circuit lines cannot address the identified needs in

¹ See PGE/600-604.

² See, e.g., Save Stafford Road's Petition to Intervene at 3 (May 2, 2024).

1 this case and/or why such methods are otherwise not viable. The Company’s supplemental
2 testimony is relevant to the issues and concerns raised in this proceeding and will ensure that the
3 Commission’s decision in this case is based on an up-to-date and accurate record.

4 PGE has attempted to confer with counsel for Staff, SSR, and the Willamette Water
5 Supply System (WWSS). Counsel for Staff and WWSS do not object to the Motion. SSR has
6 indicated that it cannot take a position on this Motion as of the time of the filing because it has
7 not yet had an opportunity to review the Motion.

8 The filing of this supplemental testimony allows for sufficient time to review and respond
9 before Staff and intervenor opening testimony is due on September 11, 2024. SSR requested that
10 there be a two-week extension in its opening testimony. PGE agrees to a two-week extension for
11 testimony responding to PGE’s supplemental testimony. The Company further commits to
12 responding to any data requests related to its supplemental testimony on an expedited basis.

13 As PGE has demonstrated good cause, the Company requests that the Commission grant
14 this Motion and accept the attached testimony for filing.

Respectfully submitted this 17th day of July 2024.

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BEFORE THE PUBLIC UTILITY COMMISSION
OF THE STATE OF OREGON

PCN 6

Petition for a Certificate of Public
Convenience and Necessity

PORTLAND GENERAL ELECTRIC COMPANY

Supplemental Direct Testimony of *Dr. Ian Beil*

July 17, 2024

Table of Contents

- I. Introduction 1**
- II. Analysis of Conservation Measures, Non-Wires Alternatives, and Construction of One or More Lower-Voltage Lines 3**
 - A. Conservation Measures..... 3
 - B. Non-Wires Alternatives 5
 - 1. Battery Energy Storage Systems (BESS)..... 5
 - 2. Dynamic Line Ratings (DLR) 9
 - 3. Series Compensation and Flow Control Devices 12
 - 4. Advanced Conductors..... 14
 - C. Construction of One or More Lower-Voltage Lines 15
- List of Exhibits 17**

1
2
3
4
5
6
7
8
9
10
11
12
13
14
15
16
17
18
19

I. Introduction

Q. Are you the same Dr. Ian Beil that filed direct testimony in support of the Company’s Petition for a Certificate of Public Convenience and Necessity (CPCN) filed on April 17, 2024 (Petition)?

A. Yes. My direct testimony is PGE/100-111, Beil.

Q. Why are you filing supplemental direct testimony?

A. While I am not an attorney, it is my understating that Save Stafford Road (SSR) believes that Portland General Electric Company (PGE or the Company) did not file a complete Petition for CPCN in accordance with OAR 860-025-0030(2)(n). That rule provides that the petitioner should include “an evaluation of available alternatives to construction of the transmission line, including, but not limited to, conservation measures, non-wires alternatives, and construction of one or more lower-voltage single or multi-circuit lines.”¹

Q. In its Petition for CPCN, did the Company discuss available alternatives to construction of the Rosemont-Wilsonville Line?

A. Yes. In its Petition, the Company discussed different transmission configurations that could potentially alleviate the multiple double outage (N-1-1) scenarios that were identified in PGE’s local transmission and distribution analysis memorialized in the January 2020 white paper (January 2020 Study).² In this local transmission planning

¹ OAR 860-025-0030(2)(n).

² Highly Protected PGE’s Petition for CPCN at 35-40 (Apr. 17, 2024); Highly Protected PGE/101, Beil/17-30 (Apr. 17, 2024).

1 document, the Company identified six transmission configuration options as potentially
2 available alternatives to construction of the Rosemont-Wilsonville Line.³

3 **Q. Why did PGE not explicitly address conservation measures, non-wires**
4 **alternatives, and construction of one or more lower-voltage single or multi-circuit**
5 **lines in its Petition?**

6 A. Other than battery energy storage, the Company did not view these methods as viable
7 alternatives to construction because they could not in any configuration or capacity
8 address the multiple N-1-1 outage scenarios identified in PGE's January 2020 Study.
9 Battery storage also has significant challenges addressing the multiple N-1-1 outage
10 scenarios identified in PGE's January 2020 Study and subsequent analyses, including
11 significantly higher costs to PGE customers than the identified transmission solutions,
12 as discussed later in this testimony.

13 **Q. Does your supplemental direct testimony nevertheless address conservation**
14 **measures, non-wires alternatives, and construction of one or more lower-voltage**
15 **single or multi-circuit lines?**

16 A. Yes. In the spirit of cooperation and to address SSR's concerns, the Company is
17 providing an explanation in the record as to why conservation measures, non-wires
18 alternatives, and construction of one or more lower-voltage single or multi-circuit lines
19 are not available alternatives to construction of the Rosemont-Wilsonville Line. The
20 Company also views this as an opportunity to provide the Public Utility Commission
21 of Oregon (Commission) and Commission Staff (Staff) a better understanding of why

³ Note that the January 2020 Study is the basis for the finding of need for the Tonquin Project, including the Rosemont-Wilsonville Line, in PGE's Near Term and Long Term Local Transmission Plans. See PGE/107, Beil/29 (Apr. 17, 2024); PGE/108, Beil/23 (Apr. 17, 2024); PGE/109, Beil/39 (Apr. 17, 2024).

1 conservation measures and non-wire alternatives, such as storage, are generally not a
2 viable alternative to addressing the transmission constraints addressed by the proposed
3 Tonquin Project transmission system upgrades.

4 **II. Analysis of Conservation Measures, Non-Wires Alternatives, and** 5 **Construction of One or More Lower-Voltage Lines**

6 **A. Conservation Measures**

7 **Q. Is PGE required to assess conservation measures as available alternatives in the**
8 **normal course of its system planning?**

9 A. Yes. PGE is required by ORS 757.054(3) to “[p]lan for and pursue all available energy
10 efficiency resources that are cost effective, reliable and feasible.”⁴ This means that PGE
11 pursues all cost-effective energy efficiency (EE) identified through the Clean Energy
12 Plan (CEP)/Integrated Resource Plan (IRP) as the best balance of cost, risk, community
13 impacts, and pace of greenhouse gas (GHG) emissions reductions. PGE is also required
14 by the same statute to “plan for and pursue the acquisition of available cost-effective
15 demand response resources.”⁵

16 **Q. How does PGE identify effective, reliable, and feasible EE measures?**

17 A. PGE relies on the Energy Trust to identify EE opportunities and to develop estimates
18 for the amount of feasible, cost-effective EE for the Company’s system. Using a
19 resource assessment modeling tool, the Energy Trust identifies, through sector-by-
20 sector analysis—e.g., residential existing homes, residential new homes, industrial,
21 etc.—the EE measures that are feasible and cost-effective, and those numbers are built
22 into the IRP load forecast and assumed to be acquired over the planning period.

⁴ ORS 757.054(3)(a).

⁵ ORS 757.054(3)(b).

1 PGE incorporates the Energy Trust’s long-term cost-effective EE savings forecast into
2 planning models, including load forecasting tools for developing long-term system
3 forecasts.⁶ These system load forecasts are utilized in PGE transmission models.⁷

4 **Q. Were conservation measures considered in the transmission planning process for
5 the Tonquin Project, including the Rosemont-Wilsonville Line?**

6 A. Yes. In the original transmission and distribution analysis, which was conducted in
7 2019, the existing loading levels in the area around the proposed Tonquin Substation
8 were increased by 5 percent to represent expectations for load growth through 2024,
9 when the substation was scheduled to be energized. This scaling factor was based on
10 information provided by PGE Load Forecasting at the time. The forecasted values from
11 the PGE Load Forecasting team take into account expected customer actions such as
12 conservation and EE measures.⁸ Therefore, EE and demand response are inherently
13 included and embedded in PGE’s transmission planning processes and specifically the
14 study of the need for the Tonquin Project.

15 **Q. Would conservation measures address the identified N-1-1 outage scenarios?**

16 A. No. Even with the benefit of these assumed conservation measures, significant risk of
17 transmission overloads was identified in the Tonquin Project area that could not be
18 remediated without the Rosemont-Wilsonville Line.

⁶ PGE/601 (PGE 2023 CEP/IRP, Appendix D, Load Forecast Methodology) (showing the inclusion of EE in the final load forecast).

⁷ PGE/602, Beil/5 (PGE 2023 CEP/IRP, Chapter 9, Transmission) (“PGE is required to plan and build its transmission system to meet the needs of all PGET transmission customers, including PGEM and ESS customers.”).

⁸ Highly Protected PGE/101, Beil/6-7.

1 **B. Non-Wires Alternatives**

2 **Q. What types of non-wire alternatives could theoretically substitute for**
3 **transmission in certain circumstances?**

4 A. Potential non-wire alternatives that could substitute for transmission include flexible
5 load/demand response, time-varying rate designs, distributed energy renewables,
6 energy storage, conservation voltage reduction, and other energy efficiency and
7 enabling technologies. Below, I specifically address the only non-wire alternatives that
8 could *theoretically* address the needs to be resolved by the construction of the
9 Rosemont-Wilsonville Line: (1) battery energy storage systems (BESS); (2) dynamic
10 line ratings (DLR); (3) series compensation and flow control devices; and (4) advanced
11 conducting.

12 *1. Battery Energy Storage Systems (BESS)*

13 **Q. Please explain the benefits of BESS.**

14 A. Energy storage serves important grid functions, including time-shifting energy across
15 hours or days; regulating grid frequency; and ensuring flexibility to balance supply and
16 demand. Energy storage is particularly important in an increasingly electrified world
17 where demand is rising and supply is shifting toward variable renewables, increasing
18 the need for dispatchable energy. BESS facilities can also, in specific situations,
19 provide reliability benefits by reducing flows on overloaded distribution or
20 transmission lines.

21 **Q. How many BESS does PGE own and operate on its system?**

22 A. PGE currently owns and operates several smaller BESS in the 1 to 20 MW range across
23 its service territory and is in the process of installing a total of 475 MW of large-scale
24 BESS capacity between September 2024 and June 2025 at three separate PGE

1 substations. These batteries are expected to be used for a variety of grid services
2 mentioned above, in particular frequency regulation and time-shifting of energy.

3 **Q. Please explain how, as a general matter, BESS may address transmission**
4 **overloads.**

5 A. In order to use a BESS to mitigate a transmission overload, two conditions must be
6 met. First, the battery must interconnect at a point on the system such that its discharge
7 (or in certain situations, its charge) causes a significant reduction in the loading on the
8 potentially overloaded line. Second, the battery must be sized with adequate energy to
9 offset the overload for the duration of the outage. Given uncertainty around outage
10 times (which can vary from under two hours to up to three days depending on system
11 conditions, weather, crew availability, etc.), the exact size requirement is usually
12 expressed as a function of the expected outage time.

13 **Q. Where would a theoretical battery storage system have to be located to potentially**
14 **address the potential N-1-1 overloads identified in the January 2020 White Paper**
15 **and PGE's subsequent analyses?**

16 A. In order to address the N-1-1 outage scenarios the Rosemont-Wilsonville Line is
17 proposed to address, a theoretical battery solution would need to be located at Tonquin
18 Substation. PGE's analysis demonstrates that a battery placed elsewhere would have a
19 negligible impact on the flows of the constrained lines. As an example, three
20 transmission-connected batteries are scheduled to be installed in PGE's service
21 territory in the coming months. Table 1 below shows the impact of discharging each of
22 the three large batteries that PGE is in the process of installing on the most heavily load

1 line associated with the Tonquin Project transmission work. Note that all three batteries
 2 under full discharge have a negligible impact on the flows on the line of concern.

Table 1. Results of the Tonquin Power Flow Analysis.

Overloaded Element ⁹	MW Rating	Overload ¹⁰	MW Overload	BESS MW Required
Line A-B (115kV)	198	120%	238	40

Table 2. Impact of Scheduled BESS (Under Full Discharge) on Overloaded Line.

Battery Name	Interconnecting Substation	BESS Size (MW)	Sensitivity to Overloaded Line A-B ¹¹	Implied Load Reduction on Line A-B when Battery at Full Discharge
Constable	Evergreen (115kV)	75	0.000082	0.006 MW
Sundial	Blue Lake (230kV)	200	0.000045	0.009 MW
Seaside	Rivergate (230kV)	200	0.000040	0.008 MW

3 Based on data requests, it appears SSR may view the Sherwood Substation,
 4 which is physically close to Tonquin Substation, as another potential location for a
 5 theoretical battery solution. However, that is not the case. Many of the identified
 6 overloads addressed by the Tonquin Project, including the Rosemont-Wilsonville Line,
 7 occur when there is an outage to the transmission connection between the Sherwood
 8 and Tonquin Substations. When this occurs, a battery at Sherwood Substation could
 9 not mitigate the identified overloads.

⁹ Line name redacted to comply with FERC Critical Energy Infrastructure Information policy.

¹⁰ Worst-case overload identified for 2025 case year.

¹¹ Line name redacted to comply with FERC Critical Energy Infrastructure Information Policy. Sensitivities indicate the change in MW flow over the line compared to MW output of the battery facility.

1 **Q. Assuming a BESS could be located at the Tonquin Substation, what are the**
2 **primary reasons a BESS is not an efficient, cost-effective, and feasible alternative**
3 **to construction of the Rosemont-Wilsonville Line?**

4 A. In answering this question, I want to start by clarifying precisely how a battery located
5 at the Tonquin Substation would function to address the reliability concerns I discussed
6 in my direct testimony. Quite simply, a theoretical battery solution could *only* be
7 discharged to address the identified N-1-1 overloads and would have to be on stand-by
8 at near-full or full charge at all other times to address a potential future overload. Thus,
9 utilizing batteries as a transmission asset precludes them from providing most other
10 grid services. For example, because the battery is being used to prevent a potential
11 overload and must remain at or near full charge waiting for an outage to occur, it cannot
12 participate in valuable grid service activities, such as energy shifting. This reduces the
13 value of other services that the battery could otherwise provide to the system and makes
14 the battery solution inefficient and ineffective.

15 Moreover, the inherent inefficiency of using a battery in this way is magnified
16 by the high cost of a BESS solution. Recent PGE BESS projects dictate an average of
17 \$450/kWh for transmission-sized batteries. An analysis of the cost of the BESS versus
18 the length of the outage duration indicates that, in order to size the system adequately,
19 the cost could exceed \$200 million. This cost estimate is over 10 times more than the
20 direct costs for the proposed Rosemont-Wilsonville Line.

Table 3. Cost of BESS Sized Per Outage Duration.

BESS Cost >50MW (per kWh)	
\$	450.00

Overloaded Element	MW Rating	Overload	MW Overload	BESS MW Required
Line A-B (115kV)	198	120%	238	40

Outage Duration (hours)	kWh required	BESS Cost
2	79,200	\$ 35,640,000
4	158,400	\$ 71,280,000
8	316,800	\$ 142,560,000
12	475,200	\$ 213,840,000

1 Additionally, this analysis is for the 2025 case year. There is significant load
 2 growth projected in the area surrounding Tonquin Substation and the Rosemont-
 3 Wilsonville Line in the coming years. As load grows, the anticipated overloads will
 4 also increase, causing a corresponding increase in the necessary size of a battery
 5 required to mitigate these overloads. Thus, the \$200 million cost estimate would be
 6 expected to increase over time, in order to future-proof for future outage scenarios.

7 *2. Dynamic Line Ratings (DLR)*

8 **Q. Please explain DLR.**

9 A. Dynamic line ratings utilize sensors installed on transmission lines in order to
 10 determine real-time wind speed and angle. This additional information allows system
 11 operators to utilize higher transmission capacities when the wind is blowing faster than
 12 the static parameter assumptions. PGE employs a temperature ambient-adjusted ratings
 13 methodology, meaning that the ampacity of the conductor is calculated for a
 14 temperature range corresponding to real-time weather. Accordingly, on a very hot day,

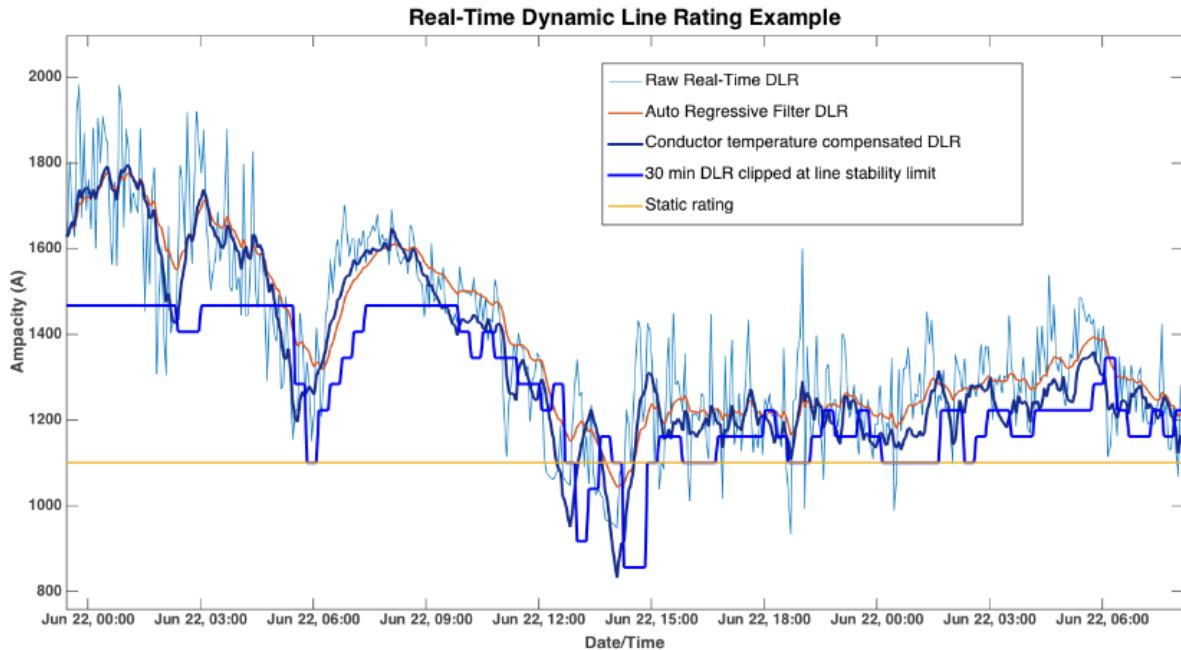
1 ampacity (and therefore facility ratings) will be lower, but on cooler days, PGE can
2 take advantage of additional capacity on transmission facilities.

3 **Q. What are the challenges of using DLR to address reliability constraints, such as**
4 **those in this case?**

5 A. The challenge in using DLR to address a reliability constraint, such as the transmission
6 overloads identified for the Tonquin Project, is that windspeeds can also drop below
7 the assumed static ratings. For example, in the chart below, the wind is usually blowing
8 faster than the assumed static rating, and the conductor experiences an uprate above
9 what it would normally. However, for a portion of the time, windspeed drops below
10 the static rating, leading to derates for this transmission asset.

11 PGE also assumes a 90-degree angle between the wind direction and the
12 transmission conductor (perpendicular), which results in the highest amount of cooling
13 effect and thus higher ratings. Wind angle varies often, and at times when the wind
14 angle is not perpendicular to the conductor, this also results in a derate to the
15 transmission conductor ratings that does not occur with static ratings.

Figure 1. Example of Dynamic Rating of a Transmission Line (Light Blue) Versus Static Rating (Yellow).¹²



1 This uncertainty makes it difficult to justify DLRs as a comparable substitute
 2 to the construction of a new transmission line or reconductor of an existing transmission
 3 line. The power flow analysis for the Tonquin Project indicates that, with upcoming
 4 load growth, there are a number of combinations of an outage to Line A + Line B that
 5 will result in an overload to Line C. Installing DLRs on all the potentially overloaded
 6 lines would provide additional capacity for a large part of the time but would not
 7 guarantee that this capacity would always be available. If these outages occurred when
 8 wind speeds were particularly low, then the capacity of the overloaded line would
 9 actually be *reduced* compared to the existing static ratings of the lines, the subsequent
 10 overload would be more severe, and the amount of load that would need to be shed
 11 (and hence customers that would be affected) would be higher.

¹² PGE/603, Beil/18 (U.S. Department of Energy, Dynamic Line Rating (June 2019)).

1 Additionally, the maximum increase in the ampacity that can be gained from
2 DLRs is typically listed in the 10-20 percent range, with certain outliers.¹³ The updated
3 power flow analysis for the Tonquin Project indicates that by 2025, overloads as high
4 as 120 percent are observable, which is already at the limit of what DLRs can typically
5 be expected to provide. If these potential overloads are not addressed with a
6 transmission solution, load growth in the area will increase the magnitude of the
7 overload above 120 percent and further preclude the ability of DLRs to address the
8 issue.

9 **Q. Are DLRs a viable alternative to constructing the Rosemont-Wilsonville Line?**

10 A. No. For the reasons enumerated above, DLRs are not an adequate substitution for the
11 construction of the Rosemont-Wilsonville 115-kV line and related transmission
12 infrastructure identified as a requirement for reliably serving the load additions related
13 to the Tonquin Project.

14 *3. Series Compensation and Flow Control Devices*

15 **Q. Please explain series compensation and series capacitors.**

16 A. Series compensation is a traditional power system engineer tool that has been used for
17 decades. It involves installing a fixed capacitor in series with a transmission line in
18 order to reduce the effective impedance of the line, and thus “push” more power over
19 the line. Series capacitors are most often used for transferring significant amounts of
20 power across long distances (approximately 50 miles or more). For example, PGE

¹³ PGE/603, Beil/23-24 (Wind speeds can vary over short periods of time, resulting in occasional transmission line uprates of 30 percent or more. However, wind gusts of this nature tend to be unpredictable and hard to plan for, making it difficult to take advantage of these higher line ratings in an operational setting.).

1 employs series capacitors on the long-distance lines that connect hydro resources on
2 the Columbia River to transmission connections in California.

3 **Q. What are flow control devices?**

4 A. Flow control devices, sometimes referred to as Flexible AC Transmission (FACTS
5 devices) or by the name of one of the device vendors, “SmartWires,” are a set of power-
6 electronics based devices that can be installed at a substation. They are a newer tool
7 that can mimic the behavior of both a series capacitor or a series reactor, allowing them
8 to effectively “push” or “pull” power depending on the state of the transmission system.
9 Flow control devices are primarily used in situations where there are multiple paths
10 from generation to load, and one of the paths is experiencing excessive loading while
11 another path is underutilized.

12 **Q. Are series capacitors or flow control devices available alternatives to constructing**
13 **the Rosemont-Wilsonville Line?**

14 A. No. The loads in the area of Tualatin, Sherwood, Wilsonville, West Linn, Lake
15 Oswego, and unincorporated areas of Clackamas County and Washington County are
16 served via a 115-kV transmission system that effectively has three existing 115-kV
17 connections to the area. The power flow analysis conducted for the Tonquin Project
18 indicates that there are a number of situations in which an outage to two lines causes
19 an overload on a third line. For that reason, series capacitors and/or flow control
20 devices will be helpful *only* to the extent there is a fourth available line onto which the
21 energy can be shifted. For these reasons, neither a series capacitor nor flow device alone
22 can address the overload scenarios that the Company is seeking to address with the
23 Rosemont-Wilsonville Line.

1 4. Advanced Conductors

2 Q. What are advanced conductors?

3 A. Per the Electric Power Research Institute (EPRI), the term advanced conductors
4 refer to conductors designed to operate at high temperatures, typically above
5 150°C, and as a result allows for more capacity to be transmitted on the line.¹⁴

6 Q. Will the proposed Rosemont-Wilsonville Line use advanced conductors?

7 A. Yes. For the Tonquin Project, the newly built sections of 115-kV transmission
8 line will utilize Aluminum Conductor Steel Supported (ACSS) conductor.
9 ACSS conductor is considered an advanced conductor per EPRI and the U.S.
10 Department of Energy. Please see Table 4 below for a list of advanced
11 conductors.

Table 4. Available Advanced Conductors.¹⁵

NAME	DESCRIPTION	TECHNOLOGY PROVIDER
Aluminum conductor composite reinforced (ACCR)	<ul style="list-style-type: none"> • Metal matrix stranded core • Aluminum-zirconium outer strands 	3M
Aluminum conductor composite core (ACCC)	<ul style="list-style-type: none"> • Mono carbon core enclosed in glass fiber • Fully annealed aluminum or aluminum-zirconium outer strands 	CTC Global
Aluminum conductor steel supported (ACSS)	<ul style="list-style-type: none"> • Galvanized or mischmetal coated steel stranded core • Fully annealed aluminum outer strands 	Various
C'	<ul style="list-style-type: none"> • Stranded carbon core • Fully annealed aluminum or aluminum-zirconium outer strands 	Southwire
TS	<ul style="list-style-type: none"> • Mono carbon core encapsulated in an aluminum sheath • Fully annealed aluminum outer strands 	TS Conductor

12 Q. Are advanced conductors by themselves an available alternative to construction
13 of the Rosemont-Wilsonville Line?

14 A. No. The January 2020 Study considered six different transmission configurations
15 options as possible ways to serve the new Tonquin Substation and the associated load.
16 A reconductor-only option was considered in this analysis. Power flow results indicated

¹⁴ PGE/604, Beil/1 (Electric Power Research Institute, Report #3002030547, Advanced Conductors (June 19, 2024)).

¹⁵ PGE/604, Beil/2.

1 that a reconductor project alone would not adequately address the identified system
2 overloads, and new 115-kV transmission construction is required to reliability serve
3 the area.¹⁶

4 **C. Construction of One or More Lower-Voltage Lines**

5 **Q. Why did PGE’s January 2020 Study not evaluate the construction of one or more**
6 **lower-voltage single or multi-circuit lines?**

7 A. PGE did not provide an evaluation in the January 2020 Study of the construction of one
8 or more lower-voltage single or multi-circuit lines because they are not viable as
9 reasonable alternatives to the proposed Rosemont-Wilsonville Line. The transmission
10 solution identified for the Tonquin Project involves construction of additional
11 transmission lines. The only transmission lines that PGE has in its service territory that
12 are lower than the proposed 115-kV Rosemont-Wilsonville Line are 57-kV assets,
13 which would not be a viable alternative.

14 As an initial matter, there are no 57-kV assets in the area surrounding Tonquin
15 Substation and PGE would not seek to build additional 57-kV assets. As compared with
16 115-kV lines, 57-kV lines require a similar amount of right-of-way, cost a similar
17 amount to construct, and do not provide either the capacity or flexibility that is provided
18 by a 115-kV line. For these reasons, PGE no longer constructs 57-kV transmission lines
19 and PGE’s Long Term Local Transmission Plans incorporate rebuilding existing 57-
20 kV lines into 115-kV lines in order to meet the needs of PGE’s system.

21 Similarly, lower voltage distribution assets would not be able to address the
22 identified transmission constraints. Any load additions on the 13-kV distribution

¹⁶ Highly Protected PGE/101, Beil/19-20 (Option 1).

1 system are ultimately served by the upstream 115-kV transmission system, and hence
2 construction of additional distribution circuits alone will not alleviate the identified
3 transmission system overloads.

4 For these reasons, the construction of one or more lower-voltage single or multi-
5 circuit lines is not a viable alternative to construction of the Rosemont-Wilsonville
6 Line.

7 **Q. Does this conclude your testimony?**

8 A. Yes.

List of Exhibits

<u>PGE Exhibit</u>	<u>Description</u>
PGE/601	PGE 2023 CEP/IRP, Appendix D, Load Forecast Methodology
PGE/602	PGE 2023 CEP/IRP, Chapter 9, Transmission
PGE/603	U.S. Department of Energy, Dynamic Line Rating (June 2019)
PGE/604	Electric Power Research Institute, Report #3002030547, Advanced Conductors (June 19, 2024)

PGE/601

**PGE 2023 CEP/IRP, Appendix D,
Load Forecast Methodology**

Appendix D. Load forecast methodology

This appendix provides detail about PGE’s load forecast methodology and results for the 2023 IRP.

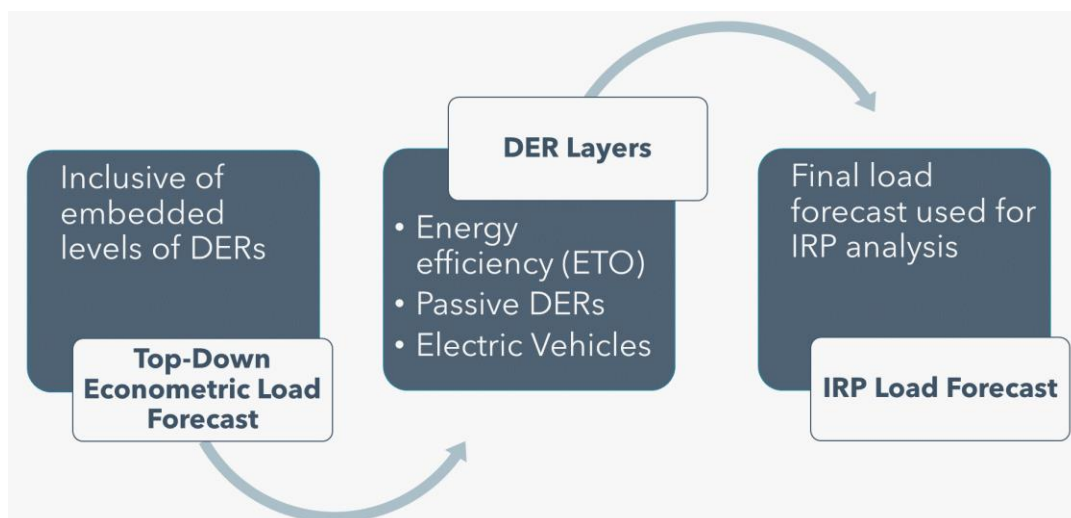
As discussed in **Section 6.2, Distributed Energy Resource (DER) impact on load**, the load forecast combines the top-down econometric forecast and the passive distributed energy resources (DER) forecast. This appendix focuses on the top-down econometric forecast models and provides annual summaries of forecast results.

Unless specified, the load values in this appendix reflect the cost-of-service supply load and do not include long-term direct access loads. The forecast vintage used is the March 2022 load forecast.

D.1 Load forecast methodology

PGE’s load forecast is a compilation of several model outputs. The top-down econometric load forecast is the focus of this appendix. This is a set of models aiming to capture the relationships between PGE’s energy deliveries and various structural trends and economic drivers. The impacts of DERs - primarily energy efficiency, rooftop solar, and transportation electrification - are modeled outside the top-down econometric framework and described in **Section 6.3, Load scenarios**. The incremental impacts of these loads are then ‘layered’ onto PGE’s base forecast, as presented in **Figure 114**.

Figure 114. Load forecast methodology



PGE’s top-down econometric load forecast consists of models focused on two distinct time horizons. **Table 99** describes some of the specific differences.

For the IRP process, PGE updates its long-term models to estimate growth rates for aggregated customer classes: residential, commercial, and industrial. However, the forecast result is dependent on the estimation of the near-term models as a starting point. The long-term growth rates described in this appendix are applied to the result of the near-term forecast model. The near-term model is focused on capturing near term business cycle impacts and individual forecasts for large projects. This model is submitted in PGE's general rate case (GRC) and annual update tariff (AUT) filings.

Table 99. Near term- vs. long-term model

Near Term (1-5 Years)	Long-Term (5+ Years)
25 regression-based monthly energy deliveries models Business cycle influences energy deliveries Individual customer forecast for ~25 large customers Historic data from 2010 to 2021 Explicitly removes incremental energy efficiency Updated as frequently as every quarter	Convergence to long-term growth rates, agnostic to the business cycle and specific customer growth. Three aggregated customer class growth rate models. Historic data from 2000 to 2021. Assumes energy efficiency is embedded in growth rates. Growth rates are appended to near-term model output. Updated annually to support IRP.

D.1.1 Refinements since last IRP

Development of PGE's econometric load forecast reported in this IRP began in 2020 with a review of critical models and an assessment of key issues raised by stakeholders during the 2019 IRP process.

In October 2020, at IRP Roundtable 20-6,⁴³¹ we discussed the impacts of COVID-19 on energy deliveries and out-of-model adjustments made in the near-term load forecast to account for those impacts. We also presented the testing of alternate economic drivers,

⁴³¹ Oct. 28, 2020, IRP Roundtable 20-6:

<https://assets.ctfassets.net/416ywc1laqmd/2XkzCQDPsoEmae8kJn5ckD/6c2e1f9462d8cc16ce8ec7752e57d67a/irp-roundtable-20-6.pdf>

particularly focusing on the use of local drivers, for the industrial forecast model in response to feedback from CUB in LC-73.

In July of 2021, at IRP Roundtable 21-5,⁴³² we presented the preliminary long-term and peak demand models, recommended alternative industrial drivers - including benchmarking to utility peers - and requested feedback on driver selection and scenarios inputs.

In April of 2022, at IRP Roundtable 22-3,⁴³³ we presented the final model results reflecting the March 2022 econometric load forecast and comparison to the 2019 IRP Update.⁴³⁴

Several refinements are reflected in the latest models.

- COVID-19 Indicator:** For the 2019 IRP Update, PGE utilized out-of-model adjustments to account for the impact of COVID-19 in the near-term models. This method was purely pragmatic, an approach to manage the extreme effects quickly. Since that time, we have implemented a more robust approach to account for the impacts of COVID-19 in the econometric model via an indicator variable in the regression analysis. A further explanation of this process can be found in **COVID-19 Impact on short-term energy use**.
- Industrial Driver:** PGE tested several local and national economic drivers for its industrial model. Variables tested included: US Gross Domestic Product (GDP), Total Oregon Income, Mean Oregon Income, Total Non-Farm Oregon Employment, Oregon GDP, and county-level GDP for PGE's service territory. Total Oregon Income was found to have the most robust relationship with PGE's industrial energy deliveries and was selected as the primary driver for the long-term industrial model.
- Peak Demand Model Structure:** PGE separated the peak model into two seasonal models; separate cooling and heating models allow for individual seasonal-level model specifications. The peak model specification can be found in **Section D.1.5, Peak model**.

⁴³² July 22, 2021, IRP Roundtable 21-5:

https://assets.ctfassets.net/416ywc1laqmd/2e13mKz2HVK1uEPogSDofW/09fbb8476086009ffe7d181dfb95dc12/IRP_Roundtable_July_21-5.pdf

⁴³³ Apr. 14, 2022, IRP Roundtable 22-3:

https://assets.ctfassets.net/416ywc1laqmd/2e732S4plWpR59ID7ZDV8q/270c1816f005d6816e63ac88e9e61879/IRP_Roundtable_June_22-5.pdf

⁴³⁴ PGE'S 2019 IRP Update:

<https://assets.ctfassets.net/416ywc1laqmd/7JkfpRUwMrqCwfKsxAPG3g/9703398aa3212f8532ffb5ced616af87/2019-irp-update-04-20-2021.pdf>

D.1.2 Inputs

Normal weather assumption

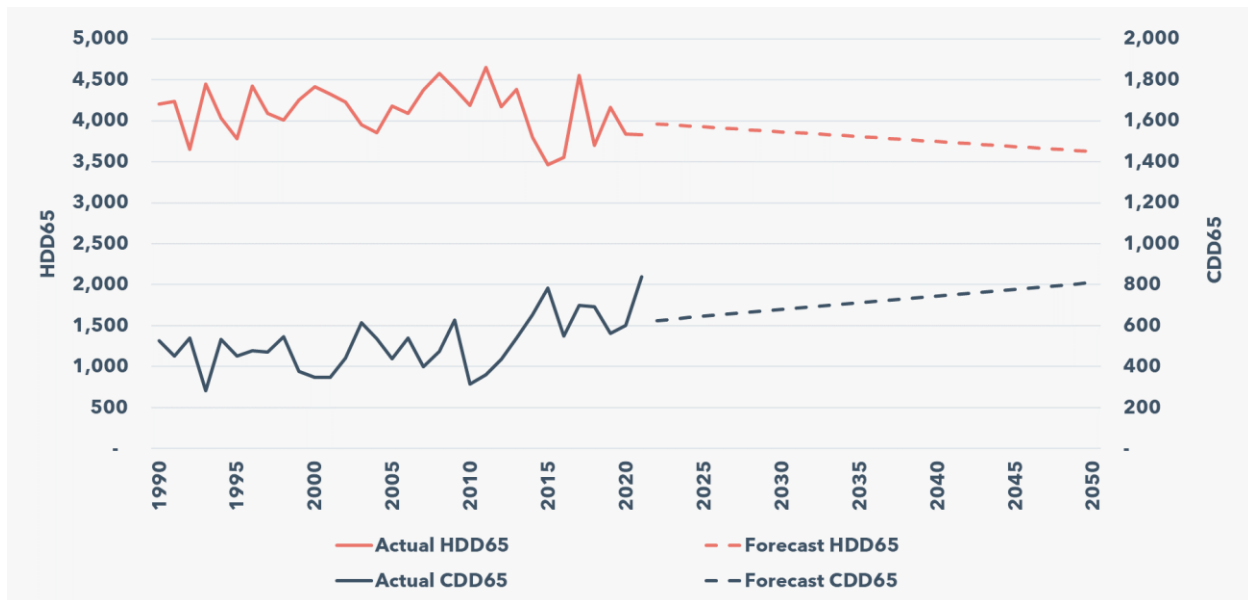
The COVID-19 pandemic has shifted energy usage in several ways. Residential usage experienced a significant increase, while in the commercial segment, initial shutdowns had a stark - but short-lived - impact on energy deliveries. PGE's industrial segment was impacted least by COVID-19 and has grown dramatically since the 2019 IRP. Recent trends impact the near-term forecast, which is the starting point for the long-term forecast.

PGE assumes normal weather year as an input to the load forecast rather than a weather forecast. Weather variability different from the normal weather assumption is expected. The intention is to use an unbiased weather assumption such that the actual weather is warmer or cooler than normal 50 percent of the time. PGE uses a trend to create the forward-looking normal weather assumption that reflects the gradually warming climate. The methodological approach continues the trend observed since 1975, using data since 1941 to "hinge" the initial point of that trend.⁴³⁵ **Figure 115** shows historical actual and forward-looking normal for heating and cooling degree days (HDD and CDD)⁴³⁶ using this methodology.

A review was performed in the 2023 IRP to compare this input assumption to specific Representation Concentration Pathway (RCP) Climate Change Scenarios. This review finds PGE's methodology to fit within the reasonable bounds of this scenario analysis. This is described further at the end of this appendix section.

⁴³⁵ Livezey, Robert E., *et al.* "Estimation and extrapolation of climate normals and climatic trends." *Journal of Applied Meteorology and Climatology* 46.11 (2007): 1759-1776. <https://journals.ametsoc.org/doi/pdf/10.1175/2007JAMC1666.1>

⁴³⁶ Heating and cooling degree days (HDD and CDD) are the number of degrees that a day's temperature deviates from the temperature set point. For heating degree days, the measurement represents the extent to which a building would need to be heated to reach the temperature set point, and for cooling degree days, the measurement represents the extent to which a building would need to be cooled to reach the temperature set point. For these regressions with monthly data, HDD and CDD are summed for all days in the month. As an example, on a day with an average temperature of 75° F, HDD₆₅ = 0 and CDD₆₅ = 75 - 65 = 10.

Figure 115. Normal weather expectation in terms of heating degree days and cooling degree days

COVID-19 Impact on short-term energy use

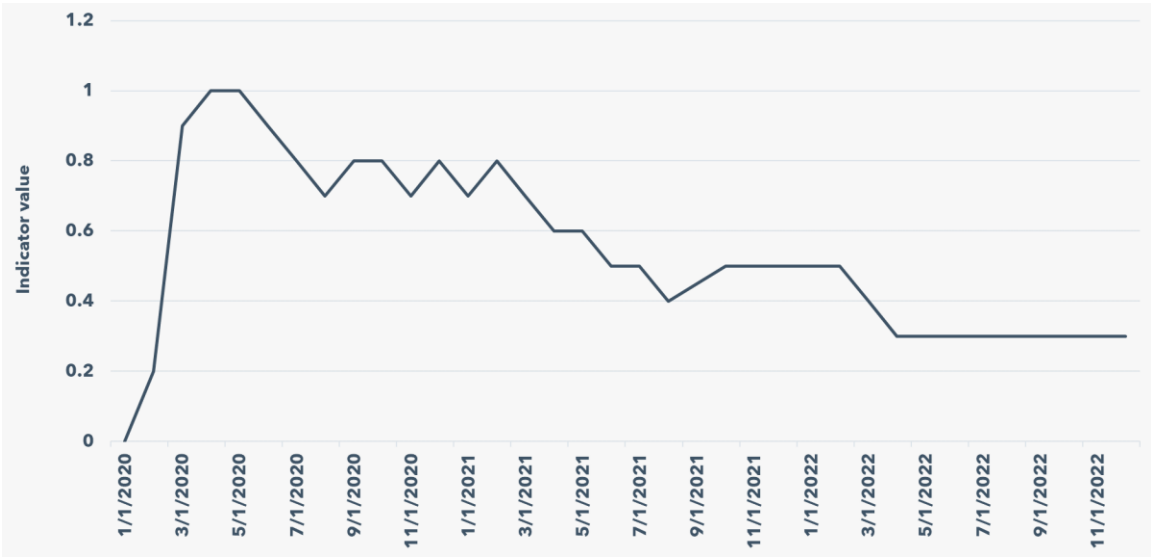
To account for changes in usage, PGE utilized a COVID-19 indicator variable based on the percent of work from home in Oregon produced by the Oregon Office of Economic Analysis.⁴³⁷ The indicator variable is designed to range from 0 to 1, work from home peaked in May 2020, and that level was set to “1”. The indicator was then scaled down based on monthly work from home compared to the May 2020 level. **Figure 116** presents the COVID-19 variable assumptions.

This variable was used in the residential model to account for the increase in usage and in the commercial model to account for the lower usage associated with the COVID-19 pandemic. Recent trends show that COVID-19 has permanently changed the way residential customers use energy. For the forecast, PGE assumed a slow decrease in work from home until April 2022, when long-term equilibrium will be reached at 0.3. This assumes that residential usage will remain elevated at 30 percent of the peak impact of COVID-19.

For the long-term models this variable is phased out in the long-term and does not impact the long-term growth rate beyond correcting the model fit in the short term.

⁴³⁷ Lehner, Josh. “Just How Much is Working from Home on the Rise?” Available at: <https://oregoneconomicanalysis.com/2021/12/16/just-how-much-is-working-from-home-on-the-rise/>

Figure 116. COVID-19 indicator variable

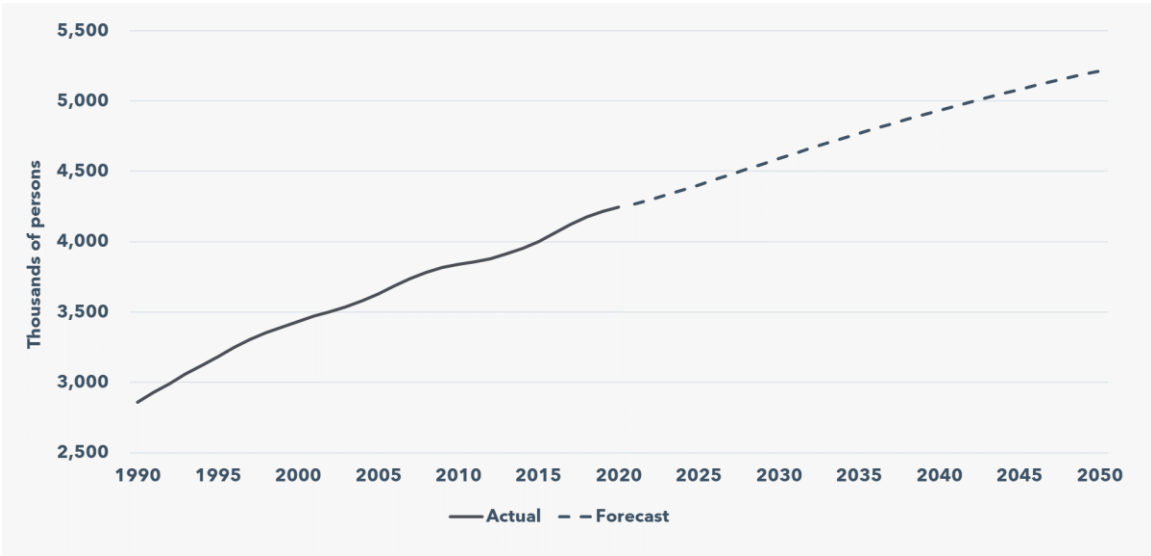


Long-term macroeconomic drivers

Oregon Population

Oregon’s Population is closely related to the number of households in PGE’s service area. It is used as a driver of residential customer count in PGE’s residential energy deliveries model. PGE uses the Oregon Office of Economic Analysis’s forecast of Oregon Population, extrapolated from 2030 to 2050. The projected average annual growth rate from 2022 to 2050 is 0.7 percent. **Figure 117** shows the historical actual and projected population levels.

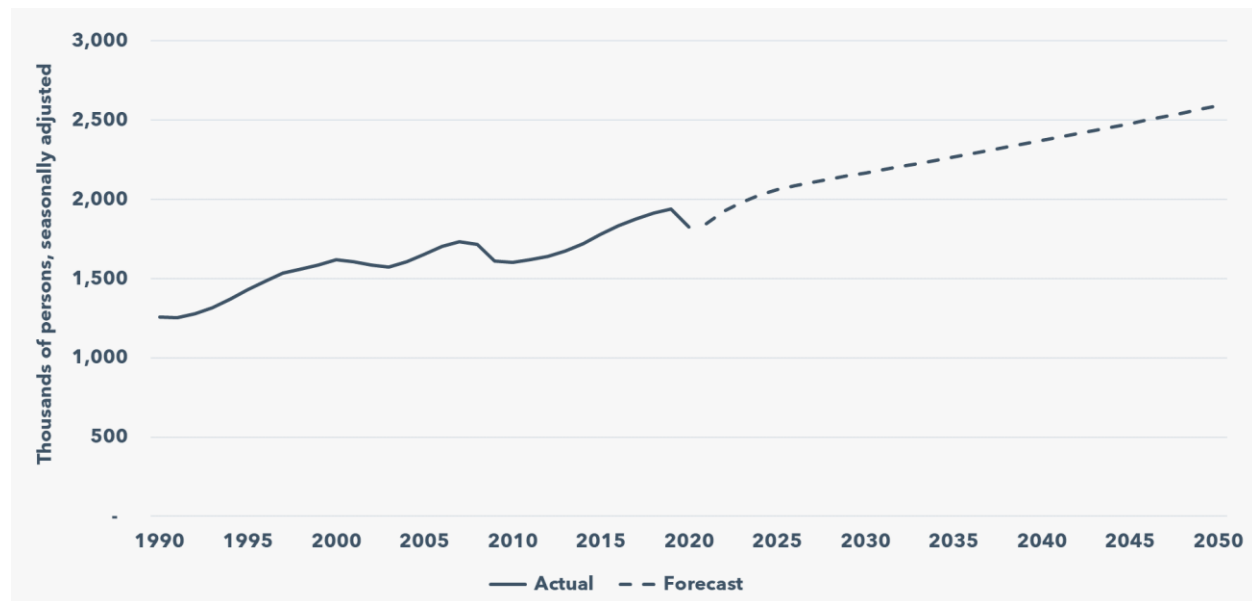
Figure 117. Oregon population



Oregon total non-farm employment

The level of employment in Oregon is the economic driver of PGE's commercial energy deliveries forecast. PGE uses the Oregon Office of Economic Analysis's forecast of employment, extended to 2050. The projected average annual growth rate from 2022 to 2050 is 0.9 percent. **Figure 118** shows the historical actual and forecasted levels of Total Non-Farm Employment.

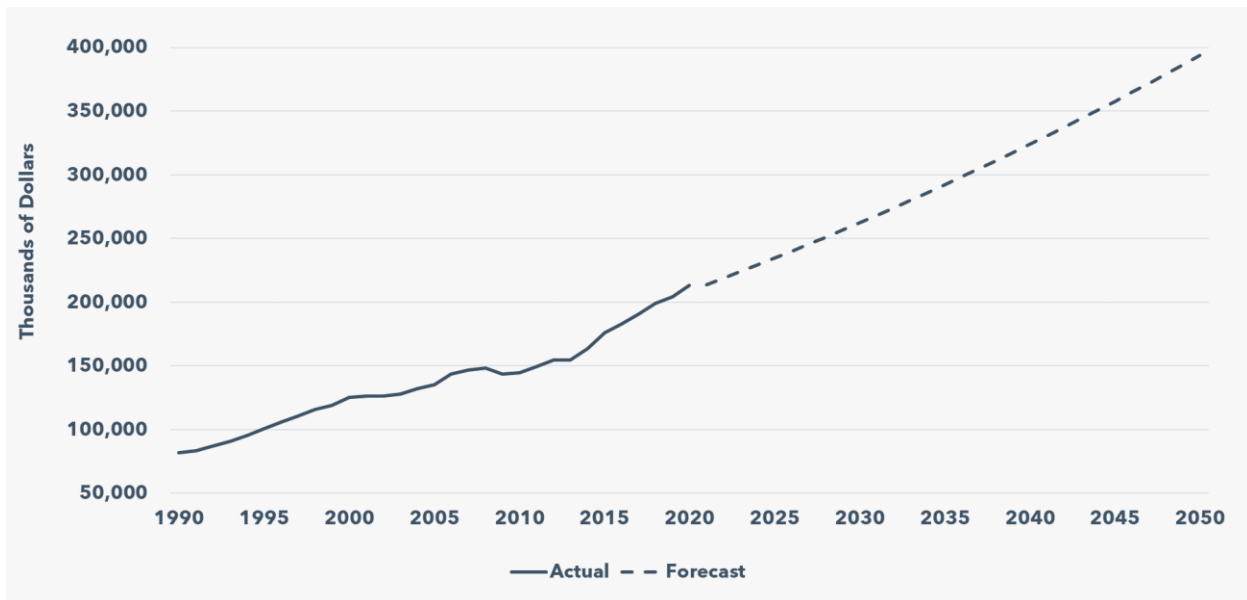
Figure 118. Oregon's total non-farm employment



Oregon Total Personal Income

Oregon's Total Personal Income is the economic driver of PGE's industrial energy deliveries forecast. Total Personal Income is income of individuals from wages, salaries, business ownership, interest and dividends, Social Security, and other government benefits. Measures of income are often used as an indication of financial health. PGE uses the vendor provided forecast released by Woods and Pool in 2021 for this input assumption. The projected average annual growth rate from 2021 to 2050 is 2.1 percent. **Figure 119** shows the historical actual and forecasted Total Personal Income.

Figure 119. Oregon total personal income



D.1.3 Model development and evaluation

In response to OPUC Staff feedback in PGE’s 2016 Integrated Resource Plan and as part of continual methodology refinement, PGE worked to standardize and more formally document its model development process and evaluation criteria.⁴³⁸

A series of testing steps are used to develop long-term forecast models. This testing includes a univariate review of the underlying structure of the energy deliveries time series; an examination of the relationship between energy deliveries to drivers, including weather variables; and the testing of alternative model structures, including naïve, differenced, and “automatic” ARIMA. The model fit statistics, coefficients, and residuals are reviewed to compare and select alternate models.

- Univariate analysis.** Univariate analysis of historical sector-level time series is conducted to identify trends, seasonality, cycles, breaks, and outliers. The first step is to inspect the data series visually. Then the autocorrelation of the series is reviewed, and statistical tests such as the Augmented Dickey Fuller (ADF) and Kwiatkowski, Phillips, Schmidt, and Shin (KPSS) tests are used to assess the underlying structure of the data. When tests imply non-stationarity in a variable, PGE explores data transformations, trend variables, and naïve forecasts.

⁴³⁸ Staff Comments available at: <https://edocs.puc.state.or.us/efdocs/HAC/lc66hac143454.pdf>

- **Weather responsiveness.** Scatter plots and testing in the regression models are used to determine the appropriate HDD and CDD variables for inclusion in each model. **Figure 120** shows the weather responsiveness of the three long-term models with monthly energy deliveries plotted against average monthly temperature using data since 2000.

In **Figure 120**, the scatter follows a relatively tight “U” shape, indicating that residential energy usage increases as the average temperature falls under 60°F and as the average temperature is higher than 65°F. This implies using an HDD variable calculated from a 60°F base and a CDD variable with a 65°F base. In (b), commercial energy deliveries increase as the average temperature falls under 50°F and when the average temperature is higher than 60°F. In (c), the broad scatter implies that energy deliveries to the industrial class have no significant weather dependence.

- **Residual review.** PGE reviews the autocorrelation and normality of residuals in the models for any alternative model structures considered. Ideally, residuals are white noise, meaning they are uncorrelated, have a mean of 0, have constant variance, and are normally distributed. The extent to which residuals of a regression statistically differ from white noise indicates the potential to improve the model specification. Residuals that are meaningfully correlated might lead to the addition of autoregressive or moving average terms to the model or re-visiting the regression model specification.
- **Alternate forecasts and out-of-sample testing.** PGE reviews a variety of alternate model specifications for each of the forecast groups. Testing includes: 1) models using a variety of economic drivers, as well as those with no economic driver; 2) models with and without monthly indicator variables; and 3) models using a variety of data transformations. As part of the standardization of the model evaluation and to benchmark against the most simplistic models, PGE also tests naïve and seasonally naïve forecasts. Out-of-sample testing, which uses a training period to estimate the model and a testing period to evaluate model performance, was included as a part of PGE’s testing process in the 2019 IRP Load Forecasting Appendix. While PGE intends to employ this method in the future, out-of-sample testing was not performed for the forecast vintage used in this IRP. PGE did not perform out-of-sample testing because the dramatic but short-lived period of impact for the COVID-19 indicator variable did not allow for a long enough period to reflect useful testing.

D.1.4 Long-term energy models

Residential model

The long-term residential energy deliveries model, shown in **Equation 1**, comprises of forecasts for both customer count, an annual model based on Oregon Population (**Equation 3**), and use-per-customer, a monthly model based on relationships to Oregon Total Non-Farm employment, COVID-19, and heating and cooling degree days (**Equation 2**). The

Clean Energy Plan and Integrated Resource Plan 2023 | Appendix D. Load forecast methodology

resulting monthly use-per-customer forecast is combined with the annual customer count forecast for a monthly forecast of residential energy deliveries.

Equation 1. Residential energy deliveries

$$kWh_{res} = UPC_{res} * CC_{res}$$

Where:

- UPC = Use-per-customer
- CC = Customer count

Equation 2. Residential use-per-customer

$$UPC_{res,t} = \sum_{k=0}^{11} (\beta_k Month_k + \alpha_k Trend_k) + \beta_{12} HDD60 + \beta_{13} CDD65 + \beta_{14} COVID Indicator_t + \beta_{15} UPC_{res,t-1} + \varepsilon_t$$

Where:

- HDD60 = Heating degree day with 60° F set point
- CDD65 = Cooling degree day with 65° F set point
- Trend = Numerical variable that increases by 1 each year
- COVID Indicator = Indicator variable between 0 and 1
- ε_t = error term

Equation 3. Residential customer count

$$\Delta CC_{res,t} = \beta_0 + \beta_1 * \Delta POP_{or} + \beta_2 \sum_{n=1}^{12} \frac{CC_{res,n}}{\sum_{n=1}^{12} n} + \varepsilon_t$$

Where:

- $\Delta y = y_t - y_{t-1}$ representing a first-order difference
- POP_{OR} = Oregon Population
- ε_t = error term

Commercial model

The commercial energy deliveries model, shown in **Equation 4**, is a monthly model that establishes a relationship between commercial energy deliveries and Oregon's Total Non-Farm employment, COVID-19, and heating and cooling degree days.

Equation 4. Commercial energy deliveries

$$kWh_{com,t} = \sum_{k=0}^{11} \beta_k Month_k + \beta_{12}HDD50 + \beta_{13}CDD60 + \beta_{14}COVID Indicator_t + \beta_{15} OENTNA + \beta_{16} kWh_{com,t-1} + \varepsilon_t$$

Where:

- HDD50= Heating degree day with 50° F set point
- CDD60 = Cooling degree day with 60° F set point
- COVID Indicator = Indicator variable between 0 and 1
- OENTNA = Oregon’s Total Non-Farm employment
- ε_t = error term

Industrial model

The annual industrial model includes Oregon’s Total Personal Income as a driver of energy deliveries (**Equation 5**).

Equation 5. Industrial energy deliveries

$$\Delta kWh_{ind,t} = \beta_0 + \beta_1 X \Delta Personal Income + \beta_2 \sum_{n=1}^{12} \frac{kWh_{ind,n}}{\sum_{n=1}^{12} n} + \varepsilon_t$$

Where:

- $\Delta y = y_t - y_{t-1}$ representing a first-order difference
- Personal Income= Oregon’s Total Personal Income
- ε_t = error term

D.1.5 Peak model

The peak models, shown in **Equation 6 and 7. Peak Demand**, are a monthly seasonal model that relates the single-hour peak demand of PGE’s net system (in MW) to average monthly demand (in MWh) and weather variables. The models consider the impact of heating and cooling degree days (HDD and CDD), as well as the summer model, which accounts for the growing saturation of air conditioning in the home in PGE’s service area. Both models include the previous day’s temperature impacts by using cooling or heating degree days, and the winter model includes wind speed.

Equation 6 and 7. Peak Demand

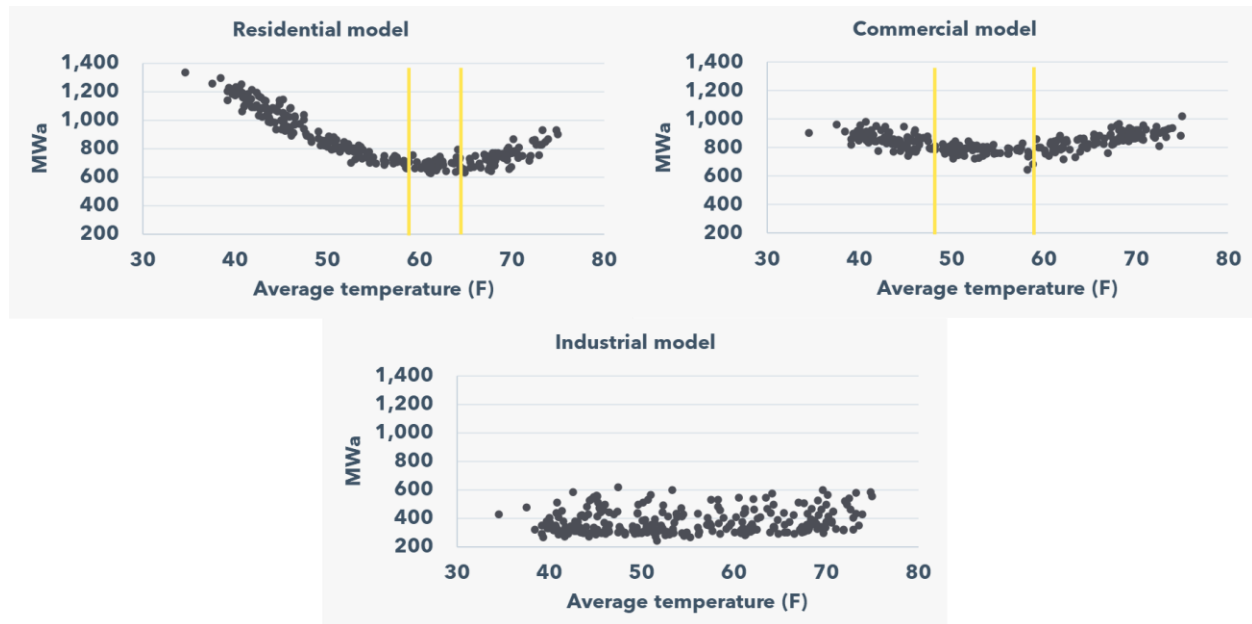
$$MW_{summer,t} = \beta_1 PKDAYCDD + \beta_2 PDCDD + \frac{\beta_3 ACSAT * NRC1_t}{1000} + \beta_4 CycleMA_t \\ + \beta_5 CDD65 + \beta_6 May + \beta_7 Jun + \beta_8 Jul + \beta_9 Aug + \beta_{10} Sep + \beta_{11} Weekend + \varepsilon_t$$

$$MW_{winter,t} = \beta_1 PKDAYHDD + \beta_2 PDHDD + \beta_3 PKDAYWIND + \beta_4 CycleMA_t \\ + \beta_5 HDD60 + \beta_6 Oct + \beta_7 Nov + \beta_8 Dec + \beta_9 Jan + \beta_{10} Feb + \beta_{11} Mar \\ + \beta_{12} Weekend + \beta_{13} STEP0811 + \varepsilon_t$$

Where:

- MWa = Average monthly demand
- PKDAYCDD = CDD with 65° F set point on the day the peak occurred
- PDCDD = CDD with 65° F set point on the day before the day the peak occurred
- NRC1 = Count of residential customers
- ACSAT = Percentage of households with air conditioning
- CycleMA = Twelve months moving average of total monthly usage
- PKDAYHDD = HDD with 65° F set point on the day the peak occurred
- PDCDD = HDD with 65° F set point on the day before the day the peak occurred
- PKDAYWIND = Average daily wind speed on the day the peak occurred
- STEP0811 = An indicator variable beginning in November 2008
- ε_t = error term

Figure 120. Weather sensitivity of energy deliveries to (a) the residential class, (b) the commercial class, and (c) the industrial class



D.1.6 Probabilistic loads

All forecasts are subject to uncertainty, including uncertainties associated with forecasts of the input variables and the complexity of the estimated relationships with those variables. Some of these uncertainties can be characterized quantitatively using model parameters.

The single most important driver of load variability is the weather. Residential and small commercial loads are particularly sensitive to the weather due to heating and cooling loads. Weather is known to be highly variable from one year to the next. PGE addresses the stochastic risk in the load forecast associated with weather, analyzing 30 years of weather variability in its Resource Adequacy model, described in **Chapter 6, Resource needs**.

Two sources of uncertainty characterized using the output statistics of the regression models described previously are model uncertainty and coefficient uncertainty. Model uncertainty is the standard error of the regression or a reflection of how the model performs over the period of data used to inform the model. Coefficient uncertainty is the standard error associated with the estimated coefficient, which defines the relationship between the dependent and driver variables.

EViews, a statistical package used primarily for time-series oriented econometric analysis, and also the software package PGE uses to conduct its load forecast, was used to run stochastic simulations that combine model uncertainty and coefficient uncertainty to create confidence bands around the base case forecast. During simulation runs, coefficients are randomly

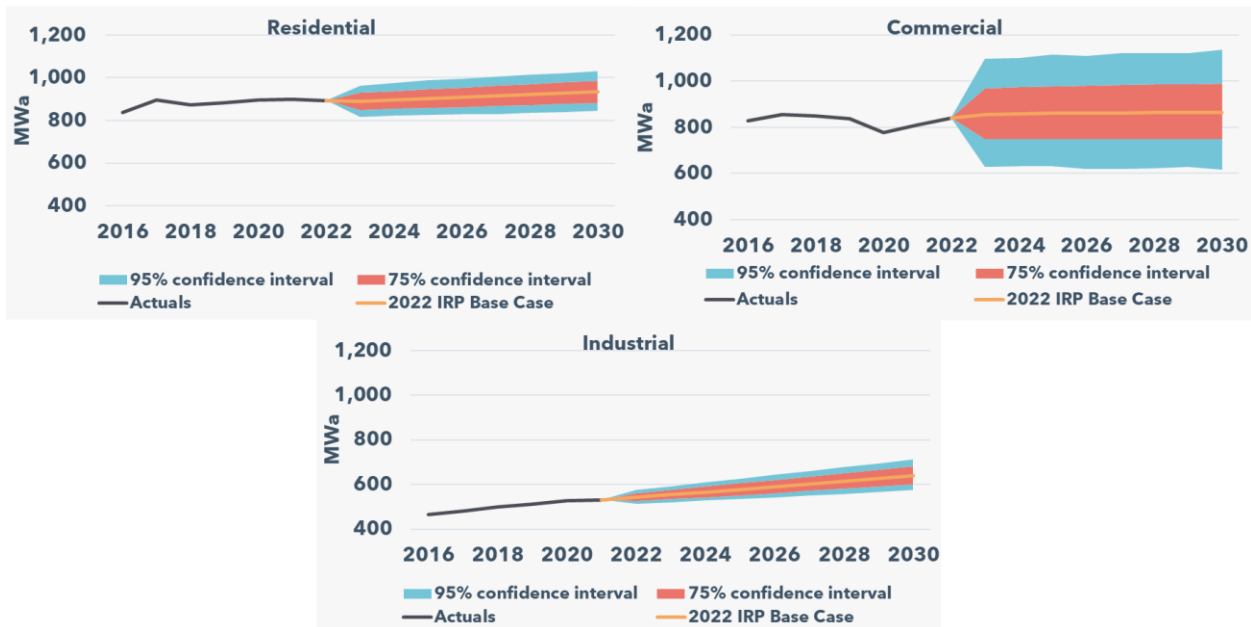
varied along with residuals, and the errors are quantified and used to obtain confidence intervals. Over 10 thousand simulations were run for each of the long-term regression models.

Figure 121 shows the 75 and 95 percent confidence bounds on the three energy deliveries models.

Another category of uncertainty relates to the driver variables used in the regression models. Uncertainties in the forecast of the economic driver variables are considered by scenario analysis, described further in **Chapter 6, Resource needs**.

Other uncertainties not quantified by this approach yet worth mentioning relate to variables excluded from the models and the estimation periods of the models. For example, specific large load might cause shifts in load that cannot be precisely timed by a driver-based model. A model is, by design, a simplification of reality. The interdependencies of energy deliveries are complex and widespread across the macroeconomy. The benefits and uncertainties of different variable selection and estimation periods are weighed during the model development and evaluation process. Drivers which may impact loads outside of this modeling process may be considered in scenario analysis outside of the modeled uncertainties.

Figure 121. Confidence interval on the net system residential (left), commercial (right), and industrial (low) energy deliveries models



D.2 Results

Results of the top-down econometric models described previously are combined with explicit forecasts for EE, EV, and behind-the-meter solar and storage to arrive at the total load scenarios shown in the following tables. These load forecasts do not include long-term direct access loads, consistent with Guideline 9.⁴³⁹ This section provides low, reference, and high forecasts for Net System Load by residential, commercial, and industrial customers. Net System Load includes both cost-of-service supply customers, long-term direct access customers and new load direct access customers.

D.2.1 Energy load forecasts

Table 100 summarizes the load forecast scenarios for energy deliveries (in MWA) at the bus bar.⁴⁴⁰

Table 101, **Table 102**, and **Table 103** provide the annual forecasts for the reference, low, and high scenarios. For these tables, note that passive DER only captures the forecasts for generation from distributed PVs.

Table 100. Load forecast scenarios in MWA⁴⁴¹

	Low Need			Reference Case			High Need		
	2023	2043	AAGR	2023	2043	AAGR	2023	2043	AAGR
Top-down Load Forecast	2,351	3,644	2%	2,365	3,970	3%	2,378	4,276	3%
Base Load Forecast	2,320	3,054	1%	2,334	3,407	2%	2,347	3,731	0
Energy Efficiency	-31	-590	0	-31	-563	0	-31	-546	17%
Rooftop PV	-1	-81	28%	-1	-50	28%	-1	-28	22%
Building Electrification	4	86	17%	4	87	17%	4	124	20%

⁴³⁹ Order No. 07-002 at 19, see Guideline 9, as amended by Order No. 07-047 at Appendix A, p.6

⁴⁴⁰ As mentioned previously, the load forecasts in this section do not include long-term direct access loads.

⁴⁴¹ The base load forecast is the top-down load forecast adjusted to exclude the impacts of the cost-effective deployable EE savings and the assumptions for the embedded distributed PV generation and electric vehicle load. The EE savings are cumulative values adjusted for line losses and intra-year deployment beginning in 2022. Note that in this and the following tables the AAGR is not calculated because savings before 2020 are not reported in these values.

Clean Energy Plan and Integrated Resource Plan 2023 | Appendix D. Load forecast methodology

	Low Need			Reference Case			High Need		
	2023	2043	AAGR	2023	2043	AAGR	2023	2043	AAGR
Transportation Electrification	13	372	18%	15	504	20%	16	590	20%
Total Load Forecast	2,305	2,841	1%	2,321	3,385	2%	2,336	3,870	3%

Table 101. Reference case load scenario with layers, MWa

Year	(a) Base load	(b) Energy Efficiency	(c) Transportation Electrification	(d) Rooftop PV	(e) Building Electrification	(f) = (a) + (b) + (c) + (d) + (e) Total Load
2023	2,334	-31	15	-1	4	2,321
2024	2,402	-61	21	-1	7	2,367
2025	2,463	-91	28	-3	10	2,407
2026	2,530	-121	38	-5	13	2,455
2027	2,594	-151	48	-8	17	2,500
2028	2,649	-181	60	-12	20	2,535
2029	2,703	-214	73	-18	23	2,567
2030	2,759	-247	91	-25	27	2,605
2031	2,817	-282	115	-31	31	2,650
2032	2,875	-316	139	-37	35	2,696
2033	2,931	-348	166	-41	40	2,747
2034	2,986	-378	196	-42	44	2,804
2035	3,040	-408	224	-43	48	2,861
2036	3,093	-435	266	-44	53	2,932
2037	3,143	-460	296	-45	57	2,992
2038	3,192	-483	327	-45	61	3,052
2039	3,237	-502	365	-46	66	3,120
2040	3,280	-518	405	-47	72	3,192

Clean Energy Plan and Integrated Resource Plan 2023 | Appendix D. Load forecast methodology

Year	(a) Base load	(b) Energy Efficiency	(c) Transportation Electrification	(d) Rooftop PV	(e) Building Electrification	(f) = (a) + (b) + (c) + (d) + (e) Total Load
2041	3,323	-533	440	-48	77	3,258
2042	3,361	-545	457	-49	80	3,304
2043	3,407	-563	504	-50	87	3,385
Average annual growth rate	2%	N/A	20%	28%	17%	2%

Table 102. Low Case load scenario with layers, MWa

Year	(a) Base load	(b) Energy Efficiency	(c) Transportation Electrification	(d) Rooftop PV	(e) Building Electrification	(f) = (a) + (b) + (c) + (d) + (e) Total Load
2023	2,320	-31	13	-1	4	2,305
2024	2,373	-61	18	-2	7	2,336
2025	2,419	-91	24	-4	10	2,358
2026	2,471	-121	31	-7	13	2,388
2027	2,520	-152	38	-11	17	2,412
2028	2,558	-184	46	-16	20	2,425
2029	2,596	-217	55	-23	23	2,434
2030	2,637	-252	68	-33	27	2,446
2031	2,678	-288	84	-43	31	2,463
2032	2,719	-323	100	-52	35	2,479
2033	2,758	-357	118	-58	39	2,501
2034	2,796	-389	138	-60	44	2,529
2035	2,833	-420	157	-63	48	2,555
2036	2,869	-449	185	-65	53	2,593
2037	2,901	-476	207	-67	57	2,622
2038	2,932	-502	230	-69	61	2,652

Clean Energy Plan and Integrated Resource Plan 2023 | Appendix D. Load forecast methodology

Year	(a) Base load	(b) Energy Efficiency	(c) Transportation Electrification	(d) Rooftop PV	(e) Building Electrification	(f) = (a) + (b) + (c) + (d) + (e) Total Load
2039	2,959	-523	257	-72	66	2,688
2040	2,984	-542	288	-75	72	2,728
2041	3,007	-558	317	-77	77	2,767
2042	3,027	-570	333	-79	80	2,791
2043	3,054	-590	372	-81	86	2,841
Average annual growth rate	1%	N/A	18%	28%	17%	1%

Table 103. High Case load scenario with layers, MWa

Year	(a) Base load	(b) Energy Efficiency	(c) Transportation Electrification	(d) Rooftop PV	(e) Building Electrification	(f) = (a) + (b) + (c) + (d) + (e) Total Load
2023	2,347	-31	16	-1	4	2,336
2024	2,428	-61	24	-1	7	2,397
2025	2,503	-91	33	-1	11	2,454
2026	2,585	-121	44	-2	15	2,522
2027	2,664	-150	56	-2	20	2,587
2028	2,733	-180	71	-3	24	2,645
2029	2,802	-212	88	-3	29	2,704
2030	2,873	-243	110	-3	34	2,771
2031	2,946	-276	140	-4	40	2,846
2032	3,019	-309	172	-5	46	2,923
2033	3,091	-340	207	-5	52	3,005
2034	3,163	-369	248	-6	58	3,094
2035	3,233	-396	287	-7	64	3,181
2036	3,302	-421	340	-8	72	3,285

Year	(a) Base load	(b) Energy Efficiency	(c) Transportation Electrification	(d) Rooftop PV	(e) Building Electrification	(f) = (a) + (b) + (c) + (d) + (e) Total Load
2037	3,368	-445	378	-10	78	3,370
2038	3,433	-467	415	-12	85	3,454
2039	3,494	-485	457	-15	92	3,544
2040	3,553	-502	499	-18	101	3,635
2041	3,613	-517	534	-21	109	3,718
2042	3,668	-528	544	-25	114	3,774
2043	3,731	-546	590	-28	124	3,870
Average annual growth rate	2%	N/A	20%	22%	20%	3%

D.2.2 Peak load forecasts

Table 104 provides the seasonal peak loads for each year and Need Future.⁴⁴² These tables reflect total load values; the top-down econometric forecast combined with the forecasts for EVs and building electrification. This forecast includes costs effective energy efficiency but does not include the impacts of passive or active demand response programs. The values in this table are reflective of the loads used in the Sequoia model, which has 30-years (1992-2021) of weather variation included (median peak loads are shown).

Table 104. Peak load forecast by Need Future and season, MW

Year	Low Need		Reference Need		High Need	
	Summer	Winter	Summer	Winter	Summer	Winter
2023	3,712	3,510	3,726	3,525	3,740	3,541
2024	3,746	3,547	3,776	3,580	3,805	3,613
2025	3,781	3,583	3,828	3,635	3,874	3,689
2026	3,822	3,626	3,888	3,699	3,953	3,774

⁴⁴² As mentioned previously, the load forecasts in the section do not include long-term direct access loads.

Year	Low Need		Reference Need		High Need	
	Summer	Winter	Summer	Winter	Summer	Winter
2027	3,861	3,668	3,948	3,766	4,032	3,864
2028	3,890	3,706	4,001	3,831	4,105	3,954
2029	3,924	3,734	4,061	3,885	4,188	4,036
2030	3,960	3,773	4,124	3,954	4,277	4,136
2031	4,002	3,814	4,195	4,030	4,376	4,244
2032	4,043	3,861	4,269	4,111	4,481	4,363
2033	4,095	3,908	4,355	4,198	4,602	4,492
2034	4,145	3,964	4,442	4,292	4,729	4,632
2035	4,200	4,020	4,535	4,389	4,860	4,773
2036	4,256	4,081	4,630	4,493	4,994	4,921
2037	4,319	4,139	4,732	4,592	5,130	5,058
2038	4,380	4,203	4,830	4,697	5,259	5,198
2039	4,442	4,267	4,930	4,801	5,383	5,329
2040	4,506	4,336	5,027	4,904	5,500	5,456
2041	4,576	4,402	5,128	5,002	5,616	5,573
2042	4,643	4,472	5,223	5,102	5,723	5,689
2043	4,709	4,540	5,316	5,197	5,824	5,797
Annual average growth rate	1.2%	1.3%	1.8%	2.0%	2.2%	2.5%

D.3 Net system load

Net System Load includes both cost-of-service supply customers and direct access customers. While Net System Load is not used in the IRP need assessments or portfolio

Clean Energy Plan and Integrated Resource Plan 2023 | Appendix D. Load forecast methodology

analysis, the information in this section is provided for reference as it reflects the level of disaggregation at which the load forecast analysis occurs.

Table 105, **Table 106**, and **Table 107** provide the reference, low, and high econometric load forecasts for Net System Load in MWa at the bus bar by class. The commercial class includes street and highway lighting, and the industrial class consists of both transmission and primary-level customers. The high and low scenarios capture high and low growth conditions and +/- 1 standard deviation of uncertainty from the regression model parameters. These forecasts do not include the impacts of the explicit forecasts for Energy Vehicles (EVs), Distributed Energy Resources (DERs), or additional Energy Efficiency (EE) savings beyond Energy Trust's projections.

Table 105. Econometric Net System Load with reference growth conditions, MWa

Year	Residential	Commercial	Industrial	Total
2022	933	802	503	2,239
2023	922	815	566	2,303
2024	918	808	615	2,341
2025	914	801	657	2,372
2026	913	794	703	2,409
2027	915	786	743	2,444
2028	921	786	760	2,467
2029	928	788	772	2,489
2030	935	790	787	2,512
2031	942	791	802	2,535
2032	949	792	818	2,559
2033	956	793	834	2,583
2034	963	795	850	2,607
2035	970	796	866	2,632
2036	977	797	883	2,657
2037	984	798	900	2,683
2038	991	800	918	2,709
2039	999	801	936	2,735

Clean Energy Plan and Integrated Resource Plan 2023 | Appendix D. Load forecast methodology

Year	Residential	Commercial	Industrial	Total
2040	1,006	802	954	2,762
2041	1,013	803	972	2,789
2042	1,021	805	991	2,817
2043	1,028	806	1,010	2,845
2044	1,036	807	1,030	2,873
2045	1,043	809	1,050	2,902
2046	1,051	810	1,071	2,932
2047	1,059	811	1,091	2,961
2048	1,067	812	1,113	2,992
2049	1,075	814	1,134	3,022
2050	1,082	815	1,156	3,054
Average annual growth rate	0.5%	0.1%	3.0%	1.1%

Table 106. Econometric Net System Load with low growth conditions, MWa

Year	Residential	Commercial	Industrial	Total
2022	933	802	503	2,239
2023	918	812	559	2,289
2024	910	802	601	2,312
2025	902	792	634	2,329
2026	897	782	672	2,351
2027	895	771	703	2,369
2028	897	769	711	2,376
2029	901	768	713	2,382
2030	903	766	719	2,388
2031	906	764	724	2,395
2032	909	763	730	2,401

Clean Energy Plan and Integrated Resource Plan 2023 | Appendix D. Load forecast methodology

Year	Residential	Commercial	Industrial	Total
2033	912	761	736	2,408
2034	914	759	742	2,415
2035	917	758	748	2,423
2036	920	756	754	2,430
2037	923	754	760	2,438
2038	926	753	767	2,445
2039	929	751	773	2,453
2040	932	749	780	2,461
2041	935	748	787	2,470
2042	938	746	794	2,478
2043	941	744	802	2,487
2044	944	742	809	2,495
2045	947	741	817	2,504
2046	950	739	824	2,514
2047	953	737	832	2,523
2048	957	736	841	2,533
2049	960	734	849	2,543
2050	963	732	858	2,553
Average annual growth rate	0.1%	-0.3%	1.9%	0.5%

Table 107. Econometric Net System Load with high growth conditions, MWa

Year	Residential	Commercial	Industrial	Total
2022	926	813	628	2,367
2023	927	808	677	2,412
2024	931	803	731	2,464
2025	937	797	779	2,513

Clean Energy Plan and Integrated Resource Plan 2023 | Appendix D. Load forecast methodology

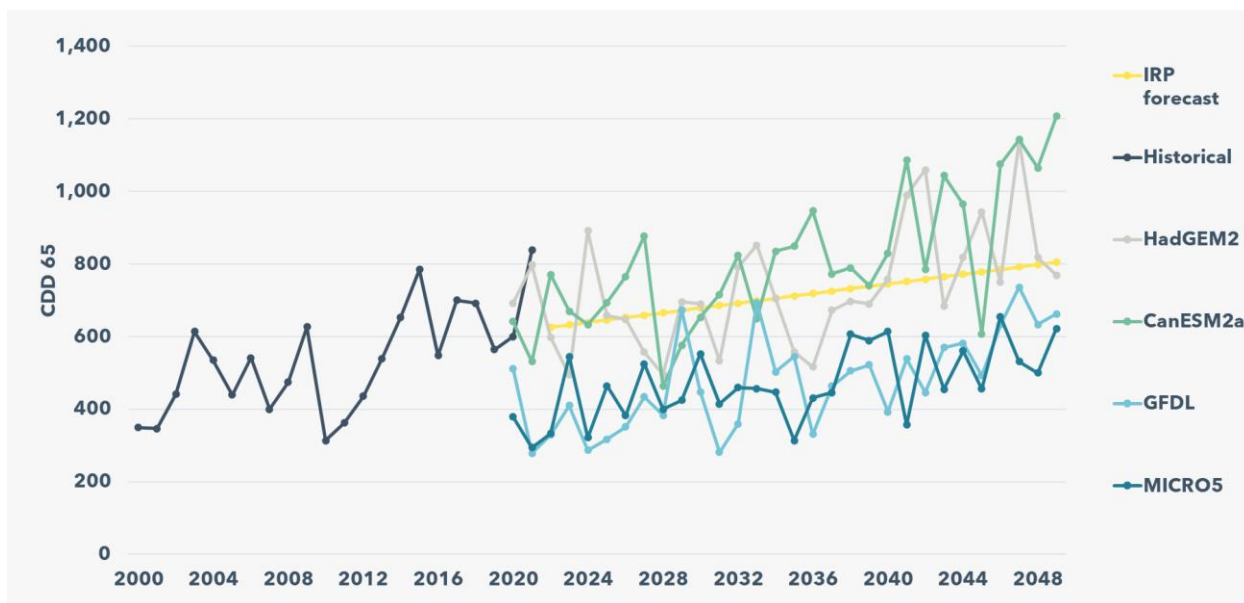
Year	Residential	Commercial	Industrial	Total
2026	947	800	804	2,552
2027	959	804	824	2,588
2028	971	808	848	2,626
2029	982	811	871	2,665
2030	994	815	895	2,703
2031	1,005	818	919	2,743
2032	1,017	822	944	2,782
2033	1,029	825	969	2,823
2034	1,040	829	994	2,863
2035	1,052	832	1,020	2,904
2036	1,064	836	1,046	2,946
2037	1,076	839	1,072	2,988
2038	1,089	843	1,099	3,031
2039	1,101	846	1,126	3,074
2040	1,113	850	1,154	3,117
2041	1,126	854	1,182	3,161
2042	1,138	857	1,210	3,205
2043	1,151	861	1,239	3,250
2044	1,164	864	1,268	3,296
2045	1,176	868	1,297	3,342
2046	1,189	871	1,327	3,388
2047	1,202	875	1,358	3,435
2048	1,216	879	1,388	3,482
2049	933	802	503	2,239
2050	926	817	572	2,316
Average annual growth rate	1.0%	0.3%	3.7%	1.6%

D.4 Climate change model data and the IRP load forecast

The temperature data used by the econometric load forecasting model have historical climate change trends built into them. In general, this increases cooling-degree days going forward and decreases heating-degree days.⁴⁴³ The IRP compares these historical trends with climate model outputs to see how similar they are. The climate model data used in the comparison are from the River Management Joint Operating Committee (RMJOC) studies that use data from the Intergovernmental Panel on Climate Change (IPCC). The four models used in the comparison were selected by the RMJOC for streamflow analysis and were recommended for the IRP analysis by Creative Renewable Solutions.⁴⁴⁴

Figure 122 compares cooling degree days (CDD 65) annually between the historical data, the trend data used in the IRP econometric forecast, and the climate model outputs. Historical data and the econometric load forecast data are in gray. There is an upward trend in the econometric load forecast data. An upward trend in CDD 65 indicates warming temperatures in summer months and more demand for mechanical cooling (air conditioning). The figure data from the four climate models are in color and trend upwards, too.

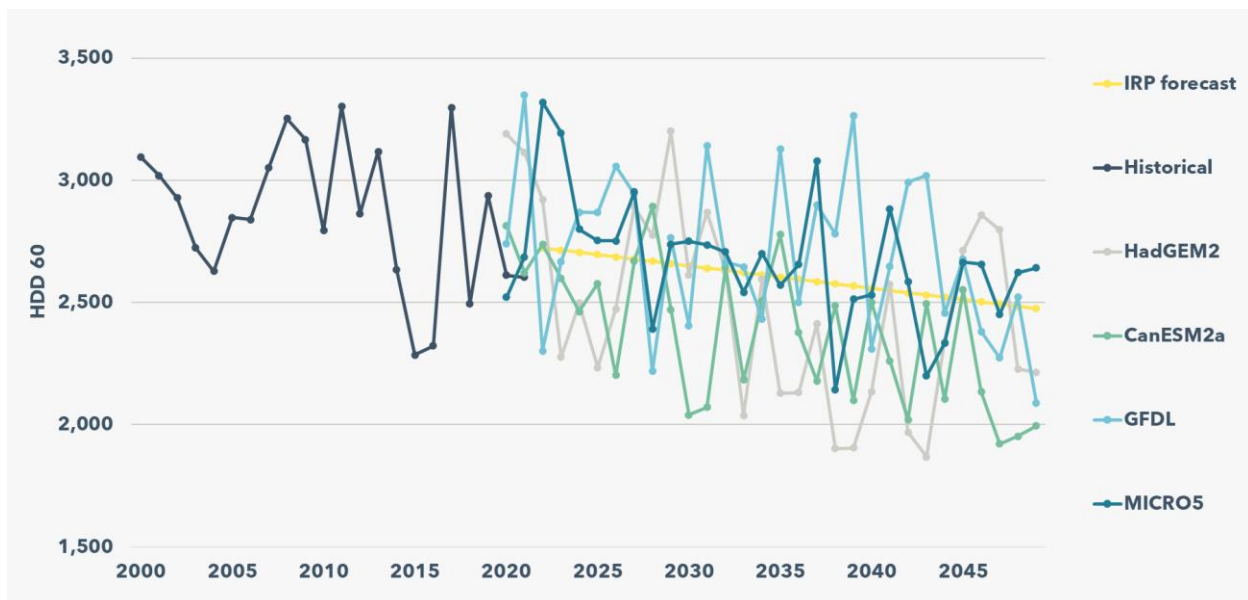
Figure 122. Annual cooling degree day forecasts



In **Figure 122**, the econometric load forecast CDD 65 inputs (in gray) trend inside the range of the climate change model data (in color). This indicates that the warming trend approach used by the econometric load forecasting model somewhat comports with the data from the climate change models.

Figure 123 compares heating degree days from historical data (in gray), the IRP econometric load forecast (in gray), and the climate change models (in color). All datasets show a decreasing trend in heating degree days on a yearly basis. This indicates warming temperatures in winter months, and a decreased need for heating.

Figure 123. Annual heating degree day forecasts



In **Figure 123**, the econometric load forecast HDD 65 inputs (in gray) trend inside the range of the climate change model data on an annual level. On a monthly level however, the econometric load forecast trend in December and February is flat, whereas the climate models have a declining trend (not shown).

Based on the observation that the annual HDD and CDD data used in the econometric load forecast are mostly in the range of the climate model data, PGE decided to stay with the warming trend approach for the 2023 IRP. In future planning work PGE will continue to update the trend approach while exploring using climate change model data.

⁴⁴³ Cooling degree days define days that average higher than a certain temperature, often 65 degrees F. An increase in cooling degree days indicates warming temperatures (and more need for air conditioning). Heating degree days define days that average less than a certain temperature, often 60 degrees F. A reduction in heating degree days indicates warming temperatures (and less need for heating).

⁴⁴⁴ Additional climate change data are available at: <https://www.bpa.gov/energy-and-services/power/climate-change-fcrps>

PGE/602

**PGE 2023 CEP/IRP, Chapter 9,
Transmission**

Chapter 9. Transmission

Portland General Electric (PGE) owns transmission assets and rights to ensure reliable delivery of electricity from generation resources to load. Many of the future resources PGE will acquire to decarbonize and maintain adequacy require additional transmission rights. However, there is a limited amount of existing transmission available for future resources to use. This chapter discusses today's transmission system, introduces the concept of transmission proxies to represent new transmission options in IRP modeling and identifies transmission projects that can be part of the IRP's Action Plan.

Chapter highlights

- PGE's unique footprint necessitates collaborative planning with Bonneville Power Administration (BPA) and regional peers to deliver resources to PGE's service area and to serve load within PGE's footprint. Transmission planning and development often takes longer than the Integrated Resource Plan (IRP) action window time horizon, necessitating early proactive efforts.
- As PGE plans to meet House Bill (HB) 2021's decarbonization targets, it is necessary to proactively mitigate transmission constraints to ensure reliable service of current and future load.
- Portfolio analysis in this IRP indicates additional transmission need on PGE's system, across BPA's system and in additional climate zones.
- PGE proposes addressing transmission need through a combination of rights and/or projects to alleviate congestion across the South of Allston flowgate, expanding transmission to reach additional climate zones that provide resource diversity, and increasing PGE's ability to import electricity through the study of upgrading the Bethel to Round Butte line from 230 to 500 kV.

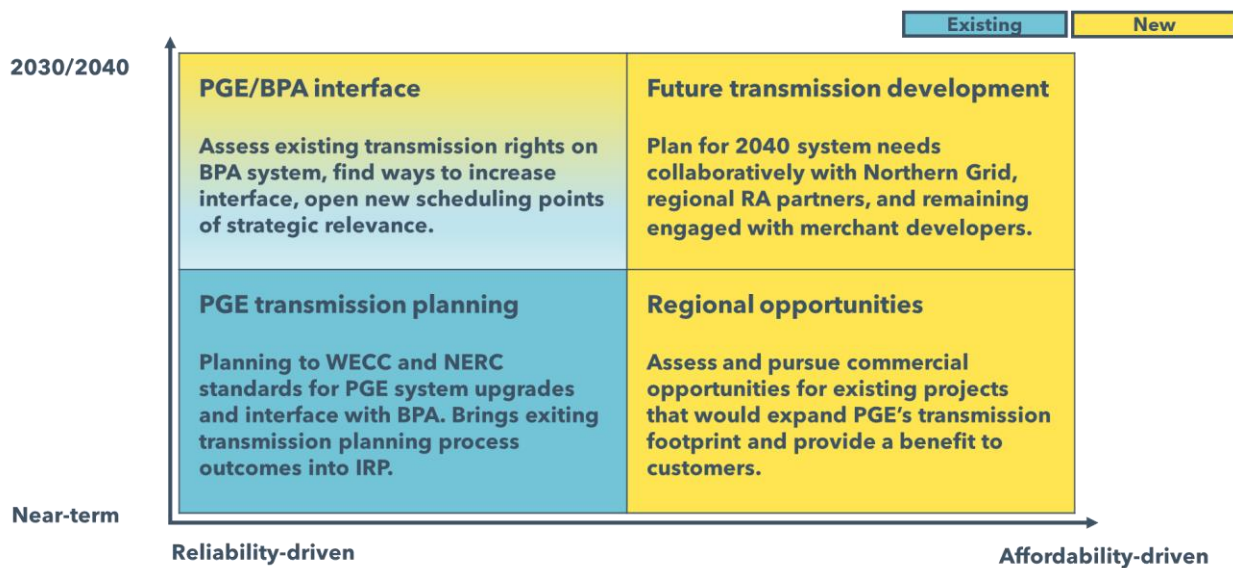
9.1 Introduction to transmission environment and impact on resource strategy

PGE's transmission portfolio – comprised of PGE-owned assets and transmission rights held on other networks – is designed to ensure reliable delivery of electricity from a broad array of generation resources to load. As PGE works toward the decarbonization goals of HB 2021, PGE will likely need to explore adding Variable Energy Resources ("VERs") that are non-

emitting electricity from new geographic areas within the backdrop of growing interconnectedness in the west. As PGE’s system evolves to meet decarbonization goals reliably, we will need to evolve our transmission portfolio to expand our reach throughout the West and strengthen our ability to serve locally.

PGE’s analysis in this IRP illustrates that the optimal portfolio balance of cost and risk includes holistic transmission investment over the next decade: through continued and expanded planning on PGE’s system, through alleviating congestion on BPA’s system, through regional opportunities to expand PGE’s historic geographic transmission footprint and through robust planning for 2040 needs. This combination of transmission additions will provide reliable service as we add generating resources in Oregon and will supplement resources close to home by providing access to climate zones with higher and diversified wind and solar production. The transmission investment introduced in this chapter and recommended for acknowledgment through portfolio analysis balances cost, risk and a continual progress toward decarbonization targets (**Figure 63**).

Figure 63. PGE holistic transmission approach



The transmission system that serves PGE customers is highly integrated with other transmission systems in the West. It provides the critical infrastructure needed to serve customers in Oregon’s largest metropolitan areas and enables economic development within the state.

PGE Transmission assets: As a vertically integrated investor-owned utility that is regulated by the Federal Energy Regulatory Commission (FERC), PGE is obligated by FERC to functionally separate its Transmission Function (PGET) from its Marketing function (PGEM). PGET is required to plan and operate PGE’s transmission system in a non-discriminatory manner that provides open access to all transmission customers, including PGEM. Put plainly;

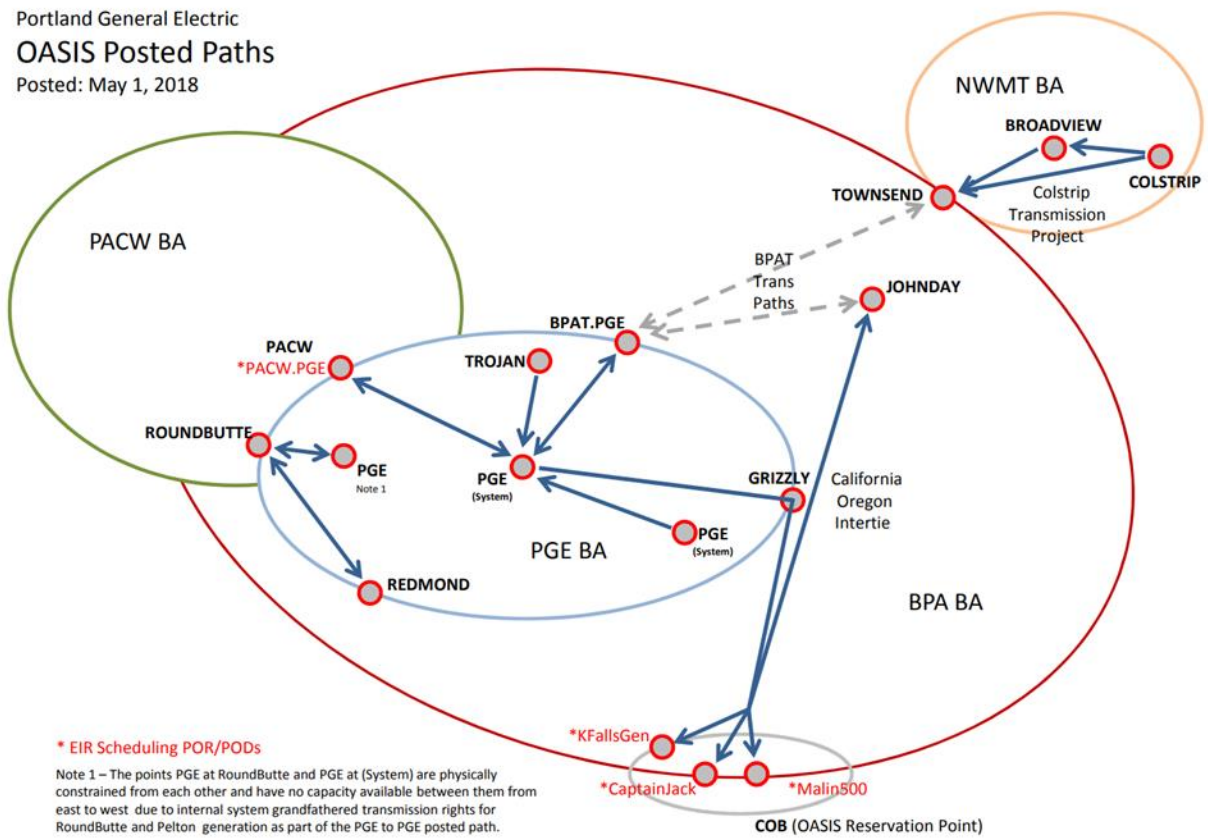
this means PGET cannot unduly preference PGEM and, by extension, the retail customers that PGE serves. PGET's transmission customers include PGEM, Oregon-defined Electricity Service Supplier (ESS) customers, BPA and transmission customers who utilize PGE's transmission system to move power across the region.

PGE merchant portfolio: PGEM is responsible for purchasing transmission rights - on PGE's transmission facilities and those of other regional providers - to deliver power to PGE's service area to meet PGE's load obligations. PGEM holds extensive rights on the BPA transmission system, the largest in the Pacific Northwest. PGE is also interconnected to the western part of PacifiCorp's system, albeit with a much smaller transfer capability than PGE's interface with BPA. PGE's interface with PacifiCorp is primarily used to meet obligations within the Energy Imbalance Market (EIM). PGE is a co-owner of the Colstrip Transmission System, a 500 kV transmission line in Montana that runs between Colstrip and BPA's system in western Montana. Additionally, PGE co-owns one of the three 500 kV circuits in central Oregon that comprise the Northwest AC Intertie (NWACI) and connects Oregon to California. PGE jointly owns NWACI with BPA and PacifiCorp and it is operated by BPA.

Planning and regional opportunities: PGE is a member of NorthernGrid, the transmission planning organization that plans the transmission system used to serve the majority of the Pacific NW and Intermountain states of the western US.

PGE is uniquely situated, with load in the northern Willamette Valley served by PGE's physical transmission system (PGET) that exists largely surrounded by, and significantly dependent on, BPA's transmission system, as shown in **Figure 64**.

Figure 64. PGE transmission and interconnection to BPA, PACW and Northwestern



9.1.1 PGE transmission to serve load

The decarbonization requirements of Oregon HB 2021 direct load serving entities including PGE to reduce greenhouse gas emissions associated with serving Oregon retail electricity consumers, compared to baseline emissions levels by 80 percent by 2030, 90 percent by 2035 and 100 percent by 2040. PGE currently estimates that compliance with this decarbonization standard will require significant addition of resources to serve load in compliance with state law. As mentioned in **Section 6.5, Energy need**, and **Section 6.6, Capacity need**, this IRP has identified a need for 905 megawatt average (MWA) of GHG-free energy and 1136 megawatts (MW) of summer capacity to reach the 2030 target and maintain system adequacy. It is important to recognize that as economic development-driven load growth happens, there may be pockets that contain high concentrations of load within PGE’s service area. To reliably serve this concentration of load, PGE will need to proactively develop unique transmission solution (see **Section 6.1.2.2, Industrial growth**).

PGE is considering investing in transmission solutions that would allow access to other climate zones to achieve additional resource diversity as its resources become more dependent on weather conditions to operate.

PGE is likely to meet transmission need through a combination of purchased transmission rights" or "transmission rights on other systems, investment in transmission assets currently in development regionally, and/or development and upgrade of PGE transmission assets to serve load.

As PGE selects the optimal portfolios of generating resources within this IRP to meet future load needs, PGE continues to plan for sufficient transmission to serve future load obligations reliably and comply with state law. The transmission options discussed in this chapter and recommended for acknowledgment in the Action Plan result directly from the future load-service needs associated with native load growth and HB 2021 requirements.

9.2 Regulatory environment

Consistent with the principles of FERC Order Nos. 890 and 1000, and requirements of PGE's FERC-approved Open Access Transmission Tariff (OATT), PGE is required to plan and build its transmission system to meet the needs of all PGET transmission customers, including PGEM and ESS customers.^{266,267} Transmission customers typically utilize PGE's transmission system to serve load contained within PGET's system footprint or to transfer power through PGET's system to other transmission systems.

Customers who serve load located on PGE's transmission system generally use a transmission service called Network Integration Transmission Service (NITS). Transmission customers who move power through PGET's transmission system for delivery to a point on another transmission system typically use Point-to-Point (PTP) transmission service. For PGET to develop its transmission plans for most NITS customers, with the State of Oregon-defined Electric Service Supplier (ESS) customers being the exception, PGE uses the ten-year load-and-resource (L&R) forecasts supplied by NITS customers along with PTP transmission service commitments and requests. ESS customers are not obligated to designate generation resources to serve their loads.

²⁶⁶ See Preventing Undue Discrimination and Preference in Transmission Service, Order No. 890, 72 Fed. Reg. 12266 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31241 (2007), available at: <https://www.federalregister.gov/documents/2007/03/15/E7-3636/preventing-undue-discrimination-and-preference-in-transmission-service>

²⁶⁷ See Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities, Order No. 1000, 76 Fed. Reg. 49842 (Aug. 11, 2011), FERC Stats. & Regs. ¶ 31323 (2011), available at: <https://www.federalregister.gov/documents/2011/08/11/2011-19084/transmission-planning-and-cost-allocation-by-transmission-owning-and-operating-public-utilities>

PGET uses the NITS customers' L&R forecasts and best available information, including transmission service, generation interconnection requests and information from neighboring transmission providers' transmission planning and construction activities, to determine the need and timing for investments in the transmission system. The bulk of PGET's NITS customer-driven needs comes from PGEM, which supplies energy and capacity for PGE's retail customers. Oregon's HB 2021 is expected to significantly impact the resource decisions of PGET's transmission customers, including PGEM, resulting in the need to develop new transmission system investment and deployment strategies. The 2022 L&R letter from PGEM to PGET documents the expectation that PGEM's future resource needs will change, given the need to comply with HB 2021. PGET must now work with its customers, including PGEM, to plan the PGET transmission system to maintain reliable service as its customers' resource mixes change over the next several years.

While PGE's transmission customers, except ESSs, are required to provide annual L&R forecasts looking 10 years into the future, transmission development in the West requires lengthy planning, rights-of-way (ROW) acquisition, permitting and construction timelines. As such, PGET cannot rely solely on the L&R forecasts to plan future transmission investments.

9.2.1 FERC transmission planning notice of public rulemaking

At the time of writing, FERC has an open rulemaking docket that seeks to explore potential improvements to the regional transmission planning requirements.²⁶⁸ In the NOPR, FERC proposes to increase the transmission planning time horizon from 10 years to a minimum of twenty, identify whether transmission planning regions should contemplate standardized needs and benefits for cost allocation, determine whether transmission planning regions should be required to identify geographic resource zones, whether FERC should reinstate the right of first refusal for incumbent transmission providers when a proposed project would run through their territory, and/or require transmission planning regions to conduct sensitivity planning analysis contemplating a prescribed number and type of specific scenarios. PGE continues to follow and participate in this rulemaking process and will make any necessary updates to its OATT to reflect changes to the transmission planning process as they are approved by FERC and implemented over the next several years.

²⁶⁸ FERC Docket No. RM21-17-000.

9.2.2 PGE transmission system reliability planning requirements

The PGE service area is a compact area located primarily in Oregon's Willamette Valley. PGE owns and operates its transmission system and Balancing Authority Area (BAA) to deliver energy to PGE's retail customers while also providing transmission service to other wholesale transmission customers as required by FERC and in accordance with PGET's OATT. Most of PGE's existing, owned transmission assets are within the PGE service area. PGE also owns transmission assets in central and southern Oregon and Montana. PGE is obligated to plan, build and operate the transmission system in a manner that reliably delivers power to serve customer load and the needs of PGET's OATT transmission customers.

The PGE transmission and sub-transmission system has 1,663 miles of lines (213 miles of 500 kV, 408 miles of 230 kV, 566 miles of 115 kV and 476 miles of 57 kV sub-transmission) and includes 176 substations and switching stations.

As PGE plans for the transmission system that contemplates the increased resource need of the future, PGE's goals are:

- Reliable delivery of non-emitting energy to serve load;
- Ability to meet growing customer loads during a broad array of planned and unplanned system outage conditions;
- Adapting to the changing system conditions from economy-wide decarbonization and electrification;
- Ability to economically transfer power from other systems when needed and better prepare our system to ensure resource adequacy together with regional peers; and
- Ensure access to a diverse transmission portfolio to limit exposure to system and market disruptions that can constrain the transmission system.

PGE is required to meet mandatory FERC, North American Electric Reliability Corporation (NERC) and Western Electricity Coordinating Council (WECC) reliability standards and planning requirements.²⁶⁹

PGE's transmission system is also required to respond to directives issued by Reliability Coordinator (RC) West, the NERC-recognized Reliability Coordinator for PGE's portion of the Western Interconnection. PGE conducts annual transmission planning system assessments to

²⁶⁹ See NERC TPL-001-4 standard, available at: <https://www.nerc.com/pa/Stand/Reliability%20Standards/TPL-001-4.pdf> and the WECC planning criteria, available at: <https://www.wecc.org/Reliability/TPL-001-WECC-CRT-3.2.pdf>, for additional details.

identify minimum levels of system performance during a wide range of operating scenarios, with all system elements in service to extreme seasonal conditions and scenarios where portions of the system are out of service. These assessments include load growth forecasts, operational history, seasonal performance, resource changes and transmission topology changes. Based on these analyses, PGE identifies potential system deficiencies and determines the necessary transmission system improvements to meet customer needs reliably.

NERC planning standards define the reliability of the interconnected bulk electric system in terms of adequacy and security. Adequacy is the electric system's ability to meet aggregate electrical demand for customers consistently. Security is the electric system's ability to withstand sudden disturbances or unanticipated loss of system elements. Increasing transmission capacity often requires redundant facilities to meet NERC reliability criteria.

Historically, PGE has focused on planning and development of reliable and load service-driven transmission given our unique geographic footprint within BPA's system. Until recently, this was primarily because BPA had ample Available Transfer Capability (ATC) on their transmission system that PGE has been able to leverage to transfer new remote generation resources to PGE's Willamette Valley load. With the recognition that ATC inventories on BPA's system have been fully allocated, PGE's transmission planning will need to evolve from an approach based primarily on reliability and load service to a more proactive approach that aligns with our future load service needs as we decarbonize. It is important to recognize the significant transmission planning and project development efforts already underway that are necessary for reliable load service with PGE's load service area.

Projects currently included in PGE's Local Transmission Plan (**Table 41**) span both projects that enhance regional transmission and expand interface capacity with BPA, as well as projects that are designed to meet high concentrations of new load and enhance reliability on specific parts of PGE's system:

Table 41. Projects included in PGE's local transmission plan

Summary of regional enhancement projects	
Title	Purpose/scope
Harborton Reliability	Reconfigure the system to reduce exposure and provide a stronger source to Northwest Portland 230 and 115 kV systems. Planned completion 2026.
Horizon-Keeler BPA #2 230kV	Accommodate load growth in Hillsboro by constructing a new bay at BPA's Keeler Substation. Expected completion 2024.
Willamette Valley Resiliency	Strengthen and increase the resiliency of PGE's system in the Central portion of PGE's territory, north of the Salem region. Expected completion 2028.
Pearl/Sherwood 230kV Reinforcement	Mitigate the overloading of the McLoughlin-Pearl BPA-Sherwood 230 kV line caused by the loss of the Pearl BPA-Sherwood 230 kV line. Expected completion 2026.
Hillsboro Reliability	Significant upgrades to prepare for load growth in the Hillsboro area. Expected completion 2027.
Horizon Keeler BPA #1 230 kV Reinforcement	Mitigate overloads seen on the Horizon-Keeler BPA #1 230 kV line due to Hillsboro-area load growth. Expected completion 2027.
Murrayhill-Sherwood #1 and 2 230 kV Reconductor	Mitigate overloads caused by the loss of other 500 and 230 kV sources during south-to-north flow conditions in the Beaverton/Hillsboro area. Expected completion 2027.
Murrayhill-St. Mary's #2	Mitigate overloads caused by the loss of other 500 and 230 kV sources during south-to-north flow conditions in the Beaverton/Hillsboro area. Expected completion 2027.

Additionally, PGE has identified projects that are included in the OATT Attachment K Local Transmission Plan and are designed to enhance local system reliability:

- Reedville Substation Rebuild
- Memorial Substation Project
- Tonquin Substation Project
- Kaster Substation Project
- Redland Substation Project
- Scholls Ferry Substation Project
- Groveland Substation Project
- Glencullen Rebuild & Cedar Hills Breaker Project
- SE Portland Conversion Project
Holgate Substation Conversion
- Mt Pleasant Substation Project

9.2.3 Regional transmission planning in advance of 2040

PGE is a member of NorthernGrid, the transmission planning organization that serves the majority of the Pacific NW and Intermountain states of the western US. NorthernGrid has fourteen members, including seven FERC-jurisdictional investor-owned utilities (IOUs), six publicly owned utilities and BPA. NorthernGrid's planning process produces its transmission plan on a biennial basis following a FERC-accepted Attachment K planning process.²⁷⁰

In addition to the NorthernGrid transmission planning process, the Western Power Pool (WPP) is currently coordinating an effort to produce two additional regional transmission studies. The first study will evaluate the risk to the transmission system because of extreme weather events like a heat dome, wildfire or west-side arctic freeze event. The WPP is also conducting a 20-year transmission planning analysis that contemplates the implementation of Oregon HB 2021 and Washington's Clean Energy Transformation Act (CETA). The purpose of the studies is to start understanding as soon as possible the extent to which these new policies will require building out the region's transmission system. Because new significant transmission projects can take 15-20 years to develop, PGE and other transmission providers in the west recognized that studying these scenarios now is necessary if the region is to meet the collective future resource targets. These studies are both expected to be complete in mid-2023.

Further, PGE will deploy a portfolio of strategies to meet the future transmission needs covered in this chapter. PGE intends to explore expanding transmission access through the acquisition of rights on third-party systems, equity investment in regional projects as they are constructed, and PGE-developed projects, including upgrades of existing assets. These different avenues of transmission expansion will allow PGE to optimize for the least cost and least risk as we plan to meet future needs.

²⁷⁰ Available at: https://www.oasis.oati.com/woa/docs/PGE/PGEdocs/PGE_OATT_01012022-v2.pdf

9.3 PGE transmission rights and regional environment

9.3.1 The Pacific Northwest transmission system

Resource portfolios have grown and shifted in response to increasing loads, new large and highly concentrated loads and the significant growth of variable energy resources. However, the delivery capabilities of the Pacific Northwest's transmission system, generally, have not kept pace with these changing demands. As a result, the region is already constrained, with little or no ATC available across all time horizons.²⁷¹ This situation concerns PGE, as many future resource alternatives being explored will be located remote to PGE's retail service area and require delivery via the region's transmission system to reach PGE's service area.

PGE's system is largely surrounded by BPA's transmission system. PGE has long relied on BPA transmission to deliver energy throughout the west to serve the PGE load. PGE currently holds over 4,000 MW of long-term firm transmission under contract with BPA. As discussed by BPA and stakeholders throughout BPA's Transmission Study and Expansion Process 2022 (TSEP),²⁷² BPA's system is fully subscribed, and incremental transmission requests are unlikely to be granted until the late 2020s or early 2030s, pending significant upgrades. As such, PGE is viewing future transmission planning and procurement activity recommended throughout this chapter as a way to expand and diversify transmission options as we work to decarbonize our energy associated with serving load and we need to explore doing so in a way that does not rely on BPA transmission to the same extent PGE has historically relied on BPA. It is important to recognize that the identification and development of transmission solutions are long lead activities that often take longer than the Action Plan window time horizon of this IRP. Given this dynamic, it is necessary to engage in transmission planning and development on a forward-looking basis beyond the Action Plan window.

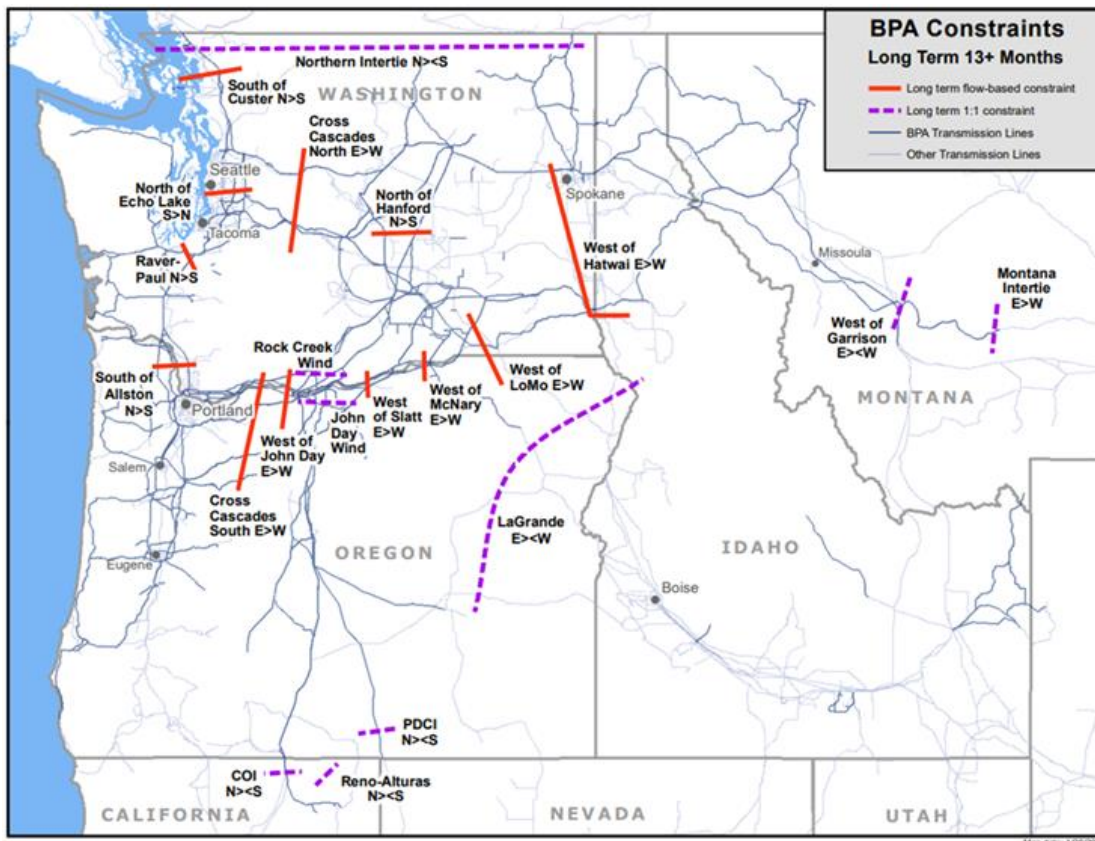
To get to PGE's system, power generated or purchased from remote locations must travel through different paths and flowgates on the region's transmission system. A flowgate is a collection of transmission lines and facilities that collectively start in a geographically similar area and terminate in a different geographically similar area. These flowgates are typically operated by BPA and are shown in **Figure 65**. The flowgates that currently have the most significant impact on PGEM's transmission rights portfolio are the South of Allston, Raver Paul, West of John Day and Cross Cascades South, all of which are constrained, with little or

²⁷¹ See BPA Presentation, TSEP Study Process Update, September 2022 p. 6: <https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/09-20-22-cluster-study-improvements-customer-update.pdf>

²⁷² Available at: [https://www.bpa.gov/energy-and-services/transmission/acquiring-transmission/tsep#:~:text=The%20TSR%20Study%20and%20Expansion,Network%20Open%20Season%20\(NOS\).](https://www.bpa.gov/energy-and-services/transmission/acquiring-transmission/tsep#:~:text=The%20TSR%20Study%20and%20Expansion,Network%20Open%20Season%20(NOS).)

no ATC. Additionally, BPA has identified the need for two new flowgates that will directly impact PGE’s ability to access new resources over the region’s transmission system. One flowgate would be in the central Oregon area and the other would bisect PGE’s service area in the Portland metropolitan area. PGE will continue to engage collaboratively with BPA as the paths are developed.

Figure 65. Northwest transmission lines and flowgates on BPA system



The following summarizes the most significant flowgates and paths affecting energy delivery from remote resources to PGE’s service area.

- Some amount of energy from the majority of PGE’s generating resources flow across the constrained South of Allston flowgate. This flowgate is most constrained during heavy summer and heavy winter loading periods.
- A portion of the energy flowing from PGE’s remote resources flows across the West of Cross Cascades South (WOCS) flowgate and, as it travels to loads in the PGE area, it flows over the West of John Day and Raver-Paul flowgates. The WOCS flowgate is most constrained during heavy winter loading, while the West of John Day and Raver-Paul flowgates are typically most constrained during heavy spring and summer loading. PGE’s

Bethel-Round Butte 230 kV transmission line is part of the WOCS path, although it is currently considered to have a de minimis impact on path flows.

- Energy from PGE’s resources in Montana first flow over the West of Garrison flowgate before reaching several other flowgates on the way to PGE’s load in the Willamette Valley.

9.3.2 Regional transmission resources are largely constrained

Some paths, like West of Garrison, are designed to operate close to their limits, while others are not; the latter group presents areas on the system where PGE sees particular importance in continuing to study, develop and possibly construct new transmission.

Figure 66 lists the Total Transmission Capability (TTC) and ATC on BPA flowgates that affect the delivery of off-system resources to PGE. This table highlights a constrained regional transmission system, especially on transmission paths impacting energy delivery outside the PGE service area.

Figure 66. Long-term firm available transfer capacity, less pending queued requests on the BPA system (as of January 27, 2023)

Path Name	TTC	LONG-TERM FIRM AVAILABLE TRANSFER CAPABILITY (ATC) LESS PENDING QUEUED REQUESTS									
		2024	2025	2026	2027	2028	2029	2030	2031	2032	
South of Allston N>S	2115	(477)	(502)	(903)	(1038)	(1274)	(1422)	(1519)	(1696)	(1798)	
Cross Cascades North E>W	10250	(4021)	(2807)	(3628)	(4307)	(4552)	(5182)	(5247)	(5388)	(5924)	
West of Lomo E>W	4200	(13)	(108)	(153)	(416)	(412)	(408)	(404)	(527)	(523)	
Cross Cascades South E>W	7500	(1502)	(2691)	(3609)	(415)	(4883)	(5858)	(5924)	(6120)	(6445)	
North of Hanford N>S	4450	211	113	(356)	(450)	(588)	(668)	(616)	(577)	(539)	
Raver-Paul N>S	1450	(140)	(270)	(568)	(707)	(777)	(875)	(983)	(1043)	(1122)	
West of McNary E>W	5230	235	(335)	(1527)	(1698)	(1681)	(1657)	(1660)	(1607)	(1584)	
West of Slatt E>W	4670	392	258	(395)	(526)	(573)	(609)	(663)	(657)	(695)	
West of John Day E>W	4530	(495)	(1134)	(1679)	(2304)	(2756)	(3433)	(3545)	(3831)	(4133)	
South of Custer N>S	900	(1169)	(1026)	(1056)	(1054)	(1052)	(1050)	(1048)	(1048)	(1046)	
West of Hatwai E>W	3650	(444)	(412)	(939)	(910)	(880)	(850)	(820)	(1033)	(1004)	
North of Echo Lake S>N	2800	(1129)	(213)	(385)	(659)	(659)	(659)	(659)	(659)	(659)	
PATH NAME	TTC MW	2024	2025	2026	2027	2028	2029	2030	2031	2032	
AC Intertie N>S	2725	(447)	(497)	(597)	(597)	(597)	(1197)	(1197)	(1197)	(1197)	
AC Intertie S>N	795	795	795	495	14	(286)	(586)	(1736)	(1736)	(2486)	
Northern Intertie N>S	2150	(200)	(200)	(200)	(200)	(200)	(200)	(200)	(200)	(200)	
Northern Intertie S>N	1120	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	(50)	
DC Intertie N>S	3100	(609)	(458)	(458)	(458)	(458)	(458)	(458)	(458)	(458)	
DC Intertie S>N	1904	1704	1704	1704	1704	1704	1704	1704	1704	1704	
LaGrande E>W	413	126	73	73	73	73	73	73	73	73	
LaGrande W>E	350	(180)	(180)	(180)	(180)	(180)	(180)	(180)	(180)	(180)	
Montana Intertie E>W	1930	112	112	144	144	144	144	144	144	144	
RATS N>S	300	(231)	(231)	(231)	(231)	(231)	(231)	(231)	(231)	(231)	
RATS S>N	300	281	281	281	0	0	0	0	0	0	
John Day Wind Gen	1255	149	149	99	99	99	99	99	99	99	
Rock Creek Wind Gen	1200	176	176	174	174	177	177	177	177	264	
West of Garrison E>W	1618	(985)	(1390)	(1490)	(1490)	(1490)	(1490)	(1490)	(1490)	(1490)	
West of Garrison W>E	931	14	13	11	10	10	10	10	10	10	

9.3.3 Regional transmission service request process

9.3.3.1 BPA TSR study and expansion process (TSEP)

BPA performs annual TSEP studies that combine various long-term Transmission Service Requests (TSRs) from transmission customers into a single study. The TSEP process is designed to obtain financial commitments from transmission customers before new facility construction. The cluster study process analyzes the impacts of the TSRs and new transmission facility requirements on an aggregated basis.

A TSR submitted to BPA could result in TSEP cluster study results with costly upgrades and completion dates of 10 years or longer. For example, the cost of the Montana-to-Washington upgrade project identified in the 2020 TSEP study was estimated at \$1.4 billion and the earliest completion date was estimated to be 2030. It will enable an incremental 500 MW transmission service from East to West across the West of the Garrison path. PGE will likely see more high-cost and long lead-time proposals in the constrained areas of BPA's system, especially the South-of-Allston and Cross Cascades transmission areas.

9.3.3.2 2019 BPA TSEP study

In June 2019, BPA published the results of the 2019 TSEP Cluster Study. The Cluster Study comprised 105 TSRs with an associated demand of 3,993 MW. Seven BPA transmission customers submitted 59 TSRs that listed PGE as a Point of Delivery (POD) with a total transmission demand of 1,356 MW. Of the 59 TSRs submitted, 40 remain in active status. The results of those 40 active TSRs are listed in **Table 42**, including the TSR status and the required upgrade project(s). These results indicate the cost and timing of future upgrades for the incremental transmission across BPA to PGE's service area.

9.3.3.3 2020 BPA TSEP study

In May 2020, BPA published the 2020 TSEP Cluster Study results. The cluster study comprised 62 TSRs with an associated demand of 3,871 MW. Five BPA transmission customers submitted 24 TSRs that listed PGE as a POD with a total transmission demand of 1,713 MW. Of the 24 TSRs submitted, seven remain in active status. The results of those seven active TSRs are listed in **Table 42**, including the TSR status and the required upgrade project(s). These results indicate the cost and timing of future upgrades for the incremental transmission across BPA to PGE's service area.

9.3.3.4 2021 BPA TSEP study

In June 2021, BPA published the 2021 TSEP Cluster Study results. The cluster study comprised 116 TSRs with an associated demand of 5,832 MW. Eleven BPA transmission customers submitted 37 TSRs that listed PGE as a POD with a total demand of 1,851 MW. Of the 37 TSRs submitted, 26 remain in active status. The results of those 26 active TSRs are listed in **Table 42**, including the status and the required upgrade project(s). These results indicate the cost and timing of future upgrades for the incremental transmission across BPA to PGE's service area.

9.3.3.5 2022 BPA TSEP study

In June 2022, BPA published the 2022 TSEP Cluster Study results. The cluster study comprised 144 TSRs with an associated demand of 11,118 MW. 49 TSRs submitted listed PGE as a POD, with 4,515 MW requested. Of the 49 TSRs submitted, 32 remain in active status. **Table 42** lists the results of those 44 active TSRs, including the status and the required upgrade project(s). These results indicate the cost and timing of future upgrades for the incremental transmission across BPA to PGE's service area.

TSRs submitted to BPA, in the 2022 TSEP, for delivery to PGE's system resulted in cluster study results that identified costly upgrades and completion dates of 10 years or longer. **Table 42** summarizes BPA upgrades required to enable delivery of power to PGE's system from the five resource zones based on geographic relationship to generic resources modeled in this IRP.

Table 42. BPA identified upgrades by resource/generation zone

Resource zones	BPA path	Upgrade(s) required BPA TSEP	(Cost \$M)	Estimated energization date
Christmas Valley Solar	1. South of Allston & Raver-Paul	1. Schultz-Wautoma Series Capacitor Project	1. n/a	1. 2024
	2. South of Allston		2. \$109.2	2. 2030
	3. Cross Cascades North	2. Ross-Rivergate 230 kV Rebuild Project	3. \$196.1	3. 2030
	4. Cross Cascades South		4. \$233	4. 2030
	5. Subgrid Portland-Pearl-Keeler		5. \$9.1	5. TBD
		3. Cross Cascades North Reinforcement Project	6. \$382.21	6. 2033
			7. Impact to Third-Party Transmission System (Intertie: PGE, PacifiCorp)	7. Impact to Third-Party Transmission System (Intertie: PGE, PacifiCorp)
				8. n/a

Resource zones	BPA path	Upgrade(s) required BPA TSEP	(Cost \$M)	Estimated energization date
	6. Subgrid Central Oregon South 7. Impact to Third-Party Transmission System (Intertie: PGE, PacifiCorp) 8. Subgrid-Impact to Third-Party Transmission System (PacifiCorp: South Oregon 230 kV network between Chiloquin, Klamath Falls and Alvey) 9. Subgrid -Impact to Third-Party Transmission System (PGE: North of Sherwood)	4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. Central Oregon South 500 kV Project 7. Impact to Third-Party Transmission System (Intertie: PGE, PacifiCorp) 8. Impact to Third-Party Transmission System (PacifiCorp: South Oregon 230 kV network between Chiloquin, Klamath Falls and Alvey) 9. Impact to Third-Party Transmission System (PGE: North of Sherwood)	8. n/a 9. TBD	9. TBD
Gorge Wind	1. South of Allston & Raver-Paul 2. South of Allston 3. Cross Cascades North 4. Cross Cascades South 5. Subgrid Portland-Pearl-Keeler	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project	1. n/a 2. \$109.2 3. \$196.1 4. \$233 5. \$9.1 6. \$35.39 7. TBD	1. 2024 2. 2030 3. 2030 4. 2030 5. TBD 6. 2028 7. TBD

Resource zones	BPA path	Upgrade(s) required BPA TSEP	(Cost \$M)	Estimated energization date
	6. Raver-Paul 7. Subgrid -Impact to Third-Party Transmission System (PGE: North of Sherwood)	4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. BPA Chehalis to Cowlitz tap 230 kV Rebuild Project 7. Impact to Third-Party Transmission System (Portland General Electric: North of Sherwood)		
SE WA Wind	1. South of Allston & Raver-Paul 2. South of Allston 3. Cross Cascades North 4. Cross Cascades South 5. Subgrid Portland-Pearl-Keeler 6. Raver-Paul 7. Subgrid -Impact to Third-Party Transmission System (PGE: North of Sherwood)	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Cross Cascades North Reinforcement Project 4. Big Eddy-Chemawa 500 kV Rebuild Project 5. Pearl-Sherwood-Mcloughlin Reinforcement Project 6. BPA Chehalis to Cowlitz tap 230 kV Rebuild Project 7. Impact to Third-Party Transmission	1. n/a 2. \$109.2 3. \$196.1 4. \$233 5. \$9.1 6. \$35.39 7. TBD	1. 2024 2. 2030 3. 2030 4. 2030 5. TBD 6. 2028 7. TBD

Resource zones	BPA path	Upgrade(s) required BPA TSEP	(Cost \$M)	Estimated energization date
		System (Portland General Electric: North of Sherwood)		
Off-Shore Wind	1. South of Allston & Raver-Paul 2. South of Allston 3. Cross Cascades North 4. Cross Cascades South 5. Subgrid South Oregon Coast 6. Subgrid -Impact to Third-Party Transmission System (PGE: Santiam-Bethel & North of Sherwood)	1. Schultz-Wautoma Series Capacitor Project 2. Ross-Rivergate 230 kV Rebuild Project 3. Big Eddy-Chemawa 500 kV Rebuild Project 4. Pearl-Sherwood-Mcloughlin Reinforcement Project 5. Southern Oregon Coast Reinforcement Project 6. Impact to Third-Party Transmission System (Portland General Electric: Santiam-Bethel & North of Sherwood)	1. n/a 2. \$109.2 3. \$196.1 4. \$233 5. 903.66 6. TBD	1. 2024 2. 2030 3. 2030 4. 2030 5. 2033 6. TBD
Montana Renewables	1. West of Garrison E>W	1. M2W	1. \$350M	1. 2030
Projects, cost and energization dates from BPA's 2022 TSEP				

Capacity limits from the generic resource zones were developed based upon PGE’s experience with ATC, transmission that may be acquired by developers and the results of the 2022 TSEP.

9.3.3.6 Montana transmission

Wind resources in Montana are attractive because of their higher capacity factors and diverse seasonal output compared to the Washington and Gorge wind currently in PGE's resource portfolio. HB 2021 decarbonization requirements and coal restrictions provide an opportunity to evaluate Montana resources and the potential repurposing of PGE's existing Colstrip transmission rights to serve future PGE load from a renewable resource over the same transmission currently used to deliver Colstrip output to PGE's system.

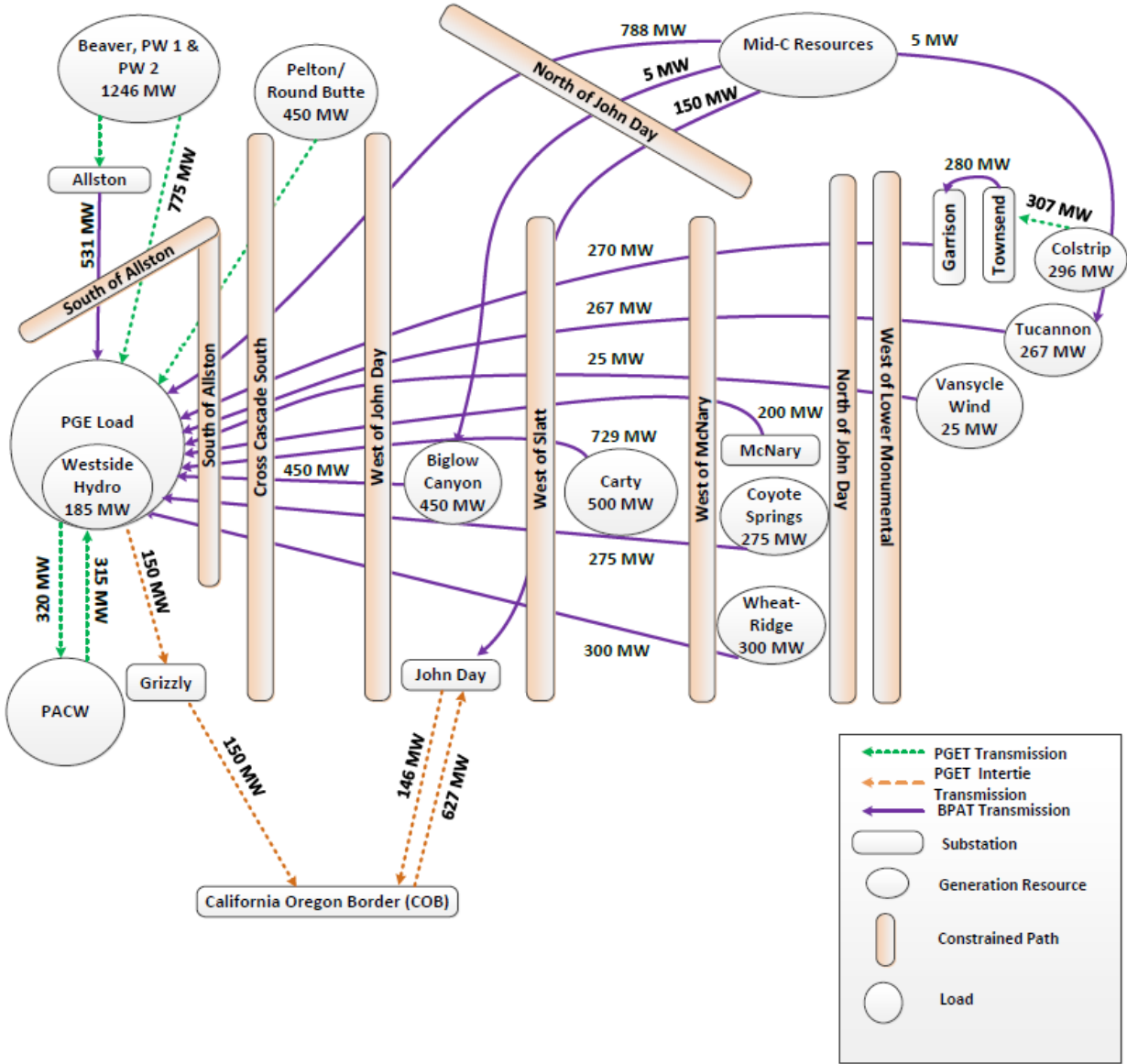
9.3.4 PGE merchant transmission portfolio

PGEM is responsible for obtaining the transmission service needed to serve PGE retail customer load and for scheduling the use of that transmission most efficiently and economically to meet demand. The transmission portfolio facilitates PGE's ability to: (1) deliver energy from generating resources to load during all seasons, (2) participate in regional energy markets and (3) optimize PGEM's energy portfolio.

PGEM's transmission portfolio consists primarily of capacity rights on the PGET and BPA systems, including the NWACI, the Colstrip Transmission System and Montana Intertie, enabling energy pathways through and into the Pacific Northwest. Due to the geographic location of PGE's service area compared to where most generation resources are or will be located, most of PGE's generation resources are outside of PGE's service area. Historically, PGEM has relied on BPA transmission rights to import power from remote generation resources and to deliver power purchases to serve PGE's load. PGEM also holds transmission rights to access the Pacific Northwest Mid-Columbia (Mid-C) wholesale power hub, which PGE relies on for balancing load, meeting peak demand and enabling economic transactions. See **Figure 67** for an overview of PGEM's transmission portfolio.

Figure 67 provides a snapshot of PGEM-contracted transmission scheduling rights to support the delivery of PGE-owned generation, power purchase agreements (PPAs) and market purchases. The tan bars in **Figure 67** represent BPA-managed flowgates. Due to the electron flow-based nature of the interconnected grid, constraints on these flowgates create limits on transfer capability to PGE's load centers, irrespective of where the source generation is located, whether on BPA's system or further away. Additionally, as described in this chapter, BPA is looking to establish new flowgates that will impact flows to and through PGE's service area.

Figure 67. Snapshot of PGE’s market function transmission portfolio with generation resources and transmission



PGEM may also use its contracted transmission rights to access the Western EIM through transmission with Avista Corp, BPA, CAISO, Northwestern Montana, PacifiCorp, Puget Sound Energy, Seattle City Light and Tacoma Power. Access to the EIM enhances PGE’s ability to efficiently integrate variable resources on an intra-hour energy basis and deliver the least-cost energy supply to customers. As additional wholesale market options develop in the West, like the CAISO’s Extended Day Ahead Market or the Southwest Power Pool’s Markets +, PGE may use its transmission portfolio to engage in these future opportunities.

9.4 Options to address transmission need

As discussed earlier in this chapter, there is a limited amount of long-term firm and conditional firm TSRs in study or confirmed status across BPA's system, deliverable to PGE without costly system upgrades. The total amount of each transmission product available is in the following table, roughly 1,800 MW combined (**Table 43**). At the same time, PGE expects to add approximately 3,000 to 4,000 MW of non-emitting resources to meet HB 2021 goals. In many scenarios, the resources needed to meet the adequacy and non-emitting energy goals require more transmission than is available.

Table 43. Transmission service requests on BPA pointed to PGE²⁷³

Conditional firm	Long-term firm
1,128 MW	690 MW

This need for additional generating resources to serve load in compliance with state law in contrast with a lack of available long-term transmission options creates a near-term need within PGE's resource plan and points to a long-term need that is outside of the IRP action window that, given the long development cycles necessary for transmission, warrant early engagement.

9.4.1 Proxy transmission options identify transmission need

To maintain system adequacy and achieve GHG reductions, PGE has analyzed transmission proxy options as part of the 2023 IRP. Like resource proxies, transmission proxies describe general characteristics that may be found on the market. If a portfolio selects a transmission proxy, that indicates that the model sees a need to expand PGE's transmission network for GHG reduction or resource adequacy purposes. PGE's portfolio modeling indicated that transmission need existed (and proxies were optimal) to meet BPA system need through the SoA proxy and to expand access to regional resources.

For the 2023 IRP, the capacity expansion model ROSE-E has two types of transmission proxies from which to choose. The choices in **Table 44** are 1) a Northwest transmission upgrade and 2) purchasing the rights on a transmission line to Wyoming or the Desert Southwest.

²⁷³ Values represent all PGE resource zones and are based on the BPA TSEP.

Table 44. Proxy transmission options²⁷⁴

Proxy transmission option	Accompanying resource	Details
South of Allston upgrade (available as early as 2027 in most portfolios, \$1.97/kilowatt (kW)-month)	IRP proxy resources	Increased transfer capacity on PGE’s share of South of Allston via upgrade. Allows up to 400 MW of additional capacity for regional proxy resources.
Generic proxy transmission (Tx) (Available as early as 2026 in select portfolios \$20.46/kW-month to WY, \$23.04/kW-month to SW)	Wyoming wind	Model can select a Tx path to access Wyoming wind.
	Desert SW Solar	Model can select a Tx path to access Desert Southwest solar.

The South of Allston upgrade alleviates congestion on the BPA system and unlocks up to 400 MW of Northwest proxy resources, like Gorge Wind or Christmas Valley solar. It is available for selection as early as 2027 in most portfolios, indicating that this need could be alleviated by the acquisition of additional rights and, eventually, the exploration of new builds or upgrades.

Transmission to Wyoming or the Desert Southwest adds an equivalent amount of transmission capacity and a wind farm in Wyoming or a solar facility in southern Nevada (for example, 200 MW of Wyoming transmission includes 200 MW of Wyoming wind). The Nevada and Wyoming transmission proxies are available for portfolio selection as early as 2026 in select portfolios, again indicating that this identified need could be met through transmission rights, partnership in projects currently being developed, and/or additional development on a longer-term time horizon. These transmission projects have the same characteristics as the other IRP proxy resources, though their differing location changes their generation profiles. Additional information about these projects, including monthly capacity factors and other details, is in **Chapter 8, Resource options**.

Beyond providing access to renewables, the IRP assumes that transmission to Wyoming or the Desert Southwest also provides market capacity at a 1-to-1 ratio (every MW of

²⁷⁴ Saadi, Fadl H, et al. "Relative Costs of Transporting Electrical Chemical Energy." *Energy & Environmental Science*, *Energy & Environmental Science*, no. 3, 29 Jan. 2018, pp. 469-475.

transmission acquired provides 1 MW of effective capacity). This is a simplifying assumption for modeling purposes only and capacity additions will be driven by access to additional climate zones through specific transmission projects and the resources within the climate zones. Additional planning for capacity will be informed by the concurrent development of the Western Resource Adequacy Program (“WRAP”), a regional day-ahead market (EDAM with CAISO or Market Plus with SPP), as well as the development of new program and storage technologies. The actual operational capacity needs will be revisited as regional conversations and study processes progress.

9.4.1.1 Transmission as a gateway to diversification

Transmission expansion in the IRP falls into two categories, Northwest expansion and expansion to other regions. The Northwest expansion increases access to resources located in the Northwest. Portfolio selection of regional proxy transmission allows access to additional climate zones and markets that could offer diversified resource options across the planning horizon.²⁷⁵

The concept of regional load diversity as a benefit is embedded in the design of the WRAP. The WRAP is planning to standardize peak capacity planning for utilities operating in the WECC region that are not within an RTO. This program will facilitate the daily exchange of resources and obligations from resources in regions that are in excess capacity to regions that find themselves in deficit. As a key component of this program’s many benefits, participating utilities would be able to reduce their individual Planning Reserve Margin (“PRM”) based on the regional load diversity. Each utility would have had to procure or build to a much higher capacity target had it not been for the transparency and standardization that the WRAP offers.

Underlying the WRAP is the ability of each of these diversified regions to transmit energy back and forth. More benefits would be associated with this program if there were more transmission capacity between the regions.

Further discussion of the WRAP can be found in **Section 3.2, Regional planning: resource adequacy**, including program details, benefits and applicability in this and future IRPs.

²⁷⁵ This does not preclude PGE from exploring transmission options to other regions.

9.4.2 Other transmission options

The transmission options tested in the 2023 IRP are proxy resources. Other transmission options, either to Northwest resource locations or to other regions, may also be available. Non-wire solutions may also be available to assist with transmission congestion. Including proxy transmission resources does not preclude PGE from exploring other transmission and/or non-wire options in future planning and acquisition work.

9.4.3 Bethel to Round Butte upgrade for future load service

With the recognition that transmission system capacity inventories on the BPA system are or are expected to be fully allocated, PGE must look for other commercial transmission development opportunities that could enable the affordable delivery of these new non-emitting resources to PGE's service area. It is widely accepted that most new resources will be located east of PGE's service area, on the other side of the Cascade Mountain Range. PGE owns one transmission line that crosses the Cascades, the Bethel-Round Butte 230 kV line that runs from approximately the Salem area to Round Butte near Madras, OR.

The Bethel-Round Butte 230 kV line was conceived in the 1960s as part of the Pelton-Round Butte Hydro project to deliver the output of the Pelton-Round Butte hydro facility to PGE's load in the Willamette Valley. Most of the line is constructed on wooden H-frame structures and is prone to damage from significant weather events, including wind, snow/ice and wildfires. During the wildfire season in 2020, a portion of the Bethel-Round Butte line was damaged by fire and had to be repaired, taking the line out of service for several months while those repairs were made, resulting in an extended transmission outage.

The eastern terminus of the Bethel-Round Butte 230 kV line, at Round Butte Substation, is then connected to the NWACI via the Round Butte-Grizzly 500 kV line. The Grizzly substation, jointly owned by PGE and BPA, is a significant substation on the NWACI. The NWACI is a collection of 500 kV transmission facilities that run from the John Day substation near the Columbia River to two different substations near the California-Oregon border, commonly referred to as the "COB" scheduling interface with the California Independent System Operator (CAISO). The NWACI facilities are primarily owned by PGE, PacifiCorp and BPA and jointly operated as a single path by BPA. Idaho Power will also have a scheduling point presence on the NWACI according to the term sheet announced by BPA, PacifiCorp and Idaho Power when BPA withdrew from being a funding partner for the Boardman to Hemingway project.

The Bethel-Round Butte 230 kV line is an existing facility with an existing Right of Way (ROW) across the Cascade Mountains. The acquisition and permitting of greenfield transmission line ROWs is the single most challenging part of developing new transmission infrastructure in

Oregon. For example, Idaho Power and PacifiCorp's Boardman to Hemingway project has been in various stages of the permitting process for nearly two decades. While there may need to be some additional ROW changes made to the existing Bethel-Round Butte ROW, because PGE already owns the ROW, it is expected to be significantly less complex than a new greenfield ROW acquisition would be.

Increasing the transfer capability between PGE's system and the NWACI will provide PGE with significant incremental direct access to solar and wind resource-rich parts of Oregon and connections with neighboring transmission providers and western markets.

Rebuilding the Bethel-Round Butte line from 230 kV to 500 kV would require replacing all the wooden H-frame structures currently in place with significantly taller and more robust steel lattice towers that are less susceptible to wildfire impacts.

PGE/603

**U.S. Department of Energy, Dynamic Line
Rating (June 2019)**



U.S. DEPARTMENT OF
ENERGY

Dynamic Line Rating

June 2019

United States Department of Energy
Washington, DC 20585

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Executive Summary

The electric grid is a complex system-of-systems that is responsible for providing safe, reliable, and cost-effective electricity to customers. If a transmission system component, such as an overhead line, is operating at its physical limit, system operators may choose to run a more expensive generator over a less expensive one in order to meet safety and system reliability standards. The events and costs associated with the suboptimal commitment and dispatch of generators is known as congestion. Congestion costs can be quite substantial; the sum of real-time congestion cost among major U.S. system operators in 2016 was \$4.8 billion.

Traditional solutions to alleviating congestion include expanding, upgrading, or rebuilding the electric infrastructure. While these long-lead-time solutions may be needed in the long term, new and innovative technologies such as dynamic line rating (DLR) may provide congestion relief in the near term at lower expense. DLR systems are one of many options for addressing grid congestion; other solutions such as power-flow controllers, energy storage, distributed energy resources, and demand response also play key roles in modernizing the grid. An additional benefit of implementing DLR is increased situational awareness of the transmission system and the potential for condition-based monitoring of transmission lines.

The maximum power flow capacity on a transmission line is limited by heating considerations to maintain safe and reliable operating conditions. These static line ratings (SLRs) are usually calculated using conservative assumptions about the transmission-line operating environment, producing an inflexible constraint that does not take advantage of changing or favorable environmental conditions (e.g., wind cooling) that allow for greater transmission usage. DLR is a blanket term for the many different technologies and methodologies for determining conductor thermal ratings in a more-dynamic fashion using improved, more granular, or real-time data. At its core, DLR systems help system operators determine the prevailing current-carrying capacity limits of transmission lines to relax constraints based on SLRs.

Over the past several decades, a diverse set of technologies, methods, and systems have been developed to enable DLR. Each system and method has advantages and disadvantages when it comes to accuracy, reliability, capital cost, ease of installation and integration, and maturity. Despite DLR's potential for realizing cost savings and its ability to increase grid reliability and resilience, several challenges remain that prevent its widespread adoption. Implementation of DLR must ensure that new hazards are not created and be tempered with consideration for other system limitations and the potential for unintended consequences.

The U.S. currently lags behind other countries in the deployment of some advanced transmission technologies, such as DLR. One of the variables is the difference in regulatory environments; the U.S. provides transmission owners little incentive to deliver more power over existing lines or to reduce transmission congestion. Additionally, wholesale electricity markets play an important role in guiding the operating, planning, and investment decisions of asset owners and developers. Broad adoption of DLR will influence the performance of

electricity markets, impacting the profitability or viability of specific generation sources. While the impact of DLR schemes on different generation technologies cannot be generalized, there are instances where specific sources can be advantaged or disadvantaged.

Overall, experience with DLR pilot studies and demonstrations have shown capacity increases, but the outcomes are difficult to extrapolate beyond the targeted lines. Numerous power grid stakeholders have also expressed support for DLR, but technical, market, and regulatory challenges remain that must be addressed to facilitate broader adoption. Further research is needed to better understand the economic benefits, costs, and impacts of wide-spread DLR adoption, especially at the regional or national level. Additional demonstrations and pilot studies can also provide utilities and other stakeholders with increased confidence in DLR methods and systems, reduce technology risk and uncertainty, and help ascertain the value of ancillary benefits such as improved situational awareness.

Abbreviation Reference

AAR	Ambient Adjusted Rating
AEP	American Electric Power
CAISO	California Independent System Operator
CIGRE	International Council on Large Electric Systems
DERs	distributed energy resources
DLR	dynamic line rating
DOE	Department of Energy
DTE	Detroit Edison (DTE Energy)
ERCOT	Electricity Reliability Council of Texas
FERC	Federal Energy Regulatory Commission
IEC	International Electrotechnical Commission
IEEE	Institute of Electrical and Electronics Engineers
ISO	independent system operator
ISO-NE	Independent System Operator New England
MISO	Midcontinent Independent System Operator
NERC	North American Electric Reliability Corporation
NYISO	New York Independent System Operator
NYP&A	New York Power Authority
REE	Red Electrica de Espana
ROE	return on equity
RTE	Réseau de Transport d'Électricité
RTO	regional transmission organization
SCADA	supervisory control and data acquisition
SIL	surge impedance load
SLR	static line rating
TCF	transmission capacity forecasting
TDU	transmission and distribution utility
WOW	Wind on Wires
WPPI	Wisconsin Public Power Inc.



DYNAMIC LINE RATING

Table of Contents

- II. Introduction 1
 - State of the U.S. Electric Grid..... 1
 - Transmission Congestion 2
 - Thermal Limits of Transmission Lines..... 3
 - Static Line Ratings 4
 - Dynamic Line Ratings 4
 - Potential Benefits of Dynamic Line Rating..... 5
 - Improved Congestion Management..... 5
 - Increased Reliability and Resilience..... 6
- III. State of DLR Technology 7
 - Sensing and Monitoring 7
 - Communications 10
 - Analytics Engine 10
 - Integration 11
 - Barriers and Limitations..... 12
 - Accuracy and Reliability 13
 - Operational Knowledge and Experience 13
 - Cost of Implementation 14
 - Monetization of Benefits 15
- IV. Stakeholder Views and System Impacts 16
 - Case Studies 17
 - Stakeholder Views 18
 - Impact on Different Generation Technologies 21
 - Other System Impacts and Considerations 22
- V. Conclusions 23
- VI. Bibliography 25

II. Introduction

The electric grid is a complex system-of-systems that is responsible for providing safe, reliable, and cost-effective electricity to customers. Developed and built over the last 125 years, the U.S. electric power system has been called the biggest machine in the world. The electric transmission and distribution infrastructure and the energy delivery it facilitates represent an essential fabric of the modern economy. Whether the grid is powering manufacturing and essential health services or our computers and cell phones, its omnipresence is felt most when it suddenly fails. Recently, investments in the grid have focused on improving its reliability, efficiency, and resiliency to meet the growing dependence on electricity across all sectors. This is a complicated task where generation and use must be balanced continuously, the ability to store electricity cost-effectively is limited, and energy consumption patterns are ever-changing.

To serve our expectation of continuous access to electricity, a collection of generators, towers, wires, transformers, switches, and poles were erected and stitched together. The electric power system is typically divided into the categories of generation, transmission, distribution, and end-use. In addition to the physical infrastructure, a centralized control paradigm was developed where large remote generators are coordinated and dispatched to ensure the reliable delivery of electricity to end-users through a vast network of high-voltage transmission lines and lower-voltage distribution systems. Balancing authorities and system operators have been tasked with the dispatch of generators to meet all loads while ensuring reliability and minimizing costs, a process known as security-constrained economic dispatch.

If a transmission system component, such as an overhead line, is operating at its physical limit, balancing authorities may choose to run a more expensive generator over a less expensive one in order to meet safety and system reliability standards. The events and costs associated with the suboptimal commitment and dispatch of generators are known as congestion [1]. Balancing authorities and system operators attempt to mitigate congestion by forecasting demand and generator availability in the short term (e.g., through day-ahead and hour-ahead markets) and identifying system needs in the long term (e.g., through multi-year resource, transmission, and distribution planning).

Ultimately, the goal of the electric grid is to deliver safe, reliable, and cost-effective electric power. For each part of the system, there are numerous tools, technologies, and approaches to help accomplish this goal. In the distribution system, vegetation management and distribution automation are used to prevent and recover from interruptions. In the transmission system, a variety of contingencies are analyzed and planned for while phasor measurement units provide wide-area situational awareness. Dynamic line rating (DLR) is one of several tools that can help address challenges with transmission operation, especially congestion management.

State of the U.S. Electric Grid

The U.S. electric grid contains more than 200,000 miles of high-voltage transmission lines and roughly 5.5 million miles of local distribution lines that operate within a patchwork of Federal,

State, Tribal, and local regulatory jurisdictions. However, the reliability of the bulk power system (i.e., large generators and the transmission network) generally fall under the purview of the Federal Energy Regulatory Commission (FERC) and the North American Electric Reliability Corporation (NERC), which issue and enforce mandatory reliability standards [2]. Several professional organizations, such as the Institute for Electrical and Electronics Engineers (IEEE), International Electrotechnical Commission (IEC), and the International Council on Large Electric Systems (CIGRE), also issue guidelines and technical standards. These various standards provide the basis for the bulk power system that is key to ensuring the safe and reliable delivery of electricity.

Climate in the U.S. spans a vast spectrum, ranging from tropical to subarctic to desert, depending on location. This means the electric power system experiences many different temperatures and weather conditions daily and throughout the seasons of the year. Additionally, the demand for electricity also changes by hour, day of the week, and season with times of peak-load varying by region. In hot climates, home air-conditioning usage increases the overall load needed in the late afternoon during the hottest part of the year. In cold climates, home heating increases loads in mid-mornings and mid-evenings during the coldest part of the year. Weather conditions are also important to grid operations since they affect system loads and extreme weather events can result in damage to infrastructure assets.

Parts of the electric grid are more than a century old, and 70 percent of the transmission lines and large power transformers are more than 25 years old [3], [4]. Along with aging infrastructure, the electric power system is evolving from one consisting of predominantly dispatchable generation sources (e.g., nuclear, coal, natural gas, and hydroelectric) to one having increasing percentages of variable generation sources (e.g., wind and solar). The deployment of variable generation varies widely across the U.S. as well as the ability of the regional grid infrastructure to accommodate them. Additionally, the centralized control paradigm where generation is dispatched to serve variable customer loads is being challenged with greater deployment of distributed energy resources (DERs). The increasing adoption of electric vehicles will also introduce load growth and potentially increased variability. These broad system changes have created a need for advanced solutions to help solve modern operational challenges.

Transmission Congestion

Transmission congestion occurs when changes in demand or generation result in power delivery that reach or exceed the physical capacity of the transmission network. Transmission constraint “refers either to [the limit placed on] a piece of equipment or an operational limit imposed to protect reliability that restricts these flows, or to a lack of adequate transmission capacity to deliver expected new sources of generation without violating reliability rules [1].” Power flows on transmission lines are limited for both electrical (e.g., voltage drop, phase, stability) and thermal (e.g., resistive heating, mechanical sag) reasons. Typically, these limits are calculated by system and planning engineers and applied by system operators to ensure safety and reliability. Transmission congestion results in generation commitment and dispatch decisions that vary from a lowest-cost basis, ultimately increasing the price of electricity.

In most organized wholesale markets, the locational marginal price of electricity (i.e., the price actually paid for electricity at different parts of the system) is calculated by adding the system marginal cost (i.e., the incremental cost of electricity to meet the last MWh of demand based on economic dispatch), the congestion component (i.e., the cost associated with the local dispatch of more expensive generation to relieve the constraint), and the marginal loss components (i.e., transmission losses associated with delivering the increment of electricity). While the settlement rules associated with these calculations vary slightly across the main wholesale markets, the result is the same: congestion costs are effectively paid for by the users of electricity.

Congestion costs can be quite substantial; between 2009 and 2017, California ratepayers' bills included \$683.5 million in congestion-related costs [5]. According to a 2018 U.S. Department of Energy (DOE) report, the sum of real-time congestion cost for 2016 among major system operators—specifically, the California Independent System Operator (CAISO), the Electricity Reliability Council of Texas (ERCOT), Independent System Operator New England (ISO-NE), Midcontinent Independent System Operator (MISO), New York Independent System Operator (NYISO), and PJM—was \$4.8 billion [6].

Traditional solutions to alleviating congestion include expanding, upgrading, or rebuilding the electric infrastructure. Transmission expansion projects in the U.S. totaled over \$20 billion every year since 2014 through 2016 [7]. Since most transmission infrastructure was built between the 1960s and the 1980s, these investments are needed to ensure grid reliability as the assets age. One estimate projects that transmission replacement costs alone will increase by \$1.2–3.2 billion per year over the next 10 years, assuming facilities need to be replaced after 60 to 80 years of operation [8]. Additionally, line reconductoring, which can be used in some situations to increase capacity on existing transmission right-of-way, can cost from \$1 million to \$8 million per mile depending on the voltage class of the line [9]. While these long-lead-time solutions may be needed in the long term, new and innovative technologies (e.g., DLR, demand response, power-flow controllers, DER, and energy storage) may provide congestion relief in the near term at lower expense.

Thermal Limits of Transmission Lines

A transmission line is referred to as being thermally limited when heating considerations set the maximum power flow capacity on the line. These thermal limits (i.e., maximum current carrying capacity at a given voltage) are determined based on the maximum operating temperature of the conductor that prevents premature aging and that limits conductor sag to maintain minimum clearances under the line for safety. Conductors expand at higher temperatures, lengthening the line and reducing the distance to the ground and other objects, which can result in arcing or faults if safe clearance distances are not maintained. Generally, the physical properties of the conductor (e.g., maximum temperature rating, electrical resistance, mechanical strength) and a set of environmental conditions (e.g., ambient air temperature, wind speed, solar radiation) are used to calculate thermal limits.

Static Line Ratings

Static line ratings (SLRs) are typically used by system operators in dispatch decisions to maintain safe operating conditions. SLRs are determined according to IEEE Standard 738, “Standard for Calculating the Current-Temperature Relationship of Bare Overhead Conductors” [10]. These thermal ratings are usually calculated using conservative assumptions about the transmission-line operating environment such as static weather conditions, average wind speeds and direction, average ambient temperatures, and solar conditions for summer and winter seasons. While these assumptions are not worst case (e.g., based on absolute maximum ambient temperatures, zero wind speed, or full solar exposure), there can be instances where the real ratings based on actual conditions are lower than SLRs, putting the conductor at risk for thermal damage and greater sag. Overall, SLRs produce an inflexible constraint that does not take advantage of changing or favorable environmental conditions that allow for greater transmission usage in many hours of the year.

Dynamic Line Rating

DLR is a blanket term for the many different technologies and methodologies for determining conductor thermal ratings in a more-dynamic fashion using improved, more granular, or real-time data. In principle, DLR uses the same heat-balance equations as SLR, but includes the more-sophisticated time varying component, as shown in [Figure 1](#). DLR can take various forms and includes dynamic thermal line ratings, ambient adjusted ratings (AARs), real-time thermal ratings, forecasted dynamic line ratings, and even analysis of existing lines with previously gathered data.

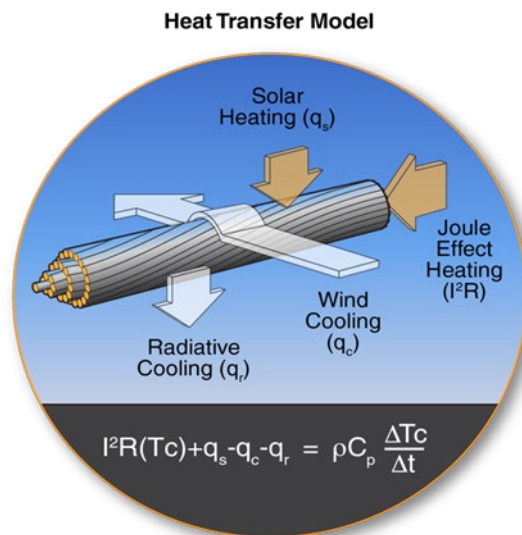


Figure 1: Heat-transfer model for a conductor.

DLR technologies have traditionally been bifurcated into weather-based and asset-based systems [11]. Weather-based systems focus on measurement of the environmental conditions that are direct variables in the heat-balance equations. Field data collected include wind speed and direction, ambient air temperature, solar radiation, and line current. Along with engineering design criteria, these parameters are used to calculate the maximum allowable

conductor current. Asset-based systems focus on measurement of the conductor itself and include local conductor temperature, position or tension, and line current. These parameters are used to establish relational results that are combined with the physical specifications of the conductor to calculate the maximum allowable conductor current.

A comparison of the different systems and methodologies can be found in the “State of DLR Technology” section of this report; a more detailed assessment is provided in literature [12]. While there are advantages and disadvantages of each system, the key distinction is whether the system provides information on conditions and physical parameters of a single point along a line or can be representative of the entire length of the line.

Potential Benefits of Dynamic Line Rating

The objective of all DLR systems is to help system operators determine, accurately and reliably, the prevailing current carrying capacity limits of transmission lines to relax constraints based on thermal considerations [13]. In some cases, the consideration of seasonal or monthly ratings may help defer some infrastructure investments made for economic reasons or increase the utilization of existing lines. DLR also has the benefit of improving reliability and resilience by providing grid operators with enhanced situational awareness of individual assets, enabling greater flexibility. DLR can be applied in a variety of circumstances and voltage classes, but is particularly well suited to manage congestion on older lines, such as those at 115, 138, and 230 kV. While new lines may be designed to avoid a thermal limit, use of DLR can still be beneficial by providing situational awareness and supporting asset management.

Improved Congestion Management

In the generator-unit commitment process, grid operators decide ahead of time which generators to start up or shut down based on expected electricity demand and transmission constraints. To perform the day-ahead security-constrained unit commitment effectively, generator availability and transmission line capacity must be estimated. DLR technology, enabled with transmission capacity forecasting (TCF) based on weather forecasting, can be used to predict a transmission line’s capacity hours or days ahead of time. By forecasting the expected transmission capacity more accurately, a more favorable commitment of generators in day-ahead markets and more efficient dispatch within real-time markets will be possible, thus reducing congestion costs.

The electric power system is becoming more dynamic with a need to make faster operational decisions based on more rapidly changing conditions. Real-time monitoring of the grid can support this need, especially as the mix of generation sources serving the country changes. For example, the growth in variable renewable generation, such as wind and solar, is introducing greater uncertainty and intermittency. The retirement of coal and nuclear plants and the addition of new natural gas plants are also changing power flows and reliability requirements for the system. When an unexpected event happens (e.g., an unplanned contingency, load- or wind-forecast error), transmission congestion can occur and grid operators may curtail generation [14]. DLR integrated into real-time operations can help better manage congestion and associated costs during these changes and events.

For example, ISO-NE realized significant consumer savings when it implemented AARs on transmission ties with New York during the 2018 “bomb cyclone.” At the time, much of the grid in the northeast was heavily congested due to high electricity demand and fuel supply constraints. ISO-NE issued an abnormal-conditions alert and increased their transmission line ratings to allow for greater capacity [15]. An ISO-NE report stated, “. . . the scheduling limit on the NY ties was increased from 1,400 to 1,600 MW. The increased limit was made possible by the cold conditions which helped to improve thermal transfer capability [16].”

It is widely accepted that implementation of DLR can provide congestion-management benefits. However, no comprehensive study has been conducted to assess the potential cost savings from widespread deployment of DLR in the U.S. across a variety of scenarios.

Increased Reliability and Resilience

Under NERC reliability rules, a power system must be operated so that it will remain stable despite the instantaneous loss of any single transmission line or generator (i.e., N-1 contingent). Grid operators and planners manage the system by ensuring there is enough spare capacity on other transmission lines and equipment so that a contingency will not overload those lines. In the event of overloads, relay settings may trigger protective actions that can lead to interruptions or outages. DLR can potentially improve reliability by calculating the true thermal limit for those lines and informing relay settings used to protect transmission equipment [9]. Furthermore, in cases where a customer’s supply might normally be disrupted to ensure system stability, the additional capacity from DLR can alleviate the situation and provide a means to avoid an outage, improving reliability metrics.

Another benefit of installing sensing and monitoring technologies like DLR is an increased situational awareness of the transmission system. Understanding when conditions may exceed constraints is critical in situations where lines may sag below clearances, making the system vulnerable to faults and safety hazards. Enhanced situational awareness can help ensure lines are not overloaded and, in effect, increase reliability metrics as well as protect the public from consequent issues of safety (e.g., fire or electric shock). Condition-based monitoring of transmission lines is also a possibility; rather than relying upon engineering assumptions and maintenance schedules, real-time status of the line can be used in decision making to mitigate component failures, boosting reliability.

FERC has stated that it understands resilience to mean “[t]he ability to withstand and reduce the magnitude and/or duration of disruptive events, which includes the capability to anticipate, absorb, adapt to, and/or rapidly recover from such an event [17].” Numerous power system events can cause disruptions, including component failure, human error, weather events, and damage—either unintentional or willful. Generally, methods, tools, and technologies that relax constraints on a system, give it more flexibility, or provide better situational awareness increase the resilience of the system. DLR can support more electric-delivery options during a disruption to mitigate load interruptions and facilitate recovery and restoration after an event.

Extreme events that cause electricity outages tend to have limited geographic scope; increasing transmission capacity to allow more power to be imported into a region from neighboring areas that are less affected by the event can increase grid resilience. DLR can be particularly beneficial during certain extreme weather conditions, such as the 2018 “bomb cyclone” and 2014 “polar vortex” events, where extremely low temperatures and wind chill caused high electricity demand and fuel prices, but also caused many generators to unexpectedly go offline due to equipment failures and fuel-supply constraints. DLR would allow grid operators to take advantage of the fact that colder temperatures and high winds in those events provided cooling that greatly increased the thermal limits of transmission lines.

In the recent FERC proceeding on power system resilience, all independent system operators explained the importance of transmission capacity for resilience. For example, the New York grid operator explained that “[m]aintaining and protecting existing interconnections between neighboring regions and continually assessing opportunities to improve interregional transaction coordination can bolster the resiliency of the grid throughout an interconnected region. These interconnections foster the opportunity for the Northeast and Mid-Atlantic markets to rely on a broader, more diverse set of resources to meet the overall needs of the region [18].”

III. State of DLR Technology

To operationalize DLR, several different technology components must be integrated into a system. The most fundamental is a means to measure the parameters that impact the transmission limits of a line. Obtaining these parameters can be accomplished through sensing and monitoring of either the conductor itself or environmental conditions. A communications channel must be established between the measurement apparatus and an analytics engine to transport data in a timely manner. The analytics engine, usually a software application, performs calculations or evaluations to translate measured parameters into information about the transmission line. Finally, the information from this process must be integrated into a control room or automated system where decisions are made.

Over the past several decades, a diverse set of technologies, methods, and systems have been developed to support DLR. Each system and method has advantages and disadvantages when it comes to accuracy, reliability, capital cost, ease of installation and integration, and maturity. Research efforts have focused on improving state-of-the-art technologies and addressing some of the barriers and limitations associated with implementing these different technologies and approaches.

Sensing and Monitoring

There are several ways to measure or determine the parameters that impact a transmission line. [Table 1](#) lists some of the common sensors and methods used for DLR, including advantages and disadvantages. As mentioned earlier, the primary approaches are divided into

monitoring either the conductor directly or the environmental parameters that affect line ratings. Direct conductor monitoring parameters, such as sag, tension, and clearance, are measurements used to calculate the conductor temperature. Generally, direct conductor monitoring approaches approximate the environmental conditions around the line, whereas environmental parameter monitoring approaches approximate the conductor conditions. The combination of measured and approximated parameters is used to dynamically rate the line.

Technology developers continue to seek the best combination of performance, cost, and ease of installation for sensing and monitoring approaches. Direct conductor monitoring tend to offer great accuracy and precision, but are challenged with installation and maintenance costs associated with adequately covering all spans or segments of a line. Some of the line-mounted sensor options may even require line outages, which impose additional costs. On the other hand, environmental parameter monitoring may be more cost-effective but are limited in accuracy by the location of weather stations and can face validation challenges. Both categories of approaches can be used in combination to complement one another in other solutions. While these various technologies and approaches have been verified in practice, the electric industry has not standardized or converged on the most accurate, efficient, or cost-effective methods for determining parameters.

Table 1: Common sensing and monitoring approaches for DLR.

	Measurement Parameter	Approach	Description with Advantages (+) and Disadvantages (-)
Direct Conductor Monitoring	Temperature	Ground-based Sensor	Devices like infrared thermometers/cameras are used to measure conductor temperature from the ground. + Temperature can be measured directly. + No line outage is required. - Difficult to verify and validate calibration. - Susceptible to physical interference, which may cause inaccurate readings.
		Line-mounted Sensor	Thermocouples or thermistors are affixed onto the conductor to measure its temperature. + Temperature can be measured directly. - Single point of measurement. - May require line outage during installation or maintenance. - Difficult to verify and validate calibration.
	Tension Monitor		Devices are attached to the conductor to measures the mechanical force between the line and the structure. + Monitors physical characteristics of a conductor and can benefit asset management (e.g., ice loading). - Requires line outage to install.

	Measurement Parameter	Approach	Description with Advantages (+) and Disadvantages (-)
	Sag	Ground- or Structure-based Sensor	Cameras monitor the distance a line has sagged. This is accomplished through image processing techniques, or with a target affixed to the line that the camera tracks. <ul style="list-style-type: none"> + No line outage is required. + Monitors physical characteristics of a conductor and can benefit asset management. - Difficult to verify and validate calibration.
		Line-mounted Sensor	Devices that measure the inclination and vibration of a line to determine the amount the line has sagged. <ul style="list-style-type: none"> + Monitors physical characteristics of a conductor and can benefit asset management. - May require line outage. - Difficult to verify and validate calibration.
	Clearance	Ground-based Sensor	Devices measure the electric fields emitted from a line to determine its distance above ground. <ul style="list-style-type: none"> + No line outage is required. - Susceptible to electromagnetic interference.
		Line-mounted Sensor	Devices mounted to the conductor that use sonar, light detection and ranging, or a range finder to measure its distance to the ground. <ul style="list-style-type: none"> + Monitors physical characteristics of a conductor and can benefit asset management. - Requires line outage to install. - Twisting lines can rotate the device, causing incorrect readings.
Environmental Parameter Monitoring	Weather	Numerical and Statistical Methods	Given historical weather data and other data sources, predicts weather conditions through computation and mathematics. <ul style="list-style-type: none"> + Minimal to no specialized hardware required. - Real-time predictions are error prone.
		Direct-Measured	Weather-station sensors measure wind speed, wind direction, temperature, and solar radiation. <ul style="list-style-type: none"> + Environmental parameters can be directly measured. - Many weather stations required to monitor large area.
		Physics Model with Direct-Measured	A computational fluid dynamics model uses analysis of the terrain to map wind speed and direction from weather stations data to adjacent areas. <ul style="list-style-type: none"> + A single weather station can effectively monitor a much larger area. - Models take additional time to run.

	Measurement Parameter	Approach	Description with Advantages (+) and Disadvantages (-)
			- Requires large amount of geographic data.
	Conductor Replica		Device uses a conductor material, placed close to and in the direction of the line to be monitored, as a proxy for the line. The material’s temperature is measured while it is heated electrically to determine the ambient cooling conditions. + Does not require a line outage. - Difficult to verify and validate calibration.

Communications

Successful implementation of DLR requires the ability to communicate between the sensing and monitoring technologies and the control rooms or other decision systems in a timely manner. Many different technologies—radio, cellular networks, satellite, fiber optics, and even physical media—can be used as communication channels. However, the choice of technology will depend on the monitoring approach as well as requirements of the application, especially when it comes to data-transfer amounts and acceptable latency. For example, simple weather stations only need to transmit a few environmental parameters to the control center. For these small data packet applications, many existing technologies can be used, and the choice becomes dependent on cost, terrain, and network availability. As the number of capabilities and measured parameters increase for sensing and monitoring technologies, the communications requirement will also increase.

As utilities and system operators begin to rely on DLR systems for control, dispatch, and market decisions, the communications channel becomes a critical asset and will need to meet NERC’s Critical Infrastructure Protection standards and requirements to ensure the authenticity and integrity of DLR data. Corruption of this data from any cause, unintentional or deliberate, becomes an operational problem that can have significant consequences. DLR system owners or service providers need to concern themselves with the reliability of the communication systems, including the cybersecurity of the sensing and monitoring technologies, the communication channels, and the operating systems. Cybersecurity breaches can manifest as data disruptions or poor data integrity that seek to invoke bad decisions or manipulate markets. System operators will need strategies and solutions for detecting and mitigating problems in communications.

Analytics Engine

The measured and approximated environmental and conductor parameters must be processed in order to become useful information. In most cases, the raw sensing and monitoring data is equated to the parameters measured without filtering or preprocessing to address potential errors. The measured conditions are analyzed according to IEEE Standard 738 or CIGRE Technical Brochure 2.12 to determine the steady-state or transient line current-carrying capacity [19]. The information resulting from these calculations can then be integrated into a

control room, usually through a software interface, or studied independently to improve decision making.

Advances in models, methods, algorithms, and computational speed can change what is possible. For example, forecasting DLRs from measured data can provide additional value over what can be achieved with real-time information alone. Combining weather-forecasting methodologies and analytics with DLR technology is still in its infancy. Several national weather forecast models with high resolution could be used for this approach. An example forecast from the National Oceanic and Atmospheric Administration with their high-resolution rapid-refresh model is shown in [Figure 2](#). This forecast gives wind speed and direction at 3 km spatial resolution for heights that roughly correspond to those of overhead transmission lines.

As with any modeling and analysis process, confidence in the data input and the validity of the processed output is critical. For example, wind speed and direction sensors can malfunction due to age or weather conditions and provide incorrect readings. A means to detect such anomalies in real time during the analysis would provide more confidence in decisions made based on these sensors. Models utilized in the analytics may also have accuracy sensitivities depending on the input range, requiring validation of models and the sensor data employed. Methodologies for providing diagnostics and forensics when system components degrade or fail are currently lacking from vendors. Similarly, assumptions made in developing models are often not validated. Remediating these shortfalls could be key to greater trust of DLR technologies in the long term.

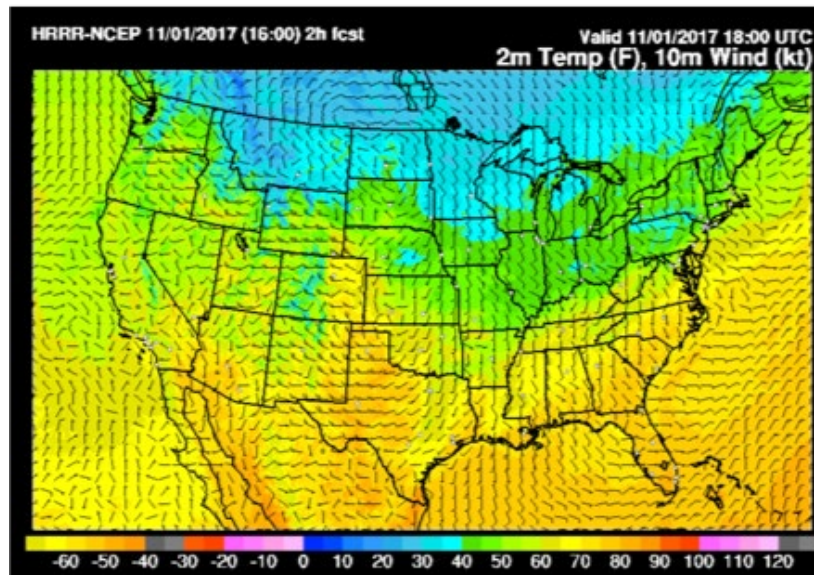


Figure 2: Example National Oceanic and Atmospheric Administration wind and temperature forecast (<http://rapidrefresh.noaa.gov>).

Integration

Integration into the control room is the most challenging step in implementing DLR because “[t]he work in a control room is highly complex [20].” Adding more information to the control

room may excessively tax operators. In theory, calculated information from the analytic engine could first be read by the supervisory control and data acquisition (SCADA) system and then be displayed to operators. The display methodology (e.g., visualization, human-machine interface) most useful for system operators has yet to be agreed upon. Many control rooms have created displays for their own use, such as the one developed by the Spanish utility Red Eléctrica de España [21].

Making information actionable to the system operators is a primary concern; operators want a maximized but stable line rating that ensures conductor temperatures do not rise to the point where excessive sagging occurs. Depending on the implementation, DLRs can be noisy due to their dependence on wind speed and direction that changes rapidly. Filtering steps to reduce the volatility of information seen by an operator and methods to increase confidence in the ratings can be performed as shown in [Figure 3](#). The bright blue line shows DLRs in 30-minute intervals with a 30 percent cap above the SLR, providing usability and ensuring safety, whereas the light blue line shows the real-time, unfiltered DLRs. The orange and dark blue lines show intermediate filtering steps. This is one example of how DLR data can be made more actionable; DOE has also funded research on alternative ways to more effectively present DLR data to system operators [20]. Overall, standardization of DLR data use and a baseline of expected functionality and performance will be needed to facilitate control room integration.

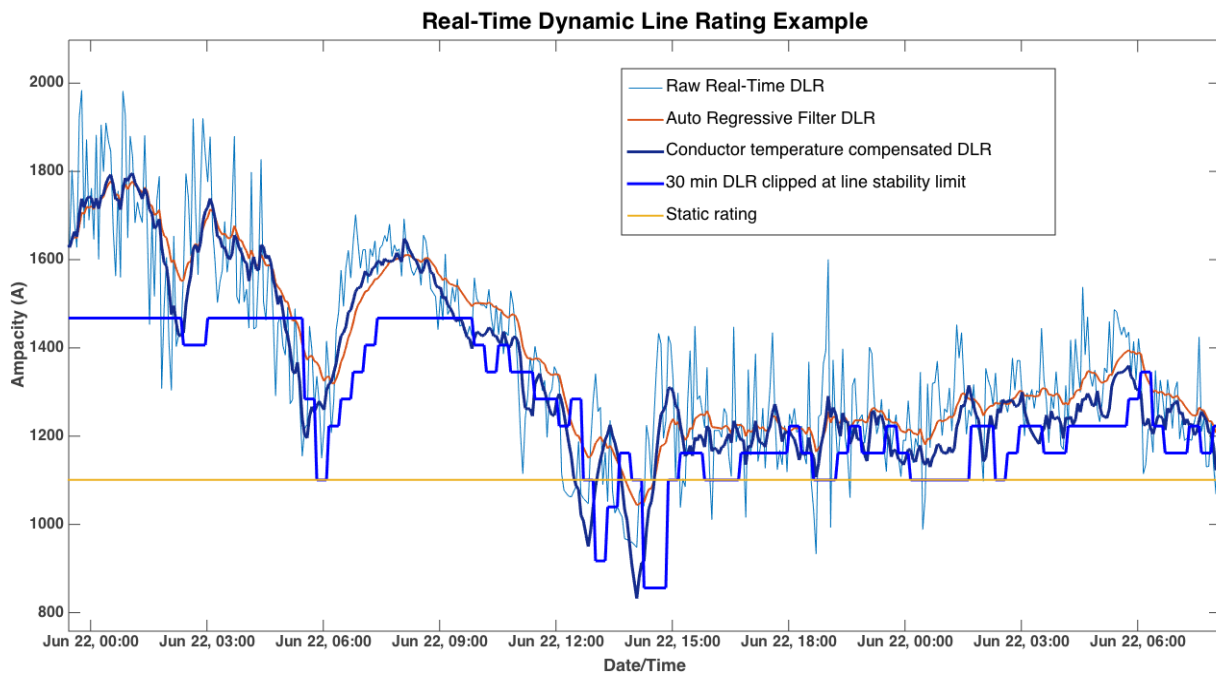


Figure 3: Example DLR calculation with raw real-time, auto-regressive average, conductor temperature compensated, and a 30-minute capped rating compared to static rating.

Barriers and Limitations

Despite DLR’s potential for realizing cost savings and its ability to increase grid reliability and resilience, several barriers and limitations prevent widespread adoption. In general, hesitation

exists in the largely risk-averse utility industry related to the use of unfamiliar technologies. One common concern is the accuracy and reliability of DLR data and related lack of operational knowledge and experience with the technology. Capital costs and installation complexities are a barrier as well. Another important variable that explains lower deployment in the U.S. relative to other countries is the different regulatory environments; the U.S. provides transmission owners little incentive to deliver more power over existing lines.

Accuracy and Reliability

The accuracy and reliability of DLR is critical to successful deployment and realization of cost savings, but inaccuracies can arise through both measurement and modeling errors [22]. Measurement errors include imprecise or inconsistent measurements and improperly calibrated direct-measurement sensors. DLR systems can also malfunction, in whole or in part, such as during a loss of communications connectivity. Additionally, some direct-measurement sensors are not able to measure transmission line parameters accurately during periods of light loading [23]. In these situations, there is always the option to revert to SLRs if the system is aware of the malfunction.

Modeling errors encompass inaccurate mathematical rating models, weather forecasting errors, and errors in collecting circuit topological and conductor data. For example, with older power lines, the thermal and mechanical properties of the conductor may have shifted over time due to aging and past use, yielding inaccurate results in clearance calculations. Similarly, CIGRE has documented that emissivity of overhead transmission lines can also change as lines age, affecting solar radiation impact and thermal-radiative properties [24]. Proper characterization of the transmission line itself should be made prior to implementing DLR.

These various sources of error reduce confidence in the capability of DLR to perform accurately and reliably. Developing methodologies and solutions to address these concerns will be critical to broader DLR adoption. Some strategies currently under investigation have employed a mathematically described confidence level within the DLR calculation, which rates the power line more conservatively proportional to lower confidence parameters such as weather predictions [25].

Operational Knowledge and Experience

As mentioned earlier, integrating DLR into control rooms requires accommodation. In a New York Power Authority (NYPA) DLR demonstration, the learning curve and trust in measurement accuracy were identified as challenges that might cause system operators to avoid adopting DLR [13]. In addition to the learning curve, introducing DLR systems would require the integration of a new terminal and additional training for employees. More importantly, a dedicated effort to ensure the system is providing accurate real-time information is required. Transmission operator feedback also suggest that they have limited time to make complex decisions and need intuitive information, especially in emergency situations [20].

Despite these challenges, studies conducted by NYPA and Oncor are optimistic about DLR implementation and offer remedies for control room integration issues: "One option is that a team of devoted engineers would oversee the DLR software and server, another option is to

outsource the software to a third party, and a third approach is to integrate the DLR system directly into system operations [13]. ” The third approach, while comparatively more difficult, is the most cohesive. One way to make this transition as seamless as possible, according to the Idaho National Laboratory, would be to “integrate the DLR calculation in the operation system behind the scenes and replace the original static line limit information with ... [the new] DLR information [20].” This approach would limit the information introduced on a system operator’s display and would not increase an operator’s mental workload.

DLR also imposes a variety of risks in its implementation. For example, if a transmission line is scheduled to operate above its static rating due to a forecast of strong winds (i.e., TCF), but a change in weather causes a sudden drop in wind speeds in real-time, the line would then be operating above its actual thermal limit. In this situation, there is an increased risk of clearance-height violations or, in extreme cases, heating to the point that the material and mechanical properties of the transmission line are degraded permanently. System operators will likely need to back up this method with shorter-term forecasting and real-time weather reporting to make operational decisions that protect assets and ensure safety. In general, changes in line ratings would be additional variables that would have to be incorporated into real-time dispatch decisions.

The use of enhanced ratings must also consider characterizing lines that run through vegetated areas to ensure proper clearance above or around vegetation, in addition to ground clearances. Vegetation near transmission lines pose a higher potential for wildfire risk, especially in drought-ridden areas [26]. Net benefits from employing DLR could quickly be lost if conductors become overheated or damaged due to incorrect sensor placement, inaccurate weather predictions, or unforeseen circumstances, leading to premature degradation and replacement, or other hidden costs.

Cost of Implementation

While relatively inexpensive compared to other transmission-capacity expansion and utilization options, cost of DLR systems and their implementation are not insignificant. Identifying the transmission line on which to install DLR and the specific technology to install can also prove difficult. The current carrying capacity of a particular line or line segment is often restricted by variations in wind cooling along the conductor [27]. For DLR to accurately and effectively maximize a transmission line’s thermal rating, the length of the line being monitored needs to be considered. Analysis is needed to determine the number of devices required and the relevant locations that give a reliable and accurate rating for the entire line. Identifying these “critical spans” is not trivial and will impact the cost of implementing DLR.

In a 2017 study by American Electric Power (AEP), a hypothetical DLR deployment on three sections of the 22-mile Cook-Olive 345 kV transmission line in the AEP transmission zone of PJM was simulated. With commercially available DLR systems, installation and implementation would have cost approximately \$500,000 and generated a net congestion savings of more than \$4 million in the year-long study [28]. This result would indicate a payback period of two

months. As a point of comparison, if that line were economically upgraded, the cost would be \$22-\$176 million based on a Pacific Gas & Electric cost-per-mile estimate [9].

Overall, there is an absence of studies analyzing the payback period for DLR under the current technical landscape and power-system conditions. Improved studies are needed to better quantify and understand the financial impacts (e.g., costs and benefits) of DLR, especially for utilities and transmission owners, to overcome conservative assumptions that can impede implementation.

Monetization of Benefits

While DLR can lead to cost savings, these savings may not accrue to the financial benefit of transmission owners in the U.S. to sufficiently incentivize them to deploy such systems and other advanced transmission technologies (e.g., power flow controllers). This is due, in part, to the financial regulatory structure for rate-regulated utilities. Transmission owners generally can recover their prudently incurred expenditures for transmission under FERC's rules. However, under the current U.S. regulatory cost-of-service model, transmission owners receive a return on invested capital rather than a premium for delivering more power over existing lines or reducing transmission congestion. In addition, DLR involve many costs that are classified as operational and maintenance expenses that are ineligible for inclusion in calculating the return on equity (ROE), unlike physical assets. Thus, there may be a financial incentive for utilities to deploy new transmission lines and other large facilities rather than DLR to manage congestion.

While some FERC incentives are available for optimization of existing transmission facilities, to date, few, if any transmission developers or operators, have sought such incentives. FERC has recognized this issue in the past, noting in a 2012 policy statement providing guidance on its transmission incentives that, "the Commission is concerned that its current practice of granting incentive ROE and risk-reducing incentives may not be effectively encouraging the deployment of new technologies or the employment of practices that provide demonstrated benefits to consumers. Accordingly, the Commission remains open to alternative incentive proposals aimed at supporting projects that achieve these ends [29]." By contrast, other countries, such as the United Kingdom, have provided more direct and more comprehensive incentives for transmission line optimization, which may have led to greater deployment of advanced transmission technologies.

Additionally, many utilities may not be ready to address the challenges of incorporating DLR into their control rooms. Instead, they opt to use SLRs, focusing on system safety, reliability, and simplicity rather than the economic interest of consumers. This reflects the fact that economic benefits of enhancements to existing transmission systems generally accrue to the consumer, rather than the utility or transmission owner, and so become a secondary consideration. As a group of researchers noted, "In the case of transmission congestion, higher-cost generation is dispatched to meet load demand. Consequently, energy customers may experience an increase in electricity prices in the form of congestion charges. Therefore,

the owner of the constrained transmission line is not directly affected by such circumstances and thus is not willing to remove the constraint [27].”

The interconnected nature of the electric grid also contributes to difficulty monetizing benefits. For shorter transmission lines (i.e., typically up to 100 km), the maximum current carrying capacity (i.e., loadability) is predominantly set by thermal limits while the maximum current carrying capacity for longer transmission lines is usually set by voltage limits and stability constraints [27]. Thermal limits tend to be higher than voltage or stability limits on longer lines, as shown in [Figure 4](#), limiting the applicability of DLR. Additionally, implementation of DLR can move power flows to other lines, possibly voltage-limited lines or those owned by others, adding complexity in how costs and benefits should be allocated.

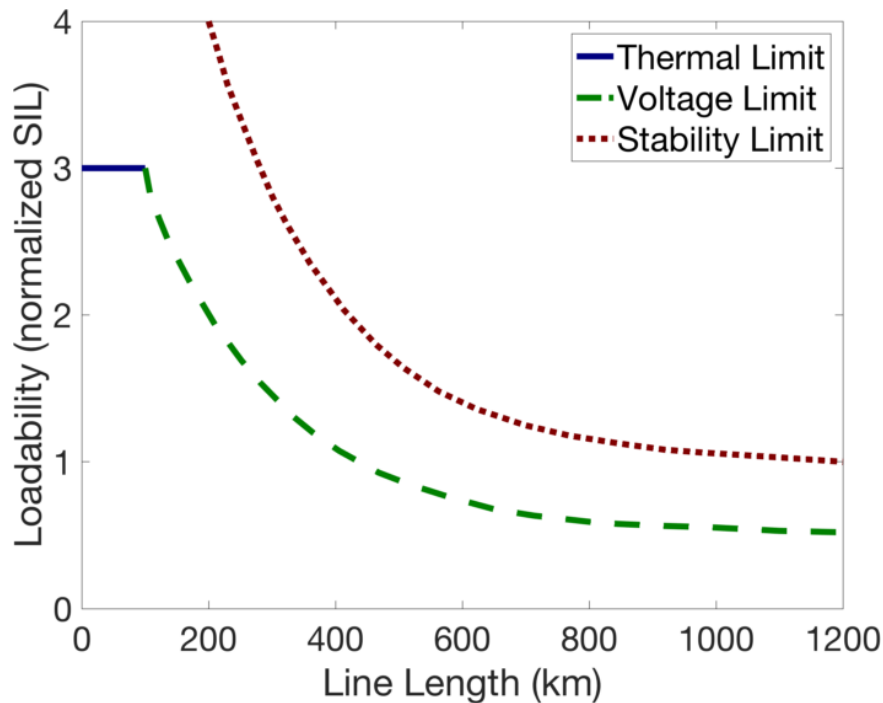


Figure 4: Power-transfer limits in relation to transmission line length, with loadability calculated per unit of surge impedance load (SIL)

IV. Stakeholder Views and Systems Impacts

The main benefit of DLR is the cost savings associated with utilizing existing equipment to carry more power, allowing greater utilization of low-cost generating resources while offering a potential low-cost alternative to spending millions of dollars on economic transmission upgrades. Increased situational awareness and better data collection would also greatly benefit a grid operator during regular operations or post-failure studies by providing more-relevant data for decision making or analysis. Due to these benefits, DLR has been deployed and studied domestically as well as internationally. However, the electric power system has numerous stakeholders, ranging from regulatory commissions to consumer advocates, industrial users to

equipment vendors to independent power producers, in addition to utilities. Understanding their perspectives on DLR is important to broader adoption. Additionally, there are other system impacts that need to be considered in order to mitigate unintended consequences.

Case Studies

DLR is a technology option that has been available for 20 years, but has yet to see wide-scale adoption. However, several prominent small-scale investigations of DLR have been performed and examples of commercial products that measure the effects of line heating have been tested. [Table 2](#) lists these known case studies (i.e., analyses, pilot implementations, and installation of commercial products) along with a description of the experience. While these results are generally positive, outcomes are difficult to extrapolate beyond the targeted lines.

Table 2: DLR case studies.

Entity	Year	Experience
REE: Spain	1998	400 kV transmission lines around Madrid were instrumented and the data stream was incorporated into the control room. DLRs showed promising headroom for increased line capacities [21].
Northern Ireland Electricity	2009	DLR was explored to address congestion from wind farm expansions. A 110 kV line was instrumented and studied, showing that line ratings could be increased by 10% to 20% in most remote locations, and by 26% in some cases [30].
RTE: France	2011	A sag sensor was tested on several 400 kV lines in France and found to be accurate enough to be used in ampacity calculations. However, they felt more research is needed to properly integrate the new data into control rooms [31].
Kepco	2013	The South Korean utility analyzed DLR for several transmission lines to address concerns with outage rates on parts of their system. DLR was found to allow maximum loading to increase by 35% over current values safely [32].
NYPA	2013	The demonstration project evaluated a variety of DLR systems and technologies, and how they could be used in transmission system engineering, operations, and planning. They found a positive correlation between increased real-time capacity and increased wind generation, and capacity increases of 30 to 44% over static ratings [13].
Oncor	2013	The demonstration project focused on monitoring an entire transmission line and included DLR integration into control systems. They observed capacity increases between 6 and 14% over AARs, available over 83% of the time. Additionally, they determined their DLR system could increase line capacity, on average, between 30 and 70% relative to static ratings [13].

TERNA: Italy	2013	The Italian transmission operator began implementing DLR on limited lines that were determined to be critical with the future objective to use data as input into optimal power dispatch. DLR has been used as a stop-gap measure to serve load prior to other network upgrades [33].
Idaho Power	2013-2018	Weather-based DLR provided increased situational awareness for more than 450 miles of transmission lines in highly complex terrain. Contingency relief has been realized multiple times as DLR forecasts are researched and validated [34], [35], [36].
AltaLink	2015	Conducted an analysis for a wind plant installation in Canada and found concurrent cooling avoided the need for system upgrades, saving the wind developer an estimated two million dollars. Further analysis showed an average 22% capacity increase over static ratings 76% of the time [37].
World Bank: Vietnam	2016	In its smart grid roadmap for Vietnam, DLR was identified as a tool to improve operational efficiency and to alleviate concerns on lines that are experiencing rapid load growth [38].
AEP	2017	Conducted a study of DLR applied to a 345-kV line across three spans. The results found significant capacity increases on the targeted line with the potential of \$4M in savings [28].

Stakeholder Views

Numerous stakeholders would be affected or have an interest in the impacts of wide-scale implementation of DLR. Among them are Federal, State, Tribal, and local regulators; generation and transmission owners and operators; financial institutions and energy traders; technology vendors; and consumers. Various workshops, meetings, and fora have been organized to discuss the potential of DLR. Several comments from power systems stakeholders representing the breadth of views, insights, and experiences are presented below.

In a presentation to the MISO Market Subcommittee, Entergy explained their reasoning for implementing DLR on certain congested facilities:

By trending historical weather within Entergy’s footprint, Entergy has found that rating adjustments based upon ambient temperature deviations from peak periods provide the most efficient gains and are most predictable on a forward-looking basis [39].

At a FERC workshop held on June 13, 2017, EDF Renewable Energy, Inc., EDP Renewables North America, LLC, and E.ON Climate & Renewables, LLC, (collectively the “Generator Group”) offered comments to elaborate on the Target Market Efficiency Project proposal. The group, concerned with unaddressed congestion at particular locations on the MISO-PJM seam, cited DLR as a possible means of addressing congestion issues and reducing costs to ratepayers:

Dynamic line ratings . . . can monitor variables such as temperature and wind speed in real time, and thus allow for greater throughput and use on an existing transmission line than use of static NERC-based limit [40].

In response to a 2011 FERC inquiry on promoting transmission investment via pricing reform, Wisconsin Electric Power Company noted in comments that while they do support new grid construction as a means to reduce congestion, DLR can be implemented to more efficiently utilize existing infrastructure:

The ability to set ratings based on near-term predicted or actual conditions could allow a significant increase of transfer capability. Much of the congestion costs are realized during non-peak periods. Therefore, production cost savings can be achieved by calculating transmission ratings based on more representative conditions [41].

In addition, Wisconsin Electric Power Company called upon the FERC to offer incentives for regional transmission organizations (RTOs) to implement DLR:

As an incentive to implement dynamic ratings, transmission owners could receive a higher ROE on assets utilizing dynamic ratings. In order to most effectively use dynamic ratings, RTOs would need to modify their systems. For this reason, the Commission should consider an appropriate incentive for the participating RTO.

System operators play a critical role in DLR technology adoption. In its 2018 Reliability Needs Assessment Report, NYISO stated that, in order to meet future reliability needs and address transmission constraints, they are able to introduce changes in operating protocol, which can include implementing DLR for particular facilities [42].

In response to a 2018 MISO market-roadmap survey on priorities, various stakeholders stated their positions regarding the potential implementation of DLR. This document is unique in that an independent system operator (ISO) specifically requested and published information from participants in its system, something other ISOs have not shared publicly [43]. Pertinent responses are shown in [Table 3](#).

Table 3: Stakeholder responses to MISO market-roadmap survey on potential implementation of DLR technology.

Survey Respondent	Response
DC Energy Member; Power Marketers/Brokers	“Pursue if MISO will be providing transparency on what ratings are used.”
Detroit Edison (DTE) Energy Member; municipals/cooperatives/ transmission and distribution utilities (TDUs)	“DTE believes this project will help leverage existing line capabilities reducing the potential overbuild of transmission and resulting cost impact to our customers.”

Survey Respondent	Response
<p>E.ON Climate and Renewables North America, LLC Member; Independent Power Producers and Exempt Wholesale Generators</p>	<p>“In addition to dynamic ratings there is a recent development of devices that can dynamically change the impedance of a line (an example would be SmartWire’s products), changing the flows in the system. We understand the integration of such devices would be a separate initiative, but we would ask MISO to consider other type of dynamic system topology changes if this initiative is implemented.”</p>
<p>Louisiana Public Service Commission Non-Member with Voting Rights; State Regulatory Authorities</p>	<p>“... Congestion savings could be significant with utilization of Dynamic & Predictive Ratings. Wind generation is driving a lot of congestion in certain areas of the MISO footprint including the MISO-[Southwest Power Pool] seam. Quite a bit of the wind generation is off-peak during the winter and shoulder months. There is quite a bit of additional transmission capacity available when wind production is high as temperatures are generally lower along with increased wind speeds. It should be noted that Entergy incorporates these Dynamic and Predictive ratings and these increased ratings were utilized during the January MAXGenAlert.”</p>
<p>Wind on the Wires (WOW) (now Clean Grid Alliance) Non-Member with Voting Rights; Environmental/Other</p>	<p>“WOW believes there is an important opportunity to make more efficient use of the transmission system with Dynamic Line Ratings, taking into account wind speed and ambient temperature. DLR should be used under normal operating conditions and not reserved only for emergency situations.”</p>
<p>Wisconsin Public Power, Inc. Energy Member; municipals/cooperatives/TDUs</p>	<p>“While very supportive of efficient use of transmission, progress won't be made on this Market Roadmap candidate until transmission owners are supportive.”</p>

FERC has discussed the deployment of DLR technology in a policy statement and FERC orders. For example, in its 2012 policy statement on transmission incentives, FERC noted that transmission projects including DLR might constitute a new technology that facilitates more efficient and reliable usage and operation of existing or new facilities that would be eligible for consideration for a risks and challenges ROE-adder transmission incentive [29]. Additionally, DLR costs may be eligible for special transmission ratemaking processes, if requested [44]. FERC has also discussed how to treat advanced technologies during planning of transmission options [45] and contemplated that reliability standards might reflect DLR implementation [46]. Further, FERC directed NERC to consider DLR in future standards revisions, calling DLR an “innovative application [47].” Many of these policies were recently discussed in a FERC staff presentation at an Idaho National Laboratories workshop on DLR [48].

Impact on Different Generation Technologies

All utility-scale generation (e.g., nuclear, coal, natural gas, hydro, wind, and solar) requires a robust and reliable transmission system to deliver electricity to customers. Under the Federal Power Act (16 U.S.C. § 791a, *et seq.*), the transmission system is both open-access and technology neutral, meaning that no one generation source has priority over any other source for the use of available transmission capacity. Deployment of smart technologies, such as DLR, that reduce constraints and increase transmission capacity would not change this mandate. While distributed generation technologies are often connected to the distribution system and are less dependent on the transmission system, their deployment can be impacted by transmission constraints because increased variability at the local level requires power inflows and outflows from the bulk power system in order to maintain system balance.

Wholesale electricity markets play an important role in guiding the operating, planning, and investment decisions of owners and developers of generation technologies. In general, advanced technologies that reduce transmission constraints will produce a freer and more-open market. Generators with a lower marginal cost of producing electricity, such as variable renewable resources and natural gas turbines, will tend to benefit more from increases in transmission capacity. Consequently, implementation of DLR schemes may have an adverse effect on generator plants that depend on a constrained network for increased profitability. Overall, it is not possible to generalize the effects of DLR on specific generation technologies or sources because power flows are different across regions and change over time, and a variety of ambient conditions can affect line capacity.

While the impact of DLR schemes on different generation technologies cannot be generalized, there are instances in which specific sources can be advantaged. Interconnecting a new generator includes costs associated with upgrading the transmission network. DLR systems could be used to reduce upgrade cost, and potentially alleviate issues with nearby lines that are influenced by the new source to expand the number of viable locations for the plant. In other cases, wind turbines can occasionally deliver more power under DLR schemes due to the concurrent cooling of nearby transmission lines during periods when wind turbines tend to generate power. However, solar farms may experience the opposite effect where increased solar radiation heats the nearby transmission lines, reducing capacity when electricity production is high.

Ultimately, the implementation of DLR schemes would improve the overall economic efficiency of operating the electric power system. The resulting power flows and associated market impacts may drive certain generator plants out of business or change the viability of specific generation sources. The transmission system and wholesale electricity markets are fundamentally designed to optimize performance across multiple variables in the interest of serving the end-user. Market rules should not be influenced by any specific generation source or technology, but rather on the operating characteristics of generation sources and the impact of technology on overall power-system performance.

Other System Impacts and Considerations

Although it has been shown that DLR can provide cost savings [49] [25], concerns have been raised about the cost of installing and maintaining monitoring equipment [50], the challenges associated with maintaining equipment calibration, and the possibility of additional cyberattack surfaces. DLR can also improve system reliability through increased situational awareness and greater transmission capacity. However, by reducing the thermal headroom associated with SLRs, grid hardware components (e.g., power lines, transformers) will operate closer to their design limits, accelerating aging effects [51] and potentially driving the power system to a more-fragile state if these impacts are not adequately taken into account. Implementation of DLR must include principles of resilience to ensure that new hazards are not created. These additional considerations and issues will impact the business and operating models of utilities and other stakeholders.

Historically, utilities have operated their equipment conservatively, with significant headroom to handle unforeseen circumstances (e.g., contingencies, load surges). If maintenance is regularly performed, equipment that was designed for 40 years, at full loading, can last up to 60 years or more before they need to be replaced or rebuilt [52]. DLR schemes would enable utilities to safely subject their equipment to increased power flows, which raises the concerns of how this practice would impact equipment lifespan and maintenance cycles [53]. The additional electrical and thermal stresses will vary depending on location and circuit topology, possibly necessitating increased monitoring of the age and condition of grid assets in general. In some cases, the DLR system itself can provide this conditioning monitoring.

As DLR is implemented on a circuit, transmission owners and operators must focus on other critical elements to ensure the grid can handle the increased loading without issues. In addition to potential impacts on grid hardware components, protection systems may need to be examined. For example, relay settings may need to be updated to correspond to the increased capacities enabled by DLR. Regulatory limits on the upper bounds allowed for DLRs may be required to avoid these issues, as well as to address risks that can occur with sudden decreases in wind speeds. Power-system protection is an area that is getting more complex with adoption of new technologies, especially with significant growth of inverter-based generation.

Cybersecurity is a growing concern for the electric power industry; cyberattacks are continuously evolving and the number of attacks in the U.S. has been on the rise since the 2000s [54]. In general, adding new sensing and monitoring technologies, communications equipment, and computers to process data increases the cyberattack surfaces on the U.S. grid [55]. Implementing DLR is no exception; because most DLR technologies rely on wireless communications, they are vulnerable to denial of service attacks [56]. Efforts are needed to ensure DLR deployments are cyber secure. Additionally, system operators must have contingency plans to ensure safety and reliability, possibly reverting back to SLRs, should the DLR system fail or become compromised.

V. Conclusion

DLR, enabled by a diverse set of technologies, has the potential to reduce cost to American homes and businesses by alleviating congestion on transmission lines and improving safety and reliability through increased situational awareness. While beneficial, DLR systems are only one of many options for addressing grid congestion or increasing resilience; transmission expansion and other solutions (e.g., power-flow controllers, energy storage, DERs, and demand response) also play key roles in modernizing the grid. Experience with pilot studies and demonstrations have shown capacity increases, but the outcomes are difficult to extrapolate beyond the targeted lines. Additionally, numerous power grid stakeholders have expressed support for DLR, but technical, market, and regulatory challenges remain that must be addressed to facilitate broader adoption.

The U.S. currently lags behind other countries in the deployment of some advanced transmission technologies, such as DLR. One of the variables is a difference in regulatory environment and associated incentives. Broader adoption of DLR will also influence the performance of electricity markets, impacting the profitability or viability of specific generation sources. Further research is needed to better understand the economic benefits, costs, and impacts of wide-spread DLR adoption, especially at the regional or national level. Additional demonstrations and pilot studies can also provide utilities and other stakeholders with increased confidence in DLR methods and systems, reduce technology risk and uncertainty, and help ascertain the value of ancillary benefits such as improved situational awareness.

DLR deployments must be tempered with consideration for other system limitations and the potential for unintended consequences. As the capacity on instrumented transmission lines increase, other constraints in the transmission system can occur. Additionally, increased power flows on circuits will also impact aging of grid hardware components on that circuit and may present challenges with protection systems and settings. Other integration challenges such as interoperability and cybersecurity must also be addressed to maximize the potential of DLR without imposing new system risk. Establishing standards and best practices to alleviate these concerns would ultimately make DLR a more viable solution across the multi-stakeholder industry.

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**Electric Power Research Institute, Report
#3002030547, Advanced Conductors
(June 19, 2024)**



Advanced Conductors

INTRODUCTION

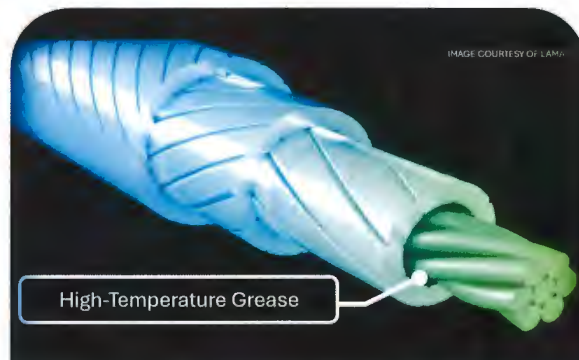
The term advanced conductors refers to conductors designed to operate at high temperatures (typically above 150°C). In recent years, conductor manufacturers have begun to produce new overhead line conductors that can operate at these higher temperatures while respecting critical safety considerations, such as managing sag to reduce electrical clearances to ground and other objects.

Some of these conductors are made of traditional materials such as aluminum and steel, while others use metal matrix or organic matrix (carbon) cores. Organic matrix core technology incorporates new materials that have not previously been used for overhead line conductors.

Advanced conductors can increase the capacity of the transmission system by:

- **Reconductoring:** This involves upgrading the existing transmission system's transfer capacity by reconductoring selected network lines with conductors capable of transmitting greater electrical capacity. This effectively increases the power transfer capacity of the existing transmission system and increases the use of existing rights of way.
- **Building new transmission lines:** Advanced conductors can be used when building new transmission lines when high power transfer capacity is needed.

Advanced conductors directly benefit alternating current (ac) lines that are thermally limited by the conductor. Using advanced conductors on these short-distance (less than 50 miles) lines could increase the current-carrying capacity by 5% to 50%.



Advanced conductors may include nonproprietary conductors—on which patents have expired, often making them more cost-effective alternatives—and proprietary conductors, which generally have a cost premium. Nonproprietary conductors are typically standard conductors with the addition of different alloys enabling higher temperature operation; e.g., zirconium may be added to an aluminum (Al) alloy to provide resistance against annealing, at the expense of conductivity. An example is gap-type GZTASCR conductor (shown in the figure) that uses a Zirconium aluminum alloy decoupled from the steel conductor core, which is coated in high-temperature grease.

Proprietary advanced conductors incorporate some or all of the following aspects that enable increased power flow:

- The ability of conductor materials to accommodate temperature increases
- Reduced thermal expansion characteristics
- Reduced conductor weight and installed tension (in carbon core and metallic matrix core conductors)

STATE OF THE TECHNOLOGY

Although these conductors have been on the market for several years, uncertainty remains on some specifications for procurement, installation, long-term performance (thermal degradation and mechanical—for example, ice loading), and inspection methods for the conductors and associated hardware.

Deployments of these conductors over the last 15 years have provided significant learnings. One such learning is that most failures of advanced conductors have been attributed to improper installation. Further research on installation, as well as long-term performance (thermal degradation and mechanical—for example, ice loading), inspection, and assessment after a critical mass of conductors is deployed can de-risk investments.

Some of the uncertainty surrounding the use of advanced conductors can be attributed to the lack of specifications during procurement. EPRI has developed guidelines to aid utilities in preparing these specifications, including tests and standards requirements. These specification guidelines have recently been made freely available to the industry.

The long-term thermal and mechanical performance of these advanced conductors is not fully understood. As more of the advanced conductors are deployed, valuable service experience is being obtained. Key topics that must be better understood include vibration and the ice-loading performance of these conductors.

As these conductors age in the field, the need for core inspection and condition assessment increases. Although several different technologies and methods for inspecting the core of steel conductors exist, it is difficult to determine the condition of nonsteel core advanced conductors.

Despite being significantly more expensive (typically 2.5 to 5 times the cost of equivalent aluminum conductor steel reinforced [ACSR] conductors), most proprietary advanced conductor options offer capacity increases that would otherwise not be achievable with conventional or nonproprietary conductors without significant modifications to the structures—or even a possible rebuild.

Reconductoring an existing line with new advanced conductors has mostly been performed when rebuilding the line is prohibitive from a network constraint perspective. In some cases, the cost of proprietary advanced conductor options may be comparable with the cost of building a new line; however, it can avoid costs related to rebuilding or reinforcing structures. Some of the advanced conductors available include those in Table 1.

Other advanced conductor technology providers include the following:

- LS Cable
- De Angeli Prodotti
- NEXANS
- Tratos Cavi
- La Farga
- J-Power

Table 1. Available advanced conductors

NAME	DESCRIPTION	TECHNOLOGY PROVIDER
Aluminum conductor composite reinforced (ACCR)	<ul style="list-style-type: none"> • Metal matrix stranded core • Aluminum-zirconium outer strands 	3M
Aluminum conductor composite core (ACCC)	<ul style="list-style-type: none"> • Mono carbon core enclosed in glass fiber • Fully annealed aluminum or aluminum-zirconium outer strands 	CTC Global
Aluminum conductor steel supported (ACSS)	<ul style="list-style-type: none"> • Galvanized or mischmetal coated steel stranded core • Fully annealed aluminum outer strands 	Various
C ⁷	<ul style="list-style-type: none"> • Stranded carbon core • Fully annealed aluminum or aluminum-zirconium outer strands 	Southwire
TS	<ul style="list-style-type: none"> • Mono carbon core encapsulated in an aluminum sheath • Fully annealed aluminum outer strands 	TS Conductor

RESEARCH AND DEVELOPMENT OPPORTUNITIES TO SCALE AND GROW

EPRI is continuing research on advanced conductors, with a focus on the activities that de-risk and optimize the use of advanced conductors:

- Improved installation procedures for newer generation conductors to prevent installation damage
- Inspection and assessment of conductors, including determination of carbon core integrity, through the development of inspection and maintenance procedures
- Safe installation tensions for aluminum conductor steel supported (ACSS) conductors, which have improved and yet unleveraged self-damping characteristics
- Incorporation of testing procedures and methods into standards, such as incorporation of EPRI's thermal mechanical test protocol into ANSI C119.7, "Connectors for Use Between Aluminum-to-Aluminum Conductors Designed for Normal Operation Above 93°C"
- Continued laboratory and field evaluations, with technology providers as well as national laboratories to increase understanding of icing, vibration, and other unknowns

EPRI's laboratory testing includes field sites where advanced conductors are being monitored with advanced sensors to assess thermal, mechanical (ice loading), and vibration

performance. The Charlotte, North Carolina laboratory test site facilitates accelerated aging thermal mechanical testing, conductor system tensile testing, vibration testing, and strand and core tensile testing.

Two field test sites are scheduled for installation in 2024 that will complement in-field monitoring of existing installations. A new monitoring project is being planned for carbon core installation in July 2024 in the northwestern United States, an environment known for icing. Two monitoring sites will continuously measure the tension, vibration, and galloping of the conductors as well as the local weather conditions.

Through EPRI's GET SET Initiative, EPRI has made public a specification that utilities may use when procuring advanced conductors. This specification, developed with member utilities and engagement with technology providers, includes new tests that utilities can use to procure advanced conductors and connectors based on the results of accelerated aging tests that EPRI has conducted for more than a decade.

Plans are in place to release a report summarizing utility use cases where advanced conductors have been implemented as well as a report summarizing more than a decade of test results.

About EPRI

Founded in 1972, EPRI is the world's preeminent independent, non-profit energy research and development organization, with offices around the world. EPRI's trusted experts collaborate with more than 450 companies in 45 countries, driving innovation to ensure the public has clean, safe, reliable, affordable, and equitable access to electricity across the globe. Together, we are shaping the future of energy.

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