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

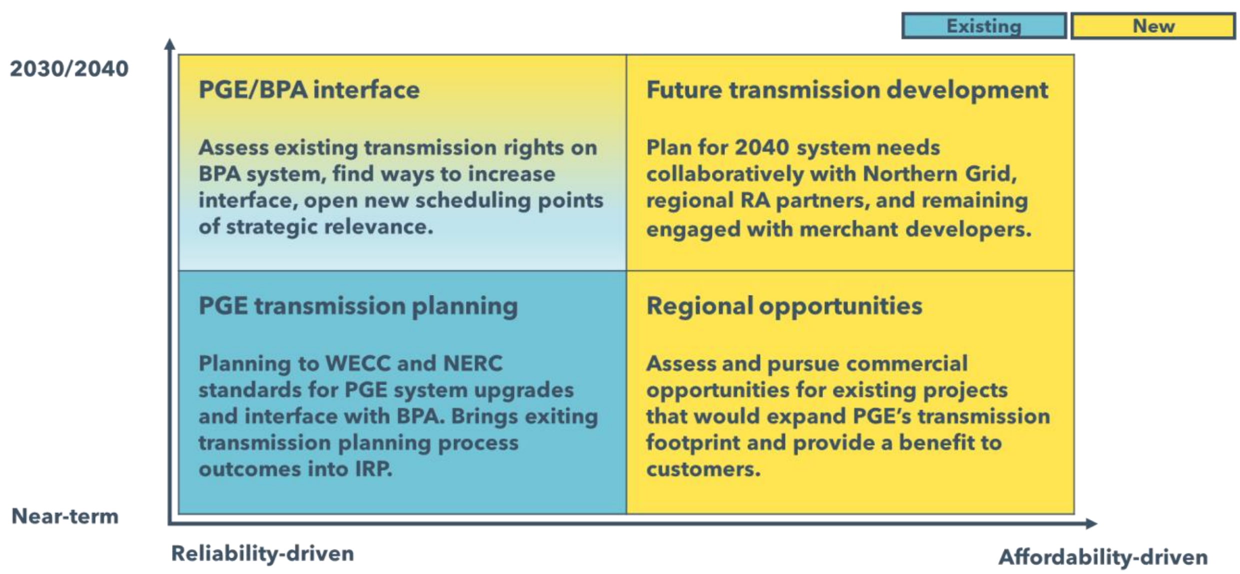
- PGE's unique footprint necessitates collaborative planning with Bonneville Power Administration (BPA) and regional peers to deliver resources to PGE's service area and to serve load within PGE's footprint. Transmission planning and development often takes longer than the Integrated Resource Plan (IRP) 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;

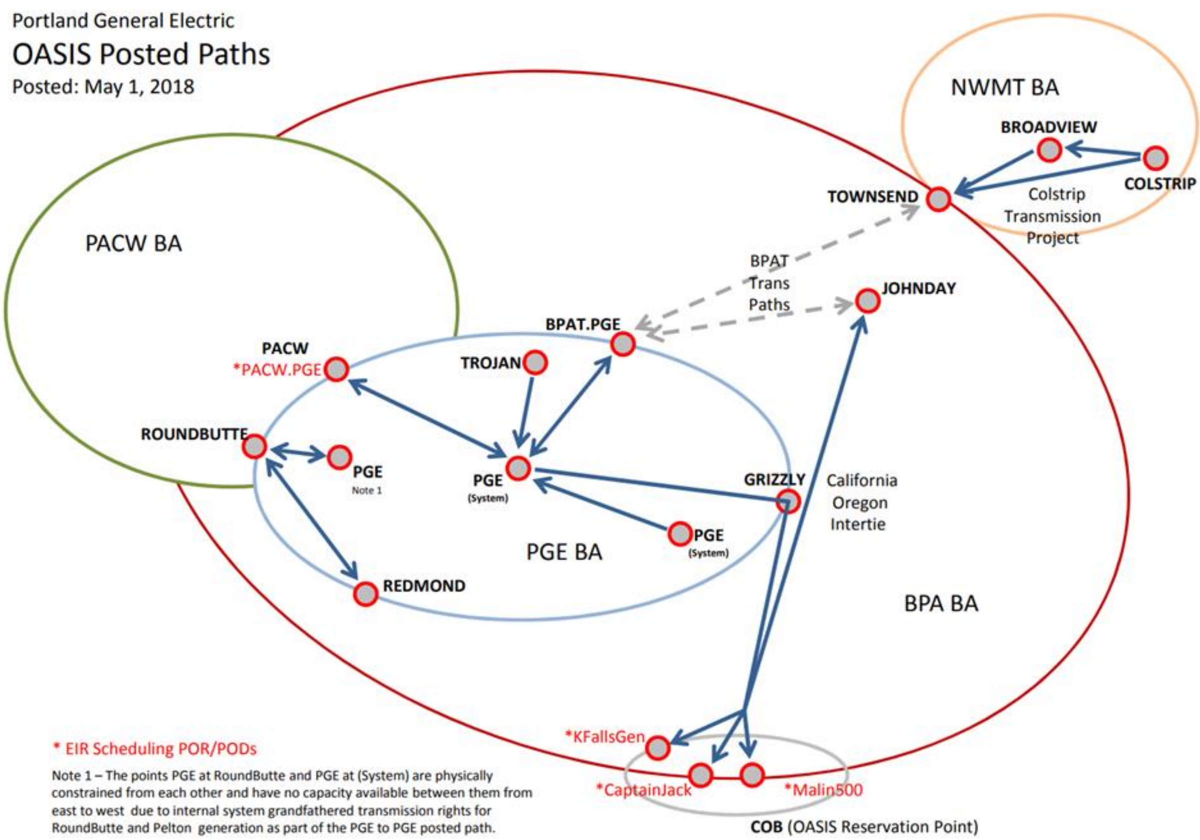
this means PGET cannot unduly preference PGEM and, by extension, the retail customers that PGE serves. PGET's transmission customers include PGEM, Oregon-defined Electricity Service Supplier (ESS) customers, BPA and transmission customers who utilize PGE's transmission system to move power across the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

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[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

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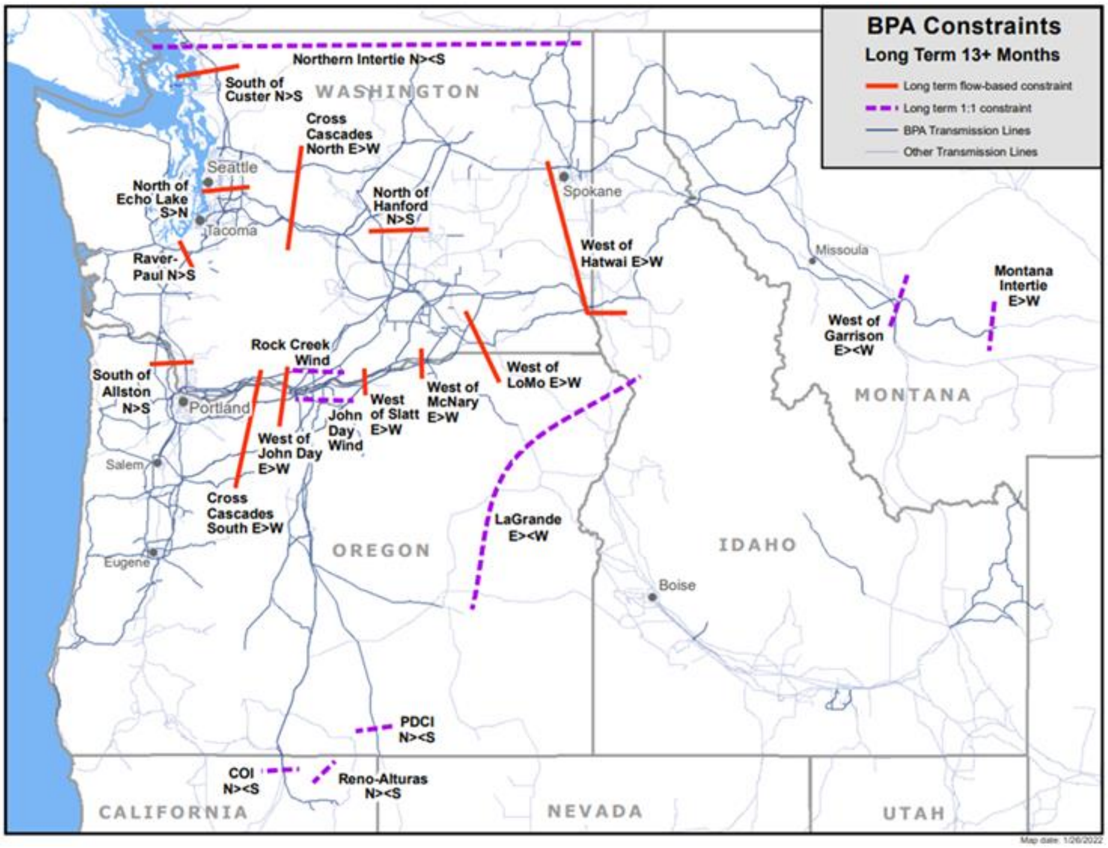
[271] See BPA Presentation, TSEP Study Process Update, September 2022 p. 6: https://www.bpa.gov/-/media/Aep/transmission/atc-methodology/09-20-22-cluster-study-improvements-customer-update.pdf
[272] Available at: https://www.bpa.gov/energy-and-services/transmission/acquiring-transmission/tsep#:~:text=The%20TSR%20Study%20and%20Expansion,Network%20Open%20Season%20(NOS).

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)

		LONG-TERM FIRM AVAILABLE TRANSFER CAPABILITY (ATC) LESS PENDING QUEUED REQUESTS								
Path Name	TTC	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 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. $382.21 7. Impact to Third-Party Transmission System (Intertie: PGE, PacifiCorp)	1. 2024 2. 2030 3. 2030 4. 2030 5. TBD 6. 2033 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.

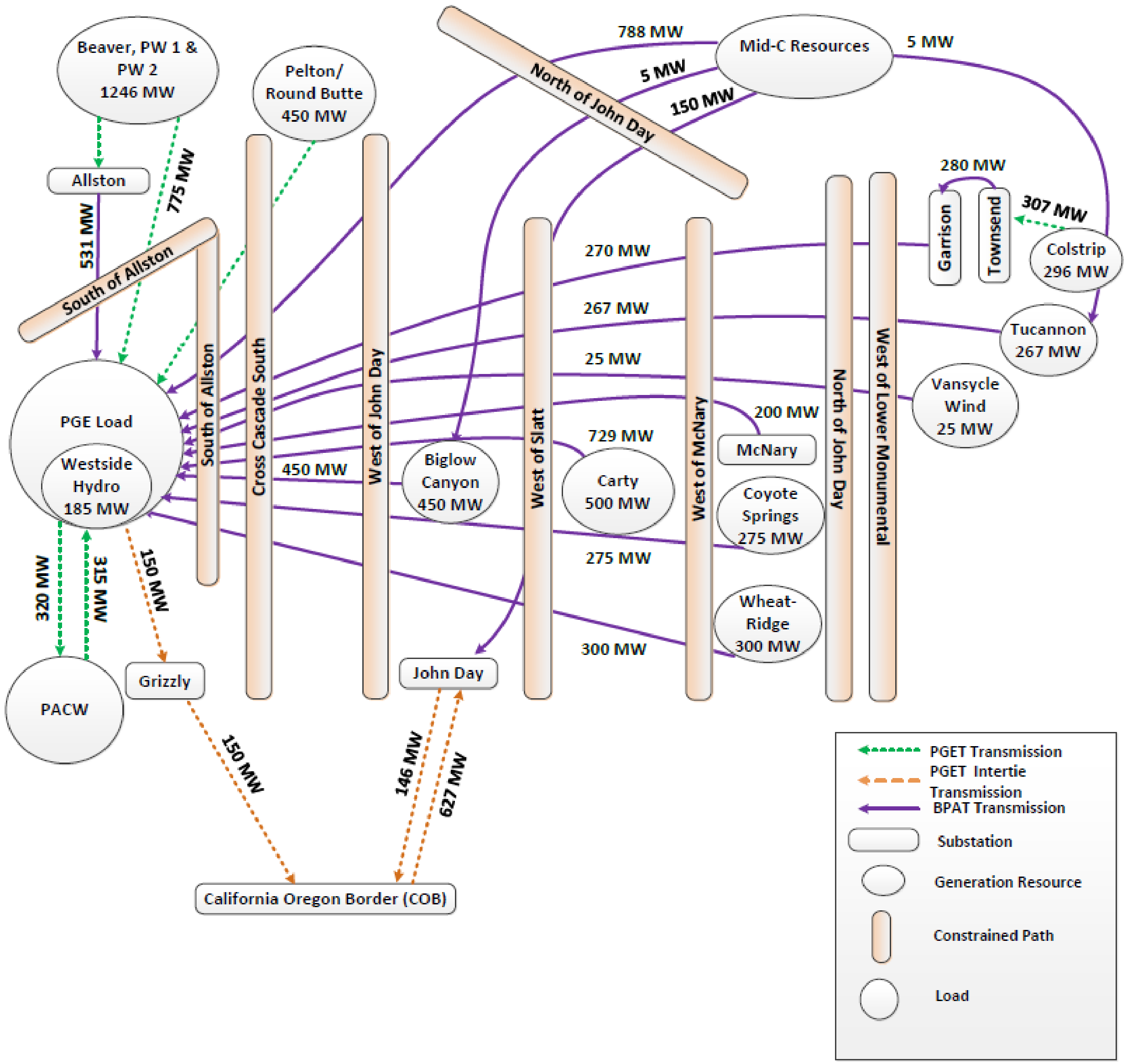
9.3.4 PGE merchant transmission portfolio

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 PGE[273]

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 options[274]

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.