

Integrated Resource Planning



STAKEHOLDER FEEDBACK: July 22, 2026

Received: Aug 4, 2026

Stakeholder: Jeff Wood

Organization: Cascade Renewable Transmission LLC

Applicable Public Meeting Date: Jul 22, 2026

Cascade Renewable Transmission, LLC ("Cascade") appreciates the opportunity to provide comments to Portland General Electric ("PGE") in PGE's public planning process for its 2026 Clean Energy Plan and Integrated Resource Plan ("CEP/IRP"). Cascade provides these comments in response to the CEP/IRP Roundtable held on July 22nd, 2026. Cascade is developing an 1,100 MW HVDC transmission interconnection between BPA's Big Eddy substation and PGE's Harborton substation (the "Cascade Project").

We appreciate PGE's responsiveness in considering how transmission solutions unlock resources to create a more reliable, integrated plan. In an effort to provide meaningful input into PGE's 2026 CEP/IRP planning process, and support PGE's consistent modeling methodology to validate the need for transmission, Cascade's comments focus on three areas: (1) assumptions for the framework used by PGE to enable capacity and market access of new transmission projects (2) technical information that supports the Cascade project providing market access essential to PGE attaining external capacity, and (3) relevant considerations for timing interdependencies between several of the modeled transmission projects including BPA's Grid Expansion and Reinforcement Projects (GERP, formerly Evolving Grid).

II. Comments

Capacity and Market Access Assumptions

In order to provide capacity value to PGE customers, a transmission project will ultimately need to prove deliverability from available resources to PGE load. At this preliminary stage in the IRP/CEP, with several subsequent steps needed from PGE



and others to prove-out that deliverability, establishing a plausible path from resources to PGE load provides sufficient indication of capacity market access. In the IRP/CEP, transmission projects can establish the plausible path using the base project combined with existing rights, repurposed rights, planned upgrades, or a combination thereof, to deliver energy and capacity to PGE. For example, PGE applies this method for North Plains Connector (NPC) #1 in the most recent analysis. NPC #1 derives value from the combination of the NPC new facilities, existing BPA rights, and expected transmission capability to form a plausible path from available resources to PGE load.

However, we see inconsistencies in application methods for transmission projects being evaluated in the IRP (e.g. SWIPN, NPC #2, WSPP, Blueprint South, etc.). For example, to apply this consistently for SWIP North, an explanation should be included on how deliveries on SWIP North in Southern Idaho get the additional 300+ miles to Portland, Oregon and the PGE system. We infer by the assumptions used in the IRP that it is BPA upgrades that will fill in this plausible path for this project and others. This could, and should, be denoted in the transmission analysis to be consistent with how it was applied for NPC #1.

Additionally, the dependencies on BPA leave some open questions before the plausible path can be logically established as follows. 1) what BPA upgrades are essential, or “contingent”, to create the full path from resources to load of each transmission option? 2) how much capacity gets created in the system by these upgrades? 3) how much of that capacity is allocated to PGE from BPA? and 4) what is the timing of those BPA upgrades and how will that impact the availability of the overall transmission project being evaluated in the IRP?

To address these questions sensitivities should be considered that evaluate various future availability of transmission, and how each of the transmission projects and corresponding resource access might be impacted. We believe that the sensitivities already run are a solid first step, but should be expanded to account for each of questions included above.

Our understanding is that BPA has not yet determined how the GERP rights will be allocated among a number of parties, including BPA preference customers in the PGE area. Additionally, for the particularly notable path on North of Pearl, all of the BPA and PGE planned upgrades appear to result in a max rating increase of 800 to 1,200 MW, depending on the season. Powerflow analysis we performed using WestTEC



cases confirms this result. We also see a high dependency on also completing transmission projects BPA's North of Marion upgrades which BPA forecasts will not be available until at least 2035. This may be particularly significant for the Warm Springs Power Pathway project that may be held back from the 2032 COD by 2035 of contingent facilities that are shared across other parties.

This raises concerns that even if PGE received nearly all of the BPA GERP value, there is a limit on the number of projects delivering near Salem that can reach PGE main system load. Additionally, for transmission projects that will require BPA's North of Marion and North of Pearl upgrades, how can they provide PGE capacity or market access value before 2035 when those upgrades are planned to be in service?

We would like to see more clarity for the BPA upgrades and other transmission on the formation of full paths. If PGE has not yet been allocated BPA GERP capacity, it seems prudent that PGE should run a IRP sensitivity with partial or delayed access to BPA GERP capacity on critical flowgates such as NOPE. If for some projects these legs are assumed in the model and with ample capacity, then the consistent approach would be to assume the legs that extend CRTP access well beyond Big Eddy are also in the model and allocatable to CRTP thereby meeting the standard of a credible and deliverable path for diverse resources to some of the regions listed.

Capacity and Market Access Assumptions for CRTP

The Cascade Project was considered in PGE's 2026 CEP/IRP analysis under the "Resulting Market Capacity Assumptions" framework presented at the February 24, 2026 Roundtable. In that analysis, PGE assigned Cascade an Extra-Regional Market designation of "None" and a Market Capacity Limit of 0 MW, resulting in no Summer or Winter Capacity Benefit credited to the project in PGE's modeling. We believe this conclusion is incorrect and that it misses an opportunity to consider Cascade's contribution to PGE's resource portfolio, for the reasons set forth below.

The Cascade Project's interconnection at Big Eddy place it one electrical bus away from the northern terminus of the Pacific DC Intertie (WECC Path 65), one of the highest-capacity long-distance transmission corridors in the western grid. The PDCI has a South to North path rating of 3,100 MW to the Celilo/Big Eddy area from the Sylmar converter station in Los Angeles, which makes Big Eddy a direct injection point toward Southern California load. Although the PDCI is often operationally limited to approximately 1,000 MW, those operational limits are not driven by the



PDCI's path rating, and studies have evaluated upgrades to increase that operating limit.

Additionally, Big Eddy 500kV is the planned northern terminal of BPA's Lower Columbia - NOB GERP transmission project which will bring Nevada Market access. If PGE is assuming unallocated BPA rights to deliver capacity and market access across North of Marion and NOPE, then the same logic should be applied to capacity on Lower Columbia - NOB to unlock Nevada (Winter) market access for CRTP. Cascade's interconnection at Big Eddy also extends the reach of PGE's system toward the termination points of other extra-regional transmission projects under analysis, making it complementary to projects such as Blueprint South, Gateway West, and North Plains Connector.

Timing Interdependencies of Proposed Transmission Solutions

As noted in prior comments, while the Cascade Project has few dependencies on other transmission projects to deliver its full 1,100 MW capacity, planned BPA transmission projects may be essential to realizing the full capacity and benefits of other proposed transmission solutions. PGE presently assumes that all BPA GERP 1.0 and 2.0 projects will be in-service for considering the extra-market benefits provided. Understanding how project timing and interdependencies affect overall transmission access is therefore critical to a complete IRP evaluation. For example, if one or more projects in BPA's Plan of Service – such as the North of Pearl 500 kV upgrade – were delayed into the 2035-2040 timeframe, what level of transmission service would remain available to PGE from the remaining upgrades alone?

Conclusion and Recommendations

We appreciate the opportunity to comment on PGE's 2026 CEP/IRP. To ensure the CEP/IRP reflects the transmission-enabled capacity value available to PGE by the time the Cascade Project reaches its 2032 COD, we request that PGE:

1. Apply a consistent framework to all considered transmission projects. Update the transmission project table to denote what, if any, contingent facilities (e.g. transmission rights or new projects) each option relies on to deliver to PGE load. For example, NPC #1 would note that it reuses existing BPA TSRs from Colstrip - NPC to PGE System for completing the full path from to PGE load. Any new projects or BPA TSRs that are needed to deliver capacity or market access from a transmission project option, such as BPA's NOPE upgrade, should be tagged. If a new transmission project is contingent on another project with a later in service date, that should delay



the availability of that transmission option in the PGE IRP model. For example, any transmission project that is reliant on BPA's North of Marion project with a planned 2035 in service date, should not be eligible for use in PGE IRP model until 2035 at the earliest.

2. Run BPA GERP transmission project scenario(s) to evaluate PGE only receiving partial BPA GERP capacity due to limited allocation and/or awaiting BPA project completion. These GERP facilities could include North of Marion, North of Pearl, and Big Eddy Chemawa.

3. Revise the resulting market capacity assumptions for Cascade to reflect Extra-Regional market access via Big Eddy/Celilo, rather than assigning an Extra-Regional Market designation of "None" and a 0 MW Market Capacity Limit.

PGE Response:

PGE's 2026 IRP modeling of CRTP does not include access to diverse market front office transaction. CRTP terminates near The Dalles, and does not reach the diverse markets of California, Desert Southwest, or SPP/MISO. To access diverse market front office transactions, a project must be able to demonstrate physical access with long term firm rights to one of these three regions.

PGE's 2026 IRP modeling of CRTP does not include access to the resource zones associated with California, Desert Southwest, and Mountain West. CRTP terminates near The Dalles, and does not reach the diverse resource zones. CRTP is able to access resources across BPA's network through assumed transmission requests or redirect requests. To diverse resource zones, a project must be able to demonstrate physical access with long term firm rights to one of these regions.

PGE's 2026 IRP describes contingent facilities associated with each transmission project including those listed on the attached table. The contingent facilities are included in the assumed COD dates of each project. The 2026 IRP does include sensitivities related to the unavailability of near term transmission projects that could be driven by the failure or delay of contingent facilities.

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Stakeholder: OPUC Staff

Organization: OPUC Staff

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Updated Transmission Analysis (Slides 7 - 19)

Any Other Feedback?

4. Staff is interested in understanding the extent to which the changes in constraints are driven by the seasonal split vs updated TTC numbers from BPA.

PGE Response:

Page 17 of the July 22 CEP/IRP Roundtable presentation summarizes the change in NOPE constraint frequency between the May 2026 analysis, which used the older static TTC values, and the July analysis, which incorporated updated seasonal TTC values from BPA.

Overall annual reduction - The July results show that the annual NOPE constraint frequency decreased from 40% in the May analysis to 16% in the July analysis.

Seasonal distribution of remaining risk: The seasonal results indicate that the updated TTC assumptions materially reduce constraint frequency in each season, while the remaining risk continues to be concentrated primarily in spring and summer. Under the July results, spring and summer constraint frequency is approximately 21% and 29%, respectively, compared with 57% and 43% in the May results. Winter and fall constraint frequency declined to 4% and 9%, respectively, compared with 29% and 32% in the May results.

This indicates that the updated BPA TTC values are the primary driver of the overall reduction in annual constraint frequency, while the seasonal split helps explain the timing and distribution of the remaining constraint risk. In both the May and July results, spring and summer remain the highest-risk seasons, indicating that seasonality is still a contributing factor even after the updated TTC values are applied.

July Results: Constraint Frequency with updated NOPE TTC values



Upgrades Scenario: Annual NOPE constraint frequency decreases from 40% to 16% under the updated TTC values. Constraint risk is primarily concentrated during Spring and Summer.

Seasonal Constraint Frequency

% of Hours Over Utilization Threshold (>=80%)

Season Name	Winter		Spring		Summer		Fall	
	No Upgrades	Upgrades	No Upgrades	Upgrades	No Upgrades	Upgrades	No Upgrades	Upgrades
Pth-BPA-North of Pearl	40%	4%	66%	21%	49%	29%	42%	9%
P04 West of Cascades-North	7%	0%	12%	0%	1%	0%	0%	0%
P05 West of Cascades-South	36%	0%	34%	1%	30%	0%	9%	0%
P06 West of Hatwai	0%	5%	0%	10%	0%	5%	0%	0%
P71 South of Allston	0%	0%	0%	0%	0%	0%	0%	0%
P86 West of John Day	1%	0%	2%	0%	1%	0%	0%	0%
P87 West of McNary	0%	0%	0%	0%	0%	0%	0%	0%
P88 West of Slatt	0%	0%	0%	0%	0%	0%	0%	0%
Pth BPA North of Grizzly	10%	0%	7%	0%	7%	0%	5%	0%
Pth BPA North of Hanford	0%	0%	0%	0%	0%	0%	0%	0%
Pth BPA River-Paul	3%	0%	9%	0%	11%	0%	0%	0%
Pth BPA West of Lower Monumental	7%	23%	2%	9%	0%	1%	0%	0%

Upgrades Scenario: NOPE Constraint Frequency Update

Season	May Results	July Results	Change
Winter	29%	4%	-25%
Spring	57%	21%	-36%
Summer	43%	29%	-14%
Fall	32%	9%	-23%
Annual	40%	16%	-24%
Risk Profile	Year-round	Primarily Spring-Summer	

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Energy Strategies Transmission Analysis (Slides 20 - 43)

Any Other Feedback?

5. In slide titled "Future Modeling: Incorporating Findings from PCM into Aurora" please explain whether the Company thinks there are any implications of not using hydro as an input variable.

PGE Response:

Hydro generation was evaluated as a potential model input but was ultimately excluded because its correlation with high NOPE flows was insufficient in the 2024-2025 historical analysis. The variables selected for the model, including High California solar net load, PNW wind output, and PNW load, are driven largely by non-dispatchable system conditions. Unlike these variables, hydro generation is dispatchable and can be actively shaped to accommodate transmission constraints, reducing its value as a predictive input. While the analysis did not identify hydro as a significant predictor during the study period, PGE recognizes that the period evaluated did not encompass the full range of hydro conditions observed in the Pacific Northwest. Accordingly, the results indicate that hydro was not a strong predictor within the study period rather than demonstrating the absence of a broader hydro-NOPE relationship.



6. In slide titled “Top Individual Correlated Factors Scatter Plot” has the Company considered whether Californian hydro may be correlated?

PGE Response: This was not identified in the Energy Strategy analysis.

7. How are the constraints at the NOPE flowgate impacted by other existing transmission constraints and the anticipated impacts of future transmission upgrades?

PGE Response: Future impacts were considered to the extent they were in the WestTEC 10 year case. The information utilized is the best available at the time of analysis being performed. PGE will continue to update and evolve information in future planning cycles.

8. To what extent are forecast constraints impacted by assumptions about future load growth? For example, how would the removal of the Salem data center load impact assumptions about NOPE flowgate constraints?

PGE Response: Future impacts were considered to the extent they were in the WestTEC 10 year case. The information utilized is the best available at the time of analysis being performed. PGE will continue to update and evolve information in future planning cycles.

Capacity Needs & ELCC Update (Slides 44 - 49)

Any Other Feedback?

9. On slide 47:

- a. What special insight does May and September provide that prompted them to be chosen for this depiction?
- b. Could you also share August and December?
- c. Could you explain why load is higher after midnight than between 9 pm and 10 pm?
- d. Why does instantaneous load cycle within each hour?

PGE Response:

- a. May CLF and September CLF refer to the vintage of the corporate load forecast (CLF) used for estimation. ELCCs depicted are summer (April-Sept) and winter (Oct-March) seasonal values.



- b. ELCC values displayed include August and December, with those months being primary drivers of seasonal values given loss of load profiles.
- c. Load values displayed are for month-hour on the x-axis. The figure displays the 90th percentile of load for each month-hour, essentially depicting a 1:10 load shape for each month of the year in which ELCCs were simulated (2032)
- d. 01-00 indicates Jan. at hour 00:00, and the point on the x-axis prior to 02-00, represents Jan. at hour 23:00. As such the 12 load shapes displayed in the graph represent a 90th percentile day for each month of the year 2032.

Updated Draft Portfolio Results (Slides 50 - 72)

Any Other Feedback?

10. See slide 60. RNW asked about why long duration storage wasn't on the charts and the Company explained that it wasn't made available that soon (by 2032). Please share the assumptions informing when long duration storage is made available.

PGE Response:

Long duration storage is available for selection in portfolio analysis beginning in 2030. Long duration storage is added to the Continued Progress Portfolio beginning in 2044 and to the Preferred Portfolio beginning in 2037. The resource was not shown in the figures because they only showed resource additions through 2036.

11. On slide 61, are the quantity of VPP dispatch events the same across the three portfolios?

PGE Response:

The portfolio benefits of VPP resources (including flex load and DSG) are modeled in PGE's capacity expansion model, ROSE-E, using ELCC curves that determine capacity accreditation per MW of resource added to the portfolio. Because the quantity of the VPP resources selected differs across the three portfolios depicted in the figures on slide 61, the quantity of capacity benefits provided differs by portfolio. The quantity of dispatch events for the VPP resources is not modeled directly in ROSE-E and therefore it is not possible to say how the quantity of dispatch events would vary across the portfolios.

The ELCC curves that determine capacity accreditation in ROSE-E are generated in PGE's resource adequacy model, Sequoia. The ELCCs generated in Sequoia are determined by the ability of the VPP resources to help meet load and prevent resource adequacy events. It is in this model that the granularity of characteristics such as number of dispatch events is represented and the impact of such characteristics is captured in the resulting ELCCs.

12. In determining the continual progress portfolio - is the Company using average costs or marginal costs, is there a differentiation between the marginal cost for core customers and large load customers, and what are the Company's assumptions about the marginal costs of serving large load customers?

PGE Response:

The Continued Progress portfolio is informed by the forecasted total costs of new resource additions in the reliability only scenario and the existing revenue requirement as of April 2026. More information is available in the May 2026 Roundtable and additional details will be included in the 2026 CEP/IRP filing.

PGE evaluated costs across scenarios that included forecasted total system load and then forecasted core-growth only load. Additional detail around this analysis and conclusions will be included in the 2026 CEP/IRP.

Draft Portfolio Resource Adequacy Assessment (Slides 73 - 82)

Any Other Feedback?

13. How does the loss of the Salem datacenter affect PGE's resource needs?

PGE Response:

We do not anticipate material impacts to near-term resource needs. Customer specific changes in load are not unusual. PGE updates the Corporate Load Forecast on a regular basis to capture changes throughout time.

A large volume of the load growth embedded in our corporate load forecast through 2030 is supported by customers that are already energized, permitted, constructed or under construction. We have a highly diversified industrial sector in our territory, including semiconductors, technology and manufacturing customers, and consider low, reference and high load forecast scenarios in the IRP to account for uncertainty in load forecast values. Customer specific changes in load are not unusual. PGE updates the Corporate Load Forecast on a regular basis to capture these changes.



14. Regarding slide 81, Staff would like the company to include in its IRP a discussion about the reliability tradeoffs between GHG, Reliability only, and Continued Progress scenarios and how risk mitigation efforts might be different under each.

PGE Response:

Discussion on the reliability tradeoffs between difference scenarios is included in the IRP. As it pertains to risk mitigation efforts, it is important to note that all portfolios meet or exceed capacity needs. PGE appreciates Staff's consideration of risk across different resource buildouts, and would be open to discuss definitions of risk and further analysis that can expose reliability tradeoffs and risk as part of future planning cycles.

15. How does the way the Company is evaluating resource adequacy compare with the methodology used by the Western Resource Adequacy Program (WRAP - it seems generally the same but there may be important differences).

PGE Response:

Both methodologies use stochastic loss of load simulation to evaluate system reliability. The primary difference is that WRAP simulates system reliability for all participants in the WRAP program given resource assumptions, transmission constraints, and load profiles as described in the WRAP Business Practice Manuals. PGE's resource adequacy assessment represents a PGE system specific assessment of the Company's load and supply resources. As such, the loss of load and ELCC metrics produced through WRAP are less granular than those produced by PGE and should be compared directionally.

16. What happens in 2028 and 2030/2031 to create sudden increases in reliability/decreases in capacity position for the Reliability Only/Continued Progress portfolios?

PGE Response:

The increase in reliability seen for the RO portfolio in 2028 is a result of prebuilding of VPP resources that have a limited window of availability for the model to select. As ROSE-E builds resources for the RO portfolio into 2030 and beyond and the capacity position suggests resource buildouts are constructed to meet a winter capacity need constraint, which results in some length in summer 2031. The length in capacity position for the Continued Progress portfolio is equivalent to the RO portfolio for the years 2028 and 2029, again a result of prebuilding. However, the length in the Continued Progress portfolio capacity position grows in the early 2030's because of resource additions associated with the minimum expenditure constraint.

Backcast Review (Slides 83 - 94)

Any Other Feedback?

17. On slide 91, what is being netted out of load for this back casted set of load duration curves?

PGE Response:

The net load shape represents the remaining load after non-dispatchable resource generation is subtracted from total load. Since hydro is not dispatchable in the Backcast Model, hydro generation is included in the calculation of net load such that for each hour h , the following equation applies:

$$Net Load_h = Load_h - Solar_h - Wind_h - Hydro_h$$

The Net Load Duration Curve demonstrates the remaining gap to serve load that is met by dispatchable resource generation and unsecured reliability purchases.

18. Slides 92 and 93 appear to show where market purchases are most relied upon to meet capacity and are particularly helpful illustrations. Please confirm whether there is any netting of load in these slides.

PGE Response:

There is no netting of load in either graphic on Slides 92 and 93.

It is important to note that total monthly energy and monthly peak demand were held constant across all historical month-year combinations and set equal to the 2030 forecast values. This approach was intended to isolate differences in hourly load shapes rather than interannual differences in overall load levels, as the results were compared against the 2030 Reliability-Only (RO) Portfolio.

As a result, while variations in daily load patterns within a month (for example, among different June years) are reflected in the analysis, differences in the overall severity of those months are not. Historical years with unusually hot or cold June conditions do not exhibit correspondingly higher or lower absolute demand levels. Instead, Aurora's backcasting methodology effectively rescaled each month's hourly load distribution to match the assumed monthly energy and peak demand targets. This is why, for example, the 2021 load profile does not show a substantially higher absolute peak than other historical years despite the extreme weather conditions observed that year. Indeed, the monthly peak load is effectively constrained to a similar level across all historical years, as evidenced by the identical maximum hourly load values shown in the analysis.

For future backcasting efforts, IRP will evaluate alternative load-scaling methods that better preserve the impact of unusually hot or cold historical periods on absolute peak demand, while still reflecting expected load growth between the historical year and the forecast year, 2030.