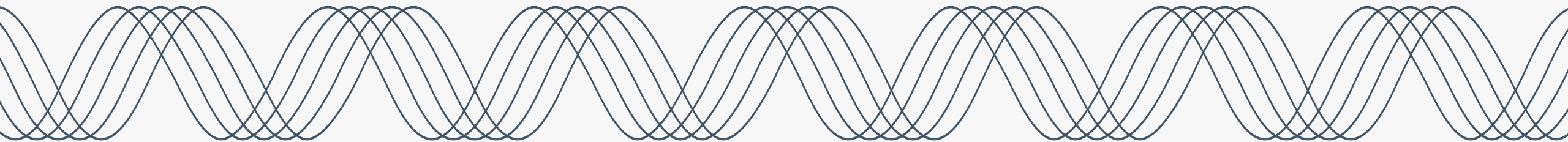




PGE CEP & IRP Roundtable 26-4

May 20, 2026



Meeting Details

1

Electronic version of presentation

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

2

Zoom meeting details

- Join Zoom Meeting
<https://us06web.zoom.us/j/84372774388?pwd=WGdNfwfAFGcWgHxYjX0Mk2QbhDDaa7.1>
- Meeting ID: 843 7277 4388
- Passcode: 108198

3

Participation

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

Meeting Logistics



Focus on Learning & Understanding

- Team members will take clarifying questions during the presentation, substantive questions will be saved for the end (time permitting)
- Attendees are encouraged to 'raise' their hand & chat to ask questions

Follow Up

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

May 20, 2026 – Agenda

9:00 | Welcome

9:05 | Stakeholder Feedback Responses

9:20 | Community Benefit Indicators (CBIs)

10:10 | Portfolio Analysis Scenarios

10:40 | BREAK

10:50 | Cost Cap Scenario Update

11:00 | Transmission Constraints Results and Analysis

11:30 | VPP Integration & ELCC Review

11:55 | Next Steps and Close

Roundtable DRAFT Schedule for the 2026 CEP/IRP



Wednesdays from 9 to 12 pm, Online Via Zoom

January 14, 2026	PGE Longer Term Local Transmission Plan For the 2024-2025 Planning Cycle, Resource Contract Extension Update, Flexibility study overview, Clean Energy Plan - Overview, Community Benefit Indicators, PGE'S Community Engagement Approach for 2026 CEP, Portfolio/Scenarios Designs
February 24, 2026	PGE Announcement To Acquire WA Utility, Clean Energy Plan & Integrated Resource Plan Community Engagement Updates, Flexibility Study Draft Results, CBRE Update, IRP Emissions Forecasting, Diverse Market Transmission Framework, Portfolio Scoring, ELCCs, RFP Update and Proxy
April 8, 2026	Community Engagement, Transmission Constraints: Methodology & Approach, Price Future Updates, Energy Value for Resources, Generic Resource Cost Update, & Market Emission Factor Scenarios
May 20, 2026	Stakeholder Feedback Responses, Community Benefit Indicators (CBIs), Portfolio Analysis Scenarios, Cost Cap Scenario Update, Transmission Constraints: Results and Analysis, and VPP Integration & ELCC Review
June 10, 2026	DRAFT: Community Impacts, Report Outline, Draft Portfolio Analysis Results, New Large Load (NLL) update, & Energy Strategy Analysis
July 01, 2026	TBD
August 2026	TBD
September 2026	TBD
October 2026	Office Hours after filing

Stakeholder Feedback Responses

Sydney Hinds



Outline

PGE's responses to stakeholder feedback through April 2026 will be available by the end of the week on PGE's [website](#).

Recent feedback includes PGE responses to:

- CBREs
- Transmission constraints
- Data Centers (New Large Load update later in the roundtable)

Provide feedback through PGE's CEP & IRP public website: [CEP/IRP Stakeholder Feedback | PGE](#)

Community Benefit Indicators (CBIs)

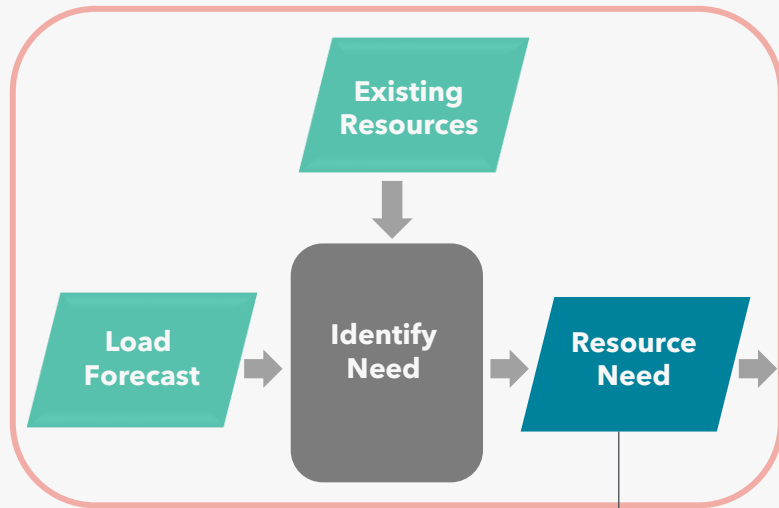
Kyle Billeci



High-Level IRP Analysis Process

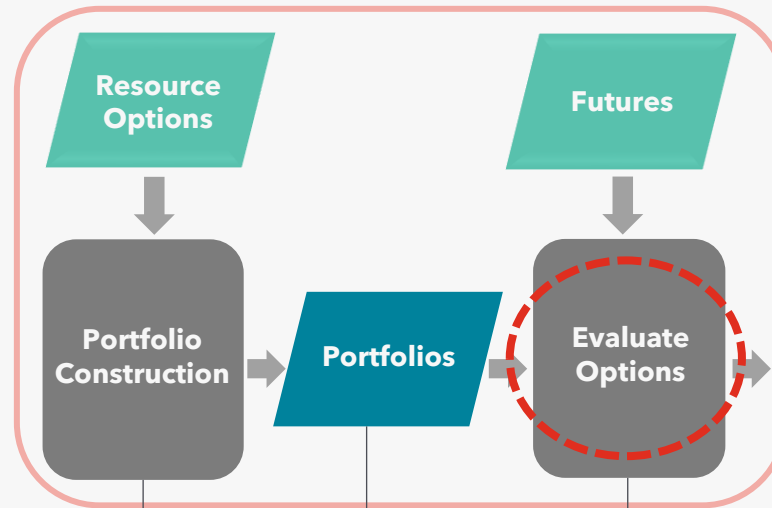


Estimate System Needs



MWs of capacity and
aMWs of energy
for system to reliably operate

Evaluate Resource Options



potential resource
additions to our system

to test resources,
incorporate regulatory
requirements, assess
impacts to needs

scenarios and sensitivities
for an informative set of
future conditions

Develop Plan



IRP has a 20-year planning
horizon, Action Plan covers
the next 2-4 years

Outline

Methodology Change from 2023 IRP

2026 CBI Revised List

CBI Evaluation & Tracking Approach

Historical Background

Defining CBIs

- Staff directed utilities to develop Community Benefit Indicators (CBIs) as part of Oregon's Clean Energy Plan framework under UM 2225, with input from communities, stakeholders, and OPUC Staff.
- CBIs were intended to supplement traditional least-cost planning by incorporating measurable community impact considerations into IRP and CEP portfolio evaluation.

CBI Categories

Initial guidance directed utilities to develop quantifiable and measurable indicators covering:

- Resilience
- Health & Community Well-Being
- Environmental Impacts
- Energy Equity
- Economic Impacts

CBI Functional Structure

Staff further directed CBIs to span three functional categories:

- Resource CBIs (rCBI)
- Portfolio CBIs (pCBI)
- Informational CBIs (iCBI)

CBI Assessment (Cadeo Study)

- Cadeo's CBI assessment established a structured framework for evaluating and tracking **community benefits** within IRP and CEP processes.
- The assessment:
 - Identified 30 CBIs across the **five** OPUC-defined categories
 - Differentiated:
 - Monetizable resource-level benefits (**rCBIs**)
 - Portfolio-level assessment metrics (**pCBIs**)
 - Informational/tracking metrics (**iCBIs**)
 - Highlighted community benefits vary by:
 - Resource type
 - Deployment strategy
 - Location
 - Program Design



[IRP Roundtable for Cadeo's CBI](#)

(Cadeo/Resource Innovations is a Portland, OR based consultant company focused on engagements that support company decarbonization goals. PGE last engaged with them in 2024 to identify CBIs).

CBI methodologies remain an evolving framework intended to improve transparency and differentiation of community impacts across portfolios

Community Benefit Indicators (CBIs)

Functional Categories Explained:

Resource (rCBI)

Limited but monetizable

- Applied at the individual resource level
- Represents monetizable benefits tied to specific technologies or programs (Energy Efficiency (EE), Demand Response (DR), Community Based Renewable Energy (CBRE))
- Applied where defensible valuation methodologies and quantifiable relationships exist

Portfolio (pCBI)

Moderate/Evolving

- Portfolio-level indicators used to compare relative community impacts across portfolios
- Can include both quantitative and qualitative community impact considerations
- Evaluates expected impacts across the five CBI categories
- Intended to improve transparency around portfolio tradeoffs via community outcomes

Informational (iCBI)

Most Mature Operationally

- Longitudinal tracking metrics used to evaluate historical and forecasted community impacts over time
- Measures realized outcomes such as participation, Distributed Energy Resources (DER) adoption, Greenhouse Gas (GHG) reductions, etc.
- Utilizes customer-level geospatial analysis to assess impacts across Environmental Justice (EJ) communities, energy burdened areas, and tribal communities.
- Primarily used for transparency and progress tracking

CBI List



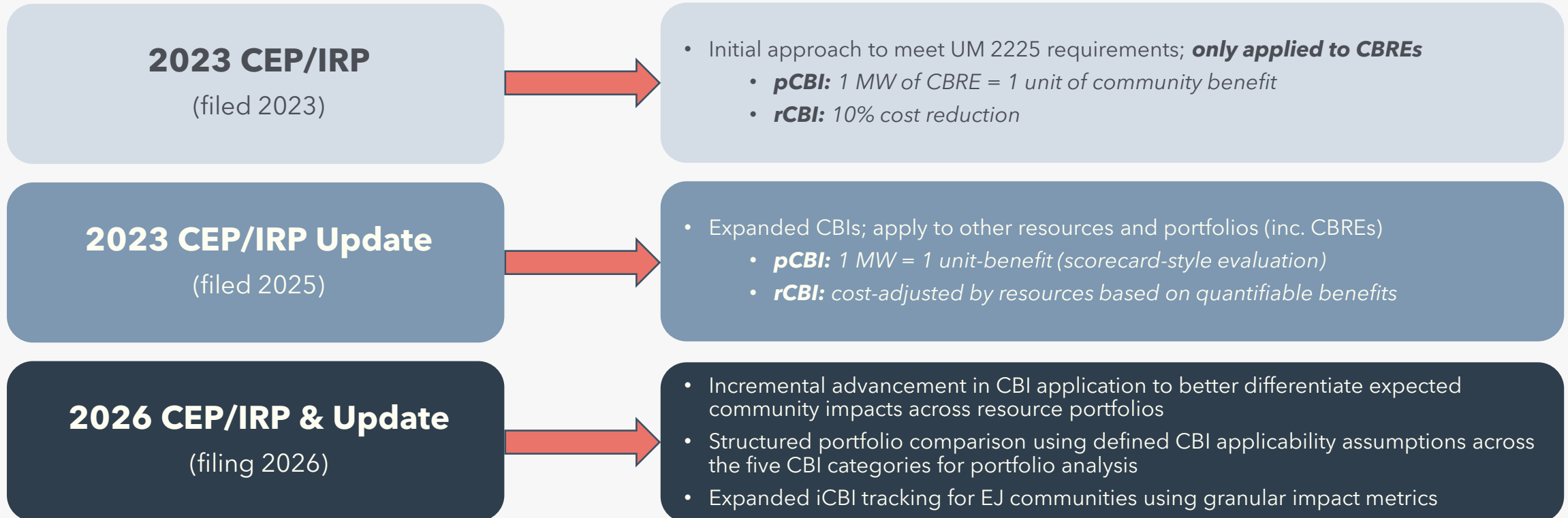
CHARACTERIZING CBIS BY CATEGORY

- Economic Impacts
- Health + Community Wellbeing
- Energy Equity
- Resilience/Reliability
- Environmental

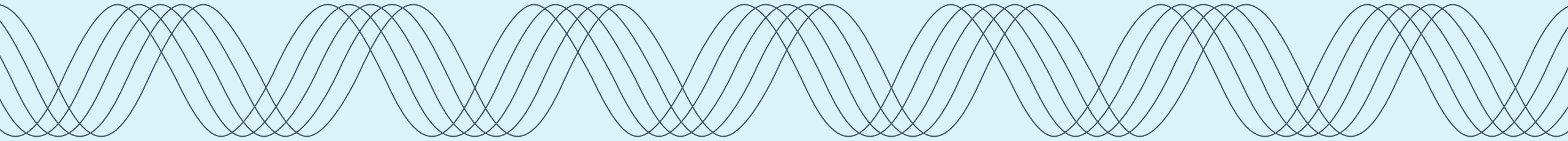
1 ● Economic development impact	7 ● Ancillary services	13 ● ● Increased availability of electricity storage in Tribal and non-Tribal communities	19 ● Increased satisfaction and pride	25 ● ● Improved grid resiliency
2 ● Increased access to jobs	8 ● ● Reduction in GHG Emissions	14 ● ● Increased number of clean energy generation that powers Tribal communities	20 ● ● Improved comfort in home	26 ● ● Increased resilience/reliability in targeted communities
3 ● ● Increased property or asset values	9 ● Improved access to reliable clean energy	15 ● ● Improve efficiency and housing stock in utility service territory, including LI housing	21 ● Improved public health outcomes	27 ● ● Reduction in recovery time and increase in survivability from outages
4 ● ● Economic well-being	10 ● Improved participation in clean energy programs by EJ communities	16 ● ● Increased energy affordability/reduction in energy burden for EJ communities	22 ● ● Improved community health outcomes in targeted communities	28 ● ● Reduction in frequency and duration of black/brownouts in target communities
5 ● ● Increased productivity	11 ● Increased awareness of utility programs for EJ communities	17 ● ● Reduced arrearages/late payments	23 ● ● Reduced local emissions (pollution burden, pollution exposure)	29 ● ● Reduced risk to targeted communities from outages
6 ● ● Energy security	12 ● Meaningful bilateral engagement between utilities and tribes on siting	18 ● ● Reduced residential disconnections and collections	24 ● Improved household health and safety outcomes in targeted communities	30 ● ● Increased neighborhood safety from natural disasters

Not all CBIs currently have mature monetization, valuation, or tracking methodologies. Implementation focus is prioritized based on data availability, measurable relationships, and applicability within IRP/CEP processes.

Methodology Refinements



CBIs in Clean Energy Plan



CBI Tracking & Development (2026 IRP/CEP)

Work from AR 669 sets out required components for development of the CEP:

Key Requests:

1. Define and describe in its CEP the **community benefit indicators** the electric company plans to track as the company implements its CEP, including metrics adopted in IRP portfolio scoring
2. CBIs must include consideration via public input, including input from environmental justice communities in Oregon
3. The company must include at least one **community benefit indicator** that addresses community resiliency
4. Report measured values for all **community benefit indicators** defined in the CEP for the previous three years, to the extent possible. If measured values are not available, the company must **explain how it plans to measure community benefits indicator in future years.**

How We Will Track

1. Define and describe in its CEP the **community benefit indicators** the electric company plans to track as the company implements its CEP, including metrics adopted in IRP portfolio scoring
2. CBIs must include consideration via public input, including input from environmental justice communities in Oregon

Integrate reportable CBIs in updated framework mapped to OPUC's five categories, documenting which metrics are incorporated into IRP and CEP.

Continue Community Benefits and Impacts Advisory Group (CBIAG) and IRP Roundtable engagement with targeted community outreach to confirm CBI metrics and ensure the framework reflects community-identified priorities.

Community Benefits and Impacts Advisory Group (CBIAG) launched in April 2023 & was established under Oregon House Bill 2021. The CBIAG provides a forum where community voices inform PGE's clean energy transition efforts.

High-Level Metrics With Trackable CBI Outcomes

Measurement

Cost comparison for portfolios with/without CBREs

Air pollutant emission metrics

Arrearages/late payments

Residential disconnections and collections

Reliability/resilience in target communities (SAIDI/SAIFI)

Participation in utility programs by EJ communities

Electric storage in Tribal and non-Tribal communities

Awareness of utility programs in EJ communities

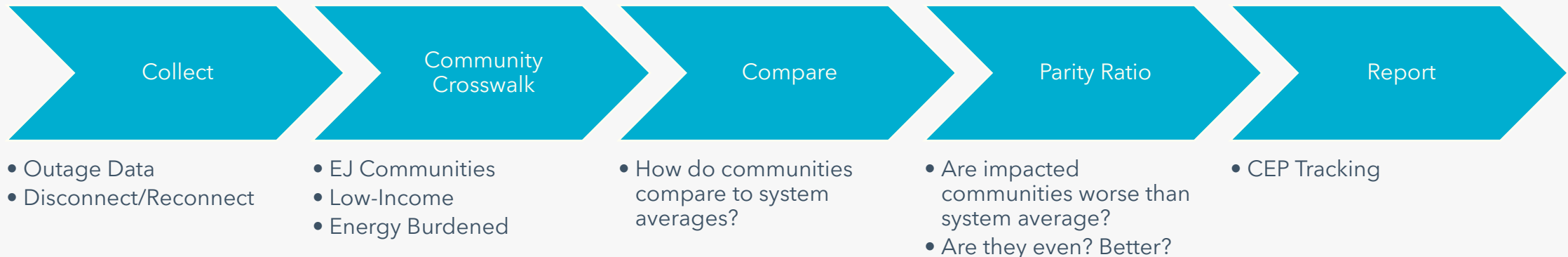
These are current CBIs that have viable data PGE has utilized in external reporting or will utilize in future tracking opportunities.

We can add layers as needed depending on the viable metrics to track (energy burden, etc.)

How We Will Track

1. The company must include at least one **community benefit indicator** that addresses community resiliency
2. Report measured values for all **community benefit indicators** defined in the CEP for the previous three years, to the extent possible. If measured values are not available, the company must **explain how it plans to measure community benefits indicator in future years.**

Resilience Example:



High-Level CBI Tracking Metrics

- Air pollutant reporting
 - 0.27 metric tons of CO₂e/MWh (*carbon intensity*)
 - Additional non-GHG air pollutant metrics
- Reliability/Resiliency
 - SAIFI = 0.53 (*less than one outage per year*)
 - SAIDI = 91 minutes (*1.5 hours of outage time per year*)
 - CEMI/CELID Mapping
 - Customers Experiencing Multiple Interruptions
 - Customer Experiencing Long Interruption Durations
- **Upcoming:** More detail on measured values at the next (June) Roundtable and in 2026 IRP/CEP
- **Future Goals:** Expand on these metrics for future implementation in IRP/CEP
 - Highlight impacts for burdened and energy justice communities



2025 Purpose and Progress Report



*Report data as of 12/31/2025. [Available here](#)

Informational CBIs (iCBIs)

Quantitative metrics used to assess and track the impacts of existing resources or the existing portfolio within tracked communities.

Example: Improved participation in clean energy programs in EJ Communities

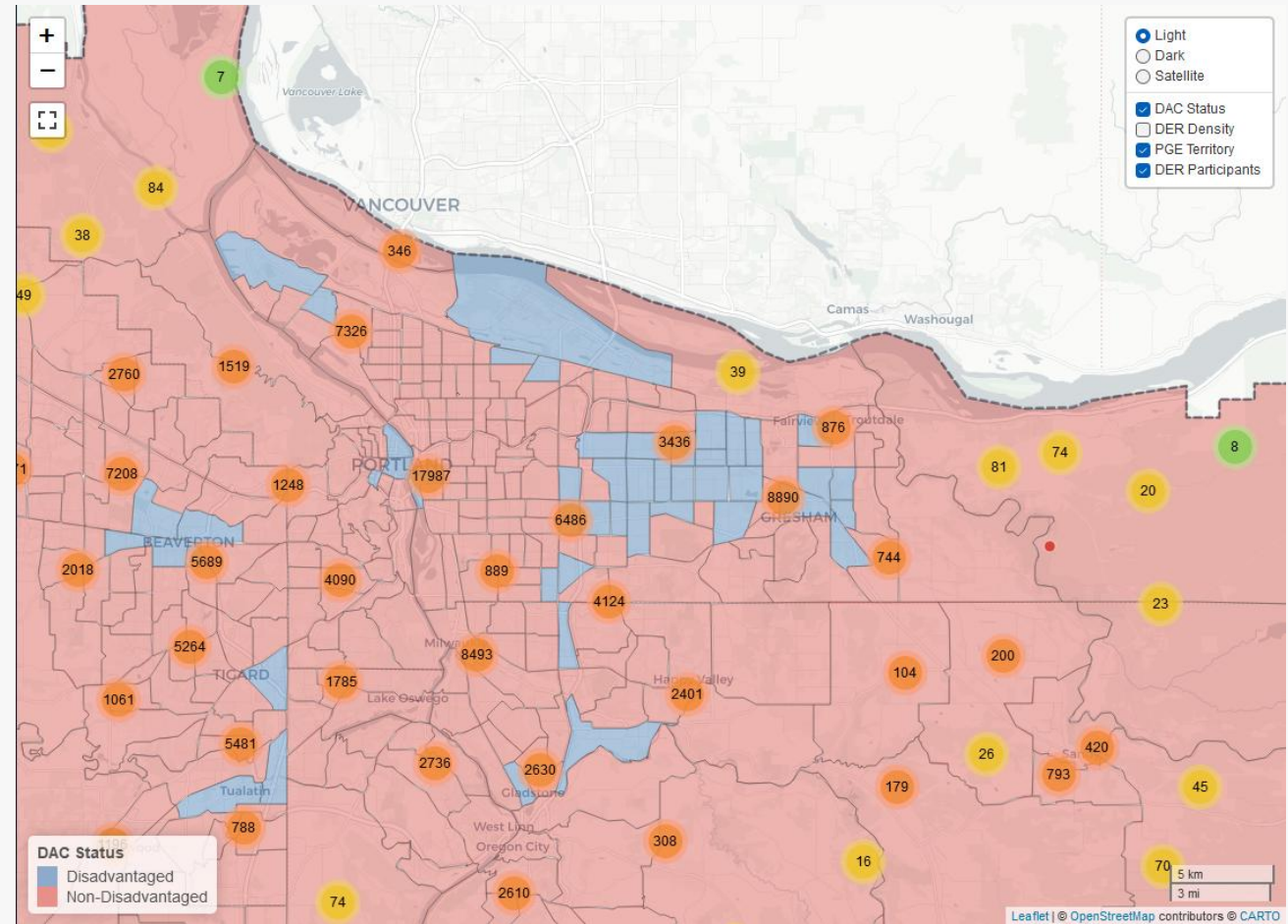
Geospatial mapping of DR programs to see where PGE programs show up within our service territory

Use historical, SPID-level enrollments to map continued progress in **Energy Justice communities** that are overburdened or underserved.

PGE Peak Time Rebate (PTR):

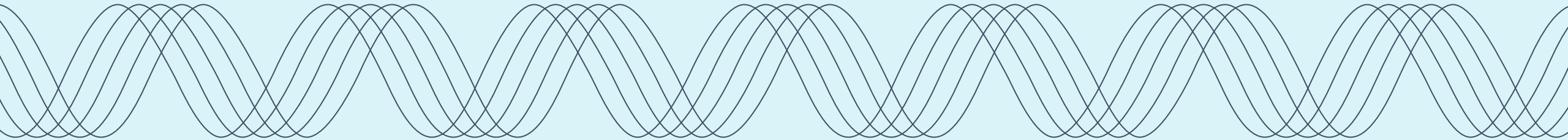
% of PTR participants by community

Community	Enrolled in PTR
Disadvantaged	15.7%
Non-Disadvantaged	16.2%



*Data as of 12/31/2025.

CBIs in Integrated Resource Plan



IRP Resource CBIs (rCBIs)

CBRE Procurement Cost Comparison Framework

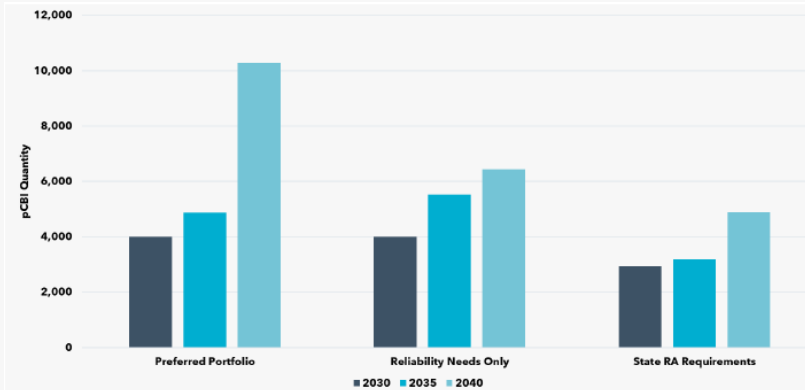
- CBRE RFO enabled bidders to submit project proposals and associated costs for resource strategies intended to support targeted community benefit outcomes
- OPUC acknowledged the final shortlist consisting of battery/storage-oriented CBREs totaling approximately 50 MW online by 2030
- Evaluation compares relative procurement costs of shortlisted CBRE projects against comparable utility-scale resources
- Incremental portfolio costs provide directional insight into procurement costs associated with pursuing targeted community benefit outcomes

Portfolio	Resource Type	Relative Portfolio Cost	Expected Community Benefits	Delta (%)
Utility-Scale Portfolio	Utility-scale solar/battery	Baseline	More limited	<i>\$/MWh for solar ~ 50% higher</i> <i>\$/kw-mo for BESS ~ 35% higher</i>
CBRE Portfolio	CBRE projects	Higher	Expanded/Targeted	

- **The cost delta provides a directional estimate of incremental procurement costs associated with pursuing resource strategies aligned with targeted community benefit outcomes.**

IRP Portfolio CBI Application

- We updated the portfolio CBI scoring approach used in portfolio assessments to align with the current set of resources selectable in ROSE-E.
- This update assigns each resource its applicable portfolio CBI impacts across the five top-level community benefit categories, allowing portfolio results to better reflect the community benefit value associated with modeled resource selections.

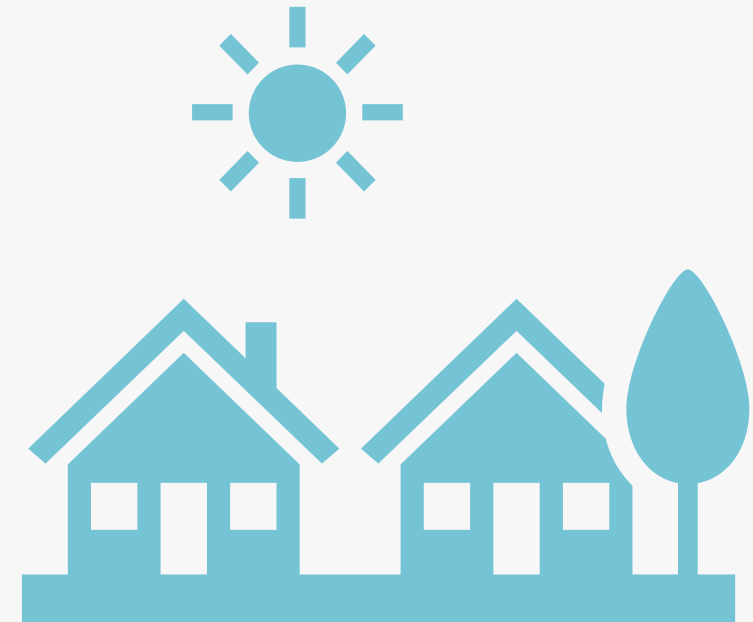


Resource	Economic Impacts*	Energy Equity	Health & Community Wellbeing	Resilience & Reliability	Environ Impacts
Storage (4, 6, 100, PH)	X			X	X
Utility-Scale Solar	X				X
Utility-Scale Wind	X				X
Solar Hybrid	X			X	X
Wind Hybrid	X			X	X
Energy Efficiency	X	X	X	X	X
Virtual Power Plant	X	X	X	X	X
CBRE	X	X	X	X	X
SSR	X	X		X	X
Natural Gas	X			X	
Transmission	X			X	

*Economic Impacts are only for in-state resources

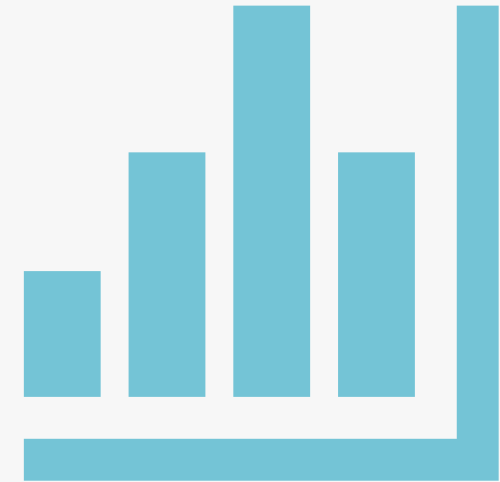
Stakeholder Engagement & Ongoing CBI Development

- Conducted stakeholder education and review of CBI framework concepts during January 2026 IRP/CEP Roundtable discussion
- Reviewed CBI methodologies, applicability, and measurement pathways with the Community Benefits & Impacts Advisory Group (CBIAG) in April 2026
- Continued stakeholder engagement will help inform prioritization of future CBI measurement, tracking, and implementation approaches based on evolving community priorities and data availability
- Current discussions continue to highlight **affordability and customer cost impacts** as key considerations alongside community benefit objectives within the IRP/CEP process



Continued Progress in Quantification & Application

- CBI methodologies continue to evolve from directional resource applicability frameworks toward more measurable and geographically differentiated community impact indicators
- Future IRP/CEP applications will prioritize defensible and trackable metrics supported by available historical data, customer participation trends, DER adoption forecasts, geospatial analysis, and reliability/resiliency indicators
- pCBIs will continue supporting directional comparison of expected community impact characteristics across IRP portfolios, while iCBIs will support tracking of realized and forecasted community outcomes
- CBIs are intended to improve transparency around portfolio tradeoffs, affordability considerations, and targeted community benefit objectives within planning decision-making processes



Guided Feedback

Summary: PGE continues to develop and apply CBIs in the 2026 IRP/CEP through CBRE cost analysis, updated portfolio benefit scoring, and a tracking framework for informational CBIs.

These updates are intended to better reflect community benefits in portfolio assessment and support continued evaluation in future planning cycles.

Purpose: Does PGE's development and continued use of CBIs in the IRP/CEP process make sense?

Do you have suggestions for improving the CBI framework, including priorities for how CBIs should be treated, measured, tracked, or applied in future portfolio assessments?

Portfolio Analysis Scenarios

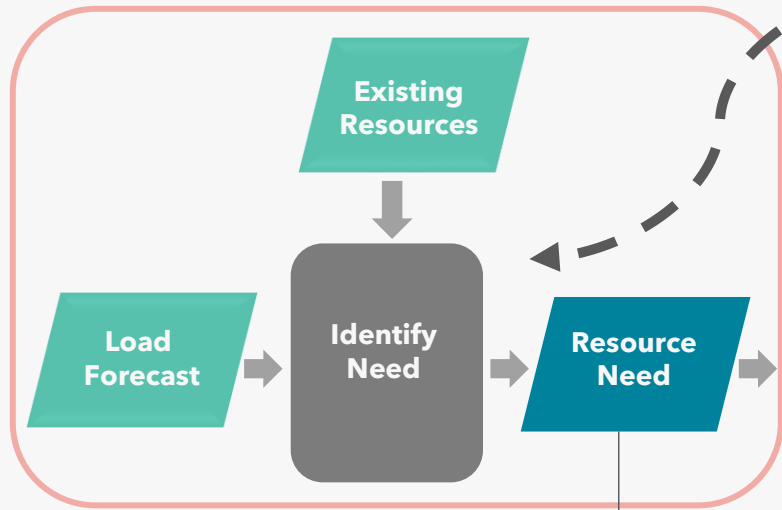
Rob Campbell



High-Level IRP Analysis Process

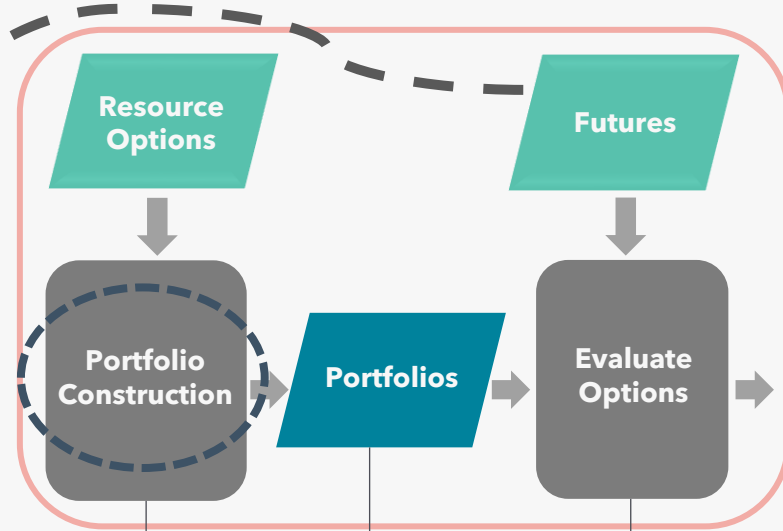


Estimate System Needs



MWs of capacity and
aMWs of energy
for system to reliably operate

Evaluate Resource Options



potential resource
additions to our system

to test resources,
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impacts to needs

scenarios and sensitivities
for an informative set of
future conditions

Develop Plan



IRP has a 20-year planning
horizon, Action Plan covers
the next 2-4 years

Outline



Quick recap on Portfolio Design presentation from Jan 2026 roundtable

Variables and assumptions that differ across scenarios

List of planned scenarios for 2026 IRP

Portfolio Design

The **goal of portfolio analysis** is to inform the creation of a Preferred Portfolio that best balances cost, risk, the pace of decarbonization and community benefits.

The **purpose of portfolio design** is to create a set of portfolios that allow us to gain insights on key questions of interest.

Thoughtful portfolio design:

1. Reasonably captures the realities of a complex long-term planning environment in a simplified modeling exercise.
2. Narrows the focus of analytical effort to key questions of interest.
3. Allows the impacts of alternative decisions to be compared.

Portfolio Analysis Overview – 5 key considerations



Regulatory Environment

PGE has designed Portfolio analysis under three main regulatory environments in order to provide insight on key planning questions of interest to stakeholders.

Regulatory Environment	Description
HB 2021 80% Emissions Reductions	<ul style="list-style-type: none"> • Thermal resources that are retained to serve retail load will decline along a linear glidepath. • No additional natural gas resources can be added.
Reliability Needs Only	<ul style="list-style-type: none"> • Minimal incremental generation needed to meet system reliability regardless of GHG constraints. • Additional natural gas resources are available for selection, beyond the already existing natural gas resources currently owned by PGE. This additional natural gas represents limited potential for new contracts and does not represent new or expanded gas-fired power plants in the state, consistent with Oregon law.
HB 2021 Cost Cap	<ul style="list-style-type: none"> • New for 2026 IRP - discussed further in later section of presentation.

Load Forecast



As discussed at the [October 2025 roundtable](#), PGE has developed a reference, low and high load forecast scenario to assess the impact of different load volumes coming online.

	Customer Growth	Economic Conditions	Data Center Expansion	DER Adoption
Reference Case	September 2025 forecast from Oregon’s Office of Economic Analysis. 10-year avg customer count growth 1.1%	September 2025 forecast of Oregon Employment from Oregon’s Office of Economic Analysis. 10-year AAGR of 0.5%	Existing segment of approx. 400 MW increases to 1 GW in 2030 and 2 GW in 2040	Alignment with today’s reference case AdopDER forecast. Current Federal and State policy assumptions
High Case	Policy steps are successful at encouraging increased building. Growth in customer count is 0.5% higher.	Optimistic case, employment in Oregon posts modest gains in the near term 10-year AAGR of 1.0%	Rapid expansion, segment increases to 1.2 GW in 2030 and 3 GW in 2040	Scenarios to be built out in future sessions
Low Case	Economic conditions weigh on housing. Growth in customer count is 0.5% lower.	Near term recession case, employment growth continues to fall in Oregon before a slow recovery. 10-year AAGR of -0.1%	Constrained growth, 500 MW in 2030 and 600 MW in 2040	Primary driver of residential usage per customer in the forecast period

PGE has also developed a **“no new large load growth”** forecast. This forecast excludes growth associated with Schedule 96 (data center) customers, consistent with the definition of House Bill 3546.⁽¹⁾ This approach is subject to change based on further review of the final order from UM 2377.

Resource Considerations

To assess the impact on resource needs, costs and other key factors, PGE has evaluated various resource additions and extensions in certain scenarios.

Resource Type	Description
Hydro	<p>To evaluate the impacts of additional hydro availability, certain scenarios include the following proxy hydro contract within the base portfolio:</p> <ul style="list-style-type: none"> • 100 MW available 2027 - 2029 • 200 MW available 2030 - 2046
Natural Gas	<p>Certain portfolios are able to select a new contract with an existing natural gas facility, in limited quantities, in addition to the already existing natural gas fleet.</p> <ul style="list-style-type: none"> • 200 MW starting in 2027 • Additional 400 MW starting in 2035 • Modeled using cost and performance characteristics of combined-cycle natural gas proxy resource
Colstrip	<ul style="list-style-type: none"> • Unless otherwise noted, all scenarios have the default assumption of Colstrip exiting PGE's portfolio at the end of 2029 • In line with Senate Bill 1547, PGE is planning to evaluate the impact of Colstrip extending through the end of 2034 in select scenarios

Capacity Methodologies – IRP Metrics v. State RA Metrics:



Portfolio analysis uses **two distinct Capacity Methodologies** for estimating need of the system (Capacity Need)⁽¹⁾ and accreditation of new proxy resources (ELCCs)⁽²⁾: **IRP Metrics** and **State Resource Adequacy (RA) Metrics**. State RA Metrics are third-party estimates used to derive portfolio outcomes to compare against those estimated using IRP Metrics.

Both methodologies produce two key metrics used for portfolio analysis:

- System Capacity Need: Quantity of “perfect capacity” required to maintain reliability, or Resource Adequacy (RA).
- Resource Capacity Contribution (ELCC): Measure of expected performance during capacity critical periods. Equivalent to the “perfect capacity” replaced through a marginal addition of the resource.

1. IRP Metrics

- Used in all scenarios, except the “State RA Metrics” scenario
- PGE’s RA model, Sequoia, is used to estimate Capacity Need and ELCCs
- Hourly assessment of capacity critical periods **specific to PGE’s system**

2. State RA Metrics

- Only used in “State RA Metrics” scenario
- Western Resource Adequacy Program (WRAP) metrics used to estimate Capacity Need and ELCCs²
- Hourly assessment of capacity critical periods of **for entire WRAP program/regions.**

[\(1\) See Dec. 10, 2025 Roundtable 25-8 - Capacity Need and Its Drivers](#)

[\(2\) See Feb. 24, 2026 Roundtable 26-2 - Effective Load Carrying Capabilities \(ELCCs\)](#)

Transmission Expansion



As discussed at the [December 2025](#) roundtable, PGE is evaluating multiple transmission options throughout portfolio analysis. These options are inputs into ROSE-E's portfolio expansion modeling to identify the areas of highest value to PGE.

- Warm Springs Power Pathway
- Cascade Renewable
- Gateway
- North Plains Connector
- Colstrip Transmission Upgrade
- SWIPN
- Trojan-Harbornton
- Greenlink
- Blueprint South



The majority of scenarios have the opportunity to select from all of the transmission expansion options listed above. PGE has also planned to run scenarios that do not include access to any transmission expansion options and some that exclude specific expansion projects. This will provide the ability to analyze the full impact of these options on resource needs and costs across the planning horizon.

Other Analysis

Small-Scale Renewables (SSR)

- SSRs are small-scale renewables less than 20 MW.
- PGE has a 10 percent SSR requirement beginning in 2030.¹
- This analysis includes SSR needs and costs assessments.
- SSR scenario in ROSE-E uses SSR proxy resource to enforce 10% requirement.²

Resource Community Benefits Indicator (rCBI)

- rCBIs reflect the societal value of community benefits associated with certain resources.
- The rCBI scenario applies reductions in fixed cost costs to certain CBRE, EE, and VPP resources.
- The reduction in fixed costs influences optimal resource selection and portfolio cost outcomes.

¹ Per ORS 469A.210

² SSR proxy is based on Christmas Valley Solar with 8% cost premium to reflect lesser economies of scale.

DRAFT: Planned Scenarios for Portfolio Analysis

- “Standard” load forecast = for each high, reference, low
- No NLL = No New Large Load growth included
- RA= resource adequacy



23 main scenarios proposed to analyze a range of policy and utility considerations

Portfolio #	Regulatory Environment	Load Forecast	Resource Considerations		Capacity Methodology	Transmission Expansion
			New Gas Contracts Available	Resource Availability		
1	80% Emissions Glidepath	Reference	No		IRP Metrics	Available
2	Reliability Only	Reference	Yes		IRP Metrics	Available
3	HB 2021 - Cost Cap	Reference	Yes		IRP Metrics	Available
4	80% Emissions Glidepath	No NLL (No DSG Growth)	No		IRP Metrics	Available
5	Reliability Only	No NLL (No DSG Growth)	Yes		IRP Metrics	Available
6	HB 2021 - Cost Cap	No NLL (No DSG Growth)	Yes		IRP Metrics	Available
7	80% Emissions Glidepath	Reference	No	Hydro	IRP Metrics	Available
8	Reliability Only	Reference	Yes	Hydro	IRP Metrics	Available
9	HB 2021 - Cost Cap	Reference	Yes	Hydro	IRP Metrics	Available
10	80% Emissions Glidepath	No NLL (No DSG Growth)	No	Hydro	IRP Metrics	Available
11	Reliability Only	No NLL (No DSG Growth)	Yes	Hydro	IRP Metrics	Available
12	HB 2021 - Cost Cap	No NLL (No DSG Growth)	Yes	Hydro	IRP Metrics	Available
13	Reliability Only	Reference	Yes	Colstrip	IRP Metrics	Available
14	Reliability Only	No NLL (No DSG Growth)	Yes	Colstrip	IRP Metrics	Available
15	Reliability Only	Reference	Yes	Colstrip + Hydro	IRP Metrics	Available
16	Reliability Only	No NLL (No DSG Growth)	Yes	Colstrip + Hydro	IRP Metrics	Available
17	80% Emissions Glidepath	Reference	No		IRP Metrics	Unavailable
18	Reliability Only	Reference	Yes		IRP Metrics	No WSPP
19	Reliability Only	Reference	Yes		IRP Metrics	No NPC
20	Reliability Only	Reference	Yes		IRP Metrics	No Trojan Harb.
21	80% Emissions Glidepath	Reference	No	SSR Eligibility	IRP Metrics	Available
22	80% Emissions Glidepath	Reference	No	rCBI	IRP Metrics	Available
23	Reliability Only	Reference	Yes		State RA Metrics	Available

Guided Feedback

Content: Are there any key planning portfolios/scenarios you believe are missing from this list that you would want to see analyzed?

Cost Cap Scenario Update

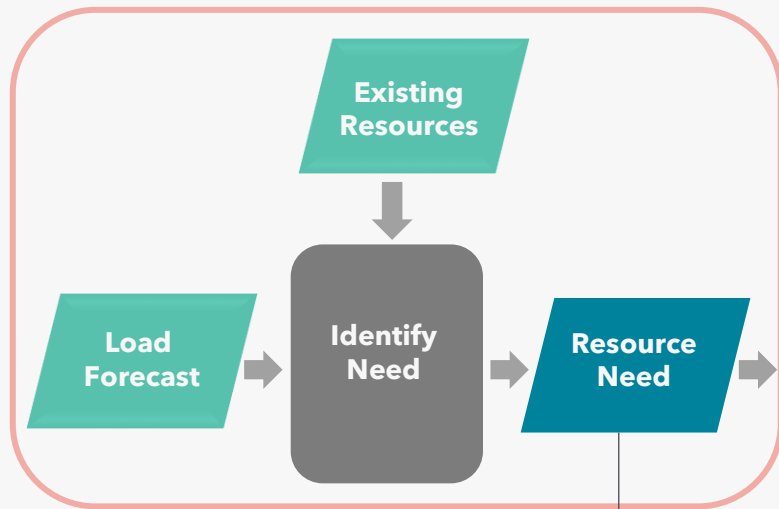
Lauren Slawsky



High-Level IRP Analysis Process

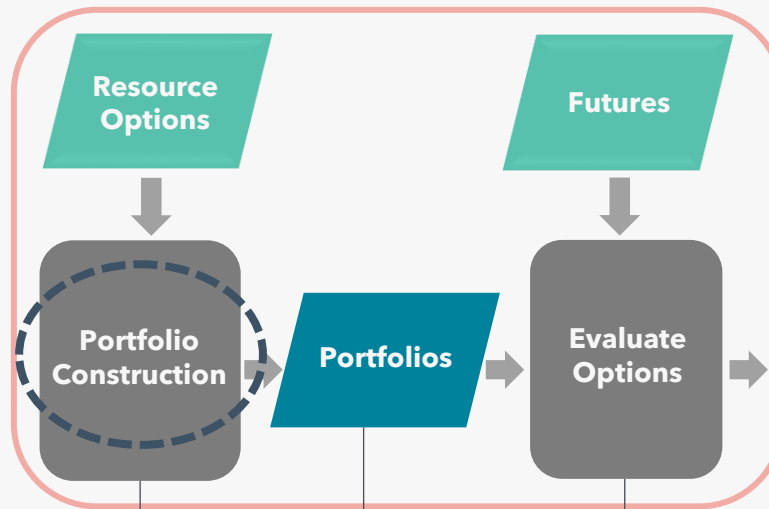


Estimate System Needs



MWs of capacity and
aMWs of energy
for system to reliably operate

Evaluate Resource Options



potential resource
additions to our system

to test resources,
incorporate regulatory
requirements, assess
impacts to needs

scenarios and sensitivities
for an informative set of
future conditions

Develop Plan



IRP has a 20-year planning
horizon, Action Plan covers
the next 2-4 years

Outline



Revisit Cost Cap scenario

Overview methodology

Discuss considerations

Cost Cap Scenario

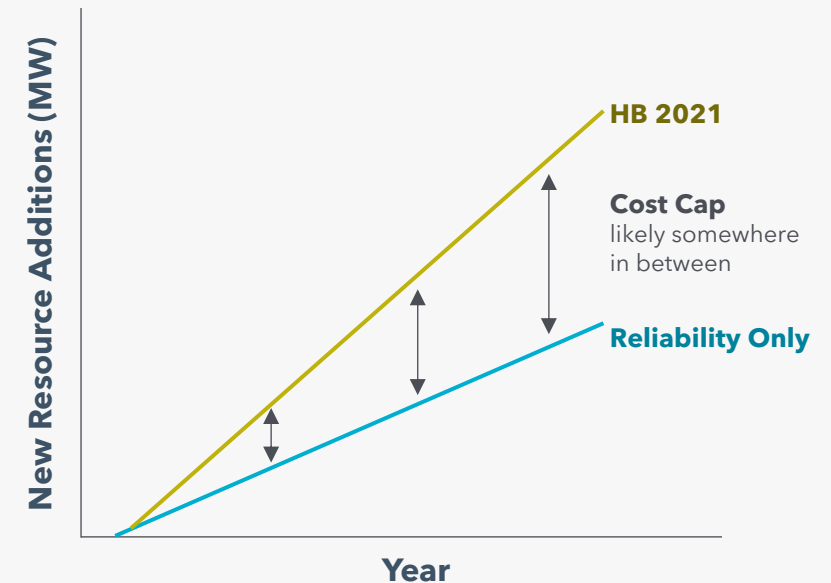


- Revisiting this topic, first introduced at the January 2026 RoundTable.
- House Bill 2021, Section 10 includes a “cost cap” provision that allows for a temporary deferral of compliance with emissions reduction targets if complying would increase rates by more than 6%.
- The 2026 CEP/IRP will include a portfolio category aimed at estimating the cost, resource need, and emissions impacts of triggering the cost cap provision.
- The resulting portfolio buildout aims to meet reliability needs and make incremental progress towards emissions reductions targets (depending on the cost cap), without being constrained to meet a GHG reduction glidepath.

Notes:

- [Oregon House Bill 2021, Section 10](#). Final outcomes may vary depending on regulatory processes.

Illustrative Scenario Results



Cost Cap Scenario Methodology



The Cost Cap portfolio category requires a two-step analysis:

Step 1: Estimate the Cost Cap spending constraint for ROSE-E:

Cost Cap Budget = 6% of Base Revenue Requirement (RR) forecast, where

Base RR Forecast = 2026 RR

(+/-) changes to existing portfolio costs in Reliability Only portfolio

(+) incremental new addition net costs in Reliability Only portfolio

Step 2: Run ROSE-E with the same assumptions as the Reliability Only portfolio and the constraint applied:

Cost Cap spending constraint = **Cost Cap Budget** applied to costs for new non-emitting resources in each year, beginning in 2030

Notes:

- [Oregon House Bill 2021, Section 10](#). Final outcomes may vary depending on regulatory processes.
- In accordance with OAR 860-090-0060(7), any cost estimates will be used for the sole purpose of evaluation within the IRP/CEP.
- IRP annual cost estimates are not equivalent to customer rate impacts, which are determined through different regulatory pathways, but can be used to shed light on the planning implications of cost-related impacts.
- New non-emitting resources includes renewables, storage, DERs, and transmission.

Cost Cap Scenario Design Considerations



Keep in mind: this IRP scenario does not try to answer all the details that may be relevant in a 'Section 10' filing, but may be helpful to directionally inform thresholds of more cost-effective progress toward HB 2021

PGE Proposed Approach	Considerations Open for Discussion Today
<p>Starting point for full revenue requirement is PGE estimate as of April 1, 2026, and for each year grows at the rate of inflation</p>	<p>This starting point does not attempt to forecast future revenue requirement changes related to any future nor open regulatory items (e.g., changes in a future GRC are not assumed) but rather starts from knowns "on the books" with the OPUC</p>
<p>Base Revenue Requirement Forecast</p> <ul style="list-style-type: none"> Based entirely in IRP proxy costs and results Existing portfolio and new additions from the Reliability Only portfolio 	<p>Forecasts resource needs and monetary changes to revenue requirement based on IRP "reliability only" scenario as the base for the "6% of revenue requirement" cost cap estimate</p> <ul style="list-style-type: none"> Includes procurements not yet in rates e.g., 2023 RFP projects
<p>All new clean resources and storage built in the IRP scenarios are assumed to count toward the cost cap, except:</p> <ul style="list-style-type: none"> Natural gas PPA (note: not allowed in HB 2021 scenarios) 	<p>Resource types or specific resources and whether and how they count toward the cost cap would be defined in the AR 685 rulemaking and/or a specific open Section 10 docket investigation (e.g., new natural gas, standalone batteries, EE, etc.)</p> <ul style="list-style-type: none"> This possibly project-specific review is not what we are trying to capture in this proxy policy representation for IRP purposes

Notes:

- [Oregon House Bill 2021, Section 10](#). Final outcomes may vary depending on regulatory processes.
- In accordance with OAR 860-090-0060(7), any cost estimates will be used for the sole purpose of evaluation within the IRP/CEP.
- IRP annual cost estimates are not equivalent to customer rate impacts, which are determined through different regulatory pathways, but can be used to shed light on the planning implications of cost-related impacts.

Guided Feedback

Content: Do you have any questions or concerns with PGE's approach to modeling a cost cap scenario? Are there any assumptions you would change or add to this proxy policy analysis?

Purpose: Do you agree that it is important for PGE to perform this proxy cost cap scenario analysis in the 2026 IRP/CEP?

BREAK



Transmission Constraints: Results & Analysis

Bhavana Katyal - Principal Production Cost Modeling Engineer

Luke Tutino - Production Cost Modeling Engineer

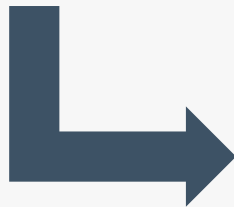
Jarek Oliver - Principal Integrated Resource Planning Analyst



Reminder: 2026 IRP Looks to Forecast Short term / Interruptible Transmission Service

IRP to incorporate prospective transmission powerflow studies to forecast non-firm transmission availability

From April 8th 2026 Round Table



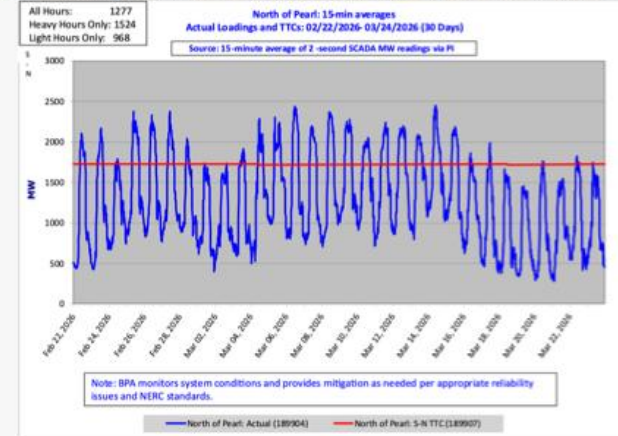
Congestion Management Impact on Non-Firm Transmission

Non-firm transmission is interruptible and unsuitable for long-term reliability purposes

Non-firm transmission is limited by important availability and curtailment concerns:

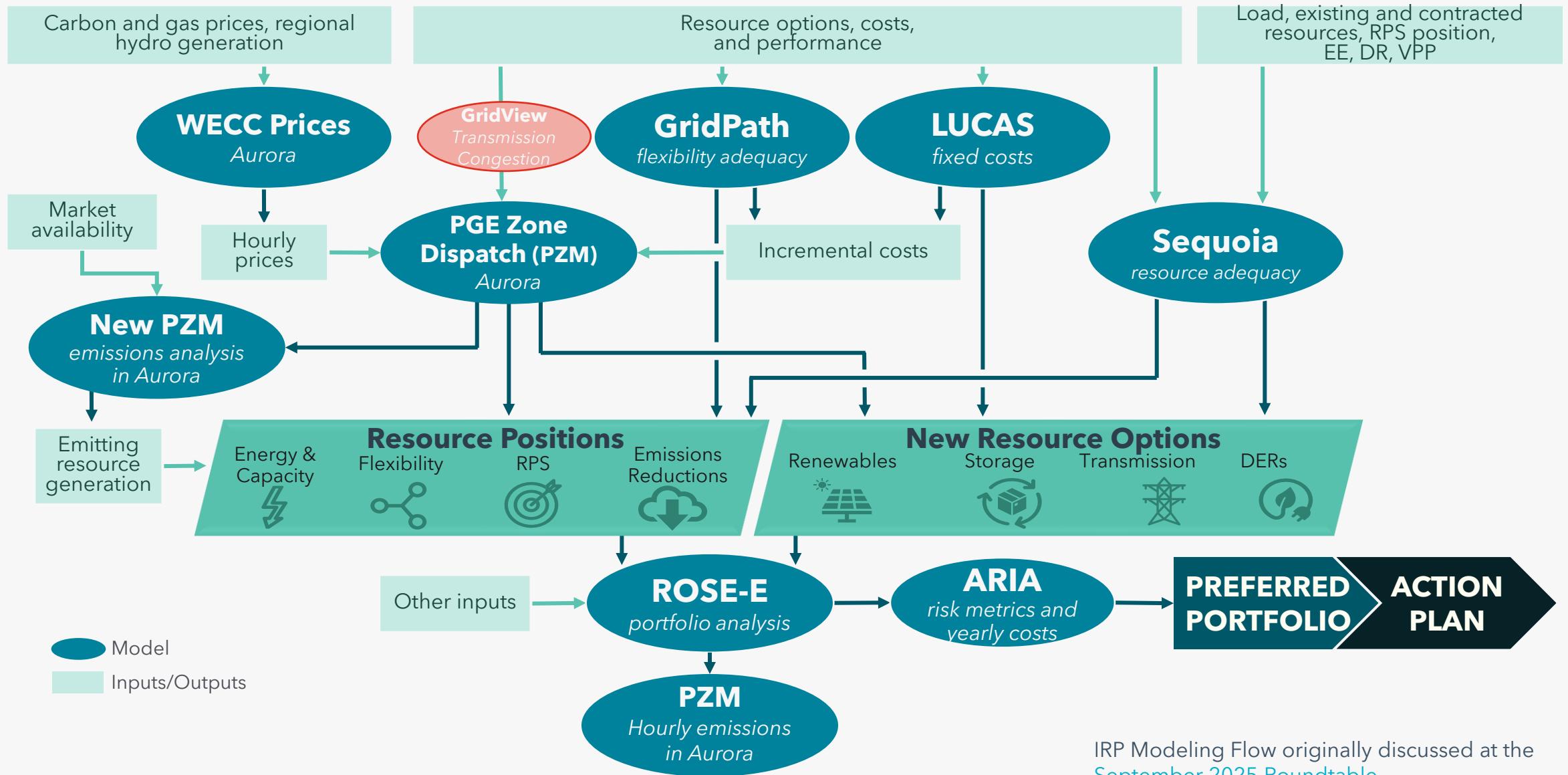
- Non-firm transmission can only be purchased on a short-term basis and cannot be reserved on a long-term basis
- A limited amount of non-firm transmission is marketed on a short-term basis given higher priority usage of transmission capacity, weather/flow conditions, and transmission outages
- Ongoing marketing of non-firm transmission can be suspended as a congestion management tool to prevent further loadings of congested flowgates
- Non-firm transmission is the first transmission product curtailed to relieve congestion

Overloading Example: March 2026 North of Pearl (NOPE) Flowgate



South to North flow can create overloads on NOPE Flowgate, resulting in potential curtailment of lower priority transmission products

2026 IRP Modeling Flow



IRP Modeling Flow originally discussed at the [September 2025 Roundtable](#)

Production Cost Modeling (PCM): Transmission Constraint Analysis Outline

10-Year Total Transfer Capability (TTC) Utilization and Path Constraints

- Path Flow 2035 TTC Utilization and Constraint Forecasting
- Heatmaps and Path Breakdowns
- Focus is Percent of Path Flow to Available TTC Limits
- North of Pearl (NOPE) Path Flow 2025 Actual to 2035 Forecast

Transmission Upgrades Path Impacts

- Impact of Transmission Upgrades on Transmission Constraint
 - Headroom Heatmap (NOPE)
 - Seasonal Utilization

Forecasting Path Transmission Constraints via PCM

- **12 BPA Interfaces Identified**
 - West of Cascades North (Path 4)
 - West of Cascades South (Path 5)
 - West of Hatwai (Path 6)
 - South of Allston (Path 71)
 - West of John Day (Path 86)
 - West of McNary (Path 87)
 - West of Slatt (Path 88)
 - North of Pearl
 - North of Grizzly
 - North of Hanford
 - Raver Paul
 - West of Lower Monumental
- **Simulation Model**
 - 2035 data obtained using GridView Production Cost Modeling (PCM) software and the WestTEC case version 2.0
- **Heatmap Grid**
 - 12x24 representing every hour of every day for each month
 - If any of the 12 interfaces is constrained the entire hour counts as constrained
 - Percent in each cell = Total Constrained Hours / Total Hours
 - Ex: A value of 100% for month 7 and hour 14 means at least one path was constrained during that hour every day in July
- **Constrained Definition**
 - If interface flow \geq 80% of TTC

2035 Combined Path Heatmap – 80% of TTC

		Month											
		1	2	3	4	5	6	7	8	9	10	11	12
Hour	1	26%	50%	42%	43%	6%	33%	19%	0%	0%	0%	0%	0%
	2	16%	50%	42%	47%	6%	27%	19%	0%	0%	0%	0%	0%
	3	16%	61%	45%	43%	10%	23%	19%	0%	0%	0%	0%	0%
	4	16%	57%	39%	50%	16%	17%	19%	0%	0%	0%	0%	0%
	5	23%	68%	35%	57%	16%	13%	19%	0%	0%	0%	0%	0%
	6	29%	79%	65%	60%	23%	37%	71%	23%	7%	0%	0%	0%
	7	45%	79%	71%	83%	39%	67%	94%	71%	67%	13%	20%	0%
	8	61%	89%	77%	100%	74%	80%	100%	97%	90%	35%	30%	6%
	9	52%	86%	87%	100%	77%	83%	100%	97%	87%	48%	53%	23%
	10	45%	93%	97%	100%	87%	90%	100%	100%	93%	68%	77%	52%
	11	65%	96%	100%	100%	94%	87%	100%	100%	93%	71%	93%	65%
	12	65%	96%	100%	100%	94%	93%	94%	100%	97%	74%	90%	77%
	13	74%	93%	100%	100%	100%	97%	97%	100%	97%	61%	80%	77%
	14	65%	93%	100%	100%	90%	93%	90%	100%	93%	55%	87%	61%
	15	71%	96%	100%	100%	90%	97%	84%	87%	90%	58%	63%	42%
	16	58%	89%	100%	100%	94%	83%	65%	61%	70%	32%	30%	3%
	17	61%	61%	100%	77%	42%	40%	16%	16%	17%	16%	33%	0%
	18	71%	61%	74%	33%	6%	7%	6%	6%	17%	13%	37%	0%
	19	55%	64%	77%	27%	0%	13%	6%	0%	10%	10%	27%	0%
	20	55%	79%	90%	50%	3%	17%	13%	0%	3%	6%	23%	0%
	21	39%	75%	74%	47%	0%	20%	19%	0%	0%	0%	10%	0%
	22	29%	54%	58%	50%	6%	27%	16%	0%	0%	0%	13%	0%
	23	16%	46%	52%	50%	3%	27%	13%	0%	0%	0%	7%	0%
	24	35%	57%	52%	33%	16%	30%	16%	0%	0%	0%	0%	0%

2035 Combined Path Heatmap – 90% and 100% of TTC



90% of TTC

100% of TTC

		Month											
		1	2	3	4	5	6	7	8	9	10	11	12
Hour	1	3%	7%	0%	17%	0%	3%	10%	0%	0%	0%	0%	0%
	2	0%	11%	0%	10%	0%	3%	10%	0%	0%	0%	0%	0%
	3	0%	7%	3%	7%	0%	7%	16%	0%	0%	0%	0%	0%
	4	0%	7%	3%	3%	0%	7%	16%	0%	0%	0%	0%	0%
	5	0%	14%	10%	10%	3%	3%	16%	0%	0%	0%	0%	0%
	6	10%	32%	13%	13%	10%	23%	45%	10%	0%	0%	0%	0%
	7	23%	32%	29%	50%	16%	43%	68%	29%	20%	0%	3%	0%
	8	23%	50%	58%	67%	19%	57%	94%	65%	60%	13%	23%	0%
	9	19%	61%	68%	83%	32%	60%	94%	71%	63%	16%	30%	10%
	10	23%	79%	87%	93%	55%	70%	90%	81%	70%	23%	47%	10%
	11	26%	86%	87%	100%	87%	83%	97%	81%	73%	23%	50%	23%
	12	35%	89%	97%	100%	90%	77%	90%	87%	60%	26%	47%	39%
	13	23%	86%	97%	100%	94%	77%	81%	84%	70%	19%	47%	35%
	14	35%	89%	94%	100%	81%	73%	74%	87%	73%	23%	57%	26%
	15	32%	86%	97%	100%	81%	63%	58%	68%	63%	29%	57%	13%
	16	19%	79%	97%	97%	52%	53%	29%	39%	43%	13%	13%	0%
	17	23%	18%	52%	63%	19%	13%	10%	0%	10%	6%	10%	0%
	18	23%	18%	35%	20%	0%	0%	6%	0%	0%	6%	17%	0%
	19	23%	32%	39%	17%	0%	0%	6%	0%	3%	6%	20%	0%
	20	26%	21%	39%	30%	0%	0%	3%	0%	0%	0%	20%	0%
	21	13%	25%	45%	33%	0%	0%	3%	0%	0%	0%	7%	0%
	22	10%	14%	45%	30%	0%	0%	6%	0%	0%	0%	0%	0%
	23	10%	7%	29%	20%	0%	3%	10%	0%	0%	0%	0%	0%
	24	3%	7%	3%	3%	0%	7%	6%	0%	0%	0%	0%	0%

		Month											
		1	2	3	4	5	6	7	8	9	10	11	12
Hour	1	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	2	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%
	3	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%
	4	0%	0%	0%	0%	0%	0%	3%	0%	0%	0%	0%	0%
	5	0%	0%	3%	0%	0%	0%	0%	0%	0%	0%	0%	0%
	6	0%	0%	3%	0%	0%	13%	23%	3%	0%	0%	0%	0%
	7	3%	4%	13%	27%	6%	27%	52%	23%	0%	0%	0%	0%
	8	3%	21%	32%	33%	13%	23%	68%	26%	13%	3%	10%	0%
	9	6%	32%	52%	57%	16%	33%	77%	42%	30%	0%	17%	0%
	10	10%	57%	65%	73%	35%	53%	71%	48%	40%	0%	30%	3%
	11	10%	75%	77%	83%	55%	53%	81%	55%	40%	3%	23%	3%
	12	10%	75%	81%	97%	71%	60%	74%	55%	33%	6%	27%	6%
	13	13%	68%	81%	90%	71%	50%	65%	52%	40%	6%	30%	6%
	14	6%	68%	77%	90%	65%	43%	55%	42%	40%	13%	30%	6%
	15	19%	64%	81%	87%	61%	23%	35%	26%	37%	13%	23%	0%
	16	6%	46%	71%	90%	35%	20%	29%	16%	27%	6%	10%	0%
	17	3%	4%	26%	30%	0%	3%	10%	0%	3%	0%	7%	0%
	18	10%	0%	10%	7%	0%	0%	3%	0%	0%	0%	3%	0%
	19	6%	4%	19%	13%	0%	0%	3%	0%	0%	0%	3%	0%
	20	3%	0%	19%	17%	0%	0%	3%	0%	0%	0%	10%	0%
	21	3%	0%	32%	10%	0%	0%	3%	0%	0%	0%	0%	0%
	22	0%	0%	29%	10%	0%	0%	3%	0%	0%	0%	0%	0%
	23	0%	0%	13%	3%	0%	0%	3%	0%	0%	0%	0%	0%
	24	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%	0%

TTC Threshold 2035 Hours Comparison

80% of TTC

Path	Constrained Hours	Percent
WO Cascades North	0	0%
WO Cascades South	5	0%
WO Hatwai	415	9%
NO Hanford	0	0%
Raver Paul	0	0%
WO Lower Mon	666	15%
SO Allston	1	0%
WO John Day	5	0%
WO McNary	0	0%
WO Slatt	0	0%
NO Grizzly	0	0%
NO Pearl	3300	75%

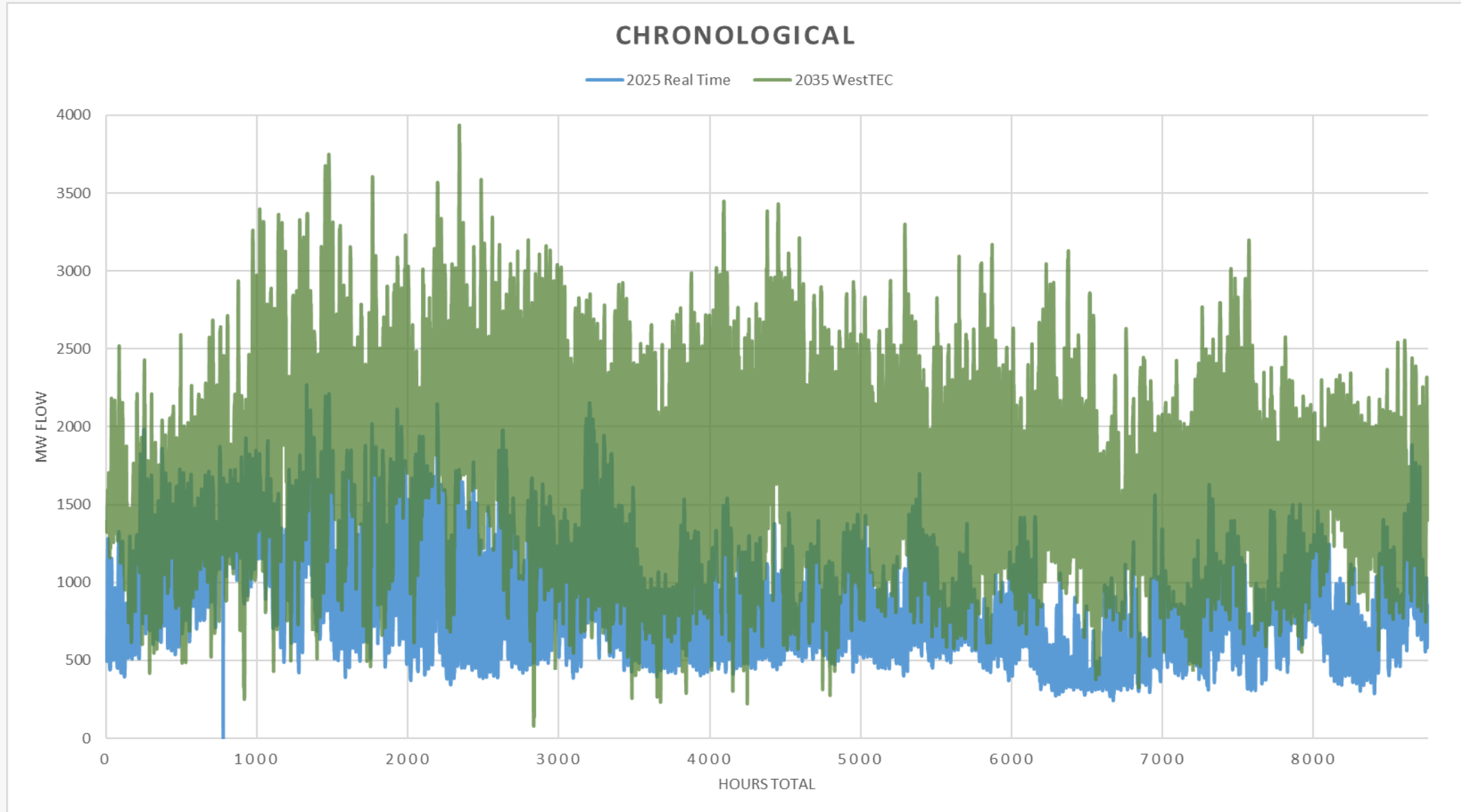
90% of TTC

Path	Constrained Hours	Percent
WO Cascades North	0	0%
WO Cascades South	0	0%
WO Hatwai	51	2%
NO Hanford	0	0%
Raver Paul	0	0%
WO Lower Mon	171	7%
SO Allston	0	0%
WO John Day	0	0%
WO McNary	0	0%
WO Slatt	0	0%
NO Grizzly	0	0%
NO Pearl	2245	91%

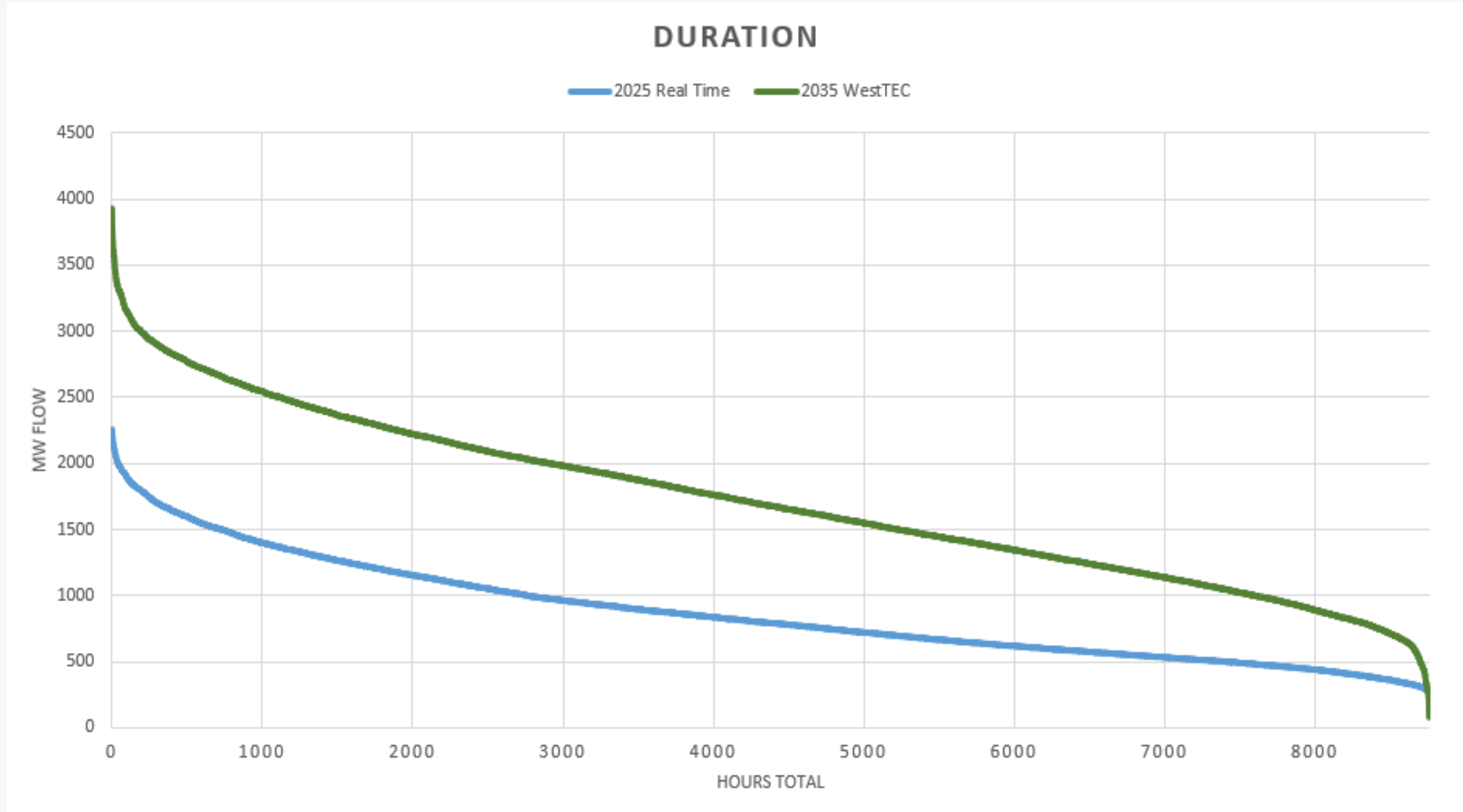
100% of TTC

Path	Congested Hours	Percent
WO Cascades North	0	0%
WO Cascades South	0	0%
WO Hatwai	3	0%
NO Hanford	0	0%
Raver Paul	0	0%
WO Lower Mon	28	2%
SO Allston	0	0%
WO John Day	0	0%
WO McNary	0	0%
WO Slatt	0	0%
NO Grizzly	0	0%
NO Pearl	1400	98%

North of Pearl (NOPE) Direct Comparison Chronological



North of Pearl (NOPE) Direct Comparison Duration



Potential System Impacts and Key Findings

1

- NOPE flows are projected to increase dramatically in 10 years
 - Load growth + WECC wide generation change
 - Transmission upgrades that decrease total path impedance

2

- Effects of congested paths may include:
 - Increased market costs
 - Reliability issues may be frequent
 - Non-firm tags may be at risk

3

- Other 11 studied paths had infrequent constrained hours and are unlikely to cause significant operational issues

Transmission Impact on Path Constraints & Utilization

Forecast Transmission Constraints

- Analyze the impact of planned network upgrades on the frequency of constrained hour and utilization rates to quantify future risk exposure

Study Setup

- Two scenarios studied in a 10-year future:
 - No transmission upgrades between 2027-2035 for regions NW, MT, ID, NV
 - With planned transmission upgrades till year 2035 in regions NW, MT, ID, NV

Headroom and Transmission Constraint Frequency



2027 Topology

Average Headroom (MW) by Month and Hour
_Pth-BPA-North of Pearl

PT Hour Ending	January	February	March	April	May	June	July	August	September	October	November	December
0	1140	990	1063	697	1112	1276	1144	1217	1255	1355	1313	1038
1	1119	953	1029	635	1135	1216	1108	1096	1175	1304	1313	1083
2	1033	882	909	599	1150	1173	1092	1041	1119	1258	1261	1032
3	996	887	841	515	1152	1144	1062	1010	1064	1190	1204	1009
4	972	896	792	500	1087	1100	1022	962	1016	1147	1163	935
5	948	913	820	513	949	727	700	888	926	1063	1210	965
6	929	913	768	190	252	223	205	452	428	817	1138	1008
7	860	662	416	31	151	127	81	235	153	360	612	868
8	614	325	183	22	92	104	37	99	68	197	337	569
9	528	205	98	8	47	40	37	61	64	162	176	403
10	448	96	28	5	18	12	27	59	56	108	94	261
11	374	36	12	0	11	13	35	50	41	112	28	156
12	275	26	12	0	0	40	80	62	48	98	37	89
13	247	35	12	0	0	41	117	91	72	134	75	150
14	245	36	13	0	8	43	161	114	75	162	73	160
15	289	25	7	2	20	69	205	171	138	228	145	287
16	548	119	12	3	50	92	286	328	337	519	756	650
17	568	323	146	90	298	388	495	547	625	736	725	680
18	527	260	193	227	729	731	722	781	745	726	627	631
19	585	250	150	213	710	799	788	751	727	689	611	675
20	615	273	158	192	640	734	750	731	658	704	561	651
21	668	306	225	181	606	717	664	743	735	794	693	698
22	779	393	332	253	622	765	710	816	736	836	723	683
23	869	464	429	334	745	868	750	837	807	912	817	785

Without Planned Transmission Upgrades

2035 Topology

Average Headroom (MW) by Month and Hour
_Pth-BPA-North of Pearl

PT Hour Ending	January	February	March	April	May	June	July	August	September	October	November	December
0	1479	1303	1232	926	1529	1529	1474	1537	1462	1462	1544	1289
1	1409	1262	1185	901	1531	1562	1400	1376	1378	1477	1517	1268
2	1367	1229	1074	850	1521	1537	1386	1305	1327	1466	1439	1217
3	1339	1227	1021	797	1579	1539	1362	1278	1293	1388	1381	1190
4	1327	1246	990	759	1492	1482	1315	1238	1260	1386	1379	1163
5	1346	1272	1023	755	1288	1098	925	1128	1178	1364	1406	1241
6	1327	1304	970	360	645	478	269	606	693	1044	1388	1280
7	1218	930	513	145	399	301	120	339	389	772	739	1067
8	880	393	306	93	257	229	61	179	223	549	583	789
9	719	228	188	31	155	169	39	138	193	488	402	628
10	656	127	95	19	95	124	39	115	174	416	276	482
11	546	76	59	6	71	87	32	106	140	375	229	355
12	457	72	47	3	49	96	92	137	171	395	249	275
13	432	87	55	5	48	70	151	166	194	413	273	292
14	456	90	63	4	94	114	218	186	205	437	293	356
15	457	72	61	5	103	163	321	263	254	462	332	469
16	729	203	48	10	158	250	463	452	445	637	679	850
17	772	518	177	238	582	705	807	786	773	816	667	861
18	736	463	244	508	1095	1162	1037	933	890	849	591	898
19	791	416	221	510	1091	1211	1091	976	861	871	667	946
20	802	394	222	457	1057	1073	1008	923	834	945	678	922
21	898	423	256	420	1052	1033	956	933	872	1043	768	939
22	1014	553	373	526	977	1040	946	985	925	1108	821	939
23	1115	619	433	567	1087	1148	989	1050	1011	1154	902	990

With Planned Transmission Upgrades

"Headroom (MW) = TTC - Actual Path Flow"

High
Constrained
Risk

Low Headroom

Low
Constrained
Risk

High Headroom

Key
Findings:

- **Peak Constrained Hours:** 8AM - 3PM (Peak Solar Production Window)
- **High South-to-North Flow on NOPE** during peak hours – driven by cheap solar energy flowing from **California** → **Northwest**

Seasonal Transmission Constraint Frequency



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

Season	Winter		Spring		Summer		Fall									
	Name	2027 Topology	2035 Topology	2027 Topology	2035 Topology	2027 Topology	2035 Topology	2027 Topology	2035 Topology							
Pth-BPA-North of Pearl		40%		29%		66%		57%		49%		43%		42%		32%
P04 West of Cascades-North		6%		0%		12%		0%		1%		0%		0%		0%
P05 West of Cascades-South		36%		0%		33%		0%		30%		0%		9%		0%
P06 West of Hatwai		0%		6%		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%		1%		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 Raver-Paul		2%		0%		9%		0%		11%		0%		0%		0%
Pth BPA West of Lower Monumental		7%		23%		2%		9%		0%		1%		0%		0%



✓ **Constraint Improvements:** Network upgrades reduced constrained hours across majority of paths.
■ **Exceptions:** *W. of Lower Monumental* (Higher East->West flows); *W. of Hatwai* (Higher ID/MT -> WA flows)
■ **Highest Constrained Path- NOPE:** High utilization & constraints risks persists year-round in both scenarios

Constrained Path Analysis Key Takeaways



- ⚠️ **North of Pearl** – Remains the highest constrained path year-round, persisting across both scenarios.
 - BPA's proposed Keeler-Pearl #2 500 kV line is a critical project to reduce constraint risk and address capacity limitations
 - ☀️ **Solar-Driven Flows** – Peak south-to-north constrained hours occurs 8AM-3PM, driven by cheap California solar energy flowing into the Northwest.

- 🔧 **Upgrade Impact** – Planned transmission upgrades reduced utilization across most WECC paths and BPA interties.
 - Exceptions: West of Lower Monumental & West of Hatwai experience higher east to west driven flows with planned network upgrades.

- ✅ **Lower Risk from 11 paths** – With planned network upgrades in place, constrained hours are infrequent and unlikely to pose significant risks to grid operations.

What does this mean for IRP modeling?

- In Aurora, the generation output of non-firm resources is constrained by the transmission heat map.
 - **Standalone non-firm resources** are constrained by a resource-level transmission derate.
 - **Hybrid non-firm resources** are constrained by a hybrid derate that applies to all resources of the hybrid project. This allows hybrid storage resources that are paired with renewables to move generation away from hours when the non-firm transmission constraint is binding.
- Reductions in output reduce the resource energy value that, in turn, increases the net cost of the resource as an input to portfolio analysis.
- Availability of non-firm resources in ROSE-E portfolio analysis limited to 712 MW based on average headroom of North of Pearl Flowgate in 2035.

Guided Feedback

Content: Do you understand how the results of this analysis impact the 2026 IRP/CEP? Do you agree with PGE's approach to limit the availability of non-firm transmission to reflect the constraints identified in this study?

We are seeking feedback on which percentage threshold best reflects the risk to non-firm transmission. Which threshold do you believe is most appropriate for PGE's 2026 IRP/CEP planning assumptions?

Purpose: Do you agree that this analysis plays a critical role in informing PGE's IRP/CEP assumptions around non-firm transmission? Do you have any suggestions for how PGE should refine this analysis?

VPP Integration & ELCC Review

Seemita Pal, Senior Principal Strategy & Planning Analyst

Kyle Billeci, Principal Strategy & Planning Analyst

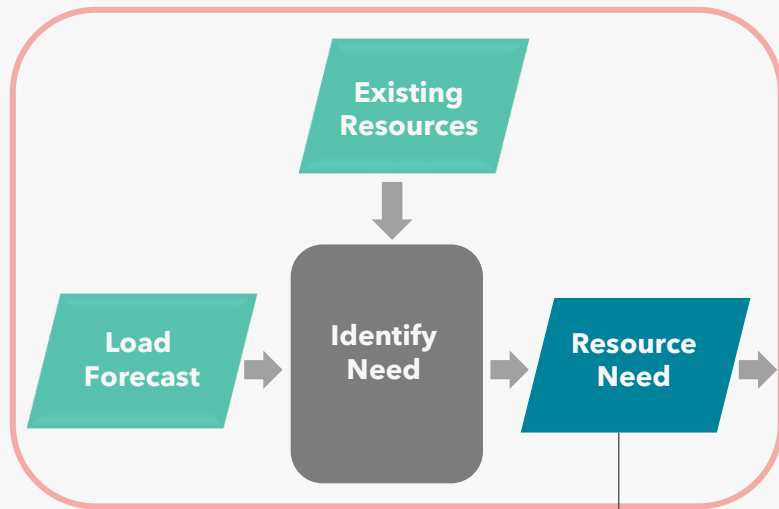
Devin Mounts, Principal Integrated Resource Planning Analyst



High-Level IRP Analysis Process

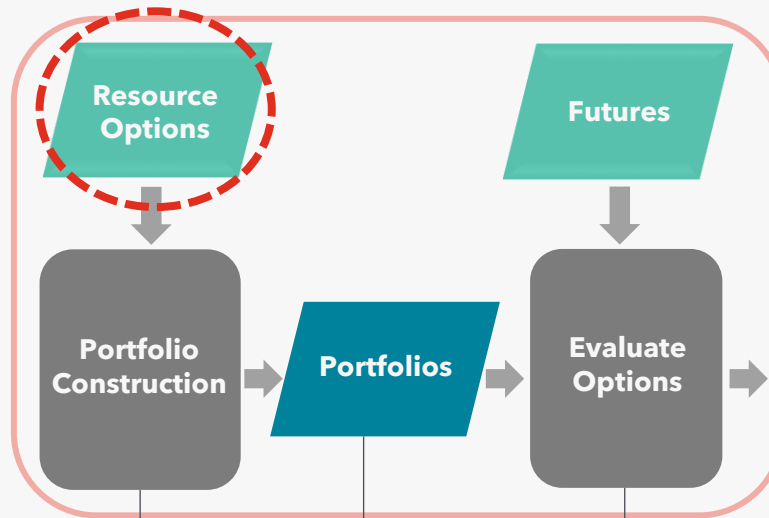


Estimate System Needs



MWs of capacity and
aMWs of energy
for system to reliably operate

Evaluate Resource Options



potential resource
additions to our system

to test resources,
incorporate regulatory
requirements, assess
impacts to needs

scenarios and sensitivities
for an informative set of
future conditions

Develop Plan



IRP has a 20-year planning
horizon, Action Plan covers
the next 2-4 years

Outline



VPP Review from December 2025

Updates on Binning DR Resources & DSG Capacities

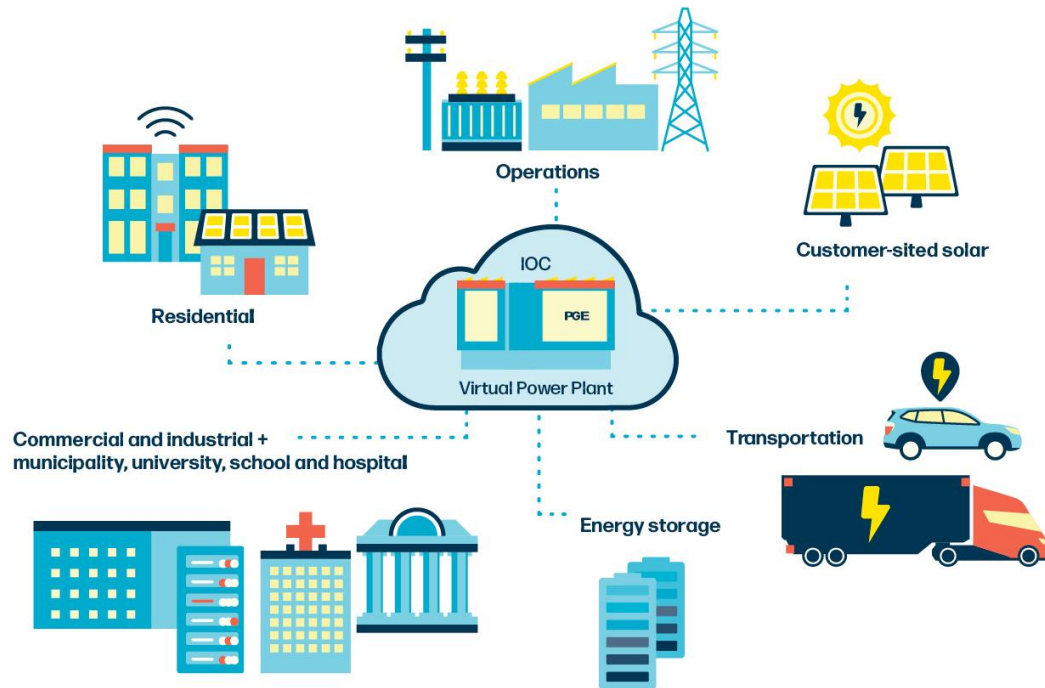
Integration to IRP Selection

ELCC Review

Virtual Power Plant (VPP)

Over 25% of our customers are participating in PGE's VPP today. VPP is the orchestration of Distributed Energy Resources (DERs) and flexible load, through technology platforms, to provide grid and power operations services. Below are examples of DER's and flexible load included in the VPP.

PGE's Virtual Power Plant at a glance



Everyday use:

Customer devices and flexible loads are dispatched regularly for services like peak shaving, energy shifting and contingency reserves.

Reliable:

During recent summer heat waves, VPP resources reduce demand and deliver energy reliably, helping avoid outages and high priced market purchases. During major heat waves in 2023, 2024, and 2025 PGE's VPP delivered triple-digit megawatts of peak reduction, avoiding power outages and reducing power costs.

Value for customers:

Participating customers earn bill credits and lower bills by managing their energy use, while all customers benefit as PGE optimizes all resources to minimize expensive power purchases.

Historical Treatment of VPP Resources in IRP

Optimal capacity expansion model ROSE-E identifies resource additions over time and across potential futures that best meet a specified objective.

Historical treatment of VPP resources in ROSE-E was as follows:

CE Flex Load

Modeled as load modifiers using AdopDER forecasts embedded in capacity and energy needs

Distributed solar

Distributed solar is forecast using AdopDER and reflected as a behind-the-meter offset to gross load

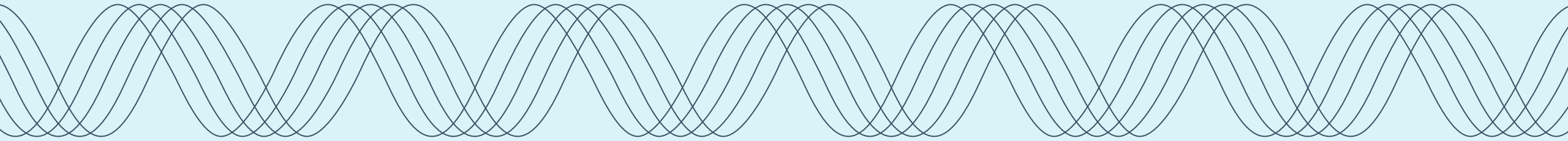
NCE DER bundles

(include NCE distributed storage and NCE flex load)

Modeled as selectable resource options. ROSE-E chooses them when they reduce cost or meet reliability/policy requirements

- CE = cost-effective
- NCE = non-cost-effective

Integrating VPPs Into IRP Modeling



How Modeling Is Changing

VPP Resource Bins in SEQUOIA & ROSE-E

- Introduces VPP resource bins representing binned Demand Response (DR) portfolios and Dispatchable Standby Generation (DSG) as selectable resources
- Enables VPP resources to compete directly with:
 - Generation
 - Storage
 - Transmission alternatives
- ROSE-E is provided with discrete VPP DR bins & DSG, each with:
 - Defined annual average availability (MW potential by year)
 - Distinct cost and capacity contribution characteristics
- Model evaluates/selects from VPP resources alongside other resources by:
 - Comparing cost per unit of capacity
 - Optimizing across all available resource options

Note: Rooftop Solar, Electric Vehicle Charging Equipment, and Building Electrification adoption are forecasted through AdopDER

Static Impacts
(2023 IRP & Update)

CE: Embedded as load modifiers
NCE: As selectable resources



Selectable
Resources

CE and NCE resources are evaluated against utility resources instead of accepted as capacity contributions without selection protocol

VPP DR Binning Framework

- Developed **five core** VPP DR resource bins, each segmented by summer and winter
- Binning aggregates diverse DERs into **standardized, selectable** capacity products for evaluation in resource adequacy modeling and portfolio selection alongside traditional resources.
- Resources are grouped based on similar **dispatchability, hourly load shapes**, and **PGE Program consolidation** which drive ELCC and overall system value.

Large MW Dispatchable PGE Programs	Non-Dispatchable PGE Programs	Other PGE Programs / Pilots	High Technical / Market Potential	Stretch/Emerging
BIN 1	BIN 2	BIN 3	BIN 4	BIN 5
<ul style="list-style-type: none"> • Res. Smart T-Stats • EP - Schedule 26 	<ul style="list-style-type: none"> • Peak Time Rebates • Time of Day 	<ul style="list-style-type: none"> • Res. EV Charging • Com. EV Charging • EP - Schedule 25 • MF Water Heaters • Res / Non-Res Storage 	<ul style="list-style-type: none"> • EP - Cold Storage • MF Ducted Heat Pump • Connected Air-Source HP • Connected Smart Electric Resistance Water Heater 	<ul style="list-style-type: none"> • EP - Ag • Microgrids • Fleet Charging (DCFC) • Single Family Water Heating • Other Potential DR

EP = Energy Partner
DCFC = Direct Current Fast Charging
TRC = Total Resource Cost

Res. = Residential
Com. = Commercial
MF = Multifamily

Average Event Capacity (MW) of VPP DR by Bin & Season



Bin	PGE Program / Pilot	Primary Value	Season	2030 Potential (Incremental)
Bin 1	Yes	Fully dispatchable capacity Established programs structure/participation	Summer	20.0
			Winter	11.5
Bin 2	Yes	Participant-driven load shifting providing broad peak reduction, but not dispatchable	Summer	16.8
			Winter	5.9
Bin 3	Yes	DR pilots with measurable but smaller capacity contribution by program	Summer	5.6
			Winter	2.8
Bin 4	No	Emerging, high-potential DR expected to become cost-effective and dispatchable with future program development	Summer	11.5
			Winter	11.7
Bin 5	No	Higher-cost DR resources capable of providing dispatchable capacity but requiring significant incentives or program funding.	Summer	10.4
			Winter	17.5

Source: Latest forecasts from AdopDER (2025 Q3)

VPP DSG Model



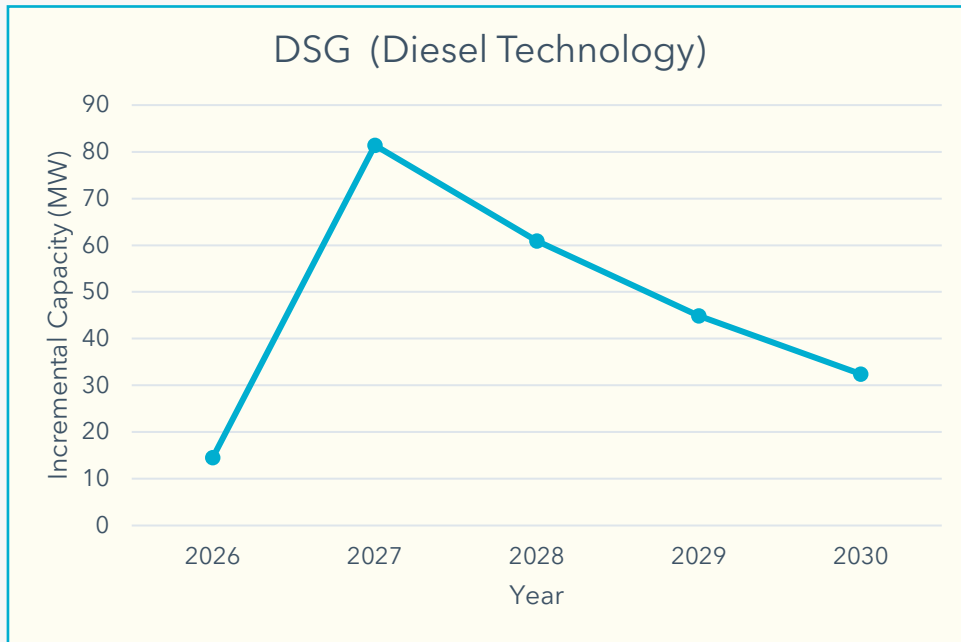
- Dispatchable Stand-by Generation resources are **call-limited resources**.
- DSG was historically not included as an option in portfolio analysis in the IRP; we are starting with a simplified model
- Call limited aspect presents **challenges in RA modeling** in Sequoia where thousands of years are simulated non-linearly

Initial model treats DSG as capacity-only resources

Inputs: forecasted capacities, levelized fixed costs and call limits

Fixed costs: capacity payments and PGE-funded interconnection, protection, controls, and comms needed to safely operate in parallel

DSG Capacity Assumptions



The figure shows incremental capacities (in MW) of DSG (diesel only) forecasted to be added

PGE recently executed multiple contracts with data center customers that include DSG resources, largely estimated to come online in 2027

- **Incremental DSG capacities are forecasted** and made available to ROSE-E for selection in portfolio along with levelized net costs of the incremental capacity additions
- Starting capacity of DSG in 2025 is **140 MW**.
- Marginal ELCC¹: 98%
- **No new DSG units** are added after 2030.

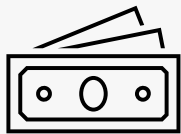
1. See [Feb. 24, 2026 Roundtable 26-2 - Effective Load Carrying Capabilities \(ELCCs\)](#)

VPP: Inputs in ROSE-E



- For **PGE's existing Flex Load Programs**

- The levelized net costs are based on the cost-effectiveness analysis which accounts for the avoided or deferred transmission and distribution capacity costs; the avoided generation capacity values are removed
- Approximate **capacity factors** have been included

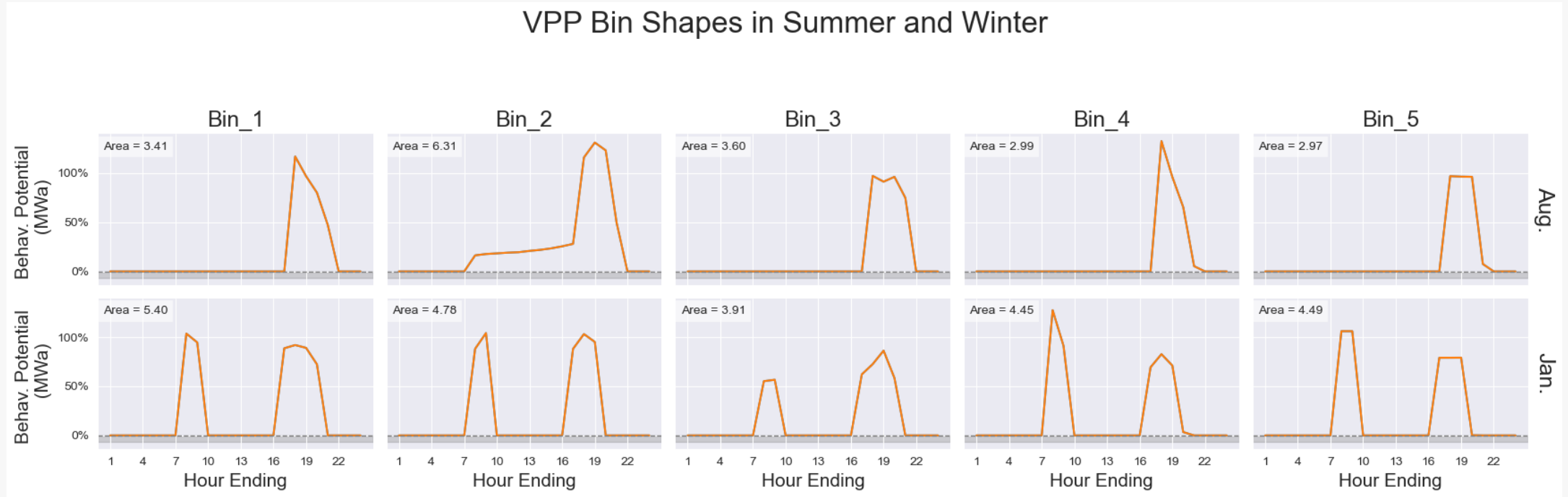


- **For DSG**, levelized fixed costs and capacity forecasts are based on its program estimates
- Capacity forecasts for existing Flex Load Programs and potential DR measures are based on **AdopDER's** outputs

Draft Flexible Load ELCCs



PGE estimated Flexible Load ELCCs using binned DR shapes informed from AdopDER outputs.



2026 IRP Assumption Revision:

The 2023 CEP/IRP and Update assumed DR events had no value on Weekends. This resulted in near zero ELCCs of most DR programs. For the 2026 IRP it is assumed DR programs have a weekend shape identical to weekdays.¹

VPP Bin	Summer ELCC	Winter ELCC
Bin 1	44%	14%
Bin 2	46%	10%
Bin 3	48%	12%
Bin 4	31%	10%
Bin 5	36%	10%

Comparatively, ELCC for a **4-hour li-ion** battery: **63% summer** and **21% winter**.

1. This previous assumption is why the VPP exit had a small MW effect as shown in slide 23 of the [December Roundtable](#)

Guided Feedback

Content:

1. Does the proposed VPP binning and application provide a credible and appropriate representation of these resources within IRP modeling?
2. What additional assumptions, or clarifications are needed to ensure confidence in the implementation and evaluation of VPP resources in the IRP?

Summary:

First iteration of VPP resource modeling within IRP for informing resource's role in PGE's least-cost least-risk resource strategy

DR represented in the form of five core bins, and Dispatchable Standby Generation (DSG) are evaluated as part of resource adequacy model and presented as selectable resources to ROSE-E

A photograph of an electric vehicle charging station with several cars plugged in, set against a dark blue background. The image is partially obscured by the text on the right.

NEXT STEPS

A recording from today's webinar will be available on our [website](#) in one week

Upcoming Roundtable: June 10, 2026

Thank you

Contact us at
IRP.CEP@PGN.COM

An

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kind of energy

ACRONYMS

ARIMA: autoregressive integrated moving average

ART: annual revenue-requirement tool

ATC available transfer capability

BPA: Bonneville Power Administration

C&I: commercial and industrial

CBI: community benefit indicators

CBIAG: community benefits and impacts advisory group

CBRE: community based renewable energy

CDD: colling degree day

CEC: California energy commission

CEP: clean energy plan

CF: conditional firm

DC: direct current

DER: distributed energy resource

DR: demand response

DSP: distribution system plan

EE: energy efficiency

ELCC: effective load carrying capacity

EJ: environmental justice

ETO: energy trust of Oregon

EUI: energy use intensity

GHG: greenhouse gas

HB 2021: House Bill 2021

HDD: heating degree day

HVDC: high-voltage direct current

IE: independent evaluator

IOU: investor-owned utilities

ITE: information technology equipment

ITC: investment tax credit

kW: kilowatt

LOLH: loss of load hours

LT/ST: long term/ short term

LTF: long-term firm

MW: megawatt

MW_a: mega watt average

NAICS: North American industry classification system

NCE: non-cost effective

NG: natural gas

NPVRR: net present value revenue requirement

OASIS Open Access Same Time Information System

ODOE: Oregon department of energy

PPA: power purchase agreement

PSH: pumped storage hydro

PUC: public utility commission

PURPA: Public Utility Regulatory Policies Act

PV: photovoltaic

REC: renewable energy credit

RLRR: low carbon price future

ROSE-E: resource option strategy engine

RPS: renewable portfolio standard

RRRR: reference case price future

RTO: regional transmission organization

SoA: South of Allston

T&D: transmission and distribution

TSR: transmission service request

TSEP: TSR study and expansion process

Tx: transmission

UPC: usage per customer

UPS: uninterruptible power supply

VER: variable energy resources

VPP: virtual power plant

WECC: western electricity coordinating council