PGE CEP & IRP Roundtable 26-3

April 8, 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

April 8, 2026 – Agenda

9:00 | Welcome

9:05 | Community Engagement

9:15 | Transmission Constraints: Methodology & Approach

10:00 | Price Futures Update

10:45 | Energy Values for Resources

11:00 | BREAK

11:10 | Generic Resource Cost Update

11:25 | Market Emission Factor Scenarios

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	DRAFT: Stakeholder Feedback Responses, CBIs, VPP Bins, Sensitivity plans/Future planning scenarios, Transmission Constraints results, Updates: Cost Cap Discussion, New Large Load and Other Large Load & Chelan PUD
June 10, 2026	TBD
July 01, 2026	TBD
August 2026	TBD
September 2026	TBD
October 2026	TBD

Clean Energy Plan & Integrated Resource Plan Community Engagement Updates

Presenter: Samantha Thompson (she/her), Senior Community Engagement Specialist

April 8, 2026

East County Resiliency Fair Recap

East County Resilience Fair

Event details

- Saturday, February 21 from 10am – 2pm
- Organized by **Community Services Network**
- Hosted by City of Portland Bureau of Planning and Sustainability and the City of Gresham
- Event sponsor, Portland General Electric (PGE)

Purpose

Public event was designed to connect individuals to programs, services and resources focused on community resilience, sustainability

Outcome

- 558 people (175 heads of households) attended
- 72 PGE Project Zero educational bags were given to youth
- Workshop collaboration with Community Energy Project (CEP) and Energy Trust of Oregon (ETO)

East County Resiliency Fair Recap Continued

Community Workshop

What we did

- Facilitated a community workshop titled ***How PGE Plans for the Future***.
- Provided an accessible overview of the Clean Energy Plan (CEP) & Integrated Resource Plan (IRP).
- Explained the long-term planning and regulatory process.
- Introduced key resource planning concepts.
- Highlighted the role of community engagement and interested parties.
- Supported participant learning through discussion and Q&A.

Principal IRP Analyst, Lauren Slawsky presenting at PGE workshop with participants at East County Resiliency Fair.

East County Resiliency Fair Recap Continued

Community Workshop

What we heard

- 100% respondents **strongly agreed** the workshop was a valuable use of their time.
- Most useful topic from presentation
  - **67%** of respondents thought ***learning about the Clean Energy Plan and Integrated Resource Plan*** was the most useful topic.
  - 33% selected *learning about who is involved in developing the IRP and why*.

Question: Based on what you learned from the presentation, what would you prioritize most in long-term planning? (Select up to three options)

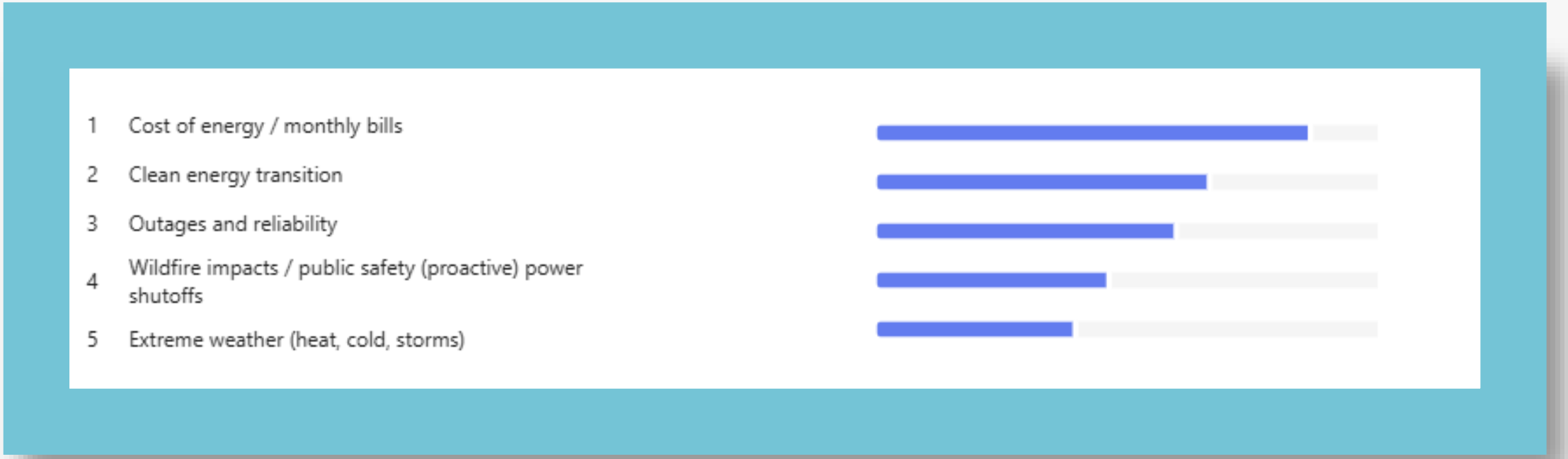
- **Prioritizing affordable power bills was selected by all respondents** (3 of 3, 100%).
- **Increasing clean energy resources was also selected by all respondents** (3 of 3, 100%).
- Improving resiliency of grid infrastructure was selected by two respondents (67%).
- Considering power reliability and frequency of outages was selected by one respondent (33%).

East County Resiliency Fair Recap Continued

Community Workshop

Question: Please rank what are your biggest concerns related to energy. Top being the biggest concern and the bottom being least concern.

Ranking of Energy Concerns



East County Resiliency Fair Recap continued

Long-Term Resource Planning Booth

What we did

- Hosted informational tables connecting community members with PGE programs and resources.
- Highlighted resiliency and preparedness resources.
- Promoted clean energy workforce pathways.
- Shared information on long-term resource planning (CEP & IRP).
- Over 100 attendees visited the long-term resource planning table.
- Conducted a resource planning survey with attendees (32 respondents).

PGE staff member, Samantha Thompson engaging attendee about long-term resource planning survey.

East County Resiliency Fair Recap continued

Long-Term Resource Planning Booth

Priorities for long-term resource planning (respondents could select up to three options)

Sample size: 32 respondents

Question: What would you prioritize most in long-term planning?

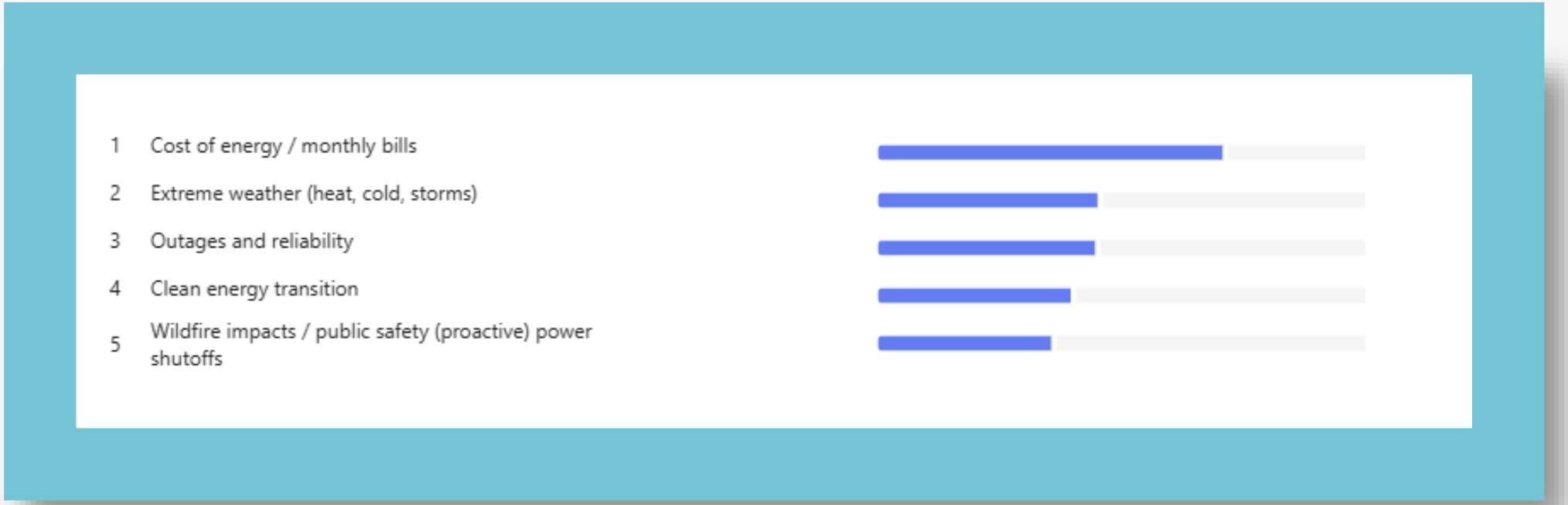
Priority	Number of Responses
Prioritizing power bill /affordability	**22**
Increasing clean energy resources	12
Considering power reliability and frequency of outages	10
Improving resiliency of grid infrastructure	9
Increasing community benefits	5

East County Resiliency Fair Recap continued

Long-Term Resource Planning Booth

Question: Please rank what are your biggest concerns are related to energy. Top being the biggest concern and the bottom being least concern.

Ranking of Energy Concerns



East County Resiliency Fair Recap continued

PGE Workshop & Informational Booth

What we learned

- Affordability emerged as the top priority across all engagement activities.
- Participants supported balancing affordability, reliability and clean energy goals.
- Interest in understanding planning processes.
- Multiple engagement approaches helped reach diverse audiences.
- Accessible and multilingual engagement supported participation.

What ‘s next

- Incorporate engagement insights from the community workshop, surveys and Community Benefits & Impacts Advisory Group (CBIAG) discussions into the 2026 Clean Energy Plan (CEP) and Integrated Resource Plan (IRP) filing.
- Continue education and awareness efforts to help customers and communities better understand long-term resource planning.

PGE staff members at informational and resource booth.

Guided Feedback

Process: What other IRP focused or PGE resource planning community engagements would you like PGE to do moving forward?

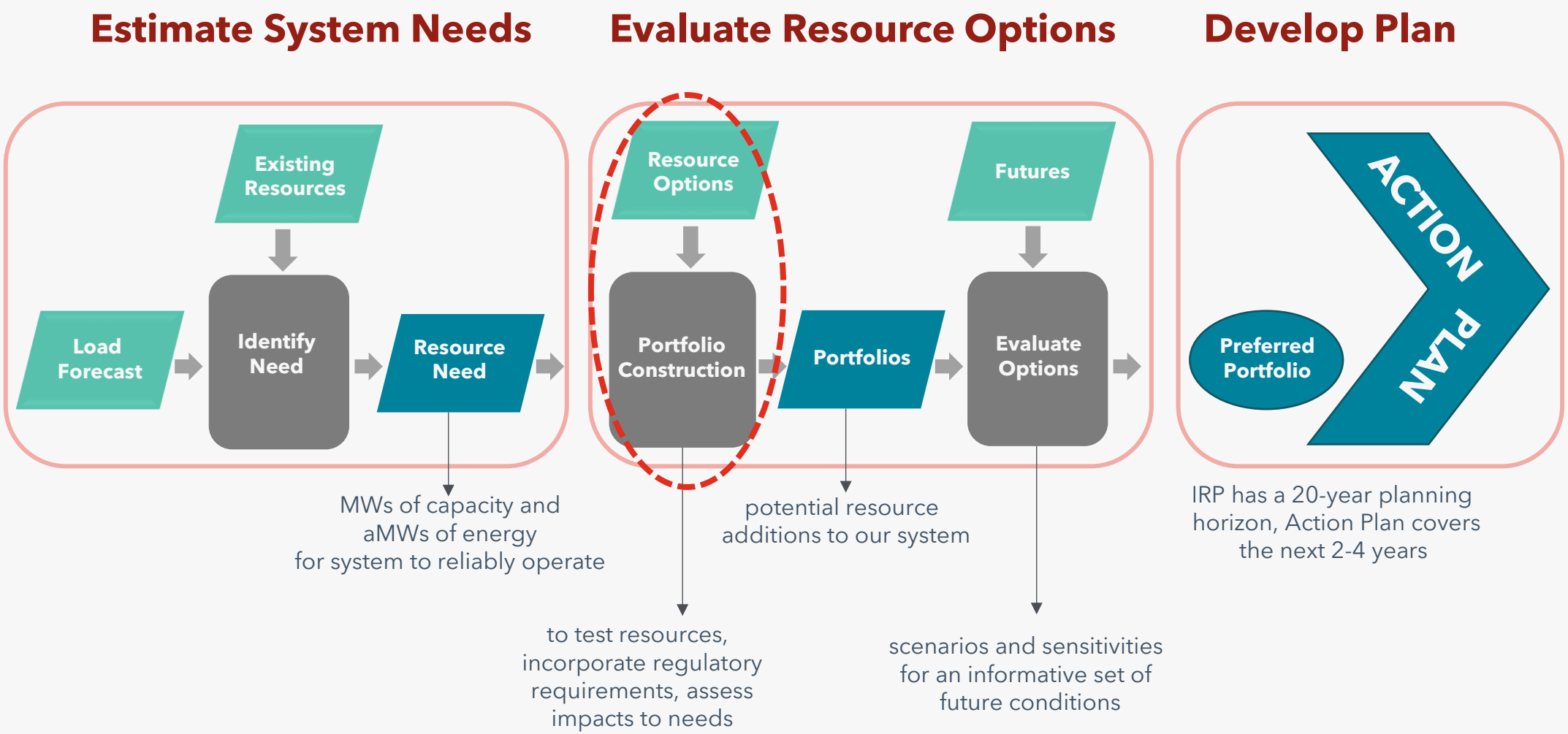
Content: How do you think the results of the East County Resiliency fair survey should influence PGE's 2026 IRP conclusions?

Transmission Constraints: Methodology and Approach

Jarek Oliver
Bhavana Katyal
Luke Tutino

PGE An Oregon kind of energy.℠

High-Level IRP Analysis Process



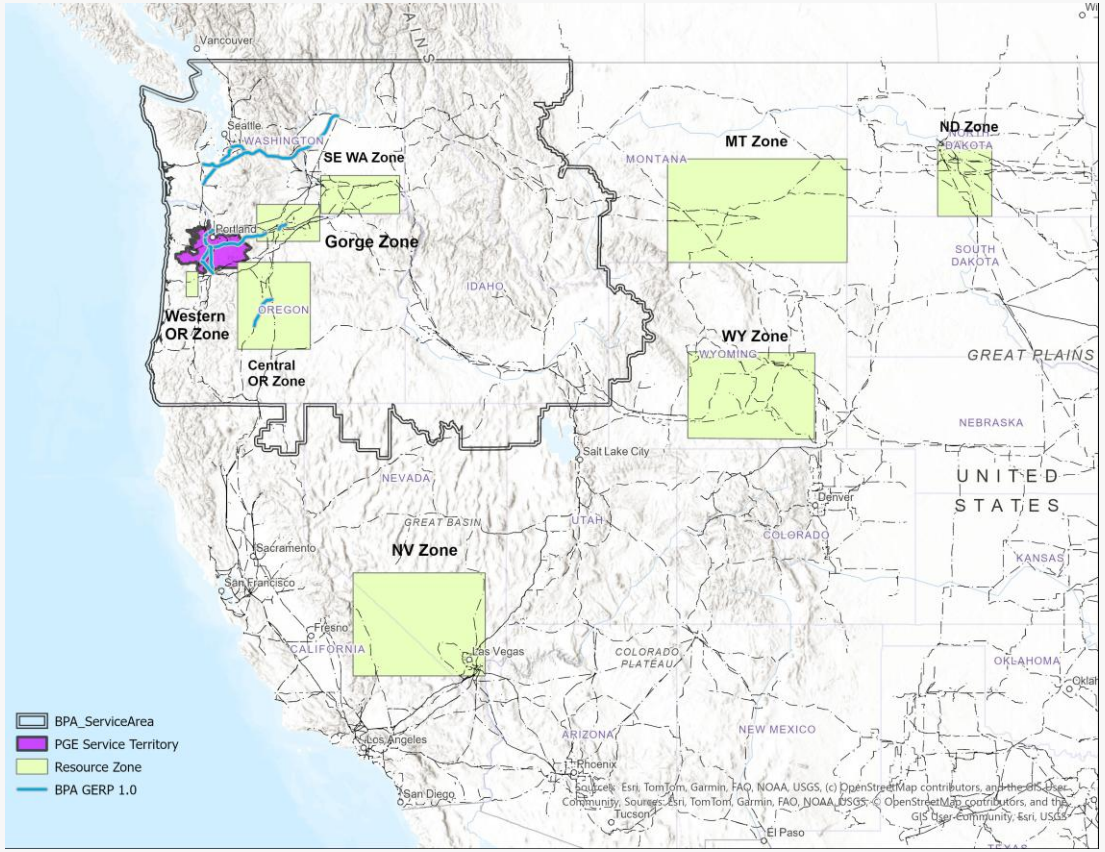
Portfolio Construction Transmission Methodology

Third-party transmission availability is an important input into PGE's portfolio construction

PGE's portfolio analysis methodology considers the availability of third-party transmission rights when performing capacity expansion

- For resources located outside of PGE's transmission footprint, use of specific transmission products is assumed to allow for delivery to PGE's system
- Using 2025 Requests for Proposal (RFP) Results to update assumed inventory of Bonneville Power Administration (BPA) long-term transmission rights (long-term firm and conditional firm)
- Transmission inventories consistent with plans of service associated with BPA's Grid Expansion and Reinforcement Portfolio (GERP) 1.0 projects

PGE Generation Zones With Existing Transmission & BPA GERP 1.0



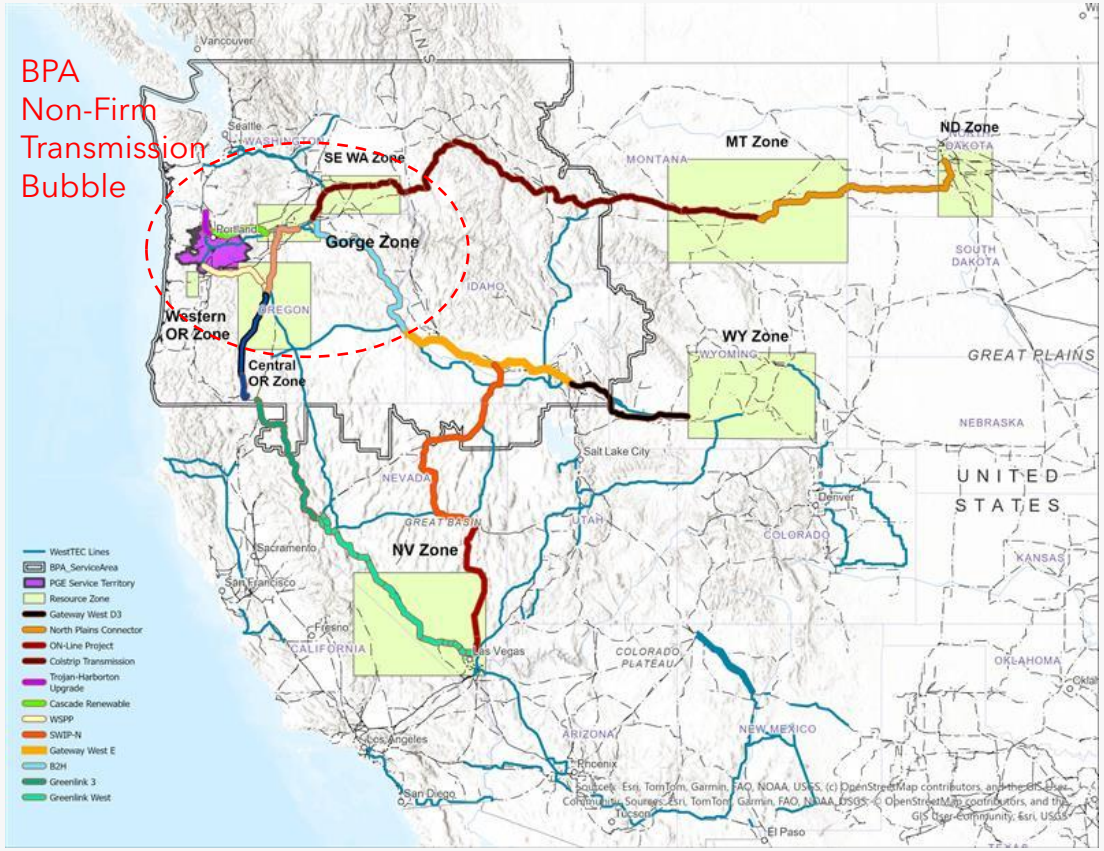
Portfolio Construction Transmission Methodology

Transmission expansion allows for expanded access for the full value of new resource development and use of non-firm transmission maximizes use of existing infrastructure

For resource needs exceeding existing inventory, portfolio analysis relies on two transmission products

1) New long-term transmission as introduced in the 2023 IRP Update and discussed at the December 2025 Roundtable
2) and/or, new for the 2026 IRP methodology, non-firm transmission within BPA's transmission footprint

PGE Generation Zones With Transmission Expansion



Non-Firm Transmission

Use of non-firm transmission for 'energy-only' clean energy resources

- In contrast to long-term firm and conditional firm transmission products, non-firm transmission is marketed by BPA exclusively on a short-term basis
- Non-firm is the lowest priority transmission product characterized by interruptible service
- When available, non-firm transmission is marketed by BPA up to total short-term transfer capability of BPA internal flow-gate when not in use by other higher priority transmission products
- Evolution of two day ahead markets in the West may have impacts to non-firm transmission products in the future

2025 BPA Transmission Plan – Path & Intertie Map

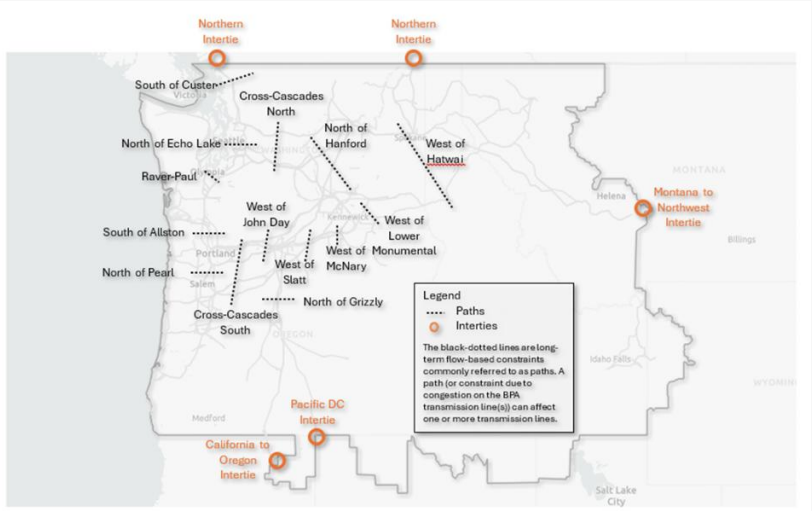


Figure 12 Path and Intertie Map

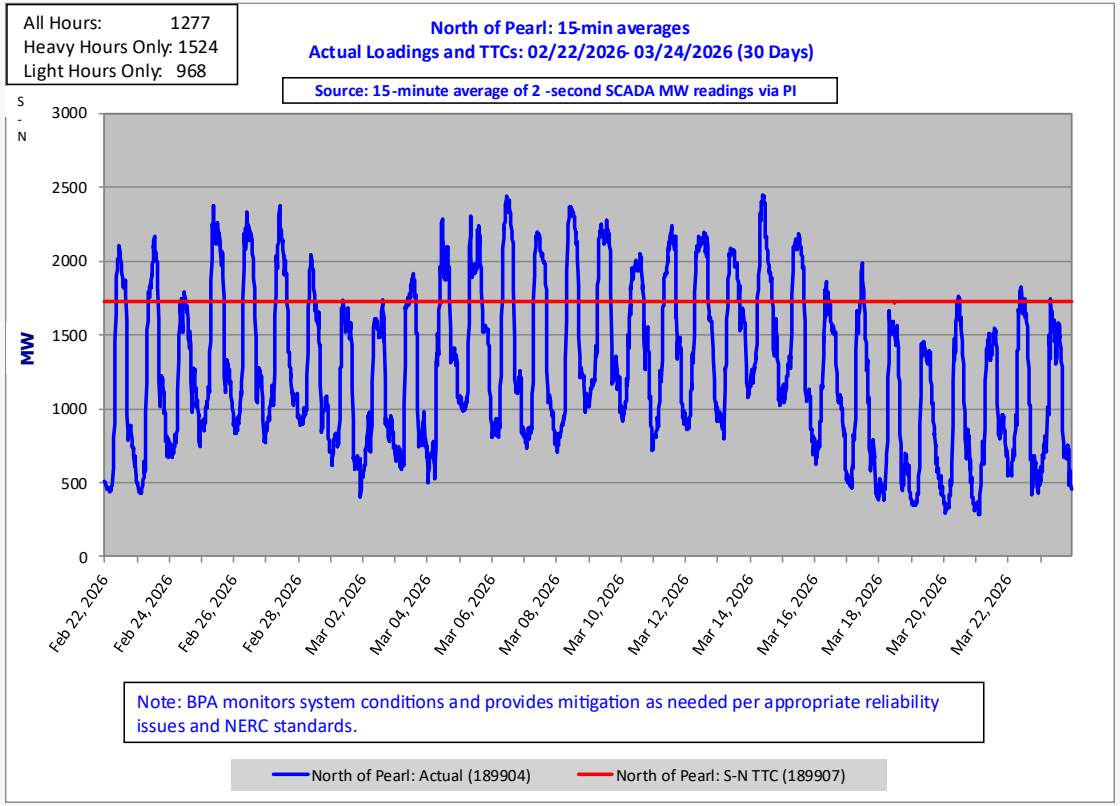
Congestion Management Impact on Non-Firm Transmission

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

Challenges for Incorporating Non-Firm Into Resource Planning

- Resource planning must account for essential differences associated with non-firm transmission when considering resources reliant on interruptible transmission service
- Consistent with Resource Adequacy (RA) frameworks, including Western Resource Adequacy Program (WRAP), non-firm transmission is not an eligible transmission product to support RA. Resources fully reliant on non-firm have no capacity contribution
- Resource energy contributions values also must account for 1) how much non-firm transmission is expected to be available across the planning horizon 2) how frequently is non-firm transmission forecasted to be suspended or curtailed across the planning horizon
  - 2025 RFP answered these questions with historical analysis of flowgate congestion
  - Assessment of these two non-firm planning questions require use of new quantitative methods – 2026 IRP will use GridView production cost modeling (PCM)

2025 RFP Assessment of Forecasted Non-Firm Congestion Based on Aggregated Historical BPA Interfaces & Flowgate Data:

HOUR \ MONTH	1	2	3	4	5	6	7	8	9	10	11	12
1	0%	0%	0%	0%	15%	2%	0%	0%	1%	2%	0%	0%
2	0%	0%	0%	2%	14%	2%	0%	0%	1%	2%	0%	0%
3	0%	0%	0%	2%	13%	2%	0%	0%	2%	2%	1%	0%
4	0%	0%	1%	3%	15%	2%	0%	0%	0%	2%	2%	0%
5	0%	0%	1%	3%	11%	2%	0%	0%	0%	1%	2%	0%
6	2%	2%	3%	3%	13%	4%	0%	0%	0%	2%	2%	0%
7	5%	6%	4%	5%	13%	6%	2%	0%	1%	2%	5%	0%
8	8%	22%	9%	16%	24%	4%	1%	1%	0%	3%	8%	0%
9	10%	30%	16%	26%	27%	9%	0%	3%	0%	4%	5%	0%
10	13%	29%	19%	25%	38%	11%	2%	4%	0%	7%	6%	2%
11	13%	24%	24%	25%	39%	15%	3%	6%	2%	8%	5%	2%
12	13%	20%	24%	24%	38%	18%	4%	4%	0%	7%	4%	2%
13	15%	21%	23%	24%	43%	18%	8%	5%	0%	6%	3%	3%
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17	6%	10%	12%	12%	40%	24%	24%	9%	0%	1%	8%	0%
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19	8%	13%	3%	5%	27%	28%	20%	17%	2%	3%	12%	0%
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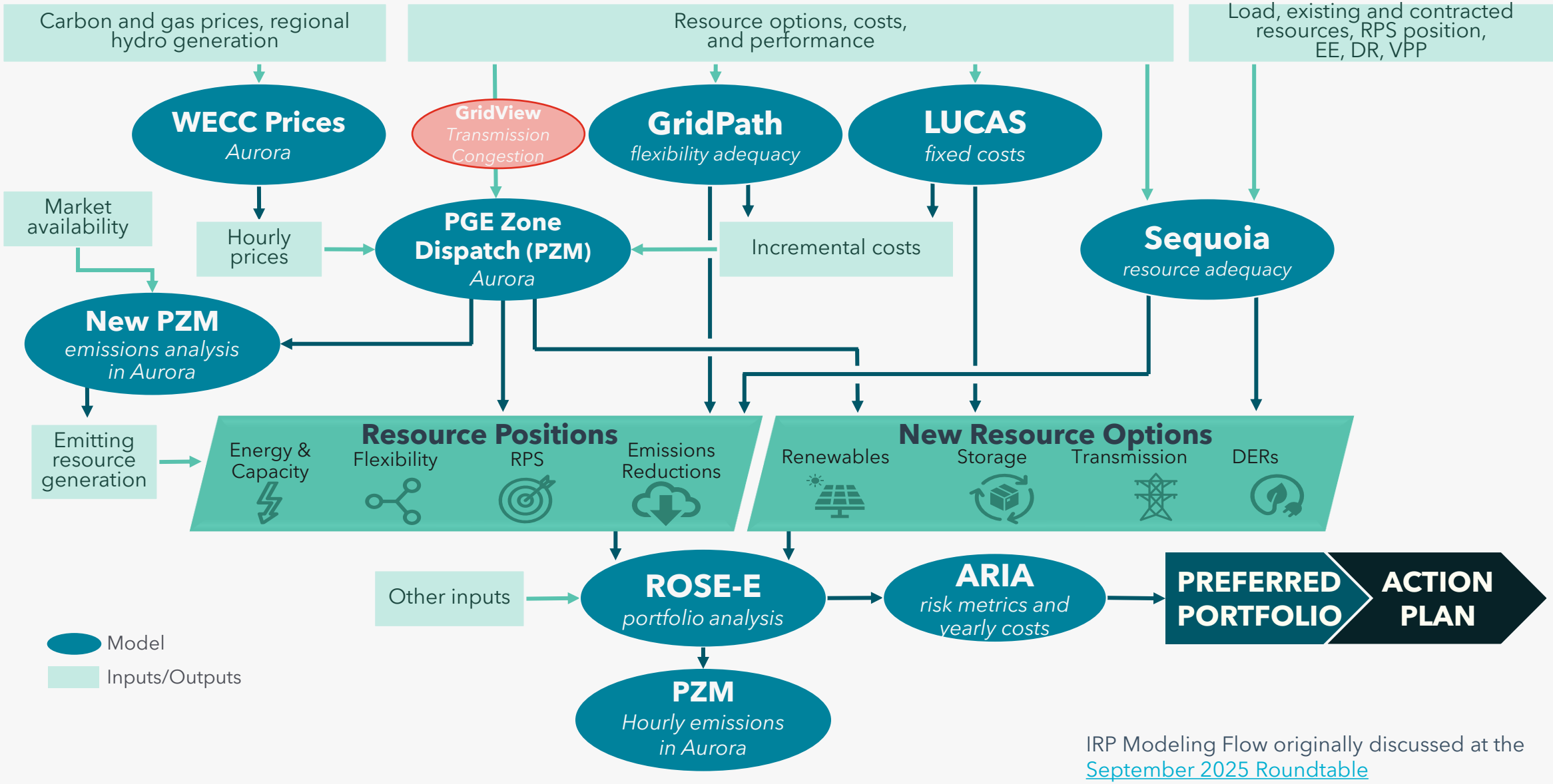
22	2%	6%	2%	4%	21%	16%	10%	6%	2%	3%	9%	0%
23	2%	3%	2%	2%	16%	5%	2%	0%	0%	2%	4%	0%
24	1%	0%	1%	2%	15%	3%	1%	0%	0%	2%	4%	0%

BPA Interfaces & a Flowgate Aggregated for Performance Review:

- 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

2026 IRP Modeling Flow



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

Purpose: PCM-Driven Transmission Constraint Forecasting & IRP/RFP Support

Forecast Transmission Constraints

- Apply Year 10 Production Cost Model (PCM) analysis to identify and forecast future transmission constraints on BPA Interties & Flowgates
- Analyze the utilization rates and frequency of constrained paths to quantify future risk exposure

Support IRP/RFP Evaluation

- The study findings are key inputs to IRP/RFP resource evaluation processes to evaluate non-firm transmission at risk
- Previously PCM analysis was contracted out

Economic Dispatch Modeling

Hourly unit commitment and economic dispatch model
• Determines least-cost generation dispatch stack while meeting demand and operational constraints. • A Nodal model simulates 8760 hours/year (scalable from days to years). • Contrasts with static power flow (PF) models that captures only a single moment. • Run times – WECC model yearly run: 2-3 days processing time

GridView Capability
• Transmission congestion analysis • Economic impact of competing transmission expansion • Resource utilization • Renewable integration analysis • Constrained hours and unserved energy events • Contingency analysis • Fuel and emission cost analysis • Reserve margin evaluation

Transmission Constraint Analysis: Methodology & Study Framework

Model & Scope

Base GridView case: WestTEC 2035 (Planned Projects Only)

Identified 12 high-impact BPA Interties & Flowgates for analysis

Constraint Identification Approach

Compare hourly path MW flow against Total Transfer Capability (TTC) values

An hour is flagged as constrained when at least one path flow reaches ≥ 80% of TTC

Heatmap Development

Populate 12×24 heatmaps with percentage of constrained hours per month

Generate additional heatmaps at 90% and 100% of TTC thresholds for comparative analysis

Benchmark 10-year PCM results against 3-year historical utilization data (Jan 2023 – Mar 2025)

Study years & Scenarios

Year 2035 case: 2035 topology, load, generation & economics

Year 2027 case: 2027 topology for subset of western interconnection; 2035 load, generation, and economics

📌 **Note:** ***Results to be presented and discussed at a future stakeholder roundtable***

Guided Feedback

Process: What remaining questions do you have regarding PGE's transmission methodology? What additional information would support your understanding of PGE's transmission constraints and GridView capabilities?

Content: Between PGE's proposed used of existing long-term transmission rights, transmission expansion options and use of short-term non-firm transmission, do you think PGE's proposed methodology well captures system transmission constraints?

Price Futures Update

Chris White

PGE An Oregon kind of energy.℠

High-Level IRP Analysis Process

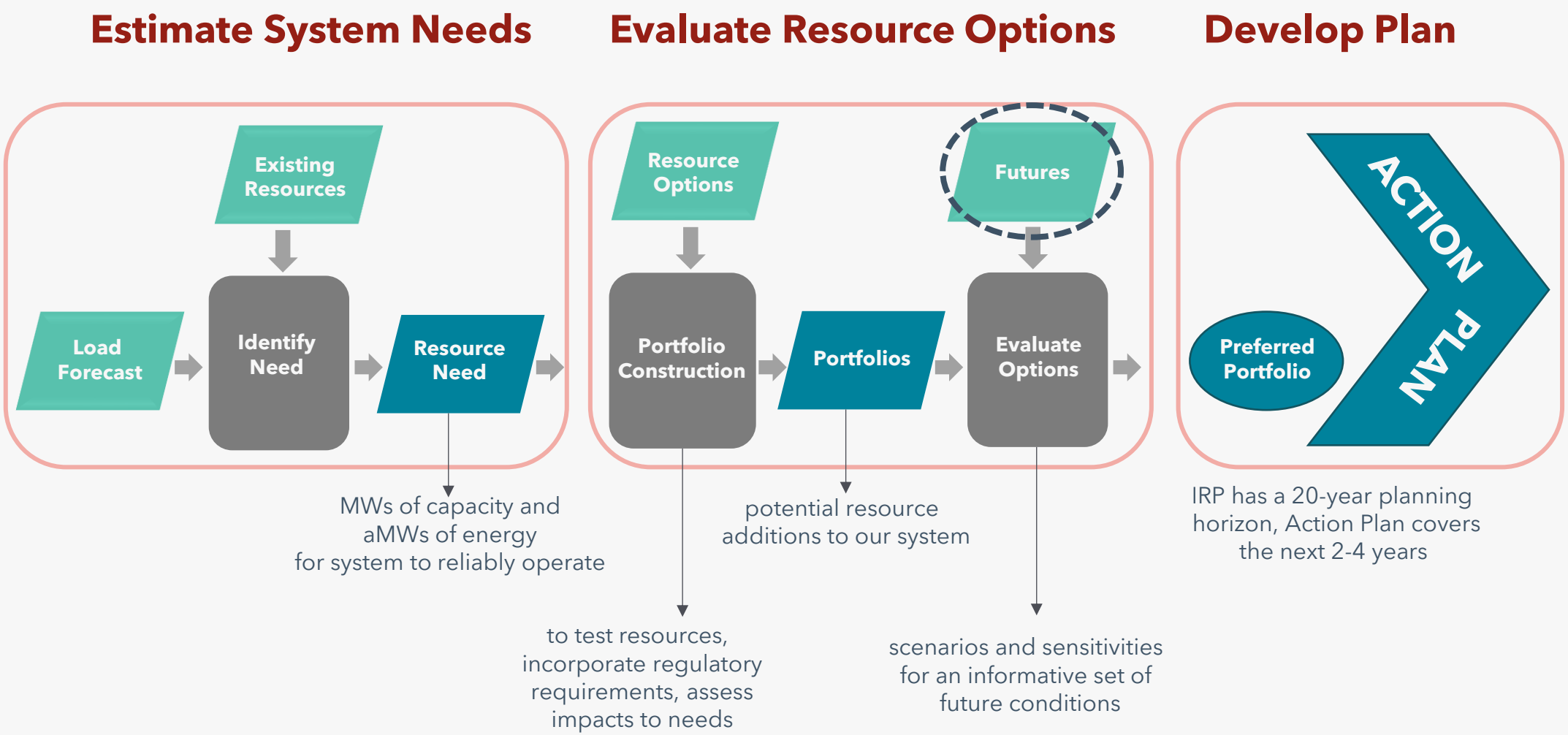
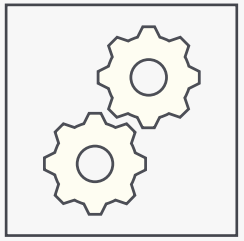


Table of Contents

Review of methodology changes

2024H2 input database

WECC model scenarios



Summary of new methodology changes

Load futures

Technology futures

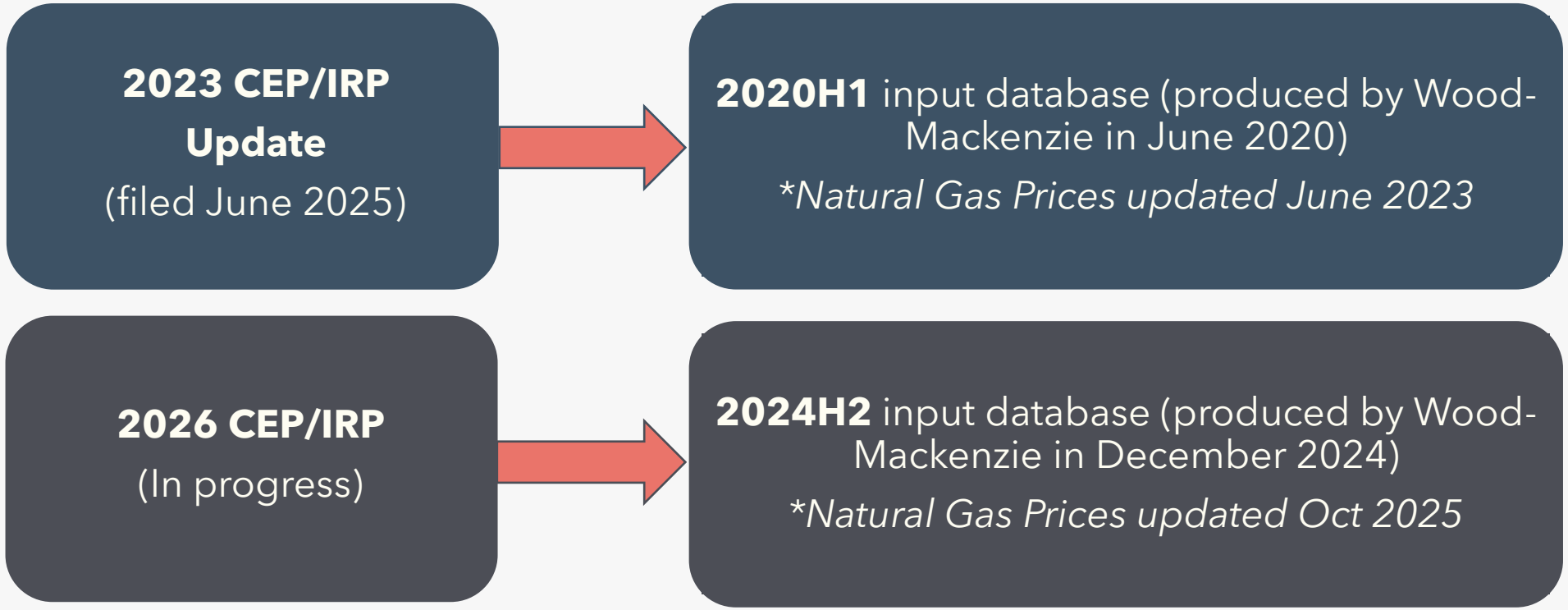
Results of WECC Model

Breakout of price futures by scenario

Summary of price futures & comparison to 2023 CEP/IRP Update reference case

Review of Methodology Changes

2024H2 Input Database



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

Review of Methodology Changes

WECC model scenarios

2023 CEP/IRP

RRRR= {reference commitment, reference carbon, reference gas, reference hydro}

Commitment Error
- Net Load Uncertainty
- Fast Start Pricing

Carbon Markets Pricing
- Low California Energy Commission (CEC) allowance
- Reference CEC allowance price applied to CA & Washington Markets
- Social Cost of Carbon applied to WECC

Gas Volatility
- Low
- Reference
- High Natural Gas Scenarios

Hydro Conditions
- Low
- Reference
- High Hydro Conditions

Proposed 2026 CEP/IRP

RRRR= {reference load, reference carbon, reference gas, reference supply stack}

Regional Load Growth
- Low
- Reference
- High load growth

Carbon Markets Pricing
- Low CEC
- Reference CEC
- High CEC applied to generation delivered to CA & WA markets

Gas Volatility
- Low
- Reference
- High Natural Gas Scenarios

Regional Supply Stack
- Reduced clean energy build - decarbonization headwinds
- Reference case resource buildout
- Accelerated advanced technology deployment

Commitment Error
- Fast Start Pricing has been incorporated into standard assumptions
- Net load uncertainty is no longer incorporated due to incompatibility with WECC model design

New Methodology:
Load

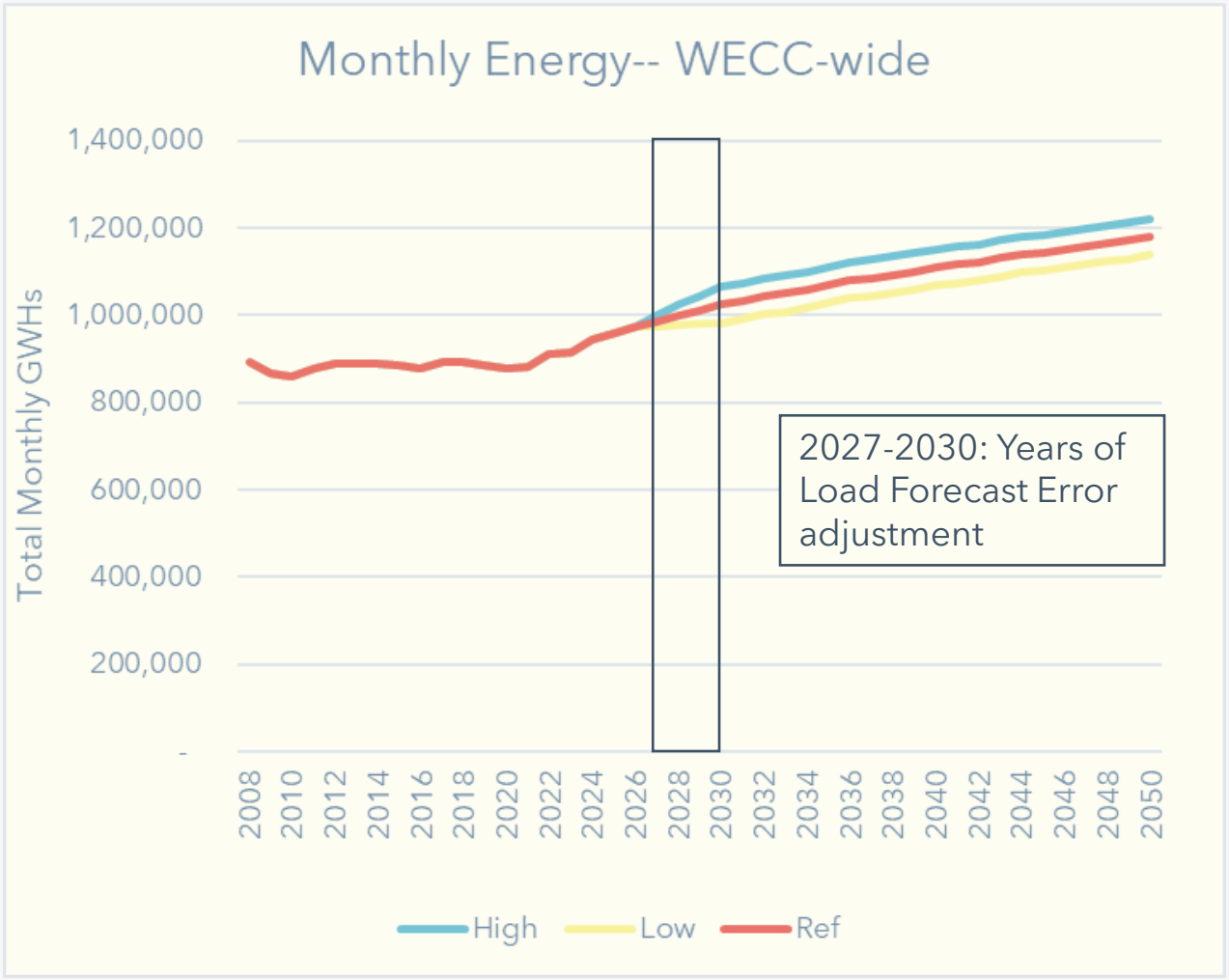
Due to significant growth in industrial loads over the past few years, PGE is testing the sensitivity of regional prices to load variation. This is indicative of PGE's view that variation in load is playing an increasingly critical role in strategic planning.

Load futures use historical growth rates from 2008-2025 by WECC region.

- **Low Load Case** – scale reference case forecast to achieve average annual historical growth rate.
- **High Load Case** - invert the difference between Low and Reference case.

Apply historical deviation in growth rates to year 2027-2030 to represent near-term load forecast error by region.

- ~4% increase/decrease in load in 2030 for high/low load scenarios.



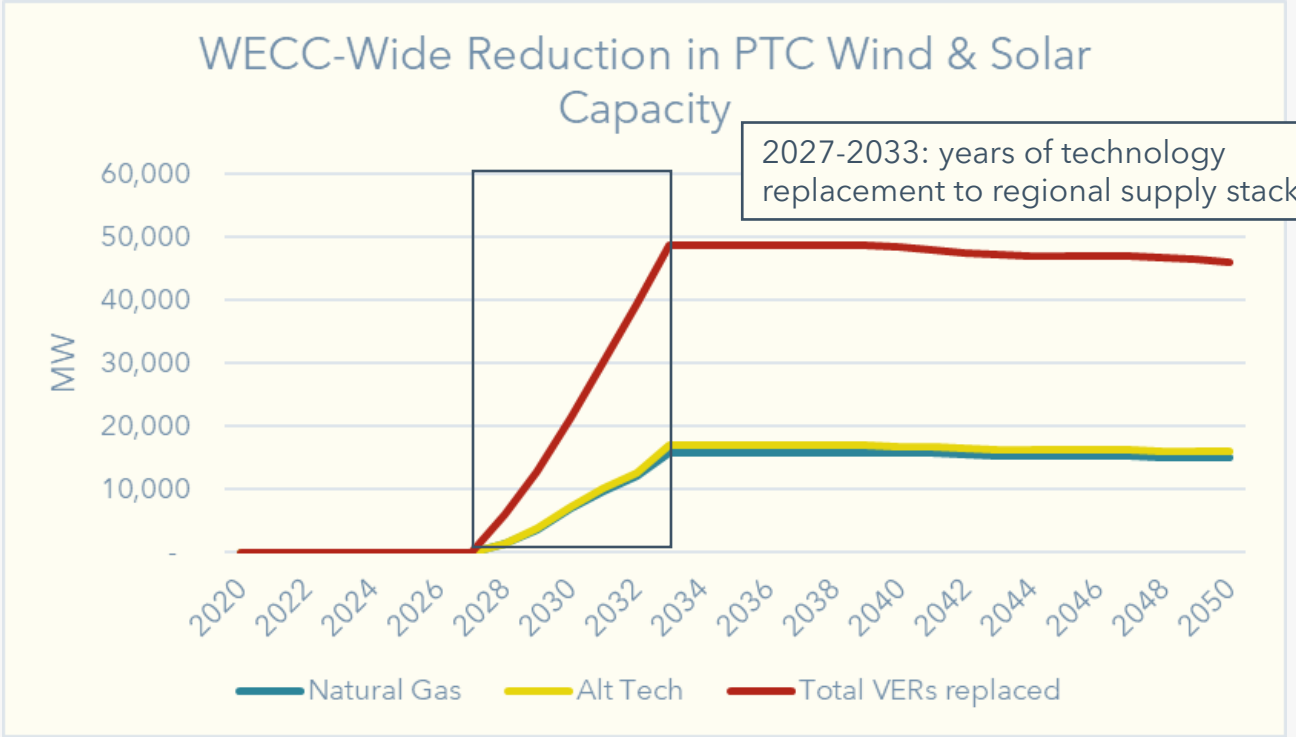
New Methodology:
Regional Supply Stack

The rollback in clean energy incentives from the One Big Beautiful Bill Act in July 2025 has led PGE to prioritize investigating price sensitivity of resource supply stack composition.

Given that the bill reduces Production Tax Credits (PTC) incentives, PGE has identified solar and wind resources that are more likely to be reliant on PTCs for financial viability.

In two alternative futures over the years 2028-2033, this selection of PTC-dependent wind and solar resources are replaced according to a 1:1 Megawatt average by either:

1. Natural Gas
2. Alternative Technology (Geothermal + Nuclear)

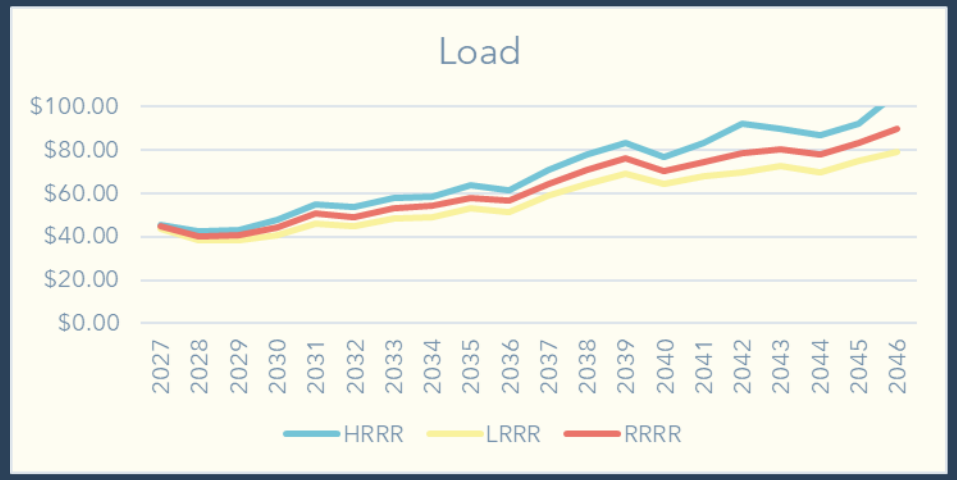


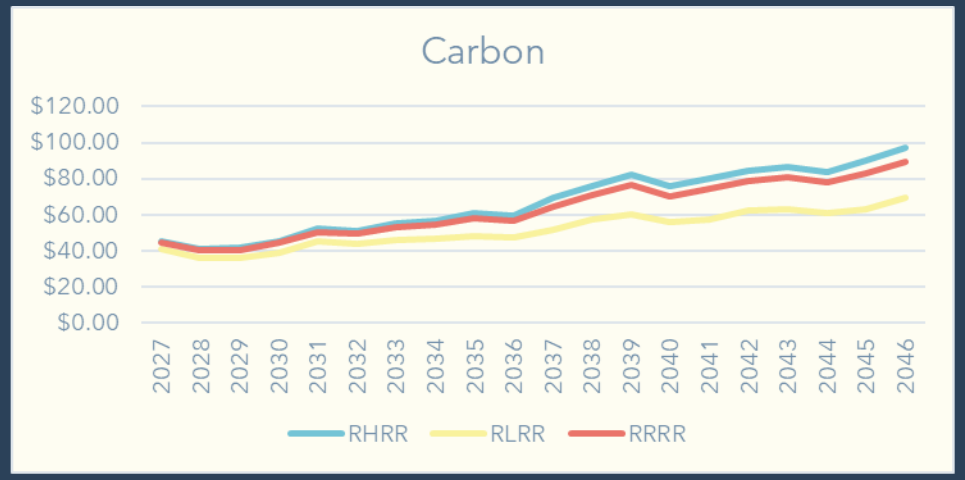
To prevent changes in overall annual energy production by zone, PGE replaces VER resources using a 1:1 ratio by megawatt-average.

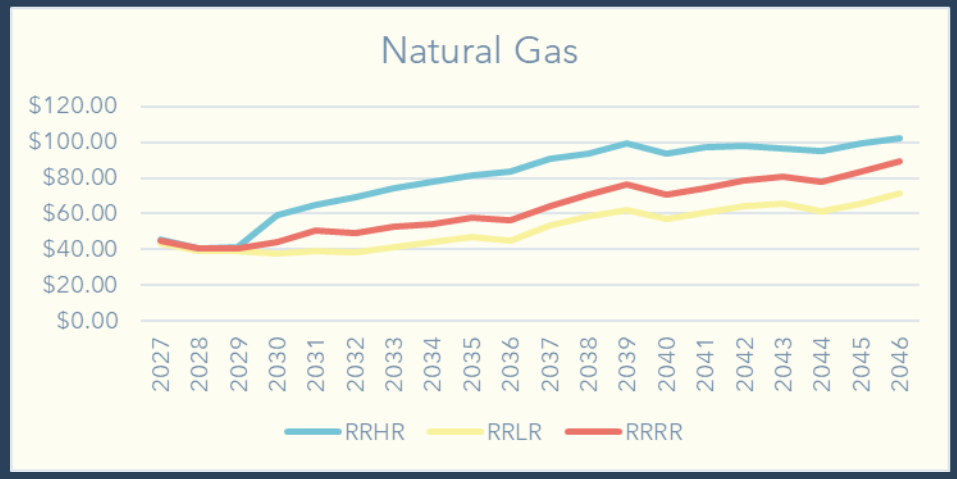
Example: *A 100 MW natural gas resources using a 95% capacity factor replaces 271 MW of wind or solar resources using a 35% capacity factor.*

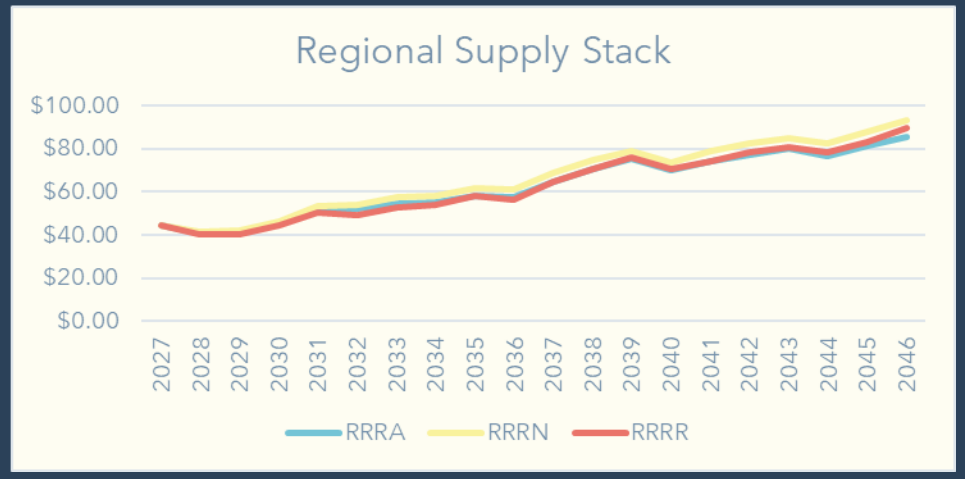
Results of WECC Model

Breakout of Price Futures by Scenario









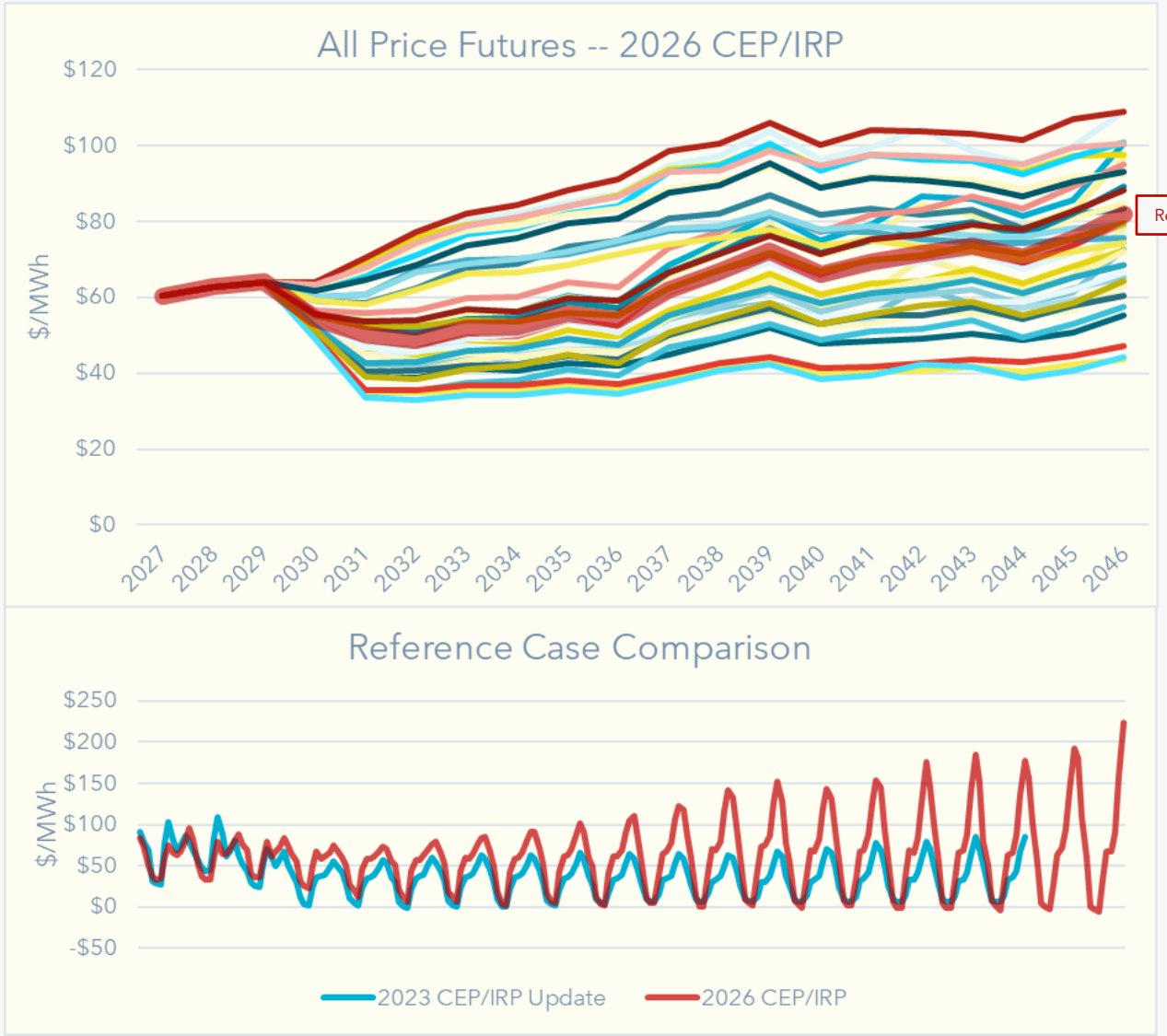
*Prices in nominal dollars

Results of WECC Model

Summary of Price Futures

From the 2023 CEP/IRP Update to the 2026 CEP/IRP, PGE observes an 87% increase in annual average forecasted price level from 2027-2044 due to the following reasons:

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



*Prices in nominal dollars

Guided Feedback

Process: New for the 2026 IRP, PGE is attempting to forecast the wholesale price risk associated with changes in WECC wide large load growth and generation technology build out. Do you understand and agree with the proposed methodology change?

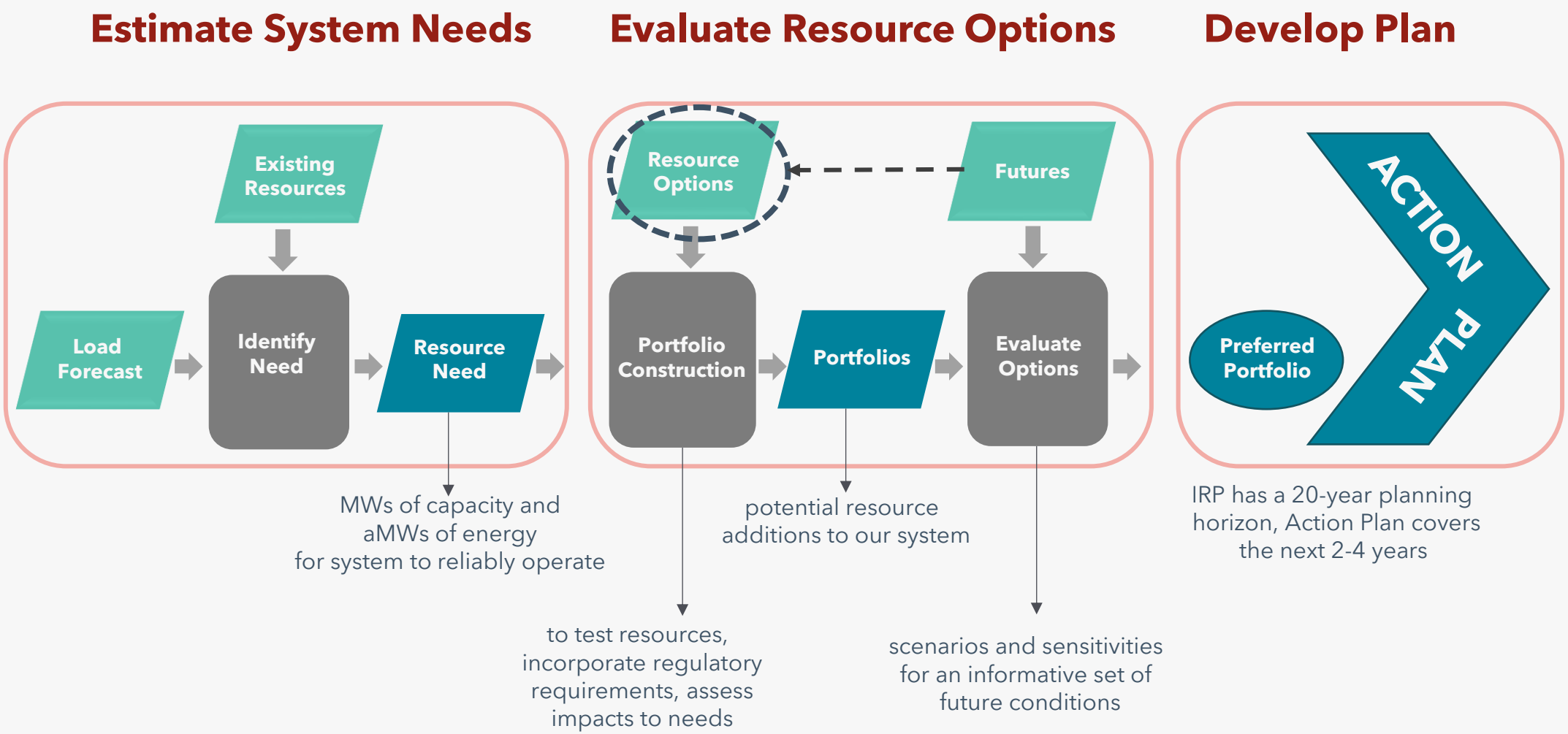
Content: PGE's draft wholesale price forecasts have directionally increased. Is that trend consistent with your expectations and how does it compare to other reports you have reviewed recently?

Energy Values for Resources

Chris White

PGE An Oregon kind of energy.℠

High-Level IRP Analysis Process



2026 CEP/IRP Energy Values

	Levelized Energy Values (2026$/MWh) for COD in 2028		
	2026 IRP		2023 Update*
Resource	Reference	Range**	Reference
Solar CV	$ 37.77	$18 - $48	$ 23.99
Solar MCMN	$ 36.17	$17 - $46	$ 22.98
Solar Wasco	$ 35.57	$17 - $45	$ 22.48
Wind Gorge	$ 47.61	$23 - $58	$ 28.26
Wind MT	$ 55.40	$26 - $66	$ 33.19
Wind SE WA	$ 51.62	$25 - $63	$ 30.64
Wind ND	$ 54.70	$26 - $66	$ 31.68
CV hybrid 1	$ 49.15	$23 - $60	$ 29.31
MCMC hybrid 1	$ 49.07	$23 - $60	$ 29.93

*From Table 19 in Chapter 5 of PGE's 2023 CEP/IRP Update, inflation adjustment to base year $2026.
**Range reflects upward and downward semi-deviations around the Reference case across price futures.

- PGE uses Aurora to estimate the energy value benefits of dispatching existing generating resources, contracts, and candidate resources using electricity prices.
- Values are presented on a levelized basis, across each resource's assumed economic life, shown for 2028 commercial operation dates.
- Resulting values for proxy new resource options shown here are ~60-75% higher compared to 2023 CEP/IRP Update, driven primarily by changes in price futures (previous agenda item) .

Guided Feedback

Process: There was no change in the process for creating levelized energy values for the 2026 CEP/IRP. Do you understand how energy values are created and if not, what additional content can PGE provide to help clarify any remaining questions?

Content: Energy Values increased substantially from the 2023 CEP/IRP Update primarily due to higher market price forecasts. Are the resulting 2026 IRP energy values in line with your expectations?

BREAK

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Generic Resource Cost - Update

Robert Brown

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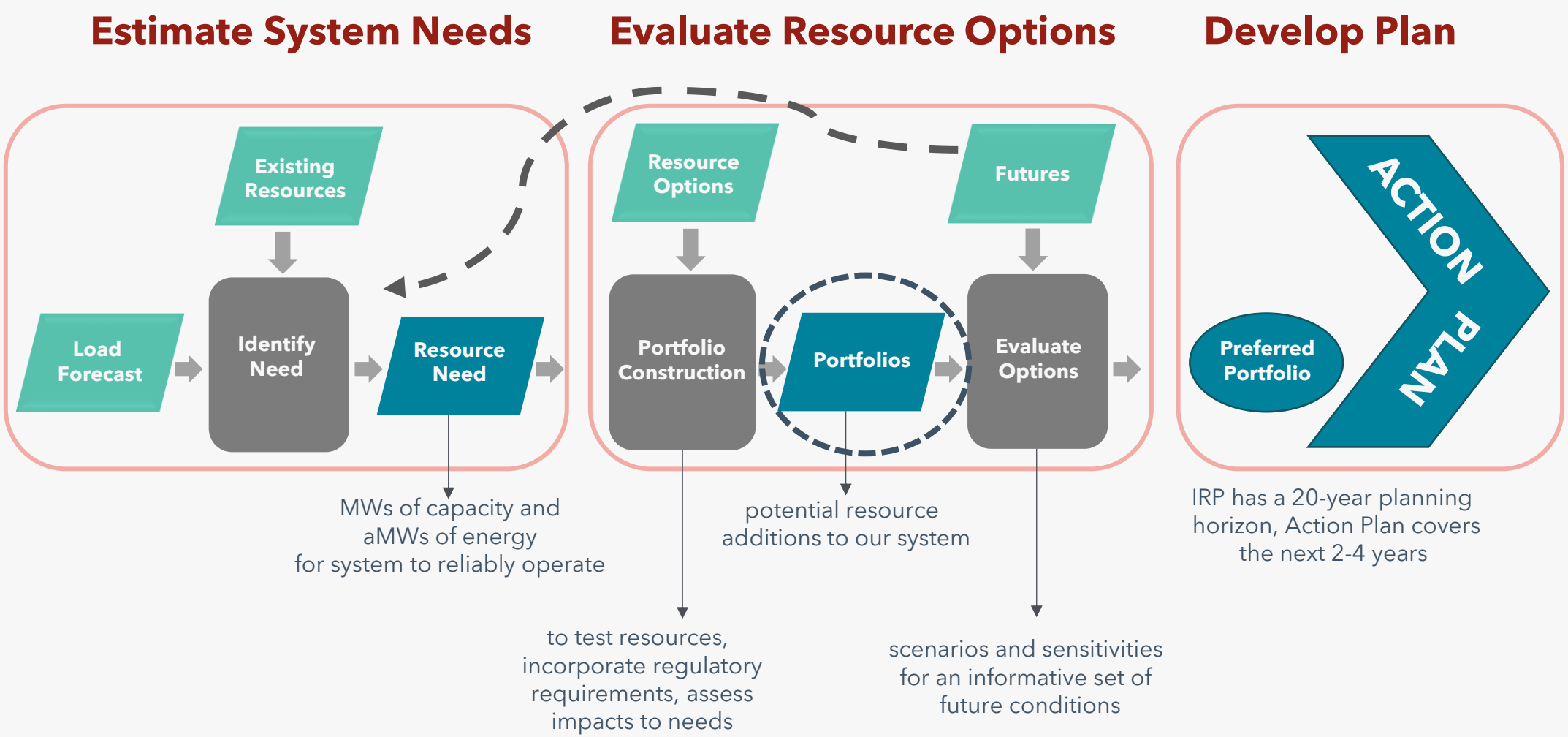
High-Level IRP Analysis Process



Outline

- Update on source for supply-side resource information
- Summary of current resource costs estimates
- Comparison with IRP Update

Sources of Supply-Side Resource Information

Recent past and current status

2023 CEP/IRP[1] and 2023 Update[2] relied on publicly-available information, primarily	National Laboratory of the Rockies (NLR) Annual Technology Baseline (ATB)	2024 ATB
	Energy Information Administration (EIA) Annual Energy Outlook (AEO)	AEO 2025 (research published Q1 2024)
2026 IRP Goal	Update cost information and resource attributes to latest NLR ATB in Q3-Q4 2025	
Current status	NLR ATB with updated data was not released	
	Relying on other options for resource assumptions to inform 2026 IRP -Wood Mackenzie resource cost research supplemented with 1898 & Co.	

[1] See PGE's 2023 CEP/IRP, Appendix M for a detailed discussion of resources considered: https://downloads.ctfassets.net/416ywc1laqmd/6B6HLox3jBzYLXOBgskor5/63f5c6a615c6f2bc9e5df78ca27472bd/PGE_2023_CEP-IRP_REVISED_2023-06-30.pdf#page=601

[2] filed June 18, 2025

National Laboratory of the Rockies was previously the National Renewable Energy Laboratory (NREL)

Wood Mackenzie

PGE uses Wood Mackenzie (WM) research to inform the resource dataset underpinning the market price simulations discussed earlier

Resource-specific research is developed with consideration of resource technology, commodities, supply chains, and regulation (among others)

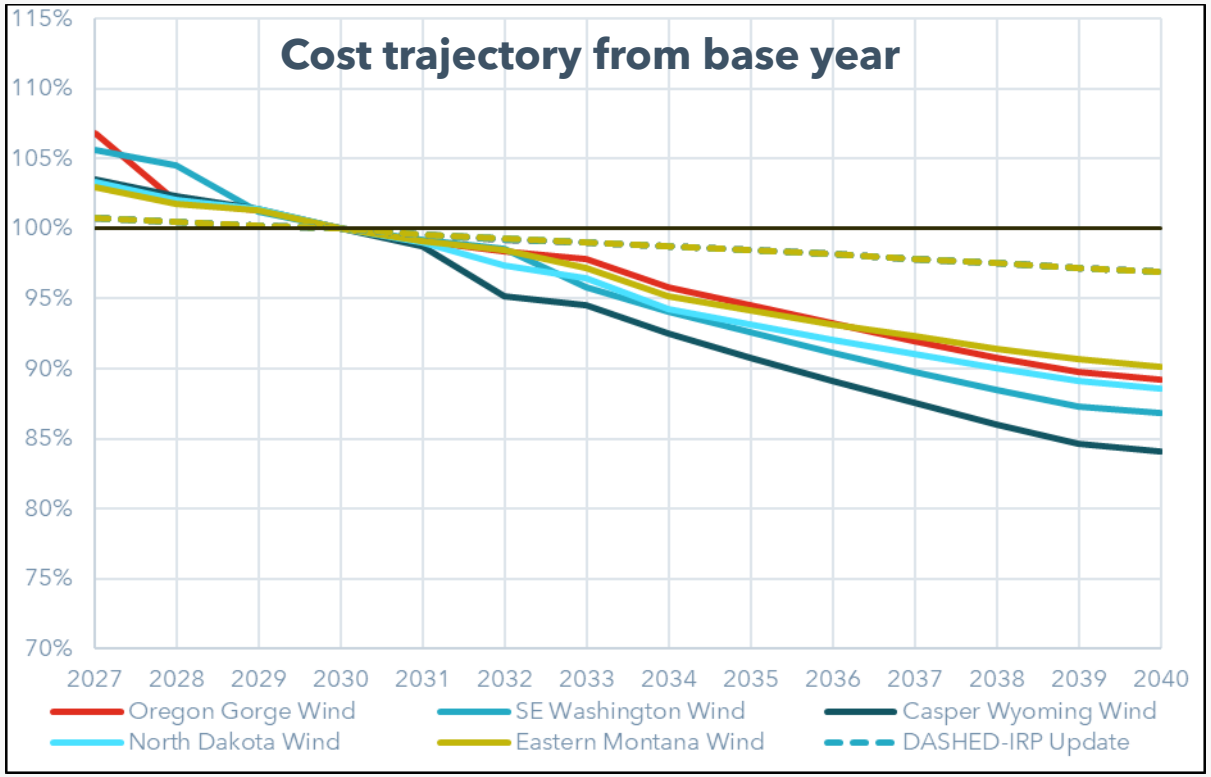
Research was published in Q4 2025 and available to PGE Q1 2026

Provides average, low, and high scenarios by resource by state across the US

Onshore Wind

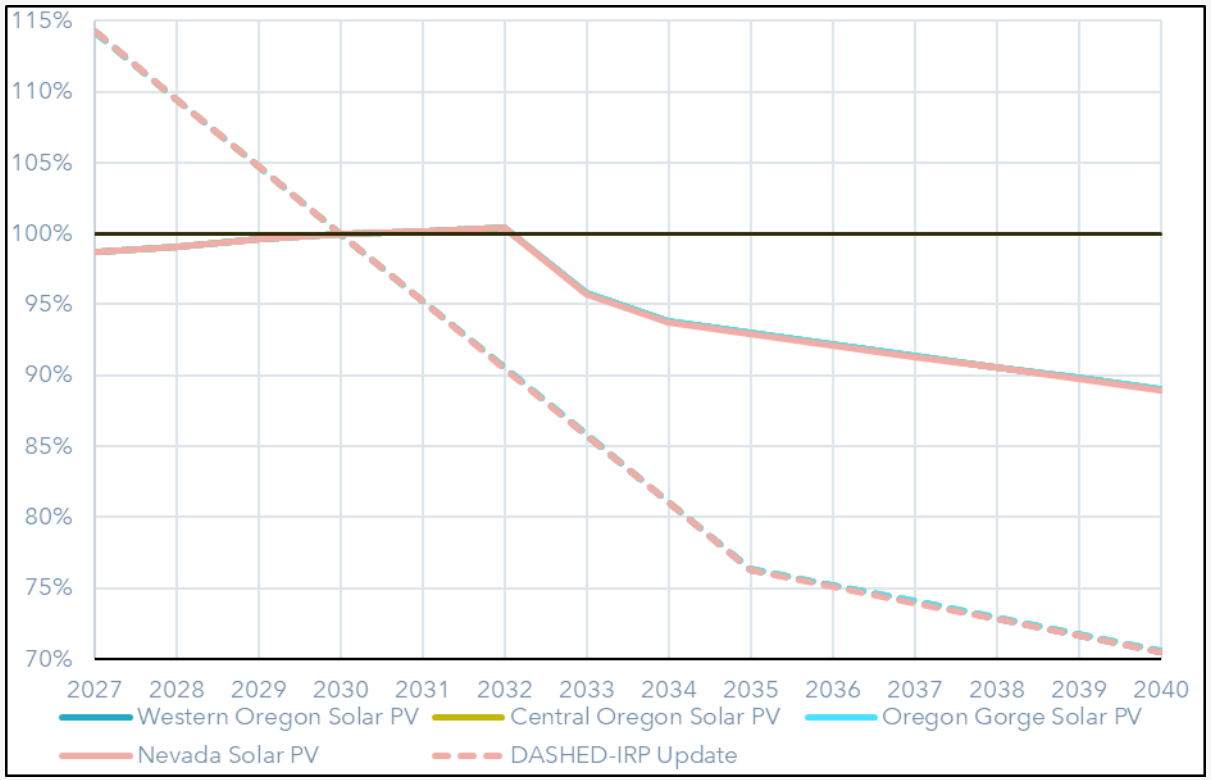
point cost estimates and trajectories (2030 COD)

	CF%	Overnight Cost (2026 $/kW)	
		Draft 2026 IRP	IRP Update
Oregon Gorge	36%	1,790	1,670
Southeast Washington	39%	2,020	1,630
Wyoming	43%	1,680	1,550
North Dakota	43%	1,720	1,580
Montana	41%	1,750	1,550



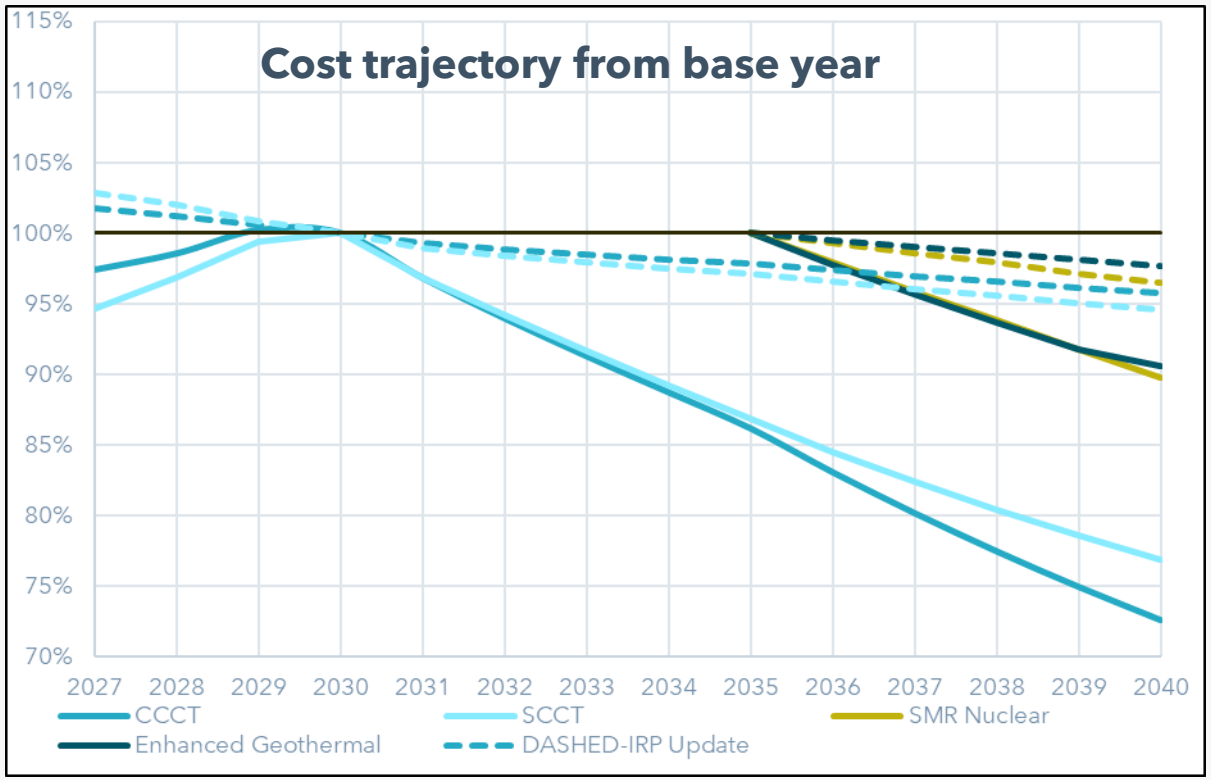
Solar PV
point cost estimates and trajectories (2030 COD)

	CF%	Overnight Cost (2026 $/kW)	
		Draft 2026 IRP	IRP Update
Western Oregon	22%	1,770	1,390
Central Oregon	27%	1,770	1,350
Oregon Gorge	26%	1,770	1,350
Nevada	32%	1,750	1,400



Dispatchable
point cost estimates and trajectories

	COD (base year)	Overnight Cost (2026 $/kW)	
		Draft 2026 IRP	IRP Update
CCCT	2030	3,080	990
SCCT	2030	1,840	870
SMR Nuclear	2035	11,780	9,050
Enhanced Geothermal	2035	5,160	5,040



Next Steps: Resource Characteristics

- Fixed cost and resource dispatch modeling inform:
  - Portfolio construction
  - Levelized Cost of Energy (LCOE)-type analysis

Guided Feedback

Process: In the absence of NLR data, PGE is utilizing publicly available data from a third-party source, Wood-Mackenzie, to inform resource cost estimates. Is this approach reasonable? Are there other sources that PGE should consider?

Content: The majority of costs have increased since the 2023 IRP Update. Is this consistent with what you'd expect? Are there additional current resource costs estimates that PGE should consider moving forward?

Market Emission Factor Scenarios

Lauren Slawsky

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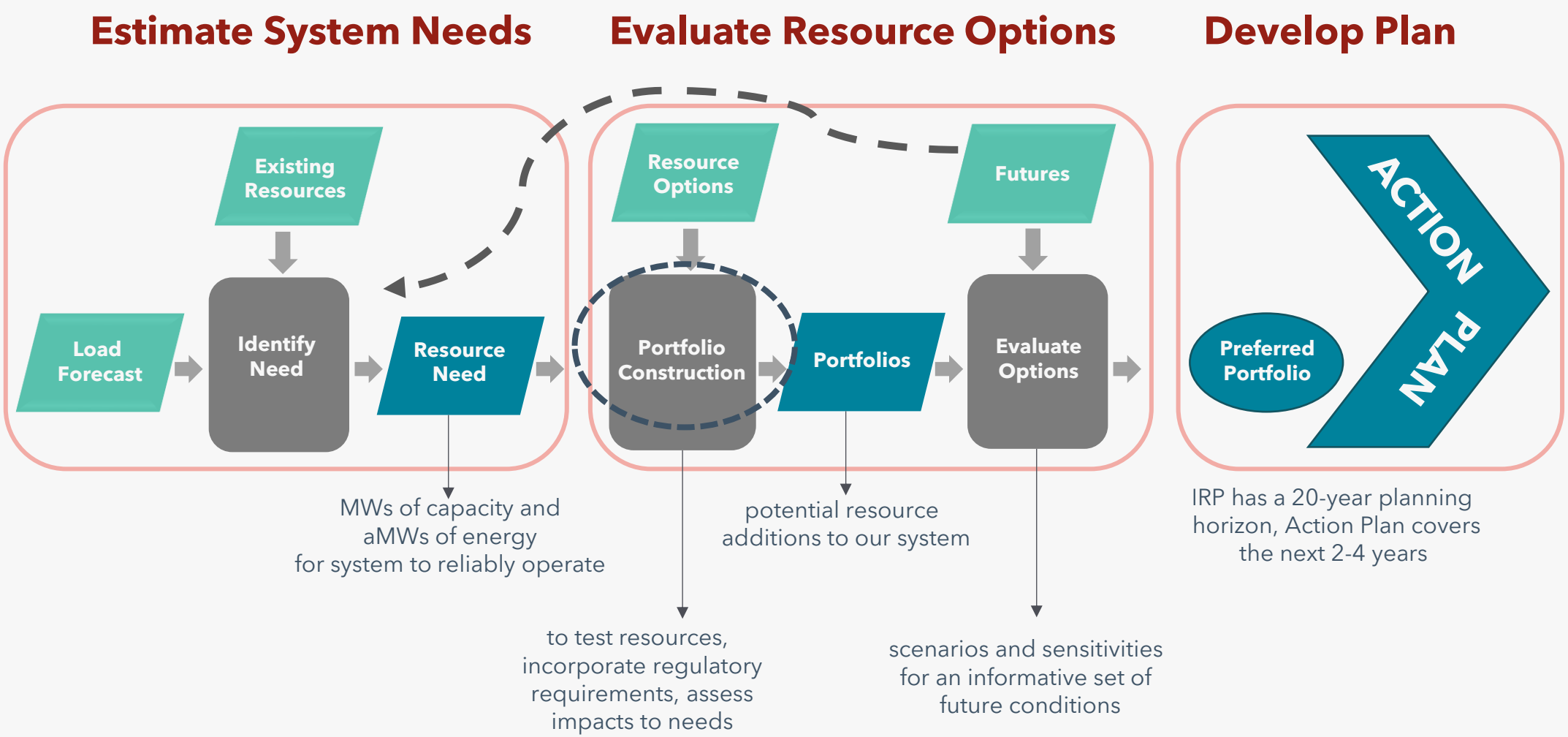
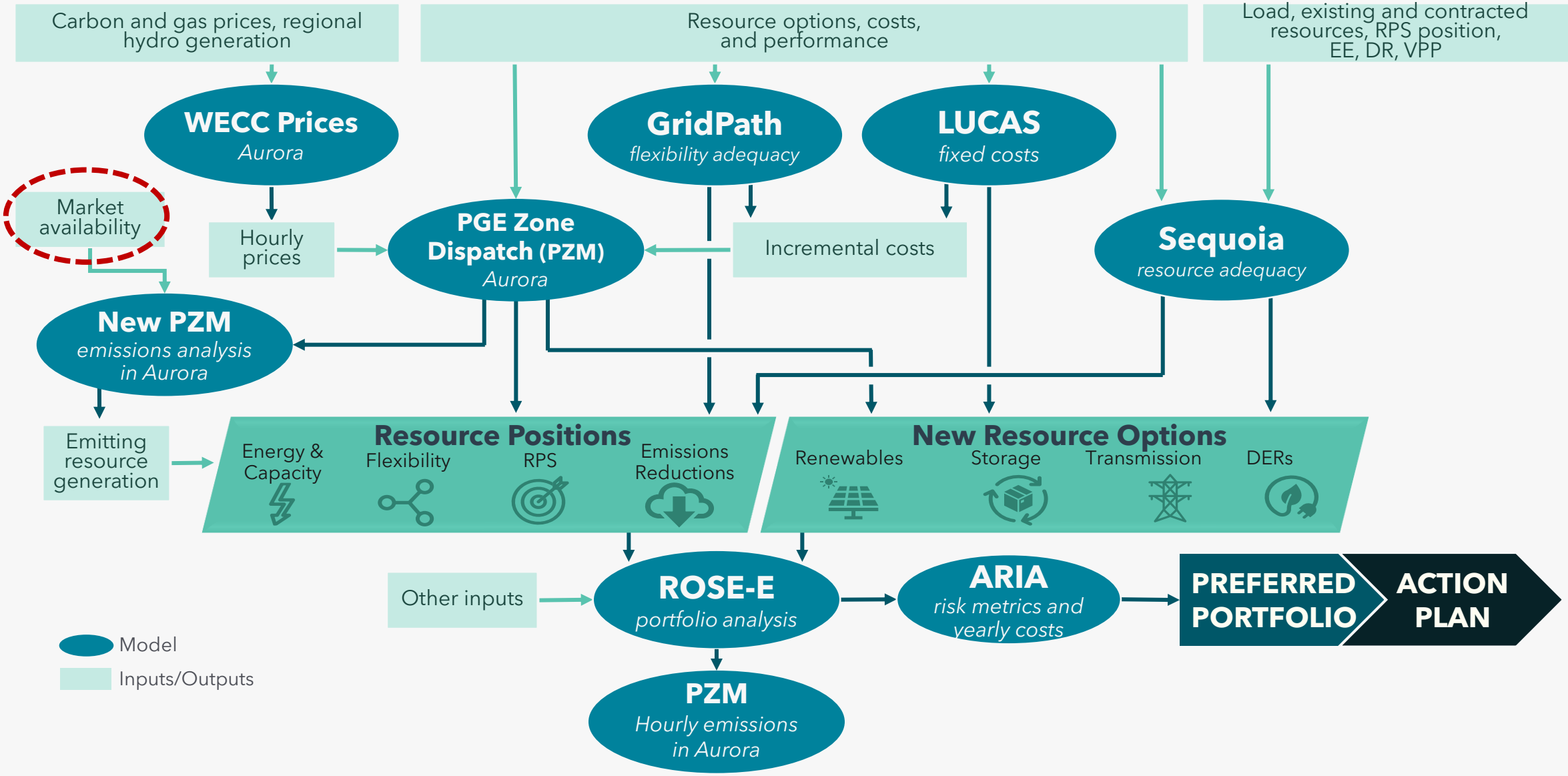
High-Level IRP Analysis Process



Outline

- Market Purchases in IRP
- Emissions Factor Assumptions
- Next Steps

2026 IRP Modeling Flow

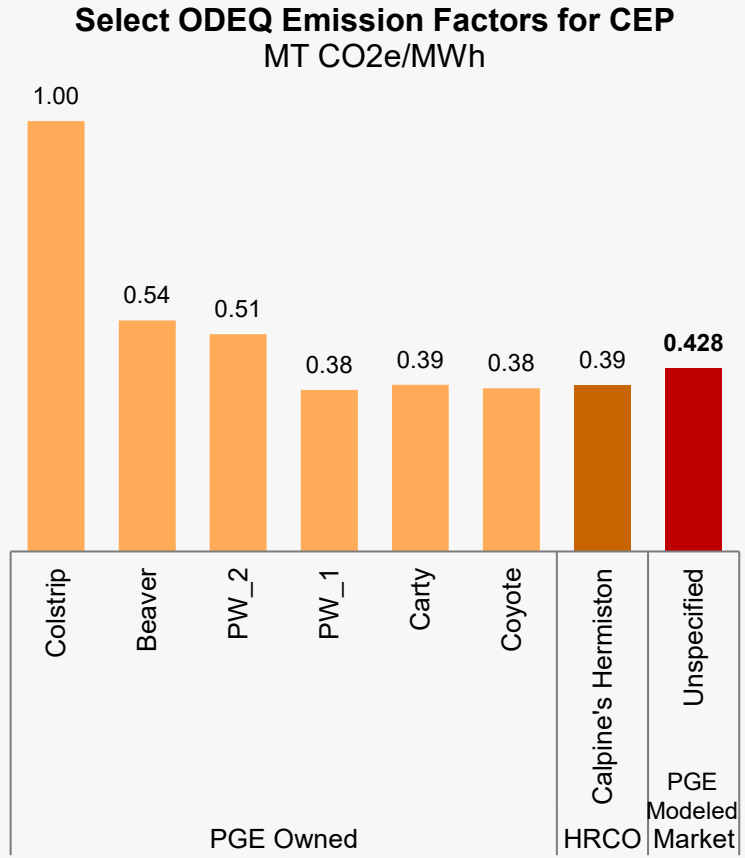


Market Purchases: Emissions Scenarios Overview

- High-level approach discussed at the February 2026 Roundtable:
  - Explore the impact of varying assumptions of emissions associated with market purchases in thermal dispatch scenario analysis using PZM (PGE Zonal Model in Aurora)

Market Purchases: Emission Factor	**CEP/IRP**
Non-Emitting Market (informed by Brattle Group study)	2023 Update
Unspecified 0.428 MTCO2e/MWh (ODEQ emission factor for unspecified & market purchases)	2026
Varying mix by year based on hourly availability (CAISO approach informed by Brattle study data)	2026

- California ISO (CAISO) -informed approach method and assumptions detailed on following slides



- HRCO = heat rate call option
- ODEQ = Oregon Department of Environmental Quality
- More from ODEQ on CEP and GHG emissions here: https://www.oregon.gov/deq/ghgp/pages/clean-energy-targets.aspx

CAISO Residual Market Mix Approach

- Emerging CAISO policy contemplates an approach to estimating annual emission factors for purchases from centralized markets that:
  - Leverages hourly load balancing
  - Overlays dispatch results with each reporting entity's owned and contracted resources
  - Represents diversity of emitting and non-emitting resources available in a residual market mix for greater accuracy and precision
- PGE is designing an approach that is informed by the CAISO policy, using model data from Aurora from the Brattle Study for the west, to estimate west-wide policy realization to forecast market emission factors for use in scenario analysis

CAISO approach to residual resources (and emissions) on the market:

Approach: On an hourly basis, calculate:

	Owned and contracted resources
-	Attributed resources
+/-	GHG pricing region adjustment
	Total
If Total > Load	
-	Allocate excess to residual rate data set
If Total < Load	
+	Add in using residual rate data set
	FINAL TOTAL

CAISO GHG Accounting Proposal: https://stakeholdercenter.caiso.com/InitiativeDocuments/Accounting-and-Reporting-Final-Proposal-Greenhouse-Gas-Coordination-Working-Group-Oct-15-2025.pdf

CAISO Residual Market Mix Methodology for IRP

Simplifying assumptions are used with forward-looking model data to simulate CAISO policy application to estimate market emission factor alternatives to ODEQ's current 0.428 MTCO2e/MWh*

CAISO Policy Approach	Key Simplification in PGE Modeling
Actual market dispatch results with information reported by entities	Forecast generation and load data from Brattle study conducted for 2023 IRP Update (assumes all state clean goals met)
Reporting entities (i.e., PGE, some participants TBD, etc.)	State-level load balancing (incl. CA, ID, NM, NV, MT, OR, UT, WY)
Owned generation, contracts, agreements, etc. will inform CAISO residual rate calculations	Total modeled generation used to inform load balancing and residual mix
Facility level emissions analysis (better captures technology, specs, efficiencies, etc.)	Fuel-tech level emissions analysis

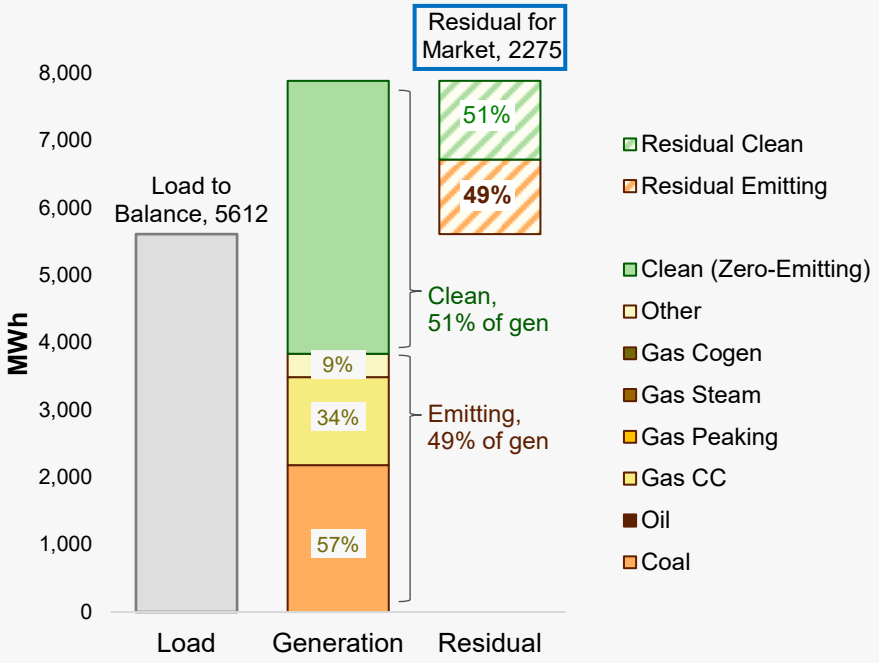
***Note**: The CAISO approach analyzed here is not yet in use nor is it adopted by ODEQ regulations which PGE must follow for emissions compliance.

Application of CAISO Policy using Model Data

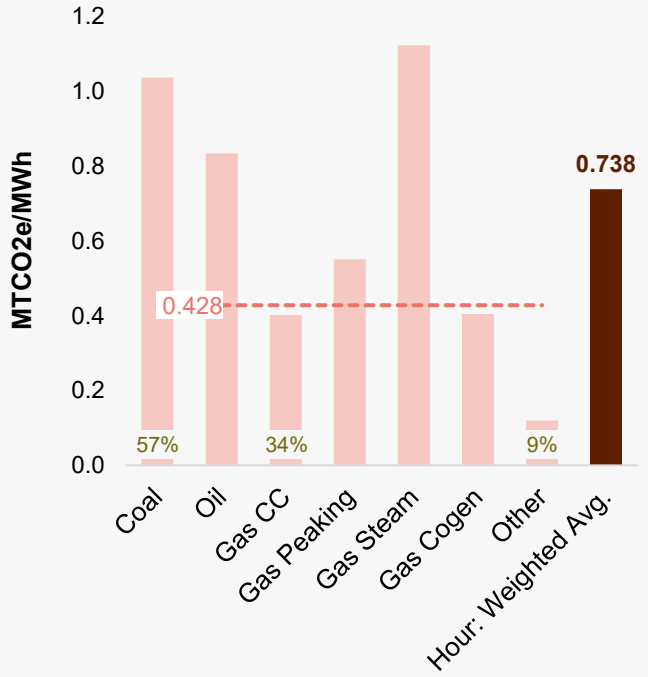
- Example process for 'weighted average' approach demonstrated for one state, one hour
- These data are rolled up with all participants' (i.e., modeled state) data for annual market emissions factors

State-level hourly load balancing to identify residual generation by type for market → **Application of fuel-tech type specific EFs to emitting power** → **Resulting market mix accounts for clean and emitting**

Utah model data for an evening hour June 2030



Resource Emission Factor (EF) Assumptions



Note: emission factor assumptions informed by EPA and ODEQ data

Emissions for this hour

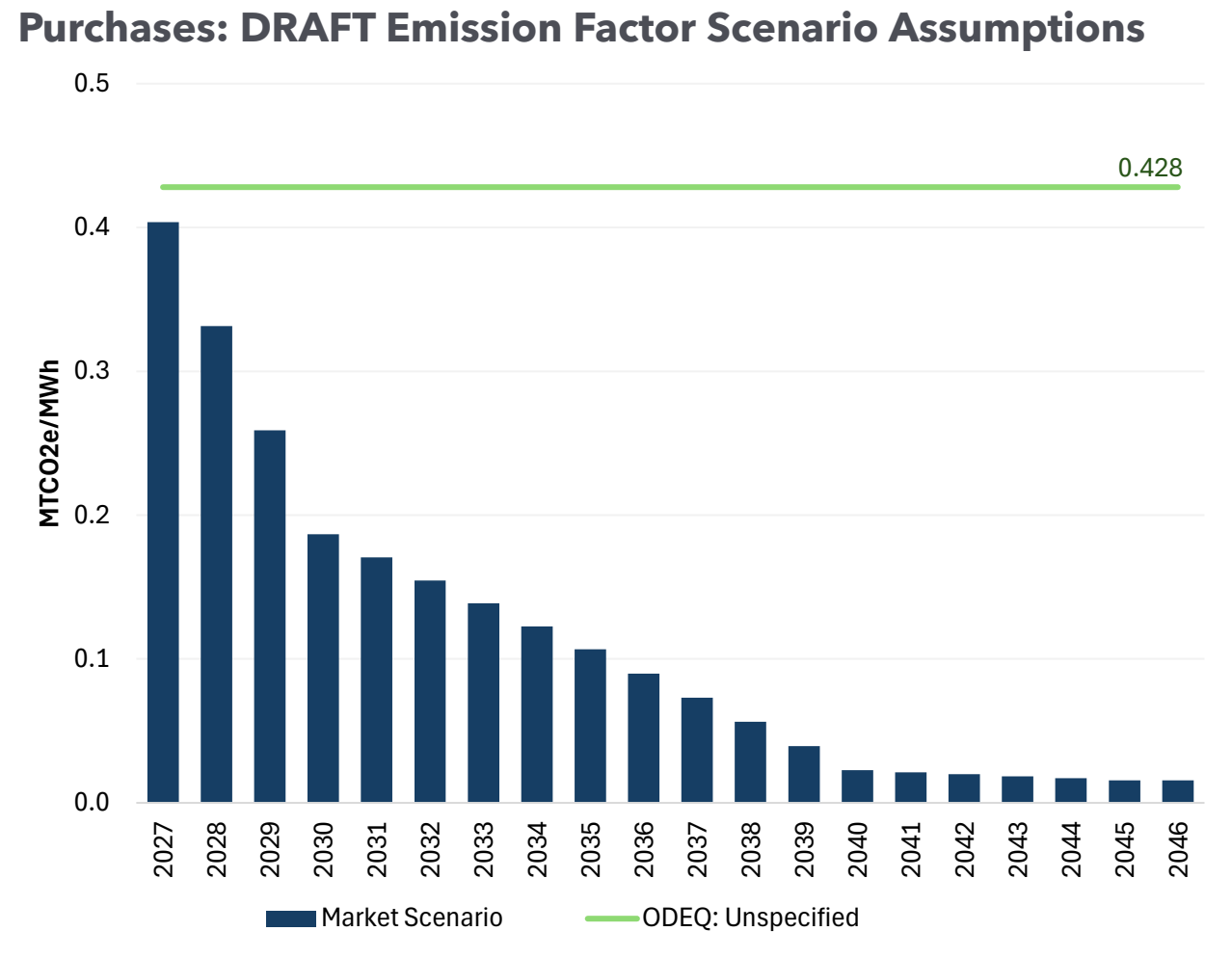
2275 MWh residual
x 49% Emitting
x 0.738 MT/MWh
= 816 MT

Emissions Factor for this hour

$$\frac{816\ \text{MT}}{2275\ \text{MWh}} = 0.358\ \text{MTCO2e/MWh}$$ Utah Residual Mix

Hourly residual MWhs and MTs summed over the year for annual market summary

Two Market Resource Mix Scenarios for use in IRP



Oregon Department of Environmental Quality (ODEQ) Unspecified Rate

- ODEQ's emission factors for use in CEP currently require the unspecified 0.428 MT/MWh to be applied to market purchases
- This factor is largely representative of a marginal gas-fired unit

Alternative Market Scenario

- CAISO's "average" (i.e., weighted average) approach results in a factor that is lower than 0.428, continuing to decline overtime as the renewables continue to come online throughout the region
- This residual market mix = average mix of resources available after meeting state loads (DRAFT analysis shown)

Notes on analysis: annual summary of hourly balancing where hourly residual mix results are summed for states for each forecasted year. Recall underlying forecast data assumes state clean goals are met and accounts for other fuel mix changes over time, such as due to retirements, etc.

Next Steps: Emission Factor Scenario Analysis

- PZM production cost modeling will be run for economic dispatch of resources
  - Resulting thermal output will vary between the two market emission factor scenarios to be analyzed
  - Emissions by resource will vary, though targets will still be met in HB 2021 scenarios
  - Costs will vary

- ROSE-E then uses above results as inputs as part of portfolio analysis
  - Portfolio analysis will further explore these different scenarios and other varying conditions to assess uncertainties, balance priorities, and ultimately inform least-cost/least-risk planning and a preferred portfolio

Guided Feedback

Content: The market emission factor forecast is informed by the CAISO method that is currently being explored, and assumes that States across the region are making progress towards and meeting current clean energy and decarbonization targets. Do you have any questions regarding this approach? Are there other methods PGE should consider?

Process: In the 2026 IRP, PGE is attempting to forecast an emission factor that more closely represents the emissions profile of a forecasted market as the region decarbonizes. Do you agree with this approach? Do you have any questions about how this rate is intended to be used in the 2026 IRP analysis?

NEXT STEPS

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

Upcoming Roundtable: May 20, 2026

Thank you

Contact us at
IRP.CEP@PGN.COM

An

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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
MWa: 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