Integrated Resource Planning

ROUNDTABLE 22-10

NOVEMBER 2022

PGE

MEETING INFORMATION

Electronic version of presentation:

https://www.portlandgeneral.com/our-company/energy-strategy/resource-planning/integrated-resource-planning/irp-public-meetings

Teams Meeting

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Please use Microsoft Edge or Google Chrome with Teams as it will give you the best experience

PARTICIPATION

During the presentation

- All attendees will be muted; to unmute yourself via computer, click on the microphone that appears on the screen when you move your mouse
- To unmute yourself over the phone, **press *6**
- If you call in using your phone in addition to joining via the online link, please make sure to **mute your computer audio**
- Use the chat feature to share your comments and questions.
- Raise your hand icon to let us know you have a question during Q&A

Interaction Agreements

- We will hold comments and questions until the end of presentations
- Please be polite and respect all participants on the webinar
- Please stay on topic; we may interrupt or shorten questions to meet the time commitment of the meeting

AGENDA

8:30 – 8:45	Welcome, Introductions, Operating Agreement, Meeting Logistics
8:45 – 9:15	Non-Cost-Effective Distributed Energy Resources
9:15 – 10:15	Emissions Forecasting
10:15 – 11:00	CBRE & Community Benefit Indicators Overview
11:00 – 12:00	Transmission Part III
12:00 – 12:30	Portfolios

Public Process Intent

Understand future long-term resource needs, analysis of the expected costs and associated risks of the alternatives to meet those needs, and the action plan to select the best portfolio of resources to meet those needs for customers.

PGE

The courageous conversations framework
By Glenn Singleton and Curtis Linton

MEETING LOGISTICS

Sharing space through facilitation

***Focus on learning and understanding*.**

Team members will present all information before taking questions

Attendees are encouraged to type questions into the chat during the presentation

Attendees are encouraged to click "thumbs up" on questions in the chat for which they'd like a response prioritized

Q&A

The meeting facilitator will read questions from the chat for presenters' response

Seven minutes will be dedicated at the end of each presentation to address questions and comments

If all questions are addressed there will be time to take verbal questions

Follow Up

If we don't have time to cover all questions, we will reach out to you directly

OPERATING AGREEMENTS

- Establishing norms with our partners is foundational to **building trust and ensuring a productive dialogue and engagement**
- Creating a **respectful and inclusive space**, starts with establishing **common agreements**

Share the Airtime

Expect and Accept Non-closure

Be Constructive

Listen to Seek Understanding, Not to Respond

Challenge Ideas and Not People

The courageous conversations framework

NON-COST-EFFECTIVE DISTRIBUTED ENERGY RESOURCES (DERs)

NIHIT SHAH, Principal Integrated Resource Planning Analyst

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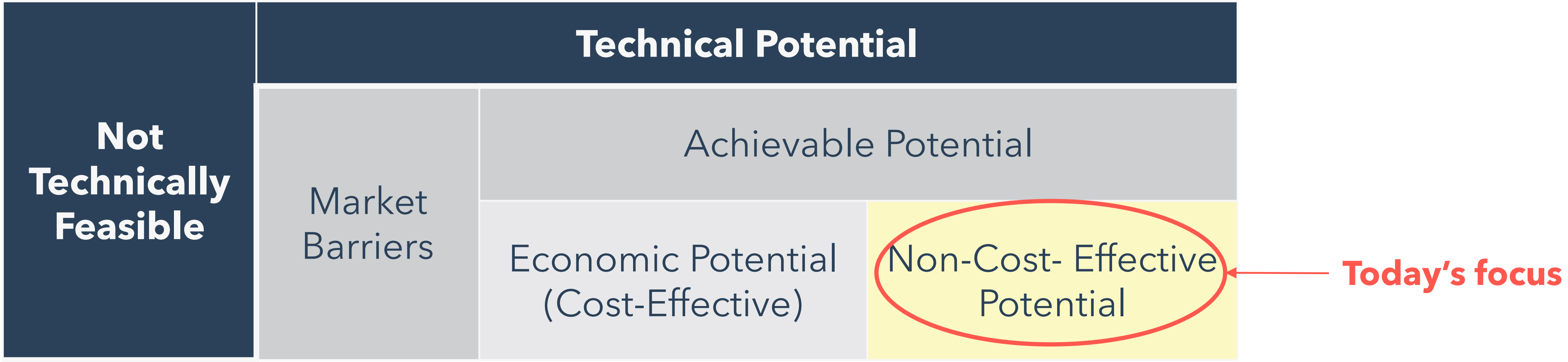
Background

Commission Order 20-152 – "Before the next IRP, PGE will work with Energy Trust and stakeholders to explore the potential for PGE's portfolio modeling to select incremental energy efficiency that is least cost, least risk, beyond Energy Trust's baseline forecast."

Non-cost-effective (NCE) potential are a part of the Achievable potential* but were deemed non-cost-effective under the previous set of avoided costs developed for UM1893 in 2021 and PGE's Distribution System Plan Part 2 in 2022



* Definition of the different potential assessment: https://www.nwcouncil.org/2021powerplan_conservation-methodologies/

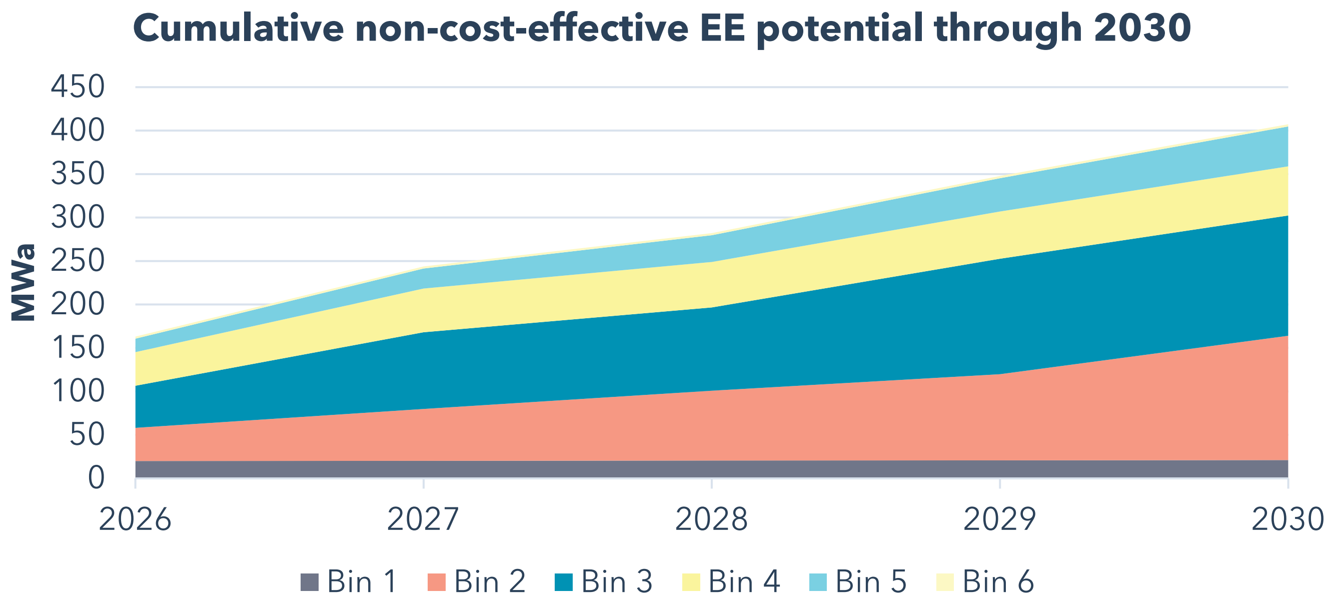
Modeling Details

Modeling non-cost-effective DERs within the IRP has the following differences from an avoided cost approach:

- The ELCC method to determine capacity contribution ensures resource interactions between the DERs and other resources are endogenously (derived internally) captured
- The transmission congestion relief of DERs are also captured endogenously

	Energy Efficiency	Demand response
Data source - annual potential and resource cost	Energy Trust of Oregon	PGE's Distribution System Plan Part 2, locational forecast
Bundling approach	Bundled by levelized cost	Bundled by dispatch characteristics
Shape	Aggregated shape of bundled measures	Matches dispatch characteristics of DR program

Non-cost-effective Energy Efficiency Potential



Cumulative potential of the non-cost-effective EE is ~400 MWa by 2030

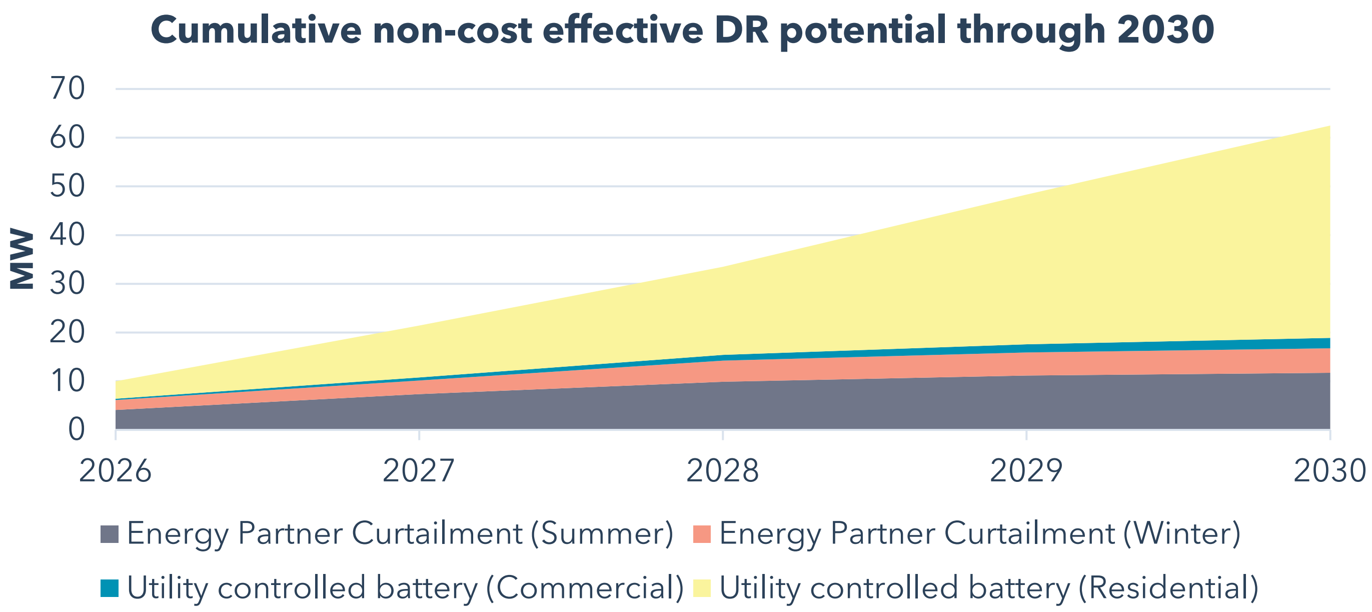
- Commercial measures represent 72% of the savings potential
- Residential measures represent 28% of the savings potential

Fixed costs account for EE specific benefits

- Distribution deferral credit
- Regional power plan act credit

Bin	Fixed costs ($/MWh)	2026 MWa potential	End uses
1	62	20	Ventilation, lighting, water heating
2	119	38	Heating, water heating, lighting, refrigeration
3	167	49	Lighting, weatherization, ventilation
4	213	39	Heating, weatherization, cooling
5	808	15	Cooling, heating, weatherization
6	1857	2	Weatherization

Non-cost-effective Demand Response Potential



Energy Partner Curtailment (Summer and winter)

The group of technologies enrolled in PGE's Energy Partner program - dispatching during weekday and weekend peaks

Utility controlled batteries (Commercial and residential)

Batteries installed by customers and controlled by PGE

- Residential batteries represent ~25% of total MW potential

Measure	Fixed costs ($/kW-yr)	2026 MW
Energy Partner Curtailment (Summer)	$972.87	4.1
Energy Partner Curtailment (Winter)	$660.26	2.0
Utility controlled battery (Commercial)	$711.11	0.3
Utility controlled battery (Residential)	$664.88	3.6

EMISSIONS FORECASTING

SYDNIE HINDS, Principal Accountant
SETH WIGGINS, Integrated Resource Planning Manager
TOMÀS MORRISSEY, Principal Integrated Resource Planning Analyst
ROB CAMPBELL, Principal Integrated Resource Planning Analyst

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Emissions Forecasting

Table of Contents

Emissions Section 1 House Bill 2021

SYDNIE HINDS, Principal Accountant

November 16, IRP Roundtable

House Bill 2021

In June 2021, the Oregon legislature passed HB 2021, establishing a 100% GHG emissions free electricity by 2040 framework for PGE and other investor-owned utilities and electric service suppliers in the state

The GHG reduction targets applicable to these regulated entities are 80% below baseline* emissions levels by 2030, 90% below baseline emissions levels by 2035, and 100% below baseline emissions levels by 2040.	Per HB 2021 Section 5, 4 (a), "a retail electricity provider shall report annual greenhouse gas emissions associated with the electricity sold to retail electricity consumers by the retail electricity provider to the Department of Environmental Quality…".	Per HB 2021 Section 7, "…electricity shall have the emission attributes of the underlying generating resource."	Regulated entities will continue to report annual GHG emissions to ODEQ, as they do today. In compliance years, which are 2030, 2035, and 2040 and every year thereafter, the OPUC will use the data reported to ODEQ for that compliance year to determine whether the reduction targets are met.

*The baseline period for the investor-owned utilities is the average annual GHG emissions for the years 2010, 2011, and 2012 associated with the electricity sold to retail electricity consumers as reported to Oregon Department of Environmental Quality (ODEQ)

Source: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled

Emissions Section 2
ODEQ Emissions Reporting

SYDNIE HINDS, Principal Accountant

November 16, IRP Roundtable

ODEQ Greenhouse Gas Reporting Protocols

Investor-owned utilities and electricity service suppliers must report their greenhouse gas emissions resulting from electricity served to end-users in Oregon to DEQ, as prescribed by OAR 340-215-0120

As an investor-owned utility with service territory only within the state of Oregon, PGE reports emissions following the **non-multijurisdictional** investor-owned utilities methodology. This reporting must reflect emissions from the previous calendar year (Jan. 1 to Dec. 31) and be submitted to the DEQ by June 1 of the following year.

PGE is required to report the megawatt-hours (MWh) of electricity **generated** or **purchased** served **to end users in Oregon** for the previous emissions year for both **unspecified** and **specified** sources of power. PGE proportionally adjusts all resources on an annual basis to account for the sale of power to the wholesale market.

Retail MWhs from Generation (Specified) + **Retail MWhs from Purchases (Specified + Unspecified)** = **Total MWhs reported to ODEQ for reporting year**

Source: https://www.oregon.gov/deq/aq/Documents/GHGRP-IOUESSProtocol(non-MJ).pdf

GHG Emissions from Specified Sources

Generated Power

PGE is required to report power as generated from a specified source when PGE is (1) a full or partial owner or operator of the generating facility or unit or (2) party to a power contract for a fixed percentage of generation from the facility or unit.

Purchased Specified Power

PGE is required to report power as purchased from a specified source when PGE can provide documentation that a power contract designated purchases from a specific generating power facility, unit, or DEQ-approved asset controlling supplier (ACS)* at the time the transaction was executed. A power source cannot be retroactively designated after a transaction occurs.

Source: https://www.oregon.gov/deq/aq/Documents/GHGRP-IOUESSProtocol(non-MJ).pdf
* Currently, BPA is the only ACS recognized by the DEQ in the state of Oregon

Reporting Requirements for Specified Power

If power is purchased or generated from specified sources, report the MWh of electricity disaggregated (e.g., broken out) by facility or unit, and by fuel type or ACS, as measured at the busbar. DEQ requires the use of a 2 percent transmission loss correction factor when reporting electricity not measured at the busbar of the generating facility

Annually, DEQ will assign facility-specific or unit-specific emission factors for all registered specified sources by dividing the emissions (MT CO2e) by the net generation (MWh) from a specified facility or unit for the most recent year data is available

Emissions from specified sources are calculated by multiplying the MWh served to end users in Oregon by the DEQ assigned facility or unit specific emission factor, and by transmission loss factor, where applicable

Source: https://www.oregon.gov/deq/aq/Documents/GHGRP-IOUESSProtocol(non-MJ).pdf

GHG Emissions from Unspecified Purchases

"Unspecified source of electricity" means a source of electricity that is not a specified source at the time of entry into the transaction to procure the electricity

- PGE must report the MWhs provided to end users in Oregon from any unspecified power source
- Electricity imported, sold, allocated, or distributed to end users in this state through an energy imbalance market or other centralized market administered by a market operator is considered to be an unspecified source. PGE must separately identify the MWh for power purchased from these markets from other unspecified sources.
- DEQ's default emission factor for calculating emissions from unspecified power is 0.428 MTCO2e/MWh
- Emissions from unspecified sources are calculated by multiplying the MWh served to end users in Oregon by default emission factor for unspecified power, and by transmission loss factor, where applicable

Source: https://www.oregon.gov/deq/aq/Documents/GHGRP-IOUESSProtocol(non-MJ).pdf

Third-party Verification of Emissions

Beginning in 2021, DEQ now requires annual reporting of GHG emissions to be verified by a third-party

PGE received a positive verification statement by the deadline of September 30, 2022 for 2021 emissions

Third-party verifiers must be certified by DEQ; DEQ also limits the repeat use of the same verifier for more than 3 consecutive years

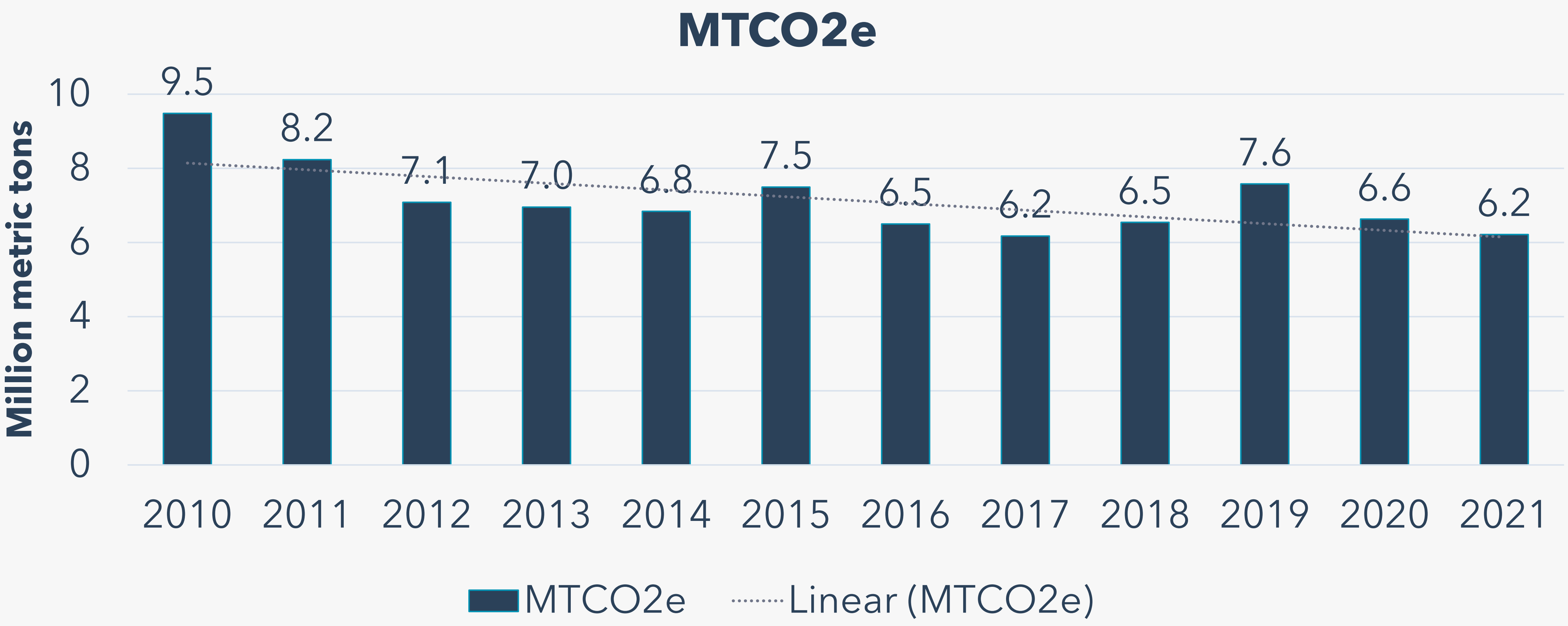
Forecasted Emissions under ODEQ Methodology

DEQ Review of Forecasted Emissions

- PGE is working closely with DEQ to develop a template that will allow for review of IRP forecasted emissions.

- DEQ will utilize the template to confirm that the emissions reported in the upcoming IRP have been calculated in line with ODEQ Greenhouse Gas Reporting protocols.

Historical GHG emissions associated with power delivered to customers, as reported to ODEQ



Emissions Section 3 Continual Progress

SETH WIGGINS, Integrated Resource Planning Manager

November 16, IRP Roundtable

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HB 2021 Continual Progress Language

SECTION 4. Clean energy plans; electric companies.

(4) A clean energy plan must;

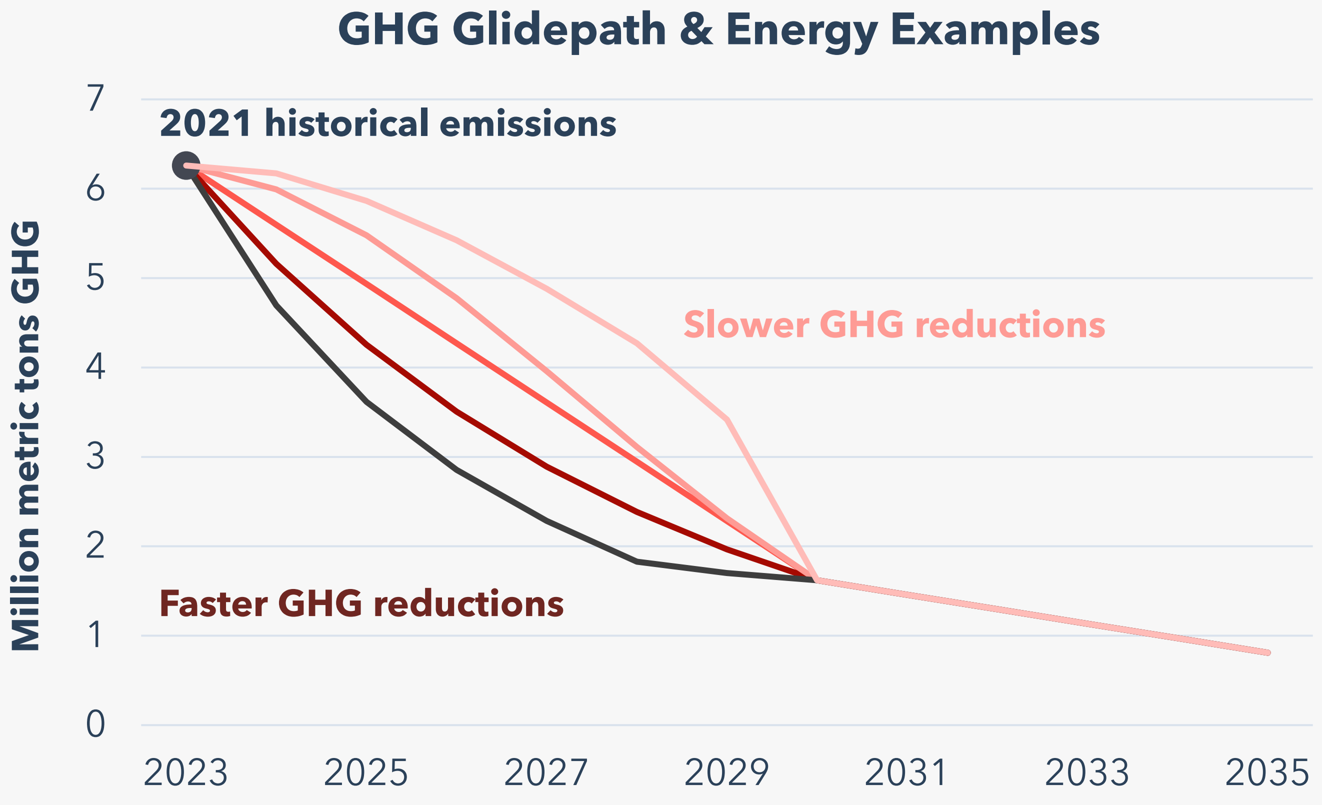
(e) Demonstrate the electric company is making continual progress within the planning period towards meeting the clean energy targets set forth in section 3 of this 2021 Act, **including demonstrating a projected reduction of annual greenhouse gas emissions;**

Formatting and highlighting by PGE (not in original text)

GHG Emission Reduction Glidepath

We are testing various GHG emission reduction glidepaths. Actual emissions will vary due to weather, incremental resource acquisition timelines, and more.

Emissions decline when PGE brings carbon free generation online – the actual pathway may vary depending on procurement and construction schedules, as well as weather, and likely won't be smooth.



Emissions Section 4

Challenges in Forecasting Methodology

SETH WIGGINS, Integrated Resource Planning Manager

November 16, IRP Roundtable

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Emissions Forecasting: 2019 IRP

GHG Emissions from existing thermal generation, based on economic dispatch from forecasted prices

+

GHG Emissions from incremental emitting generation, based on economic dispatch from forecasted prices

+

GHG Emissions associated with market purchases

=

GHG Emissions Forecasted in 2019 IRP

This step conducted in Aurora, with the assumption that:

- All emissions associated with existing & incremental resources attributable to PGE
- No emissions associated with existing and incremental resources for sales

These assumptions are not representative of operational practice

Further, using this process would not align our emission forecasts with ODEQ emission reporting methodology

All market purchases assumed to be assigned unspecified market emissions rate (.428 MMT/MWh)

Emissions Section 5
Solutions to Forecasting Methods

TOMÀS MORRISSEY, Principal Integrated Resource Planning Analyst

November 16, IRP Roundtable

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GHG Emissions/Energy Position Modeling

Thermal input data (Aurora total generation outputs and historical data) → GHG Emissions Model → Energy position & ROSE-E's starting inputs

We will discuss these data, as required by UM 2225, at a future roundtable meeting (likely Dec. 2022)

We are focusing on the middle step in this section

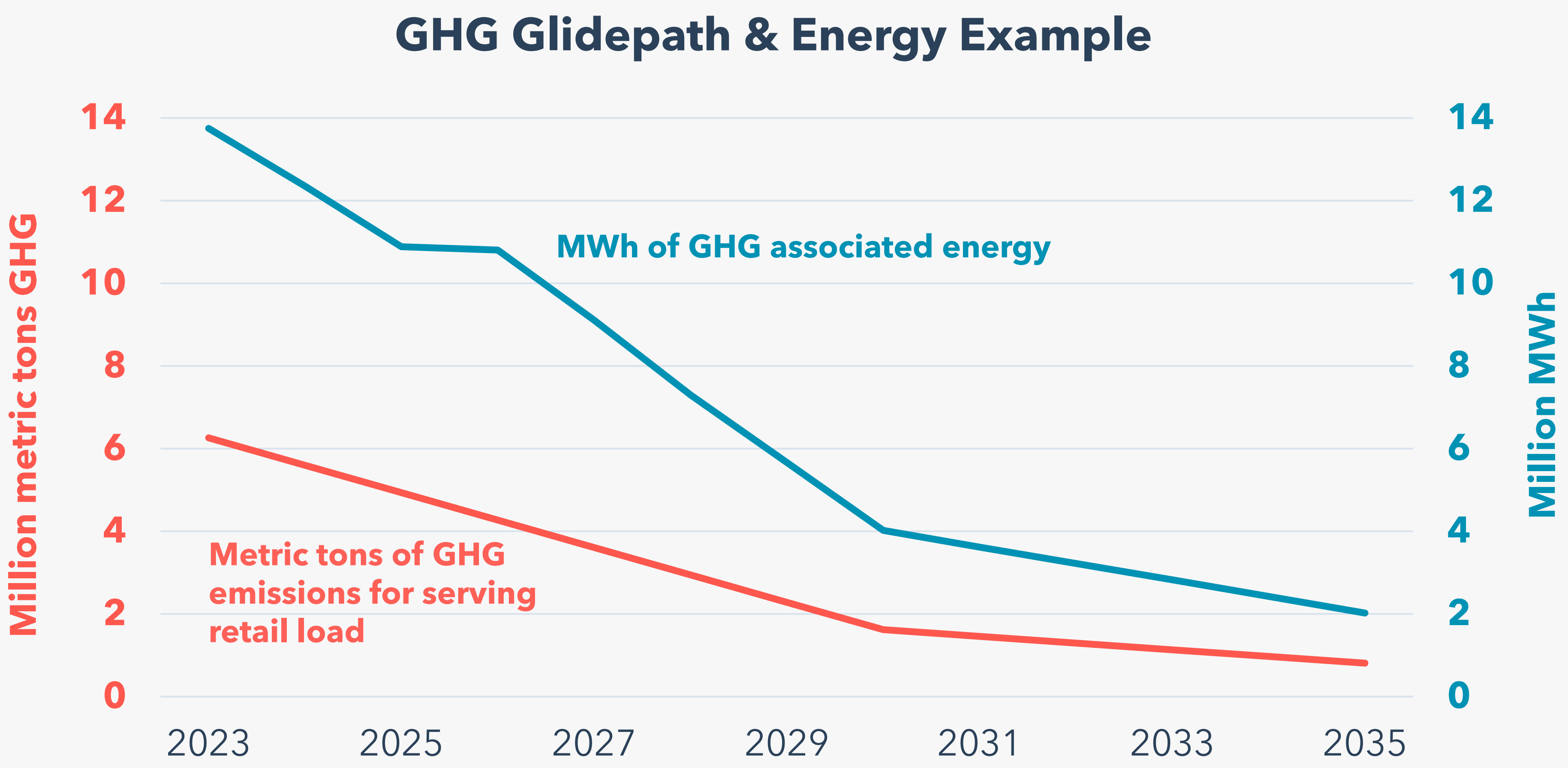
GHG Emissions Model Functions

Inputs thermal generation data from Aurora & historical sources and:

1. Ensures the GHG glidepath to 2030 and HB 2021 targets are met
2. Incorporates wholesale market activity based on historical data
   a) PGE buys and sells power on the wholesale market, the workbook accounts for this using historical data

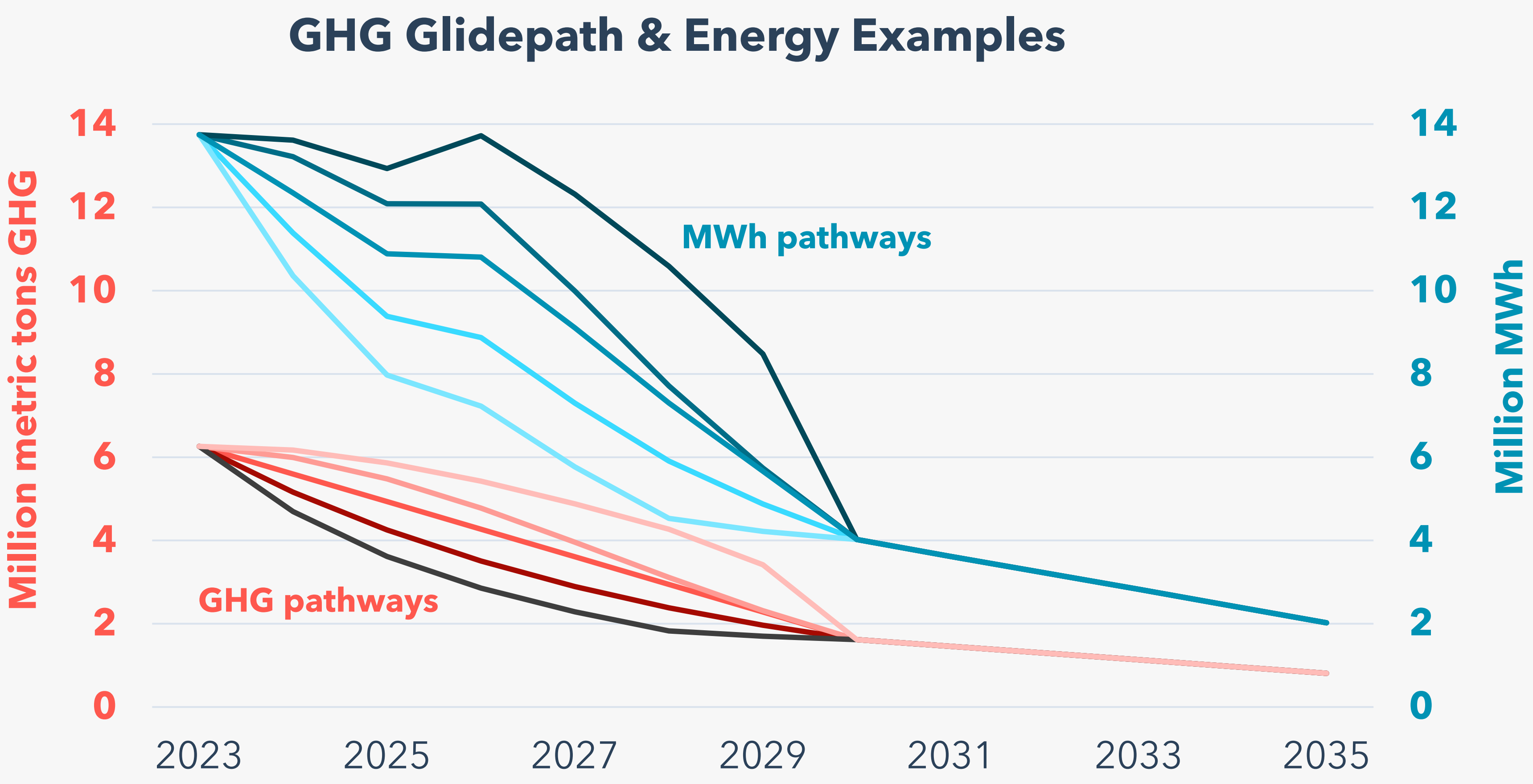
Outputs from the model include energy and GHG emissions associated with thermal usage and market activity used to meet retail load

Sample GHG Emissions Model Output



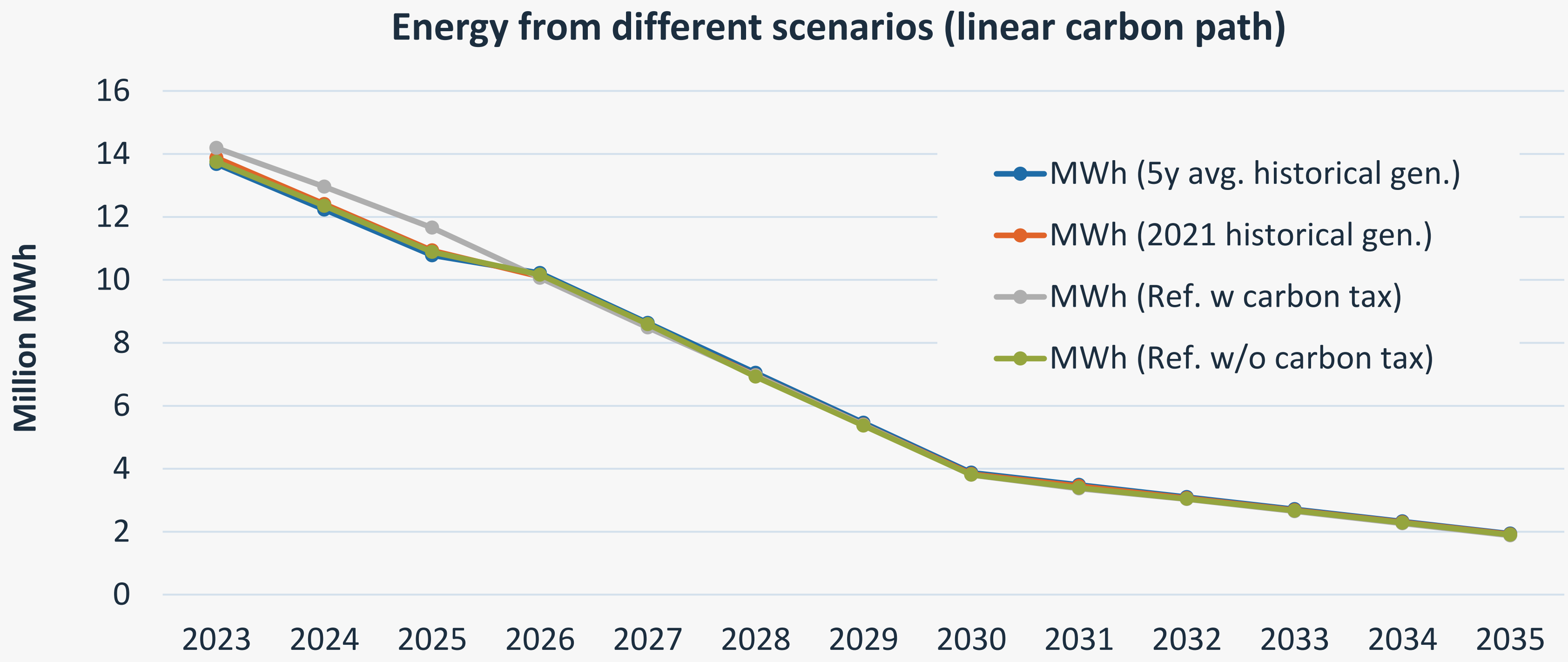
Example GHG & Energy Position Glidepaths

Beyond breaking out retail/wholesale generation and GHG emissions, using an intermediary model helps provide transparency and flexibility to run scenarios of interest



Impact of Dispatch on Energy Supply

Energy associated with GHGs is primarily dictated by GHG reduction glidepath - most emitting resources have similar GHG intensity rates, so changing dispatch assumptions does not have a significant impact on the energy position



Wholesale Market Sales

PGE buys and sells power on the wholesale market. The GHG emissions model accounts for wholesale sales as well. We are working on our modeling assumptions for wholesale sales (as required per UM 2225) and will share more information at a future roundtable meeting.

A few key points:

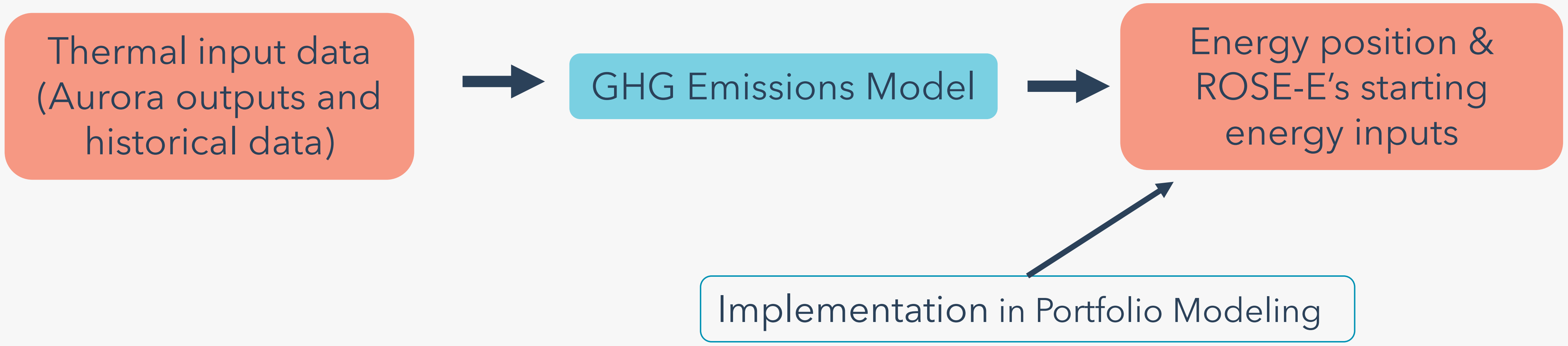
- **a** Emissions associated with wholesale market sales are not regulated under HB 2021
- **b** Wholesale market sales do not impact the need for carbon free resources to meet HB 2021 targets for retail sales
- **c** Net power costs will likely change due to wholesale market activity
- **d** Many wholesale market transactions occur with counterparties in carbon regulated markets (like California)

Emissions Section 6
Energy Workbook & Portfolio Modeling

ROB CAMPBELL, Principal Integrated Resource Planning Analyst

November 16, IRP Roundtable

GHG Emissions and Energy Flow to Portfolio Modeling



Energy and GHG Emissions Associated with Retail Sales

GHG Emissions Model

Generation and associated GHG emissions used to serve PGE retail load

- PGE resources
- Market purchases

→

Energy Position

- Generation from non-emitting sources
- Retail load forecast

→

Inputs to ROSE-E

- Generation by source
- Emissions by source
- Total emissions associated with serving PGE retail load
- Market Purchases
- Market Sales
- Net Market Purchases

GHG Emissions Targets in Portfolio Modeling

HB 2021 GHG reduction targets drive the total amount of new resources needed

ROSE-E cannot allow emissions greater than the GHG target

To satisfy GHG constraint, ROSE-E can offset emitting generation by:

- building non-emitting resources
- curtailing emitting generation

Stricter emissions targets:

- decreases available energy from emitting sources
- increases need to build non-emitting generation

Choice of *carbon glidepath* will influence the timing of resource additions between 2026 and 2043

QUESTIONS/ DISCUSSION

7

MINUTES

IRP Roundtable Slides CBRE and CBI overview

ANDY EIDEN, Distributed Resource Planning, Principal Planning & Strategy Analyst

ROUNDTABLE 22-10

Agenda

- Discuss CBRE and CBI context
- Present CBRE methodology and draft results
- Update on CBI development
- Discuss next steps for portfolio integration

CEP Guidance for CBRE in IRP analysis

- HB2021 defines Community-Based Renewable Energy (CBRE), as well as requires that utilities should incorporate analysis of CBRE into their CEPs
- In Order 22-390 in UM 2225, OPUC stated that for the first CEP, one of the most impactful elements of setting a "Community Lens Acquisition Target" is the performance of the CBRE potential study
- The potential study should be informed by communities, especially Environmental Justice (EJ) communities, as well as OPUC Staff, and stakeholders
- Further, the Community Lens potential study should either inform, or directly identify, annual megawatt (MW) or megawatt-hour (MWh) targets related to CBRE

Inclusion of Community Benefit Indicators

Order 22-390 also states that electric utilities should include at least one Community Benefits Indicator (CBI) into each of the following categories: 1) Resource, 2) Portfolio and 3) Informational

A coalition of advocates provided a list of 15 CBIs that were included in Order 22-390 (see Attachment A – Stakeholder CBI Proposal)

Directly related to utility goals and actions around CBRE target setting and procurement, and should be included in IRP portfolio analysis

Resource CBIs (rCBIs)

Measure impacts of resource portfolios on communities (e.g., particulate emissions from fossil fuels) and should be included in IRP portfolio analysis

Portfolio CBIs (pCBIs)

Provide transparency and may cover important topics (e.g., Energy Burden) but do not need to be incorporated into IRP portfolio analysis

Informational CBIs (iCBIs)

CBRE Definition in HB 2021

House Bill 2021 defines Community-Based Renewable Energy (CBRE) as:

"one or more renewable energy systems that interconnect to utility distribution or transmission assets and may be combined with microgrids, storage systems or demand response measures, or energy-related infrastructure that promotes climate resiliency or other such measures, and that:

- Provide a direct benefit to a particular community through a community-benefits agreement or direct ownership by a local government, nonprofit community organization or federally recognized Indian tribe; or
- Result in increased resiliency or community stability, local jobs, or economic development."

Source: https://olis.oregonlegislature.gov/liz/2021R1/Downloads/MeasureDocument/HB2021/Enrolled

CBRE and Small Renewables

Overlap between small-scale renewables standard and CBRE

HB2021 increased small-scale renewable requirement from 8% of total electrical capacity by 2025 to 10% by 2030

We are focusing our CBRE study on those resources that can provide community benefits highlighted by HB2021 and stakeholders

Small-scale Renewables standard (SB1547 and HB2021)

Codified under ORS 469A.210 (SB1547) and Section 37 of HB2021

1) Small-scale renewable energy projects with a generating capacity of 20 MW or less, and

2) Facilities that generate electricity using biomass that also generate thermal energy for a secondary purpose.

< 20 MW systems that are non-emitting renewable resources and provide the type of community benefits under CBRE

Community Based Renewable Energy (HB2021)

Renewable energy system(s) that connect to distribution or transmission assets and may be combined with other DERs, and that:

1) Provide direct benefit to a particular community through a CBA or direct ownership by local government, non-profit, or federally recognized Indian tribe; or

2) Result in increased resiliency or community stability, local jobs, economic development or direct energy cost savings to familes and small businesses.

CBRE Inclusion in Portfolio Analysis

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CBRE Potential Methodology Overview

Review literature

- Quantitative energy burden framework from White House's EJ40 Initiative
- Methods, Tools, and Resources companion handbook to the National Standard Practice Manual (reliability and resiliency chapter)
- NARUC-NASEO report on valuing resiliency for microgrids
- Benchmarking of other utilities and jurisdictions pursuing CBRE tariffs and acquisitions

Assess CBRE Potential

- Reviewed published municipal climate action plans with reference to any local resource targets
- Reviewed Energy Trust of Oregon project lists and customer potential for "other renewables"
- Reviewed Oregon Community Solar filings and Oregon Department of Energy Resiliency Grant pipeline
- Leveraged AdopDER work conducted for DSP to study community-resiliency microgrids

Evaluate and set targets

- IRP portfolio analysis will analyze CBRE MW potential for each year of the analysis period
- We will include a quantitative rCBI value for resiliency associated with CBRE that display those characteristics
- Additional pCBIs will be developed to evaluate the differences in portfolios
- We will work with communities to evolve iCBI approach and include results in the CEP narrative

CBRE Included in IRP Analysis

Defined three proxy resources for inclusion in IRP portfolio analysis

Proxy resources limited for purposes of bounding the IRP portfolio analysis for the first CEP. For program development and procurement activities, actual projects may have wider variety as long as they meet the scoring criteria / program requirements

Solar + storage microgrids assume incorporating existing solar + storage into local microgrid controller / DERMS. Additionally, this could act as a channel to procure additional NCE energy efficiency and demand response

CBRE

- Standalone community-scale solar
- Solar + storage microgrids
- Small in-conduit hydropower

CBRE Potential – Resource Overview

Standalone Community-scale solar

Reviewed Oregon Community Solar cost data

Solar + storage microgrid

- Leveraged Cadeo resource potential for Community Resiliency Microgrids
- Analyzed PGE reliability and outage data at feeder level
- Identified 144 feeders within criteria zones (PSPS, critical customers, # outages, etc.)
- Sized solar and storage microgrids for 72-hour duration outages
- Leverages existing installed DER on the network

In-conduit hydropower

- Discussed individual project potential with Energy Trust
- Reviewed Oak Ridge National Lab study, "An Assessment of Hydropower Potential at National Conduits" October 2022

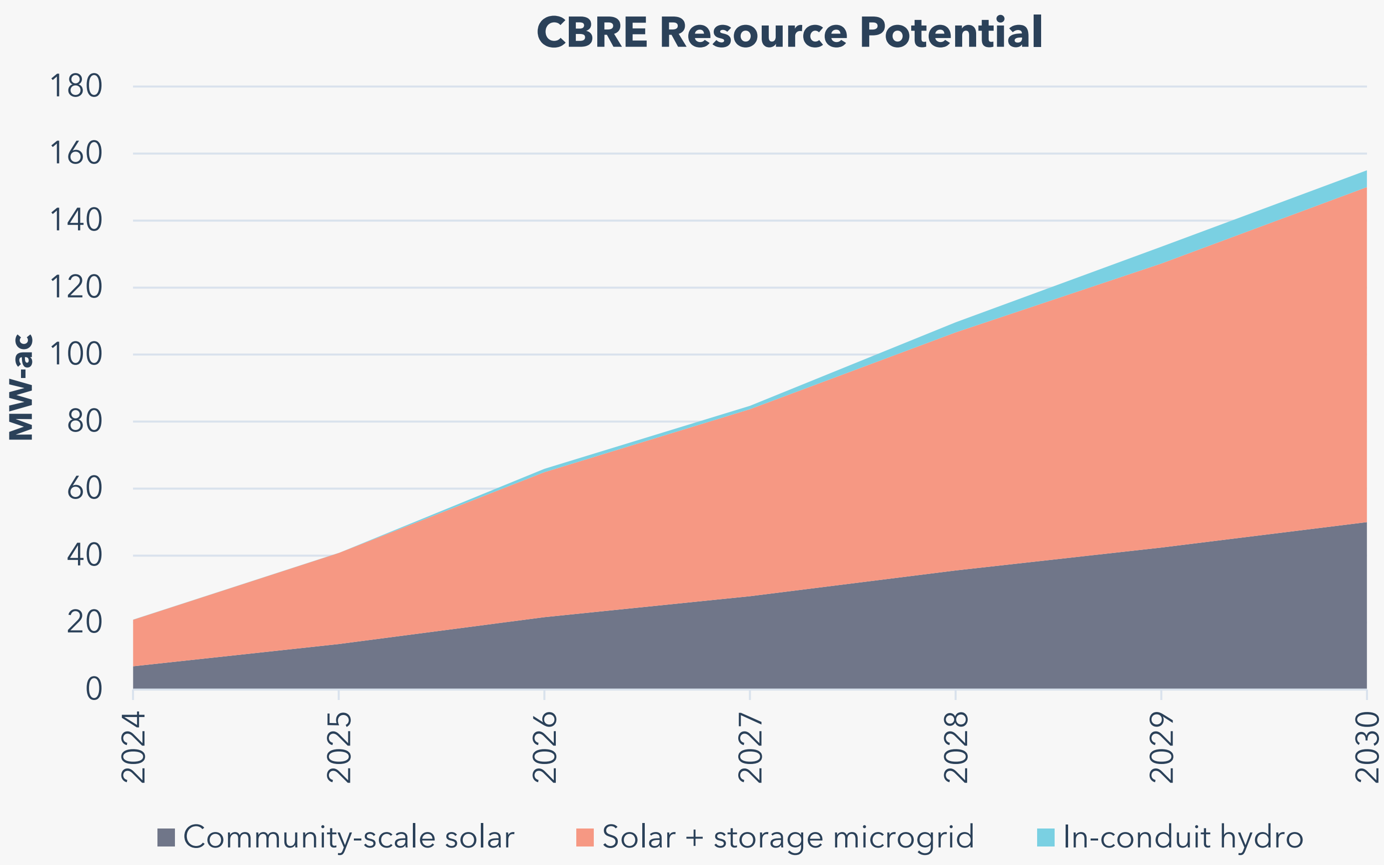
CBRE Potential – Results

155 MW-ac of full resource potential by 2030

Scaled over time to reflect uncertainty in nascent market + low bandwidth from municipal partners

Did not account for local land availability or relative real estate costs (i.e., land constraints)

Note, this does not include rooftop solar + storage, or other "climate-resiliency infrastructure" such as EE and DR, because they are separately modeled in the IRP



CBIs to Inform CBRE Analysis

Resource CBI Approach Considerations

Resiliency was highlighted by Staff's straw proposal as the number one focus for short-term inclusion into quantitative measurement

Likewise, ODOE's CBRE working group report, the single most important benefit of CBRE is local resiliency

PGE is exploring resiliency as an rCBI reflecting the quantitative value of resiliency associated with solar + storage microgrids for the first CEP

This is because microgrids have ability to provide uninterrupted service during a utility grid outage

According to a report by the NASEO-NARUC state microgrid working group, there is no standard industry methodology for valuing resiliency[1]

- We are exploring leveraging our Asset Management Team's risk methodology for assessing economic value of outages using a "value of service" approach, which was discussed in our DSP, as well as the FEMA benefit-cost methodology for resiliency
- Combines risk of outage with the consequence of outage to determine risk value
- Reflects customer value which must be balanced with other costs and risks within the IRP framework

1. See report titled "Valuing Resilience for Microgrids: Challenges, Innovative Approaches, and State Needs" available for download at: https://www.naruc.org/cpi-1/critical-infrastructure-cybersecurity-and-resilience/microgrids/

Example Risk Methodology

Annual Probability of Failure (%) **x** Consequence Of Failure ($) **=** Risk ($)

Asset Failure:

- Type of asset
- Age of asset
- Condition of asset

Geographic Risk:

- Vegetation
- Weather
- Animals
- Public

GRID & GENERATION

Direct impact of event on PGE.

Environmental and safety impacts.

GRID

Economic impact of reliability issues for customers (Value of Service ($):

+ Customer Type (R, C, I)
+ Load impacted
+ Duration of impact

GENERATION

Economic impact of outage, derate or efficiency:

+ MWs impacted
+ Duration of impact
+ Replacement Power Cost

Expressed as a financial value

Probability of Failure (%)		Consequence of Failure ($)		Risk ($)
8.30%	x	$0.9M	=	$0.1M

Example Portfolio CBIs

- Higher potential for impact
- Lower potential for impact
- Prioritized for review

Working with Cadeo to further assess pCBI candidates that can be quantified where possible, but may also include qualitative indicators

Building off previous research with Cadmus to assess the landscape of non-energy impacts (NEI)

Will socialize this approach with communities through the CEP Learning Labs

Host Customer Impacts	DR	DG - Customer	DG - Utility	Storage - Customer	Storage - Utility	EV Controls	EV Proliferation
Host Customer NEIs							
Value of Service Lost							
Transaction costs							
Asset value							
Productivity							
Economic well-being							
Comfort							
Health & safety							
Empowerment and control							
Satisfaction and pride							
Low-Income NEIs							
Reduce forced mobility							
Reduced arrearages							
Reduced disconnections / collections							

Societal Impacts	DR	DG - Customer	DG - Utility	Storage - Customer	Storage - Utility	EV Controls	EV Proliferation
Societal Impacts							
Resilience							
GHG Emissions							
Other Environmental							
Economic and Jobs							
Public Health							
Low Income (Society)							
Energy Security							

Next Steps

- Working within our Learning Labs to gather community feedback and socialize approach for CBIs
- Continue to iterate with our community partners on potential CBRE projects
- Develop forward-looking approach for how CBREs can continue to advance in utility decision-making between IRP and DSP frameworks

QUESTIONS/ DISCUSSION

7

MINUTES

Transmission Part III

SHAUN FOSTER, Manager Interconnection Services
LAUREN KERR, Senior Energy Analyst
JACOB GOODSPEED, Principal Energy Supply Procurement Originator

ROUNDTABLE 22-10

TRANSMISSION IN 2023 IRP

1 PGE proxy transmission modeling

- Quick review of proxy options and methodology
- Discussion of costs, volumes, and key assumptions
- Discussion of implied benefits

Key finding: BPA long-term inventory is limited; the IRP needs to determine the transmission volumes needed to ensure reliable portfolios as we decarbonize.

BPA: Bonneville Power Administration

Moving from “why” to “how” – modeling reliable outcomes and identifying directional value

Existing | New

2030/2040

PGE/BPA interface

Assess existing Tx rights on BPA system, find ways to increase interface, open new scheduling points of strategic relevance.

Modeling plan to be discussed today.

Future transmission development

Continue to plan for 2040 system needs collaboratively with Northern Grid, regional RA partners, and remaining engaged with merchant developers.

For discussion in a future roundtable.

PGE Transmission Planning

Planning to WECC and NERC standards for PGE system upgrades and interface with BPA.

Regional opportunities

Continue to assess and pursue commercial opportunities for existing Tx projects that would expand PGE’s Tx footprint and provide a benefit to customers.

Modeling plan to be discussed today.

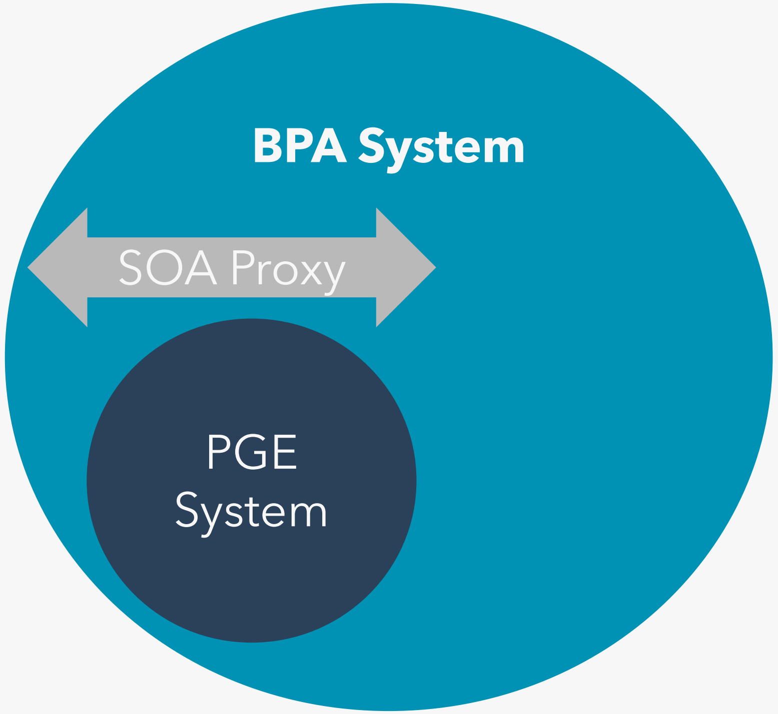
Near-term

Reliability-driven

Affordability-driven

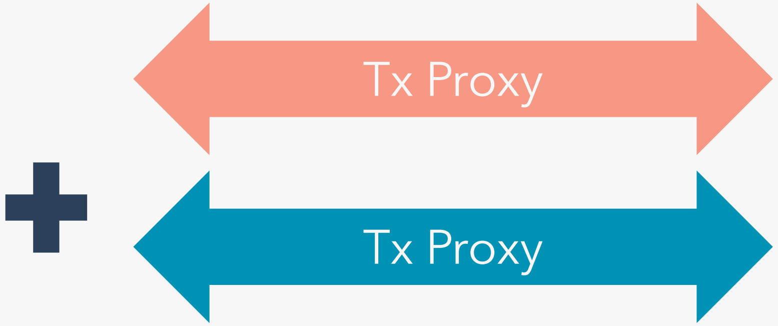
Proxy Modeling Provides Directional Value

Historically, the IRP has modeled proxy generation adds flowing across the BPA system. **Since BPA has historically planned for sufficient Tx, no off-system incremental transmission planning occurred in past IRPs.**



As BPA constraint now limits the amount of long-term Tx, the model needs additional options to solve for reliability.

An option is for the model to expand BPA availability through an assumed South of Allston (SOA) proxy.



Another option to select proxy Tx to supplement BPA once BPA availability is exhausted. **We expect both BPA and supplemental proxy options to be selected in the 2023 IRP to establish a reliable portfolio.**

Proxy selection does not specify a specific project or path, but rather shows that there is value in acquiring sufficient Tx to run the system reliably while meeting decarbonization targets.

While it seems intuitive that meeting decarbonization targets reliably is imperative, we need to know how much Tx outside of BPA's projects is needed to make that happen.

Proxy Tx modeling is performed in addition to Tx planning requirements outlined in our OATT.

Review of Proxy Projects Available for Model Selection

Our capacity expansion model (ROSE-E) will assume the availability of additional transmission capacity expansion options after 2026:

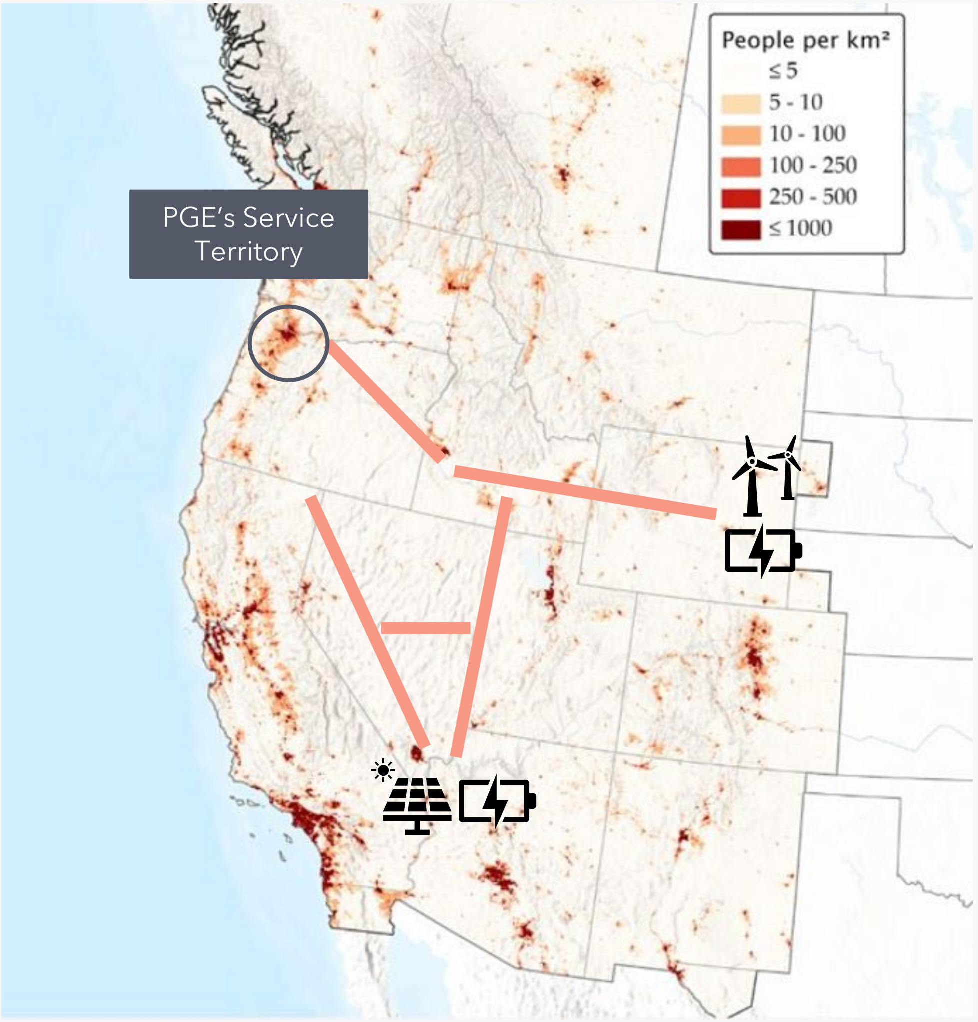
Path	Resource	Energy and capacity assumption
Generic proxy transmission (Tx Proxy)	Desert SW Solar (DSW) Wyoming wind (WY) Dispatchable Capacity	Model can select to "build" a Tx path to access resource profiles based on climate zones in the WECC. Tx resource assumed to be able to access Desert Southwest solar via Mead or Fourcorners, Wyoming wind, Idaho market, dispatchable capacity, or a combination of resource options. Tx cost, resource and capacity cost, energy and capacity benefits will each be evaluated by ROSE-E
South of Allston Expansion (SOA)	IRP proxy resource	Assumes the ability to increase transfer capacity on PGE's share of South of Allston via upgrade available in 2027. Would unlock additional capacity for resources that leverage BPA rights to get to PGE's system.

Proxy Paths Considered

Expanded Tx access outside of the Pacific Northwest could unlock access to renewable resources and market power that are somewhat uncorrelated from PGE's production and load

PGE will allow the model to choose Wyoming and Mead energy with associated proxy Tx costs and capacity value

Current projects in development could reach PGE's system through COB or Columbia Gorge. Regional need to solve for "last mile" across BPA still exists



Visuals on map shown at right are indicative only. Path studied to access resources in the IRP will be generic.

Cost Assumptions & Limitations

Tx paths are proxy paths and not indicative of specific projects

No incremental costs associated with wheeling energy to system if PGE uses pre-existing rights

Cost of Tx:

- $2,024/mile-MW for cost of new 500 kV single line is based on a publicly available source[1]
- O&M assumption is based on PGE's O&M expense (from the FERC Form 1) associated with PGE's current Tx portfolio
- Acquisition of Tx rights under applicable OATT will be considered if Tx need is established
- Assesses Tx capacity expansion at 400 MW level (SOA) and optimized volume for off-system
- Estimates distance of Tx paths

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

How Benefits are Considered

Tx expansion options allow access to energy (MWa) and capacity (MW) necessary to meet PGE's forecasted needs

Can model solve based on ~1800 MW of available BPA long-term rights (firm and CF)?

→ If Tx is insufficient to solve

SOA Proxy benefits come from expanded access to the IRP proxy resources in 2027, capped at 400 MW

→ If Tx is insufficient to solve

Tx Proxy benefits come from access to additional proxy resources and capacity. Model selects optimal number of MW and locations.

ROSE-E selects the least-cost set of resources to meet energy and capacity needs from amongst the Tx expansion options

QUESTIONS/ DISCUSSION

7

MINUTES

PORTFOLIO ANALYSIS

NIHIT SHAH, Principal Integrated Resource Planning Analyst

ROUNDTABLE 22-10

Portfolio Analysis in the 2023 IRP

June Roundtable review

In the coming IRP, portfolio analysis will be conducted like earlier iterations:

- Model will choose optimal combination of proxy supply-side resources
- Cost, risk metrics, and portfolio-CBIs are used to determine a Preferred Portfolio and Action Plan

Given the uncertainty of the resources required to meet 2040's emission reduction targets, portfolio analysis post 2030 will focus on:

- System requirements (more granularity on energy and capacity needs)
- A qualitative and quantitative assessment of the possible pathways to 2040

This will provide to us (both PGE and our public participants) the opportunity to evaluate viable emission-free options that traditional analysis with current supply-side options would not provide

Portfolio Analysis – Definitions

Portfolio: A fixed set of resource decisions set in all scenarios. The model (ROSE-E) creates resource buildouts around those choices in each scenario.

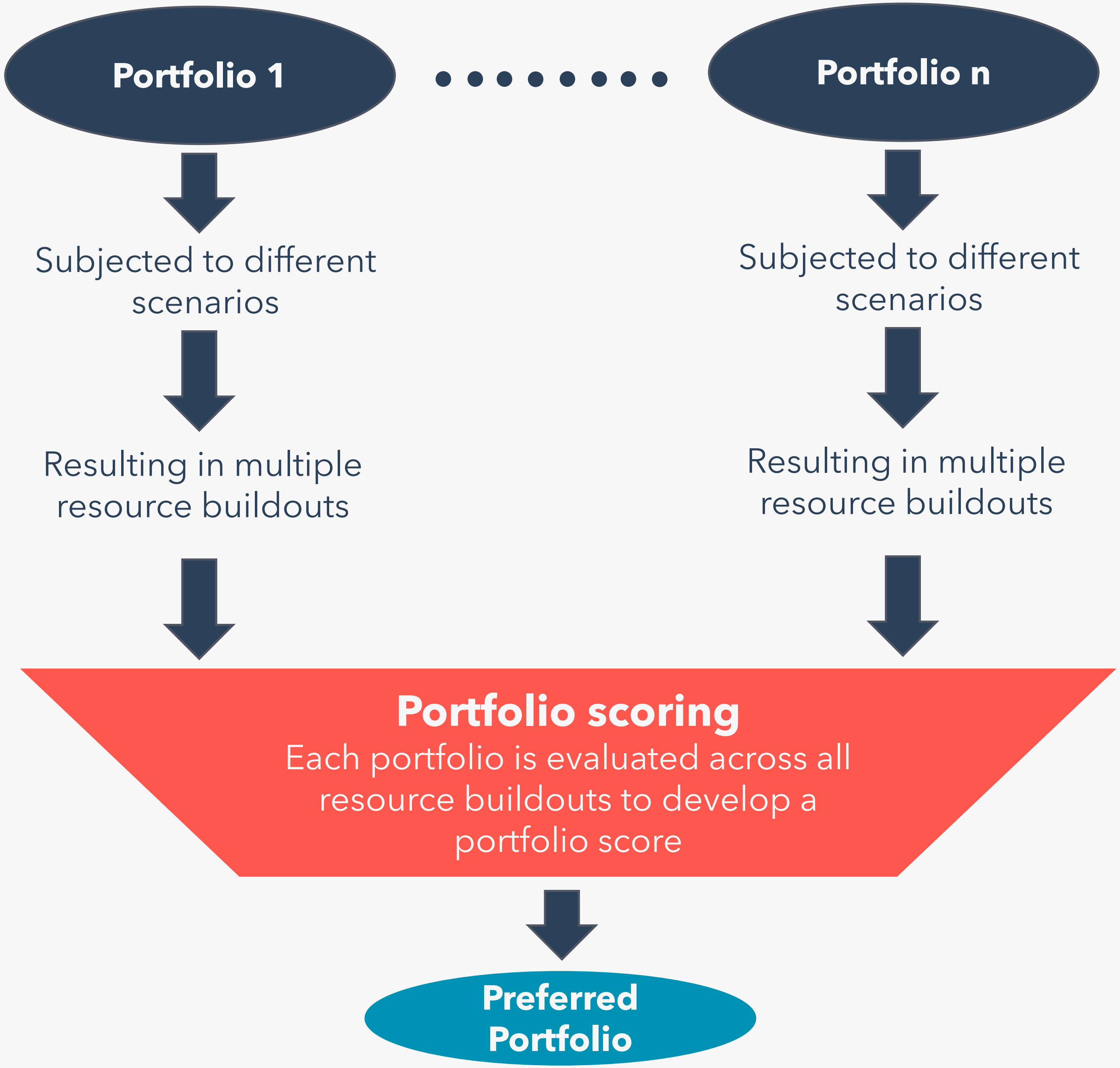
Scenarios: Refer to elements that are varied within portfolio analysis resulting in multiple resource buildouts. Some of the predefined scenarios are - need, technology cost, price, hydro

Resource buildout: Least cost set of incremental resource additions given a set of specific input conditions such as a portfolio and scenario

Sensitivities: Sensitivities test the robustness or provide additional information on the preferred portfolio by forcing changes resource constraints or other inputs

From a Portfolio to the Preferred Portfolio

Portfolio scoring currently under development



2023 IRP – Portfolio construction (1/3)

Customer Portfolios that include a defined set of customer actions

- Allow ROSE-E to pick CBREs endogenously
- Must select 100% of microgrid potential and does not select any other CBREs
- Must select 75% of the total CBRE potential annually
- Must select 30MWa of additional EE annually over the action plan window
- Assume no non-cost-effective DERs are available
- Assume no CBREs are available

Targeted Policy Limit portfolio options to meet a tagerted policy direction

- Only allow Oregon sited resources
- Enforce physical RPS compliance constraint

2023 IRP – Portfolio construction (2/3)

Emerging technology

Require adoption of a specific emerging or a long lead time technology

- Assume natural gas plants will use hydrogen blended fuel
- Assume hydrogen-based power plants in early 2030s as must take
- Assume 500MW of offshore wind in 2032 as must take
- Assume 2000MW of pumped hydro storage (PSH) by 2030 as must take
- Assume 833MW of 24 hr battery in 2030 as must take

Transmission

Explore portfolios with a set of defined transmission actions

- Assume no transmission constraints
- Assumes upgrades to PGE-transmission at South of Alston in 2027 as a given
- Assume early adoption of new transmission – Desert Southwest
- Assume early adoption of new transmission – Wyoming
- Assume the impact of a regional long-term (**2-5 years**) resource adequacy program

2023 IRP – Portfolio construction (3/3)

Optimized

Optimized endogenously within ROSE-E for cost given base constraints

- Minimizing short-term costs through 2030
- Minimizing long-term costs throughout the planning horizon
- Minimizing reference case short-term NPVRR through 2030

Accelerated decarbonization

Introduce constraints that accelerate decarbonization

- Achieving each carbon target 2 years ahead of schedule - 80% by 2028, 90% by 2033 and 100% by 2038
- Achieving 100% carbon reduction by 2035
- Meeting 2030 targets by front loading emission reduction (each year must provide half the reduction of the previous year)
- Meeting 2030 targets by rear loading emission reduction (each year must provide twice the reduction of the previous year)

Summarizing the 2023 IRP Portfolios

25 portfolios across 6 categories

- Optimized – 3 portfolios
- Accelerated decarbonization– 4 portfolios
- Customer– 6 portfolios
- Targeted Policy – 2 portfolios
- Emerging technology– 5 portfolios
- Transmission– 5 portfolios

What questions are you interested in exploring with portfolio construction?

Please email us at IRP@PGN.com, or submit your feedback at: Link

QUESTIONS/ DISCUSSION

7

MINUTES

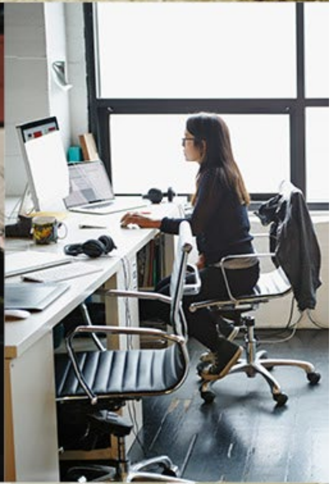
NEXT STEPS

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

Upcoming Roundtables:

- December 16
- January 26
- February 23
- March TBD





THANK YOU

CONTACT US AT:
IRP@PGN.COM

An

Oregon

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