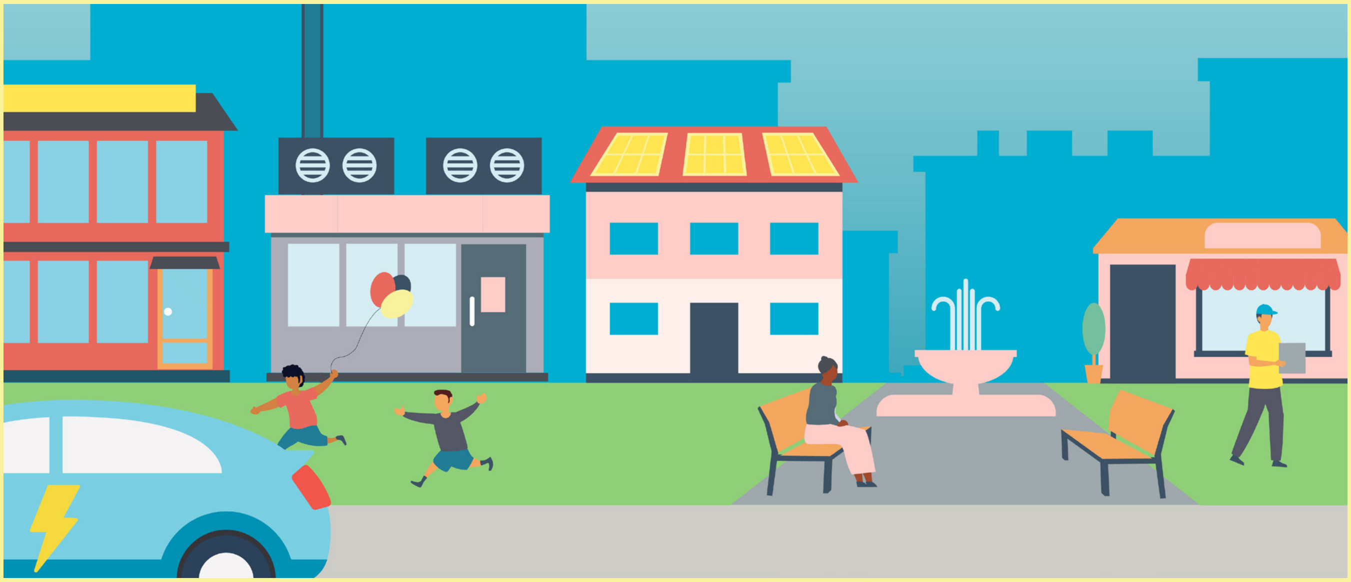
## Chapter 7.

# Evolved regulatory framework: incentives that motivate equitable DER enablement and adoption



# Chapter 7. Evolved regulatory framework: incentives that motivate equitable DER enablement and adoption

"We must now agree on a binding review mechanism under international law so that this century can credibly be called a century of decarbonization"

— Angela Merkel, Chancellor of Germany

## 7.1 Reader's guide

PGE's Distribution System Plan (DSP) takes the first step toward outlining and developing a 21st century community-centered distribution system. This system primarily uses distributed energy resources (DERs) to accelerate decarbonization and electrification and provide direct benefits to communities, especially environmental justice communities. It's designed to improve safety and reliability, ensure resilience and security, and apply an equity lens when considering fair and reasonable costs.[112]

As noted in earlier chapters, the electric sector is undergoing a profound transformation. Many elements of this transformation intersect with regulation and policy. Over the last few years, several policies have paved the way to support PGE to move forward on our vision for a clean energy future. In this chapter, we highlight key policies that enable this change and discuss potential future work that could continue to support a 21st century community-centered distribution system. PGE notes these regulations are an initial set of opportunities that can enable us to streamline and accelerate elements highlighted throughout this DSP and other related filings.

PGE expects the other regulations to surface as the DSP and related filings evolve. **Table 46** illustrates how PGE has met the Public Utility Commission of Oregon's (Commission or OPUC) DSP Guidelines under Docket UM 2005, Order 20-485.[113]

For more details on how PGE has complied with the requirements under UM 2005, Order 20-485, see **Appendix A**. DSP plan guidelines compliance checklist.

**WHAT WE WILL COVER IN THIS CHAPTER**

An overview of the regulatory framework that impacts the distribution system

How regulation affects current activities, opportunities and barriers

112. PGE uses the definition of environmental communities under Oregon House Bill 2021, available at olis.oregonlegislature.gov.
113. OPUC UM 2005, Order 20-485 was issued on December 23, 2020, and is available at apps.puc.state.or.us

**Table 46. Evolved regulatory framework: Guideline mapping**

| DSP guidelines | Chapter section |
|---|---|
| 4.4.a | Section 7.3 |
| 4.4.b.vii | Section 7.4 |
| 4.4.d | Section 7.4 |

## 7.2 Introduction

Through Order 20-485, the OPUC required investor-owned utilities (IOUs) to provide alignment with current Oregon law and policies. The Commission also required PGE to highlight opportunities and possible benefits for distribution system investments, and barriers or constraints to advancing our vision.

Driven by climate change, social and environmental justice, evolving customer and community expectations, and the proliferation of DERs, the energy sector is undergoing a paradigm shift. These shifts require us to adapt to and address risks to ensure development of a modern grid capable of serving all customers and able to recover quickly from extreme weather events, physical security attacks or cybersecurity attacks. Yet, there are other factors we must consider such as changes in customer energy usage, new system stresses, and new perspectives on local community investment and engagement. These items make a clear case that the traditional regulated utility role must evolve to keep pace with the needs of customers.

Our commitment to transforming and innovating to meet our customer needs is not new. Since 2018, PGE has shifted how we plan for resource investments to address climate change, which was robustly displayed in our *2018 Exploring Pathways to Deep Decarbonization for the Portland General Electric Service Territory*, our pursuit to accelerate flexible load resource development and transportation electrification.[114, 115] PGE is evolving our Integrated Resource Planning process to meet the goals of HB 2021 and our DSP work is evolving through UM 2005.

Through the authorship and filing of the Transportation Electrification Plan and the Flexible Load Plan, PGE has communicated our commitment to DERs to Oregon, our customers and communities, the Commission and stakeholders.

Through the OPUC's Docket UM 2005 and PGE's own investments, we are developing a new approach to distribution resource planning and system planning that will further commit the company to resource investments that are closer to and behind the customer meter. A major component of PGE's vision is to empower customers and communities on their entire energy journey so they can proactively address their energy needs. Addressing changing energy usage and the climate crisis while maintaining safety, security, reliability and resilience at fair and reasonable prices will require a shift in how we approach and understand the role of the utility. We are evolving from simple provider and deliverer of energy, to a new type of utility that is prepared and capable of delivering a holistic set of energy solutions that meet the needs of our customers and communities.

To achieve this, there is a need for regulatory change. Throughout the UM 2005 proceeding, we see intersections between the goals of the DSP and current policies, rules, standards and other regulations. Under Docket UM 2005, Order 20-485, the OPUC also recognized, "the need for ongoing conversations about how DSP activities align or interact with the utilities' existing business models and regulatory approaches." These include:

- New policies that can accelerate DER adoption and leverage their value for the grid and customers
- Current policies that inhibit DER adoption and the realization of their value to the grid and customers
- Ongoing regulation discussion and its relationship with the DSP

PGE also highlights the current policy landscape that has downstream policy implications. The evolution of the DSP will need new rules and regulations to support its success. This evolution of rules and regulation are a key component to enable the goals of the DSP.

114. This study among other insights pointed to a future where distribution sited resources could provide as much as 900 MW of energy services by 2035, available at assets.ctfassets.net.
115. UM 2141, available at edocs.puc.state.or.us.

# 7.3 Policy landscape

### 7.3.1 FEDERAL POLICY PERSPECTIVE

At the federal level, the passage of major infrastructure and budget reconciliation legislation has the potential to significantly drive efforts in the clean energy space for some time. President Biden has drawn a strong link between climate change mitigation and environmental and social justice through policies that enable human-centered planning. His administration also took bold action at the agency level in support of addressing climate change — rejoining the Paris Accord, advancing aggressive tailpipe and vehicle mileage standards, setting a higher social cost of carbon than prior administrations, and utilizing the federal government's purchasing power. These policies have several downstream implications from DER cost-effectiveness to technology cost curves. PGE believes the OPUC must align appropriate downstream regulation to maximize customer value creation through these federal policies.

Additionally, the Federal Energy Regulatory Commission (FERC) has issued a series of orders to enable aggregated DERs to participate in regional wholesale electricity markets. Traditionally, these markets have been judged to be "whole" when all supply side generation resources are either sold, bid or scheduled into these markets. But recently this paradigm has been changing by including new types of generation, demand-side resources such as energy efficiency and demand response, energy storage and other distributed energy resources. **Table 47** highlights how PGE believes these orders can unlock new possible value streams for our customers and will be a part of the broader considerations of PGE's participation in a future market.

**Table 47. Summary of FERC orders enabling DERs to provide new value**

| FERC Order | Primary implication |
|---|---|
| **FERC Order 719**[116] | First of the major FERC Orders requiring market operation changes to include a new form of energy resource (e.g., demand response)[117] |
| **FERC Order 745**[118] | The FERC found that demand response can be a cost-effective resource and included a cost-effectiveness test within the Order for determining when to accept demand response bids. |
| **FERC Order 755**[119] | Outlined how energy storage should be compensated for its dispatch response and performance accuracy |
| **FERC Order 841**[120] | Advanced rules for electric storage participation in wholesale markets |
| **FERC Order 2222**[121] | Establishes and allows for the participation of aggregated DERs in markets operated by Regional Transmission Organizations (RTO) and Independent System Operators (ISOs) |

### 7.3.2 STATE POLICY PERSPECTIVE

On the state level, Oregon has been among those at the forefront of the energy transformation with innovative policy and statewide goals. Since 1984, the legislature has passed several energy-related bills promoting the development of local renewable resources.

**Figure 36** illustrates some of the energy policies that have been established in Oregon. It is important to highlight that clean energy policies are not unique to Oregon. As recently as 2019, 11 states and territories and approximately 200 local jurisdictions have made commitments to 100% clean energy policies in the United States.[122]

116. FERC Order 719, available at www.ferc.gov.
117. 125 FERC P 61,071, Docket Nos. RM07-19-000 and AD07-7-000, Wholesale Competition in Regions with Organized Electric Markets (Issued October 17, 2008).
118. FERC Order 745, available at www.ferc.gov.
119. 137 FERC P 61,063, Docket Nos. RM11-7-000 and AD10-11-000, Frequency Regulation Compensation in the Organized Wholesale Power Markets, (Issued October 20, 2011)
120. 162 FERC P 61,127, Docket Nos. RM16-23-000 and AD16-20-000, Electric Storage Participation in Market Operated by Regional Transmission Organizations and Independent System Operators, (Issued February 15, 2018).
121. FERC Order Fact Sheet, available at www.ferc.gov.
122. State goals and mandates, available at www.cesa.org and local jurisdiction commitments and goals, available at www.sierraclub.org.

**Figure 36. State policy timeline**

| 1980 – 1999 | 2000 – 2020 | Today |
|---|---|---|
| In **1984** through a ballot measure, voters in Oregon created the Oregon Citizen's Utility Board (CUB) to advocate on behalf of residential customers of investor-owned utilities in Oregon.<br><br>In **1989** Oregon became the first state to institute long-term resource planning now called the Integrated Resource Plan (IRP).<br>• Commission Order 89-5<br><br>In **1999**, Senate Bill 1149 established a nonprofit to manage energy efficiency in Oregon.<br><br>In **1999**, HB 3219 required utilities to allow customer-generators through Net Metering | In **2018** the Oregon Public Utility Commission (OPUC), in response to SB 978, established a report to the legislature on utility model, challenges, opportunities and recommendations<br><br>In **2007**, Oregon adopted the original 25% requirement for the renewable portfolio standard that the 2016 bill, SB 1547, increased to 50% by 2030.<br><br>In **2002** Oregon was the second state to create an independent energy efficiency agency, now known as the Energy Trust of Oregon (ETO). | **House Bill 2021 A** was passed requiring that electricity supplied to retail electricity consumers:<br>• Reduces annual greenhouse gas emissions by 100% below baseline emissions level by 2040<br>• Is generated in a manner that provides additional direct benefits to communities in OR<br><br>**Utilities are required to submit a Clean Energy Plan** to the OPUC and the Department of Environmental Quality (DEQ). The plan should include annual goals for meeting clean energy targets and demonstrate continual progress towards meeting the clean energy targets. |

As the state has adopted policies to address decarbonization of the electric sector, it also has begun to ensure that energy policy also addresses equity. We see this in the bills that have recently passed the Oregon legislature and in such rulemakings as the OPUC's 2019 Order 20-485 under Docket UM 2005.[123] Key legislation and administrative actions that will inform PGE's DSP and/or DER planning are outlined below.

## SENATE BILL (SB) 1044 (2019): ZERO-EMISSION VEHICLES (ZEV)[124]

SB 1044: established metrics for evaluating statewide ZEV adoption and supporting infrastructure to meet the state's climate goals; provided flexibility to schools to use their Public Purpose Charge allocations to invest in electric buses, fleet vehicles and charging infrastructure; and codified the state's policy on alternative fuel vehicles to ensure the state was leading by example in purchasing and leasing ZEVs.

## EXECUTIVE ORDER (EO) 20-04: GOVERNOR BROWN'S CLIMATE ACTION[125]

On March 10, 2020, Governor Brown issued EO 20-04, directing state agencies to take actions to reduce and regulate greenhouse gas emissions. EO 20-04 establishes new science-based emissions reduction goals for Oregon. The EO directs certain state agencies to take specific actions to reduce emissions and mitigate the impacts of climate change. It also provides overarching direction to state agencies to exercise their statutory authority to help achieve Oregon's climate goals.

123. State of Oregon: Public Utility Commission of Oregon, available at apps.puc.state.or.us
124. SB 1044, available at olis.oregonlegislature.gov.
125. EO 20-04, available at www.oregon.gov.

### 7.3.2.1 HOUSE BILL (HB) 2021 (2021): 100% CLEAN ELECTRICITY FOR ALL[126]

HB 2021, passed by the legislature in June 2021 and signed by the Governor in July 2021, sets a framework for PGE and other electricity suppliers in Oregon to reach a 100% reduction in greenhouse gas emissions by 2040. The bill also sets interim targets on the path to 2040 including an 80% reduction in greenhouse gas emissions by 2030 and a 90% reduction in greenhouse gas emissions by 2035. These targets in HB 2021 align with our climate goals announced in November 2020. Utilities must develop a Clean Energy Plan concurrent with the development of each future Integrated Resource Plan that shows continual progress towards reaching these greenhouse gas reduction targets.

HB 2021 also establishes a grant program for community renewable energy projects from a Community Renewables Investment Fund. It also creates a Community Benefits and Impacts Advisory Group that is tasked to prepare a biennial report, which will report on:

- Energy burden and disconnections for residential customers and disconnections for small commercial customers
- Opportunities to increase contracting with businesses owned by women, veterans or members of the BIPOC community
- Actions within environmental justice communities within the electric company's service territory intended to improve resilience during adverse conditions or facilitate investments in the distribution system, including investments in facilities that generate non-emitting electricity
- Distribution of infrastructure or grid investments and upgrades in environmental justice communities in the electric company's service territory
- Social, economic or environmental justice co-benefits that result from the electric company's investments, contracts or internal practices
- Customer experience, including a review of annual customer satisfaction surveys
- Actions to encourage customer engagement

HB 2021 is an innovative policy that is not only paving the way to clean electricity, but also fosters a planning process supported through a community-centered approach. We embrace the state's policies to decarbonize the electric sector and see it as an imperative for PGE as we power the advancement of society fairly and equitably.

### 7.3.2.2 HB 2062 (2021): APPLIANCE ENERGY EFFICIENCY STANDARDS[127]

HB 2062 codified Oregon Department of Energy rulemaking that established energy efficiency standards for certain appliances sold in Oregon. Included in the bill was the requirement that electric water heaters manufactured on or after January 1, 2022, have a modular demand response communications port compliant with CTA-2045 or equivalent, enabling their participation in utility demand response programs.

### 7.3.2.3 HB 3141 (2021): PUBLIC PURPOSE CHARGE MODERNIZATION[128]

HB 3141 modernized the Public Purpose Charge (PPC) and extended it through 2035. Important provisions of the bill include increased funding for low-income weatherization, equity metrics for all funds invested by the Energy Trust of Oregon, and a required investment of 25% of renewable energy program funds to serve low- and moderate-income customers.

### 7.3.2.4 HB 2475 (2021): DIFFERENTIAL ENERGY BURDEN[129]

HB 2475 granted the OPUC the authority to consider differential energy burden in utility rates or programs and allows ratepayer-funded intervenor funding for environmental justice organizations.

126. HB 2021, available at olis.oregonlegislature.gov.
127. HB 2062, available at olis.oregonlegislature.gov.
128. HB 3141, available at olis.oregonlegislature.gov.
129. HB 2475, available at olis.oregonlegislature.gov.

### 7.3.2.5 HB 2165 (2021): TRANSPORTATION ELECTRIFICATION[130]

HB 2165 extends and improves Oregon's electric vehicle (EV) rebate to better serve low-income families, rural communities and communities of color. The bill also requires PGE and Pacific Power to collect a charge set to 0.25% of the total utility revenues to support transportation electrification, with at least half that amount spent supporting underserved communities.

The bill also recognizes that utility investments in transportation electrification infrastructure are a utility service and a benefit to ratepayers if certain conditions are met. It codifies that utility investments to support transportation electrification can include behind-the-meter infrastructure.

Together, these policies show a clear direction in accelerating DERs to decarbonize Oregon's energy mix while addressing issues such as energy burden.

## 7.4 Regulatory focused activities, opportunities and barriers

These key downstream regulatory elements will help PGE achieve the desired outcomes of these new policies. **For each element, we have provided a description and its interaction with the DSP**.

### 7.4.1 DISTRIBUTED ENERGY RESOURCE COST-EFFECTIVENESS

DERs can become grid assets under the right conditions. One of these conditions is economics, comparing DER costs and benefits relative to the alternative. PGE has taken steps to ensure that programs and products we offer are evaluated for cost-effectiveness, but we are still growing our analytical capabilities. We believe that DER cost-benefit analysis should not only accommodate utility needs but also include social and environmental policy considerations.

PGE has, in alignment with direction from OPUC Staff's ("Staff") comments in the Flexible Load Plan, undertaken an effort to update its DER cost-effectiveness method.[131] We have begun the work needed to develop a new cost-effectiveness tool to perform robust analysis that is aligned with the National Standard Practice Manual.[132] To ensure we leverage best-in-class approaches from other leading national sources and jurisdictions, we have contracted with two third-party consultants to develop the "Ben-cost" tool. These consultants will, at a minimum, help PGE by:

- Enriching PGE's decision-making on distributed energy resource (DER) investments by providing adjustments to PGE's current cost-benefit methodology (e.g., provide expert advice on cost-effectiveness best practices, cited/published literature and industry standards).
- Assisting PGE with building future capabilities on DER cost-effectiveness by evolving PGE's cost-effectiveness model framework.
- Developing a cost-effectiveness tool/model that will allow PGE to quantify cost and benefit impacts by measures, program and portfolio. The model will be built to accommodate the incorporation of other local and societal qualitative costs and benefits, as identified by PGE at a later date, such that it can address PGE's long-term needs.
- Reviewing overall methodology needed to identify where and when DERs can be compensated for benefits and be provided in ways that are efficient, accurate and fair.
- Examining, within reason, differential and equitable impacts on customers and communities (e.g., if a specific DER or electric vehicles would make a significant impact on air quality and health in an underserved part of PGE's service territory).
- Incorporating the outcomes of the Transportation Electrification Infrastructure Framework discussion currently ongoing in accordance with Executive Order 20-04.[133]
- Incorporating outcomes of UM 2011 – General Capacity Investigation focused on the avoided cost of capacity.[134]

PGE expects an updated cost-effectiveness model to not only help us better design and evaluate DER programs, but also assist our valuation of non-wires solutions moving into Part 2 of the DSP.

130. HB 2165, available at olis.oregonlegislature.gov.
131. PGE's Flexible Load Plan, available at apps.puc.state.or.us
132. The National Standard Practice Manual, available at www.nationalenergyscreeningproject.org
133. OPUC workplan on EO 20-04, available at www.oregon.gov
134. Docket UM 2011, available at apps.puc.state.or.us

### 7.4.2 ALIGNING UTILITY INCENTIVES TO SCALE DER PROGRAMS

With decision-making authority over utilities serving roughly 72% of US electricity customers, state public utilities commissions (PUCs) are uniquely positioned to orchestrate the transition to a decarbonized grid. State legislatures created PUCs in the early 20th century in response to the rise of the modern utility. To safeguard against the natural monopoly conditions utilities enjoy and to emulate competition in the absence of competitive markets, states empowered PUCs to oversee a “regulatory compact” in which utilities are obligated to provide nondiscriminatory access to reliable and safe electricity service at just and reasonable rates to customers. In exchange, utilities can recover the costs of providing service from customers and have the opportunity to earn a PUC-authorized rate of return. As a result, commission statutory authorities have traditionally focused on objectives like safety, reliability and affordability. Today, PUCs must increasingly address a broader range of outcomes than they have in the past. They remain accountable to traditional regulatory objectives but must also ensure resilience, energy justice, climate and other factors in their deliberations. Some of these objectives can be at odds under certain conditions, such as situations where the ‘fair’ solution is not the most ‘equitable’ solution.

Under Docket UM 2005, Order 20-485, the OPUC address the changes that utilities may make in implementing the DSP process, the OPUC stated it may, “explore new regulatory mechanisms that may better align with utilities’ efforts to plan and invest in DSP over the long-term.” **Table 48** is intended to assist the OPUC with exploring possible regulatory structures. Below are states where some sort of regulatory alignment has taken place in the form of a performance incentive mechanism for DER development and investment.

**Table 48. Example states with regulatory alignment incentivizing DERs**

| State | Key design features | Maximum available incentive* | Performance period |
|---|---|---|---|
| **Hawaii** | Initial, one-time incentive based on achievement of peak demand reduction target through direct procurement. | Lesser of 5% of aggregate annual contract value or $500,000 | One year |
| **Michigan** | Up to 15% of demand response costs on a sliding scale based on demand response capacity, achieved growth rate, and non-wires alternatives assessment costs | 15% of demand response spending | One-year cycle (approved for 2019 only) |
| **Texas** | 1% of net benefits for every 2% of demand reduction goal exceeded | 10% of net benefits | One-year cycle |
| **Vermont** | Percentage of total approved budget based on performance on several outcomes, including winter/ summer peak demand reduction | 2.5% of total approved budget | Three-year cycle |
| **Rhode Island** | Cash reward based on achievement of peak demand reduction, structured as a shared savings mechanism exempt from utility return-on-investment cap | 45% of net benefits | Three-year cycle |
| **New York** | Up to 100 basis points added to ROE for PIMs in aggregate; peak demand reduction achievements receive a portion | A portion of 100 basis points for SDR performance (currently approved at 65–70 total basis points) | Three-year cycle |
| **Massachusetts** | Portfolio-wide incentive based on performance from 75–125% of the PIM goals | 5.4% of cumulative budget for program costs | Three-year cycle |

### 7.4.3 REGULATIONS IMPACTING INTERCONNECTION OF DERS

PGE currently offers distribution system interconnection under PGE's Net Metering and Small Generator Interconnection processes. Under these interconnection programs, PGE has seen robust participation from both retail customers and independent power producers. Currently, PGE has approximately 12,000 net metering installations and 50 qualifying facilities (QFs) representing just under 220 MW of installed capacity.[135] Additionally, PGE has approximately 1,383 accounts enrolled in the Solar Payment Option, a now-closed pilot program based on the volumetric incentive rate pilot program derived from HB 3039 in 2007 and HB 3690 in 2010. The Solar Payment Option allocated PGE with 14.9 MW of the 25 MW statewide among the IOUs.[136] This 14.9 MW represents the upper limit to participation in the program for PGE customers.

Looking toward the future, PGE is excited to partner and engage with Staff and stakeholders as current efforts to reform the distribution system interconnection process in Oregon progress. Through UM 2099 and the Two-Meter Solution (TMS), PGE worked with stakeholders to find an alternative to costly substation upgrades when new small net metering installations interconnected to generation constrained distribution feeders. The TMS is a solution where the second meter is attached to the DER, triggering the violation with the capability to sever the link between the DER and grid to prevent reliability issues. PGE is an active participant in UM 2032 and UM 2111, which PGE believes will facilitate the modernization of the state-jurisdictional interconnection processes. Concepts that PGE recommends will be addressed under UM 2111 include, but are not limited to:

- Adoption of IEEE-1547, 2018 standard
- Implementation of rules that will allow for wide-scale adoption of smart inverter technology
- Reforms and concepts that could enable future implementation of FERC Order No. 2222
- Understanding of national approaches to cost allocation and cost-sharing for interconnection
- Analysis of the merits between cluster and serial study processes
- Development of interconnection reforms and business paradigms that can be used to enable adoption of distributed behind-the-meter storage and vehicle-to-grid discharging
- Exploration of policies and processes that will enable optimization of interconnections, possibly including utility directed operational schemes and/or control of DERs. Allowing for utility control can help alleviate the need for costly upgrades and possibly enable additional locational value for interconnected DERs.
- Simplification in the number of disparate interconnection rules and the extension of rules where none currently exist (e.g., between 10 and 20 MW). All interconnections happen to the same interconnected electrical system and the existence, and in some cases absence, of multiple sets of rules introduces unnecessary complications. With the adoption of IEEE-1547 2018 and its broad applicability, a holistic interconnection rule set could be developed.

### 7.4.4 ALIGNING EV REGULATION ACROSS LIGHT-, MEDIUM- AND HEAVY-DUTY VEHICLES

In recent years, PGE has highlighted the need for a revised cost-allocation methodology for grid investment that is predominantly driven by electric vehicle adoption. Through the work done in Adv 300, UM 1811 and others, PGE has collaborated with Staff and stakeholders to ensure fleet customers are not burdened by additional cost for switching to medium- and heavy-duty electric vehicles, which is one of the crucial elements in Oregon's push for economy-wide decarbonization.

However, similar regulation is currently not applicable for light-duty vehicles. PGE's understanding of HB 2165 focusing on infrastructure measures highlights the desire at the policy level to address this barrier for light-duty vehicles. PGE notes that EV adoption, especially light-duty vehicles, has a large "contagious" or "imitation" factor. In other words, customers are more likely to purchase EVs when they see their neighbors, friends or extended family have purchased one as well.

135. Additional information regarding qualifying facilities, available at www.oregon.gov.

136. Additional information can be found Order 10-200 in AR 538, which developed the rules for the program, available at apps.puc.state.or.us and Order 10-198, which set forth the shares amount the utilities, available at apps.puc.state.or.us.

Translating this to grid impact, it is likely neighborhoods will see spikes in adoption rather than a gradual change over time. The current cost allocation framework can deter this phenomenon, thus decreasing adoption of light-duty EVs.

We will work with the stakeholders and Staff to align relevant downstream regulations with HB 2165, addressing this barrier comprehensively for any electrification measures that provide a decarbonization benefit.

### 7.4.5 COMPARABLE TREATMENT OF NON-WIRES SOLUTIONS COMPARED TO TRADITIONAL TRANSMISSION AND DISTRIBUTION (T&D) SOLUTIONS

PGE defines a non-wires solution (NWS) as an investment intended to defer, reduce or remove the need for a specific wired solution in a specific geographical region to an identified grid need such as managing load, generation, reliability, voltage regulation and/or other wide-ranging grid needs. NWS can range from policy mechanisms such as tariffs, to technology solutions such as utility- or customer-owned DERs, to control solutions such as automated switching. Based on this definition, we consider NWS as another tool that distribution engineers can leverage to address grid needs. As these projects are implemented and confidence in the solutions grows, NWS are likely to become a larger part of the solution mix.

While PGE goes through the process of implementing and learning from NWS, a parallel discussion is needed on the regulatory elements of NWS, including the regulatory approval process and the appropriate utility incentives to maximize community impact relative to traditional T&D solutions. A review of other jurisdictions such as New York show how utilities and regulators worked with stakeholders and the community to develop a performance incentive mechanism that aligned with community interest in local investment, grid planning's desire to address a local load pocket and the ability of the utility to attract investment.[137] As part of this larger effort to normalize the application of NWS, regulators paved a path to streamline NWS approval to ensure NWS can also be leveraged for solutions with shorter lead times.

This approach and incentive mechanism was successfully leveraged by New York, but this may not necessarily be adaptable for Oregon, especially considering Oregon's focus on equity. As noted in **Chapter 2**, NWSs have a more complex relationship with the utility cost allocation than traditional T&D solutions:

- **NWS solutions cannot be evaluated the same way as traditional T&D solutions**. They require a broader consideration of costs and benefits. Costs may include RFP costs for solution procurement, added marketing and outreach, community education, socioeconomic and demographic analysis, and increased incentive costs. Benefits include distribution system benefits, bulk system benefits and societal and environmental benefits. Thus, to compare NWS to traditional T&D solutions, a more broad-based approach to costs and benefits must be considered. This, inherently, evolves the cost-benefit analysis or least-cost, least-risk approach. Part 2 of the DSP filing will include two utility pilot proposals for NWS projects where more detail will be provided. However, in the interim, PGE recommends that Staff and participants continue discussions on potential implications for NWS projects that may show higher costs and, thus, higher rate impacts than traditional solutions but provide long-term societal benefits.

- **NWS may produce higher distribution system (locational) benefits relative to system wide DER programs** because NWS are addressing specific distribution system constraints. When identifying NWS, consider that while these additional benefits can be used to increase incentives, there is an equity element that should affect how the increased benefits should be utilized. Based on the "Fair and reasonable costs" goal defined in **Section 2.3.3**, PGE's stance is that these benefits may translate, when feasible, to higher localized incentives to generate local community benefits and encourage local jobs, especially when environmental justice communities are impacted. Conversely, if environmental justice communities are not directly impacted by the local distribution system constraint, it would be equitable to ensure that these increased benefits are socialized, when feasible, similar to the treatment of costs for such a project. This ensures environmental justice communities are not bearing potentially larger upfront costs of NWS in affluent neighborhoods without receiving any local benefits, which would exacerbate the inequities. To account for this equity impact, PGE will work with Community-Based Organizations (CBO), stakeholders, and Staff to create a consistent methodology that can be applied to determine the equity impact of an NWS solution relative to a traditional T&D solution.

137. New York's Brooklyn Queens Demand Management program's information sheet, developed by Advanced Energy Economy (AEE), available at www.greentechmedia.com

### 7.4.6 REGULATORY GUIDANCE ON ENABLING INVERTER-BASED DER GENERATION

Today, the utility has a clear obligation to serve load and invest in the distribution system to ensure future load is served safely, reliably and affordably. However, similar guidance is not available to the Company to serve forecasted generation, specifically, how forecasts of inverter based DERs such as solar PV and battery storage can be used to justify distribution system investment. Currently, inverter-based system impacts on the distribution system are evaluated reactively through interconnection studies. These studies represent one of the primary means of determining distribution system investments in protection equipment necessary to enable generation for customers on existing substations.

As noted in **Section 2.5**, PGE is developing a bottom-up DER adoption model that identifies the expected solar and storage adoption at the feeder level. PGE can leverage the outputs of this model to determine net load and hosting capacity impacts at the feeder level as part of distribution planning studies to make the necessary investments to serve customer load and generation. In other words, with this new forecast, PGE can proactively make investments on the distribution system based on expected adoption of inverter-based systems, thereby removing barriers for DER adoption. PGE seeks to start a discussion with stakeholders and the Commission to finalize guidance on enabling this proactive approach to addressing adoption barriers to inverter-based DERs.

### 7.4.7 INTEGRATION OF DIFFERENT DOCKETS TO DRIVE OPERATIONAL EFFICIENCY

In the UM 2005 proceeding, Staff noted the overlap of the DSP with several other reports and plans. Overlap, in this context, refers to the same information that is presented across multiple filings. PGE believes that regulatory consolidation of these elements will reduce the overall burden for all parties involved. PGE advocates for Staff to leverage the UM 2005 proceeding to determine the optimal method to communicate this information.

Our initial set of recommendations is intended to streamline communication of relevant data (**Figure 37**):

- Establish the final guidelines of the DSP in a manner that eliminates the Smart Grid Report.
- Eliminate the duplication of the research and development (R&D) reports being made independently and in the DSP.
- Integrate distribution system specific R&D reports into the DSP and eliminate R&D annual reporting requirement required through Order 15-356 within UE 294.[138]
- Leverage dashboards to obtain and drill down on baseline and system assessment data requirements.
- Integrate Annual Reliability, Annual Small Generator and Annual Net Metering reporting with DSP requirements including associated data.

138. More information on UE 294, Order 15-356, available at apps.puc.state.or.us.

**Figure 37. DSP overlap with annual/biennial reports and plans provided to the Commission**