SB 978 — Actively Adapting to the Changing Electricity Sector

For more than a century, the Public Utility Commission of Oregon (PUC) has adapted to industry changes and new technologies—maximizing public benefits and protecting customers across the state who rely on essential utility services. By passing SB 978 (2017), the Legislature identified a moment of significant change in the electric industry and for the PUC.

SB 978 directed the PUC to “explore changes to the existing regulatory system [of electric utilities] and incentives that could accommodate developing industry trends and support new policy objectives without compromising affordable rates, safety and reliable service.” For any changes “in the interest of customers . . . and the public generally,” SB 978 directs us to plan for administrative implementation or make recommendations to the Legislature.

Through a dynamic and, participatory public process, stakeholders identified evolving objectives for the Legislature to consider and evolving regulatory tools for the PUC to use. In the SB 978 report, we:

1. Convey societal objectives that many SB 978 participants believe the PUC should have more authority to address when regulating the electricity sector;
2. Identify how the PUC will focus and evolve its regulatory tools to address today’s industry trends and legislative objectives; and
3. Describe strategies the PUC will use to improve inclusion in PUC processes.

The PUC stands ready to use the powerful tools of economic regulation—traditional and evolving—to achieve the societal objectives that the Legislature prioritizes for Oregon today.

Legislative Action on Emerging Societal Objectives

The PUC’s current legislative mandate is to ensure that regulated electric utilities make safe, reliable and fairly priced electricity—an essential service—available on non-discriminatory terms to everyone in their service territories. The PUC also implements many specific legislative policies, such as clean energy deployment and competition through direct access for large customers.

In the SB 978 process, participants:

- Reaffirmed safety, reliability, and broadly affordable rates as core societal objectives for electricity regulation.
- Broadly recognized a need for the Legislature to address the PUC’s authority to work toward:
  - Affordable outcomes for all – Many participants want the PUC to have more authority to improve affordability outcomes for low income customers.
  - Greenhouse gas reduction – Many participants want stronger legislative direction for the PUC to consider greenhouse gas reduction and climate change in its decision making.

Within our existing statutory authority, the PUC can implement specific legislated policies (e.g. the Renewable Portfolio Standard) broad and use cost- and economic risk-based analyses that indirectly address affordability and the climate change impacts of electric generation. However, the PUC cannot impose costs on utilities to accomplish societal objectives that utilities and their customers are not otherwise legally required to bear.
This report recommends that the Legislature consider direction for the PUC on these or other emerging objectives for the electric regulatory system. We are ready and willing to support this legislative process.

**PUC Action on Regulatory Tools**
The PUC has an extensive regulatory toolbox to align customer and utility incentives with the objectives set by the Legislature – even while technology continues to evolve. Our strength is using unbiased economic analysis and independent decision-making to balance trade-offs among competing priorities.

In response to the SB 978 process and the changing industry conditions, we will actively:

- Seek to improve regulatory tools to **value the system costs and benefits** of customer and competitive resources – enabling customer and competitive opportunities to expand in alignment with legislative goals and the overall financial strength and efficiency of the utility system. The PUC will actively monitor new products, services, and markets, and encourage utilities to integrate service relationships with innovative third parties.
- Cooperate with other states to explore effective development of an **organized regional market** to enable competition, deliver least cost solutions, and mitigate risks to Oregon customers.
- Explore **performance-based regulation** (PBR) and other regulatory tools to more clearly align utility financial incentives with customer goals, industry trends, and legislative objectives.

The long-standing economic incentives for utilities to invest significant capital in order to earn a return for investors and to realize earnings through sustained load growth, have produced the highly reliable, low cost, centralized utility system that we enjoy today. Though the model is challenged by the changing industry and may benefit from some realignment with today’s objectives, we recognize that adjusting a utility earnings model that has worked well for most customers is a complex endeavor that requires deliberation and careful design.

The Commission does not recommend a change to Oregon’s electricity market structure. The Legislature has concluded before that retail restructuring could make policy objectives and consumer protection significantly harder to achieve than in the current centralized, regulated environment. Instead, we commit to actively using our regulatory tools to effectively adapt to evolving technology and market conditions in a rapidly changing industry.

**Expanding Participation in PUC Processes**
The PUC’s SB 978 process benefited from a diverse range of perspectives, including participation by groups and individuals new to the PUC process. We commit to developing a strategy for **engagement and inclusion in PUC processes** beyond the SB 978 process, particularly from community-based groups representing customers affected by climate change and who have affordability concerns and less access to new electricity options.

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**SB 978 Process**
The Commission’s innovative public process exceeded its goals by engaging a wide range of participants, including many new stakeholders:

- **Educated each other** and the Commission on their perceptions of the existing system and trends;
- **Surfaced** foundational assumptions about the sector;
- **Identified** traditional and new public policy objectives; and
- **Reflected** on whether new authorities, structures, and tools could help accomplish those policy objectives in today’s environment.
I. Introduction

Since electricity was added to the Public Utility Commission of Oregon’s (PUC or Commission) regulatory mandate in 1911, the electricity sector has experienced significant changes, including dramatic changes in the technology used to supply and manage electricity. Since the 1970s, there has been a growing movement to reduce the environmental impacts of the electricity system. More recently, there has been increased customer interest in having more electricity options and an emerging awareness of social equity as a policy objective. In the past two decades, the Legislature has responded to evolving technology trends and policy goals by passing laws to promote specific new tools and technologies, including customer choice and competition, energy efficiency, renewable energy, energy storage, and utility investment in electric vehicle infrastructure.

With SB 978 (2017), the Legislature asked the Commission to explore and examine the most recent changing dynamics of the regulated electric system in a more integrated and holistic manner. When authority for the Commission was first established through the Public Utility Law of 1911, the primary concern was to bring electricity service to all citizens with an emphasis on affordability and reliability. Now, with the expansion of electric service complete and the focus on transforming the system to achieve new objectives, SB 978 asked us whether changes to the regulated electric system and its incentives would help meet today’s most important societal objectives.

The PUC aimed for innovation and new perspectives in the SB 978 public process. We used a third-party facilitator, the Rocky Mountain Institute, to design a dynamic engagement process and an outside advisor, the Regulatory Assistance Project, to assist in developing thought-provoking content. We enjoyed active participation by a wide range of stakeholders—both new to and experienced with the PUC—who challenged each other and collaborated throughout the process. Appendix A to this report summarizes these groups’ work. The mutual understanding and connections among participants achieved during the process, and the work that participants and the Commission will accomplish together moving forward, are an important outcome of the SB 978 process.

This report provides a roadmap for action that will enable the PUC to more effectively capture the benefits of technological change and help regulated utilities respond to changes occurring in the electricity industry. We identify evolving regulatory tools that the Commission can use to meet the objectives the Legislature sets for us. We also identify areas where legislative action may be required for the Commission to incorporate new objectives into our regulatory authority.

Our key areas for action are to:

- Work with the Legislature and stakeholders to consider the Commission’s role in two areas—climate change mitigation and affordability for all customers—which were regarded by a large majority of SB 978 participants as important for the regulated electric sector to address more directly.
- Evolve our regulatory tools to address utility and customer economic incentives, increase competition and address the sharing of risk caused by accelerating technology and industry change, and collaborate with other states to explore development of an organized regional market to deliver efficiencies to customers and improved access to competition.
• Develop new methods to encourage **expanded participation** from new stakeholders.

These conclusions and recommendations, discussed in Section IV, represent a roadmap for a journey that is demonstrated in pending and planned Commission dockets and investigations. Before discussing our conclusions and recommendations, we summarize very briefly the key features of Oregon’s electric regulatory system in Section II, with a significantly expanded discussion in Appendix B. In Section III, we identify key technology and policy trends that provide context for our conclusions and recommendations.

II. **Key Features of Oregon’s Electric Regulatory System**

The electric regulatory system is complex. The SB 978 process exposed new participants to the system’s physical structure, history, fundamental objectives, and basic mechanisms (a detailed summary of which can be found in Appendix B). Here, in a brief overview, we describe the fundamental foundations of Oregon’s regulatory system and market structure.

a. **The Regulatory Compact, Regulatory Objectives, and Ratemaking Mechanisms**

• **The Regulatory Compact**: Utilities are Accountable to Serve All and Entitled to Fair Compensation

As the electricity system developed and was recognized as an “essential service affected with the public interest,” a single provider that was “vertically integrated” (meaning, it owned and operated all three elements of the electricity system: generation, transmission, and distribution), could expand the system to serve everyone at lower cost with greater efficiency and reliability than if multiple competing providers were providing the same service. For-profit utilities were allowed to operate as protected monopolies in defined geographic service areas (territories) in exchange for consenting to serve all customers at a price calculated to cover operating costs plus a reasonable return on the capital invested. This is known as the “regulatory compact.”

The core elements of the regulatory compact remain in place in Oregon today. The utility has the exclusive right to serve anyone located within its service territory in a manner that is safe, reliable, and nondiscriminatory. In exchange, the utility is allowed the opportunity to collect the costs of providing that service, plus a fair return, in rates set by the Commission. The Commission’s fundamental responsibility is to regulate in the interest of utility customers, but to do so, we must also ensure that rates are fair to the utility so that the utility can satisfy its obligations to customers.

• **Traditional Regulatory Objectives**: Safe and Reliable Service at Just and Reasonable Rates

The PUC has broad authority from the Legislature to regulate in the public interest in matters of utility rates, safety, and consumer protection. However, the Commission cannot take actions or require regulated utilities to take actions that fall outside the scope of its general statutory authority and jurisdiction, or its more specific authority granted by the legislature to implement certain laws or policies that apply to regulated utilities. The Commission’s core authority is to use economic regulation to ensure that utilities provide safe and reliable electric service to everyone in their service territories at reasonable, non-discriminatory rates.
The PUC also implements energy policies that are driven by additional legislative objectives. In 1999, the Legislature adopted SB 1149 (discussed below), which prioritized competition and customer options. New laws in the 2000s required investor-owned utilities to use—or allowed customers to choose—renewable energy resources and to phase out coal-fired generation.

These policies gave the PUC new responsibilities to implement specific directives, but did not provide a holistic change to the Commission’s guiding objectives and legal authority. For example, although the Commission implements the Legislature’s numerous clean energy policies motivated in part by climate change mitigation and other environmental goals, the Commission can only consider greenhouse gas emissions and other environmental factors as an economic risk factor in utility resource planning.\(^1\)

- **Cost-of-Service Ratemaking in Oregon**: Rates Reflect the Cost of Utility Service and are Applied Equally Within Broad Customer Classes

Through the traditional regulatory model, regulators use economic incentives in the ratemaking process to align utility performance with the broad regulatory objectives of safe and reliable service, at just and reasonable rates. The Commission generally does so through cost-of-service regulation, but has adapted this traditional regulatory model in some ways. Appendix B contains a detailed review of Oregon’s ratemaking mechanisms. Here, we briefly cover a few key features of the system and example responses that are important to understanding this report’s conclusions:

- **Utility rates include the opportunity to earn a return on capital investment but not operating costs**: Rates for electric service are set by determining the annual “revenue requirement” necessary to provide service that includes: (1) the utility’s reasonable operating costs; (2) paying the utility back for capital prudently invested; and (3) a Commission-established rate of return on prudent capital investments that provides the opportunity for utility shareholders to earn a fair return. Rates do not include a return on operating costs, which may motivate utilities to prefer capital-intensive solutions. This capital investment incentive has promoted achievement of a highly reliable electric system, but capital investments are not always the optimal way to address utility system needs.

  **Example Responses**: Oregon has adopted mechanisms to balance this incentive, including scrutiny of the need for new investments and demand-side alternatives in integrated resource plans, as well as competitive bidding rules to level the playing field for solutions that do not involve capital investment by the utility.

- **Maintaining customers and increasing customer sales help utilities cover system costs and remain profitable**: To set rates, the utility’s total annual revenue requirement is spread across the expected amount of electricity sales to arrive at a rate structure for each customer class. Because fixed rates per kilowatt hour of electricity will be in place until the next rate case, utilities must address increased operating costs between rate cases by increasing electricity sales, increasing operational efficiency, or reducing quality of service. A motivation to increase electricity sales may create an economic disincentive to promote energy efficiency and distributed generation, which reduce utility electricity sales.

Example Responses: Oregon has adopted measures to counteract this disincentive, such as decoupling and creation of the Energy Trust of Oregon (Energy Trust) as a third-party to deliver energy efficiency savings.

- After-the-fact review of utility investments lowers customer risk, affects utility risk tolerance: Utility capital investments must be complete and serving customers before they can be included in customer rates. Thus, the Commission undertakes a “prudence review” of utility capital investment happens after-the-fact in the general rate case in which rate recovery is sought. This promotes a low-risk system, in which the utility is motivated to invest in proven technologies with lower cost recovery risk and may be less inclined toward innovative technologies.

Example Responses: Integrated resource planning and specific legislative resource directives have been created to provide more regulatory certainty by offering opportunities for advance Commission guidance. These tools reduce the utility’s risk of not recovering its costs for investing in new technologies through customer rates.

- Rates are collected from broad customer classes without discrimination: Rates for individual customer classes (e.g. residential, commercial, and industrial) are set based on the cost to serve classes of customers whose usage and cost profile to the utility system is similar. The Commission generally may not allow utilities to discriminate or provide preferential treatment to customers within a customer class unless there are distinguishing factors related primarily to the cost to serve those specific customers.

As this overview suggests, a centralized system that socializes costs based on broad customer classifications (also known as “service classifications”) is at the foundation of the cost-of-service regulatory and ratemaking paradigm. The Commission determines a reasonable total revenue requirement that would allow the utility to fulfill its obligation to provide safe and reliable service and comply with all public policy requirements, plus potentially earn a shareholder return on capital investments that are serving customers. Then, the Commission sets rates to allow the utility to collect the established revenue requirement from utility customers.

b. Hybrid Market Structure, Vertically Integrated Utilities and Competitive Providers

- Hybrid Market Structure: Direct Market Access for Some Customers, Utility-Provided Choices for Others

Oregon has a hybrid retail market structure, meaning the basic vertically integrated monopoly structure remains in place, but some commercial and industrial customers may bypass the utility and directly procure electricity from competitive suppliers. The Legislature adopted this hybrid structure in 1999 with the passage of SB 1149. It gave commercial and industrial customers “direct access” to third-party energy providers. Customers that switch to direct access must pay a Commission-established transition charge or credit to reflect the impacts of their departure to the utility system.

Utilities offer customers choices other than full market access by way of energy efficiency, demand response, renewable energy certificate purchasing, net metering, community solar, and voluntary renewable energy tariff programs. Most of these programs have been mandated by the Legislature and focused on clean energy policy goals. Many of the programs offer access to third party suppliers through a utility tariff or a third party administrator like Energy Trust, with PUC oversight.
By contrast, some jurisdictions outside Oregon have “fully restructured” or “deregulated” retail markets. In those areas, utilities continue to own and operate the distribution grid, but customers choose their electricity providers and a regional transmission operator organizes those providers’ access to electricity supply from the competitive wholesale market. (See graphic Appendix C). Because competitive suppliers are not regulated, meeting policy objectives relies on market forces and effective market rules or other interventions.

- **Competitive Forces**: Policies to Promote Resource Diversity and Cost Discipline in Utility Procurement

To serve customers, utilities can either own electric generating resources or purchase electricity from independent power producers through power purchase agreements. Two key policies have attempted to promote the participation of competitive providers in electricity supply.

The first is the federal Public Utility Regulatory Policies Act of 1978 (PURPA)\(^2\) that requires utilities in regions without competitive wholesale markets to purchase electricity from qualifying facilities—primarily from smaller renewable energy projects—at prices set by the PUC to reflect the avoided cost of the electricity the utility would otherwise have to procure.

The second is competitive bidding. When utilities identify a need for large new generation resources to serve customers, the PUC requires utilities to consider offers from independent power producers. The purpose of this requirement is to introduce resource diversity and cost discipline to utility procurement, rather than requiring particular procurement outcomes.

**c. Transmission and Distribution: Maintaining Reliability and Organizing Access to the Grid**

Reliable electric service requires expert management of a complex, interconnected grid. Electricity supply must be balanced with demand at all times. Utilities have the complicated and challenging task to ensure that transmission systems (large power flows across long distances) and distribution systems (smaller networks reaching end-use customers) are safe and reliable.

In most regions, a centralized operator organizes transmission systems, ensuring reliability and managing purchases and sales of electricity by wholesale market participants. In the western United States, however, there is no centralized transmission operator. Bonneville Power Administration owns and manages the vast majority of the regional transmission system, and each electric utility regulated by the PUC also controls transmission lines (or shares of transmission lines) and individually balances supply and demand and controls access by non-utility generation owners. However, all electric utilities regulated by the PUC have recently begun to participate in the California Independent System Operator (CAISO) Energy Imbalance Market (EIM), which has benefitted utility customers across the west with more efficient access to resources to meet a small portion of their moment-to-moment needs for balanced energy supply and demand.\(^3\)

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\(^2\) PURPA requires utilities to purchase the electric output from qualifying facilities of a certain size. States develop PURPA implementation rules.

\(^3\) CAISO Gross System Benefits, [https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx](https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx), Accessed Aug. 11, 2018.
All utilities must own and manage safe and reliable distribution systems—the network of substations and smaller electric lines that connect end-use customers to the larger distribution and transmission grid. The distribution grid works in two ways. It delivers electricity from the larger transmission grid to customers, and also receives electricity from distributed energy resources (rooftop solar or other distributed generation). Though some distributed energy resources have existed on utility systems for many years, the complexity of managing a two-way flow of electricity on the distribution system increases as distributed resources expand.

III. Changing Context: Technology and Policy

SB 978 provided a long list of technology trends and policy drivers for consideration in our public process. To capture those trends and policy drivers, we highlight four themes that proved significant to participants and the PUC throughout the SB 978 process:

a. Societal interests in climate change and social equity
b. Rapid change in capabilities and costs of new technology
c. Balancing individual choices and collective system goals
d. Competition and market development

Discussion of these four contextual trends provides a foundation for Section IV, where we describe the tensions these trends create and our conclusions about the best ways for the regulatory system to adapt.4

a. Societal Interests in Climate Change and Social Equity

Two of the strongest themes for participants in the SB 978 process were not exclusively utility sector trends, but instead related to the roles of regulated utilities and the PUC in advancing broader societal interests in climate change mitigation and social equity. Participants identified actions the Commission could take within its current statutory authority, but recognized that legislative action would be required to make other changes.

• Climate Change and Environmental Impacts

Since the 1970s there has been an increased focus on the environmental impacts caused by energy use. Over the years, as environmental regulation has increased, the energy sector has adjusted by making physical changes to the system, the costs of which flow through to customer rates. Stakeholders both within and outside of the SB 978 process have emphasized the continued and pressing need to mitigate environmental impacts of the energy sector, specifically greenhouse gas emissions.

Many SB 978 process participants identified climate change as an imperative issue that must be addressed as quickly as possible. They emphasized the important and central role that the electric sector

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4 We have also provided the Regulatory Assistance Project’s paper, “Trends in Technology and Policy for Utility Regulation” as Appendix D for information on additional trends.
should play in meeting the state’s greenhouse gas emission goals. In 2016, more than 26 percent of the state’s greenhouse gas emissions were attributable to the electricity sector.

In the SB 978 process, a group of participants indicated that in order to effectively decarbonize the energy system, Oregon must accomplish three overarching objectives: (1) maximize energy efficiency and conservation to reduce electricity and natural gas loads; (2) transition from fossil fuels to renewable energy sources; and (3) decarbonize the transportation sector. Participants in the SB 978 process made clear that reducing greenhouse gas emissions is a societal goal that should be integrated into legal requirements on the utilities and a role for the PUC. However, currently Oregon lacks legislative mandates to reduce greenhouse gas emissions.

How the state chooses to address greenhouse gas emission reductions will have a significant impact on the utilities the PUC regulates, ranging from what types of resources the utilities select to how they manage their greenhouse gas mitigation compliance requirements. Most stakeholders agreed that an economy-wide greenhouse gas policy is the most effective approach. Even if a greenhouse gas price or policy is mandated by the Legislature, some participants indicated there may need to be additional utility action taken to reduce emissions in the transportation sector through electrification.

- **Social Equity and Participation**

Social equity was identified by participants as something that should be a driver in PUC processes. Traditional cost-of-service regulation relies on customers to pay for the costs they cause the system, but stakeholders have indicated the PUC should focus on affordable outcomes for all customers, including low-income customers.

To address the greater energy burden on low-income customers, some states have developed Percentage of Income Payment Programs (PIPP). Under a PIPP, rather than paying the retail rate of electricity, participants pay a percentage of their income or what has been deemed “affordable.” Ohio and Colorado both have implemented PIPPs. Another program introduced in Washington and California is a retail rate reduction. Under this program, qualifying participants only pay a portion of the retail rate.

As a component of social equity, broader stakeholder representation in PUC processes is considered increasingly important as the opportunity for significant changes in the electric system have increased.

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5 Oregon’s greenhouse gas emission reduction goals are: 10 percent below 1990 levels by 2020 and 75 percent reduction below 1990 levels by 2050.
7 “Low Carbon Future Group Memo” to the Oregon PUC, May 31, 2018, Appendix E-1.
Participants indicated there should be a targeted approach to ensuring a balance of voices present in future PUC processes.

b. Rapid Change in Capabilities and Costs of New Technologies

Technology change in the electric utility industry is not new, but has become more rapid in the last ten years. Policy has accelerated some technology trends, particularly in renewable energy and storage, but other trends reflect broader market advances in digital and data technology. Because these technological advances hold promise of leading to a lower cost and lower emissions system, participants agree that the regulatory system and set of economic incentives should further adapt to integrate technology capabilities more quickly and take advantage of more opportunities. We have identified the technology trends and impacts most significant for Oregon’s electric sector, and discuss those four key themes in the bullets below, with Appendix D covering many others.

- More renewables, low natural gas prices change energy market dynamics

Across the region, new renewable energy resources have been added to the region’s foundation of hydroelectric generation in response to state policies, federal tax credits, and recently to falling prices that make wind and solar resources increasingly cost competitive with traditional fossil fuel-based resources. Ten percent of Portland General Electric Company’s and PacifiCorp’s 2014-2016 average electricity mix was met with wind and solar projects. By 2040, the amount of variable energy resources on Oregon’s electric system is anticipated to increase sharply such that 50 percent of energy needs are met by RPS eligible renewable resources. As variable energy resources increase on the electric system, the need for flexible resources to integrate these resources and balance their output with load will grow.

Low natural gas prices interact with the addition of renewables to depress energy market prices. Customers benefit when utilities can avoid new generation expenses by purchasing from the market instead of building a generating resource. However, uncertainty about future energy market prices raises difficult questions about the relative value to customers of paying the fixed costs for existing and new energy resources versus relying on market purchases. Utility service that is more expensive than market purchases—due to fixed costs and other collective system policy requirements and objectives—increases customer desire to leave the utility to take service from competitive suppliers that can offer a higher proportion of market purchases at currently lower prices.

Further, a continued trend of low energy market prices may limit the amount of available cost-effective energy efficiency. Energy efficiency is a low-cost, low impact and broadly beneficial resource, but the supply of new efficiency measures and programs is limited by the cost utilities would otherwise incur through the purchase of electricity from the market or owned generation. Although Energy Trust acquired record levels of savings in 2017, the forward outlook anticipates less available cost-effective resources. This is because the “low hanging fruit” measures have already been picked, and many new efficient technologies are not yet cost-competitive with low-cost, market resources.

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• Rapid technology and market changes challenge technology-specific policy mandates, resource planning, price setting

In today’s environment, changes in market conditions, technology capabilities, and costs move faster than policy and regulatory processes. This creates a challenge for technology-specific policy mandates, resource planning, and accurate price setting.

Legislative action to mandate specific technologies has been successful in bringing down technology costs and allowing utilities to gain experience with new resources. However, rapid technology change increasingly favors policies that define a desired system outcome that could be met by a number of technologies that compete to achieve the desired outcome most efficiently or at the lowest cost.

For resource planning, technology cost inputs that are fixed at the beginning of an integrated resource plan (IRP) process may change significantly over the period of its development and review. By the time a utility identifies a resource need and issues a request for proposal, new technologies may be capable and cost-competitive but were not evaluated in the utility’s IRP.

IRPs have been the Commission’s foundation for setting “avoided cost” prices paid to renewable energy qualifying facilities. In an environment of rapid cost change, avoided costs derived from IRPs have been out of alignment with contemporaneous market costs, leading to significant frustrations for utilities, renewable energy developers, and the Commission regarding implementation of the PURPA.

• Concerns about customer commitment to long-term investments and new technologies in a changing landscape

New utility-owned electric generating resources have significant, long-term impacts on customers. The Commission has been very deliberate in looking at the need for a new resource, the cost of a new resource, and the resource’s lifetime benefit to utility customers when deciding whether to include that investment in customer rates. While uncertainty is always present, the rapid pace of technology change poses new challenges.

With rapid technology change, it is more likely that a commitment to an investment now could prove to be less advantageous if a new technology proves to be less effective than expected, a future new technology is superior in cost and performance, or market conditions dramatically change the value of the resource to the utility system. One regulatory response to the desire to maintain a low-risk, low-cost utility system is to limit customer commitments to new resources and to maintain optionality. On the other hand, customers may benefit from utilities exploring new technologies and taking early action to secure low-cost opportunities, but deliberative regulatory processes to balance important competing interests may impede this.

Electric vehicles (EVs) provide an example of both challenges. Uncertainty about the pace of EV adoption creates uncertainty about the long-term context for evaluating the need for new generating resources; rather than the current trend of slow to flat growth in electricity load, future electric load may grow significantly as a result of EVs. Conversely, utilities may seek to invest in EV infrastructure, but investments move slowly because the PUC requires robust pilot program designs and evaluation plans vetted through highly-participatory stakeholder proceedings. This is done to ensure that utility customers will see system benefits from EV-related investments, given that customers will pay for them
in their electricity rates, and to reasonably protect against undesirable impacts of utility participation on competitive market development.

- Distribution system resources and management technologies require attention

Although penetration of distributed energy resources remains relatively low in Oregon (about one percent of customer load), costs continue to decline and customer interest and utilization is growing. More and more customer-sited energy storage projects are added to the grid each year by early adopters and critical facilities or industries driven by resiliency goals and a desire to pair storage with onsite solar resources.

Direct load control programs have potential to become firm flexible resources that utility systems will need in order to integrate the growing variable energy resources in the future. These technologies hold the promise of greater system efficiency, reliability, and other benefits, but also require substantial cost for planning and implementing these technologies throughout utility systems.

Technology advances in controls, sensors, communications, and automation equipment have the potential to add greater system awareness and real-time control capabilities for utility system operators. As interest and investment in distributed generation increases, additional location-specific data can be captured and analyzed to identify optimal locations to site new generation or storage resources. It can also be used to identify those areas where additional system upgrades are necessary prior to adding generation resources.

The rapid advancement and deployment of the digitalization of the grid is raising regulatory concerns of transparency in utility distribution system planning and asymmetry of knowledge in this area between utilities and the PUC. Also, the proliferation of digital controls and system data, including customer data, raises concerns about cybersecurity and data ownership, access, and confidentiality.

c. Balancing Customers’ Individual Choices and Collective Goals

New technologies have led to new providers and new options for utility customers. As technology has evolved, state policies have consistently directed the PUC to give customers more options for energy services. With an increasing number of programs and options that allow customers to either leave the utility system and use a competitive provider of electricity supply (direct access) or to select specific resource and rate options within the utility system (net metering, renewable energy purchasing, community solar, voluntary renewable energy tariffs), and desire for customer choice likely to continue increasing, three key trends arise.

- Managing customer choice to align with policy and regulatory objectives

The trend in Oregon legislative policy has been to offer more choices and to rely on the PUC to ensure choices are provided in a way that balances the goals of the program, the interests of the individual customer, and the goals of the collective utility system upon which non-participating customers rely.

Customer choice programs tend to be motivated by particular policy or regulatory goals, rather than purely by a desire to maximize customer independence. Some customer choice programs, such as community solar, are driven primarily by environmental policy goals (but may have secondary objectives around community well-being and economic development). Other types, such as direct access, are partially understood to be driven by economics for end use customers. Though some state policies apply
to direct access electricity service suppliers (like renewable portfolio standards, though on different terms than regulated utilities), the Commission has limited regulatory authority and oversight over competitive suppliers.

Some states have concluded that full access to customer choice is the best way to lower customer costs, allowing customers to choose from a number of energy providers to fulfill a number of service needs and desires. Other states have devised options for allowing customer choice while maintaining the benefits of aggregating load. Community Choice Aggregation allows a local government agency to purchase energy on behalf of customers in that local jurisdiction. California’s experience is instructive. With unprecedented growth in its Community Choice Aggregation program, the California Public Utilities Commission has estimated that by 2025 to 2030,14 Pacific Gas and Electric, a large California utility, may only serve half of the load in its service territory. As this load departs, questions are being raised about how to insulate the remaining utility customers from having to bear all the costs associated with investments that were made on behalf of all customers and also finance the system’s projected future obligations.

- **Quantifying the costs and benefits of customer-owned generation and market access to the utility system**

Depending on how customer choices are designed and offered, they can support or detract from general policy and regulatory objectives. Generally speaking, increasing distributed generation and other off-system choices lead to fewer customers and electricity sales from which system costs can be allocated and recovered. Transition charges paid by customers leaving the utility system must be designed to avoid harm to customers that remain with the utility. Likewise, payments for customer-owned generation must be in line with policy goals and economic value to the system.

To ensure that customer options support overall system goals, the value to the utility system of new customer options must be identifiable and customer payments must be aligned with that value. The growth of customer interest in distributed generation and energy storage challenges the PUC’s ability to value locational and other system benefits of customer generation. This leads to poor pricing signals and a mismatch in expectations between customers, utilities, and the PUC. Customers and third parties expect that the new technologies they bring to the grid will provide net system benefits, yet the quantification of these benefits remains unclear or provisional as utilities adapt their systems to take maximum advantage of distributed resources.

Increasing the granularity and accuracy with which the value of customer generation to the system can be quantified is an important and necessary step. It can help incent customer generation to locate in places that provide the highest possible value to the system and ensure that payments for customer generation do not impose significantly increased costs on the collective utility system as penetration of distributed resources grows. Without an organized market to help quantify benefits, the process must continue to evolve through regulatory analysis and price setting.

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- Monitoring markets to determine appropriate role for utility and/or third party providers

Surrounding customer choice is the question of what mix of options from the incumbent electric utility and third party providers is most appealing for customers and best adapted to other system and policy objectives. Depending on the program design, the PUC may have less regulatory oversight of non-utility providers. It is unclear whether customers have an overall preference for utility or non-utility providers, though advantages may emerge for particular new electricity services as markets develop and the impact of utility participation is evaluated.

d. Wholesale Competition and Market Development

New technologies provide increasing opportunities for third parties to provide elements of electricity service, and competitive pressure to provide wholesale supply to utilities is intense. The PUC’s competitive bidding guidelines are intended to level the playing field for competitive wholesale suppliers of electricity generation, in order to increase resource diversity and impose cost-discipline as a means to reach the least-cost, least-risk outcome for utility customers. However, some stakeholders claim that the competitive bidding process does not do enough to capture the differences in costs, benefits, and risks between utility-owned resources and power purchase agreements. Recent utility request for proposals (RFPs) for new large generating resources renewed stakeholder concerns that the utilities have an inherent unmitigated incentive to own and rate-base large investments. Some stakeholders regard the utility capital investment incentive as simply too strong for competitive bidding processes to effectively mitigate, but others believe that competitive bidding—even when it results in utility-owned generation—has produced least-cost, least-risk results for customers.

Access to transmission has complicated recent competitive bidding processes, with significant controversy about whether utility access to transmission supported by customer rates gives utility projects an unfair competitive advantage and limits options for customer access to a broad pool of diverse resources. Participants in the SB 978 process indicated that, among other potential benefits, the presence of an Independent System Operator (ISO) or a Regional Transmission Organization (RTO) would minimize this perceived barrier to competition by opening up a more transparent, organized market for access to transmission resources.

IV. What Comes Next? Tensions, Solutions and Next Steps

Technology has evolved significantly in the last 30 years and the pace of change will only increase in the energy and transportation sectors. This crucial reality is a backdrop to our recommendations. Our recommendations are designed to allow the PUC and stakeholders to thoughtfully adapt to a range of possible futures, balancing emerging risks against emerging opportunities to deliver on our regulatory mandate and implement required legislative policy goals.

The SB 978 process has confirmed the continued importance of the guiding objectives that underlie the core directives in the Commission’s enabling statutes: safety and reliability, just and reasonable rates, and a utility’s obligation to offer service to all customers in its service territory (non-discrimination). This process has prompted reflection on how the Commission defines those guiding objectives today and whether and how the Commission should incorporate new objectives for the electric system and new tools and structures to achieve those objectives.
Our conclusions and recommendations fall in six categories:

- Affordability, Equity, and Environmental Justice
- Climate Change and Greenhouse Gas Mitigation
- Retail Customer Choice
- Utility Incentive Alignment
- Regional Market Development
- Participation

We discuss in detail the tensions that lead to each of our conclusions and recommendations.

a. **Affordability, Equity and Environmental Justice**

The regulated electricity system was designed to provide universal service for customers at rates that reflect the cost to serve them, without regard for customer circumstances not related to the cost of providing electricity service, such as ability to pay. Since that time, however, the Legislature has designed a small number programs to address the needs of low income customers, including crisis energy bill assistance and weatherization programs.

One of the top issues raised by participants in the SB 978 process was whether or not more measures should be taken to increase the affordability of electricity for low-income customers and how social equity and environmental justice are integrated into the Commission's decision making practices. The Commission is already active in these areas, but concludes that further Commission and legislative action is important.

- **Affordability and Equity**

In the SB 978 process, participants and the Commission used the term “affordability” to address a variety of concepts. For clarity, we identify three distinct ways the Commission understands the concept of affordability to have been used in relation to the regulatory system during the SB 978 public process.

Customers and stakeholders generally regard affordable electricity as a core traditional objective for Commission regulation. In fact, the Commission’s legal mandate is to set “just and reasonable” rates that reflect utility operating costs and the opportunity for a fair return on capital investments. The Commission has many mechanisms (IRP, RFP, prudence review) to ensure that utilities use a least-cost, least-risk approach to operating and investing in the system, and promotes other mechanisms (like energy efficiency incentives) to help customers reduce their electricity bills. The Commission’s approach to regulation may seek to produce low rates and bills, but the Commission’s core legal mandate is to set rates that are “just and reasonable,” not to make sure rates remain at a certain level or have an equal affordability impact on all customers.

The second way the concept of affordability has been used in the SB 978 process is to assess the overall costs of the utility system, and the resulting customer rates and bills according to broad economic indicators and measures of affordability. During the SB 978 process, we reviewed the rates of Oregon’s regulated electric companies in relation to national statistics for utility rates and the rates compared with the consumer price index as a way of considering whether the system is affordable across broad classes of customers. Affordability, in this sense, could be a desired outcome that is the foundation of a target or metric for performance-based ratemaking (discussed below).
Third, even if rates can be considered affordable relative to broad economic indicators and for most members of a customer class, some SB 978 participants concluded that Oregon electric rates are not affordable because they continue to impose a significant burden for low-income customers or other, more segmented customer groups. These participants presented perspectives about affordability and in a need to adjust rates in light of the greater energy burden on low-income customers (See Appendix E-4). Participants argued that there should be a more nuanced definition of affordability and universal access that reflects the circumstances of narrower customer segments.

- **Environmental Justice**

During the SB 978 process, some participants asked the PUC to consider social equity and environmental justice impacts within its decision making. In 2007, the Legislature passed SB 420 which requires fourteen state agencies, including the PUC, to consider the effects of their actions, when those actions impact environmental justice issues, by ensuring that all voices are heard, especially those that have been historically underrepresented and disproportionately affected by environmental decisions.

The Environmental Justice Task Force has defined “environmental justice issues” as “equal protection from environmental and health hazards, and meaningful public participation in decisions that affect the environment in which people live, work, learn, practice spirituality, and play.” The PUC understands the importance of this directive and has worked to improve the accessibility of public participation in its dockets where environmental justice issues may be implicated, for example, in its review of petitions for a certificate of public convenience and necessity to construct overhead transmission lines. In these dockets, the PUC has solicited extensive comments from the public and individuals living in the potentially affected communities at public meetings and hearings, and in particular instances, traveled offsite to hold public comment hearings within the affected communities.

However, SB 420 did not amend the PUC’s enabling statutes that provide its authority with regard to setting just and reasonable rates or other statutes that provide standards for approval of applications by utilities. Thus, the PUC’s focus has been on reducing barriers to public participation to ensure that all voices are heard in the decision-making process as SB 420 directed. However, improvements can be made to provide a better understanding of the impacts on environmental justice communities if and when those decisions come before the Commission, and to more actively solicit participation from groups not traditionally active in PUC proceedings.

- **Next Steps**

As we write this report, the Governor’s Carbon Policy Office has convened a Low Income Utility Program Working Group to better understand if gaps exist between our current energy assistance programs required by the Legislature and the need experienced by low-income Oregonians today. The PUC is committed to continuing to assist the Low Income Utility Program Working Group to further understand energy burden impacts to low-income Oregonians and explore possible solutions. The work group is expected to provide recommendations to the Governor’s Carbon Policy Office in December 2018.

In the past, when programs that provide assistance to low-income customers through weatherization services or bill pay assistance have been implemented, specific legislation has required the PUC to do so. While the PUC has been able to incorporate social equity and energy burden impacts into our work based on specific direction from the Legislature, our ability to further address energy burden concerns is
limited given our statutory prohibitions against discrimination between customers (and corresponding prohibitions on preferential treatment between customers) based on factors other than cost-of-service or service characteristics, which are used to create separate classifications of service that pay different rates.

Direction from the Legislature would allow the Commission prioritize how to integrate social equity and differential energy burdens into the Commission decision-making process. The Legislature may be prepared to conclude that the Commission should be given express authority to establish a separate, low-income rate to address the energy burden of Oregon’s low-income ratepayers. For example, this could be in the form of a bill discount, a percentage of income payment program, or other approach. However, the Commission would need express authority with detailed criteria to create a low-income rate for customers while keeping rates just and reasonable for other customers.

Alternatively, or in addition, Legislature could create a low-income and environmental justice advocate. We understand that it may not be financially feasible for community-based organizations to develop the expertise required to engage in complex regulatory proceedings. This position would represent low-income ratepayers in matters before the Commission as well as ensure that environmental justice impacts are heard and included as part of the record the Commission reviews in making decisions. This position could be housed in an existing agency. The responsibility of this position would be to represent low-income ratepayers in matters before the Commission, including rate cases and other contested case proceedings.

Beyond legislative action, however, the Commission finds that there are smaller steps it can take to continue to improve in this area.

- The Commission will develop training for our staff and host a training once per year to familiarize and sensitize staff to topics related to social equity, access, and environmental justice. The Commission will engage external resources to develop this training.
- The Commission will also develop a process by which we will integrate an environmental justice impact analysis into rulemaking processes where applicable. This will raise stakeholder and Commission awareness of the impacts of decisions that may affect environmental justice communities.

b. Climate Change and Greenhouse Gas Mitigation

- Commission’s legal authority to consider greenhouse gas emissions

The Commission’s statutes require the regulation of the cost of providing energy to consumers, rather than the environmental consequences of providing such energy to consumers. Today, the state’s greenhouse gas emission reduction goals are not requirements that utilities must meet when considering resource acquisition decisions. The Commission’s current statutory authority does not allow it to impose on the utility, directly or indirectly, environmental costs that the utility is not otherwise
legally required to bear. However, the Commission may consider the cost risk that environmental regulations may be imposed in the future in the IRPs of the utilities it regulates.

Because of this legal interpretation, the Commission’s decarbonization role is focused on two areas:

- The Commission implements programs, policies, and administrative rules resulting from legislative requirements which regulated utilities must satisfy (i.e., renewable portfolio standards, transportation electrification), using the criteria provided by the Legislature. The Commission uses safety, reliability, and just and reasonable rates—not greenhouse gas reduction—as its guiding principles for implementation.
- The Commission requires utilities to consider the cost of future potential regulation of greenhouse gas emissions as an economic risk factor in its integrated utility resource planning process.\(^\text{16}\)

• **Climate Policy Perspectives**

A broad range of SB 978 participants recommended that the Legislature establish greenhouse gas emission reductions as an additional guiding objective for the regulated electric sector and the Commission, though views differed as to what the Legislature should do.

Some participants felt that the Legislature should redefine the Commission’s authority to make greenhouse gas mitigation a guiding principle, along with safety, reliability, and just and reasonable rates. Others recommended new authority for the PUC and new obligations for the regulated electric sector only as part of an economy-wide carbon policy, which would fairly distribute costs to all market participants and avoid placing the Commission in the position of setting the pace and depth of emission reductions.

While all participants emphasized the importance of accounting for the external costs associated with greenhouse gas emissions within the electric sector, some also pointed out that there could be more efficient and accelerated achievement of the state’s emission goals. That is, if the electric utilities worked to reduce emissions outside of the electric sector through beneficial electrification of other fuel uses, such as electric vehicles and other forms of electrified transportation. Because the greenhouse gas emissions associated with charging an electric vehicle are significantly less than those associated with gas-fired engines, stakeholders expressed it may be beneficial to have the electric utilities participate more significantly in advancing the adoption of transportation electrification.

Absent a directive from the Legislature to include greenhouse gas reductions from the transportation sector in rates, when the PUC considers implementation of large-scale electric vehicle programs that require substantial amounts of utility cost to be recovered from customers, it must determine, among other things, that any infrastructure investment is prudent. Short of this, limited pilots can allow utilities

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\(^{16}\) Under its current decision-making approach the Commission uses a least-cost, least-risk framework. This means the Commission balances the risks presented by proposals with the total cost to ratepayers. Environmental costs which are not currently regulated or likely to be regulated in the future by state, federal government or local jurisdictions are not accounted for in this balance test, nor can they be directly imposed on utilities.
to test whether a new and emerging program that is not currently cost-effective from an electric system perspective could produce a benefit to customers in the future. These pilots have been limited in scope and generally have not included investment in actions outside of providing traditional electricity service unless authorized by statute (i.e., SB 1547’s authorization for approval of transportation electrification programs).

- Next steps

Legislative direction and authority is needed before the Commission can require electric utilities to take new actions to reduce greenhouse gas emissions and recover increased costs of doing so from utility customers. The Commission is ready to work with the Legislature and stakeholders toward an appropriate role.

Defining a specific requirement for greenhouse gas reduction would be helpful. If the Legislature defines a specific requirement, such as a percentage of emission reductions for electric utilities in the context of a broader greenhouse gas emission policy, the Commission can develop the least-cost, least-risk method for the utility and its customers to achieve that outcome. Further, if the Legislature would like the electric sector to further reduce emissions in other sectors, such as the transportation sector, then legislative action will need to define the Commission’s authority to do so—for instance, by creating a program which would incentivize the utilities to implement beneficial electrification of other fuels.

c. Customer Choice

The Commission uses the phrase “customer choice” here broadly to refer to a utility customer’s ability to choose any product or service that is outside the general cost of service model, whether offered by utilities or through third-party providers.

- Tradeoffs and tensions with increasing customer options

In the SB 978 process, participants raised the importance of increased access to options for customers at the retail level. These choices were described in a wide variety of ways, including access to more renewable energy, energy use reduction and management opportunities, and self-generation. Participants also discussed options to purchase energy from an entity other than their utility, and more specifically, to purchase the output from a defined generation facility directly or through their utility.

Participants often asserted that customer choice would enable the state to meet its goals more quickly. For example, if customers had a choice about what resources made up their energy mix, the state would more quickly meet goals related to greenhouse gas emissions reduction. Access to greater customer choice could also help local municipalities and jurisdictions meet their climate and energy goals.

However, in order to achieve other current or emerging objectives, such as affordability and equity, customer choice programs must be designed intentionally to meet a customer’s goals to go more quickly or farther than the overall system without adding significant unwarranted costs to non-participants. Customer options can benefit the system if they are designed to incent customer actions that support utility system goals and are priced accurately to meet system objectives.

Some participants assert that customers would benefit from further opening Oregon’s market structure to competition by allowing all customers the ability to choose an energy supplier other than their current utility. Although the time and scope of the SB 978 process did not allow us to investigate these
claims, we did observe two themes that lead us not to recommend further exploration of this direction at this time. The first is that the state does not have an organized market which would provide a critical backbone for increased competition. The second is that outcomes on cost, reliability, and customer choices from restructured markets are mixed. Moreover, public policy goals and system outcomes are more difficult to control than in a regulated market structure.

- **Next steps**

The Commission observes that options for retail customers, both within and outside of the utility framework, should be understood and used as tools to achieve policy goals and objectives for the regulated utility system as well as for individual customers. Customer choice should be designed to enable customers to achieve desired outcomes that are consistent with state policies and that help the collective utility system achieve its goals and objectives, including fairness to other customers.

In our role regulating system rates for all utility customers, we must balance a wide variety of customer desires—from those interested in having more energy choices to those who just want the lights to turn on. Yet technology options for meeting individual customer goals will continue to expand, as will new opportunities to leverage customer interests to benefit the overall system. Therefore, it is critical that the PUC accelerate its efforts to better understand how individual choices can be designed to positively impact the overall system.

Currently, we are working to better understand and quantify how choices available to customers now and in the future impact the performance of the utility system as a whole, including the rates of customers who remain on standard service. Multiple pending and planned investigations span two categories of customer options: those where customers and other non-utility owners are providing generation to the grid, as well as customer rate design options to support the grid by modifying their energy usage. They include, among others:

- Resource value of solar investigation (RVOS), focused on solar photovoltaic installations including community solar;
- Upcoming investigation of the Commission’s approach to paying PURPA qualifying facilities for avoided costs to the utility system;
- Continued refinement of methodologies for valuing energy storage use cases, and monitoring utility storage pilots—including customer microgrids;
- Examination of energy efficiency avoided costs and cost-effectiveness methodologies;
- Review of utility demand response and time-of-use rate pilot programs.

Further, in PGE and PacifiCorp’s recent IRPs, the Commission acknowledged a staff recommendation to open an investigation into distribution system planning. Over the coming year the Commission anticipates this investigation will identify focus on increasing transparency and stakeholder engagement in grid modernization efforts necessary to evaluate utility investments through distribution system planning.

Coupled with ongoing grid modernization of utility systems and improved data collection and analytics, the ultimate goal of these discrete investigations is to develop an overall more accurate, granular

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17 Renewable and/or combined heat and power projects up to 80 megawatts.
approach to valuing system costs and benefits that inform fair pricing of customer options. The ability to accurately price products will lead to overall improved system efficiencies that benefit all customers.

d. Utility Incentive Alignment

One key finding of the SB 978 process is that strong stakeholder support exists to more clearly understand whether evolving regulatory tools can allow us to improve alignment between utility incentives and desired policy and customer outcomes.

- Rationale for exploring new regulatory approaches

Our review of current trends brings into question the sustainability of the current incentives for utility earnings, specifically the throughput incentive and the return on capital investments. The throughput incentive exists because utilities earn revenue on a per kilowatt hour basis, creating an incentive for the utility to sell more kilowatt hours and therefore disincentivizing reduced energy sales. The capital investment incentive exists because utility rates provide an opportunity for the utility to earn a rate of return on capital expenditures in infrastructure.

In the current construct, the system rewards utilities for load growth and asset-based solutions to customer needs. Therefore, failing to address whether these incentives can be aligned in ways that benefit both utilities and customers allows persistent tensions to grow between stakeholders concerned about the capital investment incentive’s impact on least-cost utility procurement. For example, stakeholders have raised a concern around continued utility investment in capital expenditures when access to capital is available to third-parties to develop projects that result in a reduced need for utility ownership of generation. Addressing incentive alignment also creates opportunities to reward utilities for outcomes that benefit customers, such as managing peak load growth, rather than only for building infrastructure to meet growing peak loads.

Oregon is not alone in identifying a new opportunity for alignment between existing incentives and evolving system values and conditions. Interest in investigating performance-based regulation is taking hold among stakeholders, utilities, and regulators nationwide. Several states are recognizing that the current regulatory model may benefit from adjustments in order to provide different incentives to the utility, enabling it to better adapt to this rapidly changing industry. Most jurisdictions have maintained the core cost of service model with rate-based capital but have added, or are considering adding, discrete tools for specific actions. Some examples include improvements to interconnection processes for distributed resources, or allowing an incentive for peak load reduction.

Adjusting the utility revenue model requires careful design to maximize positive outcomes while minimizing risk to ratepayers. The current regulatory structure has been successful for many years in achieving the desired outcomes identified by policy makers. Changing the incentive structure would require us to first identify the new values and new desired outcomes, and to determine how such outcomes might be measured and successfully achieved. To do this also requires us to establish both a metric to be measured and a baseline to measure success against, and to test whether achievement of the metric truly reflects utility performance.

- Next Steps
Given changes in utility industry technology and policy drivers, as well as the opportunity to more effectively align utility incentives with desired public policy outcomes, the Commission will explore performance-based regulation. It is possible that utilization of performance based incentives—allowing them to earn a return on the best performance outcomes rather than capital expenditures—will reduce competitive tensions while leading to best economic results for utility customers. We see the role of the regulator as designing economic incentives that align the interests of the utility and ratepayers, while we maintain our core statutory directives of safety, reliability, and just and reasonable rates for all customers.

A new proceeding will bring utilities and stakeholders together to explore a range of performance-based metrics for the specific utility systems that support the new desired system outcomes. Once identified, utilities and staff will track the data necessary to measure how well the current system is performing. With this information at hand, a future determination can be made as to which of the metrics lend themselves most appropriately to creation of incentives or penalties to achieve goals including overall system efficiency to the benefit of ratepayers.

From recent experience with a range of innovative pilots, we also find that the best learnings for new ways of thinking and working together may be achieved through taking small scale actions, versus beginning with a long, extended study process with a goal of evaluating large scale change. In parallel with the identification of system metrics, we will also seek to identify desired utility actions without specific incentives or penalties today which, if incented or not, would likely lead to achievement of one or more desired outcomes for the system. Utilities would be encouraged to propose one to two limited term, small scale new incentive tests to allow the Commission and parties the opportunity to gain experience in designing and integrating performance incentives into our practices.

e. Regional Market Development

A large number of SB 978 participants were encouraged by the success of the CAISO’s EIM and indicated that the state and Commission should continue to explore further opportunities to share resources regionally.

- **Opportunity to capture efficiencies**

Participants indicated that the presence of an Independent System Operator or a Regional Transmission Organization would provide a step toward improving conditions for robust competition, as it would open up a greater market for the sharing resources beyond the real-time market benefits of the EIM.

The Commission has been engaged in conversations around the expansion of the CAISO into a regional entity beyond the borders of California. These conversations began most recently in April 2015, when PacifiCorp and CAISO signed a memorandum of understanding to explore PacifiCorp becoming a participating transmission owner in CAISO.\(^\text{18}\) These conversations have slowed while the issue of governance\(^\text{19}\) has been taken up by the California State Legislature. Oregon has indicated that

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\(^{19}\) Governance is the term commonly used to refer to the structure of the CAISO Board of Directors. CAISO and its existing governance structure were developed by legislation that required certain representation on the CAISO Board. With the proposal to expand CAISO to the PacifiCorp states, there have been discussions on what the
governance is the key issue to be solved prior to moving forward with further regionalization efforts. At the time of this report, there was no final outcome on the California legislation which would make adjustments to the governance structure of the CAISO board.

- **Next Steps**

With a balanced governance structure, greater regionalized sharing of resources could create efficiencies, reduce emissions, support structures for wholesale competition, and provide cost-savings to Oregon customers. The Commission can only influence action in this area, but we commit to remaining actively engaged and contributing to the conversation around increased sharing of regional resources.

- **Participation**

The Commission recognizes that a new approach to utility regulation is not limited to the incentive structure used to encourage certain behaviors and achieve performance outcomes from the regulated utilities; it must also include designing the regulatory process itself to allow opportunities for community-based organizations, members of the public, and stakeholders new to our process to expand participation.

- **Learning from new stakeholders**

At the beginning of the SB 978 process, the Commission interviewed more than 20 organizations and individuals to better learn what aspects of the SB 978 process were most important to them. As part of these interviews, we talked with community-based organizations (CBOs) that stressed the importance of enabling and encouraging participation of citizens and new stakeholders in the discussions on re-envisioning the energy system. Members of the CBOs expressed an interest in participating in the Commission process, but also concerns around the technical knowledge and dedication of resources required to participate effectively in such a process.

In order to better understand the needs of members of the public and CBOs, the Commission applied for a Rocky Mountain Institute eLab Accelerator called Forge. This program was two and a half days of intensive, facilitated conversation with participants in the SB 978 process. Our goal was to better understand what elements of the Commission’s process form a barrier to entry and also provide opportunities for participants to better understand the types of processes the Commission utilizes and for what purposes. We are grateful to the organizations that took the time to travel to New York State to participate in the Forge process.

Beyond the Forge process, SB 978 participants took time to educate the Commission on their perspectives on participation in Commission processes. Things we learned during the SB 978 process include:

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structure of the regionalized CAISO board should be and how states will be represented in decisions made by the regionalized CAISO.


1. Some members of the public and communities have been historically marginalized and their perspectives have not been represented in the Commission process. This marginalization has happened for a number of reasons, including educational, process, and capacity barriers. These groups should be enabled to meaningfully participate in Commission processes. Such participation will better inform and provide a greater diversity of perspectives on matters before the Commission.

2. Some Commission cases, also known as dockets, can require complex technical and legal processes, especially when matters of fact are in dispute, property rights are involved, and high costs to ratepayers are anticipated. In these contested case proceedings, parties that wish to participate must petition to intervene and provide reasons of their interest in the case to the Administrative Law Judge; such petitions are typically granted. Contested Case proceedings determine the rights of individual parties and frequently involve highly technical and legally complex issues. As a result, they often require the exchange of evidence though discovery, submission of expert witness testimony, cross-examination hearings to test the veracity of witness testimony, and legal briefing when legal disputes arise. Other Commission processes, such as regular Public Meetings and rulemaking dockets, are more informal and the barriers to participation are lower, however, barriers may still exist even in these informal processes. One significant barrier identified is an understanding of the required Commission processes, how stakeholders can engage, how they can be informed about upcoming proceedings, and which proceedings would be most appropriate and impactful for them to engage in.

3. When issues have been deemed of significant interest to the public, the Commission has hosted public comment hearings or “listening sessions” in the communities impacted by these decisions. This approach allows community members an opportunity to voice concerns in front of the Commission without engaging in a complex regulatory proceeding. However, stakeholders note that how the Commission makes the decision on when and where to hold these meetings, as well as whether the Commission can consider the input from these public meetings in its decision-making, is unclear.

4. Developing educational materials and opportunities for participation is an important piece of increasing open access to the Commission process.

5. Engagement in the Commission process is beneficial, however, members of the public and new stakeholders need to understand how their comments and input will be considered as part of the regulatory process in order for it to meet the requirements of being fully inclusive.

Members of the public, new stakeholders, and community-based organizations should play a key role in the design and creation of the energy system that leads us into the future. However, there can be barriers to participation in public process and legal limitations to removing these barriers in contested case processes. The Commission also acknowledges that a targeted approach to engaging and meaningfully involving low income, environmental justice, and other historically marginalized
communities in decision-making processes would provide a more complete set of perspectives for consideration.

Further, the PUC understands that enabling broader participation will not only benefit members of community based organizations and members of the public, but third party technology providers, advocacy organizations, and others will find engagement in the Commission’s process easier as well. The PUC draws a distinction between participation in public processes and procedural inclusion. Here we reference the Urban Sustainability Directors Network definition of procedural inclusion which indicates that processes are inclusive, accessible and there is authentic engagement and representation in the process to develop programs or policies. With our recommendations we aim to create an environment of procedural inclusion.

- Next steps

The PUC commits to continue working with stakeholders to understand and develop opportunities for greater procedural inclusion and education. As previously discussed, SB 420 requires the Commission to enable the public to access its process in dockets that involve environmental justice issues. It also required the creation of a Citizen Advocate position within each of the impacted natural resource agencies. The Commission utilizes its Citizen Advocate position to engage in matters with the Environmental Justice Task Force as well as provide information to the public, however, with an increased focus on participation, the Commission recognizes utilizing this position differently may be warranted.

We commit to developing a strategy for engagement that we will carry forward beyond the SB 978 process, to create tools on our website that lead to a greater understanding of the Commission’s role and processes, enhance our Citizen Advocate position, and community-based organizations to assist them in navigating the Commission’s processes.

V. Summary of Recommendations and Actions

SB 978 is neither the beginning, nor the end, of the conversation about how the electric regulatory system will adapt to today’s industry trends and policy objectives. We have already begun that adaptation, and the SB 978 process provided the Commission and stakeholders a framework for broader dialogue around emerging system objectives and regulatory tools.

We make two major recommendations to the Legislature, reflecting the concerns that captured the most focus and the broadest support from participants in the SB 978 process:

- Climate change is an area of critical concern for many of our stakeholders and SB 978 participants, and the Legislature should consider their diverse perspectives on how the Legislature can expand the Commission’s authority to regulate greenhouse gas emissions.

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• The regulated electric system provides strong guarantees of nondiscriminatory, cost-based access to service for everyone, but many believe the Commission should have greater legislative authority to promote service that is **equitable and affordable** for all customers.

This report commits the Commission to focus action in the following areas:

• **Customer choice:** Continue to improve the Commission’s regulatory tools to value system costs and benefits of customer and competitive resources, which enables customer and competitive opportunities to expand in alignment with legislative goals and the overall strength and efficiency of the utility system.

• **Utility incentive alignment:** With deliberation and careful design, explore performance-based ratemaking and other regulatory tools to more clearly align utility financial incentives with customer goals, industry trends, and legislative objectives.

• **Regional market development:** Cooperate with other states to explore effective development of an organized regional market to enable competition, deliver least-cost solutions, and mitigate risks to Oregon customers.

• **Participation:** Develop a strategy for engagement and inclusion in PUC processes that will carry forward beyond the SB 978 process.

The PUC stands ready to use the powerful tools of economic regulation—traditional and evolving—to help achieve the public policy objectives the Legislature deems most significant today.
Appendix A: SB 978 Public Process

SB 978 Public Process

SB 978 required the Commission to establish a public process to investigate how developing industry trends, technologies, and policy drivers may be impacting the existing electricity regulatory system. Given the magnitude of examining our regulatory system, the Commission understood the importance of managing this process very differently than previous investigations hosted by the Commission. The Commission, which is an agency that has a very well-established process and approach to investigations, wanted to consider how to approach SB 978 differently and create a new, innovative path to cooperation with our stakeholders. The Commission understood that it would be important to ensure that stakeholders could work collaboratively together to help recommend solutions that would lead to constructive discussions from stakeholders even on topics which had recently created strife in our stakeholder community.

The traditional Commission process can at times it can be adversarial, where parties can be in opposition with one another. Recent significant cases and decisions that have come before the Commission have left stakeholder groups at odds with one another over some of the key issues we would investigate as part of SB 978. Those issues included competition, distributed energy resources, customer choice, and resource procurement. Also, there were new participants and stakeholders who had indicated an interest in participating in the Commission’s process. How to integrate their voices in the process and ensure their full participation was an important goal established early in our process. In order to develop as comprehensive approach as possible for the different stakeholder needs the Commission’s first step was to develop an internal project management team, whose task was to develop a process which would enable participation from a wide-variety of individuals and stakeholders and ensure participant collaboration was a key element leading to the outcomes developed at the end of the process.

Development of the Public Process

The SB 978 internal project management team included members of our Utility Division Staff (Elaine Prause, Jason Eisdorfer, and Julie Peacock), the Department of Justice (Kaylie Klein) and Administrative Hearings (Mike Grant) and was led by a Commissioner (Megan Decker). This internal planning team determined that in order to have a holistic review of the system, the Commission would need to engage stakeholders early in the process to have a better understanding of in their own terms, what elements a comprehensive and open process would include.

The planning team interviewed more than 20 sets of stakeholders and individuals to gain a better understanding of what was desired from the SB 978 process. Feedback from stakeholders included:

Ensuring new stakeholders and participants would be able to engage in the process by making it more approachable than the typical Commission docket process

Developing some capacity building aspects of the process to ensure a level starting point for discussions about changes
Ensuring the process timeline was clear to participants in the beginning, including number of meetings and timeline to completion

Utilization of third-party resources to assist the Commission in making the conversation more neutral and providing external expertise

In response to the stakeholder interviews the Commission developed an internal work plan which included strategies for integrating the feedback from participants and stakeholders. The first element was to consider external funding and the ability to utilize consultants to facilitate the meetings and provide the Commission with external expertise.

The Regulatory Assistance Project (RAP) was an invaluable partner in this process. They assisted us in locating and applying for funding from The Energy Foundation, which allowed us to utilize their services and the services of the Rocky Mountain Institute (RMI). RAP acted as a technical advisor to the Commission, providing a national perspective on trends and investigatory processes in other states. RMI acted as a third-party facilitator, designing creative agendas and meeting structures which would enable the participation of a wide-variety of participants. We are grateful for the assistance and help provided by these organizations, which we found to be invaluable in designing a process which was innovative and approachable.

Together with RAP and RMI, the internal planning team designed a six meeting process. These meetings are described briefly below.

**SB 978 Meetings Structure**

The meetings were broken into three phases, the first phase was an examination of the existing energy and regulatory systems; the second, was an investigation of the policy and technology trends driving the sector; and the third was to identify potential changes. The Commission began its process with an introductory welcome meeting in January which set the stage for the overall process.

**January** - the design of the January was provide an initial understanding of how the Commission was planning to proceed with the 978 process. It also functioned to provide opportunities for stakeholders to share initial thoughts around high-level goals and principles that they believed should guide regulation in the electric sector today. In advance of the meeting we provided stakeholders with reading materials which would 1.) Give a brief background on the efforts happening in other states 2.) A list of questions to give stakeholders a broad overview of questions others have asked and 3.) A general framework of what traditional cost of service regulation includes.

**February** - This meeting focused on a discussion of the existing energy and regulatory system, with a focus on hearing stakeholder perspectives on the structure of the existing system. RAP provided a framing paper, “Basics of Traditional Utility Regulation and the Oregon Context,” in which it described the traditional utility regulatory structure as well as a brief overview of Oregon specific context. The purpose of the framing paper was to provide participants a foundation for discussion of the existing regulatory system. At the February meeting, participants self-selected into the following groups: customer and customer representatives, generation and service providers, utilities, environmental concerns, equity and environmental justice, and Public Utility Commission staff. These groups worked together between the February and March meetings to develop presentations for the Commission
answering questions on their perspectives on the existing system. These presentations can be accessed here: [https://www.puc.state.or.us.Pages/MarchMeetingPrep.aspx](https://www.puc.state.or.us.Pages/MarchMeetingPrep.aspx)

**March** - The self-selected groups identified above gave presentations on their perspectives on the existing system and how it is operating. (Those presentations are available here: [https://www.puc.state.or.us.Pages/MarchMeetingPrep.aspx](https://www.puc.state.or.us.Pages/MarchMeetingPrep.aspx)). Participants were also given an opportunity to provide comments the Commission on the existing system, responding to specific questions the Commission had about how the current construct was working.

<table>
<thead>
<tr>
<th>January</th>
<th>February</th>
<th>March</th>
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| Activities:  
- Process Plan announced to stakeholders early Jan.  
- First external meeting, Jan. 30  
- Engage a facilitator and external expertise  
| Activities:  
- Engage stakeholders for presentations at the second external meeting  
- Develop framing paper or presentation for distribution prior to meeting  
- Second stakeholder meeting, Feb. 22 with an education focus on the topic of “Investigation of the existing energy and regulatory system”  
| Activities:  
- Third external meeting with a focus on facilitated stakeholder conversation around “Investigation of the existing energy and regulatory system”  
- After third meeting, staff will develop an outline and notes of meeting and distribute to stakeholders  
- Evaluate whether subgroups would be helpful at this phase in the project  
| Milestone: Develop an understanding of the process with stakeholders  
| Milestones: Development of framing paper, second external meeting and guiding principles  
| Milestone: Allow opportunity for stakeholder comments on investigation to date  

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<th>April</th>
<th>May</th>
<th>June</th>
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| Activities:  
- Fourth stakeholder meeting, with an education focus on the topic “Investigation of policy and technology trends” and general identification of trends  
- Report out from any subgroups that developed as a result of meeting three  
- Request that stakeholders file comments on trends  
| Activities:  
- Aggregation of any comments as a result of the previous meeting and distribution to stakeholders  
- Fifth stakeholder meeting, with a focus on facilitated stakeholder conversation on “Investigation of the policy and technology trends”  
| Activities:  
- Development of a framing document or presentation on potential changes to be distributed prior to the sixth meeting  
- Sixth stakeholder meeting, with a focus on identifying potential changes  
| Milestone: May request stakeholders file comments on trends and public policy objectives with views on how they impact the existing regulatory system  
| Milestone: Allow opportunity for stakeholder comments on investigation to date  
| Milestone: Development of a framing document for June meeting  

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<th>July</th>
<th>August</th>
<th>September</th>
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| Activities:  
- Optional seventh meeting  
- Finalize development of draft report for distribution to stakeholders in late July  
| Activities:  
- Stakeholder comments on draft report due  
- PUC will begin finalizing report  
| Activities:  
- File final report with the Legislature  
| Milestone: Distribution of draft report in late July  
| Milestone: Stakeholder comments due  
| Milestone: Submittal of final report to the Legislature by Sept. 15  

<table>
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<tr>
<th>Identify Potential Changes</th>
<th>Final Report Preparation</th>
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29
April- this meeting focused on an investigation into policy and technology trends in the regulated electricity sector. RAP provided a framing paper to aid in the conversation called “Trends in Technology and Policy with Implications for Utility Regulation”. This framing paper has been provided as Appendix D in this report. The Commission also invited several national experts in technology trends to provide presentations at the meeting. These presentations included information from the NW Power Council, Pacific Northwest National Labs, Energy Innovation, Utopus Insights, Pacific Gas and Electric, and Energy Sage. Also during the day policy makers presented on the emerging policy trends they see impacted the regulated utility sector, these presenters included Sen. Lee Beyer (District 6), Rep. Ken Helm (District 34), and Milwaukie Mayor Mark Gamba.

At the end of this meeting participants again self-selected into groups to work on a collaborative activity. These groups included economic efficiency, customer choice, low-carbon future, and access. The groups were developed in response to the major emerging themes from the stakeholder meetings and the assignment provided participants and opportunity to work between meetings to develop memos to presentation to the Commission in May. These memos have been provided as Appendixes E-1, E-2, E-3, and E-4.

May- This meeting focused on further investigating policy and technology trends, by utilizing the memos and presentations created by our participants between the April and May meetings. Participants had the opportunity to develop a short presentation to the Commission, responding to these main questions:

- **Group 1: Economic Efficiency**: Do our existing incentives lead to the most economically efficient outcomes? If not, how do we incentivize the most economically efficient outcomes?
- **Group 2: Customer Choice**: How do we balance customer options and access to market and technology choice in a socialized system?
- **Group 3: Low Carbon Future**: How can the regulated utility sector contribute to the transition to a lower carbon future? What is the role of regulators in decarbonization?
- **Group 4: Access**: Is electricity an essential service to society, and if so, how does regulation ensure affordability and reliability for all customers going forward?

June- at its final collaboratively structured meeting, the Commission provided stakeholders with a memo which summarized its understanding of participants’ perspectives in the SB 978 process to date (Appendix G) as well as six short memos from RAP which were used to form the starting point of conversations in the final meeting. These six memos focused on industry structure, low carbon policies, retail choices, distributed energy resources, utility incentives, and equity. They were designed to create conversation amongst participants leading into the final meeting. At the conclusion of this meeting participants engaged in a prioritization exercise which highlighted which areas of action seemed to have the most consensus and interest from stakeholders on. After the June meeting, participants were given the opportunity to file comments for the Commission to consider as part of writing its report.

July- this meeting provided stakeholders with an opportunity to comment on their priority items for the SB 978 report, including what recommendations they felt would be important to include.
Appendix B: History of the Physical and Regulatory System

History and the Basics of the Physical System

The existing physical system is based on an interconnected system of transmission, distribution and generation. In some cases, generation are owned and operated by entities that are not responsible for providing service to end use customers. In addition, sometimes generation must cross multiple jurisdictions prior to reaching its end use. This section briefly describes utility service territory, the interconnected electric system, and the role of reliability organizations and balancing authorities.

IOU service territories

The Commission regulates three investor-owned electric utilities (IOUs) (Portland General Electric, PacifiCorp, doing business as, Pacific Power, and Idaho Power), three investor-owned natural gas utilities (Northwest Natural Gas Company, Avista Corporation, and Cascade Natural Gas Company) more than 350 telecom companies, and about 80 small water companies. SB 978 asks the Commission investigate trends in the electricity sector, narrowing the scope of the discussion to the companies, customers, and regions listed in the table below.

Table 1. 2016 Electric IOU Statistics

<table>
<thead>
<tr>
<th>Company</th>
<th>Number of Oregon Customers</th>
<th>% of Oregon Customers Served</th>
<th>% of Total Company customers in OR</th>
<th>Annual revenues ($million)</th>
<th>Annual retail sales (MWa)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Idaho Power</td>
<td>18,848</td>
<td>1%</td>
<td>&lt;5%</td>
<td>$53</td>
<td>76</td>
</tr>
<tr>
<td>PacifiCorp</td>
<td>574,131</td>
<td>29%</td>
<td>~25%</td>
<td>$1,275</td>
<td>1,469</td>
</tr>
<tr>
<td>Portland General Electric</td>
<td>859,396</td>
<td>44%</td>
<td>100%</td>
<td>$1,704</td>
<td>1,969</td>
</tr>
<tr>
<td>TOTAL</td>
<td>1,452,375</td>
<td>74%</td>
<td>NA</td>
<td>$3,032</td>
<td>3,514</td>
</tr>
</tbody>
</table>

Each utility service territory varies and is a mix of customer density (urban vs rural), age of transmission and delivery infrastructure, generation resource portfolio, customer demographics, geography, and regional economics. This diversity across and within utility territories leads to very different day to day operational issues and considerations, but the overall scope and basic practice of Commission regulation is consistent across all three utilities.

The Interconnected Electrical System

All utilities in the state’s utilities are “vertically integrated” meaning they own (or can own) and generate or directly contract for all the energy they deliver to their customers through their transmission and distribution system. Transmission can be utility owned or contracted from another party but delivery of energy services to the end use customer site is through utility-owned distribution system.

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23 Oregon Utility Statistics Book, 2016  [https://www.puc.state.or.us/Pages/Oregon_Utility_Statistics_Book.aspx](https://www.puc.state.or.us/Pages/Oregon_Utility_Statistics_Book.aspx)
Individual utility operations and investments have impacts on the reliability of the regional grid and therefore how they make daily and long term decisions is greatly influenced by the larger system requirements within which they operate.

Oregon utilities are located within the Western Interconnect, one of three independently operating grid systems in the US where all the connected electricity is “synchronized” to the same frequency. This network of generation, transmission, and distribution lines is the interconnected physical system across which power is constantly flowing. The management of the system is done through Balancing Authorities which are mostly electric utilities which are required to ensure that their system supply and demand are balanced at all times. PacifiCorp’s system is managed through two balancing authorities, PAC-East and PACE-West, while PGE and Idaho Power operate as single balancing authorities. Without this balance of supply and demand, local and widespread blackouts can occur.

The National Electric Reliability Council (NERC) enforces reliability standards for all balancing authorities through the Western Electricity Coordinating Council (WECC) and its coordination of reliability, short- and long-term planning of operations. While other regions in the US has Independent System Operators (ISOs) or Regional Transmission Operators (RTOs) to control and monitor the grid as wholesale market operators, in the Northwest, wholesale sales are transacted bilaterally through direct party negotiations via brokers. In 2014, the California ISO created a real time market, the Energy Imbalance Market (EIM), which has expanded throughout the west in the last several years. All three electric IOUs operating in Oregon are members of the EIM and have reported net benefits since joining. Each hour, they nominate owned generation resources to the real-time market for regional system balancing while maintaining control and responsibility for balancing their own systems.

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26 [https://www.westerneim.com/Pages/About/default.aspx](https://www.westerneim.com/Pages/About/default.aspx)
History and the Basics of the Regulatory System

In the last decades of the 19th Century, when the electricity industry was beginning to develop, economic realities and public policy goals influenced how electric utility regulation would evolve over the next 100 years. Economically, it was clear that multiple companies competing to provide distribution services to a neighborhood would result in an inefficient and dangerous jumble of redundant distribution lines. The substantial amount of capital necessary to develop the costly electricity-generating units and transmission lines tended to favor large single investors who could raise capital at lower cost rather than multiple small providers competing to make investments for new and uncertain customer needs. These economic realities led to the conclusion that a single, vertically integrated provider could deliver lower cost electricity to customers more reliably than multiple competing providers.

At the same time, the public began to utilize electricity both for home and business on a rapidly increasing basis. Electricity was increasingly becoming vital to all aspects of society from the larger economy to the smallest household because of its versatile role in economic development and everyday comfort. As a result of this, policy makers determined that electricity had become an essential service affected with the public interest,” concluding that electricity service should expand to all reaches of the country, that it be safe and reliable, that it must be, and must be offered to everyone in a nondiscriminatory manner.

As the industry developed into large, single-provider systems, it became necessary to protect society from unfair practices by these new large companies. As a result, federal and state governments quickly introduced regulation in order to ensure that the public had safe, reliable, and non-discriminatory access to this essential service at reasonable rates when no competition existed to discipline the market.

Modern utility regulation was born with the concept of the “regulatory compact” as an implicit agreement between government and any for-profit utility allowing the utility to operate as a protected monopoly in a geographic service area in exchange for consenting to be regulated by governmental entities. The utility was required to serve anyone located within its exclusive service territory in a manner that was safe, reliable, nondiscriminatory, and fairly priced. In exchange, the utility was allowed to collect in its rates all reasonable operating expenses and all prudent capital investments, with an opportunity to earn a set rate of return on the capital investments it made in the electricity system.

Given the early policies of affordable universal electricity service, the regulatory structure was designed to encourage utility investors (shareholders) to invest large amounts of capital in the electricity system. This was necessary to ensure that enough generation was built to serve the growing electrical loads of customers, and to build a distribution system that was reliable and accommodated new customers safely and efficiently. State utility regulators developed regulatory tools and mechanisms to support financial incentives for utility shareholders to invest in the electrical system, while at the same time protecting captive customers from over-investment that would lead to higher-than-necessary rates. The goal was to achieve an economically efficient electricity system that served the needs of individual customers and a growing economy.

Basic Regulatory Structure
The regulation of rates for the purpose of promoting the health, comfort, safety and welfare of society is an exercise of the police power of the state. The regulation of public utilities and the fixing of rates constitutes a legislative function and the Oregon legislature has granted the Public Utility Commission the broadest authority to exercise this function. The authority conferred upon the PUC is described in its statutes, with the legislature charging the PUC with the responsibility to represent utility ratepayers and the public generally in all controversies respecting rates, valuations, service and all matters the PUC has jurisdiction over and to protect ratepayers from unjust and unreasonable rates. To ensure that customers have access to safe, reliable, and high quality service at reasonable rates, the PUC has authority to determine rates, promulgate customer protection rules, and oversee distribution system safety, among other regulatory activities. However, the PUC's authority is limited by the scope granted to it by the Legislature and by the state and federal constitutions. As a result, the Commission cannot take actions or require the utilities to take measures which are outside the scope of its statutory authority.

Utility regulation utilizes a system of incentives designed to promote specific positive customer outcomes or policy objectives. Most of these incentive mechanisms are designed to affect the behavior and performance of utility management and its shareholders, however some incentives, such as rate design, are designed to impact the behavior of the end use customer. The regulatory incentive mechanisms that encouraged the utility to grow the electrical system to ensure that all new load is served have been highly successful in achieving that policy objective. However, no incentive mechanism is perfect, especially in an increasingly complex system, or as preferred societal outcomes change and evolve. For example, the incentive for the utility to invest capital in the electrical system as a way to earn a return on its investment may also cause shareholders to seek to solve all problems or new state policy goals with more capital investment, rather than exploring less capital intensive alternatives. Over time, new regulatory mechanisms were developed and implemented, while existing mechanisms evolved, to reduce unintended consequences of incentives without disrupting the core function of utility regulation.

Today, there are several key mechanisms that underpin the regulatory objective of an efficient and reliable system with fair rates. We explore some of the mechanisms below as examples of the core regulatory incentives and additional tools used to adjust for unintended effects of those incentives. These mechanisms include the ability to set rates, decoupling, integrated resource planning, power cost adjustment, and deferred accounting to name a few. This section will review how these mechanisms have traditionally worked.

Ratemaking and the Revenue Requirement

The utility business model is designed around the concept of the annual “revenue requirement,” which is the forecasted amount of annual revenue necessary to cover operating expenses and capital investments, and earn a reasonable return on capital investments. The basic formula for the revenue requirement is as follows:

\[
\text{Revenue Requirement} = \text{Operating Expenses} + \text{Capital Investments} + \text{Reasonable Return on Capital Investments}
\]

27 City of Woodburn v. Public Service Commission, 82 Or. 114, 1916.
29 ORS 756.040.
Revenue Requirement = Operating Expenses + (Rate Base x Rate of Return)

While reasonable operating expenses are recoverable from customers without a return on those expenses, the utility does have the opportunity to earn a return on its capital investments (rate base). As a result, the utility is incentivized to maintain steady investments in the utility system.

When a utility projects that its costs are growing beyond existing Commission-approved rates, or if the utility has a new capital asset serving customers that it wants to put into rates, it will file a rate case with the PUC. The utility will propose new rates by establishing a “test year” based on forecasted loads, expenses, capital additions, and known and measurable changes from existing rates. In the end, the utility is attempting to raise its annual revenue requirement to more accurately match the cost of providing service to its customers.

In practice, because the customer is cannot choose another service provider and the utility is not subject to market competition, the regulator must design appropriate incentives akin to those found in a competitive market to align the behavior and performance of the utility with the interests of utility customers and applicable state policies. In rates cases, the Commission verifies, and in most cases reduces, the utility’s cost assumptions that produce the proposed revenue requirement included in the rate case filing. This approximately nine-month review of assumptions is performed by PUC expert staff and stakeholders within the general rate case proceeding, or other ratemaking processes, prior to the Commission’s order determining the allowable customer rates. The regulatory staff and other organizations representing utility customers will analyze the utility’s load forecast to make sure the need for new capital investment is not inflated and question the proposed operating expense levels to avoid over-collection.

Staff and the parties will question the prudence of new capital additions and determine the appropriate amount to allow into rate base. In a prudence determination, the parties are looking at whether the particular investment was reasonable given what is known at the time and is reasonably expected to benefit the ratepayer. Costs of investments not found to be prudent run the risk of not being recovered in rates. This is a form of a cost-benefit analysis which measures the relative cost of an investment against the range of benefits that will accrue to the customer. This is a recurring theme in regulation, although the form of the cost-benefit analysis might differ according to the investment, as with energy efficiency for example.

A key element of the rate case investigation is the determination of the proposed rate of return that a utility will earn on its capital investment in rate base. This rate of return is the incentive to the utility to invest capital, but it must be measured by the degree of risk to which the capital is exposed. In practical terms, the rate of return must be high enough to create an incentive to invest but not so high as to cause customers to overcompensate the investor beyond comparable risks in other industry sectors.

30 Ratebase is the remaining undepreciated book value of capital investments made to provide service, inclusive of other limited components such as working capital.
Once a revenue requirement is established, costs are allocated to customer classes based primarily on cost causality. Finally rates are designed for each class of customers to promote the efficient use of electricity.

The Commission will weigh the evidence on the record and issue an order establishing rates until the next rate case. If the utility can find operational efficiencies between rate cases or if load grows beyond the assumed forecast, it generally can retain that value until the next rate case. This promotes innovative efficiencies between rate cases, but also creates an incentive to increase the amount of energy sold to customers.

This basic model of incentive regulation has been successful in creating robust utility systems where all load growth is served and outages are very rare. However, the system also rewards the utility for load growth and asset-based solutions to customer needs. In addition, because only prudent investments are recoverable, the utility tends to be risk-averse and invest in known technologies with lower risks.

Decoupling

Decoupling is designed to “decouple,” or “disconnect,” utility profits from the volume of energy it sells. This is because tying a utility's profits to the amount of energy sold creates a disincentive for the utility to invest in programs that reduce customer usage (sales volumes) such as energy efficiency or distributed generation. The decoupling goal is to make utilities indifferent to sales volumes. In a 1992 order, the Commission concluded that “decoupling - severing of the link between sales and profits - is necessary to fully achieve the goal of encouraging utilities to acquire all cost-effective demand-side resources.” Less than ten years later, the Energy Trust of Oregon was created to acquire all cost effective energy efficiency on behalf of electric utility customers, effectively removing the concern of misaligned utility motivation for acquiring energy efficiency.

Integrated Resource Planning

In the 1980s, the Commission adopted one of the most significant non-ratemaking regulatory mechanisms: integrated resource planning. Integrated resource planning requires in-depth consideration of all known resources for meeting the utility’s forecasted load. In an integrated resource plan (IRP), the utility assesses system needs over a 20-year period and proposes an Action Plan over a two- to four-year period that demonstrates the least cost/least risk manner of serving expected load and meeting public policy goals. Per PUC guidelines, the utility must consider generation, transmission and demand-side resources (energy efficiency, demand response, etc.) on a comparable basis. Both costs and risks are analyzed. Risks that are routinely examined include natural gas cost volatility, changes in load, and the cost of future environmental regulation, including potential carbon regulation.

The utility files an IRP within two years of its previous acknowledgement order and provides an annual update on the most recently acknowledged plan. Utilities seek to have the IRP “acknowledged” by the Commission, meaning the plan becomes a working document that can be referenced by the utility, the Commission, and the public in the prudence review stage of cost recovery in a rate case. However,

31 Docket No. UM 180, Order No. 89-507 at 1 (Or. P.U.C. Apr. 20, 1989) (adopting Least-Cost Planning (LCP) for all energy utilities in Oregon).
32 Docket No. UM 1056, Order Nos. 07-002 (Or. P.U.C. Jan. 8, 2007) and 07-047 (Or. P.U.C. Feb. 9, 2007) (correcting an inadvertent omission in 07-002). For additional refinements to the process, see Order Nos. 08-339 and 12-013.
acknowledgement does not guarantee that a utility will be able to include in rates the costs associated with the new resources proposed in their IRP. Through the IRP process, the Commission has required utilities to identify and justify reasonable least cost and least risk resource portfolios in a transparent manner. The details of implementing the plans in a prudent manner are evaluated in rate cases.

Special Treatment for Power Costs

Electric and gas utilities are permitted to recover their reasonably-incurred costs of service, including power costs, based on certain forecasts and projections. This process enables utilities to adjust rates every year to account for changes in energy markets or shifts in load forecasts in the coming year. A “true-up” process takes place every year where the actual power costs incurred to serve load are examined relative to the forecasted amount and the amount the utility collected from customer rates. Earnings that are significantly greater or less than what was projected are either shared with ratepayers (when the utility took in more than projected) or recovered from ratepayers (when the utility took in less than projected) based on previously agreed upon sharing bands.

Evolving Public Policy

The basic regulatory paradigm for investor-owned utilities remained largely intact through the 1990s when new policy goals related to market competition and environmental impacts of generation began to emerge and challenge the regulated monopoly business model. As generation technology evolved, the emergence of natural gas-fired generation with a smaller footprint and lower capital costs raised the possibility of non-utility generators to provide power. At the same time, some customers began to question whether they should be captive to a utility when there were developing alternative energy providers and renewable options. The desire to leave the utility to be served by another provider is complicated by the regulatory policy of the last 100 years where system costs have largely been socialized over all ratepayers. Attempts to leave the system necessitates contemplating how to allocate costs fairly among those who depart and those who stay with the utility.

The Oregon Legislature has addressed these and other policy developments through several major pieces of legislation since 1999. These major developments are described below.

SB 1149 (1999): created three significant changes in the energy system related to for-profit utilities (or investor-owned utilities). First, it partially deregulated electricity generation, allowing large commercial and industrial customers to purchase their electricity from an electricity service supplier rather than through the utility. The second was to create a public purpose charge which would be used to fund energy efficiency and market transformation, renewable energy, and low-income weatherization. The third was to require the IOUs to offer to residential and commercial customers a series of rate options with more renewable energy. In addition, SB 1149 started a ratepayer-funded low-income assistance fund.

Direct Access: SB 1149 did not fully restructure the industry, but gave customers more options from which to purchase their energy. All non-residential customers may purchase power from their current utility under a regulated cost-of-service rate or may opt for direct access through an Electricity Service Supplier (ESS) who would provide energy services at a rate negotiated by the ESS and the customer. Large non-residential customers that opt to switch to direct access must complete the requisite opt-out
procedures, including paying a transition charge or credits to the utility to compensate for the impacts to the utility’s system.

**Public Purpose Charge:** under SB 1149, Portland General Electric (PGE) and PacifiCorp were required to collect a three percent “public purpose charge” from their customers to be used to fund conservation in schools, cost-effective energy efficiency, energy efficiency market transformation efforts, above-market costs of new renewable energy resources, and low-income weatherization. This provision also allowed the PUC to choose a non-governmental entity to serve as the agent to acquire the energy efficiency and the renewable energy rather than relying on the utility. Subsequent to the passage of SB 1149, the Energy Trust of Oregon (Energy Trust), an independent, third-party nonprofit, was created to serve as the administrator of the public purpose funds related to energy efficiency and renewable energy. In 2003, NW Natural Gas and Cascade Natural Gas in 2007, asked Energy Trust to offer comparable services to their customers. Most recently, in 2017, Energy Trust began providing services for Avista Corporation in Oregon.

**Portfolio of Options:** PGE and Pacific Power were required to offer their customers a “portfolio of options” including a market-based rate and one which includes significant new renewable energy. The Legislature provided these options to customers who desired more choice in lieu of deregulating residential and small commercial customer service. The Commission also created an advisory group called the Portfolio Options Committee whose job it is to annually review the offerings of the utility’s and make recommendations for changes to the Commission.

**SB 838 (2007):** created two significant changes in the energy system. First, it created the state’s renewable portfolio standard and, second, it clarified that the PUC could require investment in all cost-effective energy efficiency.

**Renewable Portfolio Standard and Automatic Adjustment Clause**

SB 838 established the Oregon Renewable Portfolio Standard (RPS), which required all Oregon electric utilities to deliver a percentage of their electricity from renewable resources by 2025. SB 838 also included authority to establish a renewable resource automatic adjustment clause. This adjustment clause is unique amongst ratemaking mechanisms because it allows utilities to pass-through the cost of acquiring RPS-compliant renewable resources to ratepayers without filing a request for a general rate case, but subject to Commission review and approval. This alternative ratemaking mechanism allows the utilities to avoid regulatory lag and overcome the policy against single-issue ratemaking. The law includes customer protections in the form of a cost cap, where the utility no longer has to comply with the scheduled renewable acquisitions if the cost of compliance would raise revenue requirement four percent higher than it would have been without the RPS.

**Incremental Energy Efficiency Funding:** SB 838 also clarified that the PUC could require energy efficiency investments in rates above the public purpose charge instituted in SB 1149 if the PUC believed there was additional cost effective energy efficiency available. Large customers (greater than one average megawatt) were exempted so that they would not have to pay more than the public purpose charge but they also could not benefit from more energy efficiency at the customer site beyond what the public purpose charge would otherwise provide.

33 The RPS was amended by SB 1547 (2016) which will be described later.
**SB 1547 (2016):** SB 1547 created three significant changes to the utility system. The first was increasing the state’s RPS requirements. Second, it required the state’s investor-owned utilities to remove coal from the rates of Oregon customers. Third, it created a community solar program. It also required the state’s investor-owned utilities to file transportation electrification programs with the Commission.

**Amended Renewable Portfolio Standard:** SB 1547 increased the state’s RPS obligation for the largest, investor-owned utilities to 50 percent by 2040. It also eliminated the unlimited banking of renewable energy certificates, requiring that under certain conditions they no longer had unlimited life and would have to be retired five years after they were generated.

**Coal to Clean:** SB 1547 required electric companies to cease allocating electricity from coal-fired generating units to the rates of Oregon customers on or before January 1, 2030.34

**Community Solar Program:** SB 1547 required the Commission to adopt administrative rules to develop a community solar program. This program would allow customers to choose an energy provider, which could include an electric utility or be a third-party provider. The utility is still the provider of services to the customer and the customer must enter into a separate contract with the community solar provider. This represents the first time residential and small commercial customers could in effect choose an energy provider beyond the base resource mix of the utility without having to develop their own energy resource, i.e., distributed solar.

**Other Tools**

Beyond the significant omnibus energy bills noted above, the Commission has adjusted its regulatory incentives over time to respond to Legislative mandates and to the changing demands, trends, and needs of customers and the IOUs it regulates. Below we summarize the most significant changes to the structure of regulation and incentives.

**Competitive Bidding Guidelines**

Through its Competitive Bidding Guidelines,35 the Commission requires public utilities to conduct open competitive bidding when new power supply resources are needed that constitute a Major Resource acquisition, meaning for durations greater than five years and quantities greater than 100 MW. The utility is allowed to bid in the process, but it must treat all other bids fairly without preference for its own bid. A third-party, independent evaluator is employed in the process to ensure that the request for

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34 A similar restriction on nuclear power exists. The Energy Facility Siting Council cannot issue a site certificate for a nuclear-fueled thermal power plant until the federal government has established a repository for the disposal of high-level radioactive waste. Or. Rev. Stat. § 469.595. Further, even if the federal government establishes such a site, the Energy Facility Siting Council cannot issue a site certificate for a nuclear-fueled thermal power plant until such proposal is submitted to the electors of the state in a general election and the electors vote to approve the issuance of the certificate. Id. at § 469.597(1)-(2).

35 The Commission’s Competitive Bidding Guidelines were first adopted in 1991 and have been updated several times.
proposals (RFP) if fair, transparent, and competitive. Currently, the Commission is engaged in a rulemaking to update the guidelines and promulgate them through administrative rules.

**Greenhouse Gas Emissions Standard**

In 2009, the Oregon legislature passed the greenhouse gas emissions standard, which established new and more stringent greenhouse gas emission performance standards for power plants, essentially preventing the construction of new coal plants or the adoption of long-term coal contracts.36

**Energy Storage Mandate**

In 2015 the Legislature passed only the second energy storage mandate in the country, requiring PGE and Pacificorp to file plans with the commission to invest in energy storage up to one percent of 2014 peak load. This allowed the utilities and stakeholders to explore technologies and the costs and benefits of energy storage.

In reviewing these policy developments, we find that the current system incentives and requirements look much different from the regulated system prior to 1999—it currently allows for customer choice to certain degrees, promotes acquisition of all cost effective energy efficiency, requires a minimum level of renewable resource acquisition, and requires competition in the acquisition of major resources.

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36 For more information on the greenhouse gas emission standard, see ORS 757.524.