Policy Brief: The Role of Competition in the Pacific Northwest Clean Energy Transition

by Jason Eisdorfer, on behalf of the Northwest & Intermountain Power Producers Coalition

Executive Summary

Decarbonization of the electricity sector in the Northwest will spur the development of a new portfolio of clean energy generating resources which in turn will provide both economic opportunities and risks for end-use consumers. The challenges of decarbonization require new thinking and innovative approaches. During this transition, and given the opportunity, competitive wholesale and retail options can help mitigate retail energy costs, diversify risk for customers, spur clean energy technology innovation, and hasten the development of generating resources that do not emit greenhouse gases.

Recent experience confirms the existence of robust competitive alternatives to utility-owned power plants and utility services in the Northwest. Yet traditional regulatory models based on century-old societal goals reward utility ownership of generation assets, which gives the utility an incentive to build its way out of every problem instead of using non-capital-intensive solutions or using competitive nonutility resources. As societal goals have changed, the regulatory approaches in the Northwest still largely remain tied to the traditional approach that rewards utility ownership of assets.

Both the utility and its customers will be exposed to a range of risks as the utility tries to meet the challenge of moving faster to meet greenhouse gas emission-reduction mandates over a limited period of time with a more limited set of non-fossil fuel generation resource options to serve a load that will probably grow much faster as a result of electrifying other sectors, such as transportation. These risks range from very quick development of new renewable energy generation, cost overruns, overreliance on too few generation types, swiftly growing load from transportation electrification, and uncertain timing of resource acquisition to meet load needs.

Competition offers benefits that can reduce the utility customers’ exposure to these risks arising from the utility’s decisions and can offer certain customers the opportunity to by-pass the utility and take on the responsibility of choosing the generating resources and pricing that
best fits the customer’s needs. The benefits of competition include price benefits, a more efficient energy system, risk diversification, and the promotion of innovation and customer independence.

Regulators should be aware of both the values of competition and the existing regulatory constraints that hold back those benefits. Fresh thinking can discover alternatives to the traditional regulatory model that increase competitive options, protect vulnerable customers, and provide a platform for healthy utility roles in the decarbonization challenge.

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About NIPPC: The Northwest & Intermountain Power Producers Coalition (NIPPC) is a membership organization that represents competitive power participants in the Pacific Northwest and adjacent Intermountain region. NIPPC members include owners, operators, and developers of independent power generation and storage, power marketers, transmission developers, and affiliated companies.

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Introduction
Aggressive state greenhouse gas emission reduction policies and customer demands for clean energy are sparking a permanent transition in the way electricity will be produced and delivered in the Northwest. Decarbonization of the electricity sector will spur the development of a new portfolio of clean energy generating resources which in turn will provide both economic opportunities and risks for end-use consumers. Given the opportunity, competition in the electricity sector will play a pivotal role in accelerating the clean energy transition while reducing costs and diversifying risk to consumers.

Before the 1980s, customers and regulators traditionally depended on utilities to invest in resources to serve their needs. Since then, competition from non-utilities to invest in power plants and to serve customers directly has become an integral part of the electricity sector throughout the United States. In the Northwest, while competitive service from non-utilities is a viable option for regulators and some customers, incumbent investor-owned utilities (IOUs) still work to protect their position as primary service provider. However, the challenges of decarbonization require new thinking and innovative approaches that competitive wholesale and retail options can deliver. Independent power producers (IPPs) and marketers—who provide utilities or customers directly with clean energy—can be a critical part of the decarbonization effort. Electricity sector competition is a fundamental part of a decarbonization strategy because it can help mitigate retail energy costs, diversify risk, spur innovation, and hasten the development of generating resources that do not emit greenhouse gases (GHGs).

In Oregon and Washington, the legislatures and governors have made the states’ energy policy objectives clear. To mitigate the worst impacts of climate change, policy makers are acting to lower GHG emissions from electricity, transportation, and other sectors. Promoting competitive opportunities to decarbonize does not require tearing down existing utilities or retiring their basic business model, nor does it mean placing utility customers at risk. To the contrary, utilities can coexist in various forms with competitive forces that make them more agile and efficient, and competition can serve customers by diversifying their risk exposure and creating a path toward lower rates. Given equal opportunity, wholesale and retail competition can be an equal or superior method of decarbonizing the electricity system. In this Brief, we consider the benefits and origin of competition in the privately-owned Northwest electricity sector (also known as the regulated sector)², some obstacles that are dampening competitive opportunities.

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¹ The appendix of this Brief describes in some detail the legislative and regulatory history of market competition in Oregon and Washington.
² This Brief focuses on the private sector and will use the terms “utility” and IOU interchangeably. The Northwest also has one of the largest publicly-owned power sectors in the country. “Public power” refers to these consumer-owned electric utilities and infrastructure, including municipal utilities like Seattle City Light and Eugene Water and Electric Board, community-owned utilities like Snohomish Public Utility District, rural electric cooperatives like Umatilla Electric Cooperative, and the federal Bonneville Power Administration with its service obligation to those
(including an introduction to utility profits and electric rates), and the potential for competitive alternatives to accelerate regional decarbonization in a least cost and reliable manner. This Brief focuses above all on consumers and how competition, or a lack of competition, affects them.

**Historical Framework and Competitive Choices**

The basic framework of state regulation of the private electric utility has its origins 120 years ago. This framework assumed a vertically-integrated IOU, one that owns the distribution, transmission, and generation assets and that acts as a monopoly provider in an exclusive service territory. The primary policy objective over a century ago was to electrify the nation. Policy makers supported a utility business model based on an assumption that an IOU is granted a monopoly electric service territory and authorized to recover all its prudently incurred costs, including a reasonable return or profit on its investments. In exchange, the state regulatory commissions act as an economic regulator to ensure the utilities provide adequate service at fair, just, and reasonable prices. This monopoly utility business model was intended to both give the utility confidence in cost recovery and assure all customers were served. Utilities under the traditional regulatory model enjoyed both vertical market power because they owned all aspects of the supply chain and horizontal market power because they had no competitors serving their customers.

As policy objectives have changed and technology innovations emerged, many states transitioned to different regulatory models that discouraged or even disintegrated vertical integration as a way of introducing and encouraging market competitions in the electricity sector. In very general terms, there are two kinds of competition that can benefit the consumer: retail and wholesale competition. Retail competition refers to some or all customers being allowed to by-pass the incumbent utility to purchase energy products from non-utility third parties. Wholesale competition refers to the buying and selling of large blocks of power between generators, utilities, and power marketers who in turn sell power to the final retail end-user: a residence, commercial store, or factory, for example.

The value of wholesale competition is without question today. Federal and state policies that encourage non-utility electric generation and require equal access to transmission service have opened up a competitive dynamic that produces a number of important benefits. These benefits range from lower costs to the consumer, to diversifying risk among a greater number of publicly-owned utilities. Public power, in contrast to the privately-owned sector, has a cost-based model (as opposed to profit-based) and largely governs itself rather than being subject to an external regulator like a state utility commission.

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3 While not a focus of this Brief, the ability of all parties to use the transmission network, the electricity equivalent to the highway system, is a foundational requirement for a fair market. Federal law prohibits the owners of transmission lines from preventing third parties from moving power on those lines; they must provide “open access.”
of parties, to challenging the incumbent utility’s cost of service, to rewarding innovation in energy products. When a utility today wants to acquire a new generation resource, states, including Washington and Oregon, generally require the utility to run a competitive request for proposals (RFP), in which third-party independent power producers (IPPs) and the utility itself bid in potential resources, as a way to find the lowest cost and most appropriate resource.

Retail competition invites individual consumers to by-pass their utility and make energy service arrangements with third-party energy suppliers. These suppliers act as go-betweens for the customer and generators in the wholesale market. Both Washington and Oregon allow the largest customers of the IOUs, to a greater or lesser degree, to access third-party suppliers through a regulatory process. The utility commissions make sure that large customers leaving utility power service do not strand the utility’s remaining customers with inappropriate costs. The customers with retail choice can garner valuable benefits. These benefits range from lower costs to more reliable electricity service tailored to the customer’s needs, and can also help meet the customer’s sustainability goals by supplying them with lower GHG-emitting electricity than their utility provides. These customers continue to be “wires” customers of the utility and pay for the utility’s distribution and transmission network. They merely buy power from a third party.

The appendix of this Brief describes in some detail the legislative and regulatory history of market competition in Oregon and Washington.

The Utility Ownership Bias Problem

The traditional regulatory approach developed over a century ago was built around an intentional financial incentive to encourage the utility to build major transmission and generation components to further the societal goal of electrifying the country. This regulatory approach provides the utilities an economic incentive to invest, build, and own physical distribution, transmission, and generation assets because this is how they obtain a profit for their shareholders. In other words, the main way they make money is to make reasonable investments in electricity generation resources—putting steel owned by the utility in the ground. In contrast, they do not make money when they buy the same amount of power from non-utility independent power producers nor when their customers buy power from someone else.

As societal goals have changed and as some parts of the country have transitioned to more competitive regulatory models, the regulatory approaches in the Northwest still largely remain tied to the traditional approach that rewards utility ownership of assets. If there are

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4 In the power sector, retail competition is also known as “retail choice” and, in Oregon, as “direct access.” The suppliers of this service in Oregon are known as “electricity service suppliers.” Only large commercial and industrial customers, not residential customers, are eligible for retail choice in Oregon and Washington.
competitive alternatives, why is this utility incentive still prevalent in regional utility regulatory models? In this section, we explore this utility economic incentive to understand where it came from and how it impacts utility behavior.

**Vibrant Wholesale Competitive Alternatives**
Recent analysis confirms the existence of robust competitive alternatives to utility-owned power plants in the Northwest. The Northwest Energy Coalition recently analyzed the long-term plans ("integrated resource plans") and resource procurements (RFPs) by the six Northwest IOUs (Avista, Idaho Power Company, Northwestern, PacifiCorp, Portland General Electric, and Puget Sound Energy). The study found that the proposed resource costs are falling and that extremely vigorous bids far exceed the requested supply.\(^5\) PacifiCorp’s request for 4,300 MW of energy and capacity in 2020 resulted in over 36,000 MW of proposed bids. Similarly, in 2021, Puget Sound Energy’s issuance of a request for 3,200 MW of energy and capacity resulted in 18,000 MW of proposed bids. The vast majority of these bids were competitive non-utility resources.


Yet competitive non-utility resources historically haven’t enjoyed the same consideration as the utility-owned resources in the region’s RFPs. An analysis by NIPPC in 2014 found that seven of

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eight competitive IOU bids in RFPs in Oregon between 2008 and 2013 resulted in utility-built projects. While competitive bidding rules and their results have improved since 2014, this underlying utility-bias issue remains an issue in the region.

For example, analysis of RFP results indicates that of the competitive Oregon procurements completed (through contract finalization and construction) since 2014, 70% of the resulting resources were utility owned. PacifiCorp’s 2020 procurement, which required commercial operations by the end of 2024, may result in a departure from the historical pattern. The contract and construction status of the winning bids is not yet public (as of July 2022), but approximately 80% of shortlisted generating resources would be under third-party sales contracts. But the underlying incentives for utility ownership in the Northwest persist.

In recent RFPs, the utilities have included an option for a bidder to bid a “build-own transfer” option. This means that a non-utility bid winner will build a generating resource and ultimately transfer ownership to the utility. This kind of agreement reduces some risk to the utility and its customers concerning development uncertainties, but ultimately the utility still takes full ownership of the generating asset and can earn a profit on the asset. While this reduces some upfront risk to the customer, too many utility-owned resources creates a lack of resource portfolio diversity, increasing the customers’ risk burden. In recent years, these build-own transfer projects have represented a high percentage of the projects selected by the RFP for acquisition.

Finally, utilities in the Northwest are allowed to procure some resources outside of a competitive bidding process, under certain circumstances. This has resulted in major acquisitions of utility-owned resources, including, for example, PacifiCorp’s purchase of a 240-megawatt wind farm in 2019.

How Utility Rates Are Set
An understanding of how regulated utility rates are set helps illuminate why the obstacles for non-utility generation and retail service are so high in the Northwest.

A utility commission regulates many aspects of an IOU’s business activity. The utility commission regulates resource planning, energy efficiency, the issuance of securities, safety, quality of service, and other aspects of running the business. However, the primary task of the regulator is to set rates that protect the customer and allow the utility an opportunity to earn a return on its capital investment in large costly elements of the utility’s system. Economic regulation should provide the utility with the opportunity to earn a return commensurate with returns on investments in other enterprises having corresponding risks.

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6 NIPPC comments in Oregon PUC Docket UM 1771.
The utility earns a return on its investments in the following way. The utility will periodically file a rate case with the commission to reset rates. Through a multi-month process, which includes filed testimony, discovery of information, and legal process, the commission can establish a new “revenue requirement” for the utility. This revenue requirement is the amount of money, given certain assumptions, the utility can collect from ratepayers over the course of a single year. The revenue requirement stays the same until the next rate case.

The simplified version of the revenue requirement formula is:

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\text{Revenue requirement} = \text{expenses} + (\text{rate base} \times \text{rate of return})
\]

There is a lot baked into this simplified formula. For the purposes of this discussion, the two most important points are: first, reasonable expenses, such as salaries, office supplies, and electricity purchased from non-utility IPPs, are generally collected from customers on a dollar-for-dollar basis; and second, a rate of return (the source of the IOU’s profit margin) is applied to the amount of capital sitting in rate base. “Rate base” is the account in which the utility’s capital costs for large system assets sit. Very generally, this means that customers merely reimburse the utility for reasonable expenses, whereas customers both pay the utility back for capital spent on major construction projects AND pay a return on that deployed capital. This is a crucial point to understand what drives utility behavior in all traditionally regulated states, including Oregon and Washington.

The Fundamental Regulatory Problem
The rate of return applied to rate base is a very intentional policy decision. The rationale for applying a rate of return to capital investments a century ago was to create the incentive for the utility to attract capital to invest heavily in distribution, transmission, and generation assets. At the time, the primary policy objective nationwide was to electrify the country and to build a robust, reliable electricity system. Electricity was seen as essential for health and comfort at the residential level and as a bedrock of the commercial and industrial economy. Regulators therefore sent the signal to monopoly utilities that building more would generate more shareholder profits. To the extent the utility attempted to “gold plate” the system—to overbuild it—the utility commissions used their regulatory authority to identify assets that were not “prudently” acquired (prudency is the common legal standard in the sector) and would prohibit the utility from recovering the costs from ratepayers.

Economists in the twentieth century looking at the electricity sector re-examined the notion of guaranteeing a rate of return applied to capital investment. Two economists developed a theory later called the Averch Johnson Effect which described the utility bias from an economic rather than a policy perspective.\(^9\) The authors generally found that if the rate of return is higher

than the actual cost of capital, the utility will tend to build up the rate base to increase shareholder profits.

What this means is that the utility will tend to choose to build its way to serving consumers rather than select non-capital investment options like energy efficiency. Similarly, given a choice between owning a resource that can be rate based or buying energy from a competitive resource that is not rate based, the utility would prefer the former. This regulatory construct gives the utility an incentive to invest its way out of every problem instead of using non-capital-intensive solutions or using competitive non-utility resources.

To be fair, the theoretical underpinning of allowed return was an attempt to use regulation as a substitute for market competition. One could make an argument that this “rate of return applied to rate base” approach was a major catalyst for building a strong electric grid and, in turn, the 20th century U.S. economy that depended on electrification. In the first part of the 20th century, this incentive had the practical result of the IOUs playing a key role in constructing the modern power system.

But the policy drivers in the 2020s are very different than they were in the 1920s. As policy objectives have moved from widespread electrification in 1900—when wholesale competition effectively did not exist—to greater efficiency and lower GHG emissions in 2020, 120-year-old regulatory incentives should be reexamined more fundamentally.

More non-utility ownership of power plants relied upon by a utility provides clear consumer benefits of risk diversity, innovation, and cost control (explored in more detail below). It is true that if a greater proportion of generating resources were built by non-utility entities rather than the utility, there would be less in generation-related rate base to earn a rate of return for the utility. However, in the new paradigm of a decarbonized energy system, the need for capital investment in the utility’s distribution and transmission systems (i.e., the wires and substations, or “grid” itself)—by the utility—ought to maintain a profitable future for any electric utility. In other words, there is room for both the utility and the non-utility generator and retail supplier to work together to decarbonize the Northwest.

The Benefits of Competition in the Clean Energy Transition
Given the opportunity, competition in the electricity sector can help speed up the clean energy transition while reducing costs and diversifying risk to consumers. Competition at the wholesale and retail levels can provide several types of benefits detailed in this section:

- Price benefits
- System optimization
- Risk diversification
Encouragement of innovation

Empowerment of customers

Wholesale Competition

Price Benefits
A long-standing value of wholesale competition is to keep in check the monopoly instincts and core assumptions of incumbent utilities that affect customers’ electric rates. A level playing field among competitors is a clear path to lower rates over the long haul. Level terms and conditions means that multiple parties are competing fairly to deliver the lowest cost resource to customers. The fundamental benefits of discovering lower cost options through a competitive process are undeniable.

When a utility attempts to acquire a new resource to serve its customer load, many jurisdictions require a competitive bidding process. This is to ensure that the utility takes advantage of competition and, if it is proposing to build its own projects, faces some competition of its own to identify the best resource and lowest price. Competition at the wholesale level will secure for the utility customer a path toward lower rates.

System Optimization
Enhanced system efficiency can secure lower costs as well. Organized regional markets with centralized clearing prices and generator dispatch, and shared transmission planning and operations, known in the U.S. as a Regional Transmission Organization (RTO), are designed to find efficiencies in regional electricity systems. An RTO relies on many generating resources over a large geographical area. By engaging more resources over a larger footprint, the most efficient resources can be dispatched to serve load, which tends to lower costs to the consumer and reduces GHG emissions as well. By including a greater number of resources eligible for dispatch the resource stack provides a wider array of low-cost resources than a single utility could offer. The graph below shows that the lowest cost resources will be dispatched first, using the higher cost resources only in periods of intense need.

10 The term “load” refers to the component in an electrical circuit that consumes power produced by an electric generator. For example, in a simple circuit, a light bulb or a motor is the “load.” A utility’s “load” is the aggregate of demand for power from all of the utility’s customers at any one time.

11 The term “dispatch” refers to the order by a grid operator to a power plant to generate electricity in some specific amount in a given time period.

As variable renewable resources come to dominate the resource stack it is increasingly important that the right resources get dispatched at the right time along the transmission system. In addition to finding resource efficiency, RTOs identify the need for new transmission and suggest ways to efficiently allocate the cost of that transmission expense accordingly. Forming an RTO that encompasses the Northwest would be a natural and appropriate endpoint of embracing competitive solutions to decarbonize because it establishes a neutral market platform for competitors and produces more granular and rigorous price signals. The Northwest has historically had some of the lowest wholesale power prices in the country, in large part because of the significant presence of low-cost hydroelectric generation. But the balkanized nature of the region’s grid, with approximately 38 different grid operators each running a separate system and responsible for balancing load and generation, has become an economic and institutional barrier to incorporating more and more intermittent renewable resources into an overall reliable, low-cost system.

A number of transmission studies have attempted to quantify the economic benefits of organized markets in the West. A 2021 study scored different market constructs (for example, bilateral contracts, real-time markets, and an RTO) against a number of criteria. The study found that an RTO best served the needs of increased use of clean energy technologies, reliability, and affordability compared to other market structures. A few states in the West with similarly structured power sectors as the Northwest (Nevada and Colorado) have recently enacted state laws that direct their utilities to join or form an RTO in the near future. Recently, at the direction of the Oregon legislature, the Oregon Department of Energy

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14 See, e.g., Nevada SB 448 (2021), available at: S8448 Text (state.nv.us).
completed a thorough review of the benefits, challenges, and mechanics of forming such an RTO.15

Diversifying Risk for Customers
There are several reasons why relying on utility-owned generation assets (i.e., power plants) may concentrate risk on the utility customer. When a utility brings the cost of a new generation asset to a utility commission for rate recovery, the commission will conduct a prudence review to determine if the investment is reasonable and in the interests of customers. Once the commission deems a resource prudent for cost recovery, the utility’s customers generally must pay both the capital costs of the plant and a rate of return for the lifetime of the plant. While the utility carries some risk of a resource being deemed imprudent at the outset or during plant operations, it is the customer that ultimately bears much of the risk of higher costs or lower performance of the generation resources the utility has built on the customers’ behalf.

• **Uniformity risk.** The utility shareholder generally wants to reduce its regulatory risk, so utilities tend to stick to familiar resources when considering new resource options. In the Northwest in the 1990s, it was difficult to move utilities to add wind resources to their systems because they had become familiar with thermal (fossil fuel or nuclear) generation. Wind was still a “new” technology type. This way of thinking could result in a tendency to acquire resources of similar characteristics, whereas greater technological diversity, supported by wholesale competition, may reduce uniformity risk for the consumer.

• **Cost over-runs.** Once a utility has been given the green light by the regulator to build a particular resource, the customer is on the hook for any costs above and beyond that amount proposed by the utility. A utility will forecast the cost of a resource in the planning stage, but the actual cost of construction may be higher than forecasted. Cost over-runs are typically borne by the customer unless they are the product of utility imprudence.

• **Market price risk.** If a utility wins its own competitive RFP or accepts a build-own option, then the utility-owned resource goes into rates for the life of that resource, usually between 20 and 40 years. Once a commission deems a resource prudent and the utility puts it into rates, the customer generally is served by that resource and pays the capital and operating costs. The risk of that utility-owned plant being more expensive than other alternatives stays with the customer for the life of plant. The same is not true of a third-party resource contracted for a term shorter than the life of the resource.

• **Operating risks.** Similarly, if the utility-owned resource suffers failure or if operating costs go up, or, in the case of a renewable resource, the actual output is less than that

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assumed during the RFP competition, then the customer lives with that higher cost or lesser value for the life of the resource. On the other hand, depending on the contract arrangements with a non-utility IPP, the IPP is usually required to deliver energy at a set cost for a period of time. The utility customer is not on the hook for any problems with the non-utility resource. Instead, the IPP bears that risk.

- **Stranded cost risk.** There is a risk especially prevalent now that utilities will commit customers to paying for more utility-owned generating resources just when customers are beginning to have many more energy supply options. As new technologies develop, customers can begin to self-generate or choose a competitive supplier. It will be more difficult for customers to take advantage of these options if they are increasingly burdened by having to pay for new utility-owned generating resources. Balancing the need to provide customers with energy service now with the need to avoid burdening customers with long term repayment of utility-owned assets means thinking about a diverse approach of utility and non-utility resource options.

Some of these risks can go both ways. In other words, utility-owned resources can either be a good deal or a bad deal for the customer over the life of the resource compared to other resources. However, the lack of diversity that comes with incrementally more utility-owned generation becomes a long-term risk to the customer. Especially as the region is ramping up to acquire many thousands of megawatts of new clean energy resources over the next 20 years, diversity of ownership, resource type, and length of commitment are all necessary characteristics of a well-balanced resource portfolio to meet customer demand.

**Innovation and Responsiveness**
An investor-owned monopoly utility avoiding the risk of an imprudence finding may tend to be very conservative about the kind of resources it wants to own. In fact, monopolies tend to be inherently risk-adverse; by extension, they are less likely to be a source of technological innovation. This may cause the utility to stick with a technology type it feels comfortable with. IPPs generally are more flexible in meeting the needs of the buyer and not bound to regulatory or state pressures in the same way. Certainly, IPPs want to feel comfortable with generation technology, but the accounting for risk is not as tied to the regulatory imprudence finding that shadows the utility. As such, the IPP may be more open to innovative technologies and able to draw on its experience in deploying the technology in other states or countries.

As the Northwest prepares for a new era of renewable and other clean energy resources, it is vital that the new regional portfolio of power plants represents a diverse array of technologies and locations. Over-reliance on one technology type in too few localities poses a risk of saturating the market with resources that produce energy at the same time and are unproductive at the same time. In its quest to decarbonize the electricity system, the Northwest should be interested in diverse technologies that prove reliable and cost-effective, such as distributed and central station solar, onshore and offshore wind, short- and long-duration storage (including pumped hydro storage), smart grid technologies, energy efficiency,
and perhaps technologies such as renewable hydrogen and carbon capture that are not yet widely commercialized at this point. Competition can bring a responsive dynamic to the needs of the region for diverse solutions to decarbonize.

**Retail Competition: Empowerment of Customers**

Retail competition produces many of the same price, diversity, and innovation benefits, detailed above, that accrue on the wholesale side. In the Northwest, where retail competition is available to only some large commercial and industrial customers, those able to access competitive non-utility suppliers may find a variety of benefits tailored to their needs. Those customers can access electricity service at lower prices and choose electricity products that are crafted for the customer’s needs regarding power quality, reliability, term of service, and a lower GHG emission content than could be accessed through the utility. These customers can assess various risks and can choose to opt out of the utility’s resource acquisition choices and instead negotiate resource types with a third-party provider. This means the customer avoids a stranded cost risk that stems from the utility’s choices in exchange for taking on the responsibility of choosing the resources, term, and subsequent pricing that best fits the customer’s needs. Large customers with retail choice can willingly accept that tradeoff with a full appreciation of the risks and benefits.

There has been significant demand for retail choice recently in the Northwest among customers focused on meeting corporate sustainability and decarbonization goals. For example, a data center developer in Oregon recently explained, “We purposely sought the direct access right with the intent to source low-carbon power for our Portland facility[,]” and “we prefer to develop data centers in areas with open and competitive markets.”

Similarly, major technology companies have directly pursued retail choice in Oregon. Apple secured direct access in PacifiCorp’s territory, with a representative of the company explaining, “To strengthen the connection between Apple and these projects, we use Oregon’s Direct Access program to schedule the renewable energy from these projects directly to our data center[.]” Customers are working directly with competitive retail suppliers across the West to come up with innovative ways to attempt to match facility load with emissions-free generation in real-time.

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The Policy and Market Contexts for the Clean Energy Transformation in the Northwest

The electricity sector is undergoing revolutionary change in response to climate change policies, technological innovation, changing customer expectations, and increased awareness of local community and environmental impacts. This section provides a grounding overview of these various drivers of change that will affect and overlay with market competition in critical ways.

Clean Energy Standards

In 2021, Oregon adopted a clean energy standard that requires investor-owned utilities to meet an 80% reduction in GHG emissions from a 2010-2012 baseline by 2030 and a 100% reduction by 2040. Oregon already has a renewable portfolio standard that requires the state’s largest utilities to serve their customers with 50% renewable energy by 2040. These requirements apply to the competitive retail suppliers in Oregon as well. No investor-owned utility may include coal in Oregon rates after 2029 and the state can no longer issue a site certificate for a new or enlarged fossil fuel generating plant.

Washington adopted the Clean Energy Transformation Act in 2019, applying a standard of 100% clean energy by 2045 to all utilities serving retail load. Coal must be eliminated from utility portfolios by 2025. Washington also enacted a law in 2021 creating a GHG “cap and invest” (also known as cap and trade) program to start on January 1, 2023.

The clean energy standards in both Oregon and Washington are subject to cost caps and a reliability-triggered “off-ramp.” No major grid operator in the U.S. has eliminated direct GHG emissions in the power sector to date. Doing so in the Northwest, in order to meet the states’ clean energy standards, will be a major challenge and technical accomplishment.

In all four Northwest states, many cities have also adopted clean energy commitments. Examples include clean energy goals in Montana (Helena and Missoula), Washington (Spokane, Seattle, Edmonds), Idaho (Boise), and Oregon (Portland, Eugene, Gresham, Milwaukie). In addition, individual utilities serving Northwest customers have adopted clean energy targets of their own (for example, 100% clean energy by 2045 for Idaho Power, and net zero emissions by 2050 for NorthWestern Energy in Montana).

Transportation Electrification

Northwest states have also enacted policies or investment plans to promote electrifying the transportation sector. In Oregon, HB 3055 (2021) declares that alternative forms of transportation are a benefit to electric ratepayers and makes IOU funding of electric vehicle (EV) infrastructure costs recoverable under certain conditions, and HB 2165 (2021) establishes a

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19 Oregon HB 1547 (2016), available at: [SB1547 (oregonlegislature.gov)](http://www.leg.state.or.us/billintroduction? BillNumber=SB1547&YearId=2016).
customer charge to fund EV infrastructure. In Washington, the State Department of Commerce distributes grants to cities, counties, and ports for electrification projects. In Idaho, Avista has filed a transportation electrification plan to guide its infrastructure investments.

Natural Gas Transition
State agencies and municipalities are considering the future role of natural gas service. The Oregon Public Utility Commission opened a docket to explore the future of natural gas. The Oregon Department of Environmental Quality (Oregon DEQ) is engaged in a rule making to establish a “cap and reduce” program that would cover retail natural gas service (the Climate Protection Program). The cities of Seattle and Eugene are exploring codes that limit new buildings to electric-only. There is little that is certain about the extent or timing of natural gas transition, but to the extent that it does occur, much of the existing natural gas load could shift to electricity.

Implications of Policy and Market Drivers
The net result of these and other regional dynamics means there will be a huge demand for new carbon-free resources over the next few decades. Market participants in the electricity sector have begun to respond to both the state and local policy initiatives and the market-driven demands of end-use customers. As fossil-fuel generation winds down and renewable (and other non-emitting) energy ramps up, the need for new generation investment in the Northwest will be substantial.

The Clean Energy Transformation and Risks to Utilities and Their Customers
Climate change is an existential risk to all current patterns of life on our planet. Decarbonization of the electricity sector is a necessary part of any plan to address climate change and limit its impact on human welfare. Climate change is, without question, the biggest overall risk to the focus of our attention in this Brief: the electricity customer.

Yet, transforming the existing electricity system to eliminate GHG emissions over the next 15-20 years comes with its own set of near-term risks. Many of the basic policy and physical elements of the electricity system were developed gradually over the past hundred years or more.

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22 IPCC, Headline Statements from the Summary for Policymakers (Aug. 9, 2021), available at: AR6 WGI Summary for Policymakers Headline Statements (ipcc.ch). “Human-induced climate change is already affecting many weather and climate extremes in every region across the globe. Evidence of observed changes in extremes such as heatwaves, heavy precipitation, droughts, and tropical cyclones, and, in particular, their attribution to human influence, has strengthened since the Fifth Assessment Report (AR5). […] From a physical science perspective, limiting human-induced global warming to a specific level requires limiting cumulative CO2 emissions, reaching at least net zero CO2 emissions, along with strong reductions in other greenhouse gas emissions.” See also, the full Summary for Policymakers, IPCC_AR6_WGI_SPM_final.pdf.
Shifting to all renewable (or non-GHG-emitting) generation in a relatively short amount of time carries financial, operational, and reliability challenges.

From the investor-owned utility point of view, there are a number of new challenges associated with meeting GHG emission-reduction standards. Normally, the utility has time to evaluate and procure a diverse set of generation resources (power plants) through a state-regulated planning process to serve load that grows relatively slowly through the years. The new challenge for utilities is to move faster to meet the GHG emission-reduction mandates over a limited period of time with a more limited set of non-fossil fuel generation resource options to serve a load that will probably grow much faster as a result of electrification policies. The challenges for the IOU look something like this:

**Clean energy standards:** IOUs must procure (via ownership or contract) large scale generation resources in a short time. Oregon and Washington law require 100% GHG-free generation by the 2040s. For these utilities, this means procuring many gigawatts of renewable and other non-emitting resources in less than 20 years. The 2021 Northwest Power Plan identifies the need for 3,500 MW of new renewable resources in this region by 2027 and 14,000 MW of new renewable resources by 2040. Those quantities would more than double the installed wind and solar resources in the Northwest today. (It should be noted that these projections do not include the impact of HB 2021 (Oregon’s clean energy standard) or the Washington cap and trade law which would generally result in even more renewable generation need.) A separate analysis in 2019 prepared by Evolved Energy Research on behalf of the Clean Energy Transition Institution found that deeply decarbonizing all sectors in the Northwest would lead to a 60% increase in load (because of electrifying other sectors) and therefore a need for 100,000 MW of new resources by 2050, an astounding quantity that may be considered an upper bound. This is an enormous outlay of capital that utility customers will be expected to pay for. The customers’ experience will be impacted by whether their utility seeks to own the resources or uses competitive alternatives, how the utility participates in transportation electrification, the pace of coal unit retirement, and other resource decisions.

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23 The Northwest Power Plan is a region-wide analysis of observed and forecasted trends in the power sector, including an identification of expected power demand, produced every five years by the Northwest Power & Conservation Council. The Council is an interstate compact agency established by the states under authority enacted by Congress in 1980.
Coal retirements: Another policy that increases the need for the renewable (or non-emitting) generation build-out is the retirement schedule of coal generation. Washington law requires coal to be eliminated from customer service by 2025, and Oregon law requires coal to be eliminated from customer rates by 2030. While the state laws cannot mandate coal retirement in other states, these limits should hasten the actual shut down of coal generation serving the Northwest. In addition, HB 2021 in Oregon mandates that in most cases (absent carbon capture and use or sequestration), new natural gas-fueled generation cannot be sited in the state.\(^{26}\) This means that in addition to load growth, renewable (or non-emitting) generation will be needed to replace existing fossil-fueled generation.\(^{27}\)

\(^{26}\) Even as their total output may be affected by the state emissions mandates, the existing natural gas plants in the region will likely continue to play an important role in maintaining reliability of the power system for some time. Natural gas’s potential role in a deeply decarbonized power sector and economy is still evolving.

\(^{27}\) Two states in the region (Oregon and Montana), have laws in place that place limits on the siting of new nuclear plants (including small modular reactors) in those states. Even if some amount of new (carbon-free) nuclear
**Transportation electrification:** Also impacting the size of the renewable build-out will be the pace of transportation electrification, a matter of established policy in various Northwest states. The utilities are encouraged under current law to facilitate the transportation transition from gasoline and diesel to electricity. Recent legislation in Oregon, for example, has declared that enabling that transition is in electric utility customers’ interest and can lead to streamlined utility cost recovery. The transportation electrification load by itself could add thousands of megawatts of load in the Northwest by 2040.\(^{28}\)

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\(^{28}\) 2021 *Northwest Power Plan* at 23-24. There are differing forecasts for the impact of EVs on the electric grid. There are projections of EVs “breaking the grid” and others that see no significant load impact. Important factors implicating load and peak load impacts will be the pace of EV adoption over the next 10 years, availability of charging stations, and the timing of daily EV charging (perhaps shaped by rate design).
Uncertain future of natural gas: Adding further to this theme, natural gas transition is a matter of some conversation in the Northwest. The Washington cap and trade program and the Oregon DEQ Climate Protection Plan are policies that will tend to either dampen natural gas load or increase natural gas prices. While there are no established state policies specifically to transition natural gas service to electric, there is discussion at the local level of creating moratoria for new growth of natural gas service. If policies were to emerge in the next decade to begin to replace some natural gas service with electricity, the implications of additional renewable electric resource to serve winter peak load (when natural gas for heating is currently most in demand) would be quite significant.

Uniformity risks: Heavy reliance on particular renewable generation types or on resources in limited localities may create operational challenges. For example, an overbuild of solar in a particular locality will tend to provide an abundance of energy during daylight hours and paucity of energy at night while creating huge ramping needs during those hours. An overbuild of wind in a certain locality means that the resources are subject to the same wind patterns at the same time. This issue can be overcome to a large degree by adding battery storage on-site, but doing so adds the incremental cost of batteries to the project. Relying too much on only a few resource types or on the type of resources a utility feels comfortable with can create uniformity risks for the regional system and diminishing value for the customer.

Capacity needs: More non-dispatchable resources on the system brings a need for more capacity and for resources that provide flexibility. Battery or pumped storage hydro will become increasingly important, but widespread deployment of storage resources depends in part on their costs coming down (an outcome more likely with more market competition). At the same time, capacity is likely to become more properly valued through programs such as the Western Resource Adequacy Program, a new regional compliance program to ensure utilities and competitive retail suppliers in the West have enough capacity procured.

New tests of prudence: As the system becomes more complex and nuanced, the regulatory oversight will also become more complex and nuanced. Serving load will

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29 “Ramping” refers to a rapid increase or decrease in generation in order to match a sudden loss in other generation (e.g., when the sun goes down) or sudden increase in customer demand (e.g., in the morning when people wake up and prepare for work and school). Not all types of power generation or storage technology can ramp effectively.

30 “Non-dispatchable” refers to resources that cannot be turned on at will when the grid needs them, but rather only when their “fuel” is naturally available (e.g., wind, sun, or water (for run-of-river hydroelectricity)). In contrast, storage resources (including conventional storage hydro, pumped storage hydro, and grid-scale batteries) and thermal resources that convert storable fuel (uranium and fossil fuels) into electricity are “dispatchable.”

31 In this context, “capacity” refers to resources effectively on standby and available to generate power at times of peak demand. The term encompasses dispatchable resources and some non-dispatchable resources whose output predictably lines up with peak demand. IPPs and utilities are often paid separately for providing capacity (remaining available if needed) and energy (for actual electricity generated).
necessitate considering more moving pieces as customers start charging EVs and generating their own solar energy, as utility resources are increasingly variable and non-dispatchable, and as utilities attempt to time resource additions with clean energy mandates. Both the regulator and the utility will have to reach a new understanding of what is prudent, while the regulator maintains its role of protecting customers in a race to meet clean energy goals. Given these heightened risks to consumers, regulators must be more vigilant about over-spending and mistiming by the utility.

**Debt risks:** As the utility rushes to fill out its resource portfolio, there is a real possibility of exhausting the utility’s debt load. The utility’s regulator will have to carefully consider the amount of debt and equity a utility holds. Holders of debt through commercial bonds hold a secured position in the event of default or bankruptcy, but shareholders generally are not secured in the same way. Too much debt increases the risk of bankruptcy as the debt holders could force repayment under some circumstances. Too much equity compared to debt and the stock could become diluted. Generally, this means that there are limits to the amount of capital a utility can raise while still balancing the interest of debtors and equity holders—and, ultimately, customers. This financial balance is something the utility must consider when evaluating the billions of dollars it would cost to acquire and own a significant share of renewable resources as well as the attendant transmission and distribution infrastructure, as opposed to signing power purchase agreements with IPPs.

**Uncertain load:** Even though the utility’s electrical load is likely to increase faster than at historical rates because of electrification, there is also increased uncertainty of load because of new customer service options. Some utility customers currently have service options in the form of: direct access (retail choice) to non-utility generators in Oregon, Washington, and Montana; new green tariffs and community solar served by non-utility resources; and new options in HB 2021 in Oregon that would allow municipalities to be served by the utility with more renewable resources than are in the utility’s current portfolio. Individual customers can also install solar PV at their homes or businesses. These important customer options increase the uncertainty of the utility’s future load.

**Transmission challenges:** Finally, the regional transmission system will be stressed by the new clean energy mandates. Some fossil-fuel generation will retire, which can free up transmission paths to allow non-emitting resources access to utility load. However, given the geographically diverse nature of renewable resource opportunities and the decades-long underinvestment in our transmission system, there are many constrained transmission paths in the Northwest and broader West. The state clean energy mandates will only be as successful as our ability to optimally site and build transmission (and optimize the use of existing transmission) to deliver energy to consumers.
In summary, the power system is getting more complex and a utility’s resource decisions going forward will face a new set of risks. Under the old traditional vertically integrated utility framework, there were only two parties that bore the risk and costs of the utility resource decision-making: the shareholder and the customer. Greater competitive options have progressively changed that dynamic for the better over the past forty years. Over the next two decades, with huge capital expenditures necessary to decarbonize and increased risks of a more complex energy system, competitive options provide critical ways to diversify an array of risks and to control cost increases.

Considerations For Policy-Makers: Some Ideas to Foster Competition and Harness Cost and Risk Benefits

Policymakers should consider how best to encourage opportunities for competition in the Northwest as a way to decarbonize the electricity system quicker, with less risk, and with less cost to consumers. Policymakers should evaluate this point with respect to a continuing cornerstone purpose of the utility: to build and maintain transmission and distribution infrastructure. There is no reason that utilities in the Northwest should not continue to provide most of this essential—and financially valuable—platform of the electricity sector as we know it. It is what makes possible the focus of this brief: competition and diversification of the electricity supply that plugs into the grid.

Identify the System Benefits of Retail Competition

The value of retail competition to the electricity system should be better understood. In the case of new large load locating in the Northwest, for example, allowing new large load to go straight to direct access gives the new customer choice for the resources to meet its energy needs and may be a financial benefit to existing customers because it frees the utility from having to acquire new energy or capacity resources—acquisitions that may require all customers to pay the utility an effectively guaranteed rate of return no matter the technology chosen. The quantified value may be different for each utility and dependent on who is responsible for reliability, but by not valuing this potential benefit to the utility system, retail competitive options are not given their full due.

Support Regulatory Limits on Utility Market Power and Presence

If the regulatory construct is to remain in large part vertically-integrated in the Northwest, regulators must give special attention to any activity that impairs the benefits to the system competition can provide. Considering the extent of utility ownership or carving out a stronger place for competitive generation should be considered. In any case, the utility regulator should not implicitly favor the utility solutions to resource acquisition. Policymakers should be alert to when a regulatory approach seems to lean heavily on the utility to decarbonize, and this favoritism should be made apparent so stakeholders can weigh in. Passively allowing the utility
to drive resource acquisition into rate base is contrary to the interests of customers and to the policies driving the clean energy transition in the Northwest.

A practical extension of this consideration would be to underscore the value of maintaining and improving competitive procurement by utilities of generation and storage resources, overseen by independent evaluators and subject to close scrutiny by utility commissions.

Pursue Performance-Based Ratemaking

As we explored earlier, a primary policy goal of utility regulation at the beginning of the 20th century was to build out the electricity system to electrify all parts of the country. Cost-of-service regulation relied on applying a rate of return to rate base to incentivize the utility to invest heavily in distribution, transmission, and generation assets. That policy objective, a product of its time, was wildly successful in achieving its objective (in combination with the public power movement). But there is no further need to electrify various parts of America. Two decades into the 21st century, our policy objectives for the energy system are different.

Today, in addition to the overarching objective of running a reliable and affordable system, the policy objectives in the Northwest are, in broad strokes: to decarbonize the electricity system to avoid the worst impacts of climate change, to give customers the ability to make choices about their energy supply, to invite technology innovation to support our evolving energy needs, and to address environmental justice imperatives. This revolution of policy objectives demands that we reexamine the regulatory structure and the incentives provided to utilities and their customers. “Performance-based ratemaking” is a regulatory model that rewards the utility for performing well on specific metrics such as GHG emission reduction, system efficiency, customer service, community-based solutions, etc. It is designed to align the utility’s profit incentives with our 21st century policy objectives. In a nutshell, it moves explicitly away from rewarding utilities—or anyone—for simply building their way out of our problems. It adopts the assumption that the rate base incentive has served its purpose and should be reassessed. In its place, we should consider different metrics which can provide utilities new profit centers and new ways of earning on behalf of their shareholders, and open up competitive opportunities. Performance based rate making is a less fundamental structural change to the power sector than simply divesting utilities from power plant ownership.

Performance based ratemaking can include metrics such as speed and depth of decarbonization, a targeted number of resident-owned solar installations, improved service quality, inclusion of diverse communities in decision-making process, efficiency measures, and many more possibilities. In order to implement this form of ratemaking, benchmark standards must be set and the required trajectory of the metric must be established. With the metrics established, the utility can earn money by directly supporting the policy goals set out by policy makers. This can evolve over time so that the customer, the regulator, the utility shareholder and bondholder (the sources of capital), and the credit rating agencies have confidence that the utility is in a strong earnings position and can serve its customers. Until policymakers move in
this direction, we will be employing a set of incentives established for policy goals a century old that tell the utility to build its way out of every problem.\textsuperscript{32} And until we address this incentive more directly, the ability of competition to support the policy goals of the 21\textsuperscript{st} century will be muted.

Consider Establishing Regional Organized Markets
Northwest energy stakeholders should continue discussions about establishing a Northwest-wide or West-wide regional transmission organization. Competitive and complementary generating assets optimized through economic dispatch can be one of the most important tools in decarbonizing the transmission grid in a least cost manner. The efficiencies wrung out of more generating resources over a larger footprint can significantly lower the cost of securing a clean renewable energy generation portfolio. Removing duplicate transmission rates from multiple transmission owners, consolidating the balkanized control areas of the Western grid, streamlining and allowing generators the ability to interconnect their facilities to the grid, and adopting shared transmission planning and operations will similarly lead to significant efficiency gains that will benefit customers.

Even without a regional transmission organization, the Northwest should focus on the development of new transmission paths to connect new clean energy generation to load. State regulators should encourage merchant transmission providers, utilities, the U.S. Department of Energy, and the Bonneville Power Administration to work together to build transmission to unlock geographically diverse renewable and other non-emitting resources for use to comply with clean energy mandates and to decarbonize the Northwest.

Conclusion
As we head down the path of rapid decarbonization, it is important to take account of all the tools we have at our disposal to get us to our policy destination as rapidly and as efficiently as possible. This means understanding the benefits of competition and understanding the obstacles to using competition to facilitate the clean energy transition. Policymakers should consider options that increase competitive opportunities, and thereby speed up the clean energy transition while reducing costs and diversifying risk to consumers. Considering competition-based solutions at both the legislative and regulatory levels can help us achieve our regional decarbonization goals.

\textsuperscript{32} Performance-based ratemaking is particularly valuable in vertically-integrated regulated jurisdictions, but it may also be valuable in restructured jurisdictions (such as the Mid-Atlantic and New England) that have more retail competition and less utility asset ownership than the Northwest.
Appendix: Competitive Market Designs and their History in the Northwest

Both Oregon and Washington have a history of attempting to level the playing field between utility and non-utility generation. Through both efforts to establish retail competition for large customers and creating a fair procurement process in the utility’s RFP, the utility commissions have recognized the value of retail and wholesale competition. This section provides an overview of the steps that led each state to establish regulatory tools to encourage competition. Potential further evolution of the competitive market design in the Northwest may include the establishment of new centralized wholesale energy markets and a regional transmission organization, but this Brief does not focus on those outcomes.

Oregon

**Competitive restructuring (1999):** In 1999, numerous stakeholders agreed to support SB 1149 which created a hybrid restructuring of the power sector.\(^1\) The law allows for large customers to by-pass the utility IOU to find energy services from a non-utility electricity service supplier. The departing large customer cannot shift unwarranted costs to remaining customers and is subject to a public purpose charge covering investments in energy efficiency and low income weatherization. Residential customers were guaranteed a regulated rate from the utility and rate options representing additional renewable resources or a time-of-use rate.

SB 1149 instructed the Oregon Public Utility Commission (Commission or OPUC) to develop “policies to eliminate barriers to the development of a competitive retail market structure. The policies shall be designed to mitigate the vertical and horizontal market power of incumbent electric companies, prohibit preferential treatment. . . of generation or market affiliates and determine electricity services likely to be competitive.”\(^2\)

In Oregon, a utility files an integrated resource plan (IRP) which looks at projected loads 20 years out and analyzes different portfolios of resources that might result in system investments that represent the lowest cost and lowest risk (“least cost/least risk”) service for customers. In addition to the “long” (20-year) look, the IRP will include a near-term Action Plan covering what resources should be acquired in the next 3 to 5 years. After significant stakeholder process, the OPUC acknowledges all or parts of the IRP which serves as evidence of prudence in a rate case. After the IRP, the utility is likely to file a request for proposals (RFP), which is a competitive process to determine the best resources to serve the specific needs outlined in the resource

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2 Oregon HB 1149, section 6(1).
Appendix: Competitive Market Designs and History

plan. Both the utility and third party developers can bid into the RFP. The RFP itself follows a process that invites scrutiny from stakeholders and the OPUC staff. Finally, once a resource is chosen and constructed, the utility will file a rate case with the OPUC to put the new capital asset into rate base.

**RFP reform (2004-2006):** In 2004, the Northwest & Intermountain Power Producers (NIPPC) filed a petition with the OPUC to open an investigation regarding competitive bidding requirements in the RFP process. NIPPC and others believed that there was a utility bias to own generation, which might undermine competition between utility and non-utility generation. The result of this investigation was an order that continued to allow the utility to bid its “self-build” option, but also added requirements with the goal of leveling the playing field for non-utility developers. The Commission created new guidelines that addressed the fairness of the scoring system, required the services of an independent evaluator to assess the fairness of the process, and added Commission approval of the RFP process as a judgement of the overall fairness.

Soon after this order came out in 2006, the Commission staff recommended opening a new docket to investigate regulatory tools to address the utility’s potential build-vs-buy bias. OPUC Staff discussed several reasons why the potential build-vs-buy bias might result in potential barriers to the signing of power purchase agreements (PPAs) with non-utility developers. Among the reasons were “utility-owned power plants earn a return as part of the utility’s rate base, whereas PPAs do not”, and “the concept of empire building, in which a utility may desire to accumulate assets for reasons other than providing power to customers on a least cost basis”.5

Both residential and industrial customers joined the investigation and supported the idea of creating a level playing field between utility self-build options and non-utility developer options. From a customer point of view, fair competition between the utility and non-utility generation carries many benefits. Examples of considerations from a customer point of view may be:

- Once approved in rate base, customers are hooked to a decadal resource regardless of its actual performance (barring some catastrophic operational blunder by the utility). The risk of lower-than-expected performance or higher-than-expected operating costs falls on the customer.

- The rate-based asset comes with a given rate of return regulated by the Commission, not disciplined by the market.

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3 Oregon PUC Order No. 06-446 (Aug. 2006).
4 Oregon PUC, Staff Report, Item 1 (Aug. 22, 2006) (Request to open an investigation regarding performance-based ratemaking mechanisms to address potential build-vs-buy bias).
5 Id at 1.
Utilities can be quite conservative in their approach to avoid prudence disallowances, so resources “familiar” to the utility are likely to be selected for investment. This tends to dampen innovation.

Under a PPA, the non-utility developer (an IPP) generally takes the deliverability risk, and therefore some of those performance or operating risks are transferred away from the customer to the non-utility developer.

A non-utility developer may have a higher cost of capital and a higher internal rate of return than a regulated utility, however, to win a competitive bid in an RFP, the non-utility must rationalize those costs with the competitive nature of the RFP and produce a bid low enough to win.

A time frame for a contract for energy under a PPA is generally much less than the lifetime commitment with a utility-owned resource. This can cut both ways. If the market is higher at the end of the PPA contract period, the utility must go out into this higher cost market to replace the PPA. On the other hand, if the market is lower at the end of the PPA period, the utility customers are in better shape than if they are committed to a higher priced utility-owned resource for additional decades. Similarly, the customer is in better or worse shape with a utility-owned resource at the end of its book life, where a cheaper resource is still a value, but a resource that is more expensive than the market is an albatross. All this means that diversity of ownership and resource length is a benefit to the customer.

At the core of the reforms to Oregon’s competitive procurement requirements was a recognition by the OPUC of the utilities’ ownership bias. This recognition was repeated in subsequent proceedings:

We too accept the premise that a bias exists in the utility resource procurement process that favors utility-owned resources over PPAs. This bias is really a logical inference drawn from an understanding of ratemaking practices and the effectiveness of incentives. As Staff explained in its opening comments about the lack of a return on PPAs:

[U]nder cost of service regulation, a utility’s “profit” is the opportunity to earn a return on the rate base and by purchasing a PPA in lieu of building a power plant, it is foregoing the potential to earn some amount of profit.6

Direct access: Over a period of many years, the Commission promulgated and refined the rules for retail competition in Oregon. These rules included eligibility requirements, caps on amount of direct access load for each IOU, rules pertaining to non-utility energy providers (Electricity

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6 Oregon PUC Order No. 11-001 at 5 (Jan. 3, 2011).
Service Suppliers (ESSs)), and terms for a direct access customer to return to utility service. The terms and conditions that apply to non-residential customers who are able to choose service from an ESS differ from utility to utility. Depending on the utility, a customer can choose to opt out of the utility electricity supply options for different periods of time and a “transition charge” will be assessed depending on the opt out selection. The Commission has placed caps on the overall amount of load from each utility that can go to direct access.

The establishment of these rules has been marked by competing concerns over protections of non-direct access customers and utility interests on the one side and overly rigid limits on direct access opportunities on the other side. The Commission reported that direct access services accounted for about 7% of IOU retail deliveres in 2019.7

**Green tariffs:** In 2019, the Commission approved an initial utility “voluntary renewable energy tariff” that allows some large customers to buy renewable options from the utility, as opposed to from non-utility ESSs. There was a major regulatory tension in this decision by the Commission between allowing utilities to act like third-party *a la carte* power suppliers and encouraging the retail competitive market that was authorized in 1999. The Commission has continued to wrestle with the commercial tensions created by having retail competition exist alongside regulated, monopoly utilities, for the past twenty-three years.8

**Renewable portfolio standard (2016):** In 2016, the Oregon Legislature passed SB 1547, which required the removal of coal from rates by 2030 and increased the original renewable portfolio standard. Given the significant amount of new generation that was expected to be constructed, the Legislature wanted to ensure that non-utility owned generation was fairly considered. SB 1547 specifically required the PUC to adopt rules “providing for the evaluation of competitive bidding processes that allow for diverse ownership of renewable energy sources that generate qualifying electricity.”9

**Regulatory reform (2017):** The Oregon Legislature passed SB 978 in 2017 directing the OPUC to investigate “how developing industry trends, technologies, and policy drivers might impact the existing regulatory system and incentives currently employed by the commission.” Among the current regulatory incentives specifically called out for investigation was “incentives for electric companies to place capital investment in rate base, paying particular attention to the perception of bias in resource selection[.]” The Commission conducted a month’s long process looking at many aspects of the regulatory process and produced a report to the legislature in 2018.11 The report paid particular attention to:

- Climate change policies

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8 Oregon PUC Order No. 19-075 (Mar. 5, 2019).
9 ORS 469A.075(4)(d).
10 Oregon SB 978 (2017), available at: [SB0978 (oregonlegislature.gov)](#).
11 Oregon PUC Report to the Legislature, SB 978 Actively Adapting to the Changing Electricity Sector (Sept. 2018).
Appendix: Competitive Market Designs and History

- Affordability, equity, and environmental justice
- Customer options including competitive options
- Utility incentive alignment including performance-based regulation to align utility incentives with customer objectives
- Regional market development
- Public participation including community-based groups

In this report the OPUC addressed both retail options for utility customers and wholesale competition. With regard to retail customer choices the Commission said:

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.

And addressing wholesale competition, the Commission acknowledged:

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.

**Clean energy standard (2021):** HB 2021 required both the investor-owned utilities and the competitive retail suppliers to meet the new clean energy standards (80% by 2030, 90% by 2035, and 100% by 2040). In most other respects, the law simply left in place the current competitive structure of the power sector in Oregon.

In summary, both the Oregon Legislature and the OPUC have linked competition at the retail and wholesale levels with dynamics associated with climate change policy and technological innovation.
Washington

Washington’s history with competitive alternatives is not as complex as Oregon’s. In the mid-1990s, several large customers sought opportunities to by-pass their local utility and purchase from the competitive market. In late 1995, the Washington Utilities and Transportation Commission (Commission or WUTC) issued an order setting out guiding principles about competition in the electric industry. The policy statement said the WUTC would work to promote the evolution of efficient markets but its primary goals are to keep prices affordable for electric service, protect the integrity of the system, and prevent noneconomic bypass and cost shifting to remaining ratepayers.

On the heels of these principles, in 1996 Puget Sound Energy (PSE) developed an option for its large customers to access competitively priced electricity. This schedule was eliminated in 2001 because market prices soared during the 2000-2001 Energy Crisis, however the follow on settlement proceedings resulted in a new set of schedules allowing service options for large customers of PSE. Two new schedules were created that gave specific large retail customers the option to purchase power directly from suppliers other than PSE.

In 2017, the WUTC revisited this optional competitive arrangement to consider whether Microsoft should be granted the opportunity to satisfy its energy needs with power it obtains from a provider other than PSE. The proposal to the WUTC was based on an agreement of numerous parties, and Microsoft agreed to terms relating to the purchase of renewable energy, transition costs to protect remaining customers, and funding for energy conservation and low-income assistance. The WUTC approved this settlement as being consistent with the public interest.

With respect to wholesale competition, the WUTC has adopted rules governing the RFP process that must be followed by the regulated utilities. In its RFP process to secure new resources, the utility may bid its own resource into the bidding process, but if it does so, the utility must retain the services of an independent evaluator. The independent evaluator is charged with ensuring that the RFP process is conducted fairly, verifying the utility’s inputs, and preparing a report for the Commission.

In 2019, the Clean Energy Transformation Act (described above at page 13), in addition to establishing mandates for utilities to decarbonize, also explicitly authorized utilities to earn a rate of return on some PPAs, at the discretion of the WUTC. This provision recognized the utility

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13 WUTC Docket No. ER01-2149-000, Filing Letter (May 25, 2001); approved by Letter Order (July 11, 2001).
14 WUTC Docket No. UE-161123, Order 06 (July 13, 2017).
15 WAC 480-107, available at: Chapter 480-107 WAC.
bias toward ownership by authorizing an alternative way to encourage competition by providing utilities an incentive to contract for power with third parties.\textsuperscript{16}

The Washington Legislature passed SB 5295 in 2021, directing the WUTC to conduct proceedings to develop a policy statement “addressing alternatives to traditional cost of service rate making, including performance measures or goals, targets, performance incentives, and penalty mechanisms”.\textsuperscript{17} Going forward, every rate case filed by an electricity (or natural gas) company must include a proposal for a multiyear rate plan and the Commission must determine a set of performance measures that may include affordability, cost of service, customer satisfaction, clean energy and energy efficiency procurement, etc. In adopting this concept, the Washington Legislature recognized that there is more than one way to regulate electricity service and that given new policy imperatives, simply relying on cost-of-service, rate-base centric regulation may not be the best path forward.

\textsuperscript{16} Washington SB 5116 (2019), available at: \texttt{5116-S.SL.pdf (wa.gov)}.

\textsuperscript{17} Washington SB 5295 (2021), available at: \texttt{5295-S.SL.pdf (wa.gov)}. 