Distribution Systems and Energy Efficiency

Board Learning Paper

Prepared by
Amanda Potter, Thad Roth, Hannah Kramer, Susan Jowaiszas, Becky Engel
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Preface

This paper is part of a series that describes a variety of topics identified by the Energy Trust of Oregon's Board of Directors as potentially influential to the organization during the time period of its next strategic plan (2020 – 2024). This series of papers will educate and inform the Board about the potential impact of these topics and enable its Directors to better to assess risk, identify opportunity and guide the direction and goals of Energy Trust.

Remaining current on potentially significant and influential developments in the clean energy industry is critical to the fundamental role of the Board. These topics have been identified because of their potential to influence, impact or otherwise affect Energy Trust's ability to serve the ratepayers of Oregon and Southwest Washington. **These papers should not be interpreted as policy proposals or recommendations for roles in which Energy Trust intends or desires to be directly involved.**

Introduction

Energy efficiency is the cleanest, cheapest, and most important resource for the utilities and ratepayers of Oregon and Energy Trust is the prime organization delivering that resource. Energy Trust's programs can have significant impacts on utilities' ability to effectively manage their distribution systems. The location of solar installations, for example, can affect local distribution issues on the grid. Additionally, Energy Trust's energy efficiency programs, with the types of improvements they encourage and the specific location of participant sites, can potentially be used as tool to manage constraints on the local grid.

Utilities across the country are investigating expanding the use of distributed energy resources, commonly referred to as DERs[1] as they transition to more renewable resources in the generation mix and create a more resilient and flexible system. Because of the high cost of building new central generation facilities, economics is clearly a factor, but it's not the only driver for this change. Changes in public policy and consumer demand and expectations of customers for their utilities are also playing a significant role in this transformation.

The evolution of DERs creates new challenges and drives changes in how utilities manage their distribution systems. The traditional planning process for upgrading and expanding electric distribution systems is inadequate in the age of two-way electric and data flows and decentralized generation. As they expand distributed energy resources, utilities must invest in grid modernization[2] – a smart grid – to manage the grid and avoid outages while maintaining safety and reliability in the distribution system. Of particular interest in Oregon, this situation is also providing opportunities for real benefit to utilities seeking to delay or phase in transmission and distribution investments.

In envisioning a path toward grid modernization and deeper integration of renewables, utilities are figuring out how distributed energy resources could provide load relief and serve distribution system needs. This is a case where DERs are both a challenge and a solution – they are part of what is driving the need for change in grid management and planning, but they have equal or greater potential to be part of the solution.

Consider these scenarios: Instead of adding or upgrading distribution feeders, utilities may implement a combination of **demand response[3]** during peak hours and **targeted energy efficiency** to reduce overall load growth to distribution constraint and delay or eliminate the need for capital investment. Distributed generation sources like **rooftop solar on the customer side of the meter** could be installed in locations on the grid that can best support it and thereby eliminate distribution constraints. **Battery storage with solar** could smooth out the impact of rooftop solar on the grid or be a flexible asset to provide demand response and peak mitigation.

How this transition to a modernized, resilient and flexible grid will evolve to meet these new needs is a question that can be, and is being, approached in a variety of ways. How do we value investments and benefits of targeted DER deployment versus those of traditional distribution system upgrades? What might be the role for Energy Trust of

Oregon in our future delivery of energy efficiency and renewable resource services to customers to support these efforts?

Oregon has begun the process of addressing use of DERs to alleviate distribution constraints. Oregon utilities have been reporting on smart grid enhancements that include both transmission and distribution upgrades and operations improvements. There are several open dockets with the Oregon Public Utility Commission (OPUC) on related topics, including Resource Value of Solar and Storage.

In 2017, Senate Bill 978 directed the OPUC to explore changes to the existing regulatory system and incentives that could accommodate industry trends towards utility or customer owned distributed energy resources. Oregon's investor-owned utilities as well as Bonneville Power Administration are interested in taking a proactive approach to distribution planning processes and exploring the integration of more DERs into the grid. Through Energy Trust, Oregon also has a strong program infrastructure for energy efficiency and renewable energy. This foundation for collaborative development of targeted demand-side management pilots is being explored with some of Energy Trust's funding utilities.

Oregon's needs for addressing grid constraints are less urgent than California or New York where the cost of building new infrastructure, especially in cities, is higher. But constraints on the transmission and distribution system can happen anywhere, and there is interest from all parties to avoid building infrastructure when less costly – and potentially cleaner – alternatives are available. Oregon's approach is to learn from other states while moving forward at a more deliberate pace.

This paper provides background and summarizes opportunities and challenges in implementing DERs, specifically related to delaying investment in distribution system upgrades. It draws on interviews with stakeholders in the Northwest and case studies from numerous states, including Oregon, to illustrate different strategies and identify potential pathways for Energy Trust. This national conversation is actively underway for electric utilities with needs to address distribution constraints. This paper focuses primarily on strategies for electric utilities. However, this is not solely an electric utility issue. Gas utilities may also face distribution constraints, particularly at peak times. Some gas utilities, including NW Natural in Oregon, are testing strategies to deploy targeted energy efficiency to offset gas pipeline constraints and ensure the safe and reliable delivery of natural gas.

Overview of Distribution Planning

The primary role of a utility is to ensure the safe, reliable and cost-effective delivery of electricity to their customers. The electric distribution system was designed to move electricity generated by a centralized power plant and deliver it to end-use customers through their transmission and distribution system. For natural gas utilities, transmission pipelines deliver natural gas to the distribution system of the local distribution company.

Figure 1 illustrates the layout of hardware of an electric distribution system includes:

- A distribution substation, which reduces transmission voltage from hundreds of kilovolts (e.g., 115 kV, 230 kV, 500 kV), to tens of kilovolts (12 kV is the most common);
- The feeders or circuits, which originate at the distribution substation and serve approximately 1,000 customers each;
- The customer, who is connected to the feeder by a service transformer, which reduces voltage from tens of kilovolts to hundreds of volts (e.g., 120 V for a typical household outlet or 240 V for an electric dryer).

This original design did not envision distributed energy resources, and instead assumed that power moved in a single direction from generation through transmission and distribution lines to reach end-use customers. As these new resources have emerged affecting the direction of power flows and as power demands have grown over the years, Oregon utilities have managed the relatively low penetration of DERs with moderate upgrades to their distribution systems; however, other states have challenges that are more acute.

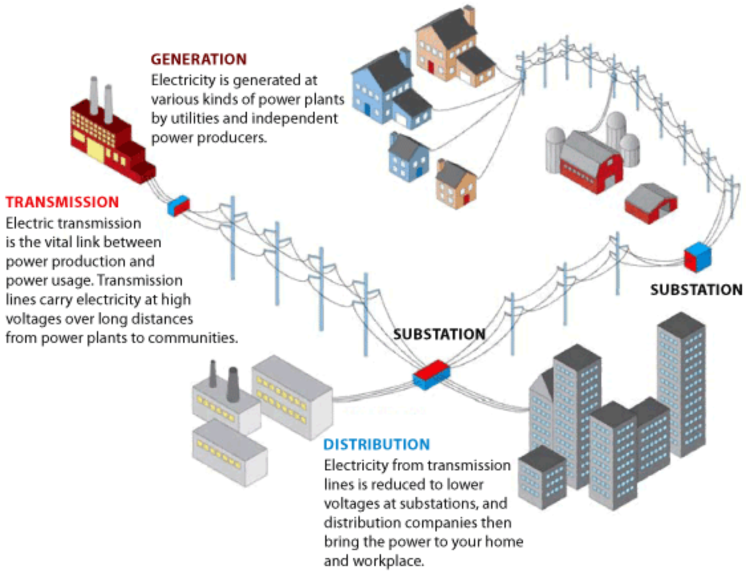


Figure 1: Layout of Typical Transmission and Distribution Systems

Utilities annually review their distribution systems against load forecasts to identify areas where new load could tax the distribution system. When faced with a distribution constraint, utilities first see whether they can reconfigure the distribution system by shifting loads through switches and by moving loads served by one substation to another substation. If this is insufficient to mitigate the constraint, the utility will look at investments in substation upgrades, capacitor bank replacements, or upgrading a feeder line to allow for more current-carrying capacity. More recently, utilities have considered non-wire alternatives[4], including DERs, to infrastructure investments; however, measuring the relative value of each of the varied alternatives is not clear-cut.

Oregon has taken steps to enable utilities to addresses this issue proactively. In the Northwest, the 7th Power Plan from the NW Power & Conservation Council[5] includes conservation resource projections for energy efficiency, distributed solar photovoltaic estimated costs and maximum achievable potential, and achievable potential for demand response in the region. This information informs plans for all utilities in Oregon.

In 2017, the OPUC indicated that utilities should begin distribution system planning to allow for the evaluation of the most beneficial placement and efficient use of new DERs.

Today's Considerations

I. Distributed Energy Resources and the Grid

To manage grid modernization costs many state regulators are starting to push for the deferral of upgrades to the transmission and distribution network through new investment in non-wire alternatives. Utilities and regulators are seeking long-term distribution planning approaches and acquiring analytical tools that support improved DER forecasting, assessment of DER locational value and analysis of least-cost hosting[6] capacity for rooftop solar. Depending on the scope of a distribution constraint, the types of DERs available, and the load forecasts, utilities may choose a number of different options.

Adding more DERs requires a comprehensive approach to grid modernization that, in turn, requires new operational capabilities for managing multi-directional power and data flows and variable grid conditions. These improvements can provide a more granular visibility into system conditions and the ability to meet load by reconfiguring the distribution grid and dispatch from a growing number of resources.

II. Opportunities: Using DER to address distribution system needs

Utilities can benefit from better DER planning in a number of ways. Providing up to date solar hosting capacity maps support a more efficient interconnection process while directing customers to invest in locations that do not lead to distribution constraints. More detailed planning expands the grid's capacity to accommodate DERs.

DERs, if deployed intentionally in specific locations on the grid, can provide a range of benefits for energy and capacity services and can also be a cost-effective alternative to traditional capital investment in infrastructure – "poles and wires."

- **Demand response** can be used to reduce load during peak times and shift usage to off-peak times
- **Battery storage systems** can provide both customer services and grid services. For instance, a battery storage system can store energy during off-peak for dispatch during peak demand times.
- **Energy Efficiency** reduces overall load, which can increase the hosting capacity of other DERs on the grid, with many measures also lowering load during peak times.
- **Solar** can provide generation to reduce load during daylight hours with the peak output dependent on the tilt and orientation of the array. Solar when paired with battery storage can become a DER option that utilities can call upon when needed.

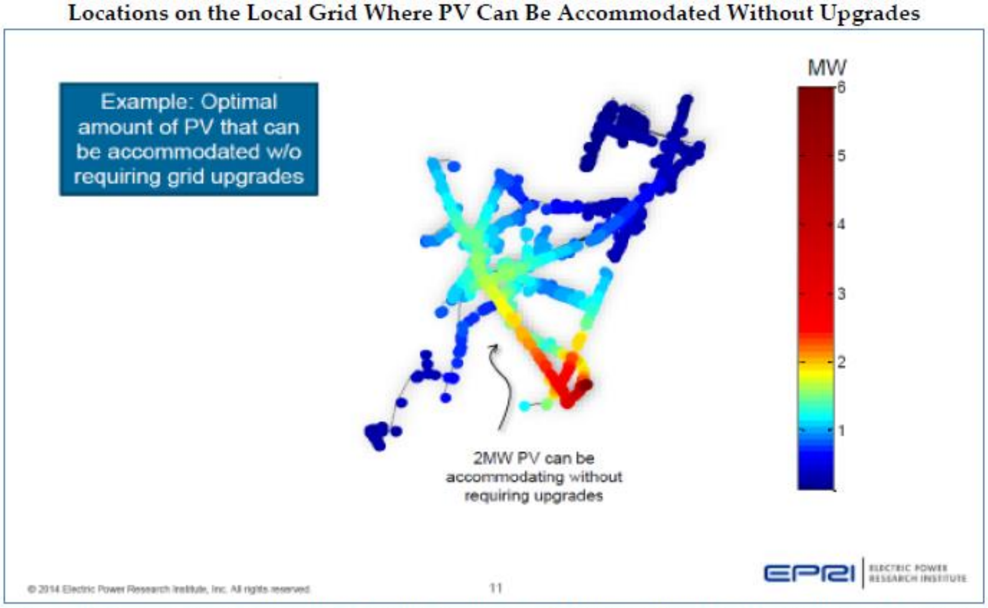
Grid conditions and DER attributes dictate which DERs will be the most viable. For example, DER that can be dispatched when the network's peak demand occurs is generally more valuable than one that is not.

As an example, according to the 7th Power Plan[7], distributed solar has no peak demand reduction potential during the 6 pm winter peak hour and only about 30% of installed solar system capacity occurs during the peak summer hour. Energy efficiency, including the current mix of Energy Trust offerings, contributes more capacity savings during the peak winter hour than the peak summer hour. By combining long-term planning processes that incorporate these complexities and grid modernization efforts that allow for better visibility and management of DERs, utilities can reap the benefits of DER expansion.

III. Challenges: Using DERs to address distribution system needs

Planning and forecasting tools have not kept pace with the evolving needs of the grid, and utilities are working hard to close this gap. Distribution constraints are not always apparent to DER developers because grid maps, like that shown in Figure 2, showing where DERs can be accommodated need to be created, updated frequently and made publicly available. This slows the analysis that can identify whether a given feeder can accept electricity from a DER and also ensure reliability.

Locations on the Local Grid Where PV Can Be Accommodated Without Upgrades



Source: EPRI map, presented in Greentech Leadership Group and CalTech Resnick Institute, "More Than Smart: Overview of Discussions Q3 2014 thru Q1 2015," Volume 2 of 2, March 31, 2015, page 42.

Figure 2: Example of DER Planning Tool

An emerging challenge for planners is implementing demand reduction efforts through targeted energy efficiency and demand response. Energy efficiency programs and their associated demand reduction cannot be easily attributed to a single location. Likewise, utilities may tap demand response to address generation capacity shortfalls and their demand response signals are made for the whole system, not specific areas. Developing strategies to localize both energy efficiency and demand response – make them more dispatchable -- is on the minds of distribution planners. Many grid operators, trained in the tradition of managing a distribution system fed by centralized power plants, are less confident in the reliability of DERs due to their frequently non-dispatchable nature.

Utilities have historically had a financial disincentive to invest in non-wires alternatives, including DERs, since utility revenues are based upon the value of investments in centralized assets comprising the utility's "rate base." But signs of change are in sight as states look at different policies, up to and including mandates and incentives for DER deployment. For traditional transmission and distribution upgrades or centralized generation plants, standard practice has been that utilities request to recover their costs through rates, while earning a negotiated rate of return on top of the cost of the investments. However, for energy efficiency and other DER investments, they may only recover their costs. This can make DER investment less attractive to the utility's bottom line.

Developing distribution management systems that provide greater visibility would help address these challenges. Having better ways of modeling and predicting how DERs will be adopted by customers (e.g., which type of DERs, where and at what rate) is one area for improvement. Enhancing operational control to view and manage what's happening in real time on the distribution system is another. Every piece of the grid matters in its management. The characteristics of each link in the chain, ranging from the characteristics and technology of the current feeder networks, to whether there are other DERs nearby, influences what approach is most cost-effective and robust for multiple, sometimes competing, grid management goals.

Current Policy Efforts and Case Studies

Regulators in some states are pushing for distribution planning changes and least-cost planning that incorporates DERs. Some utilities see this as an opportunity to meet their states' DER policy mandates while reducing distribution costs.

I. New York

The New York Public Service Commission instituted a *Reforming the Energy Vision* proceeding in early 2015 to address distributed generation and energy storage, and the ability of utilities and regulators to adopt them, in part to mitigate the relatively high cost of forecasted distribution system upgrades in New York. Through this top-down approach, the utilities are creating Distributed System Implementation Plans and tools to support valuation of DER and enable integration of higher levels of DER through third-party engagement in the market and power system. New York sees the future of the regulated utility as an enabler of customer choice and provider of distribution planning, integrated grids, and deployment of DER to cost-effective levels.

Prior to REV, New York has been proactive in integrating end-use efficiency into transmission and distribution system planning, with geo-targeted load reductions occurring since 2003 when distribution networks were approaching peak capacity. ConEd implemented geographically-targeted energy efficiency programs in over 1/3 of its distribution networks to delay or eliminate the need for distribution capacity expansion. Savings from these efforts were close to forecast and provided $300 million in net benefits to ratepayers[8].

In 2014, Con Ed received regulatory approval to invest in approaches to mitigate capacity constraints in Brooklyn and Queens and defer a $1 billion substation investment. The deferral of electric substations is expected until 2026 because of these efforts. Instead, a $150 million investment will cover increased incentives for customer-sited solutions, resulting in over 40 MW customer-sited load reduction measures (or $3.7 million per MW). Customer-sited load reduction could take the form of energy efficiency measures and on-site generation technologies.

II. California

In 2014, the California Public Utilities Commission (CPUC) initiated a Distribution Resource Plan proceeding that laid out the following goals for utilities:

- Characterize the ability of the utilities' systems to accommodate additional DERs
- Develop an approach to assign locational values in the distribution system
- Offer projections of DER growth and how that growth affects infrastructure investments
- Initiate pilot projects to demonstrate innovative technical and operational approaches to integrate DERs. In 2015, the California Investor-Owned Utilities filed distribution resource plans that described their proposed strategies to meet those goals.

Utilities and the CPUC are taking a bottom-up approach to their state's distribution system. They have jointly developed Integrated Capacity Analysis methods at the feeder level to identify the capacity of the distribution system to integrate DERs, and Locational Net Benefits Analysis methods to determine how to measure the value of DERs at specific locations on the distribution system. Southern California Edison and Pacific Gas & Electric have begun to explore how DERs, including energy efficiency, can be used to meet distribution system needs, looking at the load reductions achievable through energy efficiency at peak time periods and matching to the feeders that need it most.

III. Oregon

A. BPA: I-5 Corridor Reinforcement Project (South of Allston)

The Bonneville Power Administration had planned for an investment of more than $1 billion for 79 miles of 500 kV transmission line near Longview, Wash., called South of Allston, to address the issues of high congestion in its transmission system[9]. This project was halted in 2017 and BPA committed to evaluating how a non-wires alternative could alleviate constraints. Like other utilities, BPA is working on DER valuation analysis and screening criteria so that non-wires solutions can be evaluated as standard practice.

BPA began a two-year pilot in the summer of 2017 to analyze the costs, benefits and impacts of non-wires solutions South of Allston. It would be implemented on both sides of the meter -- customers will reduce demand on 10 summer days for four hours at a time, and BPA will forecast peak energy demands and then coordinate with generators to the south of the constraint to take the pressure off the transmission system. In terms of dispatchable resources, BPA is tapping into 46 MW of demand response for the pilot, but has chosen not to use storage at this time due to cost. BPA is also making targeted upgrades to system components – all in an effort to avoid building a new transmission line. If the pilot is successful at alleviating the strain, BPA will apply this approach to other congestion points in the system.

B. Pacific Power

Currently, Pacific Power is working with Energy Trust to identify areas where targeted community-focused DER solutions could improve system operation during specific locational peak hours and also possibly defer traditional system investments.

The first effort is a pilot in the North Santiam Canyon. The objective of this pilot project is to measure the impacts of increased marketing and outreach of existing Energy Trust energy efficiency offerings to residential, commercial and industrial customers. The results of this project will inform whether and how the utility and Energy Trust could jointly deliver targeted energy efficiency as a solution in areas at risk of distribution constraint.

Pacific Power also released a targeted locational demand response request for proposal, through which they expect to learn more about how to manage targeted demand response. The utility is developing screening criteria to help direct analysis to determine when non-wire alternatives would likely be cost-effective. The results of this pilot will produce data and findings to assist Pacific Power distribution planners in using these screening criteria.

> "PacifiCorp recognizes the role that distributed energy resources (DER) may play in the deferral or offset of traditional poles and wires infrastructure investments. Where feasible and cost-effective, DER solutions are expected to supplant traditional solutions for implementation.” [10]

C. NW Natural

Energy Trust is currently working with NW Natural to implement a multi-year pilot to develop cost, savings and timing estimates for peak-hour gas targeted energy efficiency strategies to help NW Natural plan for future capacity constraints. The pilot builds on expertise within Energy Trust program delivery and lessons learned from similar efforts. It will test the results gained through a range of delivery strategies, including but not limited to: targeted marketing, targeted delivery, and increased incentives. The pilot team will investigate the costs of these specific strategies that could help determine specific cost-per-therm for geographically targeted energy efficiency offerings.

Summary/Conclusions

I. How Do We Get There From Here? Enabling, Valuing, Planning And Regulating DERs

Reaching these goals requires that a few conditions be true:

DER Solutions are tested and reliable: Building the modern grid will require that currently available DERs, including demand response, storage and energy efficiency, are robust and reliable.

The value of DERs to the distribution grid is understood: Stakeholders in the industry must improve the valuation of DERs to the grid. Valuation methodologies must be developed and applied so distribution planners will have reliable data for decision-making on the locational net value of each DER.

Distribution planning tools exist and are in use: New solutions require a complete toolkit for planners to keep pace with changing DER integration. Utilities will help steer the market by incentivizing favorable locational deployment of DERs and dis-incentivizing unfavorable locations.

Grid modernization investments are made: All of these changes to optimize the current system are setting up a path toward the larger vision for grid modernization that can accommodate future complexity from even more DERs.

Utility policies and incentives are considered and developed: Policy changes will loom large as states address new areas, including setting conditions under which DER capacity procurements must be considered by utilities, and incentives for utilities to employ DERs to mitigate or defer distribution grid needs.

II. The Role for Energy Trust In Distribution Planning

Energy Trust serves roughly 70 percent of the state's electric ratepayers. The nonprofit's historic focus on energy efficiency and renewable energy programs has the potential to evolve to support partner utilities in different ways. Portland General Electric and Pacific Power serve very different territories and have distinct challenges in serving a growing population. Working with Energy Trust on geographically-targeted energy efficiency and renewable energy efforts to address distribution constraints or other future challenges with distribution could help all partner utilities defer costly distribution investment. One immediate opportunity is already underway to use targeted energy efficiency programs in communities to test what results are possible, what approaches are most effective and how much it will all cost compared to other non-wires alternatives or capital upgrades.

As explored earlier in this paper, Energy Trust is working currently with both Pacific Power and NW Natural to pilot how targeted energy efficiency and renewable energy program offerings can address distribution constraints with cost-effective solutions[11]. Based on this and on the development of locational avoided-costs, Energy Trust could potentially increase incentives incrementally in targeted locations.

Stakeholders see significant potential for using targeted energy efficiency as a lever for the distribution system, but they also warn of the risk of overcorrecting in the quest to meet locational needs. These stakeholders suggest careful consideration in the design of targeted energy efficiency and renewable energy efforts to ensure that they appropriately value locational benefits against other benefits.

All parties agree that a shared, big-picture view is necessary to build the grid of the future. Establishing a valuation framework to determine which DERs are cost-effective under what circumstances and how utilities and Energy Trust can combine DERs to alleviate distribution constraints is the research question at hand.

Energy Trust's next step is to continue on its path to learn from other states and from pilots here in Oregon. Developing these ideas from small-scale pilots to full-scale implementation will require that new distribution planning tools and processes be adopted by utilities. It also indicates a new paradigm for how the market interacts with utilities as they plan and operate the distribution system. Energy Trust's experience in working with customers, and with the businesses such as contractors, designers, builders and developers who serve the market, could be helpful to utilities as they make this transition.

About Energy Trust of Oregon

Energy Trust of Oregon is an independent nonprofit organization dedicated to helping utility customers benefit from saving energy and generating renewable power. Our services, cash incentives and energy solutions have helped participating customers of Portland General Electric, Pacific Power, NW Natural, Cascade Natural Gas and Avista save on energy bills. Our work helps keep energy costs as low as possible, creates jobs and builds a sustainable energy future.

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[1] Distributed Energy Resources, or DERs, is used in this paper as a term that includes rooftop solar, energy storage, demand response, combined heat and power, fuel cells and energy efficiency to deliver power to customers.

[2] https://energy.gov/under-secretary-science-and-energy/grid-modernization-initiative

[3] Demand response provides an opportunity for consumers to play a significant role in the operation of the electric grid by reducing or shifting their electricity usage during peak periods in response to time-based rates or other forms of financial incentives. Demand response programs are being used by some electric system planners and operators as resource options for balancing supply and demand. Demand Response can take many forms, including direct load control of air conditioning and industrial process load shifting. https://www.energy.gov/oe/activities/technology-development/grid-modernization-and-smart-grid/demand-response

[4] Non-wires alternatives are electric utility system investments and operating practices that can defer or replace the need for specific transmission and/or distribution projects, at lower total resource cost, by reliably reducing transmission congestion or distribution system constraints at times of maximum demand in specific grid areas

[5] https://www.nwcouncil.org/energy/powerplan/7/plan/

[6] Hosting capacity is defined as the amount of solar that can be accommodated without impacting power quality or reliability under existing control and infrastructure configurations

[7] https://www.nwcouncil.org/media/7149926/7thplanfinal_chap12_conservationres.pdf

[8] Gazze et all, 2010, ACEEE Summer Study

[9] The same issues that apply to deferring distribution are also useful in how it works on the transmission side.

[10] Pacific Power. 2017. *Pacific Power Smart Grid Oregon Annual Report.*

[11] See pages 8-9 for more information