Washington Utilities and Transportation Commission

Report on Current Practices in Distributed Energy Resource Planning

Operating Budget, Laws of 2017, Ch. 1, §142

December 31, 2017

Contents

Executive Summary

The 2017-18 biennial operating budget directed the Utilities and Transportation Commission (UTC) to, by Dec. 31, 2017:

> (R)eport findings and recommendations to the energy committees of the legislature on best practices and policies for electric utilities to develop distributed energy resource plans, applying the traditional utility regulatory principles of fairness, efficiency, reliability, and revenue stability. The report must address: A review of policies and practices for distributed energy resource planning in other states, an inventory of current utility distribution planning practices and capabilities in Washington, and recommendations for using distributed energy resource planning to inform utility integrated resource plans.[1]

Across the nation, interest in distributed energy resource (DER) planning has grown rapidly.[2] At least 16 states and the District of Columbia have active proceedings on the topic. This report studies 10 of them, including the work underway in D.C. While the motivation and goals for these proceedings vary across jurisdictions, a common set of principles and practices for DER planning is emerging across them. In general, the standards that states have adopted or are considering revolve around five overarching principles:

- Transparency: DER planning should fairly consider both wire-based and non-wires resource alternatives for meeting distribution system needs. Planning should optimize the investment decisions of customers and third parties by identifying points on the grid where distributed resources have greatest value.
- Coordination: Distribution plans should inform and interact with other utility planning processes, including integrated resource and capital budget plans.
- Flexibility: The planning process needs to improve over time and adapt to changing grid conditions, new technologies, and improved modeling capabilities.
- Reliability and Security: DER planning should ensure that reliability, physical security, and cybersecurity are maintained as the distribution grid changes.
- Inclusion: All customers should have opportunities to participate in grid modernization through tariffs and programs that compensate customers for the value of their distributed resources, with particular consideration given to low-income customers.

These principles generally apply to any utility developing a DER plan, but the specifics of how they are applied will vary. To understand how Washington utilities are currently approaching distribution system planning and identify opportunities for additional policy guidance, the UTC hired consultants to conduct a survey of Washington utilities. The team received responses from 12 utilities, which collectively serve about 80 percent of Washington customers.

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[1] Operating Budget, Laws of 2017, Ch. 1, §142.

[2] Broadly defined, a distributed energy resource (DER) is one that is connected to the distribution system and can either generate electricity or reduce the demand for electricity. Common examples are rooftop solar, energy storage, demand response, and energy efficiency.

The survey revealed that, in general, Washington utilities have already established themselves as leaders in developing robust grid monitoring capabilities and are well positioned to gather the data needed for DER planning. The survey also shows that Washington utilities are a diverse group with differing needs. Some larger utilities are already developing the tools of DER planning, while smaller utilities have not yet identified a need to do so.

To reasonably reflect the differing needs and capabilities of such a diverse group, DER planning policy must be broadly drawn. With that consideration in mind, the UTC respectfully recommends that any DER planning policies adopted by the Legislature be broad and flexible, allowing utilities and their oversight bodies to figure out the details and procedures that best fit the utility's characteristics. The Legislature may also want to consider adopting different standards based on utility size, as under the Energy Independence Act.

To guide the Legislature in this process, the UTC recommends the following best practices for DER planning. Any DER planning process should accomplish the following:

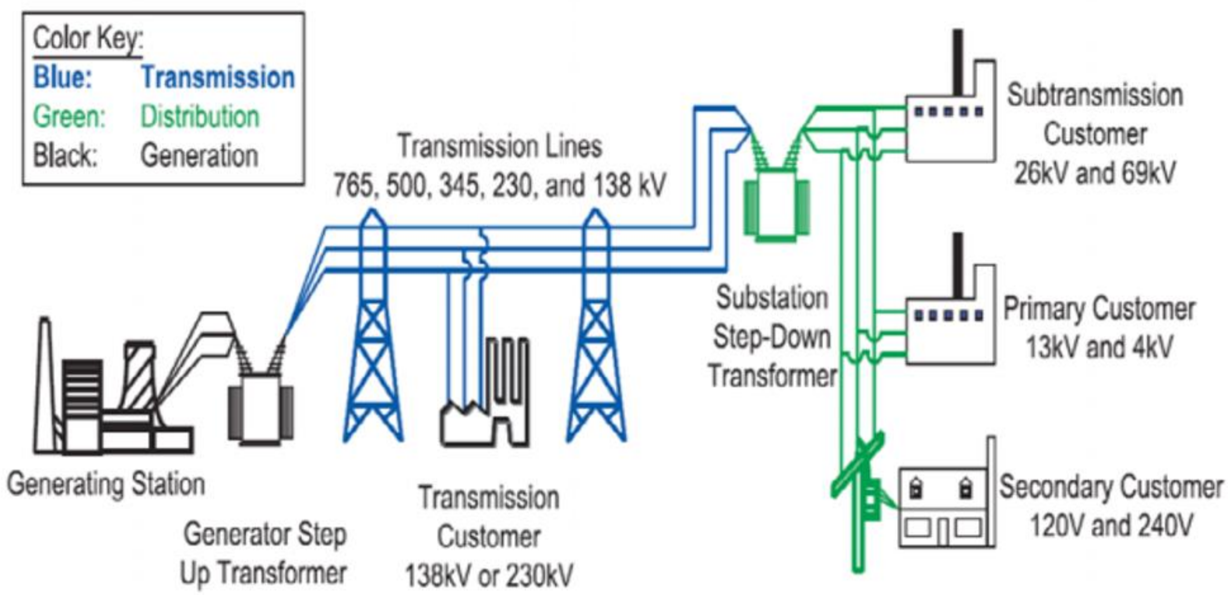
1. Identify the data gaps that impede the planning process and any upgrades (such as advanced metering and grid monitoring equipment) needed to obtain that data.
2. Propose monitoring and metering upgrades that are supported by a business case identifying how those upgrades will be leveraged to provide net benefits for customers.
3. Identify potential programs and tariffs to fairly compensate customers for the value of their distributed resources and ensure their optimal usage, including programs targeted at low-income customers.
4. Forecast, using probabilistic models, DER growth on the utility's system.
5. Identify all major, planned distribution system investments for the next 10 years and analyze non-wires alternatives for each investment.
6. Competitively procure the DER needs identified in the plan through detailed requests for proposals that identify the specific needs at each location.
7. Include the DERs identified in the plan in the utility's integrated resource plan (IRP). DER plans should be used as inputs to the IRP process, similar to the way that conservation potential assessments are used.
8. Discuss, at a high level, how the utility is adapting cybersecurity and data privacy practices to the changing distribution grid.
9. Discuss lessons learned from the planning cycle and identify process and data improvements planned for the next cycle.
10. Include a transparent approach for involving stakeholder input and feedback throughout the process.

In accordance with the Legislature's directive, this report is divided into four sections. The first section provides additional background and industry context for the report. The second section presents a summary of DER planning initiatives in various stages of development in other jurisdictions and key takeaways from each for Washington policymakers to consider, followed by a summary of the UTC's current DER planning proceeding. In the third section, we report the findings of a survey that contractors Demand Side Analytics and Apex Analytics conducted with Washington utilities to identify their distribution system planning practices. The final section presents a summary and recommendations for the Legislature's consideration.

Background and Policy Context

The Legislature's directive for this report comes at a time of significant change in the electric industry. Historically, the electric grid was designed around large, central generation facilities that, due to their size and environmental impacts, were generally sited away from population centers. Electric system planning, then, was a matter of acquiring sufficient generation resources to meet projected customer needs, and then building transmission and distribution systems to carry the energy to customers. Figure 1 illustrates this one-way system.

Figure 1: Traditional Electric Grid Structure[3]



However, rapid technological change in recent years has begun to upend that traditional structure. Customer-sited generation resources are now pushing energy onto the distribution grid, creating two-way energy flows on a system that was not necessarily designed for that purpose. Electric vehicles have the potential to increase customer demands in ways that could strain the distribution system, particularly if charging behaviors are not proactively managed. These changing demands exacerbate the challenges that utilities face in maintaining aging equipment. At the same time, technology now enables utilities and their customers to automatically adjust their loads based on utility need and customer preference.

[3] U.S. Department of Energy, "Grid Modernization Multi-Year Program Plan" (November 2015) at page 5.

Where utilities once planned to meet predictable customer loads with predictable generation resources, changing customer demands and growing saturation of variable generation resources, such as solar and wind resources, have introduced uncertainty on both the supply side and the demand side of utility operations. But technological advancements also hold out the potential for utilities to more closely monitor the health of their distribution systems and provide tools—such as aggregated demand response, energy storage, and time-based price signals to customers—to match supply and demand at all times. Meanwhile, improved grid monitoring and metering equipment offer utilities the ability to maintain reliability and respond to outages more quickly.

In this environment, utilities, regulators, and policymakers are turning their attention to grid modernization efforts. Broadly defined, grid modernization refers to any activity designed to adapt the distribution grid to incorporate or enable new technologies. Advanced metering and monitoring, distributed generation integration, and DER planning are some of the most common examples of grid modernization proceedings taking place around the country.

The North Carolina Clean Energy Technology Center at North Carolina State University provides a quarterly report on grid modernization efforts around the United States. In its most recent report, which reflects the second quarter of 2017, the Center identified 36 states, as well as Washington, D.C., that are engaged in some form of grid modernization efforts.[4] Collectively, these efforts are moving toward an interconnected grid model that allows for energy to flow in more than one direction and that enables participation from a wide variety of customer-sited resources that can be leveraged to meet grid needs. Figure 2 illustrates this dynamic.

Figure 2: Modern Grid Electric Structure[5]

[4] North Carolina Clean Energy Technology Center, "50 States of Grid Modernization – Q2 2017 Quarterly Report," page 10.
[5] U.S. Department of Energy, "Grid Modernization Multi-Year Program Plan" (November 2015) at page 5.

Planning for grid modernization requires that a utility identify not only what to build, but where and when. This type of planning is far more complex than traditional utility planning efforts. Traditional distribution system planning was an exercise of ensuring all substations and wires in a utility's system had the capacity to serve customers attached to them, and if there was not sufficient capacity, utilities had a straightforward solution to add more capacity through additional wires and transformers. Traditional IRP planning, meanwhile, requires utilities to consider a variety of resource options across of variety of uncertain futures, including factors like weather, customer needs, technology, and policy – but at a system-wide level where each scenario only has one set of needs to meet and a consistent set of resource values.

DER planning combines the complexities of both exercises. A utility still must look at every line and every substation in its system to determine if existing equipment can meet customer needs, but now must do so across a variety of potential futures that vary based on changing customer usage and uncertain DER adoption rates. And instead of evaluating a limited set of wire-based options, the utility must consider a dynamic portfolio of resource options, whose values will change based on the specific needs of each site.

Despite these challenges, it is increasingly important that utilities proactively develop their ability to evaluate distributed resources and optimize their placement and usage for the grid. Many of the states presented below are playing catch-up, trying to develop the means to optimally site and use distributed resources after there already has been a proliferation of those resources on their systems. The ability to identify the value of a given resource in a given location will continue to grow in importance, because as the system becomes more dynamic, resource values do, too.

Furthermore, as utilities replace aging grid infrastructure, they face a new host of replacement options that require more detailed analysis than historically was needed. Even utilities that are not immediately pressed to integrate distributed generation may find that new technologies offer more cost-effective ways of serving customers than traditional infrastructure investments have been able to do. The Bonneville Power Administration (BPA) recently demonstrated this by electing to forego a planned transmission line between southern Washington and northern Oregon. BPA instead met local needs through a more cost-effective suite of non-wires options.[6]

The rapid pace of innovation also magnifies the risk of long-term investments. As the Washington, D.C. Public Service Commission explained in its distribution system modernization proceeding, "rapid technological change increases the danger of 'stranded assets'—capital investments that turn out to be unneeded."[7] If a utility does not adequately anticipate customer and system needs, its investments may become obsolete before their costs have been recovered. In the case of traditional distribution system infrastructure investments, which have useful lives

[6] https://www.bpa.gov/transmission/CustomerInvolvement/Non-Wire-SOA/Pages/default.aspx
[7] Washington D.C. Public Service Commission, "Formal Case No. 1130, in the Matter of the Investigation into Modernizing the Energy Delivery System for Increased Sustainability, Order No. 19143" (Oct. 19, 2017) at Attachment A (MEDSIS Vision Statement) page 4.

of 40 years or more, the risk of stranded assets become much larger. DER planning provides utilities with important, additional information to ensure that investments are needed and prudent.

Study of Other States

At least 16 states have initiated formal procedures addressing DER planning. These states are at various points in their efforts. Some states have mature proceedings that have been underway for several years and have already implemented policy changes with observable effects. Other states are still somewhere in the middle, having issued guidance on DER planning but having not yet reviewed a plan. Most states studied are, like Washington, still in the early procedural phases of information gathering and stakeholder discussions.

While state utility commissions serve as the primary venues for these discussions, the proceedings have begun through various means. In some states, utility commissions have initiated the process. In other states, the efforts are the result of legislative or executive mandates. In at least one state, the proceeding was requested by utilities and other stakeholders. Some states have multiple, interrelated proceedings, which were initiated through a combination of these sources.

This report will summarize DER planning proceedings in nine states and the District of Columbia. For each jurisdiction, the report identifies the stage of development (mature, intermediate, or early) and the primary driver (commission, legislative, executive, stakeholder, or various). Each summary will provide a brief overview of the process, followed by a section that presents policy considerations and key takeaways for Washington.

Collectively, these 10 proceedings reflect the wide range of procedural approaches and policy options related to DER planning. From New York, which is several years into a multi-faceted process that includes redefining the responsibilities of its electric utilities, to Nevada, which is in the initial phase of a more modest approach, this report presents a broad overview of the evolving best practices in DER planning. While the motivation and goals for each of these states is different, their diverse experiences provide a general architecture of DER planning that has informed the recommendations in this report.

1. **New York** – Mature, Executive-Driven[8]

   Summary: In 2015, the State of New York initiated a sweeping re-evaluation of its energy policies known as the Reforming the Energy Vision (REV) initiative. As part of REV, the New York Public Service Commission (NYPSC) launched a multi-track, multi-year proceeding with the goal of redefining the state's utilities as Distributed System Platform Providers (DSPPs). As DSPPs, the primary responsibility of the state's electric companies is

[8] For more information, visit https://rev.ny.gov/.

to plan and operate an open distribution system that enables customers and third parties to actively participate in grid modernization and retail transactions, with both the utility and non-utility service providers.

To effectuate the transition, NYPSC directed each utility to prepare a Distributed System Implementation Plan through a transparent, public process. The initial plans were divided into a series of three filings: a stakeholder engagement plan, followed by an initial distribution plan that contained an overall assessment of the utility's distribution system and immediate needs, and, finally, a supplemental distribution plan to establish a framework for future plans.[9]

Going forward, New York utilities will file Distributed System Implementation Plans every two years, each covering a five-year planning period. The plans are to include the following components:

- Location-specific demand and distributed resource adoption forecasts;
- A review of previous forecast accuracy and identified methodological fixes;
- An assessment of available distributed resources and their technological capabilities;
- A report on current demonstration projects and how they are being used to inform the utility's resource planning;
- A report on programs for low-and moderate-income customers;
- A capital investment plan for transmission and distribution system upgrades, including a report on expenditures in those areas over the previous five years and a description of the utility's process for preparing the investment plan;
- Identification of locations on the utility's distribution systems where distributed resources would be most valuable;
- Identification of planned infrastructure projects and the potential for distributed resources to displace or reduce them;
- A discussion of cybersecurity and data privacy issues; and
- A hosting capacity[10] map and detailed report for problematic circuits.

Utilities are also required to report on a number of technical aspects in their distribution plans, including distribution system reliability, voltage optimization, generator interconnection processes, advanced metering capabilities, and customer data management practices.

Key takeaways: In redefining its utilities around the distribution system, New York is at the edge of distribution system policymaking. But New York's redefinition of utilities as DSPPs

[9] "Order Adopting Distributed System Implementation Plan Guidance," New York Public Service Commission, Case 14-M-0101 (April 20, 2016) at page 3.
[10] A hosting capacity analysis looks at every distribution circuit on a utility's system to determine how much additional distributed generation it can host before upgrades are required.

is rooted in the state's previous decisions to unbundle electric system functions[11] and to establish a statewide competitive market for generation, making that aspect likely incompatible with Washington's regulatory environment. However, the NYPSC's DER planning framework is a well-reasoned and thoroughly vetted document that sets the standard for DER planning. A key element of the New York proceeding is developing rules to ensure utilities are indifferent, from a profit perspective, as to whether transmission and distribution needs are addressed through traditional infrastructure (wires) or distributed energy resources (non-wires alternatives).

2. **Massachusetts** – Mature, Commission-Driven[12]

Summary: In 2012, the Massachusetts Department of Public Utilities (MDPU) initiated an investigation into the modernization of the electric grid. In June 2014, the MDPU ordered its three regulated electric companies to file 10-year modernization plans by August 2015. The MDPU's order identified four objectives for the plans:

- reducing the effects of outages;
- optimizing demand, including reducing system and customer costs;
- integrating distributed resources; and
- improving workforce and asset management.[13]

The MDPU established expansive requirements for the plans, directing utilities to identify not only infrastructure upgrades, but customer education and outreach, research and development programs, and new metrics for evaluating performance. The plans are divided into two components. A short-term investment component identifies capital investments in the first five years of each plan, and a long-term component identifies all grid modernization efforts over 10 years. Any investments identified in the five-year plan must be supported by a comprehensive business case analysis.

The initial plans were filed in August 2015 and have undergone extensive adjudicatory review, with an order forthcoming. Utilities will be required to update their grid modernization plans every time they file a distribution rate case with the MDPU, which must be at least every five years.

Key takeaways: Like New York, Massachusetts is a deregulated state, meaning that the utility functions of generation, transmission, and distribution have been disaggregated.

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[11] Unbundling refers to separating the functions of generation, transmission, and distribution into separate business entities. Most Washington utilities are vertically integrated, meaning that the functions of generation, transmission, and distribution are managed by the same entity.

[12] For more information, visit http://www.mass.gov/eea/docs/eea/gwsa/energy-generation-and-distribution/electric-grid-modernization.pdf.

[13] "Investigation by the Department of Public Utilities on its own Motion into Modernization of the Electric Grid," Massachusetts Department of Public Utilities, Docket 12-76-B (June 12, 2014) at page 9.

However, also like New York, the state has developed a more generic approach to DER planning with elements replicable by other utilities, such as reliability improvements, distributed resource integration and optimization, and identification of new technologies to improve efficiency of utility operations.

3. **California** – Mature, Various[14]

Summary: Through various proceedings, the California Public Utilities Commission (CPUC) is engaged in a sweeping approach to DER planning and modernization. In one proceeding, the CPUC adopted rules for DER planning as directed by the state legislature.[15] To facilitate the development of distribution plans, the CPUC required utilities to develop hosting capacity analyses, in which utilities go line-by-line through their distribution systems to identify where distributed generation can be installed, without requiring grid upgrades, to manage the additional two-way power flow. To work out the details of DER planning, the CPUC established three distinct working groups composed of representatives from commission staff, utilities, industry experts, and other stakeholders, facilitated by a third-party consultant. The first, the Distributed Resource Planning Working Group, is focused on developing methodologies for the hosting capacity analysis (which California calls an integrated capacity analysis) and determining locational net benefits of distributed resources, informed by demonstration projects.

Another workgroup is developing methodologies for distributed resource and distribution system load forecasting, while a third workgroup is working to coordinate the state's various distributed resource programs into a cohesive approach to building energy management. More information on each workgroup and its progress is available at https://drpwg.org.

In a separate proceeding, the CPUC is using the results of the hosting capacity analyses to evaluate whether changes to its interconnection rules are required to further facilitate distributed resource development.[16] In another relevant proceeding, California Independent System Operator (CAISO), which operates most electric generation and transmission in California, is developing policies to ensure that DERs can participate in the CAISO market.[17]

Key takeaways: The CPUC's decision to require utilities to conduct hosting capacity analyses for their entire distribution system has greatly increased transparency of the utilities' grid operations. However, those analyses are resource-intensive and were driven by the state's high penetration of distributed generation resources.

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[14] For more information, visit http://www.cpuc.ca.gov/General.aspx?id=5071.
[15] http://www.cpuc.ca.gov/General.aspx?id=5071
[16] http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M192/K079/192079467.PDF
[17] http://www.caiso.com/informed/Pages/StakeholderProcesses/EnergyStorage_AggregatedDistributedEnergyResources.aspx

The locational net benefits analysis workgroup has not yet reached a consensus on best practices, but its report to the CPUC is a good tool for establishing the basic framework of locational analysis. California's model of using utility-funded consultants to facilitate the process is a model that also has been adopted elsewhere.

4. **Michigan** – Mid, Commission-Driven[18]

   Summary: In separate rate case orders early in 2017, the Michigan Public Service Commission (MPSC) directed the state's two major investor-owned utilities to begin filing annual distribution investment and maintenance plans in January 2018, with draft plans due in August 2017 for review. Utilities were directed to address in the plans electric distribution system conditions (including age and the useful life of existing equipment), system goals and related reliability metrics, load system forecasts, and maintenance and upgrade plans. The MPSC held a public hearing and comment period for the draft plans, which concluded in September.

   Key takeaways: Where distribution plans have been required, states have generally engaged in extensive stakeholder processes to determine how the plans should be prepared, prior to their being filed. Michigan has taken a more aggressive approach, requiring the utilities to file plans first and then work out details through iterative reviews with stakeholder participation.

5. **Minnesota** – Early, Stakeholder- and Commission-Driven[19]

   Summary: The e21 Initiative, a consortium of stakeholders led by Minnesota's two large investor-owned utilities, released a report in December 2014 detailing a plan for transition to "a more customer-centric and sustainable framework for utility regulation in Minnesota." One of the report's many recommendations was that the state convene a DER planning and grid modernization stakeholder process.

   In 2015, the Minnesota Public Utility Commission (MPUC) convened that process with three guiding questions:
   - Are we planning for and investing in the distribution system that we will need in the future?
   - Are planning processes aligned to ensure future reliability, efficient use of resources, maximize customer benefits, and successful implementation of public policy?

[18] For more information, visit http://efile.mpsc.state.mi.us/efile/ (Search docket U-17990 or U-18014).
[19] For more information, visit https://www.edockets.state.mn.us/EFiling/edockets/searchDocuments.do?method=showeDocketsSearch&showEdocket=true&userType=public (Search Docket 15-556).

- What commission actions would support improved alignment of planning for and investment in the distribution system?[20]

MPUC held several workshops and rounds of comments before sending out a questionnaire to the state's utilities for more information about their current DER planning practices, capabilities, and recommendations. Comments were due in September, and the next step is not clear at this time.

Key takeaways: Minnesota's DER planning efforts have been marked by a lengthy stakeholder process that has spanned more than two years and continues to unfold. The process has generated a substantial amount of information from utilities, interest groups, consultants, and the U.S. Department of Energy, making the Minnesota proceeding a valuable source of information for policymakers.

6. **Rhode Island** – Early, Legislative- and Commission-Driven[21]

Summary: In 2006, the Rhode Island Legislature directed electric and natural gas distribution companies to prepare annual system reliability and least-cost procurement plans. In the plans, utilities detail how they will employ energy efficiency, distributed generation, demand response, and other generation resources to maintain system reliability.[22] When the state adopted revenue decoupling for its utilities in 2010, it also required the utilities to file annual infrastructure, safety, and reliability spending plans.[23]

Noting the overlap between these and other state policies, the Rhode Island Public Utility Commission (RIPUC) opened a docket in March 2016 to investigate the impact of the changing distribution system on utility operations and rate design. In August 2017, RIPUC issued non-binding guidance for utilities to use a new framework for determining the cost effectiveness of distributed resources and to propose rates that adequately compensate distributed resources for the value that they provide to the system.[24]

In March 2017, Governor Gina M. Raimondo directed RIPUC to work with the Rhode Island Division of Public Utilities and Carriers[25] and the Rhode Island Office of Energy Resources to identify regulatory changes that would leverage new technologies to create a cleaner, more affordable, and reliable electric grid. The agencies released a report in November that

[20] Minnesota Public Utilities Commission, "Building a Minnesota Conversation on Grid Modernization with a Focus on Distribution Systems" (May 12, 2015) at page 12.
[21] For more information, visit http://www.ripuc.ri.gov/utilityinfo/electric/DSP.html.
[22] State of Rhode Island General Laws, Section 39-1-27.7.
[23] State of Rhode Island General Laws, Section 39-1.27.7.1.
[24] In re: Investigation into the Changing Electric Distribution System and the Modernization of Rates in Light of the Changing Distribution System," Rhode Island Public Utilities Commission, Docket 4600-A (Aug. 3, 2017) at pages 5-8.
[25] Utility regulation in Rhode Island is divided into two agencies. The Rhode Island Public Utility Commission houses the commissioners, while the Rhode Island Division of Public Utilities and Carriers is functionally equivalent to commission staff.

identified 17 specific recommendations ranging from utility business models to beneficial electrification. The report contained the following recommendations related to DER planning:

- Monetization of new distribution system value streams by charging third parties for data, access, and services provided by distribution system;
- Demonstration that the utility is meeting reliability and cyber security thresholds;
- Inclusion of operating expenses in planning and ratemaking, to reduce the bias that utilities have toward capital-intensive projects;
- Deployment of advanced metering technology, supported by a business case that includes time-varying rates;
- Coordination with wireless carriers to share costs of building an advanced communications network for the distribution system;
- Synchronization of DER planning with other planning processes;
- Improvement of distribution system planning forecasts;
- Compensation for DERs based on their locational values to the system; and
- Inclusion of stakeholder feedback in the planning process.[26]

Key takeaways: Rhode Island differs from Washington in that it has retail competition for electricity and its process is broader that DER planning, dealing with utility business model reform and electrification as well. But the DER planning principles identified in its multi-agency report affirm many of the principles identified in other states, while adding some innovative thoughts around reducing the cost of grid modernization through cost sharing and monetization of the resulting communications network and the data it provides.

7. **Washington, D.C.** – Early, Stakeholder- and Commission-Driven[27]

Summary: In June 2015, the Public Service Commission of the District of Columbia (DCPSC) initiated an investigation, "Modernizing the Energy Delivery System for Increased Sustainability." The investigation came in response to stakeholder requests in other proceedings for the DCPSC to enable more distributed generation in the District.

After three public workshops, a staff report, and two more rounds of public comment, DCPSC staff issued a proposed vision statement for the proceeding on Oct. 18, 2017. Public comments were due on Dec. 5 and reply comments are due Jan. 4.

The proposed vision statement is a sweeping document that identifies 23 discrete priorities for DER planning and modernization in the District. If adopted, the statement would direct utilities to prepare distribution resource plans that identify ways to enable distributed energy

[26] "Rhode Island Power Sector Transformation: Phase One Report to Governor Gina M. Raimondo," November 2017, at pages 10-12.
[27] For more information, visit https://edocket.dcpsc.org/public/search/casenumber/fc1130.

resources, with a focus on analyzing non-wires alternatives. Utilities would be required to modernize the distribution grid to enable greater customer interaction and participation by customers of varying income levels. It would also require utilities to develop cybersecurity and data privacy protections.

Key takeaways: Washington, D.C. is still in the early stages of its process, but the language of the proposed vision statement suggests that the process will be thorough and worth following. The focus on integrating distributed resources and analyzing non-wires alternatives means that the process will explore the matter of calculating locational benefits.

8. **Illinois** – Early, Commission- and Legislative-Driven[28]

Summary: In March 2017, the Illinois Commerce Commission (ICC) announced the NextGrid initiative, an expansive undertaking designed to identify and address regulatory changes made necessary by environmental concerns and technology development. In adopting the resolution that created NextGrid, the ICC cited Illinois' history of energy policy development, particularly its early efforts to create retail choice and more recent legislation to provide support for zero-emission electricity generation resources.

NextGrid is an 18-month process that consists of seven working groups studying various issues on parallel tracks. One working group is dedicated to distributed resource integration and DER planning. Another working group is studying how to leverage advanced metering and communication technologies to enhance customer value. Other groups are studying reliability, the involvement of underserved populations, the role of distributed resources in energy markets, regulatory and environmental issues, and ratemaking.

To manage the process, the ICC hired electrical engineering professors from the University of Illinois at Urbana-Champaign to act as independent facilitators. The ICC also required its regulated utilities to fund the work of the facilitators. NextGrid officially launched in October 2017.

Key takeaways: As one of the earliest states to adopt retail choice, Illinois is approaching the issue of distribution system modernization from a different regulatory framework than Washington. But while NextGrid is still in its early stages, its structure is informative in that it recognizes that distribution system modernization is not just about technology integration. Modernization also raises regulatory, environmental, social, and economic issues. Illinois is also using California's approach of using utility-funded consultants to facilitate the process.

9. **Hawaii** – Mid, Stakeholder- and Commission-Driven[29]

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[28] For more information, visit https://nextgrid.illinois.gov/.
[29] For more information, visit http://dms.puc.hawaii.gov/dms/DocketSearch.

Summary: Driven by high electricity prices associated with its oil-fired generation fleet, Hawaii in 2015 became the first state to adopt a 100 percent renewable portfolio standard (RPS), with a target of 2045. Citing the need for significant electric grid updates to enable the RPS requirement, the Hawaiian Electric Companies (HECO) filed a Smart Grid Foundation Project with the Hawaii Public Utilities Commission (HPUC) in early 2016, asking for approval of a $340 million capital expenditure plan to install advanced meters and other distribution system upgrades.[30]

HPUC denied the application in January 2017, determining that the plan was too narrowly focused and failed to address pressing issues such as integrating customer-sited generation resources. HPUC ordered the companies to file, in June 2017, a Grid Modernization Strategy that takes a more holistic approach to grid modernization vetted by stakeholders.[31] HECO filed a draft plan by the deadline and a final plan in August 2017.

HECO's final grid modernization plan broadly identifies changes needed to grid architecture, supported by a proposed DER planning process and cost-effectiveness screening tool to identify optimal investments. The plan considers multiple scenarios for grid modernization and identifies a near-term road map and related capital projects for modernization efforts. Finally, the plan contains a customer engagement strategy.[32]

Public comments on HECO's grid modernization plan were due by September 13, 2017. HPUC is currently reviewing the plan to determine next steps.

Key takeaways: The impetus for Hawaii's grid modernization efforts—integrating large amounts of distributed generation—is not yet an issue in Washington. However, HECO's proposed procedure for DER planning provides a detailed framework for incorporating DER planning into existing resource planning processes. This framework allows for transparency and stakeholder participation. Finally, where HECO's DER planning identifies a need on the distribution grid, the company will analyze wires and non-wires alternatives.

10. Nevada: Early, Legislature-Driven[33]

Summary: In June 2017, the Nevada Legislature amended its IRP statute to require utilities to include distributed resources plans in their IRPs.[34] The new law requires the distributed resources plans to:

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[30] Hawaii PUC, Docket 2016-0087, "Application of Hawaiian Electric Light Company, Inc., Hawai'I Electric Light Company Inc., and Maui Electric Company, Limited" (March 31, 2016) at page 7.
[31] Hawaii PUC, Docket 2016-0087, Order No. 34281, "Dismissing Application Without Prejudice and Providing Guidance for Developing a Grid Modernization Strategy" (Jan. 4, 2017) at pages 3-4 and 67.
[32] Hawaiian Electric, Maui Electric, and Hawai'I Electric Light, "Modernizing Hawai'I's Grid for Our Customers," at page 6.
[33] For more information, visit http://pucweb1.state.nv.us/PUC2/(X(1)S(gxz2rxadmsfv4yf2qgy2msxl))/DktDetail.aspx.
[34] Nevada Revised Statute 704.741(5).

- Evaluate the locational benefits of distributed resources;
- Identify or propose tariffs that would enable the deployment of cost-effective distributed resources;
- Propose methods of cost-effectively coordinating various programs and incentives to maximize the locational benefits of distributed resources and reduce their costs;
- Identify any investments necessary to improve the integration of cost-effective distributed resources; and
- Identify remaining barriers to distributed resources, including safety standards.

Nevada utilities file IRPs every three years, and the first distribution plans are due with the 2019 IRP filings. The Nevada Public Utilities Commission (NPUC) initiated a rulemaking in September to implement the law. There have been two rounds of public comments and a workshop thus far.[35]

The Nevada Legislature also passed several other bills that will impact utility resource planning in 2017, including changes to energy efficiency programs, a directive to identify optimal locations for energy storage projects, a possible energy storage mandate, and procedural changes to increase public involvement in the IRP process. NPUC is conducting seven other parallel rulemakings to implement the various statutory requirements that were added in the 2017 session.

Key Takeaways: Of all the states on the list, Nevada is the most directly comparable to Washington. Like Washington, it is served by vertically integrated utilities, both investor- and consumer-owned. Also similar to Washington, Nevada has utilities participating in the Energy Imbalance Market and has an energy mix similar to Washington's investor-owned utilities. Its process will be worth following closely.

UTC Proceeding

In September 2016, the UTC initiated a rulemaking to update its IRP rules to reflect new technologies and planning practices that have emerged since the current rules were adopted in 2006.[36] The UTC's rulemaking is proceeding along six tracks: energy storage, transmission and distribution system planning, avoided costs, requests for proposals, flexible resource modeling, and general/procedural improvements.

The transmission and distribution system modeling track been discussed at two Commission workshops and in two rounds of written comments. Commission staff issued a draft framework for incorporating transmission and distribution system planning into the IRP process in March

[35] Nevada Public Utilities Commission, Docket 17-08022.
[36] The UTC's IRP rules are WAC 480-90-238 (natural gas) and 480-100-238 (electric). The rulemaking docket is U-161024.

2017.[37] The framework generally calls for investor-owned utilities to analyze their distribution system in every IRP cycle and identify any needed, major infrastructure investments. For each identified need, the utility would analyze all available resource options (wires and non-wires) and identify the least-cost resource or mix of resources to meet the need, then procure those resources through a competitive process.

The UTC plans to issue draft rules for stakeholder comment in early 2018.

Survey of Washington Utilities

To compile an "an inventory of current utility distribution planning practices and capabilities in Washington" as directed by the Legislature, the UTC retained the services of consultants from Demand Side Analytics and Apex Analytics (DSA/Apex) to survey Washington utilities regarding their distribution planning practices.

The UTC selected DSA/Apex through a competitive solicitation, based on the team's blend of subject matter expertise and familiarity with Washington's complex regulatory landscape. The project lead was Josh Bode, partner and principal consultant at Demand Side Analytics, who has developed DER planning and distributed resource valuation tools in New York, California, and Rhode Island.[38] Lauren Gage of Apex Analytics provided technical support, leveraging her experience with the Bonneville Power Administration (BPA) and the Northwest Power and Conservation Council's Regional Technical Forum to tailor the survey to Washington utilities and analyze its results.[39] DSA/Apex has been invaluable in this process, and the UTC is pleased to present their findings to the Legislature.

DSA/Apex designed an in-depth, 59-question survey that was administered online. With the help of the Washington Public Utility District Association (WPUDA), the survey was sent to nearly every utility in the state.

Before presenting the survey's findings, it is important to note two points. The first is that the survey was designed to gather general information about a utility's size, distribution system characteristics, and DER planning practices. It was not designed to imply that a utility should be conducting a given practice, and the fact that a given utility has not adopted a particular practice should not be taken as a critique of the utility. Rather, the purpose of the survey was to identify current practices and challenges utilities face for the purpose of crafting recommendations that fairly consider the needs and capabilities of all Washington utilities.

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[37] See https://www.utc.wa.gov/docs/Pages/DocketLookup.aspx?FilingID=161024, in the March 20, 2017, Notice of Workshop entry.
[38] For more information about Demand Side Analytics, visit www.demandsideanalytics.com.
[39] For more information about Apex Analytics, visit https://apexanalyticsllc.com.

The second point is that responses related to transmission system planning practices must be considered in context. The survey asked utilities about both their transmission and distribution systems, because in some cases a project that operates at transmission voltage may actually serve more of a distribution function – improving power flows within the utility's system to better meet internal customer needs. But it is important to note that all Washington utilities rely on BPA's transmission system to some degree. Smaller utilities that rely wholly on BPA for transmission services engage in transmission system planning through BPA's processes and, therefore, have no need to develop in-house transmission planning procedures.

With those points in mind, Figure 3 begins the presentation of the survey, identifying the names and sizes of the 12 utilities who responded.

Figure 3: Summary of Responding Utilities

Completed Surveys	Number of Customers	Size Category
Puget Sound Energy	1,103,611	Large
Seattle City Light	422,809	Large
Snohomish PUD	337,063	Large
Avista	246,435	Large
Clark PUD	195,142	Large
Tacoma	174,558	Large
PacifiCorp	128,983	Large
Chelan PUD	49,058	Small
Tanner Electric Cooperative	4,704	Small
Parkland Light & Water	4,555	Small
Kittitas PUD	4,304	Small
Ohop Mutual Light Company	4,258	Small

The utilities that responded collectively serve about 80 percent of Washington customers. The survey defined large utilities as those with more than 100,000 customers; all seven utilities in the state that fall into that category responded to the survey. Five small utilities also responded, representing about 13 percent of small utilities in the state and 9 percent of small utility customers. So while the responses of small utilities generally point out some of the differences between large and small utilities, the results should be viewed with caution.

DSA/Apex presented their findings at a public workshop at the UTC on Nov. 20, 2017. The slide deck from that presentation, which provides a detailed walkthrough of the survey's findings, can be found in Appendix A to this report.[40]

This report will present key findings from the survey through four themes:

[40] The slide deck in Appendix A incorporates feedback from the Nov. 20 workshop, and therefore differs slightly from the one presented at the workshop.

- There are significant differences between large and small utilities, both in terms of system needs and planning approach.
- Currently transmission and distribution system projects are generally driven by factors other than load growth and tend to be large and capital-intensive.
- Many larger utilities are engaging in the components of DER planning, but additional opportunities exist.
- Uncertainty about distributed resource adoption rates is a primary barrier to their inclusion in planning processes, but utilities also identified several other barriers.

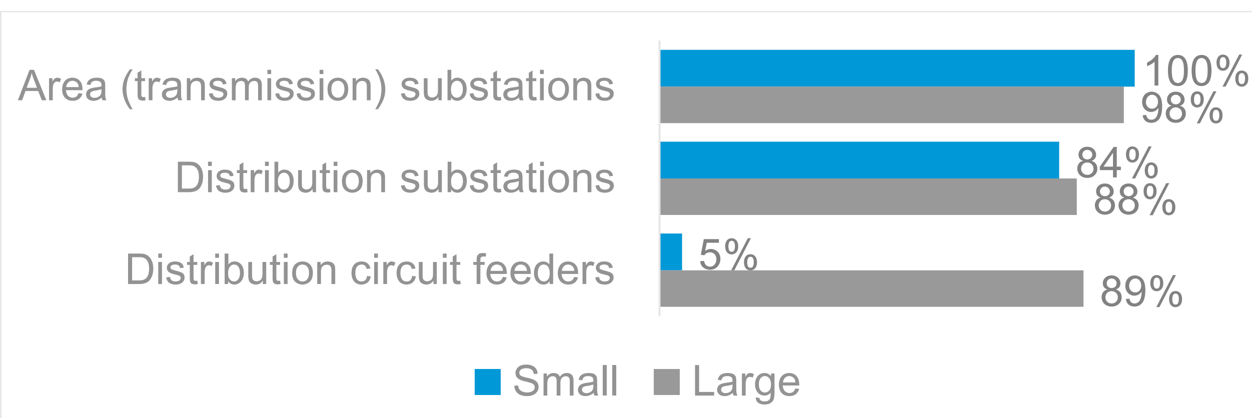
Large and small utilities differ significantly

This is perhaps an obvious conclusion, but the survey provides valuable insight into some of the ways in which large and small utilities differ, and why they are developing DER planning capabilities at different paces as a result. Three specific sources of variance that the survey captured are distribution system visibility, capital expenditure patterns, and perceived need for DER planning. Additionally, the role of BPA as a regional transmission planner is an important distinction for small and large utilities.

One of the foundational needs for DER planning is system visibility, or the degree to which utilities monitor conditions on their systems. To generate the type of data needed to inform DER planning, utilities need to have granularity, both in locational and temporal terms. Monitoring different points on a system allows a utility to understand where there are power flow issues on the grid, and receiving data from those points on an hourly basis enables the utility to identify the specific times issues occur. Utilities must know where and when these issues arise to determine the value of distributed resources on their systems.

As Figure 4 shows, the survey found that it is generally common practice for all Washington utilities to monitor large and small substations on at least an hourly basis, and large utilities generally do this for most of their distribution circuits as well.

Figure 4: Percentage of Distribution System with Hourly Data Monitoring by Utility Size



The data on transmission substations come with the caveat that only one small utility reported having transmission substations. The key takeaway of Figure 3 is that most Washington utilities have made progress in developing the visibility necessary to inform DER planning, but there remain opportunities for gathering more granular data, particularly at the distribution circuit level.

Large and small utilities also differ in their spending patterns for transmission and distribution system projects. From 2012 to 2016, small utility expenditures varied but held fairly close to their annual average of $20 million. Expenditures at large utilities, however, have steadily grown by an average rate of more than 3 percent each year, reaching an annual level of about $1.6 billion in 2016.[41]

Finally, there is a large gap between small and large utilities in terms of current DER planning practices. While four of the seven large utilities stated that they have a process for considering non-wires alternatives to traditional transmission and distribution system investments, none of the small utilities do.[42] The majority of large utilities forecast growth in distributed resources such as solar, electric vehicles, energy efficiency, and demand response, but small utilities are less likely to forecast these.[43]

Bringing these differences to the Legislature's attention should not be taken as a criticism of small utilities. Some of the differences are likely due to the transmission planning conducted by BPA on behalf of its customer utilities. Additionally, fewer personnel or resources and inadequate distribution system visibility were cited by some utilities as key barriers to DER planning.[44]

Insights from currently planned transmission and distribution projects

The survey contained a number of questions regarding utilities' historical and planned transmission and distribution system investments. The utilities' answers to these questions provide three important takeaways that illustrate the value of DER planning.

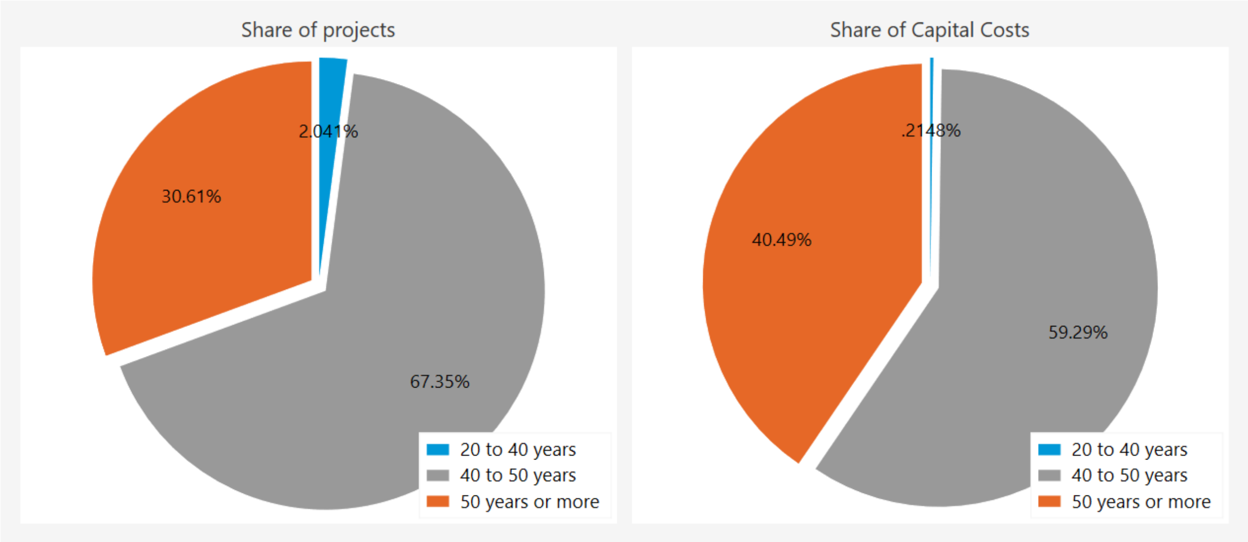
The first takeaway is that only about 26 percent of the planned transmission and distribution projects identified by responding utilities are driven by load growth.[45] This serves as an important reminder that considerations such as aging infrastructure, changing usage patterns, and the growth of distributed resources will continue to impact utility distribution systems in ways that will require grid upgrades, regardless of overall load growth or contraction. It also

[41] Appendix A, page 11.
[42] Appendix A, page 19.
[43] Appendix A, page 26.
[44] Appendix A, page 40.
[45] Appendix A, page 12. Note that for small utilities, the percentage of investments driven by load growth was about 7 percent, which would account for about $1.1 million to $1.7 million in investment per year when compared to the historical expenditures reported on page 11 of the Appendix.

demonstrates that even though electric load is declining overall in Washington,[46] uneven local growth patterns will continue to create pockets of electric load growth that will require utility investment.

The second takeaway is that planned investments driven by load growth tend to be large and capital intensive. Utilities that responded to the survey have identified a need for 49 transmission and distribution system projects, representing $460 million in investment.[47] And as Figure 5 shows, virtually all of those projects—98 percent—are expected to have a useful life of 40 years or more.[48]

Figure 5: Expected Useful Lives of Planned Transmission and Distribution Projects



As noted in the background section, the current environment of rapid technological advancement and industry change has heightened the risk associated with long-term investments. A utility that does not account for cost-effective alternatives to long-term infrastructure investments runs the risk of facing stranded assets if industry changes render those investments obsolete.

A final takeaway is that utilities plan most projects on a horizon of five years or more, suggesting that DER planning should consider a similar horizon.[49]

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[46] According to the U.S. Energy Information Administration, retail electric load in Washington declined by almost 6 percent from 2011 to 2016. Data retrieved from https://www.eia.gov/electricity/data/browser/.
[47] Appendix A, page 13.
[48] Appendix A, page 18.
[49] Appendix A, Page 10.

Utilities have made progress on DER planning but have room for improvement

Several Washington utilities have made inroads in developing the tools necessary to do DER planning, such as DER forecasting, including DERs in planning, and conducting pilot projects. But the survey also shows that work remains to be done. Utilities have limited procedures for deciding when and how to include distributed resources in planning efforts, are generally not developing distributed resource forecasts, and are often not linking those forecasts to other planning processes.

As previously noted, only four of the 12 utilities that responded to the survey have processes for analyzing non-wires alternatives to transmission and distribution projects.[50] But the details about how and when those processes are applied are unclear. Only one utility identified a specific trigger (project cost of more than $1 million) that requires a non-wires analysis;[51] only two utilities stated that they consider distributed resources to defer from generation, transmission, or distribution projects;[52] and only three utilities consider local peak needs when evaluating distributed resources.[53]

The survey also identified the degree to which utilities forecast the growth of customer-sited resources on their system and include that in resource planning. At most, half of responding utilities prepare forecasts for a given type of distributed resource aside from energy efficiency resources, and those forecasts have yet to incorporate some of the practices used in other forecasting efforts. For example, when forecasting demand in integrated resource planning, utilities use probabilistic models that account for the uncertainty inherent in forecasts. This allows them to develop flexible plans that perform well under a variety of potential futures, but the practice has not yet been applied to distributed resource forecasts.

Furthermore, the distributed resource forecasts that are being done generally are not incorporated into other planning processes, such as integrated resource plans and transmission and distribution plans. This is a missed opportunity, as distributed resources may in many cases be leveraged to meet system needs. An energy storage project used to help satisfy a local distribution peak may, for example, also be available to help with system balancing and peaking needs at other times. A customer's rooftop solar system could, with the right technology, be used to provide valuable grid support services. [54]

Yet, several of the larger utilities have considered DERs or have projects underway, as shown in Figure 6.

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[50] Appendix A, Page 19.
[51] Appendix A, Page 36.
[52] Appendix A, Page 37.
[53] Appendix A, Page 39.
[54] For a detailed breakdown of utility responses regarding their DER forecasting practices, see Appendix A, page 26.

Figure 6: Distributed Resource Projects

	We have considered this	We have pilot projects in progress or complete	We have planned projects
Distibuted generation	3	2	0
Distributed solar	3	2	2
Energy efficiency	3	4	1
Energy storage	4	2	0
Electric vehicles	2	2	1
Electric vehicle charging infrastructure	3	2	1
Demand response	3	3	1

Utilities identified several barriers to the inclusion of distributed resources in planning

One of the survey's final questions asked utilities to identify barriers to the inclusion of distributed energy resources in planning processes.[55] Responses to this question broke down sharply by utility size, with a majority of large utilities identifying uncertain rates of DER adoption, lack of DER performance data, and lack of industry standards as the most significant barriers. A majority of smaller utilities stated that they haven't identified a need for DER planning. Other barriers identified by multiple utilities include insufficient company personnel and resources, inadequate distribution system visibility, and lack of available planning software.

Conclusion and Recommendations

The records of DER planning proceedings in other states and the survey responses of Washington utilities all lead to two primary conclusions: DER planning is complex, and it is still a developing practice.

Despite the challenges, however, the pressures on utilities to engage in DER planning will continue to grow. Customers will continue to install distributed generation and purchase electric vehicles, innovators will continue to design new technology and equipment to manage the electric grid, and current infrastructure will continue to age. The pressures on utilities, and the tools to better manage those pressures, will come from many different sources and in many different ways. DER planning is the means by which utilities can manage these changes and ensure they continue to meet the needs of their customers.

What that engagement in DER planning will look like, however, will vary from one utility to another. For example, a large utility serving a metropolitan area may be tasked with integrating high levels of electric vehicle charging load and distributed generation while facing constraints related to the high cost of upgrading infrastructure in an urban area. A utility serving a rural area

[55] Appendix A, page 40.

may face none of those challenges, but may instead face the challenge of maintaining voltage on a long distribution line.

For that reason, we recommend that the Legislature take into account the differing needs of utilities as it considers DER planning policies. In the interest of fostering some level of DER planning at all utilities, the Legislature may consider a requirement that large distribution infrastructure investments for all utilities be evaluated against DER options before they are made.[56]

Beyond that, the Legislature may want to consider a bifurcated approach to DER planning policies, similar to the approach in the Energy Independence Act,[57] which only applies to utilities with more than 25,000 customers.

To the degree that the Legislature adopts DER planning policies, we respectfully recommend that any legislation be limited to identifying the goals and principles that the Legislature wants to achieve through DER planning. This will allow oversight bodies, such as the UTC, public utility district commissions, and city councils the flexibility to tailor the specific practices and procedures to the different needs of individual utilities. It will also provide statutory flexibility for utilities and oversight bodies to adapt the plans as technology and industry practice continue to evolve.

Following are the 10 principles and practices of DER planning that we recommend for the Legislature's consideration, with a brief explanation of each one.

Recommendation 1: DER planning should identify the data gaps that impede the planning process and the upgrades (such as advanced metering and grid monitoring equipment) needed to obtain that data.

Granular data on the health and performance of the distribution grid are a prerequisite to DER planning. Washington utilities have made progress in this area, but opportunities remain for collecting granular data from distribution circuit feeders.[58] Two utilities specifically identified lack of distribution system visibility as a barrier to DER planning.[59]

Recommendation 2: Proposed monitoring and metering upgrades should be accompanied by a business case that identifies how those upgrades will be leveraged to provide net benefits for customers.

Advanced metering infrastructure (AMI) generally requires accompanying programs and technologies to unlock its potential value to customers. Installing advanced equipment without a

[56] Only one utility surveyed identified a cost threshold that triggers a DER analysis, and that figure was $1 million. The consulting team recommends a threshold of $2 million.
[57] RCW 19.280.
[58] Appendix, Page 8.
[59] Appendix, page 39.

clear plan for how it will be used may cause equipment to be underutilized and reduce its cost effectiveness.

Recommendation 3: Utilities should identify programs and tariffs to fairly compensate customers for the value of their distributed resources and ensure their optimal usage, including programs targeted at low-income customers.

Tariffs that compensate customers for the value of their distributed resources allow utilities to inform customer investment decisions and harness them for the benefit of the system. Programs and tariffs may also facilitate the aggregation of those resources by utilities or third parties.

Recommendation 4: Utilities should prepare probabilistic forecasts of DER growth on their systems.

In the survey, uncertainty about DER adoption rates was the most commonly acknowledged obstacle to DER planning. Forecasting DER adoption rates involves a significant degree of uncertainty. Between learning rates for developing technologies, national and state policies, local economic conditions, and customer preferences, there are a significant number of uncertain variables that go into the forecast. Probabilistic forecasting ensures that plans account for the uncertainty.

Recommendation 5: DER plans should provide a 10-year plan for distribution system investments and an analysis of non-wires alternatives for major investments.

The suite of options for meeting a particular distribution system need will vary based on the time horizon. Some non-wires solutions, such as energy efficiency or demand response, may be dependent on customer adoption rates and may need several years to meet the need. Conversely, an immediate need may need to be met with a flexible resource that can be quickly procured and installed, rather than an infrastructure investment that could take several months to design and install.

Ultimately, the purpose of DER planning is to make a utility indifferent to the technology that it uses to meet a particular need. An analysis that fairly considers wire-based and non-wires alternatives on equal terms is foundational to achieving that goal.

Recommendation 6: Utilities should competitively procure the DER needs identified in the plan through detailed requests for proposals that identify the specific needs at each identified location.

Currently, utilities generally plan and select distribution infrastructure investments though self-build or contracting options, but non-wires alternatives are available from a growing industry of competitive, third-party providers. Competitive procurements that are tailored to solve specific needs (rather than procure a specific resource) increase a utility's ability to identify the lowest-cost, most efficient means of meeting distribution system needs.

Recommendation 7: DERs identified by a distribution plan should be reflected in the utility's integrated resource plan (IRP). Distribution plans should be used as inputs to the IRP process, similar to the way that conservation potential assessments are used.

As noted in the body of the report, distributed resources may be used to meet system needs when they are not needed to meet a local distribution need. Including selected DERs in the IRP allows those resources to displace or delay system resources in the IRP.

Recommendation 8: DER planning should include a high-level discussion of how utilities are adapting cybersecurity and data privacy practices to the changing distribution grid.

Many of the new monitoring and metering technologies that utilities will be using in DER planning rely on wireless technologies, which pose new risks related to cybersecurity and customer data privacy. As utilities plan and make these investments, they should be adapting their security practices to keep pace with those technologies. While detailed reporting of the utility's security practices would be inadvisable, a high-level discussion of the standards the utility follows would serve to foster confidence among customers and third parties considering investments in distributed resources.

Recommendation 9: DER planning should include a discussion of lessons learned from the planning cycle and identification of process and data improvements planned for the next cycle.

A common theme amongst states in which utilities have completed DER plans is that DER planning is an iterative process. Models need to be refined, new alternatives need to be considered, and changing customer needs must be worked into the process. A proactive approach to identifying and addressing planning needs will strengthen DER plans.

Recommendation 10: The DER planning process should have a transparent approach to involving stakeholder input and feedback.

The IRP process generally involves multiple stakeholder meetings, where members of oversight boards, industry representatives, and customers can understand a utility's planning approach and suggest alternate assumptions or modeling scenarios. This process improves the transparency of resource plans and facilitates acceptance of its conclusions from those same groups. It should be replicated in the DER planning process.