Oregon
Kate Brown, Governor

Public Utility Commission
201 High St SE Suite 100
Salem, OR 97301-3398
Mailing Address: PO Box 1088
Salem, OR 97308-1088
503-373-7394

UM 2005 Investigation into Distribution System Planning: Utility Survey

On March 22, 2019, the Public Utility Commission opened an investigation into Distribution System Planning (DSP)[1]. The key drivers for this investigation are 1) increasing insight into utility distribution system planning and investments, and 2) ensuring that plans and investments are optimizing system efficiency and customer value. The first phase of this investigation focuses on establishing a shared understanding of what distribution system planning currently looks like for Oregon's investor-owned utilities and how it is evolving, so that the Commission can issue guidance for utilities to file initial distribution system plans. Creating a transparent, holistic view of current utility perspectives and practices is a critical first step in this stage. Therefore, **Staff asks that Idaho Power (IPC), PacifiCorp (PAC), and Portland General Electric (PGE) create a foundation for this view through written survey responses. These responses will be posted to the docket to support a shared understanding among stakeholders.**

This survey seeks a range of specific, technical information and broader discussion about utilities' distribution planning strategy. These questions are not intended to be exclusive; utilities are encouraged to provide additional information or suggestions that are relevant to the general purpose of this document. Questions posed may involve activities, processes, or technologies that utilities do not currently employ, and as such, these questions do not imply that utilities should be undertaking those activities; they are designed to help Staff and stakeholders understand the boundaries of the current landscape. Utilities may respond to a question by stating that the question is not applicable to its system and explaining why.

The survey is divided into three sections:

- Section A – Current distribution system planning practices
- Section B – Current distribution system plans
- Section C – Current distribution system

Staff requests that IPC, PAC, and PGE respond fully, with narrative responses,[2] to the questions contained in this document, to the extent possible based on current practices and knowledge**. Responses should be filed as comments in Docket No. UM 2005 by July 10, 2019.** Stakeholders may submit questions or comments about these utility responses in writing to the docket or relay this feedback at the Utility Perspectives Workshop planned for July 17, 2019.

Please direct questions to Caroline Moore at (503) 480-9427 caroline.f.moore@state.or.us.

[1] Commission Order No.19-104.
[2] Attachments are encouraged but should not replace substantive, narrative answers.

Section A
Current Distribution Planning Processes

In Section A of your response, please provide the following information about the current distribution plans, reports, and other relevant components of distribution system planning:

1) Strategy: Please include an overview of the utility's approach to distribution system planning, including:
   a. What are the utility's planning goals? What are the major planning objectives? Which objectives are primary vs secondary?
   b. Provide a general description of how the utility plans for:
      i. Load growth
      ii. Aging infrastructure (replacement)
      iii. Increased penetration of the various types of DERs—What does the utility do to accommodate DER penetration in its distribution system?
      iv. Climate change impacts on the system
      v. Advances in equipment (e.g. controls, communications, awareness)
      vi. Reliability
   c. How does the utility define "distribution system"?
   d. In its whitepaper launching the DSP investigation, Staff cited the U.S. Department of Energy's definition of distributed energy resources (DER):

      > Distributed generation resources, distributed energy storage, demand response, energy efficiency, and electric vehicles that are connected to the electric distribution power grid

      Staff is also considering adopting the National Association of Regulatory Utility Commissioner (NARUC's) definition of a DER for this investigation:

      > A DER is a resource sited close to customers that can provide all or some of their immediate electric and power needs and can also be used by the system to either reduce demand (such as energy efficiency) or provide supply to satisfy the energy, capacity, or ancillary service needs of the distribution grid. The resources, if providing electricity or thermal energy, are small in scale, connected to the distribution system, and close to load. Examples of different types of DER include solar photovoltaic (PV), wind, combined heat and power (CHP), energy storage, demand response (DR), electric vehicles (EVs), microgrids, and energy efficiency (EE). [3,4]

      Does either definition align with the utility's definition of DERs or are there modifications that the utility would suggest?

2) Resources: Please describe the general distribution planning tools and other resources utilized, including:
   a. Types of planning and modeling software used and for what specific purpose. For example, does the utility make use of GIS technology in

---

[3] National Association of Regulatory Utility Commissioners, Manual on Distributed Energy Resources Rate Design and Compensation, p. 45. https://pubs.naruc.org/pub/19FDF48B-AA57-5160-DBA1-BE2E9C2F7EA0#page=46
[4] NARUC's definition includes a caveat that diesel-fired backup generators may also fit in this definition and the individual jurisdiction should determine whether to include in its definition of DER.

distribution system planning?
b. What advanced tools and other planning resources is the utility investing in?
c. Applicable engineering standards
d. Personnel commitment: What personnel resources are involved in distribution system planning? Please include utility personnel as well as contracted services.
    i. Please provide the number of personnel involved in distribution system planning per year, for the period of 2014 – 2018, identify whether in-house or contract staff.
    ii. Please provide an overview of roles and responsibilities.

3) Planning description: Please provide an overview of the distribution planning schedules and process, including:
    a. A description of the various distribution system planning processes, reports and other components utilized.
        i. Planning elements or considerations included (or not included) in regular updates and revisions and a description of each. For example: circuit or substation data, power flow analysis, power quality analysis, fault analysis, load and demand forecasts, external policy and regulations, etc.
    b. Frequency with which the utility conducts the distribution system planning processes.
    c. Frequency of planning updates or revisions: Are updates dependent on a set timing frequency (i.e. every 1, 2, 5, or 10 years) or are there events that may trigger a more frequent planning cycle or revision? If so, please explain.
    d. Iterative updates and/or new plans: Are planning processes based on continuations of past plans, new planning cycles, or some combination? How long is each planning cycle's time horizon?
    e. Integration of existing planning processes: How do the distribution plans inform the Integrated Resource Plans (IRPs), competitive procurement of generating resources (resource RFPs), Smart Grid Reports, transmission planning, and interconnection studies?
    f. How do IRPs, resource RFPs, Smart Grid Reports, transmission planning, and interconnection studies inform distribution system planning?
    g. What is the outcome of your distribution planning process? A plan/report? Budget by field area/region?
    h. Please include a graphic to illustrate the various plans/reports listed in this question (Section A, Question 3) and how they interact with each other.

4) Budget process: Please describe the associated capital and operation and maintenance (O&M) budgeting processes:
    a. Process of developing capital budgets for distribution infrastructure.
    b. Process for developing budgets for distribution O&M changes or projects, which may include, but are not limited to, information technology, communications, and shared services.
    c. Process for developing New Construction Reports filed with the OPUC.

d. Timing of associated distribution system budgeting processes: Describe timing of annual distribution system planning activities and specific deadlines related to broader utility planning and budgeting processes.
e. Distribution system schedule i.e., is it performed on an annual basis or on some other schedule?
f. Budget categories are used? For example, New Service, Asset Health, Street Lights, Substation Capacity, Reliability, Equipment Purchase, etc.
    i. Do you have construction allowances?
g. Which parts of the budget are discretionary i.e., the utility has some level of flexibility on timeframe, projects/solution, or other decision-making element? Please explain.

5) Capital investments and O&M projects: Please describe the processes to identify and assess capital and O&M investments:
    a. Assessment criteria and assessment process for reliability of grid assets (e.g., feeder, substation), condition of grid assets, and asset loading.
        i. How do you decide what equipment to replace (e.g., age, performance, etc.)?
        ii. How do physical inspections and other operations functions inform this assessment?
    b. Cost/benefit analyses the utility performs for distribution system planning:
        i. For what types of investment decisions are cost/benefit analyses performed?
        ii. What type of analysis is used?
        iii. Which non-monetized benefits are included in these analyses (e.g., emissions reductions?)
        iv. Are there hard-to-quantify benefits associated with the utility's investment decisions? How are these included in your analysis?
        v. When investments are interdependent with other investment decisions, how does your investment analysis change?
    c. Alternative analysis protocols for identified needs:
        i. Capital versus operating solutions: How does the utility determine whether an assessed need is best met through a capital project or through operational solutions?
        ii. Near-term versus long-term: How does the utility consider the costs and benefits of long-versus-short-term solutions?
        iii. Non-monetized benefits: Does the utility consider different benefits when taking alternative approaches to resolving system needs?
        iv. Non-wires-alternative (NWA) versus traditional solutions: How does the utility consider the potential for DER or other non-wires solutions to address an assessed need or to defer or eliminate the need for a traditional capital or operating solution? Is assessment of NWA performed in a systematic or ad hoc way? If not provided in responses to Section B, please provide examples of any NWA solutions the utility has analyzed and/or implemented, if any.
        v. Identifying solutions: How are options to meeting a need identified?

   vi. Scenario analysis: In developing solutions to an assessed need, does the utility consider multiple scenarios, including load forecasts and DER penetration? If so, what scenarios are standard?
   vii. Assessing NWA alternatives: What criteria or metrics are used in assessing whether a NWA can meet an identified need?

 d. Metrics for deciding among competing proposals: For any of the applicable categories described in 5c(i) – 5c(vii), what specific metrics are used to conduct a comparison of alternative solutions? If not provided in responses to Section B, please provide an example(s) of cost-benefit studies or reports the utilities have conducted as an attachment?

6) Demand and system loading forecast methodologies: Please describe the demand and load forecasts that inform the utility's distribution system planning, including:
   a. Granularity of load forecasting: To what level of granularity does the utility forecast? To what extent is the distribution system data collected by the utility reflected in load forecasts (e.g., does the utility employ an 8760-hour forecast at the substation level?)
   b. Use of company-wide peak forecasts versus aggregation of substation or other circuit-level peaks: Does the utility use a top-down forecasting approach versus a bottom-up approach, or some combination of these approaches? Does the utility utilize peak-hour forecasts?
   c. Comparison of actual asset loading against past forecasts: Does the utility employ backcasting or ex post true-up to assess the accuracy of its forecasting process?
   d. Minimum load assessments and forecasts: Does the utility measure minimum load by circuit? Does the utility utilize minimum load to assess potential impacts of distributed generation on power flows? Are minimum loads measured during peak hours or during night hours?
   e. Impact on load forecasts of the projected availability of DER: What approaches and models does the utility use to forecast DERs?
      i. How does the utility forecast the impact of DERs on distribution system needs?
      ii. How is utility forecasting impacted by utility assessments on adoption and penetration of DER?
      iii. Are multiple scenario forecasts developed, and if so, what are the basis of variations in scenarios?

7) Locational assessment of DER:
   a. Describe whether locational DER assessments are a part of the planning process and the process for assessing this.
   b. What form of hosting capacity software or analysis, if any, is used in the planning process? Please describe.
   c. Is hosting capacity analysis conducted system wide and/or in response to interconnection requests?

Section B
Current Distribution System Plans

In Section B of your response, please provide the following information for the current status of the utility's plans, reports, and other relevant components described in Section A. Please include information that is relevant to the utility's *Oregon* distribution systems:

1) The date initiated, completed, and the planning timeframe used: For each planning component (as described in Section A, Question 3a), the number of years to which it is applicable should be specified.

2) Scenarios: the range of any scenarios that were considered should be identified, e.g. high/low load forecast, high/low DER penetration.

3) System constraints and needs:
    a. At a high level, what system constraints and needs have your planning processes anticipated to develop or occur within the planning period? (Further detail on system characteristics is requested in Section C)
    b. How have these constraints and needs been prioritized based on assessment criteria, time sensitivity, budget impact, or other criteria?

4) A description of how the utility is planning for distributed generation coming online.

5) Historical and current budgets, including:
    a. Historical distribution system spending: Please provide historical spending over the past five years, and to the extent possible, breakdowns of categories of expenses and budgets (such as those listed in Section A, Question 4d) for capital projects, O&M projects, information technology, communications, and shared services.
    b. Current distribution system spending: Please provide capital and O&M budgets over the applicable planning period, and to the extent possible, breakdowns of categories of expenses and budgets (such as those listed in Section A, Question 4d).
        i. Where individual budget categories contain a substantial increase or decrease from historical levels, please explain the rationale for the change.
    c. Comparison: For each of the past five years, please provide a comparison of forecasted distribution system spending by year versus actual spending.

6) Currently planned distribution capital projects and O&M changes and projects, including:
    a. Whether/which alternative analyses were conducted (as described in Section A, Question 5c). Please describe.
    b. Whether future capital or O&M projects were identified using DER alternatives. Please describe.
    c. Identification of any non-monetized benefits of planned projects.
    d. Identification of any projects that will enhance the company's future ability to integrate DER into system operations.
    e. Which distribution projects are selected and approved within the scope of projects proposed. Please explain why.

Section C
Current Distribution System

In Section C of your response, please provide the following information about the current status of the utility's *Oregon* distribution systems:

1) System Protection:
   a. Describe types of protection schemes and devices utilized in distribution circuits, including but not limited to line reclosers, trip savers, tap fuses, outage management systems (OMS), etc.
   b. Provide an estimate the amount of the system where distribution automation (DA) is deployed. Please provide any relevant context about how these technologies are distributed across the utility system and why. Please include, but do not limit responses to:
      i. Volt/VAR optimization
      ii. Fault Detection, Isolation, and Restoration or Fault Location, Isolation, and System Restoration.

2) Monitoring:
   a. Percentage of substations and feeders that are equipped with SCADA in the utility's Oregon service area.
   b. Is the utility deploying AMI technology?
      i. What is the percentage of AMI meters in the Oregon service territory?
      ii. For each customer class (e.g. commercial, residential, industrial), provide the percentage of AMI meters.
   c. Describe the backhaul technology the utility employs on its Oregon distribution system. Please provide any relevant context about how these technologies are distributed across the utility system and why. Please include, but do not limit responses to
   d. What technology is being used to communicate with field devices as described in Question 1? Please also provide an estimate of what percentage of the Oregon distribution system is communicating with these field devices, if any.

3) Performance:
   a. What levels of reliability and other performance factors does the utility plan for?
      i. Please indicate whether metrics are mandated or driven by company practice or industry standard?
      ii. Please provide the utility's performance across the metrics over the past 5 years?
   b. What is the utility's plan/process to address the various types of failures that occur on the distribution system?
   c. What percentage of outages originate at the distribution level?
   d. What limits or restrictions on native load capacity, both physical and regulatory, do you currently place on the distribution system?

4) Security
   a. What controls and processes are used to secure consumer and system data, IT/communication systems, and physical infrastructure?

   b. What protocols and cooperative arrangements with NERC, NIST or other entities are used to identify threats and available defense measures?

5) DERs:
   a. What is the current and forecasted extent of DER deployment by type, size, and geographic dispersion?[5]
   b. What is the status of small generator interconnections in the Oregon service area (< 10 MW)?
      i. For each year from 2014 - 2018, please provide the number and total MW of small generators, by type, located in Oregon, interconnected to the utility, that began commercial operation in that year.
      ii. Please provide the current number of active interconnection requests for small generators located in Oregon that have not yet executed an interconnection agreement.
      iii. Please provide the current number of active interconnection requests for small generators located in Oregon that have an executed interconnection agreement, but have not reached commercial operation.
      iv. Please provide the current number of small generators located in Oregon interconnected to the utility, that have an executed interconnection agreement and are currently operating.
   c. What data and information are made available to distribution-level interconnection applicants prior to making an interconnection request? How is that information provided?
   d. Has the utility taken any steps to implement the IEEE 1547 standard or other requirements for the interoperability of DERs and the distribution system?
   e. How does the utility define microgrids? Please list any microgrids in the utility's service territory.

6) Customer values:
   a. Please describe the surveys and other market research the utility performs to understand customer values, needs, and interests related to distribution system planning.
      i. What are the major findings from this research over the past 5 years?
      ii. How does the utility use the results of this research?

[5] DERs may include small generator (e.g., solar pv), distributed energy storage, demand response, energy efficiency, and electric vehicles. However, Staff welcomes the inclusion of additional DERs that are not contemplated in this definition.