UM 2005 Distribution System Planning Technical Work Group Agenda

May 20, 2021

Oregon Public Utility Commission (PUC) Staff announces an agenda for the May 26, 2021, Distribution System Planning (DSP) Technical Work Group meeting.

The meeting will be conducted using Zoom. **Instructions for joining the workshop are below.**

Meeting Agenda
9:00 am - 12:00 pm Pacific

9:00 am – Welcome, introductions, agenda review – Nick Sayen, PUC Staff

9:20 am – Questions/clarifications/etc. on follow up materials from April 21, 2021, meeting

9:30 am – Section One questions – All participants

10:00 am – Section Two question – All participants

10:30 am – Break

10:45 am – Review and discussion of May 7 Data Transparency Workshop – All participants

11:45 am - Wrap up and review – Nick Sayen

12:00 pm - Adjourn

Meeting Materials

Included in this packet are the following:

- Technical Work Group questions for discussion at the May 26, 2021, meeting
- Questions and notes from the Technical Work Group April 21, 2021, meeting (**Important** – full follow up materials May 21, 2021 from the meeting can be found at the following link: https://edocs.puc.state.or.us/efdocs/HAH/um2005hah155041.pdf)
- Please reference Order No. 20-485 at the following link for the DSP Guidelines (Guidelines) as adopted in December 2020: https://apps.puc.state.or.us/orders/2020ords/20-485.pdf

To Join the Meeting

Please use the following link to join the meeting: https://opuc-state-or-us.zoom.us/j/83589350941?pwd=c1pKMU52U091elg2enI1Y3Nrdm92Zz09

Dial-in: 1-971-247-1195
Meeting ID: 835 8935 0941
Passcode: Hq2h.9cncN

The meeting will open approximately 5 minutes before the workshop is scheduled to begin.

Before joining a Zoom meeting on a computer or mobile device, you can download the Zoom Client for Meetings from the Zoom Download Center - https://zoom.us/download. If you have not used Zoom before, the Client will download automatically when you start or join your first Zoom meeting.

To familiarize yourself with Zoom, or to test your internet connection, join a test meeting - https://zoom.us/test.

Reminder – Future Meeting Dates for the Technical Work Group

Staff participants to reserve the following dates and times:

- Wednesday, June 30, 2021, from 9:00 am – 12:00 pm Pacific
- Wednesday, July 28, 2021, from 9:00 am – 12:00 pm Pacific
- Wednesday, August 25, 2021, from 9:00 am – 12:00 pm Pacific

The group will consider in July potential meeting time(s) and cadence for autumn 2021.

Questions or Feedback

Questions and comments can be directed to Nick Sayen via email at nick.sayen@puc.oregon.gov or by telephone at 503-510-4355.

UM 2005 Distribution System Planning Technical Work Group Questions

May 20, 2021

Below are questions for discussion during the May 26, 2021, Distribution System Planning (DSP) Technical Work Group meeting.

__Section One – Unresolved questions from the April 21, 2021, Technical Work Group meeting__

The questions below were unresolved during the April 21 Technical Work Group meeting as time ran short. Staff proposes the group take them up for resolution on May 26.

__Long Term Plan Questions__

1. Can staff provide additional context and detail on the requirements 4.4.b.i.2 and 4.4.b.i.3:
   i. "Assessment of investment options to enhance the grid across the following range of areas, including relative costs and benefits:
   …..
   2) Distributed resource and renewable resource enhancements
   a) Penetration and activation/utilization of smart inverters
   3) Transportation Electrification enhancements"

   Response: The requirement states that one part of the utility's long-term DSP vision should include assessment of potential investment options to enhance the grid, and these options should include potential investments to enhance for DERs, as well as investments to enhance for transportation electrification. The assessment should include relative costs and benefits.

   Discussion in meeting: Staff noted this question addresses content from the Smart Grid Report that was rolled into the Guidelines. This question, and Staff's draft response, will be discussed further as time ran short this meeting.

__Part 2 Questions__

2. Per requirement 4.5.a:
   "How legacy distribution planning practices will be transitioned to the requirements of Part 2"
   Can staff confirm the specific aspects of planning practices they are referencing in Part

2? For example, are DER forecasting, and non-wire alternatives analysis the two aspects of planning that are required for Part 2?

Response: "Legacy distribution planning practices" is a general reference to the activities which comprise utility distribution planning prior to Order No. 20-485 (referred to here as "status quo activities").

Part 2 articulates a process with four major components in a linear fashion (Forecasting of Load Growth, DER Adoption, and EV Adoption; Grid Needs Identification; Solution Identification; Near-Term Action Plan), however status quo activities as implemented day-to-day may not line up with the four components of Part 2. Requirement 4.5 states utilities should plan for how day-to-day implementation of status quo activities transitions to day-to-day implementation of the four components of Part 2.

Discussion in meeting: Staff noted that requirement 4.5 is for a high-level summary, and that this question, and Staff's draft response, will be discussed further as time ran short this meeting.

Section Two – New questions for discussion and consideration

Below are new questions received for discussion on May 26.

Hosting Capacity Analysis (HCA) Questions

3. To ensure options analysis is considering the needs of stakeholders, can stakeholders describe the expected use cases for a hosting capacity analysis including the granularity of data beyond the DER readiness map?

UM 2005 Technical Work Group
April 21, 2021 Notes and Questions

Below are notes from the April 21, 2021, Technical Work Group meeting, as well as revisions to questions discussed during the meeting. (Revisions were made with track changes).

Attendees:

- PUC Staff:
  - Nick Sayen
  - Kacia Brockman
- CEP
  - Charity Fain
  - Alma Pinto
- OSSIA
  - Ed Smeloff (Vote Solar)
  - Angela Crowley-Koch
- Energy Trust
  - Jeni Hall
  - Ben Cartright
  - Peter Schaffer
- Idaho Power
  - Kelley Noe
  - Jim Burdick
  - Alison Williams
  - Tim Tatum
  - Chris Cockrell
  - Mark Patterson
- PacifiCorp
  - Erik Anderson
  - Matt McVee
  - Wyatt Pierce
  - Teri Ikeda
  - Adam Lint
  - Jonathan Connelly
- PGE
  - Angela Long
  - Nihit Shah
  - Stefan Brown
  - Jason Salmi-Klotz
  - Derrick Harris
  - Joe Boyles
  - Andy Eiden
  - Bachir Salpagarov
  - Tony Grentz
  - Joe Boyles
  - Misty Gao
- NWEC:
  - Heather Moline
  - Fred Heutte
- ODOE: Jason Sierman
- CUB: Sudeshna Pal
- NW Natural: Rebecca Brown
- SBUA: Diane Henkels
- Renewable NW: Micha Ramsey
- TeMix: Stephen McDonald

Meeting recording

Following introductions Staff noted a request to record the meeting, then asked participants for reactions or objections. No objections were voiced, and the meeting was subsequently recorded.

The recording can be viewed at the following link:

https://opuc-state-or-us.zoom.us/rec/share/zzQZSOg1hpsc1ct2fal5Vlpi5OBbuflQAS8nxJairmEpOMGGfogr-Oj3LeM8PReG.gmJDbWoB3ZhkLpGn

Passcode: 2GF1?^3.yX

Discussion of Work Group Plan

Staff presented the major aspects of the Plan and noted it is in development. Participants have the opportunity to help shape this effort. The need for additional meetings will be assessed as we go. The Technical Work Group is intended to address technical questions, providing education and background is not a primary goal. Meeting announcements and follow up materials will be posted to the UM 2005 docket.

Initial feedback affirmed there is value in having this forum for technical conversations across utilities. Participants requested having information emailed in addition to being posted to the docket. Staff was asked about the preparation of meeting materials for today's meeting and explained utilities had questions as they began working on their filings which allowed Staff to draft answers in advance. Going forward, new questions may be answered in the TWG meeting. Participants noted it would be helpful to have the questions posted in advance of the meeting, and Staff confirmed the goal of posting questions 1 week in advance.

In response to this feedback Staff updated the Plan (attached) resulting in a revised Plan to be used as a Working Draft - that is a work-in-progress, which may be revisited if needed.

Questions Discussed during the April 21, 2021, Technical Work Group meeting

Please note that new content, and revised content, has been added in this section using track changes to distinguish between content circulated *ahead* of the April 21 meeting, and follow up *from* the April 21 meeting.

General Questions

1. Task 4.3.a.i (Community Engagement Plan, During Plan Development) references “b”. Can staff confirm if this a typo for “ii” or if a requirement was accidentally deleted?
   Response: The “b” should indeed be “ii”.

2. The DSP Guidelines (Guidelines) mention "Staff anticipates requesting that Order Nos. 12-158 and 17-290, issued in Docket No. UM 1460, be revised or these orders may be superseded by new requirements adopted in this docket." What is staff's expectation for the future of the Smart grid report requirement?
   Response: Assuming that the DSP plans address Commission and stakeholder goals, specifically “focused and strategic reporting on distribution planning,” Staff would recommend discontinuation of the Smart Grid Report, subject to review of non-DSP topics, and resolution of reporting on these topics.

   Discussion in meeting: Eliminating redundancy is good, but suspending the Smart Grid report may result in losing visibility into important topics, like transmission, that are not addressed in DSP. Stakeholders should provide input on the topics to be retained when the Commission decides how utilities will continue to report on those topics. Perhaps the Smart Grid report should be retained, but with reduced scope.

   Staff response: The Smart Grid report is on a one-cycle suspension (not canceled). After DSP Part 2 filings in 2022, there will be a process to review the Guidelines. As part of that process there will be opportunity to consider the Smart Grid Report, and comment on elements of it that were not incorporated into DSP, and the best place to report those going forward. **The draft response has been revised.**

3. Regarding requirements 4.1.f and 4.1.g, what does "at time of filing" mean?
   Response: For initial plans “at the time of filing” may mean the most recent calendar year where complete data is available. A utility may elect to use more recent dataset(s) if it chooses to do so.~~, or the most recent regulatory filing applicable to the data in question (for example the annual net metering report), whichever is more current.~~

   Discussion in meeting: Submitting Plans with data based on the calendar year cycle, rather than acquiring new data just before a reporting deadline, has several advantages. It would allow comparison of plans by calendar year on a consistent basis with all datasets representing the same time period (since not all data is available monthly). It would also allow time for internal review and QC before filing, as well as time for stakeholder review, which can't happen if the data is pulled at the last minute. At the same time data used for Plans should be the most up-to-date data, within reason, and so there may be tension between being most up-to-date and the calendar year cycle.

Staff response: DSP is not on a fixed calendar schedule, but a cycle based on date of Commission action on previous plan, with a goal to keep DSP synched with IRP filings. A calendar year cycle for the data included in Plan updates seems reasonable for the first filings. Further synchronization, and possibly consolidation, of data reporting needs further consideration during the review of the Guidelines. **The draft response has been revised.**

Hosting Capacity Analysis (HCA) Questions

4. Regarding requirement 4.2.a – does "…difficult to connect DERs…" refer to all DERs, such as demand response, or is this limited to customer-sited generation, such as NEM, QFs and Community Solar?
   Response: "DERs" refers to customer-sited generation, such as NEM, QFs and Community Solar. EVs could become energy-producing DERs at some point in the future.

   Discussion in meeting: Use of DER in this instance is confusing; "customer-sited generation" could be used in the future instead of "DER" when non-generating DERs such as demand response and storage are excluded from the definition. DER is understood to encompass a broader array of resources, and is defined as such for use elsewhere in the Guidelines.

   Staff response: Clarification of terminology should be considered during the review of the Guidelines.

5. What does "circuit" mean?
   Response: "The use of this terminology is to distinguish between all the parts below a substation, and the subsequent segmentation of those parts.
   "Circuit" is intended to mean all parts; the main, three-phase circuit, right out of the substation (maybe also called main or mainline).
   "Feeder" is intended to mean the circuits branching off the mainline (maybe also called laterals).
   "Line segment" is intended to further specify individual portions of circuits or feeders.

   Discussion in meeting: Terminology used by utility staff does not exactly match the terminology as applied in the Guidelines. For example: utilities use "feeder" and "circuit" interchangeably, "mainline" refers to a zone of protection, and "lateral" is part of a feeder. Staff explained the intention of the increasing granularity, and the associated Guidelines' terminology.

6. HCA Options 1-3 articulate increasing levels of granularity. Can you describe the value that is gained by the increasing granularity?
Response: The purpose of increasing granularity is to assess locations with greater specificity, and to utilize data for increasingly recent conditions.

7. Can a utility propose additional options for HCA beyond the three described in the Guidelines?
Response: Yes. If a different HCA approach warrants discussion and consideration it can be included. The utility should explain, and provide justification for the different approach.

8. Can you explain the purpose of including "…costs of upgrades assigned to planned generation…" in the HCA dataset or map? This information may be confidential.
Response: Including the "…costs of upgrades assigned to planned generation…" communicates the cost(s) required to interconnect by using the estimated interconnection costs for a new generator included in the utility's engineering studies, currently made public in OASIS. A utility is not expected to share the actual amount that ~~each~~ a specific interconnecting customer is paying to interconnect.

   Discussion in meeting: Utilities asked for clarification about whether they are expected to perform engineering studies for hypothetical new generation as part of the HCA, or just for actual project application, noting that past upgrade costs are not relevant to current HCA.

   Stakeholders discussed what triggers an interconnection study. Generators of any size can trigger studies, depending on condition of the feeder. EVs do not require interconnection studies, but utilities do try to account for EV load additions.

   HCA can become stale quickly when uptake of EVs, and other additions that don't trigger interconnection studies, accelerate.

   Assessing all the separate upgrades paid for by generators would be useful. Disparate generator-paid upgrades could result in overbuilding the distribution system.

   Staff response: The Guidelines' HCA options require reporting of costs of upgrades assigned to planned/queued generation. This is limited to generators in the interconnection queue. This will show costs that have been assigned for interconnection upgrades, but have not been completed. **The draft response has been revised.**

9. Do you expect that every location of the service territory should have HCA performed?
Response: Yes. However, if a different HCA approach – in this case one that does not evaluate the whole system – warrants discussion and consideration, a utility can

propose it. The utility would have to provide the justification for why that makes sense.

Long Term Plan Questions

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PGE's HCA Team discussion

The meeting agenda included slides PGE presented previously in its March and April Partner meetings. However, PGE presented new slides in this meeting on the Company's HCA approach, goals, and timeline, culminating in the HCA filing in October.

PGE asked for volunteers (currently limited to the TWG) to provide feedback on enhancements being made to the generation-limited feeder map used for net-metering. Please sign up by Thursday, April 22 by emailing your name and organization to DSP@pgn.com. PGE will email volunteers a link to the map, a user guide, and a spreadsheet for providing feedback.

PGE seeks immediate feedback on layers added to the map, including daytime minimum load, substations, public safety power shutoffs, and queued generation capacity. PGE notes that it's not a hosting capacity map. It's a screening tool to help generators identify feeder readiness for new generation.

PGE will request feedback in 2-3 separate 3-week "sprints" in which users provide feedback in week 1, PGE designs enhancements in week 2, and updates the map in week 3, to begin the next round of feedback. PGE wants to know how useful the information is, what additional information would make it more useful, and how often it should be updated. PGE also seeks feedback on the User Guide, particularly the introduction and who the map can help.

Information published in OASIS is the basis for the map. The data is updated twice per year. Generation-limited feeders are defined as having generation in queue that exceeds 90% of Minimum Daytime Load (MDL). MDL is the load remaining on the feeder after existing generating capacity is considered.