# Baseline Data and Systems Assessment Feedback

October 4, 2021

| | Description | Requirement | Response |
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| **1** | How granular is the SAIDI/SAIFI/MAIFI data? By feeder? By region? | 4.1.a | This information is shown by feeder in the 2020 Annual Reliability Report. |
| **2** | Can PGE provide more information about timing/coverage of map data showing net metering and QFs | 4.1.f | Information was current as of Jan 2021 and pulled from two sources: PGE Interconnection database and PowerClerk |
| **3** | How does PGE fund asset replacements? How does PGE prioritize the spending? | 4.1.a, b | • PGE conducts a risk assessment on major T&D asset categories, unit-by unit<br>• Units are ranked by risk, which is one of the metrics used to prioritize replacement<br>• Units where existing asset risk exceeds the annualized lifecycle cost of the replacement asset are recommended for replacement<br>• Decision-makers/portfolio-managers determine when the units can be replaced based on their budget cycles/available funds |
| **4** | Why are there so many distribution poles past their average life? For example some poles are 80 years old. | 4.1.b | Poles are physically inspected through PGE's Facilities Inspection and Treatment to National Electrical Safety code (FITNES)<br>• Governed by Oregon Administrative Rule (OAR) 860-024-0011<br>• Includes a detailed visual inspection as well as wood utility pole testing and treating<br>• Works on a 10-year cycle and covers 10-percent of PGE's system per year<br>• Recommends a pole be replaced if the inspection finds that insufficient pole strength or pole height exists<br>NOTE: Pole age varies depending on wood product quality. |
| **5** | Does PGE have maps of all of their asset classes by ages listed on a map? | 4.1.b | Not at this time, but this can be investigated for a future improvement. |
| **6** | Battery Storage should be added as a category (it is one of the DERs) 4.1.f | 4.1.f | PGE looks forward to discussing with participants and OPUC Staff how the Guidelines should be amended following submission of this first DSP filing. PGE is including baseline |

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|---|---|---|---|
| | | | information on its new residential battery storage pilot and will include more information on battery storage in Part II around solutions identification and bottom-up DER forecasting. |
| **7** | If a transformer is about to hit replacement time when a solar developer is about to start a project, how much of the cost of replacement is the developer responsible for? How do you plan your system assets upgrades? | 4.1.a, b | If there isn't an active project identified to replace equipment and the solar interconnection project is what triggers the replacement, the developer pays for all of it. If the asset is already planned to be replaced for vintage or some other reason, the developer does not pay for it. |
| **8** | Does every substation that is upgraded become DER ready? | 4.1.a | PGE makes a determination for whether or not to make a substation DER-ready based on the type of upgrade. For a maintenance upgrade, the substation will not receive DER-readiness benefits. If we are replacing switchgear, or performing a full rebuild, then there is high likelihood that DER ready equipment will be added to the substation breakers. We do not make it a common practice to add 3v0 in substation reconstruction scope, but we do ensure that the infrastructure is available for relatively easy installation. New construction projects have certain DER-ready protections, such as additional relays and switches.<br><br>PGE looks forward to discussing with Participants leading up to filing of Part II how bottom-up DER forecasts could inform these type of investment decisions. |
| **9** | Advanced Control: ADMS, DERMS & DRMS request for more details | 4.1.d | PGE will provide more details regarding ADMS, DERMS, & DRMS in the Grid Modernization Chapter of the Part I DSP Filing |
| **10** | Any thought given to whether some aspects (all aspects?) of the spreadsheet may be PDF'd? Or saved as a spreadsheet in an open-source format? | general | The Excel Spreadsheet was meant to be an intermediate step to assist with collecting, organizing, and communicating the baseline data requirements under the initial DSP guidelines. This data will be incorporated into PGE's initial filing, and we will revisit how to best gather |

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|---|---|---|---|
| | | | and share data as part of the lead up to future filing activity. |
| **11** | There is a lot of technical content provided (this is necessary and good); that being said the accessibility of that technical content may be improved with consistent use of some rules of thumb, such as writing out acronyms the first time used (for example: Transformer LTC R&X settings) In addition to acronyms there is some technical content that could benefit from increased clarity (e.g. made more accessible). Here's one example: "PGE's system is modeled to utilize a five-year projected 1-in-3 system loading as shown in the PGE load forecast." I think I understand the intent of that sentence, but I don't know what 1-in-3 system loading means (I think I know what five-year projected means). | 4.1.a.i & ii | PGE agrees that the DSP content is highly technical and that this will be an ongoing challenge to ensure common understanding among all parties. PGE aims to produce a technically accurate and clearly written DSP and will take this feedback into consideration when writing the DSP document.<br><br>In the DSP baseline assessment section, PGE will provide an overview of its load forecasting process as it relates to distribution planning. The information provided along with draft communication materials for baseline data may have been unclear on this matter. For readers' reference, 1-in-3 system loading refers to peak load conditions calculated based on weather conditions that PGE can anticipate experiencing once every three years. |
| **12** | The organization of the draft [PGE's draft baseline requirements spreadsheet] is a little unclear (or maybe the formatting is unclear?), for example all caps headings seem to include major steps in the process (for example base case validation), as well as definitions (for example dedicated feeders), and other important topics (for example feeder switching). Because all those things look the same it's not clear how (or if?) they relate. | 4.1.a.i & ii | PGE has attempted to communicate the form and content of Part I of the initial DSP filing as we are still developing the concepts and organization internally. For that reason, final submission might differ in form and content from any public presentation or draft materials that participants may have seen. We strive for clarity in our public communications, especially regarding a critical system plan like the DSP. We will take this feedback into consideration as we finalize the DSP Part I filing. |

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|---|---|---|---|
| **13** | Related to the organization issue noted above, in reviewing the draft I understand there to be a flow to the process described (for example, validate the base case by region, then base case analysis, then results, then possibly detailed studies, then reporting) but I may be wrong. If there is such a flow it would be helpful to articulate the flow clearly. Or use organization/formatting to make this clearer? A visual may be useful in illustrating the flow of this process | 4.1.a.i & ii | We will take this feedback into consideration as we finalize the DSP Part I filing. |
| **14** | I don't believe I saw a time horizon for the Studies as conducted today (do the studies look at the next year? 3 years? A snapshot in time of current conditions?) | 4.1.a.i & ii | PGE conducts power flow studies in CYME for multiple reasons. This could be to inform operational needs, to plan for capital projects, or as part of annual long-term forecasting. Studies typically include a snapshot of current equipment inventory, baseline historical feeder-load (5-year previous load), and a 5-year load growth forecast comprised of a combination of Corporate load growth estimates and any known lumped-load additions on the feeder.<br><br>We will take this input into consideration as we finalize the DSP Part I filing. |
| **15** | It's great to see this thorough discussion of the outage metrics. Are there any of KPMs utilized for distribution system planning purposes that are not outage metrics? | 4.1.a.iii | Reliable delivery of energy to the end user is a key component of the distribution system, and therefore many metrics are geared toward reducing outages that negatively impact customers.<br><br>There are other indicators that PGE uses in planning the distribution system such as daytime minimum load studies and peak load reports that help organize and prioritize system investments. PGE is looking at adding more customer-centric metrics into its DSP work, and looks forward to further |

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|---|---|---|---|
| | | | engagement with participants about possibilities around this topic. |
| **16** | It would be helpful to understand the source of the Average Service Life. For example, is that metric based on PGE's internal experience(s)? Or is it based on utility industry national averages? Or regional averages? Its helpful to see the "asset average life (in percentage of average service life)" graphs. However, it's also helpful see the "by age range" graphs as they present data that can be obscured by a mean value. | 4.1.b.iv | PGE recognizes that the presentation of the baseline data lacked sufficient clarity between average age and average service life, and has corrected this interpretation for the initial DSP filing.<br><br>Average age is the actual average age of all in-service assets within each group as of Q1 2021.<br><br>Average service life is derived from a 5-year depreciation study and used for cost-recovery purposes. |
| **17** | The box "SCADA Type/SCADA Protocol data time intervals" needs additional explanation/context. Is the "type" the 1/2/3 values with the "protocol time intervals" the a-d values? | 4.1.c.iv | We will review this information and consider making changes that add to clarity during finalization of the initial DSP Part I filing. |
| **18** | Some description of what this technical information means, particularly in terms of any resulting capability, would be helpful. What does having this technology deployed allow PGE to do that it otherwise couldn't? | 4.1.c.iv | Generally speaking, advanced system monitoring and control devices function to collect more information about the status and condition of the grid and relay that information in a usable manner to the substation or control center. Having this data allows PGE to monitor, manage and control devices in the field to yield a variety of grid benefits.<br><br>PGE will review the description of its monitoring and control systems, and plans for future investment, as we finalize Part I of the initial DSP filing to ensure enough context and information is provided to the reader. |

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|---|---|---|---|
| **19** | Do the table columns "4.1.c.iii SCADA Type" and "4.1.c.iii SCADA Protocol" relate to descriptions in the box "SCADA Type/SCADA Protocol data time intervals"? It appears they are related (perhaps based on?) but how is unclear to me. For example, the column "4.1.c.iii SCADA Type" contains numerous "4" values while there is no "4" in the "SCADA Type/SCADA Protocol data time intervals" box. | 4.1.c.iv | PGE will review this information and if any necessary corrections or labeling need to be made, will incorporate during finalization of the Initial DSP Part I filing. |
| **20** | Besides SCADA and AMI are there other distribution system monitoring and control technologies deployed that merit discussion? Auto-reclosers, etc.? | 4.1.c | PGE is updating the information provided for monitoring and control technologies currently deployed, as well as including discussion of their evolution in terms of our Grid Modernization plans, which will be filed with Part I of PGE's initial DSP. |
| **21** | I appreciate the category descriptions.<br>I think it may be helpful to note any distribution system-related categories of spending which are not included. An example might be vegetation management, or wildfire hardening, etc. | 4.1.e | We will include examples in the final filing of distribution-system spending that are not included in the category descriptions outlined in the Guidelines. |
| **22** | I recall from a Partners meeting that this section differs slightly from other sections in order to comply with Order 19-400. If that is correct it may be helpful to note this distinction, provide a brief explanation, and an example of how differences are manifest (for example, an asset class is included in 4.1.b and elsewhere, but is not included in 4.1.e....) | 4.1.e | PGE will note in the final DSP filing how we define the Distribution System for purposes of meeting UM2005 final guidelines, and where definitions deviate from that for specific asset accounting purposes. |
| **23** | There is a need to include historical data on system upgrades triggered by Small Generator/Net-metering interconnection to have a better range on the potential costs to bare by the solar | general | PGE maintains information about interconnection projects on the OATI OASIS website.<br><br>Go to the folder: Generation Interconnection => Oregon Small Generator Interconnection => Study |

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|---|---|---|---|
| | developers if an upgrade to the system triggered | | Reports<br><br>Inside all those reports you will find a section with Cost Estimate for upgrades to the system.<br><br>We acknowledge it is not the optimal way to access this information, and improvements to its access are already in our queue. |