Appendix A. DSP plan guidelines compliance checklist

Baseline Data and System Assessment	DSP guidelines	Chapter section
A description of any currently used internal baseline and system assessment practices (such as system reliability baseline, system asset health baseline, etc.) that includes:	4.1.a	1.2, 1.3
Method and tools used to develop the baseline and assessment:	4.1.a.i	1.3, 1.3.1, 1.3.2
Forecasting time horizon(s)	4.1.a.ii	1.3.2
Key performance metrics	4.1.a.iii	Appendix B B.1,B.2
A summary of the utility's distribution system assets including:	4.1.b	1.3, Appendix B B.3.1
Asset classes	4.1.b.i	1.3, Appendix B B.3.1
Average age of assets in each class	4.1.b.ii	1.3
Age range of assets in each class	4.1.b.iii	1.3, Appendix B B.3.1
Industry life expectancy of assets in each class	4.1.b.iv	1.3
Number of assets in each class	4.1.b.v	1.3, Appendix B B.3.1
A discussion of distribution system monitoring and control capabilities including:	4.1.c	Appendix B B.4
Number of feeders	4.1.c.i	1.3, Appendix B B.4.1.1
Number of substations	4.1.c.ii	1.3, Appendix B B.4.1.1
Monitoring and control technologies (such as SCADA, AMI, etc.) currently installed, and the percentage of substations, feeders, and other applicable equipment with each technology	4.1.c.iii	Appendix B B.4.1.1, B.4.1.2
A description of the monitoring and control capabilities (for example, percentage of system with each technology, resulting capacity, such as remote fault detection or power quality monitoring, and what time interval measurements are available)	4.1.c.iv	4.7, Appendix B B.4
A discussion of any advanced control and communication systems (for example: distribution management systems, distributed energy resources management systems, demand response management systems, outage management systems, field area networks, etc.). Include a description of system visibility and capabilities, the percentage of system reached with each capability, the percentage of customers reached with each capability, and any utility programs utilizing each capability.	4.1.d	4.7, Appendix B B.5
Historical distribution system spending for the past five years, in each category:	4.1.e	1.4
Age-related replacements and asset renewal	4.1.e.i	1.4

Baseline Data and System Assessment	DSP guidelines	Chapter section
System expansion or upgrades for capacity	4.1.e.ii	1.4
System expansion or upgrades for reliability and power quality	4.1.e.iii	1.4
New customer projects	4.1.e.iv	1.4
Grid modernization projects	4.1.e.v	1.4
Metering	4.1.e.vi	1.4
Preventative maintenance	4.1.e.vii	1.4
Net Metering and Small Generator information:	4.1.f	1.5.1
Total existing net metering facilities and small generator facilities interconnected to the distribution grid (or to the transmission system, as appropriate for small generator facilities) at time of filing, by feeder.	4.1.f.i	1.5.1
The total number of net metering facilities by resource type	4.1.f.i.1	1.5.1
The total estimated rated generating capacity of net metering facilities by resource type	4.1.f.i.2	1.5.1
The total number of small generator facilities by resource type	4.1.f.i.3	1.5.1
The total nameplate capacity of small generator facilities by resource type	4.1.f.i.4	1.5.1
The total number and nameplate capacity of queued net metering facilities and small generator facilities at time of filing, by feeder, broken down by resource type	4.1.f.ii	1.5.1
A map, in electronic format, identifying locations of net metering facilities and small generator facilities interconnected to the distribution grid (or to the transmission system, as appropriate for small generator facilities) at time of filing.	4.1.f.iii	1.5.1
Total number of electric vehicles (EVs) of various sizes served by the utility's system at time of filing	4.1.g	1.5.3
Number of EVs added to the utility's system in each of the last five years	4.1.h	1.5.3
Total number of charging stations on the utility's system, broken down by type, ownership, and feeder	4.1.i	1.5.4
Total number of charging stations added to the utility's system in each of the last five years, broken down by type	4.1.j	1.5.4
Data on the availability and usage patterns of charging stations	4.1.j.i	Appendix B B.6.2
Summary data of other transportation electrification infrastructure, if applicable	4.1.k	Appendix B B.6
A high-level summary of demand response (DR) pilot and/or program performance metrics for the past five years including:	4.1.l	1.5.2
Number of customers participating by residential and business customer class, and combined total	4.1.l.i	1.5.2
Maximum available capacity of DR by residential and business customer class, and combined total	4.1.l.ii.1	1.5.2
Season system peak	4.1.l.ii.2	1.5.2
Available capacity of DR, expressed as a percentage of the season system peak	4.1.l.ii.3	1.5.2
Plans should include the utility's most recently filed **Annual Net Metering Report** and the most recently filed **Annual Small Generator Report**, each as an appendix to the Plan.	4.1.m	Appendix C, Appendix D
Plans should include the utility's most recently filed **Annual Reliability Report** as an appendix to the Plan. Any descriptions of reliability challenges and opportunities in the Distribution System Plan should cross-reference underlying data and information contained in the Annual Reliability Report.	4.1.n	Appendix E

Hosting Capacity Analysis (HCA)	DSP guidelines	Chapter section
Upon Commission adoption of these Guidelines each utility should begin conducting a system evaluation to identify areas where it is difficult to interconnect DERs without system upgrades. Each utility should present the results through an unredacted map that is continuously available on the utility's website.	4.2.a	6.4
A utility should adopt the methodology underlying PGE's Net Metering Map, as presented in UM 2099, for calculating and identifying areas where it is difficult to interconnect DERs without system upgrades.	4.2.a.i	6.4
If this methodology is not feasible, a utility should present an alternative methodology with documentation of why it is necessary, and an explanation of any ways in which it may be different from the methodology utilized by PGE.	4.2.a.i.1	6.4
The resulting system-evaluation map should:	4.2a.ii	6.4
At minimum, meet the level of functionality of PGE's Net Metering Map.	4.2.a.ii.1	6.4
Label feeders serving Public Safety Power Shutoff areas.	4.2.a.ii.2	6.4
Each utility should analyze three options to meet future HCA needs consistent with **Figure 2**. At minimum, a utility shall develop cost and timeline estimates for each of the following three options. A utility should identify any data security, cost, result validation, or implementation concerns and/or barriers for each of the three options. Each utility should recommend a preferred timeline and development path for achieving the vision set forth in Figure 2, accounting for the relative strengths of Options 1, 2 and 3 below.	4.2.b	6.5
Option 1: The primary use of HCA is to inform Grid Needs Identification (see **Section 5.2**) and includes the following parameters: • Methodology: stochastic modeling / EPRI DRIVE modeling • Geographic granularity: circuit • Temporal granularity: annual minimum daily load • Data presentation: web-based map for the public and available tabular data • Annual refresh • Planned/queued generation details such as number and size of projects, description and costs of upgrades assigned to planned generation	4.2.b.i	6.5
Option 2: The two main uses are to inform Grid Needs Identification and to share regularly updated results publicly to inform stakeholders of potential interconnection challenges. Option 2 includes the following parameters: • Methodology: same as Option 1 • Geographic granularity: feeder • Temporal granularity: monthly minimum daily load • Data presentation: same as Option 1 • Monthly refresh • Planned/queued generation details: same as Option 1	4.2.b.ii	6.5
iii) Option 3: The two main uses are to inform Grid Needs Identification and to replace portions of the interconnection studies. Option 3 includes the following parameters: • Methodology: iterative modeling • Geographic granularity: line segment • Temporal granularity: hourly assessment • Data presentation: same as Option 1 • Monthly refresh • Planned/queued generation details: same as Option 1	4.2.b.iii	6.5

Community Engagement Plan	DSP guidelines	Chapter section
During Plan Development	4.3.a	3.1, 3.2, 3.3, 3.4, 3.5
A utility should host at least two stakeholder workshops prior to filing each Part of the utility's Plan, for a minimum total of four workshops. These workshops should be held at a stage in which stakeholder engagement can influence the filed Plan. The workshops may include presentation of the Plan outline, data and assumptions under consideration or challenges encountered, and the utility's approach to the Community Engagement Plan, described in (b). During stakeholder workshops, a utility must invite community members to share their relevant needs, challenges, and opportunities.	4.3.a.i	3.2
A utility should develop a Community Engagement Plan. The Community Engagement Plan should describe actions the utility will implement in order to engage community members and CBOs during development of the pilot concept proposals required in Solutions Identification requirements (Part 2, Section 5.3. (d)). The Community Engagement Plan should include the activities described below (1-4). A utility should implement these activities as part of the development of pilot proposals prior to filing Part 2 of its DSP Plan:	4.3.a.ii	3.2, 3.3, 3.4, 3.5
Proactively engage stakeholders regarding proposed pilots in impacted communities. Engagement of the local community may include in-person meetings located in the community; presentation of the project scope, timeline, rationale; and solicitation of public comment, particularly to understand community needs and opportunities.	4.3.a.ii.1	3.2, 3.3
Document stakeholder comments and utility response, including comments that were heard but not implemented.	4.3.a.ii.2	3.3, 3.5
Collaboratively develop and share datasets and metrics to guide community-centered planning.	4.3.a.ii.3	3.3, 3.4
Refer to Section 5.3. (d, i-vi) of Appendix A of Order 20-485 for the community-centered questions that should be addressed through the process above, and during development of pilot proposals described in Part 2, Solutions Identification.	4.3.a.ii.4	3.3
Utilities should aim to create a collaborative environment among all interested CBO partners and stakeholders. To support collaboration between all interested parties, Staff plans to host public workshops and a technical working forum. These are in addition to the utility workshops required during Plan and pilot development.	4.3.a.iii	3.2, 3.3
With consultation from utilities and stakeholders, OPUC will prepare accessible, non-technical educational materials on DSP to support public engagement.	4.3.a.iv	3.2

Long-term Distribution System Plan (LTP)	DSP guidelines	Chapter section
The utility's vision for the distribution system over the next 5-10 years, including any strategies, goals or objectives, and their alignment with State law and OPUC policies. These goals may include increased reliability, effective integration of DERs, broader greenhouse gas emissions reduction, or others.	4.4.a	2.2, 2.3, 2.4, 2.5
Roadmap of the utility's planned investments, tools and activities to advance the long-term DSP vision, using a 5-10-year planning horizon.	4.4.b	4.6.3, 5.3, 5.4, 5.5
Assessment of investment options to enhance the grid across the following range of areas, including relative costs and benefits:	4.4.b.i	4.6.3, 4.8, 5.3, 5.4, 5.5
Substation and distribution network and operations enhancements	4.4.b.i.1	4.5, 4.6, 4.7
Plans for conservation voltage reduction	4.4.b.i.1.a	4.5, 4.6, 4.7
Distributed resource and renewable resource enhancements	4.4.b.i.2	4.5, 4.6, 4.7
Penetration and activation/utilization of smart inverters	4.4.b.i.2.a	4.5, 4.6, 4.7
Transportation Electrification enhancements	4.4.b.i.3	1.5, 4.8, 5.3, Appendix B B.6
Customer information and demand-side management enhancements	4.4.b.i.4	1.5, 5.3
Plans to continue to expand customer benefits resulting from investments in advanced metering infrastructure	4.4.b.i.4.a	4.7
General business enhancements	4.4.b.i.5	4.5, 4.6, 4.7
Communications and supporting systems	4.4.b.i.5.a	4.5, 4.6, 4.7
Interoperability of systems and equipment	4.4.b.i.5.b	4.5, 4.6, 4.7
Work-management systems	4.4.b.i.5.c	4.5, 4.6, 4.7
Other enhancements	4.4.b.i.5.d	4.5, 4.6, 4.7
As applicable, any transmission network and operations enhancements	4.4.b.i.6	4.5, 4.6, 4.7
Explanation of how the investments reduce customer costs, improve customer service, improve reliability, facilitate adoption of demand-side and renewable resources, and convey other system benefits	4.4.b.ii	4.5, 4.6, 4.7, 5.3, 5.4, 5.5
Long-term assumptions, and impacts of Action Plan investments, etc.	4.4.b.iii	4.5, 4.6, 4.7
Forecasting future technical and market potential of DERs	4.4.b.iv	2.3.2, 2.4, Appendix F, Appendix G
Plans to further build community needs assessment and co-created community solutions into DSP roadmap	4.4.b.v	3.3, 3.4, 3.5
Transitional planning and operational activities underway in the organization to build capabilities in DSP-related functions	4.4.b.vi	2.5, 4.7, 5.3, 5.4, 5.5
Key barriers or constraints the utility faces to advancing investment (whether financial, technical, organizational) and mitigation plans	4.4.b.vii	4.6.1, 4.6.2, 4.6.3, 7.4
Smart Grid investment opportunities	4.4.c	4.5, 4.6
List and describe smart-grid opportunities that the utility is considering for investment over the next 5-10 years and any constraints that affect the utility's investment considerations	4.4.c.i	4.5, 4.6
Describe evaluations and assessments of any smart-grid technologies, applications, pilots, or programs that the company is monitoring or plans to undertake	4.4.c.ii	4.5, 4.6

Long-term Distribution System Plan (LTP)	**DSP guidelines**	**Chapter section**
Key opportunities and possible benefits for distribution system investment	4.4.d	4.3, 4.4, 4.5, 4.6, 5.3, 5.4, 5.5
Research and development the utility is undertaking or monitoring	4.4.e	4.8
Future policy and planning intersections:	4.4.f	2.5, 8.4
Discussion of how planned investments fit with the utility's IRP	4.4.f.i	2.5
Discussion of how planned investments fit with the utility's annual construction budget for major distribution and transmission investments	4.4.f.ii	2.5
Discussion of how distribution system planning may be coordinated in the future with other major policy and planning efforts discussed in these Guidelines. At a minimum, address the IRP and transmission planning, including how the Distribution System Plan filing is coordinated with each policy or planning effort, related inputs and outputs such as data sets or prices, and assumptions such as macro-economic policies or growth rates	4.4.f.iii	2.5
Plans to monitor and adapt the long-term Distribution System Plan	4.4.g	2.6

Plan for the development of Part 2 of the DSP	**DSP guidelines**	**Chapter section**
As Part of its Part 1 filing each utility should prepare for the upcoming transition period and include a high-level summary to discuss:	4.5	8.2, 8.3, 8.4
How legacy distribution planning practices will be transitioned to the requirements of Part 2	4.5.a	8.3
Whether all legacy distribution planning practices will be transitioned in time for filing Part 2, and if not, the expected timeframe for that eventual transition	4.5.b	8.3
Efforts to synchronize IRP activities with requirements of Part 2	4.5.c	8.4