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GOVERNMENT OF THE DISTRICT OF COLUMBIA
OFFICE OF THE ATTORNEY GENERAL

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Public Advocacy Division
Housing and Environmental Justice Section

E-Docketed

January 28, 2026

Ms. Brinda Westbrook-Sedgwick, Secretary
Public Service Commission
of the District of Columbia
1325 G Street, NW, Suite 800
Washington, DC 20005

Re: Formal Case No. 1182 – In the Matter of the Investigation into the Implementation of Integrated Distribution System Planning for Electric Utilities.

Dear Ms. Westbrook-Sedgwick:

Enclosed is a joint filing on behalf of the Department of Energy and Environment (DOEE) and the Office of People's Counsel (OPC) to support the Commission and working group members in the upcoming Integrated Distribution System Planning (IDSP) Working Group. The filing includes the following three attachments:

(1) A detailed framework and proposed requirements for IDSP in DC, including a process flow chart summarizing the framework proposed by DOEE and OPC;
(2) A roadmap identifying key topics for discussion during the working group, previously filed by OPC in FC 1182 on October 7, 2025;
(3) A summary of existing Pepco reporting requirements related to distribution system planning, for use in understanding and potentially consolidating existing reporting requirements into the IDSP process.

The documents are in draft form. DOEE and OPC welcome feedback on these recommendations and intend to evolve them based on input received during the upcoming working group.

If you have any questions regarding this filing, please contact the undersigned.

Sincerely,

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Attachment 1

Framework and Requirements for

Integrated Distribution System Planning in DC[1]

Working Draft v.2.6 (Jan. 27, 2026)

Introduction:

States around the country have begun to adopt Integrated Distribution System Planning (IDSP) to advance a variety of goals, including strengthening grid resiliency and reliability, enhancing energy affordability, and furthering public policy goals related to clean energy technologies. On November 27, 2024, the DC Public Service Commission released a Notice of Inquiry highlighting the benefits that an IDSP process could provide in DC. The NOI sought comments on a strawman proposal outlining objectives and procedures for an IDSP process in DC.

Several DC agencies, organizations, Pepco, and members of the public filed comments expressing support for an IDSP process. The parties' comments, though broadly supportive of IDSP in concept, described additional work needed to define key elements of the IDSP process. To advance this process, the Department of Energy and Environment (DOEE) and the Office of the People's Counsel (OPC) prepared the following draft IDSP requirements.[2]

Overview:

These proposed requirements are based on the Commission's NOI and party comments, with additional specifications to complete the IDSP framework. The proposal utilizes a 3-year cycle that includes preparation of a Draft IDSP, Final IDSP, and Annual Updates for years in which Pepco does not file a Final IDSP. Throughout the cycle, there are opportunities for stakeholders to provide input and feedback, including through written comments and annual technical conferences. With respect to the substantive components of the IDSP, the proposed requirements draw upon the NOI, party comments, and models from other jurisdictions to provide minimum requirements relating to forecasting, planning data, and other key topics.

As an initial note, OPC and DOEE agree with Pepco that the Company "has ultimate responsibility for the operation of its distribution system."[3] As such, the developmental process for the IDSP is meant to provide additional insight, transparency and opportunities for input into Pepco's distribution system planning. The Commission may direct certain requirements in the planning process such as enhancements to forecasting, cost benefit analyses, and justification for specific projects, but the development of capital expenditures and implementation of projects

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[1] The Office of the People's Counsel for the District of Columbia (OPC) and the DC Department of Energy and Environment (DOEE) propose this Framework for Integrated Distribution System Planning Working Group (established by the Public Service Commission, in Order No. 22464) discussions, while reserving a final position on specific recommendations for after those discussions take place.
[2] DOEE and OPC are grateful to Lawrence Berkeley National Laboratory, which provided valuable technical assistance and insights regarding experiences with IDSP in other jurisdictions.
[3] Pepco Reply Comments on the NOI, p.2. In general, references to comments in this document refer to comments on the NOI filed in Formal Case 1182, unless specified otherwise.

resides with Pepco. The Commission should not "approve" the IDSP but rather review and accept the plan similar to Pepco's current Annual Consolidated Report (ACR). As with the ACR, the Commission may order Pepco to provide greater clarity or to address certain issues such as Priority Feeders and Manhole Events. The final adjudication of capital projects occurs in rate proceedings where the reasonableness and prudency of projects and expenditures can be appropriately reviewed.

The requirements below could be adopted either through a Commission order or in formal regulations. Given the early stage of IDSP development in DC, we recommend starting with a detailed framework and set of requirements in an order (e.g., as an attachment to an order) though regulatory adoption or a hybrid approach are both possible.[4]

These proposed requirements are in draft form and we welcome feedback.

[4] For example, some states promulgate regulations that set forth the essential contours of an IDSP – e.g., the cycle for preparing and filing an IDSP every 3 years – and then include more detailed requirements in Commission orders.

1. Definitions

a) “Annual IDSP Update” means the update that the Utility publishes annually at the end of the distribution system planning cycle in the years that they do not publish a Final IDSP and that contains the information in Section 16.

b) “Demand Response” means changes in electric usage by demand-side resources from their normal consumption patterns in response to changes in the price of electricity over time or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or ensure system reliability.

c) “Distributed Energy Resource" or “DER” means front-of-the-meter or behind-the-meter electric storage, distributed generation, customer demand response, energy efficiency, thermal storage, or electric vehicles and their charging equipment. (Adapted from FERC’s definition of DER)

d) “DER Aggregation” or “DERA” means an aggregation of one or more distributed energy resources that can function as a single resource to provide certain Grid Services to address distribution Grid Needs and/or bulk power system needs. DER Aggregations are often also referred to as Virtual Power Plants (VPP). (Adapted from FERC’s definition of DER Aggregation)

e) “Distributed Generation” means an electrical generating facility located at or near a customer’s point of delivery, twenty megawatts or less, which may operate in parallel with the electric system. (adapted from ERCOT’s definition of DG)

f) “District’s Policy Goals” means the goals and associated metrics pursuant to the Clean Energy DC Omnibus Amendment Act, Clean Energy DC Plan, Climate Commitment Amendment Act of 2022, Commission’s PowerPath Vision Statement, Carbon Free DC, and subsequent goals as directed by the Commission for inclusion in an IDSP.[5] Any actions taken by the Utility to address District Policy Goals must meet the foundational requirement of ensuring electricity rates remain just and reasonable.

g) “Draft IDSP” means the preliminary IDSP prepared by the Utility and presented to stakeholders for review and feedback pursuant to Section 15 below.

h) “Energy Storage Device” has the meaning stated in 15 DCMR §4099.1.[6]

i) “Electric Vehicle” or “EV” means vehicles powered, at least in part, by electricity. Unless otherwise noted, EV refers to all plug-in vehicles, including plug-in hybrid

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[5] Citations to the statutes and plans referenced here will be added in a future version.

[6] 15 DCMR §4099.1: “‘Energy Storage’ – means a resource capable of absorbing electric energy from the grid, from a behind-the-meter generator, or other DER, storing it for a period of time and thereafter dispatching the energy for use on-site or back to the grid, regardless of where the resource is located on the electric distribution system. These resources include all types of energy storage technologies, regardless of their size, storage medium (e.g., batteries, flywheels, electric vehicles, compressed air), or operational purpose.”

electric vehicles (PHEV) and battery electric vehicles. (adapted from DC's 2022 Transportation Electrification Roadmap)

j) "Executive Categories" means the Utility's organization of its operations, maintenance, and capital expenditures as presented in Formal Case 1176. (based on OPC's Comments, p.10)

k) "Final IDSP" refers to the complete IDSP filed by the Utility every three years, following preparation of the Draft IDSP and stakeholder engagement.

l) "Grid Need" refers to the requirement for a specific mitigating action to address a distribution System Constraint, asset condition, reliability issue, or resilience vulnerability identified during the IDSP process. The specific characteristics of the Grid Need will inform the solution that mitigates the issue.

m) "Grid Modernization" means the planning, operational, and related information technologies employed to plan and operate transmission and distribution systems, including but not limited to planning and operational software, control systems, telecommunications, data management, grid sensors, field automation, protection devices, and power electronic devices.

n) "Grid Services" means operational services provisioned from customers and/or DER Aggregations to address specific Grid Needs, or providing transmission-level Grid Services by participating in PJM Interconnection, LLC's wholesale markets.

o) "Hosting Capacity" means the amount of load or DER that can be accommodated on the existing distribution system without adversely affecting power quality or reliability under existing control configurations and without requiring infrastructure upgrades. (adapted from Xcel Energy's definition of hosting capacity)

p) "Integrated Distribution System Plan" means the near-, medium- and long-term distribution expenditure plan resulting from a systematic approach to satisfying customer service expectations and District and utility objectives for distribution planning and operations. It addresses safety, reliability, resilience, capacity expansion, grid modernization, operational efficiency, and integrating and utilizing distributed energy resources. (adapted from LBNL definition)

q) "Locational Value Assessment" means the method to determine the net benefit of deploying Distributed Energy Resources in a specific location and over time, considering grid conditions, the potential to defer or avoid traditional electric distribution infrastructure investments, or other relevant locational considerations.

r) "Non-Wires Alternative" or "NWA" means a solution that makes use of Grid Services to address a Grid Need.

s) "Other Distribution Need" means the distribution operational workforce, resource, and material needs outside of specific Grid Needs identified by the Utility.

t) "Planning Criteria" means the Utility's engineering planning criteria, including Distribution Standards Guideline 1442 or its successors, the District's Policy Goals, and other applicable criteria as directed by the Commission.

u) “Planning Data” means the data and information used as inputs and assumptions in distribution planning as well as the resulting output information. Planning Metrics are a subset of Planning Data. (Gridworks provides helpful context on this term and related concepts in this paper)

v) “Planning Metrics” means quantifiable measurements used to assess performance against Planning Criteria, track progress toward the District’s Policy Goals, and/or measure the success of a process that the Utility's IDSP directly affects.

w) “Protection of Critical Infrastructure” means actions or standards focused on protecting the electric system from physical or cyber threats that could cause a power disruption. Security measures may include a combination of cybersecurity, physical security, and operational controls.

x) “System Constraint” means specific violations caused by physical characteristics of the electric distribution system exceeding the Planning Criteria, the result of which would threaten safety, power quality, or reliable delivery of power.

y) “Solution” means a Utility capital or operating expenditure that involves a Utility project or program and/or Grid Services designed to address one or more Grid Needs or Other Distribution Needs identified by the Utility. Examples of Solutions include Traditional Wires Solutions, NWAs, and Grid Modernization projects.

z) “Traditional Wires Solution” means a solution that involves a physical infrastructure expenditure by the Utility to address a Grid Need.

2. Planning Objectives & Metrics

a) The IDSP’s primary purpose is to provide a means for safe, reliable, and quality utility services at reasonable rates through cost effective improvements to and maintenance of the electric utility system in the District. Further, the IDSP should examine means to allow cost-effective sustainable energy sources to be used in conjunction with traditional solutions to address the District’s clean energy policies and goals. (based on the NOI strawman proposal and PSC Mission Statement)

b) The IDSP shall therefore address applicable District Policy Goals and other applicable goals and related metrics as directed by the Commission, including:

   i) Maintain and enhance the safety, reliability, resiliency, Grid Modernization, Protection of Critical Infrastructure, cost-effectiveness, and affordability of the electric grid in a manner consistent with the District’s laws and Policy Goals.

   ii) Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for the adoption of new distributed energy resource technologies.

   iii) Ensure optimized utilization of electricity grid assets, demand management, and distributed resources to minimize total system costs.

iv) Align the Utility's overall plan to meet the District's Policy Goals, such as strategies addressing climate change impacts on infrastructure resilience and the Commission's PowerPath Vision Statement. Any actions taken by the Utility to address the District's laws and Policy Goals must meet the foundational requirement of ensuring that electricity rates remain just and reasonable.

v) Facilitate sharing of information between the Utility and stakeholders, including government agencies, other utilities, and third-party vendors, while ensuring compliance with security protocols as needed.

c) Policy goals, including other applicable goals and metrics that are extant at the initiation of each planning cycle, shall be addressed in mid- and long-term Integrated Distribution System Plans, but not apply retroactively to near-term projects that have already been initiated. (adapted from proposed MD DSP regulations)

d) The Utility shall identify the specific Planning Metrics, consistent with the Planning Criteria, addressed in its IDSP, including at a minimum the Planning Metrics identified in Appendix A. (see note in Appendix A - still to be developed)

e) The Utility has the sole responsibility for its distribution system. The IDSP is intended to ensure transparency and opportunities for stakeholder input in the development and execution of the Utility's responsibility.

3. Filing Frequency & Commission Consideration

a) The Utility shall file its IDSP every three years.

i) The Utility shall publish a Draft IDSP and the Final IDSP on the Utility's website and file these plans with the Commission in an assigned informational docket that will inform the Utility's general rate case filings and other relevant utility filings.

ii) After the Utility files its Draft IDSP, the Commission will issue a notice of opportunity for interested persons to provide comments on the Draft IDSP.

iii) The Utility will file its Final IDSP reflecting stakeholder feedback on the Draft IDSP by [date], and every three years thereafter for subsequent IDSPs.

iv) The IDSP shall utilize the planning horizons in Section 5(b).

v) The Commission will review the Final IDSP, Annual IDSP Updates, and party comments, and may accept, accept subject to modifications, or reject the IDSP filing. Acceptance means the Commission agrees that the Utility's filing included all reporting requirements. Acceptance does not mean the Commission agrees that the improvements meet the requirement of reasonableness and prudency for cost recovery in a rate proceeding. (based on model language from the MN PUC and HI PUC, p.7)

b) The Utility shall file an Annual IDSP Update during the years in which a Final IDSP is not filed.

c) The Utility shall redact all confidential information from the IDSP published to its website or otherwise submitted publicly. However, a full version of the IDSP, including any confidential information, shall be filed with the Commission in accordance with the Commission's rules for filing confidential material, unless otherwise restricted from doing so by applicable law.

4. Stakeholder Engagement

a) IDSP Initiation Outreach (based on the NOI strawman proposal)

i) The Utility must hold outreach meetings to collaborate with and engage the community, customers, and other interested parties in a timely manner to ensure input can be incorporated into the development of the IDSP. The initial outreach meeting shall occur not less than 3 months before the IDSP filing.

ii) At least half of all, with a minimum of one, outreach meeting(s) must be held outside of normal business hours within the District and in locations convenient for customers. The Utility is encouraged to invite interested parties, community leaders, interested community and advocacy groups, and Commission Staff.

iii) For each meeting, the Utility shall make the meeting contents publicly available and provide a forum for comments to be shared by parties unable to attend in person.

b) Input and Feedback on Planning Criteria and Data: The Utility shall collect stakeholder inputs and feedback on planning criteria, data, and assumptions for consideration in the IDSP.

i) The Utility shall provide an overview of the already-collected data, including data sources.

ii) The Utility shall develop electric system planning inputs and assumptions or develop forecasts, scenarios, or other electric system planning criteria and identify opportunities for stakeholders to provide feedback.

iii) During the pre-filing stakeholder engagement period, and in the plans themselves, the Utility shall provide transparency into data sources, data, and assumptions used to develop the IDSP and Annual IDSP Updates.

iv) The Utility shall provide Planning Criteria and Planning Data access in a format that stakeholders can easily access, read, and comprehend.

v) The Utility shall document stakeholder recommendations as part of the Draft and Final IDSP and identify how they were incorporated, or show the adverse impacts of such recommendations and the reasonableness of rejecting them.

c) Annual Technical Conference for the Draft IDSP and Annual IDSP Updates

i) The Utility shall convene an Annual IDSP Update or Draft IDSP Technical Conference to present on its development of the IDSP.

ii) In years in which the Utility prepares a Draft IDSP or Annual IDSP Update, the Utility shall file the Draft IDSP or Annual IDSP Update at least 75 days before the annual technical conference. (adapted from proposed MD DSP process)

d) IDSP Working Group

i) The Commission will convene a standing IDSP working group with meetings open to the public and interested stakeholders to focus on specific topics within the IDSP such as load forecasting, priority feeders, network systems, aging infrastructure, and NWAs.

e) Written Comment Periods

i) An appropriate docket will be made available for interested parties to file written comments on the Draft IDSP, Final IDSP, and Annual IDSP Updates after filing.

5. IDSP Planning Scope

a) Planning Scope: The IDSP will incorporate all of the Utility's distribution capital and operational planning into one integrated plan. This includes consolidating the data, analysis, and reporting in the Annual Consolidated Report, the Distribution Construction Program Report, and the Transmission and Distribution 10-Year Planning Study. (to discuss – possibility of consolidating other reports into the IDSP)

i) The IDSP shall also incorporate, at a minimum, the Planning Metrics and additional Planning Data listed in Appendix A and B. (see note below in Appendix A & B)

b) Planning Horizons: The IDSP will assess distribution needs to address the District's Policy Goals and planning criteria using the following planning horizons, relative to the plan filing date: (based on the MD DSP planning horizons)

i) 1-3 years;

ii) 4-6 years;

iii) 7-10 years.

c) Relationship Between Short- and Long-Term Plans: The longer planning horizons of 4-6 years and 7-10 years should provide an extended outlook of Grid Needs and Solutions, including budgets, over the next 10 years. The short-term planning horizon of 1-3 years should be used to track the progression of long-term plans, address more immediate Grid Needs that require short-term Solutions, and include short-term construction budgets.

6. Distribution System Overview

a) The IDSP will provide a data-based review of the current and recent historical system characteristics, asset health, and relevant operations to provide a basis and context. The IDSP and updates shall be in accessible formats, including but not limited to maps and GIS data, that are easy to understand for non-technical stakeholders. (based on NOI strawman proposal)

i) Asset Health and Condition: The Utility shall provide relevant data on its distribution system assets to provide the basis of its planning efforts. Relevant data includes, but is not limited to: age, condition (such as failure rates, outage/interruption causes, and quantifiable impacts from extreme weather events), location, planned upgrades, decommissioning, overhead feeder inspection program (§1.24 & §1.25 of ACR), Neighborhood Analysis (§2.9 of ACR), Equipment Failure rates (§2.1 of ACR), Manhole Event Reports (§3.1 of ACR), Underground Failure Analysis (§3.2 of ACR), Manhole Inspection Report (ACR), 2012 Switchgear and HVCB Evaluation dated May 6, 2013.

ii) Asset Related Environmental Risks: The Utility shall provide information related to the environmental risks associated with its assets, such as Sulphur Hexafluoride (SF6) gas and amount of SF6 gas leakage each year, the status of mitigation or remediation efforts.

iii) Status of the 4kV Long Range Study dated January 3, 2005.

iv) Historical Reliability Metrics: The Utility shall include SAIDI, SAIFI, CAIDI, and CEMI-3 metrics. Benchmarking of reliability metrics against peer companies in the industry shall be performed (§1.27 and §2.8 of ACR).

v) Historical Outage Events Affecting >1% of the Utility's Customer Base in the District.

(1) O&M and capital costs associated with catastrophic event recovery.

(2) If feasible, maps of affected service territory with configurations of impacted customers.

vi) Resilience Threat Risk Assessments. The Utility shall provide information related to distribution risks of major outage events (as defined in the EQSS) due to weather and other natural causes.

vii) Historical O&M and Capital Spending by project and by Executive Categories. (based on OPC Comments, pp. 3 & 10)

viii) Grid Modernization: The Utility shall provide the status of all Grid Modernization project and program implementations, including updated completion timelines, actual costs versus original budgets, and any deviations from plans or proposals accepted by the Commission. (based on DOEE Reply Comments, pp. 4 & 9)

ix) Operations and Programs: A brief discussion or summary of the Utility's current operation strategy, including, but not limited to:

(1) Vegetation management Program (§1.26, & §2.12 of ACR), including current vegetation management cycle (feeders by year as reposted in the 2021 ACR).

(2) Storm response and restoration (§1.30 of ACR).

(3) Spare and Mobile Transformer status.

(4) Asset management: Details regarding asset management must describe approaches applied in the Utility's planning, efforts to prevent outages from occurring, and proactively reducing risk. The plans shall not only focus on asset age, but also on condition-based assessments performed through monitoring and inspections. The Utility shall also provide detailed reports from the Equipment Condition Assessment (ECA) Team (reference Order No.16975, paragraphs 39 and 98).

(5) Overlay maps of planned and historic distribution system investments.

x) Resource Challenges: Descriptions of any recent historical or ongoing resource challenges, such as workforce or material supply.

xi) Environmental Justice Mapping Analysis: An analysis of environmental justice within the Utility's territory with a discussion on environmental justice and how it is incorporated in plans to support affected customers.

xii) Additional Planning Data and Metrics: The Utility shall include the Planning Metrics and additional Planning Data listed in Appendix A and B. (see notes in Appendix A & B below)

7. Resilience and Reliability Forecasting

a) Resilience Vulnerability Assessment:

i) The Utility shall provide five- and ten-year resilience vulnerability assessments for the planning period.

ii) The identified vulnerability risks shall be mapped to planned system investments and expected improvements.

iii) Upon completion of undergrounding projects, report on the outage data for DC Plug Feeders by year.

b) Reliability Forecasting:

i) The Utility shall provide five- and ten-year projections of reliability metrics, including, where able, SAIDI, SAIFI, CAIDI, and CEMI-3, for the planning period.

ii) The identified metrics shall be mapped to planned system investments and expected improvements.

8. DER and Load Forecasting

a) DER Forecast: An IDSP shall account for the following considerations for each electric system planning cycle and scenario, as feasible:

i) The Utility shall provide the baseline information on the current quantity of each type of interconnected DER and the quantity of DER in the interconnection queue, including Distributed Generation, Energy Storage Devices, Microgrids, and DERAs.

ii) The Utility shall provide the baseline information on Demand Response measures including effectiveness to reduce localized and/or system peak demand.

iii) The Utility shall provide the baseline information on energy efficiency programs and the calculated and/or actual effectiveness of reducing localized and/or system peak demands.

iv) The Utility shall provide the baseline information on Conservation Voltage Reduction (CVR) scheme in place in the District including the calculated and/or actual effectiveness of reducing localized and/or system peak demands.

v) The Utility shall provide the baseline information on managed EV charging and discharging.

vi) The Utility shall develop separate forecasts for each relevant DER type, including energy efficiency, CVR, Demand Response, Distributed Generation, Energy Storage Devices, DERAs, and managed EV charging and discharging.

vii) The Utility shall develop hourly DER forecasts to create an aggregate DER forecast at the feeder level and substation level including firm and non-firm DER resources.

b) Load Forecast: Load forecasts shall account for the following considerations for each planning cycle and scenario at a feeder, substation, and District Ward level as follows:

i) The Utility shall provide the baseline information regarding the number of existing EV fleet and public charging facilities, data centers, and other large loads, and the number of each currently in the service connection queue.

ii) The Utility shall provide by District Ward information regarding New Business Loads including the project name, projected peak demand, the square footage, number of dwellings (if applicable), year to be on-line, and year projected to be fully loaded. The Utility shall also provide any load calculator that the Utility employs for estimating usage and peak demand from these projects. (see Pepco response to FC1156 OPC DR 20-3, referencing its 2026 Facility Load Calculator worksheet)

iii) The Utility shall incorporate the load impacts of current and future transportation and building electrification, based on available information and reasonable assumptions.

iv) The Utility shall incorporate current and planned energy codes, Building Energy Performance Standards, and other relevant information and methods to improve forecasting building load. (based on OPC Comments, pp. 3 & 8)

v) The Utility shall incorporate the aggregate DER forecast with the load forecast to create a net load forecast at a feeder level and the substation level.

vi) The Utility shall provide relevant transmission-level forecasts for the District (including those developed by the PJM Interconnection, Inc.) and explain how its distribution-level forecasts compare to those transmission-level forecasts. The Utility shall include an explanation for any differences between the forecasts (e.g., identifying and explaining the differences in assumptions).

c) Scenario Analysis:

i) The Utility shall employ scenario analysis based on the DER and load forecasts and associated sensitivities, including a minimum of 3 scenarios:

(1) Reference Scenario: A base case scenario reflecting the forecast in Section 8.b.iv. aligned to achieving the District's Policy Goals.

(2) High and Low Bookend Scenarios: Two (2) bookend scenarios reflecting a high case and a low case that bound a potential range around the reference scenario based on sensitivities regarding key DER adoption and load growth factors, such as potential changes in customer economic conditions, technology advancements, and other relevant factors. (based on examples from Hawaii and California)

ii) The Utility shall use the scenarios to evaluate potential grid needs and related solutions in assessing implementation timing and scale, as applicable.

9. Planning Analysis and Granularity

a) Planning Analyses: The Utility shall run analyses using Planning Data inputs and assumptions while considering stakeholder feedback from Sections 3 & 4 of these requirements.

b) Planning Granularity: Feeder-level and substation-level information shall be provided as part of the planning process.

c) Network Planning: The Utility shall provide information regarding violations of each network group and the proposed solutions to the violations. The Utility shall also identify network groups that are within 85% of their capacity limit as defined by the Planning Criteria.

d) Protection System Upgrades: The Utility shall also discuss protection system upgrades in terms of age and condition of assets and/or improvements to system reliability.

e) Hosting Capacity: An IDSP shall account, as feasible, for the following considerations for each planning cycle and scenario:

i) Hosting Capacity calculations shall be determined using a circuit-specific calculation, including installed and forecasted load and DER interconnections, as feasible;

ii) Load and DER forecasting shall be incorporated into determining future Hosting Capacity requirements, as feasible; and

iii) The Utility shall describe its methodology and assumptions for calculating available Hosting Capacity and, in the Annual IDSP Update and IDSP, discuss planned improvements to the system's Hosting Capacity and the methodologies for calculating and publicizing information related to Hosting Capacity.

f) Assess Results: As part of its analysis, the Utility shall assess the results of prior long-term planning, including prior IDSPs, to determine lessons learned and changes to planning assumptions as appropriate.

10. Grid Needs Assessment

a) The Utility's Grid Needs assessment shall include current and forecast distribution substation and feeder constraints, asset replacements, reliability issues, resilience vulnerabilities, and Grid Modernization requirements identified as part of each planning cycle, including the timing, magnitude, and other relevant characteristics for each identified Grid Need.

b) Replacement programs related to aging infrastructure shall include the overall plan for continued re-vitalization of the system. These programs may include replacement of PILC cable, capacitor controls, PAC cable, poles, switchgear, relays, and other relevant equipment.

c) The Annual IDSP Update shall discuss changes to the Utility's Grid Needs assessment that may occur between planning cycles.

d) The Annual IDSP Update shall address the Priority Feeders (§2.5 of ACR, Order No. 16975).

e) The Utility shall cost-effectively pursue industry best practice methods and analytical tools to improve its planning analysis and processes.

f) Information and data regarding identified Grid Needs shall be provided in the IDSP and Annual IDSP Update.

11. Locational Value Assessment

a) The IDSP shall provide, as feasible and appropriate, locational value for each identified electric Grid Need.

b) Locational value shall include the potential deferral or avoided value of a Traditional Wires Solution, as appropriate.

c) The Utility shall develop a Locational Value Assessment based on appropriate criteria and assumptions, including the Commission's Benefit Cost Analysis (BCA) framework (upon completion). (based on OPC Comments, p. 12)

d) The Utility shall report on the progress toward implementing Locational Value Assessments at annual workshops or technical conferences.

12. Other Distribution Needs

a) Forecasted Workforce and Material Resources

   i) Any resource challenges noted in Section 6 should be projected and quantified regarding their impact on system planning.

   ii) IDSPs must provide tangible examples of resource or material supply shortages and quantify the impact on system planning. Citing general market dynamics or the potential for global supply chain risks is an insufficient basis for estimating future planning requirements.

b) Any anticipated changes to operations and programs from Section 6.a.viii.

13. Identify Solutions to Grid Needs

a) Identify Possible Solutions to Grid Needs: An IDSP shall account for the following considerations for each planning cycle and scenario:

   i) An IDSP shall identify feasible solutions, including Traditional Wires Solutions and engineering and operational changes, as appropriate to address identified Grid Needs. The Utility shall provide data for each solution that, at a minimum, complies with the requirements in Order No. 16930, paragraph 485.

   ii) The Utility shall consider feasible and cost-effective Non-Wire Alternatives, including Grid Services, to address Grid Needs.

      (1) The Utility shall present its method(s) used for sourcing Non-Wires Alternatives from Aggregators and/or customers, the number of respondents to any solicitation, the criteria for evaluating possible NWAs, and the supporting analysis showing why NWAs were or were not selected.

   iii) For any proposed capacity upgrade projects, the implications for mitigating future Hosting Capacity constraints shall be considered and quantified, as appropriate.

   iv) The Utility shall assess the feasibility of utilizing new, cost-effective technologies and methodologies to address Grid Needs.

   v) The Utility shall screen for feeder limitations or other barriers to DER deployment, and evaluate potential Solutions to those limitations.

   vi) The Utility shall screen and evaluate solutions for each planning cycle and scenario. The Utility shall present its rationale for solution selection in IDSPs, including the criteria for evaluating possible solutions and the supporting benefit-effectiveness analysis.

14. Customer Affordability

a) Cost-Effectiveness and Prioritization: The Utility shall include a cost-effectiveness analysis of each proposed solution and a prioritization of all proposed expenditures, including:

i) An assessment of the solution's contribution toward achieving one or more of the Planning Criteria and a cost-benefit analysis of the solution, as applicable. The Utility shall include a cost-benefit analysis using the Commission's BCA framework upon completion of the BCA. (based on OPC Comments, p.3)

ii) Prioritizing proposed solutions that reflect the multiple objectives and metrics in the Planning Criteria to produce the highest customer value.

iii) IDSP Roadmap: The Utility shall provide an IDSP roadmap that provides a summary illustration of all prioritized Grid Need solutions with their respective timelines and sequence over the 10-year planning period. The IDSP Roadmap shall identify key milestones related to District's Policy Goals milestones, as applicable.

b) Customer Rate Impact: The Utility shall include a customer rate impact assessment, including:

i) Forecasted operations, maintenance, and capital expenditures for five- and ten-year periods by project and by Executive Categories.

ii) Projected substation and feeder level budget and cash flows by year, as well as any impact on the revenue requirement.

iii) External funding opportunities and grants to mitigate customer rate impacts.

iv) Customer rate impacts by customer class (e.g., residential, commercial, and industrial) and by District Ward.

c) Rate Case Alignment: The Utility shall reconcile differences in rate case filings and other filings proposing capital investments with the IDSP and shall provide explanations for deviations from the IDSP.

15. Draft IDSP and Final IDSP

a) The Utility shall provide a Draft IDSP that addresses the IDSP requirements in Sections 5 through 14 for stakeholder review and feedback pursuant to Section 4.

b) The Utility shall provide a Final IDSP that addresses the IDSP requirements in Sections 5 through 14, reflecting stakeholder feedback pursuant to Section 4, no later than 90 days after the Draft IDSP Technical Conference.

c) The Utility shall file the Final IDSP with the Commission for review and possible acceptance.

16. Annual IDSP Updates

a) The Utility shall file an Annual IDSP Update during the years in which a Final IDSP is not filed.

   i) The Utility shall include the following in its Annual IDSP Updates:

      (1) A narrative describing the existing planning and forecasting processes, current capabilities that exist, and plans for potential future improvements;

      (2) Relevant planning criteria utilized to identify Grid Needs and Other Distribution Needs;

      (3) Description of any new customer, market, or policy conditions that are impacting the planning environment, and, if feasible, how they plan to incorporate them into future planning;

      (4) Description of any updates to Grid Needs, Other Distribution Needs, or Solutions that may have changed from the previous year, including but not limited to:

         (a) Updates on progress regarding projects and programs that have changed from the previous year and rationale for the change;

         (b) Changes to the term capital spending, and comparison of budgeted and actual spending;

         (c) Updates regarding the Priority Feeders (§2.5 of ACR, Order No. 16975) and Manhole Events;

         (d) A review of system reliability and root causes of failure.

      (5) A report using a common framework for Utility reporting as directed by the Commission, with information regarding the status of projects designed to promote the District's Policy Goals and the Planning Criteria, including information on planning processes and implementation that promote these.

      (6) Assess Results: The Utility shall assess the results of its IDSPs to determine lessons learned and changes to future planning assumptions as appropriate.

   ii) In the year the Utility files a Draft IDSP, an Annual IDSP Update is not required.

   iii) The Utility shall publish a Draft IDSP, the IDSP, and Annual IDSP Updates on the Utility's website and file these with the Commission under the assigned IDSP docket.

Appendix Explanation:

Pepco expressed interest in consolidating certain existing reporting requirements with the IDSP. If there is interest in doing so, we recommend these appendices include more detail on data and reporting that will be included in the IDSP to understand and track which reporting elements from other areas will be incorporated in the IDSP, particularly if specific other reports (like the ACR) are discontinued. The appendices also provides a placeholder for the Commission or parties to include additional requested data based on and local needs and advances in other jurisdictions.

Appendix A: Planning Metrics

To be drafted based on Commission and party interest, feasibility, and best practices, leveraging where possible existing reporting from Pepco's Annual Consolidated report, EQSS, and other sources.

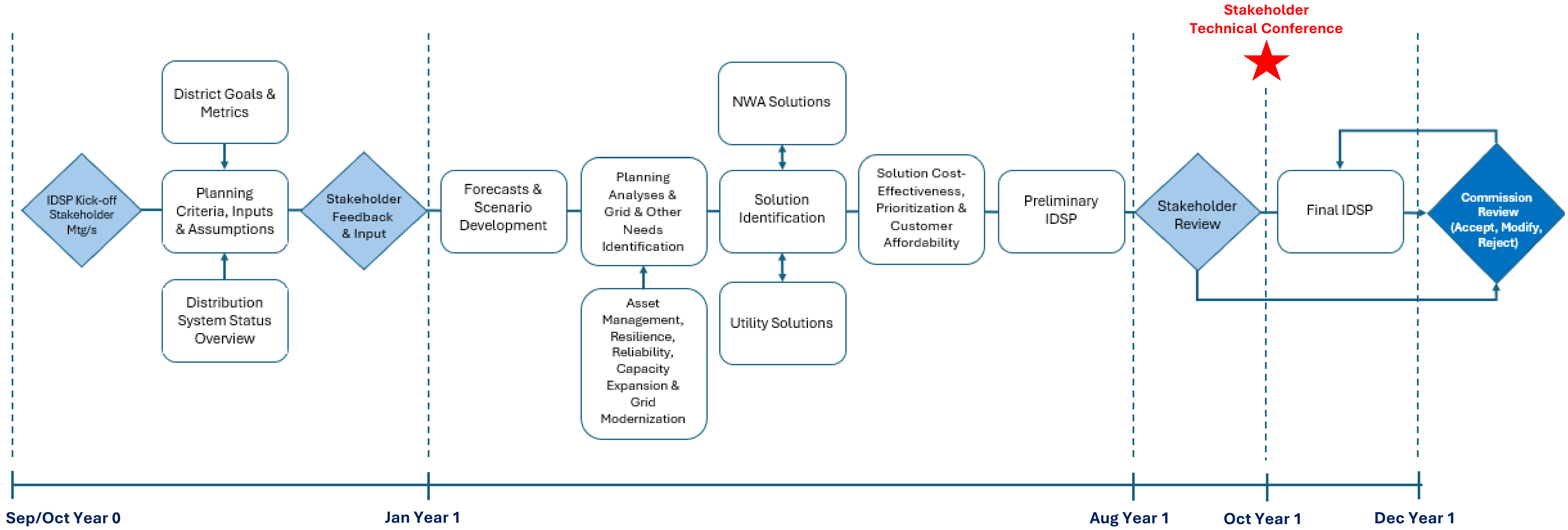
Appendix B: Additional Planning Data

To be drafted based on Commission and party interest, feasibility, and best practices, leveraging where possible existing reporting from Pepco's Annual Consolidated report, EQSS, and other sources.

1. Comparison of prior Load Forecasts to current system peaks with comments regarding the variances.

IDSP Development Process

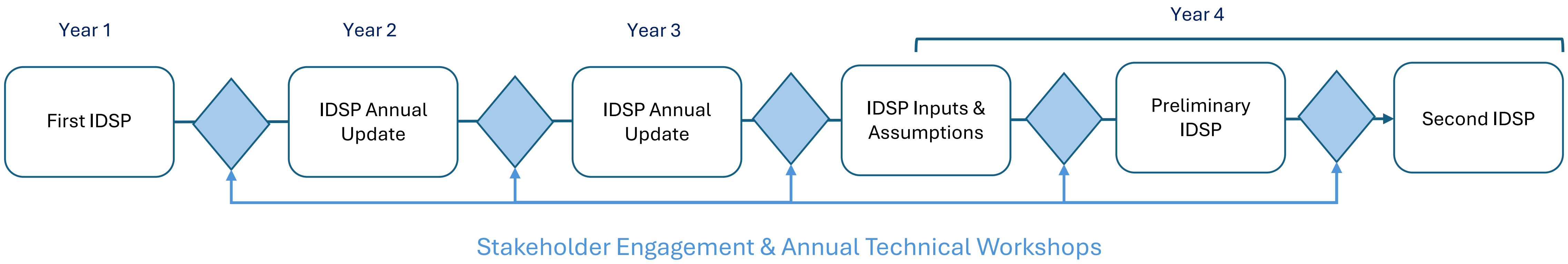
The process diagram illustrates the basic elements of IDSP development in the proposed framework



NB: Start and end calendar months are illustrative.

IDSP Multi-Year Cycle

The process diagram illustrates the basic elements of IDSP development in the proposed framework



This approach is similar to that proposed in MD and aligns with current annual Pepco DC reporting such as the ACR that could be consolidated into the IDP

Attachment 2

Proposed Roadmap for the IDSP Working Group.[1]

Topic Area	Stakeholder	Focus Area	Status/Notes	Specific Recommendations
Load Forecasting	Pepco	Traditional forecasting of New Business and new kWh consumption		Provide granular data at the feeder level which are the Construction Recommendations.
	Government: City/DOEE	Electrification Goals and Federal policies (Pepco has no control of implementation)	Pepco does not include future programs in current load forecasting. Issues with location of future loads. Need adoption patterns and demand/energy needs.	DOEE provides future load with adoption patterns to be incorporated into Pepco's projections.
	Government: City/DOEE	Transportation Electrification Goals and Federal policies (Pepco has no control of implementation)	Pepco does include "anticipated EV charging loads" Issues with location of future loads. Need adoption patterns and demand/energy needs.	DOEE provides future load with adoption patterns to be incorporated into Pepco's projections.
Planning Criteria	Pepco	Operational Criteria: Voltage capacity, N-1, etc.		
	Pepco	Aging Infrastructure		Needs more transparency on prioritization and investment planning.
	Pepco/PSC	Reliability Goals		EQSS Goals.
	Pepco	Resiliency Goals	Stated but integration with climate and	Climate vulnerability assessments need to be documented (heat, flood,

[1] The Office of the People's Counsel for the District of Columbia and the DC Department of Energy and Environment propose this Roadmap for Integrated Distribution System Planning Working Group (established by the Public Service Commission, in Order No. 22464) discussions, while reserving a final position on specific recommendations for after those discussions take place.

			DER goals needed.	wind, lightning, etc.). Use of DER to meet goals.
Load Shaping - Traditional	Pepco	Demand Side Management	Potential for more aggressive implementation.	Benefit Cost Analysis to expand this program.
	Pepco	Conservation Voltage Reduction	Potential for more aggressive implementation. Also helps with DER saturation.	Benefit Cost Analysis to expand this program. Pepco is working on expansion but lacks transparency and BCA. Include impact to DER with low operating voltage.
	City	Energy Efficiency Programs	Future EE not included in Pepco's forecast. Need adoption patterns.	DOEE provides future load with adoption patterns to be incorporated into Pepco's projections.
	City/DOEE	Goals for additional DER within the District (outside of Pepco Control)	Not included in Pepco's forecast. Need adoption patterns.	DOEE provides future load with adoption patterns to be incorporated into Pepco's projections. Map of existing solar and map of potential solar from District's total roof area.
Load Shaping – Enhanced	Pepco	DERMs for DER	Pepco in early stages of software acquisition.	Need Stakeholder review of capabilities of the system planned by Pepco.
	Pepco	Control of EV loads	Several years into the future	Benefit Cost Analysis for new program to control EV loads. May include TOU options and third-party aggregators.
	Pepco	Shift from Summer peak to Winter Peak	Change in load shape projected in 2039	Natural occurrence if electrification of heating occurs. Need to consider the impact of long-range planning.
	City	Energy Efficiency of electrification initiatives	Not included in Pepco's forecast	DOEE provides future load with localized adoption patterns to be incorporated into Pepco's projections.
Transparency	Pepco	Substation Projected Peak	Currently Reporting	Reference Attachment A of ACR.

	Pepco	Feeder level Projected Peak	Internal projections and often identified as confidential	Need to develop a means of transparency for data that may be CII.
	Pepco	Forecasted: DER Electrification Transportation Load Shaping	Does not exist in current forecasting	Incorporate inputs from DOEE to determine new load shape/new peak projections.
	Pepco	New Projects with alternate plans	Reported in Rate Cases	Stakeholders should review and affirm data as shown in FC 1176 Rate Case Cantler Testimony Exhibit H2.
	Pepco	Construction Reports	CII data	These are internal reports and need to be modified for stakeholder consumption. Reference FC 1182 Pepco Confidential Response to OPC DR4-32.
	Pepco	Transmission & Substation Plans	CII data	Need to verify application of new load projections.
	Pepco	**Aging Infrastructure** PILC cable Sub. Equipment Transmission cables 4kV conversion	Not well defined	Pepco provides budgets but not the basis for the replacements/expenditures, i.e. what is the goal being achieved and at what pace? 4kV conversion master plan should be updated.
	Pepco	**Automation Programs** 4kV SCADA Remote Monitoring System (RMS) DSM AMI upgrade (future)	Some reporting in ACR	Reporting automation programs will be extended to DERMs, DSM, CVR, etc. Therefore, the reporting needs to be clear for stakeholders relative to the goals.
	Pepco	DERMs	Budgets for programs in place	Need more transparency on functionality of proposed systems.
	Pepco	ADM	Budgets for programs in place	Need more transparency on functionality of proposed systems.
	Pepco	Communication Platforms required for	Budgets for programs in place	Need more transparency on functionality of proposed systems.

		DERMs and ADM		
Design	Pepco	Responsible for all designs of the grid	Pepco’s sole responsibility to design	
	Stakeholder	Review and comment		Stakeholders define their input/comment.
	City/DOEE	Program designs around Electrification, Transportation, and DER goals	No reporting methodology within the IDSP	City/DOEE goals and projections may be published or otherwise made available to all Stakeholders.
	PSC	Prudency Review within Rate Case		
Expanding DER	Pepco	Updated Hosting Maps		Hosting maps being discussed in FC1050. For the IDSP, these hosting maps need to feed into and influence DOEE projections of DER adoption.
	Pepco	Penetration Analysis	New	New Study for the proposed working group in Order 22464. Information should be used by DOEE and Pepco to determine impacts on projections and localization of the new DER. This study may direct Stakeholders to portions of the grid that can support DERs.
	Pepco	V2G analysis	New	Not included in Order 22464 but V2G is within a 10-year planning horizon and should be incorporated with DERMs and load planning.
	Pepco	Non-wires Alternatives for capacity issues	Needed for each system capacity upgrade (substation and feeder level)	A BCA should be determined for NWA. Analysis by Pepco in Capital Grid case included limitations of recharging BESS for prolonged equipment failure contingencies.

	Pepco	Expanding Behind the Meter BESS Value streams	New	How can customers be incentivized to add BESS to their homes/businesses. Peak shaving, ancillary services, etc. Pre-wiring for electrification.
	Pepco	Re-define Firm Resources	New	Stakeholders and Pepco need to review the application of DER as firm resources for peak and contingency planning.
Climate Resilience, Electrification and Equity	Pepco	Climate vulnerability assessments	Pepco Resiliency goals (stated above)	
	Pepco	Managed Charging	See Load Shaping Above	
	Pepco	Preparedness to support electrification	See Load Projections. Long Range planning should address in Trans/Sub 10 Year Plans	
		Environmental Justice	To prioritize equity & environmental justice communities	Mapping of RAD meters within the District may reveal areas for consideration. Expand community-based damage prevention initiatives. Communication to the public for IDSP awareness and safety.

Attachment 3

Summary of Pepco Distribution System Reporting
Version 1.0 (Jan. 27, 2026)

Background: DOEE and Synapse compiled the following summary of data currently reported in several major Pepco reports. Among other uses, this summary may be useful for participants in the FC1182 - IDSP Working Group when it comes to understanding current Pepco reporting, data, and metrics, including in discussions of whether and how to consolidate existing reports into a future IDP or IDSP framework.

Note: This summary covers one recent version of the reports listed in the table below (as of Summer 2025). We welcome suggestions, additions, or edits, including for reports not currently summarized that could be added to this list.

Report Title	**Frequency**	**Content Summary**	**Docket**
Annual Consolidated Report - Comprehensive Plan*	Annual	The Comprehensive Plan provides information related to Pepco's load forecasting and distribution system planning processes, routine capital investments, and equipment inspections.	PEPACR[year]
Annual Consolidated Report - Productivity Improvement Plan*	Annual	The Productivity Improvement Plan details metrics related to reliability and outages as well as measures to improve reliability.	PEPACR[year]
Annual Consolidated Report - Manhole Event Report	Annual	The Manhole Event Report provides statistics related to reportable manhole events.	PEPACR[year]
Long-Range Plan	Unknown	The Long-Range Plan provides data on O&M expense and capital expenditures as well as explains how Pepco's planned investments align with long-term strategic goals related to climate, resiliency, and reliability.	FC1182
Performance Tracking Metrics Report*	Quarterly	The Performance Tracking Metrics Report include performance metrics related to GHG emissions reduction, reliability, peak demand reduction, and DERs.	FC1156
Distribution Transformer Report	Annual	The Distribution Transformer Report quantifies energy and capacity savings from transformer purchases.	PEPADTR-[year]
Advanced Metering Infrastructure (AMI) Report	Quarterly	The AMI Report provides a status update on Pepco's progress on AMI deployment.	PEPAMIR[year]
Capital Grid Annual Report	Annual	The Capital Grid Annual Report provides a status update on the Capital Grid Project and the Downtown Resupply Project.	FC1144
Locational Constraints Report (DSP/NWA Report)	Annual	The Locational Constraints Report provides updates related to the NWA procurement process.	FC1130

* Indicates major reports with substantial information across several topics

The next "Summary of Pepco Reports" tab includes the data and information in the reports cited above. These data are organized using the following categories from Lawrence Berkeley National Laboratory's *Bridging the Gap on Data and Analysis for Distribution System Planning* report (Jan. 2025) (https://eta-publications.lbl.gov/sites/default/files/2025-01/bridging_the_gap_between_utilities_and_regulators_20250106.pdf):

Data Category (*From LBNL - Bridging the Gap*)	**Definition**
Load and Distributed Energy Resources (DER) Forecasting	Forecasts of gross load, load-modying technologies (e.g., energy efficiency, battery storage, demand response, electrification), distributed generation (e.g., solar PV), new construction of housing and commercial and industrial facilities.
Grid Needs Assessment	The analysis to identify specific grid deficiencies over a set period (e.g., 10 years), including a description of the deficiency, associated engineering characteristics, timing of the need, and near-term actions to address the need.
Asset Management Strategy	How utilities make decisions about building and maintaining distribution infrastructure, including initial equipment selection; design and construction practices; inspection and maintenance; and replacement.
Worst Performing Feeders	Data on the frequency, duration, and number of customer service interruptions to identify circuits (or feeders) with the worst reliability performance and develop remediation plans.
Distribution System Investment	The plan to achieve the objectives established for the utility's distribution system planning process, including asset management, reliability and resilience, capacity expansion, and advanced grid technology. *Since the first three topics overlap with other categories, only information related to advanced grid technology (solutions to advance monitor and control capabilities, including distribution automation, network and data management, planning and operational analytics, and technologies to enable DERs) is categorized as Distribution System Investment.*
Value of DER	The benefits (i.e., avoided costs) of DERs to the power system, especially at the distribution system level.
Non-Wires Alternatives (NWA) Procurement	Procurements of DERs to provide grid services at specific locations on the distribution system to reduce, defer, or avoid the need for infrastructure (e.g., feeders, substations) upgrades.

Data Category	Data Field	Geographic Level	Format	Report
Load and DER Forecasting	Description of the load forecasting process (including DERs)	N/A	Narrative	Annual Consolidated Report - Comprehensive Plan
	Description of how DERs are considered in load forecasts	N/A	Narrative	Annual Consolidated Report - Comprehensive Plan
	Historical customer counts (past 6 years)	Substation	Table	Annual Consolidated Report - Comprehensive Plan
	Historical annual load (past 6 years)	Substation	Table	Annual Consolidated Report - Comprehensive Plan
	Historical annual zonal load (past 11 years)	Utility territory	Table	Annual Consolidated Report - Comprehensive Plan
	Forecast monthly zonal load (next 1 year)	Utility territory	Table	Annual Consolidated Report - Comprehensive Plan
	% of substations with >98% power factor (past 10 years)	Utility territory	Table	Annual Consolidated Report - Comprehensive Plan
	Annual energy losses compared to other PJM utilities (past 10 years)	Utility territory	Table	Annual Consolidated Report - Comprehensive Plan
	Forecast customer counts and billing determinants by class	Utility territory	Narrative, table	Long-Range Plan
	Number of demand response customers	Utility territory, substation, feeder	Table	Performance Tracking Metrics Report
	Number of customers enrolled in TOU rates (past 5 years)	Utility territory	Table	Performance Tracking Metrics Report
	Number and aggregate capacity of rooftop and community solar systems	Utilitiy territory, ward, substation	Table	Performance Tracking Metrics Report
	Number and aggregate capacity of energy storage systems	Utilitiy territory, ward, substation	Table	Performance Tracking Metrics Report
Grid Needs Assessment	Description of the planning process for distribution system investments	N/A	Narrative	Annual Consolidated Report - Comprehensive Plan
	Details on substation addition and enhancement projects (project description, timeline, budget)	Substation	Narrative	Annual Consolidated Report - Comprehensive Plan
	Historical spending on routine capital projects (past 5 years)	Utility territory	Table	Annual Consolidated Report - Comprehensive Plan
	Future budgets for routine capital projects (next 5 years)	Utility territory	Table	Annual Consolidated Report - Comprehensive Plan
	Routine capital projects spending (past year) and budgets (next year) by executive category	Utility territory	Table	Annual Consolidated Report - Comprehensive Plan
	Net book value of distribution equipment	Utility territory	Table	Annual Consolidated Report - Comprehensive Plan
	Details on Productivity Improvement Plan (PIP) projects (project description, timeline, budget)	Substation, feeder	Narrative, table	Annual Consolidated Report - Productivity Improvement Plan
	Neighborhoods with increased load growth	Neighborhood	Narrative	Annual Consolidated Report - Productivity Improvement Plan
	Neighborhoods with decreased planned spending on 4kV to 13kV conversions	Neighborhood	Narrative	Annual Consolidated Report - Productivity Improvement Plan
	Updates on Capital Grid Project (construction status, budget, timeline)	Utility territory	Narrative, table	Capital Grid Annual Report
	Updates on Downtown Resupply Project (construction status, budget, timeline)	Utility territory	Narrative, table	Capital Grid Annual Report
	Estimated energy and capacity savings from transformer purchases	Utility territory	Narrative, table	Distribution Transformer Report
Asset Management Strategy	Description of equipment inspection processes	N/A	Narrative, table	Annual Consolidated Report - Comprehensive Plan
	Results of feeder inspections	Utility territory	Table	Annual Consolidated Report - Comprehensive Plan
	Description of vegetation management efforts	N/A	Narrative	Annual Consolidated Report - Comprehensive Plan
	Industry comparisons for reliability metrics (SAIFI, SAIDI, CAIDI)	Utility territory	Figure	Annual Consolidated Report - Comprehensive Plan
	Description of storm readiness processes	N/A	Narrative	Annual Consolidated Report - Comprehensive Plan
	Details on Neighborhood Reliability Enhancement projects (project description, timeline, budget)	Neighborhood	Narrative	Annual Consolidated Report - Productivity Improvement Plan
	Historical reliability indices (SAIFI, SAIDI, CAIDI) (past 5 years)	Utility territory	Table	Annual Consolidated Report - Productivity Improvement Plan
	Data on cross jurisdictional feeders	Feeder	Table	Annual Consolidated Report - Productivity Improvement Plan
	Neighborhoods most susceptible to non-major outages	Neighborhood	Table	Annual Consolidated Report - Productivity Improvement Plan
	Frequency and reliability impacts of primary equipment failures	Utility territory	Table	Annual Consolidated Report - Productivity Improvement Plan
	Analysis of most common equipment failures	Utility territory	Narrative, table	Annual Consolidated Report - Productivity Improvement Plan
	Outage numbers and reliability impacts by cause	Utility territory	Table	Annual Consolidated Report - Productivity Improvement Plan
	Historical budgets and spending on tree trimming	Utility territory	Table	Annual Consolidated Report - Productivity Improvement Plan
	Preventative Maintenance Schedule	Utility territory, substation, feeder	Table	Annual Consolidated Report - Productivity Improvement Plan
	Data on tree-related outages	Utility territory, feeder	Figure, table	Annual Consolidated Report - Productivity Improvement Plan
	Number of service outages, manhole incidents, and incidents resulting in personal injury or death	Utility territory	Table	Annual Consolidated Report - Productivity Improvement Plan
	Non-major outages >24 hours	Utility territory	Table	Annual Consolidated Report - Productivity Improvement Plan
	Status of lead cable replacements	Utility territory	Narrative, table	Annual Consolidated Report - Manhole Event Report
	Number of manhole events by type and cause	Utility territory	Figure	Annual Consolidated Report - Manhole Event Report
	Number of manhole events by insulation type and voltage	Utility territory	Figure	Annual Consolidated Report - Manhole Event Report
	Description and status of slotted manhole cover program	N/A	Narrative, Table	Annual Consolidated Report - Manhole Event Report
	Summary of manhole events	Utility territory	Table	Annual Consolidated Report - Manhole Event Report
	Description and status of manhole inspection program	N/A	Narrative, table, figure	Annual Consolidated Report - Manhole Event Report
	Number of customers experiencing 3 or more outages per quarter	Utility territory, ward, neighborhood	Table, map	Performance Tracking Metrics Report
	Planned capital expenditures by executive category and investment tracking number	Utility territory	Table	Long Range Plan

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Data Category	Data Field	Geographic Level	Format	Report
Worst Performing Feeders	Description of methodology to identify priority feeders	N/A	Narrative	Annual Consolidated Report - Productivity Improvement Plan
	Proposed and completed corrective actions for priority feeders	Feeder	Narrative, table	Annual Consolidated Report - Productivity Improvement Plan
	Details on priority feeders (location, reliability, outage history)	Feeder	Narrative, table, map	Annual Consolidated Report - Productivity Improvement Plan
	Description of aggressive correction action program for repeat priority feeders	N/A	Narrative	Annual Consolidated Report - Productivity Improvement Plan
	Neighborhoods served by repeat priority feeders	Feeder	Table	Annual Consolidated Report - Productivity Improvement Plan
Distribution System Investment	Description of technology initiatives and information systems used for distribution management	Utility territory	Narrative	Annual Consolidated Report - Comprehensive Plan
	Historical spending on information system projects (past 5 years)	Utility territory	Table	Annual Consolidated Report - Comprehensive Plan
	Number of installed and activated AMI meters	Utility territory	Narrative	AMI Deployment Status Report
Value of DER	Peak demand reduction from demand response	Utility territory, substation	Table	Performance Tracking Metrics Report
	Peak demand reduction from rooftop and community solar	Utility territory, substation	Table	Performance Tracking Metrics Report
	Energy savings from LMI deep energy retrofits	Utility territory	Table	Performance Tracking Metrics Report
	Energy savings from energy efficiency	Utility territory	Table	Performance Tracking Metrics Report
NWA Procurements	Description of past NWA cycles	N/A	Narrative	Locational Constraints Report
	Status of NWA process	N/A	Narrative	Locational Constraints Report
Other	Information on utility compliance with customer service standards	Utility territory	Table	Annual Consolidated Report - Productivity Improvement Plan
	O&M expense by FERC account	Utility territory	Table	Long Range Plan
	O&M expense per MWh compared to other utilities	Utility territory	Table	Long Range Plan
	Summary of capital investments supporting District climate goals, resiliency, reliability	Utility territory	Table, narrative	Long-Range Plan
	GHG emissions due to utility operations	Utility territory	Table	Performance Tracking Metrics Report
	GHG emissions from end-use customers	Utility territory	Table	Performance Tracking Metrics Report

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CERTIFICATE OF SERVICE

I hereby certify that on this 28th day of January 2026, I caused true and correct copies of the joint filing on Integrated Distribution System Planning on behalf of the Department of Energy and Environment and the Office of People's Counsel to be electronically delivered to the following:

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