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Analysis of Delaware's Electricity Distribution Grid: Final Report

Final Report to the Delaware Governor and General Assembly detailing the findings from the analysis of grid-enhancing technologies pursuant to House Joint Resolution 3

Prepared for
Delaware Department of Natural Resources and Environmental Control

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List of Acronyms

Acronym	Definition
ADMS	Advanced Distribution Management System
AMI	Advanced Metering Infrastructure
ASR	Automatic Sectionalization & Restoration
ATI	Approval to Install
BESS	Battery Energy Storage Systems
BRA	Base Residual Auction (PJM Capacity Market)
BTM	Behind the Meter
BYOB	Bring Your Own Battery
C&I	Commercial and Industrial
CAGR	Compound Annual Growth Rate
CCTV	Closed-Circuit Television
CIP	Critical Infrastructure Protection
CONE	Cost of New Entry
CSF	Cybersecurity Framework
CSIRP	Cybersecurity Incident Response Plan
CSP	Curtailment Service Provider
CVR	Conservation Voltage Reduction
DAC	Disadvantaged Community
DDOR	Distribution Deferral Opportunity Ratio
DEC	Delaware Electric Cooperative
DEMEC	Delaware Municipal Electric Corporation
DESEU	Delaware Sustainable Energy Utility
DER	Distributed Energy Resource
DERMS	Distributed Energy Resource Management System
DNREC	Delaware Department of Natural Resources and Environmental Control
DLR	Dynamic Line rating
DMS	Distribution Management System
DOE	Department of Energy
DPL	Delmarva Power and Light
DPP	Distribution Planning Process

DSM	Demand Side Management
DTR	Dynamic Transformer Rating
E-ISAC	Electricity Information Sharing and Analysis Center
EDC	Electric Distribution Company
EE	Energy Efficiency
EIA	U.S. Energy Information Administration
EV	Electric Vehicle
FACTS	Flexible Alternating Current Transmission Systems
FEMA	Federal Emergency Management Agency
FERC	Federal Energy Regulatory Commission
FLISR	Fault Location, Isolation, and Service Restoration
GDP	Gross Domestic Product
GEAC	Governor’s Energy Advisory Council
GET	Grid Enhancing Technology
GIS	Geographic Information System
GW	Gigawatt
HJR3	House Joint Resolution 3
HVAC	Heating, Ventilation, and Air Conditioning
ICS	Industrial Control Systems
IEC	International Electrotechnical Commission
INSM	Internal Network Security Monitoring
ISO	Independent System Operator
ISR	Infrastructure, Safety, and Reliability (Plan)
KPI	Key Performance Indicator
LDR	Locational Demand Response
LMP	Locational Marginal Price
LTE	Long-Term Evolution
LRDP	Long Range Distribution Plan
MED	Major Event Day
MFA	Multi-Factor Authentication
MPLS	Multiprotocol Label Switching
MRPS	Municipal Renewable Portfolio Standard

MSC	Municipal Services Commission
MW	Megawatt
MWAC	Megawatt Alternating Current
MWh	Megawatt hour
NERC	North American Electric Reliability Corporation
NIST	National Institute of Standards and Technology
NWA	Non-Wires Alternative
O&M	Operations & Maintenance
OEM	Original Equipment Manufacturer
OMS	Outage Management System
OT	Operating Technology
PJM	Pennsylvania-New Jersey-Maryland
PSC	Public Service Commission
QWP	Quarterly Work Plan
RBAC	Role-Based Access Control
REPSA	Renewable Energy Portfolio Standards Act
RF	Radio Frequency
RFI	Request for Information
RFP	Request for Proposal
RMF	Risk Management Framework
RPS	Renewable Portfolio Standard
RTO	Regional Transmission Organization
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SEO	State Energy Office
SEP	State Energy Plan
SESP	State Energy Security Plan
SLD	Single Line Diagram
SOC	Security Operations Center
SSN	Space Surveillance Network
TRC	Total Resource Cost

TSA	Transportation Security Administration
TWh	Terawatt hour
ToU	Time of Use
TYF	Ten Year Forecast
USDOE	United States Department of Energy
V2G	Vehicle to Grid
VAR	Volt-Amperes Reactive
VPP	Virtual Power Plant
VPN	Virtual Private Network
VVO	Volt/VAR Optimization

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1	06/12/2026	DNREC comments addressed
2	06/30/2026	Accessibility improvements and SEO comments addressed
3	07/23/2026	Addressed stakeholder comments

Executive Summary

Overview and Purpose

This report documents the results of a study funded by the State of Delaware. The study satisfies the requirement for the State to match federally funded investments that support the reliability of Delaware's electricity distribution[1] grid. The report also satisfies the requirements of Delaware legislation requiring the State Energy Office to analyze opportunities to adopt grid-enhancing technologies and grid supporting programs.

It provides a comprehensive statewide assessment of Delaware's electricity distribution grid and presents a structured roadmap to support modernization, resilience, and integration of emerging technologies. Prepared for the Delaware Department of Natural Resources and Environmental Control (DNREC), this analysis responds to state policy mandates and funding priorities, including House Joint Resolution 3 (HJR3) and the Bipartisan Infrastructure Law Section 40101(d) program.

The document evaluates the current state of the grid across Delaware's Electric Distribution Companies (EDCs), identifies gaps relative to leading industry practices, and defines a phased, actionable roadmap for grid modernization. The analysis is grounded in benchmarking against peer utilities, review of utility data and filings, and evaluation of emerging load, generation, and policy trends.

This report is intended to serve as a decision-support tool for state agencies, utilities, and stakeholders as Delaware transitions toward a more electrified, distributed, and resilient energy system.

Current State of the Delaware Distribution Grid

Delaware's distribution system serves a diverse customer base through a combination of investor-owned, cooperative, and municipal utilities. For many years, load growth across the state has remained relatively modest. That pattern is beginning to change as several new pressures reshape the operating environment. These include:

- Electrification of transportation and buildings
- Growing penetration of distributed energy resources (DERs), particularly solar
- Potential large-scale new loads such as data centers
- Increasing reliance on imported electricity

These changes are occurring alongside ambitious renewable portfolio standards (RPSs) and broader decarbonization goals which will require the distribution system to evolve in ways it is planned, operated, and managed. The changes are also occurring during a period of wholesale and retail electricity cost increases resulting from a variety of macro-economic factors, load growth and supply chain constraints. Sustained increases in retail electricity bills and resulting political responses may bring more scrutiny to proposed investments in hardening and modernizing the distribution system.

[1] This report is focused on Delaware's distribution grid. Reference to Transmission and Distribution is solely to provide context.

At present, Delaware's grid demonstrates strong reliability performance relative to national benchmarks. Most EDCs are achieving outage frequency and duration metrics that meet or exceed expected standards. This provides a solid foundation, but it does not eliminate the need for continued modernization. Maintaining current reliability levels under future operating conditions will require greater system flexibility, stronger situational awareness, and more advanced automation. As load patterns become more dynamic and distributed resources become more prevalent, utilities will need enhanced visibility into system conditions and faster operational response capabilities to preserve performance.

The adoption of demand-side management programs and DERs is also gaining momentum across the state. Rooftop solar deployment has increased meaningfully, and storage initiatives are beginning to emerge. In parallel, EDCs have started to implement a range of grid-enhancing technologies, including advanced metering infrastructure, distribution automation, fault detection tools, Volt/Volt-Amperes Reactive (VAR) optimization (VVO), expanded sensor deployment, and early DER management capabilities. These investments represent important progress toward a more modern grid. However, in many cases, these resources and technologies are not yet fully integrated into real-time system operations. As a result, their full value for reliability, efficiency, and system optimization has not yet been captured.

EDCs in Delaware have also established foundational cybersecurity frameworks (CSFs) that are generally aligned with national standards. Even so, the depth of implementation, consistency of operational practices, and overall visibility into cyber risk vary across utilities, particularly among smaller municipal systems. As the grid becomes more digitized and increasingly reliant on connected devices, data, and automation platforms, cybersecurity will become an even more critical component of utility operations. Strengthening these capabilities will be essential to supporting both resilience and public confidence as the distribution system continues to modernize.

Key Gaps

Benchmarking against leading U.S. utilities highlights several characteristics of advanced distribution system planning and operations:

- Long-term, multi-horizon planning to integrate load, DER growth, and resilience
- Use of advanced analytics and geospatial modeling to guide investment decisions
- Integration of DERs and DSM as active grid resources rather than passive programs
- Strong stakeholder engagement across regulators, customers, and market participants
- Robust asset management and CSFs

Compared to leading practices, our analysis identifies several priority gaps that must be addressed to enable a modern, flexible distribution system:

Data and System Visibility:

- Fragmented data systems and lack of integrated network models
- Limited ability to perform detailed power flow analysis and scenario planning

DER and DSM Integration:

- Existing programs are not fully integrated into system operations
- Limited capability to dispatch or optimize DERs for grid needs

Grid Automation and Control:

- Early-stage deployment of advanced distribution management system (DMS)
- Limited real-time monitoring and automated control capabilities

Cybersecurity Implementation:

- Variation in technical controls, asset-level monitoring, and incident response readiness
- Limited coordination and visibility across all utilities

Strategic Roadmap for Modernization

To address these gaps, the report outlines a phased roadmap. The roadmap is structured into three Phases that reflect increasing levels of system maturity and operational sophistication.

- In the **Foundations phase**, EDCs focus on establishing foundational capabilities. This includes development of core data architectures, system integration layers, and baseline operational capabilities. This phase directly addresses structural gaps identified in the current state, including fragmented data environments and limited system integration.
- In the **Enablement and Integration phase**, foundational systems should be leveraged to support advanced analytics, improve system visibility, and enhance coordination across planning and operational functions. Capabilities such as scenario-based planning, topology-aware monitoring, and coordinated Demand Side Management (DSM) and DER integration should be progressively implemented.
- In the **Optimization and Market Alignment phase**, EDCs transition toward optimization and market alignment. At this stage, advanced capabilities such as automated grid operation, dynamic network optimization, and DER market participation should be realized, subject to system readiness and regulatory alignment.

Foundations Phase	Enablement and Integration Phase	Optimization and Market Alignment Phase
P01 Core Data and Planning Foundations	**P06** Planning and Analytics Modernization	**P09** Core Grid Operations Automation
P02 Core Operational Visibility and Control Foundations	**P07** Grid Monitoring and Visibility	**P10** DER Operational Integration and Market Access
P03 Digital Work and Asset Management	**P08** Dynamic Network Modeling and Capacity Optimization	**P11** Advanced Grid Optimization
P04 DSM Optimization		
P05 DER Foundations		

Key Technologies	Key Technologies	Key Technologies
GIS and network models	Advanced analytics and planning platforms	DERMS Platform
SCADA/EMS enhancement	AMI, DMS, and sensor integration	High-frequency telemetry and data ingestion systems
Hosting capacity maps	Dynamic Line/Transformer Rating	Advanced DMS and automated control systems

Key Milestones	Key Milestones	Key Milestones
Data standards and governance	Topography-aware monitoring and visibility (real time)	Automated switching and restoration
Feeder level visibility through SCADA integration	Advanced planning and operating processes	Locational DER dispatch and market participation
DER registry and interconnection	Dynamic network modeling and optimization	Closed loop grid optimization

Figure 1 Summary of proposed roadmap

The roadmap phases are intentionally not defined by fixed time spans. Utilities may already be at different stages of progress within these phases based on their existing capabilities, investments, and operating context. Since each utility is at different stages of maturity and development, prescribing specific time-bound milestones for roadmap phases may imply that the EDCs should march in lockstep. Therefore, the phases describe a logical maturity progression rather than a prescribed schedule. Each utility should advance through them on a time frame that aligns with its starting point, priorities, and readiness.

Conclusion and Recommendations

Delaware's distribution grid is entering a period of structural change driven by electrification, DER growth, and evolving policy requirements. While current system performance is strong, the ability to sustain reliability, affordability, and resilience under future conditions will depend on timely and coordinated modernization efforts. The statewide roadmap presented in this report provides a structured path forward. It defines a sequenced approach to building foundational capabilities, enabling integration, and ultimately achieving optimized, adaptive grid operations. Importantly, the roadmap is designed to be flexible and scalable, recognizing the diversity of Delaware's utilities and the evolving nature of technology and policy conditions.

The following recommendations are provided to guide the implementation of a statewide grid modernization strategy.

- **Focus Near-Term Investments on Foundational Capabilities:** EDCs should consider prioritizing high-impact investments in data integration, system visibility, and network modeling. Establishing a more unified data and analytics foundation will help support scenario planning, DER integration, and operational optimization over time. Where appropriate, federal and state funding opportunities may also be used to help accelerate deployment of these core capabilities.
- **Adopt a Phased Modernization Approach:** EDCs should develop their own phased modernization roadmaps. These should be utilized to guide capital plans and distribution system planning processes. Smaller EDCs may also seek to promote scalability and interoperability across systems, platforms, and service territories as implementation progresses.
- **Transition DERs and DSM into Operational Grid Resources:** EDCs and policymakers should consider opportunities to move beyond programmatic deployment of DERs and DSM toward greater operational integration. Expanding dispatchability and visibility of distributed resources, including through platforms such as Distributed Energy Resource Management System (DERMS), would enhance their value to the grid. Over time, DERs will play a larger role in supporting capacity, reliability, and resilience objectives.
- **Strengthen Grid Visibility, Operations, and Automation:** EDCs should consider expanding deployment of advanced distribution management, monitoring, and control systems to strengthen grid operations. Improvements in real-time situational awareness and outage response capabilities will provide near-term operational benefits. Over the longer term, utilities should continue progressing toward more automated and adaptive grid operations as needs and capabilities evolve.
- **Advance Policy and Regulatory Enablement:** Grid resiliency, reliability and modernization will not be delivered exclusively by EDCs. State agencies and

policymakers may leverage the findings to support development of policies that enable DER integration, grid resilience, and advanced system operations. Consideration should be given to flexible interconnection policies, frameworks that support locational value of DER integration, flexible load management, and grid modernization investments.

- **Enhance Cybersecurity and Organizational Readiness:** EDCs and state agencies should consider strengthening coordination on cybersecurity governance and related practices. Increased visibility into system risks and more standardized approaches, where feasible, will support more consistent readiness across organizations. Investments in workforce development, digital skills, and change management will also help support successful grid modernization efforts.

Recognizing these structural and market constraints, the roadmap emphasizes a targeted and pragmatic approach to advancing grid modernization across Delaware's EDCs. Affordability concerns, utility investment models, and governance differences can affect how quickly investments move forward and how modernization efforts are carried out across utilities. In this context, Section 40101(d) and related funding opportunities are expected to play a critical enabling role by supporting high-impact, scalable pilots that align with each EDC's operational maturity and system needs. Recommended priorities reflect this approach, with DPL focusing on capacity optimization, DER integration, and advanced grid operations, mid-sized cooperatives and municipals advancing system visibility and control capabilities alongside demand-side programs, and smaller municipal systems prioritizing foundational upgrades and shared solutions. Collectively, these targeted investments provide a practical pathway to address identified gaps in visibility, DER integration, and operational flexibility, while positioning all EDCs to participate in a coordinated and achievable modernization trajectory.

Policy Implications

Delaware's EDCs currently demonstrate reliability performance that compares favorably with national benchmarks. However, Delaware faces a distinct structural challenge: high dependence on imported electricity, limited in-state generation growth, and significant north-to-south power transfer requirements. At the same time, new load growth from electrification, data centers, and economic development will increase demands on the system[2]. Historically, development of new large-scale generation resources in southern Delaware has proven challenging, suggesting that traditional supply-side solutions alone may not be sufficient to achieve the State's long-term reliability, resilience, and affordability objectives.

Consequently, Delaware's policy focus should increasingly shift toward enabling distributed energy resources (DERs), flexible demand, and grid-enhancing technologies as cost-effective alternatives for managing future system needs. In the near term, policymakers may prioritize investments and policies that help utilities establish foundational capabilities, including high-quality network data, integrated system models, advanced metering, visibility into distribution system conditions, and basic control capabilities. These foundational investments are prerequisites for more advanced planning, operational optimization, and

[2] Security Constrained Economic Dispatch (SCED) for Data Center Load. Siemens Energy. Study results in support of State Agency Joint Comments regarding the Large Load Tariff proposed by Delmarva Power & Light (DPL) in PSC Docket No. 25-0826. Submitted April 6, 2026.

DER integration. At the same time, demand-side management (DSM) programs should evolve from customer programs into operational grid assets capable of providing measurable capacity, reliability, and affordability benefits.

As these foundational capabilities mature, Delaware's policy framework can progressively support a second phase focused on extracting greater value from existing infrastructure through advanced planning and operational practices. Enhanced visibility, analytics, and network modeling can enable utilities to identify constrained locations, improve hosting capacity, support non-wires alternatives, and optimize utilization of existing assets.

Over the longer term, policies that support automation, DER orchestration, market participation, and operational integration of distributed resources can help transform DERs, storage, demand response, and flexible loads into active contributors to reliability, resilience, and affordability. This phased approach aligns with the objectives of HJR3 by creating a practical pathway to modernize Delaware's grid while minimizing cost impacts on customers, improving system resilience, and enabling the State's longer-term clean energy and electrification goals.

1. Introduction

This final program report has been prepared in response to the Delaware DNREC Request for Proposal NAT41172-EGS, which calls for a comprehensive statewide assessment of Delaware's electricity distribution systems to identify opportunities to modernize and strengthen the grid. The intent of this analysis is to provide a rigorous, system-wide evaluation of Delaware's EDCs, including their planning practices, infrastructure characteristics, and investment priorities, to support the State's energy transition and long-term grid resilience. To this purpose, Siemens Energy deployed a methodology emphasizing structured data collection through workshops, benchmarking against North American utility practices, and a qualitative systematic evaluation of grid modernization opportunities.

Key RFP Requirements

- Statewide analysis of baseline conditions for each Delaware EDC.
- Description of each EDC's approach to distribution system planning, including load forecasting, DER adoption, asset management, and performance assessment.
- Characterization of distribution systems with descriptive narratives and summary statistics (e.g., customer classes, voltage levels, DERs, circuit types, substations, innovative technologies).
- Satisfy the requirements of HJR3 which requires a characterization of the relative opportunities of various grid enhancing technologies to bolster the safety, resilience and reliability of the electricity grid while promoting electricity affordability for Delaware citizens.
- Utilize the recommendations regarding grid modernization within the State Energy Plan (SEP), the long-range distribution plans created by the state's EDCs, and any results from grants issued in the DNREC State Energy Office (SEO) 40101(d) program to inform the future implementation of 40101(d) and any subsequent state investment or legislation addressing grid enhancing technologies.

Purpose of the Final Program Report

This report provides a comprehensive summary of baseline system conditions for each of the three Delaware EDCs while identifying opportunities to modernize and strengthen the state's grid. The report serves to:

- Provide a clear, data-driven overview of Delaware's electricity distribution systems.
- Present an overview of each EDC's approach to distribution planning, including methodologies for load and DER growth forecasting, asset management, and performance assessment.
- Conduct a qualitative cybersecurity assessment of each EDC based on submitted documentation, benchmarking their governance, controls, and maturity against National Institute of Standards and Technology (NIST) Cybersecurity Framework (CSF) and North American Electric Reliability Corporation (NERC) Critical Infrastructure Protection (CIP) frameworks while identifying strengths, gaps, and data limitations.

- Summarize and communicate the data collected from EDCs, highlighting both the availability and limitations of data for the analyses and outcomes required by HJR3 and the RFP.
- Use the Siemens Energy Navigator framework to evaluate projects, initiatives, and strategies based on standardized criteria and industry benchmarks.
- Develop and deliver a statewide roadmap which identifies near-, mid-, and long-term actions to deploy grid-enhancing technologies and support DER integration, electrification, and resilience objectives.

Note on HJR-3 Requirements

While every effort was made to address the requirements of HJR3, we could not comprehensively determine the “potential for adoption of grid-enhancing technologies, including benefits, cost burdens and cost shifting, feasibility and barriers to adoption.” This limitation stemmed primarily from the inaccessibility of power flow models or the necessary data to develop them, such as single line diagrams (SLDs), equipment ratings and configurations, outage data, and reliability metrics. Without these data points, Siemens Energy had to rely on high-level industry standards, benchmarking, publicly available information, experience with other EDCs, and estimates provided by the EDCs themselves. As a result, the analysis of projects was conducted at a high qualitative level rather than through quantitative modeling or simulation.

Organization of the Final Program Report

This report is organized into the following six sections:

- Section 1: Introduction
- Section 2: Analytical Framework
- Section 3: Baseline conditions including inventory of EDC assumptions, key forecasts and boundary conditions
- Section 4: Long-Range Distribution Planning best practices
- Section 5: Cybersecurity compliance and policy review
- Section 6: Capabilities gap analysis
- Section 7: Implementation roadmap including inventory of grid modernization programs and initiatives and benefit-effort matrices
- Section 8: Conclusions

2. Analytical Framework

The objective of this section is to document the analytical framework used to translate stakeholder priorities into a structured, defensible basis for evaluating grid modernization initiatives and developing a phased implementation roadmap for Delaware's electric distribution system. This section explains how stakeholder survey results, and the Siemens Energy Navigator tool were integrated to define evaluation objectives, assign relative importance, and support consistent gap analysis and prioritization.

The framework builds on Siemens Energy's Navigator tool and was customized for Delaware through stakeholder engagement, and a statewide survey. The analytical framework was designed to ensure that recommended projects and programs are directly aligned with stakeholder priorities, support Delaware's policy objectives, and can be evaluated in a consistent and transparent manner. It serves three primary functions:

1. Translates stakeholder priorities into a structured set of evaluation objectives that reflect desired outcomes for reliability, DER integration, resilience, affordability, and equity.
2. Provides a consistent basis for identifying and assessing gaps between current and desired capabilities across key utility and system functions.
3. Enables prioritization of initiatives and development of a phased implementation roadmap that is grounded in both stakeholder input and analytical rigor.

2.1. Methodology

The project team engaged with stakeholders through the Governor's Energy Advisory Council (GEAC). The project team made a presentation at the GEAC meeting on November 11th, 2025. The presentation included an introduction to the project and discussion of key goals and priorities. Following the presentation, a survey was conducted to collect stakeholders' formal inputs on project goals and priorities. Twenty-six (26) responses were received from stakeholders between November 21st and December 4th, 2025. Each respondent reported their perceived importance of key priorities on a scale of 0-5, with five being the most important and zero being the least important. In addition, respondents had the opportunity to state other priorities and provide additional comments.

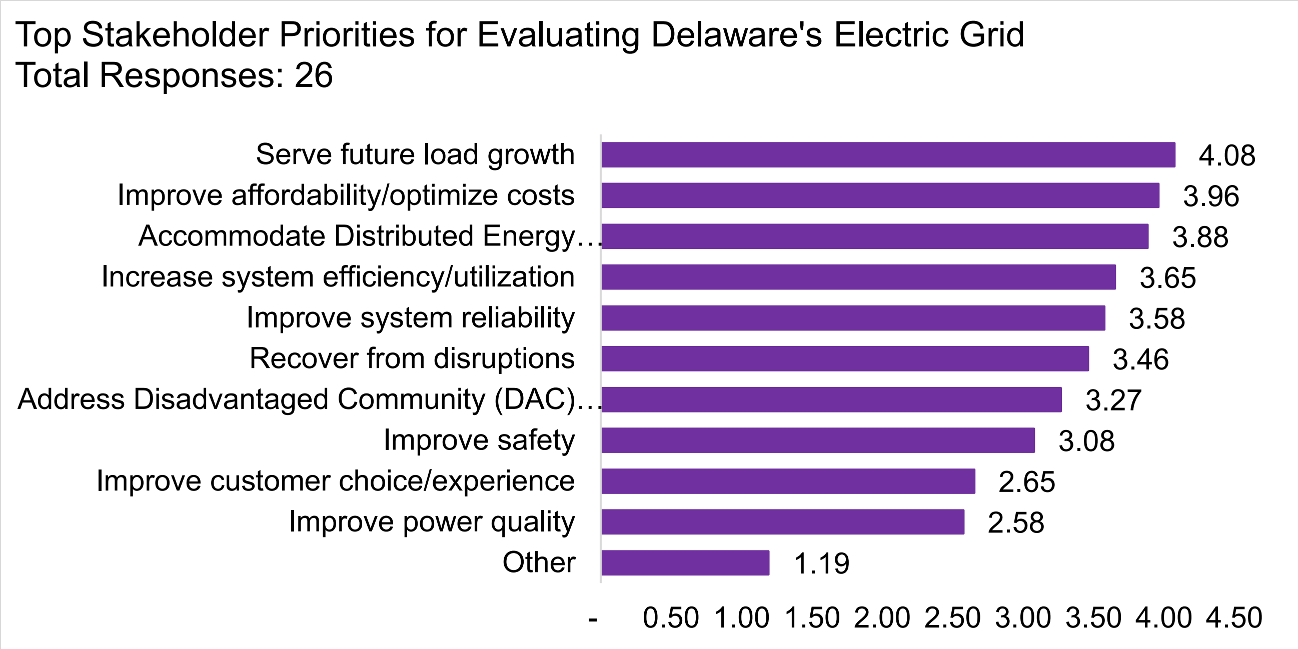

Figure 2. Stakeholder priorities

The following key insights were obtained from the survey:

- Delaware's electricity grid stakeholders prioritized serving future load growth, improving affordability, and integrating DERs and renewables.
- Grid modernization was seen as dependent on the integration of non-wire alternatives (NWA), DERs, DERMS, and virtual power plants (VPPs), with added emphasis on climate resilience and equity for disadvantaged communities.
- Survey respondents highlighted the importance of minimizing disruptions to disadvantaged communities during weather events, expanding affordable energy access, and diversifying Delaware's energy supply.
- Stakeholder feedback emphasized that grid priorities were interdependent, with investments in DERs and renewables expected to enhance reliability and support broader goals like microgrid development and equity.

Siemens Energy utilized its proprietary Navigator tool to perform gap analysis, initiative assessments and roadmap building. The Navigator tool provides a structured framework for assessing grid modernization across a defined set of business areas and objectives. Each business area represents a functional domain of the utility or regulatory ecosystem, such as grid operations, planning, asset management, and energy supply coordination. Within each business area, specific objectives describe desired capabilities, such as improving reliability, increasing grid capacity, enabling DER coordination, or enhancing data and asset visibility.

While the Navigator framework provides a comprehensive and standardized set of objectives, it is inherently technology and capability focused. To ensure that the analysis reflects Delaware-specific priorities and policy goals, stakeholder survey priorities were explicitly mapped to these objectives. This mapping step was necessary to embed stakeholder values directly into the Navigator-based evaluation and to ensure that the gap analysis and prioritization reflect what stakeholders consider most important.

Stakeholder survey priorities were systematically mapped to Navigator objectives across the applicable business areas. Each survey priority was linked to one or more relevant objectives. A mapping score ranging from one to five was assigned to represent the strength of the relationship between a given survey priority and a specific objective, where one indicates a weak or indirect relationship and five indicates a strong and direct relationship.

For example, priorities related to system reliability were strongly mapped to objectives focused on outage reduction and restoration performance, while priorities related to DER integration were mapped to objectives addressing grid capacity, DER coordination, and energy supply optimization. Equity and resilience priorities were mapped to objectives associated with outage recovery, resilience planning, customer engagement, and targeted grid investments. This structured mapping ensured that stakeholder priorities were quantitatively incorporated into the analytical process rather than addressed qualitatively.

Following the mapping exercise, objective scores were calculated by combining stakeholder survey scores with the assigned mapping scores. For each objective, the weighted score reflects both the importance of the underlying stakeholder priority and the degree to which the objective contributes to achieving that priority.

Weighted scores were aggregated across all mapped survey priorities to produce a total score for each objective. Based on the distribution of results, objectives were classified into three importance categories: High, Medium, and Low. High-importance objectives represent capabilities that strongly support multiple high-priority stakeholder outcomes. Medium-importance objectives support important outcomes but may be more enabling or secondary in nature. Low-importance objectives either support lower-ranked stakeholder priorities or reflect areas where existing capabilities are relatively mature.

2.2. Results

Table 1 summarizes the results of the objective weighting and classification process. Objectives are grouped by business area and categorized by their assigned importance level (High, Medium, or Low) based on the weighted scoring results.

Table 1. Navigator Objectives by Business Area and Importance Classification

Priority	Serve future load growth	Improve affordability/optimize costs	Accommodate Distributed Energy Resources (DERs) and renewables	Increase system efficiency/utilization	Improve system reliability	Recover from disruptions	Address Disadvantaged Community (DAC) and Equity Focus Areas (EFA) needs	Improve safety	Improve customer choice/experience	Improve power quality	Weighted Score	Objective Weight
Survey Score	4.1	3.96	3.88	3.65	3.6	3.5	3.27	3.1	2.65	2.6		
Operation and Asset Management												
Enhance resource and expenditure allocation		5									19.80	Medium
Balance risk propagation throughout grid assets					5						17.90	Medium
Streamline operational workflows				1	1						7.23	Low
Improve asset records and accessibility				1	1						7.23	Low
Grid Planning and Operations												
Improve power supply quality					1					4	13.90	Low
Reduce outages and improve reliability					5	5					35.20	High
Update safety and security protocol					1			5			18.98	Medium
Increase grid capacity for efficient energy delivery	5			5							38.65	High
Energy Supply Coordination												
Maximize emission reduction			1								3.88	Low
Enhance renewable energy portfolio		3	5				1		1		37.20	High
Optimize eMobility devlopment and allotment		1	3								15.60	Medium
Support creation of distributed energy system		2	5			2	1		1		40.16	High

3. Baseline Conditions

The objective of this section is to deliver a system-wide view of Delaware's electric distribution grid across Delmarva Power and Light (DPL), Delaware Electric Cooperative (DEC), and the Delaware Municipal Electric Corporation (DEMEC) to support DNREC's grid modernization and resilience objectives. This section characterizes each EDC's system topology, reliability, customer programs, DER adoption, and planning practices, and evaluates whether the data currently available is sufficient to support the originally proposed detailed modeling and cost-benefit analysis envisioned in the state's legislative mandate and RFP.

3.1. Methodology and Data Sources

This section employed the following methodology to collect, visualize and present baseline conditions.

Review of Existing Plans and Reports

The analysis began with a comprehensive review of existing documents, including:

- DPL Annual Update 2024 - Infrastructure, Safety, and Reliability (ISR) Plan
- DPL annual interconnection reports for 2023 and 2024
- Planning documents provided by DEC and DEMEC
- The State Energy Security Plan (SESP) to understand Delaware's emergency response framework and energy security priorities
- 40101(d) grant program applications
- The SEP's recommendations and strategies

EDC Engagement

Key stakeholders within each EDC were identified and engaged through interviews and Request for Information (RFI). These interactions provided qualitative insights into current distribution system planning practices, operational challenges, and opportunities for improvement. Data requests were issued to both regulated and non-regulated EDCs to obtain detailed infrastructure and performance metrics.

Table 2. Key EDC engagements

Date	EDC	Discussion Topics
11/05/2025	DPL and DEC	Program Kick-off
11/06/2025	DEMEC	Program Kick-off
11/10/2025	DEC	Customer programs
11/17/2025	DEC	Distribution Planning
12/04/2025	DPL	Data Access

12/08/2025	DEC	Data Access
12/09/2025	DEMEC	Data Access
12/09/2025	DPL	Data Access

Public Data Sources

Public data was collected and organized from Federal Energy Regulatory Commission (FERC), U.S. Energy Information Administration (EIA), and Pennsylvania-New Jersey-Maryland (PJM), including service territory boundaries, customer classifications, DER adoption, circuit types, substation locations, and system performance. Siemens Energy (SE) utilized Python and Excel for data visualization, creating topographical maps and dashboards to highlight key system characteristics.

Publicly available data was collected from:

- FERC Form 1
- EIA Form 850 and 851
- PJM Interconnection
- EIA Energy Atlas
- U.S. Census Bureau and Department of Labor (for demographics and Gross Domestic Product (GDP))
- RPS and Municipal Renewable Portfolio Standard (MRPS) compliance reports
- Delaware Public Service Commission (DE PSC) Dockets 24-1012, 25-0858, 25-1554, 25-1555

3.2. Overview of Delaware's Electricity System

Delaware's electric system is characterized by relatively flat historic load growth, heavy reliance on imported natural-gas-fired energy, PJM region-wide projections for accelerated load growth, resource inadequacy and rapidly emerging policy drivers that will push both demand and supply, including clean energy deployment, higher over the next decade.

Electricity Demand

Delaware's 2024 coincident summer peak load was about 4.1 Gigawatt[3] (GW), compared with a winter peak load of roughly 3.1 GW[4]. Total load has been broadly stable over the last several years when viewed at the statewide level. Individual utilities show modest year-to-year variation but no structural shift in peak magnitude between 2020 and 2024. Table 3 below summarizes the non-coincident peaks by EDC between 2020 and 2024. **Note: In some cases, DPL data as reported in EIA-861 does not differentiate between Delaware and Maryland service territories. In these cases, the reported value for DPL across both states is provided and identified as such in the footnotes.**

Table 3. Delaware EDC's peak load 2020-2024 [5]

	2020	2021	2022	2023	2024
Summer Peak Load (MW)					
Delmarva Power [6]	4,029	3,950	4,069	4,022	4,130
Delaware Electric Cooperative	415	410	405	438	460
City of Dover	156	165	157	162	164
Town of Middletown	61	63	63	65	69
City of Milford	49	51	52	51	55
City of Newark	86	89	92	94	88
Winter Peak Load (MW)					
Delmarva Power [3]	3,136	3,179	3,538	3,599	3,523
Delaware Electric Cooperative	310	310	378	400	368
City of Dover	104	104	108	113	113
Town of Middletown	60	54	59	46	53
City of Milford	38	39	43	43	45
City of Newark	56	57	59	69	57

[3] Excludes DPL MD territory
[4] PJM
[5] EIA Form 861
[6] Includes DPL DE and MD. DPL has advised that DE is approximately 63.5% of DPL total load.

Looking ahead, Delaware is poised for a period of significantly faster load growth driven by large new customers and emerging state policy. Most notably, a proposed data center project “Starwood Digital Ventures" near Delaware City may add up to 1.2 GW [7] of new load to the existing system. The 2024-2028 Delaware’s SEP explicitly anticipates higher electricity demand from building electrification, electric vehicles (EVs), and other end uses, and calls out the need to prepare “transmission lines and substations to integrate the increasing use of renewable resources” and to “modernize Delaware’s distribution networks to integrate DERs and NWA.” This trend is also reflected in PJM’s RTO Summer Peak Demand Forecast, as shown in Figure 3. This forecast has been revised upwards every year since 2023 [5].

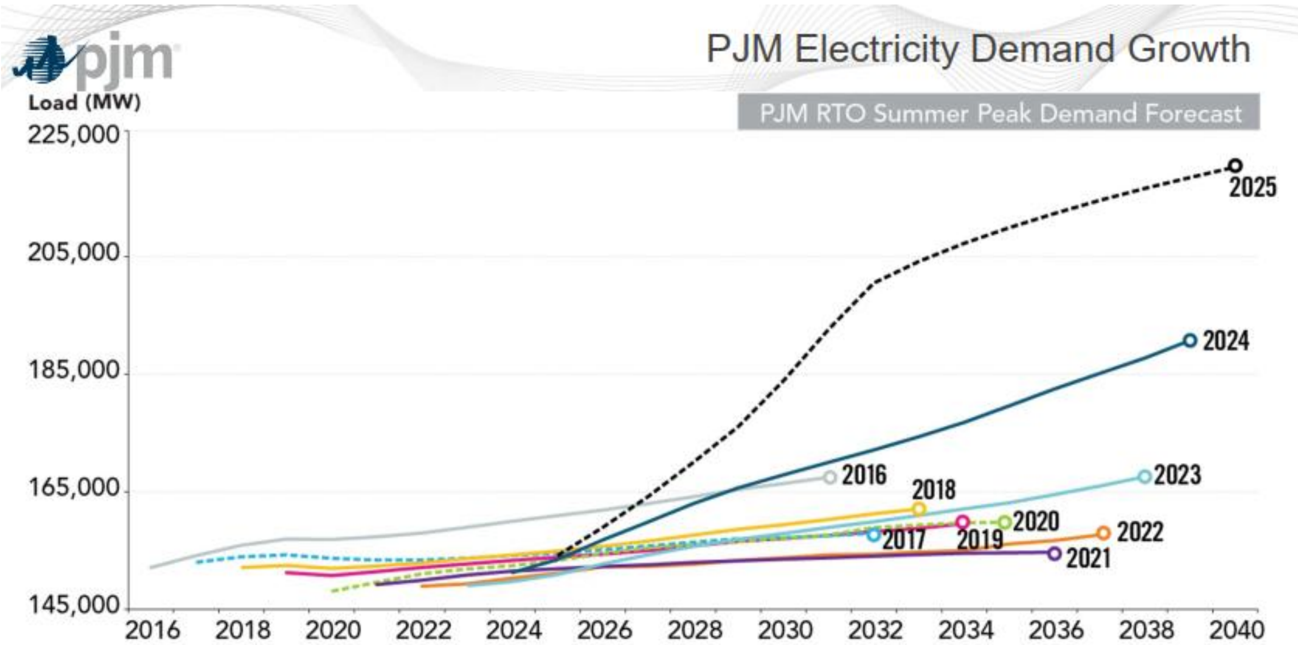

Figure 3. PJM RTO summer peak demand forecast [8]

Figure 4 shows Delaware’s net generation and imports for all sectors from 2015 to 2024. Notably, the state annually imports about 60% of its electricity needs. Within the state, natural gas is the dominant power generation fuel, accounting for more than 80% of in-state electricity net generation. Coal’s contribution has fallen from roughly 46% of net generation in 2010 to about 3% in 2024, and the retirement of the 411 MW coal-fired Indian River Generating Station in 2025 has removed nearly all remaining coal from Delaware’s capacity stack. **Note: 2024 import data is not yet publicly available.**

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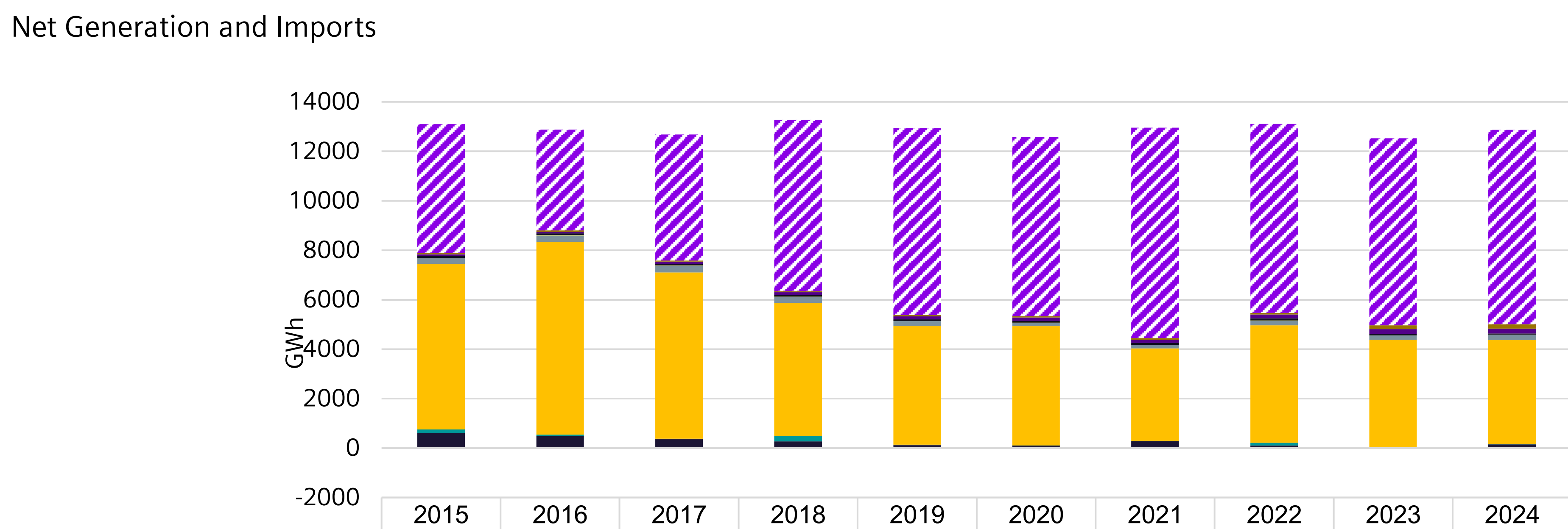
[7] New Castle County, DE Webpage.

[8] PJM 2024 Delaware State Infrastructure Report (January 1, 2024 – December 31, 2024), June 2025.



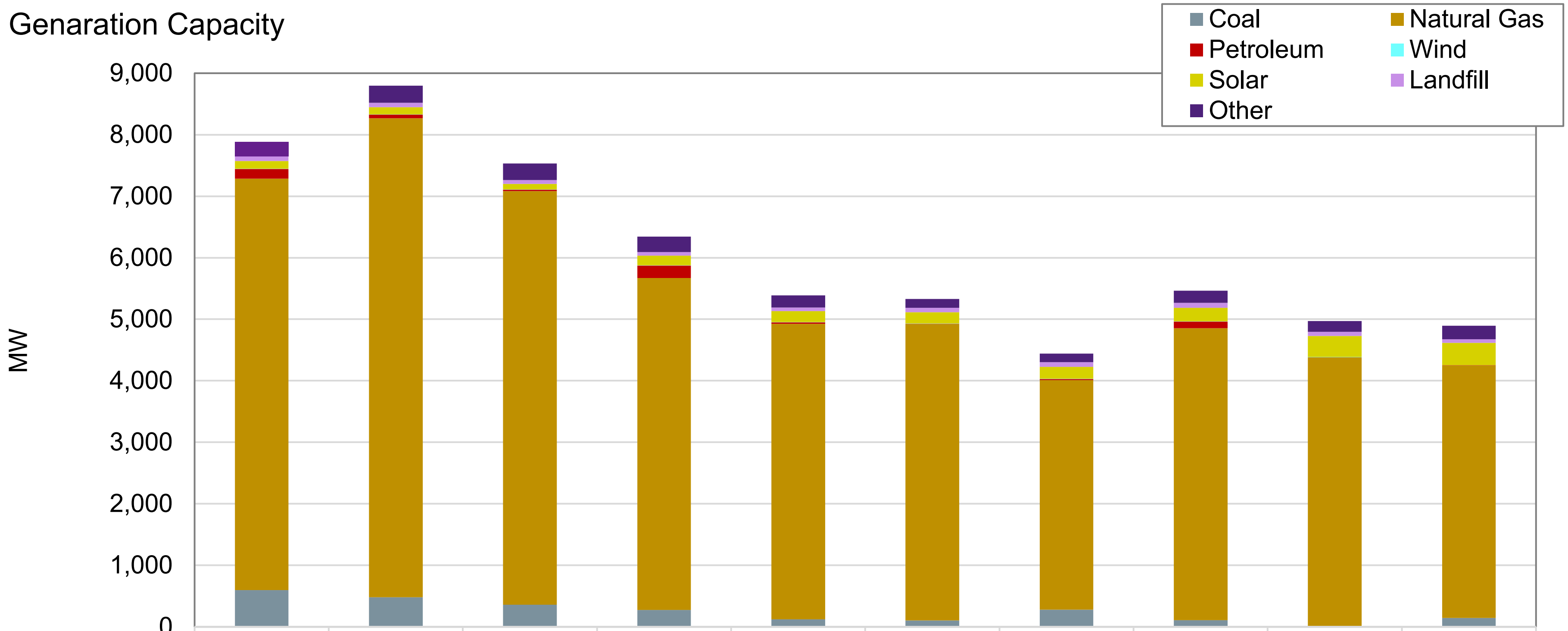
	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
imports	5,210	4,089	5,100	6,932	7,563	7,246	8,518	7,647	7,564	7,873
all utility-scale solar	49	51	50	50	54	54	57	64	155	166
small-scale solar photovoltaic	79	67	92	110	124	128	139	158	189	203
other										
biomass	76	68	63	59	61	72	74	79	66	42
wind	5	5	5	5	5	5	5	4	4	3
other gases	238	277	271	252	194	146	142	198	172	221
natural gas	6689	7787	6723	5400	4806	4818	3734	4750	4383	4206
petroleum coke	0	0	0	0	0	0	0	0	0	0
petroleum liquids	154	63	25	201	19	8	17	108	-2	18
coal	599	479	359	273	119	102	277	105	-6	144

Figure 4. Delaware net generation and imports for all sectors (2015-2024) [9]

[9] EIA 860.

Electricity Generation

Figure 5 shows Delaware's installed generation capacity from 2015 to 2024. The state has experienced a 44% decline in installed generation capacity since 2016. 84% of the currently installed capacity is natural gas-fired generation. Delaware's clean-energy policy is anchored by its RPS, codified in the state's Renewable Energy Portfolio Standards Act (REPSA). Statute and recent amendments require that 40% of electricity retail sales come from renewable resources by 2035, with at least 10% from solar energy. In 2024, about 9% of in-state net generation came from renewables, with utility and small scale solar making up roughly 8% of total generation, meaning the state is at an early stage on its trajectory toward its 2035 target.



	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
Other	238	279	271	251	195	146	141	199	174	221
Landfill	77	69	62	59	60	72	73	78	66	60
Solar	127	117	91	158	179	181	196	220	344	360
Wind	4	5	2	3	5	5	3	5	2	0
Petroleum	155	61	25	202	20	8	18	107	-3	5
Natural Gas	6688	7788	6723	5399	4807	4818	3734	4750	4384	4106
Coal	598	478	359	273	120	101	277	106	-7	144

Figure 5. Delaware installed generation capacity (MW)

Figure 6 maps Delaware's installed generation capacity. The majority of the state's generation capacity is located in northern and central Delaware, close to industrial load centers and major transmission interfaces within the bulk power system managed by the regional transmission organization (RTO), PJM Interconnection LLC (PJM), leaving southern parts of the state more reliant on transfers from neighboring Load Deliverability Areas over the system.

The future of Delaware's electricity distribution grid will be impacted by the state's 40101(d) program. Delaware's 40101(d) program, established under the Bipartisan Infrastructure Law, provides targeted funding to strengthen electric grid resilience against disruptive events such as coastal storms and flooding. The EDCs' approach emphasizes hardening infrastructure through measures like undergrounding, advanced reclosers, and DER integration, all aligned with United States Department of Energy (USDOE) resilience criteria. Delaware's strategy prioritizes solutions that reduce restoration times, improve reliability metrics, and deliver resilience benefits without materially increasing lifecycle costs.

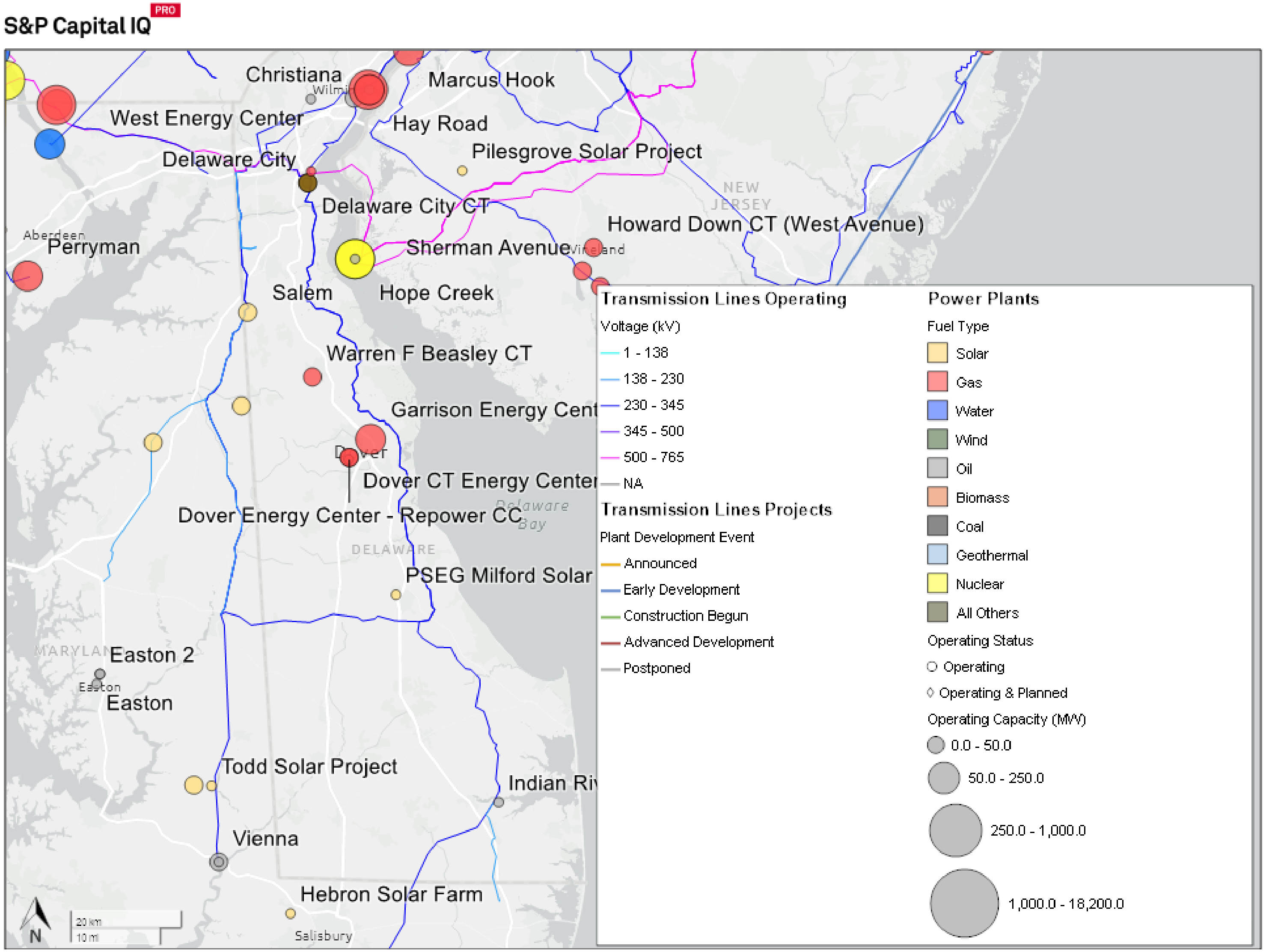


Figure 6. Delaware generation capacity map [10]

[10] Adopted from S&P Capital IQ. Does not show generation <10MW.

Distributed Energy Resources

Delaware has experienced a robust adoption of DER resources. According to DE Public Service Commission (PSC) data in Figure 7, DE has installed 264 MW of solar capacity and 1.04 Megawatt hour (MWh) of battery storage.

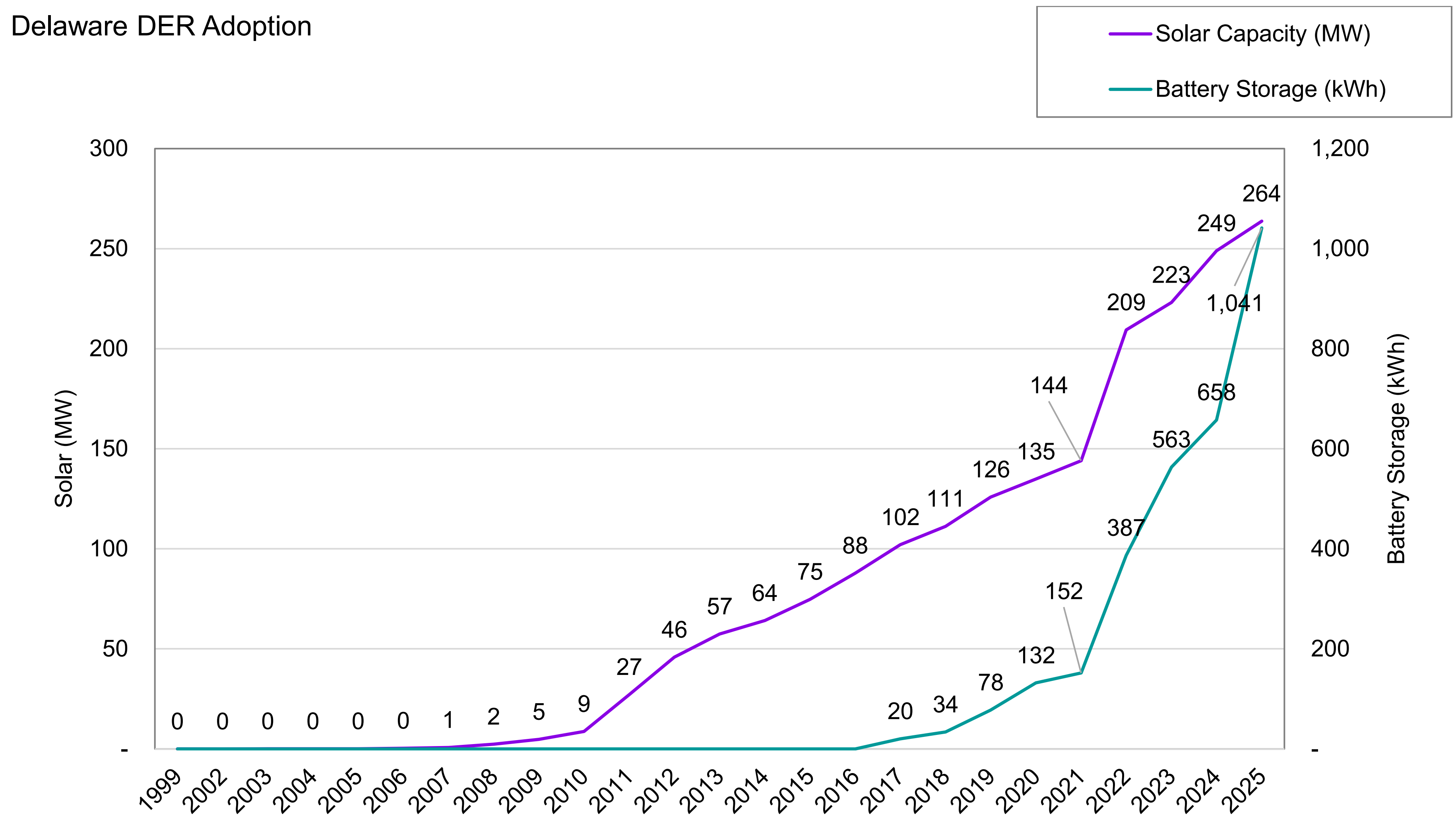


Figure 7. Delaware cumulative DER adoption [11]

[11] Delaware PSC Data

Figure 8 shows the distribution and capacity of solar photovoltaic (PV) installations across Delaware, categorized into Distributed PV (yellow) and Utility PV (orange). Marker size represents total capacity, ranging from 100 kW to >50,000 kW. The largest concentration of solar capacity appears near Middletown, with a very large orange marker indicating a major utility-scale installation. Smaller clusters of distributed PV are scattered throughout the state, particularly near Wilmington and along major highways, suggesting localized adoption in residential or commercial areas.

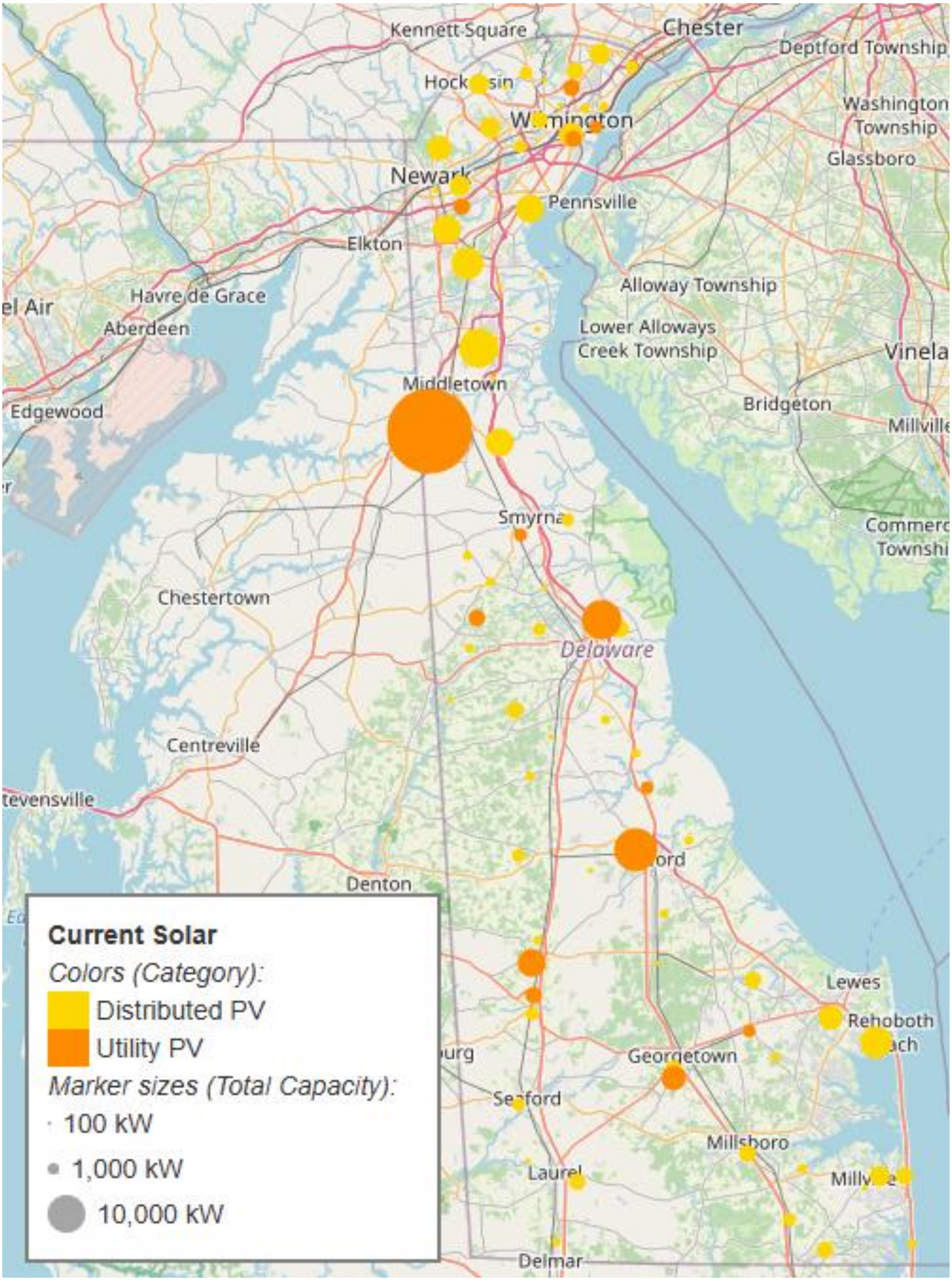


Figure 8. Delaware solar installation by postal code[12]

Electricity Transmission

Delaware's electricity transmission grid is primarily configured to deliver power from regional generation hubs and interstate lines into load centers such as Wilmington, Newark, and Dover. Figure 9 shows Delaware's transmission lines by voltage. Most high-voltage facilities serve as radial or sub-regional spurs off of the broader PJM network, with limited intra-state redundancy away from the main north-south corridors. At present there are no major new transmission projects in advanced development that would significantly alter Delaware's import paths or internal transfer capability.

[12] Berkley Labs https://emp.lbl.gov/tracking-the-sun. The bubble sizes in legend are for example only. The sizes are on a continuous scale, not bucketed.

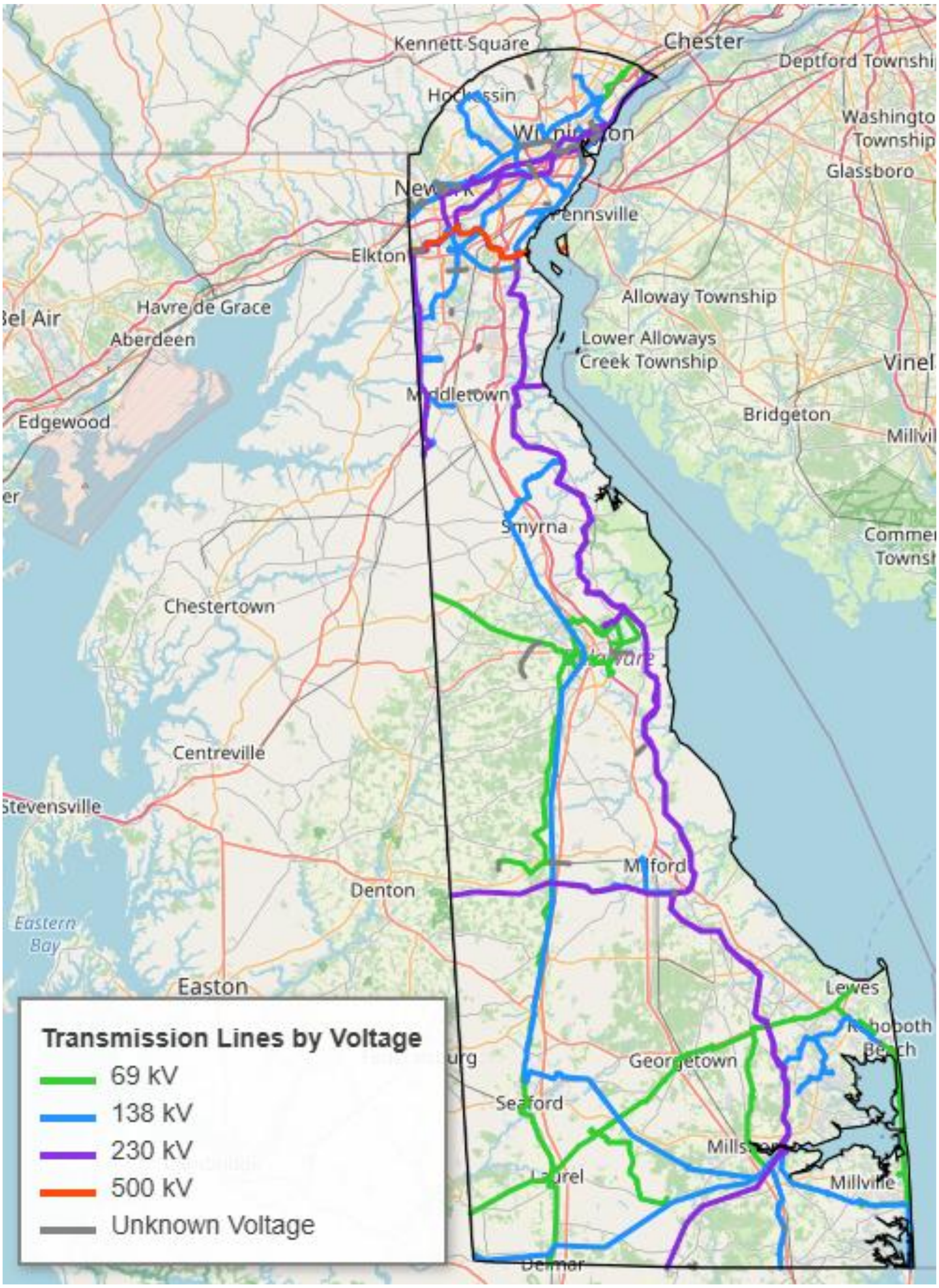


Figure 9. Delaware transmission lines by voltage [13]

[13] EIA Energy Atlas

Natural Gas Infrastructure

Natural gas infrastructure is key to the development of new generation and by extension, new transmission. Eastern Shore Natural Gas Company owned by Chesapeake Utilities is the principal gas transmission provider in the state. Eastern Shore has four primary interconnections with three major upstream interstate pipelines: Texas Eastern Transmission, Transcontinental Gas Pipe Line (Transco), and Columbia Gas Transmission, tying Delaware into the broader Marcellus and Gulf Coast supply basins. Figure 10, adopted from S&P Capital IQ, shows Delaware's gas pipelines and storage facilities. There are currently no large greenfield pipeline or in-state LNG import/export projects underway.

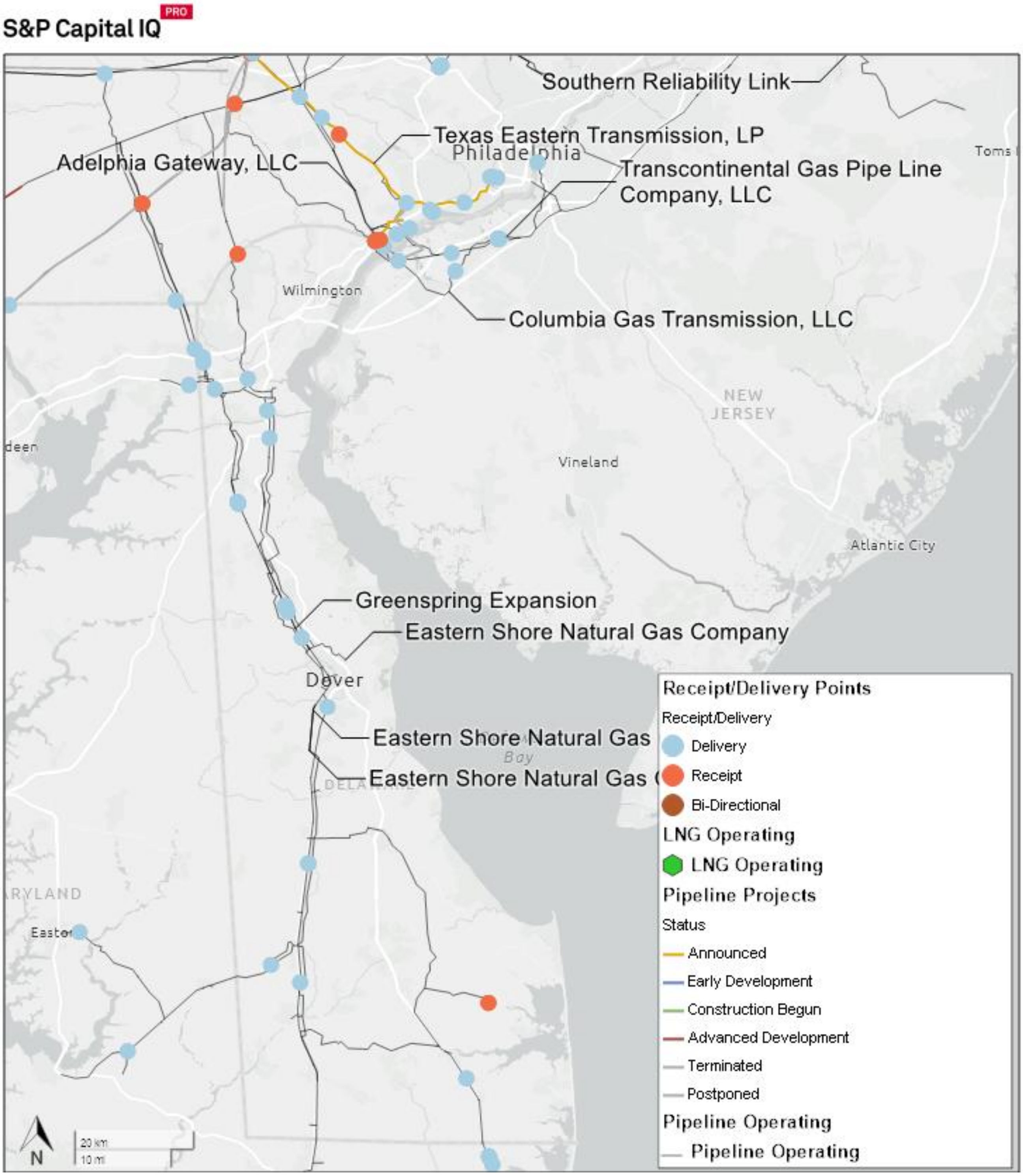


Figure 10. Delaware gas pipelines and gas storage facilities [14]

Wholesale Electricity Prices

Locational marginal prices (LMPs) within Delaware show a persistent differential between northern and southern zones, reflecting transmission topology and the location of major generators and loads. LMP reflects the cost of supplying electricity to a specific location

[14] Adopted from S&P Capital IQ.

on the grid and is influenced by three structural components: energy, congestion, and losses. The energy component represents the marginal cost of producing the next unit of electricity using the least-cost generator available. Congestion arises when transmission constraints prevent low-cost generation from reaching certain areas, creating price differences between nodes; this component reflects the cost of relieving those constraints and becomes significant when the grid is heavily loaded. The loss component accounts for the incremental transmission losses that occur as electricity flows over long distances, which vary by location and network efficiency. Together, these factors explain why LMP prices differ across regions: areas closer to generation or with robust transmission infrastructure experience lower congestion and loss costs, while zones with binding constraints or longer transmission paths see higher prices. In Delaware, the observed price spread is consistent across the energy, congestion, and loss components of LMPs, confirming structural drivers, which are less-than-ideal local generation, transmission congestion and higher losses in the south of the state. Figure 11 shows Delaware's 2024 LMP average values across the state.

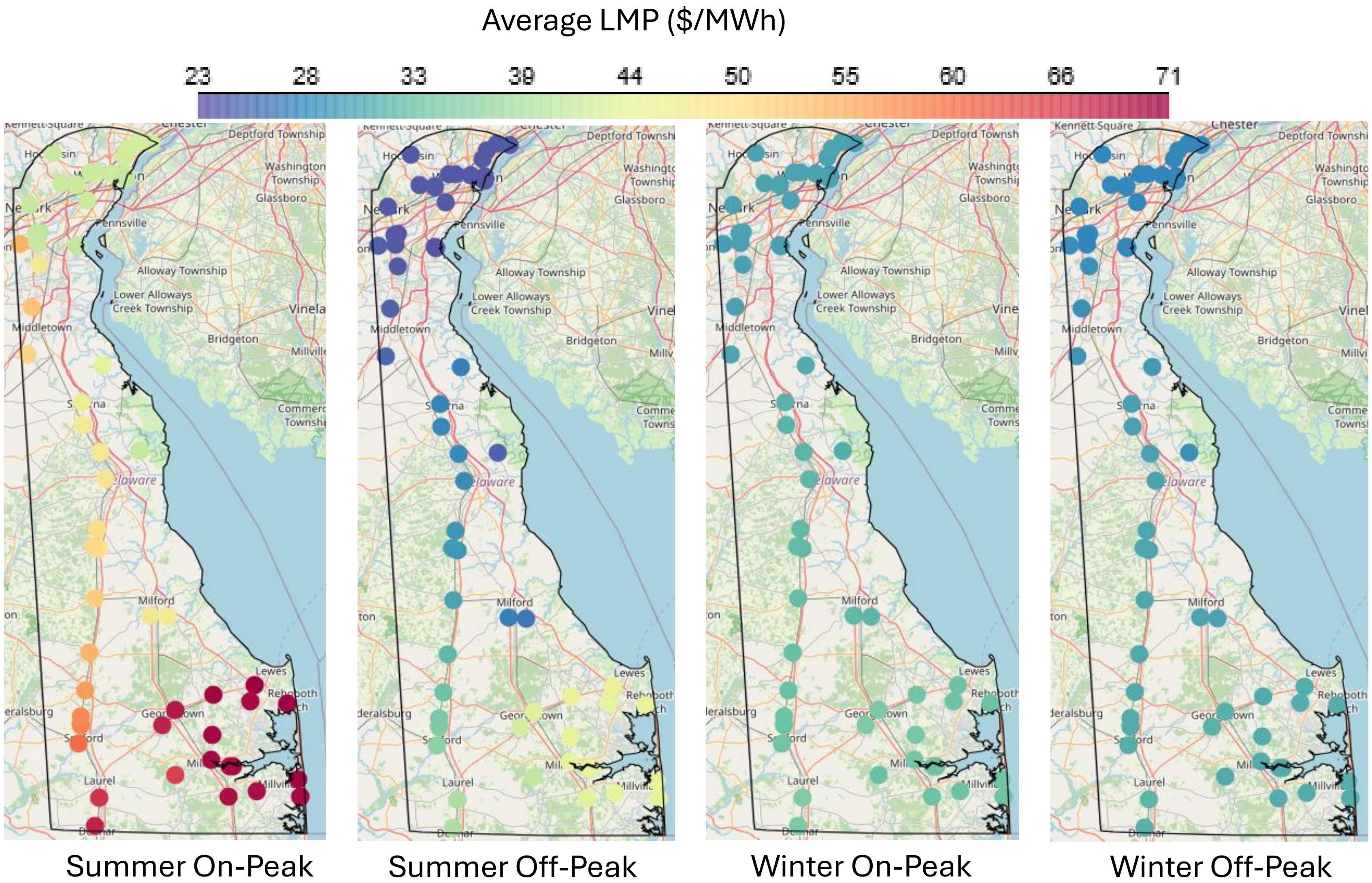


Figure 11. Delaware 2024 average LMP values[15]

[15] Siemens Energy analysis of PJM LMPs.

Capacity markets

PJM employs a market-based capacity construct referred to as Reliability Pricing Model to attract and maintain sufficient electricity generation resources to meet the resource adequacy needs across the regional bulk power system. In the PJM capacity construct, capacity prices are determined through Base Residual Auction (BRA), which secures capacity commitments three years ahead. Figure 12 shows recent PJM BRA capacity prices. Recent auctions, including the BRA for the 2024/2025 delivery year, have seen an increase in capacity prices from historically low levels, driven by tightening reserve margins and changes in market rules. In the BRA, capacity prices are capped at Net Cost of New Entry (CONE). The capacity prices have matched the cap for the last two auctions showing a need for new capacity resources within the state.

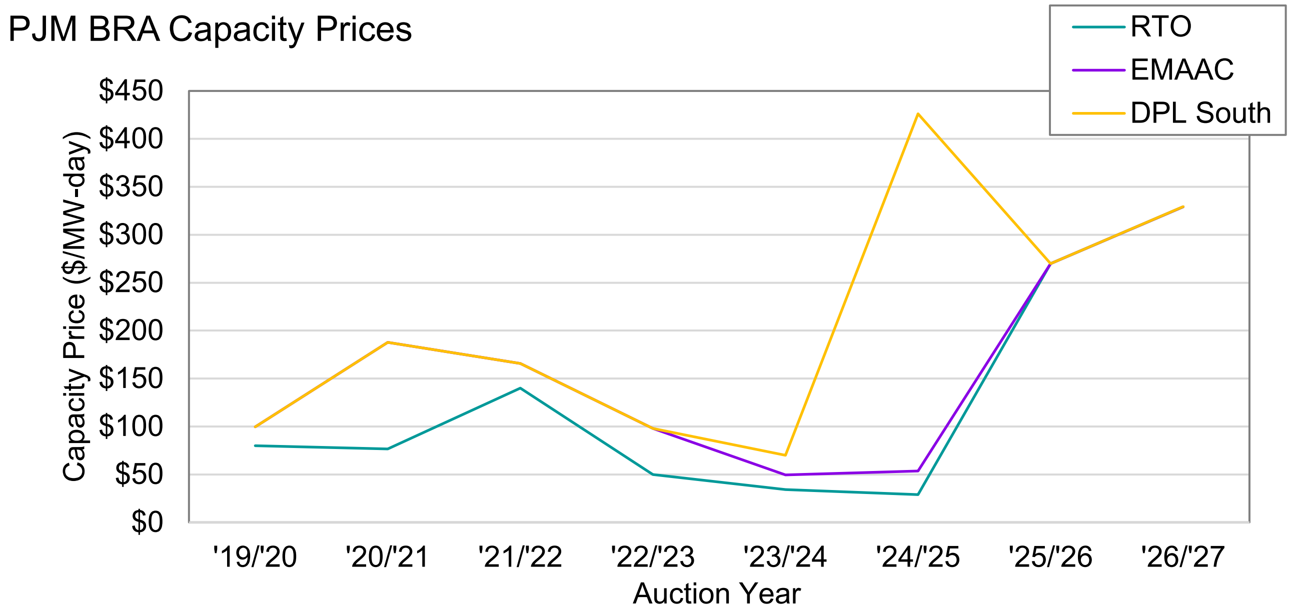


Figure 12. PJM BRA capacity prices[16]

3.3. Overview: Delmarva Power and Light (DPL)

Introduction

DPL is a regulated investor-owned utility and a subsidiary of Exelon Corporation. The US EIA reports that DPL serves 554,789 electric customers in Delaware and eastern Maryland 17, and approximately 136,000 natural gas customers in northern Delaware. Delaware represents approximately 60% of DPL's total customer base and sales revenue, with the remainder in Maryland. **Note: In some cases, DPL data as reported in EIA-861 does not differentiate between Delaware and Maryland service territories. In these cases, the net reported value for DPL across both states is provided and identified as such in the footnotes.**

[16] PJM
[17] FERC Form 1 (2024)

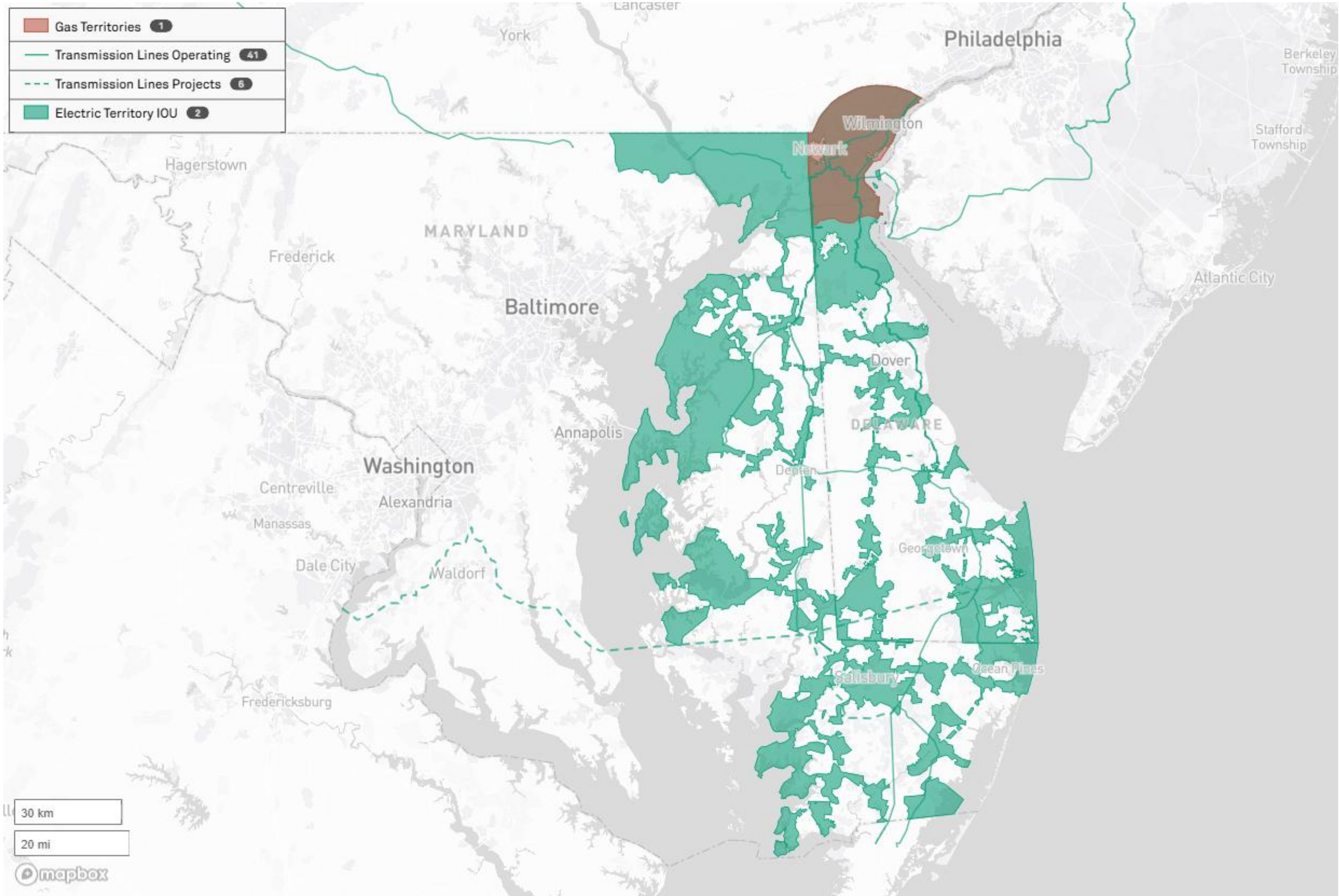


Figure 13. DPL service area

DPL operates across a 5,400-square-mile area on the Delmarva Peninsula, with more than 300,000 electric customers in Delaware. All of New Castle County and most of the populated areas of Kent and Sussex counties fall within DPL's footprint. DPL is also the primary transmission owner in the region. Table 4 shows DPL's Delaware-based commercial information by sector in 2024, where the utility delivered about 3.8 terawatt-hours (TWh) to its 300,000 customers while reporting nearly 648 million dollars in revenue.

Table 4. DPL Delaware 2024 electric sales [18]

Customer Sector	No. of Customers	Electric Sales (MWh)	Revenue ($K)
Residential	275,018	2,916,139	502,490
Commercial	26,154	869,426	143,772
Industrial	38	16,425	1,453
Transportation	0	0	0
Total	**301,210**	**3,801,990**	**647,717**

Peak Demand

DPL serves a significant portion of the state's electrical demand. Table 5 shows DPL's peak summer and winter demand over the past five years. Summer demand has shown inconsistent growth while winter demand has grown about 10% during this period.

Table 5. DPL peak demand [19]

	2020	2021	2022	2023	2024
Summer Peak (MW)	4,029	3,950	4,069	4,022	4,130
Winter Peak (MW)	3,136	3,179	3,538	3,599	3,523

System Topography

In Delaware, DPL's network comprises 273 circuits and over 160 substations, supporting a hybrid architecture with both radial and networked distribution layouts. Service reaches across dense urban and suburban loads within the peninsula's core counties. Detailed conductor mileage by voltage class is not publicly available.

[18] Source: EIA Form 861, DPL DE Only
[19] EIA form 861, includes DPL DE and MD territories. DPL has advised that DE is approximately 63.5% of DPL total load.

Reliability Performance

Table 6 shows DPL's reliability performance across a few key parameters both with and without major event days (MEDs). MED are days when extreme or unusual events cause widespread outages that are outside normal operating conditions. The System Average Interruption Duration Index (SAIDI) tracks the average duration (minutes) of outages per customer annually. The system average interruption frequency index (SAIFI) tracks the average number of outages per customer annually. Reliability trends in terms of both SAIDI and SAIFI have improved over 2020-2024 timeframe. In 2024, DPL was in the 34th percentile for SAIDI performance and 26th percentile for SAIFI performance among all US utilities that reported data, as shown in Figure 14 and Figure 15, respectively.

Table 6. DPL reliability performance 2020-2024 [20]

	All Events (With MEDs)		Without MEDs	
Year	**SAIDI**	**SAIFI**	**SAIDI**	**SAIFI**
2020	272	1.07	77	0.75
2021	61	0.82	61	0.82
2022	78	0.71	65	0.65
2023	122	0.71	69	0.57
2024	127	0.77	68	0.65

In Figure 14 below, columns show the distribution of all EDCs in the US that reported SAIDI performance in 2024. The black column contains DPL's SAIDI performance showing DPL to outperform most peers within one standard deviation from the mean. The dotted line shows the cumulative percentage of EDCs from low SAIDI to high SAIDI values. DPL is within the top 34th percentile of reporting EDCs.

[20] EIA form 861, DPL DE only.

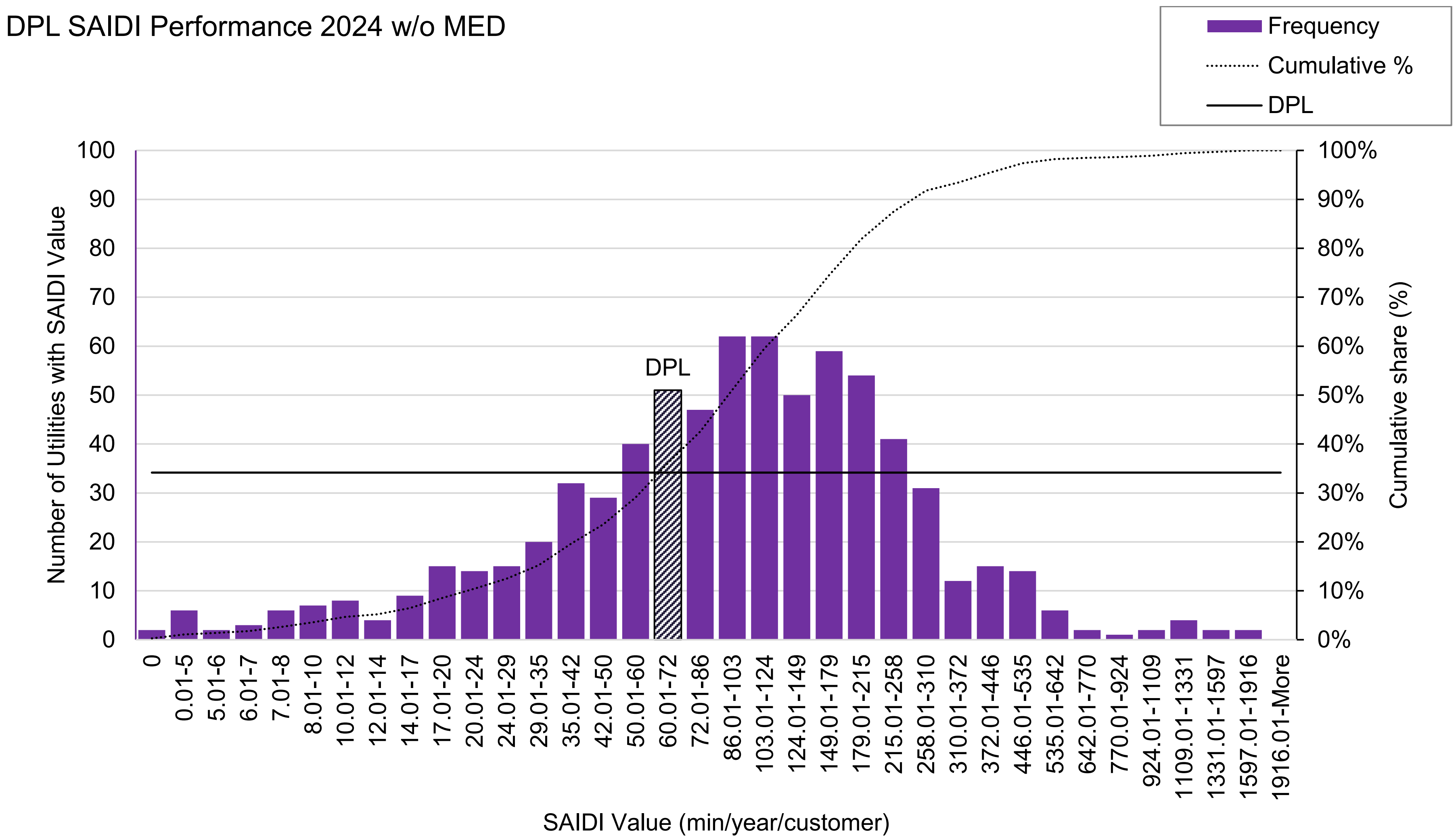


Figure 14. DPL 2024 SAIDI performance [21]

[21] SE performed histogram analysis of all entities that reported reliability data through EIA-861 for year 2024. DPL metrics are for DE only.

In Figure 15 below, columns show the distribution of all EDCs in the US that reported SAIFI performance in 2024. The black column contains DPL's SAIFI performance showing DPL to outperform most peers by over one standard deviation from the mean. The dotted line shows the cumulative percentage of EDCs from low SAIFI to high SAIFI values. DPL is within the top 26th percentile of reporting EDCs.

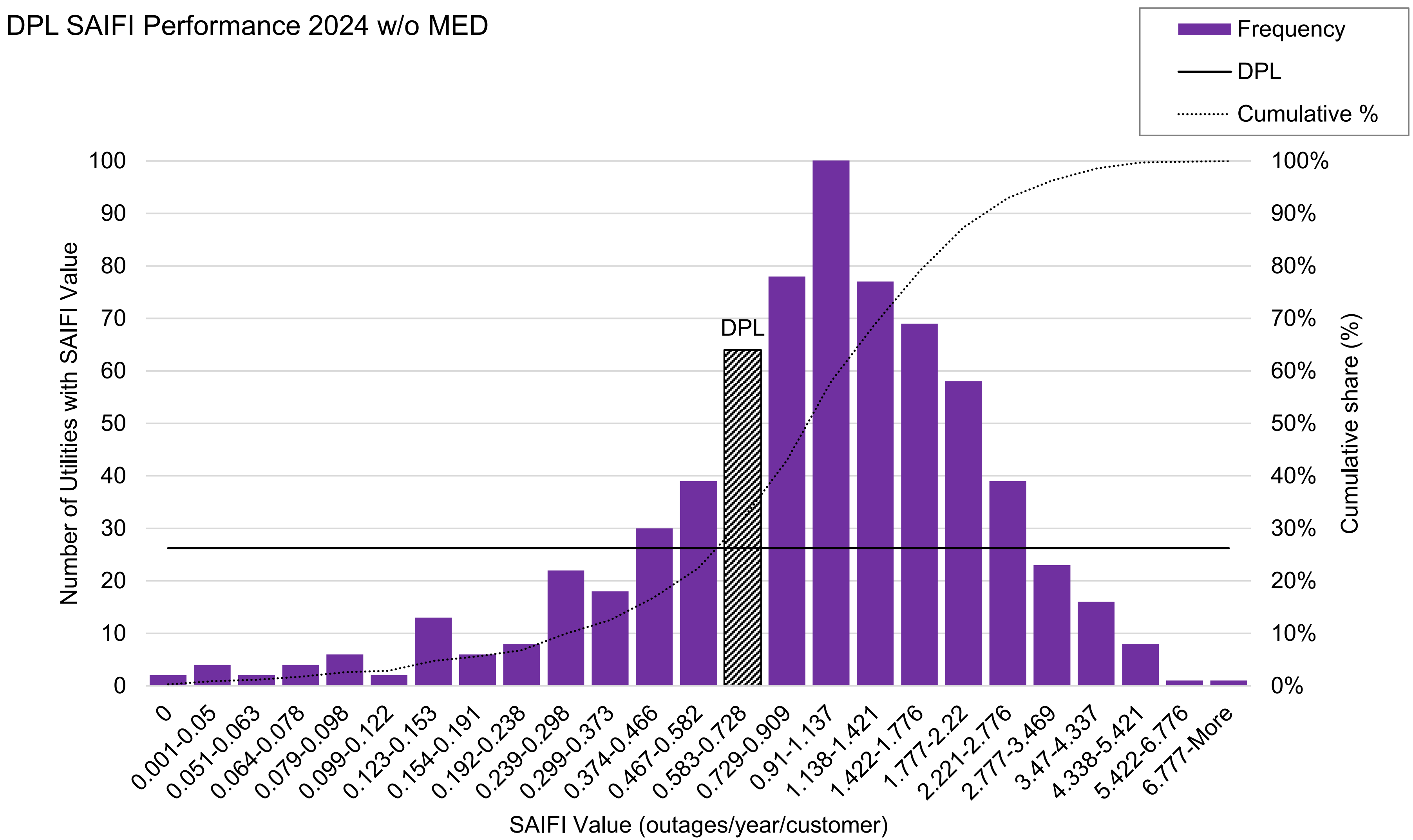


Figure 15. DPL 2024 SAIFI performance [22]

[22] SE performed histogram analysis of all entities that reported reliability data through EIA-861 for year 2024. DPL metrics are for DE only.

This robust reliability performance may present an opportunity to direct increased efforts towards grid modernization and decentralization efforts compared to traditional system hardening approaches.

Energy Efficiency

DPL's energy efficiency (EE) performance in terms of incremental annual savings is shown in Table 6 for the past five years. In 2024, DPL's EE and demand response (DR) programs delivered lower annual incremental EE savings compared to the previous four years.

Table 7. DPL EE performance [23]

Incremental annual savings	2020	2021	2022	2023	2024
Energy Savings (MWh)	42,190	65,121	55,821	25,840	19,233
Peak Demand Savings (MW)	11.0	39.6	31.8	25.1	6.0
Customer Incentives ($K)	10,055	7,821	14,006	75,495	14,577
All Other Costs ($K)	1,969	3,338	1,942	187	480
Total Costs ($K)	12,024	11,159	15,948	75,682	15,057

Table 8 shows EE performance by sector for DPL in 2024. Residential programs dominate both savings and costs, accounting for nearly all peak demand reduction and the majority of spending. The residential sector delivered 4,530 MWh of energy savings and 5.6 MW of peak reduction for DPL's programs, consuming about $9.6M (64% of total costs), with incentives making up almost all of the utility's spending on regulated program offerings. Commercial programs contributed the largest share of energy savings (14,517 MWh, or about 75% of total energy savings) but almost no peak reduction (0.4 MW), at a cost of $5.4M, which is relatively efficient on a $/MWh basis. Industrial programs are negligible, with only 186 MWh and zero peak impact for minimal cost.

Table 8. DPL 2024 EE performance by sector [24]

Sector	Residential	Commer-cial	Industrial	Total
Energy Savings (MWh)	4,530	14,517	186	19,233

[23] Source: EIA Form 861, DE only.
[24] EIA Form 861, DE only.

Peak Demand Savings (MW)	5.6	0.4	0.0	6
Customer Incentives ($K)	9,556	5,015	6	14,577
All Other Costs ($K)	71	385	24	480
Total Costs ($K)	9,627	5,400	30	15,057

Demand Response

Table 9 summarizes DPL's DR program performance from 2020 to 2024. DPL's demand response programs enrolled nearly 279,000 customers in 2024, delivering a potential peak demand reduction of nearly 110 MW and actual reductions of 40 MW. Program costs, including incentives and operations, were approximately $1.3M.

Table 9. DPL demand response performance [25]

Year	2020	2021	2022	2023	2024
No. Of Customers Enrolled	273,474	227,685	191,103	306,902	279,018
Energy Savings (MWh)	0	1,103	445	45	41
Potential Peak Demand Savings (MW)	59.9	83.5	113.0	113.0	109.6
Actual Peak Demand Savings (MW)	59.9	83.5	113.0	43.4	40.0
Customer Incentives ($K)	24	1,295	0	0	8
All Other Costs ($K)	1,325	161	1,395	1,445	1,305
Total Costs ($K)	1,349	1,456	1,395	1,445	1,313

Table 10 shows DPL's 2024 demand response program performance by sector. Residential customers dominate enrollment, yet the energy savings are only 41 MWh, indicating low per-customer savings and that the program's impact is primarily in peak demand rather than annual energy. The gap between potential peak demand savings (109.6 MW) and actual (40.0 MW) suggests about 36% realization.

Table 10. DPL 2024 demand response performance by sector [26]

Sector	Resi-dential	Com-mercial	Indus-trial	Transpor-tation	Total
No. Of Customers Enrolled	262,638	16,380	N/A	N/A	279,018
Energy Savings (MWh)	41	0	N/A	N/A	41
Potential Peak Demand Savings (MW)	108.9	0.7	N/A	N/A	109.6

[25] EIA Form 861, DE only.
[26] EIA Form 861

Actual Peak Demand Savings (MW)	40.0	0.0	N/A	N/A	40.0
Customer Incentives ($K)	8	0	N/A	N/A	8
All Other Costs ($K)	1,305	0	N/A	N/A	1,305
Total Costs ($K)	1,313	0	N/A	N/A	1,313

In 2024 [27], DPL offered two main demand response programs in Delaware:

- Energy Wise Rewards (EWR) for residential customers
- PJM Demand Response for commercial and industrial (C&I) customers.

EWR is a voluntary summer program that cycles air conditioners or heat pumps during peak periods to reduce grid stress. Participants could choose between a web-programmable thermostat or an outdoor switch, installed at no cost, and receive one-time installation credits ranging from $40 to $80 based on their selected cycling level. Customers could also earn additional bill credits through the Peak Energy Savings Credit program on designated Peak Savings Days. Events typically occur five times per summer, and occasional compliance tests are conducted under PJM directives.

For C&I customers, participation occurs through Curtailment Service Providers (CSPs) in PJM's markets. These programs provided payments for verified load reductions during emergency or economic dispatch events, with obligations such as firm load commitments, mandatory tests, and penalties for non-performance. PJM's Capacity Performance program requires year-round readiness, while Economic Demand Response allows participation in energy and ancillary service markets. Together, these type of programs help DPL maintain reliability, reduce peak demand, and offer financial incentives for customers willing to adjust consumption during critical periods.

DPL is targeting 41.6 MW savings by 2029 through proposed programs. On December 9, 2025; DPL proposed the following programs under the title; Affordability and Load Flexibility Portfolio. These changes are not yet approved.

Table 11. DPL proposed affordability and load flexibility portfolio[28]

Program name	Description	Allocated budget (Million $, 2027–2029)
Bring Your Own Device (BYOD) Smart Thermostat	Customers enroll eligible smart thermostats to participate in event-based demand response for incentives.	$1.51

[27] DPL has advised the DE PSC that it was ceasing its demand response programs and proposed new programs.

[28] DE PSC Docket 25-1554

Program name	Description	Allocated budget (Million $, 2027–2029)
Direct Load Control (DLC) 2.0	Direct cycling of central AC and heat pumps via smart thermostat or advanced metering infrastructure (AMI)-communicating load control switch; includes low-income access.	$19.55[29]
Whole-Home Time-of-Use (TOU) Rate	Time-based pricing to shift overall household consumption away from 2–8 p.m. peak to lower-cost periods.	$0.55
EV Smart Charge Management (SCM)	Managed EV charging through connected chargers or telematics to shift charging to off-peak periods.	$5.45
EV-Only TOU Program	Time-based pricing exclusively for EV charging to encourage off-peak charging.	$0.72
Bring Your Own Battery (BYOB) Pilot	Aggregates behind-the-meter batteries for dispatch during grid events; provides incentives and bill credits for discharging at peak.	$2.00[30]
Locational Demand Response (LDR) Pilot	Targets constrained feeders with enhanced incentives to test locational DR value and inform NWAs.	$1.01
Portfolio totals	Seven-program portfolio focused on affordability, load flexibility, and equity.	**$30.78**

Distributed Energy Resources

Net Metered DER, adoption in DPL's Delaware service area is robust. Table 12 shows DPL's DER adoption by technology and sector in 2024. Photovoltaics overwhelmingly dominate residential distributed resources, with 77.2 MW total capacity and 9,759 installations, driven primarily by residential and a smaller but meaningful commercial segment. Industrial participation is modest and transportation is absent. Overall, the portfolio reflects strong residential rooftop PV adoption, emerging commercial aggregation, and minimal contribution from non-PV technologies. Note: current net metering laws in Delaware only cover a narrow set of DER technologies, mainly customer-sited renewable generation. DERs, by conventional definition, also include combined heat and power, energy storage and EV Vehicle to Grid (V2G) bi-directional charging.

[29] DLC 2.0 budget includes approximately $8.5M one-time cost to refresh legacy devices
[30] BYOB pilot includes a $2M Delaware Sustainable Energy Utility (DESEU) support grant.

Table 12. DPL Net metered DER adoption 2024 [31]

Resource	Description	Residential	Commercial	Industrial	Transportation
Photovoltaic	Capacity (MW)	76.645	18.786	6.507	0.000
	Installations	9,678	313	10	0
	Energy Sold Back (MWh)	N/A	N/A	N/A	N/A
	Virtual Capacity[32] > 1 MW (MW)	0.480	6.160	0.000	N/A
	Virtual Customers > 1 MW	71	240	0	N/A
	Virtual Capacity < 1 MW (MW)	N/A	N/A	N/A	N/A
	Virtual Customers < 1 MW	N/A	N/A	N/A	N/A
Wind	Capacity (MW)	0.64	0.035	0.000	N/A
	Installations	10	5	0	N/A
	Energy Sold Back MWh	N/A	N/A	N/A	N/A
Other	Capacity (MW)	0.000	1.450	N/A	N/A
	Installations	0	2	N/A	N/A
	Energy Sold Back (MWh)	N/A	N/A	N/A	N/A
All Technologies	Capacity (MW)	77.189	26.431	6.507	0.000
	Installations	9,759	560	10	0
	Energy Sold Back (MWh)	0.000	0.000	0.000	0.000

DPL administers small generator interconnection in Delaware under 26 Del. Admin. C. 3012, using four review levels (Level 1-4) aligned with system size and complexity. In 2024, DPL received 1,047 interconnection requests (including 342 resubmissions) totaling about 159.6 MWAC of inverter nameplate capacity and approved 1,293 requests for installation totaling roughly 129.5 MWAC [33].

[31] EIA Form 861, DE Only
[32] Includes off-site or shared capacity
[33] Source: 2024 Annual Small Generator Interconnection Report.

DPL approved 955 small generator facilities in 2024, including 891 Net Metering projects, 11 Aggregated Net Metering projects, and 36 solar-plus-storage projects, plus 15 standalone battery storage and 2 storage add-on projects, with net metering alone accounting for over 21 MWAC of new capacity. DPL completed the initial completeness review within the required five business days for 89% of 2024 applications, just below the 90% benchmark. For Approvals to Install, DPL completed more than 91% of 987 Approval to Install (ATI) notices within 15 business days for Level 1 and 20 business days for Level 2, while issued 830 Authorization to Operate letters and met its 20-business-day commitment for over 97% of those.

On May 1, 2026, in a submission to Docket 24-1012, DPL reported nine community solar projects in service with a total of 23.99 MW of capacity. DPL also maintains a significant pipeline of community solar projects that are mostly sized between 2-4 MWAC.

Table 13. DPL DE community solar projections [34]

Projected in service date	Capacity (MW)	Projects
Q4 2025	22.99	9
Q1 2026	18.45	5
Q2 2026	34.59	11
Total	**76.03**	**25**
Projects in construction [35]		
July 2026	142.38	45

Currently PSC Dockets 24-1012 and 25-1048 are reviewing DPL interconnection practices for community solar and other distributed solar projects respectively. As part of a report filed in this proceeding, DPL identified several process challenges, including limited queue transparency, delays in cost letters and invoicing, and inconsistent responsiveness, which have affected project timelines and developer experience. To address these issues, DPL has initiated several process improvements. These include weekly developer check-ins, assignment of dedicated project managers by jurisdiction, standardized study and design templates, and efforts to provide greater visibility into queue position and hosting capacity. The company is also working to accelerate billing and procurement processes to reduce equipment purchasing delays.[36]

Grid Enhancing Technologies

DPL has been integrating the following grid enhancing technologies (GETs) in Delaware:

1. **Distribution Automation (DA) and Automatic Sectionalization & Restoration (ASR):** DPL has implemented ASR schemes and DA enablement projects to minimize outage duration and customer impact. These upgrades include installing

[34] Source: DPL provided data in 2025.
[35] Includes projects that have made Distribution Upgrade Payments.
[36] Delaware Community Solar Status Report, November 2025.

automated reclosers, sectionalizers, and advanced control systems that allow rapid fault isolation and service restoration.

2. **Smart Devices and Sensors:** DPL has deployed smart fault sensors and single-phase reclosing devices across its network. These technologies provide real-time monitoring and enable predictive maintenance, reducing the frequency and severity of outages.
3. **Substation Modernization:** Substation upgrades include replacing electromechanical relays with microprocessor-based relays, installing potential transformers for enhanced control, and improving physical security. These upgrades support automation and improve system resilience against equipment failures.
4. **Advanced Communication Infrastructure:** Projects such as Space Surveillance Network (SSN) Mesh Network and fiber optics enhance connectivity for automated devices and support advanced distribution management systems (ADMS), enabling better visibility and control of grid operations.
5. **Integration of DER and Hosting Capacity Improvements:** DPL is preparing its grid for higher penetration of DERs by upgrading feeders and substations to increase hosting capacity and implementing dynamic line rating (DLR) tools to optimize asset utilization.

Table 14. Summary of DPL GET implementation [37]

Technology / Program	Current or Proposed status / plan	Platform / vendor	Coverage / scale	Notes / next steps
Legacy Heating, Ventilation, and Air Conditioning (HVAC) load control	Upgrade from one-way paging to two-way switches using AMI communications	Itron network; vendor selection to align with AMI capabilities	Portfolio-wide conversion planned, subject to approvals	Improves flexibility and telemetry for demand response
TOU rates	Shortening peak window, increasing rate differential; two offerings: Whole-Home and EV-only	Tariff-based; utility-managed	Available to residential customers	Supports load shifting and EV charging optimization
Smart Charge Management (EV)	Incentive-based managed charging where customers agree to utility control of charging	Current limited vendor referenced as "Weavegrid"; final selection via competitive bid	Program to expand post board approval	Integrate telemetry with AMI/DER platforms

[37] SE interviews with DPL.

Technology / Program	Current or Proposed status / plan	Platform / vendor	Coverage / scale	Notes / next steps
BYOB	Pilot funded by Delaware SEU for behind-the-meter batteries	Customer-owned batteries; SEU grant support	Pilot scope within DPL service area	Use for peak shaving and targeted DR events
LDR	Target incentives on near-capacity feeders to reduce local peak demand	Utility program	Feeder-specific targeting	Coordination with planning to identify constrained locations
ADMS	Phased rollout under a multi-op project; limited functionality in each wave	PHI/DPL ADMS program	Multi-wave deployment	Provide timeline and go-live milestones in follow-up
VVO / Conservation Voltage Reduction (CVR)	Applied in certain areas; PJM can call events; not system-wide CVR	Substation/feeder-level controls	Selective deployment	Broader CVR strategy to be clarified with planning/automation teams
Hosting capacity	Heat maps available online for public viewing	DPL web maps	System-wide mapping interface	Share map links and documentation
V2G	Pilot with University of Delaware at Newark facility	University partnership	Pilot-scale	Leverage lessons for future managed charging

Distribution Planning Practices

DPL's distribution planning is governed by Delaware's Electric Service Reliability and Quality Standards (26 Del. Admin. C. § 3007), which require an annual ISR Plan and a rolling three-year capital spending forecast.

Delmarva Power's distribution planning practices are built around a multi-year forecasting and capacity planning process. The planning team develops both short-term and long-term capacity plans using demand projections, predictive analytics, and historical peak data. The process begins with a 10-Year Forecast (TYF), which provides a broad, long-term outlook and is updated annually to reflect summer and winter peak demands. Complementing this, a more granular 2-Year Forecast is conducted in alternating cycles, ensuring that half of the feeders are reviewed each year. These forecasts feed into a Quarterly Work Plan (QWP), which guides construction recommendations and aligns with the internal engineering calendar. The planning team leverages specialized software tools such as CYME®, DSP®, and LoadSEER® to model system needs and optimize resource allocation. The planning process also incorporates input from DER providers, technology partners, community advocacy groups, large customers and internal teams such as finance and legal 38.

Forecasting is managed by the Capacity Planning group, which integrates corporate jurisdictional forecasts with localized historical data. DPL is in the early stages of adopting LoadSEER for spatial allocation and DER forecasting. With this implementation, DPL is refining their methodology to better anticipate load growth and distributed resource impacts. Delmarva Power's latest rate filing includes the following strategies to reinforce grid reliability and meet growing energy needs in Delaware 39. These strategies are not yet approved.

Table 15. DPL Proposed grid reliability and affordability strategies

Project / Program Name	Description	Investment Budget
Red Lion Substation Upgrade	Transformer and equipment upgrades to meet growing demand and improve reliability for thousands of homes/businesses.	Part of $480M (2023–2026)
Mermaid Substation (New Castle County)	Installed animal deterrent fencing to prevent wildlife-related outages.	Not specified
Bridgeville Substation Transformer Replacement	Replaced outdated transformer to maintain power flow and reduce repair costs.	Not specified
Brookside Park Reliability Improvement	Moved overhead lines underground for safety, accessibility, and faster restoration.	Not specified
Priority Feeder Program	Identifies and repairs equipment/lines causing repeat outages.	Not specified
Multiple Interruptions Remediation Program	Investigates and upgrades equipment for customers with repeat outages.	Not specified
Bill Stabilization Adjustment (BSA)	Adjusts billing to reduce weather-related impacts and provide predictable charges.	Not specified
Low-to-Moderate Income Rate	20% discount on delivery charges for eligible customers.	Not specified
Energy Assistance & Outreach	Relief fund, payment plans, bill credits, and engagement programs.	$23M (2024 assistance)

[38] SE interviews with DPL
[39] DE PSC Docket 25-1555

3.4. Overview: Delaware Electric Cooperative (DEC)

Introduction

DEC is Delaware's only member-owned, not-for-profit electric cooperative. Headquartered in Greenwood, DEC operates as a Touchstone Energy Cooperative and is a member of Old Dominion Electric Cooperative, which provides its members with generation services. Its service territory spans both rural and coastal areas, including Georgetown, Millsboro, Laurel, Camden, and Harrington. DEC also owns a 4MW solar PV system at Bruce A. Henry Solar Farm, just outside the town of Georgetown in Sussex County. DEC serves more than 118,000 member-owners across Kent and Sussex Counties. The cooperative operates 28 substations, supported by a 250-mile custom fiber communications backbone.

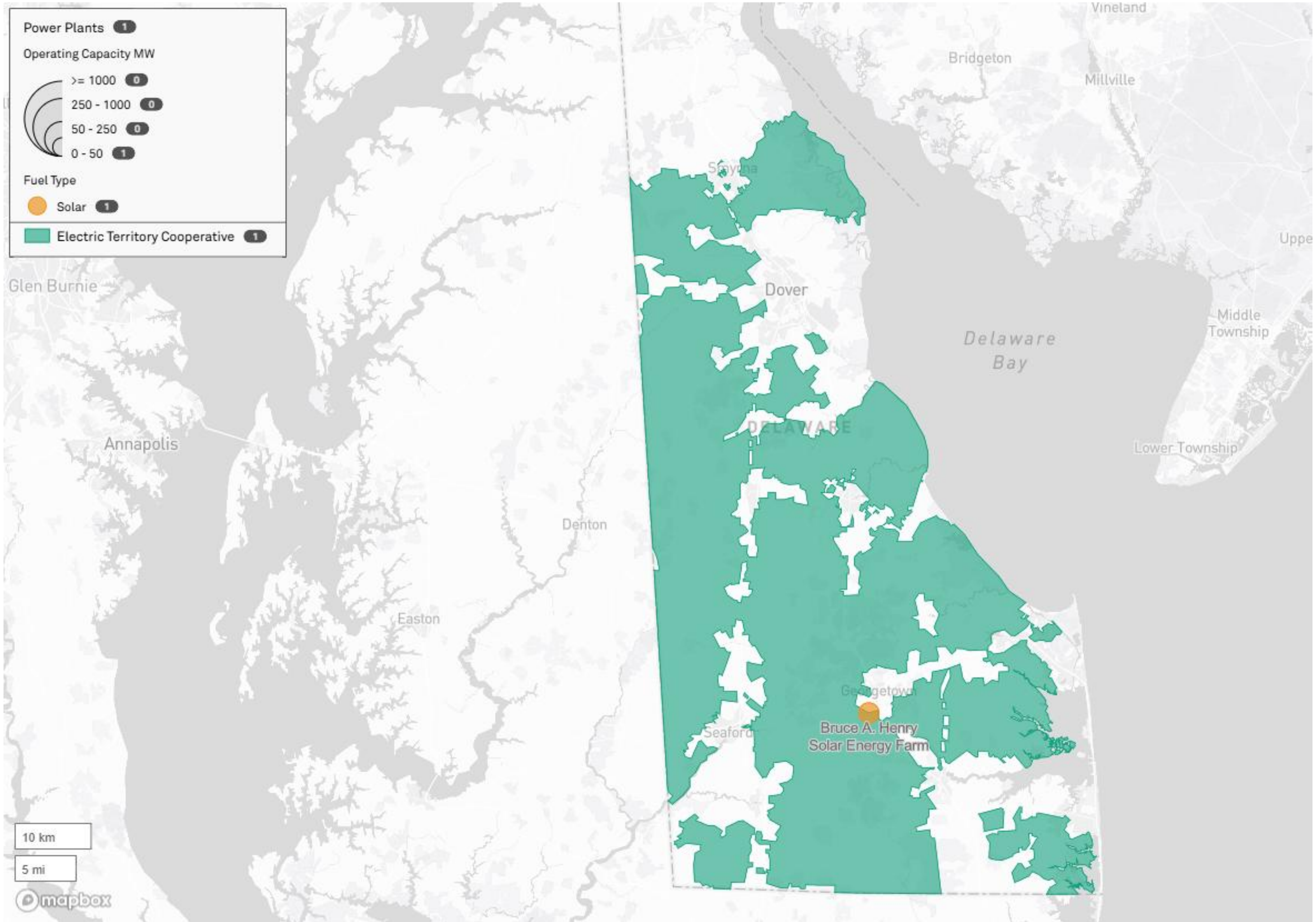


Figure 16. DEC service area

Table 16 shows DEC's Delaware-based commercial information by sector in 2024, where the utility delivered about 1.6 TWh to its 119,000 customers while reporting nearly 228 million dollars in revenue.

Table 16. DEC 2024 electric sales [40]

Customer Sector	No. of Customers	Electric Sales (MWh)	Revenue ($K)
Residential	104,839	1,297,535	184,505.0
Commercial	13,488	304,626	42,188.0
Industrial	317	4,692	873.0
Transportation	0	0	0
Total	118,644	1,606,853	227,566

Peak Demand

Table 17 shows DEC's peak summer and winter demand between 2020 and 2024. 2024 Peak demand reached 460 MW in summer and 368 MW in winter, reflecting 2.6% compound annual growth rate (CAGR) in summer demand from 2020 levels.

Table 17. DEC peak demand [41]

	2020	2021	2022	2023	2024
Summer Peak (MW)	415	410	405	438	460
Winter Peak (MW)	310	310	378	400	368

System Topography

DEC's network comprises 91 radial circuits, with conductor miles segmented by primary and secondary voltages, and relies on the traditional radial topology. Of these 91 circuits, 76 are managed using voltage optimization systems. Voltage optimization is a strategy which leverages hardware and software systems to finely control distribution circuit voltage, leading to improved service quality and reliability, and lower energy consumption.

Reliability Performance

Table 18 shows DEC's reliability performance across a few key parameters both with and without MEDs. Reliability trends in terms of both SAIDI and SAIFI have improved over 2020-2024 timeframe, reducing SAIDI from 107.6 minutes to 61.3 minutes and SAIFI from 1.55 to 0.943. In 2024, DEC was in the 30th percentile for SAIDI performance and 45th

[40] Source: EIA Form 861
[41] EIA Form 861

percentile for SAIFI performance among all US utilities that reported data, as shown in Figure 17 and Figure 18, respectively.

Table 18. DEC reliability performance 2020-2024

	All Events (With MEDs)		Without MEDs	
	SAIDI	**SAIFI**	**SAIDI**	**SAIFI**
2020	292.10	2.930	107.60	1.550
2021	78.07	1.472	78.07	1.472
2022	89.51	1.344	73.45	1.170
2023	83.12	1.292	68.14	1.134
2024	95.67	1.108	61.33	0.943

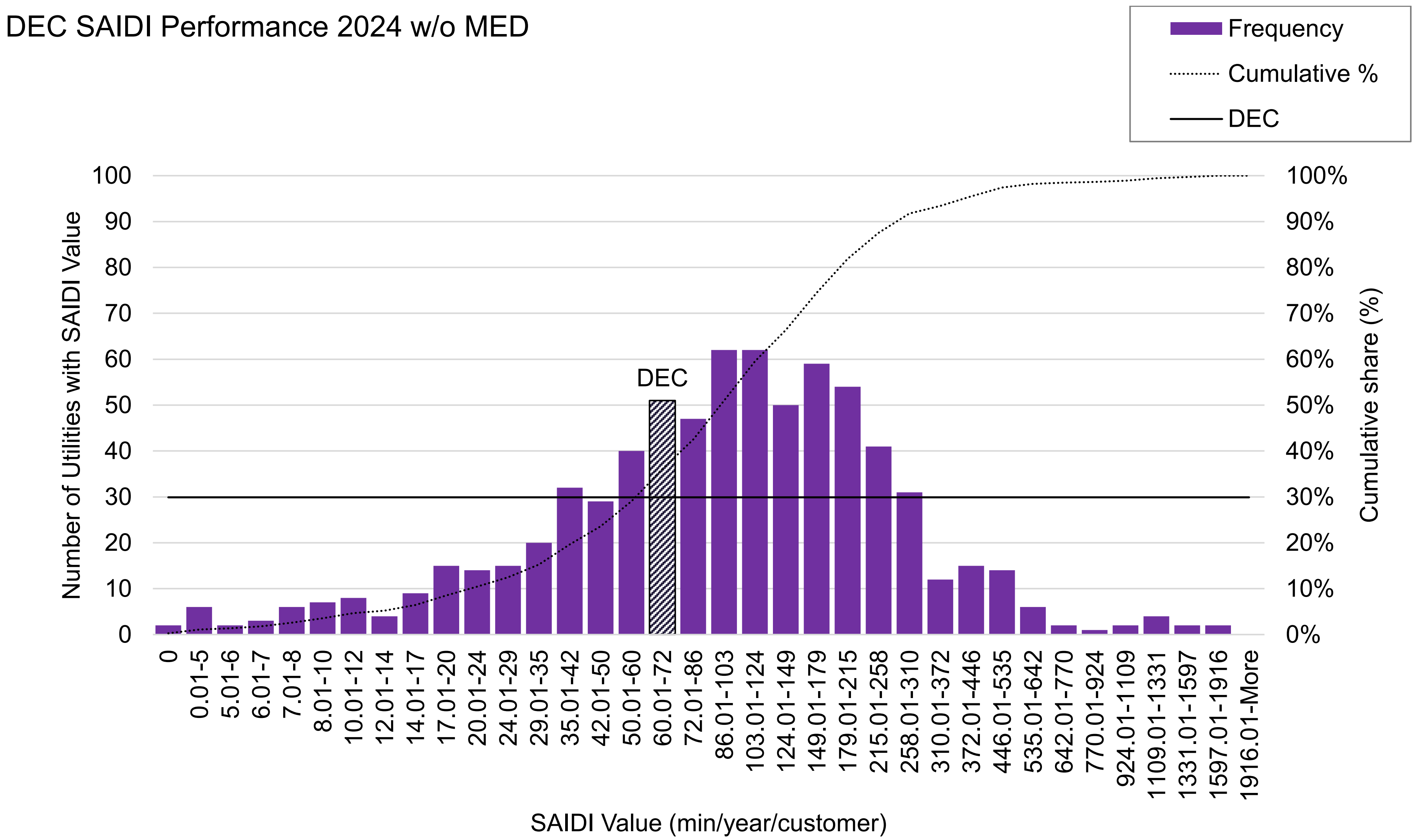


Figure 17. DEC 2024 SAIDI performance [42]

[42] SE performed histogram analysis of all entities that reported reliability data through EIA-861 for year 2024.

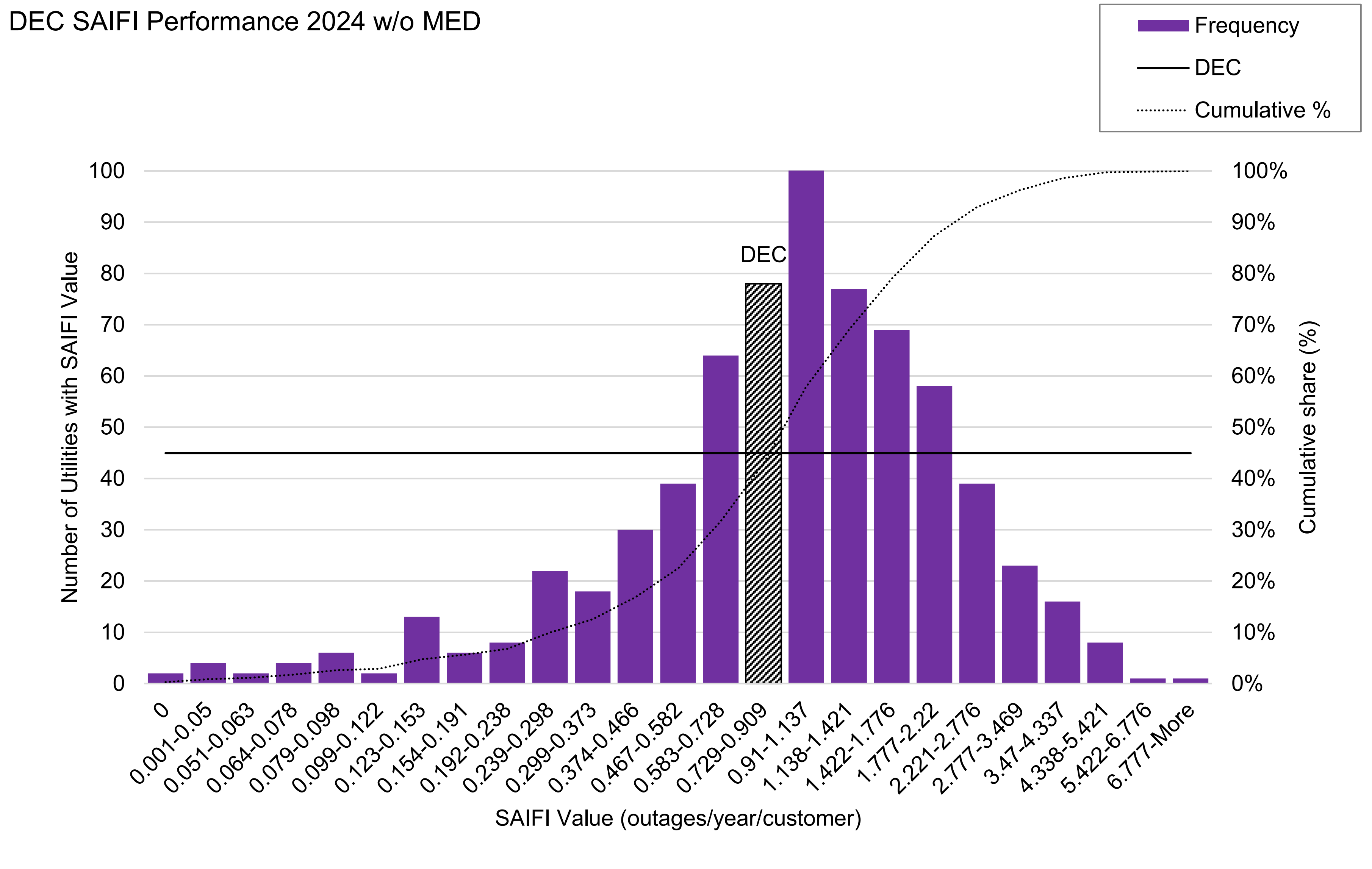


Figure 18. DEC 2024 SAIFI performance [43]

[43] SE performed histogram analysis of all entities that reported reliability data through EIA-861 for year 2024.

Energy Efficiency

DEC offers a suite of EE programs funded through both cooperative and state-level initiatives. DEC's EE performance in terms of incremental annual savings is shown in Table 19 for the past five years. EE initiatives delivered incremental annual savings of 464 MWh and 5.6 MW in 2024, supported by $1.4 million in customer incentives.

Table 19. DEC EE performance

Incremental annual savings	2020	2021	2022	2023	2024
Energy Savings (MWh)	796	722	875	916	464
Peak Demand Savings (MW)	7.0	22.0	23.0	25.0	5.6
Customer Incentives ($K)	1,777	224	1,245	1,313	1,413
All Other Costs ($K)	178	1.652	135	142	155
Total Costs ($K)	1,955	1,876	1,380	1,455	1,568

Table 20 shows EE performance by sector for DEC in 2024. Residential programs deliver the majority of energy savings (249 MWh) while accounting for all peak demand reduction (5.6 MW), at a cost of $125K (about 8% of total costs). DEC reported to EIA that their 2024 commercial programs contribute significant energy savings with 214 MWh (46% of total) but did not report significant peak reduction, while incurring $1.34M in costs.

Table 20. DEC 2024 EE performance by sector [44]

Sector	Residential	Commer-cial	Industrial	Total
Energy Savings (MWh)	249	214	N/A	464
Peak Demand Savings (MW)	5.6	0.0	N/A	5.6
Customer Incentives ($K)	114	1,299	N/A	1,413
All Other Costs ($K)	11	144	N/A	155
Total Costs ($K)	125	1,343	N/A	1,568

Demand Response

Table 21 summarizes DEC's demand response program performance from 2020 to 2024. DEC operates a demand response initiative branded as the "Beat the Peak" program, designed to reduce member electricity use during periods of highest grid demand and energy costs. The program utilizes mobile app notifications, email alerts, and automated

[44] EIA form 861

calls to inform members during events and offers bill credits or other incentives. In 2023, DEC ended its residential load control switch program for water heaters and HVAC units due to aging technology and increasing costs, which explains a drop in the number of customers enrolled in DR programs between 2022 and 2023.

Table 21. DEC demand response performance [45]

Year	2020	2021	2022	2023	2024
No. Of Customers Enrolled	30,130	28,859	28,618	3,778	4,036
Energy Savings (MWh)	0	1	0	54	26
Potential Peak Demand Savings (MW)	45.2	37.8	37.7	337.5	114.7
Actual Peak Demand Savings (MW)	37.9	32.1	32.0	41.7	33.7
Customer Incentives ($K)	563	563	563	2,008	1,748
All Other Costs ($K)	58	58	58	201	175
Total Costs ($K)	621	621	621	2,209	1,923

DEC's Beat the Peak program is voluntary, targeting both residential and commercial members. The program enables load reductions through member actions (delaying EV charging, adjusting thermostat settings, cycling HVAC, etc.), direct load control for smart devices, and energy conservation behaviors. Additionally, DEC has deployed:

- ToU tariffs for residential & commercial (mostly for farms) customers.
- Managed EV charging using telematics though Optiwatt.
- Conservative Voltage Reduction (CVR) mainly used during DR events.

Table 22 shows DEC's 2024 demand response program performance by sector. Residential customers dominate enrollment with tenergy savings of 26 MWh and peak demand savings of 95 MW. The gap between potential peak demand savings across all sectors (114.7 MW) and actual (33.7 MW) suggests about a 29% realization rate, meaning 29% percent of potential 114.7 MW savings were actually achieved on the event day. This compares to a national average of 52%.

[45] EIA Form 861

Table 22. DEC 2024 demand response performance by sector [46]

Sector	Residential	Commer-cial	Industrial	Total
No. Of Customers Enrolled	2,873	1,163	N/A	4,036
Energy Savings (MWh)	26	0	N/A	26
Potential Peak Demand Savings (MW)	94.9	19.873	N/A	114.7
Actual Peak Demand Savings (MW)	22.2	11.4	N/A	33.7
Customer Incentives ($K)	73	1,675	N/A	1,748
All Other Costs ($K)	7	168	N/A	175
Total Costs ($K)	80	1,843	N/A	1,923

Distributed Energy Resources

Table 23 shows DEC's DER adoption by technology and sector in 2024. Photovoltaics account for nearly all distributed resource capacity, totaling 38 MW across 3,427 installations, with residential contributing 26.13 MW and commercial 12.03 MW. Wind resources are negligible at 0.019 MW from 7 installations, and there is no participation from industrial or transportation sectors. Overall, DEC's DER portfolio shows strong reliance on residential and commercial PV adoption with minimal diversification into other technologies. There are no formal customer battery programs at DEC yet; around 20 customers are known to have batteries (mostly paired with solar), but they are not dispatched for demand response or other programs.

[46] EIA form 861

Table 23. DEC DER adoption 2024 [47]

Resource	Description	Residen-tial	Commer-cial	Indus-trial	Transporta-tion	Total
Photovoltaic	Capacity (MW)	26.133	12.029	N/A	N/A	38.162
	Installations	3,111	136	N/A	N/A	3,427
	Energy Sold Back (MWh)	N/A	N/A	N/A	N/A	0.000
Wind	Capacity (MW)	0.014	0.005	N/A	N/A	0.019
	Installations	6	1	N/A	N/A	7
	Energy Sold Back (MWh)	N/A	N/A	N/A	N/A	0.000
All Technologies	Capacity (MW)	26.147	12.304	0.000	0.000	38.181
	Installations	3,117	137	0	0	3,254
	Energy Sold Back (MWh)	0.000	0.000	0.000	0.000	0.000

On March 2024, DEC submitted a grant application for funding under section 40101(d) to design and install a battery storage system at the Bruce A. Henry Solar Farm near Georgetown, Delaware. This will be matched with funds from the SEU pursuant to legislation passed in the summer of 2025. The proposed project involves the installation of a 2 MW/4 MWh lithium-ion battery storage facility at the site of the existing 4 MW solar farm, which serves a designated disadvantaged community (DAC). DEC requested $1 million in grant funding over two years ($500,000 per year), with a 35% cooperative match, to cover engineering analysis, equipment procurement, infrastructure upgrades, installation, testing, and impact analysis. The total project cost is estimated at $3.56 million. The application states that the battery storage system is intended to improve grid resiliency by reducing outages for approximately 5,000 members, including those in the Georgetown DAC, and to enable the integration of additional residential solar installations in areas currently closed to new solar due to grid constraints. DEC estimates the project will offset 170 MWh of fossil fuel generation annually, resulting in an estimated reduction of 119 metric tons of CO_2 emissions and annual demand response savings of $158,000.

Grid Enhancing Technologies

DEC is implementing various Grid Enhancing Technologies (GETs) as described in Table 24.

[47] EIA form 861

Table 24. DEC GET adoption [48]

Area/Program	Status/Details
AMI	Fully deployed Radio Frequency (RF) mesh; analog opt-out available
DERMS	In use for DR (thermostats, EVs); expanding to new resources
ADMS/ Outage Management System (OMS)	Platforms in place; AMI integration for outage management
DLR	Using GRIDSIGHT software for visibility and identification of over/under-utilized transformers
Distribution Automation	Transitioning from “dumb” fault indicators to smart sensors with voltage monitoring linked to Supervisory Control and Data Acquisition (SCADA)
CVR	Used for load reduction during DR events
Bidirectional Charging	Early-stage exploration, no deployments yet
Battery/Microgrid	40101(d) grant approved for 7MW battery storage at Bruce A. Henry Solar Farm. The battery will be used for DSM applications
Hosting Capacity	Public map available; internal/consultant studies performed as needed

Distribution Planning Practices

Distribution planning follows a six-year horizon, updated every four years, with the current plan covering 2024-2028. Planning teams from engineering, substations, and system protection collaborate using tools such as Windmill for forecasting, e-Tap for modeling, and Pole Foreman for line design. Forecasting incorporates land-use trends but excludes EV growth assumptions due to low penetration (1-2% of members).

3.5. Overview: Delaware Municipal Electric Corporation (DEMEC)

Introduction

DEMEC is a not-for-profit, community-owned joint action agency, serving as the wholesale electric utility[49] for nine municipal electric departments throughout Delaware. DEMEC represents the combined electric systems of Clayton, Dover, Lewes, Middletown, Milford, New Castle, Newark, Seaford, and Smyrna. The nine DEMEC member utilities combined serve about 77,400 customers, with a combined peak demand of 472 MW. The DEMEC member distribution systems vary in size and character. DEMEC is a generation owner

[48] SE interviews with DEC.
[49] https://www.demecinc.net/about/.

and the PJM Load Serving Entity ("LSE") for its eight (8) full-requirements municipal member utilities and provides 100% of their wholesale power supply requirements.

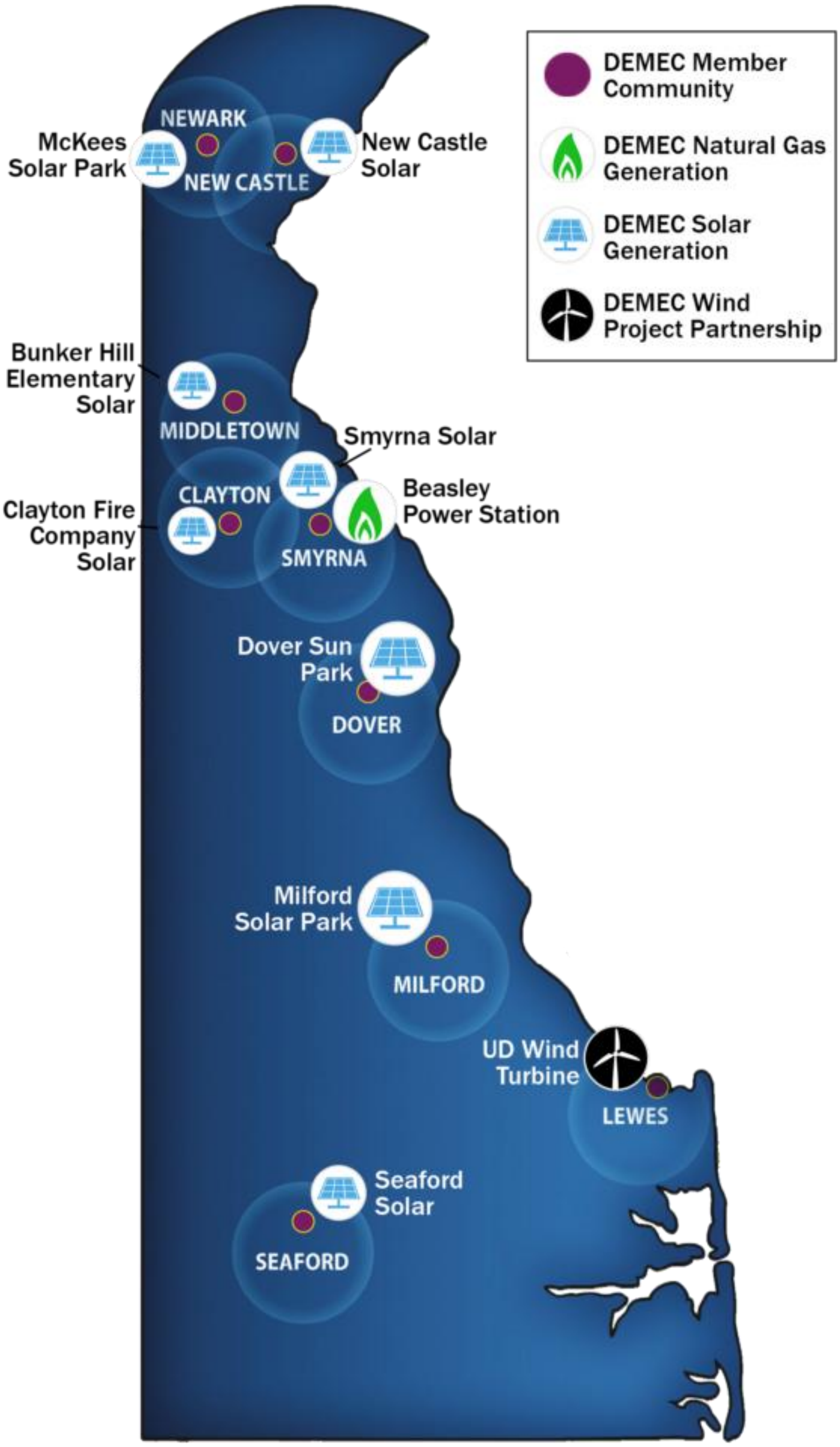


Figure 19. DEMEC members

Note: only a few DEMEC members report data through EIA form 861. The following information reflects the most detailed information publicly available. Table 25 shows

DEMEC member annual energy usage between 2020 and 2024. Annual energy usage across members totaled 2,115 GWh in 2024, with Dover, Newark, and Middletown accounting for the largest shares.

Table 25. DEMEC member usage (MWh) [50]

Member	2020	2021	2022	2023	2024
Clayton	22,887	23,745	24,246	23,740	24,715
Dover	732,176	752,237	752,618	722,160	714,884
Lewes	83,072	87,427	88,365	84,122	88,618
Middletown	263,245	279,278	284,722	280,230	290,109
Milford	234,410	244,698	250,329	242,050	248,016
Newark	433,533	451,781	454,611	438,876	436,630
New Castle	80,671	82,112	82,059	78,203	77,263
Seaford	110,241	115,224	120,019	117,209	116,979
Smyrna	119,883	123,005	122,735	117,594	117,769
Total	**2,080,118**	**2,159,508**	**2,179,706**	**2,104,184**	**2,114,983**

Table 26 shows DEMEC's commercial information by sector for its four largest members in 2024, where these four members delivered about 1.7 TWh to their 57,000 customers while recognizing nearly 228 million dollars in revenue.

Table 26. DEMEC's four largest members' 2024 electric sales [51]

Member	Customer Sector	No. of Customers	Electric Sales (MWh)	Revenue ($K)
City of Dover	Residential	21,601	211,090	32,754.0
	Commercial	3,485	222,788	28,924.0
	Industrial	40	281,006	26,276.0
	Transportation	N/A	N/A	N/A
	Total	25,126	714,884	87,954.0
Town of Middletown	Residential	9,071	100,606	17,226.8
	Commercial	694	8,162	1,506.2
	Industrial	403	164,300	21,377.5
	Transportation	N/A	N/A	N/A

[50] DEMEC responses to SE RFI
[51] EIA form 861

Member	Customer Sector	No. of Customers	Electric Sales (MWh)	Revenue ($K)
	Total	10,168	273,068	40,110.5
City of Milford	Residential	7,169	79,966	12,128.9
	Commercial	1,559	68,432	9,686.6
	Industrial	12	90,239	10,676.1
	Transportation	0.0	0	0
	Total	8,740	238,637	32,491.6
City of Newark	Residential	11,888	98,785	18,762.0
	Commercial	1,492	73,371	12,830.7
	Industrial	59	250,502	30,063.6
	Transportation	0.0	0	0
	Total	13,439	422,658	61,656.3
Total		**57,473**	**1,649,247**	**222,212.4**

Peak Demand

Table 27 shows DEMEC's peak summer demand between 2020 and 2024. DEMEC summer peak demand has remained relatively flat over this time.

Table 27. DEMEC members' summer peak demand (MW) [52]

Member	2020	2021	2022	2023	2024
Clayton	6.7	6.7	7.2	7.1	7.5
Dover	161.4	155.9	164.9	157.3	163.8
Lewes	21.3	21.6	21.9	22.3	22.4
Middletown	61.4	63.4	63.3	65.3	67.4
Milford	49.2	51.2	51.8	51.1	53.0
Newark	90.2	94.1	94.6	94.0	87.5
New Castle	18.7	18.6	18.8	18.3	18.2
Seaford	23.7	23.5	24.6	24.0	24.4
Smyrna	33.2	29.0	29.4	28.9	28.7
Total	**465.7**	**463.8**	**476.5**	**468.2**	**472.9**

[52] DEMEC responses to SE RFI

System Topography

DEMEC's member systems vary widely in size and complexity. Dover operates 52 distribution circuits, 47 of which have voltage optimization, while smaller towns like Middletown and Milford maintain fewer circuits with limited automation. Newark, with 34 circuits, began implementing advanced metering infrastructure (AMI) in 2013.

Table 28. DEMEC members' system topography, sub-selection [53]

Utility Name	Distribution Circuits	Circuits with Voltage Optimization
City of Dover - (DE)	52	47
Town of Middletown - (DE)	9	9
City of Milford - (DE)	11	0
City of Newark - (DE)	34	0

Reliability Performance

Public reliability data is limited across DEMEC. It is reported only by DEMEC members that are required to report by EIA based on size. Only the City of Newark reported reliability data through EIA Form 861. City of Newark reported a SAIDI of 84.4 minutes and SAIFI of 0.77 in 2024, indicating strong performance compared to national averages.

Table 29. City of Newark (DEMEC member) reliability performance 2024 [54]

	All Events (With MEDs)		Without MEDs	
	SAIDI	SAIFI	SAIDI	SAIFI
City of Newark	84.400	0.770	84.400	0.770

Energy Efficiency

Table 30 shows a few of DEMEC members' EE performance in terms of incremental annual savings. EE programs delivered measurable savings in 2024 in both the City of Newark and the Town of Middletown. Newark achieved 2,437 MWh of savings, primarily from commercial retrofits, while Middletown contributed 641 MWh. Both member systems achieved savings primarily from commercial customers, followed by residential customers. Incentives for these programs totaled $430,000 across both jurisdictions.

[53] EIA form 861
[54] EIA form 861

Table 30. DEMEC members' 2024 EE performance by sector, sub-selection [55]

Member	Sector	Residential	Commercial	Industrial	Total
Town of Middletown	Energy Savings (MWh)	34	607	0	641
	Peak Demand Savings (MW)	0.0	0.1	0.0	0.1
	Customer Incentives ($K)	9	18	0	27
	All Other Costs ($K)	27	52	0	79
	Total Costs ($K)	36	70	0	106
City of Newark	Energy Savings (MWh)	41	2,210	186	2,437
	Peak Demand Savings (MW)	0.0	0.3	0.0	0.4
	Customer Incentives ($K)	7	65	6	78
	All Other Costs ($K)	33	189	24	246
	Total Costs ($K)	40	254	30	324

Demand Response

Table 31 summarizes DEMEC's demand response program performance from 2020 to 2024. Demand response participation remains modest but impactful: Dover enrolled four large commercial and industrial customers, achieving 13.1 MW of peak demand reduction, while Middletown and Newark added smaller contributions. DEMEC's "Power Savers" program provides notifications and incentives for curtailment, complementing PJM market participation.

Table 31. DEMEC members' 2024 demand response performance by sector[56]

Member	Sector	Residential	Commercial	Industrial	Total
City of Dover	No. Of Customers Enrolled	N/A	3	1	4
	Energy Savings (MWh)	N/A	N/A	N/A	N/A
	Actual Peak Demand Savings (MW)	N/A	4.99	3.78	8.76
	Customer Incentives ($K)	N/A	25.30	33.02	58.32
	All Other Costs ($K)	N/A	N/A	N/A	N/A
	Total Costs ($K)	N/A	25.30	33.02	58.32

[55] EIA form 861
[56] EIA form 861

Member	Sector	Residential	Commercial	Industrial	Total
Town of Middletown	No. Of Customers Enrolled	N/A	N/A	3	3
	Energy Savings (MWh)	N/A	N/A	0	0
	Actual Peak Demand Savings (MW)	N/A	N/A	6.44	6.44
	Customer Incentives ($K)	N/A	N/A	112.73	112.73
	All Other Costs ($K)	N/A	N/A	N/A	N/A
	Total Costs ($K)	N/A	N/A	112.73	112.73
City of Newark	No. Of Customers Enrolled	N/A	2	1	3
	Energy Savings (MWh)	N/A	1	0	1
	Actual Peak Demand Savings (MW)	N/A	0.84	0.21	1.05
	Customer Incentives ($K)	N/A	1.86	0	1.86
	All Other Costs ($K)	N/A	N/A	N/A	N/A
	Total Costs ($K)	N/A	1.86	0	1.86

Distributed Energy Resources

Municipal utilities participate in the MRPS and consistently achieve established renewable portfolio goals comparable to the state. DEMEC members partner with DEMEC on load forecasting and advanced modeling and data analysis, demand response, and EE programs. Municipal utilities also continue to look at innovative technologies, such as battery storage & EVs, and consider various impacts to the distribution system. Some DEMEC members have incorporated sustainability and renewable energy goals which are more aggressive than the state's goals.

DEMEC administers the MRPS on behalf of its full requirement members. For the 2024/2025 compliance year, DEMEC was required to achieve a 24% renewable energy target, including a 3.25% solar carveout, in alignment with state law. DEMEC fulfills these obligations through a combination of owned generation assets and long-term power purchase agreements. Wind energy is sourced from the 69 Megawatt (MW) Laurel Hill Wind Farm in Pennsylvania and the 2 MW University of Delaware wind turbine in Lewes. Solar energy is supplied from multiple projects, including Dover Sun Park, Milford Solar Farm, Seaford Solar Project, McKees Solar Park, Smyrna Solar Project, and New Castle Municipal Services Commission (MSC) Project.

DEMEC's solar portfolio includes residential, commercial, community, and utility-scale installations, totaling over 1,300 systems and more than 18 MW of capacity. The organization also manages a Green Energy Grants Program to support additional renewable installations. For the 2024/2025 compliance year, DEMEC retired 195,582 renewable energy credits (RECs and SRECs), including 26,488 solar RECs, to meet MRPS requirements across its member communities. Table 32 shows DEMEC's installed behind-the-meter (BTM) solar capacity for the years between 2020 and 2024. BTM solar capacity reached 20.24 MW in 2024, up from 16 MW in 2020. Dover leads with 5.96 MW, followed by Middletown (4.5 MW) and Newark (2.76 MW). Community scale solar projects also exist in Newark (1.63 MW), New Castle (.029 MW), Middletown (3 MW), Smyrna (1.5 MW), Clayton (0.006 MW), Dover (10 MW), Milford (15 MW), and Seaford (.688 MW).

Table 32. DEMEC members' installed behind-the-meter solar capacity (MW) [57]

Member	2020	2021	2022	2023	2024
Clayton	0.22	0.42	0.48	0.50	0.55
Dover	5.69	5.99	6.39	5.71	5.96
Lewes	0.82	1.02	1.26	1.34	1.43
Middletown	3.56	3.62	3.75	3.97	4.50
Milford	1.66	1.89	1.97	2.01	2.06
New Castle	0.25	0.26	0.24	0.31	0.31
Newark	1.88	2.06	2.21	2.45	2.76
Seaford	1.24	1.24	1.24	1.30	1.33
Smyrna	0.71	0.99	1.29	1.09	1.34
Total	**16.04**	**17.48**	**18.83**	**18.68**	**20.24**

Grid Enhancing Technologies

Municipal utilities have already begun the process of implementing AMI. Through DEMEC, members are able to participate in a joint venture implementation program for their electric customers. Out of the nine municipal utilities, six have completed full implementation, one is in the process with expected completion this year, and two are in the discovery phase. Power Savers is DEMEC's demand response program which is provided to all members' customers through a notification program and a formal business incentive program. Dover also has a DR program managed by the same vendor.

DEMEC participates in several forward-looking, innovative discussions, trainings, and research to understand the tools available to municipal utilities as the energy industry changes. In supporting the important issue of resiliency, the Town of Smyrna can island itself from the grid currently by utilizing DEMEC's Beasley Power Station, an approximately 100 MW natural gas-fired peaking power plant to perform as a microgrid to the entire community, and they have done so occasionally in the past several years.

DEMEC has been actively evaluating battery storage technology for the past ten years. Recently, DEMEC performed a feasibility study in Milford, DE for a battery that would connect between Milford Solar and the nearby substation for mitigating backflow of power during shoulder seasons and solar soaking to help lower peak demand. DEMEC partnered with Energize Delaware for a $2M grant to make the project more cost effective to counter

[57] DEMEC responses to SE RFI.

recent federal tariff changes. This has helped lower the risk of cost overruns of the potential project. Further interconnection studies are under way.

On March 28, 2024, DEMEC applied for federal funding under BIL section 40101(d) to implement advanced modeling technology and workforce training for eight municipal electric utilities in Delaware. The proposal outlines plans to use CYME Power Engineering Software to conduct hosting capacity studies, develop feeder-level heat maps, and support planning for DERs such as solar and battery storage. The project budget totals $1,220,242 over three years, with a federal grant amount received of $ 915,181 and a one-third cost match from DEMEC and its partners. Objectives include improving grid reliability metrics, identifying locations for additional solar deployment, supporting low-income solar programs, and enhancing emergency preparedness for communities exposed to storm and flooding risks.

Distribution Planning Practices

Distribution planning is completed on a regular, as-needed-basis, throughout the year as municipal utilities plan for new developments and policy changes. DEMEC regularly analyzes and plans for needed growth improvements and maintenance or repairs of their distribution system, however, not all municipal utilities have the resources to implement a formal, comprehensive integrated distribution plan (IDP) at this time. DEMEC is currently working to provide financial assistance to help members in this area.

3.6. Baseline Conditions: Key Insights

The Insights section provides a comparative snapshot of Delaware's electric distribution utilities across several dimensions: system topography, EE, demand response, DERs, grid-enhancing technologies (GET), and distribution planning. Table 33 compares Delaware's three EDCs in terms of customers served, energy delivered, and peak power. DPL served about 61% of Delaware's customers, delivered 51% of Delaware's electricity sales, was responsible for nearly five times the peak load of the other EDCs in 2024, while maintaining about 60% of the state's distribution circuits. DEC served about 24% of Delaware's customers and delivered about 21% of Delaware's energy in 2024 while maintaining about 15% of the state's distribution circuits. DEMEC and its collection of nine municipal utilities served the remaining 15% of Delaware's customers and delivered the remaining 28% of the state's energy in 2024 while maintaining about 25% of the state's distribution circuits. **Note: In some cases, DPL data as reported in EIA-861 does not differentiate between Delaware and Maryland service territories. In these cases, the net reported value for DPL across both states is provided and identified as such in the footnotes.**

Table 33. EDC system summary 2024

Utility Name	No. of Customers	Energy Sold (MWh)	Summer Peak Power (MW)	Distribution Circuits
Delmarva Power (DPL)	301,210	3,801,990	2,622 [58]	273
Delaware Electric Cooperative (DEC)	118,644	1,606,853	415	71
Delaware Municipal Electric Corporation (DEMEC)	77,400	2,114,983	472	106+
Total	497,254	7,523,826	-	450+

System Topography

Table 34 summarizes the topography of each of the EDCs' or members' systems. DPL stands out for its scale, operating 273 circuits in a hybrid radial and networked configuration, while DEC and DEMEC members manage smaller, predominantly radial systems. Voltage optimization is widely deployed in DEC and some DEMEC cities, supporting both reliability and efficiency objectives.

[58] EIA Form 861. Based on 63.5% of total DPL load. Percentage estimate provided by DPL.

Table 34. System topography summary

Utility Name	Distribution Circuits	Circuit Configuration	Circuits with Voltage Optimization
Delmarva Power (DPL)	273	Hybrid (radial + networked)	N/A
Delaware Electric Cooperative (DEC)	91	Radial	76
City of Dover (DEMEC)	52	Not reported	47
Town of Middletown (DEMEC)	9	Not reported	9
City of Milford (DEMEC)	11	Not reported	0
City of Newark (DEMEC)	34	Not reported	0

Energy Efficiency and Demand Response

Table 35 summarizes the EE performance of each of the EDCs' systems in 2024. DPL shows the largest incremental energy savings as a portion of total load followed by DEMEC and then DEC. Notably, DPL and DEMEC members performed nearly in line with the national median incremental energy savings as a portion of total load of approximately 0.5%.

Table 35. EE summary [59]

Utility Name	2024 Incremental EE Savings (MWh)	2024 Total Load (MWh)	2024 Incremental EE as % of Load
DPL[60]	19,233	3,801,990	0.51%
DEC	464	1,606,853	0.03%
DEMEC [61]	3,078	726,739	0.42%

Table 36 summarizes the demand response performance of each of the EDCs' or members' systems in 2024. DEC shows the largest fraction of demand response load to summer peak load, followed by DEMEC (select members) and then DPL. Notably, both DEC and DEMEC (select members) outperform the national median fraction of demand response load to summer peak load of approximately 2%.

[59] Summarization of EIA-861 data
[60] DPL DE only
- [61] Newark and Middletown only

Table 36. Demand Response summary [62]

Utility Name	2024 Actual Demand Response (MW)	2024 Summer Peak (MW)	Demand Response Fraction of Summer Peak (%)
DPL	40.0	2,622 [63]	1.53% [64]
DEC	33.7	460	7.33%
DEMEC (Dover, Middletown, Newark)	21.8	472.9	4.6%

Distributed Energy Resources

Table 37 summarizes the DER deployment of each of the EDCs' or members' systems through 2024. DEC shows the largest fraction of DER capacity to summer peak load, followed by DEMEC (select members) and then DPL. All Delaware EDCs have performed above the national median fraction of DER capacity to summer peak load of approximately 3%.

Table 37. DER summary [65]

Utility Name	2024 DER Capacity (MW)	2024 Summer Peak (MW)	DER Fraction of Summer Peak (%)
DPL	110	2,622[66]	4.2%[67]
DEC	38.2	460	8.3%
DEMEC (Dover, Middletown, Newark)	20.24	472.9	4.3%

Grid Enhancing Technologies

Table 38 summarizes the GET deployment of each of the EDCs' systems. All EDCs are advancing grid-enhancing technologies, with AMI fully deployed at DEC and most DEMEC members, and DPL progressing on advanced distribution management and automation.

[62] EIA form 861
[63] Estimated as 63.5% of total DPL load. Percentage estimate provided by DPL.
[64] Estimated
[65] Summarization of EIA-861 data
[66] Estimated as 63.5% of total DPL load. Percentage estimate provided by DPL.
[67] Estimated

Table 38. GET summary

Technology	DPL	DEC	DEMEC
AMI	Advanced	Fully deployed	6/9 full, 1 in progress
DERMS/ADMS	ADMS in progress	DERMS in use, ADMS/OMS integrated	Varies by member
Distribution Automation	ASR, smart sensors, substation modernization	Smart sensors, SCADA-linked, Voltage optimization	Voltage optimization (Dover, Middletown)
Hosting Capacity	DLR, public map, studies	Public map, studies	Study Underway (maps to follow)
Battery/Microgrid	Community solar pipeline	7 MW battery planned	8 MW battery planned
Other Notable GETs	Fiber communications, SSN Mesh	CVR, ToU, managed EV charging	Microgrid (Smyrna), AMI joint venture

Distribution Planning

Table 39 summarizes the distribution planning practices for each of the EDCs' systems. Planning horizons and practices vary, with DPL updating annually, DEC every four years, and DEMEC members as needed, reflecting differences in organizational structure and resource availability.

Table 39. Distribution planning summary

Utility Name	DPL	DEC	DEMEC
Planning Horizon	TYF 2-year forecast QWP	6 years	As needed
Update Frequency	TYF issued annually (Oct–Apr/May cycle). 2-year forecast updated on alternating feeder cycles.	Every 4 years	Varies by member
Tools	CYME, DSP, implementing Load-SEER	Windmill, e-Tap, Pole Foreman	Varies by member, Proceeding to CYME

Utility Name	DPL	DEC	DEMEC
EV/DER Considera-tion	DER integration focus Hosting capacity studies (future, spatial method in LoadSEER) DERMS exploration Smart charging programs Demand response integration	Limited (ex-cludes EV growth)	DER integration focused hosting capacity study (battery, solar, and EVs)

4. Long-Range Distribution Planning Best Practices

The objective of this section is to provide DNREC with an evidence-based benchmarking of long-range distribution planning (LRDP) practices across leading U.S. utilities and regional plans, and identify best practices to inform Delaware's distribution planning and grid modernization roadmap. The focus of this review is on planning horizon and cadence, forecasting and DER integration, metrics, stakeholder engagement, and technology investments that improve reliability, resilience, affordability, and equity.

4.1. Methodology

Siemens Energy began the benchmarking process by developing a comprehensive set of key questions[68], underlying assumptions, and input parameters essential for effective LRDP. The aim of the resulting benchmarks are to capture the full spectrum of planning practices, including forecasting methodologies, DER integration, planning horizon and cadence, stakeholder engagement, performance metrics, and technology investments.

With these criteria established, Siemens Energy assembled an extensive list of public LRDP documents and similar planning reports from leading U.S. utilities and regional entities. This compilation ensured the inclusion of a diverse range of approaches and geographic considerations, thereby providing a robust foundation for comparative analysis. Finally, 15 plans were selected for benchmarking purposes.

[68] Detailed questions are provided in Appendix A.

Geographic distribution of utility and ISO/RTO plans analyzed

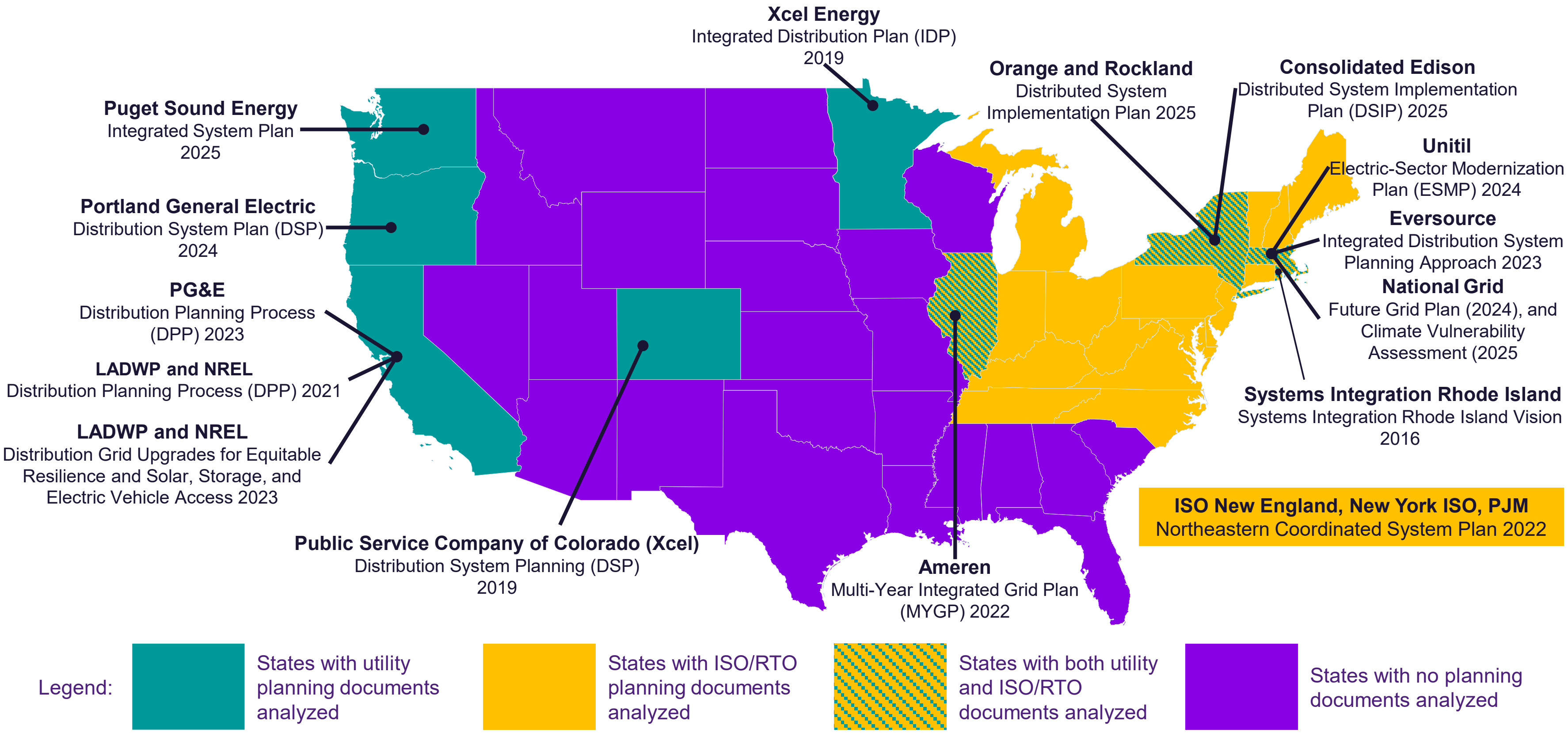


Figure 20. Map of planning documents analyzed

Table 40. Planning documents analyzed

No.	Utility	State	Study Name	Year
1	PG&E	CA	Distribution Planning Process (DPP)	2023
2	Consolidated Edison	NY	Distributed System Implementation Plan (DSIP)	2025
3	Xcel Energy	MN	Integrated Distribution Plan (IDP)	2019
4	Portland General Electric	OR	Distribution System Plan (DSP)	2024
5	Public Service Company of Colorado (Xcel)	CO	Distribution System Planning (DSP)	2019
6	Unitil	MA	Electric-Sector Modernization Plan (ESMP)	2024
7	Eversource	MA	Integrated Distribution System Planning Approach	2023
8	Orange and Rockland	NY	Distributed System Implementation Plan	2025
9	Systems Integration Rhode Island (SIRI)	RI	Systems Integration Rhode Island Vision	2016
10	Ameren	IL	Multi-Year Integrated Grid Plan (MYGP)	2022
11	Puget Sound Energy	WA	Integrated System Plan	2025
12	National Grid[1]	MA	Electric-Sector Modernization Plan (ESMP)	24/25
13	LADWP and NREL Transforming Energy	CA	Distribution System Analysis	2021
14	LADWP and NREL	CA	Distribution Grid Upgrades for Equitable Resilience and Solar, Storage, and EV Access	2023
15	Independent System Operator (ISO) New England, New York ISO, PJM	ISO New England, NYISO, and PJM	Northeastern Coordinated System Plan	2022

After collecting the 15 LRDP documents, each plan was meticulously reviewed to answer the core benchmarking questions. Siemens Energy evaluated how different organizations approached distribution planning, assessed the transparency of their processes, and examined the integration of emerging technologies and practices. Special attention was paid to the strategies employed for enhancing reliability, resilience, affordability, and equity within the grid.

The findings from this review were organized into clearly defined categories for ease of comparison. Data from the plans were systematically tabulated, allowing for quantitative assessment of key metrics and practices. Furthermore, the results are visualized through charts, graphs, and other analytical tools to highlight trends, best-in-class strategies, and areas where further innovation may be needed.

This structured approach enabled Siemens Energy to identify industry-leading best practices and provide actionable recommendations to inform Delaware's own long-range distribution planning and grid modernization efforts.

4.2. Planning Cadence & Horizon

The typical planning horizon for EDCs is between five and ten years, as shown in Figure 21. This timeframe generally offers adequate foresight for most distribution system improvements. While 33% of planning documents opt for longer-range plans, extending beyond a decade, these extended horizons tend to introduce greater uncertainty. On the other hand, shorter planning periods may not allow enough time to implement complex or long-duration projects, potentially limiting the effectiveness of strategic investments.

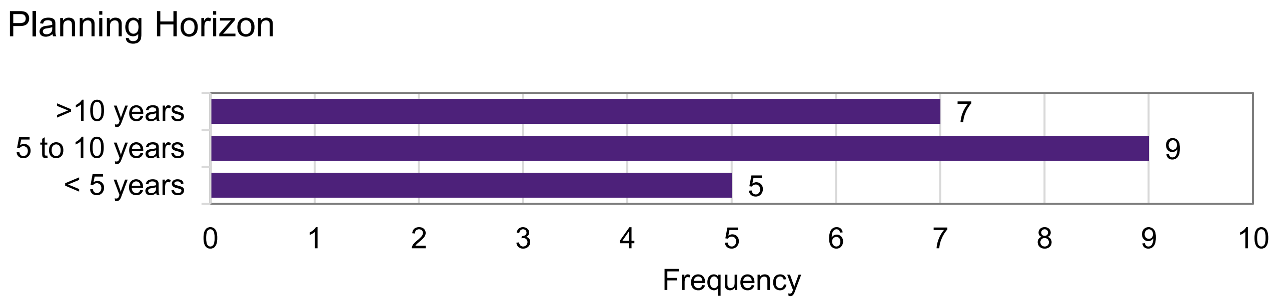


Figure 21. Planning horizon utilized by reviewed planning documents

Figure 22 shows the update cadence of each of the analyzed LRDPs. Most plans are updated annually, ensuring that utilities remain responsive to evolving grid needs and regulatory requirements. This frequent review cycle allows for timely adjustments based on new data, technological advancements, and shifting demand patterns, thereby supporting ongoing reliability and modernization efforts. It is important to note that several entities utilize multiple planning horizons tailored to specific applications. For instance, PG&E employs three distinct planning horizons: Substations/Feeders are planned over a 5-year period (2023–2027), Line Sections utilize a 3-year horizon (2023–2025), and Pre-Application Projects are considered over a 10-year span, though none were identified for 2023.

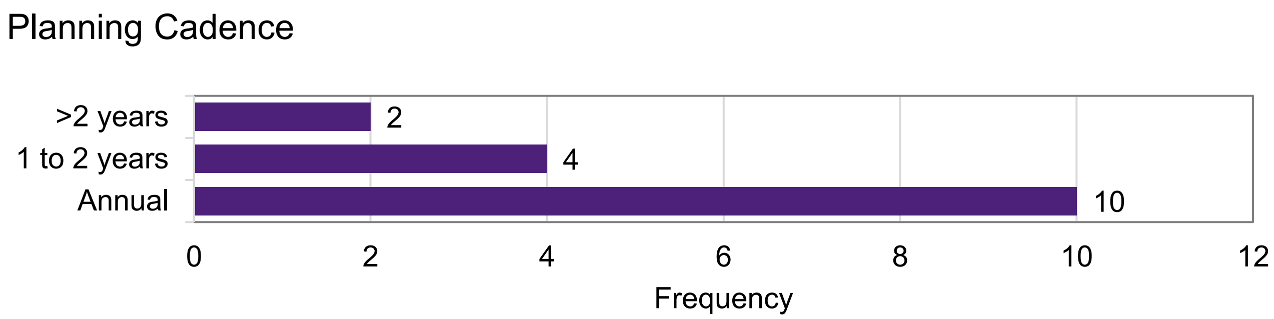


Figure 22. Planning cadence

Best Practices:

- Set a planning horizon of 5-10 years, balancing foresight with uncertainty.
- Update plans annually, ensuring responsiveness to evolving needs.
- Use multiple planning horizons for different types of projects.

4.3. Key objectives and drivers

Each LRDP was reviewed to understand the plan's key objectives and drivers. Integration of DERs is the most common driver for distribution planning. Shown in Figure 4, reliability, resiliency, and decarbonization are other key drivers frequently cited by utilities. Additionally, some plans placed significant emphasis on electrification initiatives and the adoption of NWAs to address evolving grid demands. In contrast, social justice, equity, and safety are generally not major considerations across most plans. The primary reason for this is many jurisdictions have independent initiatives or rate-case interventions to address social justice, equity and safety issues.

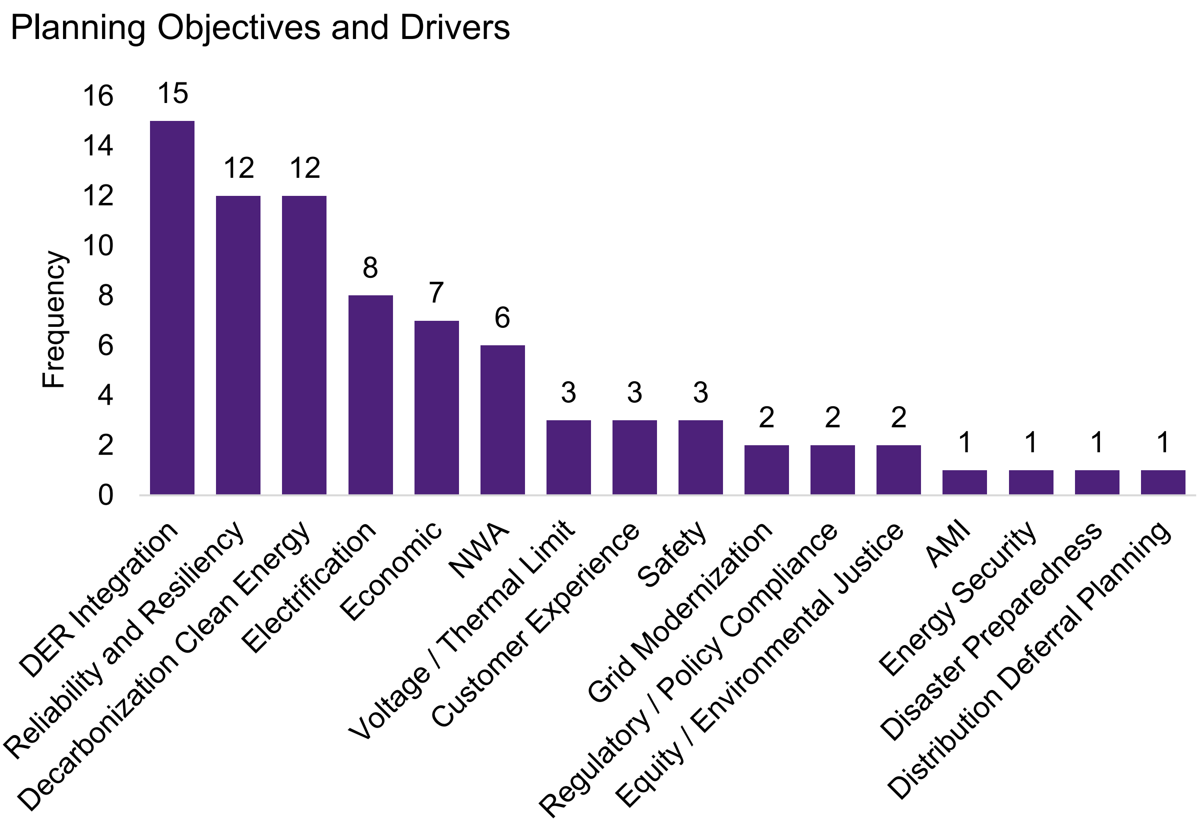


Figure 23. Planning objectives and drivers

Best Practices:

- Align plans to policy priorities such as DER integration, reliability, resiliency, and decarbonization.
- Evaluate emerging policies such as electrification and use of emerging technologies such as NWAs.

4.4. Stakeholder Engagement

An industry best practice in distribution planning is to include a diverse set of stakeholders throughout the process. This typically involves engaging regulators, ISO/RTOs, consumer advocates, and DER developers to ensure that a wide range of perspectives and expertise inform planning decisions. By fostering collaborative input, utilities can better address regulatory requirements, market trends, and community needs, ultimately leading to more robust and equitable distribution system outcomes. Figure 5 shows that commissions or regulators along with government agencies are most often consulted for policy inputs while system planning and assumption inputs from RTO/ISO are crucial for reliability and regional coordination.

Stakeholder Engagement

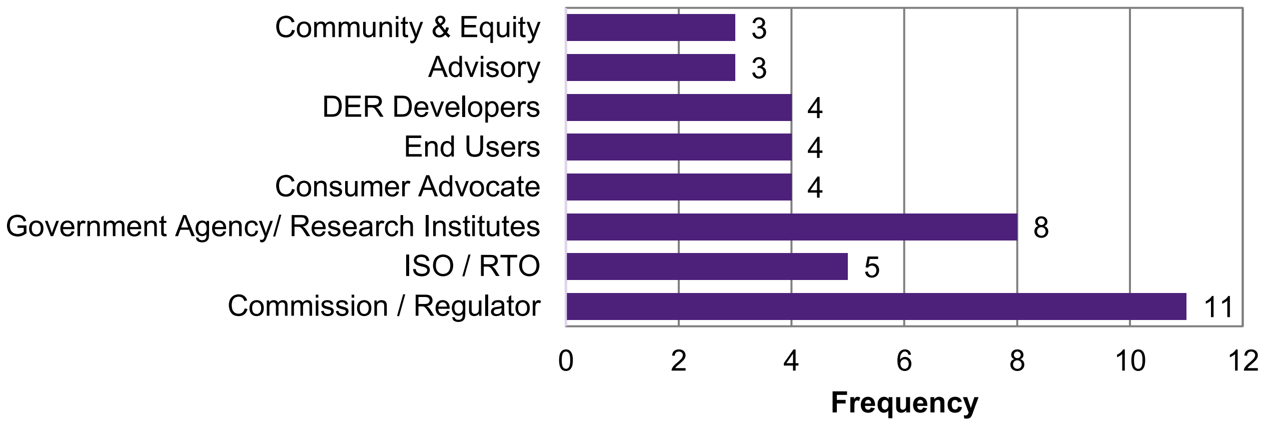


Figure 24. Number of studies engaging with each stakeholder

Best Practices:

- Engage a diverse set of stakeholders throughout the planning process.
- Ensure that plans reflect regulatory, market, and community needs.

4.5. Forecasting

Load forecast is a key planning input. A load forecast provides a view of how energy demand will evolve, allowing utilities to size infrastructure, prioritize upgrades, and maintain reliability. Most planners are expecting moderate annual load growth between 1-3%. However, this trend is changing rapidly with the increasing number of data center projects announced across the country. These developments are driving higher demand forecasts and prompting utilities to re-evaluate their long-term planning assumptions to account for potential surges in electricity consumption and infrastructure needs.

Common industry practice pairs long-term load forecasting with locational analysis to ensure utilities can anticipate when and where grid constraints will emerge. Load forecasts typically start with econometric modeling of weather normalized historic data which is often adjusted for various scenarios of DSM, DERs, and EV adoptions. System-level forecasts are supplemented with feeder- or substation-level refinement through AMI, SCADA, and Geographic Information System (GIS) datasets. Locational allocation is performed mapping load, DER adoption, hosting capacity, and equity indicators from census-tract or customer-class levels down to feeders and transformers. For larger Investor Owned Utilities (IOUs), common software platforms include LoadSEER for spatial and regression-based forecasting, and AdopDER for DER-specific load modeling.

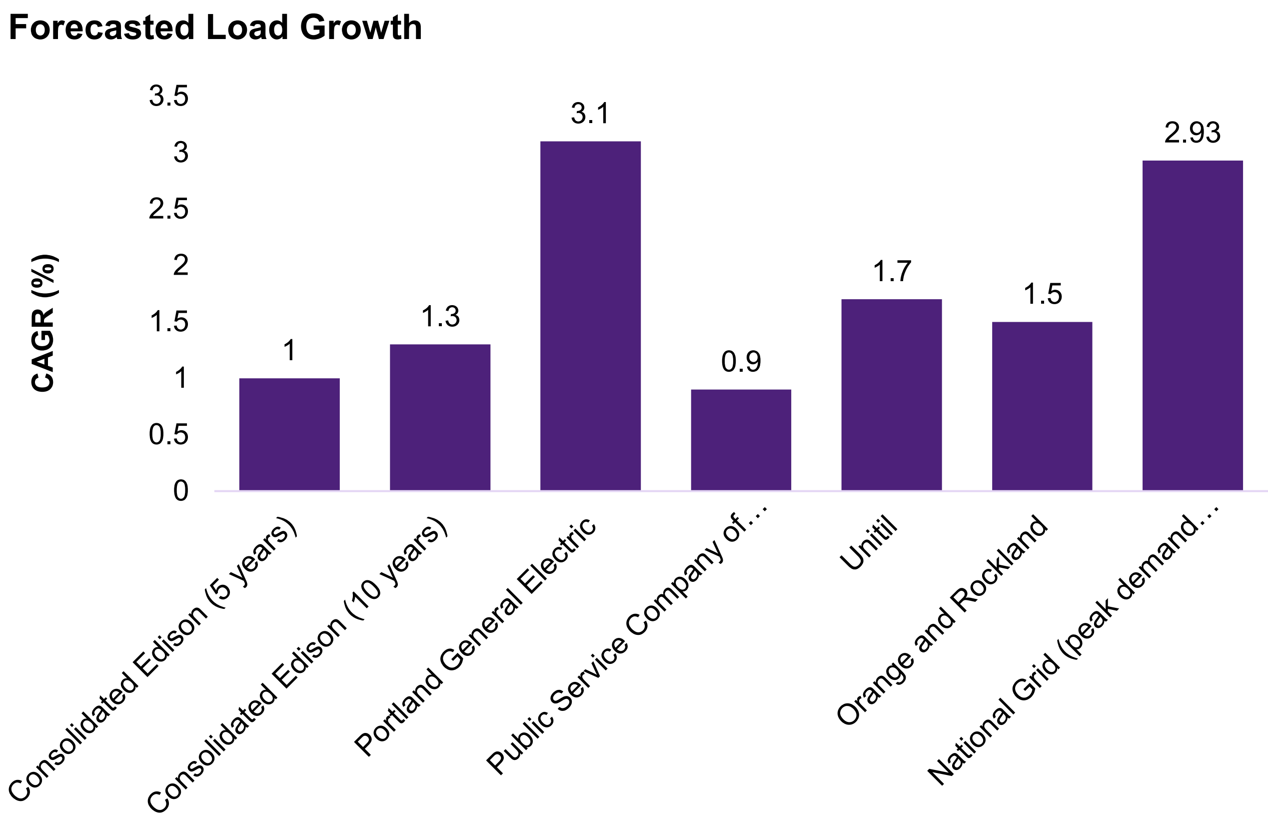


Figure 25. Forecasted load growth

Best Practices:

- Develop dynamic load forecasting with moderate baseline growth and rapid data center and electrification growth.
- Use scenario analysis to develop a robust plan.
- Regularly revisit inputs and assumptions to account for rapid changes in demand and DER adoption.
- Leverage software to develop locational forecasts.

4.6. Cost Benefit Analysis

Most benefit metrics used in distribution planning focus on five key areas: reliability, DER accommodation, risk and resilience, load serving capacity, and locational value. Figure 26 shows that within each category, certain metrics are widely favored. For reliability, SAIDI and SAIFI are commonly used to measure outage duration and frequency. DER accommodation is typically evaluated using hosting capacity metrics, which indicates how much DER capacity may be integrated without compromising grid performance. For risk and resilience, weather and climate resiliency metrics help utilities gauge preparedness for extreme events and evolving climate conditions. Load serving capacity is most commonly assessed through load ratings, reflecting the system's ability to meet demand.

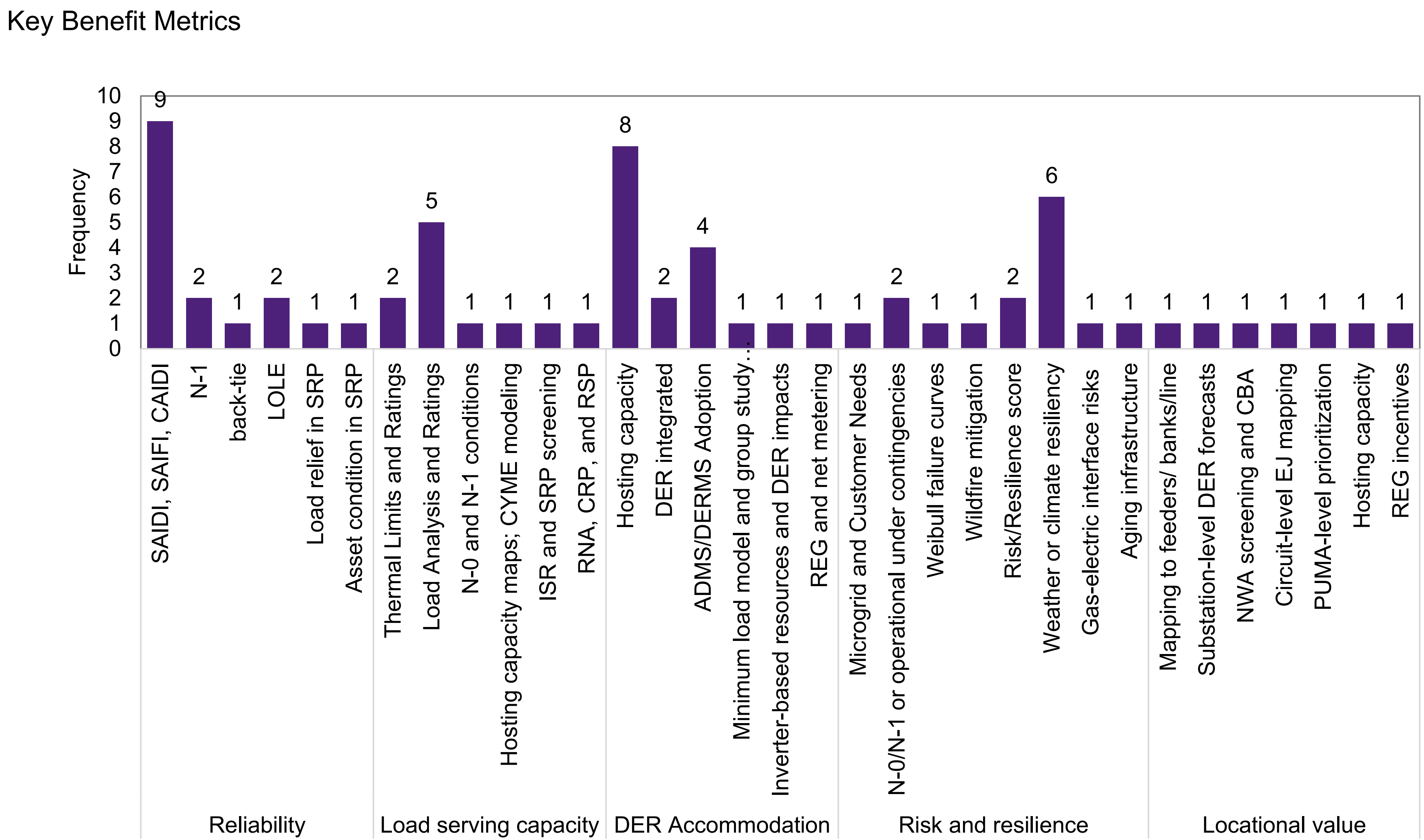


Figure 26. Key benefit metrics

An identified best practice for risk and resiliency modeling includes modeling the impacts of major storms such as Nor'easters and hurricanes, as well as extreme weather events like heat waves and cold snaps. This is done through load forecasting scenarios or contingency analysis. Coastal areas also often include an analysis of rising sea levels. This approach includes integrating Federal Emergency Management Agency (FEMA) floodplain data and leveraging PJM/NERC seasonal reliability assessments to inform scenario analysis and system preparedness.

While the Benefit/Cost Ratio and Total Resource Cost (TRC) are among the most commonly used cost metrics in system planning, best practices recommend employing a combination of metrics to obtain a more comprehensive view of project value. By integrating multiple cost metrics including those listed in Table 41, utilities can ensure planning decisions are financially robust and aligned with system objectives.

Table 41. Cost metrics

Utility	**DDOR[69] Evaluation**	**Benefit/Cost Ratio**	**Total Cost of Ownership**	**Capital and Operations & Maintenance (O&M) Budgets**	**Avoided Cost Elements**	**Net Benefits Model**	**Specific Unit Cost Database**	**TRC**
PG&E	✓							
Consolidated Edison		✓	✓					
Xcel Energy		✓		✓				
Portland General Electric					✓			✓
Public Service Company of Colorado		✓						
Unitil						✓		✓
LADWP and NREL Transforming Energy							✓	
LADWP and NREL							✓	

[69] Distribution Deferral Opportunity Ratio(DDOR) - proportion of the electric grid investment where third-party DERs could substitute for traditional infrastructure upgrades.

Orange and Rockland					✓			✓
Systems Integration Rhode Island (SIRI)								✓
Ameren		✓						

Best Practices:

- Leverage common benefit metrics to address reliability (SAIDI, SAIFI), DER accommodation (hosting capacity), load serving capacity, and risk/resilience (weather/climate preparedness).
- Plan for major storm and extreme weather impacts through scenario analysis.
- Use multiple cost metrics such as benefit/cost ratio, TRC, and avoided costs for comprehensive analysis.

4.7. Asset Management and Preventive Maintenance Programs

Figure 27 shows frequency of asset management and preventative maintenance programs planned or implemented by utilities. Among asset management and preventive maintenance programs, vegetation management and substation renewal or automation emerge as the most commonly implemented strategies across utilities. These initiatives are closely followed by pole inspection and replacement programs, reflecting their critical role in maintaining system reliability and safety.

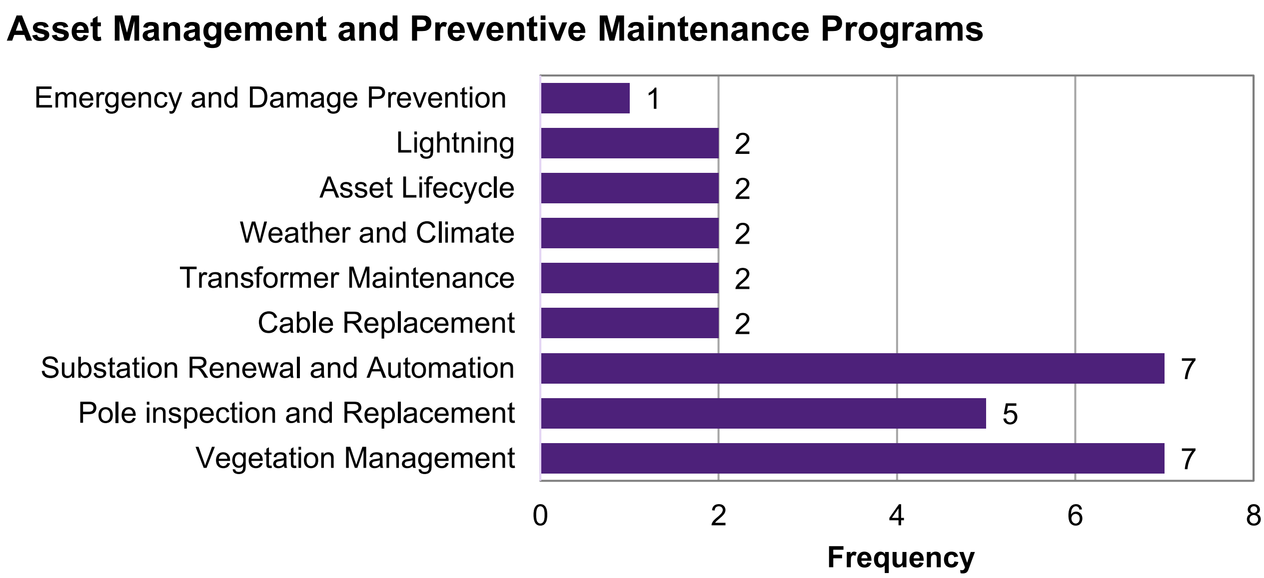


Figure 27. Asset management and preventive maintenance programs

Best Practices:

- Leverage traditional programs such as vegetation management, substation renewal/automation, and pole inspection/replacement.
- Integrate asset health visibility and analytics into maintenance programs.

4.8. Grid Enhancing Technologies

Figure 28 below presents the frequency with which key grid-enhancing technologies are referenced, piloted, or planned across leading U.S. utility LRDP programs. These counts reflect the number of plans that explicitly mention each technology as part of their modernization or grid improvement strategies.

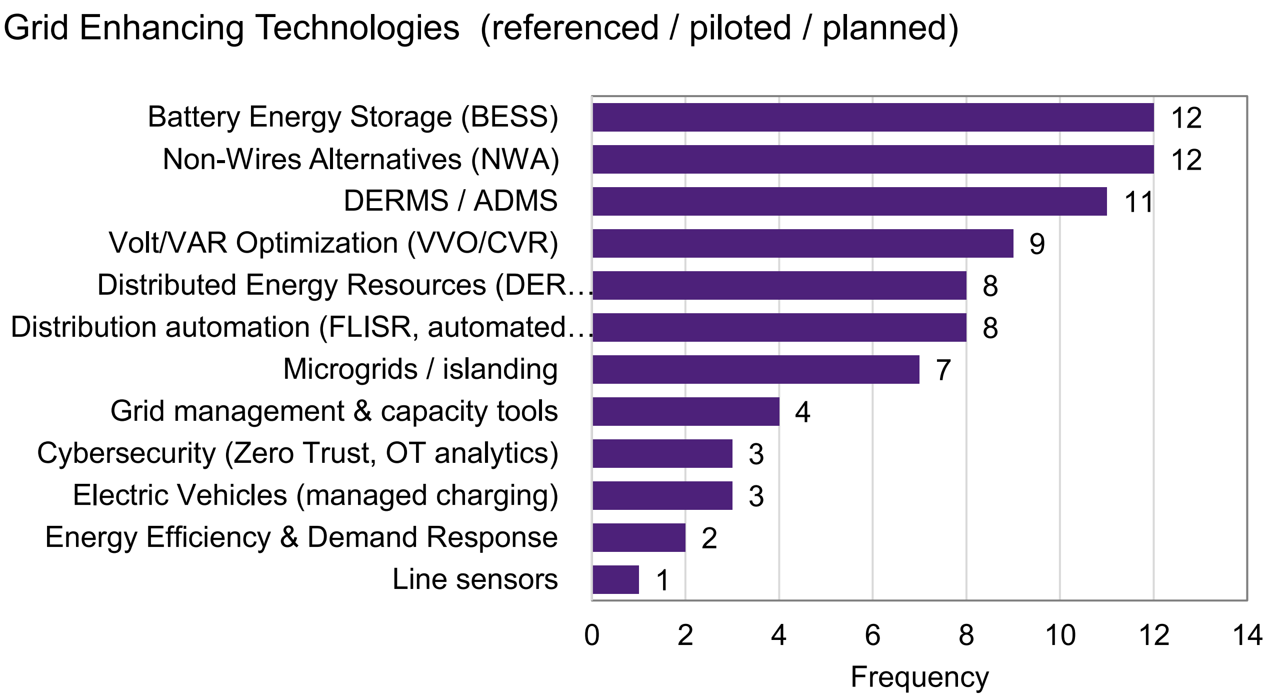


Figure 28. Grid Enhancing Technologies

Utilities leading in grid modernization typically combine these technologies within a holistic strategy, aligning investments with reliability, resilience, decarbonization, and equity objectives.

Table 42. Grid Enhancing Technologies

Technology Theme	Typical Purpose	Selected Utilities/Programs Referencing It	Key Notes
Distribution Automation (Fault Location, Isolation, and Service Restoration (FLISR), auto switching, smart reclosers)	Faster fault isolation/restoration; sectionalizing	PG&E, Xcel CO, PGE, National Grid, O&R, Unitil	Often paired with SCADA/AMI; early reliability wins.
VVO / CVR	Voltage control, loss reduction, demand savings	PGE, Xcel CO, National Grid, Ameren, PG&E	Smart inverter Volt-VAR/Watt settings complement feeder VVO.

Technology Theme	Typical Purpose	Selected Utilities/Programs Referencing It	Key Notes
DERMS / ADMS	Visibility/control of DERs; situational awareness	PG&E (developing), ConEd, PGE, National Grid, Ameren, Unitil	Roadmaps/pilots in several plans; supports NWA/VPP dispatch.
NWA / VPPs	Capacity deferral and portfolio optimization	ConEd (BQDM precedents), PGE, Xcel, Ameren, O&R, Unitil	Growing concern for portfolio discipline.
Battery Energy Storage Systems (BESS)	Peak shaving; contingency support; deferrals	ConEd (utility & BTM), PGE (BTM and utility), National Grid, O&R	Trajectories quantified in forecast; customer vs utility storage noted.
Hosting Capacity & DER Studies (OpenDSS/PyDSS, CYME, EPRI DRIVE)	Site DERs efficiently; interconnection guidance	PG&E (CYME), PGE (DRIVE), Xcel CO; LADWP/NREL (workflow automation)	Minimum-load and group studies for high-DER circuits.
Managed EV Charging	Local peak mitigation; transformer/bank protection	National Grid, ConEd, Ameren	Integrated with DER forecasts and ADMS/DERMS capabilities.
Microgrids / Grid-forming Inverters	Critical service resilience; islanding	National Grid, LADWP/NREL studies, PGE	Equity-informed siting and resilience hub concepts appear.
Field Comms & Networks (FAN, Private Long-Term Evolution (LTE)/ Multiprotocol Label Switching (MPLS))	Secure, reliable comms for automation	ConEd, PGE, Ameren	Supports FLISR/VVO/AMI and DERMS/ADMS integration.
Cybersecurity (Zero Trust, Operating Technology (OT) anomaly detection)	Protect ADMS/DERMS/AMI/SCADA assets	National Grid, PGE, Ameren	Elevated emphasis as DER orchestration expands.
Asset Health & Preventive Programs (vegetation, substation automation, pole programs)	Reliability/resilience foundation	Broadly present: PGE, Xcel CO, National Grid, O&R, Unitil, Ameren	Coupled with analytics (AMI/SCADA) and climate hardening.

Best Practices:

- Deploy core modernization tools such as distribution automation (FLISR, smart switching), DERMS/ADMS, VVO, and battery energy storage.
- Advance flexibility and resilience through NWAs, managed EV charging, and microgrids.
- Strengthen field communications, cybersecurity, and asset health to support digital grid operations.

4.9. LRDP Best Practices: Key Insights

A review of leading U.S. utility and regional LRDPs shows that successful long-term distribution planning is characterized by structured processes, robust stakeholder engagement, and strategic technology integration. The following summarizes what effective planners do in each area:

Planning Cadence & Horizon

- Successful utilities set a planning horizon of 5-10 years, balancing foresight with manageable uncertainty.
- Most update their plans annually, ensuring responsiveness to grid needs, technology and regulatory changes.
- Multiple planning horizons may be used for different asset classes or project types, optimizing investment timing.

Key Objectives & Drivers

- Most plans prioritize DER integration, reliability, resiliency, and decarbonization as central drivers.
- Electrification and NWAs are incorporated to address emerging grid demands.

Stakeholder Engagement

- Leading entities engage a diverse set of stakeholders (including regulators, ISOs/RTOs, consumer advocates, DER developers, and community representatives) throughout the planning process.
- Collaborative input ensures that plans reflect regulatory, market, and community needs.

Forecasting

- Dynamic load forecasting is used, accounting for moderate baseline growth and potential rapid growth from data centers or electrification.
- Assumptions are revisited regularly to capture rapid changes in demand and DER adoption.

Metrics & Cost-Benefit Analysis

- Most common benefit metrics address reliability (SAIDI, SAIFI), DER accommodation (hosting capacity), load serving capacity, and risk/resilience (weather/climate preparedness).

- Major storm and extreme weather impacts are modeled, integrating FEMA and NERC data for scenario analysis.
- Multiple cost metrics such as benefit/cost ratio, TRC, and avoided costs may be used for comprehensive project evaluation.

Asset Management & Preventive Maintenance

- Vegetation management, substation renewal/automation, and pole inspection/replacement are preferred asset management and preventive maintenance measures.
- Asset health visibility and analytics are integrated into maintenance programs.

Grid-Enhancing Technologies

- Distribution automation (FLISR, smart switching), DERMS/ADMS, VVO, and battery energy storage are deployed as core modernization tools.
- NWAs, managed EV charging, and microgrids are advanced for flexibility and resilience.
- Field communications, cybersecurity, and asset health monitoring are strengthened to support digital grid operations.

Overall, these practices represent the approaches most commonly used by utilities to manage long-term distribution system needs in a consistent and transparent way. As the electric system evolves, these methods provide a practical foundation that EDCs can build upon to meet emerging requirements.

5. Cybersecurity Compliance and Policy Review

The objective of this section is to provide stakeholders an evidence-based assessment of cybersecurity governance, compliance practices, and policy maturity across Delaware's EDCs, informed by submitted documentation and aligned to recognized industry frameworks. This review leverages the NIST CSF 2.0 to structure findings across the Identify, Protect, Detect, Respond, and Recover domains, and evaluates how current practices align with applicable regulatory constructs such as NERC Critical Infrastructure Protection (CIP) standards.

This section details the current cybersecurity governance programs within the state's EDCs. This executive-level analysis offers an overview of the compliance and policy as it pertains to the participating EDCs.

For the preparation of this section, the assessment team conducted a comprehensive review of the voluntary submissions of documentation from DPL and DEC. DEMEC was not able to provide requested information on behalf of all constituents. Hence DEMEC was not included in the assessment.

The assessment includes an overview of the NERC CIP standards which provide the Cybersecurity regulatory framework for electric companies in the United States. This provides relevant context to Delaware's electric grid, highlighting current and incoming compliance requirements and noting key regulatory entities that impact the state grid.

This section is not a regulatory report stating any stance on the compliance requirements or adherence to them from any participating EDCs. This limitation is due to Siemens Energy only being provided with written descriptions of the cyber documentation and controls instead of the complete RFI which includes any cybersecurity policy, procedure, and direct evidence of implementation.

Our analysis is organized by the NIST CSF 2.0 domains as follows:

- **Identify & Assess:** Focuses on recognizing and evaluating the assets that are the components of the operational technology (OT) systems of each entity. This includes topics such as asset management and vulnerability management.
- **Protect:** Examines policies and technology that is implemented to prevent cyberattacks, including rules regarding system connectivity and access management.
- **Detect:** Covers the technology and processes that are in place to monitor systems for anomalous activities or potential threats, providing mechanisms for alerting relevant personnel and stakeholders.
- **Respond:** Details of the processes and technology for preparing and responding to cyber-physical incidents.
- **Recover:** Policies and procedures, and technologies for system recovery, failure assessment, and the documentation of lessons learned.

Findings and Evaluation

Based on the most recent responses and documentation, the assessment confirms that the participating EDCs maintain a robust understanding of cybersecurity risks and the necessary controls.

The evaluation of provided written descriptions and artifacts demonstrated the outline of a robust cybersecurity program. Notably, both DPL and DEC continue to take proactive steps beyond baseline regulatory requirements by adopting industry best practice policies and recognized CSFs. However, due to the nature of available documentation, the effectiveness and consistency of policy application across all organizational levels could not be fully assessed.

Assumptions

- All established policies and procedures, including recent updates, are consistently followed by personnel throughout the organization.
- The scope of this assessment remains strictly confined to publicly available documents and information provided by DPL and DEC, including the latest submissions.
- No undocumented or informal practices are in use that circumvent the existing security controls or measures.

5.1. Methodology and Data Sources

This assessment provides a structured, holistic review of Delaware's EDCs' cybersecurity posture based entirely on the attestation documents submitted in response to Siemens Energy's information request. During the creation of this section the assessment team requested a series of documents and evidence from each EDC. However, due to the limitations of the content the EDCs where able to provide for privacy and security reasons, this section was changed to be qualitative in nature, providing an overview of the information provided and applying the NIST CSF 2.0 domains of Identify & Assess, Protect, Respond, and Recover to organize the analysis.

A full list of the requested documents is available in Appendix B: Cybersecurity Compliance and Policy Review requested documents. Table 43 shows a summary of data provided by each EDC.

Table 43. Overview of Data Collected

DEC	DPL	DMEC
• Written description of each requested item in response to RFI.	• Copy of PSC Docket No. 16-0659 – Delmarva Power & Light Company • Responses to Cybersecurity Questions - 2025	• No documentation was provided

The purpose of this assessment is to help stakeholders in Delaware understand:

1. What cybersecurity practices are the EDCs reporting as implemented?
2. How do these practices align within a recognized cybersecurity structure?
3. Where are there strengths, uncertainties, or potential gaps?
4. How do the cluster of controls, processes, and capabilities fits together from an OT/ Industrial Control Systems (ICS) perspective?

This approach supports a clearer picture of each EDC's broader cybersecurity footprint without making claims of regulatory compliance.

Qualitative Interpretation of Written Responses

Our analysis is based solely on the narrative descriptions provided by Delaware's EDCs. Since no direct evidence (e.g., configurations, logs, diagrams) was included, the findings represent:

1. Statements of capability,
2. Claims of process maturity, and
3. Descriptions of technology or policy coverage, rather than verified implementation.

Categorization Into the Five NIST CSF 2.0 Domains

To organize the information into a meaningful structure, the assessment mapped the practices described into the five NIST core domains:

- **Identify & Assess:** Focuses on recognizing and evaluating the assets that are the components of the operational technology (OT) systems of each entity. This includes topics such as asset management and vulnerability management.
- **Protect:** Examines policies and technology that is implemented to prevent cyberattacks, including rules regarding system connectivity and access management.
- **Detect:** Covers the technology and processes that are in place to monitor the systems for anomalous activities or potential threats, providing mechanisms for alerting relevant personnel and stakeholders.
- **Respond:** Details of the processes and technology for preparing and responding to cyber-physical incidents.
- **Recover:** Policies and procedures, and technologies for system recovery, failure assessment, and the documentation of lessons learned.

This method does not constitute NIST CSF compliance. Instead, it simply uses a well-understood taxonomy to help organize the section.

Holistic Categorization for Clarity and Context

The categorization is intended to help Delaware's EDCs and state stakeholders:

1. Assess how the documented controls relate to one another
2. Understand which cybersecurity functions appear stronger or less mature

3. Identify areas where additional evidence, clarification, or investment might be needed
4. Visualize cybersecurity posture from an OT/ICS-specific lens

This structure also highlights the interplay between policy, process, and technology.

No Framework Compliance Claims

Because no supporting evidence was provided, the assessment deliberately avoids:

1. Claiming alignment to any cybersecurity compliance standard
2. Suggesting the EDCs meet or do not meet regulatory obligations
3. Drawing conclusions beyond what the supplied text stated

Every observation, strength, or gap is strictly tied to statements made in the written submission.

5.2. Applicable Regulations

The EDCs operating within Delaware may be subject to a range of requirements under the NERC CIP Framework depending on how their assets have been classified. In this section, the assessment provides an overview of the NERC CIP standards that could be relevant to EDCs.

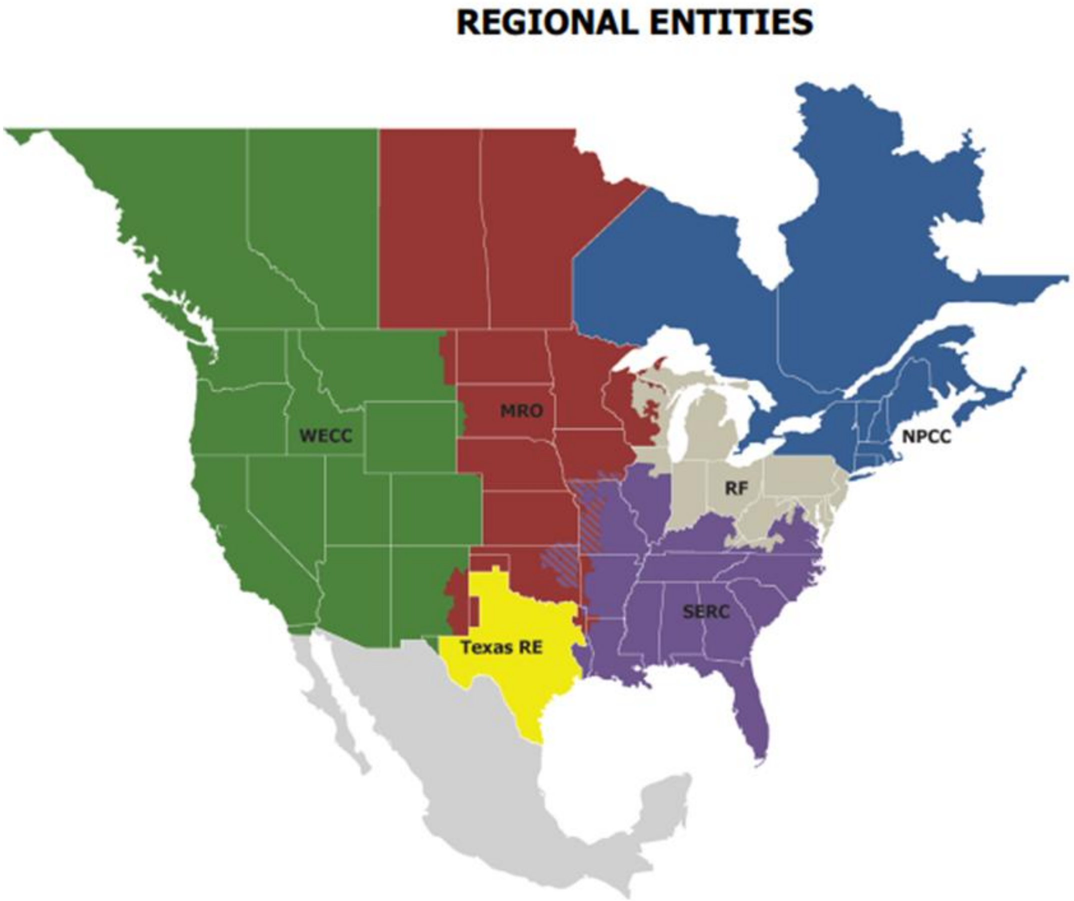
This includes descriptions of the standards and a summary of general compliance expectations for entities. Specific mapping of standards to EDCs was not possible due to a lack of information.

North American Electric Reliability Corporation

Formed originally as a voluntary entity in 1968, NERC main purpose is to protect the Bulk Electric System (BES)[70]. The BES refers to facilities such as transmission lines, power plants and substations that function within the interconnected system to transmit power across North America[71].

As a result of legislative updates in 2003, NERC's role changed to that of the regulator for electric utilities. To facilitate this, they are segmented into various regional entities as shown in Figure 29. Over its history NERC has evolved its standards to include new topics as technology implemented within the BES changed. One of these topics is the regulation of physical and cybersecurity via the CIP standards[72].

[70] NERC, "Who We Are." https://www.nerc.com/who-we-are.
[71] NERC, "Glossary of Terms Used in NERC Reliability Standards," Available: https://www.nerc.com/globalassets/standards/reliability-standards/glossary_of_terms_111225.pdf.
[72] NERC, "Reliability Standards," Available: https://www.nerc.com/standards/reliability-standards.



NERC Regional Entities		
Midwest Reliability Organization (MRO)	Northeast Power Coordinating Council, Inc. (NPCC)	ReliabilityFirst (RF)
SERC Reliability Corporation (SERC)	Texas Reliability Entity Inc. (Texas RE)	WECC
Please note that the regional boundaries in the NERC Regions map shown below are approximate. The highlighted areas denote overlap as some load-serving entities participate in one Region while associated transmission owners/operators participate in another.		

Figure 29. NERC Regions

Delaware Entities Compliance Reporting Obligations

Delaware's regulated entities are overseen by the ReliabilityFirst Organization, which is responsible for the registration and auditing of their NERC standards[73]. These compliance monitoring programs consist of three primary mechanisms: Compliance Audits, Self-Certifications, and Spot Checks[74].

Compliance Audits serve as the principal method of evaluation and are conducted by RF according to a schedule determined by the organization. During these audits, an auditor

[73] NERC, "Reliability Standards," Available: https://www.nerc.com/standards/reliability-standards.
[74] ReliabilityFirst, "Compliance Monitoring Methods," Available: https://www.rfirst.org/compliance/compliance-monitoring-methods/.

assesses a subset of standards that have previously been identified as applicable to the entity. It is important to note that the scope of these audits is not limited solely to CIP standards, and entities may undergo multiple audit cycles without a single CIP Standard being specifically reviewed.

Self-Certifications represent a secondary compliance monitoring tool and are typically required on a more frequent basis than audits. Through this process, entities are obligated to self-report on their compliance programs. This self-certification process often comprises the largest portion of compliance activity for an entity.

Finally, Spot Checks are a tool that allows RF to at any time demand entities provide a response regarding a specific standard or requirement. These checks enable RF to address targeted concerns or verify compliance on an as-needed basis75.

CIP Specifics

To ensure the effective application of standards, the systems operated by EDCs are assigned to a Bulk Electric System (BES) Impact Rating at the time of registration. These ratings, Low, Medium, or High are used to classify the systems according to the potential impact they may have on the BES.

Although these standards are largely focused on High and medium voltage assets that are operated by Transmission Owners, EDCs could still be subject to certain standards depending on the equipment they control or schemes that are in place. A common misinterpretation is that all low voltage assets are exempt but if the asset is a part of an automated Under Frequency Load shed scheme with greater than 300MW of load there are obligations to certain CIP standards. With the information provided, the application of specific standards could not be determined.

This classification process allows for assets, even those physically located within the same substation, to be assigned different BES Impact Levels if the facility's design satisfies the established separation requirements.

For instance, a system that operates a high-voltage asset, such as a transmission line with a rating of 345kV or higher, may be designated as Medium Impact. This designation subjects the asset to more rigorous security and compliance requirements. Conversely, another asset within the same substation, but operating at a lower impact level, may be classified as Low Impact and therefore be subject to less stringent controls. This approach ensures that each asset receives protection based on the specific risks it presents, rather than imposing a uniform set of requirements across all assets at a given site. The BES Impact Level is a key classification tool within the NERC CIP framework. It is used to determine the potential consequences that the loss, compromise, or misuse of an asset could have on the Bulk Electric System. Assets assigned a higher impact rating must comply with more stringent security controls and meet additional compliance requirements.

Each NERC CIP standard and its corresponding requirements are associated with specific impact ratings. Moreover, further restrictions regarding the applicability of certain

[75] ReliabilityFirst, "Compliance Monitoring Methods," Available: https://www.rfirst.org/compliance/compliance-monitoring-methods/.

requirements may apply depending on the particular circumstances of an entity. These circumstances must be evaluated and substantiated individually, on a case-by-case basis.

During this assessment, challenges were encountered in determining which specific NERC CIP standards and requirements apply to each entity because of the lack of detailed information. As a result, it was not possible to precisely identify the relevant standards for the EDCs.

Given the operating profile of EDCs, it is reasonable to state that the majority of assets would either fall outside the scope of NERC CIP or be classified as Low Impact. While there may be exceptions or unique circumstances that could result in higher impact ratings for certain assets, the absence of comprehensive data prevents us from making definitive conclusions beyond this general assumption.

To provide further context, it is important to understand the types of controls mandated by the NERC CIP standards for entities to which they apply. These controls are designed to address varying levels of risk and impact, ensuring that appropriate security measures are implemented according to the asset's classification.

Below is a high-level explanation of the NERC CIP standard, CIP-002 through CIP-015:

Table 44. CIP Standards

Standard	Initial Enforcement Year[76]	BES Impact Level	High-Level Requirements
CIP-002	2009	High, Medium, Low	Establishes criteria for identifying and categorizing BES Cyber Systems based on their impact on grid reliability, with impact levels determined by the physical characteristics of the systems such as voltage ratings, blackstart capabilities, and other operational attributes. This standard outlines how these factors are used to apply BES Cyber System impact levels and determine which assets are subject to further CIP controls.

[76] Dates are based on initial NERC CIP enforcement; individual versions and updates may vary by region and regulatory schedule. Please verify with NERC or regional authorities for specific enforcement timelines.

Standard	Initial Enforcement Year[76]	BES Impact Level	High-Level Requirements
CIP-003	2009	High, Medium, Low	Requires implementation of security policies, governance structures, and accountability measures for cybersecurity management. This standard establishes the standards (CIP-004 – CIP-015) that apply to both High and Medium impact BES Cyber Systems, ensuring that these critical assets are governed by comprehensive cybersecurity policies and procedures. For facilities categorized as Low impact, the standard prescribes a subset of mandatory controls, focusing on essential security measures to provide baseline protection while recognizing their comparatively lower risk to grid reliability.
CIP-004	2009	High, Medium	Requires development of documented procedures that address training, background checks, and access authorization for personnel with BES Cyber System responsibilities. Additionally, the entity must maintain evidence demonstrating that these procedures are implemented and the requirements are consistently fulfilled.
CIP-005	2009	High, Medium	Defines requirements for documenting controls related to electronic access to protected assets including, such as firewall configurations and secure remote access. Including implementation proof and collecting evidence to demonstrate ongoing effectiveness. The entity must ensure that all such controls are reactively enforced and maintain records that verify the compliance over time.

Standard	Initial Enforcement Year[76]	BES Impact Level	High-Level Requirements
CIP-006	2009	High, Medium	Requirements related to physical security controls plan and procedure, such as access controls and surveillance, to safeguard critical cyber assets from unauthorized physical intrusion. The outlined requirements detail the necessary levels of physical security controls and implementation of comprehensive logging of activities within protected areas. Allowing for the protection and detection of physical security events in these facilities.
CIP-007	2009	High, Medium	Requires implementation of technical and procedural controls to protect critical cyber assets by managing system access, enforcing patch management, preventing malware, and ensuring secure configurations. The requirements establish necessary cybersecurity controls, continuous monitoring, and comprehensive logging of system activities to detect, prevent, and respond to unauthorized access or system changes.
CIP-008	2009	High, Medium	Establishes measures for procedural controls to ensure organizations are prepared to respond to cybersecurity incidents by developing, implementing, and maintaining incident response plans. These requirements include detecting, reporting, investigating, and mitigating cyber events, as well as documenting actions taken and performing exercises of the incident action plan. Furthermore, dictating that the incidents be shared with the Electricity Information Sharing and Analysis Center (E-ISAC) to allow for industry specific tracking.
CIP-009	2009	High, Medium	Requires organizations to establish, implement, and regularly test recovery plans that ensure the restoration of critical functions following a cybersecurity incident. These requirements include developing procedures for backing up essential data, documenting recovery actions, and periodically exercising the recovery plan to verify its effectiveness.

Standard	Initial Enforcement Year[76]	BES Impact Level	High-Level Requirements
CIP-010	2015	High, Medium	Requires formal change management and regular vulnerability assessments for BES Cyber Systems. These measures help identify security gaps, reducing risks from unauthorized changes or new threats, and support industry cybersecurity and operational reliability standards.
CIP-011	2015	High, Medium	Rules related to the protection of data pertaining to BES Cyber Systems. These requirements ensure that critical information associated with BES operations remain protected against unauthorized access or loss throughout its lifecycle.
CIP-012	2020	High, Medium	Designed to ensure secure and reliable communication between control centers that manage BES operations. These standards mandate robust safeguards for the transmission of sensitive data, including protocols for how information is handled, securely between control rooms.
CIP-013	2020	High, Medium	This standard centers on recognizing, evaluating, and addressing cybersecurity risks that may arise within the supply chain for BES Cyber Systems. By establishing processes for risk identification and assessment, it aims to ensure that potential vulnerabilities linked to suppliers and service providers are thoroughly examined and managed.
CIP-014	2015	High, Medium	This standard requires utilities to evaluate and address the risks related to physical attacks targeting critical substations and control centers. The purpose of this assessment is to ensure that utilities proactively identify weaknesses and apply appropriate mitigation strategies to safeguard key operational sites from deliberate physical harm.

Standard	Initial Enforcement Year[76]	BES Impact Level	High-Level Requirements
CIP-015	2028 for High Impact, 2030 for Medium and Low	TBD – Pending final enforcement version	CIP-015-1, approved on June 26, 2025, introduces mandatory Internal Network Security Monitoring (INSM) requirements, which focus on continuously observing internal network traffic within BES Cyber Systems to detect anomalies, unauthorized communications, and potential cyber threats, thereby enhancing situational awareness and reducing attack dwell time.

Impact of the NERC CIP on Delaware's Grid

The introduction of new compliance requirements may place a significant burden on EDCs as they strive to meet evolving standards and implement new technologies. While the focus on compliance is intended to strengthen security, it can sometimes result in a narrow view of cyber-physical risks. Specifically, attention may be concentrated only on assets required for compliance, potentially overlooking broader risks across the system.

Investments in cyber-physical controls for compliance only may inadvertently lead to neglect of controls on assets that fall outside of compliance mandates or are non-applicable to certain standards. This can leave certain components more vulnerable, as resources and attention are diverted to only those assets deemed critical by regulatory standards.

Additionally, these requirements can influence the pace at which distribution companies adopt new technologies. Since all digital assets must undergo compliance evaluation, EDCs may hesitate to implement innovative solutions for grid enhancements. In some cases, this uncertainty can limit or even halt the adoption of new technologies if entities are unable to identify clear pathways to compliance.

To address these challenges, thorough and detailed project scoping is essential. By carefully defining project parameters and requirements, EDCs can make more informed decisions and develop effective plans for technology adoption that align to compliance obligations.

In summary, it is crucial for EDCs to approach compliance with thoughtful planning and consideration. Without adequate preparation, efforts to reduce risk may unintentionally create new vulnerabilities within the system, undermining the intended benefits of NERC CIP standards.

5.3. NIST CSF 2.0 Domain Findings

This section breaks down the key findings based on the information provided by DPL and DEC in the context of the NIST CSF 2.0 domains.

For each of the EDCs our team expects to see the following across each domain:

1. Identify & Assess
    a. An overarching OT/ICS Cybersecurity Policy that defines roles and responsibilities, risk appetite, exceptions, and scope
    b. Asset Management policy and procedures and the associated inventory outlining the items and their criticality to the system
    c. Risk Management policy and procedures that defines the tracking, reporting, and treating of the risks associated with the system
    d. Supply Chain Management policy and procedures dictating how vendors, devices, and services that are dependencies for the system are vetted
    e. Business continuity policy and procedures that define the operational and safety impact and how the system will be protected

2. Protect
    a. Access Control & Privileged Access policy and procedures that outline who has access and to what level, including how access is controlled and audited
    b. OT Segmentation policy and procedures that define how systems are separated along lines that define processes and safety barriers to limit attack surface
    c. Device and system hardening policy and procedures outlining how new devices' security settings are configured to limit the attack surface
    d. Personnel Screening policy and procedures to govern the backgrounds and reliability of the individuals who access the equipment physically and digitally
    e. Awareness and Training policy and procedures to show how individuals are trained
    f. Vulnerability Management policy and procedures that define how vulnerabilities are eliminated, mitigated, and discovered

3. Detect
    a. Security Monitoring & Logging policy and procedures outlining how item logs are collected, retained, and utilized to detect potential cyber threats
    b. Anomaly & Event Triage policy and procedures showing how potential cyber-physical threats are moved through from alert to response as needed
    c. Continuous Compliance and Framework monitoring policy and procedures that dictate how the EDCs meet applicable compliance requirements
    d. Policy and procedures showing how networks are baselined and visibility is provided to traffic for detection of potential threats

4. Respond
    a. OT/ICS Specific Incident Response policy and procedures that provide clear workflows, key contacts, and escalation requirements, while pointing to relevant documentation such as playbooks for tactical items
    b. Communications policy and procedures that cover internal and external stakeholders provide pertinent and sanitized information in a timely manner
    c. Forensics/Evidence Handling policy and procedures for maintaining the chain of custody during the incident response
    d. Vendor and Original Equipment Manufacturer (OEM) support policy and procedures that dictate how they are integrated into the response

5. Recover

a. Disaster Recovery & Service Restoration policy and procedures dictating the parameters for how and when restoration needs to be accomplished prioritizing operationally critical systems
b. Backup/Restore policy and procedures outlining the frequency, retentions, and testing of the backups for restoration
c. Post-Incident Review policy and procedures to facilitate the capturing of lessons learned

5.4. Cybersecurity Overview: DPL

This section presents an OT-focused cybersecurity assessment of DPL based solely on the written responses submitted in October 2025 to the Delaware PSC in PSC Docket 16-0659.

Table 45. DPL's Key Findings

Domain	Topic	Findings (✓ = Observed, ✗ = Not observed from documents provided)
Identify & Assess	OT/ICS Cybersecurity Policy	✓ Cybersecurity governance is structured at the DPL parent company level and applies to both IT and OT environments. ✓ Policies and procedures undergo annual expert review and senior leadership approval. ✓ A formal records retention and information management procedure is in place company wide.
	Asset Management	✗ No specific mention of an overarching Asset Management policy and procedures. • Several contributing topics are listed inferring there is a strategy in place.
	Risk Management	✓ Cybersecurity risk management program aligns with NIST CSF 2.0 and includes continuous threat assessment, risk assessment, and monitoring. ✓ DPL differentiates between IT and OT risks.
	Supply Chain Management	✓ Reference made to a dedicated department for screening Third Party Security. Requirements are mentioned to align specifically with NIST 2.0 and NERC CIP standard CIP-013-2. ✓ Reference made to cybersecurity terms being embedded into the procurement terms provided to vendors.
	Business continuity	✓ All critical business functions are captured in business continuity plans. These are noted to be exercised on a scheduled basis and evaluated. ✓ An internal Business Continuity team exists and can activate the Corporate Emergency Respond Organization for response to events.

Domain	Topic	Findings (✓ = Observed, × = Not observed from documents provided)
Protect	Access Control & Privileged Access	✓ Multi-Factor Authentication (MFA) is enforced for remote access into critical systems and access termination procedures are in-place showing alignment to NERC CIP standards 004 and 005. × OT-specific access control and methodology (role-based access control (RBAC), privileged access) is not described. ✓ Customer data is governed by a formal Information Protection Program with defined classifications (PI, PII).
	OT Segmentation	× Documentation pertaining to the OT network, including details on zones, conduits, and segmentation, was not provided. × Inferable content is provided but no specific mention.
	Device and System Hardening	× Processes are inferred to be in place based on responses but no direct mention of a policy or procedure covering this topic
	Personnel Screening	✓ Comprehensive background checks are stated as in place and extended to contractors. ✓ Requirements are enforced for both physical and cyber access. ✓ Written response mentions alignment to NERC CIP Standards but no specific standard (ie. CIP-004).
	Awareness and Training	× All personnel with network access complete annual cybersecurity awareness and phishing training with additional training for individuals accessing BES Cyber Assets
	Vulnerability Management	✓ Vulnerability management and threat intelligence are structured as centralized company programs. ✓ Dedicated internal teams to manage vulnerabilities and processes. Additionally mentions OT specific programs. ✓ DPL conducts regular vulnerability assessments on both IT and OT systems. No details are provided on the method or process.

Domain	Topic	Findings (✓ = Observed, × = Not observed from documents provided)
Detect	Security Monitoring & Logging	✓ A 24/7 internal Security Operations Center (SOC) monitors suspicious cyber activity across the enterprise. × There is no indication on whether there is monitoring in place for ICS Protocols or anomalies. ✓ Threat intelligence is continuously collected and disseminated and enriched via external partners and agencies. × Information regarding Log retention, storage or ability to access historical data was not provided.
	Anomaly & Event Triage	✓ Processes in place to disable accounts and machines that are abnormal. × Inferred processes are in place but limited details provided.
	Continuous Compliance and Framework	✓ References to ongoing internal assessments using the Department of Energy (DOE)'s Cybersecurity Capability Maturity Model. ✓ Several references to alignment and monitoring related to NERC CIP and NIST 2.0.
	OT Network Monitoring	✓ No specific references to any specific traffic monitoring or intrusion detection system.
Respond	OT/ICS Specific Incident Response	✓ DPL maintains a formal Cybersecurity Incident Response Plan (CSIRP) aligned with NIST CSF 2.0. ✓ CSIRP is regularly updated, including a major revision released in January 2025 ✓ Transportation Security Administration (TSA) Targeted Inspection found no non-compliance and praised CSIRP. ✓ Annual tabletop and operational exercises are performed. ✓ No OT-specific incident playbooks or scenarios where described.
	Communications	✓ Communications and reporting requirements (state and federal) are built into the plan. × Description of the roles and responsibilities was not included in the response. ✓ Communications with applicable regulators and internal stakeholders included.
	Forensics/Evidence Handling	× Not described in the document.

Domain	Topic	Findings (✓ = Observed, ✗ = Not observed from documents provided)
	Vendor and OEM Support	✓ Description of maintaining strong relationships with OEMs and Vendors. ✓ No specific mention of inclusion of OEM and vendors terms and conditions related to incident response.
Recover	Disaster Recover & Service Restoration	✓ IT disaster recovery plans are updated annually and tested based on system criticality. ✓ Included in the business continuity plans and tested. ✓ No specific OT systems mentioned but critical systems are mentioned as included.
	Backup/Restore	✓ Corporate Emergency Response Organization (ERO) manages high-impact events. OT-specific RTOs/RPOs for SCADA, substations, and field telecom not provided ✓ Recovery activities are communicated to internal stakeholders and executive leadership. ✗ OT backup architecture, isolation, restoration practices are not described.
	Post-Incident Review	✓ Ongoing maintenance and updating of plans and policies. ✗ No specific mention of performing post incident reviews or requiring them.

Summary

Our review of the DPL content that was provided highlights a mature Cybersecurity governance program. Although our team could not evaluate the compliance program, based on the content provided it was clear that regulatory as well as industry best practices (specifically NERC CIP and NIST CSF) were being pursued. DPL inherits a great deal of its program from Exelon's practices therefore it shows a repeatable and scalable program that exists across the multi company and multi practice enterprise.

With limited information about the tooling of the system for compliance with the stated plans and the details regarding how these are achieved, the effectiveness of these policies could not be validated.

Our team did find a particular strength in the stated information regarding clear integration between the cybersecurity governance with internal business functions such as Human Resources. Indications of direct involvement of operational departments were harder to understand and gain insights into based on the context provided.

This analysis does show that DPL has a wide coverage of the capabilities required to have a robust cybersecurity program. Although there may be gaps, there are sufficient practices and clear staff and institutional knowledge to support a pivotable organization to embrace further digitalization.

5.5. Cybersecurity Overview: DEC

This section is based solely on the written responses provided on November 19, 2025, in response to the information request.

Table 46. DEC's Key Findings

Domain	Topic	Findings (✓ = Observed, × = Not observed from documents provided)
Identify & Assess	OT/ICS Cybersecurity Policy	✓ DEC operates with an overarching cybersecurity policy that explicitly covers both IT and OT environments which includes defined roles and responsibilities for governance. ✓ Policies and procedures undergo frequent review.
	Asset Management	✓ Asset management, including OT assets, is covered by policy. × Operational details of how inventories are maintained, validated, and updated are not described.
	Risk Management	✓ Risk management is inferred to be elevated to board-level oversight, with an enterprise risk register and a stated hybrid risk methodology. Details on scoring methodology, review cadence, risk ownership, or explicit mapping of risks to critical OT assets and zones where not provided. ✓ OT-specific risks (e.g., availability and integrity of SCADA and OT networks) are recognized and reportedly integrated into the broader enterprise risk register.
	Supply Chain Management	✓ Clear processes that control the access and vetting of Suppliers and Vendors. ✓ Implemented several controls to monitor and mitigate risk related to supply chain. × Unclear practices for vetting equipment but references made to clear guidelines and integrated terms and conditions.

Domain	Topic	Findings (✓ = Observed, ✗ = Not observed from documents provided)
	Business continuity	✓ Has implemented a policy that includes backup and restore topics, cadences, and testing requirements ✓ Includes resiliency specific to backups and ransomware to mitigate gaps that are more frequent. ✓ Shows strong understanding of business continuity processes. ✗ Specific alignment between backups and OT system criticality (e.g., recovery point objectives for SCADA, substations, and field devices) is not documented in the response.
Protect	Access Control & Privileged Access	✓ Access control is governed by an overarching cybersecurity policy that includes authentication, password requirements, RBAC, least privilege, and a dedicated remote access policy. ✓ RBAC and least privilege are mentioned. ✗ There is no detail on periodic access recertification, segregation of duties, or how privileged access to OT systems is governed and reviewed.
	OT Segmentation	✓ Network architecture, segmentation, and site-specific documentation are maintained but are treated as confidential. ✓ DEC enforces network segmentation between IT and OT networks using maintained and configured firewalls, and relies on private, non-internet-accessible fiber and cellular tunnels for OT communications. ✓ Unclear how they are governed (i.e. ownership, version control) and integration into risk and change management processes are not described.
	Device and System Hardening	✓ System hardening is based on standard images and leading practices, including non-default passwords, restricted administrative access, and vendor-recommended security settings. ✗ No indication of regular baseline compliance checks in the OT environment. ✗ There is no mention of an OT-specific change management policy.
	Personnel Screening	✓ Processes and policy are embedded into the overarching cybersecurity program.

Domain	Topic	Findings (✓ = Observed, ✗ = Not observed from documents provided)
		✓ Differentiates between site access, visitors, vendors, and employee processes. ✓ Includes integration with Human Resources, Technology and Security personnel to facilitate the offboarding of individuals.
	Awareness and Training	✗ No specific mention of training and awareness but inferable that it could exist based on robust access control procedures.
	Vulnerability Management	✓ Patch and vulnerability management is driven by a risk-based approach that considers business impact and likelihood, with scanning occurring at least monthly. ✓ Patch management timelines and exception handling for sensitive OT systems (e.g., those requiring vendor validation or maintenance outages) are not described.
Detect	Security Monitoring & Logging	✓ Active and passive internal and external vulnerability scanning is performed, complemented by vendor notifications, SOC briefings, information sharing centers, and public sources such as CVE notices and bulletins. ✓ The OT environment uses commercial off the shelf and open-source logging solutions as well as proprietary vendor-based OT logging, suggesting multiple sources across IT and OT. ✓ Remote access logs and audit trails are maintained for one year, and third-party monitoring services are used for remote access sessions. ✗ The response does not show how logs or alerts from implemented solutions are triaged or correlated.
	Anomaly & Event Triage	✓ DEC utilizes a leading antivirus/endpoint detection and response (EDR) solution with immutable logging retained by a third party for one year. ✗ No specific mention of playbooks or escalation plan for event triage.
	Continuous Compliance and Framework	✓ Regular conducting of penetration tests, internal, and external based compliance checks is in place. ✓ Audit records are maintained and reviewed for continuous improvement.

Domain	Topic	Findings (✓ = Observed, × = Not observed from documents provided)
		× No mention of automation or framework tooling for reviews.
	OT Network Monitoring	✓ Stated use of tooling to monitor the internal networks with an Intrusion Detection System. × No mention of coverage of the solution, integration with OT protocols, or policy procedures for utilizing it.
Respond	OT/ICS Specific Incident Response	✓ DEC has a written cybersecurity incident plan that covers identification, protection, detection, response, and recovery across technology areas. × The level of OT specificity within the incident response plan is not described; it is unclear whether there are playbooks for SCADA, substations, field devices, or telecom-related incidents. × Testing and exercising of the incident response plan (e.g., tabletop exercises, simulations involving OT systems) are not mentioned.
	Communications	✓ A crisis communication plan exists for major adverse cybersecurity incidents, including coordination with internal and external parties. ✓ Covers internal and external stakeholder support and contacts.
	Forensics/Evidence Handling	× No specific mention of evidence collection tooling, techniques and retention.
	Vendor and OEM Support	✓ Contractual obligations and wording are in place with key vendors. ✓ SLAs are established for responses related to Cybersecurity incidents. ✓ Mentioned that these are reviewed on an annual basis.
Recover	Disaster Recover & Service Restoration	✓ Contained in the broader business continuity policy and procedure. × No specifics on implementation were provided.
	Backup/Restore	✓ DEC's business continuity and disaster recovery (BCDR) policy covers backup frequency, storage, and annual recovery testing, with emphasis on business impact and criticality. × Explicit recovery objectives (RPO/RTO) for OT systems such as SCADA, DERMS, OMS, or substations, make it difficult to assess OT recovery readiness.

Domain	Topic	Findings (✓ = Observed, ✗ = Not observed from documents provided)
	Post-Incident Review	✗ There is no detail on how incident lessons learned are captured and fed back into risk management, engineering standards, or OT security controls.

Summary

DEC demonstrates a strong cybersecurity governance program, supported by comprehensive policy frameworks. The majority of DEC's investment is evidently directed towards the development and maintenance of policies and procedures, which provide a foundation for protections across all required domains. Although the details regarding cybersecurity tooling are limited, it can be inferred that DEC possesses a clear understanding of the necessary tools and the distribution of these tools across its operational domains. However, based on the information available, it is not possible to confirm the existence or absence of gaps in their tooling.
With respect to compliance, as outlined in the methodology, the information provided was insufficient to assess DEC's compliance readiness or performance.

The assessment team reviewed the information supplied and was generally satisfied with the overall content. Minor deficiencies were observed in each area, primarily relating to the inability to assess certain topics due to a lack of specific information. The absence of details does not allow the team to assert whether these topics are addressed; only that they were not included in the documentation provided.

Within the context of the information reviewed, DEC is considered to have a substantial cybersecurity program. The program appears to be managed by experienced professionals who utilize industry-leading practices and frameworks selected for their effectiveness.

5.6. Cybersecurity: Key Insights

From the review of the content provided the assessment team was able to determine:

- Both EDCs have a defined and coordinated cybersecurity governance program.
- Several policies and procedures are defined to meet operational and compliance requirements.
- Programs point to industry standards and frameworks showing inclusion of additional cybersecurity controls beyond those required by regulators.
- Defined processes support the onboarding of new technologies.

Both EDCs, DPL and DEC, have developed mature and multi-layered cybersecurity programs that are closely aligned with recognized industry standards, such as NIST CSF and NERC CIP. These programs are underpinned by comprehensive documentation outlining their cybersecurity policies and governance structures.

The EDCs refer to maintaining robust technical controls and procedures designed to safeguard the safe and reliable operation of their assets. Regular assessments and ongoing testing of these controls are stated by each entity for continued compliance with relevant standards and to strengthen system resilience against potential threats.

Documentation provided by participating EDCs point to an understanding and implementation of controls and protections with a focus on or inclusion of the OT and IT environment, showing a deeper understanding of the attack surface of their organizations by internal staff and stakeholders.

Due to the limited data provided during this assessment, there are certain items that cannot be fully evaluated. These items are classified as unverified, and it is possible that each EDC already has established policies and procedures addressing them.

The recommendations presented are based on the scope of this assessment. They recognize that the EDCs are positioned to manage future cybersecurity risks. State regulators and other stakeholders can support them through the evolution of the Delaware grid by considering these recommendations as strategic items for enhancing their existing programs.

Recommendations

The assessment team has developed the list of recommendations below based on the current state of cyber-physical controls for the consideration of adoption by the EDCs and other stakeholders.

Table 47. Cybersecurity Recommendations

ID	Recommendation
1	Establish a state sponsored working group for Cybersecurity: Leveraging the professionals within the EDCs and external experts. Consider creating a working group that complements the existing DNREC groups. The aim would be to support each EDCs ongoing commitment to Cybersecurity in addition to increasing stakeholder visibility to the cyber programs of the EDCs.
2	Support alignment to a comprehensive CSF: Currently the EDCs adopt frameworks based on internal decisions. This is critical for protecting and detecting risks beyond those covered by regulatory frameworks. Stakeholders should encourage the adoption of control sets across the state such as NIST or International Electrotechnical Commission (IEC) 62443 by EDCs, ideally in alignment with each other and allowing for collaboration.
3	Provide support for cyber control development and implementation for Grid Enhancement Projects: As part of the project put forward as solutions for grid enhancement include stipulations that cyber risk and plans should be considered/submitted with the proposal. This will facilitate a safe and resilient implementation

ID	Recommendation
4	Encourage/facilitate threat intelligence sharing between EDCs: Support the use of sharing services such as the E-ISAC of cyber threat information. Additionally, promoting that information shared via this portal could be shared locally with each EDC to provide a more localized and rapid response to threats.
5	Include cyber risk assessments in grid status reporting: Develop and implement high-level reporting that leverages existing reporting to regulators or other entities to include the risks associated with cyber in reporting to stakeholders such as the legislature. This is to capture a more holistic view of the implications of risk to Delawares Grid.

6. Gap Analysis

The objective of this section is to present the results of the gap analysis conducted for the three Delaware EDCs. The gap analysis evaluates current state “as-is” and future state “desired” maturity across a defined set of business functions and operational capabilities that are critical to distribution system performance, resilience, and readiness for increasing electrification and DERs. The analysis is structured using a standardized capability-based framework that enables consistent assessment across utilities with differing system characteristics and organizational structures. Capabilities are assessed qualitatively across defined maturity levels and quantitatively through associated initiatives and enabling technologies, providing a transparent basis for identifying gaps and prioritizing improvement actions.

The gap analysis focuses on three core business functions that are central to distribution system planning, operations, and coordination. These business functions were selected based on project scope and relevance to Delaware policy objectives and stakeholder priorities. Within the three business functions, a total of fourteen distinct operational capabilities were assessed. Each capability represents a specific, well-defined aspect of utility operational or planning performance. Together, these capabilities provide a comprehensive view of the EDCs’ readiness to meet current operational requirements and future system needs.

Table 48. Gap Analysis Scope

Business Function	Asset and Work Management	Energy Supply Coordination	Grid Planning and Operations
Description	This business function encompasses the processes and capabilities required to manage distribution assets throughout their lifecycle, from data stewardship and system modeling to asset strategy development, planning, execution, and performance monitoring. Effective operations and asset management supports reliable service, informed investment decisions, and efficient use of utility resources.	This business function addresses coordination between the distribution system and customer-side energy resources, including demand-side management programs for residential, commercial, and industrial customers. These capabilities are increasingly important as DERs and flexible load programs play a larger role in supporting system reliability, peak management, and decarbonization objectives.	This business function includes the operational and planning capabilities required to maintain system reliability and power quality under normal and adverse conditions. It covers outage management, congestion management, voltage and power quality regulation, technical loss reduction, and coordination of planned outages. These capabilities are foundational to grid resilience and customer service performance.
Capabilities Evaluated	• Oversee Network Data • Operate Network Model • Coordinate Asset Management Strategy • Coordinate Annual Asset Workplan • Oversee Workplan Execution • Conduct Key Performance Indicator (KPI) Projections • Coordinate Distribution Network Planning	• Coordinate Distributed Residential Demand Side Management • Coordinate C&I Demand Side Management	• Regulate Unplanned Outages • Regulate Network Congestion • Regulate Power Quality • Regulate Technical Losses • Oversee Planned Outages

Each capability is assessed across six maturity levels, ranging from Level 0 to Level 5, where Level 0 represents the most basic or ad hoc practices and Level 5 represents the most advanced, integrated, and optimized state of capability maturity. Maturity levels reflect progression across dimensions such as process consistency, analytical sophistication, technology enablement, coordination across functions, and use of performance metrics. During structured workshops, each EDC evaluated its current state by indicating whether specific capability attributes were fully in place, partially implemented, or not yet implemented. Desired future maturity levels were identified based on stated aspirations, policy drivers, and stakeholder inputs. The gap for each capability is defined as the difference between current and desired maturity levels.

Identified capability gaps are linked to a set of defined initiatives that support progression from one maturity level to the next. Each initiative is associated with enabling technologies and non-technology actions, allowing gaps to be translated into actionable and sequenced improvement steps. This structure ensures that the gap analysis directly informs prioritization and roadmap development, rather than serving only as a diagnostic exercise.

Subsequent portions of this section present a detailed gap analysis for each business function and capability. The assessment evaluates current practices against state policy objectives established under HJR3 and stakeholder priorities identified through statewide engagement. Findings have been aggregated and anonymized consistent with the pledge made to workshop participants to encourage forthright participation in the process of information exchange.

6.1. Asset and Work Management

This section presents a detailed gap analysis of Asset and Work Management capabilities across the EDCs as expressed in the three workshops.

Current State

Across all EDCs, foundational asset and work management practices are well established and have historically supported reliable day-to-day operations. Each utility maintains inventories of core distribution assets, manages work orders using electronic systems, and tracks performance indicators primarily related to reliability, safety, and execution efficiency. Network models exist (or are being implemented) in electronic formats and are routinely used to support engineering studies, outage analysis, and selected planning activities.

However, the benchmarking results show clear variation across EDCs in both the maturity and the consistency of these practices as shown in Figure 30.

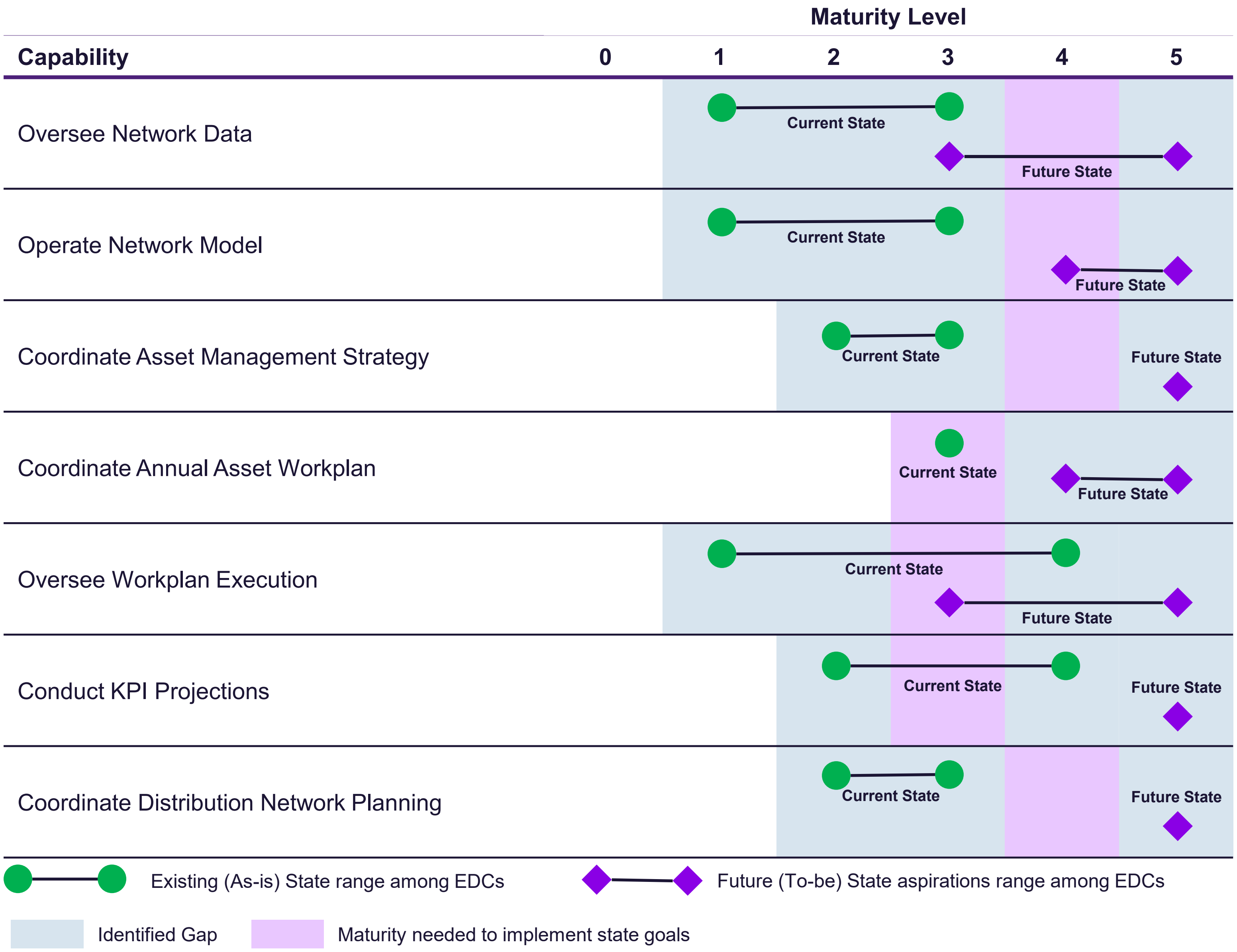


Figure 30. Gap Analysis - Asset and Work Management Functions

While one EDC has made progress toward integrated asset data management and advanced analytics, others retain simpler, scale-appropriate approaches that rely more heavily on institutional knowledge and localized processes. This is typical across EDCs, where legacy architectures, budget constraints, and differing modernization roadmaps lead to varying levels of system integration. As a result, asset, network model, work management, and performance reporting systems often remain siloed by function.

Asset data collected by EDCs is typically sufficient to identify asset location, size, and basic attributes, but information such as age, condition, manufacturer, and health indicators is not consistently standardized or integrated across departments. As a result, cross-functional access to asset information often depends on informal coordination rather than automated data flows. Network models are generally updated periodically rather than continuously.

Key performance indicators are defined and monitored across all EDCs, with a strong emphasis on traditional reliability metrics such as SAIDI and SAIFI. Some EDCs have expanded KPI reporting through business intelligence platforms, but current KPI frameworks remain largely asset- or program-centric. As reflected in Figure 30, KPIs are not consistently aggregated using network topology as the primary organizing structure, which limits visibility into system utilization, constraint management, and interactions across assets and grid segments.

Annual asset work planning processes at each EDC are generally driven by historical practices, asset class-based budgeting, and observed reliability performance. Event-driven adjustments occur following major outages or asset failures, but systematic integration of asset health, criticality, and system context into workplan prioritization is limited. Workplan execution processes are generally efficient and well understood by field personnel; however, feedback loops between execution outcomes and asset strategy or planning remain weak.

KPI forecasting and scenario analysis capabilities vary by EDC. Some utilities perform basic projections or what-if analyses for selected metrics, but forecasting is typically limited in scope and not systematically linked across KPIs or connected directly to network planning decisions. Overall, the current state reflects a set of functional but largely static practices designed around historical reliability needs rather than forward-looking system optimization.

Future State

State target maturity levels for capabilities related to Asset and Work Management are driven primarily by the intent expressed in the SEP and HJR3 and reinforced by stakeholder priorities emphasizing efficiency, resilience, and cost-effective utilization of existing infrastructure.

For the EDC functional capabilities Oversee Network Data and Operate Network Model, the state goal should be for each EDC to attain maturity Level 4. HJR3 calls for the deployment of grid-enhancing technologies such as DLRs, dynamic transformer ratings (DTRs), and topology optimization where cost effective and feasible “considering each utility’s operational standards and cycles”. These functions are not feasible without consistent asset data management across organizational boundaries and network models that reflect true electrical connectivity, including customer and DER connectivity.

For the EDC functional capabilities under the categories Coordinate Asset Management Strategy, Coordinate Annual Asset Workplan, and Conduct KPI Projections, the state goal should be maturity Level 3. This level enables risk-informed and reliability-centered decision-making using asset health and criticality indicators, event-driven workplan adjustments, and scenario-based KPI analysis. These capabilities represent the minimum required to evaluate grid-enhancing technologies, assess NWAs, and perform credible cost-benefit analysis consistent with HJR3 requirements.

The future state envisions asset and network data managed consistently across departments, with grid topology serving as the primary aggregation hierarchy for analytics and reporting. KPIs expanded beyond asset performance to include system-level indicators such as utilization, headroom, and constraint frequency. Asset strategies are informed by both reliability and system risk, and workplans dynamically reflect asset condition, system context, and emerging grid needs.

Identified Gaps

The principal gap in the Asset and Work Management function is not the absence of basic processes or tools, but rather the lack of integration and analytical depth required to manage the distribution system as an interconnected network. While each EDC demonstrates competent execution within their current operating models, existing practices do not yet provide the analytical foundation required to support dynamic ratings, topology optimization, NWAs, or large-scale DER integration.

Specific gaps identified through the workshops and benchmarking include:

1. **Fragmented asset and network data architectures**: The current state prevents consistent, enterprise-wide visibility into asset attributes, condition, and system context. Asset data exists across multiple systems with differing standards and update cycles, limiting its direct usability for advanced analytics.
2. **Network models:** The current practice to update models periodically rather than continuously and not consistently incorporate customer connectivity, DER interconnections, or switching chronology constrains the ability to perform topology-aware analysis and limits confidence in studies supporting dynamic ratings or NWAs.
3. **KPI frameworks**: A focus primarily on asset classes or individual programs rather than system behavior is functionally limiting. The absence of topology-driven aggregation limits the ability to track utilization, constraint frequency, and downstream effects of DER growth, electrification, or demand-side programs.
4. **Asset management strategies:** Siloed approaches to operations are reliability-centered in selected areas but not yet systematically risk-informed at the system level. Health and criticality indicators are not consistently combined with network context to prioritize investments or maintenance actions.
5. **KPI projections and scenario analyses:** Planning functions are limited in scope and not tightly coupled to network models or planning processes, reducing their effectiveness in evaluating future operating conditions, investment deferral opportunities, or policy-driven outcomes.

Addressing these deficiencies is a prerequisite for implementing dynamic technology ratings, topology optimization, and credible NWAs, and therefore represents a foundational step in achieving Delaware's grid modernization objectives.

6.2. Energy Supply Coordination

This section presents the gap analysis results for capabilities related to the Energy Supply Coordination function across Delaware's EDCs. The assessment focuses on the ability of the EDCs to coordinate demand-side resources, including residential and C&I programs, as active system resources in support of reliability, peak management, resilience, and policy objectives under the SEP and HJR3.

Current State

Across all EDCs, Energy Supply Coordination capabilities are present in the form of established demand-side management (DSM) and demand response programs; however, these capabilities are largely program-based and operationally decoupled from the distribution system. Energy supply coordination today is oriented toward meeting aggregate peak reduction, supporting wholesale market participation, or delivering customer program benefits, rather than addressing localized distribution system needs.

As shown in Figure 31, benchmarking results show that all EDCs fall within Level 1 to Level 2 maturity for residential and C&I DSM. At these levels, utilities maintain transparency on load types, customer classes, and estimated flexibility at an aggregate level, and in some cases can measure customer response following events. However, DSM is not managed as a grid-integrated operational resource.

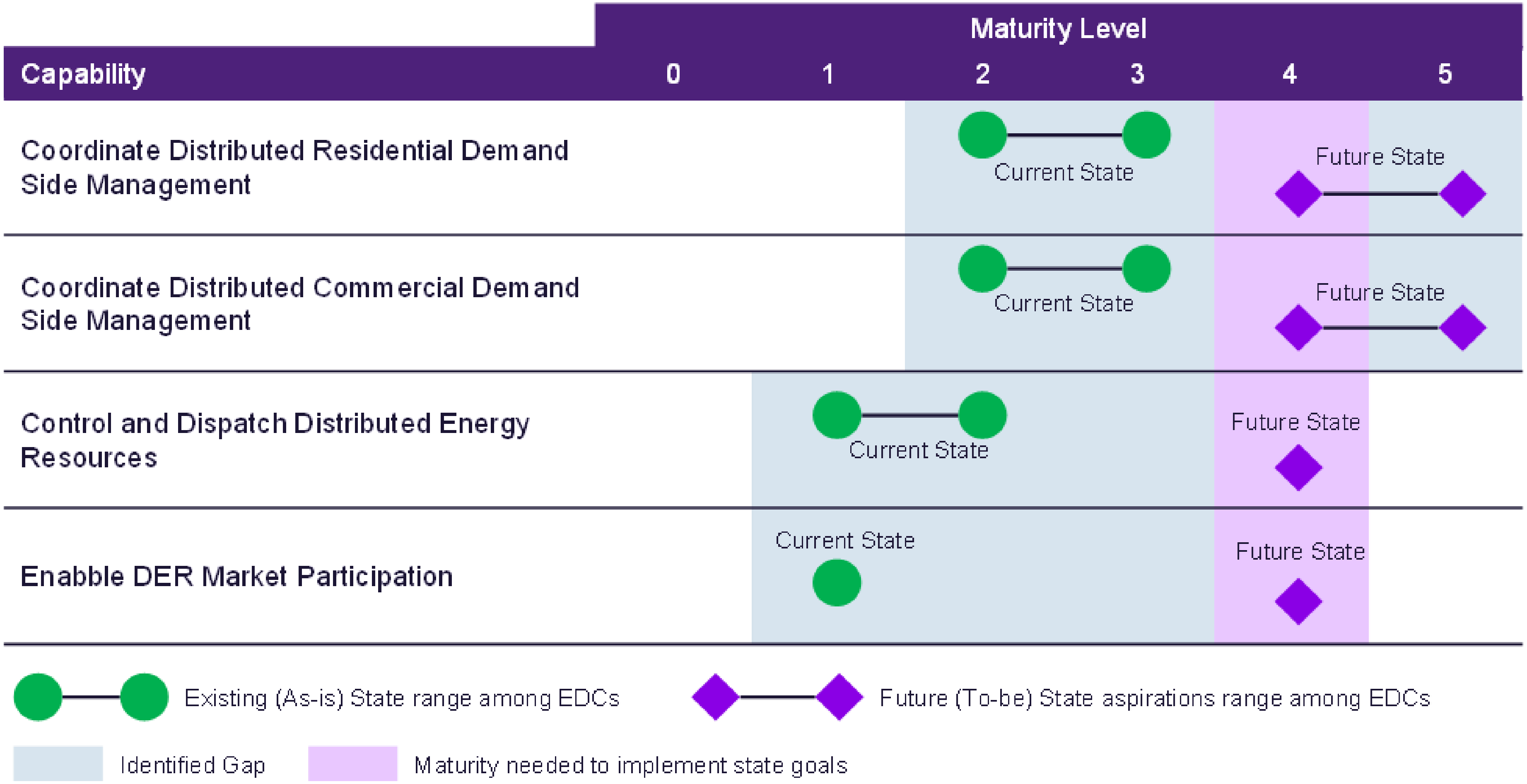


Figure 31. Gap Analysis - Energy Supply Coordination

Workshop discussions confirmed that residential DSM programs are predominantly voluntary and event-driven, with limited ability to target specific feeders, grid segments, or time-varying distribution constraints. Where enabling technologies such as basic load control exist, they are deployed statically and are not dynamically adjusted based on changing system conditions. Real-time or near-real-time visibility into residential DSM response is generally limited to post-event measurement rather than continuous monitoring. As a result, operators lack confidence in using residential DSM as an actionable system resource outside of narrowly defined peak events.

C&I DSM programs are comparatively more developed but remain indirectly coordinated. Large customers may participate in curtailable load or interruptible programs, often triggered by market price signals or advance notifications. Control and dispatch are frequently mediated through aggregators or third-party platforms, reducing direct operational visibility and limiting alignment with distribution system conditions. As reflected in the benchmarking results, C&I DSM is not routinely dispatched in response to localized congestion or feeder-specific constraints, and its impacts are not systematically reflected in distribution planning assumptions.

Across all EDCs, DSM resource information is not tightly integrated with network models. Customer connectivity and DER representation within the distribution model are incomplete, and DSM-enabled loads are not consistently mapped to specific grid nodes or segments. Connectivity relationships between customers, network elements, and grid-edge resources are not uniformly embedded in core planning or operational models. This limits the ability to associate DSM response with actual system relief or to evaluate its effectiveness as a non-wires alternative.

Coordination between DSM programs and other utility functions remains limited. Program design, enrollment, and performance tracking are typically managed within customer or regulatory groups, while distribution planning and operations rely on static load forecasts and traditional reinforcement strategies. As a result, DSM is treated as an input assumption rather than a controllable system lever.

Utilities indicated during workshops that budgeting and prioritization for DSM are generally separate from grid investment planning, with limited mechanisms to shift spending or program focus based on emerging distribution system needs. Measurement and verification practices exist but vary by program and are not standardized to support feeder-level or system-level planning use cases. KPI tracking for DSM focuses on participation rates, nominal peak reductions, or program costs, rather than on locational value or avoided infrastructure investment.

Collectively, the current state reflects a set of functionally capable but structurally siloed practices. DSM programs deliver value within their intended scope, but they lack the integration, visibility, and control needed to support grid-level coordination, non-wires alternatives, or the advanced energy supply coordination objectives outlined under HJR3.

Across all EDCs, DER control capabilities remain limited and largely non-operational. Current capabilities are generally confined to interconnection-based registries, basic DER forecasting, limited system-wide signaling, and post-event measurement. However, these capabilities remain program-driven and are not aligned with real-time system conditions, and meaningful control or dispatch capability is not yet in place.

Common limitations across all EDCs include the absence of real-time monitoring, lack of a centralized coordination platform, and limited integration of DERs with network topology or operational workflows. As a result, DERs are not currently used as dispatchable resources for system operations.

DER market participation capabilities remain at an early stage, with EDCs primarily focused on establishing DER registration and basic aggregation frameworks. While initial data collection and coordination processes exist, utilities lack the telemetry, standardized data exchange, and operational coordination required to support active participation of DER aggregations in wholesale markets. As a result, DER participation is limited to preliminary enablement activities and is not yet integrated with distribution system operations or constraints.

Future State

State policy establishes clear expectations for expanded and more integrated use of demand-side resources. The SEP and HJR3 explicitly call for the evaluation of opportunities to deploy demand response programs, including bidirectional resources such as V2G, vehicle-to-home, and customer-sited battery energy storage systems. Stakeholder survey results reinforce these directives, with respondents emphasizing EDCs' prioritization of peak management, affordability, equity, and integration of renewable resources.

To fulfill the intent of these state policies and stakeholder priorities, the state target maturity for both residential and C&I DSM is Level 4. At this level, DSM resources would be configured, scheduled, and dispatched to support:

- Local and system-wide peak reduction
- Integration of high volumes of renewable DER
- NWAs to traditional distribution investments
- Improved system resilience and operational flexibility.

Achieving this state requires DSM to function as a network-aware operational capability, not solely as a customer program or market participation tool. Dispatch decisions must be informed by network constraints, feeder-level conditions, and planning assumptions. DSM resources must be visible to, and actionable by, both operational and planning functions.

While higher levels of maturity could incorporate DSM into value-added services or advanced market participation, Level 4 represents the minimum maturity required to support current statutory and stakeholder-driven objectives.

For DER control, the state target should be Level 4, where DERs would be monitored in near real time and dispatched in a constraint-aware manner, integrated with congestion management, outage response, and operational decision-making. Achieving this state requires transitioning from program-based DER management to network-aware, operationally integrated control, supported by topology mapping, real-time visibility, and coordinated dispatch processes.

The state target for enabling VPP and DER market participation is Level 4, where DER participation is coordinated with distribution system conditions through real-time or near real-time telemetry, topology-aware integration, and constraint validation during market dispatch. This functionality is enabled by FERC Order 2222 and PJM's efforts towards crafting an implementation framework. Achieving this state requires utilities to support scalable data exchange, aggregator coordination, and operational processes that ensure alignment between wholesale market participation and distribution system reliability. In the future state, DER aggregations will be treated as active system resources, with their participation validated against network constraints and integrated into both planning and operational decision-making.

Identified Gap

The primary gap in Energy Supply Coordination is not the lack of DSM programs, but rather the limited ability to deploy DSM as a controllable, network-integrated system resource. Existing programs provide value in specific contexts but do not yet support the distribution-level functionality envisioned under HJR3.

Key gaps identified through workshops and benchmarking include:

1. **Fragmented control architectures:** Where control exists, it is often mediated through third parties or requires multiple systems and manual processes. This limits scalability, response speed, and operator confidence.
2. **Inconsistent measurement and verification:** Performance tracking varies across programs and EDCs, reducing confidence in DSM as a dependable planning and operational resource.
3. **Limited integration with distribution planning**: DSM impacts are not systematically incorporated into load forecasts, hosting capacity assessments, or non-wires alternative evaluations. Planning assumptions typically treat DSM as an exogenous or static adjustment rather than a dispatchable resource.
4. **Lack of network-aware dispatch capability:** DSM resources are not consistently mapped to feeder, substation, or grid-segment topology. As a result, dispatch actions cannot be reliably targeted to constrained or high-value locations on the distribution system.
5. **Limited readiness for bidirectional resources:** While pilots and concepts exist, current frameworks are not yet equipped to manage V2G, residential storage, or coordinated EV charging at scale with distribution system awareness.
6. **Lack of DER control and integration:** EDCs have limited capability to monitor, control, and dispatch DERs in a manner aligned with distribution system conditions. DER visibility is largely static, with no real-time monitoring or constraint-aware dispatch, and existing signaling approaches are not integrated with grid operations or topology, preventing DERs from being used as reliable operational resources.
7. **Groundwork for Market Participation:** EDCs have limited capability to enable DER participation in wholesale markets in a distribution-aware manner. While basic DER registration and aggregation frameworks are emerging, data exchange, telemetry, and coordination with aggregators remain insufficient to ensure that market dispatch is aligned with distribution system constraints and operational requirements.

Collectively, these gaps constrain the EDCs' ability to use DSM as a substitute or complement to traditional infrastructure investments. Without stronger integration across planning, operations, and DSM program management, demand-side resources cannot reliably support congestion management, peak reduction, or NWAs. Addressing these gaps is therefore essential to achieving the Energy Supply Coordination objectives articulated in Delaware state policy.

6.3. Grid Planning and Operations

This section presents the gap analysis results for Grid Planning and Operations capabilities across the EDCs. The assessment focuses on operational and planning capabilities that directly affect reliability, resilience, system efficiency, and readiness for increasing DER adoption.

Current State

Across all EDCs, core grid operations are executed effectively for historical operating conditions. All utilities have established processes for outage response, switching, and system monitoring, supported by a mix of SCADA, feeder devices, and metering systems. However, as shown in Figure 32, benchmarking results show clear differences in operational maturity across the EDCs, driven in part by system size, topology, and technology adoption.

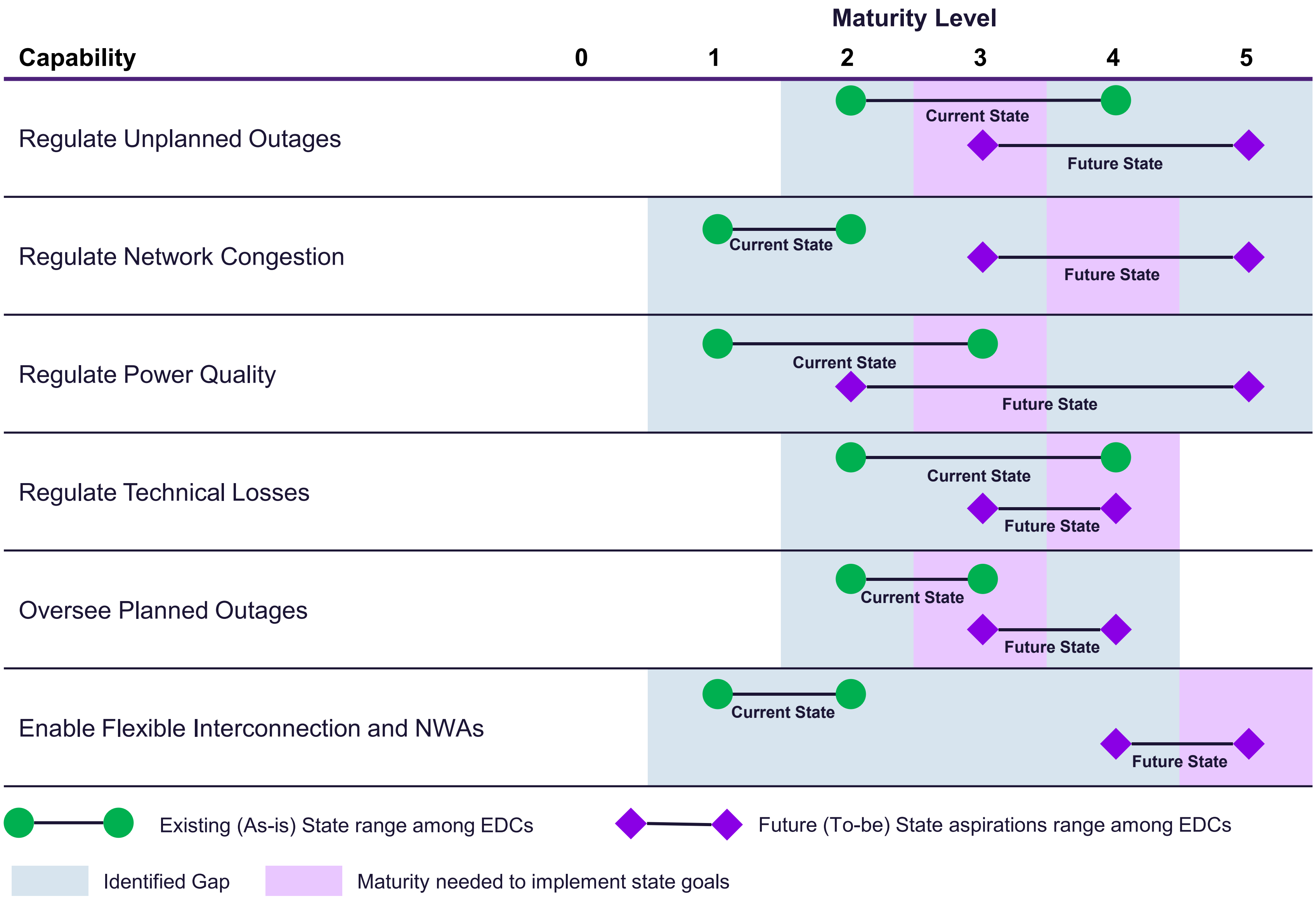


Figure 32. Gap Analysis - Grid Planning and Operations

For regulating unplanned outages, current outage detection and restoration practices are functional but vary in maturity, with capabilities ranging from broader use of distribution automation, smart meter last-gasp signals, and feeder devices to more limited automation and greater reliance on customer calls and manual processes. While some EDCs have technologies in place that support faster outage identification and reduce restoration times, self-healing capability and automatic reconfiguration are not yet established. In less automated environments, outage detection remains constrained by feeder automation coverage, AMI data quality, and system scale.

For regulating network congestion, current practice is primarily procedural and not automated. EDCs can identify loading concerns and apply remedial actions through operator intervention, including operational alerts and switching actions, but these responses are not dynamically optimized and generally require manual coordination. Situational awareness may be strong at an aggregate level, but the absence of centralized DERMS capability, fragmented system environments, and limited dispatchable DER on the distribution system constrain the ability to manage congestion in a coordinated, real-time manner.

For regulating power quality, current practices are generally reactive or localized rather than continuously monitored and topology-mapped. EDCs may have the ability to observe voltage conditions through metering platforms and investigate issues when complaints arise, often using temporary recorders and offline analysis. However, broader telemetry remains limited outside of substation-level devices, and monitoring for issues such as flicker or other localized disturbances is not consistently implemented.

For regulating technical losses, although losses can often be assessed using engineering tools, the process is typically manual and not embedded in routine operational optimization. Automated switching or active control to reduce losses is generally not in place, and in some cases technical losses are not treated as a significant priority given overall system size and characteristics.

For overseeing planned outages, coordination is generally managed through manual processes, with limited use of simulation or topology-based optimization to minimize customer impacts. Existing modeling tools may provide some support, but more advanced capabilities depend on future improvements in AMI, operational data, and broader platform integration. In some operating environments, system design and local practices reduce the immediate need for advanced outage optimization, which in turn lowers the priority of more sophisticated planning tools.nnOverall, the current state reflects competent operational execution but limited automation, limited topology-mapped analytics, and limited integration of DER or flexible load as operational resources.

Future State

State goals for Grid Planning and Operations are driven by HJR3 and SEP objectives emphasizing safety, resilience, reliability, system efficiency, and the ability to integrate and manage distributed resources. The maturity targets for this business function need capabilities beyond manual and reactive approaches.

The Navigator maturity definitions used in this assessment specify that progression requires increasingly automated detection, decision support, and execution, supported by appropriate field device coverage.

Table 49. To-be Capability Maturity

Capability	State Maturity Goals	Description
Regulate Unplanned Outages	3	The utility uses online data from feeder automation and smart meters to identify outages and executes fault isolation and restoration actions in an automated manner supported by self-healing network elements.
Regulate Network Congestion	4	Congestion management includes automatic initiation of dynamically determined remedial actions and includes DER control as part of the remedial action set.
Regulate Power Quality	3	Power quality is measured online at sufficient network points and power quality issues are automatically mapped to network topology to support systematic identification and remediation.
Regulate Technical Losses	4	Closed-loop automated analysis and control of field devices is used to optimize energy delivery, including automated determination and execution of switching schedules.
Oversee Planned Outages	3	Alternative network configurations are simulated prior to execution to determine switching schedules that minimize customer impact, leveraging real-time connectivity data where available.

These targets reflect minimum capabilities needed to support the operational requirements implied by HJR3, including improved resilience performance, integration of smart inverter settings and DER behavior, and improved utilization of existing infrastructure through more active operational management. Benchmarking results summarize the gap between current maturity and these state goals across the EDCs.

Identified Gaps

The principal gap in Grid Planning and Operations is the limited ability to execute operations in a proactive, topology-aware, and increasingly automated manner, especially under conditions that require coordination of field devices, AMI data, and distributed resources. Current practices remain largely manual or rule-based, and integration of DER and flexible load into operational control is limited.

Specific gaps identified through workshops and benchmarking include:

1. **Outage detection and restoration automation:** While some EDCs use feeder devices and AMI signals to support outage identification, self-healing concepts and automated service restoration at the level implied by the maturity target are not consistently in place. In at least one case, outage detection still relies heavily on customer calls and AMI data quality limitations reduce operational usability.
2. **Congestion management:** This capability is not automated and is weakly integrated with DER control. One EDC described manual remedial actions and operational alerts, while another described strong situational awareness but highlighted the absence of a centralized DERMS and limited dispatchable DER capability on the Delaware distribution system. This limits progression toward the state goal that requires dynamically determined remedial actions that can include DER control.
3. **Power quality monitoring:** Across the EDCs, power quality investigations are often complaint-driven and conducted using temporary recorders or offline analysis. Where voltage monitoring exists through AMI, it is not consistently paired with automated topology mapping of issues as required by the target maturity.
4. **Technical loss reduction:** Loss evaluation is commonly performed through engineering tools or ad hoc analysis, but automated switching schedules and closed-loop control are not described as current operational practice. In some cases, losses are not treated as a priority area given system scale, which creates a structural barrier to achieving the state goal where topology optimization and automated control are prerequisites.
5. **Planned outage optimization:** The process is predominantly manual and not consistently supported by simulation of alternative configurations. Planned outages are commonly scheduled and executed through established operating practices, but systematic simulation of switching plans to minimize customer impacts is not consistently embedded.
6. **Cross-capability dependencies:** Several state goals for Grid Planning and Operations depend on enabling capabilities in data integration, network modeling, and DER coordination. For example, the congestion management target explicitly assumes the ability to issue and validate DER control actions, while power quality and planned outage targets assume topology-aware analytics. Where these enabling foundations are limited, Grid Planning and Operations improvements cannot be achieved through operational changes alone.

Collectively, these gaps limit the EDCs' ability to move from competent, historically sufficient operations toward the operational maturity needed to support HJR3 outcomes, including improved resilience, more efficient utilization of the distribution system, and increasing DER adoption.

7. Program Roadmap

This section translates the capability gaps identified in the preceding section into a structured set of programs and a phased implementation roadmap.

Facilitated by the Navigator framework, the gap analysis establishes the difference between current and target capability maturity levels across key business functions, and links these gaps to a defined set of initiatives. In this we use the diagnostic assessment from the previous section to define a clear, implementable pathway for closing these gaps in a coordinated and practical way.

The roadmap provides a structured pathway to bridge:

- capability gaps
- initiatives mapped to maturity progression
- enabling technologies and operational changes.

This ensures that the recommendations are not isolated improvements, but a comprehensive and sequenced transformation program aligned with policy objectives.

This roadmap is intended as a high-level guideline that EDCs could use in guiding progression across capability maturity levels. Individual EDCs may have already made substantial progress toward specific initiatives or programs. Accordingly, EDCs should adapt the program structure and sequencing to reflect their existing capabilities, priorities, and operating context.

7.1. Program Design

Programs have been developed as aggregations of related initiatives that collectively address multiple gaps while enabling progression across capability maturity levels.

The Navigator framework identified a range of initiatives to address maturity gaps. These were organized into eleven distinct programs. Rather than organizing initiatives individually, this program-based structure reflects how utilities plan and execute transformation in practice, where investments in systems, processes, and organizational change occur in coordinated bundles.

Each program is therefore designed to address four core dimensions:

- **Capability gaps:** Programs directly target the deficiencies identified across three business functions i.e. Asset and Work Management, Energy Supply Coordination, and Grid Planning and Operations.

- **Maturity progression:** Initiatives within each program are arranged to support progression from lower to higher maturity levels within each capability.
- **Technology dependencies:** Programs include grouped initiatives that rely on common enabling technologies such as network models, integration platforms, DER systems, and analytical tools.
- **Benefit and effort prioritization:** Programs reflect prioritization outcomes derived from the Navigator framework, where initiatives are evaluated based on quantified benefit and implementation effort.

This integrated design ensures that each program delivers both incremental improvements and foundational capabilities required for subsequent stages of transformation.

7.2. Program Sequencing

The sequencing of programs follows a structured and internally consistent logic derived from the Navigator prioritization methodology.

First, capability maturity progression is enforced explicitly. Lower maturity-level capabilities are implemented before higher maturity-level capabilities within the same domain, even where higher-level initiatives may appear lower in effort. This ensures that progression is technically feasible and avoids implementation inefficiencies caused by missing prerequisites.

Second, technology dependencies are respected across programs. Foundational systems such as asset and network data integration, communication infrastructure, and system modeling platforms etc. are established early; as these form prerequisites for advanced capabilities such as DER dispatch, dynamic ratings, and automated operations.

Third, program complexity increases progressively over time. Early programs focus on data, visibility, and process standardization. Middle-stage programs introduce analytical capabilities and system integration. Later programs enable automation, optimization, and market participation.

This sequencing approach ensures that each stage of the roadmap builds logically on preceding investments, minimizing rework and ensuring that each new capability can be effectively utilized.

7.3. Roadmap Overview

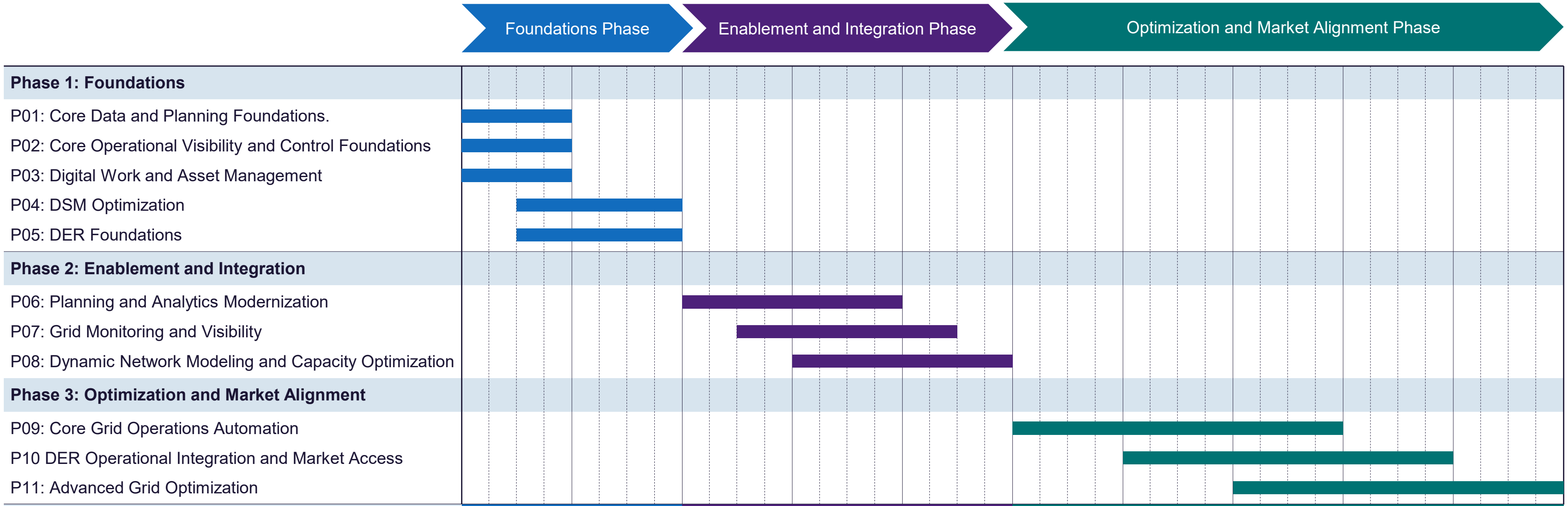
The roadmap is structured into three Phases that reflect increasing levels of system maturity and operational sophistication. The roadmap phases are intentionally not defined by fixed time spans. Utilities may already be at different stages of progress within these phases based on their existing capabilities, investments, and operating context. Rather than representing a prescribed schedule, the phases describe a logical maturity progression. Each utility should advance through them on a time frame that aligns with its starting point, priorities, and readiness.

In the **Foundations Phase**, EDCs develop core data architectures, system integration layers, and baseline operational capabilities. This phase directly addresses structural gaps identified in the current state, including fragmented data environments and limited system integration.

In the **Enablement and Integration Phase**, foundational systems can be leveraged by EDCs to support advanced analytics, improve system visibility, and enhance coordination across planning and operational functions. Capabilities such as scenario-based planning, topology-aware monitoring, and coordinated DSM and DER integration should be progressively implemented.

In the **Optimization and Market Alignment Phase**, EDCs advance their capabilities such as automated grid operation, dynamic network optimization, and DER market participation (subject to system readiness and regulatory alignment).

Across these three phases, eleven programs are sequenced to reflect maturity dependencies and implementation feasibility. Figure 33 presents the program roadmap across the three phases.



	Foundations Phase	Enablement and Integration Phase	Optimization and Market Alignment Phase
Kay Technologies	• GIS and network models • SCADA / EMS enhancements and field sensors • DER hosting capacity tools	• Advanced planning, forecasting, and simulation platforms • AMI, DMS, and sensor integration for real-time visibility • Dynamic Line/Transformer Rating • Network modeling and optimization tools	• Advanced DMS with automation and optimization engines • DERMS (Distributed Energy Resource Management System) • High-frequency telemetry and data ingestion systems • Dispatch orchestration and market integration platforms • Real-time analytics and automated control systems
Milestones	• Data standards and governance • Feeder-level visibility via SCADA integration • DER registry and interconnection process	• Topology-aware monitoring and real-time grid visibility achieved • Integration of advanced data sources into planning and operations • Real-time capacity monitoring and visualization enabled	• Automated switching, fault isolation, and restoration implemented • DER dispatch, aggregation, and market participation enabled • Real-time, constraint-aware DER dispatch operational • Closed-loop automated grid optimization and self-healing capabilities established

Figure 33. EDC Roadmap

In the **Foundation phase**, EDCs should prioritize programs that establish core system capabilities:

- P01: Core Data Foundations
- P02: Core System Foundations
- P03: Digital Work and Asset Management
- P04: DSM Optimization
- P05: DER Foundations

Foundational programs address fundamental gaps identified in the current state, including fragmented data architectures, limited DSM integration, and early-stage DER frameworks.

In the **Enablement and Integration phase**, EDCs should implement programs that build analytical and operational capabilities:

- P06: Planning and Analytics Modernization
- P07: Grid Monitoring and Visibility
- P08: Dynamic Network Modeling and Capacity Optimization

Enabling programs support a transition toward data-driven planning and operations, facilitating improved system awareness and coordination.

In the **Optimization and Market Alignment phase**, EDCs may advance toward more sophisticated capabilities:

- P09: Core Grid Operations Automation
- P10: DER Operational Integration and Market Access
- P11: Advanced Grid Optimization

Optimization and market alignment programs represent higher maturity levels, including automation of operational processes and integration with wholesale market mechanisms. Table 50 Provides a summary of program objectives, key technologies, and milestones. Detailed program descriptions can be found in Appendix C.

Table 50. Program Summary

Phase	Program	Program Name	Objectives	Program Description	Key Technologies to be Deployed	Key Milestones
Foundations	P01	Core Data and Planning Foundations	Establish integrated asset, network, and planning data foundation	Integrate GIS, asset, AMI, and operational data into a unified architecture; develop continuously maintained network models; enable data governance, KPI frameworks, and planning-ready datasets	GIS and network model management systems; enterprise data integration platforms; data analytics, visualization, and reporting tools	Enterprise data standards and governance; continuously updated network model
	P02	Core Operational Visibility and Control Foundations	Strengthen real-time visibility and basic control capabilities	Expand SCADA-integrated monitoring, deploy field sensors, improve outage detection, and enable manual control actions for improved operational awareness	SCADA enhancements; field monitoring devices and sensors; operational data visualization tools	Monitoring coverage across critical nodes; deployment of basic manual control capabilities
	P03	Digital Work and Asset Management	Improve efficiency of asset management and field operations	Digitize work management, enable mobile workforce, implement risk-based and reliability-centered asset management, and integrate asset data with operations	Digital work management platforms; mobile workforce tools; asset analytics and lifecycle management systems	Digital work management deployment; risk-based maintenance strategies; real-time field data access
	P04	DSM Optimization	Enable initial deployment and optimization of DSM capabilities	Develop DSM forecasting and behavioral analytics; enable targeted programs by customer segment; improve measurement and verification consistency	DSM analytics and response modeling tools; customer engagement and communication platforms	DSM response models; targeted, location-specific DSM deployment

Phase	Program	Program Name	Objectives	Program Description	Key Technologies to be Deployed	Key Milestones
	P05	DER Foundations	Enable structured and scalable DER integration	Establish DER registry, standardize interconnection processes, and deploy hosting capacity analysis and mapping capabilities	Hosting capacity analysis and mapping tools; DER registration and data management platforms; integration platforms for DER data exchange	Standardized interconnection framework; hosting capacity maps; DER registry deployment
Enablement and Integration	P06	Planning and Analytics Modernization	Enable advanced, scenario-based and optimization-driven planning	Introduce forecasting, scenario analysis, optimization-based planning, and integration of non-wire alternatives into planning processes	Forecasting and simulation platforms; data analytics and scenario modeling systems	KPI forecasting framework; scenario-based planning; NWA-enabled planning processes
	P07	Grid Monitoring and Visibility	Enable topology-aware, system-wide monitoring	Integrate monitoring data with network topology; expand sensor deployment; establish structured aggregation and event tracking across the network	Field sensing and monitoring equipment; DMS enhancements; network model management platforms; data integration and event processing systems	Topology-based monitoring framework; network model extended to grid edge
	P08	Dynamic Network Modeling and Capacity Optimization	Enable dynamic ratings and improved capacity utilization	Implement dynamic network models; integrate DLR/DTR; enable near real-time capacity assessment and adaptive planning approaches	Advanced network models and planning tools; dynamic rating engines	DLR/DTR model development; near real-time capacity monitoring tools

Phase	Program	Program Name	Objectives	Program Description	Key Technologies to be Deployed	Key Milestones
Optimization and Market Alignment	P09	Core Grid Operations Automation	Automate operational decision-making and response actions	Deploy automated switching, fault isolation, restoration, and network reconfiguration using advanced DMS and field automation systems	Advanced DMS with automation functions; field automation devices (switches, reclosers); protection and control systems; real-time analytics and control applications	Automated reconfiguration; fault location, isolation, and restoration capabilities
	P10	DER Operational Integration and Market Access	Enable DER dispatch and participation in markets	Deploy DERMS, integrate telemetry, enable forecasting, aggregation, dispatch, and settlement mechanisms for DER participation	DERMS; forecasting and analytics platforms; high-frequency telemetry; dispatch coordination; market integration and settlement	DER dispatch capability; aggregator coordination; settlement mechanisms
	P11	Advanced Grid Optimization	Enable continuous, autonomous grid optimization	Implement closed-loop optimization using advanced analytics, dynamic ratings, and autonomous control for self-healing and real-time system optimization	Advanced optimization and control algorithms; DMS with integrated constraint and dynamic rating management; high-speed telemetry; automated protection and control devices; real-time analytics	Closed-loop optimization; self-healing network functionality

7.4. Benefit-Effort Analysis

Program benefit scores were determined by assessing the impact of each initiative on the objectives outlined in the objective prioritization section. These scores were weighted according to the importance of each objective as expressed by stakeholders.

Table 51 offers an in-depth analysis of the anticipated program benefits, mapping each initiative against strategic objectives to highlight its contribution to the broader organizational vision. For instance, the DER Operational Integration and Market Access program is designed to provide significant value by facilitating **DER dispatch and enabling market participation**. Through the implementation of DERMS, enhanced telemetry, and seamless integration capabilities, this program empowers DERs to interact efficiently with the grid. The result is a more adaptive and resilient system, capable of responding to fluctuating demand and supply conditions. By aggregating DERs and streamlining their dispatch, the program promotes grid flexibility, boosts operational efficiency, and expands access to energy markets, all of which reinforce reliability and encourage greater customer engagement. These multifaceted benefits are directly aligned with key objectives, such as increasing system reliability, supporting decarbonization efforts, and fostering innovation in market structures.

The **Advanced Grid Optimization program**, on the other hand, is pivotal in achieving high benefit scores by transforming operational practices through automation and advanced analytics. Leveraging state-of-the-art DMS and sophisticated optimization engines, this initiative enables closed-loop optimized operations. By integrating automated optimization into existing grid processes, the program reduces manual interventions, mitigates operational costs, and improves the quality and reliability of service delivery. The automated solutions not only streamline grid control but also enhance situational awareness and decision-making for operators. The program's impact is measured by its ability to increase operational efficiency, accelerate the adoption of intelligent analytics, and support the continuous improvement of grid management. High benefit scores in Table 3 reflect the program's alignment with prioritized objectives, including reliability, efficiency, and scalability.

Each program's benefit assessment, as illustrated in Table 50, is conducted through a systematic weighting process, ensuring that the most critical objectives are given appropriate emphasis in the scoring methodology. Scores are standardized on a scale from zero to five, which allows for meaningful comparison across programs and supports transparent decision-making. This detailed approach ensures stakeholders can clearly identify the value delivered by each program, understand the strategic alignment, and make informed choices about prioritization and resource allocation.

Table 51. Program Benefits by Objectives

Program	Improve power supply quality	Reduce outages and improve reliability	Increase efficiency of energy delivery	Enhance resource and expenditure allocation	Balance risk propagation through grid assets	Streamline operational workflows	Improve asset records and accessibility	Maximize emissions reduction target completion	Enhance renewable energy portfolio	Optimize e-mobility development and allotment	Support the creation of a distributed energy system	Total Benefit Score
P01: Core Data and Planning Foundations.	○	○	◔	◕	◑	○	◕	○	○	○	○	1.6
P02: Core Operational Visibility and Control Foundations	◔	◔	◔	○	○	○	○	○	○	○	○	0.6
P03: Digital Work and Asset Management	○	○	○	◕	◕	◑	◑	○	○	○	○	1.6
P04: DSM Optimization	○	○	○	○	○	○	○	◑	○	○	◔	0.4
P05: DER Foundations	○	◑	◑	◔	○	○	◔	◔	●	○	●	4.2
P06: Planning and Analytics Modernization	○	◑	◔	●	◑	○	◑	○	◔	○	◔	2.9
P07: Grid Monitoring and Visibility	◔	○	○	◑	◑	○	◕	○	○	○	○	1.2
P08: Dynamic Network Modeling and Capacity Optimization	○	◔	◔	◑	◔	○	○	○	◔	◔	◔	1.7
P09: Core Grid Operations Automation	○	◑	◔	○	○	○	○	○	○	○	◔	0.9
P10: DER Operational Integration and Market Access	○	◔	●	○	○	○	○	◑	●	◔	●	5.0
P11: Advanced Grid Optimization	○	◕	◑	◔	○	○	○	○	○	○	○	1.8

○ No alignment ◔ Low alignment ◑ Moderate alignment ◕ High alignment ● Complete alignment

The assessment of effort is categorized into two distinct components: Technology Effort and Non-Technology Effort.

- For **Technology Effort**, each EDC evaluated the presence of technology as either full, partial, or new. The effort required to fully implement the technology was also rated by EDCs and converted into a technology score. The total technology effort score for a program represents the aggregate effort necessary to deploy all associated technologies. Technology effort includes relative estimates of labor needs, equipment, and software licensing costs, etc. Given limited availability of data, relative scores were assigned rather than actual costs estimated.
- **Non-Technology Efforts** encompass elements such as regulatory compliance, change management, training, and modifications to business processes. These efforts are scored based on their complexity.

The overall effort score is calculated by combining the technology effort score with the non-technology effort score. For comparison, both cost and benefit scores are standardized on a scale from zero to five. Table 52 shows total efforts, benefits and benefits to efforts ratio by program.

Table 52. Program Cost Benefit Analysis

Program	Total Effort Score	Total Benefit Score	Benefit to Effort Ratio
P01: Core Data and Planning Foundations.	1.5	1.6	1.1
P02: Core Operational Visibility and Control Foundations	0.8	0.6	0.8
P03: Digital Work and Asset Management	1.5	1.6	1.1
P04: DSM Optimization	0.4	0.4	1.0
P05: DER Foundations	1.5	4.2	2.8
P06: Planning and Analytics Modernization	1.4	2.9	2.1
P07: Grid Monitoring and Visibility	2.6	1.2	0.5
P08: Dynamic Network Modeling and Capacity Optimization	1.4	1.7	1.2
P09: Core Grid Operations Automation	2.8	0.9	0.3
P10: DER Operational Integration and Market Access	4.0	5.0	1.3
P11: Advanced Grid Optimization	5.0	1.8	0.4

Early-stage programs such as P01 through P03 offer moderate benefit scores but serve as crucial foundational steps for future progress. Their primary value lies in enabling other initiatives, as their impact is not immediately visible in system performance metrics but is vital for establishing the necessary data and operational groundwork.

In contrast, the modernization of planning and analytics (P06) stands out for its strong benefit-to-effort ratio, making it a pivotal leverage point for enhancing decision-making processes and optimizing investments across the grid. Additionally, programs focused on DER enablement and integration, particularly P05 and P10, achieve the highest benefit scores. This reflects their robust alignment with current policy objectives, the need for greater system flexibility, and the broader goal of long-term grid transformation, positioning them as strategic priorities for sustained improvement and innovation.

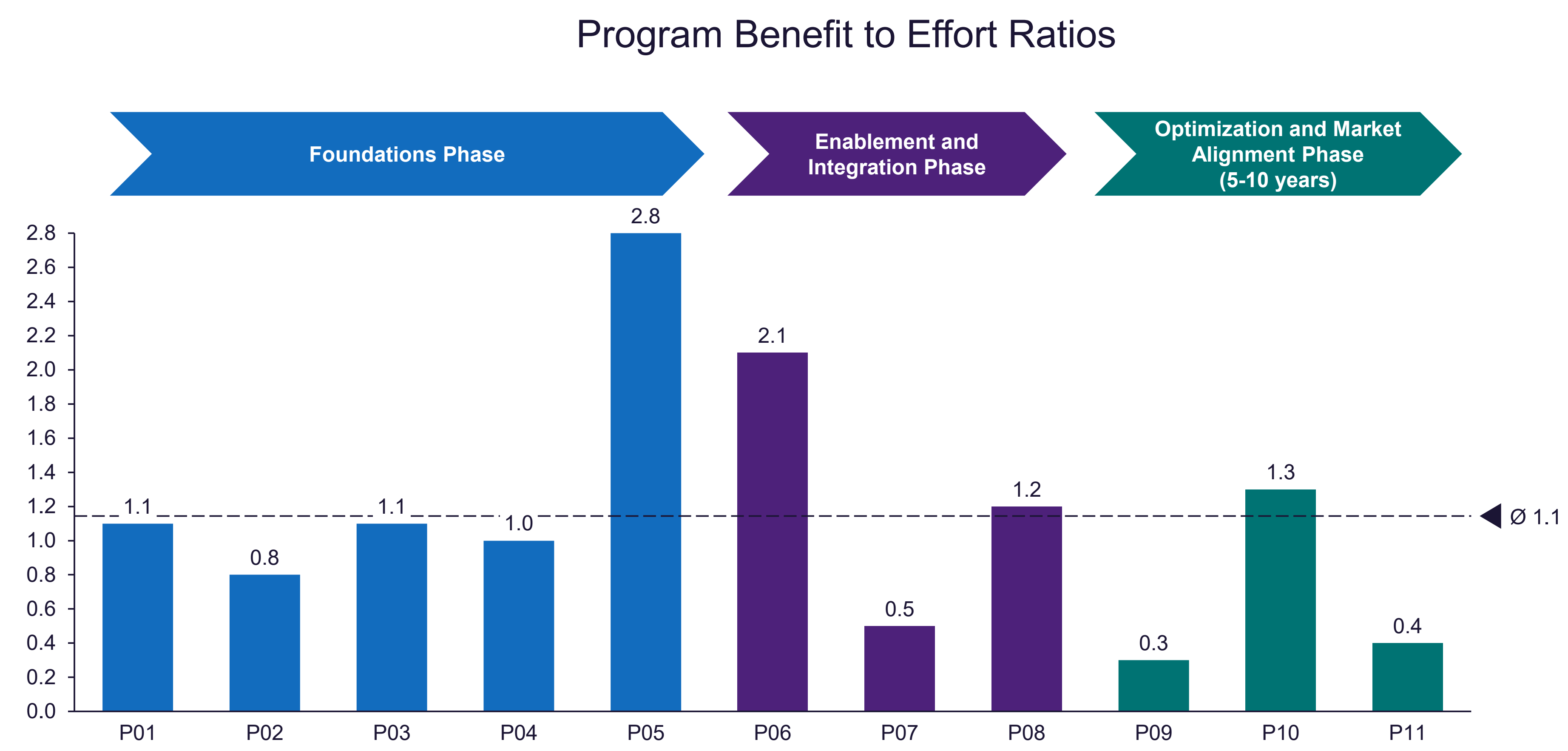


Figure 34. Program Benefit to Effort Ratio

Overall, the benefit-effort analysis highlights that strategic investments in DER integration and advanced planning deliver substantial returns, both in system performance and alignment with policy goals. By prioritizing these high-impact initiatives while maintaining foundational programs, the EDCs can achieve a balanced approach that supports immediate needs and long-term transformation. This ensures resources are allocated efficiently to maximize value across the grid modernization journey.

7.5. Role of 40101(d) Programs in the Roadmap

As part of this effort, the report and roadmap evaluated proposed projects submitted under Delaware's Section 40101(d) Grid Resilience Grant Program. These applications are directly relevant to the roadmap because they reflect near-term, utility-led investments intended to improve resilience, address local reliability constraints, support clean energy integration, and deliver benefits to disadvantaged communities. These projects provide practical examples of the types of projects that can advance Delaware's broader grid modernization and resilience strategy.

DEMEC proposed a network modeling and training initiative for its member municipal utilities. The project centers on distribution system modeling, hosting capacity analysis, feeder-level risk ranking, gap assessment between DER growth and existing capacity, and development of feeder and substation heat maps to support future planning. The application also included workforce training for municipal utility staff and was framed as a way to improve planning for solar, storage, EVs, and other grid modernization investments across multiple municipal systems. This application was approved. This program fits strongly into the roadmap because it represents a foundational planning and analytical capability investment as included in P01: Core Data and Planning Foundations. A core theme of the roadmap is that utilities need better data, modeling tools, and planning frameworks to identify grid constraints, prioritize upgrades, and enable cost-effective DER integration. DEMEC's project directly supports those needs by building the technical capabilities required for future resilience and modernization investments.

DEC proposed installation of a 2 MW / 4 MWh battery storage system at its Bruce A. Henry Solar Farm near Georgetown. The project was designed to improve local reliability and resilience, reduce outage duration, lower wholesale power costs during peak periods, and enable additional distributed solar adoption in constrained portions of the system. DEC also framed the project as a pilot that could inform broader future deployment of storage and microgrids across its service territory. This application was approved. In the long term, the DEC project supports P10 by laying the groundwork for more coordinated, system-wide DER optimization across planning, operations, and program design. The project helps establish the capabilities, processes, and decision-making framework needed to move toward a more integrated and strategic use of DERs over time. However, realizing the full benefits of system-wide DER optimization will also depend on making near-term progress on P02 and P05 in parallel. Advancing those priorities in the short term is essential to build the foundational data, operational visibility, and implementation capabilities required for P10 to deliver meaningful system-wide value.

It is important to recognize several structural and market barriers that affect the pace and scale of EDC adoption of grid enhancements. Affordability remains a primary constraint, as recent and projected increases in electric bills have heightened sensitivity among both customers and regulators to additional utility capital investments that may further increase base rates. In parallel, the traditional regulated utility business model continues to emphasize capital deployment, where returns are earned through rate-based investments with an approved return on equity, rather than through performance outcomes. This can create a misalignment with emerging policy objectives that prioritize operational efficiency, innovation, and non-wires or programmatic solutions. Finally, governance considerations introduce additional complexity, particularly in states with a mix of investor-owned and non-investor-owned EDCs. In such contexts, there may be limits to the extent to which state agencies can direct or mandate action by non-IOU entities, requiring greater reliance on incentives, coordination, and voluntary participation to advance program objectives.

In this environment, Section 40101(d) and similar governmental appropriations are expected to play a critical role in accelerating the near-term implementation of priority grid modernization investments across Delaware's Electric Distribution Companies. DNREC's intent is to direct future applications toward targeted, high-impact pilots that address identified gaps in system visibility, DER integration, and operational flexibility while remaining aligned with the scale and maturity of each EDC.

Table 53. Sample Future 40101(d) Project Recommendations for DE EDCs

Sample Future Project Recommendations	**DPL**	**DEC**	**DEMEC Members**
DLR	✓	×	×
Substation Automation Study/Pilot	×	✓	✓
Behind the meter battery incentives	×	✓	✓
Distribution field sensor deployment and SCADA integration	×	✓	✓
VVO/CVR systemwide deployment, locational pilots	×	✓	✔
LDR Pilot	✓	✓	×
Cybersecurity vulnerability and risk assessment	×	×	✓
Grid Forming Resources Incentives and Pilots	✓	✔	×
DERMS	✓	✔	×

✓= High suitability ✔= Medium suitability ×= Not suitable

DNREC recommends that DPL focus on projects that enhance system capacity utilization, enable DER integration, and support transition to more dynamic grid operations:

- DLR deployment on constrained transmission and sub-transmission spans to increase available capacity and improve operational visibility without major infrastructure expansion.
- LDR to enable feeder-level dispatch of demand-side resources, aligned with system constraints and AMI-enabled measurement.
- Grid Forming Resource incentives or pilots to support weak sections of the grid.
- DERMS development and integration, beginning with foundational capabilities that support coordination of distributed resources and enable future market participation.

For DEC, DNREC recommends that it focus on enhancing operational visibility, improving control capabilities, and enabling more advanced DER and demand-side integration:

- Substation automation pilots, including protection, automation, and asset condition monitoring to improve reliability and enable future advanced analytics.
- Completion of field sensor deployment and SCADA integration to enhance real-time visibility and enable more proactive system management.
- Behind-the-meter battery incentive programs, particularly targeted to rural and reliability-sensitive areas.
- VVO and CVR systemwide deployment to deliver measurable efficiency and peak demand reductions.
- LDR pilots to improve dispatchability and validate performance of distributed resources at the feeder level.

DNREC recommends that DEMEC and its member utilities prioritize foundational capabilities and scalable solutions suited to smaller systems:

- Field sensor deployment and SCADA integration across select feeders to improve outage detection and system monitoring.
- Substation digitalization pilots, focusing on a limited number of high-value locations each year.
- Behind-the-meter battery incentive pilots, potentially implemented across multiple member utilities.
- Cybersecurity vulnerability and risk assessments to establish consistent baseline practices across member systems.

This roadmap may serve as a practical foundation for future Section 40101(d) funding applications by helping each EDC translate strategic priorities into clearly defined proposals. By identifying system needs, evaluating gaps, and organizing recommended actions into a sequenced implementation pathway, the roadmap provides a structured basis for developing future proposals that align with federal funding objectives related to grid resilience, reliability, and modernization. EDCs may use the roadmap to demonstrate that proposed projects are grounded in a state-wide strategic planning effort, reflect Delaware-specific needs, and support measurable outcomes. In this way, the roadmap not only guides long-term utility planning, but also helps position EDCs to respond more efficiently and credibly to future funding opportunities under Section 40101(d) or related programs.

8. Conclusions and Recommendations

Delaware's distribution grid is entering a period of structural change driven by electrification, DER growth, and evolving policy requirements. While current system performance is strong, the ability to sustain reliability, affordability, and resilience under future conditions will depend on timely and coordinated modernization efforts. The statewide roadmap presented in this report provides a structured path forward. It defines a sequenced approach to building foundational capabilities, enabling integration, and ultimately achieving optimized, adaptive grid operations. Importantly, the roadmap is designed to be flexible and scalable, recognizing the diversity of Delaware's utilities and the evolving nature of technology and policy conditions.

Following recommendations are provided to guide implementation of a statewide grid modernization strategy.

- **Focus Near-Term Investments on Foundational Capabilities:** EDCs should consider prioritizing high-impact investments in data integration, system visibility, and network modeling. Establishing a more unified data and analytics foundation can help support scenario planning, DER integration, and operational optimization over time. Where appropriate, federal and state funding opportunities may also be used to help accelerate deployment of these core capabilities.
- **Adopt a Phased Modernization Approach:** EDCs should develop their own phased modernization roadmaps. These can be utilized to guide capital plans and distribution system planning processes. Smaller EDCs could also seek to promote scalability and interoperability across systems, platforms, and service territories as implementation progresses.
- **Transition DERs and DSM into Operational Grid Resources**: EDCs and policymakers should consider opportunities to move beyond programmatic deployment of DERs and DSM toward greater operational integration. Expanding dispatchability and visibility of distributed resources, including through platforms such as DERMS, can enhance their value to the grid. Over time, DERs can play a larger role in supporting capacity, reliability, and resilience objectives.
- **Strengthen Grid Visibility, Operations, and Automation:** EDCs should consider expanding deployment of advanced distribution management, monitoring, and control systems to strengthen grid operations. Improvements in real-time situational awareness and outage response capabilities will provide near-term operational benefits. Over the longer term, utilities can continue progressing toward more automated and adaptive grid operations as needs and capabilities evolve.
- **Advance Policy and Regulatory Enablement:** Grid resiliency, reliability and modernization will not be delivered exclusively by EDCs, rather through cooperation between state agencies, operators, and policymakers. State agencies and policymakers may leverage the findings to support development of policies that enable DER integration, grid resilience, and advanced system operations. Consideration should be given to flexible interconnection policies, frameworks that support locational value of DER integration, flexible load management, and grid modernization investments.
- **Enhance Cybersecurity and Organizational Readiness:** EDCs and state agencies should consider strengthening coordination on cybersecurity governance and related practices. Increased visibility into system risks and more standardized

approaches, where feasible, may support more consistent readiness across organizations. Investments in workforce development, digital skills, and change management will also help support successful grid modernization efforts.

9. Appendix A: LRDP Best Practices benchmarking questions

Siemens Energy began the benchmarking process by developing a comprehensive set of key questions, underlying assumptions, and input parameters essential for effective LRDP. The key questions are as follows:

1. Basic Information

- Utility Name
- State
- Study Name
- Latest Plan Year

2. Distribution System Planning

- What is planning horizon (5/10/15 years?)
- How frequently is the plan updated?
- What are key objectives/drivers of plan?
- Who are key stakeholders involved in the process?
- What tools are used?
- Provide a description of process/methodology.

3. Forecasting

- What was modeled load growth (CAGR)
- Which of the below loads are called out and % of total load?
    - On-site or BTM solar
    - Battery Storage
    - EVs
    - Other DER
- What locational allocation methodology was used to allocate load forecast

4. Analytical Framework

- Provide description of framework used to evaluate plan/projects?
- What were the metrics used for each of the below?
    - Cost
    - Reliability
    - Load serving capacity
    - DER Accommodation
    - Risk and resilience metrics/indices
    - Locational value

    - Societal value

5. Technologies Evaluated

- Which of the following technologies were evaluated in plan?
    - DLRs
    - Distribution automation
    - Line sensors
    - Flexible Alternating Current Transmission Systems (FACTS)
    - volt/VAR control
    - DERMS/ADMS
    - NWA
    - BESS
    - Microgrids/islanding
    - DERs
    - Grid Management and Capacity
    - Cybersecurity
    - EE and Demand Response
    - EV
    - Other (please specify)

6. Climate & Resiliency Scenarios

- Which extreme weather events were planned for?
- What methodology was used for planning for extreme events?
- Which climate change scenarios were planned for?
- What methodology was used for planning for climate change scenarios?
- Which cybersecurity risks were considered?
- What methodology was used for planning for cybersecurity events?

7. Asset Management

- What data/KPIs are monitored?
- What preventive maintenance programs does the utility have or is considering?

10. Appendix B: Cybersecurity Compliance and Policy Review requested documents

The following documents were requested of each of the EDCs in order to conduct the cybersecurity compliance and policy review.

No.	Topic	Description
1	Cybersecurity Gap Analysis	OT Cybersecurity Policy: • Defines the organization's commitment to securing OT environments. • Establishes roles, responsibilities, and governance structure.
2	Cybersecurity Gap Analysis	Access Control Policy: • Covers user authentication, role-based access, least privilege, and remote access. • Includes procedures for onboarding/offboarding personnel.
3	Cybersecurity Gap Analysis	Asset Management Policy: • Requires inventory and classification of all OT assets (hardware, software, firmware). • Supports vulnerability management and patching.
4	Cybersecurity Gap Analysis	Network Segmentation Policy: • Enforces separation between IT and OT networks (e.g., DMZs, firewalls). • Defines rules for data flow between zones (e.g., Purdue Model).
5	Cybersecurity Gap Analysis	Patch and Vulnerability Management Policy: • Establishes how vulnerabilities are identified, assessed, and remediated. • Includes timelines and exceptions for patching critical OT systems
6	Cybersecurity Gap Analysis	Incident Response Policy: • Defines how to detect, report, respond to, and recover from OT cyber incidents. • Includes coordination with IT and external stakeholders
7	Cybersecurity Gap Analysis	Change Management Policy: • Governs how changes to OT systems are proposed, reviewed, tested, and approved. • Ensures traceability and rollback procedures.

No.	Topic	Description
8	Cybersecurity Gap Analysis	Backup and Recovery Policy: • Specifies backup frequency, storage, and recovery testing for OT systems. • Ensures business continuity and disaster recovery.
9	Cybersecurity Gap Analysis	Remote Access Policy: • Controls third-party/vendor access to OT systems. • Requires secure protocols (e.g., Virtual Private Network (VPN), MFA) and session monitoring.
10	Cybersecurity Gap Analysis	Network Architecture Diagrams (including segmentation, firewalls, DMZs)
11	Cybersecurity Gap Analysis	Firewall Rulesets and ACLs
12	Cybersecurity Gap Analysis	Patch Management Records
13	Cybersecurity Gap Analysis	Vulnerability Notifications and Reports
14	Cybersecurity Gap Analysis	Antivirus/Endpoint Protection Logs
15	Cybersecurity Gap Analysis	Backup Schedules and Test Results
16	Cybersecurity Gap Analysis	System Hardening Baselines
17	Cybersecurity Gap Analysis	Remote Access Logs and Audit Trails
18	Cybersecurity Gap Analysis	Protocol Inventory
19	Cybersecurity Gap Analysis	User Roles and Work Duties Documentation: • This artifact should map users or user groups to their job functions, system access, and security responsibilities.
20	Cybersecurity Gap Analysis	OEM Support and Maintenance Contracts that include: • Support Contracts and SLAs • Remote Access Requirements (e.g., TeamViewer, VPN, jump server) • Third-Party Access Controls • End-of-Life (EOL) / End-of-Support (EOS) Dates • OEM Contact Information for Incident Response

No.	Topic	Description
21	Cybersecurity Gap Analysis	Telecom Infrastructure Overview: • Wired and Wireless Technologies (e.g., fiber, copper, Wi-Fi, LTE, 5G, microwave) • Carrier Services (e.g., MPLS, leased lines, satellite) • Redundancy and Failover Mechanisms • Latency and Bandwidth Requirements for OT Systems
22	Cybersecurity Gap Analysis	Operational Systems and Software List of all software and platforms used for: • Operations: SCADA, EMS, DMS, DERM • Maintenance: OMS, CMMS, GIS • Forecasting: Load forecasting tools, weather data systems, AMI/MDM • Criticality matrix of these systems with dependencies and interfaces
23	Cybersecurity Gap Analysis	Compliance and Audit Records: • Previous cybersecurity assessments or audits • Risk register and mitigation plans • Compliance checklists (e.g., NIST CSF, IEC 62443, NERC CIP)
24	Cybersecurity Gap Analysis	Risk Treatment Plans: • Action plans for mitigating high and medium risks • Timelines, responsible parties, and resource requirements
25	Cybersecurity Gap Analysis	Enterprise Risk Register: • Includes all identified risks (cyber, operational, physical, etc.) • Risk descriptions, likelihood, impact, and mitigation strategies • Risk owners and review/update frequency
26	Cybersecurity Gap Analysis	Physical Security Policies & Standards Example of content or comparble document naming conventions: • Site Access Control Policy • Badge and Credentialing Policy • Site Access Request and Approval Process • Visitor Management Procedure

No.	Topic	Description
27	Cybersecurity Gap Analysis	Samples of Site-Specific Documentation (2-3 sites): • Site Security Plans (for substations, control centers, remote sites) • Physical Security Risk Assessments and Mitigation Plans • Physical Security Audit Reports (internal or third-party) • Compliance Reports (e.g., NERC CIP-006, ISO 27001 physical controls) • Security Zone Maps and Access Level Definitions
28	Cybersecurity Gap Analysis	Risk Management Policy: • Defines the risk assessment methodology (e.g., qualitative, quantitative, hybrid) • Roles and responsibilities for risk identification, evaluation, and treatment • Alignment with frameworks (e.g., ISO 31000, NIST Risk • Management Framework (RMF), IEC 62443-2-1)
29	Cybersecurity Gap Analysis	Examples/Evidence of Technical and Operational Controls (2-3 sites) • Surveillance System Design and Layout (Closed-Circuit Television (CCTV) coverage maps) • Intrusion Detection System (IDS) Configuration and Monitoring • Access Control System Configuration (badge readers, biometrics) • Physical Access Logs and Audit Trails • Alarm System Configuration and Response Protocols • Environmental Monitoring Systems (e.g., temperature, fire, flood sensors)
30	Cybersecurity Gap Analysis	Risk Assessment Reports: • Results of recent risk assessments or audits (internal or third-party) • Includes residual risk ratings and control effectiveness
31	Cybersecurity Gap Analysis	Risk Appetite and Tolerance Statements: • Defines acceptable risk levels for OT operations • Guides prioritization of cybersecurity investments

No.	Topic	Description
32	Cybersecurity Gap Analysis	OT-Specific Risk Register: • Focused on ICS/SCADA, substations, field devices, and telecom • Includes cyber threats (e.g., ransomware, remote access abuse, supply chain compromise) • Mapped to critical assets and zones (e.g., per Purdue Model)

11. Appendix C: Detailed Program Descriptions

11.1. P01: Core Data and Planning Foundations

Phase
Foundations phase

Objective
Establish consistent asset, network, and planning data foundations, including integrated network models and data governance to support all downstream analytical and operational capabilities.

Program Description
P01 addresses one of the most fundamental structural gaps identified across all three business functions: data fragmentation, incomplete network models, and limited use of available information in planning and decision-making.

Current operating environments show that most EDCs maintain core asset and operational data, but integration across systems remains inconsistent. In several cases, asset, GIS, AMI, and operational data exist in parallel but are not fully linked, limiting usability for advanced planning and operations.

Through this program, EDCs establish a unified, continuously maintained system representation by integrating asset, network, and operational data into a cohesive architecture. Key initiatives include:

- **Data integration and standardization:** EDCs implement consistent asset and network data frameworks across organizational boundaries, integrating asset information from multiple systems and establishing operational data stores and pipelines. Enterprise-wide KPI frameworks are introduced, aligning performance metrics with network topology for improved cross-functional visibility.
- **Network model development and maintenance:** EDCs transition from periodic updates to CIM compliant, continuously maintained, topology-aware as-built network models. Network model stores are established to ensure consistency and accuracy, supporting both operational and planning requirements.
- **Planning data and analytics foundation:** EDCs introduce granular load profiles, improve the use of historical and AMI-derived load data, and enable scenario-ready datasets. These enhancements support advanced planning and analytics, making data more actionable and reliable.
- **Data usability improvements:** EDCs enable geospatial visualization and analytics, enhance data accessibility for planning and analytics teams, and reduce reliance on institutional knowledge for data interpretation. These improvements foster informed decision-making and streamline workflows across the organization.
- **Apply/Adopt Data Security Policy and Procedures:** Define the scope of the data and adopt robust frameworks for securing, monitoring, and managing data. Within the context of the applicable privacy and electric reliability regulations. Safeguarding the EDCs from legal liability or action from customers or regulators.

From an implementation perspective, this program combines both technology and organizational efforts. Technology deployments include GIS integration, and establishment of integration platforms, while non-technology efforts include data governance, standards development, and process alignment.

The importance of this program lies in its role as a prerequisite for nearly all subsequent capabilities. Without reliable and integrated data, advanced capabilities such as DER coordination, dynamic ratings, and automated grid operation cannot be implemented effectively.

Given differences in scale across EDCs, implementation approaches may vary. For some EDCs, this program should focus on integration and standardization rather than deploying entirely new platforms, particularly where existing systems sufficiently meet operational needs.
This program is critical as a baseline enabler, but it should be implemented pragmatically, avoiding unnecessary system complexity where operational scale does not justify it.

Key Technology Dependencies

- Communication and enterprise connectivity infrastructure
- Operational data and enterprise systems (accounting, assets, billing etc.)

Key Technologies to be Deployed

- GIS and network model management systems
- Enterprise data integration and operational data stores
- Data analysis, visualization and reporting platforms

Non-Technology Related Efforts

- Definition of enterprise data standards
- Establishment of data governance and ownership structures
- Cross-functional alignment between planning, operations, and asset teams

Program Outcomes

- Enables accurate and consistent system representation
- Improves reliability of planning and operational decisions
- Provides foundation for DER integration and system optimization

Key Milestones

- Enterprise data standards and governance framework implemented
- Continuous network model update capability established

11.2. P02: Core Operational Visibility and Control Foundations

Phase
Foundations phase

Objective
Strengthen real-time visibility and basic control capabilities across the network, enabling operators to better understand system conditions and respond more effectively to events.

Program Description
P02 focuses on building the operational backbone required for reliable grid oversight. Some EDCs have partial visibility through SCADA systems or substation monitoring, but coverage is often limited and not sufficiently granular to support consistent decision-making across the distribution network. In practice, this means data from field devices, substations, and meters may exist, yet it is not always integrated or accessible in a way that provides a clear and timely picture of the system.

This program addresses that gap by improving both the availability and usability of operational data. It also introduces initial control capabilities that allow the system to move beyond passive monitoring. Key initiatives include:

- **Deployment of targeted power quality monitoring:** EDCs introduce online power quality measurement at selected buses in the network. These locations are typically chosen based on criticality, known issues, or expected variability, allowing operators to gain more precise insight into voltage and quality conditions.
- **Manual network configuration improvement practices:** Operators are supported with tools that enable the manual identification of improved network configurations. While still human-driven at this stage, these capabilities help reduce losses and improve load balancing through informed switching decisions.
- **Enhanced outage detection using protection data:** Substation protection systems are leveraged more effectively to detect and identify outages. By utilizing existing protection signals, EDCs can improve fault visibility and reduce reliance on indirect indicators such as customer reports.
- **Expanded monitoring through SCADA-integrated field devices:** Field monitoring devices are connected to SCADA systems to increase overall data visibility. This integration provides a broader and more consistent view of network conditions, supporting faster and more informed operational responses.
- **Implementation of Defensible Architecture for remote sites:** Define a standard blueprint in alignment with regulatory and standards frameworks such as NIST or IEC-62443 to implement strong protection of new digital assets deployed into the field locations. Protecting them and the data collected from malicious and accidental cyber incidents.

From an implementation perspective, this program relies on extending existing operational technologies rather than replacing them. It focuses on connecting what already exists and filling critical gaps in visibility and control.

The outcome is a more informed operational environment. Decisions become faster and more consistent, even if they remain largely manual at this stage.

Different EDCs may approach this differently depending on the maturity of their current systems. Some may need to expand monitoring coverage, while others may focus on integrating data into a unified view.

Key Technology Dependencies

- Communication and connectivity infrastructure
- Operational data and system management platforms
- Monitoring and measurement capabilities (Profile Measurement – Field Sensors, Incident Management)
- Visualization and situational awareness systems (System Visualization)

Key Technologies to be Deployed

- SCADA enhancements and extensions
- Field monitoring devices and sensors
- Operational data visualization tools

Non-Technology Related Efforts

- Standardization of operational data usage
- Alignment between control room and field operations
- Process development for data-driven decision-making

Program Outcomes

- Improves visibility of real-time grid conditions
- Enables faster identification of outages and disturbances
- Supports more consistent operational decisions
- Provides foundation for advanced automation

Key Milestones

- Completion of monitoring coverage across critical points on
- network
- Deployment of manual control capabilities for field equipment

11.3. P03: Digital Work and Asset Management

Phase
Foundations phase

Objective
Improve efficiency and consistency in asset management and field operations by digitizing workflows, enhancing data access, enabling better planning and coordination across teams.

Program Description
P03 focuses on modernizing how EDCs manage assets and execute work in the field. While most organizations maintain asset records and work management systems, these are often disconnected from day-to-day operations or not fully utilized. In many cases, field crews rely on manual processes, paper-based workflows, or fragmented systems. Information about assets may exist, but it is not always accessible where and when it is needed. This creates inefficiencies and increases the risk of errors.

This program aims to close that gap by connecting asset data, work processes, and field execution. It also introduces more advanced approaches to managing assets over their lifecycle. Key initiatives include:

- **Modernization of asset management and maintenance practices:** EDCs should modernize asset management by combining usage-based preventive maintenance, strategic asset prioritization, reliability-centered maintenance, and risk-based asset management. This will enable more structured maintenance and investment decisions, align interventions with reliability objectives, and focus resources on assets with the greatest operational impact and risk exposure.
- **Digitalization of work management:** EDCs should digitize work management practices by enabling direct, real-time communication between field crews and dispatchers and providing field personnel with on-site access to historical asset information and relevant data. This will improve coordination during planned and unplanned work, reduce dependence on incomplete records, and support better-informed execution decisions in the field.

From an implementation standpoint, this program may require both system upgrades and process changes. Deploying tools alone is not enough. EDCs will also need to adapt workflows and ensure teams are trained to use new capabilities effectively.

The value of this program is seen in day-to-day operations. Work becomes more efficient. Decisions are better supported. Asset performance improves over time.

Adoption may vary depending on the starting point. Some EDCs may focus first on digitizing workflows, while others may prioritize advanced asset strategies.

Key Technology Dependencies

- Communication and connectivity infrastructure (Distributed Operational Network, Company Office Backbone)

- Operational data and analytics platforms (Time Series Archive, Operational Data Reporting, Analytics)
- Asset management and performance systems (Asset Information Center, Strategic Asset Management, Condition Monitoring, Performance Reporting)
- Work management and field enablement systems (Work Dispatch, Operational Planning, Mobile Workforce)
- Geospatial and visualization capabilities (Geospatial Visualization, Geospatial Analytics)
- Reliability and advanced asset analysis tools (Reliability Analysis – DMS)

Key Technologies to be Deployed

- Digital work management platforms
- Mobile tools for field crews
- Asset analytics and lifecycle management systems

Non-Technology Related Efforts

- Redesign of work processes and workflows
- Training for field and asset management teams
- Alignment between planning, operations, and maintenance functions

Program Outcomes

- Increases efficiency of field operations
- Improves visibility into asset condition and performance
- Enables better prioritization of maintenance and investment
- Reduces reliance on manual and paper-based processes

Key Milestones

- Deployment of digital communication tools for field crews
- Implementation of condition and usage-based maintenance strategies
- Enablement of real-time access to asset data in the field
- Introduction of risk informed asset management approaches

11.4.P04: DSM Optimization

Phase
Foundations phase

Objective
Enable the initial deployment and optimization of demand-side management (DSM) capabilities to better align electricity consumption with system needs and improve overall grid flexibility.

Program Description
P04 focuses on activating and structuring demand-side flexibility as a usable operational and planning tool. While many EDCs already have some form of DSM programs in place, these efforts are often limited in scope, lack coordination, or are not integrated into grid operations and planning processes. Programs are designed at a high level, applied broadly, and only connected to system level load management.

EDCs typically lack predictability and insights into how customers respond in practice, and that makes DSM unreliable for operational decisions. Key initiatives include:

- **DSM response forecasting and behavioral analytics:** EDCs should develop analytical capabilities to better understand how different customer segments respond to DSM signals. These capabilities should typically also include a locational element. These insights will help improve program design and allow demand response to be used more reliably in both planning and operational contexts.
- **DSM program optimization and targeting:** Current DSM programs have gaps (e.g. Residential DR, need for control devices upgrades). EDCs should optimize and target DSM programs across commercial, industrial, and residential customer segments by evolving from broad participation models to more tailored, customer-segment specific approaches. This includes initial deployment of controllable DSM for Residential and C&I customers, refinement of market-oriented schemes for individual facilities, and targeted residential initiatives aligned with usage patterns, system needs, and market signals.
- **Update and standardization of performance measurement and verification (Non-EDC Initiative):** EDCs highlight need to update and standardize performance measurement and verification (M&V) practices to improve consistency across PJM, state, and other agency requirements. This includes aligning methodologies, data definitions, and reporting approaches so that DSM performance should be assessed more consistently, compared more reliably across programs, and used with greater confidence in planning, regulatory, and operational contexts.
- **Define a Security Baseline and Policy for DSM Participants:** EDCs will need to develop a standard approach that segments the data connections between DSM Participants, and the EDC owned digital assets to mitigate the risks associated with increasing the attack surface. Additionally implement robust cyber detection and monitoring solutions to be able to identify anonymous behavior from asset beyond their command and control.

From an implementation standpoint, this may be a mix of tools and discipline. New analytics and control platforms may be needed. But just as important is how programs are designed, how results are tracked, and how operations begin to trust the outcomes.

This program is intentionally pragmatic. It does not try to solve everything at once. It builds the minimum level of control and predictability needed so that demand flexibility can start playing a real role in grid management. Different EDCs may move at different speeds. Some may start small, proving value through pilots. Others may scale existing programs quickly but refine them along the way.

Key Technology Dependencies

- Communication and connectivity infrastructure
- Data management and time-series platforms
- AMI
- Customer-side control and enablement systems

Key Technologies to be Deployed

- DSM analytics and response modeling tools
- Customer engagement and communication platforms

Non-Technology Related Efforts

- Evaluation of DSM portfolio and participation models
- Customer outreach and enrollment strategies
- Alignment with regulatory and tariff structures

Program Outcomes

- Makes demand response more predictable and operationally usable
- Improves the ability to manage load at a local level
- Adds flexibility without immediate infrastructure investment
- Creates a foundation for more advanced DER and market integration

Key Milestones

- Establish DSM response models
- Enable targeted, location-specific DSM actions

11.5. P05: DER Foundations

Phase
Foundations phase

Objective
Establish the foundational technical, procedural, and regulatory capabilities required to integrate DERs into distribution networks in a structured, scalable, and transparent manner.

Program Description
P05 addresses the initial transition toward more DER by focusing on the basic capabilities required to connect, assess, and manage DER. As DER penetration increases, traditional interconnection processes and planning approaches often become insufficient, leading to delays, inefficiencies, and limited visibility into system impacts.

Current environments show that many EDCs manage DER connections through fragmented processes, with limited standardization and minimal integration into broader planning and operational frameworks. Hosting capacity is often assessed on a case-by-case basis, and the ability to evaluate system impacts at scale remains constrained. Through this program, EDCs should establish structured processes and analytical capabilities that enable systematic DER integration while maintaining system reliability. Key initiatives include:

- **DER data exchange, registry, and visibility enablement:** EDCs should establish foundational frameworks and systems to support DER registration, data sharing, aggregation, and tracking of DER assets, associated tariffs, and interconnection status. This will create a more complete and consistent source of truth, improve transparency for planning, operations, and regulatory purposes, and enable better coordination of distributed resources across multiple stakeholders.
- **Standardized and flexible DER interconnection frameworks:** EDCs should establish consistent and transparent procedures for connecting DERs to the network, while enabling interconnection under defined operating constraints where appropriate. This will reduce variability across cases, provide clarity for developers, customers, and internal teams, support higher DER penetration, implement strong cybersecurity mitigations, and maintain system reliability while avoiding unnecessary reinforcement.
- **Hosting capacity assessment, mapping, and continuous update:** EDCs should establish capabilities and processes to estimate, visualize, and regularly update hosting capacity at high spatial and temporal resolution across the network. This may provide a clearer view of where additional DER can be accommodated without major upgrades and help ensure that planning decisions and interconnection approvals reflect current system conditions.

From an implementation perspective, this program combines analytical tool development with process standardization and regulatory alignment. Technology deployments focus on hosting capacity tools, DER data systems, and integration platforms, while non-technology efforts include interconnection policy development and stakeholder coordination.

This program is essential as an entry point for DER integration. Without these foundational elements, more advanced capabilities such as DER dispatch, market participation, and real-time coordination cannot be effectively realized.

Implementation approaches will differ depending on DER penetration levels and regulatory environments. Some EDCs may prioritize improving interconnection processes, while others may focus on building analytical capabilities and visibility into DER impacts.

Key Technology Dependencies

- Communication and network data infrastructure
- Network modeling and planning capabilities
- System analysis and performance modeling
- Geospatial and visualization systems

Key Technologies to be Deployed

- Hosting capacity analysis and mapping tools
- DER registration and data management platforms
- Integration platforms for DER data exchange

Non-Technology Related Efforts

- Development of standardized interconnection procedures and flexible interconnection frameworks
- Regulatory and policy alignment for DER integration
- Coordination with customers, developers, and aggregators

Program Outcomes

- Enables structured and scalable DER interconnection
- Improves visibility into network hosting capacity
- Supports efficient integration of distributed resources
- Provides foundation for advanced DER coordination and markets

Key Milestones

- Implementation of standardized interconnection processes
- Deployment of hosting capacity mapping capabilities
- Introduction of DER registration and monitoring frameworks

11.6. P06: Planning and Analytics Modernization

Phase
Enablement and integration Phase

Objective
Enhance planning processes and analytical capabilities by embedding advanced forecasting, scenario modeling, and optimization techniques into decision-making frameworks across planning and asset management functions.

Program Description
P06 addresses the growing need for more complex planning and analytics capabilities as distribution networks become increasingly complex. Traditional planning approaches, which often rely on static assumptions and limited datasets, are no longer sufficient to manage evolving system conditions, DER integration, and changing demand patterns.

In many current environments, planning activities are largely deterministic, with limited ability to evaluate alternative scenarios or proactively assess future system behavior. Data is often available but not fully leveraged to support predictive or optimization-driven decision-making. Through this program, EDCs should transform planning into a more dynamic, data-driven discipline. Key initiatives include:

- **KPI Forecasting and scenario-based planning capabilities:** EDCs should introduce forecasting approaches that project KPIs using historical data and more advanced analytical techniques, while also enabling scenario-based planning through variation of key input parameters. This will provide forward-looking insight into system performance trends, improve the accuracy and reliability of projections, and allow EDCs to evaluate alternative futures to support more resilient decision-making.
- **Optimization-driven network planning:** EDCs enhance planning practices by introducing optimization techniques guided by strategic criteria such as cost efficiency, reliability targets, and capacity constraints. These approaches enable more informed and balanced investment decisions.
- **Integration of non-wire alternatives (NWA):** Planning processes are expanded to systematically include the evaluation of non-wire alternatives. This enables comparison of traditional infrastructure investments with solutions such as DER, demand response, and storage.

From an implementation perspective, this program combines deployment of advanced analytics tools with updates to planning methodologies and internal processes. Technology efforts focus on forecasting platforms, simulation tools, and analytical engines, etc. Non-technology efforts include redefining planning standards, integrating new evaluation criteria, and aligning planning with operational insights.

This program plays a pivotal role in bridging foundational data capabilities and advanced operational outcomes. By modernizing planning and analytics, EDCs can better anticipate system needs, optimize investment decisions, and support the transition toward a more flexible and distributed grid.

Key Technology Dependencies

- Communication and enterprise connectivity infrastructure

- Core planning and network modeling systems
- AMI and SCADA

Key Technologies to be Deployed

- Forecasting and simulation platforms
- Data analytics and scenario modeling systems

Non-Technology Related Efforts

- Update of planning standards and methodologies
- Integration of NWA evaluation into decision-making processes
- Alignment between planning, operations, and asset management teams

Program Outcomes

- Improves accuracy and effectiveness of planning decisions
- Enables proactive and scenario-driven system management
- Optimizes capital investment and resource allocation
- Supports integration of DER and alternative solutions

Key Milestones

- Implementation of optimization-based planning capabilities
- Deployment of outage impact and scenario analysis tools
- Establishment of KPI forecasting and projection frameworks
- Updated optimization based planning process to include NWAs

11.7. P07: Grid Monitoring and Visibility

Phase
Enablement and integration

Objective
Develop comprehensive, topology-aware monitoring capabilities across the network to improve situational awareness and enable more informed operational and planning decisions.

Program Description
P07 focuses on addressing gaps in network visibility that limit the ability of EDCs to fully understand real-time grid conditions. Although many EDCs already capture operational data through SCADA, metering systems, and field devices, this customer connectivity information is often non-integrated, inconsistently structured, and not tightly linked to the network model.

This program enhances grid observability by integrating monitoring data with network topology, establishing structured aggregation layers, and enabling consistent events tracking across assets and network segments. Key initiatives include:

- **Topography based monitoring and asset level visibility:** EDCs should introduce structured grid hierarchies that group assets and measurements into logical aggregation layers, directly map online power quality monitoring to the network topology, and expand monitoring across critical assets to capture real-time events, alarms, and status changes. This will enable more consistent analysis, reporting, and monitoring aligned with the actual network structure, improve disturbance identification and understanding of how issues propagate across interconnected network segments, and enhance early detection of abnormal conditions through stronger asset-level visibility.
- **Standards-compliant network model including customer and grid-edge connectivity:** EDCs establish network model management practices that align with recognized standards and include detailed customer connectivity, while extending network models to incorporate grid-edge and distributed resource connectivity. This ensures consistent representation of the network for both operational and planning use cases and creates a more comprehensive system view to support monitoring, analysis, and future DER integration.
- **Integrate Secondary Asset Management and Inventory:** Integrate a robust policy and technology to inventory and manage the critical telecommunication and digital asset that are apart of the critical data path and telemetry for EDCs. Allowing for active monitoring and control of these asset to be able to assess and understand the potential impacts or activities that are reliant on these assets.

From an implementation standpoint, this program combines deployment of monitoring infrastructure with improvements in data integration and modeling practices. Technology efforts include sensors, measurement systems, and advanced management platforms, while organizational efforts focus on defining monitoring standards and aligning processes across planning, operations, and asset management teams.

This program is an essential stepping stone toward more advanced grid capabilities. Without reliable and topology-aware monitoring, capabilities such as automated operations, advanced analytics, and DER coordination cannot be effectively realized.

Key Technology Dependencies

- Communication and connectivity infrastructure
- Operational data and model management platforms
- AMI and Meter Data Management
- GIS and visualization capabilities

Key Technologies to be Deployed

- Field sensing and monitoring equipment
- Enhancements to DMS
- Network model management platforms
- Data integration and event processing systems

Non-Technology Related Efforts

- Development of standardized monitoring and aggregation frameworks
- Coordination across planning, operations, and asset management functions

Program Outcomes

- Enhances visibility into real-time grid conditions
- Supports topology-based monitoring and diagnostics
- Improves identification of power quality issues and asset-related events
- Establishes a foundation for automation and advanced grid operations

Key Milestones

- Implementation of topology-based aggregation and monitoring structures
- Extension of network models to include customer and grid-edge connectivity

11.8. P08: Dynamic Network Modeling and Capacity Optimization

Phase
Enablement and integration phase

Objective
Advance network modeling capabilities to support dynamic system representation and enable more efficient utilization of existing grid capacity through enhanced analytics and planning approaches.

Program Description
P08 addresses limitations in traditional planning practices where network models and design approaches are largely static and do not fully reflect evolving grid conditions. As DER penetration increases and system complexity grows, static assumptions are no longer sufficient to ensure efficient and reliable network operation.

Through this program, EDCs modernize their planning and modeling capabilities by incorporating dynamic data inputs, improving analytical methods, and enabling more adaptive use of grid capacity. Key initiatives include:

- **Planning and adaptive network design for emerging technologies:** EDCs should enhance planning and design processes by incorporating new data sources, technologies, and operational insights into network design, forecasting, and investment decisions, with particular emphasis on emerging resources such as batteries, EVs, and other grid-edge technologies. This will allow planning decisions to better reflect actual system behavior and adoption trends, reduce overengineering, and support more targeted, flexible, and cost-effective infrastructure investments.
- **Dynamic rating and near real-time capacity assessment:** EDCs should establish analytical models for DLR and DTR, leveraging environmental conditions and load data to determine more accurate equipment capacity in real-world conditions, and operationalize these calculations through near real-time analytics and visualization tools. This will enable operators and planners to better understand available capacity under current conditions and support more responsive use of existing infrastructure.

From an implementation perspective, this program combines enhancements in analytical tools with improvements in data usage and planning processes. Technology efforts include advanced analytics platforms, integration of weather and load data, and visualization tools, while non-technology efforts focus on updating planning standards, methodologies, and decision frameworks.

This program is a critical step toward maximizing utilization of existing infrastructure. By enabling more precise and dynamic understanding of capacity limits, EDCs can defer capital investments, integrate more DER, and improve overall system efficiency.

Key Technology Dependencies

- Network modeling and planning systems
- Field sensing and measurement capabilities

- Geospatial and visualization platforms
- Asset data management systems

Key Technologies to be Deployed

- Advance network models and planning tools
- Dynamic rating engine

Non-Technology Related Efforts

- Update of planning standards and design methodologies
- Development of operating procedures for dynamic capacity usage
- Alignment between planning and operations teams
- Training in advanced analytics and modeling techniques

Program Outcomes

- Improves accuracy and responsiveness of network planning models
- Enables more efficient use of existing grid capacity
- Supports increased integration of DER without immediate infrastructure expansion
- Enhances coordination between planning and real-time operations

Key Milestones

- Integration of advanced technologies into planning processes
- Implementation of near real-time capacity monitoring and visualization tools
- Development and validation of DLR/DTR models

11.9. P09: Core Grid Operations Automation

Phase
Optimization and market alignments phase

Objective
Enable automated, real-time grid operations by embedding intelligence into control systems, allowing faster response to network conditions and improved reliability through reduced manual intervention.

Program Description
P09 focuses on transitioning distribution grid operations from largely manual and operator-driven processes toward automated, system-assisted control. While EDCs currently rely on operator judgment supported by SCADA and outage management tools, response actions such as switching, fault isolation, and network reconfiguration often remain manual or only partially automated.

This program introduces automation across key operational processes, allowing systems to analyze conditions and execute control actions with minimal human intervention. The objective is to improve both the speed and accuracy of operational responses while reducing reliance on manual decision-making. Key initiatives include:

- **Automated network reconfiguration:** EDCs implement systems that can automatically determine improved network configurations to optimize load flows and reduce technical losses. This enables more efficient operation without requiring continuous operator intervention.
- **Targeted congestion management and control:** EDCs deploy more granular control mechanisms that allow selective management of network constraints. This includes the ability to control specific loads or assets in response to localized congestion issues.
- **Automation of switching and outage planning:** Systems are introduced to support automatic generation of switching schedules for planned outages, ensuring consistency, safety, and efficiency in execution while reducing manual workload.
- **Fault detection and service restoration:** EDCs implement automated capabilities for identifying fault locations, isolating affected sections, and restoring service to unaffected areas. This significantly reduces outage duration and improves service reliability.
- **Implementation of Baseline monitoring and logging:** To mitigate potentially harmful conditions caused by misconfiguration either malicious or unintentional EDCs should implement capabilities to alert on the logged settings and baseline changes to automation assets. This will provide assurance of the current state of these assets without requiring manual processes to validate configurations.

From an implementation standpoint, this program may require both system upgrades and process transformation. Technology deployment may include advanced control platforms, intelligent field devices, and enhanced communication systems. In parallel, EDCs may need to adapt operating procedures, redefine responsibilities, and ensure alignment between operational and technical teams.

The value of this program lies in its ability to increase grid responsiveness and resilience. Automation reduces delays associated with manual intervention and enables consistent execution of operational actions, especially under complex or rapidly changing conditions.

Key Technology Dependencies

- Network analysis and modeling capabilities
- Network configuration and change management systems

Key Technologies to be Deployed

- DMS with advanced automation functions
- Field automation devices (switches, reclosers, controllers)
- Advanced protection and control systems
- Real-time analytics and control applications

Non-Technology Related Efforts

- Revision of operational procedures to support automation
- Definition of control strategies and automation boundaries
- Training of operators in automated and semi-automated environments
- Coordination between operations, protection, and planning teams

Program Outcomes

- Reduces outage duration and improves reliability metrics
- Enables faster and more consistent operational response
- Optimizes network performance through automated reconfiguration
- Lowers operational workload and reliance on manual intervention

Key Milestones

- Deployment of automated network reconfiguration capabilities
- Activation of automated fault location, isolation, and restoration functions

11.10. P10: DER Operational Integration and Market Access

Phase
Optimization and market alignments phase

Objective
Enable full operational integration of DER while supporting their active participation in energy markets through coordinated control, forecasting, and settlement mechanisms.

Program Description
P10 is centered on moving DER from a largely passive presence on the grid into an actively managed and coordinated resource. In many current environments, DER visibility is limited, control is minimal, and participation in market mechanisms is either constrained or handled outside of core EDCs operations.

The program introduces the capabilities required to treat DER as a flexible and dispatchable part of the system. Rather than simply accommodating DER, EDCs begin to actively integrate, forecast, and utilize these resources in both operational and market contexts. Key initiatives include:

- **Locational value, forecasting, and performance verification:** EDCs should establish mechanisms that quantify the distribution-level value of DER based on location and system conditions, while also introducing advanced forecasting capabilities and performance verification processes to support scheduling, control, and validation of DER behavior. This will enable more accurate compensation structures aligned with grid needs, improve confidence in expected DER performance, and support more reliable operational and market use of distributed resources.
- **Aggregator coordination, telemetry integration, and settlement enablement:** EDCs should implement frameworks to coordinate with DER aggregators, exchange high-resolution operational measurements, integrate those measurements into core systems such as the DMS, validate dispatch performance, and support settlement processes for market participation. This will improve near real-time visibility and controllability of distributed resources while creating the operational and commercial foundation for coordinated DER participation.
- **Real-time and constraint-aware DER dispatch:** EDCs should introduce platforms and operational processes that actively manage DER dispatch while continuously validating actions against real-time network constraints. This will improve reliability, maximize system flexibility, and ensure that DER dispatch remains aligned with actual network conditions.
- **Define a Security Baseline and Policy for DER Participants:** EDCs will need to develop a standard approach that segments the data connections between DER Participants, and the EDC owned digital assets to mitigate the risks associated with increasing the attack surface. Additionally, implement robust cyber detection and monitoring solutions to be able to identify anonymous behavior from assets beyond their command and control.

From an implementation perspective, this program may represent a significant evolution in both technology and operating models. It may require integration of DERMS platforms, enhancements to existing operational systems, and development of new interfaces with external market participants. In parallel, EDCs may need to define new processes for coordination, dispatch, and settlement.

This program is critical for enabling a distributed and flexible energy system. By integrating DER into both operations and markets, EDCs can unlock additional capacity, improve system efficiency, and support broader decarbonization goals.

Given the complexity involved, implementation will typically be phased. Some EDCs may begin with visibility and forecasting capabilities before advancing toward full dispatch orchestration and market integration.

Key Technology Dependencies

- Grid-edge and communication infrastructure
- Network modeling and planning capabilities

Key Technologies to be Deployed

- DERMS
- Forecasting and analytics platforms
- High-frequency telemetry and data ingestion systems
- Dispatch coordination and control systems
- Market integration and settlement solutions

Non-Technology Related Efforts

- Development of DER compensation and market participation frameworks
- Establishment of dispatch and settlement processes
- Cross-functional alignment between operations, planning, and market teams

Program Outcomes

- Enables active DER participation in grid operations and markets
- Improves visibility and controllability of distributed resources
- Supports efficient and constraint-aware dispatch decisions
- Unlocks additional system flexibility and capacity

Key Milestones

- Implementation of DER valuation and compensation frameworks
- Establishment of aggregator coordination and settlement processes
- Enablement of real-time, constraint-aware DER dispatch

11.11. P11: Advanced Grid Optimization

Phase
Optimization and market alignments phase

Objective
Enable continuous, automated optimization of grid operations through advanced control mechanisms that dynamically respond to changing system conditions.

Program Description
P11 reflects the final stage of grid evolution, where the network operates with a high degree of autonomy. At this point, optimization is no longer something performed periodically or manually, and it becomes an inherent and ongoing function of the system itself.

In earlier stages, operators and predefined rules still play a major role in decision-making. Here, that reliance is significantly reduced. Systems should be capable of evaluating conditions in real time and determining appropriate actions without waiting for human input. The transformation is not only technological. It also represents a shift in how EDCs think about control, responsibility, and operational trust. Key initiatives include:

- **Real-time optimization with dynamic ratings and closed-loop control:** EDCs should integrate DLR and DTR capabilities directly into operational systems and tightly couple measurement, analytics, and control within a continuous feedback loop. This will allow real-time capacity limits to be considered automatically in congestion management, switching operations, and DER dispatch decisions, while enabling the system to monitor conditions, execute actions, evaluate results, and refine behavior continuously to support ongoing optimization.
- **Autonomous remedial action determination and execution:** The grid should be equipped to initiate preconfigured corrective actions as soon as specific thresholds or conditions are detected, while also gaining the ability to identify and initiate the most appropriate remedial actions based on current network conditions. This will enable immediate, consistent, and more adaptive responses to both expected and unforeseen scenarios, with less reliance on manual intervention.
- **Autonomous network reconfiguration and self-healing functionality:** EDCs should enable systems to determine and directly implement improved grid configurations while autonomously detecting faults, isolating affected sections, and restoring service wherever possible. This will ensure that the network continuously operates in a more efficient and balanced state, enhance resilience, and reduce outage impacts without requiring operator instruction for each action.
- **Update and refine Cybersecurity Policies and Procedures:** Define accountability, risk tolerance, and oversight for autonomous grid operations and decision-making. Require standardized security controls, continuous monitoring, and compliance with industry frameworks to ensure the integrity and resilience of automated systems. Mandate auditability, transparency, and human oversight mechanisms to ensure all automated actions remain traceable, controllable, and aligned with organizational risk management objectives.

From an implementation perspective, this program may require tight coordination between advanced analytics, control systems, and communication infrastructure. High-speed data exchange may become critical. Equally important are organizational changes. EDCs may need to define governance structures for automated decision-making and build confidence in systems that operate with minimal human oversight.

The outcome is a grid that continuously optimizes itself. It operates closer to its true limits while maintaining reliability. It also provides the flexibility needed to support high levels of DER integration.

Key Technology Dependencies

- Operational Data Management Systems
- Field sensing and monitoring systems
- Field device control and automation infrastructure

Key Technologies to be Deployed

- Advanced optimization and control algorithms
- DMS with integrated constraint and dynamic rating management
- High-speed telemetry and sensing technologies
- Automated protection and control devices
- Real-time analytics and decision engines

Non-Technology Related Efforts

- Establishment of governance frameworks for autonomous operations
- Definition of policies for automated control and decision-making
- Workforce training and transition to automation-driven operations
- Cross-functional integration across planning, operations, and engineering teams

Program Outcomes

- Enables continuous, real-time optimization of grid operations
- Improves reliability through fast and autonomous response mechanisms
- Maximizes utilization of existing network capacity
- Supports high DER penetration while maintaining system stability

Key Milestones

- Integration of DLR/DTR into operational decision systems
- Enablement of automated network reconfiguration execution
- Implementation of self-healing network functionality

12. Appendix D: Stakeholder Comments

From: Steve Hegedus, UD Electrical Engineering (retired)

ssh@udel.edu

July 20, 2026

To: Scott Hunter, DNREC

Re: comments regarding Siemen’s draft report “Analysis of Delaware’s Electricity Distribution Grid”

I find this a valuable document. It summarizes in one place useful numbers regarding electric generation and sales, customer class and operating characteristics for the various DE utilities. The report and their presentation on July 20, 2026 are clear and concise.

However, their findings and recommendations are quite similar to those I had in my report from 3 years ago (June 2023) where I surveyed the 3 utilities (EDC) on their grid modernization efforts. Comparing pp-4-5 of my report where I list Key Findings to pp 129-130 of Siemens report, you find that many of their findings echo what I found and our recommendations are similar as well. This suggests that while there has been some sporadic and incremental progress in this area in the past 3 years, there has not been stronger focus on innovative projects to take any of them into Grid 2.0. Common deficiencies and solutions from both reports include 1. making customer DER and DSM more visible and actively managed (DERMS) rather then just occasional peak power events; 2. more aggressive planning and deployment of NWA to meet increased demand; or 3) deploying BESS at both residential and utility scale.

Siemens took a much more comprehensive and sophisticated approach and they have much more expertise than I have. It is a more authoritative final analysis. But still it is disappointing that in 3 years we have not made more progress in this area.

It is valuable to have identified the gaps but it is concerning that there are such large gaps between current status and future goals in critical areas which I had also identified. For example, Table 30 shows significant gaps in areas releated to network operation and modeling which is necessary for knowing where and when to deploy DER or DSM resources. Being able to model power flow on their network is fundamental to a utility. I know that all of them do it so I am assuming that this gap refers to the more advanced modeling incorporating active DER and DSM control or new line sensor data.

One page 125 it says “Energy supply coordination today is oriented toward meeting aggregate peak reduction, supporting wholesale market participation, or delivering customer program benefits, rather than addressing localized distribution system needs.” To me this means they tend to address short term peaking-driven solutions rather than more holistic, system-wide solutions. This is reiterated on top of p127.

The conclusion at the bottom of page 127-128 identifies what I think is one of the biggest weaknesses and gaps for our EDCs "Across all EDCs, DER control capabilities remain limited and largely non-operational. Current capabilities are generally confined to interconnection-based registries, basic DER forecasting, limited system-wide signaling, and post-event measurement. However, these capabilities remain program-driven and are not aligned with real-time system conditions, and meaningful control or dispatch capability is not yet in place". What they are describing is a DERMS approach. This is a major investment in people, hardware and communication networks but is essential to achieve true 'smart grid' that addresses the goals outlined in first chapter.

Regarding reliability, Siemens says that all three EDC's have strong reliability numbers which exceed industry norms. On page 51 they comment regarding DPL's investments in reliability that "This robust reliability performance may present an opportunity to direct increased efforts towards grid modernization and decentralization efforts compared to traditional system hardening approaches." I would like them to emphasize this and clarify – are they recommending that DPL and perhaps other decrease funding on tree trimming and undergrounding wires to increase funding in grid modernization like NWA, DER and DSM. This would be very timely since spending to enhance reliability has become a contentious issue this year because it used by DPL as a justification for rate increase applications to the PSC yet others claim those charges not justified due to diminishing returns. This could be elevated in their conclusions.

I hope that GEAC will discuss this report in detail at our next meeting.

Two minor suggestions;

a. On page 98 they use term 'adhesion' but I think they mean 'adherence'.
b. on page 129 the paragraph starting 'The state target…" is describing VPP but does not use the acronym. Since they use the term VPP several times, they should use it again here to specify what they are referring to.

July 22, 2026

Mr. B. Scott Hunter
Principal Planner | Energy Section
Division of Climate, Coastal and Energy
Department of Natural Resources and Environmental Control
100 West Water Street
Dover, DE 19904

Dear Mr. Hunter:

Delmarva Power & Light Company (DPL) appreciates the Department of Natural Resources and Environmental Control's (DNREC) leadership in advancing grid modernization across Delaware. We specifically commend DNREC's collaboration with Siemens and utility stakeholders in developing the report, *Analysis of Delaware's Electricity Distribution Grid: Final Report*, which provides a thoughtful assessment of grid-enhancing technologies and opportunities for modernization. DNREC's partnership with Delaware's electric utilities is critical to ensuring that grid modernization efforts are practical, customer-focused, and aligned with the realities of operating the electric system.

Utilities play a unique role in advancing grid modernization through their direct relationships with customers, operational experience, and responsibility for planning and maintaining the electric system. Customer programs, advanced technologies, and modern grid management tools enable utilities to monitor, optimize, control, and upgrade the distribution system in ways that improve reliability, increase system utilization, and reduce long-term costs. These capabilities are especially important now, as Delawareans face significant affordability pressures driven by rising wholesale energy costs, capacity market volatility, and growing electricity demand.

DPL believes the report comprehensively evaluates the current state of Delaware's electric grid, identifies opportunities relative to evolving industry practices, and establishes a useful roadmap for future modernization activities. To further strengthen the report as a decision-making resource for state agencies, utilities, policymakers, and stakeholders, DPL offers the following recommendations:

Recommendation 1 - Acknowledge SB 326's Constraints and Include a Sensitivity Analysis on Policy Scenarios

The statutory caps that Senate Bill (SB) 326 introduces on the recovery of "non-mandatory capital spending," limiting recovery to $70 million in 2026–2027 and 5% of rate base beginning in 2028, create conflict and uncertainty. Yet the statewide report makes clear that Delaware is entering a period of structural change that requires accelerated investment in foundational capabilities—precisely the types of investments that fall under “non-mandatory” categories in DPL’s Infrastructure, Safety, and Reliability (ISR) Plan.

Further confusion stems from the bill defining *all* capital spending as Non-Mandatory stating that “non-mandatory capital spending shall mean all capital spending by the electric distribution company” with six limited exceptions. It does not refer to Title 26 of the Delaware Administrative Code, which states “non-mandatory spending shall include those projects, programs, or other investments, including Non-Wire Alternatives (NWA), necessary to maintain or improve distribution services and not included in the Mandatory spending category.” Nor does it define “capacity expansion” or “asset condition”, which are the two categories defined as Non-Mandatory” in Title 26 of the Delaware Administrative Code, but which are not mentioned in SB 326. DPL’s ISR Plan filing demonstrates this conflict clearly. Many of the modernization activities Siemens identified in this report—such as advanced distribution automation, Advanced Distribution Management System (ADMS) implementation, fiber optic builds, smart fault sensors, hosting capacity analytics, Distributed Energy Resource Management System (DERMS)-enabling communications networks, and system capacity/load projects—are categorized as Non-Mandatory in the ISR Plan. These categories include System Capacity/Load, System Performance – Distribution, System Performance – Automation, System Performance – Substation, and All Other Projects. These are the very categories where grid-enhancing technologies (GETs) reside: automation upgrades, smart sensors, ADMS, mesh networks, fiber builds, and Distributed Energy Resource (DER)-enabling technologies. Under SB 326, these modernization investments are subject to strict caps and therefore create conflict because the statewide report identifies them as essential to maintaining reliability and affordability.

This creates direct tension: the report calls for increased investment in foundational capabilities, while SB 326 restricts recovery of those investments. Without acknowledging this tension, stakeholders may not fully understand why modernization cannot proceed at the pace or scale the report recommends.

Beyond creating investment constraints, SB 326 may also limit Delaware's ability to achieve several of the policy objectives identified throughout this report, including increased DER adoption, electrification, managed Electric Vehicle (EV) charging, improved hosting capacity, enhanced system flexibility, expanded non-wires alternatives, and long-term affordability. Achieving these objectives requires deployment of foundational capabilities such as advanced distribution automation, DERMS, ADMS, communications networks, hosting capacity analytics, and system capacity enhancements. However, many of these investments fall within categories currently classified as Non-Mandatory under DPL's ISR Plan and are therefore subject to SB 326's recovery limitations. As a result, Delaware's policy aspirations and its current investment recovery framework may not be fully aligned.

One potential pathway to better align Delaware's policy objectives with implementation realities would be to incorporate a forward-looking ratemaking mechanism within the ISR framework for qualified grid modernization investments. Such a mechanism could facilitate timely recovery of prudently incurred investments in foundational grid capabilities identified throughout this report while maintaining Commission oversight and appropriate customer protections. By providing a regulatory pathway for deployment of qualifying grid modernization investments, a forward-looking ratemaking mechanism could help Delaware achieve the future-state capabilities and maturity goals identified throughout this report.

The report should acknowledge that successful implementation of Delaware's grid modernization roadmap depends not only on technology adoption, but also on regulatory structures that allow utilities to recover investments in a timely manner. Without such mechanisms, Delaware's ability to achieve many of the policy outcomes envisioned in this report may be significantly delayed.

To help policymakers understand the practical implications of these constraints, the report would benefit from a sensitivity analysis that evaluates how Delaware's ability to reach the future-state maturity levels identified in the GAP analysis depends on supportive regulatory and policy conditions. The GAP analysis outlines a clear trajectory toward advanced capabilities such as integrated network models, DERMS, ADMS, hosting capacity analytics, expanded automation, Demand-Side Management (DSM) optimization, and enhanced system visibility. These capabilities are foundational to achieving the reliability, flexibility, and affordability outcomes described throughout the report. However, the State's current policy environment—including SB 326's capital-spending caps—materially limits the pace and scale at which these capabilities can be deployed.

This sensitivity analysis could include four specific scenarios:

Scenario 1 — Current SB 326 Caps (Constrained Modernization)

Non-Mandatory capital recovery remains limited; GET deployment slows; foundational capabilities such as ADMS, DERMS, and hosting capacity analytics are delayed; maturity levels advance slowly; affordability pressures increase due to higher wholesale market costs, energy costs, system upgrade costs, and capacity costs.

Scenario 2 — Modified SB 326 Caps (Moderate Modernization)

The General Assembly expands or adjusts capital recovery limitations; foundational capabilities can be deployed earlier; utilities can pursue grid-enhancing technologies with greater certainty, DER integration improves; DSM and flexible load programs become more effective and set the foundation for future programs, and long-term customer costs decrease through improved system utilization and avoided infrastructure investments.

Scenario 3 – ISR with Forward Looking Ratemaking Mechanism for Grid-Enhancing Technologies (Policy Alignment Scenario)

Delaware retains existing investment controls while incorporating a forward looking ratemaking mechanism within the ISR framework for specified grid modernization investments, including ADMS, DERMS, distribution automation, hosting capacity analytics, communications networks, managed EV charging enablement, and other grid-enhancing technologies. This approach provides timely cost recovery, improves investment certainty, accelerates deployment of foundational capabilities, supports State electrification and DER objectives, and accelerates progress toward the future-state maturity levels identified in the GAP analysis while maintaining appropriate regulatory oversight and accountability.

Scenario 4 — Targeted Exemptions for GETs (Accelerated Modernization)

The Delaware Public Service Commission approves targeted exemptions from SB 326 caps for GETs, automation, and DER-enabling technologies; Delaware reaches future-state maturity levels more quickly; hosting capacity improves; DERMS/ADMS are fully utilized; affordability improves through avoided upgrades and reduced peak demand.

Including these scenarios would help stakeholders understand how enabling policies accelerate modernization and reduce long-term costs, while restrictive policies delay maturity, increase exposure to wholesale energy and capacity market volatility, and ultimately raise customer bills.

The report should explicitly recognize that Delaware's ability to achieve its reliability, affordability, electrification, DER integration, and decarbonization objectives is not solely dependent upon technology deployment, but also upon policy changes and regulatory frameworks that enable deployment of the foundational investments required to support those objectives. A forward-looking ratemaking mechanism within the ISR framework represents one potential pathway to better align these policy objectives with implementation realities.

(Reference: Executive Summary, pp. 12–18; Section 8, pp. 154–155; GAP Analysis maturity model, Section 7.1–7.4)

Recommendation 2 – Clarify Funding Realities and the Importance of Timely, Predictable Cost Recovery

The report's Executive Summary and Section 8 highlight the need for foundational investments in data integration, system visibility, automation, and DER/DSM operational integration. These investments are essential to maintaining reliability and affordability as Delaware's grid faces aging infrastructure, rising wholesale costs, increasing imports of electricity, and growing electrification demands.

Across the United States, including Delaware, utility grid modernization planning and implementation are primarily funded through regulated distribution rates paid by customers. State agencies occasionally support targeted studies, as DNREC has done with this report, and federal programs such as Section 40101(d) and the U.S. Department of Energy's (DOE) Grid Resilience and Innovation Partnerships (GRIP) program have historically helped offset costs. However, several of the federal funding opportunities that supported grid modernization in recent years are no longer available, and others have been significantly reduced or refocused. Delaware cannot rely on federal grants to sustain the level of investment required to maintain and modernize the grid.

Delayed cost recovery increases financing costs and ultimately raises customer bills. The method and timing of cost recovery are therefore critical considerations in achieving Delaware's modernization objectives at the lowest reasonable cost to customers. Regulatory mechanisms that provide timely and predictable recovery, including a forward-looking ratemaking mechanism for eligible grid modernization investments, can reduce carrying costs, improve investment certainty, and allow utilities to deploy technologies more efficiently. Such mechanisms can support investments that deliver measurable customer and system benefits, including enhanced reliability, improved hosting capacity, expanded DER integration, increased utilization of existing infrastructure, reduced peak demand, and lower long-term system costs. Conversely, prolonged recovery timelines or uncertainty regarding cost recovery can increase financing costs, delay deployment of necessary investments, and ultimately increase the total cost of achieving Delaware's reliability, affordability, and grid modernization objectives.

While Recommendation 1 addresses the policy constraints associated with SB 326 and their impact on modernization, it is equally important to recognize the economic implications of recovery timing. Even where investments are ultimately approved, delayed recovery can increase the total cost borne by customers. Predictable regulatory treatment allows utilities to invest prudently and cost-effectively, reducing long-term costs and supporting more efficient deployment of grid modernization investments. As Delaware evaluates pathways to implement the roadmap described in this report, consideration should be given to recovery structures that balance appropriate regulatory oversight with the need to minimize financing costs and support timely deployment of foundational grid capabilities. Ultimately, achieving the grid modernization outcomes envisioned in this report will require not only supportive policies, but also practical and predictable funding mechanisms that allow utilities to invest in foundational capabilities at the pace required to meet evolving system needs. The report should explicitly acknowledge the importance of stable, predictable regulatory alignment, particularly in an environment where federal support for grid modernization has diminished.

(Reference: Executive Summary, pp. 12–18; Section 8, pp. 154–155)

Recommendation 3 – Strengthen the Connection Between System Conditions, Foundational Capabilities, and Long-Term Affordability

Delaware's system conditions make foundational capabilities especially urgent. Section 3.2 documents the State's increasing reliance on imported electricity and shows PJM Interconnection (PJM) rising summer peak demand. Rising Locational Marginal Prices (LMP) values and capacity prices demonstrate the growing cost pressures facing Delaware customers. The Executive Summary also notes emerging large loads such as data centers and electric vehicle adoption, which will further increase peak demand and stress existing infrastructure.

Foundational capabilities—such as hosting capacity analytics, DERMS, ADMS, and advanced automation—allow utilities to make better use of existing infrastructure, reduce the need for expensive traditional upgrades, and support cost-effective non-wires alternatives. They also improve planning accuracy, reduce future O&M costs, and enable DERs and flexible loads to reduce peak demand and capacity costs.

Given Delaware's affordability challenges, the report should emphasize that strategic investment in foundational capabilities is essential to addressing sustained affordability, and that policy constraints such as those contained in SB 326 may unintentionally increase long-term costs for customers by limiting the very investments that reduce those costs.

(Reference: Section 3.2, pp. 27–33; Figures 11–12; Section 4.6, pp. 90–92; Section 7.1–7.4, pp. 136–144)

Recommendation 4 – Elevate the Importance of DER Integration, Hosting Capacity, and Managed EV Charging

The report identifies DER growth and discusses DER integration in Section 11.5, but the urgency of modernizing interconnection processes and hosting capacity analytics should be more strongly emphasized. Customers increasingly expect timely interconnection, transparent hosting capacity information, and programs that allow DERs to provide grid services.

Modern hosting capacity tools, integrated network models, and DERMS platforms are essential to reducing customer frustration, improving planning accuracy, and avoiding costly upgrades.

These capabilities also enable DERs to reduce peak demand and capacity costs, supporting affordability through flexible load management.

Managed EV charging is a particularly strong example of a cost-effective grid-enhancing technology. The Delmarva Power/Pepco/BGE Maryland Smart Charge Management program demonstrates measurable benefits, including approximately $300 per participating EV per year in avoided distribution costs. These findings highlight the potential for managed charging to increase utilization of existing distribution infrastructure and defer future system investments while supporting transportation electrification goals.

The Maryland program also demonstrates how smart Electric Vehicle Supply Equipment (EVSE) and vehicle telematics can be used to shift charging to lower-cost and lower-demand periods, creating value for both customers and the electric system through reduced capacity costs, reduced energy costs, avoided distribution upgrades, improved reliability, and increased operational flexibility.

Managed charging reduces peak demand, defers upgrades, improves reliability, and supports transportation electrification—all while lowering customer costs. Managed charging programs are critical building blocks for grid modernization. Having a network of enrolled customers who are educated on issues and programs that affect their bills and who trust their utility company is foundational for full integration and full optimization through future advanced programs such as Vehicle-to-Grid (V2G) and Virtual Power Plants (VPP). Getting foundational programs established is an important step in managing peak load and lowering and deferring costs for customers. Policymakers should ask, "What will customers' bills look like if we do nothing?" Building out a foundation before utilities encounter system constraints is key.

Given Delaware's growing electricity demand and increasing supply and capacity costs, the report would be strengthened by highlighting nearby examples of successful implementation, such as the experience in Maryland, that can inform future program design and deployment decisions within the state.

(Reference: Section 3.2, pp. 35–37; Section 4.8, pp. 94–96; Section 11.5, pp. 170–172; Table 43, p. 99)

Recommendation 5 – Establish a Coordinated, Statewide DSM Strategy with Clear Goals, Targets, and Market-Potential Alignment

DSM and flexible load management are essential tools for maintaining affordability, reducing peak demand, and improving system utilization. The report correctly identifies DSM as a core component of Delaware's future-state maturity model. However, DSM in Delaware remains fragmented, inconsistently funded, and not fully integrated into utility operational systems. It is critical that all program administrators for DSM programs operate in a coordinated manner across the State. Without proper alignment, the resulting fragmentation limits the effectiveness of DSM, reduces the ability to target system needs, and prevents DSM from functioning as a true grid-enhancing technology.

DSM in Delaware is also not tied to statewide goals or performance targets, nor is it grounded in market-potential studies that quantify achievable savings, flexible load potential, or cost-effective opportunities. Without clear goals, targets, and market-potential alignment, DSM cannot be evaluated, optimized, or scaled in a way that meaningfully supports affordability or grid modernization.

A coordinated statewide DSM strategy—aligned with DERMS, ADMS, hosting capacity analytics, non-wires alternatives, and utility planning processes—would help Delaware achieve the future-state maturity levels identified in the GAP analysis. Such a strategy should include statewide DSM and Energy Efficiency (EE) goals and targets tied to system needs and affordability outcomes, market-potential studies to quantify achievable DSM and EE impacts, assigned goals for each program administrator including the Sustainable Energy Utility (SEU) and utilities, and integrated planning that aligns DSM with operational tools and grid-enhancing technologies.

(Reference: Section 11.10, pp. 180–182; Section 4.8, pp. 94–96; Executive Summary, pp. 12–18)

Recommendation 6 – Highlight the Need for Coordinated Statewide Planning and Utility-Specific Roadmaps
The roadmap correctly notes that utilities differ in size, complexity, and maturity. DPL recommends reinforcing that DPL's system requires earlier and more substantial investments due to scale and load growth, while smaller utilities may benefit from shared platforms and scalable solutions. DNREC should support coordinated statewide planning frameworks that allow utilities to advance modernization at appropriate paces.
Coordinated planning helps ensure modernization is efficient, equitable, and aligned with statewide affordability goals.

(Reference: Section 7.1–7.4, pp. 136–144; Figure 33, p. 139)

In conclusion, DPL supports the report's vision for a more modern, flexible, and customer-focused electric grid. Realizing that vision, however, will require more than the identification of promising technologies; it will require policy and regulatory frameworks that enable the deployment of the foundational investments upon which those technologies depend. Importantly, House Joint Resolution No. 3 (HJR 3) directed this study to evaluate not only the benefits of grid-enhancing technologies, but also their costs, feasibility, barriers to adoption, and reasonable pathways for implementation. The recommendations provided herein are intended to strengthen the connection between Delaware's grid modernization goals and the practical mechanisms needed to achieve them. With thoughtful regulatory alignment, coordinated planning, and a continued focus on customer affordability, Delaware can enable the deployment of grid-enhancing technologies contemplated by HJR 3 and meet the highest standards of reliability and resiliency while accelerating progress toward a cost-effective energy future.

DPL looks forward to continuing its work with DNREC and all other stakeholders to advance Delaware's energy grid. Thank you again for your leadership on these timely and critically important issues. We welcome our continued collaboration and remain available to discuss any of this feedback in greater detail.

Sincerely yours,

Joshua Cadoret

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Draft DE Distribution Grid Analysis Final Report DNREC SEO 07.06.26
Comments by Willett Kempton, U Delaware
18 July 2026

This is a comprehensive report on Distribution Grids for the three Delaware EDCs., with a light description of Delaware transmission, It applies national grid analysis principles to the Delaware utilities with useful evaluations and recommendations. I find descriptions but not any recommendations on transmission. Arguably it is mainly an evaluation of Delaware's three utilities' distribution grid management and planning, not really "grid analysis" per the title. So title could be clarified.

The report evaluates BESS as the enhancement most frequently mentioned by EDCs (Fig 28) and mentions that DER optimization has the highest Benefit/Effort ratio of all listed programs (P05 in able 53, Figure 34). My remaining comments refer to DERs and BESS.

They recommend development of "feeder and substation heat maps" of hosting capacity (Section 7.5.). This excellent recommendation needs to add that such maps must be updated regularly and must be available to the public. They are needed for many DERs, for all of solar DER, for EV charging, and for BTM storage. For example DPL solar and "EV load" capacity maps are already available online (highly available; I personally haven't evaluated their accuracy or update frequency). The report could also clarify capacity hosting maps' diverse naming, specifically that Solar capacity=BESS discharge, and load capacity=EV capacity=BESS charge capacity. These maps, updated and available, are important since they make it much easier for both customers with BTM storage, and businesses offering such products to customers, can see appropriate feeders for installations. They also make it possible for EDC staff to approve interconnection applications much faster. Some clarifications should be added on this topic, especially as it ranks highest by two of your metrics.

Delaware code already requires DERs get NEM and are interconnected via new SAE and UL safety standards when the BESS is an EV. Only Maryland and Delaware do this in code now. Delaware has implemented these already in three demonstration projects. To make the report's recommendations more specific to Delaware policy, it should mention existing Delaware law facilitating interconnection of BTM storage, and refer the pending Delaware bill enabling more BTM storage in Delaware, reviewed by Sen. Hansen's "Energy Stakeholders Group". This draft act is now titled "AN ACT TO AMEND TITLE 26 OF THE DELAWARE CODE" to be more specific a reference can say the proposed bill is "regarding BTM storage and V2G". The proposed code would add that the EDC are responsible for interconnection review even if the BTM storage is used only for RTO services, and require aggregators to give deference to EDC requests for override which is important to distribution systems (both are required by FERC Order 2222). Without these references to existing and proposed Delaware code, the draft report seems disconnected from state DER and BESS policy.

The DEC BESS proposal is mentioned (Sec 7.5), as is proposed DPL BYOB (Table1) and but there's no mention of the approved, completed, and evaluated DPL/Exelon BESS project at their New Castle Regional Office (NCRO). As documented in the project report (at https://bit.ly/4vB3w6u), this BESS VPP used part of the NCRO fleet of Ford Mach-Es to provide grid services, including both PJM regulation and Delmarva retail TOU arbitrage. As documented, the use of EVs as grid-connected BTM EVs for VPP costs ⅕ that of large-scale purpose-built BESS. These low costs and proven market readiness may mean EV BTM EVSS becomes an essential contribution of BESS to distribution grids, so the report should mention this completed and evaluated DPL project along with the DEC and BYOB proposals.

I welcome questions or reactions at willett@udel.edu.

Summary of DEMEC Comments

Section	Table / Figure	Change / Comment
Executive Summary, Policy Implications	N/A	Comment: Remove reference to “regulatory frameworks” to avoid implying impacts on local decision-making authority; broaden language to include all utilities, not only cooperatives and municipal utilities.
3.5. Overview: Delaware Municipal Electric Corporation (DEMEC) Introduction	N/A	Change: Add “not-for-profit, community-owned” to more accurately describe DEMEC’s business model.
3.5. Overview: Delaware Municipal Electric Corporation (DEMEC)	Table 26	Corrected total
DEMEC System Topography	Table 28	Comment: “Newark did not just begin AMI they have been doing it for a number of years now (need to get info from Scott).”
DEMEC Reliability Performance	Table 29	Change: Clarify that reliability reporting depends on EIA reporting requirements rather than lack of available data.
DEMEC DER Performance / MRPS	N/A	Comment: Municipalities have consistently achieved and exceeded MRPS requirements and should not be described as merely aiming to meet them.
DEMEC MRPS Administration	N/A	Change: Clarify that DEMEC administers the program for Full Requirements Members; avoid implying City of Dover participation because Dover uses its own ACP funding.
DEMEC DER & Community Solar	N/A	Change: Clarify that the City of Lewes does not currently have community-scale projects.
DEMEC Hosting Capacity / Grid Technologies	Table 39	Comment: Clarify that a hosting-capacity study is underway, heat maps will follow, and an 8 MW battery is planned in Milford.

DEMEC EV / DER Integration	Table 39	Change: Clarify that DEMEC is addressing EV and DER considerations through the ongoing hosting-capacity analysis.
DEMEC Microgrid / Islanding	N/A	Change: Add clarification that the Beasley facility enables the Town of Smyrna to island itself.
DEMEC Project Funding	N/A	Change: Correct total project award amount and federal funding received.
40101(d) Recommendations	N/A	Comment: Recommendations should be presented as a statewide roadmap and not separated by utility, consistent with kickoff discussions.
Advance Policy and Regulatory Enablement	N/A	Comment: Clarify which entities, in addition to EDCs, are responsible for implementing policy and regulatory enablement actions.

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