Statewide Survey of Delaware's Electric Utility Grid Modernization Status: Current Activities and Future Readiness

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Note: Analysis and interpretation of survey data involves objective and subjective decisions and commentary. Opinions expressed are those of Dr. Steven Hegedus who wrote this report and not the University of Delaware.

Executive Summary

Rapid changes in the generation and delivery of electricity are being driven by a wide range of forces. Legislation, regulations and incentives at the state or federal levels are encouraging adoption of carbon-free energy like solar and replacing fossil fueled cars and home heating furnaces with electric vehicles and electric heat pumps. Integrating these new sources and loads requires changes to the operation and structure of all three aspects of the electric grid – generation, transmission, and distribution. Changes in the generation – smaller decentralized sources with greater intermittency from renewables – are driving the need for innovation and modernization in the transmission and distribution systems. . New technologies and new ways of interfacing with customers are required to accommodate the anticipated new technology and services while maintaining a reliable, resilient and cost-effective supply of electricity. These new applications often result in two-way power flow and communications between the customer, the utility, and local distribution grid. Unfortunately, we are trying to integrate these new technologies and financial models into last century's linear grid where power and communication flowed in one direction. Nationwide it is recognized that significant efforts are needed to modernize the transmission and distribution grid infrastructure.

The process by which utilities evaluate, plan and execute actions needed to maintain a reliable supply of electricity and to meet the expected load growth is called an Integrated Distribution Plan (IDP). Utilities are now conducting IDPs specifically focusing on the demands and challenges of integrating the new customer-owned generation (whether small solar rooftop systems or community scale solar farms), smart power devices, two-way EV charging-discharging, smart home energy managers, microgrids, batteries, or local generation plants like fuel cells or biomass. IDPs enable regulators and the public to see the assumptions and plans of the local utilities for providing reliable and cost-effective power and to provide input.

Researchers at the University of Delaware were asked to conduct a survey of Delaware's eleven electric service providers, or utilities, to provide a snap-shot of their readiness to meet statewide decarbonization goals at the distribution level and to conduct an IDP. The Delaware Municipal Electric Corporation (DEMEC) is an Joint Action Agency made up of 8 separate municipal utilities. They also represented Dover Electric for this survey[1]. The other two utilities are Pepco Holding Incorporated (PHI, locally known as Delmarva Power and Light DPL) and Delaware Electric Cooperative (DEC). The University of Delaware team developed this survey with questions relating to: 1) *General Grid Modernization and Service Practices; 2) Solar and EV Impacts and Planning; and 3) Resilience and Reliability.* A secondary goal of this survey was to determine the experience and readiness of DE's utilities to conduct a IDP that was aligned with urgent need to integrate increasing levels of distributed solar power generation and new growth in demand expected from EVs.

Key observations and comments from the survey are summarized here.

[1] Only aggregated results from the 9 municipal utilities were provided by DEMEC to the UD team.

- Regarding Advanced Metering Infrastructure (AMI, aka smart meters), over 99% of DPL and DEC customers have AMI. DEMEC is still in the process of transitioning with 5 members have completed full AMI implementation, 2 are in the process, and 2 are awaiting funding from DOE to build more innovative metering networks. Experience and applications of AMI varies but they are all using the additional information to improve their awareness of grid health, forecasting and to provide higher resolution data for them and their customers.
- All three utilities have considered batteries but to date there has been little movement towards either direct utility ownership or incentivizing customer owned batteries for self-consumption and peak reduction. These decisions have been largely driven by cost. As the cost of batteries falls and the additional benefits are evaluated, utilities are increasingly finding battery storage to be a cost-effective energy management tool.
- All three utilities have well established load management programs for HVAC (AC or heat pump) to reduce cooling demand in summer. DEC also has direct control for water heaters (WH) and irrigation pumps. There is mix, with voluntary programs where customers decide whether to adjust their temperature settings as well as direct control programs where hardware is installed to reduce the customer's energy usage when the utility decides. Voluntary programs make it difficult to quantify the exact benefits in terms of percent load or MWh of energy reduction.
- One of the motivations of this survey was the need to understand where utilities stood relative the current Net Metering solar cap of 8% and what the impact is on their operation. DEMEC has one member at 7% the others are <6%, DPL is at 5.1% and DEC is at 5.2%. Regarding peak photovoltaic (PV) capacity installed on a single feeder, most DEMEC members were below 8% but a three had single feeders with upper values of 10, 33, or 50%. DPL reports no feeders or substations above 8%. DEC has "numerous substations or circuits that exceed the 8% and substations that are at 100% solar to load saturation." This suggests that DEMEC and DPL have limited capacity to add more PV although it will vary from circuit to circuit. DEC has the most serious current challenges with PV and explains why such a large portion of their territory is a 'red zone' which disallows any new PV.
- Centralized (utility) awareness and control of generation (solar) and loads (EV) will be essential to enable greater penetration of both. This is discussed in more detail in Section V.a. Both DPL and DEC are planning very innovative <u>demonstration</u> projects for PV inverter management using a utility-managed control scheme. These pilots are funded by or have applied for funding from the US Department of Energy (DOE) and involve collaboration with organizations inside and outside of DE. If successful, these pilot projects would open up much of their circuits to new solar installations and enable utility management of customer sited solar devices to increase solar capacity while maintaining stable grid operation.
- There is a distinct lack of commitment to non-wire alternatives (NWAs) like batteries or solar+batteries as an alternative to more traditional solutions to load growth. These are being increasingly included into utility IDPs around the country and there are many successful demonstrations. NWAs are valuable tools to enable integration of more DERs and to increase reliability and resilience. In their long-range distribution plan (LRDP), DPL considered a solar+batteries NWA option for two substations (Mount Pleasant and Kent)

but found the NWA option was either insufficient to meet the growing demand or not cost effective. Some incentivization may be needed to initiate the first projects.

- Regarding having a statewide map of Hosting Capacity that would be managed by the Sustainable Energy Utility to assist planners and solar developers, none of the three utilities said they opposed a common mapping and data format for DE.
- There is growing awareness in the utility industry and US DOE that microgrids are a critical tool in the resiliency toolbox yet there are no current plans to consider utility-built or customer-built microgrids. Some states have gone beyond the demonstration project or one-off microgrid project to fully endorsing them for their ability to enhance resilience, reliability, and integration of more variable DER. DEMEC has established an intentional microgrid powered by the Beasley gas peaking plant in Smyrna as described in Section Vd.
- There are significant differences in size and resources between the utilities surveyed. DPL has almost 350,000 customers while some DEMEC utilities have a few thousand customers. DPL may have the technical staff to conduct a IDP while smaller utilities will need to hire consultants. External support will likely be needed perhaps with a small number of IDP pilot programs. It is hoped that the value provided from these initial studies would provide justification for all members to identify funds to conduct IDPs on an on-going basis.
- All approaches at grid modernization and increased DER integration will require a significant amount of network connected power electronic devices, more trained professionals, and technicians to install them, and the ability to process massive amounts of new data provided by all of the new smart devices (EVs chargers, smart solar inverters, AMI, home energy management systems, etc). We need to address the availability of a trained workforce at all levels to meet the needs of the utilities, industry, and consumers. We should expand both our training and education in this area.
- This fast-paced evolution of clean energy ecosystem will create new industries and technology integrators. We need to increase our economic development activities to attract them to DE.
- Finally, all these goals need to be accomplished while maintaining the high reliability which our utilities have been providing for decades.

I. Introduction and Background

Senator Hansen leads the DE Energy Stakeholder Panel which discusses topics related to electric energy infrastructure and supply in Delaware. In the past 2 years this has focused primarily on policies related to increasing the supply of solar photovoltaic (PV) electricity as well as the overall functioning and behavior of the entire electric grid. It has become apparent that any one aspect, such as increasing residential solar rooftop or electric vehicle (EV) chargers, cannot be considered in isolation from its impact on the rest of the grid. At the same time, the national movement towards electrification of transportation, heating and cooking will increase the need for generation to meet the growing demand. Managing the evolving grid to provide reliability of supply, fairness to all ratepayers, and introduction of new technology solutions is a complex and interactive process. Furthermore, while state policy such as Net Metering was designed to incentivize small and medium scale solar installations, there is a cap on the maximum amount of net metered solar that each utility can allow. This cap was raised from 5% to 8% in 2021 with SB 298. However, some utilities expect to reach that new cap within the next few years. Note that these percentages are relative to the peak power produced as per SB 298. In terms of annual energy consumed in Delaware, in 2021 our total solar generation represented only 1.8% of the energy we used with 1.3% from net metered residential or commercial systems and 0.5% from utility scale systems. DE has stated goals of achieving 40% renewable energy usage by 2035 of which 10% must be from the solar 'carve-out' but this includes out-of-state solar renewable energy credits (SREC's). The fraction of solar energy generated in Hawaii, Nevada and California already represents about 20% of their in-state consumption, demonstrating that significantly higher percentages are already possible. While these states have 30-40% higher annual solar irradiation, they are generating 10 times more solar electricity relative to their consumption compared to DE. Higher electricity costs, higher state solar energy targets, and resource/fuel availability also drive the higher solar fractions in other states. Delaware should be aware of the policies and technologies that enabled these states to install higher solar fractions while maintaining a reliable grid.

All of Delaware's major electric suppliers are represented on the Panel: Pepco Holding Incorporated (PHI, locally known still as Delmarva Power and Light; DPL), Delaware Electric Cooperative (DEC), Delaware Municipal Electric Corporation (DEMEC), and City of Dover (Dover). Their sizes in terms of customer meters, peak MW and MWh delivered is in Table 1 along with references. DPL is the only utility that is regulated by the Public Service Commission (PSC). Senator Hansen requested a survey to understand the ability of Delaware's electric service providers to conduct an Integrated Distribution Plan (IDP), defined below in Section IV. The goal was to assess their current knowledge of and ability to implement *grid modernization* practices especially those imposed by the growth of solar generation and electric vehicle charging and consideration of Distributed Energy Resources (DERs) and Non-Wires Alternatives (NWAs also called Non-Wires Solutions NWSs) to meet new demand. NWAs are solutions to capacity constraints and load growth that building new transmission lines to deliver more power and instead involve localized distributed energy resources (DERs like solar, microturbines, fuel cells), energy storage, demand side management and direct load control, either alone or in combinations. An IDP is an essential requirement for Grid Modernization efforts and to inform subsequent legislation regarding raising the Net Metering cap. An IDP should encourage NWAs and also address increased needs for resilience in the face of climate and cyber threats. Some of the utilities were already conducting portions of an IDP as part of their annual planning process. This is discussed in Section III.

As a PSC regulated utility, DPL had been required to provide a Integrated Resource Plan (IRP) every second year as per 'Title 26 Public Utilities Delaware Administrative Code'.[2] An IRP has some similarity to an IDP. Title 26 Del.C. §1007 "Integrated Resource Planning etc" states on page 6 "*The IRP must show an investigation of all reasonable opportunities for a more diverse supply at the lowest reasonable cost, including consideration of environmental benefits and externalities*" and *"The Company shall first consider electricity DR and DSM strategies for meeting base load and load growth needs and cost-effective renewable energy resources before considering traditional fossil fuel-based electric supply services to meet their retail electricity supplier obligations*". Here, DR are distributed resources like solar and DSM is demand side management which is same as direct load control. These requirements, while just two among many, indicate that low carbon DERs, batteries, load control, etc should be given priority to meet their demand, reliability and cost targets. However, in 2018 the legislature, through SB 191, repealed the need for an IRP with the support of the Public Service Commission (PSC). The cost of the IRP was not worth the value it had been providing since DPL procured most of their electricity from PJM, they were not making many decisions about new resources within their territory. This highlights one of the differences between an IDP and IRP. Even if the utility is not planning any new resources (requiring an IRP), they should still conduct an IDP to forecast how they will manage their evolving distribution network which includes customer sited PV, NWAs, EV charging, and load control programs. This led to the Division of the Public Advocate (DPA), PSC Staff, Delmarva Power, and Chesapeake Utilities agreeing to perform Infrastructure, Safety, and Reliability reports by the end of March each year and a 'Long Range Distribution Plan (LRDP)' every 5 years with a 10 year horizon[3]. Item 6.1.2.5 of the statute specifies "*Non-wires alternatives in whole, or in part, shall be considered as solutions to capacity and/or major asset condition related system performance issues. A project whose estimated cost exceeds $1,000,000 over the term of the LRDP shall be evaluated for a NWA.*" DPL provided us with their most recent LRDP (2022) which contained a wealth of relevant data, methodologies and forecasts.

DEMEC and DEC are not required to conduct an IRP/IDP. If they do conduct their own IDPs, it is not known how well those IDPs are aligned with the larger vision of an comprehensive IDP as described below in Section IV. Thus one goal of this survey, which is NOT the IDP itself, is to determine the readiness and ability of DEMEC and DEC to conduct IDPs. Section VI presents both technical and policy recommendation. We argue in Section VI that in our opinion, all of the utilities should provide regular IDP or IRP's adhering to the principles of being transparent, comprehensive (including up-to-date and fair consideration of DER, DLC, etc), and aligned

[2] https://regulations.delaware.gov/AdminCode/title26/3000/3010.shtml
[3] https://regulations.delaware.gov/register/december2019/proposed/23%20DE%20Reg%20444%2012-01-19.pdf

(consistent with state and community goals and expectations) as described in Section III below. Further we propose that the State should provide a roadmap to guide the electric service providers and other partners in the energy infrastructure. This may occur as part of the State Energy Plan being developed by the Governor's Energy Advisory Council.

Table 1. Total customers and total energy in MWh delivered for 2021. DPL data for DE customers. Data includes residential, commercial, industrial and agricultural loads. Data was obtained from Source links provided.

Utility company	Total customers	Delivered load (MWh)	Source
DEMEC	48,000	1,407,270 MWh	DEMEC reference (pp.vii, 14)
DEC	109,330	1,550,448 MWh	DEC reference (p.27)
DPL	342,926	7,849,000 MWh	DPL reference (p.87)
Dover	24,741	725,000 MWh	Dover reference

The survey was created by the research team at University of Delaware and was distributed to DE's 11 electric utilities (DPL, DEC, and DEMEC who represented 9 municipal utilities) in August 2022 regarding the topic of grid modernization and specifically for leading to efforts in conducting a formal Integrated Distribution Plan (IDP). The goal of this survey is to provide a snap-shot of the readiness and ability to go to the next step where each utility would conduct an IDP specifically targeted towards meeting statewide decarbonization goals and the subsequent grid modernization efforts required. The UD team developed a draft of the survey with questions relating to: *1) General Grid Modernization and Service Practices; 2) Solar and EV Impact and Planning; and 3) Resilience and Reliability*. Two virtual meetings were held with the DE Energy Stakeholder group (5/23/22 and 6/6/22) to discuss the original set of questions and format. Based on comments and feedback during and after those meetings, and further discussions with DER grid experts from U.S. Department of Energy's (DOE) National Labs and former utility employees, a refined and shorter list of 19 questions was developed. It was presented by email to the electric providers on 7/13/22.

II. Urgency

Changes in federal statutes, funding, and policy in the past few years have dramatically increased the resources and motivation to upgrade the electric grid. These are forces we cannot ignore, and utilities need to be taking action today to prepare for the on-coming surge in new clean energy projects in Delaware.

- In Delaware, SB 33, which passed into law in 2021, increases the fraction of renewable electricity generation from DE's regulated utility to 40% with 10% designated from PV. While some of that will be met with out of state RECs, some utilities have experienced problems with 5% overall PV generation because a few circuits may have a much higher level of PV than 5% leading to occasional problems. These issues will occur more frequently and over larger areas as we head to higher percentages of PV or wind. There are a variety of ways to address this using currently available technology. An IDP which included advanced grid control devices (smart inverters) and NWA would allow for a smoother implementation of avoiding problems with increasing PV levels.

- Another local motivator is the recently-delayed but still imminent closure of the Indian River coal fired power plant. Its closure was delayed by PJM out of concerns for reliability and has resulted in all DE electric customers paying a direct fee to keep it open temporarily. But it will close in a few years.

- Nationally, while we have not seen the regulations for the Inflation Reduction Act (IRA) which became law in 2022, it nevertheless will dramatically increase incentives for installing solar at all scales, EV chargers, and other energy investments. It extends the 30% solar tax credit to 2032, provides $4K tax credit for EVs, and unlocks hundreds of millions in competitive grants to enhance clean energy technology and deployment. Industry experts predict a significant increase in large and small solar installation and purchasing of EVs as a result. The IRA is also giving the states funds for utilities to modernize their grid resilience including for example microgrids and batteries, two areas that were included in the survey. DE will receive over $1M per year for five years to increase grid resilience.

- Another national motivation is the implementation of Federal Energy Regulatory Commission (FERC) Order 2222. It requires the Independent System Operator (ISO in our case this is PJM) to accommodate and manage the increase in DERs by allowing for aggregation of DERs so that they can participate in bigger transmission markets. DER aggregators will manage a large stable of small DERs so they can collectively be compensated for providing various grid services such as forming a 'virtual power plant' (VPP) using solar+battery. Their success requires significant new technology to control power flow in the distribution grid and track the financial payments.

- The utility industry typically reports that its top two challenges are aging infrastructure and integrating more renewable DER. Both are drivers for grid modernization. The

American Society of Civil Engineers gave the US electric grid infrastructure a C- grade and estimates that grid modernization will require an additional $200B investment by 2030 above what is already planned. ,

- Globally, the International Panel on Climate Change announced in February 2023 that the window to avoid the worst impacts was closing rapidly but could still be mitigated with urgent action within the decade. “Climate change is a global challenge that requires local solutions…. Adequate funding, technology transfer, political commitment and partnership are needed for more effective climate change adaptation and emissions reductions”[4].

These are just a few examples of recent policies and trends that will accelerate the deployment of solar, EV and other advanced energy concepts. Much of this will be implemented at the distribution level. These trends suggest an urgent need to assess of the readiness of all of Delaware’s electric service providers(DPL, DEC, 8 DEMEC utilities and City of Dover) to meet this expected increase in customer demand for clean energy options and to participate in the new energy economy. A huge wave of new expectations, incentives, technologies, and requirements are rapidly heading our direction along with the funds to implement them. These changes will be taking place in a time scale of a few years not few decades as has been the trend in the past. This is summed up by DPL in their LRDP (p37) by stating *“As these trends change the energy landscape, the Company will respond by transforming the grid from a one-way delivery system into a more flexible two-way system while maintaining safety, reliability, resiliency, and security. Grid flexibility includes the grid’s ability to integrate DER, increased the grid’s hosting capacity, have control and awareness of energy storage and demand response and manage new load profiles created by DER, EV, and other new generation*.”

[4] https://www.ipcc.ch/report/ar6/wg2/resources/press/press-release/

III. What is an Integrated Distribution Plan?

An Integrated Distribution Plan (IDP) is a plan for the modernization of the distribution grid. It goes beyond the traditional utility planning goal of providing generation, transmission, and distribution to reliably meet expected load at the lowest cost. At its best, the IDP is driven by: 1) increasing amounts of distributed energy resources (DERs) from smaller residential or commercial systems, which are typically net metered, and from larger utility scale systems which typically sell energy under a contract; 2) clean energy goals requiring more carbon-free electricity; 3) new load control or demand management technologies enabled by increasing interoperability and communications between devices; 4) growing customer expectation for transactional opportunities provided by the 'smart grid'; 5) a changing climate threatening existing infrastructure; 6) strategic locating of DERs that may delay, defer, or eliminate costly distribution upgrades along with robust consideration of non-wire alternatives, Volt-VAR optimization, demand response, direct load control, and many other tools already available to utilities and their customers; and 7) the need to eventually integrate all of these with a cyber-secure control and communication platform.

There are many excellent resources summarizing or providing case histories of state-level integration of DERs and NWAs into their IDP to enable grid modernization. Three are highlighted here selected in part due to their difference in scope. An article in the IEEE Power and Energy Magazine titled "Next Generation Distribution Planning" presents a recent study by the Sacramento Municipal Utility District (SMUD) "to show that, although the theoretical value of DERs can be significant, capturing it will require new thinking and methodologies for IDPs. These insights should be broadly applicable for distribution utilities facing significant growth of DERs over the next decade". Their key findings were[5]:

- The charging of EVs, which could constitute 10% of peak demand by 2030, needs careful management.
- Solar, batteries and smart inverters can become assets that reduce operation costs and help accommodate the significant load growth expectations from the electrification of transportation and buildings.
- Managing flexible loads through demand control will significantly reduce costs for integrating DERs.
- Capturing the value of DERs requires utilities and others to have visibility and control behind the customer meter to help manage those DERs and their interaction with the grid. Currently this is lacking except for direct shut off of HVAC on peak demand days.

Note that three of the four address the need for utility wide management system, often called a Distributed Energy Resource Management System (DERMS). This is a major undertaking but is widely recognized as being essential to a stable and effective modern grid. A recent (2021) survey of the electric utility industry by the engineering company Black and Veatch also

[5] "Next Generation Distribution Planning" O. Bystrom, IEEE Power and Energy Magazine March/April 2022 10.1109/MPE.2021.3134146

concluded “Now is time for utilities to set up pilots for programs and technologies such as a distributed energy resource management system (DERMS) and intelligent hardware to support bidirectional power flow. As generation sources continue to diversify, utilities will need a smarter grid to support DER and use them to their advantage.”

A 2023 report from Rocky Mountain Institute “Reimagining Resource Planning” first describes origins and status of efforts in 12 states to conduct an IDP (which they call Integrated Resource Planning IRP) and to define roles and responsibilities for different entities (regulators, utilities, legislators and the public).[6] It is relevant to note that 4 of the 12 states (Minnesota, South Carolina, Washington and Colorado) require or advise cooperatives and municipal electric corporations to submit IDPs for review. The authors then describe three essential components for an IRP to be accepted as shown in Figure 1. The process has to be: 1. Trusted (transparent and with the right stakeholders); 2. Comprehensive (integrating transmission, distribution and generation; including up-to-date values for DER and load control benefits); and 3. Aligned (consistent with goals and values including decarbonization, health, resilience, and environmental justice). The document also has comprehensive list of resources including state, federal, utility and regulatory reports.

[6] “Reimagining Resource Planning” M. Dyson et al, Rocky Mountain Institute, 2023.

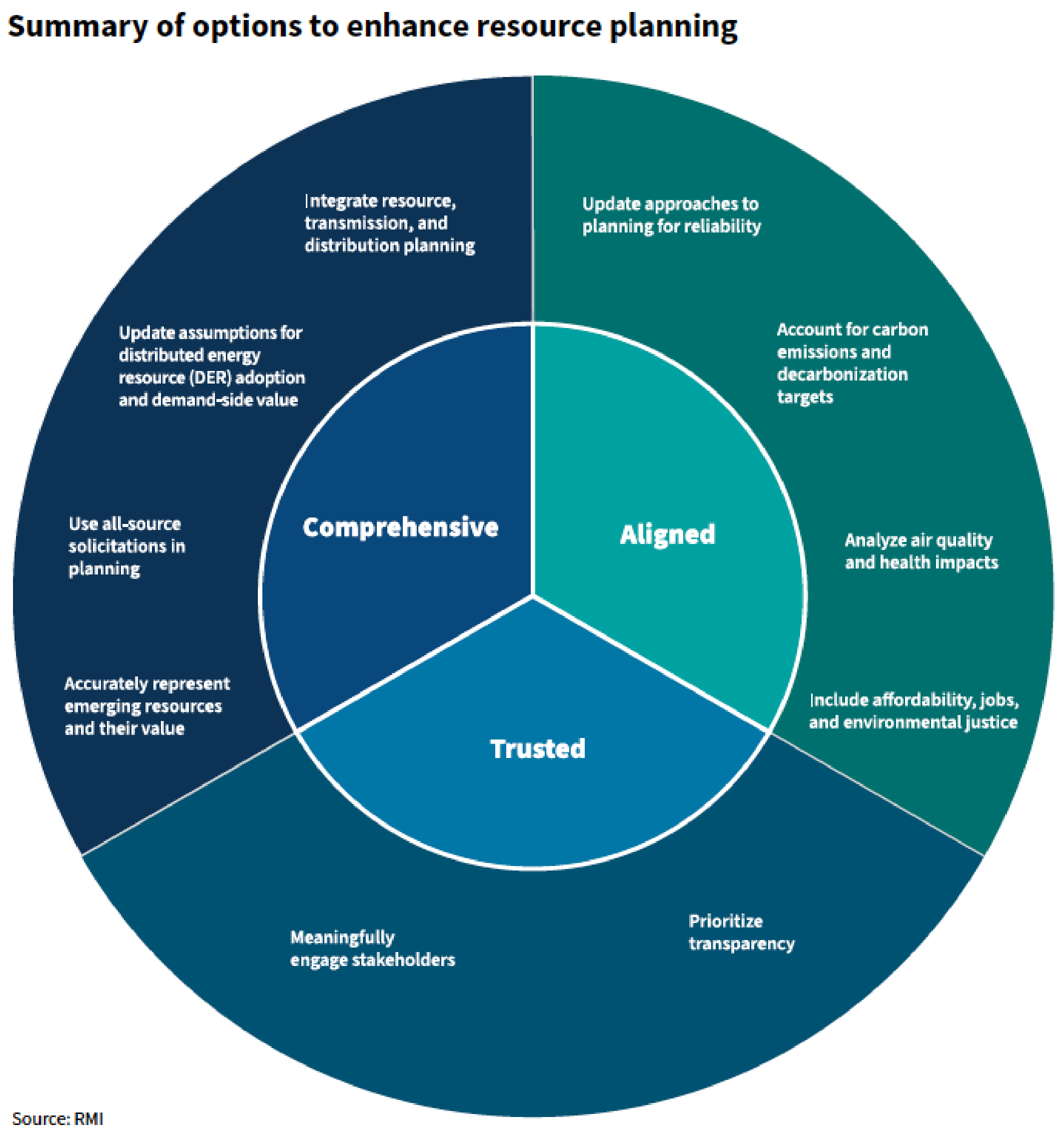

Figure 1. The three requirements for a successful IRP for a modernized electric system (From Rocky Mountain Institute reference 4).

A third useful resource is "Integrated Distribution Planning: A framework for the future" published by utility trade group Smart Energy Power Alliance (SEPA) in 2020[7]. Compared to a more traditional distribution planning, the IDP has these characteristics:

1. **Expanded requirements and objectives** – Good examples are meeting state clean energy goals, increasing customer participation, and managing bidirectional energy flow from customer sited DER.

[7] https://sepapower.org/resource/integrated-distribution-planning-a-framework-for-the-future/

2. **Transition from internal to more transparent and inclusive processes** – Stakeholders increasingly want to understand the technical challenges impacting proposed DER projects so they can devise and revise plans for siting projects or investing in new technology.
3. **Data** - Planning for a more complex, distributed grid requires increasingly complex forecasting, and assumes grid planners will have capabilities to acquire and analyze massive amounts of data along the system. This includes advanced metering infrastructure (AMI aka 'smart energy meters') but goes beyond it including applying artificial intelligence or machine learning approaches.
4. **Proactive approach to DERs and NWAs and other non-traditional solutions**. IDP increases opportunities to identify where DERs and other non-traditional solutions like NWAs can optimally benefit the grid. The utilities should provide guidance to DER project developers, entrepreneurs, and customers to accomplish mutually beneficial goals. Both utility-owned and customer-owned DER need to be considered here.
5. **Greater integration between distribution, transmission, and generation** - As DER adoption increases, it has the potential to impact transmission and generation planning. Following FERC's recent Order 2222, coordinating between transmission, distribution, and generation planning will become more important. By managing enough local generation and load on the distribution side, an effective IDP can offset, postpone, and even replace the need for much centralized generation and transmission. A key aspect of Order 2222 is that it opens the field to 'virtual power plants' or VPPs where a third party aggregates several DERs to provide dispatchable power under contract to a utility or independent system operator (ISO) like PJM[8]. Commonly these are solar+battery systems and are increasingly being utilized by utilities to meet demand.

These are but three of the many resources available to guide the design and implementation of a IDP that incudes concepts of decentralized generation, storage, and load control either under autonomous, aggregated or coordinated control.

What is the process to achieve a grid with upgraded infrastructure that can integrate larger amounts of carbon-free DER with resilience and reliability? Here are 8 steps identified by Black and Veatch's report "Grid Modernization 2022: Resilience and Reliability" listed in approximate order that they should be implemented:

1. Grid Modernization Strategy and Roadmap
2. Grid Modernization Investment Planning
3. Vulnerability Assessments
4. Grid Hardening (physical and cyber assets)
5. Distribution Asset and Device Management
6. Digitization, Modelling & Predictive Analytics

[8] https://www.forbes.com/sites/forbesbusinessdevelopmentcouncil/2021/01/07/sustainability-rules-why-ferc-2222-could-pave-the-way-for-virtual-power-plant-growth/?sh=204069a54fe8

7. Generation and Transmission Investments
8. Telecommunication Investments: the 3rd Grid

These steps involve planning, analyzing, and building. The effort must be funded either internally or externally. Some aspects are hardware focused and some are cyber focused. Clearly this is a complex, expensive, multi-year process but it is essential for the economy, society, and environment that it be undertaken by all electric service providers large and small.

IV. The Survey Process

Phase 1 was to create the survey instrument itself and was completed in July 2022. Phase 2 was to administer the survey and follow up interview and summarize the results in this report. That was completed in December 2022. Phase 3 is not funded or committed to but would be to conduct a few IDPs such as a larger and smaller municipality to evaluate the IDP process. This might include hiring of an outside consultant.

Appropriate personnel to respond to the survey at each utility were identified with help from representatives from Senator Hansen's Energy Stakeholder meetings with DEMEC, DPL, DEC, and City of Dover. DEMEC leaders offered to contact and coordinate responses from their members and Dover.

Qualtrix was used to administer the on-line survey because of the analytic tools that it offered. In retrospect a simpler Google sheet or Excel sheet would have been sufficient. It was recommended by several people connected with the survey development that after filling out the survey on-line, the UD team should have a virtual meeting with the appropriate people at each utility to discuss their responses. The goal was to encourage free-flowing discussion with both the utility and UD team collaborating to provide consistent information for the survey.

DEMEC leaders summarized the responses from their members and Dover and provided an aggregated response that did not identify individual municipalities. Also, since DPL is a regulated utility, some of its plans and programs are governed by state regulations and must be approved before expenditures are made.

To augment the survey responses in a few places, the UD team gathered additional information from Annual Reports, Budgets and other publicly available sources.

The UD team was led by Prof. Steven Hegedus, and included Sean O'Neill, from the Institute of Public Administration who created the Qualtrix survey instrument, and Electrical and Computer Engineering graduate student Thunchanok (Tasha) Kaewnukultorn who assisted in developing the survey, merging the responses, and taking notes during the dialogue sessions with DPL and DEC.

V. Summary of Responses and Discussion

Analysis and comments regarding the responses are presented below in three levels of increasing detail. Section V.a contains some general comments summarizing areas where there seems to be good efforts already underway and general areas where there are common deficiencies. It also presents some unique items worthy of highlight. Sections V.b-V.d contain more detailed summaries and discussions from the three Topic Areas. Some concluding thoughts in Section VI relate these results to the larger national trends and actions occurring in other states.

V a. General Comments and Observations

In general, the results indicate a wide range of relevant efforts already underway by each utility. Examples include both voluntary and direct load management practices to shed air conditioner load on summer peak days and a high percentage of Advanced Meter Infrastructure (AMI) already installed. All the utilities and service providers are engaged in various efforts to increase resilience such as undergrounding lines in sensitive areas, reconfiguring circuits to handle emergency load shifting, and protecting equipment from flooding. Questions about securing assets against cyber-attacks were intentionally vague due to confidentiality concerns, but overall, the replies indicate that DEC and DPL have identified assets needing protection and use accepted industry standards in their cybersecurity activities.

Development of coordinated or centralized control of distributed PV inverters and EVs is widely regarded as a key component of a modern grid. This is very similar to existing Direct Load Control (DLC) programs where utilities can control customer air conditioners to reduce summer peaks in return for some incentive. Implementing control of PV inverters and EVs requires the utility to monitor local grid conditions using AMI, determine whether any action is needed to maintain power quality, then send signals to modify the settings of a heat pump, PV inverter or EV for some period of time to maintain grid stability and quality. The utility, or customer, must install a direct load control device such as an EV charger or smart thermostat on the customer side of the meter. This may require an investment in hardware, billing, and training but allows the utility to better serve their customers while meeting clean energy goals with greater efficiency, reliability, and potentially less distribution upgrades. We highlight two pilot programs to test coordinated control of PV systems below, one at DEC and one at DPL.

Both DPL and DEC are participating or planning to participate in very innovative <u>demonstration</u> projects for PV inverter management using a utility-managed control scheme. These pilots are or expect to be funded by the US Department of Energy (DOE) and involve collaboration with organizations inside and outside of DE. For DEC, the goal is to increase the amount of PV allowed on their distribution feeders or substations while maintaining safe operating margins at their substations. Much of their territory is currently off limits for new solar, even small residential PV systems, due to backflow of solar power from large solar arrays with no local load especially on days with low usage. DEC is evaluating the automated reduction in PV output during such hours of high sunlight/low load by modifying the inverter output. If successful, this pilot study would open up much of their circuits to new solar installations.

As part of a DOE-funded project, DPL has partnered with several vendors, electric system control innovators and UD to design and deploy a system to integrate solar forecasting, distribution and transmission power flow, and localized voltage measurements then decide when to activate the customer's smart PV inverter controls to provide desired grid support. It is being rolled at a very small scale to test the controls and communications and how well it manages the power quality.

Programs to control EV charging to accomplish the same goals, often called Vehicle-to-grid (V2G) are not yet being considered by any respondents. The successful roll-out of coordinated control of PV inverters should provide guidance and confidence in applying coordinated control for EV charging and discharging to support the grid. Note that one of the world's leading experts on V2G is UD's Professor Kempton. He is working with utilities world-wide on technology and policy to implement V2G including DPL.

Each distribution utility has different methods to predict load growth especially due to the anticipated increase of EV charging. As one example, DEMEC member City of Newark reports in their 2021 Budget "*The City Electric Department recently completed an electric system analysis of the distribution system to determine its current electric system strengths and weaknesses. To perform this analysis, the City utilized Sargent & Lundy's (S&L) services. Considering projected 2030 future system loading plus EV adoption, …. S&L recommends that the City consider constructing an additional 138/34.5kV station prior to 2026, in order to provide additional margin and to increase system reliability, especially considering the planned expansion of STAR Campus, as well as the increased adoption of EVs."*

We note several areas were there should be much stronger and more focused efforts regarding grid modernization. As stated above, these efforts and remedies need to be implemented in years not decades. We highlight a few that impact increased penetration of solar and EV's.

1. Centralized awareness and control of distributed generation and consumption including at the customer level will be essential. There are two different levels – ADMS and DERMS. According to Energy Hub[9], "*the primary responsibility of the Advanced Distribution Management System (ADMS) is to integrate utility information and systems to unify distribution network management, ensuring reliability and optimal operation of the system. ADMS are typically purpose-built to monitor and control utility-owned, SCADA-connected equipment, assets, and DERs*." Thus, ADMS manages utility assets but does not have access to or awareness of DER behind the customer meter such as EV and solar. Instead, "*Distributed Energy Resource Management Systems (DERMS) manage behind-the-meter, grid-edge, and customer-owned DERs. They provide three key services to utilities: resource formation, grid services, and situational awareness*." We underlined key phrases to highlight

[9] https://www.energyhub.com/blog/adms-versus-derms-value-at-the-grid-edge/

the difference. DERMS will be one of the crucial strategies enabling coordinated control of customer sited solar, EV charging, and load control. Figure 2 shows a diagram of 2-way communications and data flow in a DERMS. Note that it includes control of customer devices as well as pricing signals to allow customer choice for example whether to consume their own solar power or sell it to the grid. DPL has ADMS in their Long Range Distribution Plan (LRDP) roadmap. DEMEC and DEC are not presently considering either ADMS or DERMS. ADMS and DERMS should be prioritized as per discussion in Section III. It will be challenging since it requires significant investment in communication and control technology, cyber protection, etc. but it will give utilities the ability to 'conduct the orchestra' of devices on their distribution network thus increasing the amount of solar, EV chargers etc. DEC's Beak The Peak and DEC's interruptible EV charging program are steps in this direction.

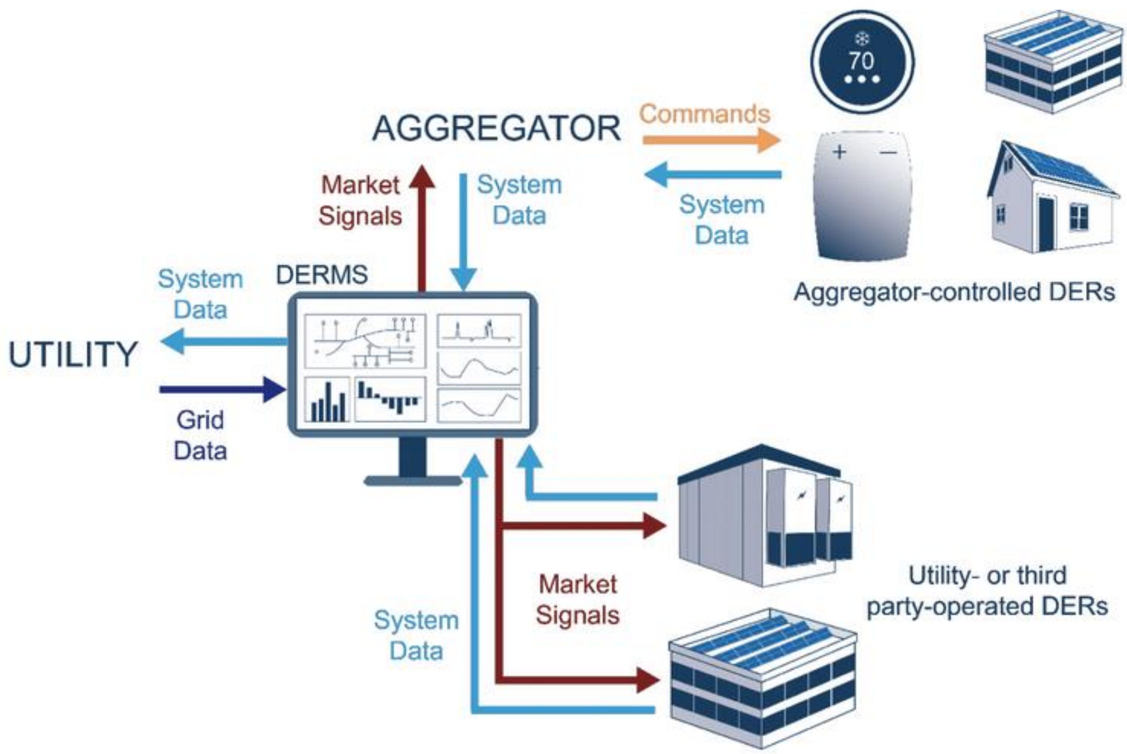

Figure 2. Distributed Energy Resource Management System (DERMS) aggregated component interaction and controls[10]. Note that both individual and aggregated (VPP) sources of energy and loads can be managed. DERMS provide 2-way communication and control from the utility to the customer and their devices.

2. There has been very little implementation of NWAs as an alternative to more traditional solutions to load growth. These NWAs are being increasingly integrated into utility IDPs around the country and there are many successful demonstrations. Both NWA and batteries are valuable tools to enable integration of more DERs and to increase reliability and

[10] https://pv-magazine-usa.com/2018/12/14/u-s-utilities-test-distributed-energy-management/

resilience. In their 2022 long range distribution plan (LRDP), DPL considered a solar+batteries NWA option for two substations (Mount Pleasant and Kent) but found the NWA option was either insufficient to meet the growing demand or not cost effective. Some incentivization may be needed to initiate the first projects.

3. Regarding having a statewide map of Hosting Capacity that would be managed by the Sustainable Energy Utility to assist planners and solar developers, none of the distribution utilities said they opposed a common mapping and data format for DE.
4. There is growing awareness in the utility industry and US DOE that microgrids are a critical tool in the resiliency toolbox yet with there are no current plans to consider utility-built or to encourage customer-built microgrids in DE. Some states have gone beyond the demonstration project or one-off microgrid project to fully endorsing them for their ability to enhance resilience, reliability, and integration of more variable DER.
5. Any and all approaches at grid modernization and DER integration will require a significant amount of wireless or internet connected power electronic devices. They represent well established vulnerabilities for cyber-attacks. Hyper-awareness and diligence are needed at all stages to harden these devices and the communication and control networks they connect to.

Survey results, as discussed in the next subsections, confirm that there is a large difference in the resources available to consider grid modernization and IDP related activities, for example between DPL and DEMEC. Municipalities would probably require assistance to create a more detailed plan as required by an IDP and more rapid transition to a 'smart grid' approach, for example to conduct Hosting Capacity Analysis (HCA), develop maps of available solar capacity on their network, and to conduct an IDP aligned with the above standards (Section III). However, some DEMEC members, like the City of Newark, have conducted related distribution studies with assistance from outside consultants as described above.

Below we summarize the comments from each utility in the three topic areas: Grid Modernization and General Practices, EV and Solar Impact and Planning, and Resilience and Reliability.

V b. Grid Modernization and General Practices

To address the growth of DERs and EVs, DPL considers NWAs as required for projects over $1M while DEC uses its previous experience to handle the increase in solar and EVs. DEMEC members establish renewable portfolio goals (RPS) comparable to the states and partner with DEMEC staff on load forecasting and advanced modeling/data analysis, demand response and energy efficiency programs. Municipals also continue to look at innovative technologies, such as battery storage & EVs, and consider various impacts to the distribution system. In summary, all the utilities conduct IDPs, but the level of alignment with the five IDP principles listed above in Section III is not known outside these utilities.

On the question of using internal vs external resources, Delmarva has used internal resources for the three short term ISR Plans but hired Quanta Technologies, LLC to perform and validate their long-range planning forecast. DEC engineering staff conducts detailed IDP analysis with support from consultants. For future IDPs, DPL says it would use in-house staff while DEC and DEMEC say they would use outside engineering consultants. This is consistent with the size and internal resources of the three organizations.

Regarding customer metering, both DPL and DEC use AMI to have visibility over 99% of the meters. DEMEC is still in the process of transitioning, but 5 members have completed full AMI implementation, 1 is in the process with expected completion this year, and 3 are in the discovery phase. Regarding how they use the AMI data, experience varies. There are two ways in which can be used, either to assist the utility in understanding the status of their grid, or for customers to understand the status of their energy usage or grid outages. Ideally it should be used for both. DPL reports extensive analysis and action based on customer AMI data. For example, AMI data is being incorporated into load forecasting and DER studies and mapped to distribution and substation facilities to perform bottom-up analysis of customer load demand. DPL also uses AMI data for alarms and notification of problems. Customers can monitor their usage data through their MyAccount which can send alerts regarding high usage. DEC says they use AMI data observe who has EVs as well as occurrence of overvoltage and undervoltage and who does load management. In the future DEC will use the data to implement advanced rate design and peak shifting. DEMEC uses AMI data to determine outages, transformer loading, voltage monitoring and more accurate load forecasting. A good follow-up would be to understand exactly how each service provider currently uses their AMI data and to identify areas where it could be leveraged to benefit customers as well as the service providers. In summary, the utilities all use AMI data to monitor for problems on the distribution grid or even in some cases at individual customer sites and enhance customer feedback.

The utilities all use a combination of passive and active forecasting, but the time frame was not specified. Passive forecasting is where developers or customers come to them with application for new loads. Active forecasting is where supplemental information is used to predict future load growth. DPL describes the data bases and mathematical functions used to develop both load and solar generation forecasts in their LRDP's Appendices C and D. DEMEC and DEC mostly use passive forecasting methods which are simply projections of current trends. DEMEC said it considers mandates which can drive growth of DERs as part of their forecasting. DPL's LRDP discusses impact on net vs gross demand especially for substation and feeder capacity. They project a long term (10 year) forecast to evaluate reliability. However, the recent federal IRA provides new incentives for EVs and heat pumps. This will increase and change the profile of electric demand. Heat pumps surpassed gas furnaces for the first time in 2022 and that was before the IRA. Unless managed, EVs will be charging in the morning when arriving at work or in the evening arriving at home, both which will drive up existing peak demand. Heat pumps are used for heating as well as cooling meaning that winter peaks will increase. All service providers need to be planning now for this increasing electric demand that will be happening in the next few years.

All the distribution utilities use commercial software to conduct periodic power flow analysis on either critical circuits and substations or network wide.

DEMEC and DPL appear to routinely consider NWA in some fashion while DEC does not. DEMEC considers load control as a NWA and has also researched batteries. DPL is required to consider NWAs for projects over $1M or selected capital projects to maintain distribution safety and reliability. Their LRDP details their cost calculation for solar+battery NWA vs traditional substation upgrades DEC feels that NWA are unreliable therefore not considered as firm capacity to meet load. This is contrary to the industry trend and neglects dispatchable DER options like PV+battery or fuel cells. However, note that neither DEMEC or DPL gave specific examples of any actual NWA project they have implemented which raises concerns about the strength of this commitment.

Regarding load management/load control, all three service providers have well established load management programs for HVAC (AC or heat pump) to reduce cooling demand in summer. DEC also has direct control for water heaters (WH) and irrigation pumps. There is a mix of voluntary programs where customers decide whether to adjust their temperature settings and direct control programs where hardware is installed to reduce the customer's energy usage when the utility decides. Voluntary programs make it difficult to quantify the exact benefits in terms of percent load or MWh of energy reduction. Direct control programs require more effort since there are physical and/or software controls that need to be installed on the customer side of the meter which necessitates additional customer contracts and incentivization. But they have much higher value since the utilities will know exactly how much demand reduction they are getting. More utilities are heading towards the direct load control for that reason.

It is no surprise that each distribution utility has well established programs to monitor health of their systems since this is crucial to reliability and cost management. They monitor a range of data from customer AMI, component infra-red thermal imaging, transformer tap changes or relay openings. They monitor for overvoltage, reverse power flow, etc. Their oversight of the grid will need to increase as more DER and EV loads appear. PV inverters and EV chargers can provide additional high-quality data to the utilities if they are able to access it. The large amounts of data that will be collected in the future will necessitate implementing data analytics and machine learning approaches which are becoming ubiquitous in all industries but require investment in people and computing. Without these investments, the data will overwhelm the current decision-making systems.

V c. Solar and EV Impact and Planning

To determine how much new solar can be installed on a given circuit, it is common practice to consider the balance between the demand for power (load) vs. the generation of distributed power from solar or other DER on a sunny day in the spring. On such days the load is small (due to minimal need for heating and cooling one of two approaches) and the generation can be near maximum. Commonly this is when problems occur with backflow (locally generated solar power flowing through the circuit towards the substation) or just creating an unstable situation where the net power at the substation is either negative or very small. DPL estimates the amount of additional DER that can be accommodated on the distribution feeder then they limit the aggregate capacity of large DERs to ensure proper system protection and operation and also to preserve existing hosting capacity for existing smaller rooftop solar customers. DEC does not perform a Hosting Capacity Analysis (HCA) or do power flow analysis but does determine maximum amount of DER allowed for each substation. They have a fixed lower value of net MW independent of the capacity of the substation. This provides a safety margin in case either load decreases or solar increases unexpectedly which could create a reverse power flow situation.

A 'Heat Map' gives an indication of how much generation (expressed in kW) is currently installed and pending installation on a feeder. The HCA map allows a point of interconnection to be analyzed to approximate the amount of remaining feeder capacity compared to the active and pending PV generation in the queue. Both DEC and DPL provide a map showing allowed and restricted regions. The DPL heat map and HCA maps are searchable by address and have numbers representing current capacity. Realistically one needs both to determine if a given connection or distribution line can accept a given new PV project or load. DEMEC had planned a member-wide hosting capacity analysis, but they postponed it awaiting the outcome of this survey.

Another question asked what the most cost-effective upgrades are to hosting capacity and would they be paid by rate basing the expenses. In some cases, it is the responsibility of the project developer. Both DEMEC and DEC said it depends on location and other factors. As the only state regulated utility, DPL did not indicate whether they would rate base the expenses.

Regarding Net Metering cap of 8%, DEMEC has one municipality at 7% the others are <6%, DPL is at 5.1% and DEC is at 5.2%. These results support the urgency to increase the value from 5 to 8% in SB 298 in 2022. Regarding peak PV on a single feeder, most DEMEC members were below 8% but a three had upper values of 10, 33, or 50%. DPL reports no feeders or substations above 8%. DEC has "numerous substations or circuits that exceed the 8% and substations that are at 100% solar to load saturation." This suggests that DEMEC and DPL have limited capacity to add more PV although it will vary from circuit to circuit. DEC has the most serious current challenges with PV and explains why such a large portion of their territory is a 'red zone' meaning no PV applications even small residential systems are being approved. Overall this data suggests the need to urgently address both the state net metering cap but also providing tools especially to DEC to enable higher penetration of PV without causing load saturation or reverse power flow. It was noted above that DEC has submitted a proposal to US DOE to creatively address this with direct control of residential PV inverters.

Since one of the main concerns with high levels of PV penetration is reverse power flow, we asked two questions about that. DEMEC has had very limited reverse power problems while DPL and DEC report no problem. While DEC has one substation that would have experienced unallowed reverse power flow into PJM transmission system, they are able to move load from nearby substations to alleviate the oversupply. When DEMEC members were asked how they would respond to this in the future, half said it would limit future DER expansion. DPL said the customer would have to pay for upgrades to mitigate the problem. DEC has several other substations that are near or at capacity for solar interconnection because of large solar arrays either in the ground or anticipated. DEC is therefore not accepting any more solar including rooftop residential on those lines.

Two questions covered utilities' experience with technical solutions to increase the penetration of solar and maintain grid stability. One strategy to integrate more PV is to use the grid control features built-in to today's smart inverters; so we asked about their experience with requiring or implementing grid-control features. In their written response, DPL says they have had 'just OK' experience with grid control features. But in the follow-up discussion, DPL said they planned to address overvoltage conditions using the smart inverter controls as part of a project partly funded by the DOE. Note that the zoom discussion included DPL staff from outside of DE so it not clear whether these comments apply to plans within DE territory. Interestingly, DEC says that it does not require smart inverter controls but they are the only one of the distribution utilities that indicated they require non-unity power factor (PF=0.98) on large systems to help manage the local grid voltage. This is not a dynamic control because it is fixed value but can be considered a simple example of a smart inverter control feature. DPL published results in 2013 showing enhanced local voltage control with a utility scale inverter in NJ when they changed the PF to 0.98. It is puzzling why this simple change in a setting is not more widely done to avoid overvoltage due to PV power export.

The second strategy is to incorporate batteries to store excess solar during midday and use it to provide rapid response to changing load or to reduce evening peaks. Batteries are widely recognized as playing a key role in integrating more solar and wind onto the grid. Due to the historically high cost of batteries, overall a total of only 6-8% of residential systems have batteries. But due to their steeply falling prices, in 2021, 38% of residential solar installed nationwide included batteries[11]. But in Delaware, one of the leading solar installers reported that in 2022 none of their residential customers got batteries, and on average 3% of the residential systems they installed over the past 5 years had batteries[12]. The reason for our low rate of battery installation is partly due to our flat-rate tariff and net metering which do not incentivize storage. The UD PV systems group recently completed a techno-economic analysis comparing the impact of time-of-use (TOU) rates on the financial viability of PV vs PV+storage for buildings in Wilmington. It was clearly seen that TOU rates greatly incentivize the addition of a few hours of storage[13]. Without TOU, batteries are not cost-effective if you have net metering. Regarding utility scale projects in the two largest PV markets, 99% of utility scale systems in CA and 28% in Texas are including 2-4 hours of battery storage. Many of these systems were installed by third parties under power purchase agreements or as 'virtual power plants (VPP)' having firm dispatch contracts with the grid operator. The financial and technical benefits of pairing a few hours of storage with utility-scale PV is demonstrated by the fact that

[11] https://www.nrel.gov/docs/fy22osti/83718.pdf

[12] private communication with CME Solar and Electric 04/12/23

[13] Sepúlveda-Mora, S. B. & Hegedus, S. (2021). "Making the Case for Time-of-Use Electric Rates to Boost the Value of Battery Storage in Commercial Buildings with Grid Connected PV Systems". Energy, Volume 218, 119447. https://doi.org/10.1016/j.energy.2020.119447

over 40% of the 640 GW of utility scale projects in the 2023-2024 interconnection queue nationwide include batteries[14].

Table 2 compares results from Lazard's 2023 analysis of Levelized Cost of Energy (LCOE) in $/kWh comparing large scale PV, PV+battery, and natural gas peaking plant in PJM territory (their reports are the industry 'gold standard' for LCOE)[15]. Adding 4 hours of battery storage increases the LCOE (midpoint value) by 20% but increases the capacity factor by 3.5 and reduces the cost to provide firm peak capacity in PJM by over a factor of 2. In contrast, gas peaking plants cost more and have an extremely low capacity factor due to their being used < 100 hours per year. Utility scale PV+battery systems can also earn additional revenue by bidding into PJM frequency regulation, energy arbitrage and non-spinning reserve markets. In 2018, the Town of Lewes considered a 8 MW battery whose primary function would be to participate in frequency regulation in the PJM wholesale market, which would benefit the entire DE grid, but the company making the battery went bankrupt.[16] This concept is a good example of applying new technology and new markets to cost-effectively modernize the grid and improve reliability. Given the reduction in costs and increased number of battery suppliers since 2018, this concept should be revisited by all utilities. Residential and commercial customers can reduce their own demand charges and provide back-up power for brief outages. To our knowledge, there are no large PV+battery installations in DE. Initial cost is often cited as the reason but with the right tariffs (TOU) or contract arrangements (VPP, frequency regulation) they can be financially viable when several revenue values are stacked. DPL can apply to the PSC for different tariffs while DEC and DEMEC members can make these decisions on their own.

Configuration	LCOE range ($/MWH)	LCOE midpoint ($/MWH)	Capacity Factor	Cost to provide firm capacity ($/MWH)
100 MW PV	25-95	60	0.19	100
100 MW PV + 4 hr Storage	45-100	74	0.70	45
50 MW Gas Peaking Plant	110-220	160	<0.01	110-220

Table 2. Comparison of utility scale PV, PV+battery, and natural gas peaking plant in PJM territory in terms of 20 year LCOE, capacity factor, and capacity to provide firm power during peak demand. From Lazard (reference 15).

DEMEC members have done preliminary research on peak load shifting utilizing batteries but no implementation. In the follow-up discussions, both DEC and DPL said they were considering a few hours of battery storage in several locations. In the discussion DPL said it had two utility

[14] https://eta-publications.lbl.gov/sites/default/files/utility_scale_solar_2022_edition_slides.pdf
[15] https://www.lazard.com/research-insights/2023-levelized-cost-of-energyplus/
[16] https://www.capegazette.com/article/bpw-battery-project-hold/148756

scale battery projects but not in DE. It is good to know that the distribution utilities have considered batteries but to date there has been little movement towards either direct utility ownership in DE or incentivizing customer owned batteries. The survey question asked about customer sited batteries because they are becoming more common and can provide grid benefits at no capital expense to the utility. Batteries are another form of DER or controllable load when properly incentivized. Utilities might also consider larger utility owned batteries to provide load shifting, frequency stabilization, or supplying steady power when intermittent solar drops off due to a cloud. Bidding into the PJM frequency market with firm power from batteries can be a source of income to offset their cost. Studies have generally found that it is more lucrative to use batteries for fast frequency response than for storing a few hours of daytime solar power to reduce evening peak demand. But both value streams can be stacked with the same battery system to improve their financial viability. However, implementation begins with education of utilities and consumers as the bidding process can be complicated.

Large PV system sizes can trigger an interconnection study, but such thresholds vary across the utilities by almost two orders of magnitude, from 25 kW to 2 MW. Costs for the study are fixed at $10K for DPL while they are variable and unknown for DEC and DEMEC. The wide range of survey responses indicate that the outcome of a given PV application in DE can vary significantly depending on which utility they are applying to.

A survey question asked about plans for Automated Distribution Management System (ADMS), which was explained above. DEMEC and DEC are not presently considering it. DPL suggests that they will consider integrating a Distributed Energy Management System (DERMS) system with their existing ADMS. A DERMS is essential to orchestrate the widely distributed customer owned generation, EV and batteries expected in the near future.

V d. Resilience and Reliability

Reliability and Resilience are critical to a utility's success. The last set of questions covered the efforts in this area.

Regarding protection of infrastructure in general anticipation of climate change, DEMEC educates its members and follows industry trends. Their plans in this area include additional substations and increased pole inspection. DPL is proactively taking action now at sites threatened by flooding with a new Flood Remediation Program including enhanced on-site monitoring as well as planning for future modifications based on updated FEMA flood maps. DEC is considering underground distribution wiring. All stated that they protect transformers in flood threatened location. These are well-established industry-accepted efforts to guard physical assets against flooding and wind.

Cybersecurity threats will only increase as the extent of digital communication and control increases. Having worked briefly in grid cybersecurity, the report authors were aware of sensitivity around this issue and phrased questions appropriately. However, DEMEC declined to respond siting confidentiality. Both DPL and DEC have identified assets requiring cyber protection and they use NIST or other industry cybersecurity standards as guidelines. DPL files an annual public report responding to Public Service Commission (PSC) staff cybersecurity questions.

There is steeply growing interest in microgrids (MGs) due to their ability to provide resilient energy in event of a grid failure and to integrate more renewable energy without impacting the macrogrid. Grid connected MGs are being installed around the country by commercial, community, non-profit and utility groups. MGs are complex but achieve multiple goals and have broad benefits if their financial value is properly assessed. The last survey question asked about plans to consider or implement microgrids. DEMEC member, Town of Smyrna, installed switchgear so it can isolate (island) itself from the grid using the 100 MW Beasley gas peaker to meet the local load including a Walmart distribution center, Bayhealth emergency room, businesses and homes. It can do this if DPL is working on the transmission lines or if there is an unplanned power outage. The Town o.f Lewes considered a battery-powered MG in 2021 to back-up a hospital but decided against it. Otherwise, there is no commitment statewide to MGs either traditional or those based on low carbon and renewable generation. DPL says the generation assets in any MG would be utility owned (not customer owned). During the discussion, DPL staff indicated awareness and interest in MGs for resilience but had concerns about unclear regulations and ownership. DEC was non-committal. Nationwide as well in DE, utilities mention cost as a concern leading to skepticism around MGs. But they often fail to include several financial benefits of a MG their analyses, i.e., cost of resilience and providing ancillary services.

A final comment here is that Delaware generates less than half of the electricity we consume, with rest being imported from other states. To increase reliability and resilience and to reduce transmission losses and expenses, the benefits of increasing our local energy such as DERs should be explored.

VI. Concluding Comments

Five comments follow derived from synthesizing the above results with state-level or industry-level trends and efforts nationwide. They include both technical and policy recommendations.

First, when the fraction of solar generation and EVs was only a few percent, they could be accommodated without any changes to the management of the distribution grid. Net metering currently rewards the solar homeowner 100% for all the energy that they inject into the grid without constraint over when they do it, i.e. whether the local distribution grid needs more power. EV owners currently can plug in whenever they want without concern over whether the distribution grid is near maximum capacity. As the amount of unmanaged solar and EVs connected to the grid increases, at some point this creates challenges between the ability to match supply and demand on a minute-by-minute basis. It is widely recognized that we cannot continue to allow unrestrained injection of solar or other variable distributed energy resource as occurs with net energy metering (NEM) nor uncontrolled charging of EV. This creates major problems for utilities in managing the reliable flow of power. One common feature of many solutions that have been proposed or demonstrated is to <u>implement coordinated management approaches that reach on the customer side of the meter</u>. The ability to monitor and control customer-owned solar generation and loads is essential to allow much greater percentages of solar and EVs to connect and will provide value to both their owners and to other ratepayers. This includes DERMS but also other arrangements between utilities, solar and EV owners and third-party aggregators. These new arrangements are essential to meet the carbon reduction goals while maintaining grid reliability. As we discussed above, both DPL and DEC are considering pilot programs to demonstrate the viability of controlling customer's PV systems with funding from Department of Energy. UD is partnering on both projects.

Second, over the past decade many states and utilities around the country have explored how to integrate more carbon-free technology on their distribution network by utilizing new technology (smart solar inverters, batteries, managed EV charging, hydrogen-powered fuel cells, microgrids, DERMS) and new policies or incentives (Time-of-Use rates, third-party aggregation of dispatchable solar+batteries and loads called a 'virtual power plant', increasing customer self-consumption of their own solar). Successful new innovations are reported monthly and federal and state funding is often available to support pilot or demonstration projects. One local example is that Bloom Energy and University of Delaware, both in Newark, have applied for federal funding to be Hydrogen Hub. **Delaware does not need to reinvent the wheel** but we do need to be aware of these pilot projects. We need to critically evaluate which ones make sense for us and to embrace them rapidly. Time is not on our side when it comes to the emerging energy landscape. Technically trained specialists are needed within the State government to provide guidance, leadership and advocacy for these efforts.

Third, the original concept that drove this study was to evaluate the readiness and capacity of DE's utilities to perform an IDP/IRP study. There are now many examples of states and cities performing <u>their own</u> studies to evaluate the costs and benefits of different clean energy scenarios to create their own roadmap of reconfiguring the local distribution network to support a low carbon future. These state and local IDP processes tend to follow the three goals shown in Figure 1 - they are transparent having stakeholder input, they align with public policy or community-defined goals, and they include technical and economic assumptions and approaches that can be openly discussed and validated, as opposed to the confidential data and evaluation by which most utility IDP/IRPs are conducted. NREL and other national clean energy groups like the Clean Energy States Alliance have developed publicly available energy system modeling and planning software which enables states to perform their own IDP/IRP planning[17]. The US EPA is providing states with funds to develop comprehensive energy plans that will reduce carbon emissions and meet green energy goals. Only DPL is currently filing public planning documents such as their LRDP and ISR plans[18]; however, that process may not necessarily be aligned or consistent with state and community goals. Delaware needs a comprehensive energy plan and utility alignment with it. This would be an excellent task for the proposed Delaware Energy Administration or Governor's Energy Advisory Council to undertake.

Fourth, the large amounts of data that will be collected in the future will necessitate implementing advanced methods of data acquisition and analysis, the latter termed 'data analytics or machine learning or just 'big data'. Instantaneous data from hundreds of thousands of smart devices and sensors will need to be evaluated and acted upon to manage the distribution grid including weather and load forecasting. These approaches are becoming ubiquitous in all industries but require investment in people and computing. Without these investments, the data will overwhelm the current decision-making systems. We note that in their LRDP (p37), DPL explicitly addresses the need for *"major IT investments (including): digital grid enablement (i.e., building fiber and wireless communication network that will enable and manage real time monitoring and control for a grid that is heavily leveraging DERs); security controls; grid and AMI analytics"*

Fifth and finally, none of this can happen without sufficient skilled professionals and technicians to help transition to the Smart Grid. We need to invest in the people and technology who will provide innovation and labor to improve the physical and digital infrastructure needed to keep clean low carbon electricity flowing reliability. This includes the local municipal electric departments, state agencies, larger utilities, and new and existing companies and organizations providing electric services to residential/commercial/industrial consumers. Being seen as a leader in this area could also attract high tech smart energy industries to our state. The nationwide shortage of trained workers to implement the low-carbon grid has gotten more attention after the IRA was passed in 2022. The IRA created over 100,000 clean energy related jobs nationwide in just 6 months and most projects haven't gotten off the ground yet. Table 3 lists the predicted jobs in four categories needed by 2025 and 2030 in Delaware to meet

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[17] https://pv-magazine-usa.com/2023/04/14/federal-grants-of-4-6-billion-available-to-states-aiming-to-model-a-clean-energy-grid/?utm_source=USA+%7C+Newsletter&utm_campaign=2bc8a60701-RSS_EMAIL_CAMPAIGN&utm_medium=email&utm_term=0_80e0d17bb8-2bc8a60701-145040441

[18] DPL's Long Range Distribution Plan (LRDP) and Infrastructure Safety and Reliability (ISR) plans provide for public comment at PSC hearing and are PSC approved.

expected national goals set in the IRA[19]. They project a more than three-fold increase in just those four categories. This excludes jobs relating to EVs, utility grid infrastructure or indirect jobs.

Career path	Jobs In 2020	Jobs needed 2025	Jobs needed 2030
Solar	523	942	1349
Wind	50	69	94
Battery	37	101	209
Energy Efficiency	228	584	1027
Total	838	1696	2679

Table 3. Predicted workforce needed in Delaware in four categories. Numbers are from modeling by National Renewable Energy Lab (NREL) and represent the size of the workforce "required to achieve projected national deployment levels of each technology for 2025 and 2030 if the state captures the same proportion of jobs in the sector as it did in 2020." (Ref. 19) Note that this does not include EV charger installation and repair or utility transmission and distribution maintenance and upgrades.

[19] "State-Level Employment Projections for Four Clean Energy Technologies in 2025 and 2030" NREL 2023 https://www.nrel.gov/docs/fy22osti/81486.pdf