MidAtlantic
Distributed Resources Initiative

Integrated Distribution Planning for Electric Utilities:

Guidance for Public Utility Commissions

October 2019

About MADRI

The Mid-Atlantic Distributed Resources Initiative (MADRI) seeks to identify and remedy retail and wholesale market barriers to the deployment of distributed generation, demand response, energy efficiency and energy storage in the mid-Atlantic region.

MADRI was established in 2004 by the public utility commissions of Delaware, the District of Columbia, Maryland, New Jersey and Pennsylvania, along with the U.S. Department of Energy, U.S. Environmental Protection Agency, Federal Energy Regulatory Commission and PJM Interconnection. The public utility commissions of Illinois and Ohio later became active participants. MADRI meetings are organized and facilitated by the Regulatory Assistance Project (RAP), with funding from the U.S. Department of Energy. MADRI's guiding principle is a belief that distributed energy resources should compete with generation and transmission to ensure grid reliability and a fully functioning wholesale electric market. MADRI provides a venue to identify and consider different perspectives and possible solutions to distributed energy resource challenges in a collaborative setting, outside of contested cases and hearing rooms. MADRI meetings are free, open to all stakeholders and the public and webcast live for those who cannot attend in person.

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Full Paper

The complete version of this guide is available on the MADRI website here:
https://www.madrionline.org/wp-content/uploads/2019/10/MADRI_IDP_Final.pdf

Executive Summary

IDP is a process that systematically develops plans for the future of a distribution grid using inputs supplied by the electric utility, the commission and interested stakeholders.

The modern electric power system is undergoing a sea change that is transforming the generation, distribution and consumption of electricity. In particular, the integration of distributed energy resources (DERs)[1] into the electric power system is profoundly changing how we plan, build and operate the system. These new resources pose a challenge and an opportunity for distribution utilities, transmission system operators, retail energy suppliers and regulators.

This manual is designed to assist utility commissions in the restructured jurisdictions that participate in the Mid-Atlantic Distributed Resources Initiative (MADRI) with guiding and overseeing the development of integrated distribution plans (IDPs) for electric utilities. Commissions in other states may also find it useful. In restructured jurisdictions, commissions generally have limited authority over generation and transmission but retain full jurisdiction over distribution services and rates. This naturally leads those commissions to focus on the distribution system. Even so, most commissions have until recently given little or no scrutiny to the details of distribution system *planning*.

IDP is a process that systematically develops plans for the future of a distribution grid using inputs supplied by the electric utility, the commission and interested stakeholders. The planning process is integrated in the sense that all possible solutions to distribution system needs are considered. The objective of the final plan is a distribution system that operates for the public good, meeting the objectives set out by stakeholders in a cost-effective manner. Over the long term, the IDP process should reduce costs, improve efficiency and point the way toward a more sustainable distribution grid — one that is safe, secure, reliable and resilient.

This manual addresses:

- Options and issues for establishing and overseeing a formal IDP process for electric utilities through regulatory action;
- Steps in the process of developing an IDP;
- Content of an IDP filing;
- Challenges for developing and implementing an IDP and potential solutions; and
- Technical considerations for planners.

Establishing a Formal IDP Requirement Through Regulatory Action

Commissions that wish to establish a formal IDP requirement will need to consider their statutory authority to administer such a requirement and the type of regulatory proceeding that will best serve their purposes. They will also need to make key decisions on a variety of procedural questions about the scope of the planning requirement, stakeholder participation and other issues. And finally, the commission will want to consider whether and how to coordinate its work on IDP with other planning processes and regulatory proceedings.

1 The term "distributed energy resource" is broadly used but may be defined differently in the statutes, regulations or policies of each jurisdiction. The term virtually always encompasses behind-the-meter distributed generation (DG) and electricity storage. In some jurisdictions, it may also include some combination of demand response (DR), energy efficiency (EE), electric vehicles (EVs) and in-front-of-the-meter generation or storage resources that are interconnected at distribution voltages. Microgrids, which typically rely on a combination of DERs, are sometimes considered to be DERs unto themselves. This guidance manual generally includes all these types of resources in its definition of DERs, with the understanding that definitions in some jurisdictions may be narrower.

Commission Authority

Most states provide their commissions with general supervisory authority over all business aspects of regulated utilities as they relate to costs and quality of service. In this regard, a clear argument can be made that supervision over distribution planning is a vital component of this authority. Fundamentally, IDP is designed to ensure that investments in the utility distribution system ensure reliability, are built to be resilient and employ least-cost options. But utilities must also enable the safe interconnection of DERs by customers and third parties and strive to optimize the use of new resources and grid technologies while reasonably balancing the risks and opportunities. Some commissions may take a narrower view of their authority to oversee and guide distribution planning and may want more specific statutory language referencing IDP. In this case, passing legislation authorizing commission involvement in and oversight of integrated distribution system planning would be necessary.

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Type of Commission Proceeding

The commission has several options for considering whether and how to develop IDPs: an issue-based investigation or workshop, a rulemaking, a utility-specific contested case or some combination of these proceedings. Some jurisdictions may opt for a more informal workshop or investigation to introduce the subject to stakeholders and receive input. This can be a productive way to learn about best practices and the pitfalls to be avoided and may be less costly (in terms of the time and human resources required) than a more formal proceeding. With a more formal process, there are a range of options. Some jurisdictions may wish to promulgate binding regulations, while others may opt for guidelines that are advisory and not enforceable.

Developing some form of consistent framework for the filing of an IDP that must be followed within each jurisdiction is important for several reasons. It ensures that the commission and stakeholders or intervenors receive the initial level of detail required to review a utility plan. It also requires a careful and thorough process by the utility to develop a plan. Furthermore, it creates uniformity in utility filings, making it easier for commission staff and the public to review them.

Regulations on an IDP process can include both the process and the substance of the filing. An IDP case filing allows the commission to review and investigate the plans of each utility under its jurisdiction to upgrade its distribution system. Having regulations in place prior to the filing provides a road map to ensure each utility initially provides all information that is necessary for the commission to begin its review and ultimately render a determination as to the reasonableness of the plan prior to any expenditures taking place.

Key Commission Decisions Regarding an IDP Proceeding

At the outset of any IDP proceeding, the commission will need to make several key decisions that shape the level of effort and roles of all parties and how the completed IDP will be used.

First, the commission must decide whether to implement IDP one utility and one case at a time or through a joint proceeding involving all regulated utilities. Taking each case one at a time may allow for a deeper dive into issues and consideration of attributes specific to each utility. A joint proceeding could produce a more consistent statewide approach to planning.

Second, the commission must decide and clearly explain the types of DERs that should be considered by utilities in the IDP process. To be used as an effective tool, an IDP needs to be comprehensive in terms of examining the entire grid and all the potential options for improving the grid from a reliability, resilience and cost-effectiveness standpoint.

Third, the commission must decide on the length of the planning horizon, the timing of plan filings and the frequency of plan updates. Based on practices observed to date, an IDP should probably cover a five- to 10-year planning horizon, at a minimum, though there are examples that reach out as far as 30 years. Where a state has multiple utilities subject to IDP filing requirements, the commission may choose to stagger the timing of each utility's initial planning process to avoid creating a strain on commission staff and stakeholder resources and to maintain their ability to review and analyze the filing. Given the rapid pace of change in the power sector, a commission might want to consider requiring relatively frequent updates to each utility's IDP — perhaps even annual updates. However, preparing, reviewing and evaluating an IDP is a considerable undertaking; therefore some commissions will find that two or three years between filings is appropriate. Commissions will want to reserve the right to order a complete or modified IDP in between the scheduled updates as may be warranted. Commissions will also want to consider whether to align the timing and frequency of IDP filings with related efforts, such as integrated resource plan filings, energy assurance plans, energy master plans and so on.

Fourth, the commission will need to decide how to involve stakeholders, including other government agencies (e.g., the state energy office). Having stakeholder participation increases transparency and creates more confidence in the commission's processes and decisions. At a minimum, stakeholders should have the opportunity to review and comment on a filed IDP. In addition, commissions may find it reasonable and in the public interest to order utilities to engage expert stakeholders collaboratively, early in the process, before anything is filed with the commission. Some commissions might even wish to appoint an independent subject matter expert to lead the stakeholder engagement activities.

Fifth, the commission must decide whether a utility filing should be informational or subject to a commission approval that binds the utility to the planned course of action. If the

Photo by Public Utilities Commission of Ohio former approach is chosen, the commission "acknowledges" that an IDP was submitted in conformance with established legal requirements but does not formally review or approve the content of the plan as it would using the latter approach. When considering the approval approach, commissions may be concerned that as the plan ages it could lead to utility actions that no longer reflect the best options available to the utility at the time of each implementation decision. To resolve this concern, the commission can note in an order or in its rules that approval of an IDP still requires that the utility's actions be reasonable and prudent at the time each action is taken to ensure cost recovery. Moreover, the rules or guidelines can include a process if there has been a significant lapse of time between approval of an IDP and the implementation of an aspect of the plan.

Content of a Commission Order Accepting or Approving an IDP

If an IDP is considered under a contested case hearing procedure that requires commission approval, a commission will need to issue a written order to memorialize its decision. The order should contain a recitation of the record and a review of the relevant statutes and regulations. These recitations should include a synthesis of the relevant issues and positions of the parties. These recitations summarize and analyze the administrative proceedings and are useful to aid a reviewing court. The relevant portions of the commission's decision will be the findings of fact relevant to each issue and the conclusions of law that follow from those facts. The result of these factual findings and legal conclusions will determine the fate of the IDP under consideration: approval (with or without modification) or denial (with or without an opportunity for revision). Where a commission approves an IDP, the order should outline any relevant next steps or opportunities for further review. The key consideration should be an order sufficiently detailed to allow implementation without additional commission input.

A commission can also approve an IDP with modifications. In this situation, the modifications should be clearly delineated and include sufficient direction for stakeholder implementation. Alternatively, a commission may deny an IDP, either with or without the opportunity for revision. Denial without the opportunity for revision rejects the proposed IDP but does not preclude future filings. As such, the denial should identify the grounds for denial, such as factual inadequacy, statutory barriers or a party's failure to sustain a burden of proof. Denial with direction to modify the IDP will provide stakeholders or parties to the proposal with an opportunity to revise and resubmit the current plan. In this situation, it is essential for the commission to provide guidance on where the existing proposal fell short so that parties may target their efforts toward modifications that will satisfy the commission.

The commission can also expect to see the results of the IDP in future rate cases. It is uncommon for a commission to preapprove cost recovery of distribution assets before they are used and useful in serving ratepayers. Thus, the implementing utility will need to seek recovery of the infrastructure elements of the IDP in a future rate case. This will give the commission the opportunity to review the implementation of the IDP for prudence and reasonableness.

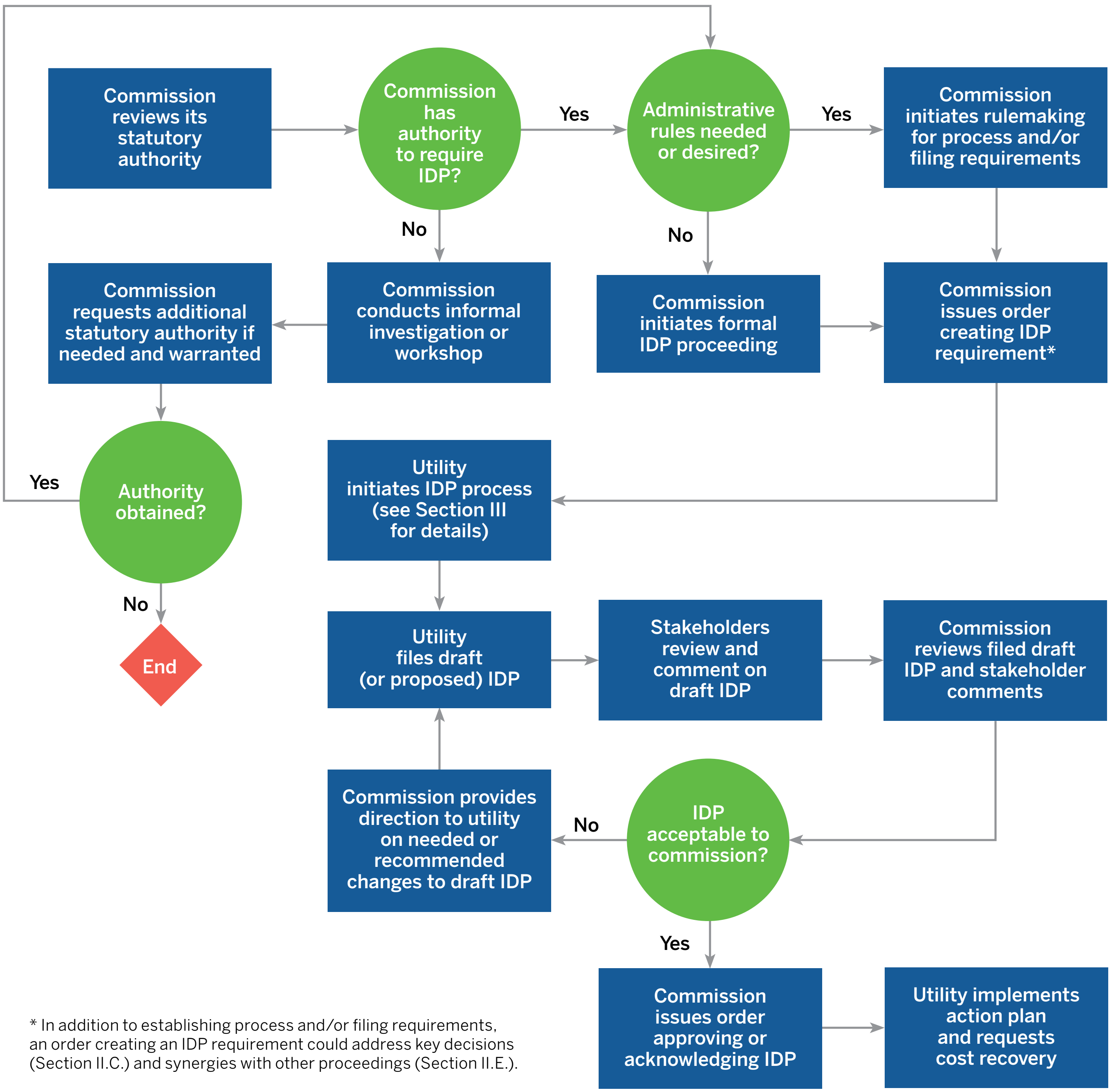
Potential Synergies With Other Electric Utility Planning Processes and Regulatory Proceedings

There are a variety of regulatory and planning issues that are not essential to an IDP process but may have a bearing on the inputs or outcomes. Commissions may wish to address some or all of these issues in concert with the decision to impose an IDP requirement: grid modernization initiatives, DER interconnection standards and procedures, the creation of a distribution system operator, changes to the electric utility business model and alternative ratemaking options, and resource or transmission planning processes.

Summary of the Commission Oversight Process

Figure ES-1 presents a flowchart summarizing the generic steps a commission might take in the process of developing and implementing an IDP requirement. Because the statutory authorities and institutional norms of every commission are unique, this figure should be viewed simply as an illustrative example.

Figure ES-1. Commission Oversight of an IDP Requirement



* In addition to establishing process and/or filing requirements, an order creating an IDP requirement could address key decisions (Section II.C.) and synergies with other proceedings (Section II.E.).

Process for Developing an IDP

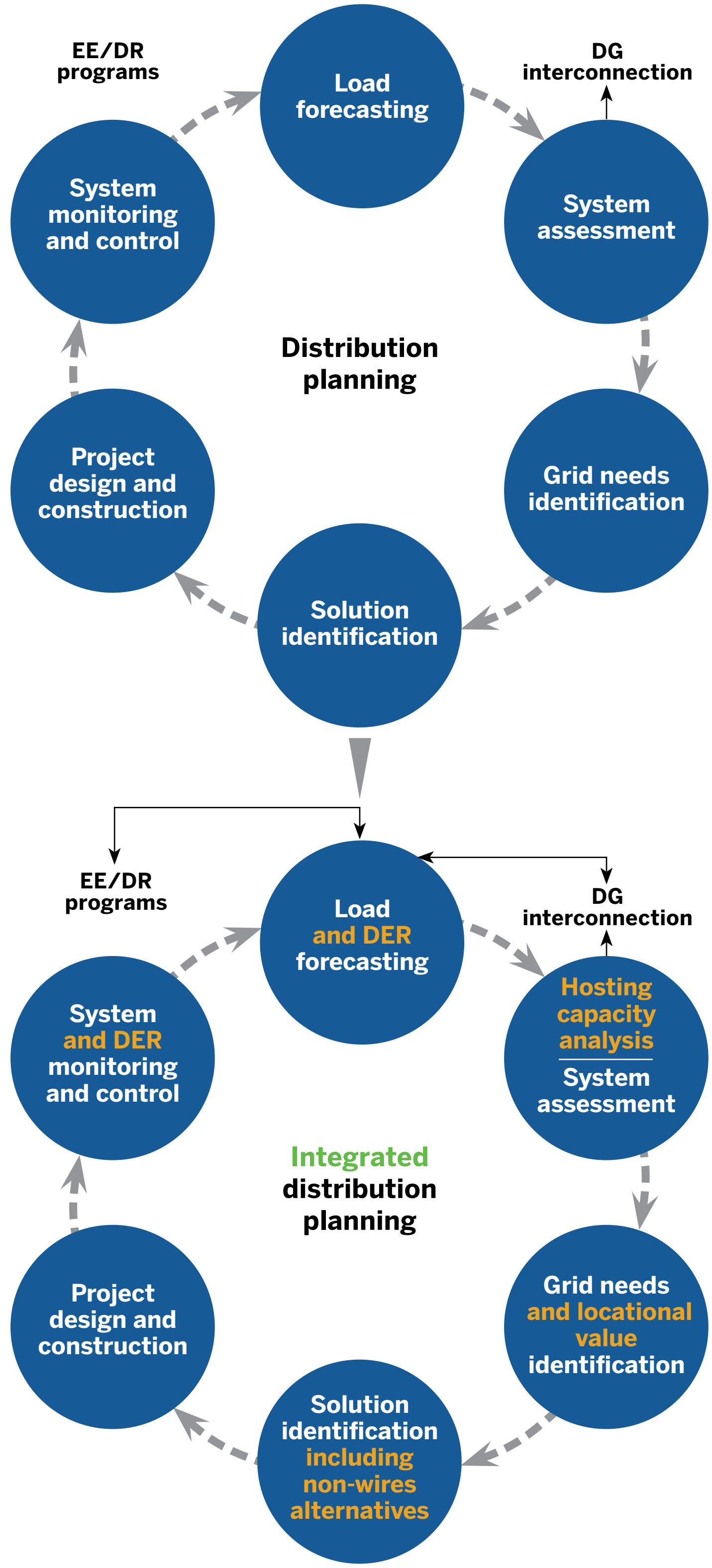
In most cases, regulatory commissions that adopt a formal IDP requirement will want to prescribe, or at least outline, a process for the development of such plans by utilities. Figure ES-2 illustrates how a typical distribution planning process, shown at the top of the figure, compares to an IDP process, as shown at the bottom of the figure. The most essential factor that separates an IDP from a traditional distribution planning process is the integrated consideration of all possible solutions to identified needs. The goal remains to find the least costly, sufficiently safe and reliable option for ratepayers, but in IDP the preferred option may or may not include transmission or distribution infrastructure and may or may not be utility owned.

The planning process shown in Figure ES-2 begins with the creation of forecasts of load and DER deployment for the utility service territory, which when combined result in a net load forecast. Forecasting is foundational to the IDP process because it defines the needs of the system over the planning period. Traditional forecasting tools have focused on customer load growth rather than DERs and mainly relied on demographic and economic data and energy usage trends. However, as DERs become more common, new models become necessary to accurately forecast DER adoption trends and their impact on future net loads. Because the hallmark of an IDP process is granularity, the forecasts will need to be spatially and temporally differentiated to enable a proper assessment of system needs and potential solutions.

The second major step in the planning process is to characterize the capabilities and limitations of the existing distribution system. This requires a detailed review of the capacity of existing infrastructure, as well as known problems, limitations and areas of concern. This step also includes (or should include) an assessment of the hosting capacity of the existing distribution system. Because system conditions and hosting capacity can vary from one line segment to the next, the assessment must be very detailed and spatially granular.

In the next step, the assessment of current system capabilities is compared with the forecasts of load and DER deployment (or net load) to identify locations on the distribution system where the forecasted needs of customers will exceed

Figure ES-2. Comparison of Typical Distribution Planning Process and IDP[2]



2 Volkmann, C. (2018). *Integrated distribution planning: A path forward.* GridLab. Retrieved from: https://gridlab.org/publications/

existing capacity and capabilities. At the same time, this analysis can also identify locations where deployment of additional DERs or traditional assets would have the greatest value. The tools for this include software for power flow analysis, power quality assessment and fault analysis. Power flow analysis identifies the operational characteristics of the existing and planned distribution grid, including how conditions change in relation to customer load and DER adoption scenarios. Power quality assessment studies the impact to power quality of increased penetration of intermittent renewables and inverter-based DERs on the distribution system, including voltage sag and harmonic disturbances. Fault analysis is used to identify anomalies in the flow of current on the distribution system. Advanced optimization tools are being developed to identify the optimal size, location and capabilities of DERs that can provide grid services.

After identifying forecasted grid needs, the planning process turns to a search for least-cost solutions to satisfy those needs. The essence of an IDP, and what sets it apart from a traditional distribution system planning process, is the *integrated* approach. All options to address forecasted needs should be considered on fair and equal footing. When all the suitable options have been assessed, a preferred solution or set of solutions can be chosen based on consideration of costs, capabilities, timing, uncertainties and risks.

Following any required stakeholder review or regulatory approvals of the IDP, the utility will begin to implement the near-term projects and actions identified in the plan. Some types of projects (e.g., construction of a new substation) may require additional preconstruction approvals from the commission, from environmental regulators or from local officials. After each project or action is completed, and on an ongoing basis, the utility will need to monitor and report to the commission on system conditions to determine if the system need has been met and to identify new capacity constraints to address in future updates to the IDP.

Content of an IDP

The key content elements of an IDP include a description of the current system, a summary of planned retirements and committed future resource additions, a load and DER forecast, a hosting capacity analysis, a needs assessment and risk analysis, an evaluation of options for meeting forecasted needs, an action plan and a summary of stakeholder engagement.

Description of the Current System

The IDP should describe the utility service territory and summarize information about the number of customers served by the utility. The IDP should also provide data about key distribution system parameters, including:

- Status of automated metering infrastructure deployment by customer class;
- Miles of underground and overhead wires, possibly categorized by voltage;
- Number and capacity of distribution substations;
- Number and capacity of distribution transformers;
- Monitoring and measurement capabilities on the distribution system — for example, the percentage of substations and feeders for which the utility has real-time supervisory control and data acquisition capability;
- Historical coincident and noncoincident peak loads on the distribution system;
- Estimated or known distribution system line losses;
- Amount of DG installed on the system (number of systems and nameplate capacity in kilowatts, or kW) by generator types, noting geographic locations as needed for planning purposes;
- Amount and locations of distributed storage installed on the system (number of systems and ratings, measured in kilowatts and kilowatt-hours, or kW and kWh);
- Number of EVs in each region of the service territory;[3]
- Number, capacity and locations of public and, where data are available, private EV charging stations;
- Number, capabilities and locations of any islandable microgrids;

3 EV batteries are technically capable of discharging energy to the grid or using it to serve other on-site loads, just like other forms of distributed energy storage. Today's EVs and EV chargers are not designed to facilitate this vehicle-to-grid, or V2G, capability, but that capability may be activated in the future. If so, planners may need to identify the number, capacity and locations of EVs with V2G capability in the same way they characterize other forms of distributed storage.

- Recent history of investment in demand-side management (EE and DR) and results (energy and demand savings); and
- Recent history of distribution system investments (in dollars) categorized by reason for investment (e.g., replace failing equipment, increase capacity, etc.).

Planned Retirements and Committed Future Resource Additions

The IDP should similarly describe any known or expected future asset changes on the distribution system and state the reason for the change. This should include planned retirements of existing assets and infrastructure projects that are already underway or to which the utility has already made financial commitments. This portion of the IDP should reflect *decisions already made;* it is separate from the analysis of future needs and alternatives and the selection of preferred solutions.

Load and DER Forecast

The IDP report should include a load forecast that covers every year of the planning horizon and forecasts of expected annual additions of each type of DER on the distribution system. Load forecasts can then be combined with DER forecasts to develop spatially and temporally granular net load forecasts. The report should also describe the methods, data sources and models used to develop these forecasts. Because forecasting is increasingly complex and uncertain, utilities and regulators now commonly use a range of forecast scenarios to inform planning processes. The IDP report should describe the assumptions underlying each scenario analyzed.

Hosting Capacity Analysis

The IDP report should provide a narrative description of any hosting capacity analysis (HCA) performed. An HCA is an analytical tool that can help states, utilities, developers and other stakeholders gain greater visibility into the current state of the distribution grid and its physical capacity to host DERs. The results of the HCA are typically displayed visually in the form of a map, which color-codes feeders or line segments according to their hosting capacity range, published with accompanying data sets containing the more detailed underlying data. The maps and data sets together provide public access to hosting capacity values by location along with information on specific operational limits of the grid and other important grid characteristics, including areas on the grid that might be able to accommodate additional DERs without violating hosting capacity limitations. The HCA may need to be run on the entire distribution system under different scenarios about assumed DER growth across *varying time horizons.*

Needs Assessment and Risk Analysis

The IDP report will need to summarize both the methods and the results of the needs assessment step. In this step the current and planned capabilities of the distribution system are assessed to see if they can adequately serve the forecasted net load. Within the needs assessment portion of the report, the utility should first explain the criteria used to assess reliability and risk and the modeling tools and methods used to identify future system needs. The IDP report should then summarize the results of the assessment, beginning with the identified needs. Finally, the IDP report should describe the criteria used to prioritize grid investments and the results of that prioritization exercise.

Evaluation of Options for Meeting Forecasted Needs

In a traditional distribution planning process, virtually every need would be satisfied by finding the least costly utility-owned transmission or distribution infrastructure investment that solved each problem. In an IDP process, those traditional options are supplemented with equal consideration of non-wires alternatives (NWAs), including targeted applications of energy storage, DG, DR, managed EV charging, microgrids and EE. Changes in rate design that affect peak demand should also be considered.

The IDP report should describe the assumed capabilities and costs of each option category considered. Because the adoption of customer-owned or third-party-owned DERs is not unlimited and not controlled by utilities, planners may need to assess the amount of DERs that might reasonably be deployed in time to meet identified needs assuming utilities apply their best efforts to encourage and incentivize such adoption. EE potential studies, for example, could be used to estimate how much EE could be procured in a targeted area over a given timeframe. Ultimately, the IDP report should identify the preferred solution and compare the expected cost of that solution to the expected cost of other options that were deemed technically capable of meeting the need. If risk or other criteria factor into the selection of the preferred solution, those criteria should also be included in the comparison. And finally, if the IDP process used a range of assumed values or assessed multiple scenarios, the least costly option might vary from one scenario to the next or vary depending on which assumptions are used. In such cases, the report should explain how the preferred solutions were selected.

Action Plan

An IDP should include an action plan, which is the culmination of the process in which numerous scenarios are considered to develop the best options for meeting forecasted needs. The purpose of an action plan is to set forth the actions that need to be implemented in the near term, as in the first four or five years of the planning period. The action plan should include the plans for soliciting the deployment of DERs, as well as plans for permitting, constructing, preparing required reports and other significant activities where replacement, upgrades or expansion of utility infrastructure has been identified as the best option. Plans for the retirement or retrofit of existing major equipment should also be identified. The action plan should include a timeline that establishes the sequence of events for each action to be taken.

Summary of Stakeholder Engagement

Finally, the IDP report should explain the roles that stakeholders played in developing the plan. This should include at a minimum identifying the involved persons and their organizational affiliations, summarizing any stakeholder meetings that were convened and noting any opportunities for comment that were afforded outside stakeholder meetings.

Challenges for Developing and Implementing an IDP

The process of developing an IDP raises new challenges for everyone involved. In this section, we examine some of the key challenges for utility commissions, utilities, customers and DER providers.

Commissions

One major challenge for utilities is the need for improved visibility of behind-the-meter resources. A lack of visibility can lead to bad infrastructure investment decisions, inefficient system operations and reliability problems.

Commissions may need to consider different approaches than their traditional regulations and practices. Most have not had experience with granular and detailed planning processes for grid investments at the distribution level. Historical tariffs, rules and practices will need to change to align costs with prices. It is imperative that a commission understands the goals it is trying to achieve and how it wants to try to achieve them and works to reduce the challenges and barriers that might impede its progress toward those goals.

Some of the biggest challenges for commissions will relate to staffing, retail rate design and DER compensation, state rules that may prohibit or inhibit DER deployment, and data transparency and ownership. Commissions can begin by making sure they have the right staff capacity and expertise to oversee the IDP planning process and utility implementation of the IDP. If necessary, gaps in capacity or technical expertise could be filled by contracting with qualified impartial experts.

Next, the challenge of developing a good IDP is closely tied to the challenge of optimizing DER deployment. If DERs are deployed in the right amounts and the right places, they can contribute to the most reliable, least-cost distribution system. If investment in DERs is too high (e.g., because they receive compensation in excess of their value to the grid) or too low (e.g., because they are not used to defer more costly system upgrades), system costs will increase. Customer decisions concerning DER deployment are heavily influenced by decisions that utility commissions make about retail rate design and DER compensation. To get the right mix of resources installed on the grid, commissions may need to reconsider their current approach to retail rate design and DER compensation. This would most likely occur outside an IDP proceeding in a general rate case or a separate rate design proceeding. Given the complexity of this topic, additional guidance is presented in Appendix 2.

Commissions can examine the regulatory environment in which DERs will be deployed to make sure that current rules do not unduly hamper DER growth at suboptimal levels. For instance, the existing statutory authority, or existing commission rules, may prohibit third-party aggregation of DR resources or third-party ownership of rooftop solar systems. Interconnection rules are another example of an area in which customers may face long delays, confusing requirements or high costs and fees. Commissions can strive to ensure their regulations address modern technology, while also staying flexible enough for future changes and third-party business models. Technology-specific rules, such as requirements for smart inverters or interoperability standards, can help steer resources in directions that can provide more benefits and options for the customers and the grid.

It is crucial that the privacy of customer-specific data be protected with modern cybersecurity best practices. Commissions generally want to ensure utilities know what is expected of them, are following the latest best practices and allow for adequate recovery of any associated costs. As commissions and utilities struggle to address this complicated topic, it is important to ensure that customers have adequate privacy protections. It is equally important to determine what types of data customers should be able to easily access and to mitigate any possible risks in providing that data to them. This includes a safe way to share customer-identifying data with third parties that wish to market and price potential services to those customers. In any event, no customer-specific information should be shared without the customer's explicit consent.

Utilities

Maintaining safe and reliable grid operations now requires more data than ever before. One major challenge for utilities is the need for improved visibility of behind-the-meter resources — that is, sufficiently accurate data about the locations, capabilities and status of DERs to enable sound


Photo by American Public Power Association on Unsplash

planning and system operations. A lack of visibility can lead to bad infrastructure investment decisions, inefficient system operations and reliability problems.

Under traditional cost-of-service regulation, utilities have an inherent incentive to maximize throughput — that is, kW and kWh sales. The throughput incentive can be a challenge for utilities implementing IDP because deployment of DERs can reduce energy deliveries or peak customer demand, resulting in lost revenues and decreased profits. Fortunately, practical solutions for addressing the throughput incentive exist. One option is to use smart rate designs and fair DER compensation mechanisms, as detailed in Appendix 2. Rate designs and compensation mechanisms that send appropriate price signals to customers about system costs and cost drivers should minimize lost revenue problems. Another common approach to addressing the throughput incentive involves revenue regulation, also known as revenue decoupling.

Under traditional cost-of-service regulation, utilities create shareholder value by adding capital assets to their rate base and earning a rate of return on the residual value of these assets as they depreciate. In contrast, operating expenses are usually treated as a pass-through expense and do not contribute to utility earnings. This creates a utility investment preference for capital expenditures rather than operating expenditures when seeking solutions to address grid needs — a “capital bias.” Ideally the decision to meet system needs through asset-based solutions or service-based solutions will be decided based on which solution set provides the best value to customers, rather than which solution set has more favorable regulatory treatment for shareholders. Regulators are investigating opportunities to level the playing field between capital expenses and operating expenses for the provision of grid services. One option is to allow utilities to earn a rate of return on total expenditures. Performance-based regulation (PBR) offers another option for addressing capital bias and aligning utility shareholder interests with least-cost IDP solutions. The most common approach to PBR worldwide is the multiyear rate plan, which enables utilities to operate for several years without a general rate case. More expansive forms of PBR can partially or fully replace rate base as the driver of utility shareholder profits. A commission can use these and other similar tools to address the capital bias and greatly improve the IDPs produced by utilities and the value they provide to the public interest. By better aligning utility shareholder interests with those of customers, commissions are then free to optimize DER deployment and compensation through rate design or other DER compensation methodologies.

The risk of stranding existing utility assets could be a challenge in developing and implementing a comprehensive IDP. This is because an IDP could reveal opportunities for distributed solutions that are cost-effective for customers but that reduce the usefulness of, or demand placed on, existing assets. In other words, when developing an IDP, utilities might be concerned with whether their existing assets will be replaced before they are fully depreciated. This is less of an issue in restructured states where distribution utilities do not own generation assets. Thus, utilities should consider the rapid pace of technological advancement and the possibility of creating a future stranded asset before making any kind of major infrastructure investment. One important strategy to reduce the risk of future stranded assets is for utilities to deploy technologies that utilize open technical standards.

Many utilities believe they are best suited to provide cost-effective DER solutions and see this as a natural expansion of their traditional role. Non-utility DER providers argue that these products and services belong in a competitive market. The decision about what types of DERs, if any, utilities can own or control has implications for the development and implementation of a comprehensive utility IDP. If the least-cost solutions involve some combination of non-utility-owned assets, such as customer or third-party-owned solar and storage, utilities may want to control or set boundaries on how those assets are operated and how the owners will be compensated for services rendered. At a minimum, if the utilities cannot control the DERs, they will need some assurance that they will at least have visibility into the operation of those

assets and that they will be operated in ways that meet identified distribution system needs. Without this, utilities will be likely to prefer a utility-owned solution, which could be costlier in some cases.

The transition to a power system involving two-way flows of electricity and information (data) will require a constant reappraisal and updating of technologies and applications.

Customers

The most fundamental challenge for customer adoption of DERs is obtaining compensation that is adequate to justify the investment. Customers will install DERs if the DERs provide value through bill savings or other revenue streams that exceed installation and operational costs. Currently, it can be very difficult for customers to determine the total value proposition that DERs will provide. In addition, most decisions regarding compensation are made by other parties. Some of the key challenges regarding customer compensation that are determined by utilities or regulators are addressed in Appendix 2.

Customers who are interested in owning or hosting DERs also face their own unique set of challenges, relating to education, equity, access to financial products, physical limitations and other issues.

DER Providers

The companies that offer DER products and services to utility customers must navigate between the realms of utility regulations, tariffs and procedures on the one hand and wholesale electricity market rules on the other. This leads to a unique set of challenges for DER providers.

Although individual DERs may be quite small (e.g., only a few kW), aggregated DER resources can add up to hundreds of megawatts and can become significant players in distribution and wholesale markets. As noted in Appendix 2, market revenues can be a key component of DER compensation. DER providers can play a key role in helping customers to access market revenues, but they face significant challenges. Their ability to overcome those challenges will influence whether DERs are deployed in an optimal fashion and whether a true least-cost IDP can be achieved in practice.

The proliferation of DERs in the electric value chain has increased the interaction that utilities have with third-party entities, particularly those that use DERs to provide services in addition to traditional DR services. Smart inverters with inherent smarter functions are being deployed with capabilities that can benefit not only the DER customer being serviced but also the utility grid in the respective area. But taking advantage of these new capabilities presents new challenges for DER providers and utilities and calls for reforming the interaction between them to achieve greater coordination of resource operations.

Other Considerations for Planners and Regulators

There are several policy and technical issues that will significantly influence the assumptions, data and analysis of modeling results for an IDP, which commissions will need to be aware of as they guide and oversee the IDP process.

To begin with, policymakers and regulators are enacting policies that are shaping the growth of DERs and net load in important ways. An understanding of how these policies affect DER adoption is important for IDPs, especially at the DER forecasting stage.

The transition to a power system involving two-way flows of electricity and information (data) will also require a constant reappraisal and updating of technologies and applications. New power grid technologies and applications are emerging and will continue to emerge, including advanced power grid components, advanced control methods, new sensing and measurement capabilities, integrated high-speed communications, and interfaces and decision support tools. Power grid technologies and applications can be categorized into the major areas they impact. Consumer-enabling technologies installed behind the meter empower customers by giving them the information, tools and education they need to

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effectively utilize the new options provided to them by the evolving grid. Advanced distribution technologies (installed between substations and customers' meters) improve reliability and enable "self-healing" while supporting two-way power flow and DER operation. Advanced distribution operation technologies (installed between the transmission system and substations) integrate the distribution system and customer technologies and applications with substations and regional transmission organization applications to improve overall grid reliability and operations while reducing transmission congestion and losses. A cost-benefit analysis can identify leading technologies in a viable solution portfolio that can improve the reliability of the grid, lower costs to consumers and yield system, consumer and societal benefits.

The term "transactive energy" is being used by some to capture the ongoing evolution from a centralized generation, transmission and distribution system to a complex two-way power-flow-enabled system that allows energy transactions at all levels of the value chain. A multitude of stakeholders and their resources, including smart homes, smart buildings and industrial sites, engage in automated market trade with other resources at the distribution system level and with aggregation or representation in the bulk power system. Communications are based on prices and energy quantities through a two-way market-based negotiation. A number of technologies and process improvements will be needed before transactive energy exchanges become commonplace, but establishing the communications network is arguably the first and most important step toward realizing value creation by expanding transactions. Transactive energy systems can use existing messaging protocols for direct or indirect control of DERs, various management functions, reporting, metering and transactive functions. Technical standardization can be accelerated by extending existing protocols. Access to electronic energy usage data allows customers to track and manage their energy consumption and thus is a prerequisite to enabling customer engagement in transactive systems. Availability of usage data also empowers nontraditional stakeholders to support the transition to a modern grid. The current inability of many utility customers to access their data or authorize the use of their data inhibits the energy marketplace. Transactive energy systems by design will include a platform where all customers and service providers have access to data. The platforms need to be user-friendly and simple for consumers.

Conclusions and Recommendations

The emergence of DERs as practical, affordable power system resources is changing the nature of the distribution grid and the roles of utilities and regulators. Power system planning, including distribution planning, must adapt to this new reality to maintain reliability and minimize costs.

A key aspect of the necessary adaptation is to inject transparency and oversight into an activity that has traditionally been left to utilities to manage on their own. Furthermore, this newly transparent process must take into consideration how DERs change load profiles and how their deployment and operation can be coordinated with the development and operation of traditional utility infrastructure. In short, IDP will become a necessary part of maintaining reliability and minimizing costs.

This paper provides detailed guidance to public utility commissions on the opportunity and the challenges associated with instituting an IDP requirement for regulated utilities. It concludes with a few of the most important recommendations found herein:

- Commissions, if they have the authority to do so, should investigate IDP and eventually institute an IDP requirement for the electric utilities they regulate;
- Because the IDP process may affect and be affected by other regulatory proceedings (e.g., grid modernization initiatives, resource and transmission planning), commissions should consider how to coordinate such efforts

to minimize counterproductive policies, confusion and workload for themselves, the utilities and all stakeholders;

- Commissions should ensure that stakeholders have a distinct and prominent role in any IDP process, not only in reviewing draft plans but also in the early stages of plan development, given that the actions of customers and DER providers will ultimately determine the rate and locations of DER deployment;
- When seeking solutions to identified grid needs, an IDP should give full, fair and equal consideration to all traditional infrastructure options as well as all cost-effective DERs, including combinations of geographically targeted DERs that constitute NWAs;
- In states that have adopted public policies favoring DERs or specifically promoting their deployment, the evaluation of solutions to grid needs should reflect those preferences, and the plan should address the need to accommodate customer deployment of DERs;
- Hosting capacity analysis and hosting capacity maps should be included in an IDP and are a crucial outcome of the planning process that can be used to steer DER deployment to where it is most valuable and expedite interconnection requests;
- Commissions, the utility planners they regulate and other stakeholders should expect IDP to be challenging, at least initially, as it is a relatively new practice but should understand that methods and tools will improve over time, best practices will be identified and improved, and local experience and knowledge will grow with each iteration of the planning process; and
- Some of the key challenges that will need to be addressed by all parties to optimize IDP outcomes include:
    - Developing staff expertise and capacity for IDP and IDP oversight;
    - Designing retail rates and compensation mechanisms to send appropriate price signals and provide fair

compensation for the system value of DERs;
- Making the locations, capabilities and operational status of DERs more visible to utility planners and transmission system operators;
- Adapting cost-of-service regulation and utility business models to make utilities indifferent to or supportive of cost-effective DER deployments;
- Educating customers about DER options and ensuring that low-income customers have reasonable opportunities to share in the benefits; and
- Enabling aggregations of DERs to provide bulk power system and distribution system services and receive compensation for those services.

The full version of this guide is available on the MADRI website here:
https://www.madrionline.org/wp-content/uploads/2019/10/MADRI_IDP_Final.pdf

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