Integrated Distribution Planning

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Prepared for the Minnesota Public Utilities Commission

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DISCLAIMER

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EXECUTIVE SUMMARY

Experience across the U.S. and globally has highlighted the need to address changes to distribution planning proactively in order to satisfy customer service expectations, guide DER development and ensure long-term infrastructure investments will continue to serve customers'[1] needs safely and reliably. This paper was developed in support of the MPUC inquiry into grid modernization and the evolution of distribution planning. [2]

The MPUC Staff Report[3] recognizes that "planning efforts will be an integral part of a systematic approach to grid modernization." As such, a necessary requirement for planning is clear objectives. The MPUC staff[4] proposed the objectives as:

"A modernized grid assures continued safe, reliable, and resilient utility network operations, and enables Minnesota to meet its energy policy goals, including the integration of variable renewable electricity sources and distributed energy resources. An integrated, modern grid provides for greater system efficiency and greater utilization of grid assets, enables the development of new products and services, provides customers with necessary information and tools to enable their energy choices, and supports a standards-based and interoperable utility network."

INTEGRATED DISTRIBUTION PLANNING

Integrated distribution system planning in the 21st Century needs to assess physical and operational changes to the electric grid necessary to enable safe, reliable and affordable service that satisfies customers' changing expectations and use of DERs. As described by MPUC Commissioner Lange and colleagues, "Updates to the distribution planning process [through a standardized planning framework] will be needed to support a reliable, efficient, robust grid in a changing (and uncertain) future; should be coordinated with resource and transmission planning; could incorporate stakeholder informed planning scenarios."[5] An Integrated Distribution Planning (IDP) framework would include the following core components and is illustrated in Figure 1 on the next page.

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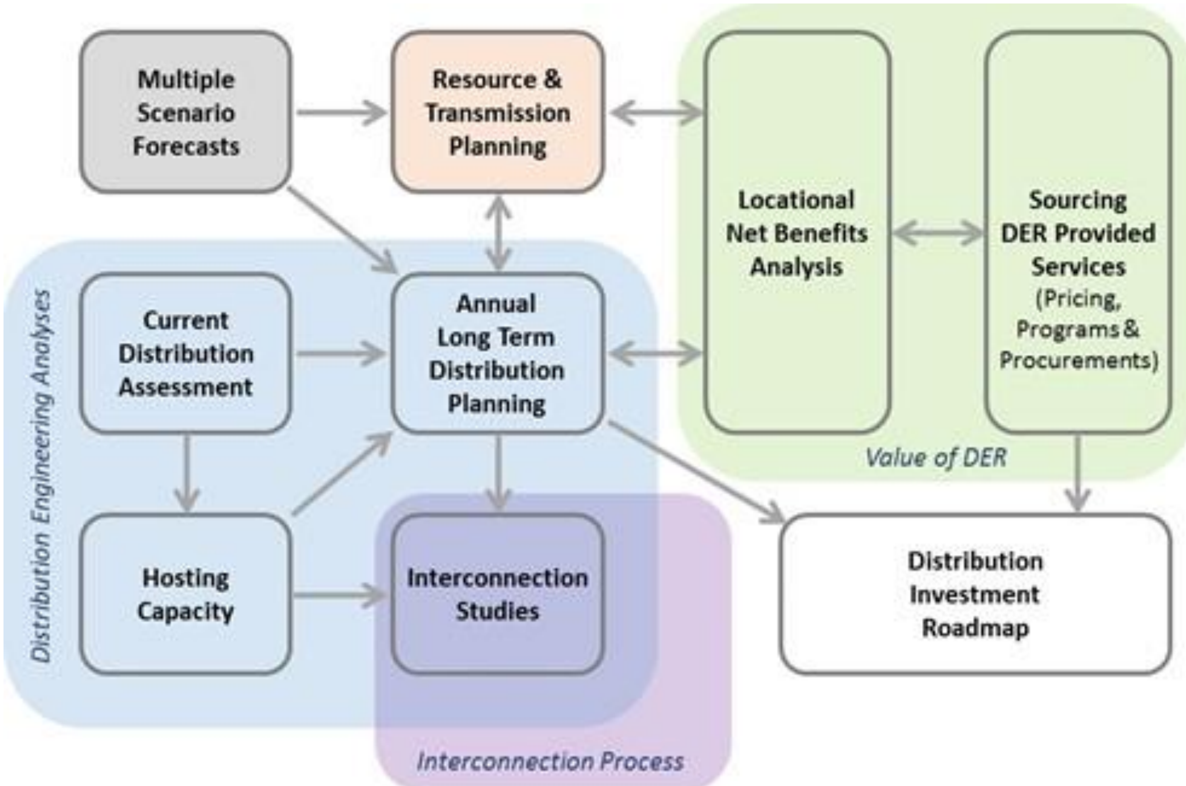
[1] "Customers" of the distribution system will expand beyond traditional end users to include merchant DER developers, aggregators and other third parties using and paying for grid delivery and related services.
[2] MPUC Grid Modernization Docket E999/CI-15-556
[3] Staff, Minnesota Staff Report on Grid Modernization, MPUC, March 2016
[4] Ibid
[5] N. Lange, A. Twite, M. Schuerger, Building a Minnesota Conversation on Grid Modernization With a Focus on Distribution Systems, MPUC, May 15, 2015

Figure 1: Integrated Distribution Planning



Current Distribution System Assessment

The laws of physics ultimately dictate the physical operation of the electric system, which means that the foundation for system planning starts with rigorous power flow analysis of the current system to fulfill obligations to provide safe, reliable service to customers at a reasonable cost. Additionally, an assessment of current feeder and substation reliability, condition of grid assets, asset loading and operations is needed along with a comparative assessment of current operating conditions against prior forecasts of load and DER adoption.

Hosting capacity

Hosting capacity analysis is used to establish a baseline of the maximum amount of DER, including portfolios of DER, an existing distribution grid (feeder through substation) can accommodate safely and reliably without requiring infrastructure upgrades. Hosting capacity methods[6] quantify the engineering factors that increasing DER penetration introduces on the grid within three principal constraints: thermal, voltage/power quality and protection limits. These methods can be applied to interconnection studies and long-term distribution planning.

[6] Staff, The Integrated Grid: A Benefit-Cost Framework, EPRI, 2015, and T. Lindl, *et al.*, Integrated Distribution Planning Concept Report, Interstate Renewable Energy Council, Inc. and Sandia National Laboratory, 2013.

Multiple Scenario Forecasts

As DER adoption grows, the distribution system will increasingly exhibit variability of loading, voltage and other power characteristics that affect the reliability and quality of power delivery. As such, the uncertainty of the types, amount and pace of DER expansion make singular deterministic forecasts ineffective for long-term distribution investment planning. A better approach is to use multiple DER growth scenarios to assess current system capabilities, identify incremental infrastructure requirements and enable analysis of the locational value of DERs.

Annual Long-term Distribution Planning

The annual distribution planning effort involves two general efforts: 1) multiple scenario-based studies of distribution grid impacts to identify "grid needs", and 2) a solutions assessment including potential operational changes to system configuration, needed infrastructure replacement, upgrades and modernization investments, and potential for non-wires alternatives. Many utilities, including those in Minnesota, perform these distribution planning processes annually with a five to 10-year planning horizon. These comprehensive studies are increasingly complex and benefit from stakeholder input on planning assumptions and engagement through a more transparent process.

Interconnection Studies and Procedures

In support of growing adoption of DER, changes to state regulatory rules on interconnection processes and the related engineering studies performed by utilities should be evaluated. Specifically, the interconnection process changes may be needed to address a growing number and diversity of customer DER and distribution-connected DER interconnection requests. In many cases distribution interconnection processes and engineering studies have largely been performed manually by engineers. There is a recognition nationally by utilities, stakeholders and regulators that improvements to processing and studying interconnection requests are needed to meet customers' expectations and manage work flow.

Integrated Resource, Transmission and Distribution Planning

At high levels of DER adoption, the net load characteristics on the distribution system can have material impact on the transmission system and bulk power system operation.[7] Today, distribution planning is typically done outside the context of integrated resource planning and transmission planning. To the extent DER is considered in resource and transmission planning, it is essential to align those DER growth patterns, timing and net load shape assumptions and plans with those used for distribution planning. Further, to the extent distribution connected DER provides wholesale energy services, it is necessary to consider the deliverability of that DER across the distribution system to the wholesale transaction point. If a state is experiencing, or anticipates, strong DER growth it is prudent to consider alignment of the

[7] "Net load" here refers to the amount of load that is visible to the TSO at each T-D interface, which can be expected to be much less than the total or gross end-use consumption in local areas with high amounts of DERs. The term "net load" is also used at the transmission system level to refer to the total system load minus the energy output of utility-scale variable renewable generation, as illustrated by the CAISO's well known "duck curve." In this report we are focusing mainly on the first sense of the term—i.e., the impact of DERs on the amount of load seen at each T-D interface.

recurring cyclical planning processes for resource, transmission and distribution so that an integrated view of system needs is effectively conducted.

Locational Net Benefits Analysis

DER have the potential to provide incremental value for all customers through improving system efficiency, capital deferral and supporting wholesale and distribution operations. However, the value of DER on the distribution system is locational in nature—that is, the value may be associated with a distribution substation, an individual feeder, a section of a feeder, or a combination of these components. The distribution system planning analyses, described above, identify incremental infrastructure or operational requirements (grid needs) and related potential infrastructure investments. The cost estimates of these investments form the potential value that may be met by sourcing services from qualified DERs, as well as optimizing the location of DERs on the distribution system to mitigate/avoid impacts. The objective is to achieve net positive value (net of costs to implement the DER sourcing) from DER integration for all utility customers.

IMPLEMENTATION CONSIDERATIONS

Proliferation of DER holds the promise of enhancing the operational, environmental, and affordability of Minnesota's electric system. This requires an integrated grid that optimizes the power system while providing safe, reliable, affordable, and environmentally responsible electricity.[8] This integrated grid will evolve in complexity and scale over time as the richness of systems functionality will increase and the distributed reach will extend to millions of intelligent utility, customer and merchant distributed resources. To address this evolution, robust planning processes and engineering methods are required to advance distribution planning. However, while a consistent approach to distribution is highly desirable in Minnesota, it is necessary to allow for differences in tactical implementation in recognition of the type of utility and differences in local drivers for change, capabilities, service territory characteristics, and cost-effectiveness for each utility to ensure net benefits for customers. In this context, and based on the MN distribution planning workshop discussions in 2015, e21 stakeholder discussions, industry research and emerging leading practices referenced in this paper, the following topics and potential requirements (Figure 2) for an integrated distribution planning are offered for consideration.

[8] Staff, The Integrated Grid, EPRI, 2014

Figure 2: IDP Topics for Consideration & Potential Requirements

Topics for Consideration	Potential Requirements
1. Scenario-driven integrated planning analysis framework	A. Framework should identify all relevant analysis and modeling interdependencies to support identified uses by stakeholders and utilities B. Planning should use scenario driven "futures" using a set of common parameters including customer DER adoption, and other critical factors C. Planning should establish baseline functionality of current distribution infrastructure
2. Standardized methodologies for distribution planning and DER locational valuation	A. Planning should be performed using a consistent set of accepted engineering and economic methodologies, but remain vendor and modeling technology neutral B. Engineering methods should address all relevant power system characteristics and dynamics for a well defined distribution area and inter-related local transmission system consistent with best practice
3. Greater access to grid planning assumption and results data	A. Utility assumptions used for distribution planning and the results should be accessible to 3rd parties and researchers under certain qualifications and subject to confidentiality and security conditions. B. Market planning data from DER developers and services firms will be available to utilities and research institutions for relevant distribution and bulk power system planning under specific conditions and subject to confidentiality
4. Integrated multi-stakeholder distribution planning process	A. Planning process should engage stakeholders, including customers and their representatives B. Stakeholder engagement should not create a bottleneck to planning process but improve planning outcomes and subsequent decision making
5. Alignment & integration of resource, transmission and distribution planning processes	A. Resource, T&D planning should each inform each other to ensure alignment in the consideration of DER across a power system. B. Consistent planning assumptions should be used for resource, transmission and distribution planning allowing for differences in granularity and other dimensions.

1. INTRODUCTION

1.1 PURPOSE

The purpose of this paper is to define an integrated distribution planning framework in the context of evolving the distribution grid as part of an increasingly integrated power system. The need for change is primarily driven by technological advancement, the adoption of distributed energy resources (DER),[9] and public policies that support the expansion of a more integrated distribution grid. Experience across the U.S. and globally has highlighted the need to address changes to planning proactively – not after DER adoption has accelerated. Additionally, a more robust planning process ensures long-term infrastructure investments will continue to serve customers' uses of the grid over 30 years or more. This presents a significant challenge given technological advancement and opportunity to consider modernization as utilities in the U.S. are currently spending over $20 billion annually to replace aging electric distribution with more modern networks.[10] Minnesota's utilities invested over $200 million in their distribution systems in 2014.[11]

As with other states, the Minnesota Public Utilities Commission (MPUC) Staff Report[12] recognizes that "planning efforts will be an integral part of a systematic approach to grid modernization." A necessary requirement for planning is clear objectives. The MPUC staff[13] proposed the objectives as:

"A modernized grid assures continued safe, reliable, and resilient utility network operations, and enables Minnesota to meet its energy policy goals, including the integration of variable renewable electricity sources and distributed energy resources. An integrated, modern grid provides for greater system efficiency and greater utilization of grid assets, enables the development of new products and services, provides customers with necessary information and tools to enable their energy choices, and supports a standards-based and interoperable utility network."

The distribution system planning framework described in this paper is based on emerging best practices regarding engineering and business processes across the United States. The paper incorporates the ongoing discussion in Minnesota regarding the need for a framework and the key elements and considerations for development and implementation of an integrated distribution planning process. It is intended as a reference to inform the MPUC and stakeholders' continuing evaluation of the development of such a framework.

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[9] DER is described as supply and demand side resources that can be used throughout an electric distribution system to meet energy and reliability needs of customers; can be installed on either the customer or the utility side of the electric meter. Includes efficiency (end use efficiency), distributed generation (solar PV, combined heat and power, small wind), distributed flexibility and storage (demand response, electric vehicles, thermal storage, battery storage), and distributed intelligence (Information and control technologies that support system integration) – Source: Cmr. Lange, MPUC Grid Modernization, MPUC Workshop presentation, September 25, 2015

[10] Staff, Minnesota Staff Report on Grid Modernization, MPUC, March 2016

[11] Ibid.

[12] Ibid

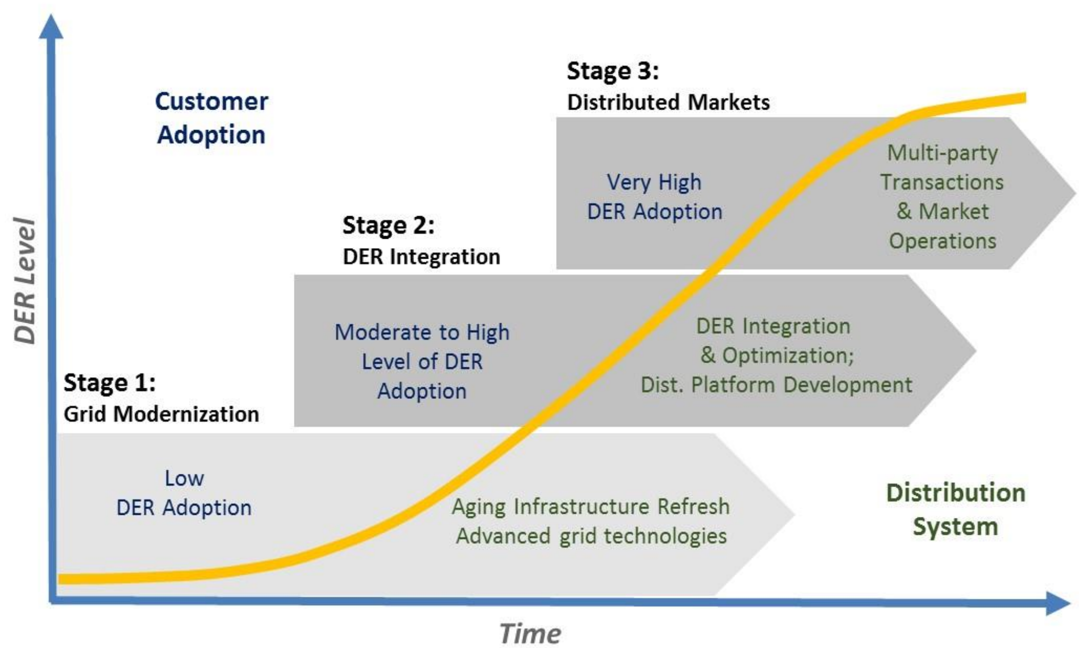
[13] Ibid

1.2 EVOLVING DISTRIBUTION GRID

Across the U.S., the adoption of DER is changing customers' service expectations and use of the distribution grid. Over the next decade in MN and elsewhere, the distribution system is expected to evolve from a one-way delivery system to a network of interconnected resources. Achieving this integrated grid "will require planning and operating to optimize and extract value throughout the electric grid."[14] However, the adoption of DER is uneven, with certain states having significant adoption while others have nearly none. This is true within a state and even within a utility service area. This patchwork of adoption is currently driven by policy, technological cost-effectiveness, local economic factors and consumer interest. The adoption patterns observed in several states and countries[15] over the past 10 years, along with the related impacts to distribution system operation, can help identify the key issues and decisions regulators and utilities are likely to face as DER adoption increases. For example, growth in adoption of DERs will change the amount, shape and predictability of net load, and at higher levels may introduce local multi-directional power flows.

Figure 3 shows a three-stage evolutionary framework for the distribution system. This framework is based on the assumption that the distribution system will evolve in response to both top-down (public policy) and bottom-up (customer choice) drivers. The yellow line represents a classic technology adoption curve as applied for DER. The Stages represent the levels of additional functionalities needed to support the greater amounts of DER adoption in relation to the level of power system integration desired. The result is an increasingly complex system.

Figure 3. Distribution System Evolution



[14] N. Lange, A. Twite, M. Schuerger, Building a Minnesota Conversation on Grid Modernization With a Focus on Distribution Systems, MPUC, May 15, 2015

[15] Experience in Hawaii, California, New Jersey, Germany, Spain and Australia, for example.

Stage 1: Grid Modernization – In this stage, the level of DER adoption is relatively low and can be accommodated within the existing distribution system without material changes to infrastructure or operations. Most distribution systems in the U.S., including Minnesota, are currently at Stage 1. A primary focus of Stage 1 is expanding distribution investments on aging infrastructure replacement to include advanced grid technologies as part of a long-term grid modernization plan. These initial grid modernization investments include network connectivity models, enhancing circuit level monitoring and related situational awareness and power system analytics along with enhanced reliability and resiliency investments in automated field switches and the field communications and operational systems (e.g., distribution management system and Volt-VAr optimization). These foundational investments (aging infrastructure replacement and initial grid modernization) also enable increased adoption of DER.

States in Stage 1 should also proactively plan for an intelligent, flexible, efficient, open, and secure distribution system that can integrate new distributed energy technologies and the complexity of many actors on the system.[16] Changes in distribution planning and investment provide immediate benefits and lay an important foundation for the future. Additionally, states should consider performing locational value assessments, to identify areas of the distribution system where the addition of DERs would benefit the system by providing services to defer infrastructure investment and improve operational efficiency. Such assessments would also help prepare for Stage 2.

Stage 2: DER Integration – In this stage, DER adoption levels become substantial and reach a threshold level that requires enhanced functional capabilities for reliable distribution operation. To address, for example, bi-directional power flows and/or voltage variations that will be problematic on high DER circuits. At these higher levels, DERs also have the potential to provide greater system benefits. For both of these reasons, changes to grid planning and operations are required. The Stage 2 DER adoption threshold, based on DER adoption experience in the U.S. and elsewhere, appears to be when DER adoption reaches beyond about five percent of distribution grid peak loading system-wide.

This level of adoption typically results in pockets of high customer adoption and commercial solar garden/farm development in some neighborhoods and commercial districts, which creates the need in Stage 2 for enhanced functionality[17] related to maintaining reliable operation of the grid and optimizing the use of DER. This enhanced functionality as part of grid modernization involves more advanced protection and control technologies and operational capabilities to manage a distribution grid safely and reliably. Additionally, the increased level of DERs may provide an opportunity to leverage their value for bulk power system and distribution grid efficiency.

Stage 3: Distributed Energy Markets – Stage 3 involves the introduction and scaling of bi-lateral energy transactions between sellers and buyers across a distribution system. It is very likely that some limited energy transactions may occur on a limited basis in Stage 2 related to multi-user microgrids, for example, but material levels of energy transactions on distribution systems will only occur at very high levels of DER that can produce excess energy that is not encumbered by pre-existing contractual obligations with end customers (e.g., solar PV leases or net energy metering tariffs). Stage 3 energy

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[16] e21 Initiative, Phase I Report: Charting a Path to a 21st Century Energy System in Minnesota. December 2014.

[17] System penetration of DERs to 5 percent of peak load is a nominal guide. Individual portions of the distribution grid may encounter higher levels of DER penetration and will require targeted mitigation and potentially application of advanced solutions to maintain required reliability and safety of the network.

markets also may only fully develop in restructured states as buyers of energy will most likely be resellers of energy such as such as competitive energy retailers, community choice aggregators and DER aggregators. It is possible for vertically integrated utilities to purchase this energy in non-restructured states, but there wouldn't be a need for an ISO type market structure in that case as there would only be a single buyer. In any event, the prerequisite in either case is high DER penetration with resources that can supply dispatchable energy and that are not encumbered by net energy metering tariffs that effectively prevent the resale of the energy produced to another party. The vast majority of energy producing DER installed and being installed is similarly encumbered and therefore it is unlikely that Stage 3 markets will develop until the next decade after DER rate reform and current incentives expire. Also, this will require regulators in most states to institute changes to allow retail energy transactions across the distribution system, including transactions that are still within a local distribution area (LDA) defined by a single T-D interface substation, thus not relying on transmission service.

2. INTEGRATED DISTRIBUTION PLANNING

2.1 OVERVIEW

Integrated distribution system planning in the 21st Century needs to assess physical and operational changes to the electric grid necessary to enable safe, reliable and affordable service that satisfies customers' changing expectations and use of DERs. Given the diversity of customer needs, distribution circuit configurations and technological advancements, planning becomes more cohesive and multi-disciplinary with a wider and more complex range of engineering and economic valuation issues. Stakeholder participation and increased transparency becomes an important part of the distribution planning process.

As identified in states' policies and regulation, including Minnesota,[18] integrated distribution planning (IDP) should address three important needs:

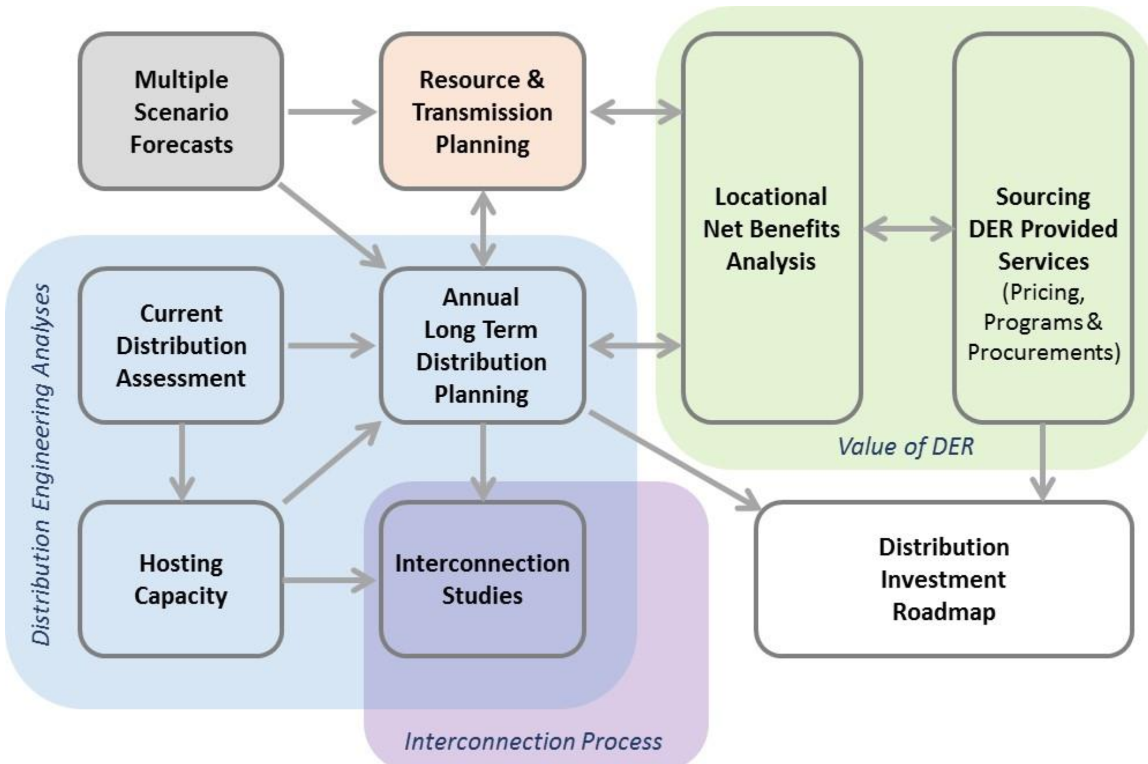
- Identify necessary distribution investments to enhance safety, reliability and security, including replacement of aging infrastructure and modernization of the grid.
- Identify necessary interconnection process and methodology changes and integration investments to support growth of adoption of distributed energy resources.
- Identify the value of DER linked to planning results and opportunities to realize net benefits for all customers through the use of DER provided services.

These aspects should be derived from an integrated planning process that evolves from current distribution engineering and economic practices. IDP has similarities to transmission planning, particularly with the requirements of FERC Order 1000.[19] In simple terms, Order 1000 requires consideration of the growth of renewable resources to support public policy in addition to traditional load growth related planning, as well as consideration of non-wires alternatives to traditional transmission infrastructure

[18] Minnesota statute 216B.2425, Subd. 2.e and Subd. 8.
[19] FERC Order No. 1000, Final Rule on Transmission Planning and Cost Allocation by Transmission Owning and Operating Public Utilities

investment. The distribution corollary is that distribution planning may need to consider the net load impact of adoption of DER under a net energy metering tariff or similar, those DER directly connected to distribution in support of state policies (i.e., Renewable Portfolio Standard), and the potential for non-wires alternatives provided by DER. This is why IDP as is being implemented in several states, is one part of a multi-stage regulatory decision process that also involves development of utility proposed investments, consideration of need, prudency reviews and determination of rate recovery.

Figure 4: Integrated Distribution Planning



A standardized planning framework is required to systemically address these needs. As described by MPUC Commissioner Lange and colleagues, "Updates to the distribution planning process [through a standardized planning framework] will be needed to support a reliable, efficient, robust grid in a changing (and uncertain) future; should be coordinated with resource and transmission planning; could incorporate stakeholder informed planning scenarios."[20] An integrated distribution planning framework would include the following core components and is illustrated in Figure 4 above:

- Engineering analysis of existing assets' condition using power flow studies to assess safety and reliability under both peak and min load conditions and contingent operating conditions.
- Identification of the distribution grid's baseline capacity to integrate DERs ("hosting capacity") based on thermal and voltage limits, power quality and protection scheme considerations as well as safety considerations.

[20] N. Lange, A. Twite, M. Schuerger, Building a Minnesota Conversation on Grid Modernization With a Focus on Distribution Systems, MPUC, May 15, 2015

- Development and use of multiple scenario forecasts for gross load (underlying customer load before DER modification of net load) and DER penetration (grid connected and customer premises) to better assess grid upgrades given long-term uncertainties regarding DER adoption and DER performance.
- Annual long-term planning analysis to assess changes in the use of the distribution grid over a 5-10 year period. This includes assessing load growth, DER diffusion and resulting net load dynamics and changes in load shape to identify needed changes and solutions.
- Interconnection engineering studies and process changes to address scale and scope of DER interconnection requests in a timely manner. This can involve leveraging hosting capacity analysis to enable fast track type reviews if the methods employed are sufficiently accurate. Additionally, automation of interconnection engineering studies can also reduce overall process times.
- Integrated resource, transmission and distribution analysis to assess the respective impacts on the distribution and transmission system given forecasted changes in load due to customer adoption of DER and use of merchant DER to meet resource adequacy, environmental, cost effectiveness and other policy objectives.

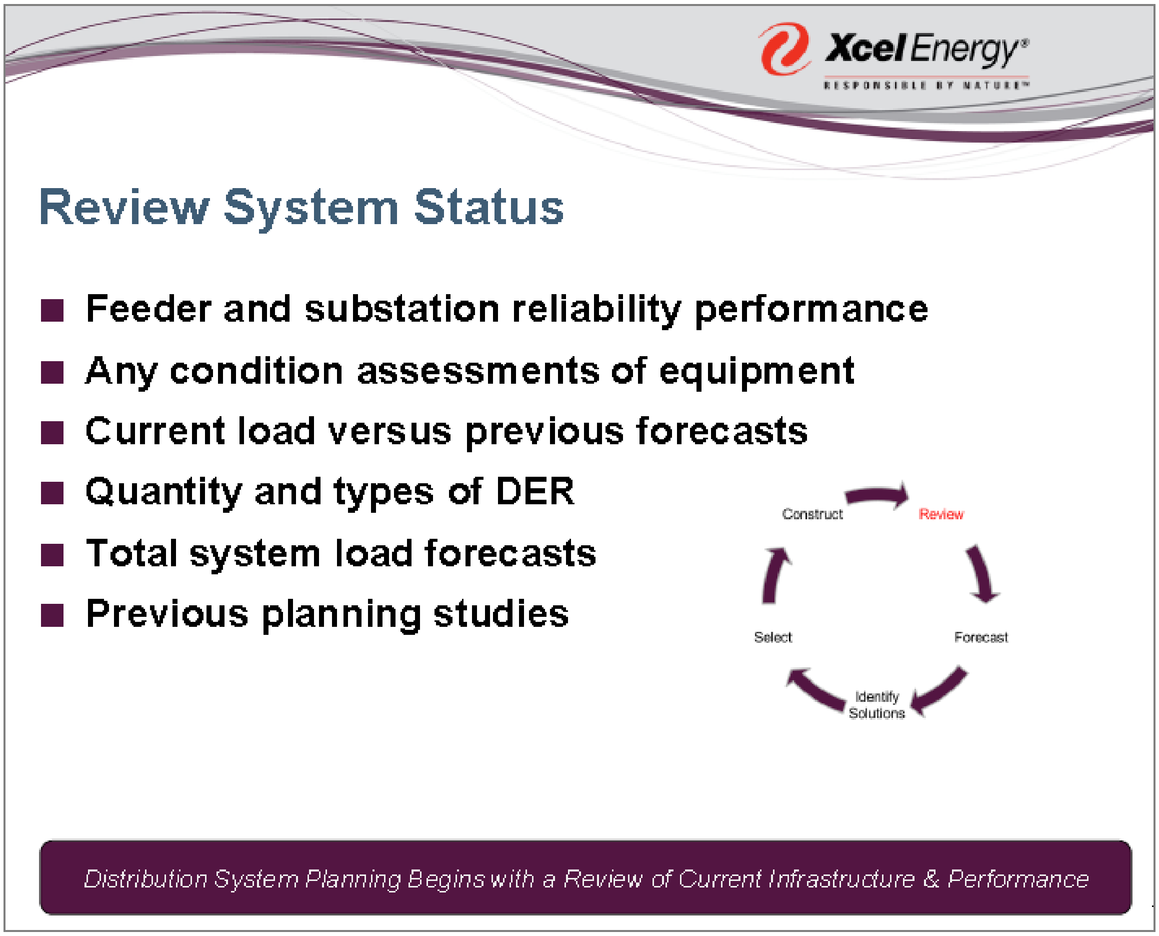
2.2 INTEGRATED DISTRIBUTION PLANNING ELEMENTS

2.2.1. Review Distribution System Status

It is important to consider that the laws of physics ultimately dictate the physical operation of the electric system and that the foundation for system planning starts with rigorous power flow analysis of the current system to fulfill obligations to provide safe, reliable service to customers at a reasonable cost. More specifically, this engineering analysis assesses the maximum electricity demand for each distribution feeder. The demand forecast used in this analysis is typically based on deterministic methods using historical peak loading normalized for weather. The purpose is to ensure that the feeders are able to supply customer demands and maintain the feeder voltages within established standards. Some reserve capacity on each feeder is also desirable to allow for new loads to be added on the feeder and enable operational flexibility to switch sections of one feeder onto an adjacent feeder for outage restoration and maintenance. Additionally, an assessment of current feeder and substation reliability, condition of grid assets, asset loading and operations is performed along with a comparative assessment of current operating conditions against prior forecasts. As described by Xcel Energy at the MPUC workshop on September 25, 2015, and highlighted in Figure 5 below,[21] distribution system planning begins with a review of current infrastructure (including prior smart grid investments) and performance.

[21] B. Amundson, MPUC Workshop presentation, September 25, 2015

Figure 5: Xcel Energy Distribution Planning Review System Status



Combined, these analyses establish the current state of a distribution system. This current state provides a baseline upon which the additional elements of an IDP below are performed. As DER adoption grows it will be increasingly necessary to have more granular information about the state of the distribution system related to power flows and quality on individual feeders and subsections of feeders. This will require an expansion of grid sensors, field communications, accurate customer-grid connectivity model and situational awareness software and analytics to assess system performance for planning and real-time operations.

Minnesota and other states should consider the following when assessing the evolution of distribution state information and analysis as part of an integrated distribution planning process:

- Consider the need for grid connectivity models to accurately identify customers and DER on distribution feeders including individual phases to improve outage management and DER integration.
- Consider the utilities' need for grid sensing and communications to support effective integration of higher levels of variable distributed resources and net customer load.
- Identify information and analytics needed to support the evolution of distribution state estimation from planning to real-time grid operations as DER growth may require.

2.2.2. Hosting Capacity

Hosting capacity analysis is used to establish a baseline of the maximum amount of DER, including portfolios of DER, an existing distribution grid (feeder through substation) can accommodate safely and reliably without requiring infrastructure upgrades. Hosting capacity methods[22] quantify the engineering factors that increasing DER penetration introduces on the grid within three principal constraints: thermal, voltage/power quality, and protection limits. Beyond the initial analysis of operating limits, hosting capacity may include a second step that considers how optimized locational adoption of DERs could enhance the hosting capacity. For example, smoothing net load profiles, improving phase balance, and managing voltage variability may increase hosting capacity. The results of baseline hosting capacity can provide, through heat maps or other means, an indication of current capability of the distribution grid to integrate DER.

As the MPUC Staff report[23] describes, "A hosting capacity analysis can help streamline the interconnection process, as proposed projects with a nameplate capacity below the available capacity can be processed more quickly." Also, as identified in the MPUC Staff report[24] and consistent with Minnesota's transmission and distribution planning statue,[25] hosting capacity analysis is a component in annual distribution system planning to identify distribution upgrades to support DER growth. As such, the engineering method/s selected for hosting capacity analysis should be robust enough to satisfy all three purposes: 1) indication of distribution feeder capacity for DER, 2) streamlining interconnection studies, and 3) annual long-term distribution planning.

To illustrate this point, consider the demonstrations underway in California. There are two methods currently in use in California, which will be evaluated by the end of 2016. One approach is EPRI's "streamline" approach,[26] which simplifies the computational requirements by using approximations on top of a power flow analysis. This is used by Pacific Gas & Electric (PG&E) for its 3,500 circuits and referenced by the California Public Utility Commission (CPUC) in a recent Assigned Commissioner Ruling.[27] While this method is more efficient from a computational perspective, it is not yet clear that it is sufficiently accurate to support fast-track interconnection decisions. The other approach is an automation of the existing iterative detailed engineering analysis used for interconnection studies. While this method is accurate for interconnection decisions, it is computationally complex requiring longer time for analysis. This method is being used by San Diego Gas & Electric (SDG&E) for its 1,500 circuits and in development by Southern California Edison (SCE) for its 4,600 circuits. These two methods will be comparatively tested in required demonstrations this year to determine a single statewide method in early 2017.[28]

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[22] Staff, The Integrated Grid: A Benefit-Cost Framework, EPRI, 2015, and T. Lindl, *et al.*, Integrated Distribution Planning Concept Report, Interstate Renewable Energy Council, Inc. and Sandia National Laboratory, 2013.
[23] Staff, Minnesota Staff Report on Grid Modernization, MPUC, March 2016
[24] Ibid.
[25] Minnesota Statute 216B.2425, State Transmission and Distribution Plan
[26] Staff, Distribution Feeder Hosting Capacity: What Matters When Planning for DER?, EPRI, 2015
[27] CPUC Commissioner Picker's Assigned Commissioner Ruling in Docket 14-08-013, May 2, 2016
[28] California ICA Working Group discussion and recommendation regarding assessment of hosting capacity methods is online at: http://drpwg.org/

Minnesota and other states should consider the following when assessing the implementation of hosting capacity as part of an integrated distribution planning process:

- Identify the uses and objectives for hosting capacity analyses (e.g., indicative information for heat maps, fast-track interconnection approvals, annual distribution system studies)
- Determine the location granularity, frequency and accuracy requirements for each use
- Determine the suitability of the various industry methods for the identified use
- Determine whether a statewide uniform methodology is required and the level of uniformity required (e.g., uniform process or uniform analytical method)
- Determine an implementation roadmap for the systematic use of hosting capacity for the identified uses

2.2.3. Multi-scenarios for distribution planning

Distribution planning has primarily focused on load forecasting, but should increasingly consider the effects of DER growth. Utilities, including those in Minnesota,[29] generally forecast load at a distribution planning area,[30] substation and down to individual feeders. Distribution planners consider location-specific information driving changes in net load, including addition or loss of customers, changes in customer demand and adoption of various types of distributed resources. These more granular feeder specific bottom-up forecasts are aggregated and compared to overall top-down system projections of load growth and distributed resources used in integrated resource and transmission planning.

Historically, these singular forecasts are largely deterministic. As DER adoption grows, the distribution system will increasingly exhibit variability of loading, voltage and other power characteristics that affect the reliability and quality of power delivery. As such, the uncertainty of the types, amount and pace of DER expansion make singular deterministic forecasts ineffective for long-term distribution investment planning horizons that often span from five to 10 years or more. A better approach is to use multiple DER growth scenarios to assess current system capabilities, identify incremental infrastructure requirements and enable analysis of the locational value of DERs (described below).

Standardized scenario parameters for use by utilities statewide should be defined for each respective forecast and linked to state policy objectives. Such scenarios need to have sufficient granularity to support substation, feeder or feeder sub-section level analysis. The level of granularity of loading, voltage and related operating characteristics is dependent on the information available to support such analysis for a particular utility's system and the planning need for such information based on DER adoption materiality. Also, there is a need to consider various local DER adoption growth patterns as well as other distribution system variations given the potential reconfigurations of the system. These scenarios should have standardized elements across the state with common assumptions as appropriate, but allowing for local differences as necessary. These standardized distribution scenarios should be aligned with existing long-term resource and transmission planning scenario assumptions. As suggested in the MPUC Staff report,[31] a base case with two additional scenarios representing a high DER

[29] Interview with Xcel Energy on May 4 & 5, 2016

[30] Distribution planning area is a subsection of a utility's distribution system usually comprised of multiple substations and related feeders.

[31] Staff, Minnesota Staff Report on Grid Modernization, MPUC, March 2016

and low DER cases could be added to enable a robust distribution system study. For example, these scenarios would enable an analysis of the incremental upgrades needed to support DER growth as required in Minnesota's Transmission and Distribution Plan statute.[32]

Minnesota and other states should consider the following when assessing the use of multiple scenarios as part of an integrated distribution planning process:

- Identify common statewide distribution scenario parameters for utility use
- Identify key assumptions and other scenario parameters that should be aligned among resource planning, transmission planning and distribution planning
- Determine the level of granularity required for distribution scenarios

2.2.4. Annual Long-term Distribution Planning

The annual distribution planning effort involves two general efforts: 1) multi-scenario-based studies of distribution grid impacts to identify "grid needs,"[33] and 2) a solutions assessment including potential operational changes to system configuration, needed infrastructure replacement, upgrades and modernization investments, and potential for non-wires alternatives. Many utilities perform these distribution planning processes annually with a five to 10-year planning horizon. In Minnesota, utilities typically use the annual planning process to develop plans and budgets for a 5-year period. However, long range planning studies up to 30 years may be performed. For example, Dakota Electric prepares long range forecasts every 10 years, to assess the need for new substations and major feeders over a 20 to 30-year period.[34] These comprehensive studies are increasingly complex and benefit from stakeholder input and engagement.

Multi-scenario based studies

The multi-scenario based studies assess current system limits (thermal, voltage & protection) under several area net load growth (including DER) scenarios. Interdependencies with transmission plans and customers' reliability expectations are also considered. These studies also incorporate contingency analyses to identify the safety and reliability impacts of component failures to identify the highest risk areas. This risk analysis is also the basis for identifying aging infrastructure for replacement. Xcel Energy described its approach to these types of studies at the MPUC workshop in fall 2015.[35] Examples of factors considered during these studies are shown in Figure 6 below from Minnesota Power.

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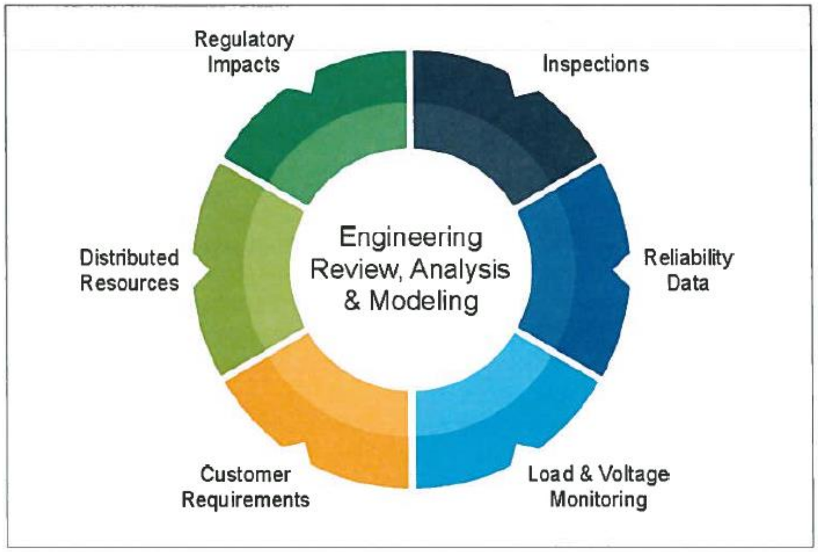
[32] Minnesota Statute 216B.2425, State Transmission and Distribution Plan. Distribution Plan requirements are limited to utilities operating under an approved multiyear rate plan
[33] Grid Engineering, A Pathway to the Distributed Grid, SolarCity, February 2016
[34] Interview with Dakota Electric on May 5 & 6, 2016
[35] Xcel, "Distribution System Planning Overview" presentation, MPUC Workshop, November 25, 2014

Figure 6: Minnesota Power Engineering Review, Analysis & Modeling



The result of these location-specific planning studies is an identification of system/operational needs defined in engineering terms. Additionally, forecasted hosting capacity analysis is used[36] to assess the grid needs to support adoption of DER, and portfolios of various DER including customer/third party owned microgrids.

Solution Identification

Distribution planners identify potential solutions to address any grid needs identified as part of their near-term (typically 1-2 years) and long-term plans (5-10+ years). Solutions must satisfy the engineering needs identified as well as several other key criteria, including cost-effectiveness and rate recovery considerations such as capital budget limits. As such, there are two categories of solutions that are generally considered by utility planners: 1) operational changes and minor near-term capital investments, and 2) major capital investments.

The first category of solutions to identify impacts may be as simple as reconfiguring a feeder by transferring part of the load to another feeder or balancing the loading of a feeder by moving service transformers to a different phase.[37] Additionally, protection scheme and voltage management settings and minor equipment replacements can also be readily accomplished in the near-term. These simple solutions can resolve a number of grid needs related to changes in net load shapes and variability, as well as bi-directional power flows associated with certain DER.

Of course, these solutions are not sufficient to solve all the typically identified distribution system needs. Major capital investments are generally required to address most of the identified grid needs identified in the annual plan. These longer term plans also need to consider the evolution of DER technology capabilities as well as the advancement of grid technologies over planning horizons longer than 5 years. This is because

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[36] California ICA Working Group presentation on hosting capacity use cases slides 7-12: http://drpwg.org/wp-content/uploads/2016/07/ICA-Working-Group-072516_final-1.pptx

[37] Distribution feeders, unlike transmission lines, are not typically operated with balanced load across the 3 phases.

the accelerating rate of technological advancement could otherwise make perfectly acceptable technology installed today functionally obsolete before the depreciation life of certain investments.

As part of investment planning, utilities' across the U.S. and in Minnesota group capital investments in various ways. But, they can be generally organized into four groups:[38]

- ***Reliability & Safety:*** Replacing infrastructure that is either experiencing high O&M costs, failure rates, old end-of-life assets that should be prudently replaced and replacements due to storms and public damage (*e.g.*, car pole accidents). Additionally, this group includes projects to relocate utility infrastructure in public rights-of-way such as road widening or realignment.
- ***Customer Connections:*** Provide service to new customers through installation or expansion of feeders, primary and secondary extensions, and service laterals.
- ***Capacity Upgrades:*** Capacity investments to increase infrastructure capacity (*e.g.*, substation transformers, distribution feeders, and voltage/reactive power devices) to handle net load growth (including customer DER) on the system and to improve operational switching flexibility to address reliability needs.
- ***Grid Modernization***: Advanced technology investments to enable improved distribution safety and reliability, operational efficiencies, integration of DER, and realization of potential DER value.

Over the past 10 years in Minnesota and nationally[39, 40] consensus has been developing on the objectives and attributes of a modern grid that affordably enables customer choice and realizes the value of DER while improving reliability and security. The MPUC Staff report outlined the five "Principles for Grid Modernization at the Minnesota Commission"[41] below:

- Maintain and enhance the safety, security, reliability, and resilience of the electricity grid, at fair and reasonable costs, consistent with the state's energy policies;
- Enable greater customer engagement, empowerment, and options for energy services;
- Move toward the creation of efficient, cost-effective, accessible grid platforms for new products, new services, and opportunities for adoption of new distributed technologies;
- Ensure optimized utilization of electricity grid assets and resources to minimize total system costs;
- Facilitate comprehensive, coordinated, transparent, integrated distribution system planning.

Planning for grid modernization should consider these characteristics as well as a holistic grid architecture[42] when developing investment plans, particularly in concert with enabling adoption of DER and those investments needed to realize the net value of DER for all customers.

Additionally, several states are pursuing changes to distribution planning processes to include requirement for consideration of non-wires alternative solutions to utility distribution capacity upgrades from customers and DER providers as part of a Locational Net Benefits Analysis (LNBA) and sourcing mechanisms. These are discussed in Section 4.

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[38] e21 Grid Modernization paper, working paper, Great Plains Institute, 2016
[39] NETL, A Systems View of the Modern Grid, US DOE, 2007
[40] Energy.gov/quadrennial-technology-review-2015
[41] Staff, Minnesota Staff Report on Grid Modernization, MPUC, March 2016
[42] J. Taft and A. Becker-Dippmann, Grid Architecture, Pacific Northwest National Laboratory, 2015

Minnesota and other states should consider the following when assessing changes to the annual distribution planning process, related grid needs assessment and investment planning as part of an overall IDP process:

- The use of forecasted hosting capacity to inform needed distribution grid upgrades to support adoption of DER.
- How to account for longer-term traditional investment in the annual planning process to align with the opportunity to consider DER as an alternative and the associated time needed for development.
- The applicability of DER to address shorter-term operational needs.
- Level of transparency including relevant data sharing in the annual planning process and stakeholder engagement as appropriate.
- Alignment of grid modernization investments linked to optimizing the value of DER adoption for all customers.

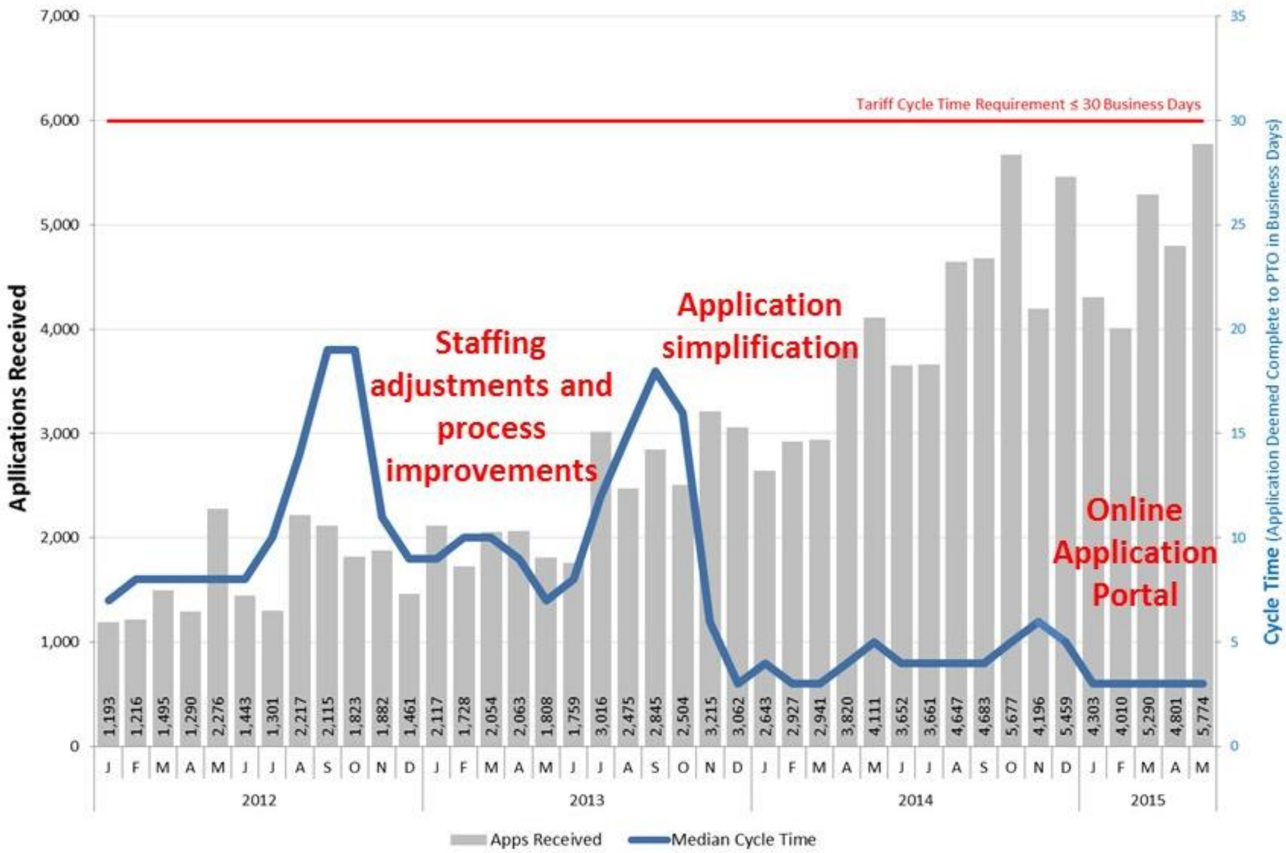
2.2.5. Interconnection Studies and Procedures

In support of growing adoption of DER, changes to state regulatory rules on interconnection processes and the related engineering studies performed by utilities should be evaluated. Specifically, interconnection process changes may be needed to address a growing number and diversity of customer DER and distribution-connected DER interconnection requests. In many cases distribution interconnection processes have largely been performed manually, including the engineering analysis. There is a recognition nationally by utilities, stakeholders and regulators that improvements to processing and studying interconnection requests are needed to meet customers' expectations and manage work flow.

As noted by the MPUC Staff, best practices for DG interconnection are emerging nationally.[43] One such emerging best practice is the incorporation of a "fast-track" approval mechanism based on the hosting capacity engineering analysis discussed earlier. Such a step requires confidence that the engineering methods used for the fast-track analysis satisfy reliability and safety criteria. Additionally, process reforms and use of automation should be implemented, such as rules for managing interconnection queues to accommodate increasing volumes of requests seeking to connect to the utility distribution system. Plus, information exchange is needed to facilitate market knowledge of the hosting capacity and beneficial locations for DER. The results of such a process improvement effort at Pacific Gas & Electric (PG&E) in California reduced the interconnection review cycle time from about 20 days to currently 3 days as illustrated in Figure 7 below.

[43] Staff, Minnesota Staff Report on Grid Modernization, MPUC, March 2016

Figure 7: PG&E Interconnection Process Improvement Results



States should consider the following when assessing changes to interconnection processes and related engineering studies, as is currently underway in Minnesota,[44] in concert with development of an IDP process:

- Identify interconnection process improvements to reduce cycle time.
- Consider improvements to the customer/developer interfaces and relevant data sharing to automate and simplify interconnection requests and process status and approval notifications.
- Consider the potential for use of hosting capacity methods to enable fast-tracking approval within an overall interconnection process.
- Consider the implication of smart inverter standards for solar PV and other applicable DER to mitigate interconnection issues such as voltage violations.
- Consideration of development of grid codes for DER to address the operational information and distributed control interfaces required for operating DER as part integrated power system operations in Stage 2.

[44] MPUC Docket Number CI-16-521, In the Matter of Updating the Generic Standards for Utility Tariffs for Interconnection and Operation of Distributed Generation Facilities under Minnesota Statute 216B.1611

2.2.6. Integrated Resource, Transmission & Distribution Planning

At high levels of DER adoption, the net load characteristics on the distribution system can have material impact on the transmission system and bulk power system operation.[45] Today, distribution planning is typically done outside the context of integrated resource planning and transmission planning. To the extent DER are considered in resource and transmission planning it is essential to align those assumptions and plans with those used for distribution planning. Further, to the extent distribution connected DER provides wholesale energy services it is necessary to consider the deliverability of that DER across the distribution system to the wholesale transaction point. If a state is experiencing, or anticipates, strong DER growth it is prudent to consider alignment of the recurring cyclical planning processes for resource, transmission and distribution so that an integrated view of system needs is effectively conducted.

This planning integration may be accomplished through an iterative approach that starts with identifying the role of customer and merchant DER in reducing and/or meeting resource adequacy. This assessment as part of Integrated Resource Planning (IRP) informs the distribution planning as to the amount of DER that will be interconnected over the planning horizon. Additionally, DER may be a viable non-wires alternative (NWA) for transmission upgrades identified in the transmission planning process. Customer and/or merchant DER providing transmission services will also need to be considered in the distribution planning analysis. The results of the distribution planning will determine the "deliverability" of these resource adequacy and transmission NWA DER. Today, it is often the case that DER is deemed deliverable across a distribution system to the transmission-distribution system interface. At low levels of DER this is not a material issue. However, at higher levels of DER participating in wholesale market and transmission services, it becomes important to assess the capacity of the distribution grid to deliver the services from the edge to bulk power system. The tools to perform a truly integrated engineering analysis are under development, for example, by Pacific Northwest National Laboratory (PNNL) with GridLab-D enhancements and commercial grid simulation software vendors.

Additionally, the integration of transmission and distribution infrastructure planning involves aligning these activities into the long-term demand forecasting and resource planning processes employed in a state. Assuming a state has an established recurring process for forecasting long-term (10 to 20 years) electricity demand, the validity of the resulting forecasts and decisions based on them will depend on how well the expansion of DERs can be forecasted and these forecasts integrated into projections of peak demand, annual energy and system load shape. Such forecasts are used, for example, to assess future generating capacity adequacy to guide procurement decisions for those utilities with load-serving responsibilities. For transmission planning, the granularity of DER forecasts will be at the T-D substation level. These forecasts can be built up from the feeder-level forecasts developed for distribution planning based on 8760 hours loading data. The point is that a jurisdiction that anticipates DER growth should

[45] "Net load" here refers to the amount of load that is visible to the TSO at each T-D interface, which can be expected to be much less than the total or gross end-use consumption in local areas with high amounts of DERs. The term "net load" is also used at the transmission system level to refer to the total system load minus the energy output of utility-scale variable renewable generation, as illustrated by the CAISO's well known "duck curve." In this report we are focusing mainly on the first sense of the term—i.e., the impact of DERs on the amount of load seen at each T-D interface.

begin to think about how to align the recurring cyclical processes for long-term load forecasting, resource procurement, and T&D planning so as to specify the timing and content of essential information flows among these processes.

Minnesota and other states should consider the following when assessing the integration of distribution planning with resource and transmission planning as part of an overall IDP process:

- Identify the planning process steps and timing of related integrated resource planning, transmission planning and respective utility distribution planning cycles for the purpose of harmonizing planning to consider impacts and benefits of DER adoption.
- Need to align planning assumptions input and time horizons for consistency across resource, transmission and distribution planning to ensure consistency and compatibility in results.
- Identify assumptions regarding deliverability of DER into wholesale markets and transmission and related impacts on distribution.
- Consider the potential for certain DER to provide services as a non-wires alternative for transmission and distribution investment and potential issues with double-counting resource contributions.

3. LOCATIONAL NET BENEFITS ANALYSIS

3.1 LOCATIONAL NET BENEFITS ANALYSIS

DER have the potential to provide incremental value for all customers through improving system efficiency, capital deferral and supporting wholesale and distribution operations. However, the value of DER on the distribution system is locational in nature—that is, the value may be associated with a distribution substation, an individual feeder, a section of a feeder, or a combination of these components. The annual distribution system planning analyses, described above, identifies incremental infrastructure or operational requirements by location and related potential infrastructure investments. The cost estimates of these investments form the potential value that may be met by sourcing services from qualified DERs as non-wires alternatives. Also, this locational value assessment of avoided costs may inform DER incentive changes to optimize the location of DERs on the distribution system to mitigate/avoid impacts. The objective is to achieve net positive value (net of costs to implement the DER sourcing) from DER integration for all utility customers.

These net values may also include avoided or deferred utility capital spent on wholesale energy and capacity, transmission upgrades and avoided operational expenses that are system-wide and not necessarily locational. There may also be environmental and customer benefits that are added to the DER value stack. Locational value of DERs is not always net positive, as it depends on any incremental distribution system costs (not including costs to the DER developer/owner) to integrate the DER. A California multi-stakeholder working group for the California Public Utility Commission's (CPUC's) Distribution Resources Plan proceeding developed the list of potential DER value components in Figure 8.

Figure 8. Potential DER Value Components and Definitions [46]

	Value Component	Definition
Wholesale	WECC Bulk Power System Benefits	Regional BPS benefits not reflected in System Energy Price or LMP
	System Energy Price	Estimate of CA marginal wholesale system-wide value of energy
	Wholesale Energy	Reduced quantity of energy produced based on net load
	Resource Adequacy	Reduction in capacity required to meet Local RA and/or System RA
	Flexible Capacity	Reduced need for resources for system balancing
	Wholesale Ancillary Services	Reduced system operational requirements for electricity grid reliability
	RPS Generation & Interconnection Costs	Reduced RPS energy prices, integration costs, quantities of energy & capacity
	Transmission Capacity	Reduced need for system & local area transmission capacity
	Transmission Congestion + Losses	Avoided locational transmission losses and congestion
	Wholesale Market Charges	LSE specific reduced wholesale market & transmission access charges
Distribution	Subtransmission, Substation & Feeder Capacity	Reduced need for local distribution upgrades
	Distribution Losses	Value of energy due to losses bet. BPS and distribution points of delivery
	Distribution Power Quality + Reactive Power	Improved transient & steady-state voltage, harmonics & reactive power
	Distribution Reliability + Resiliency	Reduced frequency and duration of outages & ability to withstand and recover from external threats
	Distribution Safety	Improved public safety and reduced potential for property damage
Customer & Societal	Customer Choice	Customer & societal value from robust market for customer alternatives
	Emissions (CO2, Criteria Pollutants & Health Impacts)	Reduction in state and local emissions and public and private health costs
	Energy Security	Reduced risks derived from greater supply diversity
	Water & Land Use	Synergies with water management, environmental benefits & property value
	Economic Impact	State or local net economic impact (e.g., jobs, investment, GDP, tax income)

Each state should determine the methods to be used to determine the benefit associated with each value component that will be considered. For Minnesota, this may offer an improvement to the recognition of locational benefits in the Value of Solar Methodology and in the Distributed Generation Interconnection Standards.[47] Benefit-cost methodologies for each value component may be incorporated into a benefit-cost analysis (BCA) handbook as developed in New York.[48] Also, an evolution of the scope of benefits that may be included in the locational benefits analysis may be dependent on changes to electrical standards, the acceptance of standardized net benefits methods, commercial analytic tools, data availability, and integration with wholesale and transmission planning. As such, a locational benefits implementation roadmap should be developed that identifies which of the value components may be evaluated in the near-term (walk) to start, in the intermediate term (jog) and in the longer term (run). This benefits roadmap should identify specific gaps regarding the necessary prerequisites to value a component.

[46] Developed by California's More Than Smart working group in support of the CPUC Distribution Resources Plan proceeding (R.14-08-013) in 2015.

[47] MPUC Docket CI-01-1023, Interconnection Standards, and the 2014 MN Value of Solar, p. 34 (Location-specific Avoided Costs).

[48] NY PSC Case 14-M-0101 - Proceeding on Motion of the Commission in Regard to Reforming the Energy Vision. Order Establishing The Benefit Cost Analysis Framework, January 21, 2016

Additionally, the level of locational analysis may be minimally identified at the distribution substation as a start. However, it may be beneficial to extend this analysis to a lower level in the distribution system as may be desirable to optimize the distribution system and facilitate market development. The locational benefits roadmap described above should also include a pathway for greater locational and temporal granularity in relation to the various value components that considers the trade-off between potential increase in economic optimization and the related increase in operational complexity and associate risk. This aspect of the roadmap should similarly identify the prerequisites, existing gaps and recommended steps necessary to implement this locational benefits roadmap.

3.2 SOURCING OF NON-UTILITY AND UTILITY ALTERNATIVES

California[49] and New York[50] are currently developing distribution operational markets to enable DER provide services as an alternative to certain utility distribution capital investment and operational expense. This market is not dissimilar to that for transmission non-wires alternatives and ancillary services. At distribution, the potential types of services may include distribution capacity deferral, steady-state voltage management, transient power quality, reliability and resiliency, and distribution line loss reduction. The distribution utility is the buyer of these services, in lieu of traditional expenditures, to meet its statutory obligations for a safe, reliable distribution grid. The distribution planning process defines the need for these grid operational services.

Pricing of these services may be based on either the locational avoided cost of traditional investments, or competitive procurements using the avoided costs to establish a ceiling by which non-wires alternatives are evaluated using standard "least-cost, best fit" method. The services provided by DER providers and customers may be sourced through a combination of three general types of mechanisms:

- **Prices** – DER response through time-varying rates, tariffs and market-based prices
- **Programs** – DERs developed through programs operated by the utility or third parties with funding by utility customers through retail rates or by the state
- **Procurements** – DER services sourced through competitive procurements

Determining an optimal mix from these three categories, plus any grid infrastructure investments, requires both a portfolio development approach and a means to establish a comparative basis for these alternatives in terms such as firmness, response time and duration, load profile impacts, and value (net of the costs to integrate DERs into grid operations).

The leading example of this approach is that used by ConEdison in New York to address an identified distribution substation capacity upgrade in Brooklyn. The resulting Brooklyn Queens Demand Management (BQDM) project incorporated elements of rate design, targeted demand response tariffs and energy efficiency programs as well as a competitive procurement to reduce the forecasted load to enable deferment of a significant capital investment as illustrated below in Figure 9.

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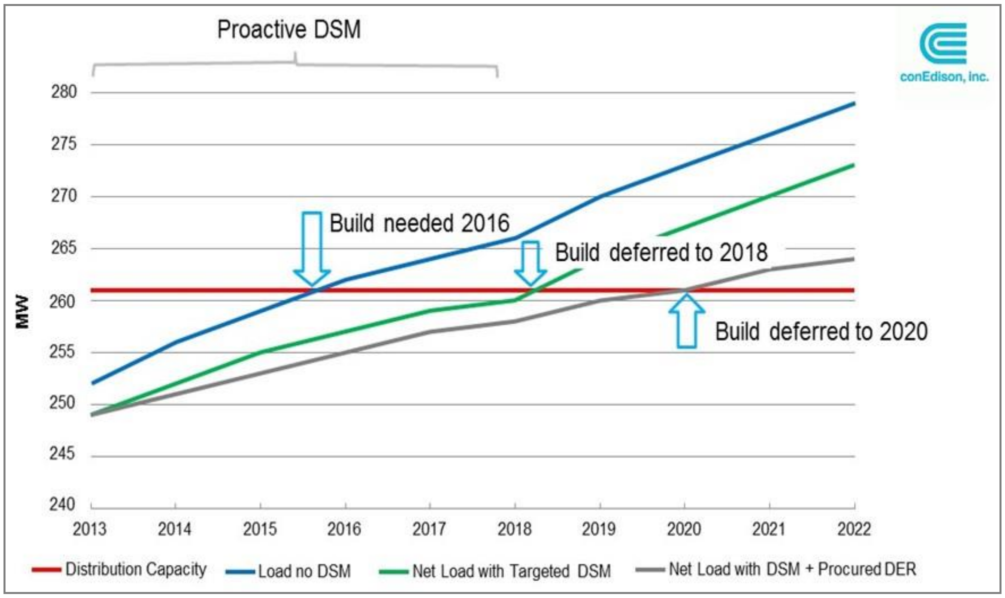
[49] California Public Utility Commission, Docket R.14-08-013, Distribution Resources Plan

[50] ConEdison, Brooklyn Queens Demand Management program, https://www.coned.com/energyefficiency/pdf/BQDM-program-update-briefing-08-27-2015-final.pdf

Figure 9: ConEdison BQDM Project Results



Minnesota and other states should consider the following when assessing locational net benefits and sourcing of DER provided grid services as part of an overall IDP process:

- Determine definition for locational net benefits analysis including value components and clarity on the meaning of "net benefits" in relation to benefits for all customers.
- Identify methodologies for determining LNBA that are consistent across a state including the granularity and temporal aspects of locational benefits and as may evolve in sophistication over time.
- Define the LNBA use cases for stakeholders and utilities to clearly identify the need/s.
- Identification of the value streams that DER may provide linked to planning (IRP, TPP, and other societal benefits).

Consider the use of DER as alternatives consistent with identified planning needs and the stage of DER adoption growth.

4. MINNESOTA IMPLEMENTATION CONSIDERATIONS

Proliferation of DER holds the promise of enhancing the operational, environmental, and affordability of Minnesota's electric system. This requires an integrated grid that optimizes the power system while providing safe, reliable, affordable, and environmentally responsible electricity.[51] This integrated grid will evolve in complexity and scale over time as the richness of systems functionality increase and the number of distributed resources extend to hundreds of thousands and possibly millions of intelligent

[51] Staff, The Integrated Grid, EPRI, 2014

utility, customer and merchant distributed resources. To address this evolution, robust planning processes and engineering methods are required to advance distribution planning. However, while a consistent approach to distribution is highly desirable in Minnesota, it is necessary to allow for differences in tactical implementation in recognition of the type of utility and differences in local drivers for change, capabilities, service territory characteristics, and cost-effectiveness for each utility to ensure net benefits for customers.

In this context and based on the MN distribution planning workshop discussions in 2015, e21 stakeholder discussions, industry research and emerging leading practices referenced in this paper, the following topics and potential requirements in Figure 10 for an integrated distribution planning are offered for consideration.

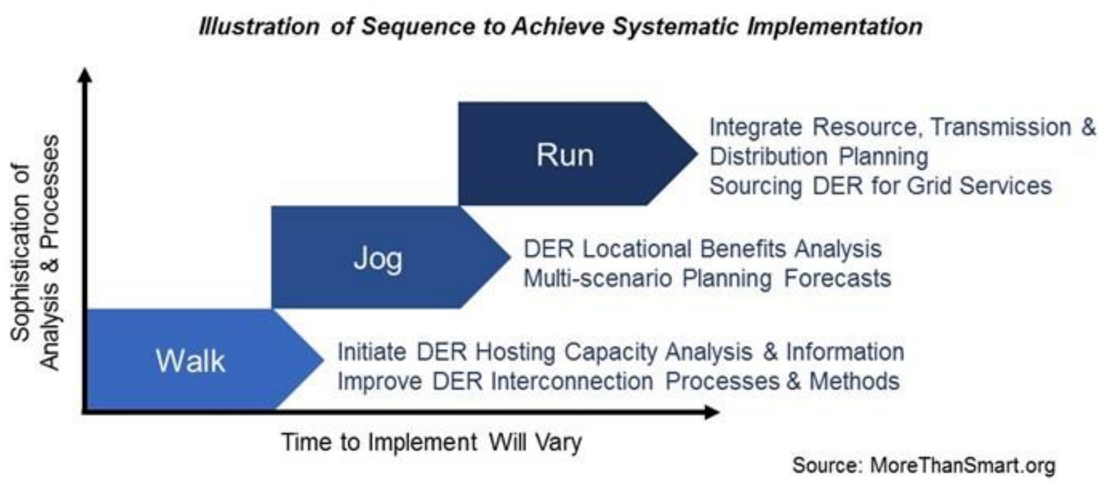
Figure 10: IDP Topics for Consideration & Potential Requirements

Topics for Consideration	Potential Requirements
1. Scenario-driven integrated planning analysis framework	A. Framework should identify all relevant analysis and modeling interdependencies to support identified uses by stakeholders and utilities B. Planning should use scenario driven "futures" using a set of common parameters including customer DER adoption, and other critical factors C. Planning should establish baseline functionality of current distribution infrastructure
2. Standardized methodologies for distribution planning and DER locational valuation	A. Planning should be performed using a consistent set of accepted engineering and economic methodologies, but remain vendor and modeling technology neutral B. Engineering methods should address all relevant power system characteristics and dynamics for a well defined distribution area and inter-related local transmission system consistent with best practice
3. Greater access to grid planning assumption and results data	A. Utility assumptions used for distribution planning and the results should be accessible to 3rd parties and researchers under certain qualifications and subject to confidentiality and security conditions. B. Market planning data from DER developers and services firms will be available to utilities and research institutions for relevant distribution and bulk power system planning under specific conditions and subject to confidentiality
4. Integrated multi-stakeholder distribution planning process	A. Planning process should engage stakeholders, including customers and their representatives B. Stakeholder engagement should not create a bottleneck to planning process but improve planning outcomes and subsequent decision making
5. Alignment & integration of resource, transmission and distribution planning processes	A. Resource, T&D planning should each inform each other to ensure alignment in the consideration of DER across a power system. B. Consistent planning assumptions should be used for resource, transmission and distribution planning allowing for differences in granularity and other dimensions.

Implementation of an integrated distribution planning process and related methodologies should be considered in a series of steps that sequentially increase the sophistication and value realization of DER in line with the pace and shape of adoption. Specifically, when regulatory actions will be needed to address specific changes. Also, increasing the sophistication will be reliant on investments to monitor and analyze a more complex distribution system. Therefore, implementation roadmaps for IDP should recognize existing gaps in planning tools and relative immaturity in industry experience.

The "Walk, Jog, Run" approach, below in Figure 11, outlines an example path that bridges the divide from today's planning to the opportunities envisioned in a more distributed future through integrated distribution planning. This path is focused on the regulatory and industry actions needed over the next 1 to 5 years on the cross-cutting issues identified in the preceding sections to enable a graceful transformation of planning for Minnesota's power system. Many of these changes and additional planning activities will need to be executed concurrently. This requires alignment of the intricate interdependencies of the various activities within each stage. The answer to how best to provide needed capabilities will depend on the stage of distribution system evolution in any particular utility and state, considering both the current stage of DER adoption, level of distribution grid modernization and the desired policy objectives.

Figure 11: Illustration of Walk, Jog, Run Approach to Implementation



5. CONCLUSIONS

The realization of the value of DER adoption and grid modernization for all customers necessitates a proactive approach to distribution system planning. Elements such as multiple scenario forecasts, hosting capacity analysis and locational net benefits analysis can enhance traditional planning processes and help establish a standardized, transparent planning framework that proactively addresses the full set of impacts and values of DER on the grid. These capabilities will help utilities to better identify necessary distribution investments, inform the continued evolution of the interconnection process and better quantify DER's value to the system as well as their benefit to all customers. The MPUC Staff Report recognizes that new planning approaches will be "an integral part of a systematic approach to grid modernization." The successful implementation of these elements will ultimately help Minnesota and other states meet public policy objectives and enable safe, reliable and affordable service that satisfies customers' changing expectations and use of distributed resources.