

Workshop #4 Report Out

This document covers the report-out from Workshop #4, which took place on November 20, 2024 from 2-4:30 pm Eastern Time.

This document summarizes the content covered in the workshop. For additional detail, please see the accompanying workshop slides and recordings.

The workshop agenda included the following:

Session
Welcome: Overview of today
Micro-Presentations: Expert speakers and state practitioners discussed the following: <ol style="list-style-type: none">Using distribution plans to inform grid modernization investment decisionsCoordinating distribution planning with multi-year rate plansCoordinating distribution planning with other planning processes (e.g. IRPs, State Plans)Using distribution plans to inform pricing, program, and procurement design
Breakout activity: Deeper dive into one of the four topics
Workshop Reflections
Closing, and what's ahead

This report-out includes the following:

- Presentation summaries, questions, breakout discussions, and key resources for the four micro-presentation topics.
- Summary of additional resources

This cohort and associated activities are part of the DOE-sponsored [NARUC-NASEO DER Integration and Compensation Initiative](#).



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Planning for a Modern Distribution System

2024 Cohort

A NARUC-NASEO Initiative

Using distribution plans to inform grid modernization investment decisions

Presentation

Speaker: Hanna Terwilliger (Minnesota Public Utilities Commission)

Integrated Distribution Planning and Grid Modernization

The presentation covered how integrated distribution planning interfaces with grid modernization decisions.

Topic	Key Points
Integrated Distribution Plan (IDP) Requirements	<ul style="list-style-type: none"> • The PUC accepts distribution plans, but it does not approve them (in other words, accepting the plan does not approve budgets, etc.). • The PUC has used distribution plans to inform policy direction and grid modernization decisions in other processes. • Utilities are required to submit distribution plans every 2 years. • Utilities must hold at least 1 stakeholder meeting prior to filing which covers forecasts, their 5-year investment plan, and their system capabilities.
Filing Requirements for Distribution Plans	<p>Distribution plans must include:</p> <ul style="list-style-type: none"> • Baseline data for the system, financials, and DERs; • Hosting capacity and interconnection; • DER futures analysis (scenario planning); • Long term distribution system investment plan (5 & 10 year); • Non-wires alternatives analysis; and • Transportation electrification plan.
Process Coordination	<ul style="list-style-type: none"> • The integrated distribution plan is coordinated with the integrated resource plan, utility rate case, and transmission planning. These integrated processes are nonlinear. • In Minnesota, grid modernization investments and cost recovery are generally approved in a rate case or rider proceeding. The more the Minnesota PUC is able to develop policy outside of the rate case in the distribution planning process the more equipped they are for the cost recovery approvals for grid modernization spending. • Grid modernization plans are included in distribution plans, as this helps depict when utilities are planning their next investments and how many investments they are planning on.
Examples of Grid Modernization Initiatives	<p>Xcel Energy’s 2023 Integrated Distribution Plan focused on four main grid modernization initiatives:</p> <ul style="list-style-type: none"> • Planned net load (PNL) – how the utility is going to value distributed solar for the distribution system. The Commission decided that Xcel’s preliminary methodology was overly conservative and provided them with guidelines on how to update the methodology and file it in their next plan. • Distributed Energy Resource Management System (DERMS) – the Commission required Xcel to develop a roadmap for implementing DERMS and get stakeholder feedback prior to submitting a request for approval. • Flexible Interconnection (FI) – the Commission directed the interconnection working group to determine if changes to interconnection standards are needed to establish flexible interconnection. • Proactive grid upgrades for DERs and electrification – established a Commission-led working group for developing a framework for proactive spending.

Questions

Plenary questions on how distribution plans can inform grid modernization investments:

Question	Answer
What does the utility want to control with the DERMS?	DERMs will enable the dynamic portion of flexible interconnection and EV charging demand response. However, the utility is still early in the process and the road map will help determine what other use cases there could be. A DERMS is needed for flexible interconnection will allow curtailment in order to defer distribution upgrades and will likely apply to larger-scale projects (1MW +) versus individual residential level projects.
Were the Grid Modernization Initiatives proposed by Xcel without Commission directions? Or was this supported by policy?	The initiatives were derived from multiple sources. The Commission required a Planned Net Load initiative, DERMS is being rolled out on Xcel's timeline (although it is encouraged by the Commission), Flexible Interconnection was brought up by stakeholders, and proactive grid upgrades was a combination of legislative direction to utilities and a Commission request for a framework.
What type of regulatory process did the Minnesota PUC use to comment and provide direction to Xcel Energy on its Grid Modernization Plans and Initiatives? Was there Stakeholder feedback or input required? (i.e. Hearing, Admin., etc.)	In MN, they use "informal" proceedings in order make the process more accessible. This consists of a written comment period where staff compiles a summary for Commissioners to make a decision. For example, a stakeholder can suggest that there needs to be a roadmap for DERMs, and the staff will then include that suggestion in its summary for Commission consideration at an open meeting.
What are the methods and assumptions being used to value DERs?	In Xcel's initial methodology in MN they used the worst solar performing months (winter) to estimate the capacity factor, and then took 15% of that capacity factor to estimate how much solar they could depend on during the peak for a distribution offset (e.g. a 10 MW solar system could provide 60 kW of dependable solar). The Commission recommended they take seasonality into account and have different factors for summer vs. winter. Battery storage was not considered in the analysis.

Breakout Discussions

The breakout group discussed challenges participants were facing with regards to distribution planning and how it ties to grid modernization investments. The table below highlights the challenges participants surfaced and the accompanying discussion.

Challenge	Discussion
As we have been working on improving the distribution planning process, interested parties in non-contested cases want distribution plans to be in contested cases to challenge what utilities are proposing.	<ul style="list-style-type: none">• Can still do information requests and the utility usually responds even though it's not formally discovery. Reputation helps encourage sharing of information.• The Commission can give policy guidance, and if there's not money associated with it then it is not worth having a contested case.
Utilities each have different distribution planning processes and provide different information	<ul style="list-style-type: none">• You can have "baseline data" that should be similar for all, such as poles, wires, substations, etc. that is collected from all utilities.• Some data is specific to utilities, where it can vary.
There are urban and rural divides in many states, how does this show up?	<ul style="list-style-type: none">• Areas served by coops don't have PUC oversight and are regulated by their boards. Participants are hoping to get a strategic way to think about how to spend distribution funds in those areas.
How can PUCs and SEOs collaborate on this process?	<ul style="list-style-type: none">• One disconnect is that the Commission is only regulating some of the distribution utilities (they regulate IOUs, but not Coops or Munis necessarily)• Participants noted that there is opportunity for increased coordination to avoid duplicative efforts and for SEOs to talk to the Commission prior to commissioning studies related to distribution planning.

Key Resources

Below are resources brought up during the presentation and subsequent breakout discussion:

[Minnesota Integrated Distribution Planning Requirements](#)

[Xcel Energy Minnesota 2023 Integrated Distribution Plan](#)

[State Energy Offices' Engagement in Electric Distribution Planning to Meet State Policy Goals](#)

[ESIG System Planning Working Group](#)

Coordinating distribution planning with rate cases

Presentation

Speaker: Scott Struck, Illinois Commerce Commission

How Distribution Planning Can Tie to Rate Cases

This presentation covered Illinois' efforts to coordinate their integrated grid plans with their rate cases. In 2021 the legislature required the state IOUs to file multi-year rate plans with corresponding multi-year integrated distribution plans. Illinois is still in the first cycle of litigating these initial plans and these are ongoing open cases.

Topic	Key Points
Multi-year integrated distribution plans	<p>Objectives:</p> <ul style="list-style-type: none"> • Align utility investments with state climate goals. • Ensure utility expenditures are cost effective using CBA and least-cost best-fit analyses. • Provide delivery rates that are affordable to all customers, including low-income customers. • Promote energy equity – at least 40% of benefits should go to disadvantaged communities. • Ensure opportunities for robust public participation through transparent planning processes. • Achieve approved performance metrics.
Multi-year rate plans	<p>Objectives:</p> <ul style="list-style-type: none"> • Sets revenue requirements for each of the subsequent four years after the end of the current plan. • Annual reconciliation to true up forecasted spending to actual, with a 105% cap. • Set reward or penalty for performance using an ROE adjustment. • Four-year investment plan must be consistent with the corresponding Multi-Year Integrated Distribution Plan. However, there is flexibility to make changes as long as there is evidence to support the change.
Relationship of rate plan to grid plan	<p>Cyclical relationship</p> <ul style="list-style-type: none"> • The distribution plan should be designed to meet Illinois' performance metrics. The distribution plan is then used to develop an investment plan, which is used in the multi-year rate plan, which then informs the performance metrics the next distribution plan must meet. • Investment plan in MYRPs must be consistent with Multi-Year Integrated Distribution Grid Plan • Distribution plans designed to achieve Performance Incentive Mechanisms used in the Multi-Year Rate Plan • Grid plans and rate plans are staggered, rate plan filed one year after grid plan is filed

Questions

Plenary questions on integrating distribution plans with rate cases:

Question	Answer
What is the planning horizon for the distribution plan?	The distribution plan's planning horizon is five years. A new one is filed every four years.
Is a cost-benefit analysis required for all investments (including "business-as-usual" investments)?	Cost-benefit analysis is only required for grid modernization investments, not business-as-usual investments.
When a utility goes for cost recovery, do they also need to do a CBA? In other words, do you need to require a CBA in the grid plan AND during the cost recovery?	Not required for the Commission to ask for the cost-benefit analysis during cost-recovery, but they could. They are still litigating the first round of these plans so they will see how it turns out.
What performance metrics have you been using for your rate plan?	Illinois' performance metrics address reliability and resiliency, peak load reductions, supplier diversity expansion, affordability, timeliness for interconnection, and customer service performance.
How are the metrics for BCAs developed? When do you use least cost best fit versus a BCA?	Utilities are required to provide BCAs and stakeholders can challenge the metrics of these BCAs. The inputs for the BCAs are determined by the companies rather than through a stakeholder process. In determining whether least-cost best-fit versus BCA tests are used, it depends. Sometimes things are required by statute or tariffs. Other times there can be a debate for other projects to see what goes in which type of analysis.
How many meetings required ahead of filing for utilities?	In the past have typically had 6-8 separate meetings and were required to hire an independent facilitator. Also needed to be available to stakeholders who don't typically have access to a lawyer.

Breakout Discussions

The breakout group discussed challenges participants were facing with regards to distribution planning and how it ties to rate cases. The table below highlights the challenges participants surfaced and the accompanying discussion.

Question	Answer/Discussion
How to ensure distribution plans are consistent with rate cases.	<ul style="list-style-type: none">• Helps to ensure planning process is completed before doing the ratemaking. Hoping for a small delta between the distribution plans and the multi-year rate plans but when going out four years it becomes harder to achieve that.• Prudence reviews when doing annual adjustments helps.
How to incorporate resilience into distribution plans	<ul style="list-style-type: none">• For resilience spending, it is important to evaluate diminishing returns and think about the time horizon needed.
Does the grid plan give false expectations that rates will be automatically approved?	<ul style="list-style-type: none">• Just because the dollars match doesn't mean that an investment is prudent.• Giving the utilities some reasonable flexibility helps.• Placing a cap on the approved revenue requirement can mitigate against large changes to spending.
Recommendations to others who are coordinating distribution planning and rate cases	<ul style="list-style-type: none">• The approach in Illinois has a lot of complexity, but it puts more light on the utilities' planning process.• It also enables more transparency and more stakeholder input.

Key Resources

Legislation listing requirements for multi-year integrated grid plans and multi-year integrated rate plans:

[220 ILCS 5/16-105.17](#)

[220 ILCS 5/16-108.18](#)

Other Resources:

[Commonwealth Edison Company Multi-Year Performance and Tracking Metrics Plan](#)

[Illinois Multi-Year Integrated Grid Plan Stakeholder Process](#)

Coordinating distribution planning with other planning processes

Presentation

Speaker: Clarice Schafer, Hawaii Public Utilities Commission

Distribution Planning in Hawai'i's Integrated Grid Planning

The presentation covered how Hawaii incorporated distribution planning into its overall planning process.

Topic	Key Points
History of integrating the planning process	<ul style="list-style-type: none">• Integrated grid planning docket proceeding opened in 2018, which combined distribution, transmission, and generation planning processes for the first time• Goal of the combined approach was to identify customer savings and emissions reductions opportunities by modeling distributed and grid-scale resources together
Integrated grid modeling framework	<p>Stakeholder engagement</p> <ul style="list-style-type: none">• Found having a single stakeholder working group to be more effective than having multiple siloed working groups• User-friendly and transparent website aided in communicating updates to modeling and planning• Independent Technical Advisory Panel also provided valuable feedback on report assumptions as well as the analytical approach and modeling methods <p>Overall modeling process</p> <ul style="list-style-type: none">• Distribution analysis conducted using LoadSEER and Synergi for both normal and contingency operating conditions to identify distribution grid needs as well as traditional and non-wires solutions• Broader stakeholder process did not focus too much on the distribution planning aspect of the overall integrated grid planning framework <p>Areas for improvement during the next iteration of the planning process</p> <ul style="list-style-type: none">• PUC did express concern about modeling changes the utility made without sufficient explanation or stakeholder input during the prior process• Preference for the utility to conduct the full modeling process during all scenarios rather than just the base case scenario• For next iteration the PUC encouraged the utility to use open models
Outcomes	<ul style="list-style-type: none">• New process led to updated and more sophisticated planning and models and allowed DERs to be integrated into the larger planning process• Still lots of room for improvement in future planning processes, such as the outcomes of the grid needs assessment being used to inform future DER programs and policies

Questions

Questions from the plenary on coordinating distribution planning with other planning processes:

Question	Answer
Did you find any impact in the required reliability standards compared to when there was not a distribution planning component?	There is no reliability standard in Hawaii. However, regarding how DERs impact the proposed reserve margins on each island, HECO's Integrated Grid Plan did not clearly articulate how the planning scenario with higher levels of DER adoption impacted the energy reserve margin.
Has seen similar concerns that the methods that use LoadSEER are a bit of a black box ... how do you navigate that?	HECO provided a high-level overview of the modelling framework and model assumptions used for LoadSEER in a single session and in a section of the IGP report but there was limited discussion of how it was used to inform the overall system-level plans beyond that. There could have been more stakeholder involvement in distribution analysis when it came to discussing assumptions.
Who is included in the independent technical group?	The technical advisory panel had expert representatives from the Environmental Defense Fund, EPRI, MISO, NREL, Telos Energy Group, Hawaii Natural Energy Institute, Energy Systems Integration Group, SoCal Edison, and PNNL. Provided pointed and objective feedback to the utility and the utility was open to making adjustments to their modeling and assumptions in response to the feedback. The report developed by the technical group included non-binding recommendations.

Breakout Discussions

The breakout group discussed challenges participants were facing with regards to integrating distribution planning with other planning processes. The table below highlights the challenges participants surfaced and the accompanying discussion.

Challenge	Discussion
How do we use the information from our dx plans & plug them into the IRPs? How do we better align these processes?	There's not a great answer yet, still lots of room to improve. Recommend the diagram (shown during Hawaii's presentation) in theory and also provided some oversight in separate dockets but still is unclear exactly how much the dx plan influenced the system plan and vice versa.
For states where the system plan and distribution plans are developed by separate entities, how can we make sure the plans are coordinated?	There is no one model that can do it all. One theme that came in through NREL training is getting your inputs & assumptions correct, having them be consistent. Same with scenarios & assumption parameters that are consistent for the two processes. Also, should the models and planning process be flexibly designed to incorporate major changes in policy that may occur during the planning proceeding? For example, IRA was passed as we were in the middle of IGP modelling, and it may or may not have been problematic that HECO did not update inputs & assumptions for tax credits in this IGP proceeding or the next. In terms of the procedural schedule, looked at inputs & assumptions & ruled on that so they didn't have to argue about it later on down the road. This had benefits and drawbacks. Benefit = procedural efficiency. Drawback = unable to update planning assumptions when there are major policy changes.
How can we make distribution plans look and function more like the IRP, where the costs that need to be approved align with the projects that appear in the plan?	This was a problem all participants shared, with a desire to make sure that assumptions are consistent and the information used is consistent between the two processes.

Key Resources

Relevant PUC Orders

Accepting 2023 Final IGP Report & Providing Guidance – [March 2024](#)

Providing Direction & Guidance on the Next Round of IGP – [Sept 2024](#)

Approving with Modifications HECO's Grid Needs Assessment – [June 2022](#)

HECO Planning Documents

[July 2024 Action Plan](#)

[Nov 2023 Supplemental Response](#)

[May 2023 IGP](#)

[Appendix E: Location-Based Distribution Grid Needs](#)

[Nov 2021 Grid Needs Assessment & Solution Evaluation Methodology](#)

[June 2020 Distribution Planning Methodology](#)

[HECO IGP Website](#)

[Hawaii Integrated Grid Planning Technical Advisory Panel](#)

Using distribution plans to inform pricing, program, and procurement design

Presentation

Speaker: Paul De Martini, Newport Consulting

IDSP Sourced DER Grid Services

The presentation walked through the principles of using distribution plans to inform pricing, programs, and procurement.

Topic	Key Points
Overview	<ul style="list-style-type: none">Informing how we leverage pricing, programs, and procurement (3 Ps) for Non-wires alternatives (NWAs) to address Dx benefits (and bulk system, by extension)
IDSP and Grid Needs, Sourcing Requirements, and Evaluation	<ul style="list-style-type: none">IDSP should be informing how we think about leveraging the 3Ps, and IDSP should help identify emerging needs in the Dx systemNWAs are one way to address constraints in Dx, but also rate design (regular rate design process and rate design for DERs) and geotargeted programs
Distribution Grid Needs Require Portfolio Approach	<ul style="list-style-type: none">Develop a portfolio informed by IDSP to target load shapes and export patterns of distributed resourcesPortfolio allows us to leverage all the 3Ps

Questions

Questions from the plenary on using distribution plans to inform pricing, program, and procurement design:

Question	Answer/Discussion
What are some examples of geo-targeted programs?	<ul style="list-style-type: none"> • Geo-targeted programs in EE and demand response to tackle distribution have largely been at the substation and feeder level. • Consider tariffs and DSMs first (before procurement): <ul style="list-style-type: none"> ○ Tariffs are low or no cost to the ratepayer ○ Redirecting DSM program (e.g., geo-targeted or temporal) funds to target Dx needs, there wouldn't be an incremental cost • Procurement has an incremental cost
What is the relationship of the filed DSP to tariff filings for geotargeted programs and time-varying rates?	<ul style="list-style-type: none"> • Typically, NWA analysis is narrowed to procurement opportunities (though we did see examples of NWA analysis as part of Dx planning today). • But there's a gap, and it would help to require recommendations on how tariffs and DSM programs can address this in Dx planning. • High-level decisions can happen in Dx planning or IDSP, then the specific program filings can happen through individual filings (MN perspective)
Do you believe NWAs should be carried out by the utilities or private individuals?	<ul style="list-style-type: none"> • NWAs involve grid services provided by customers and/or aggregators to distribution utilities. An NWA can involve a procurement and contract for service with a DER aggregator or through a utility of state DSM/DER program.
Is having a third-party provide an NWA disadvantaging the utility's ability to make the investment?	<ul style="list-style-type: none"> • Having third parties and customers provide grid services doesn't disadvantage utility investment. Utilities view NWAs as a tool to manage load growth, facilitate interconnections, and optimize investment over time to address affordability. This is because there is more to do than can be done given utilities' resource constraints and customer affordability.
Is there room for requiring that the utilities consider third parties for NWAs?	<ul style="list-style-type: none"> • Yes – there are many examples of states that have required NWAs and third-party participation. There are a few states with legislative constraints regarding DER aggregators
If you're in an area that's not part of a market, what are your thoughts on how to calculate the value of DERs?	<ul style="list-style-type: none"> • One option is to use the utility's supply costs as part of the factor (e.g., Hawaii CGS rates) • The value should include a distribution value (e.g., NY VDER) as part of the calculation for that tariff (both HI & NY were NEM successor tariffs)
Should we require electric companies to provide their portfolios of grid need tools or should this be in the Commission's toolbox?	<ul style="list-style-type: none"> • No, as the utility distribution planning tools are not theirs to provide under the terms of their software licenses with the software vendors. Also, it is impractical for stakeholders to independently conduct detailed distribution analysis in a meaningful and comparable basis. However, the input assumptions and scenarios, analytical methodologies employed, and the resulting grid needs and recommendations should be examined by stakeholders. This includes utilities explaining the reasoning for the modeling and analysis tools that they are using. • It would be helpful to understand how effective the existing sourcing methods are for addressing Dx needs and what enhancements are needed to address Dx needs, which could happen in DER proceedings or IDSP proceedings • In Dx planning, there should be recs on how tariffs, programs, and procurement processes can be applied

Breakout Discussions

Participants had ample questions for Paul throughout the breakout session that focused on implementing this work. See a summary of questions and answers below:

Question	Answer/Discussion
Can you elaborate on best practices/case studies for rate design?	<ul style="list-style-type: none">• There are no specific case studies that come to mind, as rates have not been designed to be localized. However, when thinking of critical peak pricing rates, TOU and DER rates it is important to think about how the load profile shapes you are trying to create will meet the needs of the distribution system. The distribution cost impact is significant and you can be more specific on what the load shape needs are in the planning process for distribution.• Programs can be geo-targeted programs (happen through demonstrations, Green Mountain in VT, OK utility, demos in CA)
What are the next steps after mandated TOU? Is it important to think about dynamic avoided cost considerations?	<ul style="list-style-type: none">• Start simple. See where load patterns overlap and how program design (such as EE) can address existing load shape, then consider how programs can impact this more locally• HCA can help get more dynamic and granular. National labs and consulting firms can help you think through analysis and address this, akin to IRP but more localized, cost-effective resource stack to address specific analysis
How can programs that typically target system peak transition to also help with local peaks without competing?	<ul style="list-style-type: none">• Examining the alignment or divergence of system peak and distribution peaks is important. Next is to assess the optimal use of DER/DSM to address both needs - tools can simulate this. There are opportunities to look at combination of traditional and geographically targeted elements to target urgent needs

Key Resources

[LBL website on integrated system planning](#)

[Distributed Resource Utilization Library](#)

Forthcoming: P. De Martini, S. Succar and P. Cook, *Sourcing Distributed Energy Resources for Distribution Grid Services*, DOE, (December 2024)

Additional Resources

Direct technical assistance

- For TA on distribution system planning and grid resilience planning: Contact Lisa Schwartz: lschwartz@lbl.gov
- For TA on other electricity topics, please see: [Resources and Assistance for State Energy Offices and Regulators program](#)

Upcoming opportunities

- Training for Sates on Integrated Distribution System Planning 2.0. Dates and locations of the trainings are listed below.
 - *March 11-12, 2025 - Detroit, MI: [Register Here](#).*
 - *April 30-May 1, 2025 - West (tentatively Denver, CO)*
- NARUC and NASEO Comprehensive Electricity Planning Initiative will launch in 2025. To learn more and express an interest in participating visit the [initiative web page](#).

Publications and other online resources

- See Berkeley Lab's [website](#) for additional presentations and links to recordings for prior trainings (scroll below diagram to “Regional and state trainings and presentations”)
- U.S. Department of Energy's [Distribution Grid Transformation website](#)
- State Requirements for Electric Distribution System Planning – [online catalog and interactive map](#) and forthcoming report covering more topics
- NARUC/NASEO [Blueprint for State Action](#) for comprehensive electricity planning

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