Title

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Duke Energy's Integrated System and Operations Planning: A comparative analysis of integrated planning practices

Prepared for the South Carolina Office of Regulatory Staff

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1 Introduction

The South Carolina Office of Regulatory Staff (ORS) represents the public interest in state utility regulation and is considered a party of record in all filings, applications, and proceedings before the Public Service Commission of South Carolina. In their 2018 Integrated Resource Plan (IRP), Duke Energy Progress (DEP) and Duke Energy Carolinas (DEC), subsidiaries of Duke Energy Corporation (Duke Energy), laid out their plan to incorporate their Integrated System and Operations Planning (ISOP) framework in future IRPs. The Companies cited trends in technology development, declining costs of resources, and customer preferences for distributed energy resources (DERs) such as solar and electric vehicles as contributing factors in a need to update planning tools – specifically those that can better identify the locational value of distributed generation and strengthen the link between distribution and bulk power plans (DEP 2018). In 2022, the South Carolina ORS requested technical assistance from the U.S. Department of Energy to better understand how the ISOP framework interacts with other electricity planning processes such as the IRP. In short, ISOP is Duke Energy's process for integrating planning efforts across four key domains in the power system: generation, transmission, distribution, and demand-side (Figure 1).

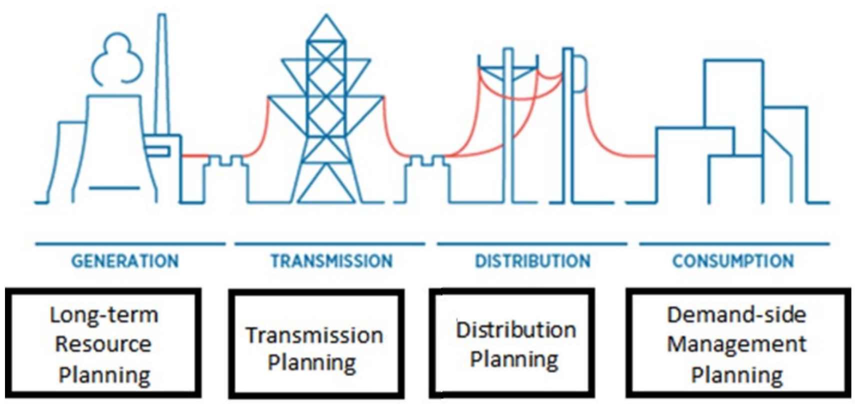


Figure 1. Power system domains included in the ISOP framework

Duke Energy envisions ISOP as a framework or process by which it would fully and fairly value all energy resources based on their functional capabilities, regardless of location. ISOP is not deterministic of outcomes; rather, continued application of judgment is needed to ensure optimal outcomes for utility customers. The company is using ISOP to develop and implement new tools for evaluating the performance of a range of portfolios across a range of futures. Duke Energy's objective for ISOP is to "cost-effectively integrate new technologies and customer programs as technology and policy continue to evolve" (Duke Energy 2019).

The company intends for ISOP to provide increasingly robust analysis of operational impacts and benefits of integrating DERs and other non-traditional solutions across generation, transmission, distribution, and demand-side planning. The framework also incorporates granular load forecasting, Advanced Distribution Planning (ADP), and capacity contributions from zero emission, load-following resources. Beyond integrating ISOP into the IRP, Duke Energy is also integrating ISOP with its Climate Risk and Resilience study (Duke Energy 2022), non-traditional grid solutions studies, and Grid Improvement Plan.

Generation, Transmission, Distribution, and Demand-Side Domains

Generation includes technologies that produce and store electricity. Generation planning, in vertically integrated jurisdictions, usually relies on IRP. In restructured jurisdictions, generation and storage investment decisions are made by entities in response to price signals in energy and capacity markets.

Bulk power system **transmission** typically covers high-voltage lines at or above 100 kV, including the transformers used to step down voltage to distribution system levels. The transmission planning process can be conducted by an RTO/ISO, utility, or both, depending on jurisdiction.

The **distribution** system typically starts at the low voltage bus in a substation that converts voltage down from transmission level to lower levels that are safe for delivery in population centers. Distribution systems are divided into primary and secondary: primary lines bring power into population centers, and secondary lines bring power to premises. Typical voltage for primary distribution systems ranges from 12 kV to 34 kV. These lines are referred to as "feeders" or "circuits" that begin at the substation circuit breaker.

The **demand side** comprises all behind-the-meter interventions that can be operated for customer and electricity system benefits. Demand-side planning typically uses one or more screening processes to evaluate the cost-effectiveness of proposed measures. When the system-level benefits of demand-side management are incorporated into distribution planning, these interventions can be included in the planning process as an element of "non-wires alternatives," "non-wires solutions" or, as in the ISOP framework, "non-traditional solutions."

ISOP is Duke Energy's internal integrated process to address planning needs across all four electric utility resource domains. Initially, Duke Energy has focused on ISOP's application to the utilities in the Carolinas region, which are vertically integrated. Duke Energy's approach to developing ISOP builds on planning and regulatory advancements already accepted in its jurisdictions, including grid modernization under the Grid Improvement Plan and scenario-based generation and transmission planning in Integrated Resource Planning. ISOP further expands on these elements in areas related to integration of renewable generation and new distributed resources, including but not limited to more granular planning forecasts and modeling systems, evaluation of non-traditional solutions for the grid, grid hosting analysis, stakeholder engagement, and new resource valuation methods to recognize value across business segments.

As a point of reference, a growing number of states are adopting regulatory requirements for various forms of integrated distribution planning (IDP), which is one of the dimensions addressed by ISOP. There are differences between jurisdictions' IDP requirements in terms of what must be filed and when various new elements of utility plans must mature for inclusion.

The regulatory focus in jurisdictions served by Duke Energy has been on IRP scenarios, grid modernization, reliability and resilience, and affordability. ISOP's planning elements reflect these priorities. When considered alongside its work in IRP and the Grid Improvement Plan, Duke Energy views

ISOP as addressing the highest-value elements of IDP as it is performed in other regions. The company's ISOP team monitors those efforts and considers them for inclusion in the ISOP roadmap if deemed appropriate for the utility and its customers and stakeholders.

ISOP shares several components with IDP, such as integrating internal utility processes for planning generation, transmission, distribution, and demand-side resources. ISOP also includes some core components of a typical IDP, such as advanced forecasting and system modeling, hosting capacity analysis, screening of non-traditional solutions, and stakeholder information sessions. There are also opportunities to improve ISOP, such as increasing stakeholder engagement, including a detailed discussion of ISOP in IRPs, and providing more information on how ISOP identifies investment decisions that are least cost and risk for maintaining a reliable, resilient distribution system.

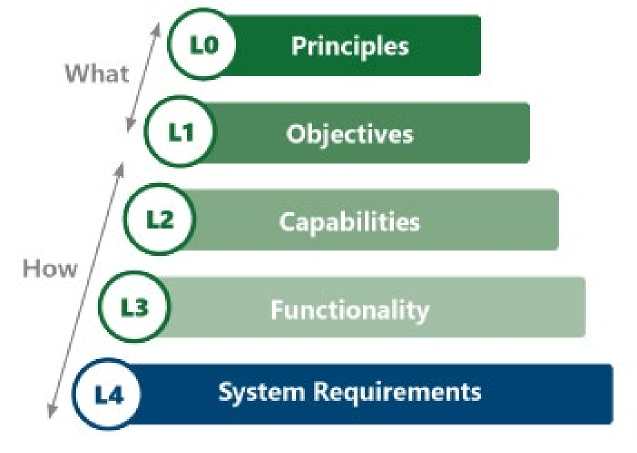
Integrated Distribution System Planning (U.S. DOE 2020)

"IDP provides a systematic approach to satisfy customer service expectations and the specific grid planning and design objectives related to reliability and resilience, safety and operational efficiency, and DER and microgrid integration and utilization. These three focus areas of modern distribution planning require a unified process integrated with system forecasts and corresponding resource and transmission planning." (p. 13)

In states that require regulated utilities to submit IDPs, utilities publicly file their plans for regulatory review and approval or acceptance, and there are provisions for significant stakeholder engagement and data access. Because South Carolina law does not require an IDP, these provisions would not directly apply. Consequently, IDP elements appear instead in Duke Energy's Grid Improvement Plan, IRP, and rate case filings. These proceedings and their attendant regulatory, stakeholder, and community engagement processes cover the planning spectrum. ISOP supports each of these planning functions with the advanced planning capabilities discussed herein. Given the overlap of some of these advanced planning elements with IDP, this report provides useful comparisons and shares emerging best practices for IDP that may reveal opportunities for further development of ISOP.

Identifying IDP Objectives (U.S. DOE 2020)[1]

"Undertaking such an effort begins with an articulation of principles and policy mandates, as well as an understanding of the evolving needs of customers and associated trends. These factors inform the development of grid modernization objectives that consider timing with respect to addressing emerging trends, customer needs, and public policies." (p18)



About 20 states require utilities to file distribution system plans (DSP), and several others require filings for certain aspects of distribution grid planning (i.e., poorly performing circuits, DER adoption targets, or grid modernization plans) (Schwartz and Frick 2022).[2] In South Carolina, DEP and DEC provide some of this information in their Grid Improvement Plan and rate cases.[3]

More than 35 states require bulk system planning filings, which usually take the form of an IRP or similar long-term investment plan (Frick et al. 2021). Duke Energy is required to regularly file IRPs, which include commitments to include detailed information and planning results from ISOP, transmission, energy storage, and customer programs. The company also files transmission plans and demand-side management plans.

[1] See Table 1 in the referenced DOE guidebook for definitions and examples for each level of the figure's taxonomy (L0-L4).
[2] Berkeley Lab's catalog of state IDP requirements will be published on its Integrated Distribution System Planning website. See https://emp.lbl.gov/projects/integrated-distribution-system-planning.
[3] In South Carolina, DEP and DEC filed their Grid Improvement Plan (ND-2020-28-E), which discusses distribution system needs. In Indiana, Duke Energy may file a 6-year plan for approval of transmission, distribution, and storage improvements; see https://www.in.gov/oucc/electric/key-cases-by-utility/duke-energy-rates/duke-energy-infrastructure-plan/.

IDP Goals and Requirements (Regulatory Assistance Project 2023)

In some jurisdictions, state IDP goals come from legislation directing commissions to provide guidance to utilities for filing distribution plans. Commissions have either directly adopted these state policy goals or used them as a starting point for a stakeholder process to fine tune and create additional goals for IDP. In other states, commissions establish IDP goals and requirements on their own motion.

A common overarching theme is ensuring a safe, reliable, and affordable system. Goals and objectives are then focused more narrowly on distribution system investments that modernize the grid while ensuring reliability cost-effectively.

In the past, regulators have had limited insight into distribution system investments. IDP goals reflect the need for transparency and stakeholder engagement. Several commissions set IDP requirements in response to lack of information provided by regulated utilities. As spending by investor-owned utilities in distribution system investments has grown to 33% of capex in 2022 (EEI 2021), regulators' interest in greater visibility in distribution planning has increased.

ISOP lays the groundwork for an ongoing integrated planning process, incorporating regular stakeholder engagement meetings, annually updating granular forecasts, and building tools to enable more streamlined and automated planning in the future. Duke Energy intends to use ISOP elements to inform the companies' IRP filings and update reports, Grid Improvement Plan filings, and rate cases.[4] Internally, Duke Energy is using ISOP to advance and automate routine distribution planning practices and advance new processes (e.g., screenings of non-traditional solutions). Many ISOP functionalities are being developed incrementally, where functionalities are being built out and accuracy is being improved in phases. For example, prior to releasing its full hosting capacity analysis in 2024, DEC is providing developers with high-level guidance maps for distributed generation.[5]

1.1 Using This Report

To create this report, Berkeley Lab and the National Renewable Energy Lab (NREL) project team:

- Met with both the South Carolina ORS and the North Carolina Public Staff to understand their research needs and questions.
- Reviewed Duke Energy's publicly available ISOP documents; interviewed Duke Energy staff to fill the gap in our understanding of ISOP; and reviewed Duke Energy's written responses to interview questions (Appendix C).
- Researched examples of IDP best practices.
- Used information from our research and interviews to create a process diagram showing key ISOP inputs, processes, and outputs.

[4] Duke also plans to use ISOP in other state proceedings (e.g., North Carolina Carbon Plan).
[5] The Distributed Generation map is available at https://dukeenergy.maps.arcgis.com/apps/webappviewer/index.html?id=4f6d46d67a2f4023ba7aae0953baf66a.

- Reviewed the process diagram with ORS, Public Staff, and Duke Energy and incorporated their feedback into a final version.

While this report was prepared for the South Carolina ORS, the information contained herein may be useful to audiences in other states who are interested in IDP, including public utility commissions, state energy offices, other state agencies, utilities, and stakeholders.[6]

The remainder of this report discusses how to access the ISOP process diagram we created for this report, which clarifies ISOP's relationship to Duke Energy's other planning processes; observations about Duke Energy's ISOP from our interviews; a review of publicly available materials; and an assessment of ISOP based on best practices for integrated distribution planning. The report concludes with opportunities to improve the transparency of ISOP.

Readers can ask themselves the following questions as they review our process diagram and apply the information in this report to their jurisdiction:

- How is distribution system planning integrated with other planning processes undertaken by regulated utilities?
- How are grid modernization strategies and DERs addressed in distribution system plans today? What improvements can be made to better plan for future uncertainties and risks?
- How do planned or proposed grid modernization investments contribute to DER integration?
- What are the criteria and/or processes used to evaluate whether proposed distribution system investments are least cost and risk?
- Are there opportunities to improve stakeholder participation, increase data transparency, and clarify the role of stakeholder feedback in distribution system planning processes?
- When evaluating distribution system solutions, are all costs and benefits of non-wires alternatives included in the analysis?

1.2 Accessing the ISOP Process Diagram

This section discusses how to access and interpret the ISOP process diagram we created for this project and explains the relationship between Duke Energy's ISOP and its other planning processes.

NREL developed the ISOP process diagram in collaboration with Duke Energy, Berkeley Lab, and ORS to create a visual representation of the relationship between ISOP and other planning processes (e.g., Duke Energy's IRP, rate cases, and asset management). The diagram shows key inputs, processes, and outputs of ISOP (Figure 2; better viewed online at the link provided in Appendix A).

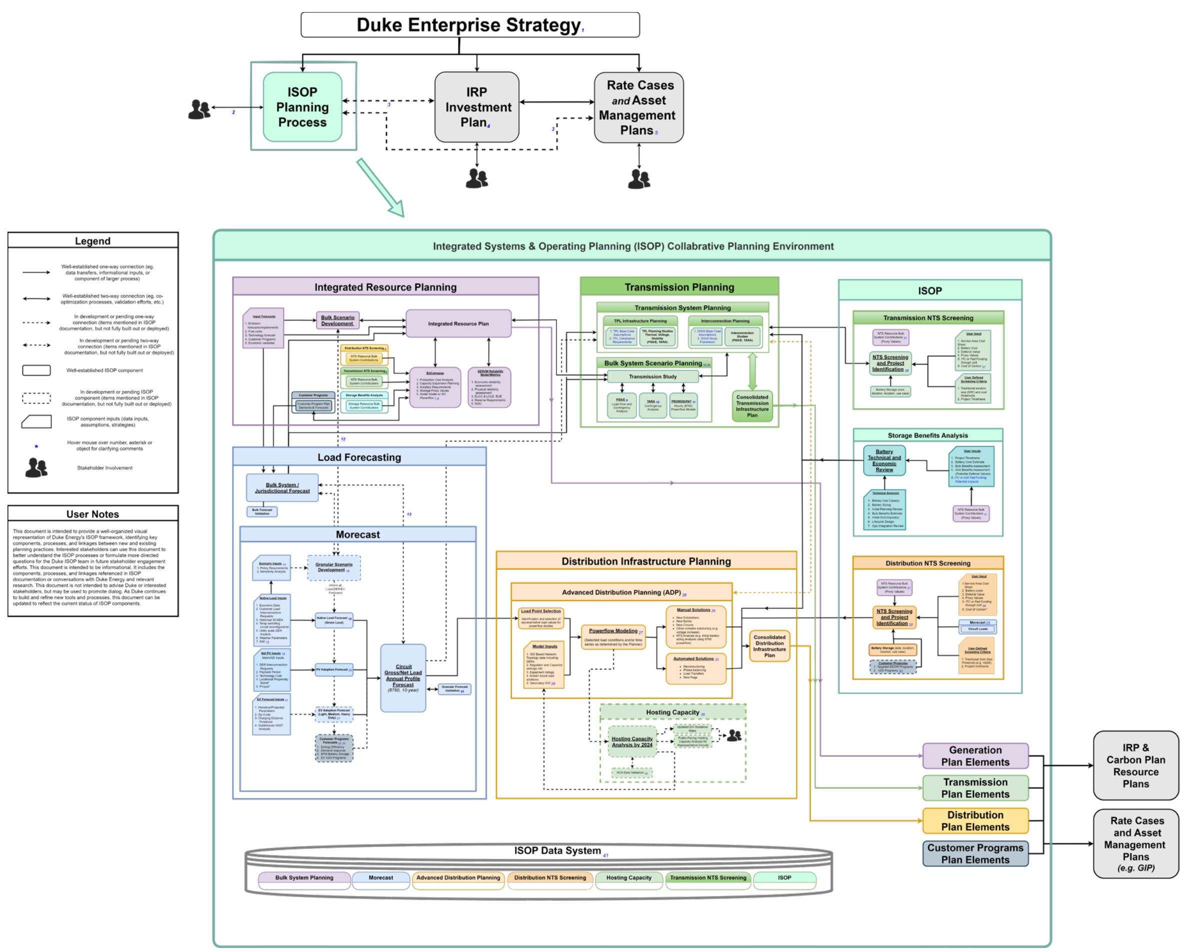
[6] Duke Energy does not explicitly refer to ISOP as IDP since it has broader objectives across the utility's business segments. However, many ISOP goals relate to distribution planning and align with common IDP goals.

Accessing the ISOP Process Diagram

The diagram was made in draw.io.[7] Users can access the fully functional online version by cutting and pasting the link in Appendix A into a browser. Use of the viewer is recommended because all footnotes can be seen by hovering over reference numbers with the user's mouse.

Solid lines are used for dependencies or components that are complete. Dashed lines and italics are used for connections or components that are pending or may warrant consideration. Hovering over "Tool Tips" shows complete footnotes in the diagram, which provide extra information. Each section of the diagram is color-coded (e.g., load forecasting is blue). Some sections contain a mix of colored, sometimes repeated components to minimize the number of connections and simplify the diagram.

Figure 2. Duke Energy ISOP process diagram (see Appendix B for footnotes)



Note: This figure is best viewed through the link provided in Appendix A.

[7] https://app.diagrams.net/.

2 Observations About Duke Energy's Integrated System and Operations Planning

This section of the report provides observations regarding six aspects of ISOP: Morecast, Advanced Distribution Planning and Distribution Non-Traditional Solution Screening, Integrated Resource Planning, Transmission Planning, Hosting Capacity, and the ISOP Data System.

2.1 Morecast

Morecast is a 10-year, hourly distribution system forecast at the circuit level describing the aggregate load at the beginning of the primary voltage feeder. The model was developed in-house by Duke Energy. Forecasts for load, electric vehicles (EVs), DER, and customer programs are used to build circuit-level net load forecasts.

DER and Load Forecasts (U.S. DOE 2020)

"System-level DER and load forecasts are primary inputs to both resource planning and distribution planning. These forecasts reflect macroeconomic trends, policy changes, retail rates, technology advancements, and diffusion patterns. The load forecasts are developed using long-term forecasts of aggregate consumer energy consumption (demand and load profiles) for a specific area (e.g., state, utility service area). This base load forecast is adjusted to reflect the net effects of customer adoption of distributed generation, storage, electric vehicles, and other load-modifying devices. Each DER component is layered onto the load forecast to reflect the net effect. The resulting aggregate net load forecast is used in an IRP analysis. System load and resource forecasts, inclusive of DER, reflect broad changes across a jurisdictional area and are not detailed to a specific location at the distribution system in an IRP. Distribution planning requires a more granular forecast that is derived from this system level forecast along with the incremental DER identified in an IRP." (p. 24-5)

The dependency between the Morecast and IRP load forecasting is under development. In conversations with the project team, Duke Energy shared that the IRP and transmission forecast is informed by Morecast but does not directly depend on it. Observations about the Morecast and load forecast relationship include the following:

- *Morecast incorporates some increased load from electrification.* Morecast accounts for electrification trends by incorporating third-party energy intensity forecasts into the load growth component of the forecast, separated by end use. In addition, as noted below, both light duty and medium/heavy duty electric vehicle forecasts predict increased charging load from public and at-home locations. Morecast may not reflect increased load from other emerging electrification trends. However, the use of scenario planning to explore electrification pathways is under investigation. Morecast produces a forecast at the feeder head (i.e., the beginning of the circuit, adjacent to the substation). For power flow purposes, it then allocates load to distribution transformers based on installed capacity. This is an imperfect approach that may not reflect increased loads from electrification of end uses that would occur in hotspots within the secondary distribution system. Growth from all loads, including electrification, may require distribution transformer expansion.

- *Inconsistencies can exist between the circuit level (Morecast) and bulk system forecasts if they reference different temperature/load assumptions and risk considerations.* In discussions with the project team, Duke Energy shared that their bulk system planning utilizes weather-normalized load forecasts and incorporates reserve margins for weather, operational risks, and load from customers that are not connected to the distribution system. T&D planning typically utilizes more demanding weather conditions and localized events to evaluate potential for unreliable operating conditions. Both forecasts use the same PV, customer programs, and energy efficiency forecasts aligned with the bulk grid forecast. According to Duke Energy, the full Morecast is not rolled up due to its circuit-level focus and the lack of other transmission-served customer loads which would introduce accumulated error when aggregated across the bulk system.
- *EV adoption is included in Morecast.* Morecast integrates the light duty, medium duty (MD) and heavy duty (HD) forecasts from the Vehicle Analytics and Simulation Tool (VAST) tool into its forecast by mapping the census-tract-level VAST forecasts to circuits. This covers residential at-home charging as well as workplace, public, and MD/HD. (Michael Rib, personal communication, June 2, 2023).[8]
- Current customer programs are accounted for in Morecast. The forecast includes incremental participation in almost all utility energy efficiency (UEE) programs (Michael Rib, personal communication, June 2, 2023).[9]
- *Duke Energy uses backcasting to validate its forecast.* Backcasting compares load forecasts with actual load after it has materialized. This should allow for continued discussion with regulators and stakeholders on forecast accuracy, how accuracy affects planning decisions, and opportunities to improve the forecast.

Several components of Morecast are in development or under evaluation:

- The inclusion of scenarios in Morecast is pending. Scenario-based analysis will be important given the increasing uncertainty of several important variables in distribution planning.
- Advanced Metering Infrastructure (AMI) integration into the native load forecast is under evaluation. AMI integration provides an opportunity to improve the native load forecast.
- Forecasts for new customer programs are in development. New forecast elements and additional integration are needed for emerging new forms of energy efficiency and demand response along with behind-the-meter (BTM) battery storage and EV vehicle-to-grid (V2G) programs.

[8] Additional information will be available in Duke Energy's 2023 IRP (to be filed in Docket No. 2023-10-E) and DEP's 2023 IRP (to be filed in Docket No. 2023-8-E).
[9] Additional information will be available in Duke Energy's 2023 IRP (to be filed in Docket No. 2023-10-E) and DEP's 2023 IRP (to be filed in Docket No. 2023-8-E).

Distribution Planning Load Forecasts (U.S DOE 2020)

"Distribution planning requires a closer examination of the potential changes to load and DERs at the level of a substation, feeder, and in some cases sections of a feeder. This involves developing a granular locational forecast as well as more detailed temporal forecasts. These locational forecasts incorporate information regarding specific new housing and commercial developments based on existing or anticipated customer service requests, DER adoption and use patterns, and other relevant information that will shape the forecast. System forecasts of DER adoption and use inform the development of more 'bottom-up' granular locational forecasts that are applicable to the specific distribution planning areas under assessment. The aggregate results are typically compared with system level projections; ideally, the granular distribution forecasts in aggregate comport with the system level forecasts." (p. 26)

2.2 Advanced Distribution Planning and Distribution Non-Traditional Solution Screening

Duke Energy's Advanced Distribution Planning (ADP) platform is a distribution power flow modeling toolset, incorporating system topology GIS data, forecasting outputs from Morecast, and Eaton's CYME power flow modeling software to conduct traditional planning studies while building capabilities for more detailed and automated analyses in the future. Duke Energy currently uses ADP to identify network constraints and automatically propose traditional distribution system solutions including reconductoring, phase balancing, load transfers, and new regulators. These automated solutions are applied only at locations downstream of the feeder substation and not at the substation. Because of their expense and complexity (e.g., planning a new circuit or substation), Duke Energy applies manual traditional solutions instead of ADP at the circuit (substation) level.

Non-traditional solutions – also known as non-wires alternatives (NWAs) or non-wires solutions (NWSs) – are resource options for meeting distribution system needs related to load growth, reliability, and resilience. Battery storage is currently the only non-traditional solution being modeled by Duke Energy in ADP for circuit-level capacity constraints (e.g., thermal thresholds of substation transformers, feeder breakers, conductors exiting the substation). According to Duke Energy, non-traditional solutions are likely to be less cost competitive than reconductoring solutions due to the latter's lower costs.

There are potential benefits in using ADP to screen non-traditional solutions. For example, ADP could allow a non-traditional solution to be evaluated on a longer time horizon and with more granularity than those traditionally modeled by planners (e.g., five-year circuit-level time horizons) to better capture added costs and benefits. Performing a power flow analysis of a non-traditional solution is also crucial in identifying locational impacts of the solution (e.g., local voltage rise, reverse power flow through protective devices, local equipment thermal constraints), which would not be revealed with a purely circuit-level analysis.

At this point, Duke Energy uses ADP to screen for potential storage projects to support peak shaving applications at the circuit level. The model allows planners to screen for storage opportunities to address overloads observed at any time in the 10-year modeling period. Duke Energy assumes that batteries have a 10-year lifespan, and thus a 10-year modeling period maximizes the battery's benefit-to-cost ratio.

Once a candidate opportunity is identified in the screening process, the planner then reviews it in more detail to determine what overloads may occur over time to select an appropriately sized battery for the next step in the non-traditional solution comparison process. This review includes a detailed technical analysis to determine the resource capacity requirements, as well as an economic comparison of the non-traditional solution versus the traditional solution. The technical analysis reveals the targeted circuit overloads, the number of years the traditional solution may be deferred based on the forecast, and the subsequent size of the battery required. The economic analysis then compares the value of deferring the traditional solution's cost with the battery, along with an estimated value of the operational benefits associated with installing the battery. There is typically also a quick check to see if the circuit and/or substation transformer bank are in a constrained area that might offer additional relief at the transmission level. To determine the battery's operational benefits, the ISOP and planning teams review the connectivity of the specific proposed battery and assess its ability to support system capacity needs, deliver energy arbitrage value, and provide ancillary services. Each of these operational values, which are termed "proxy values" for bulk system benefits, are based on EnCompass modeling runs and analysis referencing the regulatory resource plans in the IRP, and consequently these values are both internally consistent and aligned with the IRP. If results of the above analysis are reasonable and directionally correct, they are reviewed to determine if the competitiveness of the results warrants taking the study to a more detailed level (Duke 2023).

However, Duke faces several challenges in integrating and identifying non-traditional solutions in the ADP, as this is inherently a very complex modeling challenge. First, Duke's ADP has a 10-year forward-looking horizon, and their non-traditional solution screening only identifies projects that can defer a system need for a minimum of 10 years (Duke 2023). Second, as mentioned in Section 2.1, Morecast has circuit-level or coarser spatial resolution. These circuit-level forecasts must be spatially allocated across a feeder (also known as "downscaling") to identify specific locational impacts of a proposed solution. This load allocation process currently relies on algorithms from the CYME modeling software within ADP, which are often based on high-level data like transformer nameplate ratings, monthly customer energy consumption from a metering database, or customer counts on transformers. In the absence of finer-resolution forecasts, this allocation process can introduce uncertainty and potentially misrepresent local impacts of a non-traditional solution.

There are several potential improvements for Duke Energy's non-traditional solution screening process:

- Ideally, non-traditional solutions would be fully integrated into a capacity expansion optimization model. However, this could prove computationally challenging and not achievable with the planning models that Duke Energy currently has in use. Developing an iterative process to converge towards a portfolio of non-traditional solutions would produce more robust results than a single-stage screening process and better approximate the outcome of an optimization process. Currently, proxy values are calculated using Encompass.
- Duke Energy is currently studying only batteries in their non-traditional solution analysis. During our interviews, Duke Energy expressed a desire to characterize and model efficiency, demand response, and other DERs as non-traditional solutions for capacity, reliability, and resilience

benefits. As noted above, in interviews Duke Energy also shared that they are beginning to evaluate customer programs as non-traditional solutions to avoid capacity upgrades.

- The value stack for batteries in Duke Energy's non-traditional solutions analysis is currently limited to grid deferral value and bulk system benefits that address specific circuit issues (Duke Energy 2023). However, batteries may bring several additional benefits, such as local reliability and resilience enhancement. Accounting for these additional value streams may improve the non-traditional solution screening outcomes for batteries.
- Managed EV charging is not currently included as a non-traditional solution, but Duke Energy shared that they will evaluate managed charging as part of their forthcoming vehicle-to-grid pilot program to determine its applicability as a non-traditional solution.
- Duke Energy used four primary screening metrics in their 2021-2022 non-traditional solution planning cycle: project cost, in-service date, whether the traditional solution already had significant existing commitments or expenditures, and the ability to defer a traditional investment for 10 years. To date, the company's non-traditional solution screening process has not identified any cost-effective non-traditional solution projects, which is largely in line with other utility findings today.[10] Duke Energy noted that an investment tax credit (ITC), federal funding, and/or carbon cost could change the value proposition of non-traditional solutions.

2.3 Integrated Resource Planning

Duke Energy's IRP is a 15-year roadmap, filed every three years with an annual update, to identify future energy and demand requirements for their fleet of generators (DEP 2022, DEC 2022). Duke Energy uses a common approach in their IRP whereby generation needs are estimated through a combination of scenario-driven load forecasting and contingencies.

Integrated Resource Planning (U.S. DOE 2020)

"IRPs are used to identify the incremental generation and demand-side management resources required to meet changes in energy demand and resource availability over a long duration, often 10–20 years. Long-term, system-level, net-load forecasts are a key input to an IRP as discussed below. These forecasts include customer adoption of DER to create a baseline for determining incremental resource needs. An IRP also addresses contributing factors that impact electricity supply and delivery, including renewable portfolio standards, resilience and reliability objectives, and DER (including energy efficiency) policies at both federal and state levels. Resource plans increasingly include identification of additional distributed generation, storage, and demand management and energy efficiency programs needed to contribute to overall resource needs for energy, capacity, and ancillary services. These planned incremental distributed resources are combined with consumer DER adoption forecasts to inform distribution planning." (p. 24)

ISOP has both established and pending integrations with the company's IRP and its distribution planning. As is typical for resource adequacy assessments, Duke Energy uses their bulk system forecasts to create

[10] Examples of successful non-wires alternative projects in New York, California, and Michigan are discussed in Schwartz and Frick (2022), Frick et al. (2021), DTE (2021) and PG&E (2022).

different scenarios for their generation resource adequacy and transmission planning models. As mentioned in Section 2.1, the company's IRP and transmission planning forecasts are informed by common underlying elements and aligned with Morecast, but do not directly depend on it.

Duke Energy is also implementing some best practices. During discussions with the project team, Duke Energy confirmed their approach to considering contributions from DERs— the resources are evaluated to determine their effective load carrying capability (ELCC), which is aggregated up to the system level.

Duke Energy also shared that they anticipate non-traditional solutions will be integrated from the distribution and transmission levels up to the IRP resource level to appropriately recognize their contributions at the system level.

2.4 Transmission Planning

The electric power transmission system moves "bulk energy products from where they are produced or generated to distribution lines that carry the energy products to consumers."[11] Transmission planners are responsible for developing long-term plans to maintain the reliability of the bulk power system in the geographical area they oversee. As part of that, planners simulate performance of the system at a few key times, typically the summer and winter peak hours as well as a spring light-load hour, to determine if infrastructure changes are needed. Planners use these simulations to assess whether the system will meet required performance thresholds after a fault or loss of a larger generator or transmission line (Faris et al. 2020). Duke Energy's IRP and transmission planning functions are separate organizations, but they do collaborate. For example, in the most recent IRP update the transmission planning team leveraged the IRP resource requirements forecast and interconnection queue history to develop and submit requests for the Red Zone Expansion Plan, which contains proactive transmission projects shown to have reliability and resiliency benefits for customers and to alleviate some of the constraints limiting renewables additions to the system (Michael Rib, personal communication, June 2, 2023).

In accordance with FERC Order Nos. 890 and 1000, Duke Energy utilizes the North Carolina Transmission Planning Collaborative (NCTPC) as a local transmission planning process.[12] NCTPC participants currently include the Duke Energy Companies, North Carolina Electric Membership Corporation, and ElectriCities of North Carolina. These participants and other stakeholders (including South Carolina utilities and wholesale customers) may submit requests for local transmission planning studies and recommend alternative solutions to identified local transmission projects through the NCTPC Transmission Advisory Group. The NCTPC process occurs annually and ultimately results in a single Local Transmission Plan that "includes reliability, economic, and public policy considerations while appropriately balancing costs, benefits, and risks associated with the use of transmission, generation, and demand-side resources" (NCTPC 2023). The NCTPC is an integral part of the transmission process for the local transmission planning of DEC and DEP's South Carolina and North Carolina networked transmission systems. South Carolina utilities and wholesale customers may participate as stakeholders in the NCTPC as well as the Carolinas Transmission Coordination Arrangement (CTCA). There are also informal discussions about

[11] FERC Glossary. https://www.ferc.gov/industries-data/resources/public-reference-room/ferc-glossary.
[12] Joint Open Access Transmission Tariff of Duke Energy Carolinas, LLC, Duke Energy Florida, LLC, and Duke Energy Progress, LLC Attachment N-1, "Transmission Planning Process (Progress Zone and Duke Zone)."

potentially including South Carolina wholesale customers as voting members in the NCTPC and renaming the NCTPC to the Carolinas Transmission Expansion Planning group (CTEP).

In transmission planning, Duke Energy follows standard industry practice by using common tools such as PSS/E and TARA. These tools model the dynamic behavior of transmission networks in response to contingencies and the ability of the transmission network to recover to an operating point within standardized limits. Currently, Duke Energy does not include detailed transmission power flow modeling in its IRP process. In its ISOP, transmission planning, and IRP, Duke Energy has begun using DC power flow modeling for NTS screening and to support resource siting to better integrate generation and transmission planning (Michael Rib, personal communication, June 2, 2023).[13] A DC optimal power flow "nodal" model can be used to assist with the capacity expansion process and help ensure that suggestions from the IRP are robust when considering transmission constraints, thereby facilitating the transmission planning process.

2.5 Hosting Capacity

Duke Energy currently does not produce a hosting capacity analysis (HCA), but instead produces a "Distributed Generation Locational Guidance Map" depicting mainline segments of the distribution system (up to the first line voltage regulator) at resolutions of one square mile.[14] The pixels are color-coded to indicate high-level system constraints, including both the installed and queued distributed generation systems above a 250-kW nameplate. System constraints considered in this map are limited to the thermal limits of the substation transformer bank and feeder exit. This map is produced as a snapshot in time and was last updated in February 2022. Duke Energy intends to refresh the map on an annual basis.

Hosting Capacity Analysis (U.S. DOE 2020)

"Hosting Capacity Analysis estimates the amount of DER that can be accommodated, regardless of location, on a sub-transmission distribution system, substation, or a feeder without violating power quality, thermal loading, or protection requirements. The distribution planning analysis evaluates these three dimensions against distribution planning criteria. The evaluation of equipment capacity and operational flexibility is no different than the process described above for traditional one-way flow of power to serve load except that the hourly loading and DER output patterns may be different." (p. 36)

Duke Energy plans to develop a more detailed HCA for its Carolinas utilities as part of ISOP using time series power flow models from the ADP to perform hosting capacity studies. This new process will be released in 2024 in accordance with current regulatory agreements and includes a robust stakeholder engagement process to ensure that interested parties are able to influence when and what HCA results will be shared.

[13] Additional information will be available in Duke Energy's 2023 IRP (to be filed in Docket No. 2023-10-E) and DEP's 2023 IRP (to be filed in Docket No. 2023-8-E).
[14] https://dukeenergy.maps.arcgis.com/apps/webappviewer/index.html?id=4f6d46d67a2f4023ba7aae0953baf66a.

Updates to the HCA can incorporate best practices on maintaining accurate HCA maps.[15] Examples include:

- A well-documented, repeatable, transparent process with opportunities for feedback and error identification.
- The value of scripted batch processes with actual (not estimated) customer data.
- For increased transparency, Duke can add stakeholder engagement to their HCA process.

Accurate HCA can provide information to developers about the quantity of DERs that could potentially be managed on a given feeder. The utility can couple HCA with load and DER forecasting to identify feeders that are likely to see DER growth and proactively consider upgrades. Proactive planning allows the utility to provide developers with clear information on what grid services are needed and appropriate incentive levels (Schwartz and Frick 2022).

2.6 ISOP Data System

The ISOP Data System is a collection of databases. An important component of the Data System is Duke Energy's "grid map data," which refers to various investments Duke Energy has made in grid connectivity, data quality, configuration data, system capabilities, and operations history to support ISOP. Together, the ISOP Data System and grid map data allow Duke Energy engineers to easily access data for different forms of analysis. While this may not seem noteworthy, many distribution utilities have data in a collection of "silos" that make efficiently sharing data between departments and modeling systems challenging.

Duke Energy's initial focus for the ISOP Data System has been operating history, grid map data supporting the Morecast, API development, and integration with new ADP toolsets. New functionality continues to be developed to meet additional new applications as ISOP matures. Generation and transmission data integration within ISOP will be developed as needs surface. AMI is not currently integrated into the ISOP Data System. As more granular forecast options are explored for Morecast, the Data System functionality will be reexamined, including the potential to include AMI-sourced data that may be beneficial in modeling systems downstream of Morecast.

3 Assessing ISOP Based on Best Practices for Integrated Distribution Planning Processes

Typically, state law, or utility regulators as authorized by state law, establish objectives and requirements for an IDP process to achieve a variety of public interest goals. For example, the Minnesota Public Utilities Commission (PUC) established the following principles and objectives for IDP in that state (Minnesota PUC 2018):

- "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 and services, with opportunities for adoption of new distributed technologies.

[15] For example, see https://www.nrel.gov/docs/fy22osti/81811.pdf.

- Ensure optimized use of electricity grid assets and resources to minimize total system costs."

In Colorado, the Public Utilities Commission identified that the purpose of a distribution system plan is "to conduct a transparent review of utility investments in the distribution grid to ensure that they cost-effectively support grid adequacy, reliability, and resilience while simultaneously supporting diversification of energy supply through DERs, expanding the utilization of NWA that reduce the need for conventional distribution grid investment, and preparing for new expectations upon the system" (CO PUC 2020, p. 6).[16]

This section uses four guiding principles of a robust IDP framework to review Duke Energy's ISOP, based on our review of best practices across the country.[17] Such a framework should be:

1. Objective
2. Integrated
3. Transparent
4. Measurable

Importance of Planning (U.S. DOE 2020)

"Experience across the United States has highlighted the need to proactively address changes to distribution planning, to optimize distribution operational and capital expenditures, and inform DER and microgrid development…IDP provides a systematic approach to satisfy customer service expectations and the specific grid planning and design objectives related to reliability and resilience, safety and operational efficiency, and DER and microgrid integration and utilization…" (p. 4)

We define each principle, summarize how ISOP addresses it, and describe how two utilities – Xcel Energy in Minnesota and DTE Energy in Michigan – addresses each principle in their respective IDP (Alvarez and Stephens 2019, Volkmann 2019). These utilities were selected as industry examples because both have regularly filed and publicly available IDP reports, and their IDP processes illustrate the four guiding principles: objective, integrated, transparent, and measurable.

3.1 Objective

Being objective in grid planning investment decisions means being impartial to all potential solutions to grid needs. That includes all commercially available technologies; customer-sited and third-party solutions, where suitable, as well as utility solutions; and multiple acquisition strategies, including programs, procurement, and pricing. Such impartiality increases the likelihood that the largest benefits relative to costs are delivered. Impartial decision-making may be achieved by prioritizing investments based on their abilities to achieve well-defined *objectives* (e.g., resilience, reliability, affordability). Objectives may be established through state policy via legislation or by state regulators as part of a rulemaking or other regulatory process. The U.S. Department of Energy's Modern Distribution Grid

[16] *See also* Colo. Rev. Stat. § 40-2-132 (requiring utilities to file a distribution system plan and the Colorado Public Utilities Commission to promulgate rules regarding such a plan).
[17] See Chew and Cutler (2020), Alvarez, Stephens and O'Connell (2019), and Schwartz and Frick (2022).

guidebook provides an objective-driven framework for improving objectivity in grid planning investments (see text box below).

Key Concepts for DSP Process (U.S. DOE 2020)

The U.S. Department of Energy's Modern Distribution Grid guidebook presents four key concepts to consider within modern-day distribution system planning processes:

1. First, **well-articulated objectives** that convey scope and timing requirements are essential to guide the planning process. It becomes important in grid modernization plans to present a logic that links a proposed technology deployment roadmap back to stated objectives.
2. Second, grid modernization planning is one aspect of a **larger integrated distribution planning process**, in which foundational investments are required to enable advanced grid capabilities.
3. Third, undertaking a **system engineering approach** to determine functional and structural needs in line with stated objectives should inform technology choices. The Guidebook applies principles from grid architecture to govern objectives-based planning.
4. Fourth, technology implementation plans can adopt **proportional deployment strategies** (i.e., they can provide advanced grid capabilities where most needed first and/or initially improve grid function with simpler solutions, followed by more sophisticated approaches at a later time, as needed). The stratagem, termed “walk-jog-run,” is useful to consider when affordability constraints, modifications to utility processes, or technology readiness may dictate the pace of grid modernization. (p. 4)

Duke Energy Activities

Since South Carolina law does not require the development of IDP, and because the Public Service Commission of South Carolina has not established IDP requirements, Duke Energy does not have explicit state-established objectives for IDP-related elements of the ISOP process. It is unclear how ISOP prioritizes investments related to state objectives expressed in legislation or in PSCSC regulations and orders in related matters.

Utility Examples

Xcel Energy’s IDP for Minnesota provides several good examples of objective-driven distribution planning. First, prior to filing its first IDP in 2018, the PUC provided clear planning principles and objectives to guide the IDP’s development (Xcel Energy 2018). Second, Xcel Energy reiterated throughout the IDP document its strategic business priorities – namely, to lead the clean energy transition, enhance the customer experience, and keep bills low – as well as the alignment of its proposed initiatives. In addition to its overarching priorities, Xcel Energy defined three specific objectives: addressing aging assets, enabling a clean energy transition, and modernizing the grid. The company’s near-term goals target these objectives, in concert with the PUC’s principles and planning objectives. As part of the company’s Grid Modernization Roadmap, Xcel Energy drew guidance from the U.S. DOE’s Modern Distribution Grid series (DSPx). The utility defines each of its foundational core components, along with their implementation status (Figure 3); these provide the foundation for more advanced applications in the future (Xcel Energy 2021).

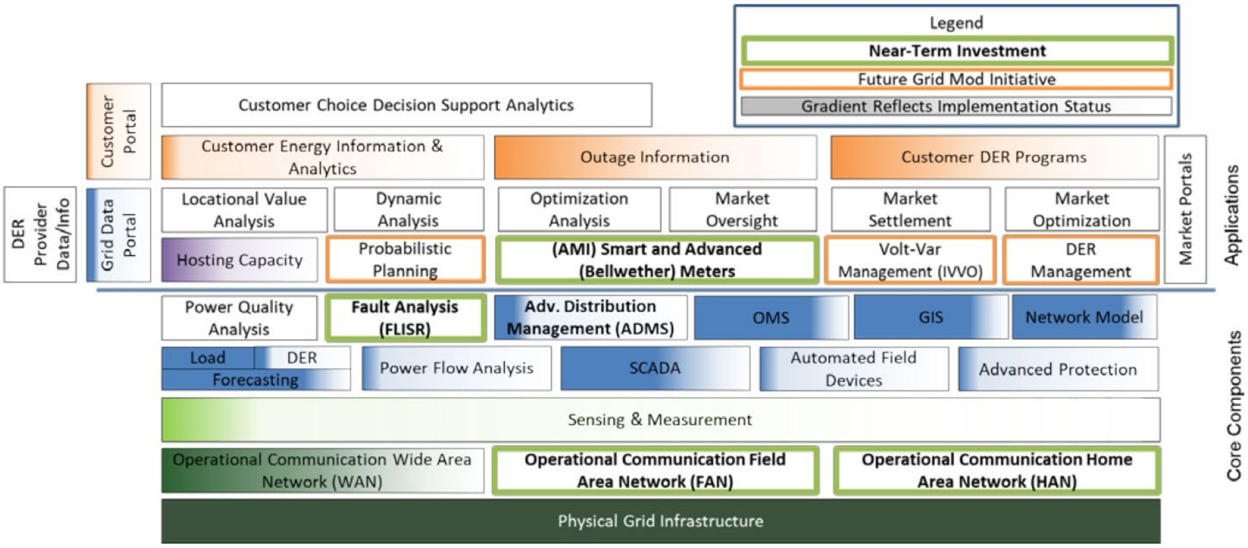


Figure 3. Xcel Energy (Minnesota) Advanced Grid Intelligence and Security (AGIS): Core components, applications, and estimated implementation status (Xcel 2021)

DTE builds on DOE's IDP framework in a similar fashion. The Michigan Public Service Commission (PSC) initially set out several objectives for IDP: safety, reliability and resiliency, cost-effectiveness and affordability, and accessibility (Michigan PSC 2017). In response, DTE defined five planning objectives to prioritize investments and evaluate alternatives: safe, affordable, reliable and resilient, customer accessibility and community focus, and clean. In 2019, these objectives expanded to include customer engagement, integrating new technologies, and optimizing grid performance and investments after the launch of the Michigan Power Grid Collaboration in partnership with the Michigan Governor's Office.[18] DTE uses a "global prioritization model" to evaluate grid investments that align with the "best-fit, most reasonable-cost" evaluation method described in DOE's guidebook. The objective-driven DOE framework also helped DTE identify that its 2021 Distribution Grid Plan did not adequately address its "clean" and "customer accessibility and community focus" objectives, and future steps were discussed to address this shortcoming. These steps include an update of the company's global prioritization model to include metrics produced by their energy justice screening tool. Lastly, in recognition that customer expectations are growing more complex, DTE developed three scenarios to guide future planning, focusing on high electrification of transport, buildings, and industry; increased frequency and intensity of catastrophic storms; and high DER adoption (DTE 2021).

3.2 Integrated

Utility planning is typically siloed between generation, transmission, and distribution departments and further siloed within the internal processes of those departments (NARUC 2018, Taft 2019). Modeling capabilities, assumptions, and data availability often vary between and within departments. For example, the asset management, capacity planning, area planning, and operations departments within a distribution utility may propose investments that are not aligned with each other or with state and utility objectives.

[18] https://www.michigan.gov/mpsc/commission/workgroups/mi-power-grid.

NARUC-NASEO Task Force on Comprehensive Electricity System Planning[19]

In 2018, the National Association of Regulatory Utility Commissioners (NARUC) and the National Association of State Energy Officials (NASEO) began a two-year effort to develop new approaches to better align resource, transmission, and distribution system planning processes. The Task Force comprised 15 states that were representative of U.S. geography, electricity market models, planning approaches, and state goals. The effort developed tools, roadmaps, a document library and other resources for all NARUC and NASEO members to adapt and refine for use in their respective states.

The Task Force created several roadmaps that represent different utility and market structures and articulate approaches to achieving six goals:

- Establishing clear expectations
- Identifying better approaches for stakeholder engagement
- Encouraging cost-effective integration of DERs
- Coordinating data, assumptions, and modeling scenarios
- Expanding on the fundamentals of distribution system planning
- Acknowledging the contribution of efficiency as a resource

The Turquoise Roadmap most closely aligns with Duke Energy's ISOP because it represents a state that has investor-owned utilities who own generation assets, is located outside of an RTO/ISO market, and is seeking to better align distribution, resource, and transmission planning processes. The Turquoise Roadmap identified an idealized process for comprehensive electricity planning.

Duke Energy Activities

Duke Energy aspires to use ISOP to support joint generation, transmission, and distribution planning decisions. Through collaborative efforts that include ISOP with its other planning teams, Duke Energy is working toward refinements and upgrades of integrated utility control systems (e.g., energy management systems, distribution management system, ADMS) that integrate both distributed resources and customer programs into real-time systems that will optimize performance and long-term planning frameworks for resource technical evaluations and comparative valuation assessments. Duke Energy's distribution and transmission planning functions interact on forecasts, coordinated planning, interconnection studies, and key grid projects. These interactions are growing more robust in support of some of the new initiatives being introduced in ISOP. The ISOP team has also made considerable progress in aligning and integrating grid and distributed resource planning data through grid data quality efforts and creation of the ISOP Data System, as noted previously. The current integration of IRP, transmission planning, and ADP is a step in the right direction. Duke Energy intends to continue developing and refining these tools and processes in a way that improves comparison of investment alternatives, including non-traditional solutions, in these domains. This is an emerging challenge for integrated processes like ISOP, and one for which there is no best practice available in the industry.

[19] https://www.naruc.org/taskforce/.

Utility Examples

The Minnesota PUC's decision on Xcel Energy's most recent IDP filing requires discussion of how the distribution system planning is coordinated with the integrated resource plan (including how it informs and is informed by the IRP), and planned modifications or planned changes to the existing process to improve coordination and integration between the two plans, including:

a. "Setting the forecasts for distributed energy resources consistently in its resource plan and its Integrated Distribution Plan.
b. Conducting advanced forecasting to better project the levels of distributed energy resource deployment at a feeder level, using Xcel's advanced planning tool.
c. Proactively planning investments in hosting capacity and other necessary system capacity to allow distributed generation and electric vehicle additions consistent with the forecast for distributed energy resources.
d. Improving non-wires alternatives analysis, including market solicitations for deferral opportunities to make sure Xcel can take advantage of distributed energy resources to address discrete distribution system costs.
e. Planning for aggregated distributed energy resources to provide system value including energy/capacity during peak hours."[20]

Xcel Energy points toward "fundamental differences" in IDP and IRP processes that make integration a challenge in the near term. While IRPs focus largely on the size, type, and timing of new resources, distribution planning requires a substantial focus on the location of resources, either at the feeder or a more granular level (Xcel 2021). In addition, many of the issues addressed on the distribution system can be more immediate in nature (e.g., thermal overloads, power quality violations, frequent outages, DER interconnections) compared to the longer-term planning horizons used for bulk system resource additions. At the same time, the planning horizon for distribution substations is sizable, and long-term distribution planning is needed for core investments in grid modernization (e.g., outage management system, distribution management system, SCADA) that provide a platform for a variety of applications (e.g., DER management, volt/VAR management, advanced utility analytics) that can be added over time.

Load forecasting is an example where Xcel Energy is focusing on integration across planning processes. The utility recently began implementing Integral Analytics' spatial load forecasting tool, LoadSEER. Like Duke Energy's Morecast, LoadSEER provides capabilities for integrating data from multiple sources beyond what has been used historically (e.g., SCADA and conventional customer usage data). LoadSEER produces forecasts with the same hourly granularity as bulk system forecasts, improving accessibility to forecasts across the utility's planning groups and exporting forecasts directly to load-flow software like Synergi Electric. LoadSEER can probabilistically estimate load growth across a given distribution feeder to provide better understanding of locational and temporal impacts.[21]

The distribution and bulk system planning groups at Xcel Energy meet at least twice a year. The distribution team provides updated forecasts as inputs for transmission planning studies, although this

[20] Minnesota PUC (2021), p.11.
[21] In the authors' experience, utilities value LoadSEER's spatial forecasting capability (i.e., forecasting downstream of circuit breakers), but due to high data requirements they have not yet implemented that functionality.

remains a mostly manual process. In addition, the same system-level DER and EV forecasts are used in all of their planning processes (Xcel 2021).

DTE is also building integration among planning processes. Team building between IRP and distribution teams is encouraged and common planning objectives are identified as a joint team effort. For example, the joint team worked together to implement conservation voltage reduction and Volt/VAR Optimization (VVO) as a generation resource alternative and to develop systemwide capacity values. Likewise, DER load forecasting is an area of continued collaboration. The IRP and distribution teams use consistent assumptions and forecasting data sets (DTE 2021).

A key component of both Xcel Energy's and DTE's IDP efforts is implementing Advanced Distribution Management System (ADMS) software. Such software can be a powerful tool in integrating into a single system model and user interface multiple grid applications like Fault Location Isolation and Service Restoration, VVO, AMI, Distributed Energy Resource Management Systems (DERMS), Grid Management Systems, Energy Management Systems, Network Management Systems, and Outage Management Systems. Integrating these applications provides a complete and integrated view of multiple utility systems and helps ensure they operate synergistically (Xcel 2021, DTE 2021).

3.3 Transparent

Transparency in grid planning means that utilities publicly file detailed planning documentation; utility regulators have insight into the utility's strategies and planned investments in the short- and long-term; and stakeholders and the public have access to and an understanding of planning processes, assumptions, and decision frameworks that lead to utility investment decisions, and are given adequate opportunities for input, review and comment.

Stakeholder engagement has been part of long-term utility planning (i.e., IRP) for decades. When well designed, the benefits of stakeholder engagement are "better information, decreased risk, and smarter solutions" (De Martini et al. 2016). However, it is relatively nascent for distribution system planning. Yet people/communities are closest to distribution infrastructure, and that's where most outages occur. Stakeholder engagement can serve many purposes:

- Provide a venue for open discussion
- Improve the quality of regulatory proceedings and their outcomes
- Develop solutions with broad support
- Build trust among parties

Duke Energy Activities

The Public Service Commission of South Carolina does not require regulated electric utilities to file an integrated distribution plan. Duke Energy files grid modernization and investment details in its Grid Improvement Plans and rate case filings in South Carolina. The reporting frequency of these filings is three years, as required by regulators and requested by stakeholders. Duke Energy currently provides transparency in the ISOP process through both third-party- and company-moderated stakeholder engagement events with Q&A, publicly available literature, web resources, and initiatives to build out tools that inform interested stakeholders. Duke Energy is also using ISOP events to provide stakeholders with details on data sources, modeling timeframes and resolutions, tools/software used, and areas where further improvements are planned. Duke Energy's efforts allow stakeholders a more comprehensive view of investment decisions, a picture of planning processes that were once kept confidential, and the opportunity to critique practices.

Duke Energy is providing stakeholders with insight and input on ISOP's developing processes. Details related to non-traditional screening and project evaluations have been shared and reviewed in sessions with stakeholders who have expressed interest. There are active engagements related to grid hosting capacity development and the Climate Risk and Resilience studies that are underway. The company will be embarking on a more formal stakeholder engagement and detailed review of the non-traditional solutions process and results based on a recent regulatory agreement in South Carolina (South Carolina Public Service Commission 2023). With inclusion of additional ISOP elements in future IRPs, there will be further opportunity to engage and share ISOP information with regulators and stakeholders.

Utility Examples

The Minnesota and Michigan regulatory commissions require regulated utilities to regularly file long-term (longer than 10-year) distribution plans with revised planning and investment strategies, as needs and objectives evolve. Requirements include stakeholder engagement.

The Minnesota PUC required Xcel Energy to file its first IDP in 2018 and annually thereafter (revised to bi-annually after the 2019 IDP). Each plan must provide updated details on such components as the current state of its distribution system, budgeted expenditures, DER forecasts, hosting capacity, planning practices, grid needs assessment, non-wires alternatives considered, the changing planning landscape, grid modernization strategy, and status of advanced grid initiatives. In a constantly evolving landscape with significant uncertainty, these regular-interval revisions can provide a better understanding of utility plans and timelines while also allowing stakeholders to hold the utility accountable as timelines progress. Figure 4 shows a roadmap of Xcel Energy's proposed investments (Xcel 2021).

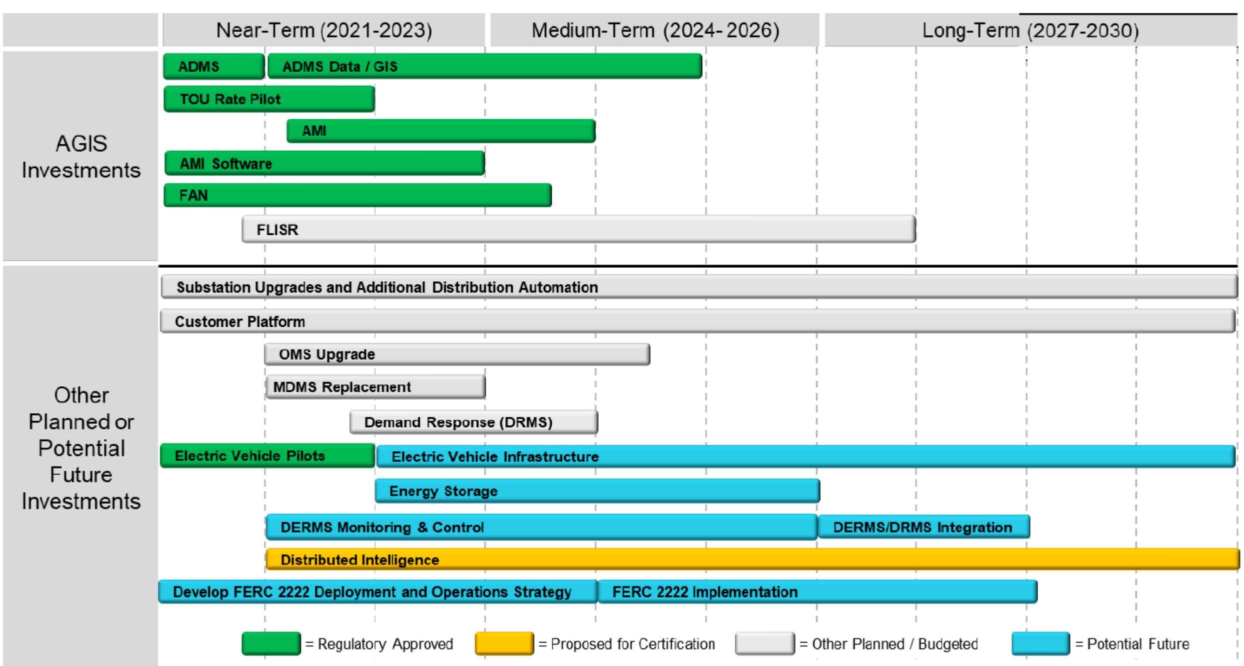


Figure 4. Xcel Energy (Minnesota) Distribution Investment Roadmap (Xcel 2021)

Xcel Energy is required to hold at least one stakeholder engagement meeting as part of its IDP process (Minnesota PUC 2018). For its 2021 IDP, the company held two virtual stakeholder workshops focusing on NWA analysis, where stakeholders could provide feedback on its practices. Part of this feedback process was a “homework assignment” where participants could suggest quantifiable benefits and costs for NWAs and provide guidance on integrating them into Xcel Energy’s future analyses. In the second NWA workshop, Xcel reviewed the categories of stacked benefits and how they could be valued in the future. As a result of this stakeholder input, the utility developed an improved NWA methodology to use in the future.

As required by state law, Xcel Energy conducts HCA to identify interconnection points for small-scale distributed generation and system upgrades to support development of these resources. The PUC requires such analysis for new solar installations of 1 MW or less. The company uses EPRI’s DRIVE tool for the analysis and prepares a heat map visual with additional pop-up data to guide developers. The company is moving from annual to quarterly HCA updates. In addition to hosting capacity maps, the utility provides a breakdown of its cost-benefit analysis for new grid investments. For example, Xcel Energy’s 2021 IDP provided example calculations for its Distributed Intelligence and Resilient Minneapolis Project initiatives (Xcel 2021).

The Michigan PSC required DTE to file its first distribution system plan in 2018 and every five years thereafter (Michigan PSC 2018). DTE’s latest (2021) five-year investment plan includes a 10- to 15-year vision with a technology roadmap that is developed using a global prioritization model (discussed in Section 3.1). The company is implementing technologies outlined in its roadmap in an iterative manner, such as building out an ADMS in phases and developing a DER Estimator tool to generate DER profiles for NWA screens. The screens currently work only with “Energy Waste Reduction” (energy efficiency) and demand response programs but will be extended to include energy storage, solar PV, managed EV charging, and microgrids in the future. Similar to Duke Energy, DTE is in the early stages of an HCA tool. It plans to start with high-level “go/no-go” assessments and transition to more detailed HCA using tools like EPRI’s DRIVE software. Over time, the company plans to provide regular updates to its HCA maps and integrate detailed findings from other studies and interconnection processes (DTE 2021).

The Michigan PSC supports strong stakeholder engagement in distribution planning proceedings,[22] and ongoing, iterative, and bi-directional stakeholder engagement is a fundamental component of DTE’s planning process. For its 2021 IDP, the utility hosted a series of focus groups discussing current perceptions of the company and soliciting reactions to grid modernization benefits. The focus groups engaged residential and commercial customers and influential community leaders. In addition, feedback from stakeholders with technical expertise was solicited through three webinars and 10 technical discussions (DTE 2021).

3.4 Measurable

It is increasingly important that utilities use quantifiable metrics to identify realized benefits. A simple example is a 10% reduction in SAIDI (System Average Interruption Duration Index) as a result of an

[22] For example, in a 2020 order, the Commission directed three investor-owned utilities in the state to share draft distribution plans with stakeholders prior to filing them with the Commission (Michigan PSC 2020). Commission Staff also holds workshops.

advanced tree-trimming initiative (IEEE 2012).[23] In some cases, however, new metrics may be needed to identify new types of benefits that may be more difficult to quantify (e.g., community-level benefits from local grid projects, energy equity, and justice).

Duke Energy Activities

Within the ISOP framework and available documentation, Duke Energy does not include metrics that can be used to measure the predicted or realized success of a given ISOP investment. To date, ISOP development has been focused on building systems and processes that provide more granular detail and visibility into planning needs and the comparisons and valuations that are typically used for least-cost planning studies; and to improve assessments for other planning processes where more of the company's metric-driven analysis is performed. As ISOP continues to develop, the need for new planning metrics will likely be discovered and developed.

Utility Examples

Xcel Energy's 2021 IDP provides an example of measuring the costs and benefits of certain IDP applications. The company explored the predicted costs and benefits of AMI and Distributed Intelligence (DI) capabilities (Figure 5). DI refers to the data collection and computing capabilities that AMI offers. The IDP outlines multiple customer-facing and grid-facing use cases for the technology and provides a breakdown of associated capital and operation and maintenance (O&M) expenses. Xcel Energy calculated an estimated bill impact for the average residential customer (+$0.31 per month in 2026) and a ratio of quantifiable benefits to costs of 0.93. The benefit/cost ratio indicates that the costs to implement DI outweigh the potential benefits. The utility acknowledges that this calculation does not consider several benefits that are more difficult to estimate, and benefits would likely improve with additional use cases (Xcel 2021).

	Total
Benefits	**40**
O&M Benefits	0
Other Benefits	40
CAP Benefits	0
Costs	(43)
O&M Expense	(26)
Change in Revenue Requirements	(17)
Benefit/Cost Ratio	**0.93**

Figure 5. Xcel Energy (Minnesota) Distributed Intelligence Foundational Capabilities and Cost-Benefit Analysis for Initial Use Cases (Net Present Value in Millions) (Xcel 2021)

DTE's IDP also demonstrates measurable improvements for planned utility investments. For example, the company reports that circuits in its new "Enhanced Tree Trimming Program" have, on average, 60% fewer outages and shorter outage durations. In areas where tree trimming and infrastructure updates are being made as part of DTE's Customer Excellence program, customers have seen a 50–70%

[23] See IEEE Guide for Electric Power Distribution Reliability Indices for more information on reliability standards. https://ieeexplore.ieee.org/document/6209381.

improvement in reliability. The company plans to continue these investments in pursuit of a 60% improvement in SAIDI by 2030. Some costs and benefits are not easily quantifiable, such as the "experiential burden" incurred by customers during long-duration outages and avoided outages. DTE used Berkeley Lab's ICE Calculator[24] to estimate interruption costs and benefits associated with reliability improvements and is working to understand dual resilience and reliability benefits from various investment strategies (DTE 2021).

4 Conclusion

Duke Energy aspires to use ISOP to support jointly optimal generation, transmission, and distribution expansion decisions. For example, the utility plans to make ISOP capabilities such as Morecast, ADP, and non-traditional solution evaluation consistent with generation and transmission planning in the IRP. Duke Energy's current integration of IRP, transmission planning, and ADP is a step in the right direction. At the same time, there is no clear information on how the portfolio of planned investments across these domains – including potential non-traditional solutions – will balance competing objectives such as cost, risk, and reliability. This is an emerging challenge for processes like ISOP and one for which there is no best practice available in the industry.

The project team identified several innovative aspects of ISOP:

- Duke Energy's Morecast, combining native load with load changes from electrification, EVs and DERs, is aligned with best practices in IDP and a recommendation in NARUC's Integrated Comprehensive Planning Framework. Duke Energy is an early adopter of this capability. In addition to enabling automated distribution upgrades, it could enable integrated transmission and distribution forecasts, and its 10-year horizon could allow Duke Energy to identify high quality upgrade solutions.
- Duke Energy's movement towards a highly granular forecast is a step in the right direction. New electrification trends will introduce substantial modification of traditional load profiles over time and the different rates of adoption of electrification within a feeder will create large differences of load growth across space. Temporal and spatial granularity in forecasting will be critical for capturing these trends and producing meaningful load forecasts that can be used by appropriate models (see ADP, below).
- Duke Energy's approach to considering contributions from DERs – i.e., evaluating resources to determine their effective load carrying capability, aggregated to the system level – is a planning best practice.
- Duke Energy's use of automation in distribution system expansion analysis can speed up the capacity expansion modeling process, examine multiple portfolios that an analysis may not consider, and screen for novel solutions for manual processing. This is a cutting-edge practice because there are not commercial modeling packages that perform automated modeling.
- Duke Energy's ADP automates circuit upgrades downstream of substations. It is a best practice that prepares the company for cost-effective constraint mitigation that will be needed with increasing electrification, EVs, and DER. Duke Energy is an early adopter of this capability.
- Duke Energy plans to begin using DC power flow modeling to screen non-traditional solutions, support resource siting, and better integrate generation and transmission planning. A DC

[24] https://icecalculator.com/home.

optimal power flow "nodal" model can be used to assist with the capacity expansion process and help ensure that results are robust when considering transmission constraints, thereby facilitating the transmission planning process.

- Duke Energy's ISOP Data System and grid map data allow its engineers to access data for different forms of analysis. Although this capability may not seem noteworthy, many distribution utilities store data in a collection of "silos" that can make sharing data between departments challenging.

Duke Energy's ISOP contains multiple core components of a typical IDP. Still, ISOP does not contain all of the elements of IDP that a growing number of states are adopting to maintain and enhance reliability and resilience and minimize electricity system costs. Instead, Duke Energy addresses several of these components in separate processes, such as the IRP and Grid Improvement Plan, which complement ISOP.

The following are opportunities for improving ISOP:

- *Enable deeper stakeholder engagement.* Duke Energy currently provides transparency in the ISOP process through third-party and company-moderated stakeholder engagement events with Q&A, publicly available literature, web resources, and initiatives to build out tools that inform interested stakeholders. The company can enhance engagement with stakeholders by providing more detail on methods and results and providing more formal channels for stakeholder comments.
- *Include a detailed discussion of ISOP in IRPs.* While South Carolina state law does not require utilities to file a distribution plan or ISOP with their IRPs, Duke Energy could include a more detailed discussion of ISOP in forthcoming IRPs and make underlying data available to stakeholders. Incorporating ISOP into the IRP more formally could create an opportunity for more robust stakeholder engagement.
- *Provide more information on how ISOP identifies investment decisions that are least cost and risk for maintaining a reliable and resilient distribution system.* Duke Energy could include a more robust discussion of how it evaluates investment options in ISOP in its IRP or other relevant filing, including the need for such investments.
- *Move towards a spatially explicit forecast that predicts load distributed throughout the circuit based on AMI and SCADA data.* This rich dataset would enable targeted interventions, identify hotspots, and support an advanced hosting capacity analysis.
- *Integrate non-traditional solutions analysis into a capacity expansion optimization model.* It does not appear that Duke Energy is analyzing non-traditional solutions directly in its capacity expansion model. While the model is not currently designed to select resource options at this detailed level of grid analysis, the company can explore analytical methods to compare traditional and non-traditional solutions.
- *Include other DERs, including managed EV charging, in non-traditional solution analysis.* Currently, Duke Energy is only considering batteries in their non-traditional solution analysis.
- *Account for all value streams in non-traditional solution analysis.* Duke Energy's value stack for batteries currently includes bulk power system benefits.
- *Explore the screening approach used by peer utilities to successfully identify non-wires alternative projects.* In the 2021/2022 non-traditional solutions planning cycle, Duke Energy used four primary screening metrics. As discussed in Section 3.3, Xcel Energy in Minnesota

updated their NWA approach in their 2021 IDP. Several aspects of their screening approach, such as timeframe and ownership model, load reduction requirement, and value streams were updated.

- *Continue to develop and enhance the HCA process.* Duke Energy can incorporate HCA results with load and DER forecasts through its distribution capacity planning processes to identify feeders that are likely to see significant DER growth and to proactively consider distribution system upgrades. The utility could provide some of this forecast information to customers and DER developers to illustrate where demand flexibility might provide the most value on the grid (Schwartz and Frick 2022).
- *Improve distribution planning analytics and HCA capabilities to help inform customers and developers about where smaller capacity distributed generation projects may be limited by the constraints shown in Duke Energy's DG Locational Guidance Map.* For example, the company can consider including portions of the distribution system that have net-metered distributed generation and other distributed generation that is smaller than 250 kW.[25] The company also can explore best practices, such as including EVs in HCA.[26] That would help Duke Energy, customers, and third-party service providers identify locations on the grid that could support EV charging or benefit from EVs discharging electricity back to the grid, or both.
- *Explore best practices for maintaining accurate HCA maps.*[27] Examples include ensuring that the analysis is a well-documented, repeatable, transparent process with opportunities for feedback and error identification; using scripted batch processes to automate analyses; and informing assumptions with empirical data.
- *Review recommendations in the Integrated Comprehensive Planning Framework for the Turquoise Roadmap.* The NARUC-NASEO Turquoise Roadmap reflects a forward-looking integrated planning process for an illustrative state located outside of an RTO/ISO market that is seeking to better align distribution, resource, and transmission planning processes and whose investor-owned utilities own generation assets.

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[25] https://dukeenergy.maps.arcgis.com/apps/webappviewer/index.html?id=4f6d46d67a2f4023ba7aae0953baf66a.
[26] See Xcel Minnesota's HCA map, which includes "analysis performed specifically for siting new or additional load, such as a new or expanding customer load, batteries (charging only), or electric vehicle (EV) fast charging stations." https://go.lbl.gov/vuqmkr.
[27] For example, see https://www.nrel.gov/docs/fy22osti/81811.pdf.

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Appendix A. Link to ISOP Process Diagram

Please cut and paste the following website into a browser window to access the diagram.

https://viewer.diagrams.net/?tags=%7B%7D&highlight=0000ff&edit=_blank&layers=1&nav=1&title=Duke_ISOP_final_Duke_Team_Review_Working_v1_221219-remove%20climate%20plan.drawio#R7b1pc9s4tj%2F8aVRPeqqs4r68tGW7O3OTjm%2Fsydx53qRoiZI4oUQ1SXnpT%2F%2FHSqIqSIIUKcmJ3V2xRXEBqYOzn9%2BZmLPNy%2B9psFt%2FThZhPDG0xcvEvJ4Yhuv [illegible]

Appendix B. ISOP Process Diagram Footnotes

Note 1:

The enterprise strategy guides the range of scenarios and available technologies that are considered in the plans. SC ORS and NREL refer to DOE's "DSPx" as a transparent, holistic, objective and performance driven process that could be reviewed for consideration in continuing development of new ISOP elements. https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

Note 2:

ISOP has engaged stakeholders in face-to-face sessions and webinars, but the ORS team suggests there may be greater stakeholder interest in aspects of the planning process. Noted that some components of ISOP, such as the T&D NTS solutions, typically have a lot of stakeholder interest that require focused attention and process transparency.

* Also noted by the ORS team that ISOP and IRP stakeholder engagement processes have not been fully integrated, but more integration is planned.

Note 3:

* Noted that integration between the ISOP and IRP is in development and more integration is planned.

* Noted that some of the toolsets in the ISOP and IRP overlap. IRP, ISOP and Transmission Planning collaborate on the bulk grid planning processes. The ISOP distribution processes (Morecast, ADP, hosting capacity) and the T&D NTS processes have not yet been directly integrated with the IRP.

* Future scenarios developed in the IRP's are shared with ISOP as a planning foundation. Aligning the full scope of the IRP scenarios from bulk grid through to distribution is still in progress. IRP are updated every two years and ISOP is being blended into the annual grid planning updates.

Note 4:

* The IRP and Carbon plan use same the workflows and tool sets. The main differences lie in the assumptions and objectives used for each plan.

Note 5:

* The final asset management plans include annual prioritization of investments and are subject to regulatory approval in rate proceedings.

Note 6: (T & D NTS in Bulk System Planning)

Contributions from distributed supply side resources like solar, solar plus storage and standalone storage systems are evaluated to determine their ELCC which are aggregated up to the system level.

Note 7: (EnCompass in Bulk System Planning)

* https://anchor-power.com/encompass-power-planning-software/

* Duke plans to add EnCompass' new DC powerflow to its planning toolset.

Note 8: (Bulk System Planning)

* Generation resource planning uses general zonal transmission representation which covers interface flow limits. DC powerflow is currently being performed in some applications. In the future, these applications will be expanded where needed to improve integrated generation and transmission planning

Note 9:

https://new.siemens.com/global/en/products/energy/energy-automation-and-smart-grid/pss-software/pss-e.html

Note 10:

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Note 11:

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Note 12: (Bulk to MoreCast)

* The focus of bulk grid scenarios and distribution scenarios may be different in certain situations. Additional ISOP integration will help achieve better alignment and consistency between T&D scenarios.

Note 13: (Bulk to MoreCast)

* Some inconsistencies naturally exist between circuit level and bulk grid forecasts since they may reference different temperature/load assumptions and risk considerations. Bulk system planning utilizes weather normalized load forecasts and incorporates reserve margins for weather and operational risks. T&D grid planning typically utilize more demanding weather conditions and localized events to evaluate potential for unreliable operating conditions. Both forecasts use similar PV, customer programs and energy

efficiency forecasts aligned with the bulk grid forecast. The full Morecast is not rolled up due to its circuit-level focus and which would introduce accumulated error when aggregated across the bulk system.

Note 14: (MoreCast Scenarios)

* Policy requirements and sensitivity analysis are included in the Morecast scenario development, but utilization in distribution planning is still in development.

Note 15: (Morecast AMI)

* AMI data are stored in a meter data management system and are not integrated with the ISOP data store, but this is planned. Duke is in early stage of using AMI to help with forecasting.

Note 16: (MoreCast Metrix ND)

* Axciom, a customer intelligence company is used to estimate a locational adoption propensity scores. https://www.acxiom.com/?utm_source=google&utm_medium=cpc&utm_campaign=awareness&utm_content=g-ad&gclid=Cj0KCQjwqoibBhDUARIsAH2OpWiSdMqRO1ioc5oDGv_cOsj6QADseRW5FpFc8peQStVnQMNpkwThUD4aArqyEALw_wcB

* PVsyst is used to design and assess PV output based using local weather. https://www.pvsyst.com/features/

Note 17: (Morecast VAST)

*Duke is using VAST by Guidehouse to forecast EV adoption and charging infrastructure requirements See: https://guidehouse.com/-/media/www/site/insights/energy/2022/guidehouseimproving-evse-networks--vast-white-pape.pdf

https://bk-apps.shinyapps.io/siting-opt-and-stranded-assets/

* Noted: This tool does support EV adoption forecasting. Duke anticipates experiencing load increases from several EV charging use cases, such as residential at-home charging.

Note 18: (Morecast)

* Morecast does provide capabilities for building multiple scenarios which are being developed and tested for future implementation.

Note 19: (Morecast)

* Circuit level forecast.

Note 20: (Morecast)

* Circuit level forecast.

Note 21: (Morecast)

* Circuit level forecast.

Note 22: (Morecast Cust Programs)

* Circuit level forecast.

* Duke has a "Bring your own thermostat" DSM program. Adoption of rate structures such as TOU, CPP, PTR has been modeled in excel using adoption curves developed by Tierra and Dunsky for the Winter Peak Study. The curves are adjusted to reach estimated program saturation points at differing future years to provide base, low and high cases.

* Duke is still working on allocating region wide energy efficiency programs down to the specific circuit level as part of continuing forecast development.

* Not mentioned: Inputs or details on "Bring your own thermostat" program

Note 23: (Morecast)

* Noted: Very little BTM storage has been adopted. New BTM storage customer programs are in early development and testing.

Note 24: (Morecast Validation)

* Duke does backcasting and compares trends with the bulk forecast.

Note 25:

* The "Morecast" is repeated here to simplify the ISOP diagram.

* Morecast is an input to Distribution NTS project selection.

Note 26: (Morecast D NTS)

* ADP modeling addresses solutions at and below the circuit level, whereas the Duke NTS process (like most utilities) focuses on the circuit level solutions. Project screening and criteria are different for ADP and NTS solutions. ADP has a 10-year forward-looking horizon. NTS screening looks at projects further out in time to include sufficient time to develop a DER solution, and solutions may span a longer timeframe (> 10 yrs) for deferral opportunities.

Note 27: (ADP)

* Forecast spatial resolution is circuit level and sometimes courser. Downscaling is necessary for feeder segment level analysis, which can affect analysis accuracy.

Note 28: (ADP)

* Secondary networks not currently modeled in ADP.

Note 29: (ADP)

* "Circuit Level" solutions are upgrades that occur at the feeder breaker or upstream. These solutions are not automated.

Note 30: (ADP)

* Not mentioned: Operational strategies being considered in the automated solutions (e.g. DERMS, VVO, etc.). Further exploration may be needed.

Note 31: (T&D NTS)

Contributions from distributed supply side resources like solar, solar plus storage and standalone storage systems are evaluated to determine their ELCC which are aggregated up to the system level.

Note 32: (D NTS)

* ADP modeling addresses solutions at and below the circuit level, whereas the Duke NTS process (like most utilities) focuses on the circuit level solutions. Project screening and criteria are different for ADP and NTS solutions. ADP has a 10-year forward-looking horizon. NTS screening looks at projects further out in time to include sufficient time to develop a DER solution, and solutions may span a longer timeframe (> 10 yrs) for deferral opportunities.

Note 33: (D NTS)

* Managed EV charging is not used as a NTS but V2G programs will be evaluated in the future after information is collected in the emerging pilot programs.

Note 34: (D NTS)

* ITC, federal IIJA funding or carbon reduction funding could affect the NTS screen.
* The threshold value was set at $2M in 2022 but is reviewed each year and subject to change based on battery costs and stacked benefit value updates.

Note 35: (T Planning)

* "Bulk System Planning" is repeated here to simplify the ISOP diagram.

Note 36: (T Planning)

* Assuming IRP/RA software are the same

Note 37: (T NTS)

* A carbon cost could affect the NTS screen. This will be addressed, as appropriate.

Note 38: (T NTS)

* Noted that selection criteria are different for NTS and traditional solutions.

Note 39: (Hosting Capacity)

* Hosting capacity capabilities are under development.
* Hosting capacity is planned to provide more detail to inform stakeholders.
* Noted that hosting capacity can be used to inform distribution planning.

Note 40: (Hosting Capacity)

* NREL noted that hosting capacity maps have a reputation for poor accuracy in the industry. Duke's process is still in development with stakeholder input to help guide information desired. NREL references https://www.nrel.gov/docs/fy22osti/81811.pdf for further information.

Note 41: (Data)

A great deal of the ISOP planning data is accessible through the ISOP data system. Initial focus for the data system has been operating history and grid map data supporting Morecast and API development and integration with the new ADP toolsets. New functionality continues to be developed to met additional new applications as ISOP matures.

Appendix C. Duke Energy Responses to Project Team Questions

From: Michael Rib, Director, ISOP Integrated Optimization, Duke Energy

To: Anthony Sandonato, South Carolina Office of Regulatory Staff
Natalie Mims Frick, Lawrence Berkley National Labs

On June 22, 2022, Duke Energy received a request from Anthony Sandonato, South Carolina Office of Regulatory Staff, to participate in a review and discussions related to the Integrated Systems Operation Planning (ISOP) process. As outlined in the description of the work below, staff from Lawrence Berkley National Labs developed a set of questions to help frame the conversations and have requested written responses to support the information exchange discussions they are planning on behalf of SC ORS. North Carolina Public Staff has also been invited to participate. This is the description of the effort provided with the request:

From: Juan Pablo Carvallo and Natalie Mims Frick (Lawrence Berkley National Lab)
RE: DRAFT Discussion questions on Duke Energy's (ISOP Process)

This memo is pursuant to a request by staff of the South Carolina Office of Regulatory Staff for technical assistance on reviewing Duke Energy's ISOP process. Berkeley Lab is providing this assistance under the Grid Modernization Lab Consortium project funded by the U.S. Department of Energy.

The South Carolina Office of Regulatory Staff (ORS) requested that Berkeley Lab review materials related to Duke Energy's ISOP process and develop questions to clarify Duke Energy's inputs, interactions with Duke Energy's integrated resource plan, and overall implementation within the ISOP, with the goal of providing guidance to ORS in their review of Duke Energy's integrated resource plan which will include components of the ISOP. ORS also identified that it would be most beneficial for Berkeley Lab to focus our review on Duke Energy's use of Morecast and Advance Distribution Planning (ADP).

Based on our review, we have developed the following questions which are organized into three categories - general modeling, Morecast, and Advanced Distribution Planning (ADP).

Duke Energy offers these initial responses to the questions to support the information exchange discussions that have been requested. Since this an informal information gathering process, the information being shared is not considered confidential, but does reflect sensitive planning development work that is in progress and subject to change and refinement and should not be published without consent and review of the parties.

Responses to these questions have been gathered from key members of the ISOP team. Questions related to these matters can be forwarded to Michael Rib, Director, ISOP Integrated Optimization at Duke Energy.

General Modeling

1. How does Duke Energy intend to combine the domain-level (e.g. generation, transmission, distribution, and customer-side) optimization analysis into a single integrated portfolio of solutions? How will Duke Energy prove that it is producing an optimal expansion plan when combining analysis that may be addressing overlapping purposes?

   Response: ISOP is viewing the industry and each segment of the business evolving in different ways with each segment of the business having unique challenges to address. It will be important for integrated utilities like Duke Energy to have visibility of the energy and reliability contributions of resources connected at all levels of the system. In real time operations, the utility will need to know what resources will be operating to ensure that at a system level, load will be served and reliability requirements will be met. For long term planning, the utility planners need to have reasonable forecasts of what the mix of resources will likely be across the generation, transmission, distribution and customer segments of the business to integrate these resources and to assess the cost and reliability aspects across the system. The current view held in ISOP is that it will examine and estimate the operating capabilities, costs and values of new distributed resources and use this information to examine optimization at the segment level as they plan to meet their specific future requirements. This approach, coupled with stacked valuation, will support integrated planning across the segments, help ensure reliable operations and support appropriate value transfer for cost effective integrated system plans. ISOP is working with all segments to explore how distributed resources will impact each of the segments and what new tools and capabilities are needed to plan for the future states envisioned.

2. What are the key decision variables from each planning model (ADP for distribution, Encompass for generation, and the transmission expansion model)?

   Response: Planning models focus on outcomes and priorities appropriate for each segment of the business.

   Generation: EnCompass is used in long term planning resource planning to support capacity expansion planning and detailed production cost analysis focusing on making cost effective resource decisions based on load, fuel, technology, emissions forecasts and constraints (e.g. CO2 emission reductions) over the planning horizon. SERVM is used to study key system reliability variables to assess loss of load potential and to characterize the ELCC of different types of resources.

   Transmission: PSS/E and TARA are used extensively in long term transmission planning to assess viability and operational reliability across a host of scenarios and contingencies. Studies are performed to assess the capacity and reliability of the grid under normal and contingency conditions in both near term and long term scenarios. In long term planning applications, studies are performed to include different generation resource dispatch options and grid configurations to support interconnection and generation portfolio analysis. PROMOD and PAT are also used for hourly load flow simulations where applicable to supplement the long term analysis and the Company has recently begun working with EnCompass to deploy their new nodal model with DC power flow capability.

   Distribution: The Advanced Distribution Planning (ADP) tools being used have been developed around enhancements to the CYME modeling toolset. The current implementation allows planners to evaluate distribution circuit capacity adequacy over a ten year planning horizon with hourly load flow capability and to examine certain solution options to address overloads or voltage deficiencies that are observed. The CYME modeling toolset is also used as it has been traditionally used in the past to perform more detailed circuit reliability analysis based on time periods identified by the planners. Plans for future ADP updates anticipate more integration around circuit reliability analysis and support for grid hosting capacity analysis.

3. How does the ISOP consider rate-driven adoption of distributed energy resources (DER) as part of the portfolio of solutions?

   Response: Rate-driven adoption of customer DERs is currently modeled independently as components of the net load forecast.

   - PV - The customer-owned PV forecast is the product of a customer adoption forecast and an average capacity value. Adoption forecasts are based on linear regression modeling in Itron MetrixND using customer payback period as the primary independent variable. Payback periods are a function of installed cost, regulatory incentives and electric bill savings. Historical and projected technology costs are provided by Guidehouse. Projected incentives and bill savings are based on current regulatory policies and input from internal subject matter experts. Average capacity values are based on trends in historical adoption.
   - EV - For EV Adoptions we use the Guidehouse VAST Model which includes forecasts of adoptions and energy profiles for LD and MD/HD EVs.
   - BYOT – Customer adoption of rate-enabled/rate-driven DERs such as Bring Your Own Thermostat (BYOT) is addressed as a component of customer programs forecasting and included in the net load forecasts.
   - Rates – adoption of rate structures such as TOU, CPP, PTR is modeled in excel using adoption curves developed by Tierra and Dunsky for the Winter Peak Study. The curves are adjusted to reach estimated program saturation points at differing future years to provide base, low and high cases.

4. How do the models distinguish between customer and utility owned DER when producing an optimal expansion plan? How does the difference in the operational profile from customer or utility owned DER change and what does it depend on?

   Response: Currently, in IRP modeling at the system level, customer owned DERs (including Net Energy Metering [NEM] customer sited solar) are modeled as a component of the net load forecast similar to energy efficiency and, thus, operates on a fixed profile forecasted for the type of resource. Utility scale DERs that are configured for utility control are modeled in larger “blocks” and the Encompass model is able to dispatch (or curtail, depending on contract provisions) these assets as needed to meet system needs. Costs for future utility scale solar resources that the planners include in the expansion planning phase represent both utility owned and 3rd party contracted resources. These resources have the same operating profiles and parameters in the modeling phase from an operability standpoint.

   For specific ISOP analyses focused on non-traditional solutions to localized grid issues, both utility and customer owned DER operations are considered as supply side or demand side resources to address the grid issues under study. The Company is continuing to develop analytical processes and systems which will speed the screening and modeling of localized non-traditional solutions for future integration into the IRP expansion planning process. Careful consideration is needed for the availability and capability of the non-traditional solution to perform its intended function economically and reliably.

5. There are several software packages that allow for the analysis of joint generation-transmission expansion to ensure coordination of these resources. This is especially valuable for vertically integrated utilities like Duke Energy. Why does ISOP use separate models for transmission and generation planning?

   Response: There are always tradeoffs in model selection and planners in the industry generally use different tools to perform detailed studies of generation and transmission and integrate these results to inform and refine generation and transmission expansion options. The EnCompass model currently being used for long term capacity expansion planning and detailed production cost analysis performs extremely well with critical parameters around conventional and renewable resource utilization, carbon mass cap emissions constraints and energy storage system operations. EnCompass also incorporates transmission system details including load and generation zones, interzonal flow limits and transmission upgrade cost estimates for each new resource option that influence resource expansion results. The analyses performed with EnCompass helps identify least cost resource plan portfolios informed with estimated transmission system upgrade costs which provides an appropriate foundation for performing the detailed transmission studies needed to examine resource placement, interconnection requirements and grid configuration options. As noted in the response to Question 2, the transmission analysis team utilizes PSS/E, TARA, PROMOD and PAT to perform the more detailed grid configuration studies need to address their planning concerns. Given the complexity of evaluating future system configurations and the importance of concurrently addressing system reliability, environmental compliance and costs, the current modeling approach Duke Energy is taking is appropriate. ISOP, IRP and Transmission Planning will continue to refine modeling capabilities and evaluate new models as they become available that may be helpful in supporting planning analysis in the future.

6. Bulk-power system expansion requires a resource adequacy analysis to ensure that the resulting power system complies with minimum reliability standards. This is typically performed within IRP, but doing so would miss on the resource adequacy contribution of non-traditional solutions (NTS). How does Duke Energy plan to perform resource adequacy assessments in the context of the ISOP, and what modeling approach will it utilize?

   Response: Duke Energy continues to perform resource adequacy analysis at the system level for long term planning. Contributions from distributed supply side resources like solar, solar plus storage and standalone storage systems are evaluated to determine their ELCC which are aggregated up to the system level. Contributions from demand side resources (e.g. customer programs, EV's and net metered solar) are currently incorporated into the load forecasts being used for system level resource adequacy studies. In some applications, these supply and demand side resources may be considered as NTS if they are being considered to perform grid support functions. ISOP is also assisting Transmission and Distribution planners in developing methods to assess contributions of supply and demand side resources toward the metrics for grid capacity which is outside the traditional IRP perspective for resource adequacy.

Morecast

Duke Energy states that Morecast will produce 10-year hourly forecasts at the circuit level. Traditional "system level" forecasts tend to have a bounded error because they average out over and under estimation across the system. However, this will not happen with Morecast because it develops individual circuit forecasts. The accumulated error on each circuit's forecast may not average out because decisions are being made for each circuit:

Response: Morecast forecasts are used to understand growth for planning at the circuit and/or bank levels. Jurisdictional forecasts are still prepared to give insight to growth expectations at the bulk level. We do not roll up Morecast to get a view of the jurisdiction as a whole due to the reasons you state. We do however check to see that the Morecast forecasts and the jurisdictional forecasts complement each other.

1. Given that forecasts are uncertain, how will Duke Energy create scenarios for the Morecast process? How will Duke Energy make the Morecast scenarios consistent with scenarios developed in other components of the ISOP?

   Response: Scenario analysis will be informed by strategic initiatives or current events/policy changes. Such scenarios may be performed at the bulk/jurisdictional level, the Granular Morecast level, or both.

2. How will Duke Energy verify and validate the Morecast forecasts?

   Response: We are going through many sets of validation to verify the forecasts. The forecast team has set up review processes to ensure peaks and load shapes look reasonable compared to history. We look at the trends of the load on the circuits to ensure we are comfortable with the trend, and we look at the cumulative growth statistics to ensure the cumulative impact of the circuit forecasts are in line with the jurisdictional forecasts.

   Once the Morecast team is comfortable, there is an additional review process performed by the distribution planners who are very familiar with the circuits. Recommendations received from the planners are evaluated and included in the forecast as appropriate.

   a. Will Duke Energy use back casting or a retrospective analysis to demonstrate the accuracy of the forecasts at the circuit level?

      Response: In preparing the forecast – back casting is one of the checks and balances we run to ensure a proper fit of the models and the residuals are reasonable. We intend to re-run forecasts at least annually, and forecast results are compared against previous estimations in the review process

3. How does Duke Energy plan to manage circuit-level forecast accuracy when part of the solutions imply shifting customers across circuits for balancing purposes?

   Response: In preparing the forecasts, we attempt to identify when temporary switching has occurred, and we remove that from the history used to forecast the circuit.

4. How does Duke Energy plan to leverage Advanced Metering Infrastructure (AMI) data to enhance the Morecast process?

   Response: We are in the early stages of looking at use of AMI data to help our circuit level forecasting activities. We are also looking at things like identifying EV charging or rooftop solar on the circuit that may better inform the forecasting process and allow us to better understand the load shapes on the circuit.

5. When referring to "circuit level" forecasts, does Duke Energy mean at the feeder head, at the distribution transformer level, or for each customer within a feeder? What is the minimum unit of analysis or resolution for Morecast forecasts?

   Response: Feeder head.

6. How is the Morecast forecast different than the bulk power system load forecast?

Response: The main difference of course is the level of granularity. Per the responses to A and B below, we attempt to align the two forecasts using consistent assumptions, and checks are made to ensure both forecasts show similar growth trends.

a. Do they use consistent assumptions (e.g. economic growth, technology adoption)?

   Response: Yes. Similar assumptions are shared across Morecast and the bulk level forecasts.

b. How will Duke Energy ensure they produce consistent outputs?

   Response: Part of the review process is to ensure growth rates in sales / peaks are similar across both forecasts.

7. Using historical data for forecasting may prove inaccurate considering the technology options and economic changes that customers are going through. What forecast model does Duke Energy plan to use for "native" load forecast growth? Will Duke Energy consider a statistically adjusted end use forecasting model instead of econometric or Analysis of Variance (ANOVA) types of models to prevent the continuity of historical trends that may not materialize?

   Response: The bulk level/jurisdictional forecast uses a statistically adjusted end use model.

8. How does Duke Energy model DER and electric vehicle (EV) adoption trends?

   Response: Duke Energy's EV load forecast is derived using the Guidehouse developed Vehicle Analytics and Simulation Tool ("VAST"). The forecast is developed for three vehicle types: light duty, medium duty, and heavy duty. Multiple parameters are accounted for when developing the EV adoption forecast including historical data, such as vehicle registrations and vehicle utilization characteristics, as well as projections of future data including cost, vehicle availability, charging infrastructure availability, and consumer acceptance. These EV adoption characteristics and trends help shape the EV forecast which are incorporated into the Duke Energy load forecast.

   The rooftop solar generation (NEM) forecast is derived from a series of capacity forecasts and hourly production profiles tailored to residential, commercial and industrial customer classes. Each capacity forecast is the product of a customer adoption forecast and an average capacity value. The adoption forecasts are developed using economic models of payback, which is a function of installed cost, regulatory incentives, regulatory statutes and bill savings. A relationship between payback and customer adoption is developed through regression modeling, with the resulting regression equations used to predict future customer adoptions based on projected payback curves.

   Historical and projected technology costs are sourced from Guidehouse, while projected incentives and bill savings are based on current regulatory policies as well as input from internal subject matter experts. Average system size (capacity) values are based on trends in historical adoption.

   The hourly production profiles have 12x24 resolution, which equates to one 24-hour profile for each month. Profiles are derived from actual production data, where available, and solar photovoltaic ("PV") modeling. The PV modeling is performed in the PVsyst model using 20+ years of historical irradiance data sourced from Solar Anywhere and Solcast. Models are created for 13 irradiance locations across DEC's service area and nine irradiance locations across DEP's service area with 21 tilt/azimuth configurations. The results for each jurisdiction are combined on a weighted average basis to produce the final profiles.

a. How does Duke Energy consider existing and prospective policy requirements in these adoption trends?

Response: For both EV and NEM forecasts, existing policy requirements are included in the base forecast. For NEM, historic practice has been to model adoption based on existing policies and tariffs at the time the forecast is developed. "Prospective" policy requirements or stated policy goals are typically modeled in sensitivity analysis. For example, the Company does not currently assume an extension of the solar ITC beyond 2023, but analyzes the impacts of a potential ITC extension in sensitivity analysis.

Similar to NEM, EV forecasts are based on existing policies at the time the forecast is developed and stated goals are modeled in sensitivity analyses. For example, the Company models the Biden Administrations goal of 50% of new vehicles being EVs by 2030 as an aggressive sensitivity rather than a base planning assumption.

b. EV adoption may be driven by policy as well as economic rationale. For many customers, it will make economic sense to save on gas and maintenance and transition from an internal combustion engine vehicle to an EV. How does Duke Energy plan to model EV adoption in terms of its costs and benefits vis a vis internal combustion engines?

Response: When the EV forecast is developed, the VAST algorithm accounts for projections of battery costs, battery sizes, fuel cost, VMT, vehicle efficiency, vehicle utilization, average vehicle cost, etc. and weighs those factors against the cost of traditional ICEV to help determine vehicle adoption.

c. How will Duke Energy model the socioeconomic aspects of DER adoption, in particular their disparate location within the distribution system that can create local hotspots in secondary and primary distribution systems?

Response: For Rooftop solar - we allocate based on propensity scores which are calculated using the Acxiom data, billing history, etc. For EV's we use information from the VAST tool that predict adoption by zip code.

9. How will Duke Energy model EV charging levels, location, and timing?

Response: Duke will use the VAST tool to help forecast chargers and their potential impacts using multiple variables including but not limited to: vehicle forecast, VMT, existing charging infrastructure, traffic data, charger-to-vehicle rations, charging siting distance thresholds, and other variables. This data helps determine the number of chargers, possible locations of chargers, and the timing of when those chargers would be needed.

a. How many charging strategies will Duke Energy consider?

Response: Currently the Company models charging behavior based on existing rate designs. The Company is evaluating new managed EV charging rate design options, but at this point, the impacts of those potential options have not been modeled.

b. Will Duke Energy treat different charging strategies as non-wires alternatives (NWA) or demand response? If, so how will Duke Energy model their costs as inputs?

Response: Charging strategies are not currently being viewed as non-wires alternatives or demand response programs. The Companies will continue to evaluate results of EV rate program pilots, EV customer charging/use patterns, and receptivity to offerings which could enable use of EVs as a grid edge resource.

c. What is the source of Duke Energy's data to model trip distance and charging location?

Response: Duke uses the Federal Highway Administration data for VMT and annual average daily traffic, Alternative Fuels Data Center (AFDC) for charging infrastructure, and Guidehouse data for the charging site distance threshold.

10. How will Duke Energy establish the baseline for DER technology penetration within its customer base? Will Duke Energy use customer surveys that show the existing number of DER/EV/DR/EE at a sample of customers? If not, how does Duke Energy plan to characterize the baseline of customer-side technologies?

Response: For rooftop solar, the Company pulls interconnection requests for residential and non-residential customers planning to install behind the meter solar at a point in time when developing the forecast. The interconnection requests include system size, location, and whether the request includes addition of behind the meter storage with the solar system. The Company applies a materialization rate of connections to the interconnection requests based on historic materialization rates.

For EVs, the Company relies on registration data sourced from IHS Markit for current light duty vehicles in the Company's service territory at the zip code level. For medium duty and heavy duty vehicle adoption the Company relies on announcement of fleet electrification, as well as, internal Company sources.

For demand response and EE programs, the current regulatory framework provides for a comprehensive assessment of potential program options and participation rates which are used in program design and implementation. The Company will continue to leverage these efforts and ongoing engagement with the Carolinas EE/DSM Collaborative to evaluate new customer programs and technology options in the future.

ADP

1. Does ADP consider operational strategies as well as investment strategies? If so, how will ADP integrate both types of strategies to produce an optimal decision?

Response: ADP is being deployed in the Carolinas using a phased approach in 2021. An overview of current ADP functionalities is provided below.

- ADP automates load flow analyses using a 10-year hourly circuit forecast and grid topology information, such as analysis limits, equipment types, ratings, etc. Like traditional load flow analyses, the tool analyzes the potential for thermal overloads and voltage issues.
- When thermal overloads and/or voltage issues arise, ADP proposes simple solutions (with costs) for traditional capacity upgrades that can include new voltage regulators, reconductoring, load transfers, and load balancing. It doesn't suggest adding a new substation or breaker, since ADP is based on existing infrastructure. From there, the planner can select a preferred solution proposed by ADP (including costs) or can cost out a new solution that is not proposed by ADP if constraints prevent the solution proposed by ADP.
- ADP allows the analysis of multiple circuits at the same time for optimal location of switching devices.
- In addition to automated load flow analyses and solution, ADP capabilities include a load flow analysis to provide insights about when batteries can be used in peak-shaving applications. These battery analyses focus on resolving the circuit issue rather than defining strategies for battery operation or control.

2. Does the ADP modeling framework include automated upgrades to compare NWA against traditional expansion?

   Response: The ADP modeling framework includes new algorithmic abilities to size and locate batteries to compare as a Non-Traditional Solution (NTS) against traditional capacity expansion. From there, the cost and bulk system benefits of an NTS is compared against the costs of a traditional capacity expansion project.

   a. If yes, how does the model incorporate NWA benefits that are outside/upstream of the distribution system?

      Response: Bulk system benefits that are upstream of the distribution system are considered through an NTS screening process that uses ADP-generated battery sizing. This NTS screening process occurs outside of ADP using the ADP outputs.

   b. If the NWA includes a behavioral element, how does ADP model this aspect?

      Response: Duke Energy is evaluating customer programs as an NTS to avoid capacity upgrades. If such a solution seems feasible, it would need to be modeled in ADP to confirm that it would address the capacity constraints. Current evaluation methods are focused on use of customer programs as a hybrid NWA where impacts from increased adoption of existing or new customer programs can offset a portion of the battery capacity or energy requirement.

      The characteristics of customer programs and EV adoption that reflect the behavioral elements are represented in the circuit forecasts that are used as inputs to the automated load flow analyses in ADP.

   c. Does NWA include rate options? If so, how are these modeled?

      Response: Rate-driven adoption of customer DERs is currently addressed as components of the net load forecasts used in modeling, as outlined in General Modeling, Question 3.

3. What variables does ADP use to identify issues on a circuit?

   Response: ADP automates load flow analyses using a 10-year hourly circuit forecast and grid topology information, such as analysis limits, wire sizes, equipment types, ratings, etc. Like traditional load flow analyses, the tool analyzes the potential for thermal overloads and voltage issues.

4. How does ADP map issues to solutions?

   Response: When ADP identifies a constraint, it provides a list of solutions that map to the constraint (or ADP will show that no solution can be found for the specific constraint). Along with the circuit ID, an equipment and device ID is mapped to each constraint that feeds into the solutioning.

5. Does ADP include circuit rebalancing or reconfiguration (including customer switching) as an option?

   Response: ADP includes circuit rebalancing or reconfiguration of Duke Energy equipment but does not model customer switching that happens beyond the point of delivery.

a. How does ADP simulate the reliability of the resulting distribution circuit after the ADP expansion optimization? Does ADP capture the resilience benefits of NWA compared to traditional solutions? If so, how?

   Response: ADP does not evaluate reliability when examining capacity needs, so reliability benefits are not captured for traditional solutions or NTS.

6. Does ADP implementation eliminate the need for hosting capacity analysis (e.g. ADP accounts for all alternatives to integrate DER)?

   Response: No. ADP provides a base automation and solution framework that provides the foundation for hosting capacity analysis, which is due in NC by the end of 2024. Duke Energy only accounts for capacity NTS through ADP. Other alternatives to integrate DER (e.g. for reliability purposes or to provide transmission solutions), are considered through different planning processes.

7. Will ADP distinguish between solutions to prevent load flow deficiencies versus solutions to improve reliability, both in failure rates as well as restoration rates? If so, how?

   Response: ADP is currently used for addressing capacity and voltage constraints, rather than reliability.

8. If the ADP identifies that an investment is needed to improve circuit reliability, will ADP use a value of lost load to monetize the benefits to the customer or will it be based on meeting a specific SAIDI or SAIFI criteria per circuit or per customer?

   Response: ADP addresses capacity constraints and does not consider the option of having unmet load in traditional solutions or NTS.

9. According to the South Carolina Grid Improvement Plan, ADP will capture the generation and transmission stacked benefits of DERs.

   Response: The initial release of the ADP toolset includes a battery storage analysis module to enable planners to assess the size and location of batteries to address overloads that are observed in their studies. Planners will then work with ISOP to further evaluate the technical and economic merits of these potential applications. ISOP NTS screening metrics will help planners and the ISOP team identify which candidates warrant further attention. ISOP is currently performing NTS screening for battery storage, and as ISOP capabilities continue to develop, other additional NTS options like customer programs will be considered for integration.

   a. How will generation and transmission benefits be calculated and used in the NWA evaluation process?

      Response: As noted, ISOP is initially focusing on storage applications. The value streams associated with potential storage projects include contributions to system capacity needs (i.e. resource adequacy), production cost savings potential for energy arbitrage and ancillary services (including regulation and contingency reserves), and potential to defer transmission and/or distribution system upgrades. Each potential project is considered in terms of its ability to support each of these value streams or services based on the expected use case and connectivity. Contributions to system capacity are addressed using the ELCC methodology outlined in the Carbon Plan. Potential production cost savings are estimated using a “proxy value” process which leverages results from specialized modeling and analysis performed using the

EnCompass model. Potential to defer transmission and/or distribution upgrade projects is evaluated on a case by case basis, working closely with the respective grid planners.

b. How will Duke Energy ensure that the calculated generation and transmission benefits are consistent with the outcome of the parallel generation and transmission planning that are considered part of the ISOP framework?

Response: Utilizing the ELCC methodology for capacity analysis and the "proxy values" process based on EnCompass help align the value of these resources across distribution, transmission and generation.

10. ADP can facilitate the analysis of multiple alternative forecasts to encompass a wide range of possible futures.

Response: Yes, ADP can incorporate multiple forecasts from Morecast (e.g. normal vs. severe weather, impact of PV/EV/EE) by selecting which variables from the Morecast to turn on or off. The scenarios of weather or adoption of PV, EV, and EE are generated within Morecast, and ADP incorporates those scenarios to derive the projected capacity constraints.

a. Will the scenarios be produced for use in Morecast or in ADP?

Response: For consistency in investment decision making, the forecasts used in ADP for each jurisdiction are based on a consistent set of assumptions. However, ADP has the capability to evaluate forecast scenarios based on different assumptions. These scenarios are produced in Morecast and can then be incorporated into ADP. The scenarios are created through multiple alternative forecasts.

b. How will Duke Energy create these scenarios? What variables will be included? How will Duke Energy manage the potential thousands of combinations?

Response: As mentioned under the Morecast questions (#1), any scenario performed will be informed by strategic initiatives or current events/policy changes. The variable(s) altered will be the outcome of many conversations and will be documented so all parties understand the parameters of the scenario. We would not look to create thousands of combinations, but instead be more strategic in our focus on altering those items we want to study.

11. Does ADP model both primary and secondary distribution systems, including transformer loading and location?

Response: ADP does not model the secondary distribution system for capacity constraints. However, ADP estimates transformer loading based on customer count and usage, and the location of transformers is known in ADP through GIS data.

a. A traditional distribution system analysis focuses on reducing losses by extending the primary voltage system and reducing the extent of the relatively inefficient secondary system. Will ADP develop this process automatically? If so, how does this process interact with other loss-reduction approaches, especially NWA?

Response: ADP will propose extending primary, but only due to the primary being overloaded, rather than to address system losses.

12. The operational performance of NWA will depend on whether it is customer- or utility-owned. When ADP is considering a NWA, does it assume that it is customer-owned or utility-owned? What does this depend on?

Response: For customer-owned resources behind the meter, operational attributes may be treated as a load characteristic if they are within the customers' control, or as dispatchable resources if they are integrated into dispatchable customer programs by the utility. ADP isn't currently used for resource commitment and dispatching, so the resources are more simply included as either supply side resource in ADP or demand side resources in Morecast. ADP is also currently being used to study battery storage options as a NTS using a new battery sizing module which does not differentiate ownership for grid tied storage.

13. What are the data sources for cost assumptions required to simulate and compare traditional solutions and NWA?

    Response: ISOP and distribution planning both rely on their planning data resources for screening and more detailed analysis of NTS candidates.

    a. What is Duke Energy's data source for distribution expansion costs, both capital and labor?

       Response: Each jurisdiction has a cost sheet that is updated regularly and shared with planning organizations. These cost sheets use up-to-date cost information based on work orders, material costs, etc.

    b. What is Duke Energy's data source for DER capital costs?

       Response: ISOP utilizes cost estimating tools that are developed with the IRP team to help ensure consistent application of technology costs in planning. As part of the suite of planning cost estimating tools, ISOP utilizes the IRP group's generic technology costs that are included in the IRP process. ISOP also utilizes tools supported by Guidehouse which are part of the IRP framework for more detailed cost estimates for solar and storage resources at DER scale, when appropriate.

14. How will Duke Energy create portfolios of NTS for comparison with traditional solutions when assessing system needs?

    Response: ISOP has developed and continues to refine an NTS screening approach which dovetails with the traditional transmission and distribution planning processes to identify potential NTS applications that warrant further detailed consideration. As each of those candidates are considered, the Company can identify opportunities where an NTS appears to be cost effective compared with traditional options in that segment. As previously noted, most of ISOP's focus has been on storage initially, but this will begin to expand to include other options in the future.

    a. How will Duke Energy prove the NTS portfolio is the optimal, least-cost solution across planning domains?

       Response: The NTS candidates noted in response to Q14 will be further reviewed by ISOP to see how they compare with options in the other business segments to see which may be most cost effective at meeting needs at the system level. Using value metrics that are aligned at the system level, as outlined in Q9, will help ensure that the comparisons are reasonable.

    b. How will Duke Energy compare NTS and traditional solutions that have different value streams (e.g. addressing a generation capacity need with NTS may also have transmission and distribution benefits)?

Response: As noted in the response to Q9, the value streams being assessed are based on system aligned values and the contributions are being considered on a case by case basis to assess applicability. Where provision of services has potential to conflict (e.g. prioritizing addressing a local grid overload over a system capacity need), adjustments will be estimated for the affected services. Where other factors differ, the planning analysis will stive to make the comparison equitable. Comparisons have been made on a PV of revenue requirements basis which allows for estimating the values for deferring traditional solutions.

c. Is there an assumption that Duke Energy is revenue-neutral regarding NTS versus traditional solutions? How will Duke Energy consider an investment (with potential to rate base costs) compared to a NTS that has no or reduced investment?

Response: The Company is assessing options from a revenue requirements standpoint which would include different avenues for addressing costs including investments, deferrals and/or contracted services. It also accounts for system operating cost savings from whatever resource options are being considered.