Case Studies of 10 Integrated Energy Network Planning Challenges – Volume 1

Phase 2 – Framework for Integrated Energy Network Planning (IEN-P)

3002014644

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NOTE

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ABSTRACT

In July 2018, the Electric Power Research Institute (EPRI) published a white paper entitled, Developing a Framework for Integrated Energy Network Planning (IEN-P): 10 Key Challenges for Future Electric System Resource Planning (EPRI report 3002010821). This paper identifies and describes 10 complex, large-scale power system planning challenges that electric power system planners and regulators are beginning to confront today, and which are expected to become more pressing and widespread in the future. In early 2018, EPRI's Technology Innovation (TI) program launched Phase 2 of this research effort, which is designed to begin to assist electric companies with determining how to implement strategies to address these challenges.

This Technical Update contains the first of a two-volume set of case studies that highlight how different electric companies in the United States have started to address the IEN-P challenges. The second volume is expected to be published later in 2019. "Key Insights" are included in each case study to enable transfer of knowledge and learnings among peers, and to show companies how others are addressing commonly occurring challenges brought upon by a rapidly changing electricity sector.

Keywords

Integrated energy network
Integrated generation, transmission, and distribution planning
Integration capacity analysis
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PRIMARY AUDIENCE: Generation, transmission, and distribution system planners in electric companies and regional transmission organizations (RTOs/ISOs); state public utility commissions (PUCs), state energy office (SEO) and related regulatory staff; federal officials and staff in the United States Department of Energy (DOE), and the Federal Energy Regulatory Commission (FERC).

SECONDARY AUDIENCE: Stakeholders and members of the public involved in electric company generation, transmission, or distribution planning and related activities, such as regional transmission system planning.

KEY RESEARCH QUESTION

This Technical Update is the first of a two-volume set of case studies that highlight how different electric companies in the United States have started to address the Integrated Energy Network Planning (IEN-P) challenges. In addition to describing how the companies are addressing each challenge, the case studies also present critical insights and lessons learned that other electric companies and stakeholders may use to inform their own efforts to adapt to the Integrated Energy Network (IEN).

RESEARCH OVERVIEW

In July 2018, the Electric Power Research Institute (EPRI) published a white paper entitled, *Developing a Framework for Integrated Energy Network Planning (IEN-P): 10 Key Challenges for Future Electric System Resource Planning* (EPRI report 3002010821). This paper identifies and describes 10 complex, large-scale power system planning challenges that electric power system planners and regulators are beginning to confront today, and which are expected to become more pressing and widespread in the future. In late 2018, EPRI's Technology Innovation (TI) program launched Phase 2 of this research effort, which is designed to begin to assist electric companies with determining how to implement strategies to address these challenges. This report is the first of a two-volume set of case studies that highlight how different electric companies have started to address one or more of the IEN-P challenges. The second volume is expected to be published in 2019.

KEY FINDINGS

- Unprecedented projected growth of solar resources in the Carolinas prompted Duke Energy to more explicitly analyze its system ancillary needs to manage associated intra-hour intermittency, net-demand load following, and load and solar forecast error mitigation.
- Southern California Edison uses Integration Capacity Analysis (ICA) to identify distribution circuits where there is sufficient hosting capacity to accommodate distributed energy resources (DERs). The company is also exploring how ICA can be used to prioritize distribution deferral.
- Great River Energy and Dakota Electric Association are attempting to coordinate aspects of generation, transmission and distribution (GT&D) planning by leveraging their member-owner relationship. Through this experience, they have also identified challenges to coordinating GT&D planning.

- Southern Company addresses uncertainty and manages risk in long-range resource planning through a formal, annual, and centralized scenario planning process.
- The Tennessee Valley Authority devised a 'multi-level' engagement strategy to meet the diverse information needs of customers, government agencies, industry groups, non-profit and advocacy organizations, and other stakeholders who are interested in learning about and commenting on their integrated resource plan (IRP).

WHY THIS MATTERS

Electric companies are in the early stages of addressing the resource planning challenges identified in EPRI's 2018 IEN-P white paper. This collection of case studies provides specific examples of how electric companies are beginning to address the IEN-P challenges and offers critical insights for other companies responding to similar issues.

HOW TO APPLY RESULTS

The case studies presented in this first volume are intended to help inform EPRI members and other stakeholders about innovative approaches being implemented by electric companies to address the 10 IEN-P challenges. "Key Insights" are included in each case study to facilitate transfer of knowledge and learnings among peers, and to show companies how others are starting to address the planning challenges triggered by the rapidly evolving electricity sector.

LEARNING AND ENGAGEMENT OPPORTUNITIES

- Integrated Energy Network
- *Developing a Framework for Integrated Energy Network Planning (IEN-P): 10 Key Challenges for Future Electric System Resource Planning* (3002010821)
- *Annotated Bibliography for 10 Integrated Energy Network Resource Planning Challenges: Phase 2 – Framework for Integrated Energy Network Planning (IEN-P)* (3002014288)
- Program 178 on Integrated Energy Planning, Market Analysis, and Technology Assessment

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PROGRAM: 178 Integrated Energy Planning, Market Analysis, and Technology Assessment

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GLOSSARY OF TERMS

AMI	Advanced metering infrastructure
AR	All requirements customers
A/S	Ancillary Services
CAISO	California Independent System Operator
CPEP	Clean Power and Electrification Pathway
DEC	Duke Energy Carolinas
DEP	Duke Energy Progress
DER	Distributed energy resources (e.g., rooftop solar PV)
DERiM	Distributed Energy Resource Interconnection maps
DR	Demand response
DRIVE	Distribution Resource Integration and Value Estimation
DRP	Distribution resource plan
EEA	EPRI's Energy and Environmental Analysis group
EIA	Environmental Impact Statement
FO	Fixed Obligation
GHG	Greenhouse gas
GIS	Geographic information systems
GMI	Grid Modernization Initiative
GRE	Great River Energy
GT&D	Generation, Transmission and Distribution
ICA	Integration Capacity Analysis
IEN	Integrated Energy Network
IEN-P	Integrated Energy Network Planning
IEPR	Integrated Energy Policy Report
IRP	Integrated Resource Planning
ISO	Independent System Operator
LPC	Local power company
MDM	Meter Data Management
MISO	Midcontinent Independent System Operator
NEPA	National Environment Policy Act
NGO	Non-governmental organization
NPV	Net Present Value
PCT	Planning coordination team

PUC	State Public Utilities Commissions or Public Service Commission
RERC	Regional Energy Resource Council
RTO	Regional Transmission Organization
SAE	Statistically-adjusted end-use
SCE	Southern California Edison
SEO	State Energy Office
TI	EPRI’s Technology Innovation program
TPP	Transmission planning process
TVA	Tennessee Valley Authority
VER	Variable renewables resources (e.g., wind and solar)

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1
FRAMEWORK FOR INTEGRATED ENERGY NETWORK PLANNING (IEN-P)

Background

The fundamental goal of traditional electric company resource planning is to develop a least-cost portfolio of electric power resources, including both supply (i.e. generation) and demand-side resources, to meet expected peak customer electricity demand plus a planning reserve margin within a defined geographic region over a specific planning time period (e.g. 5-20+ years). This approach has been used successfully to plan expansion of the electric power system for more than three decades. Although roles and responsibilities for conducting assessments have evolved in some locales as regional electricity markets have emerged (for example, ISOs and RTOs in the United States), the fundamental goal of planning has remained largely unchanged. More than 30 states require electric companies to develop Integrated Resource Plans (IRPs) or similar documents, and many of the remaining states require electric utilities to do some form of resource planning to demonstrate that company investment plans to meet electricity demand are in the public interest.

Given the rapid, ongoing transformation of the electric sector, traditional electric system resource planning methods no longer are sufficient to optimize development of a safe, reliable, affordable, and environmentally responsible power system. As natural gas generation, variable energy resources (VER)[1], and distributed energy resources (DER)[2] displace more traditional synchronous generation, their differing availability and operational reliability capabilities will need to be considered in long-term planning decisions. Additionally, long-term fuel price and energy policy uncertainty, coupled with the needs to reduce environmental impacts and withstand or recover quickly from high-impact, low frequency (HILF) events, will require attributes such as resiliency, flexibility, and sustainability to be more explicitly included in power system resource planning processes. The critical overarching challenge is to develop power system resource plans that will continue to guide investments that provide safe, affordable, reliable and environmentally responsible electricity supply. These plans also need to be resilient and flexible and support the unprecedented pace of change occurring in the production, delivery and use of electricity, and in the policies that govern energy use.

In July 2018, EPRI published a white paper entitled Developing a Framework for Integrated Energy Network Planning (IEN-P): 10 Key Challenges for Future Electric System Resource Planning. This white paper identifies and describes complex and large-scale challenges electric power system planners, regulators, and other stakeholders are confronting today in some regions of the United States and internationally, and which are expected to become more widespread in

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[1] VER refers here to renewable electric generation resources that are non-dispatchable due their variable and uncertain energy generation, such as wind and solar power resources. These types of resources also are sometime referred to as variable renewable energy (VRE) resources.

[2] DER refers broadly to supply and demand resources that are connected to the distribution system.

the future. The exploration of these critical planning challenges is an outgrowth of EPRI's Integrated Energy Network (IEN) (ien.epri.com). Electric companies, regulators, and other stakeholders can begin to take actions to implement the IEN by focusing future planning activities on addressing the challenges described in the paper.

Ten IEN-P Challenges

The ten critical IEN-P challenges identified in the IEN-P white paper are inter-related and multi-dimensional. Table 1 lists the ten IEN-P challenges along with a brief description of the challenge. The five IEN-P challenges shaded in light blue are included as case studies in this volume and the remaining five are expected to be included in the second volume. Inclusion of a challenge in the first volume of IEN-P case studies does not imply relative importance over other challenges.

Table 1-1
Ten IEN-P Challenges

IEN-P challenge	Description	Case study
Incorporating operational detail	As emerging power system resources (primarily solar and wind) replace synchronous generators (e.g., coal, natural gas and nuclear) that traditionally have provided needed operational reliability services, resource planners will need to explicitly consider operational reliability capabilities of candidate resources and methods to mitigate potential impacts.	**Duke Energy** – *Integrating dynamic ancillary service requirements into long-range planning for the Carolinas*
Increasing modeling granularity	Computer models used to conduct long-range resource planning need to include finer geographic resolution and temporal granularity to address new resource planning challenges.	**Southern California Edison** – *Integration capacity analysis (ICA) as a method for locating distributed energy resources and enhancing distribution planning*
Integrating generation, transmission, and distribution planning	Future resource planning will benefit from closer interaction of planners across the entire electricity supply chain to understand how decisions at one planning level may impact other levels, and the ability to make tradeoffs between potential investments in each of these sub-systems to optimize the future overall electric power system.	**Great River Energy and Dakota Electric Association** – *Coordinating resource planning processes across Minnesota electric cooperatives*
Expanding analysis boundaries and interfaces	Electric companies are beginning to be asked by regulators and external stakeholders to address in their resource planning activities issues outside of their electric service territories and in other parts of the economy. Efficient electrification of end-use sectors, such as transportation where electricity historically has played little role, will further expand these boundaries.	

Table 1-1 (continued)
Ten IEN-P Challenges

IEN-P challenge	Description	Case study
Addressing uncertainty and managing risk	There is a growing need for resource planners to account more explicitly for key uncertainties when developing resource plans and to adopt new approaches to manage evolving corporate risks.	**Southern Company** – *Scenario planning drives company-wide engagement and better regulatory communication in the southeastern United States*
Improving forecasting	Improved and more granular forecasting is critical for robust long-term resource planning. More accurate forecasts of electric load, VER production, DER adoption, future natural gas prices, and weather are high priorities.	
Improving modeling of customer behavior and interaction	Robust system planning in the future will need to incorporate deeper understanding of electric customer behavior, incentives to change customer behavior, and the ways customer behavior may impact the performance of emerging customer resources for energy supply, storage and demand.	
Incorporating new planning objectives and constraints	Future resource plans will need to be optimized to achieve objectives beyond traditional least-cost resource adequacy, including resiliency, flexibility, and new environmental and social objectives while adhering to system operational reliability constraints.	
Integrating wholesale power markets	Increasingly, planners will need to consider the evolution of wholesale power markets that provide opportunities for companies to buy and sell energy, capacity, and ancillary services, and the impact of these markets on the economic viability of resources that provide reliability services and other desired system attributes.	
Supporting expanded stakeholder engagement	In recent years, public involvement in company resource planning has increased dramatically. Electric utilities now are engaged more than ever before in designing extensive stakeholder engagement processes related to resource planning and responding to stakeholder comments.	**Tennessee Valley Authority** – *Communicating with diverse stakeholders through targeted engagement and social media*

System planning is inherently a local activity. The key challenges planners face today — and may potentially face in the future — certainly will vary by geographic region and jurisdiction. Not all these challenges will need to be addressed immediately or simultaneously. The specific challenges, and the approaches and timing to address them, will depend on the specific issues faced by each electric company and jurisdiction.

2
TECHNOLOGY INNOVATION PROJECT: PHASE 2 – FRAMEWORK FOR INTEGRATED ENERGY NETWORK PLANNING (IEN-P)

Project Scope

EPRI launched the "IEN-P Phase 2" project in early 2018 to continue the organization's efforts to develop a more comprehensive Framework for Integrated Energy Network Planning. Although the IEN-P white paper identifies 10 critical planning challenges, it does not begin to identify *how* these challenges may be solved or provide resources or strategies that can be used by EPRI or electric companies to begin to address these challenges in practice.

This IEN-P Phase 2 project is designed to move EPRI's IEN-P work in these directions, and to provide a "bridge" that can help electric companies begin to work on solving these issues while more focused R&D projects to address these challenges are being developed, launched, and completed by EPRI and other organizations. The IEN-P Phase 2 project is also designed to enhance the socialization of the IEN-P planning challenges among EPRI members, regulators, and other stakeholders engaged in electric power system planning.

This Technical Update serves as the deliverable for Task 2 of this project. It follows the publication in September 2018 of the Task 1 deliverable (3002014288), an annotated bibliography containing more than 175 citations, which describes EPRI and other research related to the IEN-P challenges.

Developing the Case Studies

EPRI developed the case studies included in this volume from interviews conducted with individuals from electric power companies between July and November 2018. EPRI also used material from a member webcast and presentations from the 37th Annual Seminar on Fuels, Power Markets, and Resource Planning to write the case study narratives. Researchers from EPRI's Energy and Environmental Analysis (EEA) Group conducted the interviews using a semi-structured format. EPRI provided the interview questions to the participants ahead of time, but also asked new questions based on the direction of the conversation.

A list of interview questions for each case study is available in the Appendix. The information included in the case studies is based on the interviews conducted and materials consulted. It does not necessarily represent EPRI's views on this topic. In addition, views expressed in one case study do not necessarily represent the opinions of electric companies from the other case studies. Finally, the content of this paper and the views expressed in it are solely EPRI's responsibility, and do not necessarily reflect the views of EPRI members or any other contributor.

How to Use the Case Studies

The case studies presented in this Technical Update are intended to provide examples of how electric companies are beginning to address the resource planning challenges identified in the recent IEN-P white paper. Each case study chapter contains a description of the featured IEN-P challenge along with a detailed narrative from the interviews. "Key Insights" are also included at the beginning of the chapter to provide readers with the most actionable information derived from the interviews. These insights can enable transfer of knowledge and learnings among peers and show companies how others are addressing commonly-occurring challenges brought upon by a rapidly changing electricity sector. A list of resources with weblinks is also available for those who are interested in more information.

3

DUKE ENERGY – INTEGRATING DYNAMIC ANCILLARY SERVICE REQUIREMENTS INTO LONG-RANGE PLANNING FOR THE CAROLINAS

IEN-P Challenge: Incorporating operational detail

Introduction

Increased deployment of VER complicates the assessment of power system resource adequacy. Previously, utilities and system operators simply needed enough generation to meet an annual peak load and respond to the infrequent generator failure. With increased deployment of VER, they now require sufficiently flexible generation to balance system supply and demand for electricity throughout the year, including periods of significantly lower minimum net loads, while continuing to respond to contingency events.

Unfortunately, not all resources have the same capabilities to provide needed real-time reliability services essential for system operation. Generation output from wind and solar resources, for example, is uncertain and variable on a daily, hourly, and minute-by-minute basis. Moreover, these resources cannot provide services when they do not operate. This variability and intermittency requires that other resources on the grid be able to ramp up and down quickly in response to these fluctuations to maintain system reliability. Further complicating matters, generation technologies vary widely in their ability to provide different ancillary services, from system balancing and regulation services to short circuit recovery and black start.

The changing nature of the power system, combined with the heterogeneity of technology capabilities, means that electric company resource planners need to increasingly consider the operational reliability realities of their future resource buildouts. Companies must ensure the resource portfolios they choose can operate and deliver power in a flexible and reliable manner across all time frames. And, they must do this all while ensuring that they are comparing the full costs of alternatives for producing and delivering energy.

This case study describes Duke Energy's recent experiences incorporating more detailed ancillary service requirements into their long-range planning activities for North and South Carolina.

Duke Energy conducts electric operations through its Electric Utilities and Infrastructure division, which consists of five regulated public utilities—Duke Energy Carolinas, Duke Energy Progress, Duke Energy Florida, Duke Energy Indiana, and Duke Energy Ohio. Together, Duke Energy's electric operations include approximately 51,000 MW of generating capacity, comprised of 75% fossil (natural gas/fuel oil/coal), 18% nuclear, and 7% renewables (hydro and solar); 260,000 miles of distribution lines; and 32,000 miles of transmission lines. Its total service area covers approximately 95,000 square miles in six states, within which the company serves about 7.3 million retail electric customers.

The focus of this case study is Duke Energy's regulated utilities in North and South Carolina. They include Duke Energy Carolinas (DEC) and Duke Energy Progress (DEP) and serve approximately 4.1 million retail electric customers in North and South Carolina. They own about 35,000 MW of Duke Energy's total generating capacity—62% fossil (natural gas/fuel oil/coal), 27% nuclear, and 11% hydro and other (e.g., solar). DEC and DEP's generation fleet include Duke Energy's highest percentage of renewables when compared to the company's overall fleet. DEC and DEP sell wholesale electricity to municipal utilities as well as public and private utilities. Likewise, the company purchases electricity from the open market and through long-term contracts to assist in meeting load. While DEC and DEP are operated as independent utilities, its transmission system is connected to seven different adjacent transmission operators that allow the area's utilities to share resources for reliability purposes.

Although DEC and DEP's annual Integrated Resource Plan (IRP) is filed with both the North Carolina and South Carolina public utility commissions (PUCs), the company jointly commits and dispatches its Carolinas system, balancing customer demand, energy efficiency, demand-side resources, renewable energy resources, and traditional supply-side resources over a 15-year planning horizon. This case study discusses the motivation behind DEC and DEP's new approach for analyzing ancillary service needs for resource planning. It describes the company's implementation of the approach and concludes with noteworthy challenges the company has encountered and lessons learned from this experience.

Methodology

In November 2018, Duke Energy participated in EPRI's *37th Annual Seminar on Fuels, Power Markets, and Resource Planning*, held in Washington, D.C., and hosted by EPRI's research program on Integrated Energy System Planning and Market Analysis (Project Set 178B). The event featured a presentation entitled, "Impact of Integrating Solar Resources on Ancillary Requirements," that described the company's recent advances in improving its ancillary service needs analyses, and how this has impacted long-range resource planning activities.[3] To prepare this case study, EPRI used the material from the presentation, information from a follow-up phone conversation with a member of DEC's Fuels and Systems Optimization staff (who led the analyses), and information from a phone call with two members of EPRI's Grid Operations and Planning Group staff that supported DEC in implementing the methods for the analyses. Two members of EPRI's EEA Group conducted the follow-up interview with DEC using a semi-structured format. EPRI prepared questions based on Duke Energy's presentation, but also asked new questions based on the direction of the conversation.

Duke Energy's presentation outlined the motivation for DEC and DEP's interest in better understanding their ancillary service needs, the evolution of the methods it has implemented to study ancillary requirements, and the impact the methodology has had on resource planning within the company. The follow-up interview questions focused initially on understanding details about how DEC has implemented its approach for studying ancillary service requirements, and how it incorporates the analysis into its IRP analyses. It then focused on related challenges the

[3] EPRI's Annual Seminar on Fuels, Power Markets, and Resource Planning operates under the 'Chatham House Rule,' stipulating that neither the identity nor the affiliation of any speaker or participant may be revealed when discussing the seminar afterwards. EPRI obtained permission from Duke Energy to disclose its participation and presentation topic for the purpose of this case study.

company has faced, and lessons learned that could help other electric companies interested in performing similar analyses. A list of the specific interview questions is available in the Appendix.

Key Insights

- Unprecedented projected growth of solar resources in the Carolinas prompted DEC and DEP to more explicitly analyze its system ancillary needs to manage associated intra-hour intermittency, net-demand load following, and load and solar forecast error mitigation.
- Duke Energy's methodology to assess system ancillary needs has evolved from relying on static requirements to using dynamic regulation and balancing reserve requirements based on historical hourly and sub-hourly demand, solar output, solar forecast errors, and even day-ahead reserve requirements.
- The evolution of Duke Energy's consideration of ancillary requirements has allowed the company to better understand a wide-range of long-range resource planning questions (e.g., increased system production cost, avoided costs, value of storage), and has optimized reserves.

Interview Summary

Motivations

DEC and DEP's 2018 IRPs describe the companies' objective to reduce carbon dioxide emissions as part of its overall environmental footprint by at least 40% from 2005 levels by 2030, with approximately 60% of the emission reductions coming from carbon-free clean energy resources. Combined with enabling federal and states policies, such as South Carolina's Distributed Energy Resources Program Act (SC Act 236), North Carolina's Renewable Energy and Energy Efficiency Portfolio Standard (NC REPS), and North Carolina's House Bill 589 (HB 589), the DEC region projects tremendous growth in solar resources during the next 15 years. The 2018 IRP shows growth in solar from about 1,200 MW in 2019 to more than 3,400 MW in 2033. Meanwhile, solar capacity in the DEC and DEP combined systems is projected to grow to nearly 8,000 MWs by 2025.

DEC's 2018 IRP notes the concurrent need to ensure resource adequacy and provide continuous, reliable electric service to its customers throughout its planning horizon. With the projected significant near-term growth of solar in the region, DEC and DEP became interested in better understanding strategic flexibility issues related to renewables integration, and reserves requirements to ensure resource adequacy for long-term planning. Specifically, they recognized a need to more explicitly analyze system ancillary needs given the intra-hour intermittency, net-demand load following, and forecast error issues that arise when integrating more solar.

The evolution of ancillary requirements analysis at DEC and DEP

DEC and DEP hold three main reserve products:

Table 3-1
DEC ancillary service products

Product	Service	Time frame
Regulating (up and down) reserves	Manage intra-hour intermittency and load-following needs	10-minute
Balancing (up and down) reserves	Manage inter-hour forecast errors and loss of the largest single generating resource (n-1)	Hourly
Contingency reserves (3)	Manage the loss of the largest unit in the company's Reserve Sharing Group[4]	N/A

As recently as five years ago, DEC and DEP used a static requirement to determine regulating reserves for managing intra-hour intermittency issues on the system based on 10-minute load variability. The company also used a static requirement to determine balancing reserve requirements based on a day-ahead operating reserve value in the 'up' direction only.

Motivated by the region's expected continued solar growth, DEC and DEP's Resource Planning department collaborated with the company's Fuels and System Optimization department to incorporate expertise in hourly and sub-hourly system operations planning into long-range resource planning. To do so, the company first adopted EPRI's InFLEXion Tool to aid in determining its regulating, balancing, and contingency reserve requirements. EPRI's InFLEXion flexibility assessment tool provides planners with a method to evaluate whether a power system has sufficient flexibility to meet future needs. It helps determine reserve requirements of a system over multiple horizons, the available reserves from a resource fleet, and whether a system has enough reserves to meet variability and uncertainty needs (e.g., from increased renewable deployment). The tool uses outputs from a production cost model, reviews system dispatch, and performs a 're-analysis' of how units could respond (up or down) at individual intervals should they need to do so. InFLEXion has three main levels of functionality:

- **Level 1** identifies flexibility requirements (e.g., ramping requirements, locations contributing to variability, timing of ramping requirements, forecast error metrics)
- **Level 2** assesses flexibility (engineering) capabilities of resources on the system (e.g., maximum technical flexibility, demand response)
- **Level 3** assesses frequency metrics (e.g., how often is the system short on flexibility / available reserves, net flexibility).

[4] The Reserve Sharing Group is a group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority's use in recovering from contingencies within the group.

Duke Energy initially employed InFLEXion for its Level 1 analysis capabilities, to characterize the change in variability as more renewables entered its system and to calculate detailed 24-hour monthly net-load profiles (load minus solar). The company's main interest, at that point, in InFLEXion was its 'pre-processing' capability to calculate net-load using demand and renewables combined variability. Albeit a *seemingly* small step, this departure from using static requirements and simple planning margins toward relying on more active consideration of net load based on historical hourly intermittency of load and renewables marked a major transition for DEC in how it understood its reserves needs and served as a spring-board for further analyses.

In 2018, DEC adopted EPRI's new Dynamic Assessment and Determination of Operating Reserve Software (DynADOR) methodology to continue improving its understanding about the level of ancillaries needed over different time horizons. Originally developed as an operations tool, DynADOR computes reserve requirements for power systems for day-ahead and real-time. It can also develop reserve requirement inputs for long-term planning and renewable integration studies. DynADOR uses a more sophisticated four-step methodology to:

- Define reserves based on the need and scheduling process where the reserve is held and released
- Review historical reserve needs based on variability and uncertainty
- Assess the statistical relationship between historical reserve needs and explanatory variables via regression
- Determine operating reserve requirements for future conditions (i.e., prediction based on the regression's explanatory variables and computed coefficients).

Using DynADOR's methodology, Duke Energy now analyzes regulating reserve needs via the historical sub-hourly intermittency of net demand (load minus solar) and balancing reserve needs via historical load and solar forecast errors, plus day-ahead operating reserves. The output is an 8760 hourly dynamic profile for each region within its planning area, each year of the planning horizon, and for each different ancillary product. The dynamic reserve requirements constructed have extended out 20+ years for use in the company's long-range resource planning analyses.

Consideration of these detailed reserve requirements within the company's production cost modeling has allowed Duke Energy to assess production cost increases driven by increasing regulation and balancing requirements (associated with additional solar); the impact of additional system flexibility (e.g., faster ramps, lower minimums); the potential benefits of adding storage; the capability of solar to contribute to balancing and regulation down reserves; and the impact to avoided costs (for determining qualifying facility rates). Incorporating this level of reserve requirement detail in Duke Energy's resource planning activities has helped the company better assess ancillary needs on particularly challenging days (e.g., low load/low solar across the 'valleys,' but with high load/low solar system peaks), which has in turn enabled DEC and DEP to better optimize reserves.

Conclusion

This case study highlights how two Duke Energy electric companies, DEC and DEP, have incorporated more operational detail into their long-range integrated energy network and resource planning activities. Over the last five years Duke Energy's methodology to assess system ancillary needs has evolved from relying on static requirements to using dynamic regulation and balancing reserve requirements based on historical and projected hourly and sub-hourly demand, solar output, solar forecast errors, and even day-ahead reserve requirements. Employing EPRI's InFLEXion and DynADOR flexibility and reserve requirements analysis tools, Duke Energy has more accurately assessed its ancillary needs across a range of time horizons and potential renewable forecasts, integrated detailed reserve requirement profiles into modeling analyses to better understand a wide-range of resource planning questions, and avoided over-carrying reserves. In the coming months, Duke Energy expects to implement the methodology for other operating companies within Duke Energy's Electric Utilities and Infrastructure division; Duke Energy Florida is expected to begin using the DynADOR methodology in 2019.

While the new modeling approach has been valuable to DEC and DEP, the implementation did not occur without challenges. Most noteworthy is the fact that adequate data sources are routinely hard to find. The company has used US national laboratory data for day-ahead solar forecast errors, but did note an interest in finding a new, substitute dataset. Estimating the hourly behavior of load and VER 20 to 30 years out for long-range planning analyses is another challenge the company is working through. Uncertain technology innovation and deployment, specifically for solar technologies, is just one of many issues that complicates estimating future net load. Finally, as is the case with most complex statistical analyses, finding an adequate set of explanatory variables for predicting future reserve requirements with DynADOR was challenging. The adoption by more companies of this, or a similar approach to estimating reserve requirements, could lessen the burden in this area through the sharing of insights and best practices.

Resources

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4

SOUTHERN CALIFORNIA EDISION – INTEGRATION CAPACITY ANALYSIS (ICA) AS A METHOD FOR LOCATING DISTRIBUTED ENERGY RESOURCES POTENTIAL AND ENHANCING DISTRIBUTION PLANNING

IEN-P Resource Planning Challenge: Increasing modeling granularity

Introduction

As VER and DER replace more traditional synchronous generation, system planning will increasingly need to explicitly consider the characteristics of supply-side and demand-side options to choose systems that minimize costs and still maintain reliability. Consideration of the potential operational reliability impacts of different portfolios of system resources will require resource planning models that incorporate more granular spatial and temporal assessments of power system operation.

The location of power system resources can impact operational reliability and the costs associated with a given resource plan. DERs such as battery storage and rooftop solar PV are typically adopted by neighborhood, so they can disproportionately impact local distribution circuits, and at high penetrations, can aggregately impact local transmission. Furthermore, the actual locations where DER are deployed can impact bulk generation and transmission investment decisions. Resource planners may need to model and simulate more granular spatial and temporal representations of resources and loads to better understand these interdependent transmission and distribution planning needs.

Southern California Edison (SCE), a vertically integrated, investor-owned utility (IOU), is the largest subsidiary of Edison International and supplies electricity for much of Southern California. Its service territory covers approximately 50,000 square miles and serves approximately 14 million people.

This case study describes how SCE utilizes integration capacity analysis (ICA) to analyze its distribution system with increased spatial granularity.

ICA quantifies the capacity of the distribution system to accommodate DERs and can enable more efficient siting of DERs. SCE’s experience in developing and utilizing ICA illustrates how one company visualizes their distribution system and locates DER potential, particularly battery storage and solar PV, as a part of the distribution planning processes. The case study outlines the ICA methodology used by SCE to locate DERs as well as motivations for, and insights and challenges derived from, conducting this type of analysis. It provides an example of how increasing spatial modeling granularity can facilitate distribution planning that is more responsive to changing market conditions and a shifting grid landscape.

SCE also sees value in aligning the deployment of DERs in a way that benefits its overall decarbonization strategy. In late 2017, SCE presented its plan for reducing greenhouse gas (GHG) emissions and air pollutants in a white paper, *The Clean Power and Electrification Pathway: Realizing California's Environmental Goals (CPEP).* Through CPEP, SCE has proposed a three-prong pathway to meet the myriad targets outlined in California's GHG emissions reduction legislation. The first prong aims to supply California's electricity grid with 80% clean electricity by 2030 through both utility-scale and customer-owned clean energy resources. Although CPEP acknowledges that large scale renewable energy may provide "the most significant and affordable means of decarbonizing the electricity supply," it also maintains that DERs such as rooftop and community solar can address customers' desire to make their own clean energy choices.

Methodology

In October 2018, EPRI interviewed individuals from SCE's planning departments using a semi-structured format. Two members of EPRI's EEA Group conducted the interview via webcast. EPRI provided the interview questions to the participants ahead of time, but also asked new questions based on the direction of the conversation. Prepared interview questions focused on understanding the motivations for improving model spatial resolution for distribution planning, and the specific tools and processes used to conduct this modeling. Interview questions also centered on elucidating any challenges or lessons learned from SCE's experience, as well as how the modeling effort would continue or be improved in the future. A list of the specific interview questions and topics is available in the Appendix.

Key Insights

- Legislation motivated SCE's usage of ICA to increase modeling spatial granularity for distribution planning.
- SCE uses a 'representative' circuit method to address computational tractability issues associated with circuit-level modeling for distribution systems in initial iterations of the ICA.
- SCE uses ICA to identify distribution circuits where there is sufficient hosting capacity to accommodate DERs. The company also is exploring how ICA can be used to prioritize distribution deferral.
- Developers use publicly available GIS maps that present the results of ICA to determine if a location has sufficient hosting capacity for their project and to estimate the costs of interconnection.
- SCE has identified a need to better align planning assumptions for DRP, IRP, and TPP processes both internally and externally even as the processes remain separate and maintain different objectives.

Interview Summary

Motivations

In 2013, California passed AB 327, subsequently instituted as Public Utilities Code Section 769, which required the state's regulated utilities to file distribution resource plans (DRPs) with the CPUC by July 1, 2015. The DRPs are required to "identify optimal locations for the deployment of DERs," defined by the regulation as distributed renewable generation resources, energy efficiency, energy storage, electric vehicles, and demand response technologies. Subject to this regulation, SCE sought a method to improve and enable efficient siting of DERs in its distribution system. To achieve this, the utility would need to improve the spatial resolution of its distribution system models. Specifically, they would need to understand which distribution circuits had sufficient hosting capacity to accommodate increased penetration of DER without threatening the quality and reliability of the distribution system.

SCE has also pushed internally to align the deployment of DERs in a way that benefits its overall decarbonization strategy. As a result, increasing modeling granularity may also provide a means to address other IEN-P challenges, which is discussed more in depth later in this section. In this specific case, it provides greater operational and geographic detail for distribution planning, which can assist companies with understanding how new resources, independent of their environmental benefits, will affect the operational attributes of their systems. On the other hand, it can assist utilities with meeting new planning objectives or constraints, which in SCE's case relates to the company's decarbonization goals. In this context, the increasing modeling granularity IENP challenge serves to "enable" addressing other IEN-P challenges.

Integration capacity analysis (ICA) methodology

In its rulemaking pursuant to Section 769, the CPUC instructed the California IOUs, including SCE, to develop a common methodology for facilitating DER integration and to use the same power system modeling software for analysis. SCE outlined the ICA methodology, which meets these requirements, in its DRP. Broadly speaking, SCE uses ICA to find locations on the grid where there is available DER hosting capacity. ICA quantifies the capacity of the system to integrate DERs within specific limitation categories[5] that are common among the utilities, helping to ensure operational reliability of the distribution system.

Specifically, SCE is utilizing the Iterative Method for ICA, which as a set of methodological guidelines, is compatible for use with existing distribution planning tools, including CYME, which SCE uses. The method also mirrors the 'Iterative Method' described by EPRI in the report, *Impact Factors, Methods, and Considerations for Calculating and Applying Hosting Capacity* (EPRI 2017). During the ICA development process, SCE collaborated with EPRI to benchmark results and review methodological parameters. The final guidance associated with this rulemaking also instructed the utilities to develop projects that demonstrate the technical validity of the ICA methodology, which are discussed in this case study.

Based on the results of ICA, SCE creates Distributed Energy Resource Interconnection (DERiM) maps, which are publicly available online in an ESRI ArcGIS format. The DERiM maps present the ICA data for two different types of hosting capacity (charge and discharge), but also contain additional circuit-specific information and filtering mechanisms and are accessible from mobile devices with internet access. Aside from internal use, these maps mostly are used externally by developers wanting to determine whether a specific location on the grid has sufficient hosting capacity for their project. Developers also incorporate improved estimates of the costs of interconnection obtained from the maps into their project bids.

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[5] The four limitation categories are thermal ratings, protection system limits, power quality standards, and safety standards of existing equipment.

Despite the advantage ICA provides via improved spatial resolution of distribution system models, the high number of distribution circuits significantly increases the computational power needed to conduct the ICA. SCE uses a representative circuit method to make modeling their distribution system circuits more computationally tractable. The utility used k-means clustering (k = 30) to identify 30 representative circuits based on a range of features intentionally selected based on their ability to influence hosting capacity.[6]

Use of ICA in distribution planning

Traditionally the distribution system has moved electric power in unidirectional flows from the bulk power system to end-use customers. Distribution planning focused on accomplishing this in a cost-effective way that met electricity demand and maintained reliability. With increased deployment of DERs, distribution planners must now plan for bidirectional flows of electricity and system impacts from the interconnection of customer-owned assets. Overall, ICA enables more efficient siting of DERs, which helps inform the distribution planning process and assists with smoothing the interconnection of DERs into the distribution system.

Distribution planners must also determine whether system infrastructure and assets need upgrades or maintenance. SCE is working to determine how ICA can be used to prioritize locations with sufficient hosting capacity for distribution deferral. In the past the company used qualitative metrics to assess candidate circuits but is now improving its ability to conduct this assessment with quantitative metrics. SCE noted that larger questions remain regarding where to deploy storage at the system level, and that unfortunately, it has been difficult to align transmission system planning tools with distribution planning tools.

Alignment of utility planning processes

The previous sections have discussed how SCE has used ICA to improve its distribution planning process. Another way, aside from improving modeling granularity, to meet the planning challenges of the changing electricity sector is to align, where appropriate, the various utility planning processes.

Moving forward, SCE identified a need to better align assumptions for IRP, DRP, and transmission planning (TPP) processes both internally and externally. Although these processes have different objectives and remain under the jurisdiction of separate agencies (i.e., IRP, DRP – CPUC; TPP – CAISO), it is feasible to coordinate the forecasts and assumptions that underpin them. Efforts already are underway to ensure internal consistency at SCE on demand forecasting among the DRP, IRP, and TPP teams. In another example, SCE plans to use the results of distribution deferral analysis from the DRP to inform the optimization conducted in the IRP.

Externally, SCE participates in a demand forecasting working group with other California utilities to align planning assumptions. By participating in California's Integrated Energy Policy Report (IEPR) development as well, SCE hopes to continue to align the assumptions that are input into the separate planning processes. SCE did, however, indicate a need for improvements

[6] For more information on the specific features selected and their effect on hosting capacity, see Chapter 2, Section 4 of SCE's DRP.

to the IEPR data to produce better hourly load profiles, more standardized load shapes, and application across the entire CAISO region.

Conclusion

This case study highlights the work one utility is doing to increase the spatial granularity of its power system models. SCE's experience in modeling the hosting capacity of its distribution circuits provides both a sample methodology and sample applications for this type of exercise. As the case study details, more granular spatial representation of the distribution system can have benefits for both DER deployment and improved distribution planning. When asked about next steps related to these modeling efforts, SCE offered the following insights:

- More stochastic modeling is needed, particularly in support of an improved understanding of potential future impacts of climate change.
- There is a need for more granular solar and wind forecasts that can help planners better understand resource needs, especially in the context of high renewable mandates.
- There is a need for a common view of assumptions. To SCE, consistency of the forecast and having everyone in CAISO use the same one is more important than the specific forecast used. Understanding the assumptions on which stakeholders disagree is just as important as understanding the ones on which they do agree.

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5
GREAT RIVER ENERGY AND DAKOTA ELECTRIC ASSOCIATION – COORDINATED RESOURCE PLANNING ACROSS MINNESOTA ELECTRIC COOPERATIVES

IEN-P Challenge: Integrating generation, transmission, and distribution planning

Introduction

The Integrated Energy Network (IEN) requires tighter integration of electricity generation, transmission, and distribution (GT&D) planning to optimize the system, while continuing to minimize costs and ensure system reliability. While closer coordination of traditionally separate planning processes reverses the recent trend to separate GT&D planning functions in order to promote a competitive environment, future resource planning will benefit from closer interaction of planners across the entire electric company supply chain to understand how decisions at one planning level can impact others.

Traditionally, electric companies, particularly vertically integrated utilities, have performed GT&D planning as three separate processes, aligned with their respective business units and focused on operations. Generation planners sit separately from transmission and distribution planners, with interactions between the groups typically limited to collecting basic information and performing high-level analyses to guide decision-making. For example, transmission planners may receive scenarios of potential future generation resources from resource planners and use them as exogenous inputs in their transmission planning analyses. This contrasts with the possibility of co-optimizing generation and transmission resources to arrive at potentially lower cost system designs.

However, future resource planning will require improved coordination between GT&D planners, particularly as distribution systems integrate more DER and increase their capability to provide ancillary services (A/S) to supplement or compete with bulk A/S. Appropriate data sharing and coordination of internally consistent forecasts and assumptions across planning groups within electric companies will be important to accurately capture both macro- and micro-level drivers. While this may challenge existing compartmentalized planning processes and require development of new organizational processes, it can enable optimization of investments in the face of DER uncertainty and enable more optimized deployment of DERs based on analyses that determine locational value.

This case study features an example of how two electric cooperatives, Great River Energy (GRE) and Dakota Electric Association (Dakota Electric) are attempting to coordinate aspects of GT&D planning by leveraging their member-owner relationship.

Through both a sustained effort to align forecasts and planning assumptions, and participation in grid modernization initiatives that promote advanced technology deployment, GRE and Dakota

Electric's experiences can provide valuable insight for other utilities looking to improve coordination of traditionally separate planning processes.

GRE is a member-owned, non-profit cooperative that owns generation and transmission assets in the Upper Midwest, including 3,300 MW of generating capacity and 4,600 miles of transmission lines including a 400-kV high-voltage direct-current (HVDC) line, which transports energy from GRE's largest generation facility in North Dakota to Minnesota. GRE's member-owners include 28 utilities that are all distribution cooperatives. GRE's service territory, through its member-owners, includes a large portion of Minnesota and northwest Wisconsin and about 685,000 end-user customers. Governance is structured such that the member-owner distribution cooperatives elect GRE's Board of Directors and provide additional direction and oversight through regular meetings, regional meetings, and member staff working groups.

Dakota Electric, one of GRE's member-owners, is itself also member-owned and operates as a non-profit electric distribution cooperative in four counties in the Twin Cities metropolitan area in Minnesota. As the second largest electric cooperative in Minnesota, Dakota Electric serves just over 100,000 residential, commercial, and farming members, with a peak demand of over 450 MWs. Dakota Electric purchases wholesale power from GRE and distributes it over its 4,000 miles of distribution lines. Dakota Electric is the only distribution utility of GRE's 28 member-owners that is regulated by the Minnesota PUC.

GRE, on behalf of Dakota Electric and other distribution cooperatives, met Minnesota's renewable energy goal of generating 25% of its electric energy from renewable resources by the year 2025 in 2017, and has established a voluntary target of 50% renewable energy by 2030. GRE and Dakota Electric must also meet a state requirement of 1.5% demand response (DR). They currently meet 1% of this requirement through its member directed programs, with the remaining 0.5% from its own supply-side Electric Utility Infrastructure program.

Methodology

In late July and early August 2018, EPRI interviewed individuals from GRE and Dakota Electric using a semi-structured format. Representatives from GRE were based in both the Power Supply and Transmission groups, and the representative from Dakota Electric was in the Engineering Services group. Two members of EPRI's EEA Group conducted the interview via webcast. EPRI provided the interview questions to the participants ahead of time, but also asked questions based on the direction of the conversation. Prepared interview questions focused first on understanding the respective generation, transmission and distribution planning processes in place at each cooperative. They then turned to the successes and challenges experienced by the GRE and Dakota Electric with respect to coordinated planning efforts, several of which align with grid modernization initiatives in Minnesota. A list of the specific interview questions and topics is available in the Appendix.

Key Insights

- GRE and Dakota Electric's participation in grid modernization initiatives, including that of the Minnesota PUC, has helped consolidate discussion and collaboration related to coordinated GT&D planning in Minnesota.
- Beginning in 2018, GRE will use a new modeling tool for capacity expansion and production cost modeling. The new tool includes advanced features for demand-side resources and improved user support.
- To develop estimates of load, GRE also plans to integrate more statistically-adjusted end-use (SAE) modeling alongside multiple regression-based forecasting. Presently, GRE uses retail data from Dakota Electric and its other member-owners to produce load estimates that are fed into its resource planning process.
- GRE and Dakota Electric identified several challenges related to coordinating GT&D planning including:
  - Differing data availabilities between cooperatives
  - Concerns about coordination between regulated and non-regulated distribution cooperatives that may have different planning process requirements
  - Coordination of overall planning goals, which may differ across generation and transmission utilities based on different needs
  - Future government rules or requirements that may affect existing plans
  - Uncertainty associated with DER interconnections under "requirements to serve", especially with distribution interconnected DERs that also serve transmission needs

Interview Summary

Traditional planning processes at GRE and Dakota Electric

In the past, GRE and Dakota Electric have pursued their respective planning processes both collaboratively and independently. GRE conducts its own generation and transmission planning while Dakota Electric performs its own distribution planning, but both rely on and work with each other to obtain important information for each process. Previous areas of collaboration centered mostly on coordinating and aligning forecasts, but both GRE and Dakota Electric indicated an interest in aligning additional aspects of the planning processes, particularly those impacted by increased penetration of DERs.

GRE's most recent integrated resource plan (IRP) (2018-2032 time period) was filed in 2017 and accepted by the PUC in 2018.[7] The Resource Planning staff within the Power Supply division is responsible for conducting GRE's resource planning. This team solicits and considers input from across the organization, including generation, transmission, member services, and environmental and legal. GRE engages in generation resource and transmission planning separately, and coordinates with its member-owners to develop forecasts and obtain data for these processes. GRE uses meter data, which includes total system energy and demand, from its member-owners, including Dakota Electric, to produce forecasts. For example, GRE collects data monthly from

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[7] In odd-numbered years, GRE and the other Minnesota regulated utilities are also required to file a joint report notifying the public and regulators of potential upcoming transmission projects.

its 20 "all requirements" (AR)[8] members to produce load estimates. Because GRE is not a vertically integrated utility, it does not have any of its own retail meter or sales data. As a result, it must coordinate with members to obtain and understand these data.

Distribution planning remains under the purview of the member-owners like Dakota Electric. Dakota Electric's distribution planning process involves creating a long-range system plan, which provides the foundation for the development of the backbone distribution system. As part of this process, Dakota Electric reaches out to cities, counties, and townships within its service territory to learn about long-term plans for road, sewer and other infrastructure changes. The cooperative also coordinates each year with these officials on short-term projects that may impact the distribution system. In addition, Dakota Electric learns about planned zoning changes in support of area growth. Distribution planners at Dakota Electric use this land use zoning, demographic, and historical growth data to anticipate plausible futures, but face computational tractability challenges associated with the volume of data needed to plan proactively.

Dakota Electric's actual construction of the distribution system is reactionary and covers time horizons of only 1-2 years. While construction of the backbone system follows the long-range plan, local distribution infrastructure must be designed to meet the needs of electrical loads as they materialize. A key challenge in distribution planning, which Dakota Electric has experienced too, is the difficulty in knowing future deployment of new technologies such as DERs. Despite this challenge, Dakota Electric has extensive experience accommodating significant amounts of DER into their traditional planning processes. Since the 1990s, Dakota Electric has used DERs as a means to reduce system peak load and defer distribution system upgrades and investments.

Coordinated GT&D planning initiatives at GRE and Dakota Electric

Several initiatives in Minnesota contemplate how electric utilities within the state could adapt their distribution planning processes to address ongoing changes in the electricity sector. The e21 Initiative, for example, brings together a cross-section of industry stakeholders, including utility representatives, to understand how regulatory frameworks can accommodate new public policy goals, shifting customer expectations, and adoption of new technologies. In 2016, e21 Phase II released a series of white papers on performance-based compensation, integrated system planning, and grid modernization. Among the recommendations presented in the white papers was the need to "expand the scope of the planning process to [adopt] more of an end-to-end systems approach." As it stands, the traditional resource planning process considers demand-side resources but does not optimize both supply and demand-side resources to meet electricity needs. Omitting this may overlook opportunities for both cost savings and assurance of grid services as demand-side resources become more prevalent. Amidst discussions about the most efficient way to complete coordinated GT&D (system) plans, procedural (length and complexity) and technical (computational capabilities) considerations continue to surface.

Grid modernization programs focused on upgrading the electricity grid to support a more decentralized system with bidirectional communication and resource flows can support

[8] GRE serves two types of members: All Requirements (AR) and Fixed Obligation (FO) members. AR members purchase all power and energy requirements from GRE, whereas FO members only purchase a portion of power and energy requirements from GRE. GRE serves 20 AR members and 8 FO members.

coordinated GT&D planning. GRE participates in Minnesota's Grid Modernization Initiative (GMI) and recently stood up its own company-wide GMI. As a part of this program, GRE visited other utilities around the country with experience and progress in implementing grid modernization technologies to gather information and practical advice.

Phase One of GRE's GMI has two primary objectives: (1) to develop a shared vision of the future among GRE and its members, and (2) to move toward adoption of shared technology platforms. To date the focus of the second objective has been on rolling out advanced metering infrastructure (AMI) and a new more active demand response (DR) program (webDistribute).

Adoption of shared technology platforms including AMI not only can facilitate more accurate and coordinated data collection, but also can improve communication about costs and energy usage between utilities and customers. In support of improved data gathering, Dakota Electric and GRE have worked together with implementing fiber communication to all of the Dakota Electric substations. Dakota Electric is in the middle of implementing system-wide AMI with a robust meter data management (MDM) system. At the same time, Dakota Electric is replacing all of its more than 50,000 load control receivers with controls that have two-way communication.

In 2018, GRE's resource planning group began to use a new commercial modeling tool. GRE required a new model that represented system load and generation at a more granular level (i.e., hourly inputs, hourly outputs), allowing the company to better understand whether resources should be added to meet specific peak needs or to meet extended periods of energy and capacity shortfall. The model is also a first-step towards more coordinated analysis of long-term system planning and short- to mid-term modeling of MISO market interactions. As GRE increases exposure to the market, the ability to better align planning models with market models becomes more important. Finally, the new model allows for representation of GRE's renewable energy commitments and facilitates evaluation of energy storage and demand-side management, both of which may play key roles in balancing and smoothing peak load and peak market prices with increasing penetration of intermittent resources and responsive loads.

Additionally, GRE is in the process of adopting SAE modeling methods for developing load estimates, which will allow for a better look at the progression of efficiency standards and the impacts of those on the forecasting process. GRE will begin to use SAE in regulatory filings and internal forecasting operations moving forward.

Finally, GRE currently has a pilot project to model another member's distribution system hosting capacity and overlay it on GRE's GIS systems to better understand the potential for DERs on that member's system. The project uses EPRI's DRIVE tool[9], which enables electric power companies to conduct hosting capacity analysis for both existing and proposed DER. The tool has two main components: (1) an interface that extracts information from a distribution planning model, and (2) a core solution engine that calculates hosting capacity. EPRI's recent updates to DRIVE aim to enable use of hosting capacity analysis for valuation of DER investments in addition to determining where to locate DER on the grid.

[9] Distribution Resource Integration and Value Estimation (DRIVE).

GRE noted that the large amount of switching that happens on its members' systems can quickly render the results of hosting capacity analysis null. This, combined with the small rooftop solar market in their service territory, has limited their use of hosting capacity analysis. GRE proposed that analysis of minimum substation loading levels provides a more suitable alternative to hosting capacity analysis for identifying the ability of a member system in their region to integrate larger scale installations of solar and storage.

Dakota Electric continues to communicate with GRE to see how to better coordinate the distribution and transmission planning processes, a process the company labels as "cooperative planning." Coordination of these companies' transmission and distribution planning processes could help assess the feasibility and facilitate the deployment of non-wires alternatives to meet capacity needs.

Challenges to integrating GT&D planning processes

GRE and Dakota Electric offer a proactive example of different planning groups attempting to align their planning processes, which was enabled by strong support from their management teams and broader membership. However, there are potential challenges to replicating this approach. These technology and resource differences may challenge implementation of a homogenous forecasting process for coordinated planning.

The nature of distinct service responsibilities between GRE and its member-owners can both facilitate and complicate coordinated GT&D planning. As one example, GRE's member-owners have different data availabilities. Some have 15-minute load data whereas others have only hourly load data. These differences often reflect the technological capabilities and limitations provided by third-party systems and their vendors. In some cases, the different technological capabilities result directly from disparate access to broadband internet service, which can affect the accuracy and timeliness of data collection. The size of GRE distribution cooperatives' membership also varies significantly, as do their staffing levels. For example, there are some members of GRE that do not have an engineer on staff, and others that have relatively few office staff. More frequent and expanded distribution planning processes, and associated document development, may require a significant increase in resources or employees for some cooperatives that may be financially unsustainable.

As another complexity, GRE's member-owners are largely independent distribution cooperatives that are regulated by their membership through a democratically-elected board of directors. These distribution cooperatives historically have planned their distribution systems to reflect the priorities and needs of their local membership. For sustained coordination of planning to proceed, interest and benefits must be tangible, mutual, and accepted across the broader distribution cooperative membership.

Possible competition between policy goals and system operational requirements can also challenge efficient coordination of GT&D planning. For example, currently there is no requirement for DER owners or developers to notify the distribution company, such as Dakota Electric, if they would like to connect to the grid. When they do choose to connect, the distribution company – due to its 'requirement to serve' – is required to serve that interconnection regardless of its impact on the grid. This makes it difficult to proactively plan and site DERs for efficient use as non-wires upgrades or providers of other grid services. Under a requirement to serve, the siting and integration of DERs will rarely be optimal and can result in overbuilding. Thus, the requirement may be in tension with a goal of coordinated GT&D planning, which is to minimize costs and optimize resources across a changing grid. The e21 Phase II report proposes that more appropriate rate design and compensation methodologies could help ensure equitable cost sharing between utilities and independent DER providers.

Conclusion

This case study provides an example of how two electric cooperatives in Minnesota are addressing the need to better coordinate GT&D planning. As it illustrates, both GRE and Dakota Electric pursue aspects of their respective planning processes separately but have also found areas for alignment and coordination. This has been most pronounced in their forecasting and load estimates development, but also appears in their efforts to improve integration of DERs to the grid. Challenges faced by both cooperatives in accomplishing this coordination suggest that future work to identify and share examples where these challenges have been successfully addressed or overcome would be valuable.

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SOUTHERN COMPANY – SCENARIO PLANNING DRIVES COMPANY-WIDE ENGAGEMENT AND BETTER REGULATORY COMMUNICATION IN THE SOUTHEASTERN UNITED STATES

IEN-P Challenge: Addressing uncertainty and managing risk

Introduction

An EPRI review of recently published IRPs found that uncertainty and risk are prominently considered as part of electric company resource planning processes.[10] The lengthy list of uncertainties that complicate the planning process includes, but is not limited to, unknown future fuel prices; weather-forecasts; technology costs and performances; end-use technology adoption and resulting load changes; electricity market structures and participation rules; and local, state, and federal environmental, energy, and other policies.

Electric companies rely on a variety of approaches from sensitivity analyses to carefully-crafted scenario analyses to formal stochastic and probabilistic analyses to manage risk within their resource plans. Table 6-1 provides a snapshot of the range of approaches used to address key uncertainties that impact resource planning decisions.[11] Moving forward, it will be increasingly important for resource planners to recognize uncertainty in planning and develop improved risk management tools and methods to hedge against uncertainties.

Table 6-1
Addressing uncertain variables in system planning (EPRI, 2017)

Variable influencing system planning	Methods used today	Where is it considered in the planning process?
Changes in federal, state, and local regulatory policies	Scenario analysis	Resource adequacy; transmission and distribution planning
Changing supply- and demand-side resources	Scenario analysis	Resource adequacy; transmission and distribution planning
Long-term economic activities and growth	Scenario analysis	Resource adequacy
Technology improvements	Scenario analysis	Resource adequacy; transmission planning
Population movements and growth	Scenario analysis	Resource adequacy

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[10] Evolving Practices in Electric Company Resource Planning: Key Insights from a Review of 15 Recent Electric Company Resource Plans." Palo Alto, CA: EPRI, 2017. 3002009430.

[11] Developing a Framework for Integrated Energy Network Planning (IEN-P): 10 Key Challenges for Future Electric System Resource Planning. EPRI, Palo Alto, CA: 2018. 3002010821.

Table 6-1 (continued)
Addressing uncertain variables in system planning (EPRI, 2017)

Variable influencing system planning	Methods used today	Where is it considered in the planning process?
Long-term fuel price variation	Scenario analysis	Resource adequacy; transmission and distribution planning
Weather-related variability	Stochastic analysis	Resource adequacy; transmission planning
Performance of generation and transmission components	Stochastic analysis	Resource adequacy; transmission planning

This case study describes a formal scenario planning process that Southern Company (Southern) has developed and refined over the last decade to address uncertainty and risk in resource planning.

Southern's mission calls for the delivery of 'clean, safe, reliable, and affordable' electricity to its customers. The company provides electricity to approximately 4.5 million retail customers in the southeastern United States via four regulated, vertically-integrated operating companies (Alabama Power, Georgia Power, Gulf Power (Florida)[12], and Mississippi Power). Southern also provides wholesale electricity throughout the United States via Southern Power and natural gas to retail customers in seven states through its Southern Company Gas subsidiary. The company owns approximately 46,000 MW of generating capacity; the energy mix is approximately 47% natural gas, 27% coal, 14% nuclear, and 11% hydro and other renewables. Over 6,500 MW of renewable energy-based capacity has been committed to or deployed on Southern's system since 2012. While each of Southern's vertically-integrated operating companies is regulated by its respective state's public service commission, the entire Southern system is managed and operated (economically dispatched) as a single entity.

For over a decade, Southern has performed formal scenario planning as part of its resource planning process to better manage future uncertainties and communicate with regulators. Southern's process consists first of developing a range of planning scenarios that identify important drivers of change in the energy industry, including potential future carbon and other environmental policies, fuel prices, and technology development. Each planning scenario is then analyzed using a multi-sector energy-economy model to characterize the range of potential resulting evolutions of the electricity, transportation, manufacturing, industrial, commercial, and residential sectors (i.e., 'states of the word'). These states of the world in turn provide the basis for Southern's resource planning team to assess the merits of a candidate resource strategy. This case study describes Southern's motivations in developing its existing scenario planning process; sketches how the company structured and implements the process; and concludes with some key challenges the company still faces.

[12] In May 2018, Southern Company announced the sale of Gulf Power Company, as well as Southern Power's Oleander and Stanton plants.

Methodology

In November 2018, Southern participated in EPRI's *37th Annual Seminar on Fuels, Power Markets, and Resource Planning*, held in Washington, D.C., and hosted by EPRI's research program on Integrated Energy System Planning and Market Analysis (Project Set 178B). During the event, Southern outlined the company's scenario planning process, including its main objectives and overall structure.[13] To prepare this case study, EPRI used the material from the presentation and information from a follow-up phone conversation with two members of Southern's Resource Planning staff that direct and participate in the company's scenario planning process. Two members of EPRI's EEA Group conducted the follow-up interview using a semi-structured format. EPRI prepared questions based on Southern's presentation, but also asked new questions based on the direction of the conversation. The follow-up interview focused initially on understanding the company's motivations for developing the scenario planning process and details about how the company implements the process. The follow-up interview then focused on related challenges the company has faced and lessons learned that could help other electric companies interested in performing similar analyses. A list of the specific interview questions is available in the Appendix.

Key Insights

- Southern addresses uncertainty and manages risk in long-range resource planning through a formal, annual, and centralized scenario planning process.
- The scenario planning process provides Southern with a structural and process-driven mechanism to support company-wide awareness of a range of future uncertainties (and their data sources) and create a joint sense of ownership in the scenarios.
- Southern prioritizes fostering engagement across the company, and development of a set of scenarios that can be used as part of effective and transparent communication with regulators of resource planning intentions.

Interview Summary

Motivations

Since the early 2000s, Southern has used a scenario planning process to evaluate the costs and benefits of resource strategies under a range of future electricity demand, market, technology, and policy uncertainties. Initially, scenarios focused on evaluating decisions against three relatively simple gas price forecasts. However, the company saw only limited value in such narrow analyses. Moreover, different areas of the company had different perspectives on the future of natural gas prices, resulting in the use of different forecasts and related assumptions for analyses relevant to the overall company. This decentralized process led to an overly heterogenous set of views about potential futures the company would face, and divergent views about optimal business decisions moving forward.

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[13] EPRI's Annual Seminar on Fuels, Power Markets, and Resource Planning operates under the 'Chatham House Rule,' stipulating that neither the identity nor the affiliation of any speaker or participant may be revealed when discussing the seminar afterwards. EPRI obtained permission from Southern Company to disclose its participation and presentation topic for the purpose of this case study.

The complexities that ensued from the lack of coordination prompted Southern to create a Planning Coordination Team (PCT) tasked with the objective to standardize key planning-related input assumptions among different areas of the company. The PCT's mission was not to dictate a specific assumption or set of assumptions for company-wide analyses, or reach consensus on a best set of assumptions, but instead to facilitate common awareness about the range of views for future uncertainties and streamline the acquisition of data and assumptions from the same set of sources. Overall, the process that Southern put in place to centralize its scenario planning activities consists of a structure (e.g., the PCT) and a process. One of the key deliverables is 'engagement,' with success measured by the level of company-wide understanding about the uncertainties and the development of a sense of ownership in the scenarios. According to Southern, "understanding and ownership end up being at least as valuable as the formal deliverables."

A structured, centralized scenario planning process

Southern has continued to refine its scenario planning process since the early 2000s. Today it is composed of three core structural components: an executive-level Planning Coordination Team (PCT), internal working groups, and a planning committee that includes representatives from the four retail operating companies. Each group above meets monthly. Key uncertainties that are routinely evaluated at Southern include cost and performance of technologies, environmental policies, load forecasts, and fuel supply and demand conditions.

- **Executive Planning Coordination Team (PCT):** Internal executive-level group that works across the company's 'silos,' and with external experts to develop scenarios for each cycle. The Executive PCT hears consensus recommendations from company working groups, discusses the recommendations' merits, and provides approval. The PCT has eight members, consisting of Vice Presidents and Directors from Commercial Operations, Planning, and Environmental; Financial Planning; Transmission Planning; Nuclear Regulatory Affairs; Engineering and Construction Services; R&D; and Marketing Services. The Resource Planning group manages the Executive PCT and sets the agenda for each meeting.
- **Working Group(s):** Internal staff-level (e.g., project manager) groups that perform and validate analyses, and coordinate alignment of data and assumptions across the company. Staff from each of the groups that participate in the Executive PCT form the basis of the working groups. Currently, Southern has two working groups—one related to a broad range of uncertainties and scenario development, and another focused on distributed energy resources (DERs).
- **Planning Committee:** Members of the Working Groups plus retail operating company planning and other personnel (e.g., environmental, regulatory affairs, financial planning) that provide input on the scenarios.

A fourth component of the company's overall scenario planning structure is a 'Planning Council' that involves approximately 100 individuals from the operating companies, as well as Southern Company Services itself. The goal of Planning Council meetings is to hear reports about the process and results and ask questions.

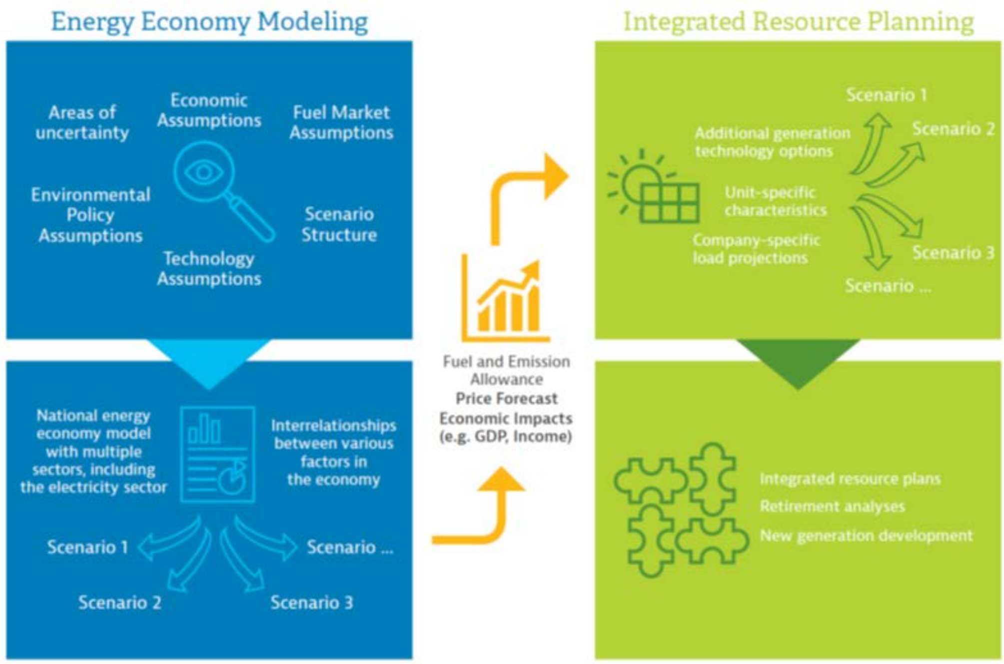

Figure 6-1
Southern Company's Scenario Planning Process (Southern Company, 2018)

Southern's scenario planning process takes place annually, supporting the company's integrated resource planning process, and occurs in two steps. As shown in Figure 6-1, the first step involves energy-economy modeling, during which the company collaborates with external experts to analyze the impact of different plausible futures (e.g., fuel market drivers, climate policy) on the evolution of the macro-economy. The company employs a multi-sector energy-economy model to develop a set of scenarios depicting the future state of multiple energy sectors, including electricity. Data outputs from the energy-economy modeling (e.g., fuel prices, load growth) are then used to inform the second step, integrated resource planning. In this step, dedicated teams within Southern's Resource Planning and Generation Planning and Development Groups use the modeling outputs to evaluate the range of costs and benefits for resource investment(s) under consideration. Resource strategies are typically analyzed for direct cost effectiveness (compared to alternative strategies), and local community impacts (e.g., jobs, taxes). Results from scenario runs are discussed with operating company personnel, and ultimately with state regulators.

It is noteworthy that Southern does not pick 'favorites' among the scenarios it chooses to analyze each year, nor does it affix probabilities to the scenarios. The scenarios and subsequent planning results are meant to convey the *range* of cost uncertainty, not a single number or summary statistic. Each resource strategy is ultimately compared against the 'next best option' in the resource planning process, and the company makes its recommendation(s) to the regulator recognizing the uncertainties.

The concept that future uncertainties create challenges for *both* business and regulatory decision-making underpins Southern's effort to communicate its scenario planning results to public service commissions alongside its filings. As an example, Southern avoids probability-weighting resource planning results by scenario 'likelihoods' because the company believes it is important to convey that the level of uncertainty in forecasts and other assumptions cannot be known by either the company or regulators with any strong degree of confidence. Put simply, the de facto 'right' answer for a specific resource strategy in the face of uncertainty cannot be known ahead of time. Instead, the company presents the full set of net present values (NPVs) resulting from evaluating the resource strategy in question against each potential scenario, emphasizing that the resource recommendation being made is a *single* decision in a larger, long-term resource planning problem. The company recommends a specific resource strategy with the best available information at the time. If, it turns out the decision was not optimal given the realization of future uncertainties, there is an opportunity to 'course-correct' at the next decision-point with the best information available at that time. Paramount to the company's scenario planning process and communication of results with regulators is that both the company and regulators truly understand and internalize the range of uncertainties at play, and the magnitude of impacts for each resource decision.

Conclusion

This case study describes how one electric company—Southern—addresses uncertainty and manages risk in resource planning through an annual, formal, and centralized scenario planning process. Motivated by an initial misalignment between different areas of the company on key inputs used in company-wide analyses, Southern created a rigorous structural and process-driven solution to support company-wide awareness of the range of future uncertainties, facilitate understanding about the uncertainties and associated data sources, and create a strong sense of ownership in the scenarios among company groups. Southern prioritizes fostering engagement across the company and development of a set of scenarios and modeling outputs that can be used to effectively and transparently communicate resource planning decisions to regulators. Overall, the company has been pleased with the effectiveness of its scenario planning. Internal engagement is high and individuals truly enjoy participating in the process, regarding it as an important mechanism to understand key drivers within the industry. Regulatory discussions have also been enhanced and have resulted in an improved understanding of uncertainty among involved stakeholders.

A key challenge experienced by Southern as it continues to execute its scenario planning process is the management of related expenses. From a labor perspective, the engagement of many different individuals on teams, working groups, and committees tasked with developing inputs, discussing and vetting modeling results, communicating results, and approving scenarios is a costly endeavor. Additionally, the use of external experts to run a multi-sector model and help develop economic assumptions for a range of possible futures is expensive. Managing these expenses to keep overall costs reasonable year after year has been challenging.

A second, related challenge is that the company's formal, centralized process (and sheer number of individuals participating), creates a need to spend extra effort 'socializing' scenario assumptions and inputs, and overall goals. Despite not needing to reach consensus on the 'right' future, Southern does seek consensus on the range of uncertainties to consider each year, and how they should be organized into a discrete set (approximately ten) of useful scenarios. To date, the company has been addressing this challenge through extensive 'leg-work' and discussions to align participants' expectations and ideas.

A third challenge lies in the assumptions about future uncertainties themselves. Developing economy-wide forecasts for major uncertainties such as GDP, income, and fuel markets over 20-40 years requires important assumptions about the trajectory of inputs to that energy-economy modeling process. And, it remains difficult, for example, for the company and its external experts to agree upon some of these assumptions (e.g., future technology costs and performance attributes). It is important for the company to consider technology development and cost impacts at the national and global scale, but also to reflect expectations about the Southeastern U.S. Unfortunately, these forecasts do not always align.

Finally, a fourth challenge Southern faces in its scenario planning is in the initial consideration of alternative futures. There remains a tension between crafting familiar scenarios that facilitate continuity and slower change from one year to the next and considering futures that lead to significant departures and more rapid changes from past plans. This is a challenge embedded in all uncertainty analysis and risk management processes, and one that Southern continues to experiment with and push the state-of-the-art on.

Resources

Evolving Practices in Electric Company Resource Planning: Key Insights from a Review of 15 Recent Electric Company Resource Plans. EPRI, Palo Alto, CA: 2017. 3002009430.

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TENNESSEE VALLEY AUTHORITY – COMMUNICATING WITH DIVERSE STAKEHOLDERS THROUGH TARGETED ENGAGEMENT AND SOCIAL MEDIA

IEN-P Challenge: Supporting expanded stakeholder engagement

Introduction

PUCs and other regulators have traditionally been the primary audience for electric company IRPs while other stakeholders such as environmental organizations, consumer advocates, business groups, and other local non-governmental organizations (NGOs), have been more peripherally engaged. In recent years, however, there has been a marked change in public expectation of involvement in electric company resource planning. Stakeholders are becoming more actively engaged in the entire resource planning process, with some explicitly wanting to address a broader array of issues, such as electricity rate design and long-term resource planning.

Electric companies and ISO/RTOs are becoming more actively involved in designing and managing extensive stakeholder engagement processes as a core part of their resource planning activities. In addition to the scoping phase of planning activities, companies are now involving customers and other stakeholders in the design and review of many aspects of their operations.

This case study describes the Tennessee Valley Authority's (TVA) approach to stakeholder engagement during its IRP process. It outlines the methods used by TVA and discusses challenges TVA has faced in creating a comprehensive stakeholder engagement strategy.

TVA has developed and expanded its stakeholder engagement activities over three IRP cycles, and its experience can provide valuable lessons learned for other utilities looking to build their own stakeholder engagement strategies.

TVA is a federally-owned wholesale electric power generation and transmission utility that provides electricity to 154 local power companies (LPCs) and several large industrial and federal customers. In total, TVA wholesale power reaches nearly 10 million customers over 80,000 square miles in seven states across the Tennessee Valley. TVA does not receive taxpayer funding and generates all revenue from its sales of electricity. TVA owns and operates more than 70 generation facilities and serves as a regional grid reliability coordinator. TVA is unique among utilities in that it also has a mission to provide additional public services to residents such as flood control, navigation and land management, and economic development opportunities.

TVA is not regulated by a state utility commission, but rather has a nine-member Board of Directors established by the Executive Branch of the United States Government. As a federal agency, TVA must comply with the National Environmental Policy Act (NEPA). As a result, the company completes an Environmental Impact Statement (EIS) that analyzes the environmental impacts of its IRP if adopted. The IRP and EIS are produced in parallel, forming Volumes I and II of TVA's IRP. TVA indicated that the EIS leads to more holistic analysis in that it covers environmental and socioeconomic issues that may not otherwise be considered in a traditional IRP. In addition, the NEPA requirement for public consultation further encouraged TVA's efforts to communicate with external stakeholders. TVA previously created IRPs in 2011 and 2015 and is currently preparing a new IRP for 2019.

Methodology

In early November 2018, TVA participated in an EPRI member webcast focused on stakeholder engagement during the IRP process. The webcast entitled, "Stakeholder Engagement in the 2019 IRP" featured a speaker from TVA's Enterprise Relations and Strategic Partnerships department. EPRI used the material from the webcast and information from a follow up conversation to prepare this case study. Two members of EPRI's EEA Group conducted the follow up interview using a semi-structured format. EPRI prepared questions based on the participant's presentation, but also asked new questions based on the direction of the conversation. TVA's presentation outlined the company's overall stakeholder engagement strategy and how it has been developed over successive IRP cycles. The follow-up interview questions focused initially on understanding in more detail TVA's social media stakeholder engagement strategy, and later focused on lessons learned and methods for measuring effectiveness. A list of the specific interview questions and the slides from the webcast are available in the Appendix.

Key Insights

- TVA devised a 'multi-level' engagement strategy to meet the diverse information needs of customers, government agencies, industry groups, non-profit and advocacy organizations, and other stakeholders who are interested in learning about and commenting on their IRP.
- As a wholesale electricity generator and transmitter, TVA was challenged in communicating its role and relevance to retail customers. TVA collaborates with local power companies (LPCs) to help explain its role and avoid confusion.
- TVA developed a new social media strategy to solicit comments on its IRP and educate stakeholders about the process of electricity delivery, from generation to final consumption.
- Framings its public messaging around the theme of 'flexibility' helped TVA communicate about its IRP in a clear, consistent, and accessible way.
- To address low turnout at open houses, TVA plans to seek additional venues, such as community meetings and academic events, where interested stakeholders are already gathering.

Presentation and Interview Summary

Multi-level Engagement Strategy

TVA defines 'stakeholders' as anyone who is influenced by or influences TVA, including, but not limited to, customers, government agencies, and other residents of the Tennessee Valley. As a result, the company has developed a 'multi-level' stakeholder engagement strategy that addresses the broad array of stakeholder interests and expertise. The goal, articulated by TVA, is to engage stakeholders consistently throughout the IRP process and not just during the typical milestones (i.e. release of a draft IRP and release of the final IRP). TVA believes that effective stakeholder engagement improves the decision-making process and leads to better outcomes.

TVA's multi-level engagement strategy consists of three tiers of stakeholder groups who provide different feedback based on their expertise and interests. They are:

- **IRP Working Group (the "Working Group").** The Working Group comprises approximately 20 individuals who are external to TVA but represent customer and other stakeholder interests. The group is established at the beginning of the IRP cycle and meets monthly throughout the cycle to review in detail the inputs and assumptions of TVA's IRP modeling. The Working Group engaged in the 2019 IRP includes the following representatives:
  - Eight customer representatives (LPCs and industrial customers)
  - Three energy and environmental non-governmental organizations
  - Three representatives from research and academia
  - Two representatives from state government
  - Two economic development representatives
  - Two community and sustainability interest representatives.
- **Regional Energy Resource Council (RERC).** TVA established this Federal Advisory Council to provide guidance on how TVA manages its energy resources against competing objectives and values. The RERC also consists of members external to TVA but meets less frequently and is responsible for validating TVA's IRP process at key milestones throughout the cycle. The RERC provides consensus advice to TVA's Board of Directors, that eventually approves recommendations from the IRP. RERC meetings are open to the public, and TVA provides advance notice of the meeting locations and topics.
- **Broader Public.** The formal groups mentioned above do not capture all stakeholders who may be interested in learning about or commenting on the IRP. TVA has created several different strategies to reach stakeholders that are not otherwise involved in the IRP process. These strategies, which are elaborated on below, include open houses, public comment periods, and social media outreach.

Recognizing that the different stakeholder groups have varying levels of familiarity and technical understanding of resource planning, TVA has devised different methods to ensure the information is accessible to all. The regularly-scheduled meetings of the formal groups mentioned above provide specific opportunities for TVA to share information and receive feedback from those stakeholders. The sustained 18-month engagement with the Working Group offers TVA the opportunity to build relationships and understand new perspectives. Throughout the IRP cycle TVA asks its Working Group members for comments and recommendations about the IRP itself and the stakeholder engagement process. Because TVA is a generator and transmitter of wholesale electricity, it does not have as much direct interaction with end-use customers. TVA invites members of LPCs, directly served customers, and customer associations to participate on the Working Group and the RERC, which helps communicate TVA's role in generating and transmitting electricity to customers, ensure consistency, and avoid confusion.

Social Media and Digital Outreach

To reach the broader public, TVA implemented a new social media strategy for the 2019 IRP cycle. The company developed content for 'traditional' social media platforms (e.g., LinkedIn, Facebook, Twitter) organized around one theme: **flexibility**. Flexibility refers to the ability to adapt to dynamic and changing conditions in the power industry brought on by, among other drivers, the rapid deployment of variable generation, dynamic load shapes, fuel price fluctuations and uncertainty, shifting policies, customer interests, and adoption of new electric end-use technologies. TVA stressed the need to communicate clearly with its diverse stakeholder audience and believed 'flexibility' articulated its motivations for and goals of resource planning in an accessible way. For TVA it was important to underscore the challenges presented by increased penetration of utility-scale and demand-side variable generation along with greater desire from customers for control over energy decisions. Framing its communication through the lens of flexibility helped accomplish this goal.

TVA used social media to deliver both invitations to review and comment on the IRP and educational resources to the broader public. With the help of in-house social media experts and external consultants, the company developed several graphics that were visually attractive and emphasized a desire to hear feedback from members of the community. Social media content is posted throughout the 18-month IRP process to maintain stakeholder awareness and engagement. TVA also plans to release a video that educates consumers on how electricity gets from the point of generation to the point of consumption. In the future, the utility plans to develop a video that explains the IRP modeling process to a non-technical audience.

TVA uses other digital resources as well to communicate with stakeholders about its IRP. It has a specific IRP website, from which it monitors web traffic, and offers two different public comment periods – one during the scoping phase of the IRP and the other after releasing the draft proposal. TVA tracks web traffic for both its social media and websites. Although there are spikes in viewership when reports are posted, visitors still spend on average only two and a half minutes on the website, which reinforces the need to create content that is easily digestible and clear. The utility also relies on consultants to help understand how social media content is best used and shared. Finally, TVA provides quarterly webinars to keep the public informed about IRP and EIS development.

Lessons Learned

TVA's extensive experience with stakeholder engagement can offer lessons learned for utilities interested in implementing or expanding engagement strategies. First, as was previously mentioned, TVA believed strongly in the need to clarify its role and relevance to end-use customers. Other utilities who engage in resource planning, but do not directly distribute electricity, may experience similar hurdles in communicating the relevance of the IRP to retail customers. Moreover, audiences have different perspectives and levels of understanding, which requires utilities to tailor their messages to meet the needs of the specific stakeholder groups.

Second, in the past TVA has tried hosting open houses to engage stakeholders but has had limited success securing adequate turnout. Even though the company planned several meetings across the Valley during the scoping period, turnout was very low. To address this, TVA now plans to host open houses and seek additional events and venues where interested stakeholders are already gathering. Examples include community meetings and academic events. The company also conducts live webinars that are recorded for individuals who cannot attend or want to watch at a later date. Compared to many traditional public meetings, web-based events often have greater participation both during and after the broadcast.

Finally, when discussing how to measure the success of its stakeholder engagement initiatives, TVA acknowledged that it may not be feasible to incorporate all the diverse views received, some of which compete with each other. Rather than trying to do so, TVA believes that it is most important to ensure that everyone who wants to have a voice and play a role is provided the opportunity to contribute to the process.

Conclusion

TVA's stakeholder engagement strategy provides valuable insight for utilities determining how to engage a broad array of interested parties. In recognizing the diverse information needs of the different stakeholder groups, TVA tailored its strategy to provide information that was relevant and accessible for each group. TVA benefited from both in-depth engagement with its IRP Working Group and broader engagement with the public through social media and other digital communication.

Resources

Developing a Framework for Integrated Energy Network Planning (IEN-P). EPRI, Palo Alto, CA: 2018. 3002010821.

Final Supplemental Environmental Impact Statement – Volumes 1 and 2. Tennessee Valley Authority, Knoxville, TN: 2015.

Integrated Resource Plan. Tennessee Valley Authority, Knoxville, TN: 2015.

TVA Integrated Resource Plan website.

A
INTERVIEW MATERIALS AND QUESTIONS

Chapter 3 – Duke Energy

Material for this case study was taken from a presentation given at EPRI's *37th Annual Seminar on Fuels, Power Markets, and Resource Planning* held in November 2018 in Washington, DC and a follow up interview after the seminar.

Table A-1
Duke -- Prepared questions for follow-up interview

Topic	Questions
Motivations	What was Duke Energy's motivation to begin using EPRI's InFLEXion and DynADOR tools?
Reserve markets	Please clarify the type of reserve markets in which DEC participates.
Use cases for InFLEXion and DynADOR	Please describe what Duke Energy used InFLEXion for.
	Please describe what Duke Energy used DynADOR for.
Methods	What methods did Duke Energy previously rely on to understand its ancillary service needs?
	What, specifically, has been most challenging about using these new methods? What would you tell other utilities that may consider doing the same thing?
Next steps	What are Duke Energy's next steps in this area?

Chapter 4 – Southern California Edison (SCE)

Material for this case study was taken from an interview with SCE in October 2018.

Table A-2
SCE -- Prepared questions for the case study interview

Topic	Questions
Circuit level modeling for distribution planning	Please describe SCE's 2015 Distribution Resource Plan (DRP). Please describe the collaboration between SCE and EPRI to develop the ICA methodology What tools were used to implement ICA? Has SCE used other methodologies in addition to or since the development of ICA to conduct circuit level modeling?

Table A-2 (continued)
SCE -- Prepared questions for the case study interview

Topic	Questions
Motivations for increasing spatial resolution of resource planning modeling	What were/are the internal and external drivers? What were/are the policy or legislative drivers?
Process behind development of ICA and other circuit level modeling methodologies	From where did the idea originate? What other processes or methodologies were used before ICA? What skills are required to complete this kind of analysis? Are there other examples of utilities doing similar analyses? Do you know of any examples of transmission circuit modeling?
Challenges associated with trying to model at the circuit level	What types of data issues did you encounter? Discuss SCE's representative circuit method and how it was used to address computational tractability/
Coordination of DRP with other SCE planning and forecasting processes	How do the processes differ? Where do they overlap? Are there any plans to integrate or connect these processes?

Chapter 5 – Great River Energy (GRE) and Dakota Electric Association (Dakota Electric)

Material for this case study was taken from separate interviews with GRE and Dakota Electric in July and August 2018.

Table A-3
GRE -- Prepared questions for case study interview

GRE Interview	
Topic	**Questions**
Understanding GRE's traditional planning process	**Generation planning/IRP** What, historically, has been the process of working within GRE across departments to acquire the data and candidate resources used in these analyses? How are sensitivity cases developed for GRE's IRP? What tool(s) does GRE use and why? **Transmission Planning** How, historically, has GRE coordinated G and T system planning? Has GRE's transmission planning used information about distribution system resources and growth? What tools does GRE use and why?

Table A-3 (continued)
GRE -- Prepared questions for case study interview

GRE Interview	
Topic	**Questions**
Understanding GRE's traditional planning process (continued)	**Distribution planning (at member companies)** Can you describe the interaction you have with the members on distribution system planning? What information, historically, has GRE considered about the distribution system in developing its long-range plans?
GRE's coordinated planning environment	Is GRE bound by any specific statutory requirement(s) to perform coordinated planning? Is there anything unique about GRE's structure that affects its ability to perform coordinated planning? Where in the company did GRE's Grid Modernization Initiative and/or any other coordinated planning efforts originate? Who/what departments in the company are affected and currently working on planning related to the Grid Modernization Initiative? What interaction do you have with the PUC on this issue? What interaction do you have with the public on this issue?
GRE's coordinated planning efforts (and/or Grid Modernization 'Initiative')	**Generation and Transmission planning** Are you doing anything different now than you did 'traditionally'? **How does GRE know how to do coordinated planning?** What materials/resources is GRE relying on? Is there anything outside of Phase 1 'Initiative' work that has been particularly helpful? (e.g., software tools, reports) **Is there anything else noteworthy that has changed?** New routine reports? New internal meetings/coordination? New tools? New data needs? Is GRE using new data? Is it accessible? New staff? Different skill sets? Training? How pervasive in GRE culture is Grid Modernization? New stakeholder processes?

Table A-3 (continued)
GRE -- Prepared questions for case study interview

GRE Interview	
Topic	**Questions**
Challenges and triumphs	What are the biggest challenges GRE has faced with respect to MN and GRE's Grid Modernization Initiatives / ongoing coordinated distribution planning efforts in the state? What is GRE (and/or your members) doing to address these challenges? Has there been anything that has been easier than expected with respect to Grid Modernization planning?
Future of coordinated planning/Next steps	What are GRE's next steps, beyond those listed in the IRP and Grid Mod Initiative brochure/pilot programs? Does fully coordinated GT&D planning have a future at GRE?

Table A-4
Dakota Electric -- Prepared questions for case study interview

Dakota Electric Interview	
Topic	**Questions**
Understanding Dakota Electric's traditional planning processes	Please describe Dakota Electric's traditional ("pre-Grid Modernization) distribution system resource planning process. Guiding questions: How frequently do you perform long-range planning? What external/PUC requirements are you under to perform planning? What departments within Dakota Electric participate? What interaction do you have with GRE in this planning? What analytical tools/models do you use? What are the key sets of input data you need? What are the main planning process results (outputs)? Is there a stakeholder participation process?
Dakota Electric's definitions	How does Dakota Electric define the following two phrases, as they relate to your organization's business? 1. "coordinated distribution planning" 2. "coordinated generation, transmission, and distribution planning"
Dakota Electric's coordinated planning efforts	Please describe Dakota Electric's main efforts and initiatives in grid modernization and/or coordinated planning.

Table A-4 (continued)
Dakota Electric - Prepared questions for case study interview

Dakota Electric Interview	
Topic	**Questions**
Emerging planning processes	Has grid modernization and/or coordinated planning affected Dakota Electric's distribution planning process? If so, how? Guiding questions: New company processes? Different data needs? New analytical tools? New staff skills, training? Different stakeholder processes? Different interaction with the PUC and other institutions?
Working groups and external forums	What external working groups and/or forums does Dakota Electric participate in with respect to grid mod/coordinated planning? Guiding questions: Working groups with neighboring distribution companies? Stakeholder engagement forums? PUC working groups? Others?
Challenges	What key challenges has Dakota Electric experienced as grid modernization and/or coordinated planning efforts have been considered in MN and/or the GRE footprint?
Next steps	What are Dakota Electric's next steps towards grid modernization and coordinated planning?

Chapter 6 – Southern Company (Southern)

Material for this case study was taken from a presentation given at EPRI's *37th Annual Seminar on Fuels, Power Markets, and Resource Planning* held in November 2018 in Washington, DC and a follow up interview after the seminar.

Table A-5
Southern -- Prepared questions for case study interview

Topic	Questions
Past processes for addressing uncertainty in long range planning	Please describe Southern's process for addressing uncertainty prior to the development and implementation of the current scenario planning process?
Challenges	What hurdles or challenges has Southern faced in implementing its scenario planning process?
Participation	Which departments participate in the scenario planning process?
Process clarification	Please clarify how Southern moves from a range of candidate decisions to a single decision. How does the company take its next steps?

Chapter 7 – Tennessee Valley Authority (TVA)

Material for this case study was taken from an EPRI Project Set 178B member webcast in October 2018 and a follow up interview in November 2018.

Table A-6
TVA -- Prepared questions for case study interview

Topic	Questions
Environmental Impact Statement (EIS) approval process	Please clarify the EIS approval process.
Social media strategy	What social media platforms does TVA use? What type of content does TVA share on social media? Does TVA quantitatively track social media engagement? Has the company received any qualitative feedback on its social media outreach?
Targeted engagement	Did TVA target specific groups during their public stakeholder engagement? Are there specific stakeholders that tend to be more engaged as opposed to others?
Theme of flexibility for 2019 IRP	From where did the idea of a theme originate? Is TVA planning on keeping the idea of themes in successive IRPs?
Metrics for success and lessons learned	How does TVA measure successful stakeholder engagement? What has TVA learned for its stakeholder engagement? Is there anything TVA plans to improve or change in the future?

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