Case Studies of Integrated Energy Network Planning Challenges – Volume 2

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

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Technical Update, December 2019

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ABSTRACT

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* (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. EPRI's Technology Innovation (TI) program launched, in early 2018, 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.

In February 2019, EPRI published an initial set of case studies that highlight how different electric companies in the United States have started to address the IEN-P challenges identified in the white paper. This Technical Update follows the publication of Volume 1 and includes case studies for planning challenges not contained in the first volume. "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 planning
Integrated resource planning
Load forecasting
CO_2 emissions accounting
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EXECUTIVE SUMMARY

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Product Type: Technical Update

Product Title: Case Studies of Integrated Energy Network Planning Challenges – Volume 2: Phase 2 – Framework for Integrated Energy Network Planning (IEN-P)

PRIMARY AUDIENCE: Generation, transmission, and distribution system planners in electric companies and regional transmission organization (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 Commissions (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 planning.

KEY RESEARCH QUESTION

This Technical Update is the second volume of case studies that highlight how different electric companies in the United States have started to address the IEN-P challenges. In addition, 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, 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 a second volume of case studies that highlight how different electric companies have started to address one or more of the IEN-P challenges. The first volume was published in February 2019 (EPRI report 3002014644).

KEY FINDINGS

- The Midcontinent Independent System Operator recognizes that the changing electricity system landscape coupled with the need to ensure grid reliability and flexibility drive the need for a shift in long-term load forecasting approaches. MISO sought an improved way to account for these emerging and load modifying technologies in its planning process.
- DTE Electric systematically tied its carbon reduction goals to its long-term planning process. It accomplished this by incorporating the goals in its Reference scenario and selecting a more holistic emissions accounting method.
- Salt River Project has turned to customer propensity modeling to better understand the location of future electric vehicle adoption on its distribution system.

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 second 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
- *Case Studies of 10 Integrated Energy Network Planning Challenges – Volume 1: Phase 2 – Framework for Integrated Energy Network Planning (IEN-P)* (3002014644)
- *Annotated Bibliography for 10 Integrated Energy Network Resource Planning Challenges: Phase 2 – Framework for Integrated Energy Network Planning (IEN-P)* (3002014288)
- *Developing a Framework for Integrated Energy Network Planning (IEN-P): 10 Key Challenges for Future Electric System Resource Planning* (3002010821)
- 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

AEG	Applied Energy Group
ANS	Annual net short (emissions accounting method)
BEV	Battery electric vehicle
BWEC	Blue Water Energy Center
CEM	Capacity expansion modeling
CO_2	Carbon dioxide
CON	Certificate of Necessity
DER	Distributed energy resources (e.g., rooftop solar PV)
DR	Demand response
DTEE	DTE Electric
EE	Energy efficiency
EEA	EPRI's Energy and Environmental Analysis group
EV	Electric vehicle
FERC	Federal Energy Regulatory Commission
GHG	Greenhouse gas
GT&D	Generation, Transmission and Distribution
HILF	High-impact, low-frequency
IEN	Integrated Energy Network
IEN-P	Integrated Energy Network Planning
IRP	Integrated Resource Planning
ISO	Independent System Operator
LRZ	Local resource zone
LSE	Load serving entity
MISO	Midcontinent Independent System Operator
MTEP	MISO Transmission Expansion Plan
OEM	Original equipment manufacturer
PCM	Production cost modeling
PHEV	Plug-in hybrid electric vehicle
PUC/PSC	State Public Utilities Commissions or Public Service Commission
RPS	Renewable portfolio standards
RTO	Regional Transmission Organization
SEO	State Energy Office
SRP	Salt River Project

SUFG	State Utility Forecasting Group
TI	EPRI’s Technology Innovation program
VER	Variable energy resources
VMT	Vehicle miles traveled

CONTENTS

LIST OF FIGURES

LIST OF TABLES

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 (e.g., energy efficiency, demand response, etc.) 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 (e.g., 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 are no longer 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*

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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.

Planning.[3] 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 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 three IEN-P challenges shaded in light blue are included as case studies in this second volume of case studies.

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.	*Included in Volume 1*
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.	*Included in Volume 1*
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-	*Included in volume 1*

[3] Available online at: http://integratedenergynetwork.com/wp-content/uploads/2018/07/3002010821_IEN-P_White_Paper.pdf.

IEN-P challenge	Description	Case study
	systems to optimize the future overall electric power system.	
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.	*Included in Volume 1*
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.	*Included in Volume 1*
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.	**Midcontinent Independent System Operator –** *New approaches to forecasting load in a changing electricity landscape*
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.	**DTE Electric –** *Embedding company carbon reduction goals in integrated resource planning*
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.	**Salt River Project –** *Improved spatial disaggregation of electric vehicle adoption through customer propensity modeling*

IEN-P challenge	Description	Case study
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.	*To be included in a future publication*
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.	*To be included in a future publication*

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 a deliverable for Task 2 of this project. It follows the publication in February 2019 of Volume 1 of IEN-P case studies.[4]

Developing the Case Studies

EPRI developed the case studies included in this volume from interviews conducted with individuals from electric power companies from July to November 2019. EPRI also used material from a member webcast 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.

[4] *Case Studies of Integrated Energy Network Planning Challenges – Volume 2: Phase 2 – Framework for Integrated Energy Network Planning (IEN-P).* EPRI, Palo Alto, CA: 2019. 3002017669.

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 some of the resource planning challenges identified in the 2018 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

MIDCONTIENT INDEPENDENT SYSTEM OPERATOR–NEW APPROACHES TO FORECASTING LOAD IN A CHANGING ELECTRICITY SYSTEM LANDSCAPE

IEN-P Challenge: Improving forecasting

Introduction

Improving the forecasting of key elements that are critical to making power system planning decisions, such as current and future load, customer resource adoption, capital costs and fuel prices will be critical to continue robust resource and transmission network planning. Equally important is the need to consider uncertainty in the methods used to forecast these elements and the future trajectories of the elements themselves. EPRI's IEN-P white paper[5] identified several inputs to electric system planning processes for which more robust forecasting methods are likely to be needed in the future, including: electric load and distributed energy resources (DER) adoption, market prices for electricity and emissions, weather and renewable generation, future policies and regulation, fuel prices, and new technology costs and performance. This case study focuses specifically on an innovative approach being used to improve forecasting of *gross* electric energy demand and load for transmission planning purposes.

Transmission planning requires detailed insight into both the availability and make-up of future electricity supply as well as future adoption of load modifying technologies and programs. Transmission planning entities such as independent system operators (ISOs) require reasonable supply and demand forecasts to plan robust future system investments. On the supply side, changing resource mixes necessitate more detailed forecasts of resource availability. On the demand side, end-use customers will continue to drive the demand for electricity but are also able to supply or store their own electricity and to alter their electricity demand. Because of this growing dual role, forecasting DER adoption and customer participation in demand response (DR) programs is becoming increasingly important for developing more robust forecasts of future electric loads. Given the uncertainty, non-uniform nature, and location of these resources in the power system, new analysis techniques and data streams will be needed to forecast load and generation at more granular levels in the system, and to project customer behaviors and other factors that will dictate new spatial and temporal behaviors of both DER and load. Within the context of transmission planning, this ability also brings the added benefit of being able to assess robustness of future investments.

This case study describes the approach of the Midcontinent Independent System Operator (MISO) to forecasting an observable net load shape from its gross energy demand forecast (i.e., gross electric load). It outlines the process MISO developed to systematize producing its demand forecast and understand key elements, including their uncertainty, that could reduce future gross

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

power demand. By moving beyond producing a simple pure gross demand forecast with limited system visibility beyond the peak hour, MISO is trying to understand, in a more detailed way, how the load shape may vary across all hours with increased adoption of load modifying technologies. MISO's effort to identify and forecast components of gross energy demand that impact observable net loads in a systematic way combined with its intensive process to receive input from MISO members and other stakeholders can provide valuable lessons learned for electric companies, other ISOs and other entities facing similar forecasting challenges.

MISO is a non-profit, transmission system operator whose territory extends from Canada, through the midwestern United States, and down to the central part of the southern United States all the way to the Gulf of Mexico. Established in 1998 and headquartered in Carmel, Indiana, MISO operates one of the world's largest real-time energy markets, encompassing 51 transmission owners and more than 65,800 miles of transmission lines. As an ISO, MISO must comply with Federal Energy Regulatory Commission (FERC) regulations related to transmission planning and expansion and energy markets. One of MISO's primary jobs is long-term transmission planning. Every year MISO produces the MISO Transmission Expansion Plan (MTEP)[6] that evaluates potential transmission projects and their potential impact on future grid reliability and wholesale power markets. MISO is utilizing the innovative forecasting approach featured in this case study for the first time in MTEP 21 cycle.

Case Study Methodology

In August 2019, EPRI interviewed two MISO staff members directly involved in the MTEP, load forecasting and specifically, development of this new technique. Two members of EPRI's Energy and Environmental Analysis Group conducted the interview via webcast 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. Prepared interview questions focused on understanding the origins of the technique, its purpose, and the ways in which it has been implemented through MISO's transmission planning. A list of the specific interview questions and the slides from the webcast are available in the Appendix.

Key Insights

- MISO recognizes that the changing electricity system landscape coupled with the need to ensure grid reliability and flexibility drive the need for a shift in long-term load forecasting approaches. MISO sought an improved way to account for these emerging and load modifying technologies in its planning process.
- MISO's objective is to create a single, long-term gross demand and energy forecast for its region, including the local resource zones (LRZs), and to identify all the components that could modify that gross forecast as separate "line items".
- MISO sought a systematic way to address two important areas of uncertainty: (1) the lack of consistency in MISO members' approaches to generating demand-related data, and (2) the unfolding energy system transition that is anticipated to introduce new supply and demand-side resources to the grid and increase the need for quality, consistent, and more granular load shapes.

[6] For information on MTEP, visit MISO's website: https://www.misoenergy.org/planning/planning/

- MISO receives demand-related data from its members and works with two consultants to review the data, correct inconsistencies and develop the gross and component forecasts.
- To address uncertainty in system "futures" and the components themselves, MISO develops multiple futures for analysis and regional demand and component forecasts.

Interview Summary

Motivations for developing a new forecasting process

Like EPRI, MISO recognizes that the changing electricity system landscape coupled with the need to ensure grid reliability and flexibility drive the need for a shift in long-term load forecasting approaches. From 2005 to 2018, coal dropped from 76% to 50% of MISO's generating fleet[7], while wind generation grew from 0% to 8%. During this period the MISO footprint also changed. In 2013, the MISO south region entered the ISO's territory and in 2012, First Energy and Duke's operations in Ohio and Kentucky moved to the PJM Interconnection. Wind and solar make up almost 90% (~80 GW) of MISO's Generation Interconnection Queue. MISO also expects greater adoption of demand-side load modification programs and technologies including energy efficiency (EE) and electric vehicles within its territory in the coming years. Due to these and other factors, MISO sought an improved way to account for these emerging and load modifying technologies in its planning process.

Traditionally, both within and outside of MISO, load forecasts were developed and used for resource adequacy purposes, to ensure that the system had enough capacity to meet peak load plus an adequate reserve margin. In these situations, forecasting the timing and magnitude of the system peak was critical. Having a more detailed understanding of the components of energy demand and the load shape over all hours of the day and year was less important. As capacity markets have evolved and the electric power industry adopts more variable generation and load modifying technologies, *all hours* – not just the peak period – start to matter to the development of load forecasts. Consequently, improving the temporal resolution and extent of load forecasts (e.g., hourly resource availability alongside estimates of *when* these technologies or programs may be adopted) becomes as important as improving their spatial resolution (*where* the different technologies or programs will be adopted).

A primary job for MISO is long-term transmission planning, which involves a detailed understanding of both the availability of electricity supply and the shape of customer demand at different points of the day and year. As stated previously, MISO annually produces the MTEP to evaluate potential transmission projects and their impact on future grid reliability and wholesale power markets. MISO's projections of future *net load* that are input into MTEP are derived from the development of its gross demand and energy forecast. While the gross demand and energy forecast serves as a key input into MTEP, it also represents a significant source of uncertainty. How the demand energy forecast evolves in the future directly impacts investment in future resources. Therefore, it is critical to understand at as granular spatial and temporal levels as possible how key load modifying elements of this forecast may evolve under different scenarios of the future evolution of the electric system.

[7] Percentage refers to MWh. During this period, energy produced by coal dropped from 76% to 50%.

New methodology for gross demand and energy forecast

As part of MTEP 21, which is expected to be released at the end of 2021, MISO is deploying a new methodology to produce its gross demand and energy forecast. Overall, MISO's objective is to create a single, long-term gross demand and energy forecast for its region, including the local resource zones (LRZs), and to identify all the components that could modify that gross forecast as separate "line items". In developing the new technique, MISO adhered to a planning paradigm that emphasizes consistency, clarity, and efficiency.

Through this new approach, MISO sought to develop a consistent methodology that could be standardized across the entire system. The organization also sought a systematic way to address two important areas of uncertainty: (1) the lack of consistency in MISO members' approaches to generating demand-related data and (2) the unfolding energy system transition that would introduce new supply and demand-side resources to the grid and increase the need for quality, consistent, and more granular load shapes. To achieve consistency, MISO also desired a process that would increase the clarity of input assumptions for each load modifying component. Figure 3-1 shows the different "components" that intersect with the gross demand and energy forecast to produce an observed net load shape. In addition to identifying and creating future projections for these components, forecasters also need to be able to run sensitivity analyses on these future projections. A more detailed discussion of how MISO accounts for uncertainty in these components and future system scenarios is provided later in this case study. Finally, alongside clarity and consistency, MISO aimed to develop an efficient forecasting process that considers the costs in time and money to MISO and its members.

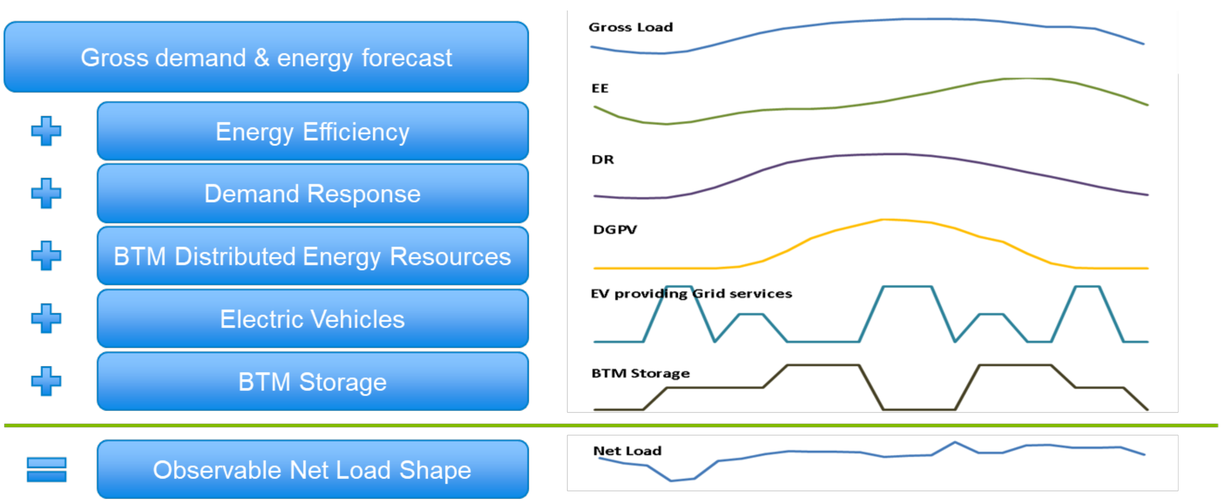

Figure 3-1
Components that may alter the gross demand and energy forecast to produce the observable net load shape. Source: MISO, 2018.

Prior to the current MTEP cycle, MISO received individual demand forecasts from its members, which MISO aggregated into total demand and reviewed against an independent load forecast provided by Perdue University. While these forecasts did provide some visibility into members' EE and load modifying programs, they lacked consistency in their granularity and method of development. The new methodology, currently deployed for MTEP19, is described below.

About 18 months prior to the MTEP publication, the load serving entities (LSEs) submit, separately, their long-term (20-year) aggregate gross demand and energy forecasts (i.e., gross load) and any data on future DR, EE, distributed generation (DG), DER, or electric vehicle (EV) programs ("the components") to MISO. MISO then works with two consultants, the State Utility Forecast Group (SUFG) at Purdue University and Applied Energy Group (AEG), to identify any gaps or inconsistencies in the members' forecast data that need clarification. When these situations do arise, the consultants work directly with the members to resolve the inconsistencies. SUFG then combines the member-provided aggregate forecast data, supplemented with its own forecast data where necessary, with the AEG-compiled component data to produce an adjusted 20-year demand and energy forecast for MISO region and each LRZ. These long-term demand and energy forecasts are then used as inputs to the MTEP Futures (described in the next section). Figure 2 provides a graphical representation of this process.

Accounting for uncertainty and addressing data limitations

The gross demand and energy forecast itself as well as each of the load modifying components are subject to uncertainty. To address this uncertainty, MTEP includes several "futures" that outline different scenarios under which the MISO system may evolve in the coming years. These futures are developed through a collaborative stakeholder process and are reviewed for relevance during each MTEP cycle[8]. MISO also conducts sensitivity analyses on the different components of the load forecast, which provides a "custom forecast, by future". In addition, because the trajectories for each component are not consistent across the entire MISO footprint, MISO develops individual gross and component forecasts for its different regions in an attempt to capture regional variability.

Developing the gross demand and energy forecast and the component forecasts for the different MISO regions requires a lot of high-resolution data from diverse sources. MISO members use different forecasting methods (econometric vs. adjusted end-use forecasting), have different business models, produce forecasts for different periods of time (short-term vs. long-term), and may or may not have data for all customer classes (residential, commercial, industrial). Sorting through and aligning all these data can present a challenge for system load forecasting. MISO believes that by developing a systematic way to collect, review, and align data with input from both its members and third-party consultants, it can overcome some of these data challenges.

Conclusion

MISO's approach to forecasting future gross energy demand and the individual components that can modify load provides valuable insight for utilities and other entities facing similar forecasting challenges. MISO understands the need for more granular demand forecasts as the electricity system accommodates new sources of generation and greater customer adoption of load modifying technologies. As part of its transmission planning cycle, the ISO is testing a new

[8] MISO describes the futures as "stakeholder-driven postulates of what the industry landscape could be in the 10 to 20-year planning horizon". In the current MTEP, there are four Futures in addition to the baseline or reference future: Continued Fleet Change (CFC), Limited Fleet Change (LFC), Accelerated Fleet Change (AFC), and Distributed Energy and Emerging Technologies (DET). "Fleet change" refers to shifts in the MISO electricity generation fleet. For more information, see: https://cdn.misoenergy.org/MTEP18%20Futures%20One-Pager111484.pdf

and innovative forecasting approach that can potentially provide a more detailed picture of how these new technologies will impact future load shapes.

Resources

MISO MTEP website[9]

MISO System Forecasting for Energy Planning website[10]

MISO Stakeholder workshops

- September 7, 2018[11]
- October 12, 2018 [12]
- January 10, 2019[13]
- April 8, 2019

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[9] https://www.misoenergy.org/planning/planning/

[10] https://www.misoenergy.org/planning/policy-studies/system-forecasting-for-energy-planning/#t=10&p=0&s=FileName&sd=desc

[11] https://www.misoenergy.org/events/past-events/energy-planning-and-load-shape-forecasting-workshop---september-7-2018/

[12] https://www.misoenergy.org/events/energy-planning-and-load-shape-forecasting-workshop/

[13] https://www.misoenergy.org/events/energy-planning-and-load-shape-merged-proposal-workshop---january-10-2019/

4

DTE ELECTRIC – EMBEDDING COMPANY CARBON REDUCTION GOALS IN INTEGRATED RESOURCE PLANNING

IEN-P Challenge: Incorporating new planning objectives and constraints

Introduction

Traditional integrated resource planning (IRP) focused on identifying the least-cost portfolio of generation assets plus demand-side management programs to meet future demand forecasts with a specified reserve margin.

Today, electric companies are increasingly being asked to meet new planning objectives, multiple objectives simultaneously, and to plan within new types of constraints. New objectives and constraints beyond least-cost resource adequacy[14] that planners may need to consider in the future include: (1) ensuring system resiliency and flexibility beyond traditional resource adequacy; (2) achieving evolving renewable portfolio standards (RPS) and reducing greenhouse gas (GHG) emissions, (3) addressing the impact of electric system operations on regional water sources, and (4) meeting corporate sustainability objectives.

This case study focuses specifically on how one electric company, DTE Electric (DTEE), has incorporated a company carbon reduction target into its resource planning process, explicitly taking into account methods the company uses to account for carbon dioxide (CO_2) emissions and the ways in which its planning process has evolved.

Even in the absence of comprehensive federal climate or GHG emissions reduction policies, many states and companies, including DTEE, have adopted their own GHG or CO_2 emissions reduction goals, which may be linked to renewables targets. Some of these targets are legislated or regulated and thus are binding, whereas others are voluntary and nonbinding. Adding further complexity and dimension to the matter is the uncertainty surrounding how federal and state policy will evolve. System planners need to perform resource planning today and typically plan how to power their system over a planning period of 10-20 years or longer. Furthermore, corporate leaders need to make decisions about future capital investments now, while future regulatory policies to reduce emissions remain uncertain. Because new power generation assets can typically be expected to operate for 30-50 years or longer, it can be difficult for electric system resource planners to address this kind of near-term policy uncertainty and mitigate the potential for large capital investments to become stranded in the future. For those like DTEE that have already adopted voluntary CO_2 and renewable company targets and additionally must

[14] Least-cost resource adequacy ensures that electric companies have sufficient capacity to meet projected load, including peak load, plus a specified planning reserve margin. The portfolio that meets these criteria should also minimize costs.

comply with state goals, the challenge becomes how to systematically and transparently embed these targets into their existing resource planning processes.

In its IRP modeling, DTEE did not simply include its corporate CO_2 reduction goal as a constraint within its IRP reference scenario, but rather explicitly embedded it as an objective throughout the development of its IRP. Driven both by internal support and pressure from external stakeholders, including large commercial customers, DTEE developed a process whereby the company, external stakeholders, and the Michigan Public Service Commission (MPSC) could monitor its progress toward meeting these goals. This case study describes DTEE's approach to accounting for CO_2 emissions associated with the electric generation delivered to its retail customers, and the ways in which the company integrated its carbon reduction goal into its most recent IRP.

DTEE's participation in a large, regional wholesale electricity market (MISO) complicates its ability to account for emissions from electricity delivered to its retail customers. This is because it becomes difficult to attribute the emissions associated with electricity that DTEE generates from its own resources and the emissions from wholesale power market purchases. DTEE's efforts related to this topic can provide valuable lessons learned for other electric companies and entities who may be interested in determining how best to account for their CO_2 emissions and systematically incorporate emissions reduction goals into their resource planning.

DTEE is a subsidiary of DTE Energy, which serves 2.2 million electricity customers over 7,600 square miles in 13 counties in southeastern Michigan. DTEE owns and operates more than 11,000 MW of electricity generation assets and over 44,000 miles of power distribution lines. In 2018, 66% of DTEE's electricity generation was coal-fired, 17% nuclear, 8% renewables, 7% natural gas, and 2% pumped hydro storage.

In 2017, DTEE, driven by support from its senior leadership, announced its initial voluntary carbon reduction target of 80% by 2050 (below 2005 levels). Based on the results of its 2019 IRP modeling, DTEE decided to accelerate its goal by a full decade, pledging to reduce carbon emissions by 80% below 2005 levels by 2040. It is important to note that DTEE's target is a *consumption-based target* – it refers to a reduction in the CO_2 emissions of the electric power *delivered* by DTE to its retail customers. The company also committed in 2018 to a voluntary 50% clean energy goal by 2030, where at least half of the 50% will come from renewable energy and the remaining balance from energy efficiency or energy waste reduction (EWR).[15] This 25% goal exceeds the 2016 state mandate of 15% renewables generation by 2021.

Case Study Methodology

In August 2019, EPRI interviewed an individual from DTEE's integrated resource planning department who managed and led the modeling for DTEE's 2017 and 2019 IRPs. Two members of EPRI's Energy and Environmental Analysis Group conducted the interview via webcast using a semi-structured format. EPRI provided the interview questions to the participant ahead of time, but also asked new questions based on the direction of the conversation. Prepared interview questions focused on understanding the motivations for adopting DTEE's emissions reduction

[15] The energy efficiency target corresponds to a 1.5% reduction in energy usage each year through energy efficiency programs.

target, how DTEE's planning process evolved to account for this target, and the tools and methods that were used to accomplish the objectives of DTEE's IRP. A list of the specific interview questions and the slides from the webcast are available in the Appendix.

Key Insights

- DTEE systematically tied its carbon reduction goals to its long-term planning process. It accomplished this by incorporating the goals in its Reference scenario and selecting a more holistic emissions accounting method.
- In response to questions about accounting for the CO_2 associated with purchases and sales that were posed in DTEE's 2017 IRP efforts, the company investigated how to accomplish this as part of its 2019 IRP process. By adopting the *annual net short* CO_2 accounting approach into its IRP, DTEE developed within its IRP a transparent process that the company, external stakeholders, and the MPSC, could use to monitor DTEE's progress toward achieving its voluntary CO_2 emissions reduction goals over time.
- DTEE chose an annual net short approach, a *load-based* accounting approach for emissions accounting, that attributes emissions based primarily on the type of power purchased and delivered from the market to an electric company's customers, due to its ability to reflect emissions from owned and purchased generation in a more definitive way.
- DTEE found it challenging to track candidate portfolio carbon emissions within the capacity expansion modeling step of its IRP process and simultaneously use its chosen emissions accounting method. Instead, DTEE evaluated the carbon emissions implications of different potential portfolios during the production cost modeling step of its IRP process.
- By utilizing the annual net short emissions accounting method and including its carbon reduction goals as a constraint in its IRP reference scenario, DTEE was able to model this new planning objective in an improved way compared to its previous IRP.

Interview Summary

Motivations and background

In 2017, DTEE filed a Certificate of Necessity (CON) with the MPSC for a new natural gas plant, the Blue Water Energy Center (BWEC), that would in part replace three coal plants set to retire by 2023. Around the same time, DTEE announced its 2017 carbon emissions reduction target of 80% by 2050. Although the MPSC approved the 2017 CON, DTEE was asked to clarify its modeling input assumptions and provide greater transparency in its next IRP. In addition, in late 2016, Michigan passed new energy legislation (Public Acts 341 and 342) that required the state's rate-regulated electric utilities, including DTEE, to submit an IRP to the MPSC by April 2019 for review and approval. Furthermore, the legislation established a new statewide renewable energy target of 15% of production by 2021. In addition, DTEE committed to a voluntary 50% clean energy goal by 2030, with at least 25% of the goal coming from renewables and the remainder from EWR. These laws and commitment did not take effect until after DTEE had filed its 2017 CON but would apply to its 2019 IRP.

In response to these developments, and ahead of its 2019 IRP filing, DTEE sought a way to systematically incorporate its long-term carbon emission reduction goals into its long-term planning process. Furthermore, the company had not previously specified what definite activities or measures it might undertake to achieve its carbon reduction target or which CO_2 accounting method it would use. The next two sections of this case study elaborate on DTEE's chosen CO_2 emissions accounting method and how DTEE integrated this method into its 2019 IRP.

Choosing an emissions accounting method

To select an appropriate accounting method, DTEE collaborated with EPRI to review and assess multiple methods used to account for the CO_2 emissions associated specifically with *undifferentiated*[16] electric power purchased in the MISO wholesale market to be resold to DTEE's retail end-use customers.[17] Methods to account for electric sector emissions generally fall under two categories: facility (or *source-based*) approaches or *load-based* approaches.

Under a facility accounting approach, electric companies simply tally the emissions associated with the generating assets that it owns or controls to arrive at its overall emissions total. This type of approach does not include emissions from purchased power.

Load-based approaches quantify the emissions associated with electricity generated or purchased and delivered to retail customers. In wholesale electricity market regions such as MISO where DTEE operates, load-based accounting is more complicated as it is impossible to know where the electrons that supplied the customer originated (hence the term "undifferentiated" electric power). This holds even if the company owns generation that it supplies to the market. In these situations, load-based accounting methods may provide more nuanced attribution of a company's emissions.[18]

Ultimately, DTEE chose to use an "*annual net short*" (ANS) approach for carbon emissions accounting. The approach is described in detail in EPRI's report, *Methods to Account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases* (3002015044). The ANS approach distinguishes between "dispatchable" and "non-dispatchable"[19] resources held by a company that participates in an electricity market. It is similar to the "*Clean Net Short*" approach adopted by the California Public Utilities Commission for integrated resource planning purposes in California.

"Dispatchable" resources in this context are those that can ramp quickly and have lower marginal costs, such as natural gas turbines and other peaking units. These units can more easily control their output and are typically used by system operators to balance the grid.

In contrast, generation resources that cannot easily control their output (i.e., renewables) and baseload generation (e.g., nuclear, coal, and hydro) that typically run at a constant output are

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[16] Undifferentiated refers to the fact that the electric power purchased from a wholesale power market is a "mix of electric power generated by all the resources generating across the entire ISO system at the time the electricity is used" (EPRI 2019, pp. 3-2). As a result, companies that purchase power through an ISO do not know the specific source of the electricity produced nor the emissions associated with it.

[17] *Methods to Account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases*. 2019. EPRI: Palo Alto, CA. 3002015044. https://www.epri.com/#/pages/product/3002015044/

[18] Except for those operating in California, electric companies are not required to use a specific emissions accounting method for their IRPs. Some companies who do participate in electricity markets may choose to use source-based and load-based accounting methods. For a full description of the different accounting methods, see EPRI report #3002015044.

[19] This distinction differs from the traditional notion of dispatchable generation, which refers to sources of electricity that can be easily turned on or off by power grid operators to meet the system's needs.

considered for this accounting purpose to be “non-dispatchable” resources. This classification of resources is used to attribute the proportion of emissions from each type of generation to companies that participate in the electricity market. In principle, the ANS approach attributes emissions based primarily on the type of power delivered to the electric company’s customers and not necessarily the power the company supplies to the grid.

Under the ANS approach, emissions associated with non-dispatchable resources are assigned to the company that owns them to the extent that the company’s load *equals or exceeds* the generation of these non-dispatchable assets. This assumes that a company’s non-dispatchable resources are built and operated to supply power to their own customers. Non-dispatchable resources effectively are treated as if they directly serve a utility’s *native load*, not the wholesale power market.

Prior to determining what proportion of a company’s non-dispatchable resources’ emissions will be attributed to its total annual emissions, the company determines its annual net load. The estimated annual generation from the non-dispatchable resources is subtracted from the estimated load to reveal how much dispatchable generation the company would draw from the grid if it is “net short” of power, or conversely, how much non-dispatchable power it would export to the grid if it is “net long” of power. If a company is in a “net short” position, it would include the emissions of all its non-dispatchable resources *plus* the additional emissions associated with its net long power position. These additional emissions are calculated by multiplying the amount of *net purchased power for resale* by the grid average “residual” emissions rate and added to the quantity of emissions associated with the company’s non-dispatchable resources to calculate the company’s total ANS emissions.

On the other hand, if the company is “net long” and generates more power from its non-dispatchable generation resources than its native load, this method explicitly assumes the company is exporting power and the associated CO_2 emissions to other parties drawing power from the grid. Any non-dispatchable generation that exceeds a company’s load results in a deduction from the utility’s total CO_2 emissions, based on the grid average “residual” emission factor.

This “net short” method is methodologically robust regardless of the source of the surplus power generation. Emissions “credits” always reflect the displacement of *dispatchable resources* (e.g., natural gas combined cycle plants) and are attributed at the *residual* emission rate, rather than the emission rate of the displacing resource (e.g., non-dispatchable coal, hydro, nuclear, and renewable generators). This approach attributes emissions for market purchases and sales using a generation-weighted grid emission factor based on the dispatchable generation resources only (i.e., often the weighted-average emissions rate of natural gas-fired generation resources). How DTEE applied this specifically to emissions accounting in its 2019 IRP is discussed below.

Development of 2019 IRP

DTEE’s IRP process begins with the development of a set of scenarios that frame its analysis and enumeration of the data assumptions that underlie these scenarios. In 2019, the MPSC required regulated utilities to include three scenarios (Business as Usual, Emerging Technology, and Environmental Policy) in their IRPs. In addition to these, DTEE created its own DTE Reference scenario, which incorporated its carbon reduction goals via a carbon price, its own fuel forecast and unit retirement schedule, and its more aggressive renewables and energy efficiency targets. Table 1 briefly lists the critical assumptions for each scenario.

Table 4-1
Critical assumptions for DTEE IRP scenarios[20]. Adapted from DTEE, 2019.

	Reference	Business as Usual (BAU)	Emerging Technology	Environmental Policy
CO_2 Assumption	CO_2 price that enables company CO_2 goals; $5/ton starting in 2025	No CO_2 price	No CO_2 price	No CO_2 price
Gas Prices	DTEE fuel forecast, transitions to PACE forecast	DTEE fuel forecast, transitions to 2018 EIA forecast	Same as BAU	Same as BAU
Capital Costs	Public sources	Public sources	Public sources. Assumed wind decreases by 17.5%; solar, battery, EWR, DR decrease by 35%.	Public sources. Assumed renewables decreased by 35%.
Retirements	Current company retirement schedule	Existing fleet remains largely unchanged	Optimistic capital costs may encourage earlier retirements	Optimistic capital costs may encourage earlier retirements
Renewables and EWR	50% clean energy by 2030	35% clean energy goal	Same as BAU	Same as BAU

DTEE then considers the generation resources available to meet customer demand in the different scenarios and generates alternative portfolios of system assets to meet that demand as it evolves over time. The generation and demand-side technologies used to construct the portfolios are screened based on their technical feasibility, practicality, and geographic limitations. The selected technologies are then represented in DTEE's resource planning modeling program and available as options for the model to select and deploy when optimizing build plans for the different scenarios.

DTEE uses a combination of capacity expansion modeling (CEM) and production cost modeling (PCM) tools to conduct its IRP modeling. Although CEMs tend to have limited spatial and temporal granularity, they are able to efficiently run many scenarios and sensitivity analyses needed for the IRP. For this IRP alone, DTEE conducted and completed a cost ranking using their CEM for over 140 different modeling runs. For each scenario, DTEE selected the least-cost build plan from the CEM and used those to determine its Proposed Course of Action (PCA).

DTEE found it challenging to use the ANS approach with the specific CEM tool it uses. To overcome this, DTEE completed its emissions accounting as a post-modeling step. Once the

[20] See the MPSC website for more details about the required scenarios. See DTEE's IRP for more detailed descriptions of the scenarios.

CEM had been completed, the team selected a final set of options that are run through a PCM outfitted with CO_2 penalties on different generating units to verify that the CO_2 reduction goals were attainable.

DTEE's PCA for its 2019 IRP includes the addition of 11 MW of solar and 693 MW of wind by 2024 and the expansion of its voluntary large customer green power purchasing program in 2021. It also calls for the retirement of three older coal plants by 2022. This capacity will be replaced by a combination of renewables and a combined cycle natural gas turbine, the Blue Water Energy Center (BWEC), which is expected to become operational in 2022. Finally, DTEE plans to implement its annual 1.75% energy efficiency savings target from 2021 through 2025. DTEE will reevaluate its plans for 2025-2030 when the company files its next IRP by early 2025.

DTEE projects, based on its ANS analysis that it will be in a net long position for the entire IRP study period (2022 to 2040) when considering the entire year (as opposed to an hourly net short period) (see Figure 4-1). As DTEE notes in its IRP, "the Company is holding itself accountable for the impact to the environment from energy that we provide to customers, regardless of whether that energy was produced by company-owned assets or secured through wholesale power purchases" (DTEE 2019, pg. 163).

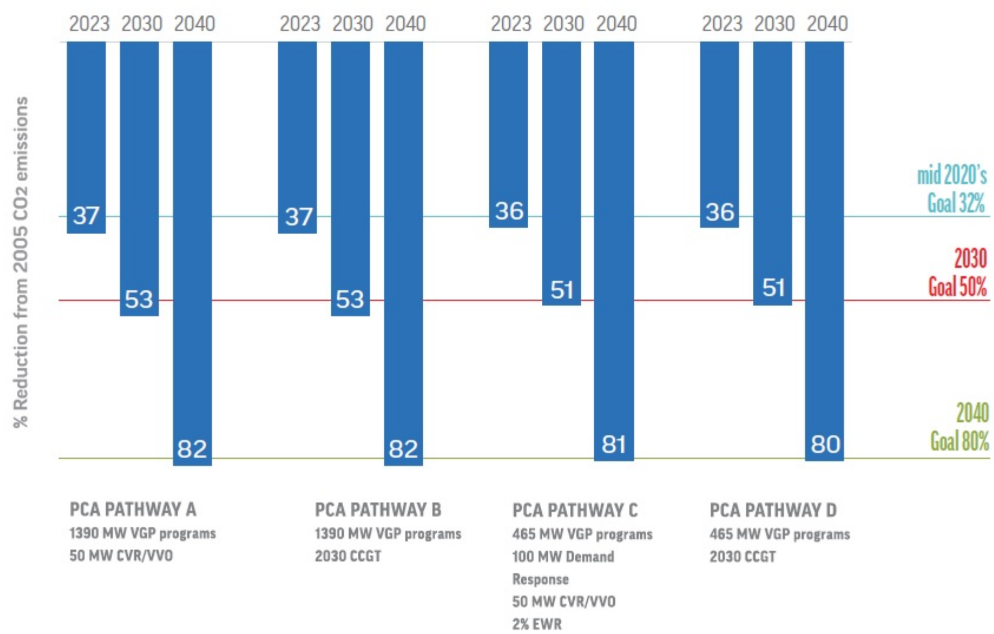

Figure 4-1
CO_2 emissions from DTEE fleet, ANS approach. Source: DTEE, 2019.

Lessons learned and next steps

DTEE conducted an extensive stakeholder outreach process consisting of public open houses and technical workshops for its 2019 IRP. The intent was to implement a comprehensive, transparent, and participatory stakeholder engagement process. The company hosted four technical workshops for stakeholders involved in the IRP's technical aspects and regulatory process and three public open houses to serve customers and the general public. These events provided stakeholders with various opportunities to provide input on how to meet Michigan's future energy and capacity needs, including reviewing and commenting on IRP inputs, sensitivities, and technology options. DTEE also found value in engaging their internal communications team early to help craft an extensive communications strategy. DTEE's next IRP must be submitted by early 2025. The company will continue to refine its modeling approach and evaluate its progress toward meeting its near and long-term carbon reduction goals.

Conclusion

DTEE's 2019 IRP is one of the first IRPs of which EPRI is aware that systematically embeds its voluntary CO_2 emission reduction goal and a specific emissions accounting method into the formal IRP submitted to its PSC. DTEE is no longer an "island" electric company that seeks to meet its own customers' "native" load with power generation resources that are entirely owned and operated by DTEE.

Because DTEE participates in the larger, integrated MISO wholesale power market, the company determined the best way to account for the emissions associated with its net purchases of undifferentiated power was to apply the ANS approach. By utilizing this method and including its carbon reduction goals as an objective when modeling its IRP reference scenario, DTEE was able to model in a quantitative way the new operating constraints it faces as it moves forward to implement its voluntary CO_2 reduction goals. These measures taken by DTEE can provide valuable insights for other electric companies facing similar challenges.

The ANS emissions accounting approach adopted by DTEE to supports its 2019 IRP and its long-term resource plan is a new and innovative approach to CO_2 emissions accounting that seeks to address some existing limitations inherent in more traditional source-based GHG accounting. Specifically, the ANS addresses accounting for the GHG emissions associated with *net undifferentiated power* purchased by DTEE for resale to end-use customers, unlike a source-based accounting approach. The ANS approach implicitly recognized the CO_2 emissions benefits associated with purchasing wind power through the use of renewable PPAs. The ANS also more accurately reflects GHG emissions associated with generation resources that ramp up and down in response to market conditions as compared to other methods.

Resources

DTE Electric "Empowering Michigan" website

DTE Electric Integrated Resource Plan Executive Summary. DTE Electric, Detroit, MI: 2019.

DTE Electric "Journey to 80" website

Methods to Account for Greenhouse Gas Emissions Embedded in Wholesale Power Purchases. EPRI. Palo Alto, CA: 2019. 3002015044.

5
SALT RIVER PROJECT – IMPROVED SPATIAL DISAGGREGATION OF ELECTRIC VEHICLE ADOPTION THROUGH CUSTOMER PROPENSITY MODELING

IEN-P Challenge: Improving modeling of customer behavior and interaction

Introduction

Electricity customers increasingly have unprecedented access to emerging electric technologies such as electric vehicles (EV) and alternative service options. As new choices proliferate, their impact on electric system operation will increase and may impact the system in fundamental ways. In the future, electric company planning can be enhanced by more accurate projections of penetrations of these technologies and locations of adoption in a particular service territory. However, many decisions that will impact electric system planning likely will be made outside of an individual company's direct control by customers who choose to deploy and use these technologies, including EVs, rooftop solar PV, and others. As a result, it is becoming more important for resource planners to incorporate end-use customer behavior and choices that impact both load and resource dynamics into their planning processes.

Electric companies increasingly are challenged by the need to anticipate the pace and location of future adoption of load-altering customer technologies (including EVs) and services (such as demand response (DR) to make optimal operational and planning decisions. While it is essential to segment customers into meaningful groups to do this, electric companies also need to be able to map expected customer adoption of new end-use technologies and services to the utility service territory and specific transmission and distribution circuits that may be impacted. Not adapting to this changing customer role may lead to sub-optimal infrastructure investments and service dislocations that may impact electric service reliability and affordability.

Electricity customers represent a diverse set of characteristics, needs, and preferences. Aside from fundamental sectoral distinctions (e.g., residential, commercial, industrial, agricultural), customers can be classified by multiple attributes, from demographic to psychographic. Energy providers increasingly need to be able to distinguish which attributes are most relevant and actionable for projecting the adoption of key technologies and uptake of utility service options and programs.

To accomplish this, electric companies will need to use sophisticated data analytics to estimate the combinatorial impact of technologies on net load shape over time by location. In the future, these more sophisticated and complex projections may need to be tightly integrated with not only distribution system planning, but also, with generation and transmission planning. This case study focuses specifically on innovative approaches to modeling customer adoption of EVs and the potential for using those projections for distribution planning needs.

The U.S. National Electrification Assessment, released by EPRI in April 2018, projected that light-duty electric and plug-in electric vehicles will comprise 75% of new vehicle sales and 75% of vehicle miles traveled (VMT) by 2050, compared to less than 1% today (EPRI, 2018).[21] In this scenario, large electric utilities could experience significant new electric demand associated with charging hundreds of thousands of vehicles on their systems. The charging habits of electric vehicle owners, influenced by technologies and motivated by rate plans, can have large potential impacts on electric loads especially at a local, distribution level. These new loads may enable the system to be run more efficiently if charging can be timed to match system generation profiles, or if not controlled, they may exacerbate local or system peaks.

The Salt River Project Agricultural Improvement and Power District (SRP), featured in this case study, is also anticipating significant future growth of EVs in its service territory. As part of its Sustainability Goals, the company recently adopted a target of enabling the adoption of 500,000 light-duty EVs in its service territory by 2035. Alongside this target, SRP aims to manage 90% of EV charging through price plans, dispatchable load management[22], original equipment manufacturer integration (OEM)[23], connected smart homes, and behavioral and other emerging programs. To manage the impact of these ambitious goals, it is important for SRP to have as detailed a picture as possible of the extent and timing of future EV adoption on its system. This case study investigates the modeling approach utilized by SRP to develop a more granular understanding of how future EV adoption could materialize in its service territory.

SRP currently serves more than 1 million electricity customers over 2,900 square miles in 3 counties in central Arizona and the Phoenix metropolitan area. SRP is a vertically integrated utility that owns and operates almost 9,000 MW of electricity generation assets and over 20,000 circuit miles of power distribution lines. In 2018, SRP's system peak for retail customers was 7,300 MW. Between 2010 and July 2019, SRP estimated that there were over 10,000 plug-in hybrid (PHEV) and battery electric vehicles (BEV) registered in its service territory compared to over 1.3 million conventional vehicles.

Case Study Methodology

In September 2019, EPRI interviewed several individuals affiliated with SRP's business development department, Analytics Center of Excellence, and sustainability team. Two members of EPRI's Energy and Environmental Analysis Group conducted the interview via webcast 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. Prepared interview questions focused on understanding SRP's expectations for future adoption of EVs in its service territory, how the company performs customer propensity modeling, the advantages and limitations of this modeling framework, and future applications of the modeling results. A list of the specific interview questions and the slides from the webcast are available in the Appendix.

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[21] This finding comes from the Reference scenario. In the Conservative scenario, which assumes slower reductions in electric vehicle costs (e.g. lower availability, slower improvement in batteries) and more rapid improvement in conventional vehicles, electric vehicles are projected to provide only 50% of VMT.

[22] SRP defines dispatchable load management as the ability to tell EVs when to charged based on a variety of factors. It allows for automated management of EV charging in real time.

[23] OEMs are car manufacturers such as Ford or Honda.

Key Insights

- SRP has turned to customer propensity modeling to better understand the location of future EV adoption on its distribution system.
- According to SRP, customer propensity modeling has the following advantages over other customer modeling methodologies:
  - Customer propensity modeling provides SRP with a way to spatially distribute high-level EV projections across its service territory.
  - Customer propensity modeling, which creates segments of adopters at the household level can provide a more spatially detailed representation of possible future adoption in SRP's service territory.
- Understanding the location of EVs could help distribution planners estimate future load on service transformers and feeders. In collaboration with EPRI, SRP is working to assess the potential overloading impact of future EV growth on service transformers.
- While customer propensity modeling can give utilities like SRP a good sense of the location and amount of future EV adoption, it is more limited in its ability to provide information about the timing of future adoption.
- Customer propensity models can be built for other customer-side technologies such as rooftop PV and customer programs, including pricing programs.

Interview Summary

Current EV landscape in SRP's service territory

SRP has a target of 500,000 light-duty electric vehicles in its service territory by 2035[24]. It estimates the current penetration to be about 10,000 PHEVs and BEVs, which translates to an average annual increase between now and then of just over 30,000 vehicles per year. To meet this target, SRP is trying to design additional programs to complement the incentive programs it already has in place. About 70% of currently identified SRP customers that own EVs participate in the company's time-of-use (TOU) program, which charges them a lower-priced off-peak rate if they choose to charge between 11:00 pm and 5:00 am.

Beyond its rate incentives, SRP is exploring ways to increase charging access. Just over two-thirds of SRP's residential customers reside in a single-family dwelling, which implies they potentially have easier access to home charging. Increasing access for residents of multi-family dwellings, who represent a smaller, but significant share of SRP's customers, is more complicated. In the near-term, the company is working with commercial customers to install workplace charging. Presently SRP offers a $500 rebate to commercial accounts that can be applied toward installation of a Level 2 charging station.

[24] SRP's service territory encompasses a largely urban setting, with most drivers following the typical driving profile for this type of resident. From 2010 to July 2019, the total number of vehicles registered (conventional and electric) in SRP's service territory was estimated to be 1,361,580.

Customer propensity modeling to understand location of future EV adoption

SRP's commitment to increasing the number of EVs in its service territory, facilitated by its rate and charging incentives, means that the company will need a more detailed understanding of how EV adoption will progress in the coming years. The location and timing of EV adoption will have important implications for the operation of SRP's distribution system. To better understand the location of future EV adoption on its distribution system, SRP has turned to customer propensity modeling.

At a basic level, customer propensity modeling separates customers into different classes of adopters and scores each segment's likelihood of adoption. Model developers receive data from multiple sources to develop the customer segments.[25] Important data inputs include, but may not be limited to, utility customer data (e.g., known owners of EVs, electricity usage, rate structure, etc.), demographic data (e.g., household income level, employment status, etc.), and neighborhood characteristics (e.g., house sale price, type of dwelling, etc.).

SRP's data analysts feed these data into a machine learning model that groups customers with similar attributes into *segments*, or classes of adopters. The model then gives these segments a score from 0 to 1 corresponding to their likelihood of adoption. Classification into a segment is done at the household level.

As an example, households with large electricity usage are more likely to adopt an electric vehicle. The propensity model would group these households into a segment with a score closer to 1. From there, SRP feeds its EV projection into the model to determine the potential spatial distribution of EVs across its service territory (Figure 5-1). These distributions can be aggregated from the household level to the distribution feeder level to the substation level to give a sense at varying spatial scales of the impact of EV adoption on SRP's distribution system. Regions with segments with higher adoption scores will see greater numbers of EV adoption.

[25] The size of these segments can vary, from large groups all the way down to a few individuals.

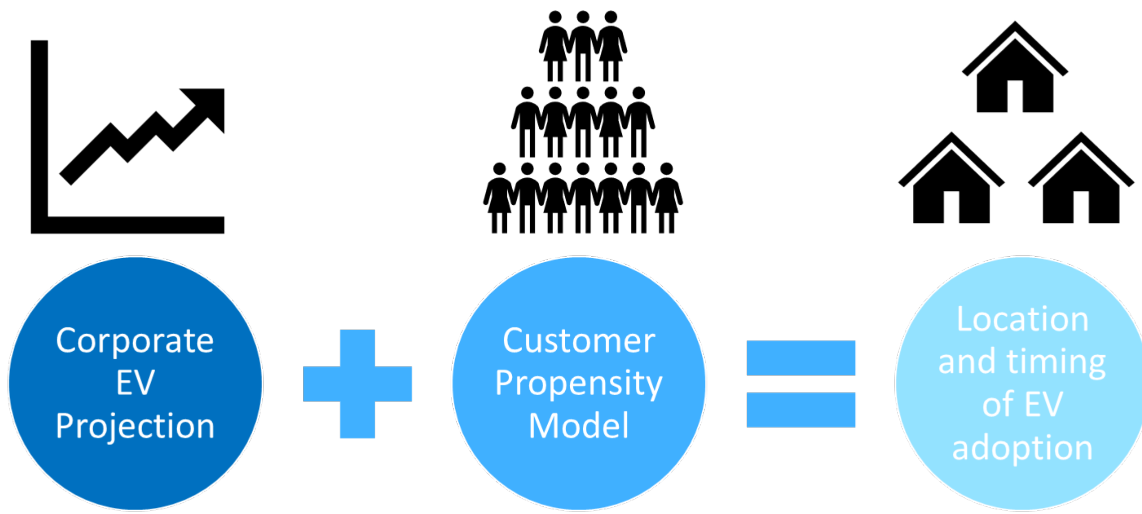

Figure 5-1
Process for using customer propensity model to spatially allocate high-level EV projections (Adapted from SRP, 2019). SRP feeds its corporate EV projection into its previously developed customer propensity model to determine whether the vehicles may show up on SRP's distribution system. The EV projection provides the number of vehicles, whereas the propensity model determines who will adopt those vehicles. The combination of these two provides SRP with a sense of where these vehicles may be adopted.

According to SRP, customer propensity modeling has several advantages over other customer modeling methodologies. First, SRP sought a way to map high-level EV projections on to its grid. These projections provide a useful estimate of the future volume of vehicles the system might see but are not spatially allocated across the system. Customer propensity modeling provides SRP with a way to distribute these high-level projections across its service territory.

A second, related advantage is the level of spatial detail that customer propensity modeling can provide to SRP. The choice to transition to an EV is dependent on several factors, meaning that adoption will not be uniform across SRP's distribution system. Considering this, it's important to have as granular a picture of future EV spatial distribution as possible, preferably at the neighborhood or household level. Fortunately, propensity model segments of adopters are determined at the household level, meaning that the model results can be used to allocate EV projections across household in a service territory. Finally, customer propensity modeling is not too computationally intensive.

SRP has spent several months building its propensity model and has now turned to validating it. In this stage, SRP is comparing modeling results to three sets of observations. First, the company compares the model's overall projected adoption (i.e. number of vehicles) to actual EV growth in its service territory for a given study period. This provides a sense of whether the model is projecting the correct volume of vehicles. Next, SRP compares the model results to the actual number of EVs adopted at the feeder level to understand how accurately it distributed the EV projection throughout SRP's service territory. Finally, SRP validates the model results at the customer level to determine how effectively the propensity model can positively project adoption for a particular customer segment with less false positives compared to results randomly obtained without the model. Figure 5-2 provides an example of how EV projections can be mapped to transformers within a service territory using customer propensity modeling.

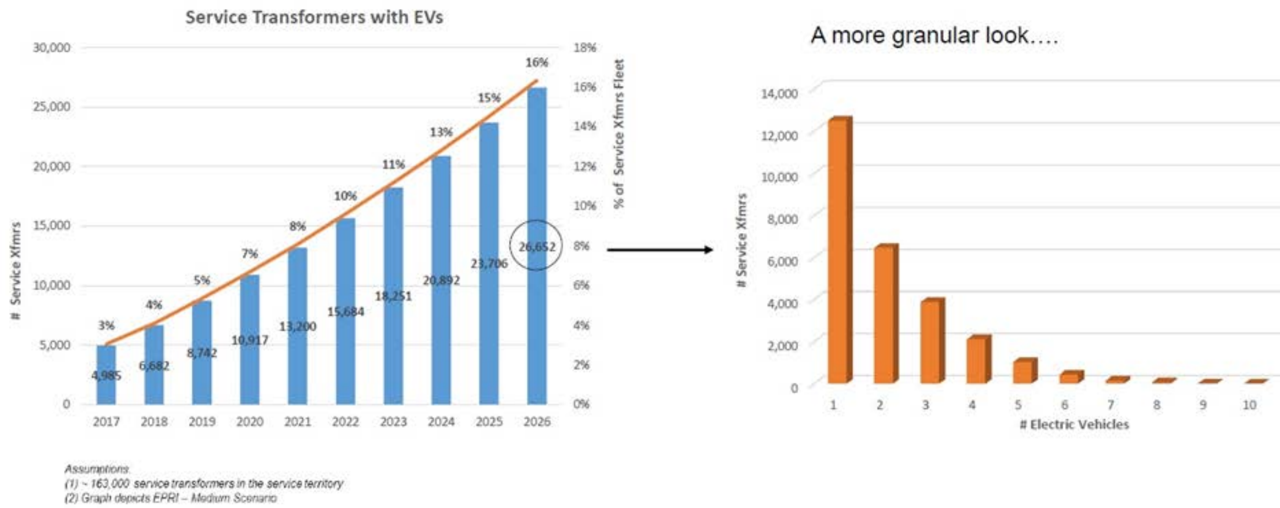

Figure 5-2
EV projections mapped to service transformers (SRP, 2018). Projected number of service transformers with EVs from 2017 to 2026 (left). Number of EVs per service transformer (right). Results from mapping to propensity model scores have been aggregated to the transformer level.

Applications of propensity model results

Although SRP remains in the model validation stage, the company has ideas for future applications of this type of modeling. As stated in the introduction to this case study, electric company planners will need to use sophisticated data analytics to estimate the combinatorial impact of technologies on hourly loads and load shapes over time by location. EVs have the potential to increase service requirements on individual feeders or transformers but can also be managed to offset demand spikes during peak periods. Understanding the location of EVs could help distribution planners estimate future load on service transformers and feeders. This type of information is useful for planning the sizing of transformers. In addition, it may provide insight into which customer programs are likely to be successful, although SRP has not yet used the modeling for this application.

In collaboration with EPRI, SRP is working to assess the potential impact of future EV growth on service transformers. Using the data from SRP's most recent propensity model output mapped to individual customers, EPRI plans to assess the number of services transformers that could become overloaded if the corporate goal of 500,000 light duty EVs in its service territory is realized. In addition, EPRI plans to comparatively analyze results from different allocation approaches using the data from SRP's propensity model. The results of this research, jointly funded by EPRI Programs 174 (Integration of Distributed Energy Resources), 182 (Understanding the Utility Customer), and 200 (Distribution Planning and Operations) are expected to be available in late 2019.

Limitations, lessons learned, and next steps

Earlier this case study discussed the importance of knowing the location and timing of future EV adoption in a utility's service territory. While customer propensity modeling can give utilities like SRP a good sense of the location and amount of future EV adoption, it is more limited in its ability to provide information about the timing of future EV adoption. Higher propensity scores may indicate more rapid adoption, but it can be difficult to tell exactly when that adoption will occur. To capture customers' behavioral change over time, the model developers periodically update the underlying data used by the model and fine-tune model hyper-parameters. Other methods such as trend analysis could be applied to further develop this understanding.

Moving forward, SRP plans to continue to refine its model, add more data, and add enhancements. The company is currently working to secure more granular data about the location of current adopters. They are also interested in developing and refining propensity models for other demand-side resources such as demand response. SRP is currently developing a propensity model for solar PV adoption.

Conclusion

Recognizing the transformational impact that increased adoption of EVs could have on the operation of its distribution system, SRP is proactively developing analytical tools to help the company better understand how this adoption may materialize throughout its service territory in the future. Using customer propensity modeling, SRP can allocate its corporate EV projection at a higher spatial resolution. The results of this type of modeling are designed to provide the company with a more accurate representation of where EVs may be located on its distribution system and enables its planners to assess how household-level adoption may translate into broader system impacts. SRP's innovative approach to modeling future customer behavior provides useful insights for other electric companies that may be facing similar challenges.

Resources

2035 Sustainability Goals. Salt River Project. Phoenix, AZ: 2018.

U.S. National Electrification Assessment. EPRI. Palo Alto, CA: 2018. 3002013582

A
INTERVIEW MATERIALS AND QUESTIONS

Chapter 3 – MISO

Material for this case study was taken from an interview with MISO in August 2019.

Table A-1
MISO – Prepared questions for interview

Topic	Questions
Clarify background and context	MISO needs load forecasts to develop its transmission expansion plan (MTEP) MISO socialized its proposal with stakeholders in late 2018. Stakeholders were invited to submit alternative proposals for load forecasting. How, if at all, is the Gross Demand and Energy Forecast technique/approach used outside of MTEP?
Collaboration with LSEs to develop gross energy and demand forecast	Describe the stakeholder engagement process for acquiring data to develop the gross energy and demand forecast for MTEP. Why in the “Merged Proposal” were LSEs asked to provide the true gross forecast and component forecasts separately? How has this new load forecasting approach been adopted within MISO? What could be some barriers to adoption?
Capabilities needed to produce this type of forecast	Describe the novelties of this technique. What differentiates it from other load forecasting techniques? What data challenges exist that may complicate/make difficult this approach? What modeling/specific capabilities are needed perform this kind of forecasting? To which components (i.e. DERs, EVs, etc.) do the forecasts appear to be the most sensitive? Are the forecasts developed for the MTEP futures disaggregated at the LRZ level?
Lessons learned and next steps	What lessons were learned during the development of this new approach? What procedures are in place to continue to refine the technique? How does MISO anticipate its new load forecasting approach may impact its overall planning reserve margin (PRM), and the PRM it requires its member electric companies to meet?

Chapter 4 – DTEE

Material for this case study was taken from an interview with DTEE in August 2019.

Table A-2
DTEE – Prepared questions for interview

Topic	Questions
Motivations	What were DTE's motivations for adopting its original CO_2 emissions target in 2017? What were DTE's motivations for further integrating its CO_2 target into its 2019 IRP? How, if at all, have the seven planning principles that DTE outlined in its 2019 IRP changed over time?
Planning process change	How did DTE's planning process change between the 2017 and 2019 IRPs? How, if at all, did the objectives change between the two IRP cycles? What specific steps of the planning process or cycle were adjusted between 2017 and 2019? To include a CO_2 constraint in its reference scenario, how did DTE have to modify its overall planning process and specifically, its IRP modeling? What, if any, barriers or challenges did DTE encounter as it modified its planning process to incorporate its CO_2 goals and new CO_2 accounting method? How did DTE overcome these challenges?
New tools and methods	Were there any new tools or methods DTE chose to use to accomplish its objectives for the 2019 IRP? What new types of modeling did DTE incorporate into the 2019 IRP? How was DTE's leadership involved in the 2019 IRP process? Did DTE's planning staff have to acquire any new skills and/or learn any new modeling techniques to accomplish the objectives of the 2019 IRP?
Lessons learned and next steps	What were some lessons learned between 2017 and 2019? How does DTE plan to continue and/or modify its planning process for the next IRP?

Chapter 5 – SRP

Material for this case study was taken from an interview with SRP in September 2019.

Table A-3
SRP – Prepared questions for interview

Topic	Questions
Background	How does SRP anticipate that EV adoption will evolve in its service territory?

	What is the typical driving profile of an SRP customer? Does SRP have any targets or incentive programs for EV adoption? What are the some of the current enablers or barriers to EV adoption in SRP's service territory?
Customer propensity modeling	Review propensity modeling basics Why did SRP select this type of modeling? What advantages does it provide when trying to project future adoption of EVs? What other methods are there to model customer adoption of new technologies? Did SRP consider them? How does SRP plan to use the results of this modeling in its distribution system planning? What is SRP's current distribution planning process? How does SRP currently incorporate projections of customer-side technologies into this process?
Modeling details	How difficult was it for SRP to acquire the customer data to develop segments of adopters? How did SRP pick the specific attributes used in the model? Is this modeling resource- and/or computationally intensive? When developing projections of the total number of EVs, what assumptions does SRP make about the future? Does SRP conduct sensitivity or scenario analyses? Has this type of modeling been used to project adoption for other customer-owned technologies? Is it used elsewhere in the industry? What are the limitations of propensity modeling?
Lessons learned and next steps	What lessons has SRP learned as it developed its propensity model for EV adoption? What are the next steps for refining the propensity model and/or incorporating its results into future distribution planning?

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