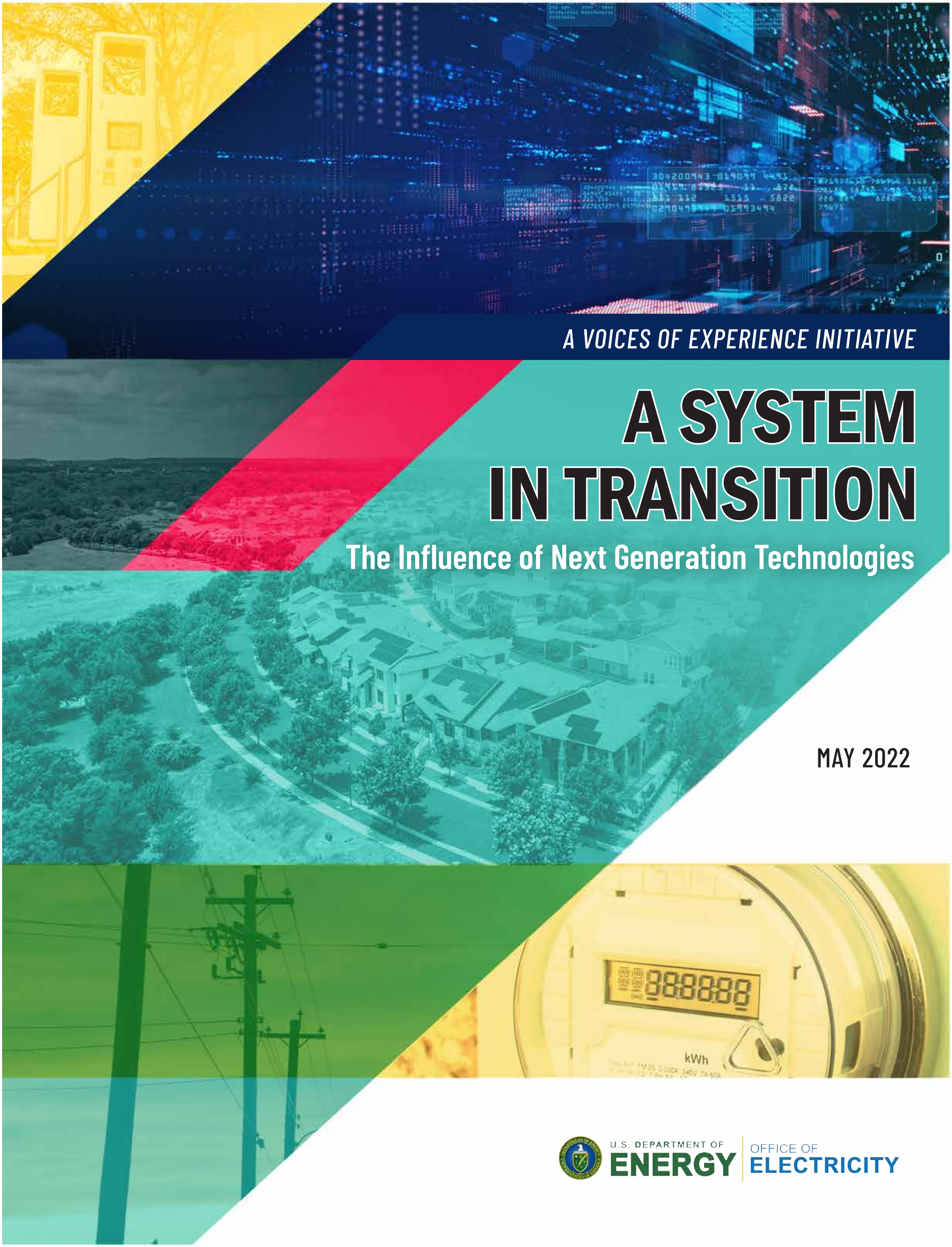

A VOICES OF EXPERIENCE INITIATIVE

A SYSTEM IN TRANSITION

The Influence of Next Generation Technologies

MAY 2022

U.S. DEPARTMENT OF ENERGY | OFFICE OF ELECTRICITY

The U.S. Department of Energy's Advanced Grid Research division and the team from E9 Insights, Plugged In Strategies, and Arara Blue Energy Group would like to thank everyone who participated in the conversation and made this report possible. Special thanks to the National Association of Regulatory Utility Commissioners for providing coordination and assistance in this project. The willingness and candor of participants were an invaluable contribution to the report.

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Executive Summary

The electric distribution system in the U.S. is in a state of transition as the grid is modernized and consumers have more control over their energy usage. Utilities are proposing – and regulators are having to evaluate – a new class of "next-generation technologies" that are not a one-for-one replacement for aging infrastructure. For the regulator, this can create challenges.

Technological advancements and evolving societal and customer preferences are driving changes that affect not only utility operations, but are impacting the regulatory process itself, raising more complex and fundamental questions. On top of this, regulators are also grappling with the challenges of aging infrastructure, extreme weather events, and initiatives to reduce carbon emissions, all while ensuring that costs remain reasonable and electricity is affordable. While these changes are happening universally across the country, the pace and specific regulatory processes in place for approval of investment proposals vary widely from state to state.

Five emerging technologies and related issues were identified that represent this change and are symptomatic of the transition before state regulators. They are:

- Next Generation Advanced Metering Infrastructure
- Distribution Controls
- Electric Vehicles
- Data access and governance
- Coordination with other relevant state agencies

Conversations with regulators, both individually and collectively, identified a series of macrotrends, themes, common challenges, and a regulatory wish list that are captured in the report. It presents the knowledge shared by participants about what they wish they had known, advice they might give to fellow regulators, and lessons they have learned along the way. It also contains specific examples of rulings and orders from commissions around the country, as well as highlights of resources to delve deeper on key components of grid modernization.

Next-generation technologies present myriad variables in their implementation and usage, and customers' needs vary as well. This report can serve as a valuable resource for regulators as they develop strategies and policies in response to this transition and as they evaluate utility plans and investments.

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Valuing New Capabilities for a Transitioning System

The electric distribution system in the U.S. is in a state of transition as the grid is modernized. Utility customers are installing solar panels to generate their own electricity. They are purchasing electric vehicles (EVs) to improve air quality and reduce emissions. They are becoming less tolerant of outages and interruptions as their lives become increasingly dependent on electricity. Grid operators and planners are continuing their traditional pursuit of ensuring safe, reliable electricity, but they must also consider the new wave of technologies that are proliferating at the customer edge of the electric grid.

What is a next-generation technology?

Next-generation technologies have the ability and potential to transform grid operations and customer interactions. Benefits are based not only on direct use, but also what they enable in grid functionality or a customer's ability to manage their energy usage and interact with the grid. These technologies can serve as a platform or an enabling technology with indirect or future benefits that do not accrue directly to a single customer.

This change is potentially a tectonic shift for the electric industry, forever changing how utilities will operate the grid and the dynamic between them and customers. Utilities will need new technologies that provide more visibility into customer equipment, that allow them to interact with and integrate flexible customer grid-edge assets – whether managed by the utility, the customer themselves, or a third party. Utilities will have to orchestrate a broad sea of technologies that have to work in concert.

Utilities are proposing – and regulators are having to evaluate – a new class of "next-generation technologies" that are not one-for-one replacements of aging infrastructure. These technologies provide new capabilities and functionality for operating, managing, and controlling the grid, and even enable integration of customer-owned resources. The investments needed to support the changing dynamic carry significant costs though, while the benefits are often intangible, hard to calculate, or not readily apparent to consumers and regulators. Rather, the technologies often offer broad benefits to society or enable a new vision for electricity delivery. Even when the benefits are direct and the capabilities are clearly articulated to commissions, it may take years to deploy the technology and integrate it with legacy systems before benefits can be fully realized.

These represent a new breed of energy infrastructure. Where utility operations – and commission proceedings – traditionally have been easily compartmentalized based on the distinct nature of specific benefits tied to a singular, clearly articulated technology, these next-generation technologies enable benefits that span across multiple proceedings or support a variety of utility services and operational areas.

Technological advancements and evolving societal and customer preferences are driving changes not only for utility operations, but are also having an impact on the regulatory process itself, raising more complex and fundamental questions. On top of this, regulators are grappling with the challenges of aging infrastructure, extreme weather events, and initiatives to reduce carbon emissions, all while ensuring that costs remain reasonable and electricity is affordable. While these changes are happening universally across the country, the pace and specific regulatory processes in place for approval of investment proposals vary widely from state to state.

About the Initiative

The Department of Energy's Office of Electricity (DOE OE) funds research to advance grid technologies that will strengthen, transform, and improve energy infrastructure so consumers have access to resilient, secure, and cleaner sources of electricity. Recognizing the value of peer-to-peer conversations for broadening perspectives and enhancing learning, DOE OE funded the Next-Generation Technologies initiative to better understand the evolving landscape, to provide insights into the challenges these technologies present, and to provide resources that can assist regulators.

Building on the *AMI in Review* initiative, this next-generation technology initiative utilized the Voices of Experience approach pioneered more than a decade ago by DOE OE, bringing together regulators for peer-to-peer conversations on specific technology areas. The project team of E9 Insight, Plugged in Strategies, and Arara Blue Energy launched the initiative in 2021, in collaboration with the National Association of Regulatory Utility Commissioners (NARUC).

To inform the discussions, a portfolio of 100 commission orders and utility proposals were reviewed to identify key issues, regional trends, and regulatory strategies. Organizers then conducted a series of discovery meetings with regulators from eight states representing a diversity of regions and levels of activity with next-generation technologies to select the technologies that were of highest interest and that best represent the changing dynamic within the regulatory review process.

Five two-hour virtual convenings took place in late 2021 and early 2022. Each meeting included presentations from state regulators sharing their experiences with the selected topic, followed by interactive discussions that raised issues and concerns while fostering peer-to-peer dialogue and learning. Eighty-three participants joined the first four virtual meetings, representing commissions in 26 states and NARUC. The fifth convening on cross-agency collaboration for transportation electrification included 94 participants, with state utility commission representatives being joined by members of the following state offices from eight states and one territory:

- Bureau of Administration
- Department of Commerce
- Department of Economic Development and Commerce
- Department of Environment and Energy
- Department of Environmental Quality
- Department of Transportation
- State Energy Office

What This Report Is... and Isn't

This report represents the collective voice of regulators. The information presented in this document collects the ideas, opinions, and experiences shared by regulators from across the country during ten hours of peer-to-peer discussions and many more direct conversations. While DOE provided questions to frame and guide the conversations, participants determined the ultimate direction and flow of the discussions. Insights, concerns, and lessons learned were compiled to find commonalities and edited to remove any identifying information about the participants.

This report is not a "how-to" guide. While participants shared advice about approaches that had worked in their jurisdictions (and those that didn't), the goal of the discussions was to allow for dialog between participants rather than digging into technical specifications. Neither the conversations held nor this document sought to construct a unanimous "right way" to do things or offer an official DOE viewpoint on any of the topics covered. The presentation of examples, excerpts, and additional resources is meant to serve as a resource to help commissioners and their staff as they navigate the evolution of next generation technology.

Each jurisdiction may require different solutions. Next-generation technologies present myriad variables in their implementation and usage, and customers' needs vary as well. Likewise, some utilities are well into their next-generation journey while others are just starting to research the technologies and how they can most effectively leverage them. There will be many solutions and policies that emerge but the hope is that the collective information in the report can provide value and insights for commissions as they evaluate utility investment proposals.

What's Inside

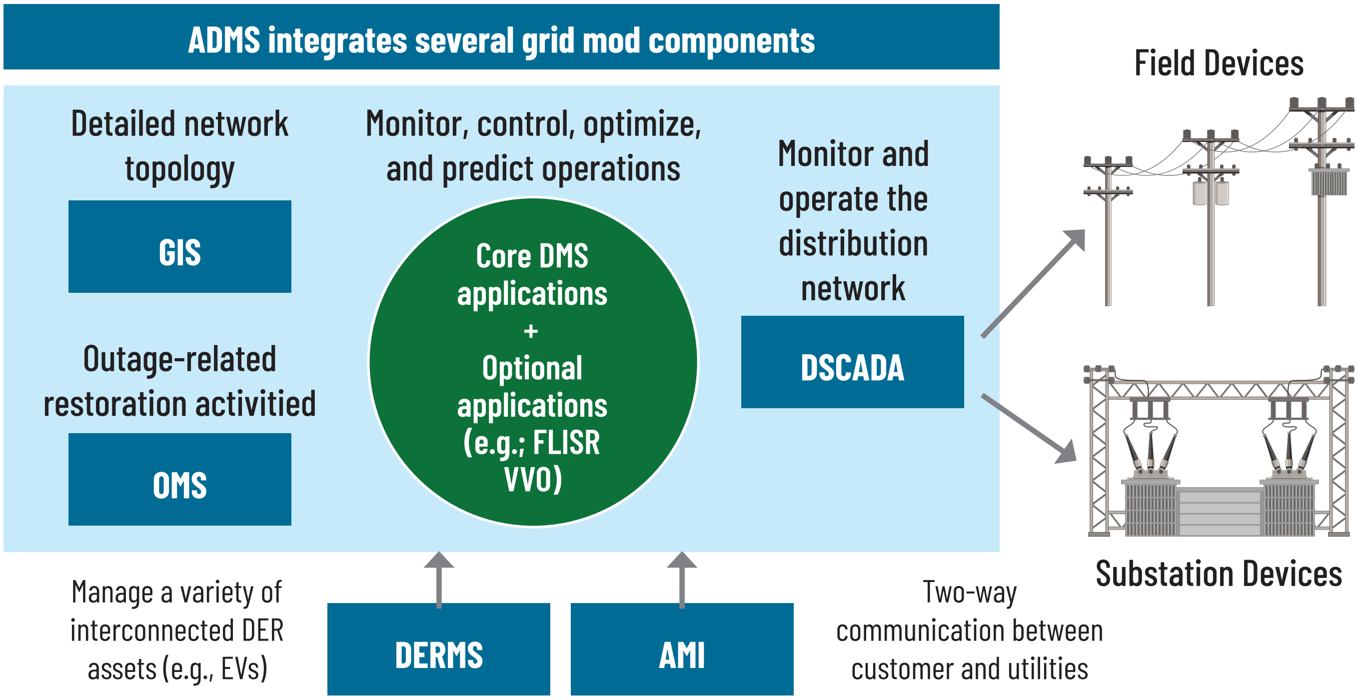
Each Specific Findings chapter includes the following sections:

- **Insights from the Conversations** – Collective views shared by participants reflecting on what they have learned, what they wish they had known, and what would be helpful for the future.
- **Questions Commissions Are Asking** –A list of overarching questions commissions are probing or asking themselves as they consider future utility investments.
- **Powering Knowledge** – Excerpts from reports or supplemental information that further explains key issues or approaches.
- **Commission Happenings** –Summaries and excerpts from commission orders that readers can draw on as they work to develop their own policies or solutions.
- **Battery of Resources** – Collected resources for those looking to do further reading

Technologies that Represent Change

Numerous new technologies driving the energy transformation are increasing the focus on the distribution system. Some of the technologies are located on the utility side of the meter and some on the customer side. Through discovery conversations with DOE, NARUC, and commissions, the initiative focused on a subset of technologies that best illustrate the changes to the regulatory review process.

Distribution controls, advanced metering infrastructure (AMI), and EVs epitomize the larger pool of technologies that are increasing focus on the distribution system. These, along with the overarching questions surrounding the handling of customer data related to all three, raise novel questions and prompt new – or different types of – evaluations. Deployments for next-generation technologies may seem straightforward on the surface, but digging into the details can uncover a hornet's nest of issues and concerns from commissions and stakeholders at large.



Source: Adapted from a DOE Grid Modernization Lab Consortium presentation for Distribution Systems and Planning Training from Tim Wolf March 7-8, 2019. https://e9radar.link/9et

Distribution Control Technologies

In many cases, distribution grid technologies are software, not hardware, and rely upon a robust communications network to receive data and send signals and commands. Taken together, the technologies allow distribution utilities to have better situational awareness of the operational characteristics of the system, and help them monitor, respond, plan, and operate their systems as more distributed energy resources (DERs) are integrated and customer participation grows. The distribution control technologies that were considered as part of the effort include: Advanced Distribution Management Systems (ADMS), Distributed Energy Resources Management Systems (DERMS), and Fault Location Isolation Service Restoration (FLISR).

ADMS is an overarching grid controller that can integrate other utility applications and functions. DERMS is typically one part of a broader ADMS package with the capability to manage a group of DER assets, such as a large number of customer-owned solar or electric vehicles. Unlike ADMS, though, DERMS will not restore service, but offers an intelligent way to manage DER by using load and weather forecasts along with pricing information to communicate and dispatch commands. It can send a price signal to the DER so it can respond accordingly, or allow the utility to control a customer's DER directly (with customer consent). FLISR technologies can operate autonomously through a distributed or central control system like ADMS, or can be set up to require manual validation by control room operators that initiate commands through field technologies (e.g., supervisory control and data acquisition [SCADA] switches).

Definitions of Distribution Control Technologies

ADMS – a software platform that integrates numerous utility systems and provides automated outage restoration and optimization of distribution grid performance.[1] It gives utilities the capability to proactively manage day-to-day maintenance, peak demand, optimization, and repair efforts. It acts as a centralized repository of data and functions, and it will prescribe and coordinate actions utilizing information from across the utility's distribution system, taking into account renewables or DERs on the system.

DERMS – a software-based solution that increases an operator's real-time visibility into the status of distributed energy resources and allows distribution utilities to have the heightened level of control and flexibility necessary to more effectively manage the technical challenges posed by an increasingly distributed grid.[2] It is a peer to ADMS.

FLISR – technologies and systems that automate power restoration, making outages shorter and lessening their impact. Such systems involve numerous components involving automated feeder switches and reclosers, line monitors, communication networks, distribution management systems (DMS), outage management systems (OMS), SCADA systems, grid analytics, models, and data processing tools.[3]

[1] https://smartgrid.gov/files/documents/ADMS-Guide_2-11.2015.pdf

[2] https://www.energy.gov/sites/prod/files/2015/09/f26/QTR2015-3D-Flexible-and-Distributed-Energy_0.pdf

[3] https://www.energy.gov/sites/prod/files/2016/10/f33/Fault_Location_Impact_Duration_Dec_2014.pdf

Advanced Metering Infrastructure

Advanced metering infrastructure (AMI) is an integrated system of smart meters, communications networks, and data management systems that enables two-way communication between utilities and customers. It provides information that was unavailable from analog meters, such as automatic, remote measurements of electricity usage or detection of tampering. AMI can also perform actions such as remotely connecting and disconnecting service or identifying and isolating outages. While the first generation of advanced meters offered significantly more functionality than their analog counterparts, second-generation advanced meters (or AMI 2.0) have even more capabilities. These next-generation meters now have distributed computational processing capabilities so rather than having to send data back to a central controller, which, in turn, issues a response, the meter can execute actions itself based on centrally-defined parameters.

AMI is at a transition point. Meters that were installed through 2012 will be reaching the end of their useful life in the next 5-7 years, and utilities may propose replacing those meters. Whether as a replacement for first-generation meters or as a first-time deployment, AMI 2.0 meters with new capabilities and functionality raise new questions for commissions both in jurisdictions with AMI deployed and those without, and potentially the need for new areas of regulation.

Electric Vehicles

Electric vehicles, their associated charging technology, and the supporting grid infrastructure are key elements in the transition to transportation electrification. The transition represents both a technological and societal shift, introducing new variables to consider when evaluating utility proposals or cost causation. EV loads are different from traditional building loads from a grid perspective: they are mobile, they will not necessarily get more efficient over time, they do not consume energy from the grid when in use, and they store energy for later use. Some vehicles may sit idle for long periods of time, allowing the possibility for charging to be shifted to another time or place or the potential to use the energy stored in vehicle batteries for customer and grid benefits.

Supporting the transition to electrified transportation will require commissions to evaluate a range of topics. Along with direct investments, there may be costs that are included in the general rate base for all customers. Commissions will have to evaluate and determine how utility charging infrastructure is funded, when it is needed, and how costs are allocated. They will also be the vital link in determining how grid infrastructure is built out and who pays for it. Commissions will need to evaluate utility investments in associated control technologies – both utility control approaches and those that leverage third-party aggregation or control. Utilities will likely need new rate structures or incentives (i.e., compensation) to encourage customers to participate in new programs or to align charging behavior with grid needs.

As more EVs are connected to the distribution grid, technologies such as ADMS and DERMS might be needed to help the utility operate its system more efficiently. Leveraging the data collected can then help the utility plan for appropriate upgrades that may be needed to integrate EV adoption in a region. While the growth of EVs may necessitate (or accelerate) the need for ADMS, DERMS, or other control technologies, such technologies often appear in front of commissions in separate proceedings.

Data

Data spans all the technologies considered as part of the project. Each technology provides robust data that is collected and transmitted to other technologies and sometimes between parties with different interfaces, boundaries, and security standards. To provide value, data must be utilized and analyzed.

Data can tell an entity where a resource is located, how much electricity it is using, and other operational information. It can be used by utilities and third parties to develop innovative programs and services for customers, or to optimize systems, networks, technologies, or operations. Often, however, parties need (or would like to have) data that other entities have, which raises privacy, confidentiality, and security concerns as information is shared, transmitted, and accessed. Data, and the sharing of data, also has monetary implications. Untangling the conflicting needs and interests as well as determining data's value to customers raises new questions and creates challenges for commissions about how the data is accessed, shared, and used.

Macrotrends

The electricity landscape, especially at the distribution level, is changing quickly as the cost of DERs decrease and adoption levels increase. Innovation is creating new approaches for utilities, while other parties are developing new products and services aimed directly at customers. The innovations and new participants can impact how the distribution grid is organized, managed, and controlled to incorporate these new resources. This is driving a change in electric grid architecture – or design – from one where the utility supplies energy to customer homes and businesses from large, centrally located power plants to one that includes millions of intelligent, customer-owned resources that are controlled by the customer or a third-party and can provide energy back to the grid. Five trends that are a result of the transformation of the electric grid emerged from conversations with regulators. These trends encapsulate the changes taking place.

Foundational Investments Underpin the Transformation

Transformation of the electric system will not happen without investments in technologies that enable that transformation. Many in industry have categorized technologies that have the potential to fundamentally change how the electric grid is managed and controlled as foundational technologies. It is their transformational component, though, that can pose challenges when assessing value. Where the legacy system is built upon a series of poles and wires that deliver electricity in one direction from power plant to customer, new technologies seek to enable and enhance grid operations that are far more flexible and interactive, often with bidirectional electricity flows to and from the customer.

To determine how a technology fits into the new energy future and what that means for utility operations and investments, commissions are beginning processes to better understand what capabilities will be needed, what gaps exist, and when investments need to be made. Commissioners may have differing opinions about whether a technology is foundational (or to what degree), what role it plays in grid modernization, and the timing for investments. All of which impact conversations and proceedings.

Regulatory Proceedings Are Evolving Too

The fundamental role of a commission – to ensure safe and reliable utility service at reasonable rates – is not changing. It is evolving though. To oversee the transition, technology choices may require new regulation, or regulators may need to leverage their tools and authority in new ways to ensure future operations are not limited by the utility's technology choices.

Every state has a unique set of governing rules that affect the policy strategies commissions will take. In some cases, commissions may seek to establish initiatives (e.g., investigations, rulemakings, workshops) prior to an investment proposal from a utility. In other cases, the state legislature may create specific laws or requirements that direct the commission to take certain actions. In still other cases, the executive branch in the state may promote policy goals to which the commission is responsive. In all cases, the regulatory process is evolving to include a mix of traditional economic regulation and deliberate actions to drive the policy agenda in the state.

Benefits Are Not Siloed

Large distribution investments are typically subject to a benefit-cost analysis (BCA) or cost-benefit analysis (CBA). These analyses aim to quantify the value of an investment and can appear to be an effective, unbiased means of assessing the costs incurred versus the value to be achieved. But a simple mathematical comparison may not be as effective for next-generation technologies.

These technologies can have significant near-term costs, but benefits that might not be achieved or realized for several years. Further, those benefits may be hard to quantify because they do not produce savings, but rather enable a transformation of grid operations. They can also depend on integration with other technology, the level of consumer engagement, the development of third-party applications, new rate designs, and other variables. Commissions may also be apprehensive about "double counting" benefits associated with more than one technology or proceeding. For example, benefits listed in a proposal for AMI could also show up in energy efficiency proceedings.

Equity Is at the Forefront

While equitable treatment has always been a concern for regulators, new technologies that introduce new market dynamics bring equity considerations into greater focus. Stakeholders and regulators are increasingly looking at how investments impact or benefit underserved communities, seeking to ensure that investments offer opportunities for all customers.

Commissions' focus on equity is not limited to access to the technology alone but also includes leveraging data to better understand service quality across the system, system constraints, and the efficacy of programs. Commissions are considering the implications of data sharing for encouraging innovation and enhancing opportunities for economic and workforce development. They are also balancing the implications of new policies and rate structures to avoid inadvertently shifting costs.

There's More Than One Way

Grid modernization is complicated by an issue of abundance: identified issues can have multiple solutions. Next-generation technologies provide more options for meeting system needs for both bulk and local systems, and some solutions may come from entities outside the utility. Non-wires alternatives that do not use traditional utility assets provide new tools to meet demand and infrastructure needs. Third-party provider solutions can take advantage of grid-edge assets, but can limit the utility's visibility and control of these resources. Utilities and regulators alike must evaluate and choose the solution that is most beneficial and most cost-effective, but also reasonable and prudent. This can require an understanding of the individual technologies, how they are integrated and implemented, and what alternatives exist.

Technology assessments are also informed by an evaluation of various risks: the risk of doing nothing versus the risk of investing in a technology that will soon be obsolete versus the risk of making significant investments to support a future that is never realized or a technology that is underutilized. Balancing risk requires consideration of customer, grid, and societal needs, along with the recognition that it is not feasible for the utility to fund all investments at one time. Another consideration is evaluating who bears the risk of the investment – the entire utility rate base, the utility shareholders, individual customers, or third parties.

What Is Grid Architecture?

It is the highest-level description of the complete grid, providing an understanding of the grid as a composition of multiple structures. It gives insight into ways to modify or extend those structures to relieve old constraints, improve grid characteristics, and enable new capabilities.

Key Themes

Next-generation technologies – and grid modernization in general – are having an impact on the type and timing of investments. Traditional investments in hardware and maintenance (e.g., conductors, substations, tree-trimming) are being complemented by more nuanced and interdependent investments that are transforming grid operations and providing customers with more options to control their energy consumption. The following represent the high-level themes that emerged from conversations with state regulators.

Technologies Are Raising More Complicated Questions

Next-generation technologies are generating a plethora of new questions that commissions are asking and are being asked to answer, whether these are fundamentally new questions or more complicated versions of questions commissions have always considered. The growing numbers of participants involved in providing electricity – from prosumers and third-party providers – and programs and services offered – from microgrids to DER aggregation – introduce new considerations about the utility business model and the amount of interaction with or control over assets utilities need. They raise questions about data access and the timing of investments. Some questions can be contentious and providing answers often requires commissions to dig deeper into the details about the technology in order to be able to provide specific guidance and direction. Questions that may seem similar to basic ones asked in rate cases can take on new meaning when considered in a high DER future.

Questions Commissions Are Asking

- What is the vision for the state regarding the electricity system?
- What is the role of the distribution utility in the vision for the state?
- What investments are required to achieve the vision?
- What opportunities exist to encourage innovations and market solutions?
- How do these technologies meet current and future customer needs and preferences?
- What is the appropriate pace of implementation to manage impacts to ratepayers?
- How are risks and benefits of investing in technologies balanced between ratepayers, shareholders, and other market participants?
- Should there be different approaches to cost benefit assessments and cost recovery?

Holistic Planning Provides a Better Understanding of Needs

The electric grid architecture or design is changing to meet societal changes and to incorporate advances in technology. Regulators may need to better understand how that architecture will be implemented. Utility investments are not necessarily a one-for-one replacement of aging equipment. Instead, the investment can be laying the foundation for a future of electricity delivery that is very different from the one of the past or it may enable capabilities that provide additional functionality. A holistic understanding of how investments fit into a new system and what it means for a changing system can help regulators better assess value. Considering utility investments in separate proceedings can make it difficult to understand how the technology fits into an overall vision, the timing of investments, and interdependencies that may not be apparent when looking at the technology on its own.

Organized and cohesive distribution planning efforts can provide transparency into the utility planning process and give regulators and other stakeholders more information about utility plans. It can also allow a forum to discuss alternatives and hear stakeholder and commission perspectives, which can then be taken into account in utility plans, easing future investment recovery discussions. Breaking down siloes and considering a holistic distribution system plan can then inform other utility and regulatory proceedings, providing needed context for any identified investments and needs.

Distribution Planning Frameworks

Information is available to help regulators understand and review utility distribution plans. Frameworks for developing distribution planning rules, understanding the technologies involved, and identifying the role of the distribution system going forward are available through efforts like:

- NARUC's distribution system planning task force
- DOE's The Modern Distribution Grid Report
- Lawrence Berkley National Laboratory's trainings on integrated distribution system planning

Scenario Planning Can Help Balance Risks and Benefits

The future is unknown, but transformation of the electric grid, along with shifting societal and customer preferences, brings additional uncertainty. Utilities will rely on forecasts and models to evaluate the need for utility-owned assets and the availability of non-utility-owned assets, but, as the adage goes, "all models are wrong, but some are useful."

Leveraging available data, such as that collected by AMI or from the DER itself, can be used to test and inform models using actual usage data. Utility forecasts that apply that data to multiple scenarios can help regulators and utilities understand the implications for a wide variety of potential futures. This can help evaluate options. Scenarios can be used in distribution planning processes and more holistically in other utility planning processes, including integrated resource planning and rate cases.

Implementation Can Be Lengthy

Regulators in most states highlighted that both regulatory approval and implementation can extend over very long time horizons. Grid modernization proceedings that address the planning and the pacing of new investments in the distribution system have taken much longer than originally anticipated in many cases. While these proceedings and the conversations surrounding them often result in a more robust and thorough planning process, including specific directives or guidance, they can also be lengthy, sometimes taking multiple years.

In addition to the pace of regulatory processes, there is also a lag from approval to fully operational deployment. Commissions noted that the timeframe from initiating a proceeding, to approval of an investment, to achieving benefits and capabilities can take close to a decade in many cases. This long timeline from proposal to operational capabilities introduces a new set of concerns and considerations, especially when the pace of technology innovation can be much faster.

Regulatory Practices May Need Updating

Policies and rules that functioned for traditional electricity service may need to be updated or revised in light of new technologies and regulatory questions. These updates will likely include new policy directives, rules, or tariffs to address the unique attributes or characteristics of next-generation technologies. For example, two-way power flows or mobile EV loads likely require new considerations about access to information for operations and to ensure interoperability.

Similarly, interconnection rules that were developed for a limited number of large-scale, centrally located renewable energy projects can prove incompatible with hundreds, or even thousands, of interconnection requests for distributed energy resources such as rooftop solar systems, energy storage, or flexible loads. Without updates, there is a risk that customer adoption may be limited and, as a result, the utility's ability to take advantage of these advanced capabilities will also be limited. As a foundational element, policies and practices that promote interoperability for all utility investments will ensure that new technologies, whether owned by the utility, customers, or third parties will work together and support market innovation.

Common Challenges

Many state commissions and utilities are grappling with an age-old challenge of whether it is preferable to be an early mover and implement technology that can drive change, or whether it is preferable to wait until the technology matures. Some commissions are proactively requesting new investment plans from utilities, while others are content to wait for utilities to bring proposals forward when the utility determines there is value. As with all emerging technology, it can be difficult to determine the sweet spot of when to invest. When utility investments are foundational for a modern electric grid, however, waiting for costs to decrease or waiting for specific indicator targets (such as a specific adoption level) may mean the grid technology will arrive too late. For the grid, this challenge is further compounded by the long timeframes for consideration of utility investments. During the conversations with regulators around the country, nine common challenges emerged. These challenges span the technology types.

Understanding the Technological Nuances

In the past, regulators did not necessarily need to have in-depth knowledge about a proposed technology or how it would be implemented. Those details could often be left up to the utility, and regulators could focus on the economic assessment. With many next-generation technologies, however, benefits and capabilities often depend on the implementation details which, in turn, affect the economics of utility service costs and rates. Effectively reviewing utility distribution plans and investments requires more definitive expertise about the technologies and is increasing the burden on regulators.

Regulators are looking for actionable information to evaluate utility investments and cost recovery during these changing times. Without knowledge of a particular technology's specific capabilities, how the technology can be used, and implementation details, it is can be difficult for regulators to provide guidance or ensure that the plans the utility has proposed will utilize the technology's capability to maximize the value of the investment and the benefits to customers. This situation may inadvertently lead to less-than-optimal implementation and, ultimately, higher costs over time for customers. Regulators are also having to become more involved in topics like standards development and adoption that were not typical activities in the past. Many commissions have limited staff with the necessary expertise, leaving them to rely on technical assistance from DOE, national labs, and outside consultants to review and adjudicate utility requests. Many participants shared their concerns about the need to create additional capacity and expertise at the commissions to address these challenges.

> *"Ambiguity is the friend of utility lawyers. Without specifics, the intent of what the commission is trying to achieve may not be achieved."*
>
> **–A Commissioner Participant**

Determining Realistic Timelines

When new investments are approved, regulators traditionally expect to see immediate benefits to customers. Regulators have found that with some next-generation technologies, it takes longer than anticipated to realize benefits. This can occur for a variety of reasons. Sometimes, the delay is due to the intrinsic nature of technology deployments. Another factor is that some benefits depend on integration with other utility systems that may require upgrades or replacement. Regulators expressed their desire for more information about realistic timelines for realizing benefits and approaches that can shorten implementation timelines (e.g., leveraging industry standards to minimize integration costs and enhance interoperability) to better assist them when developing conditions, establishing metrics, or providing direction to utilities.

Obtaining Regional Benchmarking Metrics

Commissions are interested in having data about utility investment proposals for utilities outside their jurisdiction. It could provide a reference baseline for evaluating their own utility's proposal. Such information can be difficult to procure as it may be buried deep inside rate case filings or the data may not be publicly available. This leaves regulators to rely upon projections instead of evidence, even though other utilities in neighboring states may have implemented similar technologies. Commissions are also interested in using data from new next-generation technologies in order to benchmark and measure the success (or challenges) of new programs.

Efforts to establish regional benchmarking measures would provide an open, public, and transparent accounting of the technologies, costs, and expected benefits. Such information would be a valuable resource for regulators and might reduce the need for additional discovery in proceedings.

Understanding What Is Technically Reasonable

Commissions struggle when evaluating proposals involving next-generation technologies because while an investment a utility proposes may sound necessary, the challenge is determining if it is over-engineered and unnecessarily costly. Commissions, cognizant of impacts on customer pocketbooks, attempt to balance utility investments to modernize the grid with investments needed to maintain the system. Regulators expressed that they find it difficult to determine if a utility investment is the best value for the cost and if it is technically feasible. Commissions also face the balancing act of ensuring those technologies are in place before they are needed, but not so far in advance as to be unused for years.

Making Space for Innovation

As DERs proliferate across the system, an important question for regulators is whether some investment risks are better borne by the market and developers rather than the utility and its rate base. As noted by many participants, the traditional utility business model rewards capital investment, but does not necessarily incentivize innovation or entrepreneurial initiatives. As a result, the strategies required to support innovation may not come naturally for a utility, yet they remain essential for increasing value to consumers in an evolving system. Utilities may develop new programs and services, but customer engagement and marketing are emerging skillsets for utilities, which, as regulated monopolies, have not faced the same pressures to nimbly respond to customer needs as businesses in most other industries.

Commissions are trying to determine the most productive and valuable path forward for encouraging innovation for new utility programs or services while also providing capabilities and data that encourage market innovation and growth. Regulators are striving to determine the appropriate pathways and balance so that programs are appropriately integrated into utility practices while minimizing risks to customers.

Determining Boundaries

As more and more technologies and energy management systems are deployed directly by consumers or third parties, it is changing the relationship between consumers, utilities, and regulators. Many of the next-generation technologies are being deployed by utilities in order to enable technologies connected to the grid and advanced energy management systems at customer premises. These customer-owned systems are generating new sets of detailed data about usage and operations that could help inform electric system operations, planning, or policy development. In the past, predictive models used historical information to inform the planning processes. Moving forward, planning and operations may use actual, operational data collected by systems that include a mix of utility and external systems, including AMI, DER, EVs, or other distribution control technologies. Where there was once a clear boundary between utility and customer systems, the distinction between what is in the utility or regulatory domain and what is not is blurring. As a result, regulators are contending with how to navigate new issues related to privacy, customer autonomy, and the need for transparency and well-informed planning and operations. This introduces a new set of challenges in determining what information is needed and how to balance customer interests and utility planning and operations.

Aligning Utility Practices with Customer Needs

Existing rules may inadvertently act as a barrier to the electricity transition. As technologies and standards change, regulatory rules and utility processes may need to follow suit. For example, a utility's interconnection rules may need to be updated to reflect changes to standards that now allow enhanced functionality that was previously prohibited. New data sets may need to be shared and made public to provide value to customers, developers, and market participants that, in turn, enhance the value of the investment. Similarly, interconnection policies that worked for new service requests in the past may act as a barrier with new technologies and during a fast-changing transition with accelerated customer demand. Identifying those rules that need updating is an important part of the transition.

Difficulty Navigating Opposing Positions

Stakeholders play an important role in providing regulators with information, though their vision of the future and those of the regulators can vary widely or even conflict. Technical specifications can be easily found, but the devil is in the details of implementation. That information is not necessarily easy to find, may depend on the utility's operations, and may require technical expertise to determine which view is accurate. For example, regulators struggle to find unbiased views on things like the administration costs of a project, the purpose of a technology, or its impacts on customers.

In most proceedings, participating parties have interests that may color the arguments for or against any particular investment. Regulators are looking for information from "fair brokers," neutral parties who can provide unbiased information. Untangling the weave of very strong, conflicting views may require an independent arbiter who can help regulators level set some costs, create standards, and reframe some of the more extreme statements from utilities, third parties, and other stakeholders in an objective, practical manner. This could save hundreds of manhours for regulators and commission staff.

Information Sharing Across Jurisdictions and Agencies

In many cases, there are restrictive rules about communications with regulators because of the quasi-judicial nature of proceedings. This can limit collaborative discussion opportunities, which impacts the ability of a commission to leverage such information in the development of their own procedural records. When tackling a similar issue, peer-to-peer discussions could enhance learning and accelerate progress rather than each commission needing to develop solutions independently. Collaboration along with having insight into what other commissions are doing related to a given technology and understanding how utilities in other jurisdictions are utilizing a technology could help regulators understand the options so they could ask more specific questions and make more informed decisions.

Besides communicating with other commissions, the transition to transportation electrification means that regulators will need to communicate with other state agencies inside their jurisdiction to discover common or overlapping goals, determine technology investment needs, and identify how the electricity infrastructure can support other agency goals. For example, as states look to grow EV adoption, regulators may want to coordinate with other agencies to ensure that there is sufficient charging infrastructure installed, that it is installed in places that will not negatively impact operation of the distribution system, and that rates and other utility programs enable, rather than interfere with state goals.

Regulatory Wish List

The one thing all regulators could agree was that more information is imperative and always appreciated. Whether it comes from stakeholders, reports, DOE subject matter experts, or cases before other commissions, knowledge, expertise, and new perspectives are always welcome. From the insights participants shared during the conversations, and in response to the challenges commissions are facing, regulators expressed a desire for the following:

- Actionable information to evaluate utility investment value and feasibility, as well as cost recovery during these changing times.
- Access to more specifics about the technologies, their costs, uses and capabilities, and requirement for integration with other systems from trusted experts to help alleviate the increased burden on regulators.
- Support for processes on standards development.
- More information about non-utility solutions or alternatives to investments in the distribution system.
- The ability to understand the need, timing, and phasing for future investments, and how to plan for them while also ensuring they are not deployed so far in advance as to be unused for years.
- More support orchestrating transparent, open distribution planning practices and processes.
- Access to best practice approaches for standards and interoperability and their benefits in order to shorten implementation timelines.
- Information on new regulatory metrics and strategies that other state commissions are using to establish conditions for utility investment approvals, create metrics, or provide direction to utilities.
- Help developing or access to examples of alternatives to traditional cost-benefit assessments.
- Support for the development of innovative rate designs for new technologies and tailoring those to specific applications or objectives.
- Opportunities for more educational forums that facilitate peer-to-peer engagement.
- Examples of the range of potential uses of technologies and their data.
- Support in establishing regional benchmarking measures to provide an open, public, and transparent accounting of the technologies, costs, and expected benefits.
- Input from private sectors to gain a more comprehensive understanding of the opportunities for new technologies to provide solutions and private capital.
- Frameworks for developing policies that encourage innovation and growth for new utility programs or services and for market innovation and growth.
- Assistance in developing practices and frameworks related to privacy, data access, and customer autonomy that balance customer interests and utility planning and operations.
- National-level frameworks that could assist in evaluating existing rules and their applicability to new technologies, and that could be used to develop regulations in their state.
- Forums to engage with other state agencies to identify common or overlapping goals, to determine technology investment needs, and to establish communication strategies about policy initiatives.
- Tools and expertise to develop EV roadmaps that can be used to prepare and inform infrastructure investment needs.
- More information about the interactions of EVs and DERs with wholesale markets and opportunities for grid services.

Technology Specific Findings

The forces that are driving change in state regulatory strategies have not arisen out of a vacuum. They are the result of specific proposals from utilities for next-generation technologies and a result of characteristics of the technologies themselves. Many of the observations and learnings from commissions apply broadly to the vast suite of next-generation technologies. There are also specific learnings for each of the technologies and data topics that were discussed. Insights from participants, activities from the public records, and additional resources are detailed for each in this chapter.

Accounting for Costs and Benefits for DER

National Standards Practice Manual for DER

The National Standard Practice Manual (NSPM) provides a comprehensive framework for assessing DERs, providing policy-neutral methodologies to support benefit-cost analysis. An update in 2020 focused on testing the cost-effectiveness of DER. The NSPM framework allows regulators to apply a consistent cost-effectiveness review process for DER investments, which can reduce the risk of significant over- and under-investment in a resource.

The framework is predicated on eight principles:

1. Recognize that energy efficiency and other DERs can provide energy or power system needs, and should be compared with other energy resources and treated consistently for benefit-cost analyses.
2. Align primary test with applicable policy goals.
3. Ensure symmetry across costs and benefits.
4. Account for all relevant, material impacts (based on applicable policies), even if hard to quantify.
5. Conduct a forward-looking, long-term analysis that captures incremental impacts of the DER investment.
6. Avoid double-counting through clearly defined impacts.
7. Ensure transparency in presenting the analysis and the results.
8. Conduct BCA separate from Rate Impact Analyses because they answer different questions.

The framework can help regulators discern if a DER is consistent with the policy goals of their state and can provide flexibility as policies and goals change over time.

Methods, Tools and Resources Handbook

A complementary publication to the NSPM, the *Methods, Tools, and Resources Handbook* (MTR Handbook), is a resource that includes technical information about how to quantify costs and benefits of DER investments. It is intended as a reference guide for utilities, commissions, and other practitioners, and includes links to resources and tools.

NSPM at https://www.nationalenergyscreeningproject.org/national-standard-practice-manual/
MTR Handbook: https://www.nationalenergyscreeningproject.org/resources/quantifying-impacts/

Distribution Controls / The Technology that Binds

Distribution control technologies provide greater visibility into and control of the operating conditions of the distribution system, which is a critical component of the transformation to a future, modern grid. As distributed energy resources on the distribution system increase, many of them owned directly by customers, they offer opportunities to provide value and a wide range of grid services that have traditionally been in the sole domain of the utility resources. Distribution control technologies can enable increased reliability through optimization of distribution infrastructure, faster outage response times, integration of DER, and, in some cases, even the capability to call on or dispatch customer-owned DER.

Distribution Controls Challenges

- Identifying needed functionality
- Determining timing for implementation
- Obtaining the necessary technical expertise
- Learning from other jurisdictions

Evaluating distribution control proposals can be complex and lengthy, often involving multiple proceedings that span several years, but they also involve many new policy considerations for regulators. For example, because many of the grid services are enabled by customer-owned resources, the proposals raise questions about the balance of customer autonomy, utility control, and transparency. Having visibility into how and when such resources can be optimized to reduce system operating costs, improve system efficiencies, and provide essential grid services are critical factors in assessing the value of investments into these enabling technologies. Regulators must navigate a wide range of new policy considerations, often involving opposing views from stakeholders.

Many participants reported that establishing separate proceedings for distribution system planning processes provided a useful forum to learn about technological capabilities, potential uses, and how distribution system controls align with the state's long-term vision for the electric sector, the role of the utility, and the overall evolution of the distribution system. From that foundation, it is then easier to consider specific investment proposals and cost recovery. These distribution system planning proceedings give commissions an opportunity to understand what goes on behind the scenes, to understand the utility's thinking and vision for the future. In many cases, an important outgrowth of the review process is the development of a stand-alone distribution system plan that can build consensus among the broad base of stakeholder interests.

Four I's of Distribution Controls

The following four aspects were noted as important considerations when evaluating proposals for distribution control technologies.

1. **INTERFACES** | What other utility and/or customer systems or technologies will interact with the investment?

2. **INTEGRATION** | How will the technology seamlessly integrate with other systems?

3. **INTERDEPENDENCIES** | What other investments do the benefits for the investment depend on?

4. **INTEROPERABILITY** | Will the other systems and technologies be able to communicate with each other?

Insights and Advice from the Conversation

These insights and advice capture information shared by participants about what they wish they had known, advice they might give to fellow regulators, lessons they have learned along the way, or suggested actions that could assist regulators evaluating future utility proposals.

Insights

- **The learning curve is steep.** Commissions reported having to do a lot of their own investigation and planning upfront to understand proposals and better direct utility efforts because some initial utility proposals did not include as much information as a commission would like to make an informed decision. Obtaining the necessary knowledge and understanding the scope and functionality of these technologies is not an easy undertaking, and commissions may not have the necessary expertise to fully grasp the implications and scope of the investment.
- **Distribution systems must be integrated with other systems to provide value.** ADMS, as a control system, will not do anything by itself. Integration with other utility applications, such as geographic information systems (GIS), computer information systems (CIS), AMI, and DERMS, is essential.
- **Distribution controls are more than technology deployment.** They can fundamentally change how a utility operates. Beyond the timing and phasing of implementation and integration with other utility applications, it will require new processes and procedures, along with personnel training.
- **ADMS requires foundational work prior to implementation.** Distribution control technologies are built on accurate data and a model that reflects the current distribution system connections and equipment (which can change daily). Performing a distribution system inventory that maps equipment and connections is critical for verifying the accuracy of the GIS and the network model.
- **Data cleanup is not inconsequential.** Cleanup of data is essential but often overlooked in terms of the required effort. It can be time consuming and costly. Without clean data and an accurate map and model, the value of these investments is minimized and can provide inaccurate recommendations for operators.
- **Examples of other state activities would be beneficial.** A lack of examples from other commissions or organizations can make evaluating proposals challenging. Commissions expressed an interest in having information from other states to assist them in the process, such as questions asked, reporting requirements, expected benefits, and timelines.
- **Non-utility options are considerations too.** Commissions expressed interest in non-utility options and resources as part of plans for distribution control investments. For example, relying on third-party providers (or aggregators) to control or manage multiple customer-owned DER using advanced inverter functionality could be a cost-effective solution.

Advice

- **Implementation of distribution controls is a multi-year effort.** ADMS implementation timeframes, including both the regulatory approval process and the technology deployment, can be very long. Ideally, proceedings should be initiated long before the technology is needed.
- **A distribution planning process proceeding can provide transparency and a forum for discussion.** Convening a distribution planning process proceeding may shed light on the utility's long-term plan, the value of the technology, what it can do, and the timeframe for implementation.

- **A utility roadmap can be valuable for discussions.** By outlining how the technology supports the state's future vision, and serving as a comprehensive resource plan, it can help stakeholders participating in the distribution planning process to understand the values associated with various investment options, how those align with objectives established by state commissions and legislatures, and the challenges associated with different strategic options.
- **ADMS implementation timeframes, including both the regulatory approval process and the technology deployment, can be very long.** Implementation of distribution controls is a multi-year effort. Ideally, proceedings should be initiated long before the technology is needed.
- **Waiting for key indicators might be too late.** Delaying investments until DER penetrations reach appropriate levels to warrant the investment, may leave utility capabilities lagging customer demand. Monitoring adoption and effects of DER and collecting data can provide support for investments. Phasing (or staging) elements to prepare for future implementation was a strategy commissions mentioned as valuable.
- **Positing a number of plausible outcomes for the future can help to manage the risks.** Forecasts typically drive utility planning and resource needs, but with more DER, leading indicators may come from other parts of the utility. For example, interconnections delays can signal faster than anticipated DER adoptions.
- **Don't overlook routine maintenance.** Distribution controls like ADMS have a hefty price tag, but commissions warned about deferring other necessary maintenance to offset costs.
- **Be clear on delineation of costs.** Commissions reported that cost estimates varied widely and initial costs were not necessarily reflective of final costs due to technology innovation and unforeseen challenges. Integration with other utility system can have significant impacts on costs.

Questions Commissions Are Asking

- What is the importance of distribution controls for achieving the future vision?
- When are the capabilities of distribution controls needed to support resilience and reliability?
- How will distribution controls systems integrate with or facilitate DER?
- What is needed to support new consumer technologies?
- Are there alternatives and what are their benefits or limitations compared to the proposed grid controls?
- How are the benefits of these technologies quantified or valued? (e.g., DER vs. energy efficiency vs. outages)
- How much control over DER does the utility need?
- What integration with the existing system is needed and how will that be accomplished?
- What is the level of data quality needed to operate and maintain the system effectively?
- To what extent are the technologies providing an enabling platform to other parties?

POWERING KNOWLEDGE

The Value of Guiding Principles

As the growth of DER adoption increases and utility companies invest in grid modernization, many regulators may find value in establishing clearly articulated guiding principles regarding what a future electricity system does and how it operates. Establishing these guiding principles can ensure that the overall policy priorities and long-term objectives remain well understood, especially as commissions consider utility infrastructure investments and changes to traditional operational planning.

Many participants expressed frustration that, in the detailed discussions that often comprise individual proceedings, it can be easy to lose sight of the high-level strategic objectives. In short, it is easy to not see the forest for the trees. Guiding principles can help maintain visibility and adherence to the long-term, macro-level policy priorities and ensure that proposed utility investments are aligned with those principles. Additionally, guiding principles provide an opportunity for the regulator to express their vision for the future electricity system and the role of distributed energy and other platform-enabling technologies.

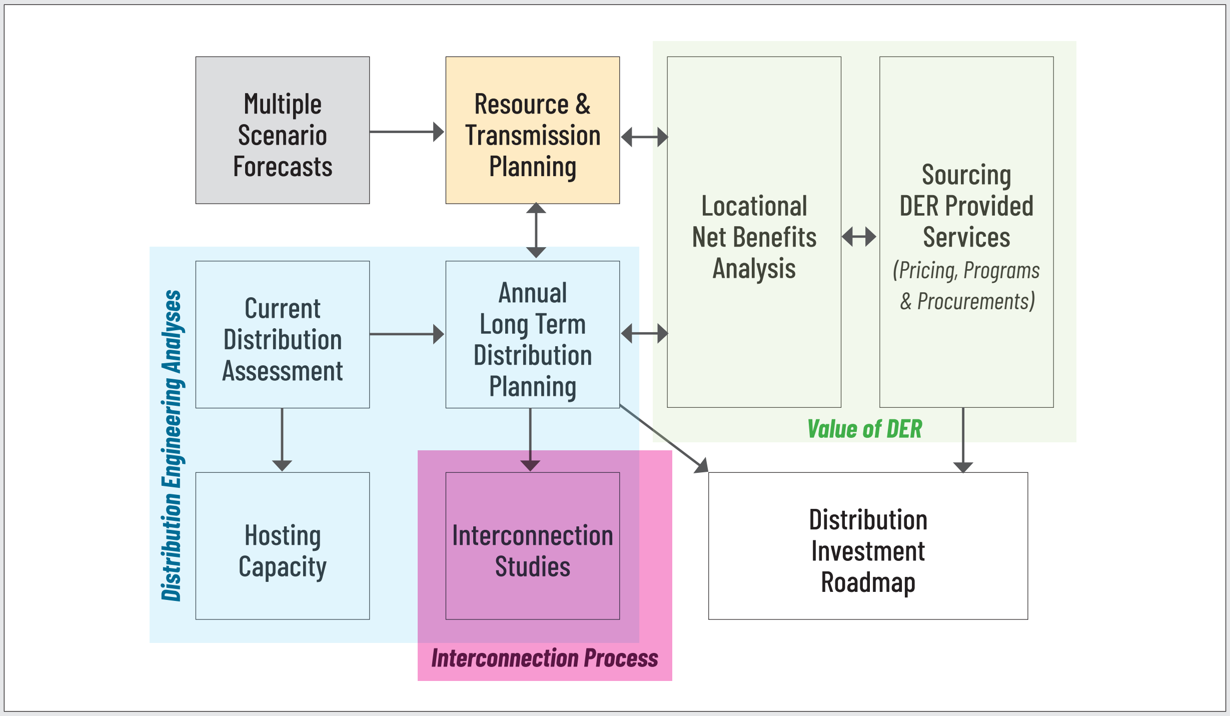
With such uncertainty about pace of innovation and adoption, need for infrastructure, and types of technologies, developing and adopting principles can help regulators, utilities, and other stakeholders outline the fundamental need and role of the distribution system, the role of DER and markets, the importance of reliability and resilience, and any other goal or objective of the jurisdiction.

Distribution System Planning

Distribution system planning is an approach to assess needed physical and operational changes to the local grid in order to maintain safe, reliable, and affordable service. Traditional distribution system planning takes place inside the utility; however, the focus is shifting to having a more public, collaborative planning process whereby stakeholders can provide input and review projections, assumptions, and analysis results in a more structured way. This includes formalizing processes across utilities inside a given state, common reporting requirements, planning horizons, and organization of the plan itself.

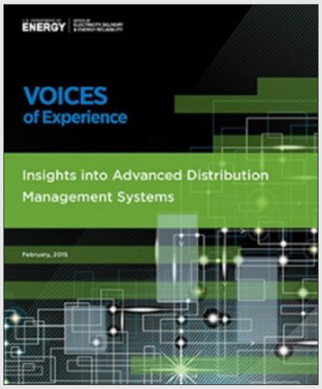
Specific requirements, mandates, or state goals around reliability and resilience, grid modernization, greenhouse gas emissions, and/or renewable energy targets set the context for distribution system planning and grid investments. Utility business objectives within the larger regulatory and prudence framework also play an important role in investment decisions.

Interdependencies between different planning areas within a utility introduce new variables and create complexity. Planners must now understand the potential for and implications of a significantly larger number of DERs, and they must perform increasingly complex analyses to account for the many variables that can impact future-load and generation requirements, including two-way power flow. This added complexity necessitates the need for flexible and adaptive approaches to implementing integrated distribution systems. A model of this transition is found in the following image from a PNNL report. This image notes the role that forecasts plays in utility planning efforts and describes the importance of taking in new information from other places inside a utility, such as interconnection, to inform the needs of the distribution system and how to plan for changing circumstances.



From https://epe.pnnl.gov/pdfs/Electric_Distribution_System_Planning_Tools_PNNL-28138.pdf

Utility Perspective: Utility-to-Utility Advice



These insights were adapted from *Voices of Experience: Insights into Advanced Distribution Management Systems* and reflect the advice utility colleagues would give to other utilities considering implementation of ADMS.

- **Making the business case for ADMS requires thinking differently about the cost-benefit analysis.** Often it is not only hard cost savings but soft cost savings, such as cost avoidance and increased customer satisfaction, that need to be included, and these can be difficult to quantify.
- **ADMS fundamentally changes how the utility operates.** It requires organizational changes and new skills. Managing these changes is difficult but important and a significant part of ADMS.
- **Integration and interoperability with other utility systems is critical for maximizing functionality, but it is difficult.** Real functionality in an ADMS requires integrating all the pieces—especially OMS and DMS—but also legacy and future systems, many of which were developed decades ago and likely were homegrown or are still to come. This integration and future-proofing, or the sharing of data and information among systems, is complex and requires a common architecture, access from multiple systems, and a common understanding of the level of integration being sought.
- **The foundation of an ADMS is the data.** The ADMS is a control hub, and it must have accurate data to correctly model the system. Data collection and maintenance in GIS is critical for ADMS implementation, and developing business processes to maintain clean data is just as important.
- **Even if a utility thinks its GIS is "clean," it probably isn't clean enough for ADMS.** Utilities reported that even when they thought they had clean GIS data, there was still a lot of work to do to get it accurate enough for the ADMS. The model will only be as good as the data in the GIS.
- **Developing clean data and inventorying the distribution system is not insignificant in terms of money or time.** Data cleanup and data mapping can be a substantial effort. It could take many months to complete and amount to 10% to 25% of your ADMS project costs. Some utilities in the working group recommended that you consider it a separate project.
- **Develop a road map of capabilities. ADMS lays the foundation.** The road map is about the capabilities the company will need and the future and the technology needed to realize those capabilities. Without a clear plan, the utility may end up heading down a path that it didn't want to be on.

Source: Voices of Experience: Insights into Advanced Distribution Management Systems

ON THE DOCKET

Distribution Controls

A review of 23 recent distribution controls proposals, related discussions, and orders in 17 states identified that discussions about distribution control systems emerged across a variety of representative docketed proceedings:

- Grid modernization plans (Dayton Power and Light[4] , Hawaiian Electric Co.[5])
- Asset investment plans (Penn Power[6], Indianapolis Power & Light[7])
- Distribution system plans (Minnesota Power[8])
- Rate cases (Northern States Power Co. North Dakota[9], Pacific Gas & Electric Co.[10])
- Rate cases paired with grid investment proposals (Unitil New Hampshire[11])
- Resource plans (NV Energy[12], NorthWestern Montana[13])

Proceeding Type	Discussion	Proposals	
		Approved	Pending
Grid Modernization Plans	1	2	6
Asset Investment Plan or CPCN	1	4	
Distribution System Plans	1		
Rate Case	1	1	
Rate Case with CPCN	1	1	1
Resource Plans	1	1	1

Additional notable topics under discussion across multiple jurisdictions

- Proposals typically review broad, long-term distribution grid improvement strategies
- Proposals discuss how related technologies (i.e. ADMS, AMI, and OMS) will interact
- Distribution controls were frequently framed as complimentary to other technology, especially AMI
- Cost recovery requests are typically filed separate from initial discussion of distribution controls
- Holding company deployment strategy shapes regional deployment of distribution controls
- Low regional DER penetration cited as a reason for delaying distribution controls

[4] Public Utilities Commission of Ohio. 18-1875-EL-GRD. The Dayton Power and Light Company Distribution Modernization Plan. December 2018. https://e9radar.link/o17n

[5] Hawaii Public Utilities Commission. 2019-0327. HECO Phase 2 Grid Modernization Plan. September 2019. https://e9radar.link/c60e5

[6] Pennsylvania Public Utilities Commission. M-2021-3024348. Penn Power 2020 Asset Optimization Plan. March 2021. https://e9radar.link/sb6

[7] Indiana Utility Regulatory Commission. Docket no. 45264. Verified Petition of Indianapolis Power & Light Company for Approval of IPL's TDSIC Plan for Eligible Transmission, Distribution, and Storage System Improvements Pursuant to Ind. Code § 8-1-39-10. July 2019. https://e9radar.link/50fx

[8] Minnesota Public Utilities Commission. Docket no. E015/19-684 In the Matter of Minnesota Power's 2019 Integrated Distribution Plan. https://e9radar.link/redirect-MN

[9] North Dakota PSC. Northern States Power Company Notice of Change in Rates for Electric Service. Docket no. PU-20-441. https://e9radar.link/2id

[10] California Public Utilities Commission. Docket no. A.21-06-021. PG&E 2023-2026 General Rate Case. June 2021. https://e9radar.link/slq

[11] New Hampshire Public Utilities Commission. Unitil Energy Systems, Request for Change In Rates. Docket no. DE 21-030. http://e9radar.link/yrc

[12] Public Utilities Commission of Nevada. Docket no. 21-06001. NV Energy 2022 Integrated Resource Plan. June 2021. http://e9radar.link/redirect-NV

[13] Montana Public Service Commission. Docket no. 2019.08.052. NorthWestern 2019 Electricity Supply Resource Plan. https://e9radar.link/redirect-MT

COMMISSIONS HAPPENINGS

Summaries and excerpts from commission orders. These examples are not meant to be definitive approaches or best practices, but are provided as approaches other states have taken that commissions can draw on as they develop their own solutions.

Kentucky Commission Directs Utility to Investigate Alternative Solutions

In a recent proceeding before the Kentucky Public Service Commission, LG&E/KU sought approval to modify its net energy metering compensation. As part of its proposal, LG&E/KU identified needed investments in the distribution system in order to mitigate the impacts of DER on its system, including ADMS and DERMS. The Kentucky Commission took issue with LG&E/KU's explanation of potential costs to the system and encouraged the utility to explore additional, alternate solutions. Due to the low adoption rate of solar in LG&E/KU's service territory and the utility's apparent lack of familiarity with advanced inverter functionality and IEEE 1547-2018, the commission asked for more investigation beyond investing in technologies that control customer inverters, saying, "The Commission is troubled that LG&E/KU have identified a substantial, ratepayer-funded investment solution without already having evaluated more incremental and likely cost-effective solutions, such as implementing autonomous smart inverter functions."

To read the full order, visit: http://psc.ky.gov/pscscf/2020%20Cases/2020-00350/20210924_PSC_ORDER.pdf

New York Order Adopting DSIP Guidance

The April 2016 Order, Adopting Distributed System Implementation Plan (DSIP) Guidance, identified the need for an improved planning process that is more collaborative and grounded in the use and availability of information to improve system efficiency and quality. The utility DSIP filings "require utilities to describe and analyze certain specified processes and data related to distribution system planning and distribution grid operations that account for distributed energy resources (DERs). The utility DSIP filings will also address common grid architecture approaches and interfaces that will be necessary, current and planned, advanced metering initiatives, and gathering and sharing of customer data to support robust and liquid retail markets." (p.3)

Read the full order: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={B1C7035C-B447-459A-8957-20BF3BDB6D0F}

Access the utility DSIP plans: https://jointutilitiesofny.org/utility-specific-pages/system-data/dsips

Hawaii Order Defining Objectives for a Grid Modernization Strategy

In 2017, the **Hawaii Public Utilities Commission (PUC)** issued Order 34281. The order acknowledged the tremendous rate of transformation for the state's grid. The commission viewed a modern grid as necessary to advance state goals. Concerns and questions emerged while reviewing Hawaiian Electric's application as it did not include the detail and specificity needed to fully evaluate the merit and value of the proposed approach. The PUC concluded that there was a need to develop a well-vetted overarching strategy that would be informed by stakeholder input. As such, the commission provided guidance that set out specific objectives to be met as Hawaiian Electric developed their grid modernization strategies. Below are the objectives identified in the order.

The Companies, informed by stakeholder input, must consider and address the following:

1. **Definition and guiding principles.** The Companies must consider and provide a specific preliminary definition and guiding principles to inform grid modernization in Hawaii.
2. **Current status of the electric grids.** The Companies and stakeholders need to assess and better understand the present status of each island's electric grid to better inform which steps must be taken to achieve the State's energy goals.
3. **Grid architecture and interoperability.** There is a need to assess a Hawaii-specific grid architecture that can actively shape the evolution of the islands' electric grids rather than to passively allow grid evolution in a bottom-up manner. In addition, open standards and interoperability must be viewed as foundational components of the integrated grid.
4. **Grid-facing technologies.** The Companies must solicit and facilitate discussion regarding the capabilities of a modern distribution network, the status of technologies required to enable these capabilities, the regulatory changes that may be necessary to facilitate the development of a modern distribution network, and the steps that the Companies should take to integrate relevant technologies in a cost-effective manner.
5. **Customer-facing technologies.** The Companies, in conjunction with stakeholders, must assess how customer-facing technologies, practices, and strategies can be used to (a) enable customers to manage their electric usage more efficiently and enable maximum customer cost savings; (b) enable customers to harness their electric loads as a responsive resource to meet grid service needs; and (c) further integrate resources such as DER, including energy storage devices and electric vehicles.
6. **Pace of implementation.** The Companies must address the sequence and pace of grid modernization infrastructure investments, including both grid-facing and customer-facing technologies.
7. **Costs and benefits.** The Companies and stakeholders should examine what might constitute an appropriate framework to evaluate the cost-effectiveness of grid modernization technologies and practices, including an evaluation of hard-to-quantify impacts such as improved reliability, increased customer choice, and reduced environmental impacts.
8. **Flexibility and resilience.** The Companies should consider how grid modernization investments can be designed and implemented to cost-effectively meet the dual goals of enhancing grid flexibility and resilience.

Hawaii Order Defining Objectives for a Grid Modernization Strategy *(continued)*

9. **Health, cybersecurity, data access and privacy.** The companies must proactively address the myriad issues related to health, cybersecurity, data access, and privacy.

To read the full order: https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A17A05B01613H26476

Minnesota Staff Report on Grid Modernization

In 2015, the Minnesota Public Utilities Commission initiated a proceeding to consider grid modernization, with a focus on distribution system planning. As defined by the Minnesota Commission, "A modernized grid assures continued safe, reliable, and resilient utility network operations, and enables Minnesota to meet its energy policy goals, including the integration of variable renewable electricity sources and distributed energy resources. An integrated, modern grid provides for greater system efficiency and greater utilization of grid assets, enables the development of new products and services, provides customers with necessary information and tools to enable their energy choices, and supports a standards-based and interoperable utility network." To support its review, the Minnesota Commission proposed three guiding questions:

- Are we planning for and investing in the distribution system that we will need in the future?
- Are the planning processes aligned to ensure future reliability, efficient use of resources, maximized customer benefits, and successful implementation of public policy?
- What commission actions would support improved alignment of planning for and investment in the distribution system?

As part of the proceeding, the Minnesota Commission staff issued a *Staff Report on Grid Modernization* that proposed a three-phased approach to Grid Modernization, including clarifying a definition, principles, and objectives for grid modernization; prioritizing potential action items; and, adopting a long-term vision for grid modernization. At the conclusion of this initiative, and in conjunction with related legislation passed by the Minnesota legislature, Minnesota's regulated electric utilities were required to submit distribution system plans for review by the Minnesota Commission. Those plans, and associated funding requests by the utilities, provide substantial insight and information into utility short-term and long-term planning efforts.

Download the filing at: https://efiling.web.commerce.state.mn.us/edockets/searchDocuments.do?method=showPoup&documentId=%7BE04F7495-01E6-49EA-965E-21E8F0DD2D2A%7D&documentTitle=20163-119406-01

Maryland Grid Modernization Proceeding

In January 2017, the **Maryland Public Service Commission** (PSC) issued an order *"In the Matter of Transforming Maryland's Electric Distribution Systems to Ensure that Electric Service is customer-centered, affordable, reliable and environmentally sustainable in Maryland"* initiating a proceeding to address grid modernization to help meet the General Assembly's ambitious targets in the Greenhouse Gas Reduction Act. The order noted that smart meters (AMI) are the foundational building block for modernizing the electric grid, and that many Maryland customers already have one installed. Maryland utilities have instituted some forward-looking programs, such as dynamic pricing and time-varying rates for EV charging. However, it also noted that much more might be done. The order included a statement of guiding principles to allow stakeholders to seek solutions consistent with the principles. Below are the Guiding Principles the commissions set forth:

Guiding Principles

a. Electric service should be reliable, cost-effective, and environmentally sustainable for numerous reasons, including the growth of Maryland's economy, and there should be a balance among these three objectives;

b. Universal access to electricity for all Marylanders is a bedrock principle of Maryland public utility regulation, so evaluating ratepayer impact – particularly for limited income Marylanders – is always a factor;

c. New and improving technologies are driving fundamental change in Maryland's electric distribution systems, and we want to enable and seamlessly integrate technologies that will result in clear benefits – including cost reductions – for Maryland's electric customers;

d. Competitive markets are an integral part of Maryland's electricity landscape that seek to promote innovation, reduce costs, and increase customers' choices;

e. Electric distribution companies and cooperatives should maintain their current role as the operators of Maryland's electric distribution grid;

f. Electric distribution companies and cooperatives must serve as impartial grid operators, particularly when non-regulated affiliates are market participants;

g. As an alternative to traditional cost-based rates, performance-based incentives or alternative revenue collection methods might be appropriate for consideration; and

h. Collaboration between stakeholders, and particularly with Maryland state agencies, is the preferred method of developing lasting solutions. During the next 18 months, we want to consider demonstrable actions, such as starting and assessing pilot programs (with defined scopes, timelines, and exit strategies) and drafting regulations as appropriate, in the topic areas outlined below.

Read the full order: https://www.psc.state.md.us/wp-content/uploads/PC44-Notice.pdf

Virginia's Conditional Approval of DERMS

In Dominion's 2020 filing, the utility proposed implementing a DERMS, asserting that the technology was needed to maintain operation of the grid with increased levels of customer-owned DER. It also represented that DERMS is scalable, which would permit the utility to deploy the technology now for "relatively low capital costs of approximately $5.2 million" and scale it as penetrations increased. Staff opposed approval, finding that implementation of DERMS would be premature, arguing that Dominion's distribution system could safely and reliably accommodate higher DER penetration and the uncertainty surrounding PJM's FERC Order 2222 compliance filing. Dominion's response to staff concerns proposed filing a report once PJM filed its compliance filing.

The commission conditionally approved deployment of DERMS, acknowledging that Dominion was required to bear the risk for grid reliability and claimed that it required DERMS to maintain a reliable grid with increasing DER penetrations. Additionally, the commission noted that DERMS would take approximately 18-24 months to implement, and that Dominion's proposed DERMS would be scalable. Therefore, to balance competing concerns, the commission required that Dominion's proposed DERMS meet the FERC Order 2222 requirements, and that Dominion file both a report when PJM makes its FERC Order 2222 compliance filing and another promptly after FERC has ruled upon PJM's compliance filing.

Dominion's reports had to confirm that, to the best of the Company's knowledge, the proposed DERMS meets the requirements of FERC Order 2222. Dominion also has to report on the various uses of DERMS, including visibility of DERs across its system and the ability to leverage DER smart inverter functionalities to provide grid support.

Read the Order: https://scc.virginia.gov/getattachment/e8e72f65-b3a7-45b3-a395-1f34431715c5/DEV-Grid-Transformation-Final.pdf

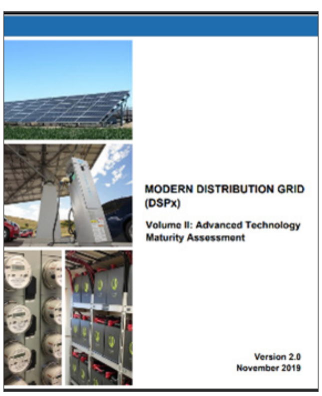
Massachusetts Grid Modernization Proceeding

The **Massachusetts Department of Public Utilities** (DPU) initiated a proceeding to consider grid modernization for its utilities. As stated, "The Department's goal with grid modernization is to facilitate the transition of the electric industry towards a more sustainable regulatory model that aligns policy objectives and the public interest with business objectives."[14] As part of this order, the DPU reviewed initial utility grid modernization proposals. The utility filings were to "submit a grid modernization plan outlining how the company proposed to make measurable progress towards" Massachusetts's grid modernization objectives.[15] For example:

- Eversource sought $20 million to implement an advanced load flow model, which is to support its ADMS build-out ($10 million for the first two years).
- National Grid sought $48 million for distribution SCADA and ADMS which would enable data preparation and modeling, ADMS build and applications integration, and active management in as-operated mode.
- Unitil asked for $7.7 million to invest in distribution automation projects, including installation of DSCADA and ADMS and installing Volt/VAr Optimization (VVO) on a substation-by-substation basis.

Read the Order: https://fileservice.eea.comacloud.net/FileService.Api/file/FileRoom/9163509

BATTERY OF **RESOURCES**



Modern Distribution Grid The report is a four-volume set intended to develop a consistent understanding of requirements that can inform investments in grid modernization. Volume I includes a taxonomy of functional requirements; Volume II evaluates the maturity of technology needed to enable the functions presented in Volume I; Volume III provides considerations for the rational implementation of advanced distribution system functionality; and Volume IV provides guidance on strategy and implementation of grid modernization plans.

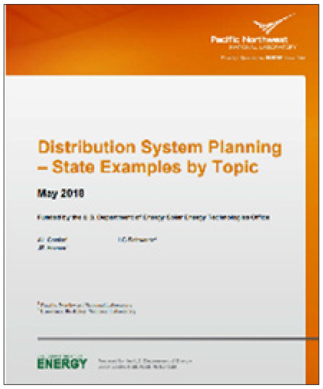
Download the reports at: https://gridarchitecture.pnnl.gov/modern-grid-distribution-project.aspx

[14] Petition of Massachusetts Electric Company and Nantucket Electric Company, d/b/a National Grid for Approval by the Department of Public Utilities of its Grid Modernization Plan, et al., D.P.U. 15-120, et al., at 8 (May 10, 2018).

[15] Id. at 13.

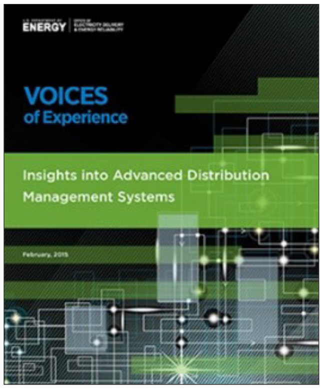
NARUC's Center for Partnerships and Innovation provides public utility commissions with regional, in-person training on electric distribution systems, utility distribution system planning, and approaches to state engagement in integrated distribution planning. There are resources on emerging issues and learning module videos are posted on the website. Two topics of note include distribution planning and interoperability which can be accessed at the following links

- Distribution planning https://www.naruc.org/cpi-1/electricity-system-transition/distribution-systems-and-planning/
- Interoperability https://www.naruc.org/cpi-1/energy-infrastructure-modernization/smart-grid/interoperability-learning-modules/

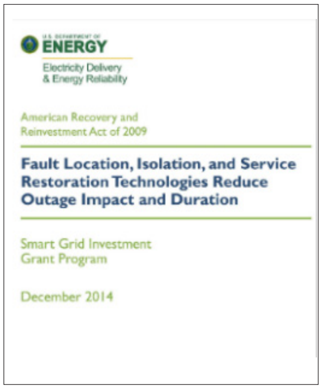


Distribution System Planning This report summarizes approaches or elements of distribution system planning adopted by various states in the context of grid modernization and higher levels of DERs for other states to consider for their own processes.

Cooke, Alan, Juliet Homer, and Lisa Schwartz. PNNL-27366. Pacific Northwest National Laboratory. Richland, Washington. May 2018.
https://www.pnnl.gov/main/publications/external/technical_reports/PNNL-27366.pdf



Voices of Experience: Insights into Advanced Distribution Management Systems
This report details insights, experiences, and lessons learned from utilities that have implemented ADMS, and can provide commissions with insights into key considerations for designing and implementing an ADMS.
https://www.energy.gov/sites/prod/files/2015/02/f19/Voices%20of%20Experience%20-%20Advanced%20Distribution%20Management%20Systems%20February%202015.pdf



U.S. DEPARTMENT OF ENERGY
Electricity Delivery & Energy Reliability

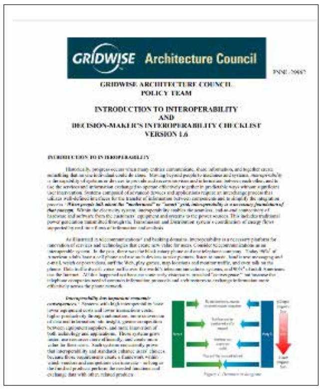
American Recovery and Reinvestment Act of 2009

Fault Location, Isolation, and Service Restoration Technologies Reduce Outage Impact and Duration

Smart Grid Investment Grant Program

December 2014

Fault Location, Isolation, and Service Restoration Technologies Reduce Outage Impacts and Duration The report provides quantitative metrics for 266 FLISR operations from five projects that were collectively implemented between April 2013 and March 2014 as part of projects funded by DOE OE.
https://www.energy.gov/sites/prod/files/2016/10/f33/Fault_Location_Impact_Duration_Dec_2014.pdf

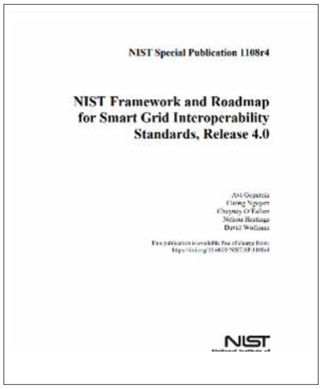


GRIDWISE Architecture Council

GRIDWISE ARCHITECTURE COUNCIL
POLICY TEAM

INTRODUCTION TO INTEROPERABILITY
AND
DECISION-MAKER'S INTEROPERABILITY CHECKLIST
VERSION 1.6

Introduction to Interoperability and Decision Maker's Interoperability Checklist Version 1.6
The checklist provides regulatory and utility decision-makers a tool to evaluate options to determine if they have the characteristics and attributes that contribute to interoperability. Decision-makers can use the checklist to evaluate a variety of electricity-related policy or asset investment proposals.
https://gridwiseac.org/pdfs/Decision_Makers_Interoperability_Checklist-_V16_PNNL_29962.pdf



NIST Special Publication 1108r4

NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 4.0

NIST

NIST Framework and Roadmap for Smart Grid Interoperability Standards, Release 4.0
The document defines interoperability and identifies how the impacts of interoperability can change with the scale of interaction (from local to regional to global). It provides updates to the Smart Grid Conceptual Model, introduces new Communication Pathways Scenarios, includes guidance on cybersecurity practices and tools, and develops the concept of an Interoperability Profile. It reflects a broad stakeholder perspective on the issues related to smart grid
https://nvlpubs.nist.gov/nistpubs/SpecialPublications/NIST.SP.1108r4.pdf

Advanced Metering Infrastructure Visibility to the Edge

As with other advanced grid technologies, AMI is rapidly evolving and leading commissions and policy makers to respond to immediate proposals while also considering broader implications centered around customer benefits, new data requirements, and opportunities for robust customer engagement. Commissions face questions about AMI, whether it is for a proposal to replace first-generation meters or installing advanced meters for the first time. Regulators want to understand AMI's full range of capabilities, how those capabilities are changing, and how they will be utilized by the utility.

AMI Challenges

- Understanding uses of AMI data
- Realizing initially identified benefits
- Extracting ongoing value from the investment
- Developing effective data governance framework
- Enabling market development

Beginning in 2006, utilities around the country began installing advanced meters that had improved functionality over their analog counterparts. The advanced meters enabled two-way communications between the utility and meter and between the meter and devices located inside a home. They no longer served as merely a cash register, but also functioned as a grid sensor that provided operational data at a granular level. They give the utility more visibility into operating characteristics at the grid edge. That data has value across the utility enterprise, as well as for customers and third-parties. Using AMI data, customers can better manage their energy usage and have more control over their energy choices. Third-party vendors can use the data to offer innovative products and services. Despite the potential benefits being well-known, however, many can be hard to quantify.

While the technology offers significant benefits, there are also direct and associated costs that must be considered and reconciled. Advanced meters offered the promise of new rates and innovative products and services, but while there are numerous examples of utilities leveraging AMI data to provide customer benefits, and some utilities have implemented modern TOU rates, overall, commissions remain frustrated with the slow realization of promised benefits. These metering systems have also introduced new questions about data access and privacy: what data can be made available, how it is accessed, and who is allowed to access it. Programs like Green Button and DataGuard (see page 63) were developed in response to these concerns.

The next generation of advanced meters (or AMI 2.0) are beginning to be deployed and installed by utilities. These new meters have even more capabilities that add to their role of enabling fundamental change. One of the technological advances is computational capabilities embedded in the meter itself that can support direct action based on centrally-defined parameters.

AMI 1.0 moved the meter from being a cash register to a grid sensor. AMI 2.0 moves beyond grid sensor to a decentralized and potentially autonomous control node that can establish a network of millions of computational points at the customer edge of the distribution system. This presents a vastly different grid architecture from the current structure where computational and control capabilities are centralized. These innovations offer new potential value streams both for the utility and third parties, but they also bring new policy questions and challenges to the regulatory review process.

Insights and Advice from the Conversation

These insights and advice capture information shared by participants about what they wish they had known, advice they might give to fellow regulators, lessons they have learned along the way, or suggested actions that could assist regulators evaluating future utility proposals.

Insights

- **Benefits create a conundrum.** AMI can enable benefits for other programs. Indirect benefits that are realized because of the foundational investment in AMI might not show up in an initial proposal. For example, benefits can show up in other dockets, such as grid modernization, storm restoration, and energy efficiency, or they can be used by other participants to create value. This makes it difficult to track benefits that accrue after AMI has been deployed.
- **Once an investment is approved, a commission is unlikely to revise cost recovery later.** Retroactively denying cost recovery for an investment as large as AMI has serious implications. Commissions are looking for approaches that they can utilize to ensure a utility works to achieve the predicted future benefits that were included in the proposal, and continues to find additional value streams in order to maximize the overall benefit of the investment.
- **Commissions are interested in how other jurisdictions are using the technology and data.** Having more knowledge about how AMI and its data can be used to achieve value or being aware of value streams other utilities are realizing can help commissions evaluate proposals or provide guidance.
- **More certainty about timelines for implementing rate designs would be helpful.** An often-cited benefit of AMI is the implementation of alternative rate designs (i.e., TOU rates). Commissions expressed frustration with the delay with which these rates are implemented. While deployment postponements and limitations of other legacy systems can cause delays, many commissions feel this is not satisfactory. They are looking for information about rate design options to speed the development.
- **Distributed intelligence is not a simple, linear path.** Meter technology is not evolving along a straight, evolutionary path. New capabilities offer new value streams for the utility, customer, and, potentially, for third parties that are not necessarily incremental. Understanding the value and tradeoffs for different parties can help commissions navigate competing interests.
- **A lack of business representation during proceedings creates knowledge gaps.** Vendors and product providers tend to not to show up to commission meetings because they worry about answering questions that might not align with their customer's business decisions (i.e., the utility). This can make it difficult for commissions to obtain unbiased, neutral information.
- **Data creates new entrants and opportunities.** New parties see value in AMI capabilities, but have differing views on what they need to achieve it. Some want access to customer data; others want access to the computing platform. New uses for AMI capabilities and data introduce new questions about the role and purpose of AMI.

Advice

- **Cost-benefit analysis presumes a level of precision that does not exist.** Assumptions about future potential benefits can be weighted differently to tip the scale either positively or negatively. A CBA evaluates whether AMI is worthwhile today but does not address whether the technology will be worthwhile in 10 years. It also cannot provide insights into whether a utility's plan for AMI is a good one compared to others, nor if it represents the best value or the best designed system.

- **The venue in which AMI is considered matters.** Commissions that open proceedings to gather technology information have opportunities to learn more about the technology, its capability, other uses of the data it collects, or how additional value can be extracted. AMI proposals in rate cases limit the commission's ability to gather more information and learn more.
- **The role and importance of data depend on what the commission wants to achieve.** When considering policies around data access and sharing, consider the business model they want to encourage. For example, if the utility will be the only party to offer demand response, then data access by customer-authorized third parties may be less important. If the commission wants to enable customer opportunities and market innovation, data access is less of a priority.
- **Data access can create value.** Conversations around data access have been occurring since early AMI rollouts but progress has been slow. States have varying levels of experience and exposure to understanding and implanting data access policies and are looking for more information. Better understanding the importance and value enabled through data access could unlock value for customers
- **Limiting data access and sharing may not be in the best interest of customers.** When AMI was initially deployed, one commission found that not allowing access to data in response to consumer privacy concerns was limiting customers' choices for energy efficiency programs.
- **Commissions are looking for a standard template for reporting benefits.** A standard template that utilities could use in their proposals would create baselines that commissions could leverage to monitor benefits and allow for comparisons with other utilities.

Questions Commissions Are Asking about AMI

- What is the vision of AMI beyond meter reading?
- To what extent is AMI aligned with the policy goals at the commission?
- Can guiding principles from the commission be helpful for providing clear direction if technology evolves while being implemented?
- What is the right approach for valuing and assessing intangible benefits of AMI?
- How can commissions ensure post-approval follow-through for benefits and achieving continued value?
- How can the utility and others leverage AMI data?
- How will investments in AMI support the cost effectiveness of other utility programs and market offerings?
- What metrics or evaluation criteria will measure the success of AMI?
- How are utilities planning to implement new capabilities of next-generation AMI?
- To what extent will consumers and third-parties be able to access and benefit from the new meters?
- What is the right approach for data access and sharing, and how is the method certified to ensure it meets commission goals?

POWERING KNOWLEDGE

Utility Perspective: Uses of AMI Data

These tables were replicated from the report, *Voices of Experience: Leveraging AMI Networks and Data*. These are the uses of AMI data that utilities reported during the efforts' utility-to-utility conversations.

AMI-Enabled Customer Benefits	
Activity	**Uses**
Fewer unplanned outages/increased reliability	• Proactive maintenance allows utilities to better assess asset health and plan equipment replacements. Planned replacements are quicker (so the outage is shorter) and cost less.
Faster restoration times and improved services	• Utilities can more accurately determine the location of outages and dispatch crews more efficiently. • More complete restorations. Crews can verify that the restoration is complete before moving to another area including detecting "nested" outages. • Outage updates and proactive outage notifications keep the customer informed.
Improved power quality	• Visibility into how the system is operating allows utilities to better detect voltage fluctuations that can create power quality issues.
More information and control	• Web portals and apps can provide information to empower customers to understand their usage patterns and find opportunities to lower their energy costs. • High bill alerts help customers track their energy usage and costs. • Additional data for high bill research that helps customers tie behavior to costs and make changesthat can lower their bill. • With more information for customer service reps, utilities report high customer satisfaction and better call resolution. • Fewer estimated reads increases customer confidence and trust.
Increased convenience	• Customers do not have to call in to report an outage. • Remote connection of service allows immediate service connections (and disconnections) withoutsending a field technician to the customer site. • More self-service capabilities such as the ability to "ping" a meter during an outage restoration, view a projected bill, pay a bill, and start or stop service online. • Information specific to the customer can be delivered proactively and made available to the call center for better call resolution.
Reduced fees and costs	• Reduction or elimination of fees for reconnecting service after no-pay or for establishing new service. • More rate options that align with customer behavior to decrease energy usage and lower costs. • Easier access to demand response programs and products that help customers to save money.
Customer safety	• Identifying unregistered PV installations/code violations • Identifying downed live conductors • Identifying heated customer panels/sockets using temperature data to help with fire prevention • Determine fire-caused outages using temperature data

How Utilities Are Using AMI Beyond Meter Reading*		
Activity	**Uses**	
Monitoring and managing operating conditions	• Improved power quality • Validation of voltage compliance • Visualizing the data/Increased system visibility	• Volt/VAr optimization (VVO) and conservation voltage reduction (CVR) • Switching analysis
Capacity planning	• Load forecasting and projected growth • Equipment investments and upgrades (e.g. distribution transformers, substation transformers, etc.)	• Line loss studies • Circuit phase load balancing
Model validation	• Validation of the primary circuit model • GIS and network connectivity corrections	• Meter to transformer mapping/ transformer load management (TLM) • Phase identification and mapping
Distributed energy resource management	• Identifying unregistered customer-owned systems • Understanding the impacts of customer-owned systems	• Determining DER capacity • Informing policy
Asset Monitoring and Diagnostics	• Proactive maintenance • Identifying over and underloaded transformers	• Identifying bad distribution voltage regulators and distribution capacitors • Identifying hot sockets
Outage management	• Verifying outages through meter pings • Estimating restoration times • Service order automation through remote connect/disconnect • Identifying outage locations	• Determining cause of outage • Customer communications • Determine fire-caused outage using temperature data • Identifying which phase of wires are down
Measuring and verification	• Reduce/eliminate estimated reads • Revenue protection • Reliability metrics • Demand response verification/ thermostat programs	• Demand response and load shifting for EV charging • Enables new rate options (e.g., time of use and prepay)
Identifying unsafe working conditions	• Identifying unregistered PV installations • Identifying downed live conductors	

*Note: The benefits or uses of AMI listed in this table cannot be achieved by merely installing the network and meters. Many will require integration with ADMS or other software solutions that allow the data to be analyzed, visualized and paired with other data.

ON THE DOCKET

Distributed Intelligence

A review of 23 recent distribution controls proposals, related discussions, and orders in 17 states identified that discussions about distribution control systems emerged across a variety of representative docketed proceedings:

2015

- Entergy Texas's AMI application lists enablement of DI as one of seven key functionalities[16]

2019

- New Jersey Board of Public Utilities commissioned report on AMI Gold Standards discusses DI[17]
- NorthWestern Energy (Montana) states an intent to study DI with demand response application[18]

2020

- Debate of DI emerges at the Colorado Public Utilities Commission (PUC), when Public Service Co. of Colorado (PSCo, an Xcel subsidiary) came under scrutiny for adding DI to its meters as part of its "Advanced Grid Intelligence and Security" (AGIS) proposal without stakeholder discussion.[19] Concerns included exercise of monopoly power, competition, data access and sharing, and technical details
- Eversource (Connecticut) discusses the value of DI in its AMI business case[20]
- Consolidated Edison cites a plan to explore DI and other grid-edge capabilities[21]

2021

- The Colorado PUC directs PSCo to re-file its AGIS CPCN[22]
- Xcel (Minnesota) includes a certification request to use DI capabilities
- National Grid briefly discusses "distributed intelligence use cases" and capabilities[23]

2022

- The Colorado PUC clarified that DI meter capabilities may not be turned on except for services provided with today's metering and distribution grid infrastructure; integrated VVO functionality; and any future orders related to data usage and DI functionality. In February 2022, parties agreed to a settlement which describes the timing and use of DI data by PSCo and the availability of such DI data by the customer and any authorized third party.[24]
- The New York PSC approves Itron's Gen5 Riva Singlephase meter application, embedded with DI capability for what Itron calls "grid edge computing"[25]

[16] Public Utilities Commission of Texas. Docket no. 47416, Direct Testimony of Rodney W. Griffith on behalf of Entergy Texas. July 2017. https://e9radar.link/devj

[17] Guidehouse Inc. AMI Gold Standards Report, An Assessment of the Smart Electric Metering Landscape. Commissioned by the New Jersey Board of Public Utilities. Q4 2019. https://e9radar.link/c0z

[18] Montana Public Service Commission. Docket no. N2018.11.78. NorthWestern Energy 2019 Electric Supply Resource Procurement Plan. https://e9radar.link/c2a328

[19] Colorado Public Utilities Commission. Docket no. 16A-0588E. Mission:Data and Western Resource Advocates' Response to Public Service Company of Colorado's Third Motion for Extraordinary Protection of Highly Confidential Information. January 2020. https://e9radar.link/lp9

[20] Connecticut Public Utilities Regulatory Commission. Docket no. 17-12-03RE02. Advanced Metering Infrastructure Business Case and Implementation Plan, Eversource Energy. July 2020. https://e9radar.link/jrh

[21] New York Public Service Commission. Docket no. 14-M-0101. Consolidated Edison Distributed System Implementation Plan. June 2020. https://e9radar.link/11f1e5

[22] Colorado Public Utilities Commission, Docket no. 16A-0588E, Commission Decision Denying Motion and Ordering a New Application. March 2021. https://e9radar.link/e9d9d

[23] Massachusetts Department of Public Utilities. Docket no. 21-81. Petition of Massachusetts Electric Company and Nantucket Electric Company each d/b/a National Grid for approval of its Grid Modernization Plan for calendar years 2022 to 2025. July 2021. https://e9radar.link/zah

[24] Colorado Public Utilities Commission. Docket no. 21A-0279E. Recommended Decision Approving Unanimous Comprehensive Settlement Agreement and Waiving Response Time March 2022. https://e9radar.link/jog

[25] New York Public Service Commission. Docket no. 21-E-0456. Order Approving Electric Meters. January 2022. https://e9radar.link/9450d0

COMMISSIONS HAPPENINGS

Summaries and excerpts from commission orders. These examples are not meant to be definitive approaches or best practices, but are provided as approaches other states have taken that commissions can draw on as they develop their own solutions.

New York Required a Benefit Implementation Plan

In November 2020, the New York PSC approved National Grid's AMI Business Plan with several conditions. One condition was the development and submittal of an AMI Benefit Implementation Plan within 60 days of the issuance of the Order to assist the commission with understanding the benefits presented in the AMI business case, tracking their attainment, and learning from the implementation of the AMI project. The **Benefit Implementation Plan** was required to include:

- **a description of the quantified and unquantified benefits** that AMI can enable, including but not limited to grid-edge computing capabilities, value-added access to useful data for customers and distributed energy resource providers, and any other benefits the utility identified prior to submittal of the plan;
- **a prioritized list of the quantified and unquantified benefits** that the Company intends to pursue, **together with specific implementation action steps and schedules with specific interim milestones**;
- **updates**, as applicable, **to the forecasted 20-year net present value of quantified benefits and costs** to achieve benefits that are identified in the October 2020 Updated BCA;
- **a BCA for any new benefits** that had been planned to be implemented, but that had not been included in the October 2020 Updated BCA; and,
- **a BCA for any benefits** that had not yet been chosen to pursue.

National Grid **was required to work with Staff to develop the plan** and any areas of disagreement between the utility and staff on benefits were to be included in the subsequent filing of the plan. The utility was also required to file semi-annual reports identifying the progress in achieving the goals set forth in the Benefit Implementation Plan.

The Benefit Implementation Plan had to describe how the utility would conduct outreach to vendors, other utilities, interested parties, and/or Staff for input on attaining benefits and achieving the vision set forth in the Company's AMI Business Case, related filings, this Order, and the Benefit Implementation Plan itself. Recognizing that timelines or attainment of benefits could change as AMI implementation progressed, **the utility could file a proposal to alter benefit implementation. Any request needed ample support and an explanation** of how the proposed alteration (or request not to implement a benefit) would more effectively support the achievement of the benefit(s), produce more benefits and/or less risk, or be appropriate for technical reasons

New York Required a Benefit Implementation Plan (continued)

Other conditions included providing data to mass market customers in 15-minute intervals with the data latency the commission specified in the order, a revised Customer Engagement Plan, a semiannual report identifying the progress made toward achieving the goals set forth in the AMI Benefits Implementation Plan, and a meter testing plan for its AMI meter population.

Read the order: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId={7F47DEF5-3F7F-4191-9A2A-FE0803682FDD}

Read National Grid's submitted Benefits Implementation Plan: https://documents.dps.ny.gov/public/Common/ViewDoc.aspx?DocRefId=%7B923313F3-41F2-47D4-A199-CA11C1FB5D97%7D

Kentucky Utilities/Louisville Gas and Electric AMI Order Write Up

In June 2021, the Kentucky PSC issued an order for the rate filings of LG&E and KU (2020-00349; 2020-00350). The PSC found that the expectation of savings from AMI drove the approval of the technology, though, approval was made with requirements placed upon LG&E/KU to ensure that customers received additional benefits beyond those identified in the initial business case. As stated by the PSC, "merely meeting the net benefits when additional customer benefits from AMI systems are available would not result in rates that are fair, just, and reasonable, nor service that is adequate, efficient, and reasonable." The PSC deemed the additional requirements adopted as "necessary to ensure" that LG&E/KU customers "receive the full benefit" of the AMI investment. The **requirements adopted by the PSC** include:

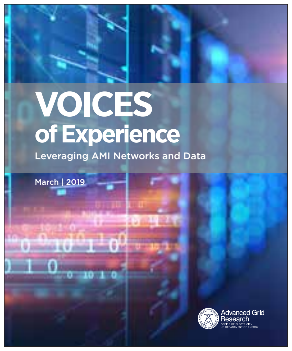
- Work with interested parties to improve the functionality of customer usage data, including evaluating the potential for implementing Green Button Connect My Data functionality, allowing customers with multiple locations to obtain their usage data through a single download, and obtain proof of certification of its Connect My Data implementation
- Establish clear and sufficient baselines for all benefits, and affirmatively show that the projected savings can be achieved on an incremental basis with periodic filings of detailed plans showing how the utility will achieve the benefits and determine if it is maximizing those benefits
- Implement the following programs:
    - Pre-pay program
    - Demand side management (DSM) programs, including those designed to target low-income customer
    - EV tariff program for home and business charging with off-peak charging incentives
    - Customer engagement program related to AMI before, during, and after deployment

Kentucky Utilities/Louisville Gas and Electric AMI Order Write Up (continued)

- Create plans for the following:
  - AMI obsolescence and replacement strategies, including review of successor technologies in order to extend the life of AMI (filed in the next rate case)
  - Identifying outages and how AMI systems will facilitate notification and communication of information, time of repair, and interaction with other "smart grid" investments, including outage management systems (filed annually in June)
  - Reducing the frequency and amounts of tariffed, nonrecurring charges from the proposed AMI meters
- Include how the utility is using data from AMI systems in its integrated resource plan and other utility systems (e.g., benefit voltage regulation, distribution system investment and utilization, load forecasting, peak reduction, and other categories)
- Include in the next base rate any other intended uses of data created by its proposed AMI systems

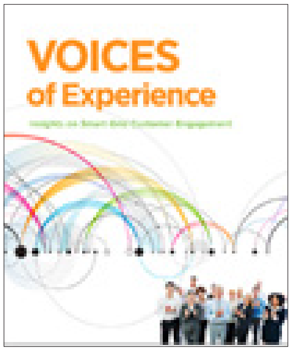
Read the Order: https://psc.ky.gov/pscscf/2020%20Cases/2020-00350//20210630_PSC_ORDER.pdf

BATTERY OF RESOURCES



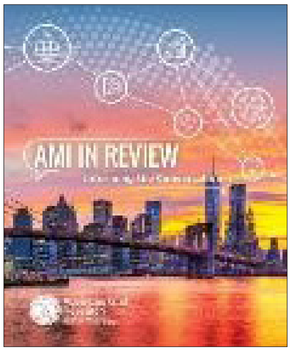
Voices of Experience: Leveraging AMI Networks and Data This March 2019 report provides an overview of the numerous ways utilities are using AMI data to increase efficiencies and improve reliability. In addition to highlighting new customer programs enabled by AMI, it focuses on the value AMI is providing to both customers and the utility beyond the initial business case of reduced truck rolls related to meter reading.

Download here: https://smartgrid.gov/files/documents/VOEAMI_2019.pdf



Voices of Experience: Insights into Customer Engagement This June 2013 report compiles insights, advice, and successful approaches used by utilities to engage customers regarding smart grid technology deployments. The main focus is deployments of advanced metering infrastructure, but can be applied more broadly to education and engagement for other utility programs, such as dynamic pricing, demand response, or outage communication.

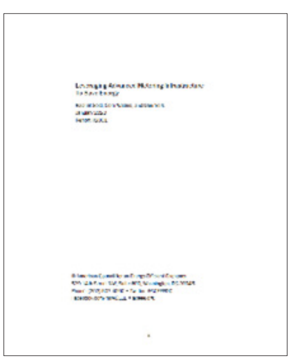
Download here: https://www.smartgrid.gov/files/documents/49225_6A20_VoicesofExperience_brochure_6.25.2020.pdf



AMI in Review: Informing the Conversation This July 2020 Report compiles the results of a phased research study to investigate regulatory applications from various parties' perspective. The research looked at utility applications, filings, and commission orders from 2010 – 2019. In addition, the study conducted regional workshops and individual meetings with stakeholders (utilities, regulators, and advocates) to understand each party's perspectives and rationale, including an evaluation of what is and is not in the record. Each chapter provides findings and captures the collective insights and perspectives of participants. The report also includes a set of elements utilities and state commissions can consider when developing or evaluating an AMI investment proposal.
Download here: https://smartgrid.gov/files/documents/AMI_Report_7_8_20_final_compressed.pdf

Compendium for AMI in Review The compendium is a database with more than 250 relevant proceedings related to AMI deployment, cost recovery, commission rulemakings, smart grid reports, and other topics. It compiles information from the more than 640 documents that were reviewed. It is organized alphabetically by state and provides links to significant documents from each proceeding along with the relevant page numbers and specific testimony presented.
Download here: https://smartgrid.gov/files/documents/Compendium_compiled.pdf

Smart Grid Interoperability: Prompts for State Regulators to Engage Utilities The This paper uses a framework developed by the GridWise Architecture Council that identifies the categories of interoperability and the interfaces between the categories. The questions provided in this document are intended to assist the regulator in reviewing utility proposals and investments of new and emerging technologies, including the cost impacts and risks of differing proposals or options. It includes four steps that regulators can use to understand the potential impacts of interoperability on utilities' technology investments.
Download here: https://pubs.naruc.org/pub/28950636-155D-0A36-313C-73CCEA2D32C1



Leveraging Advanced Metering Infrastructure to Save Energy The American Council for an Energy-Efficient Economy surveyed 52 large utilities and found that most of them are greatly underutilizing this technology. This report discusses several use cases for leveraging AMI data, describes barriers and effective practices, and concludes with recommendations for utilities, program administrators, and regulators.
Download here: https://www.aceee.org/research-report/u2001

Electric Vehicles / Driving the Future Forward

The era of electrified transportation is on the horizon as car manufacturers, states, customers, and markets look to expand opportunities for electric vehicles. This transformation will likely be accelerated with significant federal funding included within the Infrastructure Investment and Jobs Act. It shines a light on questions such as: What is needed from the electric grid to ensure there is adequate supply to meet EV charging demand? How can benefits from the vehicles be realized? What strategies are needed to utilize excess capacity while mitigating peak load impacts?

Regulators are poised to influence the speed at which the transition occurs. While some utilities are enthusiastic, actively submitting proposals to commissions, some utilities have taken more of a wait-and-see approach. Federal funding, along with commitments from vehicle manufacturers, could accelerate adoption rates, which has some commissions wondering if a more proactive approach might be warranted.

Electric Vehicle Challenges

- Establishing equitable infrastructure investment programs
- Designing new tariffs that are aligned with grid and customer needs
- Keeping up with technological changes
- Balancing the many stakeholder perspectives and opinions
- Developing grid services programs and markets to utilize EV load flexibility

While there is significant focus on charging infrastructure investments, it is important not to lose sight of the grid infrastructure needed to support vehicle charging. (See the **Powering Knowledge** section for the write up on the notional impacts of electric vehicles on the grid at different line voltages.) While studies have concluded that many drivers will charge at home, not every driver will have access to home charging, and fleets that electrify could have significant power requirements that cannot be met by available capacity at the distribution level.

Transportation electrification introduces a multitude of new uncertainties beyond whether there is there enough power to support new demand. It can heighten the need for distribution control technologies that provide visibility and control of the vehicle or charging infrastructure, while using the advanced meters (and the AMI communication capabilities) to measure vehicle energy usage. Data, which has become an increasingly important discussion with AMI, ADMS, and DERMS technologies, will receive increased focus in transportation electrification discussions because of the disparate nature of the information: no one entity may have all the data. Different parties – ranging from individuals to fleet managers to charging companies to utilities – will have information that provides valuable insights that other parties may need or want.

Commissions will find themselves in the middle of these issues, deciding the utility role, judging whether investments are reasonable and just, ensuring interoperability, and being mindful of impacts to customers. While this is familiar territory for commissions, navigating the many competing and often conflicting views will become even more challenging. Understanding the technology and the implications for customers, the market, and other stakeholders will take on heightened importance.

Discussions about new rate structures may move to the forefront to address questions such as whether electric vehicles warrant a new rate class or if new rate structures can take into account the unique nature of vehicle loads while still providing recovery for important infrastructure investments.

As the nation transitions to more electric transportation, it will be important to have rates and other approaches in place to set consumer expectations and charging behavior early on as changing these later can be difficult. There are myriad questions and issues that will come before the commissions, and the pace may be much faster and more intense with shorter timelines than previously experienced or imagined.

Insights and Advice from the Conversation

These insights and advice capture information shared by participants about what they wish they had known, advice they might give to fellow regulators, lessons they have learned along the way, or suggested actions that could assist regulators evaluating future utility proposals.

Insights

- **Commissions' knowledge on transportation electrification varies widely.** While some states have been active due to high levels of consumer interest in their jurisdiction, other commissions are just beginning to assess and understand the technology and the landscape. Some commissions may be delving into more sophisticated and complex topics while others are just embarking on the journey.
- **Electric vehicles introduce competition that is not typical for the electricity industry.** Commissions are trying to determine the role of competition, how utility investment might impact it, and what the implications will be for consumers.
- **Technology is evolving quickly. Keeping up with new technological advances can seem daunting.** Commissions are looking for assistance and information that is accessible to help them evaluate conflicting opinions. Technical workshops in which commissions can learn more about the technology's capabilities and the considerations for various implementation options was noted as a valuable approach for formalizing the process for input.
- **Fleet electrification will have unique considerations.** Forecasting fleet plans and understanding fleet charging behavior will be important for utility planning purposes. Commissions expressed an interest in their utilities developing plans to better serve fleet needs. They are also interested in how fleets may be able to provide additional services, such as demand response, to utilities and wholesale markets. Preparing for the electrification of medium- and heavy-duty fleets can raise questions around siting as well as societal good and cost causation.
- **Discussions of codes and standards can be complex.** A fundamental piece of enabling greater transportation electrification is open standards and interoperability. Standards and codes for charging equipment can ease customer frustration, while standards and codes for communicating with the utility can enable future grid services. However, conversations about standards can sound like a foreign language to the less well-versed, and there isn't always consensus across parties as they are still evolving.
- **The future must be forecast without historical data.** Typically, utilities forecast load growth using established approaches based on historical usage and other assumptions. EVs are not nearly established enough to provide that data. Trying to understand customer behavior and evaluating and planning investments, especially for fleets or in congested areas, will mean trying to predict an increasingly uncertain future.
- **Impact of FERC Order 2222 on the EV market is uncertain.** Participants reported that utility operators they spoke with are worried about the implications of FERC Order 2222, which directs regional transmission operators (RTOs) to allow DER aggregators to directly participate in bulk power markets. As defined by FERC, EVs are a DER technology that can directly participate in wholesale markets via an aggregator. Strategies for using EVs in aggregate are still being developed, and RTOs may be cautious in the development of their rules and participation models for EVs, and for DER more broadly. This will require new rules and products to enable such participation.

- **There may be new roles for commissions.** Commissions find themselves with new responsibilities, such as testing charging stations or certifying metering for retail sales as the transportation and electric power sectors come together. While these roles may seem straightforward at first, commissions have found it can add substantial workload.
- **EVs can be flexible loads.** Commissions are looking to develop frameworks for managing or moderating charging load, and are curious about grid services and opportunities for electric vehicles. Some commissions will have workshops or proceedings to explore the topic further to determine how the flexibility associated with EV loads can be mined for value. In areas with extra capacity now, there is time to have those conversations, but the topic might become more acute three or four years from now as EV adoption levels rise.
- **Rates are an essential element to establishing good charging behavior.** Commissions are encouraging utilities to develop new rates to encourage off-peak charging. At the same time, commissions are looking for rate structures that support capital investments in charging infrastructure while maintaining the business case for it. New rate structures, however, may require additional research and knowledge that is beyond commission staff expertise.

Stakeholders: Who Are They?

The term "stakeholders" gets used often in conversations about EVs and their impacts. When a pair of commissioners brainstormed the stakeholders to invite to an educational workshop on EVs, this was the list they built between them:

- State Energy Offices
- State Departments of Energy, Environmental Management, Economic Development, Workforce Development
- Consumer advocates
- Representatives from K-12 schools (buses could be a resource)
- Vocational/Technical/Higher education (pipeline for future workers)
- Utilities (Investor-Owned Utilities, municipals, and co-operatives)
- Regional Transmission Organizations/Independent System Operators – Important for the discussion because of reliability and resilience concerns
- Charging companies
- Vehicle manufacturers (plus workers and unions,)
- Property management/realty companies (when looking how to implement charging infrastructure at multiunit dwellings)
- Convenience stores, gas stations, travel plazas
- Petroleum producers

Advice

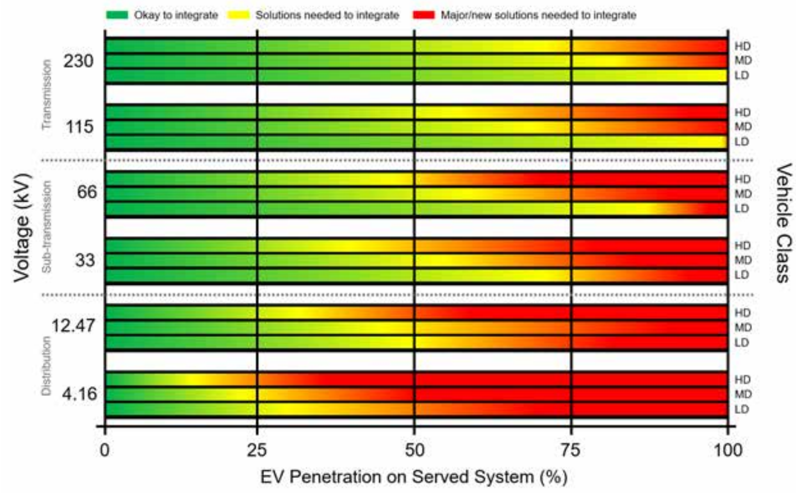
- **Commissions may need to work proactively with utilities.** Commissions whose utilities are not proactively planning for EVs may need to be more proactive themselves in engaging and driving utility actions, such as planning for investments to prepare for the "onslaught of EVs", creating programs to support fleets, and developing incentives to align customer and grid needs.
- **Roadmaps from the commission can provide overarching guidance.** Providing the commission's perspective on big issues like cost causation and interoperability can help utilities develop better proposals, which can simplify commission decision making. EV roadmaps can also be used to inform or align other planning efforts, such as distribution system planning.
- **Include a broad range of stakeholders in discussions.** Many different stakeholders will be interested in the future direction, even ones that may not be traditional stakeholders in electric vehicle discussions. Including diverse perspectives will be helpful moving forward.
- **Stakeholders may help achieve more innovative and creative utility solutions.** While utilities may be enthusiastic about transportation electrification, out-of-the-box solutions may require more input and nudging. Broad stakeholder participation in meetings can help to push the conversation beyond what the utilities might initially propose.
- **Different pathways for metering for new rates exist.** There are multiple ways to communicate and measure EV charging. Data for billing and measuring electricity usage can be collected from the advanced meter, the EV supply equipment (EVSE), or even the vehicle itself. In evaluating options, commissions are striving to balance the need for accurate, reliable information with minimizing costs to customers regardless of the tools being used.

Questions Commissions Are Asking about EVs

- How can commissions ensure that charging infrastructure supports interoperability and enables futureproofing of charging infrastructure?
- What electricity investments are needed to support electric vehicle charging, especially in remote or underserved areas?
- What data about the distribution system and charging infrastructure is needed to support EV deployments?
- How should projections of EV adoptions factor into distribution system planning?
- What is the appropriate balance between utility and private development of charging infrastructure?
- Is there a need for EV-specific rate classes for different applications?
- What are the expectations for EV adoptions in the state?
- Should there be new forms of interconnection requests?

POWERING KNOWLEDGE

Notional impacts of EV penetration for different voltage levels on the electric grid



Reference Material:

Kintner-Meyer, Davis, Sridhar, Bhatnagar, Mahserejian, and Ghosal 2020. Electric Vehicles at Scale – Phase I Analysis: High EV Adoption Impacts on the Western U.S. Power Grid. [Online]: https://www.pnnl.gov/sites/default/files/media/file/EV-AT-SCALE_1_IMPACTS_final.pdf

Southern California Edison Distribution Engineering and Advanced Technology. 2012. The Impact of Localized Energy Resources on Southern California Edison's Transmission and Distribution System. [Online]: https://efiling.energy.ca.gov/GetDocument.aspx?tn=68239

Warwick, Hardy, Hoffman, and Homer. 2016. Electricity Distribution System Baseline Report. Tech Report PNNL-25178. [Online]: https://www.energy.gov/sites/prod/files/2017/01/f34/Electricity%20Distribution%20System%20Baseline%20Report.pdf

U.S. Department of Energy, Office of Electricity Delivery and Energy Reliability. 2016. Distribution Automation - Results from the Smart Grid Investment Grant Program. [Online]: https://www.energy.gov/sites/prod/files/2016/11/f34/Distribution%20Automation%20Summary%20Report_09-29-16.pdf

Transitioning to vehicles fueled by electricity requires that the supporting grid infrastructure is able to meet both the energy and the power demands of various charging applications. The impacts from electric vehicles are highly localized and, therefore, must be understood at all levels, from transmission (or macro) to distribution and neighborhood (or micro). There have been several transmission-level studies indicating the bulk system typically has enough nameplate capacity to support an increasingly large EV fleet.[26] However, the transmission system has more diversity and higher voltage lines. As a result, it is likely that constraints will be seen most acutely on the distribution system. Distribution impacts will be different for different utilities, and even from circuit to circuit. Understanding actual capacity may require more detailed analysis from the utility, especially in areas with lower voltage lines.

Impacts from electric mobility may be especially severe when looking at underserved communities or densely populated urban areas. Many underserved communities stand to benefit greatly in local air quality from reduced vehicle emissions, but at the same time, those areas may have experienced low load growth and not have seen system upgrades to larger (higher voltage) lines. Such neighborhoods may experience system constraints at lower EV penetrations as a result. Utility systems with excess capacity – or that have upgraded distribution lines and have unused capacity – may be able to integrate a larger penetration of vehicles before constraints appear. The graph provides a notional look at impacts of different penetration levels for different conductor sizes and illustrates the need for more detailed analysis of the distribution system to understand potential impacts.

Approaches such as new EV-only rates and smart charging management can help to minimize system impacts, but on significantly constrained systems, these approaches alone may not be sufficient and more sophisticated approaches may be necessary as adoption levels grow.

[26] Kintner-Meyer, Davis, Sridhar, Bhatnagar, Mahserejian, and Ghosal 2020. Electric Vehicles at Scale – Phase I Analysis: High EV Adoption Impacts on the Western U.S. Power Grid. [Online]: https://www.pnnl.gov/sites/default/files/media/file/EV-AT-SCALE_1_IMPACTS_final.pdf.

Interoperability

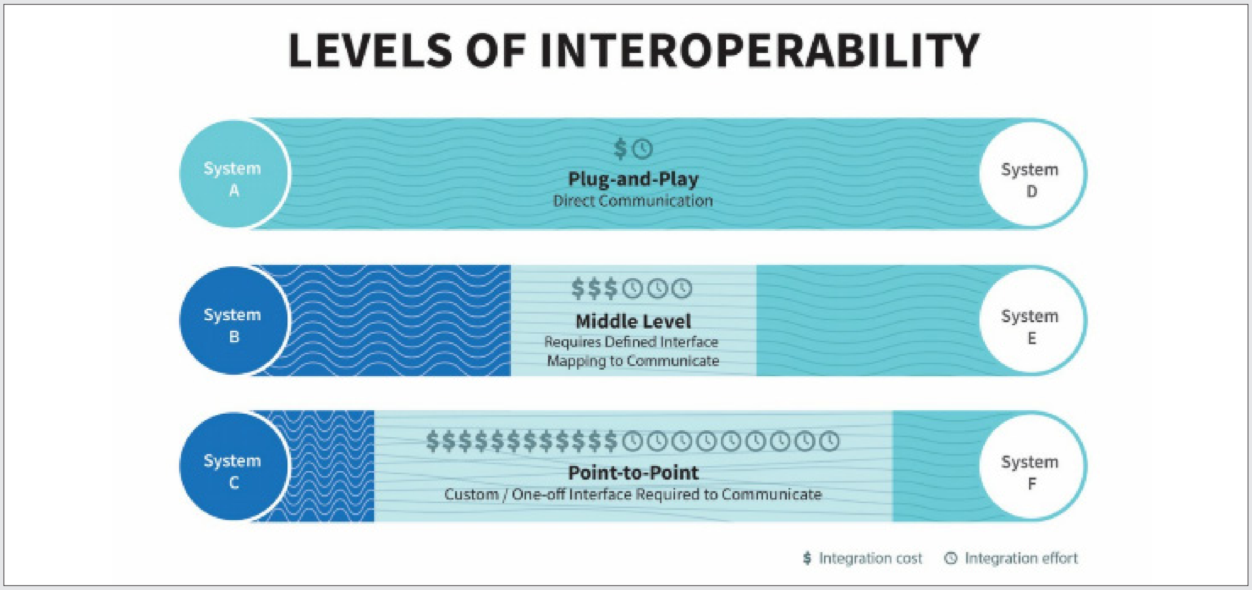
At a high level, interoperability is the ability of two products to communicate and seamlessly share information with each other. The National Institute of Standards and Technology defines interoperability as:

"The capability of two or more networks, systems, devices, applications, or components to work together, and to exchange and readily use information — securely, effectively, and with little or no inconvenience to the user. The smart grid will be a system of interoperable systems; that is, different systems will be able to exchange meaningful, actionable information in support of the safe, secure, efficient, and reliable operations of the grid. As the number of devices and systems used on the electrical grid continue to multiply, the interoperability requirements become more complex and the path to achieving interoperability becomes more challenging."[27]

What this means is that any piece of technology that a customer, utility, or other entity installs has an expectation that it will be able to communicate with another technology automatically. As an example, WiFi is in place around the world. A laptop is able to connect to any WiFi router wherever its user may be because of interoperability. For the technologies discussed in this paper, interoperability is an important part of ensuring the success of these technologies and the evolution of the electricity system overall.

If a utility ADMS system is not able to communicate with its GIS, for example, then a new piece of code or software will be needed to allow them to communicate; that comes at a cost. If an EV driver is unable to plug into or communicate with an EVSE, that will result in a poor customer experience. If data is not shared in a common format and via a standardized mechanism, that will delay benefits of AMI implementation and increase costs to the market as one-off solutions for proprietary utility implementations must be developed.

Having an interoperable system, and embedding interoperability as a foundational component of the electricity system as it evolves, will ensure that all will be able to participate and benefit from this evolution. Reliance on standards, specifically open standards with well-developed testing and certification programs, are vital to the success of this evolution.



[27] NIST Interoperability Framework at 3.

Insights from *DOE's An EV Future: Navigating the Transition* Report

The An EV Future initiative convened stakeholders to explore and discuss what the transition to electric vehicles will mean from different perspectives. This is a sampling of insights from the report

- **The pace of change is unparalleled.** Policies and procedures need to stay ahead of demand.
- **Everything in distribution is local.** Last mile distribution impacts are easy to underestimate.
- **Don't overlook grid modernization.** Without it, benefits could be limited, especially in underserved communities.
- **Leveraging existing infrastructure can benefit all utility customers...** but not everything can be managed without additional infrastructure.
- **Sometimes utility investments can be preferable to on-site solutions.**
- **Power requirements for fleets will not be inconsequential...** and first movers may have advantages.

Read the full report at: https://smartgrid.gov/files/documents/An_EV_future_10.21.21_FINAL.pdf

Cross-Agency Collaboration Related to Transportation Electrification

Cross-agency collaboration will be essential as the transportation and electricity sectors intersect. It may place utility regulators in a new position with regard to other state agencies and organizations. While some agencies involved in the transition are familiar with utility operations, others may not know how their decisions can be carried out nor the impact their decisions might have on the reliability and resilience of the electric grid.

As states prepare for the transition to electrified mobility, state commissions will influence the method of rate determination, the allocation and recovery of utility infrastructure costs, and the timing of utility investments. Regulators will also play a vital role in determining involvement by electric utilities in deploying or owning charging infrastructure and utility support for fleet electrification. Interconnection and interoperability standards and other components that will drive market development will also fall under the sway of commissions.

Coordination is increasingly necessary, especially in light of the Infrastructure Investment and Jobs Act, passed in late 2021, which makes available over $500 billion and requires states to develop comprehensive EV plans. Collaboration is important to ensure that utility infrastructure can support state plans.

Insights and Advice from the Conversation

Conversations about cross-agency collaboration included participants from state regulatory commissions, state departments of transportation, state energy offices and other state agencies that will be involved in transportation electrification.

Insights

- **Many different agencies and groups will need to be part of the conversation.** Considerations for the transition to electrified mobility are broad ranging. Topics that are top of mind include efficiently planning highway corridors, locating charging infrastructure to meet needs and encourage equitable participation, and ensuring adequate electricity infrastructure to support chargers. Decision makers are also considering the implications for reliability and resilience during extreme weather events, the role of grid services, and around data access and sharing policies.
- **States are creating new agencies, commissions, and working groups.** Today, the electricity and transportation sectors are distinct and siloed. They will converge with the transition to electric vehicles. States are noting the shift and are creating new agencies or task forces that bring together the many different components that will be needed for a successful transition.

- **Workforce and economic development are top of mind.** Factors in determining locations for charging stations include workforce development, economic growth, and equity.
- **Legacy vehicles are a consideration.** Regulators and planners are monitoring the market and trying to determine what technological advances in vehicle charging will mean for early adopters of EVs. Making sure legacy vehicles can charge at publicly funded stations is an important factor.

Advice

- **State commissions need to be involved.** Participants highlighted the importance of state commission involvement in the development of state EV plan given that utility commissions have the broad responsibility – or expectation – to support how public funds are spent. Advice from participants: If they're not involved, get them involved!
- **Start building relationships!** Outreach, coordination, and cooperation will be paramount. Don't wait for a formal process; just pick up the phone and reach out to sister agencies that have a role to play, suggested one participant. The sooner outreach occurs, the sooner coordination, and cooperation can begin. Some agencies to call might include the department of emergency management, the department of economic opportunity, the air quality office. Reach out to local and city governments as well.
- **Coordinate messaging.** Developing a consistent message that is unified across the state can reduce confusion for consumers and reinforce state goals. Participants encouraged extending this consistency in messaging to utilities in the state.
- **Integrate EV infrastructure into electric system planning.** EV infrastructure will continue to grow and grid infrastructure will need to be there to support it. The locations of charging facilities may not necessarily align with traditional population and commercial growth patterns, so incorporating them into system planning will be necessary.
- **Understanding electricity capacity to support state EV planning efforts.** Ensuring that charging infrastructure is located throughout the state is one thing; ensuring that they are have sufficient electrical capacity to serve the new load reliably is another… and equally important. Some agencies have commissioned studies or are requesting utilities evaluate state electricity infrastructure needs to support public charging. Use cases can provide an underlying framework.
- **Right-of-ways are another important component.** DOT involvement can help with rights of ways for transmission siting, especially when dealing with renewable energy resources. States are looking at statewide initiatives and how they fit together. This can be especially critical in congested areas when considering distance between station requirements for federal funding.

ON THE DOCKET

Transportation Electrification

A review of more than 27 recent transportation electrification activities and related orders in 16 states and Washington D.C. from the last five years (focus on 2020 and 2021) showed that topics in those orders included:

Category	Topic	Frequency
Grid Modernization Plans	Roadmap	9
Asset Investment Plan or CPCN	Pilot	13
Customer Segments & Infrastructure	Charging Infrastructure	14
	Underserved Communities	18
	Multifamily	10
	Fleet	10
	Buses	7
Rate Design & Programs	EV Rates	14
	Managed Charging	9
Other	New Requirements	4

Additional notable topics under discussion across multiple jurisdictions

- Regulation of Charging Station Sales: Many states have opened dockets to discuss whether the rates charged by charging stations should be regulated.
- Utility Vs. Third-Party Ownership: Debate exists as to which is model is most cost-effective.
- Demand Charges: Utilities and regulators alike are questioning whether demand charges are the appropriate rate mechanism for fast charging stations.
- Disadvantaged Communities: In some jurisdictions, regulators have directed utilities to work with local agencies rather than providing rebates and grants directly.

COMMISSIONS HAPPENINGS

Summaries and excerpts from commission orders. These examples are not meant to be definitive approaches or best practices, but are provided as approaches other states have taken that commissions can draw on as they develop their own solutions.

Connecticut's Electric Vehicle Regulatory Actions

On April 21, 2020, to support ambitious state goals for transportation electrification, **Connecticut's Department of Energy and Environmental Protection (DEEP) released, *Electric Vehicle Roadmap for Connecticut: A Policy Framework to Accelerate Electric Vehicle Adoption***. The EV Roadmap outlines a vision for 2030 and provides a comprehensive strategy for accelerating EV deployment using policy and regulatory tools. It addresses topics such as transportation equity, consumer education, charging infrastructure expansion, utility investment, and utility rate design.

This roadmap was the result of a process initiated by DEEP in November 2018. This process included multiple stakeholder meetings followed by a technical meeting, discussing a range of topics, that would inform the recommendations for the roadmap.

- **Read more information about the roadmap development process:** https://portal.ct.gov/DEEP/Climate-Change/EV-Roadmap
- **Download the roadmap:** https://e9radar.link/5ir

While the DEEP process was occurring, the Connecticut Public Utilities Regulatory Authority (PURA) had initiated a separate proceeding to discuss grid modernization. This proceeding started via an order issued on October 2, 2019 in Docket No. 17-12-03 that outlined PURA's framework for an Equitable Modern Grid.

Technical Workshop Panels and Topics

- **Public infrastructure today and into the future**
  Discussion Topics: Public EVSE ownership models; operation and management responsibilities; data collection; building codes; future-proofing; interoperability; pricing transparency
- **Accelerating EV adoption**
  Discussion Topics: EV incentives; consumer awareness and education; low- to moderate-income access; fleets
- **The role of time-of-use rates to encourage EV adoption and to mitigate adverse grid impacts**
  Discussion Topics: rate design; metering/sub-metering; managed charging; grid impacts
- **Navigating demand charges**
  Discussion Topics: grid impacts; demand charges; fleet transitions

Meeting agenda:
https://e9radar.link/qiu

Connecticut's Electric Vehicle Regulatory Actions *(continued)*

The approach utilized an iterative process that invited proposals from utilities, private developers, local and national experts, limited-income and environmental advocates ,and others involved in the effort. The PURA had Solutions Days on six topics: Energy Affordability, Advanced Metering Infrastructure, Electric Storage, Zero Emission Vehicles (ZEV), Innovation Pilots, and Interconnection Standards. PURA identified eleven near-term topics to be investigated in three additional phases. Topics included non-wires alternatives, new rate designs, and interoperability.

As it applies to the ZEV topic, PURA issued an order on July 14, 2021 in Docket No. 17-12-03RE04 that established a nine-year statewide EV Charging Program to develop a self-sustaining ZEV market that provides ratepayer, electric system, economic, health, and environmental benefits, and achieves an equitable transition to EVs across all communities in Connecticut. In the decision, **the commission issued a list of sixteen orders directing the distribution utilities in the state to perform tasks, including:**

- **Initiate a working group** that will inform the development and launch of managed charging programs for residential single-family, workplace, and light-duty fleet charging programs
- **Develop the appropriate program documents** for commission review regarding the plan to develop a hosting capacity map, specific to Level 2 and DCFC stations, that will be public through an online portal. The plan will include costs and implementation timelines
- **Submit a proposed EV Rate Rider** (requirements of two utilities in the state and each requirement was different)
- **Submit a proposed RFP to retain a third-party evaluation, measurement, and verification (EM&V) Consultant** for the first three-year program period
- **File proposed program design documents** that include 1) rules to implement a charging program for residential single-family, workplace, and light duty fleets; 2) a proposed rebate with its implementation details for residential EV drivers with an existing non-networked Level 2 charger; 3) a proposed definition of "site" and a process to determine site-by-site infrastructure upgrades to enable charging; 4) a proposed three-year program budget; and 5) a proposed joint education and outreach plan.
- **Submit for approval the EVSE vendor RFP listing minimum requirements**
- **Develop and submit program metrics**
- **File a Data Privacy and Security Plan for the EV Charging Program.**
- **Submit a proposed Level 2 EVSE Lease Program at MUD**

The decision also authorized a low- to moderate-income Customer Electrified Mobility Study. The order noted that a reevaluation by the commission would take place every three years to determine if the program is delivering the expected ratepayer benefits.

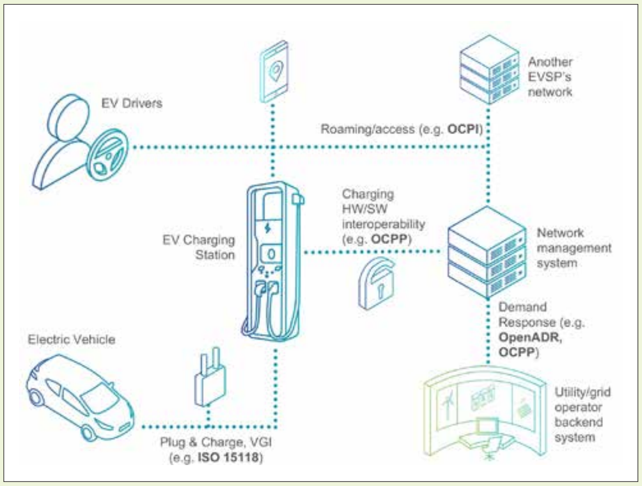
Read the order: https://portal.ct.gov/-/media/PURA/electric/PURA-Establishes-Statewide-Electric-Vehicle-Charging-Program.pdf

Connecticut's Electric Vehicle Regulatory Actions *(continued)*

Focus on Interoperability

In the July 2021 order, the PURA noted that "statewide deployment of EV charging infrastructure poses numerous interoperability considerations" and directed the formation of a working group to discuss interoperability issues associated with utility EV grant programs. The goal of the effort was to identify necessary interoperability requirements for technologies seeking funding from the utilities to implement the July 2021 order. The result of the workshops was a discussion on the interoperability impacts on EV deployment in Connecticut, identification of use cases and standards, and suggestions for ensuring interoperability to support EV growth in Connecticut. A case study detailing the work of the working group was released that includes the interoperability interfaces for the EV market.
To read the case study, visit: https://e9radar.link/ewy

EV Interfaces where interoperability is Relevant



Graphic courtesy of Shell Recharge Solutions (formerly Greenlots)

Indiana Forms EV Product Commission

The Indiana state legislature passed a law establishing the Electric Vehicle Product Commission to help carmakers in the state make the transition to producing EVs. The group investigates and evaluates the status of the EV market, including factors like the number of facilities making EVs and their production capacity, the number of workers in the EV industry, and the needs for training. Furthermore, they examine R&D opportunities, ways to leverage competencies from traditional automotive production, and results from previous retooling instances.

The 10-member commission, comprised of legislative representatives and industry leaders, is tasked with producing annual reports for the state's Economic Development Corporation on the state of the EV market.

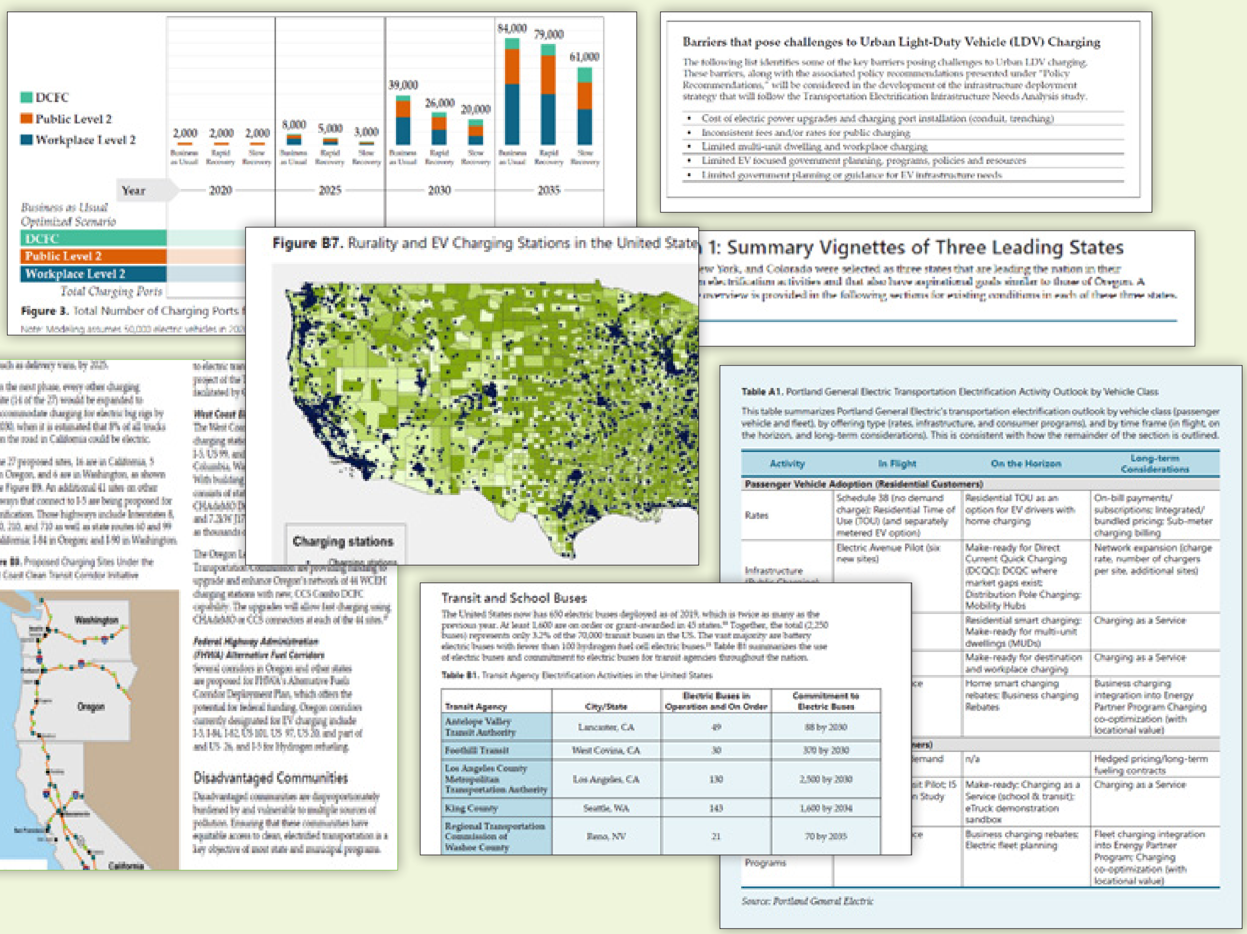
https://www.iedc.in.gov/program/electric-vehicle-product-commission/overview

Oregon Transportation Electrification Infrastructure Needs Analysis (TEINA)

Oregon has a legislative mandate to reduce light-duty vehicle emissions to zero as part of a bill passed in 2019. As directed by an executive order from the governor, the Oregon Department of Transportation commissioned the Transportation Electrification Infrastructure Needs Analysis (TEINA) study to understand charging infrastructure needs. The study included transit, delivery, freight, and micromobility vehicles in its model, simulating a period of 2020–2035 under optimistic, pessimistic, and "business as usual" economic trajectories. Particular attention was given to the charging needs of rural drivers and drivers in historically marginalized communities.

The report identifies six overarching EV infrastructure goals and recommends policies and implementation priorities for meeting state goals. In addition to reviewing the distribution of current charging infrastructure, it included an extensive literature review, stakeholder input, a needs assessment (representing the heart of the study), and resulting policy recommendations. It also includes an overview of activities in three states identified as leaders in transportation electrification efforts: California, Colorado, and New York.

A Sampling of Information in the Report:



Read the full report: https://www.oregon.gov/odot/Programs/Documents/Climate%20Office/TEINA_Final_Report_June282021.pdf

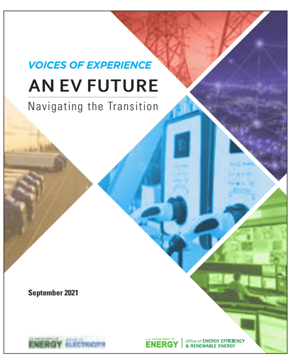
Arkansas Establishes Council on Future Mobility

Recognizing the importance of seeing the future of electrified transportation from multiple perspectives, Arkansas Governor Asa Hutchinson signed an Executive Order in February 2022 that established the Arkansas Council on Future Mobility. The group brings together representatives from corporate partners, advocacy groups, academia, utilities, and government.

The council has been tasked with three jobs: identify state laws that impede advanced mobility, recommend policies and incentives to further development of advanced mobility, and search for opportunities to partner with companies on the cutting edge of mobility technology. The council's report on these points is slated for submission at the end of November 2022.

https://governor.arkansas.gov/news-media/press-releases/governor-hutchinson-announces-arkansas-council-on-future-mobility

BATTERY OF RESOURCES



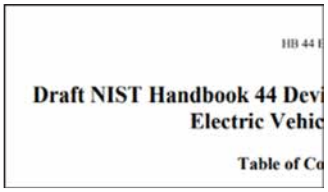
An EV Future: Navigating the Transition October 2021, A Voices of Experience Initiative. The report compiles the ideas, advice, and approaches from various stakeholder perspectives about the transition to electric vehicles (EVs). The topics vary widely from residential charging to long-haul transportation, from public transit to infrastructure deployment, from regulatory policy to new market entrants. It also includes a broader, more informal collection of experiences and observations from a variety of perspectives. The effort explored successful approaches as well as not-so-successful ones, in an attempt to uncover unanticipated challenges or barriers.

Download the report: https://smartgrid.gov/files/documents/An_EV_future_10.21.21_FINAL.pdf

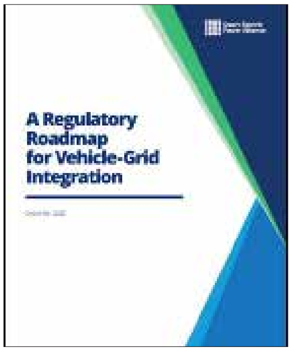
EZMT: Energy Zones Mapping Tool The free, on-line tool utilizes an extensive map library that can help identify potential locations for EV charging stations based on user specified priorities. The tool can help identify gaps in corridors and where access to charging in underserved communities is limited. The library includes mapping layers such as Electrical Substations, HUD Opportunity Zones, EPA EJ Screen 2020, and Designated Alternative Fuels Corridor. It also includes equity data such as percent low-income, percent minority, household transportation energy burden, multi-family housing density, and manufactured housing density that can be included in the EV analysis or any of the other models in the system.

- **To learn more about the tool or to register and start using the tool**: https://ezmt.anl.gov/
- **Watch "Using the EZMT to Equitably Plan for Electric Vehicle Charging Stations":** https://www.youtube.com/watch?v=bGDTsdeRVY0

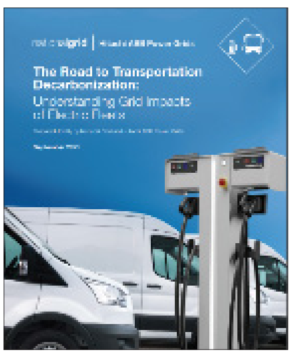
EVI-Pro Lite: Electric Vehicle Infrastructure Projection Tool The free, online tool provides an easy-to-use method for estimating the number of charging stations that will be needed to meet user-specified EV adoption numbers for a state or urban area. It also provides results on the impact to load profiles for select cities or urban areas.
Access the tool: https://afdc.energy.gov/evi-pro-lite.



Draft NIST Handbook 44 Device Code Requirements for Electric Vehicle Fueling "This tentative code has only a trial or experimental status and is not intended to be enforced. The requirements are designed for study prior to the development and adoption of a final code. Officials wanting to conduct an official examination of an Electric Vehicle Supply Equipment (EVSE) or system are advised to see paragraph G-A.3. Special and Unclassified Equipment. This code applies to devices, accessories, and systems used for the measurement of electricity dispensed in vehicle fuel applications wherein a quantity determination or statement of measure is used wholly or partially as a basis for sale or upon which a charge for service is based."
Download the handbook: https://www.nist.gov/system/files/documents/pml/wmd/3XX-HB44-EVSE-DRAFT-CODE-ver-8-28-14-SEP2014-Web-Update.pdf

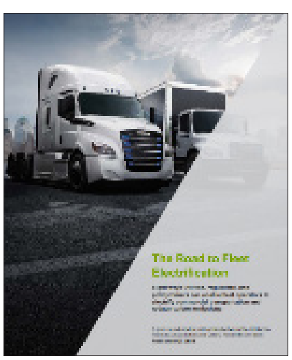


A Regulatory Roadmap for Vehicle-Grid Integration The roadmap was developed to provide regulators and their staff information to facilitate Vehicle-Grid Integration (VGI) development and deployment in their state. It provides information about what VGI is and why it is important, why regulators are key to unlocking VGI, and how to develop a roadmap.
Download the roadmap: https://sepapower.org/resource/a-regulatory-roadmap-for-vehicle-grid-integration/

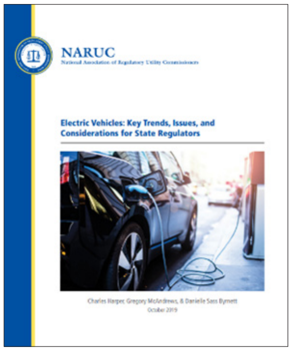


Understanding Grid Impacts of Electric Fleets A case study prepared jointly by National Grid and Hitachi ABB Power Grids that provides a "bottom-up" analysis of what long-term fleet electrification might look like on a specific part of the electric distribution system. The analysis estimates future electric loads associated with the electrification of fleets in an area of National Grid's service territory. It includes major findings and takeaways that require further analysis, but doesn't not provide specific solutions. Instead it provides a foundation for future analysis that utilities and policy makers should consider: Collaboration with fleet operators to further quantify electrification needs and timelines, detailed analysis of system needs and solutions (including transmission, distribution, DERs, and charging programs) and policy considerations and recommendations to facilitate and expedite interconnection of electrified fleets.

- **Download the case study:** https://www.nationalgridus.com/media/pdfs/microsites/ev-fleet-program/understandinggridimpactsofelectricfleets.pdf
- **View the study summary and infographic:** https://www.nationalgridus.com/media/pdfs/microsites/ev-fleet-program/fleetstudysummaryandinfographic.pdf



The Road to Fleet Electrification The guide, produced in partnership between the California Trucking Association and Ceres and funded by Amazon, was a result of a survey of companies with early fleet electrification projects. The survey identified common challenges fleet operators face when engaging utilities and recommended actions that can be taken to make fleet electrification faster, easier, better for the environment, and more affordable. These recommendations cover eight key areas where utilities, regulators, and policymakers can make an impact.
Download the report: https://www.ceres.org/sites/default/files/reports/2020-05/The%20Road%20to%20Fleet%20Electrification.pdf


NARUC
National Association of Regulatory Utility Commissioners

Electric Vehicles: Key Trends, Issues, and Considerations for State Regulators

Charles Harper, Gregory McAndrews, & Danielle Sass Byrnett
October 2019

Electric Vehicles: Key Trends, Issues, and Considerations for State Regulators
The issue brief examines trends in EV adoptions, provides a synopsis of the types of decisions commissions are facing, and offers examples of recent state regulatory approaches to EV questions. It outlines key issues and perspectives that commissions are like to hear from stakeholders.
Download the report: https://pubs.naruc.org/pub/32857459-0005-B8C5-95C6-1920829CABFE

NARUC's Center for Partnerships and Innovation Resources NARUC's CPI website on electric vehicles provides an extensive webinar library on a wide range of topics related to electric vehicles, including school bus electrification, heavy-duty truck charging, performance-based regulation, managed charging, and vehicle-to-grid.
Visit the website: https://www.naruc.org/cpi-1/energy-infrastructure-modernization/electric-vehicles/

EV States Clearinghouse The clearinghouse provides resources that States can use as they plan for and build out EV chargers in a strategic, efficient, and equitable manner. Resources include model RFPs, staffing and budgetary models, sample contracts, current state-level EV roadmaps, as well as EV infrastructure siting and assessment tools.
To register for a free account and access the clearinghouse, visit: https://evstates.org/login/

Data Flowing Throughout the System

Data and data governance are topics that span all of the next-generation technology areas, and there are data-related issues tied to each of the next-generation technologies themselves. In this digital age, data is the lifeblood of the technology platforms that are driving the transformation of the electric grid. Each technology produces a vast amount of new data about customer usage patterns, system operations, and the DER resource itself. This information has value to utilities, individual customers, third-party innovators, and policy makers alike.

Utilities can use the data to optimize their system, network, and operations. Third parties can use data – once solely in the domain of the utility – to develop innovative solutions that respond to customer needs and wants. Customers can use data to better manage their energy usage to manage costs or determine the value and benefits of DER.

Electric vehicles and FERC Order 2222 bring a whole new dimension to data discussions. With EVs, different parties will have access to different data types but may not have access to all the data they would want or need. FERC 2222 introduces new parties that will need operational and customer data. Both of these highlight the growing focus on data access and sharing across parties and technology boundaries. It heightens the need for policies and procedures.

Discussions and research revealed that access to data is a complicated question that many commissions are addressing. With DER, EVs, microgrids, and smart buildings, questions arise over ownership boundaries. When there is a discussion of data access and sharing, privacy and confidentiality quickly enter the conversation. When the monetary value of the data is added into the mix, the discussion can become contentious, and commissions must untangle the many vocal and disparate views.

In conversations about data, it is important to understand the type of the data being discussed because the sharing and access of customer and system data carry different levels of value and risk. Security concerns are often cited as barriers to sharing, but commissions struggle to understand the validity of the claim and may not have the expertise to challenge it.

Some commissions have opened dockets to further explore data access and its value to consumers and other market participants. Some have developed – or directed the utility to develop – a data framework that provides guiding principles on how data will be accessed and protected. Frameworks like the Fair Information Practice Principles and DataGuard provide approaches and mechanisms, but understanding implementation details can be essential for achieving an optimal outcome.

Whether data discussions have been smoldering under the surface or have been spotlighted on centerstage, discussions of data are here to stay and will likely see growing importance as the energy sector transforms and intersects with transportation.

Data Challenges

- Balancing competing stakeholder interests
- Ensuring implementation will achieve desired results
- Developing a framework that allows for access but appropriately accounts for cybersecurity and privacy concerns
- Determining appropriate aggregation methods
- Lack of clarity on national-level issues, such as data access and sharing

Insights and Advice from the Conversation

These insights and advice capture information shared by participants about what they wish they had known, advice they might give to fellow regulators, lessons they have learned along the way, or suggested actions that could assist regulators evaluating future utility proposals.

Insights

- **A commission's view about what data access can enable will drive policies.** If commissions see data as vital for opening competition and encouraging new, innovative solutions, then policies that provide guidelines on what data can be shared and rules for how it can be shared and accessed can provide direction. One commission noted that standardization of data access would help create a vibrant, innovative ecosystem.
- **Customers may voluntarily sacrifice security and privacy to get desired energy services.** When a customer is unable to share their own energy usage, commissions have found that customers would give other service providers the login and password to their utility account portal. Given that those portals contain information beyond just energy usage data, sharing login information jeopardized customer security and privacy – exactly the opposite effect intended by commission's limitations on access to data.
- **Data alone might not create value.** Whether providing benefits for utility operations or for customers, without analytics or tools and applications that provide actionable information and insights, data on its own, is just…well, data.
- **Data access can test different market strategies and illuminate customer interest.** Many of the proposed benefits of new technologies depend on estimations of consumer demand. Limiting access to utilities may inadvertently limit the growth of new markets and may not accurately reflect consumer interest because utilities may not have an incentive to reach beyond commission-set targets for participation.
- **Data can assist in evaluating alternatives.** With AMI, utilities have actual data at a high granularity about customer energy usage, which can help develop distribution load profiles. That information can be used by utilities and commissions to do better planning, benchmarking, and assessing alternatives.
- **Privacy and security are real issues but not all the time.** While there are legitimate security and privacy concerns, participants expressed that they feel utilities often use "security" to delay access. Commissions are seeking help to determine when concerns are justified and when they are not. Frameworks that outline the roles and responsibilities of the customer, utility, and third parties can help identify relevant issues to enabling access.

Advice

- **Limiting data access may limit choices for customers.** One key question around data is how to balance access with privacy. In response to early customer privacy concerns, one commission limited data access to customer AMI data, only to later find that customers in states that provided more access to customer energy usage data (i.e., AMI data) had more opportunities to participate in energy efficiency programs.

- **A framework or roadmap can help guide the discussion with utilities.** Commissions reported that data frameworks can be valuable in helping utilities understand how to "get from here to there" as they provide utilities insight into how the commission envisions the future role of the electric utility and the role data sharing plays in that future.
- **Be descriptive and prescriptive!** Ambiguous statements, that does not include specifics, can mean the intent of what the commission is trying to achieve is up to interpretation and debate. Commissions that have made intentionally ambiguous statements later found them manipulated by utility lawyers.
- **Data can empower creativity and innovation.** Providing access to customer energy usage data or hosting capacity information can allow innovation and creativity in the market. Some commissions have found that to reach state decarbonization goals, empowering other market players with data access will be essential.
- **Standards may drive efficiencies and lead to lower costs.** Utility proprietary solutions can cost more and can limit overall benefits. When it is necessary to move away from standard offerings, it might be better to leave software development to software developers.
- **Data can help with accountability and equity.** Accountability is a great benefit of data and achieving a system that works for everyone. Commissions are interested in utilizing data to verify savings for energy efficiency programs, as well as to benchmark state social programs and to determine how it might pertain to equity and equitable service availabilities.

Questions Commissions Are Asking

- What are the appropriate data sharing responsibilities and obligations?
- What strategies are available to commissions to ensure data access and sharing obligations are fulfilled?
- What is the appropriate balance between sharing data and system security?
- What data needs to be shared to enhance innovation and encourage customer participation?
- Is data being used to its full potential and is the "value" being maximized?
- What is the role of data access and sharing frameworks?
- What is the balance between protecting customer privacy and enabling customer choice?
- How do commissions identify legitimate security questions?

POWERING KNOWLEDGE

Green Button

In 2012, the Smart Grid Interoperability Panel (SGIP) initiated an effort to develop a Green Button standard that was built off efforts by the Federal Government to create a "Blue Button" that would support the standardized sharing of health information for our country's veterans. The Green Button standard is managed by the North American Energy Standards Board.

Green Button is a standardized means by which a customer authorized third party can access customer energy usage data. To accomplish this, there are two versions of Green Button: Green Button Download My Data and Green Button Connect My Data. Green Button Download allows the customer to download a file from their utility's MyAccount page and email it to their third party of choice. Green Button Connect allows the utility to create an API and platform to allow a customer-authorized third party to access customer data directly from the utility. While often associated with utility AMI proposals, Green Button can be implemented with whatever data is available – be it 5-minute, 1-hour, 1-day, or 1-month.

A common challenge with Green Button Connect implementation has been the difficulty third parties have faced integrating with utility systems. Utilities are often not implementing Green Button Connect in a manner that would be certified by the Green Button Alliance. In essence, utilities are implementing a one-off, proprietary version of Green Button Connect, which then undercuts the purpose of the standard overall. A number of states have begun to require that utilities seeking to implement Green Button Connect be certified by the Green Button Alliance to ensure that the utility is implementing Green Button Connect properly.

Learn more about Green Button: https://www.greenbuttonalliance.org/

DataGuard

DataGuard is a data access and privacy framework for customer energy use data that was developed through an open, consensus stakeholder process led by DOE. The key tenets of the program are:

- Consumer Notice and Awareness: Customers should be given prior notice about privacy-related policies and practices.
- Customer Choice and Consent: Customers should have a degree of control over access to their own customer data.
- Customer Data Access and Participation: Customers should have access to their own customer data and should have the ability to participate in its maintenance.
- Integrity and Security: Customer data should be as accurate as reasonably possible and secured against unauthorized access.
- Self-Enforcement Management and Redress: Enforcement mechanisms should be in place to ensure compliance with the foregoing principles.

Companies can voluntarily adopt DataGuard to demonstrate their commitment to data privacy and responsible sharing. Once companies have self-certified that their policies and procedures meet the concepts and principles laid out in DataGuard's voluntary code of conduct, they can use the DataGuard logo to communicate their commitment to customers. Commissions have used DataGuard as in input in the development of their own regulations or data access and privacy framework.

Visit https://www.smartgrid.gov/data_guard.html **to learn more and to download the Voluntary Code of Conduct.**

ON THE DOCKET

Data Access

A review of more than 24 dockets in 12 states related to data access and privacy issues identified a variety of trends, listed below. Some dockets were tagged with multiple trends, such as those in California[28] Colorado,[29] Illinois,[30] Minnesota,[31] New York, [32, 33] and Vermont.[34] Some of these dockets were opened five to ten years ago but continue to house data issue updates.

Trend	Occurances	Description
Investigation	9	Commission investigation into data topics
Anonymized	8	Data anonymity discussed
Stakeholder	7	Working groups and workshops to explore data access
AMI	6	Application of AMI capabilities, best practices
Aggregated	5	Data aggregation discussed
Green Button Connect (GBC)	5	Discussions or requirements related to Green Button Connect to My Data
Use Case: Energy Efficiency	5	Cited interest or application to energy efficiency programs
15/15 Screen	4	Use of the 15/15 screen
Access for Specific Groups	3	Data access limited to certain groups (i.e. government)
Whole-Building	3	Provisions related to whole-building data
Community	2	Community-level data discussed
Legislative Mandate	2	Data sharing or platform mandated by legislation
Use Case: DER	2	Cited interest or application to DER
Use Case: Equity	2	Attention to disadvantaged communities

Additional notable topics under discussion across multiple jurisdictions

- Several states discussed the value of uniform data formats for third parties, academic researchers, state governments, and other entities to suggest improvements to existing utility programming
- Many dockets discussed contract and non-disclosure agreement requirements for customers, including digital waivers and signature processes
- Some utility commissions used stakeholder processes and working groups as the primary format to discuss data access and privacy standards
- Data access discussions are partially driven by localized requirements for building energy efficiency and benchmarking
- In several data access discussions, including in California, New York, and New Jersey, state energy reduction and decarbonization goals were cited as drivers for the collection and sharing of data.
- Many states use a single screening test to determine aggregation standards and benchmarks, such as the 15/15 rule
- Public availability of energy data has been characterized a way tackle disparities in energy burden

[28] California Public Utilities Commission. Docket no. R.08-12-009. Smart Grid Policy. December 2008. http://e9radar.link/z5wx

[29] Colorado Public Utilities Commission. Docket no. 14R-0394EG. Data Access and Privacy for Electric Utilities. May 2014. http://e9radar.link/045l

[30] Illinois Commerce Commission. Docket no. 14-0507. Open Access Data Framework. August 2014. https://www.icc.illinois.gov/docket/P2014-0507

[31] Minnesota Department of Public Utilities. Docket no. 19-505. Citizen Utility Board of Minnesota Petition for Open Access. August 2019. https://e9radar.link/redirect-MN

[32] New York Public Service Commission. Docket no. 17-M-0315. In the Matter of the Utility Energy Registry. June 2017. http://e9radar.link/t3b6

[33] New York Public Service Commission. Docket no. 20-M-0082. Strategic Use of Energy Data. March 2020. https://e9radar.link/nhsc

[34] Vermont Public Service Commission. Docket no. 7307. Smart Metering and Alternative Rate Design. April 2007. https://e9radar.link/f5f4c

COMMISSIONS HAPPENINGS

Summaries and excerpts from commission orders. These examples are not meant to be definitive approaches or best practices, but are provided as approaches other states have taken that commissions can draw on as they develop their own solutions.

Hawaii Order Directing Development of a Data Access and Privacy Policy

In March 2019, Docket No. 2018-0141, the Hawaii Public Utilities Commission noted the increasing importance of accurate and accessible data. To build on the utilities' efforts and reinforce prior commission guidance, the commission directed Hawaiian Electric Company and Maui Electric Company to develop a Data Access and Privacy Policy that would be filed within six months of the date of the order, and would be subject to further review by the commission. Filing and acceptance of the Data Access and Privacy Policy was a condition of cost recovery.

The policy was required to describe the utilities' planned efforts and expected timeline for implementation. The policy was required to:

- explore the expenditures and time required to extend Green Button Connect and Download My Data functionality to all customers, including those without advanced meters.
- provide additional insight on data specifications, including but not limited to: (1) data sets to be offered to customers (e.g., historical and current interval usage, demand, voltage, etc.); (2) the Companies' data hosting policies; and (3) third party data access and data availability, including a discussion on the Companies' plans regarding a third-party authorization process.
- include a framework describing how the Companies intend to protect customer data.

To develop the framework, the utilities were directed to review customer data privacy policies instituted in different jurisdictions, including California and Illinois, to identify best practices and simplify implementation. In addition, the commission expected the utilities to continue to incorporate and adopt elements of DOE's DataGuard program, which had been mentioned in the Companies' Grid Modernization Strategy, and describe any modifications and additions that they may make to it in the Data Access and Privacy Policy.

The commission encouraged the use of a collaborative stakeholder process to assist in its development of the Data Access and Privacy Policy and to identify and ensure alignment with best practices. Regulators also encouraged the utilities to engage with outside experts for technical support, as necessary, including from the Advanced Grid Research Voices of Experience Initiative provided by DOE.

To read the full order, visit: https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A20E21B44345C00621

Kentucky Public Service Commission Requires Green Button Certification

The Kentucky Public Service Commission, in June 2021, issued an order on the rate case of LG&E and KU (2020-00349; 2020-00350) to approve a settlement allowing deployment of AMI throughout the utility's service territory. The Commission, however, modified the settlement, adding a number of conditions. Notably, the utilities were directed to file new DSM programs that utilize the AMI technology and address low-income customer needs. They were required to provide annual reports with details about the customer benefits achieved with AMI. Regarding data access, the stipulation further required the utility to work with interested parties to improve the functionality of customer usage data, including evaluating the potential for implementing Green Button Connect My Data functionality and allowing customers with multiple locations to obtain their usage data through a single download. Further, the stipulation required the utility to receive certification of its Green Button Connect My Data offering to both residential and non-residential customers.

Read the full Order: https://e9radar.link/vxh

Michigan's Timeline of Data Access Policy Development

For Michigan regulators, settling questions about data access has been a decade in the making. In 2012, Docket no. U-17102 first requested new tariffs for enhanced transparency and a thorough explanation of how customer data is collected and maintained. Six years later, the commission opened a new docket directing staff to conduct a stakeholder session exploring data accessibility further.

In 2019, the resulting report addressing the status of data accessibility contained a history of data privacy/access processes and recommendations for the Public Service Commission to consider. It included a review of the data privacy tariffs, customer feedback, consent for third-parties, aggregated and anonymized data, data ownership rights, and hosting additional stakeholder discussions.

The commission responded by filing order U-18485, which addressed Code of Conduct and data privacy and accessibility issues. The 2020 order approved revised data privacy and accessibility tariff language and adopted information sharing procedures, which was followed by regulated utilities filing revised data privacy and accessibility tariffs.

Four months later, in February 2021, the Commission established the Customer Education and Participation workgroup. The order integrated topics from the Customer Data Access and Privacy section into the Customer Education and Participation workgroup. This allowed staff to thoroughly assess and provide recommendations to the commission on how to provide access to customer data while maintaining customer privacy.

Read more about the Data Accessibility Stakeholder Forum: https://www.michigan.gov/mpsc/0,9535,7-395-93307_93312_93320_94544-488862--,00.html

Read the 2019 Staff report: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/068t0000004QkLxAAK

Read the 2022 Staff report: https://mi-psc.force.com/sfc/servlet.shepherd/version/download/0688y000002RDnKAAW

New Hampshire Process on a Multi-Use Energy Data Platform

In 2019, as directed by SB 284, the New Hampshire Public Utilities Commission launched an investigation into establishing "a statewide, multi-use online energy data platform that will allow utilities, their customers, and third parties to access and share data regarding customer energy usage."

Docket no. DE 19-197 was opened to evaluate the energy data platform. The docket was scoped to investigate 1) The governance, development, and implementation of the platform; 2) Standards for data accuracy, retention, availability, privacy, and security, including the integrity and uniformity of the logical data model; and 3) Financial security standards or other mechanisms to assure third-party compliance with privacy standards.

The platform design was scoped to include the following:

- logical data models
- opt-in customer data sharing
- protection from unauthorized disclosure of personal information
- voluntary participation of municipal utilities and deregulated rural electric cooperatives
- certification of the platform by the Green Button Alliance
- compliance with the North American Energy Standards Board's Energy Service Provider Interface and the Green Button Alliance's Green Button Connect My Data initiative

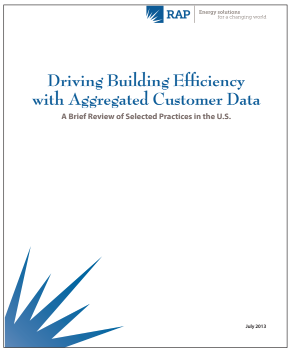
A settlement agreement was approved on March 2, 2022. While the settlement contained design parameters that would apply to a statewide data platform and its governance, including RFP and cost recovery provisions, order DE 19-197 found that platform design was "not at a point yet where the financial costs and benefits of the software development are fully developed for a commission determination." The order outlined next steps to launch the platform and requested additional detail on software design, customer preferences, available technology, and the development of a cost-benefit methodology with stakeholders. The cost-benefit analysis will consider rate design that ensures that costs are appropriately recovered from beneficiaries of the platform.

Read the settlement agreement: https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-197/TRANSCRIPTS-OFFICIAL%20EXHIBITS-CLERKS%20REPORT/19-197_2021-05-05_EXH_1B.PDF

Read the Order: https://www.puc.nh.gov/Regulatory/Docketbk/2019/19-197/ORDERS/19-197_2022-03-02_ORDER-26589.PDF

DATA

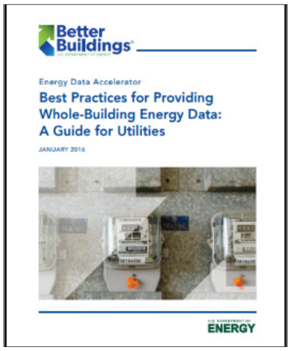
BATTERY OF **RESOURCES**



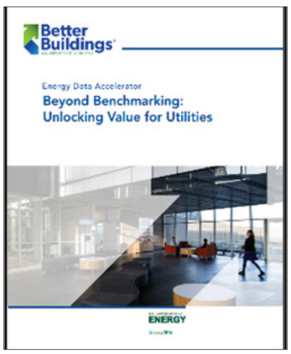
Driving Building Efficiency with Aggregated Customer Data The report, developed by the Regulatory Assistance Project (RAP)®, provides a review of select practices in the U.S. It explored how a growing number of jurisdictions have implemented statutes, rules, or benchmarking requirements that require utilities to provide building owners and third parties with customer data in aggregated form to facilitate benchmarking. **Download the report:** https://www.raponline.org/knowledge-center/driving-building-efficiency-with-aggregated-customer-data-a-brief-review-of-selected-state-practices-in-the-u-s/

Utility Energy Efficiency Scorecard The American Council for an Energy-Efficient Economy measures the 52 largest US electric utilities based on program performance, program offerings, portfolio comprehensiveness, and enabling mechanisms for efficiency. The Scorecard gives utilities, regulators, and other stakeholders benchmarking data and a roadmap they can use to track performance and strengthen utility-sector energy efficiency. https://www.aceee.org/research-report/u2004

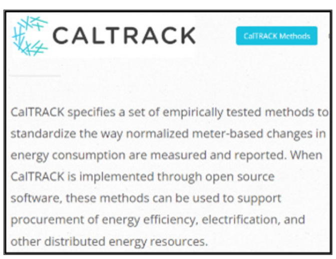
DOE Better Buildings Energy Data Access: Blueprint for Action Toolkit The website provides links to numerous documents – 'the toolkit' – including guidance documents, fact sheets, and utility best practice case studies. Notable guidance documents include a guide to data access and utility customer confidentiality, and statistical analysis of data access and privacy. https://betterbuildingssolutioncenter.energy.gov/toolkits/energy-data-access-blueprint-action-toolkit



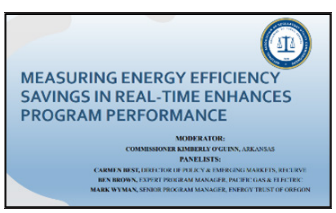
Best Practices for Providing Whole-Building Energy Data: A Guide for Utilities Drawing on the experiences of leading utilities across the country, the guide, part of the Better Buildings® toolkit, provides best practices for utilities to enable energy benchmarking. The guide summarizes the key components of developing a whole building data access solution and provides recommendations to identify and overcome process-oriented barriers. It also provides case studies and model documents to support utilities in providing whole-building data access.
Download the Guide: https://betterbuildingssolutioncenter.energy.gov/sites/default/files/attachments/Best%20Practices%20for%20Providing%20Whole-Building%20Energy%20Data%20-%20Guide%20for%20Utilities.pdf



Beyond Benchmarking - Unlocking Value for Utilities The document can assist utilities in identifying new, untapped, emerging datasets and how that information can assist building owner benchmarking efforts. The solutions presented can assist utilities and building owners alike, and identifies how benchmarking information and whole-building energy datasets can strengthen utility energy efficiency programs.
Download the document: https://betterbuildingssolutioncenter.energy.gov/sites/default/files/attachments/Beyond%20Benchmarking%20-%20Unlocking%20Value%20for%20Utilities.pdf



CalTRACK Some state public utility commissions are demonstrating the use of AMI data to validate energy savings as an alternative to EE EM&V. CalTRACK methods help calculate avoided energy use, the estimated consumption of energy in a building following an intervention as if the intervention had not taken place. This includes methods that describe how to use monthly billing data, as well as interval data from smart meters to calculate hourly or daily derivatives. https://www.caltrack.org/



NARUC Center for Partnerships & Innovation: Measuring Energy Efficiency Savings in Real-Time Enhances Program Performance The NARUC webinar panelists share perspectives on how AMI technologies can be leveraged to increase customer savings and how AMI can be optimized to improve energy efficiency programs. The recorded video of the NARUC June 18, 2020 CPI presents the basics of the open-source CalTRACK methods and the "OpenEEMeter" codebase, how Pacific Gas & Electric (PG&E) is using energy efficiency procurement to achieve and validate energy savings, and how Energy Trust of Oregon is getting contractors used to new approaches for verifying the quality of their work.
View the YouTube video of the webinar: https://www.youtube.com/watch?v=6X80MrnS_3I

The Continuing Transition

The evolution of the electric system is just starting and is far from complete. The technologies discussed in this report are only part of the coming revolution as the grid becomes more distributed, resilient, and responsive. New innovations will continue to meet changing customer and societal demands. One thing is clear: the role of the distribution system to enable and integrate these changes will only become more important, and likely complex, in the years to come. Commissions are charged with making decisions today that will influence the decades ahead, so it is vital that their evaluations of next-generation technologies are as informed as possible about the value and benefits for the future grid.

Ensuring that regulators have the best possible information and are aware of technological advances will be an essential component of modernizing the distribution system. Throughout the discussions that underlie this report, commissions called out the benefits of learning from the experience of their regulatory colleagues from around the country and expressed a desire for expert assistance that could complement their staff's expertise and capacity, especially when addressing complex new issues arising from platform technologies and the data landscape surrounding them.

The consistent message from regulators was that access to the right information at the right time was critically valuable when assessing the complicated issues that arise in proceedings and implementing policy initiatives. Whether from unbiased analysis, primer materials, technical and education workshops, or the development of valuation methodologies or analytic tools, regulators were clear that information was at a premium.

As new technologies expand across the country and utility systems modernize in tandem, commissioners, utilities, and customers alike will all benefit from sharing their experiences directly so that lessons are learned once and shared with the entire regulatory community.

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