EPRI JOURNAL

March-April 2023

Can Solar Power Help Pollinators?

ALSO IN THIS ISSUE:

EPRI JOURNAL

Table of Contents

EPRI JOURNAL

Can Solar Power Help Pollinators?

A new EPRI study examines the feasibility of co-locating solar and pollinator habitat

By Chris Warren

Anyone paying even a little attention to the power industry's transformation in recent years will know that the market for solar energy is big and growing quickly. The drivers of solar's evolution from a niche technology affordable only to those with few alternatives—NASA, to power satellites, for instance—into a mainstream energy source that routinely heads the list of new capacity additions are varied. Among the most important factors are dramatic price declines, performance improvements, favorable policies, and rapidly increasing manufacturing scale.

Taken together, these and other drivers are forecast to lead to a total of 1,600 gigawatts of solar power plants installed in the United States by 2050. Tax credits for solar in the recently passed Inflation Reduction Act of 2022 may accelerate deployment even more. While market growth will lead to the installation of an increased number of solar panels, inverters, and racks—not to mention new grid connections and substations—the size and scale of the market for turning photons into electrons can also be measured in land mass.

In fact, large-scale solar photovoltaic (PV) power plants worldwide are expected to cover over 40,000 square miles by 2030 and 140,000 square miles by 2050—equivalent to the territories of Virginia and New Mexico, respectively. The U.S. could reasonably account for about 10 percent of this land.

AN OPPORTUNITY TO BENEFIT POLLINATORS

Habitat loss, invasive species, pesticides, and climate change have all combined to threaten the ability of important pollinator species to continue to reproduce and be healthy. Pollinator species such as the rusty patched bumble bee are listed as endangered under the federal Endangered Species Act. Currently, the monarch butterfly and four additional bumble bees in the western United States are being reviewed by the U.S. Fish and Wildlife Service for possible protection as threatened or endangered.

Consider that one-third of all the food we eat, including strawberries, chocolate, and coffee, depends on healthy pollinator populations, particularly bees but also bats, birds, butterflies, and some other insects. Additionally, 28,000 medicinal plants depend on pollinators.

Some see solar's rapid development as an opportunity to protect pollinator habitat. Several energy companies and solar developers are exploring ways to leverage the large swaths of land taken up by PV plants to support healthy biodiversity. For example, Enel Green Power's 150-megawatt Aurora Solar Farm in Minnesota integrates low-growing pollinator habitat.

Developing stakeholder processes that balance community concerns with the needs of the industry is critical. But there is also a knowledge gap around the technical and environmental feasibility of emerging applications like utility-scale pollinator-solar. "A basic issue we wanted to understand was the financial feasibility of these projects, particularly in terms of the ultimate cost per kilowatt-hour," said engineer and EPRI Principal Technical leader Cara Libby.

MODELING FOCUSED ON THE COST OF POLLINATOR-SOLAR

To answer those and other questions, EPRI conducted techno-economic modeling to understand better the design, cost, and performance considerations involved with co-locating solar and pollinator habitats. EPRI used the well-established System Advisor Model (SAM) developed by the National Renewable Energy Laboratory to assess changes in the levelized cost of electricity (LCOE) over 30 years for a 150-megawatt solar facility.

The modeling included factors such as array height, the cost of establishing pollinator habitat, operations, and maintenance (O&M) costs over the lifetime of the solar facility's operation, the module technology used, and the location of the project. To incorporate variations in climate and albedo (a measure of the reflection of solar radiation), the research modeled projects in Columbus, Ohio; Jacksonville, Florida; and Las Vegas, Nevada. The impact on LCOE of a pollinator-solar facility was compared to that of a typical non-pollinator solar facility in each location.

The feasibility of co-locating solar and pollinator habitats largely depends on balancing upfront capital expenditures (CAPEX) and ongoing O&M costs. "Sometimes the native seeds can cost more upfront," Libby said, "but their long-term ecological and vegetation management benefits may outweigh the investment. This is useful to evaluate, particularly at the time of initial solar panel installation, when the costs can be covered by the larger CAPEX budget." For example, planting native plants under, between, or around the perimeter of

solar arrays may result in long-term O&M savings by reducing costs for mowing. Traditional turf grass may require mowing monthly, while native, pollinator-supporting plants may only need it annually.

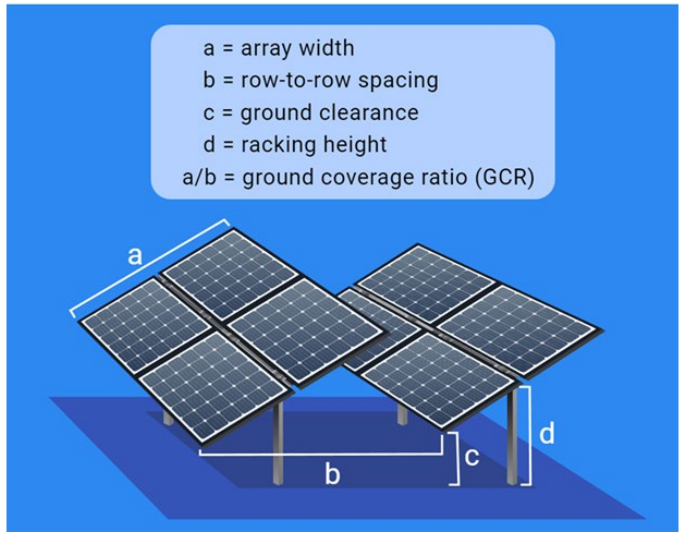
Another issue is the careful selection of pollinator plants of suitable height. "You don't want to include plant species that will grow higher than the solar arrays and shade them because that has energy production and system reliability implications," said EPRI senior technical executive and conservation biologist Jessica Fox. "It's important to choose a native seed mix with mature heights that do not exceed the minimum ground clearance height of the lower edge of arrays."

There is also an incentive to re-establish vegetation under panels quickly to close stormwater permits. Native vegetation tends to be deep-rooted, and its presence helps control stormwater runoff so that water more easily infiltrates the soil over the longer term. Native vegetation also supports soil structure, associated soil-dwelling species, and soil carbon sequestration. In addition, planning is needed to account for the additional time for native vegetation to establish fully.

PANEL TECHNOLOGY CHOICE AND ARRAY HEIGHT IMPACT ON LCOE

The modeling EPRI completed offers insights about LCOE and also illustrates the need for additional research. At a very high level, the answer to whether or not O&M savings exceed any additional CAPEX is that it depends on a range of factors.

For example, the modeling demonstrated that the choice of array height was particularly important to the LCOE of solar projects. The standard minimum array ground clearance is between 18 and 24 inches. Raising the height of the racking can prevent shading from taller pollinator plants, but building and maintaining elevated racking systems requires more steel and labor. Racking height was a main driver of LCOE across all 315 cases EPRI modeled. None of the 36- or 48-inch ground clearance designs broke even financially with the non-pollinator base design.



Module choice is also significant. Monofacial modules generate electricity using sunlight incident only on the top side of the panel. Bifacial modules, by contrast, can utilize sunlight received on both sides of the panel. Planting white or light-colored pollinator plants can increase the amount of sunlight reflected off the ground or albedo. Using bifacial modules in conjunction with such high-albedo vegetation can boost the performance of a solar power plant.

MANY QUESTIONS REMAIN

Careful techno-economic modeling work is the first step in better understanding the financial feasibility of co-locating solar and pollinator habitats. There are limitations to the research findings that will be addressed in future work. For example, the modeling relied on best-available cost estimates and design assumptions rather than data reported by individual solar developers, which tend to be proprietary.

To address that gap, EPRI plans to conduct a survey of utilities, solar developers, vegetation consultants, and others to gather data, insights, and experience that can be incorporated into the model. Those data will be used to refine the assumptions used in the first round of modeling. The results will be updated and published, along with the perspectives of those pursuing or considering solar and pollinator habitat co-location.

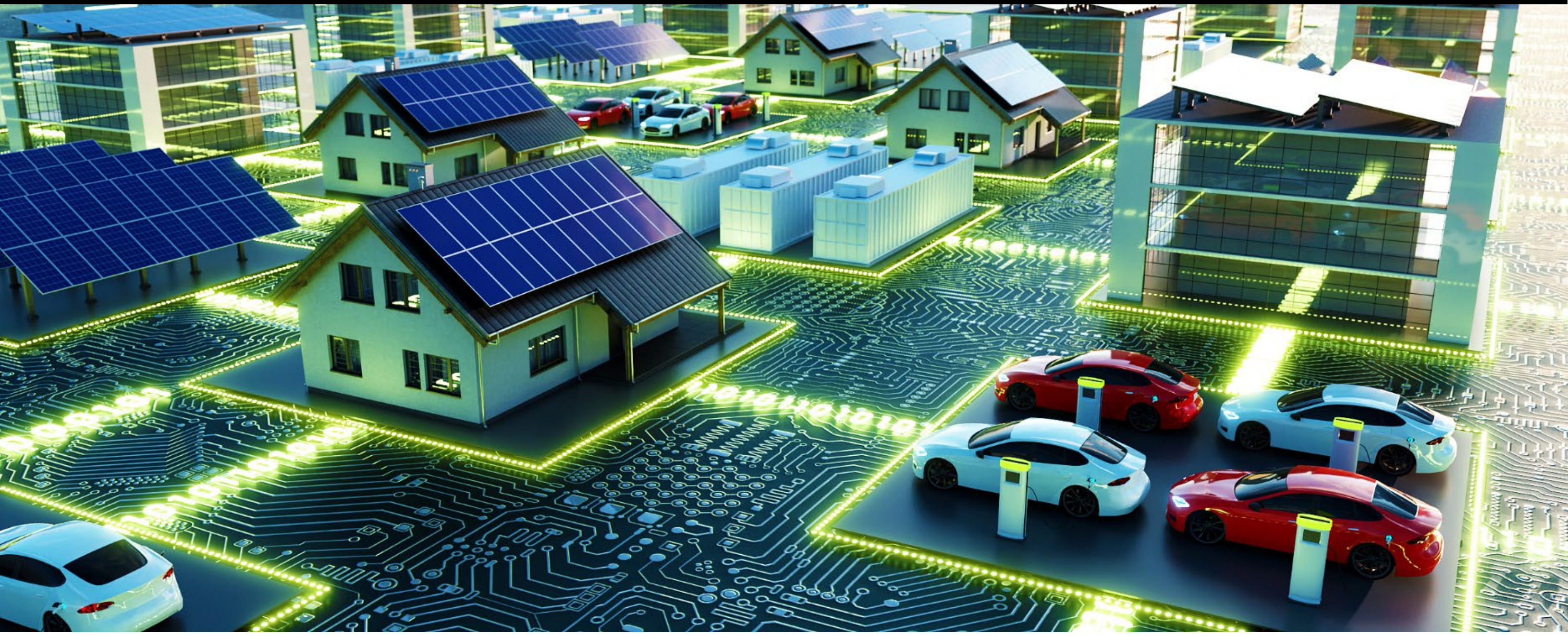
There are also myriad unresolved questions that need to be addressed to inform decisions about co-location. These include determining which native pollinator species are best suited to thrive in a partial-shade environment under arrays with 18- to 24-inch ground clearance. Other areas needing improved understanding are the albedo associated with pollinator vegetation and, at a very basic level, the measurable ecological criteria that backs "pollinator-friendly solar" designations.

Important economic questions are how the LCOE for solar projects co-located with pollinator habitat differs between community and large-scale developments, the difference in costs to establish and manage vegetation at pollinator versus non-pollinator sites, and the cost of electricity to the customer.

There is concern that incorporating pollinator habitat could slow solar development and inject additional complexity. Others argue that there is an opportunity to use the rapidly increasing pace of solar deployment to create and protect critical ecological systems. There may be a middle ground where we can accomplish climate, business, and biodiversity goals. "Solar is positioned to play a critical role in decarbonizing our energy systems," Fox said. "Especially with the United Nations' sweeping commitment in December to protect 30% of the world's biodiversity by 2030, if there are ways to build out solar quickly and affordably and also demonstrate biodiversity stewardship through dual land use, that's an even bigger win."

EPRI TECHNICAL EXPERTS

Jessica Fox, Cara Libby



The Need to Accurately Model Distributed Energy Resource Behavior

EPRI's publicly available OpenDER model aims to ensure accurate interconnection and planning studies

By Chris Warren

Distributed energy resources (DER) are being added to the power system at a rapidly accelerating pace. In the U.S., for example, the electric power sector was operating around 74 gigawatts of solar photovoltaics at the end of 2022, which was approximately three times the capacity in operation at the end of 2017.

According to the U.S. Energy Information Administration (EIA), a combination of declining construction costs and favorable tax credits will add another 63 gigawatts of solar by the end of 2024. The recently passed Inflation Reduction Act (IRA), which provides long-term financial incentives for purchasing many DERs, is expected to spur even faster market growth. By 2030, for instance, 13 percent of U.S. homes are expected to have solar.

This influx of DERs is no accident. In addition to the federal government supporting investments in low or zero-carbon DERs through tax and other incentives, the current administration set a goal of fully decarbonizing the American grid by 2035. And at the local level, 25 states plus the District of Columbia have established economy-wide greenhouse gas emission reduction targets. Corporations, too, have also set ambitious decarbonization goals. Globally, nearly 400 corporations in industries ranging from manufacturing and retail to hospitality and services have committed to achieving 100 percent renewable electricity.

"If you look at the objectives society is trying to achieve with renewable generation sources and moving towards equitable access to renewables to lower carbon emissions, DER plays a big role," said Dr. Aminul Huque. Huque is an EPRI program manager who manages smart inverter and grid support technology research that aims to improve renewables' safe and reliable integration on the power grid. "A lot of the new systems are connected on the distribution side, which is fundamentally changing how the power system is planned and operated."

THE IMPORTANCE OF DER GRID SUPPORT

Even though the power system is changing to incorporate more DERs, utilities, and grid operators are still responsible for maintaining the same (and eventually better) power quality and stability levels as they have historically. Put simply, residential and commercial electricity customers—and society as a whole—expect the decentralized and decarbonized power system to be every bit as reliable as the one that relied on large, central station power plants. It's a high bar: The National Academy of Engineering ranked electrification as the greatest engineering achievement of the 20th century, surpassing spacecraft, the Internet and computers, and agricultural mechanization.

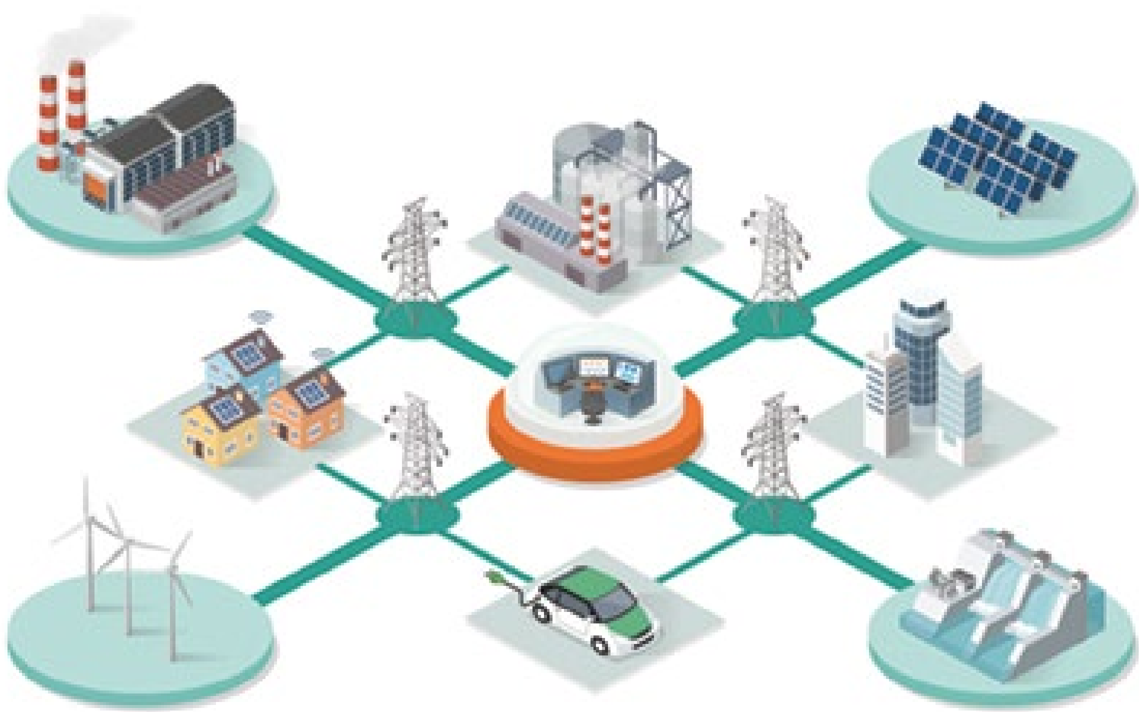
For the emerging power system to meet reliability and power quality expectations, DERs must provide grid support. For instance, DERs must be able to provide voltage support. "There are a group of active and reactive power-based smart inverter functions that are meant for grid voltage support," Huque said.

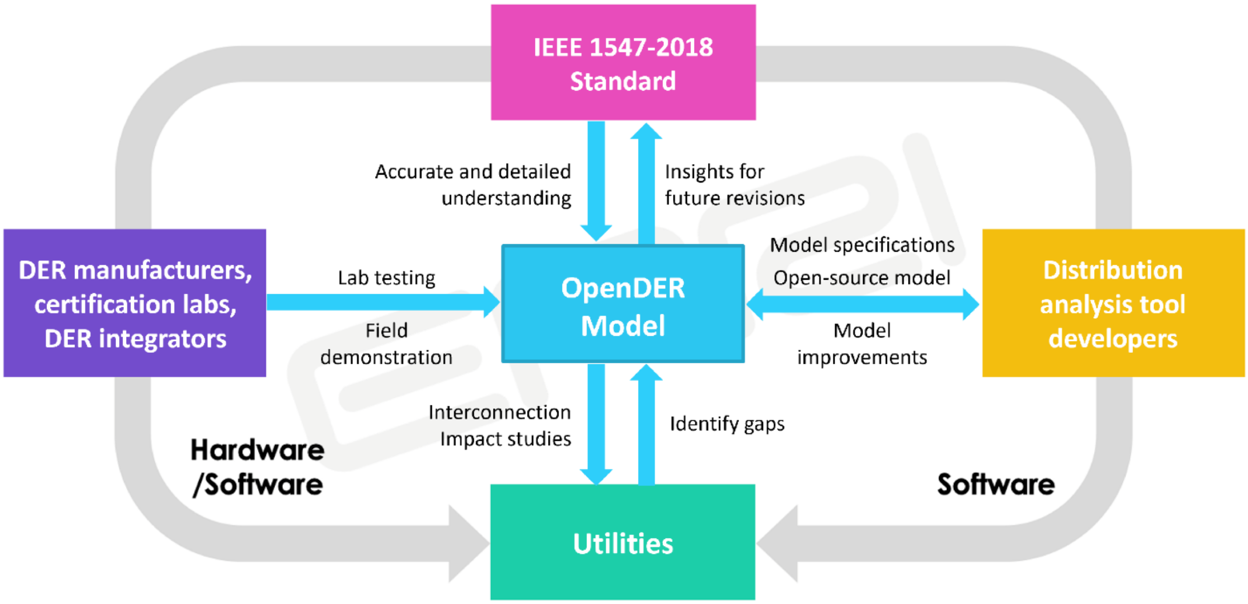
For example, smart inverters provide volt-var and volt-watt controls to ensure the distribution system doesn't experience voltage limit violations or excessive variation. DERs connected to the power system must also be able to continue operating (also known as ride-through) during a momentary voltage or frequency disturbance.

"In the past, if you had a disturbance, you wanted the DER to disconnect," said Yiwei Ma, an EPRI engineer in the DER integration research area. "That is not acceptable any longer. Now, if you have a disturbance for a few seconds and then everything is fine, you don't want millions of DERs to shut down." DERs also need to support the grid by increasing or decreasing their power when the power system's frequency fluctuates, a function known as frequency watt or frequency droop.

AN IMPORTANT STANDARD EMERGES

For years, the industry has been developing standards that ensure that DERs interconnecting to the grid meet specific requirements. That process began in 2003 with the release of IEEE Standard 1547. The standard has since evolved, with amendments in 2014 and recently in 2018, when a new edition of IEEE 1547 was published.





IEEE 1547-2018 has several significant additions and modifications, many of which are designed to ensure that DERs can provide grid-support functions like volt-var control and ride-through capabilities. Even before IEEE 1547-2018 was rolled out, states like Hawaii and California—both of which have seen significant DER growth sooner than other states—began requiring grid-support functions for DER interconnections.

Today, utilities and public utility commissions (PUCs) across the country are preparing to mandate that new DERs being interconnected comply with IEEE 1547-2018 and meet appropriate certification standards, like UL 1741SB. “As the certified inverters are starting to become available in the market, utilities are getting ready to make the new standard mandatory this year,” Huque said.

The rollout of the latest version of the standard also significantly impacts what utilities need to consider in their DER interconnection studies. These studies examine whether the approval of DER interconnecting at a specific grid location will negatively impact the power system. For very small DER, the analysis is quick and streamlined. But for larger DERs, more in-depth modeling and analysis are required.

When a potential negative impact is identified, interconnection studies also present possible solutions to solve the problem. In some instances, the solutions to address negative system impacts can be expensive, like reconductoring, changing the protection devices in place, or even swapping out transformers to allow for interconnection. These higher costs are then passed on to the DER owner. The stakes of interconnection studies, then, are very high. “The study determines if there is a problem or not,” Ma said. “If there is a problem, it also determines the solution and the cost of the solution. That is why these studies are critical and why their accuracy is so important.”

ENSURING MODELS ACCURATELY REPRESENT DER GRID SUPPORT CAPABILITIES

But here’s the challenge: Manufacturers, utilities, researchers, consultants, and software developers used to conduct DER interconnection studies need to understand and utilize the IEEE 1547-2018 requirements accurately. After all, interconnecting DER with appropriate grid support capabilities that alleviate potential grid problems can be far cheaper and quicker than infrastructure upgrades.

The only way to know that is for all stakeholders to interpret the standard uniformly. “Our vision is to ensure across the industry that utilities and product and software developers who are all pointing to this standard aren’t working in silos,” Huque said. “We want to make sure they are interpreting the standards in the way they were developed or agree to the interpretation if something is not clear. That way, when simulation tool vendors develop or update models, the behavior assumed in the simulations and studies will match how actual products behave in the field."

Past EPRI research highlighted inconsistencies in the models the industry relied on. More specifically, the model verification work examined whether existing models complied with the IEEE standard. Gaps and missing features that may impact the accuracy of the interconnection studies were identified.

To drive the consistency necessary for accurate DER interconnection and planning studies, EPRI recently released an open-source distributed energy resource model known as OpenDER. At its core, the OpenDER model represents the functional definitions and requirements of IEEE 1547-2018 to analyze both the dynamic and steady-state behaviors of DERs. The release includes the OpenDER model software implemented in Python programming language that utilities and other stakeholders can use immediately. EPRI also released a document with the model's underlying specifications and equations.

"Through this work, we are providing a detailed model specification that any software developer or consultant, or academic can review and implement in their own model. Or they can use our whole model or part of it," Ma said. "Regardless of what they use, we want to make sure that utilities, software developers, consultants, and others have a model that correctly represents the products that are being designed and certified following IEEE 1547-2018."

LEVERAGING RESEARCH EXPERTISE AND UNDERSTANDING OF THE STANDARD

As a key contributor to the development of the IEEE 1547-2018 standard and with a legacy of experience testing smart inverters in the laboratory and field, EPRI is well suited to lead the development of an open-source DER model and bring together stakeholders to build consensus.

As part of the development of OpenDER, EPRI has also conducted lab tests of inverters certified to IEEE 1547-2018 to validate that the model accurately reflects product behavior. "Because of our prior industry engagement to define smart inverter function definitions and our continued involvement in the standard development, coupled with years of field demonstrations, we are in a position to help the industry with a model that can be used as a benchmark or as an actual model," Huque said. "In collaboration with the industry, we want to make this model the gold standard."

That is also why EPRI launched the DER Model User's Group (DERMUG) soon after OpenDER was released. Just as the model itself was designed to unify and harmonize the understanding of IEEE 1547-2018, the user group provides a forum for stakeholders that may not normally interact to share feedback and insights about OpenDER and about the interpretation of the standard. The learnings will also be used for the next standard revision, which began in January.

Introductory DERMUG meetings attracted hundreds of participants who wanted to learn more about the OpenDER model. Since then, DERMUG has hosted meetings every two weeks to solicit industry feedback on the model's details and to communicate potential improvements.

"We are already making improvements to the model," Huque said. "We have a version one of the models done and reviewed by the user group, and we plan to release version two early in 2023. Moving forward, we will continue to take user group feedback and lab test results until we are confident that we have done everything possible to ensure the model is accurate."

Ultimately, the real value of OpenDER is to ensure that all the models used for interconnection and planning studies can accurately represent the power system impacts of IEEE 1547-2018 compliant DERs. "This will ensure all the studies are done according to the standard and the products being tested so that whatever impact we are seeing is correct and whatever solution we come up with using grid support matches the actual product," Huque said. "Hopefully, that will help have more efficient interconnection and sometimes reduce the cost and time of interconnection."

EPRI TECHNICAL EXPERT

Aminul Huque, Yiwei Ma

EPRI JOURNAL

Rapid Response Research

How EPRI and four member utilities fast-tracked research in response to a court decision about coal combustion products (CCPs)

By Chris Warren

The vast majority of coal plants in the United States were built between 1950 and 1990, including a burst of construction from the early 1970s to the mid-1980s. For much of the time when new coal plants were being built, few special precautions were implemented to ensure that the byproducts that come from burning coal—including fly ash, bottom ash, and boiler slag, collectively known as coal combustion products, or CCPs—didn't contaminate groundwater.

"Back then, coal ash was sometimes managed like an inert material," said Bruce Hensel, an EPRI Technical Executive, who has done extensive research about the most effective ways to protect groundwater from contamination by CCPs. Those past management practices sometimes resulted in landfills and impoundments that were built without any extra protective lining to ensure that trace elements like arsenic, boron, and selenium or soluble salts like calcium and sulfur found in CCPs couldn't leach into nearby groundwater.

The industry has made great strides over the past decades to protect groundwater and pursue many of the beneficial applications that CCPs are used in today, from cement to wallboard, to agricultural applications. When you build a landfill or any structure designed to contain a waste material today, whether it's coal ash or municipal waste or radioactive waste, modern construction standards include liners and leachate collection systems so that leachate cannot escape into the environment," Hensel said.

A COURT CHALLENGE UPENDS CCR RULE

In 2015 the U.S. Environmental Protection Agency (EPA) issued the CCR[1] Rule to govern the disposal of CCPs. As part of the rule, the EPA completed a risk assessment that showed composite liners—which combine a geomembrane barrier over compacted clay—are the most effective tool for preventing the release of CCPs leachate to groundwater.

But the 2015 CCR Rule also allowed for the use of alternate liners, such as those made with compacted and natural clay, so long as they demonstrated their ability to prevent groundwater contamination. Put simply, while the rule made it clear that the EPA considered composite liners best, the regulators allowed for the use of alternate liners that performed equally well.

Since it was first issued, the EPA's CCR Rule has been the subject of a series of litigation. One of the lawsuits resulted in a 2018 decision by the District of Columbia Circuit Court declaring that any impoundment holding CCPs that didn't have a composite liner had to close. For some utilities, this blanket-statement court ruling meant the imminent closure of CCP impoundments that had been operating effectively using alternative liners.

A RAPID RESPONSE

That was exactly the dilemma the Arizona utility Salt River Project (SRP) faced. SRP had long operated an evaporation pond that held all the non-recyclable wastewater produced at its 762-megawatt Coronado coal plant. After the EPA's CCR Rule was issued in 2015, SRP determined that the natural clay liner in place at the evaporation pond was compliant with the new regulation.

"When the CCR rule came out, impoundments could continue to receive CCRs unless they leaked. We never had a leak at the evaporation pond or any indication that the clay liner wasn't holding up," said Kent Liesemeyer, senior environmental compliance engineer for SRP, whose work focuses on water quality and waste management related to CCPs.

In fact, SRP determined that the existing natural clay liner—which was formed naturally 200 million years ago—was an important part of the utility's ability to responsibly store CCP that couldn't be used to improve other products, like concrete and asphalt. "The hopes were that Coronado would operate as long as needed, and all the coal ash would be beneficially reused, and that the evaporation pond would be closed as an ultimate and permanent CCR disposal facility for the plant. This is because the natural geological environment at the site is very good at containing the CCR and protecting human health and the environment over the long run."

SRP wasn't the only utility that felt strongly that the ruling of the D.C. court ordering the closure or retrofit of any facility lacking a composite liner didn't adequately consider the effectiveness of other alternatives. At an EPRI sector meeting just one month after the court ruling, SRP joined Great River Energy, Consumers Energy, and DTE Energy Company to initiate research that analyzed the effectiveness of impoundments using alternative liners.

Traditional EPRI projects take time to gather interest and funding before proceeding to the actual research and publication of a technical report. That methodical schedule was not an option in this case. "We had a group of advisors come together at our sector meeting who said we need something to respond to the EPA," Hensel said. "So, we pulled together this collaboration where they kicked in some money, and the research program kicked in some money, and we fast-tracked it."

EPA INCORPORATES RESEARCH FINDINGS

By February 2019, just five months after the advisory meeting and six months after the court decision, EPRI had results to share. To do the research, EPRI used the same risk assessment model that EPA had used to support its 2015 CCR Rule, albeit with modifications that allowed for analysis of the effectiveness of alternative liners. In advance of the modeling work, member utilities helped collect data and develop scenarios to model. For example, it was important for SRP to evaluate the effectiveness of different variations of natural clay liners.

Even before the research was completed, EPRI met with EPA to alert the regulators that an assessment of alternative liners was underway. By June 2019, a final report detailing the research results was complete and submitted to EPA for consideration as it formulated a rule that reflected the court's decision.

[1] USEPA used the term "coal combustion residual (CCR)" to refer to the same materials that EPRI calls CCPs. EPRI uses the CCP term to recognize the value that these materials have when beneficially used.

Photo courtesy: Salt River Project

Among the most notable findings of the research was that certain alternative liners—including thick natural clay liners and non-federally compliant composite liners—could be as protective as composite liners. When the EPA published its final Part B rule in October 2020, it cited EPRI's research as supporting the case that alternative liners can be acceptable under certain circumstances.

The EPA rule didn't specify which alternative liners would be acceptable. Instead, it issued performance standards alternative liners had to meet and provided a regulatory mechanism for operators of impoundments to submit applications for continuing the use of alternative liners.

RESEARCH VALUE

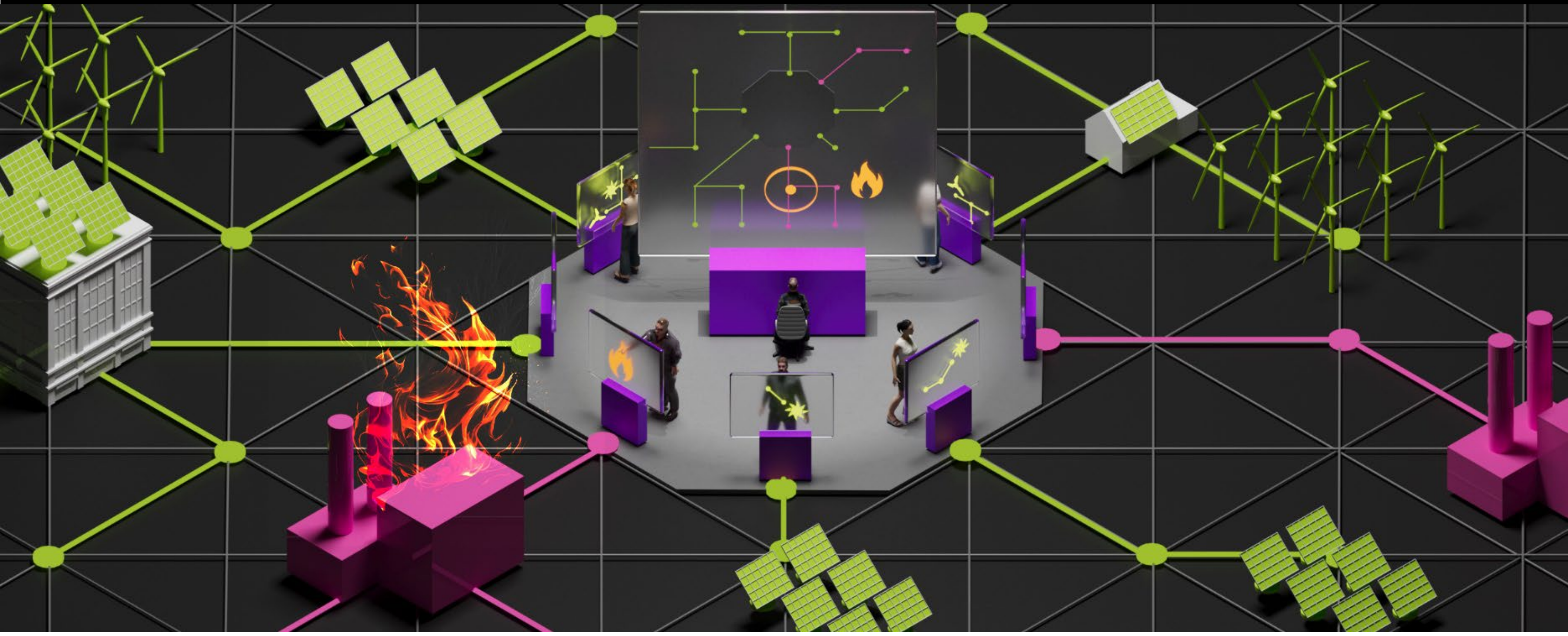
Eventually, eight companies submitted applications to use alternative liners to the EPA. Two companies withdrew their applications, and the remaining six applications were proposed to be denied by the EPA in January of 2023.

SRP was one of the companies whose application for the use of a natural clay liner EPA has proposed to deny. To support its continued use of the natural clay liner, SRP hired a consultant to drill holes every 200 feet around the 330-acre impoundment. "We wanted to further characterize what was below the ground from the surface down to the uppermost aquifer," Liesemeyer said. "One thing that couldn't be modeled in the EPRI approach was the time it takes water to penetrate the liner. When the liner is 225 feet thick, it takes a substantial amount of time."

SRP is disappointed that EPA has proposed to reject its application for continued use of the alternate liner and is planning to submit robust comments contesting EPA's proposed denial. But Liesemeyer does not question the value of collaborating with EPRI and other member utilities to evaluate the effectiveness of alternative liners. "The speed of response was a big help because it gave us a data and science-driven understanding of the solution we had in place already," Liesemeyer said. "We thought it was a wise investment to characterize that and find out what we really had in place, and the modeling by EPRI was valuable for us and tended to confirm everything we understood about the site."

EPRI TECHNICAL EXPERT

Bruce Hensel



Distribution Control Center 2.0

Operating a reliable distribution system is more complex, challenging, and important than ever before. EPRI research is identifying and sharing the skills operators need to do it well.

By Chris Warren

Public policy, regulations, and technology developments often dominate discussions about the ongoing and rapid transformation of the power system. Incentives and mandates that flow out of state renewable portfolio standards and the recently passed Inflation Reduction Act are big drivers of demand for commercial and residential purchase and interconnection of distributed energy resources (DERs), such as rooftop solar and battery energy storage. Advances in the performance and availability of technologies like electric vehicles (EVs) and heat pumps also attract attention.

Often, market forecasts and the deliberations of state and federal legislators and regulators can come across as abstract and removed from the daily responsibilities of utility workers. But there is nothing abstract about the significant impact the transition to a more decentralized and decarbonized grid will have on the role of distribution system operators. Increasingly, utilities understand that they must proactively equip control room staff with the skills and technologies necessary to operate a resilient, complex, and ever more important distribution grid.

A ROLE TRANSFORMED

To understand the velocity of change and increased complexity that distribution control center operators face today, it's helpful to remember that their past responsibilities were important but straightforward. Often referred to as dispatchers, operators responded to customer outages by directing crews to perform repairs and get service back up and running. The tools necessary to perform that task were far from high-tech.

"Historically, operators worked off a paper map with a one-line diagram that had a very simplified expression of the distribution system with enough details for the operator to direct a crew to an address or a device to do their repair work," said Nick Heine, an EPRI technical leader and co-author of the recent EPRI report *Distribution Operational*

Planning: Expanding the Capabilities of a Modern Control Center. "Dispatchers usually came from a career in field operations, and their job was to ensure safe and reliable service for utility customers."

At its core, the mission of distribution operations today is the same as it always has been. But the dramatic and accelerating transformation of the distribution system is fundamentally redefining the skills operators must possess to do the job well. For example, deployments of DERs are quickly growing. The research firm Wood Mackenzie forecasts that cumulative DER capacity in the U.S. alone will reach nearly 400 gigawatts by 2025. This influx of solar, batteries, and other DERs can substantially benefit the distribution grid. For example, the operation of DERs in aggregate may help meet peak demand, and their interconnection may delay or eliminate the need for expensive grid upgrades.

But DERs can also pose a challenge for distribution operators. A large concentration of DERs on a feeder, for instance, has the potential to negatively impact power quality and threaten safe voltage and frequency limits. Distribution operators are also increasingly charged with optimizing grid reliability and safety by using the massive volume of data utilities collect. For instance, the U.S. Energy Information Administration (EIA) reported that 111 million smart meters had been installed in the U.S. at the end of 2021. Any distribution control center would be challenged to make sense of all the data produced by sensors, smart meters, and DERs.

NEW TOOLS: MORE INSIGHTS, MORE COMPLEXITY

New tools have emerged to help distribution operators with tasks such as managing the two-way power flows of DERs and ensuring feeder-level safety and reliability. Instead of one-line diagrams, for instance, many utilities have adopted distribution management systems (DMS) that digitize their view of the distribution grid and provide a range of new capabilities.

"You can now have measurements from the SCADA [supervisory control and data acquisition system] at the substation that might show volts and amps at a specific location," said Lindsey Rogers, who runs EPRI's distribution operations and planning research program. "Many operators are working with a DMS that has a full-blown electrical model that allows them to run sophisticated analysis and have a dynamic view of the distribution grid."

Other tools have also emerged with the potential to help operators manage an increasingly complex distribution system. DER management systems (DERMS) provide operators with the visibility and control needed to dispatch and curtail DERs to both maximize their grid reliability and decarbonization benefits and allow more assets to be interconnected to the distribution system. Distribution automation devices also autonomously control switches on the grid, replacing the historical practice of dispatchers calling field crews to manually operate the switches.

At one level, the rapid change driven by digitization and automation can be seen as lessening the responsibilities and workload of operators—a belief embraced by some utility decision makers. “There are senior managers at utilities who think that automation and management systems make things easier for operators and that they need fewer people,” Rogers said. “What we are seeing, with all of the distribution system changes, is that the rubber meets the road with the operators. These changes require that operators have a new skill set and role in how the system is being managed on a day-to-day basis.”

THE NEED FOR DISTRIBUTION OPERATIONAL PLANNING

Through its research and collaboration with members, EPRI is working to identify the skills and roles needed in a modern distribution control center. EPRI is also developing training and courses provided by EPRI|U to ensure that utility personnel acquire the necessary skills.

One important new role is distribution operational planning. Operational planning is already a common job in transmission operations, where planners make decisions to prepare the grid to operate reliably in the near and longer term. Among the tasks of transmission planners are scheduling maintenance and repair work so as not to impact system reliability, assessing risks associated with forecasted grid conditions, and coordinating with neighboring grid operators and distribution utilities.

Distribution control centers traditionally haven’t needed in-house planners. But that has changed. “Operational planners are a bridge between real-time operations and the planning and protection groups that do technical analysis,” Heine said. “As we make the distribution system more dynamic and automated, we need engineering support in the control center, which has recently been provided on an ad hoc or on-call basis. Now distribution control centers need dedicated staff to provide engineering support around the clock.”

Tools like DMS and DERMS rely on accurate and continuously updated distribution system models. To be effective, distribution operational planners will need to be able to create and maintain these models. “Building and maintaining electrical models requires a lot of resources. Traditional planners have the benefit of time and can take three months or a year to run studies and propose grid upgrades,” Heine said. “But operators have three minutes or 30 minutes to make a decision, which is why it’s so critical to have up-to-date models.”

FAST DECISIONS IN A DYNAMIC ENVIRONMENT

Updated and accurate models paired with the right skills can empower operators to navigate the complexities of a modern distribution system. For instance, traditional DER interconnection studies present a picture of the grid under typical conditions. But changes such as the ability to participate in wholesale markets made possible by Federal Energy Regulatory Commission (FERC) Order

2222 mean that DERs will increasingly be operating under abnormal conditions. For operators, the influx of DERs and their participation in wholesale markets require hosting capacity analysis that considers short-term generation and load forecasts.

The ability to respond to quickly changing conditions will be essential to maintain grid reliability. "It's about taking some of the roles of the planning department and bringing them into the real-time environment of the control center," Rogers said. "It's not second by second, but a day ahead or a week ahead, and having the skills in the control room to do loading assessments and evaluate if the grid can handle EV charging or heat pumps. That is critically important so that operators can make decisions to help customers and avoid outages."

EPRI's work to provide the skills modern distribution system operators need is ongoing. Already, EPRI|U offers several online courses that delve into topics like volt/var management and DMS training. This year EPRI is investigating the training and testing that would be required to provide certification that operators have the necessary skills and competencies—a step that would drive consistency across the industry. And later this year, EPRI will release a white paper that defines the operator skills and control center capabilities to meet the requirements of FERC Order 2222.

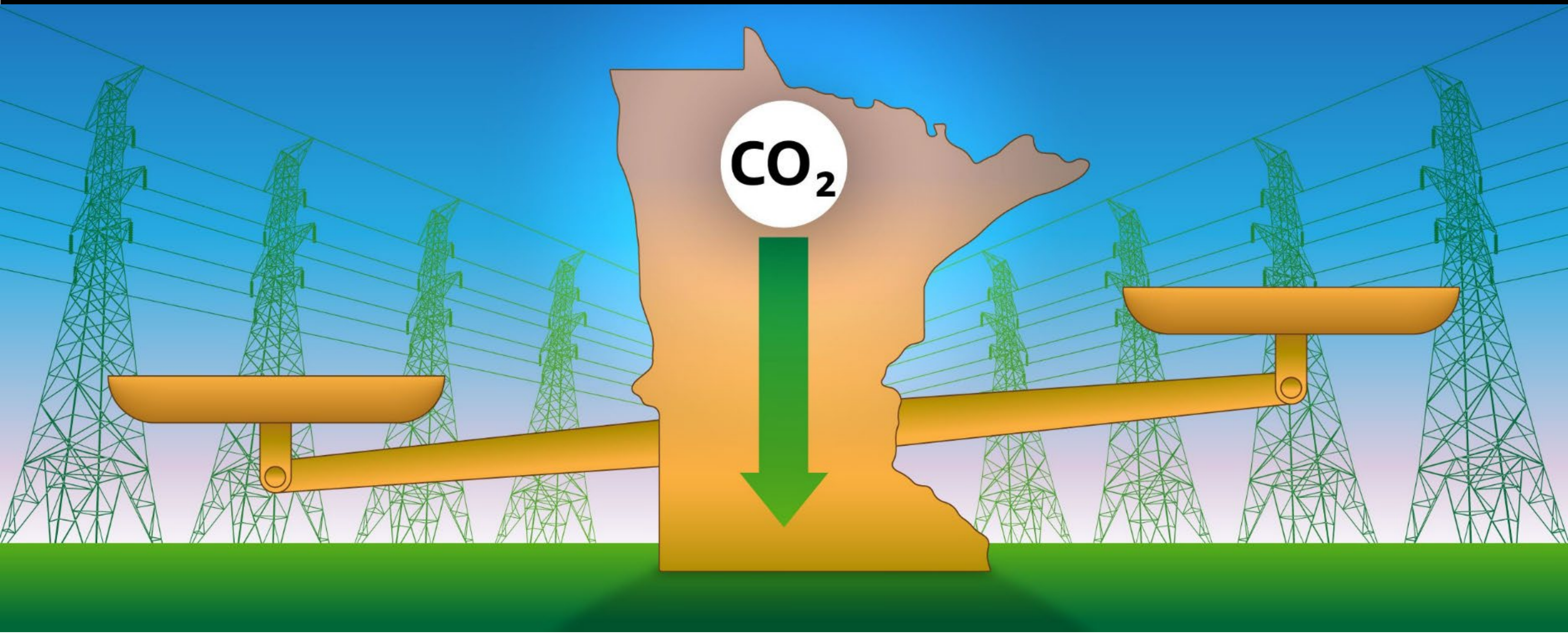
Ultimately, the goal of EPRI's work in this area is to support the training and knowledge needed for utilities to keep pace with distribution system changes. "The rate of change in the distribution system with customer and utility adoption of technologies is so fast that the current operators can't keep up," Heine said. "We are addressing that issue by identifying the skills and tools that will benefit utilities. And it's a two-sided coin. Technology adoption challenges utilities, but it also presents a big opportunity. The intersection of those two is where operational planning can benefit the industry."

EPRI TECHNICAL EXPERT

Nick Heine

ADDITIONAL RESOURCES

- Modernizing Distribution Control Center Operations: Evolving Operator Roles and Responsibilities



Decarbonization in Minnesota

EPRI modeling evaluates potential decarbonization strategies for Minnesota

By Chris Warren

At the beginning of 2023, Minnesota passed legislation requiring the state's utilities to use 100 percent carbon-free electricity by 2040. With the law's passage, Minnesota joined many other states—including California, Nevada, and New York—that have put decarbonizing the electric sector at the center of their strategies to reduce greenhouse gas emissions. The law also raised many practical questions about how utilities will reach the mandates and elevated the importance of fully grasping potential impacts on costs, technology options, and possible effects on sectors beyond the electric power industry.

Before Minnesota's new legislation became law, EPRI collaborated with Minnesota utility Great River Energy (GRE) to model and analyze potential energy system transitions under different decarbonization pathways, including a zero-emitting electric power sector, in 2040. "When we started the project, the policy landscape in Minnesota was uncertain," said Steven Rose, a principal research economist at EPRI whose work focuses on long-term modeling of socioeconomic systems and climate change impacts. "It was clear that some sort of more aggressive renewables policy was likely, but beyond that was unknown." However, even before the law passed, GRE was already on a trajectory to reduce carbon dioxide emissions by 80 percent by 2030.

One of the three policy scenarios modeled in the report, *Opportunities for Decarbonizing Minnesota's Economy: Energy System Supply and Demand Assessment*, was full decarbonization of the state electric sector by 2040. The other two policies modeled were an 80 percent economy-wide reduction in emissions by 2050 and an increase in renewables to 50 percent by 2050.

EPRI also worked with GRE on a *Minnesota Efficient Electrification Study* to evaluate the potential deployment of electric technologies in the state's buildings, transportation, and industrial sectors. The analysis was built on years of effort by GRE to educate the cooperative's members about the potential benefits of electric vehicles (EVs), including buses and forklifts, as well as air source heat pumps.

"What we found was that air source heat pumps can significantly reduce the consumption of propane in homes and enhance the economic benefits of the technology while reducing exposure to price volatility during peak demand periods," said Jeffrey Haase, GRE's director of member services and end use strategy. "One of the reasons we participated in the assessments was to inform our strategic priorities and evaluate the long-term impacts to the grid and our load curve."

For example, Haase said that one area of interest for GRE was expanding flexible load capabilities. "How do we continue to build on our legacy of load management capabilities and expand load flexibility as we see increased adoption of electric technologies such as electric vehicles and heat pumps?" Haase said. "Within the energy system modeling, we see some load dynamics as we shift into electric space heating coupled with electric transportation that could lead to significant increases in peak demand in the winter in our area. What types of programs can we develop to preserve or enhance flexibility?"

Both the electrification study and the policy scenario modeling may have an impact on utility planning. Zac Ruzycki, the director of resource planning for GRE, describes the work his group does as mainly focused on a period of five to 20 years in the future, including planning for generation assets and forecasting load, to renewable energy acquisitions and contracting.

Assessments of potential load growth, seasonal changes to peak demand, and load shape obviously have a big impact on planning. "This is a great first step to have the conversation about what you need for this big electrification buildout," Ruzycki said. "These are new challenges we are facing, and this type of analysis will be important to ensure we have the right resources to meet our policy and portfolio goals."

Findings from the electrification study reinforce both the importance of planning and some of the uncertainties. For example, there is high potential for the electrification of light-duty vehicles, although the timing and speed of EV adoption is unclear and depends on numerous factors. Similar potential and unknowns surround medium and heavy-duty EVs, which are currently in their infancy but could develop fast.

Non-road transportation equipment is currently viable for many customers in Minnesota, and many new technologies are being developed. "We are comfortable modeling residential electric vehicle uptake scenarios," Ruzycki said. "However, there is still much uncertainty in understanding how fleet electrification and the trucking industry can change demand and energy forecasts amongst our member-owners. We need to understand these areas of study more as they hold the potential for significant demand increases."

MODELING THE IMPACT OF POLICY CHOICES

To evaluate the potential decarbonization, electrification, and economic impacts of the three different policies, EPRI utilized a version of its U.S. Regional Economy, Greenhouse Gas, and Energy (US-REGEN) model. The US-REGEN model provides insights into how various policies and regulations, market dynamics, and technology innovations can affect and shape energy industry fundamentals, including greenhouse gas emissions, investments in low-carbon electricity resources, and the price of electricity.

EPRI used US-REGEN to conduct the 2018 U.S. National Electrification Assessment. It has since applied the model to analyze electrification uncertainty and opportunities in Georgia, Alabama, New York, California, and Pennsylvania and recently to help evaluate decarbonization opportunities and risks in Wisconsin. It's important to note that the findings of the modeling aren't forecasts or predictions. Instead, the modeling allows for exploring a wide range of decarbonization transitions. This includes evaluating how different potential policies and other conditions affect energy systems, economic and environmental outcomes, such as natural gas and EV battery prices, and the permissibility of low-carbon electricity imports from nearby states.

The modeling and findings from the Minnesota study are particularly relevant now that the state has established a new carbon-free standard. Some of the main takeaways from the analysis could inform a more impactful and cost-effective implementation. Supporters of the new law have clarified that decarbonization to address the negative impacts of climate change is the legislation's primary objective.

In that regard, EPRI's modeling indicates that a policy to decarbonize the Minnesota electric sector could result in more statewide emissions reductions than would be achieved by increasing renewables by 50 percent by 2050, which was another policy EPRI modeled. Nevertheless, the modeling also compared emissions reductions from electric sector decarbonization and those associated with a policy of 80 percent Minnesota economy-wide CO_2 reduction. The result is that the 80 percent Minnesota economy-wide CO_2 reduction policy had deeper emissions reductions than electric sector decarbonization.

POTENTIAL COST IMPLICATIONS

The modeling also evaluated potential policy choices that could affect electricity prices and environmental outcomes, as well as the cost-effectiveness of the carbon-free electric sector policy. One potential impact of independently decarbonizing Minnesota's electricity is an increase in customer costs. According to the U.S. Energy Information Administration, Minnesota's residential customers pay an average of just over 14 cents per kilowatt hour, below the U.S. average of 15.6 cents. A policy that requires all electric generation in Minnesota to be carbon-free by 2040 can have the potential to put upward pressure on electricity prices.

"When emissions reduction requirements are applied to the electric sector, the price of electricity increases because it is more expensive to produce electricity," Rose said. When prices for anything go up, consumers tend to adjust their behavior. In EPRI's analysis, that's exactly what happened, with customers substituting away from electricity in favor of other, more affordable fuels. The result: While electric sector emissions may be eliminated, the potential for customers to use more fossil fuels for heating, transportation, and other end uses could mean an increase in emissions in other sectors of the Minnesota economy.

THE IMPORTANCE OF A HOLISTIC APPROACH

The modeling also highlighted how a more holistic policy that included incentives for customers to use decarbonized electricity could avoid fuel switching and the higher emissions that accompany it.

EPRI's modeling of an economy-wide Minnesota decarbonization policy found a significant increase in the use of low-carbon electricity, not a decrease. "That was the cost-effective way to decarbonize the entire economy," Rose said. "That result, however, depended on the availability of incentives to reduce and avoid emissions in the rest of the economy."

There are myriad ways to incentivize greater use of carbon-free electricity for transportation, heating and cooling, manufacturing, and other end uses. One approach is to adopt policies that directly or indirectly price emissions from those activities. Yet another is to constrain those emissions. And yet another is to facilitate the adoption of electric technologies like EVs, heat pumps, and electric forklifts.

The mix of incentives can vary, but the main point is to disincentivize emissions and facilitate consumers' identification of the lowest-cost emissions reduction strategies for society—which is challenging when policies only decarbonize the electric sector. This is especially true now that Minnesota's transportation emissions are greater than those in the electric sector. "There's a tendency to try to decarbonize the electric sector first," Rose said. "Doing that without providing the incentives to use more expensive low-carbon electricity will make it harder on end use customers who may simply be confronted with higher electricity prices."

POLICY DETAILS CAN HAVE A BIG IMPACT

Past EPRI research has also demonstrated the potential unintended impacts of policies focusing on electric sector decarbonization alone. For example, EPRI examined the possible effects of a regional approach to electric sector decarbonization. Like the Minnesota modeling, the analysis found that higher-priced carbon-free electricity could raise emissions in other parts of the economy and result in higher emissions inside and outside the region. "Because of the interactions of power markets with the rest of the economy and between regions, we found emissions leakage inside and outside of the region where we implemented an electric sector emissions policy," Rose said. "The recent Minnesota analysis, and the earlier study, highlight the policy coordination challenges and the importance of developing holistic policies."

The Minnesota modeling also highlighted the importance of the specific details of electric sector decarbonization policies. For example, the type of generation technologies allowed to meet capacity reserve requirements can significantly impact costs. In the Minnesota analysis, for instance, allowing gas turbines to satisfy capacity reserves was found to be cheaper than completely prohibiting any capacity that produces greenhouse gas emissions. "If you take away the capacity reserve opportunity for emitting resources, like a gas turbine, complying with the policy could be significantly more expensive for utilities and customers," Rose said. "It is certainly worth considering letting gas turbines be available as reserves. They would not be used often, the emissions would be modest, and they could help substantially with managing the costs of a low-carbon transition."

Another factor that could have a meaningful impact on the price of electricity and policy costs under a zero-carbon electric sector policy is whether the policy allows carbon-free electricity to be imported from outside the state. The modeling indicates lower electricity prices and policy costs in Minnesota when imports are allowed.

GRAPPLING WITH UNCERTAINTY

Though the modeling provides insights into potential cost impacts and emissions reductions for different policies, it also demonstrates how much uncertainty there is in the future evolution of Minnesota's energy system, even with the new policy. A big uncertainty for Minnesota utilities is what will happen next regarding climate policy. Will other policies incentivize decarbonization in the rest of the state's economy and facilitate the cost-effective use of low-carbon electricity? What sectors will be targeted, when, and what will the incentives look like?

Other factors also contribute to uncertainty, including the future trajectory of natural gas and EV battery prices. For example, when higher future gas prices are modeled under the decarbonized electric sector policy scenario, the use of gas decreases, and generation from wind, solar, and nuclear power increases. Higher battery costs, by contrast, lead to significantly lower load and slower growth in capacity additions and generation.

In other words, the power system could change in dramatically different ways under equally plausible scenarios. "From a planning point of view, that's real uncertainty," Rose said. "Utilities are being told to do things, but it is not absolutely clear how the future will unfold, and utilities need to account for that." This becomes a risk management problem for utilities. "These uncertainties represent a real risk for decisions now for current assets and potential new investments," according to Rose.

In response to that uncertainty, EPRI has since initiated other projects aimed at helping utilities like Duke, Entergy, Ameren, Alliant, and WEC Energy Group develop tools to assess and manage climate-related risks, including low-carbon transition risk. This involves identifying the conditions associated with higher and lower-risk outcomes. "In the case of Minnesota, end use decarbonization policies that provide incentives for using low-carbon electricity, as well allowing the use of gas turbines for capacity reserves, are examples of policy design choices associated with a less risky outcome," Rose said. Risk assessment and management also involve identifying elements of the transition to decarbonized energy that are robust and occur in all plausible futures, such as a minimum level of wind and solar generation additions.

The risky conditions represent opportunities for action. "We can identify what can be done to facilitate less risky and more cost-effective outcomes for society. That could be research and development (R&D). It could be conversations with stakeholders regarding enabling policy conditions or collaborations with customers to coordinate strategies," Rose said. "Internally, the analysis insights become information that helps inform planning decisions. There are other important criteria like reliability that will, of course, also have to be considered, but the modeling helps evaluate and address transition uncertainty."

EPRI TECHNICAL EXPERT

Steve Rose

How Plant Assessments Improve Performance

EPRI and Korea South-East Power Corporation (KOEN) partner to reduce power plant outages, save money and develop a tool to improve plant performance across the industry

By Chris Warren

Like any power plant operator, the utility Korea South-East Power Corporation (KOEN) is always looking to optimize the operations of its 10,000-plus-megawatt fleet to ensure safety, efficiency, and as few unplanned outages as possible. According to Soomin Kim, senior manager of KOEN's research and technology team, the utility has traditionally done a good job ensuring its five power plants integrated the best operations and maintenance (O&M) technology.

But Kim has long seen opportunities to improve how KOEN conducts plant assessments. These assessments are a key step in improving O&M because they provide an objective appraisal of how a power plant is operated and maintained in comparison to industry best practices. "In Korea, there was no objective and credible evaluation guideline to evaluate and grasp the current [best practices]," Kim said. "While searching for various methodologies, I came across EPRI's O&M Assessment Guideline."

Kim's initial discovery of the guideline in 2015 spawned an eight-year collaboration between KOEN and EPRI aimed at developing and instituting a formalized approach to assess the utility's O&M performance and continuously improve it. The results underscore the value of the partnership. For example, in 2015, KOEN's forced outage time per unit across its fleet was 13.6 hours. By 2020, forced outage time had plummeted to 3.2 hours per unit. This O&M improvement also has quantifiable financial benefits: Avoiding the loss of revenue and restart costs associated with outages has saved KOEN an estimated $2.7 million.

A TOOL TO IMPROVE PLANT ASSESSMENTS

The collaboration with KOEN also prompted EPRI to develop a web tool that can be used to perform O&M assessments – a product that has benefitted other EPRI members. "When this first got started, EPRI would go do a plant assessment and, based off their best practice knowledge, they would give a report to the utility about what we thought they could do better," said Dwayne Coffey, program manager of Plant Management Essentials at EPRI, who has worked directly with KOEN. "For this, KOEN wanted scoring for the assessment criteria, so we had to develop a tool that had formalized scoring for industry best practices to do an assessment."

The development process involved leveraging existing EPRI O&M research and staff expertise to create an electronic tool to guide a thorough, step-by-step plant evaluation. "I sat down and talked to the EPRI subject matter experts who had been doing these individual assessments. We needed to document what they were looking at," Coffey said. "Then we developed formal assessment criteria for power plant operations, maintenance, and the overall plant."

For example, the assessment examines a plant's procedures for lockout and tagout to ensure that it consistently and adequately protects workers performing plant maintenance from dangers such as high temperatures, pressures, or exposure to electricity. The assessment tool also looks at whether there is a standard procedure for shift turnovers, including whether they include meetings to make incoming workers aware of any potential problems to monitor. The range of assessment topics is wide and includes whether staff are using personal protective equipment (PPE) or if the plant has emergency action plans in place.

For each of the areas being assessed, the tool prompts the assessor to deliver one of four ratings:

- Inadequate, meaning the plant does not meet the industry's best practice
- A marginal rating is given when the plant meets only some of the industry's best practices but could still improve
- A successful rating indicates the plant meets the industry's best practice
- And an exceptional rating is awarded when the plant exceeds the industry's best practice

The O&M tool allows those who are conducting an assessment—it could be EPRI staff, utility personnel, or both—a simple and consistent way to record their observations about how a plant is performing. "You have all these power plant industry best practice criteria. So as an assessor, you click on the criteria and add an observation you have made in the power plant," Coffey said. "The person doing the assessment would then enter one of the ratings for each of the criteria: inadequate, marginal, successful, or exceptional."

All the observations and ratings are then collected to produce an overall assessment of the plant's O&M operations. The assessment results can then be used to generate reports and charts that make it simple to communicate which areas in a plant are performing well and which need improvement. When EPRI engages with individual utilities to perform assessments, another deliverable is a final written report that includes strengths, areas for improvement (ranked by importance) with recommended corrective actions, and all observation entries and pictures.

STEADY IMPROVEMENT AT KOEN

EPRI developed its O&M assessment tool as it collaborated with KOEN and continues adding new features to the tool. For instance, the tool now has a feature that allows uploading photographs that reinforce observations made in an assessment. Ongoing upgrades include using the tool on a smartphone and recording voice observations that are saved as transcriptions.

The partnership with KOEN goes much deeper than developing and using the assessment tool. In 2016 KOEN selected personnel to visit EPRI's Charlotte, North Carolina facility for training in O&M best practices. This was an important step in building a sustainable culture of O&M excellence at KOEN. "The people who came here for training would become our assessment team so that when we went to do the first assessment in Korea, there would be a minimal EPRI presence, and it would mostly be their own people," Coffey said. "It was important to teach their staff because we can't be there all the time."

Photo courtesy: Korea South-East Power

The training in the U.S. also included a tour of a U.S. power plant, where KOEN staff had the opportunity to observe how the plant approached O&M and ask questions. With that initial training complete, Coffey and two other EPRI technical staff traveled to KOEN's Yeongheung power plant in 2016 to work with the utility's staff on an assessment. The plant today includes two 800-megawatt coal units, four 870-megawatt coal units, an eight-megawatt solar plant, a 12.6-megawatt hydro plant, a 46-megawatt wind farm, and an energy storage system.

EPRI worked with KOEN staff for a week to assess O&M performance and teach utility employees what constitutes an effective and instructive assessment. For example, it was important to reinforce that a valid observation is not an opinion. "You should only document what you see. People want to tell you good things about their plant or company, but our assessments are built on what we see," Coffey said. "We set it up so that anybody can make an entry but only team leads can approve observations. We'd also review the report each day and edit the observations to ensure they were valid and provided coaching and mentoring so they could improve."

Each day the assessment team would shadow the O&M staff and conclude the day by recording their observations into the tool. At the end of the week, EPRI provided an oral debrief to plant managers, including three areas where the plant performance was strong and three areas that could improve. Later, EPRI produced a formal assessment report for KOEN. "Part of the report is all of the observations we made, along with pictures to support the observations," Coffey said. "There's also a section of recommendations where we identify areas of improvement and provide recommendations about how to improve that tie back to EPRI research."

Since that first assessment, EPRI has worked with KOEN on assessments at other plants in 2017, 2019, and 2022. KOEN also assessed the Bundang power plant near Seoul, and the report was sent to EPRI for review and comments. The collaborative approach to assessments has delivered significant value to KOEN. "It is a good opportunity to learn evaluation techniques by directly participating in the on-site evaluation with EPRI as a mentor and KOEN directly participating in the evaluation," Kim said.

Since 2016 KOEN has made several specific changes as a result of the assessments. For example, Kim says power generation companies in Korea, including KOEN, have traditionally lacked clear standards for lockout and tagout. "Through collaboration with EPRI, a clear concept was learned, internal procedures were created, and site improvement is continuously promoted." In addition, KOEN has improved its arc flash protection guidelines. And after the 2017 assessment, the utility configured EPRI's assessment tool so that it could be used on KOEN's internal technology system.

"Each time an update is made on any items in the O&M assessment tool, we are making updates on our own tool to be on the same page as far as evolving the tool," Kim said.

EPRI TECHNICAL EXPERT

Dwayne Coffey

About EPRI

Founded in 1972, EPRI is the world's preeminent independent, non-profit energy research and development organization, with offices around the world. EPRI's trusted experts collaborate with more than 450 companies in 45 countries, driving innovation to ensure the public has clean, safe, reliable, affordable, and equitable access to electricity across the globe.

Together, we are shaping the future of energy.

EPRI, 3420 Hillview Avenue, Palo Alto, California 94304-1338 USA
800.313.3774 • 650.855.2121 • askepri@epri.com • www.epri.com