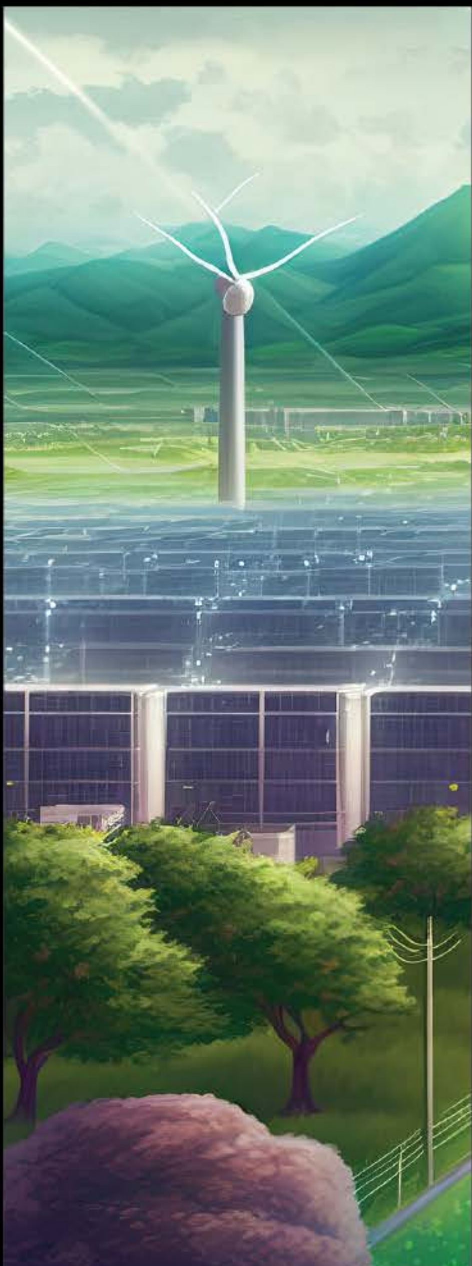
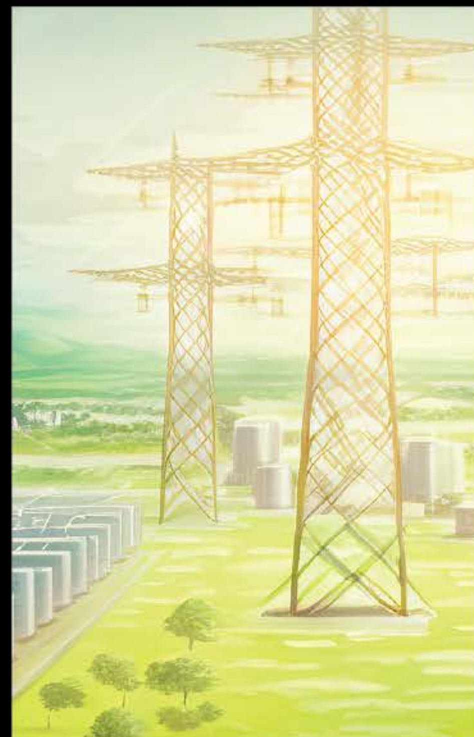
EPRI JOURNAL

FALL 2023





Confidently Scaling Microgrids Through Consistent Analytical Approaches

ALSO IN THIS ISSUE:

Table of Contents

EPRI JOURNAL

Confidently Scaling Microgrids Through Consistent Analytical Approaches

Decades of research and pilot projects inform a new EPRI methodology for assessing the viability of microgrids.

By Chris Warren

Until recently, there has been a lot more discussion about the potential of utility microgrids than their actual development and deployment. The main reason so few microgrids have been built is cost. Indeed, the vast majority of microgrid cost-benefit analyses concluded that the economics of microgrids simply did not pencil out.

In recent years, however, that has begun to change. To understand why, it's helpful to first be clear about what a microgrid is. EPRI defines microgrids, which are often referred to as community microgrids, this way: A group of interconnected loads and distributed energy resources (DERs) within clearly defined electrical boundaries that acts as a single controllable entity with respect to the grid and can connect and disconnect from the grid to operate in both grid-connected and islanded modes.

Simply stated, microgrids are a collection of DERs, like solar and energy storage, that can serve specific loads when the main grid is functioning normally and in the rare instances when there is a grid outage (when its operation is referred to as an islanded mode). With that definition in mind, the economic equation surrounding microgrids becomes clearer. As the costs for solar panels, energy storage, and other DERs that go into a microgrid have declined over the past decade, the cost-benefit analyses that once routinely led to projects being shelved have become increasingly favorable.

In fact, according to market research firm Wood Mackenzie, the U.S. microgrid market reached 10 gigawatts in the third quarter of 2022—seven gigawatts of that total is already in operation, with another three gigawatts in the planning or construction phase. Furthermore, Wood Mackenzie forecasts that the U.S. microgrid market will grow at an average rate of nearly 20 percent through 2027. Beyond declining DER costs, the growth of microgrids is also being driven by concerns over extreme weather and a desire by communities and companies to ensure a reliable supply of electricity in the event of a grid outage.

A STRONG FOUNDATION OF MICROGRID KNOWLEDGE

The fact that more microgrid projects are making it past the cost-benefit analysis litmus test means that utilities increasingly need to evaluate how to consider real-world microgrid designs and how to incorporate them into the power grid.

"Microgrids were originally thought of as something that individual customers would pursue because they wanted more autonomy with their electrical service," said Jackie Baum, an EPRI technical leader focused on microgrids and distributed energy resource management system (DERMS) integration. "Now, because microgrids are making more financial sense at both the customer and utility-scale, utilities are looking at how they need to integrate them into their existing infrastructure and be able to serve customers better. It's a different kind of conversation than before."

EPRI has been researching the technical issues of safely and efficiently developing and integrating microgrids for over a decade. Recently, EPRI has worked with member utilities like Puget Sound Energy in Washington State and Duke Energy in North Carolina to develop a guide for utility distribution planners and engineers to review proposed microgrid designs. The result is a resource that outlines the information, processes, and tools utilities need to thoroughly evaluate microgrid designs, including factors like the steady state operation of microgrids as well as grounding, protection, and power quality considerations.

The work builds on years of EPRI research into a wide variety of microgrid issues and lessons learned from demonstration projects with member utilities. In recent years, EPRI released "Understanding Community Microgrids," a report that provides a technical primer to understand the basic components, configurations, design, and operational considerations for community microgrids. The report provides foundational knowledge about the assets that come together to form a grid-connected microgrid, the drivers of accelerating microgrid development, and a discussion of communication, cybersecurity, and islanding issues that are important to the safe and reliable operation of microgrids.

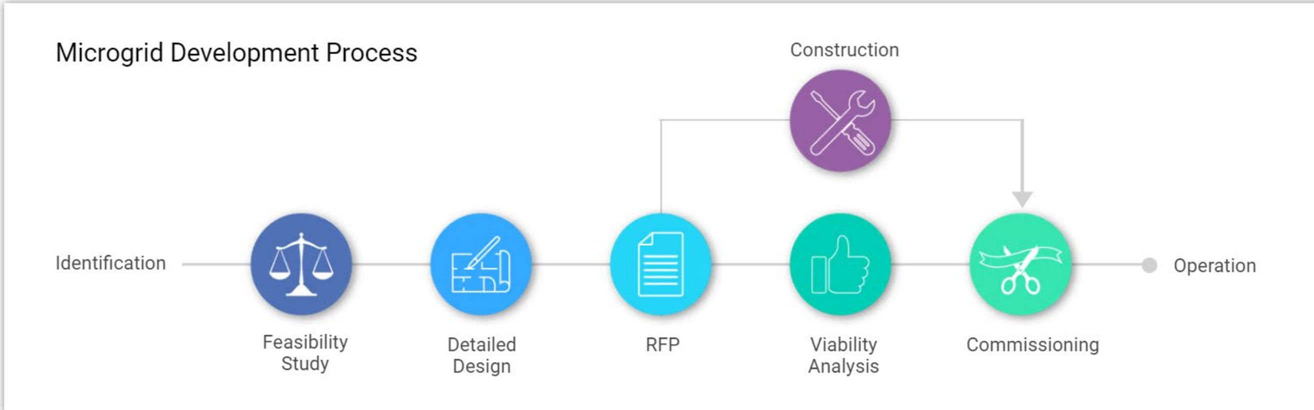
Another recent paper, "Grid Considerations for Microgrids," delves into some of the challenges that interconnecting a microgrid to the power system can introduce. In particular, the paper explores protection considerations, operating modes, DER requirements and standards, and some of the unique challenges posed when microgrids transition to and from off-grid operation. Past EPRI research has produced a microgrid cost-benefit analysis framework and an overview of expanding microgrid applications, implementations, and business structures.

UNIQUE DISTRIBUTION SYSTEMS, UNIQUE MICROGRIDS

The need for a tool to guide a rigorous analysis of microgrid designs is pressing because microgrids demand a more nuanced approach than is typical for utility distribution engineers. For instance, it's important to acknowledge that both distribution systems and microgrids are unique, as are utility business models and processes. "Microgrids are unique because utilities and distribution systems are unique," Baum said. "Even though each distribution system is unique and utility approaches to planning are unique, there are underlying components and approaches to solving the planning and design problems that can be building blocks for utilities to evaluate microgrids."

The analysis of microgrids also requires a level of cooperation within utilities that is not typically the norm. For example, traditional distribution planners will focus on addressing issues like voltage fluctuations, power quality, and potential overloading. But they rely on transmission operators to worry about balancing generation and load and managing frequency. "With microgrids, you now have to own all of that," said Ben York, manager of DER strategic projects at EPRI. "You need to bring new ideas of analysis and controls that you once separated into the realms of the transmission operator and the distribution operator. All of that comes together in doing microgrid analysis."

EPRI's research has outlined a practical approach to help distribution and interconnection engineers thoroughly analyze proposed microgrid designs. The purpose of the analysis is familiar to engineers: To ensure the safe and reliable delivery of electricity to



all customers. "Customers served by a utility-operated microgrid don't have a choice about whether they receive electricity from the microgrid or not," Baum said. "Regardless of how the utility decides to serve you or your load, you still expect to get the same utility service. Not only do engineers need to make sure microgrids run and operate, but they also must do so with quality such that individual customers won't notice there has been a change."

This means engineers must utilize unfamiliar tools and processes to model and simulate the behavior and impacts of the more dynamic and diverse set of assets that make up a microgrid than they rely on when analyzing the existing grid. For example, one of the main drivers of microgrid development is a resilience solution, particularly in rural areas where other options are expensive.

To bolster reliability, however, microgrids can be designed to transition from grid-connected to islanded operation without disruption. Proper microgrid analysis must consider the goals it is trying to achieve and whether the design is adequate to meet them. "On the reliability front, you need to understand how long the microgrid needs to island," Baum said. "Who are the customers being impacted by these outages that the microgrid servers? The answers have ripple effects on the controller design and the type of equipment that should be integrated into the microgrid design. It's essential to define what your goal is with the microgrid."

FACTORS THAT ALL MICROGRID VIABILITY ANALYSIS SHOULD INCLUDE

For example, the report, completed in conjunction with Puget Sound Energy as part of an analysis of two of the utility's proposed microgrids, covers four crucial areas that need to be part of any microgrid design analysis. They are:

- The data, tools, and skills interconnection engineers need when considering microgrids.
- The analytical processes and steps that need to be part of an interconnection evaluation.
- Gaps, design errors, and potential pitfalls engineers need to be aware of when considering a microgrid design.
- Evaluation criteria to use to verify a microgrid's successful operation.

While acknowledging the reality that all distribution systems and microgrids are unique, the report spells out the essential areas of analysis to fully vet microgrid designs. "There are underlying components and approaches to solving the planning and design problems," York said. "We can take those pieces and give them out as building blocks for the utility to take away. You still must have your own model of the distribution system and understand the characteristics of the devices in the microgrid. But we can give you the 1-2-3 steps and tell you why you should run this study and how you can use the information to prevent problems from happening."

To be more specific, the EPRI-recommended microgrid design review includes five distinct analyses: Steady state analysis; transient and stability analysis; grounding analysis; protection analysis; and power quality analysis. As just one example of the topics the review includes, consider the steps that are part of the steady state analysis :

- Power adequacy assessment to determine if the generation sources in the microgrid can serve the expected load.
- Voltage regulation analysis to gauge the microgrid's ability to maintain steady state voltage within industry standards during islanded operations.
- Evaluation to ensure microgrid equipment doesn't exceed thermal limits, especially during islanded operations.
- Verification that the worst-case load balance doesn't exceed the capabilities of the microgrid's primary generation source or that the worst-case voltage imbalance doesn't exceed the sensitivities of critical customers.

In addition to its efforts to standardize design analysis, EPRI is also pursuing research to standardize the behavior of microgrid components. "If you think about grid-forming inverters and microgrid controllers and some of the protection equipment, we want to get a consistent understanding of what equipment needs to be capable of," Baum said. "That will go a long way towards making design reviews more repeatable."

Currently, a challenge for consistent and repeatable microgrid design analysis is that the behavior of inverters, energy storage, and other components in a microgrid varies depending on the manufacturer. "This is different from the old school power plant where you can more or less say that a gas turbine is a gas turbine is a gas turbine," York said. "It's a lot more consistent when the behavior isn't software-based."

A UTILITY MICROGRID PIONEER

As Grid Modernization Strategist at Puget Sound Energy, it should come as no surprise that Joseph Do views microgrids as a potentially powerful tool to both drive decarbonization and enhance grid resilience. For instance, Do views microgrids that feature energy storage as a potentially effective solution to provide cost-effective resilience and reliability. Puget Sound Energy has already deployed or begun developing several community microgrids that include battery storage.

"For the microgrid projects we have been involved with, battery energy storage technology has been a common theme. It has an elastic effect on the grid, where at different times of the day, you have a lot of production from solar," Do said. "You can soak that up with the battery and then release that energy back when your solar is not as prevalent, but you're having a lot of customer loads coming on, especially bigger loads like EV chargers."

While Do spends a lot of time developing and implementing individual microgrid projects, he also seeks to educate his colleagues about microgrids and how they can help Puget Sound Energy better serve its customers. "My goal is to influence the company to embrace these technologies and utilize them to maintain the energy delivery system without having to overbuild infrastructure," Do said. A big part of microgrid education is explaining that microgrids aren't only designed to operate independently of the grid.

"I'm trying to change many people's perspectives within my company by saying there are grid-connected benefits. For example, maybe you optimize the efficiency of a microgrid where you can take all the demand and make it net zero," Do said. "I approach it as an engineer where the microgrid is an asset we can leverage and utilize so that we don't have to spin generators as hard or ramp up another generator. If we are able to lean into distributed energy resources as part of our energy portfolio, this can greatly change the way we think about renewable energy."

Do and his grid modernization colleagues at Puget Sound Energy worked with EPRI to complete viability analyses of two proposed microgrid designs: The Tenino and Bucoda community microgrids, which are both meant to enhance reliability in a small, rural Washington State community. The Tenino microgrid design combines a 150-kilowatt solar photovoltaic (PV) system with a 1 megawatt/2 megawatt-hour lithium-ion battery, while the Bucoda design only features energy storage.

For Do, one of the most significant benefits of collaborating with EPRI to perform the viability analysis was EPRI's comprehensive approach, which considers everything from power quality to islanding to grounding. "That allows us to be able to look at our system and see what other upgrades we need to make to our infrastructure to ensure that when we need to black start the microgrid for resiliency, it's not going to fail," Do said. "Or, during normal operations, how we best protect the system from the microgrid to keep our grid and customers safe."

Because energy storage is such an important component of the microgrids Puget Sound Energy is developing, Do says it has also been helpful to the utility to leverage EPRI's energy storage modeling capabilities and technology expertise. "Battery energy storage systems are very sophisticated pieces of equipment, and working with EPRI has informed us to be able to go out and deal with energy storage manufacturers to indicate what we are looking for and find the right vendor that can help integrate their equipment into our grid," Do said. "EPRI has really helped us navigate this very ambiguous area."

The standardized microgrid analysis process provides Puget Sound Energy with a repeatable process to follow as it increases the number of microgrids it develops and deploys. "We wanted to be able to drive that ourselves and build that experience and that knowledge internally," Do said. "And we also wanted to start figuring out what it looks like for microgrid ownership internally, like which groups will own what equipment, how are we going to make sure that it's going to be smoothly operating."

This is precisely the goal EPRI has in developing tools utilities can use to analyze potential microgrid designs. With a standardized analysis approach, the total number of microgrids being developed and deployed can increase and deliver benefits to utilities, their customers, and the grid more rapidly. "The goal was never for us to sit on this information," Baum said. "It has always been the goal to share this with the industry so that it becomes the model the rest of the industry can build from to get better outcomes across the board."

EPRI TECHNICAL EXPERT

Jacqueline Baum

Samish Island Microgrid

A 50 kilowatt/336 kilowatt-hour battery is part of the new Samish Island microgrid, which was installed to manage solar energy from residents on the island and provide better reliability.

Puget Sound Energy (PSE) commissioned a microgrid on Samish Island in June of 2023.

An 8-kilowatt ground mounted solar array is part of the microgrid aimed at increasing the use of clean energy within the Samish Island community.

EPRI JOURNAL

Getting the Social Cost of Carbon Right

Quantifying the global economic impacts of climate change is an enormously complex and high-stakes task that demands due diligence.

By Chris Warren

On January 20, 2021, newly inaugurated President Joe Biden signed 17 executive orders covering topics ranging from immigration to the COVID-19 pandemic to climate change. Among the orders issued on that first day of the new administration was one focused on the social cost of carbon.

The social cost of carbon is a monetary estimate attempting to quantify the global economic impact of emitting just one ton of the greenhouse gas carbon dioxide. Social cost of carbon estimates first gained relevance in the federal government during the George W. Bush administration, when the U.S. Ninth Circuit Court of Appeals ruled that the National Highway Transportation Safety Administration had been arbitrary and capricious in not valuing the benefits of greenhouse gas emissions reductions in setting vehicle efficiency standards.

The ruling kicked off an effort within the federal government to develop a methodology for determining the social cost of carbon. "The ruling that came back from the Ninth Circuit meant that the Department of Transportation had to come up with a number to use in their vehicle efficiency standards setting analysis," said Steve Rose, a principal research economist at EPRI for 15 years, whose work focuses on long-term modeling of socioeconomic systems, climate change, and climate change impacts. "It also meant that every rule affecting greenhouse gas emissions from every agency would need to value expected emissions changes."

At the time, Rose worked at the U.S. Environmental Protection Agency (EPA) and was researching methodologies to calculate the social cost of carbon. As one of the only people in the federal government studying the topic, Rose was called upon to educate government officials and technical staff on these methodologies and potential estimates.

The original rationale for developing estimates was to inform federal rulemaking. "The estimates were specifically developed for regulatory use and policies that only change global emissions incrementally.

Agencies propose regulations, such as the EPA's Clean Power Plan under the Obama administration, energy efficiency standards out of the U.S. Department of Energy, or even U.S. Department of Agriculture policies with respect to agricultural practices," Rose said. "In all of the cases, the idea was that if the proposed regulation affected greenhouse gas emissions, then you needed to value them and include that as part of your cost-benefit analysis."

CURRENT METHODOLOGY HAS BEEN IN PLACE FOR A DECADE-PLUS

It wasn't until 2010, during the Obama administration, that an interagency working group from across the federal government established a methodology to calculate standardized estimates of the social cost of carbon that all federal agencies could use. This 2010 methodology is still in use today, and the Biden administration decided to use it to generate its "interim" estimates. The interim estimates have remained in force while the administration works on developing updated and improved estimates, as directed by the president's executive order. The order requested interim estimates, development of updated estimates, and reconstituted the working group, which had been disbanded during the Trump administration.

On November 11, 2022, as part of a proposed rule to reduce methane emissions in the oil and gas industry, the EPA released a draft new methodology and proposed updated social cost of carbon estimates, as well as social cost estimates for other greenhouse gases—methane and nitrous oxide. While the EPA's draft new estimates have not been officially declared the interagency working group's proposed revised estimates, they are being considered.

If anything, the need for scientifically rigorous development of the social costs of carbon and other greenhouse gases has increased since 2010. That's because their use has expanded well beyond federal regulations and has the potential to influence a growing number of investments and decisions. For example, there are proposals to incorporate the social cost of carbon into the environmental impact analyses required under the National Environmental Protection Act. Other proposals seek to incorporate the metric into federal government procurement decisions by valuing the greenhouse gas emissions associated with potential suppliers' products and services.

The social cost of carbon is also being used, or is proposed for use, at the state level in regulatory analyses and other contexts, such as externalities pricing in resource planning and power dispatch. For instance, when a utility submits a generation resource plan to its state public utilities commission (PUC), the PUC may ask the utility to value the greenhouse gas emissions associated with the proposed investments.

Dispatch pricing is another potential power sector application for the social cost of carbon. "There are a variety of issues here, but as system operators are dispatching different resources, they could consider including the cost of the greenhouse gas emissions of each resource. So, if the system operator is choosing between a renewable resource with no emissions and a gas plant with emissions, they might include an adder on the gas plant dispatch price," Rose said. "However, it is more complicated than that, especially if the plant's emissions are already being regulated, or there are different emissions policies across the states in the system."

RECOMMENDATIONS TO IMPROVE THE METHODOLOGY

Estimating the social cost of carbon is important, but it's also an enormous scientific challenge. For example, carbon dioxide released by burning fossil fuels, as well as other activities, remains in the atmosphere for a hundred years. It also impacts how the world stores and releases carbon beyond that. "Which means that estimating the social cost of carbon requires modeling the world's physical and economic systems centuries into the future," says Rose. "Given the need to quantify future global economies and climate change for centuries, and how climate change could affect everything from agriculture to human health to power systems to coastal infrastructure, there is significant uncertainty that needs to be considered, quantified, and incorporated into the modeling."

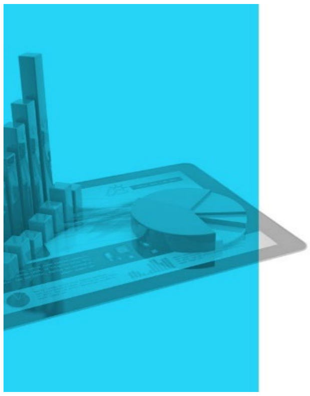
The complexity of developing a social cost of carbon methodology and estimates underscores the importance of approaching the task with scientific rigor and transparency. Soon after the administration released its executive order in January 2021, EPRI published a technical report, *Repairing the Social Cost of Carbon Framework*, that laid out a to-do list for updating the "interim" methodology in use since 2010. It included immediate fixes to the interim approach and specific scientific issues that needed to be overcome by any new methodology.

EPRI's analysis drew on over a dozen years of study of the social cost of carbon methodologies, as well as EPRI's participation on the National Academies of Sciences, Engineering, and Medicine (NASEM) social cost of carbon committee, which the Obama administration had assembled to recommend methodological improvements. In its executive order, the Biden administration called out the NASEM recommendations explicitly, stating that they should be considered in developing a new methodology and estimates.

The EPA's recent draft new methodology, however, does not address many of the NASEM recommendations. At a foundational level, the draft methodology is not scientifically reliable and robust. "What that means is that it lacks transparency and justification, and it isn't taking into account the broader scientific knowledge available, including not properly capturing uncertainty. Therefore, the numbers are not robust and would change if we used equally relevant and plausible alternative specifications and assumptions," Rose said. "The draft new estimates are simply not numbers we can rely on to influence billions of dollars of decisions."

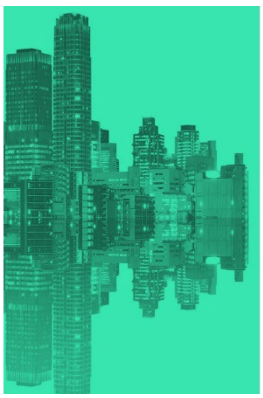
For example, NASEM, in its Phase 1 study, noted that the interim estimates and the methodology they were based on needed numerous revisions and that a partial fix would be insufficient; there were simply too many problems that needed to be addressed. Therefore, in its Phase 2 study, NASEM provided comprehensive recommendations for revisions to the framework overall and individual modules, which included fully considering the available science and uncertainties.

EPRI's recent analysis of the EPA's draft new methodology and estimates found that the NASEM recommendations were not addressed. EPRI's analysis also found that the methodology has substantive scientific issues with, for instance, robustness, plausibility, discounting, and transparency, in addition to a lack of internal consistency and coherency across the modeling.



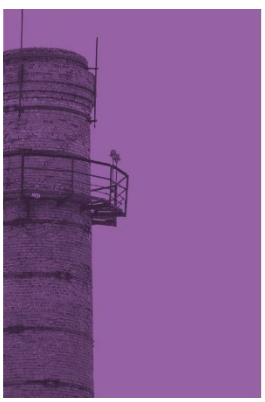
Robustness

EPRI's analysis also pointed out that the draft methodology does not adequately represent current scientific knowledge. This affects, for example, how changes in the climate are translated into economic consequences. "There is significantly more information available in terms of estimating the potential global economic implications of a projected change in climate, both in aggregate in terms of total global impacts on society and for individual categories, like health-related impacts and impacts on agriculture," Rose said. "All of that information needs to be considered. As is, it would be quite easy to insert alternative specifications into EPA's draft new modeling that could change the numbers significantly. This is a serious problem because the administration and the public need robust and reliable estimates."



Plausibility

Among the many scientific issues EPRI's analysis raised was that of plausibility. For example, some of the climate projections used in the draft new methodology envision global temperatures rising by a global average of 8°C; other projections have global emissions peaking and declining immediately. "Neither of these futures is going to happen," Rose said. "If you eliminate the future scenarios that are implausible, the estimates will change."



Discounting

Another deficiency that EPRI's analysis highlights is that the EPA's draft new methodology does not consider the full scientific factors associated with discounting future economic impacts from climate change. Discounting is necessary for computing the net present value of future estimated impacts from a unit of emissions today. Accounting for the scientific discounting factors, such as the very long duration of the climate investment associated with emitting carbon dioxide, would result in significantly different discount rates and lower social cost of carbon estimates.

Transparency

Transparency and justification are also issues. The EPA's proposed new methodology does not include documentation of the parameters and equations used in the modeling or the detailed results necessary for understanding and evaluating the modeling. Given the potential implications of the social cost of carbon in the development of policy and regulations, full transparency, as well as justification for methodological choices, is necessary for proper assessment and public trust. "The public needs to have confidence that what is being produced is scientifically reliable and that robust numbers are being used to inform policy decisions," Rose said.

TAKING THE TIME TO ENSURE SCIENTIFIC DUE DILIGENCE

EPRI's assessment of the proposed new methodology is meant to help the public understand the approach and relevant science. "Our primary function is facilitating understanding and productive conversation that helps in the eventual development of a scientifically reliable methodology and set of estimates," Rose said.

There are opportunities to enhance scientific rigor, transparency, and public trust regarding the EPA's draft new social cost of carbon methodology and estimates. Steps that could be taken include assembly of a peer review panel that appropriately evaluates the methodology. While a peer review panel was assembled, it was not asked to assess the scientific reliability of the methodology or provide feedback and recommendations agreed to by all the panelists. It was also limited in size and expertise and in its ability to engage in debate and dialogue and consider public input. Such dialogue and input are good scientific practices and valuable for engendering public confidence.

Because transparency is important to understanding and assessment, the EPA's draft methodology documentation should be enhanced to clearly communicate and justify the details. These would include the data, equations, parameters, uncertainty specifications, sources used, and detailed results that establish the methodology's reliability and robustness at every step in the calculations.

Producing a scientifically robust social cost of carbon is complex and challenging. Research and dialogue, however, also need to extend to how social costs of greenhouse gas estimates are eventually applied. "A whole new set of technical issues arise when we start talking about applications," Rose said. "Thus, this is not just a conversation about how you get the best estimates for the social cost of carbon. This is also a conversation about how to apply them properly."

EPRI has been evaluating and tracking applications of the social cost of carbon for over a decade. That line of research has found that the same carbon is being valued more than once across policies, from mineral extraction to fuel combustion to power dispatch to the use of goods and services. This multiple pricing of carbon and other greenhouse gases increases the cost of reducing carbon emissions without further reducing those emissions. EPRI's work has also found important inconsistencies across calculations used in benefit-cost analyses, as well as carbon emissions increases, commonly called leakage, elsewhere in the economy. Together, these affect the climate and net benefit estimates of policies and their reliability. For example, EPRI has found these issues to be present in the benefit-cost analyses for EPA's recent proposed oil and gas methane and power plant rules. "Overall, these technical issues, along with the social cost of carbon estimation issues, undermine confidence in the application results and insights that are informing decisions," said Rose.

While the current administration has a sense of urgency to revise the social cost of carbon methodology and estimates, the process to date has not provided the necessary scientific due diligence. "The interim estimates methodology has been with us for 13 years. We need to get things right. Whatever methodology we are going to have next is probably going to be with us for a long time," Rose said. "We need to follow proper scientific process in order to create estimates and insights that are scientifically reliable, robust, and stable. There is still much to do to get there, but fortunately, there is a clear sound scientific path forward and specific opportunities for improving both the process and the scientific basis."

EPRI TECHNICAL EXPERT

Steven Rose

EPRI JOURNAL

How a Single Device Helps EVs Provide Cost-Effective Backup Power to Homes

The Smart Power Integrated Node (SPIN) delivers backup power along with cost savings and grid support in one small box

By Chris Warren

In the summer of 2020, California's grid strained to keep up with demand for electricity during a scorching heat wave. In August of that year, rolling outages impacting hundreds of thousands of customers were initiated because not enough capacity was available to keep up with demand. The outages triggered the California Independent System Operator (CAISO), the California Public Utilities Commission (PUC), and the California Energy Commission (CEC) to issue a joint root cause analysis that found that extreme weather, market practices, and resource adequacy and planning processes combined to necessitate the power shutoffs.

At the individual household level, however, the experience of rolling blackouts and the potential for more triggered many people to investigate the potential for energy storage to provide backup power during outages. "What people are doing if they already have solar on the roof is to start to install storage," said Sunil Chhaya, an EPRI senior technology executive who leads electric vehicle (EV) and energy system integration efforts. "Solar companies do it now, and an income tax credit incentivizes it. So, when the lights go out, you can automatically switch over to storage."

Pairing rooftop solar with energy storage is a practical and reliable solution to deliver backup power during infrequent grid outages. But it's also a pricey solution that is well outside of the financial reach of many. For example, a typical behind-the-meter energy storage unit that provides about 10 kilowatt-hours of capacity – enough to deliver two to three hours of backup power to the typical home – costs about $15,000 to install.

But there's another potential backup power solution that may already be available to Californians and other Americans: the EV sitting in their driveway. "There are a lot more people who have EVs than have storage," Chhaya said. "So, the question is this:

can we use EV batteries that have 60, 80, or 100 kilowatt-hours and have already been paid for to provide backup power to the home?"

A NEW SPIN ON BIDIRECTIONAL CHARGING

There is no lack of research and discussion today about the future potential of EV batteries to provide backup power. But there are not yet any commercially available bidirectional chargers able to take electricity out of an EV battery and use it to provide backup power directly to a building. "Today, you can find vehicle-to-grid technology that only works when the grid is on," Chhaya said. "It doesn't work when the grid is off, and it only sends power from the vehicle to the grid, not to the home where it's needed."

But there is another potential solution for both tapping EV batteries for backup power and enabling EV owners to earn revenue for providing grid services and helping utilities reduce their peak load. Since 2016, EPRI has worked with Flex Power Control on developing and testing the Smart Power Integrated Node, or SPIN. SPIN is a single device with the intelligence to automatically manage a business or household's solar, EV, and stationary storage assets to achieve the building owner's priorities. For example, SPIN can automatically sense a power outage, instantly provide backup power, and send power back to the grid.

Each SPIN includes multi-port bidirectional inverters that connect both to the grid and to a home or business's solar, EV, and storage units. Each device also has a power routing matrix comprising multiple switches that connect each of the DERs and the grid in multiple configurations. Importantly, SPIN also has a brain in the form of control and coordination software that optimizes how each asset operates in grid-tied and standalone modes. Initially supported with EPRI Technology Innovation (TI) funding, SPIN has since received funding from the U.S. Department of Energy (DOE), the California Energy Commission (CEC), and the National Renewable Energy Laboratory (NREL).

For example, DOE funding supported the initial prototype development using commonly available electronic components. After demonstrating its ability to control power flow, Flex Power Control built a more sophisticated prototype that was then tested at DOE's Oak Ridge National Laboratory. There, the device was able to perform fast EV charging, dispatch an EV battery's electricity to the grid, and deliver backup power during an outage using rooftop solar and EV batteries.

Over the course of numerous projects with EPRI, DOE, and other researchers, SPIN has repeatedly demonstrated its functionality, including support for the grid. For example, in one study, the University of Kentucky researchers simulated a feeder with 70 houses. Each of the simulated houses included a 7-kilowatt solar system, a 10-kilowatt-hour energy storage system, an EV charger, and a SPIN to manage the DERs. SPIN was able to reduce the feeder's peak load by 42 percent. "Our initial challenge was to develop the technology, improve it, and show that it works and delivers value," said Greg Smith, a founder of Flex Power Control, who formerly worked as an engineer at General Motors. "We have proven the technology works and shown the potential value proposition."

HOW SPIN PROVIDES BACKUP POWER WITH MINIMAL EV BATTERY IMPACTS

EPRI summarized the research results funded by DOE and the CEC in the report *Battery Performance Assessment of Vehicle-to-Grid Capable Electric Vehicles: Testing Methodology and Experimental Results*. Among other things, the report confirms SPIN's ability to deliver backup power from an EV battery. The report also quantifies how much battery degradation would result when the battery-powered an EV and was used in a home.

To do that, researchers at NREL tested two 17-kilowatt-hour battery packs made by LG Chem that are used in Pacifica plug-in hybrid minivans. One of the batteries was charged and discharged three times each day for over 12 months to simulate an EV used for driving and delivering energy to a home. That translated into about 11.7 kilowatt-hours for transportation and 5 kilowatt-hours to the building. To compare the degradation impact of those vehicle-to-building discharges, the second battery was cycled an equal number of times daily for the same duration of time. But its discharges only simulated what was needed for driving.

By cycling the batteries three times per day, the NREL researchers were able to collect data representing about four years of operation. The test results showed that using the EV battery for typical driving and vehicle-to-building discharge had a small impact on battery degradation. For instance, the battery that provided energy for driving and a building had about 90 percent of its original capacity at the end of the testing period; by comparison, the driving-only battery had about 95 percent of its original capacity. Using these degradation rates, the researchers concluded that over 10 years, the driving-only battery would retain 82 percent of its original capacity. In contrast, the battery pulling double duty would have 77 percent of its capacity.

BENEFITS BEYOND BACKUP POWER

Clearly, an EV battery won't be called on daily to provide backup power to a home as power outages remain rare. But testing the battery as if it was being dispatched from the vehicle to a building daily also provided insights about the ability of a SPIN-managed EV to deliver additional benefits.

For example, the soon-to-be-published EPRI report includes an analysis of the potential bill savings that could come from using SPIN to shift EV charging to times when electricity rates are lowest. The potential annual bill savings for a residential customer were estimated to be almost $1200. Commercial customers using SPIN to manage charging could save over $2000 annually from lower energy costs and avoided demand charges.

The report also detailed a range of other utility, grid, and societal benefits EVs managed by SPIN can deliver. For example, 200 EVs equipped with bidirectional charging could reduce annual peak load by 750 kilowatts. By assuming an avoided cost of infrastructure of $25 per kilowatt, that would result in savings of more than $280,000 over 15 years.

Large numbers of EVs with bidirectional charging capabilities could also substantially reduce the amount of renewable energy that must be curtailed. According to EPRI, about 1500 gigawatt-hours of renewables were curtailed in 2020. But if 500,000 EVs were to charge when electricity prices are low in the late morning and late night and then discharge when demand and prices are high in the early morning and late afternoon, the curtailment would be far lower. According to EPRI's analysis, 332 gigawatt-hours would not need to be curtailed. A bill recently introduced to the California state legislature would mandate that all EVs sold in the state be bidirectional capable by model year 2027.

For utility customers – particularly those that have already purchased an EV and solar – integrating SPIN also promises to dramatically reduce the costs associated with securing backup power. By eliminating the need to install stationary storage and an inverter, SPIN can eliminate the $15,000 needed to purchase a 10-kilowatt-hour battery. In addition, with SPIN, there is no need for either a $1750 solar PV inverter or an EV charger. According to the EPRI report, these components cost $28,000, compared to the $7000 to purchase and install SPIN. EPRI will be publishing three more SPIN-related research papers in the next year.

THE ROAD AHEAD

Sunil Chhaya has been deeply involved in helping SPIN move through the many development and testing stages over the past seven years. He believes the device is ready to begin delivering benefits to utility customers, utilities, and the grid. "This is one step away from large-scale deployment," Chhaya said. "That's because it's a no-brainer. It removes a lot of hardware from the house needed for DERs. Especially for new construction, it's a no-brainer because you would just need to put it in as part of the electric panel."

For SPIN to move towards the large deployment Chhaya envisions, the next step is to receive Underwriters Laboratories (UL) certification. UL certification is expensive, and Flex Power Control is currently seeking funding to achieve certification. "Certification is really about starting a production line because for certification to occur, it's done with the products you are actually going to produce," Smith said. "It's really a product launch."

Flex Power Control now has two versions of SPIN to simplify and speed up the certification and production process. The initial focus will be on the SPIN-EVO, a bidirectional charger that can provide backup power to a home during outages. For homes already equipped with PV or storage backup, EVO adds the EV backup component only. Its addition is akin to a retrofit.

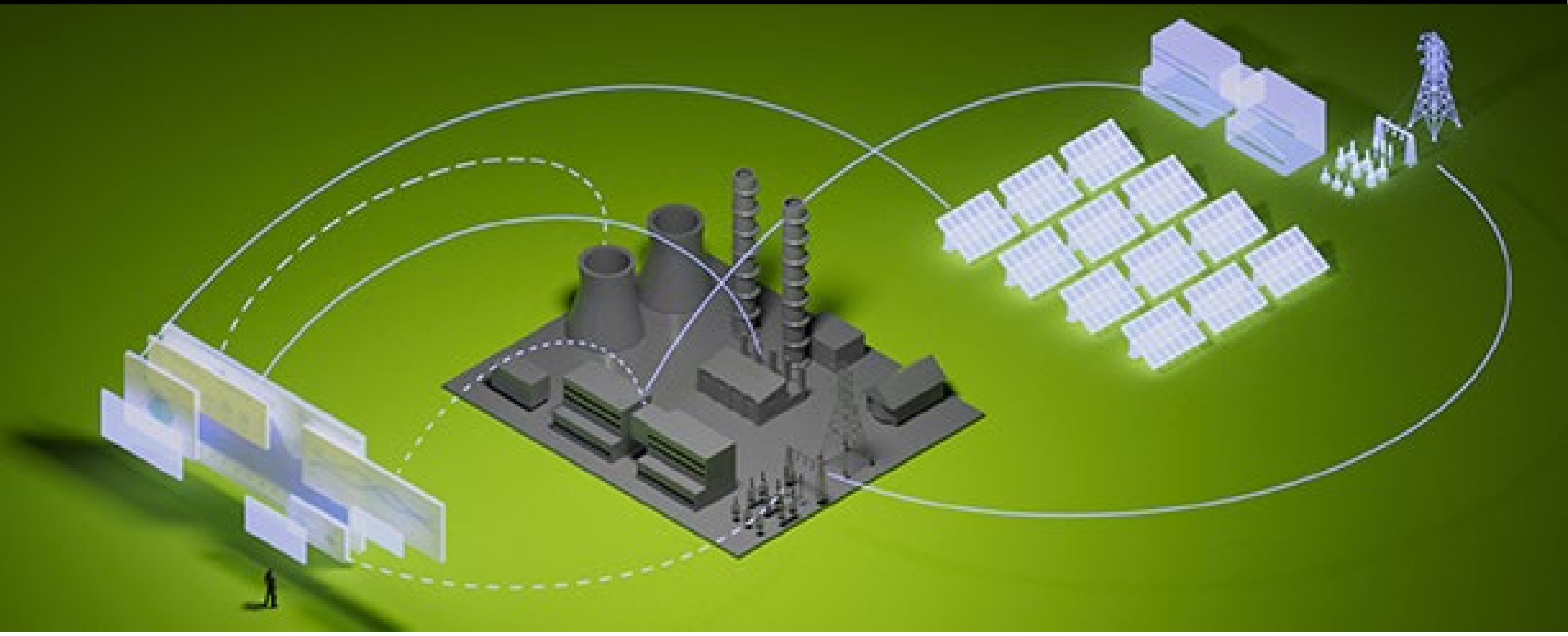
The second version, SPIN-MPX, is a bidirectional charger but also integrates inverters for solar, stationary storage, and the EV and manages all the assets according to a customer's priorities. The SPIN-MPX is more suitable for new construction or new installations because it removes the need for duplicative hardware and complexity. Instead of a separate EV charger and solar and storage inverter, new installations only require a single SPIN-MPX. Once certification is secured, Smith says SPIN devices will be available to customers through a distributor able to install and service the device.

As Flex Power Control continues to pursue the funding needed to become UL certified, the company is also actively pursuing opportunities to collaborate with utilities on pilot projects. One of the main reasons to engage with utilities is to elevate awareness about how SPIN functions and what benefits it can provide. "We want to get people to experience it so that they know it is what we say it is," Smith said. "We would first want to work with utilities in their own lab because we think it's important for them to get comfortable with it. Then we would want to do a field pilot with a limited number of customers to help determine the best use for the device at their location."

EPRI TECHNICAL EXPERT

Sunil M. Chhaya, PhD

EPRI JOURNAL



The Ideal Retirement

A series of white papers and screening tool help determine clean energy options for retiring coal plants.

By Chris Warren

In July 2023, the utility DTE Electric made an announcement that has become increasingly common over the past few years. As part of an agreement seeking regulatory approval of its integrated resource plan (IRP), the Michigan utility proposed shutting down all its coal-fired power plants by 2032. The proposal accelerates the closure of the 3,000-plus megawatt Monroe power plant by three years.

Announcements of U.S. coal plant closures are so frequent that they are difficult to track. Indeed, a report issued earlier this year by the Institute for Energy Economics and Financial Analysis found that the United States is on pace to close half of all coal-fired power plants by 2026, with coal-fired generation falling from a peak of 318 gigawatts of capacity in 2011 to 159 gigawatts in 2026 and 116 gigawatts by 2030.

In the recent past, coal plants slated for closure were often replaced by new natural gas-powered plants or redeveloped for other uses. However, a mix of policy and corporate and utility decarbonization goals are driving many utilities to consider repurposing coal plant infrastructure to site energy centers of the future.

For example, according to an analysis by the Smart Electric Power Alliance, nearly 80 percent of all U.S. customer accounts are served by a utility that either has a 100 percent decarbonization target or is owned by a parent company that does. Additionally, in 2021, the U.S. Congress and the Environmental Protection Agency specifically encouraged companies closing coal plants to redevelop the sites for renewable generation. The Inflation Reduction Act (IRA) passed in 2022 also allocated $5 billion to support the newly-created Energy Infrastructure Reinvestment program. The program is designed to provide loan guarantees that enable existing energy infrastructure no longer in operation to be repurposed for clean energy and other decarbonization uses.

GUIDANCE DRAWN FROM EPRI'S BROAD EXPERTISE

Over the past 18 months, EPRI has produced a series of white papers and, more recently, a customizable screening tool to help utilities assess coal sites for clean energy generation technologies. Led by EPRI's plant decommissioning program, the effort also integrates the expertise and experience of nine EPRI programs.

"My program is good at closing power plants down, but we don't necessarily understand what it takes to turn a coal plant into X technology," said Lea Millet, a senior technical leader who oversees EPRI's decommissioning program and spearheaded the development of the tool and the white papers. "We needed expertise from these nine other programs to tell us what you need from a coal plant for hydrogen or solar or advanced nuclear to be successful."

Retiring coal plants have many built-in features that make them promising candidates for future clean energy use. "These coal sites are generally good generation sites," said Brandon Delis, an EPRI director. "In a lot of cases, these were first-choice sites, meaning that the coal plants were sited, and then the transmission network was basically built around them. So, when you look at things like transmission, water resource availability, and transportation, they all line up well."

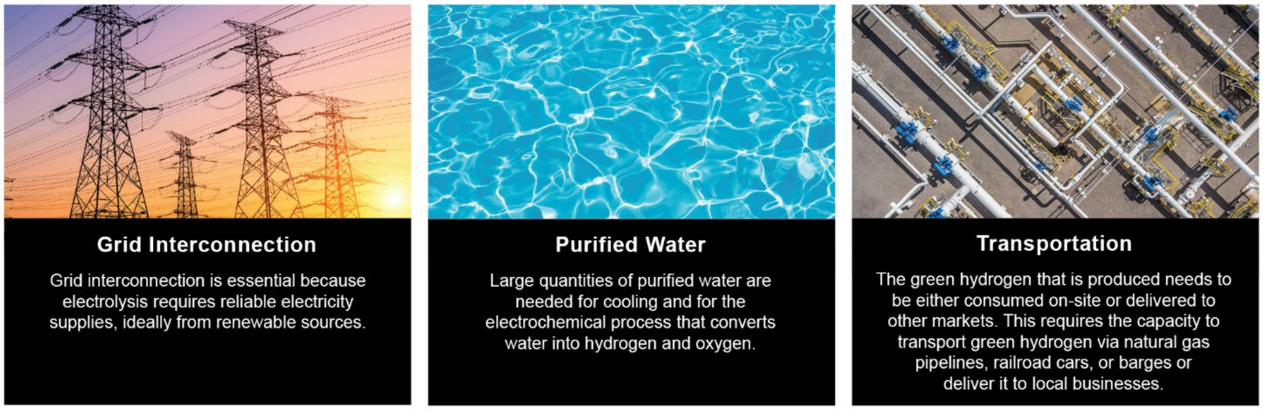
Other inherent advantages of former coal plants for second lives in renewable generation include existing interconnection, land use, and environmental permits that can streamline the often protracted permitting process. Retiring coal plants also have buildings, warehouses, and even equipment, such as generators, that can be repurposed for less than it costs to build entirely new facilities.

NOT ALL USES ARE CREATED EQUAL

The white papers and screening tool acknowledge and highlight that the choice about the optimal reuse of coal plants for new generation is not simple. Some sites are better suited for solar photovoltaics, others for advanced nuclear or energy storage. "The point of this effort was to help people narrow in on the best opportunities because, from a macro level, you look at all these sites and say, well, they're all good," Delis said. "But if you really get into evaluating a technology at a particular site, the differences are not trivial. The intent was to help narrow down particular technologies for given sites and at a fleet level."

The white paper series delves into some of the factors that make a coal site suitable (or not) for a range of commercially viable generation technologies. For example, *Repowering Coal-Fired Power Plants for Hydrogen Production with Electrolysis* explains the interest and market activity in green hydrogen production as a way to both utilize excess intermittent renewable generation and enhance grid stability and reliability. There have been times in Great Britain and the United States when an oversupply of renewable generation has resulted in negative electricity prices. That electricity could instead be used to fuel electrolysis to produce carbon-free green hydrogen.

A coal site must have these key features to be well suited for repurposing as a green hydrogen production facility.



There are many nuances to sort through to determine whether a coal site with these features is a good candidate for green hydrogen production. Depending on the planned capacity of the production facility, the transmission and distribution (T&D) lines may need to be modified or upgraded to handle the incoming power. The coal site's interconnection may also need to be upgraded by adding a substation and step-down transformers.

Separate white papers consider what makes coal sites good candidates for battery energy storage, bulk energy storage, advanced nuclear, solar PV, net zero industrial clusters, and natural gas and hydrogen-fired generation. At the same time, another examines the equity and environmental justice considerations of repowering coal plants.

A TOOL TO HELP DRIVE BETTER CONVERSATIONS AND PRIORITIZATION

The recently released screening tool allows utilities and other stakeholders to input site-specific information to evaluate different repowering options. The information required is expansive but readily available to most utilities. It includes factors like the availability of buildable land, existing permits and interconnection, available transportation infrastructure, population density of the surrounding area, and T&D line capacity. The tool weights the inputs based on the repowering option being considered and provides a high-level score about the site's suitability for different possible uses.

"We assigned points, and the tool goes through a calculation to give you an evaluated score," Millet said. The tool aims to provide objective information for stakeholders to begin understanding which repowering options hold the most promise for different sites. "What you have here is an efficient way to compare and contrast options and understand what's important," Delis said. "The utilities will still have to do the multi-million-dollar site evaluation with a consulting engineer after the fact. But this tool allows them to feel confident in what they're studying before they make that investment."

The tool can also be helpful beyond the evaluation of individual coal sites. Utilities can use it to inform their integrated resource plans. "If my IRP says that over the next ten years, I'm going to develop X percent of solar or battery storage or some other type of energy," Millet said, "this tool can help investigate what sites I already have that may be amenable to that type of energy."

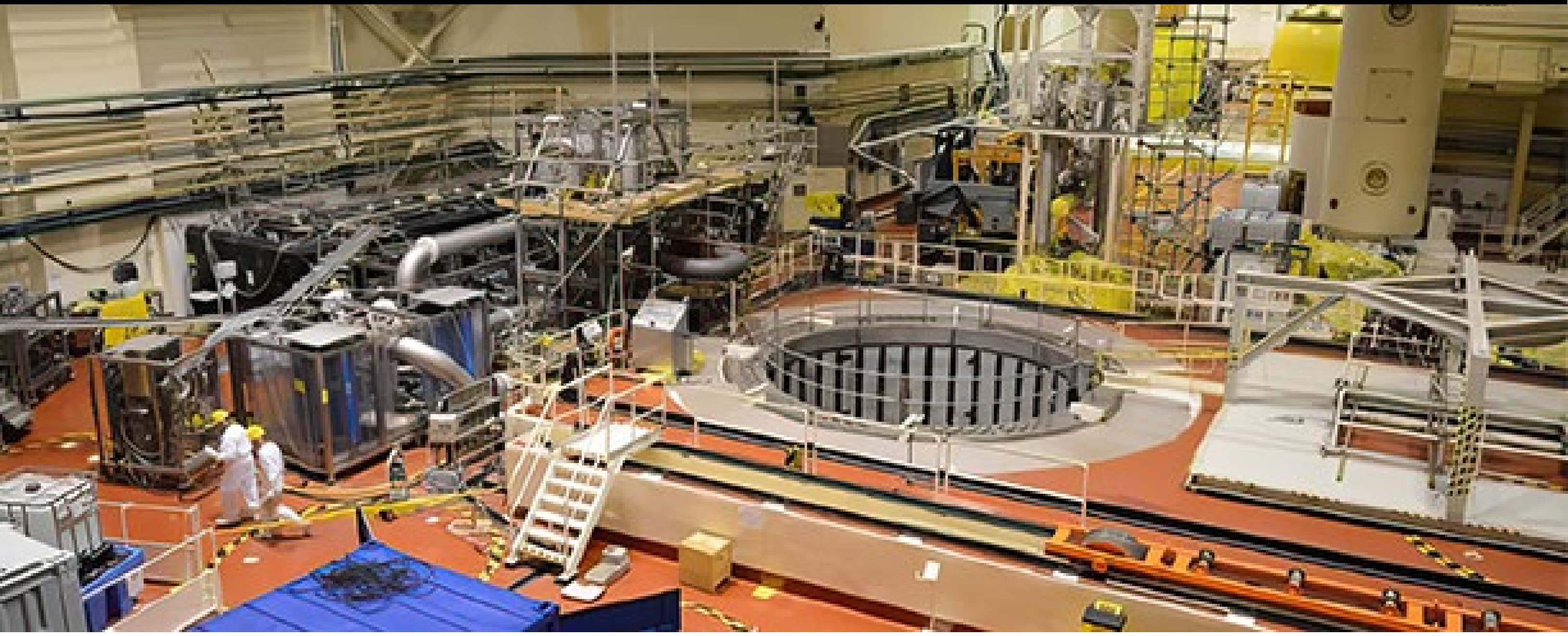
Externally, the tool can also help inform conversations with policymakers, regulators, and other stakeholders who may have definitive ideas about how retiring coal plants should be used to support decarbonization. The tool is a resource for more objective and data-driven conversations about the optimal technology choice for repowering a coal site. The tool can also be helpful to utilities as they develop pilot programs to test clean energy technologies.

"We've seen through the years where a utility will test a technology, but they will do it at a bad site," Delis said. "If it doesn't work, they'll conclude it is a bad technology. But it may just be that they chose a bad site. This tool can help avoid that problem."

EPRI TECHNICAL EXPERT

Lea Millet

EPRI JOURNAL



A Research and Experience-Driven Approach to Chemical Decontamination

Why Taiwan Power Company (TPC) decided not to chemically decontaminate its ChinShan Nuclear Power Station before decommissioning.

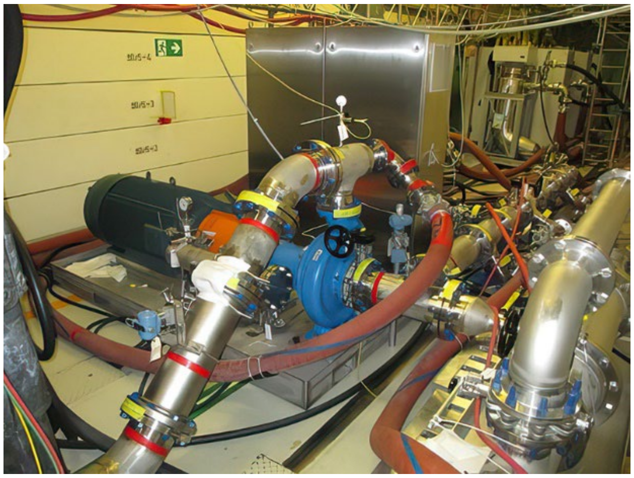
By Chris Warren

Completing a comprehensive chemical decontamination used to be standard procedure whenever a nuclear power plant was scheduled to be decommissioned. It made perfect sense. Plant operators wanted to ensure radiation exposure to workers who completed the decommissioning was maintained as low as reasonably achievable (ALARA). ALARA is a term the Nuclear Regulatory Commission (NRC) in the U.S. uses to describe efforts to limit radiation exposure that prioritize human health and also take into account the technology at a power plant, the economics of reducing exposure, and a range of other factors.

"At first, everybody did it," said Dr. Richard Reid, an EPRI technical executive who previously led chemical decontamination efforts at Maine Yankee, Michigan's Big Rock Point, and Oregon's Trojan nuclear power plants. "Dose rates then were relatively high, and plant operators felt they needed to get them down before decommissioning began."

While worker safety was the primary driver of pre-decommissioning chemical decontamination, it was also a way to contain costs. Workers performing decommissioning can only be exposed to limited amounts of radiation. When dose rates are high in a plant being decommissioned, more workers will be needed, and additional protective gear and safeguards will be required, which can add significant costs.

Another upside to chemical decontamination before plant decommissioning is to proactively reduce the amount of radioactive waste that needs to be processed and managed. "You can reduce the waste classification of the material because you take most of the radioactivity off of the piping surfaces and other components," Reid said.



Philipsburg Pump-Auxiliary Pump for Subsystem Chemical Decontamination

A MOVE AWAY FROM CHEMICAL DECONTAMINATION

Over the past two decades, though, chemical decontamination – which can also occur before maintenance work on a plant that remains operational – has become a far less routine practice before plant decommissioning. The main reason is that improvements in how nuclear power plants operate have reduced system radiation dose rates and, thus, worker exposure.

The reduction in worker radioactivity exposure has been so significant that chemical decontamination is no longer performed at any U.S. plants being decommissioned. In Europe and parts of Asia, chemical decontaminations of nuclear power plants are still performed, albeit in a reduced and strategic fashion. "Instead of doing the whole plant, they may just do certain very high dose rate areas," Reid said.

When Taiwan Power Company (TPC) began planning the decommissioning of its ChinShan Nuclear Power Station in 2015, the utility assumed that it would complete a chemical decontamination. "TPC thought it was a standard practice of the decommissioning in general," said Warren Chien, head of decommissioning section 1 at TPC.

But TPC paused before proceeding with plans to perform a chemical decontamination to understand better the costs and benefits of completing the decontamination and to survey how others in the global industry were approaching decommissioning. "TPC learned that the recent trend has been not to perform chemical decontamination in the U.S.," Chien said. "We started to reconsider the necessity of the system decontamination."

TPC had a strong rationale for investigating whether chemical decontamination in advance of plant decommissioning was necessary. The estimated cost of chemical decontamination at the two ChinShan Nuclear Power Station units was $20 million.

A DECISION GUIDED BY RESEARCH AND REAL-WORLD EXPERIENCE

To fully understand the factors to consider in its decision, TPC turned to past EPRI research, including the *Nuclear Power Plant Decommissioning Sourcebook* and the *Decontamination Handbook,* as well as technical guidance from Reid and others in EPRI's Remediation and Decommissioning Technology Program. Taken together, EPRI's decades of research and real-world experience decontaminating and decommissioning nuclear power plants provided a solid foundation for TPC to evaluate its options.

"We can guide these assessments with experience that we've built up over time. We have experience with both plants that did chemical decontamination and plants that didn't do chemical decontamination. That full experience is quite important in these kinds of decisions," Reid said. "That is really the crux of what we did with Taiwan Power Company. We gave them the insights we developed with our experience in chemical decontamination so they could use them to assess whether or not they should do it." EPRI's engagement with TPC involved analyzing each of the steps involved with decommissioning and developing an estimate of the worker radiation exposure that would occur at each step.

As part of its decision-making process, TPC relied on the EPRI Decontamination Handbook to perform a cost-benefit analysis on decontaminating the reactor recirculation system. The handbook provided guidance that decontamination is only financially worthwhile if average contact radiation rates are greater than a threshold value of 400 mR/hr. A TPC analysis found that the dose rates at ChinShan would be well below this value by the time decommissioning work commenced.

THE IMPORTANCE OF RADIOACTIVE DECAY

TPC eventually opted not to perform chemical decontamination at the ChinShan Nuclear Power Station. One big reason was that operational improvements at the power plant had significantly reduced radioactivity exposure rates to workers who would perform the decommissioning. Another driver for the decision was the future trajectory of radioactivity dose rates.

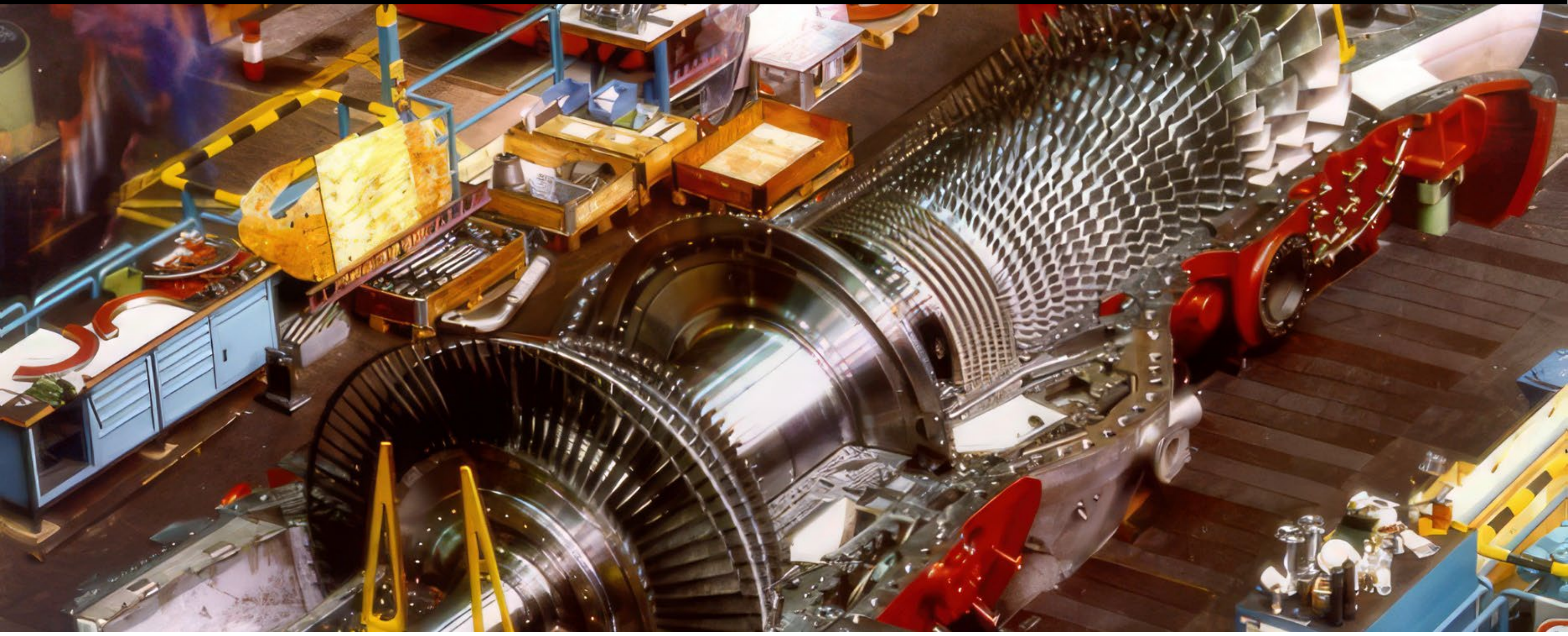
For example, cobalt-60 is a primary contributor to radioactive exposure. But its dose rates fall quickly over a short period of time. “Cobalt-60 has a half-life of five years,” Reid said. “After five years, the dose rates are naturally a factor of two lower than they were when the plant was operating. After ten years, they’re a factor of four lower; after 15 years, they are a factor of eight lower than when the plant shut down. Time and radioactive decay that happens naturally will give you the same benefit as chemical decontamination after about 15 years.”

TPC assessed dose rates in the reactor building and found they had decreased by a factor of two from 2015 to 2021, consistent with expectations. Given that the decommissioning work is not planned to begin for at least a decade after the power plants cease operation, TPC decided that natural radioactive decay would make chemical decontamination unnecessary. “TPC concluded that a minimum of 75 percent of the radioactive inventory in the reactor circulation system will have decayed away once the reactor building decommissioning commences and dose reduction in excess of 85 percent is highly possible,” Chien said. “Based on those facts, TPC utilized EPRI research and technical advice to evaluate the necessity and decided not to perform system decontamination.”

TPC will save an estimated $20 million by not completing a chemical decontamination at the ChinShan Nuclear Power Station. EPRI’s research and experience with TPC and many other utilities provides power plant operators with tools to make an objective decision about the value of chemical decontamination. “If cost is the main driver of the decision, that can be simple. It’s going to cost $20 million, and if my dose rates aren’t that high, I’m not going to do it,” Reid said. “But there are other benefits to doing chemical decontamination, and doing a comprehensive look helps you see what you’re missing by not doing it. Then, each individual utility can make their own decision about whether it’s worth it or not. And that’s going to be very country and plant specific.”

EPRI TECHNICAL EXPERT

Richard Reid



Building Utility Planned Outage Expertise

EPRI works with member utilities to develop manuals and web applications to guide critical natural gas turbine inspections and repairs.

By Chris Warren

Tennessee Valley Authority (TVA) utilizes a rigorous planning process for planned maintenance outages. For years, TVA has started planning outages 18 months in advance and has a defined process for determining the budget, scope, and technology considerations involved with each outage.

The systematic approach to outage planning is understandable. For example, TVA's fleet of generator units includes 32 GE 7EA gas turbines, and the typical cost associated with each 7EA hot gas path outage technical oversight is between $100,000 and $150,000. A 7EA hot gas path inspection (HGPI) inspection costs between $750,000 and $1 million. Besides the high cost, planned outages also pose significant financial, reliability, and safety risks.

For example, planned maintenance activities account for over 70 percent of gas turbine unit unavailability—in large part due to improper reassembly procedures and wrongly applied maintenance practices. Experience has demonstrated the critical importance of effective outages. At Enel's Dock Sud natural gas power plant in Argentina, for instance, an improperly installed SEV Burner Balcony –part of the fuel nozzle that allows a gas turbine to burn more efficiently -- disconnected and damaged turbine blades after an inspection and overhaul. The event prompted a forced outage that lasted six weeks and cost the company over $2 million in repair expenses.

A desire to ensure that GE 7EA and other gas turbine planned outages proceed efficiently and effectively led TVA to join with utilities like DTE Electric Company (DTE), Great River Energy (GRE), and Tri-State Generation and Transmission Association (Tri-State) to work with EPRI to develop the 7EA Hot Gas Path Outage Guide and an accompanying checklist to optimize each step of planned outages. For Clinton Lafferty, who worked as an outage engineer and eventually became outage manager responsible for all gas and steam turbine inspections across TVA's gas turbine fleet, the rationale for helping to develop the guide and checklist was simple.

"One gap I saw was that we do not have a lot of gas turbine expertise internally within TVA," said Lafferty, who is now senior program manager, project engineering, major projects for TVA. "There was a gap between what our less experienced gas turbine engineers knew about how machines come apart and go back together. The EPRI outage guide dovetails with the technical gap we have internally and helps guide site engineers and regional engineers to know what bolts to turn and what extra bolts to replace and all the details that go into an effective inspection and outage."

THE NEED FOR INTERNAL OUTAGE EXPERTISE

The need to close the expertise gap around planning and executing a gas turbine outage effectively and inspection is by no means limited to TVA. That is why EPRI has developed a series of outage manuals and checklists—applicable to GE 7EA hot gas path outages, Siemens 501F gas turbines, and Ansaldo/GE GT26 gas turbines—and a web application to help guide outage inspections.

It was important to comprehensively document how utilities should conduct or oversee gas turbine outages because many of the staffers responsible for conducting them are retiring. "We are finding that the industry is losing its expertise," said Leonard Angello, an EPRI technical executive who leads the Gas Turbine Life Cycle Management program. "A lot of this know-how existed with experienced engineers who didn't necessarily write that knowledge down to pass to the next generation of engineers. This is about providing a detailed framework for what a quality outage is and how to do it and helping transfer knowledge from one generation to the next."

Another driver of this research is to equip utility staff with the knowledge they need to hold original equipment manufacturers (OEM) accountable when they lead turbine outages. Across the industry, utilities have reduced costs by entering into long-term service agreements with turbine OEMs to handle any inspections and repairs. These agreements aim to reduce risk and costs for utilities.

But outsourcing outages and inspections also means knowledge, especially about new gas turbines, stays with the OEM. "The only person who has the knowledge is the OEM because the utility is not directly involved with a lot of these maintenance activities," Angello said. "For the utility, that means you have no knowledge about whether someone is doing the work correctly. These manuals and the web applications give inexperienced staff the knowledge and checklists to know if there is a deficiency in how the work is done."

EQUIPPING WORKERS FOR TODAY AND THE FUTURE

Developing the manuals and web tools was a collaborative effort between EPRI and member utilities. For example, between 2016 and 2019, EPRI worked with member utilities Enel and Naturgy to document and demonstrate outage processes, procedures, and tools at natural gas plants in Spain and South America.

"The working process consisted of sharing with EPRI our experience in outage execution and control, analyzing different problems we had suffered in previous overhauls, and defining what should be done with new outage protocols, quality control forms, and outage quality, allowing our field engineers to perform the quality check," said Tomás Alvarez, head of thermal maintenance, Iberia for Enel, whose company supported the idea of developing the manuals to provide internal direction about performing outages that went beyond what the OEM provided. One reason this was a need for Enel: The operations and maintenance (O&M) life cycle cost of a combined cycle gas turbine is more than double its initial cost.

The work resulted in a series of manuals that provide maintenance activity checklists and guidance for turbine disassembly, inspection, reassembly, and recommissioning of GT26 gas turbines during planned outages.

The collaborative fieldwork helped researchers identify risks involved with GT26 gas turbine overhauls and informed the manuals and tools that were developed. For example, during an inspection of Naturgy's San Roque power plant in 2017, several challenges inhibited the completion of a planned outage. These included limited access to the objective acceptance criteria, expected dimensions, typical findings, and acceptable field repair methods. Objective acceptance criteria provide guidance about whether damaged plant components can continue to be used or need to be repaired or replaced. Expected dimensions refer to the minimum part specifications necessary for components to work properly. Typical findings are, as the name indicates, the condition one would expect equipment to be in after operating for a period of time. And acceptable field repair methods provide guidance about the actions necessary to correct any problems that are discovered.

Following the on-site visits to plants performing GT26 outages, EPRI worked with Naturgy and Enel to outline steps to improve planned outages. These steps are documented in the manuals and web tools, and include:

- Comprehensive maintenance activity checklists that guide disassembly and reassembly hold points, verification points, and witness points with acceptance criteria.
- Inspection techniques and quality control Inspection Assessment Data Sheet (IADS) forms for the rotating, stationary, combustion, and structural turbine components. Each data sheet includes a sketch or photo of the part, its expected dimensions, typical findings, and repair methods with acceptance criteria.
- Field guidance for each of the data sheets, including recommendations for how to handle typical damages.

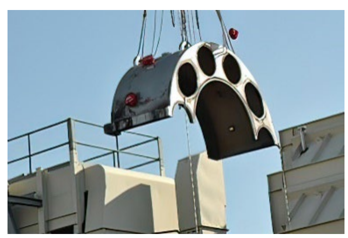
Once these best practice steps were identified, they were utilized at Enel's Dock Sud plant and Naturgy's Cartagena plant in Spain before being published in the manuals. A similarly collective approach was followed in developing the guide for GE 7EA turbine outages. For example, Lafferty and other utility engineers have extensive experience conducting outages for TVA's 32 GE 7EA turbines.

"We contributed a lot of that knowledge and lessons learned to the manual and also reviewed and provided input to the document before it was published," Lafferty said. "We had a lot of practical knowledge to provide, but we also wanted to make sure that the information in the manual was presented in an understandable way so that newer engineers would be able to follow it easily." As was the case with the GT26 manuals, the procedures and tools highlighted in the GE 7EA manual were demonstrated in real-world environments before being published. For example, the guidance and methods were implemented at outages at TVA, Tri-State, and Great River Energy power plants in 2020 and 2021.

DELIVERING REAL-WORLD BENEFITS

Conducting Outages

Since being published, the manuals and tools have made a difference in how outages are conducted. For example, TVA is in the process of starting a new round of hot gas path outages across its fleet. With the help of the manual, Lafferty sees an opportunity to improve the effectiveness of the outages and to reduce the utility's reliance on outside consultants to oversee them. "Why do we spend as much as we do on each outage when we have an engineer on-site?" Lafferty said. "We should bring the consultant in one more time and make sure the TVA engineer is paired with them and the outage guide. That engineer will then be ready for the outage the next time we do one, and we won't have to spend as much."



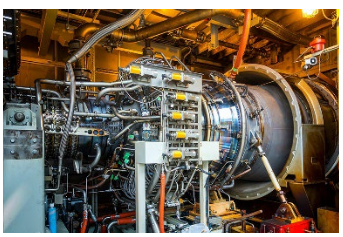
Answering Questions

The existence of the manual also means less experienced staff won't have to depend on seasoned TVA engineers to answer their outage-related questions. "If a recommendation is in the OEM manual, it's approved. And the same thing goes for the EPRI documents," Lafferty said. The benefits of the outage manual extend well beyond TVA. There are over 5,000 GE 7EA units globally and over 100 GT26 turbines. In addition, the knowledge gained by developing these instructional guides helps improve outage approaches to other gas turbines.

Greater Accountability

At Enel, the development of the manuals has resulted in greater accountability for OEMs performing outages. For example, one result of Enel's collaboration with EPRI was the development of non-conformity sheets that Enel staff can use to record and, if necessary, dispute activities performed and results of outages. The record can be used if future disputes emerge. "Additionally, this non-conformity form has to include the mitigation or correction plan to fix the non-conformity," Alvarez said.

The main change Enel has implemented as a result of the work is a detailed and thorough approach to outage activities and quality control. "The greatest benefit has been to increase the reliability and performance of each component and the whole gas turbine after the outage execution," Alvarez said. "And we have a greater quality control and knowledge of all the activities carried out during the outage."



Ongoing Development

EPRI continues to develop new manuals to guide outages for other natural gas turbines, including the GE 6FA, 7FA, and 9FA turbines and the Siemens/MHI 501G turbine. EPRI is also planning to produce more web applications. "It allows us to digitize the outage checklists that we developed and also input your own documentation, like photos of the condition of components, how measurements were taken, and some of the inspection forms," Angello said. Besides being an interactive tool, the web applications also build a repository of information about what repairs and inspections have been completed and the condition of components that can be easily referenced during future outages.

"This is all about making the actual outages, inspections, and repairs more effective," Angello said. "But these are also tools that will continue to build turbine expertise within utilities so that companies have personnel that can either lead and complete outages themselves or confidently oversee OEMs and third-party consultants when they do the work."

EPRI TECHNICAL EXPERTS

Leonard Angello, Bobby Noble

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