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Impact of renewable energy on utility infrastructures

Reliable and resilient generation is essential

DTE

on the cover

This landfill gas processing plant generates renewable electricity from methane captured from decomposing solid waste. Courtesy: NV5

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inside

UNDERSTANDING THE GROWING IMPORTANCE OF HYDROGEN

A look at hydrogen, from generation to blending with natural gas

NATURAL GAS IS AN ESSENTIAL ENERGY SOURCE. It provides instant and efficient heat for families and businesses, while providing a means for electricity generation and industry development throughout the U.S. One of the most significant challenges facing the natural gas industry is decarbonization. With the passage of state bills in California and Hawaii mandating 100% carbon-free electricity by 2045, and Massachusetts, New Jersey, New York and Washington, DC also considering similar legislation, the pressure on the industry to decarbonize has never been greater.

This article examines several key reports and studies focused on hydrogen. The literature referenced describes how hydrogen is generated, its interchangeability with natural gas and how it blends with natural gas. Also discussed is hydrogen's properties, how hydrogen affects residential and industrial equipment, how blending hydrogen in pipelines affects greenhouse gas (GHG) emissions and its costs. The article also reports on the recent partnership between Gas Technology Institute (GTI) and Electric Power Research Institute (EPRI).

FIGURE 1 (Above): Materials testing lab test replicates polyethylene pipe. Courtesy: Gas Technology Institute

Hydrogen generation

Power-to-Gas, electrolysis, methane pyrolysis, steam methane reforming (SMR) and biological processes are among the common hydrogen generation methods. Power-to-Gas is the conversion of electrical energy into chemical energy in the form of hydrogen and/or methane. The process uses water electrolysis, often powered by renewable energy sources, to split water molecules to produce hydrogen and oxygen. It takes about 2 gallons of water to produce enough hydrogen to power a single home. That's less than a single toilet flush. Jack Brouwer at University of California, Irvine calculated that 2% of the water delivered to Los Angeles by the aqueduct would produce enough hydrogen to fuel every vehicle in California.

With electrolysis, the electrolyzer can be a central component of Power-to-Gas strategies, as it enables the conversion of electrical

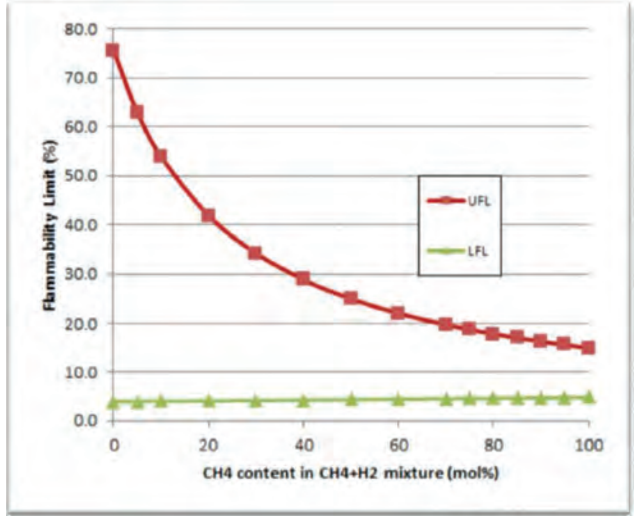

FIGURE 2: The flammable range of hydrogen at 4% to 75% by volume is far wider than that of methane at 4.4% to 17% by volume. This can be calculated for methane-hydrogen mixtures as indicated by this graph. Courtesy: Gas Technology Institute

energy into chemical energy contained in hydrogen through the electrolysis of water molecules. The three dominant technologies are alkaline, proton exchange membrane and solid oxide electrolyzer cell.

Methane pyrolysis converts natural gas to hydrogen and solid carbon. No CO_2 is produced or released. The solid carbon can be used to make tires black, or it might have applications in electronics, building materials or road fill. Anything that keeps the carbon out of the air means the hydrogen produced has zero carbon emissions.

The most common process is steam methane reforming in which natural gas is converted to hydrogen and carbon dioxide in the presence of steam and a catalyst. More than 95% of the world's hydrogen is produced using the SMR process. In this reaction, natural gas is reacted with steam at an elevated temperature to produce carbon monoxide and hydrogen. A subsequent reaction — the water gas shift reaction — then reacts additional steam with the carbon monoxide to produce additional hydrogen and carbon dioxide.

Another process is gasification, which converts biomass, coal, natural gas or waxes into a synthesis gas. This gas is primarily composed of hydrogen and carbon monoxide, but also may contain smaller amounts of methane, ethane, propane, ash and tars. "In-well gasification" converts oil and gas inside a well (maybe an old, depleted well that doesn't produce much anymore but still contains hydrocarbons) into hydrogen and CO_2. The hydrogen floats to the top for extraction; the CO_2 stays in the well. Again, it produces zero carbon hydrogen from fossil fuels.

Biological processes that produce hydrogen do exist, though the path to commercialization and market viability is much longer than the previously mentioned paths. Bacteria and microalgae can produce hydrogen through biological reactions using sunlight or organic matter as a feedstock. These technology pathways are at an early stage of research, but in the long term have the potential for sustainable, low-carbon hydrogen production.

Hydrogen and natural gas interchangeability

Blending hydrogen into the existing natural gas pipeline network has been proposed as a means of increasing the output of renewable energy systems. If implemented with relatively low concentrations — up to 5% hydrogen by volume — storing and delivering renewable energy to markets appears to be viable without significantly increasing risks associated with utilization of the blended gas in end-use equipment, overall public safety or the durability and integrity of the existing natural gas pipeline network. However, the appropriate blend concentration should be assessed on a case-by-case basis.

The consequences of mixing hydrogen with natural gas throughout the North American natural gas distribution system is important for maintaining a safe and reliable network. GTI is looking at the impact of hydrogen blends on this and on end use equipment. This work assesses the corrosion and hydrogen embrittlement mechanisms associated with adding hydrogen to natural gas.

GTI has completed hydrogen blend studies for a consortium of natural gas operators as well as the U.S. National Renewable Energy Laboratory. These projects focused on the life cycle assessment of hydrogen blending as well as the safety, leakage, durability, integrity, end use and environmental impacts. Following this study, GTI conducted an evaluation of the effects of hydrogen blending in natural gas on nonmetallic material properties and operational safety through laboratory testing (see Figure 1). This work assessed the material integrity and operational compatibility of a bounded natural gas pipeline system and its components with a 5% hydrogen-blended fuel to help determine if any system upgrades might be necessary to reduce risk and support gas interchangeability. The level of effects on uncalibrated equipment will need further investigation, and those who may operate equipment or appliances that are uncalibrated should be notified and potentially assisted through an upgrade or recalibration prior to any hydrogen blending program. Equipment with operating characteristics that are sensitive to varying hydrogen concentration will need additional study on a case-by-case basis, as a number of these combustion systems may be sensitive to small changes in gas properties. It also identified future research needs when considering gas interchangeability with blends that contain greater than 5% hydrogen.

The most common index when considering interchangeability is the Wobbe Number. Wobbe Number accounts for variations in the heating value of a fuel gas by normalizing the heating value of a fuel gas over the area of a burner orifice. The Wobbe Number of a fuel gas is defined as the heating value divided by the square root of the specific gravity. Many gas specifications use Wobbe Number as a key parameter. Wobbe Number is considered superior to heating value as an index for interchangeability determination, but a single number is insufficient for assessing interchangeability since it does not address attributes such as flame speed, lift or characteristics that can contribute to incomplete combustion.

Properties of hydrogen

The most important combustion properties in terms of the differences between hydrogen and methane combustion are calorific value, Wobbe Number, flammability range and flame speed. The calorific value of hydrogen on a volumetric basis is a third of that of natural gas primarily due to its low relative density. However, in terms of combustion, the Wobbe Number provides the most appropriate indicator of gas interchangeability. The Wobbe Numbers of hydrogen and methane are much closer together than the volumetric calorific value. The blend could be in the 15% range before the Wobbe Number of the blend dips blow acceptable limits for most equipment. The flammable range of hydrogen is 4% to 75% by volume. The flammable range of methane at 4.4% to 17% by volume. This can be calculated for methane-hydrogen mixtures (see Figure 2). However, the flammability of hydrogen is higher than methane, which could be a safety concern. But its diffusivity also is much higher, which means that hydrogen wafts away quickly.

Hydrogen is flammable when mixed even in small amounts with air. Ignition can occur at a volumetric ratio of hydrogen to air as low as 4% due to the oxygen in the air and the simplicity and chemical properties of the reaction. However, hydrogen has no rating for innate hazard for reactivity or toxicity. The storage and use of hydrogen poses unique challenges due to its ease of leaking as a gaseous fuel, low-energy ignition, wide range of combustible fuel-air mixtures, buoyancy and its ability to embrittle metals that must be accounted for to ensure safe operation. Liquid hydrogen poses additional challenges due to its increased density and the extremely low temperatures needed to keep it in liquid form.

The effect of hydrogen on gas equipment

End use equipment burning natural gas can be divided into three broad categories:

- Residential and commercial appliances
- Industrial burners equipment
- Stationary engines and turbines.

Residential and commercial appliances. Residential and commercial appliances as a class of combustion equipment are designed to operate with little monitoring by consumers. They are manufactured by many companies, can vary in burner configuration and can have a long service life. This means appliance burners have the potential to be out of tune. When gas composition is changed, out-of-tune appliances are of the most concern. Older water heaters and furnaces are at higher risk of operating out of manufacturer specifications. Changing natural gas by adding hydrogen has the potential to lower flame temperature, decrease heat transfer rates and increase CO emissions. SoCalGas is working with University of California, Irvine to explore the feasibility and cost of retrofitting residential appliances for higher hydrogen blends. If an inexpensive component like a burner orifice could be replaced, it might make higher blends of hydrogen easy to achieve.

Industrial burners. Unlike residential appliance burners, industrial burners cover a wide combustion range and much wider range of firing rates. There is a lot of opportunity in industrial applications. These are processes that are hard or impossible to electrify. Hydrogen could be a good way to decarbonize them. Industrial equipment typically is attended and is managed by control systems. The indices developed for appliance burners are not well suited for industrial burners. Instead, approaches have been developed to determine the most sensitive industrial burners and to make needed adjustments of these burners based on changes in the fuel gas composition. According to "Literature Review: Hydrogen Impact on End-Use Equipment, Infrastructure and Safety," published by GTI, two methods can be used to characterize industrial burners. The first, burner operating mode characterization groups burners by fuel type, oxidizer type, draft type, mixing type, heating type and control type. This classification approach provides guidance in identification of the burners most sensitive to fuel gas composition changes. The addition of hydrogen will lower heating value and Wobbe Number. However, these effects could be overcome by making an airflow adjustment or using a different burner nozzle.

Power turbines and large stationary engines. Turbines operate at the highest practical temperature to achieve the greatest possible efficiency. These units are sensitive to material degradation and thermal damage, according to the GTI report. Adjustments are made when fuel gas is changed to prevent material and thermal harm. These adjustments are often made when the natural gas supply changes. Hydrogen is particularly problematic for turbines because flame speeds and flame lengths change with hydrogen addition. Hydrogen also can attack metal blades at high temperatures. Turbine operators typically specify low hydrogen limits in the fuel gas to safeguard their equipment. The addition of hydrogen requires study of the impact of the hydrogen and the concentration of hydrogen on the turbine, according to the GTI review. However, manufacturers are now building turbines that can handle hydrogen blends (see "LADWP embarks on hydrogen generation project")

Stationary engines also are sensitive to fuel gas changes. However, their operating conditions are less severe than that turbine conditions. This makes large engines more tolerant of fuel gas changes. The addition of hydrogen can affect engine performance. Engine operators must be informed when hydrogen is added to the fuel gas so tunings can be changed.

Blending hydrogen with natural gas does have an impact on industrial equipment, but the studies are not conclusive. It depends on the amount of hydrogen and the content of the blend.

How blending hydrogen in pipelines affects emissions

GHG effects of blending hydrogen into natural gas supplies depend on the source of the hydrogen used in the blending strategy. The amount of benefit can be quantified in terms of a carbon intensity in grams of CO_2 emitted per megajoule of

LADWP embarks on hydrogen generation project

The Los Angeles Department of Water and Power (LADWP) is embarking on a groundbreaking hydrogen generation project, said an article from the American Public Power Association.

The article said that LADWP plans to phase out 1,800 MW, coal-fueled generation at the Intermountain Power Project (IPP), which it participates in with electric power cooperatives and other public power utilities in California, Nevada and Utah, and replace it with natural gas-fueled generation that would eventually be fueled entirely by hydrogen. In addition to generation, the IPP also includes two large transmission systems that move power throughout the region and to Southern California.

The motivation for the decision for LADWP to shut down the coal facility and replace it with another generation source was the city's adoption of a target to be powered by 55% renewable energy by 2025 and be powered 80% by renewable energy by 2036. In addition, Los Angeles, like the rest of California, faces a target of being powered 100% by clean energy by 2045.

"If you look at reality, there is no way to get to 100% renewable energy without hydrogen in the mix; it just doesn't exist," Marty Adams, LADWP's General Manager and Chief Engineer, told the utility's board of commissioners this month.

There are two main factors driving the decision to stay with a fossil fueled plant, according to the American Public Power Association article. One is the need to have a generation source that can integrate increasing amounts of renewable energy into the grid; the other is the need for "a dispatchable rotating mass" to support a 500 kV high voltage direct current (HV dc) line that runs from the plant and provides Southern California with 2,400 MW of capacity, Paul Schultz, LADWP's director of Power External Energy Resources, said.

In addition to generation from the IPP, the HV dc line also serves as a conduit to move renewable energy to California load centers. It currently connects with about 400 MW of wind power, but it could serve as a renewable energy hub in the future. There are already 2,300 MW of solar interconnection requests in the queue, and LADWP is in discussions with entities to bring as much as 1,500 MW of wind power from Wyoming.

Intermountain's role as a renewable energy hub, and its unique location, are central to the plan to convert the plant to burn hydrogen. The hydrogen to fuel the plant would have to be manufactured through electrolysis, a process where water is separated into its two constituents, hydrogen and oxygen. The process would be powered by renewable energy provided through Intermountain's transmission systems. Running that process using renewable energy helps reduce the overall emission profile of the repowering project. It could also help with the economics of the project as renewable power that might otherwise be curtailed.

Burning hydrogen does produce nitrogen oxide, but it does not produce carbon dioxide. The generator's heat recovery steam generator would be sized to increase air flow and help reduce emissions from the plant, Schultz said. LADWP also is discussing carbon capture technologies with several vendors. LADWP says that based on technology of the turbine manufacturers, the generators are expected to have the capability of burning a fuel mixture of 30% hydrogen when it begins operating in 2025.

In all, the total cost of the project, the generation and HV dc converters is $1.9 billion, Schultz said. The hydrogen conversion equipment would be a separate cost. LADWP is exploring "working with partnerships" to that portion of the project and is not yet ready to go public with a cost estimate, Schultz said. One possibility would be to secure funding through a Department of Energy grant, he said.

Converting the generation equipment to gradually increase the hydrogen burning capacity would be an "incremental capital cost" and could be coordinated with regular turbine maintenance schedules, Schultz said.

Further out, LADWP is also looking at the potential at the IPP site to store hydrogen. The plant is located on top of a large geologic salt dome, the only one in the Western U.S. A single cavern at the site could store hydrogen equivalent to 84 times as much energy as a 1,200 MWh battery system and store that energy for months at a time. The site has the potential for 100 caverns, LADWP said.

Storing hydrogen at the Intermountain site would allow for "seasonal shifting" that could provide arbitrage opportunities to defray the costs of hydrogen production, by manufacturing hydrogen when energy prices are low and using it to generate power when prices are high. The utility also is looking at the caverns to support a 160-MW compressed air energy storage generating plant.

The current energy-in, energy-out roundtrip efficiency of the renewable hydrogen process is about 30% to 35%, Schultz said, but noted that calculation does not take into account other factors such as the policy mandates the utility must comply with and other potential costs such as the potential for forced renewable energy curtailments.

"We are very excited about the opportunity to take a leadership role with this project," Schultz said. When completed, the project would be the largest commercial scale hydrogen generating plant in the world.

potential energy. Each unique source will have a unique carbon intensity value. The carbon intensity of the hydrogen fuel can be combined with the carbon intensity of the natural gas fuel on a weighted average basis, according to the GTI report.

A report titled "Pathways for Deep Decarbonization in California," published in May 2019 by Energy Futures Initiative (EFI), was produced to define the existing California clean energy landscape and recommend steps for accelerating the move to meet the state's carbon reduction goals by midcentury. According to the EFI report, there are several opportunities for reducing GHG emissions in the industry sector through fuel switching: fuel switching from fossil fuels to electrification or hydrogen, substituting gas or renewable natural gas (RNG) for coal and substituting gas or RNG for petroleum.

In cases where electrification and energy efficiency cannot lead to measurable emissions reductions, hydrogen can offer a clean-burning substitute. Certain processes require combustion-based heat because the fuel meets a specific heating need and provides components important to the chemistry of the process, according to the EFI report. Where industrial end-use systems permit, hydrogen may be blended with natural gas to reduce the emissions intensity of methane.

Cost

A report from the Hydrogen Council shows that the cost of hydrogen solutions will fall sharply within the next decade, and sooner than previously expected. As scale up of hydrogen production, distribution, equipment and component manufacturing continues, cost is projected to decrease by up to 50% by 2030 for a wide range of applications, making hydrogen competitive with other low-carbon alternatives and, in some cases, even conventional options, according to the Hydrogen Council report.

Significant cost reductions are expected across different hydrogen applications. For more than 20 of them, such as long-distance and heavy-duty transportation, industrial heating and heavy industry feedstock, which together comprise roughly 15% of global energy consumption, the hydrogen route appears the decarbonization option of choice, the report said.

The report attributes this trajectory to scale-up that positively impacts the three main cost drivers:

- Strong fall in the cost of producing low-carbon and renewable hydrogen
- Lower distribution and refueling costs thanks to higher load utilization and scale effect on infrastructure utilization
- Dramatic drop in the cost of components for end-use equipment under scaling up of manufacturing.

Because of hydrogen's impact on and value as a renewable fuel, it has zero GHG footprint (depending on the source of the hydrogen used in the blending strategy), it can be blended with natural gas and it can be stored in the natural gas infrastructure.

The benefits of scaling up the hydrogen economy extend beyond its head-to-head cost competitiveness. Hydrogen can support governments' energy security goals, and its relative abundance creates opportunities for new players to emerge in energy supply and for new job creation to stimulate the global economy. Hydrogen remains the only viable, scalable option to decarbonize industry and other segments that have struggled to minimize their environmental impact.

EPRI and GTI partnership

GTI has recently begun an unprecedented partnership with EPRI in what GTI is calling the "Low-Carbon Resources Initiative (LCRI)." It is a five-year, collaborative effort supported by major electric and gas utilities to advance the technologies needed for deep decarbonization within the next decade so they can be deployed in the 2030 to 2050 timeframe.

Both GTI and EPRI recognize that breakthrough technologies across the full energy value chain will be required to achieve decarbonization goals, and the organizations see opportunities to combine and leverage resources across the utility industry for the greater good. The effort will improve the strength, efficiency and resiliency of the U.S. energy grid and reduce impact on the environment. In addition, accelerating hydrogen successes will be a major emphasis in their work together under the LCRI.

EPRI provides thought leadership, industry expertise and collaborative value to help the electricity sector identify issues, technology gaps and broader needs that can be addressed through effective research and development programs for the benefit of society. GTI is the leading research, development and training organization addressing energy and environmental challenges to enable a secure, abundant and affordable energy future. For more than 75 years, GTI has been providing economic value to the natural gas industry and energy markets by developing technology-based solutions for industry, government and consumers.

Final thoughts

Because decarbonization is inevitable, the natural gas industry must take another look at how to achieve the goals within the 2030 to 2050 timeframe. Electrification and RNG are only part of the answer. Blending hydrogen into the existing natural gas pipeline network shows promise toward reducing GHG emissions.

Hydrogen is easily generated. Its interchangeability with natural gas is predictable. It can be blended with natural gas with little effect on equipment and pipelines and can significantly reduce GHG emissions. In addition, cost is expected to decrease over the next decade. GT

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Bridging the gap between electrical infrastructure and renewables

While renewable energy sources like wind and solar photovoltaics may be the future of a low carbon electric grid, there is a need for reliable and resilient dispatchable generation along with energy storage

RECENT POWER OUTAGES HAVE BEEN ATTRIBUTED TO CAPACITY SHORTFALLS, WHICH PLAYED A MAJOR ROLE IN THE CALIFORNIA INDEPENDENT SYSTEM OPERATOR'S (CAISO'S) ABILITY TO MAINTAIN RELIABLE SERVICE ON THE GRID. On Sept. 6, 2020, the U.S. Department of Energy (DOE) made a rare move of issuing an emergency order under the Federal Power Act (FPA) to authorize the maximum operation of three natural gas-fired facilities on CAISO's grid.

Things could get worse. A report titled "Pathways for Deep Decarbonization in California," published in May 2019 by Energy Futures Initiative (EFI), was produced to define the existing California clean energy landscape and recommend steps for accelerating the move to meet the state's carbon reduction goals by midcentury. According to the EFI report, from a systems standpoint, energy infrastructure will be exposed to increasing climatic and environmental hazards in California. The combination of sea-level rise, land subsidence and storm surges could threaten the integrity of levees and damage nearby natural gas pipelines, electric transmission infrastructure and other critical infrastructure. Oil refineries are vulnerable to sea-level rise and coastal flooding. Wildfires and flooding have already damaged the electricity infrastructure in California. Roads, railroads and grid infrastructure are vulnerable to wildfires. This not only affects transportation in general, it poses threats to the energy sector where key roads and railroads are used for the transportation of fuels.

Although the news reports focus on electricity and power outages, the real focus needs to be on power infrastructure and resiliency. The infrastructure must be upgraded to integrate new installations of renewables, while also providing redundancy and resiliency. While renewable energy sources like wind and solar photovoltaic (PV) are supposed to be helping relieve the burden on the grid, renewables are not enough. Solar PV and wind are intermittent, and require that other sources of generation, or energy storage, are used to take up the slack. Without the use of dispatchable electrical generation, the infrastructure is not able to meet the demand and/or the ability to meet GHG reduction. While conventional power plants are typically operated on natural gas today, in the future, renewable gases such as renewable hydrogen and biogas-derived renewable natural gas (RNG) can provide a clean, low carbon baseload with the same existing infrastructure. There have been advances in battery technology. However, batteries are very costly and can only provide backup power for a limited time (based on the size and energy rating of the batteries).

While California is an extreme example with its seasonal wildfires and high temperatures, the state still serves as a model for the rest of the continental U.S. in terms of environmental and energy regulations. The many California examples in this article apply to the rest of the U.S. References to Canada are exceptions and are noted.

Electrification is not a silver bullet

According to the EFI report, there are several opportunities for reducing GHG emissions in the industry sector through fuel switching: fuel switching from fossil fuels to electrification or hydrogen, substituting gas or RNG for coal and substituting natural gas or RNG for petroleum.

Electrification and RNG are only part of the answer. According to "Implications of Policy-Driven Electrification in Canada," A Canadian Gas Association (CGA) study prepared by ICF International, electrification would require a dramatic increase in electrical generation, transmission and distribution along with the associated cost increases. Electrification policy needs to be designed with consideration of the specific nature of the demand met by each of the fuels it seeks to replace, and with consideration of the need for a reliable, sustainable and affordable system, or the result could be an ineffective electrical system unable to meet critical peak demands. Electrification initiatives need to be selective to avoid negatively impacting grid reliability.

Manufacturing and industrial processes are often energy intensive, with this sector using almost as much energy as the residential, commercial and transportation sectors combined, according to the CGA study (see Figure 1). In addition, 75% of industrial energy comes from fossil fuels, making this a critical area for GHG emission reductions. We should not loose sight of the fact that energy efficiency still remains the most cost-effective way to reduce GHG emissions.

A transition from current energy systems to high levels of mandated electrification will require a significant and costly expansion of Canada's electrical infrastructure, the CGA study said. Currently only 20% of Canada's energy requirements are met by electricity. Based on this analysis, replacing refined petroleum products and natural gas in homes, businesses, industry and vehicles with electricity in Canada would require an expansion of generating capacity from 141 GW today, to between 278 GW and 422 GW of capacity by 2050. This expansion, along with the associated incremental costs of added electric energy, electric technology adoption, new transmission and distribution infrastructure and RNG, could increase national energy costs by between $580 billion to $1.4 trillion over the 30 year period between 2020 and 2050.

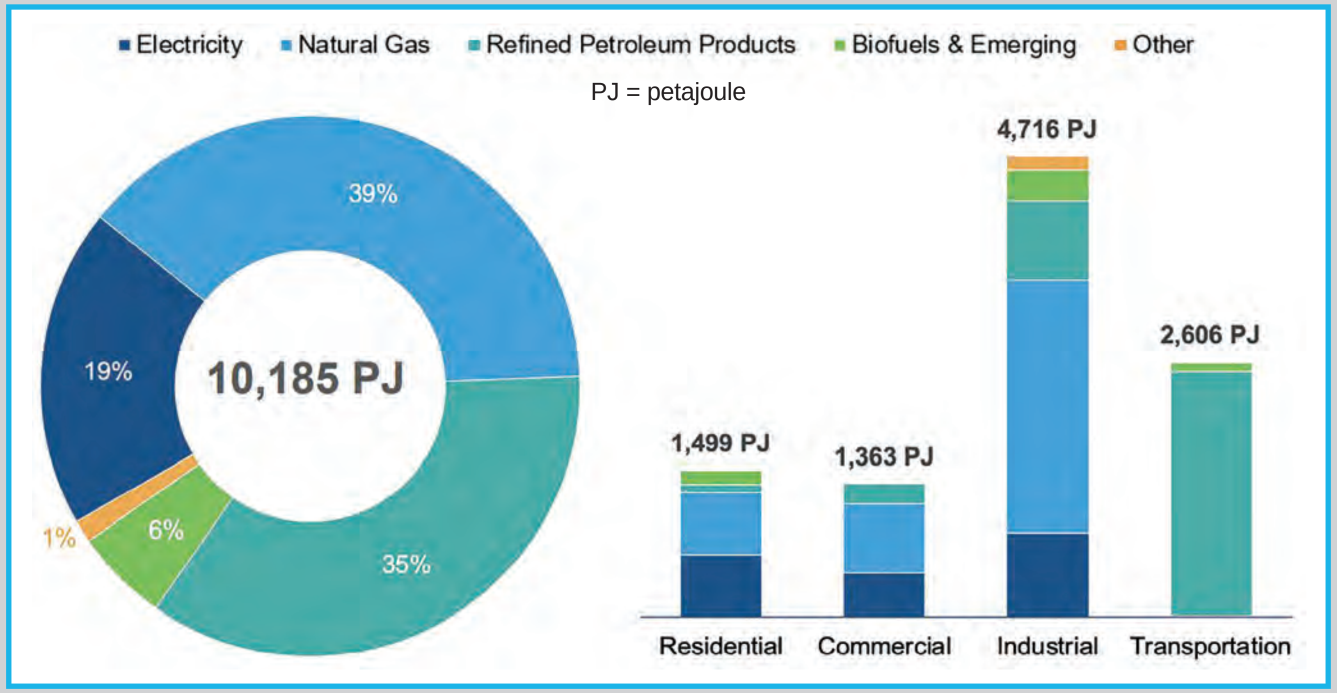

FIGURE 1: Breakdown of 2018 end use energy consumption in Canada. Courtesy: Canadian Gas Association (CGA)

Electrification only reduces industry's greenhouse gas emissions if enough renewable-generation capacity is added to decarbonize the grid and meet industry's electricity demand, according to "Plugging in: What electrification can do for industry," a report from McKinsey & Company published in May 2020. Most electrical equipment for industry is no more energy efficient than conventional equipment. Switching to electric equipment and using electricity generated by burning fossil fuels would therefore have much the same or even worse environmental impact as continuing to use conventional equipment. Electricity producers could add renewable generation capacity to the grid that delivers electricity to industrial sites. Alternatively, developers of renewable electricity generation could devote any new renewable capacity to their industrial customers by means of power purchase agreement.

Renewable energy sources are not enough

According to "Executive Summary: California's Clean Energy Future," published in 2019 by SoCalGas, in 2006 California passed the landmark legislation, known as AB 32, requiring California to increase its use of solar and wind power and significantly reduce GHG emissions. The state accomplished its AB 32 goals four years ahead of schedule. This has been due, in part, to investments in wind and solar technologies, aggressive energy efficiency goals and the movement away from coal to natural gas.

In 2018, California set an even bolder goal: to achieve carbon neutrality by 2045. Making this vision a reality will require business leaders, non-governmental organizations and policy makers to work together to reimagine how the state's energy infrastructure can operate as one integrated system that maximizes emissions reductions and minimizes waste, the Executive Summary said.

There is no single, clear path today to reach California's carbon neutral vision. Its investment in solar and wind technologies have made them price-competitive and are proof points of renewable energy innovation. Similar policies and investments have led to advances and adoptability in battery technology. But solar, wind and batteries alone will not get California where it wants to go, the Executive Summary said. The use of renewable gases and our extensive, existing natural gas infrastructure should not be overlooked.

If California (or any other state in the U.S.) wishes to develop a sustainable energy future, it will need to successfully answer the question, "How will we store solar and wind energy to use when the sun isn't shining, and the wind isn't blowing?" According to the Executive Summary, the solution to the state's renewable future is not as simple as generating more solar and wind power and adding them to the grid. Wind and solar are intermittent forms of energy. They do not provide a reliable, continuous power supply; the power they generate is not always available when people need it most. Today, California produces excess wind and solar power that cannot be used, and this energy waste is expected to grow. By 2025, California is expected to waste the amount of electricity that could power Los Angeles County for more than a month.

The Executive Summary said achieving these objectives would require California to:

- Use the suite of energy options currently available, including wind, solar, batteries and traditional natural gas
- Expand implementation of existing and nascent technologies, such as RNG, Power-to-Gas and Carbon Capture and Utilization
- Foster policies that allow for the development of innovative technologies and new ideas.

California cannot assume that all the energy solutions to achieve carbon neutrality are known and exist today.

However, using current infrastructure, excess wind and solar is either curtailed or California pays other states to take it, according to the Executive Summary. That will only increase as California increases the amount of wind and solar energy used. While batteries can help reduce the intermittency problem of wind and solar, they cannot do it alone. The state can harness this excess wind and solar by leveraging the existing natural gas infrastructure to store electricity. Using Power-to-Gas (P2G) technology, California can capture the excess wind and solar energy to be used when it is needed most. P2G does this by converting excess wind and solar power into hydrogen, which can be used alone, or mixed with traditional natural gas or combined with excess CO_2 to be stored in the current natural gas pipeline infrastructure. Several significant P2G projects have been announced, including one serving Los Angeles, from a Utah coal plant converted to natural gas. The future plan would see the Intermountain 840 MW combined cycle gas plant using 100% renewable hydrogen from P2G in the years that follow.

The Executive Summary said, "We cannot assume we now have all the answers or have developed all the solutions. That means that any policies that are developed need to allow for continued innovation."

Bridging the power gap

What comes next? How can the power infrastructure be increased with solar PV, RNG and wind doing as much as practical to bridge the gap? As previously stated, the infrastructure is not able to meet the demand or the ability to meet GHG reduction without the use of fossil fuel or renewable gas.

A more inclusive approach will be needed, said the Executive Summary — one that is technology neutral, welcomes all ideas, considers all forms of energy, encourages and allows current and future innovation and factors in the cost and affordability of energy. California has the world's fifth largest economy and is the nation's most populous state. Its people must be able to afford to live in the state and businesses must be able to stay. Achieving the state's environmental goals cannot come at the price of deepening the state's affordability crisis or continuing to widen income disparity, according to the Executive Summary.

The total expense of reaching the 2045 target, as well as the full implications to California's consumers, is unknown. What is certain is that the decisions California makes today will have far-reaching consequences across many facets of Californians' daily lives. Success will depend on remaining open to all technologies and resources that can help create a realistic and affordable path to carbon neutrality, the Executive Summary said.

Any solution California adopts must also be scalable. The state emits less than 1% of global GHG emissions. To have any meaningful impact on global GHG emissions, California's energy solutions must demonstrate results that can be adopted by other states and countries. This includes examining the entire energy value chain, so California doesn't inadvertently transfer its emissions to other regions, according to the Executive Summary.

One way the state can reduce fugitive emissions is by harnessing its waste streams; 80% of methane emissions come from daily activity — food sources and waste. California can use that waste to generate energy through the increased development and use of RNG. Most policy makers recognize at some level the need to continue to use natural gas as part of the state's fuel mix. Adding RNG helps to reduce its climate impacts, the Executive Summary said.

Replacing less than 20% of California's natural gas throughput with RNG achieves the same emissions reductions as overhauling 100% of California's buildings to all electric. In addition, we can add some fraction of P2G derived renewable hydrogen which captures, stores and transports some of California's wasted solar and wind energy. This solution does not require millions of Californians to change out their appliances or spend money to replace existing infrastructure and is two to three times less expensive than electrifying California's buildings sector. GT

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Designing a microgrid system: Li-ion versus gas generator

Battle of the backup: Evaluating a 1 MW solar PV/natural gas microgrid for firm on-peak power and resiliency

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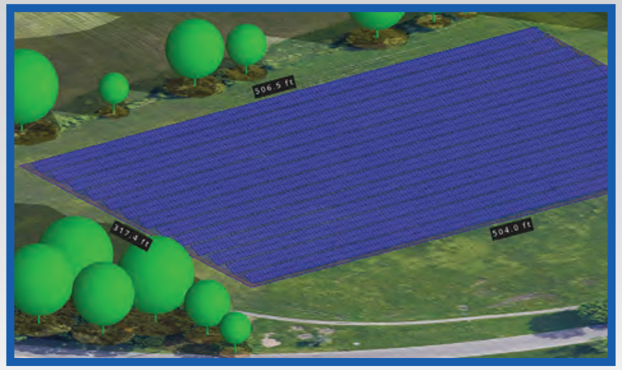
MICROGRIDS USING MULTIPLE SOURCES OF GENERATION HAVE THE POTENTIAL TO ADD RESILIENCY TO BOTH THE GRID AND TO CUSTOMER SITES. Additionally, if low carbon sources of electrical generation are used such as solar photovoltaics (PV), these microgrids can significantly reduce the energy carbon footprint (see Figure 1). However, the solar resource is variable and intermittent, requiring that other sources of generation, or energy storage, are used for a complete and resilient design. This article describes the results of a study of a 1 MW solar PV microgrid model, hypothetically located at a large Michigan commercial facility. The simulated annual PV output is connected on the customer side of the power meter, and the cost savings is analyzed against a large commercial, time-of-day primary service rate. A popular solar PV simulation software tool, Helioscope, was used to model the hourly PV output against the customer electric interval data for one year, to present both operational cost savings and performance of seven generation configurations:

FIGURE 1: Rendering of 1.3 MW dc solar photovoltaic (PV) array. Courtesy: DTE Energy, James Leidel



1. 1.0 MW dc to 1.0 MW ac solar PV array
2. 1.3 MW dc to 1.0 MW ac solar PV array
3. 1.0 MW natural gas generator only (no solar PV)
4. 1.0 MW dc to 1.0 MW ac solar PV array plus natural gas generator
5. 1.0 MW dc to 1.0 MW ac solar PV array plus 1.0 MW/8 MWh Li-ion battery
6. 1.3 MW dc to 1.0 MW ac solar PV array plus natural gas generator
7. 1.3 MW dc to 1.0 MW ac solar PV array plus 1.0 MW/8 MWh Li-ion battery.

Working with real pricing provided by engine generator and battery OEMs, the capital cost, fuel usage, maintenance, 20-year lifecycle cost and carbon savings were compared for all variations as needed to produce a firm eight hours of "on-peak" power for the customer. The results demonstrate the value and potential of hybrid microgrid systems, as well as the limitations of large Li-ion batteries as compared to a natural gas generator.

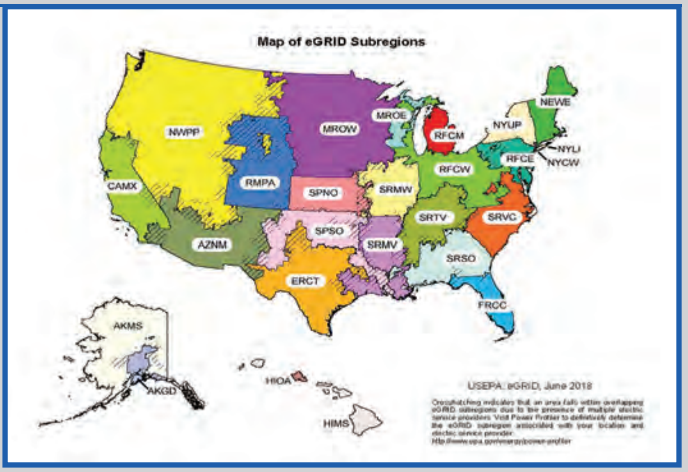
Details of the study

To provide eight hours of firm on-peak power with a solar PV array, the firming power must be capable of operating at the full 1 MW capacity for eight hours during cloudy days. This can be accomplished by a 1 MW/8 MWh battery or a 1 MW gas generator. The 8 MWh designation is the size of the battery cell storage, while the battery inverter would only be sized to the 1 MW power requirement. The on-peak hours for this rate include the hours between 11 a.m. to 7 p.m., Monday through Friday, minus 10 holidays each year, and all kilowatt demand-based charges for the monthly billing and the annual kilowatt demand peak, or "ratchet" are based on a maximum kilowatt seen in a 30-minute rolling window during on-peak hours. Additional cost savings are achieved from a 1 MW demand reduction, often called "peak shaving." Alone, solar PV can capture some fraction of this demand savings, but with the intermittent nature of solar energy, it is often one quarter to one third of the total possible demand savings, which is 1 MW for this study.

While cost savings are based on the given electric rate and a customer natural gas cost of $3.50 per million BTU, the carbon savings are generated using the Michigan electric grid for year 2020, and the estimated carbon content for year 2050. The study uses carbon data are taken from recent work by the consulting firm ICF International using USEPA eGrid Power Profiler 2018 data for the Michigan region labeled RFCM, as commissioned by the Energy Solutions Center. ICF estimated eGrid region carbon content in year 2020 and 2050 using its "Integrated Planning Model," which considers regional legislation, mandates, utility commitments and announced power generation mix from the region.

The USEPA graphic illustrates the eGrid regions, and the carbon intensity varies across the map (see Figure 2). The Midwest U.S. still contains a fair amount of coal-fired generation, yielding a 2018 eGrid RFCM (Michigan) carbon intensity of 1.66 lb CO_2 per kWh. (0.75 kg CO_2 per MWh). ICF estimates that in the year 2050, this RFCM region will still produce 0.989 lb CO_2 per MWh (0.45 kg CO_2 per MWh). There is no CO2 attributed to the solar PV output, and the gas generator is assumed to have an average 33% electrical efficiency and is fueled by natural gas producing 117 lb CO_2 per million BTU (181.5 kg per MWh) consumed.

FIGURE 2: This USEPA graphic illustrates the eGrid regions, and the carbon intensity varies across the map. Courtesy: U.S. Environmental Protection Agency eGrid Power Profiler



For the solar PV portion, zero carbon is attributed to its kilowatt-hour production, and for the natural gas generator, DTE Energy assumed a generic, 33% electrically efficient unit, with natural gas combustion producing 117 lb/MMBTU (181.5 kg/MWh).

The firming output power is controlled to provide a 1.0 MW microgrid net power output during all on-peak hours. Figure 3 shows a five-day simulated period during a higher solar resource timeframe in August. The red line illustrates the solar PV array output firmed up by the dashed blue line of firming power kilowatts. The combined output yields the bold black line showing 1.0 MW of microgrid output during all on-peak hours needed to obtain the kilowatt demand cost savings. The functionality of this system also would provide 1.0 MW of backup power to the host customer site. The battery system will be limited to eight hours, while the gas generator would provide a continuous backup for as long as needed.

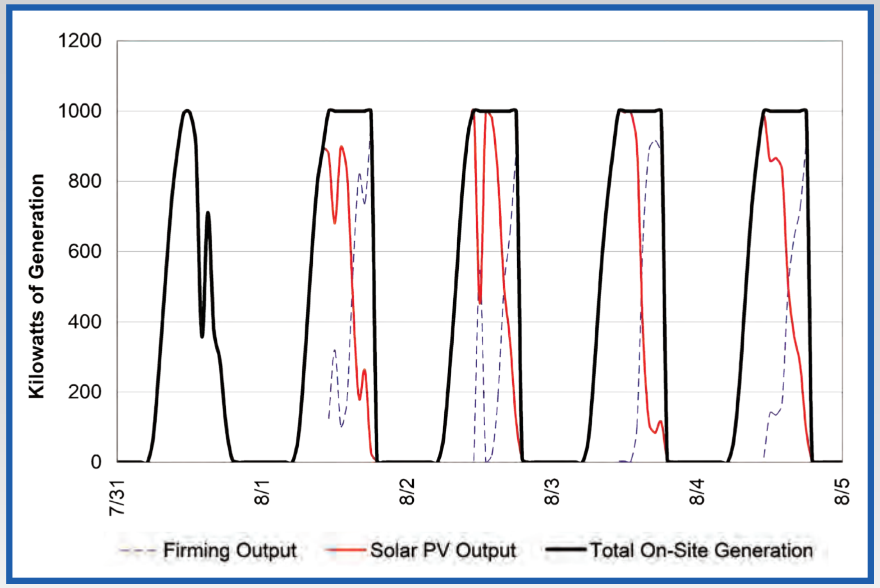
Monday through Friday on-peak times provide the firm 1.0 MW of power while the Saturday and Sundays have the naturally provided solar power only. The red line plus dashed blue line will sum to produce the full 1.0 MW black power trace between 11 a.m. to 7 p.m. The summertime solar PV capacity factor is 21% to 22% but is less than 10% during darker winter months. Adding more solar panels for a 1.3 MW dc array improves this somewhat with a peak June capacity factor of 28% in southeast Michigan. Please contact the author for more details. The simulation shows that the amount of firming power required to maintain a full 1.0 MW of power to be approximately 50% of the total output kilowatt-hours over the full year.

Keep in mind that the battery firming output source energy is from the nighttime grid, and the natural gas generator firming output is from a lower carbon natural gas generator. In certain parts of the country, and in future years, the gas generator may have a higher carbon footprint, but this is not the case today in the Midwest U.S. The 1.3 MW dc solar array yields about 380,000 kWh of additional renewable energy, (+28%) so that the solar PV could provide 60% of the total annual kilowatt-hours, with only 40% from the firming output. The capital cost needed to provide 300 kW dc of additional PV panels for this extra 28% solar boost is estimated to be less than $200,000 in capital outlay. This is a very modest impact due the low cost of solar PV panels today.

The study used a fully installed cost of $1.30/watt for the 1.0 MW dc system and $1.495/watt for the 1.3 MW dc array. These estimates do not include land costs but are fully installed ac output cost estimates for a greenfield, ground mount installation. The fully installed 1 MW/8 MWh battery system was budgeted at $3.35 million, per a quote from Michigan CAT, and the gas generator was budgeted at $840,000, also fully installed.

If there was a desire to create a firm power delivery using only solar PV and battery, DTE Energy would need to design for the worst-case scenario, which in southeast Michigan is in the month of dreary December. The poor solar resource in December only provides a 6.4% capacity factor from the 1.0 MW dc array and an 8.3% capacity factor for the 1.3 MW dc array. Using this month as the design limitation, an additional 3.95 MW of solar capacity would need to be installed to charge the Li-ion battery system from the solar PV system during daylight hours, while concurrently maintaining the 1.0 MW ac output. For the 1.3 MW dc design, an additional 3.4 MW dc of solar must be added. This is a substantial area of land and capital cost required for a purely solar/battery microgrid. This alone illustrates the value of a gas/solar hybrid system. The engineering design process involves optimization and some compromises. So, it should be obvious it is unlikely this extreme installation would be designed. More likely, the system would deal with some winter compromises, drawing from the utility electric grid to charge the battery.

FIGURE 3: Solar PV power output plus firming generation for five summer days. Courtesy: DTE Energy, James Leidel



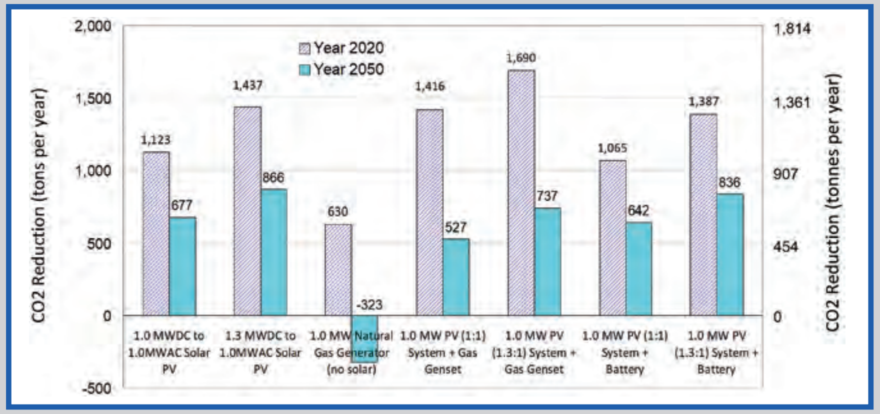


FIGURE 4: Annual CO_2 reduction estimates for 2020 and 2050 (1 tonne = 1,000 kg = 2,200 lb). Courtesy: DTE Energy, James Leidel

CO_2 reduction and cost estimates

Carbon savings are illustrated in Figure 4 for both 2020 and 2050. Each microgrid system achieves a CO_2 reduction in 2020, with the largest being the 1.3 MW dc solar plus gas generator (recall that the battery is grid-charged at night). In the year 2050, this is no longer the case, and the gas generator now produces more CO_2 than the grid. However, by this time it is likely that carbon capture from the engine exhaust or cost-effective renewable gas fuels also will lower the CO_2 footprint of this same gas generator. Renewable biogas-derived methane, and Power-to-Gas-derived renewable hydrogen are seeing significant attention and investments today, so, by 2050, they will likely become cost competitive.

Lastly, we investigate the capital cost per ton of CO_2 reduction. Decisions are most often made with financial considerations as a primary. The maximum reduction in CO_2 and the fastest method to accomplish this goal also is worthy of consideration, as well as potential future technologies and expected future grid carbon intensities.

Figure 5 illustrates the capital cost per ton CO_2 reduced in relation to the Michigan RFCM grid. The lowest cost per ton reduced is the 1.3 MW dc solar only option. However, this system is intermittent and only provides kilowatt-hour support, but not the required firm 1 MW power demand. The best performer for firm demand reduction is the 1.0 MW dc solar plus gas generator. This system also has the fastest financial payback at 6.8 years of any of the firm power solar PV options. The best payback is the gas generator only option. This is largely supported by the low natural gas fuel price of \$3.50/MMBTU (\$3.32/GJ natural gas). The significantly higher unit cost of CO_2 reduction for both PV plus battery systems is due in part to the need to charge the batteries at night from off-peak grid energy and the 2020 capital cost of the 1 MW/8 MWh Li-ion battery. In future years, the grid CCO_2 intensity will fall, as will the capital cost of utility scale Li-ion batteries. However, consider that the CO_2 intensity of the gas generator fuel supply will also fall in future years as economically priced renewable gases are introduced into the gas distribution grid as well.

Looking ahead

Solar PV plus natural gas generation is an effective and economical microgrid solution for both cost and carbon performance. This will be true for decades into the future in the Midwest U.S. Renewable gases such as renewable methane and hydrogen can make the Solar PV plus gas generator microgrid 100% net zero carbon as these fuels become more economical. Other eGrid regions will perform differently than the Michigan RFCM eGrid region, but the PV simulation and microgrid model presented here could be easily replicated for any location in the U.S. GT

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- ***Eric Burgess*** *of the Energy Solutions Center provided grid carbon intensity estimates for 2020 and 2050, via a study commissioned from ICF International (www.icf.com).*

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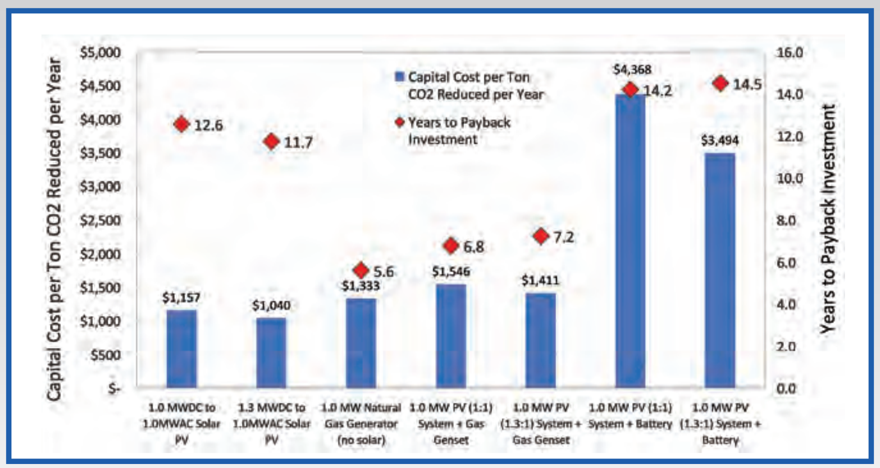
FIGURE 5: Capital cost per ton CO_2 reduced in relation to the Michigan RFCM grid. Courtesy: DTE Energy, James Leidel



Spotlight on DTE Energy

DTE Gas is taking a unique, holistic approach to achieving its net zero goal by including suppliers and customers on the journey

AS PART OF DTE ENERGY'S COMMITMENT TO REDUCE ITS CARBON FOOTPRINT, the Michigan utility recently announced that DTE Gas will reduce greenhouse gas emissions (GHG) — from procurement through delivery — to net zero by 2050.

This most recent announcement from the gas utility builds upon several previous DTE Energy announcements focused on lowering emissions and helping drive the fight against climate change. This gas announcement outlines a unique approach within the industry. DTE is taking a holistic and comprehensive approach to reducing the emissions associated with natural gas by not only achieving net zero gas emissions in its own operations by 2050 and encouraging the company's suppliers to do the same, but also by inviting customers to address up to 100% of their own natural gas carbon footprint through participation in the company's energy efficiency and voluntary emissions offset programs.

"Climate change is one of the defining public policy issues of our time and it demands a bold response," said Jerry Norcia, president and CEO of DTE Energy. "The level of impact urgently needed can only be achieved by viewing the challenge through a holistic lens, bringing our suppliers and our customers on the journey with us. This is the right plan for our environment, for our customers and for our communities."

A three-pronged approach will have profound impacts on reducing greenhouse gas emissions:

DTE Gas operations

The company will reduce greenhouse gas emissions from its internal operations to net zero by 2050 through a combination of operational improvements and carbon offsets, while continuing to provide customers with safe, reliable and affordable energy. DTE Gas's main renewal program and infrastructure modernization efforts will reduce both methane and combustion-related emissions from the company's operations. In addition, the company will invest in a combination of renewable natural gas (RNG) and carbon offsets such as bio-sequestration.

Image courtesy: DTE Energy

Powering toward a net zero carbon future

Supplier emissions net zero

Gas production, gathering, processing and transport

- Net zero greenhouse gases by 2050.
- By 2050, DTE will be removing around 1.3 million metric tons of GHGs per year through practices to procure cleaner gas from suppliers.

DTE Gas emissions net zero

DTE Storage, transmission, city gate and distribution

- Net zero greenhouse gases by 2050.
- By 2050, we will be removing around 1.4 million metric tons of GHGs per year through infrastructure upgrades, operational improvements and carbon offsets.

Helping customers reduce their carbon footprint

Natural gas use in customers' homes

- Reduce GHG 35% by 2050 (from 2005).
- By 2050, DTE will be removing around 3.5 million metric tons of GHG per year through energy efficiency programs, an enhanced voluntary emissions offset program and advanced technologies.

Working with suppliers

DTE Gas is currently working with the production and supply industry to bring awareness to the need to reduce emissions from natural gas production. The company is leading the industry toward a common goal of developing a consistent reporting standard for how emissions are measured and reported from producers who supply the company with its natural gas needs. Within the next five years, DTE Gas will tighten up the purchasing requirements for natural gas to ensure it is acquiring the cleanest gas available from producers. Ultimately, the DTE Gas goal is to only procure gas from suppliers and transporters that have achieved net zero carbon emissions across their infrastructure.

Partnering with customers

DTE Gas will continue to encourage customers to reduce their own emissions by giving them greater access to energy efficiency programs. In addition, the company is enhancing its voluntary emissions offset program to allow customers to reduce up to 100% of their homes' and businesses' emissions through renewable natural gas and carbon offsets. Over time, DTE Gas also will look to leverage advanced technologies, such as hydrogen, geothermal and carbon capture as part of our efforts to help our customers reduce their emissions.

The Michigan chapter of the global environmental nonprofit, The Nature Conservancy, is supportive of the plan. The Nature Conservancy is a global environmental nonprofit working to create a world where people and nature can thrive.

"We applaud DTE's commitment to achieve net zero carbon emissions in its gas operations, for it is an important step toward reducing Michigan's carbon footprint," said Helen Taylor, Michigan director of The Nature Conservancy. "We know that nature can provide powerful solutions and we look forward to working with DTE to identify and implement as many of those solutions as possible." GT