SPRING/20

VOLUME 33 / ISSUE 1

gastechnology

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Alternatives to Electrification

Pathways for decarbonization

DTE

on the cover

Landfill gas is composed of approximately 50% methane and 50% carbon dioxide along with trace amounts of other gases including siloxanes, which are compounds containing silicon and oxygen. This landfill gas processing plant generates renewable electricity from methane captured from decomposing solid waste. Courtesy: NV5

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Gas Technology is an educational supplement from:
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Washington, DC 20001
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Printed in the USA

energy solutions center websites

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inside

Landfill gas is composed of approximately 50% methane and 50% carbon dioxide along with trace amounts of other gases including siloxanes, which are compounds containing silicon and oxygen. This landfill gas processing plant generates renewable electricity from methane captured from decomposing solid waste. Courtesy: NV5

CUTTING CARBON IN CALIFORNIA

Environmental and energy concerns are typically addressed in California first; for a preview of what's to come regarding decarbonization, look West

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.

EFI was established in 2017 by former California Secretary of Energy Ernest J. Moniz to address the imperatives of climate change by driving innovation in energy technology, policy and business models to accelerate the creation of clean energy jobs, grow local, regional and national economies and enhance energy security. The members of EFI are fact-based analysts who provide their funders with unbiased, practical real-world energy solutions.

While most of the report deals with the residential market, this article focuses on the industrial sector.

California's industrial sector

According to the report, California's industry sector is the second-highest emitting sector in the state's economy and is one of the most technically and economically difficult to decarbonize. The California Air Resources Board (CARB) divides the industrial sector into 11 subsectors. CARB further divides one of these sectors — manufacturing — into 17 subsectors. Combined, these primary and secondary subsectors provide the framework for the analysis in the EFI report.

Each subsector has energy requirements, emissions sources and process needs. Many subsectors have large-scale, energy-intensive operations with complex supply chains and a low tolerance for operational downtime, the report said. Industrial sector decarbonization strategies looks at emission sources (coal, petroleum, natural gas), the nature of the emissions (combustion versus non-com-

FIGURE 1: Numerous industry subsectors have a high electrification potential. Some subsectors (*) that require high temperature process heat also have a high electrification potential due to available technologies such as induction heating and electric arc furnaces. Courtesy: EFI. Compiled using data from LBNL, 2018; CARB, 2018.

GHG Emissions, Process Heat Temperatures, and Electrification Potential by Industry Subsector

Subsector	California GHG Emissions, 2016 (Metric Tons CO_2e)	Process Heat Temperatures	Electrification Potential
Chemical and Allied Products	6,234,353	High	Medium
Food Products	3,290,383	Medium/High	Medium
Metal Durables: Fabricated Metal Products	454,567	High	High*
Metal Durables: Machinery	86,346	High	High*
Petroleum Refining and Hydrogen Production	29,534,155	High	Low
Plastics and Rubber	114,083	Low/Medium	High
Primary Metals	495,933	High	High*
Pulp and Paper	404,256	High	Low
Stone, Clay, Glass, and Cement	8,446,176	High	Low
Transportation Equipment	282,930	Medium/High	High
Wood and Furniture	43,387	Medium	High

bustion) and the unique characteristics defining each subsector (process heat requirements, electrification potential).

The report details nine potential greenhouse gas (GHG) emission reduction methods that can help decarbonize the industrial sector in California:

- Carbon capture, utilization and storage (CCUS)
- Fuel switching (electrification, hydrogen or renewable natural gas)
- Facility best management practices
- New technology adoption
- Biogas collection
- RNG
- Reducing fugitive emissions
- Industrial combined heat and power (CHP)
- Energy efficiency.

Given the diverse nature of many industrial processes, an effective decarbonization strategy will require tailored solutions that accommodate the unique challenges and opportunities in each subsector, the report said.

Industry is a difficult sector to decarbonize. The level of systems integration, high-temperature process heat requirements and the heterogenous nature of industrial processes remain the primary challenges to decarbonization. However, several opportunities for reducing GHG emissions that may avoid massive system retooling, protracted operational downtime or a complete overhaul in technical expertise include energy efficiency improvements and facility best management practices, new technology adoption and fuel switching, CHP and CCUS. These pathways, especially fuel switching and CCUS, can lead to measurable emissions reductions across the major industrial subsectors in California, according to the report.

Carbon capture, utilization and storage

CCUS is expected to play an important role in sectors and processes that are difficult to decarbonize. At present, CCUS is likely the only option available for decarbonizing several industrial processes such as cement production, oil refining and natural gas processing, in addition to further mitigation opportunities across California's large industrial base, the report said.

California is also well-positioned to take advantage of its estimated geologic storage potential of 34 to 424 billion metric tons of CO_2, making CCUS a viable option for industrial decarbonization, according to the report. There are many industrial facilities clustered near San Francisco and the surrounding area, Los Angeles and the surrounding area, and along the Central Valley. The proximity of these industrial facilities to potential CO_2 sequestration sites could offer an opportunity to build new infrastructure that would support the transport and storage of captured CO_2 from numerous facilities.

Costs and challenges of CCUS in industry

CCUS presents technical, economic and public policy challenges that must be addressed to ensure viability of this option. From a technical standpoint, capturing CO_2 can be a challenging and energy-intensive process. However, numerous industrial processes tend to have higher concentrations of CO_2 in their effluent streams, which can result in fewer technical (and economic) challenges for capture compared to less concentrated streams of CO_2 such as those found in the power sector (e.g., approximately 5% CO_2 concentration for natural gas plants and 15% for coal plants), the report said.

The transport and geologic sequestration of CO_2 also presents challenges that include regulatory uncertainty, post-injection site stewardship and liability, and the length of time required to demonstrate permanence. However, the recent CCS Protocol developed for the California LCFS program provides guidelines to help address some of these issues including a 100-year minimum period for post-injection site care and monitoring prior to site closure. The absence of sufficient CO_2 pipeline infrastructure in California is another impediment to CCUS project development. Pipelines remain the most cost-effective means of transporting large amounts of CO_2 over long distances for the purposes of utilization or geologic sequestration.

Cost estimates for industrial CCUS are more uncertain than those in the power sector and can vary based on the type of industrial facility and capture technology. The costs (and technical difficulties) of industrial CCUS also are affected by the number of emissions sources present at each type of facility. For example, emissions from cement plants stem from the precalciner and kiln, whereas emissions from petroleum refineries come from a much larger number of individual sources. Despite the uncertainty and variability in CCUS costs, industrial facilities tend to form regional clusters. This characteristic can be leveraged for shared CO_2 transportation networks and geologic storage opportunities, according to the report.

Fuel switching

The opportunities for reducing GHG emissions in the industrial sector through fuel switching include fuel switching from fossil fuels to electrification or hydrogen, substituting gas (or RNG) for coal and substituting gas (or RNG) for petroleum.

Electrification. Electrification could play a role in decarbonizing certain subsectors of California's industrial sector (see Figure 1). Process heat currently accounts for about 50% of the energy consumed in the manufacturing subsector, the report said. However, only 5% of process heat applications are electrified. Fossil fuels still account for most of the energy used in conventional boilers and for direct-combustion process heat.

Industrial process heat requirements can vary widely depending on the industrial subsector, ranging from 150 F to 3,000 F across several applications. Although very little process heat currently comes from electricity, electrification can be a viable near-term option for helping to decarbonize industrial processes that require low- or medium-temperature process heat (less than 752 F), while potentially being sufficient for certain high-temperature process heat requirements such as electricity-based steel production.

Many potential industrial electrification opportunities involve electrifying process heat for applications across various subsectors. Process heat can be provided through resistance heating, industrial heat pumps, electric boilers, direct resistance melting, direct arc melting, electrolytic reduction, infrared processing, induction furnaces and ultraviolet curing. In addition, the manufacturing subsector could use industrial heat pumps and electric machine drives for building HVAC and machine drives, respectively (see Figure 2). Some of the electrification technologies with the highest potential for adoption include electric boilers, electric arc furnaces, heat pumps and induction melting, according to the report.

Electrification costs and challenges. While electrification may appear attractive to some, there are challenges to widespread adoption. According to the report, challenges for industrial subsectors with electrification potential include large capital costs for equipment turnover, higher costs of electricity as a fuel relative to other energy resources and technical hurdles to achieving high temperature process heat.

Industrial segments in subsectors with high-temperature process heat requirements, such as cement production, have low potential for electrification with existing commercial technology and have fewer options for decarbonization. The remaining options remain include CCUS and using RNG or hydrogen as fuels.

In addition, oil refineries present major challenges to electrification. The extent of process integration specific to the petroleum refining and hydrogen production subsector means that any technological disruption such as electrification could require considerable system re-engineering. It is also common practice for oil refineries to self-consume energy resources generated as refining process byproducts. Electrification would eliminate this option, which could result in increased energy costs for oil refineries. CCUS may be one of the readily available options for decarbonizing California's 17 oil refineries, which have a combined capacity of more than 1.9 million barrels per day, the report said.

Additional challenges to the electrification of the industrial sector include low natural gas prices, aversion to major process redesigns and little current industry momentum for electrification. In California, industrial consumers enjoy relatively low natural gas prices, compared to end users in other sectors of the state's economy. In 2016, their natural gas prices were the second lowest of all end-use sectors — only utilities in the electric power sector paid less, according to the report. These relatively low natural gas prices, coupled with the high equipment costs of switching, could discourage industrial facilities from electrification of certain end uses.

Industrial facilities can have useful lifespans of 50 years or longer, and any process changes through retrofits or systems re-engineering can be relatively costly. This has the potential to make some commodities such as steel more expensive if it comes from an industrial facility that pursues emissions reduction strategies compared to a facility that does not employ low-carbon strategies, the report said. For

Opportunities for Industry Electrification by Technology Type

End Use	Subsector	Electrification Technology
Process Heat	Chemicals and Allied Products	Resistance heating; industrial heat pump; electric boiler
	Food Products	Industrial heat pump; electric boiler
	Plastic and Rubber Products	Resistance heating; infrared processing
	Primary Metals	Induction furnace
	Primary Metals: Iron & Steel	Direct arc melting
	Primary Metals: Non-ferrous Metals (Excluding Aluminum)	Electrolytic reduction
	Pulp and Paper	Industrial heat pump
	Stone, Clay, Glass, and Cement: Glass and Glass Products	Direct resistance melting (electric glass melt furnace)
	Transportation Equipment	Induction furnace; electric boiler
	Other Manufacturing subsectors	Resistance heating; electric boiler
Process Heat: Curing	Printing and Publishing; Wood and Furniture	Ultraviolet curing
Building HVAC	All Manufacturing subsectors	Industrial heat pump
Machine Drive	All Manufacturing subsectors	Electric machine drive

FIGURE 2: These technologies could be used to promote industrial electrification. Courtesy: NREL, 2017a; NREL, 2017b

example, fuel switching in the industrial sector typically requires a change in manufacturing processes, which can lead to substantial new equipment costs.

Another barrier to industrial sector electrification is the lack of empirical data and information, especially regarding cost, which limits the ability of analysts, modelers and policymakers to determine the efficacy of industrial electrification, according to the report. A 2017 report on industrial electrification opportunities yielded limited available data, especially for the costs of different electrification technologies. Much of the available data was reportedly anecdotal.

Another current barrier to industrial electrification involves the potentially higher cost of energy from fuel switching to electricity. One cost comparison of electric and natural gas-fired boilers indicated that although electric boilers had a lower capital cost and were more energy-efficient, the electricity price was approximately three times more expensive than natural gas on an energy-equivalent basis, making the electric boiler roughly twice as expensive as a natural gas boiler for first-year costs, the report said (see Figure 3).

Hydrogen. 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 report. Where industrial end-use systems permit, hydrogen may be blended with natural gas to reduce the emissions intensity of methane.

Alternatively, certain pieces of equipment can be retrofitted to run on hydrogen. For example, ethylene crackers have seen retrofits to support hydrogen use (and hydrogen is already a byproduct in refineries); and in cement production, hydrogen can be combined with waste-derived fuels. Clean hydrogen could replace natural gas or coal in refining and ironmaking as a substitute for fossil-based feedstocks and/or reducing agents, the report said.

Hydrogen costs. The two most common methods to produce hydrogen include steam-methane reforming (SMR) of natural gas and electrolysis. SMR is currently the cheapest method for producing hydrogen and has a high-volume production cost of less than $2 per gallon of gasoline equivalent. Large-scale SMRs (central station reformers) are a mature technology that have an initial investment cost of $400 to $600 per kilowatt. Hydrogen also can be produced using smaller, distributed SMR units that can be scaled according to the desired production level.

Aside from the cost per kilogram of produced hydrogen, other production cost estimates include a total plant capital cost of approximately $190 to $350 million depending on use and type of carbon-capture equipment; hydrogen pipeline infrastructure ($1 million per mile for dedicated hydrogen pipelines); hydrogen compression, storage and dispensing costs ($2 per kilogram of hydrogen); and CO_2 transport and sequestration (roughly $2 per metric ton of CO_2 for transport and $13 per metric ton of CO_2 for storage), according to the report. Electrolysis is currently expensive and is considered a longer-term option.

Facility best management practices

Facility best management practices were benchmarked to the U.S. Environmental Protection Agency (EPA) ENERGY STAR Challenge for Industry, which seeks to reduce the energy intensity of industrial sites by 10% in five years.

New technology adoption

New technology adoption, according to the study, included the combined emissions savings from three technologies: higher-efficiency kilns in the cement subsector (30% lower thermal fuel use), smart systems for manufacturing automation to reduce energy intensity by 20% and a 25% reduction in energy use through additive manufacturing in select manufacturing subsectors.

This means that new technology adoption is possible within the manufacturing subsector and includes additive manufacturing and smart systems. Estimates suggest that additive manufacturing could reduce energy use in manufacturing operations by 25%, the report said. It may be most relevant in the construction, electric and electronic equipment, food products, textiles, transportation equipment, and wood and furniture subsectors. Implementing additive manufacturing in these subsectors could potentially reduce emissions by 1.0 $MMTCO_2e$. Smart systems could assist process automation in the manufacturing subsector, with the potential to achieve a reduction in energy intensity of 20%. For California's manufacturing subsector, a 20% reduction in energy consumption could potentially result in an emissions savings of nearly 3.8 $MMTCO_2e$, according to the report.

Biogas capture

Biogas is waste methane that is passively emitted in many sectors. Within the industrial sector, biogas sources are found in the landfills, wastewater treatment, and solid waste treatment subsectors. In 2016, these subsectors emitted 8.83 MMTCO2e in biogas. By capturing and diverting these sources of methane for upgrading to RNG, the industrial sector could receive a double benefit in terms of methane emissions savings plus displacement of fossil natural gas.

Biogas capture costs and challenges

The typical capital cost for a 40-acre landfill gas (LFG) collection system (designed for 600 cubic feet per minute) is approximately $1.1 million with additional annual operation and maintenance costs of $191,000, the report said. Biogas collection systems generally include the processing infrastructure needed to purify the LFG for different end uses, which occurs through primary treatment (e.g., removal of water, moisture and particulates) and, if necessary, more involved processing stages including secondary treatment (removal of sulfur compounds) for power generation or medium-Btu applications and advanced treatment (removal of impurities such as CO_2) for high-Btu applications such as vehicle fuels or pipeline-quality gas.

Two of the key factors that make RNG more expensive than conventional natural gas are the special requirements for processing and upgrading RNG and pipeline interconnection fees. Prior to injection into a local distribution network through an interconnection, RNG must undergo testing and verification to ensure that it meets pipeline-quality standards. The infrastructure required to upgrade and inject RNG into a local distribution pipeline system typically makes up two-thirds of capital equipment costs for an RNG project, with the remaining one-third of the cost attributed to the actual biogas collection system (for anaerobic digestion). According to the report, these capital costs also vary by project site, with the lowest costs associated with landfill gas, and then progressively higher costs for RNG from wastewater treatment, municipal solid waste, dairy manure and forestry and agricultural residues, respectively.

Pipeline-quality renewable natural gas

Fuel switching from coal and petroleum to natural gas blended with RNG also could provide emissions reductions. RNG is biogas that has been upgraded to pipeline quality and is chemically equivalent to fossil natural gas. RNG also diverts gaseous waste streams that would otherwise emit methane. For this reason, RNG is considered a lower carbon source because the methane emissions it prevents have a higher global warming potential than the CO_2 that results from RNG combustion, the report said.

The use of RNG for decarbonizing pipeline gas is particularly well-suited to helping the industrial sector reduce its GHG emissions, since natural gas plays a prominent role in numerous industrial applications as a resource for process heat, as a fuel for CHP systems and as a feedstock for products such as chemicals and fertilizers. These industrial needs — currently met by conventional natural gas — also could be met by RNG. In addition, fuel switching to RNG could require little-to-no infrastructure turnover and therefore lower infrastructure-associated costs relative to other fuel switching options.

RNG costs and challenges

RNG is considerably more expensive to produce than natural gas (between 2-3 times the cost), according to the report. It is important to note that these costs vary based on the type of feedstock. RNG qualifies as an advanced biofuel under the federal Renewable Fuel Standard (RFS) and is

FIGURE 3: On an energy-equivalent basis, electric boilers can have a higher first-year cost than natural gas boilers. The first-year cost equates to the purchase price of the equipment plus fuel costs in the first year (calculated at 5,280 annual operating hours). Courtesy: NREL

Cost Comparison of Electric Steam and Natural Gas Boilers in the West U.S. Census Bureau Region (100-Boiler Horsepower)

Metric	Electric Boiler	Natural Gas Boiler
Purchase price	$53,860	$87,540
Fuel price ($/MMBtu)	$24.09	$6.20
Hourly fuel cost	$81.39	$25.94
First-year cost	$483,615	$224,501

eligible to generate offsets under California's LCFS and cap-and-trade programs.

Reduce fugitive emissions

According to the report, the transmission and distribution subsector was responsible for approximately 5.1 MMTCO$_2$e of California's GHG emissions in 2016, of which 80% was from non-combustion sources. Non-combustion emissions are largely fugitive emissions from natural gas pipelines, with a marginal amount of fugitive emissions from natural gas storage. Fuel combustion emissions are from natural gas.

A possible mitigation opportunity is to reduce or eliminate fugitive emissions from gas pipeline infrastructure. A second mitigation opportunity that could address fuel combustion-related emissions from natural gas is by fuel switching to hydrogen or electrification (with subsequent elimination of natural gas storage). For this analysis, reducing or eliminating fugitive emissions from gas storage and pipelines was pursued in this subsector at a 50% capture rate, the report said. Based on the illustrative mitigation portfolio, the transmission and distribution subsector could achieve an emissions reduction of 2.0 MMTCO$_2$e by 2030 through reducing fugitive emissions.

Combined heat and power

CHP can be used in industrial facilities to generate electrical and thermal energy from a single fuel source and lead to reduced energy consumption, lower fuel costs and decreased GHG emissions. According to an analysis by the DOE CHP Deployment Program, California had the second-highest total technical potential for new CHP projects in the U.S., behind only Texas.

In 2016, California had a total CHP installed capacity of 8,590 megawatts across 1,220 installations, of which 4,097 MW (48%) are in the industrial sector with just 189 installations (15%), the report said. Estimates suggest that California has 3,633 MW of new topping-cycle CHP technical potential across 4,253 sites. It also has 729 MW of new technical potential available through bottoming-cycle CHP across 62 sites. In total, the industrial subsectors with the highest technical CHP potential in California (in terms of capacity) were petroleum refining and hydrogen production (1,427 MW); chemicals and allied products (1,111 mw); food products (776 mw); stone, clay, glass, and cement (204 mw); and transportation equipment (147 MW).

CHP costs and challenges

CHP is a mature technology currently used in both the buildings and industrial sectors. The project economics for CHP are generally based on the net benefit of displacing purchased electricity and boiler fuel with self-generated power and thermal energy. CHP systems face several challenges involving different subnational laws and regulations, grid interconnection issues and accessing different fuel sources, according to the report. Challenges at the state level can have a major impact on CHP project deployment. Industrial CHP systems can range in cost depending on factors such as technology type and size of the system. An analysis of CHP opportunities in California identified reciprocating engines as the most economic CHP technology for smaller projects less than 5 MW, while gas turbines were more economic for larger projects above 5 MW.

Energy efficiency

For energy efficiency, the California Energy Commission (CEC) has estimated that compliance with SB 350 could help the industrial sector realize a potential GHG savings of 0.06 MMTCO$_2$e, the report said. Similarly, the EPA ENERGY STAR Challenge for industry aims to improve energy efficiency at any industrial site by reducing its energy intensity by 10% within five years. Achieving this target across California's industrial sector could potentially reduce fuel combustion emissions by 6.6 MMTCO$_2$e. **GT**

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Decarbonization and electrification: View from the utilities

Two utilities speak out regarding their efforts and views on decarbonization and electrification

IN 2018, NW NATURAL, PORTLAND, ORE. SET OUT ON ITS PATHWAY TOWARD A LOW-CARBON ENERGY FUTURE AND IS STARTING TO SEE MOMENTUM. According to Kim Heiting, operations senior vice president at NW Natural, the utility's strategies to decarbonize the pipeline include renewable natural gas (RNG), renewable hydrogen and end-use equipment innovation.

NW Natural serves 2.5 million people, delivering more energy in Oregon than any other utility — gas or electric. The utility is heating 74% of residential square footage in its service area. On peak days, it provides 90% of the energy needs for residential and commercial space and water heat customers. According to Heiting, the utility is meeting this demand through one of the tightest systems in the country, which minimizes emissions.

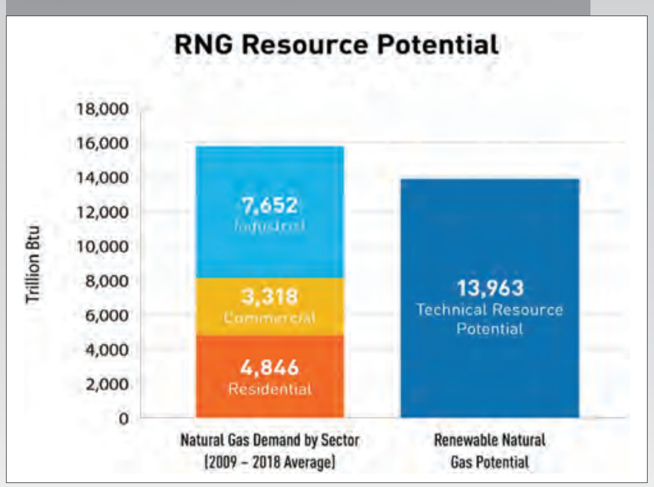
"The goal needs to be emission reduction as fast and affordably as possible," said Heiting. "Some of the questions around electrification point back to this issue. We need to make sure we are using facts, analysis and data to do the math to ensure our choices make sense. When we started to think about decarbonizing the electric system, we didn't say, 'Cut the wires.' We just said, 'Change what's going over those wires.'"

It's not just about electricity. "We need to be thinking that way about the gas system as well," Heiting said. "And that gets back to the fundamental issue: We have billions of dollars of assets already sitting in the ground. We need to think about how to sustainably evolve what's going through that pipeline network to lower the cost of meeting our climate objectives overall. From our perspective, that will mean increasingly more renewables in the pipeline over time."

NW Natural is committed to pursuing a 100% carbon neutral pipeline. "We don't see any technical barriers to getting to carbon neutrality in the pipeline," said Heiting. "The renewable energy supply is available, the technology is available, we must drive those costs down and we think that's possible. We must do that to reach our climate goals. Only focusing on 100% renewable electric system, while important, is not going to be sufficient to achieve our climate goals. We will need renewable molecules as well as electrons, if we're going to get to the goal of overall carbon neutrality."

According to Scott Dodd, director of business development at Enbridge Gas Inc. (EGI), Ontario, Canada, EGI is raising awareness of the important role the natural gas utility can play in lowering emissions and the unintended consequences of focusing on mass electrification in Ontario. The utility — Canada's largest natural gas storage, transmission and distribution company — is working on three streams to reduce carbon emissions: working with customers to use less natural gas, greening the gas grid by developing renewable natural gas and hydrogen sources of supply and using natural gas to replace higher emission fuels. At the same time, the utility is also advising stakeholders that it would be impractical to electrify everything in Ontario, as well as highly costly to electrify different loads.

FIGURE 1: An ICF national study shows renewable natural as technical potential is 88% of current direct use throughput. Courtesy: NW Natural; source: ICF, American Gas Foundation, Dec 2019



Decarbonization opportunities and solutions

According to Aqeel Zaidi, supervisor of technology development, EGI is working on several low-carbon natural gas technology solutions to help achieve Canada's greenhouse gas emissions reduction target by 2050. These initiatives include:

- Energy efficiency
- Renewable natural gas (RNG)
- Power-to-gas hydrogen production
- Gas heat pumps
- Hybrid heating
- Geothermal
- Distributed energy resources (DER); district energy, combined heat and power (CHP)/micro CHP (mCHP)
- Carbon capture.

"We are working on these technologies to demonstrate that natural gas could be a cost-effective solution to meet 2030 and 2050 goals for greenhouse gas (GHG) reduction," Zaidi said.

According to Anna Chittum, renewable resources director at NW Natural, the Oregon Department of Energy (ODOE) looks at the overall potential for RNG development in the state. ODOE found about 48 Bcf of technical potential, which is equivalent to all the residential gas use in the state. "We are currently connecting two wastewater treatment plants and an agricultural waste digester to our system. In addition, we are looking for additional RNG sources. We're looking at landfill gas, wastewater treatment, dairies, and chicken manure sources. Our aim is to decarbonize as much of our pipeline as we can cost effectively," she said.

In addition to RNG, power to gas (PtG) also is in the decarbonization mix. Chittum said NW Natural is pursuing a power to gas pilot project in the Eugene, Ore. area. Power to gas uses excess renewable electricity through electrolysis to split water into hydrogen and oxygen, which injects hydrogen into the pipeline directly as hydrogen or potentially pairs it with waste CO_2 to make methane and injects that methane into the pipeline.

PtG has the potential to convert renewable electricity resources that can vary considerably from season to season and within a 24-hour period to hydrogen, which can be stored or used in the gas pipeline in ways that can seasonably shift the usage of that energy. "We view the gas pipeline as an excellent 'battery' to store some of this abundant, but, at times oversupply of renewable electricity in the region," said Chittum.

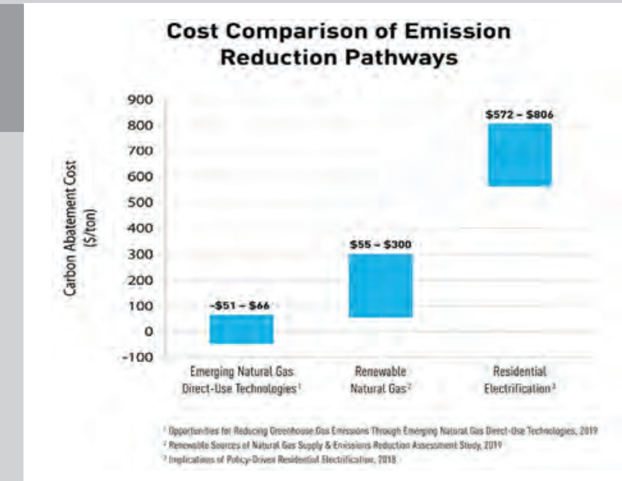
EGI has built North America's first utility-scale *PtG* plant in Toronto; there is a project on the campus of UC Irvine in California; and there is a project at the National Renewable Energy Laboratory (NREL) in Colorado.

There are factors that make PtG attractive as a potential resource for utility customers. One is that the overall capital cost of electrolyzers is coming down. Chittum expects the production costs of hydrogen to continue to fall. The other is if PtG is evaluated on a dollar per ton basis instead of the cost compared to conventional fossil gas. Instead, what is the cost per ton compared to other types of emission reduction strategies? That's where PtG can begin to get competitive with other types of emission reduction strategies, Chittum said.

Utilities have their say

Heiting said NW Natural is striving to educate communities. "There is a big energy literacy gap. We need to help communities understand there is no such thing as a ban on natural gas. We're either going to be using it efficiently in high-efficiency equipment in homes and businesses or we are going to be using more of it in power plants. We are helping our customers understand that up to about half of the natural gas used in Oregon is used in power generation," she said.

FIGURE 2: Evaluation of emission reduction strategies. Courtesy: NW Natural



EGI believes that educating policy makers and energy consumers is key to establishing support for renewable gaseous energy supplies.

According to Heiting, NW Natural's views on electrification issues include:

- We embrace the change that's needed. NW Natural can't meet its climate goals without both the electric and gas systems. We're an energy delivery company — what goes through our pipes can and will evolve. Using infrastructure in place innovatively speeds progress and reduces costs.
- We need a diversified set of solutions — green electrons and green molecules. Electrons must be used when they're generated or put in limited battery storage. Molecules have an inherent energy density advantage, and the gas system was built for winter peaks. Green molecules can be distributed and stored seasonally in the existing infrastructure.
- In terms of resiliency, two robust, low-carbon energy systems serving communities reduces risk. Gas equipment, gas generators and fuel cells can work in a power outage.

According to Dodd, EGI's views on electrification issues include:

- Natural gas meets peak heating demand. Ontario's peak gas demand in winter is more than 80,000 MW. If gas loads were converted to electricity, Ontario would need to build huge power generation, supply and distribution infrastructure costing hundreds of billions of dollars.
- It is impractical to convert some current gas-fired industrial process heating technologies without developing new electrification technologies, e.g., steel reheat furnaces and heat treat furnaces.
- Electrification in Ontario would increase gas-fired electricity generation. Electrification will have unintended consequences of increasing GHG emissions rather than reducing them since the marginal electricity produced by the less efficient central gas fired power plants (about 40%) will displace 95% efficient gas heating appliances.
- The natural gas industry needs to work with policy makers and building officials to acknowledge the site versus source benefits of natural gas use, including CHP and gas heat pumps versus electric heat pumps. Electric air-source heat pump (ASHP) are being promoted as a key space heating technology for electrification. GT

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Steam system thermal cycle efficiency

There are many chances for companies to improve overall efficiency with their steam system with a thorough analysis; learn how

By Kelly Paffel, Inveno Engineering

TRADITIONAL BUSINESS PEOPLE SEE STEAM AS A SOURCE OF HEAT AND POWER FOR PRODUCING FINAL PRODUCTS. Today's cost-conscious industrial professionals are also seeing it as a source of potential to increase corporation profits. Achieving a high steam system thermal cycle efficiency will increase profits by an average of 15% to 21%.

A high percentage of the steam systems in use in industrial applications today are operating far below world-class standards in steam system thermal cycle efficiency. Industry professionals are finding that even small improvements made to their often-ignored steam systems can yield big benefits in operating reliability, efficiency, and can contribute to an organization's bottom line.

In today's competitive market, we cannot ignore the achievable savings in improving a neglected steam system and reducing wasted steam energy. An average industrial plant will have a fuel budget of $3,500,000. Improving the steam thermal cycle efficiency by only 10% will net a savings of $350,000 for the plant's bottom line.

Using less fuel in the boiler operation to produce steam will lower the emissions from the boiler operation, which improves the plant's environmental impression.

FIGURE 1: Significant steam losses = significant dollar losses. All images courtesy: Inveno Engineering/ESC

Steam system thermal cycle efficiency

What is steam thermal cycle efficiency, and what affects that efficiency? These are questions all steam system managers must be able to answer.

The average steam system thermal cycle efficiency is 56.3%, which means 43.7% of the energy consumed in boilers is wasted or lost. It is impossible to use all the energy input into the boilers. So while the operation will have a few acceptable losses, a high percentage of losses can be prevented or eliminated. Some plants may be more efficient, and some plants may be less efficient. Until the steam system is benchmarked, plant management will not know how much energy is being lost in the steam system.

Calculate the thermal cycle efficiency by subtracting the Btus recovered and returned to the boiler plant from the total fuel energy or Btus input into the boiler to generate the steam.

- When benchmarking the thermal cycle, the quantity of the sensible energy in the condensate returned to the boiler is considered the recovered energy.
- The deaerator uses steam from the main steam line to maintain pressure and temperature on the deaerator. Therefore, it cannot be the benchmark for recovered condensate.

Components that can affect thermal cycle efficiency

The steam system components that can affect the steam system thermal cycle efficiency need to be reviewed. No item can be overlooked. Each item, if not managed properly, can contribute significant losses. Consider the following categories:

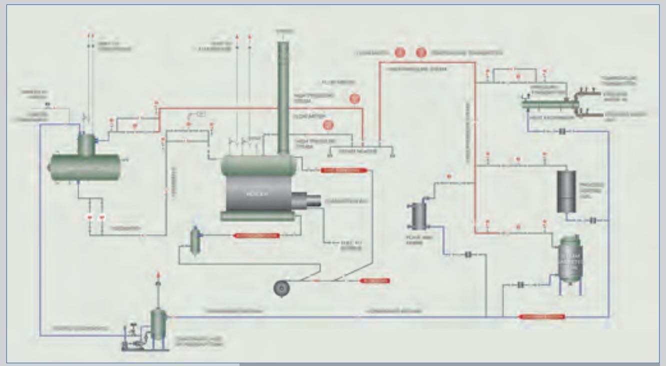

FIGURE 2: Total steam system.

Steam generation
- Boilers
- Steam turbines.

Steam distribution
- Piping
- Steam leaks
- Insulation
- Valves
- Expansion devices
- Steam trap stations.

End users
- Shell and tube heat exchangers
- Plate and frame.

Condensate systems
- Condensate lines
- Flash steam losses
- Pumps
- Condensate leaks
- Condensate losses
- Tanks.

Steam generation losses

The first areas that need to be reviewed are involved in generating steam. These can create significant energy losses before the steam is even distributed into the steam system.

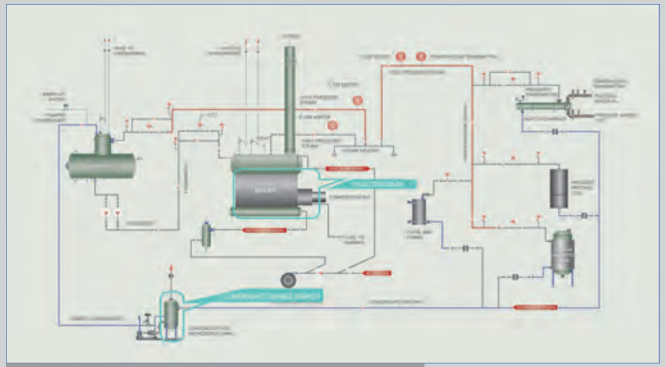

FIGURE 3: Energy in and returned.

Boiler flue gas. The boiler has, on average, a 16.4% energy loss due to the flue gas volume and the elevated temperature of the gases from the combustion process. The boiler can have several devices to lower the flue gas losses.

Boiler outer shell or casing losses. The outer shell, or the boiler's casing, will contribute a low-loss percentage (0.5%), which is acceptable as long as the boiler casing does not have hot spots or above-normal temperatures. The plant should perform an infrared camera scan of the boiler's casing at least once a year. The data is benchmarked to detect fatigue of the boiler's internal insulation.

Boiler continuous blowdown. The continuous blowdown is continually skimming the boiler water impurities slightly below the water level and discharging boiler water to a blowdown tank. The estimated energy loss from the continuous blowdown is 1.5%, which will depend on several factors discussed in other best practices.

Boiler bottom blowdown. The bottom blowdown occurs periodically from the lowest water containment area in the boiler. The periodic bottom blowdown removes sludge and discharges the water and materials to a blowdown tank. The estimated energy loss from the bottom blowdown is 0.2%, which depends on several factors discussed in other best practices.

Steam turbine. The loss of mechanical work from reducing steam pressures with a control valve and not using a steam turbine for the pressure reduction is not added into the thermal cycle losses. A rule of thumb to use is 75 lbs. of steam per hour equals 1 horsepower of work from a steam turbine. Steam turbines can be used in many different applications besides electrical generation.

Total steam generation losses. The steam has left the steam generation area, and the summary of the estimated losses include:
- Boiler flue gases: 16.4%
- Boiler outer surface losses: 0.5%
- Continuous blowdown: 1.5%
- Bottom blowdown: 0.2%
- Total: 18.6 %.

The energy loss is 18.6%, and the steam vapor has not performed any usable work.

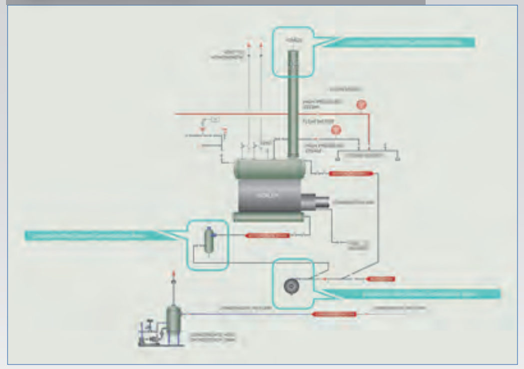

FIGURE 4: Losses in the steam generation area.

Steam distribution

To enable the steam to release the contained energy to the process, the next step is distributing the steam to the end users.

Insulation. Insulation is the most overlooked item that can provide energy savings. According to the U.S. Department of Energy Best Practices Steam program, mechanical insulation should be used on any surface hotter than 120 F (49 C). Therefore, all steam and condensate components must be insulated, and the insulation must be protected to ensure long operational life. The estimated energy loss is 6.4%.

Steam leaks. Steam and condensate leaks cost industrial plants millions of dollars in lost energy while increasing emissions, creating safety hazards and lowering the reliability of plant operations. Steam leaks result in the loss of latent and sensible energy. While plant personnel would be well advised to pay attention to all utility losses, greater attention should be paid to the costs and problems associated with those losses related to steam. An estimated energy loss from steam and condensate leakage is 7.5%.

Summary of the energy losses to this point:
- Insulation: 6.4%
- Steam leaks: 7.5%
  - o **Total:** 13.9%
- Steam generation: 18.6%
- Steam distribution: 13.9%
  - o **Total energy loss:** 32.5%.

The total energy loss is now at 32.5%, and the steam vapor has not performed any usable work.

FIGURE 5: Steam turbine.

End users

Finally, the steam has reached the intended objective, which is providing the latent energy to the process. The losses from not insulating the heat exchangers, tracer lines, jacket tank heaters, etc. have already been included in the insulation estimate. The steam leaks from flanges, threaded connections, valves, etc., have already been added into the previous estimate.

Steam trap stations

Failure rates of 18% or more with the steam trap station population have been deemed a normal steam trap station operational performance level, which is unacceptable. The failure rate of any steam trap station popu-

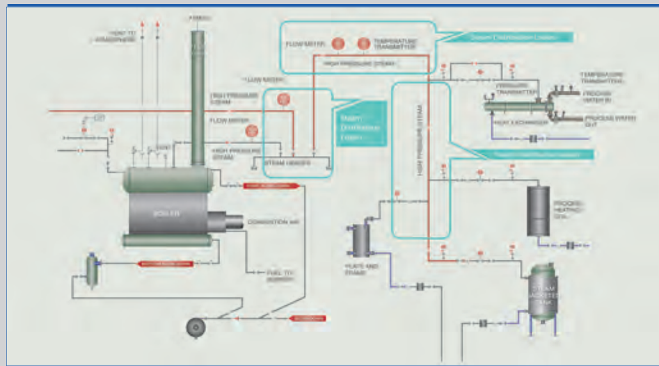

FIGURE 6: Steam distribution losses.

lation must be below 3%. The energy loss from failed steam trap stations from steam blowing through and the energy being lost to the atmosphere is estimated at 3.6%.

Summary of the end user loss points

- Insulation: 4.4%, already added in the totals
- Steam leaks: 6.5%, already added in the totals
- Steam trap station failures: 3.6%
- Total: 3.6% (insulation and steam leaks have already been added in the previous estimates).

Condensate systems

The steam has released the latent energy to the process, which means the sensible energy is in the condensate.

Condensate losses. Condensate contains 16% of the energy in the steam vapor (sensible energy). Therefore, failing to recover the condensate is a significant loss. The estimated energy loss from unrecovered condensate is 3.8%.

Steam lost to the atmosphere. The flash and live steam lost to the atmosphere represents the last of the energy losses in the thermal cycle. Venting steam to the atmosphere reduces the thermal cycle efficiency and contributes to an increase in emissions. The benchmark in today's industrial plants is to have no steam venting to the atmosphere. The steam components that allow steam to be lost to the atmosphere include:

- Vented condensate tanks
- Vented flash tanks
- Automatic steam vents
- Deaerator vents.

FIGURE 7: Steam leakage.

Average estimated loss = 7.4%.

Summary of the condensate system losses

- Condensate: 3.8%
- Steam lost to the atmosphere: 7.4%
- Insulation: 4.4%, already added in our totals
- Total: 11.2% (insulation not added in the total).

Steam thermal cycle summary

The remaining the condensate has been delivered to the deaerator operation, completing the thermal cycle. The deaerator system will use live steam to add the sensible energy to the condensate and make-up water to begin the process of elevating the temperature of the feedwater to the saturated temperature of the operating steam pressure.

- Boiler flue gases: 16.4%
- Boiler outer surface: 0.5%
- Continuous blowdown (boiler): 1.5%
- Bottom blowdown (boiler): 0.2%
- Insulation (team and condensate): 6.4%
- Steam leaks: 7.5%

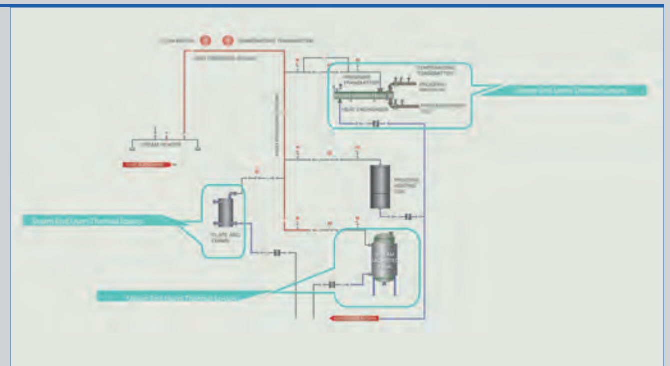

FIGURE 8: Steam end user thermal losses.

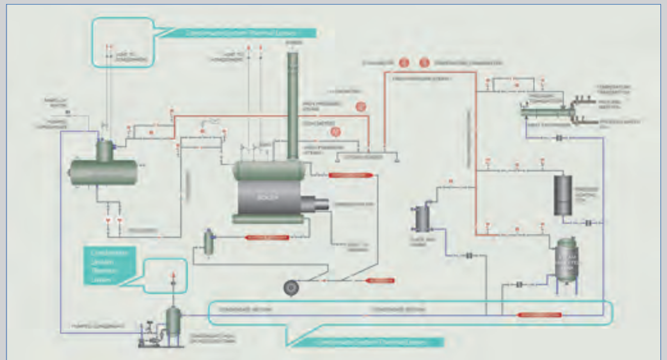

FIGURE 9: Condensate system thermal losses.

- Steam trap station failures: 3.6%
- Condensate losses: 3.8%
- Steam lost to atmosphere: 7.4%
- Total losses: 43.7%.

The steam system cycle is complete. The average energy losses are 43.7%, and only 56.3% of the steam energy was used successfully. Today, an energy cost of 43.7% is unacceptable, and optimization will improve the company's bottom line. Another tremendous plus to a steam optimization program is the reduction of emissions. GT

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LDC Focus

Spotlight on Enbridge Gas Inc.

Ontario utility embarks on North America's first utility-scale Power to Gas plant project

WITH ITS HEADQUARTERS IN TORONTO, ONT., CANADA, ENBRIDGE GAS INC. (EGI), IS NORTH AMERICA'S LARGEST NATURAL GAS STORAGE, TRANSMISSION AND DISTRIBUTION COMPANY with more than 170 years of experience in providing safe and reliable service. The utility serves more than 3.7 million customers, and heats more than 75% of the homes in Ontario. EGI's Dawn Hub is the largest integrated underground storage facility in Canada and one of the largest in North America. Between 1995 and 2017, the utility's demand side management (DSM) efforts have saved its customers approximately 25 billion cubic meters or about 880 billion cubic feet of natural gas. EGI offers a variety of energy efficiency incentive programs to help industrial customers reduce their energy costs and GHG emissions. According to Jackie Caille, Manager of Industrial Energy Conservation Sales "We have a team of highly qualified and experienced Industrial Energy Advisors that support our customers. Each of these employees are trained engineers that work very closely with industrial, institutional and greenhouse customers helping them identify and implement energy efficiency and productivity improvements at their facilities. Customer's value the technical support and expertise that our engineers are able to provide to enhance their business.

Power-to-Gas in Ontario

Power-to-Gas (PtG) is a technology that uses electrolysis to separate water into its primary parts – hydrogen and oxygen. The hydrogen can be used as fuel or industrial feedstock for a variety of products such as methanol, ammonia and fertilizer. It can also be injected directly into the natural gas grid or turned back into electricity by using a hydrogen fuel cell.

EGI's Training and Operations Centre in Markham, Ont., Canada is home to a PtG energy storage facility, which went into service in May 2018. The plant is a joint venture between EGI and Hydrogenics, a manufacturer of electrolysis-based hydrogen generators. Dubbed North America's first utility-scale PtG plant, the facility can store 8 MWh of renewable hydrogen onsite.

Image courtesy: Enbridge Gas Inc.

There was a two-part approach to the PtG project, according to Sam McDermott, Technical Manager Renewable Hydrogen at EGI. Part A was to demonstrate the plant's ability to convert electrical energy to hydrogen gas, and then back to electricity while providing frequency regulation to the Independent Electricity System Operator (IESO), Ontario's electricity system operator. Part B was to accomplish Part A and then demonstrate the ability to blend/store hydrogen in the natural gas distribution system, lowering its GHG profile and creating an intertie with the electrical grid.

PtG plant capabilities

PtG is the process of taking (low-carbon, clean) electrical energy, and through the electrolysis of water, converting that energy into hydrogen and oxygen gases. The hydrogen is used as an energy carrier, and the oxygen is currently released into the atmosphere.

The Markham PtG plant provides grid stability, frequency regulation service to the IESO, which operates the power system in real time, oversees Ontario's electricity market, promotes energy efficiency and plans for Ontario's future energy needs. The plant was constructed at 2.5 MW peak output and can expand to 5 MW in the same footprint.

Since the Ontario electricity grid is greater than 92% green, the PtG plant produces nearly 100% greenhouse gas (GHG) free electrolytic hydrogen. Maximum hydrogen production from the plant is 1,000 kg/day or 500 m^3/hr. Hydrogen from the plant is 99.99% pure and can be produced at 99.9999% purity to meet the stringent automotive standard. The electrical energy now in the form of hydrogen can be blended/stored in the natural gas grid or used in its pure form for industrial purposes. **GT**

PtG BENEFITS

PtG benefits include:

- An efficient intertie of the electrical grid with the natural gas grid
- Ancillary services: fast response frequency regulation
- The gas distribution network has the potential to provide large-scale energy storage
- Flexible technology, very low GHG profile, utilization of existing infrastructure.

PtG and hydrogen use

- Ancillary services: controllable variable load; rapid response frequency regulation
- Enabler of dispatchable power (e.g., wind, solar)
- Greening the gas grid and lowering GHG emissions
- Fuel for zero emission vehicles (FCEVs, buses, trains)
- Conversion of hydrogen back to electricity
- GHG-free heating
- Feedstock for industrial applications such as methanol and ammonia.Hi, fachuciam id catur la abus, senam,