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Idaho National Laboratory

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EXECUTIVE SUMMARY

Nuclear energy is increasingly being recognized as a valuable low-carbon, low-emissions energy source that can help meet clean energy targets being set by states, commissions, and utilities in the United States. Currently, nuclear power provides about one-fifth of the country's electricity. Nuclear power plants (NPPs) further provide the grid with all-weather season-long baseload capacity that is important to grid reliability and resiliency.

An innovative revenue model that has been proposed for U.S. LWRs is to alternatively use the heat and electricity from nuclear reactors to produce in-demand industrial products—hydrogen for use in fuel cell electric vehicles (FCEV), cofiring with natural gas (NG), petroleum and biofuel refining, ammonia production, direct-reduced iron (DRI) for steel production, and synthetic fuels (synfuels) and chemicals (synchems) such as methanol, polymers, formic acid, and others—via thermal and electrochemical processes during seasonal and daily periods of low grid-electricity market pricing (overgeneration) in lieu of being curtailed or producing electricity to the grid at a less-than-optimal electricity price. Repurposing NPPs to flexibly produce nonelectric products and clean-energy carriers could help alleviate the economic pressure on NPPs and enable decarbonization of the power sector, as well as the transportation and industrial sectors.

This study takes an in-depth look into various regions interest (Figure ES1) representing a variety of operating markets, local generation mix, and seasonal climates within the U.S. near existing LWR facilities to identify the scale, location, and accessibility of a wide variety of candidate industrial-product markets, as well as their feedstocks as applicable—for example CO_2, as a feedstock to synfuels or formic acid production—that could be accessed by producing these products using the heat and electricity from nuclear reactors. Both current and future market opportunities surrounding these nuclear plants were investigated. Regions were selected where nuclear operating utilities such as Exelon, Xcel Energy, Harbor Energy, Arizona Public Service, Duke Energy, and Southern Company are currently considering nonelectric product possibilities. Other interested utilities and the topics of possible future studies include Nebraska Public Power District and Wolf Creek Operating Corporation. This study shows a large variety of product opportunities open to nuclear plants as they diversify their offerings in addition to producing grid electricity. Electricity capacity markets are also discussed because they reward large and reliable generators, such as nuclear plants, that are able to guarantee all-weather/all-season capacity and are important in the mix of alternate revenue sources that will help these nuclear plants to remain profitable and sustainable. Also presented is a sample analysis of the economics of hydrogen production in the Minnesota area, considering the capital and operating costs of the hydrogen plant as well as local market demand for hydrogen.

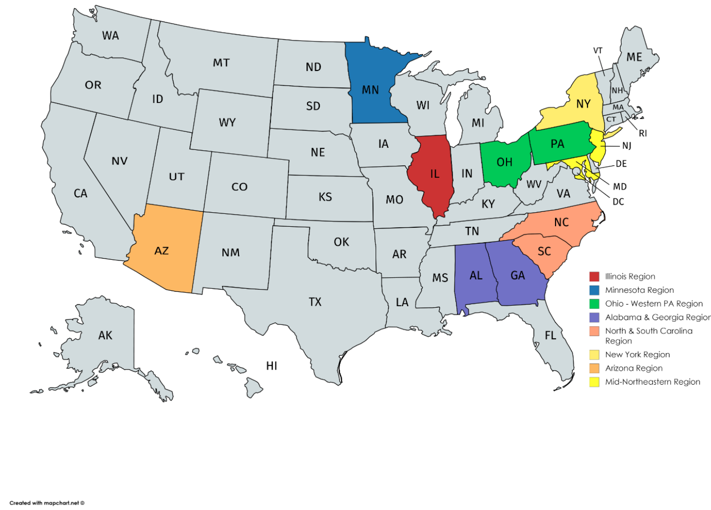

Figure ES1: Regions of study for this report

NPP operators are presented with diverse market options to consider in order to optimize their revenue by economically dispatching electricity either to the grid or to the production of industrial products, fuels, and chemicals.

The objectives of this study include:

- Provide U.S. NPP operators a robust sampling of the market demand location, scale, and accessibility (including storage and transportation) of the wide variety of industrial-product choices that could be produced using thermal nuclear energy and electricity in proximity to a subset of U.S. NPPs to inform the industry of the potential opportunity
- Show examples and trade-off analyses of how U.S. LWR operators can access these markets, including storage and transportation of industrial products to their intended markets
- Present a general analytic example for one industrial product (i.e., hydrogen) in one region (the Minnesota area), including production, storage, and transportation, to show how nuclear-hybrid integrated energy systems (IESs) could access local markets and improve the profitability of a NPP.

It is envisioned that, in the near future, large industrial processes—such as metals refineries, and synfuels and polymers production plants—may choose to advantageously collocate and closely couple with the heat and electricity generated by NPPs in order to fully realize the advantages and synergies of nuclear-hybrid IESs. By collocating industrial-process plants near NPPs, large amounts of thermal and electrical energy produced by a nuclear plant can be efficiently and locally used to produce transportable fungible products such as refined metals and steels, synfuels, polymers, ammonia, formic acid, and others onsite.

This report focuses heavily on direct demand for hydrogen and its use in making other products and chemicals such as DRI for steel production, ammonia and fertilizers, and synfuels etc). Demand for other products such as oxygen, formic acid, polymers and other applications are briefly discussed. An update to demand applications for heat from NPPs to form an energy park as well as more in-depth studies of synfuels and chemicals such as methanol coupling with NPPs will be the subjects of future studies. A separate future study will also present analysis of the national discussion around creating a clean energy credit system for electricity and non-electric products produced using nuclear energy and propose various methods for doing so.

This report begins a library of information on the demand market for nonelectric industrial products in these regions. It can inform decisions on the timing and scale of nonelectric product pilot and commercial scale demonstrations for each region. Companies' internal as well as local and state regulator decarbonization targets will play a role in these decisions. The level of clean energy and carbon emissions reduction targets for each organization may highlight additional incentives to couple nonelectric products with NPPs. As expected, carbon emissions lifecycle analyses (LCA) summarized in this report show that using nuclear power instead of fossil fuels to make these industrial products drastically reduces CO_2 emissions. Nonelectric product demand data (as presented in this report) is just one dataset needed when doing rigorous modeling in technoeconomic analysis (TEA). Other inputs such as specific electricity grid demand and structure, NPP and nonelectric product process modeling and economic parameters, etc will be collected in future specific TEAs. Individual specific TEAs have been completed for two nuclear plant locations, one for Harbor Energy (Davis-Besse) and one for Exelon (Braidwood). Future TEAs to be completed include Xcel Energy and Arizona Public Service (APS) and others in the future as interest applies. These rigorous TEAs provide modeling results specific to the NPP operator, location, and chosen nonelectric process technology to show the options, configuration, and operating strategies with the most probable success and highest financial and environmental incentives for each location.

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FIGURES

TABLES

ACRONYMS

ANL	Argonne National Laboratory
BOP	balance of plant
BWR	boiling water reactor
DOE	Department of Energy
DRI	direct reduction of iron
ENDP	electrolytic non oxidative deprotonation of ethane to form ethylene and hydrogen
FCTO	fuel cell technology office
HTE	high temperature electrolysis also termed HTSE
HTSE	high-temperature steam electrolysis also termed HTE
IES	integrated energy systems
INL	Idaho National Laboratory
LTE	low temperature electrolysis
LWR	light-water reactor
MED	multi effect distillation
NG	natural gas
NGCC	natural gas combined cycle
NHES	nuclear-renewable hybrid energy system
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
OCF	operating capacity factor
PE	polyethylene
PEM	polymer-electrolyte membrane
PFD	process-flow diagram
PP	polypropylene
PWR	pressurized water reactor
RO	reverse osmosis
SOEC	solid-oxide electrolysis cell
Syngas	synthesis gas (H_2 + CO)
TBV	turbine bypass valve

TCV	turbine control valve
tpd	tonnes per day
TRL	technology readiness level
UI	University of Idaho
WGS	water gas shift
WSC	Western Services Corporation

1. INTRODUCTION

Nuclear energy is increasingly being recognized as a valuable low-carbon, low-emissions energy source that can help achieve clean energy targets being set by states, commissions, and utilities in the United States. Currently, nuclear power provides about one-fifth of the country's electricity. Nuclear power plants (NPPs) further provide the grid with all-weather season-long baseload capacity that is important to grid reliability and resiliency. Light water reactor (LWR) NPPs in the United States, like other sources of electricity generation, are facing increasing market competition from natural-gas combined-cycle (NGCC) power plants due to historically low-priced natural gas (NG) associated with the U.S. shale gas boom. As of January 2020, six NPPs have been shut down, mainly due to economic considerations. Future closures of other plants have been announced and appear imminent unless the electricity market changes or unless new markets for these plants can be established. Therefore, the U.S. Department of Energy (DOE) Light Water Reactor Sustainability (LWRS) Program is addressing flexible plant operations that can diversify the revenue of NPPs.

LWRs can independently produce steam and electricity at a competitive cost most of the year because the capital investment associated with these plants has been retired, and the cost of producing power with these reactors is being reduced through plant modernization, extending the life of the plant through materials assessments and enhanced protection, improvements to the fuel and fuel cycle, and implementation of advanced security systems. An innovative revenue model that has been proposed for U.S. LWRs is to alternatively use the heat and electricity from nuclear reactors to produce in-demand industrial products—hydrogen for use in fuel cell vehicles, cofiring with NG, petroleum and biofuel refining, ammonia production, direct-reduced iron (DRI) for steel production, and synthetic fuels (synfuels) and chemicals (synchems) such as methanol, polymers, formic acid, and others—via thermal and electrochemical processes during seasonal and daily periods of low grid-electricity market pricing (overgeneration) in lieu of being curtailed or sending electricity to the grid at a less-than-optimal electricity price. Repurposing NPPs to flexibly produce nonelectric products and clean-energy carriers could help alleviate the economic pressure on NPPs and enable decarbonization of the power sector, as well as the transportation and industrial sectors. Previous studies have shown this can help increase the revenue of the power plants[102].

Solar and wind can arguably be used to produce industrial products during overgeneration. Two factors provide nuclear power economic advantages over intermittent renewable energy in producing non-electric products. First, the steady output of nuclear power allows high capacity factors for the equipment that produce nonelectric products to assist in recovering their capital costs. Second, nuclear power also provides large amounts of thermal energy that can increase the efficiency of thermal or electrothermal processes. One example process is production of hydrogen using solid oxide electrolysis cells (SOECs) via electrochemical high-temperature steam electrolysis (HTSE). Some thermal energy from an NPP could be extracted and integrated with the HTSE plant to substantially increase electrolysis process efficiency. Ammonia plants and refineries currently consume around 10 MMT of hydrogen a year in the U.S. A large share of this hydrogen is provided by the merchant market and is delivered to the plants through hydrogen pipelines. But there is a strong drive in the U.S. and globally to increase hydrogen production for large scale transportation and other industrial applications, such as iron and steel manufacturing. In addition, the energy from NPPs can provide steam to industries which are currently located near the NPPs or to companies that may choose to locate new facilities near nuclear plants to form an energy park.

A wide variety of products can be produced using thermal and electrochemical processes that are closely coupled to NPPs. Some of the leading options are shown in Figure 1. A few of these options are already under active consideration for demonstration at nuclear facilities. This report focuses heavily on demand for hydrogen in and of itself and for use in making other products and chemicals (DRI, ammonia, etc.). Demand for other products, such as oxygen, formic acid (FA), and other applications are briefly discussed. An update to demand applications for heat from NPPs to form an energy park as well as more in-depth studies of synfuels coupling with NPPs and clean-energy credits for nonelectric products produced from coupled NPP plants will be the subjects of future studies.

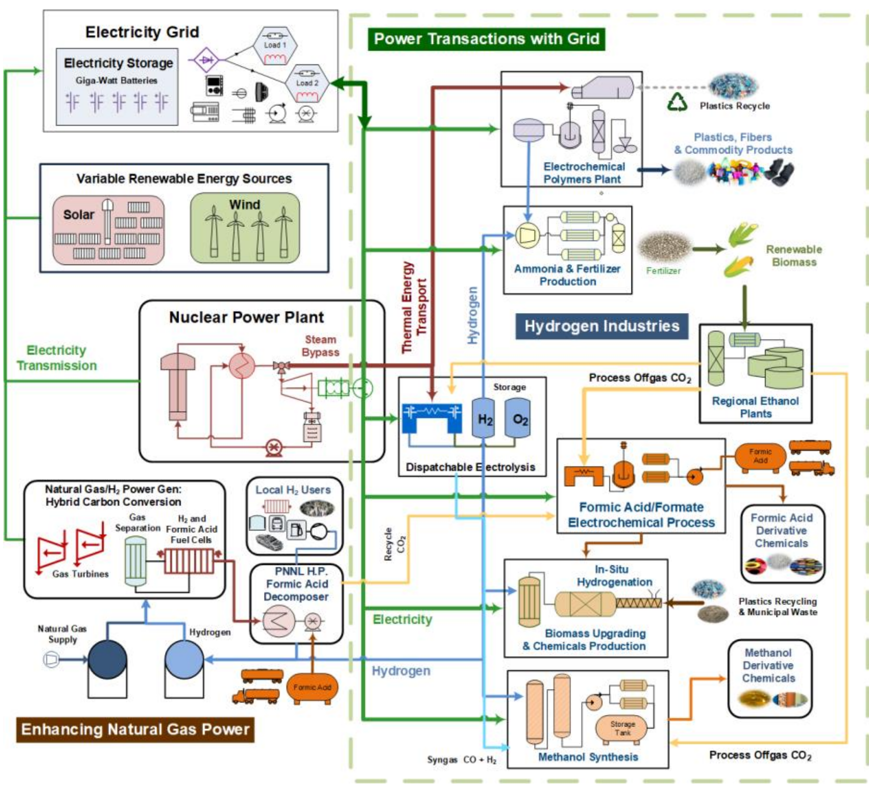

Figure 1. Integrated Energy System NPP Energy Park Concept

This study assesses existing and potential industries that could conceivably be directly coupled to existing nuclear reactors. The goal is to identify the scale, location, and accessibility of the candidate industrial-product markets, as well as process feedstocks that are available near the plants to establish new industries. For example, CO_2 as a feedstock can be combined with H_2 to produce FA, transportation fuels, and lubricants. These new plants can be entirely supported with the heat and electricity provided by a nearby NPP. The potential demand for nonelectric industrial products was assessed by documenting current and possible growth of nonelectric product markets considered. This assessment used DOE- and industry-supported tools, data, and projections to capture regional industrial market opportunities. Electricity-capacity markets that reward large and reliable generators, such as NPPs, were considered because the electricity market will likely continue to be an important revenue source to NPPs. The key is to balance the needs of energy customers so as to optimize revenue for the affiliated energy customers or partners. In most cases, flexible plant energy delivery and power generation for the grid will require either energy storage or a stock of intermediate products to sustain the industrial customers when the NPP dispatches electricity to the grid.

A diverse mix of regions with operating NPPs around the U.S.—representing a variety of operating markets, local generation mix, and seasonal climates—were chosen for this market study. Both current and future market opportunities for candidate industrial-product markets surrounding these NPPs were studied. Figure 2 illustrates the regions chosen for this study.

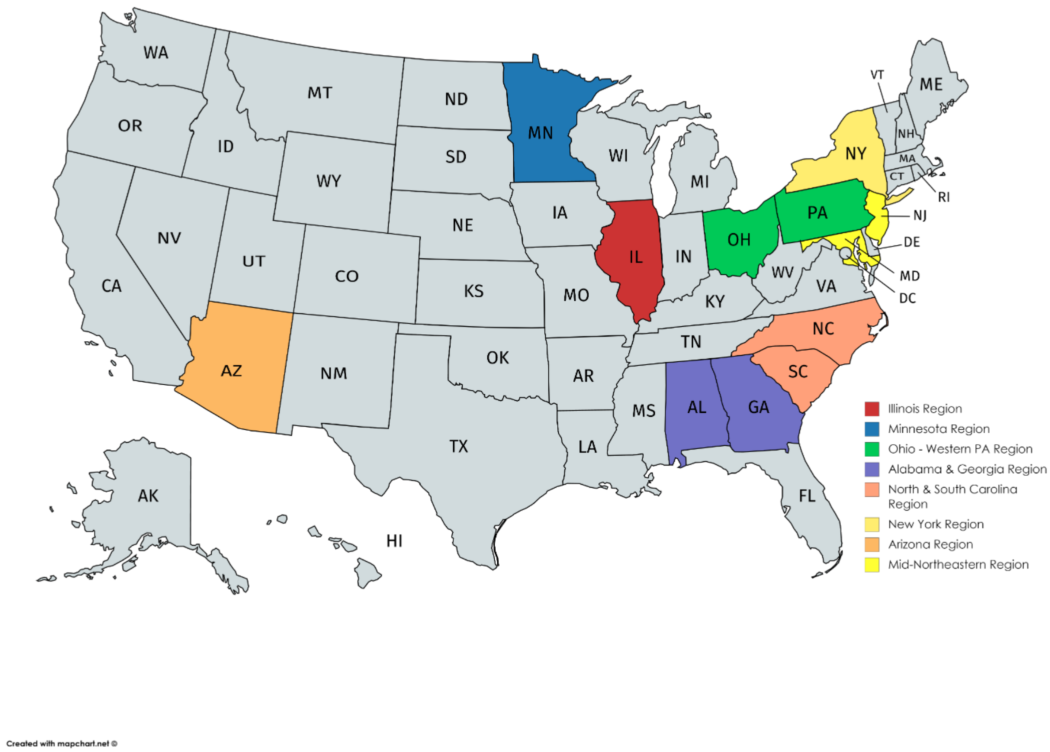

Figure 2: Regions of study for the current report.

The success of developing nonelectric industrial-product markets as alternative revenue-generating sources for LWRs depends, not only on demand from growing existing markets, such as petroleum refining and NH_3 production, but also on the development of new markets such as light-duty (LD) and heavy-duty (HD) hydrogen FCEVs, synfuels, chemical production, biofuels, metal refining, injection of hydrogen into NG pipelines for gas power-generating units, FA, polymers, and close-coupled industrial heat applications, all of which can significantly increase demand relative to current levels while decarbonizing energy sectors.

This study also presents a sample analysis of the economics of hydrogen production in an area of Minnesota, considering the capital and operating costs of a hydrogen plant as well as the local market demand for hydrogen. It includes some assumptions on electricity-grid pricing, showing how hydrogen could be integrated with an NPP and be competitive with the incumbent hydrogen-production process, steam methane reforming (SMR).

The objectives of this study include:

- Provide U.S. NPP utilities a robust sampling of the market demand location, scale, and accessibility (including storage and transportation) of the wide variety of industrial-product choices that can be produced using nuclear thermal energy and electricity proximate to a subset of U.S. NPPs to inform the industry of the potential opportunity
- Show examples and trade-off analyses of how U.S. LWR operators can access these markets, including storage and transportation of industrial products to their intended markets
- Present a general analysis example for one industrial product (hydrogen) in one region (Minnesota area), including production, storage, and transportation, to show how nuclear-hybrid integrated energy systems (IESs) could access local markets and improve the profitability of an NPP.

Due to their potentially large costs, it will be important to minimize product storage and transportation costs by producing fungible and transportable products to the extent possible and by co-locating industries close to NPPs. This study includes some discussion on the trade-offs between electricity transmission and distributed production of industrial products versus onsite production of industrial products and their storage and transportation costs. It is envisioned that, in the near future, large industrial processes—such as metals refineries and synthetic-fuel and polymer production plants—may choose to collocate advantageously and to couple closely with the heat and electricity generated by NPPs in order to fully realize the advantages and synergies of nuclear-hybrid IESs. By collocating industrial process plants near NPPs, large amounts of thermal and electrical energy produced by a nuclear plant can be efficiently and locally utilized to produce transportable fungible products, such as refined metals and steels, synfuels, polymers, ammonia, FA, and others, onsite.

2. INDUSTRIAL PROCESS AND PRODUCT MARKETS OF STUDY

2.1 Overview of Electricity Capacity Markets

Electricity-capacity markets exist to provide a free-market mechanism to ensure adequate electricity supply during periods of unusually high demand. The capacity markets function by providing guaranteed payments to generators that are able to guarantee on-demand additional electric capacity, whether that capacity is used or not. They represent an additional revenue stream for NPPs to remain connected to the power grid while providing energy to a separate production plant. It should be noted that U.S. electricity-capacity markets are a complicated and changing mix of public and private utilities, government regulators, and customers. They are subject to regulation by both state and federal agencies and appear to be in a considerable state of flux due, in part, to price pressures from increasing deployment of intermittent renewable electricity generation. The variability of markets across the U.S. means that the best economic choice for each NPP varies depending on location. This section will briefly summarize electricity-capacity markets and project reasonable revenue assumptions for various locations.

Regions studied are located in states with both “regulated” and “deregulated” electricity markets (Figure 3). In regulated states, the electric utilities are either vertically integrated—owning generation, distribution, and transmission facilities—or they negotiate bilaterally for access to these facilities. The utility negotiates with the state to project demand requirements and set prices to deliver a regulated rate of return. Thus, risk is spread across the entire portfolio of the utility[1]. In “deregulated” markets, electricity generation, distribution, and market management are undertaken by separate entities, usually a hybrid of public and private interests. Electricity retailers, which sell and distribute to customers, purchase electricity wholesale from generators on markets that are set up and managed by a regional transmission organization (RTO) or independent system operators (ISOs). There are seven RTOs and ISOs in the U.S. (Figure 4). Eighteen NPPs within three of these RTOs and ISOs are selected as the basis for the market analysis: Mid-continent ISO (Monticello, Prairie Island, and Clinton), PJM RTO (Dresden, Braidwood, LaSalle, Byron, Quad Cities, Davis-Besse, Perry, Beaver Valley, Salem, Limerick, Calvert Cliffs, Beach Bottom), and NY-ISO (Ginna, James FitzPatrick, and Nine Mile Point).

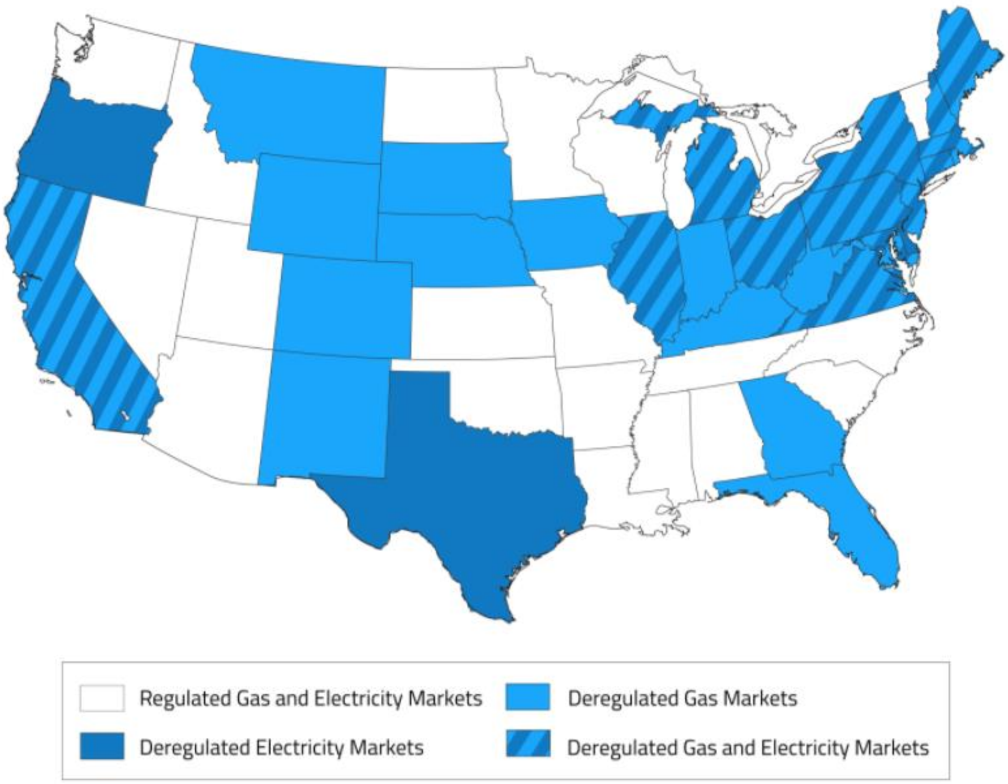

Figure 3. Map of regulated and deregulated electricity and NG markets by state in the U.S. *Source: https://energywatch-inc.com/regulated-vs-deregulated-electricity-markets/.*

Capacity markets are operated by the MISO, PJM, and NY-ISO RTOs, and are intended to incentivize generators to construct sufficient supply to meet electricity demand at all times. Overseen by the Federal Energy Regulatory Commission (FERC), each regional market operates somewhat differently. All capacity markets pay generators for the ability to deliver electricity, and levee penalties for nonperformance in the event that electricity is requested and not provided. The required capacity is determined by adding a reserve market (often ~15–20%) to projected peak demand[2]. Prices are determined by forward-looking auctions, conducted up to 3 years in advance in the PJM region. All those in the market receive the "clearing price,"—that is, the highest bid among units that satisfies the required capacity. Thus, intermittent reserves and other non-baseload suppliers can rely on a steady revenue stream separate from volatile spot-energy prices. These auction-determined transactions are often used as benchmarks for negotiations or evaluations of prices in near-term wholesale or other available markets. This process is sometimes called "price discovery."[3] Capacity payments are a significant contributor to electricity prices and utility-value propositions: in 2017, the values of the NE-ISO and PJM capacity markets were \$2.2 billion and \$8.6 billion, respectively. It has been estimated that ~10% of a homeowner's electricity bill can be directly attributed to capacity payments (Figure 5).

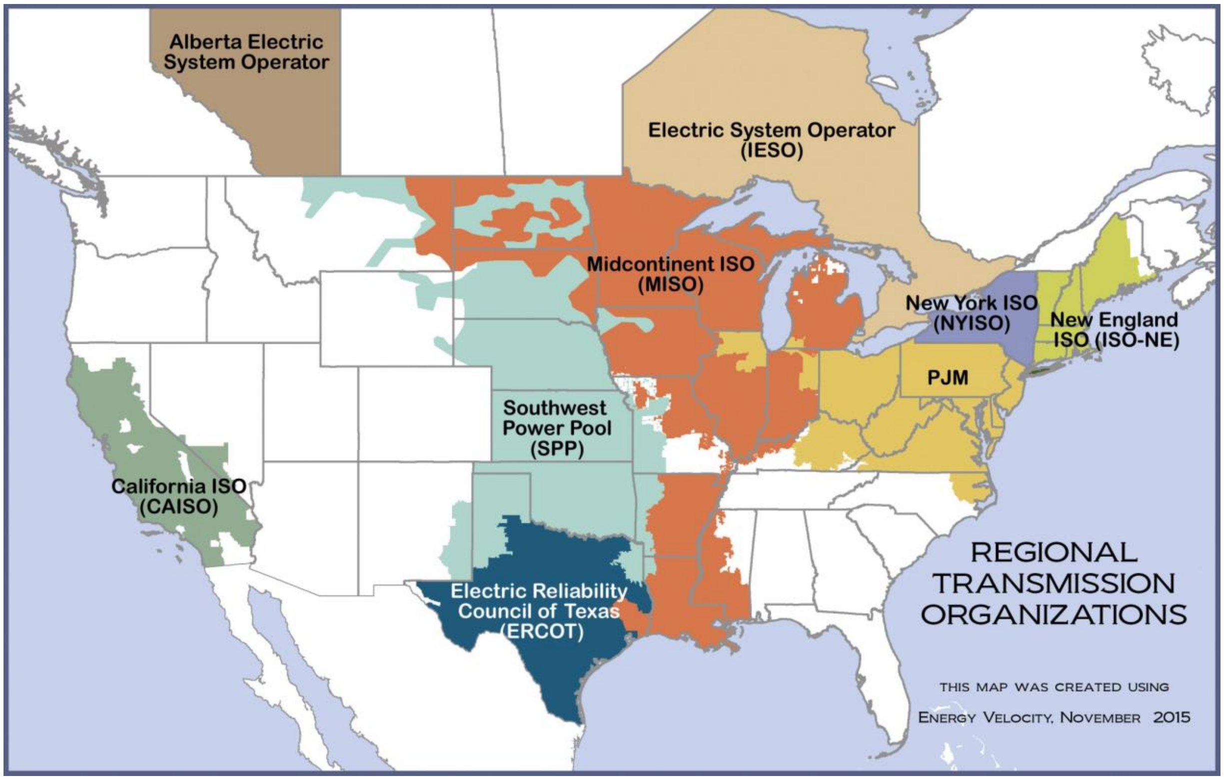

Figure 4. Map of the current RTOs and ISOs in the U.S. *Source: https://www.ferc.gov/industries/electric/indus-act/rto.asp.*

In addition to generators' bidding in capacity, some RTOs (including PJM) provide incentives for demand reduction at times of high stress or system outages. PJM, through a demand-response program, considers pledges to reduce consumption as equal to pledges to increase generation. Thus, curtailment-service providers (CSPs) pool retail or industrial customers and receive a "capacity payment" for this pool pledging to reduce their electrical load if asked. CSPs seek to spread the risk of load reduction around a large pool of customers.

Data from prior capacity auctions in the MISO, PJM, and NY-ISO regions shows that capacity-market prices can vary significantly both regionally and over time. In 2019, capacity auction-clearing prices were \$24.30/MW-day in Minnesota[4], \$100/MW-day in PJM[5], and \$50–125/MW-day in NY-ISO (depending on the specific location)[6]. Recent clearing prices in PJM have fluctuated from a minimum of \$76.50/MW-day for 2020–2021 to \$171.30/MW-day for 2021–2022.

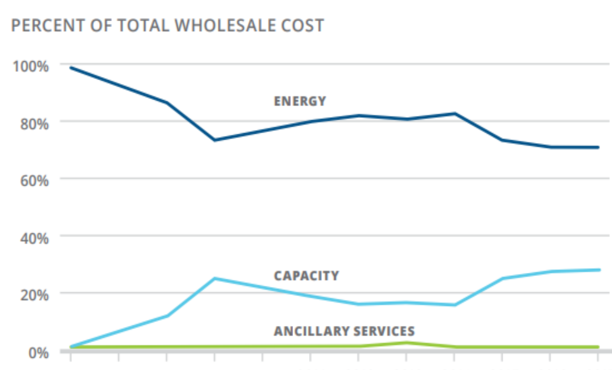

Figure 5. Contributions to total wholesale cost of energy, capacity, and ancillary services.

2.1.1 Analysis of NPP-Associated Facilities and Capacity Markets

The future of capacity markets is uncertain due to scrutiny from both industry and regulators about the fundamental purpose and fairness of the markets. A recent report suggests that mandatory capacity markets lead to large reserve margins, which translates to more than $1 B each year paid by customers in PJM, NY-ISO, and NE-ISO for roughly 35 GW of excess capacity, which is unused and unnecessary. Further, incumbent utilities that operate fossil-fuel burning plants are able to lobby RTOs to implement rules that work against renewable power sources or demand response[7]. On the other hand, state policies that seek to incentivize the construction of wind- and solar-power facilities can skew the market unsustainably. FERC commissioners have noted these and other concerns, stating that capacity markets are "untenably threatened" by increasing state subsidies for renewable generation sources[8]. Uncertainty about the appropriate rules (particularly minimum price offer floors) and regulations surrounding capacity markets have prompted FERC to delay the 3-year-ahead PJM capacity auction since August 2019, with no set date for the auction to occur[7]. The governor of Illinois has signaled a willingness to push Illinois out of the PJM region in order to meet state renewable-energy targets, further complicating the future picture[9]. This uncertainty makes it difficult to project an appropriate capacity payment revenue stream for NPPs over the next 10 years.

In addition to the future of capacity markets themselves, accessing capacity markets requires a flexible electricity-demand source that can be quickly switched on and off. RTOs generally require capacity sources to supply electricity within a short time frame, e.g., 10 minutes, when requested. Thus, an NPP-associated electrolysis demand source must be able to ramp down production rapidly and possibly unpredictably. This type of flexible operation introduces supply-chain concerns and costs that may limit the profitability of the capacity payments. During a capacity event, solid oxide electrolysis cells (SOEC) production would necessarily be curtailed. While the SOEC plants may be able to ramp up and down quickly (when starting from a hot temperature), downstream H_2 demand processes may not be as flexible. A large H_2 demand source—e.g., an ammonia plant—is not typically cycled on and off and thus requires a continuous supply of H_2 feedstock. Onsite H_2 storage with hundreds (or even thousands) of metric tonnes of capacity would therefore be required to ensure consistent nonelectric industrial-product delivery rates. In regions or during times of year when capacity pricing is low, storage and interruption costs would significantly diminish or outweigh the benefits of capacity payments received from RTOs.

In summary, capacity payments represent an attractive revenue stream, particularly in regions such as PJM, where market prices have recently been as high as >$100/MW-day. However, capacity prices have proven to be volatile, and are under regulatory scrutiny as they increase as a fraction of the total wholesale electricity cost (Figure 5). The future rules, functionality, and prices of the PJM capacity market are unclear as of the publication of this report. Further, the large generating capacity of some nuclear plants (particularly those over 2 GW) may overwhelm the capacity market in some regions (e.g., NY-ISO's heavily segmented market), reducing prices or only allowing only a fraction of the NPP capacity to be bid into the market. In addition, the storage and intermittency costs implied by electricity-capacity production should be modeled and explicitly incorporated into revenue analyses.

2.2 Electrolysis: Hydrogen and Oxygen Markets

Water electrolysis is the splitting of water into hydrogen and oxygen and is not a new process. New processes, components, methodologies, and materials are constantly being developed in order to reduce the cost and improve the efficiency of the electrolysis process. Currently two technologies exhibit advantages for hydrogen production throughout at least the next decade. The first option is low-temperature electrolysis (LTE) that uses polymer electrolyte membranes (PEMs) with the hydrogen ion being the motive ion through the electrolyte. The second option is high-temperature steam electrolysis (HTSE) using SOEC with the oxygen ion being the motive ion through the solid oxide electrolyte. HTSE has the potential to give nuclear power an edge in that some thermal energy from the nuclear reactor can be used to increase the electrical efficiency of the electrolysis process. In future decades, other options may be preferred. For example, co o-electrolysis is another process being studied and improved. In co-electrolysis, CO_2 is also taken as an input to the process along with water. The products are CO, H_2, and O_2. CO and H_2 as a mixture is called synthesis gas or syngas because these two molecules can be used in a large number of processes to synthesize fuels (synfuels) and chemicals (synchems). Another future option is higher temperature proton conducting electrolyte (PCE) cells in which the hydrogen, instead of the oxygen ion, moves through the electrolyte. PCE cells have the advantage that they can operate at lower temperatures with reduced degradation and less costly materials of construction; however, they still require laboratory development to achieve their potential.

2.2.1 Fuel Cell Electric Vehicles

Hydrogen demand for FCEVs is expected to increase as FCEVs penetrate the light-, medium-, and heavy-duty vehicle markets. Currently, FCEVs are a small share of the vehicle fleet, mainly concentrated in California due to the presence of hydrogen-fueling infrastructure and other state incentives for FCEVs. Because of regional differences in FCEV policy support, the national-level FCEV market share derived from the selected vehicle-choice model were adjusted for each region by moving FCEV market share forward or back in time on the basis of published technology roadmaps, targets, or other official support for zero-emission vehicles (ZEVs) in that region. This determination was somewhat subjective based on the available information on perceived tendency of each region to adopt FCEVs.

As a result, FCEV market penetration first becomes significant in the Western region, followed by the Northeast or ZEV/Eastern region, and then by the three other regions.

Estimates of FCEV light-duty vehicles (LDVs), i.e., car and light-duty truck (LDT), sales, stock and H_2 consumption were developed according to the following steps:

1. Total estimated FCEV market penetration and sales: Estimated FCEV LDV and LDT sales were obtained from prior U.S. DOE Fuel Cell Technologies Office (FCTO) analyses consistent with FCTO price targets for delivered H2. Annual numbers of FCEVs sold were derived by applying these estimated sales to U.S. Energy Information Agency (EIA) forecasts of national LDV sales by year.
2. Regional estimated FCEV market penetration and sales: National LDV and LDT sales were allocated to regions to estimate regional FCEV market penetration and sales consistent with the national estimates of FCEV LDV and LDT sales by year as well as regional targets (where applicable).
3. Total and regional estimated FCEV stock and hydrogen use: Regional FCEV LDV and LDT stock, vehicle miles travelled (VMTs), and H2 consumption were estimated by year and summed to produce national totals.

In accordance with the Government Performance and Reporting Act (GPRA), each year FCTO estimates the impact of its program from the present through 2050[10]. Metrics like energy use, emissions, and ownership cost are calculated on the basis of an analysis of market performance using DOE-supported vehicle choice models, which estimate the market shares of conventional internal-combustion-engine vehicles (ICEVs), FCEVs, hybrid electric vehicles (HEVs), battery-electric vehicles, and plug-in hybrid electric vehicles (PHEVs) at various range capabilities[10]. Several of these models were run, assuming not only that FCTO's FC cost and performance targets will be met (i.e., the "Program Success" case in FCTO's annual GPRA reporting[10]), but also that the retail price of H_2 will drop from an estimated \$8.70/kg currently to within the FCTO's target H_2 price range.

Argonne's VISION model uses historic annual sales, survival rates by vehicle age, and age-dependent usage profiles for several technologies to simulate vehicles' utilization, fuel use and emissions through their eventual retirement. The model estimates vehicle stock, VMTs, energy use, and emissions for each vehicle technology. VISION also estimates upstream energy use in feedstock and fuel production. For this analysis, annual region-level sales were aggregated to national estimates of medium- and HD vehicle FCEV and conventional technology sales were decreased to keep total medium- and HDV sales the same as in Annual Energy Outlook 2017[11].

For LDVs and LDTs the VISION model was used to estimate annual vehicle stock by technology and vintage in order to estimate regional VMTs and energy use by FCEVs. VISION estimates potential energy use, oil use and carbon-emission impacts of advanced LD- and HD vehicle technologies and alternative fuels. Two scenarios within the VISION model were used for LDVs and LDTs representing low and high potential hydrogen prices, which correspond to high and low FCEV shares of sales. For this analysis, "low" FCEV sales scenario was used. It is based on what was considered a moderate assumption regarding future hydrogen pricing (hydrogen production cost of $2.2 (2015$)/kgH_2 resulting in a hydrogen pump price of $5 (2015$)/kgH_2, including intermediate storage and transportation needed. The regional vehicle forecasts from the VISION model were related to five U.S. regions: western, central industrial, eastern/ZEV states, central southern, and the rest of the U.S.

For M/HDV FCEVs, market share is based on the California Air Resources Board's (CARB)[12] (2016) projections of market share of ZEVs, together with assumptions regarding the share of those which are FCEVs and assumptions regarding the adoption rates in other states. The share of potential hydrogen demand for MDVs and HDVs is small compared with that of LDVs and LDTs by 2030. For this study, we allocated FCEV hydrogen demand estimates by region[18] to states and counties based on population by U.S. Census Bureau[13] and estimated distances from the generating stations based on the county center of population[14]. Like LDVs, the regional vehicle forecasts from the VISION model were related to five U.S. regions: western, central industrial, eastern/ZEV states, central southern, and the rest of the U.S.

The greenhouse-gas (GHG) emissions associated with hydrogen production and the delivery and dispensing pathway can be estimated using a well-to-wheels (WTW) analysis with the Argonne National Laboratory's (ANL's) Greenhouse gas, Regulated Emissions, and Energy use in Transportation (GREET) 2019 model to conduct the life-cycle analysis (LCA). The WTW analysis can be further broken down into well-to-pump (WTP) and pump-to-wheels (PTW) stages. The WTP stage includes fuel production from the primary source of energy (feedstock) to its delivery to the vehicle's energy storage system (fuel tank). The PTW stage includes fuel consumption during the operation phase of the vehicle to power the vehicle's wheels. The results from WTP and PTW analyses are summed to give the WTW energy use and GHG emissions associated with various vehicle-fuel technologies. WTW analysis was carried out using the GREET 2019 model for LDVs, including FCEVs, using various hydrogen-production and delivery pathways and baseline gasoline internal combustion engine vehicles (ICEVs). Fuel economy of 26 mpg was assumed for gasoline ICEVs and 55 mpgge (miles per gallon gasoline equivalent) for H_2 FCEVs. Conventional internal combustion engines (ICEs) using gasoline and diesel were compared to FCEV's using hydrogen produced from NG SMR and nuclear electricity.

The WTW equivalent CO_2 emissions per mile for LDVs compared ICEVs using gasoline, FCEVs using hydrogen from SMR and FCEVs using nuclear-H_2. An ICE using gasoline produces 387 g CO_2 eq/mile, while FCEV using H_2 from SMR produces 170 g CO_2 eq/mile, and FCEV using H_2 from nuclear electricity produces only 33 g CO_2 eq/mile, on a WTW basis (Figure 6).

The WTW eq CO_2 emissions per mile for HDVs were also compared. The conventional HD ICEV using diesel in compression-ignition direct-injection engine produces 1.7 kg CO_2 eq/mile, the HD FCEV using H_2 from SMR produces 0.8 kg CO_2 eq/mile and the HD FCEV using nuclear-H_2 produces 0.1 kg CO_2 eq/mile (Figure 7).

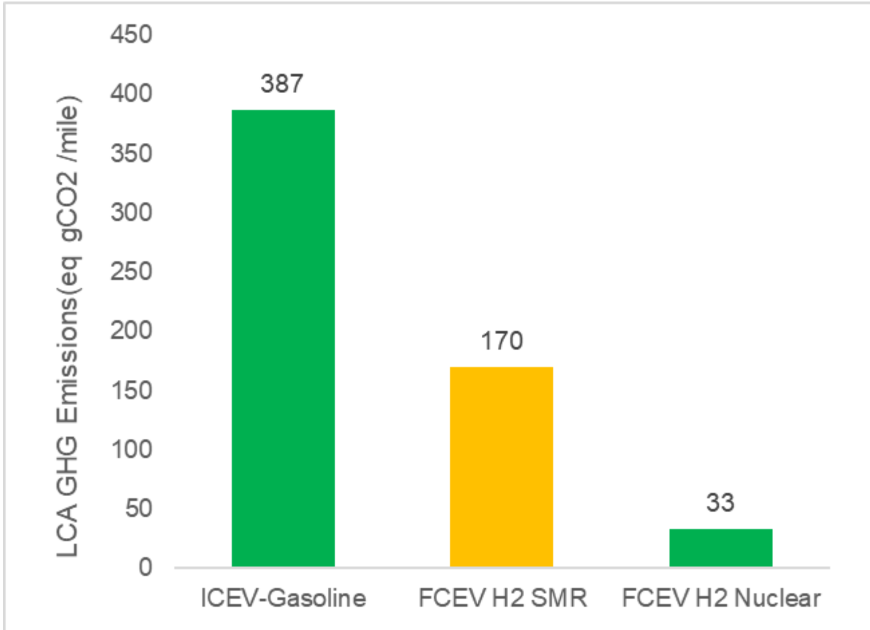

Figure 6. WTW life-cycle GHG emissions results for LDVs.

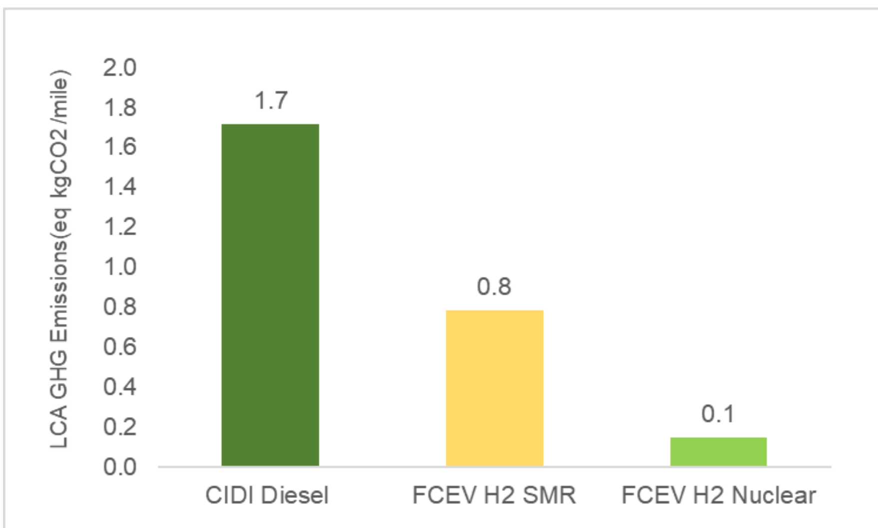

Figure 7. WTW life-cycle GHG emissions results for HDVs, including combustion ignition direct injection (CIDI) diesel engines.

2.2.2 Co-Firing of Hydrogen with Natural Gas in Combustion Turbines

Another potential use of clean hydrogen produced from nuclear energy is its injection into NG pipelines for use as a low-carbon green component of an NG-hydrogen fuel mix for general heating use or for exclusive use in CTs. The potential and barriers to mixing H_2 with NG is discussed elsewhere[18]. For the purposes of this study, potential demand is estimated for hydrogen assuming it can be used by NG CTs with a volume ratio of 30% hydrogen blended with 70% NG. Electricity generators were identified using the datasets from the EIA-860 and EIA-923 forms describing electricity-generator facility locations and fuel use. The LCA was carried out using the GREET 2019 model to estimate GHG emissions for 100% NG, as well as a mixture of 30% hydrogen and 70% NG by volume, as fuel supply to the electricity generators. The equivalent CO_2 emissions per kWh of electricity produced and transmitted to end use (i.e., at the wall outlet) are compared in Figure 8. The life-cycle GHG emissions are estimated at 425 g CO_2/kWh when using only NG as the feed, and 390 g CO_2/kWh for the mixture of 30% hydrogen and 70% NG by volume. We note that 30vol% H_2 with NG represents only ~9% blending by energy because the volumetric heating value of hydrogen is approximately 30% of the corresponding heating value of NG. Although, the potential GHG-emission reduction for this mixing ratio appears small, the amount of potential CO_2 abatement is significant due to the large contribution of NG generating plants to the U.S. national GHG-emissions inventory. Furthermore, future turbine designs that can handle higher mixing ratios, and potentially combust 100% hydrogen, will have the potential to eliminate CO_2 emissions from gas power-generation units. We also note that mixing hydrogen with NG in the near term is attractive compared to other new hydrogen end-use applications because it leverages the existing NG infrastructure and application end use (i.e., the gas turbine); thus, little new capital investment is needed. The "NG electricity generators" in the demand analysis section of this report is the hydrogen demand calculated for each of these electricity generators assuming they use a mix of 30% H_2 with NG.

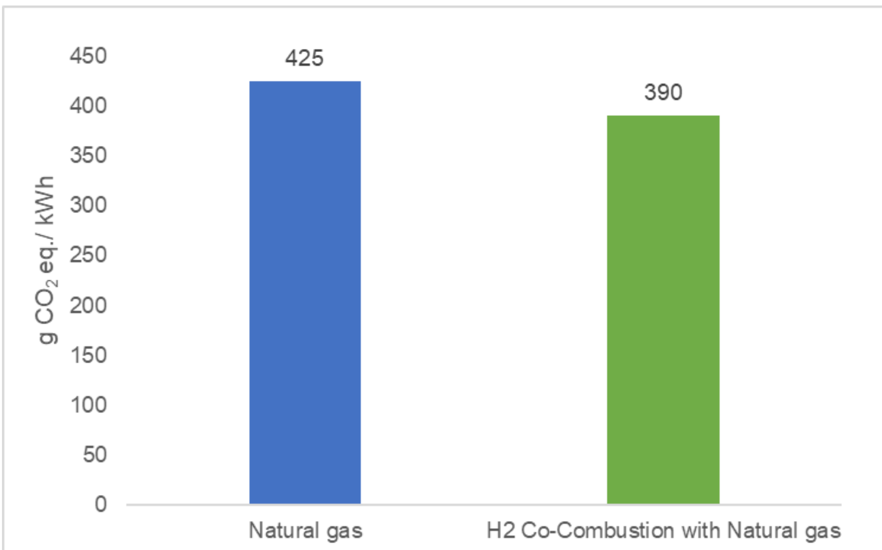

Figure 8. Life-cycle GHG emission for NG electricity generators, well-to-wall outlet analysis.

2.2.3 Petroleum and Biorefineries

Petroleum refineries are currently the most significant user of hydrogen in the U.S., consuming approximately 10 MMT of hydrogen annually, including byproduct hydrogen from naphtha reformers[15] . Approximately one-third of refinery hydrogen used is the byproduct of naphtha reforming processes while most of the rest of the needed hydrogen is typically produced onsite using the SMR process with NG as the feedstock. Some refineries also use hydrogen regional pipelines, which are mostly limited to the Gulf Coast in the U.S. The hydrogen is used primarily for hydrocracking and hydrotreating (hydrocracking is used to produce diesel from heavy crude, and hydrotreating is used to remove sulfur from feed, intermediate, and product streams). Most hydrotreating capacity is used for reducing sulfur in diesel, fluid catalytic cracker feeds, and naphtha streams. Refinery hydrogen demand is, in general, driven by the ratio of gasoline to diesel production, API gravity, sulfur content of the petroleum inputs, and the complexity of refinery processing.

Elgowainy and colleagues[18] estimated future hydrogen demand through 2050 for petroleum refining, based on projections of crude inputs and market demand for refinery products from the EIA Annual Energy Outlook[11], and crude API gravity and sulfur content based on Han and colleague's analysis[16]. The main conclusions are that crude inputs are projected to increase from 16 to 18 Mbbl/d (with a steeper increase of 9% from 2015 to 2021 and then a more gradual increase to 2050), gasoline output decreases from 8 to 6 Mbbl/d, diesel output increases slightly, and average jet-fuel output increases roughly 0.5 Mbbl/d from about 1.7 to 2.2 Mbbl/d[11].

Future refinery hydrogen requirements are estimated based on linear regression of refineries characterized by Elgowainy and colleagues[17] with crude American Petroleum Institute (API) gravity, crude sulfur content, gasoline-to-distillate ratio, and liquefied petroleum gas to total product ratio as the explanatory variables. The dataset includes 43 large refineries (each with capacity >100,000 bbl/d) in four Petroleum Administration for Defense District (PADD) regions covering over 70% of U.S. refining capacity. Elgowainy and colleagues[18] describe the details of the regression model and its valid range.

Refinery hydrogen demand by PADD region shown in Figure 9 is projected to increase due to increased ratio of diesel/gasoline demand, stringent sulfur requirements, higher API gravity and sulfur content for petroleum feedstocks, and increased petroleum inputs. This demand is estimated using the regression model and then allocated to individual refineries within each PADD based on the petroleum processing capacity of each refinery within the PADD.

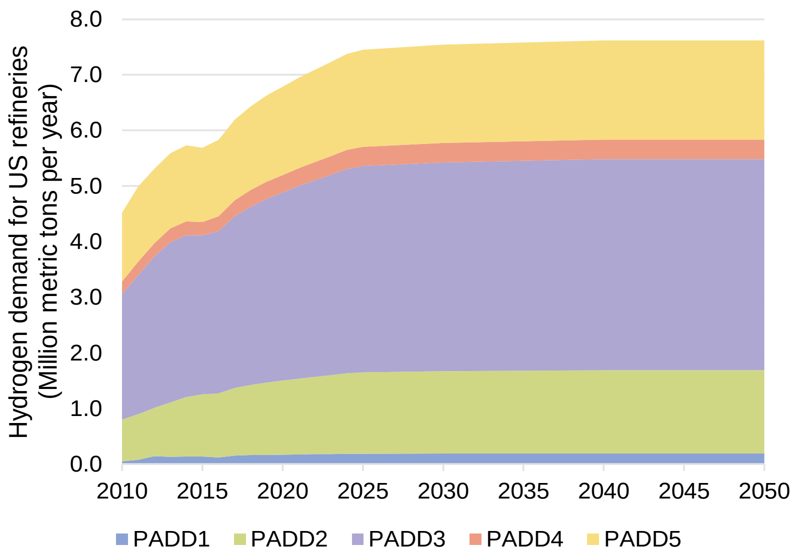

Figure 9. Projected total hydrogen demand for U.S. refineries by PADD, through 2050.

2.2.4 Direct Reduced Iron for Metals Refining and Steel Production

The direct reduction of iron is a process developed by Midrex Technologies, Inc. for producing high purity iron from ore at temperatures below the melting point of iron by reducing the iron oxide ore and driving off oxygen in a reactor using a reducing agent. The reducing agent can be elemental carbon from NG or coal, hydrogen or syngas. In the conventional approach to steel making, iron ore is reduced to pig iron using coking coal as the reducing agent in a blast furnace, and the pig iron is then converted to steel in a basic oxygen furnace (BOF). In the DRI process, DRI is converted to steel in an electric arc furnace (EAF), allowing reductions in overall energy use and CO_2 emissions compared to the conventional steel-production process. In the U.S., the amount of steel produced by EAF has been increasing and is expected to continue to grow, mainly due to the increased production of scrap, which can be incorporated in the EAF feed, while the amount produced by BOF is expected to remain relatively flat. Product quality dictates the amount of scrap that can be used in an EAF; the remainder must be made up with pig iron from a BOF or DRI. Due to its high purity, DRI has a potential to increase the amount of scrap which can be used by EAF relative to using pig iron from a BOF. The DRI process, using 100% hydrogen as the reducing agent, requires up to 100 kg hydrogen per metric tonne of steel—i.e., a mass ratio of approximately 10%. However, using hydrogen in a blend with NG with up to 30/70 ratio by energy to produce DRI would not require modifications to the original , which was technology developed to work with only NG[19].

Nuclear and renewable hydrogen could be used to offset NG or other fuels in the DRI process. For this analysis, we estimate the potential hydrogen demand for DRI based on using 30% hydrogen and 70% NG on an energy basis[19]. The locations and scale of potential hydrogen use for DRI are estimated based on total steel-production capacity, national average utilization rates for BOFs and EAFs[20], and national average DRI-feedstock shares. In 2015, BOFs and EAFs used 2.4 MMT and 1.7 MMT of DRI, respectively[20]. Thus, we estimate potential current hydrogen demand for current DRI to be 0.24 MMT H_2 for BOF and 0.17 MMT H_2 for EAF. The potential future demand for hydrogen use in the production of DRI assumes constant production by facility and replacing all pig-iron feed with DRI. In this case, hydrogen demand sees the greatest increase at the locations of current BOFs, where we estimate an additional 2 MMT H_2 could be used for DRI (for a total of 2.2 MMT). EAFs experience more modest growth in hydrogen demand, mainly due to their large share of scrap inputs. The additional hydrogen demand for future DRI production at EAF locations is estimated to be 0.17 MMT (for a total of 0.41 MMT). These estimates are conservative relative to the national estimate of Elgowainy et al.[18] for potential future hydrogen demand of 4 MMT for 30% replacement of NG on an energy basis. Their estimates are based on the Annual Energy Outlook projection of 50% growth in U.S. steel production by 2040 and full replacement of iron inputs with those produced by DRI. The GHG emissions associated with using DRI were assessed by comparing it with conventional blast furnace and EAF. These processes were evaluated using the GREET 2019 model for LCA, to estimate the eq. CO_2 emissions for each process and highlight the benefits of using Nuclear-H_2 in DRI production.

Figure 10 compares the eq.CO_2 emissions per metric tonne (MT) of steel produced for four possible process steps in the steel making process: 1) Blast Furnace / BOF (using coal), 2) EAF (using grid electricity), 3) EAF (using nuclear electricity), and 4) DRI (using nuclear H_2). The GHG emissions from each respectively is: 2.2-MT eq.CO_2 / MT steel from Blast Furnace, 0.91-ton eq.CO_2 / MT steel from EAF using grid electricity, 0.13-MT eq.CO_2 / MT steel from EAF using nuclear electricity, and 0.01-MT eq.CO_2 / MT steel from DRI using Nuclear-H_2, assuming the reducing agent is 100% hydrogen.

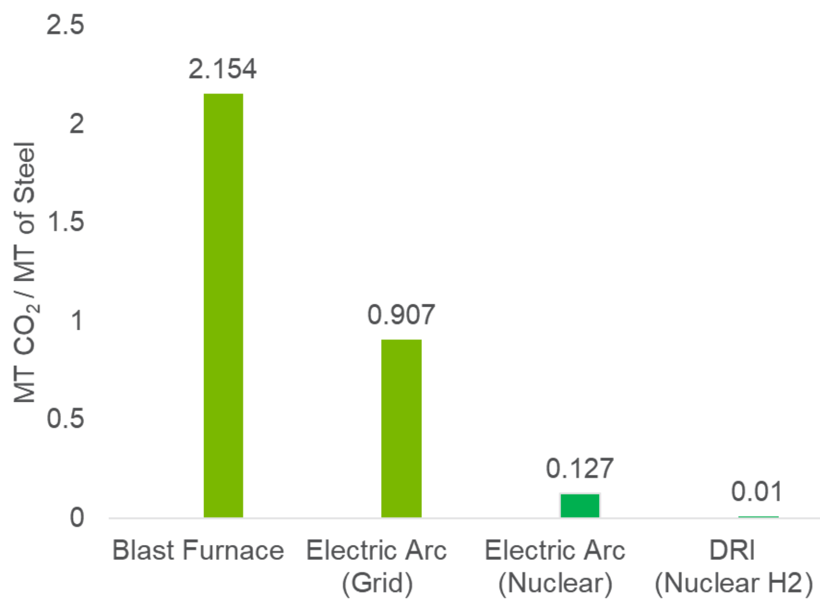

Figure 10. LCA of GHG emissions for various steel-making process options.

2.2.5 Ammonia and Fertilizers

Ammonia is produced by the Haber-Bosch process, which reacts hydrogen, usually produced from NG via the SMR process, with nitrogen separated from the air. In 2016, 14 MMT of ammonia were consumed in the U.S.[21], with 12% of consumption being for non-agricultural products, and the remainder used to produce fertilizer products, including anhydrous ammonia, urea, diammonium phosphate, monoammonium phosphate, and nitric acid. The Haber-Bosch process uses hydrogen in a molar ratio of 3 moles H_2 to 2 moles of NH_3; therefore, 0.178 kg of hydrogen are required to produce one kg of ammonia. As ammonia is the source of nitrogen in other fertilizer products, we can generalize this as 0.216 kg hydrogen per kilogram of nitrogen in fertilizer.

Estimated hydrogen demand locations for U.S. ammonia production in 2017, based on the ammonia production capacity, are shown in Figure 11. The locations and scale of ammonia production are estimated using plant capacities[22](Ammonia Industry 2018) and assuming the national average capacity utilization rate of 80%. Future production by location through 2024 is estimated based on announced plans for capacity expansion by facility which include a 40% expansion from 2019 to 2024[22] (Ammonia Industry 2018). Currently 40% of the ammonia required for fertilizer products used in the U.S. is imported, so this expansion reflects the expectation that domestic production may potentially displace imports in the U.S. market due to the availability of low-cost green hydrogen. At the national level, Elgowainy and colleagues[18] assumed that after 2024, U.S. ammonia production would increase through 2050 at a modest rate of 1% per year, assuming decreasing domestic demand for nitrogen fertilizer for corn, and relatively stable domestic demand for nitrogen fertilizer for other products, with the increased domestic production displacing nitrogen fertilizer imports in the U.S. market (Figure 12).

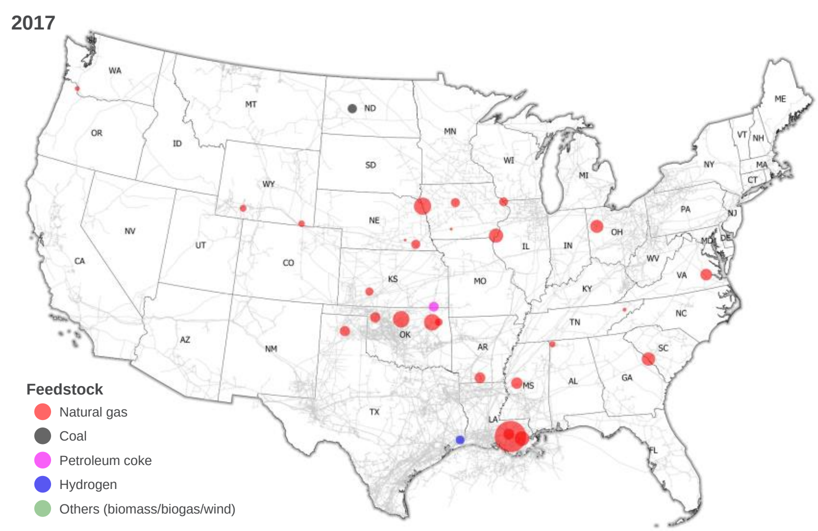

Figure 11. Estimated H_2 Demand for U.S. NH_3 Production in 2017.

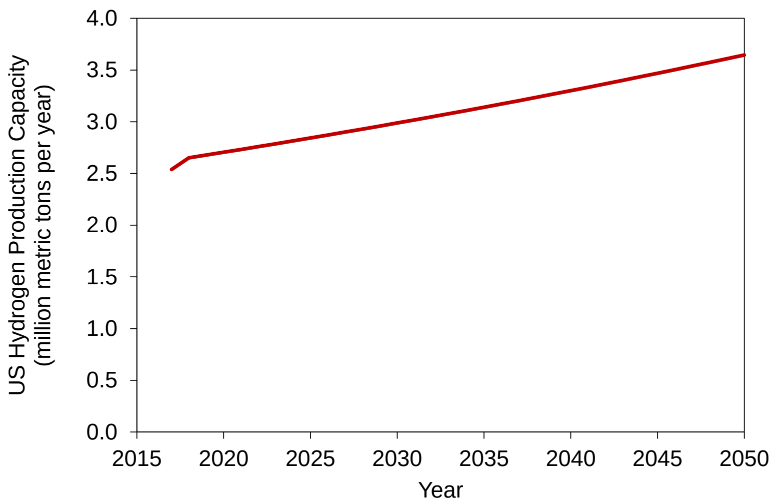

Figure 12. Current and projected hydrogen demand for U.S. NH_3 production[22] for the ammonia industry from 2018 through 2050, assuming an annual growth rate of 1%).

To evaluate the environmental benefits and trade-offs for using nuclear-H_2 for ammonia production, the Haber-Bosch process was considered. The GREET 2019 model was used to conduct the LCA for ammonia production. Various production pathways for hydrogen were considered to understand the eq CO_2 emissions associated with various ammonia-feedstock sources and production pathways. Figure 13 compares CO_2 emissions from the conventional ammonia-production process using nuclear-H_2 or grid electricity for the air separation unit (ASU). The figure compares the eq CO_2 per MT nitrogen in the fertilizer for three ammonia-production pathways, a baseline conventional pathway using SMR of NG, another pathway using nuclear-H_2 and grid electricity for the ASU, and a third pathway using nuclear power for both H_2 production and the ASU. The conventional pathway produces about 2.9 MT CO_2/ton N while the nuclear-H_2 and the nuclear for both H_2 and ASU produce 1 and 0.01 MT CO_2/ton N, respectively, on a life-cycle basis.

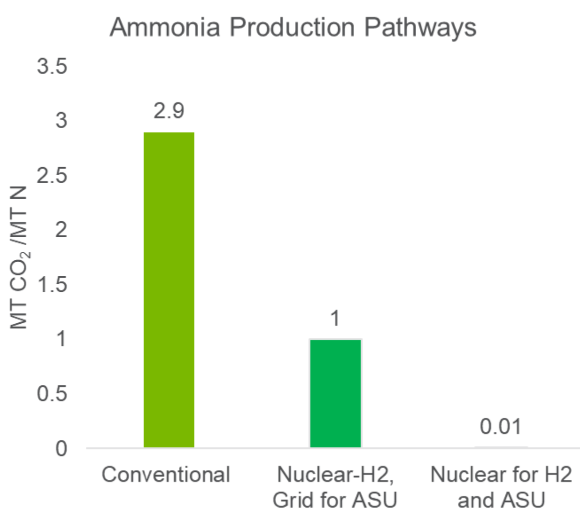

Figure 13. Life-cycle CO_2 emission for ammonia-production pathways.

2.2.6 Oxygen

2.2.6.1 Overview of the current and near-future domestic oxygen market

Assuming SOEC stacks that operate without an anode sweep gas, a ~1 GW NPP-associated water-electrolysis plant could produce ~5,500 MT/d of high-purity oxygen gas. 1 GW is used as the rough average nuclear plant capacity. It is recognized that HTSE SOEC technology is not yet technically capable of producing hydrogen at the 1 GW scale, but this number is used to show the hypothetical capacity once the technology of SOECs is able to reach this scale. U.S. industrial producers currently supply roughly 190,000 MT/d of enriched (85–99.9% purity) oxygen, totaling more than 70 MMT per year[23]. These companies received an estimated $10 B in revenue from oxygen sales in 2019, suggesting an average price of $0.13/kg O_2. This average estimate encompasses a wide range of price points, from <$0.10/kg for large-scale gaseous product from ASUs to >$1.00/kg for liquid or high-pressure O_2 delivered in cylinders. The projected compound annual growth rate (CAGR) for the global industrial oxygen market is 6–7%[24]. However, the mature nature of oxygen-consuming U.S. industries means that the projected domestic CAGR is a significantly lower: 1–3%. At 2% growth, the U.S. will add an estimated 45,000 MT/d of oxygen-production capacity by 2030 (Figure 14)[23,24,25]. Based on these estimates, the total oxygen demand in 2030 could be supplied by 40–45 1 GW NPP-associated SOEC facilities performing water electrolysis. Given the long lifetime of legacy technologies like ASUs, it is unlikely that NPP facilities would satisfy 100% of either continuing or new demand. A single 1 GW NPP-SOEC unit could produce more than 10% of new demand projected for 2030.

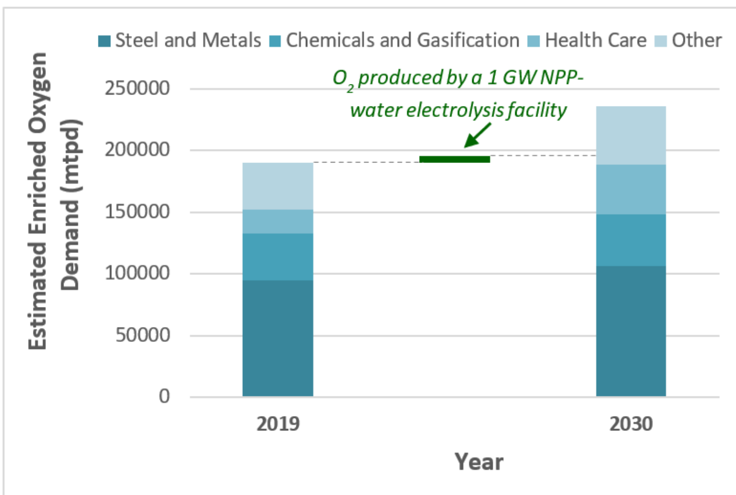

Figure 14. Estimated annual demand for enriched oxygen products by major consuming industry in 2019 and 2030, using current CAGR projections. The center bar shows the maximum daily O_2 production of a 1 GW NPP-SOEC facility (~5,500 MT/d).

Two technologies currently dominate industrial oxygen production: cryogenic air separation (CAS) and pressure-swing adsorption (PSA). The former generates 70–75% of all industrial oxygen and delivers >99% pure O_2 in both liquid and gaseous form. The gaseous-to-liquid O_2 product ratio is about 4:1[26,27]. CAS units also produce pure nitrogen and argon for operations requiring inert-gas streams. PSA units generally operate at or near ambient temperature and produce a product of lower purity (85–95%) than CAS technology. CAS units are typically built at large scale (100–5,000 MT/d) near point-source demand by large industrial gas companies[28]. By contrast, PSA units are simple and highly scalable, ranging from personal oxygen concentrators producing liters per day for breathing assistance to ~50 MT/d units for industrial applications. PSA technology does not produce gases other than oxygen.

Industrial oxygen is used in a variety of industries, most notably:

- Steel and Metals (~50% of total demand)
- Chemical and gasification (~20% of total demand)
- Health care (~10% of total demand)
- Other industries:
    - Wastewater/solid waste treatment
    - Glass and ceramics
    - Paper and pulp

Steel and Metals

In 2019, the U.S. manufactured 87 MMT of steel, 70% from EAFs and 30% from BOFs, requiring ~35 MMT of oxygen[29]. Total U.S. steel consumption is roughly 130 MMT, with the difference made up by imports, mainly from China, India, and Japan[30]. Recent projections of domestic growth have been below 1%, but the near future is relatively uncertain because it is unclear how tariffs and new technologies will affect investment decisions[31, 32]. During steel manufacturing, high-purity oxygen is injected directly into the molten metal to remove impurities, particularly carbon and silicon species. Excess nitrogen incorporation into steel causes the metal to become brittle; therefore, only high-purity oxygen can be used for this purpose. Oxygen is also used to enhance combustion, increasing flame temperatures for various steps of the steelmaking process. Both BOF and EAF technologies require substantial oxygen feeds, between 0.20–0.33 kg O_2 to produce kilogram of steel[33]. This range was used to estimate approximate oxygen-demand schedules for the steel mills discussed below. Oxygen is also used in other metals and manufacturing processes, most notably in oxy-fuel lances for cutting and processing. These applications represent small, distributed demand sources relative to the large point-source steel mills. The use of oxygen in this sector is directly tied to both overall steel demand and the economics of domestic production; therefore, tracking these factors will provide insight into future oxygen demand.

Chemicals and Gasification

In the chemicals industry, roughly 14 MMT/year of oxygen is used to synthesize oxidized chemical products and for combustion enhancement[27]. Many high-volume chemicals, notably ethylene oxide, propylene oxide, and phthalic acids, are produced using enriched-oxygen feeds to improve selectivity or reaction rates. Gasification of coal to produce syngas also requires large quantities of oxygen; 33 gasification facilities are currently operational in the US[34]. Gasification is a significant oxygen-demand source overseas, particularly in China. Increased demand for synfuels in the U.S., perhaps from recycled carbon sources, could increase oxygen demand in this sector. Refineries generating oxygen-containing products from oil or NG could likely be supplied by an adjacent ASU at low prices (≤$0.05/kg), making transportation costs key to evaluating the viability of centralized production near NPPs.

Healthcare

In health care, ~7 MMT/year of enriched oxygen (85–95%) is consumed, primarily as breathing assistance during both in- and outpatient care. Centralized demand sources such as large urban and suburban hospitals typically receive shipments of high-purity liquid oxygen from ASUs. This oxygen is then diluted to lower purities for applications such as surgery, anesthesia, medical instruments, and breathing aid[35]. Rural hospitals for whom liquid-oxygen shipments are not economic are increasingly installing on-site PSA units to provide cheap enriched O_2. Distributed services such as breathing oxygen for outpatient care often use onsite PSA units. The health care sector is driving increases in oxygen demand overall, as domestic growth rates are projected to be 7% annually[36]. However, the distributed nature of this growth and the availability of cheap supply from small- and medium-scale PSA units (reducing transportation costs) may make the healthcare industry a poor fit for centralized NPP-SOEC units.

Other Industries

Smaller-scale industrial uses of oxygen include wastewater treatment, glass and ceramics manufacture, and paper and pulp production[23,24,25]. In both the waste-management and paper industries, environmental concerns have led companies to replace toxic or caustic chemicals with oxygen feeds (occasionally enriched with ozone)[27]. These treatments remove contaminants or bleach products without potentially toxic waste streams. High-temperature combustion improves product quality in the glass and ceramics industries. Each of these applications is diffuse, and they lack point-source demands on the scale of steel mills or chemical refineries. Similar to hospitals, waste treatment or paper plants often receive shipments of liquid O_2 via truck, although large facilities may have onsite generation capabilities installed[37]. For these reasons, smaller-scale industrial uses of oxygen appear to be a poor fit for centralized NPP-HTSE plants.

2.2.6.2 NPP-associated generation and the oxygen market

While NPP-associated water electrolysis can produce inexpensive oxygen, centralized SOEC plants may have difficulty accessing key markets. The oxygen market is generally split into two categories: large point-source demand (e.g., steel mills and chemical plants) and distributed demand (e.g., healthcare and waste treatment) facilities. Large demand sources almost always have a dedicated oxygen-supply source such as a collocated ASU[38]. These large-scale units can provide cheap, high-purity gaseous (≤$0.10/kg) and liquid (≤$0.15/kg) oxygen with minimal transportation costs[39, 40]. In distributed markets, oxygen is transported either as a liquid (taken directly from a cryo-distillation tower) or compressed gas. SOEC electrolysis stacks produce oxygen at high temperature and low pressure and would incur significant liquefaction or compression costs in preparation for distributed transportation. Locating a new demand source near an NPP is critical to reducing transportation costs, but oxygen cost is not often a determining factor in location choice. For steel mills and chemical plants, factors include feedstock costs (e.g., iron ore, recycled steel, naphtha, NG, etc.), proximity to markets, and labor costs. These play a larger role in location choice. The need for an oxygen supply will likely not be a determining factor in a firm's deciding whether to collocate a steel mill or chemical plant near an NPP, but when considered as a whole—with an abundant hydrogen and thermal energy supply that an NPP-HTSE hybrid plant could provide—the oxygen supply would be a convenient ancillary benefit.

In addition to difficulty of market access, the low price of commoditized oxygen suggests that O_2 sales would have only a marginal effect on H_2 price and, by extension, SOEC plant economics. A large point-source of oxygen demand might require ~700–1,000 MT/d of oxygen, or roughly a 1:1 mass ratio of H_2 to O_2 sales for a 1 GW NPP, paired with a single large oxygen demand. Arranging oxygen demand to consume the full 5,500 MT/d oxygen generation from an NPP is considered unlikely. Analysis performed using the DOE hydrogen-analysis model indicates that selling 1–1.4 kg of oxygen for every kilogram of H_2 at $0.10/kg O_2 (potentially a high price for the market) produces a revenue stream of $0.10–0.14/kg H_2. While not negligible, these byproduct sales represent only a marginal decrease in the levelized cost of hydrogen production for SOEC plants and would likely not change the overall conclusions of an investment analysis. Thus, while oxygen sales would provide a boost to plant revenues, the difficulty of market access and low product price suggests that this revenue stream is not critical to overall plant economics and would likely be accessed only under the scenario of a large steel or chemical plant's being collocated with an NPP-HTSE hybrid plant.

2.2.7 Co-Electrolysis—Carbon Dioxide Reduction with Water

2.2.7.1 Syngas

As mentioned, the co-electrolysis process is under development. Co-electrolysis takes CO_2 and water as feeds and produces CO, H_2, and O_2. CO and H_2, as a mixture, is called syngas because these two molecules can be used in a large number of processes synfuels and synthetic chemicals (synchems). The markets for syngas, synfuels and synchems are here discussed.

Synfuels and Synchemicals

Significant quantities of high-purity CO_2 are generated in industry processes such as ethanol-production plants, SMR processes used for hydrogen production from NG for refining, ammonia production, NG power plants, and other purposes. These high-concentration CO_2 sources present opportunities for the production of synchemicals and fuels such as methanol, Fischer-Tropsch (FT) diesel, and dimethyl ether (DME), while minimizing the cost and energy penalty to capture CO_2 relative to other dilute CO_2 sources (e.g., from flue gases of coal and NG power plants). Methanol production presents an opportunity because its manufacturing process is relatively simple, and its global market is expected to grow for multiple uses, such as petrochemicals, fuel blending, or as a blendstock for transportation-fuel production. Methanol produced from waste CO_2 streams and hydrogen from clean nuclear energy offer a low-carbon alternative to methanol produced via the conventional process using NG. The merchant market for CO_2 is currently underutilized. Of the 100 MMT of CO_2 generated from ethanol production and SMR, only 14 MMT are currently available to the merchant market, of which 11 MMT are used for food processing, carbonated beverages, and other uses[41]. This leaves a significant CO_2 resource availability which could be used for methanol and synfuel production. In this report, we focus only on the potential hydrogen demand for synfuel production from highly concentrated sources of CO_2. The potential hydrogen demand for methanol production from the same CO_2 sources will be of a similar magnitude; thus, producing one chemical or fuel in lieu of the other will result in similar hydrogen demand considering the same CO_2 resources.

The hydrogen demand for synfuel production can be estimated based on the stoichiometric 1:3 mole ratio of CO_2 to H_2 that is required for the synthesis of FT diesel or DME. The availability of high-purity CO_2 from SMR associated with merchant hydrogen and ammonia production and the locations of facilities are based on values reported by facilities to the U.S. Environmental Protection Agency's Greenhouse Gas Reporting Program[42]. High-concentration CO_2 sources from ethanol production is estimated based on the 1:1 mole ratio of ethanol to CO_2 generated during the conversion of glucose and sucrose in the fermentation process. In 2017, 15.6 billion gal of ethanol were produced in the U.S.[43], which generates an estimated 44 MMT of high-purity CO_2. The locations and capacities of ethanol-production facilities are based on an EIA dataset[43] and illustrated in Figure 15, while production by facility is estimated based on the national average capacity-utilization rate. The total potential hydrogen demand to produce synfuels from high-purity, high-concentration CO_2 sources is significant, at 14 MMT, comprised of 6.0 MMT of hydrogen for synthesis processes using ethanol plants' CO_2, 2.1 MMT using CO_2 associated with current ammonia production, and 5.9 MMT using CO_2 associated with SMR for petroleum refining. While most ethanol production is clustered in Midwestern states, ammonia plants are located in a broader area, mainly in the Midwest, Gulf Coast, and Southeastern states, while other SMR plants are located near petroleum refineries, mostly along the Gulf Coast and near San Francisco, Los Angeles, Chicago, Detroit, Minneapolis, St. Louis, and Toledo. High-purity CO_2 sources for syngas production are shown in the figures and tables in this report associated with ethanol plants (syngas-ethanol), SMR plants producing hydrogen (syngas-H_2 SMR), and ammonia plants (syngas-ammonia).

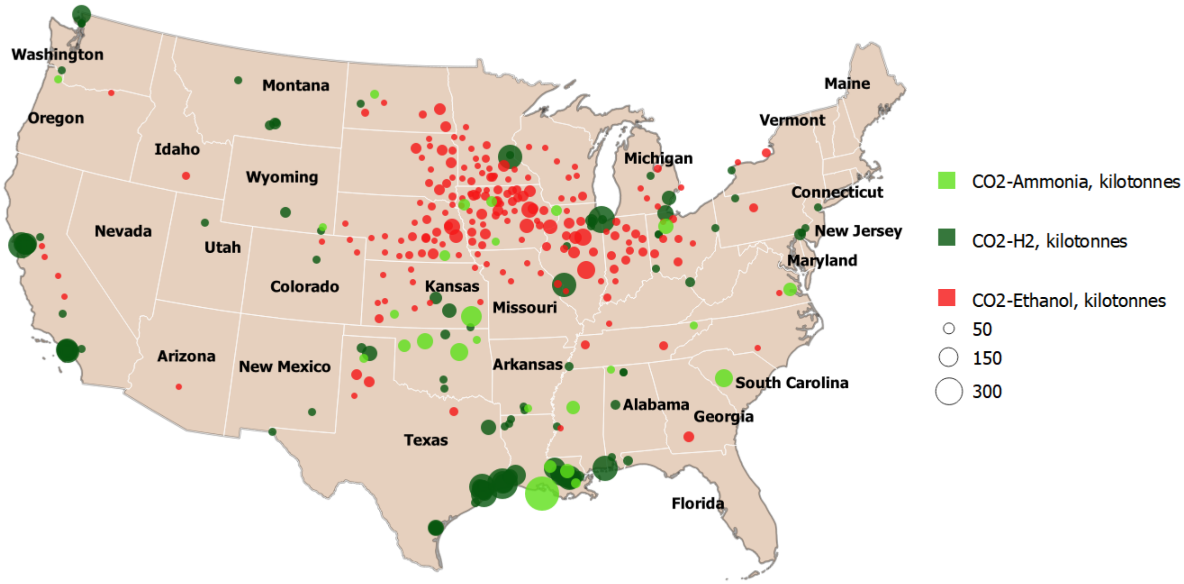

Figure 15. CO_2 sources for use in synfuels production.

The life-cycle environmental benefits associated with synfuel production using low-carbon hydrogen from nuclear power, in terms of reduction of GHG emissions, were evaluated for the FT processes producing synfuel blends, such as FT naphtha and jet and diesel fuels. The GREET 2019 model was used to estimate GHG emissions assuming captured CO_2 and nuclear-H_2 for producing these synfuels. The GHG emissions associated with synfuel production and dispensing can be estimated using a WTW analysis. Figure 16 compares the GHG emission for the production of conventional fuels, such as gasoline and jet and diesel fuels, to highlight the benefits of the FT pathway using nuclear H_2. The carbon dioxide equivalent emissions per megajoule of gasoline, jet fuel, diesel fuel, and FT fuel pathways are about 94, 86, 93 and 6 g CO_2 eq./MJ respectively.

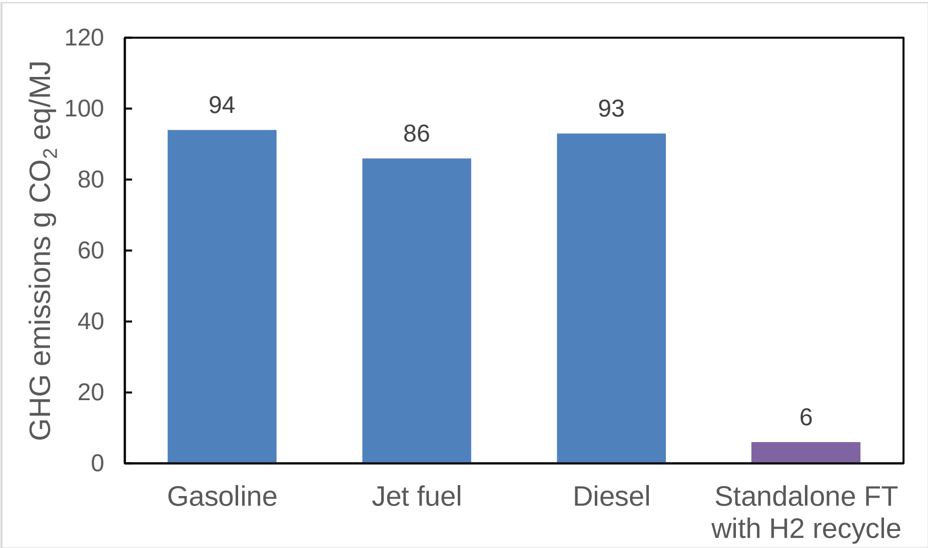

Figure 16. WTW total-O_2 emissions for gasoline, jet fuel, diesel and FT fuel (produced using nuclear H_2).

Syngas for Metals Refining

Hydrogen use in metals refining has been discussed above. Syngas ($CO + H_2$) generated from an adjusted SMR process using NG is what is currently used in the metals industry. Syngas can alternatively be produced and supplied to metals plants using CO_2 and water in the co-electrolysis process as described. There are a few advantages to using a carbon-containing molecule such as CO in addition to hydrogen in the metals refining process. First, different grades of steel require varied amounts of carbon as part of the finished alloy in order to obtain the desired material properties, so carbon will need to be incorporated regardless. Second, some carbon can be consumed in the metals-refining process, releasing energy and resulting in a more-economic process overall due to the reduced outside-heating requirements versus a metals-refining process using only hydrogen as the reducing agent.

2.2.7.2 Formic acid

FA can be produced economically using an electrochemical process by baseload low-carbon NPPs using CO_2 from sources such as local ethanol plants and even SMR plants. This has the potential to be game changing for the chemical industry. FA could serve as a durable liquid (at ambient conditions), and energy-dense hydrogen carrier that could be produced by electrolysis (co-electrolysis of CO_2 and water to make FA)[44,45].

Overview of the Current and Near-Future Formic Acid Market

FA is defined as a high-volume chemical, with global production totaling 1.2 MMT per year[46]. The total market value is estimated to be $1.1 B, indicating a global benchmark price of $1.00/kg; U.S. prices are ~25% higher[47,48,49] . U.S. demand is currently relatively small, around 0.125 MMT/year or ~10% of the global demand, 40% (i.e., 0.05 MMT/y) of which is produced in a single facility in Geismar, Louisiana, operated by BASF[50]. The remaining 60% of demand is supplied by imports from China and Germany. Worldwide growth is strong—estimated at nearly 5% CAGR through 2027—and domestic-growth estimates are even more optimistic, ranging from 5–14% CAGR due to emerging applications for FA[51]. Drivers for growth are

1. Current commodity chemical use switching from a U.S. import to a U.S. export
2. Use as a silage preservation to reduce need for animal antibiotics
3. Fracking/drilling-completion fluids
4. Displacement of phosphoric acid for cleaning and descaling applications[52]
5. Breaking down and hydrogenating carbonaceous (biomass) feedstock into high-value chemicals and fuels
6. Use of a liquid-hydrogen carrier that is easily stored and transported to distributed users.

At this growth rate, the global market will grow to ~2 MMT/year of capacity by 2030.

Conventional processes produce FA via carbonylation of methanol or carbonylation of oxalic acid. Electrochemical catalytic co-electrolysis of CO_2 and water to make FA is a promising emerging process, and one manufacturer, OCO Chemicals, boasts of a 78% efficient process with high selectivity (99%) with their licensed process that reduces CO_2 with *in situ*-generated hydrogen from water to FA or formate salts[53].

Currently, FA is used to make natural and synthetic leathers, textiles, cleaning products, rubber, and formate salts are used as deicing agents and additives in oil and gas drilling fluids[54]. Abroad, the major use of FA (accounting for 40% of demand) is as an antimicrobial additive in animal feed, but this practice is uncommon in the U.S. due to "generally low commercial availability of formic acid[55,56,57]." Domestic farmers use antibiotics instead, a practice which has come under scrutiny, presenting an opportunity for increased FA production and use[58]. FA is chemically stable and relatively nontoxic (at concentrations below 90%), making it an attractive chemical product for farming applications. The FDA has denoted FA as “generally recognized as safe,” and the European Union (EU) has certified it as a permissible additive for both human and animal food[59,60]. The Midwest (particularly Iowa, Minnesota, and Wisconsin) contains clusters of industrial cattle and pig farms, while the Southeast is a center for chicken farming[61]. NPPs in these regions making liquid products such as FA would have straightforward access to these markets. FA replacement of antibiotics in animal feed, whether motivated by regulation, public scrutiny, or price, would lead to a significant increase in domestic FA demand.

Other possibilities for replacing current chemicals, specifically acetic acid (AA), are also promising, although on a smaller scale than animal feed. Roughly 15 MMT/year of AA are manufactured worldwide, most commonly used to produce VA monomers, food-grade vinegar, acetic anhydride (an industrial solvent), and acetate salts. FA cannot replace AA as a monomer or in vinegar, but BASF markets FA as a replacement for AA (and acetate salts) in deicing agents and solvents, indicating the possibility of expanded FA demand[62]. In particular, potassium salt deicing agents represent a growth area, as potassium formate has already replaced potassium acetate for deicing at European and North American airports[58].

In addition to its use by traditional industries, FA also holds substantial promise as a hydrogen carrier for direct or indirect use in fuel-cell technologies. FA is both energy dense (1,760 Wh/kg) and hydrogen-dense (53 g/L, 44 g/kg), containing more hydrogen per volume than compressed hydrogen itself (at moderate pressures)[53,54]. It is a liquid at ambient temperature, stable, nontoxic, and durable enough for long-term storage. Further, hydrogen release from FA is exergonic (<0 free-energy change) but not exothermic (>0 enthalpy change). This allows hydrogen release to be performed at low temperatures but, perhaps more importantly, at high pressures that may be suitable for storage in fuel-cell vehicles. Other hydrogen carriers (e.g., ammonia and methanol) do not have this property, and it has been estimated to reduce storage, compression, and dispensing costs of a hydrogen refueling station by 60–70%[63]. These properties have led to increased interest in FA as a potential hydrogen carrier[64,65]. Growth of this market, combined with technological advances in co-electrolysis, could see FA become a major industrial chemical in the long-term future.

Analysis of Nuclear Power Plant Facilities and the Formic Acid Market

With substantial growth in the market, co-electrolysis to generate FA could play a revenue-generating role in a multipurpose NPP-associated facility. A single 1 GW NPP using currently available low-efficiency co-electrolysis technology could produce more than the present global demand for FA each year. INL has previously estimated the required energy input for electrolytic FA synthesis at ~4 MWh/1000 kg, assuming a large overpotential (>2 V) to increase cell current densities[65]. One gigawatt of constant electricity input could therefore produce the current annual demand of FA (1.2 MMT) in ~5000 h, or around 7 months. Assuming an electricity price of $25–40/MWh, the energy input costs are $0.10–0.22/kg FA. Assuming amortized capital expenditures of $0.20–0.25/kg (estimate from OCO, Inc.) the cost of electrochemical FA production is ~$0.30–0.47/kg. These cost targets would make FA cheaper than many alternative chemicals, opening up new markets such as silage preservation, cleaning agents, and chemicals processing. To achieve these goals, research and development is needed to increase the efficiency and current density of co-electrolysis cells, which will reduce both the operating and capital costs. If cell efficiencies are increased and the market grows significantly, particularly through adoption of FA as an H_2-energy carrier, FA production would be very well suited for NPP facility integration, especially when configured as a component of the energy industrial park concept discussed above.

2.2.8 Summary of Electrolysis Markets

2.2.8.1 Estimates of competitive hydrogen cost for various markets and applications

The estimates of threshold price in Figure 2 depicts the price at which the application would utilize hydrogen in lieu of an alternative feedstock, assuming no available incentives for low-carbon hydrogen and no penalties for carbon-generating feedstocks.

Table 1. Estimated threshold price for hydrogen to replace alternate feedstocks, by application.

Application	Threshold Hydrogen Production Price	Notes
LD FCEVs	\$2–3/kg	DOE targets for FCEVs
Medium- and HD FCEVs	\$2–3/kg	DOE targets for FCEVs
Petroleum Refining	Up to \$3/kg	Competitive with SMR. No substitute for hydrogen in refining process (inelastic demand)
NH_3	\$2/kg	Price to be competitive with imported ammonia
Synthetic FT Diesel	\$1–1.5/kg	Price to compete with petroleum diesel
Injection to NG Infrastructure	\$0.8–1/kg	Price to compete with NG on thermal-energy content, based on higher heating value
Iron Reduction and Steelmaking	\$0.8–1/kg	Price for hydrogen to compete with NG in DRI

2.2.8.2 Hydrogen storage and infrastructure cost

As stated earlier, hydrogen can be produced using LWRs at NPPs during low-demand periods when the selling price of electricity is less than the marginal cost of operation, to assist in sustainable NPP operation. The produced H_2 from these NPPs can be used in various industries as described in the previous section. Hydrogen produced at the NPP site can be transported to the demand locations via a dedicated delivery infrastructure, including storage, packaging, and transportation components. Alternatively, the nuclear power can be transmitted to the demand location, where hydrogen can be produced and used, although the added cost of transmitting and/or distributing the electric power and the inability to integrate NPP thermal energy to the electrolysis process would impact the efficiency and operation cost of producing the hydrogen. The scale of demand and its distance from the NPP would determine the economics and, thus, the mode of delivery of hydrogen from the NPP to the demand locations. Hydrogen markets tend to have inelastic hydrogen demand. Thus, the hydrogen-production plant must be able to provide hydrogen to its markets regardless of electricity pricing. In order to fully monetize both the electricity and the hydrogen markets, hydrogen-storage capabilities are needed to mitigate any mismatch between hydrogen supply and demand. Hydrogen storage provides the nuclear facility with the flexibility to operate fully in the grid-electricity and hydrogen markets. Hydrogen can be stored at low pressures (of 150 to 500 bar) economically with a cost between \$600–1000 per kilogram of hydrogen for a high-pressure vessel storage system, depending on the storage pressure, type of vessel (Types I–IV), and the nature of pressure cycles. The storage system should also include a system that compresses the hydrogen into the storage system. The capital cost of the storage and compressor for such a system are shown in Table 2. Hydrogen also may be liquefied and stored in cryogenic vessels. The cost of hydrogen liquefaction and storage are also shown in Table 2. The information in Table 2 are extracted from ANL's Hydrogen Delivery Scenario Analysis Model.[66]

The gaseous hydrogen produced at an NPP can be transported to the demand location via pipelines for large-scale demand (tens to hundreds of tonnes per day), and tube-trailers for small-scale demand locations (e.g., fueling stations with capacities of up to 1 MT/d). Compressors improve the density of hydrogen before transportation via a tube-trailer or pipeline. In general, transporting the hydrogen at higher densities enables more-economical transportation. Table 3 shows the capital cost of pipelines, tube-trailers, and cryogenic tankers for transporting gaseous and liquid hydrogen, based on the ANL model.

Table 2. Cost of hydrogen storage options.

STORAGE OPTIONS FOR HYDROGEN	
LOW-PRESSURE STORAGE	
Storage Cost	Vessel Capacity × \$600–1000/Kg_H2
Compressor Cost	40,500 × Motor Power (In Kw)$^{0.46}$
Geologic Storage	
Cavern Cost	3,738,563 × (Cavern Capacity (In M^3)/19000000)$^{0.7}$
	Density @2000psi And 20oc Is 10.5 Kg/M^3
Compressor Cost	6893 × (Motor Power In Kw)^ $^{0.7464}$
LIQUID-HYDROGEN STORAGE	
Liquefaction Cost	6,350,000 × (Liquefaction Capacity In Tonne/Day)$^{0.8}$
Cryogenic Storage Cost	5,646,600 + 3100 × Storage Volume In (M^3)
Cryogenic Storage Cost	5,646,600 + 3100 × Storage Volume In (M^3)

Table 3. Transportation cost of hydrogen using various delivery options.

DELIVERY OPTIONS FOR HYDROGEN	
PIPELINE COST	
Material Cost	69330 × Exp (Diameter [In Inches] × 0.0697) × (Length, Miles)
Labor Cost	[56.5323 × Diameter (In Inches)^2 + 47875.3 × Diameter (In Inches) + 17788.1] × Length (In Miles)
Right-Of-Way Cost	[-9e-13 × Diameter (In Inches)2 + 4,417.1 × Diameter (In Inches) + 164,241] × Length (In Miles)
Miscellaneous Cost	[333.443 × Diameter (In Inches)^2 + 14198.8 × Diameter (In Inches) + 135569.5] × Length (In Miles)
Compressor Cost	40,500 × Motor Power (In Kw)$^{\wedge 0.46}$
Tube-Trailer	1100 \$/Kg_H2 (Tubes And Trailer) + Tractor Cost (\$70,000)
Cryogenic Liquid Tanker	1,000,000 + Tractor Cost (\$100,000)

2.3 Electrochemical Monomer Production – Ethylene

An early technology readiness level (TRL) electrochemical process is being developed at INL that converts ethane (a component of NG) into ethylene and hydrogen[67]. Alternatively, an analogous process could be used to produce propylene or other higher-carbon-chain olefin monomers. This process is termed electrochemical non-oxidative deprotonation (ENDP). The ENDP process could be a future candidate for integration and coupling with an NPP providing electrical and thermal energy to the process. Currently, the ENDP process has been demonstrated at bench scale. Preliminary technoeconomic analysis and process modeling of a hypothetical scale increase of the ENDP process has been performed[68]. Possible markets to employ the hydrogen that could be produced via the ENDP process have been discussed. This section will focus on the potential markets for ethylene and propylene that could be potentially tapped by the NPP-ENDP process.

2.3.1 Overview of Ethylene and Associated Polymer Markets

Ethylene is the second-most produced chemical in the world (after ammonia), totaling over 185 MMT globally in 2019[69]. In 2018, the U.S. produced approximately 30 MMT of ethylene, and significant domestic capacity additions suggest that the domestic share of the global market will increase in the near future[70,71].

Ethylene is typically converted into key-commodity monomers, proceeding to polymer and plastic products. The most notable end-product polymers using ethylene as a key input material are

- Polyethylene: Roughly 100 MMT/year global demand in 2019, divided into a variety of high-volume products including[72]:
  - High-density polyethylene (HDPE)
  - Low-density polyethylene (LDPE)
  - Linear low-density polyethylene (LLDPE)
  - Others (ultrahigh-molecular weight polyethylene and cross-linked polyethylene)
- Vinyl chloride: ~47 MMT/year in 2019[73]
- Ethylene oxide: ~26 MMT/year in 2019[74]

Ethylene is rarely an end product, and the vast majority of ethylene is converted into other intermediates or monomers for commercial and industrial polymers. Some examples of ethylene upgrading in the polymer supply chain include:

- Chlorine addition to yield **ethylene dichloride**, which is further converted into vinyl chloride (VC). VC is polymerized to polyvinyl chloride (PVC) for use in piping, plastic parts, insulation, etc.
- Reaction with benzene to yield **ethyl benzene**, which is dehydrogenated to make styrene. Styrene is polymerized to polystyrene, used for plastic cutlery and packaging (e.g., Styrofoam), as well as rigid plastics.
- Reaction with acetic acid to yield **VA**. VA is polymerized to polyvinyl acetate, used in food packaging and glues.
- Oxidation to yield **ethylene oxide**, which is hydrolyzed to make ethylene glycol (EG). EG is used directly as a lubricant and antifreeze, or copolymerized with terephthalate to make polyethylene terephthalates, used in plastic bottles, jugs, and other packaging.

These examples represent just a fraction of the wide diversity of ethylene-containing products that are commonly used in packaging (including plastic wraps and films), bottles and jugs, piping, plastic parts, toys, textiles, lubricants, and surfactants. Ethylene-derived polymers are generally desirable due to their versatility, ease of processing, and low cost. Due to sustained demand and new polymerization technologies that improve resin performance and yield, ethylene market experts project sustained compound annual growth rates of ~4% through 2030, at or above global gross domestic product growth in this period[75,76,77,78]. Although the applications are quite diverse, the ethylene and polyethylene markets are mature and highly commoditized with stiff price competition. As a caution on market-growth projections, common applications of ethylene-derived products, such as single-use plastics, have become subject to environmental scrutiny and bans.

Nearly 80% of global ethylene is synthesized via catalytic steam cracking of either petroleum-derived naphtha (~40%) or ethane separated from NG (~38%)[76]. The majority of U.S. ethylene cracker plants are located in Texas and Louisiana, although Shell is constructing a major polyethelene facility in Western Pennsylvania[79,80,81]. Economies of scale are critical to profitable production of ethylene derivatives, particularly polyethelene. Plants are typically integrated facilities that produce ethylene from naphtha and/or ethane, and upgrade the olefin into downstream derivative products such as polyethelene (in various grades), ethylene oxide, or VC. Feedstock prices account for the the majority of costs in these high-volume commodity chemicals. Low NG prices in the U.S. have provided a competitive advantage for domestic chemical producers, leading to large investments in ethylene and polyethylene facilities in recent years[75,76,77]. Nearly 11 MMT of capacity has been or is projected to be added in the U.S. between 2017 and 2024[74]. These investments are typically made by multinational petrochemical companies such as Dow Chemical, ChevronPhillips, LyondellBasell, ExxonMobil, and SABIC.

Prices for ethylene derivatives, for example polyethylene, are heavily commoditized and volatile as a result of global supply and demand dynamics (Figure 17). Polyethylene is produced in a variety of grade, or densities, with the most widely used HDPE accounting for nearly half of total demand in 2018. Prices for the various polyethylene grades are generally similar, and currently fall between $0.60–0.90/kg wholesale[82]. Average polyethylene prices are forecast to rise at or below inflation (1.5–1.7%) through 2022[72]. As shown in Figure 17, the various types of polyethylene are subject to the same supply and demand forces, and therefore prices tend to rise and fall simultaneously with only minor differences over time.

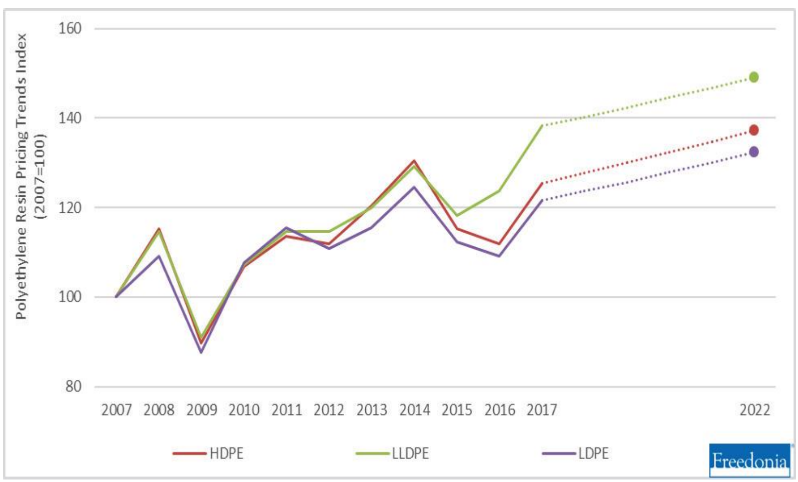

Figure 17. U.S. polyethylene prices by index, 2007–2022 (2007 = 100)[72].

Although the production of ethylene, commodity chemical derivatives, and polymers in pellet or crumb form is centralized on the Gulf Coast, manufacturing of plastic commercial and industrial end products from these building-block commodity chemicals is highly distributed. There are an estimated 16,000 plastics-production sites within the U.S., representing a wide range of firms from local companies to multinational conglomerates[83]. Many of these plastics-manufacturing firms are concentrated near the NPPs discussed in this study, including in the Midwest (Wisconsin, Illinois, Indiana, Michigan, and Ohio), Northeast (Pennsylvania, New York, and New Jersey) and Southeast (North Carolina, South Carolina, Georgia, and Alabama)[84]. Currently, commodity chemicals such as polyethylene or PVC are produced on the Gulf Coast and shipped in pellet or crumb form to demand sources upwards of 1,000 miles away. Polyethylene and PVC are solids at ambient conditions, making transportation technically straightforward, but industry analysts have identified logistics as a major sales bottleneck for chemicals producers. Logistical inefficiencies, including rail delays, labor availability, and deep-water port access, are estimated to translate to more than $50B in excess inventory and operating costs for suppliers over the next decade. The concentration of chemical manufacturers on the Gulf Coast is a major contributor to these logistical challenges. Locating new chemical manufacturing near supply concentrations in the Midwest, Northeast, and Southeast, as well as eastern seaboard ports, could side-step many issues and provide new plants with a competitive advantage in transportation costs[85].

The under-construction Royal Dutch Shell plant is seeking to exploit the combination of low NG price and relative proximity to polymer demand with a 1.6 MMT/year polyethylene plant currently under construction in Monaca, Pennsylvania, costing an estimated $6B[81]. This location is near the Marcellus and Utica NG deposits and will be within 700 miles of 73% of U.S. and Canada polyethylene demand (Figure 18). Therefore, an NPP-ENDP coupled-commodity plastics plant located in this region could achieve competitive advantages on both feedstock NG and product transportation costs. In addition to domestic demand, the facility is reasonably close to current export terminals such as Marcus Hook, Pennsylvania, near Philadelphia[86].

The Royal Dutch Shell plant could serve as a surrogate proof-of-concept for NPP-associated ethylene production facilities with similar transportation-cost advantages. The gas deposits are near multiple Midwest and Mid-Atlantic NPPs and Monaco, Pennsylvania, itself is near the Beaver Valley LWR. Thus, the region presents the synergies of 1) geographic overlap of low NG prices, 2) high regional concentration of nuclear energy, and 3) high regional demand for polymers.

Finally, the national or local regulatory and tax environment can play a large role in enticing investment. The Pennsylvania Shell plant has reportedly received tax breaks that could amount to $1.6B over the next decade[81].

Figure 18. Seventy-three percent of U.S. and Canada polyethylene demand is within 700 miles of the new Shell plant in Monaca, Pennsylvania, at the center of the above circle.[13] This region covers includes the majority of INL partner NPP facilities.

2.3.2 Analysis of NPP-associated facilities and the Ethylene Market

Through 2030, commoditized ethylene and derivatives production will be determined by global structural factors, but NPPs may have cost advantages that make them well-suited to produce these chemicals. Ethylene productivity growth and pricing tends to closely track global gross domestic product growth and oil and gas prices, respectively. However, proximity to the Marcellus, Devonian, and Utica shale deposits suggests that NPPs in the Midwest and Mid-Atlantic may be able to access a low-cost ethane (or propane) feedstock. Further, the concentration of polymer demand sources (such as plastics manufacturers) in the Midwest and Northeast suggests that well-located chemical suppliers could undercut Gulf Coast manufacturers on transportation costs. In addition, plants located near the Great Lakes or East Coast could sell into the substantial export markets, which are projected to grow due to low ethane-feedstock prices in the U.S. Thus, ENDP plants powered by NPPs in Illinois, Ohio, Minnesota, Pennsylvania, and New York could have a number of economic factors in their favor, provided the technology platform is reasonably competitive with current thermochemical-production methods.

Ethylene and ethylene-derivative products could be considered as key components of an industrial energy park model centered on NPP facilities. ENDP is a relatively low-energy process, requiring <1 V input at modest temperatures (~400°C)[67]. At these conditions, a 1 GW NPP could produce around 15,500 MT/d of ethylene, or roughly 4.5 MMT/year (assuming ~300 days of operation per year). For comparison, the large Shell plant under construction in Pennsylvania is estimated to have 1.6 MMT/year of capacity. Given this scale, it is reasonable to consider a multiproduct industrial energy park model where NPP electricity is supplied to a variety of electrolysis units working in concert to produce a broad range of monomer, polymer, and plastic products in addition to hydrogen. For example, the following technologies could all be operated simultaneously:

- Water electrolysis, producing hydrogen and oxygen
- Ethane electrolysis, producing ethylene and hydrogen
- Brine electrolysis, producing chlorine
- Co-electrolysis of water and carbon dioxide, producing syngas, formates, and possibly acetates.

In addition to direct hydrogen sales, this group of products can be combined to synthesize the key monomers and polymers outlined above, including:

- Direct polymerization of ethylene to **polyethylene**
- Ethylene chlorination to **VC**
- Ethylene oxidation to ethylene oxide, and further hydration to **EG**
- Combination of ethylene and acetic acid to synthesize **VA**

These monomers can then be upgraded onsite to polymer products, mirroring the vertically integrated production methods used in chemical refineries today. A 1 GW NPP is capable of generating enough electricity to manufacture large (i.e., approaching 1 MMT/year) quantities of each product, realizing economies of scale in a variety of chemical markets. This strategy distributes investment and operational risk across a variety of products and allows each NPP to identify local market opportunities when determining the scale of each technology installation. ENDP could also be applied to propylene production, opening another set of massive chemical markets (~110 MMT in 2019)[87,88]. Substantial advances in proton-conducting electrolysis cell (PCEC) technology are required before implementation, but the field is active with research and development. Overall, an industrial energy park centered around an NPP facility is an attractive concept that seems to offer high efficiency and good economics in a large-scale project of national economic importance.

3. REGION-SPECIFIC DEMAND

Various regions around the country were selected for study of the regional nonelectric industrial product markets that might be accessed near NPPs. Regions selected include the Illinois, Minnesota, Ohio, Alabama and Georgia, Arizona, North / South Carolina, New York, and more broad mid-northeastern regions (e.g., see Figure 19).

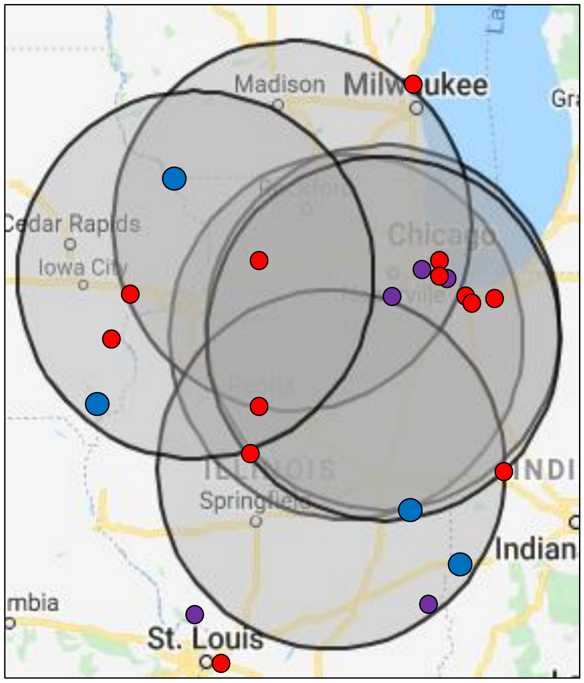

Figure 19. Location of ammonia plants (blue), oil refineries (purple), and steel mills (red) within 100 miles of the NPP facilities in Illinois. Large filled circles are drawn to indicate a 100-mile radius around each NPP

3.1 Illinois Region

This region includes six NPPs (Dresden, Braidwood, LaSalle, Clinton, Quad Cities, and Byron) with a total generating capacity of 11.6 GW[89]. There are many large-demand point sources in the region, including:

- Four ammonia plants, totaling ~1,000 MT/day H_2
  - Expanding the region to within 300 miles of NPPs captures six additional ammonia plants requiring 2,000 additional metric tonnes per day of hydrogen[90]
- Five oil refineries, totaling 300 MT/day H_2 (in addition to a small quantity of oxygen)[91]
- Thirteen steel mills, totaling ~19,000 MT/day O_2[92]

Although only four ammonia plants fall within a 100-mile radius, 10 ammonia plants exist within a 300-mile radius of the Illinois plants generally, totaling ~3,000 MT/day of H_2 demand[90]. In addition, the Chicago area remains an industrial hub for the Midwest, with five oil refineries and some of the largest steel plants in the country[91,92,93]. Similar to ammonia plants, if the relevant radius were extended to 200 miles, an additional 5,000 MT/day of oxygen demand from steel plants in Michigan, southern Illinois, and Missouri could be accessed[92]. Growth in large point-source demand is difficult to project, but in general, the oil-refining and steel industries exhibit slow projected growth rates (<2%) that make opening a new facility or expanding capacity of existing facilities in this region challenging[30,94].

In the electricity markets, Illinois is split between the PJM RTO (Quad Cities, Byron, Dresden, Braidwood, and LaSalle NPPs) and the Mid-continent ISO (Clinton) regions. As noted above, the 3-year forward-capacity market auction for PJM is currently suspended awaiting new rules from FERC regarding intermittent renewable energy sources. Illinois has also enacted state subsidies that have run afoul of new FERC rules, and Illinois state leadership has suggested that leaving the PJM market may be required to achieve renewable-energy targets[95]. Draft legislation promoting carbon-free or carbon-neutral energy generation proposes to set up a new capacity market that would be favorable to the nuclear facilities in the Illinois region, but as of February 2020, the future is unclear[9]. Previous capacity-market prices in PJM have varied from roughly $75/MW-day to more than $160/MW-day (see discussion above). The Clinton NPP facility is located in the Mid-continent ISO, but not the Minnesota region; therefore, capacity payments are quite low, only $2.99/MW-day in the winter of 2019–2020[4].

High purity CO_2 sources for syngas production are shown in the figures and tables in this report associated with ethanol plants (syngas-ethanol), SMR plants producing hydrogen (syngas-H_2 SMR), and ammonia plants (syngas-ammonia). The demand for each location has been studied and listed for each location with maps and tables. The label "NG Electricity Generators" signifies potential hydrogen demand calculated for an NG power plant assuming they use a mixture of 30% H_2 in NG. The label "Syngas-Ethanol", "Syngas-H2 SMR" and "Syngas-Ammonia" refer to high purity CO_2 sources for syngas production. The labels "Refinery" and "Ammonia" signify demand for hydrogen at the specific refinery location or ammonia-production plant. The label "FCEVs" demand is the hydrogen demand estimated for the hydrogen-fueled FCEVs at the county level. The label "DRI" is the demand of hydrogen estimated for direct reduction of iron at metal-refining facilities at the locations marked on the maps.

3.1.1 Clinton NPP, Bloomington, IL

Near-term potential hydrogen demand near the Clinton facility depends mainly on the potential of co-combusting hydrogen with NG in electricity generators, while a few DRI opportunities exist, which adds to this demand. The near-term cumulative potential hydrogen demand for this location is approximately 44 MT/day. Eighteen NG electricity generators within 100 miles of the Clinton facility have a combined potential hydrogen demand of 41 MT/day if hydrogen is blended with NG in a 30/70 volume ratio. Most of this demand is associated with four facilities which make up more than half of that demand; these are the Holland Energy Facility, the Tuscola Station, the University of Illinois Abbott Power Plant, and the Archer Daniels Midland Peoria plant.

Potential future hydrogen demand near the Clinton location will be most likely for synfuel production and for co-combustion of hydrogen with NG. Potential synfuel producing facilities within 100 miles of the Clinton plant could be co-located with ethanol plants, producing FT fuels as the major product. The combined potential demand for FT fuel production is about 1300 MT/day, about half of which is associated with two Illinois facilities, Archer Daniels Midland in Decatur and Marquis Energy in Hennepin, at 400 and 350 MT/day, respectively. Fertilizer producer Cronus Chemical in Tuscola is associated with a hydrogen demand of about 400 MT/day and is only 60 miles from the Clinton facility. A few DRI opportunities near the Clinton location will require another 14 MT/day of hydrogen by 2030. FCEVs add less than 1 MT/day to this demand because the use of hydrogen by FCEVs is limited by their low market penetration and the region's low population density. The cumulative future potential demand around the Clinton power plant is estimated at 1800 MT/day. A list of identified sources of hydrogen demand near the Clinton plant is found in Table 4. Current and future demand are illustrated in Figure 20 and Figure 21.

Table 4 Hydrogen demand within 100 miles of the Clinton Power Plant.

Name	Demand Type	Potential H_2 Demand, kilotonnes		
		Current (2017)	Future (2030)	Distance, miles
De Witt County, IL	FCEV	-	0.00	5.50
Goose Creek Energy Center: Union Electric Co - (MO)	NG Electricity Generators	0.21	0.21	17.50
Piatt County, IL	FCEV	-	0.00	24.30
McLean County, IL	FCEV	-	0.00	29.10
Macon County, IL	FCEV	-	0.00	30.10
Archer Daniels Midland Decatur: Archer Daniels Midland Co	NG Electricity Generators	0.04	0.04	30.90
Logan County, IL	FCEV	-	0.00	31.10
Adm Decatur Il, Decatur	Syngas: Ethanol	-	150.00	31.50
One Earth Energy LLC, Gibson City	Syngas: Ethanol	-	40.00	34.20
Gibson City Energy Center LLC: Mainline Generation LLC	NG Electricity Generators	0.45	0.45	34.50
Champaign County, IL	FCEV	-	0.00	36.70
University of Illinois Abbott Power Plt: University of Illinois	NG Electricity Generators	2.26	2.26	38.00
Ford County, IL	FCEV	-	0.00	45.10
Moultrie County, IL	FCEV	-	0.00	47.60
Interstate: City of Springfield - (IL)	NG Electricity Generators	0.18	0.18	50.90
Dallman: City of Springfield - (IL)	NG Electricity Generators	0.12	0.12	55.80
Sangamon County, IL	FCEV	-	0.00	57.20
Cronus Chemical, Tuscola	Ammonia	-	147.00	57.30
Douglas County, IL	FCEV	-	0.00	58.90
Tuscola Station: DTE Tuscola, LLC	NG Electricity Generators	2.64	2.64	59.20
Woodford County, IL	FCEV	-	0.00	59.80
Menard County, IL	FCEV	-	0.00	60.30
Christian County, IL	FCEV	-	0.00	62.00
Tazewell County, IL	FCEV	-	0.00	64.50
Livingston County, IL	FCEV	-	0.00	65.80

Shelby County, IL	FCEV	-	0.00	67.90
Tilton: Tilton Energy LLC	NG Electricity Generators	0.73	0.73	68.10
Mason County, IL	FCEV	-	0.00	68.40
Adm Peoria Il, Peoria	Syngas: Ethanol	-	70.00	68.80
Archer Daniels Midland Peoria: Archer Daniels Midland Co	NG Electricity Generators	2.19	2.19	68.80
Keystone Steel and Wire Co.	DRI	0.88	3.10	70.40
Powerton: Midwest Generations EME LLC	NG Electricity Generators	0.04	0.04	70.60
Vermilion County, IL	FCEV	-	0.00	70.70
Pacific Ethanol Pekin Inc, Pekin	Syngas: Ethanol	-	60.00	71.00
Illinois Corn Processing LLC, Pekin	Syngas: Ethanol	-	30.00	71.20
Kincaid Generation LLC: Dynegy Kincaid Generation	NG Electricity Generators	0.04	0.04	71.30
Peoria County, IL	FCEV	-	0.00	72.50
Iroquois County, IL	FCEV	-	0.00	73.20
Evonik Corporation	Syngas: Hydrogen, SMR	-	1.76	78.30
Coles County, IL	FCEV	-	0.00	80.60
Marshall County, IL	FCEV	-	0.00	84.40
Marquis Energy LLC, Hennepin	Syngas: Ethanol	-	130.00	87.20
Montgomery County, IL	FCEV	-	0.00	89.40
Morgan County, IL	FCEV	-	0.00	90.00
Holland Energy Facility: NAES Corporation - (WA)	NG Electricity Generators	4.06	4.06	90.90
Fountain County, IN	FCEV	-	0.00	91.10
Cass County, IL	FCEV	-	0.00	92.20
Vermillion Energy Facility: Duke Energy Ohio Inc	NG Electricity Generators	0.61	0.61	92.80
Putnam County, IL	FCEV	-	0.00	94.20
Kankakee County, IL	FCEV	-	0.00	95.10
Cayuga: Duke Energy Indiana, LLC	NG Electricity Generators	0.00	0.00	95.50
Energy Shelby County: Shelby County Energy Center, LLC	NG Electricity Generators	0.85	0.85	95.80
Warren County, IN	FCEV	-	0.00	96.20
Edgar County, IL	FCEV	-	0.00	96.80

Bunge Oil: CSL Behring LLC	NG Electricity Generators	0.18	0.18	97.10
CSL Behring LLC: CSL Behring LLC	NG Electricity Generators	0.21	0.21	97.20
Nucor Steel - Kankakee Inc.	DRI	0.56	1.99	98.50
Benton County, IN	FCEV	-	0.00	98.90
Freedom Power Project: Southwestern Electric Coop Inc - (IL)	NG Electricity Generators	0.02	0.02	98.90
Cumberland County, IL	FCEV	-	0.00	99.20
Grundy County, IL	FCEV	-	0.00	100.00

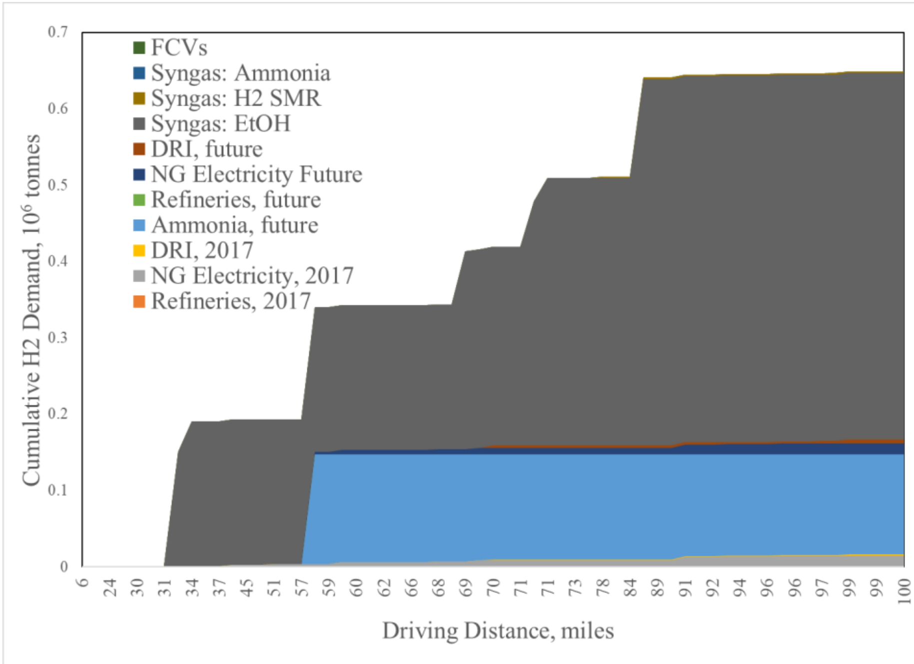

Figure 20. Cumulative potential hydrogen demand by type and distance near the Clinton power plant.

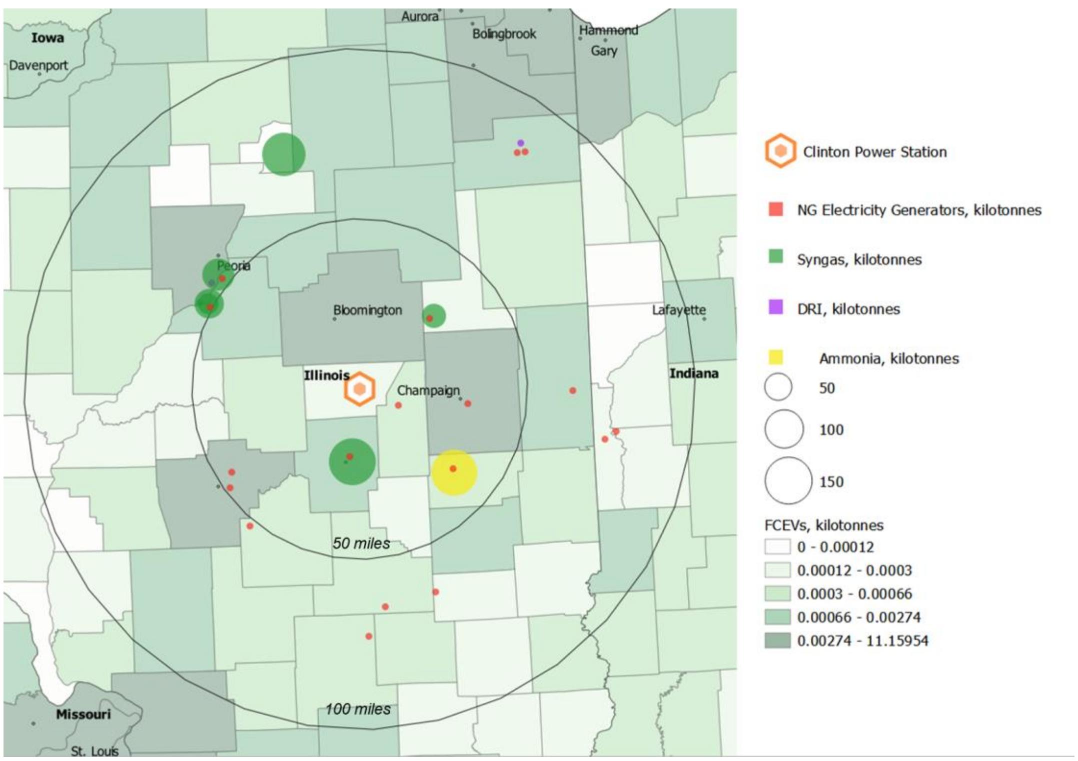

Figure 21 Future potential hydrogen demand near the Clinton power plant.

3.1.2 LaSalle NPP, Ottawa, IL

The La Salle County generating station is surrounded by refineries, potential DRI opportunities, NG electricity generators, and ethanol-production facilities. The current potential hydrogen demand within

100 miles of La Salle NPP is about 1100 MT/day, the majority of which comes from three refineries. There are about 63 NG electricity generators, with a total potential demand of 300 MT/day. The Kendall County generation facility alone accounts for a third of this total hydrogen demand.

The total cumulative future potential hydrogen demand is about 4000 MT/day. There are three refineries near La Salle power plant with cumulative potential future hydrogen demand of about 840 MT/day. A refinery in Joliet, operated by ExxonMobil, may require 240 MT/day, PDV Americas in Lemont and BP PLC in Whiting may require 180 and 420 MT/day, respectively.

There are twelve opportunities for hydrogen in making DRI, with cumulative potential future hydrogen demand of 1400 MT/day within 100 miles. Five of these facilities—ArcelorMittal in Burns Harbor, the U.S. Steel–Gary Works (No. 1 BOP and Q-BOP), and three ArcelorMittal facilities at Indiana Harbor (2, 3, and 4)—make up more than half of that demand. Potential synfuel production at six ethanol plants, located within 100 miles, require about 1000 MT/day of hydrogen. The Marquis Energy LLC in Hennepin is closest to the LaSalle NPP, only 35 miles away, with a potential hydrogen demand of 350 MT/day.

Table 5 delineates the point-source demand for hydrogen near the LaSalle NPP while Figure 22 shows the potential hydrogen demand, and Figure 23 illustrates the potential for future growth.

Table 5 Hydrogen demand within 100 miles of the LaSalle County generating station.

Name	Demand Type	Potential H2 Demand, kilotonnes Current (2017)	Future (2030)	Distance, miles
LaSalle County, IL	FCEV	-	0.00	19
Grundy County, IL	FCEV	-	0.00	25
Morris Cogeneration LLC: Morris Cogeneration LLC	NG Electricity Generators	5.73	5.73	29
Livingston County, IL	FCEV	-	0.00	30
Kendall County Generation Facility: Dynegy Kendall Energy LLC	NG Electricity Generators	37.86	37.86	34
Marquis Energy LLC, Hennepin	Syngas: Ethanol	-	130.00	34
Putnam County, IL	FCEV	-	0.00	37
Kendall County, IL	FCEV	-	0.00	41
Air Products and Chemicals, Inc. - Joliet, Il H2 Plant	Syngas: Hydrogen, SMR	-	7.11	42
Joliet 29: Midwest Generations EME LLC	NG Electricity Generators	2.41	2.41	42
ExxonMobil Oil Joliet Refinery: ExxonMobil Oil Corp	NG Electricity Generators	0.13	0.13	43
ExxonMobil Corp, Joliet	Refinery	69.98	88.66	43
Joliet 9: Midwest Generations EME LLC	NG Electricity Generators	0.41	0.41	44
Hennepin Power Plant: Dynegy Midwest Generation Inc	NG Electricity Generators	0.06	0.06	45
Fox Metro Water Reclamation District: Fox Metro Water Reclamation	NG Electricity Generators	0.00	0.00	45
CSL Behring LLC: CSL Behring LLC	NG Electricity Generators	0.21	0.21	49
Will County, IL	FCEV	-	0.01	50
Marshall County, IL	FCEV	-	0.00	50
WestRock (IL): WestRock (IL)	NG Electricity Generators	0.00	0.00	51
Nucor Steel - Kankakee Inc.	DRI	0.56	1.99	52
Elwood Energy LLC: Elwood Energy LLC	NG Electricity Generators	3.05	3.05	52
Linde Gas North America LLC, Lemont Plant	Syngas: Hydrogen, SMR	-	46.03	53
Bureau County, IL	FCEV	-	0.00	53
Princeton (IL): City of Princeton - (IL)	NG Electricity Generators	0.01	0.01	54
Kankakee County, IL	FCEV	-	0.00	55

Lemont Refinery	Syngas: Hydrogen, SMR	-	6.71	55
Bunge Oil: CSL Behring LLC	NG Electricity Generators	0.18	0.18	55
Lincoln Generating Facility: Lincoln Generating Facility LLC	NG Electricity Generators	0.27	0.27	56
Woodridge Greene Valley Treatment Plant: DuPage County	NG Electricity Generators	0.00	0.00	58
Aurora: Aurora Generation LLC	NG Electricity Generators	3.20	3.20	58
University Park South: University Park Energy LLC	NG Electricity Generators	1.40	1.40	59
University Park North: LSP University Park LLC	NG Electricity Generators	3.59	3.59	59
Nalco: Nalco Co	NG Electricity Generators	0.17	0.17	59
Kane County, IL	FCEV	-	0.01	60
PDV America Inc, Lemont	Refinery	51.60	65.38	61
McLean County, IL	FCEV	-	0.00	61
Argonne National Laboratory CHP: Argonne National Laboratory	NG Electricity Generators	0.31	0.31	61
DeKalb County, IL	FCEV	-	0.00	61
Geneva Generation Facility: City of Geneva- (IL)	NG Electricity Generators	0.02	0.02	61
Panduit Tinley Park: Panduit Corp	NG Electricity Generators	0.00	0.00	63
Crete Energy Venture LLC: Crete Energy Venture LLC	NG Electricity Generators	0.34	0.34	66
Woodford County, IL	FCEV	-	0.00	66
Hoffer Plastics: Hoffer Plastics	NG Electricity Generators	0.01	0.01	67
DuPage County, IL	FCEV	-	0.02	68
One Earth Energy LLC, Gibson City	Syngas: Ethanol	-	40.00	69
Illinois River Energy LLC, Rochelle	Syngas: Ethanol	-	40.00	69
Gibson City Energy Center LLC: Mainline Generation LLC	NG Electricity Generators	0.45	0.45	69
BP Naperville Cogeneration Facility: BP America Inc	NG Electricity Generators	0.66	0.66	70
Elgin Energy Center LLC: Elgin Energy Center LLC	NG Electricity Generators	1.27	1.27	70
1515 S Caron Road: Rochelle Municipal Utilities	NG Electricity Generators	0.00	0.00	70
Lee County, IL	FCEV	-	0.00	71
Ingredion Incorporated: Ingredion Inc - Illinois	NG Electricity Generators	1.68	1.68	71
Stark County, IL	FCEV	-	0.00	72
Lee Energy Facility: Lee County Generating Station	NG Electricity Generators	0.87	0.87	72

North Ninth Street: Rochelle Municipal Utilities	NG Electricity Generators	0.01	0.01	73
South Main Street: Rochelle Municipal Utilities	NG Electricity Generators	0.00	0.00	73
ArcelorMittal - Riverdale	DRI	1.63	23.04	74
Ford County, IL	FCEV	-	0.00	74
Loyola University Health Plant: Loyola University Health System	NG Electricity Generators	1.50	1.50	74
Patriot Renewable Fuels LLC, Annawan	Syngas: Ethanol	-	50.00	76
Iroquois County, IL	FCEV	-	0.00	77
Finkl Steel	DRI	0.07	0.23	79
Chicago West Side Energy Center: Energy Systems Group LLC	NG Electricity Generators	0.14	0.14	80
Triton East and West Cogen: Triton College	NG Electricity Generators	0.05	0.05	80
Calumet Energy Team LLC: IPA Operations Inc - Calumet	NG Electricity Generators	0.19	0.19	80
Cook County, IL	FCEV	-	0.10	80
ITT Cogen Facility: Illinois Institute-Technology	NG Electricity Generators	0.00	0.00	81
University of Illinois Cogen Facility: University of Illinois	NG Electricity Generators	0.58	0.58	81
Mars Snackfood US: M&M Mars Inc	NG Electricity Generators	0.32	0.32	81
Adm Peoria Il, Peoria	Syngas: Ethanol	-	70.00	83
Archer Daniels Midland Peoria: Archer Daniels Midland Co	NG Electricity Generators	2.19	2.19	83
Peoria County, IL	FCEV	-	0.00	84
Lake County, IN	FCEV	-	0.01	84
Presence Saint Mary of Nazareth Hospital: Presence Health	NG Electricity Generators	0.00	0.00	84
Museum of Science and Industry: Museum of Science and Industry	NG Electricity Generators	0.00	0.00	85
Southeast Chicago Energy Project: Exelon Power	NG Electricity Generators	0.27	0.27	85
Charter Dura-Bar: Wells Manufacturing Co	NG Electricity Generators	0.07	0.07	85
Big River Resources Galva LLC, Galva	Syngas: Ethanol	-	40.00	86
ArcelorMittal - Indiana Harbor #2	DRI	3.25	46.10	86
ArcelorMittal - Indiana Harbor #3	DRI	4.39	62.22	86
ArcelorMittal - Indiana Harbor #4	DRI	5.37	76.06	86
ArcelorMittal - Indiana Harbor Bar	DRI	0.34	1.19	86
Nelson Energy Center: Invenergy Services LLC	NG Electricity Generators	11.75	11.75	86

Northwest Community Hospital: Northwest Community Hospital	NG Electricity Generators	0.08	0.08	87
McHenry County, IL	FCEV	-	0.01	87
Newton County, IN	FCEV	-	0.00	87
ArcelorMittal Indiana Harbor West: ArcelorMittal Indiana Harbor West	NG Electricity Generators	2.37	2.37	87
Praxair - Whiting, In 1-4	Syngas: Hydrogen, SMR	-	21.38	87
Praxair - Whiting, In 5&6	Syngas: Hydrogen, SMR	-	198.31	87
Bp PLC, Whiting	Refinery	121.28	153.66	88
Bp Whiting Business Unit	Syngas: Hydrogen, SMR	-	-	88
Whiting Refinery: BP PLC	NG Electricity Generators	2.09	2.09	88
Whiting Clean Energy: BP Alternative Energy	NG Electricity Generators	13.88	13.88	88
Goose Creek Energy Center: Union Electric Co - (MO)	NG Electricity Generators	0.21	0.21	88
Ogle County, IL	FCEV	-	0.00	88
Indiana Harbor E 5 AC Station: Northlake Energy	NG Electricity Generators	1.23	1.23	89
Prairies Edge Generating Facility: Prairies Edge Dairy Farms LLC	NG Electricity Generators	0.10	0.10	89
Gary Works: United States Steel-Gary	NG Electricity Generators	3.79	3.79	90
US Steel - Gary Works (No. 1 BOP and Q-BOP)	DRI	11.95	169.40	90
Northeastern Illinois University Cogen: Northeastern Illinois University	NG Electricity Generators	0.00	0.00	90
Geneseo: City of Geneseo - (IL)	NG Electricity Generators	0.00	0.00	91
Henry County, IL	FCEV	-	0.00	92
Leggett and Platt Wire Rod (Formarly Sterling Steel Co. LLC)	DRI	1.58	5.57	92
De Witt County, IL	FCEV	-	0.00	92
Tazewell County, IL	FCEV	-	0.00	92
Kishwaukee CHP Plant: Rock River Water Reclamation District	NG Electricity Generators	0.01	0.01	95
Portside Energy: Portside Energy Corp	NG Electricity Generators	2.82	2.82	95
Novolipetsk Steel (NLMK Indiana)	DRI	0.53	1.87	95
Piatt County, IL	FCEV	-	0.00	95
Rocky Road Power LLC: Rocky Road Power LLC	NG Electricity Generators	0.15	0.15	96
ArcelorMittal - Burns Harbor	DRI	9.10	129.07	96

NRG Rockford II Energy Center: Rockford Generation LLC	NG Electricity Generators	0.61	0.61	96
NRG Rockford I: Rockford Generation LLC	NG Electricity Generators	0.58	0.58	96
Jasper County, IN	FCEV	-	0.00	96
ArcelorMittal Burns Harbor: ArcelorMittal Burns Harbor Inc	NG Electricity Generators	3.81	3.81	97
Logan County, IL	FCEV	-	0.00	97
Whiteside County, IL	FCEV	-	0.00	97
Winnetka: Village of Winnetka - (IL)	NG Electricity Generators	0.08	0.08	98
Champaign County, IL	FCEV	-	0.00	98
Keystone Steel and Wire Co.	DRI	0.88	3.10	98
Winnebago County, IL	FCEV	-	0.01	99
Bailly: Northern Indiana Pub Serv Co	NG Electricity Generators	0.36	0.36	99
University of Illinois Abbott Power Plt: University of Illinois	NG Electricity Generators	2.26	2.26	100

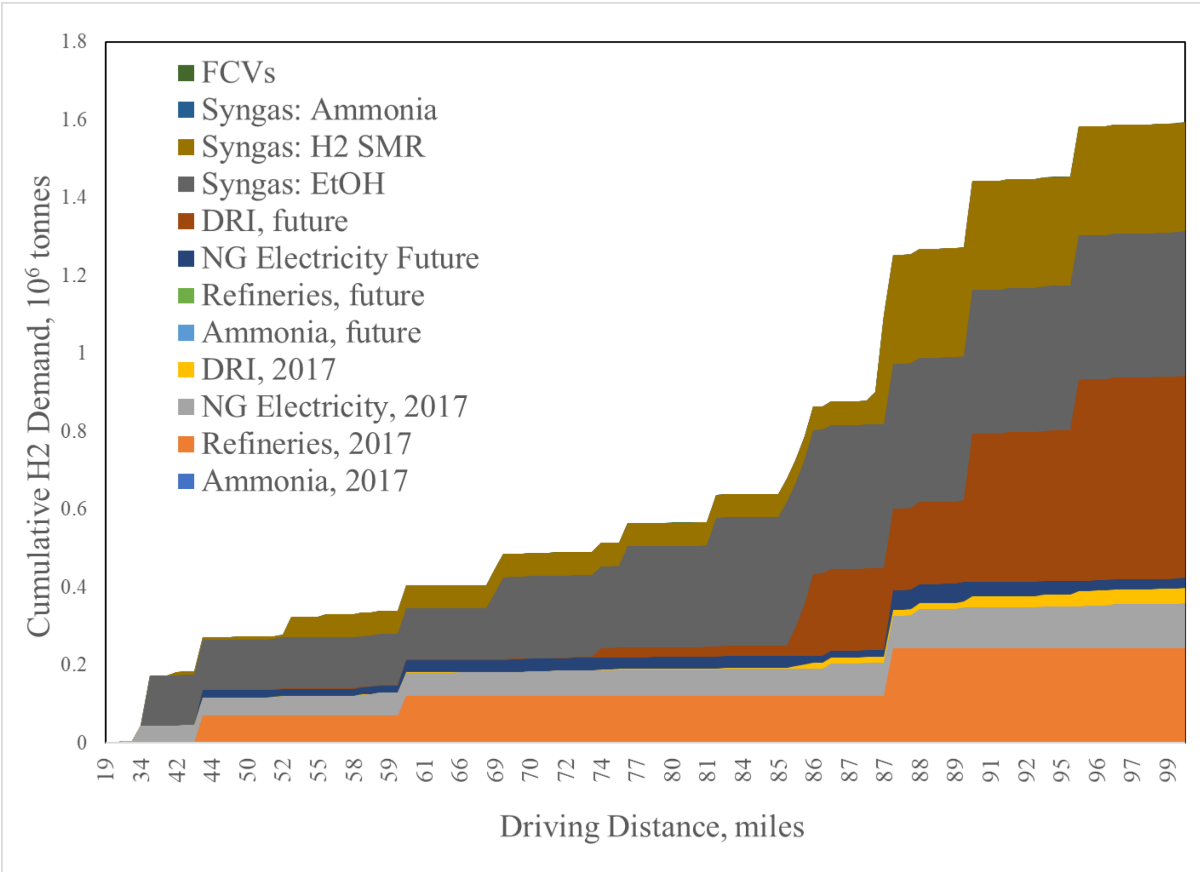

Figure 22. Cumulative potential hydrogen demand by type and distance near the La Salle generating station.

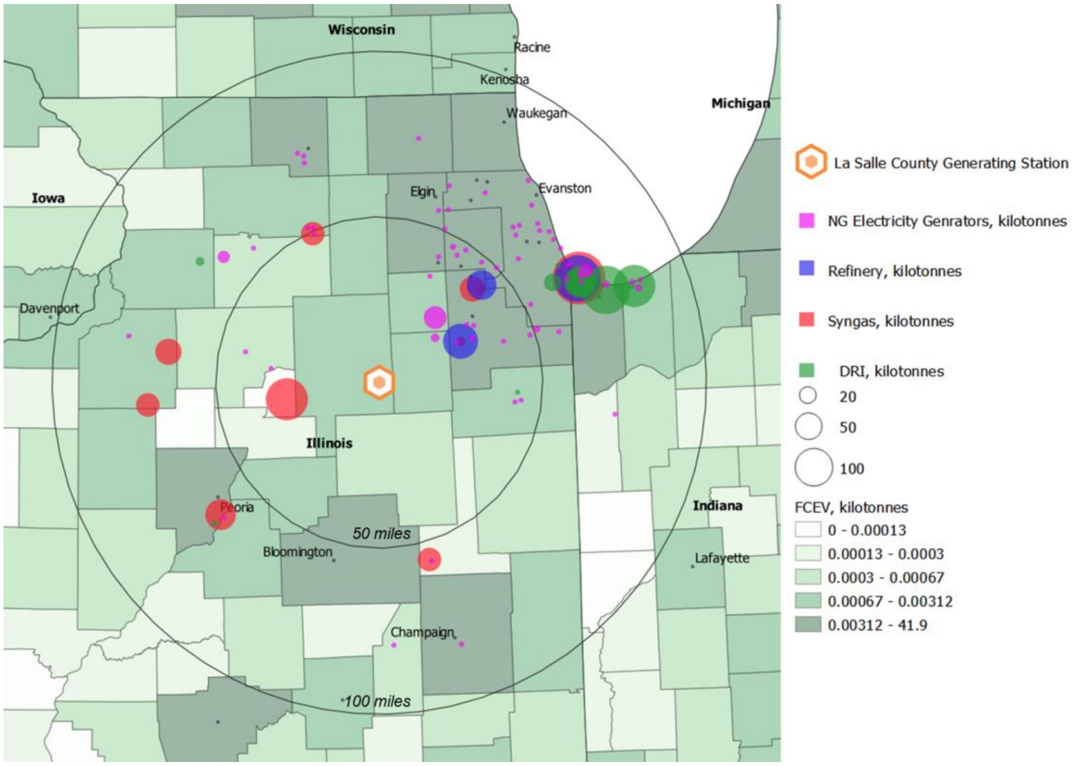

Figure 23 Future potential hydrogen demand near the La Salle NPP.

3.1.3 Braidwood NPP, Joliet, IL

Braidwood generating station produces approximately 2400 MW of power and is the largest NPP in the state of Illinois. The Braidwood location's current potential hydrogen demand stems from DRI, refinery, and NG electricity generators, with a cumulative potential demand of 1047 MT/day, mainly for the refineries proximate to the NPP. The refinery in Joliet, operated by ExxonMobil, currently has a potential demand of 200 MT/day while the PDV Americas in Lemont and the BP PLC in Whiting will require 140 and 330 MT/day, respectively. The opportunities for DRI near the generating station has potential demand of about 100 MT/day while the potential demand from sixty NG electricity generators is about 270 MT/day.

The potential future hydrogen demand near the Braidwood generating station is about 3800 MT/day, mainly from the additional demand by DRI plants and refineries. The future potential hydrogen demand, including possible synfuel production at ethanol and SMR plants, are estimated at 520 and 770 MMT/day, respectively. FCEVs in this region add less than 1 MT/day of potential demand (see Table 6.) Figure 24 and Figure 25 show graphically current potential and projected future demand near the Braidwood generating station.

Table 6. Hydrogen demand within 100 miles of the Braidwood generating station.

Name	Demand Type	Potential H2 Demand, kilotonnes		
		Current (2017)	Future (2030)	Distance, miles
Air Products and Chemicals, Inc. - Joliet, Il H2 Plant	Syngas: Hydrogen, SMR	-	7.1	14
Grundy County, IL	FCEV	-	0.0	14
ExxonMobil Oil Joliet Refinery: ExxonMobil Oil Corp	NG Electricity Generators	0.1	0.1	15
ExxonMobil Corp, Joliet	Refinery	70.0	88.7	15
Elwood Energy LLC: Elwood Energy LLC	NG Electricity Generators	3.0	3.0	20
Joliet 29: Midwest Generations EME LLC	NG Electricity Generators	2.4	2.4	21
Kendall County Generation Facility: Dynegy Kendall Energy LLC	NG Electricity Generators	37.9	37.9	22
Morris Cogeneration LLC: Morris Cogeneration LLC	NG Electricity Generators	5.7	5.7	23
Joliet 9: Midwest Generations EME LLC	NG Electricity Generators	0.4	0.4	24
Lincoln Generating Facility: Lincoln Generating Facility LLC	NG Electricity Generators	0.3	0.3	24
CSL Behring LLC: CSL Behring LLC	NG Electricity Generators	0.2	0.2	25
Kankakee County, IL	FCEV	-	0.0	25
Bunge Oil: CSL Behring LLC	NG Electricity Generators	0.2	0.2	25
Nucor Steel - Kankakee Inc.	DRI	0.6	2.0	28
Will County, IL	FCEV	-	0.0	32
Linde Gas North America LLC, Lemont Plant	Syngas: Hydrogen, SMR	-	46.0	34
University Park North: LSP University Park LLC	NG Electricity Generators	3.6	3.6	35
University Park South: University Park Energy LLC	NG Electricity Generators	1.4	1.4	35
Lemont Refinery	Syngas: Hydrogen, SMR	-	6.7	37
Livingston County, IL	FCEV	-	0.0	39
Woodridge Greene Valley Treatment Plant: DuPage County	NG Electricity Generators	0.0	0.0	39
Fox Metro Water Reclamation District: Fox Metro Water Reclamation	NG Electricity Generators	0.0	0.0	41
Kendall County, IL	FCEV	-	0.0	41
PDV America Inc, Lemont	Refinery	51.6	65.4	42
WestRock (IL): WestRock (IL)	NG Electricity Generators	0.0	0.0	42

Crete Energy Venture LLC: Crete Energy Venture LLC	NG Electricity Generators	0.3	0.3	42
Argonne National Laboratory CHP: Argonne National Laboratory	NG Electricity Generators	0.3	0.3	42
LaSalle County, IL	FCEV	-	0.0	44
Panduit Tinley Park: Panduit Corp	NG Electricity Generators	0.0	0.0	44
DuPage County, IL	FCEV	-	0.0	50
BP Naperville Cogeneration Facility: BP America Inc	NG Electricity Generators	0.7	0.7	51
Ingredion Incorporated: Ingredion Inc - Illinois	NG Electricity Generators	1.7	1.7	53
Nalco: Nalco Co	NG Electricity Generators	0.2	0.2	54
Iroquois County, IL	FCEV	-	0.0	55
Ford County, IL	FCEV	-	0.0	55
ArcelorMittal - Riverdale	DRI	1.6	23.0	55
Marquis Energy LLC, Hennepin	Syngas: Ethanol	-	130.0	56
Loyola University Health Plant: Loyola University Health System	NG Electricity Generators	1.5	1.5	56
Aurora: Aurora Generation LLC	NG Electricity Generators	3.2	3.2	57
Newton County, IN	FCEV	-	0.0	58
One Earth Energy LLC, Gibson City	Syngas: Ethanol	-	40.0	60
Gibson City Energy Center LLC: Mainline Generation LLC	NG Electricity Generators	0.5	0.5	61
Finkl Steel	DRI	0.1	0.2	61
Chicago West Side Energy Center: Energy Systems Group LLC	NG Electricity Generators	0.1	0.1	61
Triton East and West Cogen: Triton College	NG Electricity Generators	0.1	0.1	61
Calumet Energy Team LLC: IPA Operations Inc - Calumet	NG Electricity Generators	0.2	0.2	62
Geneva Generation Facility: City of Geneva- (IL)	NG Electricity Generators	0.0	0.0	62
Cook County, IL	FCEV	-	0.1	62
ITT Cogen Facility: Illinois Institute-Technology	NG Electricity Generators	0.0	0.0	62
Prairies Edge Generating Facility: Prairies Edge Dairy Farms LLC	NG Electricity Generators	0.1	0.1	62
University of Illinois Cogen Facility: University of Illinois	NG Electricity Generators	0.6	0.6	62
Putnam County, IL	FCEV	-	0.0	63
Mars Snackfood US: M&M Mars Inc	NG Electricity Generators	0.3	0.3	63
Lake County, IN	FCEV	-	0.0	66

Kane County, IL	FCEV	-	0.0	66
Presence Saint Mary of Nazareth Hospital: Presence Health	NG Electricity Generators	0.0	0.0	66
Museum of Science and Industry: Museum of Science and Industry	NG Electricity Generators	0.0	0.0	67
Southeast Chicago Energy Project: Exelon Power	NG Electricity Generators	0.3	0.3	67
ArcelorMittal - Indiana Harbor #2	DRI	3.3	46.1	68
ArcelorMittal - Indiana Harbor #3	DRI	4.4	62.2	68
ArcelorMittal - Indiana Harbor #4	DRI	5.4	76.1	68
ArcelorMittal - Indiana Harbor Bar	DRI	0.3	1.2	68
Northwest Community Hospital: Northwest Community Hospital	NG Electricity Generators	0.1	0.1	68
ArcelorMittal Indiana Harbor West: ArcelorMittal Indiana Harbor West	NG Electricity Generators	2.4	2.4	69
Jasper County, IN	FCEV	-	0.0	69
Praxair - Whiting, In 1-4	Syngas: Hydrogen, SMR	-	21.4	69
Praxair - Whiting, In 5&6	Syngas: Hydrogen, SMR	-	198.3	69
Bp PLC, Whiting	Refinery	121.3	153.7	69
Bp Whiting Business Unit	Syngas: Hydrogen, SMR	-	-	69
Whiting Refinery: BP PLC	NG Electricity Generators	2.1	2.1	69
Whiting Clean Energy: BP Alternative Energy	NG Electricity Generators	13.9	13.9	70
Gary Works: United States Steel-Gary	NG Electricity Generators	3.8	3.8	70
Marshall County, IL	FCEV	-	0.0	70
Indiana Harbor E 5 AC Station: Northlake Energy	NG Electricity Generators	1.2	1.2	70
Hennepin Power Plant: Dynegy Midwest Generation Inc	NG Electricity Generators	0.1	0.1	71
US Steel - Gary Works (No. 1 BOP and Q-BOP)	DRI	11.9	169.4	71
Northeastern Illinois University Cogen: Northeastern Illinois University	NG Electricity Generators	0.0	0.0	72
Rensselaer City Light Plant: City of Rensselaer - (IN)	NG Electricity Generators	0.0	0.0	72
McLean County, IL	FCEV	-	0.0	73
Elgin Energy Center LLC: Elgin Energy Center LLC	NG Electricity Generators	1.3	1.3	73
R M Schahfer: Northern Indiana Pub Serv Co	NG Electricity Generators	0.4	0.4	76
Hoffer Plastics: Hoffer Plastics	NG Electricity Generators	0.0	0.0	76

Portside Energy: Portside Energy Corp	NG Electricity Generators	2.8	2.8	77
Novolipetsk Steel (NLMK Indiana)	DRI	0.5	1.9	77
Rocky Road Power LLC: Rocky Road Power LLC	NG Electricity Generators	0.1	0.1	77
Iroquois Bio-Energy Co LLC, Rensselaer	Syngas: Ethanol	-	20.0	77
Woodford County, IL	FCEV	-	0.0	77
ArcelorMittal - Burns Harbor	DRI	9.1	129.1	77
Bureau County, IL	FCEV	-	0.0	78
ArcelorMittal Burns Harbor: ArcelorMittal Burns Harbor Inc	NG Electricity Generators	3.8	3.8	78
Princeton (IL): City of Princeton - (IL)	NG Electricity Generators	0.0	0.0	79
Winnetka: Village of Winnetka - (IL)	NG Electricity Generators	0.1	0.1	79
Bailly: Northern Indiana Pub Serv Co	NG Electricity Generators	0.4	0.4	81
Lake Forest Hospital: Northwestern Lake Forest Hospital	NG Electricity Generators	0.0	0.0	84
DeKalb County, IL	FCEV	-	0.0	84
Porter County, IN	FCEV	-	0.0	85
Champaign County, IL	FCEV	-	0.0	86
North Chicago Energy Center: Energy Systems Group LLC	NG Electricity Generators	0.4	0.4	89
University of Illinois Abbott Power Plt: University of Illinois	NG Electricity Generators	2.3	2.3	90
Lake County, IL	FCEV	-	0.0	90
Benton County, IN	FCEV	-	0.0	91
McHenry County, IL	FCEV	-	0.0	91
Goose Creek Energy Center: Union Electric Co - (MO)	NG Electricity Generators	0.2	0.2	92
Michigan City: Northern Indiana Pub Serv Co	NG Electricity Generators	0.1	0.1	93
Starke County, IN	FCEV	-	0.0	95
Waukegan: Midwest Generations EME LLC	NG Electricity Generators	0.2	0.2	96
Lee County, IL	FCEV	-	0.0	96
LaPorte County, IN	FCEV	-	0.0	96
Pulaski County, IN	FCEV	-	0.0	97
Lee Energy Facility: Lee County Generating Station	NG Electricity Generators	0.9	0.9	98
Stark County, IL	FCEV	-	0.0	99

Charter Dura-Bar: Wells Manufacturing Co	NG Electricity Generators	0.1	0.1	99
White County, IN	FCEV	-	0.0	100

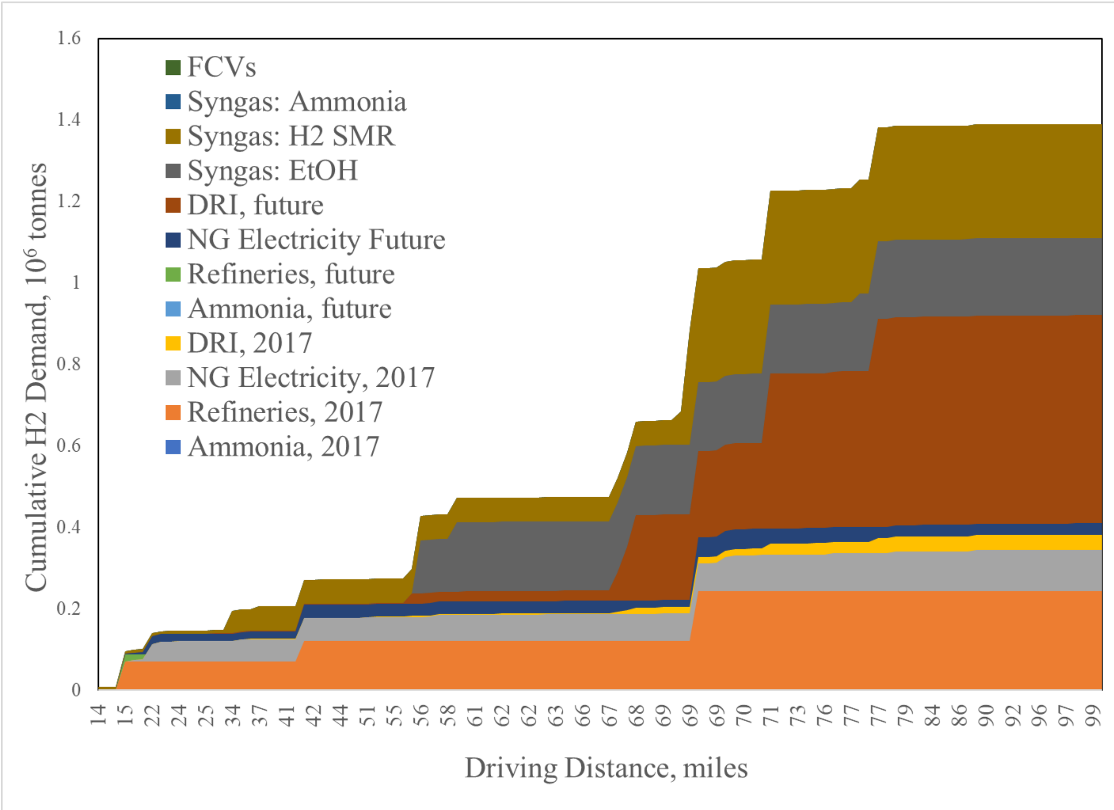

Figure 24 Cumulative potential hydrogen demand by type and distance near the Braidwood generating station.

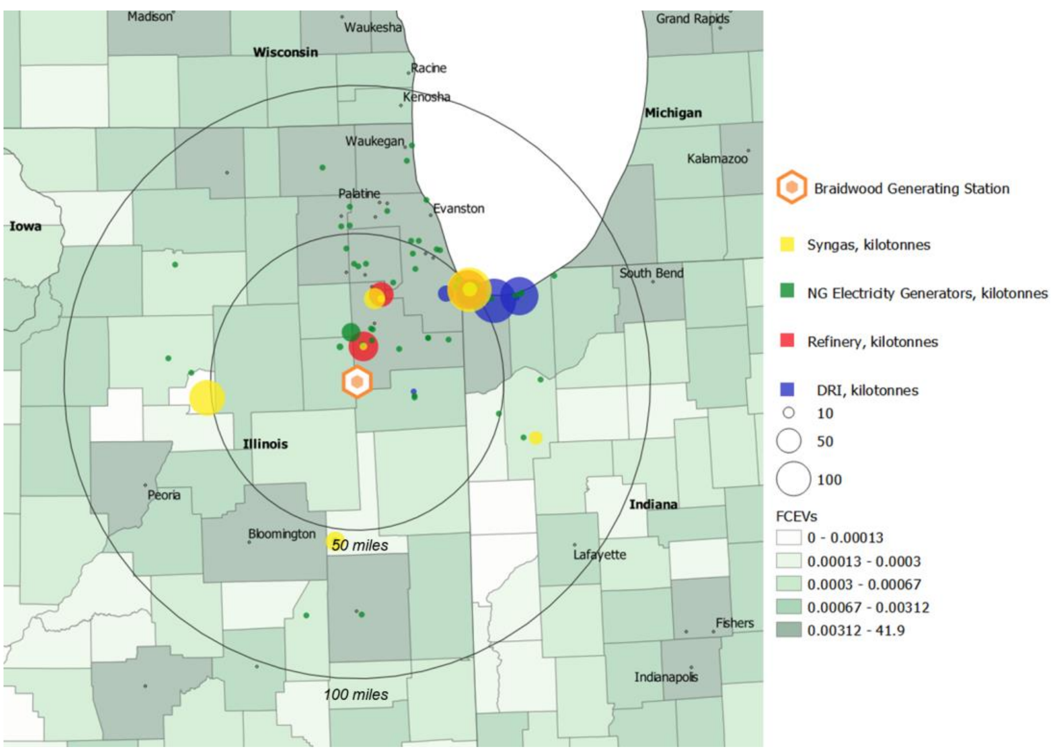

Figure 25 Future potential hydrogen demand near the Braidwood generating station.

3.1.4 Byron NPP, Rockford, IL

The Byron generating station has a potential hydrogen demand of 530 MT/day. NG electricity generators, refineries, and ammonia production account for almost the entire current potential demand, each having a demand of 230, 140, and 160 MT/day, respectively. The PDV America, Inc., refinery in Lemont, the CVR Partners ammonia production facility in East Dubuque, and the Kendall County generation facility (90 miles driving distance from the NPP) together represent almost the entire current potential hydrogen demand. (See Table 7 and Figure 26).

The future potential demand for Byron is about 2100 MT/day, the majority of which could be for synfuel production, near current ethanol plants accounting for 1200 MT/day, near hydrogen SMR plants accounting for 145 MT/day, and near ammonia plants accounting for 155 MT/day (see Figure 27).

Table 7. Hydrogen demand within 100 miles of the Byron generating station.

Name	Demand Type	Potential H2 Demand, kilotonnes		Distance, miles
		Current (2017)	Future (2030)	
Ogle County, IL	FCEV	-	0.00	5
Kishwaukee CHP Plant: Rock River Water Reclamation District	NG Electricity Generators	0.01	0.01	17
NRG Rockford II Energy Center: Rockford Generation LLC	NG Electricity Generators	0.61	0.61	17
NRG Rockford I: Rockford Generation LLC	NG Electricity Generators	0.58	0.58	17
Winnebago County, IL	FCEV	-	0.01	23
Lee Energy Facility: Lee County Generating Station	NG Electricity Generators	0.87	0.87	24
1515 S Caron Road: Rochelle Municipal Utilities	NG Electricity Generators	0.00	0.00	24
North Ninth Street: Rochelle Municipal Utilities	NG Electricity Generators	0.01	0.01	24
South Main Street: Rochelle Municipal Utilities	NG Electricity Generators	0.00	0.00	24
Lee County, IL	FCEV	-	0.00	25
Illinois River Energy LLC, Rochelle	Syngas: Ethanol	-	40.00	26
Nelson Energy Center: Invenergy Services LLC	NG Electricity Generators	11.75	11.75	32
Boone County, IL	FCEV	-	0.00	33
Leggett and Platt Wire Rod (Formarly Sterling Steel Co. LLC)	DRI	1.58	5.57	37
Stephenson County, IL	FCEV	-	0.00	37
DeKalb County, IL	FCEV	-	0.00	39
Carroll County, IL	FCEV	-	0.00	45
Adkins Energy LLC, Adkins Energy	Syngas: Ethanol	-	20.00	46
Adkins Energy LLC: Adkins Energy LLC	NG Electricity Generators	0.30	0.30	46
Whiteside County, IL	FCEV	-	0.00	47
Rock River: Wisconsin Power and Light Co	NG Electricity Generators	0.20	0.20	51
Riverside Energy Center: Wisconsin Power and Light Co	NG Electricity Generators	7.12	7.12	52
Rock County, WI	FCEV	-	0.00	55
Badger State Ethanol LLC, Monroe	Syngas: Ethanol	-	20.00	56
Kane County, IL	FCEV	-	0.01	56

Princeton (IL): City of Princeton - (IL)	NG Electricity Generators	0.01	0.01	57
Charter Dura-Bar: Wells Manufacturing Co	NG Electricity Generators	0.07	0.07	57
Bureau County, IL	FCEV	-	0.00	58
McHenry County, IL	FCEV	-	0.01	58
Green County, WI	FCEV	-	0.00	59
Hoffer Plastics: Hoffer Plastics	NG Electricity Generators	0.01	0.01	60
United Ethanol LLC, Milton	Syngas: Ethanol	-	20.00	63
Elgin Energy Center LLC: Elgin Energy Center LLC	NG Electricity Generators	1.27	1.27	64
Adm Clinton Ia, Clinton	Syngas: Ethanol	-	90.00	64
Milton L Kapp: Interstate Power and Light Co	NG Electricity Generators	0.25	0.25	65
Rocky Road Power LLC: Rocky Road Power LLC	NG Electricity Generators	0.15	0.15	66
WestRock (IL): WestRock (IL)	NG Electricity Generators	0.00	0.00	69
Clinton County, IA	FCEV	-	0.00	69
Fox Metro Water Reclamation District: Fox Metro Water Reclamation	NG Electricity Generators	0.00	0.00	70
Walworth County, WI	FCEV	-	0.00	70
Aurora: Aurora Generation LLC	NG Electricity Generators	3.20	3.20	71
Sheepskin: Wisconsin Power and Light Co	NG Electricity Generators	0.04	0.04	71
Kendall County, IL	FCEV	-	0.00	72
Nalco: Nalco Co	NG Electricity Generators	0.17	0.17	72
Cordova Energy: Cordova Energy Co LLC	NG Electricity Generators	0.42	0.42	73
Geneva Generation Facility: City of Geneva- (IL)	NG Electricity Generators	0.02	0.02	74
LaSalle County, IL	FCEV	-	0.00	74
BP Naperville Cogeneration Facility: BP America Inc	NG Electricity Generators	0.66	0.66	74
Jo Daviess County, IL	FCEV	-	0.00	75
Patriot Renewable Fuels LLC, Annawan	Syngas: Ethanol	-	50.00	76
LSP-Whitewater LP: Whitewater Operating Services LLC	NG Electricity Generators	3.71	3.71	77
RockGen Energy Center: Calpine -RockGen Energy	NG Electricity Generators	3.22	3.22	78
Lafayette County, WI	FCEV	-	0.00	78
Northwest Community Hospital: Northwest Community Hospital	NG Electricity Generators	0.08	0.08	78

DuPage County, IL	FCEV	-	0.02	81
Putnam County, IL	FCEV	-	0.00	84
Marquis Energy LLC, Hennepin	Syngas: Ethanol	-	130.00	84
Geneseo: City of Geneseo - (IL)	NG Electricity Generators	0.00	0.00	85
Woodridge Greene Valley Treatment Plant: DuPage County	NG Electricity Generators	0.00	0.00	85
Jackson County, IA	FCEV	-	0.00	85
Jefferson County, WI	FCEV	-	0.00	86
Valero Renewable Fuels LLC, Jefferson Plant	Syngas: Ethanol	-	40.00	86
Maquoketa 1: City of Maquoketa - (IA)	NG Electricity Generators	0.00	0.00	87
Hennepin Power Plant: Dynegy Midwest Generation Inc	NG Electricity Generators	0.06	0.06	88
Kendall County Generation Facility: Dynegy Kendall Energy LLC	NG Electricity Generators	37.86	37.86	90
Riverside: MidAmerican Energy Co	NG Electricity Generators	0.09	0.09	90
Moline: MidAmerican Energy Co	NG Electricity Generators	0.01	0.01	91
PDV America Inc, Lemont	Refinery	51.60	65.38	91
Triton East and West Cogen: Triton College	NG Electricity Generators	0.05	0.05	91
Argonne National Laboratory CHP: Argonne National Laboratory	NG Electricity Generators	0.31	0.31	91
Nine Springs: Madison Gas and Electric Co	NG Electricity Generators	0.01	0.01	92
Stark County, IL	FCEV	-	0.00	92
Rock Island County, IL	FCEV	-	0.00	92
Zion Energy Center: Zion Energy LLC	NG Electricity Generators	3.83	3.83	92
Henry County, IL	FCEV	-	0.00	92
Linde Gas North America LLC, Lemont Plant	Syngas: Hydrogen, SMR	-	46.03	92
Mars Snackfood US: M&M Mars Inc	NG Electricity Generators	0.32	0.32	93
Lemont Refinery	Syngas: Hydrogen, SMR	-	6.71	93
Loyola University Health Plant: Loyola University Health System	NG Electricity Generators	1.50	1.50	93
Cvr Partners, East Dubuque	Ammonia	57.00	57.00	93
Cvr Partners, East Dubuque	Syngas: Ammonia CO2	-	52.87	93
Northeastern Illinois University Cogen: Northeastern Illinois University	NG Electricity Generators	0.00	0.00	94
Sycamore (WI): Madison Gas and Electric Co	NG Electricity Generators	0.00	0.00	94

Dane County, WI	FCEV	-	0.01	95
Blount Street: Madison Gas and Electric Co	NG Electricity Generators	0.24	0.24	95
UW Madison Charter Street Plant: State of Wisconsin	NG Electricity Generators	2.46	2.46	95
Cook County, IL	FCEV	-	0.10	96
West Campus Cogeneration Facility: Madison Gas and Electric Co	NG Electricity Generators	2.58	2.58	96
Presence Saint Mary of Nazareth Hospital: Presence Health	NG Electricity Generators	0.00	0.00	97
Scott County, IA	FCEV	-	0.00	97
Big River Resources Galva LLC, Galva	Syngas: Ethanol	-	40.00	97
Concord: Wisconsin Electric Power Co	NG Electricity Generators	0.87	0.87	97
Will County, IL	FCEV	-	0.01	98
Lake County, IL	FCEV	-	0.01	98
Dubuque: Interstate Power and Light Co	NG Electricity Generators	0.00	0.00	99
Marshall County, IL	FCEV	-	0.00	100

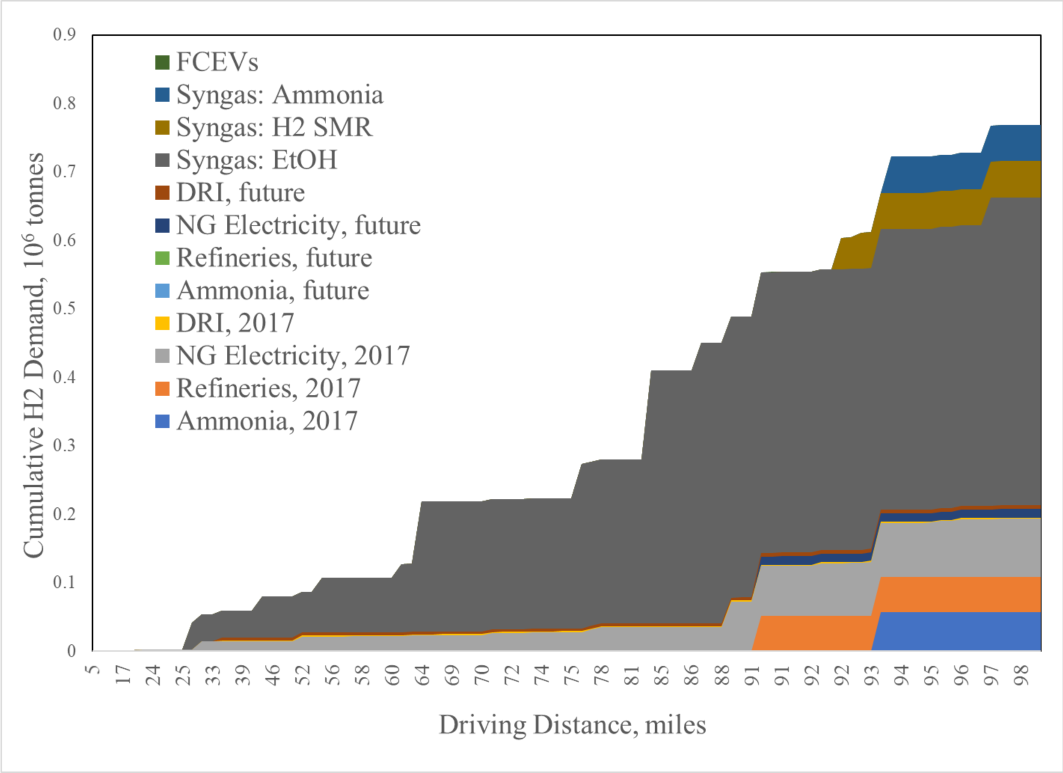

Figure 26. Cumulative potential hydrogen demand by type and distance near the Byron generating station.

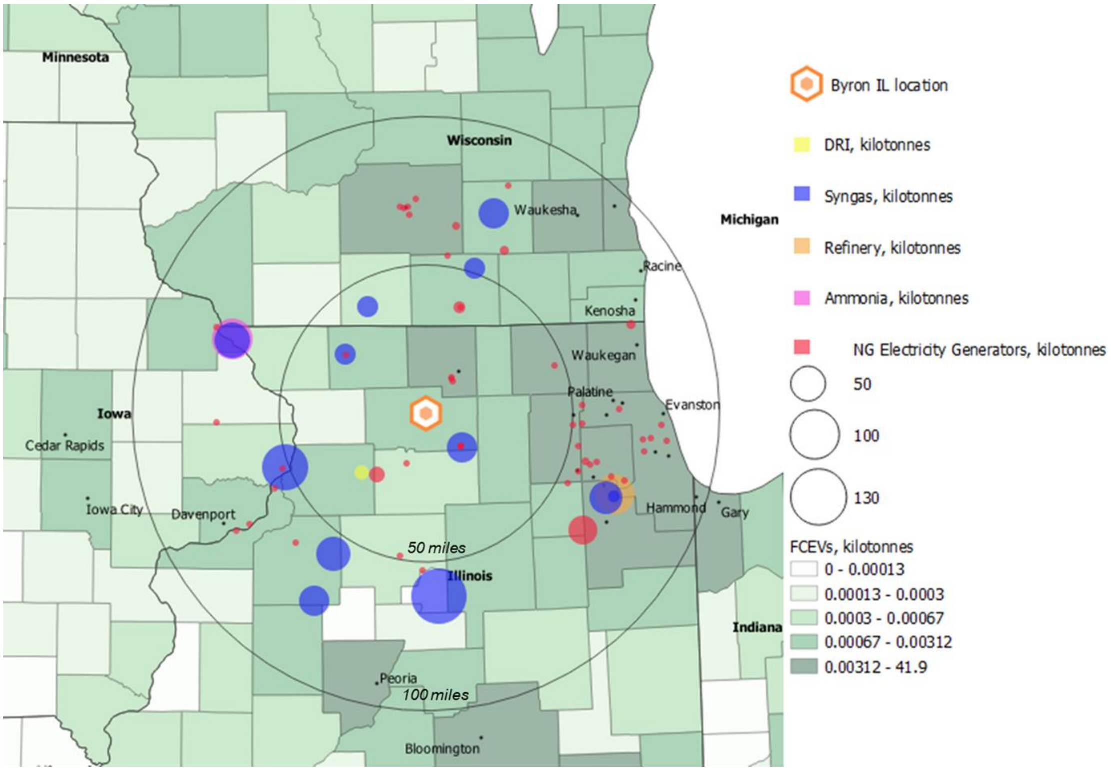

Figure 27 Future potential hydrogen demand near the Byron generating station.

3.1.5 Quad Cities NPP, Moline, IL

The total potential hydrogen demand within 100 miles of the Quad Cities generating station currently is 210 MT/day. The CVR Partners ammonia production facility, 73 miles driving distance from the NPP, has a potential hydrogen demand of 155 MT/day, and three steel producers within 50 miles driving distance have a total potential hydrogen demand of 6 MT/day if they adapt DRI. Additionally, 25 NG generators together have a potential hydrogen demand totaling 44 MT/day. One notable potential hydrogen use in NG generators is the Nelson Energy Center, with a potential demand of 33 MT/day (see Table 8 and Figure 28).

The cumulative future potential hydrogen demand within 100 miles of the Quad Cities Generating Station is 2100 MT/day, the majority of which for production of synfuels at ethanol plants. The synfuel production near ethanol plants accounts for the majority of this demand. Four ethanol facilities would create more than half that potential demand. Marquis Energy in Hennepin, with a potential hydrogen demand of 350 MT/day, Adm Cedar Rapids Dry Mill, with a potential demand of 330 MT/day, ADM Cedar Rapids Wet Mill, with potential demand of 250 MT/day, and ADM Clinton (only 16 miles from the Quad Cities location), with a potential hydrogen demand of 250 MT/day. The FCEVs will add less than 1 MT/day to the potential future hydrogen demand (see Figure 29).

Table 8. Hydrogen demand within 100 miles of the Quad Cities generating station.

Name	Demand Type	Potential H2 Demand, kilotonnes Current (2017)	Future (2030)	Distance, miles
Cordova Energy: Cordova Energy Co LLC	NG Electricity Generators	0.42	0.42	3
Adm Clinton Ia, Clinton	Syngas: Ethanol	0.00	90.00	16
Milton L Kapp: Interstate Power and Light Co	NG Electricity Generators	0.25	0.25	17
Riverside: MidAmerican Energy Co	NG Electricity Generators	0.09	0.09	21
Clinton County, IA	FCEV	0.00	0.00	24
Moline: MidAmerican Energy Co	NG Electricity Generators	0.01	0.01	24
Scott County, IA	FCEV	0.00	0.00	28
Geneseo: City of Geneseo - (IL)	NG Electricity Generators	0.00	0.00	29
Whiteside County, IL	FCEV	0.00	0.00	29
Rock Island County, IL	FCEV	0.00	0.00	31
Carroll County, IL	FCEV	0.00	0.00	35
Henry County, IL	FCEV	0.00	0.00	39
Leggett and Platt Wire Rod (Formerly Sterling Steel Co. LLC)	DRI	1.58	5.57	40
Davenport Water Pollution Control Plant: Davenport City of	NG Electricity Generators	0.00	0.00	40
Nelson Energy Center: Invenergy Services LLC	NG Electricity Generators	11.75	11.75	45
SSAB Montpelier Works	DRI	0.82	2.92	47
Patriot Renewable Fuels LLC, Annawan	Syngas: Ethanol	0.00	50.00	47
Jackson County, IA	FCEV	0.00	0.00	48
Maquoketa 1: City of Maquoketa - (IA)	NG Electricity Generators	0.00	0.00	52
Gerdau Long Steel North America - Wilton	DRI	0.23	0.80	52
Lee County, IL	FCEV	0.00	0.00	57
Lee Energy Facility: Lee County Generating Station	NG Electricity Generators	0.87	0.87	58
Knox County, IL	FCEV	0.00	0.00	58
Big River Resources Galva LLC, Galva	Syngas: Ethanol	0.00	40.00	58
Mercer County, IL	FCEV	0.00	0.00	59

Muscatine County, IA	FCEV	0.00	0.00	61
Cedar County, IA	FCEV	0.00	0.00	62
Adkins Energy LLC, Adkins Energy	Syngas: Ethanol	0.00	20.00	62
Adkins Energy LLC: Adkins Energy LLC	NG Electricity Generators	0.30	0.30	62
Tipton: City of Tipton - (IA)	NG Electricity Generators	0.00	0.00	63
Jo Daviess County, IL	FCEV	0.00	0.00	64
Grain Processing Corp, Muscatine	Syngas: Ethanol	0.00	30.00	66
Muscatine Plant #1: Board of Water Electric and Communications	NG Electricity Generators	0.03	0.03	66
Stephenson County, IL	FCEV	0.00	0.00	70
Princeton (IL): City of Princeton - (IL)	NG Electricity Generators	0.01	0.01	71
Louisa: MidAmerican Energy Co	NG Electricity Generators	0.17	0.17	72
Bureau County, IL	FCEV	0.00	0.00	73
Cvr Partners, East Dubuque	Ammonia	57.00	57.00	73
Cvr Partners, East Dubuque	Syngas: Ammonia CO2	0.00	52.87	73
Dubuque: Interstate Power and Light Co	NG Electricity Generators	0.00	0.00	74
Warren County, IL	FCEV	0.00	0.00	75
Stark County, IL	FCEV	0.00	0.00	75
Illinois River Energy LLC, Rochelle	Syngas: Ethanol	0.00	40.00	75
1515 S Caron Road: Rochelle Municipal Utilities	NG Electricity Generators	0.00	0.00	75
North Ninth Street: Rochelle Municipal Utilities	NG Electricity Generators	0.01	0.01	75
South Main Street: Rochelle Municipal Utilities	NG Electricity Generators	0.00	0.00	75
Ogle County, IL	FCEV	0.00	0.00	76
University of Iowa Main Power Plant: University of Iowa	NG Electricity Generators	0.73	0.73	77
Johnson County, IA	FCEV	0.00	0.00	78
Coralville GT: MidAmerican Energy Co	NG Electricity Generators	0.02	0.02	78
Dubuque County, IA	FCEV	0.00	0.00	79
Oakdale Renewable Energy Plant: University of Iowa	NG Electricity Generators	0.02	0.02	80
Lafayette County, WI	FCEV	0.00	0.00	82
Badger State Ethanol LLC, Monroe	Syngas: Ethanol	0.00	20.00	84

Jones County, IA	FCEV	0.00	0.00	86
Cascade: Cascade Municipal Utilities	NG Electricity Generators	0.00	0.00	87
Louisa County, IA	FCEV	0.00	0.00	87
Hennepin Power Plant: Dynegy Midwest Generation Inc	NG Electricity Generators	0.06	0.06	92
Putnam County, IL	FCEV	0.00	0.00	92
Green County, WI	FCEV	0.00	0.00	93
DeKalb County, IL	FCEV	0.00	0.00	94
Henderson County, IL	FCEV	0.00	0.00	94
Fulton County, IL	FCEV	0.00	0.00	97
Archer Daniels Midland Cedar Rapids: Archer Daniels Midland Co	NG Electricity Generators	1.99	1.99	98
Marquis Energy LLC, Hennepin	Syngas: Ethanol	0.00	130.00	98
Adm Cedar Rapids Ia Wet Mill, Cedar Rapids Wet Mill	Syngas: Ethanol	0.00	90.00	98
Peoria County, IL	FCEV	0.00	0.00	99
Adm Cedar Rapids Ia Dry Mill, Cedar Rapids Dry Mill	Syngas: Ethanol	0.00	120.00	99
Prairie Creek: Interstate Power and Light Co	NG Electricity Generators	0.07	0.07	100

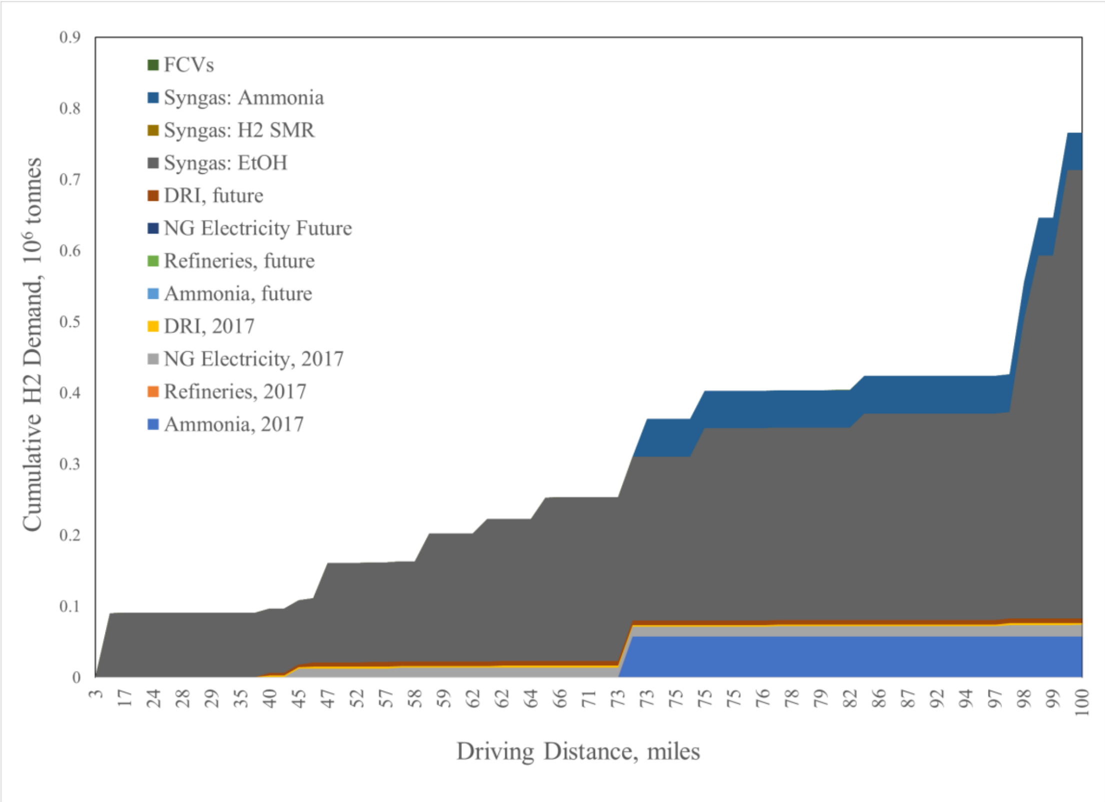

Figure 28. Cumulative potential hydrogen demand by type and distance near the Quad Cities generating station.

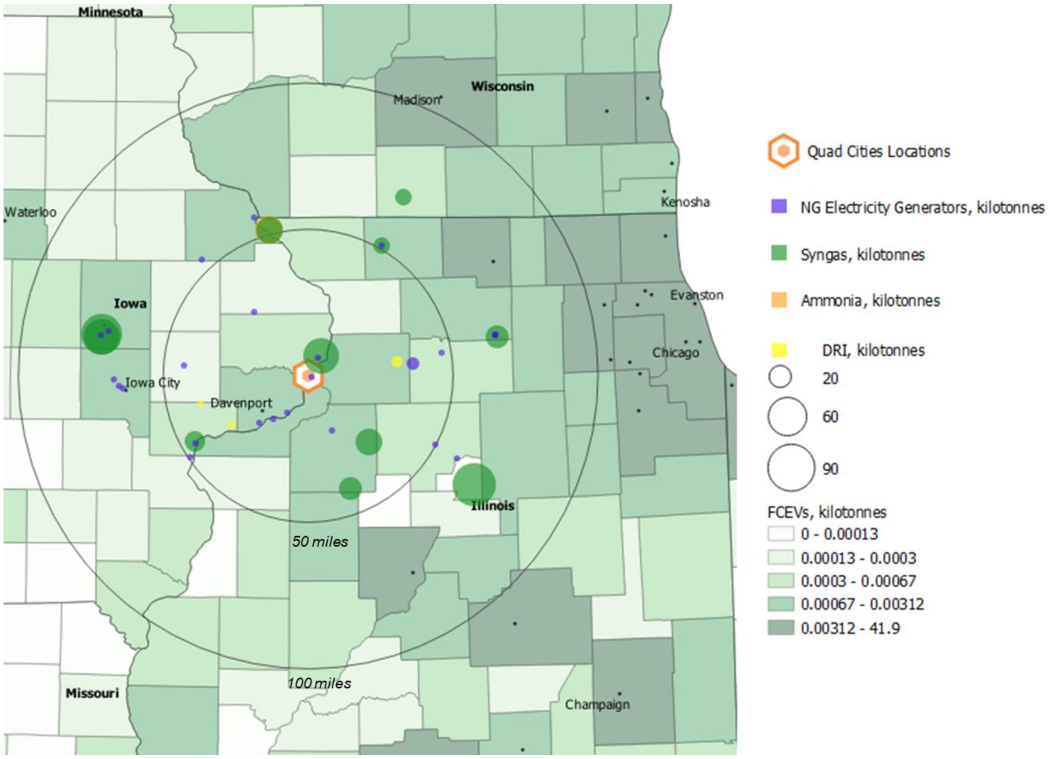

Figure 29. Future potential hydrogen demand near the Quad Cities generating station.

3.1.6 Dresden NPP, Joliet, IL

Current potential hydrogen demand within 100 miles of the Dresden facility is about 1000 MT/day, of which about 670 MT/day is from three refineries: ExxonMobil Corp, Joliet, PDV America Inc., Lemont, and BP PLC, Whiting. About 270 MT/day potential hydrogen demand is from 61 NG electricity generators. The majority of the NG electricity generators' potential hydrogen demand is from two plants. A few potential DRI facilities can be located close to the Dresden facility, with a total potential demand of 100 MT/day (see Table 9 and Figure 30).

The potential future hydrogen demand for the Dresden facility is about 4000 MT/day from facilities within 100 miles. Almost all of the future new demand within 100 miles is for synfuel production near the Praxair–Whiting 5 and 6 and the Marquis Energy LLC, Hennepin facilities, with potential hydrogen demand of 540 and 360 MT/day, respectively. The total future potential demand from steel manufacturers (for DRI) is about 1400 MT/day. The U.S. Steel–Gary Works (No. 1 BOP and Q-BOP) and ArcelorMittal–Burns Harbor have the major share of this demand, with 460 and 350 MT/day, respectively (see Figure 31).

Table 9. Hydrogen demand within 100 miles of the Dresden generating station.

Name	Demand Type	Potential H2 Demand, kilotonnes Current (2017)	Future (2030)	Distance, miles
Grundy County, IL	FCEV	0.00	0.00	8
Air Products and Chemicals, Inc. - Joliet, Il H2 Plant	Syngas: Hydrogen, SMR	0.00	7.11	13
ExxonMobil Oil Joliet Refinery: ExxonMobil Oil Corp	NG Electricity Generators	0.13	0.13	14
ExxonMobil Corp, Joliet	Refinery	69.98	88.66	14
Joliet 29: Midwest Generations EME LLC	NG Electricity Generators	2.41	2.41	20
Morris Cogeneration LLC: Morris Cogeneration LLC	NG Electricity Generators	5.73	5.73	21
Kendall County Generation Facility: Dynegy Kendall Energy LLC	NG Electricity Generators	37.86	37.86	21
Elwood Energy LLC: Elwood Energy LLC	NG Electricity Generators	3.05	3.05	21
Joliet 9: Midwest Generations EME LLC	NG Electricity Generators	0.41	0.41	23
Lincoln Generating Facility: Lincoln Generating Facility LLC	NG Electricity Generators	0.27	0.27	27
Will County, IL	FCEV	0.00	0.01	31
CSL Behring LLC: CSL Behring LLC	NG Electricity Generators	0.21	0.21	32
Kankakee County, IL	FCEV	0.00	0.00	33
Bunge Oil: CSL Behring LLC	NG Electricity Generators	0.18	0.18	33
Linde Gas North America LLC, Lemont Plant	Syngas: Hydrogen, SMR	0.00	46.03	33
Lemont Refinery	Syngas: Hydrogen, SMR	0.00	6.71	36
Kendall County, IL	FCEV	0.00	0.00	37
Nucor Steel - Kankakee Inc.	DRI	0.56	1.99	38
Woodridge Greene Valley Treatment Plant: DuPage County	NG Electricity Generators	0.00	0.00	38
University Park North: LSP University Park LLC	NG Electricity Generators	3.59	3.59	39
University Park South: University Park Energy LLC	NG Electricity Generators	1.40	1.40	39
Fox Metro Water Reclamation District: Fox Metro Water Reclamation	NG Electricity Generators	0.00	0.00	40
PDV America Inc, Lemont	Refinery	51.60	65.38	41
WestRock (IL): WestRock (IL)	NG Electricity Generators	0.00	0.00	41
LaSalle County, IL	FCEV	0.00	0.00	42

Argonne National Laboratory CHP: Argonne National Laboratory	NG Electricity Generators	0.31	0.31	42
Panduit Tinley Park: Panduit Corp	NG Electricity Generators	0.00	0.00	43
Crete Energy Venture LLC: Crete Energy Venture LLC	NG Electricity Generators	0.34	0.34	47
DuPage County, IL	FCEV	0.00	0.02	49
BP Naperville Cogeneration Facility: BP America Inc	NG Electricity Generators	0.66	0.66	50
Livingston County, IL	FCEV	0.00	0.00	50
Ingredion Incorporated: Ingredion Inc - Illinois	NG Electricity Generators	1.68	1.68	52
Nalco: Nalco Co	NG Electricity Generators	0.17	0.17	53
ArcelorMittal - Riverdale	DRI	1.63	23.04	55
Loyola University Health Plant: Loyola University Health System	NG Electricity Generators	1.50	1.50	55
Aurora: Aurora Generation LLC	NG Electricity Generators	3.20	3.20	56
Iroquois County, IL	FCEV	0.00	0.00	60
Finkl Steel	DRI	0.07	0.23	60
Chicago West Side Energy Center: Energy Systems Group LLC	NG Electricity Generators	0.14	0.14	60
Triton East and West Cogen: Triton College	NG Electricity Generators	0.05	0.05	61
Calumet Energy Team LLC: IPA Operations Inc - Calumet	NG Electricity Generators	0.19	0.19	61
Geneva Generation Facility: City of Geneva- (IL)	NG Electricity Generators	0.02	0.02	61
Cook County, IL	FCEV	0.00	0.10	61
ITT Cogen Facility: Illinois Institute-Technology	NG Electricity Generators	0.00	0.00	61
University of Illinois Cogen Facility: University of Illinois	NG Electricity Generators	0.58	0.58	62
Mars Snackfood US: M&M Mars Inc	NG Electricity Generators	0.32	0.32	62
DeKalb County, IL	FCEV	0.00	0.00	63
Lake County, IN	FCEV	0.00	0.01	65
Kane County, IL	FCEV	0.00	0.01	65
Presence Saint Mary of Nazareth Hospital: Presence Health	NG Electricity Generators	0.00	0.00	65
Museum of Science and Industry: Museum of Science and Industry	NG Electricity Generators	0.00	0.00	66
Southeast Chicago Energy Project: Exelon Power	NG Electricity Generators	0.27	0.27	66
Ford County, IL	FCEV	0.00	0.00	66
ArcelorMittal - Indiana Harbor #2	DRI	3.25	46.10	67

ArcelorMittal - Indiana Harbor #3	DRI	4.39	62.22	67
ArcelorMittal - Indiana Harbor #4	DRI	5.37	76.06	67
ArcelorMittal - Indiana Harbor Bar	DRI	0.34	1.19	67
Northwest Community Hospital: Northwest Community Hospital	NG Electricity Generators	0.08	0.08	67
ArcelorMittal Indiana Harbor West: ArcelorMittal Indiana Harbor West	NG Electricity Generators	2.37	2.37	68
Praxair - Whiting, In 1-4	Syngas: Hydrogen, SMR	0.00	21.38	68
Praxair - Whiting, In 5&6	Syngas: Hydrogen, SMR	0.00	198.31	68
Putnam County, IL	FCEV	0.00	0.00	68
Bp PLC, Whiting	Refinery	121.28	153.66	69
Bp Whiting Business Unit	Syngas: Hydrogen, SMR	0.00	0.00	69
Whiting Refinery: BP PLC	NG Electricity Generators	2.09	2.09	69
Marquis Energy LLC, Hennepin	Syngas: Ethanol	0.00	130.00	69
Whiting Clean Energy: BP Alternative Energy	NG Electricity Generators	13.88	13.88	69
Gary Works: United States Steel-Gary	NG Electricity Generators	3.79	3.79	69
Indiana Harbor E 5 AC Station: Northlake Energy	NG Electricity Generators	1.23	1.23	69
US Steel - Gary Works (No. 1 BOP and Q-BOP)	DRI	11.95	169.40	71
Northeastern Illinois University Cogen: Northeastern Illinois University	NG Electricity Generators	0.00	0.00	71
Bureau County, IL	FCEV	0.00	0.00	71
Elgin Energy Center LLC: Elgin Energy Center LLC	NG Electricity Generators	1.27	1.27	72
Princeton (IL): City of Princeton - (IL)	NG Electricity Generators	0.01	0.01	72
Hennepin Power Plant: Dynegy Midwest Generation Inc	NG Electricity Generators	0.06	0.06	73
Prairies Edge Generating Facility: Prairies Edge Dairy Farms LLC	NG Electricity Generators	0.10	0.10	73
Newton County, IN	FCEV	0.00	0.00	74
One Earth Energy LLC, Gibson City	Syngas: Ethanol	0.00	40.00	75
Gibson City Energy Center LLC: Mainline Generation LLC	NG Electricity Generators	0.45	0.45	75
Hoffer Plastics: Hoffer Plastics	NG Electricity Generators	0.01	0.01	75
Portside Energy: Portside Energy Corp	NG Electricity Generators	2.82	2.82	76
Novolipetsk Steel (NLMK Indiana)	DRI	0.53	1.87	76

Rocky Road Power LLC: Rocky Road Power LLC	NG Electricity Generators	0.15	0.15	76
ArcelorMittal - Burns Harbor	DRI	9.10	129.07	77
ArcelorMittal Burns Harbor: ArcelorMittal Burns Harbor Inc	NG Electricity Generators	3.81	3.81	78
Winnetka: Village of Winnetka - (IL)	NG Electricity Generators	0.08	0.08	78
R M Schahfer: Northern Indiana Pub Serv Co	NG Electricity Generators	0.45	0.45	79
Bailly: Northern Indiana Pub Serv Co	NG Electricity Generators	0.36	0.36	80
Jasper County, IN	FCEV	0.00	0.00	81
Marshall County, IL	FCEV	0.00	0.00	81
Lake Forest Hospital: Northwestern Lake Forest Hospital	NG Electricity Generators	0.00	0.00	83
McLean County, IL	FCEV	0.00	0.00	84
Porter County, IN	FCEV	0.00	0.00	85
Rensselaer City Light Plant: City of Rensselaer - (IN)	NG Electricity Generators	0.04	0.04	88
Illinois River Energy LLC, Rochelle	Syngas: Ethanol	0.00	40.00	88
North Chicago Energy Center: Energy Systems Group LLC	NG Electricity Generators	0.37	0.37	88
Woodford County, IL	FCEV	0.00	0.00	89
1515 S Caron Road: Rochelle Municipal Utilities	NG Electricity Generators	0.00	0.00	89
Lake County, IL	FCEV	0.00	0.01	89
Lee County, IL	FCEV	0.00	0.00	90
McHenry County, IL	FCEV	0.00	0.01	90
Lee Energy Facility: Lee County Generating Station	NG Electricity Generators	0.87	0.87	91
North Ninth Street: Rochelle Municipal Utilities	NG Electricity Generators	0.01	0.01	91
South Main Street: Rochelle Municipal Utilities	NG Electricity Generators	0.00	0.00	91
Michigan City: Northern Indiana Pub Serv Co	NG Electricity Generators	0.13	0.13	92
Iroquois Bio-Energy Co LLC, Rensselaer	Syngas: Ethanol	0.00	20.00	93
Patriot Renewable Fuels LLC, Annawan	Syngas: Ethanol	0.00	50.00	95
Waukegan: Midwest Generations EME LLC	NG Electricity Generators	0.18	0.18	95
Benton County, IN	FCEV	0.00	0.00	95
LaPorte County, IN	FCEV	0.00	0.00	95
Champaign County, IL	FCEV	0.00	0.00	97

Charter Dura-Bar: Wells Manufacturing Co	NG Electricity Generators	0.07	0.07	99
Starke County, IN	FCEV	0.00	0.00	99

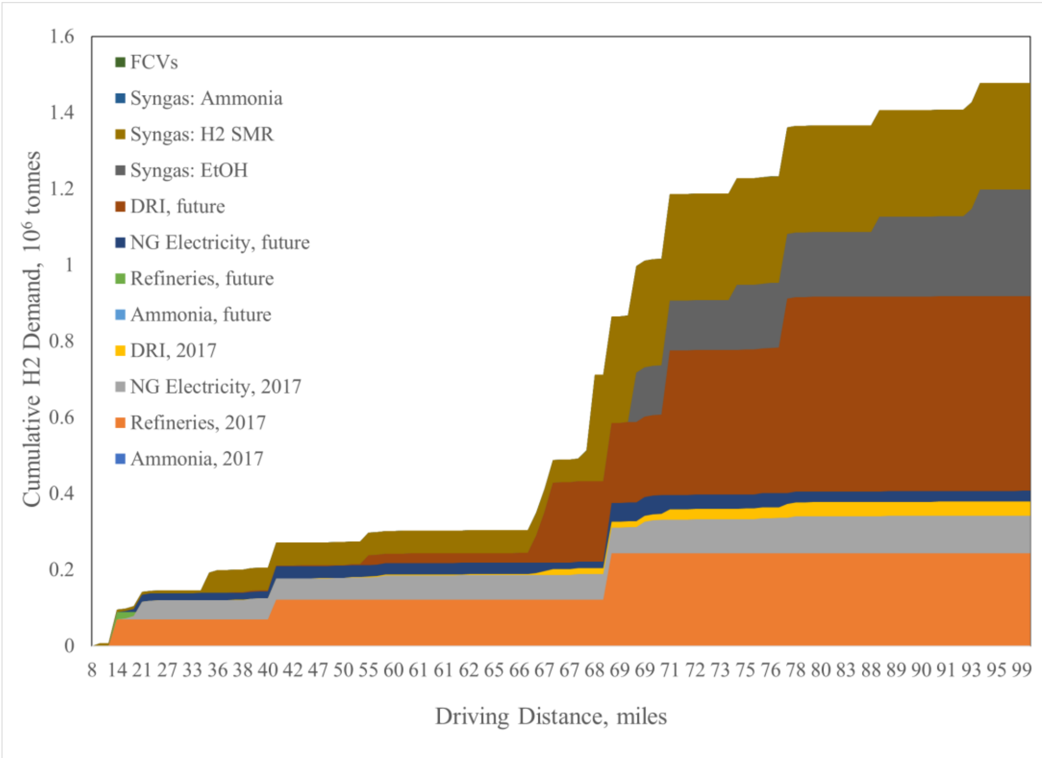

Figure 30. Cumulative potential hydrogen demand by type and distance near the Dresden generating station.

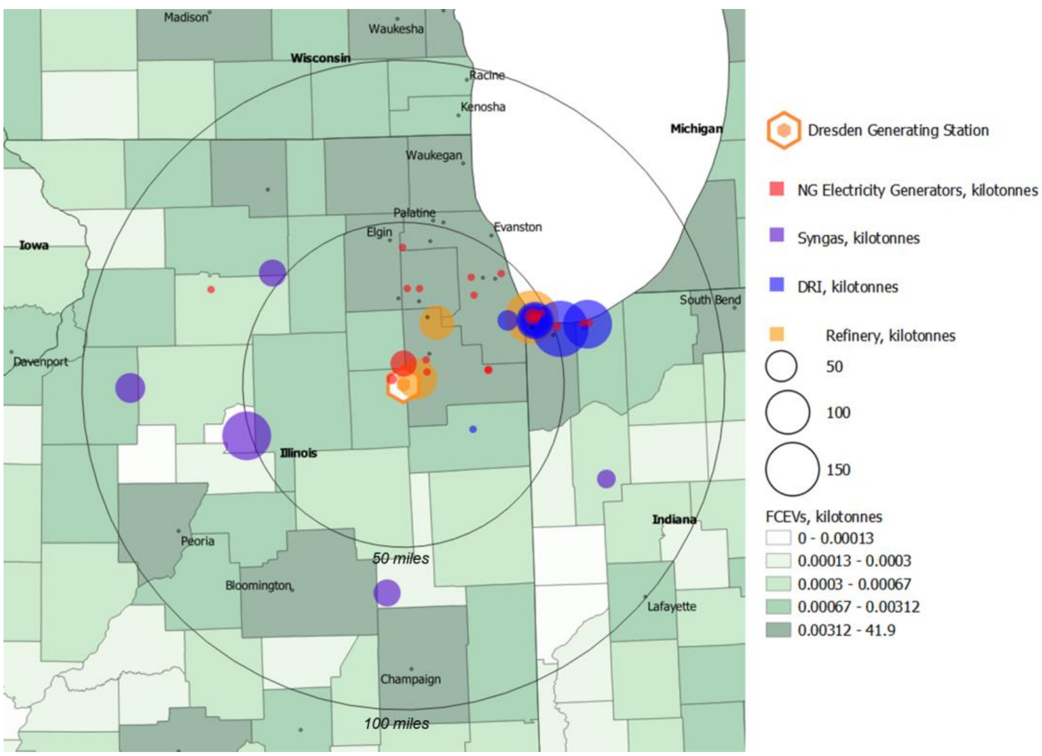

Figure 31. Future potential hydrogen demand near the Dresden generating station.

3.2 Minnesota Region

Xcel Energy corporation operates two NPPs in Minnesota, the Monticello and Prairie Island NPPs, with a total electrical output of 1.1 GW[89], providing opportunities for producing near zero-carbon hydrogen and other nonelectric products for various potential markets. These plants are eligible for capacity payments through the capacity market. The 2019–2020 Planning Resource Auction results from April 19 suggest that Minnesota resources received $24.30/MW-day for eligible capacity[4]. The potential cumulative current and future hydrogen demands out to 2030 in the regions surrounding Xcel NPPs are here examined and evaluated.

3.2.1 Prairie Island NPP, Red Wing, MN

The Xcel Energy Prairie Island NPP is a 1,100 MW facility located about 40 miles southeast of Minneapolis-St. Paul in Red Wing, Minnesota (see Table 10). Figure 32 shows the cumulative potential hydrogen demand within 100 miles of the Prairie Island Generating Station. Current hydrogen demand near the Prairie Island generating station is predominantly from the Western Refining and Koch Industries refineries, located in Saint Paul, Minnesota, within 30 miles of the NPP. The combined hydrogen demand from these two refineries is up to 300 MT/day. The rest of the potential near-term demand, 82 MT/day, is associated with the co-combustion of hydrogen with NG in 38 gas electricity generators located within 100 miles driving distance from Prairie Island generating station.

The future potential hydrogen demand for the Prairie Island Generating Station is about 1400 MT/day, from potential markets within 100 miles of the NPP (see Figure 33). The majority of the future potential hydrogen demand is from four refineries, two of which, Western Refining and Koch Industries, have a combined demand of 400 MT/day for hydrogen for the refining process, while the other two, Flint Hills Resources Pine Bend Refinery and St. Paul Park Refining Company, provide high-concentration CO_2 with an opportunity to produce synfuels, requiring up to 460 MT/day of hydrogen. Additionally, five ethanol plants—Al-Corn Clean Fuel at Claremont, Guardian Energy at Janesville, Pro Corn at Preston, Big River Resources in Boyceville, and Heartland Corn Products in Winthrop—all located within 100 miles of the Prairie Island generating station, can produce synfuels from high-purity CO_2 requiring hydrogen at 400 MT/day.

Table 10. Hydrogen demand within 100 miles of the Prairie Island NPP.

Name	Demand Type	Potential H2 Demand, kilotonnes Current (2017)	Potential H2 Demand, kilotonnes Future (2030)	Distance, miles
Red Wing: Northern States Power Co - Minnesota	NG Electricity Generators	0.02	0.02	13
Goodhue County, MN	FCEV	-	0.00	17
Cannon Falls Energy Center: Invenergy Services LLC	NG Electricity Generators	0.35	0.35	20
LSP-Cottage Grove LP: Cottage Grove Operating Services LLC	NG Electricity Generators	1.65	1.65	23
Inver Hills: Northern States Power Co - Minnesota	NG Electricity Generators	0.09	0.09	26
Flint Hills Resources Pine Bend Refinery	Syngas: Hydrogen, SMR	-	158.12	27
Western Refining Inc., Saint Paul	Refinery	28.90	36.61	27
Koch Industries Inc, Saint Paul	Refinery	85.06	107.76	27
St. Paul Park Refining Company, LLC	Syngas: Hydrogen, SMR	-	15.13	27
Gerdau Long Steel North America - St. Paul	DRI	0.40	1.42	30
Pierce County, WI	FCEV	-	0.00	32
Dakota County, MN	FCEV	-	0.01	33
St Paul Cogeneration: St Paul Cogeneration LLC	NG Electricity Generators	0.38	0.38	38
High Bridge: Northern States Power Co - Minnesota	NG Electricity Generators	10.19	10.19	39
Washington County, MN	FCEV	-	0.00	40
Allen S King: Northern States Power Co - Minnesota	NG Electricity Generators	0.04	0.04	40
Ramsey County, MN	FCEV	-	0.01	40
Wabasha County, MN	FCEV	-	0.00	40
Rice County, MN	FCEV	-	0.00	41
Univ Minnesota CHP Plant: Veolia Energy	NG Electricity Generators	0.83	0.83	45
Southeast Steam Plant: Veolia Energy	NG Electricity Generators	0.38	0.38	46
St. Croix County, WI	FCEV	-	0.00	48
Scott County, MN	FCEV	-	0.00	48
Faribault Energy Park: Minnesota Municipal Power Agny	NG Electricity Generators	3.41	3.41	48
Covanta Hennepin Energy: Covanta Energy Co	NG Electricity Generators	0.03	0.03	49

Saint Marys Hospital Power Plant: St Mary's Hospital	NG Electricity Generators	0.68	0.68	50
New Prague: New Prague Utilities Comm	NG Electricity Generators	0.01	0.01	51
Hennepin County, MN	FCEV	-	0.02	52
Water Reclamation Plant: City of Rochester	NG Electricity Generators	0.00	0.00	52
Cascade Creek: Rochester Public Utilities	NG Electricity Generators	0.21	0.21	53
Dodge County, MN	FCEV	-	0.00	53
Riverside (MN): Northern States Power Co - Minnesota	NG Electricity Generators	8.48	8.48	53
Olmsted County, MN	FCEV	-	0.00	54
Franklin Heating Station: Franklin Heating Station	NG Electricity Generators	0.86	0.86	55
Pepin County, WI	FCEV	-	0.00	55
Blue Lake: Northern States Power Co - Minnesota	NG Electricity Generators	0.65	0.65	56
Olmsted Waste Energy: Olmsted County Public Works	NG Electricity Generators	0.01	0.01	57
Shakopee Energy Park: Minnesota Municipal Power Agny	NG Electricity Generators	0.06	0.06	58
Al-Corn Clean Fuel, Claremont	Syngas: Ethanol	-	20.00	59
Anoka County, MN	FCEV	-	0.00	59
Koda Biomass Plant: Koda Energy LLC	NG Electricity Generators	0.16	0.16	63
Minnesota River: Minnesota Municipal Power Agny	NG Electricity Generators	0.00	0.00	63
Buffalo County, WI	FCEV	-	0.00	64
Steele County, MN	FCEV	-	0.00	67
Carver County, MN	FCEV	-	0.00	68
Le Sueur County, MN	FCEV	-	0.00	69
Owatonna: City of Owatonna - (MN)	NG Electricity Generators	0.01	0.01	69
Big River Resources Boyceville LLC, Boyceville	Syngas: Ethanol	-	20.00	73
Elk River: Great River Energy	NG Electricity Generators	0.24	0.24	74
Dunn County, WI	FCEV	-	0.00	74
Winona County, MN	FCEV	-	0.00	75
Chisago County, MN	FCEV	-	0.00	76
Polk County, WI	FCEV	-	0.00	77
Pleasant Valley (MN): Great River Energy	NG Electricity Generators	0.42	0.42	78

Waseca County, MN	FCEV	-	0.00	78
Janesville: City of Janesville - (MN)	NG Electricity Generators	0.00	0.00	80
Spring Valley: Spring Valley Pub Utils Comm	NG Electricity Generators	0.00	0.00	80
Guardian Energy LLC, Janesville	Syngas: Ethanol	-	60.00	81
Arcadia Electric: City of Arcadia - (WI)	NG Electricity Generators	0.00	0.00	83
Eau Claire County, WI	FCEV	-	0.00	84
Sibley County, MN	FCEV	-	0.00	85
Isanti County, MN	FCEV	-	0.00	85
Wright County, MN	FCEV	-	0.00	86
Cambridge CT: Great River Energy	NG Electricity Generators	0.20	0.20	86
Elk Mound: Dairyland Power Coop	NG Electricity Generators	0.14	0.14	87
Sherburne County, MN	FCEV	-	0.00	87
Nicollet County, MN	FCEV	-	0.00	88
Fillmore County, MN	FCEV	-	0.00	89
Wheaton: Northern States Power Co - Minnesota	NG Electricity Generators	0.80	0.80	90
Preston (MN): Preston Public Utilities Comm	NG Electricity Generators	0.00	0.00	90
Heartland Corn Products, Winthrop	Syngas: Ethanol	-	30.00	91
Mower County, MN	FCEV	-	0.00	91
Glencoe: Glencoe Light and Power Comm	NG Electricity Generators	0.00	0.00	91
Wilmarth: Northern States Power Co - Minnesota	NG Electricity Generators	0.02	0.02	94
Mankato Energy Center: Southern Power Co	NG Electricity Generators	3.80	3.80	94
Pro Corn LLC, Preston	Syngas: Ethanol	-	20.00	94
Blue Earth County, MN	FCEV	-	0.00	96
Trempealeau County, WI	FCEV	-	0.00	96
Cumberland (WI): City of Cumberland - (WI)	NG Electricity Generators	0.00	0.00	98
Hutchinson Plant #2: Hutchinson Utilities Comm	NG Electricity Generators	0.14	0.14	99
Hutchinson Plant #1: Hutchinson Utilities Comm	NG Electricity Generators	0.06	0.06	100
Freeborn County, MN	FCEV	-	0.00	100

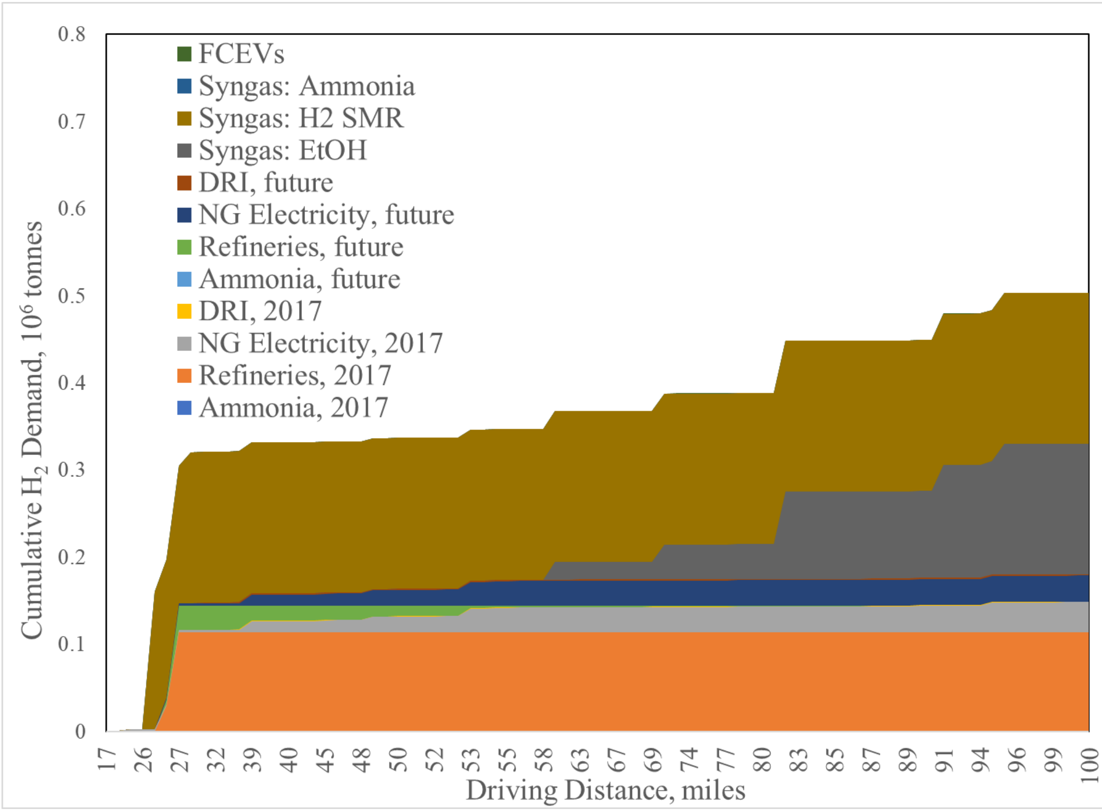

Figure 32 Cumulative potential hydrogen demand by type and distance near the Prairie Island power plant.

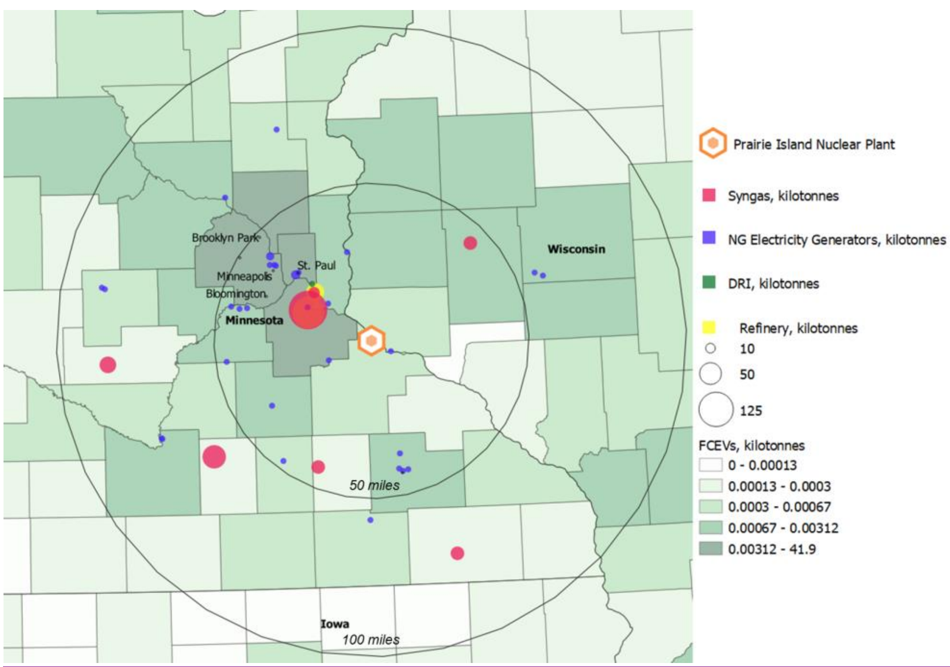

Figure 33 Future potential hydrogen demand near the Prairie Island power plant.

3.2.2 Monticello NPP, Monticello, MN

The Xcel Energy Monticello NPP is a 647 MW facility located along the Mississippi river, northwest of Minneapolis–St. Paul in Monticello, Minnesota (see Table 11). Figure 34 shows the cumulative potential hydrogen demand within 100 miles of the Monticello NPP.

Current and near-term hydrogen demand near the Monticello facility depends mainly on the co-combustion of hydrogen with NG for electricity generation, and two refineries which add to this demand. The cumulative near-term potential hydrogen demand for this location is 400 MT/day. About 27 NG electricity generators located within 100 miles of this facility, have a combined potential hydrogen demand of 85 MT/day. Two refineries, Western Refining and Koch Industries, both near Saint Paul, have an estimated hydrogen demand of 310 MT/day.

Future hydrogen demand near Monticello's location would be vastly for synfuels production, petroleum refineries, and for co-combustion of hydrogen with NG. Synfuel-producing facilities within 100 miles would have a combined future potential demand of 640 MT/day. More than half of this would be associated with CO_2 from one facility, the Flint Hills Resources Pine Bend Refinery. The refineries increase the potential demand for hydrogen to a total of about 400 MT/day. The cumulative future hydrogen potential demand for Monticello power plant would be about 1125 MT/day within 100 miles (see Figure 35).

Table 11. Hydrogen demand within 100 miles of the Monticello NPP.

Name	Demand Type	Potential H2 Demand, kilotonnes		Distance, miles
		Current (2017)	Future (2030)	
Sherburne County, MN	FCEV	0.00	0.00	12
Wright County, MN	FCEV	0.00	0.00	13
Elk River: Great River Energy	NG Electricity Generators	0.24	0.24	17
Granite City: Northern States Power Co - Minnesota	NG Electricity Generators	0.00	0.00	27
Stearns County, MN	FCEV	0.00	0.00	32
Benton County, MN	FCEV	0.00	0.00	32
Anoka County, MN	FCEV	0.00	0.00	34
Hennepin County, MN	FCEV	0.00	0.02	39
Riverside (MN): Northern States Power Co - Minnesota	NG Electricity Generators	8.48	8.48	39
Covanta Hennepin Energy: Covanta Energy Co	NG Electricity Generators	0.03	0.03	42
Southeast Steam Plant: Veolia Energy	NG Electricity Generators	0.38	0.38	43
Mille Lacs County, MN	FCEV	0.00	0.00	45
Isanti County, MN	FCEV	0.00	0.00	46
Univ Minnesota CHP Plant: Veolia Energy	NG Electricity Generators	0.83	0.83	46
Meeker County, MN	FCEV	0.00	0.00	49
Ramsey County, MN	FCEV	0.00	0.01	49
Litchfield: Litchfield Public Utilities	NG Electricity Generators	0.00	0.00	50
Blue Lake: Northern States Power Co - Minnesota	NG Electricity Generators	0.65	0.65	52
Cambridge CT: Great River Energy	NG Electricity Generators	0.20	0.20	53
St Paul Cogeneration: St Paul Cogeneration LLC	NG Electricity Generators	0.38	0.38	53
Koda Biomass Plant: Koda Energy LLC	NG Electricity Generators	0.16	0.16	54
Shakopee Energy Park: Minnesota Municipal Power Agny	NG Electricity Generators	0.06	0.06	54
Minnesota River: Minnesota Municipal Power Agny	NG Electricity Generators	0.00	0.00	54
McLeod County, MN	FCEV	0.00	0.00	55
Glencoe: Glencoe Light and Power Comm	NG Electricity Generators	0.00	0.00	55

High Bridge: Northern States Power Co - Minnesota	NG Electricity Generators	10.19	10.19	55
Hutchinson Plant #2: Hutchinson Utilities Comm	NG Electricity Generators	0.14	0.14	57
Washington County, MN	FCEV	0.00	0.00	57
Black Dog: Northern States Power Co - Minnesota	NG Electricity Generators	3.68	3.68	57
Scott County, MN	FCEV	0.00	0.00	58
Hutchinson Plant #1: Hutchinson Utilities Comm	NG Electricity Generators	0.06	0.06	58
Morrison County, MN	FCEV	0.00	0.00	59
Gerdau Long Steel North America - St. Paul	DRI	0.00	1.00	59
Carver County, MN	FCEV	0.00	0.00	59
Allen S King: Northern States Power Co - Minnesota	NG Electricity Generators	0.04	0.04	62
Western Refining Inc., Saint Paul	Refinery	29.00	37.00	62
Mora: City of Mora - (MN)	NG Electricity Generators	0.00	0.00	62
St. Paul Park Refining Company, LLC	Syngas: Hydrogen, SMR	-	15.00	62
Kanabec County, MN	FCEV	0.00	0.00	63
Bushmills Ethanol Inc, Atwater	Syngas: Ethanol	-	30.00	64
Dakota County, MN	FCEV	0.00	0.01	64
Inver Hills: Northern States Power Co - Minnesota	NG Electricity Generators	0.09	0.09	65
Flint Hills Resources Pine Bend Refinery	Syngas: Hydrogen, SMR	-	158.00	65
Koch Industries Inc, Saint Paul	Refinery	85.00	108.00	66
LSP-Cottage Grove LP: Cottage Grove Operating Services LLC	NG Electricity Generators	1.65	1.65	67
Sibley County, MN	FCEV	0.00	0.00	68
Chisago County, MN	FCEV	0.00	0.00	70
St. Croix County, WI	FCEV	0.00	0.00	74
New Prague: New Prague Utilities Comm	NG Electricity Generators	0.01	0.01	77
Heartland Corn Products, Winthrop	Syngas: Ethanol	-	30.00	78
Kandiyohi County, MN	FCEV	0.00	0.00	80
Willmar: Willmar Municipal Utilities	NG Electricity Generators	0.06	0.06	82
Cannon Falls Energy Center: Invenergy Services LLC	NG Electricity Generators	0.35	0.35	84
Pine County, MN	FCEV	0.00	0.00	86

Rice County, MN	FCEV	0.00	0.00	87
Pierce County, WI	FCEV	0.00	0.00	88
Polk County, WI	FCEV	0.00	0.00	88
Faribault Energy Park: Minnesota Municipal Power Agny	NG Electricity Generators	3.41	3.41	89
Todd County, MN	FCEV	0.00	0.00	90
Le Sueur County, MN	FCEV	0.00	0.00	90
Pope County, MN	FCEV	0.00	0.00	92
Douglas County, MN	FCEV	0.00	0.00	95
Crow Wing County, MN	FCEV	0.00	0.00	95
Renville County, MN	FCEV	0.00	0.00	96
Red Wing: Northern States Power Co - Minnesota	NG Electricity Generators	0.02	0.02	97

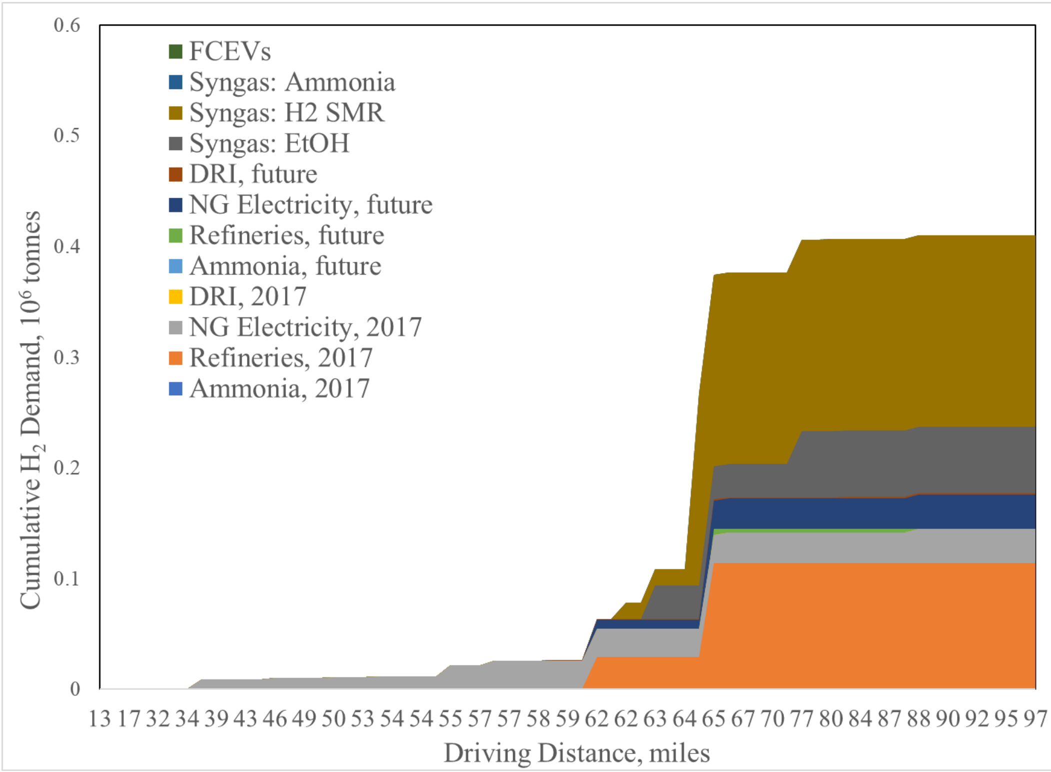

Figure 34. Cumulative potential hydrogen demand by type and distance near the Monticello power plant.

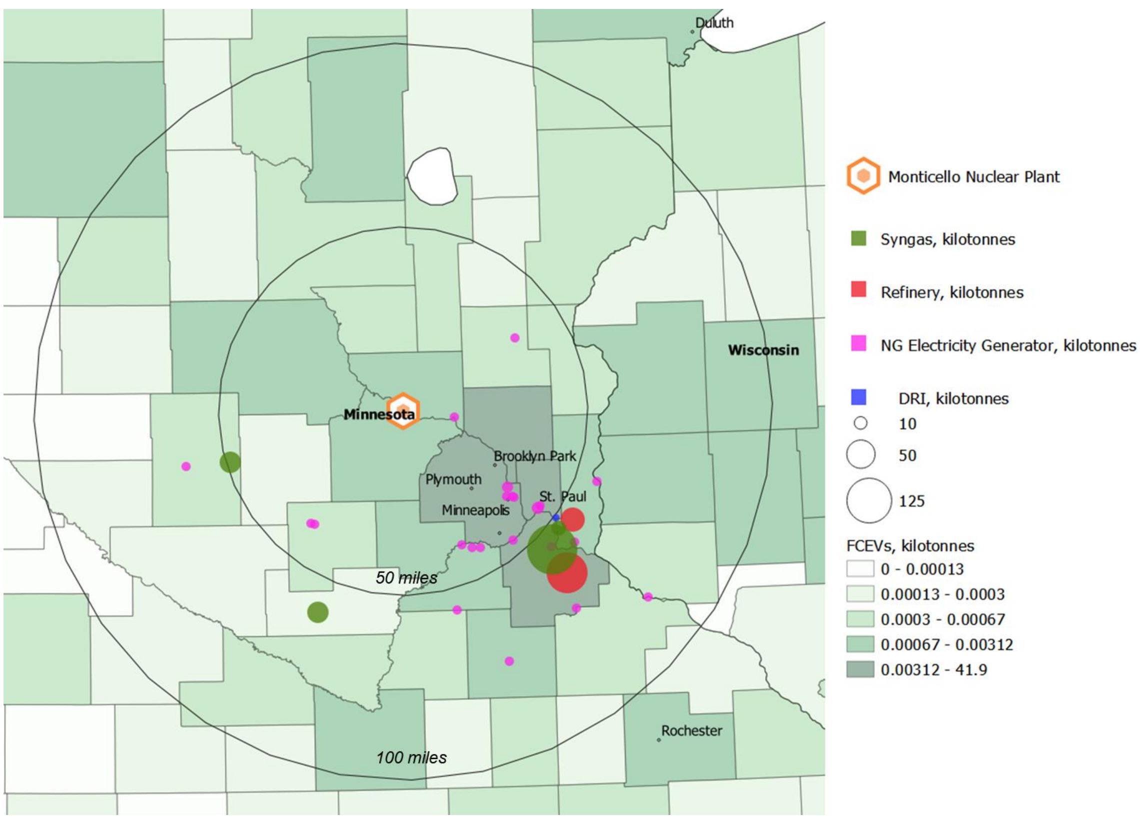

Figure 35. Future potential hydrogen demand near the Monticello power plant.

3.3 Ohio/Western Pennsylvania Region

This region includes three NPPs (Davis-Besse, Perry, and Beaver Valley) with a total generating capacity of 3.9 GW (see Figure 36). Long a manufacturing hub, this Midwestern area contains both oil refineries and an abundance of steel mills:

- Four oil refineries, totaling ~400 MT/day H_2
- Thirty steel mills, totaling ~21,500 MT/day O_2.

The Ohio and western Pennsylvania nuclear facilities are located further from farmland than the Illinois facilities; thus, they lack access to large-scale ammonia plants. There are, however, small oil refineries in Canton, Ohio, and northwestern Pennsylvania that could be served by NPP-SOEC facilities. Most notably, however, this region boasts an abundance of oxygen demand in the form of steel plants in and near Detroit, Cleveland, Canton, and Pittsburgh. The 30 steel plants within 100 miles of the three facilities represent more than 20% of total steel production capacity in the US, translating to ~21,500 MT/day O_2, actually more than the NPPs can realistically provide.

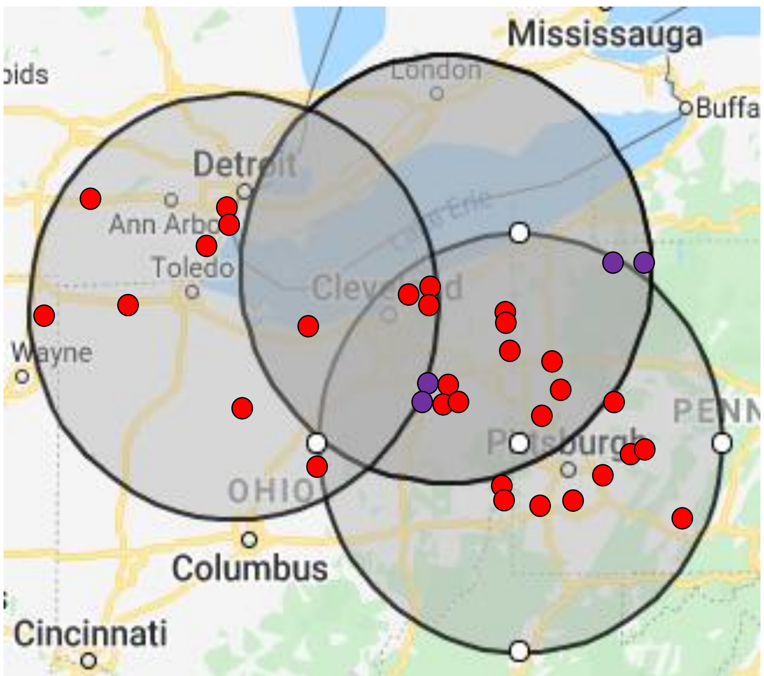

Figure 36. Location of ammonia plants (blue), oil refineries (purple), and steel mills (red) within 100 miles of the NPP facilities in Ohio and Western Pennsylvania . Shaded circles are drawn to indicate a 100 radius around each NPP.

In the electricity markets, these facilities are located within the PJM market. Although the future of capacity markets within PJM is uncertain, previous analyses have used a value of \$132/MW-day to project future capacity payments based on prior year results[102].

3.3.1 Davis-Besse NPP, Toledo OH

First Energy's Ohio facility in Oak Harbor is considered for this analysis, with potential opportunities for making and marketing nuclear hydrogen around that plant (see Table 12). Potential cumulative hydrogen demands for the current and future 2030 scenario at increasing distances from Davis Besse facility are estimated (see Figure 37 and Figure 38).

The Davis-Besse NPP is an 894 MW NPP located northeast of Oak Harbor, Ohio, in Ottawa County. The near-term cumulative potential hydrogen demand for the Davis-Besse facility is 580 MT/day, mainly for metal and petroleum refining and co-combustion with NG in gas electricity generators. Three refineries, Pbf Energy in Toledo, BP Husky Refining in Toledo, and Marathon Petroleum in Detroit account for about two-thirds of the total current demand, requiring 130, 125, and 105 MT/day, respectively. There are 29 NG electricity generators with a cumulative potential demand of 160 MT/day within 100 miles of the David-Besse power plant.

The future potential demand for hydrogen within 100 miles of the Davis-Besse facility is associated with DRI for metal refining, synfuels production, and petroleum refineries. The cumulative potential demand is 2400 MT/day for the year 2030. Majority of the future hydrogen demand is potentially for metal refining using DRI processes at 1200 MT/day, which includes the Cliffs HBI plant in Toledo, with a future potential hydrogen demand of 440 MT/day if hydrogen is used exclusively for the DRI process. Additionally, the potential future hydrogen demand for producing synfuels using CO_2 sources from Linde Gas in Toledo, and from Air Products and Chemicals in Detroit and is at 200 and 150 MT/day, respectively. The potential for synfuels production from CO_2 at ethanol-producing facilities adds another 270 MT/day to the potential future hydrogen demand.

Table 12. Hydrogen demand within 100 miles of the Davis-Besse NPP.

Name	Demand Type	Potential H2 Demand, kilotonnes Current (2017)	Future 2030)	Distance, miles
Ottawa County, OH	FCEV	0.00	0.0	5
Fremont Energy Center: American Mun Power-Ohio, Inc	NG Electricity Generators	16.51	16.5	20
Pbf Energy Co LLC, Toledo	Refinery	46.93	59.5	22
Oregon Clean Energy Center: Oregon Clean Energy Center	NG Electricity Generators	12.51	12.5	23
Linde Gas North America LLC, Toledo Plant	Syngas: Hydrogen, SMR	0.00	72.4	24
Sandusky County, OH	FCEV	0.00	0.0	25
Bp Husky Refining LLC, Toledo	Refinery	44.88	56.9	25
Cliffs HBI Plant, Toledo, OH	DRI	0.00	160.0	25
Troy Energy LLC: Troy Energy LLC	NG Electricity Generators	1.29	1.3	26
Bay View Backup Power Facility: COT/Division of Water Reclamation	NG Electricity Generators	0.00	0.0	27
Lucas County, OH	FCEV	0.00	0.0	34
Wood County, OH	FCEV	0.00	0.0	36
Erie County, OH	FCEV	0.00	0.0	36
Bowling Green Peaking: American Mun Power-Ohio, Inc	NG Electricity Generators	0.02	0.0	38
Seneca County, OH	FCEV	0.00	0.0	38
Poet Biorefining-Fostoria LLC, Fostoria	Syngas: Ethanol	0.00	30.0	40
Bowling Green Generating Station: American Mun Power-Ohio, Inc	NG Electricity Generators	0.03	0.0	41
Monroe County, MI	FCEV	0.00	0.0	44
Huron County, OH	FCEV	0.00	0.0	47
Green Plains Holdings Ii, Green Plains - Riga	Syngas: Ethanol	0.00	20.0	53
Wyandot County, OH	FCEV	0.00	0.0	57
Bluescope Steel North America	DRI	1.44	5.1	60
Fulton County, OH	FCEV	0.00	0.0	63
Napoleon Peaking Station: American Mun Power-Ohio, Inc	NG Electricity Generators	0.03	0.0	63

Oberlin (OH): City of Oberlin - (OH)	NG Electricity Generators	0.00	0.0	64
Henry County, OH	FCEV	0.00	0.0	66
Lorain County, OH	FCEV	0.00	0.0	66
Shelby Municipal Light Plant: City of Shelby - (OH)	NG Electricity Generators	0.00	0.0	67
Lenawee County, MI	FCEV	0.00	0.0	67
Hancock County, OH	FCEV	0.00	0.0	67
Wyandotte: Wyandotte Municipal Serv Comm	NG Electricity Generators	0.18	0.2	69
Crawford County, OH	FCEV	0.00	0.0	72
Sumpter: Wolverine Power Supply Coop	NG Electricity Generators	1.69	1.7	73
Marathon Petroleum Corp, Detroit	Refinery	38.72	49.1	74
Air Products and Chemicals Inc./Detroit Hydrogen Facility Marathon Refinery	Syngas: Hydrogen, SMR	0.00	56.9	75
Poet Biorefining-Leipsic LLC, Leipsic	Syngas: Ethanol	0.00	20.0	75
AK Steel Corp. - Mansfield	DRI	0.46	1.6	75
Clinton: Village of Clinton - (MI)	NG Electricity Generators	0.00	0.0	76
AK Steel Corp. - Dearborn	DRI	6.66	94.5	76
Dearborn Industrial Generation: Dearborn Industrial Gen Inc	NG Electricity Generators	21.64	21.6	76
Ashland County, OH	FCEV	0.00	0.0	76
Sauder Power Plant: Sauder Woodworking Co	NG Electricity Generators	0.00	0.0	76
US Steel - Great Lakes Works	DRI	5.20	73.7	77
Delray: DTE Electric Company	NG Electricity Generators	0.26	0.3	77
Broshco Fabricated Products: Broshco Fabricated Products	NG Electricity Generators	0.03	0.0	77
Richland County, OH	FCEV	0.00	0.0	78
Richland: Richland-Stryker Generation LLC	NG Electricity Generators	0.00	0.0	78
Poet Biorefining-Marion LLC, Marion	Syngas: Ethanol	0.00	30.0	78
River Rouge: DTE Electric Company	NG Electricity Generators	0.59	0.6	79
Wayne County, MI	FCEV	0.00	0.0	79
Marion County, OH	FCEV	0.00	0.0	79
Washtenaw County, MI	FCEV	0.00	0.0	80

East. Michigan Univ. Heating Plant: East. Michigan Univ. Heating Plant	NG Electricity Generators	0.00	0.0	80
Galion Generating Station: American Mun Power-Ohio, Inc	NG Electricity Generators	0.02	0.0	80
Nucor Steel - Marion Inc.	DRI	0.26	0.9	81
University of Michigan: University of Michigan	NG Electricity Generators	2.40	2.4	81
Warner Lambert: University of Michigan NCampus Research	NG Electricity Generators	0.25	0.3	82
Defiance County, OH	FCEV	0.00	0.0	83
West 41st Street: City of Cleveland - (OH)	NG Electricity Generators	0.00	0.0	85
Bryan (OH): City of Bryan - (OH)	NG Electricity Generators	0.02	0.0	87
ArcelorMittal - Cleveland East	DRI	3.74	53.0	88
Charter Steel	DRI	0.43	1.5	88
Charter Steel	DRI	0.42	1.5	88
Cuyahoga County, OH	FCEV	0.00	0.0	89
Putnam County, OH	FCEV	0.00	0.0	89
Arcelormittal Cleveland Inc: ArcelorMittal Cleveland Inc	NG Electricity Generators	0.42	0.4	90
Cleveland Thermal: Cleveland Thermal, LLC	NG Electricity Generators	0.89	0.9	90
ArcelorMittal - Cleveland West	DRI	3.09	43.8	90
Williams County, OH	FCEV	0.00	0.0	91
Northeast (MI): DTE Electric Company	NG Electricity Generators	0.03	0.0	92
Morrow County, OH	FCEV	0.00	0.0	93
Hardin County, OH	FCEV	0.00	0.0	93
Hancock: DTE Electric Company	NG Electricity Generators	0.09	0.1	94
Medina County, OH	FCEV	0.00	0.0	95
Hillsdale County, MI	FCEV	0.00	0.0	96
Collinwood: City of Cleveland - (OH)	NG Electricity Generators	0.00	0.0	96
Wayne County, OH	FCEV	0.00	0.0	97
Paulding County, OH	FCEV	0.00	0.0	97
Jackson County, MI	FCEV	0.00	0.0	100
Allen County, OH	FCEV	0.00	0.0	100

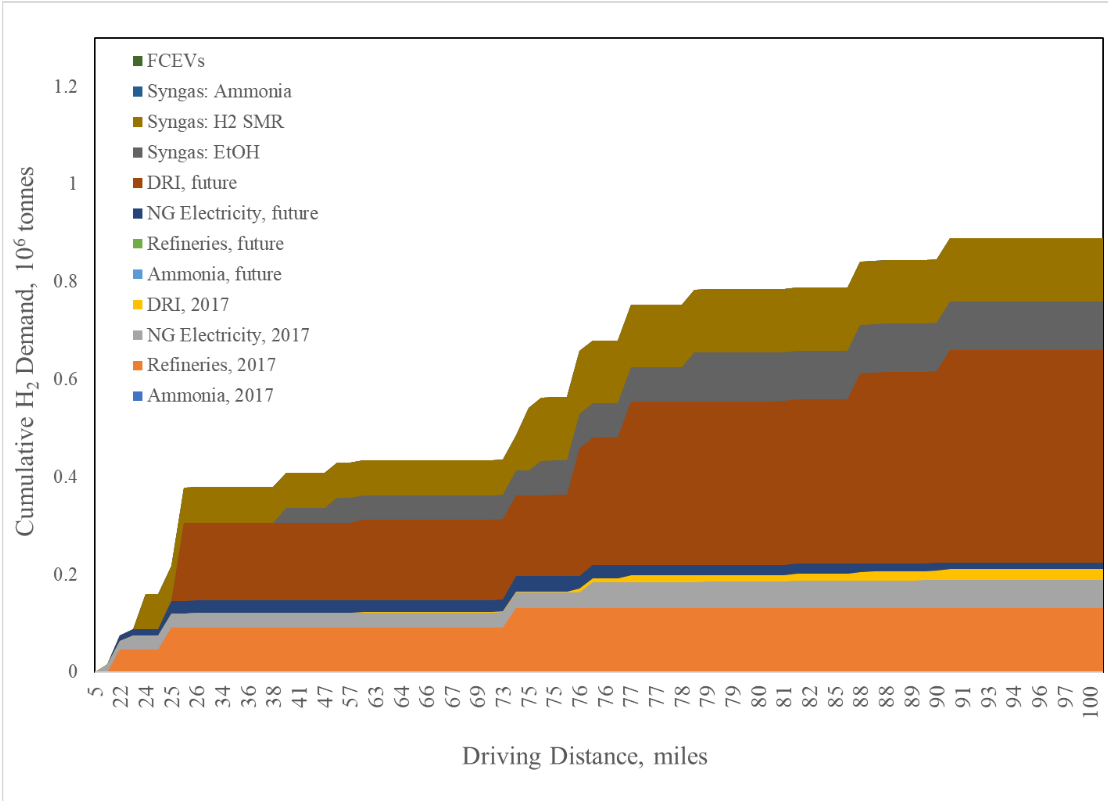

Figure 37. Cumulative potential hydrogen demand by type and distance near the Davis Besse Power Plant.

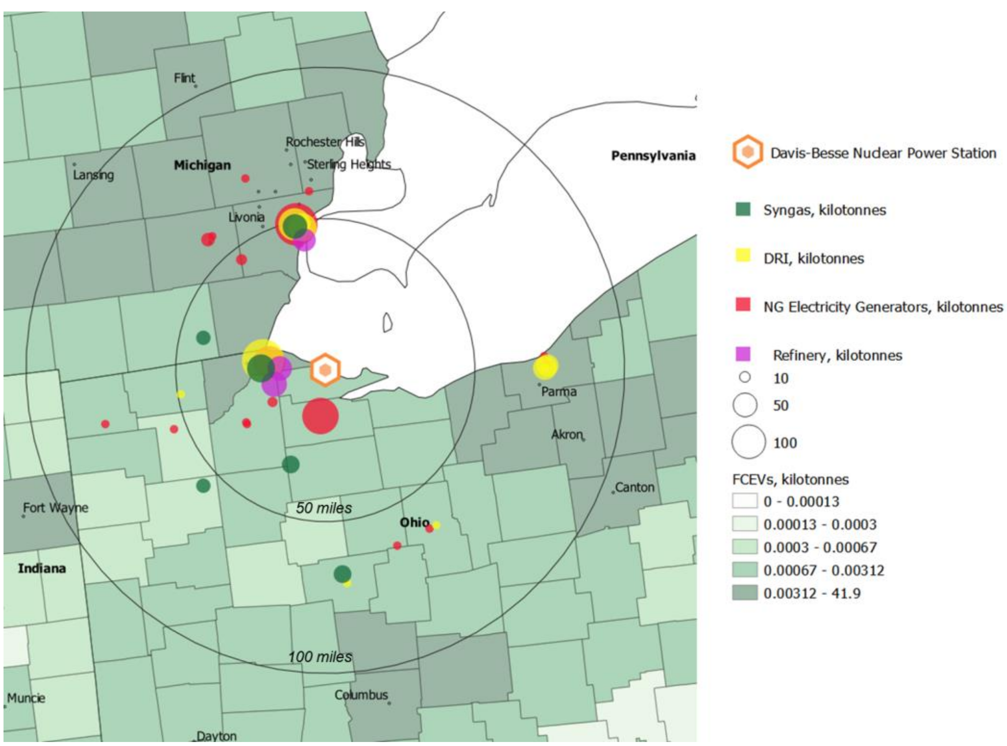

Figure 38. Future potential hydrogen demand near the Davis-Besse NPP.

3.4 Alabama and Georgia Region

The Southern Company region includes NPPs in Alabama and Georgia that supply electricity to these and surrounding states. This analysis considers three Southern Company NPPs—the Farley, Hatch, and Vogtle Generating Stations—and identifies potential opportunities for making and marketing nuclear hydrogen produced by these plants.

Figure 39. Location of ammonia plants (blue), oil refineries (purple), and steel mills (red) within 100 miles of the NPP facilities in Alabama and Georgia. Large filled circles are drawn to indicate a 100 radius around each NPP.

This region includes three named NPPs with 6 GW total capacity. This area of the Southeast lacks point demand sources of H_2 or O_2, although there are a number of large steel mills in northern and western Alabama, outside of the 100 mile radius from the Joseph Farley facility. There is a single ammonia plant in Augusta, Georgia, which consumes nearly 500 MT/day of hydrogen. The one steel mill in Jacksonville, Florida, consumes about 400 MT/day O_2, but extending the Alabama plant radius to 300 miles would bring the total accessible O_2 demand from steel mills to almost 7,500 MT/day.

3.4.1 Farley NPP, Dothan, AL

The potential near-term hydrogen demand around the Joseph Farley Generating Station is almost entirely for co-combustion of hydrogen with NG (see Table 13). Eleven NG electricity generators within 100 miles of the Farley facility have a combined potential hydrogen demand of 165 MT/day. Most of the demand is associated with three facilities, the City of Tallahassee's Arvah B. Hopkins generator at 25 MT/day, the Gulf Power's Lansing Smith generator at 60 MT/day, and the PowerSouth Energy Cooperative's McWilliams generator at 63 MT/day (see Figure 40).

The total future potential hydrogen demand around the Farley NPP is 300 MT/day. The CO_2 from the Flint Hills' Camilla ethanol facility presents an opportunity for using nuclear hydrogen produced by Southern Company to produce synfuels that could result in a potential future hydrogen demand of 140 MT/day within 73 miles from the Farley NPP (see Figure 41).

Table 13. Hydrogen demand within 100 miles of the Joseph Farley NPP.

Name	Demand Type	Potential H2 Demand, kilotonnes		Distance, miles
		Current (2017)	Future (2030)	
Georgia-Pacific Cedar Springs: Georgia-Pacific Cedar Springs LLC	NG Electricity Generators	1.25	1.25	17
Houston County, AL	FCEV	0.00	0.00	19
Henry County, AL	FCEV	0.00	0.00	24
Early County, GA	FCEV	0.00	0.00	24
Seminole County, GA	FCEV	0.00	0.00	27
Jackson County, FL	FCEV	0.00	0.00	35
Miller County, GA	FCEV	0.00	0.00	36
Clay County, GA	FCEV	0.00	0.00	37
Dale County, AL	FCEV	0.00	0.00	42
Calhoun County, GA	FCEV	0.00	0.00	43
Decatur County, GA	FCEV	0.00	0.00	44
Geneva County, AL	FCEV	0.00	0.00	46
Randolph County, GA	FCEV	0.00	0.00	52
Quitman County, GA	FCEV	0.00	0.00	53
Barbour County, AL	FCEV	0.00	0.00	54
Coffee County, AL	FCEV	0.00	0.00	54
Baker County, GA	FCEV	0.00	0.00	55
Holmes County, FL	FCEV	0.00	0.00	57
Washington County, FL	FCEV	0.00	0.00	59
Calhoun County, FL	FCEV	0.00	0.00	59
Gadsden County, FL	FCEV	0.00	0.00	65
Grady County, GA	FCEV	0.00	0.00	67
Mitchell County, GA	FCEV	0.00	0.00	69
Liberty County, FL	FCEV	0.00	0.00	72
Terrell County, GA	FCEV	0.00	0.00	73

Dougherty County, GA	FCEV	0.00	0.00	73
Flint Hills Resources LP, Camilla	Syngas: Ethanol	-	50.00	73
Pike County, AL	FCEV	0.00	0.00	74
Stewart County, GA	FCEV	0.00	0.00	75
Mead Coated Board: Mead Coated Board Inc	NG Electricity Generators	2.53	2.53	76
Albany Green Energy: Albany Green Energy, LLC	NG Electricity Generators	0.01	0.01	76
Sowega Power: SOWEGA Power LLC	NG Electricity Generators	0.33	0.33	77
Baconton Power Plant: Baconton Power LLC	NG Electricity Generators	0.00	0.00	77
MCLB Landfill Gas to Energy: Inst and Envir Div Marine Logistics Base	NG Electricity Generators	0.01	0.01	78
Webster County, GA	FCEV	0.00	0.00	79
Lee County, GA	FCEV	0.00	0.00	80
Bay County Waste to Energy: Bay County Board-County Comm	NG Electricity Generators	0.02	0.02	81
Arvah B Hopkins: City of Tallahassee - (FL)	NG Electricity Generators	9.13	9.13	83
Thomas County, GA	FCEV	0.00	0.00	84
Bullock County, AL	FCEV	0.00	0.00	84
Lansing Smith: Gulf Power Co	NG Electricity Generators	22.06	22.06	87
Covington County, AL	FCEV	0.00	0.00	89
Leon County, FL	FCEV	0.00	0.01	89
Bay County, FL	FCEV	0.00	0.01	91
Worth County, GA	FCEV	0.00	0.00	91
WestRock Panama City Mill: WestRock Corp-Panama City	NG Electricity Generators	1.92	1.92	93
Colquitt County, GA	FCEV	0.00	0.00	95
Russell County, AL	FCEV	0.00	0.00	95
Crenshaw County, AL	FCEV	0.00	0.00	96
McWilliams: PowerSouth Energy Cooperative	NG Electricity Generators	22.64	22.64	97
Walton County, FL	FCEV	0.00	0.00	98
Sumter County, GA	FCEV	0.00	0.00	99
Schley County, GA	FCEV	0.00	0.00	100

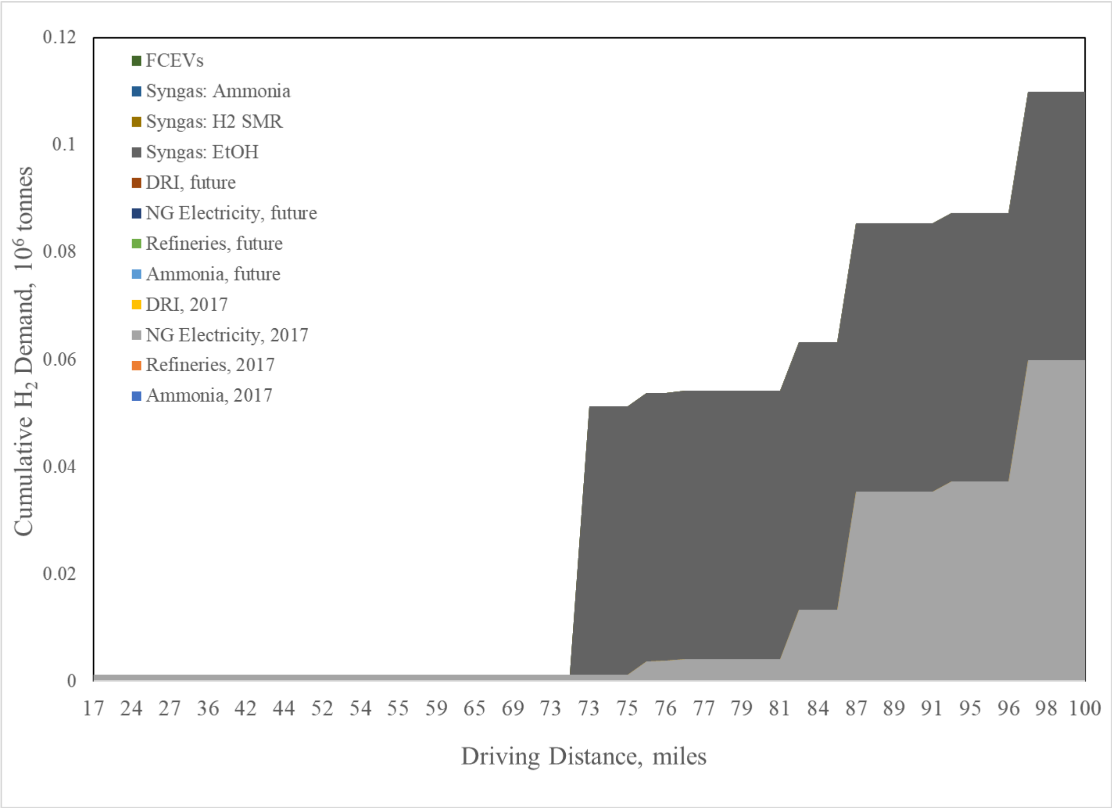

Figure 40. Cumulative potential hydrogen demand by type and distance near the Farley NPP.

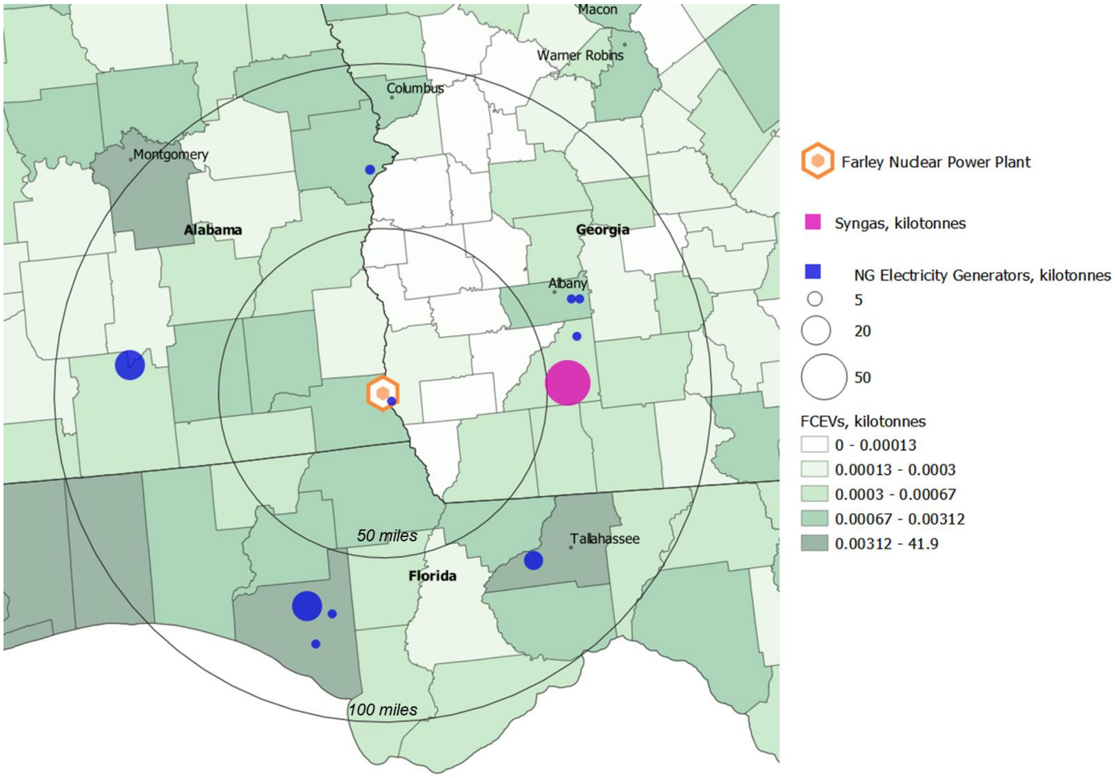

Figure 41. Future potential hydrogen demand near the Farley NPP

3.4.2 Hatch NPP, Vidalia, GA

The total current near-term potential hydrogen demand within 100 miles of the Hatch generating station is 190 MT/day, entirely for co-combustion of hydrogen with NG in 13 NG generators (see Table 14). Two notable potential hydrogen markets associated with co-combustion of hydrogen in NG generators are the Georgia Power's McIntosh generator, at 125 MT/day, and Effingham County Power Project in Effingham, at 35 MT/day, as illustrated in Figure 42.

The additional potential future demand for the Hatch nuclear plant may come from fuel cell vehicles, which adds less than 1 MT/day around Hatch facility (see Figure 43).

Table 14, Hydrogen demand within 100 miles of the Hatch NPP,

Name	Demand Type	Potential H2 Demand, kilotonnes Current (2017)	Future (2030)	Distance, miles
Appling County, GA	FCEV	0.00	0.00	12
Toombs County, GA	FCEV	0.00	0.00	20
Jeff Davis County, GA	FCEV	0.00	0.00	21
Montgomery County, GA	FCEV	0.00	0.00	22
Tattnall County, GA	FCEV	0.00	0.00	25
Bacon County, GA	FCEV	0.00	0.00	30
Evans County, GA	FCEV	0.00	0.00	37
Treutlen County, GA	FCEV	0.00	0.00	39
Wayne County, GA	FCEV	0.00	0.00	42
Candler County, GA	FCEV	0.00	0.00	44
Jesup Plant: Rayonier Advanced Materials	NG Electricity Generators	1.43	1.43	46
Pierce County, GA	FCEV	0.00	0.00	47
Coffee County, GA	FCEV	0.00	0.00	49
Emanuel County, GA	FCEV	0.00	0.00	50
Long County, GA	FCEV	0.00	0.00	51
Ware County, GA	FCEV	0.00	0.00	56
Liberty County, GA	FCEV	0.00	0.00	59
Bulloch County, GA	FCEV	0.00	0.00	59
Laurens County, GA	FCEV	0.00	0.00	61
Dodge County, GA	FCEV	0.00	0.00	63
Johnson County, GA	FCEV	0.00	0.00	64
Brantley County, GA	FCEV	0.00	0.00	64
Ben Hill County, GA	FCEV	0.00	0.00	67
Atkinson County, GA	FCEV	0.00	0.00	67
Bryan County, GA	FCEV	0.00	0.00	69

Jenkins County, GA	FCEV	0.00	0.00	70
Irwin County, GA	FCEV	0.00	0.00	70
Interstate Paper LLC Riceboro: Interstate Paper LLC	NG Electricity Generators	0.20	0.20	72
Wilcox County, GA	FCEV	0.00	0.00	74
Effingham County, GA	FCEV	0.00	0.00	79
Bleckley County, GA	FCEV	0.00	0.00	79
McIntosh County, GA	FCEV	0.00	0.00	80
Brunswick Cellulose: Brunswick Cellulose LLC	NG Electricity Generators	1.10	1.10	81
Pulaski County, GA	FCEV	0.00	0.00	81
Effingham County Power Project: SEPG Operating Services, LLC Effingham	NG Electricity Generators	13.00	13.00	82
Screven County, GA	FCEV	0.00	0.00	82
PInova Inc: PInova Inc	NG Electricity Generators	0.13	0.13	83
Clinch County, GA	FCEV	0.00	0.00	83
Jefferson County, GA	FCEV	0.00	0.00	85
Washington County, GA	FCEV	0.00	0.00	86
Savannah River Mill: Georgia-Pacific Consr Prods LP-Savannah	NG Electricity Generators	0.52	0.52	86
Berrien County, GA	FCEV	0.00	0.00	88
Tift County, GA	FCEV	0.00	0.00	88
International Paper Savanna Mill: International Paper Co	NG Electricity Generators	3.85	3.85	88
Lanier County, GA	FCEV	0.00	0.00	89
Chatham County, GA	FCEV	0.00	0.00	89
Turner County, GA	FCEV	0.00	0.00	90
Imperial Savannah LP: Imperial Savannah LP	NG Electricity Generators	1.38	1.38	90
Wilkinson County, GA	FCEV	0.00	0.00	90
McIntosh Combined Cycle Facility: Georgia Power Co	NG Electricity Generators	46.19	46.19	92
Charlton County, GA	FCEV	0.00	0.00	92
Burke County, GA	FCEV	0.00	0.00	93
McIntosh: Georgia Power Co	NG Electricity Generators	0.48	0.48	93
Port Wentworth Mill: International Paper Port Wentworth Mill	NG Electricity Generators	0.86	0.86	93

Crisp County, GA	FCEV	0.00	0.00	97
Mid-Georgia Cogeneration Facility: SEPG Operating Services, LLC MGC	NG Electricity Generators	0.91	0.91	98
Twiggs County, GA	FCEV	0.00	0.00	98
AL Sandersville LLC: SEPG Operating Services, LLC ALS	NG Electricity Generators	0.01	0.01	99

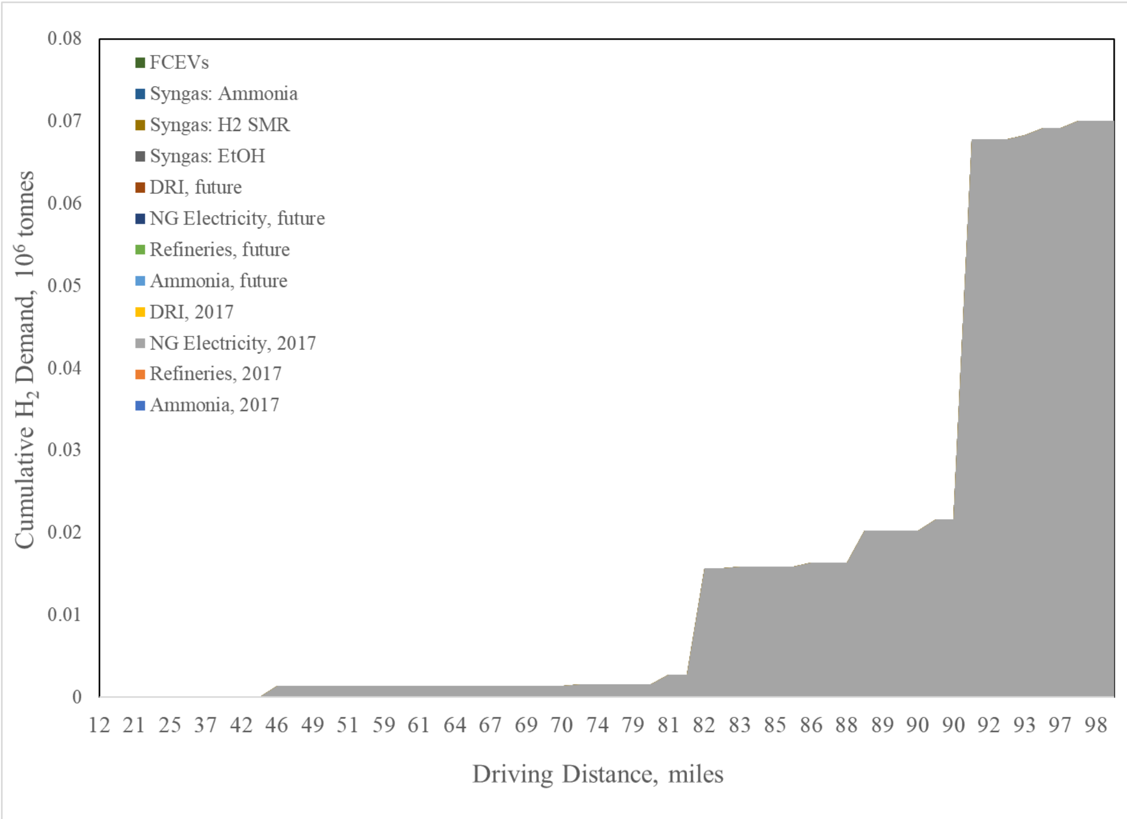

Figure 42. Cumulative potential hydrogen demand by type and distance near the Hatch NPP.

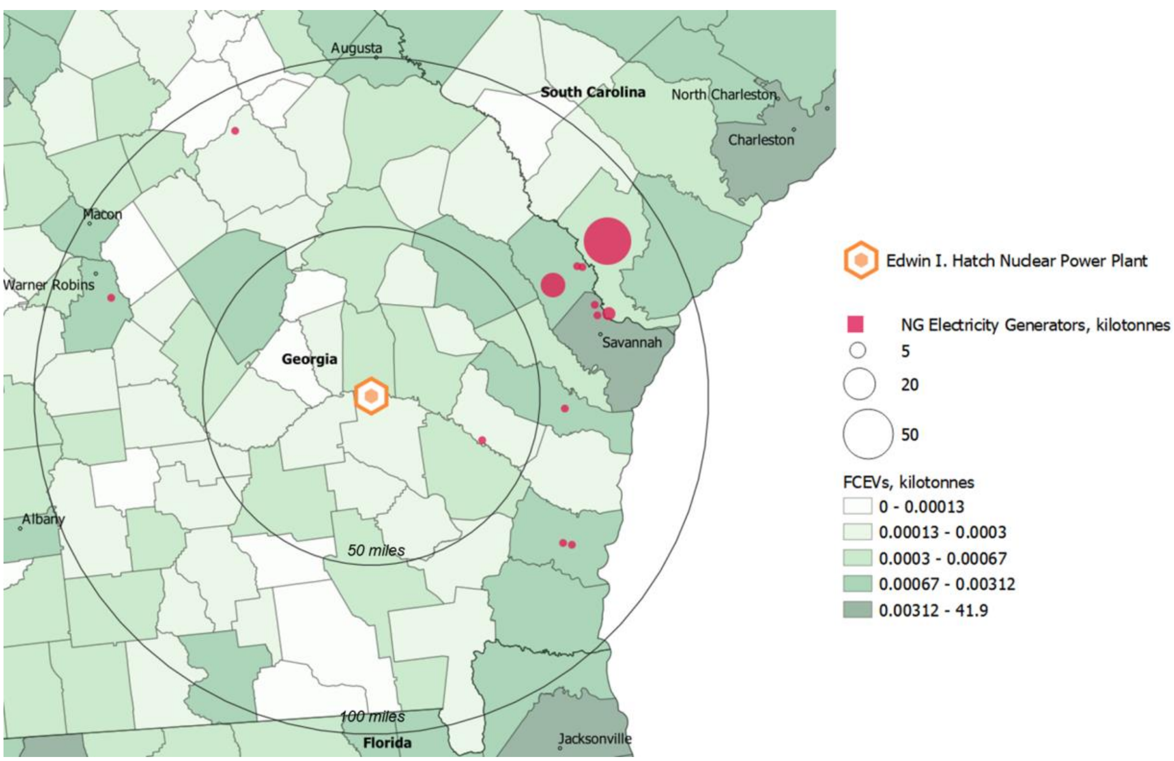

Figure 43. Future potential hydrogen demand near the Hatch NPP.

3.4.3 Vogtle NPP, Augusta, GA

The total near-term potential hydrogen demand within 100 miles of the Vogtle Generating Station is 670 MT/day. Half of this demand is associated with the Nutrien's Augusta facility, producing ammonia within 34 miles, with a potential hydrogen demand of 350 MT/day. Most of the other half—i.e., 320 MT/day—is for co-combustion of hydrogen with NG in 19 gas electricity generators. Of this, 210 MT/day is associated with two NG generators, Georgia Power's McIntosh, and the South Carolina Electric and Gas Company's Jasper, at distances of 78 and 85 miles, respectively, from NPP (see Table 15 and Figure 44).

The most notable increase in future potential hydrogen demand near the Vogtle Generating Station is 380 MT/day for production of synfuels using Nutrien Augusta's by-product CO_2. The total future potential demand around the Vogtle facility is 1000 MT/day. Future demand is represented in Figure 45.

Table 15. Hydrogen Demand within 100 miles of the Vogtle NPP.

Name	Demand Type	Potential H2 Demand, kilotonnes		Distance, miles
		Current (2017)	Future (2030)	
Burke County, GA	FCEV	0.00	0.00	19
International Paper Augusta Mill: International Paper Co-Augusta	NG Electricity Generators	2.17	2.17	24
Richmond County, GA	FCEV	0.00	0.00	33
Nutrien, Augusta	Ammonia	127.00	127.00	35
Jenkins County, GA	FCEV	0.00	0.00	36
Nutrien, Augusta	Syngas: Ammonia CO2	0.00	140.15	36
Screven County, GA	FCEV	0.00	0.00	36
Urquhart: South Carolina Electric&Gas Company	NG Electricity Generators	13.77	13.77	37
Allendale County, SC	FCEV	0.00	0.00	42
Columbia County, GA	FCEV	0.00	0.00	45
Jefferson County, GA	FCEV	0.00	0.00	48
Aiken County, SC	FCEV	0.00	0.00	50
Kamin LLC Wrens Plant: Kamin LLC	NG Electricity Generators	0.02	0.02	52
Barnwell County, SC	FCEV	0.00	0.00	57
Hampton County, SC	FCEV	0.00	0.00	59
Edgefield County, SC	FCEV	0.00	0.00	59
Emanuel County, GA	FCEV	0.00	0.00	61
Bulloch County, GA	FCEV	0.00	0.00	61
Glascock County, GA	FCEV	0.00	0.00	62
McDuffie County, GA	FCEV	0.00	0.00	64
Bamberg County, SC	FCEV	0.00	0.00	66
Candler County, GA	FCEV	0.00	0.00	66
Warren County, GA	FCEV	0.00	0.00	67
Washington County, GA	FCEV	0.00	0.00	68
Lincoln County, GA	FCEV	0.00	0.00	70

Cope: South Carolina Electric&Gas Company	NG Electricity Generators	1.19	1.19	73
McCormick County, SC	FCEV	0.00	0.00	73
Effingham County, GA	FCEV	0.00	0.00	74
Effingham County Power Project: SEPG Operating Services, LLC Effingham	NG Electricity Generators	13.00	13.00	75
Johnson County, GA	FCEV	0.00	0.00	75
Savannah River Mill: Georgia-Pacific Consr Prods LP-Savannah	NG Electricity Generators	0.52	0.52	77
AL Sandersville LLC: SEPG Operating Services, LLC ALS	NG Electricity Generators	0.01	0.01	78
McIntosh Combined Cycle Facility: Georgia Power Co	NG Electricity Generators	46.19	46.19	79
McIntosh: Georgia Power Co	NG Electricity Generators	0.48	0.48	80
Colleton County, SC	FCEV	0.00	0.00	83
Treutlen County, GA	FCEV	0.00	0.00	84
Saluda County, SC	FCEV	0.00	0.00	85
Bull Street Plant: City of Orangeburg - (SC)	NG Electricity Generators	0.00	0.00	85
Jasper: South Carolina Electric&Gas Company	NG Electricity Generators	30.26	30.26	85
Rowesville Rd Plant: City of Orangeburg - (SC)	NG Electricity Generators	0.00	0.00	86
Washington County Power LLC: SEPG Operating Services, LLC WCP	NG Electricity Generators	0.92	0.92	87
Evans County, GA	FCEV	0.00	0.00	87
Wilkes County, GA	FCEV	0.00	0.00	87
Jasper County, SC	FCEV	0.00	0.00	88
Hancock County, GA	FCEV	0.00	0.00	88
Port Wentworth Mill: International Paper Port Wentworth Mill	NG Electricity Generators	0.86	0.86	88
Substation 20 Plant: City of Orangeburg - (SC)	NG Electricity Generators	0.00	0.00	88
Imperial Savannah LP: Imperial Savannah LP	NG Electricity Generators	1.38	1.38	89
Orangeburg County, SC	FCEV	0.00	0.00	89
Taliaferro County, GA	FCEV	0.00	0.00	89
Toombs County, GA	FCEV	0.00	0.00	89
International Paper Savanna Mill: International Paper Co	NG Electricity Generators	3.85	3.85	93
Lexington County, SC	FCEV	0.00	0.00	94

WestRock Southeast, LLC.: SP Fiber Technologies LLC	NG Electricity Generators	0.64	0.64	94
Laurens County, GA	FCEV	0.00	0.00	95
Tattnall County, GA	FCEV	0.00	0.00	95
Chatham County, GA	FCEV	0.00	0.00	96
Greenwood County, SC	FCEV	0.00	0.00	97
Montgomery County, GA	FCEV	0.00	0.00	98
McMeekin: South Carolina Electric&Gas Company	NG Electricity Generators	2.78	2.78	99
Calhoun County, SC	FCEV	0.00	0.00	100

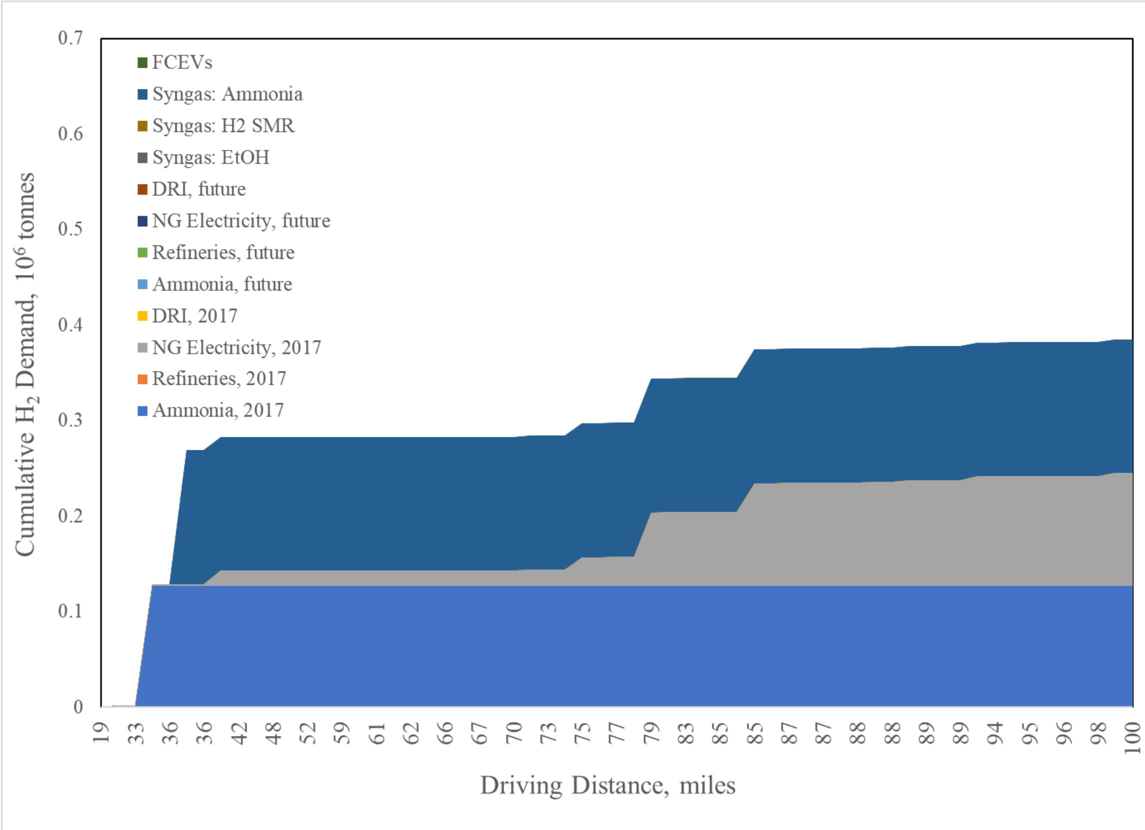

Figure 44. Cumulative potential hydrogen demand by type and distance near Vogtle generating station.

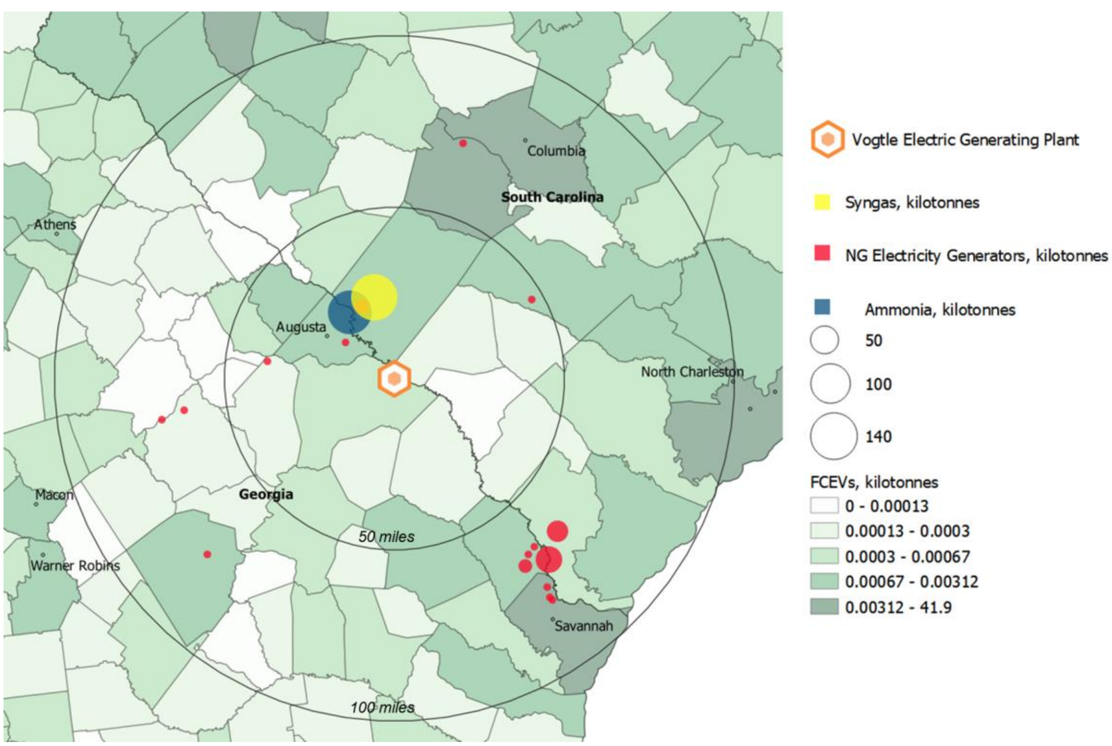

Figure 45. Future potential hydrogen demand near the Vogtle generating station.

3.5 Arizona Region

3.5.1 Palo Verde NPP, Tonopah, AZ

The Arizona Public Service (APS) Company's Palo Verde Nuclear generating station is the largest power plant in the U.S., producing 3.8 GW of electricity (assuming a 93% capacity factor, for roughly 8,200 hours per year). It supplies electricity to densely populated parts of Southern Arizona and Southern California—e.g., Phoenix and Tucson, Arizona, Los Angeles and San Diego, California. Possible non-grid electricity demand sources are discussed below, along with a broad analysis of market and technical challenges.

3.5.1.1 Water desalination

Providing potable water for Arizona's large and growing population, as well as extensive agriculture, is of critical importance to Arizona's economy. Five million of Arizona's roughly 7 million residents live in the Phoenix metropolitan area, which is one of the fastest-growing large cities in the country[96]. As a whole, Arizona used 2.3T gallons of water in 2018 (7.1 acre-feet, a standard measure of water consumption)[97]. Seventy-four percent of this water was designated for agricultural use while 21% was for municipal use, leaving 5% for industrial use, statewide. Roughly 55% of this supply comes from rivers, with another 40% coming from groundwater[98]. Arizona has strict groundwater-use regulations under the Groundwater Management Act of 1980[99]. Should the availability of these resources be impacted, NPP-associated reverse osmosis (RO) purification of briny-water sources (either from aquifers or ocean water) could help fill any potential gaps. Care should be taken when identifying potential briny-water sources to consider the sustainability and long-term future of the water source under conditions of increasing population.

A first-estimate analysis of energy requirements suggests that the Palo Verde plant could provide the desalination electricity to supply more than 95% of Arizona's yearly potable water. Recent analyses estimate that a RO plant with a typical seawater feedstock consumes around 14 Wh/gallon of potable water produced[100]. Improvements in RO membrane and plant technologies could reduce this number further. Applying current technology, the Palo Verde plant could theoretically purify 2.2T gallons of water per year, or more than 95% of the Arizona's total water requirements.

Given the cost of RO processes and the risks of centralized water production, it is unlikely that the state's entire water supply would be derived from a single purification plant. However, a water-purification facility could be considered as part of a comprehensive strategy for the Palo Verde plant wherein a wide variety of products, chemical or otherwise, are produced.

3.5.1.2 Energy Industrial Park

The chemicals and plastics industries do not currently have a significant foothold in Arizona, but the centralized energy offered by the Palo Verde plant could provide an entry point via the energy industrial park model. Palo Verde is less than 1,000 miles from the Permian basin, the site of major oil and NG deposits. Products from this region are generally shipped over 500 miles via pipeline to refineries on the U.S. Gulf Coast but could reasonably be taken in the opposite direction to Arizona at the same cost, given the similar distances. An energy industrial park using NG-derived ethane and propane, plus CO_2, to produce a variety of chemical products (ethylene, propylene, olefin derivatives, FA, hydrogen, syngas, etc.) could theoretically produce massive amounts of material using the energy from Palo Verde. This would represent a new growth industry for Arizona and would likely attract demand in the form of downstream polymer and plastics manufacturers, spurring growth in the region. Thus, a new chemical manufacturing facility in central Arizona could feasibly use advantaged feedstock, in the form of Texas-based NG, and provide polymer and plastics products to large population centers in Phoenix and Southern California. In addition, the Palo Verde plant is conveniently located for product distribution. The facility is located near both the Interstate-10 road corridor for truck shipment and a near-dormant rail line for train shipment. Admittedly, this proposal faces a number of challenges, both technical (e.g., the low TRL of paraffin-deprotonating electrolysis cells) and market (e.g., the lack of current infrastructure or related investment in the region).

3.5.1.3 Hydrogen Demand

This analysis considers Palo Verde's potential opportunities for marketing near zero-carbon hydrogen which it could produce (see Table 16). Figure 46 shows potential cumulative hydrogen demand within 400 miles of the Palo Verde generating stations' facility.

Figure 46 includes both current and future potential hydrogen demand estimates, with the current demand shown below the future demand to facilitate interpretation. Hydrogen demand values are stacked such that the Y-axis is the sum of hydrogen demands for each demand type plus those below it in the legend. Figure 47 illustrates the locations of potential hydrogen demand near the Palo Verde GS facilities. Each facility is marked with a hexagon while large concentric circles show distances of 100, and 400 miles around the facility. Locations of potential hydrogen demand are depicted by colored circles with size reflecting the scale of potential demand.

Current hydrogen demand within 400 miles of the Palo Verde generating station is predominantly for petroleum refining and co-combustion of hydrogen with NG. The cumulative current hydrogen demand within 400 miles of the generating station is approximately 3000 MT/day. About 200 NG electricity generators have a combined potential hydrogen demand of 1600 MT/day for co-combustion with hydrogen. There are roughly 10 refineries that have a combined hydrogen demand of 1450 MT/day, with two of them making up approximately half of that demand. The Tesoro Corporation in Carson, California, and Chevron Corporation in El Segundo, California, each has a current hydrogen demand of approximately 350 MT/day.

The potential hydrogen demand in the future scenario for the Palo Verde Generating Station is about 5800 MT/day (or 2.1 MMT/year) from potential facilities within 400 miles. The majority of the future potential hydrogen demand is from synfuel-producing facilities, refineries, NG electricity generators, and FCEVs in California. The potential synfuels market will have hydrogen demand of up to 2000 MT/day. The 10 refiners will likely increase their hydrogen demand in the future, for a total potential demand of 1830 MT/day. In the future, FCEVs in California are expected to increase rapidly in their demand for H2, to 280 MT/day, with the Los Angeles County contributing the highest potential hydrogen demand of about 120 MT/day (sufficient for ~200,000 FCEVs).

Table 16. Hydrogen demand within 400 miles of the Palo Verde NPP.

Name	Demand Type	Potential H2 Demand, kilotonnes		Distance, miles
		Current (2017)	Future (2030)	
Mesquite Generating Station Block 2: CAMS	NG Electricity Generators	16.47	16.47	6
Mesquite Generating Station Block 1: Salt River Project	NG Electricity Generators	10.83	10.83	6
Arlington Valley Energy Facility: Arlington Valley LLC	NG Electricity Generators	10.88	10.88	6
Red Hawk: Arizona Public Service Co	NG Electricity Generators	24.36	24.36	9
Harquahala Generating Project: New Harquahala Generating Co, LLC	NG Electricity Generators	9.74	9.74	20
Gila River Power Block 4: Salt River Project	NG Electricity Generators	6.49	6.49	44
Gila River Power Block 3: Tucson Electric Power Co	NG Electricity Generators	12.50	12.50	44
Gila River Power Block 1: CXA Sundevil Power I	NG Electricity Generators	0.02	0.02	44
Gila River Power Block 2: CXA Sundevil Power II	NG Electricity Generators	0.14	0.14	44
West Phoenix: Arizona Public Service Co	NG Electricity Generators	17.26	17.26	52
Agua Fria: Salt River Project	NG Electricity Generators	1.81	1.81	54
Maricopa County, AZ	FCEV	-	0.09	60
Arizona State University CHP: NRG Energy Center Phoenix LLC	NG Electricity Generators	0.39	0.39	66
Ocotillo: Arizona Public Service Co	NG Electricity Generators	1.98	1.98	67
Kyrene: Salt River Project	NG Electricity Generators	5.55	5.55	70
Santan: Salt River Project	NG Electricity Generators	21.01	21.01	82
Pinal Energy LLC, Maricopa	Syngas: Ethanol	-	20.00	94
Commercial Metals - Mesa	DRI	0.19	0.67	95
Desert Basin: Salt River Project	NG Electricity Generators	5.64	5.64	104
La Paz County, AZ	FCEV	-	0.00	105
Sundance: Arizona Public Service Co	NG Electricity Generators	3.12	3.12	109
Pinal County, AZ	FCEV	-	0.01	113
Coolidge Generation Station: Coolidge Power LLC	NG Electricity Generators	1.24	1.24	114
Blythe Energy Inc: AltaGas Blythe Operations Inc	NG Electricity Generators	9.44	9.44	117
Yavapai County, AZ	FCEV	-	0.00	136

Saguaro: Arizona Public Service Co	NG Electricity Generators	0.54	0.54	139
North Loop: Tucson Electric Power Co	NG Electricity Generators	0.00	0.00	157
Yuma County, AZ	FCEV	-	0.00	159
Yuma Cogeneration Associates: Falcon Power Operating Company	NG Electricity Generators	0.10	0.10	162
Yucca: Arizona Public Service Co	NG Electricity Generators	2.70	2.70	166
Demoss Petrie: Tucson Electric Power Co	NG Electricity Generators	0.00	0.00	167
University of Arizona - Biosphere 2: University of Arizona - Biosphere 2	NG Electricity Generators	0.00	0.00	168
Cogeneration 2: University of Arizona	NG Electricity Generators	0.35	0.35	169
Pima County, AZ	FCEV	-	0.02	170
Cogeneration 1: University of Arizona	NG Electricity Generators	0.48	0.48	170
H Wilson Sundt Generating Station: Tucson Electric Power Co	NG Electricity Generators	6.32	6.32	176
Gila County, AZ	FCEV	-	0.00	182
Black Mountain Generating Station: UNS Electric, Inc	NG Electricity Generators	0.42	0.42	191
Griffith Energy LLC: Star West Gen Griffith Energy LLC	NG Electricity Generators	10.73	10.73	192
Mohave County, AZ	FCEV	-	0.00	193
Rockwood: Imperial Irrigation District	NG Electricity Generators	0.02	0.02	200
Desert View Power: Desert View Power Inc	NG Electricity Generators	0.03	0.03	205
Spreckels Sugar Company: Spreckels Sugar Company	NG Electricity Generators	0.96	0.96	205
Coachella: Imperial Irrigation District	NG Electricity Generators	0.03	0.03	208
Imperial County, CA	FCEV	-	0.75	208
Novo BioPower Plant: Novo Biopower LLC	NG Electricity Generators	0.00	0.00	214
Graham County, AZ	FCEV	-	0.00	215
Niland Gas Turbine Plant: Imperial Irrigation District	NG Electricity Generators	0.52	0.52	216
Coconino County, AZ	FCEV	-	0.00	217
El Centro: Imperial Irrigation District	NG Electricity Generators	6.42	6.42	217
Municipal Cogen Plant: Palm Springs City of	NG Electricity Generators	0.02	0.02	226
Santa Cruz County, AZ	FCEV	-	0.00	227
Indigo Energy Facility: Diamond Generating Corporation	NG Electricity Generators	0.55	0.55	230
Valencia: UNS Electric, Inc	NG Electricity Generators	0.04	0.04	231

Sentinel Energy Center, LLC: CPV Sentinel LLC	NG Electricity Generators	3.54	3.54	233
Navajo County, AZ	FCEV	-	0.00	243
Apache Station: Arizona Electric Pwr Coop Inc	NG Electricity Generators	1.44	1.44	244
MCAGCC Cogen Plant: DOD USMC Marine Air Ground Combat	NG Electricity Generators	0.74	0.74	244
Cochise County, AZ	FCEV	-	0.00	249
Cholla: Arizona Public Service Co	NG Electricity Generators	0.00	0.00	256
Nevada Solar One: Acciona Solar Power	NG Electricity Generators	0.03	0.03	261
Desert Star Energy Center: Desert Star Energy Center SDG&E	NG Electricity Generators	5.99	5.99	262
Greenlee County, AZ	FCEV	-	0.00	264
Energy Center: University of Redlands	NG Electricity Generators	0.04	0.04	270
Saguaro Power: Saguaro Power Co	NG Electricity Generators	4.88	4.88	272
Clark (NVE): Nevada Power Co	NG Electricity Generators	6.38	6.38	275
Ivanpah 2: NRG Energy Services	NG Electricity Generators	0.30	0.30	275
Mountainview Generating Station: Southern California Edison Co	NG Electricity Generators	23.10	23.10	275
Springs Generating Station: City of Riverside - (CA)	NG Electricity Generators	0.01	0.01	275
Riverside County, CA	FCEV	-	9.99	275
Nevada Cogen Associates 2 Black Mountain: Nevada Cogeneration Assoc # 2	NG Electricity Generators	5.01	5.01	276
Ivanpah 1: NRG Energy Services	NG Electricity Generators	0.31	0.31	276
Amazon San Bernardino: Bloom Energy	NG Electricity Generators	0.04	0.04	276
Loma Linda University Cogen: Loma Linda University	NG Electricity Generators	0.74	0.74	276
Ivanpah 3: NRG Energy Services	NG Electricity Generators	0.30	0.30	278
Higgins Generating Station: Nevada Power Co	NG Electricity Generators	14.25	14.25	279
Inland Empire Energy Center: Inland Empire Energy Ctr LLC	NG Electricity Generators	1.97	1.97	279
Drews Generating Facility: Colton Power LP	NG Electricity Generators	0.02	0.02	281
Century Generating Facility: Colton Power LP	NG Electricity Generators	0.02	0.02	281
Sun Peak Generating Station: Nevada Power Co	NG Electricity Generators	0.19	0.19	282
Clark County, NV	FCEV	-	11.16	283
Agua Mansa Power Plant: E I Colton LLC	NG Electricity Generators	0.09	0.09	283
CityCenter Central Plant Cogen Units: CityCenter Land LLC	NG Electricity Generators	0.47	0.47	284

Nevada Cogen Assoc#1 GarnetVly: Nevada Cogeneration Assoc # 1	NG Electricity Generators	4.65	4.65	286
Cal State Univ San Bernardino FC01: Southern California Edison Co	NG Electricity Generators	0.06	0.06	286
San Bernardino County, CA	FCEV	-	8.90	287
Riverside RWQCP Fuel Cell: Riverside Fuel Cell, LLC	NG Electricity Generators	0.00	0.00	287
Riverside Energy Resource Center: City of Riverside - (CA)	NG Electricity Generators	0.73	0.73	287
Las Vegas Generating Station: Nevada Power Co	NG Electricity Generators	2.21	2.21	290
Etiwanda Generating Station: NRG California South LP	NG Electricity Generators	1.24	1.24	292
Praxair Ontario Ca	Syngas: Hydrogen, SMR	-	9.68	292
Mira Loma Peaker: Southern California Edison Co	NG Electricity Generators	0.18	0.18	292
Parallel Prodts Of California, Rancho Cucamonga	Syngas: Ethanol	-	-	293
Gerdau Long Steel North America - California	DRI	0.50	1.76	293
Grapeland Peaker: Southern California Edison Co	NG Electricity Generators	0.19	0.19	293
New-Indy Ontario Mill: New-Indy Ontario LLC	NG Electricity Generators	2.58	2.58	293
Starbucks - Evolution Fresh: Bloom Energy	NG Electricity Generators	0.04	0.04	294
Kaiser Ontario: Bloom Energy 2009 PPA	NG Electricity Generators	0.01	0.01	294
Corona Energy Partners, Ltd: WCAC Operating Company	NG Electricity Generators	0.68	0.68	295
Clearwater Power Plant: City of Riverside - (CA)	NG Electricity Generators	0.17	0.17	298
San Antonio Regional Hospital: San Antonio Regional Hospital	NG Electricity Generators	0.12	0.12	299
OLS Energy Chino: OLS Energy-Chino	NG Electricity Generators	1.44	1.44	302
Bear Valley Power Plant: Golden State Water Company	NG Electricity Generators	0.01	0.01	309
Chuck Lenzie Generating Station: Nevada Power Co	NG Electricity Generators	33.76	33.76	310
Harry Allen: Nevada Power Co	NG Electricity Generators	17.76	17.76	311
Apex Generating Station: Los Angeles Department of Water and Power	NG Electricity Generators	16.42	16.42	312
Silverhawk: Nevada Power Co	NG Electricity Generators	12.77	12.77	312
Anaheim GT: City of Anaheim - (CA)	NG Electricity Generators	0.55	0.55	312
Orange Grove Peaking Facility: Orange Grove Energy LP	NG Electricity Generators	0.35	0.35	312
Canyon Power Plant: City of Anaheim - (CA)	NG Electricity Generators	1.27	1.27	313
Walnut Creek Energy Park: NRG Walnut Creek LLC	NG Electricity Generators	2.50	2.50	314
Cuyamaca Peak Energy Plant: San Diego Gas and Electric Co	NG Electricity Generators	0.07	0.07	314

El Cajon Energy Center: El Cajon Energy LLC	NG Electricity Generators	0.11	0.11	314
Fullerton Mill CHP: Kimberly-Clark Worldwide Inc	NG Electricity Generators	0.73	0.73	315
CSUF Trigeneration: California State University at Fullerton	NG Electricity Generators	0.26	0.26	316
AT&T Anaheim: Bloom Energy	NG Electricity Generators	0.05	0.05	316
Grossmont Hospital: Sharp Grossmont Hospital	NG Electricity Generators	19.44	19.44	317
UCI Fuel Cell: UCI Fuel Cell, LLC	NG Electricity Generators	0.07	0.07	318
B Braun Medical: B Braun Medical Inc	NG Electricity Generators	0.42	0.42	319
MillerCoors Irwindale Brewery: MillerCoors Irwindale Brewery	NG Electricity Generators	0.11	0.11	320
Orange County, CA	FCEV	-	13.15	320
Apache County, AZ	FCEV	-	0.00	322
UCI Facilities Management Central Plant: University of California Irvine	NG Electricity Generators	0.94	0.94	322
San Diego State University: San Diego State University	NG Electricity Generators	0.50	0.50	322
Barre Peaker: Southern California Edison Co	NG Electricity Generators	0.25	0.25	323
High Desert Power Plant: MRP Generation Holdings, LLC	NG Electricity Generators	12.22	12.22	324
CalPeak Power Enterprise Peaker Plant: Calpeak Operating Services, LLC	NG Electricity Generators	0.10	0.10	324
Goal Line LP: Goal Line LP	NG Electricity Generators	0.15	0.15	324
Escondido Energy Center: Wellhead Energy, LLC	NG Electricity Generators	0.34	0.34	324
Palomar Energy: San Diego Gas and Electric Co	NG Electricity Generators	13.18	13.18	324
Hidalgo County, NM	FCEV	-	0.00	325
Biola University: Biola University	NG Electricity Generators	0.12	0.12	325
Lordsburg Generating: Public Service Co of NM	NG Electricity Generators	0.08	0.08	326
Plant No 1 Orange County: Orange County Sanitation Dist	NG Electricity Generators	0.03	0.03	327
Kearny: NRG Cabrillo Power Ops Inc	NG Electricity Generators	0.08	0.08	327
Wheelabrator Norwalk Energy: Wheelabrator Environmental Systems	NG Electricity Generators	0.31	0.31	328
Hoag Hospital Cogen Plant: Hoag Memorial Presbyterian Hospital	NG Electricity Generators	0.26	0.26	328
Plant No 2 Orange County: Orange County Sanitation Dist	NG Electricity Generators	0.00	0.00	328
Kyocera International Project: Kyocrea International, Ind	NG Electricity Generators	0.01	0.01	328
Childrens Hospital: DTE San Diego COGEN Inc.	NG Electricity Generators	0.30	0.30	328

San Diego County, CA	FCEV	-	13.76	329
Naval Station Energy Facility: Applied Energy Inc	NG Electricity Generators	2.74	2.74	329
Naval Hospital Medical Center: Department of the Navy	NG Electricity Generators	0.31	0.31	329
AES Huntington Beach LLC: AES Huntington Beach LLC	NG Electricity Generators	3.38	3.38	330
C P Kelco San Diego Plant: CPKelco U S Inc	NG Electricity Generators	0.79	0.79	330
Center Peaker: Southern California Edison Co	NG Electricity Generators	0.18	0.18	331
Encina: NRG Cabrillo Power Ops Inc	NG Electricity Generators	4.78	4.78	331
NRG Energy San Diego: NRG Energy Center San Diego LLC	NG Electricity Generators	0.02	0.02	331
Rohr Inc, a UTC Aerospace Systems Company: UTAS Aerostructures	NG Electricity Generators	0.16	0.16	331
California Institute of Technology: California Institute-Technology	NG Electricity Generators	0.82	0.82	332
Caltech Central: Bloom Energy 2009 PPA	NG Electricity Generators	0.04	0.04	332
Alon Israel Oil Company Ltd, Paramount	Refinery	39.64	50.22	332
Haynes: Los Angeles Department of Water and Power	NG Electricity Generators	16.12	16.12	332
AES Alamitos LLC: AES Alamitos LLC	NG Electricity Generators	7.48	7.48	332
Watkins Manufacturing Co.: Watkins Manufacturing Corporation	NG Electricity Generators	0.05	0.05	332
Miramar Energy Facility: San Diego Gas and Electric Co	NG Electricity Generators	0.83	0.83	332
North Island Energy Facility: Applied Energy Inc	NG Electricity Generators	2.21	2.21	332
Kaiser Downey: Bloom Energy 2009 PPA	NG Electricity Generators	0.04	0.04	333
Civic Center: Los Angeles County	NG Electricity Generators	1.35	1.35	333
P Plant: Qualcomm Incorporated	NG Electricity Generators	0.29	0.29	333
NTC/MCRD Energy Facility: Applied Energy Inc	NG Electricity Generators	1.42	1.42	333
Reid Gardner: Nevada Power Co	NG Electricity Generators	0.01	0.01	334
Glenarm: City of Pasadena - (CA)	NG Electricity Generators	0.63	0.63	334
Commerce Refuse To Energy: Los Angeles County Sanitation	NG Electricity Generators	0.08	0.08	334
Q Plant: Qualcomm Incorporated	NG Electricity Generators	0.26	0.26	334
W Plant: Qualcomm Incorporated	NG Electricity Generators	0.26	0.26	334
Chula Vista Energy Center: Wellhead Energy, LLC	NG Electricity Generators	0.04	0.04	334
Larkspur Energy Facility: Diamond Generating Corporation	NG Electricity Generators	0.38	0.38	334
Los Angeles County, CA	FCEV	-	41.91	335

Life Technologies Carlsbad: Bloom Energy	NG Electricity Generators	0.04	0.04	335
UCSD Fuel Cell Plant: BioFuels Point Loma LLC	NG Electricity Generators	0.07	0.07	335
University of California San Diego: University of California San Diego	NG Electricity Generators	1.68	1.68	335
Malburg: Colorado Energy Management LLC	NG Electricity Generators	4.18	4.18	336
H. Gonzales: City of Vernon	NG Electricity Generators	0.02	0.02	336
Carson Cogeneration: Carson Cogeneration Co	NG Electricity Generators	0.03	0.03	336
CalPeak Power Border Peaker Plant: Calpeak Operating Services, LLC	NG Electricity Generators	0.10	0.10	336
Pio Pico Energy Center: Pio Pico Energy Center LLC	NG Electricity Generators	1.26	1.26	336
World Oil Co, South Gate	Refinery	3.99	5.05	337
Otay Mesa Generating Project: Otay Mesa Energy Center LLC	NG Electricity Generators	11.55	11.55	337
Pyramid: Tri-State G and T Assn, Inc	NG Electricity Generators	0.24	0.24	338
Tesoro Corp, Carson	Refinery	126.29	160.00	338
Air Products Carson Hydrogen Plant	Syngas: Hydrogen, SMR	-	101.34	338
Watson Cogeneration: ARCO Products Co-Watson	NG Electricity Generators	22.95	22.95	338
South Bay Fuel Cell Plant: BioFuels Point Loma LLC	NG Electricity Generators	0.02	0.02	338
Richard J Donovan Correctional Facility: California Dept of Corrections	NG Electricity Generators	0.12	0.12	338
Phillips 66 Company, Wilmington	Refinery	65.21	82.62	339
Tesoro Corp, Wilmington	Refinery	44.52	56.40	339
Valero Energy Corp, Wilmington Asphalt Plant	Refinery	2.96	3.74	339
Tesoro Carson Refinery	Syngas: Hydrogen, SMR	-	138.55	339
Grayson: City of Glendale - (CA)	NG Electricity Generators	0.87	0.87	340
Equilon Los Angeles Refining: Tesoro Refining and Marketing Company	NG Electricity Generators	1.48	1.48	340
Valero Energy Corp, Wilmington Refinery	Refinery	39.88	50.52	340
THUMS: THUMS Long Beach Company	NG Electricity Generators	2.77	2.77	340
Verizon-Torrance: Bloom Energy	NG Electricity Generators	0.04	0.04	340
Phillips 66 Los Angeles Refinery - Carson Plant	Syngas: Hydrogen, SMR	-	38.40	341

Air Products Wilmington Hydrogen Plant	Syngas: Hydrogen, SMR	-	88.24	341
Harbor Cogen: Harbor Cogeneration Co.	NG Electricity Generators	0.01	0.01	341
Long Beach Generation LLC: NRG El Segundo Operations Inc	NG Electricity Generators	0.40	0.40	341
Pbf Energy Co LLC, Torrance	Refinery	70.79	89.69	342
Southeast Resource Recovery: SERRF Joint Powers Authority	NG Electricity Generators	0.26	0.26	342
Honda Torrance: Bloom Energy	NG Electricity Generators	0.04	0.04	342
McKinley County, NM	FCEV	-	0.00	343
Lake One: City of Burbank Water and Power	NG Electricity Generators	0.12	0.12	343
Magnolia Power Project: City of Burbank Water and Power	NG Electricity Generators	7.67	7.67	343
Torrance Refining Company LLC	Syngas: Hydrogen, SMR	-	136.21	343
Phillips 66 Los Angeles Refinery - Wilmington Plant	Syngas: Hydrogen, SMR	-	61.46	345
Total Energy Facilities: Los Angeles County Sanitation	NG Electricity Generators	0.07	0.07	345
Los Angeles Refinery Wilmington: Phillips 66 - Los Angeles	NG Electricity Generators	1.12	1.12	345
Harbor: Los Angeles Department of Water and Power	NG Electricity Generators	0.71	0.71	345
AES Redondo Beach LLC: AES Redondo Beach LLC	NG Electricity Generators	4.73	4.73	346
El Segundo Cogen: Chevron USA Inc-El Segundo	NG Electricity Generators	11.79	11.79	347
CBS Studio Center: Crestmark Bank	NG Electricity Generators	0.06	0.06	348
Chevron Products, El Segundo Refinery	Syngas: Hydrogen, SMR	-	64.85	348
Chevron Corp, El Segundo	Refinery	126.20	159.88	348
Saint Johns Health Center: Saint John's Health Center	NG Electricity Generators	0.00	0.00	349
UCLA So Campus Cogen Project: University of California-LA	NG Electricity Generators	2.75	2.75	349
Valley (CA): Los Angeles Department of Water and Power	NG Electricity Generators	8.27	8.27	350
Air Liquid Large Industries Us, Lp	Syngas: Hydrogen, SMR	-	87.68	350
Central Utilities Plant LAX 2: LAX Airport	NG Electricity Generators	0.27	0.27	350
Encina Water Pollution Control: Encina Joint Powers Authority	NG Electricity Generators	0.01	0.01	350
SEGS IV: FPL Energy Operating Services Inc - SEGS	NG Electricity Generators	0.01	0.01	351
SEGS III: FPL Energy Operating Services Inc - SEGS	NG Electricity Generators	0.01	0.01	351
SEGS V: FPL Energy Operating Services Inc - SEGS	NG Electricity Generators	0.11	0.11	351
Hyperion Treatment Plant CHP Plant: Constellation New Energy Inc.	NG Electricity Generators	0.08	0.08	351

SEGS VI: FPL Energy Operating Services Inc - SEGS	NG Electricity Generators	0.10	0.10	352
SEGS VII: FPL Energy Operating Services Inc - SEGS	NG Electricity Generators	0.11	0.11	352
Scattergood: Los Angeles Department of Water and Power	NG Electricity Generators	10.82	10.82	352
El Segundo Energy Center LLC: NRG El Segundo Operations Inc	NG Electricity Generators	8.20	8.20	352
Western Refining Inc., Gallup	Refinery	7.82	9.90	354
Olive View Medical Center: Los Angeles County	NG Electricity Generators	0.24	0.24	355
US Borax: U S Borax Inc	NG Electricity Generators	2.97	2.97	360
CSU Northridge Plant: California State University, Northridge	NG Electricity Generators	0.05	0.05	362
Berry Placerita Cogen: Berry Petroleum Co	NG Electricity Generators	2.80	2.80	363
Nye County, NV	FCEV	-	0.22	364
Catron County, NM	FCEV	-	0.00	370
SEGS IX: FPL Energy Operating Services Inc - SEGS	NG Electricity Generators	0.20	0.20	370
SEGS VIII: FPL Energy Operating Services Inc - SEGS	NG Electricity Generators	0.22	0.22	371
Grant County, NM	FCEV	-	0.00	372
Pitchess Cogen Station: Los Angeles County	NG Electricity Generators	1.34	1.34	372
Escalante: Tri-State G and T Assn, Inc	NG Electricity Generators	0.07	0.07	383
Chino Mines: FreePort-McMoRan-Corp-Chino Mines	NG Electricity Generators	0.01	0.01	384
Luna Energy Facility: Public Service Co of NM	NG Electricity Generators	14.01	14.01	386
Ventura County, CA	FCEV	-	3.52	387
CSUCI Site Authority: CSUCI Site Authority	NG Electricity Generators	1.12	1.12	387
Luna County, NM	FCEV	-	0.00	389
Kane County, UT	FCEV	-	0.00	390
Houweling Nurseries: Houweling's Tomatoes	NG Electricity Generators	0.49	0.49	391
E F Oxnard Energy Facility: EF Oxnard, LLC	NG Electricity Generators	1.11	1.11	395
Oxnard: Procter&Gamble Paper Products Co-Oxnard	NG Electricity Generators	3.72	3.72	395
Oxnard Paper Mill: New-Indy, Oxnard LLC	NG Electricity Generators	1.64	1.64	398
Ormond Beach: NRG California South LP	NG Electricity Generators	2.07	2.07	398
Oxnard Wastewater Treatment Plant: Oxnard City of	NG Electricity Generators	0.01	0.01	398

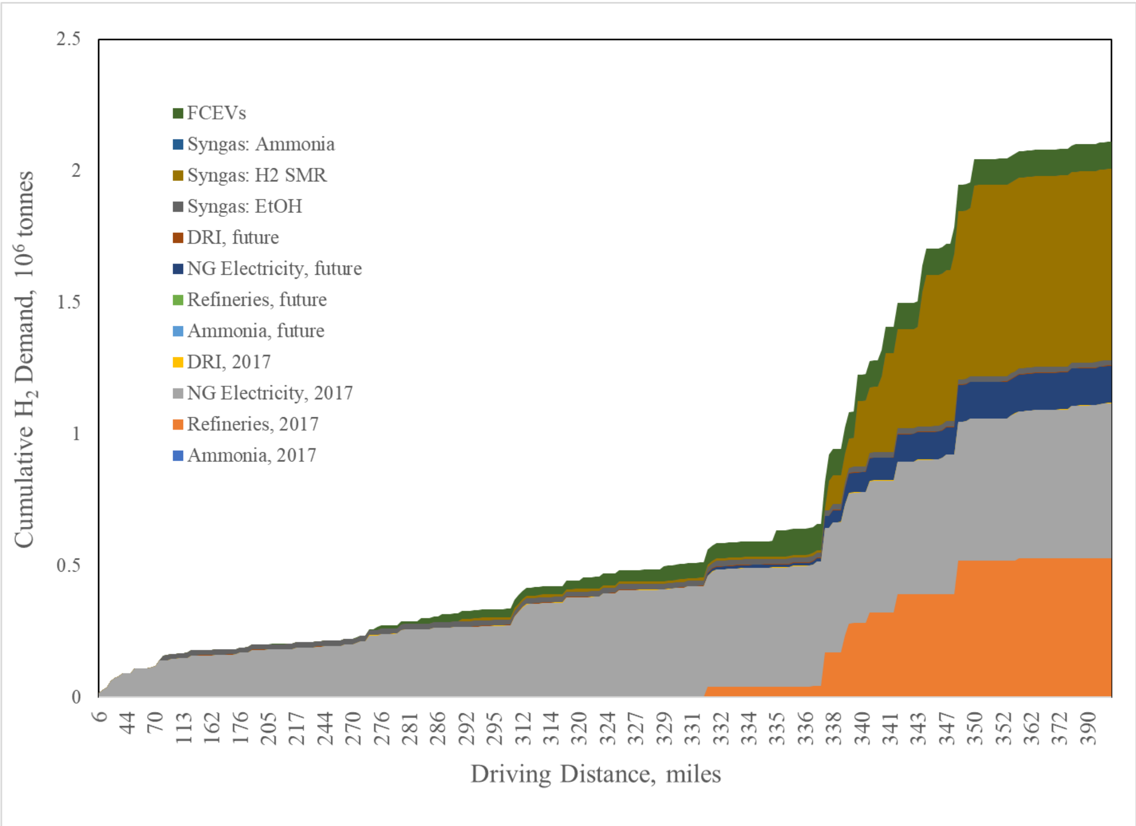

Figure 46. Cumulative potential hydrogen demand by type and distance near the Palo Verde generating station.

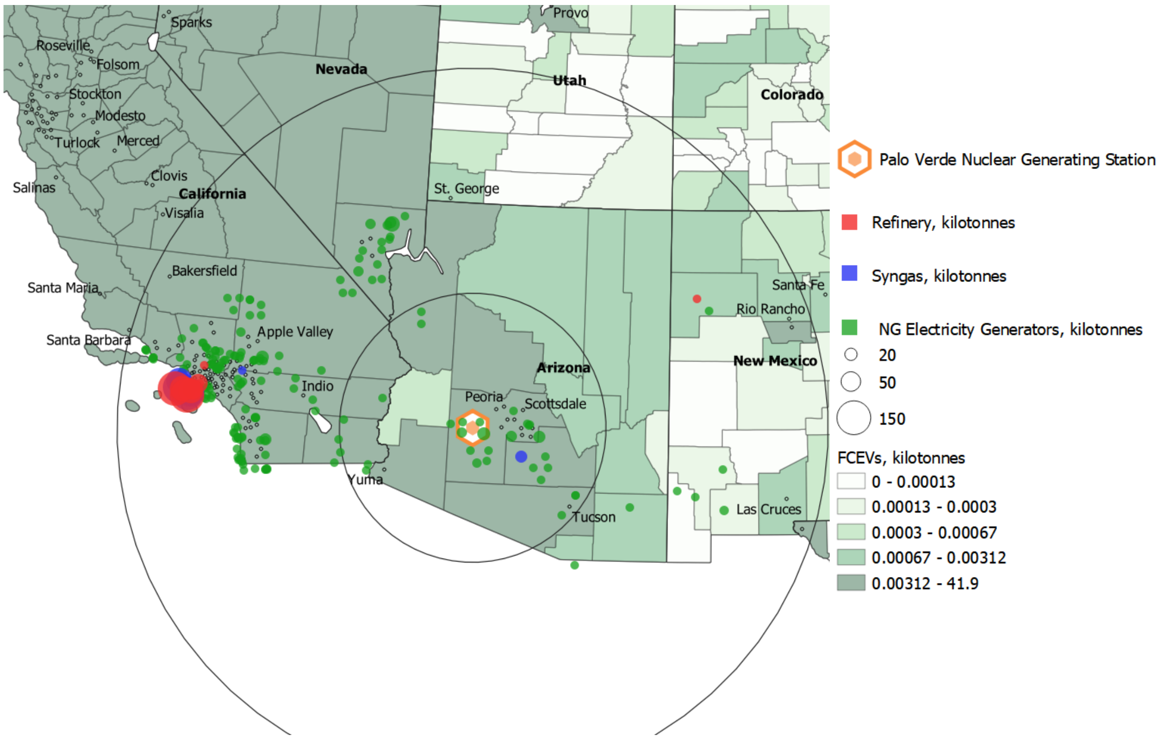

Figure 47. Future potential hydrogen demand near the Palo Verde generating station.

3.6 North / South Carolina Region

This region includes three NPPs, Oconee, Catawba, and McGuire, producing nearly 7 GW of electricity. Within 100 miles, these plants have no ammonia plants, but two plants, requiring ~300 MT/day H_2 fall just outside the 100-mile radius. In addition, there are four steel mills requiring roughly 3,000 MT/day O_2, although only one of these, in Charlotte, North Carolina, is particularly convenient to a nuclear facility. North and South Carolina have regulated retail electricity markets, meaning there is no available capacity market for alternative NPP revenue streams.

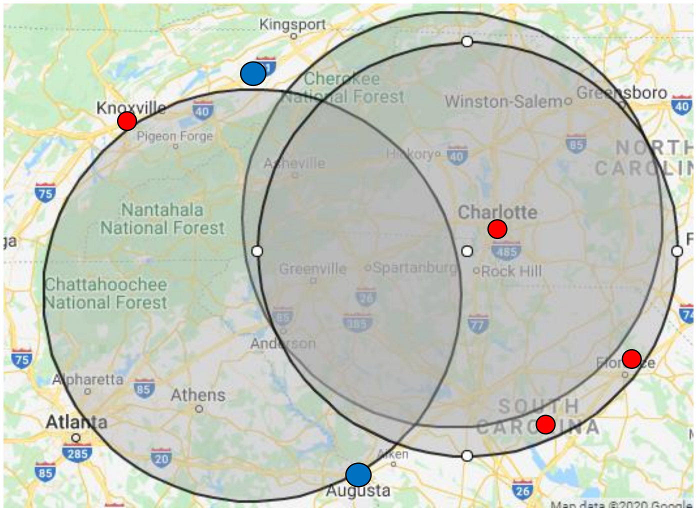

Figure 48. Location of ammonia plants (blue) and steel mills (red) within 100 miles of the NPP facilities in North and South Carolina.

3.7 New York Region

This region includes three NPPs, Ginna, James Fitzpatrick, and Nine Mile Point, totaling 3.1 GW of electricity generation. This region lacks significant point-source demand, with no ammonia plants or oil refineries, and only two steel mills requiring 400 MT/day O_2. NPP-electrolysis facilities in this region would need to cultivate new demand sources or incur significant transportation costs to be economically viable.

In the electricity markets, these facilities are located in the NY-ISO region. Results from recent capacity auctions suggest a typical price of $43/MW-day in the hotter summer months, but only $5/MW-day in the colder winter months, suggesting an average price of $24/MW-day for the year. However, only 3–4 GW appear to be accepted in the capacity market during each auction, casting doubt on whether all 3.1 GW of NPP electricity would be eligible for capacity payments[101].

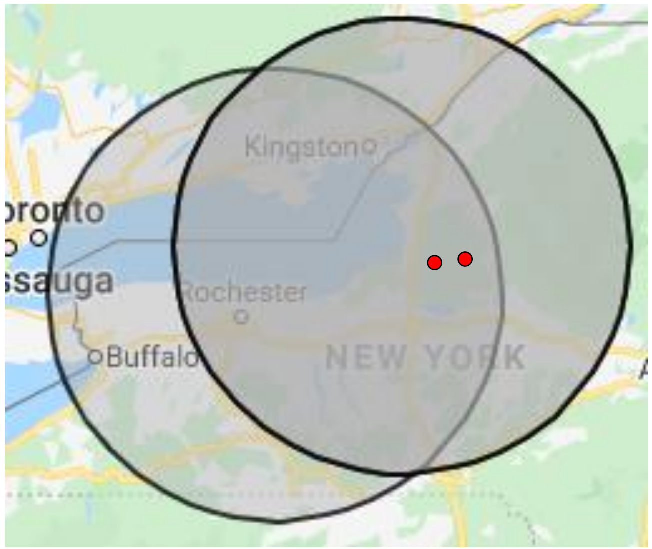

Figure 49. Location of steel mills (red) within 100 miles of the NPP facilities in New York. Large shaded filled circles are drawn to indicate a 100 radius around each NPP.

3.8 Mid-Northeastern Region

This region includes four NPPs (Salem, New Jersey, Limerick and Peach Bottom-East, Pennsylvania, and Calvert Cliffs, Maryland) producing 8.5 GW of electricity (see Figure 50. Location of oil refineries (purple) and steel mills (red) within 100 miles of the NPP facilities in the Mid-Atlantic US.). Although there are no nearby ammonia plants, this region does contain significant hydrogen and oxygen demand point-sources, including:

- Six oil refineries, totaling ~1,000 MT/day H_2
- Seven steel mills, totaling ~5,500 MT/day O_2.

The Philadelphia area contains four oil-refining facilities, generating products for both domestic use and export. These refineries would represent a critical demand source for SOEC plants at the Salem, Limerick, and Peach Bottom NPPs. Additionally, a fraction of the generated oxygen, totaling ~5,500 MT/day, could be sold to local steel mills.

In terms of the electricity markets, these facilities are located within the PJM market. Although the future of capacity markets within PJM is uncertain, previous analyses have used a value of $132/MW-day to project future capacity payments based on prior year results.

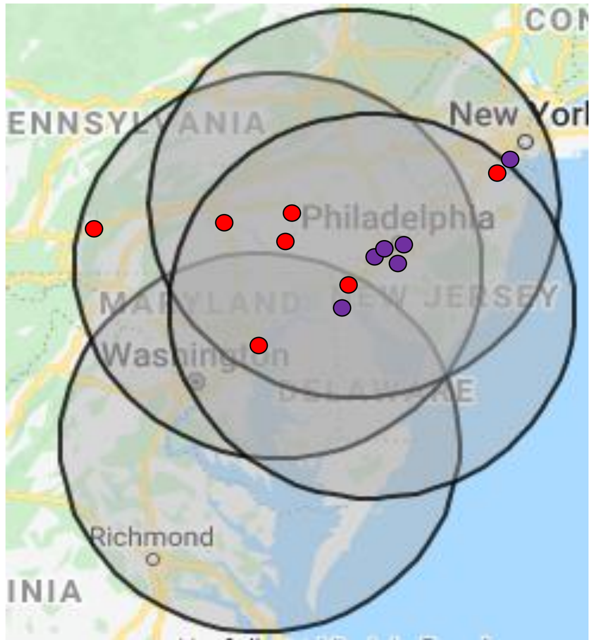

Figure 50. Location of oil refineries (purple) and steel mills (red) within 100 miles of the NPP facilities in the Mid-Atlantic US.

4. GENERALIZED SAMPLE ECONOMIC ANALYSIS OF HYDROGEN PRODUCTION COUPLED WITH NUCLEAR ENERGY IN A REGULATED MARKET

This analysis represents a sample analysis using hydrogen market-demand data presented in this report for the Minnesota region. The purpose of this analysis is not to give an exhaustive analysis into hybrid energy systems evaluation but to provide to U.S. NPP operators an example of how a nonelectric product such as hydrogen can be coupled to form a hybrid nuclear-hydrogen integrated energy system that can access local markets, be a viable positive investment under certain conditions, and be competitive the incumbent production process (SMR, in this example). Such an investment would enable the production of green hydrogen from a low-carbon and low-emissions source that may also have premium marketability in markets where a carbon-credit tax system becomes reality.

HTSE is selected as the method of hydrogen production in this example because it provides the ability to increase the electrical efficiency of the water electrolysis process by close coupling both steam and electricity from the NPP. The hybrid NPP-HTSE plant is setup to provide a constant stream of hydrogen to a hypothetical end user. However, during peak demand, electricity is redirected from the HTSE and sold back to the grid. This essentially allows the NPP-HTSE plant to operate as reserve capacity, similar to a large-scale battery. During this time, previously stored hydrogen is provided to the customer to ensure a constant supply. As a result, a trade-off exists between the 1) stored capacity of hydrogen, 2) size of the HTSE plant, and 3) price of peak electricity. The final product of this study is a parametric evaluation of these different market conditions and component specifications. This will inform potentially interested parties on the key dynamics affecting the economic viabilities of NPP-HTSE hydrogen production.

Main assumptions will first be discussed. These have a large impact on the overall viability of a project and should be reevaluated on a case-by-case basis. Next, an overview of the simplified cost estimates, including capital cost (CAPEX), is provided. The overall benefit and costs to the grid are then estimated for a regulated market using simplified assumptions in lieu of complex grid-level analysis[102] .

The second stage of the analysis considers two hydrogen market conditions: (1) fixed price and (2) dynamic market response. In the first instance, hydrogen price is assumed to be fixed irrespective of the overall demand being serviced. In the second case, competition with an SMR plant is assumed. In this instance, the SMR sets the market price for hydrogen for a given demand size. Finally, sensitivity analyses are provided for potential carbon-tax impacts and variables that are strongly case-dependent.

4.1 Economic-Model Development

This economic analysis relies heavily on the evaluations conducted in INL/EXT-19-55395, *Evaluation of Hydrogen Production Feasibility for a Light Water Reactor in the Midwest* [102]. The approach is simplified for this analysis (i.e., no stochastic optimization is performed). While the previous study focused on a deregulated electricity market, this analysis of the Minnesota region will consider a regulated market. The main differences relate to the selling price of electricity being driven directly by NPP operation and maintenance (O&M) costs, rather than being determined by the market. In addition, a fixed capacity payment is received for operating the plant partially as an electricity reserve (when electricity is redirected from the electrolyzer to the grid).

4.1.1 Key Assumptions

Parameters taken into account in this analysis are grouped as floating variables, which can be optimized (e.g., the size of the HTSE), fixed parameters (e.g., HTSE O&M costs), estimated parameters for which a range is provided (e.g., H_2 demand distance), and key results that are derived as part of the analysis (e.g., H_2 daily production rate, HTSE overcapacity, and HTSE CAPEX). The price of hydrogen, as mentioned, will be: 1) set at a fixed price and 2) estimated based on market-price competition with an SMR plant.

To account for uncertainty and variability in different locations, an estimated range of low, base, and high is considered, with some parameters to quantify their impact, as summarized in Table 17. The analysis first assumes the base values and then the low and high values individually in later sections to assess their impact on overall profitability.

Table 17. Estimated range defined for some specific parameters.

Parameter	Low	Base	High
Weighted average cost of capital	5%	7.5%	10%
Reserve capacity costs ($/kW/year)	$1/kW/year	$5/kW/year	$10/kW/year
Peak electricity payment ($/MWh)	$25/MWh	$50/MWh	$100/MWh
H_2 demand distance (miles)	20	30	40

Fixed parameter specifications are summarized in Table 18, along with a reference source. A standard pressurized water reactor (PWR) is assumed for the analysis. The NPP O&M costs are assumed to be $20/MWh. While this is below the currently reported rates of some NPPs, other NPPs are approaching or already under this cost while others in the industry are setting aggressive short-term cost targets in this range in order to remain competitive. Electricity peaks are assumed to last for around 2.4 hours and to occur at an average every two days. This translates to 2.4 hours of hydrogen storage needed, and a distance between electricity demand peaks (i.e., the time available to replenish the hydrogen storage) of 45.6 hours. HTSE specifications are all based on INL/EXT-19-55395[102]. Note that updates to previously published assumptions, such as capacity replacement costs, were made following an internal review. Capacity replacement costs are based on online values provided by the National Renewable Energy Laboratory (NREL)[103]. The depreciation rate selected is standard for assets with comparable lifetimes to HTSE. The federal corporate tax is the post-2019 rate in the U.S. while the state corporate tax is an approximation based the on markets considered relevant to the study.

Table 18. Specifications selected for the fixed parameters.

NPP O&M costs	$20/MW$_e$h	Internal INL assessment.
H_2 storage time	2.4h	Internal INL assessment
Time to replenish storage	45.6h	Internal INL assessment
NPP power	3411 MW$_{th}$ / 1095 MW$_e$	Westinghouse 4-loop[104]
HTSE efficiency	37.70 kW$_e$h/kg-H_2	INL/EXT-19-55395[102]
Steam/Electricity ratio	17.11%	INL/EXT-19-55395[102]
HTSE capacity factor	92%	Based on NPP Capacity Factor
HTSE O&M costs	$8.88/MW$_e$h	INL/EXT-19-55395[102]
H_2 storage costs	$600/kg-$H_2$	INL/EXT-19-55395[102]
H_2 transportation costs	$996,492/mile	INL/EXT-19-55395[102]

Hot standby electric load	10%	INL/EXT-19-55395[102]
Steam hot standby	100%	INL/EXT-19-55395[102]
HTSE construction time	3 years	Internal INL assessment.
HTSE lifetime	20 years	Internal INL assessment
Alternate O&M costs	$36.4/MWh	NREL[103]
Alternate CAPEX	$898/Kw	NREL[103]
Depreciation rate	MACRS 15-year property class	-
MN state corporate tax	9.8%	-
Federal corporate tax	21%	-

4.1.2 Base Case Development

The size of the hydrogen plant is determined by its electrical energy consumption. Initially, a hypothetical 100 MW_e plant was considered as a base case; later in this report sensitivity studies on the plant size are presented. For the base case, thermal energy of 17 MW_{th} is required in steam supply, which corresponds to a steam/electricity ratio of 0.17.

The rate of hydrogen production depends on the system efficiency. Assuming a value of 37 $kW_eh/kg\text{-}H_2$, a 100 MW_e HTSE plant would produce a maximum theoretical output of 2,652 $kg\text{-}H_2/h$. Assuming that both the HTSE and the NPP have a capacity factor of 92% and that 5% of the hydrogen produced goes to storage (this is equivalent to 2.4 hours of storage capacity dispatched every 48 hours). The daily average output would be 2,318 $kg\text{-}H_2/hour$, corresponding to a total output of around 20 kilotonnes-$H_2/year$. These different values, which are based on the 100 MW_e base case assumption, along with the fixed parameters in Table 18, are summarized in Table 19. Later sections will investigate the interdependence of HTSE size and hydrogen selling price in further detail.

Table 19. Summary of base case values.

HTSE thermal consumption	17 MWth
Storage fraction	5% (corresponds to 2.4h/48h)
Nominal hourly output	2,652 kg-H2/h
Yearly output	20.3 kilotonnes-H2/year
Storage capacity	6,047 kg-H2
Storage feed rate	122 kg-H2/h
Storage capacity	6,047 kg-H2
Assumed H2 selling price	$1.8/kg-H2 (revisited in later sections)

4.1.3 Cost Estimation

4.1.3.1 HTSE capital costs

HTSE plant CAPEX costs are based on INL/EXT-19-55395[102], with some updates, as noted:

- CAPEX are categorized and scaled as either "conventional" or "modular" system components
- Nth-of-a-kind HTSE plant construction is assumed in lieu of first-of-a-kind plant construction
- Revised indirect capital cost factors reflect cost savings associated with modular plant construction.

Conventional components include equipment that scales with plant capacity (i.e., the heat exchangers and piping associated with the nuclear process-heat delivery equipment). Modular components include equipment that is installed in parallel to achieve increased plant capacity (i.e., multiple identical HTSE modules, each having the same equipment specifications and production capacity are operated together to achieve the required hydrogen production). Capital-cost savings for the modular equipment are achieved through economies of mass production while capital-cost savings for conventional equipment are achieved through economies of scale.

The HTSE plant total direct capital cost (DCC) was determined by summing the conventional and modular equipment costs (Equation 1). The equipment in each of these CAPEX categories scales with plant capacity according to a different scaling exponent.

$$DCC = CAPEX_{conventional} + CAPEX_{modular} \qquad \text{Equation 1}$$

Conventional CAPEX Equipment Calculation

The conventional equipment capital cost scaling factor was determined by evaluating the capital costs of each conventional-equipment component (heat exchangers, pumps, pipes, etc.) over a range of equipment sizes (corresponding to different HTSE plant capacities), and curve fitting the resulting total conventional equipment capital cost versus plant-capacity data. Aspen Process Economic Analyzer was used to estimate the equipment capital costs at each of the specified equipment sizes. The conventional equipment cost for a 25 MW_e HTSE unit was estimated at $2.22M and vary with plant capacity according to a scaling exponent of 0.571 (Equation 2). For a 100 MW_e plant, this corresponds to conventional costs of around $5M.

$$CAPEX_{conventional} = \$2.22 \times 10^6 \left(\frac{P_{HTSE}}{25\ MW_e}\right)^{0.571} \qquad \text{Equation 2}$$

Modular CAPEX Equipment Calculation

Modular equipment costs were calculated from several sources, including SOEC-manufacturer cost estimates for specialty components such as the SOEC stacks, and Aspen Process Economic Analyzer cost estimates for modular balance-of-plant equipment such as heat exchangers, pumps, vessels, etc. Modular equipment costs were estimated for an HTSE module with 25 MW_e hydrogen-production capacity, and a learning curve relationship was used to determine modular component costs for both first-of-a-kind (FOAK) as well as Nth-of-a-kind (NOAK) plant construction.

FOAK construction was assumed in the analysis presented in report INL/EXT-19-55395. For FOAK plant construction, the costs of each module are assumed to decrease in accordance with a learning curve, and the total modular-component capital costs are the cumulative sum of the capital costs for each modular unit. For the case of an FOAK plant, the capital costs for the first 25 MW_e module were estimated as \$10.3M. A scaling exponent of 0.936 provides a fit of the cumulative modular equipment costs for the case of a 95% learning curve (Equation 3).

$$CAPEX_{modular,FOAK} = \$10.3 \times 10^6 \left(\frac{P_{HTSE}}{25\ MW_e}\right)^{0.936} \qquad \text{Equation 3}$$

For NOAK plant construction, the modular-component capital costs are assumed to scale linearly with plant capacity because the learning-curve effects are negligible for an NOAK plant (Equation 4)—i.e., the learning curve is flat for a small batch of units positioned far from the origin (a large number of previous HTSE module installations, N) on the curve. The learning rate determines the magnitude of the modular equipment cost reductions for an NOAK plant; in the current analysis, a 95% learning rate was assumed. For the hypothetical plant size of 100 MW_e, modular costs correspond to around \$29M.

$$CAPEX_{modular,NOAK} = \$7.34 \times 10^6 \left(\frac{P_{HTSE}}{25\ MW_e}\right) \qquad \text{Equation 4}$$

The current analysis also utilized indirect cost multipliers modified to reflect the cost savings associated with NOAK modular plant construction. The indirect-cost multipliers were specified as 5% for site preparation (F_{SP}), 2% for engineering and design ($F_{E\&D}$), 10% for project contingency (F_{CNTG}), 3% for contractor's fee (F_{CNTR}), 2% for legal fee (F_{LGL}) and 1.5% for land cost (F_{LAND}). The total depreciable capital costs (TDCC) are obtained by multiplying the DCC by the sum of the indirect depreciable cost multipliers (Equation 5).

$$TDCC = DCC \cdot (1 + F_{SP} + F_{E\&D} + F_{CNTG} + F_{CNTR} + F_{LGL}) \qquad \text{Equation 5}$$

The HTSE total capital investment is the product of the total depreciable capital costs and the non-depreciable capital cost multipliers (Equation 6).

$$TCI = TDCC \cdot (1 + F_{land}) \qquad \text{Equation 6}$$

For a NOAK 100 MW_e capacity HTSE plant, the total capital cost is therefore \$42M, or \$424/kW_e. The construction time is assumed to be 3 years, and the lifetime of the plant is assumed to be 20 years.

4.1.3.2 HTSE operating costs

The HTSE operating costs (OPEX) are expressed as a function of the NPP plus some overhead (labor, maintenance, etc.). In a regulated electricity market, the energy costs are driven directly by the NPP O&M. The assumed \$20/MW_eh is for NPP O&M with an additional \$8.88/MW_eh assumed for the HTSE plant O&M.

4.1.3.3 Hydrogen storage costs

As described previously in this report, hydrogen storage costs are subdivided into two main components: storage vessel and compressor costs. The total stored capacity is expressed as a function of the number of hours during which electricity is diverted from the HTSE to the grid. For 2.4 hours of storage time, a 100 MW_e plant will need to store around 6 T-H_2. Following the costing algorithms previously presented, the vessel costs can be expressed as a function of stored capacity (in kg-H_2) while the compressor costs are expressed as a function of its required power (P_{comp}) in kilowatts:

$$CAPEX_{vessel} = \$600 \times capacity \quad \text{Equation 7}$$

$$CAPEX_{comp} = \$40{,}500 \times \left(P_{comp}\right)^{0.46} \quad \text{Equation 8}$$

The storage and transportation costs are greatly impacted by different system pressures. The strategy identified by Yildiz et al.[105] was employed in this analysis. The electrolysis feedwater was pumped to a pressure of 2 MPa followed by additional compression of the hydrogen product to a pressure of 10 MPa for pipeline transport or 20 MPa for hydrogen storage. The hydrogen delivery pressure (the pressure at which hydrogen customers would receive hydrogen from the pipeline) was assumed to be equal to 3.5 MPa.

Compressor- and pump-equipment sizing were calculated based on correlations[106]. Separate compressors are needed for storage and transportation to pressurize the product hydrogen to the required conditions. The storage compressor pressurizes to a higher pressure than the transportation compressor, so the storage vessel can release into the lower transportation infrastructure without the need for additional compression.

For a 100 MWe HTSE plant with 45.6-hour storage ramp-rate time, the corresponding hydrogen flow rate to the storage tanks is around 0.03 kg-H_2/second. Four compressor stages operating at 85% efficiency are assumed. With these specifications a total storage compressor power of 150 kW is needed. This corresponds to a total compressor cost of around \$400k. With vessel costs of around \$3.6M, the total storage CAPEX equates to \$4.0M for the example base case.

4.1.3.4 Hydrogen transportation costs

Hydrogen transportation costs will depend on the distance between the NPP and the area of consumption. An initial distance of 30 miles is selected for the analysis. The cost correlations previously presented were used to estimate hydrogen compressor and pipeline costs. Compressor costs for transportation were based on their power requirements, similar to what was calculated for hydrogen storage. Pipeline costs are based on pipeline diameter and length. The calculated pipeline diameter was rounded up to the closest nominal diameter in order to calculate pipeline costs. The pipeline cost correlation includes contributions for materials, labor, right-of-way, and miscellaneous costs.

The Equation 9 can be used to calculate the inside diameter of a pipeline for liquid or gas transport[107] [108]:

$$D_i = \left\{\frac{-64Z_{ave}^2R^2T_{ave}^2f_F\dot{m}^2L}{\pi^2\left[MZ_{ave}RT_{ave}\left(p_2^2-p_1^2\right)+2gP_{ave}^2M^2(h_2-h_1)\right]}\right\}^{1/5} \quad \text{Equation 9}$$

where D_i is the internal pipeline diameter (m), Z_{ave} is the average fluid compressibility, R is the universal gas constant (Pa m³/mol K), T_{ave} is the average fluid temperature (K), f_F is the Fanning friction factor, $\dot{m}$ is the design mass flow rate (kg/s), L is the pipeline segment length (m), M is the molecular weight of the stream (kg/kmol), g is acceleration due to gravity (m/s²), p is pressure (Pa), h is pipeline elevation (m), where 1 and 2 represent upstream and downstream locations.

Pressure varies non-linearly in the pipeline and must be calculated using Equation 10[107]:

$$P_{ave} = \frac{2}{3}\left(p_2 + p_1 - \frac{p_2p_1}{p_2+p_1}\right) \quad \text{Equation 10}$$

Zigrang and Sylvester [109] provide an explicit approximation for the Fanning friction factor, presented as Equation 11:

$$\frac{1}{2\sqrt{f_F}} = -2.0\log\left\{\frac{\varepsilon/D_i}{3.7} - \frac{5.02}{Re}\log\left[\frac{\varepsilon/D_i}{3.7} - \frac{5.02}{Re}\log\left(\frac{\varepsilon/D_i}{3.7} + \frac{13}{Re}\right)\right]\right\} \quad \text{Equation 11}$$

where ε is the roughness of the pipe (m), and Re is the Reynolds number (Equation 12):

$$Re = \frac{4\dot{m}}{\mu \pi D_i} \qquad \text{Equation 12}$$

where µ is the viscosity of the fluid (Pa s).

The Fanning friction factor is a function of the pipeline diameter and the Reynolds number and does not have a direct analytical solution. The Fanning friction factor must therefore be iteratively solved along with the pipeline diameter and Reynolds number.

The diameter of the pipeline used to transport the fluid is highly dependent on the fluid-transport conditions (temperature and pressure) and the resulting fluid properties. In this analysis, REFPROP v9.1 was used to calculate temperature- and pressure-dependent fluid properties.

Using the strategy of Yildiz et al.[105], the 2 MPa hydrogen product stream from the HTSE must be raised to 10 MPa before injecting into the pipeline where the receiving end has a pressure of 3.5 MPa. For the selected example case, this corresponds to a pipeline diameter of 4 in. Assuming a single pipeline supplying customers along a 30-mile distance, the corresponding piping costs are broken down as follows:

- Material costs: \$2.7M
- Labor costs: \$6.3M
- Right of way costs: \$5.4M
- Miscellaneous costs: \$5.9M
- Total piping costs: \$20.4M.

This corresponds to piping costs of around \$681 k/mile. The compressor costs can then be estimated following a similar approach conducted for storage compression. For a 100 MWe HTSE plant, the hydrogen-product output flowrate to the pipeline distribution system is approximately 0.7 kg-H_2/sec. One compressor train with three stages, each operating at a compression ratio of 1.7 and 85% efficiency, are assumed. Using these specifications, the pipeline inlet-compressor power requirement is equal to 1.9 MW_e and the compressor capital costs are estimated as \$1.3M.

Therefore, for a 100 MW_e HTSE plant supplying users on a single pipeline 30 miles from the NPP-HTSE plant, the total transportation costs are \$21.7M. It is expected that the resulting demand for the HTSE hydrogen would stem from more than one customer scattered around a 30-mile radius. Therefore, a sensitivity study on the piping length is considered at a later stage of the analysis.

4.2 Economic Analysis Results

4.2.1 Single Fixed Hydrogen Price

With all the different hydrogen-related cost and revenue streams accounted for, a cash-flow analysis can be conducted to provide a first-order estimate of plant viability. Hydrogen sale prices can depend on a wide range of factors. As previously stated, two alternative approaches will be used to estimate price ranges in later sections. To illustrate the calculation methodology, an assumed fixed price of \$1.8/kg-H_2 is assumed at this stage. With hydrogen production over 20 kT-H_2/year, this corresponds to a revenue of \$36M/year. Equation 13

Assuming the MACRS 15-year property class for the depreciation schedule, the free cash flow to the firm (FCFF) can be computed by:

$$FCFF = (Revenue - O\&M - Depreciation) \times (1 - tax) + Depreciation - CAPEX \qquad \text{Equation 13}$$

where the tax rates of 9.8% and 21.0% are used for the state and federal level, respectively. Using a weighted average cost of capital (WACC) of 10%, the net present value (NPV) can be computed by:

$$NPV = \sum_{y=1}^{N} \frac{FCFF}{(1+WACC)^y} \quad \text{Equation 14}$$

This results in an NPV of around $10M for the considered inputs in this section. It does not include indirect revenues or costs that are grid dependent. These will be considered in the following two subsections. The profitability index (PI) can be also computed as the ratio of cumulative weighted FCFF to the total capital expenditure. A PI value of 117% is obtained at this stage.

4.2.1.1 Grid costs and benefits considerations in a regulated market

An additional aspect to consider is the overall cost and benefit to the grid by operating the LWR-HTSE hybrid plant such that it could supply electricity to the grid-electricity market as reserve capacity when needed in lieu of producing hydrogen. Hypothetically, there could be two key components to this:

1. Reserve capacity—electricity can be diverted from the HTSE to the grid during periods of high electricity demand. In essence, the original baseload capacity is converted to a reserve capacity. Currently, reserve capacities are more valuable to a grid with high penetration of variable energy sources (such as renewables). The NPP-HTSE plant may be able to receive a yearly capacity payment as a result of this conversion and create revenue from electricity sales during these demand peaks.
2. Lost capacity for hot standby operation— current HTSE designs require the HTSE to remain in hot standby when not being used in order to avoid very long startup times. The steam and electricity required for hot standby operation cannot be diverted to the grid during high grid demand. This lost capacity would need to be replaced on the grid by an alternative source of dispatchable electricity (typically a combine gas turbine). To maintain similar costs to the grid, the local regulator may require the NPP-HTSE plant to cover the cost of the allocated CAPEX of such alternative facility and the difference in OPEX costs between it and the original NPP O&M.

Assuming that both of these components must be accounted for, the hot standby capacity of the HTSE must be computed. It is assumed that the HTSE requires 100% of its nominal heat intake and around 10% of its electrical consumption when in hot standby in order to maintain minimal operations and temperatures. This results in a 90 MW_e reserve capacity that can be fed back to the grid (Component 1), and 15.5 MW_e in lost capacity that will need to be replaced with another source (Component 2). The gain from operating the reactor partially as a reserve is assumed to be $5/kW/year in terms of capacity, and $50/MWh in electricity sales. Assuming the HTSE will dispatch to the grid during 182 peaks of 2.4 hours each (corresponds to 5% overproduction), this provides an additional revenue of around $2.4M/year.

If the cost of replacing the 15.5 MW_e is considered lost capacity by the grid regulator, then this would incur a cost to the system. The standard capacity cost for an equivalent dispatchable source is taken as $898/kW, which corresponds to a combined-cycle gas turbine, and the typical O&M costs such a power source is $36/MWh[103]. This results in a total CAPEX cost of around $14M, and a yearly O&M costs of around $2M/year. Note that the original NPP O&M costs are subtracted to obtain this number in order to maintain a similar cost to the grid in a regulated market. Future technological improvements that might limit the hot stand-by requirements could therefore contribute to important cost savings in the overall systems. For instance, if hot standby required 100% of steam input (difficult to vary), but only 5% of the electricity input, the CAPEX penalty and the yearly O&M costs would be reduced by 32%.

Accounting for all these effects together (with the assumed 10% electricity diversion during hot standby), the NPV of the NPP-HTSE cogeneration plant would still be positive, at around $786k, making it an attractive proposal. The overall profitability index is 101%. Following a few iterations, it can also be determined that the average price of H_2 sales must be at or above $1.795/kg-$H_2$ to ensure a positive NPV under the assumed conditions.

4.2.2 Hydrogen Contract Price at Five Fixed Price Tiers

Hydrogen prices strongly impact the profitability of hydrogen production at the NPP. The long-term selling price will be negotiated with different buyers at a contract competitive market rate. The price will likely be locked down for the duration of the contract; hence, no time variability in selling prices is assumed in the analysis. Using the economic model developed, a parametric evaluation of hydrogen price and other metrics was performed to estimate their impact on overall plant profitability. Figure 51 plots the NPV as a function of HTSE size for different prices of hydrogen. The analysis assumes a fixed contract price of hydrogen set with the buyer. In reality, there will likely be a market response for the introduction of large quantities of hydrogen in the market. This first-order estimate is still a useful approach for elucidating the impact of the key variables of plant size and hydrogen price on the economics of hydrogen production via the NPP-HTSE plant.

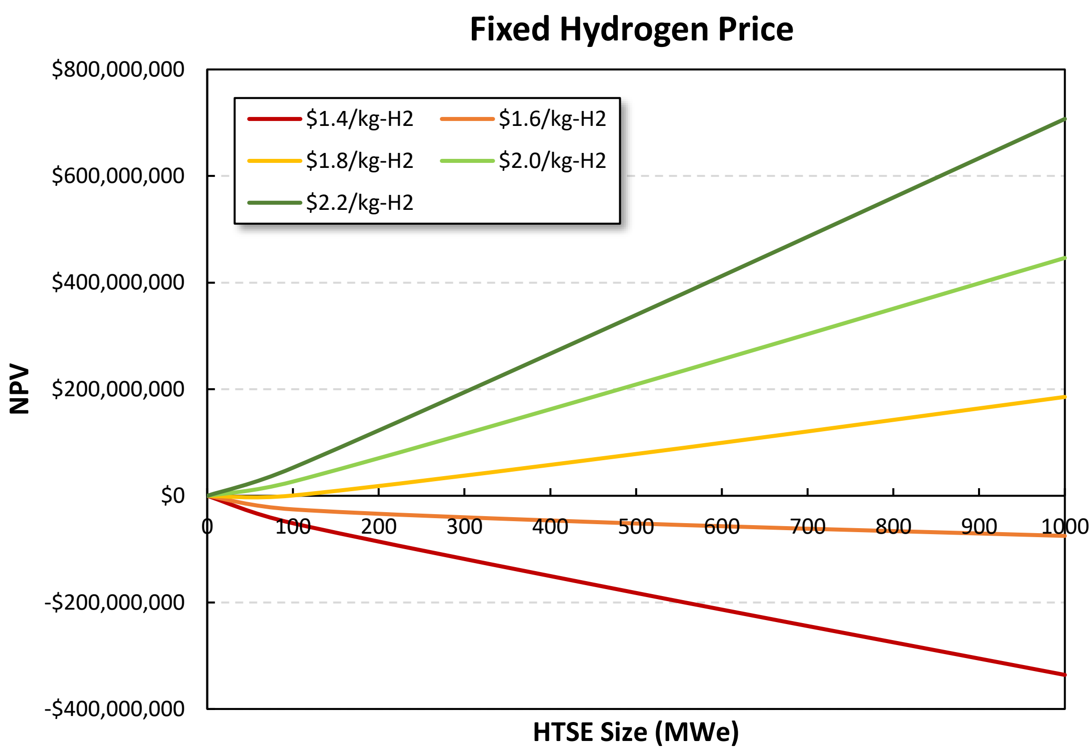

Figure 51. Impact of fixed hydrogen prices on the overall profitability of the system.

It is important to emphasize that all assumed parameters are held constant in this analysis (e.g., transportation distance, storage time, peak electricity payments). However, some level of feedback between these variables is likely in an actual deployment scenario. A complex grid-level simulation[102], is needed to reach that level of fidelity. Nevertheless, Figure 51 provides a useful first order estimate for possibly viable sizes of NPP-HTSE hydrogen production with sample assumptions.

Under fixed hydrogen contract price conditions, profitability curves vary in a near-linear relation with HTSE size. As such, for price points that start out with a negative NPV (e.g., \$1.6/kg-H_2), the losses are only exacerbated if the plant size is increased. However, at price points which start with a positive value (e.g., \$1.8/kg-H_2) gains are compounded. Per this analysis and assumptions, to ensure a positive NPV under the assumed market conditions, the hydrogen contract sale price must be above \$1.795/kg-H_2. A different type of behavior is observed under market response conditions, as will be discussed.

Overall, assuming fixed hydrogen prices, it appears to be favorable to maximize the HTSE size under any positive NPV condition. However, this is not fully grounded in reality as it ignores potential competition. It is unlikely that the selling price of hydrogen for 100 MW_e HTSE plant producing 20 kT-H_2/year will be the same as a 500 MW_e plant generating ~100 kT-H_2/year. The main objective here is to illustrate the general trends available to operators considering hydrogen production at a given NPP.

4.2.3 Dynamic Hydrogen Price Market Response

The incumbent competitor to an NPP-HTSE hydrogen plant is NG SMR. As a result, the highest hydrogen price as a function of demand size will be determined by the economies of scale that an SMR plant can achieve. It should be noted, however, that the economics of NG plants are very different to those of an NPP-HTSE. While fuel costs are low for an NPP, they are the main contributor for an NG plant. While NG prices are currently very low, they have historically seen much variability. As a result, three conditions are considered in this subsection: (1) a medium gas price (similar to current market rates), (2) a low price, assuming gas prices drop further, and (3) a high NG price. Figure 52 plots the price of hydrogen as a function of demand for each of these three NG price conditions (as dictated by the cost of hydrogen production via SMR).

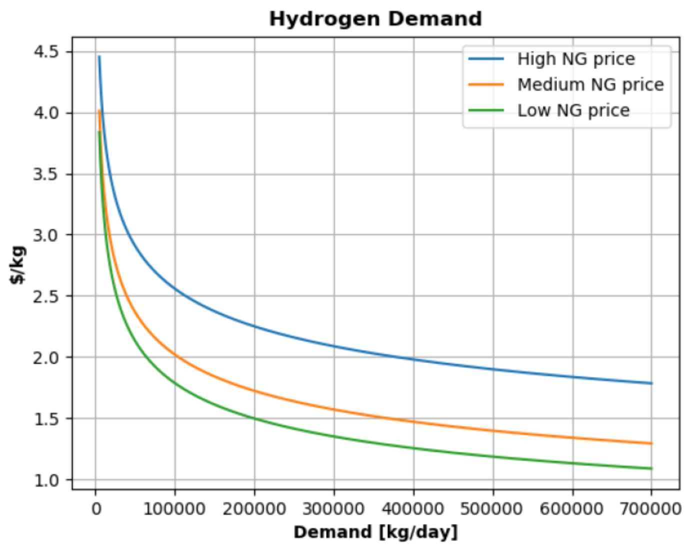

Figure 52. Price of hydrogen as a function of demand for low, medium, and high NG price assumptions (as dictated by the cost of hydrogen production via SMR)[102]..

Correlations from Figure 52 were plugged into the base-case model developed and previously described to express the hydrogen price as a function of the total supply quantity from the HTSE plant. This approach essentially assumes that, for a given size of the hydrogen market, the HTSE will have to compete with a new SMR plant of similar size. It does not account for the capability of an existing SMR plant to increase production, or for the ability of an SMR plant to service both the considered market alongside additional ones nearby. As a result, with the hydrogen price-to-demand correlations, the model accounts for feedback of increasing the HTSE size to supply larger demand. Figure 53 illustrates the NPV versus HTSE size when the hydrogen price-to-demand correlations are taken into account for the three selected NG prices.

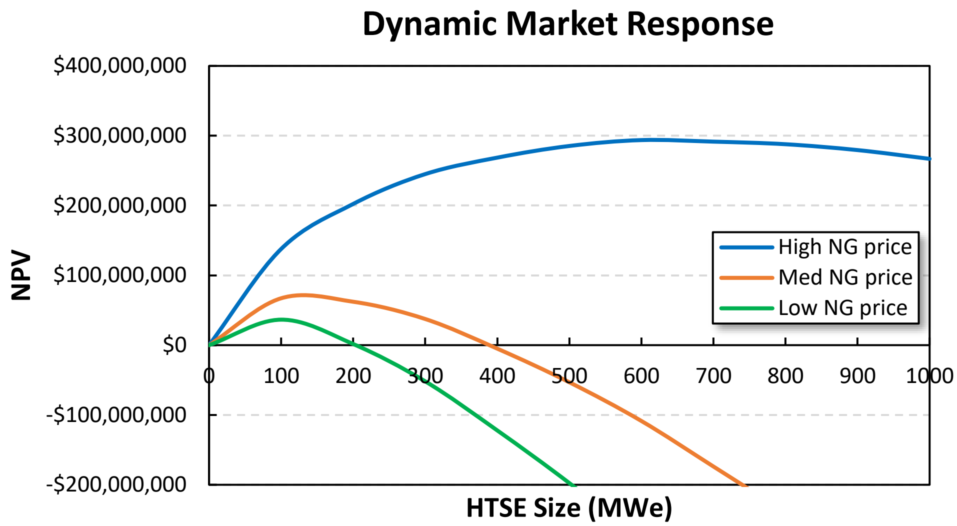

Figure 53. NPP-HTSE plant NPV as a function of HTSE size, assuming a dynamic hydrogen-market-price response, based on competition with SMR using NG. Three price points for NG are considered for comparison.

The NPV versus HTSE size is no longer the linear behavior observed in Figure 51. As market size increases, SMR plants reach economies of scale faster than the modular HTSE plants; they therefore drive down market prices for hydrogen. On the other hand, HTSE plants are very economical in smaller markets where SMR plants are less cost efficient. As a result, the NPV values for a given NG price tends to peak at a certain market size, and these two competing effects balance each other. It is also observed that in some cases (med/low), a threshold exists beyond which the HTSE may not be economically attractive proposition. Table 20**Error! Reference source not found.** summarizes these different points for each NG price considered.

Table 20. HTSE size at which peak NPV is reached (optimal) and the largest HTSE size (maximum) with a positive NPV.

	Optimal HTSE Size	Maximum HTSE Size
Low NG Price	50-150 MW_e	~200 MW_e
Medium NG Price	100-200 MW_e	~400 MW_e
High NG Price	600-700 MW_e	> 1,000 MW_e

The reported values show the range at which HTSE can compete with SMR. Under current market conditions for NG (medium price), the optimal plant size for an HTSE is approximately 100–200 MW_e, and may be competitive up to 400 MW_e. The prospects of NPP-HTSE hydrogen-production plant appear promising under the assumptions mentioned and will likely become more attractive in the future as HTSE technology improves and NPPs continue to bring their operating costs down. Again, it is important to keep in mind that these analyses, assumptions, and technologies are forward looking, preliminary estimations that are subject to change as models, technology, and assumptions improve. Large-scale HTSE demonstrations are still in the planning stages. When commissioned, they will provide much more valuable information. These analyses are not meant to be definitive, but to provide order-of-magnitude estimations of profitability to guide future research and development to catalyze change and improvement.

4.2.4 Sensitivity Analyses

4.2.4.1 Impact of estimated variable ranges

This section illustrates some of the possible order-of-magnitude sensitivities of the overall plant profitability to the estimated parameters listed in Table 17. An assumed low/high end for each of these parameters was proposed. Starting from the base case of a 100 MW_e plant with a \$1.8/kg-H_2 selling price, the resulting changes in NPV can be compared when one of these parameters is varied at a time while the others are held at their base-case settings. With the base conditions, a final NPV of \$786k was computed. The new NPV under each condition is illustrated in Figure 54. Varying the WACC has the most impact of all the parameters modeled.

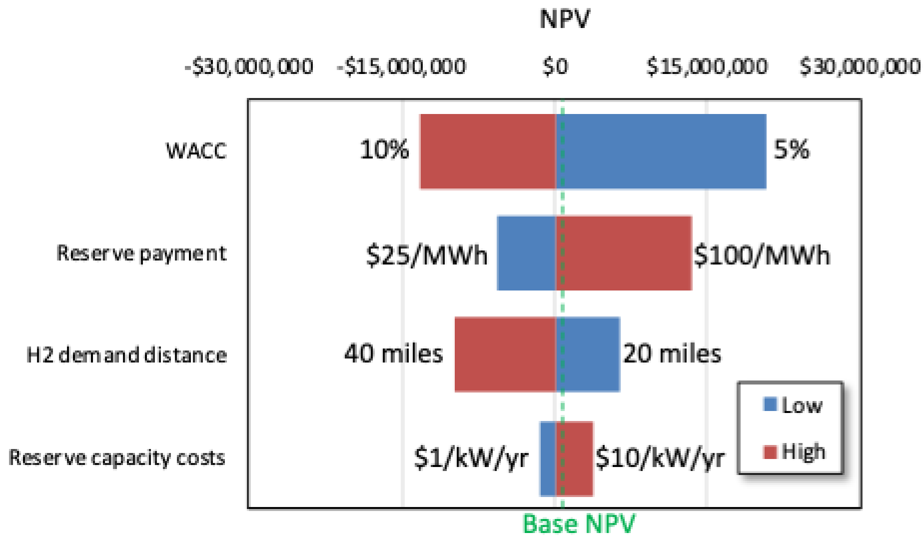

Figure 54. Sensitivity tornado chart of various low/high estimates for the different variables previously considered.

The final values are summarized in Table 21, along with a sensitivity coefficient to help estimate the NPV for variable values other than those considered. A linear approximation was found to be suitable in most cases. For instance, if the demand is at distance of 50 miles, the resulting NPV would be:

$$\text{NPV}(50\text{ mile}) = \alpha_{distance} \times (50 - 30) + \text{NPV}(30) = -802{,}851 \times (20) + 785{,}597 \ = -\$15M$$

To verify the linear approximation, the 50-mile distance was manually input into the model and was found to agree within 7.6%. The same analysis could be repeated for different variables, including fixed ones (e.g., NPP O&M costs, storage time, etc.).

Table 21. NPV for the low and high estimates for the different variables previously considered.

	Low	High	Sensitivity Coeff.
Weighted average cost of capital	\$20.7M	-\$13.1M	-\$677M/WACC
Reserve capacity costs	-\$1.5M	\$3.7M	\$0.58M/(kW/year)
Peak electricity payment	-\$5.5M	\$13.4M	\$0.25M/(MWh)
H_2 demand distance	\$6.3M	-\$9.7M	-\$0.8M/mile

Figure 54 highlights how the NPV is more sensitive to certain parameter than others. A decrease in the WACC of just 2.5 percentage points, can lead to a jump in NPV of over 2,500%. It has an important compounding effect over the 20-year lifetime assumed for the HTSE. Conversely, reserve-capacity payments have a lower impact on the overall NPV due to their small contribution to the revenue for the given market conditions. The distance and peak electrical payments have a larger impact on the NPV, albeit lower than the WACC.

It should be noted that these estimates are simplistic in an attempt to be more generally applicable. Ideally, a case-by-case analysis should be conducted because regional variations can be substantial. This would allow parameters to be more-explicitly considered. For instance, future studies could use a more-accurate framework to account for the interdependence of H_2 demand and transportation costs. This could be done by considering the location of multiple sources of demand and their relative proximity to one another. A variable function of pipeline costs versus the hydrogen demand could then be constructed. Additionally, it may be useful to consider alternative transportation options, such as truck delivery. This could be in liquid- or gaseous-hydrogen form. A cost-benefit analysis would need to be conducted in more detail. This could be especially relevant if the demand for hydrogen proves too diverse (e.g., in the case of future FCEV-refilling stations).

4.2.4.2 Impact of carbon tax

The current and future price of hydrogen is tied to the NG industry, specifically the availability of NG in the U.S. market and the possible future implementation of a carbon tax or credit system. While the impact of the price of NG was considered previously, this section will investigate the implementation of carbon taxes. In theory, this could be both in the form of a traditional tax, or as a function of the cost of carbon sequestration. A low value of \$25/T-CO_2 corresponds to the 2025 anticipated rate in the region considered[110]. Some studies even envision prices as high as \$100/T-CO_2 to reach deep decarbonization[111]. This will be selected as the high value.

The next step is to translate this tax to an increase in the market price for hydrogen (based on SMR production). Using estimates from NREL/TP-570-27637, the life-cycle emissions from an SMR plant can be calculated at around 8.9 kg-CO_2/kg-H_2[112]. For the low and high carbon-tax rates, this corresponds to an added \$0.22/kg-H_2 and \$0.89/kg-H2 respectively.

Taking the medium price of NG from the previous section, new plots can be generated to estimate the new ranges of competitiveness of HTSE plants if carbon taxes are applied. Figure 55 plots the variation if no carbon tax is applied, the low-carbon tax is applied, and the high carbon tax is applied. Note that the ‘no tax’ curve corresponds to the same one from Figure 53.

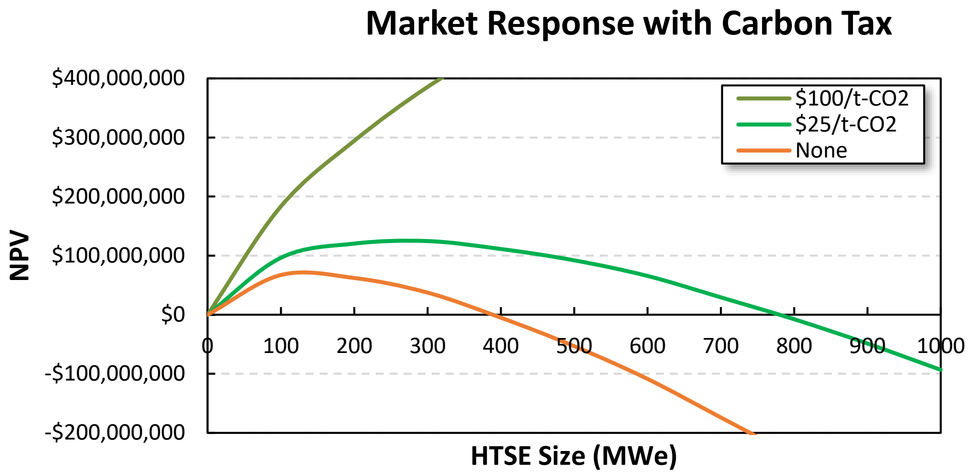

Figure 55. Impact of carbon tax on NPP-HTSE plant NPV curve as a function of HTSE size. Assumes a dynamic market response based on competition with an NG-powered SMR (at medium NG price).

The new dynamic that emerges greatly expands the profitability and the range of viable HTSE plant sizes. With \$25/T-CO_2, the HTSE NPV remains positive up to 800 MW_e. For the high carbon-tax rate, the range is above 1,000 MW_e although it should be noted that other alternative forms of hydrogen production might also become competitive under a high carbon-tax scenario. This would alter the hydrogen price curve as a function of demand. Nevertheless, this analysis still illustrates the competitiveness of an NPP-coupled HTSE for "green" hydrogen market.

Table 22 summarizes the different metrics for the two carbon tax scenarios. The range of viability of the HTSE plant greatly increases under these conditions. The case with low NG price and a low carbon tax corresponds roughly to the case with medium gas prices and no carbon tax, thereby doubling the viability range for the HTSE size. Similarly, under the current (medium) NG prices with only the low carbon-tax rate applied, the HTSE can remain competitive up to 800 MW_e while greatly increasing its overall profitability throughout that range. This highlights the strategic value of HTSE investments in regional markets where carbon taxes are anticipated in the near future.

Table 22. Impact of carbon tax and NG prices on HTSE economics.

Carbon Tax	**–**	**\$25/t-CO_2**	**\$100/t-CO_2**
H_2 price at low NG for 100 MW_e HTSE	\$2.1/kg-H_2	\$2.3/kg-H_2	\$3.0/kg-H_2
H_2 price at med NG for 100 MW_e HTSE	\$2.3/kg-H_2	\$2.5/kg-H_2	\$3.2/kg-H_2
H_2 price at high NG for 100 MW_e HTSE	\$2.9/kg-H_2	\$3.1/kg-H_2	\$3.7/kg-H_2
Optimal HTSE Size at med NG	100–200 MW_e	250–350 MW_e	>1,000 MW_e
Maximum HTSE Size at med NG	~400 MW_e	~800 MW_e	>1,000 MW_e

4.3 Economic Results Summary

Overall, the analysis shows the viability of an NPP-HTSE coupling to act as a form of electricity storage during periods of peak energy demand and to also to provide an additional revenue source for a NPPs via hydrogen sales. While the model developed and presented depends on different key market assumptions, it does highlight the order-of-magnitude conditions under which hydrogen production may be profitable. The economic model was used to estimate the NPV of the project under different conditions: fixed hydrogen price, dynamic market response, and varying market conditions. The main findings are summarized in Table 23. With the current market assumptions, a price of hydrogen above approximately \$1.8 kg-H_2/year appears to show profitability. In a dynamic market, this corresponds to an approximate maximum HTSE capacity of around 400 MW_e. If a carbon tax of \$25/ton-CO_2 is considered, the range of profitability expands up to approximately 800 MW_e. It should be emphasized how sensitive these estimates are to assumed parameters, including the WACC, the NPPP O&M, the hot standby requirements, and electricity-storage requirements, etc. These need to be carefully evaluated on a case-by-case basis to determine the estimated profitability of an NPP-HTSE plant.

Table 23. Summary of key findings from the economic model evaluations.

Optimal HTSE size under dynamic market and medium NG prices	100-200 MW_e
Maximum profitable HTSE size in dynamic market and medium NG prices	~400 MW_e
Sensitivity of NPV on the Weighted Average Cost of Capital (WACC)	-\$677/WACC
Maximum profitable HTSE size in dynamic market, medium NG prices, and low-carbon tax	~800 MW_e

5. CONCLUSIONS

In this study, nonelectric product markets have been studied generally both nationally and in diverse regions around the U.S. to ascertain the respective current and future possible market demands for nonelectric products that can be produced using the heat and electricity available from NPPs in the various regions. For each region, tables and charts have been provided showing the specific nonelectric product-demand sources and their distance from each NPP in the region. The goals of this study were to provide a sampling of the demand to the NPP operators so they could evaluate the options and make the best decision for their businesses.

The complimentary revenue model of producing non-electric products flexibly while supporting grid needs can help ensure the current fleet of LWRs can remain a sustainable pillar of the national electric grid while providing a bridge to future next generation advanced nuclear reactor deployments. LWR-Hybrid IES plants can provide a concentrated source of reliable clean energy that can operate flexibly producing grid electricity or non-electric products and intermediate products storage. They can support conversion of biomass and CO_2 from ethanol plants to fuels and chemicals, produce fungible fuels to substitute or blend with motor gasoline or diesel, and support production of other chemicals such as methanol and formic acid. Finally, the heat requirements of these non-electric industrial process in an energy park could be provided by NPPs.

5.1 Capacity Markets

Capacity payments represent an attractive revenue stream, particularly in regions such as PJM where market prices have recently been as high as >\$100/MW-day. However, capacity prices have proven to be volatile and are under regulatory scrutiny as they increase as a fraction of the total wholesale electricity cost (Figure 5). The future rules, functionality, and prices of the PJM capacity market are unclear as of the publication of this report. Further, the large generating capacity of some NPPs (particularly those over 2 GW) may overwhelm the capacity market in some regions (e.g., NY-ISO's heavily segmented market), reducing prices or only allowing a fraction of the NPP capacity to be bid into the market. In addition, the storage and intermittency costs implied by electricity capacity production should be modeled and explicitly incorporated into revenue analyses.

5.2 Markets for Direct Hydrogen and Indirect Hydrogen (DRI, Ammonia, Synfuels), Oxygen, and Polymers

Sources of CO_2 nationwide are shown in Figure 56 below. These sources of CO_2 can be utilized to capture CO_2 to be used for the manufacture of synfuel, formic acid and other synthetic chemicals. Ammonia (CO_2-Ammonia), steam methane reforming (CO_2-H_2), and ethanol plants (CO_2-Ethanol) are noted in the figure.

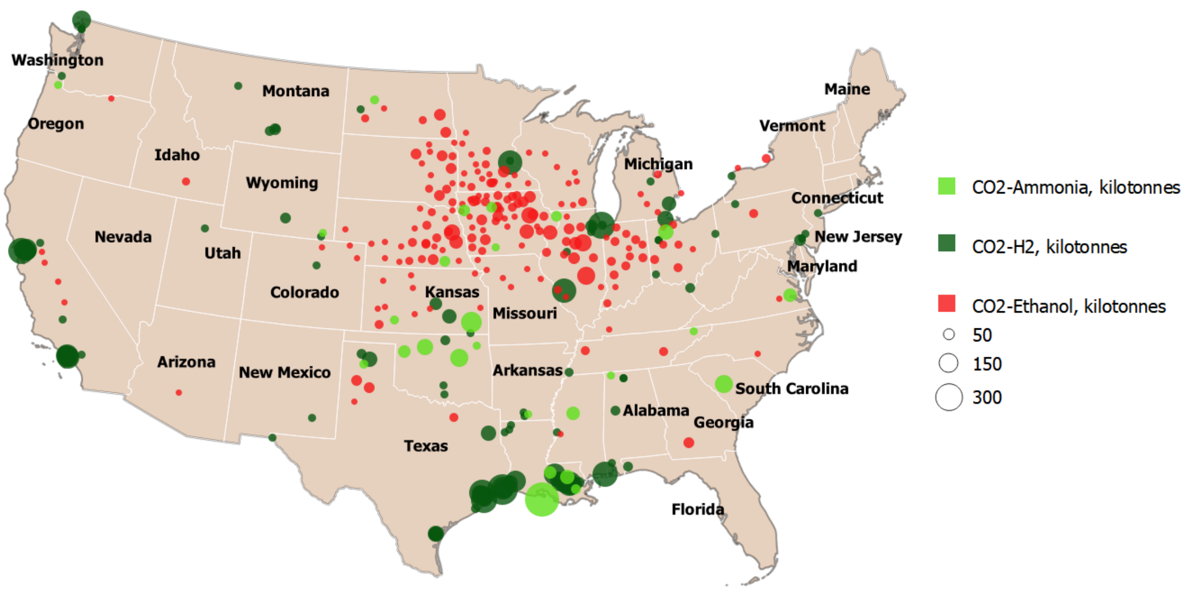

Figure 56. CO_2 sources for use in synfuels production.

Table 1Table 24 below shows the approximate hydrogen prices to be competitive in the respective markets presented.

Table 24. Estimated threshold price for hydrogen to replace alternate feedstocks, by application.

Application	Threshold Hydrogen Production Price	Notes
LD FCEVs	$2–3/kg	DOE targets for FCEVs
Medium- and HD FCEVs	$2–3/kg	DOE targets for FCEVs
Petroleum Refining	Up to $3/kg	Competitive with SMR. No substitute for hydrogen in refining process (inelastic demand)
NH_3	$2/kg	Price to be competitive with imported ammonia
Synthetic FT Diesel	$1–1.5/kg	Price to compete with petroleum diesel

Injection to NG Infrastructure	\$0.8–1/kg	Price to compete with NG on thermal-energy content, based on higher heating value
Iron Reduction and Steelmaking	\$0.8–1/kg	Price for hydrogen to compete with NG in DRI

5.3 Carbon Emissions Life-Cycle Analysis

As expected, LCA shows that carbon emissions for products generated from nuclear energy are much lower than the incumbent processes that currently produce these nonelectric products. The case of a 30–70 vol% hydrogen with NG mixture in combustion turbines for power results in only an ~8% reduction in carbon emissions. This is because this 30–70vol% mixture is only ~9% hydrogen by energy; the volumetric heating value of hydrogen is approximately 30% of the corresponding heating value of NG. However, the amount of potential CO_2 abatement is significant due to the large contribution of NG generating plants to the U.S. national GHG-emissions inventory. Furthermore, future turbine designs that can handle higher mixing ratios, and potentially combust 100% hydrogen, will have the potential to eliminate CO_2 emissions from gas power-generation units. It is also noted that mixing hydrogen with NG in the near term is attractive compared to other new hydrogen end-use applications because it leverages the existing NG infrastructure and application end use (i.e., gas turbine); thus, little new capital investment is needed.

5.4 Nuclear-Hydrogen Hybrid Sample Model Analysis

With the current market assumptions, a price of hydrogen above approximately \$1.8 kg-H2/year appears to show profitability. In a dynamic market, this corresponds to an approximate maximum HTSE capacity of around 400 MWe. If a carbon tax of \$25/ton-CO2 is considered, the range of profitability expands up to approximately 800 MWe (Table 25). It should be emphasized how sensitive these estimates are to assumed parameters including the WACC, the NPPP O&M, the hot-standby requirements, and electricity storage requirements, etc (Figure 57). These items need to be carefully evaluated on a case-by-case basis to determine the estimated profitability of an NPP-HTSE plant.

Table 25. Summary of key findings from the economic model evaluations.

Optimal HTSE size under dynamic market and medium NG prices	100-200 MW_e
Maximum profitable HTSE size in dynamic market and medium NG prices	~400 MW_e
Sensitivity of NPV on the Weighted Average Cost of Capital (WACC)	-\$677/WACC
Maximum profitable HTSE size in dynamic market, medium NG prices, and low-carbon tax	~800 MW_e

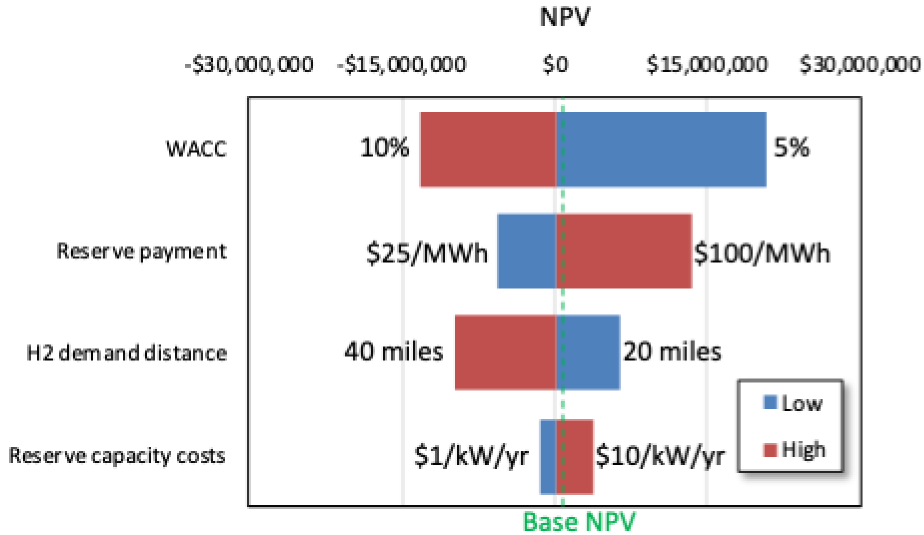

Figure 57. Sensitivity tornado chart of various low/high estimates for the different variables previously considered.

5.5 Future Work

Domestic fertilizer, polymer products, and iron/steel, methanol, and hydrogen fuel markets have the potential to continue rising and companies are beginning to look for cost-competitive clean products. This report focuses heavily on demand for hydrogen in and of itself and for use in making other products and chemicals such as DRI for steel production, ammonia and fertilizers, and synfuels etc). Demand for other products such as oxygen, FA, polymers and other applications are briefly discussed. An update to demand applications for heat from NPPs to form an energy park as well as more in-depth studies of synfuels and chemicals such as methanol coupling with NPPs will be the subjects of future studies. Some example steam-duty needs that could be met by NPPs include food processing, minerals concentration, plastics recycling, etc. A separate future study will also present analysis of the national discussion around creating a clean energy credit system for electricity and non-electric products produced using nuclear energy and propose various methods and school of thought for doing so.

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