NATIONAL LABORATORY OF THE ROCKIES

Region-Specific Merchant Hydrogen Market Assessment and Techno-Economic Assessment of Electrolytic Hydrogen Generation

Cooperative Research and Development Final Report

CRADA Number: CRD-18-00751

Technical Contacts:
Richard Boardman,[1] Mark Ruth,[2] Bethany Frew,[2] Daniel Levie,[2] Daniel Wendt,[1] Samuel Bates,[1] Amgad Elgowainy,[3] Troy Hawkins,[3] Noah Meeks,[4] Uuganbayar Otgonbaatar,[5] and Frank Novachek[6]

[1] *Idaho National Laboratory*
[2] *National Laboratory of the Rockies*
[3] *Argonne National Laboratory*
[4] *Southern Company Services, Inc.*
[5] *Exelon BSC*
[6] *Xcel Energy*

The National Laboratory of the Rockies is a national laboratory of the U.S. Department of Energy, Office of Critical Minerals and Energy Innovation, operated under Contract No. DE-AC36-08GO28308.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Technical Report
NREL/TP-6A20-78011
February 2026

NATIONAL LABORATORY OF THE ROCKIES

Region-Specific Merchant Hydrogen Market Assessment and Techno-Economic Assessment of Electrolytic Hydrogen Generation

Cooperative Research and Development Final Report

CRADA Number: CRD-18-00751

Technical Contacts:
Richard Boardman,[1] Mark Ruth,[2] Bethany Frew,[2] Daniel Levie,[2]
Daniel Wendt,[1] Samuel Bates,[1] Amgad Elgowainy,[3] Troy Hawkins,[3]
Noah Meeks,[4] Uuganbayar Otgonbaatar,[5] and Frank Novachek[6]

[1] *Idaho National Laboratory*
[2] *National Laboratory of the Rockies*
[3] *Argonne National Laboratory*
[4] *Southern Company Services, Inc.*
[5] *Exelon BSC*
[6] *Xcel Energy*

Suggested Citation
Boardman, Richard; Mark Ruth, Bethany Frew, Daniel Levie, Daniel Wendt, Samuel Bates, Amgad Elgowainy, Troy Hawkins, Noah Meeks, Uuganbayar Otgonbaatar, and Frank Novachek. 2026. *Region-Specific Merchant Hydrogen Market Assessment and Techno-Economic Assessment of Electrolytic Hydrogen Generation: Cooperative Research and Development Final Report, CRADA Number CRD-18-00751.* Golden, CO: National Laboratory of the Rockies. NREL/TP-6A20-78011. https://www.nlr.gov/docs/fy26osti/78011.pdf.

The National Laboratory of the Rockies is a national laboratory of the U.S. Department of Energy, Office of Critical Minerals and Energy Innovation, operated under Contract No. DE-AC36-08GO28308.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Technical Report
NREL/TP-6A20-78011
February 2026

National Laboratory of the Rockies
15013 Denver West Parkway
Golden, CO 80401
303-275-3000 • www.nlr.gov

NOTICE

This work was authored by the National Laboratory of the Rockies for the U.S. Department of Energy (DOE), operated under Contract No. DE-AC36-08GO28308. Funding provided by the U.S. Department of Energy Office of Energy Efficiency and Renewable Energy Hydrogen and Fuel Cell Technologies Office. The views expressed herein do not necessarily represent the views of the DOE or the U.S. Government.

This work was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, nor any of their contractors, subcontractors or their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or any third party's use or the results of such use of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise, does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof or its contractors or subcontractors. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof, its contractors or subcontractors.

This report was produced when the laboratory operated as the National Renewable Energy Laboratory (NREL). The laboratory is now the National Laboratory of the Rockies (NLR).

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

U.S. Department of Energy (DOE) reports produced after 1991 and a growing number of pre-1991 documents are available free via www.OSTI.gov.

Cover photos (clockwise from left): Josh Bauer, National Laboratory of the Rockies 61725; Visualization from National Laboratory of the Rockies Insight Center; Getty-181828180; Agata Bogucka, National Laboratory of the Rockies 91683; Dennis Schroeder, National Laboratory of the Rockies 51331; Werner Slocum, National Laboratory of the Rockies 67842.

National Laboratory of the Rockies prints on paper that contains recycled content.

Cooperative Research and Development Final Report

Report Date: August 5, 2020

In accordance with requirements set forth in the terms of the CRADA agreement, this document is the final CRADA report, including a list of subject inventions, to be forwarded to the DOE Office of Scientific and Technical Information as part of the commitment to the public to demonstrate results of federally funded research.

Parties to the Agreement:

- Battelle Energy Alliance, LLC, as Operator of Idaho National Laboratory ("INL") under its U.S. Department of Energy Contract No. DE-AC07-05ID14517
  2525 N. Fremont Avenue
  Idaho Falls, ID 83415
- UChicago Argonne, LLC, as Operator of Argonne National Laboratory ("ANL") under its U.S. Department of Energy Contract No. DE-AC02-06CH11357
  9700 S. Cass Avenue
  Argonne, IL 60439
- Alliance for Sustainable Energy, LLC, Manager and Operator of National Renewable Energy Laboratory ("NREL") under its U.S. Department of Energy Contract No. DE-AC36-08GO28308
  15013 Denver W Pkwy
  Golden, CO 80401
- Southern Company Services, Inc. ("SCS")
  600 18th Street North
  Birmingham, AL 35203
- Exelon Business Services Company, LLC ("Exelon")
  10 South Dearborn Street, 49th Floor
  Chicago, IL 60603

CRADA Number: NREL No. CRD-18-00751; INL No. 18-CR-08; ANL No. 2018-18078

CRADA Title: Region-Specific Merchant Hydrogen Market Assessment and Techno-Economic Assessment of Electrolytic Hydrogen Generation

Responsible Technical Contact at Alliance/NREL:

Mark Ruth | mark.ruth@nlr.gov
Bethany Frew | bethany.frew@nlr.gov
Daniel Levie | daniel.levie@nlr.gov

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

In conjunction with partnering National Laboratories:

Richard Boardman, INL | richard.boardman@inl.gov (Corresponding/Lead Author)
Daniel Wendt, INL | daniel.wendt@inl.gov
Samuel Bates, INL | samuel.bates@inl.gov (sbates4101@gmail.com)
Amgad Elgowainy, ANL | aelgowainy@anl.gov
Troy Hawkins, ANL | thawkins@anl.gov

Name and Email Address of POC at Company: (Including Contributing Authors)

Noah Meeks, Southern Company Services, Inc. | ndmeeks@southernco.com
Uuganbayar Otgonbaatar, Exelon BSC | uuganbayar.otgonbaatar@exeloncorp.com
Frank Novachek, Xcel Energy | frank.novachek@xcelenergy.com

Sponsoring DOE Program Office(s):

Office of Energy Efficiency and Renewable Energy (EERE), Hydrogen and Fuel Cell Technologies Office

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Joint Work Statement Funding Table showing DOE commitment:

1. Estimated Income/Expenditures/Distributions

INCOME	PY1 (01-12 months)	TOTAL
DOE Contribution ($80,000 to INL, $20,000 to NREL)	$100,000.00	$100,000.00
Total Government	$100,000.00	$100,000.00
Southern Company Services, Inc.		
Funds-In Contribution ($25,000 to ANL, $50,000 to NREL)	$75,000.00	$75,000.00
In-Kind Contribution*	$50,000.00	$50,000.00
Total Southern Company Services, Inc.	$100,000.00	$250,000.00
Exelon BSC		
Funds-In Contribution ($25,000 to ANL)	$25,000.00	$25,000.00
In-Kind Contribution*	$25,000.00	$25,000.00
Total Exelon BSC	$50,000.00	$50,000.00
Total CRADA Value	$250,000.00	$250,000.00

***(In-Kind is a non-monetary estimation of the salary, equipment, travel, etc. that will be expended to support the collaboration)**

EXPENDITURES	PY1 *(01-12 months)*	TOTAL
INL (combined in-kind and funds-in)	$80,000.00	$80,000.00
NREL (combined in-kind and funds-in)	$70,000.00	$70,000.00
ANL (combined in-kind and funds-in)	$50,000.00	$50,000.00
Southern Company Services, Inc. (In-Kind Contribution)	$25,000.00	$25,000.00
Exelon BSC (In-Kind Contribution)	$25,000.00	$25,000.00

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

EXPENDITURES	PY1 *(01-12 months)*	TOTAL
Total CRADA Value	$250,000.00	$250,000.00

Executive Summary of CRADA Work:

Utilities need to recover value from baseload and some renewable assets even when the electricity is curtailed. The declining cost of renewables (particularly solar), the persistently low-cost of natural gas, and the declining electricity demand, have all worked to lower the price of electricity. Furthermore, the baseload assets have a high turndown cost, which is not reflected in the low market electricity prices. One option for utilizing the curtailed electricity is hydrogen generation. One important aspect of this project will be to provide a "go/no-go" recommendation on the economic feasibility of pursuing hydrogen generation vs. other markets that could offtake curtailed electricity or nuclear steam.

This project will specifically assess the opportunities for hydrogen production and use in the service territories of Southern Company Services (SCS), Exelon BSC, and Xcel Energy. Each utility partner represents a different mix of generation fleets: Exelon has significant nuclear assets, Xcel is primarily renewables (wind) with some nuclear, and SCS represents both a renewables fleet and a heavily baseload fleet, which includes significant nuclear.

The Contractors will conduct the study of hydrogen market opportunities by first considering the approximate electricity demand and price profiles for the year, and power generation capacity that can be used to produce hydrogen. Therefore, a profile for hydrogen generation will also be developed to better understand the quantity and timing of hydrogen production. Once the hydrogen production schedule is estimated, hydrogen storage requirements can be determined. This effort will provide sufficient information to make a go/no-go decision on moving ahead with a detailed regional case study for hydrogen production in any of the three utility areas.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Table of Contents

TASK 1: Identify, validate, and rank regional hydrogen markets (relative to utility service territories.) **10**
TASK 1 DESCRIPTION: 10
TASK 1 SUMMARY AND OUTCOME: 10
1.1 Petroleum Refineries 10
1.2 Ammonia Producers 11
1.3 Synthetic Fuel Production 11
1.4 Direct Reduction of Iron 12
1.5 Co-combustion with Natural Gas 13
1.6 Fuel-cell Vehicles 13
1.7 Exelon: Potential Demand Near a Representative Nuclear Power Plant 14
1.8 Southern: Potential Demand near Southern Company 18
1.9 Xcel Energy: Potential Demand near Prairie Island Nuclear Power Plant 22
1.10 References 25
TASK 2: Project preliminary power generation and load demand profiles (relative to select nuclear plants and estimate value of grid services, capacity payments, grid stability factors). **27**
TASK 2 DESCRIPTION: 27
TASK 2 SUMMARY AND OUTCOME: 27
ELECTRICITY MARKET **27**
2.1 Price-duration Curves 28
2.2 Capacity Market Pricing 29
2.3 Scenarios by Utility 31
2.3.1 Southern Company 31
2.3.2 Exelon 33
2.3.3 Xcel Energy 34
2.4 References 38
TASK 3: Preliminary assessment of hydrogen storage needs, opportunities, and challenges. **40**
TASK 3 DESCRIPTION: 40
TASK 3 SUMMARY AND OUTCOME: 40
TASK 4: Preliminary Technical/economic analysis of hydrogen generation plant options. **41**
TASK 4 DESCRIPTION: 41
TASK 4 SUMMARY AND OUTCOME: 41
HYDROGEN PRODUCTION **41**
4.1 Steam Methane Reforming 42
4.2 Low-temperature Electrolysis 43
4.3 High-temperature Electrolysis 44
4.4 Basis of Calculations 49
4.4.1 Capital-cost Estimation 51
4.4.2 Estimation of Revenue 57
4.4.3 Estimation of Manufacturing Costs 58
4.4.4 Estimation of Delivery and Compression Costs 60
4.5 References 61
HYDROGEN-GENERATION COST PROJECTIONS **63**
5.1 Steady-state Hydrogen Plants 63
5.1.1 Small-scale Steady-state LTE and SMR Hydrogen Plants 65
5.1.2 Large-scale Steady-state HTE and SMR Hydrogen Plants 66
5.2 Dynamic Plant Operation 68
5.2.1 Analysis Methods 69
5.2.2 Southern Company Scenarios 78
5.2.3 Exelon Scenarios 86

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

5.2.4 Xcel Energy Scenarios 90
5.2.5 Summary 101
5.3 References 103
TASK 5: Final report: Comparison of TEAs and recommendations. 105
TASK 5 DESCRIPTION: 105
TASK 5 SUMMARY AND OUTCOME: 105

List of Figures

Figure 1. Hydrogen demand by type and distance from an Exelon nuclear facility in Illinois, (a) demand up to 100 miles from the power-generating station, (b) demand up to 500 miles from the power-generating station, and (c) demand up to 1000 miles from the power generating station. 15
Figure 2. Hydrogen demand near an Exelon nuclear facility in Illinois, (a) current demand (2017), (b) potential future demand by approximately 2030. 17
Figure 3. Hydrogen demand by type and distance from Southern Company generation stations: (a) demand up to 300 miles from the Farley Generating Station and (b) demand up to 500 miles from the Farley Generating Station, (c) demand up to 400 miles from the Hatch Generating Station, (d) demand up to 500 miles from the Hatch Generating Station, (e) demand up to 300 miles from the Vogtle Generating Station, and (f) demand up to 500 miles from the Vogtle Generating Station. 19
Figure 4. Hydrogen demand near the Southern Company Farley, Hatch, and Vogtle Generating Stations, (a) current demand (2017), (b) potential future demand in approximately 2030. 21
Figure 5. Hydrogen demand by type and distance from Prairie Island Generating Plant: (a) demand up to 50 miles from the Prairie Island and (b) demand up to 150 miles from Prairie Island, (c) demand up to 400 miles from the generating station. 23
Figure 6. Hydrogen demand by type and distance from Xcel Energy facility in Denver, Colorado: (a) demand up to 50 miles from the facility, (b) demand up to 150 miles from the facility, and (c) demand up to 400 miles from the facility. 25
Figure 7. Map of RTOs within contiguous United States [7]. 28
Figure 8. 10 MW solar-PV production-duration curve. 32
Figure 9. Exelon scenarios' price-duration curve. 34
Figure 10. Aligning Xcel Energy projected price-duration curve with 2017 volatility. 36
Figure 11. Xcel Energy price-duration curves for Scenarios 1 and 2: Minnesota–MINN HUB. 36
Figure 12. Xcel Energy Scenario 3 price-duration curve: SPP–South. 37
Figure 13. Xcel Energy Scenario 4 price-duration curve: Colorado–PSCo. 37
Figure 14: Xcel Energy Scenario 5-7: PPA Contract Price 38
Figure 15. Generalized Steam Methane Reforming Process Flow Diagram 42
Figure 16. Generalized PEM electrolyzer system [3]. 43
Figure 17: Cross-section of a cathode-supported planar SOEC stack. The case of co-flow is depicted [4, 6]. 44
Figure 18. High Temperature Steam Electrolysis process flow diagram. 46
Figure 19. Process-flow diagram of the thermal delivery loop that supplies heat from the LWR to the HTSE process (LWR/HTE thermal integration). The "HTE Steam Generators" in this figure corresponds to the HX-22 Steam Generator in Figure 19. 47
Figure 20. Hydrogen Recovery and Feed Conditioning area process-flow diagram. 48
Figure 21. General energy and product flows for the LWR/HTSE integration case. 49
Figure 22. Conventional HTSE equipment units costs as a function of plant capacity 52
Figure 23. Estimated unit cost of HTSE process modular components vs previously installed HTSE capacity 54

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Figure 24. Natural gas prices (USD2017) projected by (AEO 2018). Mean natural gas prices are $8.0/MMBtu (million British thermal units), $5.4/MMBtu and $4.2/MMBtu for high, baseline, and low natural-gas price scenarios, respectively. 65
Figure 25. (SS, LTE) Comparison of hydrogen-production costs for 46-tpd small-scale/steady-state LTE and SMR plants (assuming 97% OCF, LTE curves for PEM stack costs, no oxygen sales credit, and no capacity payment). 66
Figure 26. (SS, HTE) Comparison of hydrogen-production costs for 562 tpd large-scale/steady-state LWR/HTE and SMR plants (assuming Nth-of-a-kind 608 tpd design capacity LWR/HTE plant with 92.4% OCF and 624 tpd design capacity SMR with 90% OCF, no LWR/HTE oxygen sales, compression and delivery costs of $0.34/kg for LWR/HTE and $0.07/kg for SMR, and LWR/HTE capacity-payment credits of $0 or $132.4/MWe-day). 67
Figure 27. Hybrid power/hydrogen plant concept 68
Figure 28. Current hydrogen demand in Alabama, Georgia, and Mississippi (region serviced by Southern Company power generation assets) 70
Figure 29. LTE process fractional operating time versus the process activation price (example plot using MISO-MINN LMP data). 71
Figure 30. LTE process input power cost versus the process activation price (example plot using MISO-MINN LMP data) 71
Figure 31. LTE process average power purchase price versus the process operating capacity factor (example plot using MISO-MINN LMP data). 72
Figure 32. LTE hydrogen production supply curve (100 MWe LTE plant with $232/kW CAPEX operating in MISO-MINN market) 72
Figure 33. Hybrid nuclear electricity/hydrogen plant approach to minimizing hydrogen production costs. 73
Figure 34. HTSE operating time versus bid price (example plot using MISO-MINN LMP data) 74
Figure 35. Average market clearing price versus bid price (example plot using MISO-MINN LMP data) 74
Figure 36. Average LWR/HTSE byproduct power sales revenue versus HTSE capacity factor (example plot using MISO-MINN LMP data) assuming LWR O&M cost of $30/MWh and LWR/HTSE outage rate of 5%. 75
Figure 37. HTE hydrogen production supply curve (1000 MWe HTE plant with $249/kW CAPEX operating in MISO-MINN market) 76
Figure 38. PV/LTE hydrogen production supply curve (100 MWdc PV plant with varying LTE plant capacity ($232/kW CAPEX) operating in Columbus, Georgia) 77
Figure 39. Southern Company AL/GA/MS current hydrogen demand 80
Figure 40. Southern Company AL/GA/MS future hydrogen demand 80
Figure 41. Southern Company Scenario 1 supply vs demand curve 81
Figure 42. Southern Company Scenario 1 supply vs. demand curve (to 50 kilotonnes per year) 82
Figure 43. Southern Company Scenario 1 supply (multiple LTE plants) vs demand 83
Figure 44. Southern Company Scenario 2 supply vs demand curve 84
Figure 45. Southern Company Scenario 3 supply vs demand curve (to 250 kilotonnes per year) 85
Figure 46. Southern Company Scenario 3 supply vs. demand curve (to 10 kilotonnes per year) 86
Figure 47. Exelon current hydrogen demand 88
Figure 48. Exelon future hydrogen demand 88
Figure 49. Exelon Scenario 1 supply vs demand curve (to 50 kilotonnes per year) 89
Figure 50. Exelon Scenario 2 supply vs demand curve (to 1000 kilotonnes per year) 90
Figure 51. Xcel Energy Minnesota current hydrogen demand 92
Figure 52. Xcel Energy Minnesota future hydrogen demand 92
Figure 53. Xcel Energy Colorado current hydrogen demand 93
Figure 54. Xcel Energy Colorado future hydrogen demand 93

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Figure 55. Xcel Energy Scenario 1 supply vs demand curve **94**
Figure 56. Xcel Energy Scenario 1 supply vs. demand curve (to 25 kilotonnes per year) **95**
Figure 57. Xcel Energy Scenario 2 supply vs demand curve **96**
Figure 58. Xcel Energy Scenario 3 supply vs. demand curve (to 25 kilotonnes per year) **97**
Figure 59. Xcel Energy Scenario 4 supply vs demand curve **98**
Figure 60. Xcel Energy Scenario 4 supply vs. demand curve (to 25 kilotonnes per year) 98
Figure 61. Xcel Energy Scenario 5 supply vs demand curve (Minnesota) 99
Figure 62. Xcel Energy Scenario 6 supply curve (SPP South) 100
Figure 63. Xcel Energy Scenario 7 supply vs. demand (Colorado) 101
Figure 64. CRADA Final Report Cover 105

List of Tables

***(In-Kind is a non-monetary estimation of the salary, equipment, travel, etc. that will be expended to support the collaboration)** **3**
Table 1. Recent capacity market clearing prices within PJM ComEd. **29**
Table 2. Recent capacity market clearing prices within MISO Zone 1. ..... **30**
Table 3. Southern Company Scenarios. **31**
Table 4. Itemized solar-PV installation costs in $/Wdc by installed capacity, taken from the "Q1 2018 U.S. Solar Photovoltaic System Cost Benchmark." **33**
Table 5. Exelon scenarios. **33**
Table 6. Xcel Energy scenarios. **35**
Table 7. HTE electrolysis-cell parameters. **46**
Table 8. Hydrogen production summary. **49**
Table 9. Summary of financial model input parameters. **50**
Table 10. TCI for the baseline LTE case (48-tpd design capacity, $86/kWe PEM stack capital cost). **55**
Table 11. TCI for the baseline HTE case: 608-tpd design capacity, $50/kWe SOEC module capital cost. **56**
Table 12. TCI for the SMR cases. **57**
Small scale (52 tpd[a]) **57**
Large scale (624 tpd[b]) **57**
Table 13. Annual revenue for the small-scale baseline cases: electricity price of $30/MWh, mean natural gas price of $5.4/MMBtu. **58**
Table 14. Annual revenue for the large-scale baseline cases: electricity price of $30/MWh, mean natural gas price of $5.4/MMBtu. **58**
Table 15. Annual manufacturing costs for the baseline LTE case: 48-tpd capacity, PEM-stack capital cost of $86/kWe, electricity price of $30/MWh. **59**
Table 16. Annual manufacturing costs for the baseline HTE case: 608-tpd capacity, SOEC module capital cost of $50/kWe, electricity price of $30/MWh. **60**
Table 17. Delivery adders for hydrogen production. **61**
Table 18. Hydrogen threshold pricing by market segment **69**
Table 19. LTE plant capital cost estimates used in supply curve analysis. Listed values represent installed costs including power electronics, gas conditioning, and balance of plant. **77**
Table 20. HTE plant capital cost estimates used in supply curve analysis. Listed values represent installed costs including power electronics, gas conditioning, and balance of plant. **78**
Table 21. Summary of Southern Company Supply Curve Analysis Scenarios **79**
Table 22. Summary of Exelon Supply Curve Analysis Scenarios **87**
Table 23. Summary of Xcel Energy Supply Curve Analysis Scenarios **91**
Table 24. Summary of LMP curve metrics **101**
Table 25. Summary of minimum LCOH conditions for market pricing based scenarios with IEA Today-2030 CAPEX projections[a,b,c] **102**
Table 26. Summary of minimum LCOH conditions for market pricing based scenarios with IEA long term CAPEX projections[a,b,c] **102**
Table 27. Summary of minimum LCOH conditions for market pricing based scenarios with future

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

CAPEX cost estimates[a,b,c,d] 103

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Summary of Research Results:

TASK 1: Identify, validate, and rank regional hydrogen markets (relative to utility service territories.)

TASK 1 DESCRIPTION:

This Task will build on three previous efforts conducted by national labs: INL analysis of industrial hydrogen markets, NREL nationwide hydrogen potential market study, and ANL market assessment for hydrogen with low CO2 footprint. The Task will also build on work by Exelon to identify potential hydrogen customers. Deliverables: 1) hydrogen demand curves for each utility service territory, and 2) list of market opportunities (quantity, purity, cost, etc.) in each utility service territory

TASK 1 SUMMARY AND OUTCOME:

ANL led the effort to identify and quantify demand opportunities. A number of options were considered and the results for each location were used to develop demand curves. Further details follow.

1.1 Petroleum Refineries

Petroleum refineries are currently the most significant user of hydrogen in the U.S., consuming 10 million metric tonnes (MMT) of hydrogen annually (EIA 2018c). Of the 10 MMT of hydrogen used by petroleum refineries, approximately 6-7 MMT is provided by dedicated hydrogen production sources such as SMR, while the remaining ~3 MMT of hydrogen is produced as a by-product mainly from naphtha reformers in refineries. The hydrogen is used primarily for hydrocracking and hydrotreating where 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, treating the fluid catalytic cracker feed, and treating naphtha. Refinery hydrogen demand is essentially driven by the ratio of gasoline to diesel production, API gravity, sulfur content of the petroleum inputs, and complexity of refinery processing.

Elgowainy et al. (2019) estimated future hydrogen demand for petroleum refining based on projections of crude inputs and market demand for refinery products from the EIA "Annual Energy Outlook" (EIA 2017a), and crude API gravity and sulfur content, based on Han et al.'s analysis (2015). The main features are that crude inputs increase from 16 to 18 million barrels per day (with a steeper increase of 9% from 2015 to 2021 and then more gradual to 2050), gasoline output decreases from 8 to 6 million barrels per day, diesel output increase slightly, and average jet-fuel output increases roughly half a million barrels per day from about 1.7 to 2.2 million barrels per day (EIA 2017a).

Future refinery hydrogen requirements are estimated based on linear regression of refineries characterized by Elgowainy et al. (2014) with crude API, 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

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Administration for Defense districts (PADDs) covering over 70% of U.S. refining capacity. Elgowainy et al. (2019) describe the details of the regression model and its valid range.

Hydrogen demand by refineries is projected to increase through 2030 due to an increased ratio of diesel and 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 for each of the PADDs and then allocated to individual refineries within each PADD based on the petroleum processing capacity of each refinery within the PADD.

1.2 Ammonia Producers

Ammonia is produced by the Haber-Bosch process which reacts hydrogen, usually produced from natural gas via the SMR process and with nitrogen from the air. In 2016, 14 MMT of ammonia were consumed in the United States (USGS 2017), with 12% of this 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 kilograms of hydrogen are required per kilogram of ammonia. As ammonia is the source of nitrogen in other fertilizer products, we can generalize this as 0.216 kgH2/kgN2 in fertilizer.

The locations and scale of ammonia production are estimated using plant capacities (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 (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 will displace imports in the U.S. market. At the national level, Elgowainy et al. (2019) estimate that after 2024, U.S. ammonia production will increase through 2050 at a modest rate of 1% per year. This projection is based on decreasing domestic demand for nitrogen fertilizer for corn, relatively stable domestic demand for nitrogen fertilizer for other products and increasing domestic production displacing nitrogen-fertilizer imports into the U.S. market.

1.3 Synthetic Fuel Production

Significant quantities of high-purity carbon dioxide are generated by both the ethanol-production process and the SMR process, used to produce hydrogen from natural gas for refining, ammonia production, and other purposes. This high-purity carbon dioxide presents an opportunity for the production of synthetic fuels such as methanol, Fischer-Tropsch diesel, or dimethyl ether, while avoiding the cost and energy penalty to capture CO_2 from other sources (e.g., coal and natural-gas power plants). In particular, methanol presents an opportunity as its manufacturing process is relatively simple, and its global market is expected to grow related to its use as a petrochemical feedstock, fuel-blending component, or a blendstock for transportation fuel. Methanol produced from waste carbon dioxide streams with renewable hydrogen offers a low-carbon alternative to methanol produced via the conventional process using fossil natural gas. The merchant market for carbon dioxide is currently saturated. Of the 100 MMT of carbon dioxide generated from ethanol production and steam methane reforming, only 14 MMT are currently available to the merchant market and 11 MMT are used for food processing, carbonated beverages, and other

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

uses (Supekar and Skerlos 2014). This leaves a significant amount that could be used for synthetic fuel production.

The hydrogen demand for synthetic-fuel production can be estimated based on the 1:3 mole ratio of CO_2 to H_2 that is required for the synthesis of Fischer-Tropsch diesel or dimethyl ether. The availability of high-purity carbon dioxide 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 (EPA 2017). High-purity carbon dioxide from ethanol production is estimated based on the 1:1 mole ratio of ethanol to carbon dioxide generated during the conversion of glucose and sucrose in the fermentation process. In 2017, 15.6 billion gallons of ethanol was produced in the United States (EIA 2018d) which generates an estimated 44 MMT of carbon dioxide. The locations and capacities of ethanol-production facilities are based on an EIA dataset (EIA 2018d), and production by facility is estimated based on the national average capacity-utilization rate. The total potential hydrogen demand to produce synthetic fuels from high-purity carbon dioxide sources is significant, at 14 MMT, comprising the production of 6.0 MMT of ethanol, 5.9 MMT of ammonia, and 2.1 MMT from merchant hydrogen production. 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, and other merchant hydrogen plants are located near petroleum refineries, mostly along the Gulf Coast, and near San Francisco, Los Angeles, Chicago, Detroit, Minneapolis, and St. Louis.

1.4 Direct Reduction of Iron

The direct reduction of iron (DRI) is a method for producing high-purity iron from ore at temperatures below the melting point of iron by driving off oxygen in a reactor with a hydrogen and carbon monoxide gas environment. The DRI process reduces energy use and carbon dioxide emissions associated with steel production compared with the basic oxygen furnace (BOF) technology, which uses coking coal to smelt iron. In the U.S., the amount of steel produced by electric-arc furnace (EAF) has increased and is expected to continue to grow while the amount produced by BOF is expected to remain relatively flat due to the increased production of scrap, which can be incorporated in the EAF feed. Product quality dictates the amount of scrap which can be used in an EAF, and the remainder must be made up with pig iron from a BOF or DRI. Due to the high purity of DRI, it has the potential to increase the amount of scrap which can be used at an EAF relative to using pig iron from a BOF. The DRI with hydrogen requires approximately 100 kg hydrogen per metric tonne of iron—i.e., a mass ratio of 10%.

Renewable hydrogen could be used to offset natural gas 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% natural gas on an energy basis (Chevrier 2018). 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 (USGS 2018), and national average DRI feedstock shares. In 2015, BOFs and EAFs used 2.4 MMT and 1.7 MMT of DRI, respectively (USGS 2018). Thus we estimate maximum potential of current hydrogen demand for the DRI at 0.24 MMT for BOF and 0.17 MMT for EAF (assuming 10% mass ratio of H_2/steel). Future demand for hydrogen for DRI is based on the assumption of 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

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

BOFs, where we estimate an additional 2.0 MMT of hydrogen could be used for DRI (assuming 30/70 H_2/natural gas mix for DRI). These estimates are conservative relative to the national estimate of potential future hydrogen demand of 4 MMT for 30% replacement of natural gas on an energy basis (Elgowainy et al. 2019). Those estimates were based on the Annual Energy Outlook projection of 50% growth in U.S. steel production by 2040 and full replacement of iron inputs from DRI.

1.5 Co-combustion with Natural Gas

One potential use of renewable hydrogen is its injection into natural gas pipelines for use as a low-carbon component of a natural gas-hydrogen fuel mix. Elgowainy et al. (2019) discussed the potential and barriers to this use of hydrogen. As a scenario for the purposes of this study, we estimate potential demand for hydrogen, assuming it can be used by natural-gas electricity-generating units with a ratio of 30% hydrogen with 70% natural gas by volume. This is consistent with gas turbine OEMs general agreement that current technology can utilize up to 30vol% hydrogen. Electricity generators were identified using the datasets from the EIA-860 and EIA-923 forms describing electricity-generators' facility locations and fuel use.

1.6 Fuel-cell Vehicles

Hydrogen demand for fuel-cell vehicles (FCVs) is expected to increase as FCVs penetrate the market. Currently, FCVs are a small share of the vehicle fleet and are concentrated in California due to the presence of hydrogen-fueling infrastructure and other state incentives for fuel-cell vehicle purchases. Elgowainy et al. (2019) estimate future hydrogen demand for FCVs in three steps: 1) apply FCV shares of vehicle sales by class each year to EIA forecasts of vehicle sales by class for each year; 2) allocate national FCV sales by class for each year to states based on regional vehicle-sales forecasts adjusted to account for regional FCV targets; and 3) apply estimates of regional vehicle lifetimes, usage, and fuel economy to estimate FCV stocks and hydrogen demand by state. These estimates considered four classes of vehicles: cars, light-duty trucks, medium-duty trucks, and heavy-duty trucks. For cars and light-duty trucks, Argonne's VISION model was used to estimate annual vehicle stock by technology and vintage in order to estimate regional vehicle-miles traveled and energy use by FCVs. Two scenarios were run for cars and light-duty trucks representing low and high potential hydrogen prices, which resulted in high and low FCV shares of sales. For this analysis, we used their low-FCV-sales scenario, which is based on what they considered a moderate assumption regarding future hydrogen price of 2.20 USD/kg for hydrogen production and 5.03 USD/kg for hydrogen at the pump (estimates in 2015 U.S. dollars). The regional vehicle forecasts from the VISION model relate to five U.S. regions: western, central industrial, eastern/zero emissions vehicle states, central southern, and rest of U.S. The Farley Generating Station is located in that "rest of U.S." region, which includes Alabama, Florida, Georgia, and South Carolina, among other states, and is characterized by states having no incentives for FCVs or hydrogen-fueling infrastructure and, therefore, low projected FCV adoption rates. For medium-duty and heavy-duty vehicles, market share is based on the California Air Resources Board's (CARB's) 2016 projections of market share of zero-emission vehicles, together with assumptions regarding the share of those which are FCVs and assumptions regarding the adoption rates in other states. The share's potential hydrogen demand for medium- and heavy-duty vehicles is small compared with that of cars and light duty trucks. For this study, we allocated FCV hydrogen-demand estimates by region in Elgowainy et al

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

(2019) to states and counties based on population (USCB 2018) and estimated distances from the generating stations based on the county center of population (USCB 2015).

1.7 Exelon: Potential Demand Near a Representative Nuclear Power Plant

A nuclear power generating station located in Illinois was selected as an example for this study. This analysis considers potential opportunities for marketing renewable hydrogen which could be produced by the facility. Figure 1 shows potential cumulative hydrogen demand at increasing distances from an Exelon nuclear facility in Illinois. Figure 1a shows cumulative hydrogen demand within 100 miles of the nuclear power plant, while Figure 1b and Figure 1c extend the distance to show the total potential hydrogen demand within 500 and 1,000 miles of the plant, respectively. Entries in Figure 1 include both current and future potential hydrogen-demand estimates, with current demand plotted below 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 all those appearing below it in the legend of the figure. Figure 2 illustrates the locations of potential hydrogen demand near the facility. The facility is marked by an orange hexagon, and around it, large concentric circles are drawn at distances of 50, 100, and 300 miles. Locations of potential hydrogen demand are depicted by colored circles, their size reflecting the scale of potential demand. Figure 2a shows potential demand estimates based on the current potential hydrogen market, while Figure 2b shows the potential demand based on a future scenario reflecting a 2030 projection.

Current hydrogen demand near the nuclear power plant is primarily from refineries, Exxon Mobil in Joliet at 70,000 MT/year, PDV America in Lemont at 50,000 MT/year, and BP in Whiting at 120,000 MT/year. Use of 30% hydrogen with natural gas offers additional nearby opportunities, notably the Kendall County Generating Station, which is 22 miles from the nuclear plant, with a potential hydrogen demand of additional 40,000 MT/year. Other potential hydrogen demand for cofiring with natural gas within a 50 mile radius of the nuclear facility is 15,000 MT/year across 15 natural-gas electricity generators. Nucor Steel in Kankakee and ArcelorMittal in Riverdale offer potential hydrogen demand for DRI, although this demand is modest at only 600 MT/year for Nucor Steel and 1600 MT/year for Arcelor Mittal. Eight more facilities near Gary, Indiana, offer the potential for an additional hydrogen demand of 35,000 MT/year for DRI under the current scenario.

Notable additions to potential hydrogen demand in the future scenario include expansion at the Exxon Mobil refinery in Joliet, Illinois, and the introduction of two new ammonia producers: Cronus Chemical in Tuscola, Illinois, and Phibro in West Terre Haute, Indiana. The expansion at the Exxon Mobil refinery increases their hydrogen demand from 0.070 MMT/year to 0.089 MMT/year, an additional 50 MT per day. Cronus Chemical in Tuscola, Illinois, represents new hydrogen demand of 0.15 MMT/year for ammonia production, beginning in 2021, and Phibro in West Terre Haute, Indiana, represents new hydrogen demand of 0.087 MMT/year for ammonia production beginning in 2020, for a total additional demand of 690 MT per day from these additional markets.

Three nearby merchant hydrogen producers have the combined potential for hydrogen demand of 0.060 MMT/year if their byproduct carbon dioxide were used to produce synfuel with renewable

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

hydrogen. Near the Exxon Mobil refinery in Joliet, Air Products and Chemicals has the potential to add hydrogen demand of 0.007 MMT/year only 14 miles from the nuclear power plant. The Linde Gas plant in Lemont has the potential for hydrogen demand of 0.046 MMT/year, and the nearby Lemont Refinery has the potential for an additional 0.007 MMT/year, both less than 40 miles by road from the nuclear facility. The Praxair operations in Whiting have the potential for synfuel production with hydrogen demand of 0.22 MMT/year.

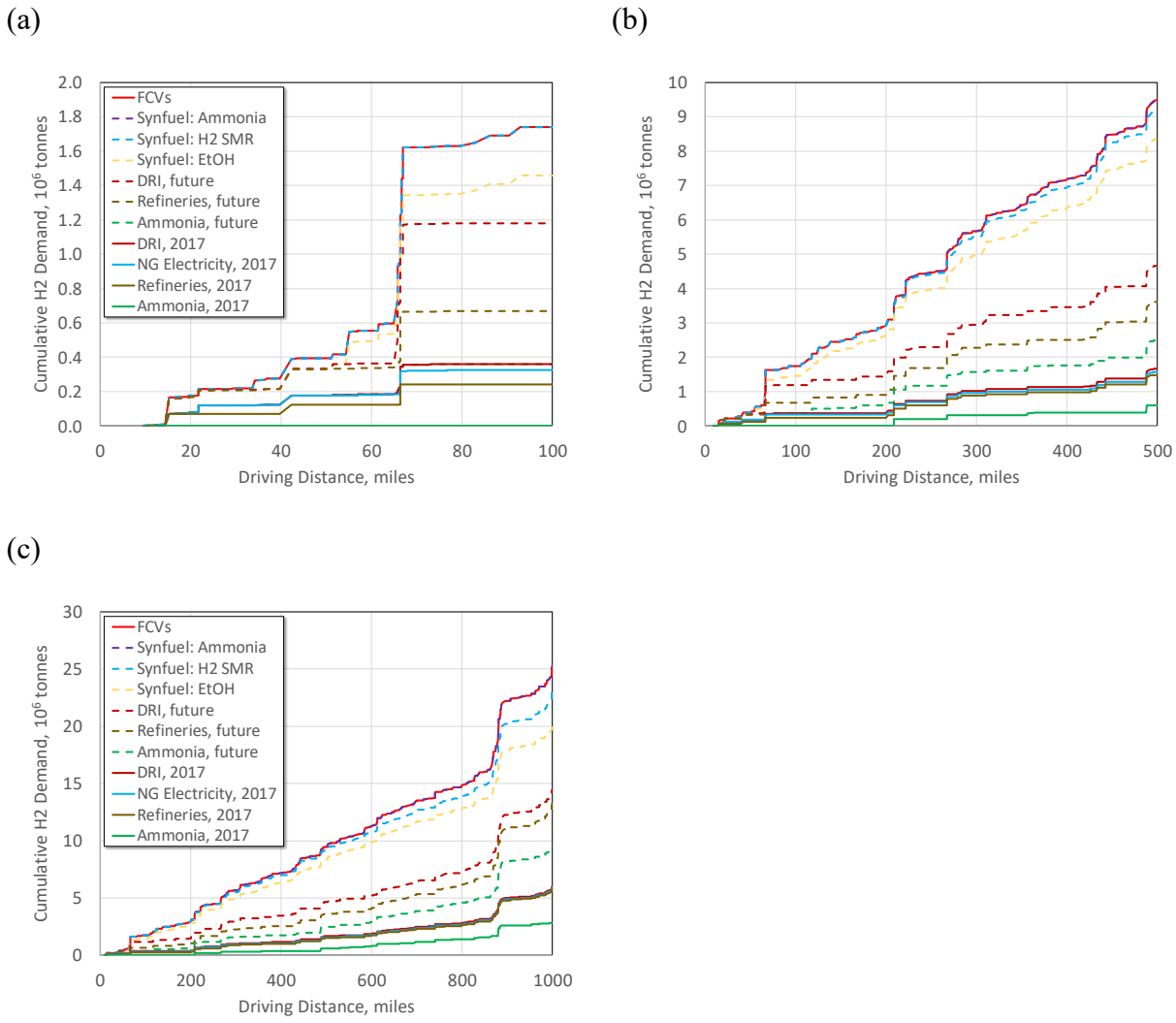


Figure 1. Hydrogen demand by type and distance from an Exelon nuclear facility in Illinois, (a) demand up to 100 miles from the power-generating station, (b) demand up to 500 miles from the power-generating station, and (c) demand up to 1000 miles from the power generating station.

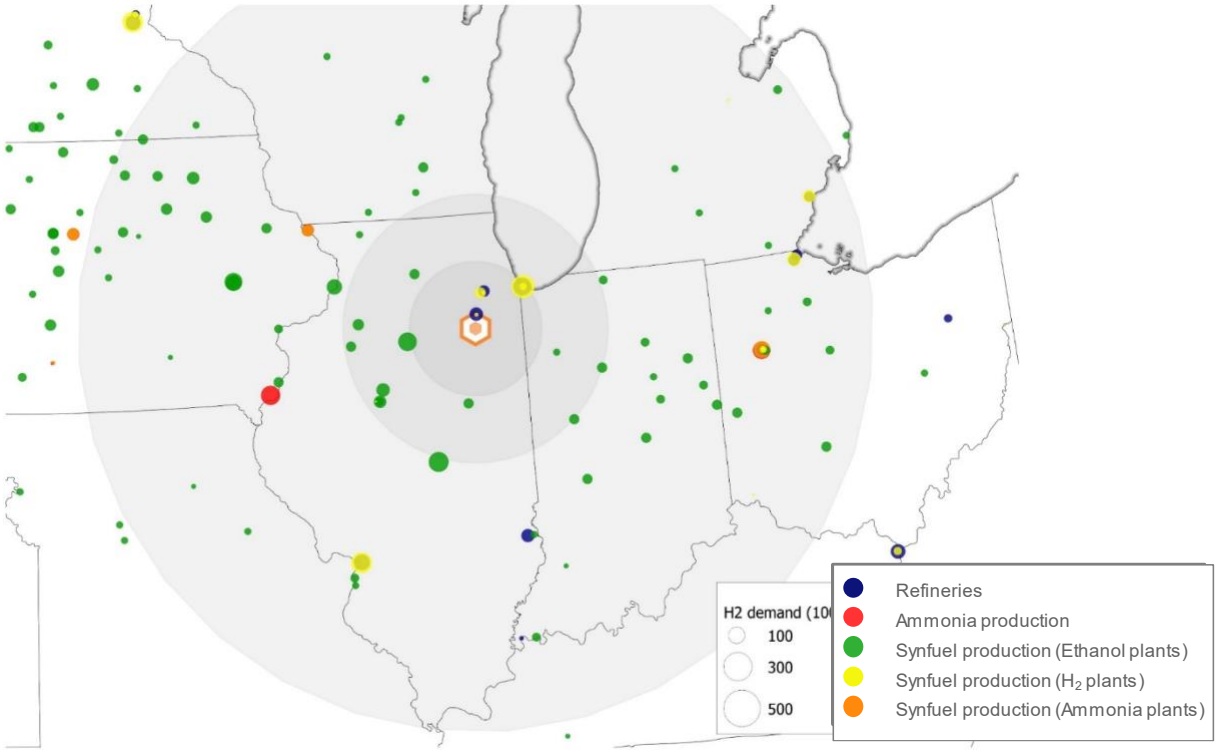
Six steel producers within 70 miles have the potential for 0.51 MMT/year hydrogen demand for DRI. The closest of these is the ArcelorMittal facility in Riverdale, which has the potential for 0.023 MMT/year hydrogen demand. The Arcelor Mittal Burns Harbor and Indiana Harbor facilities have a combined potential hydrogen demand for DRI of 0.31 MMT/year. Finally, the U.S. Steel Gary Works has a potential hydrogen demand of 0.17 MMT/year for DRI.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Many ethanol producers are sited in the region of the representative nuclear facility. If their byproduct carbon dioxide were used for synfuel production, the potential hydrogen demand within 100 miles by road would be 0.28 MMT/year across five facilities. The most significant of these is also the closest: Marquis Energy in Hennepin, Illinois, with potential demand of 0.13 MMT/year. Expanding to 300 miles by road, another 47 ethanol producers have a combined potential hydrogen demand of 1.7 MMT/year for synfuel production. The most significant of these are ADM facilities in Decatur, Illinois, and Cedar Rapids, Iowa, with potential hydrogen demand of 0.15 MMT/year and 0.21 MMT/year, respectively. Future hydrogen demand for FCVs is modest, with a total projected hydrogen demand of 0.0002 MMT/year within 300 miles of the nuclear facility by road.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

(a)



(b)

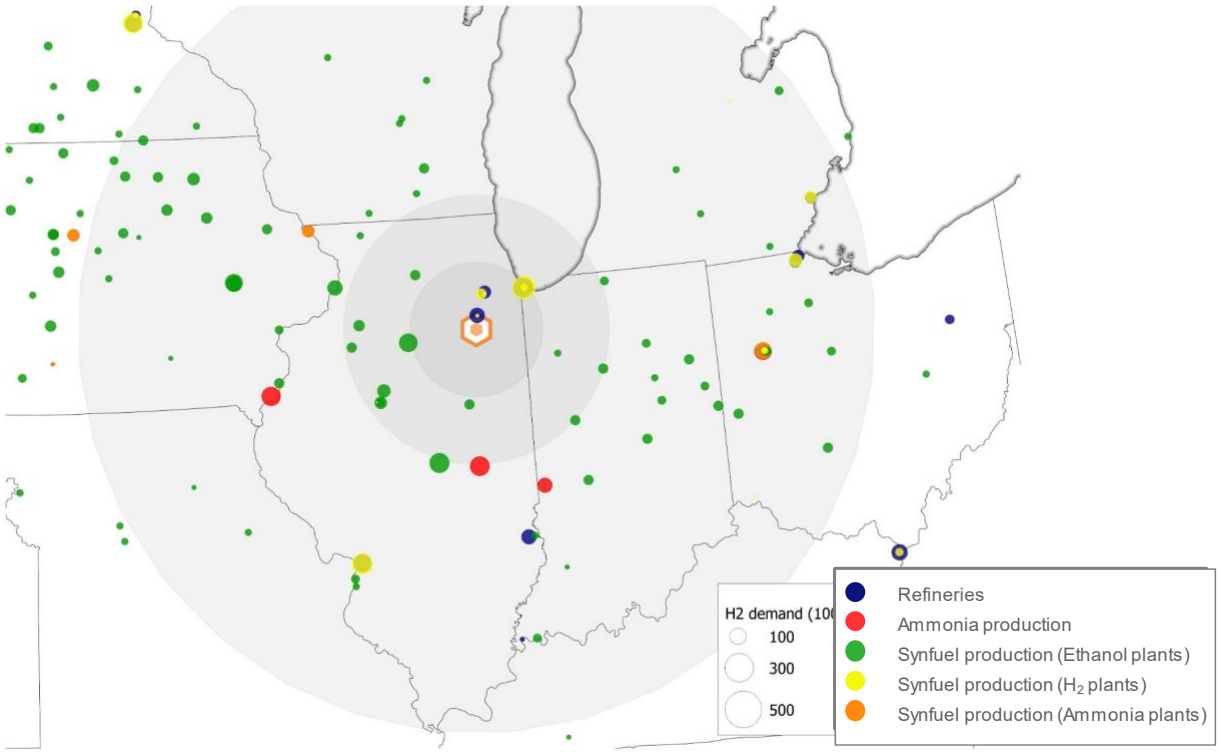


Figure 2. Hydrogen demand near an Exelon nuclear facility in Illinois, (a) current demand (2017), (b) potential future demand by approximately 2030.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

1.8 Southern: Potential Demand near Southern Company

The Southern Company region includes southeast Mississippi, most of Alabama, and Georgia. This analysis considers three Southern Company nuclear power plants, the Farley, Hatch, and Vogtle Generating Stations and the potential opportunities for marketing renewable hydrogen which they could produce. Figure 3 shows potential cumulative hydrogen demand at increasing distances from each of these facilities. Figure 3a shows the cumulative hydrogen demand within 300 miles of the Farley Generating Station, while Figure 3b extends the distance to show the total potential hydrogen demand within 500 miles of that facility. Figure 3c and Figure 3d show the cumulative potential hydrogen demand within 300 and 500 miles of the Hatch Generating Station, while Figure 3e and Figure 3f show the cumulative potential hydrogen demand within 300 and 500 miles of the Vogtle Generating Station. Entries in Figure 3 include both current and future potential hydrogen-demand estimates with the current demand shown below 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 5 illustrates the locations of potential hydrogen demand near the three Southern Company facilities. Each facility is marked with a hexagon while large concentric circles show distances of 50, 100, and 300 miles around each facility. Locations of potential hydrogen demand are depicted by colored circles with size reflecting the scale of potential demand. Figure 5a shows the potential demand estimates based on the current hydrogen market, and Figure 5b shows the potential demand based on a future 2030 scenario.

Current hydrogen demand near the Farley Generating Station is almost entirely for co-combustion of hydrogen with natural gas. Eleven natural-gas electricity generators within 100 miles of the Farley facility have a combined potential hydrogen demand of 0.060 MMT/year (or 164 MT/day). Most of this is associated with three facilities: the City of Talahassee's Arvah B. Hopkins generator, at 0.009 MMT/year; Gulf Power's Lansing Smith generator, at 0.022 MMT/year; and PowerSouth Energy Cooperative's McWilliams generator, at 0.023 MMT/year. At distances between 100 and 200 miles, another 44 natural gas electricity generators provide an additional potential combined hydrogen demand of 0.3 MMT/year. Over half of this is from four facilities, Southern Company's H. Allen Franklin, E.B. Harris, and Wansley generators, at 0.065, 0.028, and 0.045 MMT/year, respectively, and Tenaska's Central Alabama generator at 0.025 MMT/year. The Royal Dutch Shell Group Saraland refinery has a potential hydrogen demand of 0.028 MMT/year at a distance of 216 miles. In total, the 15 refineries and ammonia-production facilities within 400 miles of the Farley facility have a current total potential hydrogen demand of 0.94 MMT/year (about 10% of the current total annual U.S. hydrogen production). Four facilities comprise over half of this amount: the Chevron Pascagoula refinery, Nutrien's August ammonia facility, Dyno Nobel's Waggaman ammonia facility, and Marathon's Garyville refinery. At 408 miles, the CF Industries' Donaldsonville ammonia facility has significant potential hydrogen demand at 0.68 MMT/year. Current potential hydrogen demand for DRI does not add significantly to this total, with 14 facilities within 400 miles having a combined potential hydrogen demand of only 0.013 MMT/year.

Considering other markets, the Flint Hills' Camilla ethanol facility presents an opportunity for using renewable hydrogen produced by Southern Company to produce synthetic fuel, which would result in an additional hydrogen demand of 0.050 MMT/year at a distance of 73 miles from the production site, Farley Generating Station. Another opportunity for synthetic fuel production is the Ascend Performance Materials merchant hydrogen production process near

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Pensacola, which has the potential to use 0.027 MMT/year of hydrogen for synthetic fuel production. Finally, expansions at the Royal Dutch Shell Group's Saraland refinery are expected to add 0.0075 MMT/year to their demand. All of the potential future hydrogen demand for DRI is further than 200 miles from the Farley facility. Steel producers between 200 and 300 miles from the Farley facility have the potential to use 0.070 MMT/year of hydrogen, with 0.050 MMT/year of this associated with U.S. Steel's Fairfield Works located within 225 miles.

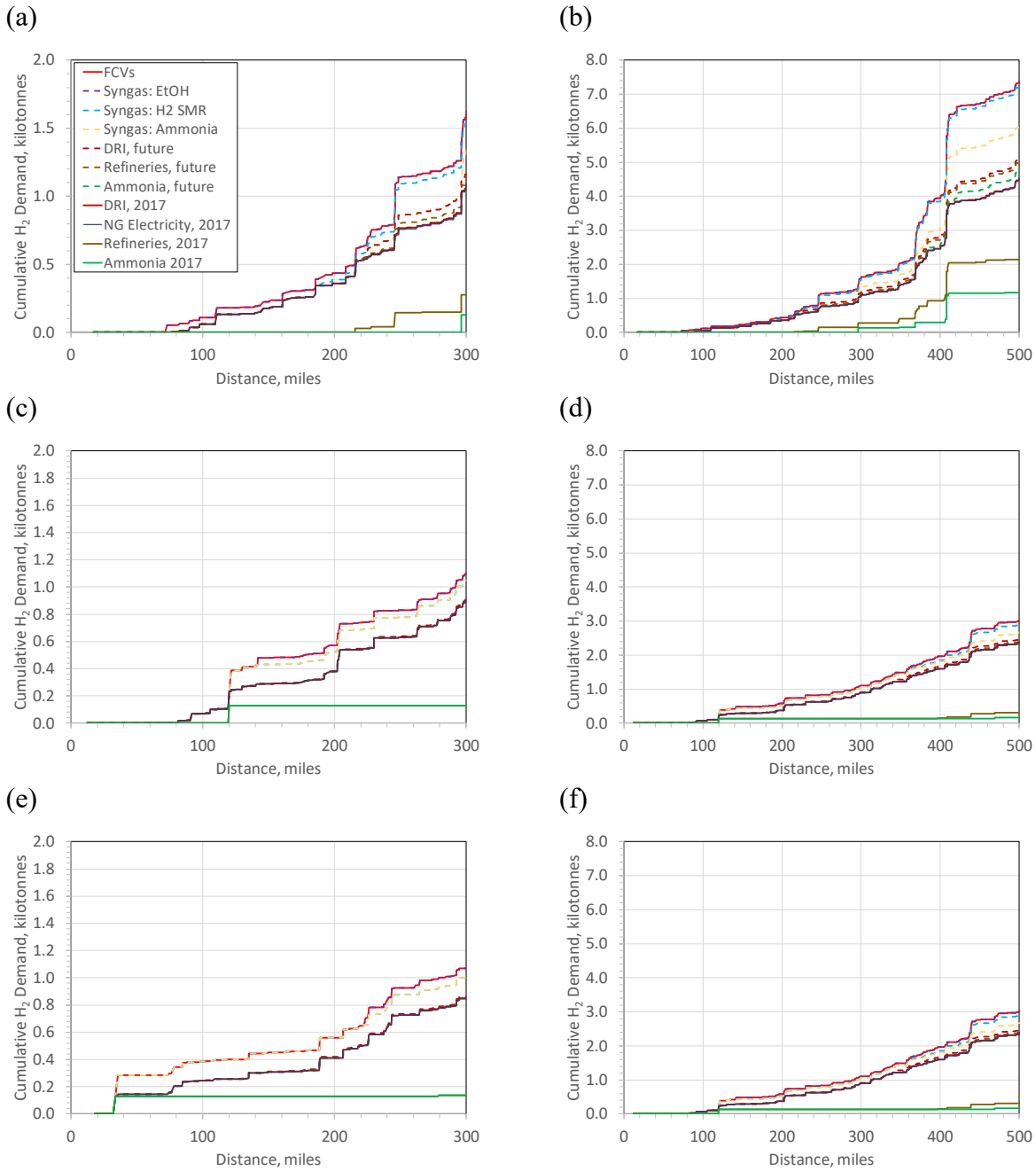


Figure 3. Hydrogen demand by type and distance from Southern Company generation stations: (a) demand up to 300 miles from the Farley Generating Station and (b) demand up to 500 miles from the Farley Generating Station, (c) demand up to 400 miles from the Hatch Generating Station, (d) demand up to 500 miles from the Hatch Generating Station, (e) demand up to 300 miles from the Vogtle Generating Station, and (f) demand up to 500 miles from the Vogtle Generating Station.

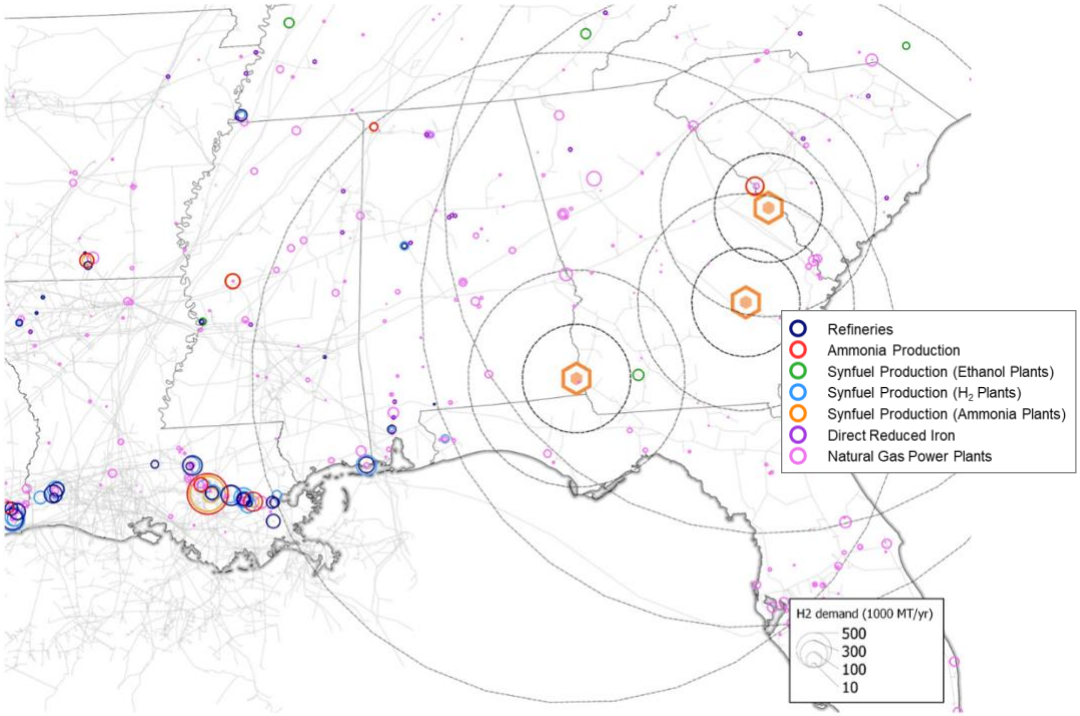
This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

The total potential hydrogen demand within 200 miles of the Hatch Generating Station currently is 0.38 MMT/year (or 1000 MT/day), consisting of one ammonia producer, the Nutrien's Augusta facility at a distance of 120 miles, with potential hydrogen demand of 0.13 MMT/year, two steel producers with a total potential hydrogen demand of 0.001 MMT/year, and 71 natural-gas generators with potential hydrogen demand totaling 0.25 MMT/year. Four notable potential hydrogen markets for burning in natural-gas generators are Georgia Power's McIntosh generator at 0.046 MMT/year, South Carolina Electric & Gas' Jasper generator at 0.030 MMT/year, JEA's Brandy Branch generator at 0.021 MMT/year, and South Carolina Public Service Authority's John S. Rainey generator at 0.037 MMT/year. The increase in future potential hydrogen demand within 200 miles of the Hatch Generating Station is 0.14 MMT/year for production of synthetic fuels from Nutrien Augusta's byproduct carbon dioxide, 0.050 MMT/year for production of synthetic fuels from byproduct carbon dioxide from Flint Hills Resources' Camilla ethanol-production facility, and 0.037 MMT/year for producing DRI at the Gerdau Long Steel Jacksonville and Commercial Metals' South Carolina facilities.

The total potential hydrogen demand within 200 miles of the Vogtle Generating Station currently is 0.26 MMT/year (or 700 MT/day). Half of this is Nutrien's Augusta facility at a distance of 34 miles, with a potential hydrogen demand of 0.13 MMT/year. Most of the other half, i.e., 0.13 MMT/year, is for hydrogen co-combustion with natural gas, with demand coming from 23 natural-gas electricity generators. Of these, 0.076 MMT/year is from two natural-gas generators: Georgia Power's McIntosh generator and South Carolina Electric & Gas Company's Jasper generator, at distances of 78 and 85 miles, respectively. The remainder comes from four steel producers, with a combined potential hydrogen demand of 0.003 MMT/year for DRI. Note the mismatch between the total and the sum is due to rounding. The most notable increase in future potential hydrogen demand near the Vogtle Generating Station is 0.14 MMT/year for production of synthetic fuels from Nutrien Augusta's byproduct carbon dioxide. Other potential hydrogen demands are associated with four steel producers that have a combined potential future hydrogen demand for DRI of 0.01 MMT/year. Future hydrogen demand for FCVs is modest, with a total projected hydrogen demand of 0.0014 MMT/year in 2030 across the entire states of Alabama, Florida, Georgia, Louisiana, Mississippi, North Carolina, South Carolina, and Tennessee.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

(a)



(b)

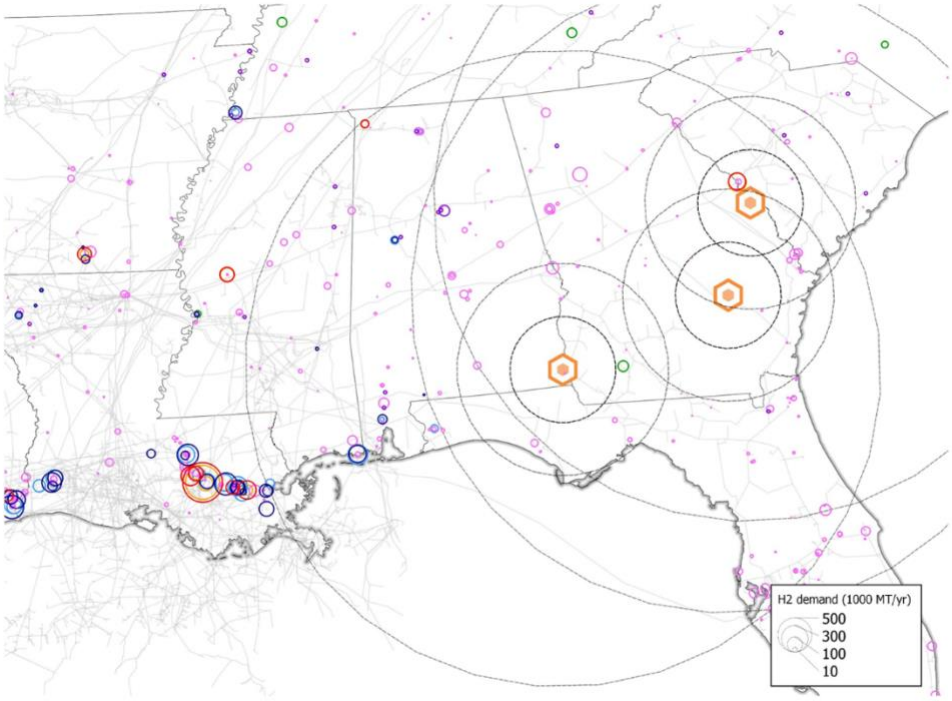


Figure 4. Hydrogen demand near the Southern Company Farley, Hatch, and Vogtle Generating Stations, (a) current demand (2017), (b) potential future demand in approximately 2030.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

1.9 Xcel Energy: Potential Demand near Prairie Island Nuclear Power Plant

The Xcel Energy Prairie Island Nuclear Generating Plant is a 1,100 MW facility located about 40 miles southeast of Minneapolis-St. Paul in Red Wing, Minnesota. This analysis considers the potential opportunities for marketing renewable hydrogen which they could produce. Figure 5 shows the potential cumulative hydrogen demand at increasing distances from the facility. Figure 5a shows the cumulative hydrogen demand within 50 miles of the Prairie Island Generating Plant, while Figure 5b extends the distance to show the total potential hydrogen demand within 150 miles of the facility. Figure 5.c shows the cumulative hydrogen demand within 400 miles of the facility. Entries in Figure 5 include 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 all those below it in the legend.

Current hydrogen demand near the Prairie Island Generating Plant is predominantly from the Western Refining, Inc., and Koch Industries, Inc., refineries located in Saint Paul, Minnesota, within 30 miles from the facility. The combined hydrogen demand from these two refineries is up to 0.114 MMT/year. The rest of the demand of 0.006 MMT/day is associated with the about 24 natural-gas electricity generators located within 150 miles driving distance from Prairie Island.

The potential hydrogen demand in the future scenario for the Prairie Island Generating Plant is about 0.32 MMT/year from facilities within 30 miles. The potential future hydrogen demand would increase to 0.46 and 0.65 MMT/year within 100 and 150 miles, respectively. A majority of the future potential hydrogen demand within 30 miles is from four refineries, two of which—Western Refining Inc., and Koch Industries, Inc.—have a combined demand for 0.145 MMT/year of hydrogen for the refining process, while the other two—Flint Hills Resources Pine Bend Refinery and St. Paul Park Refining Company, LLC.—provide high-purity carbon dioxide with an opportunity to produce synthetic fuels requiring up to 0.17 MMT/year of hydrogen. Additionally, four ethanol plants are located within 100 miles of the Prairie Island Generating Plant: Al-Corn Clean Fuel at Claremont, Guardian Energy, LLC, at Janesville, Pro Corn LLC, at Preston, and Absolute Energy LLC, St Ansgar. These plants can produce synthetic fuels from high-purity carbon dioxide, which would require 0.140 MMT of hydrogen per year. Furthermore, another seven ethanol plants within 150 miles of Prairie Island Station would have a potential hydrogen demand of about 0.19 MMT/year to produce synthetic fuels. Expanding the distance to 400 miles by road from the generating station, the potential total hydrogen demand grows to 2.8 MMT/year.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

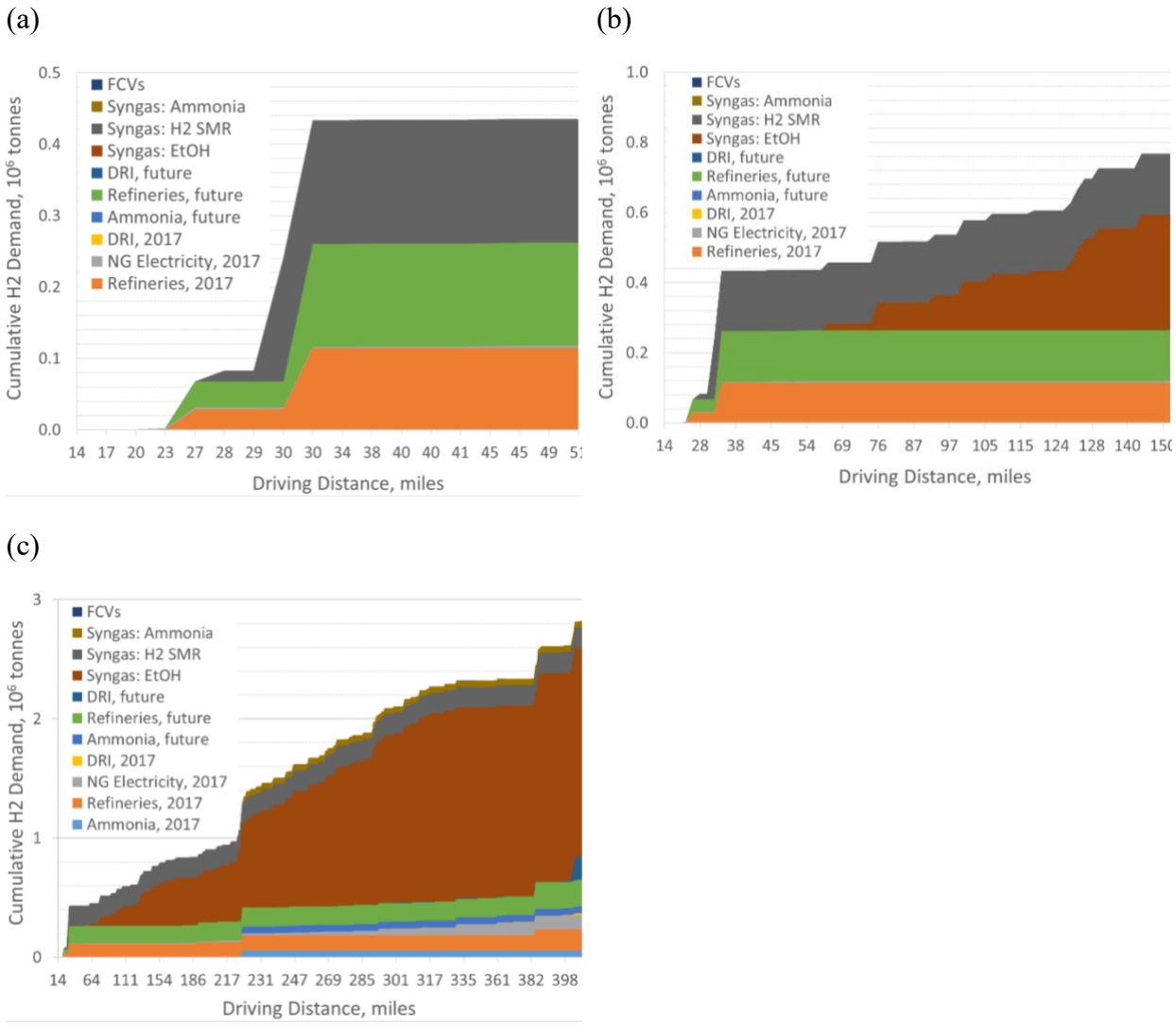


Figure 5. Hydrogen demand by type and distance from Prairie Island Generating Plant: (a) demand up to 50 miles from the Prairie Island and (b) demand up to 150 miles from Prairie Island, (c) demand up to 400 miles from the generating station.

Xcel Energy Denver, Colorado, demand estimates correspond to the following central location (39°45'00.2"N 104°59'24.0"W) near interstate I-25. Figure 6, displays the potential cumulative hydrogen demand at increasing distances from that location. Figure 6a shows cumulative hydrogen demand within 50 miles of the Xcel Denver facility, while Figure 6b extends the distance to show the total potential hydrogen demand within 150 miles of the facility and Figure 6.c shows the cumulative hydrogen demand within 400 miles of the facility. Entries in Figure 6 include both current and future potential hydrogen-demand estimates, with the current demand shown below 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 all those below it in the legend.

Current potential hydrogen demand within 50 miles distance from the Xcel Energy Denver facility is about 0.095 MMT/year (or 260 MT/day), of which about 0.041 MMT/year is from two

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

refineries: Suncor Energy Inc, Commerce City West and Suncor Energy Inc, Commerce City East. About 0.054 MMT/year potential hydrogen demand is from 15 natural-gas electricity generators. About 94% of the natural-gas electricity generators' potential hydrogen demand is from six plants. Increasing the distance range to 100 miles, the current potential hydrogen demand increases to 0.155 MMT/day. A total of 0.61 MMT/year is added due to the increase of the distance from 50 to 100 miles, with 0.049 MMT/year from one refinery, the Hollyfrontier Corp. (0.019 MMT/year), and one ammonia plant, Dyno Nobel (0.03 MMT/year), both at Cheyenne, Wyoming. The majority of the rest of the demand within 100 miles is from 10 natural-gas electricity generators. When the distance from the facility is increased to 150 miles, an additional hydrogen demand of 0.01 MMT/year is added, the majority of which is from two natural-gas electricity generators: the Pueblo Airport Generating Station, Black Hills Service Company LLC (0.0073 MMT/year), and the Comanche, Public Service, Co., of Colorado (0.0011 MMT/year).

The potential hydrogen demand in the future scenario for the Xcel Energy Denver facility is about 0.067 MMT/year from facilities within a 50 miles. The potential future hydrogen demand would increase to 0.182 and 0.223 MMT/year within 100 and 150 miles, respectively. Almost all of the future demand within 50 miles is from three refineries, two of which—the Suncor Energy, Inc., Commerce City West, and the Suncor Energy, Inc., Commerce City East—are expected to use the hydrogen in refineries while the third, Suncor Energy, Commerce City Refinery, has a high-purity carbon dioxide source. Hence, it has the potential to produce synthetic fuels using hydrogen. Extending the distance to 100 miles, the potential future hydrogen demand near the Xcel Energy Denver facility increases by 0.115 MMT/year. Almost all of that increase is associated with five facilities, three of which have the opportunity to produce synthetic fuels with the available high-purity carbon dioxide. These would require 0.061 MMT of hydrogen per year. The other two facilities include a refinery requiring about 0.024 MMT/year and an ammonia production plant, which requires 0.03 MMT/year. Further increasing the distance to 150 miles, the potential demand for hydrogen increases by another 0.043 MMT/year, of which 0.04 MMT/year of hydrogen can be used to produce synthetic fuels using high-purity carbon dioxide from two ethanol plants: Yuma Ethanol LLC, at Yuma, and Sterling Ethanol LLC, at Sterling. A small share of potential hydrogen demand is from possible on-road FCVs by 2030. Expanding the distance to 400 miles from the Xcel Energy Denver facility, the potential total hydrogen demand would be up to 1.2 MMT/year.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

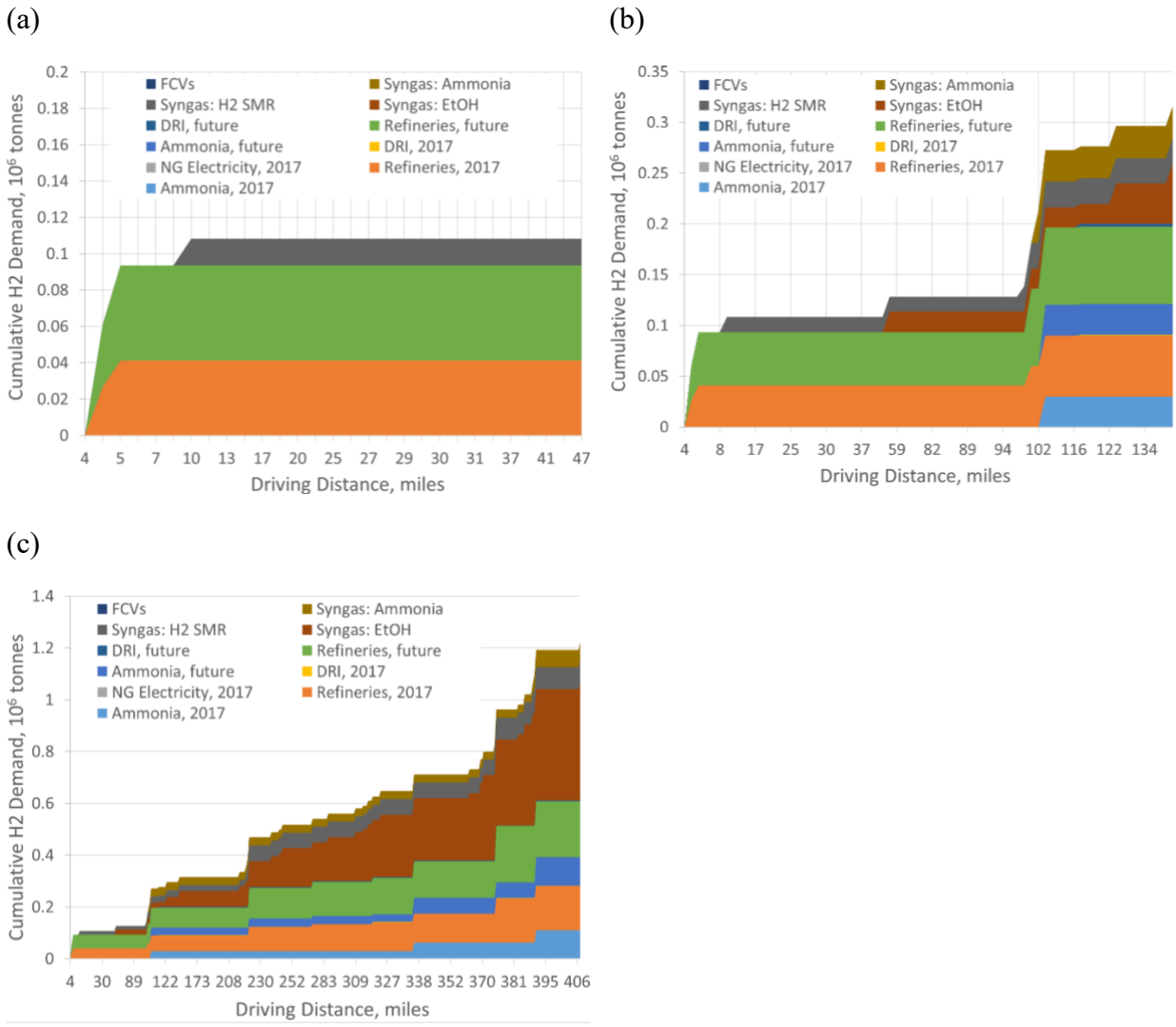


Figure 6. Hydrogen demand by type and distance from Xcel Energy facility in Denver, Colorado: (a) demand up to 50 miles from the facility, (b) demand up to 150 miles from the facility, and (c) demand up to 400 miles from the facility.

1.10 References

Ammonia Industry, 2018. "Ammonia Capacity in North America." https://ammoniaindustry.com/download-ammonia-capacity-in-north-america/

CARB, 2016. *Mobile Source Strategy*, California Environmental Protection Agency, Sacramento, CA.

Chevrier, V., 2018. "Hydrogen Uses in Ironmaking," presented at the H2@Scale Workshop, Chicago, IL (August 1). https://www.energy.gov/sites/prod/files/2018/08/f54/fcto-h2-scale-kickoff-2018-8-chevrier.pdf

EIA, 2017a. *Annual Energy Outlook 2017.* DOE/EIA-0383(2017), U.S. Energy Information Administration, Washington, DC. https://www.eia.gov/outlooks/aeo/.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

EIA, 2017b. “Petroleum & Other Liquids.” https://www.eia.gov/petroleum/.

EIA, 2018a. “Petroleum & Other Liquids: Refinery Capacity Report.” https://www.eia.gov/petroleum/refinerycapacity/.

EIA, 2018b. “Petroleum & Other Liquids: Natural Gas Used as Feedstock for H_2 Production.” https://www.eia.gov/dnav/pet/pet_pnp_feedng_k_a.htm.

EIA, 2018c. “Petroleum & Other Liquids: Refinery & Blender Net Input.” https://www.eia.gov/dnav/pet/PET_PNP_INPT_A_EPOOOH_YIR_MBBL_A.htm.

EIA, 2018d. Petroleum & Other Liquids: U.S. Fuel Ethanol Plant Production Capacity Archives. https://www.eia.gov/petroleum/ethanolcapacity/archive/2017/index.php.

Elgowainy, A., J. Han, H. Cai, M. Wang, G.S. Forman, and V.B. DiVita, 2014. “Energy Efficiency and Greenhouse Gas Emission Intensity of Petroleum Products at U.S. Refineries,” *Environmental Science & Technology,* Vol. 48(13):7612–7624. https://doi.org/10.1021/es5010347.

Elgowainy A, Mintz M, Han J, Lee U, Stephens T, Sun P, Vyas A, Zhou Y, Talaber L, Folga S, McLamore M. ‘Assessment of the Potential Demand for Hydrogen in Vehicle and Industrial Applications.’ Argonne National Laboratory. Lemont, Illinois. **2019**.

EPA, 2017. *Inventory of U.S. Greenhouse Gas Emissions and Sinks 1990–2016*. Report EPA 430-R-18-003, Washington, DC. https://www.epa.gov/sites/production/files/2018-01/documents/2018_complete_report.pdf

Han, J., A. Elgowainy, M.Q. Wang, and V.B. DiVita, 2015. *Well-To-Wheels Analysis of High Octane Fuels with Various Market Shares and Ethanol Blending Levels*, ANL/ESD-15/10. Argonne National Laboratory, Argonne, IL.

Liebman M., 2018. ‘North American Steel Plants Map, 2018 Edition.’ AIM Market Research. http://aimmarketresearch.com/?page_id=357

Supekar, S.D., and S.J. Skerlos, 2014. “Market-Driven Emissions from Recovery of Carbon Dioxide Gas,” *Environmental Science & Technology,* Vol. 48(24):14615–14623. DOI: 10.1021/es503485z

USGS, 2017. *Mineral Commodity Summaries 2017*, U.S. Geological Survey, Reston, VA. https://minerals.usgs.gov/minerals/pubs/commodity/nitrogen/mcs-2017-nitro.pdf.

USGS, 2018, ‘Metals and Minerals: U.S. Geological Survey Minerals Yearbook 2014, Volume I: Iron and Steel.’ U.S. Geological Survey. Reston, Virginia. https://doi.org/10.3133/mybvI

USCB, 2015. ‘Centers of Population by County for the 2010 Census.’ U.S. Census Bureau. Washington, D.C. https://www.census.gov/geographies/reference-files/2010/geo/2010-centers-population.html

USCB, 2018. ‘Annual Resident Population Estimates, Estimated Components of Resident Population Change, and Rates of the Components of Resident Population Change for States and Counties: April 1, 2010 to July 1, 2017.’ U.S. Census Bureau. Washington, D.C. https://www2.census.gov/programs-surveys/popest/datasets/2010-2017/counties/totals/co-est2017-alldata.pdf

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

TASK 2: Project preliminary power generation and load demand profiles (relative to select nuclear plants and estimate value of grid services, capacity payments, grid stability factors).

TASK 2 DESCRIPTION:

This task will be completed by NREL, based on input from SCS, Exelon, and Xcel, and NREL lab data bases and future supply/demand profile projections. Task 2 will bound the value that electrolysis can provide to the grid, based on previous studies and through communication with the utility partners and by incorporating recent energy and capacity market prices in the relevant service territories. Deliverable: Data files indicating temporal analysis of projected electricity prices and power generation by renewables and nuclear plants bases for each utility.

TASK 2 SUMMARY AND OUTCOME:

NREL led the effort to develop power generation profiles and price duration curves. NREL also considered capacity payments under each utility's situations. Further details follow.

2 ELECTRICITY MARKET

In the U.S., there are two electricity-market configurations: regulated and deregulated. In regulated markets, states oversee utility decisions about the amount of capacity to procure from power plants and other resources [7]. In deregulated markets, entities known as regional transmission organizations (RTOs) act as electricity suppliers and purchase electricity at independently owned power plants to sell to retail customers. Seven RTOs operate across the U.S.: the California Independent System Operator (ISO), Southwest Power Pool, Electric Reliability Council of Texas (ERCOT), Midcontinent ISO, PJM Interconnection (PJM), New York ISO, and ISO New England, as illustrated by Figure 7. It should be noted that not all RTOs operate in deregulated markets; in other parts of the U.S., the RTOs act only as grid operators based on fixed purchase and selling prices.

For purposes of this study, two key differences are noted. First, for regulated utilities such as Southern Company and Xcel in Colorado, the price of electricity is the same regardless of location. However, for Xcel in other states and for Exelon, the location as well as the hour must be specified to understand the electricity price. Second, regulated utilities work with their states to ensure adequate capacity to serve all customers is available. However, in deregulated markets, RTOs issue manage a capacity market, in addition to the energy market.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

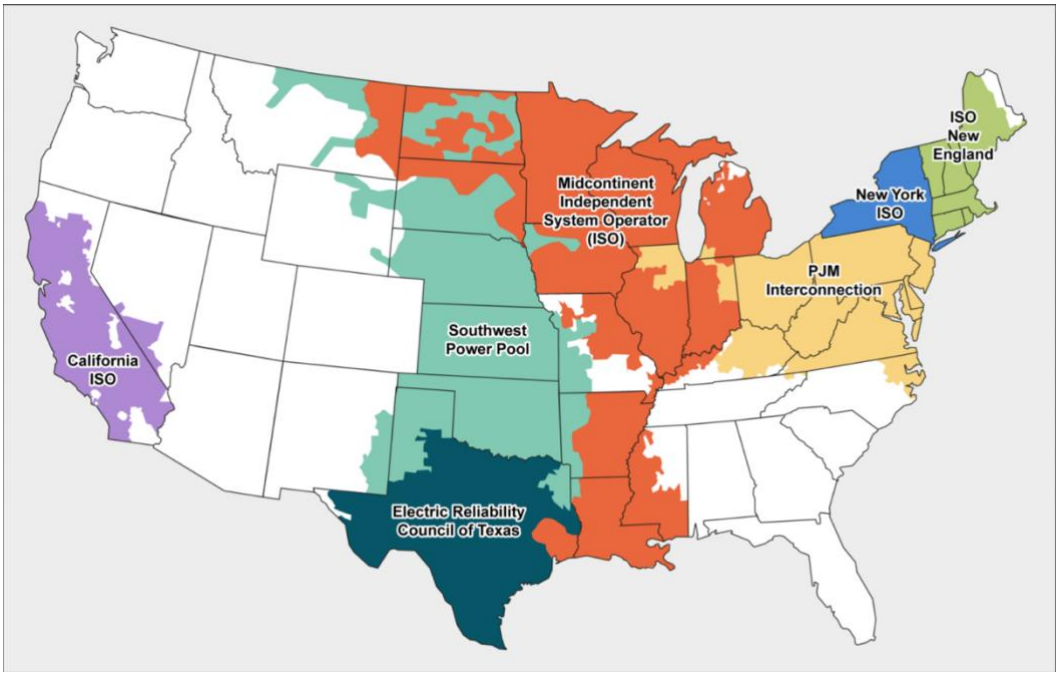


Figure 7. Map of RTOs within contiguous United States [7].

Historical and projected power prices for specific regions within the operating regions of the Southern Company, Exelon, and Xcel Energy were assimilated to allow further analysis into business cases for hydrogen produced via both low-temperature high-temperature electrolysis (HTE). Through communication with the CRADA partners, a set of scenarios were identified, along with their individual specifications. The scenarios identified have one of three different pricing structures: 1) market-based locational marginal price (LMP), or hourly pricing in regulated markets, which represents the cost of providing the next Megawatt (MW) of electricity at a specific node or within the service territory at each hour of the year or 2) a contract-based power-purchase agreement (PPA) for which a fixed dollar-per-MWh value was determined for all hours of the year, or 3) direct renewables (solar PV)-to-hydrogen production (isolated from the grid).

Through several rounds of conversations with the CRADA partners, the energy and grid services required for the project were identified. Prices relating to energy and capacity markets were determined to have the most value whereas price information relating to ancillary services was determined to have less value and was therefore not included in the analysis. The project team discussed and settled on exact time frames and data sources after several rounds of analysis and discussions. During those iterations, NREL obtained historical LMPs for multiple years, as well as a set of potential projected prices. Those projected prices are from previous capacity-expansion and economic-dispatch models and studies that NREL had previously completed. The reported price data consist of both NREL-obtained and utility-provided data; details are in following sections.

2.1 Price-duration Curves

The format identified for electricity prices was a price-duration curve. A price-duration curve sorts its data from the largest positive to the most negative numbers. A typical price-duration

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

curve has a flat middle section between two tails at the extreme ends of the data set. The data collected by NREL was hourly, and each price-duration curve therefore has 8760 data points. The PPA-based scenarios did not have a price-duration curve, as the price in each hour was equal. Therefore, the formatting of the data into a price-duration curve was only required for scenarios which assumed a market-based LMP pricing structure. Because price-duration curves are sorted from highest to lowest price hours, the timing and frequency of changes are not reported in them. The project team did not use those factors within this analysis.

2.2 Capacity Market Pricing

In many restructured electricity markets, capacity payments are made to generators for the capacity they have available to produce electricity at key times, regardless of how much electricity they actually produce. Such capacity markets are run to ensure reliability of the power system by incentivizing entry of new generation and to provide payments to generation that may be critical for system reliability but may not be profitable from selling electricity alone.

Capacity markets are only present in some regions which are part of auction-based wholesale electricity markets run by an ISO or RTO. These include, among others, the PJM and Midcontinent Independent System Operator (MISO) ISO regions. Exelon and Xcel Energy have operating regions that are situated within PJM and MISO controlled regions; therefore, historical and recently cleared capacity market prices are available for each and are used in this study. The Southern Company is a vertically integrated utility with no auction-based markets (capacity or otherwise). Therefore, we excluded capacity payments from all scenarios for the Southern Company, as well as from scenarios using a cost-of-service-based PPA structure.

PJM runs their capacity market with a 3 year forward period [8, 9]. Capacity clearing prices were therefore available from 2012 to 2021. This can be seen in **Table 1**. We focus on the ComEd Capacity Market Zone, which is where the Exelon scenarios take place. Note all prices are nominal

Table 1. Recent capacity market clearing prices within PJM ComEd.

Capacity Market Zone	ISO Name	Capacity Commitment Period Start Date	Capacity Price $/MW-Day (nominal)
ComEd	PJM	6/1/2012	16.74
ComEd	PJM	6/1/2013	27.73
ComEd	PJM	6/1/2014	125.92
ComEd	PJM	6/1/2015	134.62
ComEd	PJM	6/1/2016	59.37
ComEd	PJM	6/1/2017	119.67
ComEd	PJM	6/1/2018	212.71
ComEd	PJM	6/1/2019	199.56
ComEd	PJM	6/1/2020	188.05
ComEd	PJM	6/1/2021	195.55

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Unlike PJM, MISO procures capacity on an annual basis. The MISO capacity planning period is from June to May and capacity is procured in April of the same year. Capacity clearing prices were available from 2013 to 2018. They are summarized in **Table 2**. We focus on the Zone-1 Capacity Market Zone, which is the location of the Minnesota-based Xcel Energy scenarios [10].

Table 2. Recent capacity market clearing prices within MISO Zone 1.

Capacity Market Zone	ISO Name	Capacity Commitment Period Start Date	Capacity Price $/MW-Day (nominal)
MISO Zone 1	MISO	6/1/2013	1.05
MISO Zone 1	MISO	6/1/2014	3.29
MISO Zone 1	MISO	6/1/2015	3.48
MISO Zone 1	MISO	6/1/2016	19.72
MISO Zone 1	MISO	6/1/2017	1.50
MISO Zone 1	MISO	6/1/2018	1.00

The annual capacity payment made to generators is based on the amount of capacity the generator has agreed to provide to the capacity market (in MW) multiplied by the capacity market clearing price (in $/MW-day) times 365 days in the year. Thus, the total capacity payment received would be:

Capacity Submitted × Clearing Price × 365 = Total Capacity Payment

Generators that provide capacity in the capacity market will receive a daily credit for every day of the delivery year, regardless of how much electricity is generated [11].

Within MISO and other ISOs, variable resources, such as wind, are eligible to bid in a de-rated amount of their nameplate capacity because their generation is variable. This de-rating is often called the capacity credit and is based on historic performance of wind generators during certain peak-demand periods during the year. In MISO, the capacity credit is calculated for each wind commercial-pricing node (CPNode) in the MISO system, of which there were 207 at the end of 2017 (up from 204 in 2016). The historic output at each of these wind CPNodes is tracked over the top eight daily peak hours for each year from 2005 to 2017 (or since the windfarm was commissioned). The average capacity factor for each CPNode during all 104 hours (8 hours × 13 years) is then used as a basis for awarding the capacity credit. In the 2018–2019 MISO planning year, the average wind capacity credit across the CPNodes within MISO Zone 1 was 18.3% [12].

The capacity submitted to the capacity markets within PJM and MISO is called unforced capacity (UCAP), and it must be less than or equal to the generator's installed capacity adjusted by the equivalent-demand forced-outage rate (EFORd). The EFORd is a measure of the probability that a unit will not be available due to forced outages or forced de-ratings when there is a demand on the unit to generate [13]. Therefore,

Unforced Capacity = Installed Capacity × [1 - Equivalent Demand Forced Outage Rate]

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

For a nuclear generator the EFORd is usually very small, and in 2015 the U.S. average was 1.1% [14]. This small EFORd for nuclear is reflected by historic nuclear UCAP bids. For example, the nuclear UCAP submission to the PJM capacity market each year is very close to the actual installed capacity of the nuclear fleet, suggesting that most nuclear generators are submitting almost 100% of their installed capacity to the PJM capacity market [15].

Therefore, we recommend using an EFORd of 1.1% for the nuclear generators' capacity payments. Following conversations with Exelon, it was agreed that it can be assumed that any unit looking to install hydrogen production will have cleared 100% of bid capacity. For Xcel Energy, we recommend using the installed capacity of the Prairie Island Nuclear Power Plant to align with Xcel Energy's high-temperature electrolysis scenario. The installed capacity of the Prairie Island plant is 1041 MW.

2.3 Scenarios by Utility

In the following sections the scenarios and their price-duration curves for each of the three utilities will be presented.

2.3.1 Southern Company

Three scenarios are examined for Southern Company, as detailed in Table 3. The first is a direct PV-to-hydrogen production facility that is isolated from the grid: all electricity generated via the solar panels is used to create hydrogen via electrolysis. NREL created ten different sets of PV results with installed capacities of 10–100 MW, the solar facility was modeled in Columbus, Georgia, using NREL's System Advisory Model (SAM) software [16]. Hourly outputs from SAM were organized from peak output to minimum output to create a production-duration curve, as seen in Figure 8. A production-duration curve is formatted in the same way as a price-duration curve defined previously, with units in MW rather than $/MWh. Total capital expenditure costs were also calculated using SAM with specific individual-element costs taken from the "Q1 2018 U.S. Solar Photovoltaic System Cost Benchmark" [17], itemized costs for each installation are presented in Table 4. Because the PV and hydrogen facility are isolated from the grid, no electricity will be bought or sold. Therefore, this scenario does not have a price-duration curve or other MWh pricing structure. The set of production-duration curves and capital expenditure costs were then passed to INL, which conducted further analysis including the sizing of an electrolyzer to the PV installation.

Table 3. Southern Company Scenarios.

#	Scenario Name	Location	Electricity Pricing	H_2 Technology	Data Year	Capacity Market Scenario
1	Low Temp Electrolyzer	Southern – Footprint Wide	2025 - Marginal Cost Timeseries	Low Temp Electrolyzer	2025 (Hourly)	No
2	HTE Steam Reforming	Southern – Footprint Wide	2025 - Marginal Cost Timeseries	HTE Steam Reforming	2025 (Hourly)	No
3	Solar PV to H_2	Columbus, Georgia	Direct PV to H2 no electricity pricing	Solar PV to H_2	Q1 2018 PV Technology Costs	No

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

In Figure 8, the peak output of the PV site is curtailed to 8.33 MW due to the modeled DC to AC inverter ratio of 1.2, which is a typical value used in industry. The reason for combining a smaller rated inverter with a larger rated PV array is primarily an economic one. Since the output of the PV panels may only reach their maximum DC capacity for a few hours of the year, it is usually not cost effective to size an AC inverter to capture the full output [18].

Modules, power converter, permitting, land purchase and land preparation have a constant $/Wdc cost across all PV installations, as seen in Table 4. Balance of system (BOS) costs, installation labor, and overhead have a variable $/Wdc cost across the PV installations, with larger installations costing less per Wdc.

The second and third Southern Company scenarios model grid-connected low- and high-temperature electrolysis installations, using a marginal cost timeseries formatted as a price-duration curve. Southern Company provided NREL with a set of energy prices ranked by the fraction of annual hours at or below each price. NREL then used this information to create an 8760 price-duration curve.

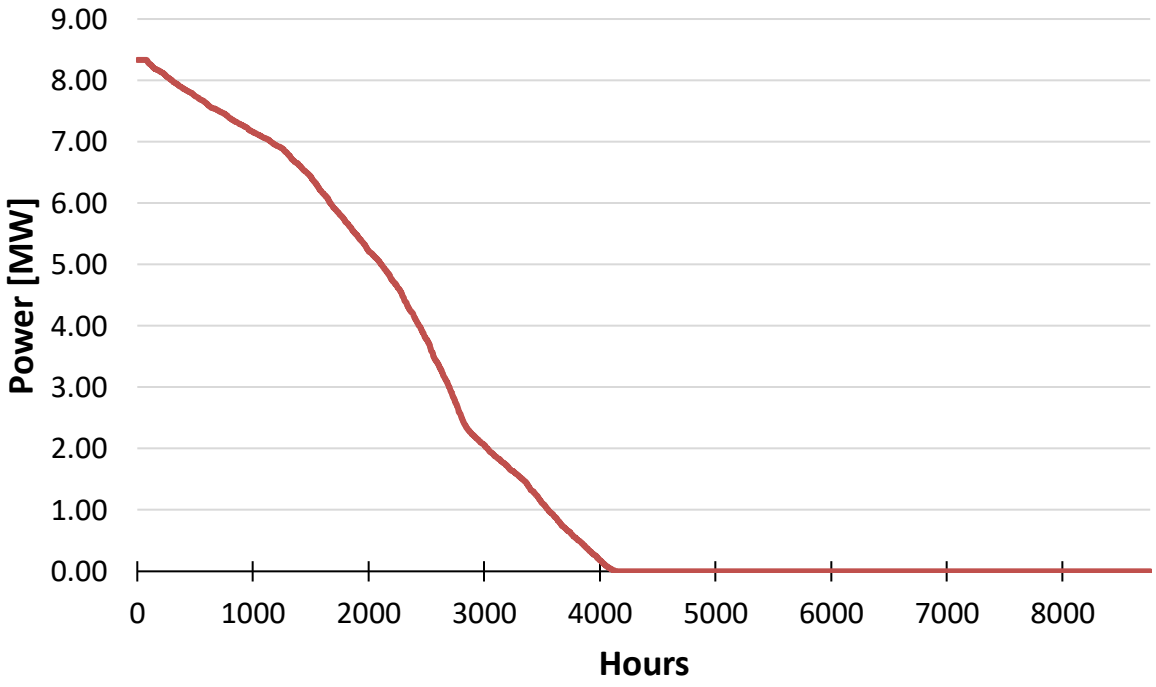


Figure 8. 10 MW solar-PV production-duration curve.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Table 4. Itemized solar-PV installation costs in $/Wdc by installed capacity, taken from the "Q1 2018 U.S. Solar Photovoltaic System Cost Benchmark."

	10 MW	20 MW	30 MW	40 MW	50 MW	60 MW	70 MW	80 MW	90 MW	100 MW
Module	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47	0.47
Power Converter	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
BOS	0.3	0.29	0.28	0.26	0.25	0.24	0.23	0.22	0.22	0.21
Installation Labor	0.12	0.12	0.12	0.11	0.11	0.11	0.11	0.1	0.1	0.1
Installer Margin and Overhead	0.09	0.09	0.09	0.08	0.08	0.08	0.07	0.07	0.06	0.06
Permitting	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
Developer Overhead	0.09	0.08	0.06	0.04	0.03	0.03	0.03	0.02	0.02	0.02
Land Purchase	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Land Prep	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
Total $/Wdc	1.18	1.16	1.13	1.07	1.05	1.04	1.02	0.99	0.98	0.97

2.3.2 Exelon

Two scenarios are examined for Exelon. Both scenarios are based on High Temperature Electrolysis (HTE) and use historical LMP data from the Northern Illinois Hub from 2017. The LMP data were obtained through the licensed ABB Energy Velocity Suite. Table 5 details the two scenarios.

Table 5. Exelon scenarios.

#	Scenario Name	Location	Electricity Pricing	H_2 Technology	Data Year	Capacity Market Scenario
1	HTE: Small Demo Recent History	Ni-Hub PJM	Hourly Market LMP	HTE: Small Demo	2017 (Hourly)	Yes
2	HTE: Large Demo Recent History	Ni-Hub PJM	Hourly Market LMP	HTE: Large Demo	2017 (Hourly)	Yes

The price-duration curve used for both Exelon scenarios can be seen in Figure 9. The maximum LMP value is greater than 600 $/MWh, but LMPs are limited to 200 $/MWh in the figure for easier viewing.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

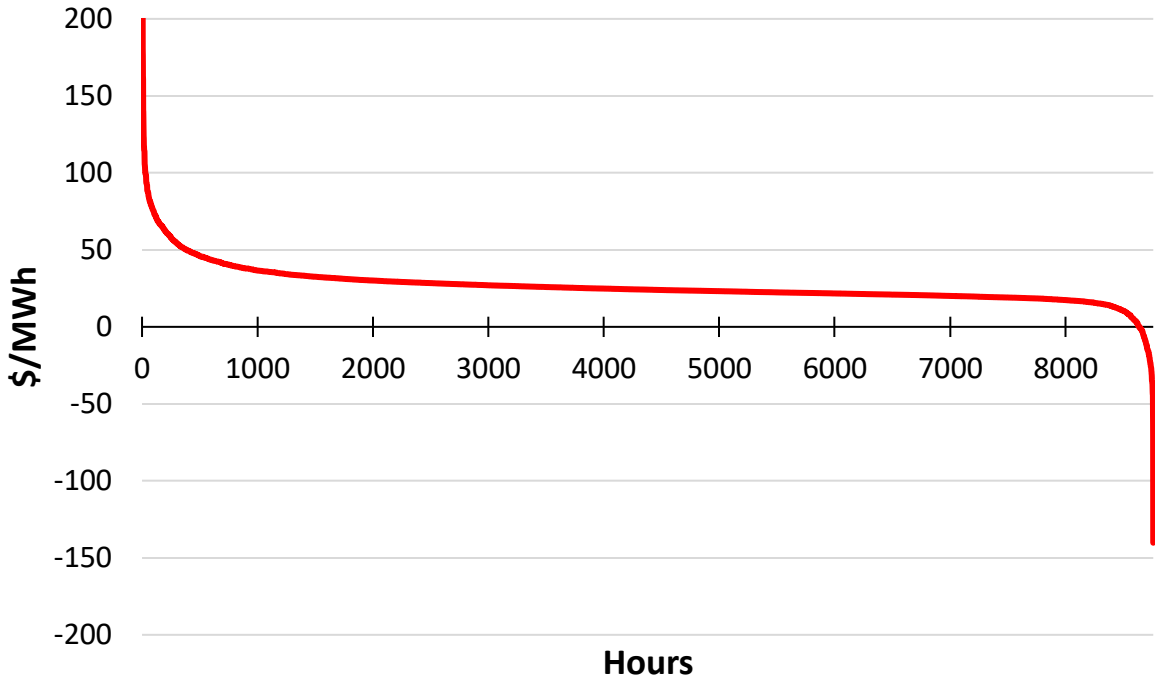


Figure 9. Exelon scenarios' price-duration curve.

2.3.3 Xcel Energy

Xcel Energy has multiple operating locations, which encompass different market and vertical utility operating areas. Seven scenarios are examined for Xcel Energy, taking place in 3 different locations. Four of the scenarios use an hourly pricing structure and three use a (fixed) PPA pricing structure. All scenarios are based on a wind-to-hydrogen technology, except for one which is a nuclear HTE scenario. **Table 6** details the seven Xcel Energy scenarios.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Table 6. Xcel Energy scenarios.

#	Scenario Name	Location	Electricity Pricing	H_2 Technology	Data Year	Capacity Market Scenario
1	MISO-MINN Market Wind to H_2	Minnesota MINN Hub	Hourly Market LMP	Wind to H_2	2025 (hourly)	Yes
2	MISO-MINN Market HTE	Minnesota MINN Hub: Prairie Island Nuclear	Hourly Market LMP	HTE	2025 (hourly)	Yes
3	SPP South Market Wind to H_2	SPP-South	Hourly Market LMP	Wind to H_2	2025 (hourly)	No
4	Colorado Market Wind to H_2	Colorado: PSCo	Hourly Avoided Cost	Wind to H_2	2025 (hourly)	No
5	Colorado PPA Wind to H_2	Colorado: PSCo	PPA Contract – $25/MWh	Wind to H_2		No
6	MISO-MINN Market Wind to H_2	Minnesota MINN Hub	PPA Contract – $25/MWh	Wind to H_2		No
7	SPP South PPA Wind to H_2	SPP-South	PPA Contract – $25/MWh	Wind to H_2		No

Xcel Energy supplied projected price-duration curves to NREL, but upon inspection, these projections lacked the volatility seen in historic years (i.e., the tails do not include high or low [i.e., negative] prices). In order to reflect this real-world volatility in the price projections, we modified the largest 2000 hours and smallest 2760 hours of the Xcel Energy price-duration curve data to reflect the volatility observed in these tail hours in the 2017 data.

We used hour 2000 of the 2017 data's price-duration curve as the reference. A delta for each previous hour (hours 1 -1999) was calculated as the difference in price between hour 2000 and that previous hour. For example, if the LMP price at hour 2000 is 30 $/MWh and the LMP price at hour 1 is 530 $/MWh, the delta at hour 1 would be 500 $/MWh or the difference in price between hour 1 and 2000. We then calculated new prices for hours 1-1999 in the 2025 projections as their values in hour 2000 plus the delta for each hour.

The same method was then used between hours 6000 and 8760 of the 2017 price-duration curve, with hour 6000 used as the reference. Figure 10 shows this process for the SPP–South price-duration curve.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

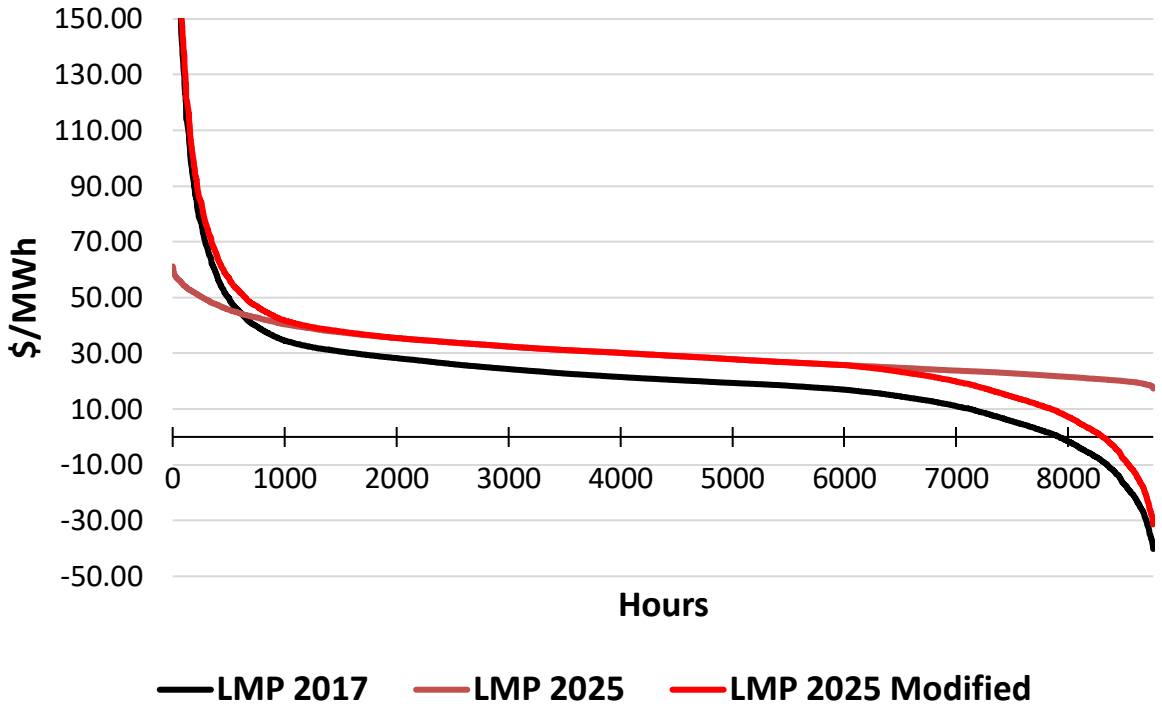


Figure 10. Aligning Xcel Energy projected price-duration curve with 2017 volatility.

The price-duration curves for the four LMP scenarios can be seen in Figure 11 through Figure 13. Scenarios 1 and 2 use the same price-duration curve.

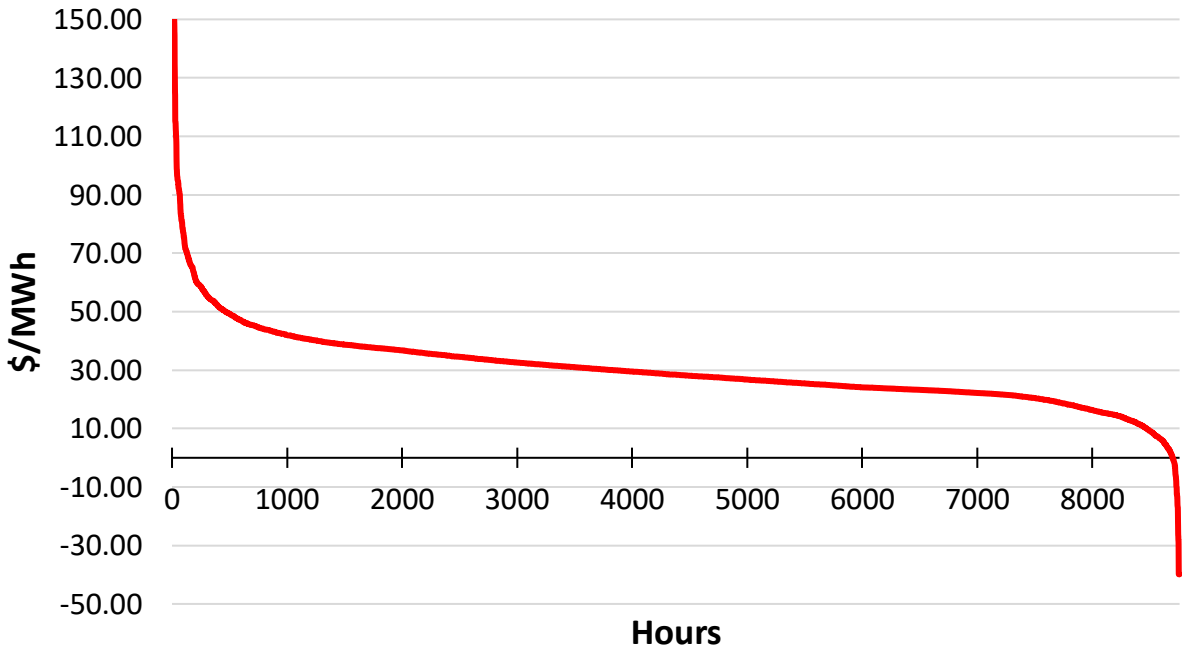


Figure 11. Xcel Energy price-duration curves for Scenarios 1 and 2: Minnesota–MINN HUB.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

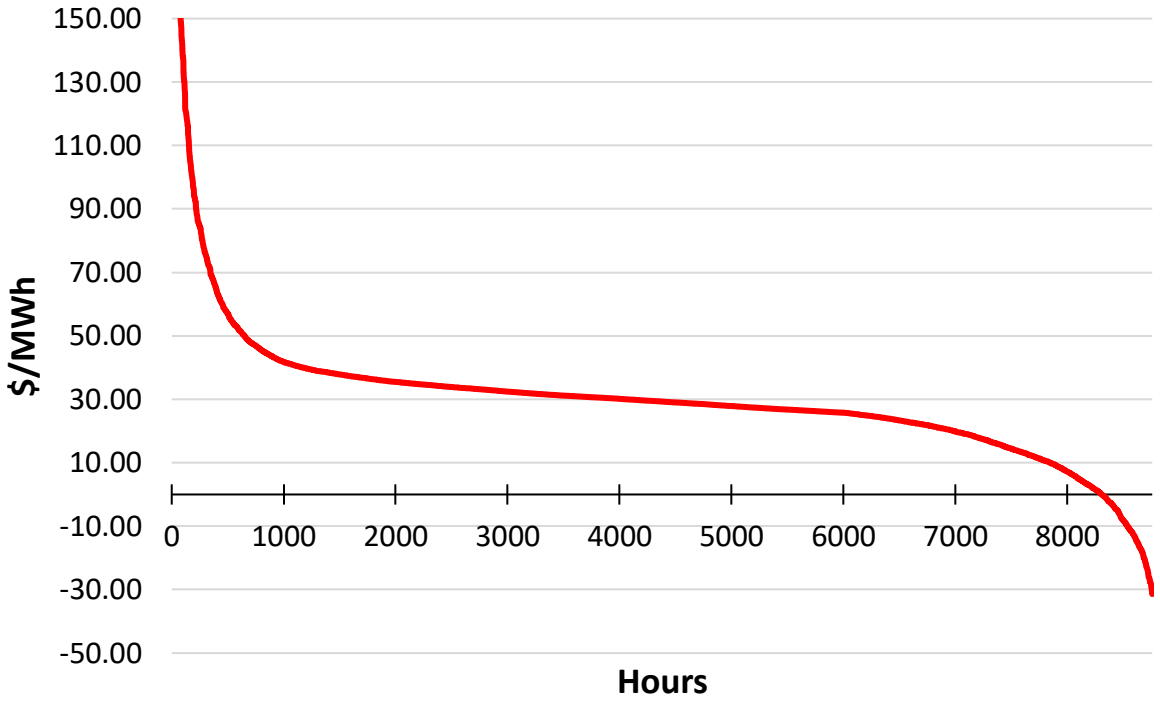


Figure 12. Xcel Energy Scenario 3 price-duration curve: SPP–South.

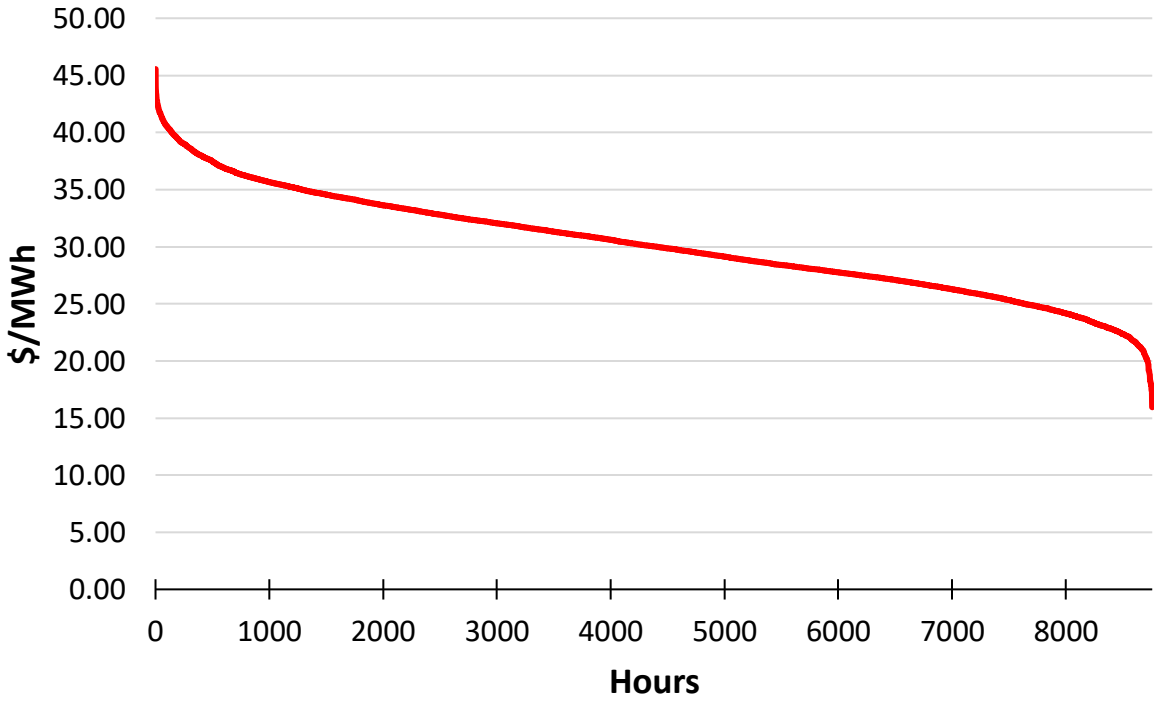


Figure 13. Xcel Energy Scenario 4 price-duration curve: Colorado–PSCo.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Scenarios 5, 6 and 7 use fixed electricity pricing of 25$/MWh. Following conversations with Xcel Energy, this was determined to be a good contract-price estimate for wind generation operating in the 2025–2030 time period within Colorado, Minnesota, and SPP-South. Figure 14 shows this PPA contract graph.

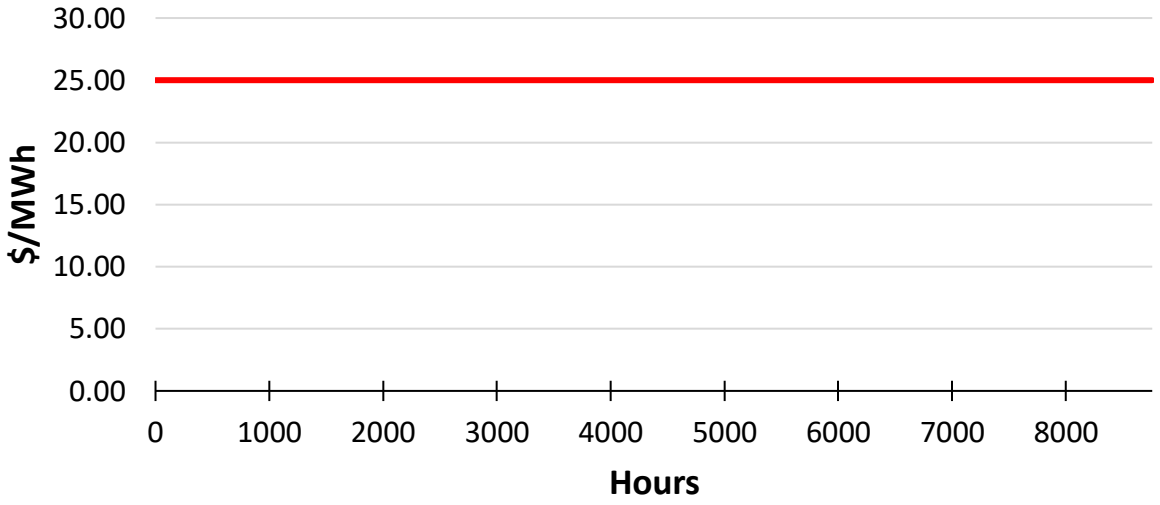


Figure 14: Xcel Energy Scenario 5-7: PPA Contract Price

2.4 References

[1] U.S. Energy Information Administration. (2020, March 11). *U.S. EIA Glossary*. Available: https://www.eia.gov/tools/glossary/

[2] Bird L, Cochran J, Wang X. Wind and Solar Energy Curtailment: Experience and Practices in the United States. Golden, Colorado: National Renewable Energy Laboratory; 2014.

[3] Rogers J, Fink S, Porter KE, Erik. Examples of Wind Energy Curtailment Practices. Columbia, Maryland: Exeter Associates, Inc.; 2010.

[4] St. John J. (2017, March 11). *California's Flood of Green Energy Could Drive a Record 8GW of Curtailment This Spring*. Available: https://www.greentechmedia.com/articles/read/californias-flood-of-green-energy-could-drive-a-record-6-to-8-gigawatts-of

[5] Paulos B. (2017, March 11). *Too Much of a Good Thing? An Illustrated Guide to Solar Curtailment on California's Grid* Available: https://www.greentechmedia.com/articles/read/an-illustrated-guide-to-solar-curtailment-in-california

[6] Fuel Cell Technologies Office. *H2@Scale*. Available: https://www.energy.gov/eere/fuelcells/h2-scale

[7] United States Government Accountability Office. Electricity Markets: Four Regions Use Capacity Markets to Help Ensure Adequate Resources, but FERC Has Not Fully Assessed Their PerformanceGAO-18-131, 2017.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

[8] PJM. (2018, November 27). *Capacity Market (RPM): 2021-2022 Pricing Points*. Available: https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/2021-2022/2021-2022-rpm-pricing-points.ashx?la=en

[9] PJM. (2018, November 27). *Capacity Market (RPM)*. Available: https://pjm.com/markets-and-operations/rpm.aspx

[10] MISO. (2018, April 13). *MISO Energy: 2018/2019 Planning Resource Auction Results*. Available: https://cdn.misoenergy.org/2018-19%20PRA%20Results173180.pdf

[11] PJM. 1.1 Overview of the PJM Capacity Market. PJM Manual 18: PJM Capacity Market2018. p. 15-20.

[12] MISO. (2017). *MISO Energy: Planning Year 2018-2019 Wind Capacity Credit*. Available: https://cdn.misoenergy.org/2018%20Wind%20Capacity%20Report97278.pdf

[13] PJM. 4.2.5 Equivalent Demand Forced Outage Rate (EFORd). PJM Manual 18: PJM Capacity Market2018. p. 68.

[14] Statistica. *Forced outage rate of U.S. nuclear reactors from FY 2000 to FY 2015*. Available: https://www.statista.com/statistics/187283/forced-outage-rate-at-us-nuclear-reactors-since-2000/

[15] PJM. (2018, May 23). *Capacity Market (RPM): Commitments by Fuel Type & Delivery Year 2007/08 - 2021/22*. Available: https://pjm.com/-/media/markets-ops/rpm/rpm-auction-info/rpm-commitment-by-fuel-type-by-dy.ashx?la=en

[16] National Renewable Energy Laboratory. *System Advisor Model (SAM)*. Available: https://sam.nrel.gov/

[17] Fu R, Feldman D, Margolis R. U.S. Solar Photovoltaic System Cost Benchmark: Q1 2018: National Renewable Energy Laboratory; 2018.

[18] EIA. (2018). *Solar plants typically install more panel capacity relative to their inverter capacity*. Available: https://www.eia.gov/todayinenergy/detail.php?id=35372

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

TASK 3: Preliminary assessment of hydrogen storage needs, opportunities, and challenges.

TASK 3 DESCRIPTION:

This task will be completed by ANL utilizing ANL existing models applicable to hydrogen storage and delivery systems. Estimated weekly and annual hydrogen storage needs will be projected. Recent DOE reports on cavern storage will be used in case of large energy storage needs. Deliverable: Tabulated storage requirements needed in each service territory to support firm capacity, and the requirements to support regional hydrogen markets.

TASK 3 SUMMARY AND OUTCOME:

The CRADA team determined that storage could not be estimated under this project's funding level and scope because it would require hourly hydrogen production and demand profiles. Since those were not generated in Tasks 1 and 2, they were not available. Therefore, instead of estimating storage requirements for each area, additional costs for storage and delivery were added based on each technology. Those include:

- For LTE, an additional delivery and storage cost of $0.08/kg was added to the LCOH calculated by the H2A model.
- For HTE, an additional delivery and storage cost of $0.34/kg was added to the LCOH calculated by the H2A model.
- Xcel scenarios 5, 6, and 7: A delivery & storage cost of $0.40/kg for all scenarios independent of region size and plant capacity.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

TASK 4: Preliminary Technical/economic analysis of hydrogen generation plant options.

TASK 4 DESCRIPTION:

Two cases will be considered: 1) electrolysis of steam provided by the nuclear plant, and 2) low temperature electrolysis that draws only electricity from the nuclear plant. The economic and technical benefits of hybrid operation of the hydrogen plant will be evaluated and compared with the same benefits provided by a cluster of small hydrogen plants that are connected to the grid. Hybrid operations can provide frequency regulation and help firm grid capacity. Assuming that the schedule of hydrogen production and use differ under hybrid operation, the scale, cost, and delivery of hydrogen to end users will also be assessed. Variation in daily, weekly, and seasonal hydrogen production rates will be quantified.

The TEA for centralized plants will be completed by INL. This TEA will be based on a nuclear plant that is closely coupled to a centralized hydrogen production plant that enters into an energy purchase agreement with the nuclear plant owners. A TEA for smaller hydrogen generation plants clustered at industrial plant locations and drawing electrical power from the grid will be completed by NREL. The H2A model will be used to complete both of these analyses. A comparison of hydrogen production costs versus annual operation capacities and estimated power plant capacity payments, grid service benefits, and air pollutant emissions reduction will be made to address the economic feasibility of hydrogen production in each of the utilities' service areas. Capital expenditure (CAPEX)/operational expenditure (OPEX) data for H2A will be updated by INL and NREL, respectively, with current/relevant data obtained from commercial suppliers of technology for distributed electrolysis-based hydrogen plants. The value of low-carbon products will be obtained from a third party. Deliverable: Interim technical evaluation report on TEA outcomes.

TASK 4 SUMMARY AND OUTCOME:

INL led the effort to perform technoeconomic analyses (TEAs) of the selected scenarios. Capital and operating costs and efficiencies of hydrogen production technologies were collected and are in the first subsection. Results from the TEAs are in the second subsection.

4 HYDROGEN PRODUCTION

Hydrogen can be produced from a number of different technology pathways and diverse resources. Today, 95% of the hydrogen produced in the United States is made by natural gas SMR in large central plants. SMR is the most economic technology available in most cases, primarily owing to an abundance of low-cost natural gas. However, this project strictly covers electrolysis—the splitting of water into H_2 and O_2 using electricity—which is commercially available in two technology types, alkaline and PEM. Both of these are low temperature technologies. However, the availability of steam connected with a nuclear power plant is driving interest in solid oxide electrolysis as it is potentially more efficient when utilizing available steam. Thus, this study will look at PEM electrolysis and solid oxide electrolysis.

These electrolysis types are distinguished by the chemistry and materials of separator in the electrolysis cell. Polymer electrolyte membrane (PEM) electrolysis operates at lower

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

temperature, whereas solid oxide (ceramic) electrolysis operates at higher temperature. At the higher temperatures, less electricity is needed to produce the same hydrogen; however, a high-quality heat source must be available. Generally, PEM electrolysis is associated with using grid or renewable electricity, while solid oxide electrolysis is assumed to be co-located with a nuclear power plant.

4.1 Steam Methane Reforming

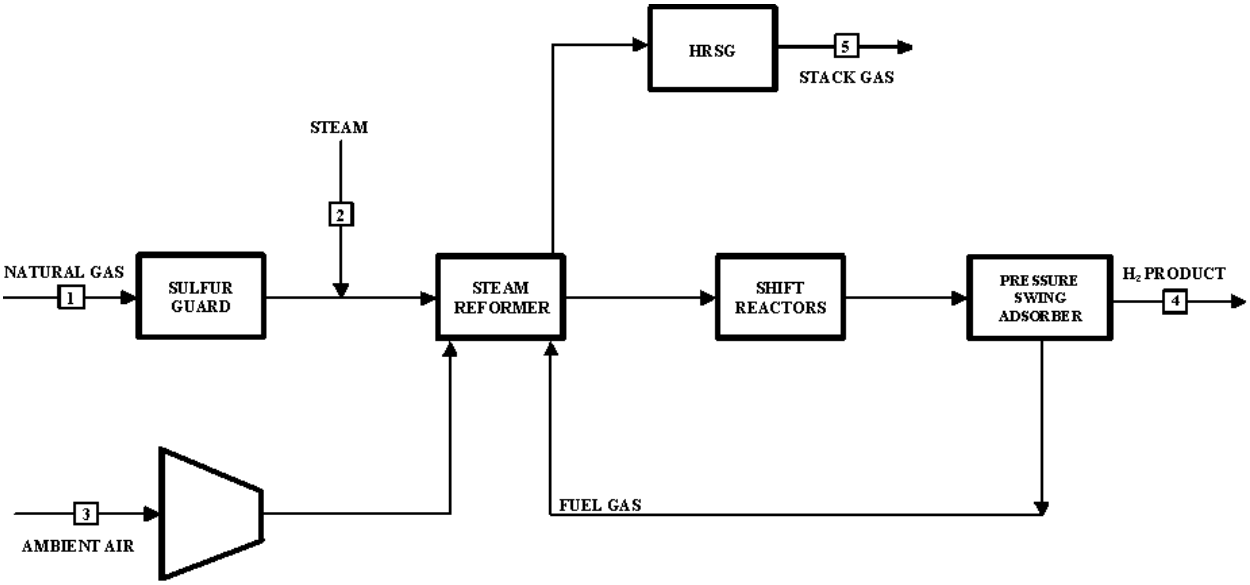


Figure 15. Generalized Steam Methane Reforming Process Flow Diagram

Steam methane reforming (SMR) process is the hydrogen production process commonly used at the present time for industrial scale hydrogen production. SMR uses hydrocarbon and steam feed streams and produces a purified hydrogen product. The carbon and oxygen atoms introduced to the process from the hydrocarbon and steam feed streams are released as carbon dioxide. SMR process technology is well established and SMR processes can be constructed using conventional approaches with capital cost savings achieved from economies-of-scale in large scale installations. Further description of the SMR process is provided in the following excerpt from [1]:

> *The [SMR] process involves a catalytic conversion of the hydrocarbon and steam to hydrogen and carbon oxides. Since the process works only with light hydrocarbons that can be vaporized completely without carbon formation, the feedstocks used range from methane (natural gas) to naphtha to No. 2 fuel oil.*
>
> *Natural gas is fed to the plant from the pipeline at a pressure of 450 psia. The gas is generally sulfur-free, but odorizers with mercaptans must be cleaned from the gas to prevent contamination of the reformer catalyst. The desulfurized natural gas feedstock is mixed with process steam to be reacted over a nickel based catalyst contained inside of a system of high alloy steel tubes. The reforming reaction is strongly endothermic, and the metallurgy of the tubes usually limits the reaction temperature to 1400-1700°F. The flue gas path of the fired reformer is integrated with additional boiler surfaces to produce about 700,000 lb/hour steam. Of this, about 450,000 lb/hour is superheated to 450 psia and 750°F, to be added to*

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

the incoming natural gas. Additional steam from the boiler is sent off-site. After the reformer, the process gas mixture of CO and H2 passes through a heat recovery step and is fed into a water gas shift reactor to produce additional H2.

The Pressure Swing Adsorption (PSA) process is used for hydrogen purification based on the ability to produce high purity hydrogen, low amounts of CO and CO2, and ease of operation. Shifted gas is fed directly to the PSA unit where hydrogen is purified up to approximately 99.6%.

Life cycle analysis of the SMR process indicates that each kilogram of hydrogen produced in the SMR process results in the release of approximately 10 kilograms of carbon dioxide. The total carbon dioxide emissions include contributions from natural gas production and transport (14.8%), electricity generation (2.5%), SMR plant operations (83.7%), and other minor contributions [2]. Eliminating the significant CO_2 emissions (and, to a lesser extent, NOx) emissions associated with SMR brings an additional cost.

4.2 Low-temperature Electrolysis

The study focuses on LTE, based on the emerging PEM technology. Water is split by supplying an electrical current to a PEM cell in which the anode and cathode are separated by a solid polymer electrolyte [3]. Water is passed over the anode while the anode is supplied with an electrical current. The current splits the water into protons (H^+) and oxygen (O_2). The protons pass through the polymer electrolyte to the cathode. At the cathode, the protons reform into diatomic hydrogen, H_2, and leave the system to be further purified, as needed [3]. The hydrogen outlet pressure is 6.9 MPa. Once desired purity is reached, the hydrogen can then be used as fuel. Oxygen likewise leaves the electrolysis cell from the anode side of the system, where it may have been diluted with air (if a sweep gas is used). For this reason, no practical use for the oxygen is considered for LTE hydrogen-production analysis. Figure 16 depicts a generalized PEM electrolyzer system.

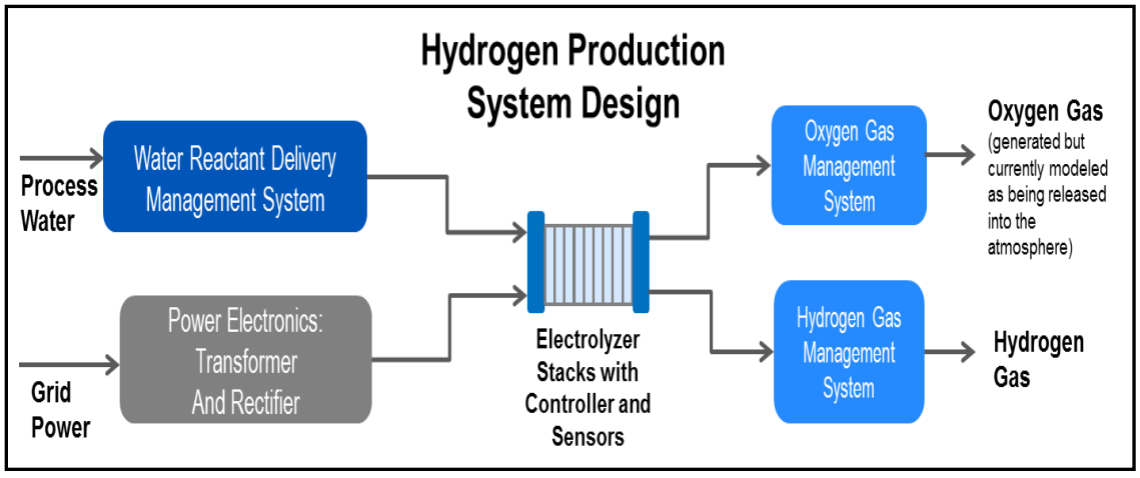


Figure 16. Generalized PEM electrolyzer system [3].

PEM electrolysis has inherent advantages over SMR; however, assigning value to these advantages is beyond the scope of this study. As mentioned earlier, hydrogen may be produced with lower CO2 or NOx emissions, depending on the emissions associated with the electricity

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

generation. Beyond this, electrolyzers may be responsive load on power grids owing to their ability to turn on and off within minutes and to cycle output within subseconds [4]. Although this study considers centralized hydrogen production, PEM-based LTE is more modular, allowing for hydrogen production on-site and avoiding significant infrastructure costs for delivery of hydrogen. This feature takes advantage of the near-universal electrical distribution infrastructure.

The economic potential estimates in this study assumed 50.2 kWh of electricity is required to produce 1 kg of hydrogen (46.7 kWh from electrolyzer-stack use and 3.5 kWh from balance-of-plant use). These input parameters are consistent with those used in the H2A v3.2019 Future Central PEM Electrolysis Case Study [5].

4.3 High-temperature Electrolysis

High-temperature steam electrolysis (HTSE) is another type of electrolysis. While LTE uses only electrical energy, HTE is able to boost overall efficiencies by utilizing both heat and electricity. (Or, considered differently, the energy required to dissociate water is a function of temperature, and it requires less energy at higher temperatures typical of solid oxide fuel cells.). Figure 17 shows a cross-section of a representative planar SOEC stack.

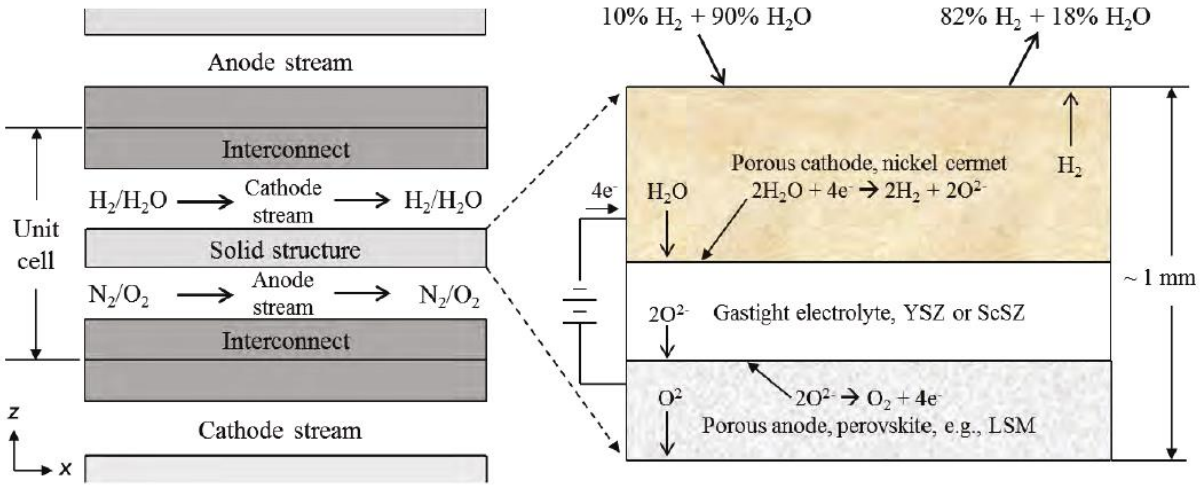


Figure 17: Cross-section of a cathode-supported planar SOEC stack. The case of co-flow is depicted [4, 6].

The cathode-supported cell consists of a three-layer solid structure (composed of porous cathode, electrolyte, and porous anode) and an interconnected (separator) plate [7]. An oxygen-ion conducting electrolyte (e.g., yttria-stabilized zirconia or scandia-stabilized zirconia) is generally used in SOECs [8]. For electrically conducting electrodes, a nickel cermet cathode and a perovskite anode such as strontium-doped lanthanum manganite are typically used. The interconnect plate separates the process-gas streams; it must also be electrically conducting and is usually metallic, constructed, for example, of a ferritic stainless steel. Stack operation typically occurs at what is known as the thermoneutral point. At the thermoneutral point, thermal energy consumed by the electrolysis reaction precisely matches heat generation via irreversible losses [4]. In practical terms, this means that all energy input into the stack is absorbed by the electrolysis reaction, meaning zero heat consumption or loss from the environment.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

HTE has an operating range between 600 and 850°C and uses electricity and heat to produce hydrogen. Electrolysis efficiency increases at higher operating temperatures, requiring less electrical energy. This increased efficiency can lower production costs because the thermal energy required is generally less expensive than electrical energy. This assessment focuses on oxygen-conducting SOEC-based HTE, which is driven with steam and electricity at a nuclear power plant (pressurized light water reactor).

While no solid oxide electrolysis cell has been deployed at a nuclear power plant, flowsheets have been developed previously by INL. Figure 18 is an AspenTech HYSYS [9] process flow diagram of the HTE process, with highlights showing low- and high-temperature heat recuperation, nuclear process-heat integration, and electric topping heat. Steam would be diverted from the nuclear power plant to preheat feedwater for the HTE unit via intermediate heat exchangers. Additional electrical heating is used to further boost temperatures. The overall energy split of thermal energy vs. electrical topping energy vs. electrical energy for electrolysis is generator- and electrolyzer-specific. As a general rule, when working with LWRs, about 7–10% of the total energy input into the HTSE process is in the form of thermal energy. Of the 90-93% that is electrical energy, about 5–20% may be used for heating, and the remainder of the electricity utilized for electrolysis.

Once feedstock temperature and pressure are sufficient, the feedstock (steam) is run through the electrolyzer stacks. In the stacks, electricity is supplied, and the electrolysis process begins to take place, splitting the steam into oxygen and hydrogen. During normal operation, a portion of the hydrogen produced is recycled back into the stacks to reduce corrosion and pitting inside the stacks.

The SOEC stacks considered in this analysis operate isothermally at 735°C. The stacks as assumed to operate at the thermal neutral voltage, which results in adiabatic operation where external heat is neither added nor removed to maintain the specified operating temperature. The SOEC operating pressure is 0.5 MPa, producing a design capacity of 608 tonnes per day of hydrogen at a pressure of 2.1 MPa. Table 7 summarizes the electrolysis-cell conditions applied in the analysis.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

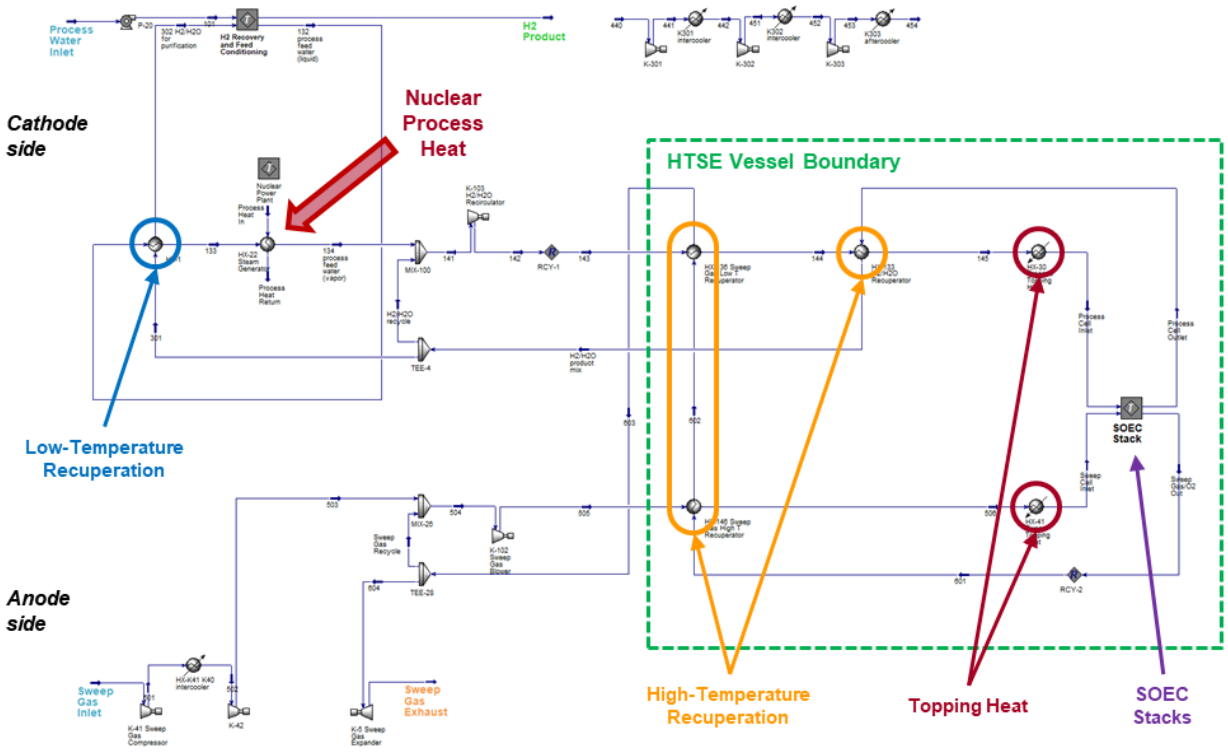


Figure 18. High Temperature Steam Electrolysis process flow diagram.

Table 7. HTE electrolysis-cell parameters.

Parameter	Unit	Value
Total Cell Active Area	cm^2	$6.9x10^8$
Current Density	$amperes/cm^2$	1.0
Area Specific Resistance	$Ohms \times cm^2$	0.25
Operating Voltage	Volts	1.285
Current (per cell)	Amperes	81
Hydrogen Inlet Mole Fraction	%	50
Operating Temperature	°C	735
Operating Pressure	MPa	0.5

Figure 19 shows the HYSYS process model developed for the thermal and electrical integration of the HTE plant with a pressurized LWR. A generic pressurized water LWR with a nominal electrical generation capacity of 1,000 MWe is considered in this analysis. The model utilizes the steam-generator conditions and electricity produced by the power plant for the integration. Electricity is produced by a subcritical Rankine cycle at the plant net-thermal efficiency of 33.5%. The HTE process draws steam from the steam generator for use in the electrolysis process. The LWR/HTE integration case consumes all of the thermal and electrical energy generated internally leaving no excess energy in the system.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

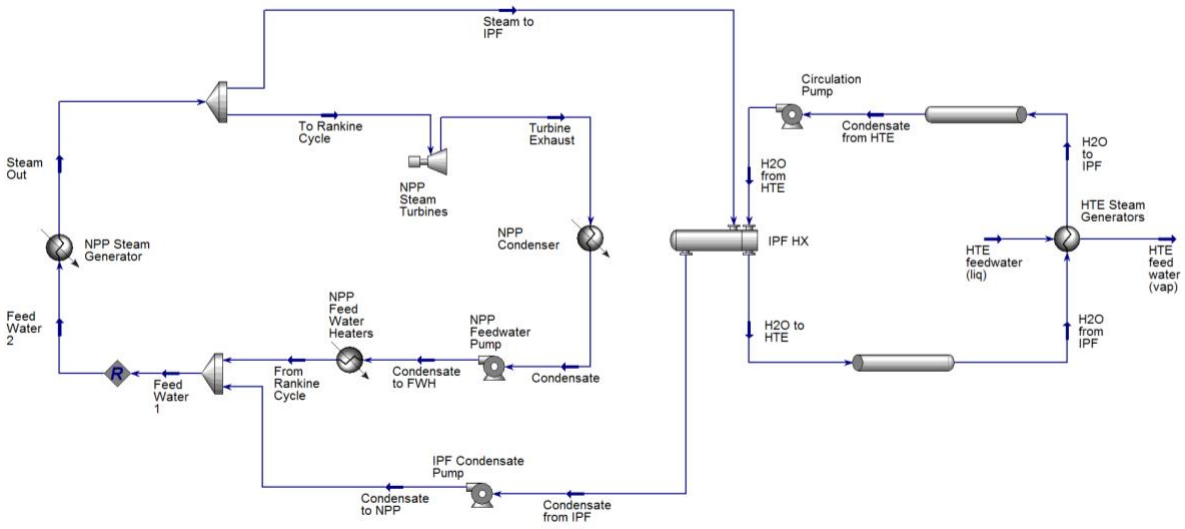


Figure 19. Process-flow diagram of the thermal delivery loop that supplies heat from the LWR to the HTSE process (LWR/HTE thermal integration). The "HTE Steam Generators" in this figure corresponds to the HX-22 Steam Generator in Figure 19.

Steam from the LWR steam generator is sent to an intermediate processing facility (IPF), where heat from the LWR steam is used to generate steam in a separate closed thermal loop. The steam from the IPF heat exchanger is used to transfer thermal energy from the nuclear reactor to the HTE plant at a distance of 1000 m. The condensate is pumped from the HTE plant back to the IPF steam generator. A separate water source is required for the electrolysis process. This is mostly a safety consideration. Because the steam generator is rated for a specified steam flow, the reactor system would not respond well to a decrease in steam should there be a situation at the HTE plant, even if it were only a 10% decrease in steam flow. Future work will explore the use of different thermal-integration techniques to determine the best options.

Figure 20 is a process flow diagram of the hydrogen purification sub process. This process area removes water from the product gas stream to provide a purified hydrogen product gas stream. The method for removing water utilizes a series of knockout drums with increasing pressure and decreasing temperature. These conditions promote the condensation of water from the product gas stream to provide a 99.95 mol% purity hydrogen product stream at a pressure of 2.1 MPa (21 bar). The hydrogen purification process area uses feed water as well as cooling water to provide the required cooling duty. The addition of heat to the feed water in the hydrogen purification process area reduces the quantity of heat that must be added later in the process via nuclear heat input, process heat recuperation, and/or electrical topping heat input.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

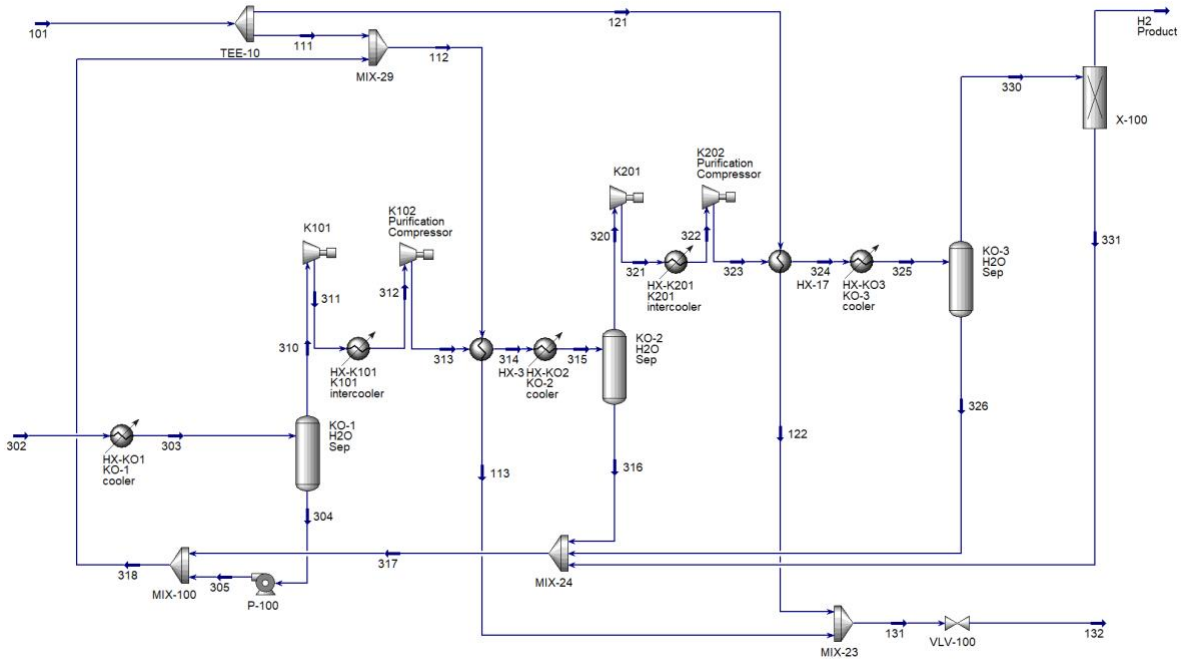


Figure 20. Hydrogen Recovery and Feed Conditioning area process-flow diagram.

Figure 21 graphically presents a high-level material and energy balance summary for an LWR/HTSE-integration case at nominal operating conditions corresponding to a nuclear reactor with a nominal output of 1,000 MW electricity. The breakdowns of electricity and thermal-energy consumptions, as well as cooling water use, are summarized in Table 8. A secondary steam loop transfers ~260°C steam from the IPF to the HTSE facility, where feedwater is converted to low-temperature steam. High- and low-temperature recuperators are subsequently used to superheat the steam used in the electrolyzers. A total of about 163 MWt of thermal energy is needed for this purpose.

The HTSE process requires both the feed and sweep streams to be heated to 735°C, which necessitates additional topping heat from an auxiliary heat source. This heat source could come from a combustor, electric heating, or waste heat from a neighboring process. In this assessment, this topping heat is provided by electrical heaters at the power rating shown in Table 8.

The hydrogen production efficiency for the HTSE process is defined as the higher heating value (HHV) of the product hydrogen, divided by the HHV of feed gas and other thermal-energy input into the process [4]. As shown in Table 8, the production efficiency of hydrogen (33.1%) is very close to the thermal-to-electrical conversion efficiency (33.3%). Standard electrolysis of water typically is less than around 25% efficient when evaluated on an equivalent basis (HHV of hydrogen product; NPP thermal energy equivalent for the electrical power requirements) [10].

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

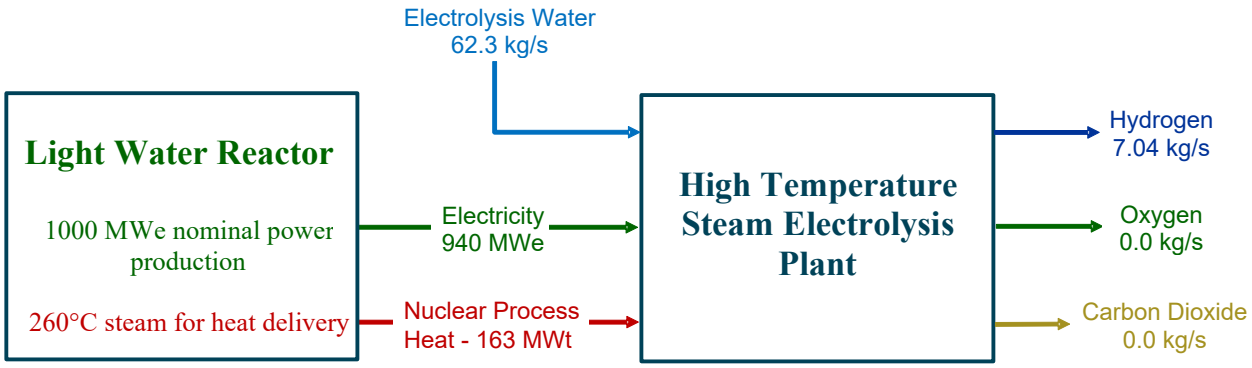


Figure 21. General energy and product flows for the LWR/HTSE integration case.

Table 8. Hydrogen production summary.

Description	Unit	Value
Input		
Reactor Thermal Power	MWt	2983
Outputs		
Hydrogen	kg/s [tpd]	7.04 [608]
Hydrogen Production Efficiency	%	33.1
Power Cycle Thermal Efficiency	%	33.3
Utility Summary		
Total Power Consumed	MWe	940
Electrolyzer	MWe	892
Pumps	MWe	0.3
Compressors	MWe	24.0
Topping Heaters	MWe	23.2
Nuclear Process Heat		
Total Nuclear Process Heat	MWt	163.3
Water Consumption		
Cooling Water for HTE Process	kg/s	1,118
Water Consumed by Electrolysis	kg/s	62.9
Carbon Dioxide (CO_2) Emissions		
Emitted	tpd CO_2	0

Note: The reported values are based on the plant's nominal design capacity—i.e., an operating-capacity factor (OCF) of 100%. The actual values depend on the OCF, which in this report is 92.4% for the steady state hydrogen production cases and in the variable dispatch cases varies with the percentage of time that the LWR/HTE plant dispatches hydrogen versus electricity; the economic optimal product distribution is a function of the locational marginal pricing in the region considered.

4.4 Basis of Calculations

For all cases considered, the levelized cost of hydrogen (LCOH) that achieves a 12% internal rate of return for the given capital cost (CAPEX) and operating cost (OPEX) was calculated. This value is typically reported in the open literature as it serves as a common reference for investor decisions. Table 9 summarizes the economic parameter specifications for the current assessment.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Table 9. Summary of financial model input parameters.

Description	Value	Comments
Oxygen selling price	N/A	HTSE process with air sweep gas evaluated; Oxygen not readily recovered from an air sweep gas exhaust stream.
Nominal IRR	12%	Selling price of hydrogen computed for each case
Electricity price ($/MWh-e)	20, 25, 30, 40, 50	Prices listed are used in the steady state hydrogen production analysis.[β]
Thermal-energy (steam) cost ($/MWh-t)	Varies	Multiple of an electricity price and the thermal-to-electrical conversion efficiency of 32.3%
Capacity market payment ($/MWh-day)	Varies by scenario	See Section 4.4.2 for detailed calculation; only for HTE cases
Debt to equity ratio	80% debt, 20% equity[α]	80%/20% debt-to-equity ratio for a first-of-a-kind private/public project
Debt interest rate	5%[α]	Debt backed under Federal Loan Guarantee Program
Debt period	20 years	Debt backed under Federal Loan Guarantee Program
Annual inflation rate	1.9%	
Overall tax rate	24.8%	20% federal; 6% state
Capital depreciation schedule	Standard modified accelerated cost recovery system (MACRS) depreciation method	Depreciation method, with a property class of 15 years
Decommissioning	10% of total depreciable capital	
Salvage value	10% of TCI	
Working capital	10% of the annual change in total operating costs	
Plant construction period	1 year for the LTE and HTE cases, 3 years for the SMR cases	Percent capital invested for the SMR plant is 8, 60, and 32 for the 1st, 2nd, and 3rd years, respectively
Start-up year	2025	
Start-up time	1 year	Operating costs and revenues during start-up are 75% and 50% of the total values, respectively
Plant life and analysis period	20 years	Excluding construction time
Operating-capacity factor	97, 92.4, and 90% for the LTE, HTE, and SMR cases, respectively[δ]	LWR-integrated HTE system assumed to undergo coordinated outages/maintenance

Notes: α - A debt interest rate of 5% reflects the concept that State or Public Utilities Commissions will approve municipal bonds or the Project will qualify for Federal Loan Guarantees to help encourage continued operations of a Nuclear Power Plant.
β - In variable hydrogen/electricity dispatch scenarios the electricity price for the HTE plant is equal to the specified NPP O&M cost and market pricing for electricity sales to the grid are obtained from price duration curves.
δ - Capacity factors have been selected based on actual histories for SMR and LTE. HTE capacity factors assume solid oxide cell replacements are more frequent.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

4.4.1 Capital-cost Estimation

Depreciable capital costs consist of the direct and indirect costs. The direct capital costs (DCCs) for the LTE and SMR hydrogen-production systems were adapted from the standard H2A v3.1 default values [11]. The DCCs for the HTE cases were estimated based on equipment sizing specifications calculated from Aspen HYSYS [12] process model mass and energy balance data. Aspen Process Economic Analyzer [13], literature data, and vendor data were used to estimate capital costs based on the calculated equipment sizing.

For the LWR/HTE integration cases, the DCC estimates were generated for the HTE system, balancing-gas system, feed and utility system, sweep-gas system, hydrogen/steam system, hydrogen-purification system, and nuclear steam-delivery system. In the GW-scale HTE concept evaluated, these systems are comprised of either conventional or modular components.

Conventional Process Components

Conventional components scale with the process capacity, and capital cost savings can be achieved through conventional economies of scale (equipment costs scale with scaling exponent of less than 1). In the LWR/HTE design, the nuclear process heat delivery system, high-pressure product compression system, and feed and utility systems are comprised of conventional process components. A summary of the process equipment included in each of these systems is listed below:

- Nuclear process heat delivery system: Intermediate processing facility heat exchanger, steam and condensate piping, and associated pumps and valves
- High-pressure product compression system: Multi-stage, reciprocating hydrogen compressor and associated intercoolers
- Feed and utility systems: Feed water purification equipment, evaporative cooling tower

The equipment costs of these systems were calculated using Aspen Process Economic Analyzer (APEA) [13] and previous reports [14, 15]. Analysis of equipment costs over a representative range of HTSE plant capacities was performed using APEA to establish equipment-specific cost scaling factors. Figure 22 is a plot of the unit cost of the conventional equipment design as a function of HTSE plant capacity. The total conventional equipment capital costs of the LWR/HTSE (FuelCell Energy) process were found to vary with plant capacity according to a scaling factor of 0.62 as indicated in the equation below:

$$\frac{Conventional\ Equip\ CAPEX_2}{Conventional\ Equip\ CAPEX_1} = \left(\frac{HTSE\ capacity_2}{HTSE\ capacity_1}\right)^{0.62}$$

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

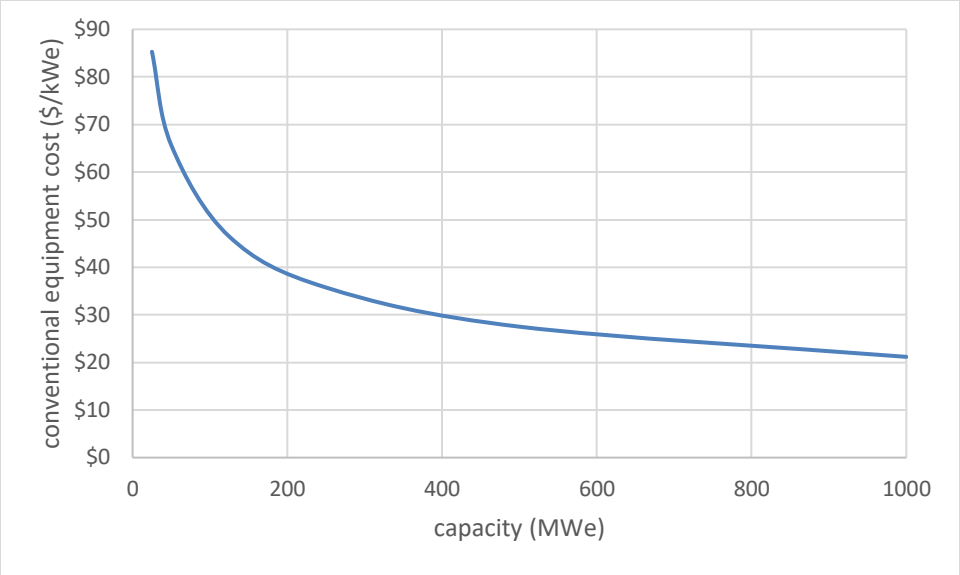


Figure 22. Conventional HTSE equipment units costs as a function of plant capacity

Modular Equipment Components

The SOEC module assemblies, sweep-gas system, hydrogen/steam system, and hydrogen purification system are modular system components. The equipment in these sub-process areas would be constructed using modular construction techniques in which the modules are mass produced at a centralized manufacturing facility, transported to the HTSE process site, and connected to the common process and utility equipment. Modular components are installed as blocks of fixed capacity units, and large process capacity is achieved through installation of parallel units. Use of modular equipment is associated with reductions in engineering, installation, and contingency costs [16, 17]. Since capacity increases are achieved through installation of parallel units, conventional economies of scale are not realized with modular systems, but economies of mass production (cost savings associated with large manufacturing volume) can be realized. The cost savings associated with mass production and repeated assembly techniques can be quantified using a learning curve relationship:

$$P_n = P_1 x^{\log_2(b)}$$

Where the unit cost P_n of unit number n decreases from the unit cost of the first unit P_1 according to the learning rate b, which is expressed as a percentage. In this relation, the cost of unit n decreases by an amount equal to (1-b) with every doubling of production. In this analysis a learning rate of 90% was assumed for the modular system components; in this case the cost of unit number 2 is 90% the cost of unit 1, the cost of unit 4 is 81% the cost of unit 1, etc. The assumed learning rate is within the values reported in the literature for the energy sector [18-20].

Capital cost estimates were prepared for two separate HTSE plant installation cases: First-of-a-kind and Nth-of-a-kind. The first-of-a-kind cost estimates were used in the small scale HTSE demo scenarios (Exelon Scenario 1) while the Nth-of-a-kind cost estimates were used in the large scale HTSE demo scenarios (Southern Company Scenario 2, Exelon Scenario 2, and Xcel Energy Scenario 2). The SOEC module (stacks and containing vessels) costs for the first modular unit constructed (i.e. modular unit #1 for the first-of-a-kind plant installation) were set

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

equal to $50/kWe [21]. The balance of plant equipment costs were added to obtain the full HTSE process capital costs.

First-of-a-kind

In the First-of-a-kind plant installation case (Exelon Scenario 1), the highest price is paid for the first modular HTSE and BoP units purchased and installed. Cost reductions are then realized for each subsequent unit installed as a result of learning effects. A larger capacity installation will achieve the greatest decreases in the module installed costs since larger installations will benefit from increased learning effects associated with the higher number of units installed.

It is important to note that the total project cost is equal to the cumulative cost of all installed units, and in the first-of-a-kind analysis each modular unit has a different cost (each successive unit has a lower cost than the previous unit due to learning effects). Mathematical approximations of the cumulative cost exist for N>100. However, in the first-of-a-kind HTSE analysis the number of units installed is less than 100 so regression-based correlation was used to predict the cumulative cost as a function of the number of units installed. The regression equation has the same mathematical form as the conventional CAPEX cost scaling equation, so the exponent from the regression equation was used to estimate module costs in the existing H2A model framework.

Figure 23 is a plot of the HTSE process modular component unit costs as a function of installed LWR/HTSE capacity (industry wide). Figure 23 indicates that the modular component unit cost for the first module in a First-of-a-kind plant installation is equal to $457/kWe. For a 100 MWe small scale HTSE demonstration learning effects would decrease the costs of the second through fourth SOEC and BoP modules (25 MWe capacity per SOEC/BoP module set) such that the unit cost of the fourth module is equal to $370/kWe and the average cost of the modular components is equal to $382/kWe (the cumulative average cost of modular units one through four).

Nth of a kind

In the large scale HTSE scenarios (Southern Company Scenario 2, Exelon Scenario 2, and Xcel Energy Scenario 2) use of Nth-of-a-kind plant installations is assumed. In the Nth-of-a-kind plant installations the modular equipment component costs would have decreased due to learning effects associated with previous HTSE plant installations. To estimate Nth-of-a-kind plant modular equipment costs, a learning curve with a 90% learning rate was applied to the HTSE and BOP module costs. A value of N=100 was selected to represent Nth of a kind construction, which corresponds to 2.5 GWe of previously installed capacity based on use of 25 MW_e HTSE modules. At N=100 the learning curve has “flattened out” and the cost reduction from one unit to the next unit due to learning effect are small (a 90% learning curve results in a ~50% reduction in cost from unit 1 to unit 100, however the costs for unit 100 and 150 differ by less than 6%). Therefore, this analysis assumes that the cost of the modular equipment installed for a given project has a constant cost equal to that of the N=100 (Nth of a kind) unit, and that the modular equipment unit costs do not vary with plant scale. Figure 23 indicates that the unit costs of the HTSE process modular components decrease to $227/kWe with 2500 MWe of previously installed LWR/HTSE capacity (industry wide).

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

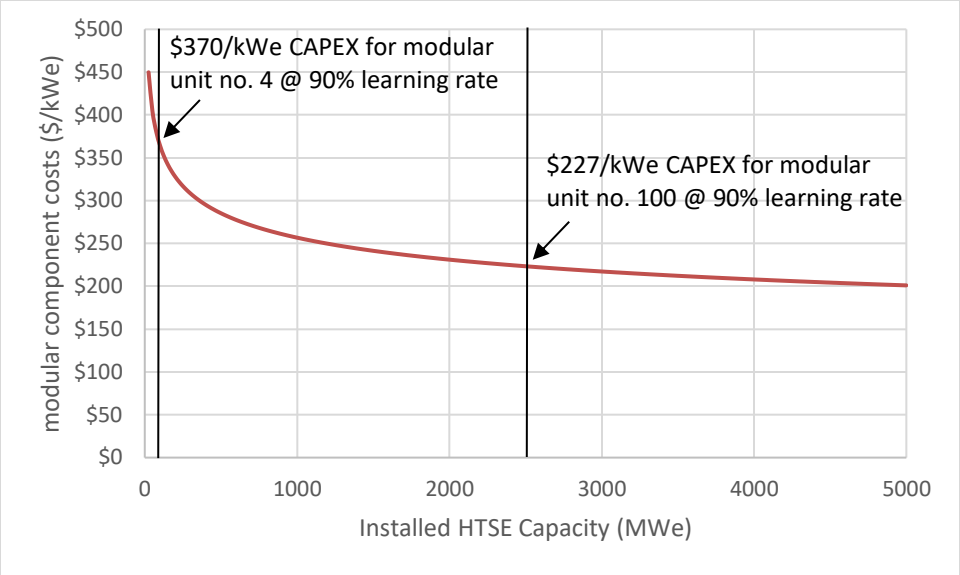


Figure 23. Estimated unit cost of HTSE process modular components vs previously installed HTSE capacity

After the DCCs were obtained, the site-preparation cost (10%), engineering fee (10%), project contingency (15%), contractor's fee (3%), and legal fee (2%), which make up the indirect costs, were assumed for the LTE and SMR cases. The multipliers used in the HTE case for site preparation cost (5%), engineering fee (2%), and project contingency (10%) were reduced from the values in the standard H2A model cases to account for Nth-of-a-kind plant using modular construction. The indirect cost multipliers used for the HTE case are comparable to the H2A v2 default values of 1% for site preparation, 5% for engineering and design, 10% for project contingency, and 1% for up front permitting [22].

The cost of land is non-depreciable and was taken as 1.5% of the total depreciable capital (TDC) [23]. Finally, the TCI was calculated by summing the total depreciable and non-depreciable capital costs. Table 10, Table 11, and Table 12 present the capital-cost breakdown for the LTE (baseline), HTE (baseline) and SMR cases, respectively. Note that the capital costs presented are for inside the battery limits and exclude costs for administrative offices, utilities, storage areas, and other essential and nonessential auxiliary facilities. The results show that the largest single component contributor to the TCI for the baseline LTE case is the power electronics (31%), followed by the PEM stacks (26%). In the case of baseline HTE, the largest single component contributor to the TCI is are the SOEC modules (34.7%), followed by the hydrogen purification system (19.5%) and the sweep gas system (16.3).

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Table 10. TCI for the baseline LTE case (48-tpd design capacity, $86/kWe PEM stack capital cost).

Depreciable capital costs ($)		
Direct (bare-module) costs		
PEM stacks	7,968,438	[26.0]
H_2-management system (cathode system side)	215,363	[0.7]
O_2-management system (anode system side)	215,363	[0.7]
Water-reactant delivery-management system	215,363	[0.7]
Thermal-management system	1,507,542	[4.9]
Power electronics	9,475,980	[31.0]
Controls and sensors	215,363	[0.7]
Mechanical balance of plant	430,726	[1.4]
Assembly labor	646,090	[2.1]
Other	646,090	[2.1]
Total direct capital cost	21,536,318	[70.4]
Indirect costs		
Site preparation	2,153,632	[7.0]
Engineering and design	2,153,632	[7.0]
Contingencies and contractor's fee	3,876,537	[12.7]
Legal fee	430,726	[1.4]
Total indirect capital cost	8,614,527	[28.1]
Non-depreciable capital costs ($)		
Land	452,263	[1.5]
TCI ($)	**30,603,108**	**[100]**
Electrolyzer power consumption (MWe)	93	
DCC per DC power input to PEM stacks ($/kWe)	232	
TCI per DC power input to PEM stacks ($/kWe)	329	

Note: Values in the brackets are the breakdown of TCI expressed in terms of percentage.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Table 11. TCI for the baseline HTE case: 608-tpd design capacity, $50/kWe SOEC module capital cost.

Depreciable capital costs ($)		
Direct (bare-module) costs		
SOEC modules[a]	100,781,663	[34.8]
Feed and utility system[b,c]	16,999,160	[5.9]
Sweep-gas system[c]	47,225,901	[16.3]
Hydrogen/steam system[c]	4,932,658	[1.7]
Hydrogen purification system[c]	56,578,615	[19.5]
Nuclear process heat delivery system[c]	7,372,121	[2.5]
Total direct capital cost	233,890,117	[80.8]
Indirect costs		
Site preparation	11,694,506	[4.0]
Engineering and design	4,677,802	[1.6]
Contingencies and contractor's fee	30,405,715	[10.5]
Legal fee	4,677,802	[1.6]
Total indirect capital cost	51,455,826	[17.8]
Non-depreciable capital costs ($)		
Land	4,280,168	[1.5]
TCI ($)	**289,626,111**	**[100]**
HTSE process electrical power usage (MWe)	940	
DCC per HTSE electrical power usage ($/kWe)	249	
TCI per HTSE electrical power usage ($/kWe)	308	

Note: Values in the brackets are the breakdown of TCI expressed in terms of percentage.
[a] Derived from [21] for case with approximately 500 MWe SOEC annual manufacturing volume
[b] Water Pretreatment Filter/Softener System and Water Treatment RO/EDI System costs obtained by scaling values reported in Dominion Report [14].
[c] Estimated by APEA.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Table 12. TCI for the SMR cases.

	Small scale (52 tpd[a])		Large scale (624 tpd[b])	
Depreciable capital costs ($)				
Direct (bare-module) costs				
Process plant equipment	30,285,730	[50.1]	135,264,020	[50.1]
Balance of plant and offsites	12,100,192	[20.0]	54,042,633	[20.0]
Selective catalytic reduction nitrogen oxides (NOx) control on stack	179,794	[0.3]	803,008	[0.3]
Total direct capital cost	42,565,717	[70.4]	190,109,661	[70.4]
Indirect costs				
Site preparation	4,256,572	[7.0]	19,010,966	[7.0]
Engineering and design	4,256,572	[7.0]	19,010,966	[7.0]
Contingencies and contractor's fee	7,661,829	[12.7]	34,219,739	[12.7]
Legal fee	851,314	[1.4]	3,802,193	[1.4]
Total indirect capital cost	17,026,287	[28.1]	76,043,864	[28.1]
Non-depreciable capital costs ($)				
Land	893,880	[1.5]	3,992,303	[1.5]
TCI ($)	**60,485,883**	**[100]**	**270,145,828**	**[100]**

Note: Values in the brackets are the breakdown of TCI expressed in terms of percentage.
[a] Scaled to match LTE H_2 production capacity (applying an OCF of 90%).
[b] Scaled to match HTE H_2 production capacity (applying an OCF of 90%).

4.4.2 Estimation of Revenue

Yearly revenues were estimated for all cases based on the LCOH specific to each case. For the HTE case, additional revenues were considered: capacity (market) payments.[1] Due to use of an air-sweep HTSE process design, oxygen sales were not considered.

Table 13 and Table 14 present the revenues for the small- and large-scale baseline cases, respectively, for an electricity price of $30/MWh. Note that the revenues presented for each case are based on the corresponding operating-capacity factor (OCF, see Table 9) assuming steady state hydrogen production (the OCFs and revenues differ for the variable hydrogen/electricity scenarios discussed in a later section of this report). Also, these revenues did not consider the hydrogen delivery and compression costs, which are discussed in detail in Section 4.4.4.

[1] *Capacity payments* are made to generators for the capacity they have available to produce electricity at key times, regardless of how much electricity they actually produce. Such capacity markets are run to ensure reliability of the power system by incentivizing entry of new generation and to provide payments to generation that may be critical for system reliability, but may not be profitable from selling electricity alone.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Table 13. Annual revenue for the small-scale baseline cases: electricity price of $30/MWh, mean natural gas price of $5.4/MMBtu.

		LTE	*SMR*
Hydrogen	Price ($/kg H_2)	2.32	2.29
	Produced (kg/day)	46,375	46,375
	Annual revenue ($)	39,295,760	38,829,205

Table 14. Annual revenue for the large-scale baseline cases: electricity price of $30/MWh, mean natural gas price of $5.4/MMBtu.

		HTE	*SMR*
Hydrogen	Price ($/kg H_2)	1.36	1.49
	Produced (kg/day)	561,720	561,720
	Annual revenue ($)	279,789,552	304,684,605
Capacity payments	Market clearing price ($/MWe-day)	132.4	
	Capacity submitted to the capacity markets (MWe)	877	
	Annual revenue ($)	42,391,971	
Total annual revenue ($)		**322,181,522**	**304,684,605**

4.4.3 Estimation of Manufacturing Costs

Manufacturing cost is the sum of direct and indirect manufacturing costs. Direct manufacturing costs for this project include the cost of raw materials, utilities, and operating labor and maintenance. Indirect manufacturing costs include estimates for the cost of overhead and insurance and taxes.

The stack-cell replacement costs were calculated assuming stack replacement every 10 and 7 years for the PEM and SOEC stacks, respectively, based on the work (Projected Future cases) shown in [3]. Royalties were assumed to be 2% of the TDC [23]. Labor costs were estimated based on the number of operators per shift[2], shift frequency (five shift for all cases), and labor cost[3] of $30.8/hr (USD2019) for a total of 2,080 hr/yr. Maintenance costs were taken as 2% of the TDC, multiplied by 2.3 to take into account salaries and benefits for the engineers and supervisory personnel and materials and services for maintenance [23]. An overhead of 26% of the labor and maintenance costs was assumed. Annual property taxes and insurance were estimated at 2% of the TDC, which corresponds to a process of low risk, located away from a heavily populated area [23]. Table 15 and Table 16 provide the manufacturing costs for the

[2] The assumed numbers of operators per shift were 10, 16, 8, and 14 for the LTE (48-tpd capacity), HTE (608-tpd capacity), SMR (52-tpd capacity), and SMR (624-tpd capacity) cases, respectively. For each case scenario, they were scaled accordingly to match the target H_2 production capacities.

[3] In 2017, the average operator salary in the United States was $61,620 or $29.6/hr, for a total of 2,080 hrs per year. Applying an annual inflation rate of 1.9%, it is $30.8/hr in USD2019.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

baseline LTE and HTE cases, respectively, for an electricity price of $30/MWh. Again, operating availabilities of 97% and 92.4% for the LTE and HTE plants were assumed, respectively.

Table 15. Annual manufacturing costs for the baseline LTE case: 48-tpd capacity, PEM-stack capital cost of $86/kWe, electricity price of $30/MWh.

Direct costs		
Materials		
PEM stack replacement ($)		414,754
Utilities		
Electricity	Price ($/MWh-e)	30
	Consumed (MWe)	100
	Annual cost ($)	25,491,600
Water	Price ($/k-gal)	2.64
	Consumed (k-gal/day)[b]	190
	Annual cost ($)	177,881
Royalties ($)		603,017
Labor and Maintenance ($)		5,879,709
Indirect costs		
Overhead ($)		1,909,242
Insurance and taxes ($)		612,062
Total manufacturing costs ($)		**35,088,265**

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Table 16. Annual manufacturing costs for the baseline HTE case: 608-tpd capacity, SOEC module capital cost of $50/kWe, electricity price of $30/MWh.

Direct costs		
Materials		
SOEC stack replacement ($)		**4,596,698**
Utilities		
Electricity	Price ($/MWh-e)	30.0
	Consumed (MWe)	940
	Annual cost ($)	228,163,562
Nuclear process heat (steam)	Price ($/MWh-t)[a]	10.0
	Consumed (MWt)	163
	Annual cost ($)	13,209,507
Process Water	Price ($/k-gal)	2.64
	Consumed (k-gal/day)[b]	1,438
	Annual cost ($)	1,280,654
Cooling Water	Price ($/k-gal)	0.13
	Consumed (k-gal/day)	20,725
	Annual cost ($)	880,743
Royalties ($)		5,706,891
Labor and Maintenance ($)		19,881,343
Indirect costs		
Overhead ($)		4,306,709
Insurance and taxes ($)		5,792,495
Total manufacturing costs ($)		**283,818,604**

[a] Steam price is estimated by *steam price ($/MWh-t)* = η∗*electricity price ($/MWh-e)*, where η is a thermal efficiency.
[b] Amount of water consumed only considers the process water for electrolysis, excluding the required cooling water amount, which is assumed to be available from the nearby Great Lakes.

4.4.4 Estimation of Delivery and Compression Costs

In addition to the hydrogen-production costs, the study calculated a delivery adder (i.e., the sum of delivery and compression costs) to account for the costs associated with transmitting hydrogen from a central production facility to consumption areas. Delivery costs vary with location, quantity delivered, and delivery method (e.g., pipeline, gaseous truck, liquid truck), but estimating all potential delivery pathways and costs is outside the scope of this analysis. Instead, the hydrogen-delivery scenario analysis model (HDSAM) [24] was used to calculate pipeline delivery costs for the considered cases: small-scale LTE (short-distance transmission), small-scale SMR (short-distance transmission), large-scale HTE (long-distance transmission), and large-scale SMR (short-distance transmission) cases, shown in Table 17. The economic potentials for all cases presented in Section 5 include the delivery adder costs.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Table 17. Delivery adders for hydrogen production.

Cases		Distance (km)	Transmission [Compression] ($/kg H_2)	Adder Total ($/kg H_2)	Pipeline Inlet Pressure (MPa)	Pipeline Outlet Pressure (MPa)
Small-scale case	LTE	3.22	0.08 [0.00]	0.08	6.89	4.86
	SMR	3.22	0.08 [0.06]	0.14	2.39	4.86
Large-scale case	HTE	250	0.28 [0.06]	0.34	2.20	4.86
	SMR	3.22	0.01 [0.06]	0.07	2.39	4.86

4.5 References

[1] Rutkowski M. Hydrogen from Natural Gas Reforming, H2A Version 1 Case Study. DOE/FE/NETL; 2003.

[2] Spath PL, Mann MK. Life Cycle Assessment of Hydrogen Production via Natural Gas Steam Reforming: National Renewable Energy Laboratory; NREL/TP-570-27637, 2001.

[3] James BD, DeSantis DA, Saur G. Final Report: Hydrogen Production Pathways Cost Analysis (2013–2016). Arlington, VA: Strategic Analysis Inc.; DOE-StrategicAnalysis-6231-1, 2016.

[4] Kim JS, Boardman RD, Bragg-Sitton SM. Dynamic performance analysis of a high-temperature steam electrolysis plant integrated within nuclear-renewable hybrid energy systems. Applied Energy. 2018;228:2090-110.

[5] James B, Colella W, Moton J, Saur G, Ramsden T. PEM Electrolysis H2A Production Case Study Documentation: Strategic Analysis; 2013. Available: https://www.nrel.gov/hydrogen/assets/pdfs/h2a-pem-electrolysis-case-study-documentation.pdf

[6] Kim JS, McKellar M, Bragg-Sitton SM, Boardman RD. Status on the Component Models Developed in the Modelica Framework: High-Temperature Steam Electrolysis Plant & Gas Turbine Power Plant. Idaho Falls, ID: Idaho National Laboratory; INL/EXT-16-40305, 2016.

[7] Udagawa J, Aguiar P, Brandon NP. Hydrogen production through steam electrolysis: Model-based steady state performance of a cathode-supported intermediate temperature solid oxide electrolysis cell. Journal of Power Sources. 2007;166:127-36.

[8] O'Brien JE. Thermodynamic considerations for thermal water splitting processes and high-temperature electrolysis. 2008 ASME International Mechanical Engineering Congress and Exposition. Boston, MA2008.

[9] AspenTech. Aspen HYSYS. V10 (36.0.0.249) ed2017.

[10] O'Brien JE. Thermodynamics and Transport Phenomena in High Temperature Steam Electrolysis Cells. Journal of Heat Transfer. 2012;134.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

[11] U.S. Department of Energy. *DOE Hydrogen and Fuel Cells Program: DOE H2A Production Analysis*. Available: https://www.hydrogen.energy.gov/h2a_production.html

[12] AspenTech. *Aspen HYSYS*. Available: https://www.aspentech.com/en/products/engineering/aspen-hysys

[13] AspenTech. *Aspen Process Economic Analyzer*. Available: https://www.aspentech.com/en/products/pages/aspen-process-economic-analyzer

[14] Krull P, Roll J, Varrin RD. HTSE Plant Cost Model for the INL HTSE Optimization Study. Reston, VA: Dominion Engineering; R-6828-00-01, 2013.

[15] Shaw. NGNP Hydrogen Plant Alternatives StudyNGNP-HPS SHAW-HPA, Revision 1, 2009.

[16] Seifert T, Sievers S, Bramsiepe C, Schembecker G. Small scale, modular and continuous: A new approach in plant design. Chemical Engineering and Processing: Process Intensification. 2012;52:140-50.

[17] Sievers S, Seifert T, Franzen M, Schembecker G, Bramsiepe C. Fixed capital investment estimation for modular production plants. Chemical Engineering Science. 2017;158:395-410.

[18] McDonald A, Schrattenholzer L. Learning rates for energy technologies. Energy Policy. 2001;29:255-61.

[19] Schoots K, Kramer GJ, van der Zwaan BCC. Technology learning for fuel cells: An assessment of past and potential cost reductions. Energy Policy. 2010;38:2887-97.

[20] Weber RS, Holladay JE, Jenks C, Panisko EA, Snowden-Swan LJ, Ramirez-Corredores M, et al. Modularized production of fuels and other value-added products from distributed, wasted, or stranded feedstocks. Wiley Interdisciplinary Reviews: Energy and Environment. 2018;7.

[21] Tang E, Wood T, Brown C, Casteel M, Pastula M, Richards M, et al. Solid Oxide Based Electrolysis and Stack Technology with Ultra-High Electrolysis Current Density (>3A/cm²) and Efficiency: FuelCell Energy; DE-EE0006961, 2018.

[22] U.S. DOE Fuel Cell Technologies Office. Multi-Year Research, Development, and Demonstration Plan: Planned program activities for 2011-2020: U.S. Department of Energy; 2012. Available: https://www.energy.gov/sites/prod/files/2014/12/f19/fcto_myrdd_full_document.pdf

[23] Seider WD, Seader JD, Lewin DR. Product & Process Design Principles: Synthesis, Analysis and Evaluation: John Wiley & Sons; 2009.

[24] Argonne National Laboratory. *Hydrogen Delivery Scenario Analysis Model (HDSAM)*. Available: https://hdsam.es.anl.gov/index.php?content=hdsam

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

5 HYDROGEN-GENERATION COST PROJECTIONS

In this section, the cost projections for generating hydrogen are covered in the following order:

- Steady-state hydrogen plant
  - Steady-state small-scale LTE (~48 tonne/day hydrogen) LTE PEM
  - Steady-state small-scale SMR (~48 tonne/day hydrogen) natural gas SMR plant
  - Steady-state large-scale HTE (~600 tonne/day hydrogen) HTSE
  - Steady-state large-scale SMR (~600 tonne/day hydrogen) natural gas SMR plant
- Electricity/hydrogen hybrid plant
  - Southern grid hydrogen plant.; LTE and HTE
  - SPP hub; wind LTE
  - Colorado hub; wind LTE
  - Minnesota hub, nuclear hydrogen plant
- Solar PV-to-hydrogen
  - Fixed size 50 MW_e electrolysis facility
  - Fixed-size 100 MW_{dc} solar field

The standard DOE H2A models for LTE and SMR were used for these cases to calculate the production costs of hydrogen. The DOE H2A HTE model for large central plants was modified to be consistent with the capital and operating cost data presented above in Section 4.

5.1 Steady-state Hydrogen Plants

The main assumption for the steady-state hydrogen plant operation is based on a PPA that provides a fixed-price of electricity and/or steam from either the grid or coupled to a nuclear plant. The U.S. existing fleet of nuclear reactors has been in operation for many years and has therefore paid down debt. The cost of producing power with new nuclear reactors, such as the Alvin W. Vogtle Electric Generating Plant can be projected by Southern Company.

In this assessment, CAPEX and OPEX for the nuclear system were not separately estimated because of the complexity and uncertainty of such a direct approach. Instead, the purchase price of electricity was used parametrically to account for all CAPEX and OPEX of the nuclear system. The wholesale prices of electricity considered ranged from $25–50/MWh. Steam purchased from the nuclear facility (also referred to as nuclear process heat) was priced at the parametric cost of electricity times the 33.3% thermal efficiency expected for the power-conversion system at a typical single-unit nuclear power plant. This effectively equates the cost of heat to the cost of electricity that could otherwise be produced and sold using this heat.

The hydrogen-production cost sensitivities to variations in the PEM stack capital costs were also assessed. For the LTE plant, a PEM stack cost of $172/kWe (DC power input to PEM or, equivalently a total uninstalled capital cost of $400/kWe [total system power usage]) corresponds

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

to a Projected Future case[4] defined in James, et al. (2016) [1]. However, this stack cost seems too conservative based on conversations with industry researchers; based on that input, the baseline PEM stack cost considered in this analysis was halved to $86/kWe. The PEM stack costs of $130/kWe (+50% baseline) and $60/kWe (-30% baseline) were considered for the LTE cases to reflect an expected spread in the cost of PEM cells. Varying only the stack cost was an adequate assumption because the stacks account for a large percentage of the overall cost for electrolytic hydrogen-production systems [2].

For the HTE plant, the baseline SOEC module cost considered was $50/kWe (the module includes the SOEC stacks, the containing vessel, insulation, gas distribution, heat exchange, electrical distribution, and instrumentation components); this cost is based on cost information from manufacturers of solid oxide electrolyzer cells [3] and is also recommended by the Pacific Northwest National Laboratory based on relevant experience in solid-oxide fuel-cell development.[5]

For LTE hydrogen-production analysis, this report considered a 48-tpd plant (or 46 tpd with a 97.0% annual overall OCF), which requires a total system power input of 100 MWe. It is assumed that system power could be supported via a dedicated transmission line connecting the nuclear plant to an industrial plant. Such a scale is typical of a merchant hydrogen supply to, for example, an average oil refinery and is defined as a small-scale (or low-volume) production case in this analysis.

For HTE hydrogen-production analysis, the report considered a nominal 1,000 MWe LWR power plant coupled to a ~608-tpd HTE nameplate-capacity plant (or 562 tpd average output at 92.4% OCF), which requires the electrical and thermal energy of 940 MWe and 163.3 MWt, respectively. In this case, the report considered HTE integrated with the LWR at the nuclear power plant site as the source of heat and electricity. Such a world-class scale would provide hydrogen to multiple industries and is defined as a large-scale (or high-volume) production case in this analysis.

The cost of producing hydrogen using SMR is highly dependent on the cost of natural gas. Similarly, the cost of producing hydrogen by electrolysis (LTE and HTE) is a strong function of the cost of electricity. Several case studies were conducted to parametrically analyze the effect of such variable operating costs, as well as capital costs (i.e., electrolysis-stack costs), on the economic performance of the three hydrogen-production technologies considered.

The study of hydrogen production via SMR process was based on three natural-gas price scenarios, which utilized pricing data from the EIA (AEO 2018) [4]: low oil and gas resources and technology (high natural-gas prices), high oil and gas resources and technology (low natural-gas prices), and reference natural-gas price scenarios. The cases considering a reference natural gas price scenario served as SMR baseline cases throughout this assessment. Figure 24 shows natural-gas prices in the Upper Midwest (East North Central region) as projected by (AEO 2018).

---

[4] A *Projected Future* case forecasts improved process parameters with normal improvements in technology as times passes and reduced costs, which are likely attributed to the new materials and systems with higher H_2 production efficiency, longer plant lifetime, and improved replacement cost schedule.

[5] HTE builds on the same technology used in solid-oxide fuel cells; hence, the manufacturing costs should rapidly decline as a market for fuel cells used for distributed power generation and heavy-duty transportation vehicles rises.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

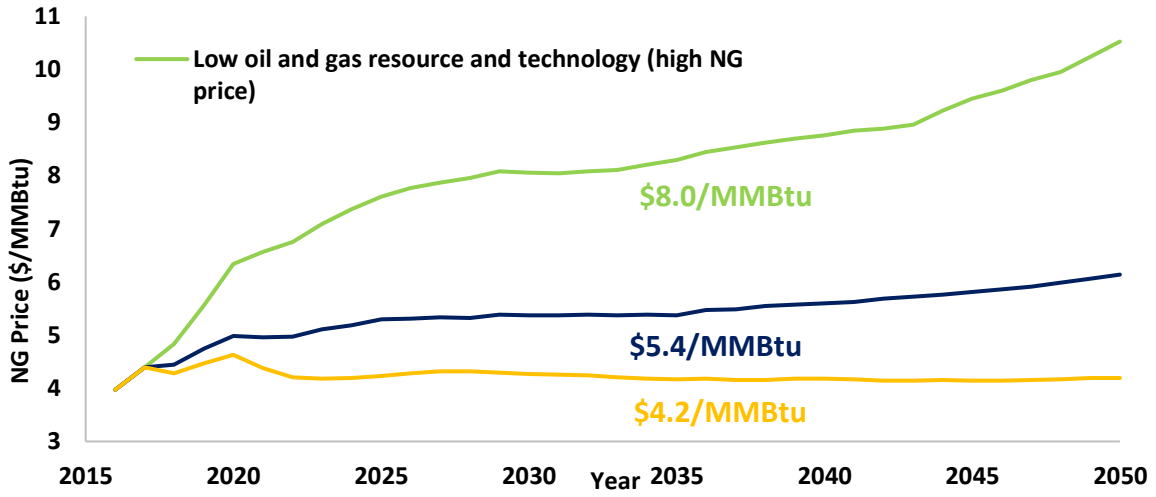


Figure 24. Natural gas prices (USD2017) projected by (AEO 2018). Mean natural gas prices are $8.0/MMBtu (million British thermal units), $5.4/MMBtu and $4.2/MMBtu for high, baseline, and low natural-gas price scenarios, respectively.

For comparison to both the small- and large-scale cases, an economic potential for the SMR hydrogen-production plant (with a 90% OCF) was assessed. The capacity of an SMR plant was scaled to match the capacity of a given electrolytic hydrogen-production system.

5.1.1 Small-scale Steady-state LTE and SMR Hydrogen Plants

Figure 25 plots hydrogen-production costs versus price of electricity for LTE. Three levels of LTE-stack costs are plotted as curves. This represents the potential learning and progression of the manufacturing and supply chain for the core component of PEM electrolysis units. The horizontal lines plot the cost of SMR hydrogen-production corresponding to natural-gas prices (AEO 2018). A histogram of LMP data for the Northern Illinois Hub is shown at the bottom of this figure to illustrate the electricity market conditions in 2017 impacting electricity sales to the grid.

The three intersections shown in the plot reveal the conditions for competitive LTE hydrogen production versus a similar SMR small-scale plant—namely $20.6/MWh relative to low natural-gas costs, $28.8/MWh relative to the reference cost of natural gas, and $41.3/MWh relative to the high natural-gas cost projection.

The analysis did not take credit for oxygen sales. For a small-scale plant, it may be economically viable to capture and sell byproduct oxygen. The calculations also do not attribute any value to reducing CO_2 or air-pollutant emissions relative to the emissions of the SMR plant.

A coordinated set of small-scale LTE plants could be used for grid-ancillary services at the power-distribution level. However, it may be difficult to establish a PPA near the LMP because of transmission costs.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

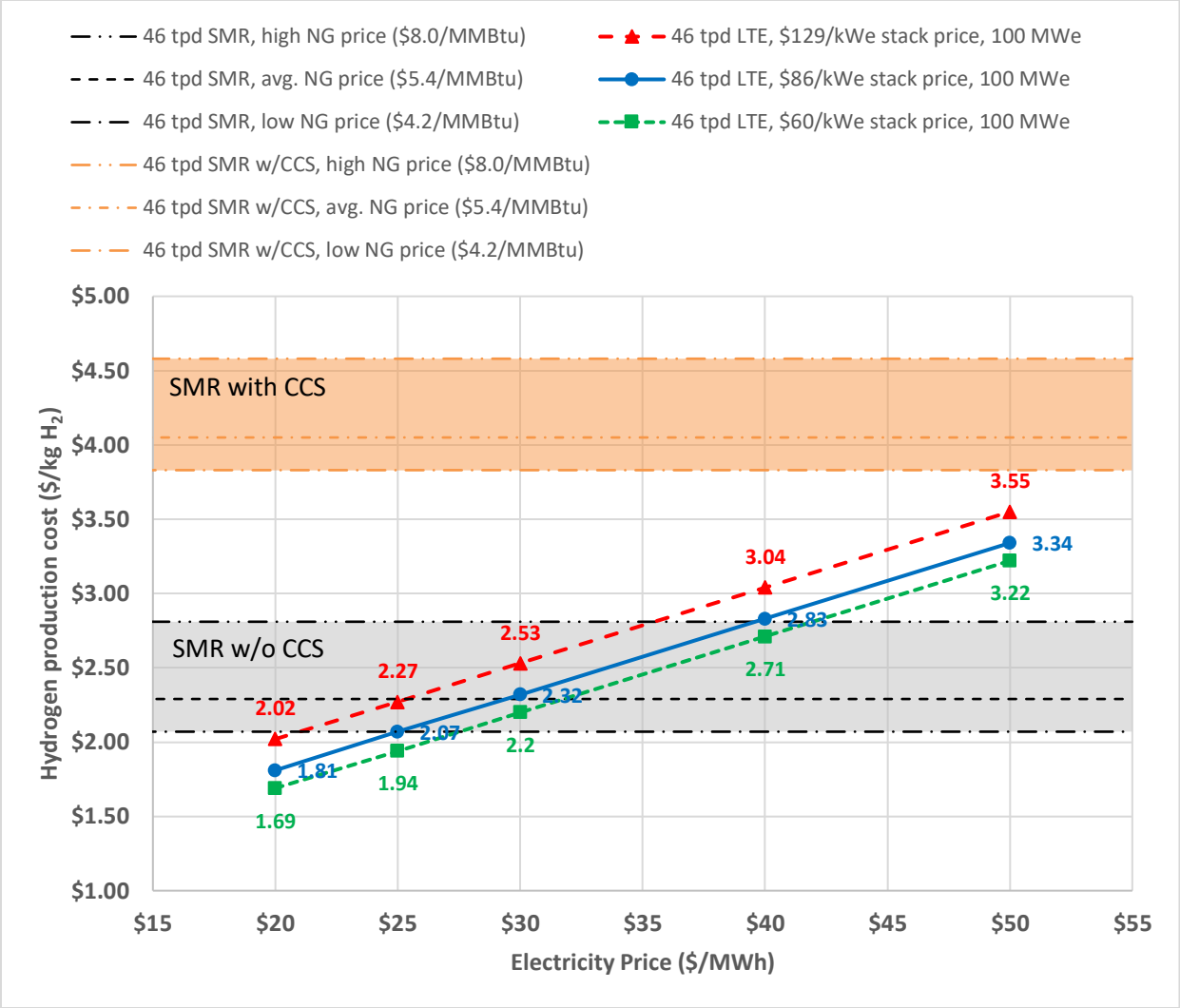


Figure 25. (SS, LTE) Comparison of hydrogen-production costs for 46-tpd small-scale/steady-state LTE and SMR plants (assuming 97% OCF, LTE curves for PEM stack costs, no oxygen sales credit, and no capacity payment).[6]

5.1.2 Large-scale Steady-state HTE and SMR Hydrogen Plants

Figure 26 plots the hydrogen production costs versus the price of electricity for a large-scale (~562 tpd) HTE. The histogram of 2017 LMP data for NI-Hub is again shown at the bottom of this figure. The horizontal lines again plot the cost of an equivalent-scale SMR hydrogen plant based on the three levels of natural-gas prices derived from (AEO 2018) [4]. These projections include credits for capacity payments as listed in Section 4. No credit is taken for oxygen sales or reducing CO_2 emissions relative to SMR plants. The LWR/HTE case includes compression and

[6] SMR+CCS calculated using H2A model v3.1 capital, electrical, and O&M cost estimates from "Carbon Sequestration" tab. Additionally, the following CAPEX were specified for the 380 tpd baseline design capacity plant to reflect the modified/additional SMR process capital costs for carbon capture: Process Plant Equipment $39.975m; Balance of Plant and Offsites $15.972m; SCR NOx Control on Stack $0; Process CO2 Removal $4.858m; Stack CO2 Removal $4.272m.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

delivery costs of $0.34/kg and the SMR case includes compression and delivery costs of $0.07/kg (Table 17).

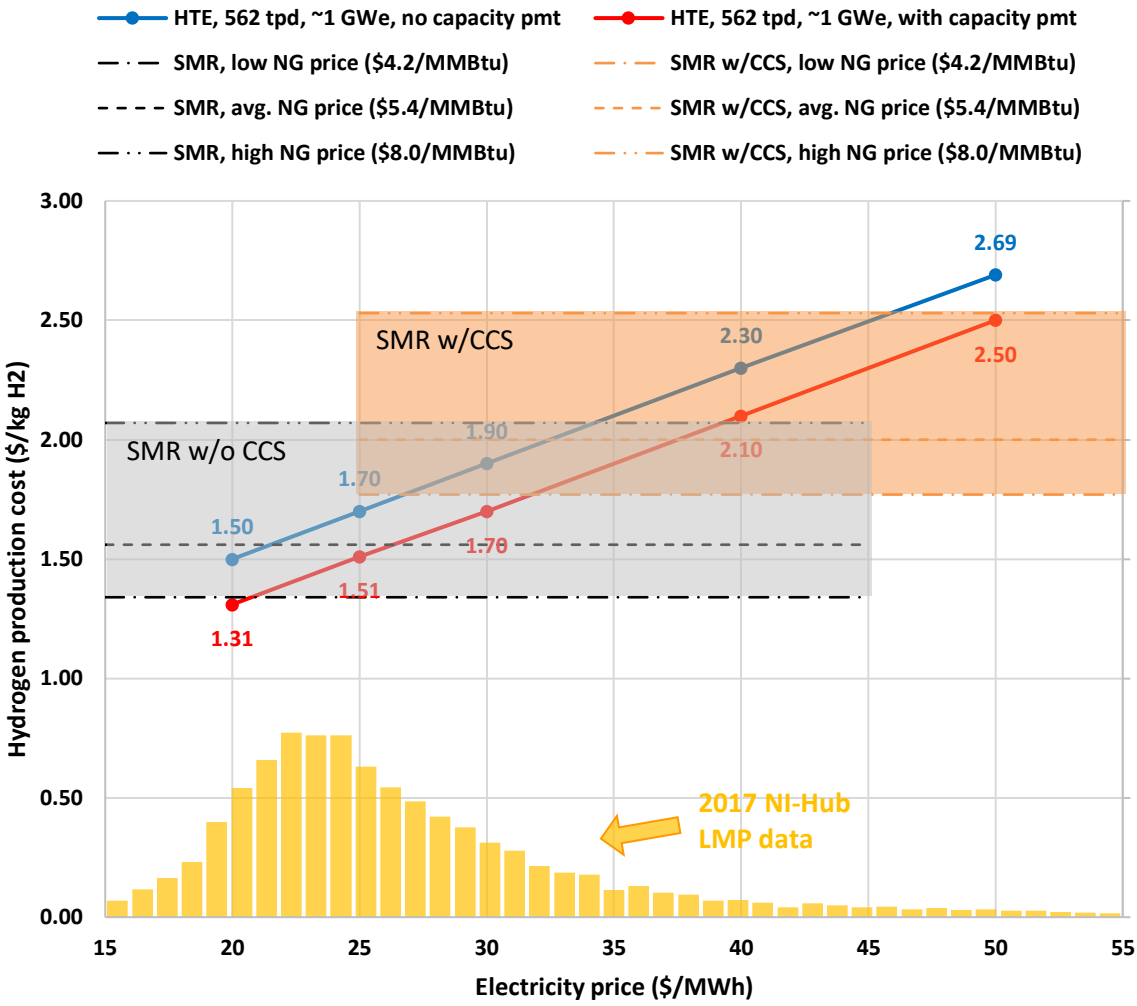


Figure 26. (SS, HTE) Comparison of hydrogen-production costs for 562 tpd large-scale/steady-state LWR/HTE and SMR plants (assuming Nth-of-a-kind 608 tpd design capacity LWR/HTE plant with 92.4% OCF and 624 tpd design capacity SMR with 90% OCF, no LWR/HTE oxygen sales, compression and delivery costs of $0.34/kg for LWR/HTE and $0.07/kg for SMR, and LWR/HTE capacity-payment credits of $0 or $132.4/MWe-day).[7]

The results of this assessment indicate a nuclear plant selling electricity to a close-coupled large HTE plant can compete with natural-gas SMR plants. These costs projections for a large central plant may provide incentive for ammonia producers or DRI projects to build their plants near the central hydrogen plants to take advantage of a reliable, sustainably low-cost supply of hydrogen. In addition, hydrogen produced by a nuclear-derived energy source could benefit from any value ascribed to reducing CO_2 and other air-pollutant emissions. For example, the HTE would reduce

[7] SMR+CCS calculated using H2A model v3.1 capital, electrical, and O&M cost estimates from "Carbon Sequestration" tab. Additionally, the following CAPEX were specified for the 380 tpd baseline design capacity plant to reflect the modified/additional SMR process capital costs for carbon capture: Process Plant Equipment $39.975m; Balance of Plant and Offsites $15.972m; SCR NOx Control on Stack $0; Process CO2 Removal $4.858m; Stack CO2 Removal $4.272m.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

CO_2 emissions by approximately 10 kg-CO_2 per kilogram of hydrogen [5]. Thus, each production of 1,000 kg-H_2 by an HTE tied to a clean energy source would avoid 10,000 kg-CO_2. In monetary terms, if CO_2 emissions were to be taxed \$25/tonne-CO_2, then the SMR process would be penalized \$0.25/kg-H_2 produced. From another view, the hydrogen produced by HTE with the low-emissions power produced by renewable and nuclear energy, could receive a credit of \$0.25/kg-H_2.

In summary, when a vibrant supply chain of solid-oxide electrolysis cells is established, then a large HTE plant purchasing electricity and steam (or thermal energy) from a nuclear power plant could produce and sell hydrogen for around \$1.00–2.00/kg-H_2 depending on contract conditions and credits. This falls within the DOE target and may spur future hydrogen markets.

5.2 Dynamic Plant Operation

For purposes of terminology, a hybrid plant is defined as a plant that dispatches one or more energy outputs to produce at least two unique products in a manner that optimizes at least one objective such as 1) revenue generation, 2) pollutant-emissions reduction, or 3) grid reliability, resiliency, or stability. For this analysis, a look at optimizing revenue by selling electricity to the grid or to an electrolysis plant has been considered. Figure 27 illustrates how electricity produced at the marginal electricity selling price could be sold to the grid or used to generate hydrogen. In this case, the systems may be viewed as a "price taker" so far as it will schedule ahead for the power market anytime the marginal electricity price exceeds some price point (referred to herein as the cutoff price).

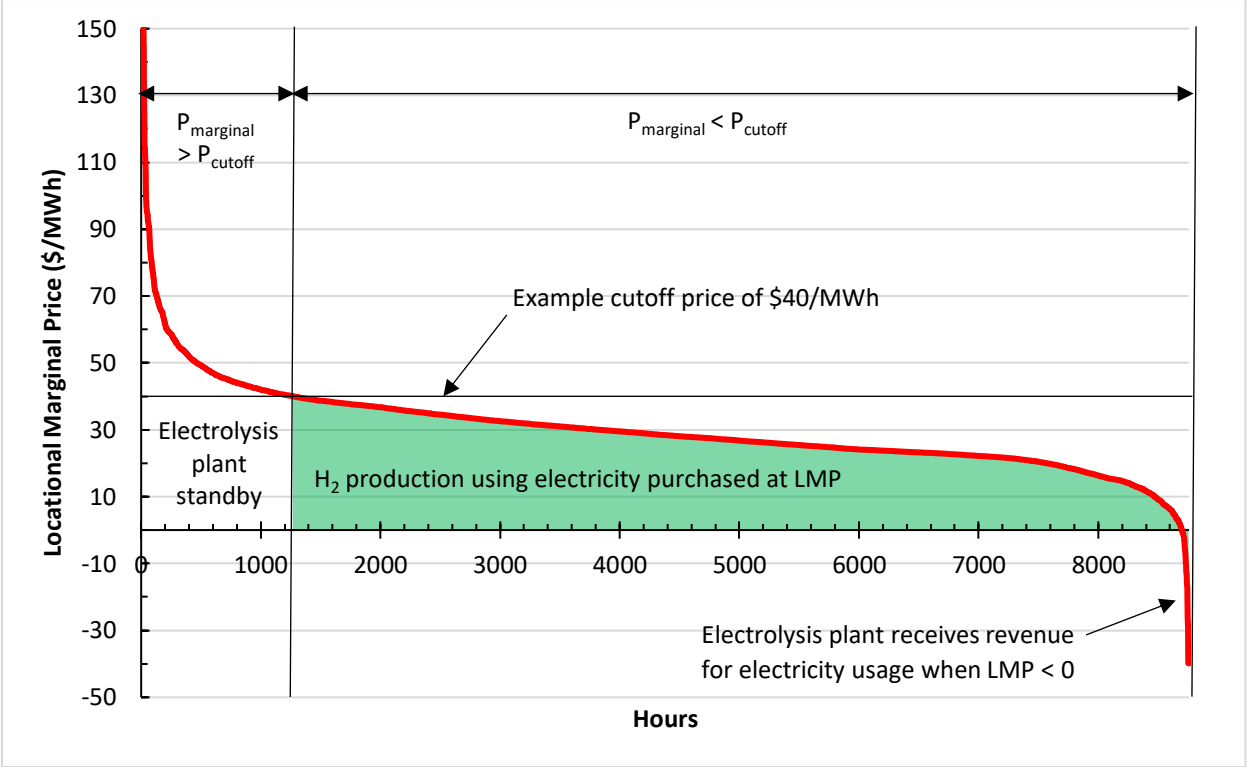


Figure 27. Hybrid power/hydrogen plant concept.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

The following assumptions apply to all of the supply curve analyses described in the sections below:

- An outage rate of 5% is specified for both HTE and LTE plants; additional reduction to capacity factor results from curtailing plant operations due to locational marginal pricing and for SOEC stack degradation over the project life.
- The plant size and the corresponding direct capital costs are held constant within each scenario with the exception of Xcel Energy Scenarios 5, 6, and 7 (fixed PPA pricing). In Xcel Energy Scenarios 5, 6, and 7 the electricity pricing is held constant and the plant capacity is varied (the capital costs are assumed to scale with a scaling factor exponent equal to 0.6) to estimate the resulting hydrogen cost variation. In all other scenarios the specified DCCs and plant capacities are held constant (i.e., the specified DCC is assumed for a plant with the specified capacity; the DCCs are not scaled up or down from a baseline plant with a different capacity than that specified)

5.2.1 Analysis Methods

5.2.1.1 Regional Hydrogen Demand Curves

The hydrogen demand curves were constructed by coupling the hydrogen potential demand data with the hydrogen prices presented by Ruth et al (2019) [6], and include potential current and future hydrogen demand values for several hydrogen market segments. The hydrogen threshold prices applicable hydrogen customers are assumed to be able to pay are summarized in Table 18. A representative hydrogen demand curve is presented in Figure 28 (current hydrogen demand in region serviced by Southern Company).

Table 18. Hydrogen threshold pricing by market segment

Hydrogen Market Segment	Threshold Price ($/kg)
Ammonia	$2.00
DRI	$1.70
FCEV	$2.20
NG Electricity Generators	$1.00
Electricity: NG Fired Generators	$1.00
Refinery	$3.00
Syngas: Ammonia CO2	$1.50
Syngas: Ethanol	$1.50
Syngas: Hydrogen, SMR	$1.50

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

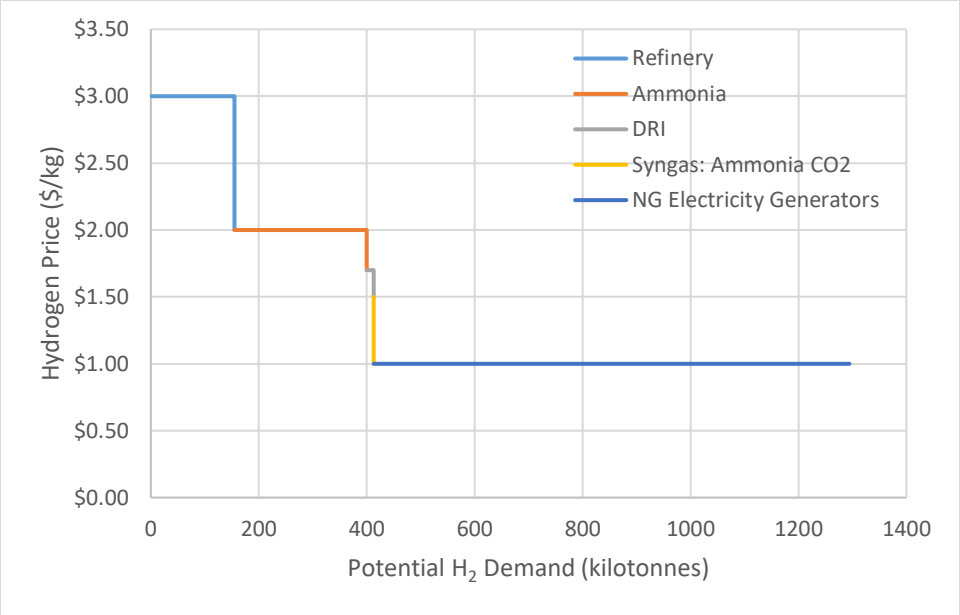


Figure 28. Current hydrogen demand in Alabama, Georgia, and Mississippi (region serviced by Southern Company power generation assets)

5.2.1.2 LTE Supply Curves

Locational Marginal Pricing (LMP) curves corresponding to the electricity markets each of the CRADA participant utilities operate within were used to establish the relationship between the LTE plant operating time and average cost of electricity purchased by the plant. The dynamic process operating strategy utilizes an approach in which the LTE plant is started up when the electricity market price is lower than a specified "activation price". The LMP data was analyzed to establish curves of LTE process operating time versus the activation price (Figure 29) and the average cost of electrical power purchased by the LTE plant versus the activation price (Figure 30). The LTE process operating time and average electricity purchase price data obtained from the activation price analysis can then be used along with the assumed LTE plant outage rate (5%) to determine the average LTE process electricity cost as a function of the LTE process operating capacity factor (Figure 31). The electricity price versus capacity factor was imported to the H2A model (along with other required input specifications including plant capacity, equipment capital costs, financial assumptions, etc.) to calculate the levelized cost of hydrogen.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

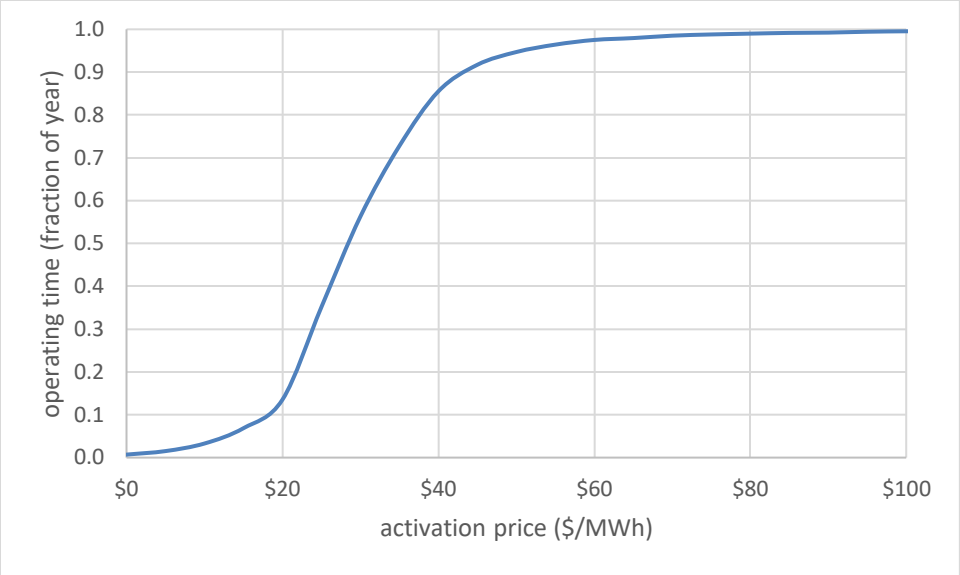


Figure 29. LTE process fractional operating time versus the process activation price (example plot using MISO-MINN LMP data).

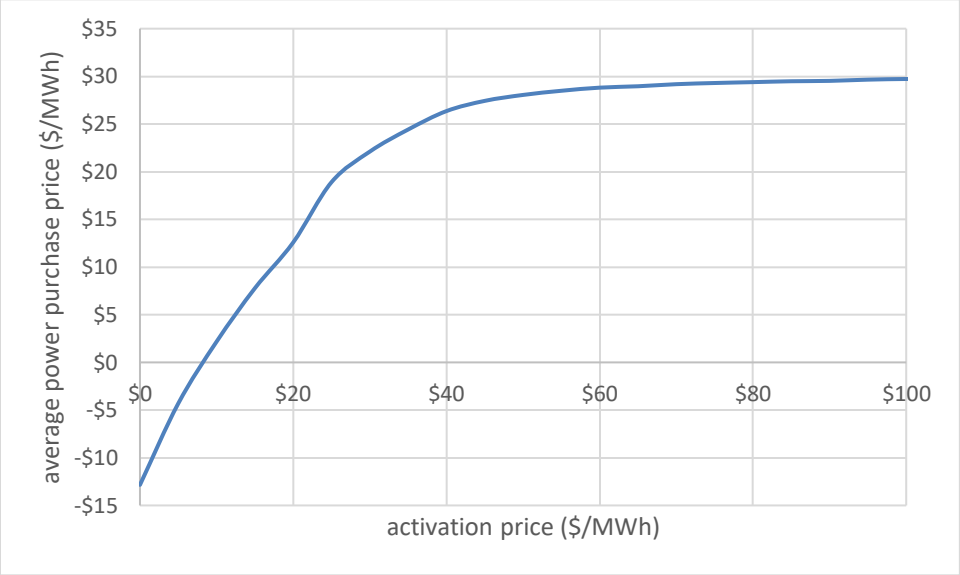


Figure 30. LTE process input power cost versus the process activation price (example plot using MISO-MINN LMP data).

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

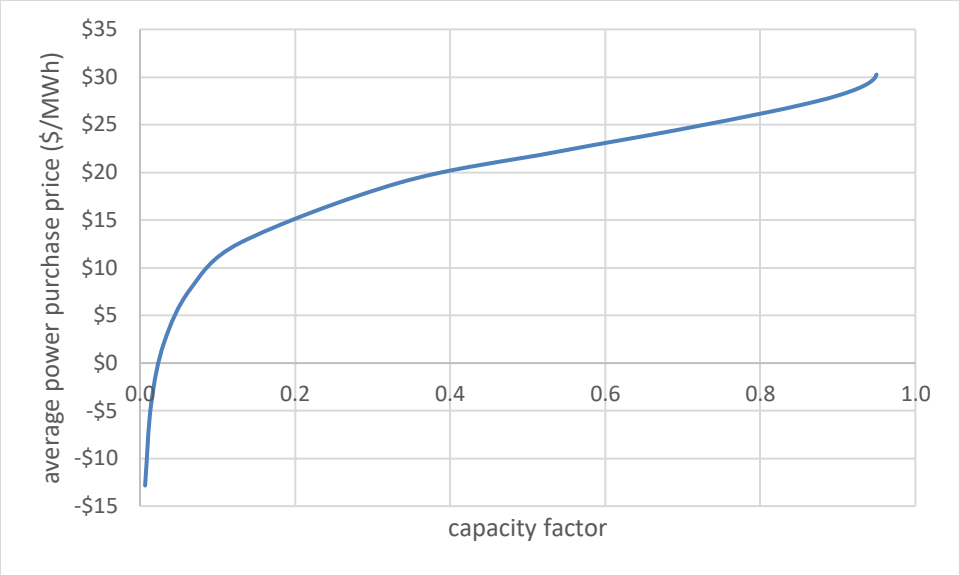


Figure 31. LTE process average power purchase price versus the process operating capacity factor (example plot using MISO-MINN LMP data).

The LTE scenario supply curves were constructed by plotting the levelized cost of hydrogen and annual hydrogen production values (LCOH vs annual production data was generated by evaluating multiple data points from the average power purchase price versus capacity factor curves above using the H2A model). An additional delivery and storage cost of $0.08/kg was added to the LCOH calculated by the H2A model (Table 17, Section 4.4.4). A representative supply curve is presented in Figure 32.

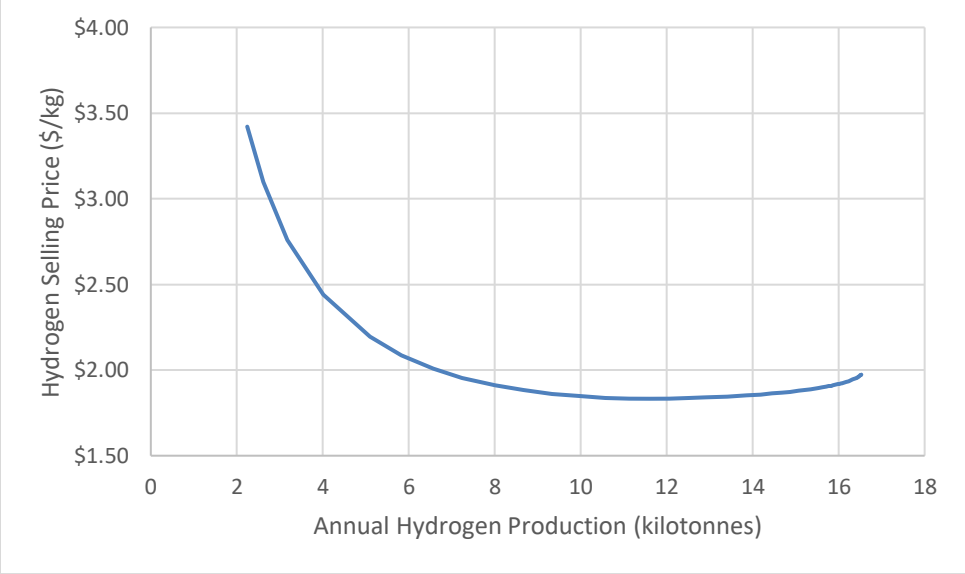


Figure 32. LTE hydrogen production supply curve (100 MWe LTE plant with $232/kW CAPEX operating in MISO-MINN market)

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

5.2.1.3 LWR/HTE Supply Curves

LMP curves for the electricity markets each of the CRADA participant utilities operate within were used to establish the potential electricity sales price as that could be obtained by an LWR with variable electricity/hydrogen dispatch capabilities.

These calculations assume the generation source is constant and is capable of dispatching electricity to the hydrogen plant or selling to the grid throughout the entire year. This is not a practical assumption for renewable wind or solar generation. However, for a nuclear power plant, it is reasonable for the plant to switch between hydrogen and electricity sale to the grid.

The overriding assumption is revenue gained from power sales is included in the cash flow of the hydrogen production plant. Thus, this cash flow is used compute the cost of hydrogen production as the to reduce the project net present value (NPV) to zero when covering manufacturing costs and the investment capital discount rates for debt and equity listed in Table 9.

The dynamic process operating strategy utilizes an approach in which the HTE plant is curtailed when the electricity market price is higher than a specified "bid price" such that the LWR can dispatch electrical power during time periods when electricity prices are elevated (Figure 33). It is important to note that in the LTE cases hydrogen production starts when the LMP pricing is below the activation price, while in the HTE cases hydrogen production is curtailed when the LMP pricing is above the bid price.

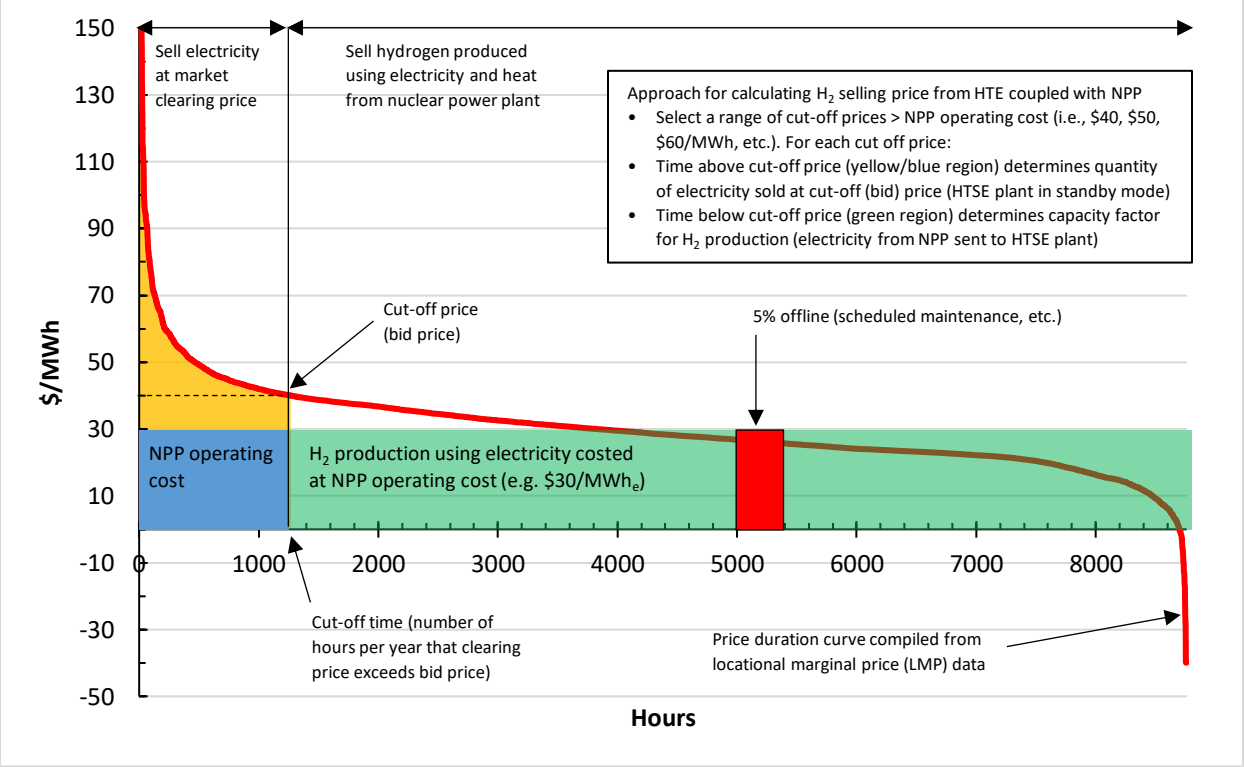


Figure 33. Hybrid nuclear electricity/hydrogen plant approach to minimizing hydrogen production costs.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

The LMP data was analyzed to establish curves of HTE process operating time versus the bid price (Figure 34) and the average market clearing price for power sold by the LWR/HTE plant versus the bid price (Figure 35).

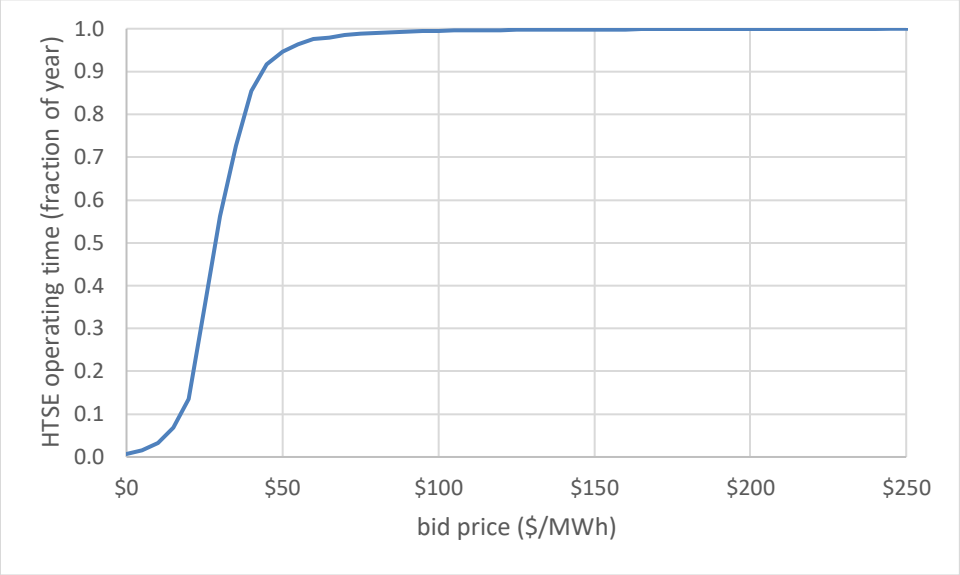


Figure 34. HTSE operating time versus bid price (example plot using MISO-MINN LMP data)

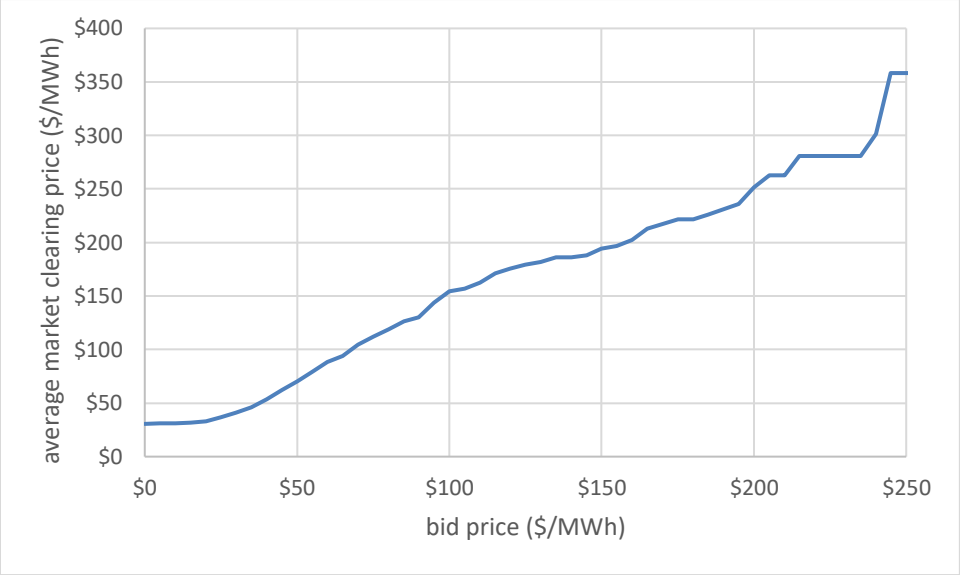


Figure 35. Average market clearing price versus bid price (example plot using MISO-MINN LMP data)

Electrical power dispatched from the LWR/HTE plant during periods when the market clearing price is above the bid price provides the LWR/HTE plant with revenue equal to the market clearing price minus the NPP O&M cost. The revenues from the LWR/HTE hybrid plant electrical power generation are included in the LCOH calculation in the form of byproduct sales. Figure 36 is plot of the average LWR/HTSE byproduct power sales revenue versus HTSE capacity factor assuming an LWR O&M cost of $30/MWh and LWR/HTSE outage rate of 5%.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

The average LWR/HTSE byproduct power sales revenue versus capacity factor was imported to the H2A model (along with other required input specifications including plant capacity, equipment capital costs, financial assumptions, etc.) to calculate the levelized cost of hydrogen.

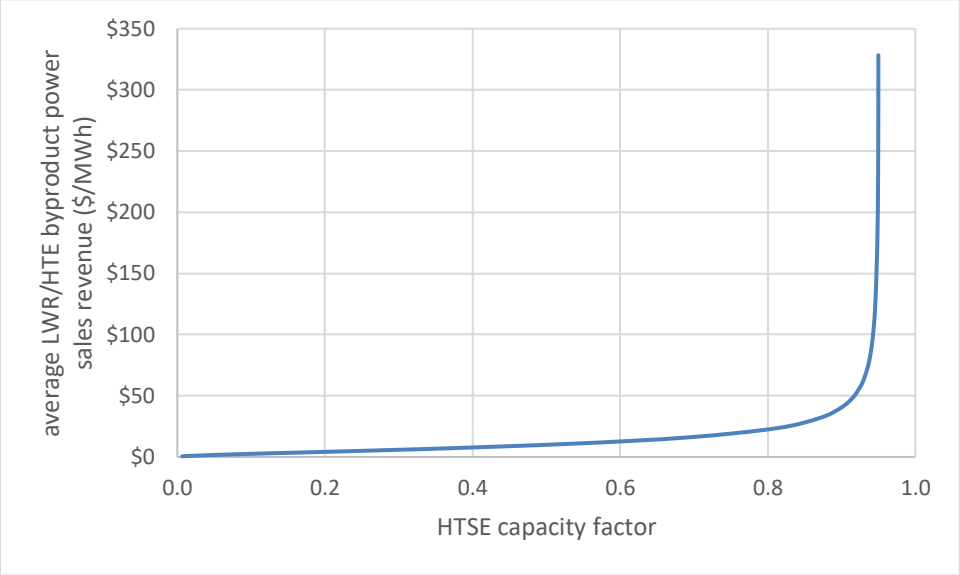


Figure 36. Average LWR/HTSE byproduct power sales revenue versus HTSE capacity factor (example plot using MISO-MINN LMP data) assuming LWR O&M cost of $30/MWh and LWR/HTSE outage rate of 5%.

In the LWR/HTSE case the capacity submitted to the capacity markets corresponds to the capacity that can be made available by operating the HTSE process in the hot standby mode. In hot standby mode the SOEC stack electrical power can be turned off, but electrical power is still required to operate the HTSE process topping heaters, pumps, blowers, and compressors. Additionally, it is assumed that 100% of the HTSE process thermal energy demand is required during hot standby mode. Therefore, the capacity submitted to the capacity market is equal to the SOEC stack electrical power demand (892 MWe for a nominal 1,000 MWe NPP as described in Section 4.3). The unforced capacity is determined by adjusting this capacity by the equivalent demand forced outage (EFORd) rate per Section 2.2. In this analysis the capacity market pricing was assumed to equal the median value reported in Table 1 and Table 2 ($130.27/MWe-day for PJM ComEd and $2.40/MWe-day for the MISO Zone 1).

Several additional assumptions apply to the capacity payment analysis. First it is assumed that generation associated with capacity payment generation requests occurs during periods of high power demand and that no further adjustment to the HTE capacity factor is required. Second, it is assumed that the hydrogen product is sold into a hydrogen market such that individual hydrogen customers can purchase hydrogen from other suppliers during periods of time that electricity is dispatched from the LWR/HTE plant. Therefore, no onsite hydrogen storage capacity is required.

The HTE scenario supply curves were constructed by plotting the levelized cost of hydrogen and annual hydrogen production values (LCOH vs annual production data was generated by evaluating multiple data points from the average byproduct power sales revenue versus capacity factor curves above using the H2A model). An additional delivery and storage cost of $0.34/kg

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

was added to the LCOH calculated by the H2A model (Table 17, Section 4.4.4). A representative supply curve is presented in Figure 37.

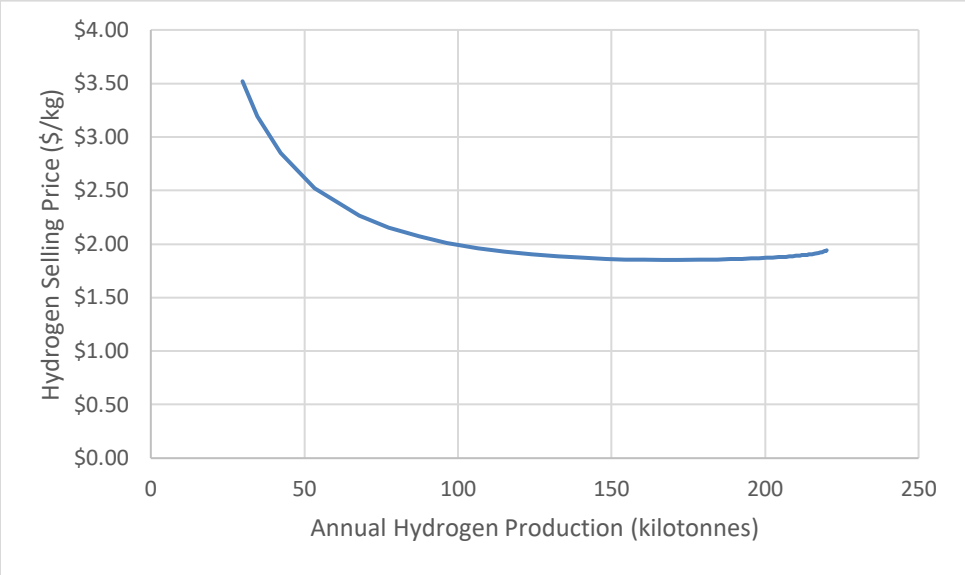


Figure 37. HTE hydrogen production supply curve (1000 MWe HTE plant with $249/kW CAPEX operating in MISO-MINN market)

1.1.1.1 PV/LTE Supply Curves

Given the interest in solar power in the Southeast, the cost of hydrogen production in the Southern Company power district was analyzed. Southern Company Scenario 3 evaluates hydrogen production from a solar PV power plant coupled to an LTE plant. The system is assumed to be isolated from the electrical grid such that the variation in electricity market pricing illustrated by the LMP curves does not apply. Instead, the hydrogen price and annual production is determined as a function of the PV power plant output, the LTE plant capacity, and the system costs.

The analysis assumes that the solar field has a fixed capacity of 100 MWdc and is located in Columbus, Georgia. The levelized cost of the electricity produced by the PV plant is calculated as $46.6/MWh using the NREL System Advisor Model (SAM). The LTE plant size is varied over a range of plant capacities less than or equal to the solar field design power output.

The LTE plant capacity factor is then calculated by comparing hourly PV plant power output against LTE plant capacity. During periods of time when the PV plant power output exceeds the LTE plant capacity the excess power generation is curtailed. The calculations do not assume electricity is sold to another customer; rather, it is simple grounded and wasted. The solar plant electricity price is corrected upward such that the annual solar plant power sales revenue is equal to the case where 100% of the generated power is sold. During periods of time when the LTE plant capacity exceeds the solar plant power output, the LTE plant is assumed to operate at partial capacity using all power produced by the PV plant.

The PV/LTE hydrogen price versus production supply curve data is calculated by evaluating multiple LTE plant capacities coupled with the specified PV plant. Since the solar field capacity

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

is assumed fixed at 100 MWe, the minimum hydrogen price will correspond to the optimal LTE plant capacity to PV plant capacity ratio. An additional delivery and storage cost of $0.08/kg was added to the LCOH calculated by the H2A model (Table 17, Section 4.4.4).

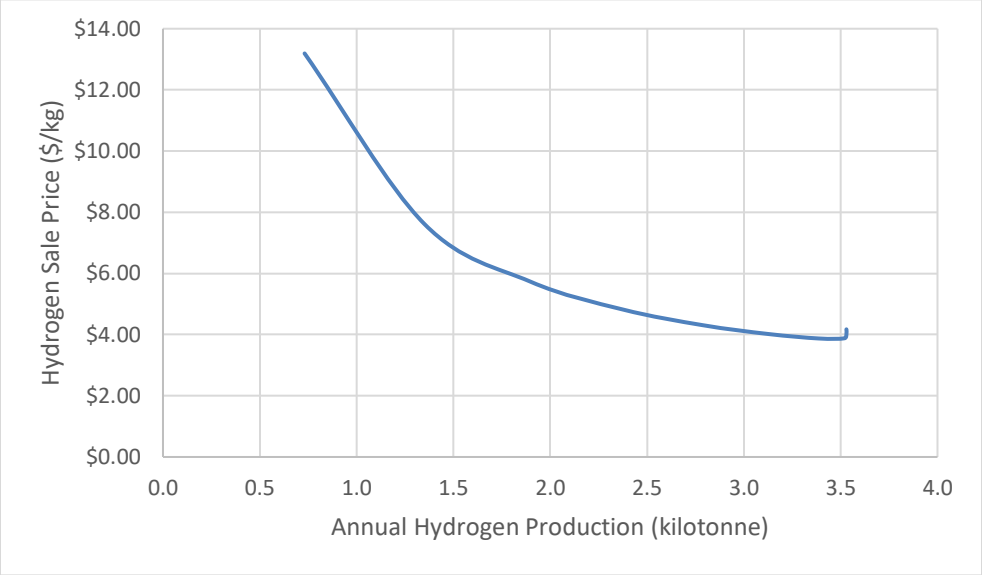


Figure 38. PV/LTE hydrogen production supply curve (100 MWdc PV plant with varying LTE plant capacity ($232/kW CAPEX) operating in Columbus, Georgia)

5.2.1.4 LTE/HTE Capital Costs

The LTE and HTE process capital costs are an important input parameter in the supply curve analysis. The LTE and HTE capital costs reported in Section 4.4.1 correspond to future cost projections using mature LTE and HTE hydrogen production technologies that are mass produced and have achieved cost reductions as a result of learning effects from previous industrial scale installations. However, projections of HTE and LTE capital costs reported elsewhere in the open literature have identified a range of capital cost estimates over varying time scales. For purposes of comparison the supply curve analysis presented herein includes results based on capital cost projections from this report as well as from other literature sources. The individual capital cost estimates used for generating the families of supply curves presented in each LTE and HTE scenario are listed below in Table 19 and Table 20, respectively.

Table 19. LTE plant capital cost estimates used in supply curve analysis. Listed values represent installed costs including power electronics, gas conditioning, and balance of plant.

	CAPEX ($/kWe)	Reference
Future Cost Estimate	$232/kWe	Section 4.4.1
Long Term Cost Projection	$500/kWe	IEA PEM electrolyser CAPEX projection [7] $200-900/kWe (long term)
Today-2030	$1100/kWe	IEA PEM electrolyser CAPEX projection [7] $1100-1800/kWe (today) $650-1500/kWe (2030)

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Table 20. HTE plant capital cost estimates used in supply curve analysis. Listed values represent installed costs including power electronics, gas conditioning, and balance of plant.

	CAPEX ($/kWe)	Reference
Large Scale HTSE (1000 MWe) Nth-of-a-Kind Plant Future Cost Estimate	$249/kWe	Section 4.4.1 $227/kWe modular components $22/kWe conventional components
Small Scale HTSE (100 MWe) First-of-a-Kind Plant Future Cost Estimate	$432/kWe	Section 4.4.1 $382/kWe modular components $50/kWe conventional components
Long Term Cost Projection	$750/kWe	IEA SOEC electrolyser CAPEX projection [7] $500-1000/kWe (long term)
2030 Cost Projection	$1800/kWe	IEA SOEC electrolyser CAPEX projection [7] $800-2800/kWe (2030)

5.2.2 Southern Company Scenarios

The Southern Company supply curve analysis scenario input parameters are summarized in Table 21. Supply versus demand plots are presented for each scenario in the subsequent sections.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Table 21. Summary of Southern Company Supply Curve Analysis Scenarios

No.	Scenario Description	Electrical Energy Usage (kWhe/kg)	Thermal Energy Usage (kWht/kg)	System Capacity (MWe)	System Capacity (tonne H_2/day)	Direct Capital Costs ($/kW)	NPP O&M Cost ($/MWh)	Capacity Payment ($/MWe-day)	Capacity Credit (%)
1	Low Temp Electrolyzer - Marginal Cost Timeseries	50.2	N/A	100	47.8	232, 500, 1100	N/A	N/A	N/A
2	HTE Steam Reforming - Marginal Cost Timeseries	37.7	6.5	940	608	249, 750, 1800	30	N/A	N/A
3	Solar PV with LTE H2 production isolated from electrical grid	50.2	N/A	10-100	4.78 – 47.8*	232, 500, 1100	N/A	N/A	N/A

*The actual system performance differs considerably from the rated capacity in Scenario 3 due to the low capacity factors associated with the PV power plant (no energy storage capacity is included in the scenario)

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

5.2.2.1 Alabama/Georgia/Mississippi Demand Curves

Figure 39 and Figure 40 are plots of the current and future potential demand, respectively, in the states of Alabaman, Georgia, and Mississippi. Southern Company serves customers in a region that covers large areas within states. The potential hydrogen demand is divided into five end use applications, including refineries, ammonia production, direct reduction of iron (DRI), synthesis gas (syngas) applications, and electricity generation applications. Each of these end use application is assumed to be able to pay a different price for hydrogen as described in Table 18 of Section 5.2.1.1.

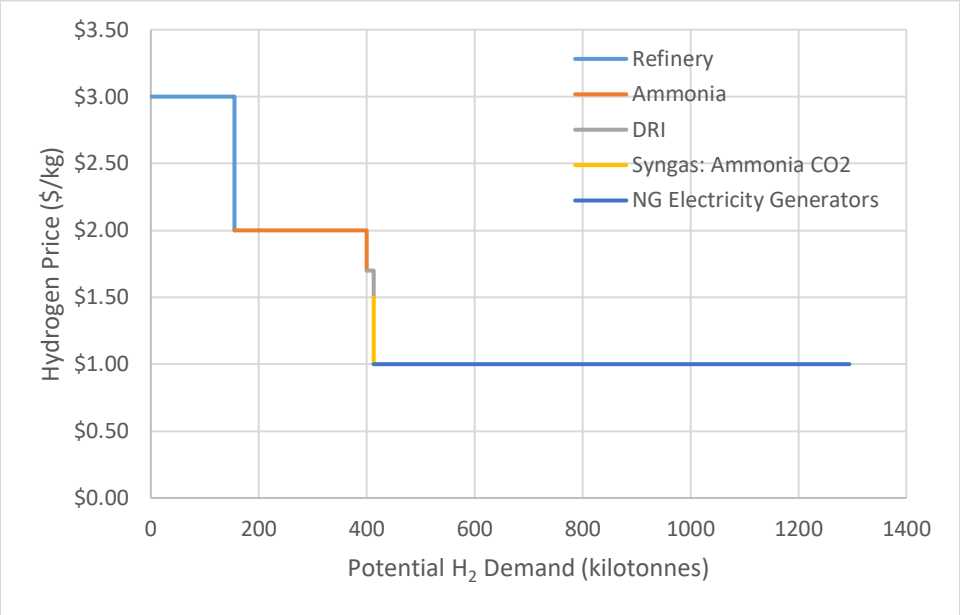


Figure 39. Southern Company AL/GA/MS current hydrogen demand

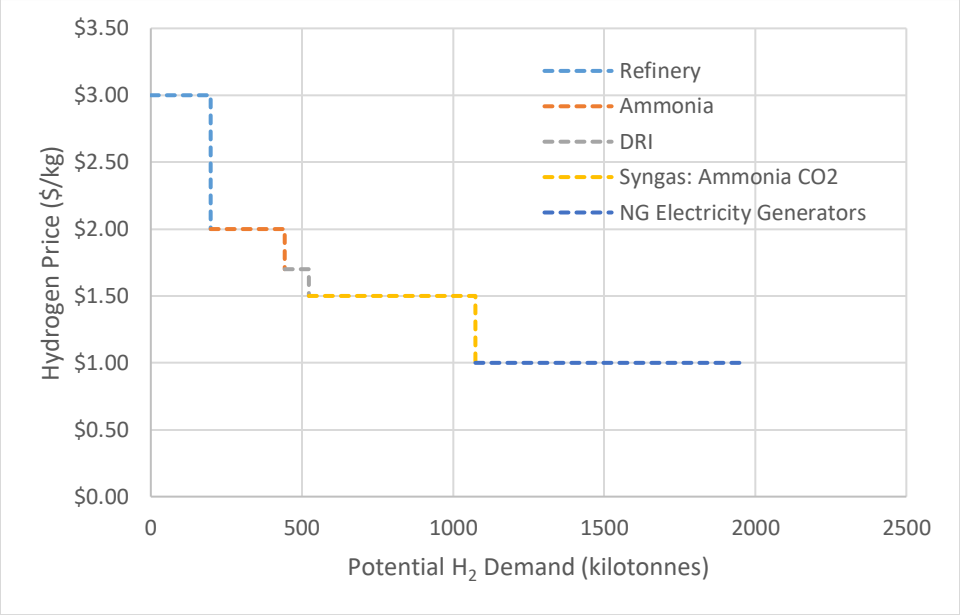


Figure 40. Southern Company AL/GA/MS future hydrogen demand

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

5.2.2.2 Southern Co Scenario 1: Low Temp Electrolyzer - Marginal Cost Time Series

Figure 41 is a supply versus demand plot for Southern Company Scenario 1. Both current and future potential hydrogen demand curves are plotted. The hydrogen price is assumed equal for each hydrogen customer type (end use application) in the current and future cases, but the number of customers and potential hydrogen demand per customer does vary between the current and future cases. Supply curves for LTE hydrogen production based on the Southern Company footprint wide LMP are presented for different values of the LTE plant direct capital cost as described in Section 5.2.1.4.

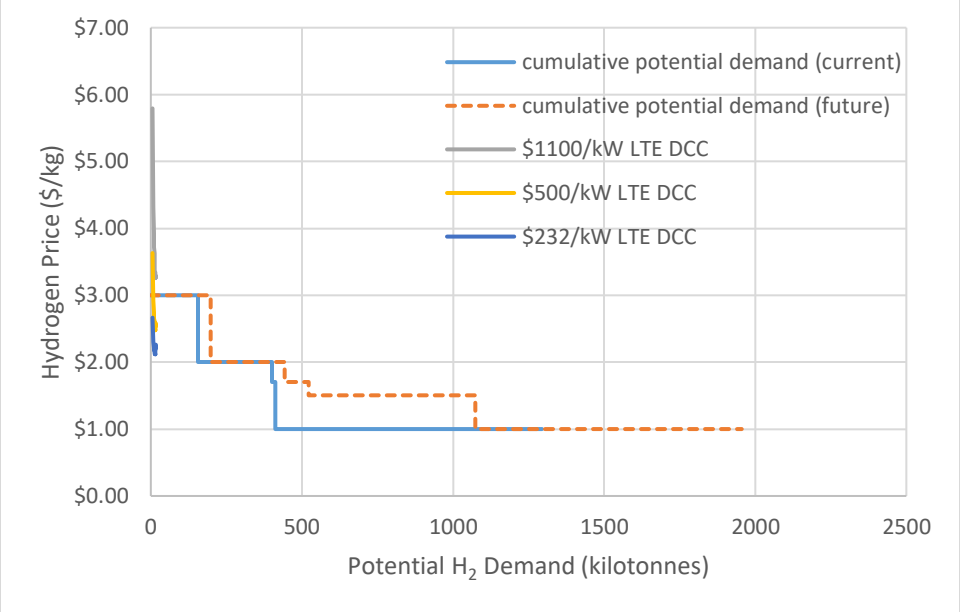


Figure 41. Southern Company Scenario 1 supply vs demand curve

Figure 42 is a modified version of Figure 41 in which the scale of the x-axis (potential hydrogen demand) is decreased to provide a higher resolution view of the LTE supply curves. The LTE plant capacity evaluated in this scenario provides an annual supply of hydrogen less than the highest cost customer (refineries @ $3/kg) demand, such that the demand for the second highest cost customer (ammonia production @ $2/kg) is outside the data range included in the plot, resulting in only a single visible section of the demand curve in this plot.

The supply curves in Figure 41 and Figure 42 represent the hydrogen that could be supplied by a single 100 MWe LTE plant in Southern Company Scenario 1. This plant size is assumed to represent an electrical power demand that is sufficiently small so as to not influence the LMP. Each of the LTE plant supply curves plotted in Figure 41 and Figure 42 takes the form of a curve with a minimum hydrogen price at a point within the extents of the plotted data. Since the plotted data is for a single LTE plant, the difference in the supplied hydrogen capacity plotted for each curve is associated with differences in the plant capacity factor.

Per the discussion in Section 5.2.1.2, the plant capacity factor and the average price of electricity purchased by the LTE plant vary with the activation price. The higher cost hydrogen on the left side of each supply curve corresponds to the data for which the activation price is low such that the plant operates during a small percentage of the year resulting in less plant operation time and

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

a corresponding low capacity factor. The higher cost hydrogen on the right side of each supply curve corresponds to the data where the activation price is high such that the plant operates during a large percentage of the year but the average price of the electricity purchased by the plant is higher, which results in higher supply but at a higher cost.

It can be observed from Figure 42 that LTE plants with capital costs of $232/kW (future cost estimate, INL) and $500/kW (long term projection, IEA) are capable of supplying hydrogen at a cost lower than what the highest price customer (refineries) are able to pay. The minimum hydrogen sales prices in each of these supply curves correspond to an operating strategy in which the LTE plant is operated when the LMP price is lower than the optimal activation price of $40/MWh ($232/kWe DCC) and $46/MWh ($500/kWe DCC) resulting in OCFs of 81% and 85%, respectively.

In a market without other hydrogen producers, an LTE plant with a capital cost of $500/kW or lower, operated when the LMP price is lower than the optimal activation price, would be capable of selling the full output capacity to refineries at a cost of less than $3/kg. However, it is important to note that SMR would generally be able to produce hydrogen at a price of less than $3/kg, which would provide competition in the market. In the event that SMR were able to provide hydrogen at a cost lower than the LTE plant, the LTE plant would require subsidies, incentives, or "green hydrogen" premium pricing to secure the sale of the full plant production capacity into the market.

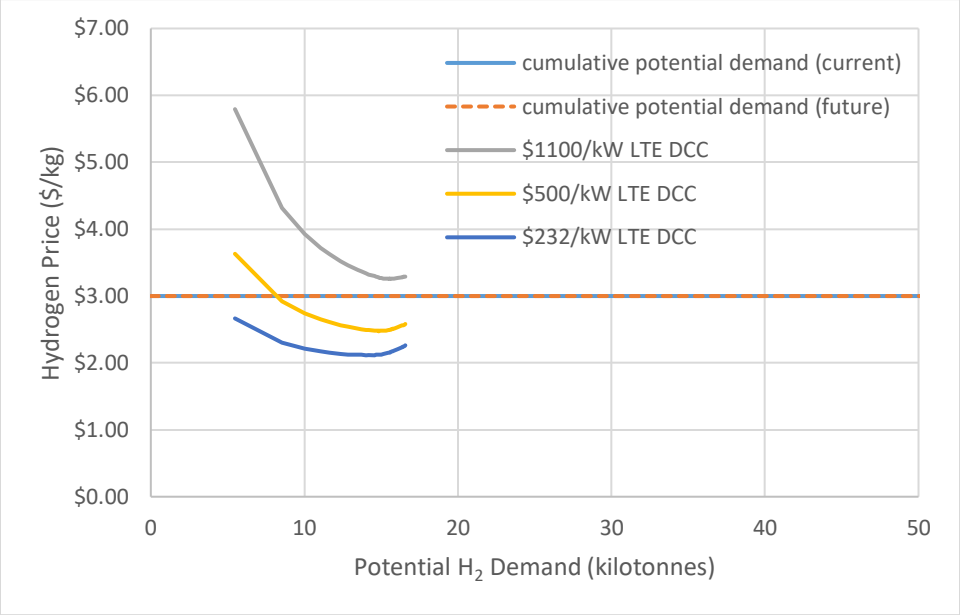


Figure 42. Southern Company Scenario 1 supply vs. demand curve (to 50 kilotonnes per year)

In Figure 43 the supply curves for the $232/kW and $500/kW LTE plants are replaced with horizontal lines representing the supply of hydrogen that could be provided by multiple plants operated at capacity factors of 81% and 85% corresponding to the optimal activation prices of $40/MWh and $46/MWh, respectively. Installation of fourteen LTE plants would provide the hydrogen supply required to satisfy the potential future refinery demand in the Alabama/Georgia/Mississippi region. However, as previously noted, the large electrical load

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

associated with multiple LTE plant installations may perturb the regional electricity market resulting in a shift in the LMP curve (such that the analysis presented above would no longer be applicable).

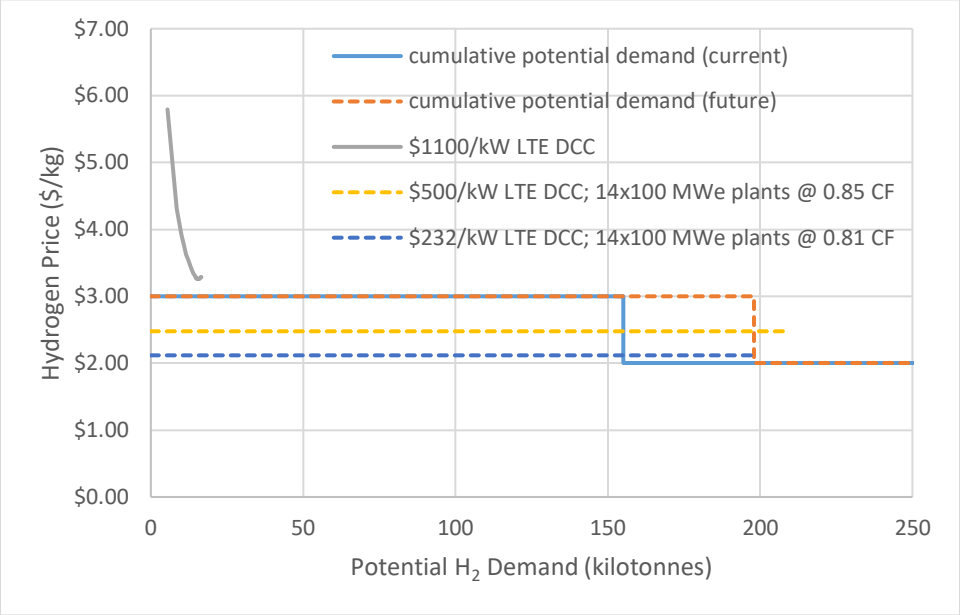


Figure 43. Southern Company Scenario 1 supply (multiple LTE plants) vs demand

5.2.2.3 Southern Co Scenario 2: HTE Steam Reforming - Marginal Cost Time Series

Figure 44 is a supply versus demand curve for Southern Company Scenario 2. Similar to the supply curves presented previously, both current and future potential hydrogen demand curves are plotted and the hydrogen price is assumed equal for each hydrogen customer type (end use application) in the current and future cases. Supply curves for HTE hydrogen production based on the Southern Company footprint wide LMP are presented for different values of the HTE plant direct capital cost as described in Section 5.2.1.4.

The supply curves in Figure 44 represent the hydrogen that could be supplied by a single 1,000 MWe HTE plant in Southern Company Scenario 2. The difference in the supplied hydrogen capacity plotted for each curve is associated with differences in the plant capacity factor. Each of the HTE plant supply curves plotted takes the form of a curve with a minimum hydrogen price at a point within the extents of the plotted data.

Per the discussion in Section 5.2.1.3, the plant capacity factor and the average price of electricity sold by the LWR/HTE plant vary with the bid price. The higher cost hydrogen on the left side of each supply curve corresponds to the lower bid price data such that the HTE plant is operational only for a small percentage of the year resulting in less plant operation time and a corresponding low capacity factor. The higher cost hydrogen on the right side of each supply curve corresponds to the higher bid price data where a less than optimal amount of electrical power is dispatched from the LWR/HTE hybrid and electrical power sales revenue is not maximized.

It can be observed from Figure 44 that the 1,000 MWe capacity HTE plant evaluated in this scenario provides an annual supply of hydrogen sufficient to meet the demand associated with

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

the highest cost customer (refineries @ $3/kg) as well as partial demand associated with the second highest cost customer (ammonia production @ $2/kg). An HTE plant with a capital cost of $249/kW (future cost estimate, INL) is capable of supplying hydrogen at a cost lower than the refinery and ammonia plant demand curve prices, while an HTE plant with a capital cost of $750/kW (long term projection, IEA) is capable of supplying hydrogen at a cost lower than the refinery demand curve price. The minimum hydrogen sales prices in each of these supply curves correspond to an operating strategy in which the LWR/HTE plant is operated when the LMP price is less than or equal to the optimal bid price of $36/MWh ($249/kWe DCC) and $57/MWh ($750/kWe DCC) resulting in HTE OCFs of 72% and 89%, respectively.

In a market without other hydrogen producers, an HTE plant with a capital cost of $750/kW or lower, operated when the LMP price is lower than the optimal bid price, would be capable of selling the full output capacity to refineries at a cost of less than $3/kg. An HTE plant with a capital cost of $249/kW or lower would be capable of selling its full hydrogen production capacity to refineries or ammonia plants at a cost of less than $2/kg. However, SMR technology is able to produce competitively priced hydrogen such that the HTE plant may require subsidies, incentives, or "green hydrogen" premium pricing to secure the sale of the full plant production capacity into the market.

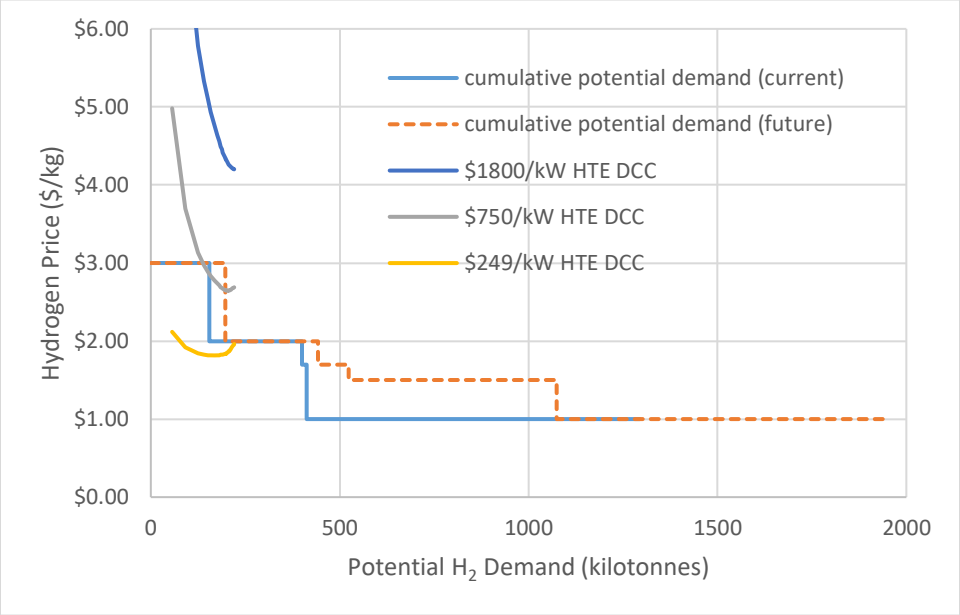


Figure 44. Southern Company Scenario 2 supply vs demand curve

5.2.2.4 Southern Co Scenario 3: LTE Hydrogen from Solar PV (isolated from grid)

Figure 45 is a supply versus demand plot for Southern Company Scenario 3. Figure 46 is a modified version of Figure 45 in which the scale of the x-axis (potential hydrogen demand) is decreased to provide a higher resolution view of the LTE supply curves. The LTE plant capacity evaluated in this scenario provides an annual supply of hydrogen less than the highest cost customer (refineries @ $3/kg) demand, such that the demand for the second highest cost customer (ammonia production @ $2/kg) is outside the data range included in the plot.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

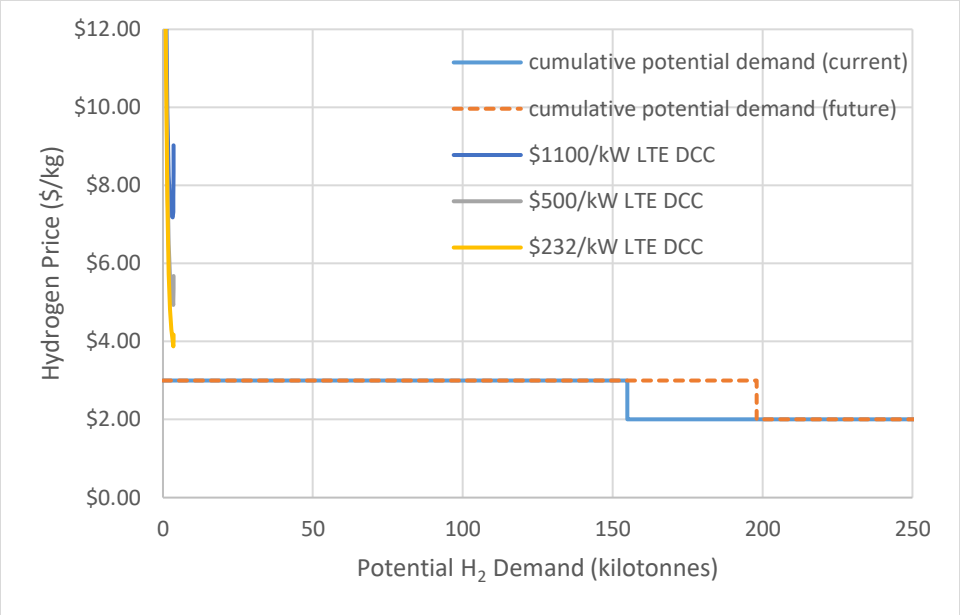


Figure 45. Southern Company Scenario 3 supply vs demand curve (to 250 kilotonnes per year)

The supply curves in Figure 45 and Figure 46 represent the hydrogen that could be supplied by a single 100 MWdc PV power plant disconnected from the grid and instead coupled to an LTE plant of varying capacity (up to 100 MWe) in Southern Company Scenario 3. The variation in the hydrogen production capacity is associated with the different LTE plant capacities evaluated.

Each of the LTE plant supply curves plotted in Figure 45 and Figure 46 displays a minimum hydrogen price. The minimum LCOH point corresponds to the optimal LTE plant capacity to PV plant capacity ratio. At points to the left of the minimal LCOH, the LTE to PV plant capacity ratio is lower than optimal and there are large periods of time when the PV plant produces power in excess of what can be utilized by the LTE plant; this excess power must be grounded which results in elevated LCOH due to the increased average price that must be paid for the electricity that is used. Battery storage of the excess electricity might justify building a larger LTE plant. At points to the right of the minimal LCOH the LTE to PV plant capacity ratio is higher than optimal and there are large periods of time where the PV plant is unable to provide the LTE plant with the electrical power input required to operate at full capacity, which results in elevated LCOH due to low LTE plant capacity factor.

The PV/LTE Scenario does not include energy storage, and since the system is not connected to the grid the OCF is relatively low for all LTE to PV plant capacity ratios (the maximum LTE capacity factor of 42% occurs at a LTE to PV plant capacity ratio of 0.1, while the minimum LTE capacity factor of 20% occurs at a LTE to PV plant capacity ratio of 1.0). As a result the LCOH values calculated for Southern Scenario 3 are all above the maximum demand curve price of $3/kg, and profitable sale of hydrogen from the PV/LTE system would not be possible in the absence of subsidies, incentives, or “green hydrogen” premium pricing.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

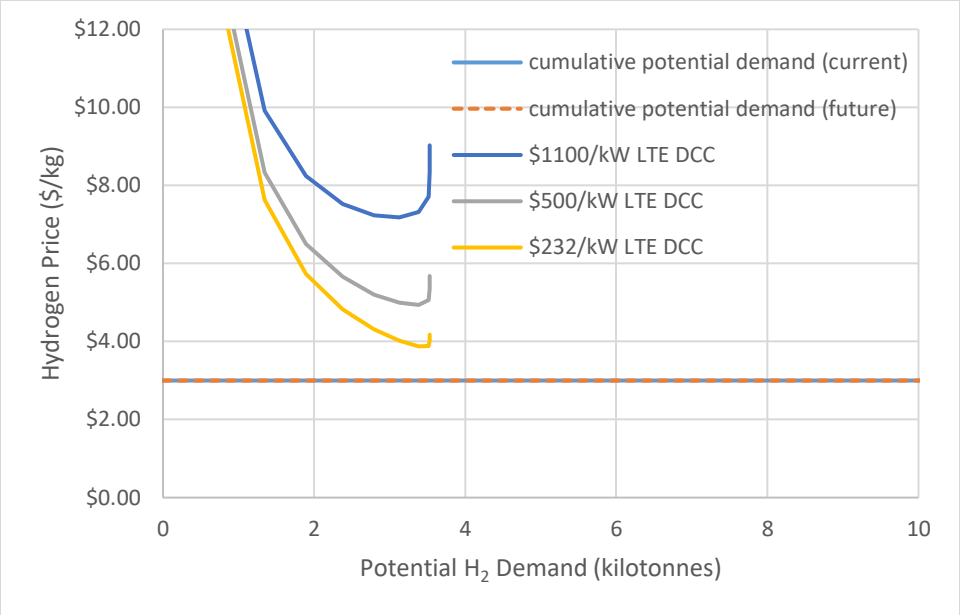


Figure 46. Southern Company Scenario 3 supply vs. demand curve (to 10 kilotonnes per year)

The production rate of about 10.5 tpd hydrogen matches many of current and future hydrogen users in the Southern Company region. However, at a minimum production cost exceeding \$4/kg-H_2 for all of the LTE system capital costs evaluated, additional incentive may be required for a commercial project. A natural-gas SMR plant can produce hydrogen for around \$2.60–3.00/kg-H_2 (Figure 25, small scale).

5.2.3 Exelon Scenarios

The Exelon supply curve analysis scenario input parameters are summarized in Table 22. Supply versus demand plots are presented for each scenario in the subsequent sections. The demand curve figures in this section are functionally similar to those in Section 5.2.2.1 (Alabama/Georgia/Mississippi regional demand). The supply versus demand curve figures are functionally similar to those in Section 5.2.2.3 (Southern Company Scenarios). The primary differences are that the demand curves in this section are constructed using data from the region surrounding Exelon nuclear assets while the supply curves are constructed using PJM ISO LMP and COMED Capacity Market Zone data. Additionally, both small scale and large scale HTE cases are evaluated in the Exelon Scenarios.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Table 22. Summary of Exelon Supply Curve Analysis Scenarios

No.	Scenario Description	Electrical Energy Usage (kWhe/kg)	Thermal Energy Usage (kWht/kg)	System Capacity (MWe)	System Capacity (tonne H_2/day)	Direct Capital Costs ($/kW)	NPP O&M Cost ($/MWh)	Capacity Payment ($/MWe-day)	Capacity Credit (%)
1	HTE – Small Demo Recent History	37.7	6.5	100	64	432, 750, 1800	30	130.27	98.33
2	HTE – Large Demo Recent History	37.7	6.5	940	608	249, 750, 1800	30	130.27	98.33

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

5.2.3.1 Northeastern Illinois Demand Curves

Figure 47 and Figure 48 are plots of the current and future potential demand, respectively, in the area surrounding an Exelon nuclear facility in Illinois. The potential hydrogen demand is divided into five end use applications, including refineries, ammonia production, direct reduction of iron (DRI), synthesis gas (syngas) applications, and electricity generation applications. Each of these end use application is assumed to be able to pay a different price for hydrogen as described in Table 18 of Section 5.2.1.1.

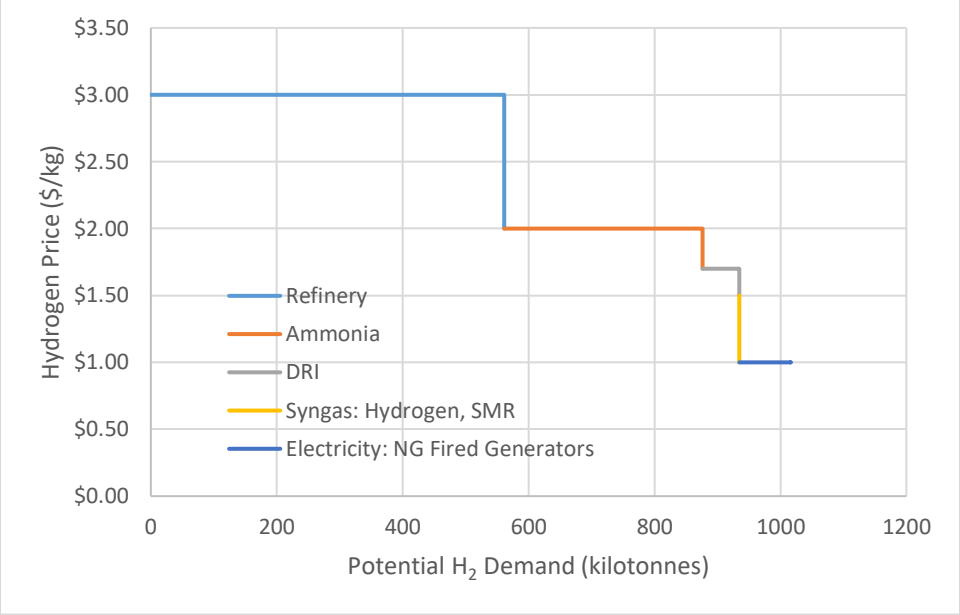


Figure 47. Exelon current hydrogen demand

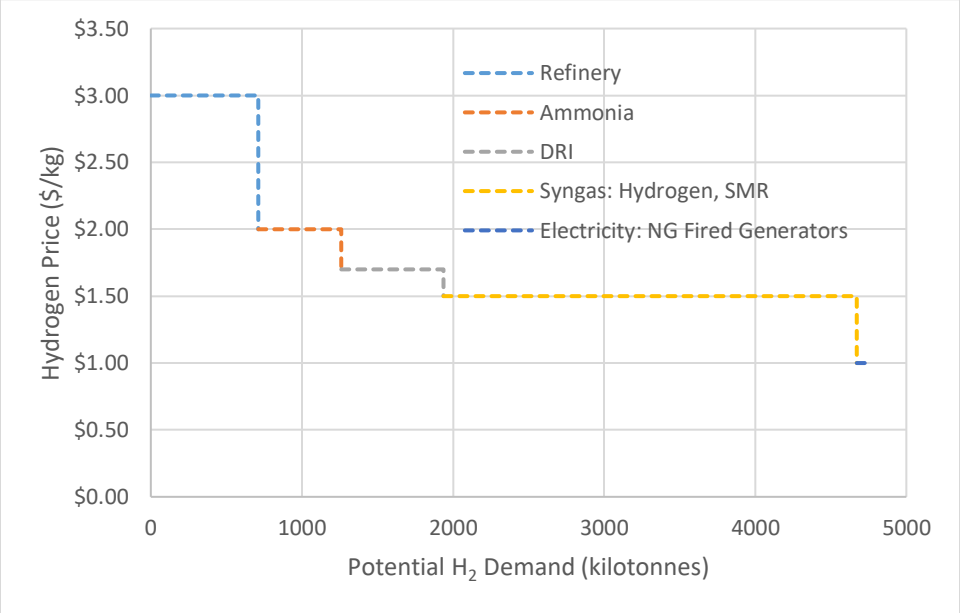


Figure 48. Exelon future hydrogen demand

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

5.2.3.2 Exelon Scenario 1: HTE – Small Demo Recent History

Figure 49 is a plot of the supply versus demand curves for the small demo LWR/HTE Scenario. The small scale HTE demo is assumed to have a capacity of 100 MWe. The future target capital costs of $432/kW for the small demo scenario correspond to the INL First-of-a-kind plant installation case.

Figure 49 is functionally similar in construction to Figure 44 in Southern Company Scenario 2. The difference in the supplied hydrogen capacity plotted for each curve is associated with differences in the plant capacity factor. Per the discussion in Section 5.2.1.3, the plant capacity factor and the average price of electricity sold by the LWR/HTE plant vary with the bid price. The higher cost hydrogen on the left side of each supply curve corresponds to the lower bid price data such that the HTE plant is operational only for a small percentage of the year resulting in less plant operation time and a corresponding low capacity factor. The higher cost hydrogen on the right side of each supply curve corresponds to the higher bid price data where a less than optimal amount of electrical power is dispatched from the LWR/HTE hybrid and electrical power sales revenue is not maximized.

It can be observed from Figure 49 that a 100 MWe capacity HTE plant with capital costs of $750/kW (long term projection, IEA) is capable of supplying hydrogen at a cost lower than the refinery demand curve price ($3/kg), while an HTE plant with a capital cost of $432/kW (future first-of-a-kind cost estimate, INL) is capable of supplying hydrogen at a cost lower than the refinery demand curve price and approximately equal to the ammonia plant demand curve price ($2/kg). The minimum hydrogen sales prices in each of these supply curves correspond to an operating strategy in which the LWR/HTE plant is operated when the LMP price is less than or equal to the optimal bid prices listed in Table 25, Table 26, and Table 27 (Section 5.2.5).

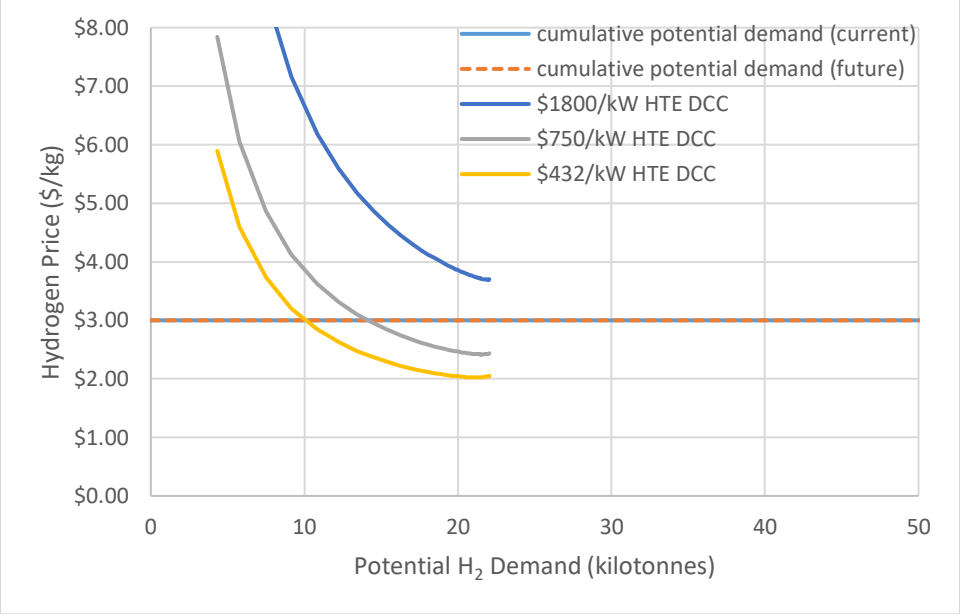


Figure 49. Exelon Scenario 1 supply vs demand curve (to 50 kilotonnes per year)

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

5.2.3.3 Exelon Scenario 2: HTE – Large Demo Recent History

Figure 50 is a plot of the supply versus demand curves for the large scale LWR/HTE Scenario. Figure 50 is functionally similar in construction to Figure 44 in Southern Company Scenario 2. The large scale HTE plant is assumed to have a capacity of 1,000 MWe. The future target costs of $249/kW for the large scale scenario correspond to the INL Nth-of-a-kind plant installation case.

It can be observed from Figure 50 that a 1,000 MWe capacity HTE plant with capital costs of $750/kW (long term projection, IEA) is capable of supplying hydrogen at a cost lower than the refinery demand curve price ($3/kg), while an HTE plant with a capital cost of $249/kW (future Nth-of-a-kind cost estimate, INL) is capable of supplying hydrogen at a cost lower than both the refinery and ammonia plant demand curve prices of $3/kg and $2/kg, respectively. The minimum hydrogen sales prices in each of these supply curves correspond to an operating strategy in which the LWR/HTE plant is operated when the LMP price is less than or equal to the optimal bid prices listed in Table 25, Table 26, and Table 27 (Section 5.2.5).

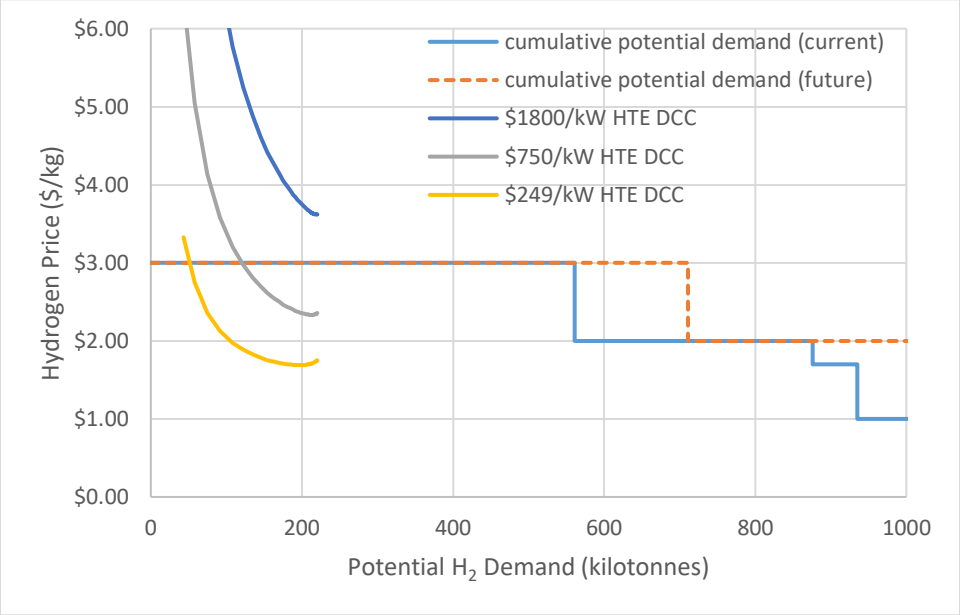


Figure 50. Exelon Scenario 2 supply vs demand curve (to 1000 kilotonnes per year)

5.2.4 Xcel Energy Scenarios

The Xcel Energy supply curve analysis scenario input parameters are summarized in Table 23. Supply versus demand plots are presented for each scenario in the subsequent sections. The supply versus demand plots include scenarios in three separate market regions: Minnesota MISO, SPP South, and Colorado. The LMP curves for each electricity market were used to construct the supply curves in the market pricing-based scenarios. The supply curves for each scenario are plotted against demand for the corresponding region, with the exception of the SPP South case for which no demand data was available. Therefore, for Scenarios 3 and 6 only the supply curves are plotted.

Since the PPA pricing scenarios us a fixed price for electrical power, the supply curves for the PPA pricing scenarios are presented in terms of LCOH as a function of plant scale (assuming that the same PPA price would be available independent of the plant capacity).

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Table 23. Summary of Xcel Energy Supply Curve Analysis Scenarios

No.	Scenario Description	Electrical Energy Usage (kWhe/kg)	Thermal Energy Usage (kWht/kg)	System Capacity (MWe)	System Capacity (tonne H_2/day)	Direct Capital Costs ($/kW)	NPP O&M Cost ($/MWh)	Capacity Payment ($/MWe-day)	Capacity Credit (%)
1	MISO-MINN – Market – Wind to H2	50.2	N/A	100	47.8	232, 500, 1100	N/A	2.40	15.2
2	MISO-MINN – Market – HTE	37.7	6.5	940	608	249, 750, 1800	30	2.40	98.33
3	SPP South – Market – Wind to H2	50.2	N/A	100	47.8	232, 500, 1100	N/A	N/A	N/A
4	Colorado – Market – Wind to H2	50.2	N/A	100	47.8	232, 500, 1100	N/A	N/A	N/A
5	MISO-MINN - PPA - Wind to H2	50.2	N/A	20 - 1000	10 – 500*	232, 500, 1100	N/A	N/A	N/A
6	SPP South – PPA – Wind to H2	50.2	N/A	20 - 1000	10 – 500*	232, 500, 1100	N/A	N/A	N/A
7	Colorado - PPA - Wind to H2	50.2	N/A	20 - 1000	10 – 500*	232, 500, 1100	N/A	N/A	N/A

* In the PPA scenarios, the specified CAPEX applies to a baseline plant size of 50 tpd H_2. CAPEX for varying plant capacity were scaled according to the six-tenths rule.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

5.2.4.1 Minneapolis and Denver AreaDemand Curves

Figure 51 and Figure 52 are plots of the current and future potential demand, respectively, in the area surrounding Xcel Energy Prairie Island Nuclear Generating Plant located about 40 miles southeast of Minneapolis-St. Paul in Red Wing, Minnesota. The potential hydrogen demand is divided into six end use applications, including refineries, fuel cell electric vehicles (FCEV), ammonia production, direct reduction of iron (DRI), synthesis gas (syngas) applications, and electricity generation applications. Each of these end use application is assumed to be able to pay a different price for hydrogen as described in Table 18 of Section 5.2.1.1.

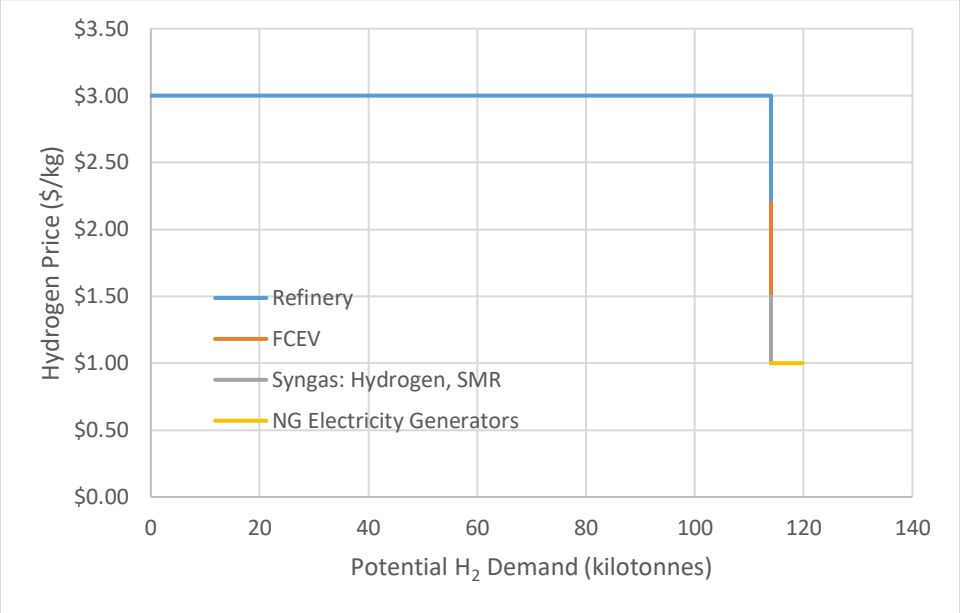


Figure 51. Xcel Energy Minnesota current hydrogen demand

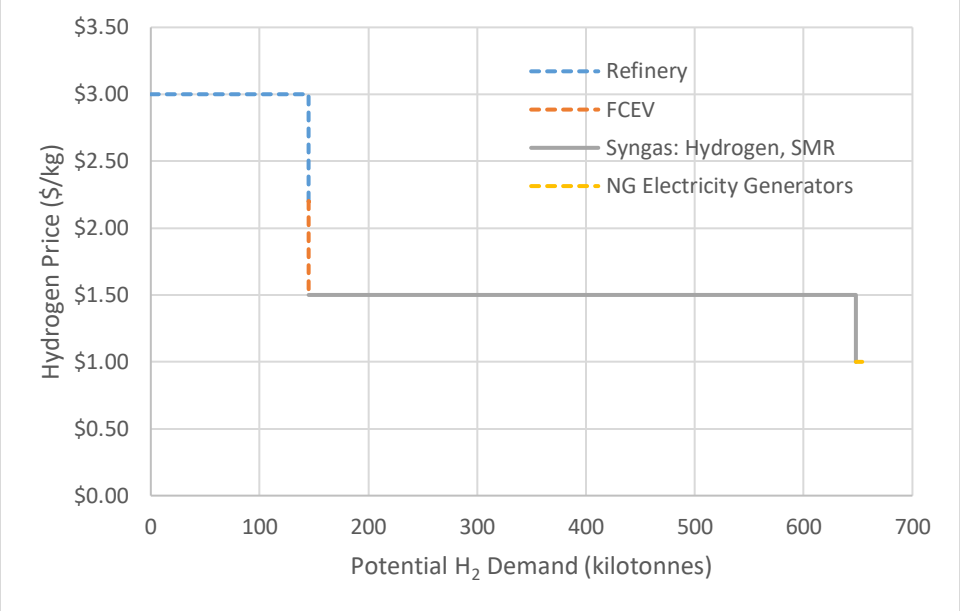


Figure 52. Xcel Energy Minnesota future hydrogen demand

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Figure 53 and Figure 54 are plots of the current and future potential demand, respectively, in the following central location (39°45'00.2"N 104°59'24.0"W) near interstate I-25 in the Denver, Colorado area. The potential hydrogen demand is divided into six end use applications, including refineries, fuel cell electric vehicles (FCEV), ammonia production, direct reduction of iron (DRI), synthesis gas (syngas) applications, and electricity generation applications. Each of these end use application is assumed to be able to pay a different price for hydrogen as described in Table 18 of Section 5.2.1.1.

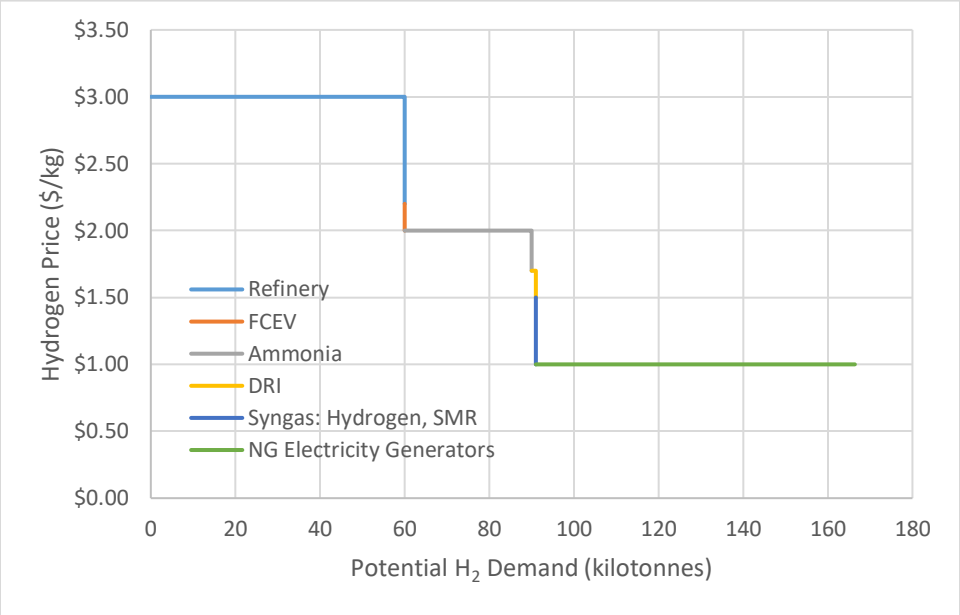


Figure 53. Xcel Energy Colorado current hydrogen demand

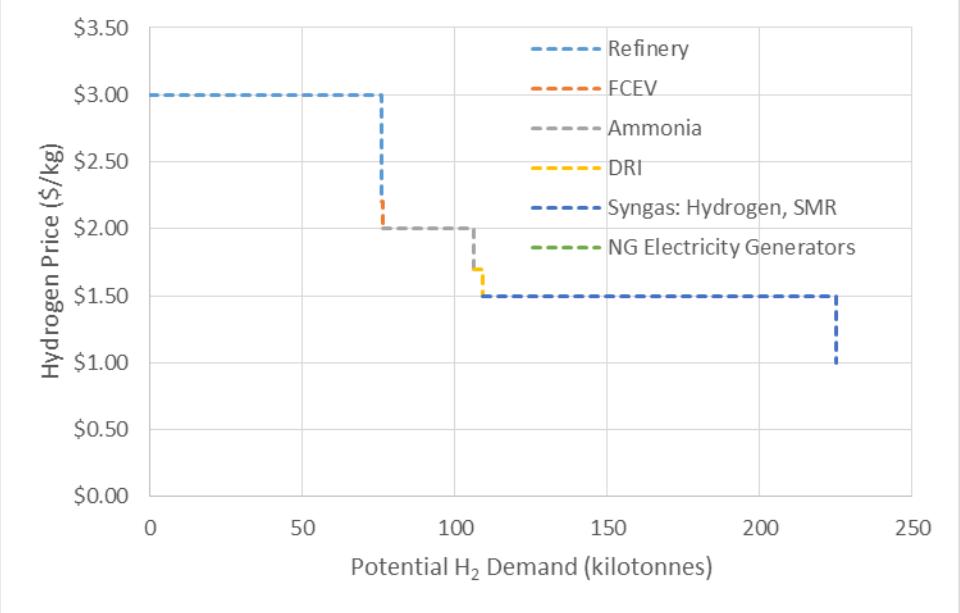


Figure 54. Xcel Energy Colorado future hydrogen demand

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

5.2.4.2 Xcel Energy Scenario 1: MISO-MINN – Market – Wind to H2

Figure 55 and Figure 56 are plots of supply versus demand for Xcel Energy Scenario 1, which uses MISO-MINN LMP data and Minnesota region hydrogen demand. Figure 55 and Figure 56 are functionally similar in construction to Figure 41 and Figure 42, respectively, in Southern Company Scenario 1. The LTE plant evaluated is assumed to have a nominal capacity of 100 MWe. It can be observed from Figure 55 and Figure 56 that 100 MWe capacity LTE plants with capital costs of $1100/kW (Today-2030, IEA), $750/kW (long term cost projection, IEA), or $232/kW (future target cost estimate, INL) would all be capable of supplying hydrogen at a cost lower than the refinery demand curve price ($3/kg). The minimum hydrogen sales prices in each of these supply curves correspond to an operating strategy in which the LTE plant is operated when the LMP price is less than or equal to the optimal activation prices listed in Table 25, Table 26, and Table 27 (Section 5.2.5).

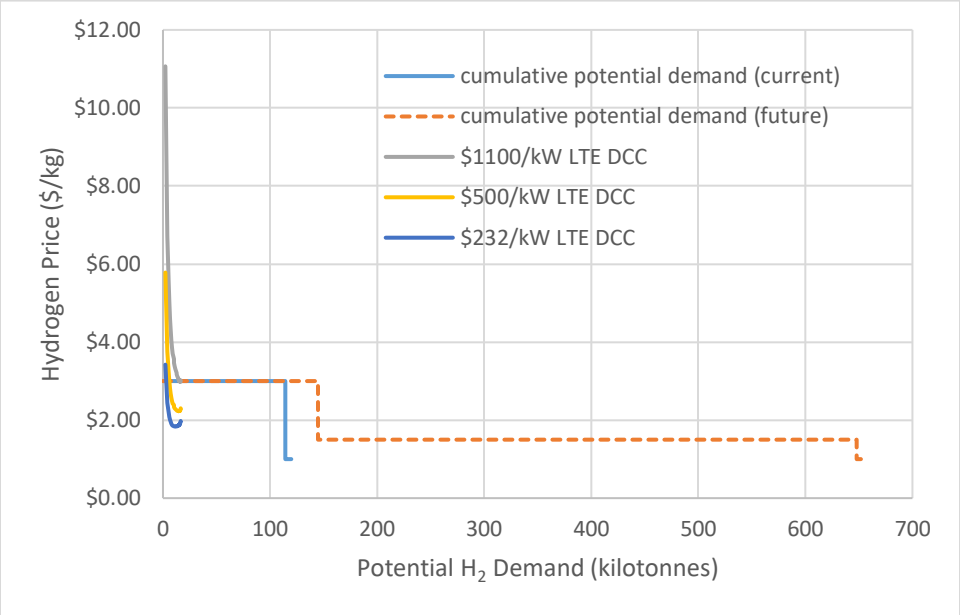


Figure 55. Xcel Energy Scenario 1 supply vs demand curve

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

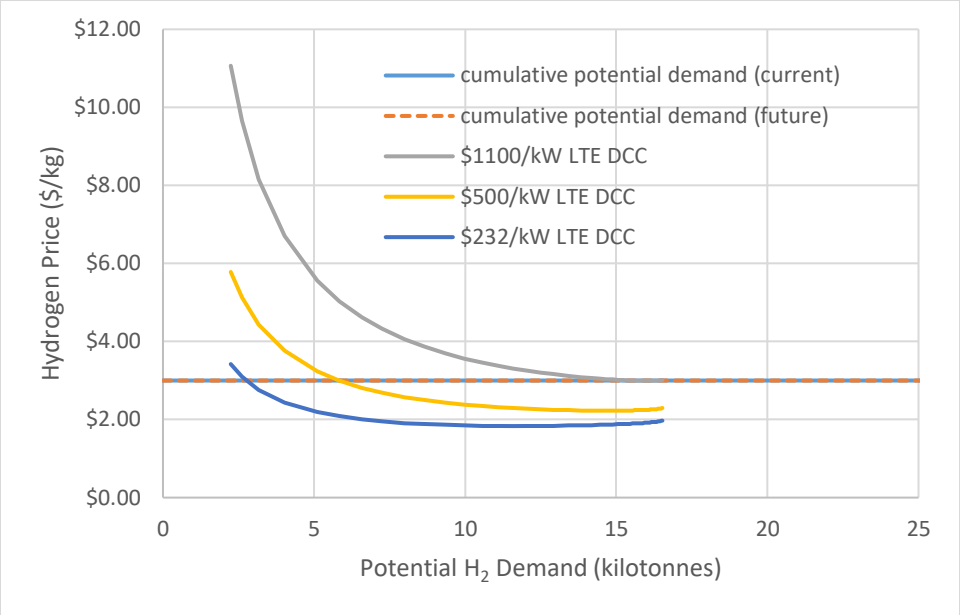


Figure 56. Xcel Energy Scenario 1 supply vs. demand curve (to 25 kilotonnes per year)

5.2.4.3 Xcel Energy Scenario 2: MISO-MINN – Market – HTE

Figure 57 is a plot of the supply versus demand curves for the large scale LWR/HTE Scenario, which uses MISO-MINN LMP data and Minnesota region hydrogen demand. Figure 57 is functionally similar in construction to Figure 44 in Southern Company Scenario 2. The large scale HTE plant is assumed to have a capacity of 1,000 MWe. The future target costs of $249/kW for the large scale scenario correspond to the INL Nth-of-a-kind plant installation case.

It can be observed from Figure 57 that a 1,000 MWe capacity HTE plant with capital costs of $750/kW (long term projection, IEA) or $249/kW (future first-of-a-kind cost estimate, INL) would both be capable of supplying hydrogen at a cost lower than the refinery demand curve price ($3/kg). The minimum hydrogen sales prices in each of these supply curves correspond to an operating strategy in which the LWR/HTE plant is operated when the LMP price is less than or equal to the optimal bid prices listed in Table 25, Table 26, and Table 27 (Section 5.2.5).

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

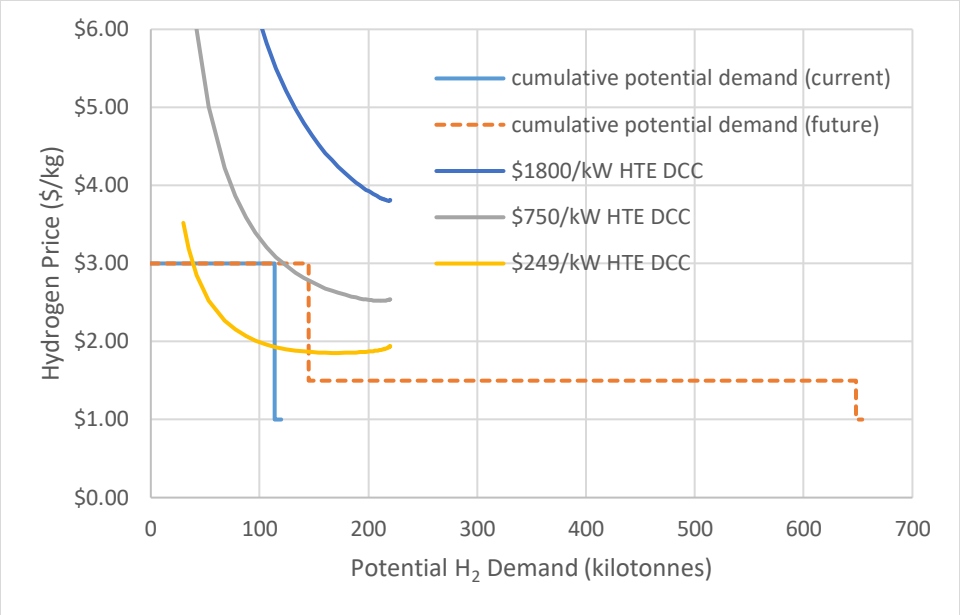


Figure 57. Xcel Energy Scenario 2 supply vs demand curve

5.2.4.4 Xcel Energy Scenario 3: SPP South – Market – Wind to H2

Figure 58 is a plot of the supply curve for Xcel Energy Scenario 3 which uses SPP South LMP data. No SPP South demand data was available and therefore no demand curve is included in Figure 58. The LTE plant evaluated is assumed to have a nominal capacity of 100 MWe.

Figure 58 is functionally similar in construction to the LTE supply curves presented in previous sections. Each of the LTE plant supply curves plotted in Figure 58 takes the form of a curve with a minimum hydrogen price at a point within the extents of the plotted data. Since the plotted data is for a single LTE plant, the difference in the supplied hydrogen capacity plotted is associated with differences in the plant capacity factor.

Per the discussion in Section 5.2.1.2, the plant capacity factor and the average price of electricity purchased by the LTE plant vary with the activation price. The higher cost hydrogen on the left side of each supply curve corresponds to the data for which the activation price is low such that the plant operates during a small percentage of the year resulting in less plant operation time and a corresponding low capacity factor. The higher cost hydrogen on the right side of each supply curve corresponds to the data where the activation price is high such that the plant operates during a large percentage of the year but the average price of the electricity purchased by the plant is higher, which results in higher supply but at a higher cost.

The minimum hydrogen sales prices in each of these supply curves correspond to an operating strategy in which the LTE plant is operated when the LMP price is less than or equal to the optimal activation prices listed in Table 25, Table 26, and Table 27 (Section 5.2.5).

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

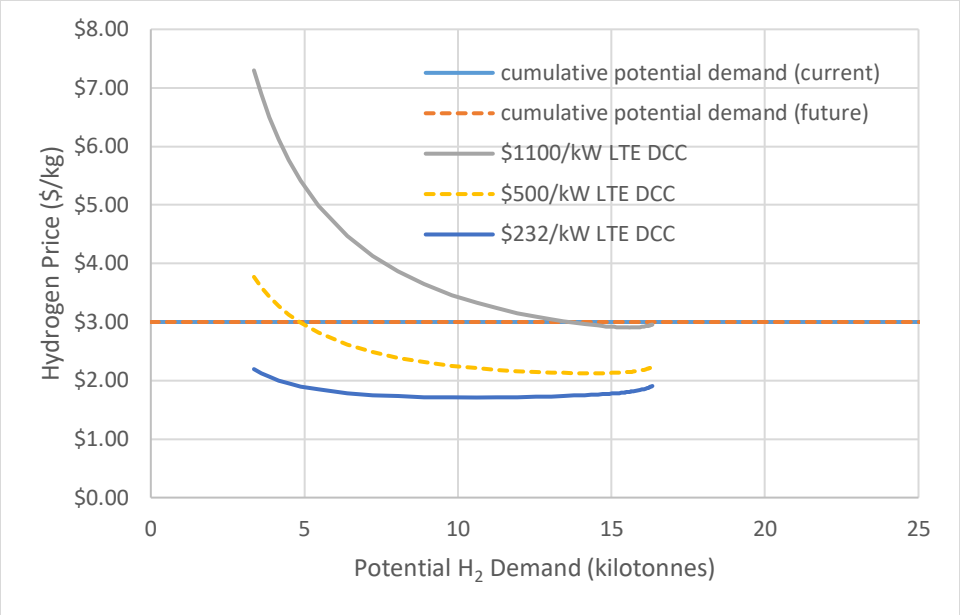


Figure 58. Xcel Energy Scenario 3 supply vs. demand curve (to 25 kilotonnes per year)

5.2.4.5 Xcel Energy Scenario 4: Colorado – Market – Wind to H2

Figure 59 and Figure 60 are plots of supply versus demand for Xcel Energy Scenario 4 which uses Colorado LMP data and Denver, Colorado area hydrogen demand. Figure 59 and Figure 60 are functionally similar in construction to Figure 41 and Figure 42, respectively, in Southern Company Scenario 1. The LTE plant evaluated is assumed to have a nominal capacity of 100 MWe. It can be observed from Figure 59 and Figure 60 that 100 MWe capacity LTE plants with capital costs of $1100/kW (Today-2030, IEA), $750/kW (long term cost projection, IEA), or $232/kW (future target cost estimate, INL) would all be capable of supplying hydrogen at a cost lower than or approximately equal to the refinery demand curve price ($3/kg). The minimum hydrogen sales prices in each of these supply curves correspond to an operating strategy in which the LTE plant is operated when the LMP price is less than or equal to the optimal activation prices listed in Table 25, Table 26, and Table 27 (Section 5.2.5).

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

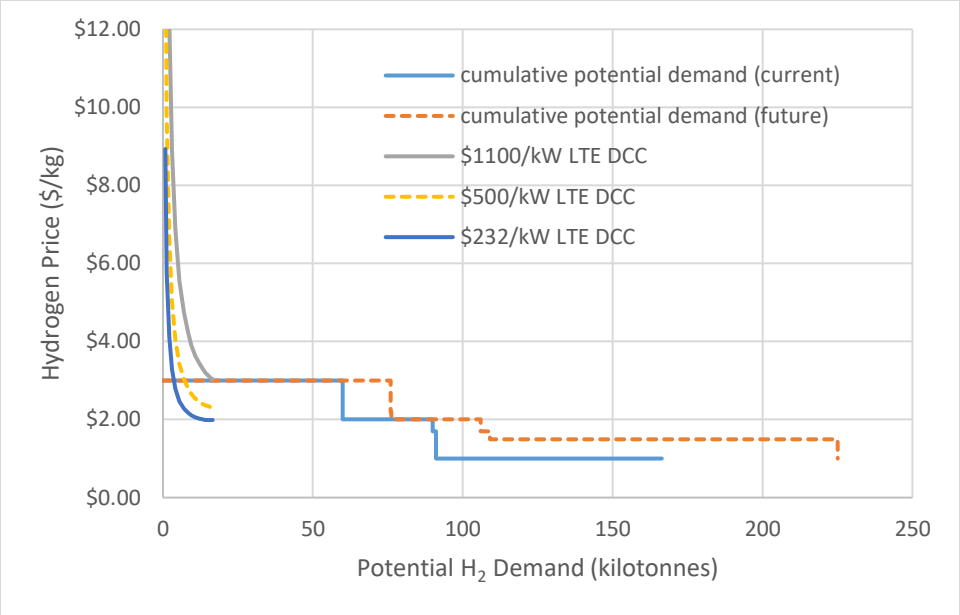


Figure 59. Xcel Energy Scenario 4 supply vs demand curve

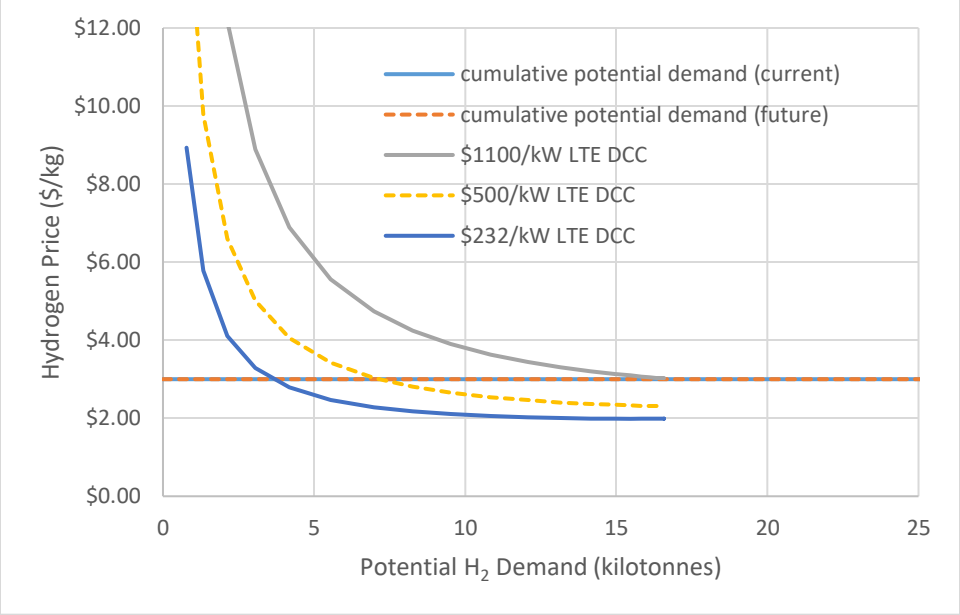


Figure 60. Xcel Energy Scenario 4 supply vs. demand curve (to 25 kilotonnes per year)

5.2.4.6 Xcel Energy Scenarios 5/6/7: MISO-MINN/SPP South/Colorado - PPA - Wind to H2

In Xcel Energy Scenarios 5, 6, and 7 supply versus demand curves were generated for the case in which a PPA pricing contract exists, i.e., the electricity prices do not vary. The supply curves were constructed by varying the LTE plant capacity (capital costs are scaled as a function of plant capacity using a 0.6 scaling factor exponent) to estimate the resulting hydrogen cost variation. The hydrogen price is plotted as a function of LTE plant scale ($25/MWhe PPA pricing, 95% LTE OCF). The specified LTE DCC corresponds to a 50,000 kg/day scale plant

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

(17.3 kilotonnes of hydrogen per year at an OCF of 95%). A delivery & storage cost of $0.40/kg for all scenarios independent of region size and plant capacity [6].

The Scenario 5 supply and demand curves are plotted in Figure 61. In this figure potential hydrogen supply is plotted as a function of the LTE plant capacity. The demand curve is based on Minneapolis area potential hydrogen demand data. The analysis suggests that if LTE plants could be scaled up to a capacity of approximately 330,000 kg/day (114 kilotonnes/yr) to 420,000 kg/day (145 kilotonnes/yr) with capital costs following the six-tenths scaling rule that all plants in the capital cost ranges evaluated ($232/kW to $1100/kW at a baseline capacity of 50,000 kg/day) would be able to supply hydrogen at a price lower than the refinery demand price of $3/kg.

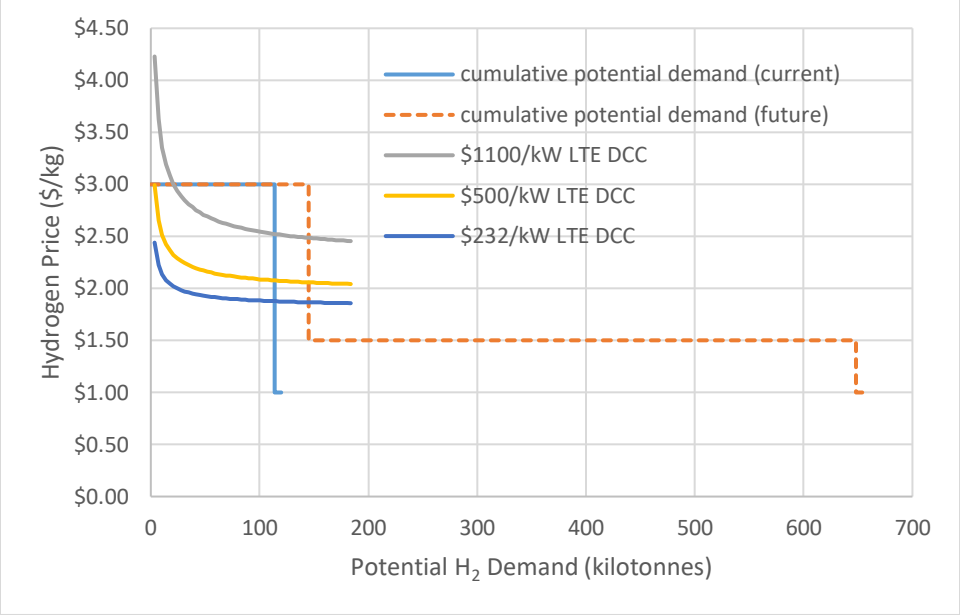


Figure 61. Xcel Energy Scenario 5 supply vs demand curve (Minnesota)

The Scenario 6 supply curves are plotted in Figure 62. In this figure potential hydrogen supply is plotted as a function of the LTE plant capacity. No SPP South demand data was available and therefore no demand curve is included.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

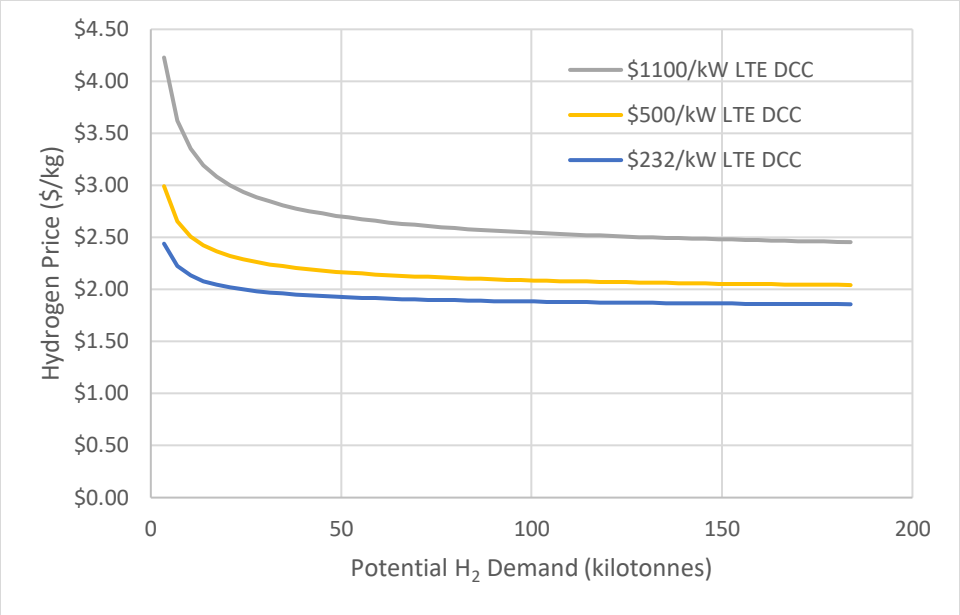


Figure 62. Xcel Energy Scenario 6 supply curve (SPP South)

The Scenario 7 supply and demand curves are plotted in Figure 63. In this figure potential hydrogen supply is plotted as a function of the LTE plant capacity. The demand curve is based on Denver area potential hydrogen demand data. The analysis suggests that if LTE plants could be scaled up to a capacity of approximately 180,000 kg/day (62 kilotonnes/yr) to 220,000 kg/day (76 kilotonnes/yr) with capital costs following the six-tenths scaling rule all plants in the capital cost ranges evaluated ($232/kW to $1100/kW at a baseline capacity of 50,000 kg/day) would be able to supply hydrogen at a price lower than the refinery demand price of $3/kg. Additionally, if LTE plants could be scaled up to a capacity of approximately 260,000 kg/day (90 kilotonnes/yr) to 320,000 kg/day (110 kilotonnes/yr) according to the six-tenths scaling rule plants with capital costs of $232/kW at a baseline capacity of 50,000 kg/day would be able to supply hydrogen at a price lower than the ammonia plant demand price of $2/kg.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

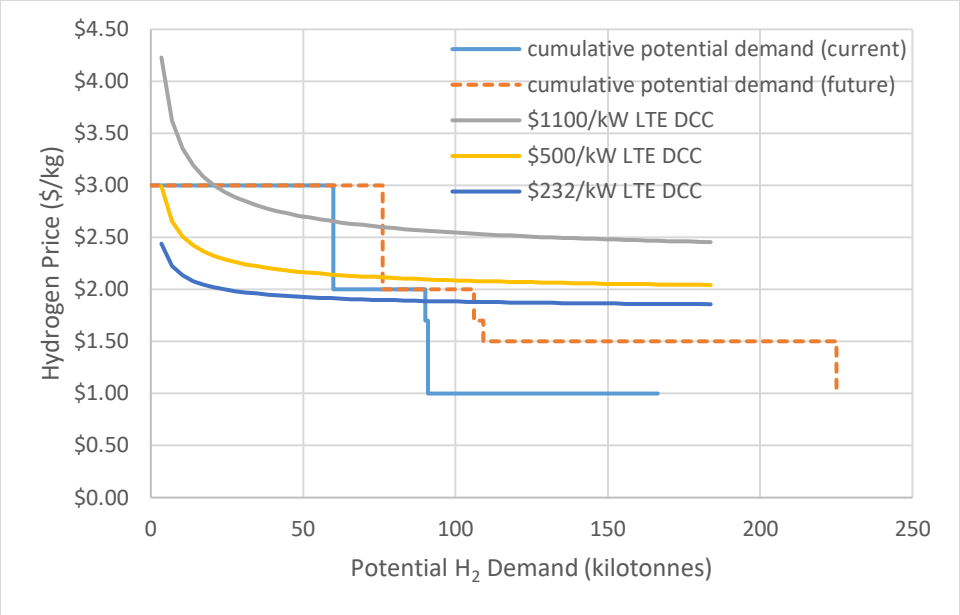


Figure 63. Xcel Energy Scenario 7 supply vs. demand (Colorado)

5.2.5 Summary

Table 24 provides a summary of LMP curve metrics for each of the regions evaluated. Table 25 (Today-2030 CAPEX), Table 26 (long term CAPEX projection), and Table 27 (future CAPEX estimate) summarize the operating strategy and plant specifications corresponding to the minimum LCOH operating point for the market pricing scenarios described above. The LTE-based scenarios report the optimal activation price (LTE plant would startup when the LMP is less than or equal to the activation price), the LTE plant operating capacity factor, annual hydrogen production, and the minimum LCOH including a $0.08/kg adder for delivery and compression. The LWR/HTE-based scenarios report the optimal bid price (HTE plant would enter hot standby mode when the LMP is greater than or equal to the bid price to allow the LWR to dispatch electricity to the grid), the HTE plant operating capacity factor, annual hydrogen production, and the minimum LCOH including a $0.34/kg adder for delivery and compression.

Table 24. Summary of LMP curve metrics

	Average Price ($/MWh)	Minimum Price ($/MWh)	Maximum Price ($/MWh)
Southern (AL/GA/MS)	$35.45	$25.00	$83.00
Exelon (NI)	$26.69	-$140.20	$685.16
Xcel (MINN)	$30.29	-$39.86	$358.28
Xcel (SPP)	$30.98	-$31.39	$565.60
Xcel (CO)	$30.18	$15.94	$45.55

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Table 25. Summary of minimum LCOH conditions for market pricing based scenarios with IEA Today-2030 CAPEX projections[a,b,c]

Scenario	Energy Source and Electrolysis Technology	Optimal Activation or Bid Price [plant capacity]	LTE or HTE Plant OCF	Annual Production (kilotonne H_2)	Minimum LCOH ($/kg)
Southern 1	Grid/LTE	$59	0.889	15.5	$3.26
Southern 2	LWR/HTE	$82	0.95	220.7	$4.20
Southern 3	PV/LTE	[60 MWe]	0.298	3.1	$7.18
Exelon 1	LWR/HTE	$90	0.945	22	$3.69
Exelon 2	LWR/HTE	$85	0.944	219.3	$3.62
Xcel 1 (MINN)	Grid/LTE	$57	0.92	16.1	$2.99
Xcel 2 (MINN)	LWR/HTE	$85	0.942	218.9	$3.81
Xcel 3 (SPP)	Grid/LTE	$55	0.892	15.6	$2.91
Xcel 4 (CO)	Grid/LTE	$45	0.95	16.6	$3.02

a. LCOH calculations based on IEA Today-2030 CAPEX projections of $1100/kW for LTE and $1800/kW for HTSE [7]
b. Minimum LCOH includes compression and delivery costs of $0.08/kg for LTE scenarios and $0.34/kg for HTSE scenarios
c. Green text designates LCOH values lower than the highest demand curve pricing (refineries @ $3/kg) while green bold text designates LCOH values lower than the DOE target of $2/kg.

Table 26. Summary of minimum LCOH conditions for market pricing based scenarios with IEA long term CAPEX projections[a,b,c]

Scenario	Energy Source and Electrolysis Technology	Optimal Activation or Bid Price [plant capacity]	LTE or HTE Plant OCF	Annual Production (kilotonne H_2)	Minimum LCOH ($/kg)
Southern 1	Grid/LTE	$46	0.852	14.9	$2.48
Southern 2	LWR/HTE	$57	0.888	206.3	$2.65
Southern 3	PV/LTE	[70 MWe]	0.277	3.4	$4.93
Exelon 1	LWR/HTE	$60	0.925	21.5	$2.42
Exelon 2	LWR/HTE	$53	0.915	212.7	$2.33
Xcel 1 (MINN)	Grid/LTE	$42	0.842	14.7	$2.23
Xcel 2 (MINN)	LWR/HTE	$53	0.909	211.3	$2.52
Xcel 3 (SPP)	Grid/LTE	$40	0.823	14.4	$2.12
Xcel 4 (CO)	Grid/LTE	$43	0.949	16.6	$2.31

a. LCOH calculations based on IEA long term CAPEX projections of $500/kW for LTE and $750/kW for HTSE [7]
b. Minimum LCOH includes compression and delivery costs of $0.08/kg for LTE scenarios and $0.34/kg for HTSE scenarios
c. Green text designates LCOH values lower than the highest demand curve pricing (refineries @ $3/kg) while green bold text designates LCOH values lower than the DOE target of $2/kg.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Table 27. Summary of minimum LCOH conditions for market pricing based scenarios with future CAPEX cost estimates[a,b,c,d]

Scenario	Energy Source and Electrolysis Technology	Optimal Activation or Bid Price [plant capacity]	LTE or HTE Plant OCF	Annual Production, kilotonne H_2	Min LCOH (variable ops), $/kg	Min LCOH (steady state ops), $/kg
Southern 1	Grid/LTE	$40	0.814	14.2	$2.12	
Southern 2	LWR/HTE	$36	0.724	168.2	**$1.82**	**$1.99**
Southern 3	PV/LTE	[70 MWe]	0.277	3.4	$3.87	
Exelon 1	LWR/HTE	$51	0.911	21.2	$2.02	
Exelon 2	LWR/HTE	$37	0.847	196.3	**$1.69**	**$1.99**
Xcel 1 (MINN)	Grid/LTE	$34	0.665	11.6	**$1.83**	
Xcel 2 (MINN)	LWR/HTE	$36	0.716	166.4	**$1.85**	**$1.99**
Xcel 3 (SPP)	Grid/LTE	$32	0.608	10.6	**$1.71**	
Xcel 4 (CO)	Grid/LTE	$37	0.887	15.5	**$1.98**	

a. LCOH calculations based on future CAPEX cost estimates of $232/kW for LTE, $249/kW for Nth-of-a-kind large scale HTSE, and $432/kW for first-of-a-kind small demo HTSE
b. Minimum LCOH includes compression and delivery costs of $0.08/kg for LTE scenarios and $0.34/kg for HTSE scenarios
c. Green text designates LCOH values lower than the highest demand curve pricing (refineries @ $3/kg) while green bold text designates LCOH values lower than the DOE target of $2/kg.
d. Minimum LCOH for steady state operations is calculated using an assumed electricity price of $30/MWh (the assumed NPP O&M cost). No capacity payments are included in the reported steady state operations LCOH.

5.3 References

[1] James BD, DeSantis DA, Saur G. Final Report: Hydrogen Production Pathways Cost Analysis (2013–2016). Arlington, VA: Strategic Analysis Inc.; DOE-StrategicAnalysis-6231-1, 2016.

[2] Krull P, Roll J, Varrin RD. HTSE Plant Cost Model for the INL HTSE Optimization Study. Reston, VA: Dominion Engineering; R-6828-00-01, 2013.

[3] Tang E, Wood T, Brown C, Casteel M, Pastula M, Richards M, et al. Solid Oxide Based Electrolysis and Stack Technology with Ultra-High Electrolysis Current Density (>3A/cm²) and Efficiency: FuelCell Energy; DE-EE0006961, 2018.

[4] U.S. Energy Information Administration. *Annual Energy Outlook 2018*. Available: https://www.eia.gov/outlooks/aeo/tables_ref.php

[5] Spath PL, Mann MK. Life Cycle Assessment of Hydrogen Production via Natural Gas Steam Reforming: National Renewable Energy Laboratory; NREL/TP-570-27637, 2001.

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

[6] Ruth M, Jadun P, Elgowainy A. (2019). *H2@Scale Analysis, Project ID #sa171, DOE Hydrogen and Fuel Cells Program 2019 Annual Merit Review and Peer Evaluation Meeting, April 30, 2019.* Available: https://www.hydrogen.energy.gov/pdfs/review19/sa171_ruth_2019_o.pdf

[7] International Energy Agency. The Future of Hydrogen: Seizing Today's Opportunities 2019. Available: https://www.iea.org/hydrogen2019/

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

TASK 5: Final report: Comparison of TEAs and recommendations.

TASK 5 DESCRIPTION:

A technical evaluation (TEV) report that summarizes Task 1-4 will be provided. This report will be reviewed and issued under the INL Scientific and Technical Information System. It will specifically combine, compare, and contrast the Task 4 TEAs and will provide recommendations on regionally-appropriate economic/market feasibility of producing hydrogen with existing or soon-to-be-built electric utility assets. Deliverable: Final Project Report, designated as a TEV.

TASK 5 SUMMARY AND OUTCOME:

INL led the effort to publish a final report with all the CRADA Team members listed as authors. Almost all the content in this report is copied from that report. Figure 64 is the cover of that report.

Figure 64. CRADA Final Report Cover

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.

Subject Inventions Listing:

None

ROI #:

None

This report is available at no cost from the National Laboratory of the Rockies (NLR) at www.nlr.gov/publications.