CALIFORNIA ENERGY COMMISSION

Energy Research and Development Division

FINAL PROJECT REPORT

The Challenge of Retail Gas in California's Low-Carbon Future

Appendices A-G

Gavin Newsom, Governor

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APPENDIX A: Frequently Asked Questions

1. Will Additional Biomass Be Available From Dead and Dying Trees? Are the Results of This Report Sensitive to Assumptions About the Biomass Supply?

The long-term supply of biomass from dead and dying trees is uncertain, and it may not represent a sustainable source of biomass. That said, if there were a large increase in the long-term supply of low-cost biomass to make fuels, this would reduce the cost of all scenarios, particularly the "no building electrification" scenario. However, it does not seem likely that the sustainable supply of biomass is significantly higher than the assumptions already embedded in this study.

The forest residue biomass assumptions in this study are based on the U.S. Department of Energy (U.S. DOE) Billion Tons study,[1] which is generally understood to represent an optimistic outlook on biomass resource potential. This study assumes 44 million dry tons per year of forest residues in the U.S. biomass supply,[2] of which 2.8 million dry tons per year are assumed available in California.

Research is ongoing about the sustainable potential for harvesting dead and dying trees for bioenergy to reduce wildfire risk.[3] In fact, if a high level of tree mortality persisted through 2050, this mortality would likely lead to a change in the underlying forest ecosystem structure, which could reduce biomass availability from forest residues. It would be risky to develop a strategy to decarbonize buildings that depends upon a continual resource of dead and dying trees.

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1 DOE, U.S. Department of Energy. 2016. *2016 Billion-Ton Report: Advancing Domestic Resources for a Thriving Bioeconomy, Volume 1: Economic Availability of Feedstocks*. M. H. Langholtz, B. J. Stokes, and L. M. Eaton (Leads), ORNL/TM-2016/160. Oak Ridge National Laboratory, Oak Ridge, Tennessee. 448p. See https://www.energy.gov/sites/prod/files/2016/12/f34/2016_billion_ton_report_12.2.16_0.pdf (accessed October 21, 2019).

2 A dry ton, also referred to as "bone dry ton," is one ton mass of dry biomass after all moisture has been removed.

3 A three-year research project known as the California Biopower Impacts Project started in 2017 to assess the potential for harvesting forest biomass for bioenergy, as well as positive and negative environmental impacts, but no findings are currently available. See Schatz Energy Research Center California Biopower Impacts Project (https://schatzcenter.org/cbip/) (accessed June 21, 2019) as well as https://schatzcenter.org/docs/CBI-projectbrief-20190128v2.pdf.

The best current estimate of the accumulated dead tree biomass due to drought and bark-beetle damage from 2010 through 2018 that could be harvested is from 6.9 million to 25.3 million tons;[4] this magnitude of dead biomass would need to be available every year through 2050 to change appreciably the scenario analysis in this study.

The research team reviewed many biomass assessments in conducting this study, including California-specific studies. Biomass estimates are in line with other published California specific studies, as shown in the table below. This study assumes that California uses all its own biomass resource and is able to import some limited quantity of biomass from the rest of the United States.

Table A-1: California Biomass Availability for Different Data Sources (Millions of Dry Tons per Year)

Biomass Type	CEC/UC Davis*: 2013 resource	CCST[5]: 2050 resource, baseline scenario	CCST: 2050 resource, high-biomass scenario	E3 assumptions: 2040 resource
Wastes & Residues	31.0	36.1	77.1	28.0
Energy crops	*Not included*	*4.5*	*45.7*	*Not included*
Total Excluding Energy Crops	31.0	36.1	77.1	28.0
Total including assumptions about imported biomass from rest of U.S.	*Not included*	*Not included*	*Not included*	43.3

***Does not count landfill or wastewater treatment gas, which are not listed in dry tons. As with the previous table, numbers from the Bioenergy Association of California (BAC) document prepared by Rob Williams of UC Davis are used, which are based on prior CEC work. However, the numbers in the BAC document for agricultural waste biomass availability are slightly lower than what is listed in the CEC reports (8.7 million vs 12.1 million dry tons).**

Source: E3

The U.S. DOE Billion Ton study was selected as the basis for the biomass resource potential of this study because it was important to maintain a consistent national framework for estimating biomass potential and allowing scenario-based assumptions, such as the import of biomass from outside the state to meet in-state biofuel demand.

For a more complete comparison of the biomass estimates for California of this study with other studies, see Appendix D.

4 University of California, Agriculture and Natural Resources. "The California Tree Mortality Data Collection Network—Enhanced Communication and Collaboration Among Scientists and Stakeholders." http://calag.ucanr.edu/archive/?article=ca.2019a0001.

5 CCST. 2013. *California's Energy Future—The Potential for Biofuels,* https://ccst.us/wp-content/uploads/2013biofuels.pdf.

2. Will Building Electrification Add to Wildfire Risks? Will Increased Wildfire Risks Change the Conclusions of This Study?

No, it is not likely that building electrification will increase the risk of wildfires.

Building electrification is a smaller driver of projected load growth in the study scenarios than transportation electrification, and transportation electrification is required in every mitigation scenario. The research team agrees that further research is needed into this topic. To the extent the risk of wildfires is related to footprint of the electricity grid rather than the annual energy being used, then building electrification would have negligible impact on that risk. In all mitigation scenarios, it will be important to incorporate new electric loads in a flexible way that provides the best use of transmission and distribution infrastructure.

This analysis also finds that higher electricity costs, due to wildfire costs or otherwise, are unlikely to change the basic conclusion that building electrification will lead to long-term bill savings for customers relative to continued reliance on natural gas in homes.

Unfortunately, climate vulnerability and climate-related disasters are now becoming more commonplace in California and across the world. While these impacts are real, the state will need to invest in electric infrastructure resiliency regardless of which future GHG mitigation scenario the state follows, and certainly in a business-as-usual or reference scenario. Indeed, as long as they are managed to minimize the need for expanded transmission and distribution capacity, new electric loads can help make needed upgrades to the state's electricity infrastructure more affordable by spreading new fixed costs over more energy consumption and thus alleviating rate impacts.

Wildfires and climate resiliency are challenges that the state needs to address today and in any future, regardless of whether building electrification is pursued as a GHG mitigation strategy. A key consideration, of course, should be how the state can meet its climate resiliency and adaptation goals while reducing greenhouse gas emissions in the lowest-cost, most sustainable way possible.

3. Shouldn't We Be Capturing Methane From Landfills and Dairies and Putting This to Better Use?

This study assumes that methane from landfills and dairies is captured and used in the gas distribution pipeline to displace natural gas use in all GHG mitigation scenarios. The biomethane is used in compressed natural gas (CNG) vehicles and in industry and buildings as it is blended into the pipeline.

To estimate the available supply of biomethane, the research team assumed that California could import up to its population share of US residue biomass resources for conversion into biomethane and other biofuels based on the U.S. DOE Billion Ton study. In addition, because the DOE study does not include as detailed a treatment of waste biogas resources as some studies, and excludes landfill gas currently used for energy, researchers supplemented the DOE biomass supply with a study by Jaffe et al. (2016)

that estimated in-state biogas from landfills, manure, and other waste resources. Indeed, the research team's estimates of in-state biogas potential are in line with other published estimates, including estimates from the California Biomass Collaborative (CBC)[6] at UC Davis and the related 2017 CEC publication on *Renewable Energy Resource, Technology, and Economics Assessments* (CEC-500-2017-007).[7]

Table A-2 provides a side-by-side estimate of the California supply of biomethane potential from a number of recent studies. A more detailed comparison is available in Appendix D.

It is important to note that in the E3 economy-wide PATHWAYS scenarios, a large portion of the available biomass is not used to produce biomethane, but rather is converted into renewable liquid fuels to displace fossil petroleum demands in heavy-duty and off-road transportation.[8] Those end-uses are not only more difficult to electrify, but the displaced petroleum is more expensive and has higher GHG emissions-intensity than natural gas. Moreover, while the scenarios in this project focus on an 80 x 50 climate goal that allowed for some remaining fossil energy in transportation and industry, a scenario targeting carbon neutrality would only increase the value of drop-in fuels in those sectors.

6 The California Biomass Collaborative is a statewide collaboration of government, industry, environmental groups, and educational institutions administered for the state by the University of California, Davis. Sponsored by the California Energy Commission and other agency and industry partners, the Collaborative works to enhance the sustainable management and development of biomass in California for the production of renewable energy, biofuels, and products. See https://biomass.ucdavis.edu/about/ (accessed October 21, 2019).

7 Jenkins, Brian and Adam Schultz, 2017. *Renewable Energy Resource: Technology and Economic Assessments.* CEC-500-2017-007. See https://ww2.energy.ca.gov/2017publications/CEC-500-2017-007/CEC-500-2017-007.pdf (accessed Oct 21, 2019).

8 Using biogas for CNG trucks is another way to use the biomass to displace petroleum. In all the scenarios, at least 24 percent of heavy-duty trucks switch to CNG. This shifts the optimized economywide biofuel portfolio toward more RNG but does not alter the economics of using RNG to decarbonize buildings.

Table A-2: Estimates for California Biomethane Availability (BCF/yr)

Biomass Type	Jaffe et al., 2016[9]	CEC/UC Davis, 2015 and 2017[10]	Bioenergy Association of California, 2014[11]	NREL, 2016[12]	E3 estimates (in-state only, assuming all feedstocks go to RNG)
Biogas Resources	84	161	138	87	309
Residues	*Not included*	191	112	21	79
Energy crops	*Not included*	*Not included*	*Not included*	*Not included*	*Not included*
Total Excluding Energy Crops	**84**	**352**	**249**	**108**	**387**
Total including assumed imports from rest of US	*Not included*	*Not included*	*Not included*	*Not included*	**592**

Biogas Resources = Manure, wastewater treatment plants, landfill gas, and other MSW resources

Residues = Agricultural and forest cellulosic and woody residues

Source: E3

4. Why Aren't the LCFS and Carbon Pricing Programs Accounted For?

The economywide scenario cost metric is based on the total cost to the California economy. Transfer payments between consumers, households, businesses, and the state government are not included, as they do not represent a net cost to the whole economy. Likewise, new policy incentives that may be used to encourage consumer

9 Jaffe, Amy Myers, Institute of Transportation Studies, UC Davis. Prepared for the California Air Resources Board and the California Environmental Protection Agency. *Final Draft Report on the Feasibility of Renewable Natural Gas as a Large-Scale, Low-Carbon Substitute.* https://ww3.arb.ca.gov/research/apr/past/13-307.pdf.

10 The numbers presented here are from a Bioenergy Association of California document prepared by Rob Williams of UC Davis, showing the technical potential for biogas production. These numbers are based on UC Davis work, under CEC projects CEC-500-11-020 and CEC-500-2017-007. The research team chose to use the numbers from the Bioenergy Association of California document here because the CEC reports do not include estimates for RNG potential from nondigestible feedstocks. (Only the raw biomass potential is included.)

11 Levin, Julia, Katherine Mitchell, and Henry Swisher. Bioenergy Association of California. 2014. *Decarbonizing the Gas Sector: Why California Needs a Renewable Gas Standard.* http://www.bioenergyca.org/wp-content/uploads/2015/03/BAC_RenewableGasStandard_2015.pdf.

12 Penev, Michael, Marc Melaina, Brian Bush, Matteo Muratori, Ethan Warner, and Yuche Chen. National Renewable Energy Laboratory. 2016. *Low-Carbon Natural Gas for Transportation: Well-to-Wheels Emissions and Potential Market Assessment in California.* Prepared for the Southern California Gas Company by the Joint Institute for Strategic Energy Analysis. https://afdc.energy.gov/files/u/publication/w2w_emissions_assessment-ca.pdf.

behavior, over and above the realized cost to the consumer, are not included. This approach is similar to what the CPUC uses for energy efficiency cost-effectiveness analysis, using the "total resource cost" metric.

5. Can Excess and Otherwise Curtailed Energy From Intermittent Renewables Be Used to Make Electrolytic Fuels More Cheaply Than Assumed in This Study?

Though some curtailment of renewables is occurring today, it is likely that a variety of new sources of flexibility or uses for otherwise curtailed energy will arise, rather than seeing curtailment increase indefinitely. This is partly because a solar-heavy renewable mix in California can be mostly balanced with diurnal shift rather than requiring massive overbuild for long-duration energy storage, as long as several percent of generation is allowed to come from dispatchable resources (modeled here as from a blend of natural gas and biomethane, but this could come from a low carbon resource in the future).

In optimal electricity portfolios attained in the RESOLVE model comparable to those used in the economywide scenarios here, curtailment of about ~10% to 15% occurs in 2050. This is much smaller than the quantity of energy that would be needed for the electrolytic fuel production required in the No Building Electrification scenario of about 200 TWh—more than two thirds of today's total state electricity demand.

Furthermore, using only intermittent electricity at very low capacity factor requires a large overbuild in the infrastructure for fuel production, including electrolyzers, methanators, and CO_2 capture equipment. It also requires building new transmission to connect the fuel production to the rest of the grid. Instead, this study assumes off-grid generation at the capacity factor of new renewables to minimize the need for new transmission.

6. What Natural Gas Leakage Assumptions Are Used? Does a 3 Percent Leakage Rate Double the Effective Greenhouse Gas Emissions? Will Production of New Methane Lead to More Fugitive Emissions? Since California Imports About 90 Percent of the Natural Gas Consumed in the State, Why Are the Methane Emissions Associated With the Extraction of Natural Gas Outside California Not Considered in This Study?

In-state methane leakage from natural gas pipelines and extraction are based on the CARB inventory for 2015-year emissions. The inventory for 2017-year emissions, released in August of 2019, also includes 0.9 MMT CO_2e from behind-the-meter leakage of methane from residential buildings, but these were not available when the analysis in this study was completed. In addition, the GHG mitigation scenarios assume that the state achieves reductions in methane and other SLCPs consistent with a 40% reduction in methane by 2030, and a 55% reduction in total emissions from methane and F-gases relative to 2015 levels by 2050. No adjustment to these fugitive emissions is made as a function of changes in natural gas throughput in these scenarios, because it is uncertain how much these emissions would decrease with less reliance on the natural gas pipeline network in the absence of complete pipeline shutdown as well as decommissioning of in-state natural gas production. Likewise, no new fugitive emissions are assumed in the case of gasification or methanation to produce RNG. Both of these assumptions could lead to under-estimating the emissions in the No Building Electrification scenario; however, if these emissions were higher, that would not change the conclusions that the No Building Electrification scenario is not likely to be a viable future in which the state's GHG goals are met.

Out-of-state emissions from natural gas extraction and transportation are not included in the CARB emissions inventory used to track progress towards state policy goals; nor are upstream or lifecycle emissions from other fossil fuels or biofuels; which is why these emission sources are not included in this analysis.

All scenarios dramatically reduce reliance on fossil energy sources, and all scenarios restrict use of biofuels to residue resources unlikely to induce new emissions from agricultural practices or indirect land use change.

This analysis uses the 100-yr global warming potential (GWP) in accordance with CARB and other GHG inventory protocols, but notes that conventional GWP metrics cannot universally equate short-lived climate pollutants like methane with long-lived GHGs like CO_2. A shorter time-horizon GWP may be appropriate when considering near-term and peak warming, but even the 100-yr GWP can underestimate the primacy of CO_2 for the long-term goal of climate stabilization (Allen et al. 2016). New metrics such as "GWP*" attempt to equate annual emissions rates of short-lived climate pollutants with pulse emissions of CO_2.[13]

The mass-based 100-year GWP of methane is 25 times that of CO_2, and the 20-year GWP is 72 times that of CO_2. This is based on the IPCC Fourth Assessment Report (Forster et al. 2007) as used in the California GHG inventory, although this was increased in the Fifth Assessment report, to a range of 28 to 34 for 100-yr GWP and 84 to 86 for 20-yr GWP.[14] However, when calculating the GHG emissions from natural gas

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13 See Allen et al. 2018. "A Solution to the Misrepresentations of CO2-Equivalent Emissions of Short-Lived Climate Pollutants Under Ambitious Mitigation." *Climate and Atmospheric Science.* Also see Cain, Michelle. 2018. "A New Way to Assess 'Global Warming Potential" of Short-Lived Pollutants." *Carbon Brief.* https://www.nature.com/articles/s41612-018-0026-8, https://www.carbonbrief.org/guest-post-a-new-way-to-assess-global-warming-potential-of-short-lived-pollutants.

14 Myhre, G., D. Shindell, F.-M. Bréon, W. Collins, J. Fuglestvedt, J. Huang, D. Koch, J.-F. Lamarque, D. Lee, B. Mendoza, T. Nakajima, A. Robock, G. Stephens, T. Takemura and H. Zhang (2013) "Anthropogenic and Natural Radiative Forcing". In: *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*. Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y.

leakage, the molar-based GWP (not the more commonly reported mass-based metric), is the relevant GWP number that accounts for the difference in molar masses between CH_4 and CO_2 (a ratio of 0.36). Using a mass-based 100-yr GWP of 25, the molar-based GWP of methane is 9 times that of CO_2, meaning that each molecule or percent loss of methane that was intended for combustion results in 9 times the emissions impact as if it had not leaked and was combusted to CO_2. Likewise, using 86, the high end of the range of the most recent 20-yr GWP, each molecule or percent loss of methane would cause 31 times the impact, implying that a 3% leakage rate nearly doubles the effective emissions relative to the remaining combusted methane.

7. Why are the economywide net costs modeled here lower than previous estimates?

The net costs relative to the Reference scenario in the "High Building Electrification" scenario stay relatively flat after 2030, in contrast to the "High Electrification" scenario in E3's Deep Decarbonization study for the CEC (Mahone et al 2018), which showed net costs continuing to rise through 2050. This difference is due to several factors; it is important to note that the net cost metric is sensitive to the policy and technology assumptions in the Reference as well as the GHG policy-compliant "mitigation" scenarios. Some of these factors are listed below.

- The fixed costs of renewable generation and storage are much lower than previously modeled in the 2030-2050 time frame, based on updated data reflecting recent cost declines (Appendix E).
- The Reference scenario now includes the impact of SB 100, decreasing the electricity cost difference with the mitigation scenarios; the Reference used in the previous Deep Decarbonization study assumed only a 33% renewable portfolios standard.
- The costs of the biofuels are lower than previously estimated based on the updated information available in this project (Appendix C and Appendix D), including modest projected increases in conversion efficiency over time. Note that nearly the same quantity of biofuels is utilized in both of the mitigation scenarios, so these reduced costs do not affect the comparison between the High Building Electrification and the No Building Electrification scenarios.
- The above factors acting to decrease net costs are modestly offset by the inclusion of building electrification retrofit costs (Appendix E).
- Additional differences between the previously published Reference and the Reference scenario used here may have small net effects on the economywide costs, including more assumed zero emission vehicles, building energy efficiency, and short-lived climate pollutant reductions. This is because the Reference used

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Xia, V. Bex and P.M. Midgley (eds.). Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA.

here is designed as a “Current Policy” scenario, while the previously published Reference was designed as a “business as usual” scenario not including the effects of policies enacted after 2015.

APPENDIX B: Technical Advisory Committee Members

Invited Technical Advisory Committee members included:

- George Minter, Allison Smith from Southern California Gas Company
- Brianna Exume, Dana Golan, and Despina Neihaus from SDG&E
- Dr. Jeffrey Reed from University of California, Irvine
- Valentino Tiangco and Dagoberto Calamateo from Sacramento Municipal Utility District
- David Lewis, Claire Holbrook, Maurice Winn and Valerie Winn from Pacific Gas and Electric Company
- Madeline Stano formerly of Greenlining Institute
- Merrian Borgeson from Natural Resources Defense Council
- Dr. Rosa Dominguez-Faus from the University of California, Davis
- Dr. Nathan Parker from Arizona State University
- David Yanagisawa from Mitsui & Co.
- Marc Carrera Sospedra from the South Coast Air Quality Management District
- Tim O'Connor and Michael Colvin from Environmental Defense Fund
- Eileen Hlavka and Stephanie Kato from the California Air Resources Board; and
- Arun Raju from the University of California, Riverside

Members of the TAC do not necessarily support or condone the research findings presented herein.

APPENDIX C:
Technology Options to Decarbonize the Natural Gas System

Background

The goal of this task is to identify, characterize, and quantify important considerations in the role of alternative renewable and low-carbon gaseous fuel production technologies including power-to-gas (P2G) and biomass conversion, including factors such as large-scale production, pipeline injection, and feedstock availability.

Technology selection was accomplished using technology readiness levels (TRL). The US Department of Energy has established guidelines based on guidelines from NASA and the Department of Defense (US DOE, 2011). A TRL of 5 is described as laboratory scale testing under relevant environments with the system being nearly prototypical. A TRL of 6 is described as prototype testing at pilot scale whereas a TRL of 7 is a full-scale prototype tested in relevant conditions with final design essentially complete. A TRL of 8 is operation and commissioning of the actual system where TRL 9 is operation of the actual system over the full range of operating conditions.

Technologies Considered

For P2G, the technologies considered are electrolyzers, methanators, sources for carbon dioxide, heat sinks, blending of hydrogen into the natural gas pipeline, and interconnecting the P2G plant to the natural gas pipeline. Electrolyzer technologies included in this study are alkaline electrolytic cells (AECs), proton exchange membrane electrolytic cells (PEMECs), and solid oxide electrolytic cells (SOECs). For scenarios in which methane is produced, methanators are included, and these need both carbon dioxide input and heat sinks. Sources of carbon dioxide for the methanator are electrolytic cation exchange module (E-CEM) which extracts carbon dioxide from seawater (Parry, 2016), post-combustion capture (PCC) which extracts carbon dioxide from power plant and other carbon-rich exhausts, and direct air capture (DAC) which extracts carbon dioxide from ambient air. Heat sink technologies for the methanator considered are steam turbines, boilers, and, in methanation pathways using SOECs, the SOECs themselves. Also included are hydrogen blending and gas interconnection equipment for scenarios involving injection into the natural gas grid.

Gasification technologies considered include gasifying media of oxygen, steam, and air; reactor technology of fixed/moving bed, fluidized bed, and entrained flow; as well as some more novel gasification technologies such as multi-stage, dual bed, and chemical looping (sorption enhanced).

Anaerobic digestion (AD) technologies considered include wet substrates and dry substrates, and batch and continuous reactors.

Data Collected

This work is a techno-economic assessment for the future of the natural gas grid. Therefore, this work focuses on collecting efficiency and cost data, including their relationship to scale, as well as learning rates that relate production capacity with cost reduction.

For P2G pathways, efficiency and cost data were collected for the various P2G technologies listed above, which allows for calculation of overall pathway.

Gasification efficiency and cost data were collected for the production of both substitute natural gas (SNG) and hydrogen.

AD efficiency and cost data were collected for both manure and organic feedstocks for the production of SNG.

According to (Billig & Thrän, 2016), the most important parameters for biomethane production are energy efficiency and production costs, which is not surprising (Billig & Thrän, 2016). Therefore, the collection of efficiency and cost data as stated above is adequate for the techno-economic analysis conducted herein.

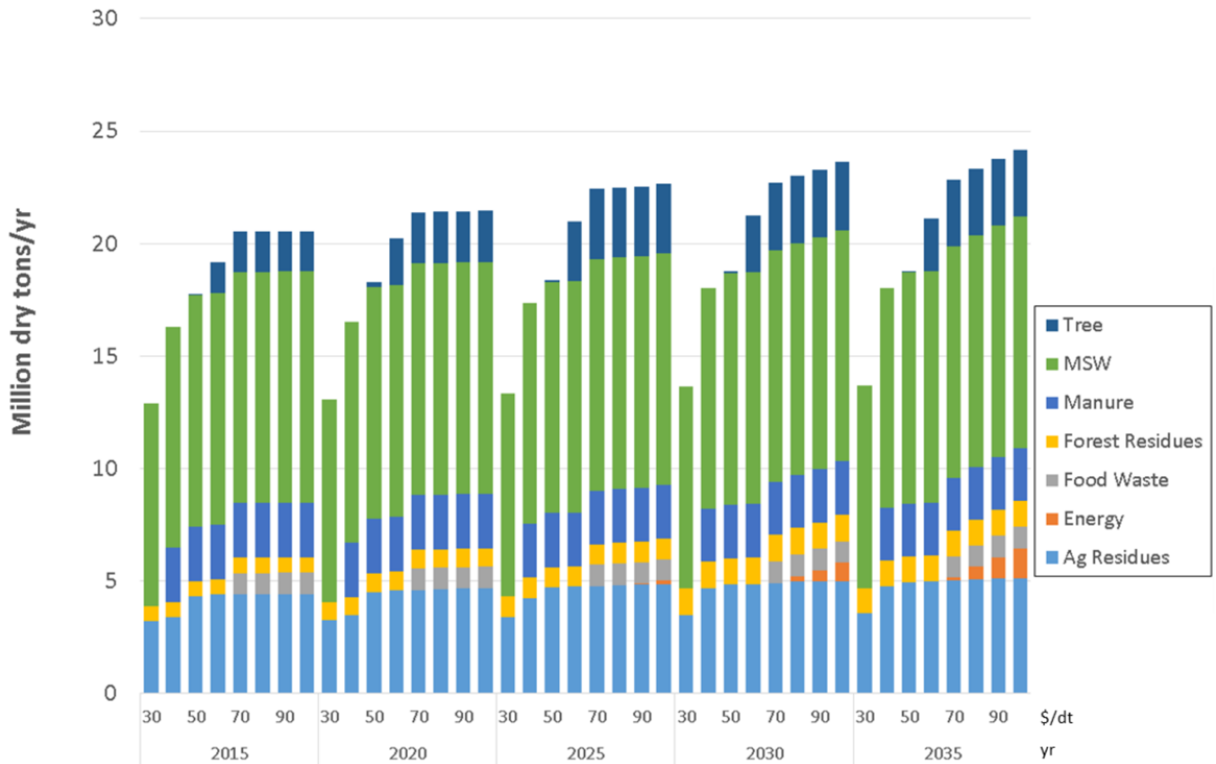
Expected Flow into PATHWAYS

To make application into E3's PATHWAYS simple, data collected and calculations performed yield costs per unit of fuel output, as well as overall process energy efficiency, which are direct inputs into PATHWAYS.

Feedstock Supply Estimates

Two main sources are consulted for estimates of biomass supply. The first is the US DOE's Billion Ton Report (Langholtz, Stokes, & Eaton, 2016), whose data are presented below in Figure C-1. Note that biomass availabilities are projected to 2040, with quantities categorized by feedstock type and selling price. A higher selling price yields higher quantities available.

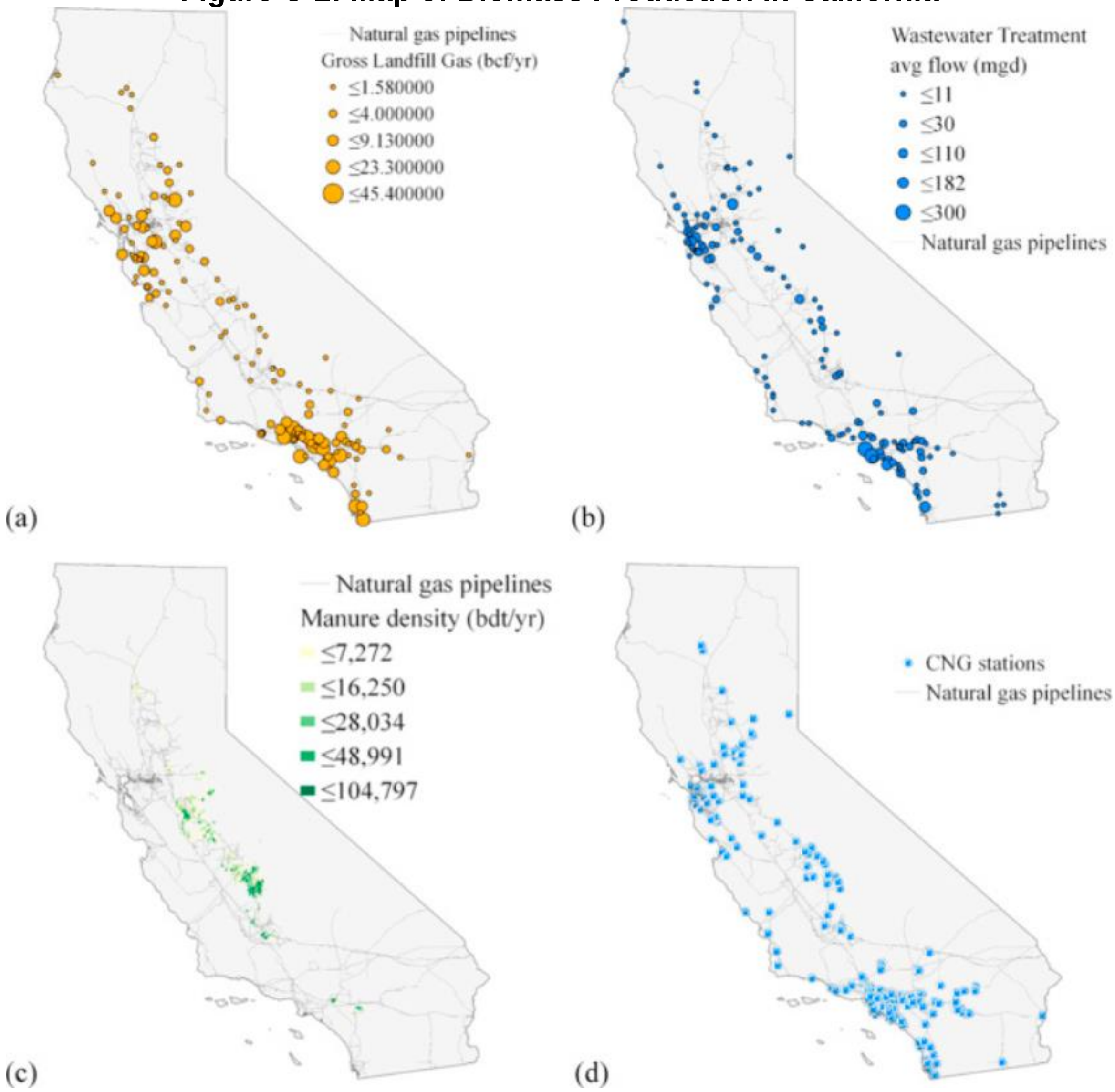
Figure C-1: Current and Potential Biomass Production for Energy Use in California Based on Medium Housing, Medium Energy Use, and Base Case Energy Crop Growth Scenario



Source: Data from (Langholtz et al., 2016)

A second source of data is used to support that of the Billion Ton Report. Data from Jaffe et al. offer more detailed biomass availabilities for feedstocks including landfill gas, wastewater treatment plants, manure, and food waste (Myers Jaffe, Dominguez-Faus, Parker, & Scheitrum, 2016) (N. Parker, Williams, Dominguez-Faus, & Scheitrum, 2017a). Some of these authors are at or were previously at the California Biomass Collaborative. These data, shown in Figure C-2, are noted to be accurate for the time range 2018 through 2025. These data are also spatially resolved within the State of California, whereas the Billion Ton Report is not spatially resolved within the State.

Figure C-2: Map of Biomass Production in California



Source: (N. Parker et al., 2017a)

Conversion Technology Selection Process

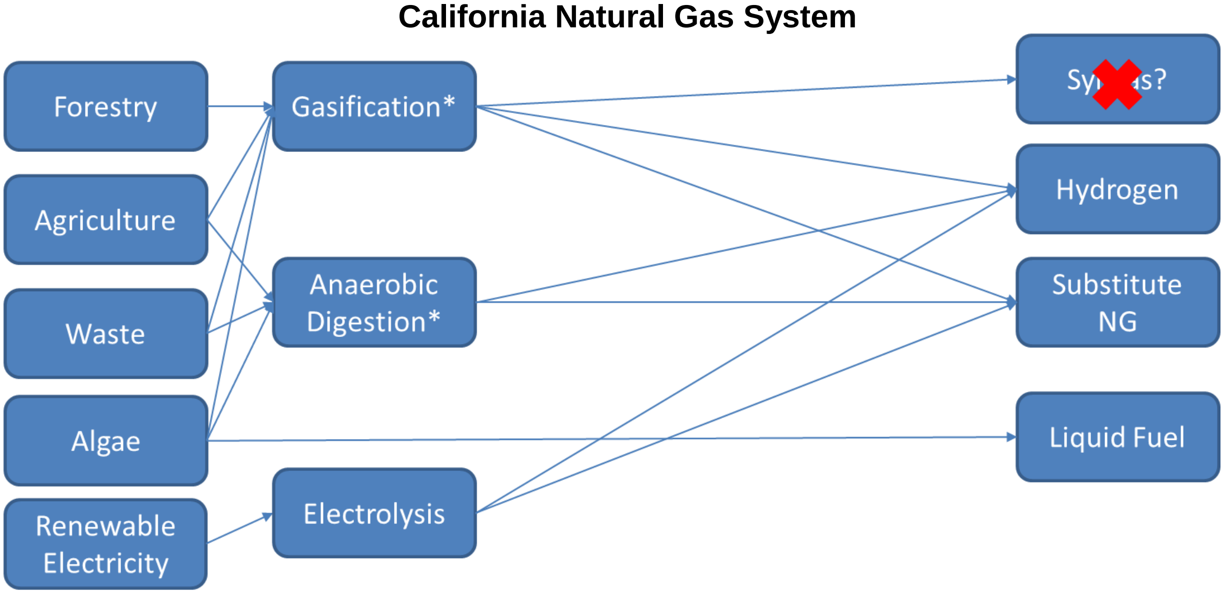
Through internal discussion with UCI experts, the following TRLs have been determined for the technologies to be considered in this work.

Table C-1: Technology Readiness Levels of Various Equipment

Technology	TRL
Power-to-Gas – Electrolysis of Renewable/Nuclear Electricity	7 to 9
Biomass Conversion Technologies	6 to 9
Carbon Capture and Sequestration	7 to 9
Artificial Photosynthesis	3 to 5
Various hybrid and advanced strategies	
Solar thermal assisted SMR/Gasification	<5
P2G assisted anaerobic digestion/hydrogasification	5 to 6
Algae process waste to gaseous fuel	5 to 6
Natural gas SMR to produce H2 and carbon (black carbon/nanotubes,/etc.	<5
Bioelectrosynthesis	3

Source: UCI

Figure C-3: Main Gas Production Pathways Considered for Decarbonizing the California Natural Gas System



Source: UCI APEP

Technology selection was accomplished using TRLs. The US Department of Energy has established guidelines based on guidelines from NASA and the Department of Defense (US DOE, 2011). A TRL of 5 is described as laboratory scale testing under relevant environments with the system being nearly prototypical. A TRL of 6 is described as prototype testing at pilot scale whereas a TRL of 7 is a full-scale prototype tested in relevant conditions with final design essentially complete. A TRL of 8 is operation and commissioning of the actual system where TRL 9 is operation of the actual system over the full range of operating conditions.

The TRL for the various technologies considered in this work were used to down-select, leading to fewer technologies to use in the analysis.

Conversion Technology Pathways Descriptions and Literature Review

Electrolysis

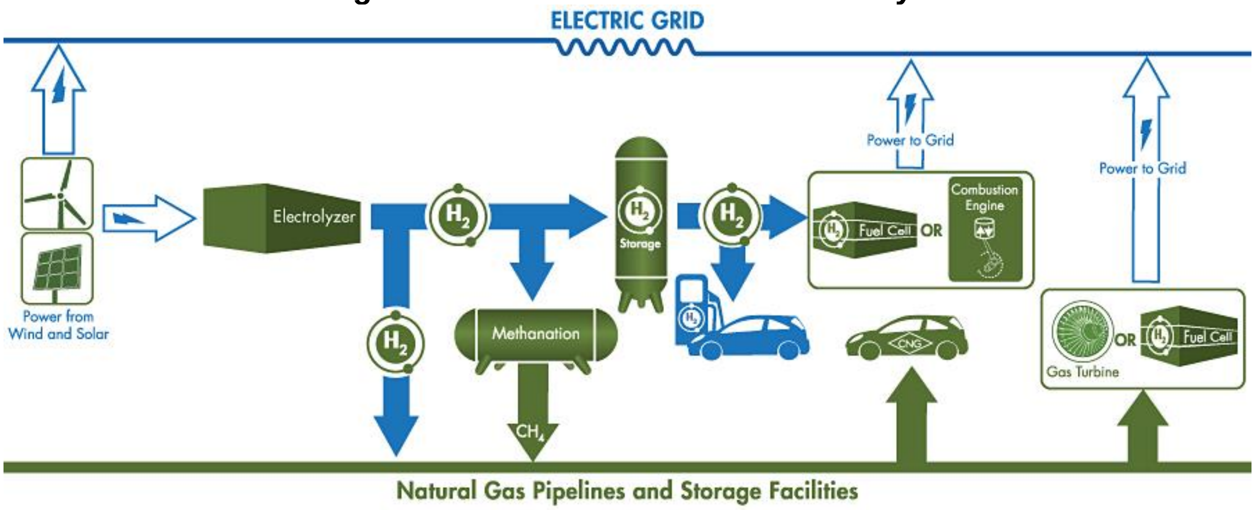
P2G is an emerging technology that transforms energy in the form of electricity to energy in the form of either hydrogen or methane, which are gaseous fuels. This is useful due to the increasing amount of renewable energy such as wind and solar which are intermittent and not easily predictable. P2G can be used as a form of energy storage in that the hydrogen or methane that are produced from electricity can be stored in containers or even the natural gas grid for later use.

P2G is flexible due to the numerous possible pathways for energy to flow. These pathways are depicted below. P2G connects the electric grid and the natural gas grid, two large energy distributors of the modern day. This allows the benefits of both grids to be utilized while downplaying their characteristic issues. For example, P2G can use the highly efficient electric grid when possible (meaning there is demand for more electricity), but also use the natural gas grid when there is not an immediate demand for power (making use of the natural gas grid's inherent storage ability). P2G also enables other transfers of energy, such as fueling vehicles that run on hydrogen, natural gas, or electricity.

The first step in P2G, no matter which pathway is being followed, is using electricity in an electrolyzer to produce hydrogen. Therefore, the emissions associated with P2G are directly tied to the emissions associated with the production of the electricity used by the electrolyzer. While the diagram only shows renewable sources of electricity, P2G can of course use conventional sources of electricity which do have emissions.

A particularly attractive use of P2G comes from using what would be curtailed, or wasted, electricity from renewable energy sources such as solar panels and wind turbines. As mentioned above, both wind and solar power are intermittent and hard to predict precisely. P2G is able to use electricity from these renewable sources at times when the electric grid might not be able to accept them, which is brought about by the fact that electricity must continually be used at the same time as it is generated. This means more of the renewable electricity generated would be used in other areas such as making renewable natural gas or hydrogen fuel for stationary power production or for vehicle fuel. Increasing renewable energy usage will decrease the emissions associated with both the electric grid and the natural gas grid, which are both intertwined with the advent of P2G.

Figure C-4: Schematic of P2G Pathways

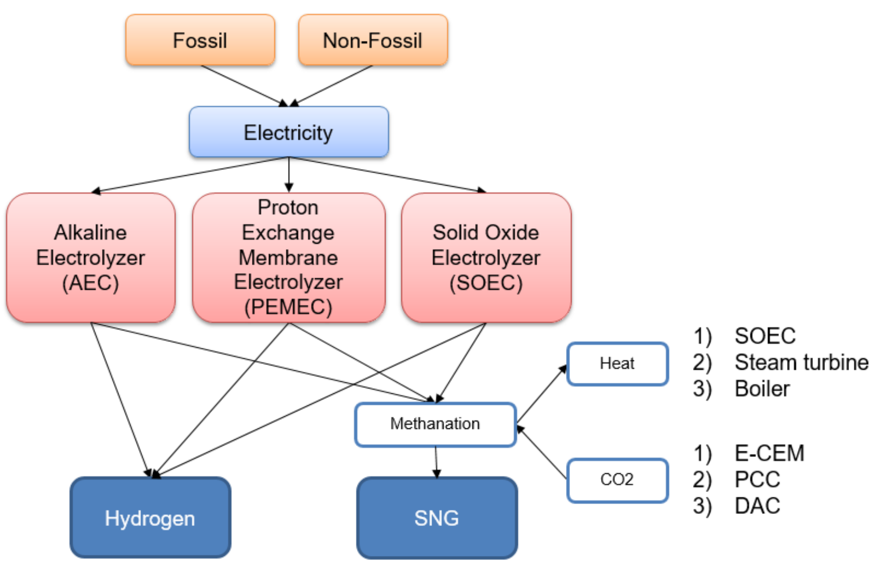


Source: UCI APEP

While some of these pathways are not relevant for this project, it is still important to be aware of them as the energy sector evolves and these other pathways are potentially used.

To focus on the work conducted within this report, it is beneficial to summarize the pathways and technologies herein. Figure C-5 is a flowchart that includes all such pathways.

Figure C-5: Flowchart of Analyzed P2G Pathways



Source: UCI APEP

The overall idea of these pathways is to turn electricity (produced from either fossil fuels or non-fossil fuels such as solar and wind power) to either hydrogen or methane. Both of these gaseous fuels can be made by any of the three electrolyzer technologies displayed in the figure. To make methane, the extra step of methanation is required, and as depicted, carbon dioxide is needed and heat is a product in methanation.

Three types of electrolyzers are considered in this work. These are AECs, PEMECs, SOECs. AECs are the most mature form of electrolyzers of these three in that they have been available commercially for the longest time. PEMECs are the next most mature. SOECs are the least mature electrolyzer, with limited commercially available examples available and a TRL of 5-7.[15]

Regarding capacity factor, which is a measure of how productive a plant is compared to how productive it could be if it were run at full capacity at all times, two scenarios have been chosen to inform the PATHWAYS scenarios. The first is a high capacity factor of 0.85, which depicts a scenario in which P2G is run nearly continually to maximize the usage and fuel output. The second is a low capacity factor of 0.2, which is meant to give an idea of what would happen if P2G is used for what would otherwise be curtailed power, often in the form of intermittent renewable power such as solar and wind. Note that the PATHWAYS scenarios in Chapter 3 interpolate between these bookends to use capacity factors representative of the electricity generation source in each scenario. Previous work has shown that due to the production costs, P2G with methanation does not economically make sense for low capacity factor scenarios (Collet et al., 2017). The present work will provide more insight into this area.

Notable research in P2G has been conducted by the National Renewable Energy Laboratory (NREL), who analyzed 10 P2G pathways and determined their associated levelized cost of hydrogen and greenhouse gas emissions. Data used for this analysis are sourced primarily from the H2A Production Model, the Hydrogen Delivery Scenario Analysis Model, GREET, and the Cost-per-Mile Tool. The updated version of the report includes, in addition to up-to-date data, additional P2G pathways that add up to the 10 mentioned as well as more analysis with FCEVs. The pathway with distributed natural gas reforming led to the lowest levelized cost of hydrogen, and the pathway with

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15 James, Brian D, Daniel A. DeSantis, Jennie M. Huya-Kouadio, Cassidy Houchins (Strategic Analysis), and Genevieve Saur (National Renewable Energy Laboratory). 20165. *Analysis of Advanced H2 Production Pathways.* Cites: US DOE: https://www.hydrogen.energy.gov/pdfs/review16/pd102_james_2016_o.pdf. Wang et al. 2017. "Optimal Design of Solid-Oxide Electrolyzer-Based Power-to-Methane Systems: A Comprehensive Comparison Between Steam Electrolysis and Coelectrolysis." *Applied Energy,* Vol. 211, pp 1060-1079. https://www.sciencedirect.com/science/article/pii/S0306261917316367.
Skov, Iva Ridjan and Brian Vad Mathiesen. 2017. *Danish Roadmap for Large-Scale Implementation of Electrolysers.* Aalborg University, Denmark. https://vbn.aau.dk/ws/portalfiles/portal/257488009/Roadmap_for_large_scale_implementation_final.pdf.

distributed ethanol reforming led to the highest levelized cost of hydrogen (Ramsden, Ruth, Diakov, Laffen, & Timbario, 2007).

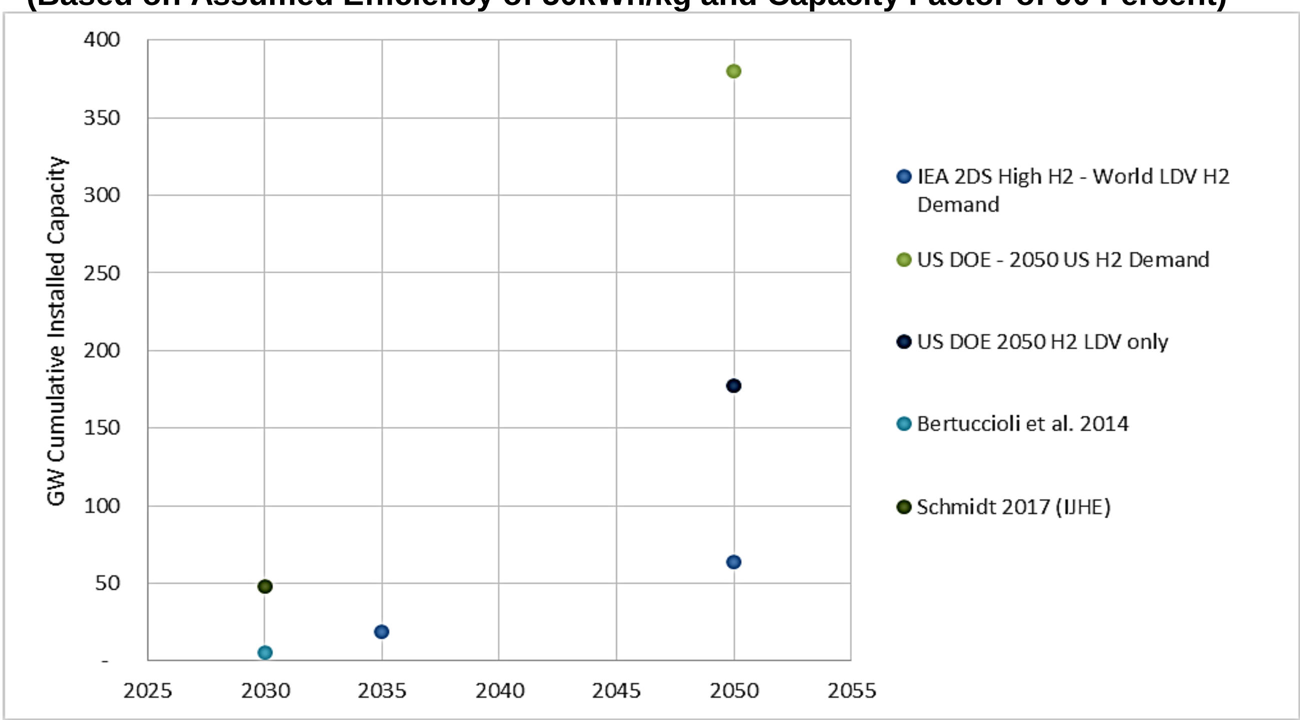
NREL has also studied the value that hydrogen energy storage, an aspect of P2G, has in California specifically in the electricity market. This study found that hydrogen from P2G is more valuable when selling it as hydrogen than it is as energy storage to be converted back to electricity later. Furthermore, they have found that increasing the capacity for hydrogen storage beyond daily fluctuation does not improve the value of the system. These two conclusions are valid for the year of 2012. NREL concedes that the conclusions may be different in the future as the energy grid changes (Eichman, Townsend, & Melaine, 2016).

A third NREL report mentions the possibility of blending hydrogen from P2G into the natural gas system to increase the amount of renewable energy used. The report also details the benefits of P2G at various scales, from small scale with fork lifts and backup power, to medium scale with fuel cell electric vehicles, to large scale with more renewable energy interplay (M. Melaina & Eichman, 2015).

Electrolysis Market Size and Efficiency

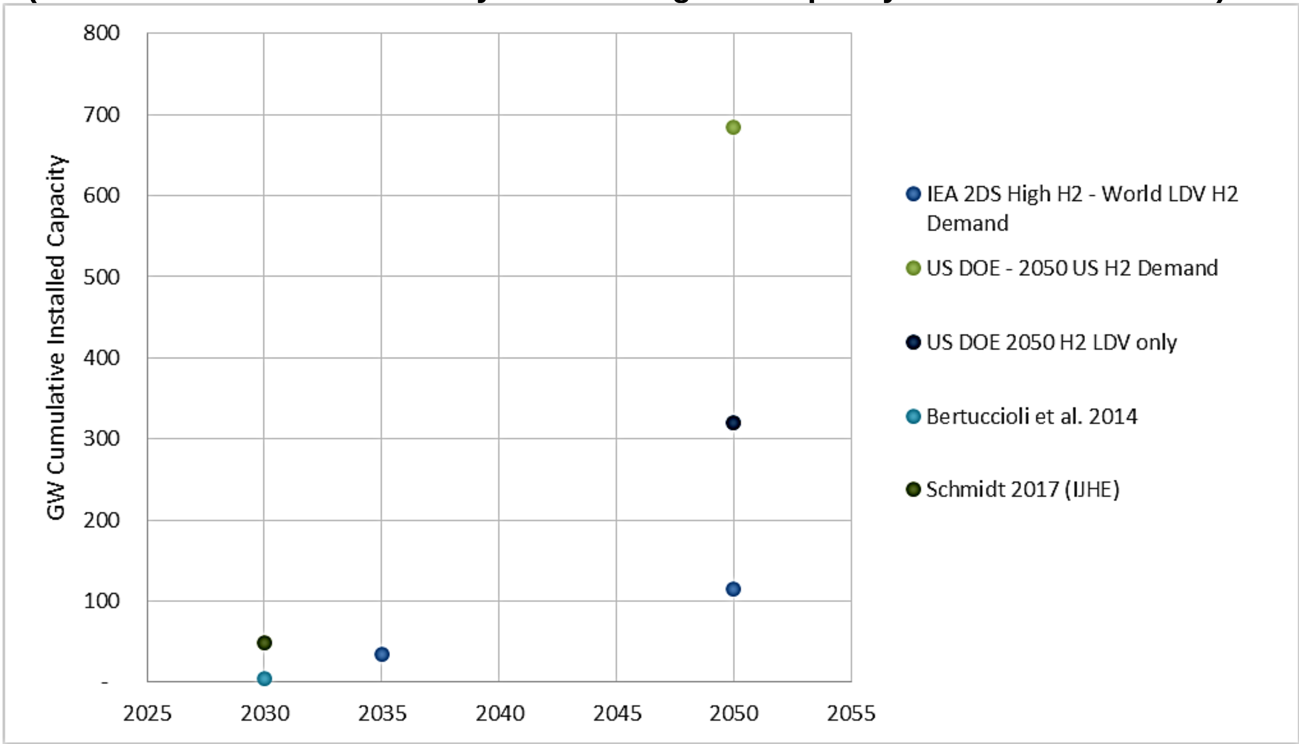
Various electrolyzer market size projections are shown in the following figures. It is clear that there is a general consensus on the mid-term market size around the year 2030, but further projections out to 2050 are much more scattered.

Figure C-6: Future Electrolyzer Market Size Projections in 2030, 2035, and 2050 (Based on Assumed Efficiency of 50kWh/kg and Capacity Factor of 90 Percent)



Source: Data from (Bertuccioli et al., 2014a; IEA, 2012; Pivovar, 2016; Schmidt, Gambhir, et al., 2017a

Figure C-7: Future Electrolyzer Market Size Projections in 2030, 2035, and 2050 (Based on Assumed Efficiency of 50kWh/kg and Capacity Factor of 50 Percent)



Source: Data from (Bertuccioli et al., 2014a; IEA, 2012; Pivovar, 2016; Schmidt, Gambhir, et al., 2017a)

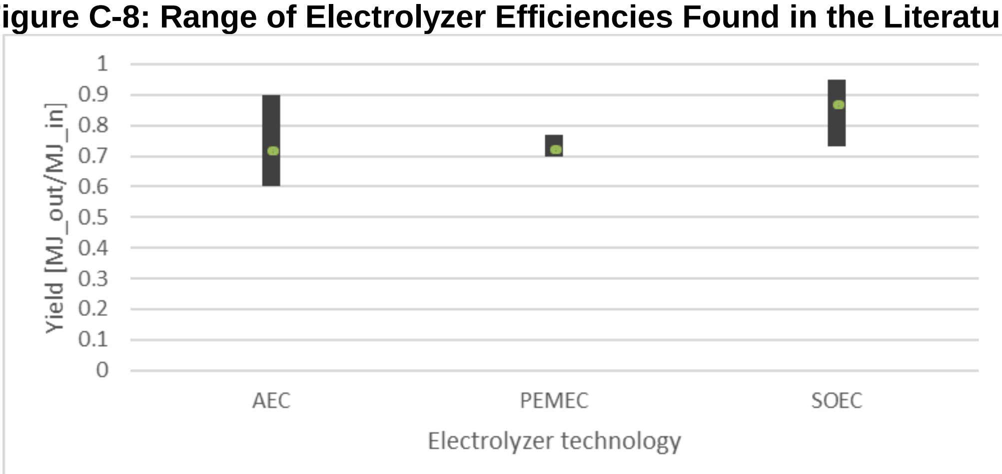
Literature values for electrolyzer efficiency give a range of efficiencies both now and into the coming decades. Recent and current values for electrolyzer efficiency are shown in Table C-3.

Table C-3: Information on Efficiency for SOEC, PEMEC, and AEC

EC Type	Author	Year	Source Info	Stack LHV efficiency (%)
SOEC	Tang et al.	2016	(Tang, Wood, Brown, Pi, & Presenter, 2016)	83.9
	Ouweltjes et al.	2007	(Ouweltjes, van Tuel, van Berkel, & Rietveld, 2007)	79-95
	Pan et al.	2017	(Pan et al., 2017)	73
	Paakkonen et al.	2018	(Pääkkönen, Tolvanen, & Rintala, 2017)	95
PEMEC	Millet et al.	2010	(Millet et al., 2010)	71-72.5
	Gibson and Kelly	2008	(Gibson & Kelly, 2008)	75-77
	Siracusano et al.	2010	(Siracusano et al., 2010)	70
	Paakkonen et al.	2018	(Pääkkönen et al., 2017)	70
AEC	Campanari et al.	2009	(Campanari, Manzolini, & Garcia de la Iglesia, 2009)	60-90%
	Bolat and Thiel	2014	(Bolat & Thiel, 2014)	61-79%
	Paakkonen et al.	2018	(Pääkkönen et al., 2017)	70%

Source: Data from sources cited in table.

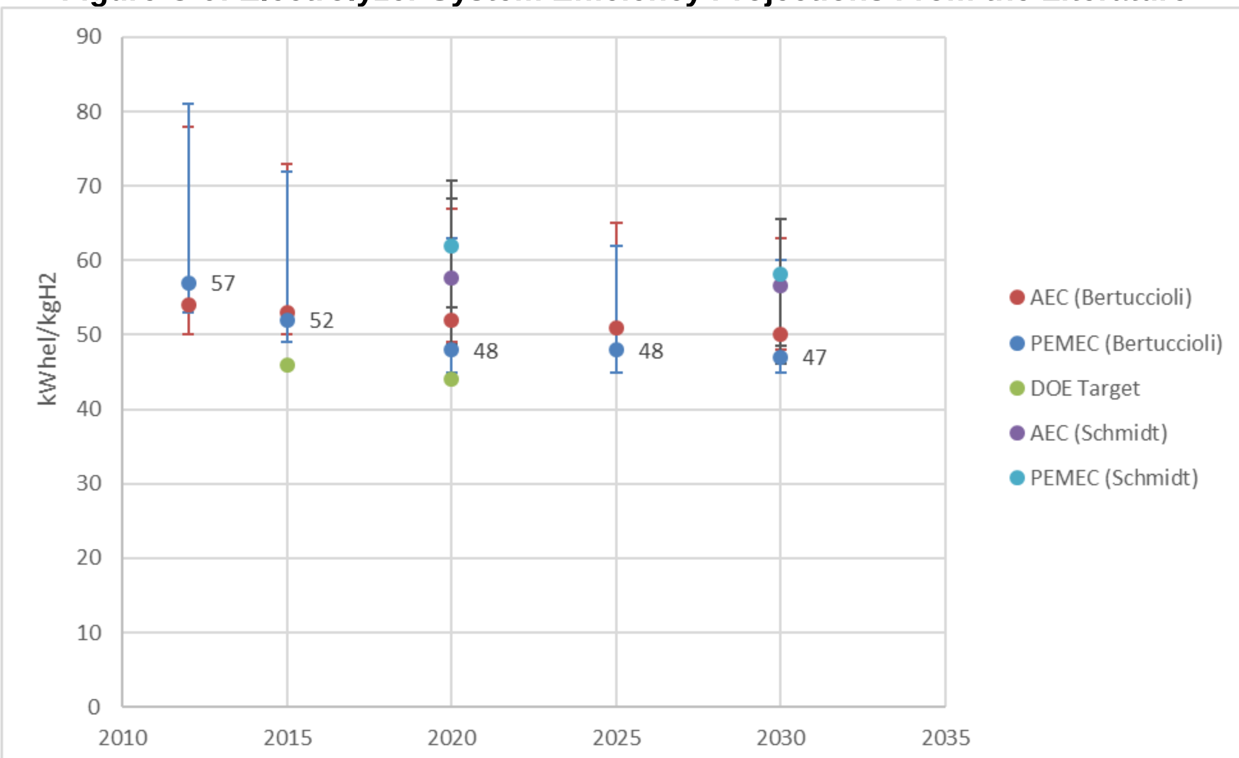
Figure C-8: Range of Electrolyzer Efficiencies Found in the Literature



Source: Data from sources cited in Table C-3.

Also necessary is determining the evolution of electrolyzer efficiency with time. According to (Schmidt, Gambhir, et al., 2017a), efficiency projections are not as important as others due to manufacturers stating they are focusing on cost reduction and overall P2G efficiency instead of simply electrolyzer efficiency. See Figure C-9 for projections of various electrolyzer efficiency projections from the literature. Note the focus on data from (Bertuccioli et al., 2014a; Department of Energy, n.d.; Schmidt, Gambhir, et al., 2017a) as these sources were the most credible and well-sourced from our literature review.

Figure C-9: Electrolyzer System Efficiency Projections From the Literature

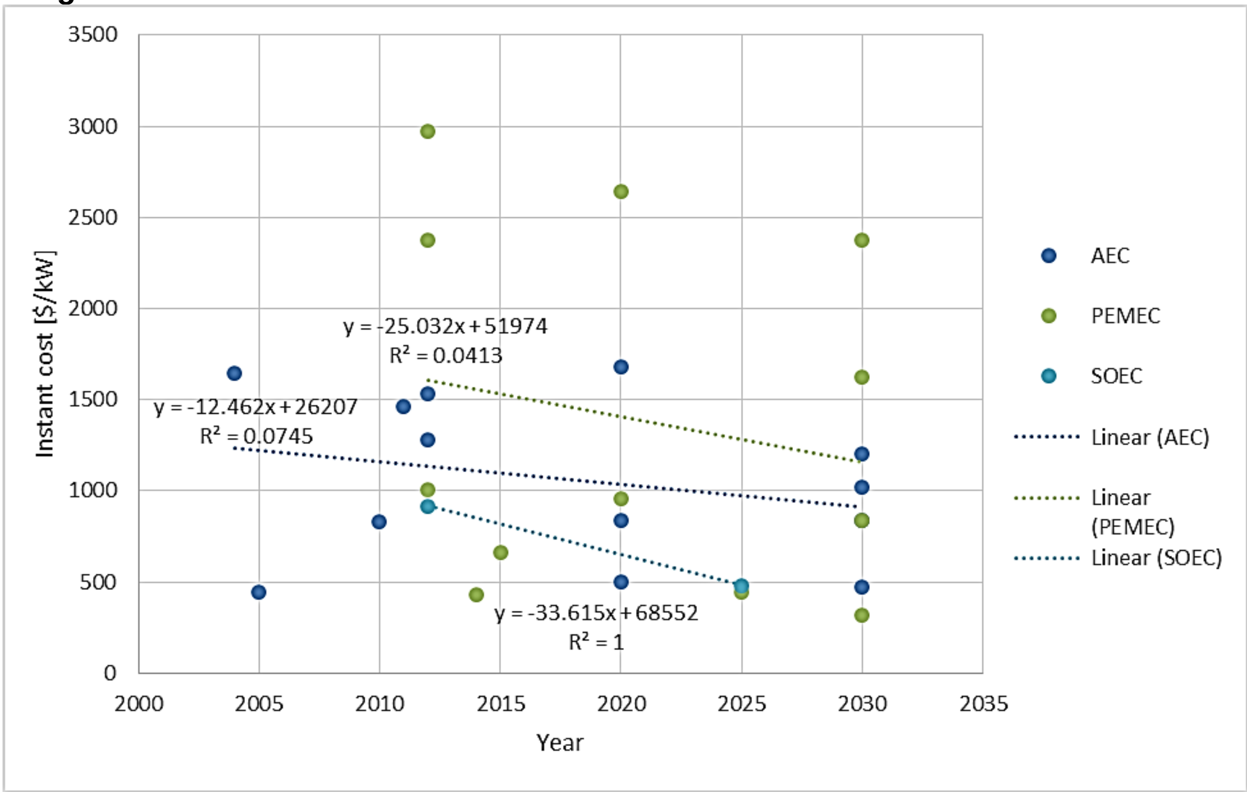


Source: Data from (Bertuccioli et al., 2014b; Department of Energy, n.d.; Schmidt, Gambhir, et al., 2017a)

Electrolysis Costs

Two areas are important here for cost: the first is current cost estimation, and the second is future cost projection. Literature was again consulted for this, and the findings for current cost estimations are presented below.

Figure C-10: Information on Uninstalled Cost for PEMEC and AEC Versus Time



Source: Data from sources cited in Table C-4.

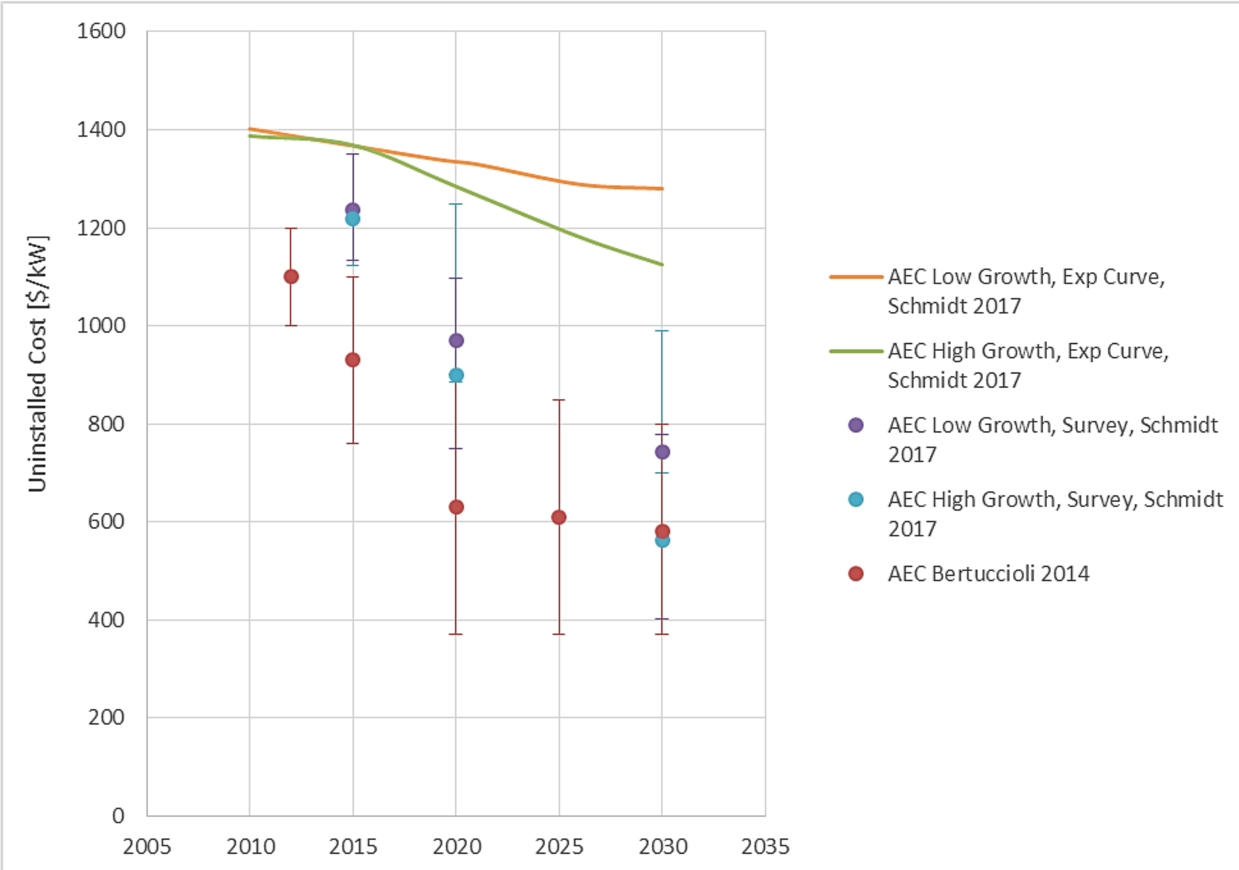
Table C-4: Information on Uninstalled Costs for PEMEC, SOEC, and AEC

EC Type	Author	Year	Source Info	Uninstalled cost ($/kW)
SOEC	US DOE	2012	(Brisse, Hartvigsen, Petri, & Tao, n.d.)	918
	US DOE	2025	(Brisse et al., n.d.)	481
PEMEC	Bertuccioli et al.	2012	(Bertuccioli et al., 2014b)	2376-2970
	Bertuccioli et al.	2030	(Bertuccioli et al., 2014b)	320-1626
	Godula-Jopek et al.	2015	(Godula-Jopek & Millet, 2015)	665
	Schmidt et al.	2020	(Schmidt, Gambhir, et al., 2017b)	960-2640
	Schmidt et al.	2030	(Schmidt, Gambhir, et al., 2017b)	840-2376
	James (DOE, SAI)	2013	(James, Colella, Moton, Saur, & Ramsden, 2013)	1008
	James (DOE, SAI)	2025	(James et al., 2013)	448
AEC	Mansilla et al.	2011	(Mansilla, Louyrette, Albou, Bourasseau, & Dautremont, 2013)	1464.
	Krewitt and Schmid	2005	(Krewitt & Schmid, 2005)	445
	National Research Council	2004	(Committee on Alternatives and Strategies for Future Hydrogen Production and Use & National Research Council, 2004)	1643
	Bertuccioli et al.	2012	(Bertuccioli et al., 2014b)	1280-1536
	Bertuccioli et al.	2030	(Bertuccioli et al., 2014b)	469-1024
	Schmidt et al.	2020	(Schmidt, Gambhir, et al., 2017b)	840-1680
	Schmidt et al.	2030	(Schmidt, Gambhir, et al., 2017b)	840-1200
	NEL/H2V Agreement	2020	(Nel, 2017)	~500

Source: Data from sources as cited

Again, literature values vary significantly. Therefore, the studies by (Bertuccioli et al., 2014a; Schmidt, Gambhir, et al., 2017a) are used to narrow the values using the most credible data, shown below. Also, note the inclusion of the experience curve data from (Schmidt, Gambhir, et al., 2017a) that attempt to approximate survey data with mathematical equations.

Figure C-11: More Detailed Information on Uninstalled Cost for AEC Versus Time to Show Difference Between Survey Information and Experience Curve Calculations



Source: Data from (Bertuccioli et al., 2014a; Schmidt, Gambhir, et al., 2017a; Schmidt, Hawkes, Gambhir, & Staffell, 2017)

Methanation

Methanation is the chemical reaction that turns carbon dioxide and hydrogen into methane and water. This chemical reaction is also known as the Sabatier reaction, and it is exothermic meaning heat is a product. The chemical equation is depicted as

$$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O$$

with the correct stoichiometric numbers. Each mole of reaction leads to 165 kJ of heat being released (Stangeland, Kalai, Li, & Yu, 2017).

Literature was consulted for technologies that provide carbon dioxide for making natural gas from hydrogen as well as technologies to make use of the heat produced during the methanation process. Both of these technologies are needed because the Sabatier reaction (1) is an exothermic reaction that requires a heat sink for sustained reaction, and (2) requires carbon dioxide as input to convert hydrogen into methane (Ralston, 2010).

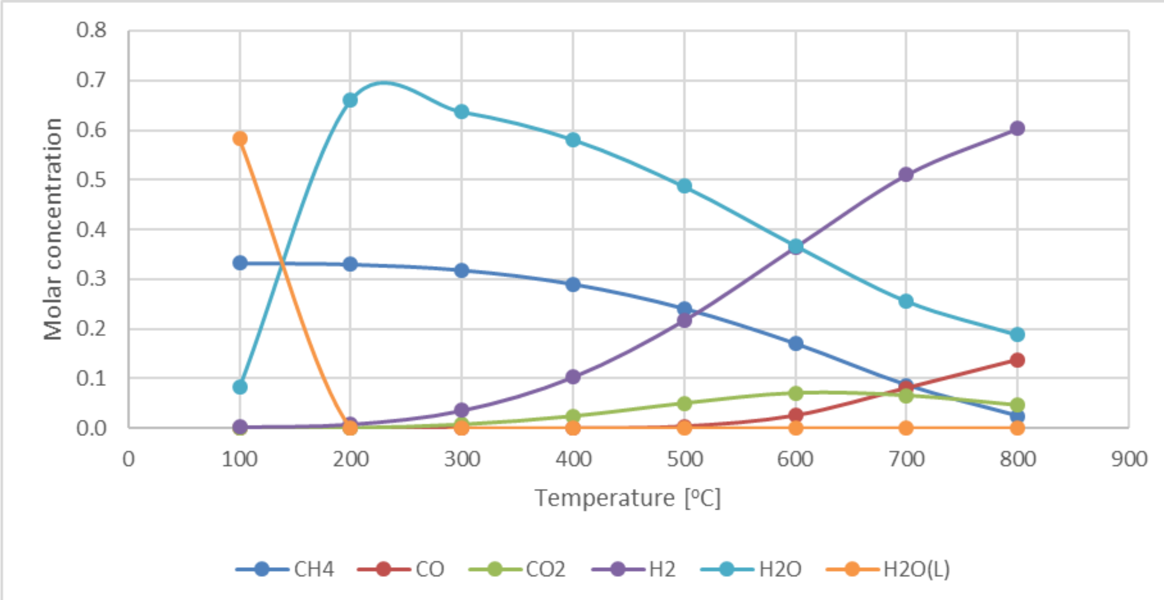
The primary benefit of methanation is the ability to take advantage of the natural gas infrastructure. Without methanation, hydrogen is the main product of P2G. However, there is not much infrastructure in the US, or even the world, for hydrogen. Therefore, the extra step of methanation makes P2G much simpler to integrate into the power grid of today. Use of natural gas pipelines and storage throughout the country and much of the rest of the world make P2G more practical today. The tradeoff for this practicality is the loss of efficiency by adding the extra step of methanation. The calculation of the efficiency of this step is calculated next.

Because methanation can take place at a range of temperatures and its efficiency is benefitted by some pressurization, it is wise to include a range of temperatures and an above-ambient pressure in calculations (Stangeland et al., 2017). An equilibrium analysis using NASA's Chemical Equilibrium with Applications code at 5 atmospheres of pressure at 400, 500, and 600°C leads to an average methanation efficiency of 0.7904 (Maroufmashat & Fowler, 2017; NASA, n.d.; Schaaf, Grünig, Schuster, Rothenfluh, & Orth, 2014). This is calculated by analyzing the products of the Sabatier reaction at the given pressure and temperatures, and determining what fraction of the products is methane, the desired product.

Methanation is pressure dependent in such a way that it is more efficient at producing methane at higher pressures (Götz et al., 2016). Methanation efficiency is highly dependent on reaction temperature. At 400°C with a 4 to 1 molar ratio of hydrogen to methane input (the stoichiometric ratio of the Sabatier reaction), the methanator output is 92% methane; at 500°C, the output is 81% methane; and at 600°C, the output is 64% methane. Therefore, operating at a lower temperature would increase the amount of methane coming out of the methanator, which could also remove the need for any gas cleanup before injection into the natural gas pipeline. However, it is important to keep in mind other effects of lowering the temperature of the methanator. One major impact is there will be lower quality waste heat which would be used in other P2G processes to be expanded upon later. This could lower the overall process efficiency, even if the amount of methane is decreased. A more careful analysis would be needed based upon an individual plant design.

See below for equilibrium species concentration of a methanator at 5 atmospheres of pressure. Note that some methanators may not allow for expected conversion of carbon dioxide and hydrogen to methane due to time reacting. Because the calculations discussed are for equilibrium concentrations, and equilibrium takes time to achieve, actual methanation efficiency may be lower than calculated if time spent reacting in the methanator does not allow for equilibrium to be reached. Therefore, it is important to ensure reactor design does so, or account for the drop-in conversion efficiency of the methanator used.

Figure C-12: Methanator Equilibrium Species Concentrations at Five Atmospheres of Pressure



Source: Data from chemical equilibrium code from (NASA, n.d.)

Lastly, the energy required for the methanation process itself as well as any necessary gas cleanup before injecting must be considered. According to (Collet et al., 2017), when a nearly stoichiometric ratio of hydrogen and carbon dioxide are input to the methanator, the above two processes account for a mere 1.3% of the amount of energy input to the electrolyzer. Therefore, these two processes can be assumed to be of negligible energy requirement for the overall P2G process. However, it is important to remember that gas cleanup will be needed, and that need increases as the methanator temperature increases because less methane will be output from the methanator as the temperature increases. Two steps are required: (1) carbon dioxide removal and (2) water removal. Carbon dioxide removal is accomplished amines, similar to how carbon dioxide is sourced for the methanation process in general. This carbon dioxide can be recirculated back into the methanator to improve process efficiency. Water removal is accomplished through cooling of the gas mixture and collecting the water as it condenses back out. This water can be recirculated back to the electrolysis step, also improving process efficiency. These two cleanup steps produce gas that is able to be injected into the natural gas grid (De Saint Jean, Baurens, Boualou, & Couturier, 2015). In some scenarios, simply a removal of the water is all that is needed to produce natural gas pipeline-quality gas (El Sibai, Rihko Struckmann, & Sundmacher, 2017).

Heat Sink

The heat sink technologies for the methanation process that have been considered are SOECs, steam turbines, and boilers to produce steam.

Table C-5: Technology Readiness Level for Heat Sinks

Technology	Technology readiness level
SOEC	5
Steam turbine	9
Boiler	9

Source: E3

Solid Oxide Electrolyzers

SOECs are a high temperature electrolyzer technology which take in electricity and water and outputs hydrogen and oxygen. Because they operate at high temperatures of up to 800°C, they often require heat input to achieve those high temperatures. Because the range of operation temperatures of methanation reactors is similar to that of SOECs, SOECs can serve as heat sinks for the methanation process (Bailera, Lisbona, Romeo, & Espatolero, 2017; Pan et al., 2017).

SOECs stand out in this application because they can be used to produce more hydrogen, a major goal of P2G in general as it is a fuel. With the heat coming from the Sabatier reaction at a high temperature, the only other needed input is water to produce hydrogen with the SOECs. However, SOECs have a lower technology readiness level, so they are not necessarily an option for 2030 or even 2050. As they are, they also react slower than other electrolyzer technologies and therefore need to improve their dynamics for P2G applications, but this improvement is expected to be realistic (Pääkkönen et al., 2017; L. Wang et al., 2018).

Steam Turbines

Steam turbines are another attractive option in that they produce electricity with the waste heat of the Sabatier reaction, and this electricity could be used to power components of the P2G site or be put into the electric grid. Steam turbines are used in a Rankine cycle to produce electricity. They are a well-established technology that come in various power capacities, making them flexible for different-sized P2G plants in the future. Steam turbines would be sized to take advantage of the waste heat from the methanation process and produce as much electricity as possible.

Steam Production

The last option considered, producing steam, would be able to provide heat to any components of the P2G site or be piped to any nearby industrial or other facility in the vicinity that might need steam. Like steam turbines, the heat exchangers that could produce the steam are a well-established technology. Furthermore, they can also be easily sized to meet the heat sink requirement of the methanation process at P2G plants.

Carbon Dioxide Source

The carbon dioxide source technologies that have been considered are post-combustion capture (PCC), direct air capture (DAC), and electrolytic cation exchange modules (E-CEM). Additionally, further analysis is done to consider co-locating P2G plants with a biorefinery to source carbon dioxide from them.

Table C-6: Technology Readiness Levels for CO2 Sources

Technology	Technology readiness level
PCC	**9**
DAC	**5**
E-CEM	**3**

Source: E3

Post-Combustion Capture

PCC is attractive in that it pulls carbon dioxide from the exhaust stream of a power plant, a stream that is relatively dense in carbon dioxide compared to ambient air. Various solvents, sorbents, and membranes are used to capture the carbon dioxide from the exhaust stream as the carbon dioxide-containing exhaust flows through the PCC system. Solvents and sorbents capture carbon dioxide and release it under certain conditions such as heating or compressing. Membranes allow only specific molecules, such as carbon dioxide in the case of PCC, to pass through, and other molecules are blocked from passing (National Energy Technology Laboratory, n.d.; U.S. Department of Energy, n.d.).

The relatively high concentration of carbon dioxide in the exhaust stream of a power plant makes capturing carbon more efficient. Priority should be given to the largest sources of carbon dioxide, such as very large power plants, so these PCC installations can capture the most emissions with the least effort of installing systems.

Direct Air Capture

DAC also involves a sorbent or liquid solvent to capture carbon dioxide from the ambient air (Socolow et al., 2011) (NAS 2019)[16]. Because of the lower density of carbon

16 National Academies of Sciences, Engineering, and Medicine. 2019. Negative Emissions Technologies and Reliable Sequestration: A Research Agenda. Washington, DC: The National Academies Press. https://doi.org/10.17226/25259.

dioxide in ambient air compared to the exhaust stream of a power plant, DAC is not as efficient as PCC.

There are two major technological approaches to DAC: (1) liquid amine solvent and (2) solid amine sorbent. The liquid amine solvent approach uses amines, which are ammonia-based liquid compounds, to chemically absorb carbon dioxide from the flowing air containing carbon dioxide as the air passes over the liquid solution. For the solid amine sorbent approach, the amine is coated on the surface of a solid with high surface area, and again carbon dioxide is adsorbed onto the surface as the air passes over.

Typically, capturing the carbon dioxide is a spontaneous reaction, but extraction of the carbon dioxide is not. Extraction of carbon dioxide requires either a certain temperature or pressure on the liquid or solid. Energy requirements including heat are roughly 9.9 to 14 GJ per ton of carbon dioxide captured for liquid solvent DAC technology and 4.0 to 5.9 GJ per ton of carbon dioxide captured for solid sorbent DAC technology, though some systems do exhibit either higher or lower efficiency (NAS 2019). The present work uses an optimistic solid sorbent DAC system with an efficiency of 1.1 GJ of electricity and 6.1 GJ of heat input per ton of carbon dioxide captured.

Due to the nature of carbon dioxide's effect on climate change, DAC units can be placed anywhere and have the same impact. A given amount of carbon dioxide captured has the same effect on climate change no matter where that carbon dioxide is captured. However, it would be wise to place the DAC units in places with cheap power to make operation more economical. Additionally, ambient air characteristics affect performance of the DAC systems, so placement should be done based on careful analysis. Humidity has a significant effect on performance due to the water molecules' interference with carbon dioxide capture. Similarly, other molecules in the air such as pollution can effect carbon dioxide capture by either their physical presence or chemical reactions with parts of the DAC system (Socolow et al., 2011).

A further consideration for DAC is the effect it has on ecosystems. Because DACs take in ambient air, the concentration of carbon dioxide is much lower than in the exhaust for power plants. Therefore, DAC has the potential to deplete carbon dioxide to a level that could affect downstream ecosystems (Socolow et al., 2011). And again, carbon dioxide levels should be reduced; this is simply a side-effect that should be considered.

Electrolytic Cation Exchange Module

E-CEM technology is being pursued by the U.S. Navy and is promising due to its ability to capture both carbon dioxide and hydrogen from seawater (Parry, 2016). Here the carbon dioxide would be used as an input to the Sabatier reaction, and the hydrogen again is useful as a fuel or as more reactant for the Sabatier reaction. E-CEM was originally developed for jet fuel production in the sea to overcome the need for resupply of fuel on military missions involving aircraft carriers. However, the basic technology can be adapted to P2G by removing the final fuel synthesis step and instead stopping with carbon dioxide and hydrogen as the desired products, which are exactly what are needed for the methanation reaction.

The process is powered by ocean thermal energy conversion (OTEC), which uses the temperature difference in water at different depths. While circulating through the OTEC process, small amounts of the carbon in water, in the form of dissolved carbon dioxide, can be captured. Further carbon dioxide can be captured from the carbonates in seawater with additional capture materials and power from OTEC. Hydrogen is produced by PEMEC or AEC technology, using the electricity produced by OTEC (Willauer, Hardy, & Williams, 2010). While not mentioned in the report, SOEC technology could be used for hydrogen production as well.

The technology readiness level for E-CEM is low and therefore the option may not be ready in time for use in 2030 or 2050.

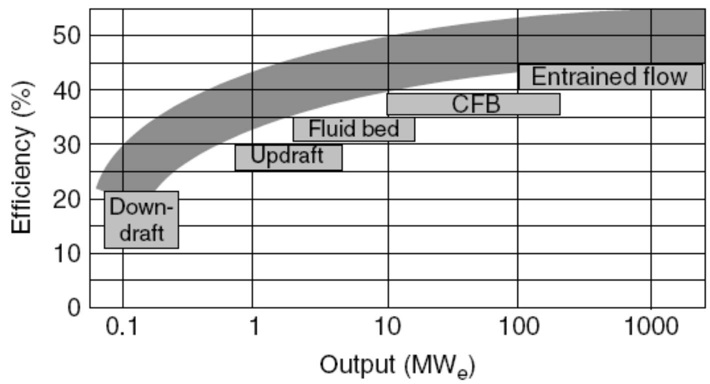
Co-locating P2G Plant with Biorefinery

Biorefineries such as those producing biofuels from anaerobic digestion, pyrolysis, hydrolysis, and gasification have streams with relatively high concentrations of carbon dioxide (US EPA, n.d.)(Jones et al., 2013)(Kabir Kazi, Fortman, & Anex, 2010)(Humbird et al., 2011)(Davis et al., 2014)(N. C. Parker, Ogden, & Fan, 2008)(Liu, Norbeck, Raju, Kim, & Park, 2016). The carbon dioxide can be separated from the streams rather efficiently, typically using differences in condensing temperatures of the stream constituents. Note that this separation technology is effectively the same as that of PCC mentioned previously. Each of the above-mentioned production methods will have different concentrations of carbon dioxide in various streams, so the efficiency and quantity of carbon dioxide will be different for each. However, there is an expected synergy of co-locating a P2G plant with a biorefinery due to the much higher concentration of carbon dioxide in the stream so of the biorefinery compared to the ambient air (in the case of a DAC) and the seawater (in the case of E-CEM). This is similar to the high carbon dioxide concentration utilized in PCC, but biorefineries have the added benefit of using biomass as input, drastically improving the carbon impact of these facilities. This concept is particularly attractive in situations in which the biorefineries are co-located with electrolysis plants with solar or wind power on-site. The coalescing of these pieces of equipment create a synergy of fuel production, of both the original fuel of the biofuel plant and the electrolytic SNG. The main benefit of this layout is to take advantage of low electricity costs due to on-site renewable generation and the otherwise-wasted carbon dioxide from the biomass at a low marginal cost.

Gasification

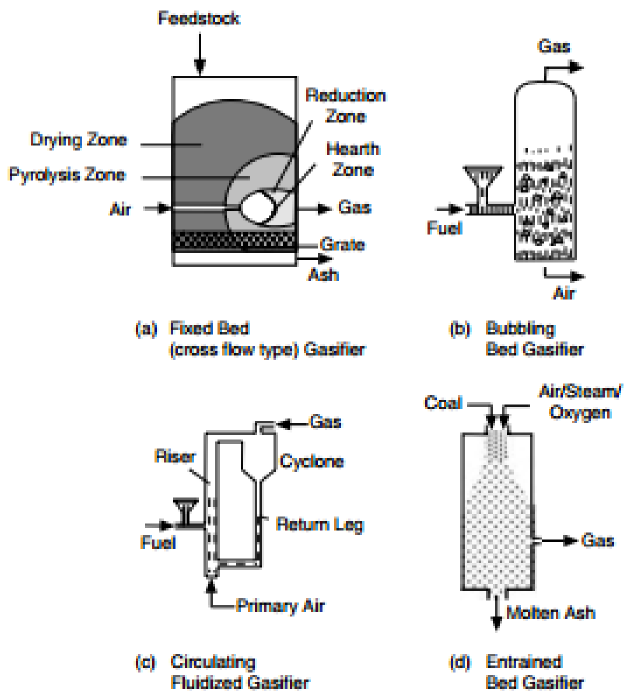
Gasification units are classified according to the gasifying medium (oxygen, steam, air) and the reactor technology used (fixed/moving bed, fluidized bed, entrained flow). The typical efficiencies and size ranges as well as example schematics of these systems are shown in Figure C-13 and Figure C-14, respectively. The fixed bed gasifiers can be further classified by the flow of the gasifying medium: updraft, downdraft, side draft/cross flow.

Figure C-13: Typical Electrical Conversion Efficiencies for Different Types of Gasification Technologies



Source: (Bridgwater, 2006)

Figure C-14: Representations of Different Types of Gasifiers



Source: (Basu, 2006)

Fluidized bed gasifiers are classified according to the extent of fluidization, i.e., distribution of bed material throughout reactor (circulating) or bed concentrated at the reactor bottom (bubbling). Biomass gasification using entrained flow technology is not used commercially because of the requirement for fine particles given the short residence times (Basu, 2013) unless biomass is being co-fed into a coal gasification unit. Commercial and near-commercial designs include Linde/CarboV, Air Liquide/Bioliq, UNIFHY, GoBiGas, and others. The commercial availability of each technology was inventoried in 2000 for the European Commission through industry surveys (Knoef, 2000). This inventory showed that downdraft gasifiers accounted for 75% of commercially available products with fluidized beds accounting for 20%, updraft for 2.5% and 2.5% of other types (Bridgwater, 2006). A likely reason for this is the typically low tar yields in downdraft gasifiers (H. Yang & Chen, 2015).

A key issue for biomass gasification is gas clean up, particularly for the production of gaseous fuels (Basu & Basu, 2013; Heidenreich, Müller, & Foscolo, 2016). The key contaminants to be removed are tar (formed during pyrolysis) and fine particulates. Some gasification technologies show better performance with respect to tar and fine particulate production with tradeoffs being typical, e.g., between tar production and other performance parameters.

Updraft moving bed gasifiers are one of the oldest gasifier designs and is used in the Sasol liquid fuel production plant in South Africa. The updraft gasifier uses the heat from combustion efficiently given the good heat recovery that results from the counter flow arrangement. This leads to higher carbon conversion efficiencies and deals better with moisture. However, the updraft arrangement does lead to higher tar production. The downdraft configuration results in lowest tar production of all types because the product gas leaves the reactor at the bottom passing through the hot ash where favorable conditions for tar cracking exist (Basu & Basu, 2013). Fluidized bed gasifiers were first studied in the 1920s by Winkler, and in fact he developed a commercial air blown fluidized bed gasifier (Basu, 2006; EPA, 2007). Fluidized bed gasifiers offer good mixing and uniform temperature distributions as well as large thermal inertia, which allow for flexibility in the biomass feedstock type. However, these systems also typically have high tar and fine particulate production in addition to lower conversion efficiencies (H. Yang & Chen, 2015). Entrained flow systems require pulverized fuel particles to be used (<0.15 mm) making this technology difficult to use with biomass. However, the syngas produced has very low or zero tar content in addition to high carbon conversion efficiencies.

Other more novel gasifier designs include multi-stage, dual bed, chemical looping (sorption enhanced), plasma, and new concepts integrating filtration and secondary tar reduction directly into the gasifier (Basu & Basu, 2013; Heidenreich, Müller, & Foscolo, 2016; H. Yang & Chen, 2015). Staged gasification is the creation of different temperature zones by staging the addition of oxidant. First investigated in 1994, it was found to decrease the tar yield significantly (Bui, Loof, & Bhattacharya, 1994). More recent research has developed biomass gasifiers with three stages, i.e., FLETGAS concept (Gómez-Barea, Leckner, Villanueva Perales, Nilsson, & Fuentes Cano, 2013; Heidenreich, Müller, Foscolo, et al., 2016). Other staged biomass gasification designs include the VIKING gasifier, Carbo-V, and LT-CFB (Heidenreich, Müller, Foscolo, et al., 2016). Dual bed gasification separates the combustion and gasification processes into two different reactors and circulates the bed material between the two reactors to provide thermal integration. The benefit of this separation is avoiding dilution of the syngas stream as a result of the addition of air to supply the oxidant. Dual bed biomass gasifiers include the well-known Güssing gasifier, the Silvagas process developed by Battelle, a patented process by FERCO, and the MILENA gasifier developed in the Netherlands (Heidenreich, Müller, Foscolo, et al., 2016). The chemical looping concept involves the use of a sorbent to produce two gas streams. The typical sorbent used is lime (CaO) for sorption of CO_2. The sorbent is later regenerated in another process providing a stream of CO_2 that can be sequestered. The sorption of CO_2 also allows increased production of hydrogen via Le Chatelier’s principle. Plasma gasification is fuel flexible and exhibits destruction of contaminants and pollutants, but requires electricity. Additional advanced concepts, such as integrating the filtration and secondary tar removal steps into the freeboard of the gasifier, are being developed. This integration has been named the UNIQUE gasifier concept and has been deployed at a pilot gasifier in Europe called UniFHY (Heidenreich, Müller, Foscolo, et al., 2016). Table C-7 summarizes some of the operational parameters of various pilot and experimental biomass gasifiers constructed.

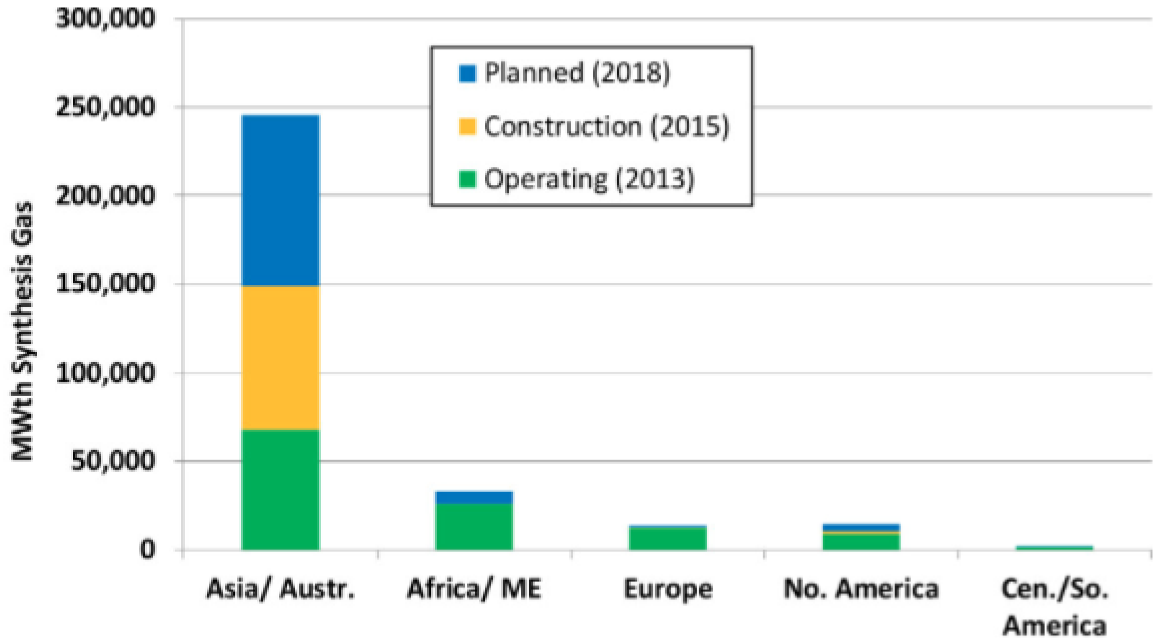
Table C-7: Example Biomass Gasifiers From the Literature

Name	Feed-stock	Products	Gasifier Type	Size	Gasify-ing Agent	Pressure [bar]	CGE
Viking - Danish Tech Univ	Wood	Elec/Heat	2-stage Pyrolysis then Throated Downdraft	75 kWth	Air	1	93
Wang 2015	Sawdust /Cotton Stalk	DME	2-stage Pyrolysis then Throated Downdraft	-	Air/O2	1	
FLETGAS - Univ of Sevilla	still developi ng pilot	-	3-stage (FB for devolatil, SMR, downdraft)	-	Air / Steam	-	81
LT-CFB - Dong Energy	Various	Elec/Heat	Dual Bed (CFB pyrolysis, BFB Char gasif)	6 MWth demo at Asnaes plant	Air	-	87-93
Carbo V	Various	FTL DME	3 stage (pyrolysis, comb, gasif)	1 MWth	Oxygen	5	82
Bioliq	Oil-char slurry	FTL	Lurgi Entrained flow	5 MWth	Oxygen	80	60-70
Gussing /FICFB	Wood	Elec/Heat	FICFB	8MWth	Steam	1	85-90
SilvaGas	Wood	Elec/Heat	Dual CFB	42 MWth	Steam	1	70
MILENA	Wood	Elec/Heat	Dual- BFB (comb) CFB (gasif)	300 kWth	Steam	1	80

Source: Data from (Basu & Basu, 2013; Bui et al., 1994; Gómez-Barea et al., 2013; Heidenreich, Müller, & Foscolo, 2016; Heidenreich, Müller, Foscolo, et al., 2016; H. Yang & Chen, 2015)

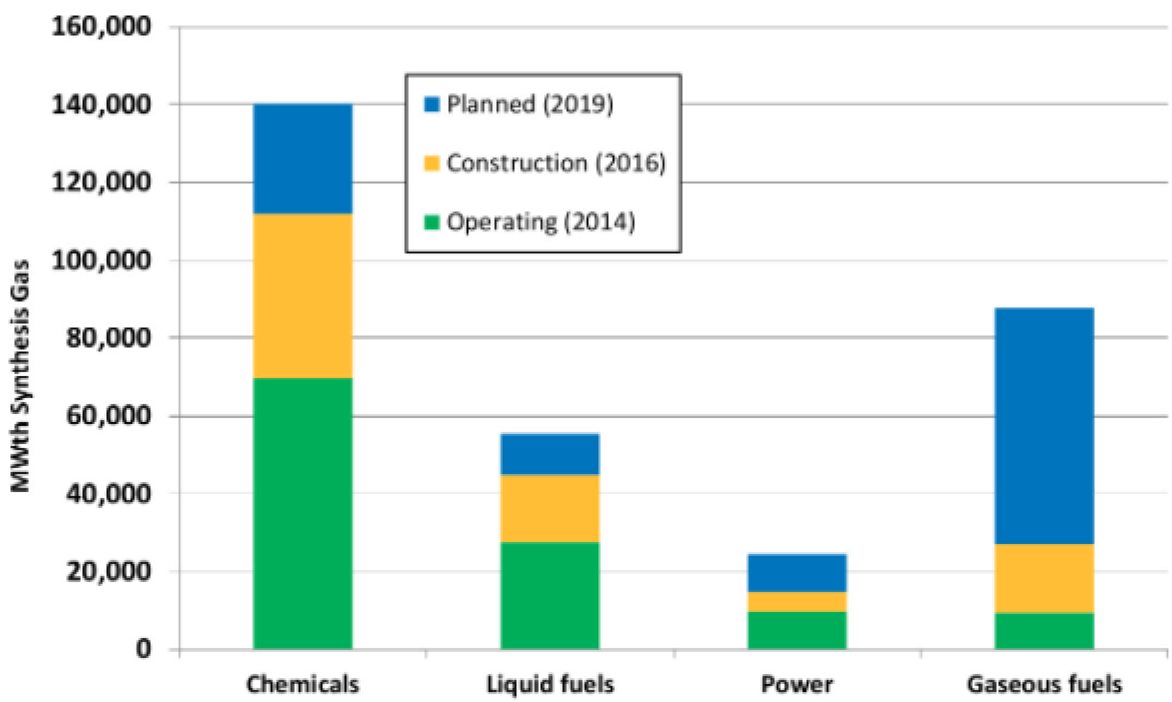
The figures below show the operating, in-construction, and planned gasification plants worldwide by quantity of product, type of product, and type of feedstock, respectively.

Figure C-15: Gasification Plants Installed and Planned in Different Regions of the World



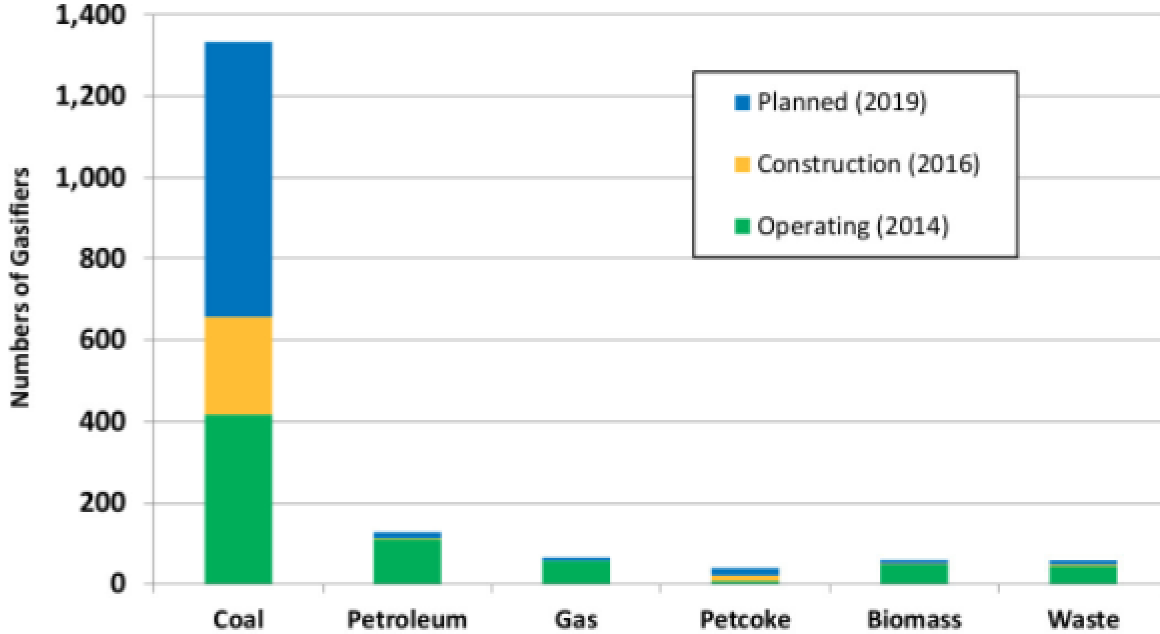
Source: Data from (Global Syngas Technologies Council, 2018)

Figure C-16: Gasification Plants Installed and Planned Disaggregated by Product



Source: Data from (Global Syngas Technologies Council, 2018)

Figure C-17: Gasification Plants Installed and Planned Disaggregated by Feedstock



Source: Data from (Global Syngas Technologies Council, 2018)

The US DOE also tracks gasification plants around the world and in the US. Their database shows that there are 13 biomass or waste gasifiers installed, under construction, or planned in the US with an additional 9 worldwide (all located in the EU) (US DOE, 2016). Some of these installations have been delayed and their future is uncertain. Only one of the projects in the US is producing gas (ICM/JUM Gasification Demonstration in Santa Clara, California) while the others are either producing liquids or electricity. Similarly, in the world (EU), there is only one project aimed at producing gas, Vaskiluodon Voima Oy in Vaasa, Finland. The gas is then injected into a pulverized coal boiler. The feedstock is forestry, demolition wood, and plastics. The capacity is 140MWth and has been operating since April 2012. There are smaller plants missing from these US DOE databases, e.g., there is the GoBiGas demonstration plant (18MWth) in Sweden, but these sources provide a reasonable estimate of market size that varies between 1 and 10 GW cumulative capacity for biomass gasifiers.

Table C-8 summarizes the TRLs as estimated by application of the US DOE guidelines by these authors for various biomass gasifiers. The technologies with the highest TRLs and strongest industrial commitments for commercial offerings are the Linde Carbo-V process and the FICFB process. The other technologies with TRLs of 7-8 only have industry partners which does not suggest as strong or timely pathway to commercialization as Carbo-V and FICFB.

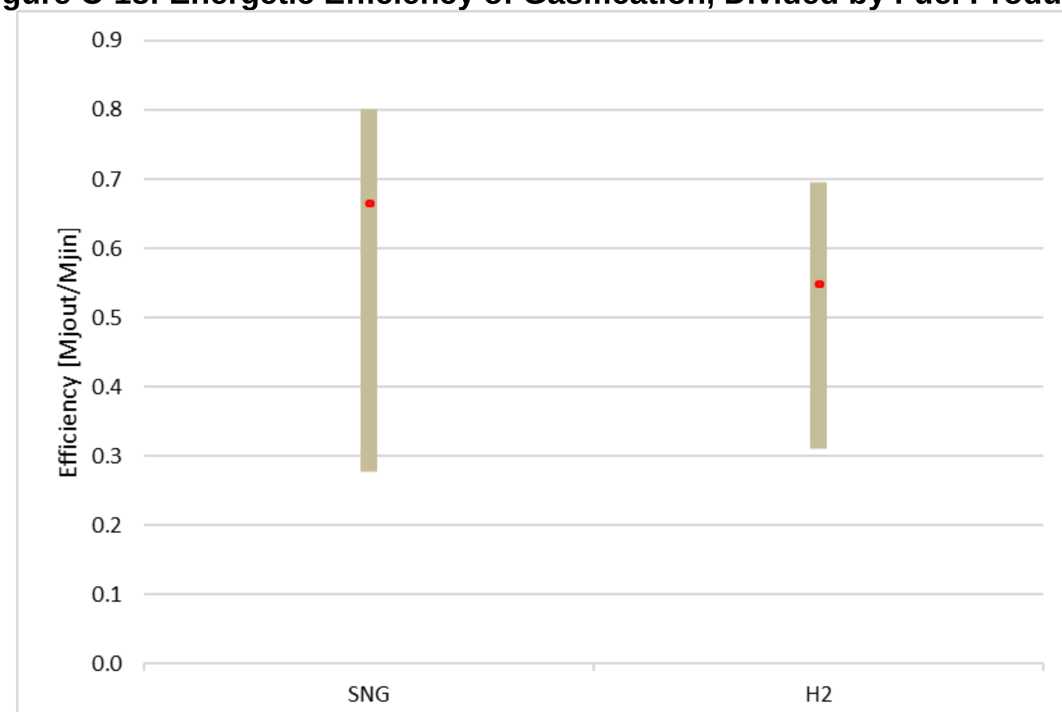
Table C-8: Technology Readiness Levels of Various Biomass Gasification Technologies

Name	TRL	Scale at Commercial	Additional Information
Viking - Danish Tech Univ	6	Unknown	Pilot scale with long term operation
Wang 2015	5	Unknown	Lab scale
FLETGAS - Univ of Sevilla	5	Unknown	Still developing pilot
LT-CFB - Dong Energy	7	Unknown	6 MWth demonstration at Asnaes plant
Carbo V	7-8	0.1-1 GWth	Linde acquired technology and actively advancing. Demonstration plant operated (40MWth)
Bioliq	7-8	1GWth	Led by Karlsruhe Inst. Technology but partnered with Air Liquide. Development of pyrolysis process underway but to be linked with commercial entrained flow gasifier (Lurgi)
Gussing /FICFB	7-8	10-100MWth	Long term operation of pilot scale plant with several commercial operating plants (10-50MWth). Offered by California company West Biofuels, LLC.
SilvaGas	7-8	Unknown	Demonstration plant operated but no company actively pursuing
MILENA	7-8	50-500MWth	Demonstration plants operated successfully. Partnered with Dahlman.

Source: Data from (Basu & Basu, 2013; Bui et al., 1994; Gómez-Barea et al., 2013; Heidenreich, Müller, & Foscolo, 2016; Heidenreich, Müller, Foscolo, et al., 2016; H. Yang & Chen, 2015)

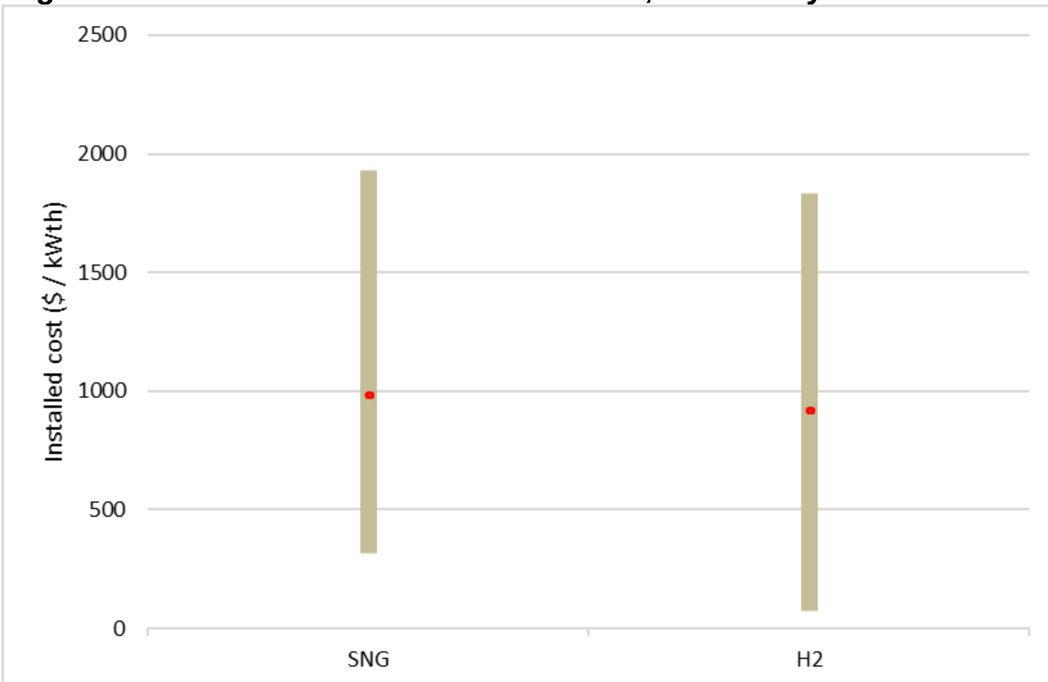
Shown below in Figure C-18 are the range of values and the average for energetic efficiency of gasification technology from the literature, specified by the fuel being produced. Sources for the H2 production data are the following: (Sentis et al., 2016)(P. Spath et al., 2005)(Larson, Jin, & Celik, 2005; Lau et al., 2002)(Corradetti & Desideri, 2007; Hamelinck & Faaij, 2002; Katofsky, 1993; Laser et al., 2009; N. Parker, Fan, & Ogden, 2010; Sarkar & Kumar, 2010; P. L. Spath, Mann, & Amos, 2003; Tock & Maréchal, 2012). Sources for the SNG production data are the following: (Alamia, Magnusson, Johnsson, & Thunman, 2016; Duret, Friedli, & Francois, n.d.; Fahlén & Ahlgren, 2009; Feng, Song, Shen, & Xiao, 2016; Galvagno et al., 2017; Gassner & Maréchal, 2009, 2012; Gu, Song, Xiao, Zhao, & Shen, 2013; Haarlemmer, Boissonnet, Peduzzi, & Setier, 2014; Herguido, Corella, & González-Saiz, 1992; Jenkins, Arthur, Miller, & Parsons, 1984; Johansson, 2013; H. Li, Larsson, Thorin, Dahlquist, & Yu, 2015; Molino & Braccio, 2015; Mozaffarian & R.W.R., 2003; Seemann, Schildhauer, & Biollaz, 2010; G. Song, Xiao, Yu, & Shen, 2016; Guohui Song, Feng, Xiao, & Shen, 2013; Sheng Wang, Bi, & Wang, 2015)(Arteaga-Pérez, Gómez-Cápiro, Karelovic, & Jiménez, 2016; Axelsson et al., 2012; Difs, Wetterlund, Trygg, & Söderström, 2010; Heyne, Thunman, & Harvey, 2012; Kopyscinski, Schildhauer, & Biollaz, 2010; S. Li, Jin, Gao, & Zhang, 2014; Rönsch et al., 2016; J. Song, Yang, Higano, & Wang, 2015; van der Meijden, Veringa, & Rabou, 2010; Vitasari, Jurascik, & Ptasinski, 2011; L. Zhu, Zhang, Fan, Jiang, & Li, 2016; Zwart & Boerrigter, 2005). Figure C-19 shows the same, but for installed cost of gasification. The cost data for all biomass conversion technology, including gasification, are from (Blumenstein, Siegmeier, & Möller, 2016a; Budzianowski & Budzianowska, 2015; Chen et al., 2017a; Fernández-González, Grindlay, Serrano-Bernardo, Rodríguez-Rojas, & Zamorano, 2017; Gebrezgabher, Meuwissen, Prins, & Oude Lansink, 2010; Karthikeyan & Visvanathan, 2013a; Legrand, 1993; H. Li, Tan, Ditaranto, Yan, & Yu, 2017; Rajendran, Kankanala, Martinsson, & Taherzadeh, 2014; Wilkinson, 2011).

Figure C-18: Energetic Efficiency of Gasification, Divided by Fuel Produced



Source: Data from (Alamia et al., 2016; Arteaga-Pérez et al., 2016; Axelsson et al., 2012; Corradetti & Desideri, 2007; Difs et al., 2010; Duret et al., n.d.; Fahlén & Ahlgren, 2009; Feng et al., 2016; Galvagno et al., 2017; Gassner & Maréchal, 2009, 2012; Gu et al., 2013; Haarlemmer et al., 2014; Hamelinck & Faaij, 2002; Herguido et al., 1992; Heyne et al., 2012; Jenkins et al., 1984; Johansson, 2013; Katofsky, 1993; Kopyscinski et al., 2010; Larson et al., 2005; Laser et al., 2009; Lau et al., 2002; H. Li et al., 2015; S. Li et al., 2014; Molino & Braccio, 2015; Mozaffarian & R.W.R., 2003; N. Parker et al., 2010; Rönsch et al., 2016; Sarkar & Kumar, 2010; Seemann et al., 2010; Sentis et al., 2016; G. Song et al., 2016; Guohui Song et al., 2013; J. Song et al., 2015; P. Spath et al., 2005; P. L. Spath et al., 2003; Tock & Maréchal, 2012; van der Meijden et al., 2010; Vitasari et al., 2011; Sheng Wang et al., 2015; L. Zhu et al., 2016; Zwart & Boerrigter, 2005)

Figure C-19: Installed Cost of Gasification, Divided by Fuel Produced



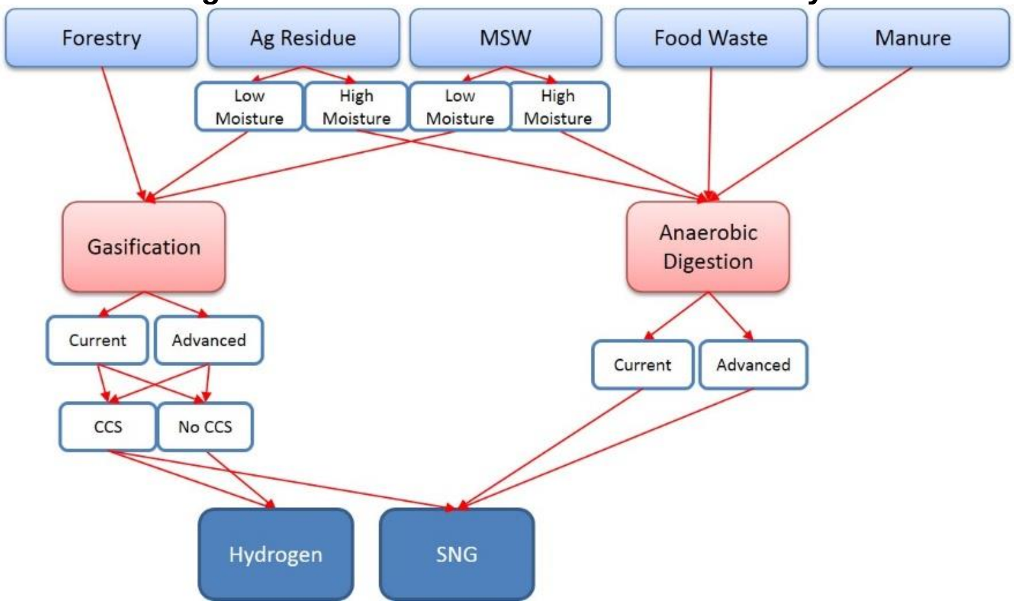
Source: Data from (Blumenstein et al., 2016a; Budzianowski & Budzianowska, 2015; Chen et al., 2017a; Fernández-González et al., 2017; Gebrezgabher, Meuwissen, Prins, & Oude Lansink, 2010; Karthikeyan & Visvanathan, 2013a; Legrand, 1993; H. Li et al., 2017; Rajendran et al., 2014; Wilkinson, 2011)

Anaerobic Digestion

In California, biomass is a potential resource for increasing the state's percentage of renewable energy and contributing to reaching state energy goals. from the Billion Ton Study which includes the current and projected amount of biomass available from different feedstocks. In current practice, biomass is often left to decompose naturally, such as in forestry applications, or in covered lagoons and later flaring the resulting gases from decomposition, such as for municipal solid wastes (MSW). The off-gases of the decomposing biomass include methane, which is the majority component in natural gas. Methane has about 25 times the global warming potential as carbon dioxide (IPCC, 2007), so it is imperative to decrease methane emissions to the atmosphere. Methane, instead of being released straight into the environment, can be used as an energy source via various conversion processes. Below, potential biomass conversion pathways are outlined to produce two useful end products, substitute natural gas (SNG)[17] and hydrogen, which would contribute to the state's exiting natural gas capacity or supply California's nascent hydrogen vehicle fueling infrastructure, respectively. This report focuses on the AD pathways.

17 Note that SNG is used in this appendix section as a broad term to include what is separated out in the main text as biomethane and electrolytically derived synthetic natural gas.

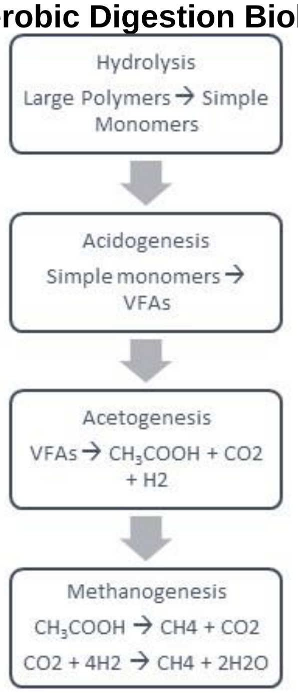
Figure C-20: Biomass Conversion Pathways



Source: UCI APEP

Anaerobic digestion is a series of biological processes through which microorganisms decompose biomass in the absence of oxygen (reactions shown below), with the operational inputs of heat and electricity. The end products are biogas and digestate. The biogas is typically around 60% methane in composition and can be combusted for heat and electricity or put into the natural gas system. The digestate is useful in agricultural applications, such as for fertilizers.

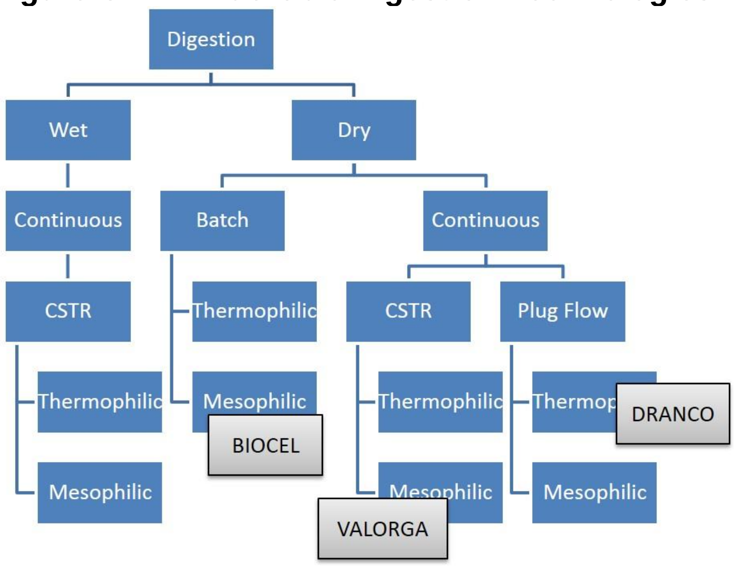
Figure C-21: Anaerobic Digestion Biological Processes



Source: UCI APEP

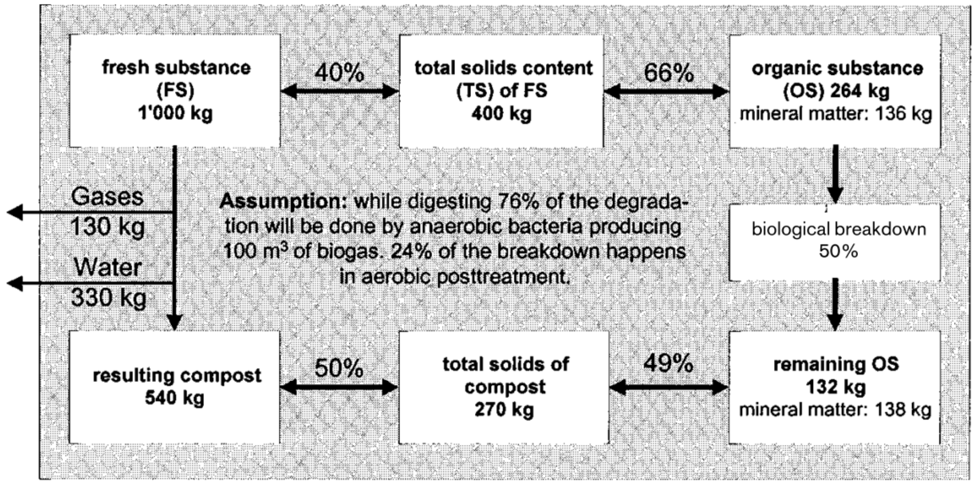
The type of technologies used in an anaerobic digestion plant depend on the type of biomass being processed and how the input will be processed. One of the main considerations is the moisture content of the input substrate. Moisture content is categorized into wet substrates and dry substrates, which are defined as approximately <10% total solids and 20-40% total solids, respectively (Karthikeyan & Visvanathan, 2013c). The next major level of categorization is between batch and continuous reactors, which describes the substrate loading strategy. A detailed breakdown of digester reactor technologies is in Figure C-22, along with where various commercial processes fall within the categorization. Figure C-23 shows the mass balance for an anaerobic digestion plant.

Figure C-22: Anaerobic Digestion Technologies



Source: (Mozaffarian, Ree, & Veringa, 2003)

Figure C-23: Anaerobic Digestion Mass Balance Diagram



Source: (Edelmann, Schleiss, & Joss, 2000)

Anaerobic digesters are a mature and commercialized technology and are currently being used at facilities like wastewater treatment plants and agriculture and livestock farms, which are utilizing the resulting biogas via combined heat and power (CHP) units to satisfy on-site heating and electrical demands. The increasing amount of biomass in California is coming from places such as the agriculture and livestock industries, the increasing organics diversion from landfills in accordance with AB 341, the increasing urban waste streams resulting from population growth, etc. This would enable an increased utilization of this technology.

Many useful papers on anaerobic digestion in the literature are review papers. They provide the characteristics and performance of AD systems as well as the biogas productivity of various input feedstocks. One comprehensive review paper was written by Karthikeyan and Visvanathan in 2013 for the journal *Reviews in Environmental Science and Biotechnology* (Karthikeyan & Visvanathan, 2013b). The paper discusses both wet and dry anaerobic digestion but mainly focuses on the latter. The paper categorizes wet AD as having input with <10% total solids content and dry AD as having input with >20% total solids content. The paper summarizes the characteristics of various dry AD projects from literature, including each's substrate, reactor type, and specific methane production, of which the values are included in the yield table below in Table C-9. The authors also summarize common commercial dry AD systems, like Dranco and Valorga, and the characteristics of various dry AD feedstocks, such as cattle manure, corn fiber, and municipal solid waste (MSW). Li 2011 (Cui, Shi, & Li, 2011) also describes Dranco and Valorga systems, which are used mainly in MSW, kitchen waste, and yard waste applications. Batch AD systems are also commercially available and are mainly used in agricultural applications due to lower cost and maintenance. A review paper by Chynoweth (Chynoweth, Owens, & Legrand, 2001) provides an overview of the anaerobic digestion process and compares the biomethane yield of biomass and waste feedstocks, in which the biodegradability of the feedstocks can reach up to 90%

(in the case of sorghum) instead of the 50% biodegradability usually assumed. Appels 2011 (Appels et al., 2011) is another review paper, and goes into detail on biomass and waste inputs and each's methane yield, of which sewage sludge is the highest at 0.59 m^3/kg organic dry solids. Parker, et al.'s 2017 review paper (N. Parker, Williams, Dominguez-Faus, & Scheitrum, 2017b) looks at the use of anaerobic digestion to produce renewable natural gas for California's transportation fuels market. In its goal to produce supply curves, the authors take into account feedstocks coming from food waste, green waste, and dairies.

Other papers focus more on the economics of AD plants, taking into account heat sales, electricity sales, and incentive programs. Blumenstein et al.'s 2016 paper published in *Biomass and Bioenergy* (Blumenstein, Siegmeier, & Möller, 2016b) focuses on comparing the techno-economic performance of anaerobic digestion using feedstocks from either organic farms or conventional agriculture, along with different mixtures of plant and manure feedstocks. For the purpose of this literature review, the conventional agriculture numbers were looked at. Data in this paper include a detailed categorization of plant costs, including investment, capital, operational, and consumption-related costs, and revenue drivers, such as electricity and heat sales. The auxiliary electricity assumed in this paper were between 2.6-3.4% of the biogas energetic input, depending on the system size. An exceptional aspect of this paper is that it considered variations in mixture proportions of cattle manure and plant silage and the effect of the varying mixtures on biogas output. In Gebrezgabher, et al.'s 2010 paper (Gebrezgabher, Meuwissen, Prins, & Lansink, 2010a), the authors explore, via a linear programming model, the economics of a biogas plant, based on a plant shared by 50 swine farmers. The substrate considered in the paper is a manure-majority mixture (82%) that is co-digested with plant matter, with each unique substrate type's methane yield values cited from other papers. The results are optimized for maximum profit with respect to electricity, digestate, and water profits or costs. For a 67,500 ton yearly substrate input, the plant's installed cost is 4,178,328 €, based on the paper's reported interest rates and payments.

Some form of carbon capture technology is needed to remove excess CO2 from the raw biogas in order for the biogas to be of sufficient quality to be added to the natural gas system. Typical upgrading media are chemical adsorption via amines (e.x. methyl diethanolamine (MDEA), monoethanolamine (MEA), dieethanolamine (DEA)), pressure swing adsorption (PSA), water scrubbing, and membrane separation (Leme & Seabra, 2017; Ullah Khan et al., 2017). These technologies typically produce methane with around 95% purity (Sun et al., 2015; L. Yang, Ge, Wan, Yu, & Li, 2014).

A summary of anaerobic feedstock characteristics is below, as found across literature. In the cases where assumed feedstock higher heating values were not explicitly state in the paper, values from a UC Davis' report were used (Williams, Jenkins, & Kaffka, 2015)

Table C-9: Summary of Feedstock Methane Yields From Literature

Feedstock	Dry Matter (% of fresh matter)	Organic dry matter content oDM (% of DM)	Gas yields (m^3 biogas ton^{-1} oDM)	High methane yield (m^3 methane ton^{-1} oDM)	Low Methane yield (m^3 methane ton^{-1} oDM)	Mean methane yield (m^3 methane ton^{-1} oDM)	Source(s)
Algae				340	90	215	(Karthikeyan & Visvanathan, 2013b)
Banana Waste				320	240	280	(Karthikeyan & Visvanathan, 2013b)
Corn Stover	22			360	223	290	(Karthikeyan & Visvanathan, 2013b; J. Zhu, Wan, & Li, 2010)
Flower Bulbs	10	80				500	(Gebrezgabher, Meuwissen, Prins, & Lansink, 2010b)
Food Wastes	15	80		500	300	400	(Chen et al., 2017b; Cho, SC, & HN, 1995; Gebrezgabher, Meuwissen, Prins, & Lansink, 2010a; Karthikeyan & Visvanathan, 2013c; Mancliclic, 2016)
Grass	32	90	590	319	318	318	(Blumenstein et al., 2016b)
Leaves				300	100	200	(Karthikeyan & Visvanathan, 2013c)
Maize	35	95	650	390	338	364	(Blumenstein et al., 2016b; Gebrezgabher, Meuwissen, Prins, & Lansink, 2010a)
Manure, cattle	25	85	410	250	150	200	(Blumenstein et al., 2016b; Kaffka et al.,

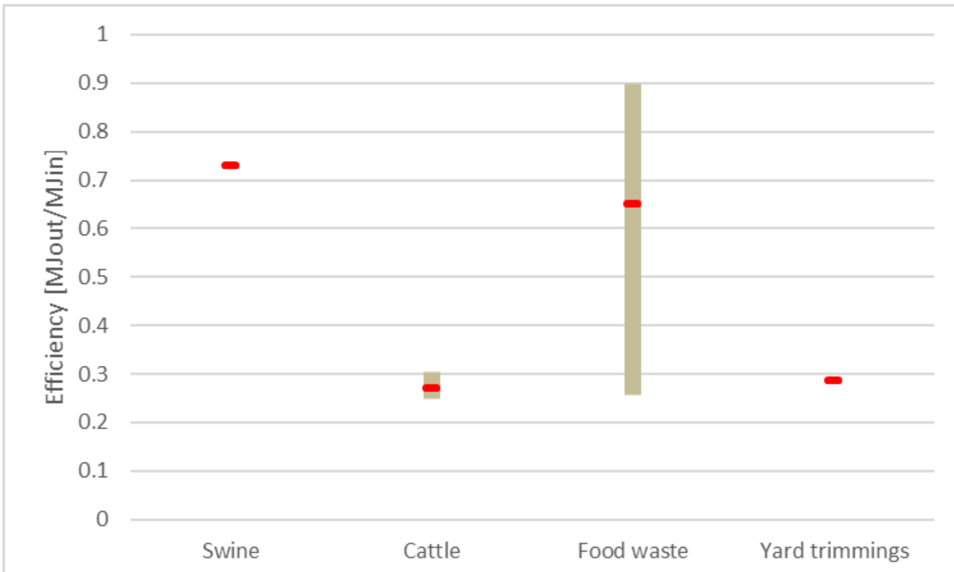
Feedstock	Dry Matter (% of fresh matter)	Organic dry matter content oDM (% of DM)	Gas yields (m^3 biogas ton^{-1} oDM)	High methane yield (m^3 methane ton^{-1} oDM)	Low Methane yield (m^3 methane ton^{-1} oDM)	Mean methane yield (m^3 methane ton^{-1} oDM)	Source(s)
							2016; Karthikeyan & Visvanathan, 2013c)
Manure, poultry	20	80				410	(Gebrezgabher, Meuwissen, Prins, & Lansink, 2010a)
Manure, swine	7	80		360	356	358	(Gebrezgabher, Meuwissen, Prins, & Lansink, 2010a; Karthikeyan & Visvanathan, 2013c)
OFMSW	20			300	115	225	(Bolzonella, P, Mata-Alvarez, & Cechhi, 2003; Dong, Zhenhong, & Yongming, 2010; Forster-Carneiro, Pérez, & Romero, 2008; Gallert & Winter, 1997; Karthikeyan & Visvanathan, 2013c; Montero, Garcia-Morales, Sales, & Solera, 2008)
OFMSW, MS	18					342	(Gallert & Winter, 1997; Karthikeyan & Visvanathan, 2013c)
OFMSW, SS						490	(Pavan, Battistoni, Mata-Alvarez, & Cecchi, 2000)
Paper, news						100	(Karthikeyan & Visvanathan, 2013c)

Feedstock	Dry Matter (% of fresh matter)	Organic dry matter content oDM (% of DM)	Gas yields (m^3 biogas ton^{-1} oDM)	High methane yield (m^3 methane ton^{-1} oDM)	Low Methane yield (m^3 methane ton^{-1} oDM)	Mean methane yield (m^3 methane ton^{-1} oDM)	Source(s)
Paper, office						370	(Karthikeyan & Visvanathan, 2013c)
Primary Wastewater Solids						590	(Karthikeyan & Visvanathan, 2013c)
Rice Straw						350	(Karthikeyan & Visvanathan, 2013c)
Rye Silage	35	95	620			330	(Blumenstein et al., 2016b)
Sewage Sludge	20					190	(Duan, Dong, Wu, & Dai, 2012; Karthikeyan & Visvanathan, 2013c)
Smooth Cordgrass	92			412	268	340	(Karthikeyan & Visvanathan, 2013c; Liang, Zheng, Hua, & Luo, 2011)
Sweet sorghum				320	290	305	(Karthikeyan & Visvanathan, 2013c)
Wheat Straw	22					150	(Cui et al., 2011; Karthikeyan & Visvanathan, 2013c)

Source: Data from sources cited in table.

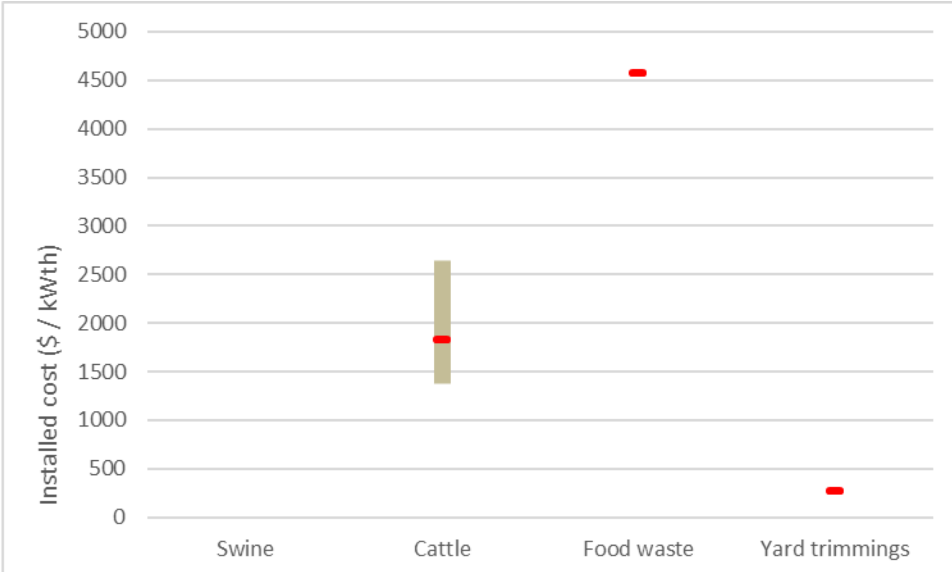
In Figure C-24 and Figure C-25 below, the performance and installation cost per kW of biogas produced, respectively, are graphed with respect to each feedstock category. The performance data are from the literature shown in Table C-9. As mentioned previously for gasification, the cost data for biomass conversion technology, including AD, are from (Blumenstein et al., 2016a; Budzianowski & Budzianowska, 2015; Chen et al., 2017a; Fernández-González et al., 2017; Gebrezgabher, Meuwissen, Prins, & Oude Lansink, 2010; Karthikeyan & Visvanathan, 2013a; Legrand, 1993; H. Li et al., 2017; Rajendran et al., 2014; Wilkinson, 2011).

Figure C-24: Energetic Efficiency of Anaerobic Digestion, Categorized by Feedstock



Source: Data from (Appels et al., 2011; Blumenstein et al., 2016b; Chynoweth et al., 2001; Cui et al., 2011; Gebrezgabher, Meuwissen, Prins, & Lansink, 2010a; Karthikeyan & Visvanathan, 2013b; Leme & Seabra, 2017; N. Parker et al., 2017b; Sun et al., 2015; Ullah Khan et al., 2017; Williams et al., 2015; L. Yang et al., 2014).

Figure C-25: Installed Cost of Anaerobic Digestion System, Categorized by Feedstock



Source: Data from (Blumenstein et al., 2016a; Budzianowski & Budzianowska, 2015; Chen et al., 2017a; Fernández-González et al., 2017; Gebrezgabher, Meuwissen, Prins, & Oude Lansink, 2010; Karthikeyan & Visvanathan, 2013a; Legrand, 1993; H. Li et al., 2017; Rajendran et al., 2014; Wilkinson, 2011)

Injection Requirements and Costs

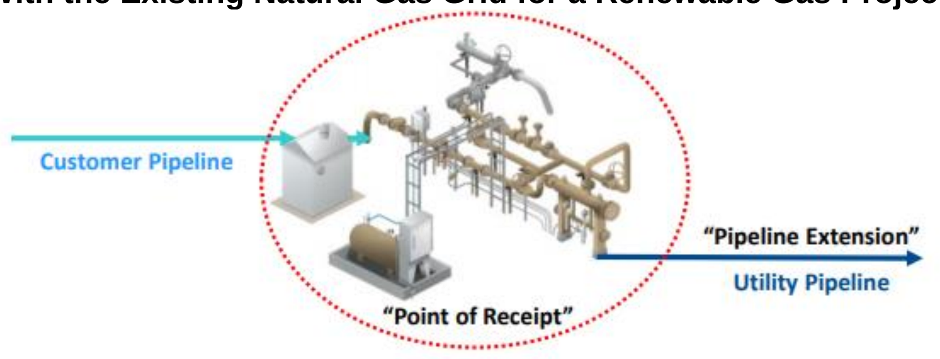
Costs associated with injecting renewable gas produced via P2G pathways, including hydrogen and SNG, into the existing natural gas infrastructure include (1) pre-injection costs prior to the injection of hydrogen or SNG in the utility pipeline; (2) the interconnection costs associated with connecting the P2G facility to the utility pipeline; and (3) the post-injection ongoing costs of maintaining and operating the renewable gas facility and pipeline access. Estimating these costs for P2G pathways is challenging as the capital and operational costs will vary depending on the composition (e.g., hydrogen vs. SNG) and source of renewable gas, the proximity of the P2G facility to the gas transmission system, and the various facilities that may be required to process and monitor the renewable gas. Thus, costs for injection will vary significantly with respect to individual P2G projects. Key considerations for the assessment of interconnection potential from (McLafferty, 2016) include:

- **Project Distance to Gas Main:** Location of a P2G facility relative to the existing utility gas lines has direct impact on costs and permitting difficulties
- **Pipeline Capacity to Receive Supplies:** Ensure sufficient volume in the pipeline at the point of injection to receive the volume of renewable fuel produced
- **Pressure headroom on Gas Main:** pipeline pressure at the site of potential injection point may already be operating at or near the maximum

- **Customer Demand on Pipeline:** Ensure customer gas demands (i.e., load) near points of injection are sufficient to accept continuous supply of injected renewable fuels.

Figure C-26 displays the two key components required for interconnection including the receipt point facility and the pipeline extension connecting the facility to the nearest appropriate gas utility main. Pre-injection costs are associated with the planning and construction of appropriate infrastructure such as the renewable gas receipt point facility, the cost of any gas upgrading or blending required prior to injection, and any costs associated with monitoring, testing, reporting and recordkeeping systems. Sempra Energy estimates point of receipt facility construction costs could range from $1.2 million to $1.9 million with monthly operating costs around $3,500 for delivery volumes ranging from 1 MMscfd to 10 MMscfd, depending on the facility size and output (Lucas, 2016). Development of the receipt point facility includes one-time testing and start-up costs for project development and construction, pipeline tap, measurement and gas quality control equipment, valves and piping, communications and data acquisition equipment, electrical ground, and road access. Sempra estimates the cost of one-time pre-injection testing as adopted by D.14-01-03 at $14,000 (Lucas, 2016).

Figure C-26: Two Key Components of Developing Interconnection Capabilities With the Existing Natural Gas Grid for a Renewable Gas Project



Source: (Lucas, 2016)

For biogas projects, facilities are potentially required to facilitate blending with pipeline gas to meet heating value standards. Blending facility costs are high, e.g., ranging between $330,000 and $660,000. However, it is unknown if P2G produced renewable fuels will require blending and the costs associated with blending systems may or may not be incurred. Currently, the regulatory standard for biogas injection established by the California Public Utilities Commission (CPUC) Decision (D.) 14-01-034 is a heating value of 990 British Thermal Units per standard cubic foot of gas (BTU/SCF) (CPUC, 2015). The injection of renewable methane assumes the inclusion of a methanation step, which could result in small amounts of CO and CO_2 being included in the total gas volume supplied to the pipeline. However, it is likely that the overall heating value will still meet the 990 BTU/SCF limit and not require blending. Conversely, given the low density of hydrogen if the limit is imposed it may require blending upstream of pipeline injection if strictly interpreted on a per volume basis, despite the higher heating value of hydrogen relative to methane.

Interconnection costs include any required studies, permitting and regulatory steps, land, design and construction, and equipment and materials necessary to connect the renewable gas receipt point facility to the utility pipeline, and to meter the gas flow. Construction of a pipeline from the point of receipt facility to the nearest compatible utility gas pipeline can represent a significant cost with the location of the extension the major determinant. Sempra estimates the approximate cost at $200 to $300 per foot for more involved work (e.g., ashphalt/concrete cutting, traffic control, night work required) and $50 to $100 per foot for less challenging areas (Lucas, 2016). Real world estimates for pipeline extensions associated with biomethane injection are shown in Table C-10. As can be seen, total cost can be significant and depend on the size and location of the project. It should be noted that the distance considered must be the nearest utility pipeline capable of accepting the volume of gas produced by a P2G facility, and not simply the nearest existing pipeline within the utility network.

Table C-10: Estimated Costs for Real-World Pipeline Extensions in California to Support Renewable Gas Injection Into the Existing Natural Gas Grid

Company/Project, Location	Pipeline Length	Estimated Total Cost
Colony Energy, Tulare County	100-foot	$1.5 million
CR&R, Riverside County	1 mile	$5 million
Real Energy	1 mile	$2.2 million
Organic Waste Systems	2.2 mile	$4.2 million

Source: Data from ("Renewable natural gas: monetary incentive program for biomethane projects," 2016)

Post-injection costs are the ongoing costs of equipment, odorants, and labor costs required for compliance with the routine operating costs associated with testing and monitoring and operations and maintenance costs associated with the receipt point facility. Estimations for post-injection costs for biomethane facilities have been estimated at a minimum of $7,610 per month by CRNG (CPUC, 2015). Similarly, Sempra estimates ongoing annual testing costs may range from $6,250 to $25,000 depending on the frequency of testing (CPUC, 2015). However, injection of hydrogen or SNG developed through P2G may not require the same testing levels as biomethane due to an absence of key constituents that require regular testing for biomethane. Therefore, post-injection costs for P2G renewable gas production may be lower than those estimated above.

A summary of potential costs for the injection of fuels produced via P2G pathways is provided in Table C-11. Available data for costs associated with injection of renewable gas into the utility gas network is primarily associated with biomethane projects. However, the injection of hydrogen or SNG from P2G pathways would likely be subjected to many of the same requirements as biomethane and are likely comparable to those reported here. For biomethane projects, total costs for interconnection have been estimated to range from $1.5 million to $3 million depending on the location of the renewable gas facility and the proximity to an appropriate gas utility pipeline (CPUC, 2015). A Sempra interconnection cost estimate provided for a ten million SCF per day interconnection with a one-mile feeder line totaled approximately $4.1 million ("Renewable natural gas: monetary incentive program for biomethane projects," 2016). Furthermore, if blending is required the costs may be significantly higher. Conversely, estimated interconnection costs outside of California have been reported at $75,000 to $500,000 (CPUC, 2015). Costs in California are significantly higher than for other states, due in part to the standards and requirements adopted in D.14-01-034. While the cost of interconnection is high as estimated here, future policy streamlining and incentives can allow for significant reductions. For example, the CPUC has instituted an incentive policy for biomethane projects in California to potentially subsidize 50% of the projects interconnection costs up to $3 million (CPUC, 2015). This conclusion is also supported by the significantly lower estimated interconnection costs for biomethane projects outside of California.

Table C-11: Summary of Potential Costs for Injection of P2G Fuels Into the Existing Natural Gas Grid

Phase	Process	Cost
Pre-Injection	Receipt Point Facility Construction	$1.2 to $1.9 million (one-time)
Pre-Injection	Pre-Injection Testing	$14,000 (one-time)
Interconnection	Pipeline Construction	$50-$250 per foot
Post-Injection	Testing, monitoring, etc.	$520 to $2,083 per month
Post-Injection	O & M for Point of Receipt Facility	$3,500 to $7,610 per month
Total Costs	Total cost for interconnection	$1.5 to $4.1 million (CA) $75,000 to $500,000 (US)

Source: Data from (CPUC, 2015), ("Renewable natural gas: monetary incentive program for biomethane projects," 2016)

Pipeline H2 Concentration Limits and Leakage

Blending hydrogen into the natural gas pipeline has a practical limit of about 15% of the pipeline by volume, or 5% by energy, before there are any serious concerns of safety or integrity (M. W. Melaina, Antonia, & Penev, 2013; US DRIVE, 2013). Blending hydrogen into the natural gas grid would also require interconnections to be built to connect to the grid itself, increasing cost significantly (CPUC, 2015).

Another concern regarding hydrogen in the natural gas infrastructure is leakage. Hydrogen has different density, diffusivity, viscosity, and molecular weight than natural gas, so many hypothesize that wide-scale addition of hydrogen to the natural gas infrastructure will increase leakage rates. Prior work show hydrogen leaking at 1.29 to 3 times the rate of natural gas, depending on flow regime (Hormaza Mejia & Brouwer, 2018; M. R. Swain & Swain, 1992; Michael R. Swain, Shriber, & Swain, 1998). However, some work suggests gas leakage in the context of low-pressure, such as natural gas infrastructure, happens at the same rate for both hydrogen and natural gas (Hormaza Mejia & Brouwer, 2018).

Technology Levelized Cost Projections

Projecting Technological Progress

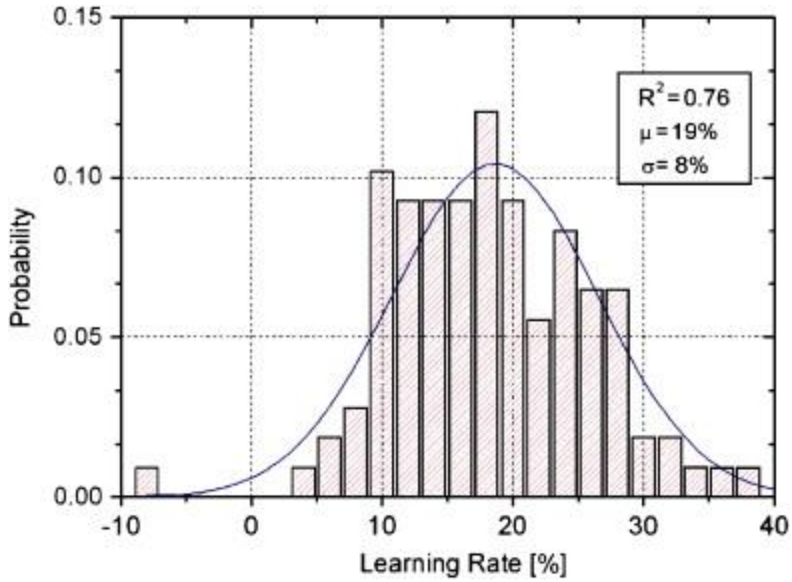
Many methods have been proposed for estimating technological progress and the effects on cost. These include Moore's law (Moore, 1965), Wright's law (Wright, 1936), and various other variants (Nagy, Farmer, Bui, & Trancik, 2012). Nagy et al. tested these different methods for estimating technological progress based on a database of 62 different technologies and showed that Wright's law and Moore's law perform essentially the same with a slightly better performance by Wright's law.

Wright's law projects future capital costs based on the cumulative capacity produced (rather than using time as in the case of Moore's law). The equation for Wright's law can be written as

$$C(p_t) = C(p_i)\left(\frac{p_t}{p_i}\right)^{-b}$$

(Ferioli, Schoots, & van der Zwaan, 2009) where p_i is the initial production volume, p_t is the production volume at time t, $C(p_t)$ is the cost at production volume at time t, $C(p_i)$ is the cost at the initial production volume, and b is an exponential learning parameter related to the learning rate (LR) by the equation LR = 1 - 2^{-b}. Figure C-27 shows the probability distribution of learning rates for various industrial technologies collected from 108 studies (Ferioli et al., 2009).

Figure C-27: Probability Distribution of 108 Studies That Report Learning Rates in 22 Industrial Sectors



Source: (Ferioli et al., 2009)

Power-to-Gas

The Monte Carlo simulation approach was used at first, but it was clear that this approach did not account for the probability of the various scenarios (i.e. The Monte Carlo approach applies equal probability to all possible scenarios, and we know that this is not true, particularly with some scenarios at the borders being highly unlikely). The learning rate methodology was then adopted, average values from strong literature sources and appropriate learning rates for the various pieces of technology.

Power-to-Gas Scenarios for Use in PATHWAYS

The span from the above work results in a wide range of potential values for installed capacities and costs, with some scenarios at the borders being highly unlikely. Therefore, it is prudent to use an intuition of the learning rate method when analyzing the above results.

Looking back at the literature values for electrolyzer efficiency, there is clearly a wide range of values in this set, so some work must be done to simplify the data into more usable values. To distill efficiency information from the literature into values to use for this analysis, two efficiency scenarios are introduced. The first is the conservative scenario, which uses efficiency numbers on the lower end of the spectrum of the literature data. The second is the optimistic scenario, which uses efficiency numbers on the higher end of the literature data.

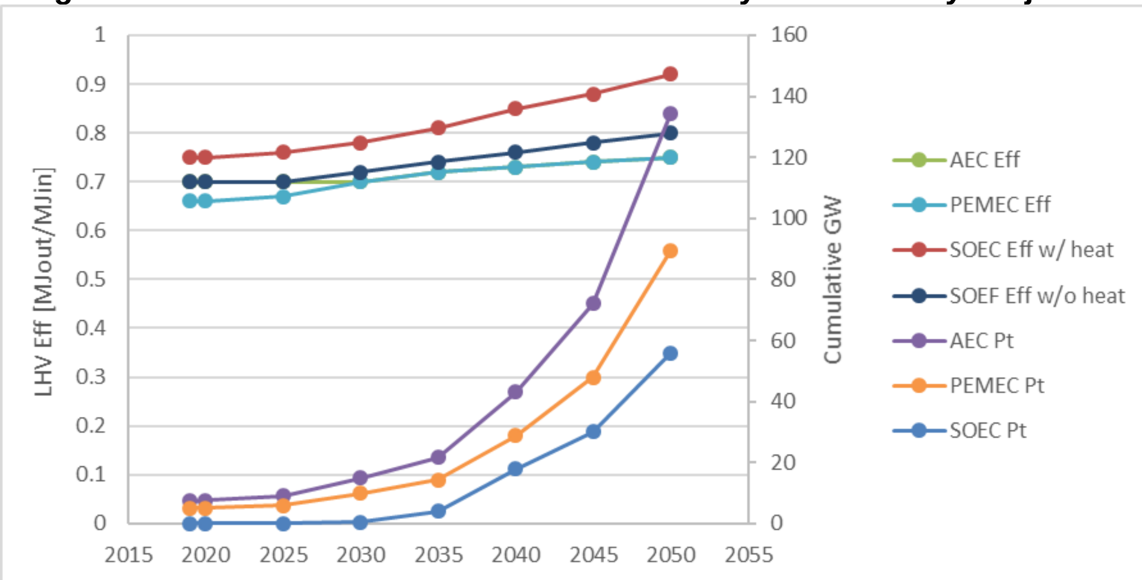
In addition to the initial values used for efficiency, as well as some long-term efficiency estimates from the literature, intuition and an understanding of general technology learning assisted in creating curves for the evolution of electrolyzer efficiency. One detail that stands out for the efficiency evolution is for SOECs. SOECs are unique among the electrolyzer technologies selected in that they are high temperature and get more efficient as their temperature increases. This means that they are able to use the waste heat of methanation, which is an exothermic reaction, to increase their efficiency instead of any other potential use of heat. Therefore, two SOEC scenarios are considered: (1) lower efficiency SOECs without methanation where the end product is hydrogen, and (2) higher efficiency SOECs with methanation where the end product is methane.

Plots for the installed capacities and efficiencies of the three electrolyzer technologies for the conservative scenario and the optimistic scenario are found below in Figure C-28 and Figure C-29, respectively.

Electrolyzer capacities were calculated using a combination of currently installed capacities for AECs and PEMECs and the total consumption of natural gas. Natural gas was used as a proxy because it is used today like P2G fuel (either hydrogen or substitute natural gas) will be used in the future. Additionally, P2G can make use of the natural gas infrastructure, so looking at the consumption and capacities of natural gas can easily translate to capacities for P2G. And in order to make P2G fuels, electrolyzers are required. Therefore, the electrolyzer capacities in the future can be equated to the natural gas consumption of today.

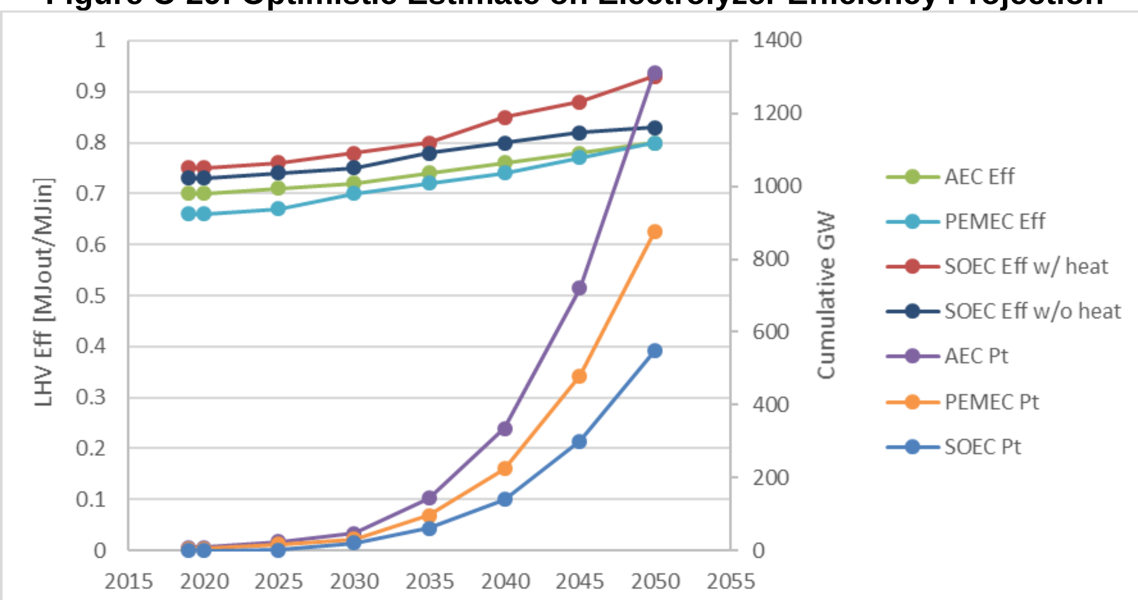
Growth scenarios for electrolyzer technologies are bounded by current capacity and market size. Current capacity for electrolyzers is sourced from Schoots et al. (Schoots, Ferioli, Kramer, & van der Zwaan, 2008), with a split of 60% AEC technology and 40% PEMEC technology, based on the fact that AEC technology is more mature and deployed than PEMEC technology. Future projections for electrolyzer production scale are by IEA and DOE projections for hydrogen usage and then back-calculating the required installed capacity of electrolyzers (IEA, 2012; Pivovar, 2016). Growth for electrolytic SNG technologies is bounded by natural gas utilization in the US and worldwide, which are 1 TW and 4 TW, respectively. This is due to the market size cap of SNG being the amount of natural gas used, and this is a reasonable limit to the amount of SNG produced by 2050. These natural gas usage data are sourced from the US Energy Information Administration (EIA) (US Energy Information Administration, 2017). The 60/40 split is assumed to stay constant for AECs and PEMECs, but as SOEC technology improves, SOECs are assumed to have 20% of the market share. The remaining 80% is split 60% for AECs and 40% PEMECs.

Figure C-28: Conservative Estimate on Electrolyzer Efficiency Projection



Source: UCI APEP

Figure C-29: Optimistic Estimate on Electrolyzer Efficiency Projection



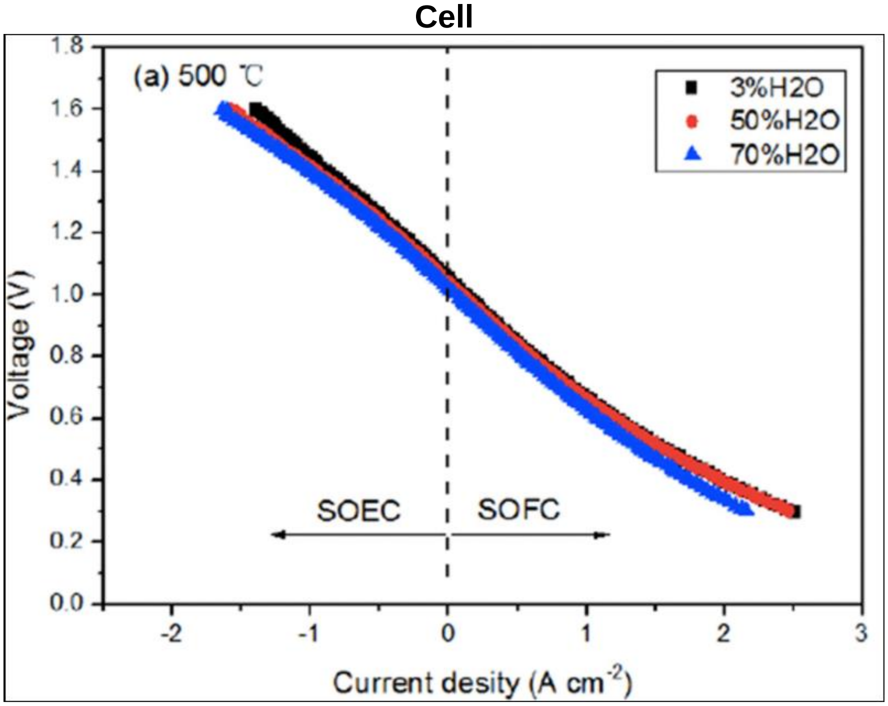
Source: UCI APEP

Similar to the efficiencies detailed for the electrolyzers, a conservative and an optimistic scenario are conceived in this work for the cost projections. The conservative scenario is the median or mean of the previous results of the sampling methodology. This conservative growth case assumes 14% learning rate throughout the years considered.

The optimistic growth case assumes four times the growth in 2035 and 2050 (e.g., US accounts for 25% of world's energy consumption so this case takes US DOE assumptions and assumes they occur across the world). With this assumption, the following costs are estimated for 2035 and 2050 while still randomly sampling from the probability distributions for the other parameters. Optimistic growth case starts with 25% learning rate until 2030, 15% learning rate until 2035, and then 10% learning rate until 2050.

Note that the cost for SOECs in the optimistic projection using the above learning rate methodology leads to very low future cost. This is due to the learning rate methodology used and the projected cumulative SOEC production. Even early on, the SOEC costs decrease markedly due to early projected market size growth rates. To prevent SOEC costs from becoming unreasonably low, literature was consulted to determine the cost of an electrolyzer from a ground-up methodology, which would give end-game costs of the technology. Work from (Scataglini et al., 2015) determined the above for a solid oxide fuel cell, so the final cost per power capacity was divided by two to account for the same stack being able to operate at twice the power in electrolyzer mode compared to fuel cell mode. This is due to the fact that when a solid oxide cell is operated at a given current density, its voltage is approximately twice as high in electrolysis mode than in fuel cell mode, leading to twice the power for the same stack in electrolysis mode compared to fuel cell mode (note Figure C-30) (Shaorong Wang, Hao, & Zhan, 2017). This methodology leads to a price floor for SOECs of $191/kW.

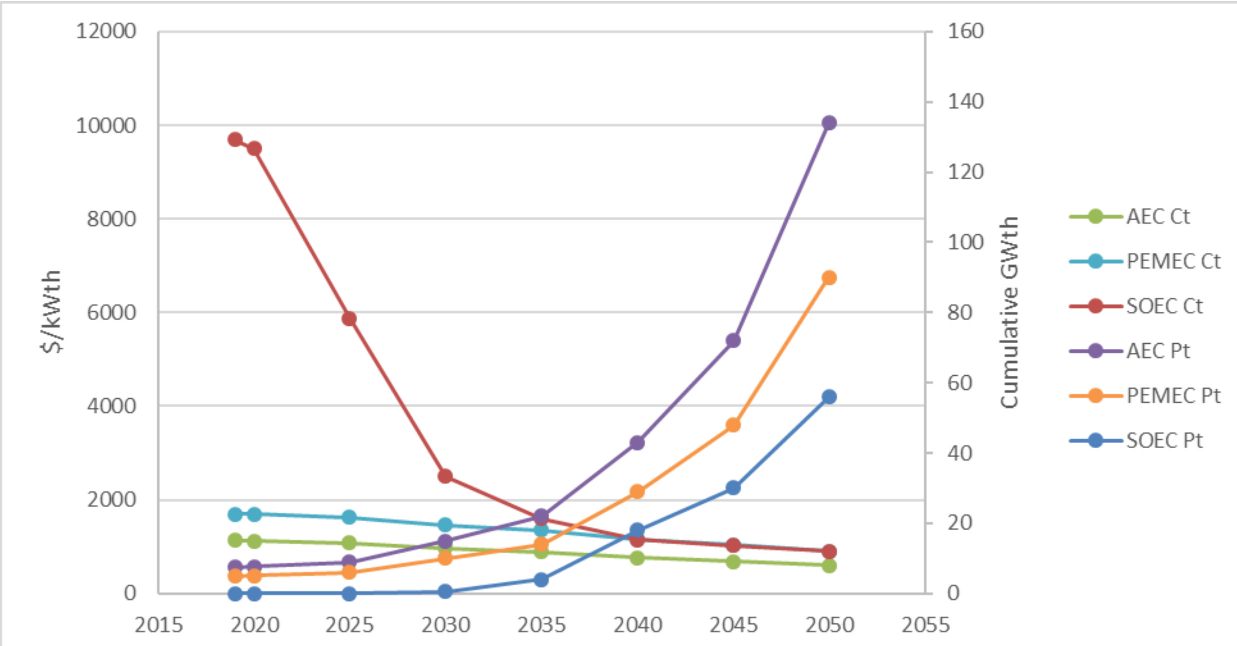
Figure C-30: Voltage and Current Density for a Solid Oxide Electrolyzer and Fuel Cell



Source: (Shaorong Wang et al., 2017)

The conservative and optimistic projections are shown below. Note that while some recent bids on large-scale P2G projects, particularly in Europe, have lower unit costs than the starting costs from this work, the optimistic scenarios serve as a lower bounds that is appropriately optimistic with low electrolyzer costs, particularly with SOECs.

Figure C-31: Conservative Projection of Uninstalled Cost and Electrolyzer Market Size

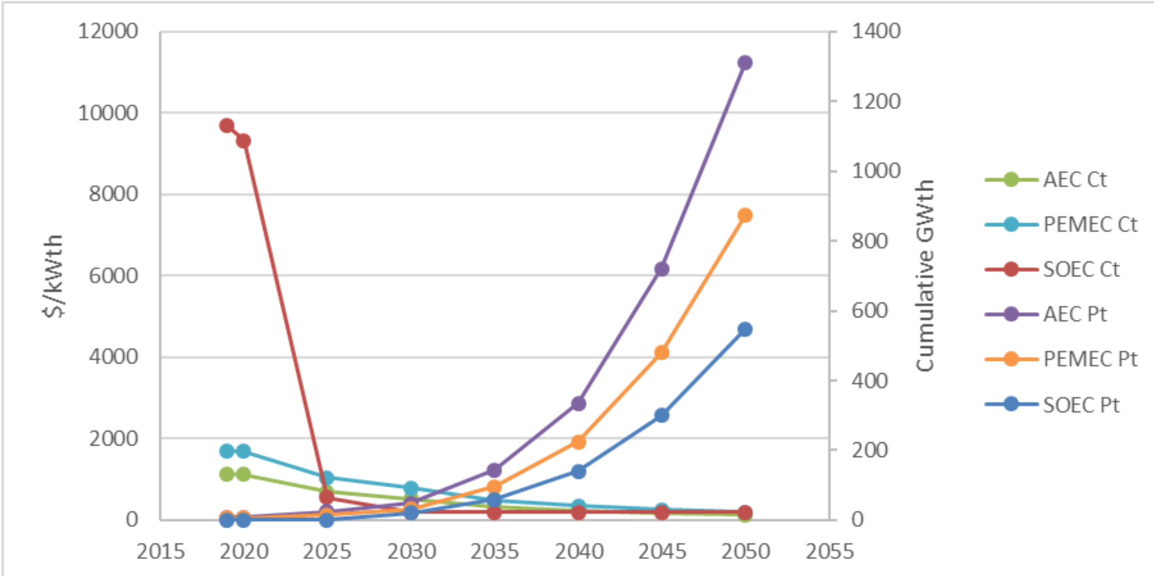


Source: UCI APEP

Table C-12: Conservative Projection of Uninstalled Cost And Electrolyzer Market Size

	AEC PT [GW]	AEC CT [$/KW]	AEC LR [%]	AEC CAGR [%]	PEMEC PT [GW]	PEMEC CT [$/KW]	PEMEC LR [%]	PEMEC CAGR [%]	SOEC PT [GW]	SOEC CT [$/KW]	SOEC LR [%]	SOEC CAGR [%]
2019	7.5	1130			5	1700			0.001	9700		
2020	7.6	1127	14%	1%	5.1	1693	14%	2%	0.0011	9501	14%	10%
2025	9	1086	14%	3%	6	1634	14%	3%	0.01	5877	14%	55%
2030	15	972	14%	11%	10	1462	14%	11%	0.5	2509	14%	119%
2035	22	894	14%	8%	14	1359	14%	7%	4	1596	14%	52%
2040	43	773	14%	14%	29	1160	14%	16%	18	1150	14%	35%
2045	72	691	14%	11%	48	1039	14%	11%	30	1029	14%	11%
2050	134	603	14%	13%	90	906	14%	13%	56	899	14%	13%

Figure C-32: Optimistic Projection of Uninstalled Cost and Electrolyzer Market Size



Source: UCI APEP

Table C-13: Optimistic Projection of Uninstalled Cost and Electrolyzer Market Size

	AEC PT [GW]	AEC CT [$/KW]	AEC LR [%]	AEC CAGR [%]	PEMEC PT [GW]	PEMEC CT [$/KW]	PEMEC LR [%]	PEMEC CAGR [%]	SOEC PT [GW]	SOEC CT [$/KW]	SOEC LR [%]	SOEC CAGR [%]
2019	7.5	1130			5	1700			0.001	9700		
2020	7.6	1124	25%	1%	5.1	1686	25%	2%	0.0011	9324	25%	10%
2025	24	697	25%	26%	16	1049	25%	26%	1	552	25%	291%
2030	47.5	525	25%	15%	31.68	790	25%	15%	19.8	191	25%	82%
2035	144	331	15%	25%	96	499	15%	25%	60	191	15%	25%
2040	336	233	10%	18%	223.68	351	10%	18%	139.8	191	10%	18%
2045	720	170	10%	16%	480	256	10%	16%	300	191	10%	16%
2050	1313	132	10%	13%	875.52	199	10%	13%	547.2	191	10%	13%

Comparing the above projections to values from (Schmidt, Gambhir, et al., 2017a), the cost for AECs, PEMECs, and SOECs align well for 2020, with the conservative scenario yielding a value at the upper end of the ranges provided and the optimistic scenario yielding a value at the lower end of the ranges. For 2030, similar is true except for the optimistic SOEC scenario. In that scenario, the present work predicts a value that is slightly below the low range of values from (Schmidt, Gambhir, et al., 2017a). Overall agreement between costs is encouraging here.

Methanation Unit and Supporting Equipment Cost Projections

Methanation cost is determined using the same learning rate methodology as for the electrolyzers. Below, the installed methanator capacity is determined by the capacity required for methane production corresponding to the installed electrolyzer capacity. Capacities are given as GW of methane output.

Table C-14: Projection of Methanator Cost and Installed Capacity

	PT [GW] (Conservative)	CT [$/KW] (Conservative)	PT [GW] (Optimistic)	CT [$/KW] (Optimistic)
2019	7.48	340.00	7.48	340.00
2020	7.60	339.18	7.60	338.83
2025	8.99	330.68	24.55	262.56
2030	15.27	305.08	59.27	216.74
2035	23.95	284.90	179.61	170.28
2040	53.88	251.86	418.48	141.65
2045	89.803	233.05	898.03	119.97
2050	167.63	211.95	1638.00	105.26

Carbon Capture Cost for Methanation Projections

For carbon capture technologies, the average electricity input required for the three carbon capture technologies is used to get a fleet-wide installed capacity. Below, the installed carbon capture capacity is determined by the capacity required for methane production corresponding to the installed electrolyzer capacity. Capacities are given as GW of electricity input. Carbon capture cost is determined using the same learning rate methodology as for the electrolyzers, with a learning rate of 10% for the conservative scenario and 14% for the optimistic scenario. Two different costs are used at the initial year of 2019. For the conservative scenario, a high cost value from the literature is used. For the optimistic scenario, an average cost value from the literature is used.

Table C-15: Conservative Projection of Carbon Capture Cost and Installed Capacity

	E-CEM PT [GW]	E-CEM CT [$/TONCO2/D]	PCC PT [GW]	PCC CT [$/TONCO2/D]	DAC PT [GW]	DAC CT [$/TONCO2/D]
2019	0.2203	1.82E+06	0.2203	6.36E+04	0.2203	4.56E+05
2020	0.2238	1.82E+06	0.2238	6.35E+04	0.2238	4.55E+05
2025	0.2645	1.77E+06	0.2645	6.19E+04	0.2645	4.44E+05
2030	0.4493	1.63E+06	0.4493	5.71E+04	0.4493	4.09E+05
2035	0.7048	1.53E+06	0.7048	5.33E+04	0.7048	3.82E+05
2040	1.5859	1.35E+06	1.5859	4.71E+04	1.5859	3.38E+05
2045	2.6432	1.25E+06	2.6432	4.36E+04	2.6432	3.13E+05
2050	4.9339	1.13E+06	4.9339	3.97E+04	4.9339	2.84E+05

Source: UCI APEP

Table C-16: Optimistic Projection of Carbon Capture Cost and Installed Capacity

	E-CEM PT [GW]	E-CEM CT [$/TONCO2/D]	PCC PT [GW]	PCC CT [$/TONCO2/D]	DAC PT [GW]	DAC CT [$/TONCO2/D]
2019	0.2203	1.82E+06	0.2203	4.37E+04	0.2203	3.16E+05
2020	0.2238	1.81E+06	0.2238	4.36E+04	0.2238	3.15E+05
2025	0.7225	1.41E+06	0.7225	3.38E+04	0.7225	2.44E+05
2030	1.7445	1.16E+06	1.7445	2.79E+04	1.7445	2.01E+05
2035	5.2864	9.12E+05	5.2864	2.19E+04	5.2864	1.58E+05
2040	12.3173	7.58E+05	12.3173	1.82E+04	12.3173	1.32E+05
2045	26.4319	6.42E+05	26.4319	1.54E+04	26.4319	1.11E+05
2050	48.2117	5.64E+05	48.2117	1.35E+04	48.2117	9.77E+04

Source: UCI APEP

Co-locating P2G Plant with Biorefinery

Co-locating a P2G plant with a biorefinery producing biofuels can be a particularly attractive option both economically and environmentally. Economically, this concept would use PCC technology, which is the lowest cost carbon capture technology as seen above. Environmentally, this concept would use biomass feedstocks to produce either a gaseous or liquid fuel in a manner such as AD or pyrolysis, in addition to carbon dioxide that can be added to hydrogen to produce SNG. This would maximize the fuel potential and therefore energy extraction of carbon that is stored in biomass.

While this co-location is attractive for the reasons stated above, it is important to note that there are practical limitations that may hinder widespread adoption. A P2G plant must be fed by off-grid solar or wind to economically make fuel in a carbon-free manner. Additionally, electrolysis requires water input, so this P2G plant must also be at or near a large source of water for economic and logistic reasons. Lastly, this P2G plant must also be located adjacent to a biorefinery to get the carbon dioxide from that plant. This biorefinery would be best located near a large source of biomass to improve efficiency, economics, and logistics of the biorefinery. One can now see the many factors that must be aligned for a P2G plant co-located with a biorefinery to come to fruition. Therefore, these combined plants should be considered an optimistic option that should be pursued when possible, but should not be assumed to be widely existent in the future.

Additional Cost Parameters Used in Analysis

Steam turbine

Steam turbine installed capacity is determined as the power output of the turbines that would be required by the heat output of the methanator for the given scenario's power input. Costs are again determined using the learning rate methodology, with a learning rate of 10% for the conservative scenario and 14% for the optimistic scenario.

Here, it is important to determine the size of steam turbine that would be expected to be at a P2G plant. This is because the cost and efficiency of steam turbines vary based on scale. Estimating P2G plants to be approximately 50 MW of electricity input (Kent, 2018) and using the heat rejected from the methanator, we arrive at a steam turbine on the order of 3 MW, which is a medium-sized turbine. This sets the unit cost of the steam turbines, which can be used along with the installed capacity to determine the overall cost of steam turbines in a given scenario. Results are shown below.

Table C-17: Projection of Steam Turbine Cost and Installed Capacity

	Steam Turbine, conservative PT [GW]	Steam Turbine, conservative CT [$/KW]	Steam Turbine, optimistic PT [GW]	Steam Turbine, optimistic CT [$/KW]
2019	5.627	682.00	5.627	682.00
2020	5.717	680.36	5.717	679.65
2025	6.757	663.30	18.456	526.67
2030	11.478	611.96	44.563	434.75
2035	18.005	571.49	135.041	341.56
2040	40.512	505.21	314.645	284.14
2045	67.520	467.47	675.203	240.65
2050	126.038	425.16	1231.571	211.15

Source: UCI APEP

Boiler

Boiler installed capacity is determined as the power output of the turbines that would be required by the heat output of the methanator for the given scenario's power input. Costs are again determined using the learning rate methodology, with a learning rate of 10% for the conservative scenario and 14% for the optimistic scenario. Results are shown in below.

Table C-18: Projection of Boiler Cost and Installed Capacity

	Boiler, conservative Pt [GW]	Boiler, conservative Ct [$/kW]	Boiler, optimistic Pt [GW]	Boiler, optimistic Ct [$/kW]
2019	1.400	400.00	1.400	400.00
2020	1.422	399.04	1.422	398.62
2025	1.681	389.03	4.591	308.90
2030	2.855	358.92	11.085	254.98
2035	4.479	335.18	33.592	200.33
2040	10.078	296.31	78.270	166.65
2045	16.796	274.17	167.961	141.14
2050	31.353	249.36	306.361	123.84

Source: UCI APEP

Blending

Electrolyzer installed capacity is used as a proxy for hydrogen blending equipment installed capacity. This is because the more electrolysis there is, the greater the need for blending hydrogen into the natural gas grid and therefore the more blending equipment needed. Costs are again determined using the learning rate methodology, with a learning rate of 10% for the conservative scenario and 14% for the optimistic scenario. Two different costs are used at the initial year of 2019. For the conservative scenario, a high cost value from the literature is used. For the optimistic scenario, an average cost value from the literature is used. Results are shown below.

Table C-19: Projection of Blending Cost and Installed Capacity

	Blending, conservative Pt [GW]	Blending, conservati Ct [$/kW]	Blending, optimistic Pt [GW]	Blending, optimistic Ct [$/kW]
2019	12.5	6.60E+05	12.5	3.30E+05
2020	12.7	6.58E+05	12.7	3.29E+05
2025	15.0	6.42E+05	41.0	2.55E+05
2030	25.5	5.92E+05	99.0	2.10E+05
2035	40.0	5.53E+05	300.0	1.65E+05
2040	90.0	4.89E+05	699.0	1.37E+05
2045	150.0	4.52E+05	1500.0	1.16E+05
2050	280.0	4.11E+05	2736.0	1.02E+05

Source: UCI APEP

Interconnection

Electrolyzer installed capacity is used as a proxy for interconnection equipment installed capacity. This is because the more electrolysis there is, the more P2G plants there will be and therefore the more interconnect equipment will be needed to get the hydrogen or methane into the natural gas grid. Costs are again determined using the learning rate methodology, with a learning rate of 10% for the conservative scenario and 14% for the optimistic scenario. Two different costs are used at the initial year of 2019. For the conservative scenario, a high cost value from the literature is used. For the optimistic scenario, an average cost value from the literature is used. Results are shown in below.

Table C-20: Projection of Interconnection Cost and Installed Capacity

	Interconnection, conservative Pt [GW]	Interconnection, conservative Ct [$/kW]	Interconnection, optimistic Pt [GW]	Interconnection, optimistic Ct [$/kW]
2019	12.5	4.10E+06	12.5	5.00E+05
2020	12.7	4.09E+06	12.7	4.98E+05
2025	15.0	3.99E+06	41.0	3.86E+05
2030	25.5	3.68E+06	99.0	3.19E+05
2035	40.0	3.44E+06	300.0	2.50E+05
2040	90.0	3.04E+06	699.0	2.08E+05
2045	150.0	2.81E+06	1500.0	1.76E+05
2050	280.0	2.56E+06	2736.0	1.55E+05

Source: UCI APEP

Miscellaneous

The discount rate used is 0.05, and the lifetime for the P2G plant is set as 20 years. A capital recovery factor (CRF) of 0.12 is used. This recovery factor represents a low-risk investment (U.S. Department of Energy, 2013), with the assumption that the parties creating the P2G plants will be large, established entities such as utilities. Fixed operations and maintenance (FOM) is estimated as $200/kW-yr for E-CEM scenarios, $10/kW-yr for PCC scenarios, and $8/kW-yr for DAC scenarios, as literature was scarce and this was the best estimate we could attain (Simon, Kaahaaina, Friedmann, & Aines, 2011; US Department of Energy, n.d.; Willauer et al., 2010).

Variable operations and maintenance (VOM) is estimated as $10/MWh for all scenarios, as again literature values are scarce (Michigan, 2003; U.S. Department of Energy, 2015, 2016; US Department of Energy, n.d.).

Levelized cost inputs to PATHWAYS

With all of the major costs associated with the various P2G pathways determined, it is now possible to calculate the cost for each of the P2G pathways. Nine such pathways are considered herein, and they are listed below.

Table C-21: P2G Pathways Analyzed for Cost

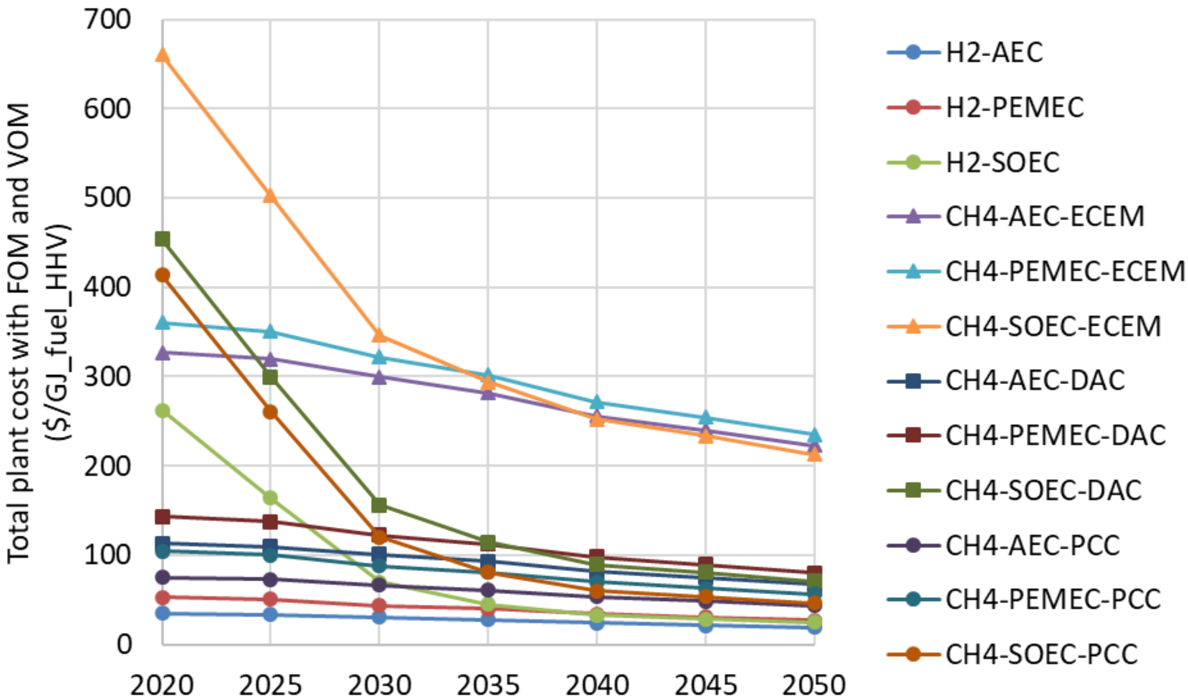
Pathway #	Product	Electrolyzer	CO2 Source	Heat Sink
1	Hydrogen	AEC	-	-
2	Hydrogen	PEMEC	-	-
3	Hydrogen	SOEC	-	-
4	Methane	AEC	E-CEM	Boiler
5	Methane	PEMEC	E-CEM	Boiler
6	Methane	SOEC	E-CEM	SOEC
7	Methane	AEC	DAC	Steam turbine
8	Methane	PEMEC	DAC	Steam turbine
9	Methane	SOEC	DAC	SOEC
10	Methane	AEC	PCC	Boiler
11	Methane	PEMEC	PCC	Boiler
12	Methane	SOEC	PCC	SOEC

Source: UCI APEP

Note that the heat sink technology, where applicable, is chosen as the one that leads to the lowest overall cost of the product. It turns out that the boiler is the lowest cost heat sink technology for the pathways considered that use E-CEM as the CO2 source technology. Additionally, the steam turbine is the lowest cost heat sink technology for the pathways considered that use DAC as the CO2 source technology. For SOEC scenarios, the heat sink is chosen to be the SOEC itself. Additional heat for the SOEC leads to a slight increase in efficiency of the electrolyzer.

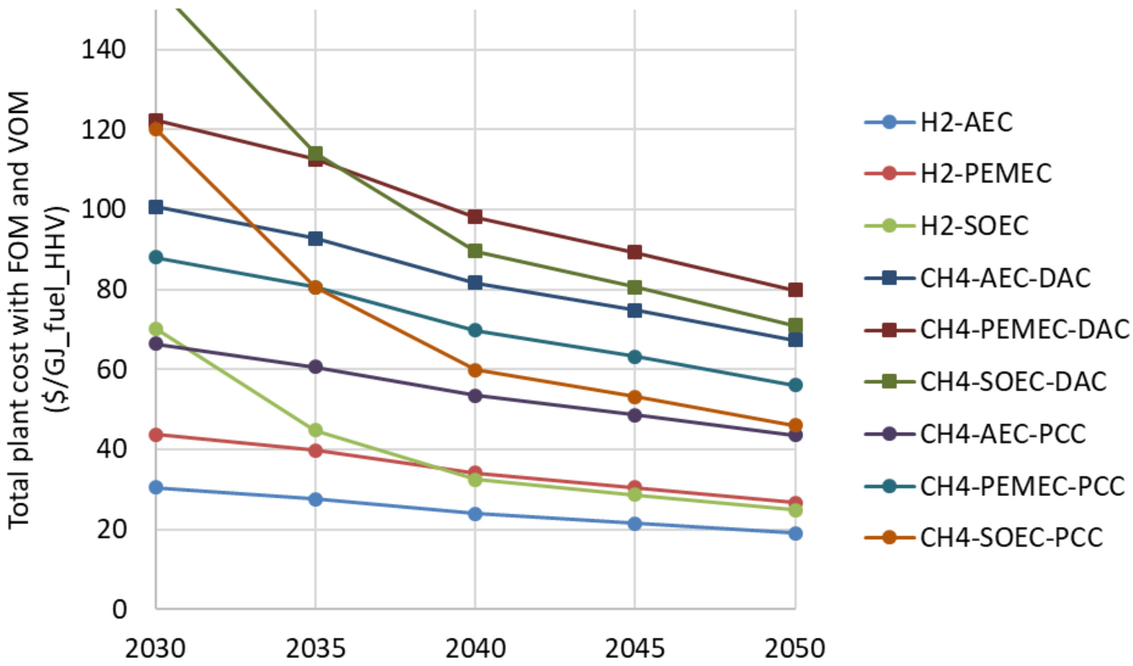
Costs for the 12 pathways detailed above are displayed below. These four plots are the four scenarios described previously of conservative and optimistic scenarios with 20% and 85% capacity factor. Displayed is the total cost for the P2G plant including FOM and VOM. Two plots are shown for each of the figures: one to provide context for the entire landscape and the second to focus on the lower-cost options in the timeframe of 2030 to 2050.

Figure C-33: P2G Pathways Cost, Conservative Scenario With 20 Percent CF



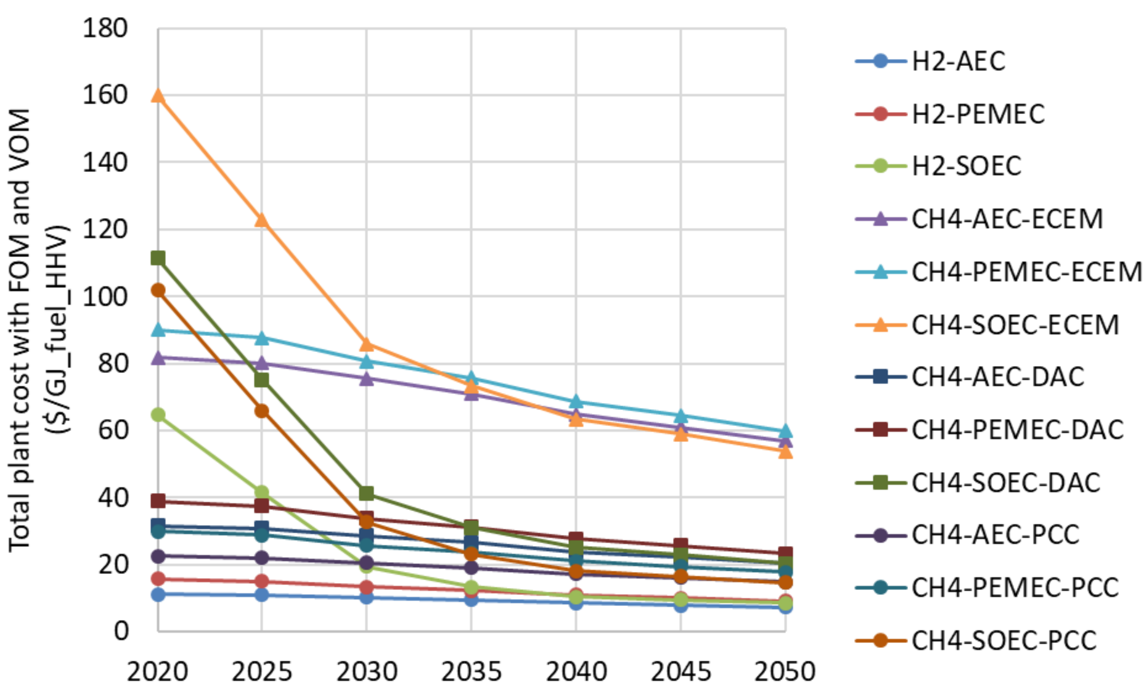
Source: UCI APEP

Figure C-34: P2G Pathways Cost, Conservative Scenario With 20 Percent CF Focused on 2030 to 2050



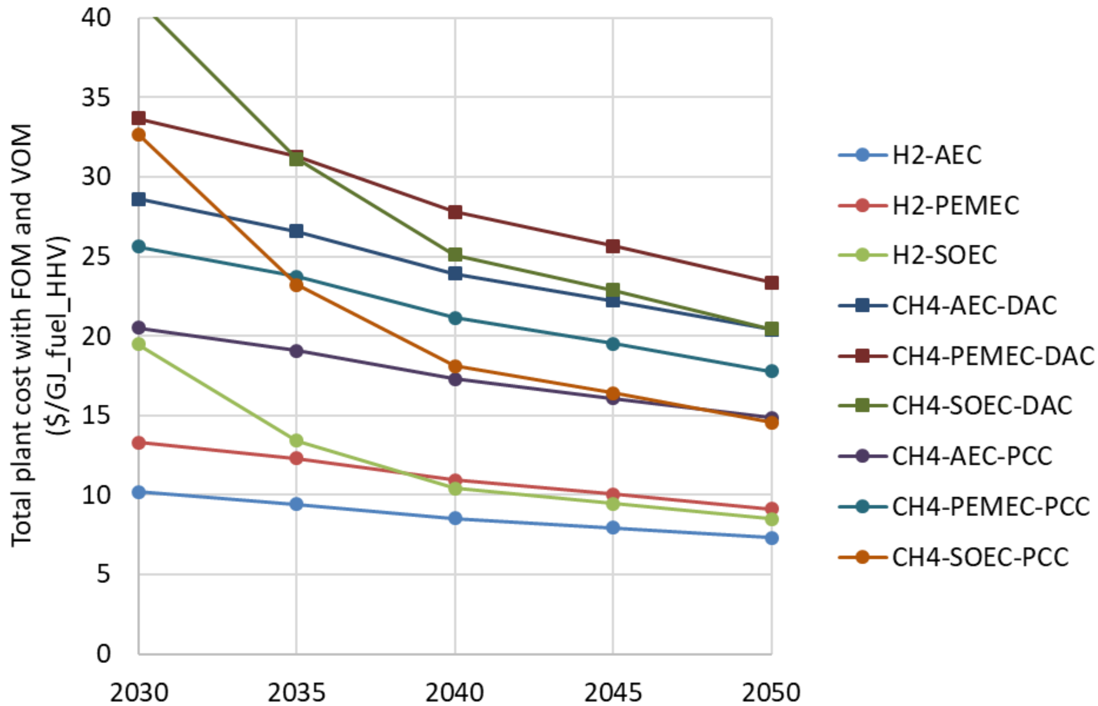
Source: UCI APEP

Figure C-35: P2G Pathways Cost, Conservative Scenario With 85 Percent CF



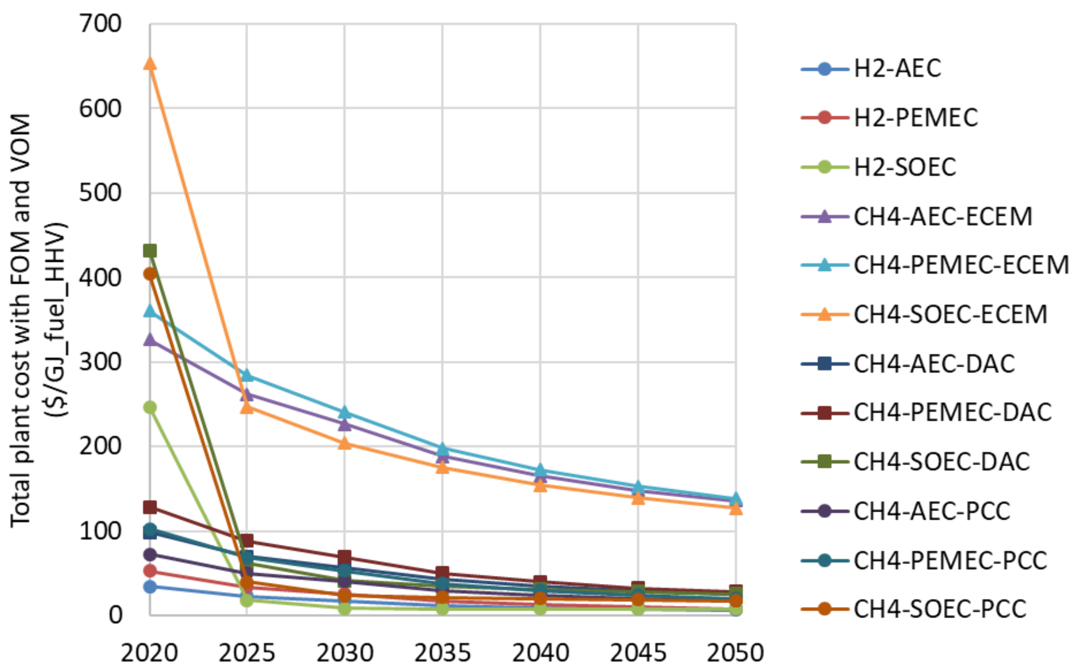
Source: UCI APEP

Figure C-36: P2G Pathways Cost, Conservative Scenario With 85 Percent CF Focused on 2030 to 2050



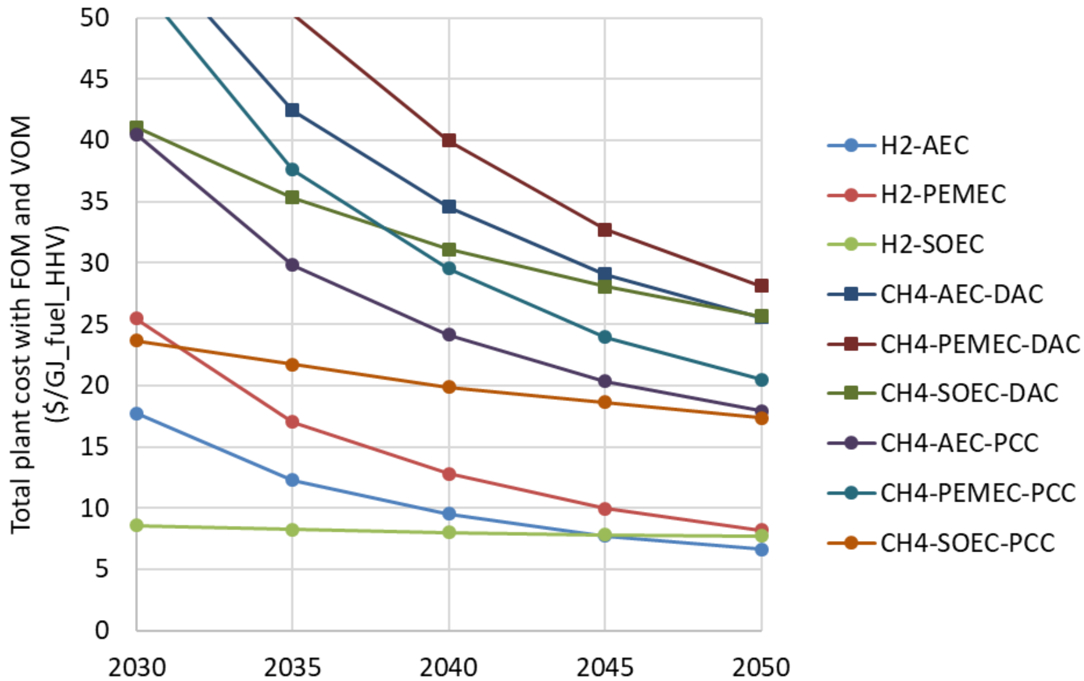
Source: UCI APEP

Figure C-37: P2G Pathways Cost, Optimistic Scenario With 20 Percent CF



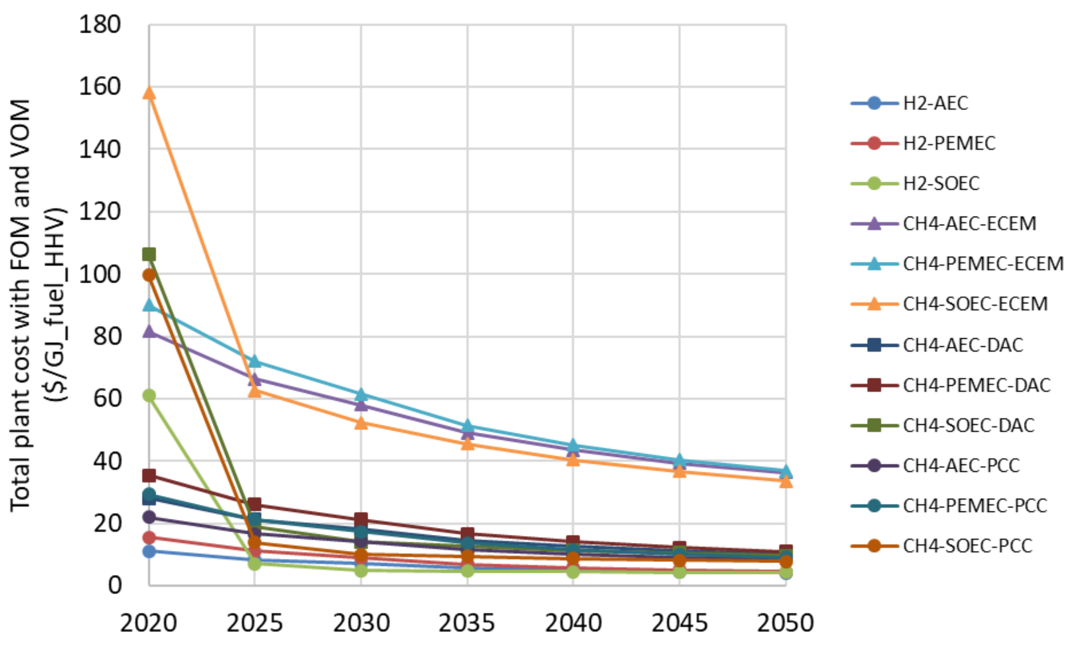
Source: UCI APEP

Figure C-38: P2G Pathways Cost, Optimistic Scenario With 20 Percent CF Focused on 2030 to 2050



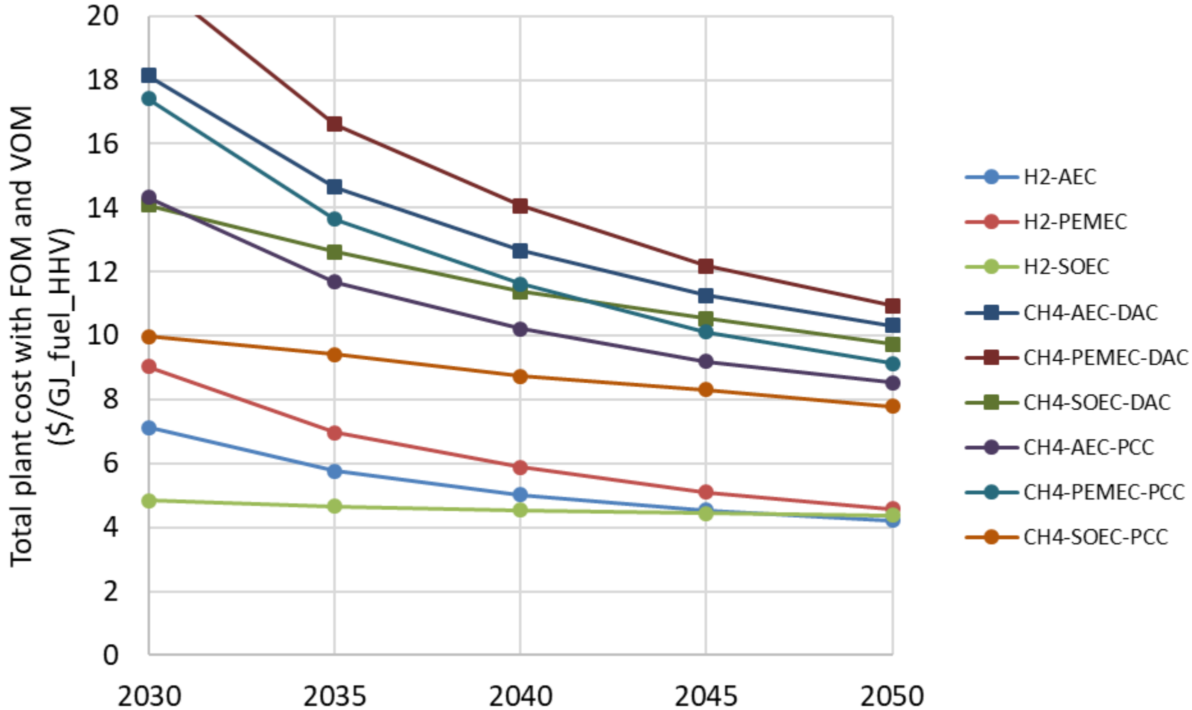
Source: UCI APEP

Figure C-39: P2G Pathways Cost, Optimistic Scenario With 20 Percent CF



Source: UCI APEP

Figure C-40: P2G Pathways Cost, Optimistic Scenario With 20 Percent CF Focused on 2030 to 2050



Source: UCI APEP

Not surprisingly, the scenario with the highest total cost per fuel output was the conservative scenario with 20% capacity factor and the scenario with the lowest total cost per fuel output was the optimistic scenario with 85% capacity factor.

For both the conservative and the optimistic scenarios, the 85% capacity factor led to a significantly lower (about one-third) cost compared to the corresponding 20% capacity factor scenarios. This makes sense because the capital costs for a given nameplate capacity are the same no matter the capacity factor, so being able to run the P2G plant more often means the money spent on the plant will lead to more product. This is true also because the VOM costs are not critically high.

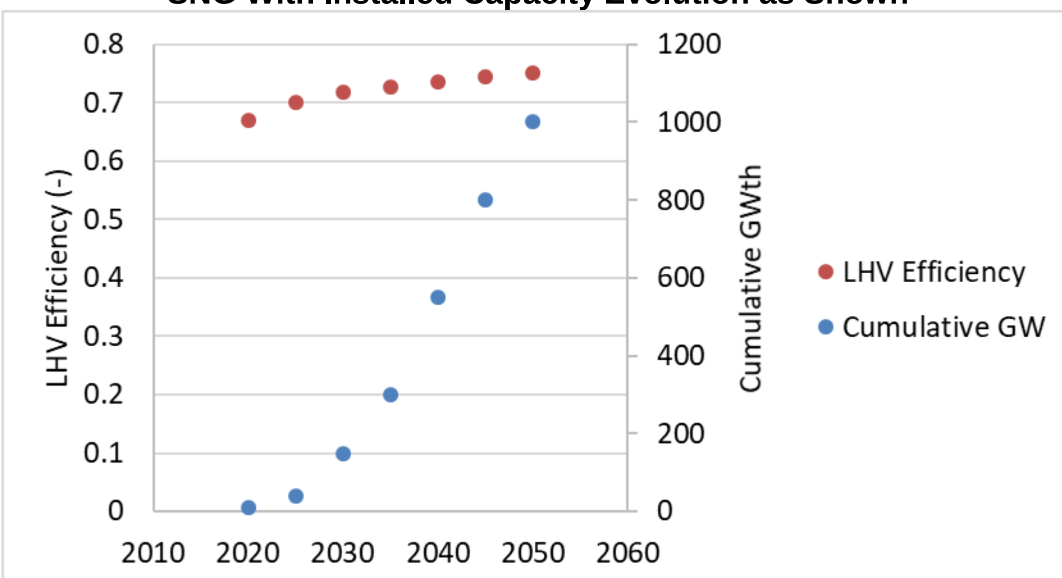
One thing to note is that water costs were not considered in this study. It is conceivable that in the future, water may be significantly more expensive. If this were true, it is possible that the VOM costs would be more significant and therefore lower capacity factor scenarios would be more competitive.

Gasification

Efficiency

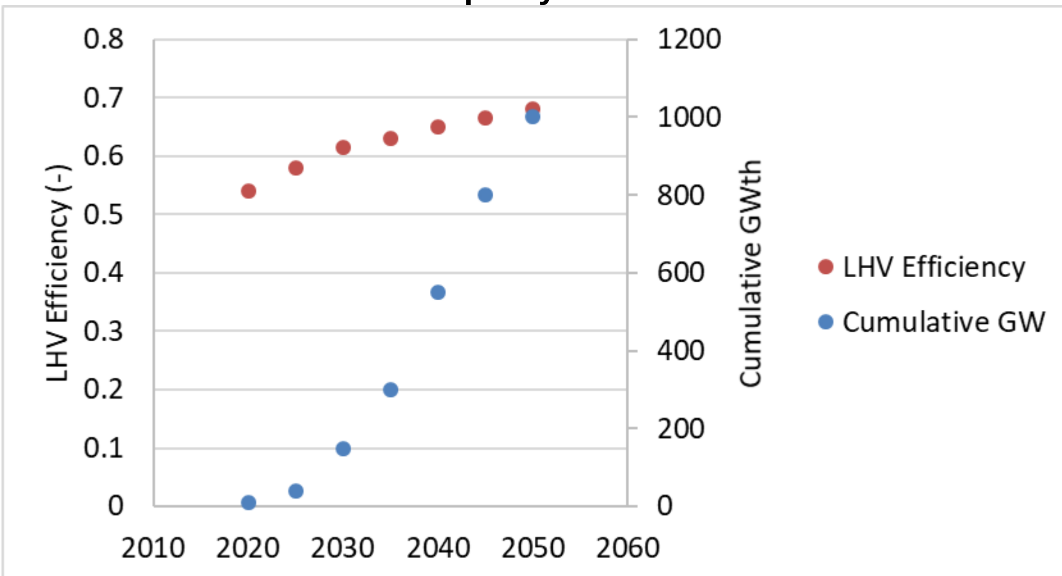
According to IEA, biomass accounts for about 1TW average power production annually (International Energy Agency, 2017). It is therefore reasonable to assume the following market sizes in 2035 and 2050 for biomass gasifiers: 500 GW and 1000GW, respectively. An assumption is that gasification technology is more established and simpler than that of electrolyzers, there is less potential for efficiency increase, and therefore efficiency improvements are more limited than electrolyzers. Assumed in this work is that the highest efficiency is achieved by gasifiers in 2050, and progress is halfway there by 2035. See below for the market size and efficiency projections for gasifiers producing SNG and hydrogen.

Figure C-41: Efficiency Projections for Biomass Gasification for Production of SNG With Installed Capacity Evolution as Shown



Source: UCI APEP

Figure C-42: Efficiency Projections for Biomass Gasification for Production of H2 With Installed Capacity Evolution as Shown

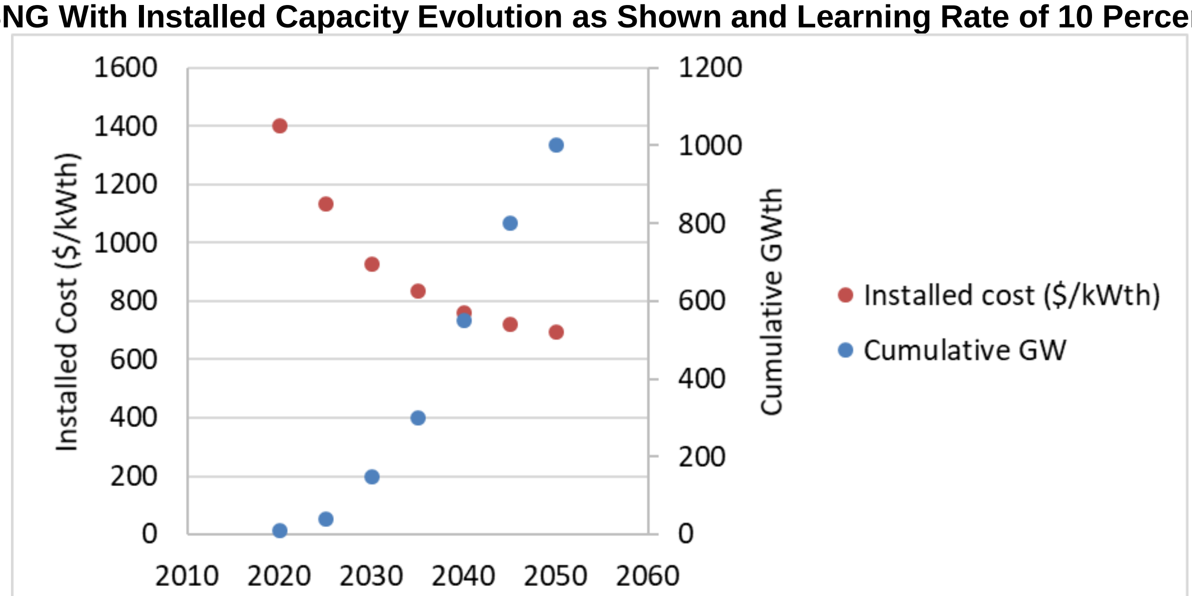


Source: UCI APEP

Cost

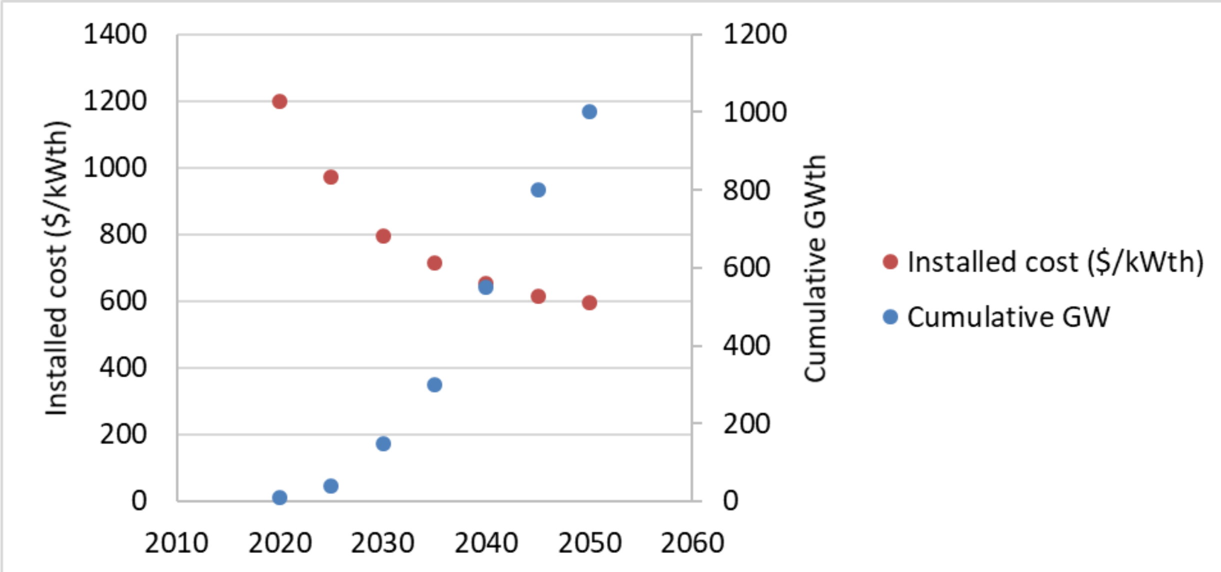
For cost projections, Wright's law is again used with a learning rate of 10%, representative of a more conservative technology growth given that gasifiers are a more established technology than electrolyzers. These cost projections are shown below for SNG production and hydrogen production.

Figure C-43: Installed Cost Projections for Biomass Gasification for Production of SNG With Installed Capacity Evolution as Shown and Learning Rate of 10 Percent



Source: UCI APEP

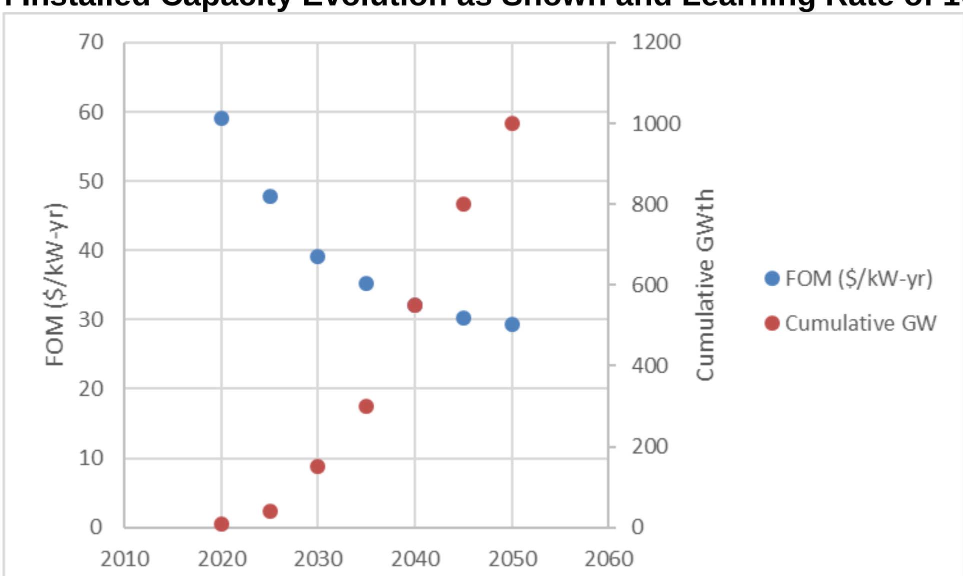
Figure C-44: Installed Cost Projections for Biomass Gasification for Production of H2 With Installed Capacity Evolution as Shown and Learning Rate of 10 Percent



Source: UCI APEP

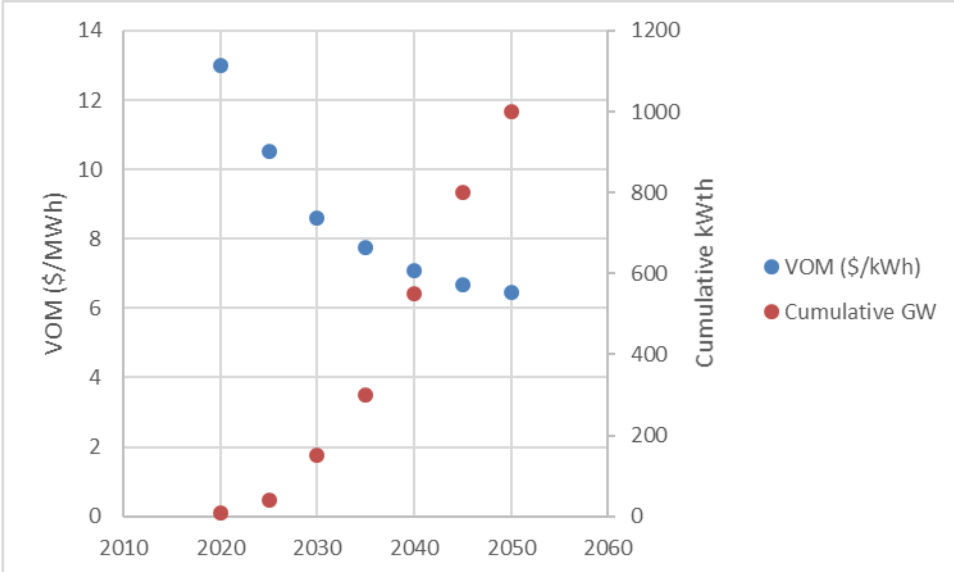
A 10% learning rate is also applied to the FOM and VOM of gasification, leading to the cost projections shown below.

Figure C-45: FOM Cost Projections for Biomass Gasification for Production of SNG With Installed Capacity Evolution as Shown and Learning Rate of 10 Percent



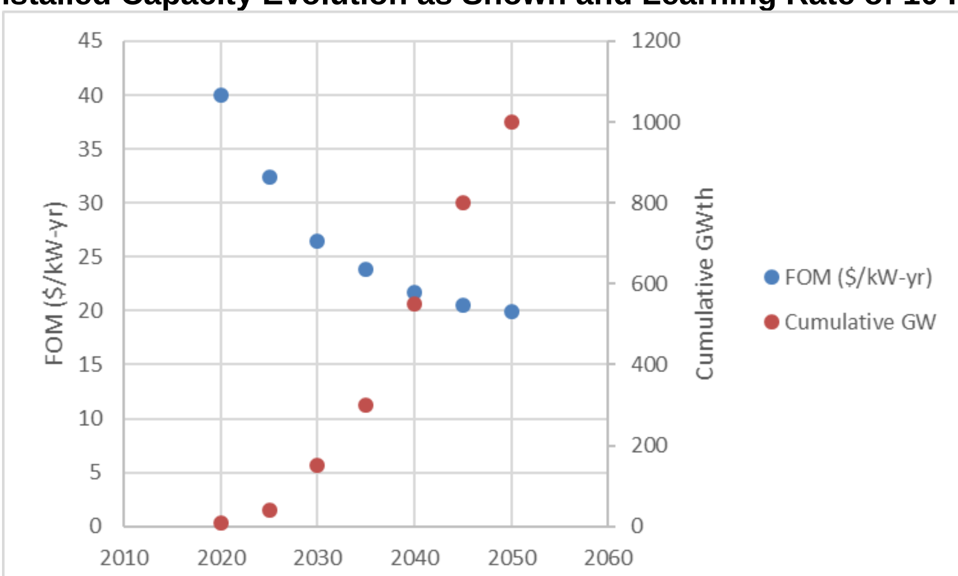
Source: UCI APEP

Figure C-46: VOM Cost Projections for Biomass Gasification for Production of SNG With Installed Capacity Evolution as Shown and Learning Rate of 10 Percent



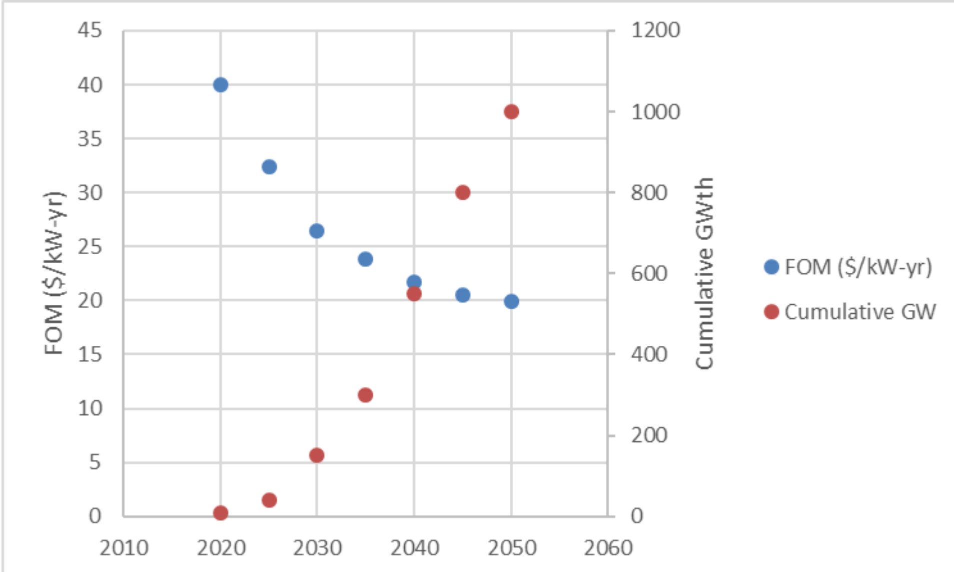
Source: UCI APEP

Figure C-47: FOM Cost Projections for Biomass Gasification for Production of H2 With Installed Capacity Evolution as Shown and Learning Rate of 10 Percent



Source: UCI APEP

Figure C-48: VOM Cost Projections for Biomass Gasification for Production of H2 With Installed Capacity Evolution as Shown and Learning Rate of 10 Percent



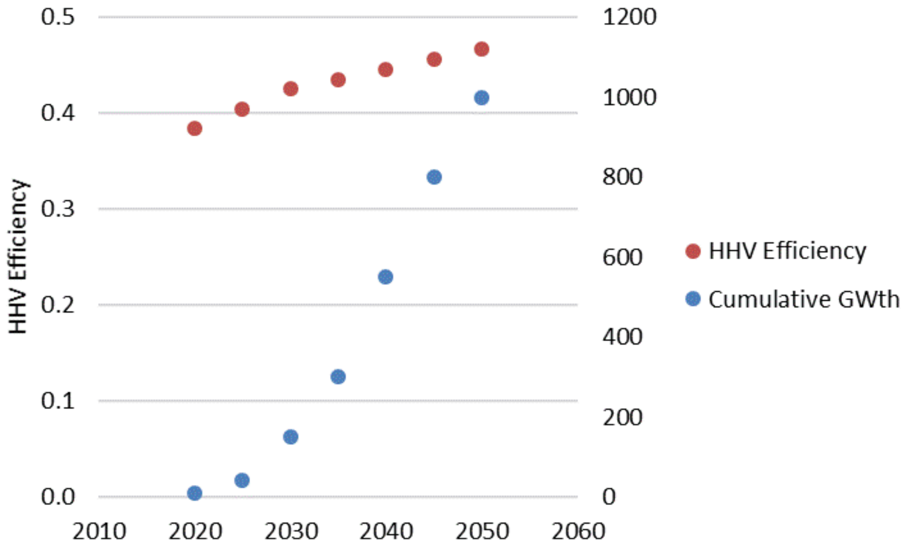
Source: UCI APEP

Anaerobic Digestion

Efficiency

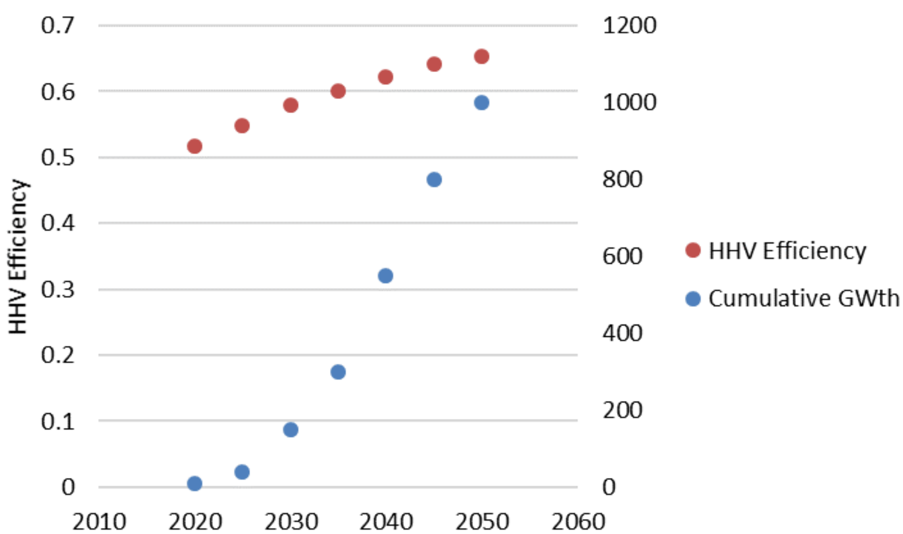
Again, according to IEA, biomass accounts for about 1TW average power production annually (International Energy Agency, 2017). The same market size projections are used here for anaerobic digestion as for gasification as both fill a similar area in the market. Anaerobic digesters are not as established as gasifiers, so there is more room for efficiency improvements. Similar to gasifiers, assumed in this work is that the highest efficiency is achieved by anaerobic digesters in 2050, and progress is halfway there by 2035. See below for the market size and efficiency projections for manure and organic feedstocks.

Figure C-49: Projected HHV Efficiency and Market Growth for Anaerobic Digesters With Manure Feedstocks



Source: UCI APEP

Figure C-50: Projected HHV Efficiency and Market Growth for Anaerobic Digesters With Organic Feedstocks

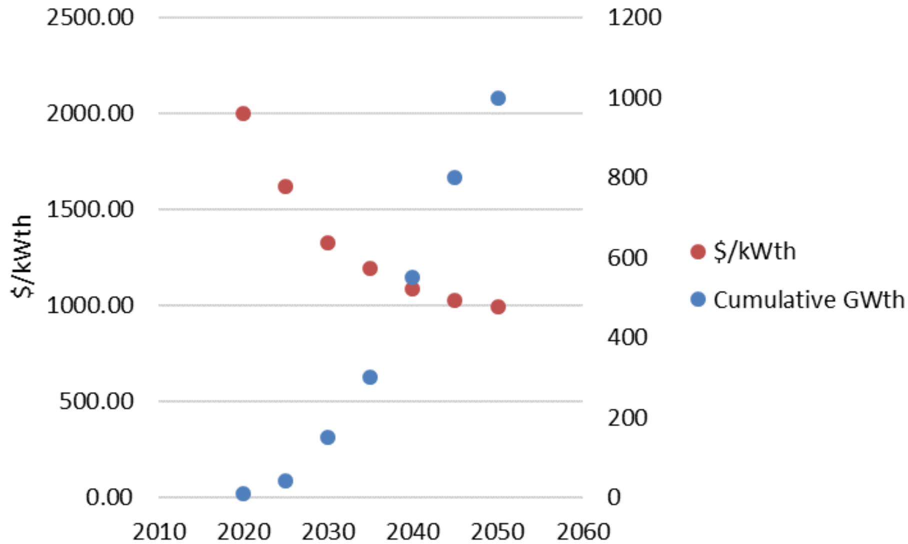


Source: UCI APEP

Cost

Below are the projected costs as a function of cumulative market capacity according to Wright's Law, for manure and organic feedstocks (both are the same), with a 10% learning rate.

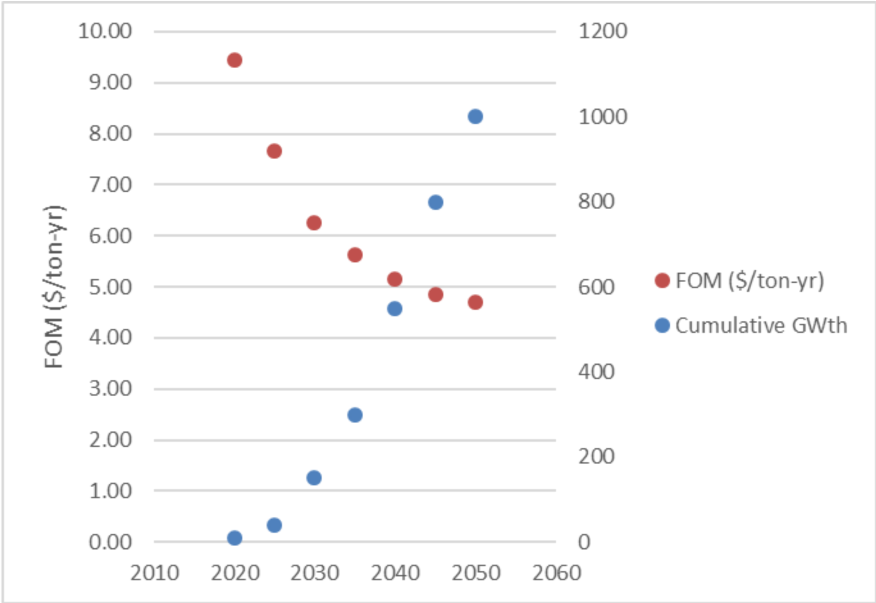
Figure C-51: Projected Installation Cost and Market Size for Anaerobic Digesters With Manure and Organic Feedstocks



Source: UCI APEP

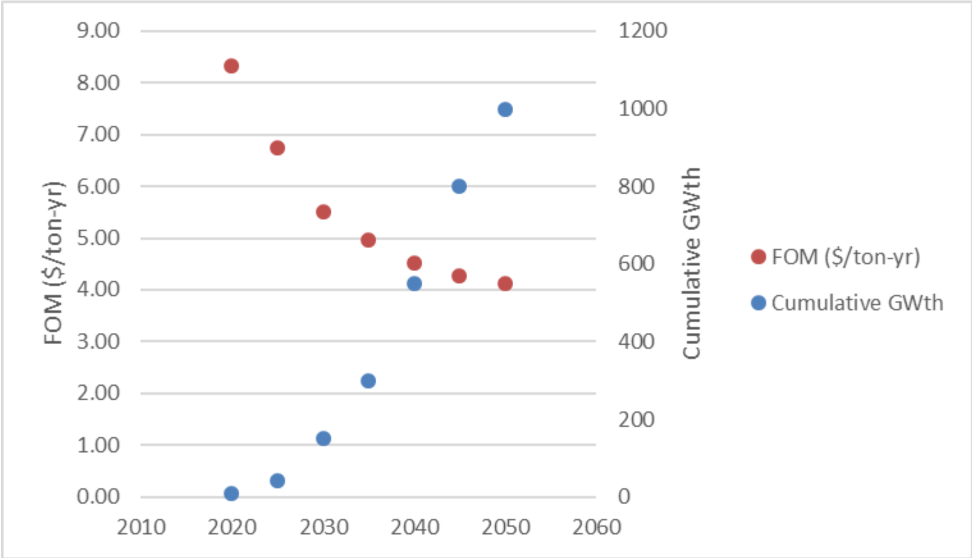
A 10% learning rate is also applied to the OM (the sum of FOM and VOM, due to not enough literature values to separate FOM and VOM) of anaerobic digesters, leading to the cost projections shown in below for manure feedstocks and organic feedstocks.

Figure C-52: OM Cost and Market Size for Anaerobic Digesters With Manure Feedstocks



Source: UCI APEP

Figure C-53: OM Cost and Market Size for Anaerobic Digesters With Organic Feedstocks



Source: UCI APEP

Costs of CO_2 Transport and Storage

Though the literature is in agreement that the costs for CO_2 capture represent the largest share within CCS, costs from transport and storage of CO_2 should also be considered (Knoope, Ramírez, & Faaij, 2013). Currently, it is believed that the most practical long-term storage sites for CO_2 are various forms of natural underground geologic cavities including depleted oil and gas wells, saline formations, unmineable coal seams, and saline-filled basalt formations (Rhodes, 2012). Captured CO_2 must be transported from the point of origin to the storage site. Generally, this is accomplished by liquefaction and transport to the storage facility by truck, rail, or pipeline. Costs of carbon storage will largely be the fixed and variable costs of CO_2 liquefaction, transport to storage site, and injection (Herzog, 2011). Fixed costs include the costs of pressurized transport trucks and rail cars, and the costs of constructing pipelines, and any equipment required for offloading and injection into a storage site. Variable costs include labor, purchase of replacement parts, and fuel and electricity to operate and maintain trucks, trains, pipelines, and injection equipment. Post-injection costs, including the ongoing costs of monitoring for leakage, will be minimal compared to costs from other stages (Bergstrom & Ty, 2017).

CO_2 Transport

The majority of available studies estimating costs for CCS focus on pipeline transport in place of truck, rail, or ship. This is largely due to a focus on large-scale deployment at centralized power plants which results in pipelines being preferred due to the very large volumes of CO_2 that are estimated require transport. While detailed construction cost data for real-world CO_2 pipelines are not readily available, similarities between transport of CO_2 and natural gas (e.g., transport at similar pressures, similar materials for dry CO_2) allow for comparison with natural gas pipelines as a proxy (Bergstrom & Ty, 2017). Although it should be noted that doing so can underestimate the material cost for CO_2 pipelines. Total construction costs for pipeline projects include materials, labor, right-of-way, and miscellaneous costs. Using modeling, capital costs for CO_2 pipeline transport are estimated to range from $1.5 to 9.5 million (2010 dollars) per mile for a pipeline diameter of 2.62 feet and a length of 15.5 miles (Knoope et al., 2013). O&M costs for the same pipeline specifications were estimated to be $8,545 to $142,411 per mile per year. O&M cost of operating a 290 mile CO_2 pipeline were estimated at $40,000 to $60,000 per month, or $5,230/mile annually (2004 dollars) (Bock et al., 2003). Overall, it has been estimated that the cost for CO_2 transport by pipeline could range from approximately $2 to $0.5 2010 U.S. per tonne of CO_2 with a decreasing trend inverse to flow rate (GCSI, 2011). Table C-22 provides ranges of CO_2 transport cost by pipeline by distance.

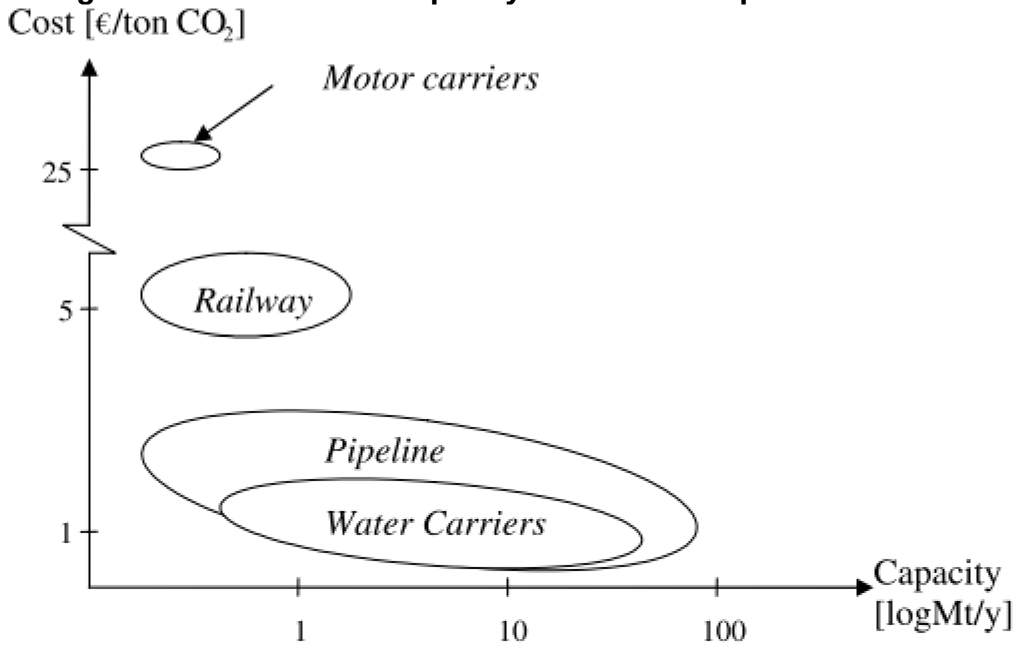
Table C-22: Ranges of CO_2 Pipeline Transport Cost in Relation to Transport Distance

Transport Distance (Miles)	Min-Max $USD_{2005}/tonCO_2$
<31	\$0.08-\$5.15
31-124	\$0.18-\$28.97
124-310	\$1.09-\$78.86
310-1242	\$2.57-\$321.87
>1242	\$9.66-\$347.62

Source: Data from (Koelbl, Van den Broek, van Ruijven, Faaij, & Van Vuuren, 2014)

However, the transport and storage of CO_2 from facilities in this work likely represent much smaller volumes of CO_2 and it may not be economically or technically attractive to construct a new pipeline. Therefore, transport by truck, train, or ship may be the most viable option as these methods have also been found to be more economical for plants with shorter life spans (Norişor, Badea, & Dincă, 2012). Mobile land transport equipment such as train and truck may be employed when the location of a facility does not have feasible access to existing pipeline facilities and the quantity of captured CO_2 does not justify the construction of a novel pipeline. Close proximity of an existing railway system to the facility can give the use of rail tankers a distinct advantage over truck transport, given the fact that truck tankers have the least volumetric capacity versus all other forms of CO_2 transport. Additionally, transport of CO_2 via motor vehicle has been estimated to have the highest cost of transport methods (shown in Svensson et al., 2004 and Svensson, Odenberger, Johnsson, & Stromberg, 2004). A cost analysis in China estimates that for 4000 tons CO_2 per day ship tankers cost \$7.48 per metric ton, railway tankers cost \$12.64 per metric ton, and 300 km pipelines \$7.05 per metric ton (Gao, Fang, Li, & Hetland, 2011). Demonstrating the importance of regional impacts, CO_2 transport cost by ship to offshore storage locations in Europe has been estimated to range from \$16 to \$42 per ton CO_2 (Neele et al., 2017).

Figure C-54: Cost and Capacity for CO_2 Transport at 250 Km



Source: (Svensson et al., 2004)

Transport via rail will likely require CO_2 to be liquefied and refrigerated, and contained in refrigerated tanker/trailers, rail cars, or refrigerated storage tanks.

CO_2 Storage

Storage costs vary significantly and depend on CO_2 injection rate, storage capacity, reservoir type and features (e.g., pressure, thickness, permeability and depth) and location (onshore-offshore). Table C-23 shows estimated storage costs for various storage options. Typical costs of geological storage in saline formations or in depleted oil or gas fields are \$0.50 to \$8.00 per metric ton of CO_2 injected, with an additional \$0.10 to \$0.30 per metric ton of CO_2 injected for the cost of monitoring equipment (Rhodes, 2012). However, as shown in Table C-24, depending on location costs can exceed \$13 per metric ton. The site screening for a saline aquifer with beneficial properties for storage was estimated at \$66 million (GCSI, 2011).

Table C-23: Estimated CO_2 Storage Costs

Reservoir Type	Depth [ft]	Storage Rate [Mt/year]	Storage Cost [2007 $/ton CO_2]
Aquifer onshore	3280-8200	1-2	4.02
Aquifer onshore	3280-8200	2-4	2.68
Aquifer offshore	4920-8200	1-2	10.73
Aquifer offshore	4920-8200	2-4	6.71
Gas field onshore	8200-11480	1-2	4.02
Gas field onshore	8200-11480	2-4	2.68
Gas field offshore	9840-13120	1-2	13.42
Gas field offshore	9840-13120	2-4	8.05

Source: Data from (Damen, van Troost, Faaij, & Turkenburg, 2007)

Table C-24: Costs for CO_2 Storage by Process

Process	Minimum 2010 U.S. [$]
3D Seismic survey	18/survey
Deep monitoring well costs	5/well
Shallow monitoring well costs	1/well
Injection well costs	10/well
Injection well abandonment costs and rehab	1/well
Monitoring well abandonment costs and rehab	0.5/well
In-field flow lines	0.25/well
Monitoring OPEX	0.1/year
Fees and rents OPEX	0.1/year

Source: Data from (GCSI, 2011)

Greenhouse Gas and Criteria Air Pollutant Emissions

This section describes the emissions analysis used for air quality and criteria pollutant analysis, including lifecycle accounting of GHG emissions. Note that the PATHWAYS model (Chapter 3) uses a direct emissions accounting framework used by the California Air Resources Board inventory.

A common method of comparing the environmental impacts of various processes and equipment is by comparing emission factors. Emission factors give the emission intensity by the ratio of the quantity of emissions given off per the amount of activity. The amount of activity can be number of units, miles driven, or the amount of energy associated with a process. In this work, emission factors generally take the form of quantity of emissions given off per the amount of associated energy.

Fuel emissions can be separated into two categories: electricity and biomass. In general, the emissions associated with fuel production are dependent on the feedstock (electricity or a type of biomass) and the efficiency of that pathway. While this may be obvious for the electricity feedstock, it may not be as obvious for the biomass feedstocks. For pathways using biomass as a feedstock, the main inputs to the fuel production process are the feedstock itself, heat, and pressure. Both heat and pressure can be produced by simply burning some of the biomass feedstock. Because the efficiencies cited in previous sections are in terms of primary energy input, this efficiency along with the emission factor of the biomass feedstock are all that are necessary for calculating the emissions associated with fuel production.

The majority of the feedstock emission factors used in this work are from Argonne National Laboratory's GREET 2016 (Argonne National Laboratory, n.d.). More up-to-date data for electricity GHG emission factors that account for SB 100 goals of zero-carbon electricity by 2045 were sourced from the PATHWAYS Reference scenario, which projects lower GHG emissions in later years compared to GREET; however, the CAP emission factors were sourced from GREET as that has the most detailed CAP emissions data for electricity.

Due to a lack in emission factors for some biomass feedstocks, some assumptions are made for the feedstocks that do not have data available to link them to types of biomass that they are most similar to and do have emission factor data. All straw biomass (barley straw, rice hulls, rice straw, and wheat straw) are assumed to have the same emission factors as corn stover. Residues (cotton gin trash, cotton residue, noncitrus residues, primary mill residue, secondary mill residue, paper, paperboard, plastics, rubber, leather, textiles, yard trimmings, and other) are all assumed to have the same emission factors as citrus residues. Both hardwood and softwood variations are assumed to have the same emission factors as forestry. Lastly, MSW wood is assumed to have the same emission factors as construction and demolition waste.

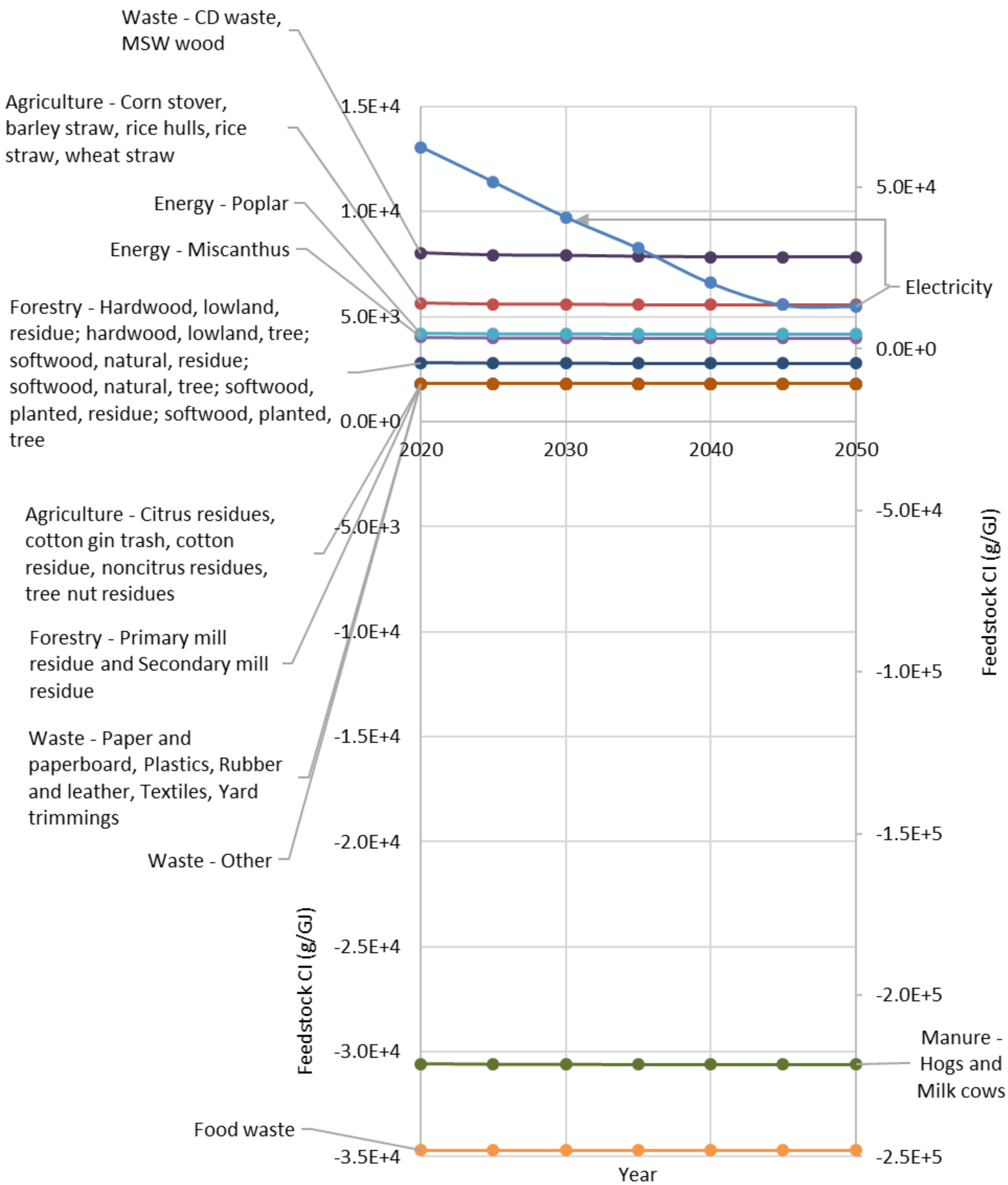
Two biomass categories are not present in GREET and therefore other sources were consulted. For citrus residues (and the other biomass types that are approximated to have the same emission factors), emission factors are sourced from Pourbafrani et al. (Pourbafrani, McKechnie, Maclean, & Saville, 2013). Food waste emission factors are taken from ARB (ARB, 2014).

Note also that GREET emissions factors are projected into 2040. For the present work, these projections are carried out to 2050, assuming emissions factors stay the same after 2040. For the emission factors sourced from Pourbafrani et al. and the ARB, they are assumed constant throughout the timeframe of this work as there was no indication of changing values. It should be noted that this is a valid assumption as most emission factors are nearly constant, as will be shown shortly.

CAP emission factors for electricity are specifically for California from the "Fuel" category of the "Electric" tab of GREET. Emission factors for the various biomass feedstocks found in GREET are sourced from the feedstock emissions section of the various production pathways detailed.

GHG emission factors, also known as carbon intensities (CIs), for the feedstocks are shown in Figure C-55. There are a wide range of biomass varieties with a wide range of CI values. Note that both manure and food waste biomass feedstocks have negative CIs. This is because both of these categories of biomass naturally release methane into the atmosphere. Turning these feedstocks into fuels stops them from emitting into the atmosphere, at least until they are later used (depending on the method of conversion). Important to note in this figure is that the CIs for electricity and manure are on the secondary y-axis on the right side, which has a much greater magnitude of values. The rest of the feedstocks have CIs detailed by the primary y-axis on the left side.

Figure C-55: Feedstock Carbon Intensities



Source: Data from (ARB, 2014; Argonne National Laboratory, n.d.; E3, 2016; Pourbafrani et al., 2013)

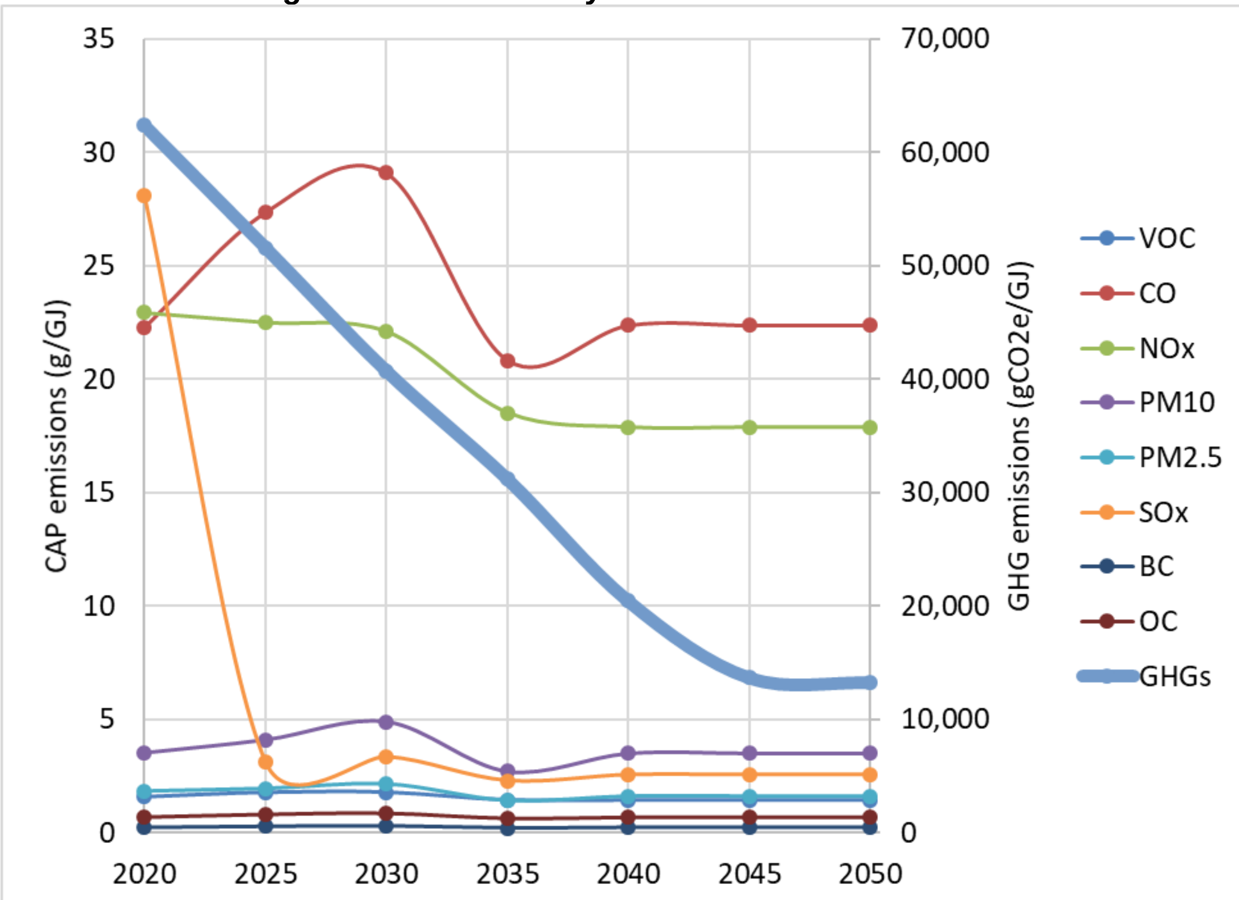
The highest CI is for electricity, which is close to ten times higher than the next-highest CI, though it should be noted that electricity is the only fuel feedstock with a CI that comes down significantly with time. This is due to legislation that mandates increasing renewable electricity production with time. By 2045, the CI of electricity is much more comparable to some of the biomass feedstocks. The lowest CI is for manure, which has a very negative value. Compared to these two extremes, all other feedstocks considered (besides food waste) have a relatively low spread between their CIs.

Note, as previously mentioned, most feedstocks have relatively constant emission factors throughout time. The one exception to that is electricity, which has a somewhat significant decrease with time. This is due to an increasing amount of carbon-free renewable electricity generation being installed on the electric grid, more-efficient fossil generation, and, perhaps most importantly, legislation such as SB 100 which require cleaner electricity production into the future. Biomass feedstocks' emission factors stay relatively constant as the emission factors come from farming, land use change by removing the biomass to harvest for fuel, and transporting the biomass to a fuel production facility. Both farming and land use change emissions do not change much with time. Additionally, GREET likely assumes conventional transport of the biomass feedstock to fuel production facilities (which will likely change). While vehicles are assumed to be more efficient as time progresses, there is not a drastic difference in these transportation emissions. Therefore, the overall feedstock emission factors are nearly constant for most biomass feedstocks.

An important concept to keep in mind is that the feedstock emission factors are not the only data that matter when determining the climate change and air quality impacts of a fuel. Also important are the efficiency of the fuel production pathway as well as the emissions from the end uses themselves. Consider the following: if one feedstock has particularly low emission factors, but it must be made using in an inefficient process and it must be used in an inefficient vehicle, the overall emissions associated with that process may be much higher than using a feedstock with higher emission factors but that be made into a fuel more efficiently and be used in a more efficient vehicle.

GHG and CAP emission factors for electricity are shown below in Figure C-56. The GHG and CAP emission factors for the biomass feedstocks are shown in the Appendix C.

Figure C-56: Electricity GHG and CAP Emissions



Source: Data from (Argonne National Laboratory, n.d.; E3, 2016)

Summary and Conclusions

There is a wide range of values in the literature for costs and efficiencies of electrolyzers, gasifiers, and anaerobic digesters. Therefore, experience in this area, as well as focusing strong sources in the literature, are required to narrow the wide range to usable values. Additionally, projections of cost and efficiency into the future are similarly scattered but also scarcer (particularly projections out to 2050).

The method this work uses to project future costs of equipment is Wright's law. Wright's law predicts reduction in cost with increasing capacity production. Learning rate is a term that affects how much cost reduces given an increase in production. Higher learning rates yield more cost reduction. To capture the uncertainty of technology progress in some of the equipment considered (particularly electrolyzers, which are not as mature as much of the other equipment considered), two scenarios are developed: conservative and optimistic. The conservative scenario has lower learning rates which leads to less price reduction, and the optimistic scenario has higher learning rates which leads to higher price reduction.

Another important factor for the cost of fuel produced is the feedstock cost. Like the technology costs, feedstock cost projections are varied. For the cost of the various biomass supplies, the DOE Billion Ton Study is respected and thorough (Langholtz et al., 2016). E3's PATHWAYS model projects the cost of electricity out to 2050 (Energy and Environmental Economics, 2016). While not yet studied, the cost of these various feedstocks may have a significant impact on the overall cost of the product fuel.

For the P2G technologies, SOECs have the highest efficiency and, due to their very low current production amount, have the greatest potential for price reduction. Despite have significantly higher current price than AECs and PEMECs, SOECs become competitive with PEMECs around 2035 in the conservative scenario and SOECs are cheapest electrolyzer technology by 2025. This is based on the use of Wright's law and its dependence on production capacity.

Regarding the biomass conversion technologies, gasification is currently about 50% more efficient than AD, but this gap in efficiency may decrease with time. Additionally, AD is about 30% more expensive than gasifiers on a thermal input basis.

Using the values presented in this report, along with the feedstock costs, overall fuel cost and associated emissions can be calculated and compared for the various electrolytic and biomass conversion pathways.

APPENDIX D: PATHWAYS Renewable Natural Gas and Biofuels Analysis

Translating Renewable Natural Gas Data Inputs Into PATHWAYS

This appendix describes the process used to update the data inputs for the PATHWAYS model based on the technoeconomic assessment in Appendix C conducted by the Advanced Power and Energy Program at the University of California at Irvine (UCI) team. PATHWAYS incorporated updated inputs such as capital costs, production costs, and efficiencies for producing renewable natural gas (biomethane, hydrogen, and synthetic natural gas) to displace fossil natural gas. Because PATHWAYS integrates modeling of biomethane potential and scenario-specific production with modeling of liquid biofuels, updates were incorporated into the PATHWAYS biofuels module described in E3's 2018 Deep Decarbonization analysis (Mahone et al, 2018).

Updating RNG Production Pathways

As part of this update, E3 asked the UCI team to identify, characterize, and quantify important considerations in the role of alternative renewable and low-carbon gaseous fuel production technologies including power-to-gas (P2G), biomass conversion, and other advanced renewable gaseous fuel production technologies (e.g., algae, direct solar fuels) including factors such as large-scale production, pipeline injection, feedstock availability, and technology readiness levels.

Biomethane and Other Biofuels

Biofuels are modeled using the E3 PATHWAYS biofuels module previously developed for the CEC.[18] For this project, the research team has updated data inputs to the biofuels module.

1. The raw biomass feedstock supply curves are based on the 2016 DOE Billion Ton Update.[19] The DOE developed several scenarios of agricultural yields and of

18 See Appendix C, PATHWAYS Biofuels Module Methodology in *Deep Decarbonization in a High Renewables Future*. CEC-500-2018-012. (Available at https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf.)

19 U.S. Department of Energy. 2016. *2016 Billion-Ton Report: Advancing Domestic Resources for a Thriving Bioeconomy.* https://www.energy.gov/eere/bioenergy/2016-billion-ton-report.

biomass utilization for other uses. For this study, the research team used the base case biomass yield growth assumptions ("Basecase, all energy crops") and the low alternative biomass demands assumptions ("Medium housing, low energy demands"). Researchers excluded purpose-grown crops and forests from the DOE data in this project, leaving **352 million dry tons** of residue and waste biomass potential nationwide. As in E3's 2018 Deep Decarbonization analysis, a supplemental assessment of in-state biogas resources is included, covering landfill gas, manure, and municipal solid waste and wastewater treatment.[20]

2. Liquid biofuel conversion pathway assumptions are based on an internal analysis performed by Black and Veatch for E3 in 2016 which include increases in conversion efficiency over time associated with innovation. Assumptions for 2050 are included in the tables below. Where multiple conversion pathways exist for a given pair of feedstock and final fuel, a prescreening step is used to determine the cheapest conversion process, considering the benefits of increased yield at a predetermined carbon price (\$500/tonne CO_2 in this analysis). For instance, hydrolysis of cellulose to produce renewable drop-in gasoline is always preferred to pyrolysis in the 2050 timeframe.

3. Gaseous biofuel conversion assumptions for biomethane production are based on work done by UCI as part of this project, with 2050 assumptions included below. For input into PATHWAYS, UCI determined a single set of conversion inputs for each feedstock and conversion pathway combination, for each feedstock in the DOE dataset, and for every 5 years from 2015 to 2050. These inputs consist of overall energy efficiency (GJ HHV/dry ton) and levelized process conversion costs (2012\$/GJ).

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20 Jaffe, Amy Myers, Rosa Dominguz-Faus, Nathan C. Parker, Daniel Scheitrum, Justin Wilcock, and Marshall Miller. UC Davis Institute of Transportation Studies. 2016. *The Feasibility of Renewable Natural Gas as a Large-Scale, Low-Carbon Substitute.* https://steps.ucdavis.edu/wp-content/uploads/2017/05/2016-UCD-ITS-RR-16-20.pdf.

Electrolytic fuels (H_2 and SNG[21])

UCI also developed a set of cost and efficiency assumptions for production of hydrogen and SNG using electrolysis and, in the case of SNG, methanation of a source of renewable CO_2. The assumptions consist of inputs indexed by fuel, electrolysis technology, CO_2 input, year, and level of industry learning assumed to occur between 2020 and 2050. CO_2 sources include direct air capture (DAC), electrochemical oceanwater capture (Electrolytic-Cation Exchange Module, or E-CEM), and biorefining co-product ("PCC" as in the common term "Post-Combustion Capture", although combustion may not occur during biorefining). Inputs consist of levelized capital cost and annual fixed O&M cost (combined in PATHWAYS), variable O&M cost, and overall energy efficiency considering only renewable electricity as the energy input, including for heat input if applicable. These assumptions yield the table included below for input into PATHWAYS. Modeling within PATHWAYS also includes several scenario-specific assumptions detailed for the conservative and optimistic P2G cost scenarios described.

When the biorefining co-product CO_2 source is used, the quantity of CO_2 available is harmonized with the biomass utilization in the scenario. UCI provided approximate CO_2 yields for biorefining processes, detailed below. For the conservative P2G cost scenario, biorefining CO_2 was only assumed to be available from in-state MSW resources, as spatially distributed resources may not be as easily centrally processed: this provided enough CO_2 for 60 TBTU of SNG in 2050, with the remaining CO_2 utilizing DAC. For the optimistic P2G cost scenario, all imported biomass was assumed to provide biorefining CO_2, a sufficient supply for all of the SNG in that scenario to be produced with biorefining CO_2.

21 Synthetic natural gas, here referring specifically to natural gas produced by the combination of electrolysis and methanation with a renewable CO2 source. Outside this report, SNG sometimes can include biomass-derived natural gas without supplemental energy or hydrogen input, which is referred to here as biomethane. Biomethane is modeled within the E3 biomass module that includes competition with other biofuels for the same feedstocks, while SNG is modeled in a separate synthetic fuels module with a prescribed CO2 source.

Data Tables

Table D-1: 2050 Biomethane Conversion Inputs

Feedstock Type (Disaggregated)	Feedstock Category	Conversion Process	Efficiency (GJ/dry ton)	Process Costs (2012$/dry ton)
Barley straw	Ag Residues	gasification	14.001	80.65
Biomass sorghum	Ag Residues	gasification	13.864	79.28
CD waste	Other MSW (Wood)	gasification	13.985	80.59
Citrus residues	Ag Residues	gasification	13.744	79.21
Corn stover	Ag Residues	gasification	13.535	78.10
Cotton gin trash	Ag Residues	gasification	14.884	85.97
Cotton residue	Ag Residues	gasification	13.190	76.53
Energy cane	Purpose-Grown Grasses	gasification	13.623	78.26
Eucalyptus	Purpose-Grown Trees	gasification	15.141	87.15
Food waste	Other MSW	gasification	11.487	66.41
Hardwood, lowland, residue	Forest Residues	gasification	14.700	84.63
Hardwood, lowland, tree	Purpose-Grown Trees	gasification	14.700	84.63
Hardwood, upland, residue	Forest Residues	gasification	14.700	84.63
Hardwood, upland, tree	Purpose-Grown Trees	gasification	14.700	84.63
Hogs, 1000+ head	Manure	anaerobic digestion	7.415	79.81
MSW wood	Other MSW (Wood)	gasification	14.346	82.76
Milk cows, 500+ head	Manure	anaerobic digestion	8.096	87.13
Miscanthus	Purpose-Grown Grasses	gasification	14.346	82.41
Mixed wood, residue	Forest Residues	gasification	14.700	84.63
Mixed wood, tree	Purpose-Grown Trees	gasification	14.700	84.63
Non-citrus residues	Ag Residues	gasification	13.655	77.95
Oats straw	Ag Residues	gasification	13.663	78.25
Other	Other MSW	gasification	12.852	73.55
Other forest residue	Forest Residues	gasification	13.655	77.95
Other forest thinnings	Forest Residues	gasification	13.655	77.95

Feedstock Type (Disaggregated)	Feedstock Category	Conversion Process	Efficiency (GJ/dry ton)	Process Costs (2012$/dry ton)
Paper and paperboard	Other MSW (Cellulose)	gasification	15.824	91.34
Pine	Purpose-Grown Trees	gasification	15.021	86.29
Plastics	Other MSW	gasification	28.460	163.12
Poplar	Purpose-Grown Trees	gasification	15.085	86.84
Primary mill residue	Other MSW (Wood)	gasification	15.342	88.15
Rice hulls	Ag Residues	gasification	12.210	69.84
Rice straw	Ag Residues	gasification	12.266	70.38
Rubber and leather	Other MSW	gasification	21.367	122.27
Secondary mill residue	Other MSW (Wood)	gasification	15.342	88.15
Softwood, natural, residue	Forest Residues	gasification	14.860	85.41
Softwood, natural, tree	Purpose-Grown Trees	gasification	14.860	85.41
Softwood, planted, residue	Forest Residues	gasification	14.860	85.41
Softwood, planted, tree	Purpose-Grown Trees	gasification	14.860	85.41
Sorghum stubble	Ag Residues	gasification	11.808	66.87
Sugarcane bagasse	Ag Residues	gasification	13.623	78.26
Sugarcane trash	Ag Residues	gasification	13.382	77.04
Switchgrass	Purpose-Grown Grasses	gasification	13.471	77.75
Textiles	Other MSW	gasification	14.095	80.52
Tree nut residues	Ag Residues	gasification	15.294	87.75
Wheat straw	Ag Residues	gasification	15.704	89.80
Willow	Purpose-Grown Trees	gasification	14.796	85.26
Yard trimmings	Other MSW (Cellulose)	gasification	13.688	78.61

Source: E3

In addition, landfill gas is assumed to be convertible to biomethane at $37.38 GJ per ton of raw landfill gas (which is assumed to be 50% CH_4 and 50% CO_2), at a process cost of $266/ton in 2012$.[22] Unless otherwise noted, for determining liquid fuel conversion assumptions below, Ag Residues are grouped with cellulose, forest residues are grouped with wood, and MSW is grouped with cellulose. Manure and landfill gas can only be converted into biomethane in the model, not into liquid biofuels.

Table D-2: 2050 Conversion Inputs for Liquid Biofuels

Feedstock Type (Aggregated)	Fuel	Conversion Process	Efficiency (GJ/dry ton)	Process Costs (2012$/dry ton)
Cellulose	renewable gasoline	hydrolysis	10.101	175.74
Cellulose	renewable gasoline	pyrolysis	8.088	206.49
Cellulose	renewable ethanol	hydrolysis	6.328	86.71
Cellulose	renewable diesel	pyrolysis	8.949	228.48
Cellulose	renewable diesel	biomass to liquids*	10.705	126.43
Cellulose	renewable jet fuel	pyrolysis	8.682	221.65
Wood	renewable gasoline	pyrolysis	10.784	206.49
Wood	renewable ethanol	hydrolysis	7.838	92.57
Wood	renewable diesel	pyrolysis	11.933	228.48
Wood	renewable diesel	biomass to liquids*	10.705	126.43
Wood	renewable jet fuel	pyrolysis	11.576	221.65

Biomass to liquids refers to thermochemical conversion using gasification plus Fisher-Tropsch synthesis of drop-in synthetic fuels.

Source: E3

22 This is consistent with Mahone et al. (2018).

Table D-3: Power-to-Gas Fuel Inputs to PATHWAYS (Hydrogen and SNG), Conservative Cost Scenario, Hydrogen Only

Hydrogen Technology – Variable	2020	2025	2030	2035	2040	2045	2050
AEC – Levelized Capital Cost (2016$/GJ-yr)	6.13	5.91	5.28	4.73	4.03	3.55	3.06
PEMEC – Levelized Capital Cost (2016$/GJ-yr)	9.76	9.28	7.95	7.18	6.05	5.34	4.60
SOEC – Levelized Capital Cost (2016$/GJ-yr)	51.65	31.95	13.26	8.21	5.76	5.02	4.27
AEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	3.97	3.97	3.97	3.86	3.81	3.75	3.70
PEMEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	4.21	4.15	3.97	3.86	3.81	3.75	3.70
SOEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	3.97	3.97	3.86	3.75	3.65	3.56	3.47
AEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.70	0.70	0.70	0.72	0.73	0.74	0.75
PEMEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.66	0.67	0.70	0.72	0.73	0.74	0.75
SOEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.70	0.70	0.72	0.74	0.76	0.78	0.80

Source: E3

Table D-4: Power-to-Gas Fuel Inputs to PATHWAYS (Hydrogen and SNG), Conservative Cost Scenario, E-CEM CO2 Capture Process

Hydrogen Technology – Variable	2020	2025	2030	2035	2040	2045	2050
AEC – Levelized Capital Cost (2016$/GJ-yr)	49.47	48.11	44.12	40.86	35.87	32.91	29.65
PEMEC – Levelized Capital Cost (2016$/GJ-yr)	55.45	53.67	48.50	44.90	39.19	35.85	32.18
SOEC – Levelized Capital Cost (2016$/GJ-yr)	118.29	86.42	55.20	45.07	37.42	34.10	30.47
AEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	6.53	6.53	6.53	6.35	6.26	6.18	6.09
PEMEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	6.93	6.82	6.53	6.35	6.26	6.18	6.09
SOEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	6.09	6.01	5.86	5.64	5.38	5.19	4.97
AEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.44	0.44	0.44	0.46	0.46	0.47	0.48
PEMEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.42	0.42	0.44	0.46	0.46	0.47	0.48
SOEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.44	0.45	0.46	0.48	0.50	0.52	0.54

Source: E3

Table D-5: Power-to-Gas Fuel Inputs to PATHWAYS (Hydrogen and SNG), Conservative Cost Scenario, DAC CO2 Capture Process

Hydrogen Technology – Variable	2020	2025	2030	2035	2040	2045	2050
AEC – Levelized Capital Cost (2016$/GJ-yr)	20.82	20.18	18.35	16.79	14.60	13.22	11.75
PEMEC – Levelized Capital Cost (2016$/GJ-yr)	26.80	25.74	22.73	20.83	17.92	16.17	14.28
SOEC – Levelized Capital Cost (2016$/GJ-yr)	90.05	58.89	29.80	21.35	16.45	14.70	12.82
AEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	6.53	6.53	6.53	6.35	6.26	6.18	6.09
PEMEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	6.93	6.82	6.53	6.35	6.26	6.18	6.09
SOEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	6.09	6.01	5.86	5.64	5.38	5.19	4.97
AEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.36	0.36	0.36	0.37	0.37	0.38	0.38
PEMEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.34	0.35	0.36	0.37	0.37	0.38	0.38
SOEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.38	0.39	0.39	0.41	0.42	0.44	0.45

Source: E3

Table D-6: Power-to-Gas Fuel Inputs to PATHWAYS (Hydrogen and SNG), Conservative Cost Scenario, PCC CO2 Capture Process

Hydrogen Technology – Variable	2020	2025	2030	2035	2040	2045	2050
AEC – Levelized Capital Cost (2016$/GJ-yr)	13.086	12.646	11.397	10.300	8.860	7.910	6.917
PEMEC – Levelized Capital Cost (2016$/GJ-yr)	19.059	18.195	15.777	14.337	12.175	10.856	9.443
SOEC – Levelized Capital Cost (2016$/GJ-yr)	81.841	50.911	22.463	14.512	10.400	9.107	7.738
AEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	6.530	6.530	6.530	6.348	6.261	6.177	6.094
PEMEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	6.925	6.822	6.530	6.348	6.261	6.177	6.094
SOEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	6.094	6.014	5.860	5.643	5.377	5.194	4.968
AEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.456	0.456	0.456	0.470	0.477	0.484	0.491
PEMEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.428	0.435	0.456	0.470	0.477	0.484	0.491
SOEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.456	0.462	0.474	0.492	0.517	0.535	0.559

Source: E3

Table D-7: Power-to-Gas Fuel Inputs to PATHWAYS (Hydrogen and SNG), Optimistic Cost Scenario, Hydrogen Only

Hydrogen Technology – Variable	2020	2025	2030	2035	2040	2045	2050
AEC – Levelized Capital Cost (2016$/GJ-yr)	6.11	3.74	2.78	1.70	1.17	0.83	0.63
PEMEC – Levelized Capital Cost (2016$/GJ-yr)	9.72	5.96	4.29	2.64	1.81	1.26	0.95
SOEC – Levelized Capital Cost (2016$/GJ-yr)	48.60	2.84	0.97	0.93	0.91	0.89	0.88
AEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	3.97	3.91	3.86	3.75	3.65	3.56	3.47
PEMEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	4.21	4.15	3.97	3.86	3.75	3.61	3.47
SOEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	3.81	3.75	3.70	3.56	3.47	3.39	3.35
AEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.70	0.71	0.72	0.74	0.76	0.78	0.80
PEMEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.66	0.67	0.70	0.72	0.74	0.77	0.80
SOEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.73	0.74	0.75	0.78	0.80	0.82	0.83

Source: E3

Table D-8: Power-to-Gas Fuel Inputs to PATHWAYS (Hydrogen and SNG), Optimistic Cost Scenario, E-CEM CO2 Capture Process

Hydrogen Technology – Variable	2020	2025	2030	2035	2040	2045	2050
AEC – Levelized Capital Cost (2016$/GJ-yr)	49.40	36.64	29.73	22.58	18.37	15.29	13.26
PEMEC – Levelized Capital Cost (2016$/GJ-yr)	55.34	40.29	32.23	24.11	19.42	16.01	13.78
SOEC – Levelized Capital Cost (2016$/GJ-yr)	116.77	34.72	26.44	21.06	17.68	15.14	13.38
AEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	6.53	6.44	6.35	6.18	6.01	5.86	5.71
PEMEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	6.93	6.82	6.53	6.35	6.18	5.94	5.71
SOEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	6.09	6.01	5.86	5.71	5.38	5.19	4.91
AEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.44	0.45	0.46	0.47	0.48	0.50	0.51
PEMEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.42	0.42	0.44	0.46	0.47	0.49	0.51
SOEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.44	0.45	0.46	0.47	0.50	0.52	0.54

Source: E3

Table D-9: Power-to-Gas Fuel Inputs to PATHWAYS (Hydrogen and SNG), Optimistic Cost Scenario, DAC CO2 Capture Process

Hydrogen Technology – Variable	2020	2025	2030	2035	2040	2045	2050
AEC – Levelized Capital Cost (2016$/GJ-yr)	17.87	12.21	9.57	6.73	5.19	4.13	3.47
PEMEC – Levelized Capital Cost (2016$/GJ-yr)	23.81	15.86	12.07	8.27	6.24	4.85	3.99
SOEC – Levelized Capital Cost (2016$/GJ-yr)	85.66	10.60	6.53	5.42	4.68	4.13	3.71
AEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	6.53	6.44	6.35	6.18	6.01	5.86	5.71
PEMEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	6.93	6.82	6.53	6.35	6.18	5.94	5.71
SOEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	6.09	6.01	5.86	5.71	5.38	5.19	4.91
AEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.36	0.36	0.37	0.38	0.39	0.39	0.40
PEMEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.34	0.35	0.36	0.37	0.38	0.39	0.40
SOEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.38	0.39	0.39	0.40	0.42	0.44	0.46

Source: E3

Table D-10: Power-to-Gas Fuel Inputs to PATHWAYS (Hydrogen and SNG), Optimistic Cost Scenario, PCC CO2 Capture Process

Hydrogen Technology – Variable	2020	2025	2030	2035	2040	2045	2050
AEC – Levelized Capital Cost (2016$/GJ-yr)	12.642	8.158	6.226	4.109	3.008	2.284	1.843
PEMEC – Levelized Capital Cost (2016$/GJ-yr)	18.580	11.809	8.723	5.639	4.054	2.998	2.366
SOEC – Levelized Capital Cost (2016$/GJ-yr)	79.948	6.238	2.933	2.594	2.321	2.133	1.965
AEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	6.530	6.438	6.348	6.177	6.014	5.860	5.713
PEMEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	6.925	6.822	6.530	6.348	6.177	5.936	5.713
SOEC – Levelized Non-Energy VO&M Cost (2016$/GJ Fuel HHV)	6.094	6.014	5.860	5.713	5.377	5.194	4.915
AEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.456	0.463	0.470	0.484	0.498	0.513	0.527
PEMEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.428	0.435	0.456	0.470	0.484	0.505	0.527
SOEC – Overall Process Energy Efficiency (GJ Fuel HHV / GJ Input)	0.456	0.462	0.474	0.486	0.517	0.535	0.565

Source: E3

Table D-11: Biorefining CO2 Yield

Feedstock Category and Conversion Pathway	Yield (t CO_2/t feedstock)
Cellulose – Biomass to liquids	0.46
Cellulose – gasification	0.46
Cellulose – hydrolysis	1.04
Cellulose – pyrolysis	0.46
Landfill Gas – anaerobic digestion	0.40
MSW – Biomass to liquids	0.33
MSW – anaerobic digestion	0.33
MSW – gasification	0.89
Manure – anaerobic digestion	0.21
Wood – Biomass to liquids	0.51
Wood – gasification	1.01
Wood – hydrolysis	1.16
Wood – pyrolysis	0.51

Source: E3

Comparison of Estimated California Biomass and RNG Supply to Other Studies

Overview

Below is an overview to help understand the comparison.

- **The research team screened purpose-grown crops but otherwise included a relatively expansive view of the potential biomass and RNG resources.** Unlike some previous studies, this study excludes purpose-grown resources. At the same time, estimates are optimistic about utilization of the full potential supply of MSW and manure for advanced biofuel, as researchers assumed innovation will lead to increasing conversion efficiencies over time for all resources. The resulting estimate of RNG potential for California is near the high end of what is found in the literature.
- **The research team assumed California can use its own resources and import additional US resources up to a total based on its population share**. Because California has less residue and waste resources per capita than the national average, researchers assumed it can import from other states in a national biomass market, such that the total resource made available does not exceed its population share. This is to account for utilization of biomass in other regions as they decarbonize their own economies, as well as the philosophy that California's decarbonization strategy should be one that can be scaled up to larger regions.

- **Because of limited treatment of in-state biogas resources in the national DOE dataset used in this study, the potential feedstock supply is supplemented by an in-state assessment.** This in-state biogas potential is purely additive for each feedstock and does not reduce or supplant the state-level data from the national study.
- **Many biomethane feedstocks can also be used to make liquid fuels to displace petroleum.** The PATHWAYS biofuels module assumes that biomass can be allocated to different final fuels and end uses based on an optimization to maximize the cost-effective reduction in GHG emissions attainable with the biomass supply. Unlike studies focusing on the technical potential for directing biomass towards one particular sector or fuel, the PATHWAYS scenarios are designed around a limited fossil CO_2 and biofuel budget across all sectors in 2050, so using more biofuels in one sector necessarily reduces those available in another sector. State policy may incentivize a different biofuel portfolio, though the research team notes that current state policy directs nearly all biofuels towards displacing petroleum fuels in the transportation sector, rather than displacing fossil NG in the pipeline.
- **Avoided methane emissions from manure and waste resources are assumed to occur in all scenarios consistent with the state's SLCP Strategy.** These are accounted for as non-combustion emission measures rather than associated with bioenergy utilization in PATHWAYS using the CARB direct emissions accounting rather than lifecycle emissions accounting, but this analysis does prioritize the utilization of manure biogas that would not otherwise be cost-effective because of this co-benefit, based on the Low Carbon Fuel Standard (LCFS) carbon intensity (CI) for manure biogas.
- **The biomass supply potential assessed here focuses on economic or technical potentials, not gross potentials.** The gross potential is the total quantity of raw biomass generated each year. The technical potential is the quantity that could be physically recovered. The economic potential is the quantity that can be utilized economically, which depends somewhat on the value of the resulting fuels and the availability of alternatives.

Feedstock Availability

The biomass feedstock availability data for this study is from the 2016 update to the Department of Energy Billion-Ton Study (BTS)[23], and is supplemented with California-specific data from Jaffe et al. (2016)[24] for certain renewable natural gas feedstocks that

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23 U.S. Department of Energy. 2016. *2016 Billion-Ton Report: Advancing Domestic Resources for a Thriving Bioeconomy.* https://www.energy.gov/eere/bioenergy/2016-billion-ton-report.

24 Jaffe, Amy Myers, Rosa Dominguz-Faus, Nathan C. Parker, Daniel Scheitrum, Justin Wilcock, and Marshall Miller. UC Davis Institute of Transportation Studies. 2016. *The Feasibility of Renewable Natural*

are not well modeled in the BTS. The BTS dataset includes feedstocks disaggregated by state, feedstock type, and price and focuses primarily on resources from agriculture and forestry with some inclusion of solid MSW resources. It specifically excludes existing biomass resources that are currently used for bioenergy (such as for baseload electricity generation, combined heat and power, or conventional ethanol and biodiesel); it also lacks gaseous biogas resources. Consequently, as in E3 (2018)[25] the research team supplemented the BTS with feedstocks provided by Jaffe et al., consisting of landfill gas and biogas from wastewater treatment plants, manure, and food waste. There may be overlap between these supplemental feedstocks and the feedstocks included in the BTS, but it was not possible to discern where this overlap was or to directly correct for it. However, in comparing these results for final biogas availability to other studies, discussed further below, the research team found that these results are generally comparable, with some important caveats. The impact of double-counting is likely to have a small impact on results and to bias them towards overestimating RNG potential.

The total biomass available to California is assumed to be the state's population-weighted share of the national supply. Since California's proportion of the national population is larger than its proportion of the national biomass supply, this results in out-of-state biomass being available to California. All of California's biomass is assumed to be used in California (an assumption that would not be possible in states with a disproportionately large biomass supply relative to population). None of the scenarios assume that California imports biomass or biofuels from outside the U.S. or that California uses more than its population-weighted share of the U.S. biomass supply. This assumption is based on the scenario design philosophy that as California continues to decarbonize its energy economy, the rest of the U.S. and the world will also do so, claiming access to proportional shares of biomass and biofuels. By applying these assumptions of limited biomass, the scenarios create decarbonization strategies for California that could be replicated in other biomass-constrained parts of the world seeking to follow a similar decarbonization trajectory.

This study excluded energy crops and purpose-grown forest feedstocks from the analysis due to sustainability concerns. Energy crops are uncertain in their ability to reduce lifecycle GHG emissions[26], and can have other detrimental environmental

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Gas as a Large-Scale, Low-Carbon Substitute. https://steps.ucdavis.edu/wp-content/uploads/2017/05/2016-UCD-ITS-RR-16-20.pdf.

25 Mahone, Amber, Jenya Kahn-Lang, Vivian Li, Nancy Ryan, Zachary Subin, Douglas Allen, Gerrit De Moor, and Snuller Price. Energy and Environmental Economics, Inc. 2018. Deep Decarbonization in a High Renewables Future: Updated Results From the California PATHWAYS Model. https://www.ethree.com/wp-content/uploads/2018/06/Deep_Decarbonization_in_a_High_Renewables_Future_CEC-500-2018-012-1.pdf.

26 Plevin, Richard J., Michael O'Hare, Andrew D. Jones, Margaret S. Torn, and Holly K. Givvs. 2010. "Greenhouse Gas Emissions From Biofuels' Indirect Land Use Change Are Uncertain but May Be Much

impacts such as depletion of water resources and competition for land use with other crops.[27]

Comparison to Other Biomass Availability Data Sources

The DOE BTS is the primary data source on biomass availability in the United States, and thus there is not a large literature of other data sources that can be considered as reliable or more reliable. The research team identified two non-BTS sources to compare to for California biomass availability, and two non-BTS sources for national biomass availability. The results of this comparison are presented below in Table D-14.

Greater Than Previously Estimated." *Environ. Sci. Technol,* Volumn 44, No. 21, pp. 8015-8021. https://pubs.acs.org/doi/abs/10.1021/es101946t.
Melillo, Jerry M., John M. Reilly, David W. Kicklighter, Angelo C. Gurgel, Timothy W. Cronin, Sergey Paltsev, Benjamin S. Felzer, Xiaodong Want, Andrei P. Sokolov, and C. Adam Schlosser. 2009. "Indirect Emissions From Biofuels: How Important?" *Science,* Vol. 326, Issue 5958, pp. 1397-1399, https://science.sciencemag.org/content/326/5958/1397.
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27 Spawn, Seth A., Tyler J. Lark, and Holly K. Gibbs. 2019. "Carbon Emissions From Cropland Expansion in the United States." *Environmental Research Letters,* Volume 14, Number 4. https://iopscience.iop.org/article/10.1088/1748-9326/ab0399.

Table D-12: California Biomass Availability (In-State Only) for Different Data Sources (Millions of Dry Tons per Year)

	CBC / UC Davis*: 2013 resource	CCST**: 2050 resource, baseline scenario	CCST: 2050 resource, high-biomass scenario	Breunig et al. (2018)***: 2050 resource	E3 assumptions: 2040 resource
Residues	19.5	18.8	27.9	44.1	6.0
Waste resources	11.3	17.3	49.2	44.1	22.0
Energy crops	*Not included*	*4.5*	*45.7*	*Not included*	*Not included*
Total Excluding Energy Crops	30.8	36.1	77.1	44.1	28.0

All numbers shown above are for the technically available biomass potential, rather than the gross biomass potential.

***Does not count landfill or wastewater treatment gas, which are not listed in dry tons. The numbers presented here are from a Bioenergy Association of California document prepared by Rob Williams of UC Davis, showing the technical potential for biogas production. These numbers are based on UC Davis work, under CEC projects CEC-500-11-020 and CEC-500-2017-007. This study uses the numbers from the Bioenergy Association of California document here because the CEC reports do not include estimates for RNG potential from non-digestible feedstocks (only the raw biomass potential is included). Note, however, that the numbers in the BAC document for agricultural waste biomass availability are slightly lower than what is listed in the CEC reports (8.7 vs 12.1 million dry tons).**

**** Youngs, Heather, and Christopher R. Somerville. California Council on Science and Technology. 2013. California's Energy Future—The Potential for Biofuels.**

***** Breunig, Hanna Marie, Tyler Huntington, Ling Jin, alastair Robinson, and Corinne Donahue Scown. 2018. "Temporal and geographic drivers of biomass residues in California." Resources, Conservation and Recycling, Vol. 139, pp. 287-297 (https://doi.org/10.1016/j.resconrec.2018.08.022) Technical potential number obtained through correspondence with author; numbers included in published paper are gross potential. Also note that "residues" in this study encompasses some portion of what is considered "waste resources" in other studies. This study defines residues as "the organic fraction of municipal solid waste (MSW), crop residues, food and fiber processing residues, and forestry residues." Finally, note that the technical potential found by the authors is 37 million BDT in 2014, increasing to 44 million BDT in 2050 (these numbers are converted to short tons).**

Source: E3

Table D-13: National Biomass Availability for Different Data Sources (Millions of Dry Tons per Year)

	National Petroleum Council*: 2035-2050 resource	Union of Concerned Scientists**: 2030 resource	E3 assumptions: 2040 resource
Residues	272	175	242
Waste resources	80	102.3	120
Energy crops	*164*	*400*	*Not included*
Total Excluding Energy Crops	352	277.3	362

*** National Petroleum Council. 2012. "Topic Paper #22 Renewable Natural Gas for Transportation: An Overview of the Feedstock Capacity, Economics, and GHG Emission Reduction Benefits of RNG as a Low-Carbon Fuel." Numbers included are technical potential.**

**** Union of Concerned Scientists, 2012. The Promise of Biomass: Clean Power and Fuel—If Handled Right. (Accessed in Feb, 2019). Study does not specify whether numbers are gross potential or technical potential, but they are based on Billion Ton Study numbers which are technical potential.**

Source: E3

For California, this study's residue availability is lower than that of other studies examined. This is somewhat balanced by included estimates on waste resource availability, which is generally higher than the other studies. This study's total biomass availability for California is lower than the other studies examined, but higher than the DOE BTS due to the addition of supplemental feedstocks from Jaffe et al. (2016).

For national biomass availability, this study's supply numbers for residues and waste resources are generally comparable to the other two studies examined. Total biomass supply excluding energy crops is slightly higher than either of the two other studies.

Comparison of renewable natural gas availability to other data sources

In addition to comparing numbers on raw biomass to other studies, researchers examined how numbers for final RNG availability would compare to other studies if all feedstocks were converted to RNG and Table D-). This study performs an economy-wide optimization for biofuel allocation, finding that a large portion of the feedstocks modeled would go to displace petroleum fuels rather than provide RNG to serve existing pipeline gas end uses in most PATHWAYS scenarios, because it is more cost-effective to displace petroleum fuels that have a high CO_2-intensity and cost compared with natural gas.[28] Dry feedstocks are most frequently used for liquid fuels, while wet feedstocks generally are used for RNG. Other RNG resource assessment studies that assume dry feedstocks can be converted to RNG have noted that dry feedstocks are likely to see significant competition with liquid fuel production.

28 One option to displace diesel in trucks is to switch to more CNG trucks, which would allow more biomethane to be used cost-effectively in the economy-wide scenario, but would not make more biomethane available to displace NG from existing pipeline end uses. All of the PATHWAYS scenarios include an increasing share over time of CNG trucks and decreasing share of diesel trucks. Scenarios with more CNG trucks do have a greater share of biomethane relative to liquid biofuel production projected by the biofuel optimization module.

Table D-14: Estimates for California RNG Availability (BCF/yr)

	Jaffe et al., 2016[A]	CEC/UC Davis, 2015 and 2017[B]	Bioenergy Association of California, 2014[C]	NREL, 2016[D]	ICF, 2017[E]	E3 estimates (in-state only, assuming all feedstocks go to RNG)
LFG[F]	51.0	53.0	52.1	20.1	22.0 - 54.8	41.0
Manure	10.0	19.5	19.4	27.7	12.3 - 18.7	29.8
MSW and WWTP	22.5	88.2	65.9	39.1	26.6 - 57.3	238.1
Residues	Not included	190.8	112.0	21.3	44.1 - 77.4	78.5
Energy crops	*Not included*	*Not included*	*Not included*	*Not included*	*Not included*	*Not included*
Total Excluding Energy Crops	83.5	351.5	249.4	108.2	105.0 - 208.2	387.4

A: Jaffe, Amy Myers. UC Davis, Institute of Transportation Studies. 2016. *The Feasibility of Renewable Natural Gas as a Large-Scale, Low-Carbon Substitute.* Numbers included are technical potential.

B: Same as note above for the Bioenergy Association of California document. Numbers included are technical potential.

C: Levin, Julia, Katherine Mitchell, and Henry Swisher. Bioenergy Association of California. 2014. *Decarbonizing the Gas Sector: Why California Needs a Renewable Gas Standard.* Numbers included are technical potential.

D: Penev, Michael, Marc Melaina, Brian Bush, Matteo Muratori, Ethan Warner, and Yuche Chen. National Renewable Energy Laboratory. 2016. *Low-Carbon Natural Gas for Transportation: Wells-to Wheels Emissions and Potential Market Assessment in California.* Report does not specify whether these numbers are technical or gross potential.

E: Sheehy, Philip, and Jeff Rosenfeld. ICF. 2017. *Design Principles for a Renewable Gas Standard.* Note this report is cited in the 2017 IEPR.

F: Note that the estimate for LFG in this analysis is lower than that of Jaffe et al. because only LFG from Jaffe available at less than $11/MMBtu is included.

Source: E3

Table D-15: Estimates for U.S. RNG Availability (BCF/yr)

	NREL[A]	National Petroleum Council	AGF low[B]	AGF high	USDA[C]	E3 estimates (assuming all feedstocks go to RNG)
LFG	108	340	182	365	284	41[D]
Manure	84	140	148	493	257	142
MSW and WWTP	154	460	73	220	113	1538
Residues	Not included	2400	483	1208	Not included	3064
Energy crops	*Not included*	*1500*	*80*	*200*	*Not included*	*Not included*
Total Excluding Energy Crops	346	3340	886	2286	654	4785

A: National Renewable Energy Laboratory. 2013. "Energy Analysis—Biogas Potential in the United States." https://www.nrel.gov/docs/fy14osti/60178.pdf. Does not specify whether these numbers are technical or gross potential.

B: Gas Technology Institute. 2011. *The Potential for Renewable Gas: Biogas Derived From Biomass Feedstocks and Upgraded to Pipeline Quality.* Prepared for the American Gas Foundation. https://www.eesi.org/files/agf-renewable-gas-assessment-report-110901.pdf. Does not specify whether these numbers are technical or gross potential.

C: U.S. Department of Agriculture, U.S. Environmental Protection Agency, and U.S. Department of Energy. 2014. *Biogas Opportunities Roadmap: Voluntary Actions to Reduce Methane Emissions and Increase Energy Independence.* https://www.usda.gov/oce/reports/energy/Biogas_Opportunities_Roadmap_8-1-14.pdf. Does not specify whether these numbers are technical or gross potential.

D: Landfill gas outside of California was not assumed to be available for use in California and so not included in the E3 estimates.

Source: E3 (Note that estimates only include California LFG, as LFG is not included in the BTS.)

For California RNG availability, this study's estimate of 387 BCF per year is significantly higher than other studies, except for the CBC Davis work. (Note that including imported biofuel potential up to California's population-weighted share increases the RNG potential to 613 BCF per year, which appears in is primarily because most other RNG-specific studies do not include agricultural and forest residues that are likely to be used for liquid fuels rather than RNG. Note that the final results of this study's scenarios reflect these competing uses, but the comparison tables in this section assume that all feedstocks are converted to RNG. In addition, several MSW resources in the BTS dataset, including plastics and textiles, include some non-renewable content, and the research team recommends revisiting this inclusion in future California scenarios.

An additional reason that this study's MSW estimates are much higher than others is that, based on the integration of UCI biofuels conversion inputs into the PATHWAYS biofuels optimization model, this study projects that food waste and some other wet resources may be processed using thermochemical pathways such as gasification to RNG, rather than anaerobic digestion. In general, wet feedstocks are currently most cheaply converted to biomethane via anaerobic digestion, but UCI provided guidance that thermochemical processes can have a higher conversion efficiency than anaerobic digestion, and so may be optimal in an advanced biofuels market. This assumption leads to a higher RNG yield from the same feedstock quantity as compared with other RNG estimates. For US RNG availability, the numbers presented here are much higher than most other studies, for the same reasons. The exception is the National Petroleum Council study, which has an RNG availability number similar to ours due to optimistic assumptions for residues as well as the inclusion of energy crops.

In addition to differences in raw biomass estimates, the projected RNG technical potential may be somewhat higher than others because industry learning is assumed to enhance conversion yields over time, according to UCI's analysis. These efficiency assumptions are likely to differ from other studies, particularly when a closer time frame is examined.

The BTS dataset excludes currently used biomass resources for energy and fiber, even though some of these could be repurposed for higher value uses in a deep decarbonization scenario, and this presents another possible reason for differences between estimates in this study and others. This shortcoming was addressed first by using the BTS scenario that subtracts the least amount of existing resources from biomass availability for biofuels ("Medium housing, low energy demands"). Second, this shortcoming was addressed specifically for biogas resources such as landfill gas currently used for baseload electricity generation, by using the Jaffe et al. data. No suitable data was available to project whether other resources, like wood wastes currently used in the US for CHP in industry, could be repurposed for advanced biofuels in a deep decarbonization scenario.

APPENDIX E: PATHWAYS Scenarios

Model Updates

The PATHWAYS analysis builds off the modeling work previously done for the CEC (Mahone et al. 2018). For this study, the research team updated the biofuels and electrolytic fuels modules as described in Appendices C-D. In addition, several other model updates were included.

Electricity Inputs

Capital costs for new onshore wind, utility-scale solar, and battery storage were updated to reflect the E3 2018 assessment derived from the 2018 National Renewable Energy Laboratory Annual Technology Baseline (NREL ATB). This results in much lower projected renewable electricity costs, especially in the post-2030 timeframe, consistent with recent trends.

Retrofit Costs

It is typically assumed that it is more expensive to install heat pumps and other electric appliances when retrofitting existing buildings for the first time than for purchasing replacement units or for new construction. This study defines this cost increment as the "retrofit costs" incurred upon fuel-switching or upgrades (e.g., switching from a simpler, inefficient appliance like an electric resistance heater to a heat pump) for existing buildings, over and above the capital cost that would be required to replace existing appliances upon burnout with the same appliance (i.e. "like for like" replacements). This is difficult to implement in PATHWAYS modeling because PATHWAYS lacks an explicit characterization of appliance stocks by building type and vintage, but rather separately tracks the stock-rollover of each appliance type, residential buildings, and commercial square feet. Furthermore, there is a lack of comprehensive data on what these "retrofit costs" are.

A crude estimate of these costs was incorporated despite their uncertainty because neglecting them entirely assumes they are zero, which is certainly an underestimate. Based on electrification literature and the capital cost estimates in [E3, 2019], this study focused on two sources of retrofit costs incurred in residential buildings: electrical infrastructure upgrades, such as the main electrical panel or new electrical lines, and appliance installation costs, such as the placement of a new compressor when adding a heat pump HVAC system in the absence of existing air conditioning. The research team assumed that each of these costs amounts to $4000, tied for simplicity to the heat pump space heating end use in PATHWAYS, but the $4000 does not apply to all buildings and vintages. In existing homes that were built before and not experiencing other upgrades since 1995, the electrical infrastructure costs apply, but not to newer buildings. With new construction and turnover of existing buildings as older buildings are otherwise upgraded, this share declines as a share of the building stock to be a minority of buildings by 2030. The appliance installation costs were applied to 50% of all existing buildings experiencing upon retrofit. Similar logic was used in commercial buildings, with a single combined retrofit cost equal to the assumed cost of installing new air conditioning equipment, applying to 50% of all commercial heat pump HVAC retrofit installations.

These retrofit costs are added to the capital cost of appliances and are annualized over the new appliance useful life as for other appliance capital costs. This results in peak annual scenario retrofit costs in 2048 of about $3B across residential and commercial buildings, beginning to decline by 2050. Note that independent of these retrofit costs, net capital cost savings occur when heat pump HVAC systems displace the combination of a natural gas furnace and a separate air conditioner.

Building Stock Turnover

As in (Mahone et al., 2019), the turnover lifetime of residential buildings in between deep retrofits or rebuilds was increased to 75 years from 50 years, with a broader survival profile distribution assumed based on the research team's judgment. Little data is available to confirm this choice, except insofar as recent building turnover in California has lagged behind population and economic trends, so even the longer lifetime tends to overpredict near-term building turnover. This assumption primarily impacts the retrofit cost calculation above, in addition to resulting in very slightly higher building energy demands due to slower upgrades to more efficient building shells.

Gas Heat Pump Technology Option for Residential and Commercial Water Heating and Space Heating

Some of the additional scenarios (below) included natural gas heat pumps, for which technology cost and efficiency assumptions were added to PATHWAYS. Gas heat pumps were assumed to be installed as a combined unit comprising a water heater and space heater, following Aas et al (2018). The higher cost estimate in that study (from the National Energy Modeling System) was used for installations in 2018, trending down to the lower cost estimate by 2030. However, retrofit costs for appliance installation (but not for electrical infrastructure upgrade) were applied similarly to electric heat pumps.

Hydrogen Fuel Cell Truck and Liquid Hydrogen Distribution Efficiency and Costs

For this study, E3 updated assumptions for hydrogen fuel cell trucks based on a bottom-up estimate and internal analysis. Capital costs and efficiencies were updated based on various engineering sources (see references below), leading to somewhat less expensive hydrogen trucks than in Mahone et al. (2018). The capital cost increment for heavy-duty trucks over conventional diesel trucks was modeled as $118,000 in 2030, declining to $102,000 by 2050. Truck efficiency was modeled as 8.4 mi per gallon of gasoline-equivalent in 2030, increasing to 9.1 by 2050.

In addition, hydrogen liquid fuel delivery assumptions were modified based on the US Department of Energy "H2A" model.[29] Delivery efficiency was modeled as 77%, with an 8% hydrogen loss factor associated with boil-off. Levelized liquid hydrogen delivery costs were modeled as $20/mmBTU.

Fuel Cell Vehicle References

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[29] Elgowainy, A. and Reddi, K. 2012. HRSAM Version 2.0, 2012, Argonne National Lab

Scenario Measures

Table E-1: Shared Scenario Measures for All Mitigation Scenarios

Sector	Measure	All Scenarios
Buildings	Conventional electric energy efficiency (excluding electrification)	All scenarios include a doubling of historical energy efficiency through 2030, benchmarked to the California Energy Commission's IEPR (Integrated Energy Policy Report) 2016 forecast.
Buildings	Conventional natural gas energy efficiency	All new natural gas furnaces and water heaters are very high efficiency by 2025, equivalent to condensing furnaces.
Transportation	Smart growth & reduction in driving demand	Per-capita vehicle miles traveled are reduced by 7% by 2030 and 19% by 2050, relative to 2015.
Transportation	Electrification: Cars and light trucks	100% of new car and light truck sales are electric vehicles (battery-electric or plug-in hybrid) by 2035.
Transportation	Electrification: Buses	100% of new bus sales are battery-electric by 2030.
Transportation	Electrification: Off-road	75% of rail, 80% of ports, and 50% of other ground vehicles & equipment are electrified by 2050.
Industry	Energy efficiency: non-petroleum industries	Energy demand is reduced by about 15% by 2050, relative to 2015.
Industry	Demand reduction: petroleum industries	Production and energy demand for in-state oil and gas extraction and oil refining are reduced by about 90% by 2050, commensurate with declining demand for liquid petroleum fuels.
Electricity	Zero-carbon electricity	All scenarios reach about 95% zero-carbon electricity (% of generation) by 2050, including pipeline biomethane; precise percentages vary by a few percent between scenarios.
Electricity	Total wind build	All scenarios assume 51 GW of total wind capacity available to the state by 2050 to complement solar, modeled here as including about 39 GW of out-of-state wind (alternatives would include offshore wind or more batteries).
Biofuels	Advanced biofuels	All scenarios include the full resource of 43 million dry tons of residue biomass by 2050, the population-weighted share of US supply. Biomass is assigned to biofuels based on the final fuel demands for each scenario, optimized to minimize scenario cost.
Non-Combustion	Emissions reduction	Non-combustion emissions are reduced by 62% for fluorinated gases and methane, and 42% for other gases, by 2050, relative to 2015 emissions.

Source: E3

Table E-2: Scenario-Specific Measures: Primary "Bookend" Mitigation Scenarios

Sector	Measure	High Building Electrification (HBE)	No Building Electrification (NBE)
Summary		Heat pumps and other building electrification are included, with moderately high electrification in other sectors.	No building electrification, with increased used of RNG in the pipeline, including SNG.
Buildings	Building electrification: heat pumps	Space heater and water heater sales increase to 100% electric heat pumps by 2040, replacing natural gas, propane and electric resistance heating.	Heat pumps only replace electric resistance heaters, replacing 100% of new sales of these by 2040.
Buildings	Total building electrification	Electricity serves 91% of energy consumption in buildings by 2050.	Electricity serves 49% of energy consumption in buildings by 2050.
Buildings	Advanced natural gas efficiency: NG heat pumps	None	None
Transportation	Medium-duty truck electrification: battery-electric trucks	Battery-electric trucks reach 39% sales of new trucks by 2040.	Battery-electric trucks reach 71% sales of new trucks by 2040 and 91% by 2050.
Transportation	Zero-emission heavy-duty trucks: Battery-electric for short haul and hydrogen fuel cell for long haul	Zero emission trucks reach 31% of sales of new trucks by 2040 and 34% by 2050.	Zero emission trucks reach 67% of sales of new trucks by 2040 and 69% by 2050.
Transportation	Alternative fuels: compressed natural gas trucks	CNG trucks reach 69% of HDV sales and 61% of MDV sales by 2040.	CNG trucks reach 24% of HDV sales and 7% of MDV sales by 2040.
Industry	Electrification: substitution of electricity for NG end uses in non-petroleum industries	Only HVAC is electrified.	Only HVAC is electrified.
Industry	Total industry electrification: non-petroleum industries	Electricity serves 18% of energy consumption in industry by 2050.	Electricity serves 18% of energy consumption in industry by 2050.
Pipeline	Renewable natural gas: renewable hydrogen blend	None	7% blend (by energy) of hydrogen gas is blended into the pipeline.
Pipeline	Renewable natural gas: synthetic natural gas from electrolysis and renewable CO2	None	21% blend (by energy) of SNG is blended into the pipeline.
Pipeline	Renewable natural gas: biomethane	25% blend (by energy) of biomethane in the pipeline.	16% blend (by energy) of biomethane in the pipeline.
Electricity	Storage build: pumped hydro and batteries to reduce curtailment of solar and wind	35 GW of storage is included in the 2050 portfolio.	35 GW of storage is included in the 2050 portfolio.

Source: E3

Table E-3: Scenario-Specific Measures: Additional Mitigation Scenarios (Not Included in Body of Report)

Sector	Measure	High Building Electrification with Less CNG Trucks	No Building Electrification with Gas Heat Pumps	No Building Electrification with Industry & Truck Measures	Delayed Electrification	Slower Electrification	Mixed with Gas Heat Pumps
Summary		Heat pumps and other building electrification are included, with moderately high electrification in other sectors. Less CNG trucks and more diesel trucks are used than in HBE	No building electrification, with a combination of gas heat pumps and increased RNG, including SNG.	No building electrification, trying to minimize use of SNG by relying on aggressive electrification and hydrogen measures in industry and transportation.	Mixed strategy through 2030, followed by rapid building electrification.	Mixed strategy through 2030, with gradual building electrification thereafter, e.g. focusing on new construction.	Mixed strategy through 2030, followed by rapid shift to gas heat pumps.
Buildings	Building electrification: heat pumps	Space heater and water heater sales increase to 100% electric heat pumps by 2040, replacing natural gas, propane and electric	Heat pumps only replace electric resistance heaters, replacing 100% of new sales of these by 2040.	Heat pumps only replace electric resistance heaters, replacing 100% of new sales of these by 2040.	Space heater and water heater sales reach 20% electric heat pumps by 2030 and 100% by 2040, replacing natural gas, propane, and electric	Space heater and water heater sales reach 20% electric heat pumps by 2030 and about 68% by 2050, replacing natural gas, propane, and electric	Space heater and water heater sales reach 20% electric heat pumps by 2030 and 40% by 2050, replacing natural gas, propane, and electric

Sector	Measure	High Building Electrification with Less CNG Trucks	No Building Electrification with Gas Heat Pumps	No Building Electrification with Industry & Truck Measures	Delayed Electrification	Slower Electrification	Mixed with Gas Heat Pumps
		resistance heating.			resistance heating.	resistance heating.	resistance heating.
Buildings	Total building electrification	Electricity serves 91% of energy consumption in buildings by 2050.	Electricity serves 55% of energy consumption in buildings by 2050.	Electricity serves 49% of energy consumption in buildings by 2050.	Electricity serves 84% of energy consumption in buildings by 2050.	Electricity serves 64% of energy consumption in buildings by 2050.	Electricity serves 62% of energy consumption in buildings by 2050.
Buildings	Advanced natural gas efficiency: NG heat pumps	None	New natural gas water heaters and furnaces (space heaters) are replaced with natural gas heat pumps, reaching 100% of natural gas heater sales by 2035 (and 90% of all heater sales).	None	Some new natural gas water heaters and furnaces (space heaters) are replaced with natural gas heat pumps, reaching 10% of sales by 2030.	Some new natural gas water heaters and furnaces (space heaters) are replaced with natural gas heat pumps, reaching 10% of sales by 2030.	Space heater and water heater sales reach 60% sales of natural gas heat pumps by 2040, replacing natural gas and propane heating.
Transportation	Medium-duty truck electrification: battery-electric trucks	Battery-electric trucks reach 41% sales of new trucks by 2040 and	Battery-electric trucks reach 71% sales of new trucks by 2040 and 91% by 2050.	Battery-electric trucks reach 100% sales of new trucks by 2035.	Battery-electric trucks reach 41% sales of new trucks by 2040 and 71% by 2050.	Battery-electric trucks reach 71% sales of new trucks by 2040 and 91% by 2050.	Battery-electric trucks reach 71% sales of new trucks by 2040 and

Sector	Measure	High Building Electrification with Less CNG Trucks	No Building Electrification with Gas Heat Pumps	No Building Electrification with Industry & Truck Measures	Delayed Electrification	Slower Electrification	Mixed with Gas Heat Pumps
		71% by 2050.					91% by 2050.
	Zero-emission heavy-duty trucks: Battery-electric for short haul and hydrogen fuel cell for long haul	Zero emission trucks reach 31% of sales of new trucks by 2040 and 34% by 2050.	Zero emission trucks reach 67% of sales of new trucks by 2040 and 69% by 2050.	Zero emission trucks reach 100% of sales of new trucks by 2035.	Zero emission trucks reach 31% of sales of new trucks by 2040 and 34% by 2050.	Zero emission trucks reach 67% of sales of new trucks by 2040 and 69% by 2050.	Zero emission trucks reach 67% of sales of new trucks by 2040 and 69% by 2050.
	Alternative fuels: compressed natural gas trucks	CNG trucks reach 24% of HDV sales and 7% of MDV sales by 2040.	CNG trucks reach 24% of HDV sales and 7% of MDV sales by 2040.	CNG trucks reach 24% of HDV sales and 7% of MDV sales by 2040.	CNG trucks reach 24% of HDV sales and 7% of MDV sales by 2040.	CNG trucks reach 24% of HDV sales and 7% of MDV sales by 2040.	CNG trucks reach 24% of HDV sales and 7% of MDV sales by 2040.
Industry	Electrification: substitution of electricity for NG end uses in non-petroleum industries	Only HVAC is electrified.	Only HVAC is electrified.	HVAC, 100% of boilers, 20% of process heating, and 30% of other NG end uses are converted to electricity.	Only HVAC is electrified.	Only HVAC is electrified.	HVAC, 30% of boilers, 20% of process heating, and 30% of other NG end uses are converted to electricity.

Sector	Measure	High Building Electrification with Less CNG Trucks	No Building Electrification with Gas Heat Pumps	No Building Electrification with Industry & Truck Measures	Delayed Electrification	Slower Electrification	Mixed with Gas Heat Pumps
Industry	Total industry electrification: non-petroleum industries	Electricity serves 18% of energy consumption in industry by 2050.	Electricity serves 18% of energy consumption in industry by 2050.	Electricity serves 48% of energy consumption in industry by 2050.	Electricity serves 18% of energy consumption in industry by 2050.	Electricity serves 18% of energy consumption in industry by 2050.	Electricity serves 38% of energy consumption in industry by 2050.
Pipeline	Renewable natural gas: renewable hydrogen blend	None	7% blend (by energy) of hydrogen gas is blended into the pipeline.	7% blend (by energy) of hydrogen gas is blended into the pipeline.	None	7% blend (by energy) of hydrogen gas is blended into the pipeline.	4% blend (by energy) of hydrogen gas is blended into the pipeline.
Pipeline	Renewable natural gas: synthetic natural gas from electrolysis and renewable CO2	None	10% blend (by energy) of SNG is blended into the pipeline.	None	None	None	None
Pipeline	Renewable natural gas: biomethane	16% blend (by energy) of biomethane in the pipeline.	16% blend (by energy) of biomethane in the pipeline.	20% blend (by energy) of biomethane in the pipeline.	23% blend (by energy) of biomethane in the pipeline.	19% blend (by energy) of biomethane in the pipeline.	20% blend (by energy) of biomethane in the pipeline.
Electricity	Storage build: pumped hydro and	35 GW of storage is included in	35 GW of storage is	48 GW of storage is	35 GW of storage is	48 GW of storage is	48 GW of storage is included in

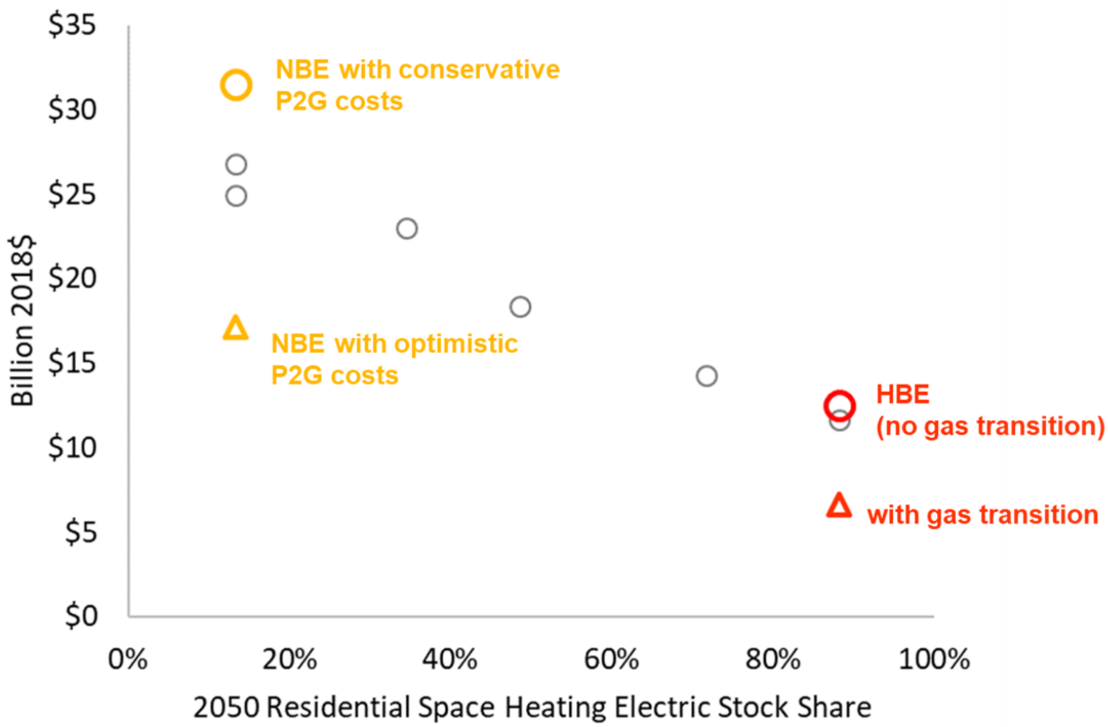
Sector	Measure	High Building Electrifi-cation with Less CNG Trucks	No Building Electrification with Gas Heat Pumps	No Building Electrification with Industry & Truck Measures	Delayed Electrification	Slower Electrification	Mixed with Gas Heat Pumps
	batteries to reduce curtailment of solar and wind	the 2050 portfolio.	included in the 2050 portfolio.	included in the 2050 portfolio.	included in the 2050 portfolio.	included in the 2050 portfolio.	the 2050 portfolio.

Source: E3

Scenario Net Costs

A scatterplot of scenario net costs relative to a metric of the degree of building electrification is shown in Figure E-1. Scenarios with intermediate levels of building electrification had intermediate levels of key diagnostics as well, such as net economywide cost relative to the Reference. This study concluded that across the range of scenarios tested, the two “bookend” scenarios would suffice to illustrate the economywide implications of contrasting building decarbonization strategies.

Figure E-1: Annual Net Economywide Cost in 2050 Relative to Reference



Source: E3

APPENDIX F: Air Quality Impacts of Future of Natural Gas Scenarios

The following document represents a current synopsis of the air quality research conducted for the project. It includes an assessment of three scenarios for impacts on regional, outdoor air quality and associated human health benefits, including consideration of impacts to disadvantaged communities. However, the air quality work will be expanded to include additional assessments, including the potential impacts of sited biorefineries throughout the State, and the potential impacts of changes in end-use emissions due to hydrogen blending within the natural gas pipeline system. The results presented here, along with the results of the additional work, will be published in a forthcoming standalone report focused on air quality and human health impacts.

Introduction

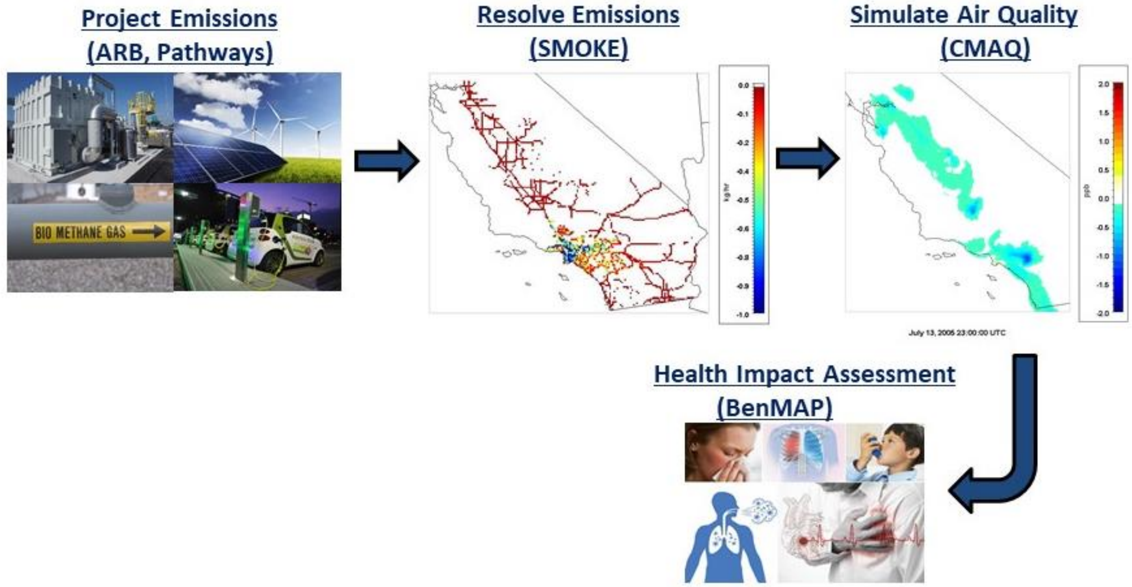
The technology assumptions within long-term low-carbon scenarios will impact criteria air pollutant emissions including oxides of nitrogen (NO_x), particulate matter (PM), carbon monoxide (CO), reactive organic gasses (ROG), and oxides of sulfur (SO_x). Such shifts occur quantitatively (in total), spatially (where), temporally (when), and in composition (what); all of which subsequently influence ambient concentrations of primary and secondary air pollutant species including ozone and $PM_{2.5}$. Further, the formation and fate of secondary air pollutants is governed by complex, non-linear atmospheric processes, e.g., shifts to electric technologies will achieve air quality benefits via reductions in ozone as a result of ROG and NO_x emission reductions. However, without atmospheric modeling, quantification of ozone concentration reductions is not possible as ozone formation in the atmosphere does not linearly correlate to pre-cursor emission reductions. Nor can the spatial locations and temporal periods of ground-level ozone concentration changes be determined. Finally, how these impacts might be different in the future given the significant change in emissions and emission sources expected to the year 2050 is unclear. Therefore, an in-depth understanding must be obtained regarding emissions from all relevant stages followed by simulations of atmospheric chemistry and transport to properly evaluate impacts on regional air quality.

The goal of this task is to characterize and quantify the air quality and human health impacts for a set of long-term low-carbon scenarios established in Task 4 to provide insight into the co-benefits of technological shifts within cases. Using output from PATHWAYS, the research team developed spatially and temporally resolved characterizations of criteria pollutants for each scenario for all major end-use sectors in California, including all stationary and mobile sources. Next, researchers translated emission changes into impacts on atmospheric pollution levels, including ground level ozone and $PM_{2.5}$, via a 3-D photochemical air quality model that accounts for atmospheric chemistry and transport. Impacts on regional air quality were then used to conduct a health impact assessment which provides a quantitative estimate of the incidence and value of avoided harmful health outcomes associated with air pollution.

Methods

On overview of the modeling methods utilized for the assessment is provided in Figure F-1. To evaluate regional air quality impacts in 2050, emission fields must be developed accounting for differences in energy consumption and the technological composition of all end-use sectors. This requires two steps: 1 - projecting emissions from current levels to the simulation period (2050) and 2 - spatially and temporally allocating emissions throughout the modeling domain and period consistent with the activity of emission sources. For the first step, a California state-wide emissions inventory for 2012 developed by California Air Resources Board (CARB) is used as the baseline [1]. The 2012 emissions are then projected to 2035 using statewide growth and control factors developed from CARB's CEPAM: 2016 SIP - Standard Emission Tool [2]. The CEPAM inventory accounts for current policy with implications for future emissions, e.g., included are the South Coast Air Quality Management District's Rule 1111 and the San Joaquin Valley Air Pollution Control District's Rule 4905 limiting NO_x emissions from natural gas furnaces. Output from PATHWAYS is used to project emissions from 2035 to 2050 accounting for assumptions made with regards to energy consumption and technology deployment. The second step is carried out using the Sparse Matrix Operator Kernel Emissions tool (SMOKE) [3]. SMOKE is an emissions processing system that develops appropriately formatted emission fields for air quality model input using a series of matrix calculations and allows for rapid and flexible processing of emissions data [4]. SMOKE carries out the core functions of emissions processing including spatial and temporal allocation, chemical speciation, generation of biogenic emission estimates and control of area-, mobile-, and point-source emissions.

Figure F-1: Overview of the Modeling Methods Used for the Air Quality and Human Health Assessment



Source: UCI APEP

Simulations of atmospheric chemistry and transport are accomplished via the Community Multi-scale Air Quality Model version 5.2 (CMAQv5.2) [5] to establish fully developed distributions of concentrations of pollutants of interest, including ground-level ozone and $PM_{2.5}$. CMAQ is a comprehensive air quality modeling system developed by the US Environmental Protection Agency (EPA) and widely used for a numerous air quality assessment needs [6], [7]. The two pollutants considered to assess air quality are $PM_{2.5}$ and tropospheric ozone as many regions of California experience ambient levels in excess of State and Federal health-based standards [8], and both are associated with human health detriments supported by a broad body of scientific literature [9]–[11]. Two simulation periods are conducted to capture the effect of seasonal variation in meteorology and emissions concentrations including a summer episode (July 8-21) and winter episode (January 1-14). For consistency with ambient air quality standards, ground-level concentrations are reported as maximum daily 8-h average ozone (MD8H) and 24-h average $PM_{2.5}$ calculated by two different methods. First, to capture the peak impacts this analysis calculates the largest MD8H ozone and 24-h $PM_{2.5}$ average that occurs for each model grid cell for any averaging period within the episode. This provides an understanding of the maximum impact that may be experienced in California for the given conditions. Second, to provide a marker of the general impact experienced throughout the entire episode, the average MD8H ozone and 24-h $PM_{2.5}$ experienced for each modeling grid cell was calculated.

Epidemiology studies have shown that a diminution in air pollution concentration results in a reductions in the incidence of deleterious health effects across exposed populations. The tool used to quantify these impacts is the environmental Benefits Mapping and Analysis Program—Community Edition (BenMAP-CE) from the U.S. EPA

[12]. BenMAP-CE allows for the estimation of the avoided incidence and economic value of health impacts resulting from changes in air pollution concentrations [13]. The methods used closely follow those in the South Coast Air Quality Management District's (SCAQMD) Socioeconomic Report for the 2016 Air Quality Management Plan (AQMP), including selection of concentration-response and valuation functions [14]. Though BenMAP-CE can be used to estimate long-term health impacts such as those occurring from annual average $PM_{2.5}$ changes, impacts are reported here for short-term exposure to ozone and $PM_{2.5}$ as appropriate for the modeled episode. It should be noted that the value of short-term health benefits estimated in BenMAP-CE are generally lower than those estimated for long-term, and this should be considered when comparing the results to other studies.

Results

Scenario Development

The Current Policy Reference Case (herein referred to as the Reference Case) is used as a baseline for the analysis of mitigation scenarios. Three alternative cases are assessed for impacts on air quality and human health, including the High Building Electrification (HBE) Case, No Building Electrification (NBE) Case, and High Building Electrification with Truck Measures (HBEwT) Case. All three alternative cases assume the implementation of GHG mitigation measures relative to the Reference Case (i.e., efficiency increases, transitions to low carbon fuels and near-zero/zero emission technologies) which correspondingly influence criteria pollutant emissions across numerous end-use sectors, including light duty vehicles (LDV), offroad equipment, petroleum refineries, industry, and others. However, all of the assumptions are held constant across the HBE, NBE, and NBEwT Cases, with the exception of those applying to medium- and heavy-duty vehicles (MDV and HDV), residential and commercial buildings, and electricity generation. Table F-1: displays the assumptions made within the residential and commercial building and HDV sectors for the three alternative cases. Within the HBE Case, it is assumed that appliances (including those for space heating, water heating, cooking, and other uses) within buildings experience a significant transition from natural gas to electric. The sources correspond to all those supplied by natural gas only, and do not assume changes in emissions from other fuel sources in buildings including emissions from wood burning in the residential sector, which remain constant for all cases. Therefore, the air quality impacts described for buildings can be attributed solely to the use of natural gas in the residential and commercial sectors. In contrast, the NBE Case assumes little electrification of buildings, but also assumes a greater penetration of zero- and low-emission stock within MDV and HDV than does the HBE Case. It should be noted that the low- and zero-emissions truck measures include the use of battery electric, hydrogen fuel cell, and advanced compressed natural gas (CNG) vehicles. The HBEwT Case encompasses the measures assumed for both building electrification in the HBE Case and the MDV and HDV stock in the NBE Case, allowing for comparisons across cases to be made which provide insight into the relative impacts of buildings and trucks.

Table F-1: Scenario Assumptions Regarding the Electrification of Residential and Commercial Buildings and Heavy-Duty Vehicles

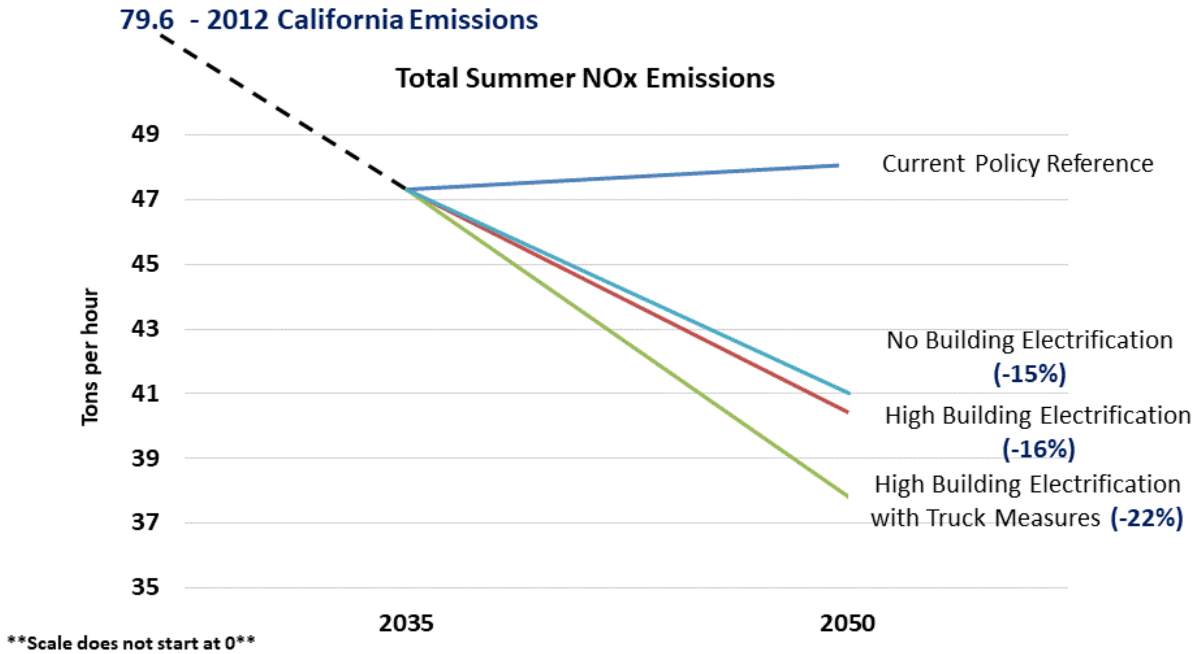
Scenario	Building Electrification (% residential space heating stock in 2050)	Low and Zero Emission Trucks* (heavy-duty truck stock in 2050)
High Building Electrification	88%	53%
No Building Electrification	13%	86%
High Building Electrification with Trucks	88%	86%

Source: E3

Emissions

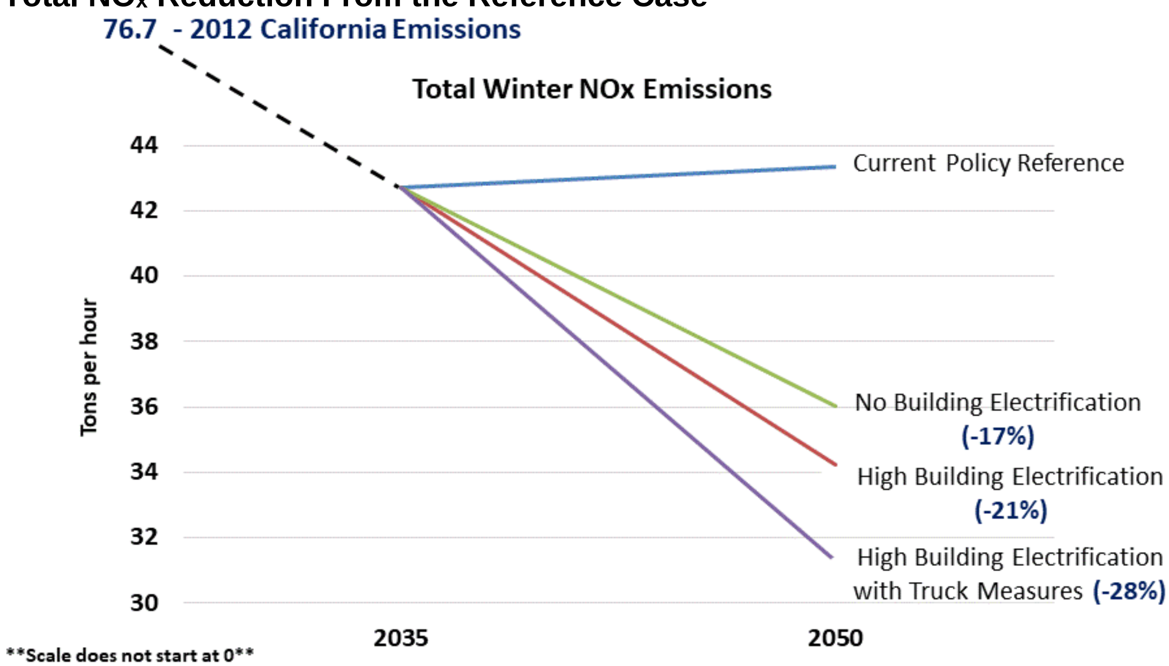
The following section presents the change in criteria pollutant emissions for the alternative scenarios when the assumptions regarding end-use sectors are applied to the base year inventory. Figure F-2: and Figure F-3: display the total emissions of NOx in summer and winter for the cases considered from 2035 to 2050, respectively. Additionally, total NOx reported in the ARB inventory for 2012 is shown demonstrating the significant reductions assumed to 2035 as a result of current California regulatory policy. In the Reference Case, total NOx increases moderately to 2050 for both winter and summer, largely as a result of increased energy consumption and the lack of additional alternative technology deployment. Relative to the Reference Case, in summer the alternative cases achieve reductions in total NOx of -15% (NBE), -16% (HBE), and -22% (HBEwT). In the winter episode, total NOx reductions are -17% (NBE), -21% (HBE), and -28% (HBEwT). These differences result from the mitigation measures that are assumed within all sectors, including LDV, MDV, HDV, offroad, rail, aircraft, ships, petroleum refining, industry, etc. In contrast, differences between the three alternative cases themselves (e.g., NBE vs. HBE) are driven by only by the mitigation measures described in Table F-1:.

Figure F-2: Projected Total NO_x Emissions in the Summer Episode for the Cases Considered Within the Air Quality Assessment. Percentages in Blue Indicate the Total NO_x Reduction From the Reference Case.



Source: UCI APEP

Figure F-3: Projected Total NO_x Emissions in the Winter Episode for the Cases Considered Within the Air Quality Assessment. Percentages in Blue Indicate the Total NO_x Reduction From the Reference Case



Source: UCI APEP

The effect of seasonal energy demands is evident in the NO_x reduction trends for residential and commercial building electrification as more natural gas is used for space heating during winter months. In summer, the difference between a very high level of electrification within buildings in the HBE Case and the alternative truck measures assumed for the NBE Case result in a difference of total NO_x of 1% (-15% vs. -16%). When these measures are both assumed within the HBEwT Case, the total reduction reaches 22%. However, increased natural gas demand for residential and commercial space heating in winter yield larger emission reductions from building electrification, resulting in a greater difference between the NBE and HBE Cases (-17% vs. -21%) and total reduction in the HBEwT Case (-28%).

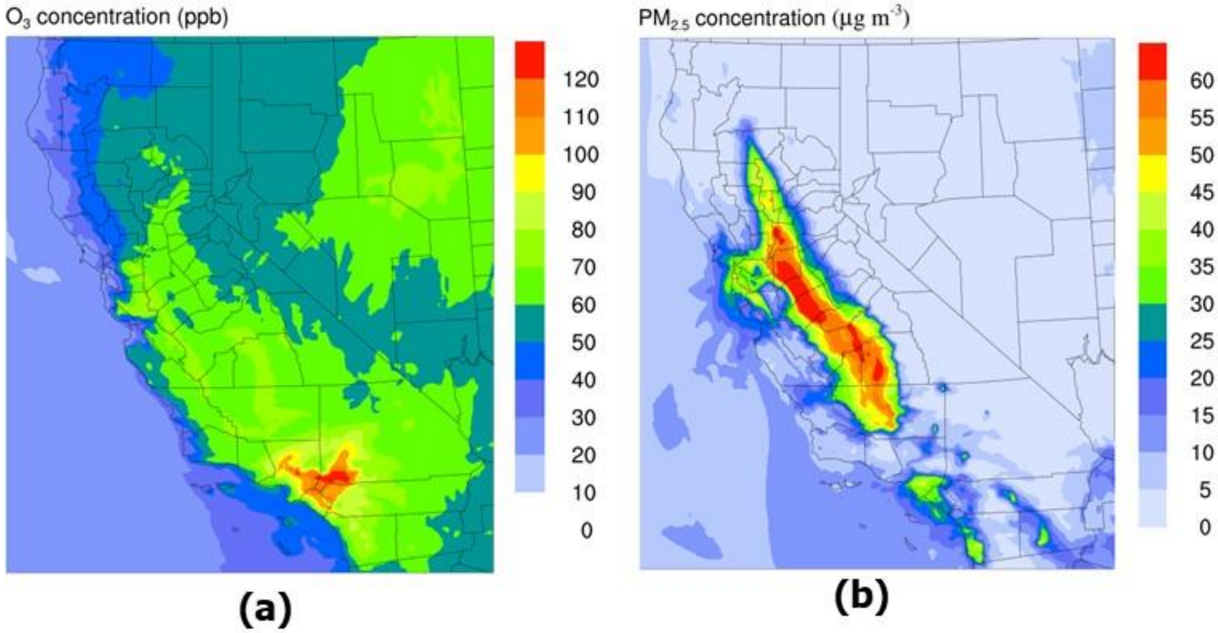
Air Quality

The following section presents the impacts on regional air quality for the reference and alternative cases for differences in both peak and average ozone, and peak and average $PM_{2.5}$. It should be noted that differences in ozone and $PM_{2.5}$ are driven by the emission reductions characterizing each case, both quantitatively (how much) and spatially and temporally (where and when) the reductions occur. For example, emission reductions from building electrification will occur at different locations and times than emission reductions from HDV. First, the absolute concentrations are reported for the Reference Case in 2050 to establish baseline air quality. Next, concentration differences are reported for the HBE Case, NBE Case, and HBEwT Case from the Reference Case to demonstrate the overall impact of measures considered for all sectors including LDV, MDV, HDV, off-road, ships, residential and commercial buildings, industry, etc.

Absolute Concentrations for the Reference Case

The Reference Case serves as the baseline for comparison of the alternative cases. The maximum concentrations simulated for summer MD8H ozone (120 ppb) and winter 24-h $PM_{2.5}$ (63 ug/m^3) are presented in Figure F-4:. It should be noted that these values represent the highest value in one grid cell within the modeling domain, and the majority of the domain experiences lower concentrations. When averaged across the modeling period, concentrations for the same periods reach 58 ppb and 43 ug/m^3. The locations of peak impacts (both maximum and average) are important as they carry implications for human exposure and subsequent deleterious impacts on health. Considering ozone, the highest ozone levels occur in the densely populated South Coast Air Basin (SoCAB), with peaks occurring in eastern portions including San Bernardino and Riverside Counties. For $PM_{2.5}$, the highest levels for both winter and summer occur in the Central Valley, although winter concentrations peak in northern regions Valley and summer 24-h $PM_{2.5}$ is highest in southern portions. It should be noted that the modeled episodes are selected to be representative of peak episodes of degraded air quality, i.e., periods of very high pollutant concentrations.

Figure F-4: Peak (a) Summer MD8H Ozone and (b) Winter 24-h $PM_{2.5}$ Predicted for the Reference Case

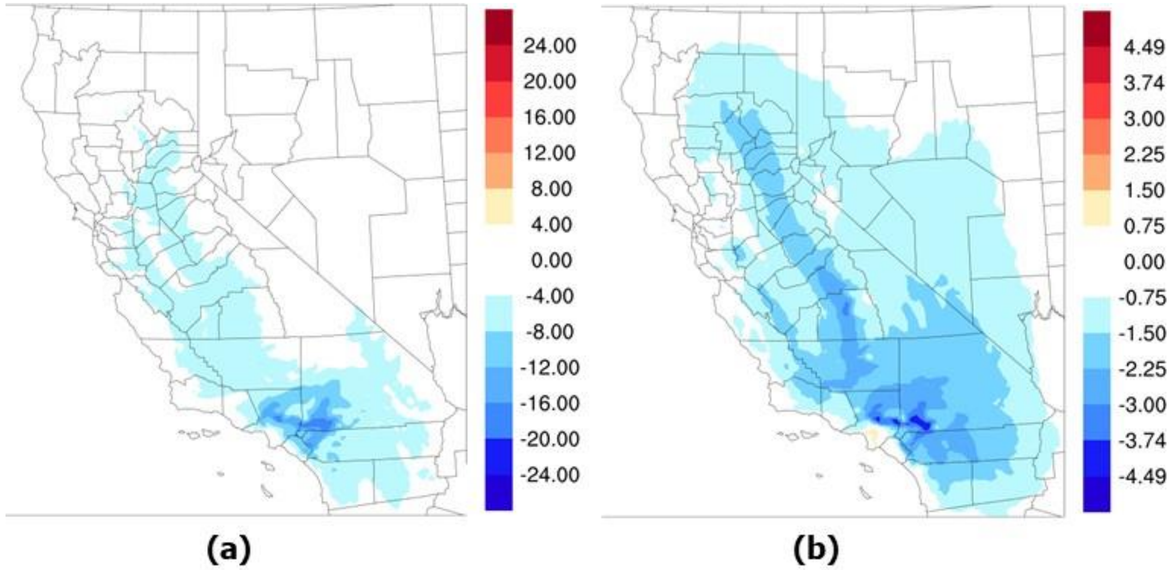


Source: UCI APEP

Concentration Differences for the High Building Electrification Case

The following section presents the changes in pollutant concentrations from the Reference Case that occur due to the mitigation measures assumed within the HBE Case. The differences in both peak and average summer MD8h predicted for the HBE Case relative to the Reference Case are shown in Figure F-5. The results are reported as reductions from the absolute concentrations described for the Reference Case i.e., delta ozone and $PM_{2.5}$. Two metrics are quantified to characterize the air quality impacts – maximum reductions and average reductions as described in the methods section. Maximum improvements in ozone reach -19.4 ppb while average reductions reach -4.5 ppb. Spatially, impacts are most pronounced in the SoCAB, which is important from a human health standpoint given the associated high population and the location of the highest background levels. Impacts are also noted in the Central Valley with similar importance.

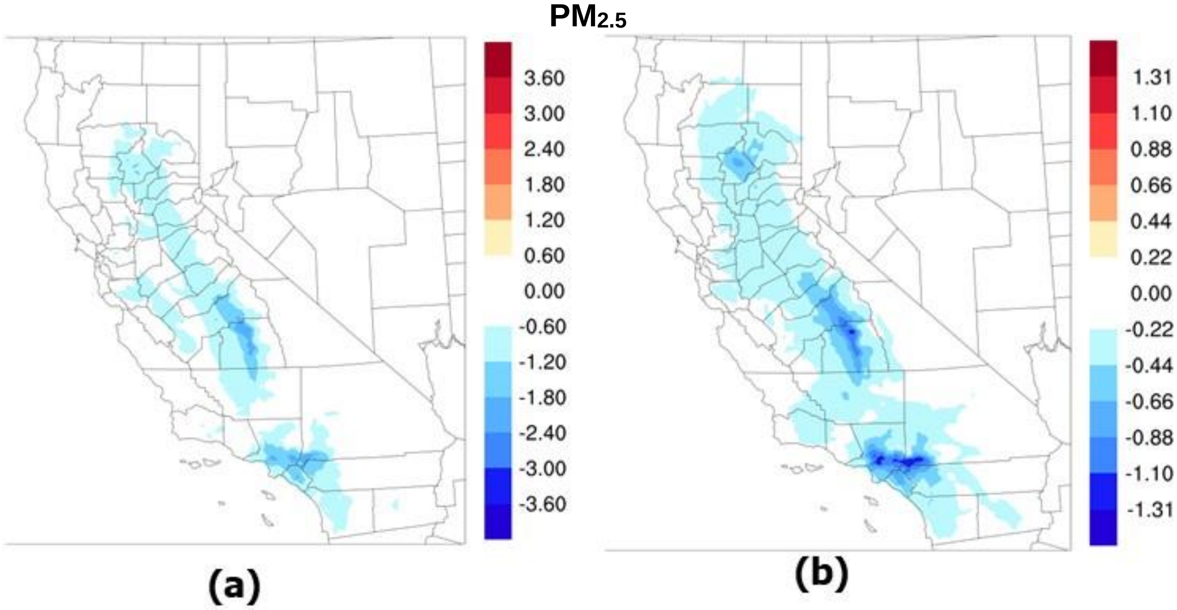
Figure F-5: Difference From the Reference Case Predicted for the High Buildings Electrification Case for Summer (a) Maximum MD8H Ozone and (b) Average MD8H Ozone



Source: UCI APEP

The differences in summer $PM_{2.5}$ predicted for the HBE Case relative to the Reference Case are shown in Figure F-6. Maximum improvements in $PM_{2.5}$ reach -2.5 ug/m^3 while average reductions reach -1.3 ug/m^3. With similarity to ozone, impacts in summer are most pronounced in the SoCAB and the Central Valley.

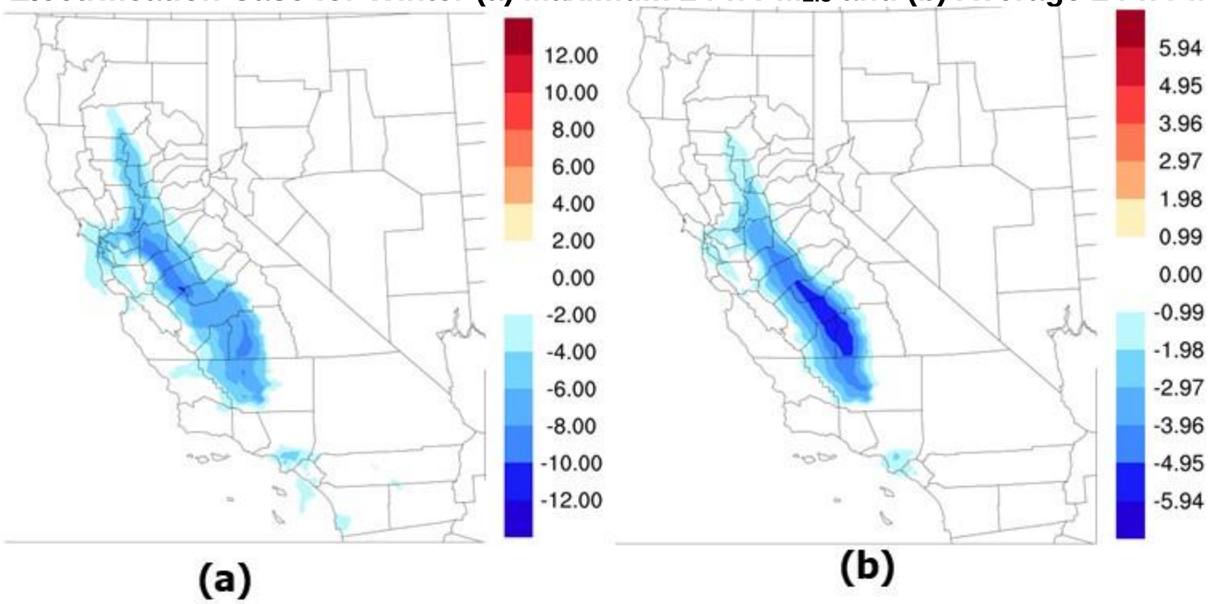
Figure F-6: Difference From the Reference Case Predicted for the High Buildings Electrification Case for Summer (a) Maximum 24-h $PM_{2.5}$ and (b) Average 24-h $PM_{2.5}$



Source: UCI APEP

The differences in winter $PM_{2.5}$ predicted for the HBE Case relative to the Reference Case are shown in Figure F-7:. Maximum improvements in $PM_{2.5}$ reach -10.1 ug/m^3, while average reductions reach -5.9 ug/m^3.

Figure F-7: Difference From the Reference Case Predicted for the High Buildings Electrification Case for Winter (a) Maximum 24-h $PM_{2.5}$ and (b) Average 24-h $PM_{2.5}$

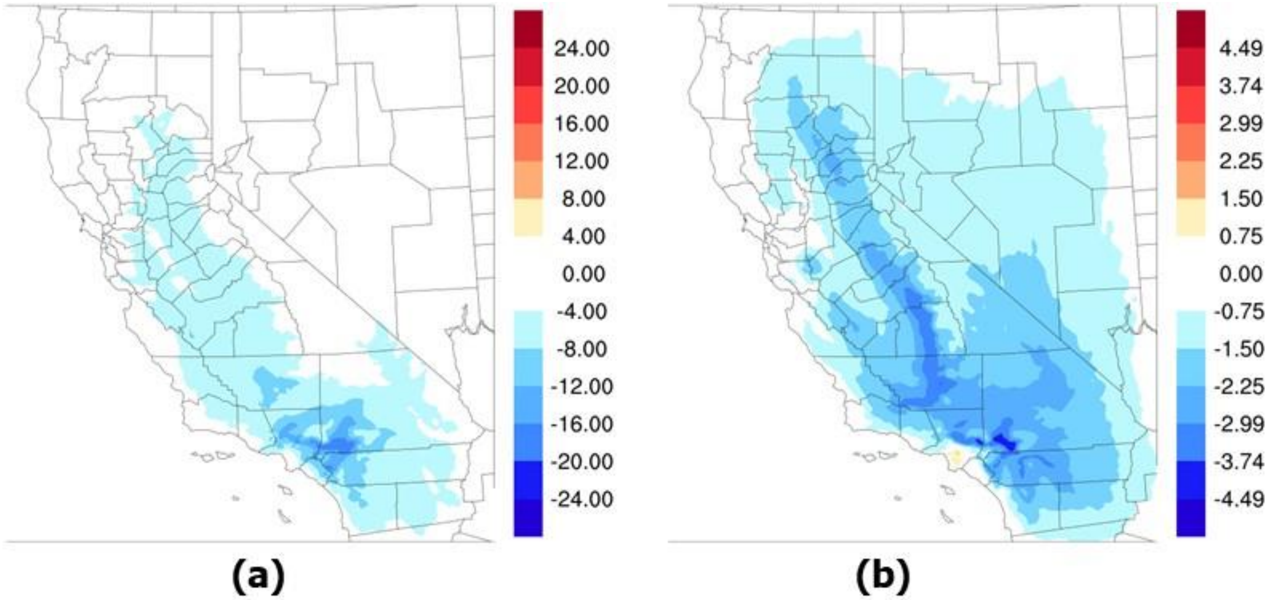


Source: UCI APEP

Concentration Differences for the No Building Electrification (NBE) Case

The following section presents the changes in pollutant concentrations from the Reference Case that occur due to the mitigation measures assumed within the NBE Case. The differences in both peak and average summer MD8h predicted for the NBE Case relative to the Reference Case are shown in Figure F-8. Maximum improvements in ozone reach -19.8 ppb while maximum reductions average -4.5 ppb.

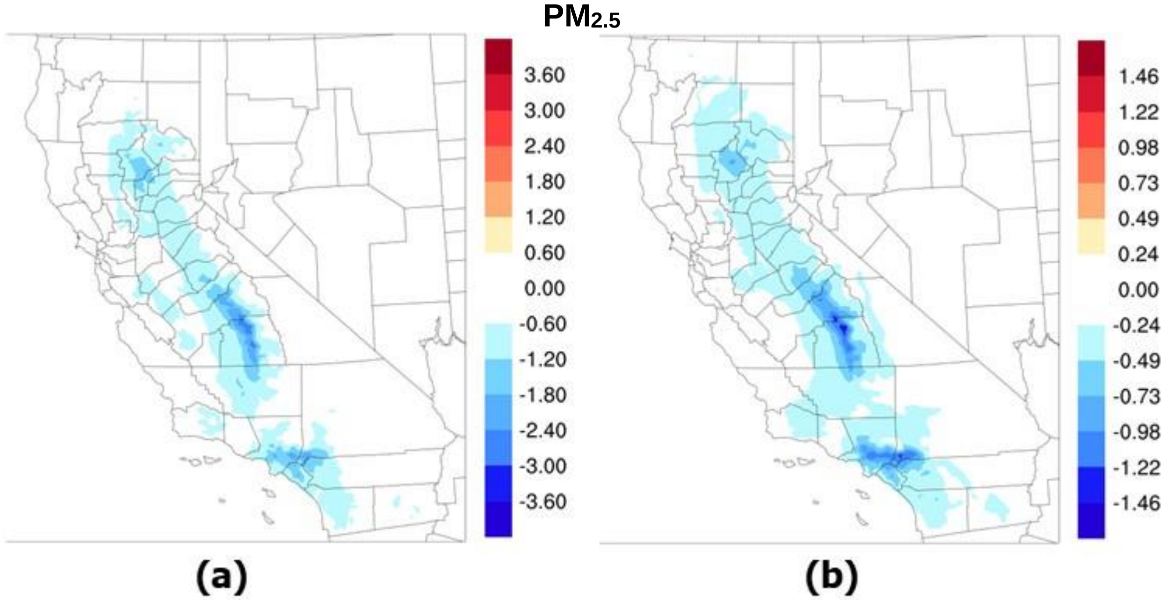
Figure F-8: Difference From the Reference Case Predicted for the No Buildings Electrification Case for Summer (a) Maximum MD8H Ozone and (b) Average MD8H Ozone



Source: UCI APEP

The differences in both peak and average summer $PM_{2.5}$ predicted for the NBE Case relative to the Reference Case are shown in Figure F-9. Maximum improvements in $PM_{2.5}$ reach -2.9 ug/m^3 while maximum reductions average -1.5 ug/m^3. Spatially, impacts follow the trends described for previous scenarios.

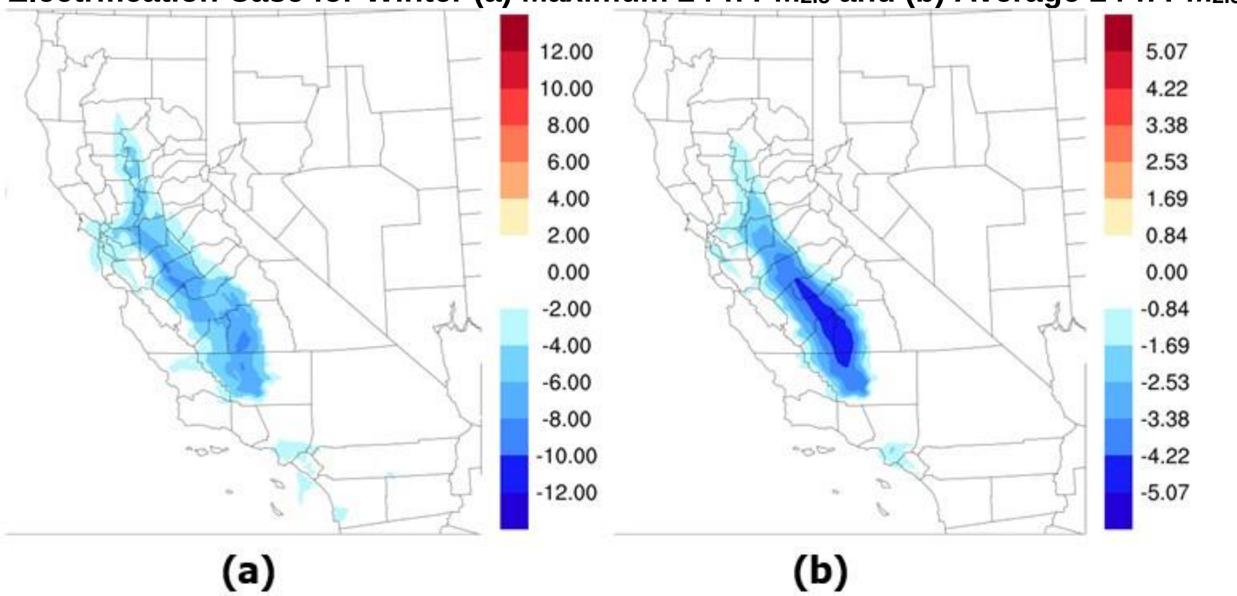
Figure F-9: Difference From the Reference Case Predicted for the No Buildings Electrification Case for Summer (a) Maximum 24-h $PM_{2.5}$ and (b) Average 24-h $PM_{2.5}$



Source: UCI APEP

The differences in both peak and average winter $PM_{2.5}$ predicted for the NBE Case relative to the Reference Case are shown in Figure F-10. Maximum improvements in $PM_{2.5}$ reach -8.9 ug/m^3 while maximum reductions average -5.1 ug/m^3. Spatially, impacts follow the trends described for previous scenarios.

Figure F-10: Difference From the Reference Case Predicted for the No Buildings Electrification Case for Winter (a) Maximum 24-h $PM_{2.5}$ and (b) Average 24-h $PM_{2.5}$

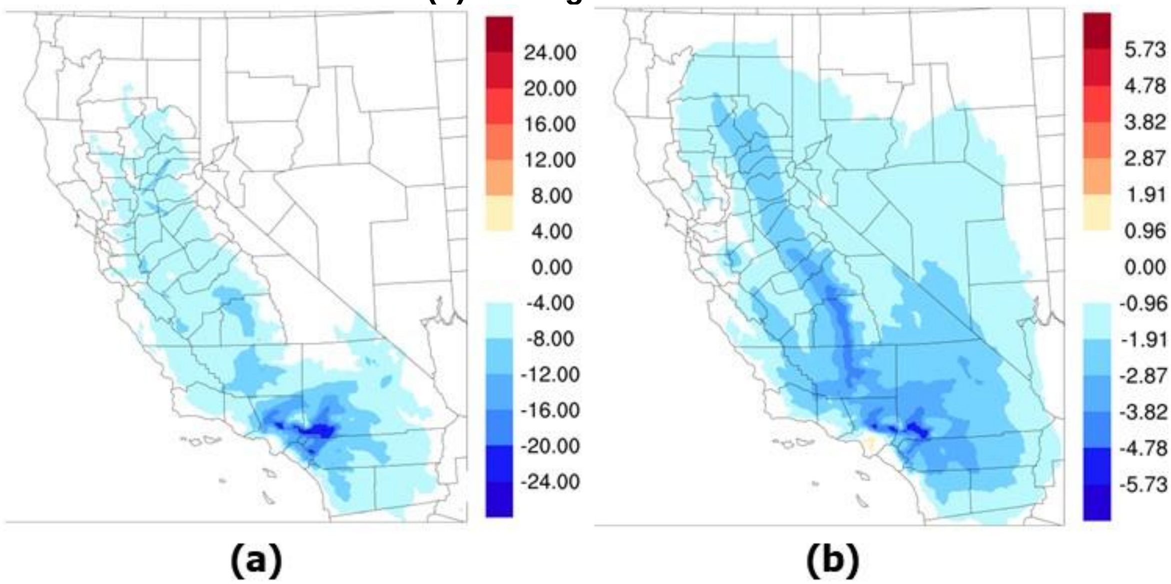


Source: UCI APEP

Concentration Differences for the High Building Electrification with Truck Measures (HBEwT) Case

The following section presents the changes in pollutant concentrations from the Reference Case that occur due to the mitigation measures assumed within the HBEwT Case. The HBEwT Case has the largest reduction in total NO_x, and can therefore be expected to have the highest air quality impacts. Reductions in both maximum and average summer MD8h predicted for the HBEwT Case relative to the Reference Case are shown in *Figure F-11*. Maximum improvements in ozone reach -25.1 ppb, and average reductions reach -5.7 ppb. Spatially, impacts are most pronounced in the SoCAB, which is important from a human health standpoint given the associated high population and highest background levels. Impacts on ozone are also noted in the Central Valley, with similar importance to those for SoCAB.

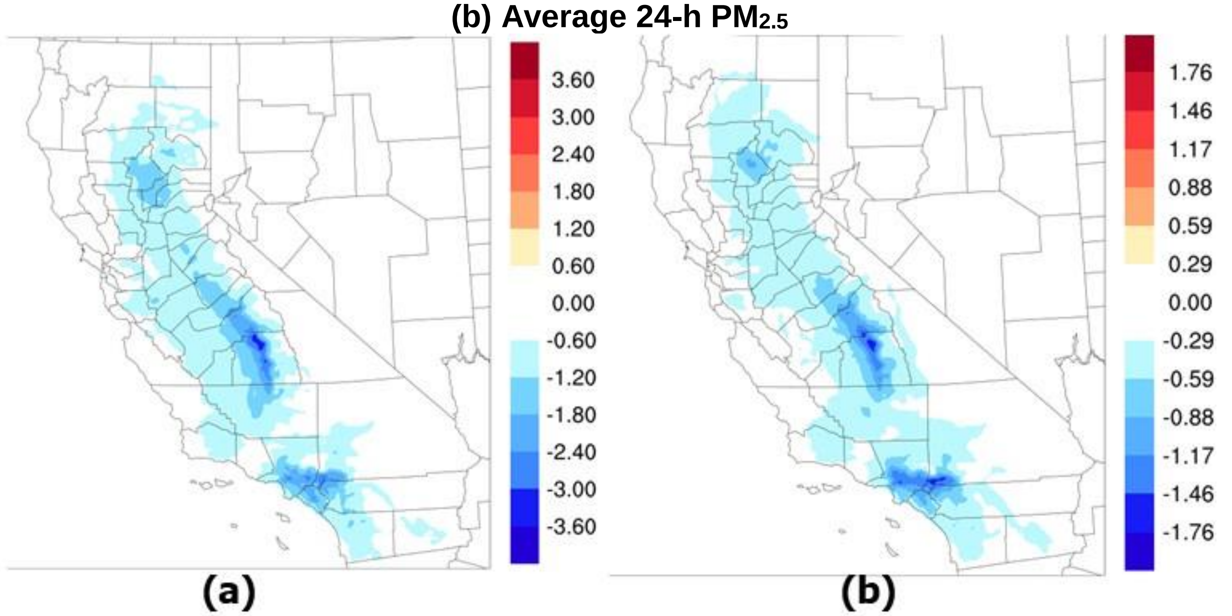
Figure F-11: Difference From the Reference Case Predicted for the High Buildings Electrification With Truck Measures Case for Summer (a) Maximum MD8H Ozone and (b) Average MD8H ozone



Source: UCI APEP

The differences in both peak and average summer $PM_{2.5}$ predicted for the HBEwT Case relative to the Reference Case are shown in Figure F-12. Maximum improvements in $PM_{2.5}$ reach -3.5 ug/m^3, while average reductions reach -1.8 ug/m^3. Impacts are noted throughout the SoCAB, Central Valley, and greater Sacramento.

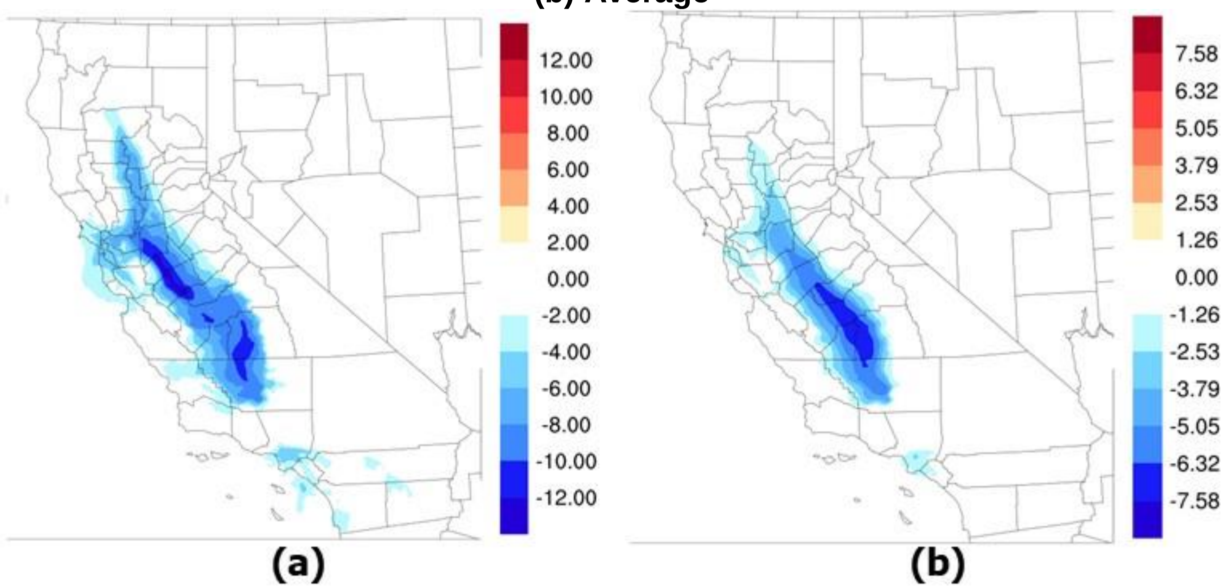
Figure F-12: Difference From the Reference Case Predicted for the High Buildings Electrification With Truck Measures Case for Summer (a) Maximum 24-h $PM_{2.5}$ and (b) Average 24-h $PM_{2.5}$



Source: UCI APEP

The differences in both peak and average winter $PM_{2.5}$ predicted for the HBEwT Case relative to the Reference Case are shown in Figure F-13. Maximum improvements in $PM_{2.5}$ reach -13.1 ug/m^3 while maximum reductions average -7.6 ug/m^3. Impacts in winter are most pronounced in the Central Valley, particularly the lower and central portions.

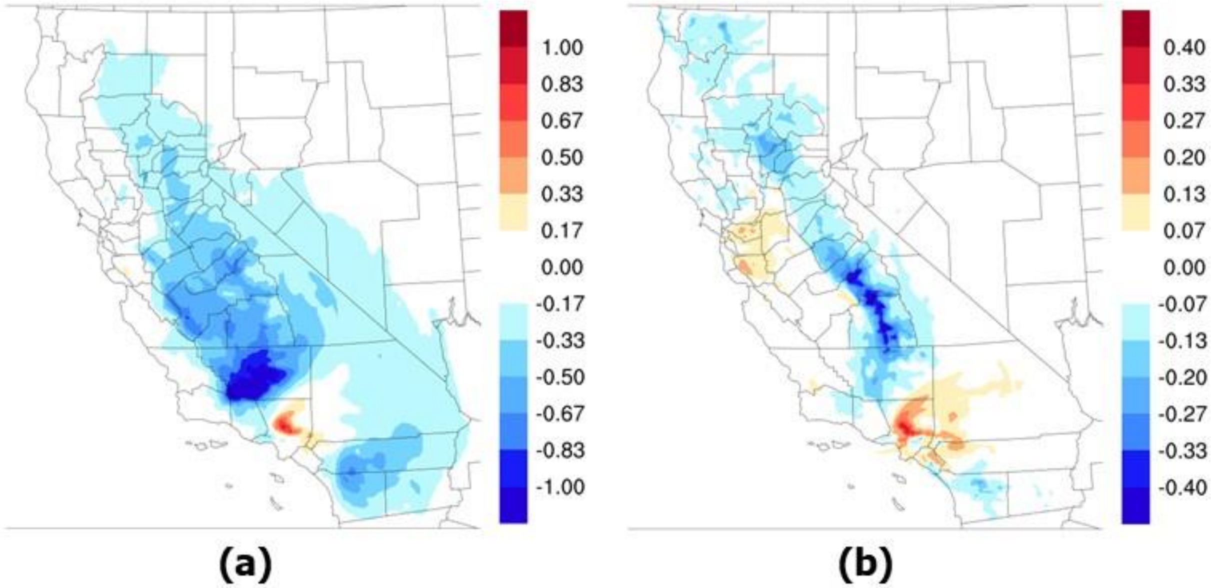
Figure F-13: Difference From the Reference Case Predicted for the High Buildings Electrification With Truck Measures Case for Winter (a) Maximum 24-h $PM_{2.5}$ and (b) Average



Source: UCI APEP

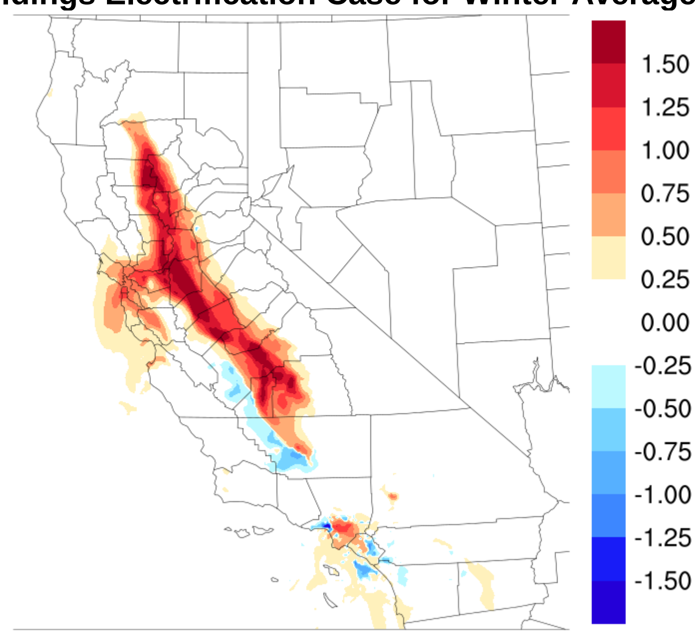
When comparing the air quality results for the NBE and HBE Cases, it is interesting to note the similarity in the largest reductions for both peak and average ozone (i.e., for ozone approximately -19 ppb peak and -5 ppb average), however the spatial distribution of the reductions varies. This is because the peak values only correspond to one individual 4 km x 4 km cell within the modeling grid, and provides no information about the spatial and temporal changes throughout the entire domain. By quantifying the difference in concentrations between the two cases differences in the spatial location of air quality impacts can be discerned. Figure F-14 displays the difference in average MD8H summer ozone and average 24-h $PM_{2.5}$ concentrations between the NBE and HBE Cases, rather than the difference from the Reference Case. Figure F-15 displays the same for differences in winter $PM_{2.5}$. The plots in Figure F-14 and Figure F-15 are generated by subtracting the concentrations in the HBE Case from the concentrations in the NBE Case. Therefore, the way they should be interpreted is that negative values (blue in the maps) correspond to locations where the pollutant concentrations in the NBE Case are lower than the concentrations in the HBE Case, indicating that the impacts from HDV are achieving a higher benefit than building electrification. Conversely, positive values (red in the maps) indicate locations where the pollutant concentrations in the NBE Case are higher than the HBE Case, indicating that emission reductions from buildings yields larger benefits than HDV.

Figure F-14: Difference From the High Building Electrification Case Predicted for the No Buildings Electrification Case for Summer (a) Average MD8H Ozone and (b) Average 24-h $PM_{2.5}$



Source: UCI APEP

Figure F-15: Difference From the High Building Electrification Case Predicted for the No Buildings Electrification Case for Winter Average 24-h $PM_{2.5}$



Source: UCI APEP

When the concentrations are compared to each other the NBE Case has a much larger and widespread impact on ozone than does the HBE Case, particularly in the Central Valley. This result is due to the larger reduction of HDV emissions in the NBE Case, which are important contributors to ozone burdens in that region [15]. In contrast, a small area within the SoCAB experiences a greater improvement in ozone in the HBE Case relative to the NBE Case, highlighting the impact of emissions from highly concentrated buildings (again it should be considered that larger reductions are assumed from the building sectors than from MDV and HDV). In contrast, the HBE Case has a larger impact on winter $PM_{2.5}$ than does the NBE Case, indicating the importance of building emissions (particularly NO_x) to secondary $PM_{2.5}$ during that period. Impacts on $PM_{2.5}$ in winter are higher than summer and most pronounced in the Central Valley and S.F. Bay Area, which reflects differences in both atmospheric chemistry and energy demands that occur seasonally. For example, stagnant conditions occur in the Central Valley in winter which contribute to high $PM_{2.5}$ levels [16]. Additionally, increased demand for space heating in the winter months is reflected in increased emissions associated with buildings in the winter months compared to those in summer [2]. Therefore, the $PM_{2.5}$ reductions estimated here are important because they occur in the regions which frequently experience degraded air quality, including episodes of non-compliance for NAAQS, and occur coincident with urban populations.

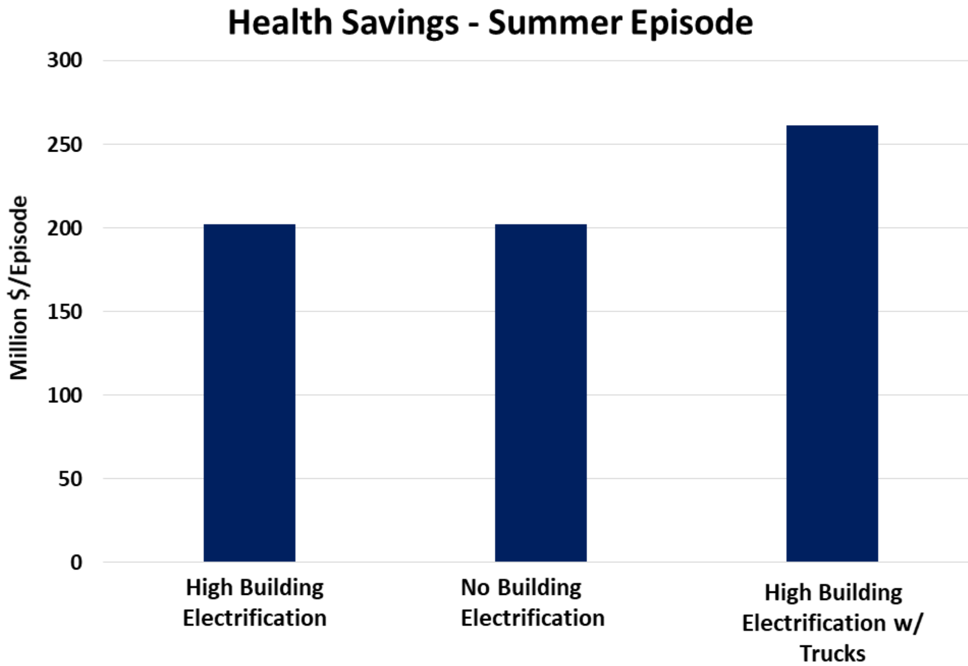
The impacts noted here highlight the need for photochemical modeling to quantify and resolve how changes in emissions translate to differences in atmospheric concentrations, followed by an understanding of how population exposure changes through a health impact assessment.

Health Impact Assessment

The following section presents the total health savings from avoided incidence of mortality and morbidity that accrue from reductions in ozone and $PM_{2.5}$ predicted for the alternative cases relative to the Reference Case. The results are reported as the mean values from the BenMAP-CE model summed across the modeled episode for both summer and winter.

Health savings for the alternative cases as a result of air quality improvements in summer are shown in Figure F-16:. Total savings are estimated at approximately $202 million for the HBE Case, $202 million for the NBE Case, and $261 million for the HBEwT Case. The bulk of the health savings are associated with avoided incidence of mortality and are approximately split between impacts on ozone and $PM_{2.5}$ (see Figure F-18: and Figure F-21:). Comparing the cases yields marginal benefits from the building electrification assumed in the HBE Case of $58 million, and the marginal benefits from the truck measures assumed in the NBE Case of approximately $59 million. The similar magnitude of these benefits should again be considered within the context that larger reductions are assumed within buildings than within trucks. Therefore, these results are not meant to directly compare buildings and trucks, but rather to quantify the potential benefits of assuming very high electrification within buildings, and a relatively high, but more moderate, deployment of alternative truck technologies.

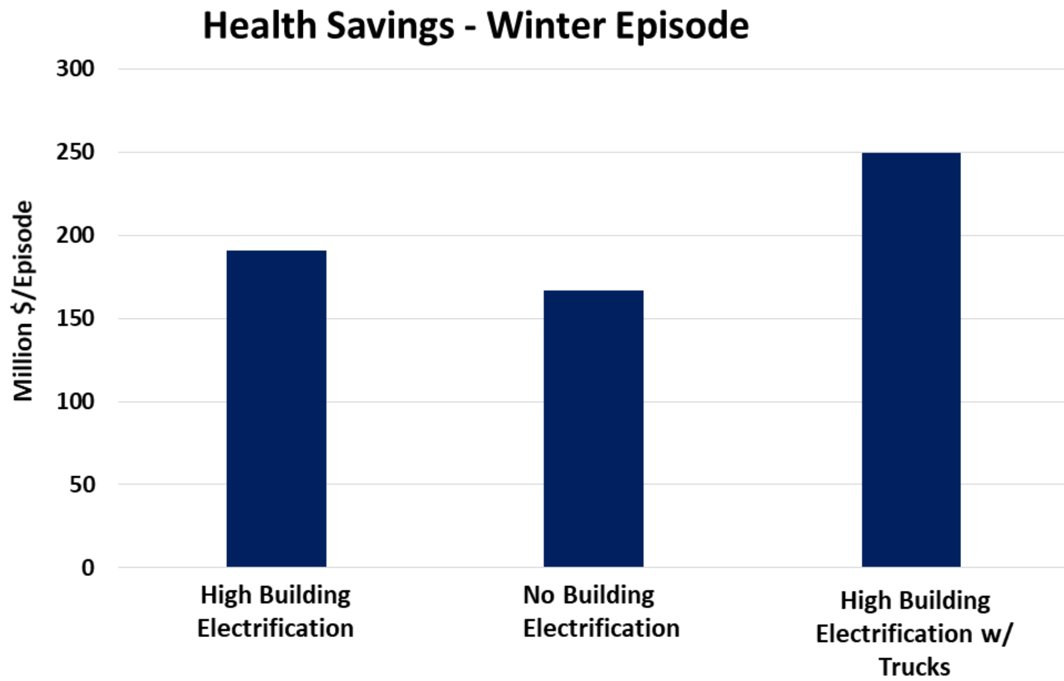
Figure F-16: Mean Health Savings for the Air Quality Improvements Estimated for the Summer Episode



Source: UCI APEP

The mean health savings for the alternative cases as a result of changes in $PM_{2.5}$ concentrations in the winter episode are shown in Figure F-17:. Shown in Figure F-19:, health savings result solely from $PM_{2.5}$ reductions, as ozone concentrations are inversely correlated with NO_x emission reductions due to titration effects well known to occur in California during winter, e.g., see [17][18]. Total savings for the episode are estimated at approximately $190 million for the HBE Case, $166 million for the NBE Case, and $249 million for the HBEwT Case. Comparing the cases yields marginal benefits from the building electrification assumed in the HBE Case of $82 million, and the marginal benefits from the truck measures assumed in the NBE Case of approximately $59 million. Compared to the results from summer, building electrification has a larger impact on $PM_{2.5}$ in winter due to higher energy demands and associated emissions from space heating of residential and commercial buildings. The improvements in $PM_{2.5}$ largely result from reductions in direct emissions of NO_x, which reduce levels of secondary $PM_{2.5}$.

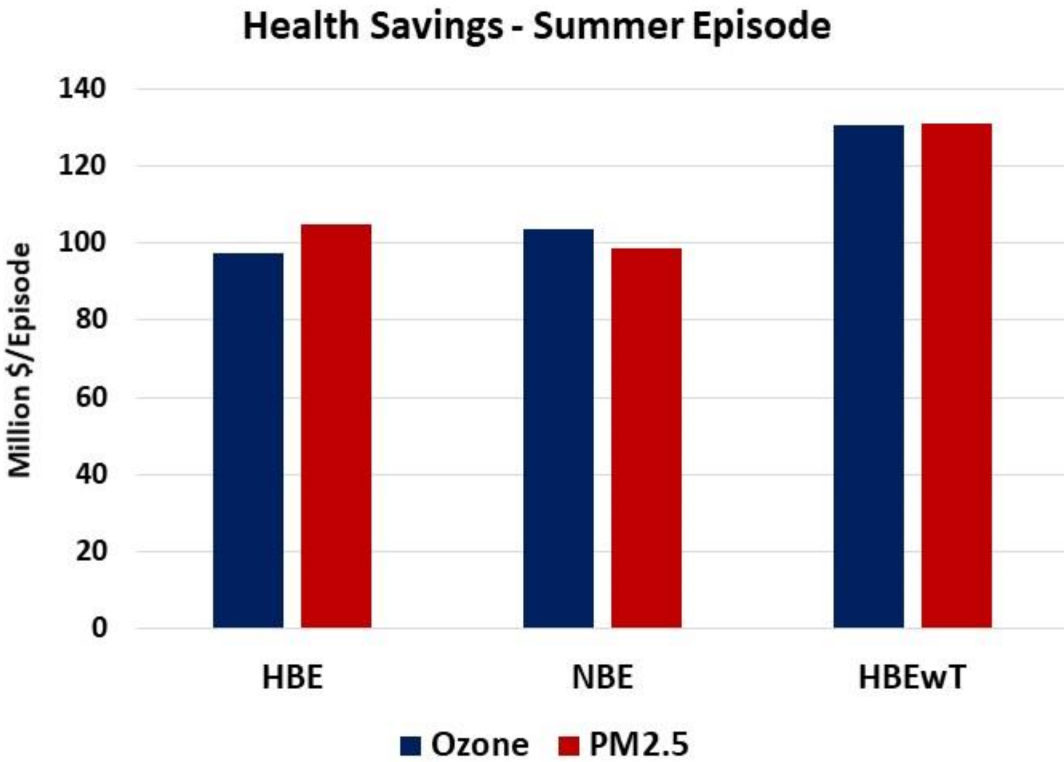
Figure F-17: Mean Health Savings for the Air Quality Improvements Estimated for the Winter Episode



Source: UCI APEP

Figure F-18: displays the health savings estimated for the three alternative cases relative to the Reference Case in the summer episode distributed between ozone and $PM_{2.5}$. Overall, the health savings are approximately equivalent between those quantified for reduced ozone concentrations and those for reduced $PM_{2.5}$ concentrations. However, demonstrating the moderately higher impact of MDV and HDV to summer ozone, the NBE Case is associated with slightly higher ozone benefits. Conversely, for the HBE Case $PM_{2.5}$ impacts have a slightly higher impact as a result of building emission reductions.

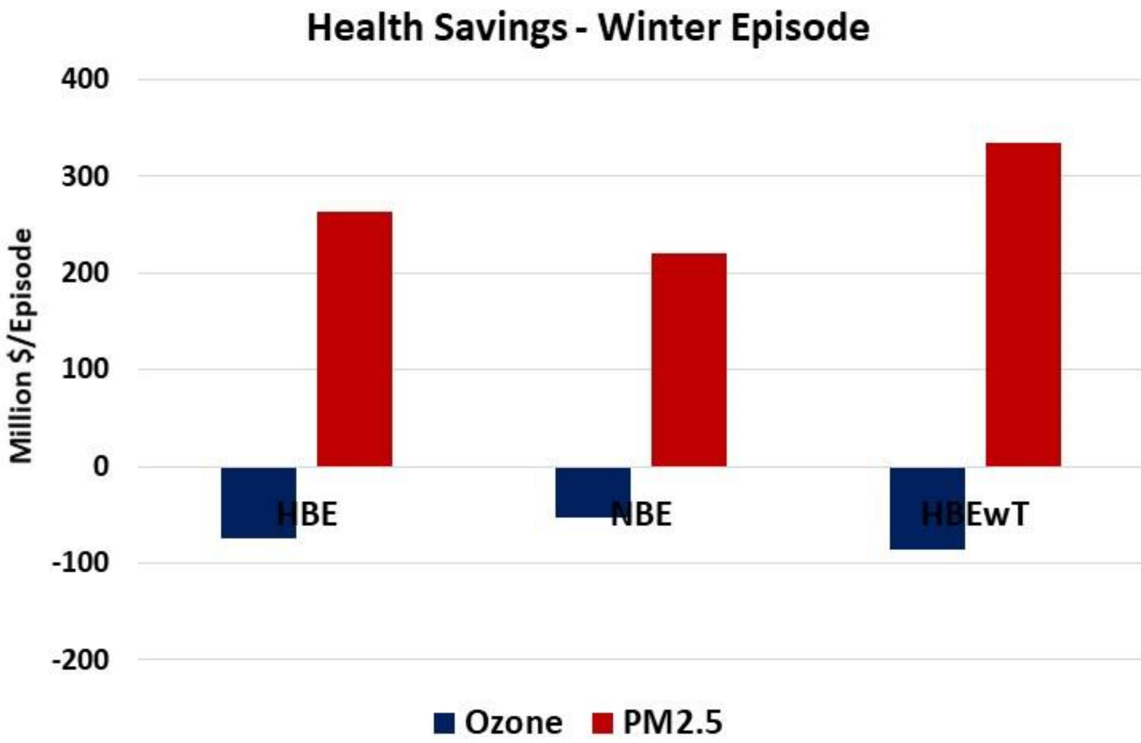
Figure F-18: Total Health Savings Estimated for the Summer Episode for Ozone and $PM_{2.5}$ Reported as Mean Values Estimated From the BenMAP-CE Model. HBE: High Building Electrification, NBE: No Building Electrification, HBEwT: High Building Electrification With Truck Measures



Source: UCI APEP

Figure F-19: displays the health savings estimated for the three alternative cases relative to the Reference Case in the winter episode distributed between ozone and $PM_{2.5}$. Due to the effects of titration in winter, ozone concentrations experience an increase as a result of reductions in pre-cursor emissions. Therefore, health savings are negative in winter, i.e., increased incidence of harmful outcomes. This phenomena is well known in California and has been demonstrated in other studies if no threshold is used (as the research team did here) [18]. However, reductions in $PM_{2.5}$ attain health savings that far exceed the negative impacts from ozone, resulting in net positive health savings for the scenarios considered. Following the air quality trends described above, the HBE Case is associated with moderately larger health savings from $PM_{2.5}$ in winter than the NBE Case, as a result of improvements in the Central Valley and S.F. Bay Area.

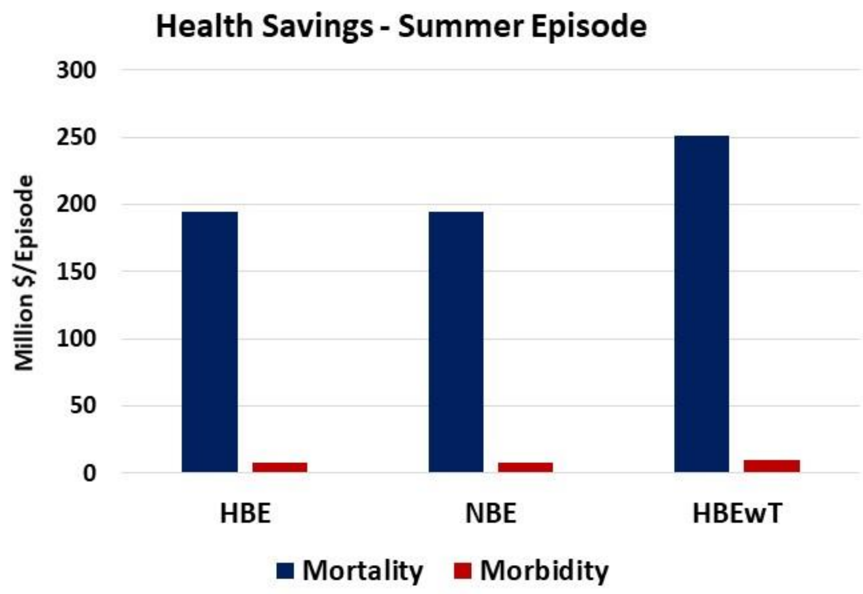
Figure F-19: Total Health Savings Estimated for the Summer Episode for Ozone and $PM_{2.5}$ Reported as Mean Values Estimated From the BenMAP-CE Model. HBE: High Building Electrification, NBE: No Building Electrification, HBEwT: High Building Electrification With Truck Measures



Source: UCI APEP

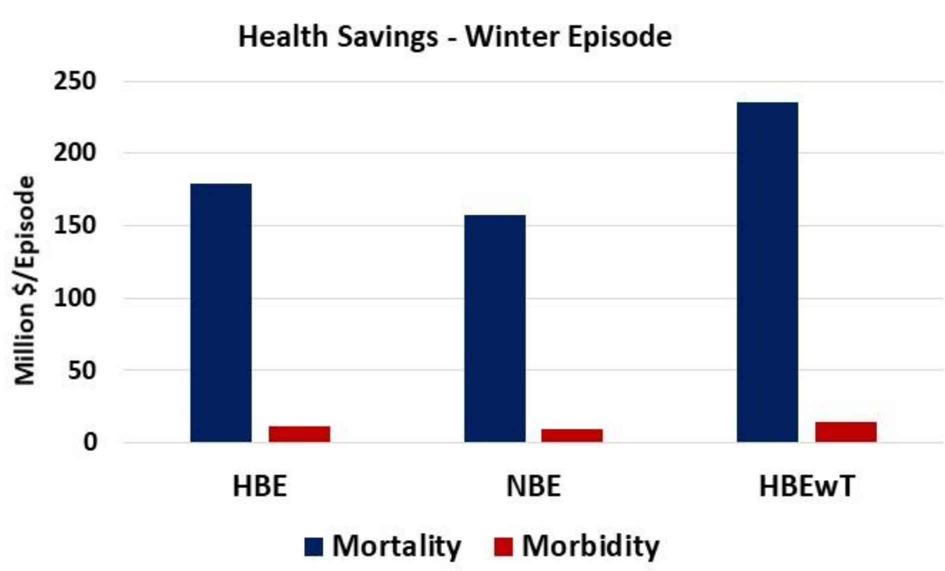
Figure F-20: and Figure F-21: display the estimated health savings for winter and summer grouped by mortality and morbidity. Morbidity is used here as referring to unhealthy conditions which do not include death, and examples of morbidity incidence quantified within BenMAP include hospital admissions from asthma attacks and other respiratory disorders, non-fatal heart attacks and strokes, and others. For the cases considered, health savings predominantly result from avoided incidence of mortality in both the summer and winter episode.

Figure F-20: Total Health Savings Estimated for the Summer Episode for Mortality and Morbidity Reported as Mean Values Estimated From the BenMAP-CE Model. HBE: High Building Electrification, NBE: No Building Electrification, HBEwT: High Building Electrification With Truck Measures



Source: UCI APEP

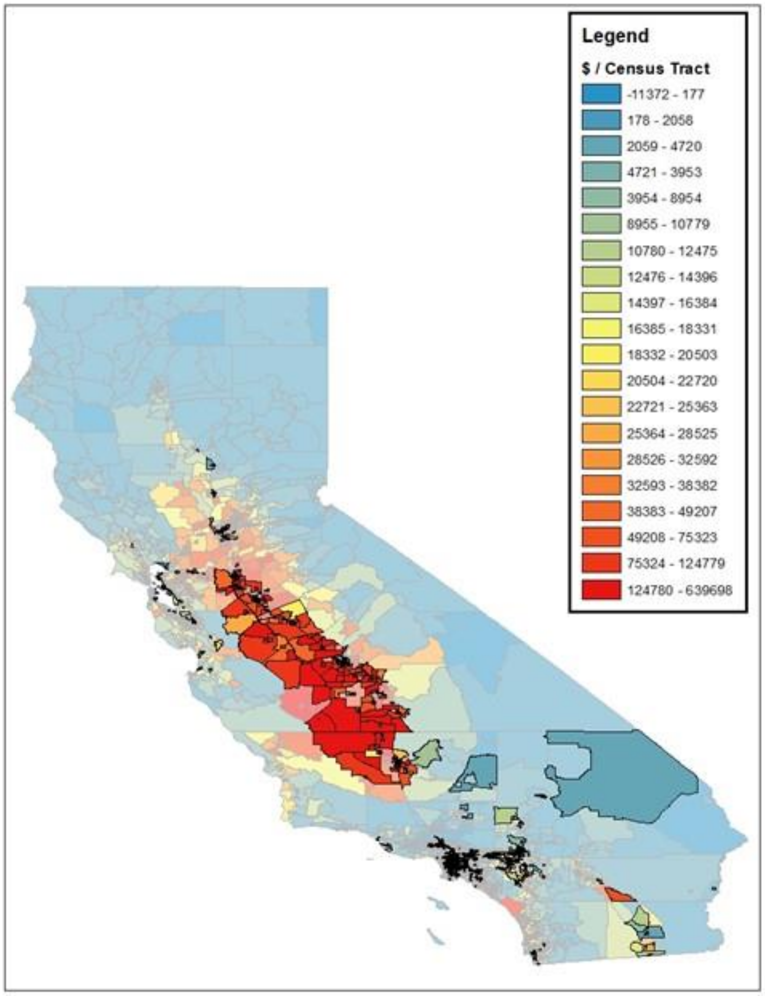
Figure F-21: Total Health Savings Estimated for the Winter Episode for Mortality and Morbidity Reported as Mean Values Estimated From the BenMAP-CE Model. HBE: High Building Electrification, NBE: No Building Electrification, HBEwT: High Building Electrification With Truck Measures



Source: UCI APEP

Furthermore, it is important to contextualize health savings through impacts occurring within disadvantaged communities (DAC), as these are the locations where benefits are most needed [19][20]. The tool used in California to identify and characterize DAC is CalEnviroScreen 3.0 through the use of sets of pollution and other socioeconomic criterion at the census tract level. Figure F-22: displays the health savings estimated for the HBEwT Case in winter allocated to census tracts in California with those designated as DAC highlighted. The health savings estimated for the HBEwT Case in winter provide benefits to DAC, most notably within the Central Valley. When these health savings are totaled for DAC, they are equivalent to 39% of the total health savings, while the summer health savings for the same case total 31%. These percentages are comparable to similar results reported for an air quality assessment of electrification in 2050, and are notable given that approximately 25% of the state population is estimated to live in DAC. [18]

Figure F-22: Health Savings for the High Building Electrification With Trucks Case in Winter Allocated to Census Tracts in (a) California, (b) Southern California, (c) S.F. Bay Area. Disadvantaged Communities From CalEnviroScreen Are Highlighted



Source: UCI APEP

Summary and Conclusions

The emission reductions that result within the cases considered here are attained through the deployment of various GHG mitigation measures within a wide range of end-use sectors. Taken together, these measures reduce ozone and $PM_{2.5}$ concentrations and correspondingly improve human health in important locations within California that experience high levels of atmospheric pollution and are characterized by large populations. Furthermore, the results from this work support the findings from additional studies that have emphasized the significance of air quality and human health co-benefits of technological evolution to support GHG mitigation within California's energy end-use sectors [18], [21]–[23].

The health benefits estimated for the HE and NBE Cases are very similar, demonstrating that multiple technological pathways can achieve comparable impacts on air quality. These impacts vary by season and region, with implications for regional planning. For example, in summer, the NBE Case achieves slightly higher air quality benefits due to the impact of MDV and HDV on ozone, while in winter the HE Case achieves higher benefits due to the impacts of buildings on $PM_{2.5}$. When the benefits of trucks and building electrification are combined, the health savings are notable and include important benefits to disadvantaged communities.

It should be noted that MDV and HDV are well known to be key sources of air pollution in California, and represent a key focus of the state's criteria pollutant mitigation planning documents [24]. They are also a dominant source of emissions within the CARB inventory used for this work [2]. This importance is clearly demonstrated in the results, as the assumptions of low- and zero-emission trucks within the NBE Case and NBEwTrucks Case are associated with important health savings from both reduced ozone and $PM_{2.5}$ in the summer and winter episodes. Due to the spatial distribution of truck travel, impacts occur widely throughout California with peak savings in the Central Valley and SoCAB. As a mix of battery electric, hydrogen fuel cell, and low NO_x CNG vehicles is assumed, a comparison of the individual technologies cannot be made. Valuable future work could include a more in-depth analysis of alternative truck technologies and fuels accounting for the numerous factors effecting deployment including technological maturity and other techno-economic factors. It should also be considered that this analysis does not assume differences in electrification for other sources between cases, and thus does not highlight these sources here. However, it is likely that similar importance would be attributed to off road equipment, ships, rail, aircraft, industrial equipment and processes, and others.

Electrifying natural gas building appliances predictably achieves benefits in urban locations characterized by dense building populations, and can further benefit areas that are located downwind of these areas. For example, reduced NO_x emissions from buildings was predicted to improve secondary $PM_{2.5}$ concentrations in SoCAB in the summer and (most notably) the S.F. Bay Area and Central Valley in winter. However, while the assumptions for building appliances reflect current policy, if novel lower emission natural gas appliances are developed in the future the benefits reported here would be reduced. On the other hand, it is also important to note that this analysis does not include any assessment of the potential indoor air quality impacts of the scenarios. Natural gas building appliances are responsible for criteria pollutant emissions that can contribute to poor indoor air quality and could be associated with adverse human health effects [25]–[27]. Therefore, the electrification of building appliances could yield additional indoor air quality benefits to those estimated here for outdoor ambient concentrations, which should be considered in future work.

However, there are important caveats that should be considered when interpreting this work. The scenarios considered here were not designed from an air quality perspective and do not allow for a direct comparison of the impacts of different end-use sources, e.g., while this analysis focuses on the impacts of buildings and MDV/HDV, a direct quantification and comparison of health savings cannot be made between the two as it assumes a very high electrification of buildings and more moderate assumptions within MDV/HDV. Rather, this study seeks to elucidate the technical components of potential impacts to support policy design that maximizes the air quality and health co-benefits from both buildings and trucks. Additionally, the episodic modeling method used to determine AQ impacts does not allow for annual health savings to be estimated, which would yield substantially higher benefits due to the use of long term exposure $PM_{2.5}$ health impact functions, e.g., those used in Reference [18]. Finally, the results presented here are representative of difference in 2050, and do not account for the accrued benefits from present day. While the method used is the principal method for conducting assessments such as these (e.g., see [18], [21]–[23]) due to the considerable time and resources that would be required to model air quality and human health savings for the period of current day to 2050, it should be noted that near-term savings could be higher for some sources relative to others, including alternative technologies in MDV and HDV.

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APPENDIX G: E3 Gas Revenue Requirement Model

General Description

The Natural Gas Revenue Requirement Model (RR Model) is a capital investment and depreciation model that simulates a gas utility's revenue requirement and rates through 2050 under different decarbonization scenarios. E3's economy-wide carbon emissions model, PATHWAYS, models large-scale changes in the natural gas system including changes in gas demand and commodity prices. The RR Model is designed to supplement PATHWAYS, adding a representation of the existing capital assets, operating expenses, and revenues of a gas utility. In addition, the RR Model includes parameters that determine capital reinvestment, depreciation lifetime, cost allocation, and other levers that influence gas revenues and rates. The RR Model is implemented for PG&E and SoCal Gas using information derived from publicly available regulatory filings.

California's natural gas utilities own billions of dollars in capital assets, ranging from meters and pipes to vehicles and computers. In the representation of the gas system, natural gas capital is grouped into four different categories:

- Distribution capital related to gas throughput,
- Distribution capital related to gas customer accounts,
- Transmission and storage capital related to gas throughput, and
- General capital unrelated to gas demand.

The model is populated with existing capital assets detailed in regulatory filings as well as new capital expenditures requested in general rate cases.

As gas demand changes over time, the size of the gas system may also change. The model uses a capital reinvestment logic that enables it to reinvest in a fraction of the retired capital. This reinvestment fraction is meant to reflect the need for ongoing investment to maintain safety and reliability of the remaining gas system.

After capital, O&M expenses make up the next largest share of the gas revenue requirement. Future O&M expenses are modelled using two different methods: fixed-rate escalation, and O&M proportional to the value of gas capital. The RR Model uses a combination of these methods to predict future O&M, where the ratio of the two methods is a user-defined value.

Calculating rates requires the allocation of the revenue requirement to customer classes. In the model, cost allocation begins with present-day allocations and includes the option to gradually transition to allocating costs based on distribution- and transmission-level throughput for each customer class.

All scenarios see increased gas rates for remaining customers in late model years, including dramatic increases in some scenarios. A number of parameters provide options for mitigating these impacts. In addition, decreasing capital reinvestment, as described above, other user-defined parameters include accelerated depreciation terms, reduction in capital removal costs, rate modifications including exit fees and fixed fees, and other additional revenue streams.

Data Sources

The PATHWAYS model provides forecasts of natural gas demand, both gas throughput and gas customer accounts, which are used as inputs in the RR Model. In addition, the RR Model uses gas commodity prices for each mitigation scenario that come from PATHWAYS. The RR Model also incorporates information derived from publicly available regulatory filings, as well as other data sources. The key data sources are documented below:

Table G-1: RR Data Sources

	PG&E	SoCal Gas
Gas throughput forecasts	PATHWAYS	PATHWAYS
Gas customer account forecasts	PATHWAYS	PATHWAYS
Gas commodity price forecasts	PATHWAYS	PATHWAYS
Utility Plant by category Original cost, removal cost, book reserve, book life, remaining life	• GRC 2020 Phase I, Exhibit 10, Tables 11-2 and 11-3 • GT&S, Ch 14, Table 14C-1	• 2019 SCG GRC Application Attachment D, • SCG 2019 GRC Application Revised Workpapers Schedule A
Near-term CAPEX expenditures	• GRC 2020, GT&S	• 2019 SCG GRC Decision, CPUC 2019
Present O&M costs	• GRC 2020 Phase I Workpaper 16-151 • GTS 2019 Appendix 1 - Tax Cuts Update - Table 1	• 2019 SCG GRC Hom PRR Table RH-1U
Near-term O&M costs	• GRC 2020 Phase I Workpaper 16-151 • GTS 2019 Appendix 1 - Tax Cuts Update - Table 1	• 2019 SCG GRC Wilder testimony Table SRW-2
Long-term CAPEX cost escalation	• GRC 2020 Phasae I, Exhibit 12, Table 4-2	• 2019 SCG GRC Decision, CPUC 2019
Long-term O&M cost escalation	• GRC 2020 Phase I, Exhibit 12, Table 4-1 • GRC 2010 Phase I, Exhibit 8, Table 4-3	• Wilder testimony Table SRW-2
Distribution utilization by sector	• GCAP 2018 Table 3-3	• TCAP 2017 Phase 2 Table 1
Utility cost of capital	• GRC 2020 Phase I, Exhibit 10, Table 16-3	• Cost of Capital Application 2020

Source: E3 and regulatory filings cited above

Gas Capital

Representation of Existing Capital

Regulatory filings detail existing capital assets by asset type, e.g. individual line items representing "Meters", "Transmission Mains", and "Office Furniture." For each asset type, the utility provides the original cost, removal cost, book reserve (accumulated depreciation), book life, and remaining life.

The RR Model groups these assets into four categories:

1. Distribution capital related to gas throughput
2. Distribution capital related to gas customer accounts
3. Transmission and storage capital related to gas throughput
4. General capital unrelated to gas demand

Within each category, the model generates total (summed) values for original cost, removal cost, and book reserve, as well as cost-weighted averages of book life and remaining life. The result is a representation of the existing utility capital as four large assets (one for each category), each with a distinct book value and depreciation schedule. This design choice represents the assumption that present-day utility capital has the same book life as future capital investments. For example, within the transmission and storage category, the RR Model assumes that new capital assets will have the same average book life as today's capital.

In addition to existing assets, the RR Model includes investments in capital that are requested in the most recent regulatory filings (e.g. General Rate Cases). In the case of SoCal Gas, the model reflects the 2019 revenue requirement and 2020, 2021 and 2022 attrition years approved by the CPUC on September 26, 2019. In the case of PG&E, whose GRC remains outstanding, the full value of the outstanding requests are included in the RR Model by default. The user has the option to input their choice of smaller values.

Capital Reinvestment Logic

Within each category, the RR Model determines capital investments through the year 2050. A general statement of the reinvestment logic is that the size of today's system is appropriate for serving demand, absent a decision to reduce the size of the gas system. By default, in every year the model will invest in an amount of new capital equal to the full replacement costs of retiring capital assets, i.e. their original value escalated based on their age. If the user chooses to reduce investment after a certain year, the model will only invest in an amount of new capital equal to some fraction of the replacement costs, e.g. 50% of those costs.

The model tracks new capital by vintage, linearly retiring each vintage as the model progresses through future years. Thus, reduced reinvestment has a compounding effect, wherein decreasing investment in one year will subsequently decrease replacement costs in future years.

Depreciation and Rate Base

Depreciation and return on rate base make up a substantial portion of the revenue requirement and the careful tracking of these accounts is a fundamental component of the RR Model. While the prior section described the modeling of physical assets in service, this section describes the modeling of accounting tools that represent the utility's financial return of and on capital.

The RR Model tracks the value of rate base in parallel to the unretired assets, fully separating the accounting metrics from the physical assets. This enables the independent user selection of depreciation terms and capital retirement lifetimes. By default, both the depreciation term and retirement lifetime of an asset are set to the average book life of the capital asset category. However, they can be varied independently, e.g. to model extended capital maintenance or accelerated depreciation.

The model also considers removal costs, which represent the cost of removing capital at the end of its useful service. The treatment of removal costs in utility finances derives from the treatment of salvage value. In the past, retired capital often had salvage value and utilities were required to return this to ratepayers as an annualized reduction in depreciation expense:

$$annual\ accruals = \ deprecation - salvage\ value$$

Although the annual accruals to the utility were reduced, the utilities were compensated via the rate base, which would decline at a slower rate (i.e.: by the reduced annual accruals) and would only be adjusted to zero when the utility retired the asset and recovered the salvage value.

Today, most utility capital has negligible salvage value and instead has substantial removal costs, often called "negative net salvage." However, the financial model remains the same. Thus, annual accruals are now increased by the annualized removal costs:

$$annual\ accruals = \ deprecation + removal\ costs$$

The accrual expenses can be modeled with more detail. Straight-line depreciation is the default method for modeling the depreciation of utility capital. New capital (built by the RR Model) is catalogued by vintage, and the straight-line method is used to calculate annual accruals from each vintage. However, the straight-line method does not produce realistic accruals for existing capital, which is not catalogued by vintage. This method would suggest a fixed annual amount should be collected over the average remaining life of the assets. However, the accrual expenses for existing capital should steadily decrease as old assets are fully depreciated. In addition, accruals should extend to the full book life of the existing assets, representing that some were purchased only last year. As a better approximation, the RR Model tracks accruals of existing assets using a quadratic function, recovering the linearly amortized accruals in the first year and varying amounts thereafter, extending to the full book life of the assets.

O&M Expenses

Annual expenses for Operations and Maintenance ("O&M") are a significant portion of the natural gas revenue requirement. Regulatory filings detail present-day O&M expenses as well as forecast escalation rates for the next few years. However, in the long term, it is not clear to what extent O&M expenses should track the size of the gas system. As this remains an open question, O&M is modelled using two different methods and allow the user to choose one option or a mix of the two.

The first method assumes that annual O&M expenses are completely decoupled from the value of gas capital. In this view, O&M expenses are dominated by costs that do not scale with the size of the gas system, e.g. administrative costs, pensions, etc. In this method, the user can choose an annual escalation rate, with a default value provided from regulatory filings. Real O&M costs then escalate annually at this rate.

The second method assumes that O&M costs scale with the value of unretired gas capital. In this view, O&M expenses are dominated by the costs of maintaining existing infrastructure and serving demand. In this method, O&M expenses are divided into categories that match those for capital assets. Year-over-year, each class of O&M expenses grows or shrinks by the same proportion as the corresponding capital, which is determined by the reinvestment logic described above.

Using these two methods, the model calculates two values of O&M for each model year. A weighted average of these values is taken as the final O&M expense, with the weights determined by a user-input parameter. This allows the user to decide approximately what share of O&M expenses scales with capital, with the rest escalating at a fixed rate.

Rates and Cost Allocation

By tracking capital investment and depreciation as well as O&M expenses, the model determines the revenue requirement in every model year. In most scenarios, today's natural gas rates will be inadequate to meet the utility's revenue requirement through 2050. To illustrate this, the model first looks at total costs without considering cost allocation. In this analysis, the RR Model assumes that real natural gas rates are fixed at rates in the reference scenario, then calculates the gap between the cumulative revenue requirement and cumulative revenues through 2050. This gap corresponds to gas system transition costs that must be paid by some combination of ratepayers, taxpayers, and/or shareholders.

Another way to illustrate the gas system transition costs is to model the customer rates that would be required to meet the full revenue requirement. While today's cost allocations are largely driven by peak demands, this may not be representative of costs in the future. The RR Model begins with present-day cost allocations and includes the option to gradually transition to cost allocation based on distribution- and transmission-level throughput. In addition to transportation rates, the model also includes commodity costs, which are outputs from PATHWAYS and vary based on the blend of natural gas and other low-carbon gasses such as hydrogen and synthetic gas.

Cost and Rate Impact Mitigation Parameters

The RR Model includes potential strategies to reduce system costs and mitigate the impact on ratepayers. The most effective way to reduce costs is to reduce the size of the gas system. As described above, this is implemented through reduced reinvestment. A decrease in capital expenditures will eventually reduce all components of the revenue requirement.

Coupled with declining reinvestment, accelerated depreciation may be an effective method to mitigate rate impacts in a shrinking system, as costs are collected earlier and thus from more customers and spread over more throughput. The RR Model includes the option to set depreciation terms for each category of capital asset. Another strategy to reduce the revenue requirement is to reduce the removal costs associated with capital retirement. If assets are not being replaced, some could potentially be retired in place or repurposed for other uses. The RR Model includes the option to reduce removal costs by a user-determined percent.

The RR Model also includes option to vary cost allocation from today's allocations to a system based on distribution- and transmission-level throughput. In addition, the model includes the ability to shift costs over time. Through fixed fees and/or exit fees, costs can be spread over customer bills in the short term, with the revenues then used to offset rates in later model years. Finally, the model allows outside revenues to directly offset rates. This could represent cap and trade revenues, funds raised through securitization, revenues from electric rates, or other sources.