Energy+Environmental Economics

Draft Results: Future of Natural Gas Distribution in California

CEC Staff Workshop for CEC PIER-16-011

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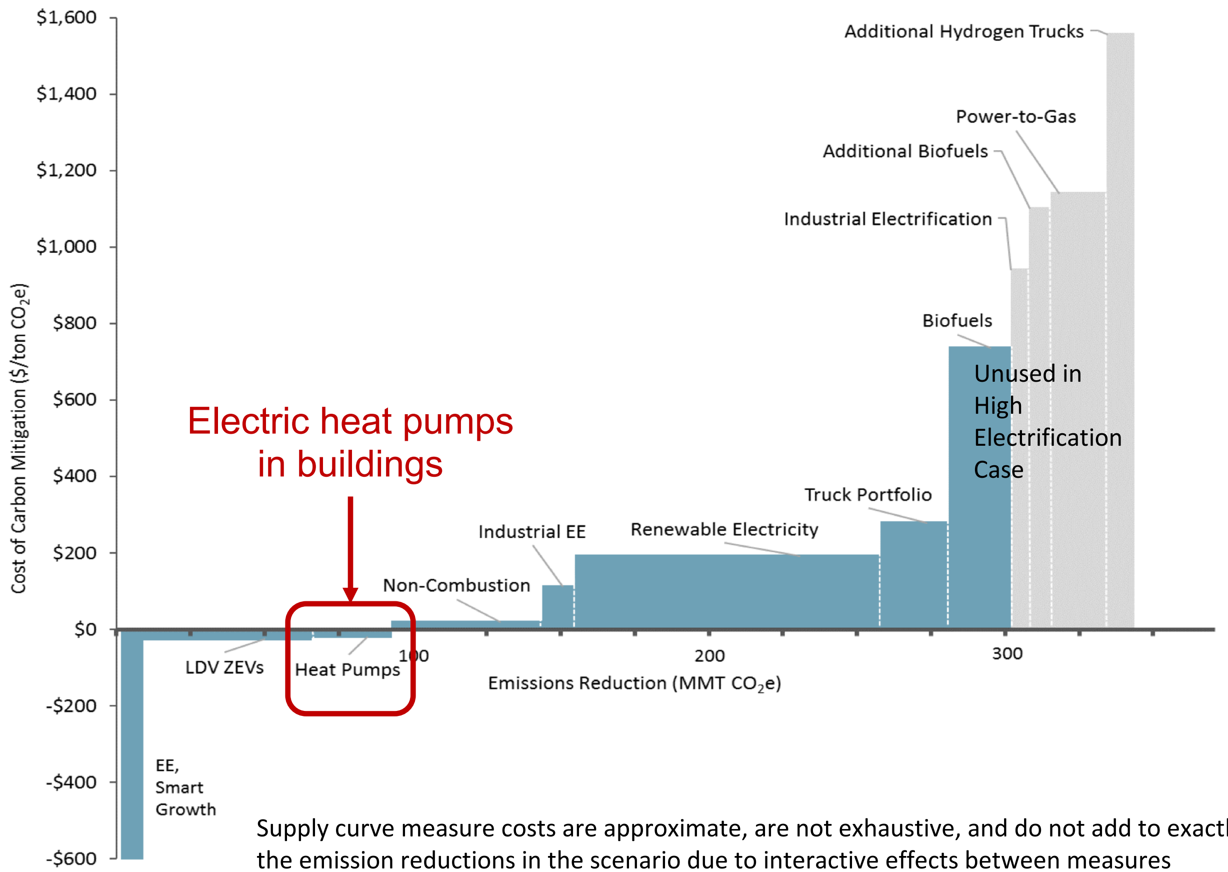
Agenda

+ Project Introduction
+ Technology Options to Decarbonize the Natural Gas System
+ Potential Pathways for the Natural Gas System in the Context of Decarbonizing California's Energy System
+ Implications for Natural Gas Customers
+ Air Quality and Public Health Implications
+ Next Steps

This work builds on E3's 2018 CEC Report "Deep Decarbonization in a High Renewables Future"

- **2018 study evaluated 10 scenarios to meet California's climate goal of an 80% reduction in GHGs by 2050, in a high renewables future**
  - Scenarios account for a changing climate in CA
- **Building electrification was shown to be one of the lower cost GHG mitigation strategies**
- **2018 study focused on an economy-wide resource cost metric, not on distributional impacts or impacts to gas customers**

2050 Incremental Carbon Abatement Cost Curve in the High Electrification Scenario



Supply curve measure costs are approximate, are not exhaustive, and do not add to exactly the emission reductions in the scenario due to interactive effects between measures

Source: E3 report on "Deep Decarbonization in a High Renewables Future," June 2018, CEC-500-2018-012

This project evaluates gas customer implications and health impacts of a low-carbon future in California

+ Key questions

- What are the economy-wide costs of achieving a low-carbon future? What strategies are available to reduce the consumer cost impacts of decarbonizing buildings, and make the transition more equitable?
- What are the health implications of different electrification and decarbonization strategies?

+ Analysis team

- E3: California economy-wide GHG scenarios, gas transition scenarios, bill impacts
- UC Irvine Advanced Power & Energy Program: Renewable natural gas technical analysis and air quality impacts

+ Project Partners

- SoCalGas, SMUD

+ Technical Advisory Committee

- SoCalGas, SMUD, PG&E, NRDC, EDF, and others

Research & Modeling Approach

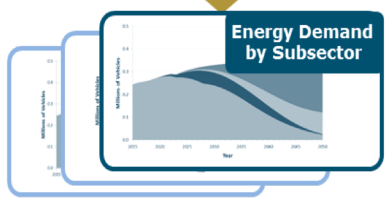
PATHWAYS model:
California economy-wide energy scenarios

Renewable Natural Gas Technology Costs
(UCI lead)
- Biomethane
- Hydrogen
- Synthetic natural gas

California economy-wide scenarios to achieve 80% reduction in GHGs by 2050
(with focus on strategies to decarbonize buildings)

Technology Energy Demand

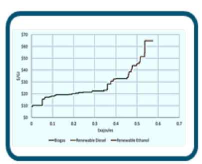
Stock Rollover

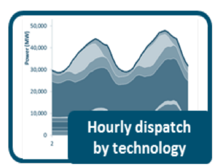


Fossil and Other Fuels

Biofuel Supply Curves

Hourly Electricity Supply





Natural Gas Utility Revenue Requirement Model
Gas rates by customer class over time, by scenario

Household Energy Bills
by scenario, over time

Local Air Quality Impacts
(UCI lead)
SMOKE & CMAC models

Health impacts
(UCI lead)
BenMAP model

Draft conclusions

- **Using renewable natural gas (RNG) to decarbonize buildings—with foreseeable technology—is an expensive strategy**
  - The high cost of RNG would likely encourage economic electrification for some
- **Replacing gas equipment with electric equipment upon burnout lowers the societal cost of achieving California's climate policy goals**
- **Gas demand decreases in all of the GHG mitigation scenarios. As gas demand falls, average costs for remaining customers increase**
  - Absent policy intervention, low-income customers who are less able to electrify may face a disproportionate share of those costs
- **A gas transition strategy is needed to reduce the costs of the gas system and protect consumers. Such a strategy could include:**
  - Reducing gas system expenditures (i.e. via targeted retirements of gas pipelines)
  - Changes to gas rates & rate design
  - Recovery of gas system costs from electric ratepayers or from other funds
- **Building electrification improves air quality and health outcomes in urban centers**

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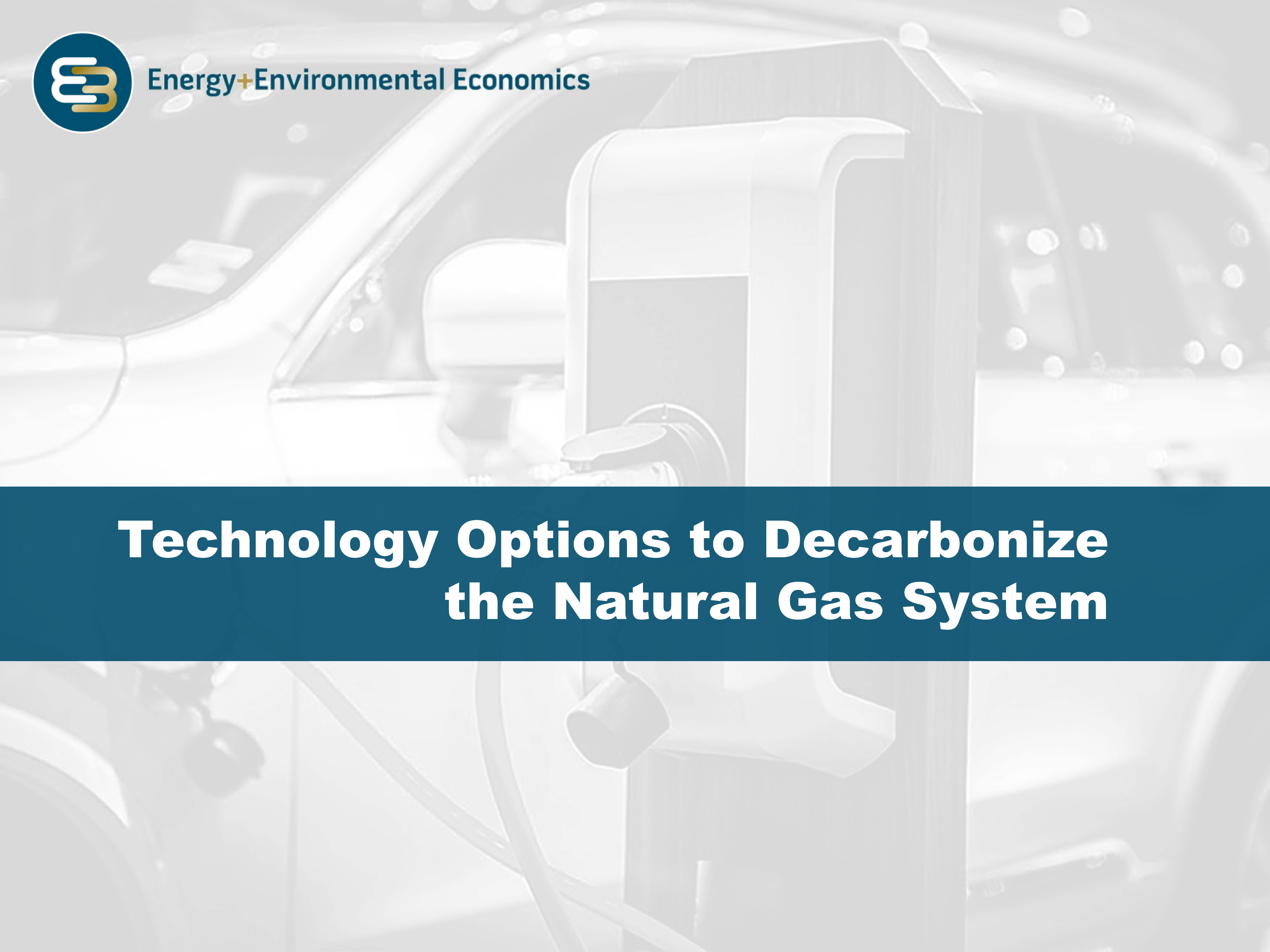


Technology Options to Decarbonize the Natural Gas System

Methods to evaluate the costs of renewable natural gas technologies

+ **Renewable natural gas (RNG) is a term used to encompass: Biomethane, climate neutral hydrogen, and synthetic natural gas (SNG)**
+ **UCI estimated production efficiency, levelized capital costs, and variable O&M costs over time for each biomass feedstock type (e.g. manure, wood waste, etc.) for RNG production**
+ **Costs are a function of:**
  - Industry learning rate and global installed capacity
  - Electrolysis technology
  - Load factor
  - For SNG, the CO_2 source
+ **Developed assumptions about global installed capacity of RNG technologies**
+ **Applied learning rate assumptions to develop cost trajectories over time**

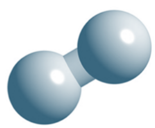
Biomethane is an important resource in all scenarios, but feedstocks are limited

Waste biogas	**Gasification of biomass residues**
✓ Municipal waste ✓ Manure X Very limited supply	✓ Agricultural residues ✓ Forest residues including from forest management of dead and dying trees X Limited supply and competing uses

Given sustainable biomass supply constraints, scenario-specific competing uses for biofuels, and changes in pipeline gas throughput by scenario, biomethane supplies fall in the range of **16%** to **25%** of throughput in 2050

+ **Biomass feedstocks used to produce biomethane and liquid biofuels are assumed to be equal to the CA population-weighted share of the US supply of biomass wastes & residues**
  - 43 million dry tons by 2050
  - Biomass potential is based on DOE 2016 Billion Ton Update + additional CA biogas resources harmonized with Jaffe et al (2016)
+ **PATHWAYS biofuels module estimates the least-cost biofuel portfolio given competing demands for fuels**
  - Optimization maximizes cost-effective CO_2 reduction
  - For each scenario, the selected biofuels portfolio displaces liquid and gaseous fossil fuel, based on fuel demand remaining after electrification

Hydrogen and SNG are less constrained by feedstock potential, but face other challenges



H_2

Hydrogen

- ✓ Electrolysis + zero-carbon electricity
- ✓ Steam methane reformation (SMR) + CCS*
- X Limited pipeline blend (7% by energy, 20% by volume)**

CH_4

Synthetic Natural Gas (SNG)

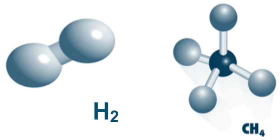
- ✓ Renewable hydrogen + waste bio-CO_2 or renewable hydrogen + direct air capture (DAC) used to produce climate neutral methane
- X Limited commercialization of key technologies

* We did not model SMR + CCS

** We did not evaluate conversion of the gas system to 100% hydrogen, which would require replacement of end-use devices and gas pipeline upgrades

- **Benefits of hydrogen and SNG include the ability to utilize existing gas distribution infrastructure with some upgrades to pipelines and burn-tips in end use equipment**
- **Challenges for hydrogen include cost & limited potential to blend in pipeline**
- **Challenges for SNG include cost & sourcing climate neutral carbon**
- **Selected UCI capital cost scenarios layered on top of PATHWAYS energy costs to develop all-in commodity costs**

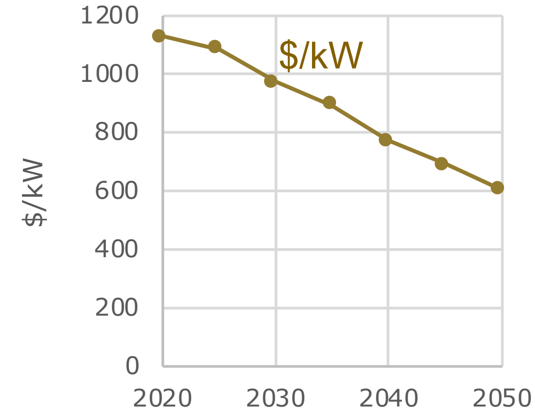
Base case and low cost assumptions for hydrogen and SNG are evaluated

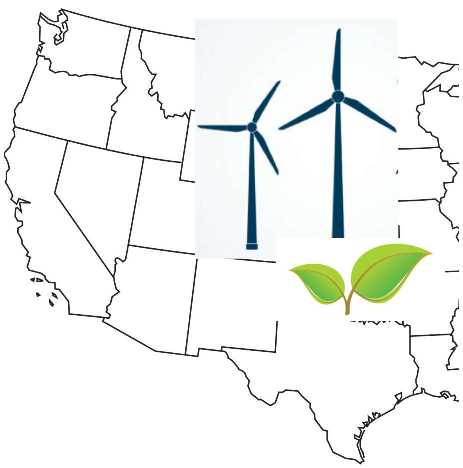


Base Case Assumptions: Hydrogen & SNG

- Electricity source: Fuel production facilities are mostly co-located with off-grid CA solar
  - On-grid renewable curtailment is not sufficient to meet fuel production loads in most scenarios
- CO_2 sources for SNG: Mostly DAC powered by off-grid solar, with limited CA waste bio-CO_2
- Technology Learning: Moderate industry learning rate for electrolysis, methanation, and DAC

Example electrolyzer capital costs (w/ base case learning)

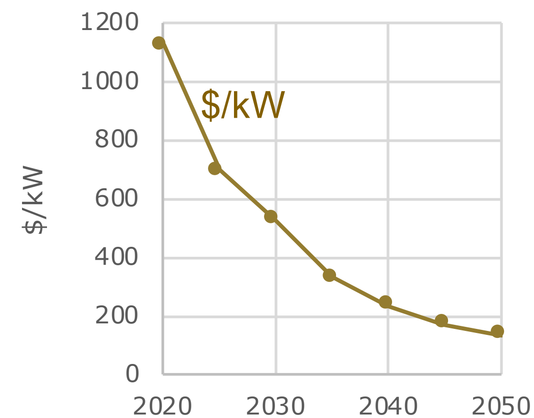




Low Cost Assumptions: Hydrogen & SNG

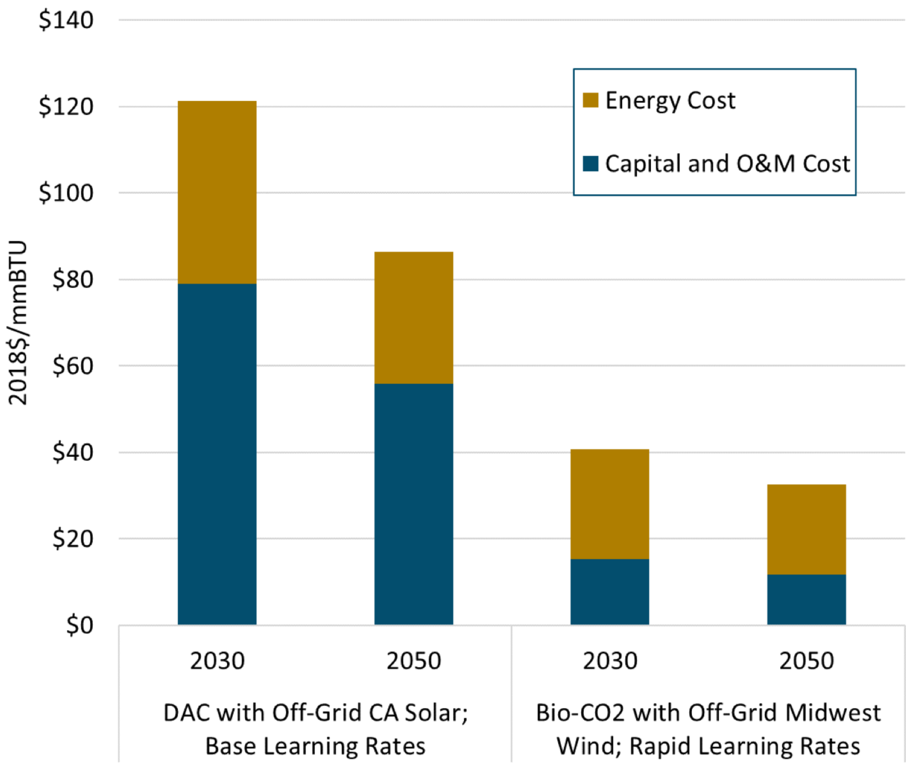
- Electricity source: Fuel production facilities are co-located with off-grid Midwest wind
  - On-grid renewable curtailment is not sufficient to meet fuel production loads in most scenarios
- CO_2 sources for SNG: waste bio-CO_2 from Midwest biofuel production
- Technology Learning: Rapid industry learning rate for electrolysis and methanation

Example electrolyzer capital costs (w/ rapid learning)



SNG commodity costs combine UCI inputs with PATHWAYS scenario assumptions

SNG Commodity costs for production from a new plant in 2030 or 2050



*PATHWAYS scenarios represent changes in technology capital costs over time by vintage, transition of electrolysis technology, and different fuel costs for SNG based on source of CO_2.

+ **Renewable synthetic natural gas (i.e. power-to-gas methane) requires:**

1. **Renewable hydrogen produced via electrolysis**
2. **Renewable CO_2 source**
   - CO_2 captured from biorefining
   - Direct air capture powered by renewables
3. **Methanation and upgrading to pipeline quality**

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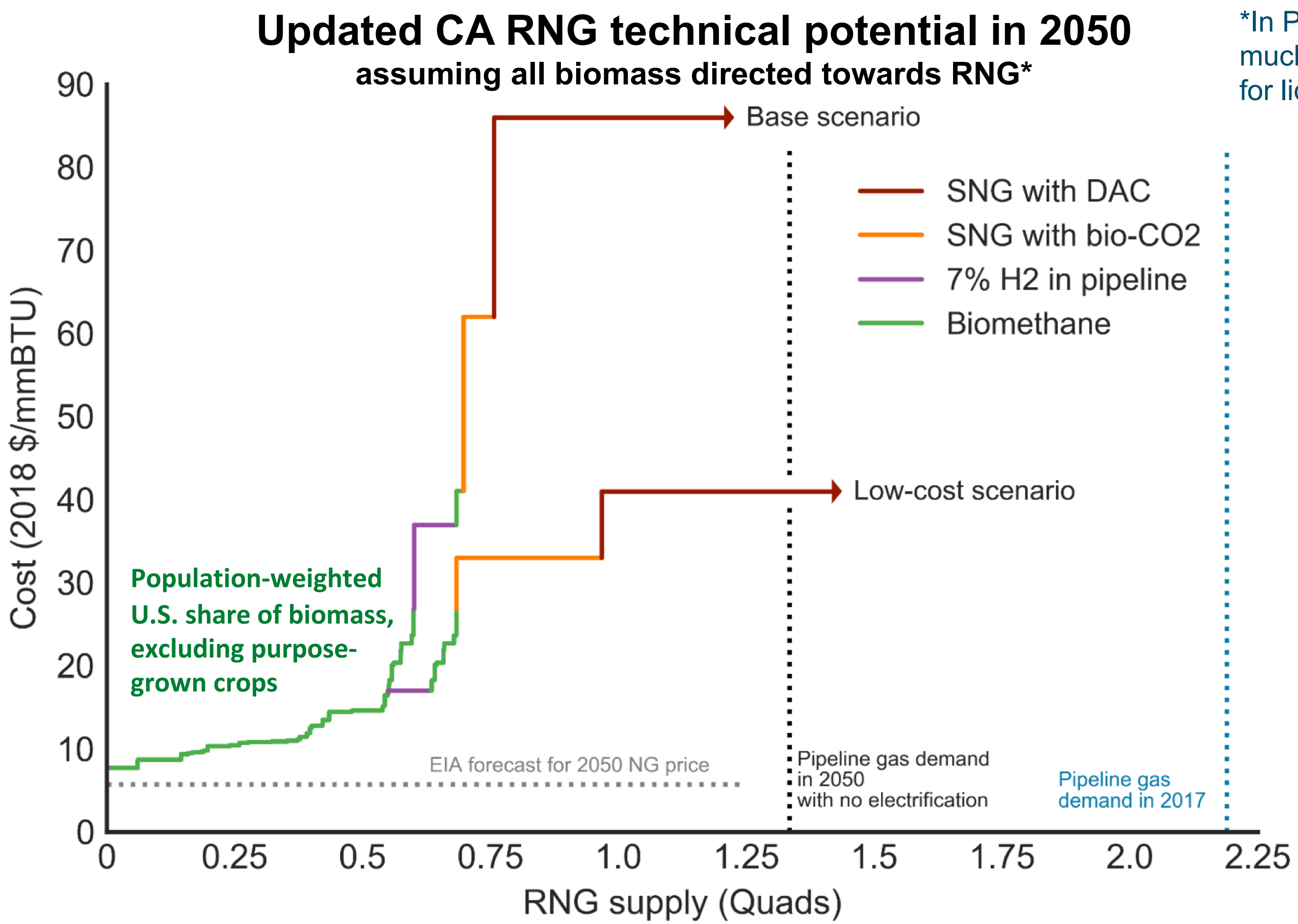
California Economy-wide Decarbonization Scenarios

There is insufficient low-cost RNG to fully decarbonize the pipeline without electrification

+ **Expensive RNG would likely be needed to decarbonize gas demand without electrification, even with aggressive technology learning and use of best-case out of state resources to produce hydrogen and SNG**

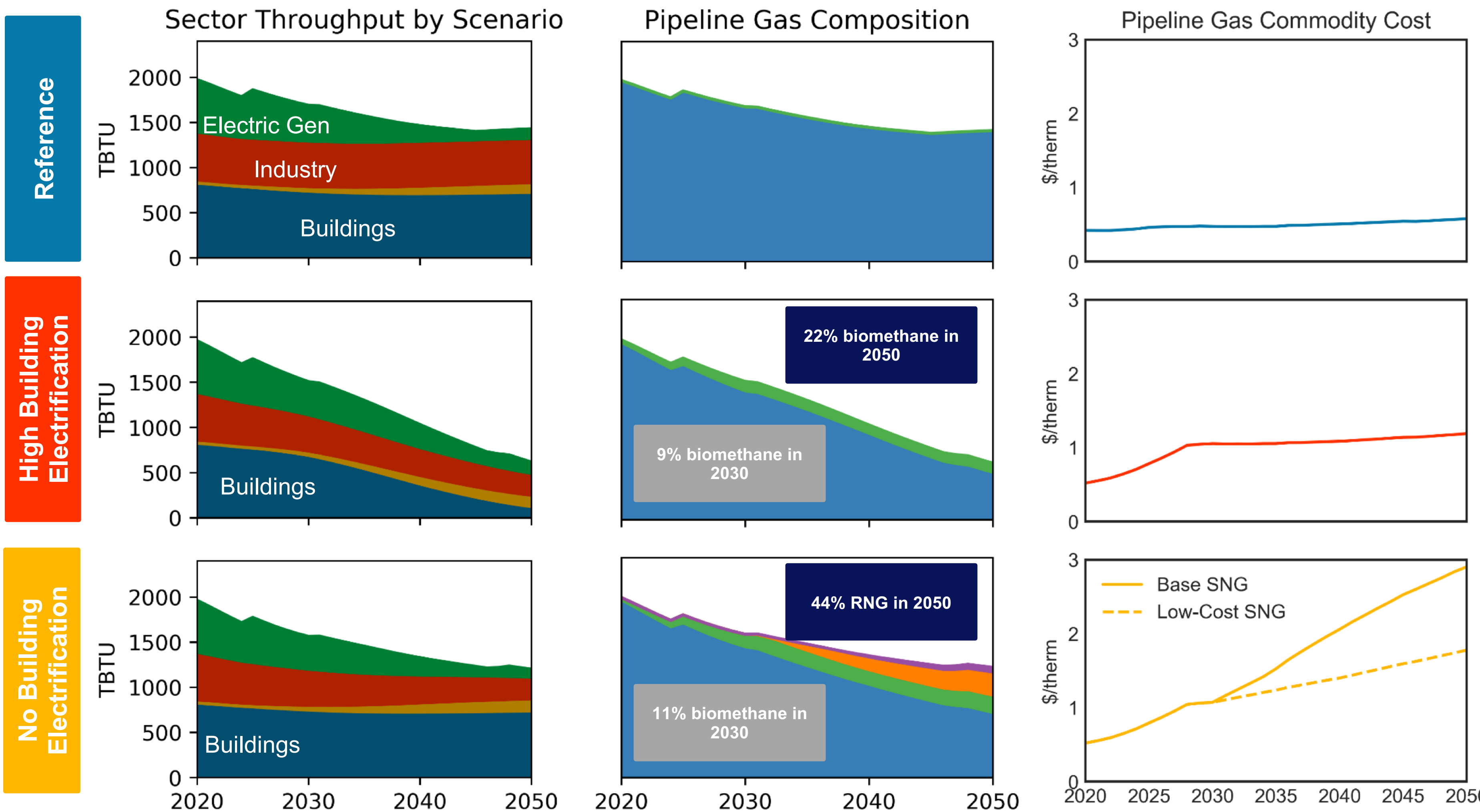


*In PATHWAYS scenarios, much of the biomass is used for liquid biofuels.

Analysis focuses on three key scenarios

1. **Current Policy Reference**
   Does not meet 2030 or 2050 economy-wide GHG goals
   - Reflects SB 350, consistent w/ a “zero-carbon retail sales” interpretation of SB 100
2. **High Building Electrification**
   Achieves economy-wide 40% reduction in GHGs by 2030 & 80% by 2050
   - High electrification of buildings (50% heat pump sales by 2030, 100% by 2040) and light-duty vehicles
   - Pipeline biomethane (along with liquid biofuels) mostly serves industry & CNG trucks; remaining fossil budget used in transportation and industry
3. **No Building Electrification**
   Achieves economy-wide 40% reduction in GHGs by 2030 & 80% by 2050
   - No electrification in buildings, high electrification of light-duty vehicles
   - In addition to using all available biomethane, adds hydrogen and SNG in the pipeline and more ZEV trucks than high electrification scenario
   - Pipeline gas blend remains 56% fossil in 2050, so a large share of the 2050 emissions budget is in buildings

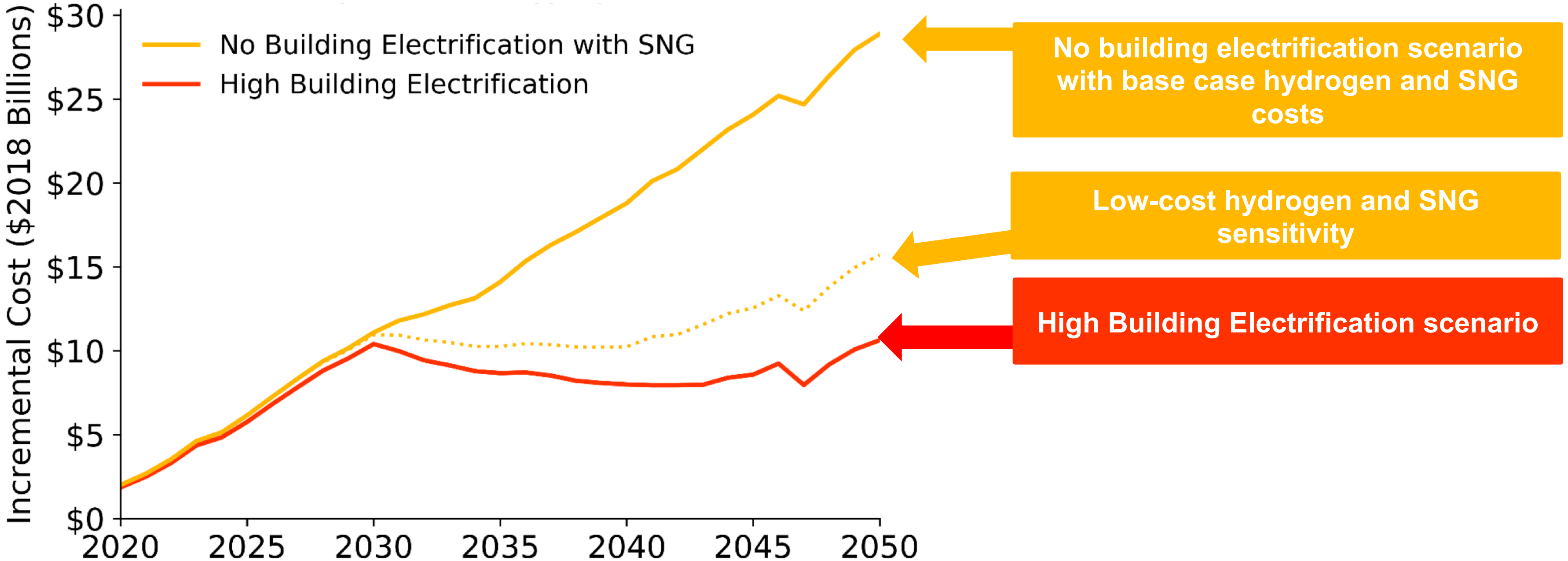
Gas throughput declines in all scenarios: Gas use in buildings is a key difference



Pipeline commodity costs do NOT include gas transmission, storage or distribution costs

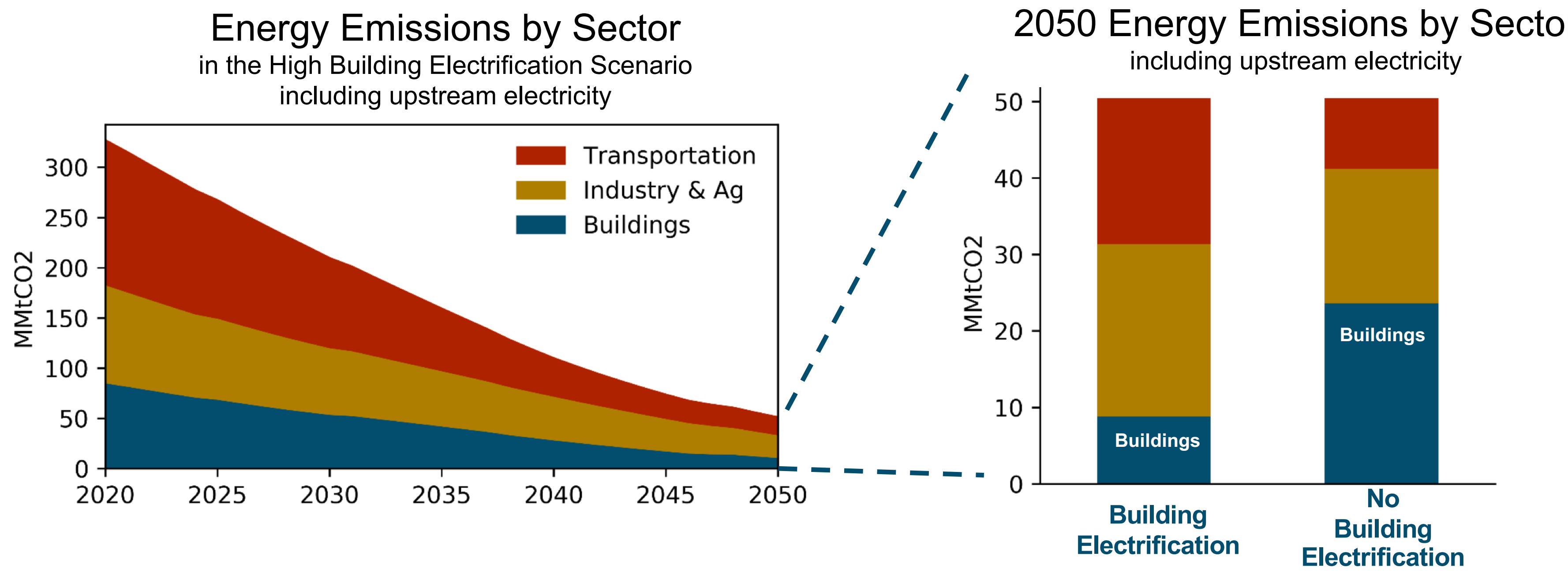
Building electrification projected to lower economywide costs

Economy-wide annual net costs, relative to Current Policy Reference scenario



- Use of hydrogen and SNG drive cost increases post-2030 in No Building Electrification Scenario, with a wide range reflecting uncertainty in SNG cost
- Costs in the High Building Electrification scenario stabilize as other mitigation costs (e.g., renewables, electric vehicles) continue to decline post-2030
- Transfer payments (e.g. LCFS, cap-and-trade) do not increase the total societal cost

Remaining emissions in 2050 and implications for net-zero GHG emissions



+ **Both scenarios would require additional GHG mitigation measures throughout the economy to achieve net-zero GHG emissions**
  - The High Building Electrification decarbonizes buildings more completely by 2050 and has more low-cost options remaining in transportation and industry.
  - Using SNG to reduce building sector emissions to the same level as the "Building Electrification" scenario would require more DAC
  - \$4 - \$9/therm → an additional cost of \$11 - \$24 Billion/year in 2050

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Implications for Natural Gas Customers

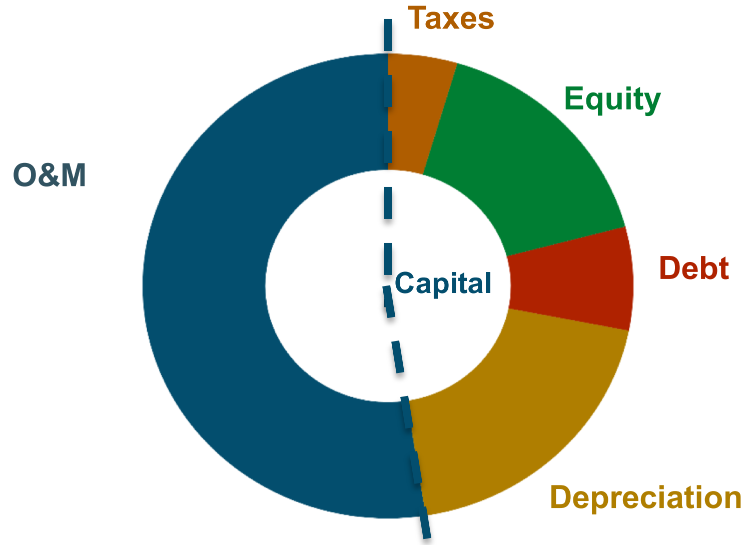
California's current energy cost challenge

- **Natural gas costs are increasing**
  - Following the San Bruno explosion and Aliso Canyon gas leak, gas utilities in the state are in the midst of safety driven expenditures, markedly increasing their costs
- **Electricity costs are increasing**
  - Electric utilities expect increases in cost due to wildfire liability and to harden their systems against wildfire risks
- **The extent and duration of increases remain uncertain**

Utility	2018 – 2022 estimated BAU % change in rates (real, above inflation)
SoCalGas (gas)	30% (2019 GRC)
PG&E (gas)	15% (2020 GRC)
Electric utilities	Uncertain: 6% - 8% modeled here

The structure of gas utility revenue requirement today

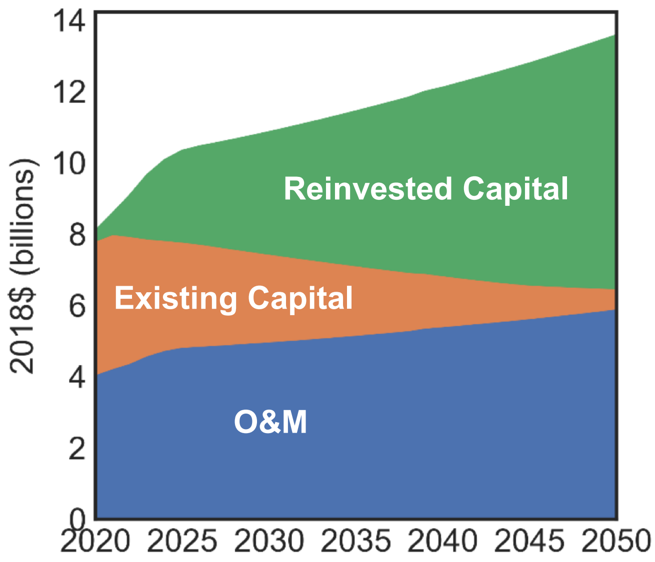
California's 2019 gas infrastructure revenue requirement



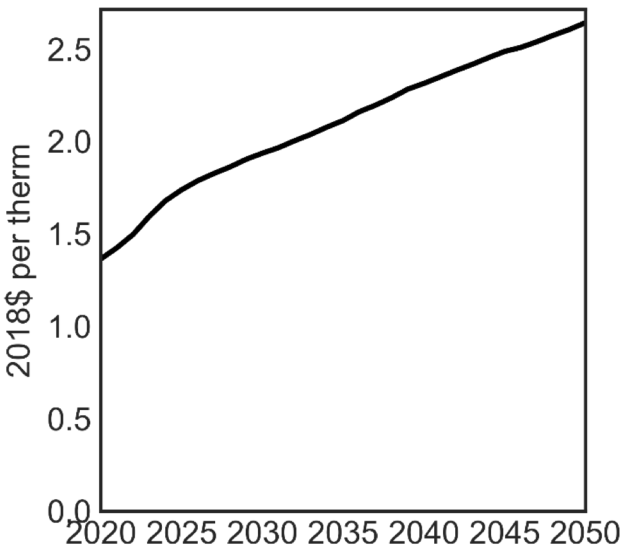
- **E3 estimates that California natural gas utilities collect $7.5B in revenues per year**
  - E3 developed a gas utility revenue requirement tool estimating gas rates through 2050 under different scenarios
- **These revenues cover both ongoing operations and maintenance (O&M) costs, as well as pay for infrastructure replacement and expansion**
  - **O&M costs are just over half the revenues of gas utilities.**
  - **Costs related to capital investments are just under half of gas utility revenues.**
- **The costs of commodity gas are tracked separately from the utility revenue requirement and are a pass-through expense**

Current Policy Reference scenario gas system costs are uncertain, but will likely increase over time

Reference Scenario Statewide Gas Utility Delivery Revenue Requirement

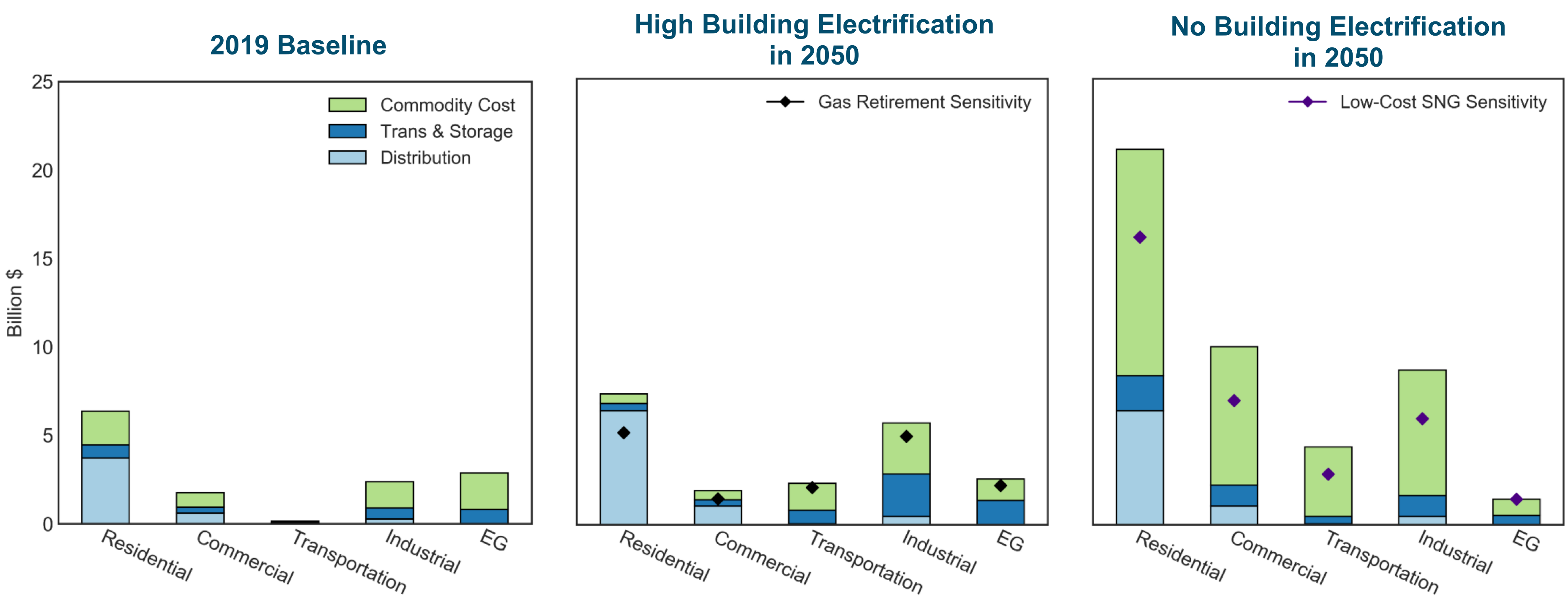


Reference Statewide Scenario Residential Rates



+ **By 2050, gas system costs would be substantially higher even in a "Reference" scenario due to capital cost escalation and continued safety enhancements and system reinvestments**

Statewide gas utility revenue requirement and commodity cost in 2019 and 2050

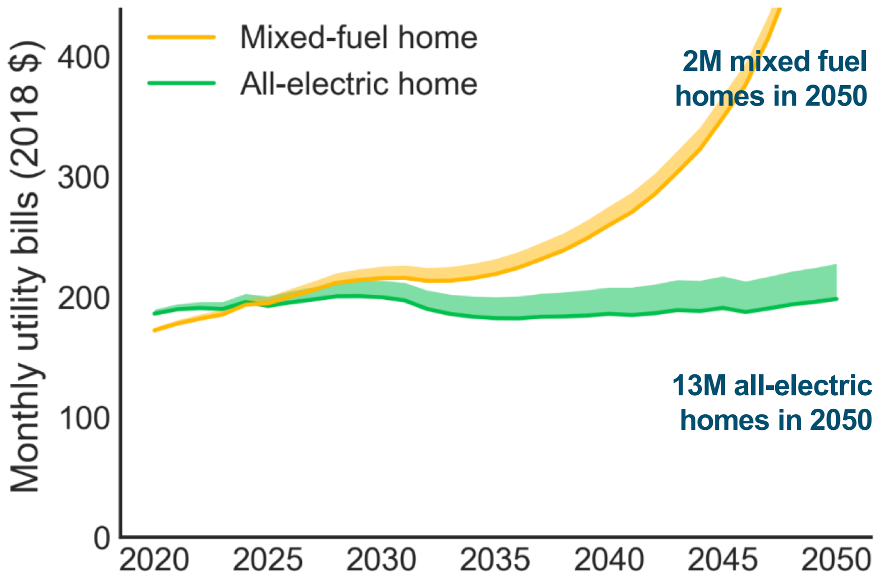


- Today, delivery costs are the majority of residential gas bills.
- By 2050, gas distribution costs may be larger than today, even in a future with high building electrification and gas infrastructure retirement
- By 2050, gas system costs are substantially higher in the No Building Electrification scenario than the High Building Electrification scenario due to 1) higher throughput and 2) more expensive commodity costs

Average residential utility bills

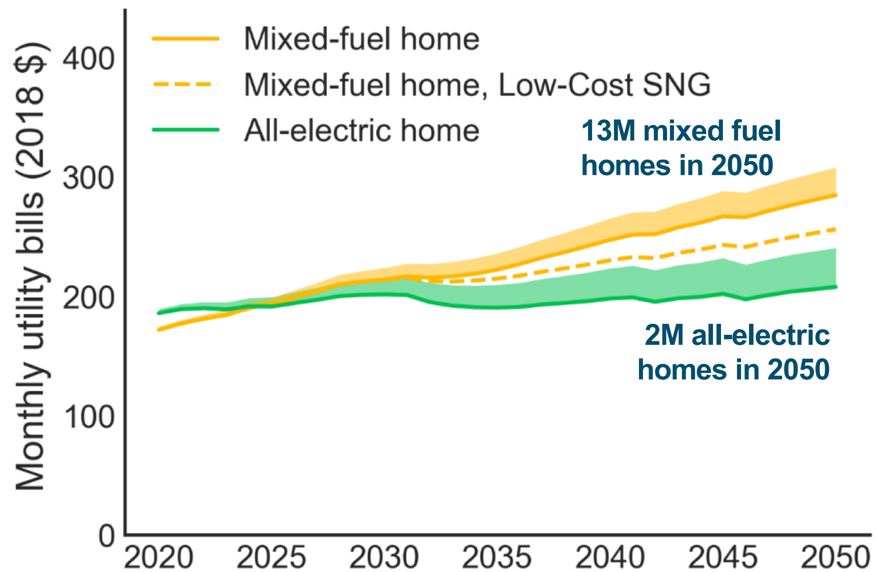
High Building Electrification scenario with no gas transition strategy

Mixed-fuel bills* rise due to delivery costs



No Building Electrification Scenario

Mixed-fuel bills* rise due to commodity costs

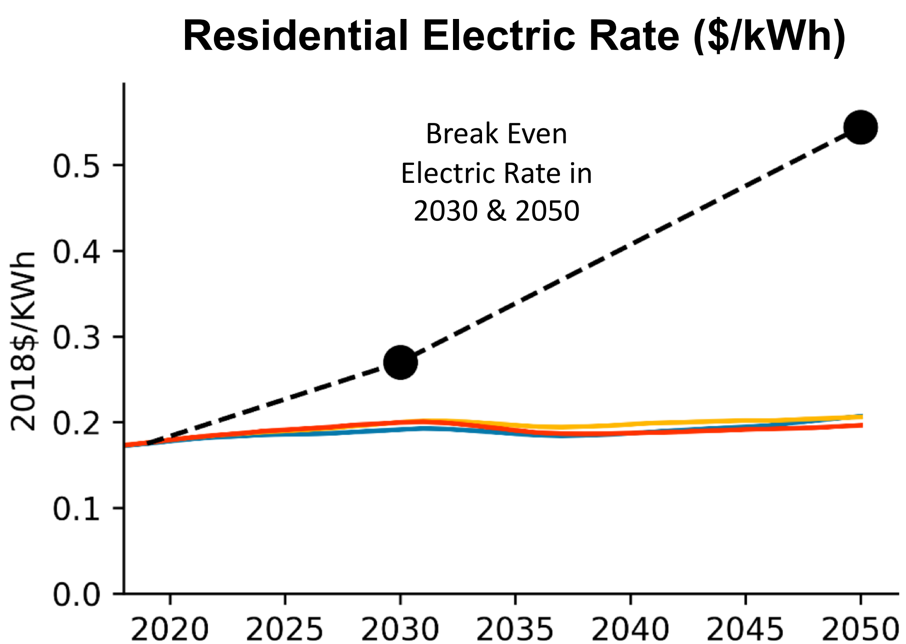


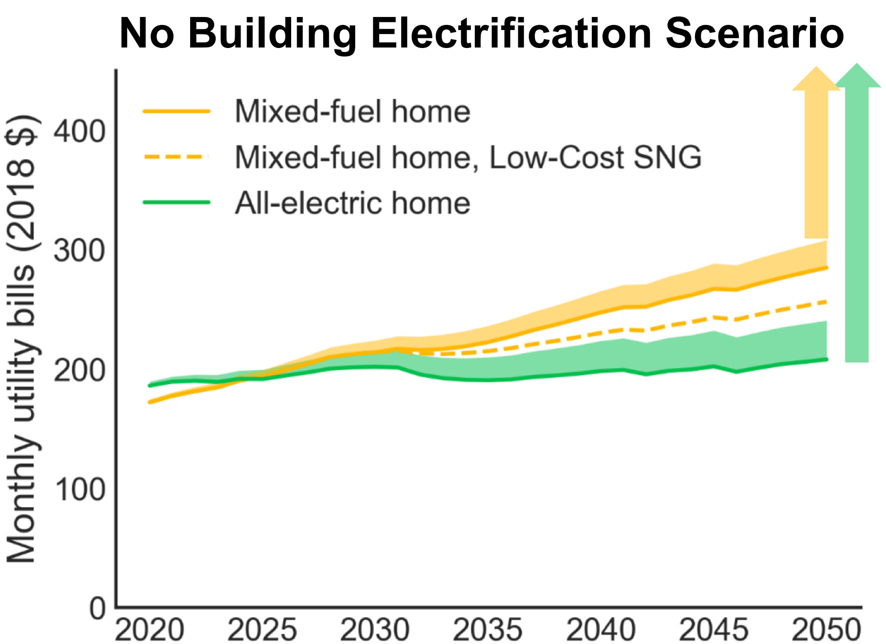
*Bills include all electric and gas end-uses in the home, not electric vehicle charging

- Low-income gas consumers would likely need rate protection and/or transition assistance if large numbers of customers opt for economic electrification
- Post-2030, mixed-fuel homes always have higher bills than all-electric homes
- This scenario assumes no economic electrification. Gas rates and bills would increase further than shown here if customers choose to electrify

Thought experiment: electric rates

- How high would electric rates have to increase for mixed-fuel and all-electric customer bills to be equal in 2050 in the No Building Electrification Scenario?





- In 2050, electric rates would need to be $0.55/kWh to reach a break-even utility bill with mixed-fuel customers. This would impose significant affordability challenges on all California customers
- High electric rates would reduce the economic advantages of electrification in both the transportation and buildings sectors

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Examples of a Gas Transition Strategy

Components of a gas transition

- ❑ Reduce barriers to building electrification
- ❑ Targeted building electrification pilots

1. Market transformation of building electrification

- ❑ Avoid gas system expansion, reduce costs
- ❑ Targeted retirements of gas distribution system

2. Decrease gas distribution system costs

- ❑ Accelerated depreciation
- ❑ Changes to rate design and cost allocation

3. Change in gas rate design

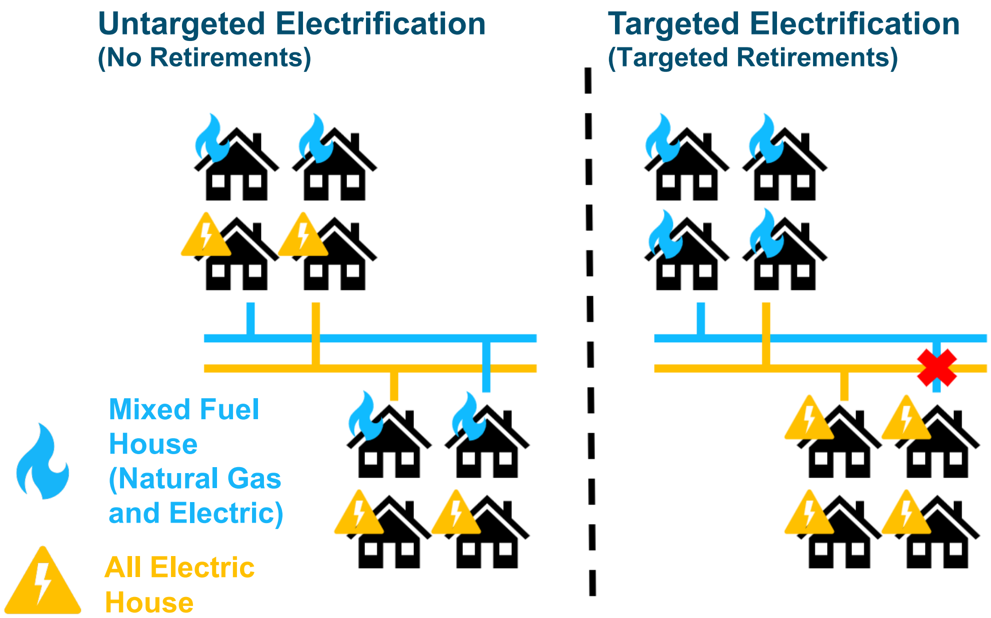
- ❑ Exit fees for departing gas customers
- ❑ Other funds to manage the equity impacts

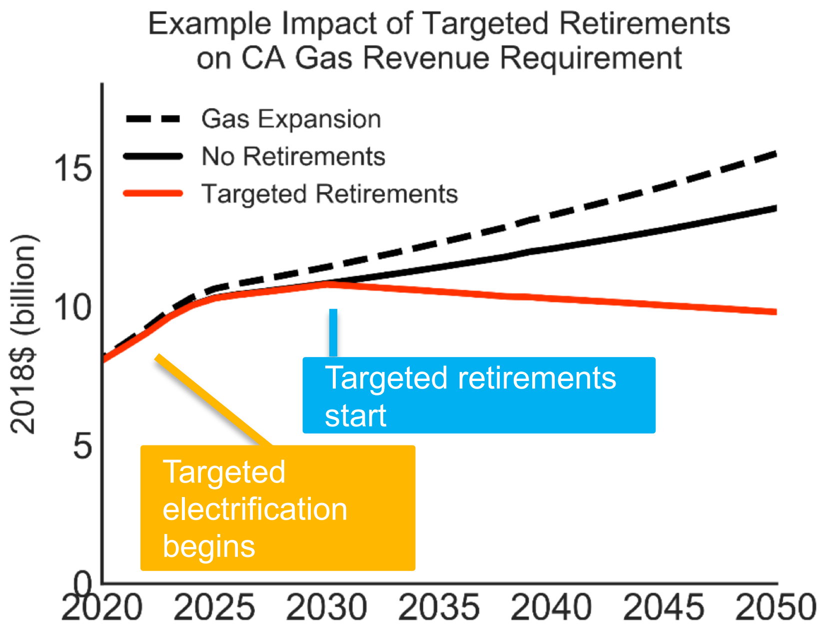
4. Gas cost recovery from electric rates or additional funds

- ❑ Shut-down gas distribution system and replace any remaining gas-connected end-uses with electric or other fuels

5. Shut-down the gas distribution system

Targeted electrification could potentially reduce gas system costs



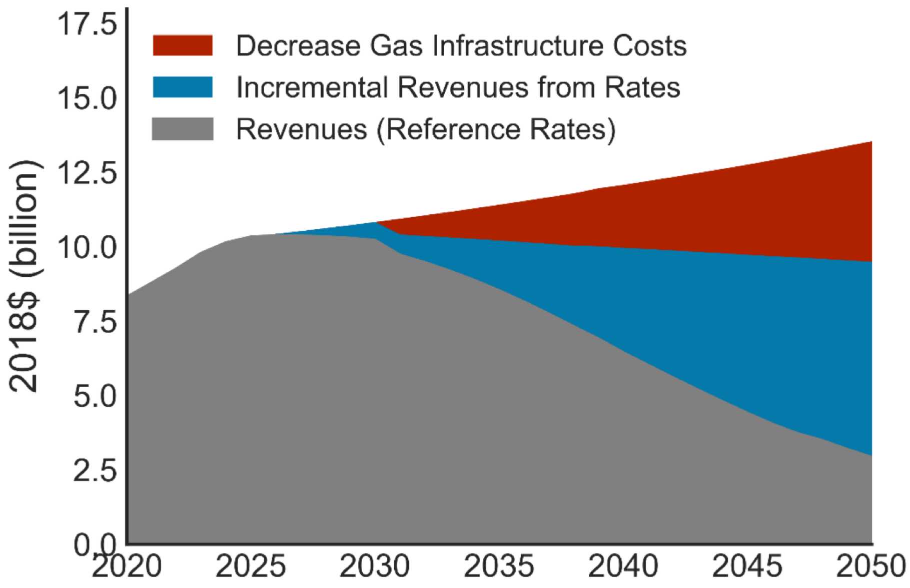


- **The gas system requires ongoing investment to maintain safety and reliability for remaining customers**
- **A key question is to what degree, and under what conditions, gas pipeline infrastructure could be retired while sustaining necessary safety reinvestments**
  - Reinvestments result in long-lived assets, typical distribution capital investments have lifetimes of 50 to 65 years
- **Expanding the gas system could further increase the Reference scenario revenue requirement**

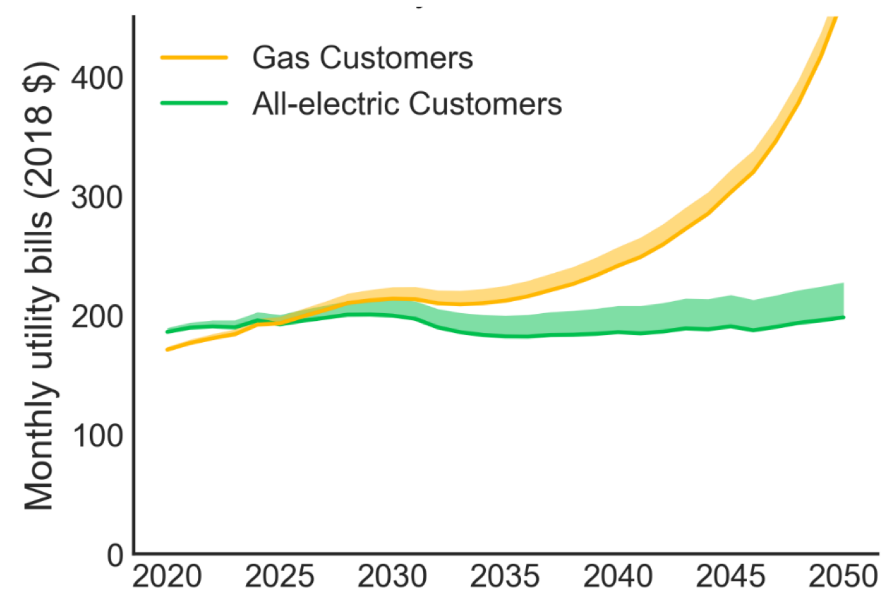
Targeted gas retirements still lead to high gas customer bills, absent other gas transition strategies

Example 1

High Building Electrification Scenario: Revenues Raised from Rates Only



High Building Electrification Scenario: Bill Impacts with targeted gas pipeline retirements

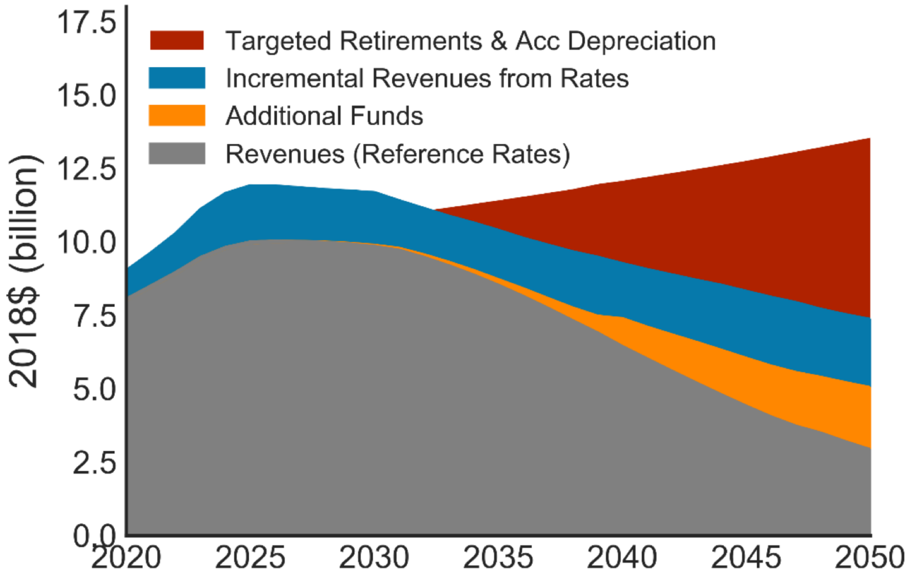


- **Combined electric and gas bills for remaining gas customers are over $490/month in 2050, a 2.5X increase over current bills**
- **Higher bills would provide a powerful economic signal to spur electrification, but could also harm low-income consumers who are renters and do not own their water heaters or space heating equipment or are unable to afford the upfront costs of electrification**

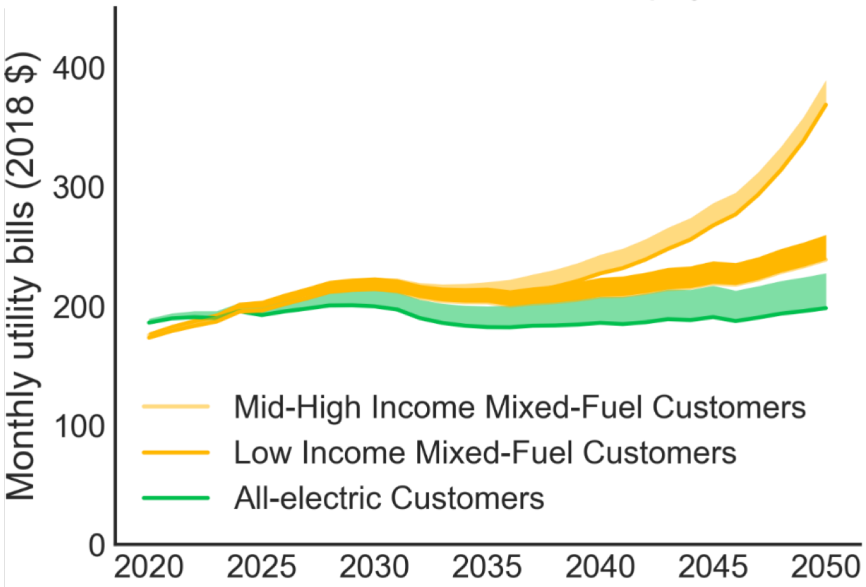
Example transition strategy: Targeted gas retirements, higher rates, plus outside funds to subsidize low-income gas ratepayers

Example 2

High Building Electrification Scenario: Revenues Under Example Transition Strategy



High Building Electrification Scenario: Bill Impacts with example transition strategy

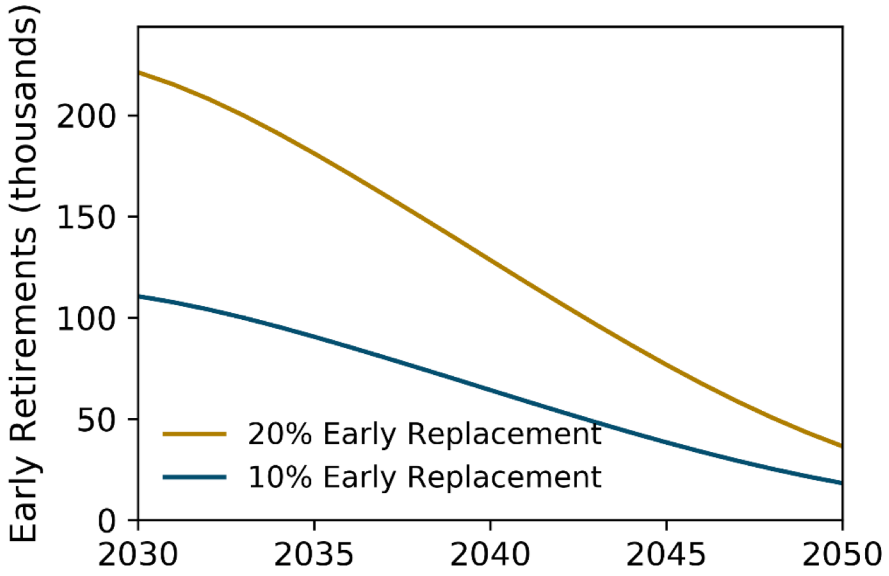


- **This example assumes: targeted gas retirements, higher rates, accelerated depreciation and $14B (NPV) in additional funds, used mostly to subsidize low-income rates through 2050**
- **Bills for remaining gas customers are:**
  - $390 / month for middle-to-high income customers
    $260 / month for low-income customers

Targeted replacement of gas equipment may reduce gas infrastructure costs, but incurs additional costs

- In the preceding examples, targeted gas system retirements reduce gas system-costs by $4 billion in 2050 and by $25 billion total in net present value terms
- Targeted gas system retirements may not be achievable without some early replacement of consumer gas end-uses (e.g. furnace, stove, water heater) with electric.
- A gas transition strategy would ideally ensure that early replacement costs do not exceed the savings from reduced gas system costs. Example below:

Illustrative numbers of early retirements



20% Early Replacement implies that 20% of electrifying customers incur early retirement costs, at an NPV of between $8 to $12 billion

10% Early Replacement implies that 10% of electrifying customers incur early retirement costs, at an NPV of $4 to $6 billion

Note: NPV ranges reflect uncertainty on the full-cost of electrifying homes early in any given year. The installed cost of replacing remaining appliances are assumed to be between $10k- $30k per household

Additional research needs

- **Engineering and safety**
  - What are the costs of safely maintaining the natural gas distribution system as gas throughput declines?
  - To what degree can targeted electrification efforts reduce the size of the natural gas system and save on gas distribution expenditures?
- **Legal and regulatory**
  - Will natural gas companies be able to collect the entire book value of their assets? Will shareholder return be affected?
  - How do retirements interact with California utilities' obligation to serve?
- **Policy**
  - How should transition costs be allocated within and between customer types and classes?
  - How should transition costs be allocated between gas, electric and other sectors?
  - What sources of non-ratepayer funds could be available to achieve an equitable gas transition?

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Air Quality Analysis

CEC Long Term Natural Gas System Plan: Air Quality Results Update

RESULTS ARE PRELIMINARY

Advanced Power and Energy Program

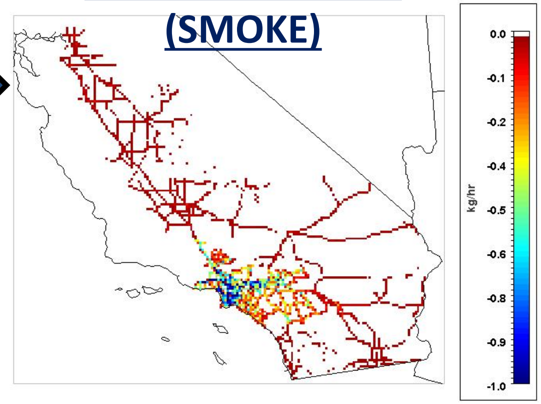
University of California, Irvine

AQ Assessment Methodology

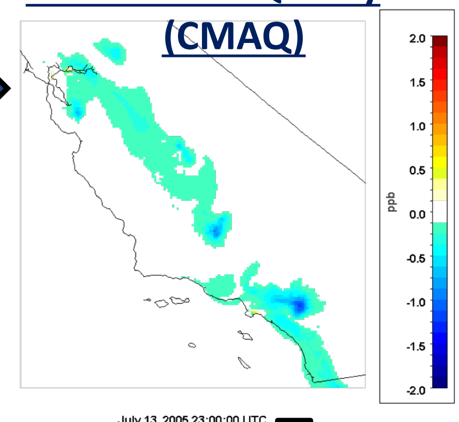
- **Assess impacts on emissions, air quality, and human health from low carbon mitigation scenarios from the PATHWAYS model**
  - Provide insight into the air quality co-benefits of technological shifts within cases

Pathways Scenarios

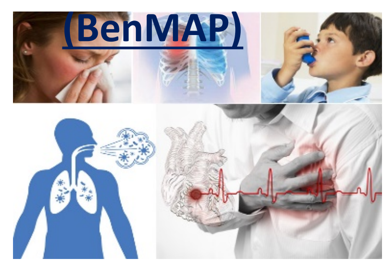
Resolve Emissions (SMOKE)



Simulate Air Quality (CMAQ)



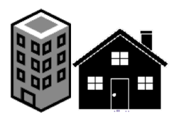
Health Impact Assessment (BenMAP)



- ~15 different scenarios considered
- Scenarios not designed from an AQ impact perspective, i.e., targeting criteria pollutant emission reductions

Scenario Development

- **Scenarios encompass shifts in energy consumption, technologies and fuels from Current Policy Reference Scenario**
  - All assume measures in LDV, Off-road, Rail, Aircraft, Ships, Refining, Industry, etc.
  - Three scenarios presented here have differences in:
    - ✓ MDV and HDV, Residential and Commercial Buildings, Electricity Generation

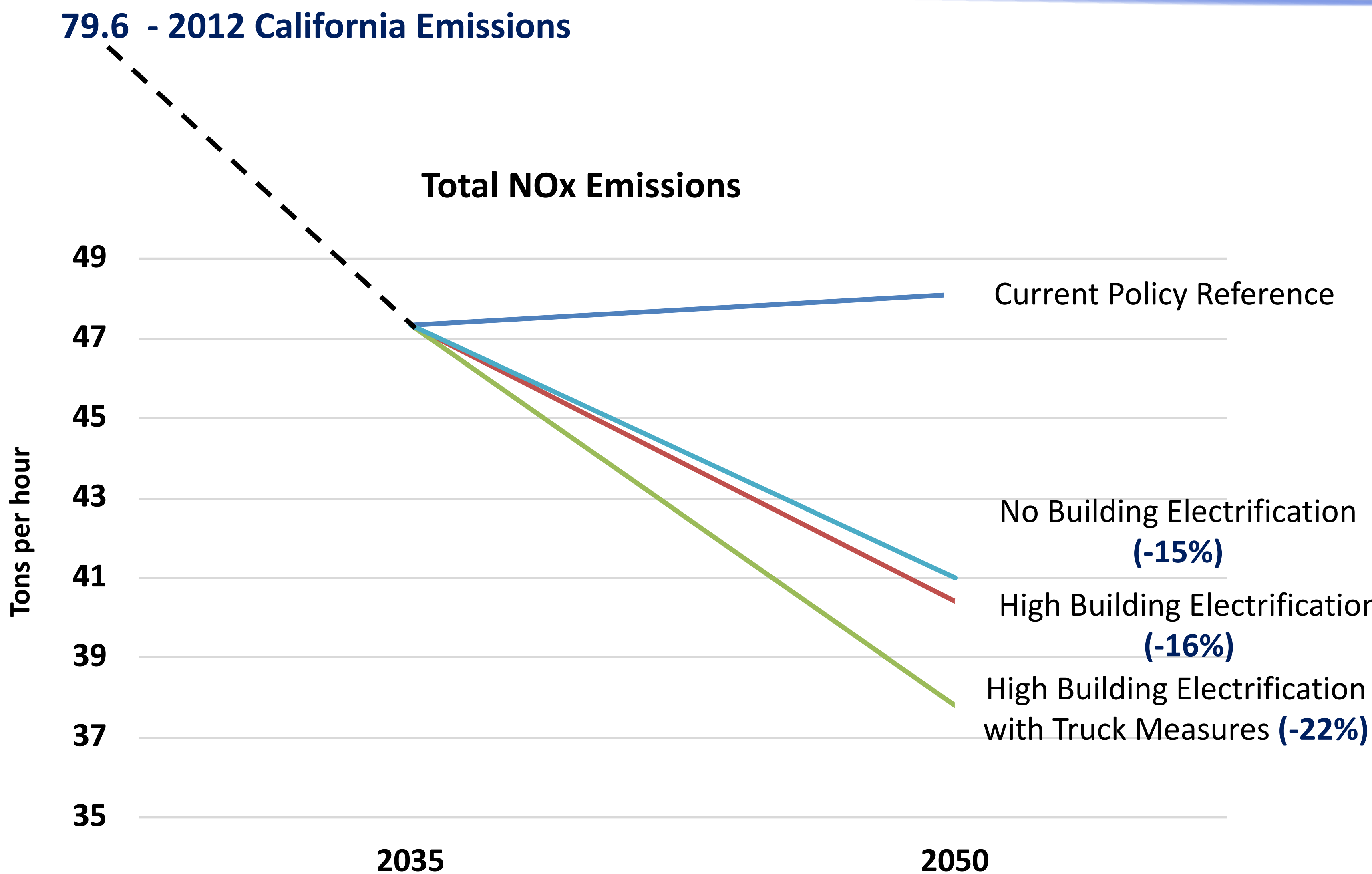


Scenario	Building Electrification (% residential space heating stock in 2050)	Low and Zero Emission Trucks* (% heavy-duty truck stock in 2050)
High Building Electrification	88%	53%
No Building Electrification	13%	86%
High Building Electrification with Trucks	88%	86%

*Includes the use of battery electric, hydrogen and low NO_x CNG

RESULTS ARE PRELIMINARY

Emissions Projection Results



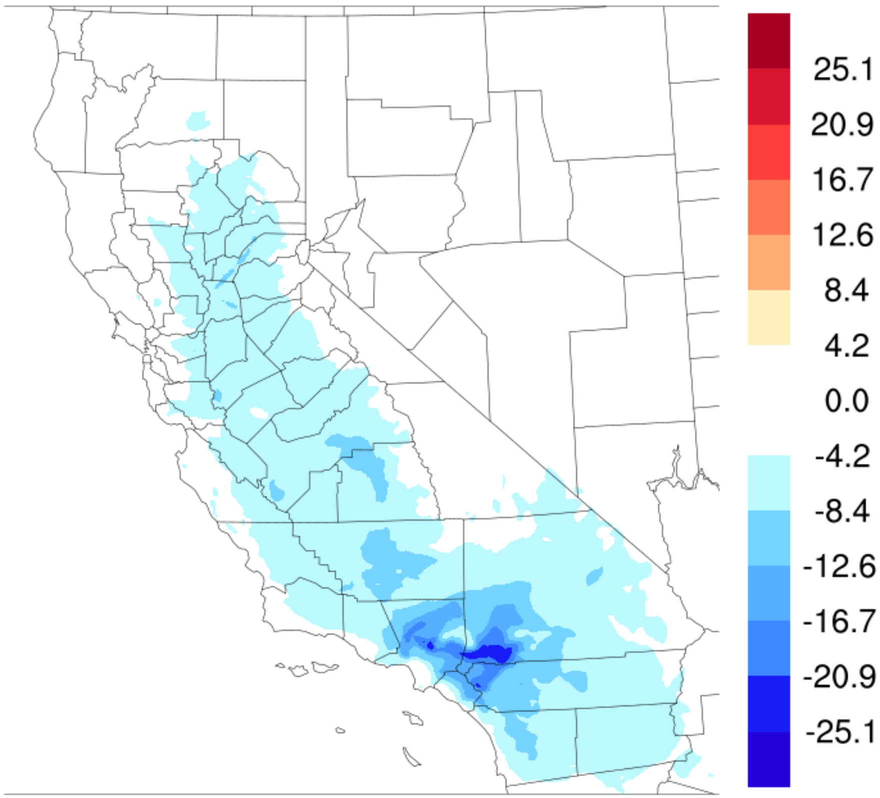
Scale does not start at 0

RESULTS ARE PRELIMINARY

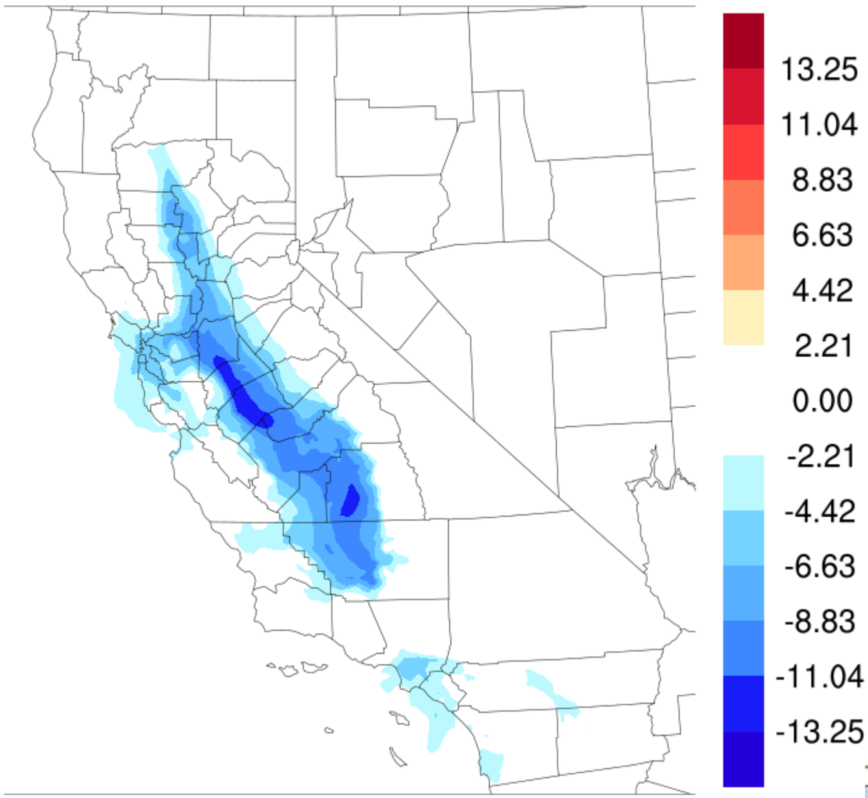
AQ Impacts: HBE with Truck Measures

- **Significant improvements in key locations (high population + base line levels) from CPR reference scenario in 2050**
  - Ozone benefits in SoCAB and Central Valley, $PM_{2.5}$ in Central Valley

Peak Summer MD8H Ozone : -25.1 ppb



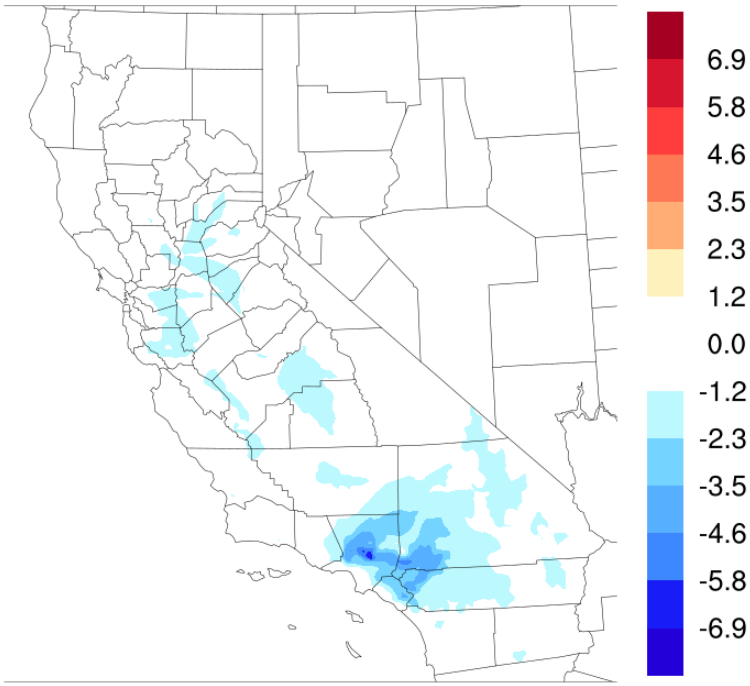
Δ Winter $PM_{2.5}$: - 13.3 μg/m^3



AQ impacts of the Electrification of Buildings

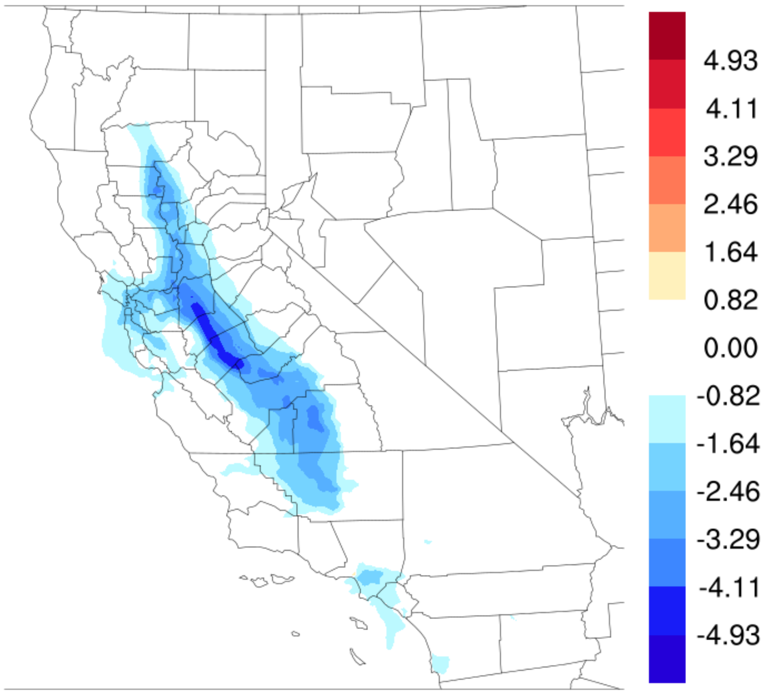
- **Largest impacts correlated with locations of urban population centers**
  - Difference between the HBE with Truck Measures and NBE scenarios
  - Secondary $PM_{2.5}$ reductions in Central Valley/Bay Area from NO_x reductions

Summer Ozone



-6.9 ppb peak difference in SoCAB

Winter $PM_{2.5}$

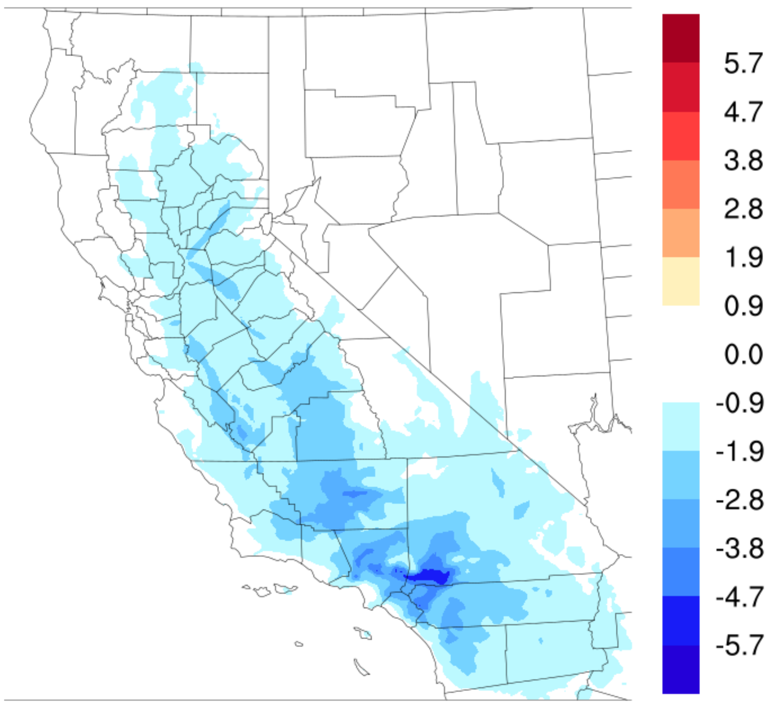


-4.93 ug/m^3 peak difference in SJV

AQ impacts of the Electrification of Trucks

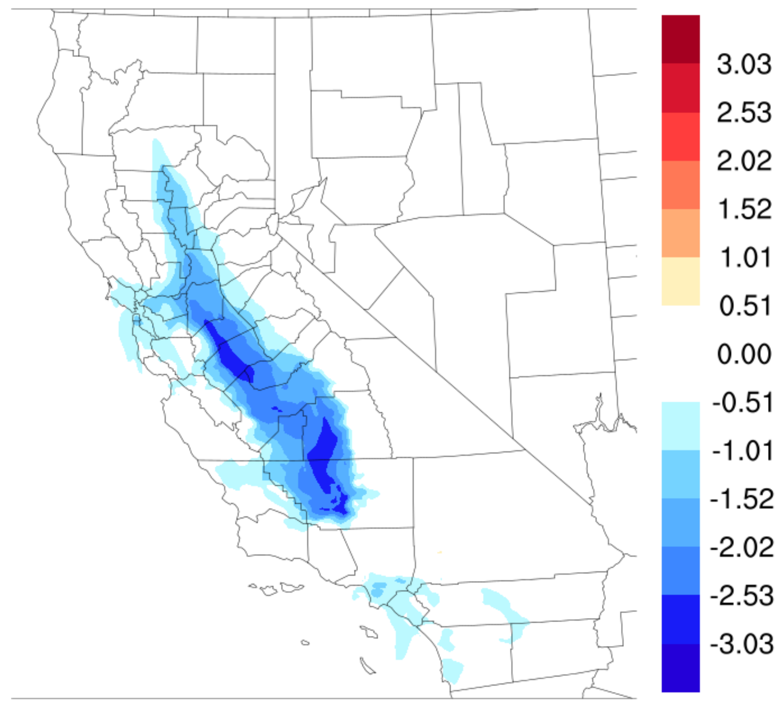
- **Benefits to ozone widespread throughout the State, peak in SoCAB**
  - Should be noted this is in the context of significant HDV reductions for all cases
  - Difference between the HBE with Truck Measures and HBE scenarios

Summer Ozone



-5.6 ppb peak difference in SoCAB

Winter $PM_{2.5}$

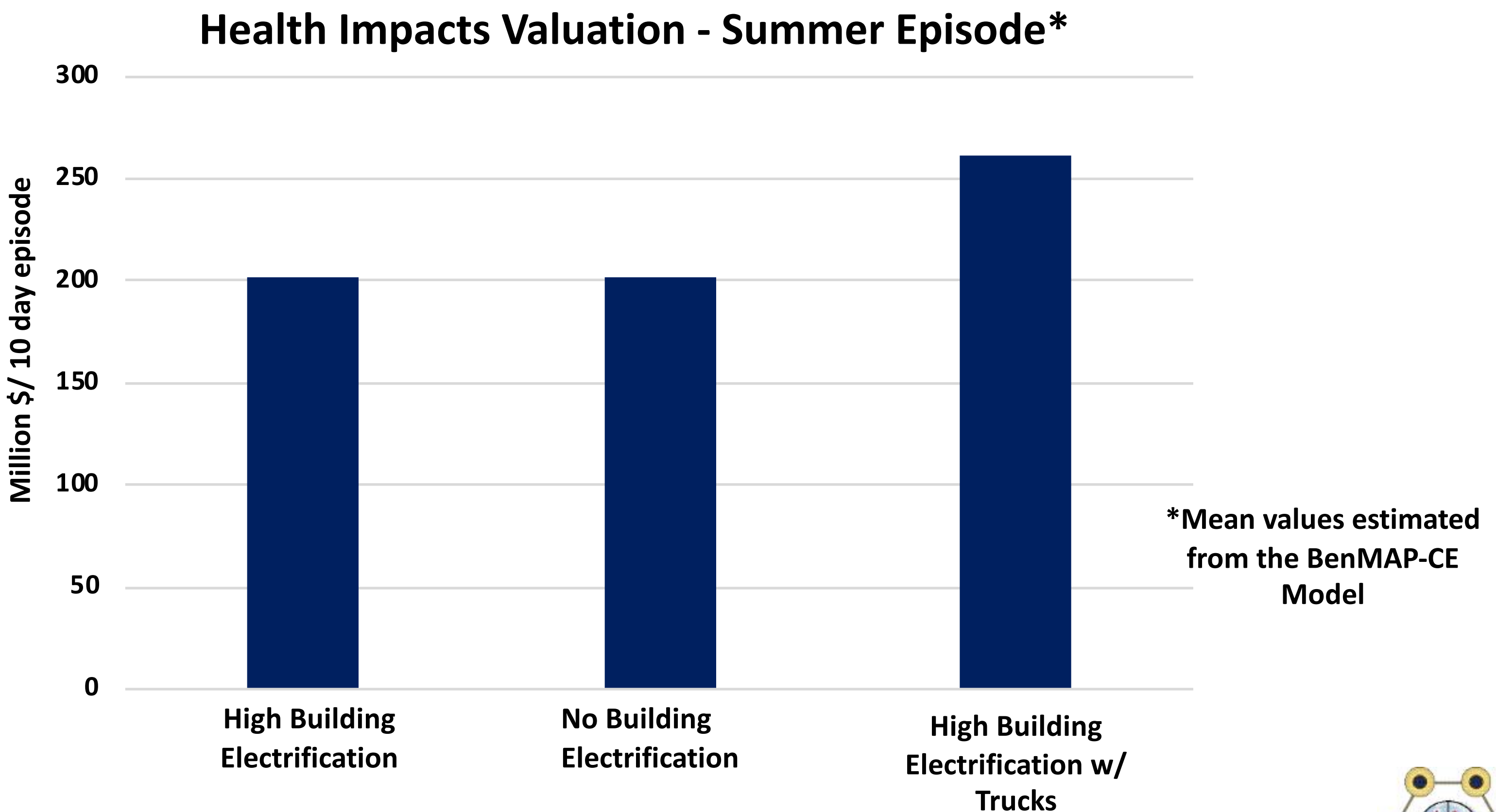


-3.0 ug/m^3 peak difference in SJV

RESULTS ARE PRELIMINARY

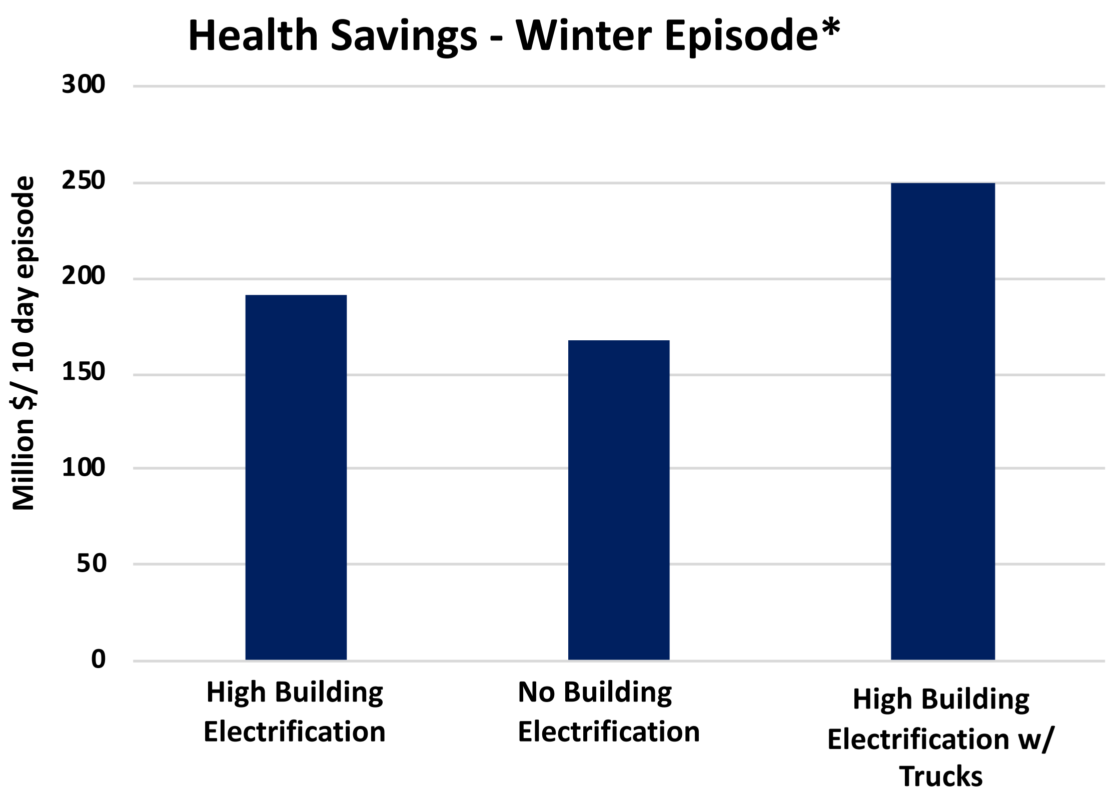
Value of Health Savings: Summer Episode

- **Health savings of $202 to 261 million for the modeled episode**
  - Impacts of MDV/HDV NO_x mitigation on ozone and $PM_{2.5}$ in the South Coast Air Basin
  - Impacts of building NO_x reductions in the South Coast Air Basin



Value of Health Savings: Winter Episode

- **Health savings of $166 to $249 million for the modeled episode**
  - Impacts on secondary $PM_{2.5}$ in the Bay Area/Central Valley from NO_x reductions from NG appliances have a major impact
  - Impacts from trucks achieve health savings from the same mechanism



*Mean values estimated from the BenMAP-CE Model

Initial Conclusions

- **Technological strategies to reach 2050 carbon goals attain notable co-benefits to air quality and human health**
  - **Impacts vary by season, source, and region**
- **Reductions from MDV/HDV attain important benefits**
  - **Widespread benefits to ozone and secondary $PM_{2.5}$ in summer from NO_x reductions**
- **Building electrification has important impacts in densely populated urban areas**
  - **Impacts on secondary $PM_{2.5}$ in winter from NO_x reductions from NG appliances**

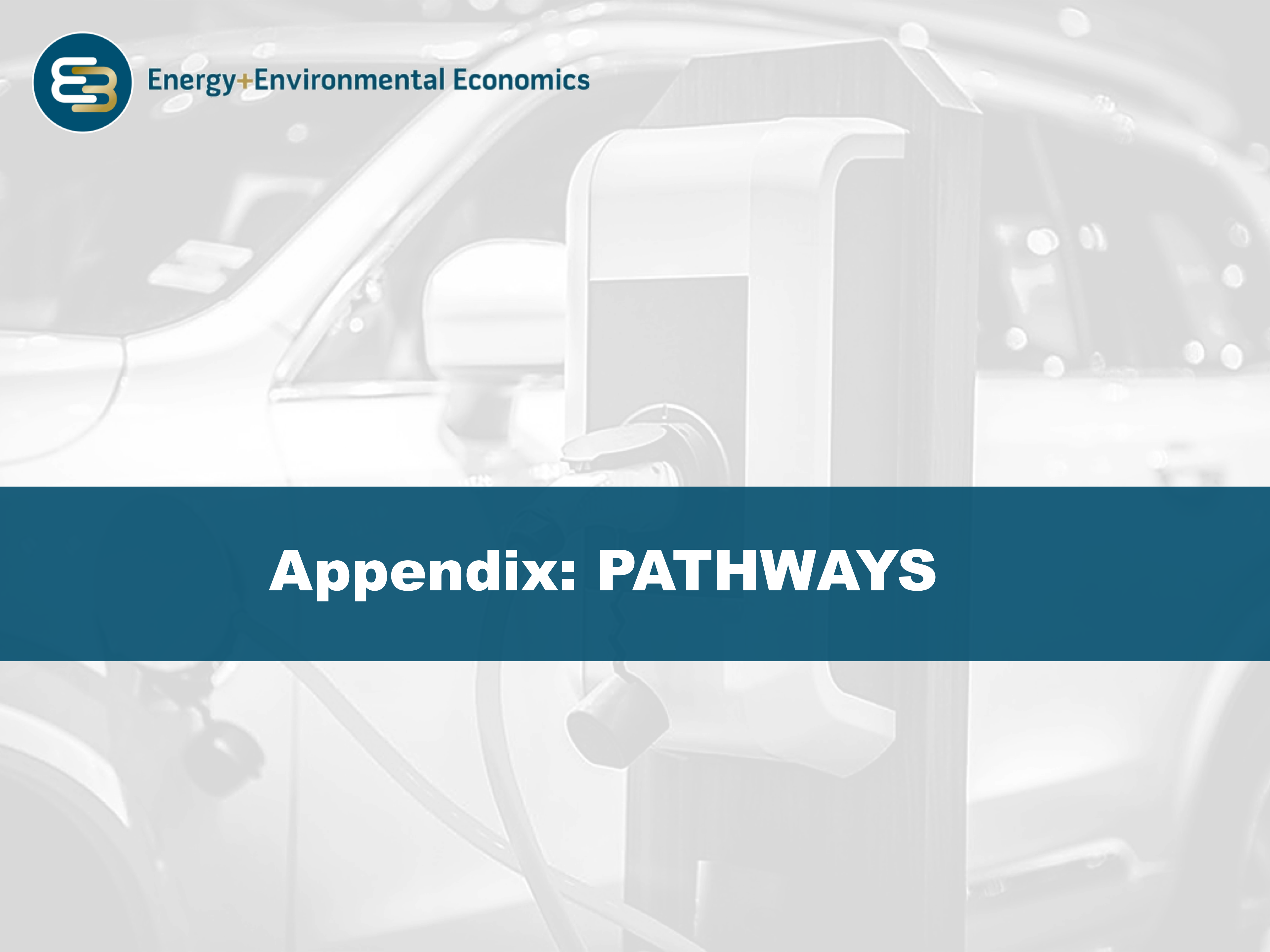
Next Steps

- **Integrate and assess the potential impacts of biorefineries**
  - **Results presented here do not account for emission impacts of renewable fuel production**
- **Develop methodological framework for contextualizing results through impacts to disadvantaged communities**
  - **Integration of results from CMAQ and BenMAP with CalEnviroScreen 3.0**
- **Develop and asses scenario considering potential emission impacts from hydrogen/NG blending**
  - **End-use impacts could be positive or negative**

Next Steps

Energy+Environmental Economics

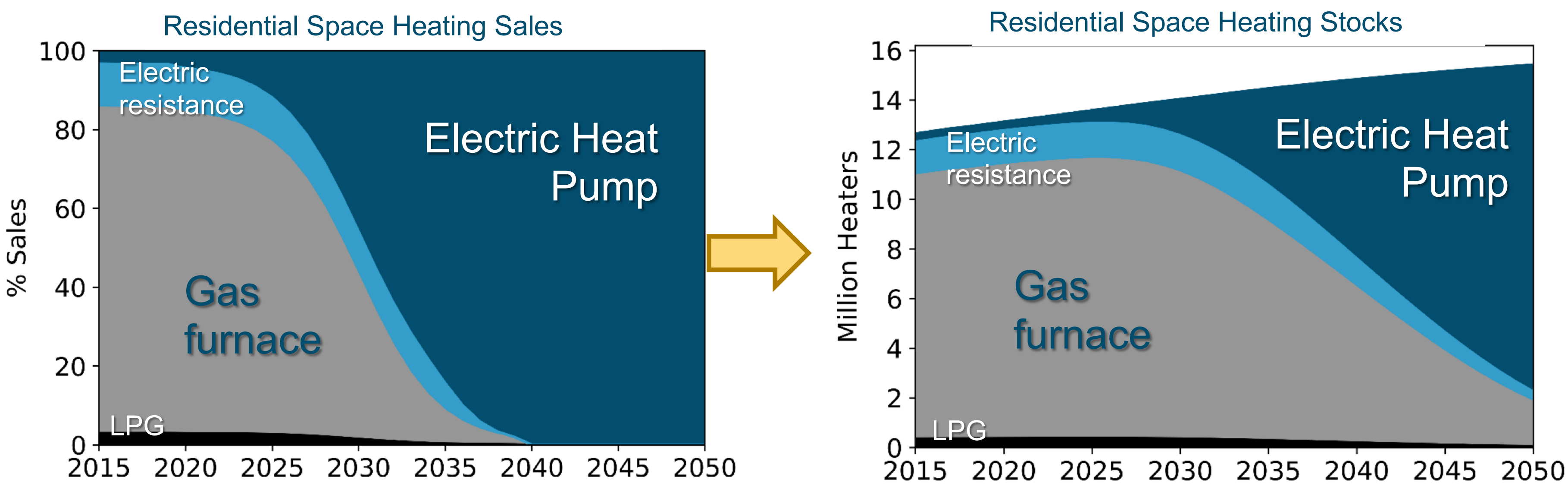
Thank You



Appendix: PATHWAYS

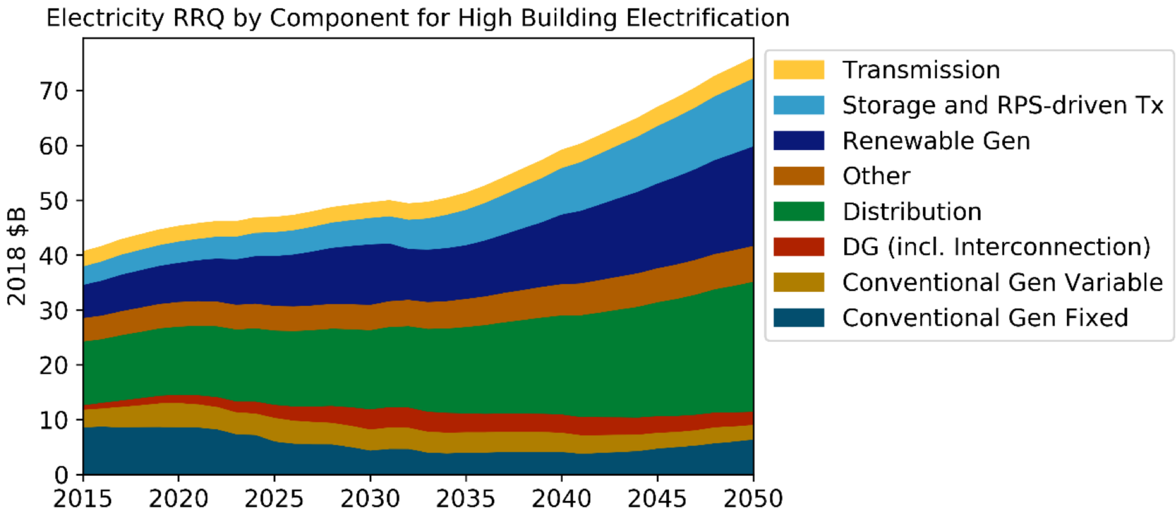
Electric equipment stock lags sales

High Building Electrification Scenario

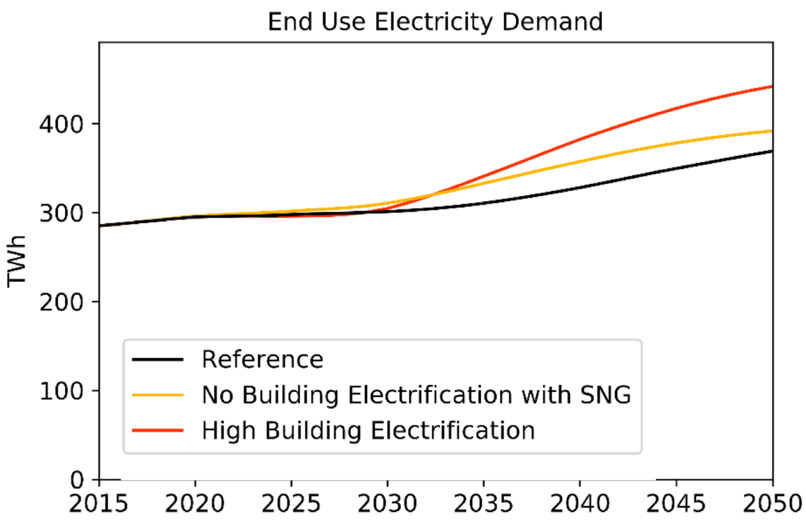


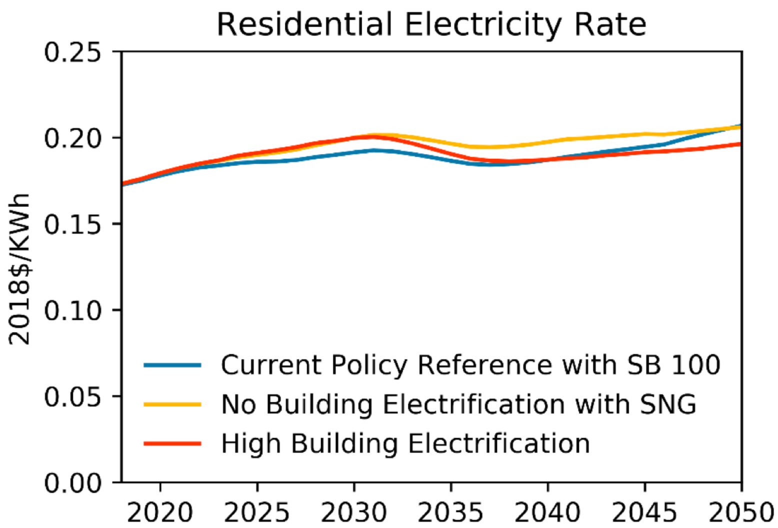
- **Rapid adoption of electric heat pumps in High Building Electrification scenario:**
  - **In 2030**, 50% of HVAC and water heater sales are electric heat pumps
  - **In 2040**, 100% of HVAC and water heater sales are electric heat pumps
  - Retirement of the gas distribution system before 2050 is likely to require even more rapid deployment of electric end uses in buildings, achieving 100% of sales in the 2020s – 2030s
- **No Building Electrification With SNG scenario assumes no new building electrification; existing electric heating switches to heat pumps**

Electricity revenue requirement and rates in PATHWAYS scenarios

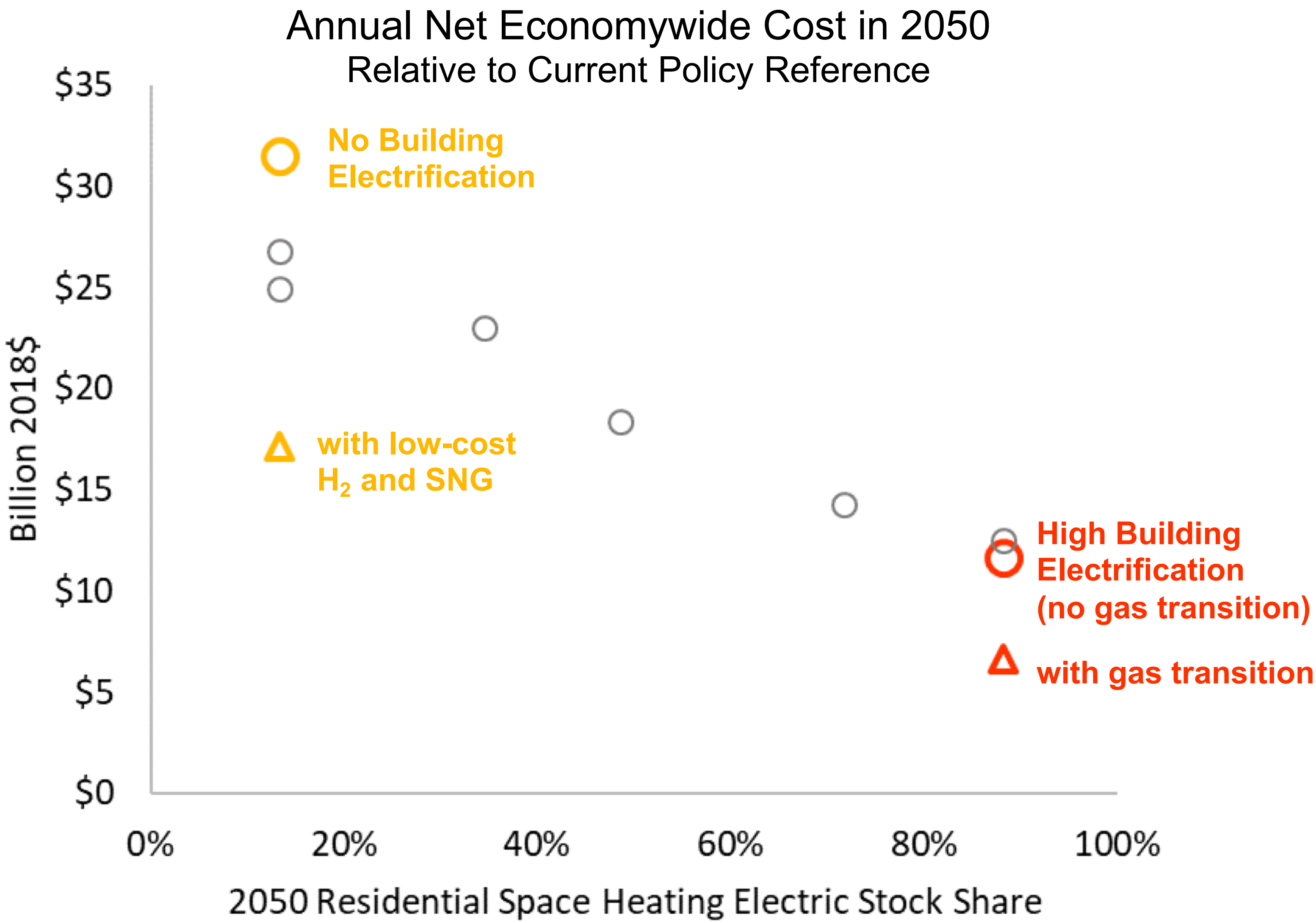


- Electric revenue requirement growth is largely driven by load growth from electrification
- Most hydrogen and SNG fuel production is modeled as off-grid, so does not affect electric revenue requirement

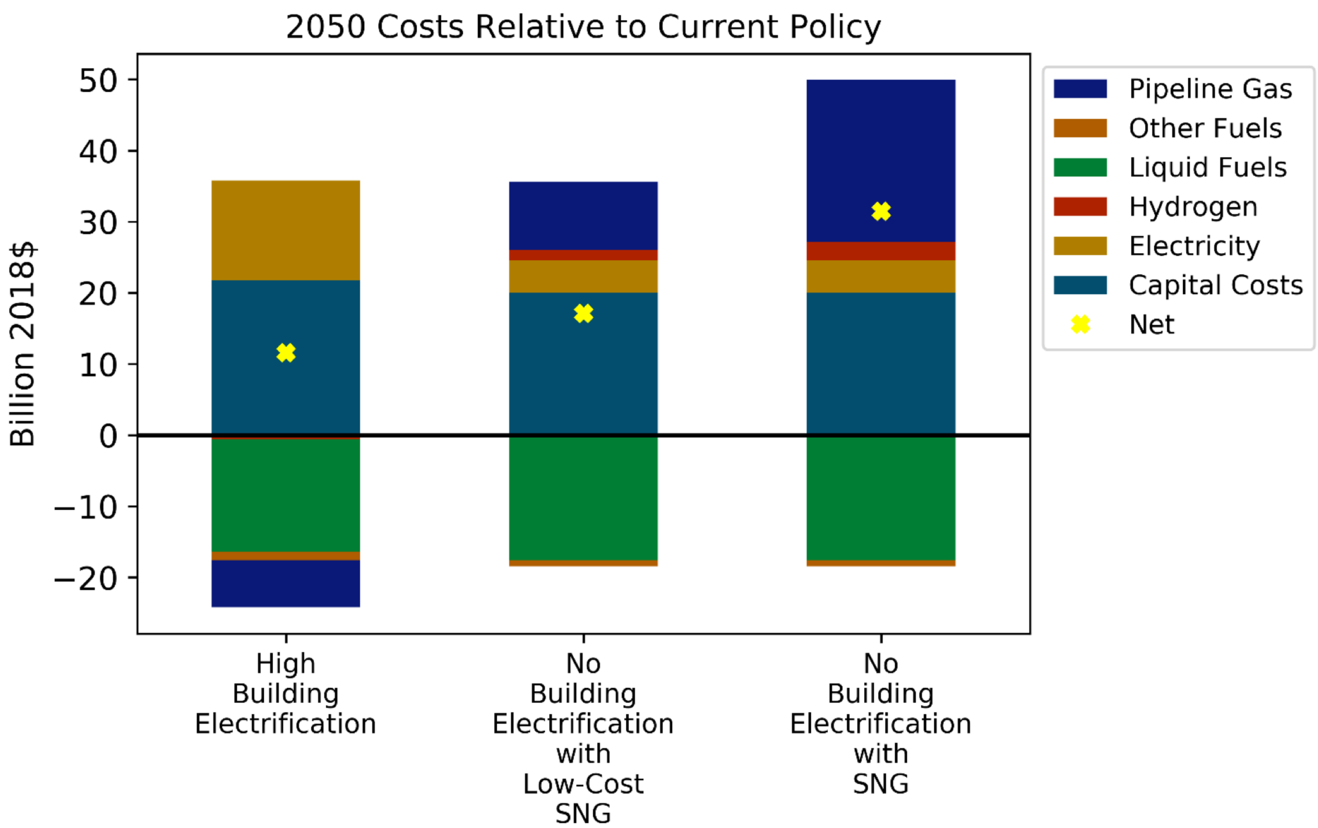




Scenarios with more building electrification have lower economy-wide costs

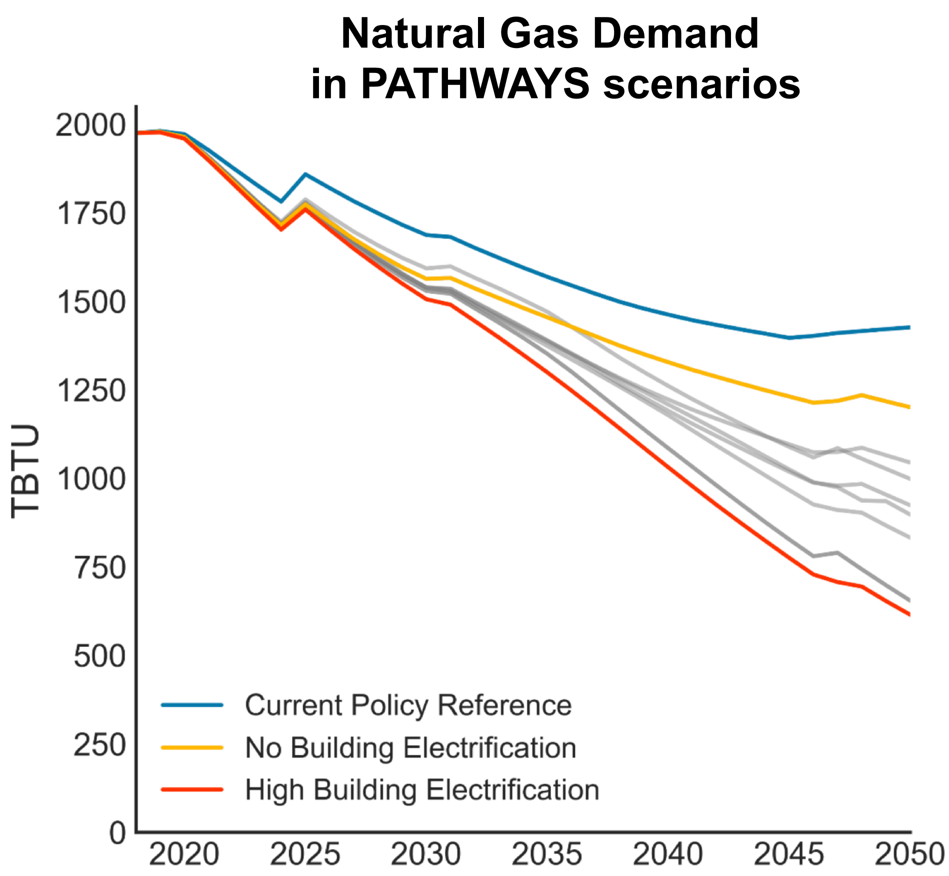


Total economy-wide 2050 annual net costs, relative to Reference scenario



- Incremental cost of the No Building Electrification scenario is largely driven by the high cost of SNG, with small savings in electricity and appliance capital costs.
- This figure does not show costs of the High Building Electrification scenario with a gas transition strategy

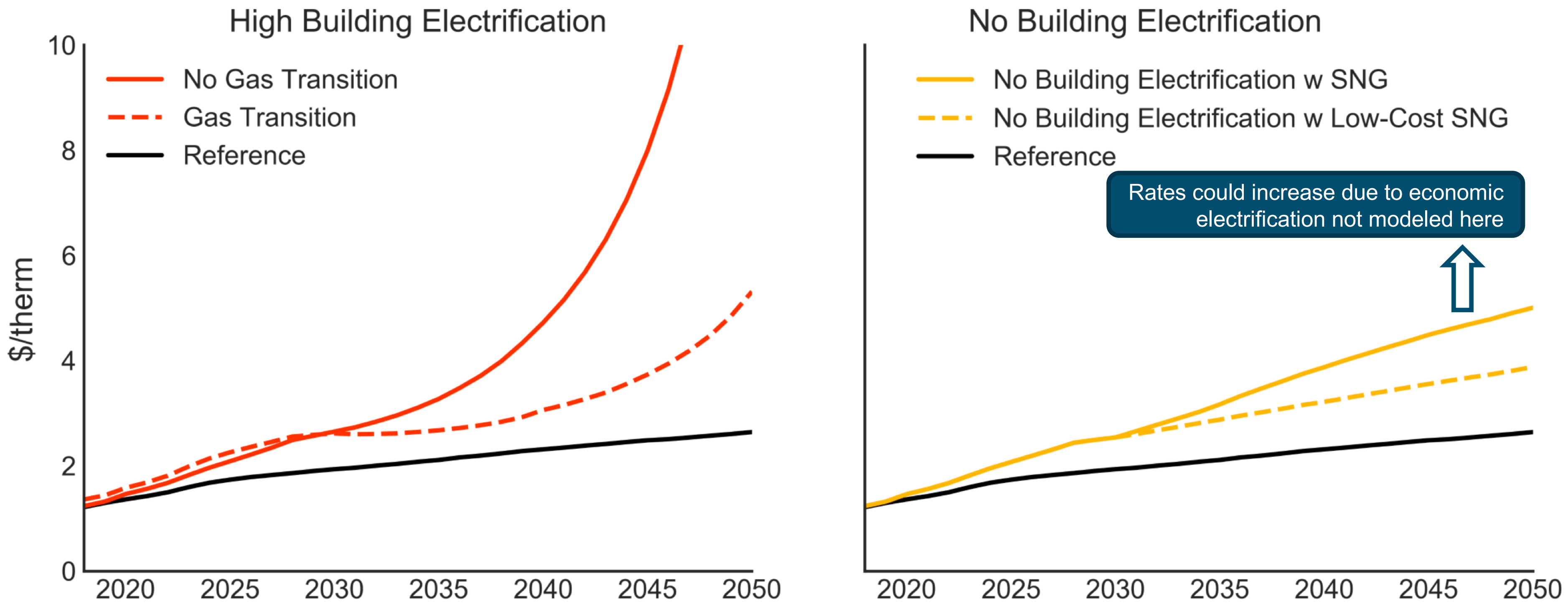
E3 evaluated several PATHWAYS scenarios: gas demand falls in all of them



- Gas demand decreases in the Current Policy Reference scenario due to energy efficiency and SB 100
- Intermediate scenarios have differing levels of building electrification
- In the High Building Electrification Scenario, remaining gas throughput in 2050 primarily serves industry

Residential gas rates by scenario statewide average (2018 $/therm)

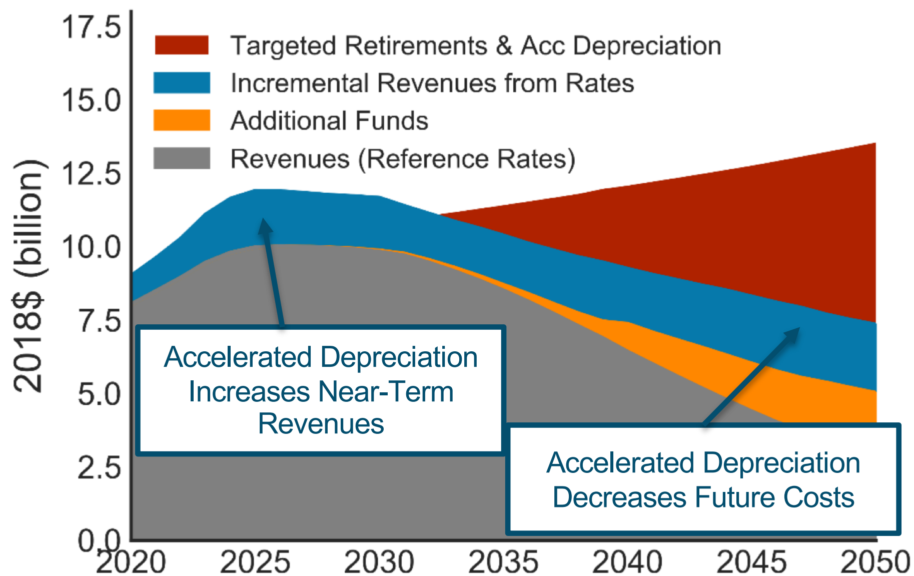
+ **Gas rates are not reflective of customer bills due to differences in equipment efficiency for electric and gas end uses (heat pumps are more efficient)**
+ **Gas rates do not account for potential economic fuel switching from gas to electric due to differences in customer bills**



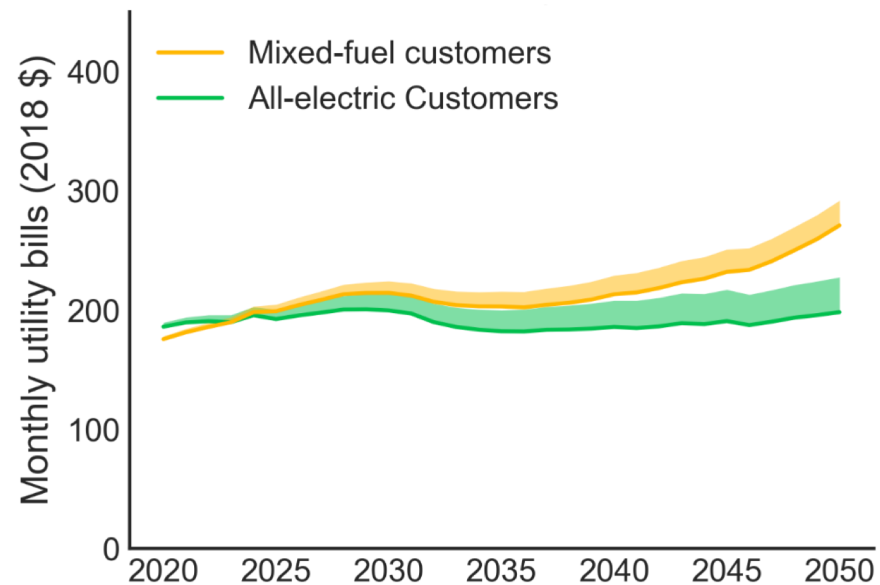
Example transition strategy: Targeted gas retirements, higher rates, plus outside funds to subsidize remaining gas ratepayers

Example 2

High Building Electrification Scenario: Revenues Under Example Transition Strategy



High Building Electrification Scenario: Bill Impacts with example transition strategy



- **This example assumes: targeted gas retirements, higher rates, accelerated depreciation and $14B (NPV) in additional funds, used mostly to subsidize all remaining gas customers through 2050**
- **Bills for remaining gas customers are: $290 /month**

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Appendix: UCI Air Quality Slides

RESULTS ARE PRELIMINARY

Task 4 –AQ Results

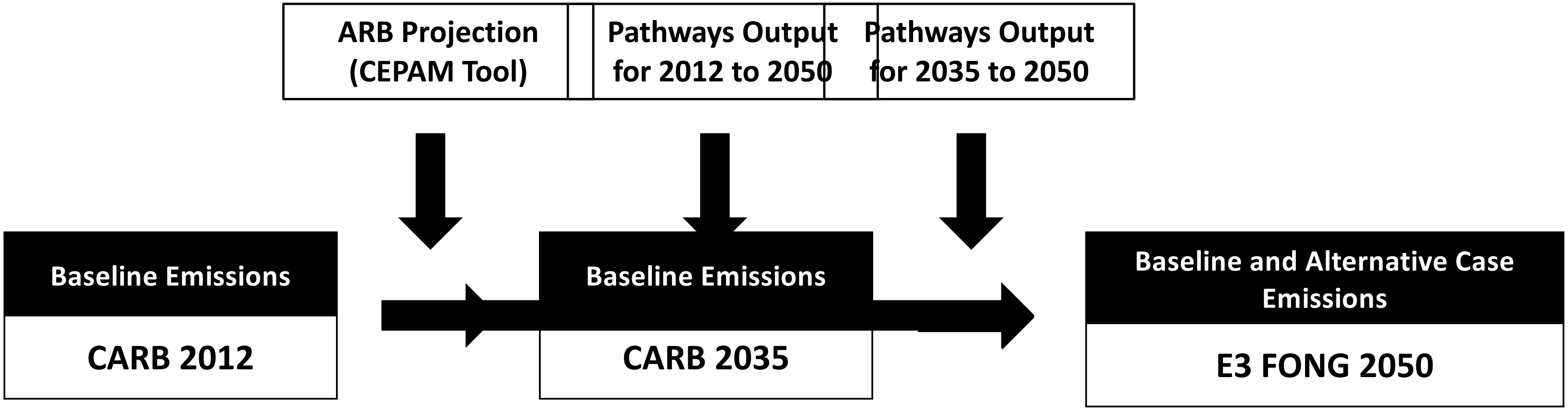
- Summer MD8H
  - Average difference: -2.7 ppb to -3.41 ppb
  - Peak difference: -13 ppb to -18 ppb

- Summer 24-h $PM_{2.5}$
  - Average difference: -0.89 ug/m^3 to -1.37 ug/m^3
  - Peak difference: -2.0 ug/m^3 to -2.91 ug/m^3

- Winter 24-h $PM_{2.5}$
  - Average difference: -4.01 ug/m^3 to -6.03 ug/m^3
  - Peak difference: -8.41 ug/m^3 to -12.72 ug/m^3

Task 4 – Emissions Projection Methodology

- **Emissions projection based on CARB 2035 emissions projected to 2050 via Pathways Output**
  - Projection of 2012 to 2050 yielded unrealistic concentrations
  - CEPAM 2016 is ARB projected emissions to 2035 accounting for current policy



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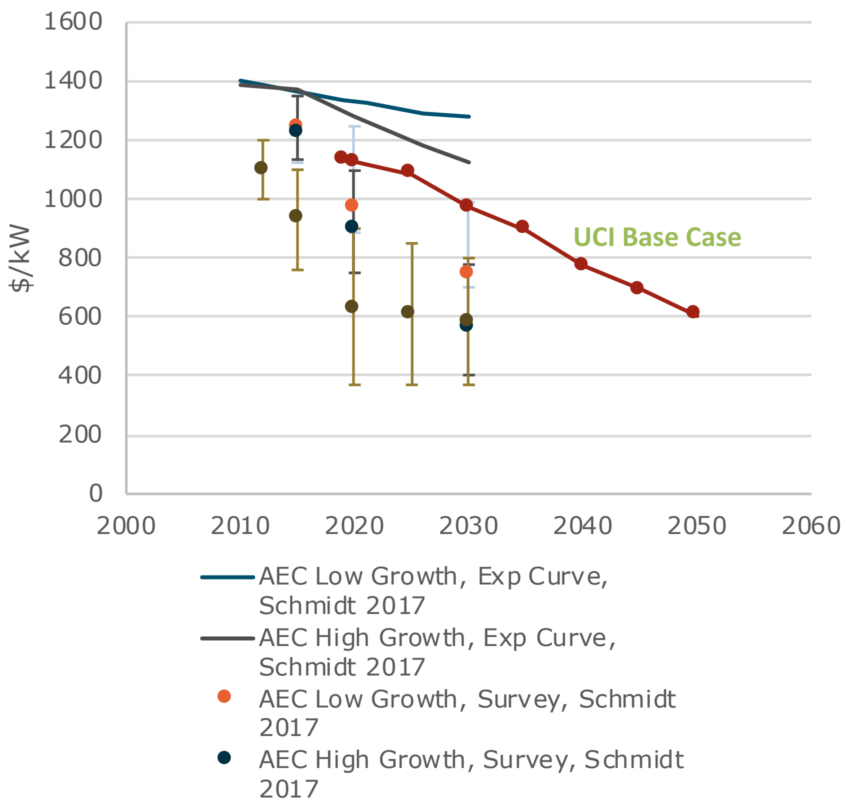
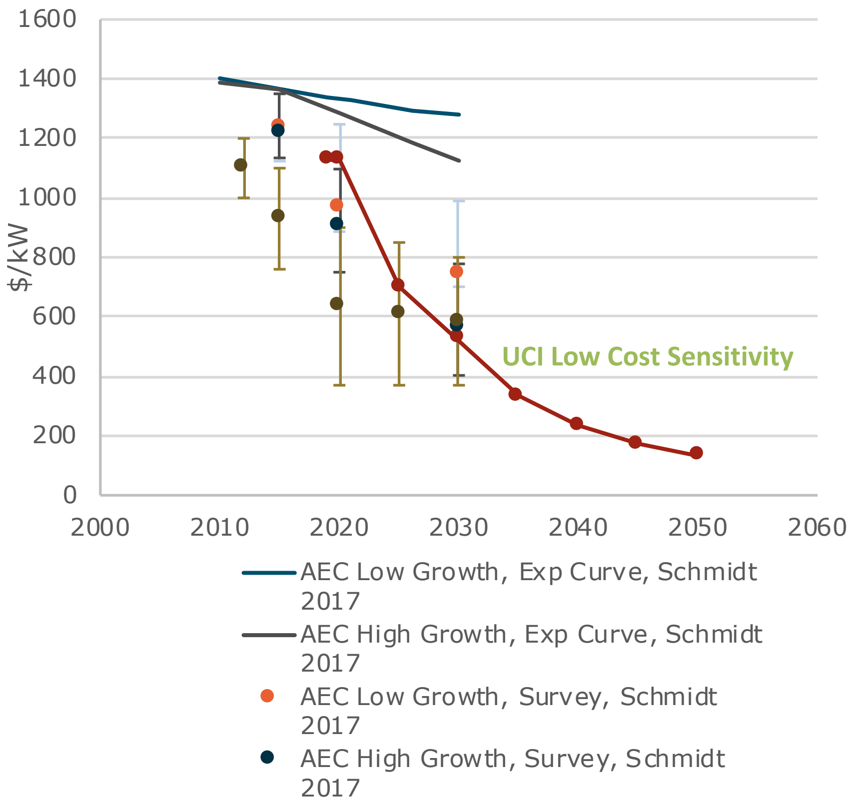
Appendix: UCI Technology Slides

Comparison of technology cost assumptions for RNG pathways

+ **Learning curves were developed for biomethane process conversion, electrolysis, CO_2 capture, and methanation, resulting in decreasing technology costs over time**

Technology costs over time illustrated for alkaline (AEC) electrolyzers

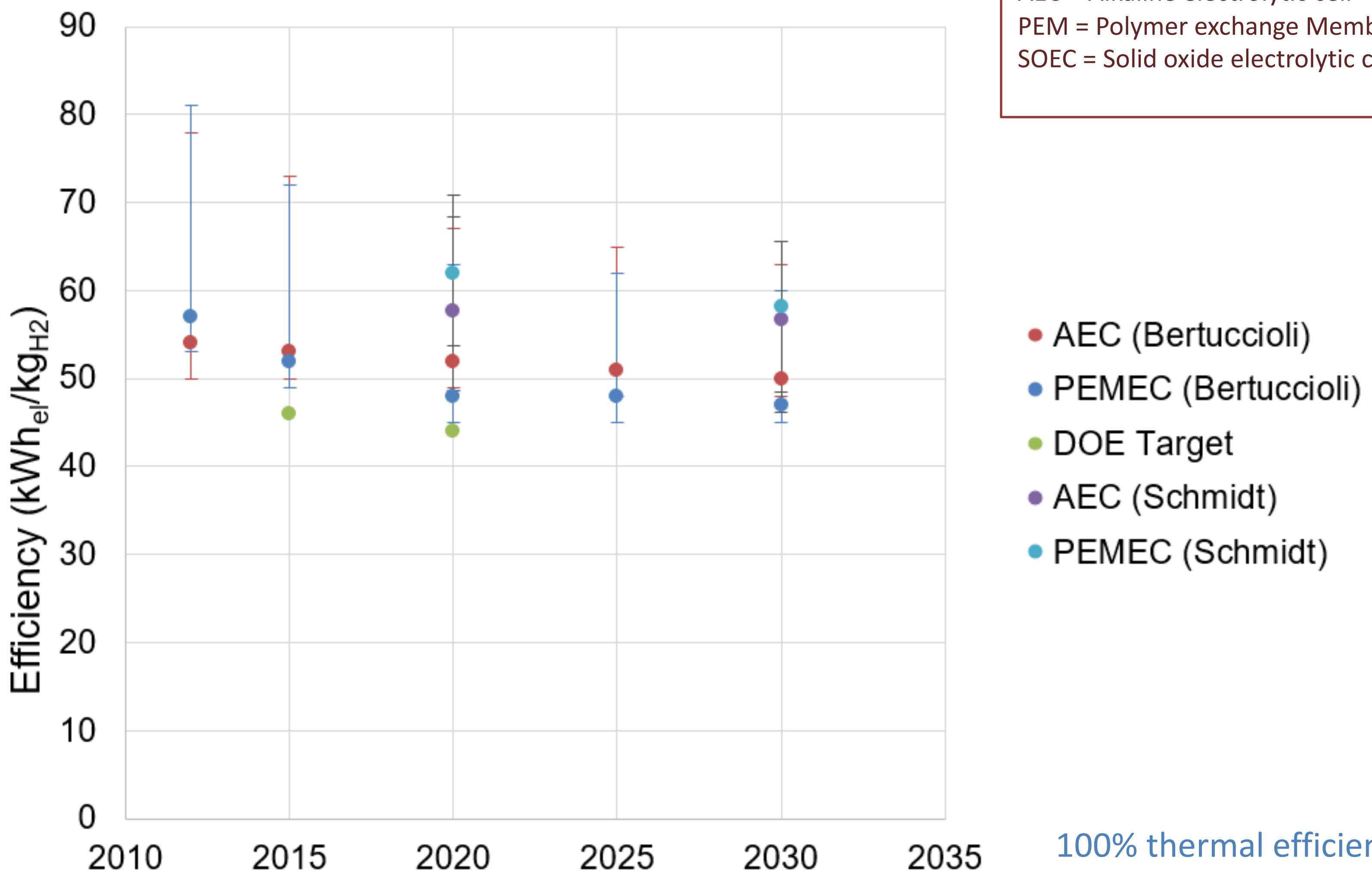




RESULTS ARE PRELIMINARY

Electrolyzer efficiency from the literature

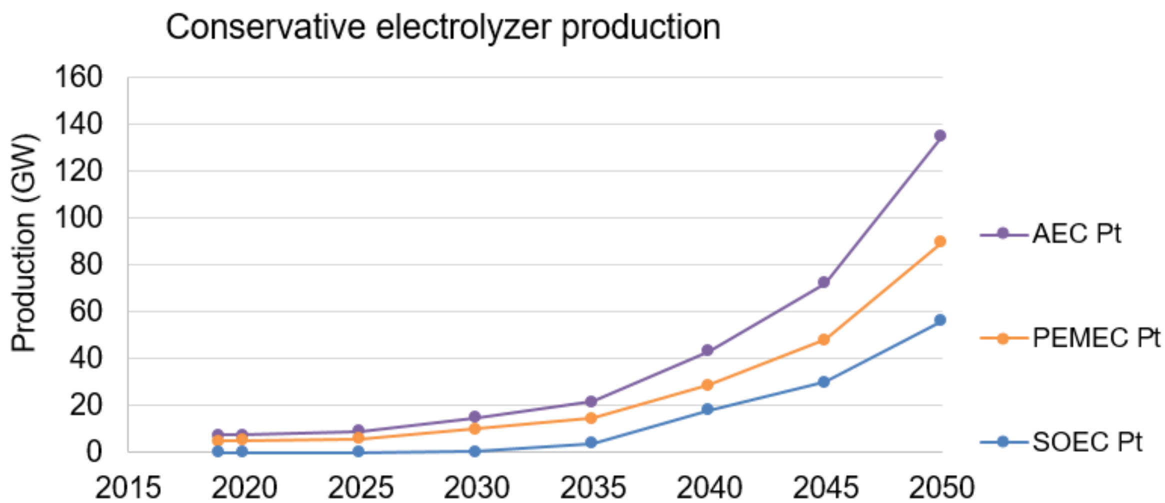
AEC = Alkaline electrolytic cell
PEM = Polymer exchange Membrane
SOEC = Solid oxide electrolytic cell

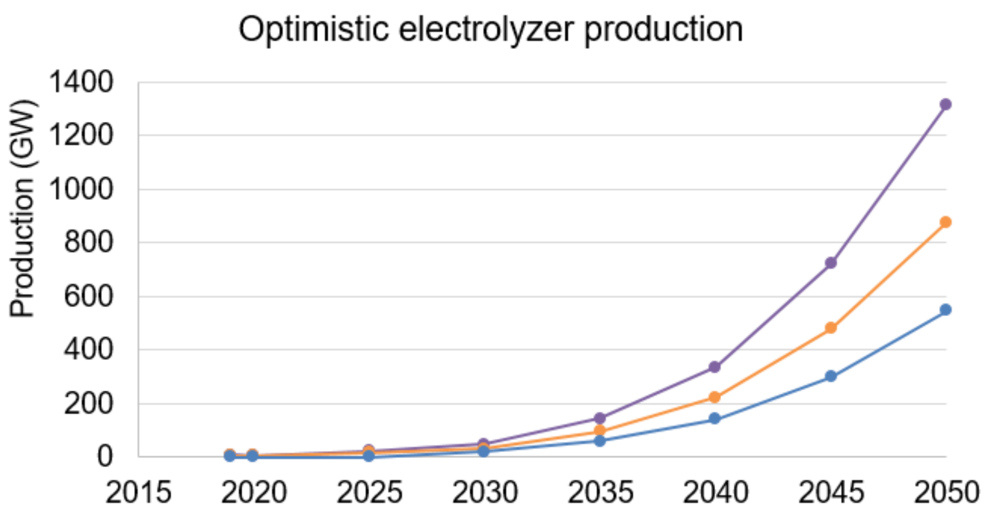


100% thermal efficiency = 33.3 kWh_e / kg H_2

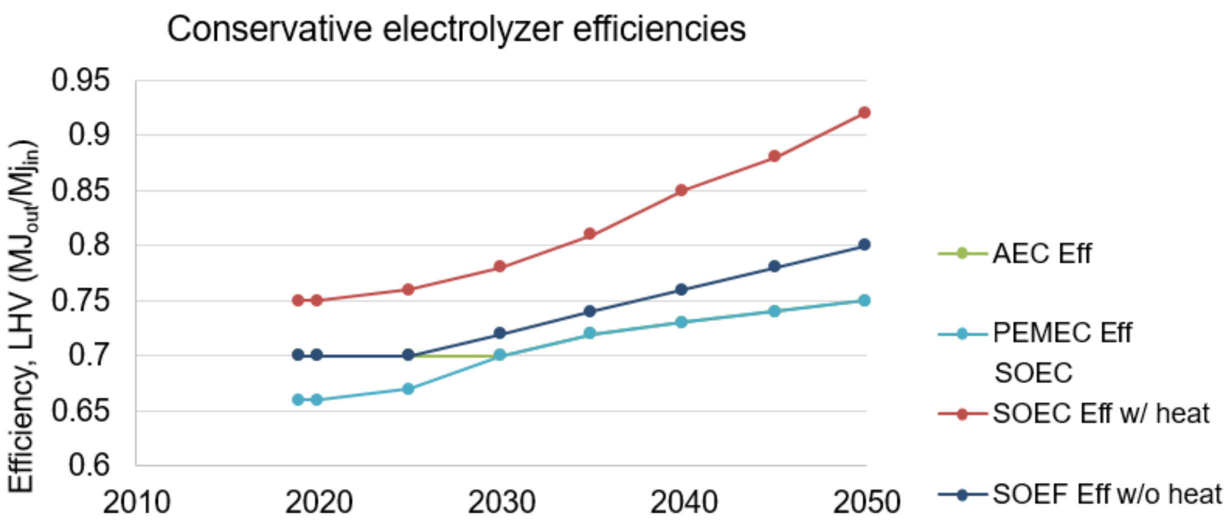
RESULTS ARE PRELIMINARY

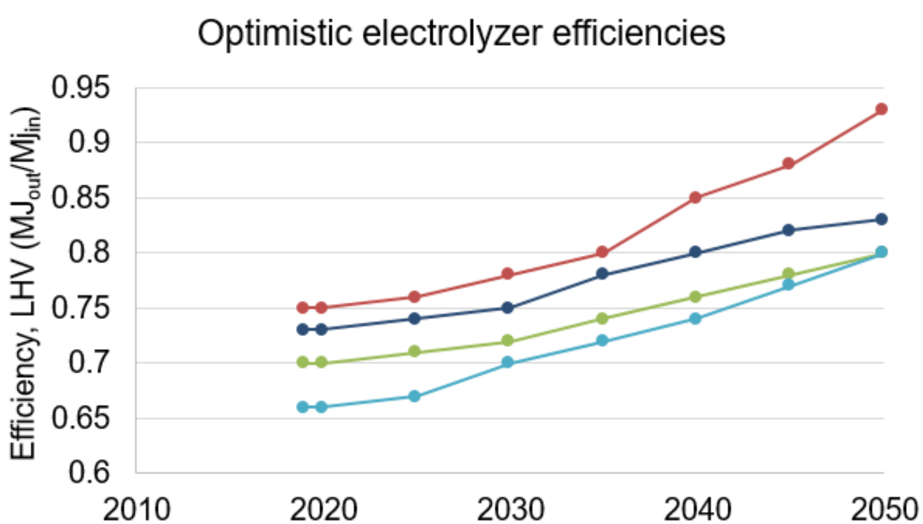
Electrolyzer cumulative global production projections





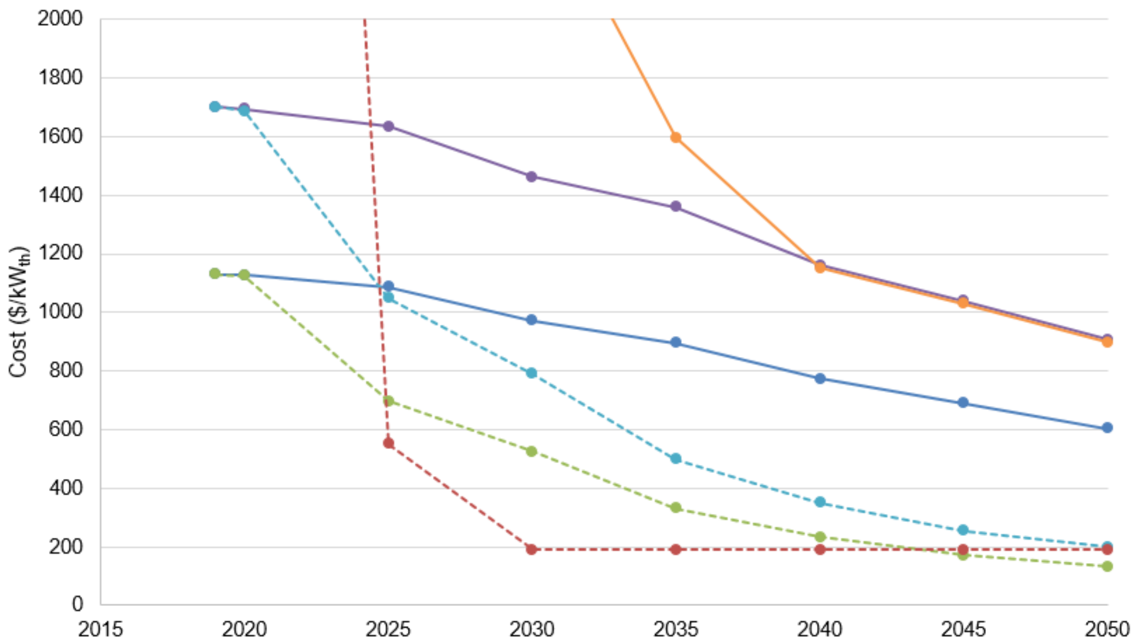
Electrolyzer efficiency projections





RESULTS ARE PRELIMINARY

Electrolyzer capital cost projections



<u>Note:</u>
SOEC cost is above $2,000/kW for some time

Pt = cumulative global production
Ct = Installed capital cost

Conservative projections

	AEC		PEMEC		SOEC	
	Pt [GW]	Ct [$/kW]	Pt [GW]	Ct [$/kW]	Pt [GW]	Ct [$/kW]
2019	7.5	1130	5	1700	0.001	9700
2020	7.6	1127	5.1	1693	0.0011	9501
2025	9	1086	6	1634	0.01	5877
2030	15	972	10	1462	0.5	2509
2035	22	894	14	1359	4	1596
2040	43	773	29	1160	18	1150
2045	72	691	48	1039	30	1029
2050	134	603	90	906	56	899

Optimistic projections

	AEC		PEMEC		SOEC	
	Pt [GW]	Ct [$/kW]	Pt [GW]	Ct [$/kW]	Pt [GW]	Ct [$/kW]
2019	7.5	1130	5	1700	0.001	9700
2020	7.6	1124	5.1	1686	0.0011	9324
2025	24	697	16	1049	1	552
2030	47.5	525	31.68	790	19.8	191
2035	144	331	96	499	60	191
2040	336	233	223.68	351	139.8	191
2045	720	170	480	256	300	191
2050	1313	132	875.52	199	547.2	191

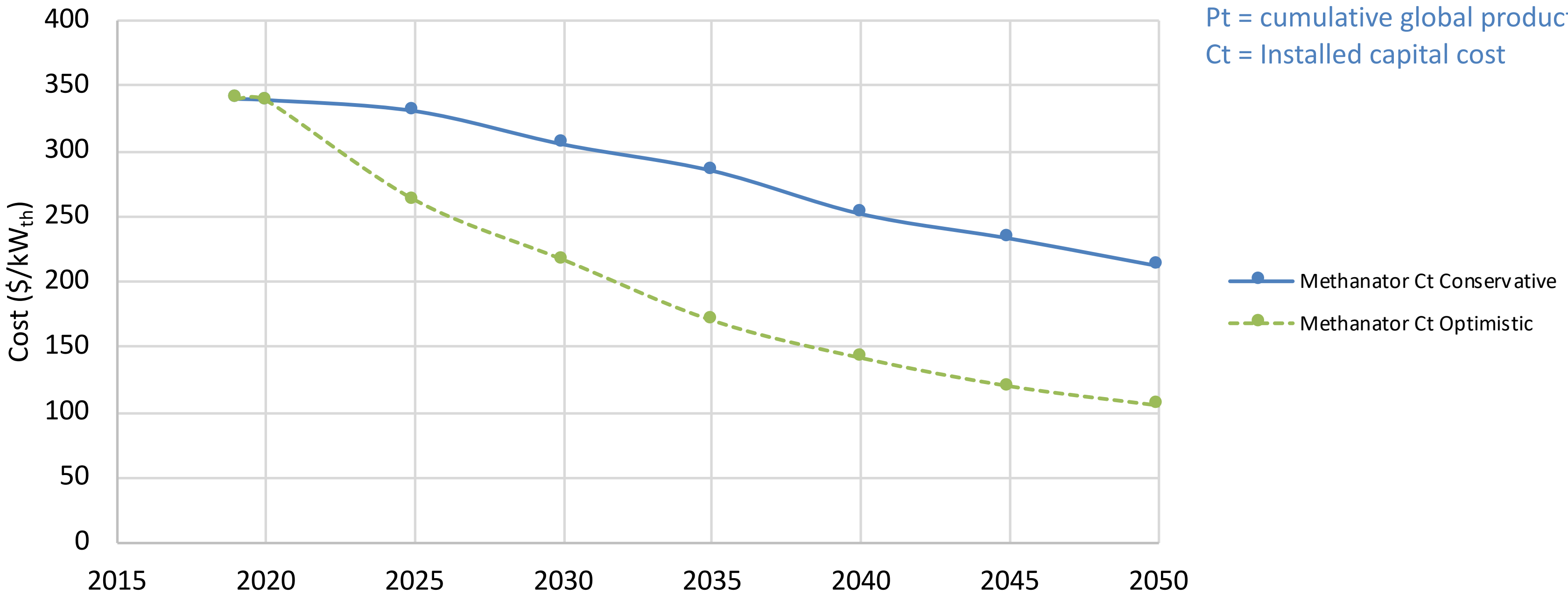
RESULTS ARE PRELIMINARY

Methanator capital cost projections

Conservative scenario:
10% learning rate

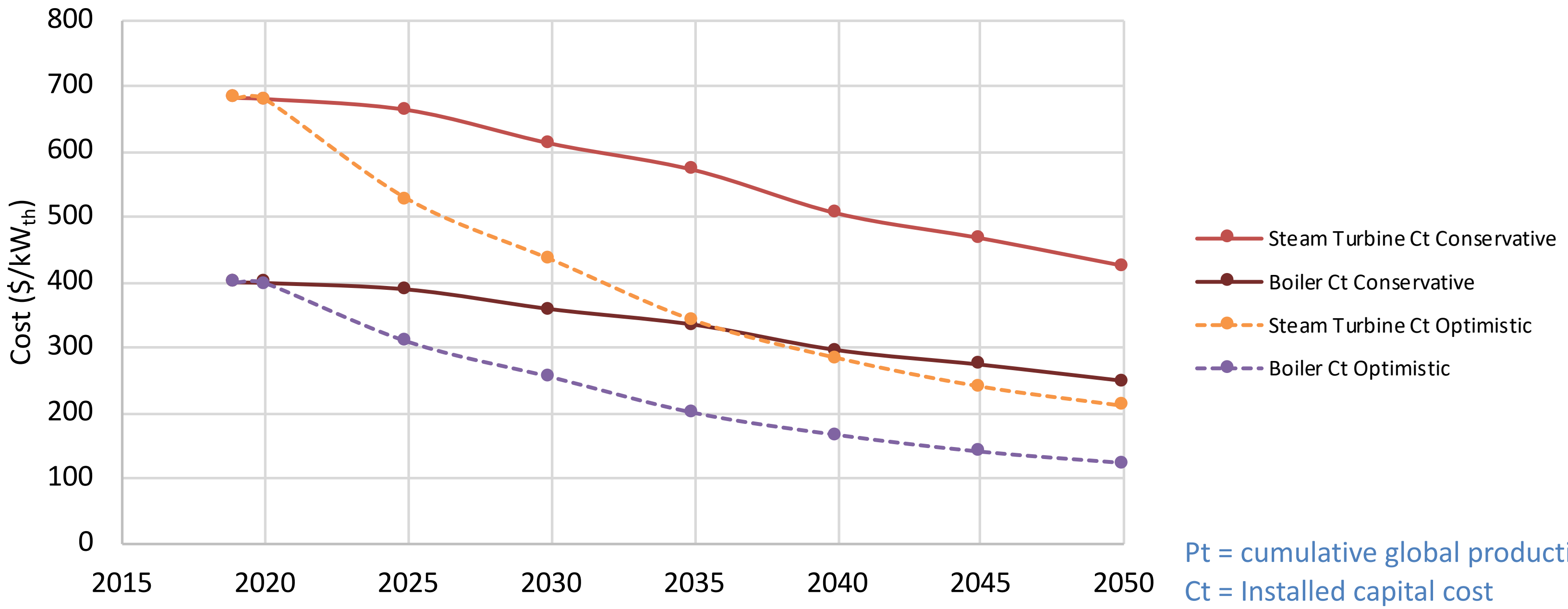
Optimistic scenario:
14% learning rate

	METHANATOR, CONSERVATIVE		METHANATOR, OPTIMISTIC	
	Pt [GW]	Ct [$/kW]	Pt [GW]	Ct [$/kW]
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



Pt = cumulative global production
Ct = Installed capital cost

Heat sink capital cost projections



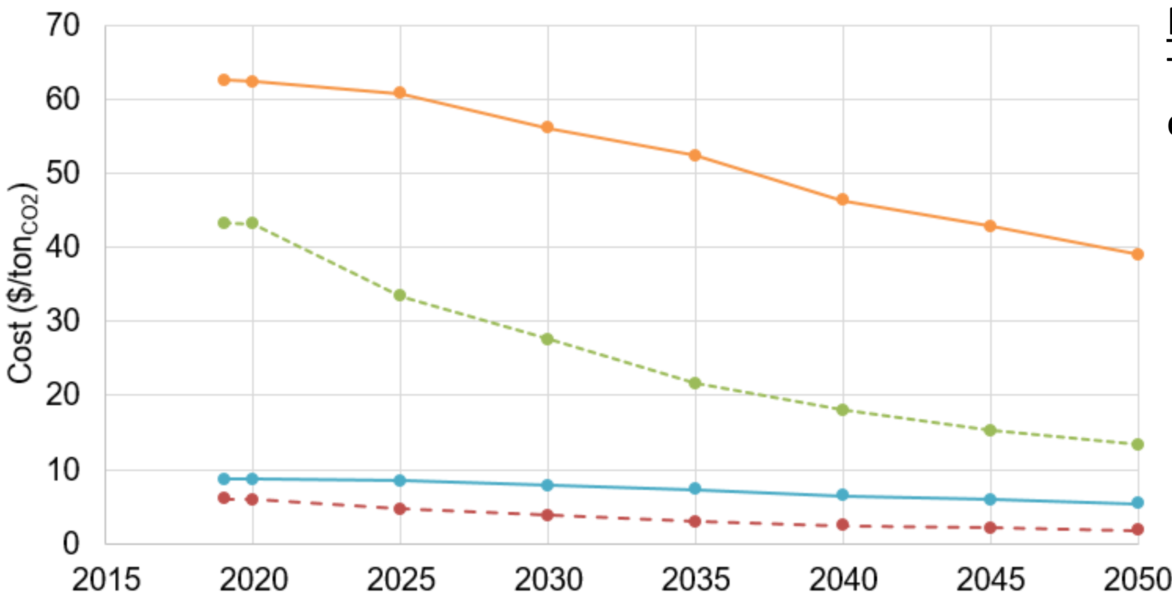
Pt = cumulative global production
Ct = Installed capital cost

	STEAM TURBINE, CONSERVATIVE		BOILER, CONSERVATIVE	
	Pt [GW]	Ct [$/kW]	Pt [GW]	Ct [$/kW]
2019	5.627	682.00	1.400	400.00
2020	5.717	680.36	1.422	399.04
2025	6.757	663.30	1.681	389.03
2030	11.478	611.96	2.855	358.92
2035	18.005	571.49	4.479	335.18
2040	40.512	505.21	10.078	296.31
2045	67.520	467.47	16.796	274.17
2050	126.038	425.16	31.353	249.36

	STEAM TURBINE, OPTIMISTIC		BOILER, OPTIMISTIC	
	Pt [GW]	Ct [$/kW]	Pt [GW]	Ct [$/kW]
2019	5.63	682.00	1.400	400.00
2020	5.72	679.65	1.422	398.62
2025	18.46	526.67	4.591	308.90
2030	44.56	434.75	11.09	254.98
2035	135.04	341.56	33.59	200.33
2040	314.65	284.14	78.27	166.65
2045	675.20	240.65	167.96	141.14
2050	1231.57	211.15	306.36	123.84

RESULTS ARE PRELIMINARY

Carbon capture levelized capital cost projections



Note:
These costs use a 100% capacity factor

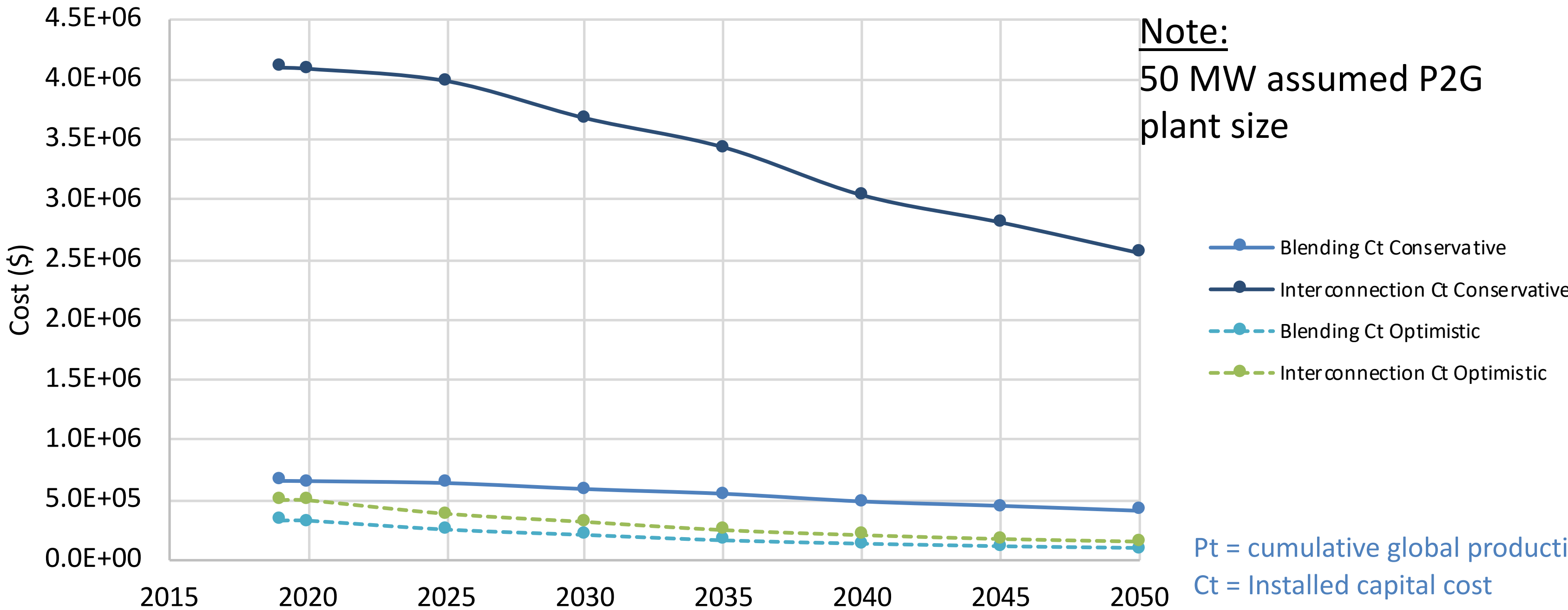
DAC = Direct air capture;
PCC = Post-combustion capture*
*Here applied to bio-CO_2 captured as a co-product of biorefining

	E-CEM, CONSERVATIVE		PCC, CONSERVATIVE		DAC, CONSERVATIVE	
	Pt [GW]	Ct [$/tonCO2]	Pt [GW]	Ct [$/tonCO2]	Pt [GW]	Ct [$/tonCO2]
2019	0.2203	249.37	0.2203	8.72	0.2203	62.50
2020	0.2238	248.77	0.2238	8.70	0.2238	62.35
2025	0.2645	242.53	0.2645	8.48	0.2645	60.79
2030	0.4493	223.76	0.4493	7.82	0.4493	56.08
2035	0.7048	208.96	0.7048	7.30	0.7048	52.37
2040	1.5859	184.73	1.5859	6.46	1.5859	46.30
2045	2.6432	170.93	2.6432	5.97	2.6432	42.84
2050	4.9339	155.46	4.9339	5.43	4.9339	38.96

	E-CEM, OPTIMISTIC		PCC, OPTIMISTIC		DAC, OPTIMISTIC	
	Pt [GW]	Ct [$/tonCO2]	Pt [GW]	Ct [$/tonCO2]	Pt [GW]	Ct [$/tonCO2]
2019	0.2203	249.37	0.2203	5.99	0.2203	43.25
2020	0.2238	248.51	0.2238	5.97	0.2238	43.10
2025	0.7225	192.58	0.7225	4.63	0.7225	33.40
2030	1.7445	158.96	1.7445	3.82	1.7445	27.57
2035	5.2864	124.89	5.2864	3.00	5.2864	21.66
2040	12.3173	103.90	12.3173	2.50	12.3173	18.02
2045	26.4319	87.99	26.4319	2.11	26.4319	15.26
2050	48.2117	77.21	48.2117	1.85	48.2117	13.39

Pt = cumulative global production; Ct = Installed capital cost

Blending and interconnection plant cost projections



Note:
50 MW assumed P2G plant size

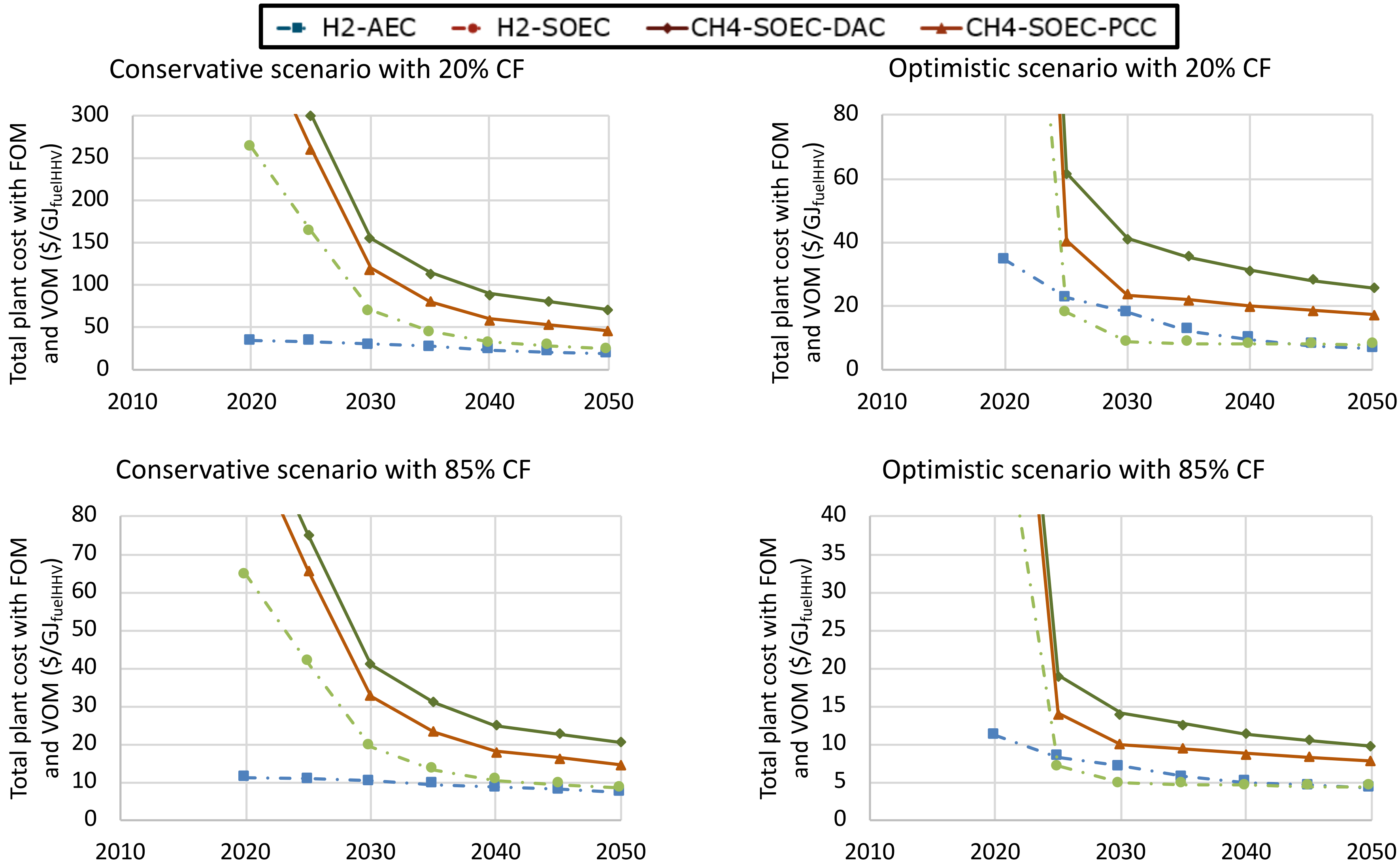
Pt = cumulative global production
Ct = Installed capital cost

	BLENDING, CONSERVATIVE		INTERCONNECTION, CONSERVATIVE	
	Pt [GW]	Ct [$]	Pt [GW]	Ct [$]
2019	12.5	6.60E+05	12.5	4.10E+06
2020	12.7	6.58E+05	12.7	4.09E+06
2025	15.0	6.42E+05	15.0	3.99E+06
2030	25.5	5.92E+05	25.5	3.68E+06
2035	40.0	5.53E+05	40.0	3.44E+06
2040	90.0	4.89E+05	90.0	3.04E+06
2045	150.0	4.52E+05	150.0	2.81E+06
2050	280.0	4.11E+05	280.0	2.56E+06

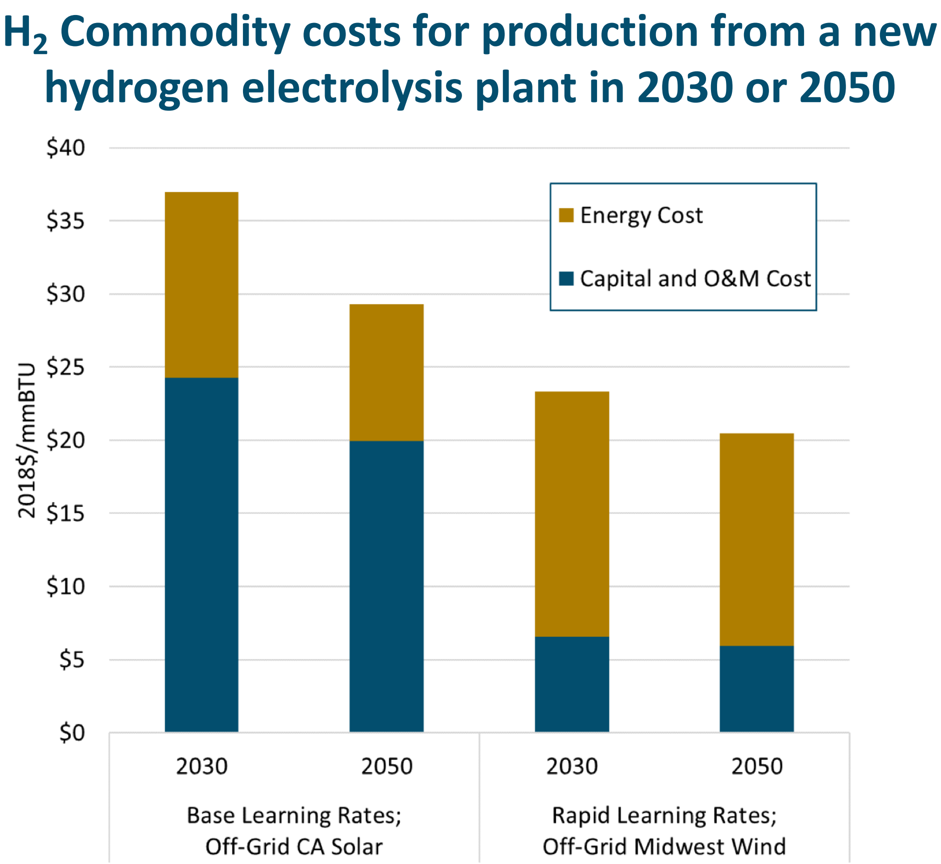
	BLENDING, OPTIMISTIC		INTERCONNECTION, OPTIMISTIC	
	Pt [GW]	Ct [$]	Pt [GW]	Ct [$]
2019	12.5	3.30E+05	12.5	5.00E+05
2020	12.7	3.29E+05	12.7	4.98E+05
2025	41.0	2.55E+05	41.0	3.86E+05
2030	99.0	2.10E+05	99.0	3.19E+05
2035	300.0	1.65E+05	300.0	2.50E+05
2040	699.0	1.37E+05	699.0	2.08E+05
2045	1500.0	1.16E+05	1500.0	1.76E+05
2050	2736.0	1.02E+05	2736.0	1.55E+05

RESULTS ARE PRELIMINARY

P2G capital cost projections



H_2 commodity costs combine UCI inputs with PATHWAYS scenario assumptions



*PATHWAYS scenarios represent changes in technology capital costs over time by vintage and transition of electrolysis technology.