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IICEC ENERGY AND CLIMATE RESEARCH PAPER

EXPLORING THE RAPIDLY CHANGING ENERGY SYSTEM

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Introduction

The global energy sector faces the grand challenge of meeting the increasing demand while profoundly reducing greenhouse gas emissions [1]. Today's energy sector is responsible for approximately 80% of the world's total GHG emissions, and the electricity sector is the largest single emitting sector with 33% share. Industrial processes constitute 22% of emissions, while the transportation sector is responsible for 16% [2]. Moving forward, the evolution of energy systems is characterized by greater convergence of power, transportation, and industrial sectors and inter-sectoral integration. Investigating powerful complexities arising from this paradigm shift using the existing techniques and instruments is difficult to all stakeholders. Understanding the implications of these dynamics requires novel tools and techniques that provide deep systems-level insights. To address this pressing need, we have developed a modelling framework that is designed to explore the impacts of all relevant technological, operational, temporal, and geospatial characteristics of the evolving energy system [3].

This paper presents key insights from our modelling work. The analysis focuses on two major energy vectors for deep decarbonization: electric power system and hydrogen. First, the status quo of global coal power plants is presented to demonstrate the need for carbon capture, utilization, and storage for reducing emission intensity of electricity generation. The discussion on power system then explores the impact of meaningful variable renewable energy sources in power generation mix on the performance of existing fossil fuel fired power plants. Key observations from the state of California, USA is presented as a case study. Third, options to address the challenges of balancing the power system with intermittent sources is discussed. Versatility of hydrogen can play an important role in electric power system as well as in other hard to decarbonize sectors. Importance of optionality in addressing the global energy challenge and need for wholistic approach are highlighted in conclusion.

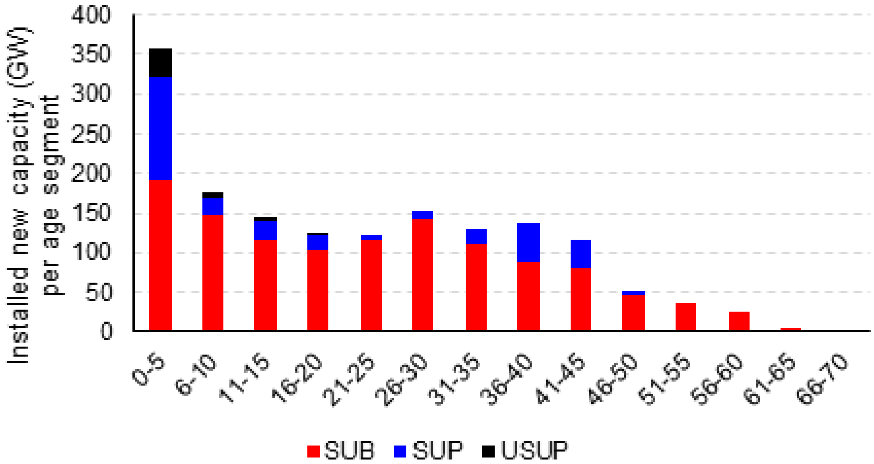
Electric Power System

Progress to date towards carbon-reduction goals has often been driven by decarbonization progress in the electric power sector [4]. For example, in the United States, the electric power sector was responsible for a 15 percent reduction in carbon emissions between 2013 and 2017. However, the power sector is the still largest CO_2 emission contributor by both number of sources (63% of total CO_2 sources) and CO_2 emission amount. Although unlike the industrial sector, the power sector has low carbon energy alternatives such as renewables and nuclear, the sustained presence of coal and natural gas power plants will be a large CO_2 emission source. Even under best-case scenarios, the implementation and penetration of renewable power generation capacity at scale will take time. In the interim period, a meaningful carbon mitigation strategy requires the utilization of carbon capture, utilization and storage systems with fossil-fuel driven power plants.

Global Coal-Fired Power Plants

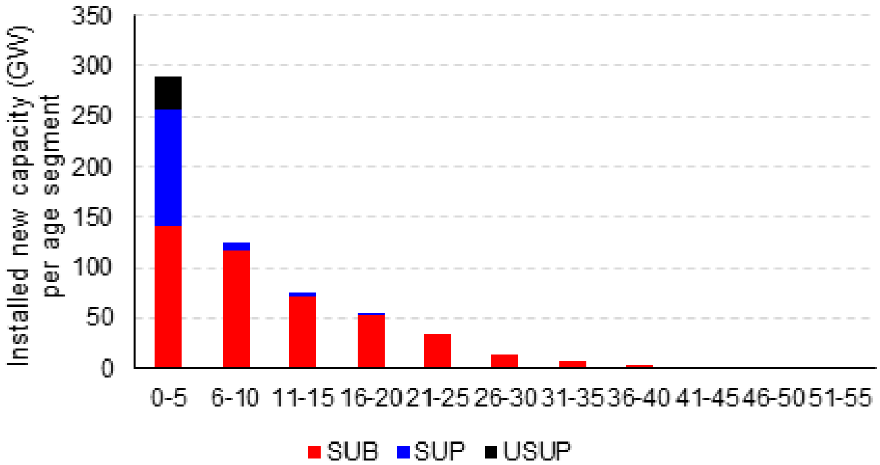
Globally, installed coal-fired power plant fleet consists of approximately 1,627 GW total generating capacity. More than one-fifth of the currently installed capacity is younger than five years, and more than half of the installed capacity is younger than 20 years **(Figure 1)**. The majority of the installed capacity is composed of power plants larger than 300 MW of generating capacity. The generating capacities of the units younger than 5 years are predominantly larger than 500 MW. Although supercritical and ultra-supercritical PC units have some presence in the newly installed capacity, subcritical PC dominates the installed capacity.

Figure 1: Global coal power plant capacity by age segment and power plant technology. (Data source: IEA, CCS Retrofit, 2012 **[5]**)



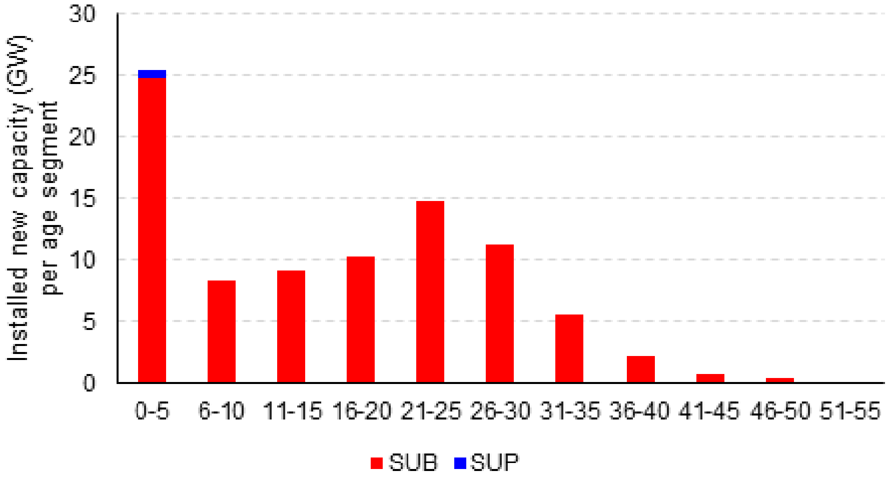
China has 2929 power units with total capacity of 669 GW **(Figure 2)**. China has the youngest fleet among the focus countries with a steep increase in the last 20 years. Approximately 300 GW of new capacity has been built in the last five years. Almost half of these newly built power plants utilizes sub-critical power cycles. The fraction of the most efficient Ultra-super critical power plants is fairly low.

Figure 2: China's coal power plant capacity by age segment and power plant technology. (Data source: IEA, CCS Retrofit, 2012 **[5]**)



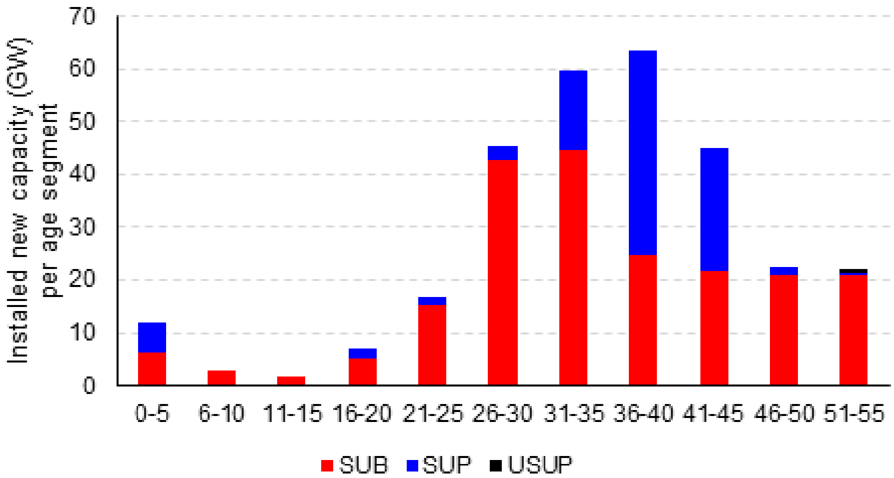
India has a total of 809 units with total capacity of 100 GW **(Figure 3)**. India significantly increased its generating capacity in the last five years. The Indian fleet consists almost entirely of sub-critical plants and this technology continues to dominate new builds.

Figure 3: India's coal power plant capacity by age segment and power plant technology. (Data source: IEA, CCS Retrofit, 2012 **[5]**)



The US has the oldest coal fleet consisting of 1368 units with total capacity of 336 GW **(Figure 4)**. The majority of these power plants are 25 years of age or older. Although it is hard to predict the future for coal with the repeal of Clean Power Plan, the existing scale of the fleet will mean an important role for coal in the overall US fleet for decades to come.

Figure 4: US's coal power plant capacity by age segment and power plant technology. (Data source: IEA, CCS Retrofit, 2012 **[5]**)



CCUS, is the only low-carbon technology option that can directly reduce carbon emissions while continuing the utilization of fossil resources. CCUS plays a critical role to prevent the early retirement of existing or newly built fossil fuel conversion plants and to unlock the potential of fossil reserves. Hence, any attempt to reduce the carbon intensity of the energy sector requires the implementation of CCUS systems in scale.

The current CCUS systems consist of a carbon dioxide capture process in which carbon dioxide is separated from a gas mixture, a utilization stage in which the captured carbon dioxide is used to produce other chemicals or to promote production processes, and a storage stage in which captured carbon dioxide is sequestered permanently. Currently, there are seventeen operational CCUS projects in the world most of which capture carbon dioxide from natural gas processing facilities. Current most common practice is to use the captured carbon dioxide for enhanced oil recovery (EOR), which is a is a proven oil recovery method for getting 4-15% more of the original oil in place from the well. With EOR, the majority of injected CO_2 is stored permanently. Though the number of operational projects is increasing, half of the planned large-scale CCUS projects has been cancelled since 2013. Hence, in the last 4 years, very few projects were able to survive through development stages.

Among the operational CCUS projects, there are only two coal power plant projects (Boundary Dam in Canada launched in 2014 and Petro Nova in the US launched in 2016). These two projects were retrofits to existing coal power plants to equip with carbon dioxide capture and use the captured carbon dioxide for EOR applications. Although global power generation sector is dominated by coal power plants, the number of CCUS projects are very few. The operational projects are built by government support. Most of the cancelled projects are power plant projects that losing their government support or shifting their focus on renewable and gas-fired power plants.

The Response of Existing Power Plants to Growing Renewable Power Fleet

The integration of renewable power has led to considerable changes in how the fossil-fired power plant fleet is being dispatched relative to a decade ago. Fossil power plants will have to play an increasingly dynamic role in balancing the power system to complement the variable renewable energy sources. This mode shift from base load to more dynamic operation will create a technical challenge for CCUS integration. Additionally, there are emission consequences of operating fossil power plant at off peak regimes. To understand these dynamics, we can investigate a region that has high penetration of renewable power in their generation mix.

California's electric power grid is in the midst of a major transformation. Given the state's decarbonization targets, understanding the evolution of emission intensity of power generation is increasingly important. The sole emission source for in-state generation is natural gas power plants, which consist of combined cycle gas turbine, open cycle gas turbine, and steam turbine units. These units are suitable for different applications such as providing baseload or peaking capacity. Their operational performance is sensitive to parameters such as loading relative to peak capacity, ambient temperature and relative humidity. Furthermore, the frequency of start-ups and shut-downs as well as the duration of operation impact the environmental footprint of the natural gas power generation fleet. The structure of the grid, particularly, growth of renewable power (solar and wind), availability of hydropower, and retirement of nuclear plants impacts how natural gas plants are dispatched.

Over the last decade, the California's in-state generation emission has seen some fluctuations though the total generation was quite constant. The unprecedented growth of solar power in California's electric power grid has surely reduced the emissions for in-state power generation. However, the penetration of intermittent solar power creates complex dynamics for the rest of the system.

Hourly average emission intensity profile shows significant alteration over the last decade. The surge in emission intensity corresponds to dirtier operation of these assets. Annual capacity factor (ACF) distribution demonstrates the evolution of utilization of thermal generation units over years. The ACF of CCGT units have been decreased especially from 2012 onward. CCGT units shifted from providing baseload power to providing more short-term peaking power. The ACF of OCGT units have increased to balance the intermittently available renewable power generation. From emission perspective, OCGT units are less efficient than CCGT units, resulting in increased emissions for the same power output. ST units are mostly part of combined heat and power generation that are not affected from the changing grid structure.

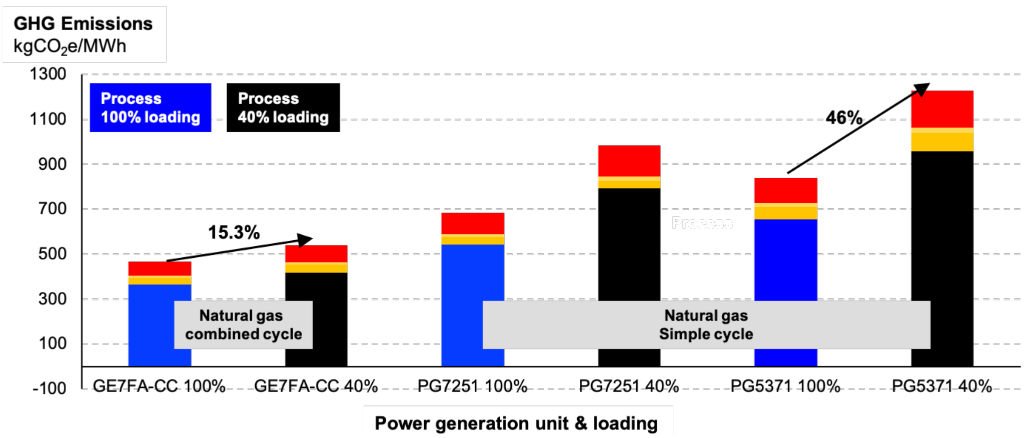
Using high-resolution data from US EPA (Environmental Protection Agency) Continuous Emission Monitoring Systems (CEMS) to draw conclusions based on gas unit operation. This analysis covers the generation and emission data for 99% of CCGT and 95% of OCGT units.

Table 1: Data coverage of the analysis

EPA CEMS CAISO Data (2010-2017)		
Observations	14.5 million	
Sample	No. of units	% of generation
CCGT	42	99%
OCGT	54	95%

The significant change in plant-level operations have a range of complex performance and emission consequences. The impact of operation at different loading levels is shown in **Figure 5**. The life cycle greenhouse gas emissions for CCGT units increase by 15% at a lower loading of 40% of peak capacity. For OCGT units the emission intensity increase can be as high as 46% at a lower loading of 40% of peak capacity **[3]**.

Figure 5: Life cycle greenhouse gas emissions of combined cycle and open cycle gas turbine units operated at full load and 40% part-load.



This significant increase overshadowed with the emission intensity increase during start-up and shut down periods. Example observed emission intensities for CCGT and OCGT units are shown in **Figure 6** and **Figure 7**, respectively. CCGT unit cycling and more frequent OCGT starts and stops leads to increased hours of part-load operation. Enclosed areas in the figures represent the cycling or the operation of these units. These figures clearly show the significant emission intensity rise during the start-up and shut down periods.

Key Takeaways: Renewable Penetration

- There is a considerable alteration in how the natural gas power plants have been dispatched over the last decade.
- The number of starts for gas turbine units has been significantly increased over the last decade.
- Operating hours for CCGT units running less than 24 hours have been drastically decreased.
- The various alterations in operating regime resulted in modified emission profiles.
- The emission intensity has been increased as a result of more frequent cycling and high number of start-up and shut-downs.

Figure 6: Observed annual emission intensity variation for a real CCGT plant in California

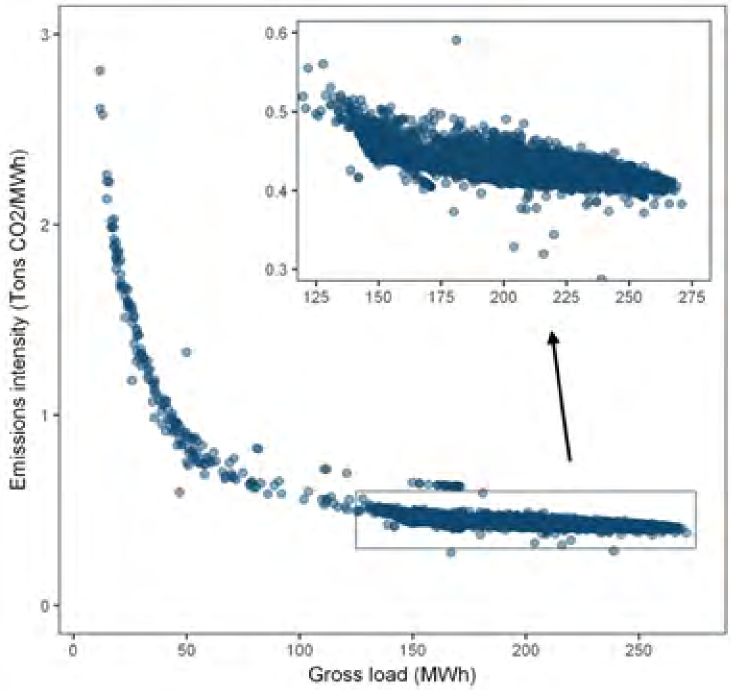
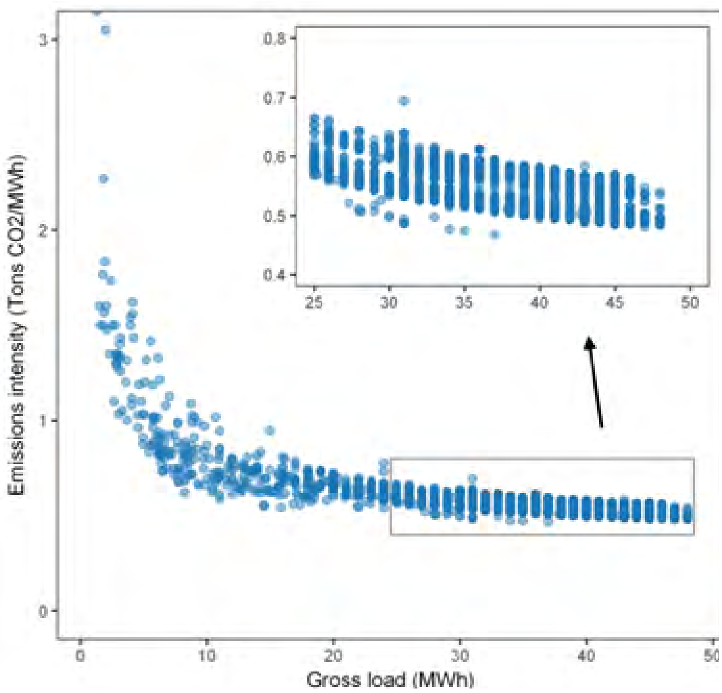


Figure 7: Observed annual emission intensity variation for a sample OCGT plant in California



The change in generation mix leads to more dynamic operation of the natural gas power plants, which alters total CO_2 emissions and the ratio of emissions during these part-load periods.

Hybridization of Gas Fired Power Plants

The growing adoption of intermittent renewable energy resources put unprecedented stress on grid reliability. Gas fired power plants undertake the balancing role for the grid, that significantly alter the dispatch, operational mode, and hence performance of these assets. Frequent start-up and shut down, cycling within wide capacity ranges, running at less than minimum load and for shorter durations are some example changes in the natural gas power plant operations. The conventional gas fired power plants need to evolve to be responsive to the dynamics of the grid's needs with minimal performance and cost penalty.

Deployment of energy storage is mostly presented as an alternative to gas fired power plants. However, reaching the capacity currently provided by gas plants is currently uneconomical. Instead, a hybrid solution, which integrates battery energy storage with gas turbines by combining the strongest features of both technologies can be adopted. Here, we present a snapshot of this innovative technology, its characteristics and advantages.

No single power generation technology is best suited for all applications. Natural gas power plants consist of combined cycle gas turbine (CCGT), open cycle gas turbine (OCGT), and steam turbine (ST) units. These units provide different services such as providing baseload or peaking capacity. In addition to natural gas fuel use, depending on the cooling system, power plants need significant amounts of fresh water for operation. The frequency of start-ups and shut-downs as well as the duration of operation impact the environmental footprint of the natural gas power generation fleet.

Hybridization of power plants integrate multiple power generation technologies to complement deficiency of each technology and create a synergistic hybrid system. In theory, hybridization can involve combination of any technology, each one of which can provide different functions. Here we explore hybrid battery energy storage (BES) – CCGT and BES-OCGT systems.

Hybrid BES-OCGT

OCGT units have a peaking duty cycle role—specifically, they are called upon to meet peak demand loads for a few hours on short notice, often in the 15-minute or 5-minute-ahead real-time market. Although it has been significantly improved, the efficiency of OCGT units are low (average performance of OCGT units in California; efficiency: 33.4%, heat rate: 10,213 Btu/kWh). The average observed efficiency is significantly lower than the nameplate performance due to change in operation towards non-optimal regime. Hybridization with energy storage can improve the performance by running the gas turbines at peak load for longer period of time, storing the excess power, and discharging to meet the demand. The availability of energy storage further increases the speed of power dispatch as peaking plant.

Hybrid BES-OCGT

A CCGT power plant has a generation block consisting of at least one gas turbine, a heat recovery steam generator, and a steam turbine (ST). The higher fuel efficiency results from the ability of the heat recovery steam generator to capture exhaust gas from the gas turbine to produce steam for the ST, often augmented with duct burning of natural gas in the heat recovery steam generator. CCGT units have significantly higher efficiencies relative to OCGT units (average performance of CCGT units in California; efficiency: 46.7%, heat rate: 7,304 Btu/kWh). The average observed efficiency is significantly lower than the nameplate performance due to change in operation towards non-optimal regime. Particularly, higher number of start-ups increase the emission intensity of CCGT units. Hybridization of CCGT units with energy storage allows faster start-up. The hybridized plant will have OCGT flexibility with combined cycle efficiency. This provides Additional peaking capacity for the grid.

Commercially Available Hybrid Models

GE's LM6000 Hybrid EGT™ integrates a Battery Storage system with the LM6000 gas turbine, enabling contingency (spinning) reserve without fuel-burn between demand events. This also enables high speed regulation, primary frequency response, and voltage support (-8 to +5 MVAR) with the combined response of the gas turbine and battery storage system.

The hybrid system provides as advertised:

- *50 MW+ of greenhouse gas free contingency reserve*
- *50 MW+ of flexible capacity*
- *50 MW+ of peaking energy*
- *25 MW of high quality regulation*
- *10MVA of reactive voltage support and primary frequency response when not online*
- *Zero Fuel use and emissions between dispatch events while supporting ancillary services*

Though LM6000 Hybrid EGT is currently the only packaged hybrid model conceptual designs on combined cycle hybrid models and deployment of batteries with existing plants have also been advertised.

Figure 8: GE's LM6000 Hybrid EGT

Operational Projects

Southern California Edison (SCE) installed the world's first, and only so far, hybrid gas turbine system in 2017. The hybrid system integrates 50 MW gas turbine unit with a 10MW/4.3MWh li-ion battery.

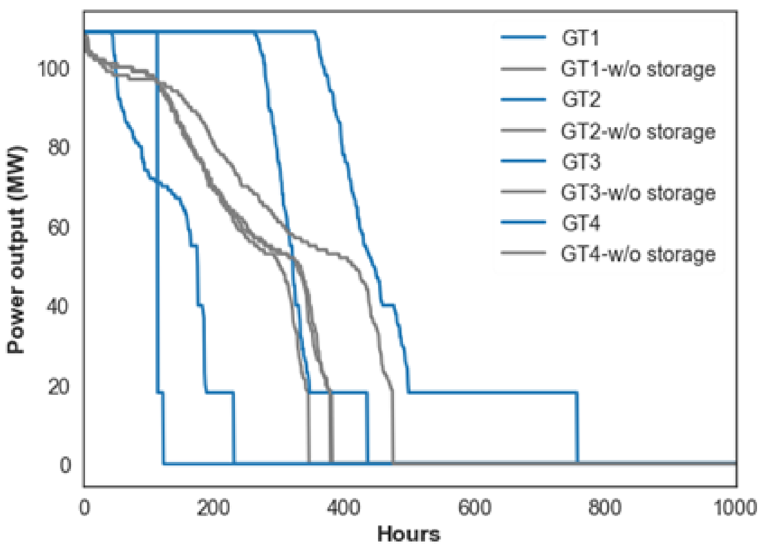
Figure 9: The installed hybrid gas turbine and battery energy storage system California. Image: GE Reports/GE Energy Connections (https://www.ge.com/reports/power-couple-battery-jet-engine-hybrid-will-help-california-grab-renewables/)

The system is designed to immediately supply power when needed; the first response is discharging the battery while starting up the gas turbine to provide the required energy. SCE estimated that the hybrid system will reduce the greenhouse gas emissions of the peaker plant by 60% over its life time.

Case Study

To investigate the dynamics of hybrid power plant systems, an optimization model is developed. Hourly load profiles of four OCGT units, each with a capacity of 109 MW, of a power plant located in California have been selected as base case. From the hourly load profile, off-peak operations have been identified. The hybrid system consisting of the same OCGT units and a 40MW-4hr li-ion battery is designed to meet the same load profile by maximizing the optimal operation that will minimize the operational cost and emissions of the power plant.

Figure 10: Load duration curves of four real OCGT units and their optimized hybrid operations



The load duration curves of these four OCGT units are shown in **Figure 10** (gray lines). The optimum operation is also shown in Figure 10 (blue lines). Current load duration curve shows a wide range loads over the total operation duration. The optimal profile shows a much higher operation at the nameplate capacity of these units. The heat rate at minimum load is 70% higher than the heat rate at full load.

The performance of these units has been modeled based on their hourly heat rates **(Figure 11)**. The minimum load for these OCGT units is approximately 20% of the nameplate capacity. The heat rate follows an almost linear trend (shown with red curve).

Figure 11: Hourly heat rate of one of the OCGT units modeled for hybridization study.

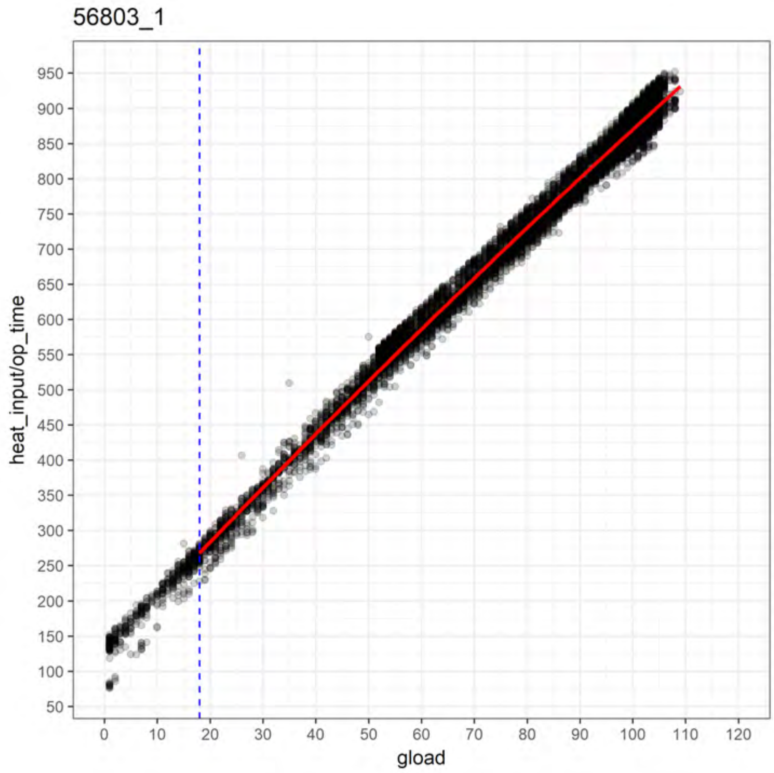
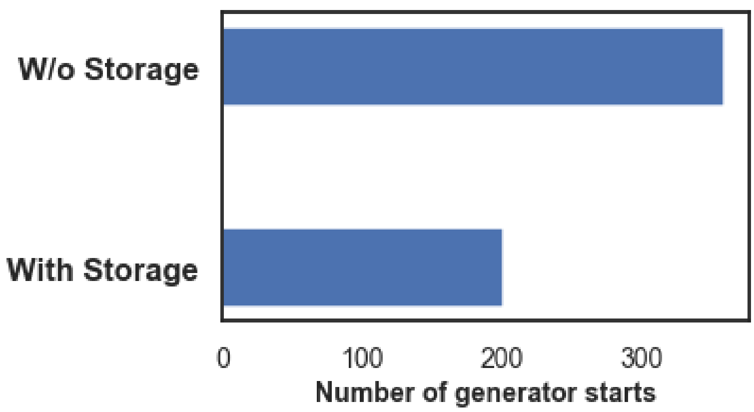


Figure 12: Number of starts for hybrid versus standalone OCGT units

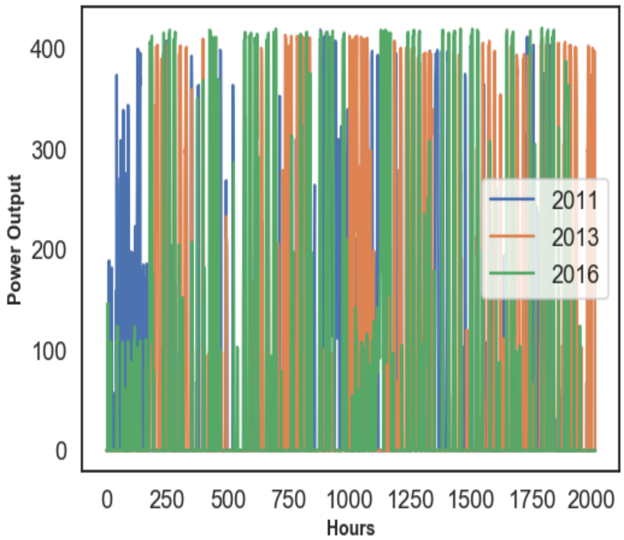


In addition to the longer operation at peak load, there is a marked reduction in the number of generator starts, 351 starts for the observed operation and 206 starts for the hybrid solution **(Figure 12)**. The highest emission intensity occurs during start-up; hence this decrease in number of starts significantly decrease greenhouse gas emissions.

For the economic optimization, the optimal design has 20% lower annual cost than the conventional OCGT plant. The cost reduction is mainly due to the lower fuel consumption as a result of improved overall efficiency of the plant.

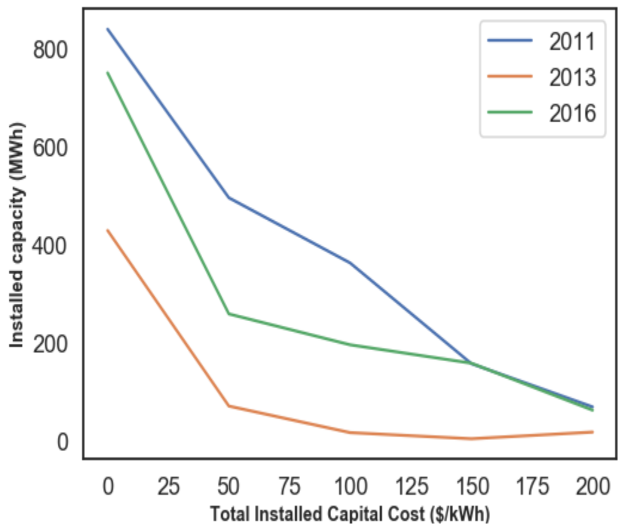
The hybridization requires an in-depth analysis of historical load profiles. The year-to-year variation is shown in **Figure 13**. For the same time period the total power output for this peaking plant is quite different in 2011, 2013, and 2016.

Figure 13: Hourly load profile variation across years



Based on this variability the optimal design and hybridization extent changes. **Figure 14** summarizes a sensitivity analysis looking at the impact of installed capital cost of energy storage based on the load profiles of different years. The optimum energy storage deployment is higher at any price point for 2011 load profile due to shorter duration of operation after each start event. 2013 displays longer runs/higher power outlets for every start hence the benefit of energy storage is marginal. The model deploys very small capacity of energy storage even at low capital costs. 2016 falls between 2011 and 2013 operation so does the level of battery deployment.

Figure 14: Optimal storage installation trends



Key Takeaways: Hybridization

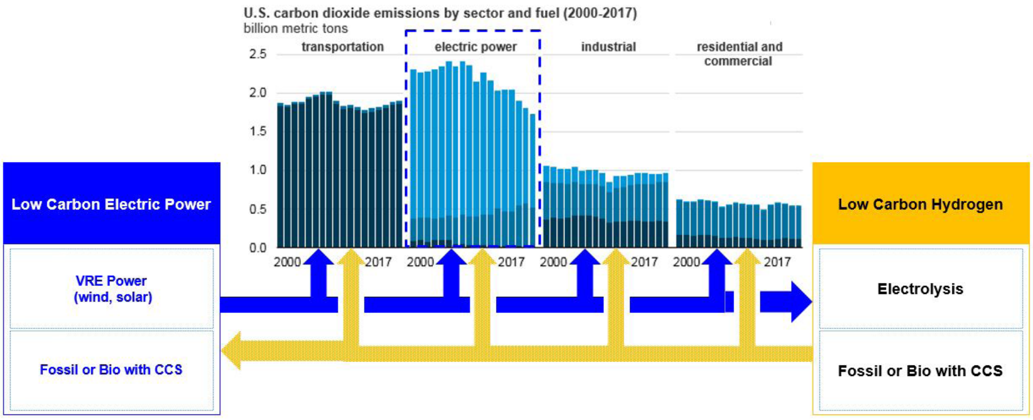
Hybridization of gas fired power plants with battery energy storage can;

- Improve matching of power production and consumption profiles
- Reduce O&M costs through shared services
- Reduce fuel consumption and CO_2 emissions by displacing fossil generation
- Reduce transmission and distribution (T&D) CAPEX by shifting generation to meet peak load
- Increase T&D expected lifecycle because of lower peak utilization
- Increase revenue through increased participation in multiple ancillary services market
- Reduce system levelized cost of electricity (LCOE) by optimizing the mix of renewables and thermal supply

Hydrogen for Deep Decarbonization

The carbon-reduction progress of electric power sector is a major step towards economy-wide decarbonization, however, achieving deep decarbonization requires more. **Figure 15** shows the carbon dioxide emissions of transportation, electric power, industrial, and residential and commercial sectors in the US from 2000 to 2017. Over this time period the only emission reduction is realized in electric power sector. The electrification strategy can be a viable solution for decarbonizing some elements of other sectors such as light duty transportation, residential heating. However, for industries requiring high temperature heat, storing energy for long term at large scales, and heavy-duty transportation, there is a need for a low carbon molecule. Hydrogen can play a critical role in the decarbonization efforts across all components of the energy system and complement the progress in the electric power sector. The versatility of hydrogen as energy carrier creates this multi-sectoral opportunity solution. Of course, *how hydrogen is produced* is very important.

Figure 15: Low carbon electric power and low carbon hydrogen: Two energy vectors for economy-wide decarbonization.



Hydrogen Production Background

Today more than 95% of global hydrogen supply is produced by natural gas reforming. Although, the use/combustion of hydrogen does not have any greenhouse gas emissions, the natural gas-based production processes emit 9-12 tons of CO_2 per ton of hydrogen produced. The source of hydrogen hence makes a huge difference in its environmental footprint.

In addition to conventional reforming processes, hydrogen can be produced via electrolysis for which electricity and water are the only inputs to the process. The emission intensity of electrolytic hydrogen production is dependent on the source of electricity. Hydrogen produced solely from renewable energy sources will be referred as *green hydrogen*. For the case of natural gas reforming, the only solution to reduce its emission intensity is to deploy carbon capture, utilization and storage (CCUS) technologies. A significant fraction of carbon dioxide produced during the reforming can be captured, reducing the environmental footprint of natural gas-based hydrogen, also referred as *blue hydrogen*. Deployment of carbon capture for the steam methane reforming process is mature and already implemented in 3 large scale facilities (there are 18 global operational CCUS projects including these reforming facilities). The CO_2 concentration of reforming flue gas is higher relative to that of power plants making the capture process less energy intensive and less expensive.

Options and Challenges for Hydrogen

The suitability of hydrogen production method is closely dependent on the application of interest. The opportunities for hydrogen are not limited to power sector, which makes hydrogen option especially interesting. Hydrogen is an important feedstock for many chemical conversion and food processing processes [6]. Hydrogen is the key chemical for the production of ammonia that is precursor of most of the fertilizers. Biofuel production other than fermentation processes also needs hydrogen to convert the bio energy-based oil into drop-in fuels [7]. In addition to all these current use cases, hydrogen's role for sectors that are hard to decarbonize via electrification such as heavy duty transportation and industries using high temperature heat, prompts interest.

A key barrier to boost this transition is the lack of hydrogen infrastructure. Hydrogen pipelines exist and currently operational (1600 miles in the US) for industrial applications. The infrastructure need will be determined mainly based on the low carbon hydrogen production mode (distributed vs. centralized) and demand profile. In addition to dedicated hydrogen pipelines, natural gas network can be retrofitted or hydrogen can be mixed with natural gas. Additionally, hydrogen storage infrastructure should be deployed. On the flip side, the high investment requirement of hydrogen infrastructure can be amortized by the multi-use cases for hydrogen. The demand for hydrogen fuel cell vehicles is also growing, especially in California and Japan. All these developments and potential uses of hydrogen are of utmost importance for the hydrogen infrastructure investments.

Electrification of light duty transportation is relatively easy task however to reduce the carbon footprint of the entire transportation sector, there is a greater need to decarbonize medium and heavy duty (long haul trucks, trains, airplanes) transportation. For these transportation modes, energy density plays an important role. Direct use of hydrogen and biomass derived drop-in fuels are two viable solutions. Production of low carbon hydrogen is also critical for biofuel route since most of biofuel production processes require addition of hydrogen to convert bio-oils into drop-in fuel. The infrastructure requirement (fueling stations) for only supplying heavy duty transportation is also very different from adding more fuel cell electric vehicles into the light duty vehicle fleet.

Decarbonization of industry require industry-specific solutions. For some industries electrification can be considered but for most carbon intensive industries such as iron & steel manufacturing, cement production, and refining and chemicals, high temperature heat requirement of the conversion processes makes this transition very difficult. Conventionally, a fuel is combusted in boilers to supply the high temperature heat, a low carbon alternative is providing the thermal energy using low carbon hydrogen. Another alternative is to deploy carbon capture and sequestration (CCS), however, for all of there are multiple sources of emissions with varying CO_2 concentrations that hardens the coupling of CCS.

To compensate the variability and intermittency of renewable power generation, significant energy storage capacity spanning various duration needs should be deployed. For seasonal and year-to-year variation due to change in availability of renewable resources, the grid stability can only be maintained with long term energy storage. Hydrogen for long term energy storage provides great optionality as low carbon hydrogen can be produced from various sources/pathways (reforming of natural gas with carbon capture and electrolysis using low carbon electricity), there is a large existing production capacity mostly to supply feedstock need of industry, there are various choices for power generation (retrofitting existing natural gas-fired power plants, hydrogen gas turbine and combined cycle units, fuel cells), various storage solutions for both large scale (underground salt caverns) and small scale (above ground pressurized vessels, tanks) exist. Furthermore, it can be converted to other stable molecules such as ammonia and synthetic natural gas if needed. Storing the same amount of energy will require orders of magnitude higher volumes for other energy media.

In electric power system context, the first use case for hydrogen is using the existing gas power generation fleet. Although current gas turbine models can handle hydrogen/natural gas blend as fuel, the injection system and combustion chamber of gas turbines need a modification to handle pure hydrogen. Vattenfall is currently converting its 440 MW gas power plant Magnum in the Netherlands into a hydrogen-fired power plant **(Figure 16)**. The plant will use blue hydrogen (partnership with Equinor). The potential CO_2 emission reduction for the project is estimated to be 4 million tons CO_2 per year. Successful execution of this project will be a major milestone for the potential low carbon operation of gas power generation fleet.

Figure 16: Vattenfall's 440 MW gas power plant Magnum in the Netherlands that will be converted to hydrogen-fired power plant.

The second use alternative for power generation is hydrogen fuel cells. Hydrogen fuels cells are significantly more efficient than conventional gas plants. However, fuel cells are currently more suitable for small scale applications.

For hydrogen either green or blue, to be a viable option, its cost needs to be competitive with other solutions. Here, we present a case study for producing hydrogen from solar PVs for constant supply to industrial process, pipeline or any other application and compare the cost to alternative hydrogen production pathways.

Renewable Hydrogen Case Study

We have estimated the cost of producing H_2 at a steady rate using solar PV and low-temperature electrolysis technologies, with an explicit accounting for the variability in PV resource availability and the role for energy storage to mitigate this variability. The integrated design and operation of the PV-electrolysis process is modeled to identify the process configuration that minimizes the sum of the annualized capital costs and operating costs while adhering to various system constraints. These include: **1)** inter-temporal constraints on the available capacity of energy storage in each hour of the year (H_2 and battery storage), **2)** limits on hourly PV resource availability for the region of interest, **3)** AC power requirements for H_2 compression and **4)** power and energy capacity limits of various components (e.g. PV, electrolysis, battery).

The capacity of H_2 storage required to meet hourly production requirements is set by the storage requirements during the winter months when solar resource availability tends to be the lowest across the year. During the summer, the amount of H_2 stored is much less than 20 hours of storage, and is reflective of the need to manage the diurnal variability in solar availability. In winter, however, there may be instances when hourly PV output during the day may be insufficient to even supply the instantaneous hourly production requirements. At such times, H_2 storage needs to be discharged over much longer durations without having the opportunity to be recharged. Solar availability has a major impact in the cost of hydrogen produced. According to our analysis, estimates short term cost of hydrogen for a solar PV and electrolysis system is \$4.5 – \$8.5/kg of H_2 in , the long term estimations are in the range of \$2.5 – \$6/kg of H_2.

Table 2 summarizes cost estimates reported for electrolytic H2 production from a few prior studies. In general, prior assessments have presumed the use of grid-based electricity without fully characterizing the temporal trends in electricity supply attributes (availability, emissions intensity, costs) and the potential role for integrating energy storage, either as batteries or H2 storage[8–11]. For instance, the U.S. Department of Energy's H2A analysis estimates the costs of centralized and distributed H2 production via electrolysis based on electricity procured from the grid at average wholesale electricity prices, to be \$4.5-\$5.2/kg [8]. These costs are similar to the costs for similar electrolyzer capital cost assumptions and PV capital costs between \$500-\$700/kW, reflecting the approaching parity between the levelized cost of electricity from PV and grid electricity. At the same time, the cost estimates in this study include the cost of H_2 storage to enable steady H_2 supply, which is another factor contributing to higher cost estimates compared to those reported in the H2A analysis[8].

Table 2: Survey of previously reported cost estimates for electrolytic H_2 production

Description	Capacity (tonnes/d)	H_2 production cost[a,b] (\$/kg)
H2A centralized electrolysis [8]	50	4.5-5.2
H2A distributed electrolysis [8]	1.5	4.5-5.2
Central electrolysis with wind [9]	52	4.3
Co-located Wind electrolysis [10]	50	2.8-12.2
PV electrolysis: grid assisted vs. PV only [11]	10	6-12.1

a. Costs are as-reported in each of the analyses and do not reflect any adjustments to facilitate comparison (e.g. common base year). **b.** To the extent possible, cost of H_2 delivered has been subtracted to report only the production cost estimates.

As a contrast to the cost of electrolytic H_2 production routes, **Table 3** summarizes cost of producing H_2 from different natural gas(NG)-based pathways, sourced from H2A analysis[8]. Centralized NG steam methane reforming (SMR) which dominates the global supply of H_2 currently[12], has the lowest production cost at NG prices consistent with current trends in the U.S.. Although integrating CO_2 capture and sequestration into a centralized NG-based H_2 production pathway increases the cost of H_2 production, these costs are still lower than the lowest costs estimated for distributed electrolytic H_2 production in this study. It should be noted that any centralized H_2 production route has to contend with additional costs of delivering H_2 to the end user, which in the case of the transport sector, could be comparable to the cost of supply(~\$2/kg)[13] due to the distributed nature of demand. Accounting for this delivery cost estimate for centrally produced H_2 from NG raises the total cost of low-carbon NG-based H_2 routes to ~\$3.5/kg, which is similar to the lower range of costs estimated for electrolytic H_2 production in this study.

Currently, there is no viable pathway for distributed H_2 production from NG along with CO_2 capture. Thus, the value of distributed PV-based electrolytic H_2 production may emerge from the ability to provide a near zero carbon source of H_2

supply in close proximity to demand and avoiding the infrastructure needs of H_2 delivery. A throughput of 10 tonnes/day considered in this study is comparable to the typical capacity assumed for future H_2 refueling stations at 1.5-2 tonnes/day[8]. The modularity of electrolyzer H_2 production routes implies that the levelized costs are likely to be less sensitive to the scale of production as compared to NG-based pathways.

Table 3: Levelized cost of H_2 production for different natural gas (NG) based routes. Sourced from H2A analysis[8]. SMR = Steam Methane Reforming. CCS = Carbon Capture and Sequestration

Pathway	Capacity (tonnes/d)	NG price ($/MMBtu)	H_2 cost ($/kg)
Centralized NG reforming - SMR	380		1.10-1.15
Centralized NG reforming -SMR with CCS	380	3.73	1.52-1.56
Distributed NG reforming	1.5		1.40-1.50

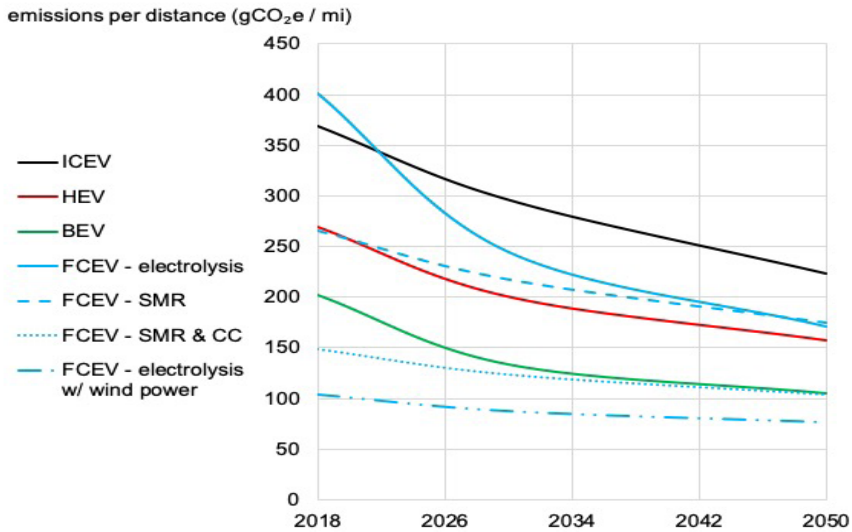
Key Takeaways: Hydrogen

- Hydrogen as an energy carrier can serve as energy storage medium at different scales for the stability of the electric power grid.
- Hydrogen can be used to generate electricity via efficient fuel cells or modified conventional gas power plants.
- Low carbon hydrogen can be produced by natural gas reforming with CCUS (blue hydrogen) or renewable power based electrolysis (green hydrogen).
- Although natural gas based hydrogen production is currently much cheaper than electrolysis based options, with anticipated equipment cost reduction, green hydrogen can be competitive beyond 2030.
- Electrolytic hydrogen is suitable for distributed production that significantly reduces the need for hydrogen infrastructure.
- Hydrogen is a versatile molecule, in addition to its applications in power system, it can be used as transportation fuel, feedstock for chemical and industrial processes. This unique feature can create opportunities for value creation.

Hydrogen for light duty transportation

Hydrogen fuel cell vehicles are zero emission and run on compressed hydrogen fed into a fuel cell that produces electricity to power the vehicle. However, zero emissions from vehicle does not mean zero overall emission. The emission intensity of hydrogen fuel cell electric vehicle is dependent on the source of hydrogen. As discussed in earlier sections, today's dominant hydrogen production method is based on fossil fuel conversion. **Figure 17** summarizes the comparison of life cycle greenhouse gas emissions of Internal Combustion Engine Vehicles (ICEV), Hybrid Electric Vehicles (HEV), Battery Electric Vehicles (BEV), and Fuel Cell Electric Vehicles (FCEV) with various hydrogen production cases. The projections include the advancement in vehicle technologies such as fuel economy improvement and light weighting, and reduction of emission intensity of electric power grid. Today, most emission intensive option is to drive FCEV fueled by electrolytic hydrogen produced from US average grid (453 gCO_2e/kWh). However, as the power generation gets cleaner this option drops below ICEV option. Current SMR based hydrogen ranks similar to HEV option. BEV charged with average grid is a lower emission option. Hydrogen produced from SMR with carbon capture and sequestration, and electrolysis powered by wind turbines have significantly lower emission intensity relative to other light duty transportation options. Relative ranking of BEVs and FCEVs is extremely sensitive to grid mix.

Figure 17: Evolution of life cycle greenhouse gas emissions of Internal Combustion Engine Vehicles (ICEV), Hybrid Electric Vehicles (HEV), Battery Electric Vehicles (BEV), and Fuel Cell Electric Vehicles (FCEV) with various hydrogen production cases.



Key Takeaways: Hydrogen Fuel Cell Electric Vehicles

- Electrolysis with wind or renewable power is the cleanest alternative.
- Compared to SMR, electrolysis with average grid does not have greenhouse gas emission benefits for FCEVs, even with ~50% drop in emission intensity from 2018 to 2050.
- Adding carbon capture to SMR reduces FCEV emissions to similar level as BEVs.

Conclusions

One of the global community's most significant contemporary challenges is the need to satisfy growing energy demand and increasing energy access while simultaneously achieving significant reductions in the greenhouse gas emissions associated with the production, delivery, and consumption of this energy. To-date, progress toward realizing meaningful carbon reductions has largely been centered on the electric power sector. An ongoing transition towards lower-carbon fuels, the expanded deployment of new low-carbon generation technologies, and an embracing of energy efficiency measures have all contributed to this dynamic. The widespread adoption of renewable generation technologies like wind and solar PV is of particular significance because as these technologies begin to play a meaningful role in meeting overall electricity demand, their presence on the system also introduces some challenges linked to their inherent intermittency and diurnal variability. Currently, global power sector is still the largest source of CO_2 emissions and will continue to grow with the new additions to the global power plant fleet (more than 500 GW of installed coal power plant fleet is younger than 10 years). For existing fossil fuel fired power plants especially the young coal power plants carbon capture, utilization, and sequestration (CCUS) is critical towards meeting decarbonization targets. The rapid transformation of the energy system has unintended consequences such as the presented emission intensity increase of natural gas power plant fleet due to operational changes. To address these a number of technological options can be adopted hybridization is being one of them. Irrespective of the improvement of power sector, economy-wide decarbonization needs another energy vector. The versatility and multi-sectoral nature of hydrogen makes hydrogen a plausible option. Hydrogen can play a critical role in the decarbonization efforts across all components of the energy system and complement the progress in the electric power sector such as for industries requiring high temperature heat, storing energy for long term at large scales, and heavy-duty transportation. To conclude, a plethora of options and solutions are needed, the adoption of a holistic systems approach supported by rigorous quantitative analysis is essential to tackle the grand energy challenge in front of us.

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