EMISSIONS IMPACTS OF MARGINAL ELECTRICITY DEMAND FOR CALIFORNIA HYDROGEN SUPPLY PATHWAYS

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1. Introduction

Hydrogen and electricity are both high-quality energy carriers that can be made from diverse primary energy resources and can be inter-converted using electrolyzers and fuel cells. Unlike today's energy system, where electricity and transportation fuels have very different supply chains, these characteristics suggest that supply pathways for electricity and transportation fuels might "converge" in a future hydrogen economy. If both sectors come to rely on the same primary energy sources, the implications could be significant, and might lead to profound changes in the way energy is supplied. While a switch from gasoline to hydrogen might lead to higher demand for primary energy resources (e.g., biomass, natural gas, or coal), it would also offer opportunities to improve the efficiency and reliability of energy supply by integrating the electricity and transportation fuel systems. For example, efficiency gains and cost reductions might be realized by co-producing hydrogen and electricity at the same facility.

A shift to hydrogen is likely to increase electricity demands for fuels production and distribution, as well. Although some pathway components – such as hydrogen production from coal gasification – may be electricity-neutral or may even generate by-product electricity, many other components require additional electricity for hydrogen production, liquefaction, and/or compression. The impacts of these new (i.e., "marginal") demands on the electricity sector, the sector's subsequent evolution, and the resulting economic and emissions impacts for both electricity and fuels production, will be shaped by two important factors: total energy demand (e.g., MWh), and the timing of demand.

We investigate these impacts on California's electricity sector by developing an electricity dispatch model to compare generation resources used to meet marginal electricity demands for transportation fuels, and to understand the resulting emissions. We look at the current grid in California, and the affect of substituting conventional vehicles with battery-electric vehicles (BEVs), plug-in hybrid vehicles with 20-mile all-electric range (PHEV20s), or fuel cell vehicles (FCVs) supplied by various hydrogen pathways. This work represents initial progress in a longer-term project that looks at interactions between hydrogen and other alternative transportation fuels and electricity and natural gas markets in California. The authors, at the Institute of Transportation Studies at UC Davis, are working on this project along with the California Energy Commission (CEC), Lawrence Livermore National Laboratory (LLNL), and others.

2. Electricity dispatch model

The dynamic nature of electricity demand, coupled with the inability to efficiently store electricity on a large scale, requires generation to continuously respond to demand in real time.

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Electricity dispatch is the process by which ever-changing generation requirements are assigned to available power plants. It is used by utilities, regional transmission organizations, independent system operators (ISOs), and others to assign lowest-cost generation in day-ahead and real-time markets. A schedule of costs versus production levels is developed for each available generator, and – theoretically – plants are dispatched in order of increasing cost until generation requirements are met. (In competitive electricity markets, this schedule reflects unit offers bid by generators, and presumably reflects the variable costs of a generation unit. In regulated markets, the schedule represents average generation costs.) But practically, dispatch is more complicated, and does not simply follow a cost-based merit order. Several constraining factors must be accounted for, which extend dispatch beyond simply allocating generation to plants with the lowest variable costs or unit offers. These include:

- Contractual obligations
- Environmental regulations
- Plant availability, operational limits, ramp rates, and start-up costs
- Reliability requirements
- Transmission constraints

2.1. Dispatch model description

While utilities and ISOs develop complicated optimization models based on plant-level data to determine lowest-cost dispatch, we present a simpler one here (Figure 1). We develop our model in Excel, and classify generation in California according to 16 power plant types that we dispatch according to an ordered set of rules to meet electricity demands. Each power plant type is characterized by cumulative capacity (in MW) or generation (in MWh), and average CO_2 emissions, cost parameters, and heat rates.

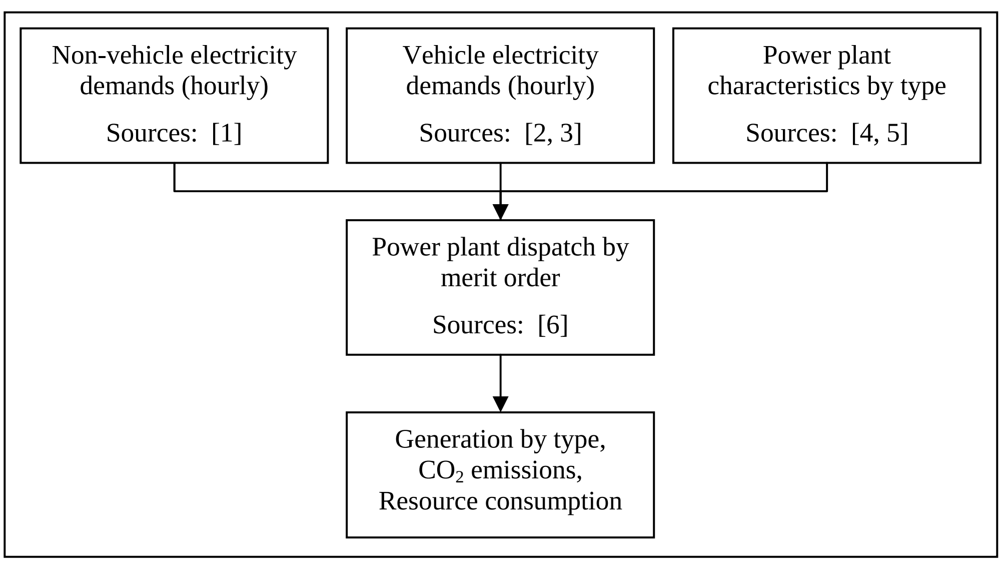

Figure 1. Schematic of dispatch model.

The power plant types included in our model are listed in merit order in Table 1, and are classified as *must-run* or *dispatchable*. They represent aggregated data from 2004 from the EPA's 2006 eGRID database [4]. Must-run plants include baseload coal and nuclear generation, firm imports, and renewables (Some biomass and solar power plants in California use natural gas as a supplemental generation resource. Emissions associated with those power plant types come from the natural gas contribution). All other plants, including system imports, are dispatched in the order listed.

The model can dispatch each power plant type up to its full available capacity in a given hour. If demand is not met by one type of plant, the model moves through the queued plant types, dispatching generation until demand is satisfied. Plant availability accounts for resource availability and forced and scheduled plant outages, derived from historical data from the Generating Availability Data System [7]. Hydroelectric generation and imports are modeled as energy constrained – rather than capacity constrained – and available capacity varies on an hourly basis.

Table 1. Power plant types, in dispatch order, included in dispatch model.

		MW[a]	GWh[a]	Variable cost[b] (¢/kWh)	CO2 emissions[a] (g/kWh)
Must-run	**Coal**	439	--	--	1,018
	Nuclear	4,577	--	--	0
	Firm imports	--	39,311	--	750
	Wind	2,041	--	--	0
	Biomass	2,268	--	--	172
	Solar	396	--	--	150
	Geothermal	2,732	--	--	0
Dispatchable	**Hydro**	--	33,311	--	0
	Other	83	--	0.3	517
	NW imports	--	21,447	4.4	333
	NG Combined Cycle (NGCC)	17,555	--	7.3	562
	SW imports	--	21,707	8.1	652
	NG Steam Turbine (NGST)	11,000	--	8.4	585
	Oil	461	--	8.7	912
	NG Gas Turbine (NGGT)	10,000	--	9.4	605
	New capacity	--	--	9.4	652

[a] Data for instate power plant capacity and generation from eGrid2006 database [4]. Imports estimated from Alvarado (2006) [5].
[b] Capital and operating cost estimates from assumptions from the 2006 Annual Energy Outlook [6], based on heat rates from eGrid database [4].

Further details regarding the dispatch of specific plant types are listed below:

- Thermal plants (*Coal*, *NG*, *Other*, and *Oil*) – Available generation (on an annual basis) is limited by historical scheduled and forced outages [7]. Scheduled outages are distributed evenly on an hourly basis throughout months of low demand (November–April), and forced outages are distributed evenly throughout the year.
- *Nuclear* – California has two nuclear plants. We assume they operate at full capacity except during scheduled outages. Each plant has one scheduled outage that keeps it offline entirely for 40 consecutive days. The outages take place during winter and spring months, and do not overlap.

- *Firm imports* – Firm imports represent out-of-state generation from facilities owned by California utilities. Among the nine plants represented in this category, seven are coal facilities, one is a nuclear plant, and one is hydroelectric [5]. They are assumed to be baseload facilities, and run continuously throughout the year.
- *Wind* – Availability varies randomly, constrained by ramp rates to limit variation in generation from one hour to the next. The average capacity factor is 0.29.
- *Solar* – Availability varies from 8 AM to 6 PM, peaking at 100% at 2 PM.
- *Biomass, Geothermal* – Biomass and geothermal generation are operated continuously at their historical annual capacity factors, 40.6% and 50.2%, respectively.
- *Hydro* – Hydro is an energy constrained resource that is assumed to follow demand. We calculate a demand threshold above which hydro is dispatched to full availability and below which availability is scaled by demand. The threshold constrains annual energy generation.
- System imports (*NW imports*, *SW imports*) – Availability follows the hourly imports profile for 2005 [8], and is constrained by 2005 annual imports. NW system imports are predominately from natural gas (46%) and hydro plants (50%), and include some coal (4%). SW system imports are from natural gas (96%) and coal (4%) [5].
- *New capacity* – New capacity is modeled as *SW imports*, and serves as a proxy for new capacity that would be needed to supply additional demands from some fuel pathways. Note that the CO_2 emissions from these categories exceed those from in-state natural gas generation that is otherwise on the margin.

Our current representation of California's electricity system in an aggregate form limits the scope of our model, but it provides an adequate tool to compare the impact of alternative fuel pathways on the electricity grid. While we continue to work on the model and improve its representation of the electricity sector in California (see *Section 5*), in its current form it offers valuable insights from which to compare fuel pathways.

2.2. California electricity demand

We model hourly electricity demands as the sum of hourly non-vehicle electricity demands and hourly vehicle electricity demands, developed as described in *Section 3*, below. Total required electricity generation is equal to this sum scaled by a factor of 1.08, to account for average transmission and distribution losses (assumed to be 8%).

Previously, we have projected energy demands in California through 2050 for five scenarios related to economic, efficiency, population, and service demand parameters [1]. The projections include hourly electricity demands for each of five economic sectors: residential, commercial, industrial, agricultural, and 'other'. We use hourly electricity demands for 2007 from the baseline scenario in this model. (The baseline scenario assumes each of the relevant parameters follows recent historical and projected near-term trends).

2.3. Model output

The model allocates generation among the 16 power plant types on an hourly basis to meet demand (accounting for transmission and distribution losses).

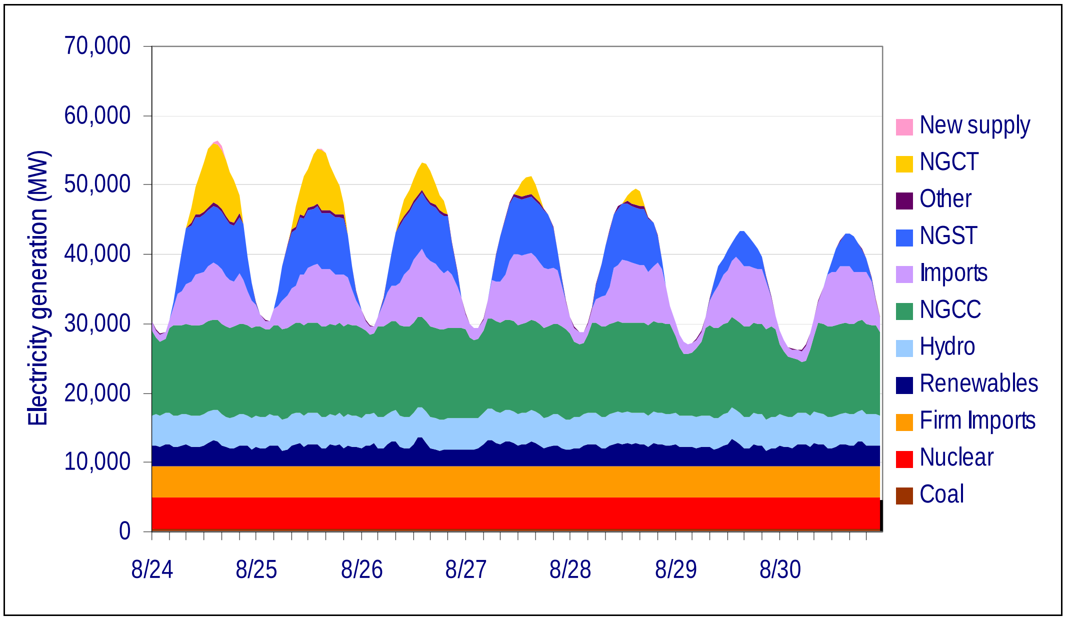

Figure 2. Dispatch model output for the week of 8/24/07 (no added vehicle electricity demand).

Figure 2 shows a sample output for the case of no added vehicle electricity demands (i.e., only gasoline vehicles). The figure depicts seven days worth of generation, including the projected peak demand day, August 24th. As mentioned above, coal, nuclear, and firm imports are assumed to be baseloaded resources. Renewables and hydro generally vary on an hourly basis, although hydro generation appears relatively constant in this case due to the high levels of demand. Natural gas-fired generation primarily serves on the margin, through one of the three instate generation resource types (natural gas combined-cycle (NGCC), natural gas steam turbine (NGST), or natural gas gas turbine (NGGT)), or through imports. Coal or hydro imports, or in-state oil-fired generation, might be on the margin occasionally, as well.

2.4. Model validation

Figure 3 compares output from backcast runs of our dispatch model to historical data for the years 2002-2005. Average generation by resource over the four year period as predicted by the model matches well with the data. This implies that the types of results that we are interested in (electricity cost and annual CO_2 emissions) should be relatively accurate.

Figure 4 elaborates on the averages depicted in Figure 3. The figure shows the ratio of total generation (MWh) predicted by our model to historical generation data from the CEC, for five generation types and total overall generation, for each of the four years included in Figure 3. (Note that we did not force total generation to match historical data in our backcasts.)

The figure illustrates a somewhat noticeable variation between our model estimates and historical data on a year-to-year basis. For example, our model overestimates nuclear generation by 18% in 2004, and underestimates hydroelectric generation by 16% in 2005. We do not include probabilistic treatment of outages, precipitation, or other factors that might influence availability in our model, and thus do not account for a particularly dry year, or prolonged maintenance, for example. But the yearly variations average out, and our model accurately represents average conditions in California, as seen in Figure 3.

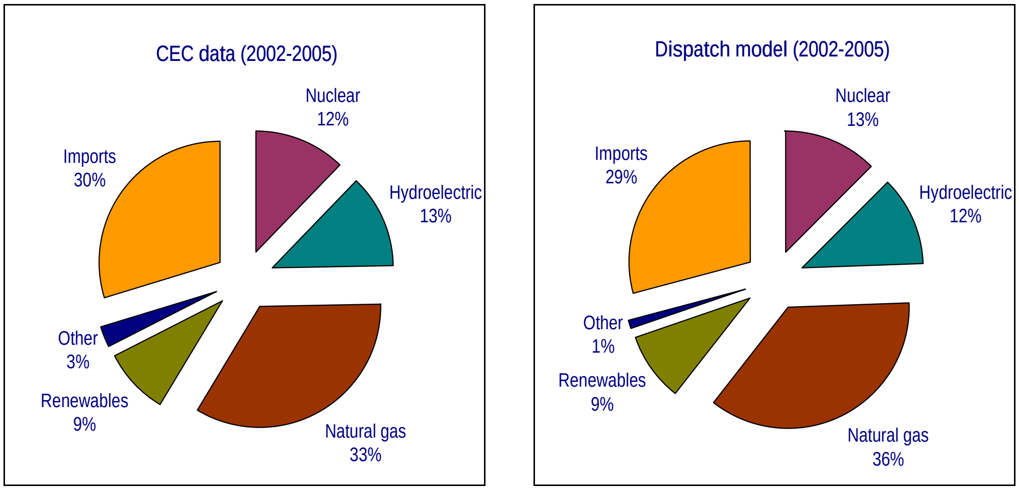

Figure 3. Average California electricity generation by resource from 2002-2005: Historical data (left), and as predicted by our dispatch model (right).

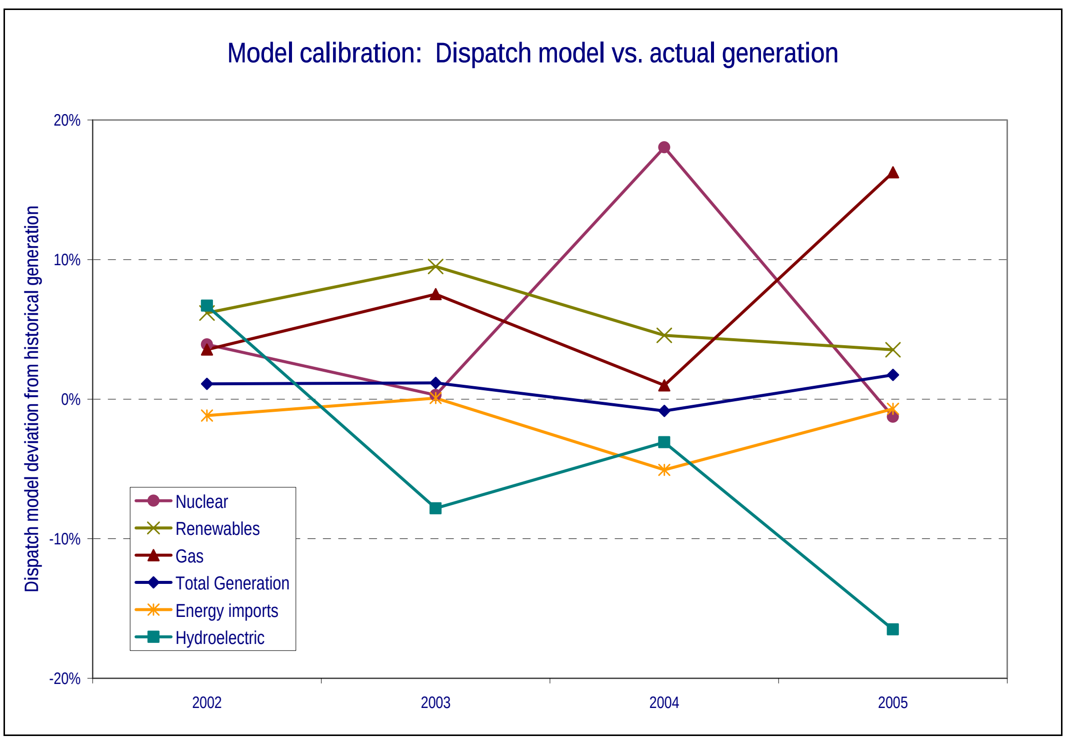

Figure 4. Deviation from historical generation of dispatch model results, by resource.

2.5. Average vs. marginal emissions

The dispatch model allows us to directly compare a system with added demand from transportation to a baseline, business-as-usual case. Thus, we are able to determine the marginal CO_2 emissions from electricity generation attributable to the new demands.

Figure 5 illustrates the dispatch model output for the same week shown in Figure 2, but with additional electricity demand for vehicles. In this case, we replace the entire vehicle fleet with fuel cell vehicles using liquid hydrogen produced at centralized natural gas steam-methane reformation (SMR) plants. Note that the electricity demand for fuel is significant, increasing peak demands above the capability of in-state generation and average import levels (see *Section 3* for a discussion of fuel pathway electricity demands).

Average emissions are determined by taking the generation-weighted average of emissions for all electricity generated in the period of interest. Subtracting generation for non-vehicle demands and taking the weighted average of emissions for the additional electricity generation attributable to the additional transportation-related demands yields the marginal electricity emissions (Figure 6). Note that the additional demand from vehicles will change average emissions compared to the baseline (no vehicle electricity demand), as well.

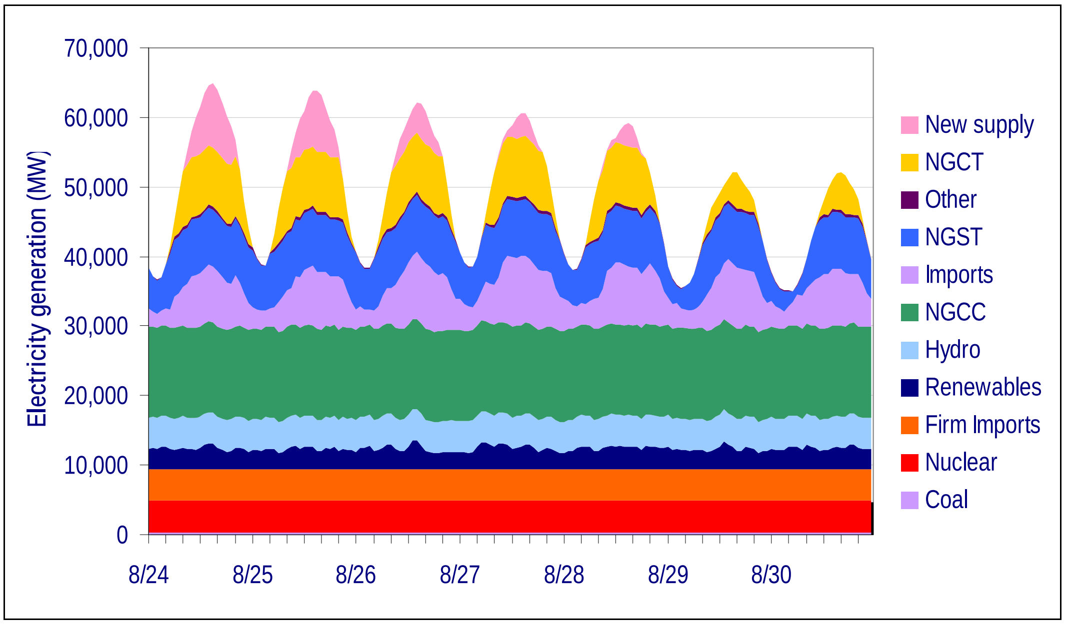

Figure 5. Dispatch model output for week of 8/24/07 (centralized SMR, liquid H_2 pathway).

The use of marginal versus average generation in determining fuel pathway emissions is a somewhat contentious issue, but is a very important one from a policy perspective. In California, for example, with the recent adoption of greenhouse gas emissions limits (AB 32) and the Low Carbon Fuel Standard, allocating emissions to fuels and other energy uses gains significance. But how should electricity emissions be accounted for in the transportation sector? Can an electron from a particular power plant be attributed to a particular end use?

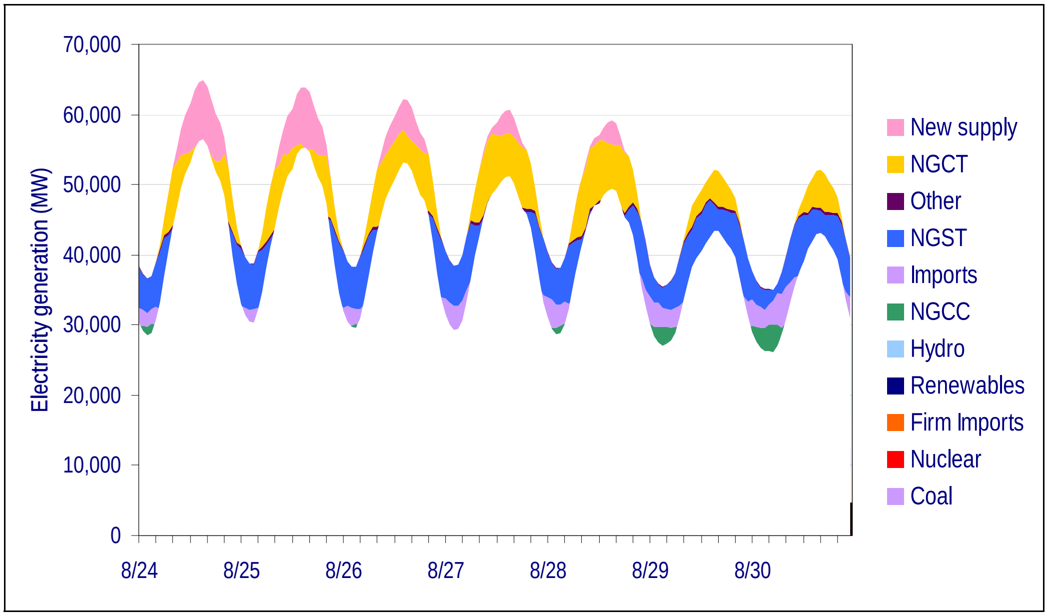

Figure 6. Marginal generation attributable to added vehicle demands (centralized SMR, liquid H_2 pathway).

The obvious answer to the latter question is no. And, as a transition to alternative fuels takes place – one that is likely to take decades – the electricity sector will evolve accordingly (based on total energy demand and demand timing) and the distinction between 'baseline' and 'marginal' demands will blur. From this perspective, attributing average electricity emissions to all demands only seems reasonable. But in our static analysis presented here, where we compare distinct systems with and without additional demands from vehicles, it makes sense to consider marginal emissions. In the system we have defined, the additional emissions are directly attributable to the marginal demands we add to the system, after all.

An important point to emphasize is that the issue is one of *allocating* emissions. Combined emissions from the electricity and transportation sectors will be the same for a given pathway regardless of the allocation method; it is a matter of the fraction of emissions charged to each sector (and, in a greenhouse gas-constrained future, who pays for them).

We focus on marginal emissions in the well-to-wheel results we present in *Section 4* because we feel they most accurately represent the differences among the presumed systems we model. But we recognize the contentious nature of the issue, one that is likely to become more prominent as greenhouse gas limits are more readily implemented.

3. Vehicle and fuel pathways

We develop hourly electricity demands for eight alternate vehicle and fueling pathways and add them to the projected hourly non-vehicle electricity demands. For each vehicle and fuel scenario, we assume the pathway encompasses all light-duty vehicle demand (i.e., each pathway fuels 100% of vehicle miles traveled). We derive annual vehicle electricity demand requirements (MWh) from the H2A analysis of the U.S. DOE and translate them into hourly demands based on assumed timing profiles [2].

Two factors distinguish among the pathways in the dispatch modeling: total demand, and timing of demand. A given pathway with a set total electric energy requirement could have very different generation resources supplying it on the margin, depending upon the timing of the load profiles. Variable timing profiles could then lead to noticeable variation in the associated costs, emissions, and resource use for a single pathway (e.g., onsite electrolysis). This is an important sensitivity to recognize, and is one that we will investigate in more depth in future work (see *Section 5*). But for simplicity in our presentation here, we assume a single timing profile for each scenario.

Table 2 lists the vehicle and fuel pathways included in our analysis, the electricity demands for each, and the hourly load profile that describes the timing of electricity demand. In addition to the baseline case, which takes the current light-duty vehicle fleet in California, we consider substituting battery electric, plug-in hybrid, and fuel cell vehicles (FCV). For the fuel cell vehicle case, we consider six hydrogen pathways: onsite electrolysis, onsite natural gas steam methane reformation (SMR), three centralized SMR pathways, and a centralized coal pathway with carbon sequestration and storage. Fuel cell vehicles using hydrogen from onsite electrolysis require more than twice as much electricity per-mile as the next most electricity-intensive pathway: BEVs. Plug-in hybrids and FCVs using hydrogen transported as a liquid also include a significant electricity input. Electricity demands for the remaining pathways are relatively small, limited mostly to compression and auxiliary requirements at refilling stations.

Table 2. Vehicle and fuel pathways included in analysis.

Vehicle	**Fuel economy (mpgge)**	**Fuel**	**H_2 pathway**	**Electricity demand** kWh/mi	**Electricity demand** kWh/kg	**Electricity demand timing**
Conventional	24.8	Gasoline	--	--	--	--
BEV	86.8	Electricity	--	0.384	--	Load-leveling
PHEV20[a]	50.0	Electricity	--	0.267	--	Load-leveling
FCV	57.5	H_2	Onsite electrolysis	0.855	49.2	Load-leveling
FCV	57.5	H_2	Onsite SMR	0.051	2.9	Follows gasoline refueling profile
FCV	57.5	H_2	Central SMR, tube trailer	0.068	3.9	Production & distribution: Continuous (24/7) Station demands: Follow gasoline refueling
FCV	57.5	H_2	Central SMR, liquid truck	0.240	13.8	
FCV	57.5	H_2	Central SMR, pipeline	0.063	3.6	
FCV	57.5	H_2	Central coal w/ CCS, pipeline	0.054	3.1	

[a] PHEV20 assumes 40% of VMT supplied in all-electric mode.
Sources: [2, 3]

The table also summarizes our assumptions regarding electricity demand timing for vehicle use. The direct electricity pathways (BEV, PHEV20s, and onsite electrolysis) are modeled as load-leveling demands. While this scenario assumes ideal charging behavior from consumers, a large penetration of electric vehicles (as modeled here) would presumably induce action from utilities to manage demand timing and create the proper incentives. Other timing profiles can contribute to peak demands and could increase pathway emissions. Electricity demand timing for onsite SMR follows the hourly gasoline refueling profile in California. For each of the centralized pathways, we assume that electricity demands associated with production and distribution are continuous, and that those related to station demands follow the gasoline refueling profile.

Figure 7 illustrates the electricity requirements and demand timing for each of the pathways for the projected peak demand day (8/24). Demand for the load-leveling pathways peaks during nighttime, when non-vehicle electricity demand is low. The minimum point in these pathways corresponds to peak non-vehicle electricity demands (around 4 PM in this case). The minimum demand for onsite electrolysis is about 17 GW, representing a corresponding increase in peak electricity demand for the system. Battery electric vehicles almost perfectly load-level the system, while demand from plug-in hybrids is insufficient to entirely fill in troughs in non-vehicle demand (on a peak summer demand day). Electricity demand for the centralized SMR pathway with liquid hydrogen transport is relatively flat, due to the assumption that production and liquefaction electricity demands are distributed evenly throughout the day. The remaining pathways essentially follow the gasoline refueling profile – since electricity demands for production and distribution are minimal – leading to a daytime peak that coincides with peak non-vehicle electricity demand.

Load-leveling demand could transform the electricity sector by reducing the need for peaking power plants that tend to be more expensive, inefficient, and polluting than baseload and intermediate power plants. In turn, it might encourage developing more baseload plants – generally coal or nuclear – which could shift the average generation mix.

The annual load factor, defined here as the ratio of average hourly load to annual peak-hour load, serves as a measure of the degree of variability in load (demand plus transmission and distribution losses). Load factors for each of the vehicle and fuel pathways are listed in Table 3. Load-leveling pathways (most notably FCVs using hydrogen from onsite electrolysis) increase the load factor relative to the base case. This implies less variability among average and peak demands, and consequently, less need for expensive, inefficient peaking power plants. *Central SMR*, *liquid truck* also increases the load factor noticeably, by adding significant, essentially constant, demands to the system.

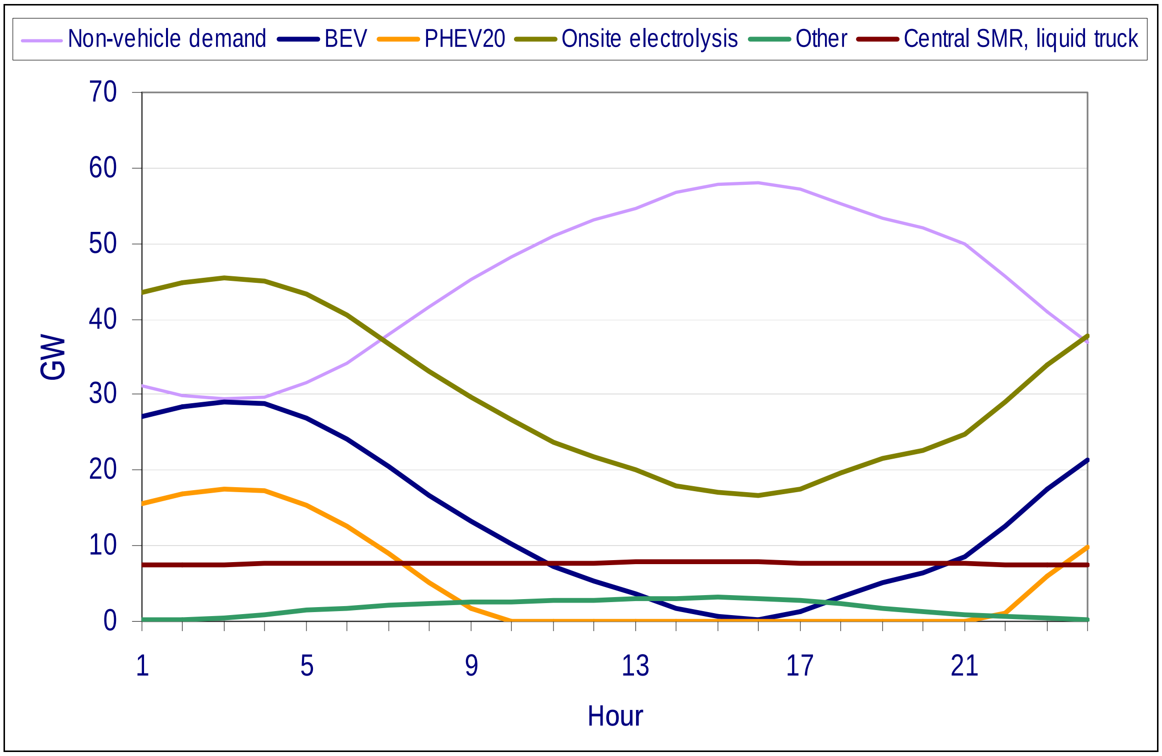

Figure 7. Vehicle pathway electricity demand profiles for the peak electricity demand day.

If the timing of added vehicle demands is coincident with non-vehicle electricity demand (i.e., they peak during the same hours), it exacerbates demand variability and the load factor declines. This is seen (only minimally) in the *onsite SMR* pathway, in which vehicle-related electricity demands peak during the day. If we had attributed the same timing to electricity demands from *onsite electrolysis,* the difference would be much more apparent.

Table 3. Annual load factors by pathway.

Pathway	**Peak load (GW)**	**Average load (GW)**	**Minimum load (GW)**	**Load factor**
Conventional (no vehicle electricity)	56.4	34.3	22.0	60.8%
BEV (load-leveling)	62.1	48.9	39.8	78.8%
PHEV20 (load-leveling)	56.4	40.2	31.4	71.1%
Onsite electrolysis (load-leveling)	81.7	66.9	56.2	81.9%
Onsite SMR	59.7	36.2	22.6	60.7%
Central SMR, tube trailer	60.0	36.9	23.5	61.5%
Central SMR, liquid truck	64.9	42.7	29.5	65.9%
Central SMR, pipeline	59.9	36.7	23.3	61.3%
Central coal w/ CCS, pipeline	59.5	36.3	23.0	61.1%

4. Dispatch model results

The dispatch model allows us to quantify the emissions and resource consumption associated with the vehicle pathways.

Figure 8 illustrates the generation required for each pathway. Non-vehicle electricity demands (in green) are projected to require 300,418 GWh in 2007 (demand plus losses). Adding vehicle-related electricity almost doubles generation requirements for *onsite electrolysis.* Substituting BEVs for conventional vehicles increases annual electricity generation by 128,336 GWh, or 43%. *Central SMR*, *liquid truck* and *PHEV20* also increase electricity requirements significantly, by 25% and 17%, respectively. The remaining pathways increase generation requirements by 6%-8%.

The figure also depicts the average and marginal CO_2 emission rates from electricity generation for each pathway. Average CO_2 emissions increase with electricity demand, as an increasing share of natural gas-fired generation to supply marginal demands dilutes the share of non-emitting nuclear, hydro, and renewable resources in the generation mix. Marginal emissions are higher – roughly equal to the emission rate of an average natural gas-fired power plant (incidentally, 600 g CO_2/kWh is about equal to the average emission rate of the U.S. grid mix). Emissions are especially high for *onsite electrolysis*, which requires significant imports from the southwest (*new capacity*), bringing additional coal generation.

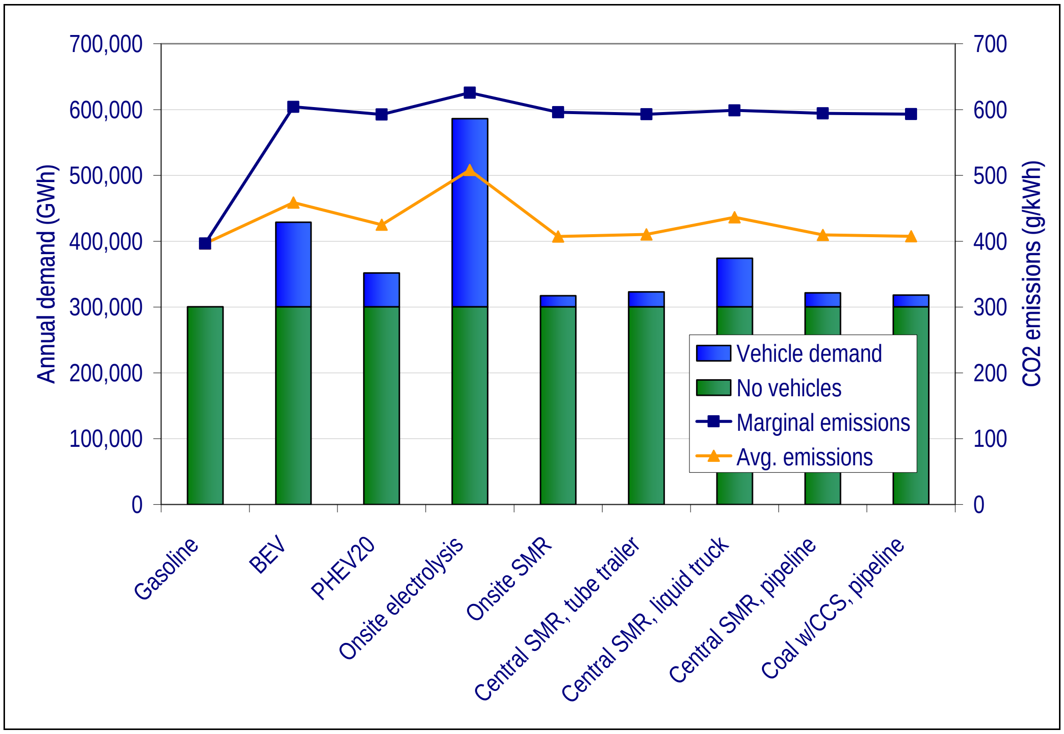

Figure 8. Required electricity generation by pathway, and associated emissions.

Attributing marginal electricity emissions to the transportation pathways yields the CO_2 emissions shown in Figure 9. The figure divides emissions by source, with those coming from electricity generation in green. All of the pathways except *onsite electrolysis* result in an improvement over conventional vehicles.

If we attribute average emissions to the pathways, the electricity portion of emissions – the green portion of the bars – would be about 50% less. That would lead *onsite electrolysis* to appear to be an improvement over conventional vehicles. Recall, though, that the issue is *allocating* emissions. The emissions attributed to electricity generation for non-vehicle demands would be correspondingly higher, but combined emissions for electricity and transport remain the same.

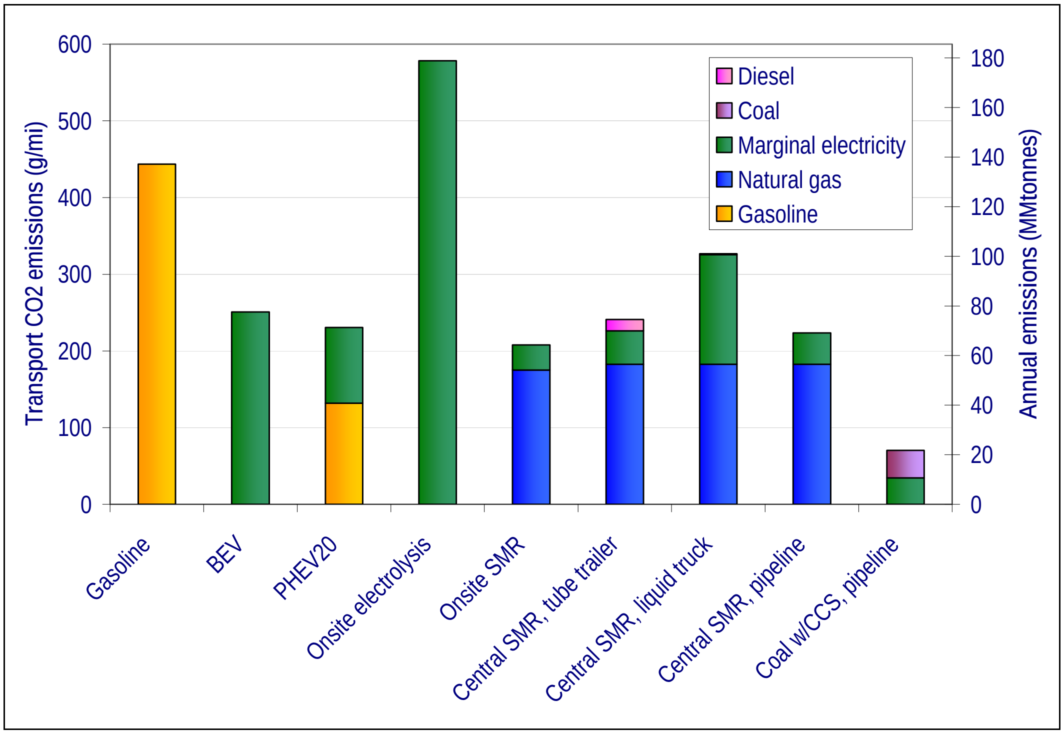

Figure 9. Pathway well-to-wheels CO_2 emissions by source.

Natural gas consumption associated with each pathway is an important consideration, as well, as domestic supplies tighten and imports are projected to increase [9].

Natural gas usage associated with each pathway for fuels and electricity generation is illustrated in Figure 10. In the base case, 1,379 trillion Btu of natural gas is used for electricity generation. A similar amount, 1,455 trillion Btu, is projected to be consumed in all other sectors in 2007 (non-transport and non-electricity generation) [1]. *Onsite electrolysis* triples natural gas consumption for vehicles and electricity generation (about doubling total natural gas consumption in the state). *BEV* almost doubles consumption for vehicles and electricity generation, increasing total consumption by 47%. The hydrogen pathways utilizing natural gas as a feedstock increase total consumption by 36%-58%, while the coal pathway increases total consumption the least, by 6%.

Interestingly, hydrogen pathways that use natural gas as a feedstock may actually reduce natural gas consumption, compared to electricity-intensive pathways. It is a consequence of natural gas almost entirely providing for electricity generation on the margin, and a difference of conversion efficiencies. The conversion of natural gas to hydrogen via SMR is about twice as efficient as generating electricity from natural gas (68% for centralized SMR, compared to 32% for average natural gas-fired power plants in California). As more efficient natural gas power plants are constructed, the discrepancy will decrease (some combined-cycle plants can achieve efficiencies above 50%, and fuel cell/gas turbine hybrid power plants can approach 70% efficiency). It may diminish entirely in the future, as the mix of power plants becomes more efficient, especially considering the higher fuel economy of BEVs relative to FCVs.

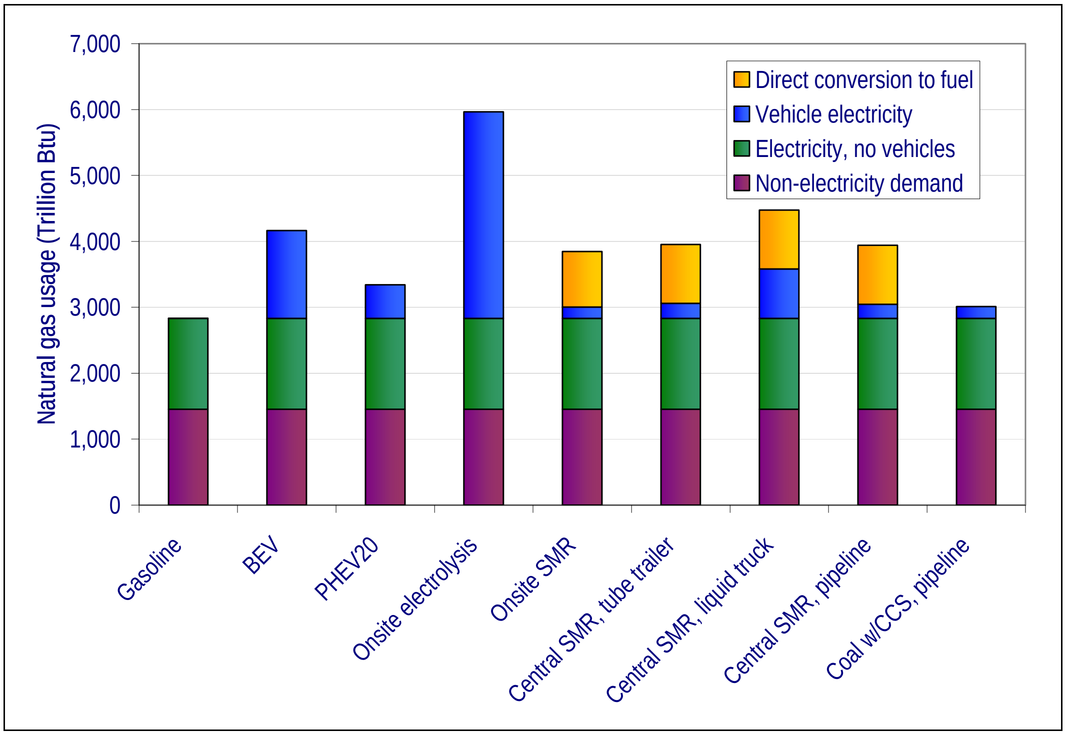

Figure 10. Natural gas usage for fuels production and electricity generation, by pathway.

5. Conclusions

This paper describes an electric sector dispatch model and the preliminary application of the model to investigate the impact of electric and fuel cell vehicles on the electricity sector. It provides a useful tool for investigating the response of the electricity system to changing demand load profiles, and matches well with how the current system is operated. Specific findings from this initial application include:

- Additional electricity for supplying transportation fuels will vary in quantity and timing
- Emissions and the evolution of electricity grid (e.g., the need for new plants, the type of plants, load factor) depend on these two issues (quantity and timing)
- Electricity and natural gas usage can vary widely for different electric-drive vehicle pathways
- How emissions are allocated will affect the distribution of emissions among sectors, but not total emissions, unless sector-specific emissions limits are imposed
- Given the efficiency of the current mix of power plants in California, electrolysis is not an efficient use of natural gas

6. Future work

We are continuing to develop the dispatch model and improve its representation of the California electricity sector. Among other improvements, we hope to:

- Acquire data that will allow for a better representation of each generation resource, especially intermittent sources such as wind and hydro, and imports,

- Extend the model into the future to investigate transitions to alternative vehicles and fuels. This will include modeling capacity expansion and retirements, accounting for total demand and demand timing,
- Treat availability stochastically,
- Better represent costs and pricing, including those for capacity expansion, emissions, reliability, and reserves,
- Include hydrogen and electricity co-production pathways.

As we develop the model, we will apply it to investigate a number of issues associated with fuels and electricity interactions, including:

- Timing of demand (e.g., daytime vs. nighttime vs. load-leveling recharging of electric vehicles),
- The effects of various electricity supply scenarios (e.g., adding significant intermittent renewables capacity, simulating the proposed Renewables Portfolio Standard in California),
- The implementation of carbon mitigation policies, through taxes, caps or other mechanisms,
- Opportunities for hydrogen and electricity co-production.

7. Acknowledgements

We would like to thank the California Energy Commission and the sponsors of the Hydrogen Pathways Program and the Sustainable Transportation Energy Pathways (STEPS) Program at UC Davis for financial support.

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9. Author biographies

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Ryan is a PhD student in Civil and Environmental Engineering at the University of California, Davis. His research interests revolve around the integration of hydrogen supply systems with other energy sectors, and the associated impacts on economics, the environment, reliability, and resource use. His current work focuses on co-production of hydrogen and electricity, and interactions between the hydrogen, natural gas, and electricity sectors in California. Ryan served as technical lead for UC Davis' Team Eno in NHA's 2004 Hydrogen Student Design Competition, and participated on the Societal Benefits topic team for the California Hydrogen Highway Network. He received a Master's degree in Civil Engineering at UC Davis, and holds a B.S. in Structural Engineering from the University of California, San Diego.

Dr. Christopher Yang
Christopher Yang is a Research Engineer at the Institute of Transportation Studies at the University of California, Davis and co-director for the "Infrastructure Modeling" Track within the Sustainable Transportation Energy Pathways (STEPS) Program. His primary research focus is on modeling of hydrogen production and distribution infrastructure in order to understand how a hydrogen economy might evolve over time. Other research interests include interactions between fuel and electricity production in a hydrogen economy.

Dr. Joan M. Ogden
Dr. Joan Ogden is Professor of Environmental Science and Policy at the University of California, Davis and Co-Director of the Sustainable Transportation Energy Pathways (STEPS) Program at the campus's Institute of Transportation Studies. Her primary research interest is technical and economic assessment of new energy technologies, especially in the areas of alternative fuels, fuel cells, renewable energy and energy conservation. Her recent work centers on the use of hydrogen as an energy carrier, hydrogen infrastructure strategies, and applications of fuel cell technology in transportation and stationary power production.