Impacts of Electric-drive Vehicles on California's Energy System

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Abstract

Although the transportation and electricity sectors are largely independent today, a shift away from the current convention could lead to increased integration of the two sectors. If alternatives such as battery-electric vehicles, hydrogen, or plug-in hybrids penetrate the market significantly, they would add additional demands to the electricity system with unique load profiles. Estimating the economic, environmental, and resource impacts of these new fuel pathways requires understanding the broader energy systems-context within which their respective supply pathways exist. Specifically, there are important interactions with the dynamic electricity grid. We develop a set of energy demand scenarios for the State of California through 2050, and characterize the electricity sector using a dispatch model to simulate the operation of the grid on an hourly basis. We consider the impact on hourly electricity demand of several electric-drive vehicles and hydrogen pathways – including production from electrolysis and other methods, and compression, liquefaction and refueling station demands. We also investigate impacts associated with varying the time-of-day of these demands. The outputs quantify greenhouse gas emissions and resource use associated with the scenarios, providing useful insight regarding a transition towards electric-drive vehicles in near-term and emerging markets.

Keywords: dispatch, power grid, plug-in hybrid, fuel cell, hydrogen

Abbreviations

BEV	Battery electric vehicle
CA	California
CAISO	California Independent System Operator
CCS	Carbon capture and storage (sequestration)
CEC	California Energy Commission
CO_2	Carbon Dioxide
DOE	U.S. Department of Energy
eGRID	Emissions and Generation Resource Integrated Database
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
FCV	Fuel cell vehicle
g	gram
GREET	Greenhouse Gases, Regulated Emissions and Energy Use in Transportation
GW	Gigawatt
GWh	Gigawatt-hour
HEV	Hybrid electric vehicle
ISO	Independent System Operator
ITS	Institute of Transportation Studies
kg	kilogram
kWh	kilowatt-hour
LDC	Load duration curve
mi	mile
mpg	miles per gallon
mpgge	miles per gasoline gallon equivalent
MW	Megawatt
MWh	Megawatt-hour
NG	Natural gas
NGCC	Natural gas combined-cycle (power plant type)
NGCT	Natural gas gas turbine, or Natural gas combustion turbine (power plant type)
NGST	Natural gas steam turbine (power plant type)
NW Imports	Electricity imported from the Pacific Northwest
PHEV	Plug-in hybrid vehicle
PHEV20	Plug-in hybrid vehicle with 20-mile all-electric range
SMR	Steam-methane reformation of natural gas
STEPS	Sustainable Transportation Energy Pathways Program
SW Imports	Electricity imported from the Southwest
UC Davis	University of California, Davis
VMT	Vehicle-miles traveled

1. Introduction

In today's energy system, electricity and transportation fuels are delivered via distinct supply chains that are largely isolated from one another. But this paradigm is to change. A shift away from conventional internal combustion engines or petroleum-based fuels could lead to new interactions between the sectors; indeed, electricity and fuels supplies may "converge" into an integrated system.

The implications could be significant, and might lead to profound changes in the way energy is supplied. For one, a shift is likely to generate additional electricity demands from the transportation sector. This connection is obvious for battery-electric vehicles (BEV) or plug-in hybrid vehicles (PHEV), but is apparent for hydrogen, as well. Electricity demands are high for some hydrogen pathway components, including production from electrolysis, or liquefaction and compression requirements for hydrogen distribution. The impacts of these new ("marginal") demands on the electricity grid, 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.

Direct interaction between the sectors in terms of increased electricity demand leads to higher consumption and competition for some primary energy resources, including biomass, coal, or natural gas. But a coming-together of the sectors also provides opportunities to improve the efficiency and reliability of energy supply. Electric-drive vehicles may include the ability to feed electricity – either stored in batteries or generated onboard with fuel cells – back to the grid, offering peaking power or ancillary services to the power sector. If fuel cells and hydrogen penetrate the market significantly, opportunities arise for efficiency gains and cost reductions in energy supply by co-producing hydrogen and electricity at the same facility.

The issues and opportunities associated with a convergence of the sectors are vast. In this paper, we begin to explore this topic by investigating the greenhouse gas emissions and resource impacts associated with new transportation electricity demands in California. We develop an electricity dispatch model to compare generation resources used to meet marginal electricity demands for several alternative fuels and vehicle platforms, considering the current grid composition in California, and explore the effect of substituting conventional vehicles with BEVs, PHEVs with 20-mile all-electric range (PHEV20s), or FCVs supplied by various hydrogen pathways.

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.

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 an allocation simply according to cost or unit offers. These include:

- Contractual obligations
- Environmental regulations
- Plant availability, operational limits, ramp rates, and start-up costs
- Reliability and reserve 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 17 power plant types that are dispatched 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.

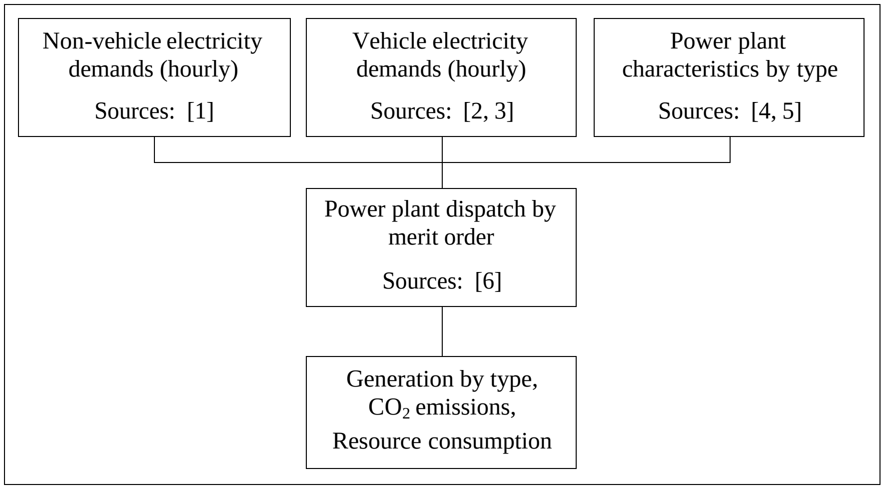

Figure 1: Schematic of dispatch model.

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
	Wind	2,041	--	--	0
	Biomass	2,268	--	--	172
	Solar	396	--	--	150
	Geothermal	2,732	--	--	0
	Firm imports	--	39,311	--	750
	Baseload hydro[c]	--	5,703	--	0
Dispatchable	Peaking hydro[c]	--	30,114	--	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 (NGCT)	10,000	--	9.4	605
	Additional SW Imports	--	--	9.4	652

[a] Data for in-state 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].
[c] Hydro generation data from personal communication with Joseph Gillette at the California Energy Commission, 5/21/2007 [8].

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 for California in 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.

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 per year that keeps it offline entirely for 40 consecutive days. The outages take place during winter and spring months, and do not overlap. The assumption that nuclear plants undergo maintenance each year underestimates nuclear generation in some years, as actual maintenance intervals tend to be closer to 18 months [9].
- *Wind* – Hourly wind profiles for four regions in California are aggregated into a single profile for the State. The wind shapes are derived from average hourly wind speeds using publicly-available anemometer data [8]. The average capacity factor is 0.25.
- *Solar* – Availability varies from 6 AM to 7 PM, peaking at 100% at 1 PM.
- *Biomass, Geothermal* – Biomass and geothermal generation are operated continuously at their historical annual capacity factors, 40.6% and 50.2%, respectively.
- *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.
- *Baseload hydro, Peaking hydro* – Hydro is modeled as an energy-constrained resource based on projected availability for the coming year [8]. Available generation varies on a monthly basis reflecting seasonal river and reservoir levels. *Baseload hydro* runs at constant levels (varying monthly) and reflects run-of-the-river resources and minimum flow requirements from dams. It constitutes about 16% of in-state hydro generation. Distribution of the remaining generation, modeled as *Peaking hydro,* follows demand and is constrained based on monthly hydro availability.
- System imports (*NW imports, SW imports*) – Availability follows the hourly imports profile for 2005 [10], 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].
- *Additional SW imports* – *Additional SW imports* serves as a proxy for new capacity that would be needed to supply additional demands from some fuel pathways that exceed current capacity. Note that the CO_2 emissions from these categories exceed those from in-state natural gas generation that is otherwise on the margin.

Representing the 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 and investigate aggregate emissions and resource usage. 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 plus hourly vehicle electricity demands, developed as described in *Section 3*, below. Total required electricity generation is equal to this sum scaled by a loss factor 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 17 power plant types on an hourly basis to meet demand (accounting for transmission and distribution losses).

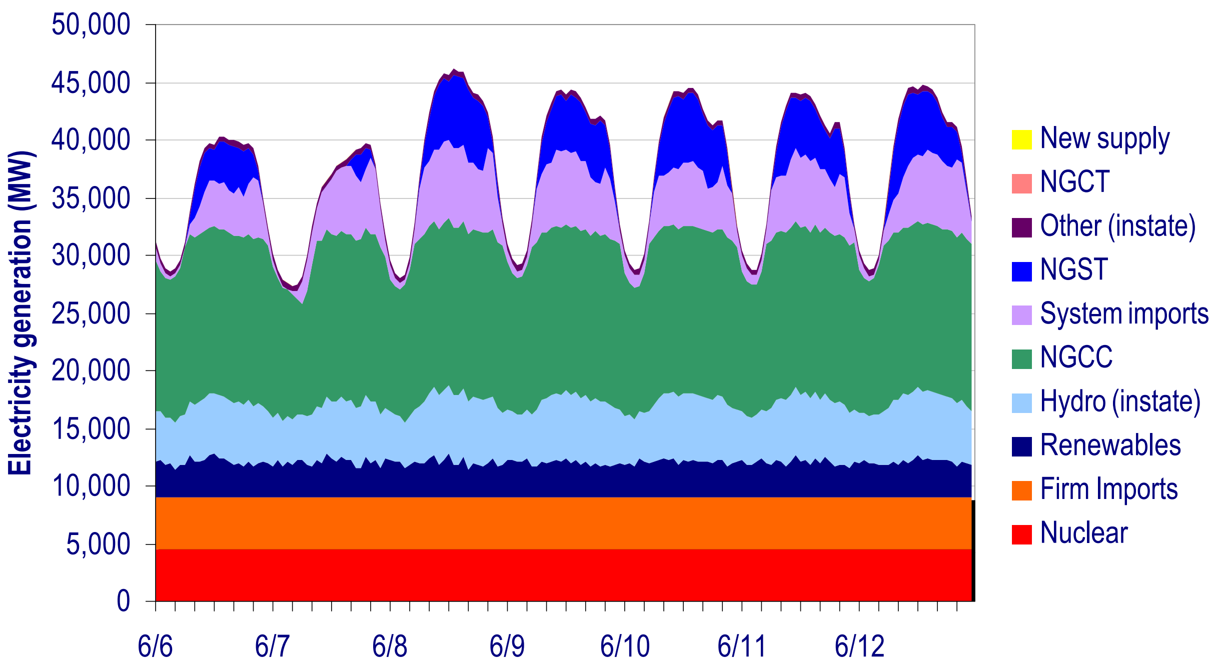

Figure 2: Dispatch model output for the week of 6/6/07 (no added vehicle electricity demand).

Figure 2 shows a sample output for the case of no added vehicle electricity demands. The figure depicts a seven day span and divides generation into ten categories. (Some of the 17 power plant types listed in Table 1 are combined into a broader category. *Renewables* includes wind, solar, biomass, and geothermal, for example.) As mentioned above, coal, nuclear, some hydro, and firm imports are assumed to be baseloaded resources. Renewables and the remaining hydro vary on an hourly basis. Natural gas-fired generation primarily serves on the margin, through one of the three in-state 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 (included in *Other (in-state)*), might be on the margin at times, 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.

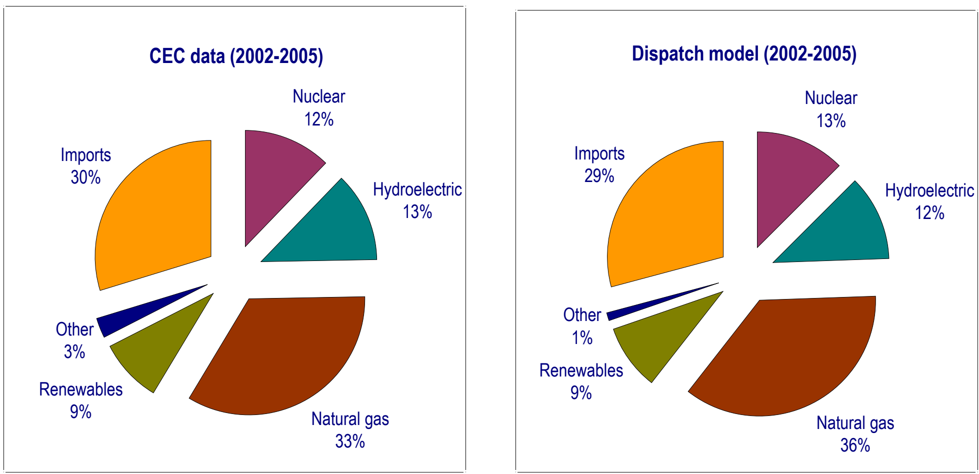

Figure 3: Average California electricity generation by resource from 2002-2005: Historical data (left), and as predicted by our dispatch model (right).

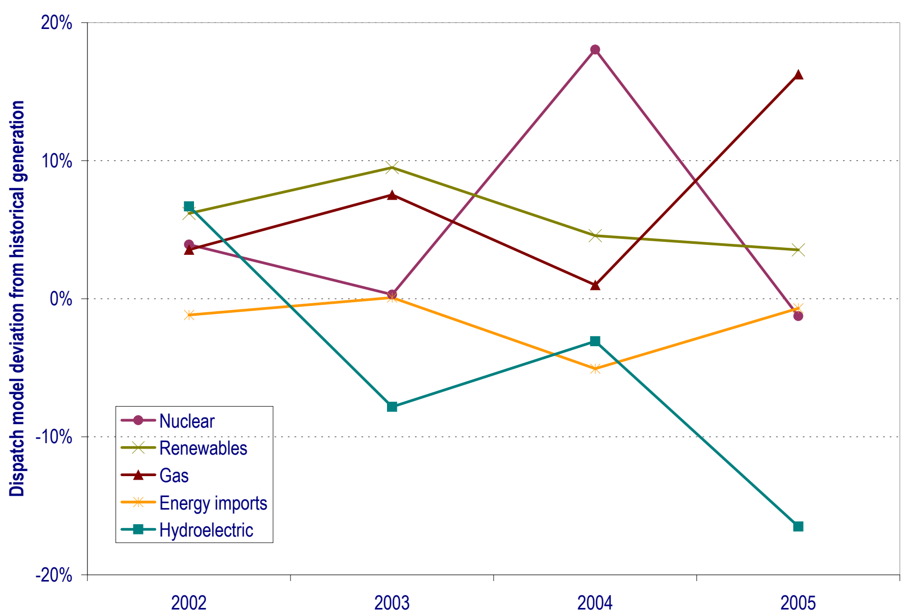

Figure 4: Deviation from historical generation of dispatch model results, by resource.

Figure 4 elaborates on the averages depicted in Figure 3. The figure shows the ratio of total generation predicted by our model to historical generation data from the CEC by generation type 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.)

he 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.

2.5. Average versus marginal emissions

The dispatch model allows us to directly compare electricity generation in a system with added demand from transportation to electricity generation in a baseline system without additional transportation electricity demands. 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 50% of vehicle-miles traveled (VMT) with PHEV20s that are recharged so as to load-level daily electricity demand. In this paper, "load-leveling" vehicle electricity demands are distributed to fill in troughs in the demand profile without consideration of charge times of individual vehicles or consumer behavior. Their ability to level electricity demands depends on the variability in non-vehicle electricity demand and the total vehicle and non-vehicle electricity demands for any given day. In the figure below, the point at which the vehicles can load-level the system is close to 35,000 MW on a low demand day (6/7) and about 40,000 MW on a day with different electricity and vehicle demand profiles (6/12).

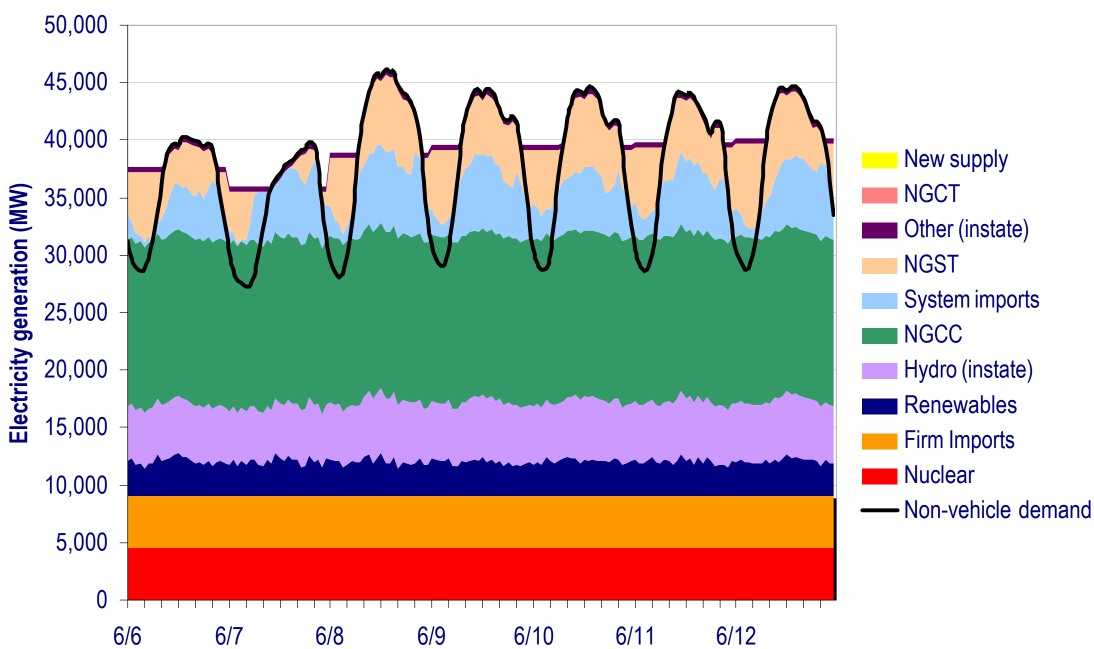

Figure 5: Dispatch model output for week of 6/6/07 (50% PHEV20s, load-leveling).

The power plant types that provide generation for the vehicle electricity demands are depicted in Figure 6. In the week shown, NGCC and NGST provide the majority of electricity, along with some additional imports. The new demand profile shifts hydro generation, as well. With higher "off-peak" electricity demands in the load-leveled system, there is more hydro generation at night than in the baseline case, some of which supplies vehicles. Less hydro is available during daytime hours, and additional fossil resources (mostly NGST) are brought online to meet peak demands. Interestingly, although there is no vehicle electricity demand during the daytime, the marginal demands affect the composition of the grid during the day nonetheless.

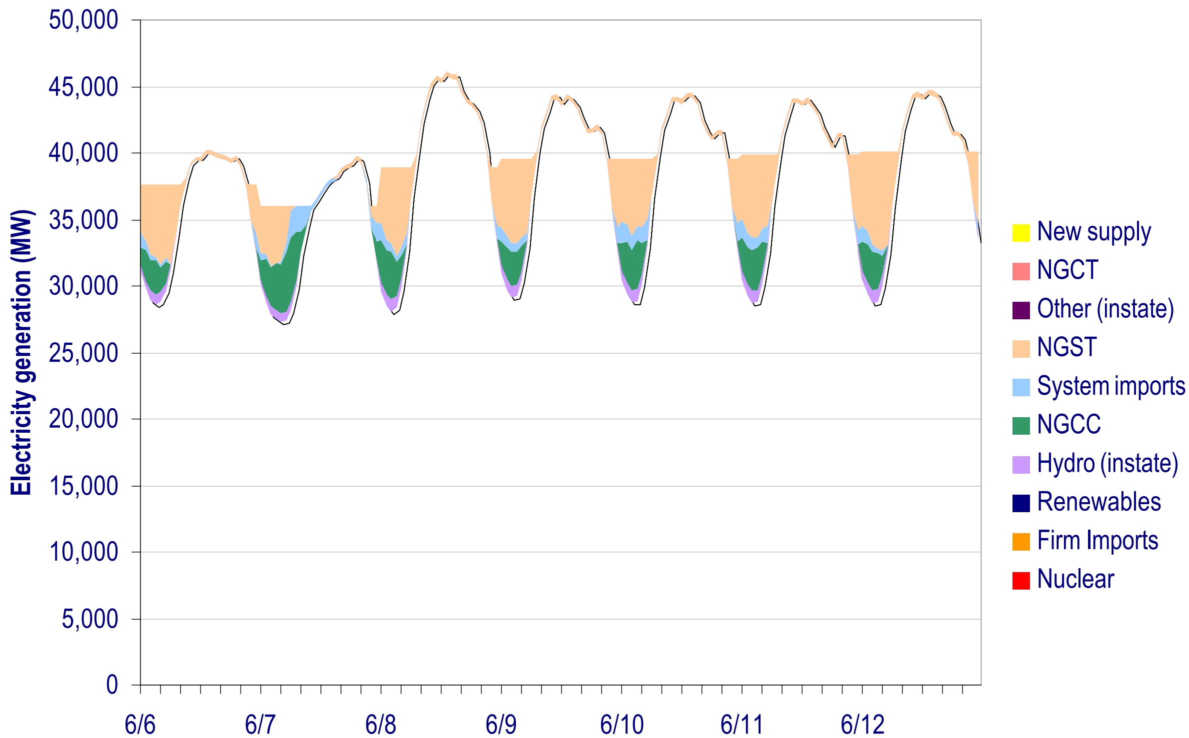

Figure 6: Marginal generation attributable to added vehicle demands (50% PHEV20s, load-leveling).

Average emissions are determined by taking the generation-weighted average of emissions for all electricity generated in the period of interest. Subtracting non-vehicle demands and taking the generation-weighted average of emissions for the remaining electricity load 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.

The use of marginal versus average generation in determining fuel pathway emissions is a somewhat contentious issue, but also 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? The obvious answer to the latter question is no. Additionally, 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. After all, in the system we have defined, the additional emissions are directly attributable to the marginal demands we add to the system.

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 widely adopted.

3. Vehicle and fuel pathway electricity demands

We develop hourly electricity demands for eleven alternate vehicle and fueling pathways at each of four penetration levels (5%, 25%, 50%, and 100% of vehicle-miles traveled) and add them to the projected hourly non-vehicle electricity demands. 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].

The vehicle pathways are distinguished by two energy demand factors in the dispatch modeling: total demand and timing of demand. 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). A given pathway with a set annual electric energy requirement could have very different generation resources supplying it on the margin than the same pathway with the same energy requirement but a different timing profile.

Table 2 lists the vehicle and fuel pathways included in our analysis and the electricity demands for each. In addition to the baseline case, which takes the current light-duty vehicle fleet in California, we consider substituting BEVs, PHEV20s, and FCVs. For the FCV case, we consider four hydrogen pathways: onsite electrolysis, onsite natural gas steam methane reformation (SMR), centralized SMR with liquefied hydrogen transport, and centralized coal with carbon sequestration and storage and hydrogen transport via pipeline. 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 (*Onsite SMR* and *Central coal w/ CCS, pipeline*) are relatively small, limited mostly to compression and auxiliary requirements at refilling stations. Results for these pathways are somewhat similar, and they are referred to collectively as *Non-electricity intensive* H_2 in the results.

The table also summarizes our assumptions regarding vehicle electricity demand timing. The direct electricity pathways (BEV, PHEV20s, and onsite electrolysis) are modeled with both load-leveling demand profiles and daytime demand profiles. The daytime demand profile follows historical hourly gasoline refueling profiles for the State. The load-leveling profile presents a best-case from a cost perspective, and the daytime profile presents a worst case. 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 constant throughout the day, and that those related to station demands follow the gasoline refueling profile.

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[a]
Conventional	24.8	Gasoline	--	--	--	--
BEV	86.8	Electricity	--	0.384	--	Daytime
BEV	86.8	Electricity	--	0.384	--	Load-leveling
PHEV20[b]	50.0	Electricity	--	0.267	--	Daytime
PHEV20[b]	50.0	Electricity	--	0.267	--	Load-leveling
FCV	57.5	H_2	Onsite electrolysis	0.855	49.2	Daytime
FCV	57.5	H_2	Onsite electrolysis	0.855	49.2	Load-leveling
FCV	57.5	H_2	Onsite SMR	0.051	2.9	Daytime
FCV	57.5	H_2	Central SMR, liquid truck	0.240	13.8	Production & distribution: Continuous (24/7)
FCV	57.5	H_2	Central coal w/ CCS, pipeline	0.054	3.1	Station demands: Daytime

[a] The daytime profile is modeled based on hourly gasoline refueling profiles in the state.
[b] PHEV20 assumes 40% of VMT supplied in all-electric mode.
Sources: [2, 3]

Figure 7 illustrates the demand timing for each of the pathways for the projected peak demand day (August 24) in the 100% vehicle penetration case. Demand in the load-leveling pathways peaks at night when non-vehicle electricity demand is low. The minimum point in these pathways corresponds to peak non-vehicle electricity demands (around 4 PM). Demands for onsite-electrolysis and BEVs are sufficient to load-level the system entirely (meaning electricity demand is constant throughout the day), as demand from those pathways never reaches zero. Electricity requirements for PHEV20s is not sufficient to entirely fill in troughs in non-vehicle demand (on a peak summer demand day). 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. Figure 8 illustrates the effects of the timing profiles on total 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 influence of vehicle and fuel electricity demands on electricity demand variability is illustrated in Table 3. The average hourly electricity demand for each of the pathways is shown, assuming they supply 100% of light-duty VMT (average non-vehicle electricity demand is 38.1 GW). Load factors for the pathway demands and the combined system demands are also shown. These represent the ratio of average hourly load to annual peak-hour load, and serves as a measure of the degree of variability in load (constant demand would have a load factor of one). Load-leveling pathways (most notably *Electrolysis, Load-level*) increase the system load factor, whereas pathways with high daytime electricity demands reduce the load factor, relative to the base case. *Central SMR, liquid truck* also increases the load factor noticeably, by adding significant, essentially constant, demands to the system.

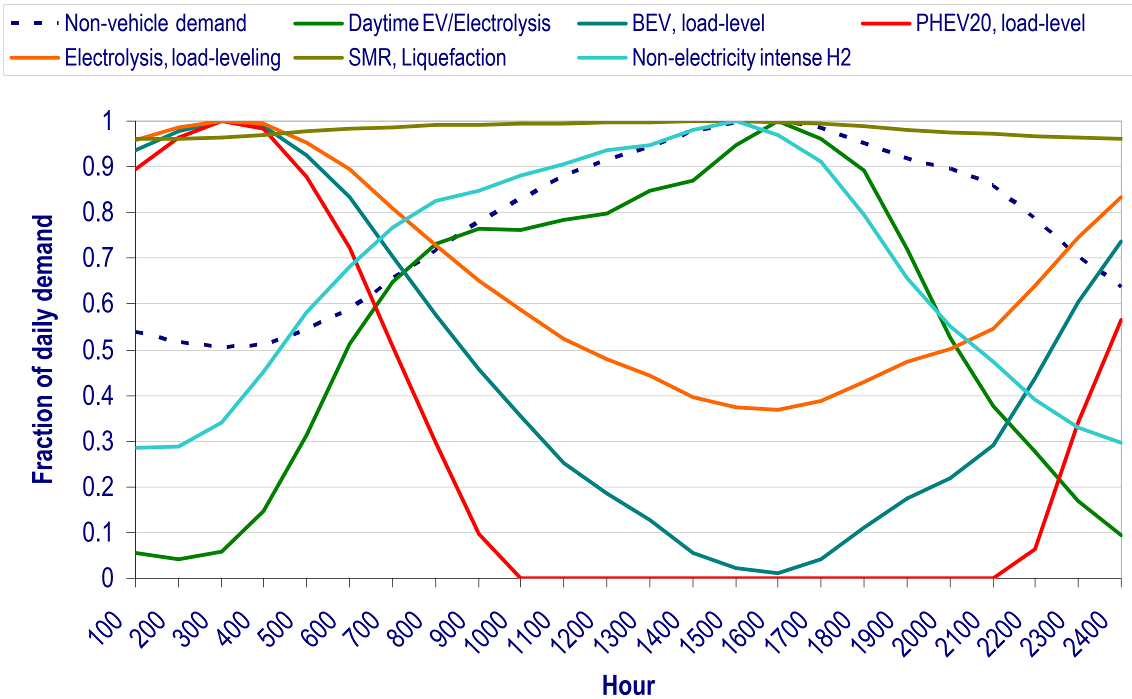

Figure 7: Vehicle pathway electricity demand profiles, peak electricity demand day (100% of VMT).

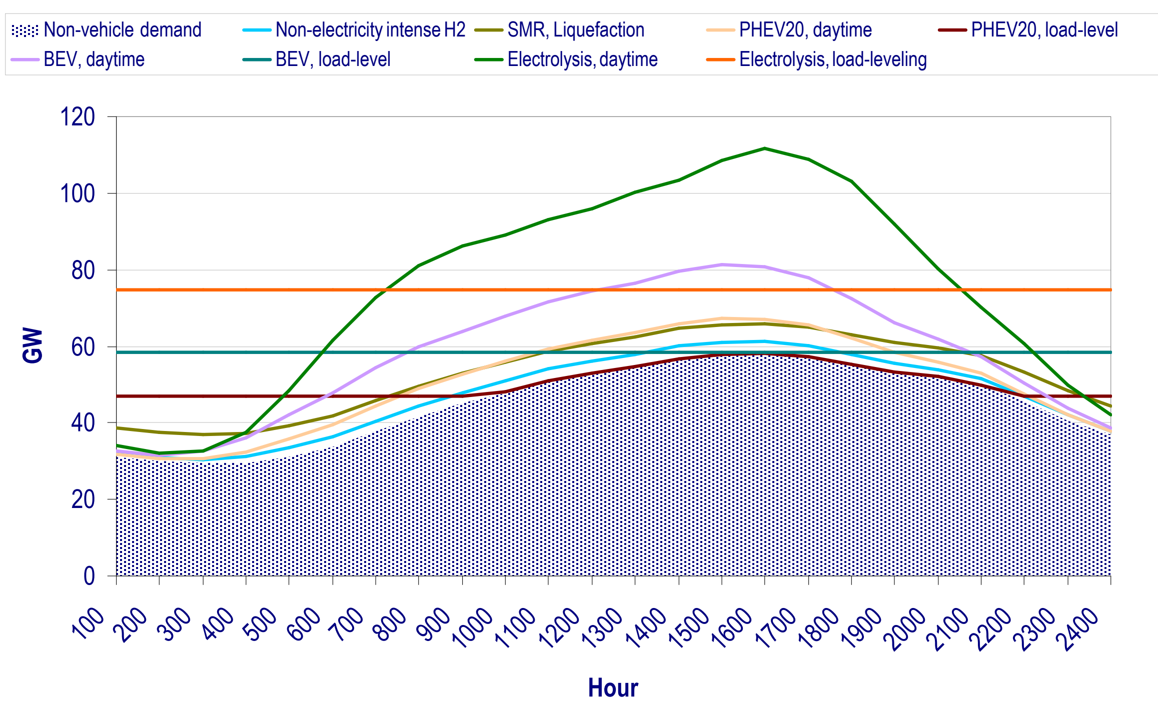

Figure 8: Vehicle pathway electricity demands and non-vehicle electricity demand (100% penetration).

Table 3: Annual load factors by pathway (100% VMT penetration).

Pathway	Avg. vehicle demand (GW)	Vehicle load factor	System load factor
Baseline (gasoline)	0.0	0.0%	60.8%
BEV, Daytime	13.6	50.1%	59.0%
BEV, Load-level	13.6	46.3%	80.6%
PHEV20, Daytime	5.4	50.1%	60.6%
PHEV20, Load-level	5.4	29.9%	70.1%
Electrolysis, Daytime	30.2	47.2%	54.9%
Electrolysis, Load-level	30.2	63.6%	83.2%
Central SMR, liquefaction	7.8	86.7%	65.4%
Non-electricity intensive H_2	1.8	50.1%	60.7%

Another way to depict the effects of transportation electricity demand timing on variability of demand is through load-duration curves (LDC), which illustrate the number of hours per year in which demand exceeds a given level. Load duration curves for the pathways with 100% penetration are illustrated in Figure 9. A flat LDC corresponds to stable electricity demand, seen in the load-leveling pathways, while a steep curve represents variable ("peaky") demand.

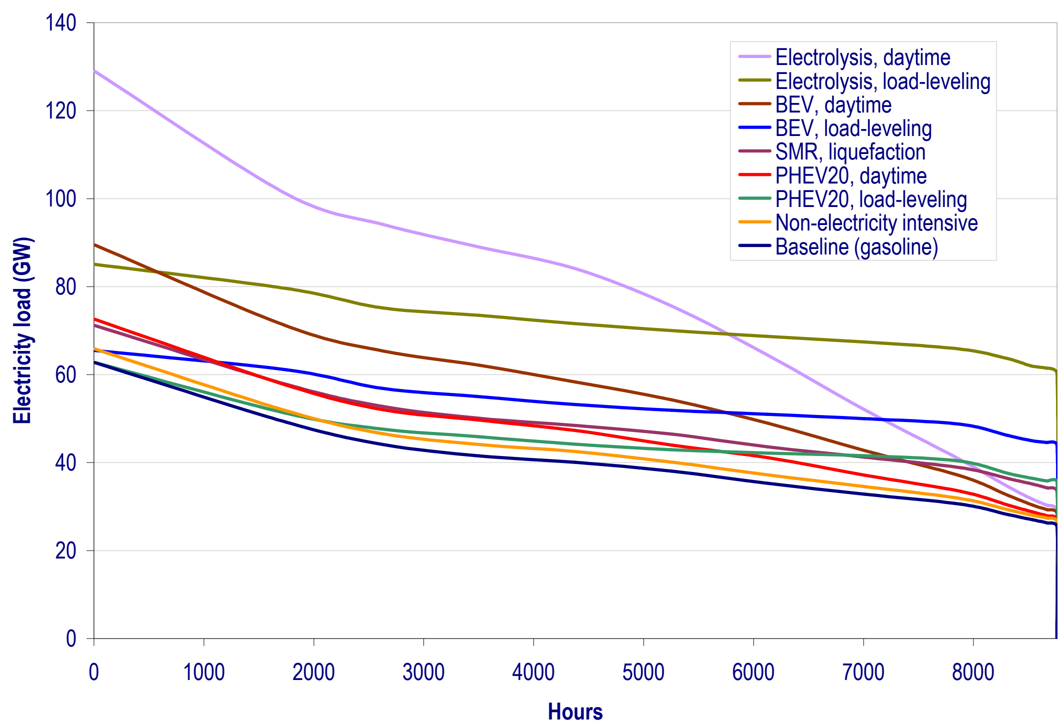

Figure 9: Pathway load duration curves (100% of VMT)

4. Dispatch model results

Figure 10 illustrates the marginal generation required for each pathway, for the 100% penetration case. Non-vehicle electricity demands are projected to require 300,418 GWh in 2007 (demand plus losses). Thus, 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%. The SMR pathway with liquefaction and the PHEV20 pathways also increase electricity requirements significantly, by 25% and 17%, respectively. The remaining pathways increase generation requirements by 6%-8%.

Pathways with a significant electricity input require additional imports from the Southwest to meet demand. (This is an assumption of the model. Future versions will include capacity expansion to meet growing vehicle and non-vehicle electricity demands over time.) Otherwise, in-state NGST and NGCT plants provide the majority of power on the margin.

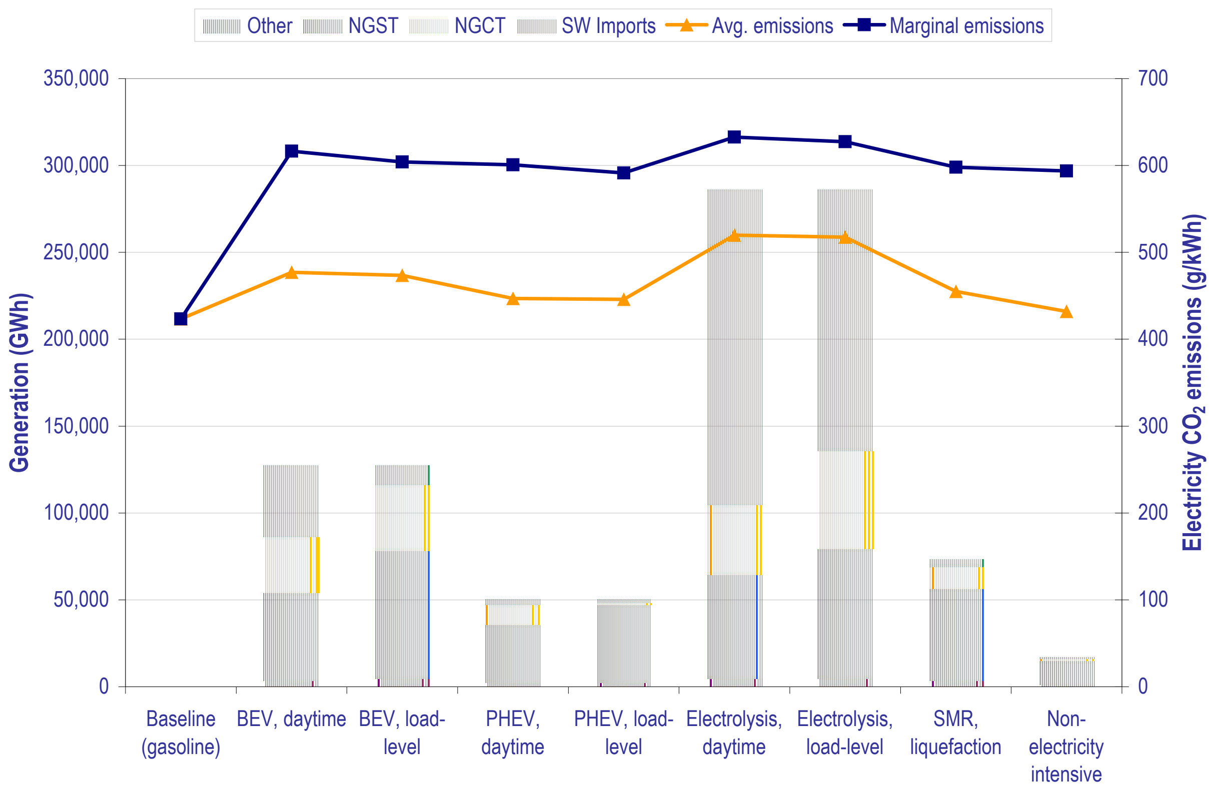

Figure 10: Marginal generation by resource and associated emissions.

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 (see Figure 11). 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 the electrolysis pathways, which meet very high demands with additional imports from the southwest, bringing more coal generation.

The variation in marginal generation resources is noticeable for a single pathway with different timing profiles. Namely, a high level of daytime electricity demand requires additional imports from the Southwest. It is interesting, then, that there is little variation in emissions for these pathways. This finding is a result of the predominance of natural gas in the marginal generation mix – either imported, or from an in-state steam turbine or gas turbine (or both). The average emission rates from these plant types for the current California power plant mix are quite similar, and so too are the corresponding emission rates for a pathway with different timing profiles.

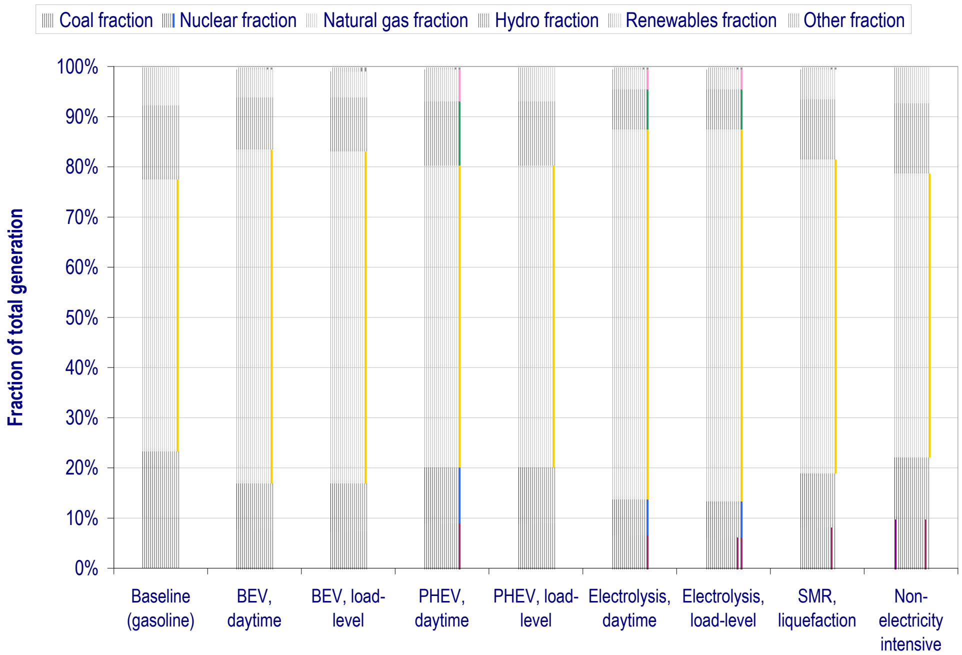

Figure 11: Fraction of total electricity generation by resource.

Figure 12 elaborates on the variation of electricity emission rates with demand levels. It compares marginal CO_2 emissions from the electricity sector with the level of advanced vehicle penetration. It is apparent again that electricity emission rates increase with demand. In the most extreme case (*Electrolysis*, *daytime*), marginal electricity emission rates increase by about 7% as FCV penetration increases from 5% of VMT to 100% of VMT. Note that these emission rates only refer to the marginal emission rates from the electricity sector associated with the vehicle pathways. They are needed to calculate well-to-wheel emissions for a vehicle pathway (Figure 13), but might only account for a portion of total vehicle emissions.

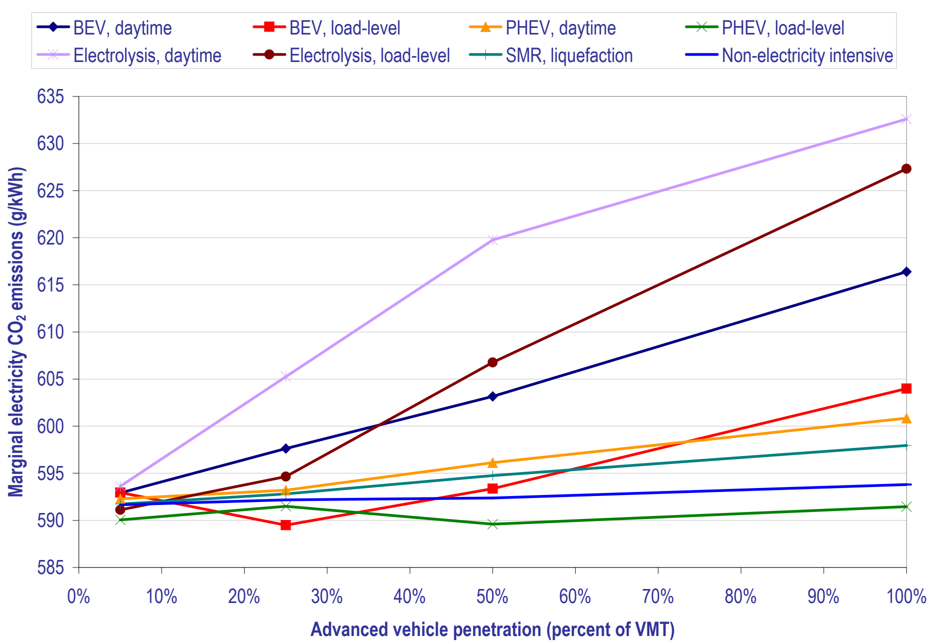

Figure 12: Marginal electricity CO_2 emission rates versus vehicle penetration.

Attributing average and marginal electricity emissions to the transportation pathways yields the CO_2 emissions shown in Figure 13. The figure divides emissions by source, with those coming from electricity generation in green (the shaded portion refers to the average emissions). All of the pathways except for the electrolysis pathways result in an improvement over conventional vehicles. For reference, an improved conventional vehicle is shown as well, assumed to be a 40 mpg hybrid electric vehicle (HEV). (Emissions for pathways with daytime charging profiles are similar to those shown for the load-leveling profiles.)

Attributing average electricity emissions to the pathways reduces emissions from the electricity sector by 20%-30%. Recall, however, that the issue is *allocating* emissions. Emissions attributed to electricity generation for non-vehicle demands would then be correspondingly higher, and combined emissions for electricity and transport remain the same.

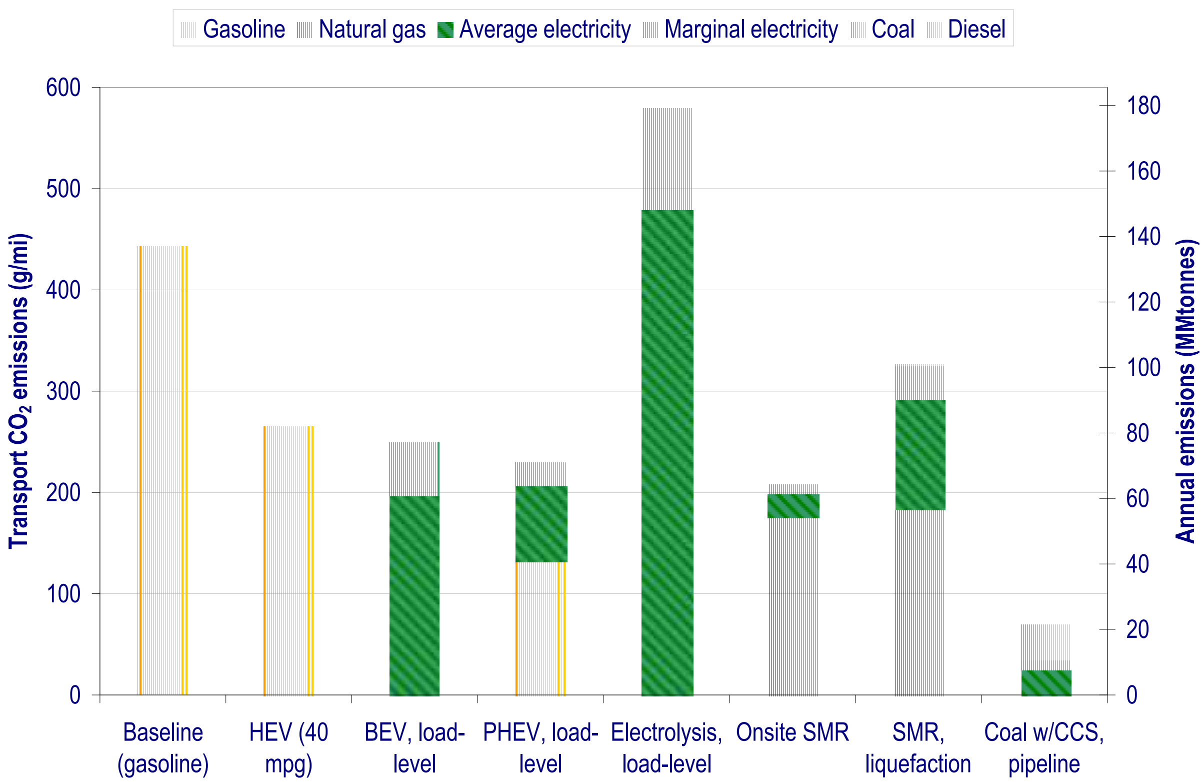

Figure 13: Fuel and vehicle pathway well-to-wheels CO_2 emissions by source (marginal emissions).

Natural gas consumption associated with each pathway is an important consideration, as well, as domestic supplies tighten and imports are projected to increase [11].

Natural gas usage associated with each pathway for fuels and electricity generation is illustrated in Figure 14. In each scenario, 1,748 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]. Electrolysis triples natural gas consumption for vehicles and electricity generation (about doubling total natural gas consumption in the state). Battery-electric vehicles increase natural gas requirements for electricity generation by 75% and total consumption by 40%. The hydrogen pathways utilizing natural gas as a feedstock increase total consumption by 30%-50%, while the coal pathway increases total consumption the least, by 6%.

Interestingly, hydrogen pathways that use natural gas as a feedstock use less natural gas than the 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 our model). 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.

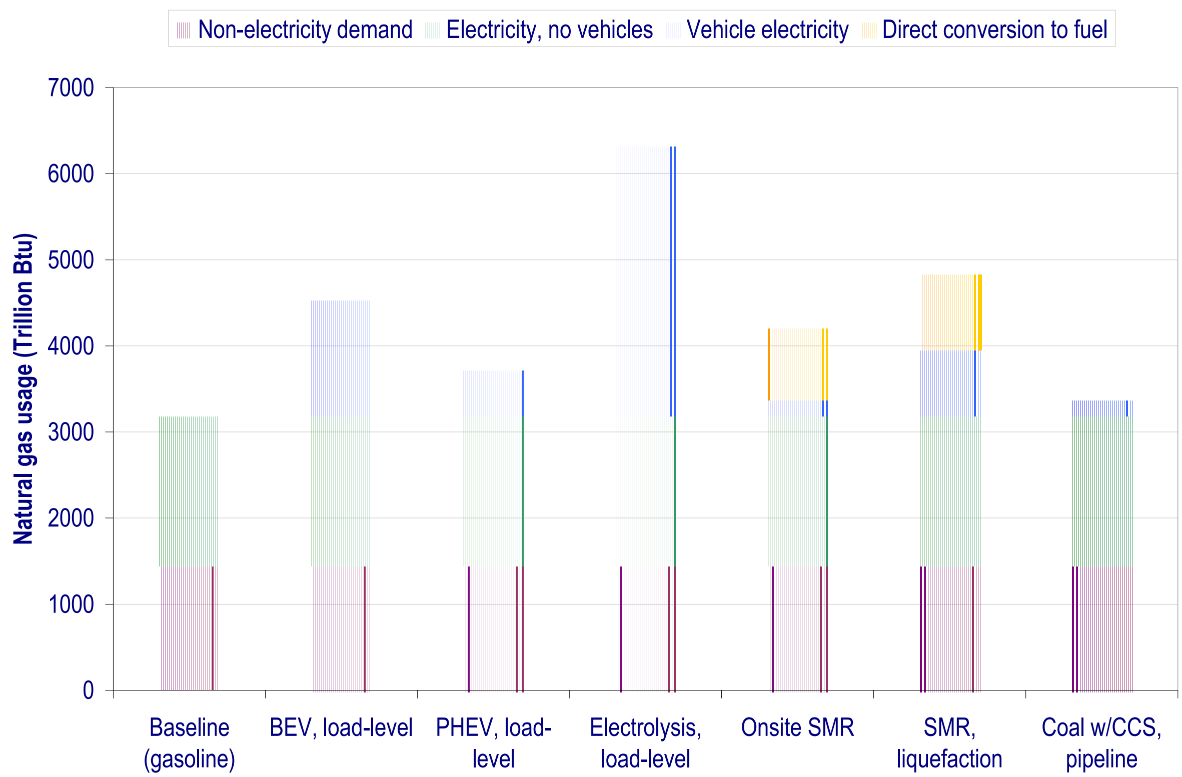

Figure 14: Natural gas usage for fuels production and electricity generation, by pathway.

5. Conclusions

This paper describes an electric sector dispatch model and the preliminary application of the model to investigate the impact of electric-drive vehicles on the electricity sector in California. 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,
- Generation, 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),
- The addition of significant vehicle demands to the electricity system will affect the composition of the grid, even during periods of zero marginal demand,
- Electricity emissions and natural gas usage can vary widely for different electric-drive vehicle pathways, and can vary significantly within a single pathway, depending on timing,

- 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,
- Treat availability of intermittent resources including wind and hydro stochastically,
- Better represent costs and pricing, including those for capacity expansion, emissions, reliability, and reserves,
- Add environmental constraints such as emissions of criteria pollutants,
- Include a representation of vehicle-to-grid applications and 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:

- 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

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8. References

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9. Author biographies

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