IMPACTS ASSESSMENT OF PLUG-IN HYBRID VEHICLES ON ELECTRIC UTILITIES AND REGIONAL U.S. POWER GRIDS
PART 1: TECHNICAL ANALYSIS

Michael Kintner-Meyer
Kevin Schneider
Robert Pratt
Pacific Northwest National Laboratory[a]

November, 2007

ABSTRACT

The U.S. electric power infrastructure is a strategic national asset that is underutilized most of the time. With the proper changes in the operational paradigm, it could generate and deliver the necessary energy to fuel the majority of the U.S. light-duty vehicle (LDV) fleet. In doing so, it would reduce greenhouse gas emissions, improve the economics of the electricity industry, and reduce the U.S. dependency on foreign oil. Two companion papers investigate the technical potential and economic impacts of using the existing idle capacity of the electric infrastructure in conjunction with the emerging plug-in hybrid electric vehicle (PHEV) technology to meet the majority of the daily energy needs of the U.S. LDV fleet.

This initial paper estimates the regional percentages of the energy requirements for the U.S. LDV stock that could potentially be supported by the existing infrastructure, based on the 12 modified North American Electric Reliability Council regions, as of 2002. For the United States as a whole, up to 84% of U.S. cars, pickup trucks, and sport utility vehicles (SUVs) could be supported by the existing infrastructure, although the local percentages vary by region. Using the LDV fleet classification, which includes cars, pickup trucks, SUVs, and vans, the technical potential is 73%. This has an estimated gasoline displacement potential of 6.5 million barrels of oil equivalent per day, or approximately 52% of the nation's oil imports. The paper also discusses the impact on overall emissions of criteria gases and greenhouse gases as a result of shifting emissions from millions of individual vehicles to a few hundred power plants. Overall, PHEVs could reduce greenhouse gas emissions with regional variations dependent on the local generation mix. Total NO_X emissions may or may not increase, dependent on the use of coal generation in the region. Any additional SO_2 emissions associated with the expected increase in generation from coal power plants would need to be cleaned up to meet the existing SO_2 emissions constraints. Particulate emissions would increase in 8 of the 12 regions. The emissions in urban areas are found to improve across all pollutants and regions as the emission sources shift from millions of tailpipes to a smaller number of large power plants in less-populated areas. This paper concludes with a discussion about possible grid impacts as a result of the PHEV load as well as the likely impacts on the plant and technology mix of future generation-capacity expansions.

The second paper (Part II: Economic Assessment) discusses the economics of the new PHEV load from the perspective of a load-serving entity. It discusses the potential downward pressure on rates as revenues increase in the absence of new investments for generation, transmission, and distribution.

(a) Operated for the U.S. Department of Energy by Battelle under Contract DE-AC05-76RL01830.

INTRODUCTION

The U.S. electric infrastructure is designed to meet the highest expected demand for power, which only occurs for a few hundred hours a year, at most (about 5% of the time). For the remainder of the time, the power system is underutilized and could generate and deliver a substantial amount of energy needed to fuel the nation's light-duty vehicle (LDV) fleet: cars, pickup trucks, sport utility vehicles (SUVs), and vans. This paper estimates the percentage of the U.S. LDV fleet that could be supplied with energy from the existing U.S. power system without additional investments in generation, transmission, and distribution (T&D) capacities. This paper postulates an electric-vehicle scenario that is based on the concept of a plug-in hybrid electric vehicle (PHEV) with a battery size that would satisfy the daily average driving requirement of 33 miles per day, solely on electricity. The battery is charged with electricity from the electric grid during off-peak hours, most of which occur during the night. Driving beyond the daily driving range (i.e., long distances) requires that the PHEV's gasoline engine be used. Because PHEVs are not commercially available, it is not clear if all PHEVs will feature an electric-only operating mode. Preliminary information about the Chevy Volt suggests that this option will be available[a]. However, other manufacturers may only provide a mixed electric-gasoline mode. For the purpose of this analysis, we assumed a vehicle with an electric range of 33 miles.

The analysis of this paper estimates the upper limit of the PHEV (or pure electric vehicles with similar electric performance) penetration without requiring new investment in generation and T&D capacity expansions. This paper should be viewed as a technical potential analysis that attempts to estimate a defensible limit of today's grid infrastructure to support a new transportation load, not as a forecast or prediction of what will happen in the future. We applied a methodology that froze our growing demands for transportation (in terms of vehicle miles traveled) and our steadily growing infrastructure in time and then estimated the percentage of the nation's LDV stock that could be "fueled" by today's grid. This approach deliberately disregards the fact that the penetration of PHEVs will occur gradually and that the electric infrastructure is constantly being upgraded to meet the native load growth of our established and existing end-uses in the residential, commercial, and industrial sectors. Furthermore, the future grid will become "smarter" and "greener," judging from the current investments in advanced metering infrastructure (AMI) and distribution automation and the existing renewable portfolio standards in 23 states and the District of Columbia as well as tightening criteria emissions regulated by the U.S. Environmental Protection Agency's (EPA's) Clean Air Interstate Regulation (CAIR). In addition, the vehicle technology will improve, resulting in cleaner and more efficient vehicles. Customer preferences may change, impacting the current vehicle class mix. Customers may like to replace an SUV with a car or lighter vehicle. Many complex energy policies and customer preference mechanisms need to be addressed in an analysis that looks into the future. By framing the PHEV impact discussion as a technical potential analysis of today's grid and vehicle class mix, we minimize the degree to which the outcome of this discussion is driven by the assumptions of the future power plant mix and vehicle fleet.

Even though we analyzed today's grid with today's LDV fleet and driving behavior, we applied several assumptions about the operating procedures of the entire electricity infrastructure, in which the grid has never been operated. We discuss the likely impacts of high utilization of the grid operating near capacity almost all the time.

(a) Concept Chevy Volt information available at: http://www.chevrolet.com/electriccar/

This paper first describes the methodological approach for estimating the existing idle generation capacity to be used for PHEV charging and then comparing the resulting generation figure (in MWh) to the energy requirements of the U.S. LDV fleet for daily driving. The resulting percentage of the LDV fleet constitutes the upper limit of the electrification potential for the LDV fleet, displacing gasoline fuel with electricity. We presume that the transmission and distribution system would be capable of delivering the electricity to the new PHEV load and present a rationale for this assumption. Assuming that the upper limit of the technical-fuel-displacement potential would occur, we discuss the question of what are the net impacts to the overall emissions as the emission source shifts from millions of vehicle tailpipes to a smaller number of large power plants. There are favorable economic impacts associated with a high fuel-displacement scenario. PHEVs provide power sales revenues without requiring additional new infrastructure. This translates into additional profits and, from a regulated electricity industry point of view, puts downward pressure on rates. The economics from both the electricity providers' and the customers' point of view are presented in the companion paper (Part II: Economic Assessment).

BACKGROUND

In his 2006 State of the Union address,[(a)] President George W. Bush identified the U.S. dependency on foreign oil as a major national security issue. In the United States, transportation is the largest consumer of petroleum products of any economic sector. As a consequence, cars, vans, and light duty trucks are a logical target for alternative fuel supplies. High oil prices during 2005, exacerbated by the supply disruption in gasoline products in the aftermath of hurricanes Katrina and Rita, brought concerns about the supply of petroleum to the attention of the public.

These events have increased efforts to identify alternatives to petroleum, including biofuels and hydrogen. For the reasons noted by the President and national security experts, the faster the United States can reduce reliance on petroleum, the better. Rapid transition to new alternative fuels will require significant investment in new fuel production and distribution infrastructure. This is not the case for PHEVs, as the necessary charging infrastructure is already in place. As new alternative fuels enter the market, they can be used in PHEVs to further reduce the need for imported petroleum products.

METHODOLOGICAL APPROACH

The study is divided into two analytical components. The first is an analysis of the upper limit of PHEV penetration using off-peak power for charging the battery. The second is an analysis that assesses the impacts on the overall emissions as electricity displaces gasoline in the LDV fleet.

We used a conservative approach to identify the maximum use of PHEVs by restricting our analysis to the existing electric infrastructure that does not include expansion of generation and T&D capacity as PHEVs make inroads into the market place, increase the electric load, and alter the load shape. Because we do not know when and at what rate PHEVs may penetrate the market, nor do utility planners, constraining our analysis to the current power system infrastructure appears to be a defensible and plausible approach.

(a) State of the Union Address available at http://www.whitehouse.gov/.

Estimating existing idle electric generation capacity in a region is based on a "valley-filling" methodology in which the margin between the installed system capacity and the system load is determined. The system load is based on the North American Electric Reliability Council (NERC) data for 2002. Because of the large regional differences in the load profiles and the generation mix, the analysis is performed for 9 eastern North American Electric Reliability Council (NERC) regions as well as the 3 sub-regions of the Western Electricity Coordinating Council (WECC). The results from these 12 areas are aggregated to discuss the results from a national perspective. The Energy Policy Act of 2005 resulted in significant changes in the structure of the NERC regions. Because the data used for analysis pre-date the Energy Policy Act of 2005, this analysis is based on the regional structure as it existed in 2002.

Particular attention was given to the issue of power transfers that occur between regions. In some cases, a region's native generation will be supplemented by inter-regional power transfers, while in others, the native generation will supply a load that exists outside the region. When determining the generation that is available to recharge PHEV batteries within a region, power transfers into and out of the region are taken into account.

The second component of the analysis assesses the impacts on overall emissions as electricity displaces gasoline in the LDV fleet. We distinguish between total emissions and emissions released in urban areas with high human-health implications. The emissions analysis employs a well-to-wheel analysis of the entire energy conversion path from extracting the primary energy out of the ground to delivering useful energy in the form of miles traveled. The Argonne National Laboratory's Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model is used for this analysis [GREET, 2001]. The emission analysis is performed for the 12 modified NERC regions to reflect the varying electric generation mix for charging the PHEV batteries. The analysis includes a discussion of the shift from mobile to stationary emission sources as well. Finally, this paper discusses the petroleum-displacement opportunity for the upper-limit PHEV penetration scenario.

The sections below describe the data sources and the methodological approaches in detail.

Data Sources and Level of Aggregation

Because of large variations with respect to the electric infrastructure, generation mix, and diversity in load profiles across the United States, this analysis has been performed on a regional basis, dividing the United States into 12 regions. The definition of a region is adopted from the NERC and the Energy Information Administration (EIA) regionalization.

System load profile data were obtained from NERC. The most recent and complete data set available at the time of this analysis consists of hourly load data by NERC regions and sub-regions for the year 2002.[a] NERC compiles load data reported from load-serving entities to perform system assessments and reliability analyses.[b] Of the 10 NERC regions, 9 are represented in their entirety in this study. WECC is disaggregated into three modified sub-regions according to EIA's definition for the Annual Energy Outlook [EIA, 2006a and 2006b]. The analysis employed the following definition of regions:

(a) Data were obtained from NERC 2/24/2006.

(b) NERC compiles system load data from different sources, including NERC's regional councils and Federal Energy Regulatory Commission (FERC) Form 714—Annual Electric Control and Planning Area Report.

1. ECAR (East Central Area Reliability Coordinating Agreement)
2. MAAC (Mid-Atlantic Area Council)
3. MAIN (Mid-America Interconnected Network)
4. MAPP (Mid-Continent Area Power Pool). Only the U.S. segment is used.
5. SPP (Southwest Power Pool)
6. ERCOT (Electric Reliability Council of Texas)
7. SERC (Southeastern Electric Reliability Council)
8. FRCC (Florida Reliability Coordinating Council)
9. NPCC (Northeast Power Coordination Council). Only the U.S. segment is used.
10. NWP (Northwest Power Pool Area), sub-region of the WECC
11. AZN&RMP, combining two sub-councils: Arizona-New Mexico-Nevada Power Area and the Rocky Mountain Power Area within the WECC.
12. CNV (California and Southern Nevada), sub-region of the WECC.

Figure 1 shows the 12 modified NERC regions as used in the analysis. For the northern regions that include areas of Canada, NERC identified the U.S. segments so that only the U.S. load profile could be extracted. This applied to the regions of WECC, MAPP, and NPCC. The resulting 12 regional system load profiles for the year 2002 established the main data source for this analysis. Furthermore, EIA annual cumulative generation data are used as well as the installed capacity by major fuel and plant-type for the year 2002. The EIA data are provided at the same regional disaggregation level as the NERC data set [EIA, 2006b].

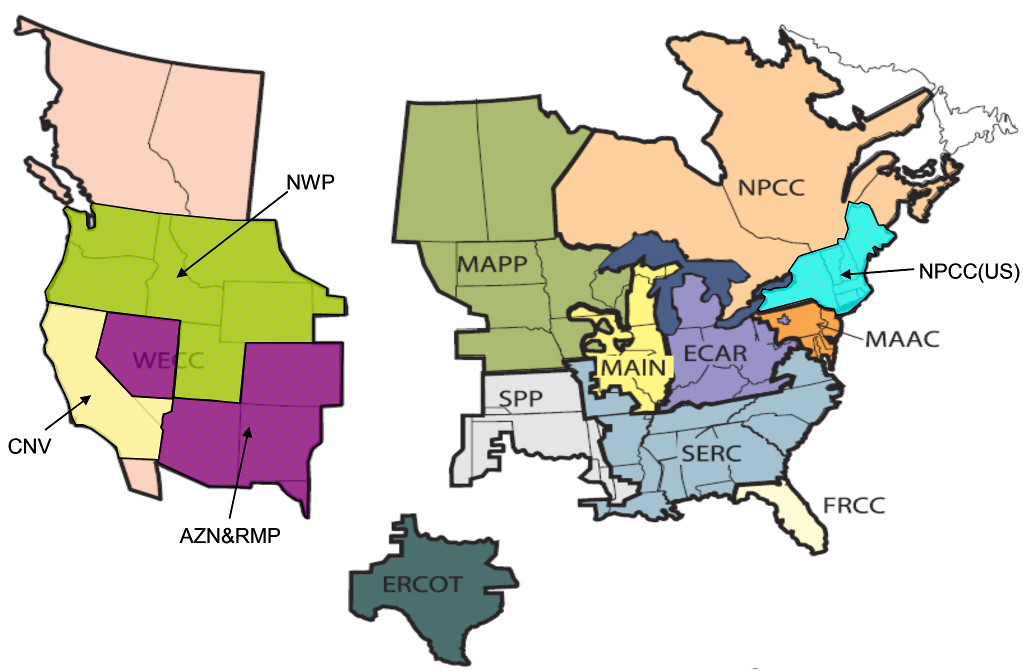

Figure 1: Definition of Regions Used in this Study—12 Modified NERC Sub-Regions Based on the Pre-1/1/2006 Regional Council Structure(a)

(a) After 1/1/2006, the Regional Reliability Councils—ECAR and MAAC—were aggregated into Reliability First Corporation. Sections of the MAIN merged into SERC and into the Midwest Reliability Organization (MRO). More information can be found at: http://www.nerc.com/~org/entities/.

Vehicle Stock and Vehicle Utilization Data

The source for the U.S. vehicle stock is the 2001 motor vehicle registration, by states, as published by the U.S. Department of Transportation [DOT, 2002]. Registration figures were chosen for cars, light trucks, SUVs, and vans, generally referred to as LDVs. Motorcycles are not included. Approximately 217 million vehicles were registered in the LDV category in 2001. Registrations for cars, pickup trucks, and SUVs alone amounted to 198 million. Other heavier vehicles, such as busses and trucks, are not considered in this study, although there are no technical reasons that would prevent busses and trucks from adopting plug-in hybrid electric technology. This analysis strictly focuses on LDVs, excluding motorcycles.

The average daily driving per person is determined using detailed household travel survey data collected in 2001 [Davis and Diegel, 2006]. This survey estimated miles per year traveled in daily trips by personal vehicles to be approximately 12,000 miles per year per vehicle or about 33 miles per day per vehicle. Although this figure is strictly valid for personally owned vehicles, we assign it to all vehicles, including commercial vehicles. This simplification may underestimate the actual daily driving of the commercial vehicles in the LDV fleet. The 33 miles per day per vehicle is then used to determine the energy requirements to be provided by electricity. It would translate to a PHEV33, which notates the number of miles (33) that can be traveled in an electricity-only mode before re-charging or the use of gasoline becomes necessary.

Other researchers in the PHEV community often cite a 1990 survey performed by U.S. Department of Transportation [Hu and Young, 1994] in which the cumulative percentage of personal automobiles is plotted over the average daily travel distance per vehicle. Using data of the 1990 survey, it is frequently emphasized that 50% of personal automobiles travel 20 miles or less daily, and 70% drive 33 miles or less [Graham, 2005; Taylor, 2003]. The average daily miles traveled is about 28, slightly lower in 1990 than in the more recent survey [DOT, 2003]. The cumulative percentage figures emphasize the distribution of personal driving patterns and point out that greater than 50% of personal travel will be less than 33 miles and that only a small percentage of the population drives significantly further than 33 miles per day, skewing the average upward. This means that the majority of the vehicles may not fully discharge their batteries with a 33-mile range. There will be a small population that would either drive on gasoline beyond the first 33 miles or recharge the battery sometime before they complete their daily trip, e.g., at work. Because this study assumes that <u>each</u> vehicle drives 33 miles per day, there is an implicit assumption that the electric energy not used to charge those that drive less is shifted to others that drive more than 33 miles per day.

Valley-Filling Approach for Estimating Available Electric Generation

The valley-filling approach requires a dispatch of the electric generators to meet the regional load demand. Once the dispatch is complete, the total installed capacity less the dispatched units sets the upper limit on the generation available for charging PHEVs. A simplified approach is chosen that reduces the complexity of a production cost modeling that simulates and optimizes an 8,760-hour dispatch (1 year), to two 24-hour dispatches, a typical summer and winter day. The simplification applied a typical plant dispatch merit order to two limiting cases when the entire electric grid is likely to have the least reserve capacity and available generation resources for recharging the PHEV batteries. Spring and fall seasons commonly offer significantly more excess generation capacity because of reduced load demand. It is noted that reserve margins could be low during brief periods in the fall season when several power plant operators schedule planned outages for plant maintenance after high plant utilization during the summer. However, it is assumed that there is sufficient scheduling flexibility throughout the fall such that the available reserves remain always larger than during the peak summer season. This assumption will be the subject of future investigation.

The 24-hour generation dispatch is performed using a merit-order approach based on typical production costs, combined with the following rules, considering common plant operating practices. General plant type categories as defined by EIA in the Annual Energy Outlook are used [EIA, 2006a and 2006b].

- Nuclear capacity. Nuclear power plants are operated as a base-load plant at maximum generation capacity. The common capacity factor is 0.90 [EIA, 2006b].
- Coal-fueled capacity. Coal plants are operated primarily to meet base-load with capabilities to ramp up and down generation.
- Natural gas combined cycle and conventional steam plant. Plants can meet base-load and intermittent load such as load following.
- Conventional hydro capacity. Hydro systems are used to meet base-load, intermittent load, and peak load. The hydro systems in the west and the east have reached their annual generation capabilities already. Although there is significant hourly and daily generation flexibility in the installed hydro capacity, the total annual energy produced is constrained by the finite water resources and other operational requirements for wildlife preservation [BPA, 2003]
- Renewable (non-conventional hydro) energy generation. This includes wind, solar, biomass, and geothermal capacities. Renewable-energy resources are used to the maximum generation capability to displace conventional fossil-fuel generation.
- Peaking plants (combustion turbines). These plants are designed for a relatively short run time. Typical capacity factors for combustion turbines are in the 0.15 to 0.20 range. Although the capacity factor could be increased to some degree, the significantly higher operating costs are unlikely to make combustion turbines a viable resource for PHEVs.

The dispatch is then performed for each modified NERC region for an average summer and winter day, defined as the average hourly system load over a 3-month period. The summer period started on June 1 and ended August 31. The winter period is defined as the period from December 1 through February 28. Each average summer and winter day generation dispatch is then projected for a 6-month period, and the combined annual generation figure is compared with annual generation data. The daily profiles are adjusted to meet EIA's annual generation data as reported for 2002 in the Annual Energy Outlook 2006 (AEO2006) [EIA, 2006b]. The results of this step are two 24-hour generation dispatches representative of a typical summer and winter day.

To estimate the regional unused generation capability, we determined the difference between the total installed capacity (summer capacity de-rated by the availability factor) and the hourly generation that is already committed to meeting the current load demand. This level of potential generation is further curtailed by precluding the use of peaking plants for the charging of PHEV batteries. Peaking plants are designed for relatively short run-time operations and would be uneconomical for continuous operation over long periods of time. Figure 2 illustrates the valley-filling approach.

The remaining marginal generation capacity consists of coal-fired thermal plants, natural-gas-fueled steam plants, and combined cycle plants. Not considered as marginal capacity for the valley-filling are nuclear, conventional hydro power, and renewable energy capacities because these are already fully utilized. Nuclear capacity is normally operated at its maximum capacity. Wind and solar generators are fully utilized whenever the resource is available. Conventional hydro generation is limited by finite water resources and seasonal water flows.

The installed coal and natural-gas fueled capacity is then de-rated by the availability factor to account for planned and forced outages. We chose the capacity factor as an approximation of the availability factor.[a] A capacity factor of 0.85 is used for both coal and natural-gas plants [EIA, 2006c]. This assumption implies that planned outages are scheduled uniformly throughout the year, which is a simplified approximation to the actual maintenance schedule. Maintenance is typically scheduled during a low-load period (commonly in the fall and spring) to make the full generation capacity available for the peak seasons. Thus, the simplified approximation for outage scheduling represents a conservative estimation of the available capacity during the summer and winter months. Petroleum-fuel steam generators, with a small contribution to the total U.S. electric generation of 3%, are grouped together with the natural-gas steam generators and are classified by EIA as "other" fossil steam generation [EIA, 2005b]. Figures A.1 through A.6 in Appendix A show the winter and summer dispatch profiles for one winter-peaking region (NWP), and two summer-peak regions (ECAR and CNV). The figures show the generation for valley-filling generation denoted as "additional" generation resources.

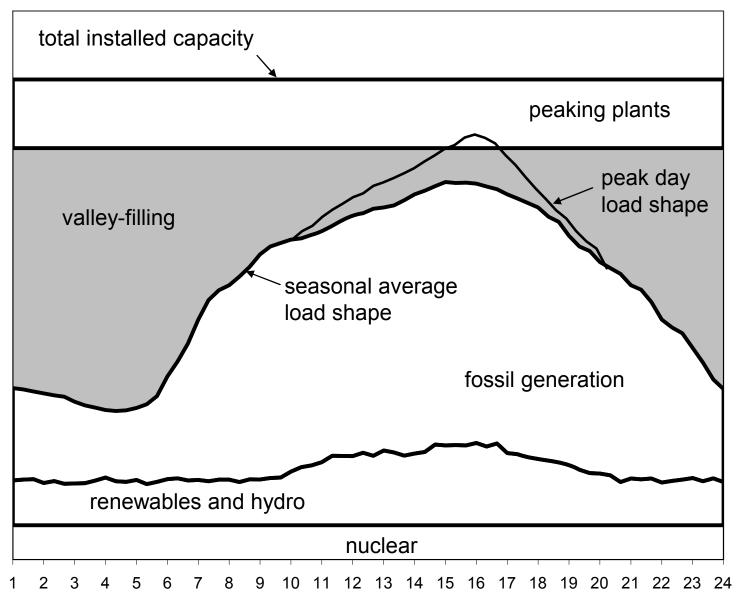

Figure 2: Stylized Load Shape for 1 Day During Peak Season, Generation Dispatch, and Installed Capacity

The margin between the system load profile and the total installed capacity after all exclusions constitutes the power available for charging PHEV batteries, in megawatts (MW). When the MWs available for charging are determined for a 24-hour period, the total energy available for charging PHEV batteries in a single day can be estimated, in megawatt-hours (MWh). This is considered the technical

(a) Availability factor is the ratio of hours a plant is available to operate in one year divided by 8760 hours. EIA publishes only capacity factors, which are the ratio of total generation in (MWh) produced in one year over the total generation capability (rated capacity times 8760 hours).

potential for supporting the daily recharging of the PHEVs batteries. The size of this energy block is determined for both the typical summer and typical winter day. The lower value of the two is then used as the regional representative resource estimate in MWh for PHEV battery charging.

The simplified valley-filling approach warrants the following comments:

1. Simplifying the valley-filling approach to a daily problem with a 24-hour dispatch greatly reduced the computational complexity of the resource estimation. Of interest is the limiting case or cases that impose a lower bound on the resource assessment. This particular case occurs during peak conditions when most generators are being used. Because the peak demand day may or may not be coincident with the day of the maximum dispatched generation, we represented the two load profiles, a summer and a winter day, to ascertain that the limited case is captured in the analysis.
2. The choice of using a seasonal average load shape rather than the load shape of the peak generation day is motivated by the dual-fuel capability of the PHEV, recognizing that there may be a few days out of the year in which the PHEV battery may not be fully recharged to its maximum storage capacity. The lack of stored electric energy will then need to be compensated for using the internal combustion engine. Restricting recharging during these periods can be accomplished through price signals or other load-control methods.
3. The available capacity for valley-filling, using coal and natural-gas plants, is de-rated by their capacity factors to represent an average availability and utilization of those plants. However, during peak seasons, most coal and natural-gas plants are typically operated to their full name-plate capacity. The unavailability commonly occurs during fall and spring season when the load is generally reduced, and less capacity is needed. By applying the 15% unavailability during the peak season, we underestimated the true capacity that is available.
4. By excluding peaking plants, in conjunction with de-rating the coal and natural-gas capacity by 15%, the resulting maximum demand in MW for valley-filling never exceeds the maximum system peak demand. This implies that the valley-filling method of charging PHEV batteries will never require transfers of electric power through the T&D system (at least not through the transmission system) greater than those during system peak hours (see Figure 2).

The result of the estimated valley-filling resource estimate is a block of electric energy indicated in MWh. This energy resource then is converted into a percentage of the energy requirements for the daily driving of the regional LDV stock. The energy requirements per mile for selected LDV classes are adopted from Electric Power Research Institute's (EPRI's) Hybrid Electric Working Group [Duvall, 2002, 2003, and 2004] as listed in Table 1.

Table 1: Specific Energy and Energy Storage Requirements by Vehicle Classes

Vehicle Class	**Specific Energy Requirements [kWh/mile]**	**Size of Battery for PHEV33 [kWh]**
Compact sedan	0.26	8.6
Mid-size sedan	0.30	9.9
Mid-size SUV	0.38	12.5
Full-size SUV	0.46	15.2

The energy requirements of the vehicle classes above are used in the 2001 regional fleet proportions using the Department of Transportation (DOT) motor vehicle registration data set. Because the DOT data set did not further specify cars into compact and mid-size, we selected an arbitrary 50/50 split. Likewise, the same split is used for the full-size and mid-size SUVs. Pickup trucks are assigned the same energy requirements as SUVs. In addition, an 8% loss in the transmission and distribution system is employed [DOE, 2003]. Efficiencies for the battery charger and the battery over a round-trip of full charge and discharge cycle are assumed to be 87% and 85%, respectively [Duvall, 2002].

Methodology for Emission Impact Analysis

The emissions impacts as a result of the additional central plant generation for charging PHEV batteries are evaluated using the GREET model. The GREET model accounts for the entire energy flow from the well of the primary energy source to the final conversion in the vehicle, propelling it 1 mile. Many assumptions are made in GREET regarding the individual efficiencies and emissions along the entire well-to-wheel energy path. This analysis adopted all of the default assumptions of the Version 1.6 model [GREET, 2001]. We used the electric-vehicle definition to represent a PHEV, recognizing that we modeled a PHEV when it is operating in an electric-only mode. We excluded any mixed electric/internal combustion engine driving modes.

Key input variables to the GREET model are the composition of the existing generation mix and the additional generation dispatched for PHEVs. The GREET model uses the existing generation (in GREET parlance "average generation mix") for all conversion processes except for electric vehicles. The electricity used to fuel electric vehicles is called "marginal generation." The GREET model uses market shares of the generation by five fuel types (residual oil, natural gas, coal, nuclear power, and others). The average generation mix for a given region is used from the Annual Energy Outlook (AEO) 2006 regional tables for the year 2002 [EIA, 2006b]. The marginal generation is assigned using the result of the valley-filling approach, which is a combination of coal and natural-gas resources. The GREET model simulates three vehicle types (passenger cars and light duty truck, Class 1 and Class 2) for near-term and for the longer-term. We use the near-term projections, which are based on car technologies and characteristics more amenable to today's vehicles than the longer-term projection. The vehicle types, particularly the passenger car and the light duty truck, scale relatively well such that the results expressed as a ratio of PHEV to conventional vehicle varied negligibly across the vehicle types. All results are then expressed as emission ratios.

Although the GREET model accounts for all energy conversions and the release of emissions associated with the energy conversions from well to wheel, it is not designed to consider national emissions caps. For instance, Title IV of the Clean Air Act sets goals for reducing SO_2 emissions for U.S. power plants, and the more recent EPA CAIR sets even stricter rules for total SO_2, NO_x, and fine particulate emissions. EPA established a cap-and-trade system as a market-based mechanism to reduce emissions. These cap-and-trade mechanisms are complex and go beyond the scope of the GREET model. As a consequence, the GREET model results need to be screened for emission compliance within the larger national regulatory context.

DISCUSSION OF RESULTS

The results of the analysis indicate that significant portions of the U.S. gasoline-operated vehicle fleet could be fueled with the available electric capacity. For the nation as a whole, about 84% of the energy needed for operating cars, pickup trucks, and SUVs (or a maximum of 73% of the energy of the LDV fleet) could be supported using generating, transmission, and distribution capacity currently available. This would require power providers to use all the available electric generation, base-load and intermediate generation, at full capacity for most hours of the day. If charging periods are to be constrained to a 12-hour period starting at 6 pm and ending at 6 am, the technical potential would be reduced to 43% of the LDV fleet. From a regional perspective, there is some diversity in the technical potential.

The midwestern region of the United States with a significant level of coal generation could provide the necessary energy for the entire region's LDV fleet while still exporting excess power to neighboring regions, assuming no limiting interregional transfer constraints to the adjacent regions.[a] This would require the entire 24-hour time period for recharging the PHEV batteries. The technical potential for the western regions, while still significant, is only about ½ of that of the eastern regions and about ¼ of that in the midwestern regions. A key contributing factor is the large share of hydro-electric generation, which is already at maximum sustainable generation levels. Results from ERCOT indicate it has one of the highest technical potentials because of its significant reserve capacity, some of which is taken out of service temporarily for economic reasons because of the existing excess capacity [Potomac, 2006]. With growing electricity demand, these generating units are expected to resume operation. Because ERCOT's link to the eastern interconnected system has only a small transfer capability, the export capability is assumed to be negligible, requiring all of the generation to be used for intra-regional consumption. Because of the lack of export capabilities out of ERCOT, its technical potential of fueling 136% of ERCOT's LDV fleet is reduced to 100%.

Figure 3 displays the results in graphical format, and Table 2 shows the results in tabular format. Results are shown for a 24-hour and a 12-hour night-charging period to illustrate the impacts of a constrained charging period to 12 hours (6 pm to 6 am). Even when constraining the battery charging to the night period, a significant fraction of the regional vehicle fleet could still be supported with the existing grid infrastructure. Furthermore, additional vehicles could be supported if one makes the reasonable assumption that PHEVs will not be electrified clones of existing vehicles, but optimally designed for fuel efficiency, regardless the "fuel" source. Finally, the charging capability could be extended by adding generation from traditionally "intermittent" resources, such as wind turbines, because PHEVs provide a ready use for this power whenever it is available. The addition of new wind generation could increase the fraction of PHEVs the WECC region could support.

(a) Based on the National Electric Transmission Congestion Study, the midwestern regions were not identified as critical congestion areas, nor as congestion areas of concern. Only when assuming high wind penetration in the Midwestern regions may significant congestion occur [DOE, 2006].

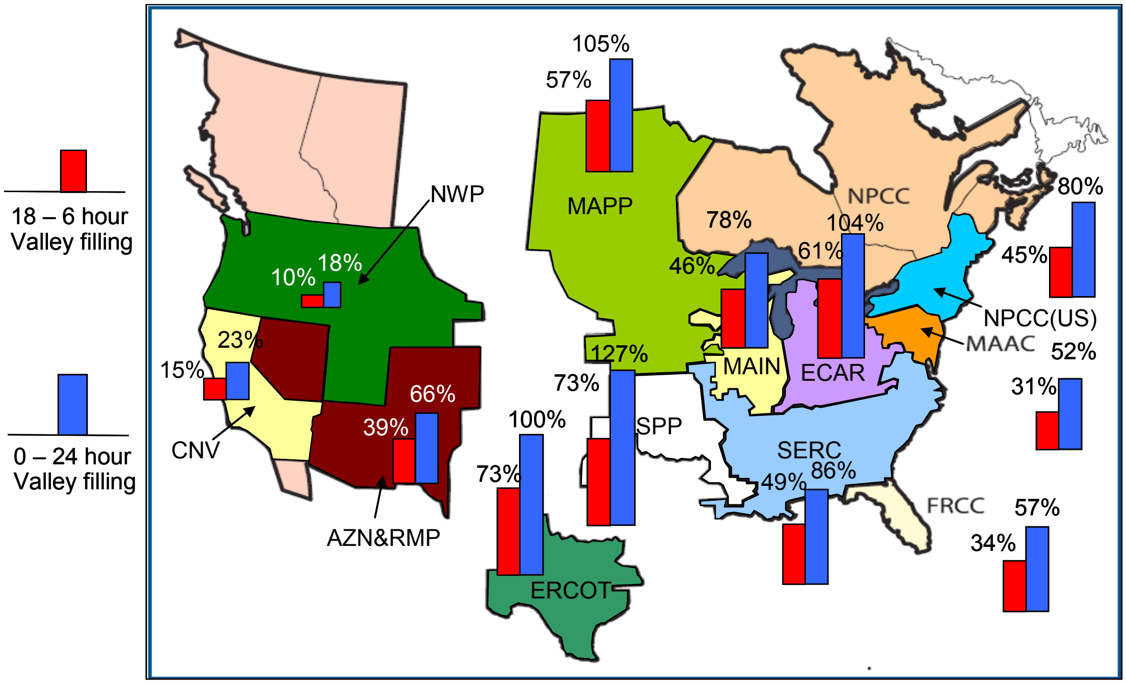

Figure 3: Technical Potential for Fueling the Regional LDV Fleet with Available Electric Capacity

Table 2: Results of Technical Potential by Regions

Region	Total Number of Vehicles in Mill.	24-Hour Valley Filling	6 pm–6 am Valley Filling	24-Hour Valley Filling	6 pm–6 am Valley Filling
		Technical Potential in %		Technical Potential in Mill. Vehicles	
ECAR	27.7	104	61	28.6	16.8
ERCOT	15.5	100	73	15.5	11.3
MACC	20.0	52	31	10.4	6.2
MAIN	16.7	78	46	13.1	7.7
MAPP	5.8	105	57	6.1	3.3
NPCC (U.S.)	19.6	80	45	15.6	8.9
FRCC	11.5	57	34	6.5	3.9
SERC27	37.8	86	49	32.5	18.4
SPP	11.9	127	73	15.1	8.7
NWP	15.7	18	10	2.8	1.6
AZN&RMP	8.8	66	39	5.8	3.4
CNV	25.8	23	15	6.0	3.9
National Average *	**216.9**	**73**	**43**		

* Weighted average of all regions. Those regions with technical potential greater than 100% are assumed to export to regions with potential less than 100%. ERCOT's technical potential is truncated from 136% to 100% because of negligible transfer capability out of ERCOT.

Results of Emissions Impacts

The conversion of LDVs to PHEVs has significant implications for overall emissions as electricity displaces gasoline. The net balance in the emissions of this fuel-displacement process along the entire fuel cycle from the extraction of the primary energy to the final conversion in the vehicle into useful energy is discussed below.

For the nation as a whole, the total greenhouse gases[(a)] are expected to be reduced by a maximum of 27% from the projected penetration of PHEVs. The key driver for this result is the overall improvement in efficiency along the electricity generation path compared to the entire conversion chain from crude oil to gasoline to the combustion process in the vehicle. Fundamental to this result is the assumption that a PHEV by itself would be more efficient than a conventional gasoline car because of the regenerative braking capability that stores the kinetic energy in the battery during deceleration and because the engine operates at near optimal conditions more of the time than in conventional vehicles. On a regional basis, the improvements in greenhouse gas emissions could be as large as 40%, as in ERCOT, which has a large penetration of natural-gas power plants. Conversely, the improvement in greenhouse gas emissions could be zero or slightly negative for the MAPP region with essentially all coal generation (see Table 3).

Total volatile organic compounds (VOCs) and carbon monoxide (CO) emissions would improve radically by 93% and 98%, respectively, as a result of eliminating the use of the internal combustion engine. The VOC emissions reduction may be significantly over-estimated because PHEVs will still have gasoline in their tanks and vent to the atmosphere during refueling and to some extent while parked and during driving. The total nitrogen oxides (NO_X) emissions are significantly reduced (31%), primarily because of the avoidance of the internal combustion process in the vehicle as well as reducing the volume of gasoline to be produced in refineries.

The total particulate emissions (PM10) are likely to increase nationally by 18%, caused primarily by the increased dispatch of coal-fired plants. As can be seen in Table 3, however, in regions with a large contribution to the marginal generation from natural-gas fueled plants, total particulate emissions could improve. The total SO_X emissions require special interpretation. The GREET indicates an increase at the national level by about 125%, primarily caused by additional generation from coal-fired power plants. However, because of the current EPA emissions regulations (Clean Air Act and Clean Air Interstate Rule), the total emissions from U.S. power plants are capped. To meet these regulatory requirements while, at the same time, increasing the generation from existing coal-fired power plants requires additional technologies for reducing sulfur emissions. The capital requirements for the necessary emission reductions are difficult to estimate and require complex production cost and capacity expansion modeling tools.

It should be noted that with the emergence of PHEVs, the emission sources will shift from millions of individual vehicles to a few hundred central generation facilities. All urban emissions are expected to significantly improve (see Table 3). The economics for emission-reduction and carbon-sequestration technologies may look much more attractive when installed at central power plants rather than in motor vehicles, especially when the costs are spread over longer operating periods and billions of additional kilowatt hours.

(a) Greenhouse gases are defined as: carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) [Brinkman et al., 2005, p. 13].

Table 3: Emissions Results Using the GREET Model

	ECAR	ERCOT	MACC	MAIN	MAPP	NPCC	FRCC	SERC	SPP	NWP	AZN& RMP	CNV	U.S. total
	Power Generation Composition												
Natural Gas	32%	94%	74%	42%	1%	91%	69%	57%	78%	43%	63%	93%	
Coal	68%	6%	26%	58%	99%	9%	31%	43%	22%	57%	37%	7%	
Emissions	**Emissions Ratio (Electric Vehicle/Gasoline Vehicle)**												
GHGs	0.87	0.60	0.69	0.83	1.01	0.61	0.71	0.76	0.66	0.84	0.73	0.61	0.73
VOC: Total	0.11	0.04	0.06	0.10	0.14	0.04	0.07	0.08	0.06	0.10	0.07	0.04	0.07
CO: Total	0.01	0.02	0.02	0.02	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02
NOx: Total	1.02	0.38	0.59	0.93	1.35	0.41	0.64	0.76	0.54	0.93	0.71	0.39	0.69
PM10: Total	1.55	0.81	1.06	1.45	1.94	0.86	1.13	1.26	0.99	1.46	1.19	0.84	1.18
SOx: Total	3.94	0.42	1.68	3.59	5.96	0.64	2.05	2.67	1.34	3.77	2.35	0.53	2.25
VOC: Urban	0.00	0.01	0.01	0.01	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
CO: Urban	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NOx: Urban	0.10	0.11	0.11	0.10	0.09	0.11	0.11	0.10	0.11	0.10	0.10	0.11	0.10
PM10:Urban	0.60	0.62	0.62	0.60	0.58	0.62	0.61	0.61	0.62	0.61	0.61	0.62	0.61
SOx: Urban	0.35	0.04	0.14	0.30	0.51	0.05	0.17	0.22	0.12	0.31	0.20	0.04	0.19

Potential to Reduce Dependency on Foreign Crude Oil Imports

One of the key premises of the PHEV technology, from a policy perspective, is the potential to reduce U.S. dependency on imports of foreign crude oil. To illustrate the potential benefits of a conversion from a gasoline-driven LDV fleet to PHEVs, we estimated a displacement potential on the total national consumption of gasoline. This figure is an upper-bound estimate on the gasoline-displacement potential. The realizable potential will most likely be smaller to account for the long-distance driving above 33 miles per day and the few days during the year when PHEVs may not be fully charged because of maximum peak conditions on the grid. **Error! Reference source not found.** shows that in 2005, the United States consumed gasoline at a rate that required 9.1 million barrels of crude oil per day [EIA, 2005a]. Considering that the LDV fleet consumes 97% of the entire gasoline supply, the conversion of 73% of the LDV fleet to PHEVs could reduce gasoline consumption by a crude oil equivalence of 6.5 million barrels per day (MMBpd). This reduction in the U.S. gasoline consumption is the equivalent of 52% of foreign petroleum imports.

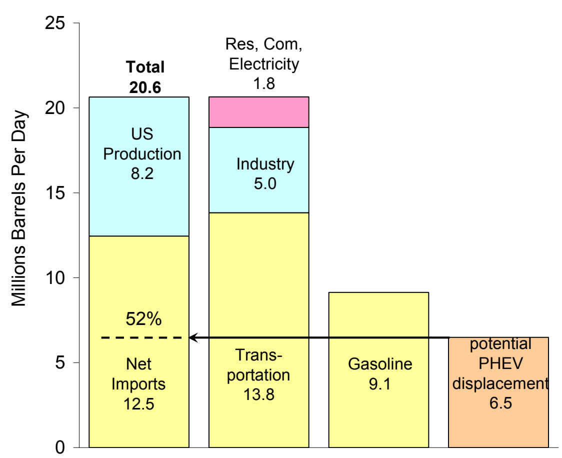

Figure 4: Petroleum Supply, Consumptions, and PHEV Displacement Potential [EIA, 2005a]

Other Electric System Impacts

Providing 73% of the daily energy requirements of the U.S. LDV fleet with electricity would add approximately 910 billion kWh, an increase of about 24% of the total U.S. annual generation, in 2002 [EIA, 2006b]. Without further infrastructure investments, the current electric power system would be heavily loaded for most hours of all days. It is questionable whether today's electricity infrastructure and capacity mix will be able to support this level of loading on a sustained basis. Planned outages for plant maintenance would likely need to occur more frequently, making it more difficult to schedule maintenance. Furthermore, the overall system reliability could be reduced in this high-use scenario as less reserve capacity is available to the system operators for managing system emergencies. Grid operating procedures would need to be changed to shift some of the ancillary services to load resources to free up generation capacity for energy production. "Smart" PHEV charging systems that recognize grid emergencies could mitigate the extent and severity of these grid emergencies. Vehicle-to-grid (V2G) concepts (not examined in this study) could potentially provide additional reliability enhancements using the storage capacity of the PHEV by reversing the power flow from the battery to the grid [Kempton, 2005a and 2005b]. Particularly with high system utilization, smart loads become an attractive reliability resource that could become more prevalent with current communications and automation investments.

The valley-filling methodology is predicated on the notion that the entire PHEV load is managed to fit perfectly into the valley without setting new peaks. One approach to realize load management is via electricity pricing that discourages customers from charging the PHEVs during peak periods and encourages them to charge during off-peak periods. The PHEV charger would need to be a smart device equipped with communications or—in the most simple way—a timer to prevent charging during peak periods.

While we rationalized that PHEV charging could be done without setting new system peaks and causing new transmission congestions, it represents a significant shift from a power system with peaks and valleys to one that is constantly loaded. While the bulk power system is designed to operate reliably at these levels during peak periods, sustained operation at these levels may reveal new constraints. For example, there may be intra-regional transmission constraints that come into place when transmission lines are heavily loaded for extended periods. Specific and detailed regional studies would reveal these delivery constraints. Similarly, the distribution system may impose some additional constraints on the delivery limits to off-peak PHEV charging. System components such as transformers may impose additional constraints on the delivery limit because they may not be designed to sustain a constant high loading without a period of lower load conditions during which the equipment can cool down. Preliminary analyses of residential distribution feeders load data suggest that the characteristics of the residential load shapes are similar in proportion to the peak and valley as observed at the regional system level.[a] This provides some evidence that the additional load could potentially be accommodated in the off-peak valley without setting a new peak during the former off-peak period. However, additional analyses of impacts on the distribution system with a different composition of industrial, commercial, and residential customers are warranted to investigate the assumptions made in this study.

(a) Based on substation and feeder data from predominantly residential feeders in Southern California Edison's and Allegheny Power's service territory.

The expected anti-cyclical load shape of the emerging new PHEV load will flatten the overall load duration characteristics, and as a result, it is likely to change the mix of future power plant types and technologies with important implications to base-load coal and nuclear technologies. This is potentially beneficial for these power generation technologies, as they typically have the lowest power-production costs. Similarly, PHEVs provide a ready source of demand for power from intermittent renewable resources that may allow greater utilization of power from the wind and sun than otherwise. However, with an increasing share of intermittent resources to the total generation mix, the load-following and regulation services requirements increase to compensate for the growing intermittency and variability in the power supply. This reduces the availability of the capacity of some intermediate power plants to provide baseload energy. Instead, this capacity is required for meeting the increased load-following needs.

In the short run, the expected increased-use scenario will affect wholesale electricity markets as supplies of generation resources remain tight over longer periods. One result could be an upward pressure on wholesale electricity prices, although the persistence of higher prices will induce investments in new generation and transmission capacity. In the long-term, the supply will follow the load to meet the growing demand. The development of a new transportation load may facilitate the financing of low-cost base-load generation and renewables that is currently lacking in the marketplace. The potential for short-term price increases and longer-term price and rate decreases needs to be analyzed further and considered as part of the public policy debate. A fuller discussion of the economic assessment of PHEVs is in the companion paper (Part II: Economic Assessment), which examines impacts to the revenue requirements and the electric rates in a fully regulated utility environment.

SUMMARY

The results of the technical potential analysis are listed below:

- The existing electricity infrastructure as a national resource has sufficient available capacity to fuel up to 84% of the nation's cars, pickup trucks, and SUVs (198 million) or about 73% of the light duty fleet (about 217 million vehicles) for a daily drive of 33 miles on average.
- There are potentially significant emissions impacts if the gasoline-based LDV fleet were to transition to a PHEV technology. Greenhouse gases and some criteria emissions would be reduced based on total emission figures. Particulates emissions would increase as a result of increased dispatch of coal-fired power plants. Furthermore, the increased generation from coal power plants requires SO_2 emission-reduction technologies to meet EPA regulations. There are also regional differences that depend upon the mix of coal and natural-gas-fired power plants. All emissions in urban areas are expected to improve because of the shifting of the emission sources from millions of individual vehicles in population centers to central generation plants that are traditionally located away from population centers.
- A shift from gasoline to PHEVs could reduce the gasoline consumption by up to 6.5 MMBpd, which is equivalent to 52% of the U.S. petroleum imports.
- Several other grid-related impacts are likely to emerge when adding a significant new load for charging PHEVs. Higher system loading could impact the overall system reliability when the entire infrastructure is used near its maximum capability for long periods. However, "Smart" PHEV charging systems that recognize grid conditions could mitigate the extent and severity of grid

emergencies. Near maximum utilization of the nation's power plants is also likely to impact wholesale electricity markets. The mix of future power plant types and technologies may change as a result of the flatter load-duration curve favoring more base-load power plants and intermittent renewable energy resources.

ACKNOWLEDGEMENT

The authors would like to acknowledge the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy (DOE) for support of the analysis. Particular thanks are extended to the DOE program manager, Eric Lightner, who provided helpful directions for writing this paper.

CONTACT

Michael Kintner-Meyer, Ph.D., Pacific Northwest National Laboratory. Phone: 509.375.4306. Email: Michael.Kintner-Meyer@pnl.gov.

REFERENCES

BPA. 2003. Federal Columbia River Power System (Bonneville Power Administration) Brochure: available online: http://www.bpa.gov/corporate/BPANews/Library/images/Dams/.

Brinkman, N., Wang, M., Weber, T., Darlington, T. 2005. Well-to-Wheels analysis of Advanced Fuel/Vehicle Systems – A North American Study of Energy Use, Greenhouse Gas Emissions, and Criteria Pollutant Emissions. Argonne National Laboratory, Argonne, IL.

Davis, S; Diegel, S. 2006. Transportation Energy Data Book . 25th Edition. p. 8-15. ORNL-6974. Center for Transportation Analysis, Oak Ridge National Laboratory, Oak Ridge, TN.

DOE. 2003. Technology Options For the Near and Long Term. A Compendium of Technology Profiles and Ongoing Research and Development at Participating Federal Agencies. Section 1.3.2. DOE/PI-0002. Department of Energy, Washington, DC.

DOE. 2006. National Electric Transmission Congestion Study. Office of Electricity Delivery and Energy Reliability. U.S. Department of Energy, Washington, DC.

DOT. 2002. Highway Statistics 2001. Table 5-1: Motor-Vehicle Registrations: 2001. U.S. Department of Transportation, Federal Highway Administration, Washington, DC.

DOT. 2003. Highlights of the 2001 National Household Travel Survey. BTS03-05. Table A-8. U.S. Department of Transportation, Bureau of Transportation Statistics, Washington, DC.

Duvall, M. 2002. Comparing the Benefits and Impacts of Hybrid Electric Vehicle Options for Compact Sedan and Sport Utility Vehicles. Final Report 1006892. Electric Power Research Institute. Palo Alto, CA.

Duvall, M. 2003. Electricity as an Alternative Fuel: Rethinking Off-Peak Charging. Plug-in HEV workshop. Electric Power Research Institute. Palo Alto, CA.

Duvall, M. 2004. Advanced Batteries for Electric Drive Vehicles. A Technology and Cost-Effectiveness Assessment for Battery Electric Vehicles, Power Assist Hybrid Electric Vehicles, and Plug-in Hybrid Electric Vehicles. Final Report. 1009299. Electric Power Research Institute, Palo Alto, CA.

EIA. 2005a. Annual Energy Review, 2005. Based on Energy Flow Diagram p. 3. DOE/EIA-0384(2005), Energy Information Administration, Washington, DC.

EIA. 2005b. Electric Power Annual 2005. Energy Information Administration. DOE/EIA-0348(2005). Energy Information Administration, Washington, DC.

EIA. 2006a. The Electricity Market Module of the National Energy Modeling System. Model Documentation Report. DOE/EIA M068. Energy Information Administration, Washington, DC.

EIA. 2006b. Annual Energy Outlook 2006. Supplemental Tables. DOE/EIA-0383(2006). Energy Information Administration, Washington, DC.

EIA. 2006c. The Electricity Market Module of the National Energy Modeling System. Model Documentation Report. DOE/EIA-M068(2006).

Graham, B. 2005. EPRI and Its Plug-In Hybrid Vehicle Initiative. Presentation. Electric Power Research Institute, Palo Alto, CA.

GREET. 2001. Development and Use of GREET 1.6 Fuel-Cycle Model for Transportation Fuels and Vehicle Technologies. Argonne National Laboratory, Argonne, IL.

Hu, P. and Young, J. 1994. 1990 Nationwide Personal Transportation Survey Databook. Vol. 1 and 2. Oak Ridge National Laboratory, Oak Ridge, TN.

Kempton, W.; Tomić, J. 2005a. Vehicle-to-Grid Power Implementation: From Stabilizing the Grid to Supporting Large-Scale Renewable Energy. Journal of Power Sources. Vol. 144, Issue 1, pages 280-294. Elsevier, Atlanta, GA.

Kempton, W.; Tomić, J. 2005b. Vehicle-to-Grid Power Fundaments: Calculating Capacity and Net Revenue. Journal of Power Sources. Vol. 144, Issue 1, pages 268-279. Elsevier, Atlanta, GA.

Potomac. 2006. 2005 State of the Market Report for the ERCOT Wholesale Electricity Markets. Potomac Economics, Ltd. Advisor to the Wholesale Market Oversight Public Utility Commission of Texas.

Taylor, D. 2003. Plug-in HEVs. Presentation. Southern California Edison.

APPENDIX A

The figures below show for selected regions a daily load profile for the summer and winter seasons. Each figure shows 1) average seasonal load profile, 2) generation dispatch to meet average seasonal load profile, 3) valley-filling generation potential shown as hatched bars and denoted in the legend as "additional" plant type, and 4) seasonal peak load day.

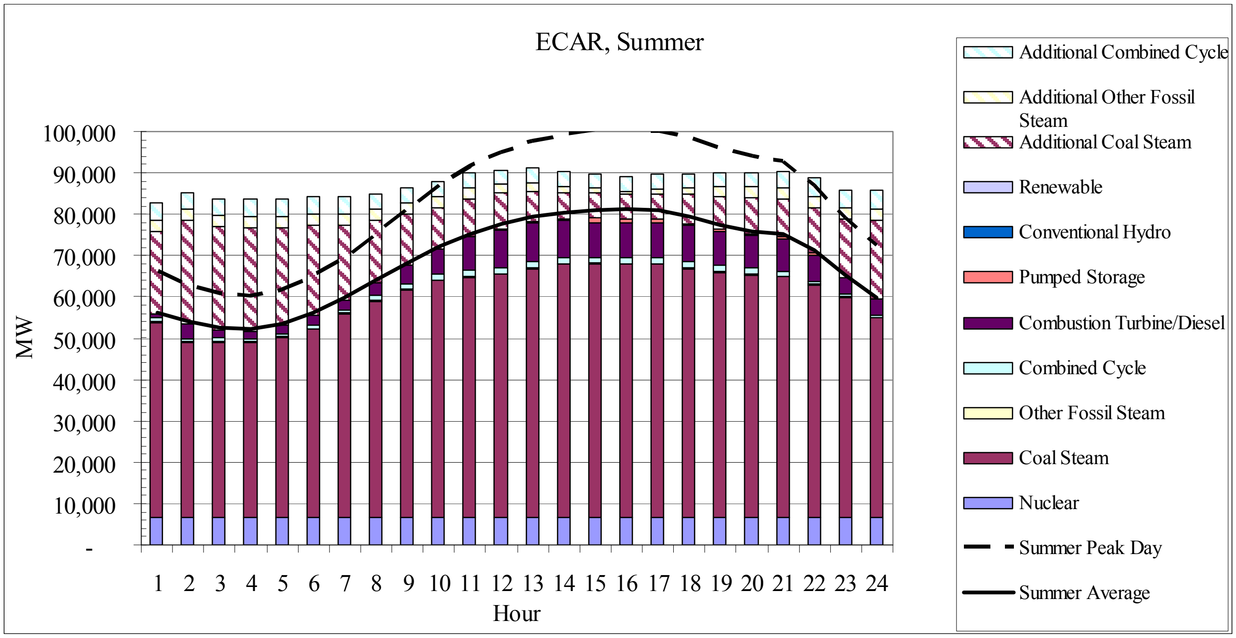

Figure A.1: ECAR Dispatch for Summer Average Load Profile, Valley-Filling Potential, and Peak Day

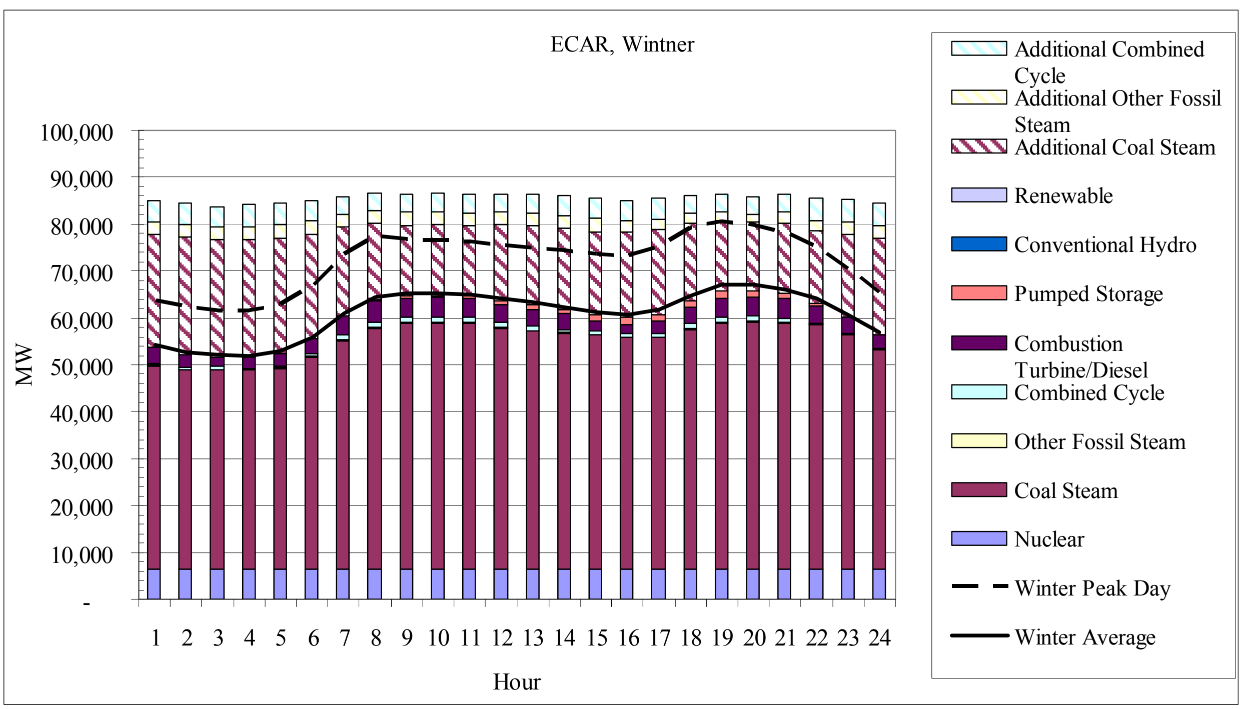

Figure A.2: ECAR Dispatch for Winter Average Load Profile, Valley-Filling Potential, and Peak Day

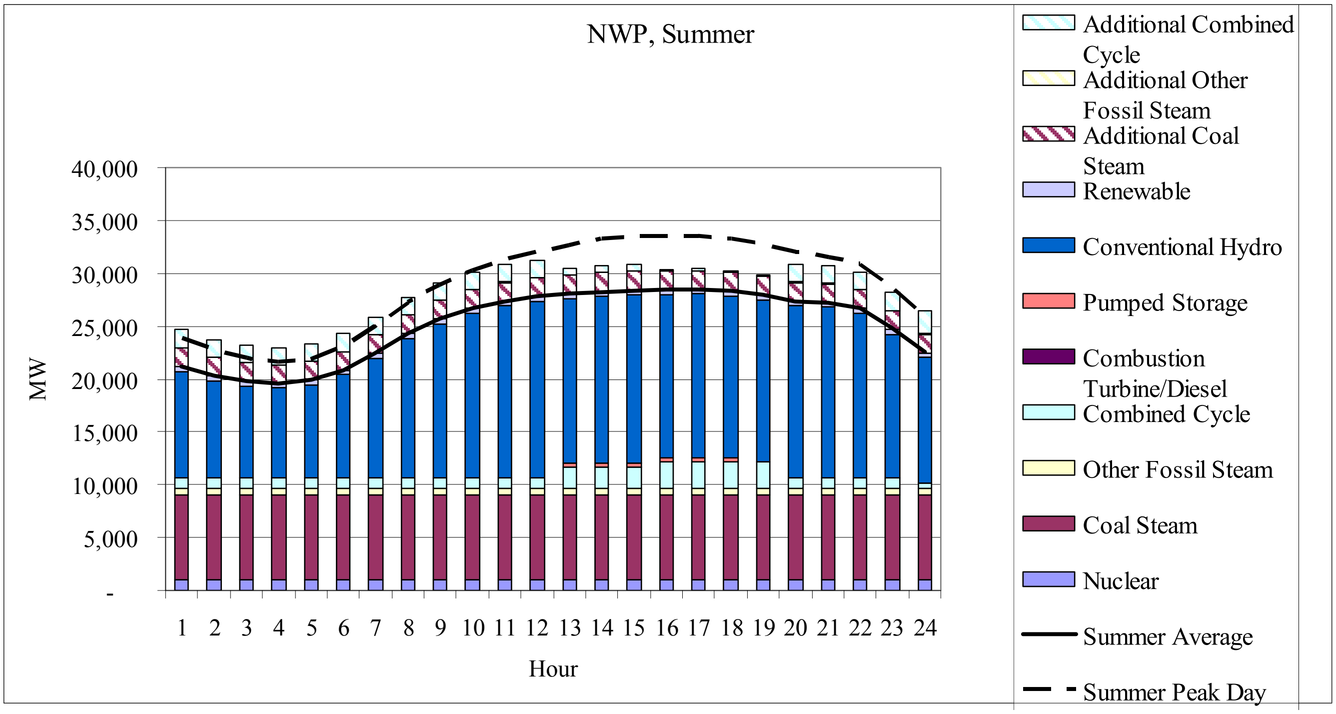

Figure A.3: NWP Dispatch for Summer Average Load Profile, Valley-Filling Potential, and Peak Day

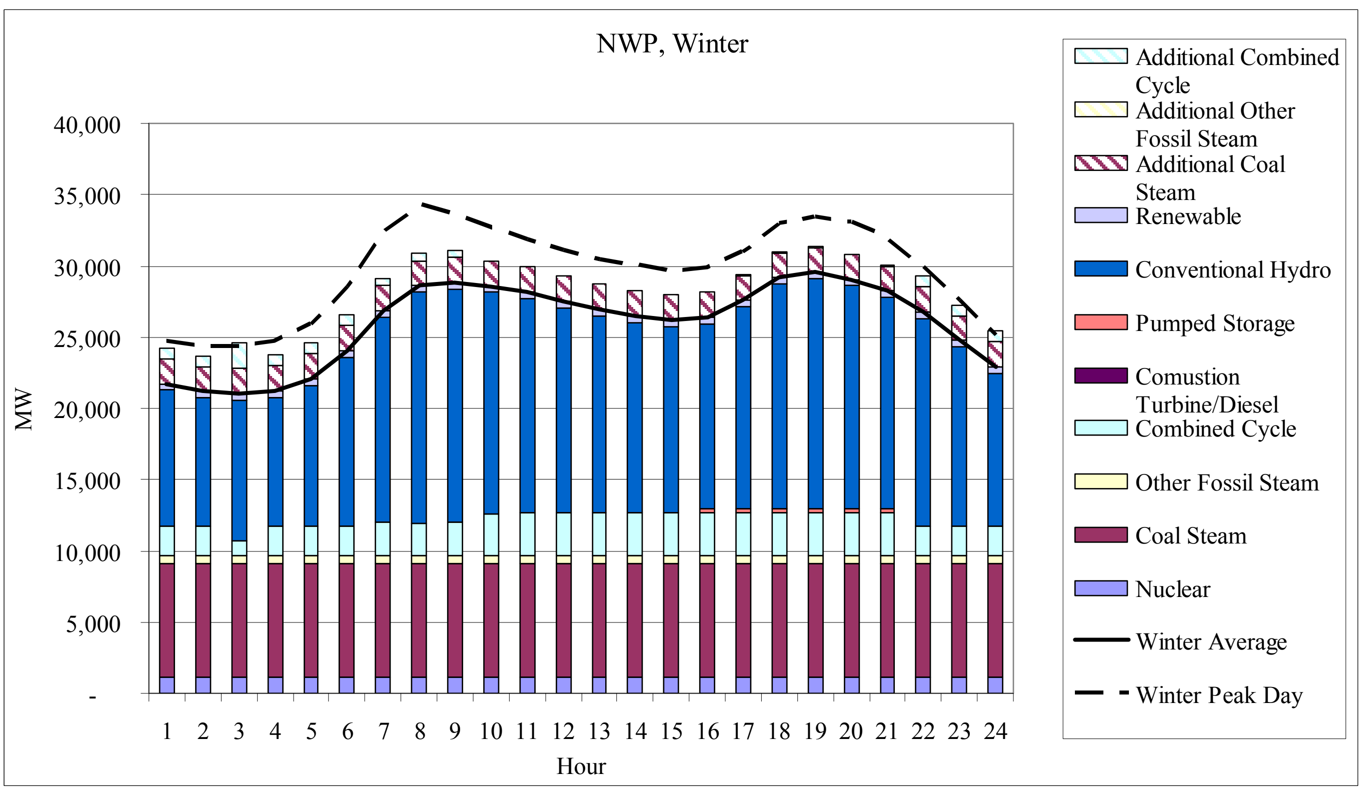

Figure A.4: NWP Dispatch for Winter Average Load Profile, Valley-Filling Potential, and Peak Day

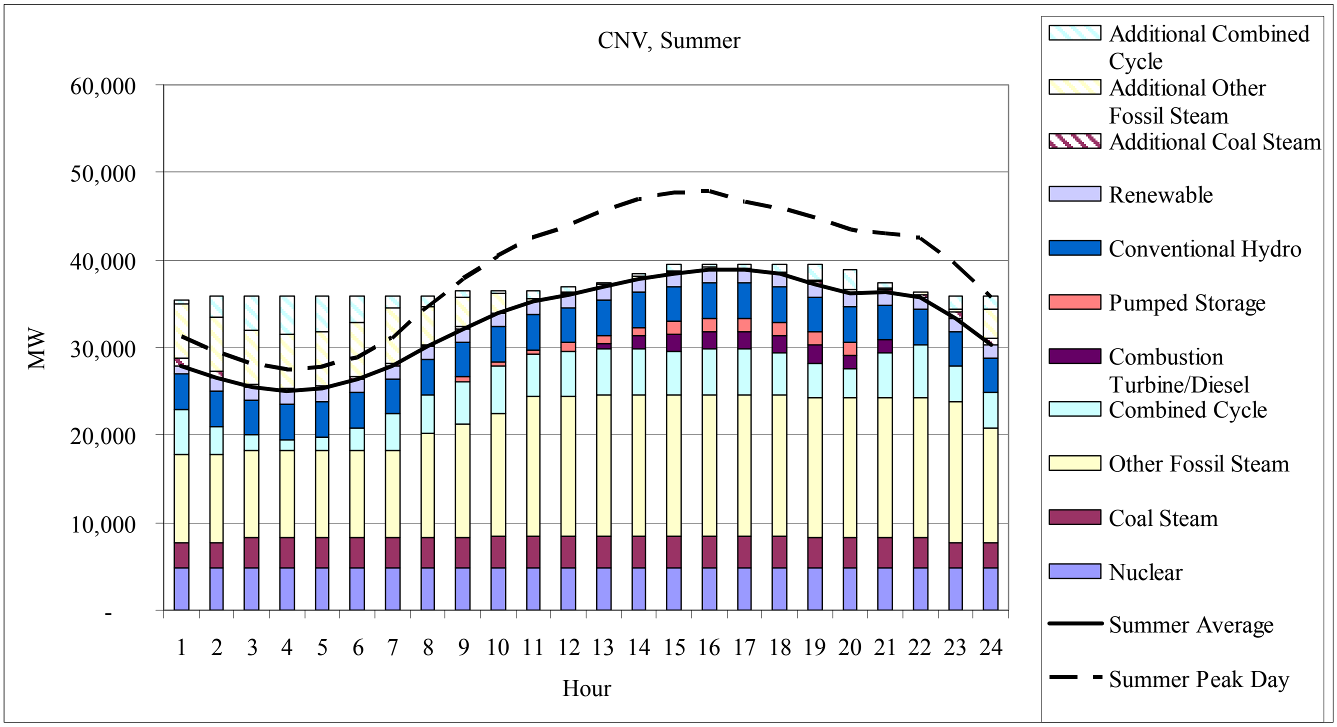

Figure A.5: CNV Dispatch for Summer Average Load Profile, Valley-Filling Potential, and Peak Day

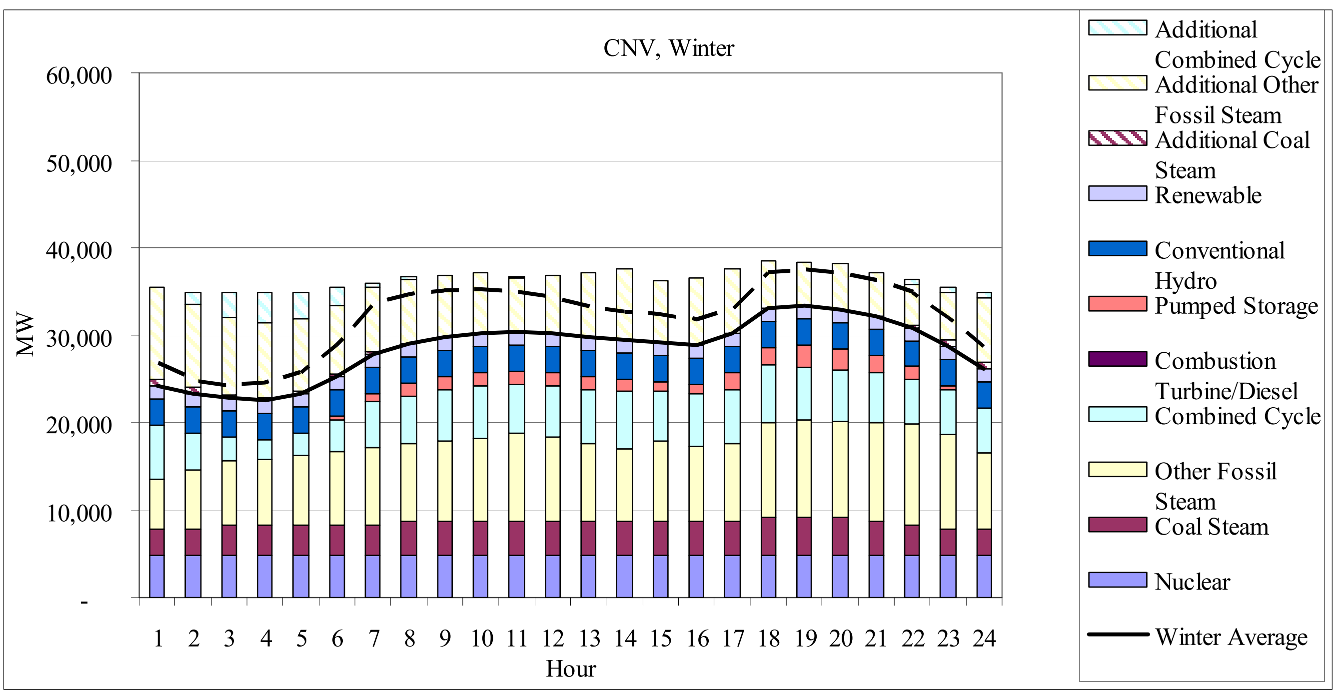

Figure A.6: CNV Dispatch for Winter Average Load Profile, Valley-Filling Potential, and Peak Day

IMPACTS ASSESSMENT OF PLUG-IN HYBRID VEHICLES ON ELECTRIC UTILITIES AND REGIONAL U.S. POWER GRIDS: PART 2: ECONOMIC ASSESSMENT

Michael J. Scott
Michael Kintner-Meyer
Douglas B. Elliott
William M. Warwick
Pacific Northwest National Laboratory[(a)]

November, 2007

ABSTRACT

The current U.S. electric grid has spare generation and transmission capacity at night. Without considering some of the practical constraints that could apply to the significantly increased operation of the existing capacity or the need to maintain operating reserves, the current spare capacity could generate and deliver the necessary energy to power the majority of the U.S. light-duty vehicle fleet, if that fleet consisted of plug-in hybrid electric vehicles (PHEVs). If this occurred,, it would reduce greenhouse gas emissions, improve the economics of the electricity industry, and reduce the U.S. dependency on foreign oil. Two companion papers investigate this concept. The overall screening approach frames the analysis from a simple grid capability and economics point of view. The first paper (Part 1) discusses the maximum technical potential of PHEVs without adding new electricity infrastructure or considering operational constraints. This second paper (Part 2) provides an economic assessment of the impacts of PHEV adoption on vehicle owners and on electric utilities. To estimate vehicle owner impacts, the paper calculates the life-cycle cost (LCC) of private vehicle transportation for vehicle owners with PHEVs and compares it with the LCC for conventional light-duty vehicles. To calculate the impacts on electric utilities, the paper provides estimates of the impacts of PHEVs on the revenue and cost streams of two sample utilities, one with its own generating resources, and one that is highly dependent on imported power ("wires only"). This calculation assumes that the host utility and the grid will have to make only minor accommodations to absorb a substantial number of vehicles. With these and other assumptions, the paper finds favorable impacts on the LCC of vehicle owners and average costs of power for both types of utilities.

INTRODUCTION

The current U.S. electric infrastructure operates with generation reserves and spare transmission capability the majority of the time. The system operates at its full capacity only a few hundred hours per year at most. Combined with technical improvements in vehicle electronics and batteries, this "spare" capacity has attracted the interest of a number of vehicle and utility researchers. The economics of all-electric vehicles are rapidly changing due to the recent development of commercial hybrid electric vehicles (HEVs) and a fledging after-market for modifications of these vehicles for plug-in capability. Current demand for and commercial production of hybrid and electric vehicles now justifies updated

(a) Operated for the U.S. Department of Energy by Battelle under Contract DE-AC05-76RL01830.

analyses of how they can be supported by the bulk power system and the associated consequences. The results obtained in Part 1 of this analysis [Kintner-Meyer et al. 2007] indicate that the use of off-peak power generation and transmission capability could deliver a substantial portion of the energy needed to fuel the nation's light-duty vehicle (LDV) fleet—cars, pickup trucks, sport utility vehicles (SUVs), and vans. Some researchers recently have even explored the idea of using plug-in hybrid electric vehicles (PHEVs) to provide peak electrical power back to the grid using a concept known as vehicle-to-grid (V2G) (see for example, Kempton and Tomić [2005a, 2005b] and Denholm and Short [2006], who also discuss some of the earlier research and some of the utility impacts of PHEV charging, which we deal with at a more detailed level in this paper). However, whether utility-generated electricity is ever used to power a significant portion of the LDV fleet depends on the collective but independent economic decisions of prospective vehicle owners, who need to know whether the purchasing and operating costs of PHEVs are favorable compared with other alternatives, of electric utility executives, who will want to understand the impacts of large-scale LDV electricity consumption on the utility's bottom line, and of utility regulators concerned about the impact on utility rates and consumer power bills. This paper provides some perspective on these questions by comparing the life-cycle costs of PHEVs with three other types of vehicles and by estimating the economic impact on the average costs of power for two dissimilar electric utilities in the existing U.S. power system.

The analysis in this paper is based on a prototype PHEV, an HEV with additional battery-storage capacity sized to satisfy daily average driving requirements (33 miles per day), solely on electricity.[(b)] The battery is charged with electricity from the electric grid during off-peak hours, all of which occurs during the night. Driving beyond the daily driving range (i.e., long distances) requires that the PHEV's gasoline engine be used. The analysis of this paper focuses on 1) the life-cycle cost (LCC) of a PHEV purchase decision for a variety of electricity prices, gasoline prices, and alternative conventional vehicle efficiencies and 2) the impacts to the cost of electricity as response to a large-scale market penetration of PHEVs that does not require new investment in generation and transmission and distribution (T&D) capacity expansions. We do not discuss the economics of V2G applications. Because we only consider the electrical performance of a PHEV in this paper, the fundamental approach used applies for a pure electric vehicle with electric performance similar to that of a PHEV.

VEHICLE PURCHASER LIFE CYCLE COST (LCC) ANALYSIS

The LCC analysis provides some insights into the economics of PHEV cars from a vehicle purchaser's point of view. We estimate the premium that a prospective vehicle purchaser could pay for a PHEV and still break even on discounted costs when both the premium and the value of energy cost savings are calculated over the life of the vehicle. The LCC economics are considered potentially favorable for a PHEV purchase in those circumstances where a positive premium is calculated. Because the vehicle market is rapidly changing, we make no attempt to compare estimated premiums with actual premiums that may exist currently. The analysis is performed for prospective vehicle purchasers in the states of California and Ohio, the former to reflect an area with high electricity prices, and the latter to reflect more "average" conditions. These states include the service areas of San Diego Gas and Electric and the

(b) It is likely that many drivers of PHEVs will operate their vehicles in a hybrid mode, consuming both gasoline and electricity. For purposes of the simplified screening study, we assume that the PHEV would operate in an electric-only mode. To the extent that drivers operate in a hybrid mode, they and their serving electric utilities will not obtain the cost savings discussed in this paper. Operation in the hybrid mode (e.g., for long commutes, for convenience, or for intercity travel) is beyond the scope of this paper.

Cincinnati Gas and Electric, which are the example electric utilities used in the utility economics analysis in the next section.

Methods

We compare the premium for the purchase of a PHEV car over the price for a conventional car with the savings accrued by using electricity rather than gasoline. The price premium in purchasing a PHEV is amortized over the average length of ownership of 9 years [Hu, 2006]. The following assumptions for the life-cycle cost analysis are used:

- Prevailing discount rate: 8% real
- Life time of ownership: 9 years (ignoring resale value)
- Purchase price premium of PHEV: varying from $1,000 to $10,000
- Price of gasoline: varying from $2.5 per gallon to $3.50 per gallon.
- Average residential electricity rates: California: $0.12 per kWh, Ohio: $0.083 per kWh(c)

To illustrate the sensitivity of the cost-analysis results with respect to the purchasing price premium, gasoline cost, and electricity cost, we choose a range of these three parameters. The residential electric rates are based on average rates determined by state published by the Energy Information Administration [EIA, 2005].

The base-case comparison is performed using a Honda Civic, a compact car with an estimated mixed city-highway fuel economy of 35 miles per gallon (mpg) as the base-case competing vehicle [DOT 2005]. The energy requirements for the PHEV in an electric mode are 0.26 kWh per mile for a compact car. For a broader array of drivers who might be considering an upgrade to a more fuel-efficient vehicle, we also compared the PHEV with a vehicle achieving the current corporate average fuel economy (CAFE) for cars of 27.5 mpg [DOT 2005]. Finally, we compare the PHEV with a Toyota Prius HEV with an estimated mixed city-highway fuel economy of 56 mpg [DOT 2005]. We assume that the PHEV battery has a round-trip full charge and discharge cycle of 80% and an efficiency of 87% for the charger [Duvall 2002, 2003, and 2004]. Discounted maintenance and repair costs are assumed to be the same for conventional vehicles and PHEVs over the life of the vehicle.(d) We also assume that there is no premium or discounted resale value of a PHEV in comparison with conventional vehicles, which allows us to ignore the time period after the 9-year ownership period.

(c) Residential rates in California are tiered, and rates in the top tier are in the range of $0.30 to $0.40 per kWh. However, California does have rate schedules for electric vehicles (EV) and the application of the EV rate schedules requires customers to have a separate meter.

(d) Hybrid battery replacement is an item of repair cost not applicable to internal combustion vehicles. Reducing the cost and extending the lifetime of these batteries is a goal of active current research sponsored by the U.S. Department of Energy and private organizations.

Results

Figure 1 shows the life-cycle-cost analysis results for purchasing and operating a PHEV compared with a conventional high-fuel-efficiency vehicle such as a Honda Civic. The results are expressed by diagonal break-even lines for varying gasoline prices. Each break-even line in the figure assumes a specific gasoline price and delineates a region below and to the left of the line in which a PHEV would have a lower life-cycle cost than a conventional vehicle and therefore would justify a premium purchase price. This is described as a cost-effective region. Above each line is the region where the PHEV is not cost effective. The premium can be read off the horizontal axis for a given electricity price. For instance, using California average residential rates of 12 cents per kWh and a price of the gasoline of $2.50 per gallon, the break-even point for the purchasing premium is $2,000 for California. In the state of Ohio, with lower electric rates, the break-even point at the gasoline price of $2.50 per gallon is $3,000 (see Figure 1).

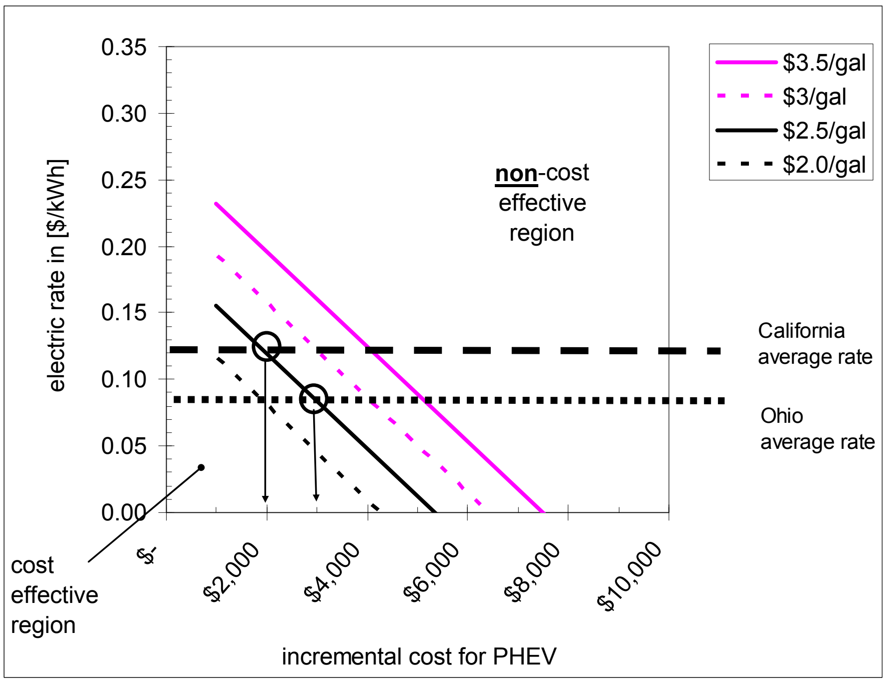

Figure 1: Results of the Life-Cycle Cost Analysis for a PHEV Compared with a Honda Civic with 35 MPG Mixed City-Highway Fuel Economy. Diagonal Lines Denote the Break-Even Point.

Figure 2 offers a comparison to a vehicle meeting the CAFE standard of 27.5 mpg. At California electricity prices of $0.12 per kWh and $2.50 per gallon, the calculated premium rises to about $3,500 over that of a conventional vehicle. In Ohio, the premium rises to slightly below $4,600 (see Figure 2).

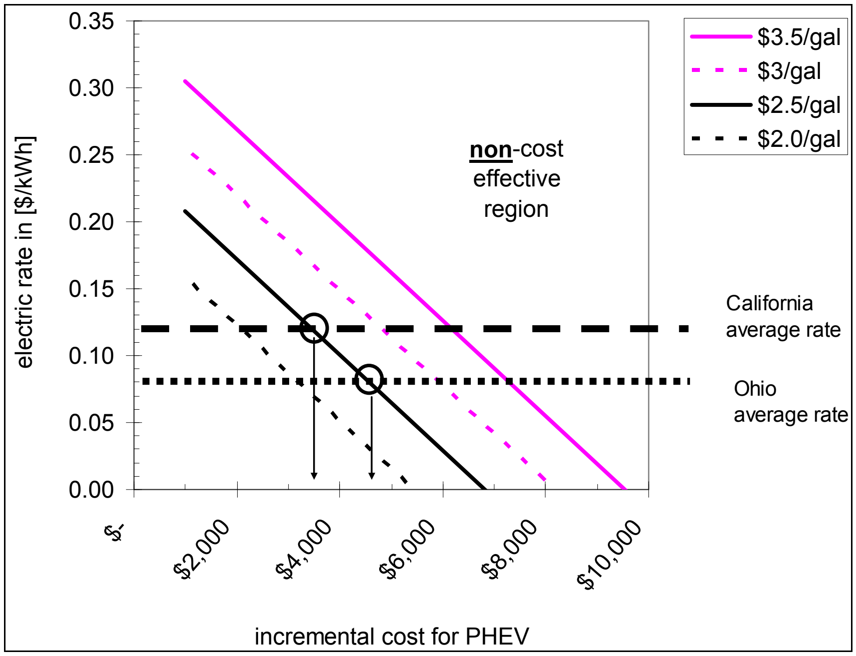

Figure 2: Results of the Life-Cycle Cost Analysis for a PHEV Compared with a Conventional Vehicle with 27.5 MPG Fuel Economy. Diagonal Lines Denote the Break-Even Point.

Examining the cost-effectiveness of a PHEV compact car to an HEV represented by a Toyota Prius with a mixed city/highway fuel efficiency of 56 mpg, we find that with California average residential electricity rates, the allowable purchasing premium is zero. With the lower electric rates in Ohio, the allowable premium for cost-effectiveness is about $1,000, given a fuel cost of $2.50 per gallon (see Figure 3).

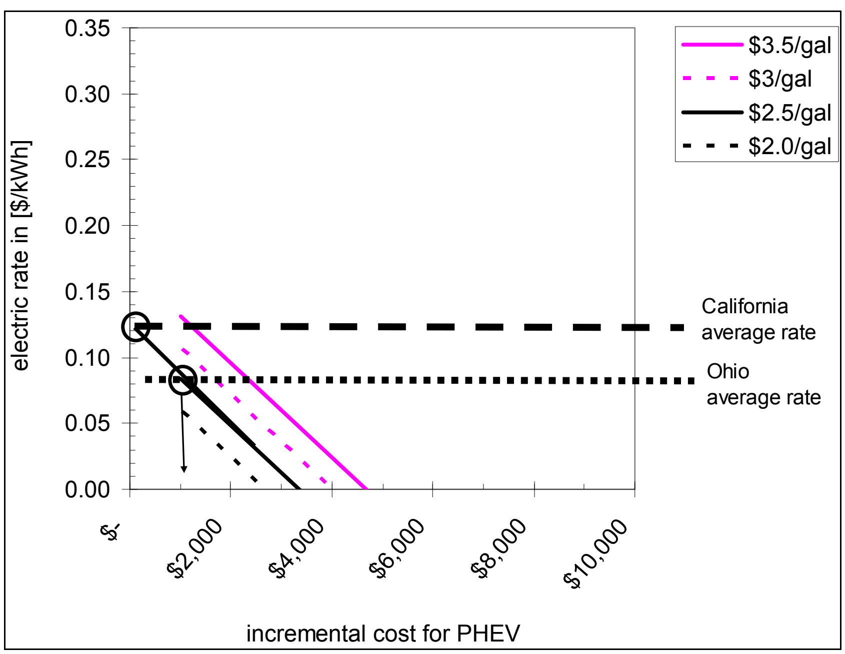

Figure 3: Results of The Life-Cycle Cost Analysis for a PHEV Compared with a Toyota Prius with 56 MPG Mixed City-Highway Fuel Economy. Diagonal Lines Denote the Break-Even Point.

UTILITY ANALYSIS

This section of the paper investigates the revenue and cost effects of large-scale instantaneous adoption of PHEVs from the perspective of electricity demand and costs in the grid for 2003–2004. It does not address any additional benefits or costs of vehicle-to-grid electric power generation or spinning reserve services that PHEVs may provide in the future.

Methods

The analysis of impacts on the electric utilities was conducted on two very different utilities, Cincinnati Gas and Electric Company (CGE), which is located in the East Central Area Reliability Coordinating Agreement (ECAR) North American Electric Reliability Council (NERC) region, and San Diego Gas and Electric Company (SDG&E), which is located in the California and Southern Nevada (CNV) part of the Western Electricity Coordinating Council (WECC) NERC region (see Figure 1 in the Part 1 paper, Kintner-Meyer et al. 2007]. To discuss the PHEV impacts on electric utilities, the paper estimates the impacts on the average total cost and its allocation to generation and T&D as additional electricity is generated or purchased for the support of PHEVs. Two example utilities are discussed—one with substantial fossil fuel-fired base load and load-following generating resources (CGE), and one that is highly dependent on purchased power, largely from natural gas-fired power plants (SDG&E). Throughout the analysis, it is assumed that electricity prices to rate payers are unchanged; thus, decreases in utility average costs would increase profitability, while increases in average costs would decrease profitability. Increases in utility profits could induce rate reductions to rate payers should the regulatory authorities so choose. (Note also that special EV rates could be designed to keep both ratepayers and utility shareholders whole.)

Table 1 shows the characteristics of these utilities in the years 2003 and 2004 (data availability did not allow CGE to be evaluated for 2004). CGE generates more power than it sells to its retail customers (26,938 GWh generated, vs. 20,590 sold at retail). It also wheels and exchanges significantly more than that (total power supply, including wheeling and wholesale, equals over 179,000 GWh), but that additional power is sold at wholesale to a broader market. Based on the typical dispatching pattern of power plants for ECAR, we assume that CGE has the capability of operating its steam electric power plants a higher percentage of the time than it currently does for valley-filling purposes. SDG&E, by contrast, only generates 36.5% of the electricity it sells at retail. All of that electricity is generated by the San Onofre, CA, nuclear power plant. Because nuclear power plants are typically run at 100% of capacity when available, SDG&E would have to purchase any additional electricity it sells for valley-filling from other entities. It is, in effect, a “wires only” utility for purposes of this paper.

The difference between these two utilities also extends to their cost structure and the average cost of power. CGE has an average cost of power production of about \$39 per MWh (\$0.039 per kWh), of which 40% is variable (mostly fuel), and 60% is fixed. Purchased power costs (all variable) are \$33 per MWh (\$0.033 per kWh). Transmission costs are approximately \$0.50 per MWh (\$0.001 per kWh), but are mostly borne by wheeled and exchanged power. Distribution costs are \$14 per MWh (\$0.014 per kWh) and are virtually all fixed costs. San Diego’s (nuclear) own generation costs of \$78 per MWh (\$0.078 per kWh) are 14% variable and 86% fixed. Its power purchase costs of \$70 per MWh (\$0.070 per kWh) are all variable, and its T&D costs of \$47 per MWh and \$85 per MWh, respectively, (\$0.047 and \$0.085 per kWh), are almost all fixed.

Table 1: Key Characteristics of Cincinnati Gas and Electric and San Diego Gas and Electric

Key Feature	Cincinnati Gas and Electric (Part of Cinergy) 2003	San Diego Gas and Electric (Part of Sempra) 2004
Number of Customers	659,444	1,297,693
Number of Residential Customers	591,050	1,159,634
Total Power Supply (GWh), Including Net Wheeling and Wholesale	179,078	8,448
Total Retail Sales (GWh)	20,590	8,230
Total Residential Sales (GWh)	7,020	3,663
Annual Electric Generation (GWh)	26,938	3,006
Annual Purchased Power (GWh)	152,826	5,472
Average Residential Rate (Revenue per MWh)	$73 per MWh	$146 per MWh
Breakdown of Generation (Annual GWh)		
Steam Electric (Coal or Natural Gas)	26,848	0
Nuclear	0	3,006
Pumped Storage	0	0
Other	90	0
Total	26,938	3,006

Sources: Platts [2005], EEI [2006].

For both utilities, the impact on overall cost and revenue depends on the additional variable cost associated with generating (CGE) or purchasing (SDG&E) electricity to serve the PHEV market and the ability of the utilities to spread fixed cost over more power sales. Average variable costs may rise with increased sales, either because of a shorter supply of electricity at wholesale or because higher-cost generation assets are brought on line, or a combination of both. Average fixed costs will decease, assuming no new infrastructure investment, because the existing debt-service obligation is spread over more MWh sold. As off-peak residential load is added to the system, do the average variable costs rise more than the average fixed costs fall?

To answer this question, we analyze a case that featured substantial market penetration of PHEVs into the residential sector of both the CGE and SDG&E service areas. For purposes of this analysis, we assume that every residential customer has one PHEV. Obviously, this level of market penetration is far beyond what would be expected in the next few years (or, perhaps, even decades), but the case illustrates vividly what the considerations are for electric utilities attempting to absorb PHEVs into their systems. To stay clear of the peaking hours, we assume that all charging takes place during the time period 10 pm to 6 am and that all additional generation will fit into the valley without creating new system peaks. A broad range of battery capacities and recharge requirements is possible. For example, Part 1 of this analysis [Kintner-Meyer et al. 2007] evaluates daily charging requirements from 8.6 kWh to 15.1 kWh per day. For the analysis in this paper, we assume a value toward the upper end of that distribution, 13 kWh per day. For CGE, we evaluated the utility system and hourly demand and concluded that there was more than sufficient off-peak generating and T&D capacity to fully charge one vehicle per residential customer between 10 pm to 6 am on an average day during the summer peak demand season. For SDG&E, which purchases most of its electricity from others, we assume that there is sufficient off-peak power available at wholesale to supply the PHEVs. An evaluation similar to that for CGE indicated that there likely was sufficient 10 pm to 6 am off-peak T&D capacity in the SDG&E system to fully charge one vehicle per residential customer. However, with one vehicle per residential customer, SDG&E off-peak demand approached the overall system peak value, which might mean that T&D capacity, as well as possible additional reserves to meet resource adequacy requirements, would have to be added with 100% market penetration (one PHEV per residential customer). Therefore, we also evaluated SDG&E with a 60% market penetration. The appendix shows the derivation and implications of this additional case.[e]

The following key assumptions for PHEV charging are used:

- Charging time: 10 pm to 6 am (valley-filling) on an average day during the peak summer season.
- 13 KWh per vehicle per night. Average power load per vehicle of 1.625 kW (roughly, 13.5 amps at 120 V alternating current standard service in the home).
- One vehicle per residential customer (100% market penetration). Sensitivity analysis of 60% market penetration was conducted for SDG&E.

Three scenarios are examined.

1. A short run scenario with no change in variable cost including fuel cost.
2. A short run scenario with increase in variable cost due to increases in fuel cost. We assumed that the fuel and other variable resources necessary to generate additional power were more expensive than for current generation and that the additional generation cost was added to the cost of electricity. For CGE, we assumed that the average variable cost of power generation (primarily cost associated with fuel) doubled for the additional generation required. For SDG&E, the baseline cost of natural gas was already very high, so it was assumed that the average variable cost increased for the incremental energy by an arbitrary 50%.
3. A long run scenario with investment for generation. We assume that in the context of the generally growing demand for electricity, the new residential demand represented by PHEVs might require early investment in additional generation. To investigate this possibility, for CGE, we assumed that an additional 600-MW coal-fired power plant would be required at a first cost of approximately $750 million [EIA, 2006]. For SDG&E, which is effectively prohibited by CO_2 emissions standards in California state law from using or importing coal-fired generation, we assumed a gas-fired plant at a first cost of about $350 million [EIA, 2006].

More details on the definition of the scenarios are listed in Table 2.

(e) After this paper was written in January, 2007, the authors were made aware of a similar analysis of vehicle owner and utility economics that was conducted with detailed utility operational information and examined the impacts of a range of charging scenarios [Parks et al. 2007]. The broad conclusions of that study are similar to those contained here.

Table 2: Utility Scenarios Examined

Scenario	Cincinnati Gas and Electric (2003)	San Diego Gas and Electric (2004)
1. Short Run: No Change in Fuel Prices; no Additional Investment	Average Variable Cost: $15.80/MWh (coal-fired) No incremental investment	Average Variable Cost: $57.13/MWh (mainly natural gas-fired) No incremental investment
2. Short Run: Fuel Costs Higher for Incremental Generation	Average Variable Cost: $17.29/MWh (coal-fired). Average variable cost doubles for incremental generation. No incremental investment	Average Variable Cost: $68.37/MWh (mainly natural gas-fired). Average variable cost increases 50% for incremental generation. No incremental investment
3. Long Run: Incremental Investment in New Coal-Fired 600-W(e) Generating Plant	Average Variable Cost: $15.80/MWh (coal-fired) Incremental investment = $750 million	Average Variable Cost: $52.18/MWh (natural gas-fired) Incremental investment = $350 million

Results for CGE

In the short run, the 100% residential market penetration of PHEVs results in an additional 591,000 PHEVs that collectively result in an additional demand of 960 MW between 10 pm and 6 am, or about 2,800 GWh per year. The additional cost of generating and transmitting this power is about $43.2 million, but the average cost of power declines because all of the power is produced and consumed off-peak and contributes no additional fixed cost. As shown in Figure 4, the average cost of power declines from $54 to $50 per MWh in the short run. This cost savings is available either to reduce rates or to increase profits or both. Any rate-making response by the utility and its regulators is beyond the scope of this paper and has not been considered.

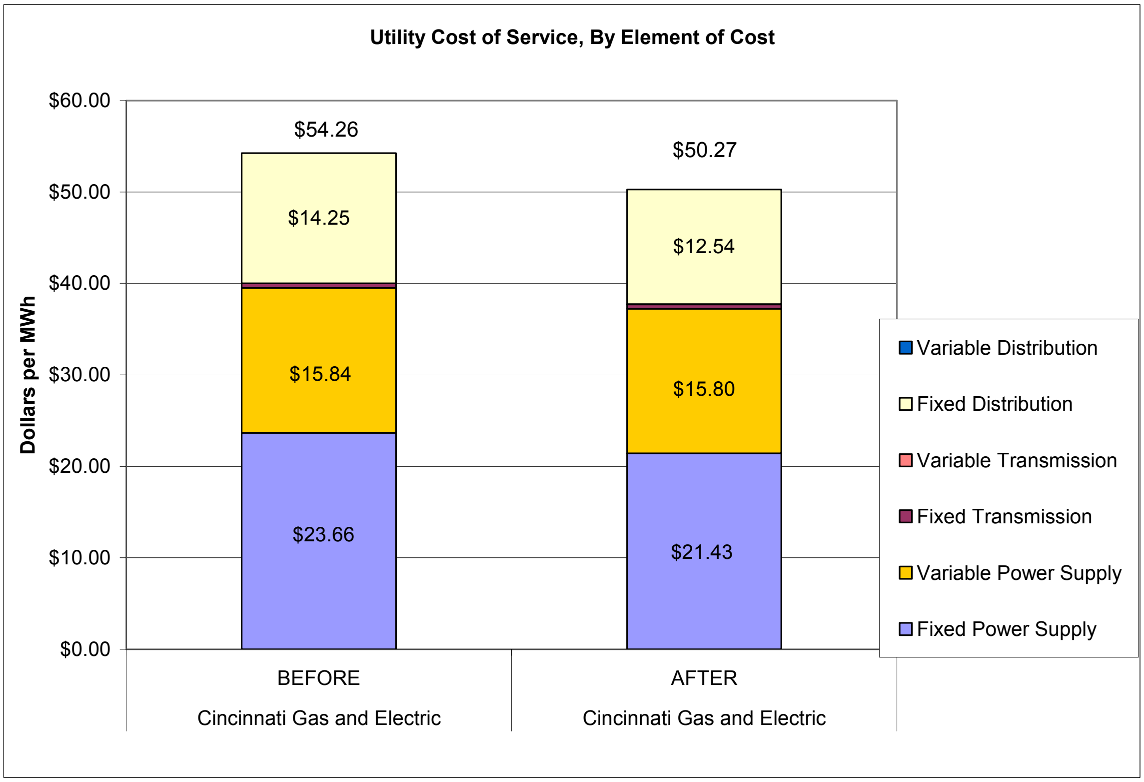

Figure 4: Short Run Impact of PHEV Valley-Filling on Components of System Cost for Cincinnati Gas and Electric

The analysis shown in Figure 4 assumes that there is essentially no change in the average variable cost of generating power in the short run as the PHEVs penetrate the market, and the off-peak demand for power increases. An alternative possibility is that the additional demand could result in more expensive power, either because the utility would be operating less-efficient generating facilities more often or else would have to pay a premium for the additional coal. In Figure 5, we imagine a case where the variable cost of incremental generation doubles because of increased fuel costs. Fuel costs make up 83% of the variable cost. The result of this scenario is shown in the third bar in the Figure 5. Even though the increase in the average variable cost of generation does increase the average cost of electricity by a small amount compared with the base-case, the PHEVs still confer a significant beneficial reduction in the average cost of power.

Finally, the last bar in Figure 5 shows what happens if higher off-peak demand from PHEVs results in a new coal-fired power plant being built, together with the necessity to retire its fixed costs, principal, and interest over 40 years (the resulting annualization of $750 million at an assumed interest rate of 6% is $48.9 million per year) in addition to the already-assumed $43.2 million for extra fuel cost. Here, the economics are not quite as favorable, but the average costs of power still fall to $52 per MWh from $54 per MWh in the base case. A utility with relatively low marginal costs of generation, high fixed costs, and a large difference between peak and off-peak demand can benefit from market penetration of PHEVs.

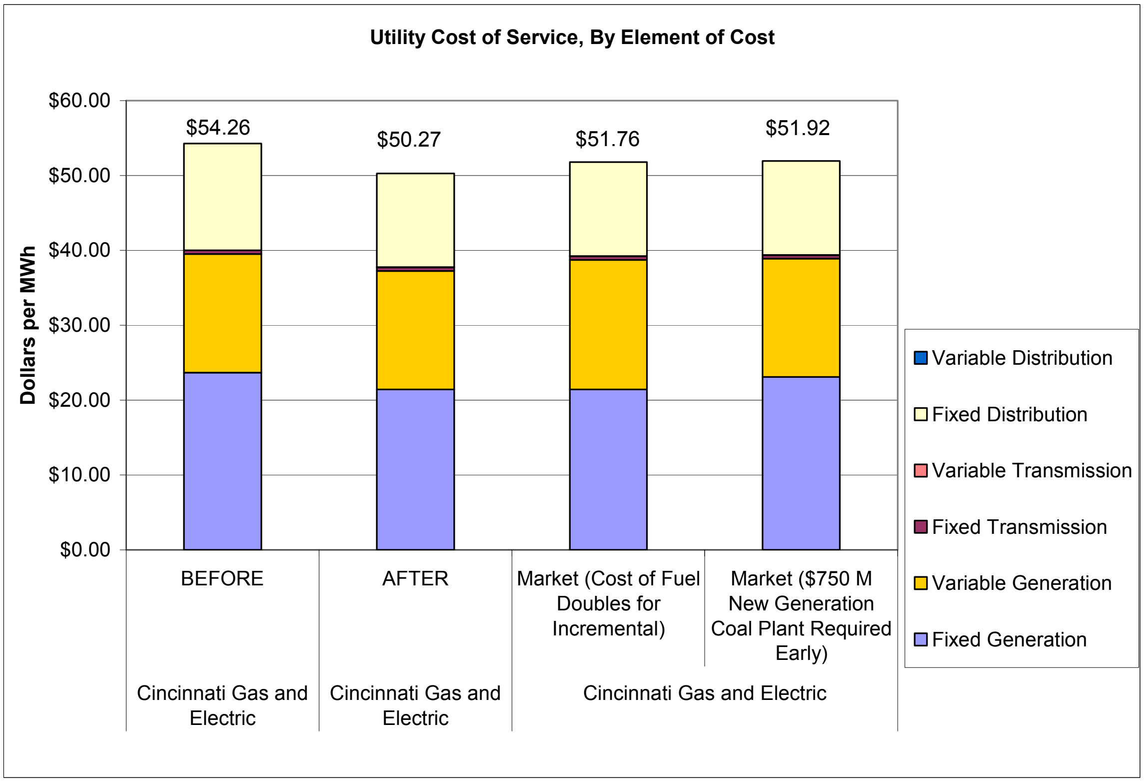

Figure 5: Impact of Alternative Cost Scenarios for Cincinnati Gas and Electric

Results for SDG&E

San Diego Gas and Electric is a net purchaser for over half of the electric power it consumes. Over 36 percent of the electricity sold is generated by one nuclear power plant. The remainder is purchased from others. As market penetration of PHEVs increases, SDG&E would need to purchase the power to serve this market from other generators on the grid. For purposes of this analysis, we assume that SDG&E can do this in the short run at a constant price of about $70 per MWh ($0.070 per kWh), which is consistent with their current average cost for purchased power. Because it is quite possible that the off-peak price in the late evening hours could be lower than the current average price, this price may be conservatively high. This assumption results in an overall average variable cost of power of $57 per MWh (see Table 2). Figure 6 shows the impact of a 100% residential market penetration of PHEVs into the SDG&E service area, about 1.1 million vehicles (this would be about 4% of the California LDV market [DOT, 2002]. Unlike CGE, since SDG&E is in effect a "wires only" utility buying relatively expensive power, the utility gets no cost-reduction benefit from more effective use of its generating facilities and must pay a lot for additional power to service PHEVs. However, SDG&E has a large investment in T&D capital that it is able to use more effectively in off-peak periods, so its overall average cost of power declines from $205 per MWh to $151 per MWh, as shown in Figure 6. In addition, as stated earlier, off-peak purchases may be lower in price than the current average price and could help reduce the average costs of power still further.

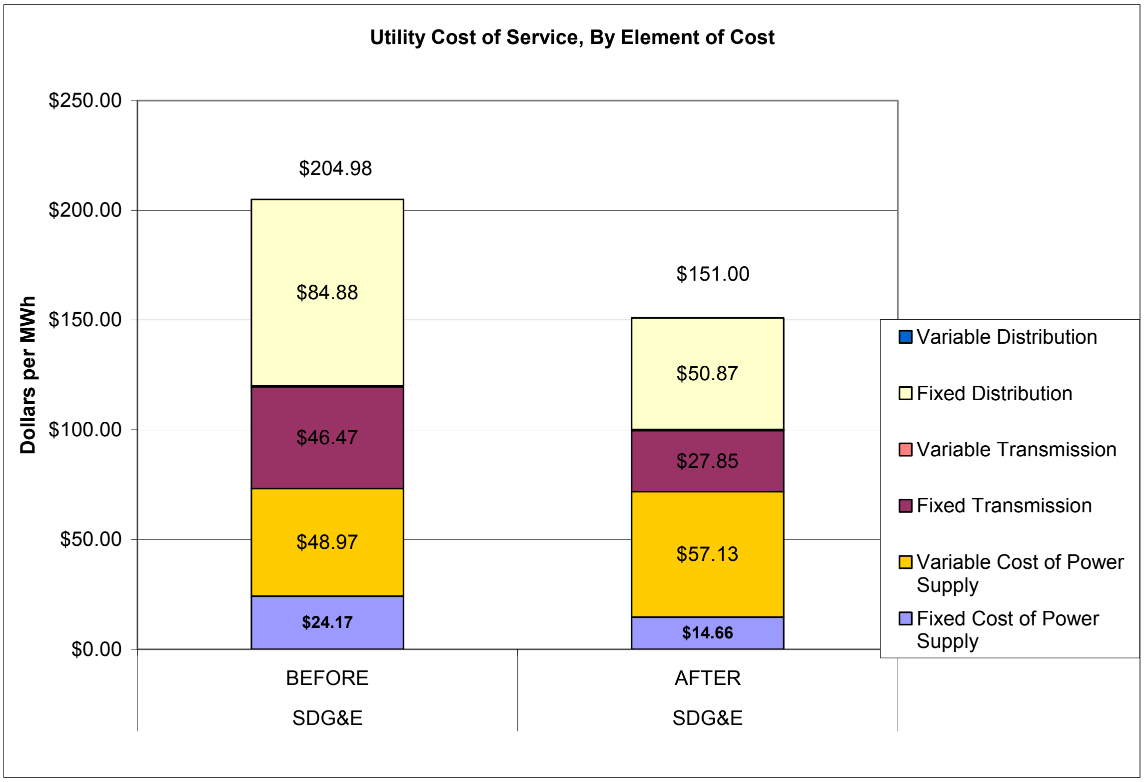

Figure 6: Short-Run Impact of PHEV Valley-Filling on Components of System Cost for San Diego Gas and Electric

In Figure 6, as in Figure 4, we assumed that there is no change in the average variable cost of generating power in the short run as the PHEVs penetrate the market and the off-peak demand for power increases. Figure 7 shows the impacts of all scenarios, including the base-case as a reference. The resulting increase in the average variable cost of generation does put upward pressure on the overall average cost of power in Scenario 2; however, the valley-filling for charging PHEVs still reduces the average cost from $205 per MWh to about $162 per MWh.

The results of Scenario 3 show the impacts of higher off-peak demand from PHEVs, resulting in a new natural gas-fired power plant being built (likely somewhere outside of Southern California), together with the necessity to retire its fixed costs ($350 million at an assumed interest rate of 6%, or $22.9 million per year). For reasons of simplicity, we adopt the average variable costs for the new generation in the base-case example, which reduces the average variable cost overall (although not quite as much as in Scenario 1). Here, the economics are still favorable, largely because the reduction in the average fixed costs of power generation, transmission, and distribution still dominate the increase in variable generation costs. The average cost of power falls from $205 per MWh in the base case to about $153 per MWh.

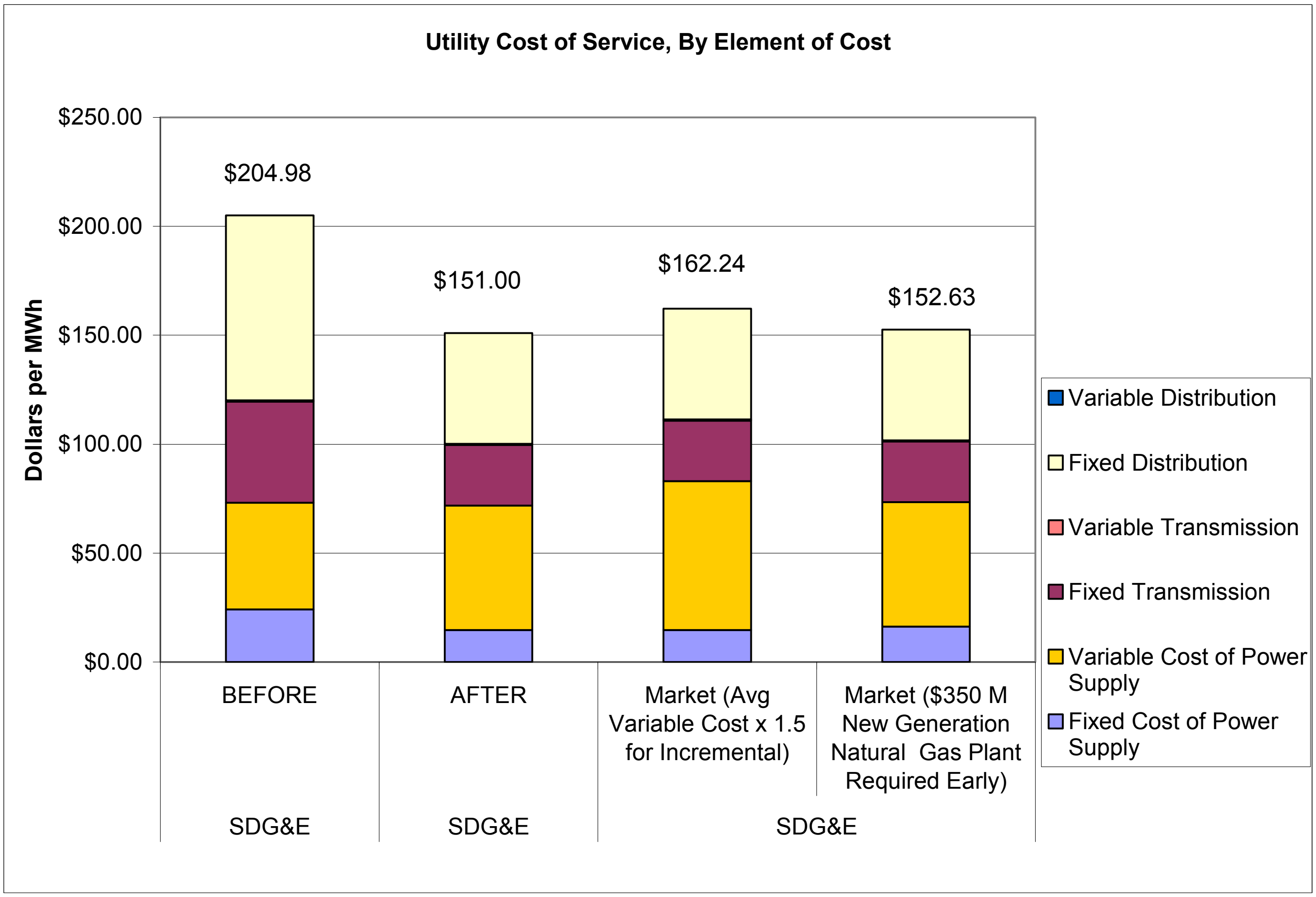

Figure 7: Impact of Alternative Cost Scenarios for San Diego Gas and Electric

DISCUSSION OF RESULTS

The LCC analysis of purchasing decisions shows that at existing average residential electricity rates and over a range of gasoline prices, prospective vehicle purchasers could afford to pay a premium of up to a few thousand dollars over the cost of either a standard 27.5-mpg and/or high-efficiency 35-mpg vehicle and still break even on the life-cycle cost of purchasing and operating a PHEV. The prospective premium is expected to decrease as the cost of electricity increases and the price of gasoline decreases. When compared with an HEV such as the Prius, the economics of the PHEV are not favorable at high electricity prices and marginally favorable at lower electricity prices. This conclusion could change if electric utilities offered reduced electric rates for large blocks of electricity purchased off-peak (and possibly increased them on-peak). The utility analysis indicates that large-scale market penetration of load-leveling off-peak PHEV charging could reduce utility system average costs of power and make such preferred rates a possibility.

Based on our examination of two very different electric utility circumstances, it appears from the utility analysis that under reasonable assumptions, a high rate of market penetration of PHEVs can achieve significant load leveling, improve the efficiency of the use of fixed capital, and provide significant average cost savings for a wide variety of electric utilities. We do not directly address the implications for rate-making, which is still cost-based in many parts of the country, or the impacts on profitability, but there likely would be enough money to share between ratepayers and stockholders, or as indicated in the previous paragraph, to offer incentive rates for PHEVs. The major tradeoff for electric utilities with PHEVs is always whether the average variable costs associated with the additional generated or purchased power necessary to serve the PHEVs are greater than or less than the reduction in average fixed cost achieved by spreading fixed costs over more kWh. Viewing the two very different electric utilities discussed in this paper, we notice that the most advantageous conditions for PHEVs are where the utility in question has

- high fixed unit costs and low variable unit costs of generation
- considerable spare off-peak capacity or access to low-cost purchased power.

However, the San Diego Gas and Electric example illustrates that under the correct circumstances, PHEVs and valley-filling can even be helpful in an (almost) wires-only utility that has a high variable cost of power.

CONCLUSIONS AND FUTURE WORK

PHEVs have the prospect of entering the U.S. electrical grid, but whether they ever do so in large numbers will depend in part on their relative economics compared with more conventional transportation choices as well as their impact on utility economics, which likely would affect the prices charged for their fuel (plug-supplied electricity) and arrangements made by utilities to accommodate their recharging. The analyses conducted for this paper show that the economics for both the prospective vehicle owner and the electric utility are promising and that more detailed analysis could more completely identify and evaluate opportunities.

Much research yet remains to be done. For example, the analysis conducted in this paper assumes that charging a PHEV would be a relatively simple affair with each vehicle plugged into a home circuit, probably governed by an on-board timer that allows only late-night charging. Much more elaborate grid-smart "smart charging" systems that could optimally and instantaneously match PHEV charging to the real-time condition of the electric grid and possibly allow V2G applications are the subject of current research and development. The analysis in this paper has yet to be conducted for such systems, including their costs and a realistic technical and economic assessment of their likely effects on the grid. In this paper, we also have assumed that the host utility and the grid have to make only minor accommodations to absorb a substantial number of vehicles. However, the relationships between the grid as a whole, generating companies, regulators, and retail electric utilities all have become extremely complex in the last 10 years. It is not at all certain in the case of wires-only utilities that they would be able to contract for relatively inexpensive off-peak electricity from generating entities to charge PHEVs without bidding up the price of such electricity. In the case of utilities that own their own underused generating plants, it is not obvious that they would run these generating plants to meet the expanded off-peak demand from their residential customers if other, more lucrative, market opportunities were available or if running these plants were far costlier than their "average" plant as shown here. In summary, while more economic analysis needs to be done using production-cost approaches with regional power systems or individual electric utilities along with utility economic data, this paper illustrates the general economic proposition that off-peak power revenues from PHEV owners could be attractive and beneficial for both the electricity service provider and the rate payer.

ACKNOWLEDGEMENT
The authors would like to acknowledge the Office of Electricity Delivery and Energy Reliability of the U.S. Department of Energy (DOE) for support of the analysis. Particular thanks are extended to the DOE program manager, Eric Lightner, who provided helpful directions for writing this paper.

CONTACT

Michael J. Scott, Ph. D., Pacific Northwest National Laboratory. Phone: 509.372.4372. Email: michael.scott@pnl.gov

Michael Kintner-Meyer, Ph.D., Pacific Northwest National Laboratory. Phone: 509.375.4306. Email: Michael.Kintner-Meyer@pnl.gov.

Robert Pratt, Pacific Northwest National Laboratory. Phone: 509.375.3648. Email: Robert.Pratt@pnl.gov.

REFERENCES

Denholm, P., and W. Short. 2006. An Evaluation of Utility System Impacts and Benefits of Optimally Dispatched Plug-In Hybrid Electric Vehicles. Technical Report NREL/TP-620-40293. National Renewable Energy Laboratory, Golden, CO.

DOT (Department of Transportation). 2002. Highway Statistics 2001. Table 5-1: Motor-Vehicle Registrations: 2001. U.S. Department of Transportation, Federal Highway Administration, Washington, D.C.

DOT (Department of Transportation). 2005. Summery of Economy Performance. U.S. Department of Transportation, National Highway Traffic Safety Administration. Washington, D.C.

Duvall, M. 2002. Comparing the Benefits and Impacts of Hybrid Electric Vehicle Options for Compact Sedan and Sport Utility Vehicles. Final Report 1006892. Electric Power Research Institute. Palo Alto, CA.

Duvall, M. 2003. Electricity as an Alternative Fuel: Rethinking Off-Peak Charging. Plug-in HEV workshop. Electric Power Research Institute. Palo Alto, CA.

Duvall, M. 2004. Advanced Batteries for Electric Drive Vehicles. A Technology and Cost-Effectiveness Assessment for Battery Electric Vehicles, Power Assist Hybrid Electric Vehicles, and Plug-in Hybrid Electric Vehicles. Final Report. 1009299. Electric Power Research Institute, Palo Alto, CA.

EEI (Edison Electric Institute). 2006. Typical Bills and Average Rate Report. Winter 2006. Edison Electric Institute, Washington, D.C.

EIA (Energy Information Administration). 2005. Residential Electricity Prices: A Consumer's Guide. DOE/EIA-X061. Energy Information Administration. Washington, DC.

EIA (Energy Information Administration). 2006. "Electricity Market Module." Assumptions for the Annual Energy Outlook. DOE/EIA-0554(2006). Energy Information Administration, Washington, D.C.

Hu, P. 2006. Americans and Their Vehicles. Center for Transportation Analysis. Oak Ridge National Laboratory, Oak Ridge, TN.

Kempton, W., and J. Tomić. 2005a. Vehicle-to-Grid Power Fundamentals: Calculating Capacity and Net Revenue. Journal of Power Resources 144(1): 268-279.

Kempton, W. and J. Tomić. 2005b. Vehicle-to-Grid Power Implementation: From Stabilizing the Grid to Supporting Large-Scale Renewable Energy. Journal of Power Resources 144(1): 280-294.

Kintner-Meyer, M., K. Schneider, and R. Pratt. 2007. Impacts Assessment of Plug-in Hybrid Vehicles on Electric Utilities and Regional U.S. Power Grids. Part I. Technical Analysis. Paper presented at the 2007 Electric Utilities Environmental Conference, Tucson, AZ, January 21-24, 2007.

Parks, K., P. Denholm, and T. Markel. 2007. Costs and Emissions Associated with Plug-In Hybrid Electric Vehicle Charging in the Xcel Energy Colorado Service Territory. NREL/TP-640-41410. National Renewable Energy Laboratory, Golden, CO. National Technical Information Service, U.S. Department of Commerce, 5285 Port Royal Road, Springfield, VA 22161. Available electronically at http://www.osti.gov/bridge.

Platts. 2005. POWERdat Database. December 2005 Version. Platts, Boulder, CO.

APPENDIX A: IMPLICATIONS OF A 60% MARKET PENETRATION OF PHEVS FOR SAN DIEGO GAS AND ELECTRIC SERVICE AREA

With one PHEV per residential customer discussed in the text of this article, SDG&E demand approached the overall system peak value, which means that T&D capacity might have to be added to cope with 100% market penetration. Therefore, we also evaluated SDG&E with a 60% market penetration. This value was derived by taking the current system peak from the hottest day and subtracting the actual demand on an average summer day in each hour between 10 pm and 6 am. This determined the approximate level of extra hourly demand that could be fit under the system peak if it were to occur during the hours of 10 pm to 6 am. We then calculated the number of vehicles that could be simultaneously charged with that electricity, which resulted in a market penetration of 61% of residential customers. This was rounded down to 60%. Although this would result in a new nighttime "peak" on an average summer day, it still would be less than the current system peak on the hottest days and should therefore be possible to serve with existing T&D resources.

Figure A.1 shows the impact on the components of average system costs. Overall, the average cost of power declines.

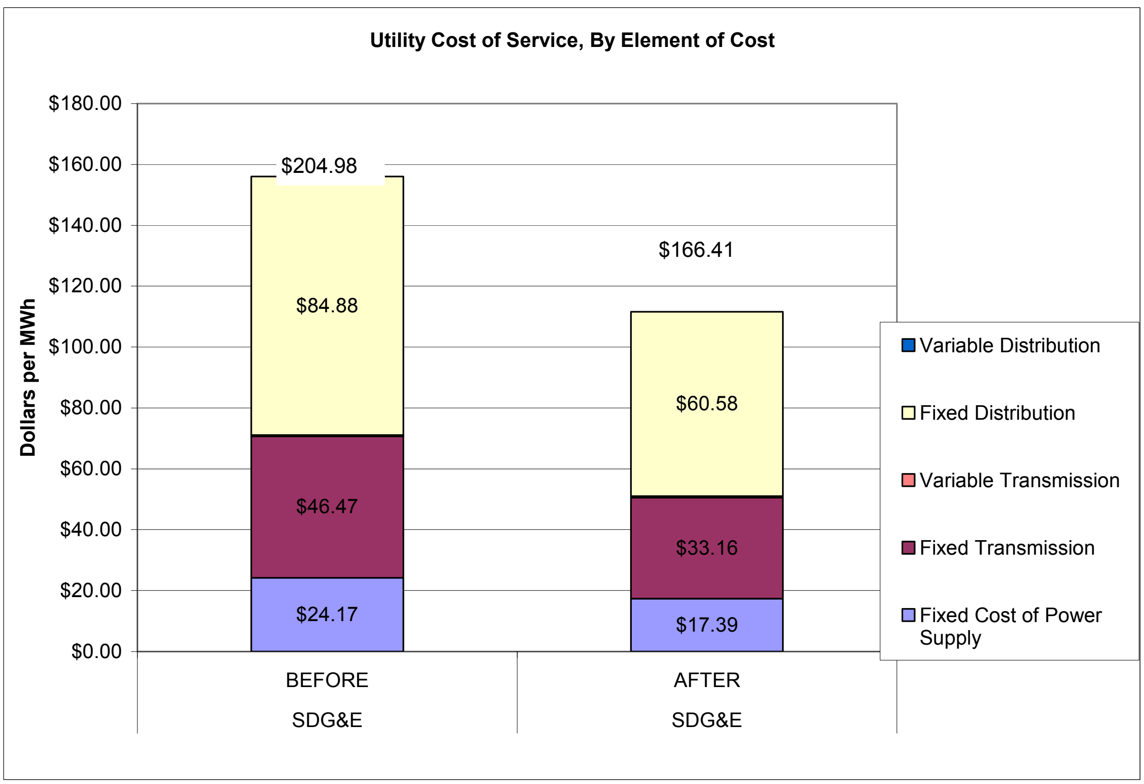

Figure A.1: Short Run Impact of PHEV Valley-Filling on Components of System Cost for San Diego Gas and Electric with 60% Market Penetration of PHEVs

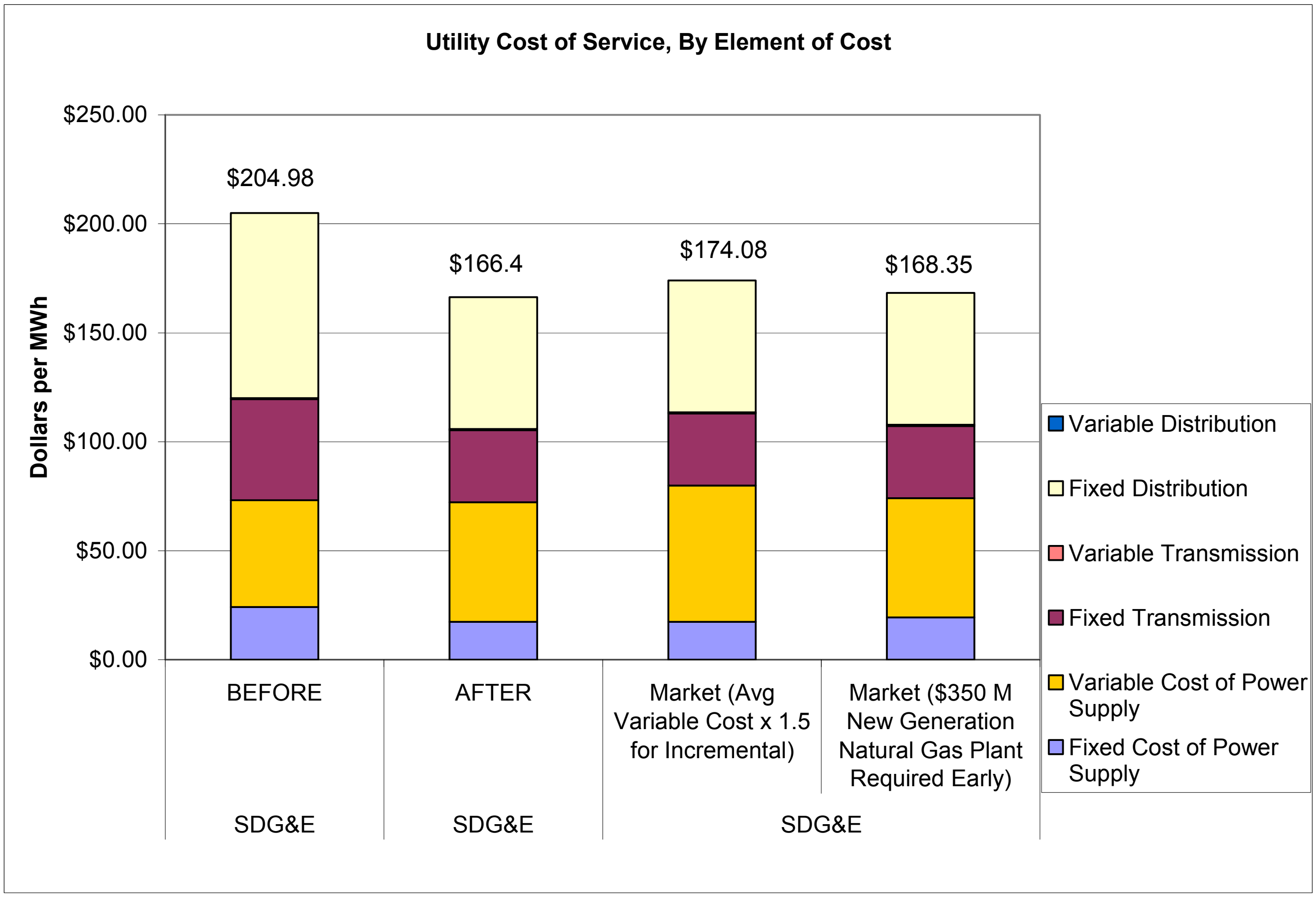

Figure A.2: Impact of Alternative Cost Scenarios for San Diego Gas and Electric with 60% Market Penetration of PHEVs