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Plug-in Hybrid Electric Vehicle Research Project

Phase Two Report

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Plug-in Hybrid Electric Vehicle Research Project: Phase II Report
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Executive Summary

This report contains five substantive sections describing plug-in hybrid electric vehicle (PHEV) related research conducted over an 18-month period by faculty and graduate students at the University of Vermont. Funding for these separate but related projects was provided by the Transportation Research Center, electric utilities, and Vermont State Agency partners.

Section 1.2 of this report presents a literature review of prior studies regarding the proportion of miles driven under gasoline and electric power respectively, the resulting gasoline displacement and net change in greenhouse gas (GHG) emissions associated with PHEV operation, the generating capacity available to charge PHEVs and vehicle lifetime ownership costs. Section 2 is an analysis of state and federal policies to enhance the economic competitiveness of PHEVs. Two models of the impact of electricity demand for PHEV charging are described in Sections 3 and 4. The first of these models looks at the impact of this additional electricity demand on carbon allowance prices and generating costs under an electricity sector only cap-and-trade program while the second explores its impact on medium voltage distribution circuits. Section 5 estimates the economic potential for bi-directional interfacing between vehicles and the grid, a concept know as vehicle-to-grid or V2G, in Vermont. The key findings are listed here and in more detail following each section.

Key findings

State and federal policies to enhance the economic competitiveness of PHEVs (Section 2, pages 12-20)

A range of near term policy options are available that can make PHEVs cost competitive with other vehicles on the market. Many of these policy options have only recently been implemented or are only currently under active development. Though reducing greenhouse gas emissions from transportation is a key component of most if not all state Climate Action Plans, state level policies promoting PHEV cost competitiveness are in their infancy.

Modeling the electricity demand for PHEV charging (Sections 3 & 4, pages 21-39)

The results in Section 3 indicate that PHEV demand would increase CO_2 emissions allowance prices when the electricity sector has a GHG cap but the transportation sector does not. In this case switching energy consumption from the liquid fuels sector to the electricity sector, as occurs with PHEV deployment simultaneously reduces overall CO_2 emissions and drives CO_2 allowance prices up in the electricity sector.

In the model described here, a 5% deployment of PHEVs would increase the price of CO_2 allowances from $3.4 to $8.4, increasing electricity costs by about 1.4%.

These results suggest that an electric sector only cap, such as the Regional Greenhouse Gas Initiative (RGGI), creates a perverse incentive against potentially environmental beneficial fuel switching from gasoline toward electricity. An economy-wide cap on CO_2 emissions, which was tradable among sectors, would not have this effect.

Section 4 model findings indicate that the deployment of PHEVs in a distribution circuit will have diverse effects on the distribution infrastructure. Careful modeling of these impacts can be valuable in the development of utility operations and maintenance plans given potential increases in demand due to PHEV or EV deployment.

Economic potential for Vehicle-to-Grid services in Vermont (Section 5, pages 40-58)

Vermont consumers will likely have the option to purchase a plug-in vehicle within the next few years. These vehicles in aggregate represent a relatively small addition to Vermont's total electricity load, in the range of 1 percent to 8 percent of the total energy consumed in Vermont in 2005. However, when the vehicle fleet is viewed as a V2G resource the potential is significant. By 2020, an all-electric vehicle fleet in Vermont could represent a power resource of 300 MW with the ability to store 1,000 MWh of energy. This new resource could be used in a variety of ways to enhance the reliability of the Vermont grid and to assist with the integration of intermittent sources of energy like wind and solar.

Findings suggest that the use of V2G resources is best suited for the high value grid support service known as regulation. Based on analyses presented here, a V2G-equipped vehicle could potentially generate between $1,000 and $2,000 in gross revenue annually.

1. Introduction

Several political, economic and environmental factors are contributing to increasing interest in alternative vehicle technologies. These factors include rising global demand for oil, concomitant increases in fuel prices and anthropogenic climate change [1, 2]. Rising global demand for oil has both economic and political consequences. Increasing demand has a direct economic impact via increased commodity prices as well as a number of geopolitical implications that create political challenges for countries that rely on imported oil for economic activity. Moreover, evidence of the increasing dangers posed by climate change adds to the urgency to reduce the greenhouse gas (GHG) emissions from all sources. GHG emission from the transportation sector are growing more rapidly than from any other economic sector and accounted for 28% of total US GHG emissions in 2004 [3].

The plug-in hybrid electric vehicle (PHEV) is one technology that is nearing commercial deployment and has the potential to address all three of these issues to varying degrees. PHEVs, like current hybrid electric vehicles (HEVs), are equipped with an internal combustion engine, an electric motor and a battery that can be charged both via regenerative braking and by a generator driven by the internal combustion engine. In contrast to current HEVs, however, PHEVs have much greater battery capacity and, most importantly, the capacity to charge the battery from external electricity sources, including the electrical grid [1]. The ability to charge directly from the electrical grid means that PHEVs can displace a portion of the fossil fuels used in the transportation sector. In addition to reducing the absolute volume of oil consumed, this displacement can cause a net reduction in GHG emissions, depending on the performance of the PHEV and the GHG intensity of the electric source.

Most major automobile manufacturers are currently developing PHEVs and several including GM, Toyota and Ford have announced plans to bring them to market within the next two years [1, 4]. BYD, a Chinese manufacturer, has been selling the F3DM PHEV in China since December 2008. Given their near-term deployment it is especially critical for policy makers and electricity industry members to understand the environmental, economic and grid impacts of wide-scale PHEV adoption will bring in order to develop strategies that allow for a smooth transition to the use of grid power to supplement traditional liquid fuels. PHEV research has or is being conducted at five national laboratories (Oak Ridge, Pacific Northwest, Argonne, Idaho, and the National Renewable Energy Laboratory) and at a number of universities, utilities and car manufacturers resulting in a growing body of information on the generating capacity available to charge PHEVs, PHEV oil displacement, life cycle emissions and operating costs.

This report builds on this existing research by addressing a number of questions that have not been adequately answered in existing published literature. Specifically we address questions related to the impacts of PHEV charging on the medium voltage electric power distribution infrastructure[1], and the impact of PHEV deployment on GHG cap-and-trade systems. This report also includes a summary of policy incentives related to PHEV cost competitiveness and the potential for using PHEVs to provide bi-directional

[1] The medium voltage power distribution infrastructure includes all of the equipment that connects the high-voltage (generally 50kV and above) transmission system that moves power over long distances with the low voltage (<600V) infrastructure that serves end use customer equipment.

ancillary services for the Vermont power grid, a process referred to as Vehicle-to-Grid services (V2G). Each of these research areas comprises one of the sections in this report.

Studies of PHEV impacts on the grid have focused on the capability of existing generating infrastructure to meet PHEV charging demand but relatively little attention has been given to the impact that PHEV charging will have at the distribution circuit level. Information on distribution level impacts will be vital to utilities as PHEVs use becomes more widespread. The UVM TRC created a model to assess these effects focusing on the changes in expected operating lifetime of transformers and underground cables at the distribution circuit level.

In addition, the TRC modeled the impacts of PHEV charging on carbon prices under the Regional Greenhouse Gas Initiative (RGGI), a cap-and-trade program for CO_2 from electricity generation covering the northeast United States. Both vehicle electrification and cap-and-trade programs are being advanced as means to minimize GHG emissions. Our analysis indicates that a cap-and-trade system that covers only the electricity sector could create a disincentive toward PHEV adoption by increasing the operating costs of PHEVs relative to those of conventional vehicles.

Finally, this report provides a preliminary assessment of the potential market for V2G services in Vermont and an analysis of policies related to PHEV cost effectiveness at the state and federal levels.

1.1. Organization of this Report

Section 1.2 of this paper presents key finding from prior studies regarding the distribution of gasoline and electricity used by PHEVs, the resulting gasoline displacement and net change in GHG emissions associated with PHEV operation, the generating capacity available to charge PHEVs and the vehicles' lifetime ownership costs. Section 2 is an analysis of state and federal policies to enhance the economic competitiveness of PHEVs. Two models of the impact of electricity demand for PHEV charging are described in Sections 3 and 4. The first of these models looks at the impact of this additional demand for electricity on carbon prices and generating costs under an electricity sector only cap-and-trade program while the second explores its impact on medium voltage distribution circuits. Finally, section 5 estimates the economic potential for V2G services in Vermont.

1.2. Overview of Prior Research

1.2.1. Distribution of Primary Energy Consumption

The impact of PHEVs depends heavily on the percentage of the vehicles' power that is derived from external electricity rather than from gasoline. Since commercialized PHEVs have yet to be brought to market at a large scale, researchers must rely on performance data from computer simulations and converted HEVs to determine the distribution between gasoline and electricity powered travel. The differing modes in which a PHEV can operate and the variability in efficiency with trip length complicate this assessment [5, 6]. Factors such as a PHEV's all-electric range (AER), battery depletion strategy, charge pattern and drive pattern, are critical determinants of the fraction of PHEV vehicle miles traveled (VMT) that are powered by electricity from the grid. The fraction of VMT that is powered by electricity, often termed the vehicle's "utility factor"[7], drives the assessment of oil displacement, net change in GHG emissions and impact on the electrical grid. Utility factor can be calculated by:

$$UF = \frac{VMT_e}{VMT_e + VMT_g} \tag{1}$$

where VMT_e represent the vehicle miles traveled using electric drive and VMT_g represents the gasoline powered vehicle miles traveled. The studies reviewed here use different assumptions regarding PHEV specifications, driving patterns, and charging characteristics that influence VMT_e and therefore use different utility factors. The comparisons presented here do not adjust for the variations in utility factor among studies.

Many existing studies rely on the Electric Power Research Institute's (EPRI) assessments of PHEV performance from 2001 and 2002 [6-10]. Two studies [11, 12] generated performance data using the ADVISOR software package. One study [13] extrapolated PHEV electric efficiency from EPA fuel economy data from a single existing electric vehicle, the Toyota RAV4. Other groups, including the US Department of Energy through the Advanced Vehicle Testing Activities (AVTA) of the Idaho National Laboratory and Google's "RechargeIT" PHEV initiative, have gathered data from conventional hybrids that that have been converted into PHEVs [5, 14]. Early tests of these conversions were conducted primarily in warm climates with relatively flat terrain. The initial AVTA road tests have been conducted in and around Phoenix, AZ and the RechargeIT tests in Mountain View, CA.

1.2.2. Gasoline Displacement

Since PHEVs can be powered in part or in total by energy from the electrical grid, PHEVs are capable of displacing a portion of the gasoline used by the transportation sector. Numerous studies have examined the issue of fuel displacement and all of these studies found significant gasoline displacement from PHEVs relative to both conventional internal combustion engine vehicles (ICEVs) and HEVs [7-12, 14-16]. The fuel displacement from replacing a non-PHEV with a PHEV is given by:

$$FD = \frac{f_{REF} - f_{PHEV}}{f_{REF}} \tag{2}$$

where f_{REF} is the fuel use of the reference vehicle and f_{PHEV} is the fuel use of the PHEV. For all but two studies this calculation is made using the annual fuel consumption of an individual PHEV and reference vehicle. In the case of Gonder et al. [11], fuel displacement was calculated from simulated fuel use over 227 real world driving profiles. Based on the performance of a converted Prius, Kliesch and Langer [15] estimated VMT_e to be one half of miles traveled within the vehicle's AER and derived the fuel displacement from the percentage of miles traveled under electric power. As well as the PHEV's utility factor, discussed previously, the fuel efficiency of the reference vehicle influences the calculation of fuel displacement and varies among these studies.

A 2007 study conducted by EPRI in conjunction with the Natural Resources Defense Council (NRDC) [7] examined PHEVs with AERs of 10, 20 and 40 miles, and found gasoline displacement ranging from 42% to 78% relative to ICEVs and from 12% to 66% relative to HEVs. The other studies that quantified gasoline displacement found reduction values within these ranges [9, 11, 12, 15]. See Figure 1-1 for a summary of the fuel displacement results. Three additional studies concluded that PHEV use would lead to gas displacement but did not quantify the reduction in fuel use [8, 10, 16].

The overwhelming consensus of these studies is that PHEVs would be effective in reducing gasoline consumption in the transportation sector. As discussed previously, the exact amount of this reduction depends upon a number of factors including the PHEV utility factor and the fuel efficiency of the vehicles replaced by PHEVs.

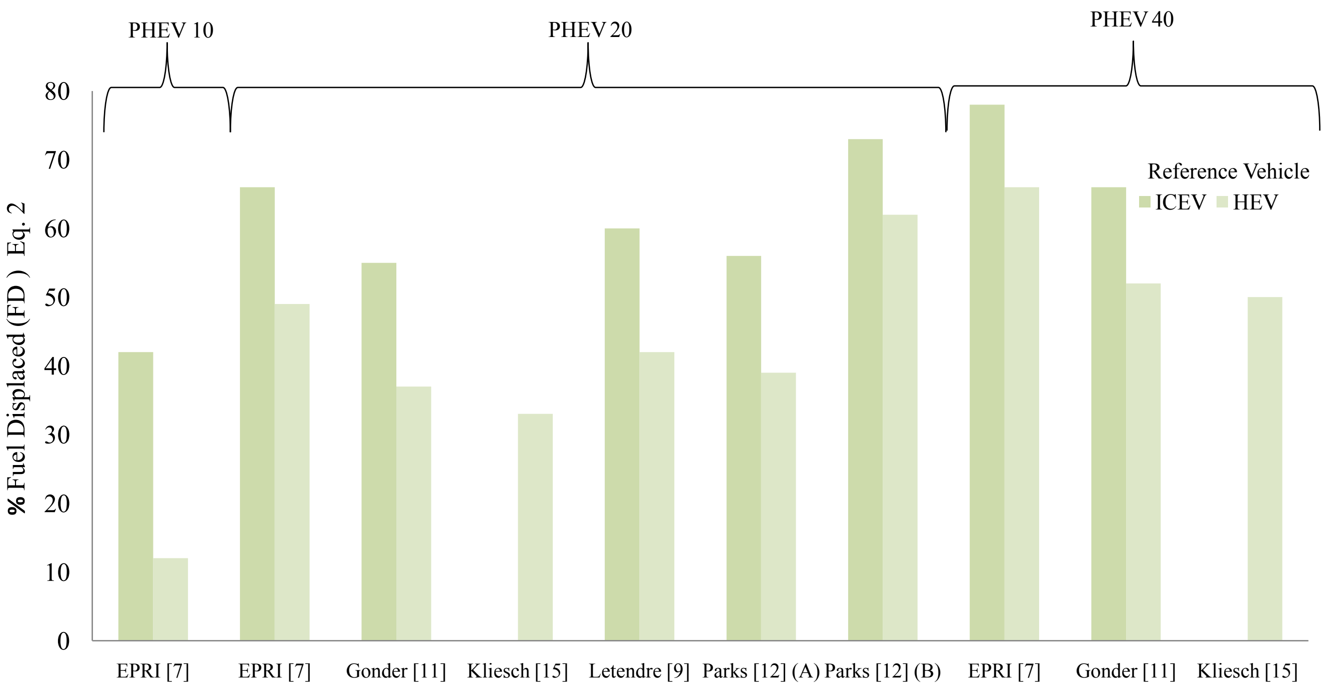

Figure 1-1. Fuel displacement from PHEVs with varying all-electric ranges. [12] (A) assumed that the PHEV charged once per day. [12] (B) assumed that the PHEV charged whenever it was not in use. In scenario [12] (B) where the PHEV charged more frequently, a higher proportion of VMT are fuel with electricity, increasing the percent of gasoline that is displaced.

1.2.3. Net Change in Greenhouse Gas Emissions

While PHEVs reduce GHG emissions at the tailpipe, drawing power from the electrical grid requires additional electricity generation and additional GHG emissions from the electrical sector. The net change in GHG emissions realized by replacing a non-PHEV with a PHEV is the difference between the GHG emissions avoided by reduced gasoline consumption and the GHG emissions caused by generating additional electricity as well as any additional GHG emitted in the construction of a PHEV rather than a HEV or ICEV [10]. The balance of emissions avoided and produced depends upon a number of factors, most importantly the GHG intensity of the electricity used to charge the PHEV, the utility factor of the PHEV, and the fuel efficiency of the vehicle that the PHEV replaces. GHG intensity is a measure of the quantity of GHG emitted to generate a unit of electricity and is determined primarily by the fuel type and plant technology [17]. Recent studies have reached a range of conclusions about the GHG implications of PHEVs depending on the assumptions that they make about each of these factors. The change in GHG emissions from a PHEV relative to a non-PHEV is calculated by:

$$\Delta GHG = \frac{GHG_{REF} - GHG_{PHEV}}{GHG_{REF}} \tag{3}$$

where GHG_{REF} represents the fuel cycle greenhouse gas emissions from the reference vehicle and GHG_{PHEV} represents the fuel cycle emission of the PHEV including the fuel cycle emissions of electricity generation.

Since the GHG intensity of electricity generation varies with the supply mix, the net change in GHG emissions related to PHEV adoption varies dramatically by region [8, 13, 15, 16]. All studies that compared PHEVs and ICEVs found a significant net decrease in GHG emissions with PHEVs relative to ICEVs [7, 9, 12, 13, 16]. Results for the net change in GHG emissions for a PHEV relative to an HEV, however, were more varied. Using the current national average for GHG intensity, a number of studies have found reductions in GHG emission for PHEVs ranging from 4% to 25% relative to HEVs [10, 13, 15, 16]. Looking at marginal generating capacity in the Xcel Territory in Colorado, Parks et al. [12] also found reductions in GHG emissions relative to HEVs in that generating region. The study conducted by EPRI and the NRDC [7] compared PHEVs to ICEVs and HEVs using specific generating technologies rather than national or regional averages and concluded the PHEVs would result in a net increase of GHG emission relative to HEVs when charged exclusively from coal fired plants but a net decrease when charged using natural gas power plants. See Figure 1-2 for a summary of findings on net change in GHG emissions with current generating technologies and mixes.

It is important to note that only one of the studies discussed above [10] considered GHG emissions from the vehicle manufacturing process. This study concluded that lithium-ion battery manufacturing for PHEVs contributed anywhere from 2 to 5% of the total life cycle GHG emissions associated with the vehicles. Studies that do not account for these emissions are likely to overstate the GHG benefit of PHEVs.

Figure 1-2. Change in GHG Emissions. [7] (A) assumed charging with electricity generated from coal power plants while [7] (B) assumed that the electricity was generated from combined cycle natutal gas. [18], [15] (A),[10] and [13] all used the national average generating mix while [15] (B) & [9] used regional averages for CA and New England respectively.

Understanding the GHG impact of PHEVs in the future requires projecting the GHG intensity of future electricity generation. Hadley and Tsvetkova [8] as well as EPRI [7] used models of the electricity generation system to project the GHG intensity of electricity to 2030 and 2050 respectively with strikingly different results. Working from the Energy Information Administration's assessments of future electricity generation and modeling the additional emissions caused by the electricity demand due to projected PHEV use, Hadley and Tsvetkova [8] determined that, in most scenarios, PHEVs would cause a net increase in GHG emissions when compared to a 40 mpg HEV. The results of this study varied considerably with time of charging and region, as mentioned previously. For example, in both their 2020 and 2030 assessments, nighttime charging in New England, when additional demand would be met by relatively clean combined cycle generation, resulted in a net decrease in GHG emissions. The electricity generated for evening charging in New England, however, would rely more on oil and coal generation and increase overall GHG emissions. In the Mid-American Interconnect Network, GHG emissions were higher in both evening and nighttime scenarios in 2020 and 2030. The EPRI study [7], in contrast, assumed that some form of carbon restriction or pricing measures would be implemented in the near future. As a result of this assumption, all of the scenarios that EPRI modeled going forward had a lower GHG intensity than the current national average. Consequently, PHEV use always resulted in a net reduction in GHG emission relative to 46 mpg HEV.

Samaras and Miesterling [10] also considered three different hypothetical GHG intensity scenarios. In the two scenarios at or below the current national average for GHG intensity, PHEVs had lower GHG emissions than comparison HEVs. In their high GHG intensity scenario, however, PHEVs increased total GHG emissions relative to HEVs.

1.2.4. Supply Adequacy for PHEV Charging

On average, U.S. power plants operate at approximately 60% of their nominal capacity and experience their lowest utilization during overnight periods [6]. Controlled PHEV charging during periods of minimum demand would increase utilization of base load generating capacity, flatten the overall load curve and decrease plant cycling, potentially decreasing the cost of electricity generation [6]. Numerous studies have examined current capacity to charge PHEVs during off-peak hours and concluded that current generating capacity could support a large fleet of PHEVs without increasing peak demand [6, 8, 9, 12, 13, 18]. These studies have taken two basic approaches to determining the current generating capacity available to support PHEV charging. The first, used by Kintner-Myer et al. [18] and Stephan and Sullivan [13], is a valley filling approach in which the idle daily generating capacity is derived from representative load curves and allocated to PHEV charging in an optimal manner for maximum load leveling. This approach represents the maximum PHEV penetration prior to increasing peak demand. The second approach is a scenario building approach in which the additional electrical demand from varying levels of PHEV penetration is added to the load curve. Since a limited number of scenarios are modeled, this approach does not yield an absolute maximum supportable level of PHEV penetration. As with fuel displacement and net change in GHGs, the utility factor of the PHEVs impacts the number of vehicles that can be charged and varies among the cited studies.

Based on average daily load curves from summer and winter, Kintner-Meyer et al. [18] used a valley-filling approach to estimate the unused generating capacity that is available to charge PHEVs. They calculated that the current system has the capacity to fuel 73% of all light duty vehicles in the United States on a daily basis. If charging was restricted to between 6 pm and 6 am, this number falls to 43% of the light duty fleet. While these estimates represent a theoretical maximum charging capacity for each time period, the authors did note that operating the electric power system at this high continuous load might not be sustainable and that planned outages for maintenance purposed would be more frequent and more difficult to schedule. Moreover, as Gaines et al. [19] noted, regulatory caps on SO_2 and NO_x emissions would precluded running existing power plants at maximum capacity without additional investment in emissions controls. Stephan and Sullivan [13] used a similar approach to calculate nighttime charging capacity but limited charging to "maximum economic capacity" which they defined as 90% of peak capacity. Using this method, they calculated that available capacity between 10 pm and 8 am could charge 34% of the light duty vehicle fleet.

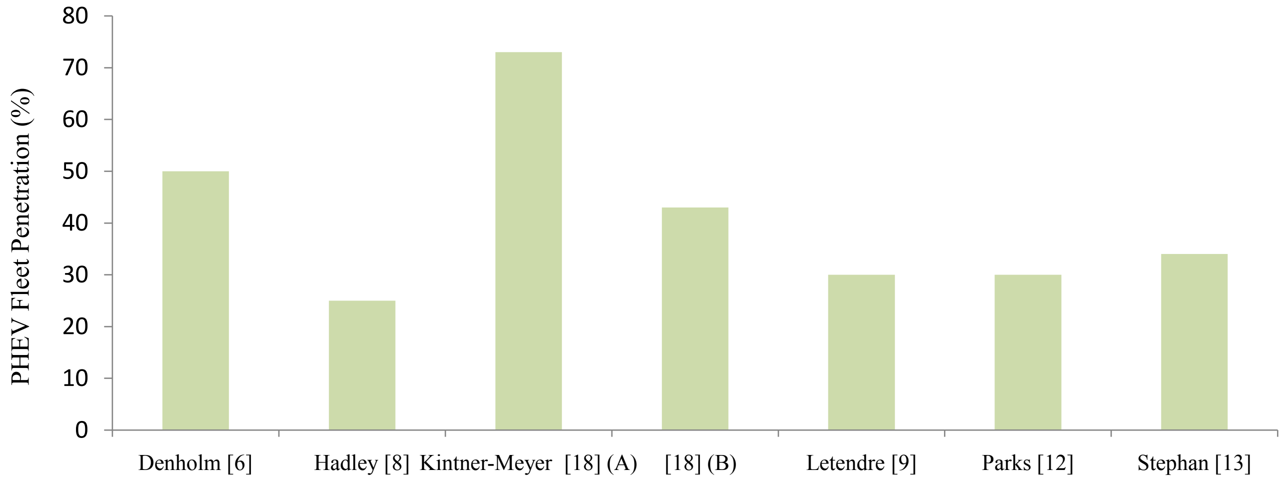

Figure 1-3. Currently supportable PHEV fleet penetration assuming optimimal charging patterns. [18] (A) assumed optimized day and night charging. [18] (B) assumed optimized night charging only.

Using the scenario building approach and assuming optimal charging patterns, Denholm and Short [6] concluded that current national generating capacity could support 50% PHEV fleet penetration. Assuming delayed charging beginning at 10 pm, a separate study [8] concluded that 25% PHEV penetration of the light duty vehicle fleet would not increase peak demand. Two regional studies, also assuming optimal charging patterns, found that generating capacity in Vermont [9] and the Xcel territory in Colorado[12] could support 30% PHEV penetration.

Several of the scenario building studies also examined a variety of uncontrolled charging scenarios [8, 9, 12, 20]. Each of these studies found that uncontrolled charging of PHEVs was likely to increase peak demand. In their comprehensive study of the impact of PHEVs on the electrical grid, Hadley and Tsvetkova [8], concluded that large numbers of PHEVs charging at or near peak hours would necessitate constructing new generating capacity in 10 of the 13 regions studied.

Even off-peak charging, however, may have an impact on the service life and maintenance costs of the distribution circuits. Transmission lines, generators, phase correcting capacitors, and transformers will all experience increased loading if PHEVs come into widespread use. The possible impact of increased loading on medium voltage distribution systems is examined in more detail in Section 4.

1.2.5. Lifetime operating cost relative to alternatives

All studies that examined fuel costs for PHEVs determined that, per mile traveled, electricity was a cheaper source of energy than gasoline [8, 9, 12, 16, 21]. Consequently, operating costs for PHEVs are generally assumed to be lower than those of ICEVs or HEVs, though this will also depend on as yet unknown repair costs and battery lifespan. The purchase price of PHEVs, on the other hand, is expected to be significantly higher than for comparable ICEVs or HEVs due primarily to the high costs of the battery systems [15]. Several studies have concluded that in most circumstances the vehicle's lower operating costs do not offset the high purchase price of the vehicle over the vehicle's lifetime [13, 15, 21]. Depending on future oil and electricity prices and reductions in battery costs, PHEVs may eventually become more affordable than conventional vehicles [20].

The balance between higher upfront costs and lower operating costs could also be shifted by government incentives or by creating a revenue stream from V2G services. The role of government policy in PHEV cost competitiveness is investigated in Section 2. Section 1.2.6. provides background on the economic potential of V2G while section 5 explores the V2G in greater depth with a particular focus on its potential in Vermont.

1.2.6. Economic Potential of Vehicle-to-Grid Integration

V2G describes the two way integration of EVs, including PHEVs, into the electrical grid. With V2G, vehicles are able feed electricity back into the grid as well as drawing electricity from it. Vehicle batteries are idle for 96% of the time [22]. V2G technology has the potential to make use of this idle capacity and thus provide substantial value to the electricity sector. Using various assumptions about vehicle owner preferences regarding V2G, market prices for the different generation types, battery capacity, cost of providing V2G services and electric line capacity, the value of V2G services from one vehicle has been estimated at as high as $7,738/year [23]. Figure 1-4 provides a range of these findings [23-28]. A selection of V2G studies and demonstration projects are explored in greater depth in Section 5.

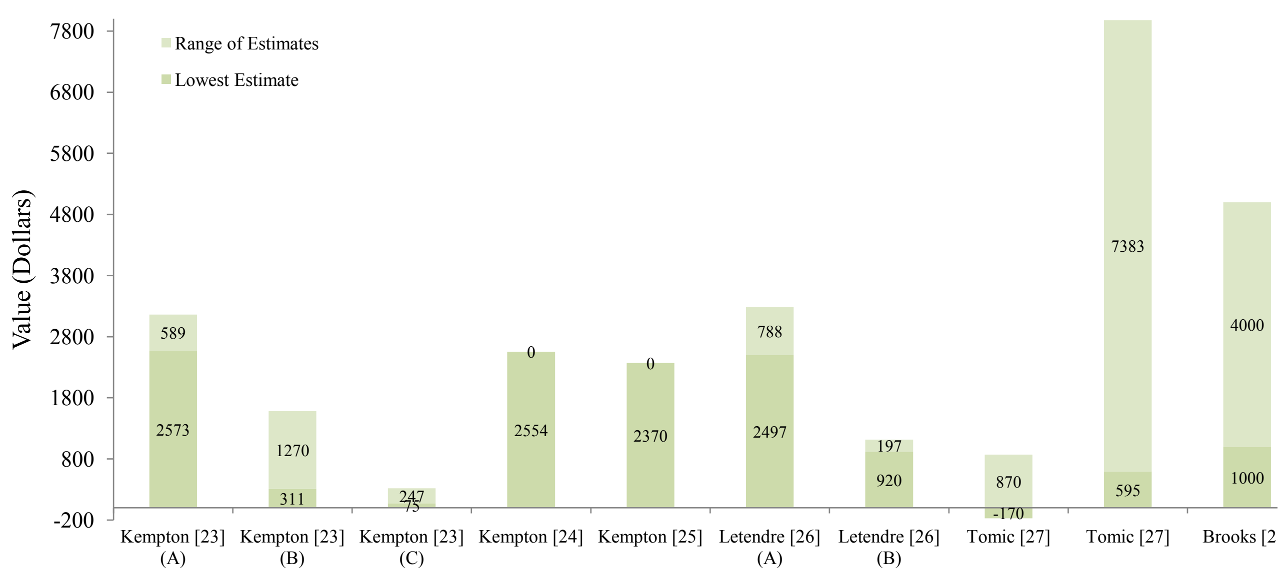

Figure 1-4. Estimated annaul value of V2G services from a single vehicle. (A) indicates V2G for regulation, (B) for spinning reserves and (C) for peak power.

In the US there are 176 million light duty vehicles, which have a total capacity of 19.5 TW of mechanical power [22]. In comparison, the capacity of electrical power plants in the US is approximately 900 GW [22]. At 20% conversion efficiency the vehicle fleet could produce 3840 GW, over four times the US generating capacity. Assuming contracted regulation of 1.5% of peak demand [26] and that each V2G-enabled vehicle could supply 10kW of regulation, 0.8% of the light duty vehicle fleet could meet all regulation requirements. Even doubling this number to ensure that enough vehicles are plugged in at any given time to provide a reliable source of regulation would require only 1.6% of the vehicle fleet [22]. The advantages of V2G to provide ancillary service are valuable but the value is not infinitely scalable.

A separate benefit of V2G is that using the vehicles for electrical storage could facilitate higher penetration rates for intermittent renewable energy sources such as solar and wind. Currently, bulk energy storage options, such as thermal storage, pumped hydro, compressed air, and battery systems, are expensive. V2G may provide a cost effective way to provide energy storage and backup for these intermittent sources. Many solar photovoltaic (PV) sites are adopting an energy buffer that can supply the full capacity of the station for a short period of time. The minimum buffer storage requirement (MBSR) is length of time that a PV station must be able to supply power without light. In California a PV plant is considered to have a firm capacity rating if it has an MBSR of 0.75-1 hour [22]. If 1/5th of the country's generation was from PV, it would take 26% of the light duty vehicle fleet to meet this required MBSR [22]. Wind generation is less predictable than PV and consequently may need reserves to cover a longer interval than is required for PV [22]. For large scale dispersed wind generation, estimates of required reserves range from 11% - 20% of capacity [22]. Using the lower estimate, Kempton and Tomic [22] calculated that if half of US power came from wind, 38% of the light duty vehicle fleet would be needed to provide adequate reserves.

2. PHEV Policy

President Obama established a goal of having one million PHEVs on the streets by 2015 [29]. As described in Section 1.2, research into PHEVs has consistently found that they use less liquid fuel than either ICEVs or HEVs [7, 11, 12]. Moreover, including the GHG emissions associated with electricity generation, they emit less GHG than ICEVs and, depending on the electricity source, they can emit less GHG than HEVs [7, 10, 13]. Concerns about oil prices and dependence on foreign oil as well as accelerating global climate change make these desirable vehicle characteristics. Both consumer acceptance and cost competitiveness of PHEVs, however, mean that achieving the rapid rate of PHEV deployment inherent in the President's plan is unlikely to be achieved without policy incentives [21, 30].

This section of the report examines estimates of the policy incentives necessary to make PHEVs economically competitive with other vehicles on a life-time ownership basis and provides a framework for categorizing policies geared toward increasing the rate of PHEV adoption, as well as an overview of existing and pending policies at both the state and federal level. The analysis of state level policies focuses on New England and California. Finally, since widespread PHEV adoption has the potential to impact the grid, policies related to PHEV infrastructure development and charging patterns are examined.

2.1. Background

Vehicle purchase price and operating costs are major determinants of vehicle purchasing decisions, and, due primarily to high battery costs, PHEVs are projected to be significantly more expensive than comparable ICEVs and HEVs. Estimates of the PHEV battery costs range from $250 - $2,000 per kWh of battery capacity [21]. Using Samaras et al.'s best estimate of $1,000 per kWh, this translate into a premium of $16,000 on a vehicle like the Chevy Volt which has a 16 kWh battery and an AER of 40 miles. The higher upfront costs for PHEVs are partially offset by lower operating costs; per mile traveled, operating a PHEV on electricity from the grid is substantially cheaper than operating a ICEV on gasoline. In most circumstances however, the lower operating costs of a PHEV over the vehicle's operational lifetime are not sufficient to offset the higher purchase price [13, 15, 21, 30].

The incentive levels required to make PHEVs cost competitive with currently available vehicles depends upon the net present value of the operating cost savings over the vehicles' lifetime relative to the upfront price premium. A number of interrelated factors influence this relationship, including battery costs, electricity and gasoline prices, and individual driving patterns. Battery costs determine the purchase premium of the PHEV, while the proportion of vehicle miles traveled on electric power and the relative prices of gasoline and electricity determine the operating cost savings of the vehicle. Both the upfront cost of the vehicle and the operating cost savings are related to the vehicle's battery capacity; large batteries cost more than smaller batteries but are also capable of using electric power for a higher proportion of vehicle miles traveled thus generating greater operational savings.

Selecting a battery capacity that aligns with individual driving patterns would therefore enable individual consumers to minimize the lifetime ownership costs of a PHEV [21, 30]. For example, drivers who routinely drive short trips and have frequent opportunities to charge their vehicle would realize the greatest economic benefit by purchasing a vehicle with a smaller battery. It is currently unclear, however, how large a variety of battery sizes, and consequently electric ranges, will be available in commercial PHEVs. The Chevy Volt, for example, is expected to have a 40 mile AER while the plug-in Toyota is currently reported to have an AER of less than ten miles. BYD's F3DM, now selling in China, has an AER of 60 miles.

Table 2-1. Anticipated release dates for several PHEVs.

Manufacturer	Vehicle (All Electric Range)	Anticipated Release Date
BYD	F3DM (60 miles)	Released Late 2008
Toyota	Plug-in Prius (10 miles)	Late 2009
General Motors	Chevy Volt (40 miles)	2010
Chrysler	Jeep Wrangler (40 miles)	2010
Fisker	Karma (50 miles)	2010
Ford	Escape (40 miles)	2012

In the absence of fixed figures for AER, and for electricity and gasoline prices, Samaras et al. calculated the required subsidy to make PHEVs cost competitive under a range of scenarios [21]. Using "best estimate" scenarios, the researchers found that only a PHEV10 would be cost competitive over its operational lifetime. PHEV30s would require a subsidy with a net present value of approximately $5,500 and a PHEV50 nearly $13,000. The results of this analysis, however, were found to be highly sensitive to battery costs, battery size, and gasoline prices. The required level of support could be much higher if, for example, battery prices per kWh remain closer to $2000 than the $1000 estimate used in the analysis.

Lemoine et al. approached the economics of PHEV operations by estimating the battery cost levels that would result in a equal net present value for the upfront premium and operating cost savings [20]. They estimated that depending on the price of electricity, battery costs would have to drop to between $162 and $479 per kWh to be cost competitive with ICEVs at gasoline prices of $3 per gallon.

The analyses of both Samaras et al. and Lemoine et al. focus on establishing price parity between PHEVs and other vehicles on the market. Each acknowledges that non-economic factors play into consumer preferences. For some segment of the car buying population, therefore, the difference in life-time operating costs would not need to be completely eliminated to make the PHEV a desirable purchase.

2.2. Methods

Researchers estimated the price premium on PHEVs and, consequently, of the financial incentives necessary to overcome this premium, based on existing literature. Current and pending policies were drawn from government documents, media reports, advocacy groups and academic journals. At the state level, the researchers examined state Climate Action Plans and contacted officials in state departments of energy, transportation and public utility commissions in New England. These policies were then categorized according to a policy framework developed by Theodore Lowi which is described below.

2.2.1. Policy Framework

A number of different policy approaches could be implemented to achieve the goal of accelerated PHEV sales. In fact, a wide range of policies from research and development funding to tax credits to feebates to manufacturing quotas and fuel standards either have already been implemented or are under consideration at different levels of government. One useful framework for categorizing these policy options is the policies matrix laid out by Theodore Lowi which characterizes policies as distributive, redistributive or regulatory in nature [31]. By imposing costs and/or benefits to different groups or individuals, all three of these policy approaches can change incentive structures and the economic viability of different production and consumption decisions. The particular characteristics of each of the approaches vary considerably. Distributive policies provide benefits to individuals or businesses without imposing costs on other specific sets of individuals. The policies can be very narrowly targeted, and, since the costs are widespread, do not create direct confrontation between policy beneficiaries and policy funders [31]. Redistributive policies, in contrast, directly influence the relationship between categories of individuals by providing one group with a benefit directly funded by the second group [31]. Finally, regulatory policies limit the decision making ability of the regulated parties, by requiring a certain action or sets of actions, and are generally applied along sectoral lines.

Using the Lowi framework, research and development funding and tax credits are characterized as distributive policies. These policies allocate benefits to particular interest groups, potential PHEV buyers and manufacturers, but the costs of the policies are diffused across all tax payers. In contrast, feebates, the practice of assessing a fee on one purchase type to underwrite a rebate for a competing purchase type, are a redistributive policy. There is a clear and unidirectional relationship between the fee paying and rebate receiving groups. Redistributive policies offer both an incentive for one action as well as a disincentive for another action so they may be more effective at changing behavior than distributive policies, which do not offer the same disincentives. In addition, redistributive policies can be designed to be revenue neutral, with the rebate and fee portions of the program offsetting one another [32]. Distributive policies, however, may be easier to enact legislatively as they do not face opposition from a concentrated interest group [31]. Production quotas and fuel standards represent regulatory policy as they impose statutory requirements that limit the decision making ability of automobile manufactures.

2.3. Analysis of Existing and Proposed Policies Impacting PHEV Sales

There are three primary means of improving the economic competitiveness of PHEVs for the consumer. The first of these is to subsidize the vehicle purchase price either through distributive or redistributive policies. Tax incentives, rebates and feebates could all be used to bring down the price paid by the consumer to the point that PHEVs would be cost competitive with ICEVs. The second option is to decrease the costs associated with PHEV production. Lower costs would then be passed onto the consumer, eliminating the need to subsidize purchases. In the short term, decreasing production cost could be achieved through tax breaks for the manufacturers and, in the longer term, by technological innovations. The final method would be to set up a framework that allows the consumer to capitalize on any environmental co-benefits, reduced life cycle GHG emissions for example, derived from PHEV purchases. This approach would require a regulatory framework that allows these positive externalities to be priced and valued. Creating additional value for the PHEV would help to offset its higher upfront costs. Each of these approaches is being considered to varying degrees at both the state and federal levels.

Table 2-2. Federal PHEV Related Policies

Policy	Impact on PHEVs	Cost Primarily Born By	Status
Distributive and Redistributive Federal Policies			
Research and Development Funding	Potential reduction in battery costs would decrease PHEV price premium	Tax payers at large	On-going Alternative Vehicle funding expanded under ARRA
Tax Credits for PHEV purchases	Reduction in PHEV price premium	Tax payers at large	Created under EESA, expanded under ARRA
Regulatory Federal Policies			
CAFE Standards	Fuel efficient PHEVs may benefit from stricter fuel economy standards which cause the automobile manufactures to adjust pricing engage in mix shifting	Automobile manufacturers and purchasers of vehicles with lower fuel efficiency	Strengthened by EISA

2.3.1. Federal Policies

Distributive and Redistributive Policies

Tax Credits

Tax credits are one straightforward method of underwriting vehicle purchases. This method was widely used on both the state and federal level when HEVs were first introduced [32]. The Federal government also recently began applying this strategy to PHEVs. The U.S. Emergency Economic Stabilization Act of 2008 (EESA) included provisions for tax credits of up to up to $7,500 on the first 250,000 PHEVs sold between 2009 and 2014 [33]. More recently, the provisions have been expanded under the American Recovery and

Reinvestment Act of 2009 (ARRA). The law doubled, to 500,000, the number of vehicle eligible for the tax credit and included new provisions for the conversion of existing vehicles. Reflecting the increasing costs associated with larger batteries, the tax credits is set up with a base tax credit of $2,500 for a 4 kWh battery, with increases of $417 for each kWh of battery thereafter. The value of these tax credits is in line with, or slightly above, those that Samaras et al. estimate would be required to make PHEV 10 (4 kWh battery) and PHEV 30 (11.9 kWh battery) costs competitive. Tax credits, however, do have certain limitations. First, only consumers whose tax obligation exceeds the tax credit are eligible to receive the full benefit of the incentive. Second, consumers place greater value on near-term incentives and therefore value a tax credit less than immediate incentives such as sales tax waivers, even when the value of the tax credit is greater [32].

Research & Development

In addition to subsidizing the purchase price of PHEVs, PHEV competitiveness can also be enhanced by measures that reduce manufacturing costs. For more than a decade, the federal government has supported the development of PHEVs through basic research into batteries and alternative vehicle technologies in a number of the National Laboratories. Research and development on battery technology in particular could significantly reduce the price premium on PHEVs. ARRA stipulated that $2 billion of grant money be made available for manufacturing advanced batteries systems, specifically including "advanced lithium ion batteries [and] hybrid electrical systems." Battery prices are expected to decrease over time as the technologies and manufacturing techniques mature. This stipulation is intended to hasten that process though its exact impact is difficult to predict. Funds from ARRA will also stimulate increased activity in EVs and PHEVs in other ways. In some cases, ARRA funds flow directly into existing programs, and in other cases there are new competitive solicitations for PHEV-related programs. These programs may invest in demonstration projects, hardware development and new charging infrastructure. The following is a snapshot of some of these programs that relate to PHEVs in the northeast.

State Energy Office Program funds: Under ARRA, state energy offices have seen substantial increases in their funding levels for programs that can have a transportation and energy related component. Some states are using these funds to invest in renewable and energy efficiency related projects. Funds are administered by State Energy Offices. For more information: State Energy Program Formula Grants (Reference Number: DE-FOA-0000052).

Clean Cities Petroleum Reduction Technology Projects for the Transportation Sector: Funding of $300 million is allocated in a competitive process to the 80 Clean City Coalitions spread across the U.S. Programs in Vermont, Maine and New Hampshire are jointly submitting a proposal for $30 million that will include demonstration and outreach programs with EVs and PHEVs. For more information: Clean Cities FY09 Petroleum Reduction Technologies Projects for the Transportation Sector (Reference Number: DE-PS26-09NT01236-04).

Energy Efficiency and Conservation Block Grants: Funded at $3.2 billion, this program is designed to invest in projects at the local level that improve energy efficiency in transportation, building and related sectors. For more information Energy Efficiency and Conservation Block Grants - Formula Grants (Reference Number: DE-FOA-0000013).

Smart Grid programs: The Department of Energy (DOE) has two solicitations out for programs to improve the capacity of the electric grid. These funds can be used to integrate EVs and charging stations with the electric grid. For more information: Smart Grid Demonstrations (Reference Number: DE-FOA-0000036) and Smart Grid Investment Grant Program (Reference Number:DE-FOA-0000058A).

Transportation Electrification programs: About $378 million is available in the first phase of this program. The objective is to accelerate the development and production of various electric drive systems to substantially reduce petroleum consumption. Several teams from the northeast are proposing projects to address the various areas of interest. Several sections require teaming with a manufacturer and placing at least 100 advanced electric drive vehicles (AEVs) in demonstration projects on the road. For more information: Transportation Electrification (Reference Number: DE-FOA-0000028).

Electric Drive Vehicle Battery and Component Manufacturing Initiative. In this program, National Energy & Technology Laboratory on behalf of DOE is seeking applications for grants supporting the construction (including production capacity increases for current plants), of U.S.-based manufacturing plants to produce batteries and electric drive components. For more information: Electric Drive Vehicle Battery and Component Manufacturing Initiative (Reference Number: DE-FOA-0000026).

Regulatory Policies

Fuel Economy Standards

Finally, the Corporate Average Fuel Economy standards (CAFE) may also impact the PHEV market by creating additional value for PHEV efficiency. CAFE standards require that automobile manufacturers achieve a specified, sales weighted, average fuel economy for both passenger cars and light duty trucks. Manufactures that fail to meet the target average fuel economy face fines of $5.50 per vehicle sold for each tenth of a MPG below the target MPG [34]. One approach that manufactures have employed to meet CAFE requirements is a practice known as mix-shifting, whereby the manufacturer adjusts its overall price structure in favor of vehicles with high fuel economy values [35]. Effectively, mix-shifting underwrites the sales of high efficiency vehicles by placing a premium on less efficient vehicles. Since PHEVs offer higher fuel efficiency, they are likely to benefit from mix-shifting pricing, reducing their upfront costs and improving their economic competitiveness. A 2003 study by EPRI suggested that each PHEV 20 sold could provide car manufactures with a value of approximately $1,000 by improving average fuel economy and helping the manufacturer meet its CAFE obligations, depending on the specific manufacturer's CAFE compliance circumstances [36]. Since the 2007 Energy Independence and Security Act (EISA) mandated an increase in overall fleet efficiency of 40% by 2020, this value may well be significantly higher than it was in 2003.

2.3.2. State Policies

New England & California

While more limited in geographic scope and authority, state policy can also play a significant role in shaping the PHEV market. All New England states are currently considering policies that have the potential to impact PHEV sales. Due to its large size and the fact that it is the only state authorized to set its own vehicle emissions standards, California has historically had a leadership role in setting vehicle policy. In keeping with this tradition, California is currently developing and implementing a range of policies that will impact the market for PHEVs. Since the New England states have generally been aggressive in adopting the standards and policies developed in California, the impact of California's regulatory policies are also considered here.

Table 2-3. State PHEV Related Policies

Policy	Impact on PHEVs	Cost Primarily Born By	Status by state in New England
Distributive and Redistributive State Policies			
Fuel efficiency/GHG emissions based Feebates	Reduction in PHEV price premiums relative to ICEVs due to differential pricing which favors fuel efficiency and lower GHG emissions	Purchasers/operators of lower efficiency/higher emitting vehicles	Under development in: MA Under consideration in: CT, ME, RI, VT
PHEV sales tax waiver	Reduce PHEV price premium	Tax payers at large	Under consideration in: CT
Regulatory State Policies			
California AB 1493 Standards	Requires reduction in tailpipe GHG emissions which may induce mix shifting favorable to PHEVs	Automobile manufacturers and purchasers of lower fuel efficiency vehicles	Adopted by: CT, MA, ME, RI, VT
Low Carbon Fuel Standards (LCFS)	LFCS credits for PHEVs could provide a revenue stream for vehicle owners	Fuel providers	Under development: Regional plan including all NE states

Distributive and Redistributive Policies

Feebates

Several states are considering or developing feebates and tax incentives for low emissions vehicles including, but not limited to, PHEVs. Feebates are mentioned as a policy tool in the state Climate Action Plans of Connecticut, Maine, Massachusetts and Rhode Island as well as in the New England Governors Commission Climate Action Plan [37] and the VTrans Climate Action Plan [38]. In early 2009, the Governor of Massachusetts announced that the state would institute a feebate registration system based on vehicle efficiency. It is believed to be the first state level program of its kind. The details of the program and level of the feebate are currently under development [39].

Sales Tax Exemptions

In 2008, the Connecticut Senate considered a bill, SB510, to create a sales tax exemption for PHEVs with a battery capacity of at least 4 kWh and an AER at least 10 miles. Though approved by the Environment Committee, the Planning and Development Committee and, in slightly modified form, the Finance, Revenue and Bonding Committee, the bill was not brought to vote in the full Senate [40].

Regulatory Policies

Two California initiatives, California AB 1493, which regulates vehicle emissions, and the Low Carbon Fuels Standard (LCFS), create a regulatory environment that benefits PHEVs. As with CAFE standards, these initiatives do not directly regulate PHEVs, but PHEV vehicle characteristics may give the vehicles added value as a method of meeting the regulatory requirements mandated in the measures.

Emissions Standards

AB 1493, passed in 2002, required that new cars reduce overall GHG emissions by 18% by 2020 and 27% by 2030. The EPA initially declined to issue a waiver authorizing the regulation but ultimately issued the waiver in June of 2009. The California Air Resources Board subsequently amended the regulation to reduce GHG emissions by 22% by 2012 and 30% by 2016 [41]. To date fifteen other states including every New England state except for New Hampshire have adopted the California standard [42]. Like the CAFE standards, AB 1493 will create an incentive for mix shifting toward lower emission vehicles like the PHEV.

Low Carbon Fuel Standards

California is also in the process of developing a LCFS which is intended to diversify the state's fuel supply and, pursuant to AB32, reduce GHG emissions from the transportation sector. The LCFS is a technology neutral, regulatory policy that requires fuel providers (defined as producers, importers, refiners and blenders) to meet a declining average GHG intensity in the fuel that they sell in California. The standard will require a 10% reduction in the carbon intensity of transportation fuel by the year 2020 [43].

Again, since PHEVs charged from the California grid have a lower GHG intensity than other vehicles [15], they offer one route for meeting the regulatory criteria. Indeed PHEVs are identified as one method for meeting the LCFS in several of the state's planning documents [43]. While a policy analysis by Farrell and Sperling identified several obstacles to incorporating PHEVs into low carbon fuel accounting, most notably the difficulty of accurately tracking "fuel electricity" use, they nonetheless concluded that "LCFS credits created by electric vehicle usage could be significant and could stimulate desirable changes in technologies and travel behavior" [44]. Capturing a portion of the value of these LCFS credits would provide another method for reducing the life time operating costs of PHEVs and increase their attractiveness to car buyers. Uncertainty about how to calculate and evaluate positive environmental externalities from PHEVs is a major issue. EPRI is currently in the process of studying how the value of PHEV emissions reductions can quantified and incorporated into GHG offset and LCFS programs [45].

In 2008, the governors of Pennsylvania and the 10 RGGI states, which include all six New England states, and entered into an agreement to establish a regional LCFS. This standard is expected to be similar to the California program [39] and would create similar opportunities for PHEVs.

2.3.3. Proposed Policies Impacting PHEV Charging

Because more frequent vehicle charging increases the proportion of vehicle miles traveled powered by electricity, increasing the convenience of daytime charging, by expanding publicly available charging infrastructure for example, increases the fuel cost savings and positive environmental impacts of PHEVs. As the number of PHEVs in use increases, however, their impact on the electric grid will also increase, potentially increasing peak electricity demand. Numerous studies have found that with controlled charging, scenarios in which PHEV charging is limited to overnight and other off-peak periods, the grid could support anywhere from 20% [8] to 73% [18] PHEV fleet penetration without requiring the construction of additional generating capacity. Consequently, policies are currently being considered both to expand and facilitate PHEV charging and to limit charging during peak periods.

Differential time-of-use pricing is frequently cited as the mechanism to ensure off-peak charging [12, 20, 39]. As yet, no regulatory agency that we are aware of has established a uniform policy in this regard. Several individual utilities are exploring or have established time-of-use pricing policies related to vehicle charging. For example, in California, Pacific Gas and Electric offers an "Experimental Residential Time-of-Use Service for Low Emission Vehicle Customers." The program creates a price differential of $.24 per kWh between on-peak and off-peak electricity prices, essentially making peak period charging cost as much as driving on gasoline at $3.73 and off-peak charging cost the equivalent of $.65 per gallon [20]. In Vermont, Central Vermont Public Service offers a time-of-use rate plan aimed at EV owners [46].

In 2007, California lawmakers introduced AB 1077 to require that the Public Utilities Commission to mandate that electrical corporations develop variable pricing and other mechanism to promote off-peak charging and the use of PHEVs [47]. The bill, however, ended the legislative session in committee.

On the Federal level, H.R. 1730, the "Vehicles for the Future Act," was introduced in March of 2009. This bill, which would amend the Public Utility and Regulatory Policies Act of 1978, would require all utilities to develop plans supporting the PHEV use, smart grid vehicle integration to enable EVs to be individually indentified while charging, and review time-of-use pricing [48]. Smart grid development and appropriate pricing strategies are among the key developments currently being explored by many PUCs [39, 49].

2.4. Conclusions & Further Research

A range of near term policy options are available that can make PHEVs cost competitive with other vehicles on the market. Many of these policy options have only recently been implemented or are only currently under active development. Though reducing GHG emissions from transportation is a key component of most, if not all, state Climate Action Plans, state level policies promoting PHEV cost competitiveness are in their infancy [39, 49-51].

Further research is required to determine which of these policy options would be the most cost effective in promoting PHEV sales. Research into consumer preferences relating to hybrid electric vehicles has indicated that savings that are immediately realized, such as sales tax waivers, are more desirable than future saving, such as tax credits [32]. This suggests that state policy, though less geographically far reaching, may be able to provide a greater return on investment. The ultimate desirability of these policies also depends on the future GHG intensity of electric power generation, modeling of purchaser behaviors, and consideration of alternate uses of these dollars.

3. PHEVs and Cap-and-Trade[2]

In order to reduce the negative impacts of climate change, the Obama administration recently endorsed the target of an 80% reduction in U.S. GHG emissions by the year 2050 [52]. Since the electric power and transportation sectors are the two largest sources of GHG emissions in the United States, accounting for 34% and 28% of total US emissions, respectively, [53], significant emissions reductions will need to be made in both of these sectors in order to achieve the overall emissions reductions that the administration has targeted. A cap-and-trade system is one method of reducing GHG emissions in targeted sectors. Every cap-and-trade bill proposed in the 110th Congress included coverage of the electric power sector [54]. On the transportation side, PHEVs have the potential to reduce life cycle GHG emissions and the Obama administration has identified PHEVs as a desirable technology for combating climate change and reducing dependence on foreign oil [29]. If widely deployed, PHEVs are likely to create significant new demand for electricity, and thus their deployment will have important implications for electricity sector cap-and-trade systems.

Cap-and-trade systems can be an effective, economically efficient method of reducing pollutants. Cap-and-trade has been used successfully in the U.S. to reduce SO_2 since 1990 and is currently being used in the European Union to reduce GHG emissions [55]. These systems are well suited to situations in which aggregate emissions reductions are more important than geographically specific reductions [56]. In addition, transaction costs may be lower when dealing with smaller numbers of large emitters [54]. For these reasons, cap-and-trade systems are particularly suited to reducing GHG emissions from the electric power sector. By creating a cost associated with GHG emissions, cap-and-trade systems decrease the economic competitiveness of high GHG intensity fuels, such as coal, relative to lower GHG intensity fuels. Since the cost of the allowances creates an additional marginal cost for power generators, cap-and-trade systems increase electricity prices in the short run. The magnitude of this increase depends on the price of carbon allowances, which in turn depends on the stringency of the cap relative to the demand for electricity as well as on the available generating technologies.

The transition to vehicle electrification could have a significant impact on electricity demand and should be considered in conjunction with cap-and-trade systems when assessing the impact of these systems on electricity prices. The price impact may be particularly important when the cap-and-trade system is not economy wide but rather applies only to the electric power sector, as changes in relative energy prices could lead to shifts in the type of energy used in other sectors.

While several researcher have examined the impact of cap-and-trade systems on electricity prices, such as RGGI [57], the European Union Emissions Trading Scheme [58], and others have examined the impact of PHEV load on electricity prices [8], the authors are unaware of any published results that estimate the effect of PHEV demand on electricity costs, given a GHG cap. This section presents a model of the impact of PHEV charging on marginal and average fuel costs in the electricity sector given an electricity sector only

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[2] Note, Section 3 is a modification of Dowds, J., Hines, P., Farmer, C., Watts, R. (in press). *Estimating the Impact of Electric Vehicle Charging on Electricity Costs Given an Electricity Sector Carbon Cap.* Transportation Research Record: Journal of the Transportation Research Board. Authors are encouraged to cite the final TRR publication.

cap-and-trade program for GHG emissions. Specifically, the model examines this effect in the short-run for the New England electricity market, which as of January 2009 operates under RGGI, a cap-and-trade system for CO_2.

The RGGI cap-and-trade program covers CO_2 emissions from electricity generation in ten northeastern states. The initial cap set by RGGI was intended to replicate current emissions levels to minimize the immediate impact on electricity prices. Under RGGI the cap will be held constant for the years 2009-2014 and then decrease by 2.5% per year between 2015 and 2018.

The model presented here simulates the electricity market at current cap levels and therefore represents price impacts only over the next five year period. Thus, the goal of this work is to estimate the impact of PHEV charging on fuel costs and CO2 allowance prices given an electric sector cap-and-trade system. The methods section of the paper describes the model, the data source and assumptions used to construct it, and the scenarios that were modeled. The model results are presented subsequently, followed by a brief discussion and conclusion.

3.1. METHODS

Least cost production allocation is analogous to a perfectly competitive market with perfectly inelastic demand and is frequently used for modeling the effects of regulation on the electric power sector [59]. To explore the impact of PHEV electricity demand on marginal fuel costs under the RGGI carbon constraints, we created a short-run, fixed capacity, dispatch model for New England power plants which dispatches power plants to minimize total fuel costs given inelastic electric demand. Dispatch decisions within the model are generated on an hourly basis and the optimal generation from each plant as well as the systemic marginal fuel cost is calculated for each hour of the year. The model was run for a baseline scenario that did not include a carbon cap or demand from PHEVs, a scenario with the RGGI cap but no demand from PHEVs, and nine different scenarios involving the RGGI cap and different levels of PHEV fleet penetration and charging patterns described below.

The model includes 90 of the 103 thermal plants in New England with generating capacities of at least 25 MW, the minimum capacity covered under RGGI. Thirteen plants operating on waste fuels (black liquor, digester gas and municipal solid waste), totaling 2,051MW of capacity, were excluded from the model as fuel availability was assumed to be limited by nonmarket factors. The 90 remaining plants had a cumulative nameplate capacity of 31,257 MW. The set of all excluded thermal plants, non-thermal plants, and plants smaller than 25 MW had a nameplate capacity of only 3,479 MW. Transmission constraints, strategic bidding, O&M costs, and ramping time and were not represented in the model.

All power plant data, including heat and emissions rates and generating capacity, are from EPA eGRID for the year 2005, the most current data available from the EPA [60]. Hourly demand and fuel cost data are also for 2005 and are from the ISO New England (ISO-NE) [61] and the EIA [62], respectively. The EIA projects continued growth in electricity demand of approximately 1% per year. However, Ruth et al. [57] argued that demand would decrease under RGGI, due largely to state level investments in energy efficiency programs. Given these conflicting projections, the model used unadjusted hourly demand from 2005.

The model used linear optimization to minimize the fuel costs (used as a proxy for variable costs) of electricity generation in the ISO-NE region (Eq 1) subject to the constraints that supply equal demand for every hour of the year (Eq 2) and that during ozone season, May 1 to September 30, NO_x emissions from plants in Clean Air Interstate Rule (CAIR) states must not exceed the NO_x cap for those states (Eq 3). For all model runs other than the uncapped baseline run, the optimization was also constrained by the requirement that CO_2 emission not exceed the New England allocation of the RGGI CO_2 cap (Eq 4).

$$\text{minimize} \quad \sum_{h=1}^{8760} \sum_{I=1}^{ng} C_{f_{ih}} r_{ih} G_{ih} \tag{1}$$

$$\text{subject to} \quad \sum_{I=1}^{ng} G_i = D_h, \forall_h \tag{2}$$

$$\sum_{h=2880}^{6552} \sum_{I=1}^{ng} \rho_{NOxi} G_{ih} \leq NOx\ Cap \tag{3}$$

$$\sum_{h=1}^{8760} \sum_{I=1}^{ng} \rho_{CO2i} G_{ih} \leq CO2\ Cap \tag{4}$$

In Eqs. (1)-(4), C_{fih} is the cost of fuel of plant i at hour h in \$/MMBTU; r_{ih} is the heat rate of plant i at hour h in MMBTU/MWh; and G_{ih} is the energy output of plant i at hour h in MWh. D_h is the energy demand in MWh at hour h. Time-specific demand for PHEV charging was added to baseline demand according to several scenarios described below. The NO_x emissions rate for plant i in kg/MWh is given by ρ_{NOxi}. NO_x emissions for plants outside the CAIR region were excluded from the calculation of equation three. The CO_2 emissions rate for plant i in kg/MWh is given by ρ_{COxi}.

3.1.1. Additional Demand Due to PHEV Charging

The additional electricity demand created by PHEV charging is a function of the number of PHEVs in operation, the rate and time at which they charge, and the energy required to completely charge each vehicle's battery. We modeled three levels of PHEV fleet penetration, 1%, 5% and 10% of the total New England light duty vehicle fleet. Given a LDV fleet of approximately 11 million vehicles [63], these scenarios correspond to 110,000, 550,000 and 1,100,000 PHEVs, respectively, operating in New England. The Obama Administration has set a target of 1 million PHEVs sales by 2015 [29], while the market research firm, Pike Research, has projected that total U.S. PHEVs sales are only likely to reach 610,000 by 2015 [64]. The middle and high penetration scenarios, therefore, are less likely to occur in the near future in the absence of additional policy measures to promote PHEV sales or significant changes in the prices of batteries, electricity or gasoline.

The authors calculated values for PHEV charging rates, battery capacity and electric drive efficiency from reports on the performance of the Chevy Volt, one of the first PHEVs expected to come to market in the U.S. GM reports that the Volt will be capable of driving 64.4 km on 8.8 kWh of electric energy and will fully charge from a standard 120v outlet in approximately 8 hours [65]. This corresponds to a charge rate of 1.1 kW/h and an electric drive efficiency of 7.3 km/kWh. For other estimates of PHEV performance see [7, 30]. Based on this electric drive efficiency and an average annual vehicle kilometers traveled of 20,100 [66], the authors calculated that each vehicle would require, on average, 7.6 kWh of electric energy to completely recharge each day. Given a charger efficiency of 82% and battery charging efficiency of 85% [67], each vehicle would add 10.9 kWh of demand each day. The low fleet penetration scenario of 110,000 PHEVs would correspond to 437,000 MWh of additional demand annually, an increase of 0.33% of the baseline 2005 demand. The medium fleet penetration scenario, 550,000 PHEVs, would increase annual demand by 2,188,000 MWh or 1.66% of baseline demand. The high fleet penetration scenario, 1,100,000 PHEVs, would increase annual demand by 4,376,000 MWh, a 3.26% increase in total demand.

Once the energy required to recharge the battery was calculated, each vehicle was assigned a charging start time for each of three scenarios: evening charging, delayed nighttime charging and twice-a-day charging. The modeled fleet penetration and charging scenarios are summarized in Table 3-1.

Table 3-1. PHEV Penetration Scenarios Modeled

Scenarios		PHEV Fleet Penetration	Added Demand	Charging Scenario
Baseline – No Cap	**(B_0)**	0%	N/A	N/A
Baseline – RGGI	**(B_R)**	0%	N/A	N/A
Low	**(L_1)**	1%	0.33%	Evening Charging
	(L_2)	1%	0.33%	Delayed Charging
	(L_3)	1%	0.33%	Twice a day
Medium	**(M_1)**	5%	1.66%	Evening Charging
	(M_2)	5%	1.66%	Delayed Charging
	(M_3)	5%	1.66%	Twice a day
High	**(H_1)**	10%	3.26%	Evening Charging
	(H_2)	10%	3.26%	Delayed Charging
	(H_3)	10%	3.26%	Twice a day

In the evening-only scenario, vehicles charge once per day starting at 6, 7 and 8 PM. In the delayed nighttime charging scenario, vehicles have charging periods beginning at 10 pm, 11 pm and 12 am. In the twice-a-day scenario, vehicles charge both in the morning and evening starting, at 8, 9 and 10 AM and 6, 7 and 8 PM, respectively. In this last scenario, each vehicle consumes 5.45 kWh in both the morning and evening hours. In the three scenarios, the vehicles were evenly distributed among the three start times and charged continuously until completely recharged.

Similar charging scenarios have been included in a variety of other PHEV studies including [9, 67]. Some of these and other studies have also considered "optimal" charging scenarios, where PHEVs load is coordinated with the utilities to manage demand; however while communication between the utilities and PHEVs may make optimal charging possible, the authors assumed that this practice would not be widespread in the short-run and did not include it the model.

3.2. RESULTS

The model results show that instituting a carbon cap caused an increase in marginal and average fuel costs and that additional demand from PHEVs exacerbated these increases in addition to increasing the cost of CO_2 emissions relative to the baseline capped case. These results were true at all penetration levels and in all charging scenarios and, as expected, were largest in the high fleet penetration case and lowest in the low fleet penetration case. In addition, as expected, the nighttime charging scenarios consistently had the lowest impact on costs of any of the charging scenarios. The baseline supply curve is shown in Figure 3-1, below.

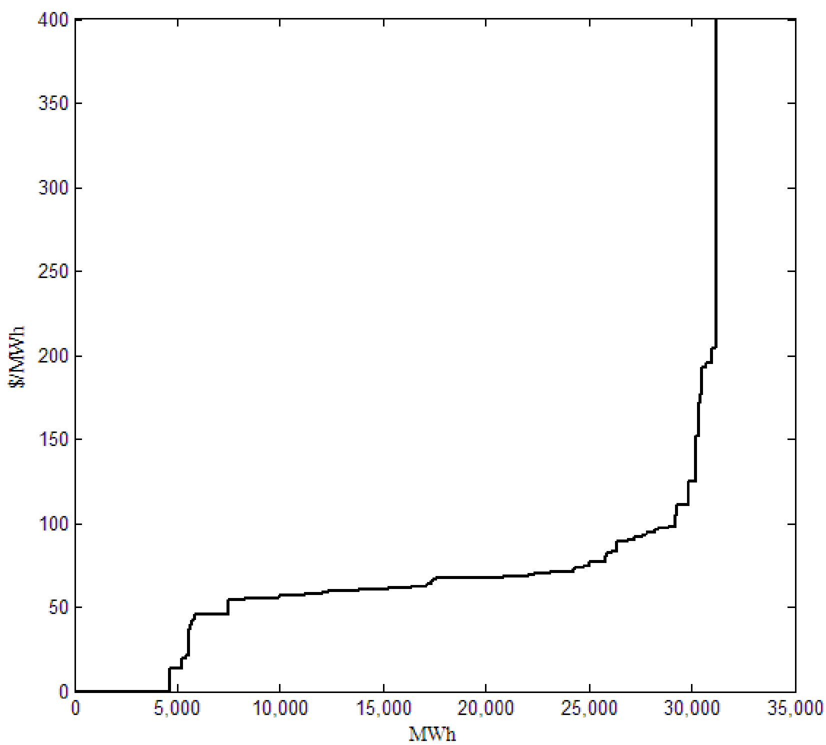


Figure 3-1. Baseline Supply Curve.

The impact of each of the three charging scenarios on daily electricity demand is shown in Figure 3-2. The high fleet penetration case is shown since this case illustrates where PHEV load is added to the baseline demand with the greatest visual clarity. Charging scenarios 1 and 3, evening charging and twice-a-day charging, respectively, increased peak demand on both summer and winter days. Charging scenario 2, delayed nighttime charging, did not impact peak demand in either season.

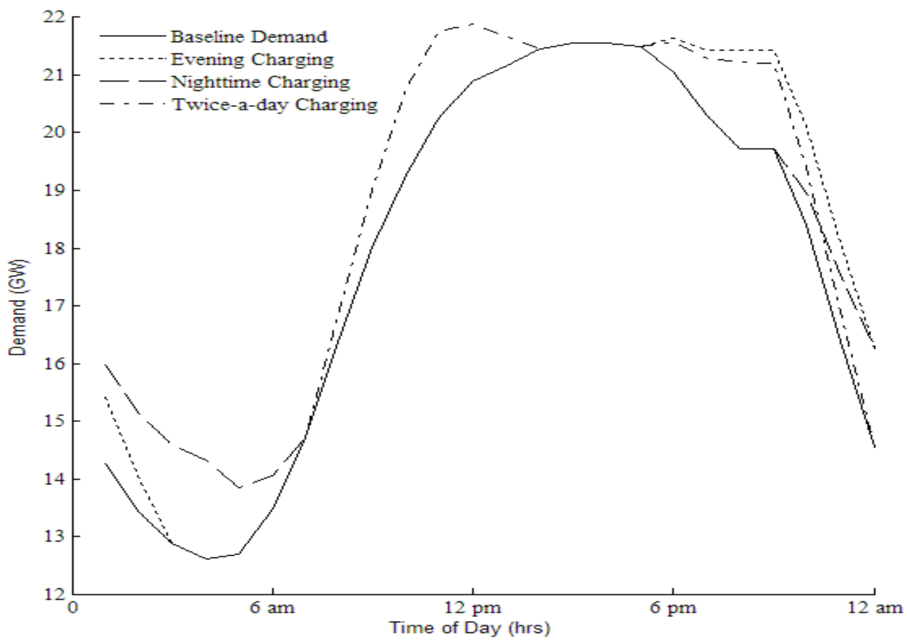


Figure 3-2. Electricity demand curves. The solid line shows baseline electricity demand from August 22, 2005 in GWs. The dashed lines show the new electricty demand with 10% PHEV fleet penetration under a variety of charging scenarios.

Figures 3-3 and 3-4 show the estimated impact of PHEV electricity demand on average fuel costs and marginal fuel costs, respectively. In all cases, the price increase was greatest in the twice-a-day charging scenario and lowest in the delayed charging scenario.

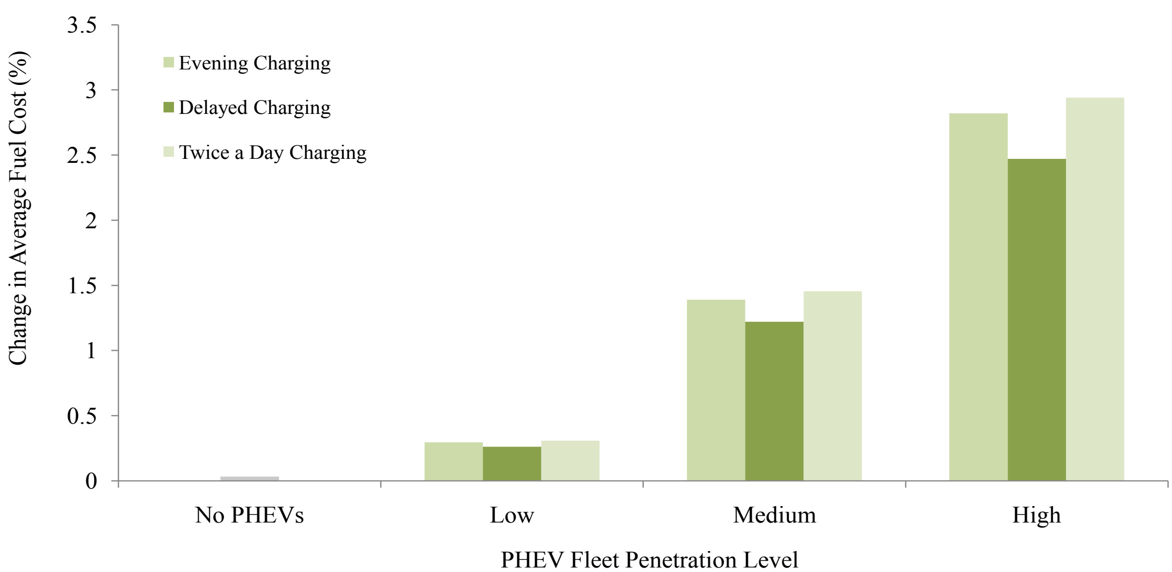


Figure 3-3. Estimated change in average fuel costs under various PHEV charging scenarios.

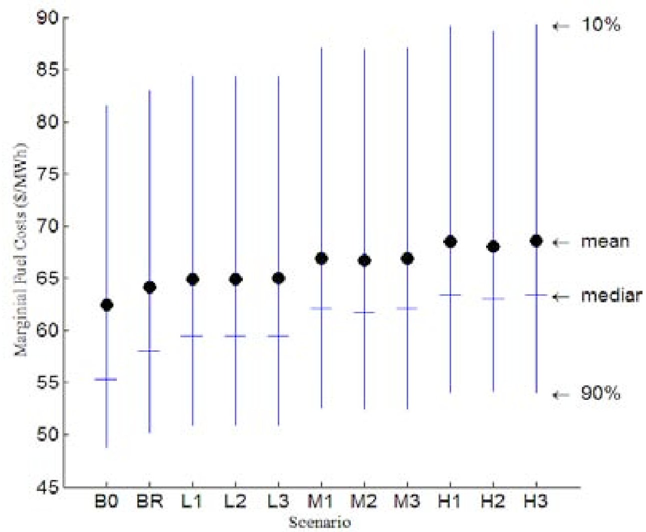


Figure 3-4. Distribution of marginal fuel costs for each of the modeled PHEV charging scenarios.

Due to the exclusion of operation and maintenance (O&M) costs and other dispatch and transmission considerations from the model, the marginal costs calculated in the model are lower than the wholesale electricity prices in the ISO-NE market. The average marginal cost in the uncapped baseline scenario was $62.47/MWh while the average marginal cost for ISO-NE in 2005 was $76.64/MWh.

Figure 3-5 shows the cost per ton of CO_2 emissions in each of the scenarios. The baseline CO_2 price projected by the model, $3.40 per ton, is closely in line with the market price for RGGI allowances. Through the first four auction rounds, 2009 allowances have ranged in price from $3.07 to $3.51 per ton [68]. Charging scenario 2, delayed nighttime charging, caused the smallest increase in costs. In both the high and low penetration scenarios, twice-a-day charging had the largest impact on costs. In the medium penetration case, evening and twice-a-day charging had an equal effect on costs.

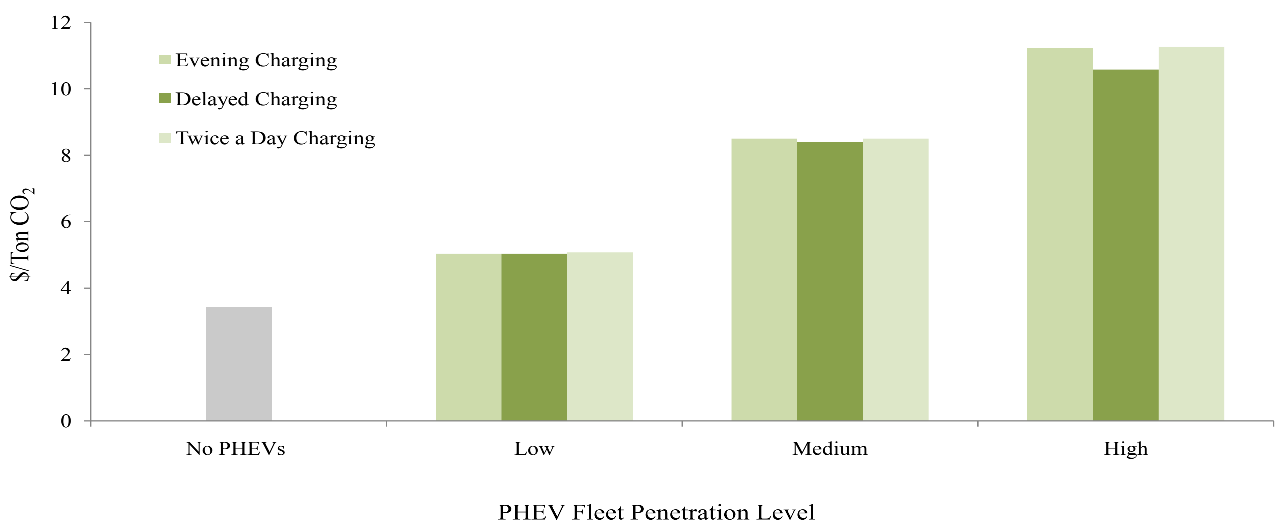


Figure 3-5. Carbon price in $/Ton CO2 for all PHEV charging scenarios.

Total CO_2 costs in the baseline RGGI scenario are \$172 million. Assuming nighttime charging, which minimizes CO_2 costs, this cost rises to \$255 million with 1% PHEV penetration scenario, \$425 million with 5% PHEV penetration scenario and \$535 million with 10% PHEV penetration.

3.3. DISCUSSION

The model results demonstrate a clear, positive relationship between PHEV driven electricity demand and increased fuel and CO_2 costs when electricity sector carbon emissions are capped. This impact is greatest when charging takes places during times of high demand, the morning and evening, likely reflecting that a greater proportion of total generating capacity must be dispatched to meet demand which reduces the overall plant dispatch flexibility relative to periods of lower demand. As modeled here, nighttime charging had the lowest impact on generating costs. Several other studies have found that nighttime and off-peak charging would have substantial benefits to both grid operators and consumers [6, 18]. The current results support those findings.

The model described in this paper estimates the short term impact of PHEV charging on electricity generating costs. Because the focus is on short-run effects, several factors could alter the outcomes from those described here. Changes in the generating mix through new plant construction and/or plant retirement would change the basic underlying supply curve and thus change the optimal dispatch order and, consequently, electricity prices. Given the relatively long period of time required for power plant permitting and construction, significant changes in the generating mix are unlikely to occur in the 2009 – 2014 cap period modeled in this paper. In addition, significant changes in relative fuel prices could also alter the least cost dispatch order and change the marginal cost of generation. Though these changes could change the specific impact of PHEV demand on generating costs, the relationship between increased demand and increased fuel and emissions cost is unlikely to change in the near term.

3.4. CONCLUSION

Several studies have demonstrated the potential for PHEVs to reduce overall emissions across the electricity and transportation sectors. The results presented here show that PHEV demand would increase CO_2 emissions allowance prices when the electricity sector has a GHG cap but the transportation sector does not. In this case switching energy consumption from the liquid fuels sector to the electricity sector, as would occur with PHEV deployment, simultaneously reduces overall CO_2 emissions and drives CO_2 allowance prices up in the electricity sector. In the model described here, a 5% deployment of PHEVs would increase the price of CO_2 allowances from \$3.40 to \$8.40, increasing electricity costs by about 1.4%.

Taken together, these results suggest that an electric sector only cap, such as RGGI, creates a perverse incentive against potential environmentally beneficial fuel switching from gasoline toward electricity. An economy-wide cap on CO_2 emissions, which would be tradable among sectors, would not have this effect.

Further research and model runs could assess the sensitivity of these results to changes in car charging parameters, relative fuel prices and varying cap levels. Additionally, since O&M costs vary considerably by plant type, including O&M costs in future work would also refine the accuracy of the model outputs.

4. Modeling the Impact of Increasing PHEV Loads on the Distribution Infrastructure[3]

Increasing numbers of PHEVs may require utilities to invest in the distribution infrastructure to support circuits being used for vehicle charging. Utilities will need good decision tools to help in the evaluation of distribution system investment options. With this in mind, the goal of this research is to develop a model that allows distribution utilities to evaluate the impact of increasing PHEVs on medium and low voltage transformers and underground cables. The results from this tool, the expected time to failure for distribution circuit components, will allow utilities to prioritize investments given load growth projections.

This section is structured as follows: Section 4.1 reviews common causes of transformer failure and the potential impact the PHEV load could have on the rates of these types of failures; Section 4.2 describes the proposed distribution circuit/PHEV modeling method in detail; Section 4.3 describes the distribution circuit that we use as a test case for our model, and preliminary results from this application; and Section 4.4 provides some preliminary conclusions.

4.1. Potential distribution system impacts

Given standard loading profiles and proper maintenance, manufactures report an expected transformer lifetime of 40-50 years. Under more realistic conditions the actual average lifetime of a transformer is 17 years [69]. Transformers fail most frequently due to line surges/short circuits, the deterioration of insulation, lightning strikes, inadequate maintenance, high oil moisture content, and loose connections [69]. Additional load, such as that required to charge PHEVs, increases the average operating temperature of the transformer, which contributes to insulation breakdown.

Insulation failure increases the quantities of dissolved gases in the insulating oil [70]. These gasses include acetylene and hydrogen from arcing, ethane, ethylene, and methane, and carbon monoxide from superheated paper insulation [70]. Formation of gasses in the insulating oil reduces the dialectic strength of the oil and can create or aggravate short circuits between coil windings [71]. High levels of combustible gasses can lead to explosions. For low voltage transformers, suggested gas limits can be found in [70]. To our knowledge there is no consensus on acceptable levels of these gasses in high voltage transformers. Sudden increases in the level of any of these gas levels may lead to transformer failure.

Additional demand from PHEV charging may have positive or negative effects on transformer aging. For example, increased charging demand will increase transformer temperatures, which may decrease transformer life expectancy. Section 4.2.5 describes this phenomenon in more detail. Alternatively, the flatter load profile resulting from off-peak PHEV charging could reduce the daily expansion and contraction of the transformer, which could reduce wear-and-tear on the transformer bushings. Since bushings are the

[3] Note, Section 4 is a modification of Farmer, C., Hines, P., Dowds, J., Blumsack, S. Modeling the Impact of Increasing PHEV Loads on the Distribution Infrastructure. *Proceedings of the 43rd Hawaii International Conference on System Sciences,* Kauai, 2010. Authors are encouraged to cite the *Proceedings* paper.

primary entry points for oxygen, water, and contaminates [71], load leveling could decrease the probability of transformer failure. Lower water and oxygen levels reduce the number of drying and degassing operations that are required and decrease the likelihood of a failure from these two sources. Lower levels of solid contaminates (dirt/dust) decrease oil viscosity and reduce lifetime strain on oil pumps, thus reducing the required pump maintenance [71]. The current percentage of failures due to dirt, oxygen, and water may be as high as 50% [69]. Insulation materials, structural and electrical components may also experience reduced damage as a result of reduced thermal expansion and contraction.

Further research is needed to understand the effects of thermal expansion and contraction on the maintenance costs of transformers. If the cost savings from reduced thermal expansion/contraction are significant, they could offset the decreased transformer life due to temperature increases [72].

Harmonic distortion from the power electronics in PHEV chargers may also have some negative effects on the distribution infrastructure. PHEVs charge by drawing low voltage AC power and converting it to DC. This process involves rectifying the AC signal and running the rectified signal through a DC/DC converter. Both of these processes produce harmonic distortion in the distribution system [73]. Harmonic distortion causes power loss in transformers due to increased average temperature generated from increased eddy currents in the transformer core and decreased skin depth on the transformer windings and harmonic distortion also creates higher high spot temperatures [74, 75] compared to loads without harmonic distortion. An Institute of Electrical and Electronics Engineers (IEEE) draft standard, P1495, states that the total harmonic distortion (THD) of a low voltage single phase load under 600 watts must be 15% or less [76]. The California Energy Commission has set their EV battery charger THD standard limit at 20% or less [73]. These figures indicate a possible maximum harmonic distortion before transformers experience excessive capacity loss.

Large numbers of harmonic loads on a single distribution circuit will result in some harmonic cancelation between the loads which may reduce overall harmonic distortion [77]. If PHEV penetration was sufficiently high such that the majority of off-peak load was from PHEVs, harmonic loading on distribution equipment could be very high during night-time charging hours. However, lower night time temperatures will help cool the transformer, which may keep the transformer from overheating even if the internal losses are higher [75]. According to [25] a 10% THD could correspond to a 6% loss in transformer life, relative to a load with no harmonic distortion.

PHEV market penetration is likely to be higher in some areas than in others. Even if national PHEV/EV penetration is low, adoption in certain communities could be very high. It is important for utilities to be aware of regions with high PHEV penetrations in order to appropriately focus maintenance and monitoring resources. Ultimately, the financial impact of widespread PHEV adoption on the electrical sector will depend on several factors including: (1) the effects of a level load equipment operation and maintenance; (2) the extent to which reduced plant cycling reduces generating cost; (3) the reliability and generation investments needed to meet higher overall demand; and (4) the revenue generated from increased electricity sales.

4.2. The PHEV Distribution Circuit Impact Model (PDCIM)

The purpose of the PHEV distribution circuit impact model (PDCIM), described here, is to estimate the impact of increasing PHEV charging loads on underground cables, medium voltage distribution substation transformers, and low voltage residential distribution transformers. Given a known number of PHEVs to be deployed on a distribution circuit, PDCIM randomly distributes the PHEV loads throughout the circuit and estimates the hour-by-hour annual loading profile on individual components. These new load profiles are used to calculate the expected lifetime of each component in the model. Based on these results utilities can flag components that show a substantially reduced expected lifetime for service, additional monitoring or replacement. Table 4-1 summarizes the inputs, outputs, and variables for PDCIM.

Table 4-1. PDCIM Inputs, Outputs, and Notation

Inputs	
L_h	The average total circuit load (kW) during each hour h
M	Circuit model, which includes the network topology, the locations and ratings of components, and the distribution of load through the circuit
N_i	The number of PHEVs in the circuit at PHEV deployment level i
$\theta_{A,h}$	Hourly ambient temperature
T	Time of day (hour) at which charging begins
E	Energy consumed during one PHEV charging cycle (kWh)
P	PHEV charging rate (kW)
Outputs	
$L_{k,h}(i)$	The load on each component k at hour h at PHEV deployment level i (with N_i vehicles charging)
$\Delta F_{k,i}$	Change in expected lifetime for component k, at PHEV deployment level i
Additional notation	
D	The set of all demand serving devices (distribution transformers) in the circuit
K	Index for distribution circuit components (most notably transformers and cables)
I	PHEV deployment level, with N_i vehicles charging on the circuit
L_k (M)	The demand on component k in the base case circuit model M
$R_{\beta(h)}$	Scaling factor used to increase/decrease loading from the base case (See Section 4.2.1)
$G_k(i)$	The power demand added to device k due to PHEV, at PHEV deployment level i

PDCIM requires the following inputs: a model of the distribution circuit (M), hourly total circuit loading data (L_h in kW), demand serviced ($L_k(M)$) by each low voltage transformer k, hourly ambient temperatures ($\theta_{A,h}$), and some basic information about the PHEVs that are expected to charge on the circuit. In the implementation described here, PDCIM estimates hourly component loading (8760 load levels for a one year study) by completing a small number of load flow calculations and interpolating from these results. PDCIM follows a five step process to obtain the change in component loading and expected lifetime for each component from the input variables. These steps are described in sections that follow.

4.2.1. Step One: Developing the baseline demand profile

The first step uses the hourly circuit load L_h and the load on each demand component ($L_k(M)$ for each k in D) to estimate the hourly baseline load on each load-serving component ($L_{k,h}(0)$, where the 0 indicates that this is the baseline case with no PHEV load). The load-serving components (D) are typically low voltage transformers that feed one or more residential or commercial customer. $L_{k,h}(0)$, in kW, is estimated by scaling the component loading from the model $L_k(M)$ by an hourly scaling factor R_h which is generated from the hourly circuit load L_h:

$$L_{k,h}(0) = R_h L_k(M) \tag{1}$$

where R_h ranges between $R_{\min}$ and $R_{\max}$, which are calculated by dividing the minimum and maximum hourly loads by the baseline demand in the model:

$$R_{\min} = \frac{\min_h \left(L_h\right)}{\sum_{k\in D} L_k\left(M\right)} \tag{2}$$

$$R_{\max} = \frac{\max_h \left(L_h\right)}{\sum_{k\in D} L_k\left(M\right)} \tag{3}$$

Scaling the load in this way allows us to match the load on each component with hourly data from the distribution substation, which are typically quite accurate.

While it is feasible to generate one scaling factor (R_h) for each hour, and thus produce 8760 variants of the circuit model for a one-year study period, performing a large number of power flow calculations may be computationally prohibitive. To reduce the computational burden, we produce a limited number of scaling factors $R_{\beta(h)}$ that vary linearly between R_{min} and R_{max}. Each hour maps to exactly one load level (β) and thus one $R_{\beta(h)}$, whereas each load level β can represent many hours. The load duration curve in Figure 4-3 illustrates this assignment. Eq. 4 defines the step size among the scaling factors:

$$\delta = \frac{R_{\max} - R_{\min}}{n_\beta - 1} \tag{4}$$

Eq. 5 gives the individual values of R_β:

$$R_\beta = R_{\min} + \delta \cdot (\beta - 1) \tag{5}$$

Finally, Eq. 6 approximates the load on component k at hour h from the approximated scaling factor:

$$L_{k,h}(0) = R_{\beta(h)} \cdot L_k(M) \tag{6}$$

The number of unique values of R_β (n_β) determines the resolution of the hourly component loading profiles. A higher n_β will increase the computational burden but will result in more accurate load profiles.

4.2.2. Step Two: Adding PHEV demand

The second step creates the PHEV demand on each load-serving component by randomly distributing PHEVs to residential customers in the circuit, with a maximum of two vehicles per customer. Each end use device may have multiple residential customers attached to it, so a single device may have more than two PHEV loads.

In our example results, we estimate the impact of PHEVs at several deployment levels ($i = 0,\dots n_i$), where i=0 corresponds to zero PHEVs and i=n_i corresponds to the maximum PHEV level for this circuit. In Section 4.3, the maximum PHEV deployment is chosen based on the number of customers in the circuit. Given the charging rate for the PHEV being modeled and the number of PHEVs assigned to each component, this process produces the PHEV charging load on each load-serving component k for each deployment level i, $G_k(i)$.

In this version of PDCIM all PHEVs are assumed to charge at the same rate and consume the same amount of energy per charge. Future versions of this model will allow for more flexibility in these parameters. Once the PHEV demand $G_k(i)$ has been created for all distribution levels, it is added to every unique value of the baseline demand profile:

$$L_{k,\beta(h)}(i) = R_{\beta(h)} \cdot L_k(M) + G_k(i) \tag{7}$$

At this point the model has produced an estimated demand profile for each load-serving component at each PHEV deployment level. However, it is important to note that the PHEV load is added to every hour, not only during charging hours.

4.2.3. Step Three: Power-flow calculations.

The third step is to compute the loading on the upstream components, such as underground cables and the substation medium voltage transformer by running a power-flow calculation on the circuit for every loading profile (each load level β and each PHEV distribution level i). The outcome is an estimate of loading on each component. Note that there are only $n_\beta(n_i+1)$ unique values for $L_{k,h}(i)$: one for each combination of i and β. To simulate one year of data, the number of power flow calculations is reduced from 8760(n_i+1) to $n_\beta(n_i+1)$.

In the current implementation we used CYMDIST an industry standard distribution circuit power flow software package [78] to calculate the load on each component and at each loading level, as given by:

4.2.4. Step Four: Setting the PHEV charging patterns

Step four in PDCIM uses the estimated load on all components $L_{k,\beta(h)}(i)$ and the PHEV time-of-day charging information to produce the final estimated hourly loading profiles on all the components $L_{k,h}(i)$. In this preliminary model, PHEVs are assumed to arrive daily at hour T and charge at rate P until each car has consumed exactly E kWh of electric energy. Hour h is a charging hour if it falls within hour T and hour $T+E/P$. If at hour h the PHEVs are charging then $L_{k,h}(i)$ equals the loading after charging loads are added. If h is not a charging hour, $L_{k,h}(i)= L_{k,h}(0)$.

$$L_{k,h}(i)=\begin{cases} L_{k,\beta(h)}(i) & \text{if} \quad \text{Charging}(h) \\ L_{k,\beta(h)}(0) & \text{Otherwise} \end{cases} \tag{12}$$

At this point we have acquired the first PDCIM output, the hourly loading profile on individual components $L_{k,h}(i)$. In the following section we use this hourly profile to calculate the change in expected lifetime resulting from additional PHEV charging loads.

4.2.5. Step Five: Translating hourly loading to expected lifetime

To estimate the change in expected lifetime for distribution circuit components, we follow the transformer reliability model described by IEEE standard C57.92-1981 [79], as interpreted in [80]. Our model roughly follows the approach described in [72].

The calculation of transformer aging includes two steps. The first is to estimate the temperature of the hottest point within the transformer (the "hot spot" temperature, θ_H) for each hour in the period of study. The hot spot temperature is a function of ambient temperatures and transformer load. The second step is to translate θ_H into a measure of transformer aging. IEEE Standard C57 provides a function for translating hot spot temperature into an accelerated aging factor (F_{AA}), which can be used to estimate the loss in transformer life that can result from higher temperatures and heavy loading. Sections 4.2.5.1 and 4.2.5.2 describe these two steps in detail. Underground cables have different physical properties and insulation from transformers, but they are also subject to aging through increased temperature. Specific guidelines regarding the aging of various types of underground cables must be sought out through the various manufactures. Future versions of the PDCIM model will have a separate set of generalized equations for predicting aging of underground cables.

4.2.5.1 Estimating the winding hot spot temperature, θ_H. PDCIM uses the following procedure to estimate the winding hot spot temperature. First, we calculate the thermal time constants for the transformer oil (τ_{TO}) and windings (τ_W). Both represent the thermal inertia of the transformers. Given the weight of the transformer (W_T, in lbs.), the gallons of oil in the transformer (G_O), the temperature rise of the top-oil above ambient (typically 30°C) at rated load ($\Delta\theta_{TO,R}$) and the power losses at rated load ($P_{T,R}$), Eq.11 (derived from [80]) is used to calculate τ_{TO} for each transformer:

$$\tau_{TO} = \frac{(0.06W_T + 1.93G_O)\Delta\theta_{TO,R}}{P_{T,R}} \tag{11}$$

Eq. 11 is a minor simplification of the equation for τ_{TO} given in IEEE C57.92, which provides a method for calculating a time-varying time constant. The approximation is appropriate for small time steps, which we have with the hourly model. IEEE C57.92 does not provide a method for calculating the winding time constant. Following [80], we assume that τ_W is small (τ_W=0.25 for the example calculations in this paper). Second Eqs. 12, 13 and 14 (also from [80]) allow one to calculate the initial transformer temperature gradients ($\Delta\theta_{TO,}$ and $\Delta\theta_{H,0}$):

$$\Delta\theta_{TO,0} = \Delta\theta_{TO,R} A(L_{k,0}) \tag{12}$$

$$\Delta\theta_{H,0} = \Delta\theta_{H,R} A(L_{k,0}) \tag{13}$$

where $\Delta\theta_{H,R}$ and $\Delta\theta_{TO,R}$ are the rated hot spot and oil temperature increases, respectively, and $A(L_{k,0})$ is a transformer loading factor:

$$A(L_{k,h}) = \left(\frac{(L_{k,h} / L_{k,R})^2 (P_{T,0} / P_{T,R}) + 1}{P_{T,0} / P_{T,R} + 1} \right)^{n_t} \tag{14}$$

In Eq. 14, $L_{k,h}$ and $L_{k,R}$ are the actual and rated loading of the transformer, respectively; $P_{T,R}$ and $P_{T,0}$ are the power losses of the transformer at rated and no load, respectively; and n_t is a parameter that comes from the cooling class of the transformer. We use n_t = 0.8, the value for Oil/Air (OA) transformers, in this paper. Third, PDCIM calculates the hot spot temperature gradients for each time step using Eqs. 15 and 16:

$$\Delta\theta_{TO,h} = \Delta\theta_{TO,h-1} + (\Delta\theta_{TO,R} A(L_{h,0}) - \Delta\theta_{TO,h-1})(1 - e^{-\Delta t/\tau_{TO}}) \tag{15}$$

$$\Delta\theta_{H,h} = \Delta\theta_{H,h-1} + (\Delta\theta_{H,R} A(L_{h,0}) - \Delta\theta_{H,h-1})(1 - e^{-\Delta t/\tau_W}) \tag{16}$$

where Δt is the length of the time step in hours (1 hour in PDCIM). The hourly hot spot temperatures ($\theta_{H,h}$) are derived from the ambient temperature at hour h and the temperature gradients:

$$\theta_{H,h} = \theta_{A,h} + \Delta\theta_{TO,h} + \Delta\theta_{H,h} \tag{17}$$

4.2.5.2 Calculating the change in expected component life. Given the winding hot spot temperature, $\theta_{H,h}$, IEEE C57.92 specifies that the following formula can be used to estimate the per unit accelerated aging (F_{AA}) of a transformer:

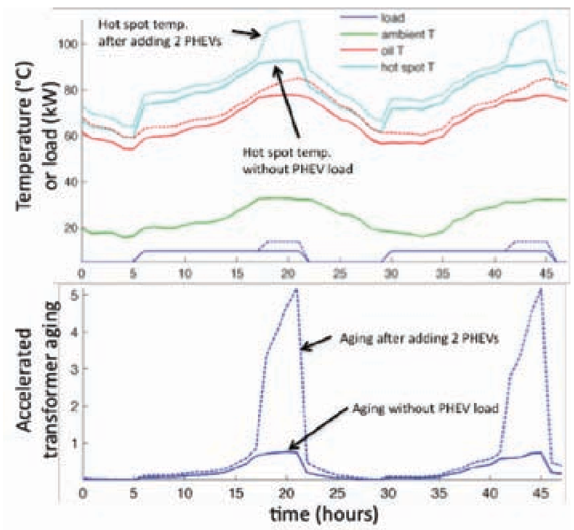
$$F_{AA}(\theta_{H,h}) = e^{B/\theta_{H,R} - B/\theta_{H,h}} \tag{18}$$

where B is a constant given as 15,000 in [80], and $\theta_{H,R}$ is the rated maximum hot spot temperature for the transformer. Eq. 19 allows us to estimate the change in expected life due to thermal loading at PHEV distribution level i over a one-year period:

$$\Delta F_{k,i} = \frac{1}{8760} \sum_{h=1}^{8760} F_{AA}(\theta_{H,h}(\mathbf{L}_{k,h}(i))) - F_{AA}(\theta_{H,h}(\mathbf{L}_{k,h}(0))) \tag{19}$$

where $\theta_{H,h}(L_{k,i})$ and $\theta_{H,h}(L_{k,0})$ represent the winding temperatures with PHEV distribution level i and without additional PHEV load, respectively.

4.2.5.3 Example results for a single transformer. To illustrate the aging simulation we calculate the accelerated aging for a single 10kVA transformer, which is loaded at 5kVA during the evening hours and at



Hot spot temp.
after adding 2 PHEVs
load
ambient T
oil T
hot spot T
Hot spot temp.
without PHEV load
Temperature (°C)
or load (kW)
Aging after adding 2 PHEVs
Aging without PHEV load
Accelerated
transformer aging
time (hours)

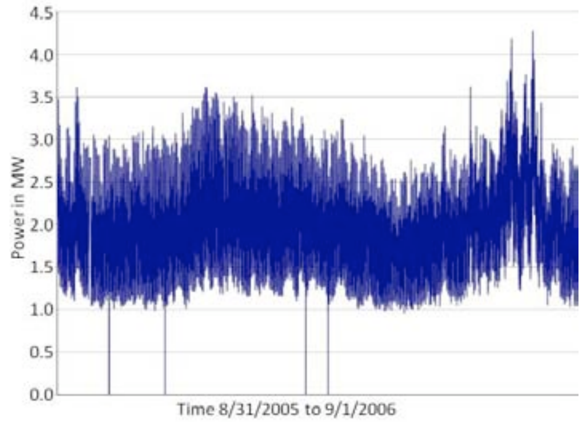


Figure 4-2. Hourly Circuit Loading. Chronologically ordered hourly total circuit loading for the GMP test circuit from 8/31/2005 to 9/1/2006.

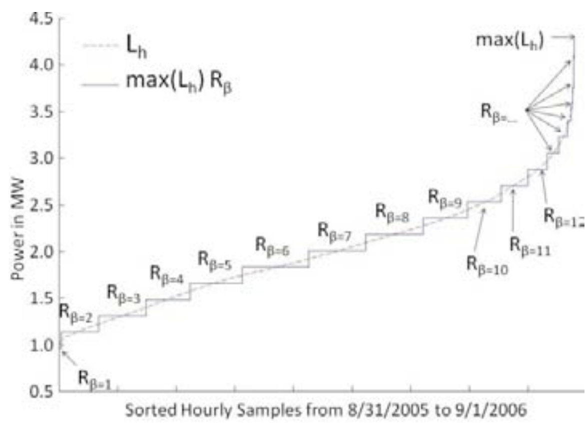


Figure 4-3. Load duration curve for the GMP test circuit. The jagged edge shows the approximate load after application of the scaling factor $R_β$.

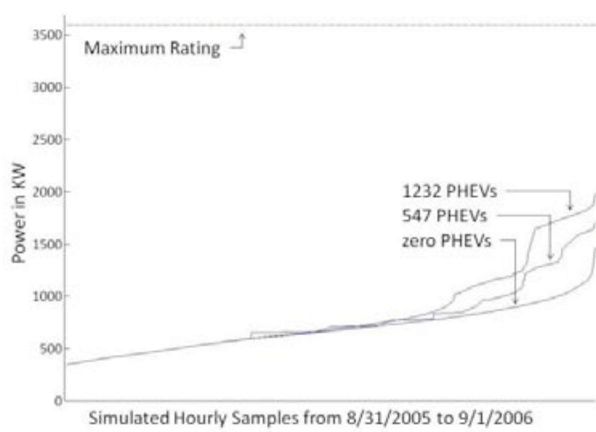


Figure 4-4. Load duration curves for one underground distribution cable at three PHEV deployment levels. This particular cable

had the greatest increase in loading out of all the underground cables in this study.

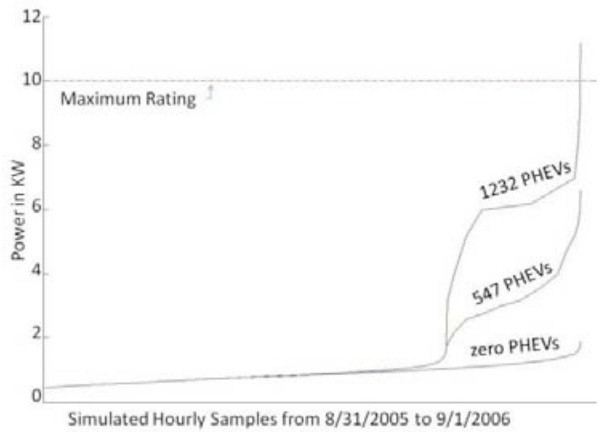


Figure 4-5. Load duration curves for one transformer at three PHEV deployment levels. This transformer had the greatest increase in loading of all the transformers in this study. At the highest PHEV level, the transformer exceeds it's maximum rating for part of the year.

To compare the differences between PHEV impacts on underground cables and transformers Figure 4-6 shows a probability density function (PDF) for the average percent increase in loading. The distributions are heavy-tailed due to outliers. These outliers are important to the results, because they contribute disproportionately to component aging.

Furthermore, in this example, transformers in comparison to underground cables are more likely to experience low increases in percent average load. Also underground cables more frequently experience moderate increases in percent average load. In the extremes, transformers more frequently experience a high increase in average load. Also underground cables more frequently experience a very low increase in percent average load. Application of Step five (transformer aging) to the test circuit is left for future work.

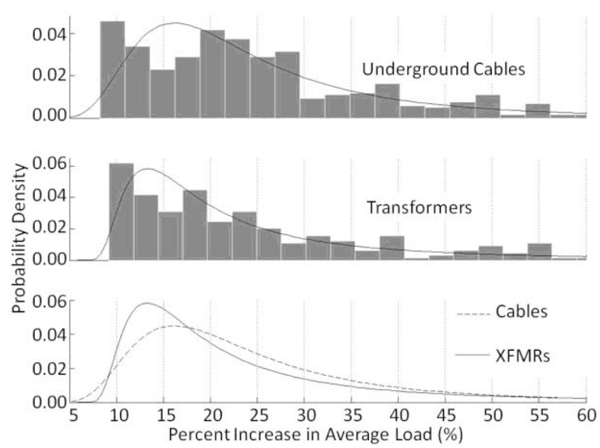


Figure 4-6. Percent increase in average loading for all the components for the highest PHEV deployment level (1232 vehicles). From these data we calculated a Type II Generalized Extreme Value Distribution, which produced the highest likelihood value out of several attempted distribution fits.

4.4. Conclusions

In this section of the paper, we describe a method for modeling the impact of increasing PHEV charging loads on the medium voltage electrical distribution infrastructure. The model is applied to circuit data from a distribution utility in Vermont. While our results are preliminary, and some modeling work remains for future research, they indicate that the deployment of PHEVs in a distribution circuit will have diverse effects on the distribution infrastructure. Careful modeling of these impacts can be valuable in the development of utility operations and maintenance plans given potential increases in demand due to PHEV or EV deployment.

5. Vehicle-to-Grid Opportunities in Vermont

The electric power infrastructure is often strained during periods of peak demand, leading to increased electricity costs during these periods. Prior analyses in Vermont and elsewhere in the country [9, 18, 67] suggest that controlling the timing of PHEV charging may be necessary to avoid increasing the peak demand for electricity. Many analysts view smart charging of an emerging fleet of advanced electric vehicles, including PHEVs, as part of the larger smart grid concept being pursued by utilities across the country. Smart grids use digital technology to facilitate interaction between suppliers of power and consumers with the goal of saving energy, reducing costs, and enhancing system reliability.

The further development of smart charging to provide a bi-directional interface between vehicles and the grid has become popularized under the heading V2G. Vehicles under this scenario are envisioned as interactive storage devices that both charge from the grid and return power back to the grid using smart grid controls [81, 82]. A significant literature has developed in the past decade exploring the best applications for V2G resources and their economic value. The use of V2G equipped vehicles to provide ancillary services used to maintain system reliability could potentially generate thousands of dollars for the vehicle owner over the life of the vehicle [83]. Furthermore, some view a longer-term opportunity for V2G resources serving to integrate large quantities of intermittent resources such as wind and solar into the grid [22, 84].

5.1. Recent V2G Literature Review and Projects Updates

A limited number of academic papers have been published on the topic within the past two years. Tomic and Kempton [27] analyzed the revenue potential for two electric vehicle (EV) utility fleets. The study analyzed V2G opportunities for a fleet of 100 Th!nk EVs and a fleet of 252 Toyota RAV4 EVs. The authors identified three important parameters that influence the economic value of using fleets as V2G resources. These variables are: (1) the market value of regulation services, (2) the power capacity (kW) of the electrical connections and wiring, and (3) the energy capacity (kWh) of the vehicle's battery. Based on the study, they found that, with a few exceptions when the annual market value of regulation was low, that a fleet of V2G EVs providing frequency response regulation services were profitable across the four markets analyzed (New York, Texas, California, and the mid-Atlantic region served by PJM). The authors found that, assuming no more than current Level 2 charging infrastructure (6.6 kW), the annual net profit for the Th!nk City fleet ranges between $7,000 to $70,000 providing regulation down only. The annual net profit for the RAV4 fleet was estimated to be between $24,000 to $260,000 providing both regulation down and up. The wide range of net profits in this study results from fluctuations in the market price for regulation from year to year and from region to region. The authors conclude that, "Vehicle-to-grid power could provide a significant revenue stream that would improve the economics of grid-connected electric-drive vehicles and further encourage their adoption. It would also improve the stability of the electrical grid."

Denholm and Letendre [85] produced a paper titled "Grid Services from Plug-In Hybrid Electric Vehicles: A Key to Economic Viability?" for presentation at the 2007 Electrical Energy Storage Applications and Technologies Conference. The authors recognize that the significant higher cost of plug-in vehicles associated with the onboard battery storage may be a significant barrier to widespread adoption. They evaluate how the potential revenues from providing grid services could serve to mitigate the initial higher cost of plug-in vehicles allowing for more rapid deployment. Specifically, the authors find that V2G revenues can significantly reduce the payback period associated with plug-in vehicles relative to conventional gasoline vehicles from over 10 years to fewer than 6 years. As a result, they conclude that unlocking the value of V2G services may be essential for the widespread adoption of advanced clean vehicle technology.

A study by Sioshansi and Denholm [86] compared the emissions of ICEVs, with HEVs and PHEVs at various market penetration rates from 1 percent to 15 percent. The study considered four emissions categories: tailpipe emissions, refinery emissions, up stream generator emissions and generator emissions to assess net emission impacts from the introduction of plug-in vehicles in Texas. The authors used a unit commitment dispatch model of the Electric Reliability Council of Texas (ERCOT) territory to model the generation-related emissions impacts from PHEV charging, including the emissions impacts from using PHEVs to provide V2G services. The model dispatched the resources in the system to minimize overall operational costs.

The study found that changes in generator dispatch for PHEV charging for a fleet of up to 15% of light-duty vehicles would decrease net generator NO_x emissions during the ozone season in Texas when the negative impacts of ozone are most severe. This is projected despite the additional generation required to charge vehicles due to the fact that optimized charging can lead to significant improvements in generator efficiencies. However, the study found that PHEV charging results in increases in generator emissions of CO_2 and SO_2. Furthermore, the study found that using the V2G capability of the vehicle fleet to provide the services of spinning reserves and energy storage can serve to reduce NO_x emissions beyond the charge-only scenario and contribute to reduced generation emissions of CO_2 and to a lesser extent SO_2 relative to the charge only scenario. When V2G capable PHEVs are used to provide spinning reserves, they tend to reduce the need to keep natural gas-fired generators online leading to these emissions reductions. The lower sulfur content of natural gas relative to coal implies that V2G services will have more of an impact in reducing CO_2 and NO_x emissions as compared to SO_2. In summary, the study found that using a PHEV fleet to provide V2G services can mitigate the increased generation-related emissions associated with PHEV charging.

The authors used the estimated PHEV generation-related emissions combined with estimates of tailpipe and certain upstream emissions to compare the net impact of PHEVs with ICEVs and HEVs. The study finds that PHEVs can reduce transportation-related air emissions for both CO_2 and NO_x during the ozone season when compared to ICEVs and HEVs. However, SO_2 emissions increase due to the fact that coal generation accounts for approximately 20 percent of the generation for PHEV charging. The authors note that SO_2 is capped in the US and thus any increases from PHEV charging would need to be offset by other reductions by covered entities. The study found that additional transportation-related emission reductions can be achieved when PHEVs are utilized as V2G resources. This is the first study to estimate the potential emissions benefits associated from PHEVs providing V2G services. Finally, the authors acknowledge that the emissions impacts of PHEVs will be highly sensitive to the generation mix and the importance of conducting detailed emissions impact studies for different regions.

A second paper by Sioshansi and Denholm [87] due to be published in *The Energy Journal* in 2010 used the same unit commitment dispatch model for ERCOT to assess the economic value of a V2G-equiped PHEV fleet providing ancillary services. Prior studies [82, 83] relied on historical wholesale market prices for ancillary services to estimate V2G revenues. In contrast, the simulation by Sioshansi and Denholm models the economic dispatch of resources serving ERCOT. This modeling suggests that V2G resources participating in wholesale power markets place downward pressure on the market clearing prices for ancillary services, thus leading to lower revenue potential. In fact, they found that when PHEVs reach 15 percent of the vehicle fleet, they would saturate the market for spinning reserves. However, their study did conclude that a PHEV fleet can result in substantial cost savings for a power system of more than $200 annually per vehicle. This is significantly lower than the prior studies referenced above that focus on the more valuable ancillary service called regulation. This study only considered the ancillary services known as spinning and non-spinning reserves, which have lower prices in regional wholesale power markets. Sioshansi and Denholm in this study further conclude that the potential revenue from the provision of V2G services can help to recover the higher upfront capital cost for a PHEV from over nine years to about seven year.

In the past several years, there have been several demonstrations of V2G technology. Two such demonstrations use technology developed by the San Demas-based electric vehicle development company AC Propulsion, who currently offer an EV conversion of the Scion xBox for approximately $70,000 called the eBox. AC Propulsion's AC 150 high performance electric drive system comes standard with an integrated charger with V2G capability. The charger is capable of bi-directional power flows of 19 kW on command.

The first known demonstration occurred in 2002 by AC Propulsion under contract with the California Air Resources Board. A test vehicle was fitted with the AC Propulsion drive train with an integrated bi-directional charger and wireless internet connectivity. An aggregator function was developed to represent a commercial middleman between the grid operator and multiple vehicles. Working with the California ISO (Independent System Operator) power dispatch commands were sent wirelessly to the vehicle at 4-second intervals, and the vehicle response was monitored and recorded. The testing occurred over 227 hours. The results showed that wireless data transmission times were within ISO system requirements, and that the energy throughput through the battery due to regulation is similar to that of typical daily driving. Brooks [88] concluded that the value created by providing regulation services exceeds the battery degradation costs under most operating assumptions.

A second demonstration is currently underway as part of the Mid-Atlantic Grid Interactive Cars Consortium (MAGICC). MAGICC was created to further develop, test, and demonstrate V2G technology and includes core partners from academia and the electric, automotive, and communications industries. The consortium is currently testing one EV conversion of the Scion xBox with the AC Propulsion drive train that has been modified with logic and controls to allow the vehicle to respond to the real-time regulation signal from the regional grid operator PJM. In October of 2007 the vehicle was successfully interconnected to the PJM grid using a direct signal from the PJM control center to dispatch the vehicle as a regulation resource, like traditional generators. Communications from PJM to the vehicle occurs via a power line carrier ethernet bridge connected to the charging line circuit (alternative communication technology could be deployed such as cell-phone or other signal medium). The command signal from PJM is lifted from the power line and decoded onboard the car by the Arcom Director, an industrial communications gateway also used by conventional generators providing ancillary services. This project provides further proof of concept that AEVs can serve as grid resources. A report by Kempton et al. [89] describes the overall project, along with background information on V2G fundamentals and the initial results of the V2G vehicle testing.

Additional limited demonstrations have been conducted to highlight the V2G potential. In 2007 the California Utility Pacific Gas & Electric showcased a PHEV with bi-directional power flow capabilities. The company used a PHEV conversion with an inverter to power several small appliances. Some have referred to this application as Vehicle-to-Home (V2H), whereby a PHEV or EV could be used to power a home in the case of a power outage. This demonstration did not demonstrate a truly grid-interactive vehicle like the demonstrations described above, whereby a vehicle can be centrally dispatched to provide grid support services on demand.

Additional demonstrations have been announced that are at different stages of implementation. One includes Excel Energy's Smart Grid Project. According to a press release in October of 2008 the company plans to convert 60 existing hybrid electric vehicles to PHEVs with V2G technology. The cars will be part of the City of Boulder, Boulder County, and University of Colorado fleets. In early 2009 a project based in Denmark was announced, called Electric vehicles in a Distributed and Integrated market using Sustainable energy and Open Networks. The proposed project involves deployment of V2G equipped electric drive vehicles on a Danish island to facilitate greater integration of wind power into the island's power grid. We expect a number of additional demonstrations of V2G technology taking place in the coming years as V2G technology evolve and interest continues to grow.

5.2. V2G Resource Assessment in Vermont

In this section, we provide an assessment of a possible fleet of PHEVs and EVs in Vermont serving as V2G resources. To begin, we present a market penetration model of advanced electric drive vehicles (AEVs) in Vermont. Based on this analysis we characterize the size of a potential V2G resource in Vermont along with a brief discussion of how this resource might be used to enhance the regional power grid.

5.2.1. PHEV Market Penetration Model

While almost every major automobile company has announced plans to produce some form of AEVs, either PHEVs and/or EVs, as early as 2010, it is unclear how quickly these vehicles will begin to penetrate the new vehicle market and whether or not they will be equipped with V2G technology. The exact specifications of these vehicles are unknown, particularly with regard to the onboard storage capacity. For example, GM has announced that its Volt will have the ability to travel 40 miles on electricity or approximately 16 kWh of storage capacity. In contrast, although no details have been given, it is likely that Toyota's plug-in Pruis will have a much smaller battery pack, possibly in the range of 5 – 8 kWh. Thus the rate of market penetration and the vehicle configurations make characterizing future fleets of AEVs difficult. Furthermore, none of the major automobile manufacturers have announced plans to integrate V2G technology within their vehicles. Initial V2G opportunities may result from aftermarket conversions leveraging smart grid and charging technologies. Thus the rate of market penetration, the onboard storage capacity, and the timing of V2G technology deployment will dictate the size of an emerging V2G resource in Vermont.

A model was developed to predict the number of AEVs in Vermont and the size of the onboard storage capacity beginning in 2010 through 2030. A four-year annual average (2004 – 2007) of 38,600 new light vehicles sold in Vermont was used to predict annual new vehicle sales for the timeframe under consideration. A study conducted by researchers at the Argonne National Laboratory assumed that AEVs achieve a market share of 25 percent of new vehicles sold in 2020, starting at zero percent in 2010 and ramping up over 10 years. The study assumed that AEVs maintain 25 percent market share through 2030 [8]. These assumptions were used for our baseline analysis. We also analyze both low and high market penetration scenarios using 15 and 45 percent by 2020 respectively. For each scenario, it was assumed that vehicle have a 10-year useful life. Figure 5-1 illustrates our projections for plug-in cars based on the above assumptions. Based on our model, we project that between 30,000 and 75,000 plug-in AEVs will be in Vermont by 2020 and between 60,000 and 135,000 by 2030.

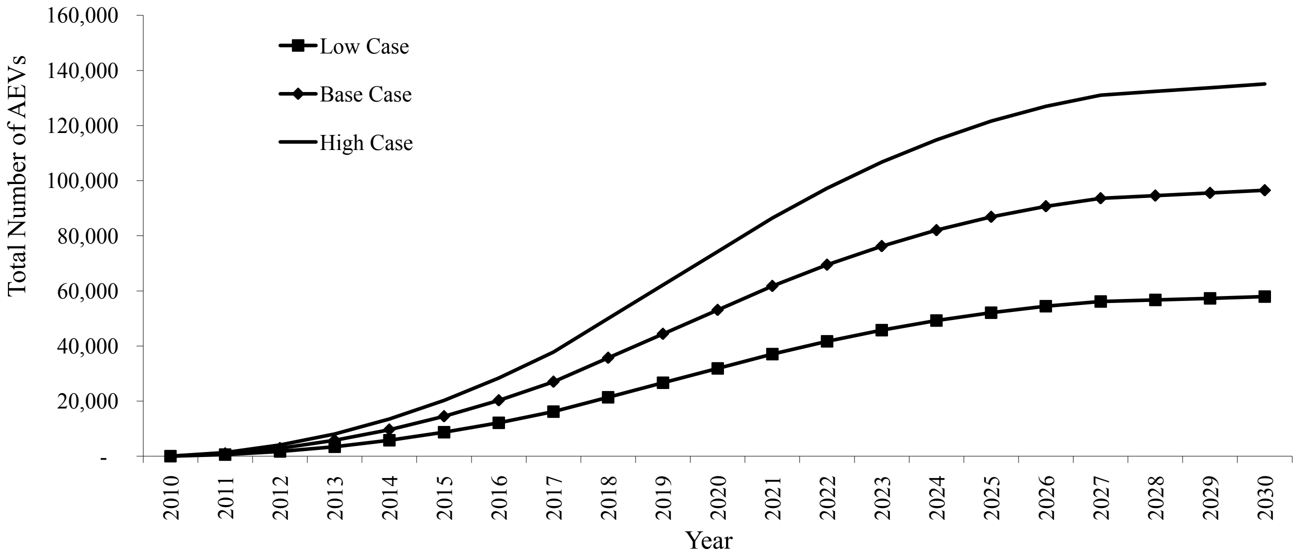


Figure 5-1. Projected Number of Advanced Electric Vehicles in Vermont 2010 – 2030.

A variety of factors could influence the market penetration of plug-in vehicles in the timeframe considered. The future price of gasoline will be a significant factor. Higher gasoline prices will make electricity from the grid an even more economically attractive option reducing the time it takes for fuel costs savings to pay for the initial higher price of AEVs. In addition, advances in technology leading to lower cost, more efficient energy storage technologies would greatly influence the rate of consumer adoption of plug-in vehicles. Finally, government policy in the form of tax credits and incentives can influence the rate of consumer adoption of new technology. We believe that these uncertainties are captured in our sensitivity analysis. However, we acknowledge that the penetration of AEVs in Vermont could be much lower than our low case scenario if gasoline prices do not rise significantly over this time horizon and the price premium for AEVs is high. Alternatively, it is conceivable that market penetrations rates could be higher than our high case if gasoline prices rise significantly, technological breakthroughs are realized, and/or significant government support emerges for AEVs within the next twenty years.

Next, we forecast the onboard energy storage capacity for the average vehicle in the AEV fleets projected above. A basic assumption based on expert opinion is that the size of the onboard battery storage of plug-in vehicles will increase over time as the cost of battery storage declines from improvements in manufacturing techniques and economies of scale from mass production. Again, we conduct sensitivity analyses and consider both low and high case scenarios in addition to the base case. Figure 5-2 presents our assumptions about vehicle energy storage capacity as plug-in vehicle technologies evolve. We estimate that the average plug-in car sold in Vermont by 2020 will have between 10 and 14 kWh of onboard energy storage. We project that that will increase to between 16 to 24 kWh by the end of 2030. This is based on the judgment that battery costs will decline over time along with improved energy and power densities, thus allowing larger battery packs to be relatively less expensive in subsequent years.

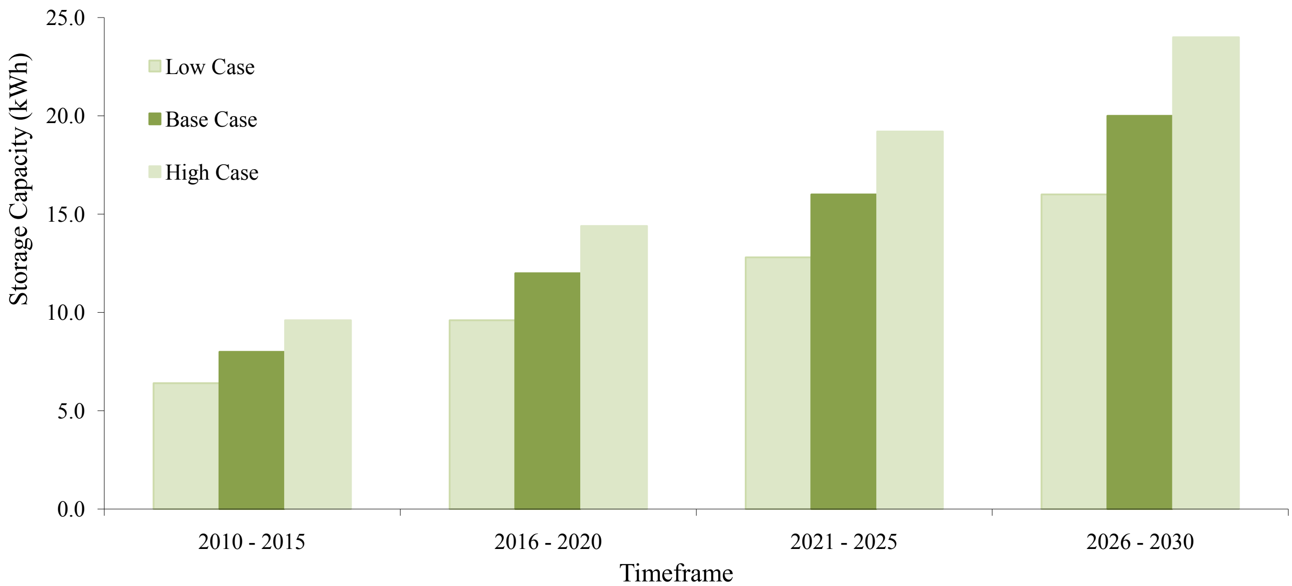


Figure 5-2. Onboard Energy Storage Capacity of AEVs from 2010 – 2030 (kWh).

Letendre, Watts, and Cross [9] investigated the grid impacts of an emerging fleet of PHEVs in Vermont. In their study, they considered the energy requirements to charge a fleet of PHEV20s, plug-in hybrids with an all electric range of 20 miles. They considered three different fleet sizes: 50,000, 100,000, & 200,000 PHEVs. They found that a fleet of 50,000 PHEV20s would consume approximately 163 GWh of energy assuming a full charge daily over the year. This represents about 2.6 percent of the total energy consumed in Vermont in 2005. A fleet of 200,000 PHEVs—approximately 1/3 of Vermont's light vehicle fleet—would consume 650 GWh of energy each year, or approximately 10 percent of Vermont's annual electricity consumption. These scenarios, however, were not based on a market penetration analysis like that described here and made the simplifying assumption that the vehicles would charge each day of the year.

Here, we estimate the annual energy consumption of a fleet of PHEVs based on our market penetration model. We use the mileage weighted probability (MWP) concept to estimate the number of full charges that would likely occur each year. The MWP provides an estimation of the portion of a PHEV's daily and annual mileage will be operated in all electric mode [90]. It represents a statistical probability that a PHEV will be driven less than or equal to its all electric range in a given day. A report by the Electric Power Research Institute [90] describes a methodology for calculating MWP and presents MWP estimates for a PHEV20 and PHEV60. Equation 1 presents the calculation to estimate the MWP.

$$MWP = \sum_{i=0}^{n} All\ Electric\ Mileage\ \div \sum_{i=0}^{n} Trip\ Mileage$$

Table 5-1 below presents the assumptions used in our estimates of annual energy consumption from a fleet of PHEVs in Vermont based on our market penetration model. We assume total annual miles of travel per vehicle of 15,000. Thus, for the timeframe from 2010 – 2015, we assume that 40 percent of the total annual miles are traveled on electricity, which requires approximately 195 full charge cycles in the year. As the energy storage increases over time to 2030, we see a higher percentage of miles being traveled on electricity but fewer charges are required due to the fact that a larger battery will be fully depleted less often.

Table 5-1. Electric Range, MWP, and Annual Full Charges Assumptions

	2010 - 2015	2016 - 2020	2021 - 2025	2026 - 2030
Electric Range (miles)*	21	32	42	53
MWP	40%	50%	60%	70%
Annual Full Charges	195	163	145	137

* Assumes an average fleet efficiency of 3.3 miles per kWh.

Based on the assumptions in Table 5-1 and the number of AEVs projected to be operating in Vermont, we estimate the total annual energy consumption for vehicle charging. Figure 5-3 presents these estimates for the base, low, and high scenarios. The low scenario represents our lower bound as it represents the low case for vehicle penetration (15% by 2020) and the smaller onboard energy storage assumptions presented in Figure 5-2 above. The high scenario in Figure 5-3 represents our upper bound estimates as it represents the high AEV penetration scenario (45% by 2020) and the larger onboard energy storage assumptions. Thus, we predict that by 2020, total annual energy consumption for vehicle charging will be somewhere between 50 to 204 GWh, or approximately .8 to 3.4 percent of total electrical energy consumed in Vermont in 2005. This range is projected to increase in 2030 to between 150 – 520 GWh, which represents approximately 2.5 to 8.6 percent of total electrical energy use in Vermont in 2005.

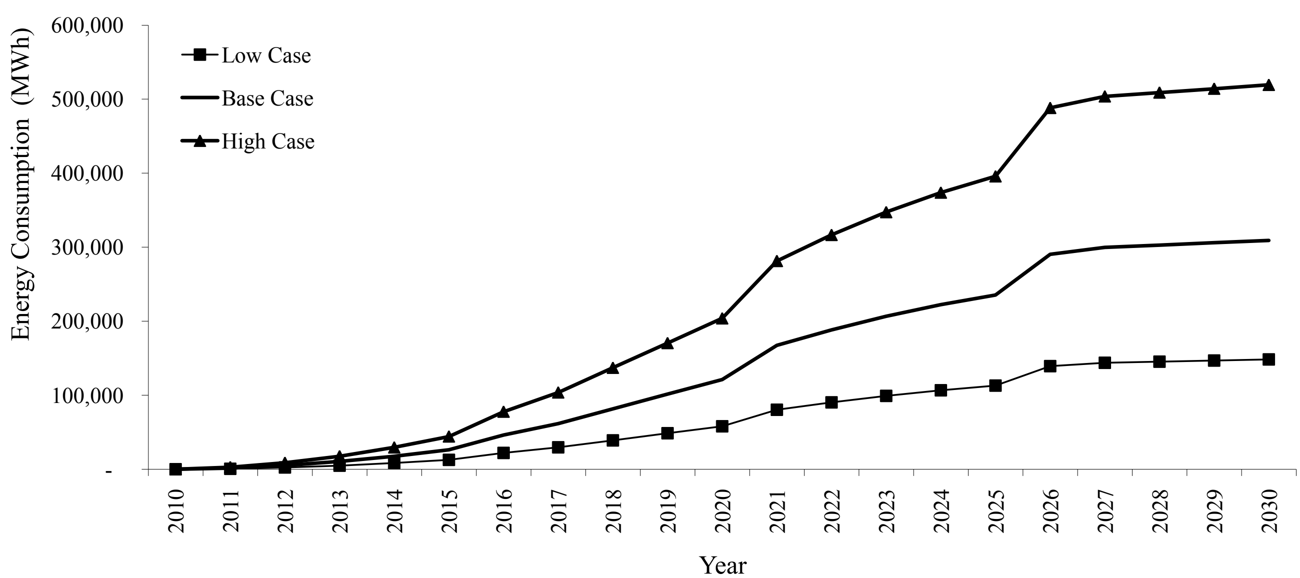


Figure 5-3. Total Annual Energy Consumption for AEV Charging in Vermont 2010 – 2030.

5.2.2. V2G Resource Assessment

Electricity generating resources are typically characterized in terms of the capacity they add to the system and the energy that is delivered over some specified period. The rated capacity in MW of a resource indicates what its instantaneous power output potential is. The concept of capacity factor is used to understand the energy that is delivered over some specified period of time. For example, a thermal plant with a 500 MW capacity with a 60 percent capacity factor (capacity factor—the percentage of time a resource produces at its full rated capacity over the 8,760 hours in a year) delivers approximately 2,600 GWh of energy during the year. In contrast, energy storage resources such as V2G resources are not considered generation resources. We do not consider the case whereby the vehicles' gasoline engines are used to produce power that is then distributed through the grid. Rather, we consider these resources in terms of their ability to store energy and add capacity to the system.

The first attempt to understand AEVs as power sources for the grid by Kempton and Letendre [81] found that when viewed as power resources, the nation's fleet of vehicles although presently dominated by internal combustion engines, represent a huge power resource several times larger than the installed generation capacity of the US. More recently Kempton and Tomic [24] provided detailed equations to calculate the power output and revenue potential for V2G-equipped AEVs. The power that an AEV can inject onto the grid is limited by the onboard vehicle power electronics and the plug connection. Given the high power design of hybrid vehicles, the internal power electronics of AEVs will likely not limit power flows from the vehicle to the grid. The rating of the plug is thus the ultimate constraint on how much power a vehicle can return to the grid. We assume two different plug connections for charging rates and the power output potential of AEVs; Table 5-2 presents our assumptions.

Table 5-2. Plug Connection Assumptions and Charging Rate/V2G Power Output

	Volts	Amps	Power (kW)*
Slow Charging	120	20	1.9
Fast Charging	240	40	7.7

*Assumes 80% of rated capacity for safe charging/V2G power output

Based on the assumptions in Table 5-2, we estimate the power output potential of a fleet of AEVs based on our market penetration model. Table 5-3 illustrates the power output potential under the base, low, and high market penetration assumptions assuming the two plug connections described in Table 2 above. The values in Table 5-3 assume that all AEVs in each of the years identified are connected and are capable of reverse flow power to the grid. In 2020, assuming the base case of vehicle market penetration and fast charging, the aggregate vehicle fleet would represent a 409 MW power resource, which is about equal to capacity from Vermont Yankee utilized in-state. It is unrealistic to assume that all vehicles would be V2G equipped or that they would all be plugged in at the same time. Thus, the values in Table 3 provide a general sense of the power potential of V2G resources in Vermont. Furthermore, the ability of a fleet to sustain output at the levels presented in Table 5-3 depend on the total energy storage capacity of the fleet.

Table 5-3. Estimated V2G Power Output for AEV Fleets in Vermont (MW)

	2015		2020		2025		2030	
	Slow	Fast	Slow	Fast	Slow	Fast	Slow	Fast
Low Case	17	67	61	245	99	401	110	446
Base Case	28	111	101	409	165	669	183	743
High Case	39	156	141	572	231	936	257	1,040

An emerging V2G resource in Vermont can also be understood in terms of its total energy storage capacity. Figure 5-4 presents the total energy storage capacity of the fleet of AEVs in the timeframe under consideration. These values are calculated by simply multiplying the projected number of vehicles by the estimated average onboard energy storage capacity per vehicle. The low case scenarios in Figure 5-4 assume the low AEV market penetration and the small onboard battery storage. In contrast, the high case scenario assumes high AEV market penetration and the large onboard battery storage capacity. In 2020, the base case estimates that the total energy storage capacity of the AEV fleet in Vermont is 637 MWh. To put this in perspective, the average Vermont household uses about 600 kWh per month or 20 kWh per day. The projected AEV fleet in 2020 could power 32,000 Vermont households for an entire day. Again, it is unlikely that all vehicles in an emerging fleet of AEVs will be V2G equipped and plugged in at the same time. The analysis here provides an order of magnitude in terms of what the V2G resource storage capacity might be.

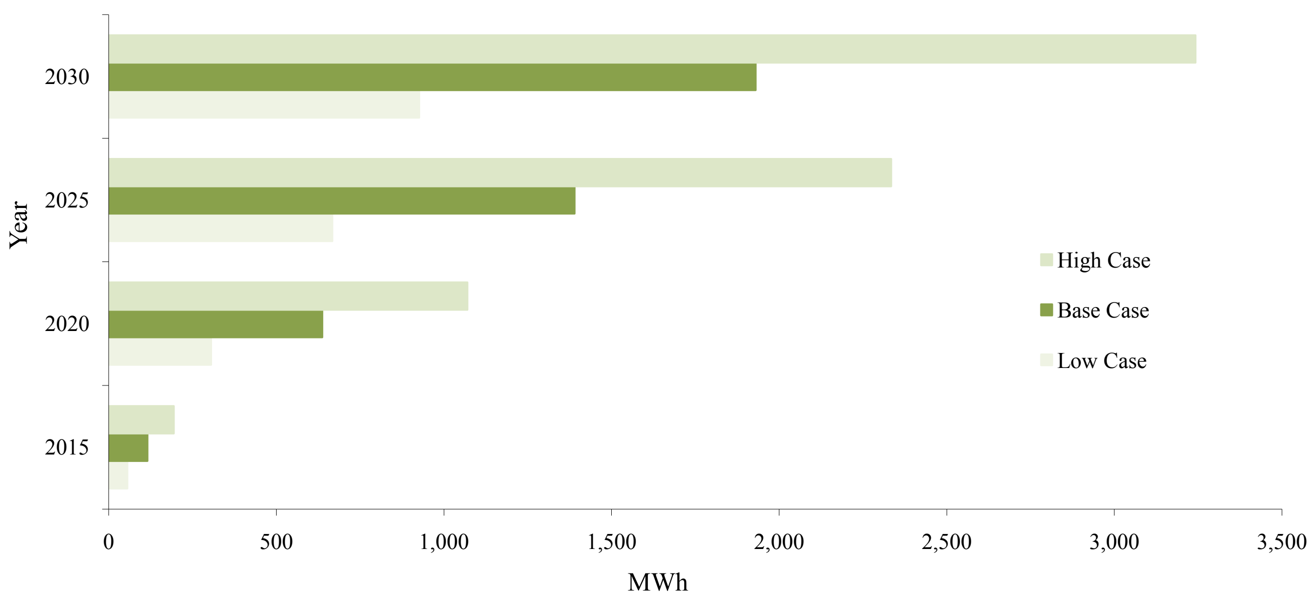


Figure 5-4. Energy Storage Capacity of AEV Fleet in Vermont 2015 – 2030.

Electricity is a unique commodity in that it is produced and consumed simultaneously. System operators (SO) must constantly match the power supply with the demand. Currently, the power grid has very little storage on the system. Energy storage is generally too costly to deploy in large quantities, although pumped hydro storage can be economical in certain locations. As indicated above in Figure 5-4, thousands of V2G-equipped vehicles represent a potentially large storage resource that could be used in various ways. The pumped hydro storage resources mentioned above typically use off peak power to pump water up a hill into a holding pond, which is released during periods of peak power demand. This application is referred to as peak shaving or load leveling. While V2G vehicles could perform this function, prior research suggests that higher value applications exist that are well suited for vehicle battery systems.

Letendre and Kempton [82] argue that V2G cars are well suited to provide ancillary services. While there is no universal definition of ancillary services the Federal Energy Regulatory Commission (FERC) in 1995 defined them as "…those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operation of interconnected transmission system." Given the characteristic of AEVs that will likely appear in Vermont in the next two decades described above, these potential V2G resources are best suited to provide only those ancillary services that are fast response and used for short durations. The limited on-board energy storage can be accessed very quickly given proper control and communication ties, but could only sustain limited discharging given the size of battery storage capabilities as a binding constraint. These fast response short duration services are generally placed in the category of operating reserves.

Each SO reserves a certain amount of generation capacity to serve different functions. The highest value reserves are used to provide frequency response or regulation services. Regulation and frequency response services are necessary for the continuous balancing of supply and demand for power to maintain interconnection frequency at 60 Hz. This service is accomplished by committing on-line generators whose output is raised or lowered as necessary to follow moment-by-moment changes in load. These generators are under the direct control of the SO through the automatic generation control (AGC) system and are sent commands to either increase or decrease output every four seconds depending on the imbalance between supply and demand at that instance. For example, if the supply of power is slightly greater than the demand, the SO calls for regulation "down." In contrast, generators are asked to ramp up (regulation "up") if demand is slightly greater than the supply.

The second most valuable category of reserves is referred to as spinning reserves. These are typically provided by generators that are spinning and ready to deliver power to the grid in a matter of minutes when called upon in the case of a contingency. These reserves are only used when a scheduled generator trips off line or a transmission or distribution facility fails. Experience shows that spinning reserves are rarely called upon and when they are called, are required for only a short amount of time.

The specific amounts of regulation and spinning reserves that the SO must carry are dictated by the national and regional reliability councils. The North America Electric Reliability Council (NERC) and the eight regional reliability councils are charged with establishing reliability standards that are used to determine the amount of reserves each region must maintain. Generally though, the regulation requirement is typically about 1% of a region's peak demand for power. The requirement for spinning reserves is typically based on replacing the single largest contingency on the system. Stated another way, the grid operators must maintain sufficient spinning reserves equal to the largest power plant in service during the operating day.

Regulation and spinning reserve services are traded in hourly markets in five different regions with established wholesale markets managed by SO. These markets include California, Texas, New England, New York, and the PJM Interconnect—the SO serving the mid-Atlantic and mid-western region. In total, these regions represent a significant portion of the total electrical energy produced and consumed nationwide. Furthermore, other regions are in different stages of developing wholesale markets for both bulk power and ancillary services such as regulation and spinning reserves. While each region has slightly different market structures, they generally include day-ahead and hour-ahead markets for trading these services.

Load serving entities operating in each region are assigned a proportional obligation, based on the volume of load served, of the regulation and spinning reserve requirements established by the appropriate reliability council. These services can be arranged through bilateral contracts or self provided. The remaining regulation and spinning reserve requirement not scheduled through these means are purchased on the open markets by the SO and the expense charged accordingly. Over the past several years a wealth of market data on these services has accumulated, and in total represent a multi-billion dollar national market.

Longer term, some view V2G resources as providing storage for intermittent forms of renewable energy such as wind and solar [22, 84]. Moving from grid regulation, to spinning reserves and then to storage for intermittent forms of renewable energy generation necessitates storage that can accommodate longer dispatch periods. Figure 5-5, a table from Kempton and Tomic [22], provides a framework for understanding the time interval for various fluctuations in power output. The ability of a V2G fleet to meet the different "storage intervals" outlined in this table depends on the size of the onboard energy system and the state of charge (SOC) when the power is needed on the system.

Table 2
Meeting wind storage needs with electric markets and strategic management

Storage interval	Time range	Cause of fluctuation	Suggested electric market or strategy
1	Minute to hour	Gusts, weather	Regulation, some intrahour adjustments or spinning reserves
2	Hour to day	Weather and daily thermal cycles	Operating reserves (spinning and non-spinning reserves)
3	1–4 days	Movement of fronts	Dispersion of wind resources with transmission; operating reserves; load management; dedicated storage (in sequence—see text)
4	Seasonal	Seasonal thermal and weather cycles	Long-term match with of load (e.g., if wind is stronger in winter, move space heating toward electric heat pumps rather than fossil fuel)

Source: Kempton and Tomic, 2005b

Figure 5-5. Time Interval for Various Fluctuations in Power Output.

The type of grid services that V2G-equipped vehicles could provide depends to some degree on the SOC of the vehicles in the fleet. With experience, it will be possible to predict what the SOC of an aggregated fleet of vehicles would be at any given time during the day. Here we attempt a very basic assessment of what might be expected for the fleet of AEVs in Vermont in terms of SOC and time of day. Here we assume that one-half of the stored energy is used during the morning commute leading to an overall fleet SOC of 50 percent while parked at work during the daytime hours. The commute to home results in a depletion of the battery pack, until charging commences in the late evening / early morning. The vehicle fleet reached an SOC of 100 percent by 6:00 a.m. ready for the morning commute. Figure 5-6 illustrates the potential to have significant energy reserves available during the afternoon hours, when summer peak demand for power is highest.

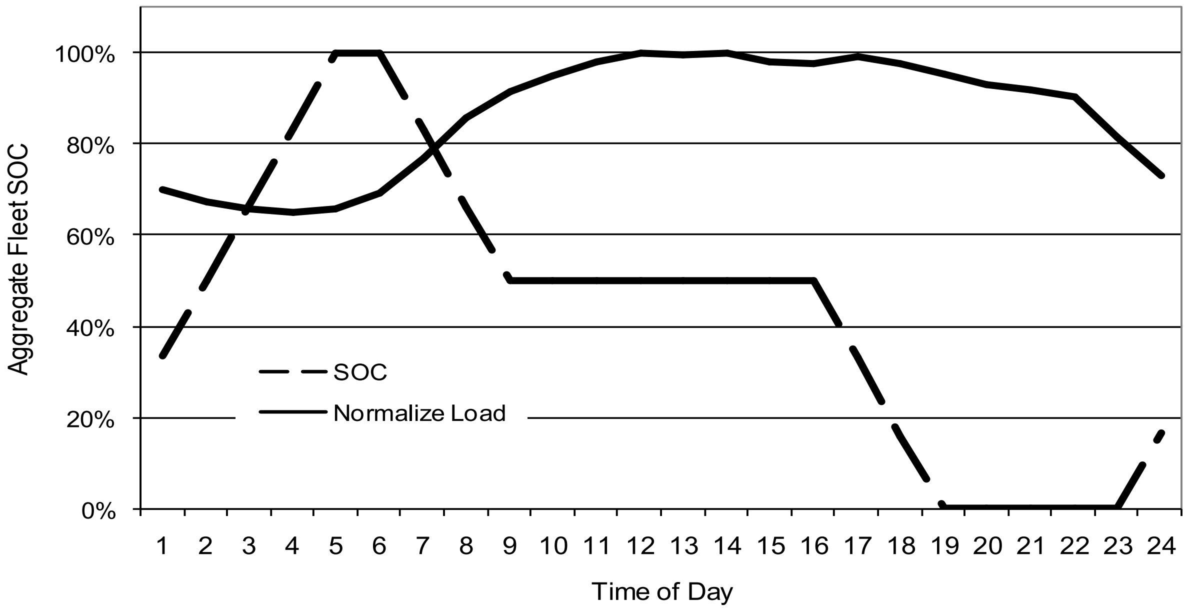


Figure 5-6. Projected SOC of V2G Fleet vs. Normalized Summer Load Duration Curve.

5.3. The New England Market for Ancillary Services

Vermont is part of the larger New England grid, which is managed by the Independent System Operator of New England (ISO-NE)—a non-stock corporation incorporated under the laws of the State of Delaware. The ISO-NE maintains a central control center in Holyoke, Massachusetts where they manage the flow of power throughout New England based on a least cost central dispatch protocol. In 2008 the peak demand for power in the New England region was over 26,000 MW, with Vermont representing just 1,000 MW of this total or approximately 4 percent. On an energy basis, 131,736 GWh of energy were delivered throughout New England in 2008. Vermonters consumed over 6,000 GWh annually or about 4.5 percent of total electricity consumption in New England.

ISO-NE is charged with maintaining a reliable supply of low-cost power to the region. It meets this obligation in three ways: "…by ensuring the day-to-day reliable operation of New England's bulk power generation and transmission system, by overseeing and ensuring the fair administration of the region's wholesale electricity markets, and by managing comprehensive, regional planning. (www.iso-ne.com)." The wholesale electricity markets operated by the ISO-NE provide a mechanism for buyers and sellers of energy and ancillary services to contract. In this section, we focus on the markets for ancillary services, as prior research suggests that these are the most promising initial markets for V2G resources.

5.3.1. New England Ancillary Services Market

As discussed above, V2G resources are particularly well suited to provide ancillary services. In New England, and several other regions of the country, deregulation of the electricity industry occurred in the mid-1990s. As part of the deregulation process, unbundling occurred whereby the transmission and distribution of power was delineated from the supply of power. Further unbundling occurred to distinguish between capacity, energy, and ancillary services as distinct products. In New England separate markets structures were created to encourage the competitive provision of operating reserves (both spinning and non-spinning reserves) and regulation.

The New England reserve capacity market is unique relative to those in other regions. ISO-NE operating procedures require that reserve capacity capable of replacing the largest generator delivering power to the grid must be available within 10 minutes. In general, capacity equal to between one-fourth and one-half of this 10-minute reserve requirement must be synchronized to the power system, termed 10-minute spinning reserve (TMSR), while the rest of the 10-minute requirement may be 10-minute non-spinning reserve (TMNSR). Additional reserves, termed 30 minute operation reserve (TMOR), must be available within 30 minutes to meet one-half of the second largest system contingency. Generators are compensated for providing reserves through both the locational Forward Reserve Market (FRM), which offers a product similar to a capacity product, and real-time reserve pricing [91].

The FRM acquires only those resources needed to satisfy off-line reserve requirements, namely TMNSR and TMOR. To acquire appropriate forward-reserve obligations, the FRM conducts twice-yearly auctions for the summer and winter reserve periods (June through September and October through May, respectively). Essentially, resources are paid based on the amount of capacity they agree to make available to the system during these two reserve periods. Those resources that win the FRM auctions must turn their obligations into actual reserve delivery through the participation in the real-time energy market. Reserve pricing optimizes the use of local transmission capabilities and generating resources to provide electric energy and reserves. This allows the dispatch software to choose whether transmission should be used to carry electric energy or left unloaded to provide reserves when satisfying zonal reserve requirements. This optimization is based on the real-time energy offers of resources; there are no separate real-time reserve offers. Real-time reserve credits are the revenues paid to participants with resources providing reserve during periods with positive real-time reserve prices [91].

Regulation in New England is procured through a real-time market. The regulation clearing price (RCP) is calculated in real time and is based on the regulation offer of the highest-priced generator providing the service. Compensation to generators that provide regulation includes a regulation capacity payment, a service payment, and unit-specific opportunity cost payments. Unit-specific opportunity cost payments are not included as a component of the regulation clearing price.

The system wide market clearing prices for TMNSR based on the FRM auctions in 2008 were $8.88/kW-month during the summer reserve period and $6.74/kW-month during the winter reserve period. In 2008, $50.5 million was spent on regulation in New England. The average RCP in 2008 was $13.75/MWh. It is important to note that the RPC is just one part of the three payments that are made to generators providing regulation in New England. Thus, to estimate the total per MW value of regulation in New England we can take the total amount spend referenced above of $50.5 million and divide that by 8,760 hours in a given year and then divide that by the annual average regulation requirement of 120. This calculation yields a value of \$48/MW-h for regulation in New England.

Based on the market data from 2008, we estimate the annual revenue potential from a V2G-equipped vehicle based on the two charging scenarios described above (1.9 kW and 7.7 kW). Figure 5-7 presents annual revenue potential for providing 10-minute operating reserves based on the potential revenue from the FRM and for providing regulation. It is assumed that the vehicle is able to provide regulation for 7,000 hours during the year for the high scenario and 3,500 hour for the low scenario or about 80 and 40 percent of the time respectively. It is clear from Figure 5-7 that regulation is the more valuable market for V2G vehicles in the near term.

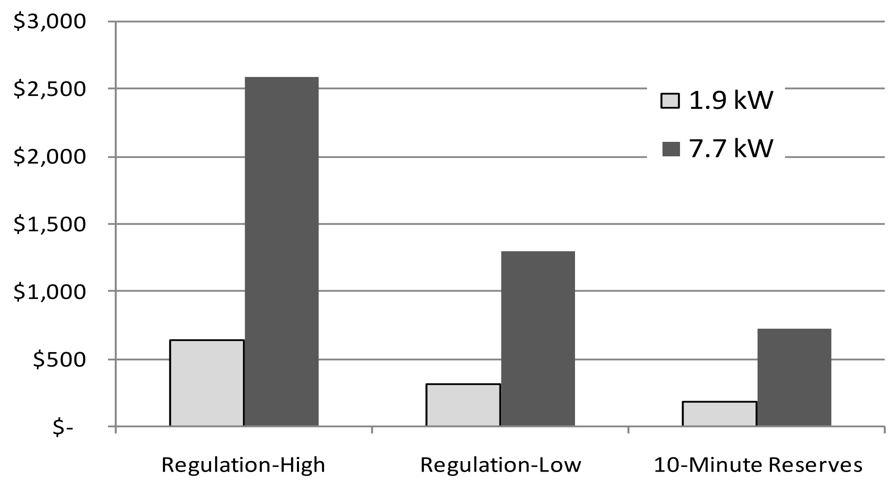


Figure 5-7. Potential Annual V2G Gross Revenue Providing Ancillary Services.

5.3.2. Regulation Services

As described above, regulation is the highest value grid-support service that is particularly well suited for vehicle battery storage systems. As described above in Section 5.1, two demonstrations have shown that AEVs can provide regulation that meets the response time requirements of system operators. However, there is limited experience using energy storage devices to provide regulation. In New England, gas generators provide over 90 percent of regulation services. These units are on AGC and respond to frequent (4-second) signals from the ISO-NE based on the instantaneous mismatch between power supply and demand. If the supply of power is above the demand, a regulation down signal is sent to those generators on AGC. In contrast, when supply is less than demand a regulation up signal is sent out to generators on AGC.

The amount of regulation that the ISO-NE must carry is established based on system reliability criteria. For the New England Area, NERC has set the Control Performance Standard 2 (CPS 2) at 90 percent. CPS 2 is the primary measure for evaluating control performance and area control error. The ISO-NE seeks to maintain CPS 2 within the range of 92 percent and 97 percent. The ISO-NE has continually met its more stringent, self-imposed CPS 2 targets and thus has been able to reduce the average amount of reserves held to provide regulation from 181 MW in 2002 down to 120 MW in 2008.

It is important to understand the relationship between what is required to provide regulation services and how those reserves are utilized. A specific amount of regulation is required in each hour, which can vary by month to meet the CPS 2 target. Figure 5-8 illustrates the 4-second signals from ISO-NE on March 3, 2008 from 7:00 a.m. to 7:59 a.m. During this hour in March, the ISO-NE is required to carry 200 MW of regulation reserves. We see from Figure 5-8 that calls for regulation up (above zero) were balanced with calls for regulation down (below zero). We calculate a measure called dispatch-to-contract ratio for both regulation up and regulation down, which measures how much of the regulation reserves that were required were actually used in a given hour. In this case the regulation down dispatch-to-contract for regulation up was 0.09 and 0.12 for regulation down. A ratio of one would indicate that the maximum regulation required in an hour was used for the full hour to provide either regulation up or down.

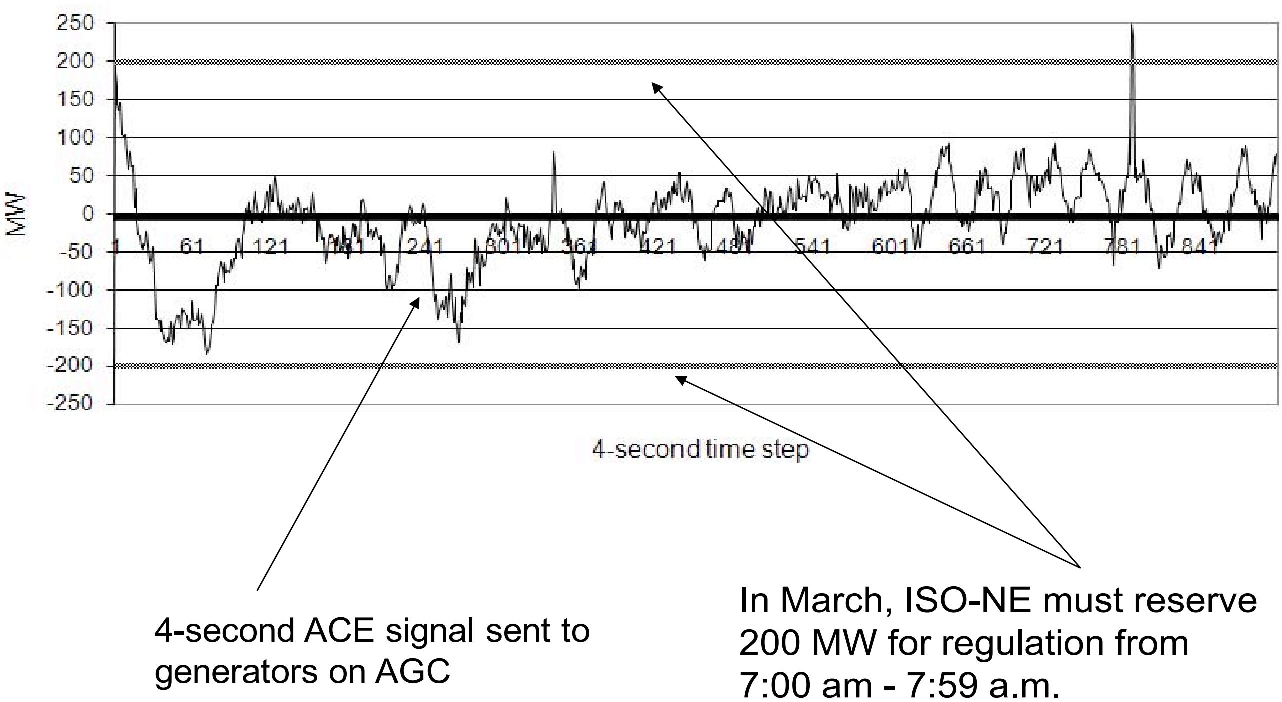


Figure 5-8. Regulation Requirement versus Regulation Use, March 3, 2008 (7:00 a.m.).

Figure 5-9 is again the actual 4-second signals compared to the regulation reserve requirement for March 3, but for the hour 7:00 p.m. to 7:59 p.m. Here the dispatch to contract ratios for regulation up and down are 1.01 and 0.20 respectively. It is clear from these ratios and the chart that there was a much greater need for regulation up relative to down regulation during this hour on March 3, 2008.

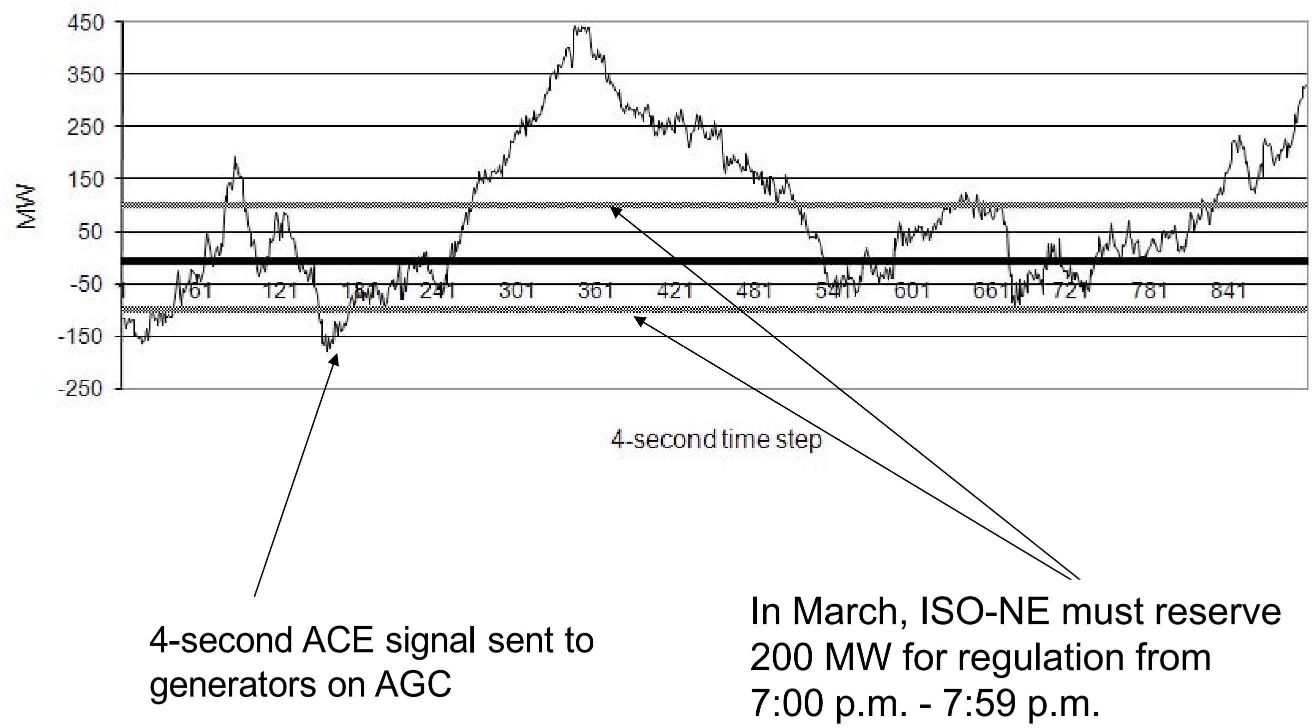


Figure 5-9. Regulation Requirement versus Regulation Use, March 3, 2008 (7:00 p.m.).

In the case of a storage device providing regulation, calls for regulation down would result in charging. Whereas V2G resources called to provide regulation up would entail discharging the stored energy onto the grid through a bi-directional interface. Thus, it is conceivable that a storage device could be fully depleted from a string of regulation up events or fully charged in the case of a string of regulation down signals. Thus, it is important to understand the variability of regulation signals over time to determine how long a storage device is able to continue providing the service before the system is either fully charged or depleted. Some limited experience based on the demonstration project discussed above in Delaware indicates a bias toward regulation down on one day leading to the battery being fully charged and thus unable to continue to respond to the signal from PJM for regulation down [89].

Here we take the hourly dispatch to contract ratios for two days of operation in the ISO-NE region to simulate the change in battery state SOC for a V2G equipped vehicles. Table 5-4 provides the dispatch to contract ratios by hour for the two days of ACE (area control error) data provided by ISO-NE. These ratios can be used to estimate the net change in SOC for a storage device providing regulation. For example, in the first hour of on March 3, 2008 there was a greater need for regulation down than regulation up. As a result, a battery storage device providing regulation during this hour would experience an increase in its SOC, given that regulation down results in charging of a battery pack. We assume that the vehicle has usable storage capacity of 13 kWh and is connected at the two plug connections described in Table 5-2, allowing for bi-directional power flows of 1.9 kW and 7.7 kW. It is assumed that the vehicles begins at hour one with a SOC of 50 percent.

We find that on March 3 using at 7.7 kW bi-directional capability, the battery becomes fully depleted at 11:00 a.m. and thus can provide regulation on this day for nine consecutive hours. In contrast, assuming a

Table 5-4. Hourly Contract to Dispatch Ratios for Regulation Up & Down, ISO New England

Hour	March 3, 2008		February 1, 2008	
	D-to-C_Up	D-to-C_Down	D-to-C_Up	D-to-C_Down
1	0.19	0.51	0.14	0.16
2	0.47	0.18	0.56	0.33
3	0.43	0.36	0.92	0.14
4	0.31	0.47	0.73	0.03
5	0.35	0.43	1.83	0.07
6	0.65	0.12	0.63	0.03
7	0.16	0.17	0.33	0.02
8	0.09	0.12	0.08	0.11
9	0.09	0.13	0.18	0.13
10	0.35	0.11	0.20	0.10
11	0.46	0.07	0.47	0.46
12	0.38	0.05	0.52	0.06
13	0.28	0.20	0.15	0.19
14	0.51	0.02	0.14	0.45
15	0.58	0.04	0.53	0.04
16	0.50	0.09	0.54	0.06
17	0.31	0.05	0.16	0.09
18	0.23	0.25	0.42	0.32
19	0.86	0.72	0.59	0.02
20	1.01	0.20	0.44	0.09
21	0.85	0.05	0.15	0.11
22	0.20	0.25	0.11	0.24
23	0.15	0.16	0.14	0.34
24	0.43	0.15	0.15	0.69

1.9 kW bi-directional capability, the vehicle could provide regulation until 8:00 p.m., or for 19 hours out of the operating day. In contrast assuming a 7.7 kW capable plug connection, on February 1, 2008 the vehicle's battery pack is depleted in just two hours as a result of the large need for regulation up in the third hour of the operating day. Assuming a 1.9 kW plug connection expands by two hours the V2G vehicle's ability to provide regulation on February 1, 2008. The analysis here suggests more work needs to be done to better understand how best V2G resources can be deployed to provide regulation services in New England. In particular, a fleet of vehicles with each individual vehicle having a different SOC may serve to address the constraint identified here.

5.4. Conclusion

It seems likely that Vermont consumers will soon have the option to purchase a plug-in vehicle within the next few years. It is difficult to predict how quickly consumers will adopt plug-in vehicles or exactly what the characteristics of these vehicles will be. Based on new vehicle sales, we estimate the number of plug-in cars that we might expect to see in Vermont in the 2010 – 2030 timeframe. We estimate that by 2015 we could see 15,000 of these vehicles in Vermont, increasing to 50,000 in 2020 and approximately 100,000 in 2030. These vehicles in aggregate represent a relatively small addition to Vermont's total electricity load, in the range of 1 percent to 8 percent of the total electrical energy consumed in Vermont in 2005. However, when the vehicle fleet is viewed as a V2G resource the potential is significant. By 2020, an AEV fleet in Vermont could represent a power resource of 300 MW with the ability to store 1,000 MWh of energy. This new resource could be used in a variety of ways to enhance the reliability of the Vermont grid and to assist with the integration of intermittent sources of energy like wind and solar.

It appears that the use of V2G resources is best suited for the high value grid support service known as regulation. Based on analyses presented here, a V2G-equipped vehicle could potentially generate between $1,000 and $2,000 in gross revenue annually. Additional research is needed to more fully understand this opportunity in Vermont and New England. This includes analyses of regulation data over longer periods of time, understanding the costs to enable V2G with ISO-NE protocols, and other overhead expenses associated with the aggregation of a fleet of AEVs participating in New England's competitive wholesale ancillary services markets. Furthermore, a small fleet of AEVs demonstrating the opportunity could yield useful information.

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