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Long-Term Electric System Investments to Support Plug-in Hybrid Electric Vehicles

Seth Blumsack, *Member, IEEE*, Constantine Samaras, *Student Member, IEEE* and Paul Hines, *Member, IEEE*

***Abstract*—Plug-in Hybrid Electric Vehicles (PHEV) represent a promising pathway to reduce greenhouse gas emissions associated with the U.S. transportation sector. A large-scale shift from gasoline-powered automobiles to PHEVs would inextricably link the U.S. transportation system with its electric system. We build on [4] to perform a regional emissions analysis of a PHEV use pattern where PHEVs are charged at night and discharged during the day. We find that in some coal-intensive regions like the Midwest, charging PHEVs by burning coal may produce more emissions than burning gasoline. Overnight charging of PHEVs will deteriorate the system load factor by increasing off-peak demand. This may have deleterious effects on system infrastructure. We perform some simple simulations looking at the effect of off-peak PHEV charging on the performance of oil-cooled substation transformers.**

***Index Terms*—Electricity restructuring, climate change, transformers, plug-in hybrid electric vehicles**

I. Introduction

Transportation represents the second-largest source of greenhouse gas (GHG) emissions in the United States. Only the electric power sector is responsible for more GHG emissions [1]. The two together are responsible for approximately 60% of U.S. GHG emissions. One promising technology for decreasing GHG emissions associated with the U.S. transportation sector is the plug-in hybrid electric vehicle (PHEV). Like conventional hybrid electric vehicles (HEV, such as the Toyota Prius), get some of their power from an on-board battery or other electric storage device, but also have the ability to burn gasoline, diesel, or almost any other liquid fuel [2]. Since they can operate in either all-electric or HEV mode, and since the vehicle's batteries can be charged using normal electrical outlets, PHEVs can drive distances similar to conventional gasoline-powered vehicles. The fact that PHEVs can be plugged in to wall outlets for charging overcomes a potential issue with charging infrastructure for HEV batteries [3].

Samaras and Meisterling [4] report that 61% of travel in the U.S. represents trips 50 km (30 miles) or less. Particularly in urban areas and for commuting purposes, PHEVs have some potential to displace a considerable number of conventional automobiles and light trucks.

PHEVs have the primary effect of coupling the U.S. transportation and electricity systems. The typical usage scenario for a PHEV involves the vehicle's battery being discharged during the day and charged at night. The possibility that PHEVs could be used to provide energy and perhaps even regulation services to the grid (so-called Vehicle to Grid or V2G applications) has been investigated in [5]. This, however, would require a more significant investment in infrastructure, primarily for interface equipment in homes and parking garages. A charging scenario where a large number of PHEVs draw power from the electric grid at night would have the effect of increasing off-peak electric demand and increasing the load factor. The daily load curve would be flattened, but because of load elevation during off-peak periods and not because of peak-shaving or demand reduction. Even though the electric grid has been designed to handle peak demands (meaning that at any given time, there is likely spare capacity in the system), impacts on existing electricity infrastructure are unavoidable and require analysis and mitigation.

This paper reports on two analyses aimed at determining the kinds of system investments necessary to support the reduction of GHG emissions via large-scale PHEV charging (that is, powering cars from the grid instead of using conventional gasoline or diesel fuels). Specifically, we conduct a regional life-cycle analysis of nighttime PHEV charging, and we investigate the effects of a flattening in the daily load curve (via increased off-peak demand) on a simple piece of system equipment, the oil-cooled substation transformer.

While this is a relatively new research area, there is a small literature examining the capacity of the electric grid to handle PHEV charging demands, as well as environmental effects. Both [6] and [7] estimate the number of conventional vehicles that could be displaced by PHEVs while still respecting system capacity constraints. Using data at the NERC region level, [6] determines that up to 73% of the light-duty vehicle fleet in the U.S. could be replaced with PHEVs supported by the existing electric grid, or 43% of the light-duty fleet if charging was restricted to the twelve hour period from 6pm to

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6am. Denholm and Short [7] estimate a more conservative penetration number of 50%. Regional emissions effects from a large-scale adoption of PHEVs are estimated in [4, 6, 8-10]. The existing literature suggests that nationwide, emissions of several criterion pollutants (CO_2, NO_x, and others) would be reduced compared to a scenario where the use of gasoline-powered cars continued. In [4], Samaras and Meisterling note that PHEVs have superior GHG emissions reductions to coal-to-liquids fuels, even with carbon capture and sequestration. Both [6] and [9] note that regional generation mixes may yield regional emissions effects different from the national average. Samaras and Meisterling [4] examine life cycle impacts of PHEVs by including impacts from battery production, explore the sensitivity of GHG emissions benefits from PHEVs charged with electricity of varying carbon intensity, and evaluate impacts from potential biofuel use in PHEVs.

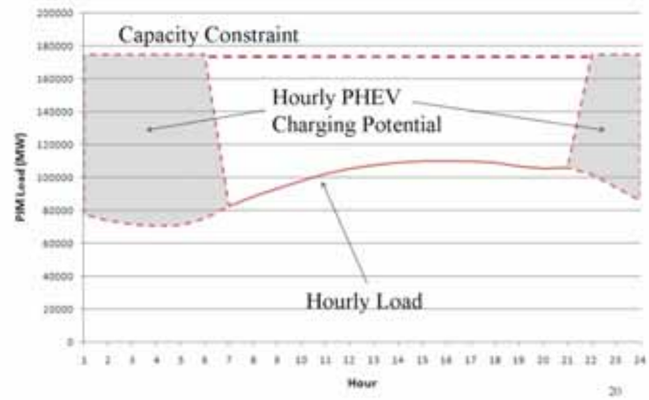

Figure 1: Conceptual illustration of the capacity constraint, using data for PJM on April 25, 2006.

II. A Regional Emissions Analysis of PHEVs

The existing analyses of the environmental effects of PHEVs have been made using primarily data from NERC regions. However, NERC regions are in a state of flux, as boundaries change and adjustments are made pursuant to mandatory reliability rules. Since the onset of U.S. electric restructuring, a better unit of analysis is the Regional Transmission Organization (RTO). The RTO is superior to the NERC region primarily because all generation within the footprint of an RTO is dispatched jointly. In general, this has led to increased utilization of low-cost generation sources [11]. Substitution of PHEVs for conventional vehicles transfers a portion of GHG emissions from the tailpipe to the central-station power plant. The off-peak generation mix of each RTO is thus critical in determining the environmental effects of nighttime PHEV charging.

A. Problem Boundaries and Upstream Emissions Assumptions

We calculate life-cycle emissions from off-peak PHEV charging in three RTOs: PJM (covering most of the Mid-Atlantic and parts of the Midwest), MISO (most of the remaining Midwest) and ERCOT (Texas). To be somewhat conservative, we define PHEV charging potential as the difference between the highest hourly level of off-peak demand and the total system capacity of central-station generation. This is illustrated conceptually in Figure 1. By this measure, we obtain that approximately 30% of the current conventional vehicle fleet could be displaced by PHEVs (this is consistent with [8]).

Electricity production and fuel combustion comprise the primary sources of emissions for PHEVs. The life cycle of these emissions include the mining/extraction, processing, transport, and burning of fossil fuels. Jaramillo, et al. [12] estimate emissions of 11.6 pounds of CO_2 equivalent per million BTU for coal mining, processing and transport. The manufacture of the battery also contributes to PHEV emissions. We take our battery manufacturing emissions numbers from [4], who estimate average annual emissions of 800 to 2,400 pounds of CO_2 equivalent associated with lithium ion batteries for PHEVs. We assume that the emissions related to the battery as well as upstream emissions related to coal production are identical for all regions.

B. Estimating Regional Emissions Using Plant-Level Data

We perform new analysis to calculate the regional environmental impacts of nighttime PHEV charging. We focus on CO_2 equivalent emissions. We define the off-peak period as hours-ending 2300 to 2400, and 0100 to 0600. We simulate nighttime PHEV charging demand by gathering hourly demand data for the three RTOs we analyze, and increasing demand during our defined off-peak period each day. Following [4], we assume that each vehicle requires 0.2 kWh of electrical energy (plant-to-wheel) to travel one kilometer; assuming each vehicle drives 50 km per day on battery power alone yields a total daily demand of 10 kWh per electric vehicle. The GHG emissions due to PHEV charging and operation can be written as [4:

$$\frac{GHG}{km} = (\alpha)\left(\frac{kWh}{km}\right) * \left(\frac{GHG_{powerplant+upstream}}{kWh}\right) + (1-\alpha) * \left(\frac{l}{km}\right)\left(\frac{GHG_{fuel} + GHG_{fuelupstream}}{l_{fuel}}\right) \quad (1)$$

Where α represents the fraction of travel powered by electricity. We set $\alpha = 0.63$for this analysis.

For each region, we assume that the RTO dispatches generation resources in merit order until demand is satisfied. We further assume that the merit order is determined by marginal cost (in other words, we assume that all of the RTO markets feature perfectly competitive bidding and pricing). Using average heat rate data from the U.S. EPA eGrid database [12], and appropriate regional fuel prices as in [13], we construct the short-run marginal cost (SRMC) curves for each of the three RTOs we consider. The SRMC curves we calculate for each region are shown in Figures 2 through 4, while our assumptions about fuel prices are shown in Table 1.

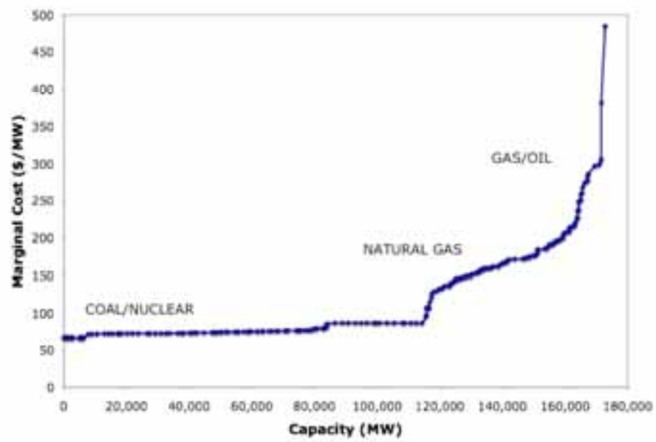

Figure 2: Short-run marginal cost curve for PJM.

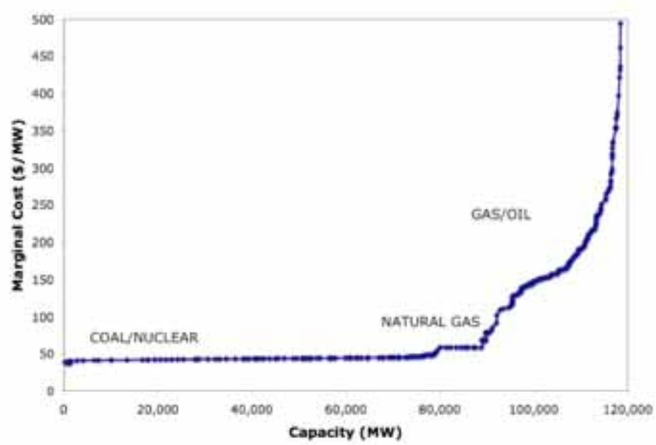

Figure 3: Short-run marginal cost curve for Midwest ISO.

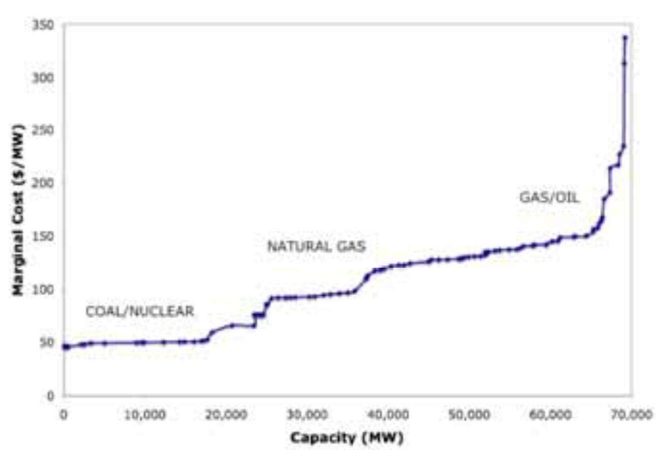

Figure 3: Short-run marginal cost curve for ERCOT.

TABLE 1: ASSUMED FUEL PRICES (FOSSIL UNITS) AND VARIABLE COSTS (NON-FOSSIL UNITS), FROM [13]

Assumed fuel prices and variable costs

		PJM[a]	MISO[b]	ERCOT[c]
Nuclear	($/MWh)	16.5	16.5	16.5
Wind[d]	($/MWh)	20	20	20
Hydro	($/MWh)	10	10	10
Biomass	($/MWh)	50	50	50
Coal	($/MMBTU)	1.73	1.41	1.29
Natural Gas	($/MMBTU)	9.95	10.52	7.79
Oil[e]	($/MMBTU)	8.49	11.63	10.45

[a] estimate from EIA MidAtlantic census division including New Jersey, New York, Pennsylvania
[b] from EIA East North Central census division including Illinois, Indiana, Michigan, Ohio, Wisconsin
[c] from EIA Texas state data
[d] excludes production tax credit
[e] Distillate fuel oil includes all diesel, No. 1, No. 2, and No. 4 fuel oils

We use 2006 data for each of the three RTOs. For each hour, we determine (using the SRMC curve) which generating units are dispatched to meet demand (including PHEV charging). We assume that all generators are always available when called upon to provide power, and we assume that there are no transmission constraints in the system. Thus, we model a pure economic dispatch. We use average CO_2 equivalent emissions data from the eGrid database to simulate total CO_2 emissions from each generator during each hour, with and without additional PHEV charging demand. The emissions difference therefore represents CO_2 equivalent emissions due to PHEV charging.

Our results for PJM, MISO and ERCOT are shown in Figure 5. For comparison, we also show life-cycle CO_2 equivalent emissions for a number of other transportation technologies. Thenumbers are from [4], except for coal-to-liquids (CTL), which is from [14]. Our results show significant regional differences in the environmental impacts of nighttime charging of PHEVs. Emissions in the ERCOT region, which is dominated by nuclear power and natural gas, are much lower than in PJM or MISO, which have more coal in their generation mixes. MISO in turn, has more emissions associated with nighttime PHEV charging than does PJM.

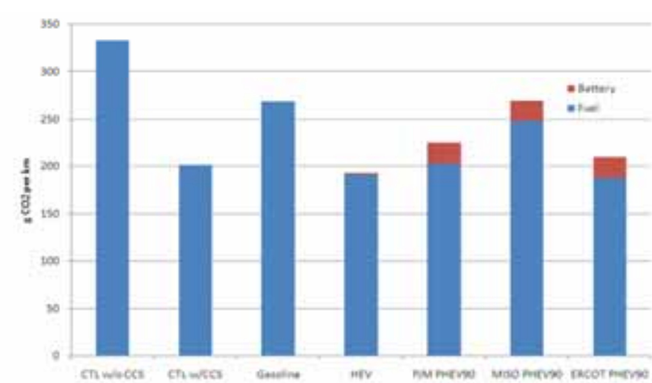

Figure 5: Life-cycle emissions for PHEVs in PJM, MISO and ERCOT as compared with conventional gasoline vehicles, conventional HEVs, and coal-to-liquids. Figures for gasoline vehicles, HEVs, and coal-to-liquids are from [4] and [14].

Most significant are comparisons between regional GHG emissions from PHEVs and the emissions shown in Figure 5 for conventional gasoline vehicles and conventional hybrid vehicles (such as the Toyota Prius). In both PJM and ERCOT, displacing conventional gasoline vehicles with PHEVs would reduce CO_2 equivalent emissions by between 50 and 70 grams per kilometer traveled. In MISO, however, there is only a negligible difference between emissions from PHEVs and emissions from conventional gasoline vehicles. Emissions in MISO are significantly worse when compared to conventional HEVs.

C. *Discussion*

PHEVs do have the potential to reduce CO_2 equivalent emissions from the U.S. transportation sector, but only to the extent that emissions can be reduced in the electricity generation sector [4]. In examining PHEV charging in RTOs, we conclude that PHEVs will not achieve their environmental goals unless carbon-intensive RTOs are decarbonized significantly. We also build on the findings of [14] and note that even without CCS, CO_2 equivalent emissions from PHEVs in PJM, MISO, and ERCOT are significantly lower than coal-to-liquids gasoline (note that emissions from PHEVs *without* CCS in ERCOT are similar to coal-to-liquids *with* CCS). Thus, a sensible policy would encourage the decarbonization of the electricity sector to support PHEVs, rather than coal-to-liquid fuels [4].

III. Effects of PHEV Charging on Electric System Infrastructure

As discussed in previous sections, the effect of nighttime PHEV charging is to flatten the load curve by increasing the off-peak demand for electricity, rather than by depressing the peak. One consequence of this is that electric-system infrastructure will become more heavily utilized on a more regular basis. Since much of the transmission and distribution capacity in the U.S. is effectively sitting idle many hours of the year, heavier utilization for PHEV charging represents something of an efficiency gain, distributing average costs over a greater number of kilowatt-hours.

However, some equipment on the electricity system was designed for a distinct pattern of peak/off-peak usage. Oil-cooled transformers are one example. The windings inside a transformer are subject to thermal and resistive losses similar to transmission and distribution wires. To keep the heat associated with these losses from deteriorating the transformer insulation, a number of internal cooling mechanisms are used [15, Ch. 9]. One of the more common is to use a kind of mineral oil (known as transformer oil) for both cooling and insulation.

Oil-cooled transformers are given a variety of different thermal operating limits. The flash point of transformer oil is 135^{o} C to 140^{o}C. What constitutes a "normal" operating temperature limit varies with the size of the transformer, but [15] report that 98^{o}C is a commonly-used standard number. Transformers are normally designed for cyclic use; that is, they are allowed to run "hot" (above the normal temperature) during peak periods, to accommodate higher demands, but should be allowed to "cool down" (operate near the normal temperature) during off-peak periods [16]. A transformer allowed to run "hot" for too many hours in a day may have is useful life shortened significantly. The thermal inertia and maximum temperature limit produce a daily energy constraint in addition to the current loading constraints. Thus, increased off-peak usage must be accompanied by reduced on-peak usage if the useful life of the transformer is to be maintained.

The relationship between temperature θ and life expectancy L of a transformer (in years) can be described using the Montsinger equation:[1]

$$(2) \quad L = De^{+p\theta},$$

Where D and p are constants (D has units of years and p has units of $^{o}C^{-1}$). A rule of thumb given by [15] is that the useful life of the transformer insulation is reduced by half for every 6^{o}C increase in θ. From this, we may solve for the constant p as $p = 0.1155^{o}C^{-1}$ (a full derivation is given in [15], p. 380).

Define θ_n as the temperature at which life expectancy of the transformer insulation is expected to be normal. Then, using (2) we can define the aging factor as:

$$(3) \quad K = \frac{De^{+0.1155\theta_n}}{De^{+0.1155\theta}}.$$

At normal life expectancy where $\theta_n = 98^{o}$C, we solve for the aging factor as:

$$(4) \quad K = e^{0.1155(\theta-98)}.$$

The significance of the aging factor can be seen by differentiating both sides of (4) with respect to θ, as follows:

$$(5) \quad \frac{dK}{d\theta} = \frac{d}{d\theta} e^{0.1155(\theta-98)} = 0.1155 e^{0.1155(\theta-98)}$$

If the transformer is subjected to some temperature $\theta \neq \theta_n$ for y hours, this is equivalent to $yK(\theta)$ hours of operation at the normal temperature θ_n.

Using this property of the aging factor, we can derive a relationship between a given overload temperature θ^* and any other temperature θ over a given day. Suppose that the temperature is θ for h hours and is θ^* for $24 - h$ hours. Then, from (4) we have:

$$(6) \quad 24 = he^{p(\theta-98)} + (24-h)e^{p(\theta^*-98)}$$

After some manipulation, we may solve for θ^* as:

$$(7) \quad \theta^* = \frac{1}{p}\left[\ln\left(24 - he^{p(\theta-98)}\right) - \ln\left(24-h\right)\right] + 98.$$

Finally, the relationship between temperature and power throughput is given by:

$$(8) \quad \Delta\theta = P \cdot R_T,$$

[1] [15] notes that this equation is only valid between temperatures of 80^{o}C and 140^{o}C.

where R_T is the thermal resistance of the transformer insulation.

Equations (7) and (8) essentially provide a constraint on how much PHEV charging can take place, given a set overload temperature and overload time required. In other words, the equations define an effective charging capacity rather than a total charging capacity (as in Figure 1). We illustrate this constraint on a hypothetical oil-cooled transformer on a circuit with a daily peak load (and capacity constraint) of 1,000 MW and a total PHEV charging capacity of 200 MW, as shown in Figure 6.

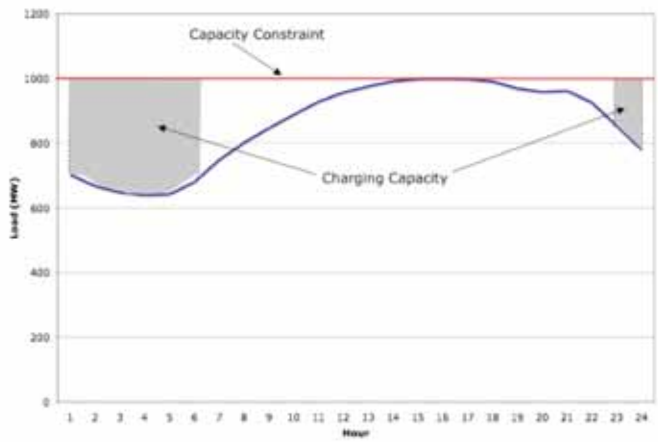

Figure 6: PHEV charging capacity for a hypothetical circuit.

We calculate the amount of nighttime PHEV charging can take place without reducing the useful life of the transformer. We assume that the overload period must last for six hours (specifically, between hours ending 1400 and 2000) at a normal temperature of 98°C. We do not choose a specific value for θ*, the overload temperature, but rather conduct a sensitivity analysis relating the allowable overload temperature to the effective PHEV charging capacity. The results are shown in Figure 7.

Figure 7 suggests that the current transformer designs may represent a significant constraint with respect to integrating PHEVs into central-station power systems. If the charging regime for PHEVs consist of nighttime charging over eight consecutive hours, the effective charging capacity of PHEVs is between 90 MWh and 110 MWh (approximately 9,000 to 11,000 PHEVs, assuming that 10 kWh is required to charge the battery for a travel distance of 50 km), if the overload temperature is not permitted to surpass 110 °C. Past this temperature, eight-hour nighttime PHEV charging is not possible without some degradation in transformer lifetime.

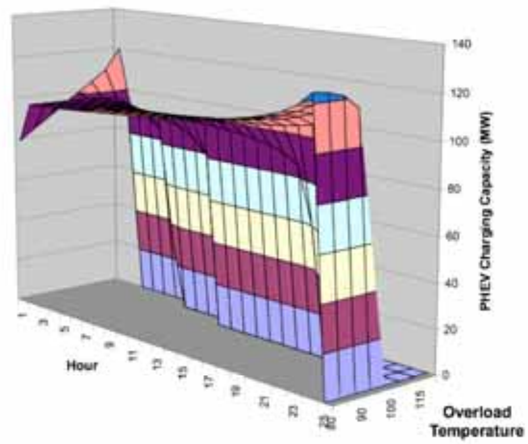

Figure 7. PHEV charging capacity limits.

IV. Conclusion

Nighttime charging of PHEVs couples the U.S. transportation system with its electric power system. We examine two fundamental changes that will need to be made to the U.S. electrical system in order for PHEVs to make a meaningful contribution to emissions reduction. We perform a life-cycle analysis of the CO_2 equivalent emissions from nighttime charging of PHEVs. Even in regions such as ERCOT that have a larger share of low-carbon generation assets than PJM or MISO, significant de-carbonization of generation is required before emissions can be reduced well below those of conventional gasoline vehicles or conventional HEVs.

We also investigate the effect of nighttime PHEV charging on a particular type of network equipment, the oil-cooled transformer. These transformers are designed to be able to run at above-normal temperatures during peak hours, provided that they are allowed to cool to normal or below-normal temperatures during off-peak hours. Large-scale PHEV market penetration will interrupt this normal operating cycle. Transformers will either need to be replaced more often, which will raise costs, or new insulation mechanisms will need to be designed.

Throughout this paper, we have assumed a very simple charging pattern where PHEVs are plugged in during the eight off-peak hours each evening. In addition to being simplistic, such a charging pattern may actually harm distribution system infrastructure, partly for reasons described in Section III. It is easy to imagine an intelligent control system that would charge PHEVs at times when the environmental or system impacts would be smallest (whether during off-peak hours or at other times), and could also allow for PHEVs to provide valuable services to the grid, as in [5]. Such a control scheme would require additional investments in advanced communications and control infrastructure.

V. Acknowledgments

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VII. Biographies

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