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Consumer Adoption and Grid Impact Models for Plug-in Hybrid Electric Vehicles in Wisconsin

Part B: Grid Impact Studies

Prepared by:

Jessica Y. Guo, Giri Venkataramanan, Bernie Lesieutre, Anthony Smick, Megan Mallette, Chris Getter

University of Wisconsin-Madison

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Contributors

This document was prepared by

University of Wisconsin-Madison
1415 Engineering Dr.
Madison, WI 53706

Principal Investigators
G. Venkataramanan, Jessica Guo, Bernie Lesieutre

Project Engineers
Megan Mallette, Anthony Smick, Chris Getter

Executive Summary

This study focuses on assessing the demand for plug-in hybrid electric vehicles (PHEV) in Wisconsin and provides near term recommendations to manage its impacts on the State's electric grid.

This study has two main objectives:

- To enhance the understanding of consumers' perception of and demand for PHEVs in order to assess the market potential of PHEVs in Wisconsin, thereby informing policy development for wider PHEV deployment.
- To estimate the associated vehicle charging patterns, electricity consumption, and infrastructure needs.

In view of the time frame for the study, our analyses were limited to the Greater Madison area. As such, the project serves as a demonstration of research methodology as well as a preliminary study for future expansion to analyzing the PHEV impacts to the entire state of Wisconsin.

While the objectives have been accomplished through three major research components, namely, infrastructure readiness assessment, consumer preference analysis and grid impact studies, this report focuses on presenting the results from the grid impact studies.

Demand response is quickly evolving and playing a greater role in the electric industry, particularly with recent promotion of smart grid activities across the nation. PHEV have the potential to provide a significant amount of demand response through a variety of methods. A brief overview of different demand response scenarios from a US-Midwest regional perspective has been studied along with an outline of the different future possibilities of the ways in which PHEV may participate as demand response resources. Furthermore, the case for developing a vision that encourages PHEVs to participate in demand response for their energy storage potential, thus enabling a higher penetration of intermittent and variable generation such as wind and solar energy resources is been put forth.

Specifically, in developing demand response incentives, there should be a clear benefit for PHEV owners who choose to participate in time-of-use programs and charge their vehicles during off-peak hours. However, if PHEV owners are unable to charge during off-peak hours, participation in time-of-use metering programs is detrimental. Additional quantitative studies are needed to determine if the potential savings accrued through time-of-use metering and reduction is gasoline consumption is sufficient to recoup the purchase premium of a PHEV over a hybrid electric vehicle or a conventional vehicle. In addition, if the usable storage capacity of a battery is allowed to time shift household residential electricity usage to off-peak hours, it is likely that the required levels of subsidy may change or even become unnecessary. In such a case, a temporary subsidy would be sufficient to encourage residential customers to participate in time-of-use metering programs.

Continuing comprehensive modeling and analytical studies are necessary to determine the necessary magnitude of these subsidies in order to enable PHEV owners to achieve cost recovery on the purchase premium of a PHEV over the life of the vehicle.

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Table of Contents

List of Tables

List of Figures

Nomenclature

AC:	Alternating Current
AEIC:	Association of Edison Illumination Companies
AMI:	Advanced Metering Infrastructure
ANSI:	American National Standards Institute
ASHRAE:	American Society of Heating, Refrigerating, and Air-Conditioning Engineers
ATC:	American Transmission Company
BACnet:	Building Automation and Control Networks
CEA:	Consumer Electronics Association
CIM:	Common Information Model
DC:	Direct Current
DDR:	Dispatchable Demand Response
DER:	Distributed Energy Resource
DG:	Distributed Generation
DMS:	Distribution Management System
DOE:	Department of Energy
DRR-I:	Type I Demand Response Resource
DRR-II:	Type II Demand Response Resource
DSM:	Demand-side Management
EDR:	Emergency Demand Response
EISA:	Energy Independence and Security Act
EPACT:	Energy Policy Act of 1992
EPRI:	Electric Power Research Institute
FERC:	Federal Energy Regulatory Commission
HEV:	Hybrid Electric Vehicle
IEC:	International Electrotechnical Commission
IEEE:	Institute of Electrical and Electronics Engineers
ISO:	Independent System Operator
ITU:	International Telecommunication Union
LMR:	Load Modifying Resource
MGE:	Madison Gas & Electric
NDDR:	Non-dispatchable Demand Response
NEC:	National Electric Code
NEMA:	National Electrical Manufacturers Association
NERC:	North American Electric Reliability Corporation
NIST:	National Institute of Standards and Technology

NPTS:	National Personal Transportation Survey
OpenADR:	Open Automated Demand Response
OpenSG:	Open Smart Grid
PAP:	Priority Action Plan
PHEV:	Plug-In Hybrid Electric Vehicle
PUHCA:	Public Utility Holding Company Act
PURPA:	Public Utilities Regulatory Policy Act
RTO:	Regional Transmission Organization
SAE:	Society of Automotive Engineers
SEP:	Smart Energy Profile
SG:	Smart Grid
SOC:	State Of Charge
TC:	Technical Committee
TOU:	Time-of-Use
V2G:	Vehicle-To-Grid
VMT:	Vehicle Miles Traveled
WPPI:	Wisconsin Public Power Incorporated

1. Introduction

Motivation

The relative success and failure of new technologies is greatly impacted by the governing political environment. For example, zero-emissions vehicle mandates in the 1990's spurred the early development of electric vehicles. However, reduced regulations were partly to blame for the nonsuccess of those initial electric vehicles. The Obama administration has set a goal to put 1 million PHEVs on the road by 2015. Automobile manufacturers are just preparing to ramp up production and marketing of these vehicles. This alignment of politics and industry has created an environment in which we can expect to see significant penetration of PHEVs.

Why should we be concerned about the future penetration of PHEVs? How are they any different from the plasma televisions and influx of other appliances that have contributed to rising electricity consumption in the past? First and foremost, PHEVs exist at the intersection of the electric and automotive industries. Historically, these two industries have primarily operated in parallel, but PHEVs offer a unique opportunity to reduce reliance on crude oil as the only transportation fuel. There is also a spatial aspect to PHEV load that is unique among devices that consume electricity. In addition to the uncertainty inherent in forecasting load levels, there is an added uncertainty about the location in which load will occur. Finally, PHEVs have the potential to serve as an energy storage resource. This has important implications for integration of renewable resources and grid reliability as a whole.

Objectives of the research

Assuming that future penetration of PHEVs is inevitable, this research attempts to explore the potential impacts that these vehicles will have on the electric industry. As the market share of PHEVs increases, there are three distinct penetration phases to consider. During the first phase of vehicle penetration, the primary impacts will likely occur on distribution equipment as vehicle clustering leads to local overloads. Increasing participation in demand response programs will likely mitigate the impact of vehicle charging during the second phase of PHEV penetration, if appropriate incentives are embraced. Finally, implementation of vehicle-to-grid technology will enable PHEVs to play a larger role in demand response programs, to the extent that vehicles might provide reserve and regulation services or emergency energy. The potential impacts are dependent on the regional electric infrastructure and vehicle customer base. Thus, this research presents a detailed case study of the future impacts in Dane County, WI. The methods described in this paper can be expanded over larger geographic/electric regions or used to more narrowly predict the impacts in more local regions.

Document organization

Chapter 1 briefly describes changes that have occurred in the electric industry since its inception in the days of Thomas Edison. Significant changes have led to striking revolutions in operating strategies. Relatively recent attempt to deregulate the industry and foster competition through energy markets have had unexpected impacts on reliability. In particular, the creation of open access transmission tariffs has caused existing infrastructure to be used in unprecedented ways. The multitudes of recent changes have contributed to the need to understand how PHEVs will further compound or alleviate existing concerns.

Chapter 2 provides background material on existing demand response programs and current efforts to remove any remaining barriers to demand response. Again, the interests of government and industry are aligned to more fully utilize demand response to alleviate constraints on existing infrastructure. Demand response has been shown to increase competition in energy markets, reduce the carbon intensity of electricity production, and increase the robustness and flexibility of the bulk electricity system. Appropriate use of demand response resources has been shown to postpone or lessen the need to invest large amounts of capital in electric infrastructure.

Chapter 3 presents information relevant to PHEV-related standards development. In order for PHEVs to successfully participate as demand response resources, standards must be developed in areas such as metering, charging, and communications. These standards will be essential in effectively integrating PHEVs in with existing electric infrastructure. They will also ensure smooth transitions as we progress through the three stages of PHEV penetration.

Chapter 4 includes a list of relevant assumptions that were made in order to complete the Dane County case study. These assumptions are regionally specific to Dane County. The primary assumption made during the analysis are related to vehicle charging characteristics, vehicle adoption models, the regional policy environment, and regional characteristics of electric infrastructure. Numerous scenarios were considered in order to account for the inherent uncertainty associated with forecasting.

Chapter 5 depicts the initial infrastructure impacts of PHEVs during the first phase of vehicle penetration. During this first phase of vehicle penetration, the majority of impacts will occur on distribution infrastructure due to the natural clustering of vehicle owners. However, if PHEV charging remains unchecked, it has the potential to exacerbate existing constraints on transmission infrastructure, making day-to-day operation more difficult.

Chapter 6 portrays the benefits that can be derived from increased participation in demand response programs by PHEV owners. Existing demand response programs such as direct load control programs and time-of-use pricing programs can enable PHEV owners to save money on monthly electricity bills, while simultaneously reducing the negative impacts associated with uncontrolled charging of PHEVs. Additional demand response programs particularly designed for PHEVs can take advantage of variable charging rates to further minimize charging impacts. In order to effectively deploy demand response programs certain incentives will be required to encourage participation by PHEV owners.

Chapter 7 considers how bi-directional power flow will further facilitate PHEVs' participation as demand response resources. With vehicle-to-grid technology, PHEVs will be able to provide valuable ancillary services such as reserve and regulation to enhance grid flexibility and robustness. Traditionally, generators have been the sole providers of these resources. Enabling demand resources to provide these services will greatly further competition within energy markets. Also, taking advantage of the existing unused battery capacity of the PHEV fleet will provide some of the energy storage that is needed to continue integration of variable, renewable resources. Finally, utilizing the energy storage capacity of PHEVs will enable a certain degree of peak power usage to be shifted to off-peak hours.

This will further reduce the need to invest large amounts of capital into additional infrastructure reinforcements and will result in cleaner operation of existing assets.

Chapter 8 summarizes the key findings that are developed throughout the paper. It attempts to paint a broad picture of potential impacts stemming from PHEV adoption to PHEV owners, electric utilities, and policymakers. Finally, it highlights areas in which future work is needed in order to more fully understand the full impacts of PHEV penetration.

2. Background

2.1. A Brief History of Electric Utility Regulation

In 1882, Thomas Edison began generating electric power at Pearl Street Station in lower Manhattan. This first central generation station was initially capable of serving four hundred lamps owned by eighty-five customers using direct current (DC) transmission technology. Edison chose to locate Pearl Street Station in lower Manhattan based on its proximity to the central financial district and the customers that he intended to serve [1]. Due to significant electrical losses associated with the high currents, transmitting large amounts of power over large distances was impossible.

A few years later, George Westinghouse used technology developed by Nikola Tesla to build the first high-voltage transmission line using alternating current (AC) technology [1]. Higher transmission voltages resulted in lower currents, directly corresponding to lower line losses. Lower line losses enabled electricity to be transmitted over much larger distances. With this increased ability to transmit power it was now possible to construct larger and more efficient generating plants away from population centers. Smaller electric companies began to consolidate in order to more effectively cover the costs of larger plants and longer lines. Due to the capital intensity of building power plants and transmission lines it was much more practical for a single electric company to provide service to a given area [2]. The requirement for a direct connection between generation and individual end-use consumers made competition between electric companies absurd. Imagine the cost and annoyance of three sets of distribution lines tied to a single home in order to give the residents a choice of electric service providers. Without competition, electric companies were able to set prices and primarily provide service to densely populated, profitable areas.

These early electric monopolies operated unchecked into the beginning of the 20th century. In 1907, New York and Wisconsin were the first states to extend the jurisdiction of their state regulatory commissions to include electric companies. By 1943, an additional forty-three states had followed suit [2]. However, in the mean time the continuing consolidation of companies had resulted in electric companies with service territories that crossed multiple state borders. These companies were exempt from state jurisdiction, leading to the necessity of establishing regulation at the federal level.

President Roosevelt signed the Public Utility Holding Company Act (PUHCA) into effect in 1935. PUHCA placed limits on the geographic scope and corporate structure of electric utilities. It also established the Federal Power Commission, known today as the Federal Energy Regulatory Commission (FERC) [3]. The Federal Power Act of 1935 explicitly divided regulation responsibilities between federal and state governments. The Federal Power Commission was given jurisdiction over wholesale power sales and over transmission. State governments continued to control siting issues and distribution rates [3]. Electric policy has since, until very recently, been dictated by the assumption that the electric industry is a natural monopoly due to high fixed costs and economies of scale.

2.2. Current Attempts to Encourage Competition in Energy Markets

The electric industry is currently experiencing its greatest transformation since the inception of federal regulation with PUHCA in 1935. The first hints of change arose due to increasing energy costs and slowing expansion of generating capacity during the 1970s. Skyrocketing oil prices led to a fear of relying too heavily on fossil fuel imports from foreign countries with potentially unstable governments and a fear that there was a limited remaining amount of fossil fuels available for consumption [4]. Also, people were just beginning to consider the negative environmental consequences that would result from continued fossil fuel plant operations [4].

These changes gave rise to the Public Utilities Regulatory Policy Act (PURPA) of 1978. PURPA created a market for non-utility electric power producers. The ultimate goal was to increase the amount of renewable generation and simultaneously reduce dependence on foreign oil. Existing utilities were required to purchase the power generated by these non-utility electric power producers at a price equivalent to the avoided cost of building a new generating plant [4]. The existing utilities argued that it was unfair to allow independent power producers to generate power without the added capital costs of transmitting and distributing this power; however, they were unsuccessful in preventing implementation of the act. Existing utilities eventually came to appreciate the reduced need to make uncertain capital expenditures [4]. PURPA ultimately resulted in a large number of new hydro generation plants and natural gas cogeneration plants. Following implementation of PURPA, some people began to question the validity of the natural monopoly model. The establishment of non-utility electric power producers had unwittingly introduced a certain amount of competition into the generation side of the electric industry [4].

The Energy Policy Act of 1992 (EPACT) further separated the electric industry from a monopolistic model by removing some of the remaining obstacles to wholesale power competition. EPACT also directed FERC to require wholesale wheeling in an effort to encourage development of generation resources [5] FERC fulfilled its responsibilities by issuing Orders 888 and 889 in 1996, thus promoting non-discriminatory open access transmission service [5]. Essentially, this required all transmission owners to transmit inexpensive power from any electric company to areas with high demand. Smaller electric service providers were now able to purchase power from the cheapest source if unable to generate enough electricity internally to meet demand. Previously, smaller electric service providers were limited to the generation prices set by its nearest neighbors with direct transmission connections. In order to ensure that transmission owners were abiding with the new regulations they were required to openly share information about their transfer capabilities and schedules.

Orders 888 and 889 had a positive impact on generation resources; however, they placed additional burdens on the transmission system. Soon after implementation of Orders 888 and 889, the North American Electric Reliability Corporation (NERC) published a reliability assessment claiming that "the adequacy of the bulk transmission system has been challenged to support the movement of power in unprecedented amounts and in unexpected directions [6]." In response to these concerns, FERC issued Order 2000 in 1999. Order 2000 encouraged the establishment of Regional Transmission Operators (RTOs) to provide transmission services and independently operate energy markets within their service territory.

According to the final order passed by FERC, RTOs would improve efficiencies in the management of the transmission grid, improve grid reliability, remove opportunities for discriminatory transmission practice, improve market performance, and facilitate lighter-handed governmental regulation [7].

2.3. Unintended Consequences of Incorporating Competition in Energy Markets

Despite significant progress towards deregulation and a competitive energy market, mounting evidence suggests that modernization of the current transmission system is still required. The transmission system must be flexible enough to match generation to load every second of every day. Historically, load patterns have been very predictable. This has enabled generation resources to be scheduled in order to meet the typical demand. Small fluctuations in demand have been accounted for by automatic governor response of certain generators. This is increasingly difficult in the face of growing demand and integration of variable resources. Essentially, the number of unknown operational quantities has been increasing significantly. This requires additional transmission infrastructure in order to ensure that the bulk electric system is capable of withstanding numerous different system biases and configurations. For example, transmission infrastructure in Wisconsin has to be capable of importing large amounts of power from the Wisconsin – Minnesota interface when large amount of wind generation in operational in the Iowa and the Dakotas. However, during periods when there is little wind generation, the system must be able to withstand large energy imports from the Wisconsin – Illinois interface in order to meet demand within the state. Also, federal regulations require that the system will remain intact for loss of any single contingency.

Additionally, end-use customers want to have access to the lowest cost generation, which is often not located in proximity to densely populated areas. In order to allow low cost generation to adequately compete in the new electric markets, additional transmission lines must be built to connect these low cost generators to areas of high load. With the onset of state renewable portfolio standards and the potential for a federal renewable portfolio standard, there is an increasing realization that the existing transmission infrastructure will need to be supplemented in order to adequately transmit solar and wind energy. Along with biomass, these two technologies are anticipated to play a large role in reducing greenhouse gas emissions and slowing the impacts of climate change. However, the most efficient solar power installations will be located in the southwestern United States and the most efficient wind turbines will be located in the Midwest. Neither of these locations is highly populated. Thus, a great deal of infrastructure expansion will be needed to fully take advantage of the available resources. A large, nation-wide network of 765 kV lines has been proposed to connect locations with high renewable generation potential to areas with high demand [8].

The restructuring of the electric industry has created the need for a discussion between government officials and industry representatives to discuss who will build and pay for new transmission lines. Vertically integrated utilities have historically built sufficient transmission infrastructure to transmit the energy that they generated to their customers. With required open access transmission tariffs, there is less incentive for these vertically integrated utilities to build new infrastructure. Also, new financial uncertainties in electric power markets have made raising sufficient capital to build new transmission difficult.

However, transmission constraints are contributing to increasing electricity costs and additional reliability concerns. According to an independent study conducted by the Department of Energy (DOE), interregional transmission congestion costs consumers hundreds of millions of dollars annually [9]. Over the past decade, these changes have led to the formation of two transmission-only companies. The first of these two companies, American Transmission Company, owns and operates approximately two-thirds of the transmission infrastructure in Wisconsin. The second independently owned transmission company, International Transmission Company, owns and operates transmission infrastructure in parts of Iowa, Minnesota, and Michigan. Both of these companies are operated independently of generation which enables them to be unbiased when considering future transmission upgrades. Because they receive revenue based on the amount of power that flows across their lines, reducing system losses and congestion are important considerations. All potential transmission upgrades are reviewed and approved by the state Public Service Commissions in order to prevent abuse in the form of overbuilding.

However, these two companies have limited service territories. As a whole, the bulk electric system is still suffering from insufficient transmission capacity due to vertically integrated utilities that have not placed sufficient interest in expanding the transmission system over the past decade. In a National Transmission Grid Study performed in 2002, the National Energy Policy Development group proposed to relieve transmission bottlenecks by completing the transition to competitive regional wholesale markets through better operations and effective investments [9]. The DOE has taken an increased leadership role in transmission by creating the new Office of Electricity Transmission and Distribution to lead national efforts to modernize the electric grid, enhance security and reliability of the energy infrastructure, and facility recovery from disruptions to energy supply. Although there appears to be potential efficiency and rate benefits due to increasing competition in energy markets, it is very important to take certain precautions during the transition in order to prevent a repeat of a situation such as the California electricity crisis. Severe system reliability issues were experienced in California due to manipulation of the energy markets that occurred during deregulation. Deregulation can be accompanied by additional opportunities to make a profit at the expense of reliability of the system if care is not taken to ensure that the system is not abused.

Demand response has been proposed as a potential method to increase competition within the electric industry while simultaneously improving the reliability of the bulk electric system. Essentially, the power to determine energy prices no longer resides solely with the cost of generation. Energy customers that feel that the price is too high can reduce energy consumption. When sufficient energy customers reduce consumption, higher cost generation will no longer need to run. A great deal of research has gone into determining the benefits of demand response and defining the remaining barriers to wide-spread use of demand response. Combining appropriate use of demand response resources with the existing attempts at deregulation of the industry will ideally minimize unintended congestion and reliability impacts that have been associated with deregulation thus far. The next chapter more fully explores the potential benefits of demand response and the remaining barriers to wide-spread participation in demand response programs.

3. Demand Response

3.1.Definition of Demand Response

FERC has defined demand response as any "changes in electric usage by end-use customers from their normal consumption patterns in response to changes in the price of electricity over time, or to incentive payments designed to induce lower electricity use at times of high wholesale market prices or when system reliability is jeopardized [10]." Essentially this refers to the ability of variable load to address energy emergencies, respond to high energy prices, and potentially maintain system frequency. Demand response programs have been offered by local utilities for many years under the name 'interruptible loads.' Interruptible loads have always been a last resort available to electricity companies during periods of extremely high demand or system contingencies with significant reliability impacts. More recently, Independent System Operators (ISOs) and (RTOs) have begun to create market programs for use of demand response resources, enabling these resources to be used on a more regional basis. This coincides with the general trend within the industry to optimize operations across the entire grid, as opposed to optimizing operations within smaller company service territories.

Demand response programs can be separated into dispatchable demand response (DDR) and non-dispatchable demand response (NDDR). DDR programs include direct load control, interruptible tariffs, and certain demand bidding programs. In all cases listed above, the local balancing authority has a direct method to curtail load. NRRD programs, on the other hand, rely on customer response to a price signal reflecting the cost of energy production and delivery. Examples of NDDR programs include time-of-use pricing, critical peak pricing, real-time pricing, and certain demand bidding programs [11].

The informal interruptible load contracts that existed prior to the onset of electricity markets were typically made with large industrial loads. These resources could be dispatchable or non-dispatchable depending on the preferences of the customer. Compensation was provided for the willingness to reduce demand during system reliability emergencies; however, electric companies tried to avoid prolific use of these resources. Over use could result in an unwillingness to participate in such programs in the future. Competitive electricity markets have the potential to open up the market for demand resources to any customer that is capable of sufficient metering and response times. New demand response programs will need to be designed such that there is a significant benefit to the consumer in order to promote adoption and a significant benefit to the reliability of the system in order to ensure that the electric companies feel justified in making the effort to offer these programs.

Demand response is expected to complement existing energy programs, such as distributed generation and demand-side management (DSM). The National Energy Policy Development group has suggested that increasing the role of all types of energy management is the only way to ensure a robust and reliable electric system in the future [9]. Distributed generation (DG) is primarily composed of small-scale power production, typically connected to distribution systems. Often located at sites such as hospitals and industrial facilities, these resources have traditionally been used as emergency back-up power sources for essential local operations in the event of a blackout. In many cases, these generation resources are located behind-the-meter and are therefore unable to be monitored separately from the local demand. DG can also include small solar panel or wind turbine installations that individuals install at their homes. These installations typically are only used to offset energy purchases from the grid; however, there are certain times when these generators can actually feed energy back into the grid.

DSM includes both energy efficiency and demand response. Energy efficiency programs attempt to permanently reduce electricity demand during all hours of the year. Examples of energy efficiency measures include replacing incandescent light bulbs with compact fluorescent bulbs, insulating homes in order to minimize wasted heat and air conditioning, and replacing old appliances with new energy efficient appliances. In addition to the overall energy savings achieved through the use of energy efficiency programs, the corresponding reductions in the peak demand may defer the need for new investments in both generation and transmission. Demand response programs, on the other hand, are designed to decrease electricity demand only during peak periods based on high wholesale prices or low-reserve conditions. Demand response is expected to become a critical resource for maintaining system reliability in the future.

3.2. Benefits of Demand Response

Demand response has already proven itself as a valuable tool to ensure reliability of the bulk electric system. During the summer heat wave of 2006, the Midwest ISO avoided firm load shed using interruptible load, demand-side management, and public appeals. Over 2,500 MW of load curtailment occurred on August 1st alone.

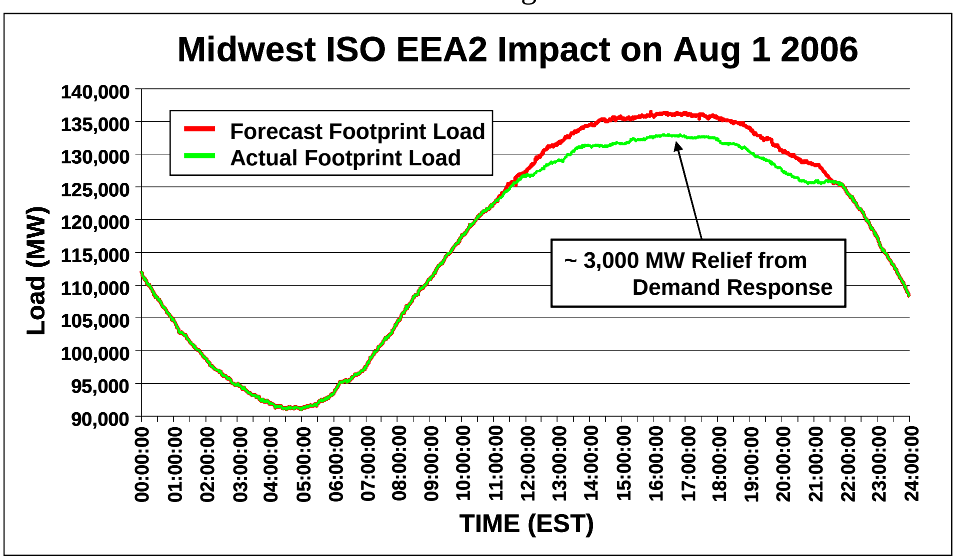

Figure 1: Impact of Demand Response on Reliability in the Midwest ISO's Footprint

Many other regions also utilized demand response to avoid firm load shed in July and August of 2006 as high temperatures swept across the nation. In this example, demand response (a.k.a. interruptible load and public appeals) helped to maintain reliability of the bulk electric system [13]. Even if it means spending a significant amount of money, paying energy customers to reduce their load during system emergencies is much less expensive than paying for the damages that result from cascading blackouts. Forced customer outages lead to significant expenses including lost production and sales, food spoilage, or overtime for employees that work an extra shift to make up for lost production.

Some energy customers are more suited towards provided certain types of demand response than others. For example, an automobile manufacturing facility can relatively easily stop production and pick it right back up without damaging any equipment. However, processes such as the smelting of aluminum require a certain range of temperatures at all times. If the temperature deviates beyond a certain bandwidth and the molten aluminum hardens it can be weeks before the equipment is functioning again. As demand response participation increases and demand response resources are allowed to more fully participate in energy markets, there is a great potential for these resources to provide economic benefits in addition to reliability benefits. Some of the positive impacts that are expected to result from increasing participation of demand response are reliability benefits, market performance benefits, market-wide financial benefits, and participant financial benefits. Each of these impacts is discussed in further detail below.

Reliability Benefits

Appropriate use of demand response resources can enhance system reliability by sending more efficient generation and transmission capacity signals. Depending on the geographical distribution of these resources, it is possible that they can be used to mitigate congestion and optimize the flow of electricity on the grid [14]. In addition to the actual amount of infrastructure required to meet system demand, electric companies are required to have a certain amount of capacity in case equipment fails or demand changes. Some types of demand response can also be used to fulfill resource adequacy requirements. This means that these resources can be used during system emergencies in order to ensure that no firm load is shed. Finally, demand response will be able to provide the robustness and flexibility that the grid needs to support increasing amounts of variable generation.

Market Performance Benefits

A great deal of the interest in demand response can be linked back to changes in governmental regulation and policy. For instance, tighter environmental regulations have required the electric industry to look for new methods to decrease the amount of greenhouse gas emissions. Reducing demand during select peak hours throughout the year instead of running peaking units may result in an overall cleaner electrical system footprint, depending on the local generation mix [14]. For example, areas with a great deal of old coal technology or constrained generators will benefit more than areas with cleaner and more efficient cogeneration plants. It is possible that the government will place some sort of tax on carbon emissions in the future. In this scenario, the increase in the price of electricity generated using fossil fuel technology will likely be accompanied by a corresponding increase in demand response participation, helping to maintain reasonable energy prices. Also, the government is currently pushing the electric industry to remove any remaining barriers to true competition in electric markets. Allowing demand resources to participate in energy and ancillary services markets will lead to reduced potential for generators to exert market power [14].

Market-Wide Financial Benefits

Demand response can play a crucial role in reducing the volatility of power prices [14]. This is especially important in the face of widely fluctuating gas prices, increasing concerns about dependence on foreign fuels, and large proposed amounts of renewable generation. As the price of natural gas increases, reducing load for a few hours each day instead of turning on a peaking plant to meet demand can result in significantly lower locational marginal prices. Generator prices are typically inelastic over the vast majority of demand levels. This is illustrated by the primarily horizontal nature of the supply curve shown in Figure 2. At a certain level of demand, more expensive generators must be brought online. Suddenly, small increases in demand can cause significant increases in the price of electricity. Thus, a small amount of demand reduction corresponds to a much larger electricity price reduction.

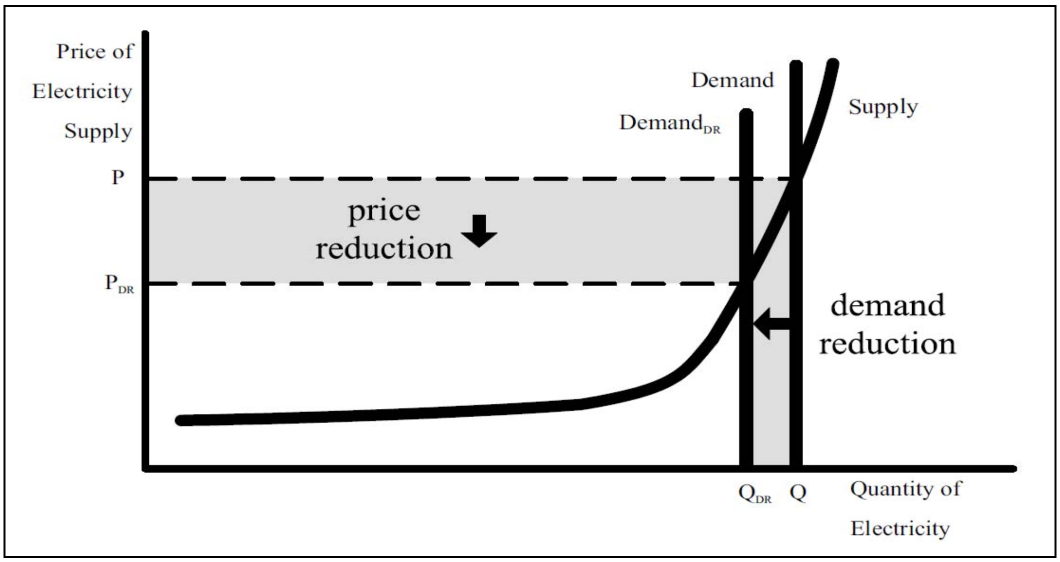

Figure 2: Illustration of the Economic Benefits of Demand Response

Certain types of demand response are capable of providing regulation services. An example of a demand response resource that can provide regulation services is an aluminum smelting plant. The output of the plant is dependent on the amount of energy that is used to heat the smelter. However, small increases or decreases in energy will not have a significant impact on output, provided that the average amount of energy supplied remains the same. In this situation, the variations in wind energy output can be matched by variations in load instead of generation. Also, since some types of demand resources can be used to fulfill resource adequacy requirements, less over-building of infrastructure will be needed. The increased use of demand response can lead to delayed or avoided generation and transmission infrastructure [14].

Participant Financial Benefits

Increased prevalence of demand response will heighten customer awareness of the time-dependent nature of actual electricity costs [14]. At this time, few demand response programs are offered to residential customers. Existing programs include controlled air conditioner and water heater programs. This is partially because residential customers only have a significant impact on reliability or price when they are aggregated together. Recent developments in some states have created a market for aggregators to offer bids on behalf of a number of residential customers into energy markets [14]. In the future, customers will be able to define the value of the electricity that they consume, and feel more empowered to control their consumption. Some customers will be more capable of reducing load during periods of high locational marginal prices. Customers that reduce demand will be compensated for their services. The ultimate result will be lower costs for safe and adequate electric service for all customers [14].

3.3. Demand Response Participation in the United States Today

Significant benefits from demand response will accrue only with sufficient levels of customer participation. In 2008, nearly 8% of customers in the United States were participating in at least one type of demand response program [16]. FERC estimated that the potential annual resource contribution of demand response resources available in the United States was approximately 41,000 MW, or 5.8% of the forecasted U.S. peak demand for 2008 [16]. This number is a nine percent increase from the availability of approximately 38,000 MW of total potential peak load reduction in 2006 [16]. Actual load reductions are less than half of the total potential load reduction. Sixty-nine percent of the actual load reduction that occurs in the United States is located in the regions that include the Reliability First Corporation, the Midwest Reliability Organization, and the Southeast Electric Reliability Council. This is likely due in part to the relatively large geographical area, high populations, and significant amounts of heavy industry that exist in each of these regions [16].

The difference between actual load reduction and potential peak load reduction can be partly explained by the fact that many demand response resources are reserved for use during system emergencies. The actual peak load reduction for economic-based demand response resources in a given year is very much dependent on the volatility of electricity prices. Economic demand response programs are only utilized when locational marginal prices reach a certain set point. If the price to generate and transmit electricity remains low, these resources will not be used [16]. For example, total demand in the United States has been lower than anticipated this year, coinciding with the economic downturn. Without high electricity demand, low cost coal and nuclear generators are capable of meeting the demand throughout the entire day. More expensive gas units are not needed, thus reducing overall price volatility. Most demand response resources have fairly high costs to reduce load. Without high levels of price volatility it does not make economic sense to utilize these resources. Ancillary services that can be offered by demand response participants include operating reserves, frequency support, and voltage support. Resources capable of providing ancillary services are not necessarily called on during system peaks, but rather are called on throughout the year [16]. These numbers will not be reflected in the ratio of actual to potential peak load reduction, further contributing to the difference between actual load reduction and potential peak load reduction.

3.4. Remaining Barriers to Demand Response

Despite the observed and anticipated benefits of demand response, there are several barriers that must be addressed before it becomes standard within the electric industry. FERC published a report in 2008 that identifies some of the significant barriers. One major barrier is the limited number of residential customers that participate in time-based rate programs

[16]. Residential customers are largely protected from the variable nature of energy prices. Without direct exposure to energy prices customers have no incentive to reduce energy usage, nor do they know when conservation is most needed. Ideally, exposing all customers to the real-time locational marginal price would require people to actually consider the value of the electricity that they use. In lieu of real-time pricing, time-based rates encourage customers to use electricity during periods that typically see less demand.

The lack of customers participating in time-based rate programs is due in part to the limited variety of demand response programs that are offered by utilities [16]. Encouraging residential participation in demand response programs is a pivotal step in demand response policy because the residential sector ultimately has the potential to surpass other sectors in total demand response reductions. Figure 3 shows the achievable peak reduction by different sectors under a range of demand response scenarios [10]. The business-as-usual scenario assumes the same level of advanced metering infrastructure deployment and dynamic pricing programs as exist today. The expanded business-as-usual scenario assumes that additional dynamic pricing programs will be available to customers, and 5% of customers will voluntarily participate in these programs. The achievable participation scenario assumes full advanced meter deployment and assigns dynamic pricing as the default rate structure for customers. Based on the ability of customers to choose not to participate, it is assumed that 60 – 75% of customer will actually participate in one of the dynamic pricing programs. The full participation scenario assumes full deployment of advanced meters and mandatory participation in dynamic pricing programs.

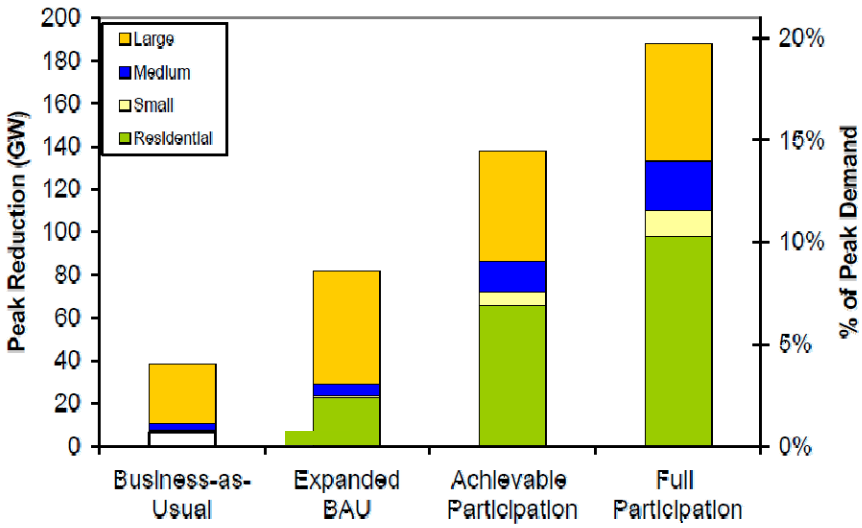

Figure 3: United States Demand Response Potential by Sector

Another remaining barrier to demand response is the relatively low penetration of advanced metering devices [16]. Advanced metering devices are needed for demand response participants in order to measure the duration and amount of actual load reduction. Without an accurate measurement, compensating the participant is impossible. Also, utilities need accurate measurements of actual load reduction in order to verify the ability of participants to provide the expected amount of curtailment in the pre-defined time period. Many utilities are planning to replace their existing meters with advanced metering devices in the near future. Existing installations of advanced metering devices have demonstrated their ability to reduce costs; however, there is still a significant up front installation cost which makes it difficult for some utilities to make the change [16].

The FERC report also found that policies regarding access to meter data can be a barrier to demand response, even in areas with high penetration of advanced metering devices [16]. The time and money required to access meter data can prevent customers from participating in demand response programs. Enhanced meter transparency could optimize utility operations and planning through better tracking of consumer demand and patterns.

3.5. Creation of a National Action Plan for Demand Response

In order to facilitate the removal of remaining barriers FERC is in the process of creating a National Action Plan for demand response. The three objectives to be fulfilled through the National Action Plan include "identification of requirements for technical assistance to States to allow them to maximize the amount of demand response resources that can be developed and deployed, design and identification of requirements for implementation of a national communications programs that includes broad-based customer education and support, and development or identification of analytical tools, information, model regulatory provisions, model contracts, and other support materials for use by customers, states, utilities and demand response providers [17]." The proposed method to achieve these objectives is the creation of a coalition of stakeholders. This coalition will make decisions about methods to ensure a graceful transition to an electric industry with extensive demand response participation [17]. Ideally, this means that the individuals that are making the decisions will be those that have the most expertise in the area. It will also ensure that input from all interested parties is considered. The coalition must include federal/state regulators and policymakers, ISOs/RTOs, generation/transmission/distribution owners and operators, goods and services providers, and concerned consumer advocates and non-profit agencies. Such a large and diverse membership will likely extend the duration of the process; however, the outcome will more comprehensively address barriers to implementation.

A number of possible activities to promote demand response in accordance with the three specified objectives have been proposed. One of the first tasks will be to begin organization of a national forum on demand response in order to facilitate conversations on a nation-wide basis [17]. In addition to the national forum, information sessions and communications training will be provided to policymakers, regulators, and local governing officials [17]. These activities will ensure that those in the upper echelon are better prepared to implement demand response in their respective regions. Opening these training sessions to load serving entities would be beneficial since they will be playing a major role in encouraging end-use consumers to participate in demand response programs. Also, this will provide an additional outlet for representatives from the policy world to interact with industry representatives. Other activities intended to provide technical assistance include building a panel of demand response experts, sponsoring technical papers, establishing a demand response assistance program, and establishing a demand response grant program [17]. Combining the goals of building a panel of demand response experts and sponsoring technical papers will result in the greatest efficiency of resources. Technical experts will be the most qualified authors of demand response related papers. Conversely, authors of demand response related papers will be highly qualified as technical experts.

A number of activities are planned to support the establishment of a national communications program. The ultimate goal of all these communications-related activities is to present a consistent messaging framework on a national level [17]. This will require a great deal of foundational market research in order to determine the most effective vocabulary and means for communicating. There are already a number of smart energy usage marketing campaigns such as energy efficiency and energy conservations. It will be important to determine if consumers will be more open to demand response if it is marketed as an additional subset of existing energy usage campaigns or as a new and unique concept. Also, different marketing strategies will need to be developed based on the customer class. For example, large industrial customers may respond better to a national campaign because they are likely able to participate directly in energy markets. However, residential customers are much more dependent on the local programs offered in their immediate areas. A national campaign may not be suitable for marketing to smaller customers. In order to maintain a consistent messaging framework, the coalition may elect to provide communications toolkit materials and assistance for more local campaigns [17]. There are also plans to create corporate and organizational partnerships to increase effectiveness and visibility in a low-cost manner [17]. Manufacturers and retailers that are allowed to market their products as demand response capable will contribute to customer awareness and interest without any effort on the part of the coalition. An example of this is the marketing of Energy Star appliances. The consumer is encouraged to purchase these products due to the energy savings that they will achieve on their monthly electricity bill; however these customers are simultaneously contributing to nation-wide energy efficiency efforts.

Tools and materials that the coalition will be working to create include demand response estimation tools and processes, standards and protocols for demand response, information to design pilot demand response programs, and guidelines on rate designs for dynamic pricing [17]. These tools are intended to facilitate the transition to increased demand response penetration for policymakers, utilities, and demand response participants. Some of these tools will be used to demonstrate the potential benefits incurred through demand response participation. After-the-fact verification that demand response actually has the anticipated results will be equally important in order to encourage additional demand response participants, and to determine just how much demand response resources can be relied on to meet their commitments.

Another suggested activity for the coalition is to compile information and case studies on a web-based clearing house that will be made available to those in the electric industry attempting to incorporate demand response [17]. This will provide the coalition with an accessible means to disseminate information. Summaries from the national forum and regional meetings might be additional items of interest to include. Creating a separate website with the purpose of providing information to and answering the questions of end-use consumers about demand response might also be beneficial.

3.6. Plug-In Hybrid Electric Vehicles in the National Action Plan

Many discussions have taken place about the ability of Plug-In Hybrid Electric Vehicles (PHEVs) to provide significant amounts of demand response. Although the proposed National Action Plan will likely have positive implications for demand response on a national basis, there has been very little specific research on implementation and impacts of large amounts of PHEVs providing various types of demand response services. Specific mention of PHEVs occurs in the National Action Plan discussion draft in two sections. The first section suggests that PHEVs should be included in the technical paper sponsorship categories of interest. More specifically, the interest lies in "a study of how PHEVs interact with demand response programs, examining whether demand response rate design provides a price signal that encourages PHEVs to charge during off-peak hours as well as how different demand response pricing mechanisms interact with PHEVs and their net impacts on how electricity might change [17]."

An additional concern is addressed in the section of the National Action Plan discussion draft that addresses standards and protocols for demand response. One of the suggested areas to explore is "adoption of nationwide standards for PHEVs and all electric vehicle charging station, with appropriate communications, metering and electric flow control, and standardized plug interface would facilitate use of PHEVs and electric vehicles variable storage potential to provide ancillary services to the electric grid and would reduce barriers to interoperability posed by having various state-by-state standards [17]."

PHEVs have the potential to more fully allow residential customers to participate as demand response resources. Customers with flexible charging patterns may be able to use smart charging systems to charge their vehicles when demand and energy prices are low. Similar to the way utilities are able to control some air conditioners and water heaters, PHEVs could potentially be a large load source that can be cut in times of emergency or high prices. The utility could then pool all participating PHEVs and bid this into energy markets, lowering prices and increasing reliability. However, before investing in the metering and charging infrastructure that will be required to fully optimize PHEV demand response participation, it is important to consider all the potential impacts.

The following chapter describes some of the specific standards that are under development in order to facilitate PHEV adoption and participation in demand response programs. Even in the absence of PHEVs, numerous standards are in development that will facilitate and simplify participation in demand response programs. Many of these standards are related to smart grid initiatives that are intended to increase the overall reliability and robustness of the bulk electric system. Other standards are needed to more explicitly address characteristics that are unique to electric vehicles.

4. Overview of Relevant Standards Development

4.1. Importance of Standards to Plug-In Hybrid Electric Vehicle Penetration

Development of appropriate standards will be essential in order to smoothly integrate PHEVs into the existing electric and transportation sectors. Standards are important for a number of reasons. First of all, standards ensure that new products will not pose a threat to the safety and health of end-use consumers. Standards also serve to align product development goals between different research entities, and thus allow product research to be divided among different specialty areas. For example, an automobile manufacturer is able to design and produce a new gasoline-fueled vehicle with the knowledge that any individual purchasing the vehicle will have access to refueling stations. The automobile manufacturer does not need to concern itself with developing and installing new refueling infrastructure. An additional benefit stemming from the alignment of product development goals is increased competition within specialty areas. For example, a common refueling mechanism enables numerous automobile manufacturers to compete in the automotive market. Finally, standards are able to guide consumer usage patterns. This enables consumers to receive optimal benefits from their products, but prevents them from abusing the rights of others.

Recent changes in policy priorities have set an aggressive schedule for the deployment of new technologies in both the electric and transportation sectors. The electric and transportation industries have historically operated independently of each other. However, the deployment of PHEVs has suddenly forced the two industries to operate in much closer proximity. The difficulties presented by this new interdependency between the electric and transportation sectors are exacerbated by additional changes faced by the electric industry including installation of advanced metering devices, development of demand response programs, and integration of variable resources. These changes have created a need to review existing standards and develop new standards to guide the electric and automotive industries through this significant transition.

Numerous organizations exist to develop and publish standards applicable to the electric and transportation industries. Determining which organizations have the appropriate expertise to develop standards can be an extremely tedious and difficult task. The Energy Independence and Security Act (EISA) of 2007 assigned "primary responsibility to coordinate development of a framework that includes protocols and model standards for information management to achieve interoperability of smart grid devices and systems [18]" to the National Institute of Standards and Technology (NIST). In partial fulfillment of its responsibilities, NIST partnered with the Electric Power Research Institute (EPRI) to identify a preliminary set of existing standards pertinent to smart grid applications and potential areas that merit new standard development [19]. This preliminary information was then used to develop a number of Priority Action Plans (PAPs) to specifically address certain areas related to smart grid implementation. The stated goal of each PAP is to "define the problem, establish the objectives, and identify the likely standards bodies and users associations pertinent to the standards modifications, enhancements, and harmonization required [21]."

4.2. Development of Standards Nonspecific to Plug-In Hybrid Electric Vehicles

There are a number of standards gaps that must be addressed in order achieve a smooth transition as PHEVs enter the consumer market. However, there are a number of broader smart grid issues that need to be addressed prior to considering standards specific to PHEVs. NIST has classified these broader issues into the following categories: advanced metering, customer interactions with the smart grid, and smart grid communications [21]. A number of PAPs have been developed within each of these categories.

Priority Action Plans Related to Advanced Metering

Advanced metering infrastructure is of crucial important when attempting to facilitate any form of demand response, including PHEVs. Many utilities are currently in the process of installing advanced metering devices within their footprints. However, the possibility of installing infrastructure that will be incapable of complying with future smart grid standards has caused many utilities to hesitate. PAP 00 was intended to ensure that near-term installations of advanced metering devices will be capable of complying with future standards. This will allow utilities to continue the installation of smart grid infrastructure prior to full development of smart grid standards. The National Electrical Manufacturers Association (NEMA) took the lead on developing standards for meter upgradeability. Due to its high priority, NEMA Smart Grid Standards Publication SG-AMI 1-2009 – Requirements for Smart Meter Upgradeability was approved by NEMA's Codes & Standards Committee approximately 90 days after issuance of PAP 00 [21].

PAP 05 was developed to create standard meter data profiles, thus facilitating timely access to meter data. Ideally, this will enable increasing numbers of end-use consumers to obtain data to help them manage energy consumption. It will simultaneously allow electric utilities to more efficiently access the data required to implement demand response programs [21]. American National Standards Institute (ANSI) Standard C12.19 contains information about which data elements may be stored in meters, relays, communications modules, and data management systems. The PAP 05 task force plans to determine any changes that may need to be made to this standard in order to more fully facilitate demand response resources. Also, this task force will play a role in creating the Association of Edison Illumination Companies (AEIC) Guidelines v2.0 to ensure that ANSI C12.19 is utilized in the most effective manner [22].

Priority Action Plans Related to Smart Grid Customer Interactions

PAP 10 was developed in order to further facilitate access to meter data through the creation of standards for energy usage information. The inability to conveniently access data from advanced metering devices is one of the remaining barriers to demand response. Simplifying accessing to energy usage data will enable end-use energy customers to more easily identify potential methods to control energy consumption and measure their progress. Ultimately, increased awareness and control over energy consumption will increase reliability of the bulk electric system while simultaneously reducing end-use customers' monthly electricity bills [21]. The PAP group tasked with developing standards for energy usage information has identified a number of existing models on which to base future metering information requirements. These models include OpenADR, IEC CIM, IEC 61850, ZigBee SEP, and ASHRAE BACnet, among others. The PAP 10 task force is currently extracting requirements from these existing models and attempting to create a standard composite information model [21].

Ideally, increasing numbers of installed advanced metering devices, coupled with simplified data acquisition methods, will enable additional end-use consumers to participate in demand response programs. However, there is still a great deal that needs to be accomplished in order to standardize demand response signals. Demand response resources can be signaled on the basis of threats to reliability, high locational marginal prices, or violation of predefined environmental metrics. PAP 09 was created to define signals that can be used to call on demand response resources and to explore various methods of implementation. The PAP 09 task force plans to create a comprehensive set of demand response signal specifications, drawing on existing standards bodies such as OpenADR, OpenSG, and IEC TC57 [21].

PAP 03 was developed to create a common specification for price. Energy regulators are currently pushing the electric industry to embrace competitive energy pricing. In a perfectly competitive market, price is a reflection of numerous product characteristics including availability, quality, and demand. Heavy regulation, and the assumption that the electric industry must operate as a natural monopoly, has historically prevented electricity prices from reflecting actual market conditions. Recent regulatory changes are forcing the electric industry to completely restructure operations, with particular emphasis on encouraging competition in energy markets. In order to ensure successful implementation of energy markets, PAP 03 has been assigned the task of creating a common price model to define which characteristics should be associated with electricity prices [21].

Of equal importance to developing a common pricing model is development of a common scheduling model. PAP 04 was developed to streamline scheduling communications in energy transactions. Scheduling is of particular importance to the electric industry due to limited storage mechanisms and a constant need to instantaneously match supply and demand. Historically, scheduling has consisted of forecasting load and dispatching sufficient generation resources. Increasing penetration of variable resources has added an extra dimension of uncertainty in available generation resources. Also, demand response programs are beginning to play a larger role in balancing supply and demand. This sudden influx of unknown variables has resulted in the need to identify key players in energy scheduling and standardized methods to convey the necessary information to these players [21].

Priority Action Plans Supporting Smart Grid Communications

One of the anticipated benefits from smart grid implementation is an increased capability for communication between elements in the bulk electric system. Three PAPs have been developed to address smart grid communication mechanisms. PAP 01 was intended to create guidelines for the use of IP protocol suite in the smart grid and PAP 02 was intended to create guidelines for the use of wireless communications in the smart grid. The increased capability for communication is accompanied by increasing concern about protection of critical infrastructure. When determining how the electric industry should proceed in the realms of internet and wireless communications, cyber security is of utmost importance.

PAP 15 is devoted to harmonizing power line carrier standards for appliance communications in the home. Power line-based communications will be an essential part of integrating appliances, meters, and other consumer communications into the smart grid. There are a number of existing power line-based communications standards including ITU G Hn (HomeGrid), IEEE P1901 (HomePlug™), and ANSI/CEA 709.2 (Lonworks™). Unfortunately, these existing standards are not interoperable and may negatively interfere with each other. The PAP 15 task force is focused on facilitating consistency among these standards [21].

4.3. Standards to Address Mobile Aspect of Plug-In Hybrid Electric Vehicles

Wide spread adoption of PHEVs has the potential to place a significant strain on existing electric infrastructure if charging characteristics are not carefully controlled. However, appropriate control mechanisms will enable PHEVs to increase utilization of existing infrastructure while simultaneously increasing reliability and robustness of the bulk electric system. Based on the increasing role that energy markets are playing in electric operations, demand response is a likely method that will be used to control PHEV charging characteristics. The previous sections have outlined a number of PAPs that will be crucial in setting the stage in order to enable PHEVs to participate in demand response programs. However, there are a number of additional standards that will need to be developed in order to address the mobile nature of PHEVs.

PAP 11 was designed to facilitate development of the interoperability standards required to support PHEVs. The mobile nature of PHEVs is a key concern to be addressed vie PAP 11. Assuming that PHEVs will ultimately be capable of charging outside their home locations, determining appropriate settlement mechanisms will be essential [21]. For example, PHEV owners are likely to participate in certain rate structures offered by their local electric service provider. The utility can then track vehicle consumption and charge based on the applicable rate structure. However, when extended traveling takes PHEV owners outside the footprint of their local electric service provider the settlement mechanism becomes much more complex. Another concern being considered by the PAP 11 task force is the ability for Distribution Management Systems (DMSs) to communicate with PHEVs that are enrolled in demand response programs. The ability to access the PHEV fleet and influence charging profiles is essential if PHEVs are to contribute to increasing the reliability and robustness of the bulk electric system. Four pressing items that have been identified by the PAP 11 task force are discussed below.

IEC 61850-7-420 for Distributed Energy Resource Equipment

Increasing numbers of distributed energy resource (DER) installations prompted the International Electrotechnical Commission (IEC) to begin drafting IEC 61850-7-420 in order to provide standards related to the communications aspect of monitoring and controlling DER systems [23]. The standard currently includes information relevant to photovoltaic systems, fuel cells, diesel generators, batteries, and combined heat and power systems [21]. Additional forms of DERs and energy storage devices require that this standard be expanded. Other existing standards that also need to be reviewed in order to ensure smooth communications as the number of PHEVs interfacing with the grid increases include ANSI C12.19/22 and ZigBee SEP 2.

IEC 61968 Distribution Common Information Model

Closely related to communication with DERs and energy storage devices is standard IEC 61968. This standard outlines information exchanged concerning the configuration and status of distribution electrical networks and will need to be updated in order to incorporate models for new forms of DERs and energy storage devices. IEC 61968 and IEC 61850-7-420 need to be updated in conjunction with each other in order to facilitate unimpeded communications [21].

Electricity Resale Rules and Metering Requirements

At this time there is a great deal of uncertainty about how PHEVs will interact with electricity markets. Unlike existing DERs and energy storage devices, the spatial distribution of PHEVs is an unknown quantity. This is a cause of concern both within a single utility's footprint and between different utilities' footprints. PHEVs have the flexibility to participate in energy markets as demand response resources, energy storage devices, or ancillary service providers. Continuation of existing electricity market regulations will place a significant burden on utilities to manage complex accounting and settlement processes. However, utilizing retail methods might simplify accounting and settlement for both utilities and PHEV owners. Members of the PAP 11 task force are exploring numerous new methods to facilitate simplified market transactions [21].

IEEE 1547 Standard for Interconnecting Distributed Resources

If PHEVs are to serve as DERs, the Institute of Electrical and Electronics Engineers (IEEE) 1547 standard needs to be reviewed to ensure that it adequately addresses relevant interconnection requirements. It is possible that additions will need to be made in order to protect local distribution equipment and the vehicle itself during charging and discharging events [21]. Article 705 of the National Electric Code (NEC) relating to interconnected electric power production sources may need to be revised in order to accommodate the needs of PHEVs [24].

There will also need to be a review of standards relevant to the actual charging connection that is used by PHEV owners to charge their vehicles. This will be important to understand the impacts that vehicle charging may have on local distribution systems and to ensure the safety of individuals as they connect and charge PHEVs. Society of Automotive Engineer (SAE) standard J1772 covers physical, electrical, communications protocol, and performance requirements for an electric vehicle conductive charging system and coupler [25]. SAE standard J1773 provides the same information for an electric vehicle inductive charging system and coupler [26]. Article 625 of the NEC includes requirements for design and installation of equipment necessary for electric vehicle charging [27]. These three standards need to be reviewed in order to verify that they are sufficient to safely utilize PHEVs as demand response resources, energy storage devices, and ancillary service providers.

5. Relevant Assumptions and Background Information

5.1. Plug-In Hybrid Electric Vehicle Charging Characteristics

To adequately evaluate the potential impacts of PHEVs it is essential to understand how they will interact with the electric grid. Although there may eventually be energy flow to the grid through vehicle-to-grid (V2G) technology, the initial interaction will most likely be one-way charging. This has the potential to place additional stress on distribution system. The amount of stress added is highly dependent on the level of charging. The Electric Power Research Institute has defined three potential levels of charging. Level 1 charging will most likely be the primary method of charging PHEVs as they first enter the market. At this level, vehicles are charged from a standard 120VAC 15A outlet that is available in many attached garages. These outlets are rated to provide power up to 1.4kW [28].

Some early PHEV adopters may also have access to a 240VAC 30A outlet in their garage. This has been defined as Level 2 charging and is usually considered the preferred means to charge PHEVs because of the reduced amount of time required to fully charge the vehicle [28]. Level 2 charging could potentially result in an instantaneous power consumption of 6 kW [29]. As the market penetration of PHEVs increases, Level 2 charging stations may be constructed in public places for the convenience of patrons or employees.

When higher penetrations of PHEVs are achieved, PHEV owners may begin to see fast charging stations that are similar to today's gas stations. At these charging stations vehicles can achieve 50% charge in just 10 to 15 minutes through a 480VAC, three phase circuit. This is referred to as Level 3 charging [28]. An alternative to Level 3 charging stations are battery exchange stations. Instead of stopping to recharge the PHEV battery, the battery is actually swapped out for a fully charged battery. The battery exchange station would maintain fully charged batteries as needed to meet demand in the area. This option would require less additional infrastructure than the fast charging station; however, there would also be a significant investment in batteries. In addition, ownership of the batteries at end-of-life becomes a concern.

While increasing the charging level reduces the amount of time required to charge PHEVs, the total charging time also depends on the size of the battery pack. Most PHEVs are classified based on the number of pure electric miles that they can travel. For example, a PHEV20 is capable of driving twenty miles before starting the internal combustion engine. Similarly, a PHEV40 is capable of driving forty all-electric miles and a PHEV60 is capable of driving sixty all-electric miles. Figure 4 presents daily driving distance data collected by the 1995 National Personal Transportation Survey (NPTS) [30]. It also shows the utility factor calculated based on the cumulative percentage of trips that are less than or equal to a given distance.

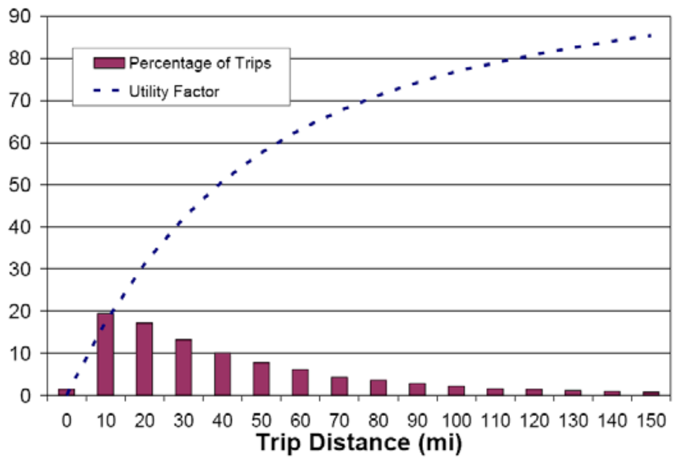

Figure 4: 1995 Data on Daily Driving Distance Distribution and Resulting Utility Factor

From Figure 4, it is apparent that 30% of daily vehicle miles traveled (VMT) are less than or equal to twenty miles and 50% of daily VMT are less than or equal to forty miles. These lower-ranged vehicles will likely be the most accessible to consumers due to smaller and less costly battery packs. These vehicles provide sufficient all-electric miles for many consumers to complete the majority of typical trips without using the internal combustion engine. The amount of time required to charge these vehicles will be less than that required to charge vehicles with larger battery packs. In the future, vehicles with larger battery packs will likely be capable of more fully participating in certain types of demand response programs. As the ability of PHEVs to participate in demand response programs increases, there will be a corresponding increasing incentive for consumers to purchase vehicles with larger battery packs.

PHEVs with equal all-electric ranges will not necessarily have the same sized battery packs. The actual battery pack size will be dependent on the size and weight of the car. Table 1 summarizes the typical size of battery packs required for different passenger vehicle types with an all-electric range of twenty miles [29]. The charging times below are calculated assuming that the battery has been fully discharged to 20% state of charge (SOC) and incorporates one to two hours of battery conditioning prior to start of charging [29].

Table 1: Charging Requirements for PHEV20

PHEV20 Vehicle	Battery Pack Size	Charger Circuit	Charging Time (from 20% SOC)
Compact Sedan	5.1 kWh	120VAC/15A	3.9 – 5.4 hrs
Mid-size Sedan	5.9 kWh	120VAC/15A	4.4 – 5.9 hrs
Mid-size SUV	7.7 kWh	120VAC/15A	5.4 – 7.1 hrs
Full-size SUV	9.3 kWh	120VAC/15A	6.3 – 8.2 hrs

The charging characteristics for different PHEV20 passenger vehicle types are displayed graphically in Figure 5 below [29]. The figure assumes Level 1 charging, or a maximum charging rate of 1.4kWh. As the battery pack approaches its full state of charge a reduction in charging rate is required in order to prevent overcharging the batteries. This reduction in charging rate is reflected in Figure 5 in the final hour of charging.

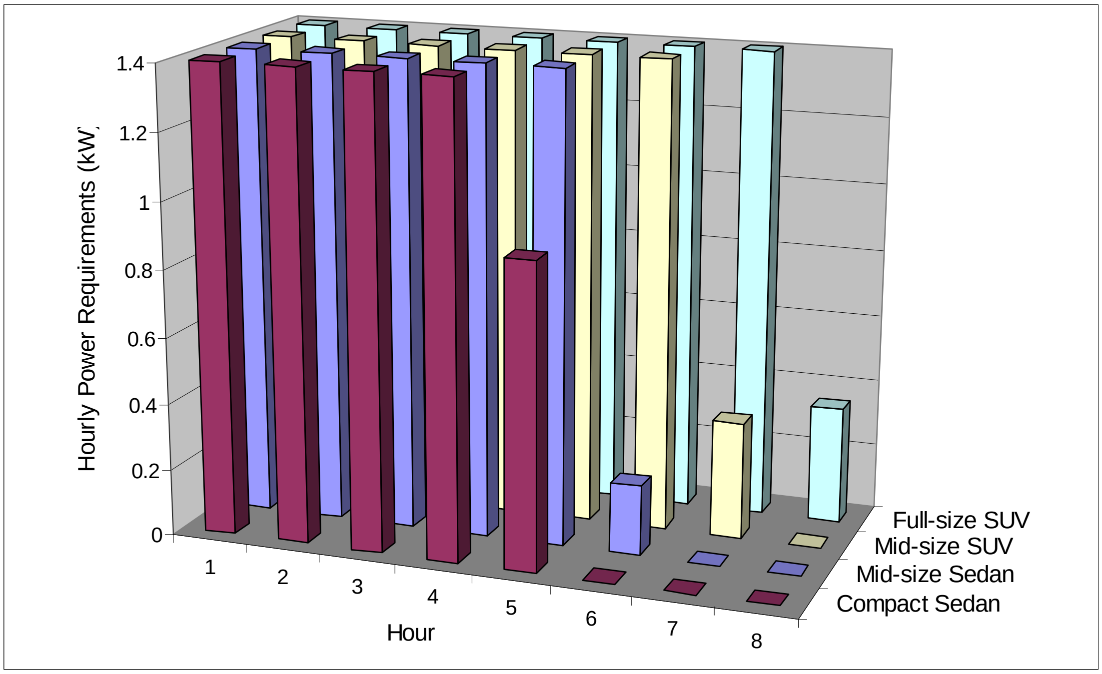

Figure 5: Power Requirements by Hour for PHEV20 at 120VAC/15A

With Level 1 charging, the differing battery pack sizes have a relatively significant impact on total charging time. Each additional increase in vehicle size adds an hour to the total amount of time required to fully charge the vehicle. If access to higher levels of charging is unavailable, consumers in the market for larger vehicles are likely to be dissuaded from purchasing PHEVs due to the prohibitively large amount of time required for charging.

Increasing to Level 2 charging rates has a significant impact on the amount of time required to charge a single PHEV. Figure 6 illustrates the charging characteristic for different PHEV20 vehicle types at Level 2 charging rates [29]. At Level 1 charging rates, a mid-size SUV required seven hours to fully charge. As indicated in Figure 6, the amount of time required to charge the same mid-size sedan at Level 2 charging rates drops to two hours.

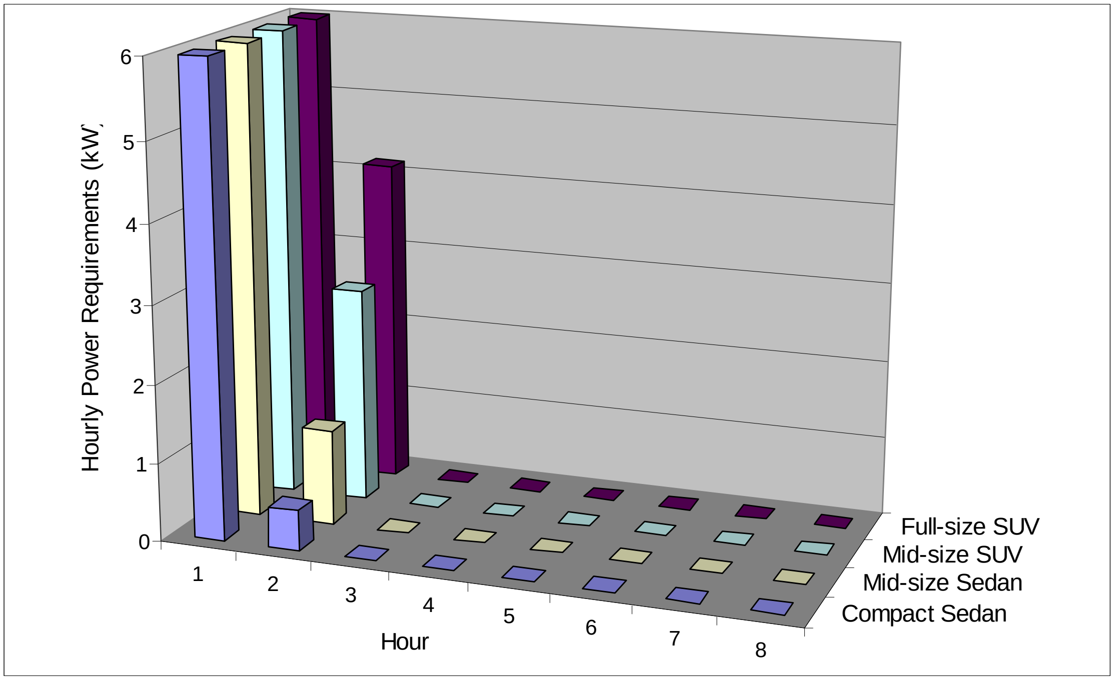

Figure 6: Power Requirements by Hour for PHEV20 at 240VAC/30A

In fact, Level 2 charging rates essentially negate any differences in charging time between vehicles of different sizes. Thus, increasing to Level 2 charging has a much more significant impact on convenience for owners of larger vehicles.

5.2.Plug-In Hybrid Electric Vehicle Adoption Models

It is necessary to make certain assumptions about the market penetration rate of PHEVs prior to considering any potential future impacts. There are a number of unknown variables that will affect the actual market penetration of PHEVs; however, according to the Duvall report, a reasonable approximation is to assume a national market potential of 25% of passenger vehicle sales by 2018 [31]. Passenger vehicles include cars, pickups, vans, sport utility vehicles, and other light trucks. The assumed PHEV market penetration characteristics that result in the desired national 2018 market potential are shown in Figure 7. The market penetration characteristics are typical of new technology deployment. Initial technology adoption is relatively slow. As the technology matures there is a period of rapid adoption which gradually slows as the new technology saturates the market. Technology improvements that occur during market penetration can increase the adoption period prior to market saturation. However, the development of alternative technologies can reduce the adoption period prior to market saturation. Governmental incentives and subsidies intended to encourage new technology adoption often play a role in encouraging an earlier transition to the period of rapid adoption.

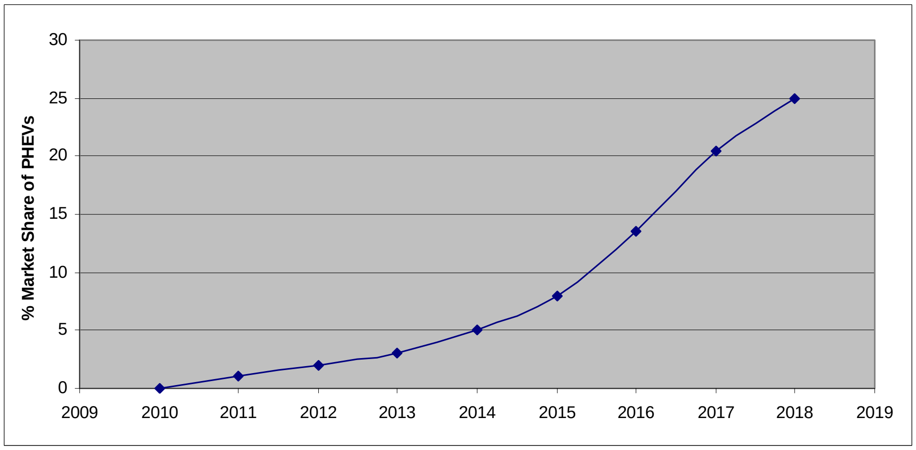

Figure 7: Aggressive Assumptions for Percent Market Share of PHEVs between 2010 and 2018

The actual annual number of vehicles sold can be calculated by multiplying the percent market share of PHEV and the total number of vehicles sold per year in the United States [29]. Because this analysis is primarily concerned with PHEV impacts specific to Dane County, the total number of PHEVs sold nationwide must be scaled to accurately represent the number of vehicles sold in Dane County. This is accomplished using the number of vehicles sold per year in the United States [32], vehicle registration data available per state [33], and population data available per county [34]. The number of PHEVs sold in Dane County through the year 2018 is shown in Figure 8. The cumulative number of vehicles comprising the Dane County PHEV fleet through the year 2018 is also shown.

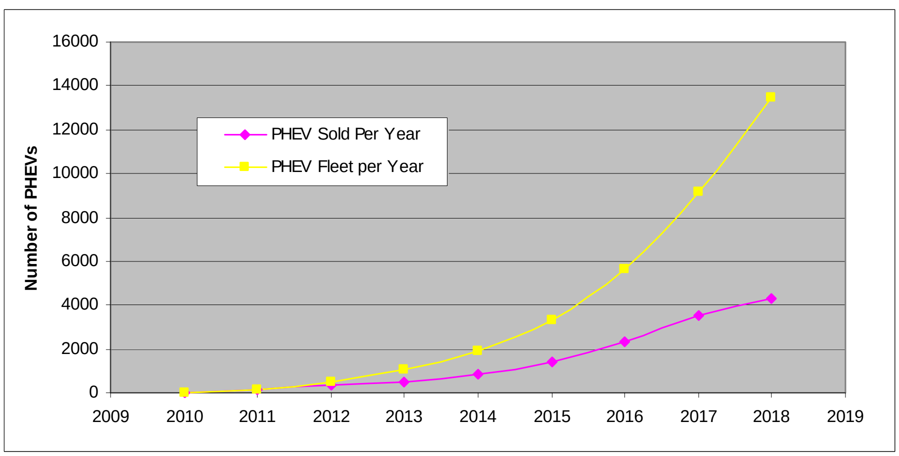

Figure 8: Total Number of PHEVs Sold per Year and Total Fleet Size Assuming Aggressive Penetration

The worst-case charging scenario would be for the entire PHEV fleet to begin charging at the same time. This maximum instantaneous demand can be calculated by multiplying the total number of fleet vehicles by the charging rate that corresponds to each charging level.

Figure 9 shows the maximum instantaneous vehicle load for Level 1 and Level 2 charging, based on the previous market penetration assumptions.

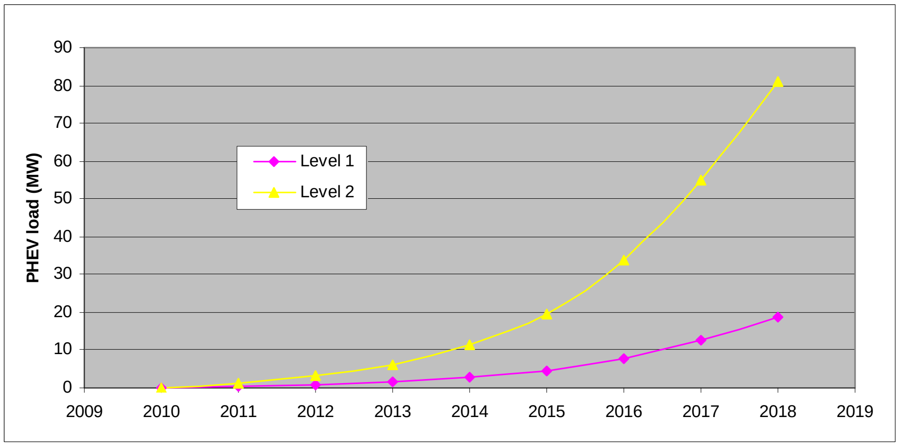

Figure 9: Maximum Instantaneous Demand for PHEV Fleet per Year with Uncontrolled Level 1 and Level 2 Charging, Assuming Aggressive Penetration

According to the forecasting method used, the PHEV fleet in Dane County, WI will exceed 6,500 vehicles by the year 2015. This corresponds to a national PHEV fleet of 3.8 million in 2015. In 2008, the Obama administration set a goal to put 1 million PHEVs on the road by 2015 [35]. Assuming the same technology adoption pattern as the Duvall report, Figure 10 illustrates this less aggressive penetration scenario for PHEVs through 2018.

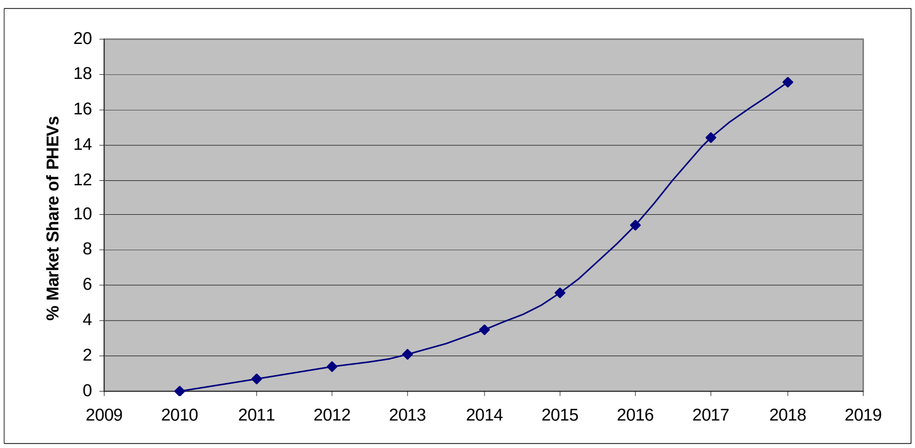

Figure 10: Non-Aggressive Market Penetration Assumption for PHEVs between 2010 and 2018

The two scenarios presented will be used in order to provide upper and lower bounds for the magnitude and time frame of effects stemming from PHEV penetration. The corresponding number of vehicles that can be expected in Dane County, WI is shown in Figure 11.

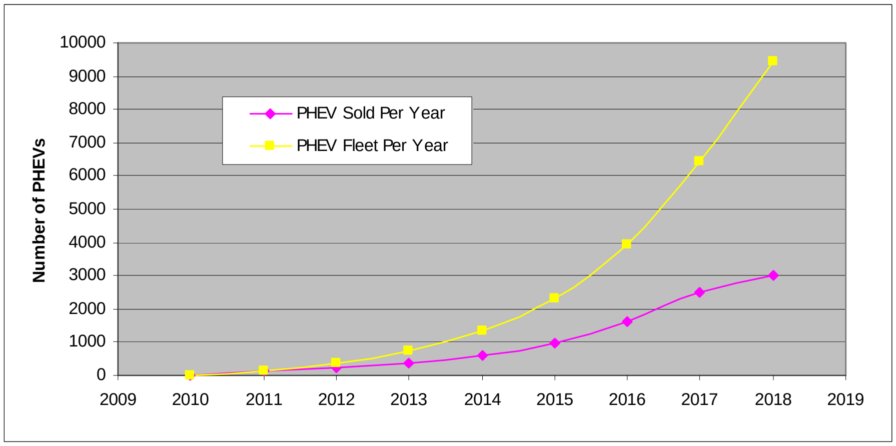

Figure 11: Total Number of PHEV Sold per Year and Total Fleet Size Assuming Non-Aggressive Penetration

Figure 12 illustrates the worst-case instantaneous demand that would result from concurrent charging of all vehicles under the non-aggressive market penetration scenario.

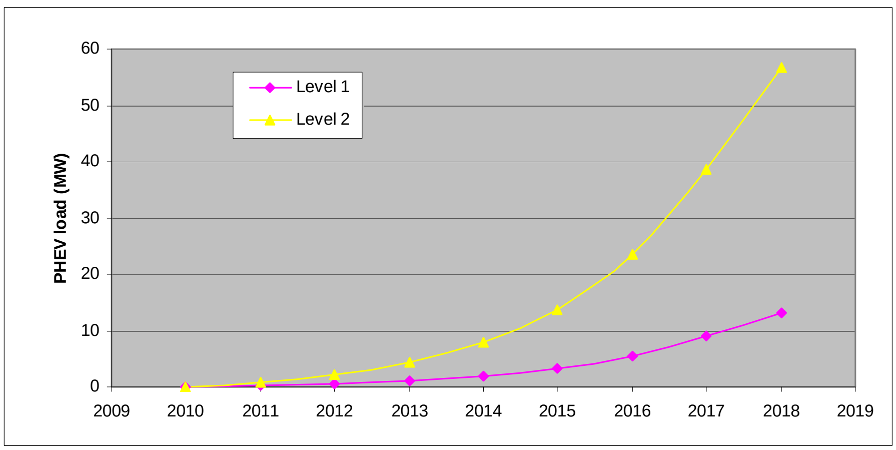

Figure 12: Maximum Instantaneous Demand for PHEV Fleet per Year with Uncontrolled Level 1 and Level 2 Charging, Assuming Non-Aggressive Penetration

Preliminary research indicates that there are three likely stages of PHEV penetration and participation as demand response resources. Initially, distribution infrastructure will likely need to be reinforced in order to meet the additional charging demand of the PHEVs. The extent of infrastructure reinforcement required will be highly dependent on the rate of vehicle adoption and the spatial distribution of the charging locations of the adopted vehicles. Higher penetration rates will certainly increase the amount of reinforcement necessary. However, even low penetration rates might require a significant amount of infrastructure reinforcement depending on the proximity of charging locations. It is likely that most initial PHEV adopters will not participate in demand response programs because these programs will still be in the very initial stages of implementation. Also, due to limitations in the number of charging locations available, most PHEV owners will only charge their vehicles at night.

As demand response becomes more widely accepted and utilized, the majority of PHEV owners will begin to participate in these programs due to the large potential for fuel savings.

Ideally, enabling technology will allow PHEV owners to take advantage of the benefits possible through demand response participation with little personal inconvenience. This is the second stage of PHEV penetration. These first PHEV demand response programs will likely allow vehicles to regulate their charging rates to maintain low locational marginal prices and enhance system flexibility and robustness.

Finally, the third stage of PHEV penetration and demand response participation will evolve from ‘smart grid’ initiatives and vehicle-to-grid technology. Also, increased penetration of charging locations outside the home will contribute to an increased number of vehicles connected to the grid throughout the day. At this point, PHEV will be able to charge during off-peak hours and then supply stored energy back into the grid during periods of high locational marginal prices or system reliability events. Potentially even more beneficial, the aggregate fleet of PHEV will be capable of providing regulation services throughout the day.

5.3. Existing Policy and Regional Characteristics in Dane County, Wisconsin

When considering the potential future impacts of PHEV penetration, clearly defining the geographical scope of interest is of utmost importance for a number of reasons. First of all, the existing robustness of the bulk electric system varies in different areas. For example, certain areas are more likely to be constrained by voltage limitations while other areas are constrained by the thermal limits of equipment. Also, generation profiles for an area can be significantly different from generation profiles for another area. Actual dispatched generation resources are often dependent on the economics of bringing certain generation resources online, in addition to ensuring compliance with any local environmental restrictions. In 2006, over half of the state of Wisconsin’s electricity was generated by coal-fired plants [36]. However, there is currently a push to increase the amount of wind resources available in the area. Additionally, many of the proposed upgrades to the existing transmission infrastructure are designed to import renewable or alternative generation resources into Wisconsin from surrounding states. The potential for increasing renewable generation is certainly regionally specific. For example, the Midwest has more accessible wind power than any other region of the United States. However, the Midwest is not likely to see a large amount of commercial solar generation. Solar generation is much more likely to be seen in the Southwestern United States.

Secondly, customer behavior varies greatly due to climate and geographical differences. For example, customers residing in warmer climates typically consume more electricity for air conditioning needs than customers in cooler climates. The amount of humidity in the air can also impact air conditioning use in certain areas. Customers in cooler climates often use more electricity during the winter months due to increased lighting and heating needs. The magnitude of impact due to increased heating depends on whether the heating infrastructure in an area is predominantly gas or electric. The temperature, snow, and road conditions in colder climates often result in reduced average vehicle efficiencies.

Finally, electric industry regulations and environmental policies vary between regions. For example, many areas in the United States are currently in the process of establishing regional electricity markets for generation dispatch. Other areas still allow utilities to operate in a more traditional, vertically-integrated fashion with strict regulations in place to prevent monopolistic behavior. Independent of the broader regulatory setting, rate structures and programs offered by local electric service providers are not consistent across different utilities. Residents in some areas may not be capable of participating in any demand response programs while residents in other areas may have an array of demand response options from which to choose. Many of the existing environmental policies are implemented at the state level. Certain states have set forth renewable portfolio standards while others have not. For example, the Wisconsin Public Service Commission has set a goal of meeting 10% of electric demand with renewable resources by 2015, but states including Tennessee, Florida, and Wyoming have no similar goals [37].

The geographical scope of this study includes Dane County, Wisconsin. The city of Madison and the surrounding communities electrically dominate the Dane County area. Alliant Energy, Madison Gas & Electric (MGE), and Wisconsin Public Power Incorporated (WPPI) are the three distribution utilities that serve residents in the Dane County area. The city of Madison is the most likely area for significant PHEV load to impact distribution equipment due to its large population density, and its centralized commercial sector. For this reason, all initial distribution impact analyses are based on information collected on the policies, electric system, and customer base of MGE.

MGE currently offers a direct load control program and a time-of-use metering program to residential customers. Participants in the direct load control program agree to allow MG&E to remotely shut off their air conditioners when emergency power is needed. This service is only utilized during the select few times a year when peak demand is nearing excess of available generation resources. Participants are compensated $8 per hour of interruption and can expect to be interrupted six cumulative hours over a ten-year period [38]. The expected return for a single month's participation in the direct load control program is $0.40. Individuals who participate in the time-of-use metering program pay a premium for electricity service during peak hours, but receive a significant rate reduction on electricity service during off-peak hours. Peak hours are defined between 10am and 9pm on weekdays. Off-peak hours include weekends and weekdays between 9pm and 10am [38]. Time-of-use metering program is intended to reduce peak demand on a daily basis, as opposed to select hours throughout the year. Unlike energy efficiency programs, direct load control and time-of-use metering programs are not designed to reduce overall electricity consumption.

American Transmission Company (ATC) owns and operates the transmission network that serves the Dane County area. The region is primarily served by a double circuit 345-kV line from the Columbia Power Plant to the northern edge of Dane County and by a double circuit 138-kV line from the Christiana Power Plant to the southwest corner of Dane County. Several 69-kV lines tie into this area as well. Table 2 summarizes the existing Dane County area interface tie lines [39].

The Dane County area includes the Blount Power Plant and the West Campus Cogeneration Facility; however, these generators may be offline if more economical generation is available outside the region. Smaller generations within the Dane County area include the Fitchburg Power Plant, the Sycamore Power Plant, and the Nine Springs Power Plant. Although the Christiana Power Plant is geographically located within Dane County, loss of the double circuit 138-kV line isolates this generation from the Dane County area load. Table 3 summarizes Dane County generation [39].

Table 2: Dane County Area Interface Tie Lines

From Bus	To Bus	Voltage	Line Name
Stoughton	Sheepskin	69-kV	Y-12
Kegonsa	Christiana	138-kV	G-CHR21
Kegonsa	Christiana	138-kV	X-59
Verona	Belleville	69-kV	Y-42
Mount Horeb	Forward	69-kV	Y-135
Arena	Spring Green	69-kV	Y-62
Dane	Lodi	69-kV	Y-8
Deforest	Arlington	69-kV	Y-28
North Madison	Columbia	345-kV	L-COL21
North Madison	Columbia	345-kV	W-7

Table 3: Dane County Area Generation Resources

Station	Generator	Capacity	Fuel
Blount Power Plant	G3, G4, G5, G6, and G7	189.2 MW	Coal
West Campus Cogeneration Facility	CT1, CT2, ST	160.0 MW	Gas
Fitchburg Power Plant	G1 and G2	43.0 MW	Gas
Sycamore Power Plant	G1 and G2	36.5 MW	Gas
Nine Springs Power Plant	G1	12.3 MW	Gas

The Dane County area is susceptible to voltage instability when load is high compared to generation and a critical transmission system outage occurs. The critical transmission system outages include the loss of either double circuit line into the Dane County area [39]. These N-2 contingencies are typically not included in real-time contingency analyses programs used by ATC. These critical outages only become a concern during planned outages of one or more element in the area or during inclement weather such as tornado warnings or blizzard alerts. Following loss of either double circuit line, generation in the Dane County area can be used to alleviate transmission constrains. This will potentially allow additional load in the area to be supported following a critical transmission system outage. The generators most likely to be utilized in the event of a critical transmission system outage include the Blount Power Plant and the West Campus Cogeneration Facility [39]. Potential reactive power contributions vary between generators in the Dane County area.

In addition to the concerns faced by the Dane County area transmission network for the loss of a critical transmission system outage, there are a number of low voltage and transmission facility overloads that have been identified in the ATC 10-yr Transmission Assessment.

These problems have been attributed to rapid growth in the area, increased import capability from Illinois, and changes to generation dispatch scenarios. The transmission system in the Dane County area is shown in Figure 13 along with the identified areas with low voltage concerns and areas with transmission facility overloads [40]. The areas with low voltage concerns are highlighted in yellow and the areas with transmission facility overloads are highlighted in green.

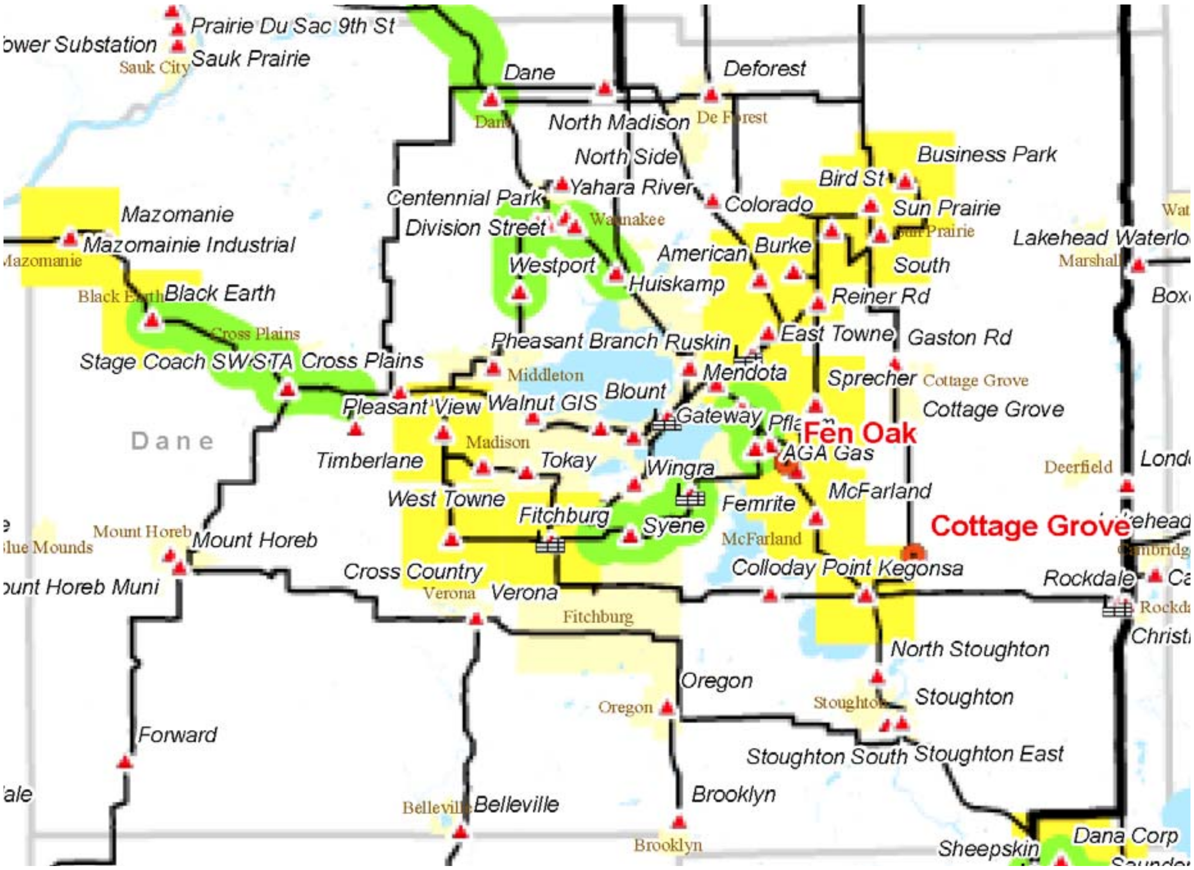

Figure 13: Dane County Area Transmission System Map with Potential Low Voltages Denoted in Yellow and with Potential Transmission Facility Overloads Denoted in Green

The Public Service Commission of Wisconsin has recently approved plans for ACT to construct two projects that will have an impact on serving load in Dane County. The first of these projects is a 345-kV line between Illinois and Southeastern Dane County that is intended to aid in importing power into the state [41]. The project is scheduled for completion in spring of 2010. The additional import capability will possibly reduce the amount of power generated by coal-fired and gas-fired plants in Southern Wisconsin, including those in Dane County. The second project is an additional 345-kV line that feeds the Western side of Dane County. This line will be placed in-service in 2013 and is expected to alleviate the potential for voltage collapse in the Dane County area following a critical transmission system outage. It will also play a role in reducing thermal overloads in the area [40].

The next chapter describes the initial impacts early penetration of PHEVs is likely to have on existing electric infrastructure, assuming that vehicle charging will remain largely uncontrolled during the early stages of market penetration. First, the potential to experience overloading on distribution infrastructure in explored. Due to the networked nature of the transmission system, it is likely that significant negative impacts will be delayed. However, the later section of the following chapter describes the potential impacts to transmission over an extended time frame, assuming the charging remains uncontrolled.

6. Initial Infrastructure Impacts of Plug-In Hybrid Electric Vehicles

6.1. Distribution Infrastructure Impacts

Initial penetration of PHEVs may present a new set of challenges to the reliability of the bulk electric system. The previous chapter outlined charging characteristics for different types of PHEVs. It also proposed two market penetration models that predict how many vehicles will be purchased over the next years. Additional factors that will aid in determining the magnitude of challenges posed by initial PHEV penetration include hourly load-use characteristics, spatial distribution of charging locations, and existing distribution equipment capacity.

Hourly Load-Use Characteristics in Dane County

Assuming that initial PHEV penetration precedes wide-spread installations of public charging stations, the majority of initial PHEV adopters will likely charge their vehicles at home. This necessitates knowledge of existing residential load-use patterns in order to determine whether PHEV charging will contribute to peak energy usage or off-peak energy usage. Due to certain common behaviors shared by the majority of residential customers, residential load-use patterns are very predictable. Prominent features of typical residential load curves include a small morning peak as individuals wake up in the morning and a much larger evening peak as individuals arrive home from work in the late afternoon or evening. However, regional climate differences can significantly change the magnitude of the two peaks experienced during a typical day. An accurate assessment of distribution infrastructure impacts must take the regional differences in load-use patterns into account. Load-use patterns for Dane County, WI were obtained from a database of regional load profiles created by Itron Incorporated. Data from over 20,000 individual sites across the United States was compiled in order to develop the database [42]. The state of Wisconsin falls within the Central Industrial region. Other states included in the Central Industrial region are Illinois, Indiana, Michigan, and Ohio. Data is available for a variety of housing characteristics. The load-use patterns presented here assume gas heating and central air. Figure 14 shows typical winter and summer load curves for residential electricity demand in the Central Industrial region for 2005 [42]. The typical winter curve is calculated by averaging the hourly load data for all weekdays between December and February, excluding the three most extreme days. The typical summer curve is calculated by averaging the hourly load data for all weekdays between June and September, excluding the three most extreme days.

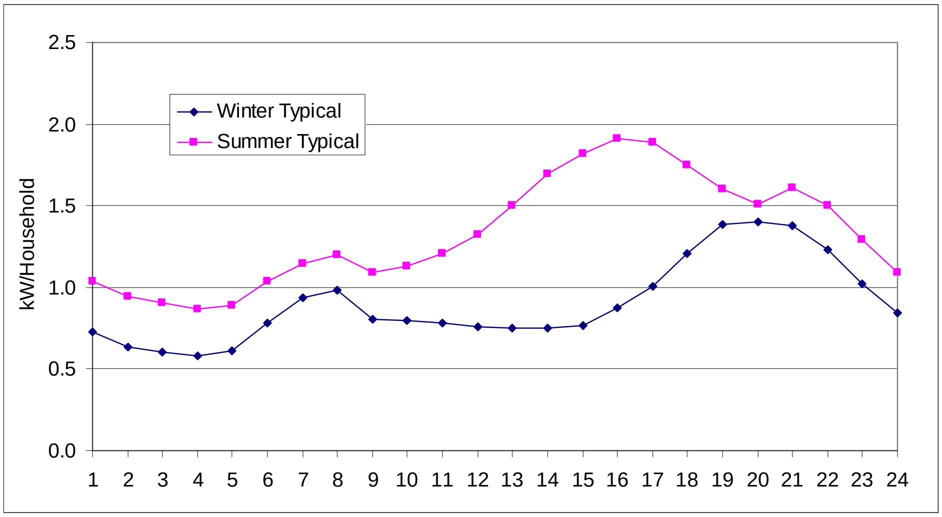

Figure 14: Typical Household Electricity Usage as a Function of Time for a Single Household in the Central Industrial Region in 2005, Sampled on an Hourly Basis

Although assessing the impact that PHEVs may have on distribution infrastructure on typical winter and summer days facilitates identification of potential trouble areas, owners of the distribution infrastructure are often more interested in peak loading scenarios. Distribution infrastructure must be built to withstand peak potential loading in order to prevent damage to equipment during extreme events. Figure 15 shows peak winter and summer load curves for residential electricity demand in the Central Industrial region for 2005 [42]. The peak winter curve is calculated by averaging the three most extreme weekdays between December and February. The peak summer curve is calculated by averaging the three most extreme weekdays between June and September.

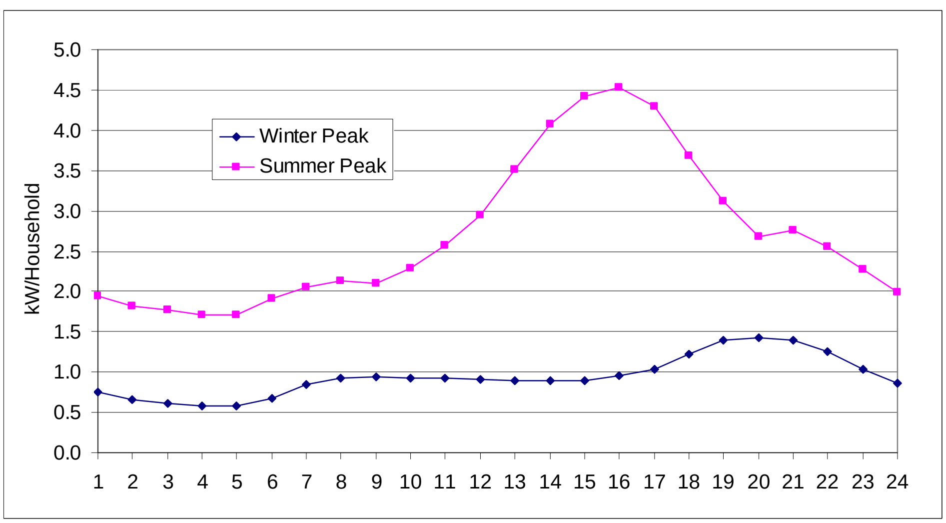

Figure 15: Peak Household Electricity Usage as a Function of Time for a Single Household in the Central Industrial Region in 2005, Sampled on an Hourly Basis

These load curves will be used as a baseline to evaluate changes in stress experienced by distribution infrastructure. Before assessing potential infrastructure impacts, certain assumptions need to be made about the number of PHEVs that will be electrically connected to pieces of equipment at any given time.

Assumed Spatial Distribution of PHEVs in Dane County

According to a study performed by Duke Energy, the most significant impacts of PHEV market penetration will likely be due to geographic clustering of the vehicles [43]. This means that certain localized areas may have much higher penetration of PHEVs than other areas. For example, areas with convenient charging locations and higher socio-economic statuses may have higher levels of PHEV market penetration. Most likely, the vast majority of early PHEV adopters will be single-family homeowners with attached garages [43]. PHEV owners will need to have access to a safe, secure charging location at home because it will take a great deal of time before charging locations are prevalently available in public places.

Due to the existing purchase premium associated with buying a PHEV over a conventional internal combustion engine vehicle, the rate of market penetration will likely be slow. Early adopters are likely to share certain characteristics including high incomes and/or high property values, access to a convenient and secure charging locations, and concerns with the United States' use of fossil fuels. It is very likely that individuals sharing these characteristics will live in close proximity to each other [43]. This means that even with relatively low rates of market penetration, equipment in certain areas might reach maximum rating very quickly if large numbers of vehicles are charged at the same time, coinciding with the pre-existing peak demand. Unfortunately, the most likely scenario in the early stages of PHEV penetration is individuals arriving home from work and immediately plugging in their vehicle for the sake of convenience.

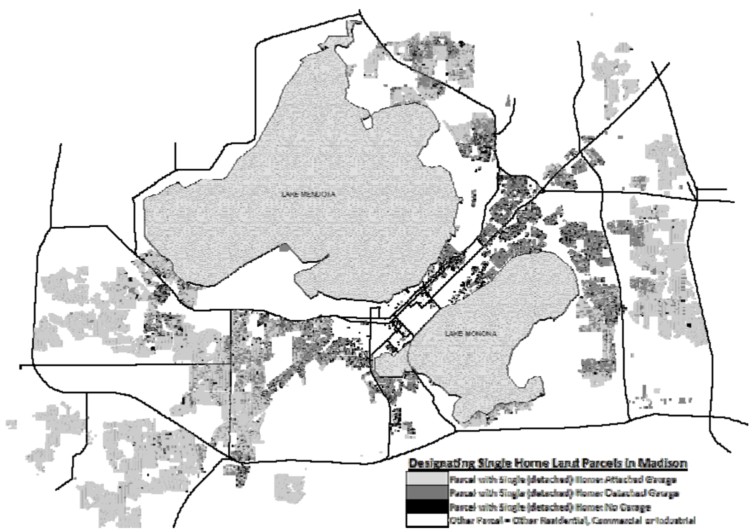

Figure 16: Single Home Land Parcels in the City of Madison with Garage Type Specified by Shading

During the initial period of PHEV penetration, it is likely that convenient access to a secure charging location will be a primary characteristic of PHEV owners. Using data obtained from the City of Madison, it is possible to identify land parcels that would likely provide PHEV owners with secure charging locations [44]. The characteristics of land parcels that are likely to have secure charging locations include residential, single-family, and attached garages. The parcels within the City of Madison that fit these characteristics are shown the lightest gray in Figure 16 [44].

A second common characteristic that is likely to be shared by initial PHEV adopters is high property values [43]. Figure 17 shows the spatial distribution of housing unit values for census tracts within the City of Madison [34].

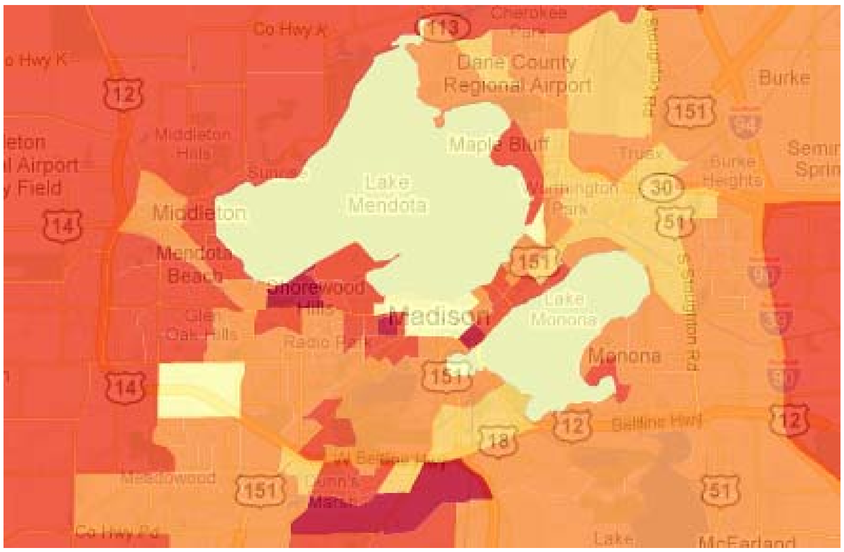

Figure 17: Median Value of Housing Units in the City of Madison with Darker Shading Indicating a Higher Value and Lighter Shading Indicating a Lower Value

As an example, Figure 18 overlays data concerning the median value of housing units over a map that shows single-family homes with attached garages [44, 34]. Households located in areas in which high housing unit values overlap with the desired housing characteristic are the most likely to purchase a PHEV in the near future.

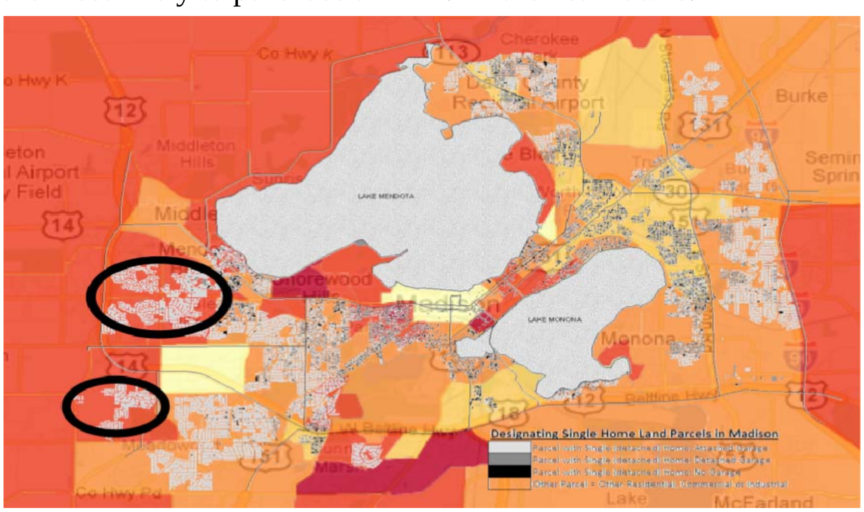

Figure 18: Overlay of Single Home Land Parcels and Median Housing Unit Values

According to Figure 18, the greatest area of concern in the Madison area is on the far Western side of the city. There are a handful of potential problem areas more centrally located; however, these areas are not as densely filled with single family homes with attached garages.

Transformer Overload Analysis

From Figure 18, census tract 550250002052 was selected as a potential area that can expect to see large number of PHEVs during the initial penetration stage. It is located in an area that typically has high property values and the majority of parcels in the area are single family homes with attached garages. There are approximately 1,200 housing units in census tract 550250002052, corresponding to a population of 2,818. According to the penetration study performed by Duke Energy, energy customers that live in areas with higher property values are up to 3.5 times more likely to purchase PHEVs than energy customers that live in areas with average property values.

Figure 19 shows the upper and lower bounds of expected PHEV penetration in census tract 550250002052 assuming that residents are 3.5 time more likely to purchase PHEVs than the typical consumer. The shaded region between the two penetration scenarios presented in Figure 19 represents an infinite range of potential future PHEV penetration scenarios.

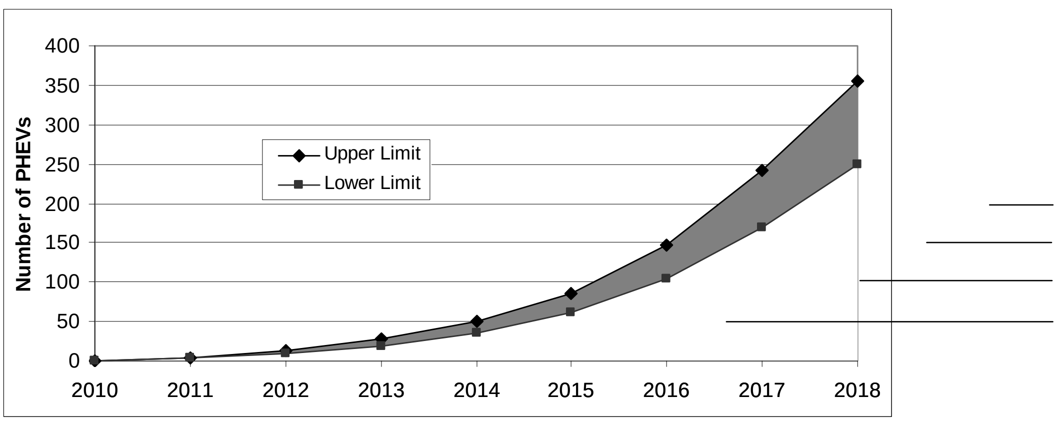

Figure 19: Upper and Lower Limits on Expected PHEV Penetration in Census Tract 550250002052

The most immediate infrastructure impacts are likely to be observed at the distribution transformer level. As the electrical territory served by distribution equipment increases, there is a corresponding increase in the potential to rapidly accumulate customer outage hours following equipment failure. Thus, additional capacity is typically incorporated into the distribution equipment upstream of the transformers. In order to demonstrate the potential impact of PHEVs at the transformer distribution level, a single 50 kVA transformer located in census tract 550250002052 was selected for analysis. The selected transformer was assumed to serve eight households. Actual transformer ratings and numbers of customers served per transformer can differ significantly. The process outlined here can be utilized by any utility that is interested in a more comprehensive analysis of equipment by modifying the assumed transformer rating and number of customers served. Figure 20 illustrates an upper and lower bound for the number of PHEVs that can be expected on the selected transformer through the year 2018. These numbers were determined by scaling the aggressive and non-aggressive penetration scenarios for census tract 550250002052 by the number of individuals residing in eight households.

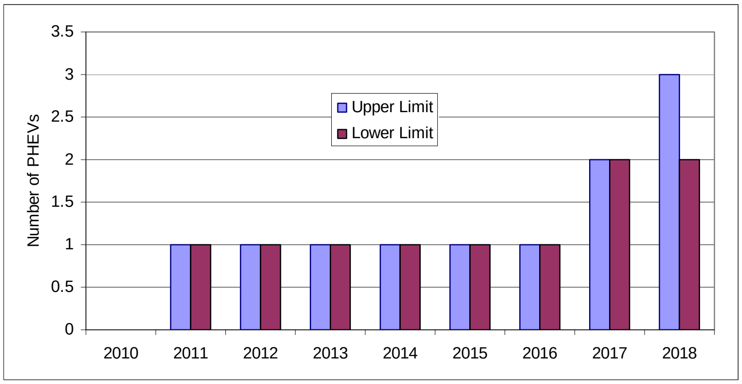

Figure 20: PHEV Penetration for a 50 kVA Distribution Transformer Serving Eight Customers

Assuming that convenience will be the predominate factor in determining consumer charging behavior, the majority of initial PHEV adopters will likely elect to immediately charge their vehicle as they arrive home from work in the evening. Therefore, this assessment of initial penetration impacts assumes that all PHEV owners begin charging their vehicles at 5:00pm. Changes in charging behavior patterns that may result from various demand response program options will be discussed in more detail in the following chapter. The first step in assessing the initial impacts of PHEVs on distribution transformers was to scale the individual load curves presented earlier in this chapter to represent the total transformer load without PHEVs. The non-PHEV transformer load was assumed to remain constant over the range of years studied; however, this likely underestimates the total transformer load for future years.

Secondly, the hourly power requirements for a single PHEV were multiplied by the total number of vehicles expected to be simultaneously charging from the selected 50 kVA transformer through the year 2018. A comprehensive set of scenarios were considered, including all combinations of the following characteristics:

- Summer and winter seasonal load curves
- Peak transformer loading and typical transformer loading curves
- Predominant installations of Level 1 and Level 2 charging infrastructure
- Aggressive and non-aggressive vehicle penetration models

Finally, the cumulative PHEV power requirements for each year were added to the total transformer load under each combination of the characteristics above, beginning at 5:00pm. An assumed residential power factor of 0.8 was used to calculate the apparent power seen by the selected 50 kVA transformer.

Figures 21 and 22 illustrate the impact that additional PHEV load will have on the selected transformer during peak loading periods assuming aggressive vehicle penetration and Level 1 charging infrastructure. After the cumulative addition of three PHEVs in year 2018, the summer peak transformer loading has increased from 90.7% to 96.5%. The winter peak transformer loading has increased from 28.5% to 39.0%. Under these conditions, the transformer does not become overloaded. However, reducing the transformer rating to 25 kVA causes the summer peak transformer loading to reach 193.0% and the winter peak transformer loading to reach

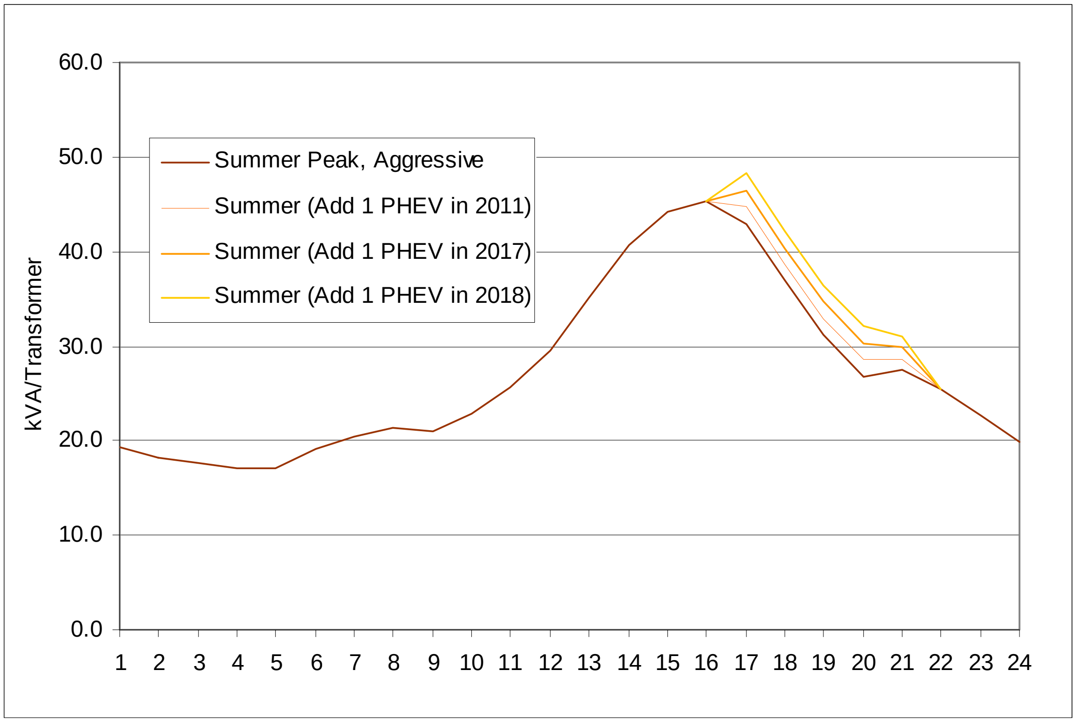

Figure 21: Impact of Aggressive PHEV Penetration on Peak Summer Transformer Loads Assuming Predominance of Level 1 Charging Infrastructure with Charging Beginning at 5:00pm

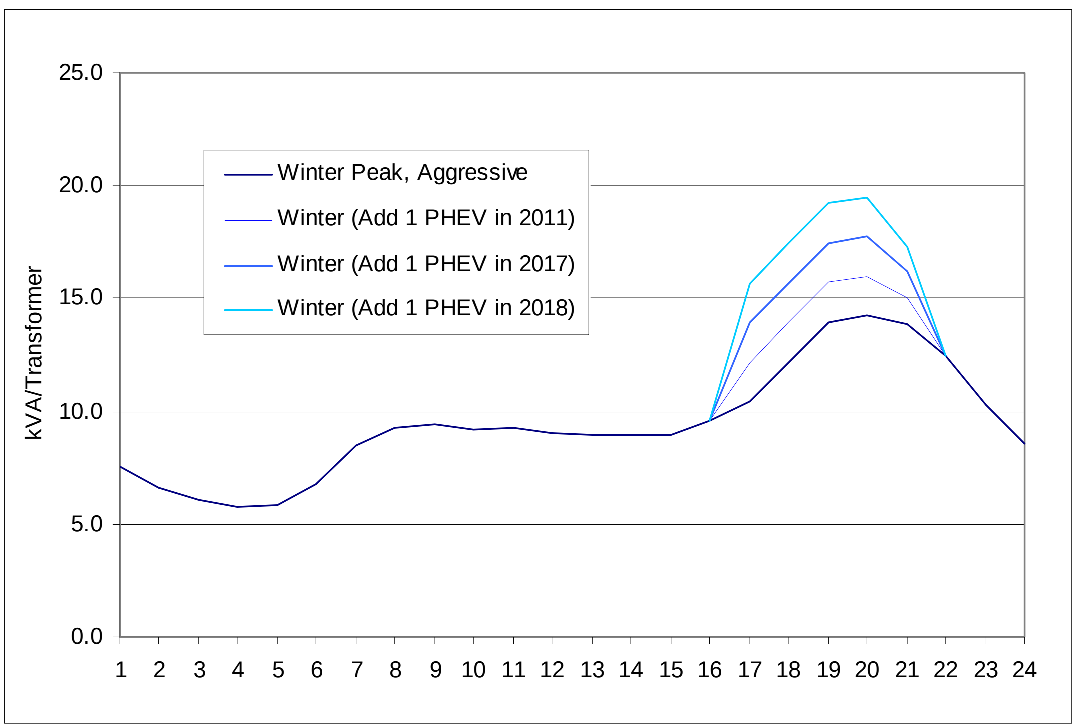

Figure 22: Impact of Aggressive PHEV Penetration on Peak Winter Transformer Loads Assuming Predominance of Level 1 Charging Infrastructure with Charging Beginning at 5:00pm

78.0% by the year 2018. Under a typical transformer loading scenario, a 25 kVA transformer would cause the typical summer transformer loading to reach 96.6% by the year 2018, and the typical winter transformer loading to approach 77.1%. With no change in the number of vehicles added to the selected 50 kVA transformer, an additional two households would cause the summer peak transformer loading to increase from 96.5% to 118.0% by the year 2018. However, these additional households have a smaller impact on winter peak transformer loading, only causing the winter peak transformer loading to increase from 39.0% to 46.1%. Under the non-aggressive PHEV penetration scenario, a single PHEV will be added to the transformer load in 2011 and a second PHEV will be added to the transformer load in 2017. The additional transformer load added in the non-aggressive scenario is equivalent to year 2017 of the aggressive scenario.

The negative impacts on transformers will obviously be increased if Level 2 charging infrastructure becomes the preferred method of vehicle charging. Figures 23 and 24 illustrates the impact that additional PHEV will have on the selected transformer during peak loading periods assuming aggressive vehicle penetration and Level 2 charging infrastructure. In Figure 23, the selected 50 kVA transformer has clearly surpassed its rated value. In fact, after the cumulative addition of three PHEVs in year 2018, the summer peak transformer loading has increased from 90.7% to 131.0%. The summer peak transformer loading is already exceeding 100% after the addition of a single PHEV in the year 2011. Although the winter peak transformer rating does not exceed 100% through the year 2018, it does increase from 28.5% to

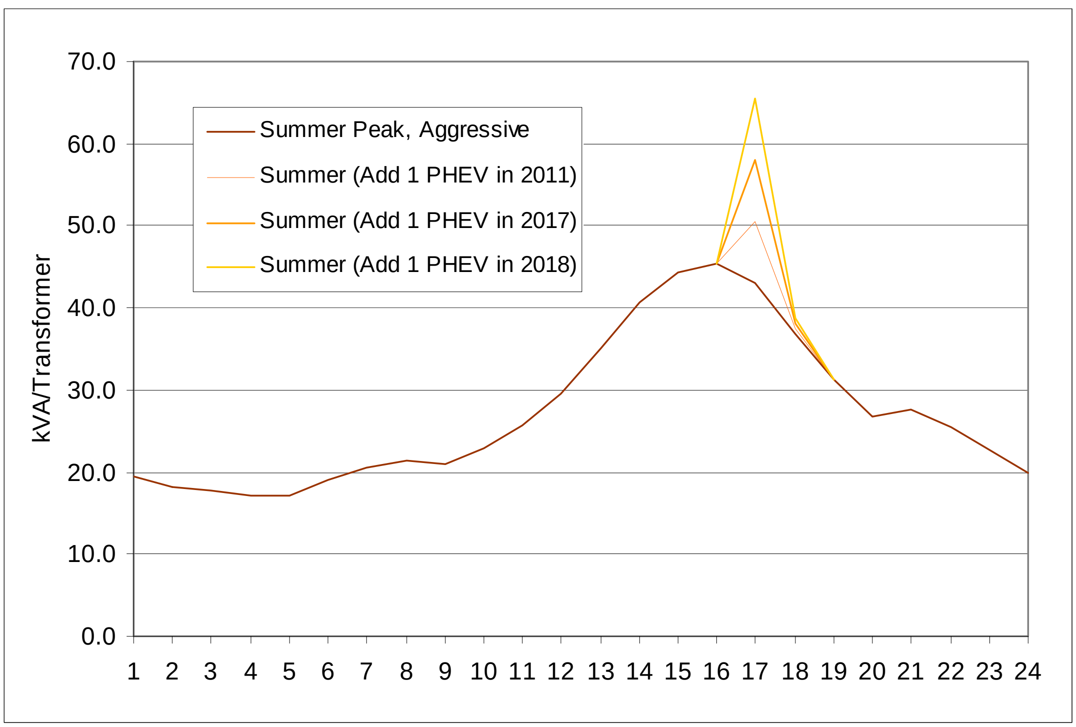

Figure 23: Impact of Aggressive PHEV Penetration on Peak Summer Transformer Loads Assuming Predominance of Level 2 Charging Infrastructure with Charging Beginning at 5:00pm

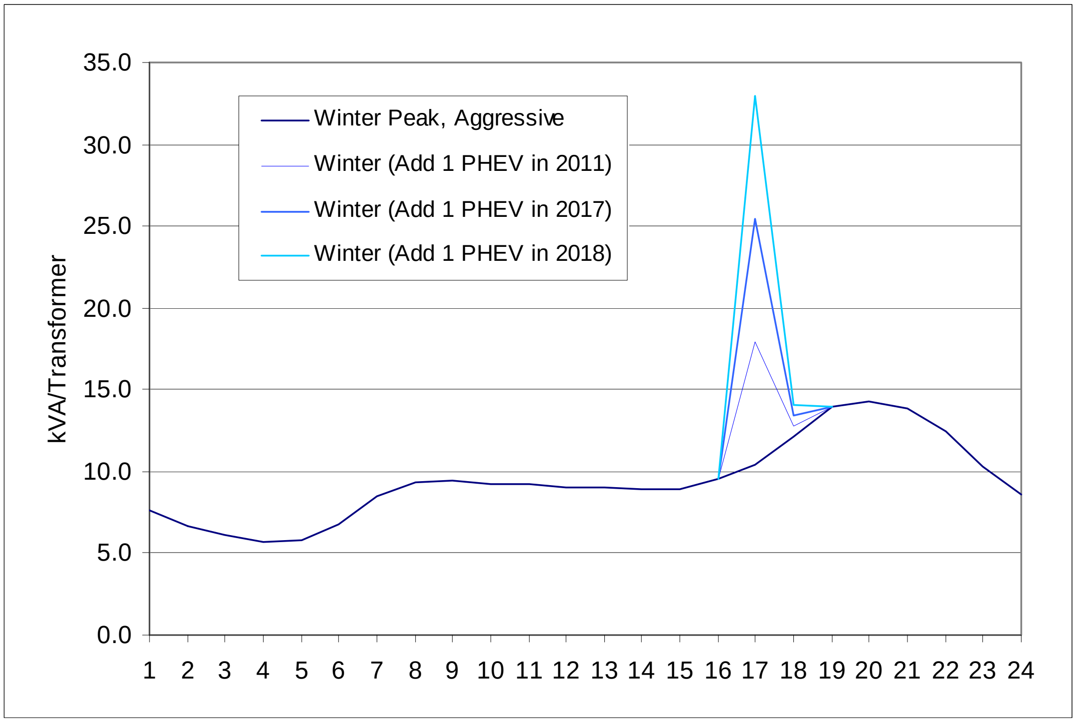

Figure 24: Impact of Aggressive PHEV Penetration on Peak Winter Transformer Loads Assuming Predominance of Level 2 Charging Infrastructure with Charging Beginning at 5:00pm

65.8%. Under the scenario in which Level 2 charging is preferred, the transformer load factor diminishes rapidly as PHEVs are added. Prior to the addition of any PHEV load, the summer typical transformer load factor is 0.70 and the winter typical transformer load factor is 0.64. The values of load factor are 0.35 and 0.31, respectively, following the cumulative addition of three PHEVs in year 2018. In both cases, the values have approximately been cut in half.

With Level 2 charging, the cumulative addition of three PHEVs in the year 2018 results in a typical summer transformer loading of 82.8%, illustrated in Figure 25. For the same amount of PHEV penetration, the typical summer transformer loading was only 48.3% with Level 1 charging infrastructure. Under the same Level 2 charging conditions, the typical winter transformer loading is 65.1%.

The typical summer transformer loading on a 25 kVA transformer exceeds 100% of rated load after the addition of a single PHEV in the year 2011. Typical winter transformer loading exceeds 100% of rated load after the cumulative addition of two PHEVs in 2017. With no change in the number of vehicles to the 50 kVA transformer, the addition of two more households causes the summer peak transformer loading to reach 122.5% after the addition of a single PHEV in 2011. However, the addition of these households only increases winter peak transformer loading to 71.0% through the year 2018.

Figure 26 shows the changes in summer peak loading on the selected 50 kVA transformer assuming non-aggressive vehicle penetration and Level 2 charging infrastructure. As apparent in the figure, the cumulative addition of 2 PHEVs in the year 2017 results in a summer peak transformer loading of 116.0%.

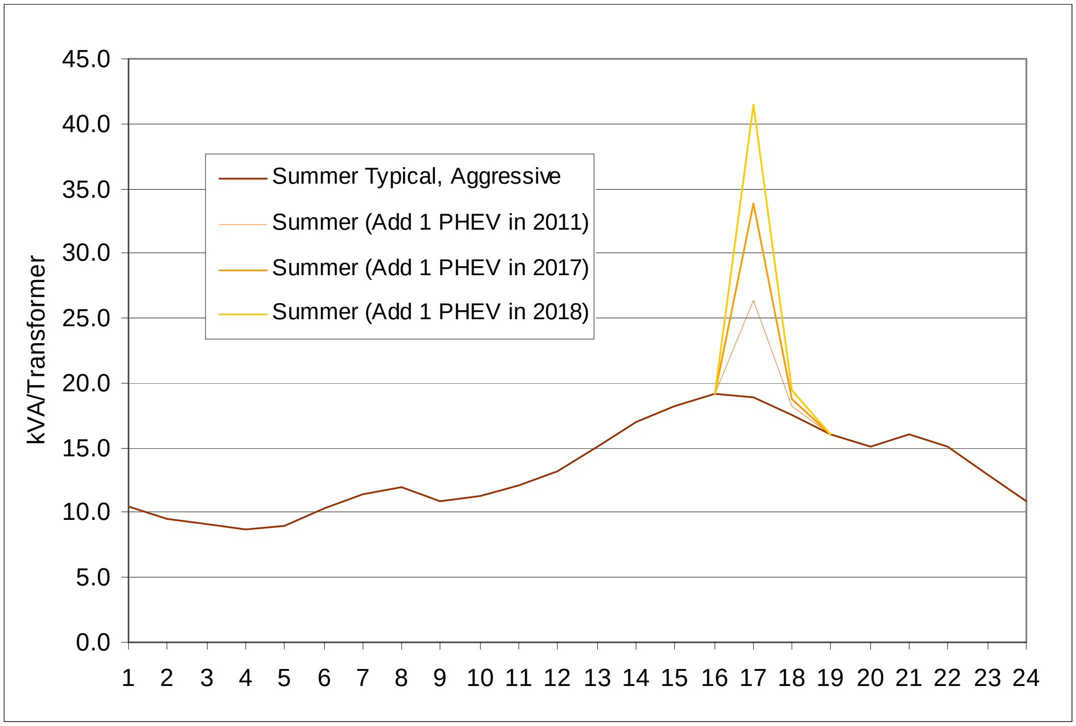

Figure 25: Impact of Aggressive PHEV Penetration on Typical Summer Transformer Loads Assuming Predominance of Level 2 Charging Infrastructure with Charging Beginning at 5:00pm

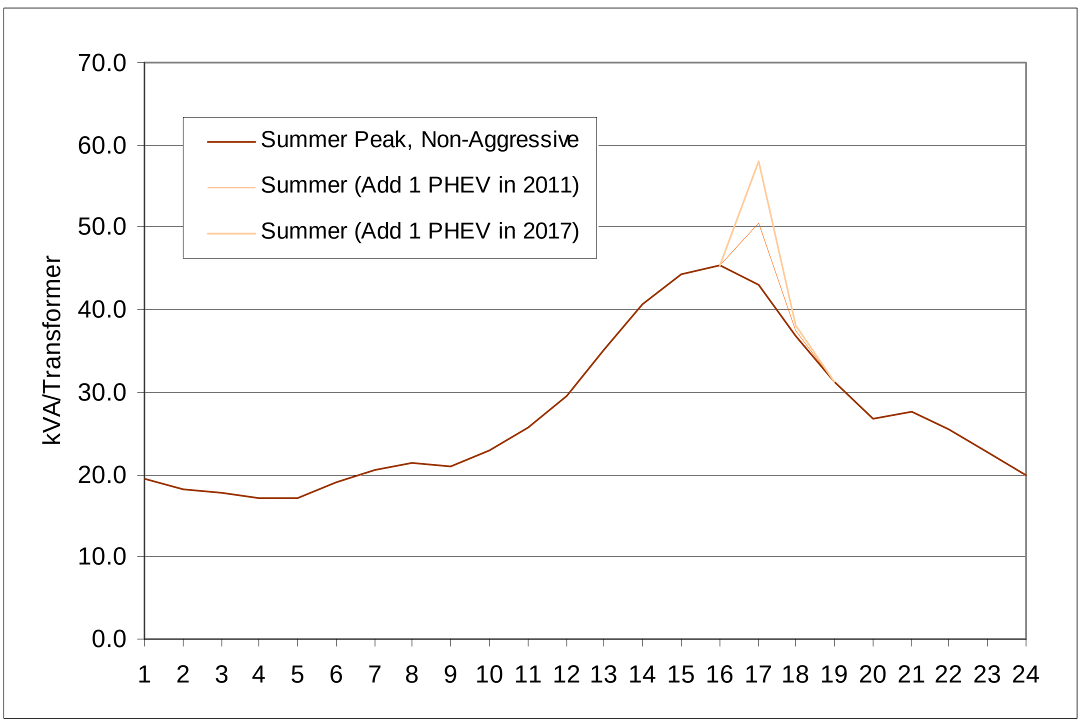

Figure 26: Impact of Non-Aggressive PHEV Penetration on Peak Summer Transformer Loads Assuming Predominance of Level 2 Charging Infrastructure with Charging Beginning at 5:00pm

6.2. Transmission Infrastructure Impacts

To a certain extent, the initial distribution impacts stemming from PHEV penetration are unavoidable due to the existing technology and policy environment. The automotive industry is outpacing the electric industry in development and implementation of PHEV technologies and policy. The majority of these distribution impacts will be able to be handled on a local level without significantly impacting reliability of the bulk electric system. Failure of any given distribution transformer will be limited to a handful of houses. Utilities are fairly adept at responding quickly to the failure of these small transformers. However, if the electric industry is unable to devise policy mechanisms to control PHEV charging characteristics, extensive capital investments will be required in order to prevent the transmission system from becoming overly constrained.

Extended Plug-In Hybrid Electric Vehicle Adoption Model

Although some PHEV-related transmission constraints will surface prior to the year 2018, it is likely that existing equipment and near-future projects will be sufficient to adequately control most system constraints. In the Dane County area, this is likely to involve additional operation of generators including the Blount Power Plant and the West Campus Cogeneration Facility, potentially out of preferred economic order. Beyond 2018, significant problems requiring major infrastructure upgrades will begin to emerge unless the electric industry successfully implements policy to encourage and facilitate PHEV participation in demand response programs. In order to model the transmission constraints that occur in the years beyond 2018, the PHEV market share under aggressive penetration assumptions was assumed to increase by 1% annually through 2026. Each PHEV was assumed to have a ten-year lifespan. In an aggressive penetration scenario, this results in a PHEV market share of 33% by 2026. Under non-aggressive PHEV penetration assumptions, this results in a PHEV market share of 8.7% by 2026.

Figure 27 shows the extended PHEV penetration assumptions through the year 2026.

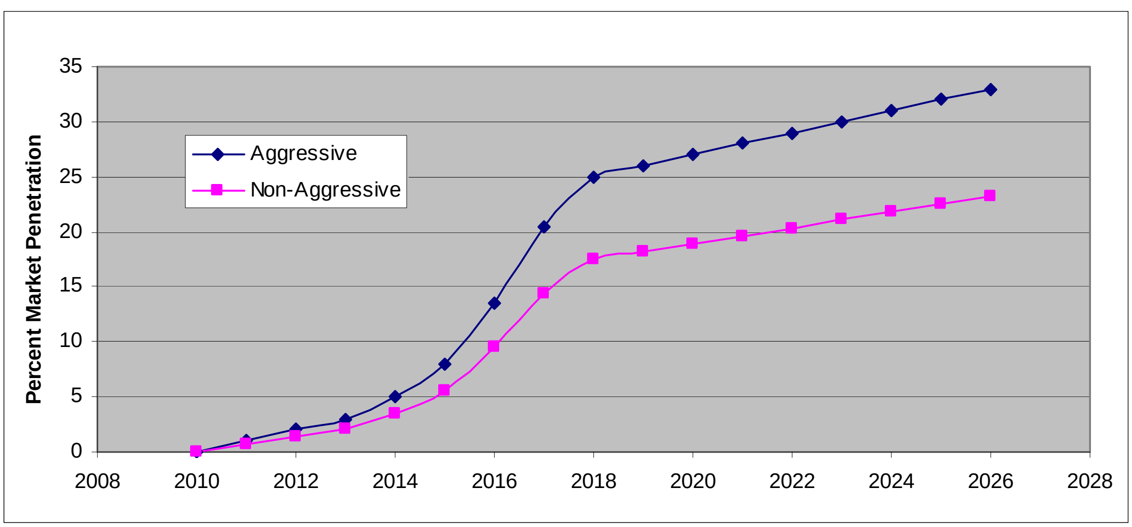

Figure 27: Percent PHEV Market Penetration Expanded beyond 2018, through 2026

Figure 28 illustrates the total number of PHEVs that are expected in Dane County per year through the year 2026 under both aggressive and non-aggressive scenarios.

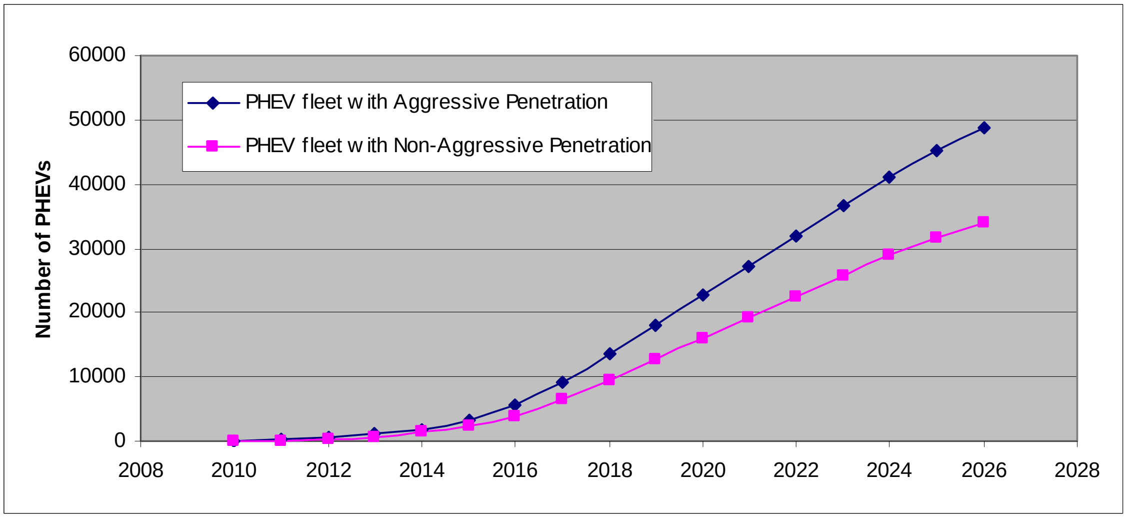

Figure 28: Dane County Plug-In Hybrid Electric Vehicle Fleet in Extended Penetration Scenarios

Definition of Basecase Scenario and Modeling Assumptions

A single snapshot derived from the ATC Energy Management System was selected to determine potential PHEV-related transmission impacts. Criteria used to select the powerflow snapshot included an initial Dane County load exceeding 800 MW, absence of online Dane County generation, and system intact conditions in Dane County and the surrounding region. The total Dane County area load was modeled by summing the load at all MGE buses, in addition to all Alliant Energy buses that lie within the region defined by the Dane County interface tie lines, presented in the previous chapter. The initial Dane County load in the selected powerflow snapshot was 806.7 MW. Dane County area generation totals are modeled by summing the generation at all MGE buses. Alliant East has no generation within the region defined by the Dane County interface tie lines.

The voltage stability analysis uses a set of pre-defined transfer scenarios to stress the study model in small increments. Dane County area load and ATC generation (excluding Dane County generation) are both incremented in order to stress Dane County imports. A power flow is then performed at each step to solve the stressed case. Capacitor banks are not switched during this study. Changing the status of capacitor banks within Dane County could potentially allow additional load to be supported in the area. It would also shift the location of the lowest voltage buses. However, the impact of the capacitor banks will be much less than incrementing Dane County generation.

After the power flow has solved for each transfer level, a contingency analysis is performed for a pre-determined set of contingencies. If a contingency is found to cause voltage collapse or thermal overloading over 110%, the simulation is stopped and the results are reported. This process is repeated until a violation is found or the model reaches the set limits of load and generation scaling. The contingency set studied includes all on-line Dane County generators, all Dane County transmission lines greater than or equal to 69-kV, and all double circuit lines that feed the Dane County area. Major generators and transmission lines in the near vicinity of Dane County are also included in the contingency analysis.

Tables 4 and 5 summarize the voltage and thermal limits of the selected powerflow snapshot, respectively. Due to the susceptibility of the Dane County area to voltage instability following the loss of critical double circuit outages, separate studies were performed to monitor single circuit outages and double circuit outages.

Table 4: Transmissions Peak Basecase Voltage Limits

	Contingency	Pre-Ctg Limit	Load Margin
N-1	ROE-WPTN 345-kV	1471.7 MW	665 MW
N-2	COL-NMA 345-kV dbl ckt	1016.7 MW	210 MW

Table 5: Transmission Peak Basecase Thermal Limits and Violations

	Contingency	Pre-Ctg Limit	Load Margin	Affected Lines	Percent Overload
N-1	BLT-SYC 138-kV	1191.7 MW	385 MW	GWY-SYC 69-kV	110.2%
N-2	COL-NMA 345-kV dbl ckt	806.7 MW	0 MW	PTE-COL 69-kV	134.1%

The pre-contingent load limit represents the total load that can be supported in the Dane County area without collapsing the voltage or causing thermal overloading of greater than 110% following loss of the specified contingency. The load margin is defined as the additional amount of load that can be supported above and beyond the initial value of Dane County area load. As the load margin decreases, it becomes increasingly important to consider expansion of transmission infrastructure. An alternative to transmission infrastructure expansion is additional operation of Dane County area generation resources. However, this contributes to congestion and prevents appropriate operation of the Midwest ISO's security-constrained economic dispatch model. The affected lines listed in Table 5 are lines that experience thermal overloads following the loss of the specified contingency. Finally, the percent overload represents the overloading that the affected line will experience following loss of the specified contingency.

Figures 29 and 30 summarize the per unit behavior of voltages at the worst-case bus for the N-1 and N-2 basecase analyses, respectively. As shown in Figure 29, post-contingent thermal loading begins to exceed 110% of rated values at a Dane County import level of 1191.7 MW. In the N-1 basecase analysis, Dane County voltage does not approach the point of collapse until Dane County load reaches 1471.7 MW.

For the N-2 basecase analysis presented in Figure 30, post-contingent thermal overloads exist at the initial level of Dane County load. From the figure, it is clear that loss of either double circuit line feeding the Dane County area will cause a significant reduction on the total amount of load that can be supported. With post-contingent voltage collapse occurring at 1016.7 MW, there is very little margin for additional PHEV load. Moreover, the worst-case Dane County bus voltages drops below 0.9 pu before Dane County imports reach 900 MW. This indicates that system upgrades will be necessary in order to protect Dane County equipment damage in the event of an N-2 contingency.

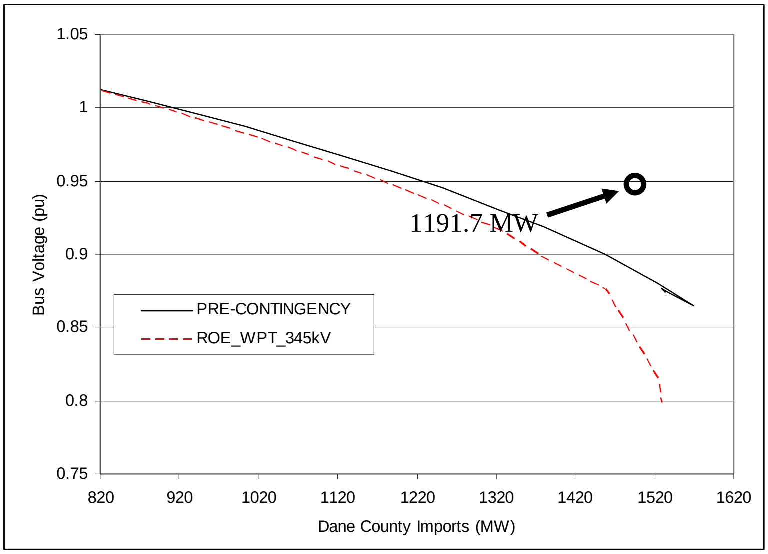

Figure 29: Transmission Peak Base case Power-Voltage Characteristics for Loss of the Single Worst-Case N-1 Contingency

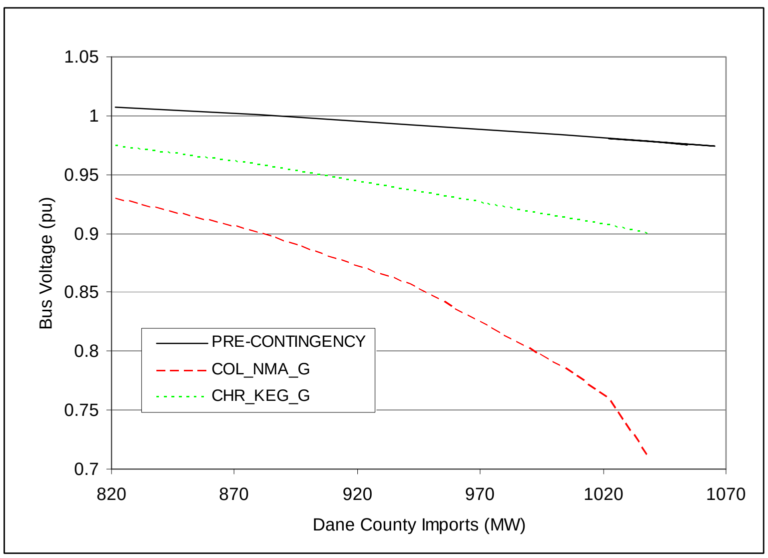

Figure 30: Transmission Peak Basecase Power-Voltage Characteristics for Loss of the Two Worst-Case N-2 Contingencies

Voltage and Thermal Violation Analysis

In order to further determine the impact of PHEV penetration on the Dane County area transmission system, additional voltage stability analyses were performed for each of the eight scenarios considered. In lieu of knowledge pertaining to the end-use customer base served by each transmission bus, the percentage of residential load at each bus was used to determine the most probable locations to expect future PHEV load. The percentage of residential load at each pertinent bus is presented in Appendix A. Peak summer load forecasts for the years 2018 and 2026 were obtained from ATC.

These load forecasts were used in conjunction with the residential load percentages to assign actual values of PHEV load to transmission buses under the constraints of each penetration scenario. Table 6 presents the maximum instantaneous PHEV load values that are expected to result from uncontrolled PHEV charging in each of the studied scenarios. Hereafter, each PHEV penetration scenarios will be referred to by the ID number listed in Table 6.

Table 6: Load Added to the Dane County Transmission System in Each of the Studied Scenarios

ID Number	Scenario Summary	PHEV Load
1	2018, Level 1 charging, Non-Aggressive penetration	13.24 MW
2	2018, Level 1 charging, Aggressive penetration	50.32 MW
3	2018, Level 2 charging, Non-Aggressive penetration	56.75 MW
4	2018, Level 2 charging, Aggressive penetration	215.66 MW
5	2026, Level 1 charging, Non-Aggressive penetration	47.79 MW
6	2026, Level 1 charging, Aggressive penetration	68.10 MW
7	2026, Level 2 charging, Non-Aggressive penetration	204.82 MW
8	2026, Level 2 charging, Aggressive penetration	291.86 MW

Figure 31 illustrates the N-1 and N-2 load margins calculated by the voltage stability program for each of the eight PHEV penetration scenarios. It also includes the load margins calculated in the N-1 and N-2 basecase analyses. From the previously presented basecase analyses, the N-1 load margin was identified as 665 MW and the N-2 load margin was identified as 210 MW.

From the figure, it is clear that the aggressive penetration and Level 2 charging characteristics of scenario 8 cannot be sustained through the year 2026 under N-2 conditions. Under these conditions, the voltage stability analysis program identified pre-contingent violations and was therefore unable to perform the contingency analysis. A considerable reduction in load margin is apparent in year 2026 assuming N-1 conditions and charging characteristics of scenario 8. In scenario 7, less aggressive penetration still cause dramatic reductions in load margins by the year 2026 under both N-1 and N-2 conditions. Even through year 2018, significant reduction in load margin can be observed in both N-1 and N-2 analyses under scenario 8.

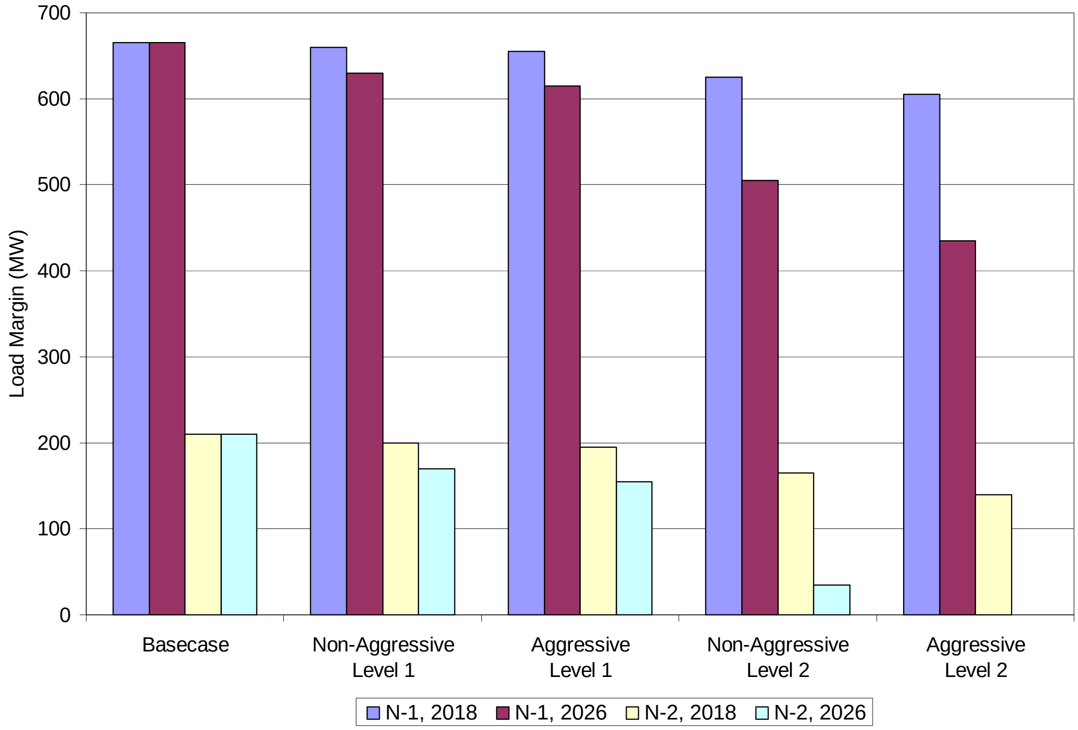

Figure 31: Calculated Transmission Load Margin Following Addition of Peak PHEV Load

In the Dane County area, voltage violations are typically preceded by certain thermal violations. In fact, the voltage stability assessment identifies thermal overloads in excess of 110% occurring in the N-2 basecase, prior to any additional PHEV load. Emergency line ratings may enable the limited equipment to sustain high currents for short periods of time. Nonetheless, increasing levels of PHEV load adds a number of thermal constraints that must be closely monitored in the Dane County area, particularly under N-2 conditions. The susceptibility of the Dane County area to critical transmission outages precludes tolerance of thermal overloading. If any one of the interface tie lines that feeds Dane County were to unexpectedly fail, other interface tie lines with prior thermal overloads are likely to rapidly follow suit. The resulting damage to equipment will ultimately leave the Dane County area without sufficient import capacity to support the load until the damaged equipment can be replaced.

In the N-2 basecase analysis, the initial areas of thermal loading concern were limited to the 69-kV network just outside Dane County via the double circuit 345-kV lines between the North Madison and Columbia Substations. However, the addition of PHEV load under any of the proposed N-2 scenarios adds another point of concern on the Western Dane County interface tie line between the Spring Green and Arena Substations. In addition to exacerbating the thermal concerns in Western Dane County, a third area of thermal concern surfaces in the Northwestern corner of Dane County between the Lodi and Dane Substations under N-2 PHEV penetration scenarios 4 and 7. The combination of N-2 conditions and scenario 8 charging characteristics leads to a situations in which voltage collapse precedes any thermal violations. In the N-1 analysis, thermal violations were located in the vicinity of the Sycamore and Fitchburg Power Plants. It is likely that these areas of concern would be electrically and geographically shifted depending on the online generation facilities within the Dane County area.

7. Benefits of Increased Demand Response Participation

7.1.Infrastructure Benefits from PHEV Demand Response Participation

From the previous Chapter, it is clear that there will need to be significant transmission infrastructure upgrades if an alternative method is not devised to otherwise control the charging of PHEVs. Figure 32 was obtained from a similar PHEV penetration study performed on the 1999 California ISO system [46]. The figure illustrates the changes to total California ISO system load due to evening charging of 1, 5, and 10 million PHEVs.

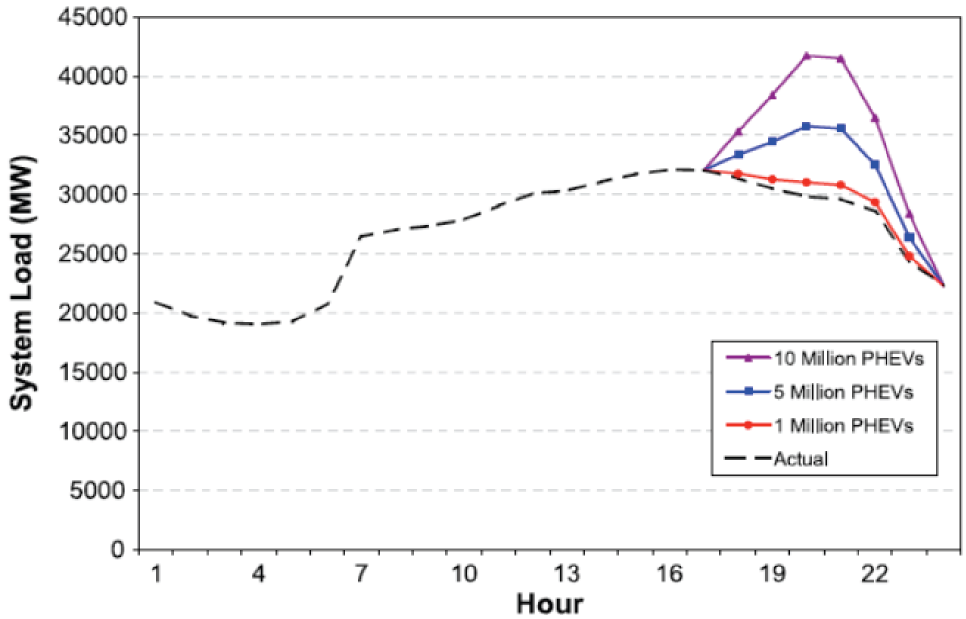

Figure 32: California ISO System Load as a Function of Time with the Impacts of Uncontrolled PHEV Charging Superimposed

A preferable scenario would be for PHEV owners to charge their vehicles during periods of low demand. This is sometimes referred to as 'load-leveling.' Transmission and distribution systems must be designed and built to withstand demand during peak loading periods. However, this results in a capacity surplus under normal operating conditions. Any addition to peak load will likely require additional infrastructure; but large numbers of PHEVs can likely be added during off-peak periods without leading to a need for increased infrastructure. According to typical load curve patterns, the optimal time period during which to charge PHEVs is between the late evening and early morning, corresponding to the lowest system load. Figure 33 shows the impact of this controlled charging on total California ISO system load with the addition of 1, 5, and 10 PHEVs [46]. Controlled charging optimizes the use of existing equipment, thus increasing the overall load factor.

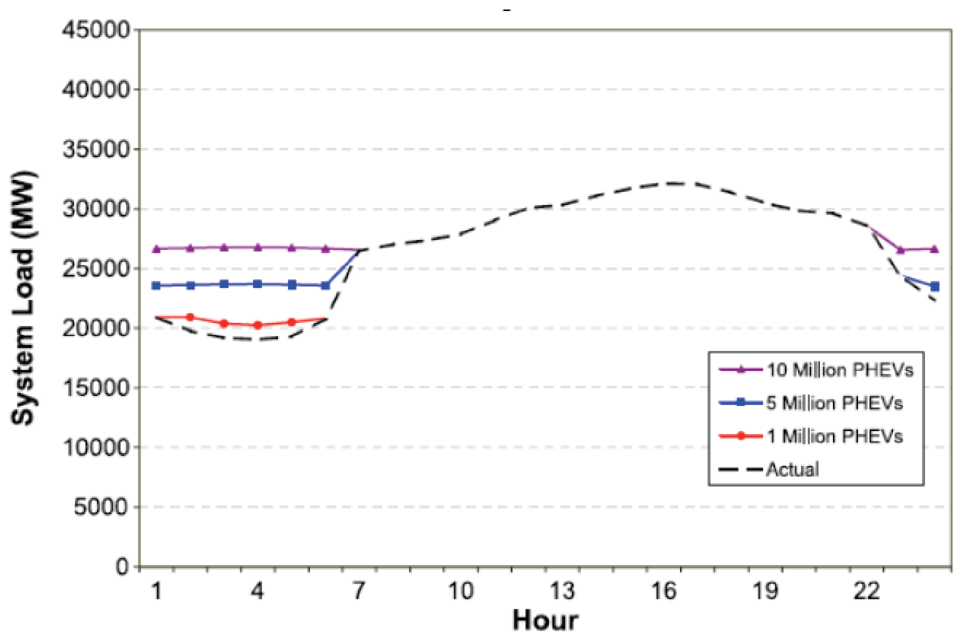

Figure 33: California ISO System Load as a Function of Time with the Impacts of Controlled PHEV Charging Superimposed

An important question to answer before PHEVs enter the automotive market is how the electric industry is going to ensure that the second charging scenario occurs. Enabling technologies such as basic timers will be very important. A timer would allow PHEV owners to plug in their vehicle immediately when arriving home from work, but would then postpone charging until a certain time. Without this technology it is likely that most customers would select convenience over cost and charge immediately when arriving home from work anyways. If not, they might risk forgetting to charge the vehicle at all.

Beyond the enabling technology, certain rate structures could be used to provide an incentive for PHEV owners that take advantage of the enabling technology. Effective means for providing that incentive include time-sensitive pricing schemes such as time-of-use, critical peak pricing, and real-time pricing. Time-of-use pricing divides the day into different blocks of time and charges different unit prices for energy use during different blocks. This pricing strategy typically involves an on-peak and an off-peak price for energy [16]. Many commercial and industrial customers already participate in existing time-of-use pricing programs. Creating a time-of-use rate structure for residential PHEV owners would easily allow them to use timers to optimize energy use. The ability to participate in time-of-use rate structures might additionally encourage residential energy consumers to more carefully consider when they are using energy.

Critical peak pricing involves charging a pre-specified high rate for a pre-specified number of hours throughout the year. The hours are selected based on periods of high wholesale market prices or system events that impact reliability [16]. This pricing scheme is also widely used for commercial and industrial customers. However, opening this type of rate to residential customers would likely prove to be difficult. The regular pricing pattern that is known well in advance associated with time-of-use pricing would be much more convenient for residential customers. It would be very easy for a residential customer to forget that a critical peak period had been declared and then be upset by the corresponding increase in that month's electricity bill. Real-time pricing schemes allow the price of electricity to fluctuate on a day-ahead or hour-ahead basis in order to reflect the wholesale price of electricity [16]. Similar to critical peak pricing, this pricing scheme places much of the burden on the individual residential customers.

Among these three time-sensitive pricing options, time-of-use pricing appears to place the smallest burden on the residential customer. As such, it is likely to receive the least amount of criticism from participants. Ideally, PHEV owners would be automatically enrolled in time-of-use programs due to the high potential that they have to contribute to equipment peaks. Other customers could choose to continue with their regular pricing scheme or switch over to the time-of-use pricing scheme. Many customers could likely save money on their monthly bill by switching over to the time-of-use pricing scheme and keeping a careful watch on when they use electricity. In the telecommunications industry, most companies provide free minutes to customers at night in order to reduce the number of calls made during peak hours. A time-of-use pricing scheme for electricity would be similar.

It is also possible that some early PHEV adopters will elect to participate in demand response programs. Based on the existing infrastructure, the most likely programs that will be available to PHEV owners will be direct load controlled programs. Many residential customers are currently participating in direct load control programs with air conditioners and water heaters. It would be a relatively simple matter to add PHEVs, however, more advanced forms of demand response participation by PHEV would likely take more time to introduce.

Distribution Infrastructure Benefits

Using the same assumptions for transformer loading and PHEV penetration presented in Chapter 5, a second distribution infrastructure impacts analysis was performed assuming controlled charging of PHEVs. Following the process outlined in Chapter 5, a single representative household load curve was scaled by the eight households expected to be fed by a single 50 kVA transformer. Representative data was obtained for peak summer transformer loading, peak winter transformer loading, typical summer transformer loading, and typical winter transformer loading. This non-PHEV transformer load was assumed to remain constant over the studied timeframe. Next, the total power requirement for a single PHEV was multiplied by the number of vehicles expected to be simultaneously charging from a 50 kVA transformer through year 2018, under both aggressive and non-aggressive PHEV penetration scenarios. Lastly, the cumulative PHEV power requirements for each year through 2018 were added to each of the representative transformer load curves. In order to simulate controlled charging characteristics, no PHEV charging was allowed to occur prior to 11:00pm. Between 11:00pm and 7:00am, the charging rate was fluctuated in an attempt to maintain a consistent level of transformer load, subject to the constraints of Level 1 and Level 2 charging infrastructure.

Figure 34 illustrates the impact that additional PHEV load will have on peak loading of a single 50 kVA transformer during off-peak loading periods, assuming aggressive vehicle penetration and Level 1 infrastructure. Even after the cumulative addition of three PHEVs in the year 2018, no additional peak load has been added to the transformer. Summer and winter peak transformer loading remain constant at 91% and 28% respectively. However, the peak summer load factor of the transformer has improved from 0.60 in year 2010 to 0.62 in year 2018. This improvement is accentuated for the peak winter load factor, increasing from 0.66 in year 2010 to 0.71 in year 2018. The changes in transformer loading that result from replacing Level 1 infrastructure with Level 2 infrastructure are essentially negligible. The differences between Figures 34 and 35 are indicative of replacing Level 1 infrastructure with Level 2 infrastructure, assuming controlled PHEV charging. This is strikingly different from the significant impacts observed due to charging infrastructure in the uncontrolled PHEV charging analysis.

Although the peak transformer demand is significantly reduced in typical transformer load curves, the cumulative addition of three PHEVs in year 2018 does not cause any increase in peak load.

Figure 36 illustrates the impact that additional PHEV load will have on typical loading of a single 50 kVA transformer during off-peak loading periods, assuming aggressive vehicle penetration and Level 1 infrastructure. Summer and winter typical transformer loading remain constant at 38% and 28%, respectively. With the cumulative addition of three PHEVs in year 2026, the typical summer load factor improves from an initial value of 0.70 to 0.75 and the typical winter load factor improves from an initial value of 0.64 to 0.71.

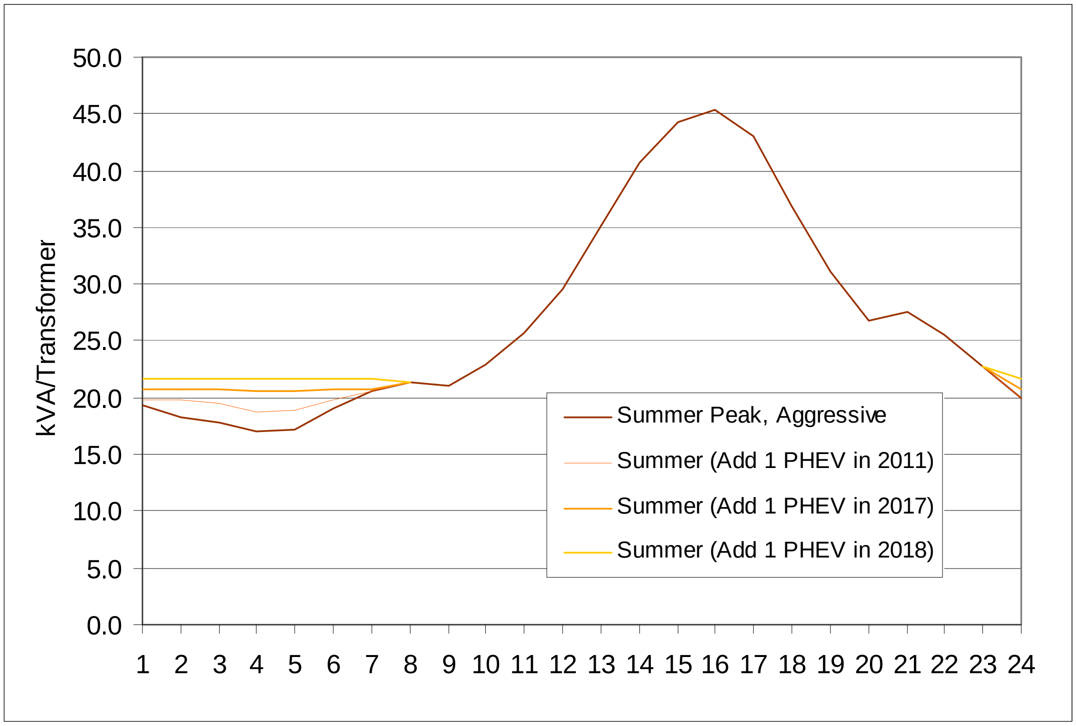

Figure 34: Impact of Aggressive PHEV Penetration on Peak Summer Transformer Loads Assuming Level 1 Charging Infrastructure with Controlled Charging between 11pm and 7am

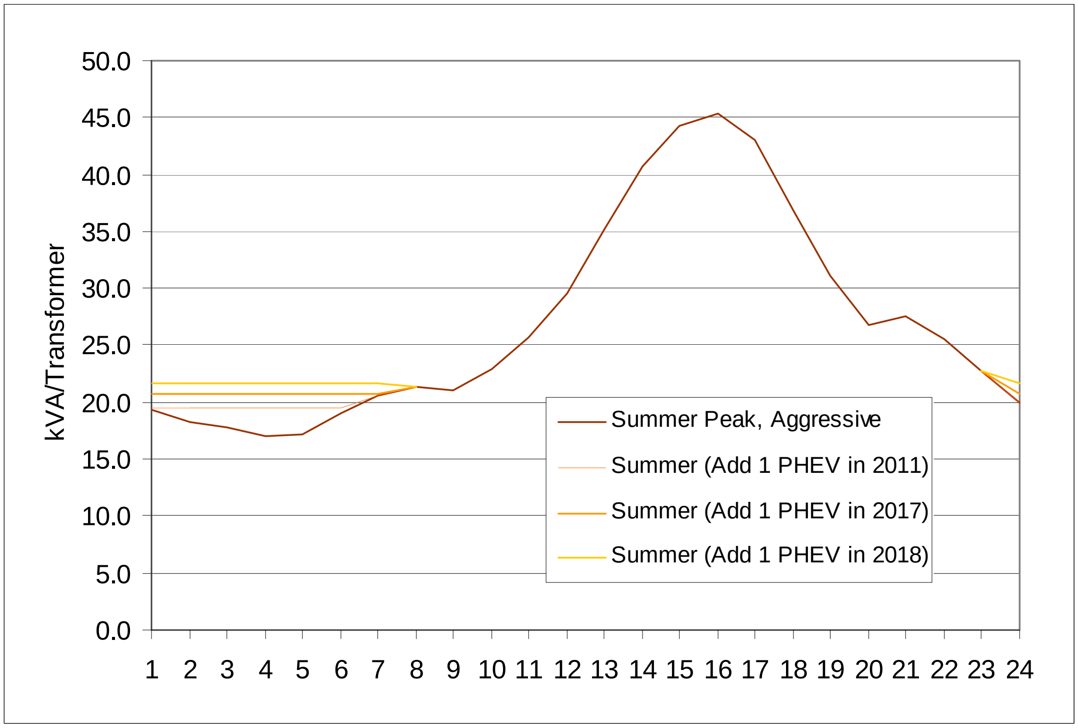

Figure 35: Impact of Aggressive PHEV Penetration on Peak Summer Transformer Loads Assuming Level 2 Charging Infrastructure with Controlled Charging Between 11pm and 7am

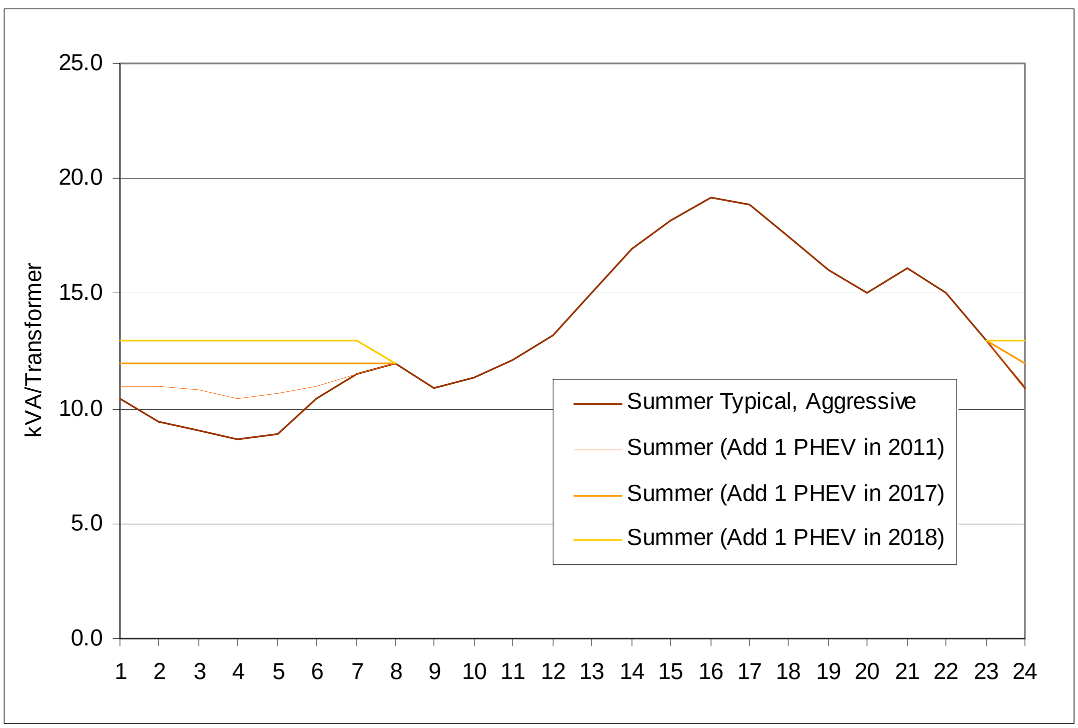

Figure 36: Impact of Aggressive PHEV Penetration on Typical Summer Transformer Loads Assuming Level 1 Charging Infrastructure with Controlled Charging Between 11pm and 7am

The improvements in load factor observed in the controlled charging analysis indicate increased utilization of existing distribution equipment. However, increasing transformer loading during off-peak hours will significantly diminish the amount of cooling time that inherently exists for electric equipment due to typical energy consumer behavior. An increasing average operating temperature has the potential to ultimately reduce the longevity of equipment. However, much higher levels of PHEV penetration will be needed before equipment failure due to insufficient cooling period becomes an area of significant concern. Equipment failure due to increased peak loading of transformers is an area of much more immediate concern.

Transmission Infrastructure Benefits

A second transmission infrastructure impacts analysis was performed assuming all PHEV charging occurs during off-peak hours through the year 2026. The off-peak ATC Energy Management System snapshot was selected as the lowest Dane County load occurring between 11:00pm and 7:00am immediately following the selected peak snapshot that was used in the transmission analysis presented in Chapter 5. No significant changes in system configuration or generation dispatch occurred in the Dane County area during the period between the two snapshots. The initial Dane County load in the selected off-peak powerflow snapshot was 484.6 MW.

Using the same voltage stability analysis process described in Chapter 5, the N-1 and N-2 load margins were determined for each of the eight PHEV penetration scenarios presented in Table 6 (available in Chapter 5). Although ideal controlled charging will prevent the aggregate instantaneous PHEV demand from reaching the 1.4 MW and 6.0 MW maximums, these values will be used in this analysis as upper bounds based on charging infrastructure capabilities.

Tables 7 and 8 summarize the voltage and thermal limits of the selected off-peak powerflow snapshot, respectively. The N-1 basecase voltage stability load margin and the N-1 basecase thermal load margin have increased by 40.6% and 32.5%, respectively. More significantly, the N-2 basecase voltage stability load margin has more than doubled from 210 MW to 520 MW, an increase of 147.6%. In the peak Dane County load analysis presented in Chapter 5, N-2 basecase thermal violations occurred at the initial value of Dane County load resulting in an N-2 basecase thermal load margin of 0 MW. However, there is an N-2 basecase thermal load margin of 285 MW in the off-peak Dane County load analysis.

Table 7: Transmission Off-Peak Basecase Voltage Limits

	Contingency	Pre-Ctg Limit	Load Margin
N-1	ROE-WPTN 345-kV	1419.6 MW	935 MW
N-2	COL-NMA 345-kV dbl ckt	1004.6 MW	520 MW

Table 8: Transmission Off-Peak Basecase Thermal Limits and Violations

	Contingency	Pre-Ctg Limit	Load Margin	Affected Lines	Percent Overload
N-1	BLT-SYC 138-kV	994.6 MW	510 MW	GWY-SYC 69-kV	110.0%
N-2	COL-NMA 345-kV dbl ckt	769.6 MW	285 MW	PTE-COL 69-kV	110.9%

Figure 37 illustrates the N-1 and N-2 load margins calculated by the voltage stability program for each of the eight PHEV penetration scenarios shown in Table 6, assuming that PHEVs are charged off-peak. It also includes the load margins calculated in the N-1 and N-2 basecase analyses. Although there are still readily apparent reductions in load margin as the amount of additional PHEV load increases, the lowest values are still greater than the basecase values of load margin identified in Figure 31.

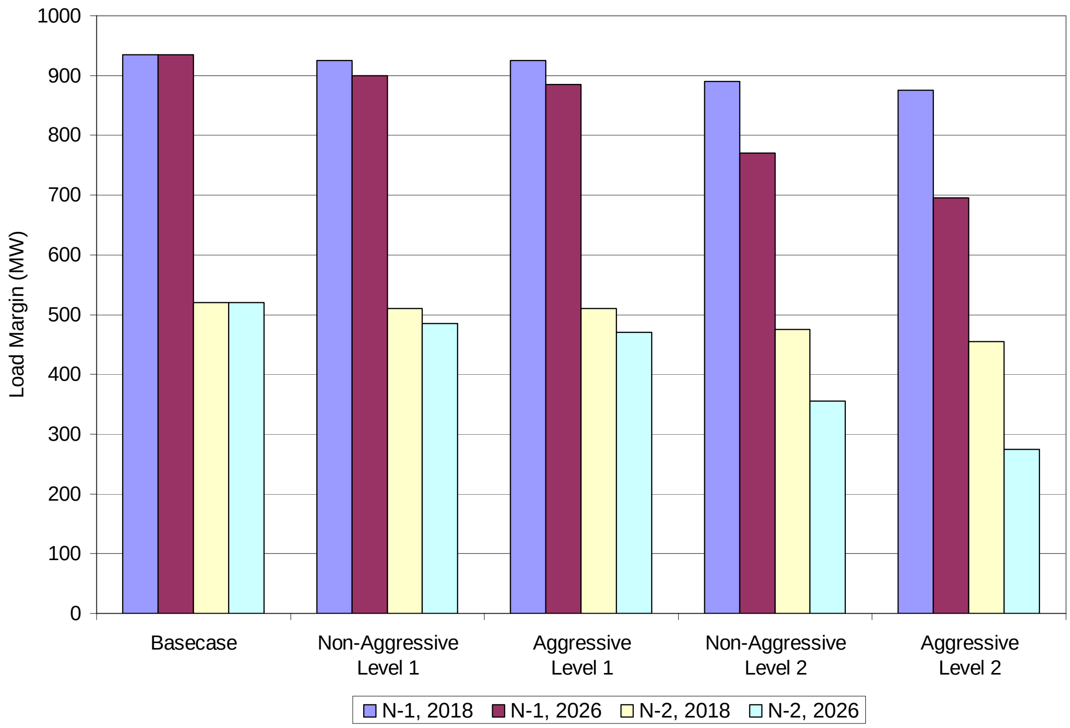

Figure 37: Calculated Transmission Load Margin Following Addition Off-Peak of PHEV Load

When PHEV load is added to off-peak Dane County area load, thermal overloads in excess of 110% do not occur at initial aggregate load levels in any of the eight PHEV penetration scenarios. As post-contingent thermal loading limits are reached, N-2 thermal overloads are contained to the 69-kV network just outside Dane County via the double circuit 345-kV line between the North Madison and Columbia Substations. N-1 thermal overloads are contained to the area immediately surrounding the Sycamore Power Plant. Small changes to system configuration, such as operation of Dane County capacitor banks, would likely mitigate thermal concerns until higher load levels.

7.2. Existing Demand Response Programs Conducive to PHEV Participation

This section describes the demand response options currently available to MGE residential customers. MGE then reserves these resources for use during local system emergencies or chooses to bid these resources into the Midwest ISO markets for system-wide economic and reliability use [47]. Based on the capabilities of the demand response resources, there are a number of different methods for MGE to participate in the Midwest ISO markets. However, in order for this system to work satisfactorily, MGE must select appropriate market bids to receive cost recovery for their aggregate resources.

MGE currently offers a direct load control program and a time-of-use metering program to residential customers. Participants in the direct load control program agree to allow MGE to remotely shut off air conditioners and/or water heaters when emergency power is needed. MGE periodically performs tests at different ambient temperatures in order to determine the actual achievable load reduction. This ensures that MGE is capable of accurately accounting for the capabilities of this resource in reliability calculations and/or bids submitted to the Midwest ISO markets [47]. Participants are compensated $8 per hour of interruption and can expect to be interrupted six hours over a ten-year period. The expected return for a single month's participation in the direct load control program is $0.40.

Individuals who participate in the time-of-use metering program pay a premium for electricity service during peak hours, but receive a significant rate reduction on electricity service during off-peak hours. Peak hours are defined between 10am and 9pm on weekdays. Off-peak hours include weekends and weekdays between 9pm and 10am. Advanced metering infrastructure is required for individuals to participate in the time-of-use metering program. However, MGE has recently received stimulus grant money to install a network of 1,750 smart meters [48]. The installation of these meters will significantly increase the number of customers that are capable of participating in time-of-use metering programs.

Provided that certain metering requirements are met, MGE is able to bid these demand response resources into the Midwest ISO markets as Emergency Demand Response Resources (EDR), Type I Demand Response Resource (DRR-I), Type II Demand Response Resources (DRR-II), or Load Modifying Resources (LMR). At this time, MGE does not have any demand response resources that are capable of meeting the requirements for participation as DRR-I or DRR-II. It is possible that increasing penetration of advanced metering infrastructure and increased participation in demand response programs will ultimately MGE to bid DRR-I and DRR-II into the Midwest ISO markets [49].

EDR provide voluntary load reduction in response to price signals. During an energy emergency alert level 2 or 3, emergency demand response resources with offers below the locational marginal price are called on to reduce their demand. There are no penalties for failing to reduce demand; however, no compensation is received if the specified amount of load reduction is not achieved [49].

DRR-I are capable of supplying a specific quantity of energy to the market through physical load interruption. Generally, this means that the load is either on or off, with little to no controllable range. These resources can provide energy and reserve to the Midwest ISO markets. They may also be designated as capacity resources, provided that they are able to meet the requirements listed in the tariff. Typically, DRR-I require significant notification time before being able to reduce load and are therefore less responsive to prices than DRR-II [49]. DRR-II are capable of supplying dispatchable energy to the market through behind-the-meter generation or controllable load. Unlike DRR-II, these resources are able to provide varying amounts of load reduction depending on the need. This enables DRR-II to provide regulation services, in addition to energy and reserve. If a DRR-II plans to offer regulation services into the market, there are additional metering requirements that it must meet. DRR-II are also able to meet capacity requirements. Typically, DRR-II are capable of responding quicker than DRR-I, and are thus more price responsive [49]. If DRR-I or DRR-II fail to respond after submitting bids into the Midwest ISO markets, they must pay the difference between the day-ahead and real-time locational marginal prices. Resources that reduce load by too much or too little may also be subject to excessive and deficient charges [49].

LMR provide capacity, and are thus the last resort during energy emergencies before firm load shed. These resources must meet the requirements listed in the Midwest ISO tariff to serve as capacity resources. Each LMR must meet its state's requirements in addition to being verified and accredited by the Midwest ISO. If an LMR fails to reduce demand by the required amount when called upon there are significant penalties up to and including decertification of that resource from serving as an LMR in the future [49].

7.3. Benefits Accrued by Participants in Existing Demand Response Programs

MGE offers a direct load control program and a time-of-use (TOU) rate program to residential customers within their service territory. Although the incentives to participate in the critical peak pricing program are relatively high, lack of utilization reduces the actual expected return for participants. As described in Chapter 4, participants in MGE's critical peak pricing program only have an expected return of $0.40 per month [38]. Increased utilization of participating resources will result in higher expected returns, thus encouraging additional participation. However, at this point it is very difficult for MGE to financially justify increased use of these resources due to the difficulty of achieving cost recovery. As the Midwest ISO markets mature and evolve, MGE will likely be able to gradually increase utilization of the critical peak pricing program as they become more proficient at optimizing market bids.

TOU programs enable energy customers to sacrifice a certain degree of convenience in return for reduced monthly electricity bills [38]. As shown in Figure 9, a typical Midwestern household would likely be able to save a small amount of money on monthly electricity bills by switching to TOU rates. However, the savings are nearly negligible, particularly when coupled with the potential for unexpected peak electricity usage to result in exorbitant bills. Certain behavioral changes can be used to shift additional load off-peak, thus increasing the potential for savings.

PHEV charging load will significantly increase the monthly electricity consumption for a typical household. A PHEV20 owner that participates in a standard rate structure and travels an average of thirty miles per day will pay an additional $11.81 per month for vehicle charging. PHEV owners that charge their vehicles during peak hours after electing to participation in a TOU rate structure will pay $20.84 per month to charge the same vehicle. This is equivalent to a 76.5% increase over the price of charging the vehicle assuming standard electricity rates. Clearly, if unable to ensure that vehicles are charged during off-peak hours, it would be uneconomical for PHEV owners to participate in TOU programs. However, if controlled charging techniques are used to ensure that the vehicles are only charged during off-peak hours, the cost of charging the vehicle on a TOU rate structure drops to $5.71, or a reduction of 51.7% from the standard electricity rate.

Table 9: Typical Household Monthly Electricity Bills in Madison Gas and Electric's Service Territory

	Standard Meter Summer	Time-of-Use Meter Summer	Standard Meter Winter	Time-of-Use Meter Winter
Monthly Usage	1005 kWh	1005 kWh	665 kWh	665 kWh
Monthly Bill	$139.42	$136.04	$85.01	$80.95

Although there are clearly inherent cost savings, the current on-peak and off-peak prices in MGE's TOU programs are not necessarily designed to encourage PHEV participation. As shown previously in this chapter, controlled vehicle charging will enable the existing electric infrastructure to support expected numbers of PHEVs through year 2026. Thus, MGE will likely need to review the existing incentives, and potentially make changes and/or additions in order to most effectively control PHEV charging behavior. It is possible that some incentives will be governmentally-funded in an effort to successfully meet the PHEV penetrations goals set by the Obama administration. In order to determine the financial incentives necessary to entice PHEV owners to participate in TOU programs, the life-time fuel savings of a single vehicle will be compared to the purchase premium associated with PHEVs. The analysis will be conducted by calculating simple payback periods for various future policy options. In addition to a business-as-usual scenario in which no changes are made to the existing TOU program, this analysis will consider the impact of an additional upfront rebate following purchase of an electric vehicle and the impact of an additional reduction in off-peak electricity prices for the charging of PHEVs.

In order to determine the life-time fuel savings accrued by PHEVS, the amount of electricity required to charge each vehicle must be calculated. The amount of electricity required to charge a given PHEV is dependent on battery-size; and is thus a direct function of the number of all-electric miles that the vehicle can travel on a single charge [30]. The numbers shown previously assume that the vehicle can travel twenty electric miles prior to switching on the internal combustion engine.

Table 10 presents monthly cost data for charging a single PHEV in the summer if participating in standard electric rates, TOU electric rates with peak charging, and TOU electric rates with off-peak charging [50]. The cost data in Table 10 is presented for vehicles that are capable of traveling twenty, forty, and sixty all-electric miles. The electricity required to charge PHEVs is also a function of total miles driven per day. The data in Table 10 assumes thirty miles of driving per day. According to the 1995 National Personal Transportation Study approximately 50% of the population travels fewer than thirty miles per day [30].

Table 10: Monthly Cost to Charge PHEVXX (Assumes Thirty Miles of Travel/Day)

	PHEV20	PHEV40	PHEV60
Energy Needs	88.1 kWh	152.6 kWh	165.9 kWh
Elec. Consump.	0.09 kWh/mi	0.15 kWh/mi	0.19 kWh/mi
Standard Meter	$12.22	$21.18	$23.01
On-Peak Charging	$21.55	$37.36	$40.59
Off-Peak Charging	$5.91	$10.24	$11.13

In addition to electricity, PHEVs require gasoline to operate. Thus, the total refueling expense for any given PHEV is the sum of electricity cost and gasoline cost. Table 11 describes the gasoline efficiency assumptions made in this analysis [50].

Table 11: Gasoline Consumption Assumptions (Assumes Thirty Miles of Travel/Day)

	CV	HEV	PHEV20	PHEV40	PHEV60
Gasoline Consump.	0.04 gal/mi	0.03 gal/mi	0.02 gal/mi	0.02 gal/mi	0.02 gal/mi

Crude oil prices have been fairly unpredictable over the past few decades [51]. For this reason, a range of possible scenarios will be presented including low, medium, and high expected prices per gallon of gasoline. The price per gallon in each of these scenarios is $2.00, $4.00, and $6.00, respectively. After calculating the fuel expenses for an equivalently-sized internal combustion engine vehicle, the sum of monthly electricity costs and monthly gasoline costs can be scaled to determine the total life-time fuel savings expected for different PHEVs in different scenarios. As described earlier, it will be uneconomical for PHEV owners to participate in TOU programs and charge their vehicles during peak hours. Thus, no payback period will be calculated for this future scenario. Table 12 presents the assumed price for each vehicle included in the study [50].

The color and shading convention defined in Figure 38 below is used throughout the remainder of this section to differentiate between the scenarios of interest.

Table 12: Assumed Electric Vehicle Purchase Prices

	CV	HEV	PHEV20	PHEV40	PHEV60
Purchase price	$23,392	$26,658	$31,828	$34,839	$36,681

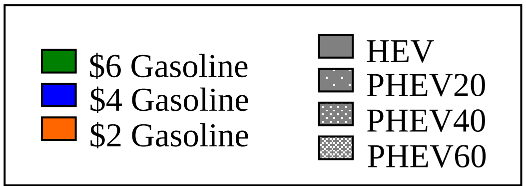

Figure 38: Legend for Following Figures

Figure 39 illustrates the number of years required to recoup the purchase premium of an electric vehicles for the range of scenarios studied. It assumes that no policy measures are enacted to encourage PHEV adoption of TOU program participation by PHEV owners. Assuming that gasoline prices reach or exceed $6 per gallon, the lifetime fuel savings of all vehicles included in this analysis would exceed the purchase premium of each respective vehicle. However, with gasoline prices in the vicinity of $4 per gallon, the only electric vehicle with a payback period of less than ten years is the HEV. With gasoline prices at or below $2 per gallon, none of the electric vehicles have payback periods of less than ten years.

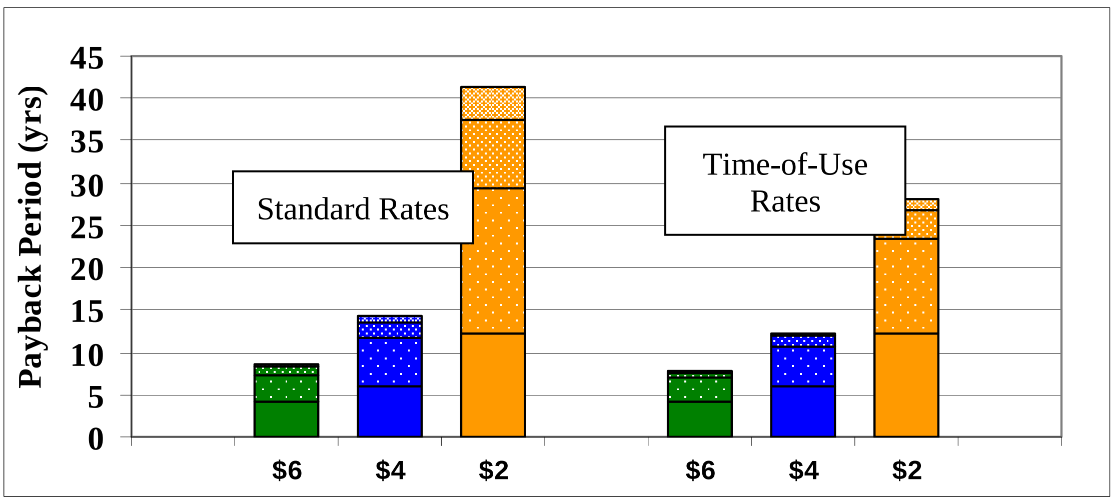

Figure 39: Years to Repay Purchase Premium of HEV/PHEV over CV with no Additional Rebates or Incentives for Standard and TOU Rates

Although it will be impossible for PHEV owners to recoup the entire purchase premium of PHEVs unless gas prices reach $6 per gallon, Figure 39 does indicate that PHEV owners who participate in TOU programs will pay significantly less than PHEV owners who choose to remain on the standard rate structure. This reduction in total refueling costs is more pronounced at lower gasoline prices.

7.4. Incentives Necessary to Encourage Demand Response Participation

In order to quantify the impact of possible future PHEV policy on the payback period of each vehicle, a sensitivity analysis was performed for two likely policy scenarios. The first policy option considered is an upfront rebate for any individual who purchases a PHEV. An example of a similar program is the upfront Californian rebate on PV installations of less than 100 kWp. Individuals that elect to install compliant PV systems are eligible for an upfront rebate of $2.50/Wp of installed capacity. In order to evaluate the effectiveness of this type of policy for PHEVs, upfront rebates of $2000, $4000, and $6000 were considered. In some cases, these upfront rebates actually reduce the initial upfront purchase price below that of a conventional internal combustion vehicle. Rather than displaying negative payback periods, the figures will indicate a payback period of zero in these situations.

Figure 40 compares the number of years required to payback vehicle purchase premiums for individuals that elect to participate in standard rates structures verses those that elect to participate in TOU rate structure. The assumed upfront financial incentive in Figure 40 is $4000.

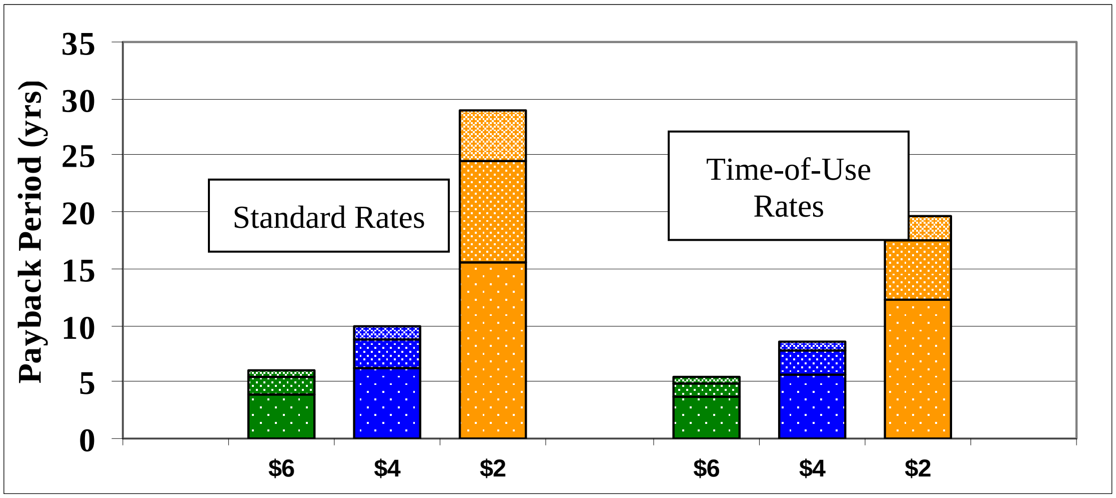

Figure 40: Years to Repay Purchase Premium of HEV/PHEV over CV with an Upfront Rebate of $4,000 on Electric Vehicle Purchases for Standard and TOU Rates

With an upfront rebate of $4000, the lifetime fuel savings of all the vehicles considered will exceed the purchase premium of each respective vehicle when gasoline prices exceed $4 per gallon. However, if gasoline prices approach $2 per gallon, the upfront $4000 rebate will not be sufficient enough to recoup the purchase premium of any of the PHEV studied over their ten year lifespan. The upfront $4000 rebate actually reduces cost of HEVs below that of an equivalent conventional internal combustion engine vehicle in each of the scenarios presented. With the additional fuel savings over the lifespan of the vehicle, it would be difficult for individuals in the market to purchase a vehicle between $20,000 and $25,000 to economically justify the purchase of a conventional internal combustion engine vehicle.

Similarly to the business-as-usual scenario, the payback period for PHEV owners that participate in TOU programs is less than that for PHEV owners that participate in standard rate structures. Assuming that the majority of owners will elect TOU rates, Figure 41 illustrates the sensitivity of payback periods to the actual amount of upfront rebate. With an upfront rebate of $6000, it is possible that lifetime fuel savings will payback the purchase premium of a PHEV20 even with gasoline prices as low as $2 per gallon. However, with an upfront rebate of $2000, the HEVs no longer have negative payback periods for any of the considered gasoline prices.

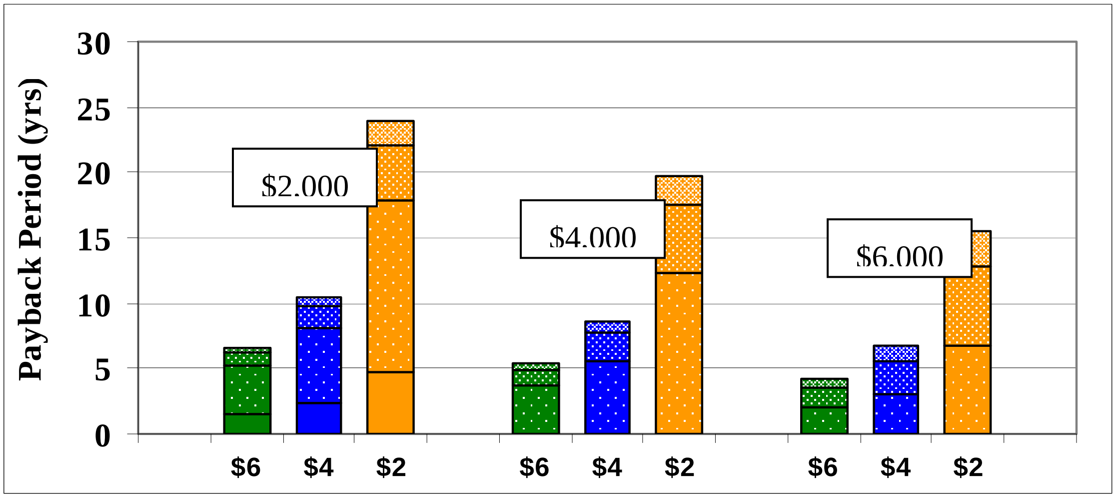

Figure 41: Years to Repay Purchase Premium of HEV/PHEV over CV with Upfront Rebates of $2,000, $4,000, and $6,000 on Electric Vehicle Purchases for TOU Rates

The second PHEV policy option considered is a reduction in the prices of electricity per kWh when charging the vehicle. Although not considered here, an additional stipulation to encourage off-peak charging of vehicles would be for the price reduction to only apply during off-peak hours. An example of a similar program is the Californian per kWh subsidy on PV installations. Participants receive a subsidy of $0.39 per kWh for all electricity produced. Subsidies of $0.02, $0.04, and $0.06 per kWh of electricity consumed during charging were considered in order to evaluate the effectiveness of this type of policy for PHEVs.

Figure 42 shows the number of years required to payback vehicle purchase premiums assuming a rebate of $0.04 per kWh. The data is presented for both standard rate participants and TOU rate participants. With a rebate of $0.04 per kWh consumed in vehicle charging, all electric vehicles become economically viable if gasoline prices reach $6 per gallon. HEVs are the only vehicles that are economically viable for gasoline prices of less than $4 per gallon. Although the payback periods have been slightly reduced for each case considered, no additional vehicles beyond those identified in the business-as-usual scenario have become economically viable.

Again assuming that PHEV owners will elect to participate in TOU rates, Figure 43 shows the sensitivity of payback periods to the value per kWh subsidy. From the figure, it is clear that the payback period for electric vehicles is much less sensitive to the selected per kWh subsidies as opposed to selected upfront vehicle rebates. In fact, even if the subsidy on electricity consumed by PHEVs when charging is increased to $0.06 per kWh, the PHEV20 just barely becomes economically viable with gasoline prices at $4 per gallon. With subsidies any higher than $0.06 per kWh, MGE would essentially be paying PHEV owning customers to charge their vehicles during off-peak hours.

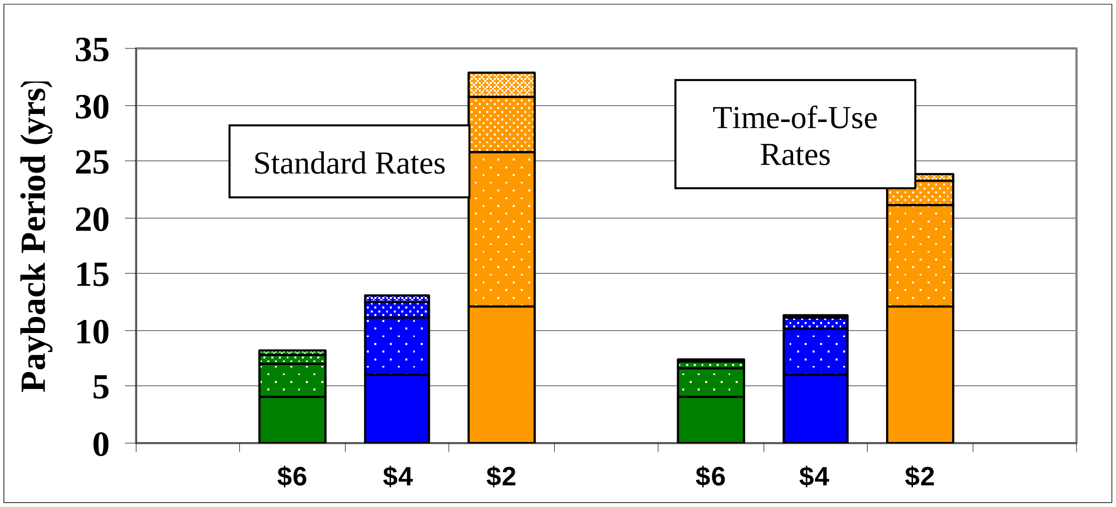

Figure 42: Years to Repay Purchase Premium of HEV/PHEV over CV with Rebates of $0.04 per kWh on the Electricity Consumed during Electric Vehicle Charging for Standard and TOU Rates

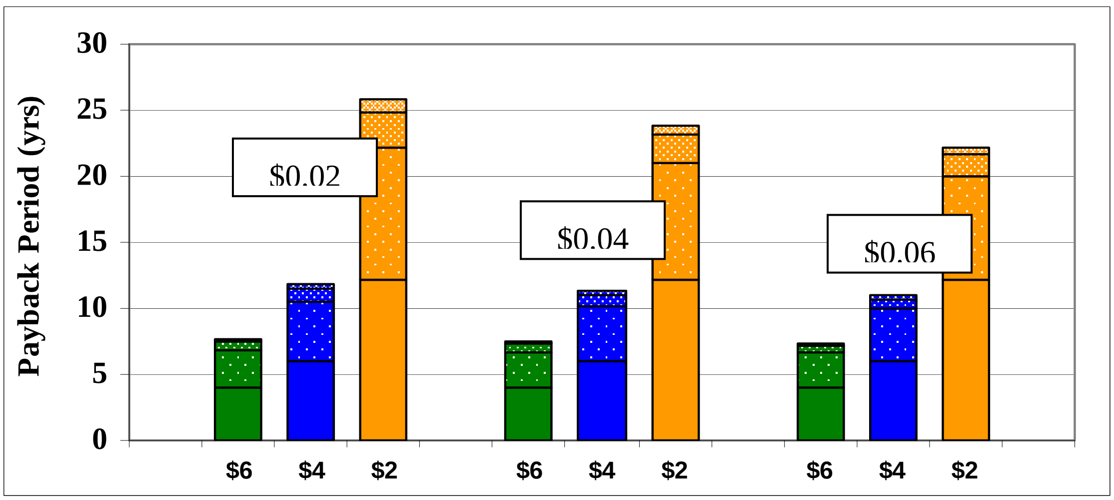

Figure 43: Years to Repay Purchase Premium of HEV/PHEV over CV with Rebates of $0.02, $0.04, and $0.06 per kWh on the Electricity Consumed during Electric Vehicle Charging for TOU Rates

In all of the figures above that compare payback periods for standard rate participants and TOU rates participants, it is interesting to note that the payback periods for HEVs are independent of electric rate structure. Electricity is not fed into these vehicles from an external source; thus, the per kWh rebate also has no impact on the payback period for HEVs. Another point to be aware of is that the lower-ranged PHEVs typically pay themselves off more quickly than the higher-ranged PHEVS. However, the additional payback period for each increment of PHEV battery capacity is less than the last. For individuals with daily commutes greater than thirty miles per day, a vehicle with additional battery capacity might be more economically viable.

8. Potential Storage Opportunities with Vehicle-To-Grid Implementation

8.1. Comparison of National Energy Usage and PHEV Storage Capacity

Although PHEV participation in direct load control programs and time-of-use rate structures will reduce any negative impacts stemming from PHEV charging, V2G technology will provide an additional means for PHEV to participate as demand response resources. Bi-directional power flow will enable PHEVs to provide ancillary services such as reserve and regulation into energy markets. Such broader participation by vehicles in grid operations in a spatially distributed manner represents one enabling solution necessary for increased penetration of environmentally benign, but operationally challenging intermittent and variable generation, such as wind and solar energy resources.

One of the primary remaining barriers to increased renewable generation is energy storage technology. With target goals of over 25% electricity from renewable sources by 2025 [52], innovative storage solutions are necessary. Provided that there exists a method for PHEVs to participate as demand response resources in the future, and that V2G technology continues to develop, it is possible that these vehicles will help bridge the gap between consumer electricity demand and the existing capabilities of renewable generation technologies. Assuming that the majority of PHEV owners participate in a controlled charging program, and that night charging minimizes any negative infrastructure impacts, optimal vehicle charging periods are fortuitously aligned with the availability of underutilized wind resources.

Using the PHEV penetration scenarios presented previously, an initial study was performed in order to gauge the maximum storage potential of the PHEV fleet in each of the four geographical regions defined by the United States Census Bureau. Figure 44 illustrates the four regions as defined by the Census Bureau [53]. Different geographical areas have geographic and climate differences that can make the installation of certain types of renewable generation more or less effective. Renewable portfolio standards also differ in different regions throughout the United States. Geographic and climate differences also lead to a certain degree of variability in typical values of household electricity consumption, potentially requiring larger PHEV fleet to offset the same percentage of electricity use.

As initially described in Chapter 4, PHEVs are typically classified by the number of pure electric miles that they can travel. The following section analyzes PHEV20, PHEV40, and PHEV60, which are capable of traveling twenty, forty, and sixty all-electric miles before utilizing the internal combustion engine, respectively. Based on the battery energy and state-of-discharge window, the maximum possible storage capacity of a fully charged battery can be calculated. This storage capacity differs depending on the size of the battery, and thus the number of all-electric miles that a particular vehicle is capable of traveling before utilizing the internal combustion engine. Table 13 summarizes the maximum possible energy available for PHEV20, PHEV40, and PHEV60 [50]. For comparison, a typical household consumes approximately 32 kWh or electricity per day in the summer. Of these 32 kWh consumed on a typical summer day, 18 kWh will be consumed during peak hours [42].

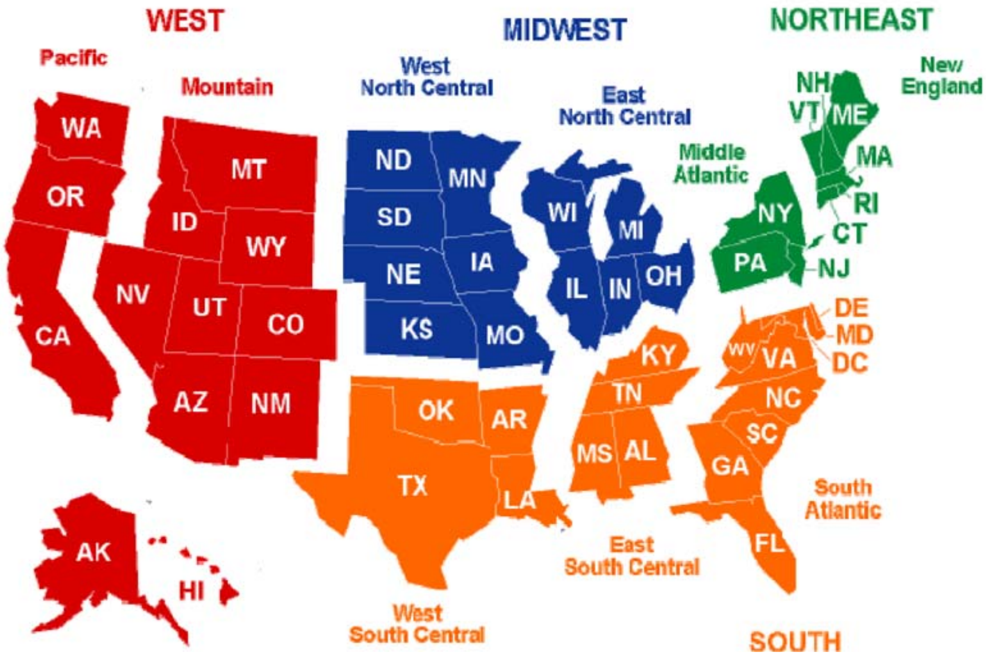

Figure 44: Census Regions and Divisions in the United States

Table 13: Maximum Daily Energy Available From PHEVXX

	PHEV20	PHEV40	PHEV60
Battery Energy	11.8 kWh	19.0 kWh	23.6 kWh
SOC Window	47%	59%	73%
Available Energy	5.55 kWh	11.2 kWh	17.2 kWh

Assuming that each vehicle is entirely discharged during the day and then provided the opportunity to fully recharge every night, the daily available battery energy can be scaled by the number of days in a year to determine the annual storage capacity of a single PHEV. Table 14 presents this data for the three sizes of PHEVs considered in this analysis.

Table 14: Maximum Annual Storage Capacity Available From PHEVXX

	PHEV20	PHEV40	PHEV60
Annual Available Energy	2024 kWh	4092 kWh	6288 kWh

In order to determine the annual storage capacity for regional PHEV fleets, the same aggressive and non-aggressive PHEV penetration scenarios presented in earlier chapters were used. Based on the previously presented penetration scenarios, the number of PHEVs expected in years 2018 and 2026 were calculated. The total numbers of vehicles in each scenario were then divided among the four Census Regions according to the percentage of passenger vehicles that currently exist in each region. Interestingly, the percentage of vehicles owned corresponds closely to the population percentage in each region [54]. However, typical household electricity consumption in the Southern region is significantly higher than in any other region [55]. When scaled to account for the differences in population, the Southern region has a disproportionately high percentage of electricity consumed per year compared with the other three regions. This means that even though there are additional vehicles in the Southern region due to higher population levels, the energy storage of the PHEV fleet in this region will be a lesser percentage of total residential electricity consumption for the region. Table 15 describes the vehicle ownership percentages that were used to assign specific numbers of PHEVs to each region [56].

Table 15: Existing Geographical Distribution of Vehicles in the United States

Household Census Region	Percent of Total U.S. Vehicles
Northeast	16%
Midwest	25%
South	37%
West	22%

The total impact of the PHEVXX fleet in each region was then calculated by scaling the impact of a single PHEVXX by the total number of forecast PHEVXX in each region for each of the years of interest. Figure 45 defines the color and shading conventions used in Figure 46 to differentiate between scenarios and regions.

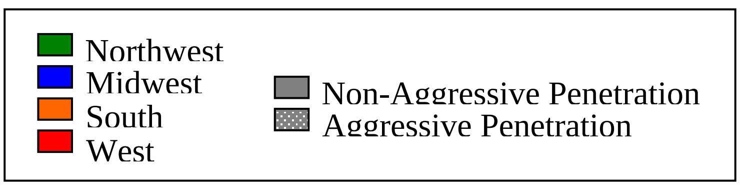

Figure 45: Legend for Following Figures

Figure 46 illustrates the potential aggregate regional battery storage capacity for each of the penetration scenarios studied. The three different axes represent PHEV20, PHEV40, and PHEV60, moving from the interior axis outwards.

The cumulative national level of potential aggregate regional battery storage capacity for each of the penetration scenarios studied is shown in Figure 47. As in the previous figure, the three different axes represent PHEV20, PHEV40, and PHEV60, moving outwards.

In 2007, approximately 105,000 thousand Megawatt hours, or a little more than 2.5% of electricity generated in the United States was generated using renewable technologies (excluding conventional hydroelectric generation). The net renewable generation capacity in 2007 was just over 30,000 MW [57]. From Figure 47, it is apparent that an additional 30,000 thousand Megawatt hours from the total installed renewable generation capacity could be utilized assuming non-aggressive penetration of PHEV20 occurs through year 2026. With larger vehicles such as PHEV40 and PHEV60, and/or increased vehicle market penetration, utilization of installed capacity continues to increase. In the most aggressive scenario studied, with aggressive penetration of PHEV60 through year 2026, the existing renewable generation can potentially be more than doubled.

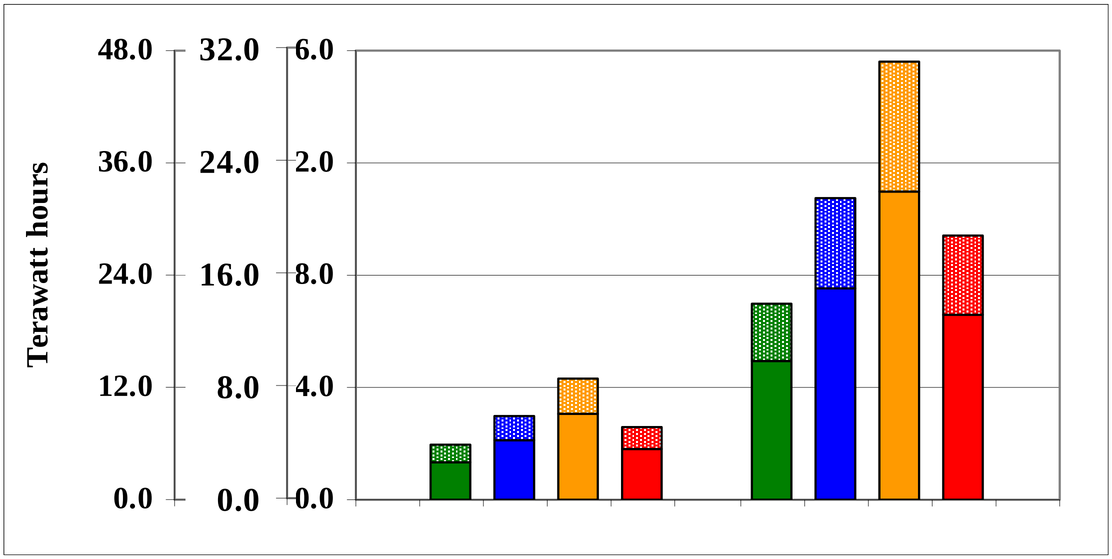

Figure 46: National PHEV20 Storage Capacity by US Census Region

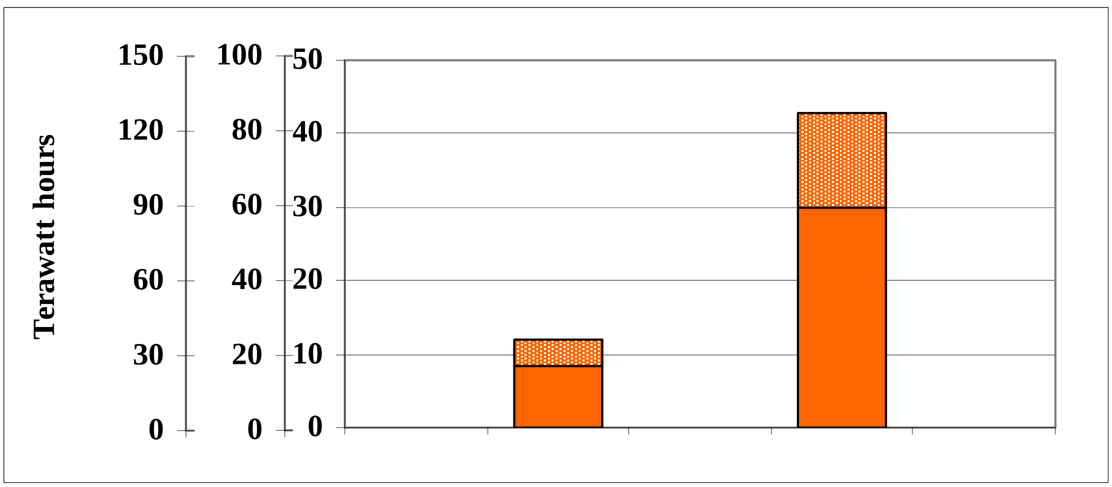

Figure 47: National PHEV20 Storage Capacity

One additional item to consider is the geographical distribution of the technical feasibility of different types of renewable generation resources. For example, the Western region is particularly suited for solar renewable generation, while the Midwestern region is more suited towards wind renewable generation. As the total storage potential of regional PHEV fleets increases, it is possible that the total storage capacity will outstrip the availability of renewable resources. Certain areas in the Southern region are particularly susceptible to this due to the large number of vehicles and comparatively low likely installations of renewable generation resources. At this point, strengthening transmission interconnections between the regions will more aptly match renewable generation resources to storage resources.

8.2. Ability for the PHEV Fleet to Complement Renewable Generation by Region

At a more regional level, Figure 48 illustrates potential battery storage capacity for PHEV fleets in Wisconsin and Dane County, under the same set of scenarios presented in the previous section. The interior axis represents the storage capacity of a fleet composed of PHEV20, the central axis is scaled to represent a fleet composed of PHEV40, and the exterior axis is scaled to represent a fleet composed of PHEV60. As before, the solid bar indicates non-aggressive PHEV penetration and the shaded bar represents aggressive PHEV penetration. The color convention changes from the previous section. Green now represents battery storage potential in Dane County and blue represents battery storage potential in the state of Wisconsin. Relatively high levels of distributed generation resources in Dane County make the addition of regional storage resources of particular value.

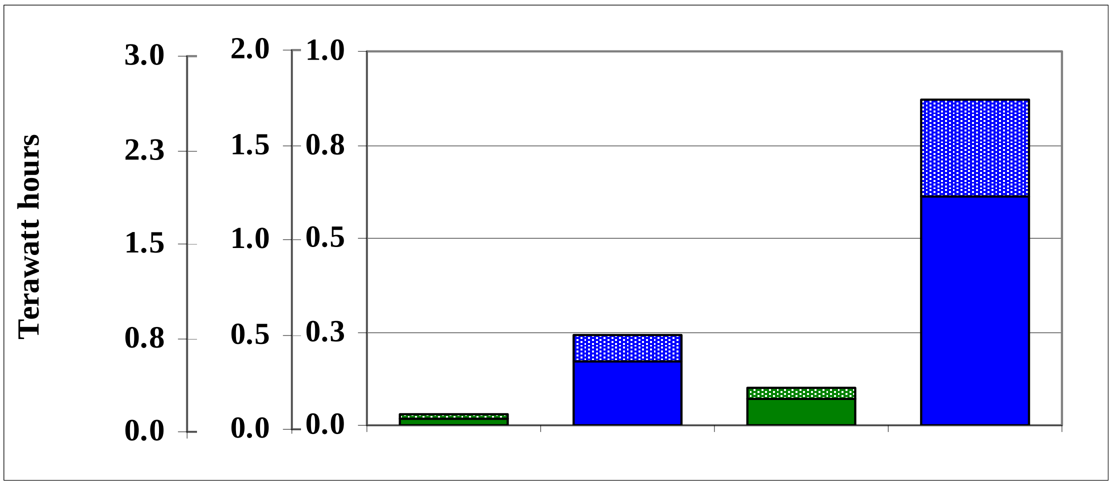

Figure 48: PHEV20 Storage Capacity for Wisconsin and Dane County

8.3. Comparison of Household Energy Usage and PHEV Storage Capacity

The daily electricity consumption of a typical Midwestern household is very much on par with the storage capacity of a single PHEV battery. In some cases, the vehicle battery actually has sufficient storage capacity to eliminate peak power usage between the hours of 10:00am and 9:00pm. Realistically, the majority of PHEVs will not be geographically located at home during these peak periods. However, there is the potential for PHEVs to plug-in at other locations in lieu of plugging in at home, thus creating the same net effect, but spatially corrected from home to work locations. Separate studies have been performed on the ability for PHEVs to support commercial office buildings during the work day [58].

Table 16 illustrates the percentage of total typically daily household electricity use that could be offset by PHEV20, PHEV40, and PHEV60. Table 17 illustrates the corresponding percentage of daily typical household electricity use that could be offset by PHEV20, PHEV40, and PHEV60 during peak hours.

Prior to implementation of such net metering programs, certain agreements and policies will need to be created between electric utilities in order to account for the eventuality of participating individuals who live in one electric service territory, but work in another. Dane County load is served by three unique electric service providers, making the likelihood of this occurring particularly high in this county.

Table 16: Percentage of Typical Daily Household Electricity Offset by PHEVXX

	PHEV20	PHEV40	PHEV60
Winter Peak Day	25%	50%	76%
Summer Peak Day	9%	17%	27%
Winter Typical Day	26%	52%	80%
Summer Typical Day	17%	35%	54%

Table 17: Percentage of On-Peak Typical Household Electricity Offset by PHEVXX

	PHEV20	PHEV40	PHEV60
Winter Peak Day	46%	94%	144%
Summer Peak Day	14%	29%	45%
Winter Typical Day	50%	101%	156%
Summer Typical Day	31%	63%	97%

Metering and vehicle communications standards will also be essential in order to facilitate the interaction between utility and customer.

9. Summary and Future Work

Summary of Significant Results

Assuming that current political and technological drivers remain constant in the coming years, a certain degree of PHEV penetration is inevitable. The methods used to incorporate PHEVs into the existing electric and automotive industries will dictate whether these vehicles are helpful or hurtful in the long run. Initial clustering of vehicles is assured to amplify the impact that initial PHEV penetration will have on existing distribution infrastructure. With level 2 charging, the addition of a single PHEV can cause peak summer transformer loading to exceed rated values. Although level 1 charging reduces the increased load placed on transformers, the addition of three PHEVs causes the peak summer transformer loading to approach rated values.

Early penetration of PHEVs is less likely to have a detrimental impact on larger equipment to higher amounts of installed capacity. However, if uncontrolled charging is allowed to continue over an extended timeframe, increasing peak demand will ultimately be reflected by an increasing frequency of voltage and thermal violations on transmission equipment. Under an aggressive PHEV penetration scenario and with level 2 charging, the additional PHEV load exceeds the Dane County area N-2 load margin by year 2018. Although less aggressive penetration scenarios and/or charging characteristics do not necessarily cause PHEV load to exceed load margins, they can significantly reduce load margin, thus reducing the robustness and flexibility of the bulk electric system.

Controlled charging techniques can be used to prevent PHEV load from contributing to peak electricity demand. This greatly extends the amount of time that will elapse before reinforcements and/or additions are needed for the bulk electric system. Additionally, demand response can enable PHEV owners to reduce the cost required to charge their vehicles, thus creating a situation in which all stakeholders appear to benefit. However, the savings accrued by PHEV owners under existing demand response programs (e.g. direct load control and time-of-use pricing programs) are insufficient to convince PHEV to sacrifice convenience for financial savings. Additional rebates and incentives can be used to encourage PHEV owner participation. The metric used to ascertain the effectiveness of different rebates and incentives was the ratio of vehicle purchase premium to fuel cost savings over the ten year life of the vehicle. The effectiveness of each proposal was highly dependent on both gasoline prices and the electric range of the vehicle. In each of the cases considered in this analysis, upfront rebates were more effective than energy usage rebates. However, reductions in the upfront rebates and/or increased energy usage rebates could be used to make the two more equivalent.

Future implementation of V2G technology will enable PHEV to provide additional benefits to the bulk electric system, beyond mitigation of their own impacts. Unused battery capacity can be used to offset the variability inherent in renewable generation, thus resulting in an overall cleaner electrical system impact. Also, the aggregate PHEV fleet can be used to provide valuable ancillary services such as reserve and regulation. Currently, generation resources are the primary providers of these resources. Further opening this market to demand-side resources will enhance competition in energy markets. PHEV owners that decide to utilize their batteries as energy storage resources will be capable of shifting a significant percentage of their daily household energy usage to off-peak hours. Certain batteries are actually capable of completely eliminating peak energy usage for a typical household.

Future Work

There is still a great deal of work that remains in order to ensure a smooth transition to an electrified automotive industry. First of all, regional consumer surveys are needed to better identify characteristics that are indicative of likely PHEV adopters. These surveys should be designed to such that they characterize both spatial and temporal aspects of PHEV adoption. Additionally, these surveys can help determine the probability that early PHEV adopters will participate in existing demand response programs and/or evaluate which rebates and incentives are the most lucrative to potential vehicle owners. After creating a regionally-accurate picture of future PHEV penetration, the initial distribution and transmission equipment impact assessment should be expanded to include all equipment in the region of interest, according to the spatial and temporal penetration characteristics. Finally, an analysis needs to be performed in order to evaluate whether or not the benefits recouped by electric utilities from PHEV participation in demand response programs are sufficient to achieve cost recovery for each of the proposed rebates and incentives.

Conclusions Demand response is quickly evolving and playing a greater role in the electric industry. PHEV have the potential to provide a significant amount of demand response through a variety of methods. However, without careful development of demand response programs that benefit the consumer while maintaining system reliability, PHEVs have the potential to be part of the problem as opposed to part of the solution.

This report has presented a regional distribution and transmission impact analysis of initial PHEV penetration on electric infrastructure in Dane County, WI. It has also offered an outline of the different future possibilities of the ways in which PHEVs may participate as demand response resources with the currently available demand response programs, thus improving the reliability and robustness of the bulk electric system in Dane County. Furthermore, it has described a future vision that encourages PHEVs to participate in demand response programs that will be developed in order to take advantage of these vehicles' unique energy storage potential, thus enabling a higher penetration of intermittent and variable generation such as wind and solar energy resources.

It is clear that the current definition of linking demand response either to pricing of electricity or jeopardy of system reliability may be too restrictive in scope. A policy regime that recognizes the value of PHEVs for their energy storage and provides incentives for owners to enroll in an appropriate demand response program and receive additional compensation in exchange for use of their vehicles' participation in grid operations is worthy of exploration in light of its strong societal impact. Numerous technical, operational, economic, and logistic challenges need to be overcome before such a broad V2G visions can be realized. Thus, the remaining question is how to move forward and aptly utilize PHEV resources as they become available.

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Appendix A

Dane County, Non-Aggressive/Aggressive, 2019 - 2026

	2019	2020	2021	2022	2023	2024	2025	2026
Non-Aggressive Annual Sales	3153	3274	3395	3517	3638	3759	3880	4002
Non-Aggressive Cumulative Fleet	12612	15886	19160	22434	25708	28861	31771	34136
Aggressive Annual Sales	4493	4666	4838	5011	5184	5357	5530	5702
Aggressive Cumulative Fleet	17971	22637	27303	31968	36634	41127	45274	48644

Wisconsin, Non-Aggressive/Aggressive, 2019 – 2026

	2019	2020	2021	2022	2023	2024	2025	2026
Non-Aggressive Annual Sales	27890	28963	30035	31108	32181	33254	34326	35399
Non-Aggressive Cumulative Fleet	111560	140523	169486	198448	227411	255301	281046	301963
Aggressive Annual Sales	39743	41272	42800	44329	45858	47386	48915	50443
Aggressive Cumulative Fleet	158973	200245	241517	282789	324061	363804	400490	430298

United States, Non-Aggressive/Aggressive, 2019 – 2026

	2019	2020	2021	2022	2023	2024	2025	2026
Non-Aggressive Annual Sales	1368421	1421053	1473684	1526316	1578947	1631579	1684211	1736842
Non-Aggressive Cumulative Fleet	5473684	6894737	8315789	9736842	11157895	12526316	13789474	14815789
Aggressive Annual Sales	1950000	2025000	2100000	2175000	2250000	2325000	2400000	2475000
Aggressive Cumulative Fleet	7800000	9825000	11850000	13875000	15900000	17850000	19650000	21112500

Appendix B: Distribution Impact Results (Without Demand Response)

Non-Aggressive/Aggressive, Level 1, 8 Households per Transformer (through 2018)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	1 PHEV																							
Winter Peak	7.6	6.6	6.1	5.7	5.8	6.7	8.5	9.3	9.4	9.2	9.2	9.0	9.0	8.9	8.9	9.6	12.2	13.9	15.7	16.0	15.0	12.5	10.3	8.6
Summer Peak	19.4	18.2	17.7	17.0	17.2	19.0	20.5	21.3	21.0	22.9	25.6	29.5	35.1	40.8	44.2	45.3	44.7	38.6	32.9	28.6	28.7	25.5	22.7	20.0
Winter Typical	7.3	6.4	6.0	5.8	6.1	7.8	9.3	9.8	8.1	7.9	7.8	7.6	7.5	7.5	7.7	8.7	11.8	13.8	15.6	15.8	14.9	12.3	10.2	8.4
Summer Typical	10.4	9.4	9.1	8.7	8.9	10.4	11.5	12.0	10.9	11.3	12.1	13.2	15.0	16.9	18.2	19.1	20.7	19.3	17.8	16.8	17.2	15.0	13.0	10.9
	2 PHEV																							
Winter Peak	7.6	6.6	6.1	5.7	5.8	6.7	8.5	9.3	9.4	9.2	9.2	9.0	9.0	8.9	8.9	9.6	13.9	15.7	17.5	17.7	16.2	12.5	10.3	8.6
Summer Peak	19.4	18.2	17.7	17.0	17.2	19.0	20.5	21.3	21.0	22.9	25.6	29.5	35.1	40.8	44.2	45.3	46.5	40.4	34.7	30.3	29.8	25.5	22.7	20.0
Winter Typical	7.3	6.4	6.0	5.8	6.1	7.8	9.3	9.8	8.1	7.9	7.8	7.6	7.5	7.5	7.7	8.7	13.5	15.6	17.3	17.5	16.0	12.3	10.2	8.4
Summer Typical	10.4	9.4	9.1	8.7	8.9	10.4	11.5	12.0	10.9	11.3	12.1	13.2	15.0	16.9	18.2	19.1	22.4	21.0	19.5	18.6	18.4	15.0	13.0	10.9
	3 PHEV																							
Winter Peak	7.6	6.6	6.1	5.7	5.8	6.7	8.5	9.3	9.4	9.2	9.2	9.0	9.0	8.9	8.9	9.6	15.7	17.4	19.2	19.5	17.3	12.5	10.3	8.6
Summer Peak	19.4	18.2	17.7	17.0	17.2	19.0	20.5	21.3	21.0	22.9	25.6	29.5	35.1	40.8	44.2	45.3	48.2	42.1	36.4	32.1	31.0	25.5	22.7	20.0
Winter Typical	7.3	6.4	6.0	5.8	6.1	7.8	9.3	9.8	8.1	7.9	7.8	7.6	7.5	7.5	7.7	8.7	15.3	17.3	19.1	19.3	17.2	12.3	10.2	8.4
Summer Typical	10.4	9.4	9.1	8.7	8.9	10.4	11.5	12.0	10.9	11.3	12.1	13.2	15.0	16.9	18.2	19.1	24.2	22.8	21.3	20.3	19.5	15.0	13.0	10.9

Non-Aggressive/Aggressive, Level 1, 10 Households per Transformer (through 2018)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	1 PHEV																							
Winter Peak	9.5	8.3	7.6	7.2	7.3	8.4	10.6	11.6	11.8	11.5	11.5	11.3	11.2	11.2	11.2	12.0	14.8	17.0	19.2	19.5	18.5	15.6	12.9	10.7
Summer Peak	24.3	22.8	22.2	21.3	21.5	23.8	25.6	26.7	26.2	28.6	32.0	36.9	43.9	51.0	55.3	56.7	55.5	47.9	40.7	35.3	35.6	31.9	28.4	25.0
Winter Typical	9.1	7.9	7.5	7.2	7.7	9.8	11.7	12.3	10.1	9.9	9.7	9.5	9.4	9.4	9.6	10.9	14.3	16.8	19.0	19.3	18.3	15.4	12.7	10.5
Summer Typical	13.0	11.8	11.4	10.8	11.2	13.0	14.4	15.0	13.6	14.2	15.1	16.5	18.8	21.2	22.7	23.9	25.4	23.6	21.8	20.6	21.2	18.8	16.2	13.6
	2 PHEV																							
Winter Peak	9.5	8.3	7.6	7.2	7.3	8.4	10.6	11.6	11.8	11.5	11.5	11.3	11.2	11.2	11.2	12.0	16.5	18.7	20.9	21.3	19.6	15.6	12.9	10.7
Summer Peak	24.3	22.8	22.2	21.3	21.5	23.8	25.6	26.7	26.2	28.6	32.0	36.9	43.9	51.0	55.3	56.7	57.2	49.6	42.5	37.0	36.7	31.9	28.4	25.0
Winter Typical	9.1	7.9	7.5	7.2	7.7	9.8	11.7	12.3	10.1	9.9	9.7	9.5	9.4	9.4	9.6	10.9	16.1	18.6	20.8	21.0	19.5	15.4	12.7	10.5
Summer Typical	13.0	11.8	11.4	10.8	11.2	13.0	14.4	15.0	13.6	14.2	15.1	16.5	18.8	21.2	22.7	23.9	27.1	25.4	23.6	22.3	22.4	18.8	16.2	13.6
	3 PHEV																							
Winter Peak	9.5	8.3	7.6	7.2	7.3	8.4	10.6	11.6	11.8	11.5	11.5	11.3	11.2	11.2	11.2	12.0	18.3	20.5	22.7	23.0	20.8	15.6	12.9	10.7
Summer Peak	24.3	22.8	22.2	21.3	21.5	23.8	25.6	26.7	26.2	28.6	32.0	36.9	43.9	51.0	55.3	56.7	59.0	51.4	44.2	38.8	37.8	31.9	28.4	25.0
Winter Typical	9.1	7.9	7.5	7.2	7.7	9.8	11.7	12.3	10.1	9.9	9.7	9.5	9.4	9.4	9.6	10.9	17.8	20.3	22.5	22.8	20.6	15.4	12.7	10.5
Summer Typical	13.0	11.8	11.4	10.8	11.2	13.0	14.4	15.0	13.6	14.2	15.1	16.5	18.8	21.2	22.7	23.9	28.9	27.1	25.3	24.1	23.5	18.8	16.2	13.6

Non-Aggressive/Aggressive, Level 2, 8 Households per Transformer (through 2018)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	1 PHEV																							
Winter Peak	7.6	6.6	6.1	5.7	5.8	6.7	8.5	9.3	9.4	9.2	9.2	9.0	9.0	8.9	8.9	9.6	17.9	12.8	14.0	14.2	13.9	12.5	10.3	8.6
Summer Peak	19.4	18.2	17.7	17.0	17.2	19.0	20.5	21.3	21.0	22.9	25.6	29.5	35.1	40.8	44.2	45.3	50.5	37.5	31.2	26.8	27.5	25.5	22.7	20.0
Winter Typical	7.3	6.4	6.0	5.8	6.1	7.8	9.3	9.8	8.1	7.9	7.8	7.6	7.5	7.5	7.7	8.7	17.5	12.7	13.8	14.0	13.8	12.3	10.2	8.4
Summer Typical	10.4	9.4	9.1	8.7	8.9	10.4	11.5	12.0	10.9	11.3	12.1	13.2	15.0	16.9	18.2	19.1	26.4	18.2	16.0	15.1	16.1	15.0	13.0	10.9
	2 PHEV																							
Winter Peak	7.6	6.6	6.1	5.7	5.8	6.7	8.5	9.3	9.4	9.2	9.2	9.0	9.0	8.9	8.9	9.6	25.4	13.5	14.0	14.2	13.9	12.5	10.3	8.6
Summer Peak	19.4	18.2	17.7	17.0	17.2	19.0	20.5	21.3	21.0	22.9	25.6	29.5	35.1	40.8	44.2	45.3	58.0	38.2	31.2	26.8	27.5	25.5	22.7	20.0
Winter Typical	7.3	6.4	6.0	5.8	6.1	7.8	9.3	9.8	8.1	7.9	7.8	7.6	7.5	7.5	7.7	8.7	25.0	13.3	13.8	14.0	13.8	12.3	10.2	8.4
Summer Typical	10.4	9.4	9.1	8.7	8.9	10.4	11.5	12.0	10.9	11.3	12.1	13.2	15.0	16.9	18.2	19.1	33.9	18.8	16.0	15.1	16.1	15.0	13.0	10.9
	3 PHEV																							
Winter Peak	7.6	6.6	6.1	5.7	5.8	6.7	8.5	9.3	9.4	9.2	9.2	9.0	9.0	8.9	8.9	9.6	32.9	14.1	14.0	14.2	13.9	12.5	10.3	8.6
Summer Peak	19.4	18.2	17.7	17.0	17.2	19.0	20.5	21.3	21.0	22.9	25.6	29.5	35.1	40.8	44.2	45.3	65.5	38.8	31.2	26.8	27.5	25.5	22.7	20.0
Winter Typical	7.3	6.4	6.0	5.8	6.1	7.8	9.3	9.8	8.1	7.9	7.8	7.6	7.5	7.5	7.7	8.7	32.5	14.0	13.8	14.0	13.8	12.3	10.2	8.4
Summer Typical	10.4	9.4	9.1	8.7	8.9	10.4	11.5	12.0	10.9	11.3	12.1	13.2	15.0	16.9	18.2	19.1	41.4	19.4	16.0	15.1	16.1	15.0	13.0	10.9

Non-Aggressive/Aggressive, Level 2, 10 Households per Transformer (through 2018)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	1 PHEV																							
Winter Peak	9.5	8.3	7.6	7.2	7.3	8.4	10.6	11.6	11.8	11.5	11.5	11.3	11.2	11.2	11.2	12.0	20.5	15.9	17.4	17.8	17.4	15.6	12.9	10.7
Summer Peak	24.3	22.8	22.2	21.3	21.5	23.8	25.6	26.7	26.2	28.6	32.0	36.9	43.9	51.0	55.3	56.7	61.2	46.8	39.0	33.5	34.4	31.9	28.4	25.0
Winter Typical	9.1	7.9	7.5	7.2	7.7	9.8	11.7	12.3	10.1	9.9	9.7	9.5	9.4	9.4	9.6	10.9	20.1	15.7	17.3	17.5	17.2	15.4	12.7	10.5
Summer Typical	13.0	11.8	11.4	10.8	11.2	13.0	14.4	15.0	13.6	14.2	15.1	16.5	18.8	21.2	22.7	23.9	31.1	22.5	20.1	18.8	20.1	18.8	16.2	13.6
	2 PHEV																							
Winter Peak	9.5	8.3	7.6	7.2	7.3	8.4	10.6	11.6	11.8	11.5	11.5	11.3	11.2	11.2	11.2	12.0	28.0	16.5	17.4	17.8	17.4	15.6	12.9	10.7
Summer Peak	24.3	22.8	22.2	21.3	21.5	23.8	25.6	26.7	26.2	28.6	32.0	36.9	43.9	51.0	55.3	56.7	68.7	47.4	39.0	33.5	34.4	31.9	28.4	25.0
Winter Typical	9.1	7.9	7.5	7.2	7.7	9.8	11.7	12.3	10.1	9.9	9.7	9.5	9.4	9.4	9.6	10.9	27.6	16.3	17.3	17.5	17.2	15.4	12.7	10.5
Summer Typical	13.0	11.8	11.4	10.8	11.2	13.0	14.4	15.0	13.6	14.2	15.1	16.5	18.8	21.2	22.7	23.9	38.6	23.2	20.1	18.8	20.1	18.8	16.2	13.6
	3 PHEV																							
Winter Peak	9.5	8.3	7.6	7.2	7.3	8.4	10.6	11.6	11.8	11.5	11.5	11.3	11.2	11.2	11.2	12.0	35.5	17.1	17.4	17.8	17.4	15.6	12.9	10.7
Summer Peak	24.3	22.8	22.2	21.3	21.5	23.8	25.6	26.7	26.2	28.6	32.0	36.9	43.9	51.0	55.3	56.7	76.2	48.0	39.0	33.5	34.4	31.9	28.4	25.0
Winter Typical	9.1	7.9	7.5	7.2	7.7	9.8	11.7	12.3	10.1	9.9	9.7	9.5	9.4	9.4	9.6	10.9	35.1	17.0	17.3	17.5	17.2	15.4	12.7	10.5
Summer Typical	13.0	11.8	11.4	10.8	11.2	13.0	14.4	15.0	13.6	14.2	15.1	16.5	18.8	21.2	22.7	23.9	46.1	23.8	20.1	18.8	20.1	18.8	16.2	13.6

Appendix C: Transmission Bus Loading (Without Demand Response)

Non-Aggressive/Aggressive, Level 1/2, 2018/2026

	Non-Aggressive Level 1 2018	Non-Aggressive Level 2 2018	Aggressive Level 1 2018	Aggressive Level 2 2018	Non-Aggressive Level 1 2026	Non-Aggressive Level 2 2026	Aggressive Level 1 2026	Aggressive Level 2 2026
AMN	0.07	0.31	0.10	0.45	0.26	1.13	0.37	1.61
AMN	0.10	0.41	0.14	0.59	0.38	1.65	0.55	2.35
BKE	0.04	0.19	0.06	0.27	0.14	0.59	0.20	0.84
BLE	0.07	0.28	0.09	0.40	0.25	1.06	0.35	1.50
BLH	0.21	0.88	0.29	1.26	0.64	2.73	0.91	3.88
BLH	0.23	1.00	0.33	1.43	0.72	3.11	1.03	4.43
BLT	0.03	0.12	0.04	0.17	0.09	0.38	0.13	0.54
BLT	0.07	0.29	0.10	0.42	0.21	0.91	0.30	1.30
BLT	0.28	1.22	0.40	1.73	0.88	3.77	1.25	5.37
BLT	0.31	1.34	0.45	1.91	0.97	4.15	1.38	5.92
BPK	0.04	0.16	0.05	0.23	0.12	0.52	0.17	0.74
BRD	0.23	0.97	0.32	1.38	0.72	3.10	1.03	4.42
BYN	0.17	0.75	0.25	1.07	0.69	2.97	0.99	4.24
CCS	0.08	0.35	0.11	0.49	0.38	1.62	0.54	2.31
CCS	0.49	2.08	0.69	2.96	2.28	9.75	3.24	13.90
CDO	0.18	0.78	0.26	1.10	0.58	2.48	0.82	3.53
COD	0.08	0.35	0.12	0.50	0.31	1.32	0.44	1.88
COGT	0.19	0.81	0.27	1.15	0.80	3.42	1.14	4.87
CRP	0.14	0.59	0.20	0.84	0.47	2.01	0.67	2.87
DAN	0.05	0.22	0.07	0.32	0.22	0.93	0.31	1.33
DEF	0.09	0.37	0.12	0.53	0.34	1.46	0.49	2.09
DEF	0.10	0.43	0.14	0.61	0.39	1.69	0.56	2.41
ECA	0.01	0.04	0.01	0.06	0.03	0.13	0.04	0.19
ECA	0.15	0.65	0.22	0.93	0.49	2.09	0.69	2.97
ECA	0.19	0.81	0.27	1.16	0.60	2.56	0.85	3.64
ECA	0.35	1.48	0.49	2.11	1.09	4.66	1.55	6.64
ETN	0.07	0.30	0.10	0.42	0.27	1.16	0.39	1.65
ETN	0.11	0.46	0.15	0.66	0.41	1.77	0.59	2.53
FCH	0.28	1.21	0.40	1.73	1.03	4.42	1.47	6.30

FCH	0.43	1.86	0.62	2.65	1.63	7.01	2.33	9.98
FEM	0.06	0.24	0.08	0.34	0.22	0.96	0.32	1.36
FEM	0.07	0.29	0.10	0.42	0.24	1.04	0.34	1.48
GAST	0.21	0.89	0.29	1.26	0.97	4.16	1.38	5.93
GWY	0.04	0.19	0.06	0.27	0.14	0.60	0.20	0.85
HKP	0.14	0.59	0.20	0.84	0.43	1.85	0.61	2.63
HKP	0.18	0.79	0.26	1.13	0.58	2.47	0.82	3.52
MAZ	0.10	0.44	0.15	0.63	0.40	1.70	0.57	2.42
MCF	0.20	0.84	0.28	1.19	0.73	3.13	1.04	4.46
MHL	0.00	0.01	0.00	0.02	0.01	0.04	0.01	0.05
MOH	0.01	0.04	0.01	0.06	0.03	0.14	0.05	0.20
MOH	0.04	0.19	0.06	0.27	0.14	0.58	0.19	0.83
MOH	0.08	0.36	0.12	0.51	0.31	1.31	0.44	1.87
NSP	0.11	0.47	0.16	0.67	0.41	1.74	0.58	2.48
NSP	0.24	1.03	0.34	1.47	0.88	3.77	1.25	5.38
NSTT	0.06	0.28	0.09	0.40	0.20	0.86	0.28	1.22
NSTT	0.08	0.34	0.11	0.49	0.25	1.05	0.35	1.50
OKG	0.28	1.21	0.40	1.73	1.10	4.70	1.56	6.70
ORE	0.07	0.31	0.10	0.44	0.30	1.27	0.42	1.80
ORE	0.11	0.48	0.16	0.69	0.47	2.00	0.67	2.85
PFL	0.04	0.16	0.05	0.23	0.12	0.50	0.17	0.72
PFL	0.20	0.87	0.29	1.25	0.74	3.17	1.05	4.51
PHB	0.26	1.12	0.37	1.60	0.87	3.74	1.24	5.33
PHB	0.28	1.18	0.39	1.68	0.94	4.02	1.34	5.73
PLV	0.02	0.08	0.03	0.12	0.08	0.36	0.12	0.51
PLV	0.04	0.17	0.06	0.24	0.15	0.64	0.21	0.90
PLV	0.08	0.36	0.12	0.51	0.30	1.29	0.43	1.84
RKN	0.15	0.62	0.21	0.89	0.49	2.08	0.69	2.97
RKN	0.21	0.92	0.30	1.31	0.71	3.05	1.01	4.35
RYS	0.06	0.24	0.08	0.34	0.17	0.73	0.24	1.04
RYS	0.17	0.71	0.24	1.01	0.53	2.27	0.76	3.24
SPR	0.30	1.26	0.42	1.80	1.24	5.30	1.76	7.56
SPR	0.37	1.57	0.52	2.23	1.46	6.24	2.07	8.89
ST1	0.03	0.12	0.04	0.17	0.09	0.37	0.12	0.53
ST1	0.04	0.18	0.06	0.26	0.13	0.56	0.19	0.80
ST2	0.06	0.25	0.08	0.35	0.18	0.76	0.25	1.08
ST2	0.07	0.29	0.10	0.41	0.21	0.89	0.30	1.27
STO	0.06	0.27	0.09	0.38	0.26	1.11	0.37	1.58

SUP	0.08	0.33	0.11	0.47	0.25	1.05	0.35	1.50
SUP	0.09	0.37	0.12	0.53	0.28	1.19	0.40	1.70
SUP	0.13	0.56	0.18	0.79	0.52	2.24	0.74	3.19
SYC	0.08	0.35	0.12	0.50	0.30	1.30	0.43	1.85
SYC	0.19	0.83	0.28	1.19	0.72	3.11	1.03	4.43
SYN	0.13	0.57	0.19	0.81	0.50	2.13	0.71	3.04
TBL	0.13	0.56	0.18	0.79	0.49	2.09	0.69	2.97
TKY	0.12	0.49	0.16	0.70	0.36	1.56	0.52	2.22
TOC	0.15	0.66	0.22	0.93	0.54	2.30	0.77	3.28
VER	0.06	0.25	0.08	0.35	0.25	1.06	0.35	1.51
VER	0.14	0.60	0.20	0.86	0.66	2.82	0.94	4.02
WE1	0.00	0.01	0.00	0.01	0.01	0.02	0.01	0.03
WE3	0.14	0.58	0.19	0.83	0.44	1.88	0.63	2.68
WGA	0.13	0.57	0.19	0.82	0.49	2.09	0.70	2.98
WGA	0.22	0.93	0.31	1.33	0.76	3.28	1.09	4.67
WLT	0.11	0.48	0.16	0.69	0.37	1.57	0.52	2.24
WLT	0.19	0.84	0.28	1.19	0.60	2.59	0.86	3.69
WLT	0.31	1.31	0.44	1.87	1.00	4.31	1.43	6.14
WMD	0.05	0.20	0.07	0.28	0.20	0.85	0.28	1.21
WMD	0.22	0.96	0.32	1.37	0.86	3.70	1.23	5.27
WPK	0.17	0.75	0.25	1.07	0.57	2.43	0.81	3.46
WPT	0.34	1.47	0.49	2.10	1.38	5.91	1.96	8.42
WTN	0.13	0.56	0.19	0.80	0.48	2.05	0.68	2.92
WTN	0.20	0.85	0.28	1.21	0.68	2.91	0.97	4.14
WTN	0.33	1.42	0.47	2.03	1.11	4.76	1.58	6.78
YAR	0.04	0.16	0.05	0.22	0.15	0.65	0.21	0.92

Appendix D: Transmission Impact Results (Without Demand Response)

N-2, Non-Aggressive/Aggressive, Level 1/2, 2018

	Voltage Contingency	Voltage Load Margin	Worst-Case Bus	Thermal Contingency	Overloaded Equipment	Percent Overload	Thermal Load Margin
Basecase	COL-NMA dbl ckt	210	696 WLT	COL-NMA dbl ckt	PTE-COL 69-kV	134.1%	0
Non-Aggressive Level 1	COL-NMA dbl ckt	200	696 WLT	COL-NMA dbl ckt	ARE-SPG 69-kV PTE-COL 69-kV	111.8% 136.3%	0
Aggressive Level 1	COL-NMA dbl ckt	195	696 WLT	COL-NMA dbl ckt	ARE-SPG 69-kV PTE-COL 69-kV	112.6% 137.3%	0
Non-Aggressive Level 2	COL-NMA dbl ckt	165	696 WLT	COL-NMA dbl ckt	DHT-OKE 69-kV ARE-SPG 69-kV PTE-COL 69-kV	111.9% 118.0% 144.0%	0
Aggressive Level 2	COL-NMA dbl ckt	140	696 WLT	COL-NMA dbl ckt	DHT-OKE 69-kV ARE-SPG 69-kV PTE-COL 69-kV	117.2% 122.7% 149.4%	0

N-1, Non-Aggressive/Aggressive, Level 1/2, 2018

	Voltage Contingency	Voltage Load Margin	Worst-Case Bus	Thermal Contingency	Overloaded Equipment	Percent Overload	Thermal Load Margin
Basecase	ROE-WPT ckt	665	709 NSP	BLT-SYC ckt	GWY-SYC 69-kV	110.20%	385
Non-Aggressive Level 1	ROE-WPT ckt	660	709 NSP	BLT-SYC ckt	GWY-SYC 69-kV	110.50%	375
Aggressive Level 1	ROE-WPT ckt	655	709 NSP	BLT-SYC ckt	GWY-SYC 69-kV	110.60%	370
Non-Aggressive Level 2	ROE-WPT ckt	625	709 NSP	BLT-SYC ckt	GWY-SYC 69-kV	110.00%	330
Aggressive Level 2	ROE-WPT ckt	605	709 NSP	BLT-SYC ckt	GWY-SYC 69-kV	110.20%	310

N-2, Non-Aggressive/Aggressive, Level 1/2, 2026

	Voltage Contingency	Voltage Load Margin	Worst-Case Bus	Thermal Contingency	Overloaded Equipment	Percent Overload	Thermal Load Margin
Basecase	COL-NMA dbl ckt	210	696 WLT	COL-NMA dbl ckt	PTE-COL 69-kV	134.1%	0
Non-Aggressive Level 1	COL-NMA dbl ckt	170	696 WLT	COL-NMA dbl ckt	DHT-OKE 69-kV ARE-SPG 69-kV PTE-COL 69-kV	110.4% 116.7% 142.4%	0
Aggressive Level 1	COL-NMA dbl ckt	155	696 WLT	COL-NMA dbl ckt	DHT-OKE 69-kV ARE-SPG 69-kV PTE-COL 69-kV	113.8% 119.9% 146.1%	0
Non-Aggressive Level 2	COL-NMA dbl ckt	35	696 WLT	COL-NMA dbl ckt	DHT-OKE 69-kV ARE-SPG 69-kV MZI-ARE 69-kV PTE-COL 69-kV LOD-DAN 69-kV	148.3% 150.2% 114.3% 183.0% 117.6%	0
Aggressive Level 2	COL-NMA dbl ckt	0	696 WLT	N/A	Insecure Basecase	N/A	N/A

N-1, Non-Aggressive/Aggressive, Level 1/2, 2026

	Voltage Contingency	Voltage Load Margin	Worst-Case Bus	Thermal Contingency	Overloaded Equipment	Percent Overload	Thermal Load Margin
Basecase	ROE-WPT ckt	665	709 NSP	BLT-SYC ckt	GWY-SYC 69-kV	110.20%	385
Non-Aggressive Level 1	ROE-WPT ckt	630	709 NSP	RYS-RYS ckt	SYN-FCH 69-kV	110.10%	345
Aggressive Level 1	ROE-WPT ckt	615	709 NSP	BLT-SYC ckt	GWY-SYC 69-kV	110.20%	330
Non-Aggressive Level 2	ROE-WPT ckt	505	709 NSP	RYS-RYS ckt	SYN-FCH 69-kV	110.10%	205
Aggressive Level 2	ROE-WPT ckt	435	709 NSP	RYS-RYS ckt	SYN-FCH 69-kV	110.10%	125

Appendix E: Distribution Impact Results (With Demand Response)

Non-Aggressive/Aggressive, Level 1, 8 Households per Transformer (through 2018)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	1 PHEV																							
Winter Peak	7.9	7.9	7.8	7.5	7.6	7.9	8.5	9.3	9.4	9.2	9.2	9.0	9.0	8.9	8.9	9.6	10.4	12.2	14.0	14.2	13.9	12.5	10.3	8.6
Summer Peak	19.9	19.9	19.5	18.8	18.9	19.9	20.5	21.3	21.0	22.9	25.6	29.5	35.1	40.8	44.2	45.3	43.0	36.9	31.2	26.8	27.5	25.5	22.7	20.0
Winter Typical	8.1	8.1	7.8	7.5	7.9	8.1	9.3	9.8	8.1	7.9	7.8	7.6	7.5	7.5	7.7	8.7	10.0	12.1	13.8	14.0	13.8	12.3	10.2	8.4
Summer Typical	11.0	11.0	10.8	10.4	10.7	11.0	11.5	12.0	10.9	11.3	12.1	13.2	15.0	16.9	18.2	19.1	18.9	17.5	16.0	15.1	16.1	15.0	13.0	11.0
	2 PHEV																							
Winter Peak	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.3	9.4	9.2	9.2	9.0	9.0	8.9	8.9	9.6	10.4	12.2	14.0	14.2	13.9	12.5	10.3	9.0
Summer Peak	20.7	20.7	20.7	20.5	20.7	20.7	20.7	21.3	21.0	22.9	25.6	29.5	35.1	40.8	44.2	45.3	43.0	36.9	31.2	26.8	27.5	25.5	22.7	20.7
Winter Typical	9.2	9.2	9.2	9.2	9.2	9.2	9.3	9.8	8.1	7.9	7.8	7.6	7.5	7.5	7.7	8.7	10.0	12.1	13.8	14.0	13.8	12.3	10.2	9.2
Summer Typical	11.9	11.9	11.9	11.9	11.9	11.9	11.9	12.0	10.9	11.3	12.1	13.2	15.0	16.9	18.2	19.1	18.9	17.5	16.0	15.1	16.1	15.0	13.0	11.9
	3 PHEV																							
Winter Peak	10.0	10.0	10.0	10.0	10.0	10.0	10.0	9.3	9.4	9.2	9.2	9.0	9.0	8.9	8.9	9.6	10.4	12.2	14.0	14.2	13.9	12.5	10.3	10.0
Summer Peak	21.7	21.7	21.7	21.7	21.7	21.7	21.7	21.3	21.0	22.9	25.6	29.5	35.1	40.8	44.2	45.3	43.0	36.9	31.2	26.8	27.5	25.5	22.7	21.7
Winter Typical	10.2	10.2	10.2	10.2	10.2	10.2	10.2	9.8	8.1	7.9	7.8	7.6	7.5	7.5	7.7	8.7	10.0	12.1	13.8	14.0	13.8	12.3	10.2	10.2
Summer Typical	13.0	13.0	13.0	13.0	13.0	13.0	13.0	12.0	10.9	11.3	12.1	13.2	15.0	16.9	18.2	19.1	18.9	17.5	16.0	15.1	16.1	15.0	13.0	13.0

Non-Aggressive/Aggressive, Level 1, 10 Households per Transformer (through 2018)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	1 PHEV																							
Winter Peak	9.8	9.6	9.4	8.9	9.0	9.6	10.6	11.6	11.8	11.5	11.5	11.3	11.2	11.2	11.2	12.0	13.0	15.2	17.4	17.8	17.4	15.6	12.9	10.7
Summer Peak	24.7	24.4	23.9	23.0	23.2	24.6	25.6	26.7	26.2	28.6	32.0	36.9	43.9	51.0	55.3	56.7	53.7	46.1	39.0	33.5	34.4	31.9	28.4	25.0
Winter Typical	9.9	9.7	9.3	9.0	9.4	10.1	11.7	12.3	10.1	9.9	9.7	9.5	9.4	9.4	9.6	10.9	12.6	15.1	17.3	17.5	17.2	15.4	12.7	10.5
Summer Typical	13.6	13.4	13.1	12.6	12.9	13.6	14.4	15.0	13.6	14.2	15.1	16.5	18.8	21.2	22.7	23.9	23.6	21.9	20.1	18.8	20.1	18.8	16.2	13.7
	2 PHEV																							
Winter Peak	10.9	10.6	10.5	10.4	10.4	10.7	11.1	11.6	11.8	11.5	11.5	11.3	11.2	11.2	11.2	12.0	13.0	15.2	17.4	17.8	17.4	15.6	12.9	11.1
Summer Peak	25.5	25.3	25.1	24.8	25.0	25.5	25.8	26.7	26.2	28.6	32.0	36.9	43.9	51.0	55.3	56.7	53.7	46.1	39.0	33.5	34.4	31.9	28.4	25.7
Winter Typical	11.0	10.7	10.7	10.6	10.7	11.1	11.7	12.3	10.1	9.9	9.7	9.5	9.4	9.4	9.6	10.9	12.6	15.1	17.3	17.5	17.2	15.4	12.7	11.3
Summer Typical	14.5	14.3	14.2	14.1	14.2	14.5	14.8	15.0	13.6	14.2	15.1	16.5	18.8	21.2	22.7	23.9	23.6	21.9	20.1	18.8	20.1	18.8	16.2	14.7
	3 PHEV																							
Winter Peak	11.9	11.7	11.5	11.4	11.5	11.7	12.1	11.6	11.8	11.5	11.5	11.3	11.2	11.2	11.2	12.0	13.0	15.2	17.4	17.8	17.4	15.6	12.9	12.1
Summer Peak	26.5	26.2	26.1	25.9	26.0	26.4	26.8	26.7	26.2	28.6	32.0	36.9	43.9	51.0	55.3	56.7	53.7	46.1	39.0	33.5	34.4	31.9	28.4	26.7
Winter Typical	12.0	11.8	11.7	11.6	11.7	12.1	12.5	12.3	10.1	9.9	9.7	9.5	9.4	9.4	9.6	10.9	12.6	15.1	17.3	17.5	17.2	15.4	12.7	12.3
Summer Typical	15.6	15.3	15.2	15.1	15.2	15.6	15.8	15.0	13.6	14.2	15.1	16.5	18.8	21.2	22.7	23.9	23.6	21.9	20.1	18.8	20.1	18.8	16.2	15.7

Non-Aggressive/Aggressive, Level 2, 8 Households per Transformer (through 2018)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	1 PHEV																							
Winter Peak	7.8	7.8	7.8	7.8	7.8	7.8	8.5	9.3	9.4	9.2	9.2	9.0	9.0	8.9	8.9	9.6	10.4	12.2	14.0	14.2	13.9	12.5	10.3	8.6
Summer Peak	19.5	19.5	19.5	19.5	19.5	19.5	20.5	21.3	21.0	22.9	25.6	29.5	35.1	40.8	44.2	45.3	43.0	36.9	31.2	26.8	27.5	25.5	22.7	20.0
Winter Typical	7.9	7.9	7.9	7.9	7.9	7.9	9.3	9.8	8.1	7.9	7.8	7.6	7.5	7.5	7.7	8.7	10.0	12.1	13.8	14.0	13.8	12.3	10.2	8.4
Summer Typical	10.8	10.8	10.8	10.8	10.8	10.8	11.5	12.0	10.9	11.3	12.1	13.2	15.0	16.9	18.2	19.1	18.9	17.5	16.0	15.1	16.1	15.0	13.0	10.9
	2 PHEV																							
Winter Peak	9.0	9.0	9.0	9.0	9.0	9.0	9.0	9.3	9.4	9.2	9.2	9.0	9.0	8.9	8.9	9.6	10.4	12.2	14.0	14.2	13.9	12.5	10.3	9.0
Summer Peak	20.7	20.7	20.7	20.7	20.7	20.7	20.7	21.3	21.0	22.9	25.6	29.5	35.1	40.8	44.2	45.3	43.0	36.9	31.2	26.8	27.5	25.5	22.7	20.7
Winter Typical	9.2	9.2	9.2	9.2	9.2	9.2	9.3	9.8	8.1	7.9	7.8	7.6	7.5	7.5	7.7	8.7	10.0	12.1	13.8	14.0	13.8	12.3	10.2	9.2
Summer Typical	11.9	11.9	11.9	11.9	11.9	11.9	11.9	12.0	10.9	11.3	12.1	13.2	15.0	16.9	18.2	19.1	18.9	17.5	16.0	15.1	16.1	15.0	13.0	11.9
	3 PHEV																							
Winter Peak	10.0	10.0	10.0	10.0	10.0	10.0	10.0	9.3	9.4	9.2	9.2	9.0	9.0	8.9	8.9	9.6	10.4	12.2	14.0	14.2	13.9	12.5	10.3	10.0
Summer Peak	21.7	21.7	21.7	21.7	21.7	21.7	21.7	21.3	21.0	22.9	25.6	29.5	35.1	40.8	44.2	45.3	43.0	36.9	31.2	26.8	27.5	25.5	22.7	21.7
Winter Typical	10.2	10.2	10.2	10.2	10.2	10.2	10.2	9.8	8.1	7.9	7.8	7.6	7.5	7.5	7.7	8.7	10.0	12.1	13.8	14.0	13.8	12.3	10.2	10.2
Summer Typical	13.0	13.0	13.0	13.0	13.0	13.0	13.0	12.0	10.9	11.3	12.1	13.2	15.0	16.9	18.2	19.1	18.9	17.5	16.0	15.1	16.1	15.0	13.0	13.0

Non-Aggressive/Aggressive, Level 2, 10 Households per Transformer (through 2018)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
	1 PHEV																							
Winter Peak	9.7	9.4	9.3	9.2	9.2	9.5	10.6	11.6	11.8	11.5	11.5	11.3	11.2	11.2	11.2	12.0	13.0	15.2	17.4	17.8	17.4	15.6	12.9	10.7
Summer Peak	24.3	24.0	23.9	23.7	23.7	24.2	25.6	26.7	26.2	28.6	32.0	36.9	43.9	51.0	55.3	56.7	53.7	46.1	39.0	33.5	34.4	31.9	28.4	25.0
Winter Typical	9.7	9.5	9.4	9.4	9.5	9.9	11.7	12.3	10.1	9.9	9.7	9.5	9.4	9.4	9.6	10.9	12.6	15.1	17.3	17.5	17.2	15.4	12.7	10.5
Summer Typical	13.4	13.2	13.1	13.0	13.1	13.4	14.4	15.0	13.6	14.2	15.1	16.5	18.8	21.2	22.7	23.9	23.6	21.9	20.1	18.8	20.1	18.8	16.2	13.6
	2 PHEV																							
Winter Peak	10.9	10.6	10.5	10.4	10.4	10.7	11.1	11.6	11.8	11.5	11.5	11.3	11.2	11.2	11.2	12.0	13.0	15.2	17.4	17.8	17.4	15.6	12.9	11.1
Summer Peak	25.5	25.2	25.1	24.9	25.0	25.4	25.8	26.7	26.2	28.6	32.0	36.9	43.9	51.0	55.3	56.7	53.7	46.1	39.0	33.5	34.4	31.9	28.4	25.7
Winter Typical	11.0	10.7	10.7	10.6	10.7	11.1	11.7	12.3	10.1	9.9	9.7	9.5	9.4	9.4	9.6	10.9	12.6	15.1	17.3	17.5	17.2	15.4	12.7	11.3
Summer Typical	14.5	14.3	14.2	14.1	14.2	14.5	14.8	15.0	13.6	14.2	15.1	16.5	18.8	21.2	22.7	23.9	23.6	21.9	20.1	18.8	20.1	18.8	16.2	14.7
	3 PHEV																							
Winter Peak	11.9	11.7	11.5	11.4	11.5	11.7	12.1	11.6	11.8	11.5	11.5	11.3	11.2	11.2	11.2	12.0	13.0	15.2	17.4	17.8	17.4	15.6	12.9	12.1
Summer Peak	26.5	26.2	26.1	25.9	26.0	26.4	26.8	26.7	26.2	28.6	32.0	36.9	43.9	51.0	55.3	56.7	53.7	46.1	39.0	33.5	34.4	31.9	28.4	26.7
Winter Typical	12.0	11.8	11.7	11.6	11.7	12.1	12.5	12.3	10.1	9.9	9.7	9.5	9.4	9.4	9.6	10.9	12.6	15.1	17.3	17.5	17.2	15.4	12.7	12.3
Summer Typical	15.6	15.3	15.2	15.1	15.2	15.6	15.8	15.0	13.6	14.2	15.1	16.5	18.8	21.2	22.7	23.9	23.6	21.9	20.1	18.8	20.1	18.8	16.2	15.7

Appendix F: Transmission Bus Loading (With Demand Response)

Non-Aggressive/Aggressive, Level 1/2, 2018/2026

	Non-Aggressive Level 1 2018	Non-Aggressive Level 2 2018	Aggressive Level 1 2018	Aggressive Level 2 2018	Non-Aggressive Level 1 2026	Non-Aggressive Level 2 2026	Aggressive Level 1 2026	Aggressive Level 2 2026
AMN	0.07	0.31	0.10	0.45	0.26	1.13	0.37	1.61
AMN	0.10	0.41	0.14	0.59	0.38	1.65	0.55	2.35
BKE	0.04	0.19	0.06	0.27	0.14	0.59	0.20	0.84
BLE	0.07	0.28	0.09	0.40	0.25	1.06	0.35	1.50
BLH	0.21	0.88	0.29	1.26	0.64	2.73	0.91	3.88
BLH	0.23	1.00	0.33	1.43	0.72	3.11	1.03	4.43
BLT	0.03	0.12	0.04	0.17	0.09	0.38	0.13	0.54
BLT	0.07	0.29	0.10	0.42	0.21	0.91	0.30	1.30
BLT	0.28	1.22	0.40	1.73	0.88	3.77	1.25	5.37
BLT	0.31	1.34	0.45	1.91	0.97	4.15	1.38	5.92
BPK	0.04	0.16	0.05	0.23	0.12	0.52	0.17	0.74
BRD	0.23	0.97	0.32	1.38	0.72	3.10	1.03	4.42
BYN	0.17	0.75	0.25	1.07	0.69	2.97	0.99	4.24
CCS	0.08	0.35	0.11	0.49	0.38	1.62	0.54	2.31
CCS	0.49	2.08	0.69	2.96	2.28	9.75	3.24	13.90
CDO	0.18	0.78	0.26	1.10	0.58	2.48	0.82	3.53
COD	0.08	0.35	0.12	0.50	0.31	1.32	0.44	1.88
COGT	0.19	0.81	0.27	1.15	0.80	3.42	1.14	4.87
CRP	0.14	0.59	0.20	0.84	0.47	2.01	0.67	2.87
DAN	0.05	0.22	0.07	0.32	0.22	0.93	0.31	1.33
DEF	0.09	0.37	0.12	0.53	0.34	1.46	0.49	2.09
DEF	0.10	0.43	0.14	0.61	0.39	1.69	0.56	2.41
ECA	0.01	0.04	0.01	0.06	0.03	0.13	0.04	0.19
ECA	0.15	0.65	0.22	0.93	0.49	2.09	0.69	2.97
ECA	0.19	0.81	0.27	1.16	0.60	2.56	0.85	3.64
ECA	0.35	1.48	0.49	2.11	1.09	4.66	1.55	6.64
ETN	0.07	0.30	0.10	0.42	0.27	1.16	0.39	1.65
ETN	0.11	0.46	0.15	0.66	0.41	1.77	0.59	2.53
FCH	0.28	1.21	0.40	1.73	1.03	4.42	1.47	6.30

FCH	0.43	1.86	0.62	2.65	1.63	7.01	2.33	9.98
FEM	0.06	0.24	0.08	0.34	0.22	0.96	0.32	1.36
FEM	0.07	0.29	0.10	0.42	0.24	1.04	0.34	1.48
GAST	0.21	0.89	0.29	1.26	0.97	4.16	1.38	5.93
GWY	0.04	0.19	0.06	0.27	0.14	0.60	0.20	0.85
HKP	0.14	0.59	0.20	0.84	0.43	1.85	0.61	2.63
HKP	0.18	0.79	0.26	1.13	0.58	2.47	0.82	3.52
MAZ	0.10	0.44	0.15	0.63	0.40	1.70	0.57	2.42
MCF	0.20	0.84	0.28	1.19	0.73	3.13	1.04	4.46
MHL	0.00	0.01	0.00	0.02	0.01	0.04	0.01	0.05
MOH	0.01	0.04	0.01	0.06	0.03	0.14	0.05	0.20
MOH	0.04	0.19	0.06	0.27	0.14	0.58	0.19	0.83
MOH	0.08	0.36	0.12	0.51	0.31	1.31	0.44	1.87
NSP	0.11	0.47	0.16	0.67	0.41	1.74	0.58	2.48
NSP	0.24	1.03	0.34	1.47	0.88	3.77	1.25	5.38
NSTT	0.06	0.28	0.09	0.40	0.20	0.86	0.28	1.22
NSTT	0.08	0.34	0.11	0.49	0.25	1.05	0.35	1.50
OKG	0.28	1.21	0.40	1.73	1.10	4.70	1.56	6.70
ORE	0.07	0.31	0.10	0.44	0.30	1.27	0.42	1.80
ORE	0.11	0.48	0.16	0.69	0.47	2.00	0.67	2.85
PFL	0.04	0.16	0.05	0.23	0.12	0.50	0.17	0.72
PFL	0.20	0.87	0.29	1.25	0.74	3.17	1.05	4.51
PHB	0.26	1.12	0.37	1.60	0.87	3.74	1.24	5.33
PHB	0.28	1.18	0.39	1.68	0.94	4.02	1.34	5.73
PLV	0.02	0.08	0.03	0.12	0.08	0.36	0.12	0.51
PLV	0.04	0.17	0.06	0.24	0.15	0.64	0.21	0.90
PLV	0.08	0.36	0.12	0.51	0.30	1.29	0.43	1.84
RKN	0.15	0.62	0.21	0.89	0.49	2.08	0.69	2.97
RKN	0.21	0.92	0.30	1.31	0.71	3.05	1.01	4.35
RYS	0.06	0.24	0.08	0.34	0.17	0.73	0.24	1.04
RYS	0.17	0.71	0.24	1.01	0.53	2.27	0.76	3.24
SPR	0.30	1.26	0.42	1.80	1.24	5.30	1.76	7.56
SPR	0.37	1.57	0.52	2.23	1.46	6.24	2.07	8.89
ST1	0.03	0.12	0.04	0.17	0.09	0.37	0.12	0.53
ST1	0.04	0.18	0.06	0.26	0.13	0.56	0.19	0.80
ST2	0.06	0.25	0.08	0.35	0.18	0.76	0.25	1.08
ST2	0.07	0.29	0.10	0.41	0.21	0.89	0.30	1.27
STO	0.06	0.27	0.09	0.38	0.26	1.11	0.37	1.58

SUP	0.08	0.33	0.11	0.47	0.25	1.05	0.35	1.50
SUP	0.09	0.37	0.12	0.53	0.28	1.19	0.40	1.70
SUP	0.13	0.56	0.18	0.79	0.52	2.24	0.74	3.19
SYC	0.08	0.35	0.12	0.50	0.30	1.30	0.43	1.85
SYC	0.19	0.83	0.28	1.19	0.72	3.11	1.03	4.43
SYN	0.13	0.57	0.19	0.81	0.50	2.13	0.71	3.04
TBL	0.13	0.56	0.18	0.79	0.49	2.09	0.69	2.97
TKY	0.12	0.49	0.16	0.70	0.36	1.56	0.52	2.22
TOC	0.15	0.66	0.22	0.93	0.54	2.30	0.77	3.28
VER	0.06	0.25	0.08	0.35	0.25	1.06	0.35	1.51
VER	0.14	0.60	0.20	0.86	0.66	2.82	0.94	4.02
WE1	0.00	0.01	0.00	0.01	0.01	0.02	0.01	0.03
WE3	0.14	0.58	0.19	0.83	0.44	1.88	0.63	2.68
WGA	0.13	0.57	0.19	0.82	0.49	2.09	0.70	2.98
WGA	0.22	0.93	0.31	1.33	0.76	3.28	1.09	4.67
WLT	0.11	0.48	0.16	0.69	0.37	1.57	0.52	2.24
WLT	0.19	0.84	0.28	1.19	0.60	2.59	0.86	3.69
WLT	0.31	1.31	0.44	1.87	1.00	4.31	1.43	6.14
WMD	0.05	0.20	0.07	0.28	0.20	0.85	0.28	1.21
WMD	0.22	0.96	0.32	1.37	0.86	3.70	1.23	5.27
WPK	0.17	0.75	0.25	1.07	0.57	2.43	0.81	3.46
WPT	0.34	1.47	0.49	2.10	1.38	5.91	1.96	8.42
WTN	0.13	0.56	0.19	0.80	0.48	2.05	0.68	2.92
WTN	0.20	0.85	0.28	1.21	0.68	2.91	0.97	4.14
WTN	0.33	1.42	0.47	2.03	1.11	4.76	1.58	6.78
YAR	0.04	0.16	0.05	0.22	0.15	0.65	0.21	0.92

Appendix G: Transmission Impact Results (With Demand Response)

N-2, Non-Aggressive/Aggressive, Level 1/2, 2018

	Voltage Contingency	Voltage Load Margin	Worst-Case Bus	Thermal Contingency	Overloaded Equipment	Percent Overload	Thermal Load Margin
Basecase	COL-NMA dbl ckt	520	696 WLT	COL-NMA dbl ckt	PTE-COL 69-kV	110.90%	285
Non-Aggressive Level 1	COL-NMA dbl ckt	510	696 WLT	COL-NMA dbl ckt	PTE-COL 69-kV	110.40%	270
Aggressive Level 1	COL-NMA dbl ckt	510	696 WLT	COL-NMA dbl ckt	PTE-COL 69-kV	110.40%	265
Non-Aggressive Level 2	COL-NMA dbl ckt	475	696 WLT	COL-NMA dbl ckt	PTE-COL 69-kV	110.60%	230
Aggressive Level 2	COL-NMA dbl ckt	455	696 WLT	COL-NMA dbl ckt	PTE-COL 69-kV	110.20%	205

N-1, Non-Aggressive/Aggressive, Level 1/2, 2018

	Voltage Contingency	Voltage Load Margin	Worst-Case Bus	Thermal Contingency	Overloaded Equipment	Percent Overload	Thermal Load Margin
Basecase	ROE-WPT ckt	935	709 NSP	BLT-SYC ckt	GWY-SYC 69-kV	110.00%	510
Non-Aggressive Level 1	ROE-WPT ckt	925	709 NSP	BLT-SYC ckt	GWY-SYC 69-kV	110.50%	505
Aggressive Level 1	ROE-WPT ckt	925	709 NSP	BLT-SYC ckt	GWY-SYC 69-kV	110.40%	500
Non-Aggressive Level 2	ROE-WPT ckt	890	709 NSP	BLT-SYC ckt	GWY-SYC 69-kV	110.10%	470
Aggressive Level 2	ROE-WPT ckt	875	709 NSP	BLT-SYC ckt	GWY-SYC 69-kV	110.40%	455

N-2, Non-Aggressive/Aggressive, Level 1/2, 2026

	Voltage Contingency	Voltage Load Margin	Worst-Case Bus	Thermal Contingency	Overloaded Equipment	Percent Overload	Thermal Load Margin
Basecase	COL-NMA dbl ckt	520	696 WLT	COL-NMA dbl ckt	PTE-COL 69-kV	110.90%	285
Non-Aggressive Level 1	COL-NMA dbl ckt	485	696 WLT	COL-NMA dbl ckt	PTE-COL 69-kV	110.80%	240
Aggressive Level 1	COL-NMA dbl ckt	470	696 WLT	COL-NMA dbl ckt	PTE-COL 69-kV	110.60%	220
Non-Aggressive Level 2	COL-NMA dbl ckt	355	696 WLT	COL-NMA dbl ckt	PTE-COL 69-kV	110.50%	90
Aggressive Level 2	COL-NMA dbl ckt	275	696 WLT	COL-NMA dbl ckt	PTE-COL 69-kV	110.20%	5

N-1, Non-Aggressive/Aggressive, Level 1/2, 2026

	Voltage Contingency	Voltage Load Margin	Worst-Case Bus	Thermal Contingency	Overloaded Equipment	Percent Overload	Thermal Load Margin
Basecase	ROE-WPT ckt	935	709 NSP	BLT-SYC ckt	GWY-SYC 69-kV	110.00%	510
Non-Aggressive Level 1	ROE-WPT ckt	900	709 NSP	BLT-SYC ckt	GWY-SYC 69-kV	110.10%	485
Aggressive Level 1	ROE-WPT ckt	885	709 NSP	BLT-SYC ckt	GWY-SYC 69-kV	110.30%	475
Non-Aggressive Level 2	ROE-WPT ckt	770	709 NSP	BLT-SYC ckt	GWY-SYC 69-kV	110.00%	385
Aggressive Level 2	ROE-WPT ckt	695	709 NSP	ROE-WPT ckt	ARE-SPG 69-kV	110.50%	315

Appendix H: Simple Payback Period Results (With Demand Response)

PHEV Electricity Requirements

	10 mi/day	on-peak cost	typical cost	off-peak cost	30 mi/day	on-peak cost	typical cost	off-peak cost	70 mi/day	on-peak cost	typical cost	off-peak cost
CV												
HEV												
PHEV10	15.66 kWh	$3.83	$2.17	$1.05	46.97 kWh	$11.50	$6.52	$3.15	109.59 kWh	$26.82	$15.20	$7.35
PHEV20	28.38 kWh	$6.95	$3.94	$1.90	85.13 kWh	$20.84	$11.81	$5.71	198.63 kWh	$48.62	$27.56	$13.33
PHEV30	38.16 kWh	$9.34	$5.29	$2.56	114.48 kWh	$28.02	$15.88	$7.68	267.13 kWh	$65.38	$37.06	$17.92
PHEV40	46.97 kWh	$11.50	$6.52	$3.15	140.90 kWh	$34.49	$19.55	$9.45	328.77 kWh	$80.47	$45.61	$22.06
PHEV50	52.84 kWh	$12.93	$7.33	$3.55	158.51 kWh	$38.80	$21.99	$10.64	369.87 kWh	$90.53	$51.31	$24.82
PHEV60	58.71 kWh	$14.37	$8.14	$3.94	176.13 kWh	$43.11	$24.43	$11.82	410.96 kWh	$100.59	$57.01	$27.58

PHEV Gasoline Requirements

	10 mi/day	high cost ($6)	medium cost ($4)	low cost ($2)	30 mi/day	high cost ($6)	medium cost ($4)	low cost ($2)	70 mi/day	high cost ($6)	medium cost ($4)	low cost ($2)
CV	13.31 gal	$79.87	$53.25	$26.62	39.94 gal	$239.62	$159.75	$79.87	93.18 gal	$559.11	$372.74	$186.37
HEV	9.56 gal	$57.38	$38.26	$19.13	28.69 gal	$172.15	$114.77	$57.38	66.95 gal	$401.69	$267.79	$133.90
PHEV10	8.40 gal	$50.41	$33.60	$16.80	25.20 gal	$151.22	$100.81	$50.41	58.81 gal	$352.84	$235.22	$117.61
PHEV20	7.37 gal	$44.20	$29.47	$14.73	22.10 gal	$132.60	$88.40	$44.20	51.57 gal	$309.41	$206.27	$103.14
PHEV30	6.46 gal	$38.77	$25.85	$12.92	19.39 gal	$116.32	$77.55	$38.77	45.24 gal	$271.41	$180.94	$90.47
PHEV40	5.82 gal	$34.90	$23.26	$11.63	17.45 gal	$104.69	$69.79	$34.90	40.71 gal	$244.27	$162.85	$81.42
PHEV50	5.30 gal	$31.79	$21.20	$10.60	15.90 gal	$95.38	$63.59	$31.79	37.09 gal	$222.56	$148.37	$74.19
PHEV60	4.78 gal	$28.69	$19.13	$9.56	14.35 gal	$86.08	$57.38	$28.69	33.47 gal	$200.84	$133.90	$66.95

PHEV Total Fuel Requirements, Assuming 10 miles of travel per day

	on-peak and high cost	on-peak and medium cost	on-peak and low cost	typical and high cost	typical and medium cost	typical and low cost	off-peak and high cost	off-peak and medium cost	off-peak and low cost
CV	$79.87	$53.25	$26.62	$79.87	$53.25	$26.62	$79.87	$53.25	$26.62
HEV	$57.38	$38.26	$19.13	$57.38	$38.26	$19.13	$57.38	$38.26	$19.13
PHEV10	$54.24	$37.44	$20.63	$52.58	$35.78	$18.97	$51.46	$34.65	$17.85
PHEV20	$51.15	$36.41	$21.68	$48.14	$33.40	$18.67	$46.11	$31.37	$16.64
PHEV30	$48.11	$35.19	$22.26	$44.07	$31.14	$18.22	$41.33	$28.41	$15.48
PHEV40	$46.39	$34.76	$23.13	$41.41	$29.78	$18.15	$38.05	$26.42	$14.78
PHEV50	$44.73	$34.13	$23.53	$39.12	$28.53	$17.93	$35.34	$24.74	$14.14
PHEV60	$43.06	$33.50	$23.93	$36.84	$27.27	$17.71	$32.63	$23.07	$13.50

PHEV Total Fuel Requirements, Assuming 30 miles of travel per day

	on-peak and high cost	on-peak and medium cost	on-peak and low cost	typical and high cost	typical and medium cost	typical and low cost	off-peak and high cost	off-peak and medium cost	off-peak and low cost
CV	$239.62	$159.75	$79.87	$239.62	$159.75	$79.87	$239.62	$159.75	$79.87
HEV	$172.15	$114.77	$57.38	$172.15	$114.77	$57.38	$172.15	$114.77	$57.38
PHEV10	$162.71	$112.31	$61.90	$157.73	$107.33	$56.92	$154.37	$103.96	$53.56
PHEV20	$153.44	$109.24	$65.04	$144.41	$100.21	$56.01	$138.32	$94.11	$49.91
PHEV30	$144.34	$105.57	$66.79	$132.20	$93.43	$54.66	$124.00	$85.23	$46.45
PHEV40	$139.17	$104.28	$69.38	$124.23	$89.34	$54.44	$114.14	$79.25	$44.35
PHEV50	$134.18	$102.39	$70.59	$117.37	$85.58	$53.78	$106.02	$74.22	$42.43
PHEV60	$129.19	$100.49	$71.80	$110.51	$81.82	$53.13	$97.89	$69.20	$40.51

PHEV Total Fuel Requirements, Assuming 70 miles of travel per day

	on-peak and high cost	on-peak and medium cost	on-peak and low cost	typical and high cost	typical and medium cost	typical and low cost	off-peak and high cost	off-peak and medium cost	off-peak and low cost
CV	$559.11	$372.74	$186.37	$559.11	$372.74	$186.37	$559.11	$372.74	$186.37
HEV	$401.69	$267.79	$133.90	$401.69	$267.79	$133.90	$401.69	$267.79	$133.90
PHEV10	$379.66	$262.05	$144.43	$368.04	$250.43	$132.82	$360.19	$242.58	$124.97
PHEV20	$358.03	$254.89	$151.75	$336.97	$233.83	$130.69	$322.74	$219.60	$116.46
PHEV30	$336.79	$246.32	$155.85	$308.47	$218.00	$127.53	$289.34	$198.87	$108.39
PHEV40	$324.74	$243.32	$161.89	$289.88	$208.46	$127.03	$266.33	$184.91	$103.48
PHEV50	$313.09	$238.90	$164.71	$273.87	$199.68	$125.50	$247.38	$173.19	$99.00
PHEV60	$301.43	$234.48	$167.54	$257.86	$190.91	$123.96	$228.42	$161.47	$94.52

No Policy, Years required to repay the purchase premium of HEV/PHEV over CV

Assuming 10 miles of travel per day

	on-peak and high cost	on-peak and medium cost	on-peak and low cost	typical and high cost	typical and medium cost	typical and low cost	off-peak and high cost	off-peak and medium cost	off-peak and low cost
HEV	12.1	18.2	36.3	12.1	18.2	36.3	12.1	18.2	36.3
PHEV10	20.5	33.2	87.7	19.2	30.1	68.7	18.5	28.3	59.9
PHEV20	24.5	41.8	142.2	22.2	35.4	88.4	20.8	32.1	70.4
PHEV30	26.6	46.8	193.8	23.6	38.2	100.5	21.9	34.0	75.9
PHEV40	28.5	51.6	272.8	24.8	40.6	112.5	22.8	35.6	80.6
PHEV50	29.6	54.3	335.8	25.5	42.0	119.5	23.3	36.4	83.2
PHEV60	30.1	56.1	411.6	25.7	42.6	124.2	23.4	36.7	84.4

Assuming 30 miles of travel per day

	on-peak and high cost	on-peak and medium cost	on-peak and low cost	typical and high cost	typical and medium cost	typical and low cost	off-peak and high cost	off-peak and medium cost	off-peak and low cost
HEV	4.0	6.1	12.1	4.0	6.1	12.1	4.0	6.1	12.1
PHEV10	6.8	11.1	29.2	6.4	10.0	22.9	6.2	9.4	20.0
PHEV20	8.2	13.9	47.4	7.4	11.8	29.5	6.9	10.7	23.5
PHEV30	8.9	15.6	64.6	7.9	12.7	33.5	7.3	11.3	25.3
PHEV40	9.5	17.2	90.9	8.3	13.5	37.5	7.6	11.9	26.9
PHEV50	9.9	18.1	111.9	8.5	14.0	39.8	7.8	12.1	27.7
PHEV60	10.0	18.7	137.2	8.6	14.2	41.4	7.8	12.2	28.1

Assuming 70 miles of travel per day

	on-peak and high cost	on-peak and medium cost	on-peak and low cost	typical and high cost	typical and medium cost	typical and low cost	off-peak and high cost	off-peak and medium cost	off-peak and low cost
HEV	1.7	2.6	5.2	1.7	2.6	5.2	1.7	2.6	5.2
PHEV10	2.9	4.7	12.5	2.7	4.3	9.8	2.6	4.0	8.6
PHEV20	3.5	6.0	20.3	3.2	5.1	12.6	3.0	4.6	10.1
PHEV30	3.8	6.7	27.7	3.4	5.5	14.4	3.1	4.9	10.8
PHEV40	4.1	7.4	39.0	3.5	5.8	16.1	3.3	5.1	11.5
PHEV50	4.2	7.8	48.0	3.6	6.0	17.1	3.3	5.2	11.9
PHEV60	4.3	8.0	58.8	3.7	6.1	17.7	3.3	5.2	12.1

Policy decision: PHEV owners who participate in time-of-use programs will receive an incentive per kWh
Years required to repay the purchase premium of HEV/PHEV over CV

Assuming 10 miles of travel per day

	on-peak and high cost	on-peak and medium cost	on-peak and low cost	typical and high cost	typical and medium cost	typical and low cost	off-peak and high cost	off-peak and medium cost	off-peak and low cost
HEV	12.1	18.2	36.3	12.1	18.2	36.3	12.1	18.2	36.3
PHEV10	19.8	31.4	75.8	18.6	28.5	61.2	17.9	26.9	54.1
PHEV20	23.1	37.9	105.8	21.0	32.6	72.8	19.8	29.8	60.1
PHEV30	24.8	41.5	127.1	22.2	34.6	79.0	20.7	31.2	62.9
PHEV40	26.3	44.8	151.1	23.1	36.3	84.5	21.4	32.2	65.1
PHEV50	27.1	46.6	165.8	23.7	37.2	87.5	21.8	32.8	66.4
PHEV60	27.5	47.6	178.2	23.8	37.5	89.0	21.8	32.9	66.5

Assuming 30 miles of travel per day

	on-peak and high cost	on-peak and medium cost	on-peak and low cost	typical and high cost	typical and medium cost	typical and low cost	off-peak and high cost	off-peak and medium cost	off-peak and low cost
HEV	4.0	6.1	12.1	4.0	6.1	12.1	4.0	6.1	12.1
PHEV10	6.6	10.5	25.3	6.2	9.5	20.4	6.0	9.0	18.0
PHEV20	7.7	12.6	35.3	7.0	10.9	24.3	6.6	9.9	20.0
PHEV30	8.3	13.8	42.4	7.4	11.5	26.3	6.9	10.4	21.0
PHEV40	8.8	14.9	50.4	7.7	12.1	28.2	7.1	10.7	21.7
PHEV50	9.0	15.5	55.3	7.9	12.4	29.2	7.3	10.9	22.1
PHEV60	9.2	15.9	59.4	7.9	12.5	29.7	7.3	11.0	22.2

Assuming 70 miles of travel per day

	on-peak and high cost	on-peak and medium cost	on-peak and low cost	typical and high cost	typical and medium cost	typical and low cost	off-peak and high cost	off-peak and medium cost	off-peak and low cost
HEV	1.7	2.6	5.2	1.7	2.6	5.2	1.7	2.6	5.2
PHEV10	2.8	4.5	10.8	2.7	4.1	8.7	2.6	3.8	7.7
PHEV20	3.3	5.4	15.1	3.0	4.7	10.4	2.8	4.3	8.6
PHEV30	3.5	5.9	18.2	3.2	4.9	11.3	3.0	4.5	9.0
PHEV40	3.8	6.4	21.6	3.3	5.2	12.1	3.1	4.6	9.3
PHEV50	3.9	6.7	23.7	3.4	5.3	12.5	3.1	4.7	9.5
PHEV60	3.9	6.8	25.5	3.4	5.4	12.7	3.1	4.7	9.5

Policy decision: HEV/PHEV owners who purchase vehicles receive a one-time, up-front rebate
Years required to repay the purchase premium of HEV/PHEV over CV

Assuming 10 miles of travel per day

	on-peak and high cost	on-peak and medium cost	on-peak and low cost	typical and high cost	typical and medium cost	typical and low cost	off-peak and high cost	off-peak and medium cost	off-peak and low cost
HEV	2.7	4.1	8.2	2.7	4.1	8.2	2.7	4.1	8.2
PHEV10	7.5	12.1	32.1	7.0	11.0	25.1	6.8	10.3	21.9
PHEV20	12.9	22.0	74.8	11.6	18.6	46.5	10.9	16.9	37.0
PHEV30	16.1	28.3	117.4	14.3	23.2	60.9	13.3	20.6	45.9
PHEV40	18.5	33.6	177.5	16.1	26.4	73.2	14.8	23.1	52.4
PHEV50	20.1	36.9	228.0	17.3	28.5	81.1	15.8	24.7	56.5
PHEV60	21.0	39.2	287.7	18.0	29.8	86.8	16.4	25.6	59.0

Assuming 30 miles of travel per day

	on-peak and high cost	on-peak and medium cost	on-peak and low cost	typical and high cost	typical and medium cost	typical and low cost	off-peak and high cost	off-peak and medium cost	off-peak and low cost
HEV	0.9	1.4	2.7	0.9	1.4	2.7	0.9	1.4	2.7
PHEV10	2.5	4.0	10.7	2.3	3.7	8.4	2.3	3.4	7.3
PHEV20	4.3	7.3	24.9	3.9	6.2	15.5	3.6	5.6	12.3
PHEV30	5.4	9.4	39.1	4.8	7.7	20.3	4.4	6.9	15.3
PHEV40	6.2	11.2	59.2	5.4	8.8	24.4	4.9	7.7	17.5
PHEV50	6.7	12.3	76.0	5.8	9.5	27.0	5.3	8.2	18.8
PHEV60	7.0	13.1	95.9	6.0	9.9	28.9	5.5	8.5	19.7

Assuming 70 miles of travel per day

	on-peak and high cost	on-peak and medium cost	on-peak and low cost	typical and high cost	typical and medium cost	typical and low cost	off-peak and high cost	off-peak and medium cost	off-peak and low cost
HEV	0.4	0.6	1.2	0.4	0.6	1.2	0.4	0.6	1.2
PHEV10	1.1	1.7	4.6	1.0	1.6	3.6	1.0	1.5	3.1
PHEV20	1.8	3.1	10.7	1.7	2.7	6.6	1.6	2.4	5.3
PHEV30	2.3	4.0	16.8	2.0	3.3	8.7	1.9	2.9	6.6
PHEV40	2.6	4.8	25.4	2.3	3.8	10.5	2.1	3.3	7.5
PHEV50	2.9	5.3	32.6	2.5	4.1	11.6	2.3	3.5	8.1
PHEV60	3.0	5.6	41.1	2.6	4.3	12.4	2.3	3.7	8.4

Appendix I: Aggregate Regional Battery Capacity Results

	PHEV20 in 2018 with Non-Aggressive Penetration	Fleet Capacity (TWh)	PHEV20 in 2018 with Aggressive Penetration	Fleet Capacity (TWh)	PHEV20 in 2026 with Non-Aggressive Penetration	Fleet Capacity (TWh)	PHEV20 in 2026 with Aggressive Penetration	Fleet Capacity (TWh)
Dane County	9459	0.02	13479	0.03	34136	0.07	48644	0.10
Wisconsin	83670	0.17	119230	0.24	301963	0.61	430298	0.87
United States	4105263	8.31	5850000	11.84	14815789	29.99	21112500	42.74

	PHEV40 in 2018 with Non-Aggressive Penetration	Fleet Capacity (TWh)	PHEV40 in 2018 with Aggressive Penetration	Fleet Capacity (TWh)	PHEV40 in 2026 with Non-Aggressive Penetration	Fleet Capacity (TWh)	PHEV40 in 2026 with Aggressive Penetration	Fleet Capacity (TWh)
Dane County	9459	0.04	13479	0.06	34136	0.14	48644	0.20
Wisconsin	83670	0.34	119230	0.49	301963	1.24	430298	1.76
United States	4105263	16.80	5850000	23.94	14815789	60.62	21112500	86.38

	PHEV60 in 2018 with Non-Aggressive Penetration	Fleet Capacity (TWh)	PHEV60 in 2018 with Aggressive Penetration	Fleet Capacity (TWh)	PHEV60 in 2026 with Non-Aggressive Penetration	Fleet Capacity (TWh)	PHEV60 in 2026 with Aggressive Penetration	Fleet Capacity (TWh)
Dane County	9459	0.06	13479	0.08	34136	0.21	48644	0.31
Wisconsin	83670	0.53	119230	0.75	301963	1.90	430298	2.71
United States	4105263	25.81	5850000	36.79	14815789	93.16	21112500	132.76

Appendix J: National Battery Capacity Results

	PHEV20 in 2018 with Non-Aggressive Penetration	Fleet Capacity (TWh)	PHEV20 in 2018 with Aggressive Penetration	Fleet Capacity (TWh)	PHEV20 in 2026 with Non-Aggressive Penetration	Fleet Capacity (TWh)	PHEV20 in 2026 with Aggressive Penetration	Fleet Capacity (TWh)
Northeast	673263	1.36	959400	1.94	2429789	4.92	3462450	7.01
Midwest	1030421	2.09	1468350	2.97	3718763	7.53	5299238	10.73
South	1498421	3.03	2135250	4.32	5407763	10.95	7706063	15.60
West	903158	1.83	1287000	2.61	3259474	6.60	4644750	9.40

	PHEV40 in 2018 with Non-Aggressive Penetration	Fleet Capacity (TWh)	PHEV40 in 2018 with Aggressive Penetration	Fleet Capacity (TWh)	PHEV40 in 2026 with Non-Aggressive Penetration	Fleet Capacity (TWh)	PHEV40 in 2026 with Aggressive Penetration	Fleet Capacity (TWh)
Northeast	673263	2.75	959400	3.93	2429789	9.94	3462450	14.17
Midwest	1030421	4.22	1468350	6.01	3718763	15.22	5299238	21.68
South	1498421	6.13	2135250	8.74	5407763	22.13	7706063	31.53
West	903158	3.70	1287000	5.27	3259474	13.34	4644750	19.00

	PHEV60 in 2018 with Non-Aggressive Penetration	Fleet Capacity (TWh)	PHEV60 in 2018 with Aggressive Penetration	Fleet Capacity (TWh)	PHEV60 in 2026 with Non-Aggressive Penetration	Fleet Capacity (TWh)	PHEV60 in 2026 with Aggressive Penetration	Fleet Capacity (TWh)
Northeast	673263	4.23	959400	6.03	2429789	15.28	3462450	21.77
Midwest	1030421	6.48	1468350	9.23	3718763	23.38	5299238	33.32
South	1498421	9.42	2135250	13.43	5407763	34.01	7706063	48.46
West	903158	5.68	1287000	8.09	3259474	20.50	4644750	29.21