



**Review of Utility Integrated
Resource Plans and Electric Vehicle
Load Forecasting
September 2013**



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Executive Summary

As the number of plug-in electric vehicles (EVs) in use continues to grow, the grid implications of these vehicles is an important planning consideration for energy utilities. In the short term, EVs will comprise a relatively small but growing proportion of the nation's vehicle fleet and research suggests that current grid infrastructure is sufficient to support EV charging needs. There is some concern around whether the grid's distribution infrastructure will have the capacity to accommodate the additional load of EV charging in the long term, especially if this charging adds to peak load. However, there is also an opportunity to use this demand-side resource to support integration of renewables energy or other demand response activities. Tracking deployment of EVs and EV charging infrastructure and encouraging off-peak charging are thus important steps for utilities to consider. Integrated Resource Plans (IRPs) or similar long-term plans from utilities across the U.S. were reviewed to investigate their inclusion of EVs in load forecasts.¹ Plans from a total of 31 utilities that varied in size (fewer than 15,000 customers to greater than 5 million) and type (investor-owned, community-owned, and federally-owned) were reviewed. Plans from years 2008 through 2013 were reviewed and covered a planning horizon through 2031. This review is focused on plans from those states that are expected to have a higher than average rate of EV penetration (including California, Oregon, and Vermont), and plans that included some discussion of EVs.

The majority of utilities included in this review incorporated EVs into their plans, either in the load forecasts or in the plan text (19 of 31). For those IRPs that did calculate additional load due to EV charging, this demand was generally a small proportion of total projected load: from less than 1% to a maximum of 4%-5% in 2030. Plans from states predicted to have high levels of EV penetration tended to include EVs, although not necessarily an in-depth analyses of EV grid implications. None of the plans reviewed from California included EVs, although this state is predicted to have the highest per capita penetration of EVs and currently has some of the most EV-friendly state policies in place (including tax incentives and zero-emissions vehicle mandates for vehicle manufacturers that sell in the state). Time of use (TOU) rates were the most commonly referenced mechanism to mitigate grid impacts of EV deployment. EV-specific time of use rates are currently available in some areas, and data from the U.S. Department of Energy (DOE)-sponsored 'EV Project' have already shown such rates to be a highly effective means of achieving off-peak EV charging.

The most detailed analyses of additional load and potential peak load implications of EVs were presented in the plans of Connecticut Light and Power and United Illuminating (a single IRP for both utilities), Chelan County Public Utility District (Washington), Seattle Light and Power, and Dominion North Carolina Power and Dominion Virginia Power (a single IRP). In addition, Dominion is performing a pilot project with EV drivers using separate metering to track charging behavior and effects of time of use (TOU) rates. EVs were commonly included in IRP discussions of emerging technology and uncertainty. Many of these plans acknowledged the potential load growth that may result from EV charging, but did not perform any additional modeling or analyses to incorporate EVs into load forecasts. There was little to no discussion in most plans of any spatial considerations of EV energy demand, nor the robustness of distribution infrastructure.

- **Recommendations for consideration by utilities and policymakers of how future IRPs and long-term plans can incorporate EVs include:**
- **Track EV and charging infrastructure deployment through coordination with local transportation partners (state Departments of Transportation, State Energy Offices, Clean Cities Coalitions, and EVSE installers).**
- **Develop projections of EV penetration rates, additional energy demand, and peak load effects**

¹For the purposes of this report, all long-term utility plans included in this analysis are referenced as integrated resource plans (IRPs).

in the utility service area.

- **Determine spatially explicit infrastructure needs that may result from EV use.**
- **Consider how utility efficiency programs can reduce projected demand resulting from EV charging.**
- **Consider EVs as a grid resource facilitated and optimized by vehicle-to-grid technology and interoperability.**

We suggest that utilities partner with local transportation planning organizations and Clean Cities Coalitions to better understand travel patterns and integrate this information into the EV planning process. Planning for EVs, including how much additional energy they will require and where and when charging will occur, is a new challenge for the electric sector and may call for integration of travel behavior data, previously relegated to the transportation sector. Coordination with public agencies (mainly state Departments of Transportation, State Energy Offices, and State and Municipal Public Utilities Commissions) will facilitate optimal deployment of EVs, ensuring not only that electric infrastructure is adequate to handle the additional load in the necessary locations in coming years, but also that appropriate charging infrastructure is located so that travel demand can be met using EVs.

1. Introduction

As the number of plug-in electric vehicles (EVs) in use continues to grow, the grid implications of these vehicles is an important planning consideration for energy utilities and government entities responsible for maintaining resilient grid infrastructure and reliable electricity delivery. Although Pacific Northwest National Laboratory (2009) estimates that the idle capacity of the nation's electric grid is adequate to meet the energy needs of 73% of the nation's vehicle fleet, optimized planning for EVs must consider both spatial and temporal aspects of EV charging. EVs present both a source of additional energy demand and a possible grid resource with vehicle-to-grid (or vehicle-to-building) interoperability. Depending on when they are charged, EVs have the potential to be either load-filling at night or load-building during the day. In addition, evidence suggests that the distribution of EVs in communities will not be random but may occur in clusters, correlating with political views, socio-demographic factors, and the presence of other EVs (Aultman-Hall et al. 2012, Zhu and Liu 2013). There is some concern about the electric grid's long-term ability to serve the additional demand introduced by EVs, especially if this demand is clustered or occurs during peak hours. In light of these factors—increased demand, potential clustering of that demand, need for off-peak charging, and the potential for EVs to act as a grid resource— utilities must begin (or continue) to include these vehicles in their long-term planning.

This report reviews integrated resource plans (IRPs) and other long-term utility plans from states across the U.S. to investigate their consideration of EVs.² Plans included in this review are presented in Table 1. This report focuses on plans that include some mention of EVs. The extent to which these plans considered the impact of EVs varies widely. In addition, an effort was made to obtain plans from states expected to have levels of EV penetration higher than the national average, including California, Oregon, and Vermont. Not all states anticipated to have high numbers of EVs require utilities to file an IRP (Massachusetts and Maine). One IRP for National Grid, a utility that operates in Massachusetts, among other states, was obtained, but none for utilities operating in Maine.

EVs are essentially big appliances operating in an environment (electric utilities) unfamiliar with mobile appliances of this size. Thus planning for EVs, including how much additional energy they will require and where and when charging will occur, is a new challenge for the electric sector and requires integration of travel behavior data previously relegated to the transportation sector.

²For the purposes of this report, all long-term utility plans included in this analysis will hereafter be referenced as integrated resource plans (IRPs).

Table 1. Integrated Resource, Long-Term, and Long-Term Procurement Plans Reviewed

Utility	Location	Utility Type	# Customers or Towns Served	IRP Year	Consideration of EVs included in IRP? ³	Projected additional EV load
AEP-East	Indiana, Michigan, Kentucky, Ohio, Tennessee, Virginia, West Virginia	Investor-owned	7.2 million	2010	No	-
Alaska Energy Authority-Southeast	Southeast Alaska	Community-owned	30 communities	2011	Yes	-
Avista	Washington, Idaho, Montana	Investor-owned	680,000	2011	Yes	<1% annual load growth
Black Hills Power	South Dakota, Wyoming, Montana	Investor-owned	70,000	2011	Yes	-
Central Valley Electric Cooperative	Southeastern New Mexico	Cooperative	14,000	2013	No	-
Central Vermont Public Service Corporation (merged with Green Mountain Power in 2012)	Central Vermont	Investor-owned	159,000	2011	Yes	-
Chelan Public Utility District	Chelan County, Washington	Community-owned	47,000	2012	Yes	0.36-1.93 MW (< 1% total load)
Connecticut Light and Power	Connecticut	Investor-owned	1.2 million	2010	Yes	3% total load in 2030
Consolidated Edison Company of New York	New York City, Westchester County	Investor-owned		2013	Yes	-
Delmarva Power and Light Company	Delaware and Maryland	Community-owned	300,000	2010	No	-
Dominion North Carolina Power and Dominion Virginia Power	North Carolina and Virginia	Investor-owned	-	2012	Yes	806 GWh in 2027 (<1% total load)
Duke Energy	North and South Carolina, Florida, the Midwest	Investor-owned	7.2 million	2011	Yes	-
East Kentucky Power Cooperative, Inc.	Kentucky	Cooperative	520,000	2009	No	-
El Paso Electric Company	West Texas	Investor-owned	380,000	2012	No	-
Entergy	Arkansas, Louisiana, Mississippi, Texas	Investor-owned	2.8 million	2012	No	-

³IRPs that considered EVs either included EVs in load forecasts or included a substantive discussion of EVs in the plan text.

Utility	Location	Utility Type	# Customers or Towns Served	IRP Year	Consideration of EVs included in IRP? ³	Projected additional EV load
Green Mountain Power	Central and northwest Vermont	Investor-owned	-	2012	Yes	65 GWh in 2030 (4% total load)
Hawaiian Electric Company	Hawaii	Investor-owned	1.4 million	2013	Yes	319 GWh in 2033 (4%-5% of total load)
Indianapolis Light and Power	Indiana	Investor-owned	470,000	2012	Yes	-
Minnesota Power	Central and northeastern Minnesota	Investor-owned	144,000	2013	No	-
National Grid	New Hampshire, Massachusetts, New York	Investor-owned	3.5 million	2010	No	-
New Hampshire Public Service	New Hampshire	Investor-owned	500,000	2010	Yes	-
Northwest Power and Conservation Council	Oregon, Washington, Idaho, Montana	Planning organization	n/a	2010	Yes	100-550 MW in 2030 (<1% - 2% total load)
PacifiCorp	Utah, Colorado, Wyoming, Idaho, Oregon, Washington, California	Investor-owned	1.7 million	2011	No	-
Platte River Power Authority	Colorado	Community-owned	4 municipalities	2012	No	-
PNM	New Mexico	Investor-owned	500,000	2011	Yes	-
Portland General Electric	Northwestern Oregon	Investor-owned	800,000	2009	Yes	5-50 MW in 2020 (< 1% total load)
San Diego Gas and Electric	San Diego, CA	Investor-owned	1.4 million	2012	No	-
Seattle City Light	Seattle	Community-owned	400,000	2012	Yes	36 MW (2.6% total load) in 2030
Tennessee Valley Authority	Tennessee, Virginia, Kentucky, North Carolina, Georgia, Mississippi, Alabama	U.S. government-owned corporation	9 million	2011	Yes	-
United Illuminating	Connecticut	Investor-owned	325,000	2010	Yes	3% total load in 2030
Vermont Electric Co-op	Northern Vermont	Cooperative	32,000	2012	No	-

1.1 Electric Vehicle Planning

There are two types of plug-in electric vehicles: plug-in electric hybrid vehicles (PHEVs), which have a both an electric motor and a gasoline engine, and All-Electric Vehicles (AEVs). PHEVs now on the market have an electric range of 10-35 miles, while AEVs have an electric range of 75-250 miles (Alternative Fuels Data Center (1) 2013). In this review the term EV includes both PHEVs and AEVs.⁴ The amount of electricity required to power EVs will vary with vehicle range but some approximation of additional energy demand is possible to calculate. Electric vehicle efficiency ranges from 0.3 to 0.4 kWh/mile (AFDC (2) 2013). At 0.34 kilowatt-hours (kWh) per mile, an AEV driven approximately 10,650 miles⁵ requires a total of 3,621 kWh annually. Thus 5,000 AEVs driving and charging in a utility's service area would require an additional 18,105 megawatt-hours (MWh) annually. At current rates of annual residential electricity usage (11,280 kWh; EIA 2011), this additional demand would amount to the equivalent of 1,605 of new homes being added to a service territory (EIA 2011). In the case of a PHEV, 70% of annual vehicle miles traveled (VMT) being powered by electricity would result in an additional 12,670 MWh of electricity usage (AFDC (3) 2013).

There are three levels of charging or Electric Vehicle Supply Equipment (EVSE) available for EVs with very different implications for the electric grid (Table 2; AFDC (4) 2013). Level 1 uses a 120-volt AC connection and takes 14-22 hours for a full charge on an AEV with a 60-80 mile range. Level 2 uses a 240-volt AC connection and requires four to seven hours to fully charge an AEV with a 60-80 mile range. DC Fast Charging uses a 480-volt DC connection and takes 30 minutes to charge an AEV 80%. This type of charging requires a rapid draw of energy over a short period of time and is now only available at public charging stations (and potentially for fleet use in the future), but not residences. Much of DC fast charging is likely to occur during peak hours. In contrast, Levels 1 or 2 charging require a much slower, more gradual flow of energy.

Table 2. Electric Vehicle Charging Levels and Time

Charging level	Charge time
Level 1 (120-volt AC)	2-5 miles range added per hour
Level 2 (240-volt AC)	10-20 miles range added per hour
DC Fast Charging (480-volt DC)	60-80 miles range added per hour

Due to the high power draw demanded by DC fast charging stations, these stations may be subject to costly demand charges (although not every utility uses demand charges).⁶ Demand charges are fees levied on commercial customers and other large users of electricity for peak power usage. These charges are generally calculated each billing cycle, based on the maximum demand for power that occurs during any one 15 to 30 minute peak demand interval. The charge is not based on the total amount of energy used at the peak rate (Iowa State University Center for Industrial Research and Service 2005). The EV Project, a DOE project collecting data on electric vehicle driving and charging behavior in nine states and the District of Columbia (described further below), reports that demand charges for DC fast charging stations included

⁴The terminology used to describe electric vehicles continues to evolve and is not yet standardized. Other terms used to describe electric vehicles include: battery electric vehicle (BEV), a term synonymous with all-electric vehicle; extended-range electric vehicle (EREV), which includes vehicles such as the Chevrolet Volt that operate in all-electric mode and switch to a gasoline engine when battery is fully discharged; and hybrid electric vehicles (HEVs), which are vehicles that do not plug in but use an electric motor, such as the standard Toyota Prius.

⁵Mean miles traveled per light duty vehicles in 2010. Federal Highway Administration 2012..

⁶In addition, there are DC fast chargers designed to work at lower power levels in order to avoid demand charges and there are also some designs with distributed energy storage options that avoid demand charges that when present, normally start at 20 kW or higher levels.

in the project's area ranged from having no demand charge to more than \$20 per kilowatt, with the upper end of the range potentially becoming cost-prohibitive (Wishart 2012). Demand charges for Level 2 charging stations may be lower than those for DC fast charging due to the more gradual draw of energy required by Level 2 EVSE. However, this depends upon the number of Level 2 EVSE installed at a particular site, configuration of the metering, and usage patterns of the charging stations.

Residential charging is a mixture of Level 1 and Level 2 and much of this could occur off-peak (overnight), especially with implementation of time of use rates (Table 3). Public charging will most likely occur at Level 2 during peak hours. Workplace charging will be a mixture of Level 1 and Level 2, also occurring during peak hours. The majority of charging will most likely occur at home. Thus far, data shows that 15%-33% of EV charging occurs away from home, although this percentage could grow as away-from-home EVSE becomes more widely available (Meyn 2012, EV Project 2012, U.S. DOE 2013). However, the cost of EV charging may also alter charging behavior away from home.

Table 3. Predicted characteristics of EV charging by EVSE type (residential, work place, and public)

Type of charging	Predicted predominant charging level	Predicted predominant time of charging
Residential	1	Night (off-peak with time of use rates)
Workplace	1 and 2	Day (peak)
Public	2 and DC Fast Charging	Day (peak)

EV Sales

Currently there are more than 100,000 EVs registered in the U.S. (Electric Drive Transportation Association 2013; Figure 1), considerably more than the 12,500 projected by the Energy Information Administration for 2013 (EIA 2010). Although still a small portion of total vehicle sales, EV sales are actually greater than early sales of hybrid electric vehicles (more commonly called hybrids or hybrid vehicles), such as the standard Toyota Prius. In their first 24 months of availability, approximately 30,000 hybrid vehicles had been sold. In contrast, during the initial 24 months of EV availability, more than 60,000 EVs have been sold. Hybrid vehicles are powered entirely by gasoline and are not considered electric vehicles for the purposes of this review, since they do not connect to the electric grid for recharging. Hybrids do use regenerative braking and the gasoline engine to charge the onboard battery packs.



Source: Electric Drive Transportation Association

Figure 1. U.S. Monthly Electric Vehicle Sales, Dec. 2010 - May 2013

EVs are often considered strong candidates for fleet vehicles because of their reduced operating and fuel costs. In addition, fleet vehicles often access centralized fueling areas and have predictable routes, which may make them suitable to early EV adoption. Due to the limited range of AEVs, PHEVs may be a better option for many fleets because of the back-up gasoline engine (Clean Cities 2012). To date, no entity differentiates and tracks EVs purchased for fleet use from those purchased for personal use.

EV Policy Context

There are about 10 models of EV on the market, although most of these are only available in limited areas. The vehicle market is shaped in part by government programs such as national Corporate Average Fuel Efficiency (CAFE) standards and California’s Zero Emissions Vehicle (ZEV) regulation. CAFE standards mandate a minimum average fleet fuel efficiency that car manufacturers must meet (35.5 miles per gallon in 2016 and 54.5 miles per gallon in 2025). This average minimum will increasingly be met through the use of alternative fuel vehicles such as hybrids and EVs (NHTSA 2012). Similarly, the ZEV regulation, adopted as part of California’s Low Emission Vehicle Program, mandates that a given percentage of manufacturers’ vehicle fleet be zero-emission; currently, only AEVs meet the ZEV standard (CARB 2012). The Low Emission Vehicle Program and specifically the ZEV regulation is considered a driving force behind the high number of hybrid and EV sales in California. Some models of EVs (e.g., the Honda Fit EV) are only available in California, where manufacturers are required to offer them as a means of meeting the ZEV requirement. This standard has since been adopted by 10 other states— Connecticut, Maine, Maryland, Massachusetts, New Jersey, New Mexico, New York, Oregon, Rhode Island, and Vermont— and the District of Columbia, and may be influential in determining the future spatial distribution of EVs (Barry 2011, CARB 2009, Vermont Agency of Natural Resources 2012). Table 4 presents a list of policies and incentive programs available in the states covered in this review that encourage EV adoption and may impact penetration rates in these states.

Table 4. State policies and incentive programs promoting EV deployment (Alternative Fuels Data Center)

State	Incentive/Policy
Colorado	Tax credits available for purchase of EVs and EVSE.
Connecticut	Grants available to municipalities and public agencies for EVs (and other alternative fuel vehicles).
Delaware	Retail electricity customers with a grid-integrated EV can receive kWh credits for energy discharged from the vehicle battery to the grid.
Georgia	Tax credit available for AEVs and conversion of a conventional vehicle to AEV. Tax credit available for purchase of ZEV (including AEV). Tax credit available to businesses for EVSE purchase and installation.
Florida	Financing available to property owners for EVSE installation.
Hawaii	EVs may use high-occupancy vehicle lanes and are exempt from parking fees charged by any non-federal government entity. All parking facilities with at least 100 parking spaces must designate one parking space for EVs equipped with EVSE.
Indiana	Grants available to fleets for purchase of alternative fuel vehicles (AFV). Tax credit available to AFV manufacturers in Indiana.

State	Incentive/Policy
Louisiana	Tax credit available for conversion of conventional vehicles to EV, purchase of an EV, and installation of EVSE. Green jobs tax credit available for capital infrastructure projects related to advanced drivetrain vehicle industry.
Mississippi	Revolving loan program available to school districts and municipalities for purchase of AFVs.
New York	Vouchers available for purchase of heavy-duty AFVs. New York has adopted California's LEV policy and also requires original equipment manufacturers (EMS) to make available in NY any ZEV or PZEV (partial zero emission vehicle) that is available in CA.
Ohio	Grants available for EVSE installation.
Oregon	Vouchers available for commercial electric trucks. Tax credits available for residential and commercial EVSE installation.
South Carolina	Tax credit available for PHEV purchase.
Tennessee	Rebate available for the first 1,000 EVs sold in Tennessee.
Texas	Rebate available for EV purchase.
Utah	Tax credit available for purchase of EV. Grants and loans available to businesses and government agencies for EVSE installation.
Virginia	Alternative Fuels Revolving Fund distributes loans and grants to municipal and county agencies to support AFV programs and improve AFV infrastructure.

Nationally, the U.S. Department of Energy's Clean Cities program supports the deployment of EVs. Clean Cities is a network of nearly 100 local coalitions located across the country that work toward reducing petroleum use in the transportation sector. A primary Clean Cities activity is providing technical assistance to large fleets to both reduce petroleum use and to deploy alternative fuel vehicles. From coast to coast, regional, state, and local initiatives are incentivizing and raising awareness of EVs. For example, the Northeast EV Network is a partnership of 11 states working to encourage deployment of EVs, develop partnerships between the private sector, utilities, and public entities, and coordinate regional EV planning efforts. This is just one example of many efforts to electrify the transportation sector.

Electric Vehicle Grid Impacts

EVs have the potential to increase peak load, but they can also increase overall grid efficiency through off-peak charging and to serve as energy storage units through vehicle to grid, home, and/or building interoperability. Controlled charging of EVs and full integration with modern and emerging grid technology has the potential to mitigate negative grid impacts that may result from EV charging.

Timing of EV charging

Generally it is assumed (and has been observed) that most EV charging will occur at home, with smaller amounts occurring at workplaces and public charging stations. The most complete data on charging behavior

is available through the EV Project, a DOE-funded project that has been tracking travel and charging behavior of thousands of EVs in nine states since 2011. Data from this project has shown that in areas with time of use (TOU) rates, the majority of EV charging occurs during off-peak hours. This was not the case in areas without TOU rates, where demand generally peaked in the early evening when EV owners returned home from work (Schey et al. 2012, EV Project 2013). Figure 2 demonstrates that TOU rates in San Francisco and San Diego clearly affected the time of day when EV drivers chose to charge: off-peak. In Los Angeles and Washington, where TOU rates are not used, charging behavior is much more erratic and an early evening spike in charging (during peak demand hours) is evident. These results are evidence that TOU rates are an effective mechanism to shape electric load from EVs.

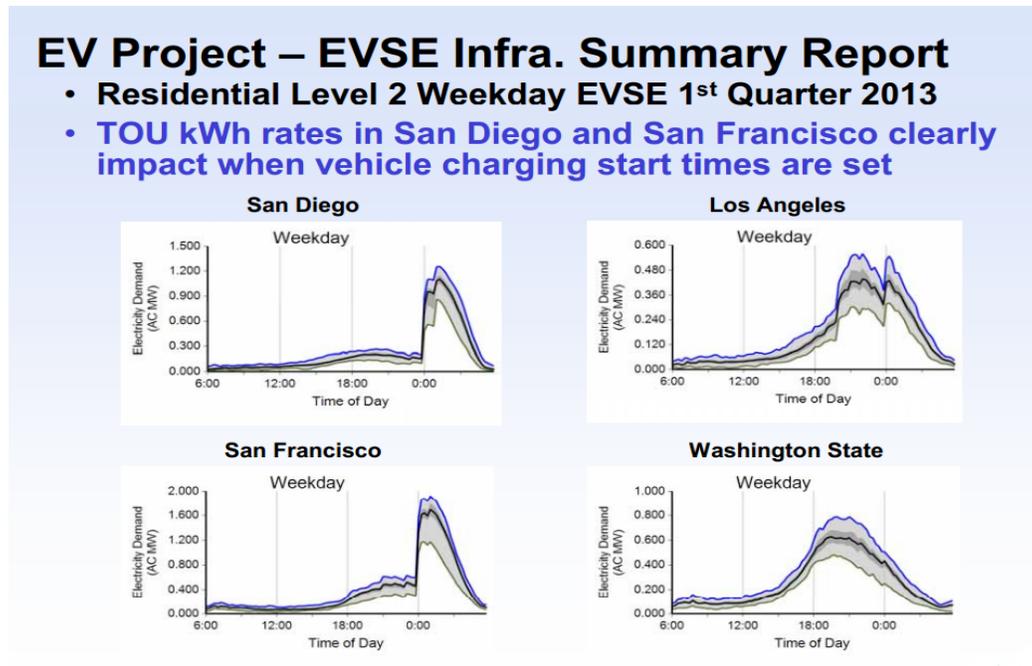


Figure 2. EV Project Electric Vehicle Charging Patterns With and Without Time of Use Rates (EV Project 2013)

If EV charging occurs without control or coordination, the potential exists for such charging to result in additional load during peak hours. However, if utilities take measures to confine the bulk of charging to times when demand on the grid is low, EVs could fill valleys in system demand (Glazner 2012, Kintner-Meyer et al. 2007, Parks et al. 2007). Analysis of the projected impacts of EV charging on regional utilities across the U.S. concluded that utilities can increase profitability (and/or potentially lower electricity rates for customers) by having EVs charging during off-peak evening hours (Galus et al. 2012, Scott et al. 2007).

Predicting Additional Load from EVs

Accurately predicting the additional load that will result from EV charging requires integration and modeling of travel behavior, charging behavior, and spatially explicit EV penetration scenarios, including effects on peak load and effects of TOU rates. Further, there is evidence to suggest that EV penetration may be clustered, as hybrid vehicle penetration has been; those people who live near a hybrid vehicle are more likely to be hybrid owners themselves (Aultman-Hall et al. 2012).

There is some question as to how well the current electricity distribution network will be able to accommodate the additional load resulting from EV charging and potential clustering of that load (Shao et al. 2009, Hilshey et al. 2013). Distribution transformers generally serve four to ten households. An electric vehicle uses about one-third of one household's annual energy; thus, even a small degree of clustering might be problematic (EIA 2011, Sullivan 2009).

Vehicle- to-Grid and Building Interoperability and Smart Grid Technology

In the future, with proper infrastructure, energy markets, and volume of EVs, EV batteries may serve as storage units or frequency regulation for the grid, residences, and other buildings, storing excess energy as it is produced and feeding it back as needed. Because such energy storage is generally expensive, using EVs in this capacity may increase the cost-effectiveness of intermittent, renewable energy sources such as solar and wind. Vehicle-to-grid and building interoperability would require two-way communication and flow of energy between the vehicle and the grid.

Grid integration of EVs will involve an additional meter (or submeter) to differentiate and monitor EV charging. Control over EV charging—starting and stopping charging and monitoring battery state of charge—would require additional IT infrastructure. Several technologies are emerging to enable control of EV charging and submetering, many of which use cellular connections to connect charging equipment with power managers at a distribution utility (Alizadeh et al. 2011). Currently, the University of Delaware, the energy supplier Hydro-Quebec, the U.S. Department of Defense and the National Renewable Energy Lab (NREL) are leading vehicle-to-grid interoperability studies (Hydro-Quebec 2013, University of Delaware 2013, Simeone 2013, NREL 2012, Kempton et al. 2008). Nissan Leafs are already used for vehicle-to-home systems in Japan and Toyota is testing a vehicle-to-home system in Japan with the Toyota Prius Plug-in. These systems are not yet available in the U.S.

EV Planning Conclusions

There are short- and long-term planning considerations associated with EVs. In the short term, EVs will comprise a relatively small proportion of the nation's vehicle fleet and research suggests that current grid infrastructure is sufficient to support EV charging needs (PNNL 2009). In the longer term, however, infrastructure updates to the grid may be required, depending on rates of EV adoption and spatial and temporal patterns in EV charging. Although EVs have the potential to increase total and peak load, with adequate planning they also have the potential to flatten demand profiles and serve as a grid resource, ultimately lowering rates for utility customers. It is thus crucial that utilities begin considering the nature of EV electricity demand in their planning, including temporal and spatial characteristics. Our review of individual IRPs and other utility plans in the following section is meant to provide a representative sample of the current state of such planning.

1.2 Long Term Planning

Integrated resource planning (IRP) became a prominent form of long-term energy planning in the late 1980s. This type of planning differs from traditional utility planning in its focus on both demand and supply-side options to meet energy needs. Traditional energy planning focused solely on supply-side options and associated infrastructure. In an IRP process, energy efficiency and demand management measures are also considered. The goal of integrated resource planning is to minimize the total cost of energy generation, distribution, and use, rather than to just reduce average rates (ACEEE 2010). More recently, the goals of resource diversity, energy security, and environmental sustainability have also been included in the IRP process. Reducing demand for energy reduces associated environmental impacts, lowering the total cost to society. Generally, energy efficiency performs well as a cost-effective potential resource within the IRP process, and some states give preference to efficiency over supply-side resources in the IRP process. Hirst and Goldman (1991) provided the following summary of how the IRP process differs from traditional utility planning:

Table 5. Differences Between the Traditional Utility Planning Process and Integrated Resource Planning
(adapted from Hirst et al. 1991)

Traditional Planning	Integrated Resource Planning
Focus on utility-owned central station power plants	Diversity of resources considered, including: utility-owned plants, purchases from other organizations, conservation and load management programs, transmissions and distribution improvements, pricing
Planning internal to utility: systems and finance departments	Planning spread among several departments in the utility and involves customers, public utility commission staff, and other energy experts
All resources owned by utility	Some resources owned by other utilities, by small or independent power producers, and by customers
Resources selected to minimize electricity rates and maintain system reliability	Diverse resource selection criteria, including electricity prices, revenue requirements, energy service costs, utility financial condition, risk reduction, fuel and technology diversity, environmental quality, and economic development

This review focuses on IRPs but also covers other types of utility plans, including long-term procurement plans (LTPP). Long-term procurement planning (LTPP) began to replace integrated resource planning in the mid 1990s as some state deregulated and restructured the electric industry. In states with deregulated markets, utilities do not own generation. LTPPs consider purchase of capacity and energy, rather than generation, as well as demand management options. LTPPs often cover a shorter time frame than IRPs (five to ten years rather than 10 to 20; Synapse Energy Economics 2011, CPUC 2008). As of 2011, 39 states required electricity utilities to submit an IRP or some other type of planning document to a public utility commission (Wilson and Biewald 2013, SEEACTION 2011, Louisiana Public Service Commission 2012; Figure 3). Neither IRPs nor procurement plans are required to be public in all states.

2. Review of Integrated Resource Plans and Utility Long-Term Plans

In an effort to achieve a diversity of utility geography, size, and type, IRPs and long-term plans from a range of utilities were reviewed. Most plans were accessed online, while others were obtained directly from utilities. Although not all states require utilities to file an IRP or long-term plan, many utilities operate in multiple states, some of which do require IRPs; thus we were able to obtain plans even for some utilities operating in states with no state-regulated IRP process (such as Massachusetts). There are approximately 3,000 utilities operating in the U.S. and in this report we review 30 plans from 31 utilities (Connecticut Light and Power and United Illuminating have a combined plan for 2010). As seen in Table 6, multiple utility models exist to serve electricity customers. The IRPs selected for this report reflect this reality. Our intention is to present a representative sample of how utilities of all types and sizes are incorporating EVs into their planning process.

Table 6. U.S. Utility Sales, Customers, and Revenue by Utility Type (EIA 2010, American Public Power Association 2013)

	Investor-owned	Publicly-owned	Cooperatives	Federal Power Agencies	Power Marketers
# Organizations	194	2,006	874	9	168
# Total Customers	98 million	21 million	18.5 million	41,000	6 million
Sales (thousands MWh)	2.1 million	572,000	413,000	43,000	570,000
MWh sales (% total)	57	15	11	1	15
Revenue (% total)	61	14	11	0.5	13
Total revenue (billions)	\$224	\$53	\$40	\$1.8	\$49

This review included plans from 12 investor-owned utilities, five community-owned utilities, three cooperatives, one federally owned utility (Tennessee Valley Authority) and one public energy planning organization (the Northwest Power and Conservation Council; Table 7). The majority of plans reviewed included EVs. In those states with more than one plan reviewed, generally at least one plan included EVs.

Table 7. Reviewed Integrated Resource Plans and Utility Long-Term Plans

Utility Type	# IRPs reviewed	IRP includes EVs	IRP does not include EVs
Federally owned	1	1	0
Cooperative	3	0	3
Community-owned	5	4	1
Investor-owned	21	14	7

Some utilities were found to be calculating their own projections of EV sales, while others are taking projections from other research, such as the Electric Power Research Institute (EPRI) and the Energy Information Administration (EIA). Of those utilities whose plans included vehicle projections, many assumed that the additional load resulting from EV charging will be minor and thus demand forecasts were not adjusted. Others assumed that the additional demand will be small enough that it is covered in the “high

demand” load forecasts and did not perform additional analysis. Many of these plans acknowledged the potential load growth that may result from EV charging, but did not actually include any additional modeling or analyses to incorporate EVs. For those IRPs that did include calculations of additional load due to EV charging, this demand was generally a small proportion of total projected load— from less than 1% to a maximum of 4%-5% in 2030 (see Table 1). The plans reviewed included both load forecasts—a traditional form of utility planning—and scenario planning. Forecasting generally focuses on a reference or baseline case, with some associated variability, while scenario planning may include a broader range of possible future outcomes. Scenario planning may use quantitative modeling, probabilistic modeling, and/or event-driven scenarios. As uncertainty has grown around things such as electricity generation, environmental policy, and emerging technologies (such as Smart Grid technology and EVs), some utilities have opted for scenario planning to model such uncertainty (NARUC 2012).

Although many plans included forecasts of EV penetration and additional electricity demand, few addressed the effect, if any, that EVs may have on electricity rates. The Hawaiian Electric Company IRP notes that while current trends toward increasing efficiency may reduce demand to the extent that rate increases may result, the additional demand introduced by EVs may reverse this trend. The New Hampshire Public Service Company predicts that if EV charging is not temporally spread out within the ISO-New England area, electric rates could increase 2%. There was little to no discussion in most plans of any spatial considerations of EV energy demand, nor of the robustness of distribution infrastructure. Few of the plans included any discussion of travel patterns beyond average estimates of vehicle miles traveled, or the importance of optimal locations of EVSE. There was also limited to no discussion of the ability of EVs to serve as a grid resource through vehicle-to-grid interoperability.

Some of the IRPs examined included EVs in discussions of emerging technology and uncertainty; however, the additional load from EV charging was not included in the utility load forecasts. Most plans that included discussion of EVs acknowledged the potential to integrate these vehicles with Smart Grid technology to enable smart charging and submetering. EV smart charging involves interrupting or delaying charging when demand on the grid is high or distribution transformer temperatures become too high.

In those states where EV penetration is expected be higher than the national average, including Vermont, California, and Oregon, many of the IRPs did reference increased demand for energy due to EVs. In California, where EV penetration has been higher than the national average, utilities are required to submit a Long-Term Procurement Plan to the California Public Utilities Commission, rather than an Integrated Resource Plan. Procurement plans are generally more focused on supply-side options to meet energy demand and neither of the procurement plans reviewed for California included EVs. In spite of this omission, California utilities such as San Diego Gas and Electric and Southern California Edison are already offering customers EV-specific rates and reference materials on their websites. IRPs from Washington, Seattle City Light, and the Northwest Power and Conservation Council incorporated actual EV charging data from the EV Project. All states included in this review are presented in Figure 4. In some cases, we reviewed multiple plans from a single state.

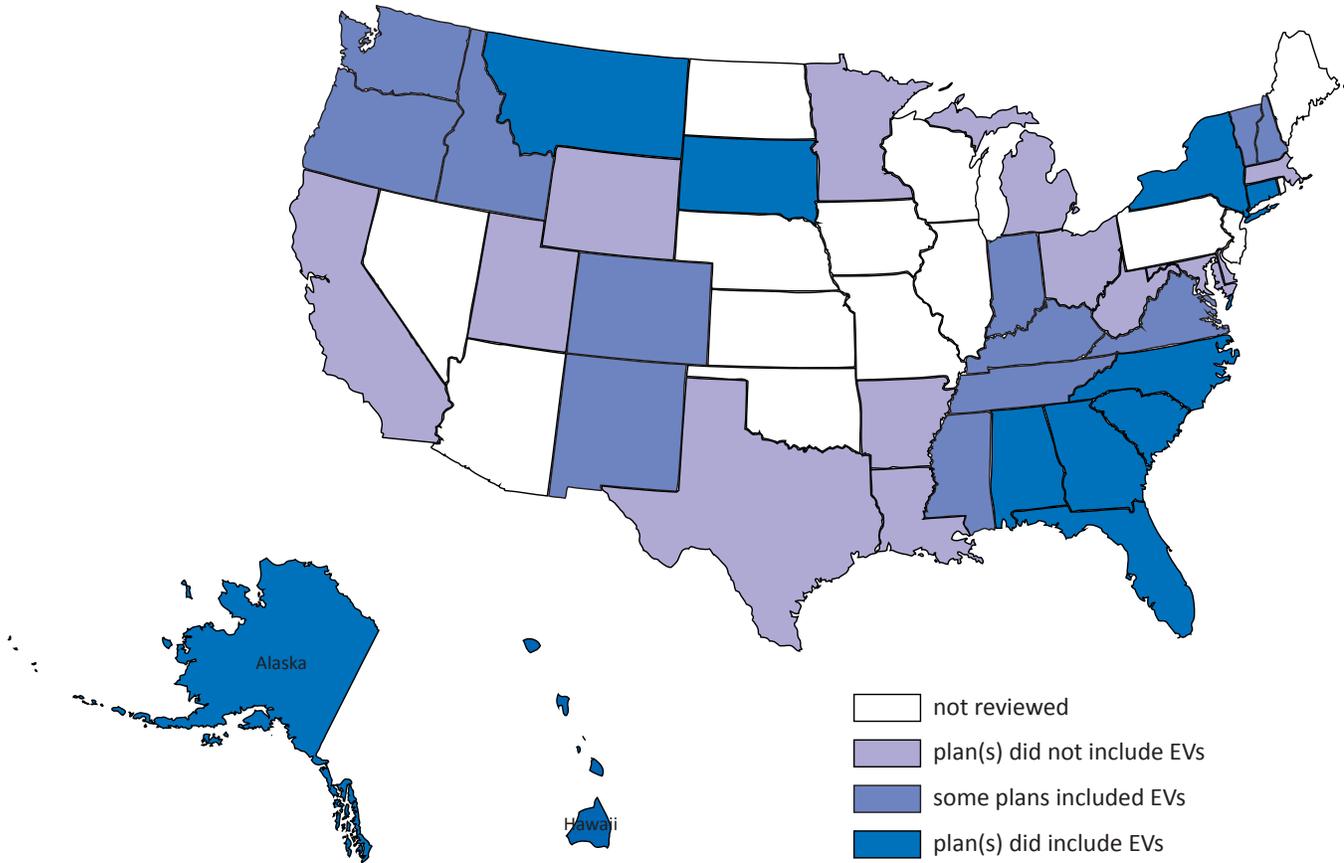


Figure 4. State Integrated Resource Plans Reviewed

2.3 Individual Plan Summaries

The following is a summary of how IRPs either included EVs in their load forecasts or included some discussion of EVs in the plan text:

Alabama

Utility: Tennessee Valley Authority (see Tennessee)

Alaska

*Utility: Alaska Energy Authority
Service Territory: Southeast Alaska*

*Planning Timeframe: 2011-2061*In this IRP for the Southeast Alaska region, the high scenario load forecast included load growth due to EVs (in addition to high levels of economic growth). EV projections were calculated for different areas of Southeast Alaska for the years 2010 through 2061. These calculations were based on 2010 national projections of EV sales from the EIA which assume growth in EV adoption as the technology becomes more affordable and widely accepted. Projected market penetration in 2010 is 0, 2.3% in 2040, and 12.6% in 2061. Associated load requirements were estimated using projected EV penetration rates, an average EV energy requirement of 0.35 kWh/mile, and per capita vehicle miles traveled (15 miles per day per person with a 3% annual growth rate).

Colorado

*Utility: Platte River Power Authority
Service Territory: Colorado
Planning Timeframe: 2012-2016*

The 2012 Platte River Power Authority notes that EVs are a potential factor to consider in load forecasts but the short-term impact on municipal loads is expected to be small. In the longer term (ten years +), and if charging occurs during peak hours, the IRP states that additional distribution infrastructure may be needed. The plan also notes that use of Smart Grid technology may mitigate effects of EVs on load.

Connecticut

*Utility: Connecticut Light and Power and United Illuminated
Service Territory: Connecticut
Planning Timeframe: 2012-2020*

One IRP was prepared for both of these utilities. This IRP includes a discussion of EVs and notes that in Connecticut, utilities participate in the Governor's Electric Vehicle Infrastructure Council and have joined the New England Regional Electric Vehicle Initiative. The scenarios presented on EV penetration, impact on the grid, and potential gasoline savings were among the most detailed of any plan reviewed. The plan acknowledges that there is uncertainty around EV penetration levels, but predicts that such levels will be significant. EV projections from a variety of sources are noted (EPRI, EIA, Massachusetts Institute of Technology) and the plan uses a 5% penetration rate for 2020. The plan states that when the barriers of vehicle cost and manufacturing capability are removed, consumer acceptance of EVs is expected to be high, as much as 20% by 2020 and 50% by 2030. A review of grid impact studies (by Pacific Northwest National

Laboratory and Oak Ridge National Laboratory) notes that with appropriate timing of EV charging, substantial additional infrastructure should not be required. Additionally, this IRP assumes that widespread access to charging infrastructure will prevent many drivers from charging during a narrow window.

This IRP considers the grid impacts of various levels of EV fleet penetration and hourly distributions of EV charging load. As seen in Figure 5, a number of scenarios were run to determine how the distribution of EV load is affected by the timing of charge: evening concentrated (most EVs begin charging around 5-6 PM), evening diversified (charging is spread out over the evening and uses a slower charge, presumably Level 1, although the plan does not specify), increased work access (half of charging is done at work, starting 8-9 AM), and off-peak (10-11 PM until morning).

Hourly Distribution of the Incremental Plug-In Hybrid Load

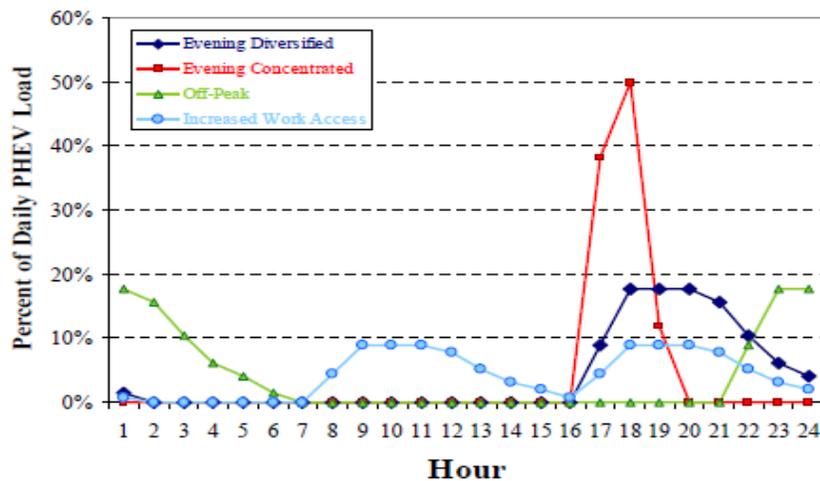
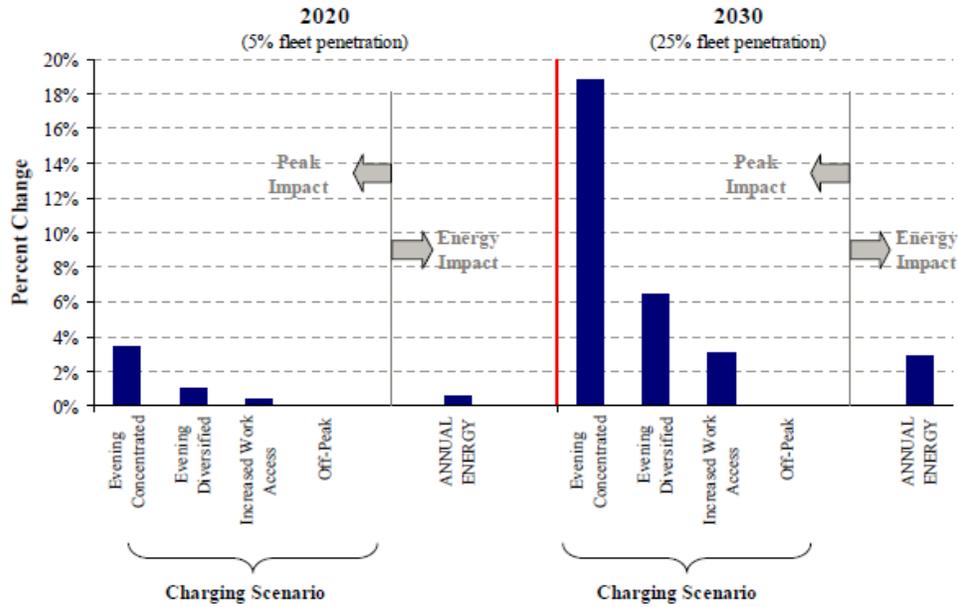


Figure 5. Hourly Distribution of the Incremental Plug-in Hybrid Load in Connecticut (Connecticut Light and Power 2011 IRP).

Potential grid impacts were assessed by combining penetration scenarios and different patterns in charge timing. A 5% level of penetration was determined to result in at most a 3.5% increase in peak energy demand in 2020, while a 25% increase caused an increase of 19% in peak demand when evening charging was concentrated. Spreading charging out beyond a few evening hours reduced peak demand to only 0%-6% (Figure 6). The total increase in energy demand is expected to be 3% by 2030, a relatively modest amount, although there could be areas of local strain on the grid, depending on the geography of EV charging and grid infrastructure. Although this IRP included extensive analysis of EV energy requirements, this additional demand was not included in load forecasts.

Potential Impact of Plug-In Hybrids on New England System Demand



Notes:

- [1] 40 miles/day, 42 mpg (CS mode) and 200 Wh/mi (CD mode) for PHEV
- [2] 200 million fleet size for the U.S. in 2020, and 5.2 percent fleet share for New England.
- [3] 2020 hourly system load based on DAYZER simulation inputs.
- [4] 2030 projections are based on 2020 hourly data, assuming an average 1.1 percent/year growth rate from 2020 to 2030.

Figure 6. Potential Impact of Plug-in Hybrids on New England System Demand (Connecticut Light and Power 2011 IRP).

Georgia

Utility: Tennessee Valley Authority (see Tennessee)

Florida

Utility: Duke Energy (see North Carolina)

Hawaii

Hawaiian Electric Company
 Service Territory: Hawaii
 Planning Timeframe: 2013-2033

The Hawaiian Electric Company 2013 IRP included a description of the Hawaii Clean Energy Initiative. This initiative undertaken by the state and the U.S. DOE has a goal of achieving 70% clean energy by 2030, including renewable energy and energy efficiency. The IRP includes low, medium, and high EV- penetration scenarios in its load forecasts. Energy use by EVs (in this case, all EVs were assumed to be PHEVs) was estimated using average annual vehicle miles traveled (7,300 miles in Hawaii) average vehicle efficiency

(0.33 kWh/mile), and charging largely after 9 PM, having little effect on peak energy demand. Projected EV energy demand varied from 159 gigawatt-hours (GWh) in 2033 to 637. Under a scenario of high EV penetration, slow economic growth, and aggressive efficiency efforts (the last two of which would reduce overall electricity demand), EVs are projected to comprise 14% of total load in 2033. In contrast, under a scenario of low EV penetration, strong economic growth, and less aggressive efficiency efforts, EVs only make up 1.5% of total load in 2033.

The plan notes that trends toward increasing efficiency may result in decreasing demand for electricity and higher rates for customers. EVs may alter this scenario.

Idaho

Utility: Avista (see Washington)

Utility/Planning Council: Northwest Power and Conservation Council (see Oregon)

Indiana

Utility: Indiana Power and Light Company

Service Territory: Indiana

Planning Timeframe: 2012-2021

The Indiana Power and Light Company 2012 IRP accounts for EVs in its load forecasts but does not explicitly state what assumptions were made regarding EV penetration rates or charging patterns. In the IRP, IPL recognizes the environmental and security advantages of EVs and notes the company's efforts to advance EV use through charging station installation (65 built, 200 planned), and participation in the group Project Plug-in. Funding received through the U.S. DOE and Indiana State office of Energy Development will be used to install charging infrastructure that can be integrated with the Smart Grid. The company sought and received approval from the Indiana Utility Regulatory Commission to implement an EV-specific TOU rate.

Kentucky

Utility: Tennessee Valley Authority (see Tennessee)

Mississippi

Utility: Tennessee Valley Authority (see Tennessee)

Montana

Utility: Avista (see Washington)

Utility: Black Hills Power (see Wyoming)

Utility/Planning Council: Northwest Power and Conservation Council (see Oregon)

New York

Utility: Con Edison Company of New York (CECONY)
Service Territory: New York City, Westchester County, NY
Planning Timeframe: 2012-2031

The plan states that Con Edison expects increased demand for electricity from the transportation sector due to EVs. Overall electricity demand is expected to increase by 1.1% per year over the IRP's 20-year planning period in the CECONY service area. This increased demand is attributed to both electric vehicles and economic growth. The plan predicts that this increase in demand will be mitigated by demand response measures, although overall, demand will grow. In response to this growing demand, the utility is budgeting for increased capital spending for system expansion. This spending accounts for 44% of total capital spending, slightly less than will be invested in the reliability and replacement categories combined. CECONY also notes that it expects alternative fuel vehicles, including EVs and natural gas vehicles, to play a large role in New York City meeting its city-wide goals to reduce greenhouse gas emissions. These goals are laid out in the city's PlaNYC, released in 2007, and specifically target fleets such as taxis and school buses for alternative fuel vehicles.

The plan presents a low case, baseline case, and high case of energy demand, as outlined in Table 8. Although EVs are clearly included in the CECONY load forecasts, it is not clear what proportion of demand they are expected to comprise.

Table 8. Con Edison Company of New York Long Range Plan Assumptions

Scenario	Increase in electricity demand	# EVs on the road	Reduction in peak energy demand
Low	-0.15%	190,000	7%
Baseline	1.14%	380,000	3%
High	1.93%	570,000	3%

New Hampshire

Utility: New Hampshire Public Service Company
Service Territory: New Hampshire
Planning Timeframe: 2010-2015

This IRP concludes that EVs will have little impact on the grid in the near future and that most early adoption will occur in major metropolitan areas. A penetration of fewer than 10,000 vehicles in New Hampshire (consistent with achieving President Obama's goal of 1,000,000 EVs on the road by 2015) would result in increased load of 50-338 MW in the ISO-New England area, depending on timing of charging. In this scenario, if charging is not spread out among EV users, rates could increase by 2%.

New Mexico

Utility: PNM
Service Territory: New Mexico
Planning Timeframe: 2011-2030

The PNM 2011 IRP includes an extensive discussion of EV penetration and energy use through 2030. PNM developed an EV penetration scenario using EV sales forecasts (from the energy consultancy KEMA) and

current rates of auto ownership in New Mexico. This penetration scenario assumes that EV adoption will be slow during initial market entry (2011-2012), when penetration will grow by 3% annually. By 2013, this growth rate is expected to grow to 6% and by 2018, 25%. EV charging patterns were predicted using research from EPRI that suggested that most charging will occur at night (the PNM plan assumes that approximately 15% of charging will occur between 9 AM and 5 PM).

PNM ran 26 load forecast scenarios, one of which included EVs (for this scenario, EVs were incorporated into the base case). Annual EV load in the PNM service territory in 2030 is predicted to be 329,000 MWh. The plan also includes a discussion of EVs as an emerging technology and their potential to serve as energy storage for the grid through vehicle-to-grid interoperability. Further, the plan notes that EV production may drive down the cost of battery types and units, making energy storage a more cost-effective option for utilities. Monitoring of EV deployment and industry research is listed in the IRP four-year action plan.

North Carolina

Utility: Dominion North Carolina Power: see Virginia (Dominion Virginia Power)

Utility: Duke Energy

Service Territory: North Carolina, South Carolina, Florida, Midwest

Planning Timeframe: 2011-2031

The Duke Energy IRP from 2011 anticipates higher load starting in 2011 with the sale of PHEVs and adjusted the plan load forecasts accordingly, although the assumptions used (number of EVs projected, amount of additional demand) are not explicitly stated.

Utility: Tennessee Valley Authority (see Tennessee)

Oregon

Utility/Planning Council: Northwest Power and Conservation Council

Service Territory: Washington, Oregon, Idaho, Montana

Planning Timeframe: 2010-2030

The Northwest Power and Conservation Council conducts region-wide energy planning for the states of Washington, Oregon, Idaho, and Montana, as directed by the 1980 Pacific Northwest Electric Power Planning and Conservation Act. This 2010 plan models a number of PHEV penetration scenarios and estimates that additional load will range from 100 MW to 550 MW by 2030, or < 1% to 2% of total projected load. In its analysis, the plan assumes that 95% of EV charging will occur off-peak and recommends time of use rates be implemented to encourage this behavior. The plan also notes that use of PHEVs in the region would substantially reduce CO₂ emissions, from two million to nine million metric tons by 2030, depending on the timing of charging and the future mix of generation. The analysis also notes that if the plan's energy conservation targets are met, the reduction in off-peak energy demand (3,800 MW in 2030) would be enough to meet the additional demand arising from PHEVs. A 2012 report of the 2010 plan notes that off-peak load (late night) has increased and is expected to continue to do so in part due to EV charging, as well as data centers and industry. Although the plan includes estimates of PHEV electricity demand, these estimates are not included in the overall plan demand scenarios.

Portland General Electric
Service Territory: Portland, Oregon
Planning Timeframe: 2010-2020

The 2009 PGE IRP includes an extensive discussion of EVs, as well as potential penetration scenarios and additional energy demand. Based on research performed by Oak Ridge National Laboratory, the plan assumes that the Pacific Northwest grid could handle up to 75% fleet penetration by EVs, although clustering of EVs may present infrastructure problems for distribution networks in some areas, mainly through overloading transformers. The plan assesses additional energy required by high (170,000 vehicles), medium (85,000 vehicles), and low (17,000 vehicles) 2020 penetration scenarios. Estimated total annual energy requirements for these vehicles range from 5 MW to 50 MW. Due to the uncertainty surrounding EV penetration rates, the high load growth scenario is assumed to adequately capture any additional load that may result from EV charging. The plan does acknowledge the possibility of EVs to provide electricity to the grid and commits the utility to continue to monitor and encourage EV adoption.

South Dakota

Utility: Black Hills Power (see Wyoming)

South Carolina

Utility: Duke Energy (see North Carolina)

Tennessee

Utility: Tennessee Valley Authority
Service Territory: Tennessee, Virginia, Kentucky, North Carolina, Georgia, Mississippi, Alabama
Planning Timeframe: 2011-2020

EVs are included in the Tennessee Valley Authority 2011 IRP load forecasts as a key uncertainty that could affect patterns in load shape. The plan explores eight different load forecast scenarios that vary factors such as rate of economic growth and federal regulation of carbon. The assumptions made around EVs are not explicit. In addition, TVA is actively preparing for EVs in other ways. The utility is involved in the Electric Vehicle project and partnered with Nissan and EPRI in 2011 to develop a plan of EVSE deployment.

Vermont

Utility: Central Vermont Public Service Corporation (now part of Green Mountain Power)
Service Territory: Central Vermont
Planning Timeframe: 2011-2031

CVPS included discussion of EVs in their 2011 IRP. This plan includes EVs in a discussion of highly efficient electric devices, along with electric water heaters: these are devices that are substantially more efficient than their fossil fuel-powered equivalents. The plan acknowledges that with proper planning, the bulk of EV charging can occur off-peak, and thus will not require additional generation or distribution infrastructure. Further, the plan frames EVs as a possible means of lowering utility rates by filling load during off-peak hours. The plan also mentions the potential of Smart Grid technology to allow support of EVs. The plan does not detail demand scenarios nor scenarios of EV adoption in the CVPS service area. CVPS was purchased by Green Mountain Power in 2012.

Utility: Green Mountain Power
Service Territory: Central and Northern Vermont
Planning Timeframe: 2011-2031

The Green Mountain Power (GMP) IRP includes EVs in the load forecasts, including summer and winter peak forecasts. GMP modeled two scenarios of EV penetration: a reference case and a low case. EV penetration rates and charging patterns were adopted from a University of Vermont Transportation Research Center Report (Letendre et al. 2008). Both cases assumed that ‘Uncontrolled Nighttime Charging’ occurred, meaning no mitigation of peak load through TOU rates. Annual load forecast of the reference case was approximately 65 GWh in 2030, or approximately 4% of total load (total load for the GMP service area is projected to be approximately 1,750 GWh). The low case resulted in a forecast of just over 30 GWh in 2030. While the low case had minimal effect on peak load, the reference case was found to increase projected peak load by 10 MW in winter and 20 MW in summer.

Utility: Vermont Electric Co-op
Service Territory: Northern Vermont
Planning Timeframe: 2012-2031

EVs are included as an ‘inherent uncertainty’ because not only are future rates of adoption difficult to characterize, but also these vehicles could serve to increase demand for electricity and serve as a distributed energy resource through battery storage and smart grid technologies. EVs are not included in the load forecasts of the 2012 IRP. However, in an memorandum of understanding (MOU) issued by the Vermont Electric Co-op in response to comments on the IRP by the Vermont Energy Investment Corporation and the Vermont Department of Public Service, the utility agreed to consider EVs in the utility’s next IRP. The IRP mentions that VEC is working with Sandia National Laboratories on leveraging Smart Grid and improved cyber security technologies that will in turn help the system to integrate the additional load resulting from EV use.

Virginia

Utility: Dominion North Carolina Power and Dominion Virginia Power
Service Territory: North Carolina, Virginia
Planning Timeframe: 2013-2027

Dominion Power includes forecasting of EV penetration and additional energy demand in its 2012 IRP. The utility is clearly tracking EV developments and associated implications. The IRP notes that the Volt and the Leaf became available in Dominion’s service area in 2011 and that Richmond, VA, has been selected as an ‘initial launch’ city for the Ford Focus EV. The plan notes that initial penetration levels of EVs has been slower than expected, but the pattern of EV adoption is anticipated to follow historic hybrid adoption patterns. In the IRP, Dominion used data from EPRI and Polk Automotive to develop load shapes and assess the impact of EV charging on the system. Dominion projects that 252,895 EVs will be on the road in the company’s service area (North Carolina and Virginia) by 2027, resulting in an additional 150 MW of load and additional annual energy usage of 806 GWh (out of 113,008 GWh of total energy demand forecast in the service territory).

The IRP also conducts sensitivity analysis to assess the additional load that would result from an additional 50,000 EVs by 2027. This scenario of higher EV penetration results in an estimated 360 MW of peak load and 2,400 GWh of annual energy usage from EV charging. In addition, the IRP assesses the costs associated with a base plan (no resource additions) and three other plans of potential resource additions for the company: one that incorporates higher fuel diversity, one that incorporates higher use of renewable resources, and one that incorporates the cost of developing additional coal facilities to generate power.

The scenario of higher EV penetration (750,000 vehicles by 2027) was modeled for each of the four plans and the estimated cost differential among them. Under the base plan, the higher penetrations of EVs increased total cost of the plan to the utility by 3%. Under the fuel diversity plan, higher EV penetration increased costs by nearly 7%. Costs increased by 9% under both the plan using more renewable sources of energy and the plan that calls for developing coal resources.

Also included in the Dominion IRP is discussion of an EV pilot project, initiated in 2011. The pilot project is a demand-side management initiative currently underway in Virginia, which will run until 2014. The project offers experimental and voluntary rate options to residential EV owners to encourage them to charge during off-peak hours. One option allows EV owners to apply time of use rates to their entire house, the other only to their EV. The utility supplies customers with a separate meter for their EV, although the customer may be responsible for some installation costs.

Utility: Tennessee Valley Authority (see Tennessee)

Washington

Utility: Avista

Service Territory: Washington, Idaho, Montana

Planning Timeframe: 2012-2031

This IRP accounts for EV demand in its load forecasts, predicting that this additional demand will increase steadily between 2012 and 2031. Overall demand is predicted to grow by 1.65% over these 20 years. Exclusion of PHEVs in models results in projected load growth of 1.57%.

Utility: Chelan County Public Utility District

Service Territory: Chelan County, Washington

Planning Timeframe: 2012-2022

Chelan County Public Utility District is one the 100 largest public utilities in the country, serving nearly 50,000 people. The 2012 IRP includes extensive discussion of EVs. The plan recognizes the difficulty of utilities tracking locations of EV owners and charging infrastructure. EV-specific rates are currently being considered by the utility for Level 3 charging locations (DC Fast Chargers) but have not been implemented. These EV rates would be achieved through separate meters at DC fast-charging stations. At present the utility has no plans to separately meter Level 1 charging at residences, nor to use Smart Grid technology in conjunction with EV infrastructure or operation. There are two known DC fast chargers in the utility area and an estimated ten Level 2 EVSEs. In addition, the area is anticipating the arrival of a small fleet of electric buses. Public policy in Washington requires local governments to allow charging infrastructure in all areas with some exceptions (residential areas). The utility intends to track the EV market and update its policies as needed.

Low, base, and high projections of EV penetration are incorporated into the usual load forecasts. The Chelan County PUD IRP estimates that by 2022 the district will have between 1,250 and 6,600 EVs in use (out of 35,000 to 41,000 total vehicle sales in the district over the planning period, 2012-2022). Additional electric load due to EVs is expected to be 0.36 MW to 1.93 MW annually by 2022. The base case load forecast predicts total annual energy load will be more than 600 MW by 2022, indicating that increased demand from EVs will be less than 1%. Chelan PUD does not anticipate requiring new resources to meet the additional demand presented by EVs in the period covered by the plan. The plan does not anticipate EVs having a substantial effect on peak load, although there may be a small effect on summer time afternoon peak. Most charging is expected to occur at home using Level 1 charging (Figure 7).

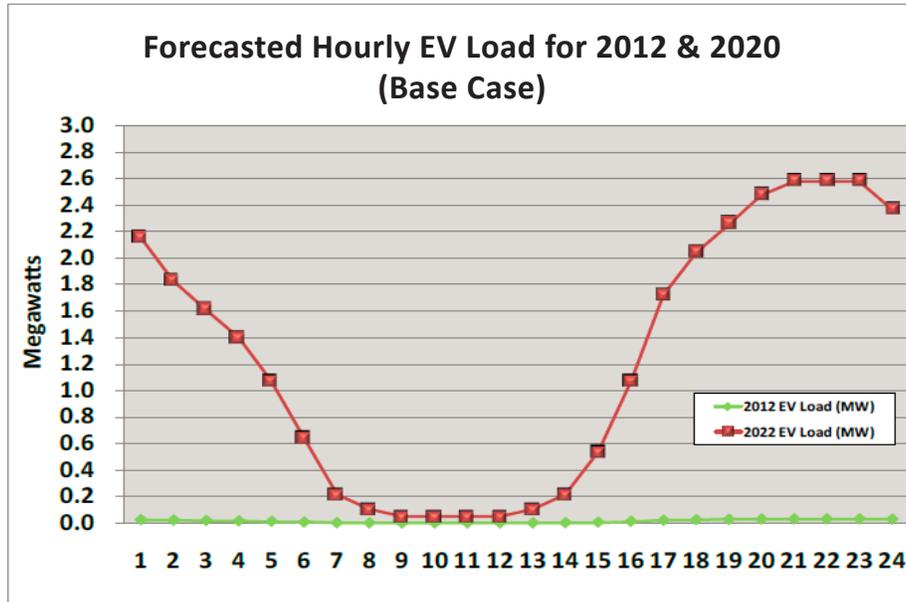


Figure 7. Forecasted Hourly EV Load for 2012 and 2022 in Chelan County, Washington (Chelan County PUD 2012 IRP)

Utility/Planning Council: Northwest Power Conservation Council (see Oregon)

Utility: Seattle City Light

Service Territory: Seattle, Washington

Planning Timeframe: 2012-2030

As a participant in the EV project, the city of Seattle expected EV adoption to be higher than the national average. Seattle is already home to at least one DC fast-charging station. The 2012 Seattle City Light IRP projects that total EV load will be 130-580 MW per year by 2030 in the Northwest Region. Seattle is projected to use 6% of the region's total EV load, approximately 36 MW annually, by 2030, or ~2.6% of total load. As of 2011, more than 1,200 EVs were registered in Washington and as of 2012, the Washington Department of Planning and Development had issued 480 permits for EVCE. The plan observes that TOU rates are very effective in encouraging off-peak EV charging. The IRP concludes that the utility should continue to monitor EV use and sales and should consider effects that EV charging may have on the distribution system, as well as load.

The additional load presented by EVs is predicted to be manageable, especially with off-peak charging of vehicles. Observed energy use for EV charging in 2012 was considerably smaller than the amount predicted by the 2010 IRP, due to slower than expected rates of EV adoption. EV adoption in the Seattle City Light service areas is predicted to be 6% annually 2012-2016, and then 25% annually 2018-2030. Under this scenario, the number of EVs in use in the service territory is approximately 1,700 in 2011 and grows to nearly 55,000 in 2030. Total daily energy used in EV charging is estimated to be 29 MWh per day in 2011 and 903 MWh in 2030. In calculating load growth, the plan assumes that most charging will occur off-peak and that this behavior will be encouraged through time of use rates.

Wyoming

Utility: Black Hills Power

Service Territory: South Dakota, Wyoming, Montana

Planning Timeframe: 2011-2030

The Black Hills Power 2011 Integrated Resource Plan includes a relatively brief discussion of EVs, including the mobile nature of the demand they place on the grid and their potential to increase peak load. Although the plan acknowledges the likelihood that EVs will soon be in wide use, the plan does not incorporate EVs into the load forecast nor into its transmission and distribution plans.

2.3 Patterns in IRP and Long-Term Plan Inclusion of EVs

After reviewing the IRPs and plans above, we explored patterns in plan inclusion of EVs, specifically:

- Some areas expect to have rates of EV adoption higher than the national average, due to state policies and incentive programs and consumer preferences. Are plans from these areas more likely to include EVs?
- Is there a relationship between utility size or type and tendency include EV in its plan? (Are large utilities more likely to have the resources to devote to EV analysis? Are small utilities more nimble and able to respond to market place and technological changes?)

Geographic Patterns in Projected EV Penetration and IRP Inclusion of EVs

Projected EV registrations from the Center for Automotive Research (2012) indicate that rates of EV ownership are predicted in California, Vermont, Oregon, Washington, and Connecticut (Figure 8, Table 9). The projections for each state are based on 2007-2009 hybrid vehicle sales. Geographic patterns in EV adoption are expected to be similar to those observed in hybrid vehicle adoption (Sullivan et al. 2013). As of 2009, California had the highest per capita rate of hybrid adoption, followed by Vermont, Oregon, and Washington.

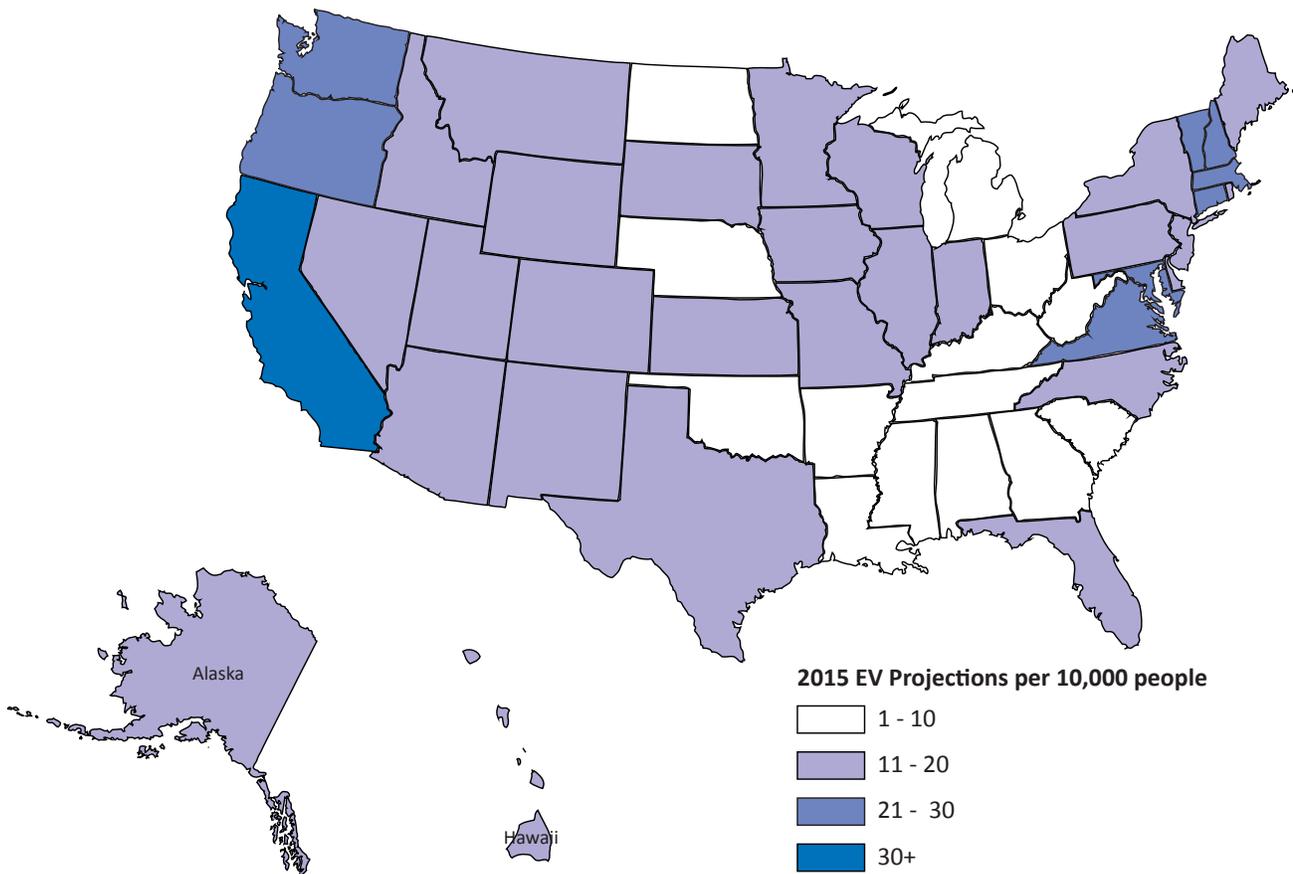


Figure 8. Projected 2015 EV Registrations by State (Center for Automotive Research 2012)

Table 9. Hybrid Vehicle Registrations per 10,000 Residents, 2007-2009, Top 10 states

State	Hybrid Vehicle Registrations per 10,000 people
California	54.0
Vermont	48.3
Oregon	45.6
Washington	44.4
District of Columbia	43.2
Connecticut	41.1
New Hampshire	41.1
Massachusetts	39.0
Virginia	38.7
Maryland	38.6

The states predicted to have the highest per capita rates of EV penetration by 2015 are presented in Table 10. Generally, IRPs of utilities in these states included EVs, with the notable exception of California. California currently has the highest rate of hybrid registrations per capita and is projected to have the highest number of per capita EV registrations in 2015. California does not have an IRP process, although it does require utilities to submit a Long-Term Procurement Plan (a similar process, although one that has less emphasis on demand-side management options). We reviewed two plans of utilities that operate in California: PacifiCorp (IRP) and San Diego Gas and Electric (LTPP). Neither of these plans included EVs. In contrast, plans reviewed from other states predicted to have high levels of EV adoption tended to include EVs, including two of three plans reviewed from Vermont, two of three reviewed from Oregon, and four of five reviewed from Washington. Of the 20 IRPs reviewed from the states presented in Table 10, only seven included EVs in the utility load forecasts. Of those states projected to be in the top ten of per capita EV registrations by 2015, the District of Columbia, Massachusetts, and Maryland do not have an IRP process.

Table 10. IRP Inclusion of EVs in States with Highest 2015 Per Capita EV Projections

State	Projected EVs per 10,000 people*	State requires IRP process?	IRPs that included EVs	IRPs that included EVs in load forecast	Total IRPs (or similar planning document) reviewed
California	30	No (Long Term Procurement Plan required)	0	0	2
Vermont	27	Yes	2	1 (Green Mountain Power)	3
Oregon	25	Yes	2	1 (Portland General Electric)**	3
Washington	25	Yes	4	3 (Avista, Chelan County PUD Seattle City Light)	5

State	Projected EVs per 10,000 people*	State requires IRP process?	IRPs that included EVs	IRPs that included EVs in load forecast	Total IRPs (or similar planning document) reviewed
District of Columbia	24	No	0	0	0
New Hampshire	23	Yes	1	0	2
Connecticut	23	Yes	1	0	1
Massachusetts	22	No	0	0	1
Virginia	21	Yes	2	2 (Dominion and Duke)	2
Maryland	20	No	0	0	1

*Center for Automotive Research 2012

** The Portland General Electric IRP assumed that the high-load scenario captured any additional load due to EVs.

IRP and Long-Term Plan Inclusion of EVs and Utility Size

No clear patterns arose around utility size and tendency to include EVs in their IRP or long-term planning document. Although larger utilities may have more resources to devote to planning and associated analysis, they appear to be no more likely to include EVs in their planning than smaller, generally municipally owned, utilities. Approximately half of utilities in the four size categories designated included EVs in their IRP.

Table 11. IRP and Long-Term Plan Inclusion of EVs by Utility Size

Utility Size (# customers)*	# Plans that included EVs	# Plans that did not include EVs
< 100,000	2	1
100,000 – 1 million	8	6
1 – 5 million	2	3
> 5 million	2	1

*Size information was not available for all utilities.

3. EV Planning Considerations for Utilities and Policymakers

Utilities and policymakers should consider a variety of factors in their preparation for electric vehicles, some of which can be integrated into the IRP process, some of which will occur outside of that process. All utilities should engage in some sort of EV planning, regardless of whether they operate in a state that requires an IRP to be filed, particularly those states that expect a high level of EV penetration based on historic hybrid sales (e.g., Massachusetts and Maine). This review recommends that utilities consider the following recommendations and questions when developing their next IRP or long term procurement plan. Policymakers should consider the policies and programs that might facilitate the implementation of these recommendations.

1. Coordinate with state Departments of Transportation, State Energy Offices, Clean Cities Coalitions, regional planning groups, EVSE installers, and other stakeholders to facilitate the transition to EVs.

- *Track EV deployment*

Tracking new registrations of EVs through collaboration with the state Department of Motor Vehicles will allow utilities to identify those areas that may experience higher than average penetration as well as EV penetration in areas that may have less robust infrastructure.

- *Track EVSE installation in the utility service area*

Additional energy demand resulting from EV use will be driven by both the number of EVs in use and charging patterns (including when and where charging occurs). Utilities should track public and residential charging infrastructure as it is installed in their service areas. Although utilities may not be able to require that ratepayers notify them when new charging installations are planned and built (without passage of new regulation), they can provide incentives for doing so and seek such information on a voluntary basis. Utilities and policymakers can work with building code inspectors and EVSE installers to assist in data collection.

- *Integrate travel behavior data and modeling into EV planning*

Working with the state DOT and municipal planning organizations to better understand local travel behavior and implications that this will have on EV use and charging will augment EV planning and energy demand forecasts, as well as inform where public charging infrastructure should be built.

- *Plan for optimal build-out of charging infrastructure*

Consider where Level 1, Level 2, and DC fast-charging stations make sense from a travel behavior and utility perspective: Where will travelers need them and where can the grid handle them? Where should load be filled and where can it be built? Of interest to utilities is not just where EVs will 'live' but also where they will charge. Presumably the bulk of charging will occur at home, but considerable charging will also occur at work (during peak hours) and at public locations, such as retail stores, park-and-rides, etc. These locations should be identified and considered from both a transportation and energy perspective.

2. Develop projections of EV penetration rates and associated additional energy demand and peak load effects in the utility service area.

- *Project EV adoption*

Projections can be based on EIA estimates, local sales of EVs and hybrids, state DMV EV reg-

istration data, and other sources as they become available. Presumably, EV adoption rates will vary geographically, depending on local incentives and EV model availability (some models are only available in California, driven by OEM attempts to meet state regulations).

- *Track EV charging behavior*

Tracking of charging behavior requires separate metering. Because timing is important a pilot study like Dominion's may be worthwhile. The Dominion pilot study was one of the few mentioned in the IRPs reviewed, although other utilities are already offering EV-specific TOU rates, including San Diego Gas and Electric, Southern California Edison, and NV Energy in Nevada. Currently, the most detailed (publicly available) charging behavior information is available through the EV Project (www.theevproject.com).

- *Estimate high and low projections of peak and off-peak use under varying EV penetration scenarios and charge-time scenarios.*

- *Consider how Levels 1, 2, and 3 charging and timing of such charging will affect total load and peak load.*

- *Consider how time of use electric rates affect EV charging patterns*

Data from the EV Project suggests this is a very effective means of encouraging off-peak charging.

- *Consider offering EV owners TOU EV rates and whole-house rates, as Dominion Power has in a pilot project.*

- *Consider the necessity of demand charges as applied to various types of EVSE infrastructure.*

3. Determine spatially explicit infrastructure needs that may result from EV use.

- Can current and planned distribution infrastructure handle the projected number of EVs, especially in areas of high penetration? For how long? Specifically, consider transformer insulation as points of vulnerability.

4. Reducing projected demand through increased efficiency.

- Consider how utility efficiency programs can reduce projected demand resulting from EV charging: e.g., incentivizing Level 2 charging due to increased efficiency, incentivizing particular vehicle models, reducing (electric) vehicle miles traveled. In addition, improving energy efficiency more generally within the service territory will provide buffer capability for increased load resulting from EVs.

5. Consider EVs as a grid resource facilitated and optimized by vehicle-to-grid technology and interoperability.

- The IRP process has traditionally included in its planning resources owned by other entities, including other utilities, power producers, and customers. When considering EVs as grid resources and energy storage units, they can be included in this process as distributed assets owned by customers. Vehicle-to-grid interoperability provides a means of mitigating negative EV grid impacts and improving overall grid efficiency.

6. Further Study

- Consider recruiting EV drivers for studies of travel behavior and charging patterns. Access to up-to-date, local data will assist planning efforts.

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