

# Chapter 5: The Impact of Distributed Generation and Electric Vehicles

In this chapter, we discuss the challenges and opportunities associated with distributed generation (DG) and electric vehicles (EV). Supported by public policies reflecting a range of concerns and goals, these technologies are expected to increase in penetration over the next few decades. At high penetrations they may require systemic changes in the way the electric grid is planned and operated. The successful integration of growing penetrations of DG units and EVs primarily will be the concern of industry engineers. Similar to Chapters 2 and 3, this chapter provides important background and context for the chapters that follow.

Section 5.1 focuses on DG. It starts by defining distributed generation and describes recent deployment trends. It then describes the potential benefits of DG, followed by a discussion of the interconnection challenges related to DG. We introduce the primary interconnection standards for DG and discuss several potentially important modifications to the standards. These modifications are required to allow the full realization of several of the projected benefits of DG. Finally, we briefly describe several effects of DG on distribution system operations.

Section 5.2 discusses EVs. It begins by introducing the different types of EVs and recent forecasts of their potential penetrations over the next several decades. It then describes electric vehicle charging requirements and discusses the importance of influencing the timing of electric vehicle charging. We find that influencing the timing of vehicle charging could improve system operation and avoid investments in infrastructure upgrades that would otherwise be necessary.

Section 5.3 provides our conclusions and recommendations. We recommend that the main standard governing DG interconnection be revised to permit voltage regulation by DG units and that utilities provide incentives for off-peak vehicle charging in regions with high EV penetrations.

## 5.1 DISTRIBUTED GENERATION

Distributed generation refers to relatively small-scale generators that produce several kilowatts (kW) to tens of megawatts (MW) of power and are generally connected to the grid at the distribution or substation levels.<sup>i</sup>

Distributed generation units use a wide range of generation technologies, including gas turbines, diesel engines, solar photovoltaics (PV), wind turbines, fuel cells, biomass, and

small hydroelectric generators. Some DG units that use conventional fuel-burning engines are designed to operate as combined heat and power (CHP) systems that are capable of providing heat for buildings or industrial processes using the “waste” energy from electricity generation.<sup>1</sup> For example, our own institution, MIT, has a combined heating, cooling, and power plant based on a gas turbine engine rated at about 20 MW, connected to our local utility at distribution primary voltage (13.8 kV). Distributed

<sup>i</sup> It is important to note that distributed generation is distinct from *dispersed generation*, which is not connected to the grid. Dispersed generation is typified by standby diesel generators that provide backup power in the event of a grid failure. Because these units typically do not impact utility operation or planning activities, we do not discuss them. Though not connected to the grid, dispersed generators can participate in demand response programs (see Chapter 7).

**Table 5.1 Theoretical Benefits of Distributed Generation**

Reliability and Security Benefits	Economic Benefits	Emission Benefits	Power Quality Benefits
<ul style="list-style-type: none"> <li>• Increased security for critical loads</li> <li>• Relieved transmission and distribution congestion</li> <li>• Reduced impacts from physical or cyberattacks</li> <li>• Increased generation diversity</li> </ul>	<ul style="list-style-type: none"> <li>• Reduced costs associated with power losses</li> <li>• Deferred investments for generation, transmission, or distribution upgrades</li> <li>• Lower operating costs due to peak shaving</li> <li>• Reduced fuel costs due to increased overall efficiency</li> <li>• Reduced land use for generation</li> </ul>	<ul style="list-style-type: none"> <li>• Reduced line losses</li> <li>• Reduced pollutant emissions</li> </ul>	<ul style="list-style-type: none"> <li>• Voltage profile improvement</li> <li>• Reduced flicker</li> <li>• Reduced harmonic distortion</li> </ul>

Source: U.S. Department of Energy, *The Potential Benefits of Distributed Generation and Rate-Related Issues that May Impede Their Expansion: A Study Pursuant to Section 1817 of the Energy Policy Act of 2005* (Washington, DC, 2007); and P. Chiradeja and R. Ramakumar, “An Approach to Quantify the Technical Benefits of Distributed Generation,” *IEEE Transactions on Energy Conversion* 19, no. 4 (2004): 764–773.

generation can be owned and operated by utilities or their customers and can provide a variety of theoretical benefits to their owners and the broader power system. Large DG units are typically dispatchable and communicate with system operators like central station generation facilities do. However, neither utilities nor system operators typically monitor or control the operation of small DG units, especially those in residential applications. Renewable DG from wind and solar power also typically is not dispatchable or easily controllable. These units present the greatest challenge and are the primary focus of this chapter.

*Distributed generation can be owned and operated by utilities or their customers and can provide a variety of theoretical benefits to their owners and the broader power system.*

In 2009, about 13,000 commercial and industrial DG units with a combined capacity of about 16 gigawatts (GW) were connected to utility systems in the U.S.<sup>2</sup> Of these units, 10,800 (83%) were smaller than 1 MW, averaging 100 kW each.<sup>3</sup> Internal combustion

engines, combustion turbines, and steam turbines comprised more than 4 GW each of installed capacity, while hydroelectric, wind, and other generator technologies totaled 3 GW.<sup>4</sup> In the same year, 93,000 residential PV installations totaled about 450 MW of capacity.<sup>5</sup> While 90% of solar PV installations between 1998 and 2007 were smaller than 10 kW, the largest installations generated more than 14 MW.<sup>6</sup>

Federal and state policies are expected to drive growth in DG in the coming decades. Sixteen states and the District of Columbia currently have renewable portfolio standards with specific DG provisions.<sup>7</sup> For example, some states have provisions in their renewable portfolio standards that require some fraction of retail electricity sales to come from renewable DG by 2020.

Distributed generation advocates cite a litany of good things DG can do. Distributed generation installations theoretically can improve reliability, reduce costs, reduce emissions, and improve power quality (see Table 5.1).<sup>8</sup> However, the benefits of DG are highly dependent on the characteristics of each installation and the characteristics of the local power system.

Furthermore, many benefits accrue to specific stakeholders and may not benefit the distribution system operator or the other customers of the system. Finally, existing DG interconnection standards prevent owners from realizing some of these hypothetical benefits.

Improved system reliability results from the ability of DG units to maintain supply to local loads in the event of a broader system outage. This could be done by creating “islands” in which a section of a distribution feeder is disconnected from a faulted area. Such an action is called “islanding.” Successful islanded operation requires sufficient generation to serve local loads and also the necessary distributed system control capabilities.<sup>9</sup> The potential reliability benefits of generators based on variable energy resources, generators with limited fuel reserves, or generators with low individual reliability are limited even if islanded operation is possible.

Economic benefits can be realized when utilities deploy DG to defer investments in transmission or distribution infrastructure.<sup>10</sup> Since DG is typically located closer to load relative to central plants, it can reduce congestion and system losses in some instances.<sup>11</sup> Customer-sited DG, on the other hand, often reduces utility revenue but can offer customers long-term electricity cost stability and, in some cases, savings. This savings can come in different forms. First, current rules allow customers with DG to avoid paying their share of fixed network costs (See Chapter 8). Second, because electricity generated by DG installations is typically more expensive than electricity generated in central stations, customers subject to increasing block electricity tariffs (in which customers who use more than some amount of electric energy pay a high rate) or who are offered sufficient subsidies can realize energy cost savings with DG. Combined heat and power (CHP) systems also can reduce total energy costs for their owners.

Emission benefits can be realized by renewable generators, such as solar photovoltaics (PV), which have no marginal emissions, or CHP systems whose use of waste heat can result in higher efficiencies than central generation units.<sup>12</sup> The magnitudes of emissions benefits associated with DG depend on both the characteristics of individual DG units and the characteristics of the power system to which they are connected.

Distributed generation capable of providing constant, uninterrupted power can improve power quality by mitigating flicker and other voltage regulation problems. On the other hand, distributed generation connected to the grid via power electronic inverters (e.g., solar PV, fuel cells, and most wind turbines) are widely understood to be sources of voltage waveform distortion. However, if designed and implemented properly, the power electronics could theoretically cancel grid distortions and help regulate voltage.<sup>13</sup> Many inverters on the market today are capable of these advanced functions, but such features add cost, and today DG owners rarely have incentives to invest in this added functionality.<sup>14</sup>

At present installed costs, many renewable DG installations remain dependent on these mandates or subsidies. The durability of such government policies will largely determine the rate of growth of installations over the next several years. In the long term, cost reductions also may drive DG growth. The average installed cost of residential and commercial solar PV installations dropped from about \$10.50 per  $W_{dc}$  in 1998 to about \$7.60 per  $W_{dc}$  in 2007 (both figures are in 2007 USD before incentives or tax credits).<sup>15</sup> As of September 2011, residential, commercial, and industrial PV installed system costs had fallen to \$7.10, \$5.10, and \$3.70 per  $W_{dc}$ , respectively.<sup>16</sup> While these costs are not competitive with conventional generating sources in most locations, if they continue to fall, solar PV systems will

ultimately become competitive. As described in Chapter 8, net metering policies that favor renewable DG could accelerate the adoption of residential rooftop solar PV generation even before this type of generation becomes otherwise economically viable.

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## FINDING

**Distributed renewable generation, though becoming more cost competitive with conventional generation technologies, is still significantly more expensive and strongly dependent on mandates and subsidies for its economic viability.**

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### Meeting Interconnection Challenges

The integration of DG presents new challenges for distribution system planning and operations, principally because the configuration of power lines and protective relaying in most existing distribution systems assume a unidirectional power flow and are designed and operated on that assumption. Historically, the penetration of DG was sufficiently small to be regarded as simply a reduction in load, but this will change if DG penetrations grow. While the physical wires and transformers can carry power flow in the reverse direction, DG nonetheless can have adverse impacts on system reliability, power quality, and safety.<sup>17</sup>

#### *IEEE Standard 1547*

In recognition of the potential adverse impacts of DG on distribution systems and the need for uniform criteria and requirements for the interconnection of DG, the industry collaborated with the Institute of Electrical and Electronics Engineers (IEEE) to create IEEE Standard 1547,<sup>18</sup> first released in 2003 and later incorporated into the Energy Policy Act of 2005.<sup>19</sup> The standard's primary intent is to ensure that DG units do not have negative impacts on

other customers or equipment connected to the grid; it applies to the interconnection of all generation with aggregate capacity of 10 megavolt amperes (10 MVA, approximately 10 MW) or less to the distribution system.

The standard includes several provisions to mitigate DG's potential negative impacts on power quality. For example, the standard requires that DG not "create objectionable flicker for other customers."<sup>20</sup> "Flicker" refers to rapid variations of voltage that can cause noticeable variations in lighting and interrupt the operations of electronics. Flicker can occur, for example, when clouds pass by photovoltaic cells, rapidly changing their power output.<sup>21</sup> Solar plant operators can use energy storage, static volt-ampere reactive compensators, or other forms of reactive compensation to mitigate potential flicker problems.<sup>22</sup> Distributed generation connected to the system with inverters (as are all solar PV systems) could use advanced inverter functionality to provide this reactive compensation.

IEEE Standard 1547 also seeks to address potential safety issues with DG, as it would threaten the safety of utility workers were it to keep a line energized after a fault when the line is thought to be "dead."<sup>23</sup> The standard requires that DG units disconnect from the system when local faults occur or when the voltage or frequency at their interconnection point falls outside prespecified ranges. DG units are also required to detect unintentional islanding, circumstances in which DG supplies a local portion of the grid that has been disconnected from the bulk power system, and disconnect "within two seconds." While the standard does not explicitly forbid "intentional islanding," it does not specify requirements for islanded operation and indicates that islanding is "under consideration for future revisions" of the standard.

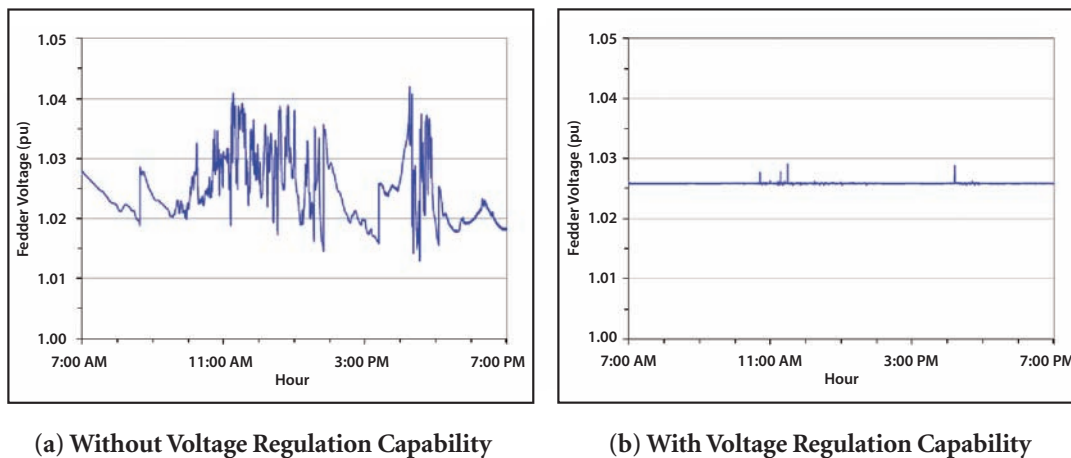
### BOX 5.1 DISTRIBUTED GENERATION'S CONTRIBUTION TO VOLTAGE REGULATION

In a recent study, General Electric discusses the potential benefits of allowing distributed generation (DG) units to actively regulate voltage.<sup>24</sup> The study simulates a 10 megawatt (MW) solar photovoltaic (PV) system connected to a 13.8 kilovolt (kV) feeder whose peak load reached 12.3 MW. The system also had 600 kilowatt (kW) solar PV inverters that could simultaneously supply real power and produce or absorb up to 290 kV-amperes of reactive power in order to regulate voltage levels.

Figure 5.1 illustrates the significant difference in feeder voltage with and without voltage

regulation observed in this study. As an additional benefit, allowing the solar PV system to regulate the voltage at its interconnection point was found to significantly reduce the need to operate other voltage regulation devices located along the simulated feeder. This result suggests that allowing DG units to actively regulate the voltage at their point of connection could sharply reduce voltage variation under high penetrations of DG. If such operation were to reduce the need for mechanical tap-changing transformers, installed to regulated voltage, it also would reduce maintenance costs. The results likely would be similar for more moderately sized DG units on low-voltage circuits.

**Figure 5.1 Feeder Voltage at the Point of Interconnection of a Solar PV System**



Note: The voltage scales on these plots are in a normalized measure called per-unit (pu). The normalizing constant is the nominal voltage of the line, 13.8 kV in this case. The line is operating at approximately 1.026 pu, which is 14.2 kV.

Source: ©2010 IEEE. Reprinted, with permission, from R. A. Walling and K. Clark, "Grid Support Functions Implemented in Utility-Scale PV Systems," paper presented at the Transmission and Distribution Conference and Exposition, 2010 IEEE Power & Energy Society, New Orleans, LA, April 19–22, 2010.

Since the original creation of IEEE Standard 1547, IEEE has supported efforts to create eight additional supplemental standards documents intended to extend and/or clarify the provisions in the main standard text.<sup>25</sup> For example, IEEE Standard 1547.4, completed in 2011, specifies

the required capabilities of DG and necessary operating procedures that can be used to create intentional islands, thereby partially filling the previously mentioned gap in IEEE Standard 1547. While five of these documents have been completed, three additional documents are

currently in development and are expected to be released over the next few years. IEEE Standard 1547 itself was reaffirmed without change in 2008 and is next up for revision in 2013.

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## FINDING

### The potential negative impacts of DG on the power system are being mitigated by the establishment of interconnection standards through the IEEE.

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#### Future Modifications to IEEE Standard 1547

Since its initial drafting, several weaknesses in IEEE Standard 1547 have become apparent. Grid-connected DG units, especially those based on variable energy sources, were not as prominent when IEEE Standard 1547 was first created as they are expected to be over the next 20 years. As the number of DG installations grows, modifications may be needed to ensure that the standard continues to address current state-of-the-art practices and needs. This section discusses several changes to IEEE Standard 1547 that should be considered if DG penetrations are to continue to grow.

#### *Distributed generation can complicate the regulation of voltage across the length of distribution feeders.*

**Voltage Regulation.** Distributed generation can complicate the regulation of voltage across the length of distribution feeders. But DG units connected to the grid via advanced power electronics also could play a role in actively reducing voltage flicker and regulating voltage levels at the point of interconnection (see Box 5.1). Power-conditioning modules within DG units that are capable of voltage regulation have improved considerably in recent years. However, IEEE Standard 1547 forbids DG units from actively regulating the voltage at their interconnection point.

**Islanded Operations.** IEEE Standard 1547 requires DG units less than 10 MVA to disconnect when an outage (or a large voltage drop) on the main system is detected. The standard requires disconnection in the event of unintentional islanding and does not discuss requirements for intentional islanding. In the development of IEEE Standard 1547, some argued that DG units should disconnect from the system to prevent damage to distribution system equipment and ensure the safety of utility crews repairing outages. The requirement that DG units disconnect during system outages effectively prevents DG units from providing reliability benefits to surrounding customers.

The recently released IEEE Standard 1547.4 discusses the intentional use of DG to supply power to a disconnected part of the distribution system when a fault is present in another part of the system. Distributed generation units that are connected to the grid in a way that complies with this standard should be capable of sustaining islanded operation and providing reliability benefits.

However, intentional islanding will require generators that are large enough to supply adequate real and reactive power to the island. It also necessitates distributed monitoring and control systems capable of maintaining local supply and demand balance as well as regulating the voltage and frequency within appropriate ranges. These monitoring and control capabilities add cost, and owners of very small DG units are unlikely to invest in this capability. Additionally, voltage and frequency regulation capabilities only are allowed in islanding operations and not when the island is reconnected to the distribution system. Therefore, even though IEEE Standard 1547.4 has been released, intentionally designed islanding schemes (for example, see Box 5.2) probably will be limited to larger DG units for the immediate future.

### BOX 5.2 MICROGRIDS

Microgrids that are capable of separating from the utility system and operating autonomously as electrically isolated islands for extended periods of time can be formed by a part of the distribution network incorporating distributed generation, storage, uninterruptible power supplies, or a combination of the three.<sup>26</sup> Such capability may be desirable for customers or groups of customers that require unusually high reliability levels. Military bases, college campuses, hospitals, semiconductor manufacturers, and data centers are examples of customers with high reliability needs. Microgrids in island operation would ensure that customers within the island would still have electric power supplied to them despite a fault upstream.<sup>27</sup>

Microgrid R&D is still in the early stages. Of the 160 active microgrid projects encompassing 1.2 gigawatts (GW) of installed DG worldwide, the majority have been demonstrations and research pilots.<sup>28</sup> Microgrids are expensive because they require power electronics and sophisticated coordination among different customers or areas.<sup>29</sup> It is our sense that in most situations, the cost of configuring an area as a microgrid does not justify the reliability benefits, which may be achieved through other means, such as backup generators. Despite the challenges, microgrids have the potential to bring new control flexibility to the distribution system and thus will continue to receive much academic interest.

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### FINDING

**Interconnection standards have recently been revised to allow for the realization of the reliability benefits of DG by permitting the operation of islanded distribution networks.**

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### Active System Management

Distributed generation imposes new challenges on distribution systems that cannot be mitigated by modifying interconnection standards. The most prominent of these impacts is the ability of DG to disrupt the operation of system protection schemes.

Modern system protection schemes typically use multiple layers of coordinated protection devices, including circuit breakers and fuses, to interrupt current and short-circuit faults while affecting service to the smallest possible number of customers. These devices are set based on fault current levels and other characteristics of the local distribution network. Distribution networks today are typically designed using a “fit and forget” approach in which settings for protection equipment remain static.

Distributed generation units can increase current at a fault and reduce it at the protection device for the period before the DG senses the fault and disconnects, making it harder to detect a fault and complicating the coordination among protection devices.<sup>30</sup> In addition, fault currents at points of system protection will depend on which DG units are connected and operating at any given time. Changing fault currents with the introduction of DG could lead to unreliable operation of protective equipment and result in faults propagating beyond the first level of protection. The propagation of faults through system protection layers can reduce system reliability and safety.

In contrast to the passive operation approaches described here, new technologies promise to allow active management of distribution systems.<sup>31</sup> For example, it has been envisioned that utilities could use real-time information about the operation of the network and the nature of connected resources to dynamically change protective relay settings. Active management distribution system operation techniques, such as actively using DG and loads for voltage control and fault current level control, can also be used to reduce the costs of mitigating

challenges related to regulating voltage profiles and ensuring adequate power quality with high penetrations of DG.

## 5.2 ELECTRIC VEHICLES



Similarly to DG units, electric vehicles could have a disruptive impact on the electric grid if not integrated carefully because they will connect to the distribution network to charge. As we discuss below, some such vehicles will represent a larger load than a house. The extent of their impact will depend on the degree and density of their penetration, charging requirements, and the time of day they are charged.

“Hybrid electric vehicle” (HEV) refers to a vehicle with an electric motor, an internal combustion engine, and limited onboard energy storage that improves fuel and engine

*Electric vehicles could have a disruptive impact on the electric grid if not integrated carefully.*

efficiency. HEVs, such as the Toyota Prius, have already penetrated the automotive market. Automotive manufacturers are now turning to plug-in hybrid electric vehicles (PHEV) and battery electric vehicles (BEV). PHEVs and BEVs have more onboard energy storage than HEVs and give owners the ability to charge the vehicle battery from a stationary electrical source—for example, an outlet in the garage. A PHEV contains an internal combustion engine, has a limited range in all-electric mode, and uses gasoline for long trips. A BEV has an electric motor, but no internal combustion engine, and it has a larger battery and a range longer than the all-electric range of a PHEV.

**Table 5.2 Representative Electric Vehicles Available in the United States by 2012**

	 Tesla Roadster	 Nissan Leaf	 GM Chevy Volt	 Toyota Plug-in Prius
Type	Battery	Battery	Plug-in hybrid	Plug-in hybrid
Electric Range	245 miles	100 miles	35 miles	15 miles
Battery Size	53 kWh	24 kWh	16 kWh	4.4 kWh
Onboard Charger	9.6 kW	3.3 kW	1.44 kW	1.44 kW
Quick Charger	16.8 kW	60 kW	3.3 kW	3.3 kW
Charging Time	6 hours (onboard) 3.5 hours (quick)	6 hours (onboard) 0.5 hours (quick)	10 hours (onboard) 4 hours (quick)	3 hours (onboard) 1.5 hours (quick)
U.S. Launch	March 2008	December 2010	December 2010	Spring 2012
Price (MSRP)	\$109,000	\$35,200	\$40,280	\$32,000

Source: Tesla Motors Inc., “Roadster Features and Specifications,” <http://www.teslamotors.com/roadster/specs>; Nissan Motors Company Ltd., “Nissan Electric Leaf Car: 100% Electric. Zero Gas. Zero Tailpipe,” <http://www.nissanusa.com/leaf-electric-car/>; J. Wiesenfelder, “Cars.Com Field Trial: Mobile EV Quick-Charging,” *Kicking Tires*, July 26, 2011, <http://blogs.cars.com/kickingtires/2011/07/carscom-field-trial-mobile-ev-quick-charging-.html>; General Motors Company, “2011 Chevrolet Volt,” [http://www.gm.com/content/gmcom/home/vehicles/browseByBrand/baseball\\_cards/chevrolet/volt.html](http://www.gm.com/content/gmcom/home/vehicles/browseByBrand/baseball_cards/chevrolet/volt.html); General Motors Company, “Chevrolet Volt’s 240V Home Charging Unit Priced at \$490,” press release, October 6, 2010, Detroit, MI, <http://gm-volt.com/2010/10/06/gm-announces-chevrolet-volt-240v-charger-pricing-and-installation-service-provider>; Toyota Motor Sales, USA, Inc., “Toyota Introduces 2012 Prius Plug-in Hybrid,” press release, September 16, 2011, Richmond, CA, <http://pressroom.toyota.com/releases/toyota+introduces+2012+prius+plug-in+hybrid.htm>.

Note: “Battery Size” gives the energy storage capacity of the battery in kilowatt-hours. This parameter also provides a relative physical size of the battery—for a given battery chemistry, e.g., lithium-ion, the battery size is directly proportional to capacity. “Onboard Charger” is the power capability of the charger which is integral to the car. This is the rate at which the battery can be charged by the internal charger. “Quick Charger” is the power capability of an external (optional) charger. The quick charger can provide a more rapid charge than the internal charger, as shown by the “Charging Time” data.

PHEVs and BEVs (collectively EVs) may emerge as a significant new distribution system load.<sup>32</sup> EVs as they are emerging today have batteries, usually lithium-ion, ranging in energy capacity from about 5 kilowatt hours (kWh) for short-range PHEVs to about 50 kWh for high-performance BEVs. By comparison, the Toyota Prius HEV has a 1.3 kWh nickel-metal hydride battery. Some representative EVs are shown in Table 5.2. As this table illustrates, EVs today are being designed with a range of specifications. Because BEVs have larger batteries, one would expect that they will be charged at considerably higher rates than PHEVs in order to limit the charging time, as illustrated by the table.

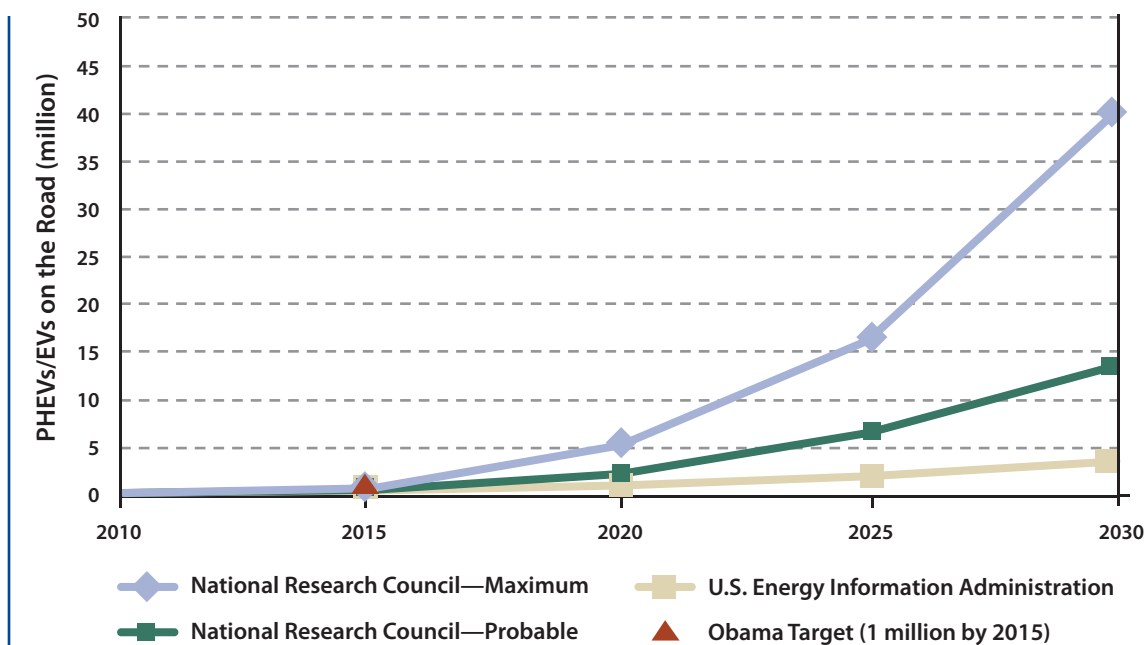
### Degree and Density of Electric Vehicle Penetrations

The impact of EVs on the electrical system depends on their market penetration. Several past and ongoing studies attempt to estimate

national EV penetration;<sup>33</sup> we illustrate four resulting projections in Figure 5.2. A carefully analyzed mid-range prediction from the National Research Council suggests that by 2030, 13 million PHEVs and BEVs, nearly 4.5% of the expected national fleet, could be on the road.<sup>34</sup> A projection by the U.S. Energy Information Administration (EIA) shows a substantially smaller penetration of EVs.<sup>35</sup> Of course, penetrations could be significantly higher or lower than these estimates depending on battery costs, gasoline prices, charging infrastructure, competition from other vehicles, and government policy. However, it is not the national penetration but the regional or local penetration that is of importance to utilities. The variances in estimates of regional and local penetration are also significant.

EVs will not initially be a concern for every utility. Varying geographic density of electric vehicles will mean that some utilities or regions

**Figure 5.2 Projected Electric Vehicles on the Road by 2030**



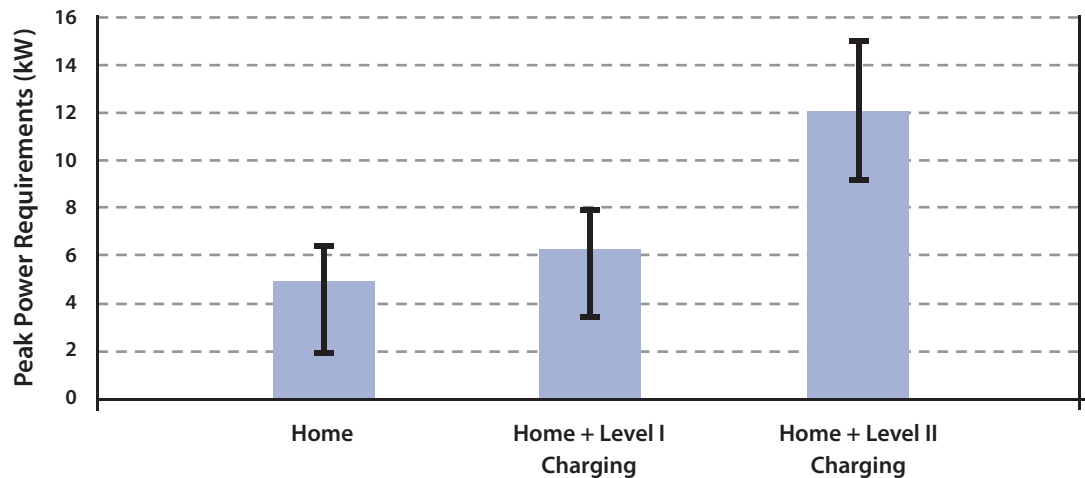
Source: Projection data from Committee on Assessment of Resource Needs for Fuel Cell and Hydrogen Technologies and National Research Council, *Transitions to Alternative Transportation Technologies—Plug-in Hybrid Electric Vehicles* (Washington, DC: National Academies Press, 2010); Daily Compilation of Presidential Documents 2011 DCPD No. 00047, p. 3 (January 25, 2011); and U.S. Energy Information Administration, *Annual Energy Outlook 2011* (Washington, DC: U.S. Department of Energy, 2011).

### BOX 5.3 HOUSEHOLD POWER AND ELECTRIC VEHICLE CHARGING REQUIREMENTS

Figure 5.3 compares requirements for vehicle charging to the average peak load of a single home near San Francisco Bay. The narrow vertical bar represents the variance in average

home peak loads for locations throughout the San Francisco area. The broad bars show the peak power requirements for the same home by itself and with EVs charging at the two standard levels: 1.4 kW (Level I) and 7.2 kW (Level II).

**Figure 5.3 Power Requirement of a Single Home in the San Francisco Bay Area with and without Electric Vehicle Charging**



Source: Data from D. Bowermaster, "Plug-in Electric Vehicles and Their Impact: An Integrated, Multi-Stakeholder Approach," presentation at Environmental Quality Policy Committee Meeting, League of California Cities, Sacramento, CA, January 21, 2011, [http://www.cacities.org/resource\\_files/29491.PGEPEVIntro\(2011-01-18\).pdf](http://www.cacities.org/resource_files/29491.PGEPEVIntro(2011-01-18).pdf).

within utilities may be more severely impacted by the presence of EVs than others. Even within regions or utility footprints, only certain hotspots will need significant focus even in the medium term.

If the current geographic distribution of HEVs is a good indicator of demand for PHEVs and BEVs, distribution systems in California, Oregon, and Washington likely will experience considerably higher penetrations than average.<sup>36</sup> For example, Southern California Edison has projected a mid-case of 5% penetration, or 0.5 million PHEVs and BEVs in its service territory by 2020.<sup>37</sup> Even citing average penetration across a service area may understate the challenge, as PHEVs and BEVs may

cluster in particular neighborhoods, thereby increasing concern for the local distribution system. Early integration problems are likely to arise most often when local demand rapidly increases because of uneven distribution of vehicles. Importantly, promotional policies, incentives, and the deployment of the necessary infrastructure will strongly influence the geographic distribution of EVs.<sup>38</sup>

#### FINDING

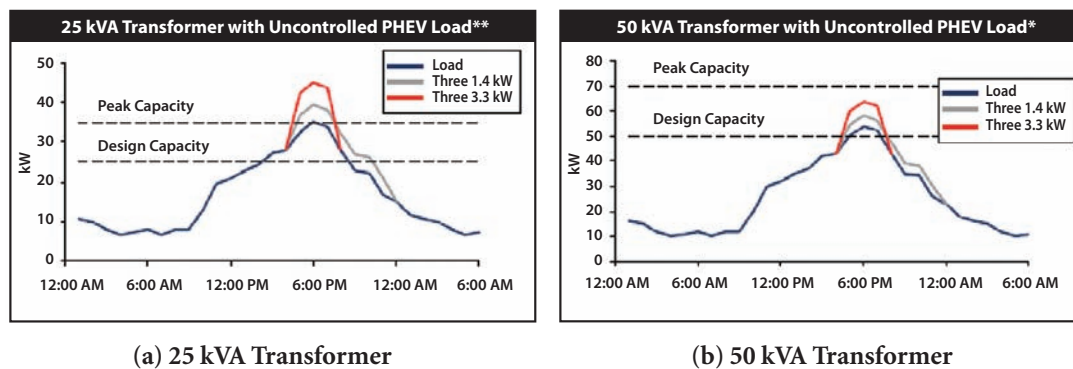
**Projections of EV penetration nationally are highly varied. However, some local regions are likely to experience penetrations much higher than the national average.**

#### BOX 5.4 THE EFFECT OF UNCOORDINATED CHARGING ON TRANSFORMERS:

DTE Energy recently conducted a study on the impact of plug-in hybrid electric vehicles (PHEV) on distribution system components in its service territory. Figure 5.4 shows the impact on both a 25 kilovolt-ampere (kVA) transformer and a 50 kVA transformer of three PHEVs

charging at two rates, 1.4 kilowatts (kW) and 3.3 kW, on a warm summer day. These transformers are loaded beyond their design capacity for both charging rates, and the 25 kVA transformer exceeds even its peak (short-term) capacity rating in both cases. This could lead to voltage dips, service interruption, and transformer failure.

**Figure 5.4 Impact of Three PHEVs on Transformer Loading**



Source: J. LeBrun, DTE Energy, "Plug-in Electric Vehicle Overview," presentation at A Tale of Three Cities, webcast hosted by Intelligent Utility, January 6, 2011.

### Electrical Vehicle Charging

EVs are expected to charge at one of three power levels. The Society of Automotive Engineers has established charging standards (in Standard J1772) that cover the following two charging power levels:

- Level I — up to 1.92 kW
- Level II — up to 19.2 kW

Level III has not yet been standardized in the U.S., but will enable full BEV charging within minutes.

At the residential level, the majority of PHEVs are expected to charge using Level I chargers, while BEVs are expected to charge at Level II. Charging BEVs will have more impact on the distribution system due to their higher-power charging and higher energy capacity than

PHEVs. On the other hand, PHEVs are expected to comprise a majority of EVs, and a few PHEVs charging simultaneously could have an impact similar to one BEV. Therefore the potential impact of these two types of vehicles likely will be similar.

A study in 2008 estimated that if each North American Electric Reliability Corporation (NERC) region were to have a 25% penetration of PHEVs in the year 2030, each area would require less than a 5.5% increase in generation.<sup>39</sup> Aggregate power requirements are also unlikely to require significant upgrades to the bulk power system. If 25% of the national fleet were PHEVs, the power requirements could be up to 30% of generation capacity if simultaneously charged at 6 kW.<sup>40</sup> However, this increase is unlikely to materialize as there will be temporal diversity in the time of arrival at home and most charging will probably be at

levels lower than 6 kW.<sup>41</sup> Nevertheless, there is some concern that EV charging could impact local distribution systems, requiring mechanisms to influence the timing of vehicle charging, discussed in the next section. Because an EV charging with a Level II charger is a bigger load than the average house, even a few EVs on a distribution feeder could overload that feeder and associated transformers (see Box 5.4).<sup>42</sup>

### Influencing Electric Vehicle Charging

If electric rates do not vary over time, most EV owners will plug in their vehicles and begin charging when they arrive home each day, in many cases at the same time as neighborhood load peaks. This would exacerbate local peak load conditions, forcing utilities to invest in

expanded infrastructure (see Box 5.5).<sup>43</sup> Early results from an ongoing Electric Power Research Institute (EPRI) project suggest that peak charging, higher charger power ratings, and increases in the number of EVs on a transformer could yield decreases in transformer lifetimes due to temperature-induced insulation aging from capacity overload.<sup>44</sup> The additional cost to the system of provisions for EVs would be a substantial but not dominant expense that most likely all system ratepayers would bear, though costs also could be recovered through higher fixed capacity charges (see Chapter 8) in neighborhoods where EVs required system upgrades.

Influencing the timing of vehicle charging can avoid these outcomes, reducing peak loading and improving load factor—that is, the ratio

#### BOX 5.5 VEHICLE-TO-GRID OPERATIONS

Some observers have suggested that the flow of energy between the power system and EVs could be bidirectional.<sup>45</sup> This concept is most often referred to as “vehicle-to-grid operation.” While most often discussed in the context of vehicles providing frequency regulation services, in theory, energy stored in vehicles’ batteries could provide various types of operating reserves. In regions with organized wholesale markets, it has been envisioned that vehicles could participate in frequency regulation or other reserve markets by supplying energy to the grid.

V2G operations would require substantial and expensive modifications to conventional unidirectional vehicle chargers and controls. V2G concepts also face other substantial technical challenges—degradation of battery life, OEM warranty issues, complexity and expense of added controls and communication with the utility, and the relatively small amount of energy involved if the battery is always to be

sufficiently charged for driving the car—and are unlikely to achieve widespread deployment in the short term.

Beyond the technical challenges, the economic incentives for V2G operation also appear weak. In those markets with a regulation product, the price paid to participants for regulation services has historically been relatively low. The participation of EVs in these markets would likely cause the prices to decline further.

A more cost-effective alternative use of EVs would be to provide regulation or operating reserves only through control of their (unidirectional) charging rate—for example, decreasing their rate to provide up regulation, and increasing it for down regulation. While still requiring communication between vehicles and the utility, the charger requirements would be much simplified. This mode of operation would also have a much more limited impact on vehicle battery life. Particularly attractive is the use for this purpose of commercial EV fleets which have deterministic charging patterns.

between average and peak power. According to a 2002 study, if vehicle charging were influenced by policy or controls to produce a flat load between 6 p.m. and 6 a.m., the regional generation capacity could handle a PHEV penetration level from a low of 15% in California to a high of 73% in Texas.<sup>46</sup>

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#### **FINDING**

#### **For real-time pricing to be effective, EVs must be capable of automatically responding to price signals.**

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Two viable methods for influencing the timing of charging have emerged: time-differentiated tariffs and centralized charging control structures. Time-differentiated tariffs can be structured in a variety of ways: they can be static and based on time of use, or they can be signaled a day ahead, an hour ahead, or in real time. Vehicle owners might respond to time-of-use pricing by simply putting the vehicle charger on a timer set to avoid the most expensive times of day. If the time-of-use tariff were to have uniform timing over the whole system, a secondary peak load probably would develop at the time of price change.<sup>47</sup> Regulators might counter this effect by staggering the rate structure geographically.

A weakness of price signals for the distribution system is that they offer little insight into neighborhood congestion levels. As a result, time-of-day, period-ahead, and even real-time pricing would improve system-wide load factor, but are unlikely to have a substantial impact on feeder overloading. Utilities can more directly mitigate the impacts of EV charging on distribution circuits by remotely controlling charging. The exact mechanisms for accomplishing this in ways acceptable to consumers have not yet been fully worked out, but advanced metering infrastructure would help enable such a scheme.

The requirements include a tool to control charging power at each vehicle; a two-way communication link between the charging station and utility; and knowledge of the system state, the number of vehicles requiring charging, and the state of charge of each of those vehicles.<sup>48</sup> Controlling the charging of EVs may enable them to benefit utility operations by providing ancillary services such as frequency and/or voltage regulation (see Box 5.5).

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#### **FINDING**

#### **Using time-differentiated tariffs or central control schemes to discourage electric vehicle charging at peak times can improve system operation and avoid requiring capital investments in new infrastructure.**

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To give an idea of the effect, researchers simulated controlled and uncontrolled charging of an aggressive 75% penetration of EVs in the Netherlands.<sup>49</sup> They assumed two charging rates for the vehicles: 3 kW and 10 kW. In the uncontrolled case, owners would begin charging their vehicles on arrival at home, overloading 22.1% and 31.4% of the local distribution transformers at the 3 kW and 10 kW rates, respectively. The controlled charging case set charging rates to be inversely proportional to the historical load but ensured that enough energy was transferred to the vehicle for its next day's trips. With controlled charging, even this high penetration of vehicles would require upgrading only 1.9% of transformers.

Customer reactions to such a control scheme would be complicated and potentially negative. Implementing it might require a price break for participating customers and a mechanism for overriding the direct control at some cost. In designing measures to influence demand, the differences between PHEVs and BEVs must be carefully considered. With their fuel-powered

engines, PHEVs offer their owners more flexibility in the timing of their vehicle charging, and owners may be more willing to

*Controlling the charging of EVs may enable them to benefit utility operations by providing ancillary services such as frequency and/or voltage regulation.*

take advantage of lower rates. By comparison, BEV owners may want to keep their batteries fully charged, charging when they have a chance, and therefore may resist methods that influence vehicle charging.

The introduction of time-differentiated tariffs is not only being considered in the context of PHEVs and BEVs. As discussed in Chapter 7, demand response programs aim to shift total demand away from peak periods to realize both short-run operational benefits and long-run investment efficiency improvements. Electric vehicles could make these programs even more important.

### **5.3 CONCLUSIONS AND RECOMMENDATIONS**

Distributed generation and plug-in electric vehicles are qualitatively different from the types of generation and loads that have been connected to the electric power system in the past. Widespread deployment of these technologies will change the requirements of the distribution system.

Growth in DG will arise from the economic advantages of cogeneration and policies that encourage distributed renewable generation, such as rooftop solar panels. IEEE Standard 1547 was a first attempt at establishing uniform interconnection criteria for small generators and included a range of provisions to mitigate many of the challenges associated with DG.

However, as DG penetrations continue to grow, modifications to this standard will become increasingly important. In particular, adding provisions for islanded operation of DG units would permit them to enhance the reliability of supply, and enabling DG units to actively regulate the voltage at their interconnection points would ease the burden of providing uniform and constant voltage along distribution feeders.

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#### **RECOMMENDATION**

**DG interconnection standards should permit voltage regulation by distributed generators to enable them to help maintain distribution voltages within limits.**

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Growth in DG also will motivate the deployment of active distribution system management technologies, including the deployment of additional communication and sensors. Ultimately, deployment of these technologies could reduce the total costs of integrating high penetrations of DGs.

Plug-in hybrid and battery-powered electric vehicles, collectively referred to as EVs, have begun to enter the U.S. market. The number of EVs on the road in the U.S. by 2030 will depend on a number of factors that are difficult to predict. National projections range from as few as 3.3 million to 40 million by 2030. More important than the magnitude of penetration is the fact that it is not expected to be uniform across the nation because of state incentives, charging infrastructure availability, and consumer preference and income. In fact, EVs are expected to cluster in select high-income and eco-conscious neighborhoods. Between the two types of EVs, PHEVs will achieve greater penetration than BEVs due to their superior range and operational flexibility.

The degree to which EVs pose a stress to the power grid depends on their local penetration rate, as well as the power and time at which they charge. If regulators and utilities appropriately influence charging so that it mostly does not coincide with the system peak demand, EVs will improve system load factor and will not cause unmanageable disruption to the bulk generation and transmission system. Otherwise, integrating these loads will require more investment in equipment.

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**RECOMMENDATION**

**Utilities in regions with potentially high penetrations of EVs should explore mechanisms to incent off-peak charging.**

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