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Projecting Electricity Demand in 2050

July 2014

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U.S. DEPARTMENT OF
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Summary

This paper describes the development of end-use electricity projections and load curves produced for the Renewable Electricity (RE) Futures Study (hereafter RE Futures), which explored the prospect of higher percentages (30% − 90%) of total electricity generation that could be supplied by renewable sources in the United States. As input to RE Futures, two projections of electricity demand were produced representing reasonable upper and lower bounds of electricity demand out to 2050.

The electric sector models used in RE Futures required underlying load profiles. RE Futures produced load profile data in two formats: 8760 hourly data for the year 2050 for the GridView model, and in 2-year increments for 17 time slices as input to the Regional Energy Deployment System (ReEDS) model. The process for developing demand projections and load profiles involved three steps: discussion regarding the scenario approach and general assumptions, literature reviews to determine readily available data, and development of the demand curves and load profiles.

Contents

1.0 Introduction

The U.S. Department of Energy (DOE) sponsored a study to analyze the grid integration opportunities, challenges, and implications of high levels of renewable electricity generation within the United States (NREL 2012).[1] The projection of electricity demand is an important consideration in determining the extent to which a predominantly renewable electricity future is feasible. Because of the uncertainties involved in this type of analysis, the Renewable Electricity (RE) Futures Study (hereafter RE Futures) modeled and analyzed multiple scenarios to consider the impacts of alternative assumptions. As an example, a scenario assuming lower future electricity demand would require less growth in the renewable industry to achieve a higher penetration of renewable generation compared to a scenario with higher demand growth. For this reason, two “bounding” demand trajectories were developed to determine the impact of end-use demand on generation requirements.

Any scenario regarding future electricity use must consider many factors, including technological, sociological, demographic, regulatory, and economic changes (e.g., the introduction of new energy-using devices; gains in energy efficiency and process improvements; changes in energy prices, income, and user behavior; population growth; and the potential for carbon mitigation). Although a substantial body of literature is dedicated to factors affecting energy demand, including behavioral influences, climate change, and new technologies and materials, the explicit inclusion of the potential impacts arising from these influences was beyond the scope of RE Futures. RE Futures relied on readily available data and projections to the extent possible, and attempted to stay within reasonable bounds established by recent literature. RE Futures was further constrained by the modeling requirement for hourly load projections through the study period. This required the conversion of the estimated projections of electricity consumption into regional hourly load profiles. Although studies projecting potential energy consumption futures are plentiful (e.g., Brown et al. 2008; Cleetus et al. 2009; EPRI 2009; Granade et al. 2009; McCarthy et al. 2008; NAS 2009), studies that tie those consumption futures to hourly loads are not readily available.

For RE Futures, two sets of underlying load profiles were developed as inputs to the two electric system models used in the study: an 8760 hourly load profile by sector and region for use in the GridView model, and a compilation of those loads into 17 time slices for use by the Regional Energy Deployment System (ReEDS) model (hereafter ReEDS).

GridView is a model that simulates security-constrained unit commitment and economic dispatch in large-scale transmission networks, and ReEDS is a capacity expansion model used to forecast the deployment of supply-side electricity generation and transmission capacity. Both models only address the contiguous United States. While the ReEDS framework considers grid operation and renewable integration issues, RE Futures needed a finer temporal resolution and a more accurate representation of transmission flow, so the ReEDS projection of generation and transmission capacity was imported into GridView to determine the operational feasibility of the capacity expansion scenarios (Mai et al. 2012).

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[1] Funding for this work was provided by the U.S. DOE Office of Energy Efficiency and Renewable Energy. The opinions represented in this article are the authors’ own and do not reflect the views of the U.S. Department of Energy or any agency thereof.

2.0 End-Use Demand Scenario Development

RE Futures represented an initial investigation of the extent to which renewable energy supply would be able to meet future electricity demand. For RE Futures, two demand projections were developed to represent probable higher and lower electricity use trajectories—hereafter referred to as the *High-Demand Baseline* and the *Low-Demand Baseline*. Projecting electricity use 40 years into the future is a highly uncertain undertaking. Thus, the two trajectories were chosen to represent reasonable higher and lower "bounds" on electricity use, with the expectation that actual electricity use in 2050 will fall between the two trajectories. The higher and lower trajectories helped to provide an estimate of the impact of end-use demand on the resulting electricity generation mix. The basis for these scenarios was predominantly drawn from the U.S. Energy Information Administration's (EIA's) Annual Energy Outlook (AEO) for 2009 (industrial sector) and 2010 (buildings sector).[1]

The *High-Demand Baseline* is a business-as-usual scenario that assumes trends for the residential, commercial, and industrial sectors as forecast to 2030 by the EIA in its AEO for 2009 (EIA 2009b and EIA 2010). Because the AEO contained only a forecast through 2030, RE Futures extended the AEO trends out to 2050. Under this scenario, the overall electricity intensity within the buildings sector remains relatively unchanged from 2010 to 2050, and the industrial sector electricity intensity declines by approximately 35% during the RE Futures period (2010–2050). Consistent with EIA's AEO, the intensity for the residential sector is in terms of electricity use per household; for the commercial sector it is in terms of energy use per square foot of floor space; and for the industrial sector, the intensity is computed as the electricity consumption per dollar (in real terms) of shipments. The *High-Demand* scenario assumed no significant changes in available technologies or consumer behavior, although current technologies would evolve in terms of cost and efficiency. No new regulations or laws not already enacted are included in an AEO Reference Case, and beyond its 2030 horizon, a simple extrapolation was made to 2050. Because the 2009/2010 AEO reference case did not incorporate many of the trends expected to lower demand (EIA 2010), such as more recently enacted appliance and equipment efficiency standards, proposed building energy code changes, or consumer and supplier preferences for green energy, it was chosen to represent a probable higher end-use demand projection.

The *Low-Demand Baseline* reflects emerging trends in the drivers for electricity demand, such as the growing interest in green buildings and green supply chains, carbon mitigation activities, anticipated equipment standards and energy code changes, research and development in energy efficiency, shifting away from energy-intensive manufacturing, and increasing foreign competition for manufacturing (DOE EERE 2008, 2009). Based on these trends, a scenario was developed in which there is an approximate 30% reduction in overall electricity intensity within the buildings sector and a 50% reduction in industrial electricity intensity by 2050. While explicitly a technical feasibility study, because the context of RE Futures represented diversification away from fossil energy and reduction of carbon emissions, this scenario also included electrification of approximately 40% of the light-duty vehicle stock by 2050. Table 1 provides the resulting equivalent intensity reductions for the two baselines.

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[1] During the course of the study, the 2010 version of the Annual Energy Outlook was released, so building sector calculations were revised to reflect the newer AEO. Because the industrial sector used the EIA Waxman-Markey analysis for the *Low-Demand Baseline*, which was run based on the AEO 2009, the decision was made to continue to use AEO 2009 for the industrial sector.

Table 1. Comparison of Efficiency Assumptions in 2050: *High-Demand Baseline* versus *Low-Demand Baseline*.

Sector	High-Demand Baseline	Low-Demand Baseline
Residential	2% decline in intensity compared to 2010 levels	30% decline in intensity compared to 2010 levels
Commercial	5% increase in intensity compared to 2010 levels	32% decline in intensity compared to 2010 levels
Industrial	35% decline in intensity compared to 2010 levels	50% decline in intensity compared to 2010 levels
Transportation	<3% PHEV penetration	40% of vehicle sales are PEVs

PHEV = plug-in hybrid electric vehicle; PEV = plug-in electric vehicle.

The electricity demand forecasts for buildings, industry, and transportation represent sales trajectories. Transmission and distribution losses are not considered part of these onsite electricity projections. The electricity sector is expected to deliver these energy quantities according to the timing and distribution specified by the corresponding load profiles used in the models.

Figure 1 illustrates the resulting demand trajectory for the *Low-Demand* and *High-Demand baselines* through 2050. For comparison, the EIA analysis (EIA 2009a) of the American Clean Energy and Security Act of 2009 (the Waxman-Markey Climate Bill of 2009) is included, using the 2025–2030 trend to extend the analysis to 2050.

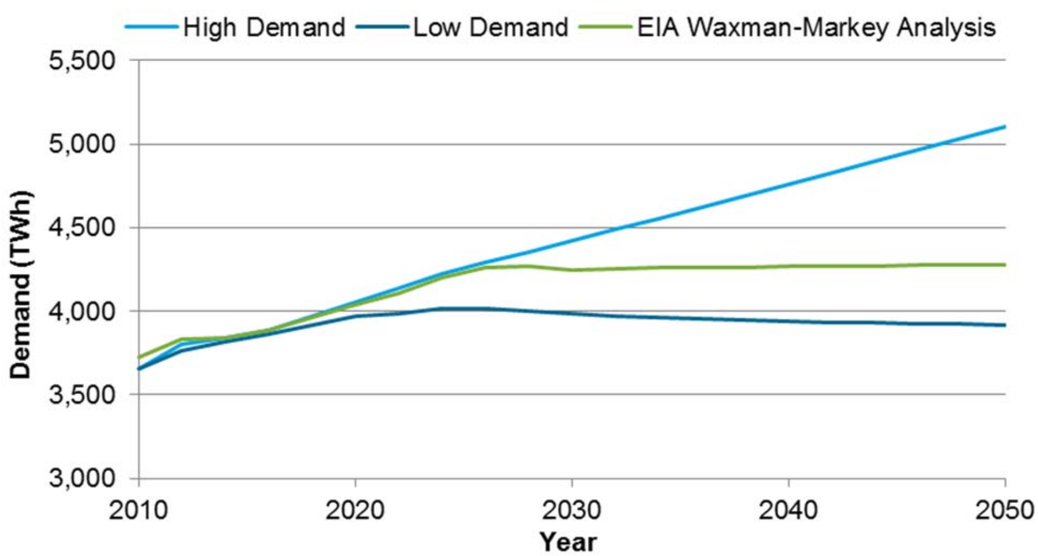

Figure 1. Total electricity demand, 2010–2050.

The potential for renewable electricity production to meet a large portion of future electricity demand depends not only on the magnitude of that demand but also on its variability regionally, seasonally, and diurnally; therefore, RE Futures focused on regional load profiles. A central challenge for RE Futures was to convert the energy forecasts to 134 regional hourly system load profiles required for the models.

Because the *High-Demand Baseline* is a direct extension of a National Energy Modeling System (NEMS) run, the load profiles for all sectors can be derived directly from NEMS, and the underlying assumptions for the *High-Demand Baseline* are not further discussed in this paper because they are addressed in AEO documentation (EIA 2009b and EIA 2010). The *Low-Demand Baseline* poses a different challenge, and is the focus of this paper. Figures 2 and 3 illustrate the resulting non-plug-in electric vehicle (PEV) load-shapes under the two baselines. Figure 2, the *High-Demand* profile, illustrates the typical large summer peak, while Figure 3, the *Low-Demand* profile, illustrates the impact of efficiency measures, particularly in the summer.[2]

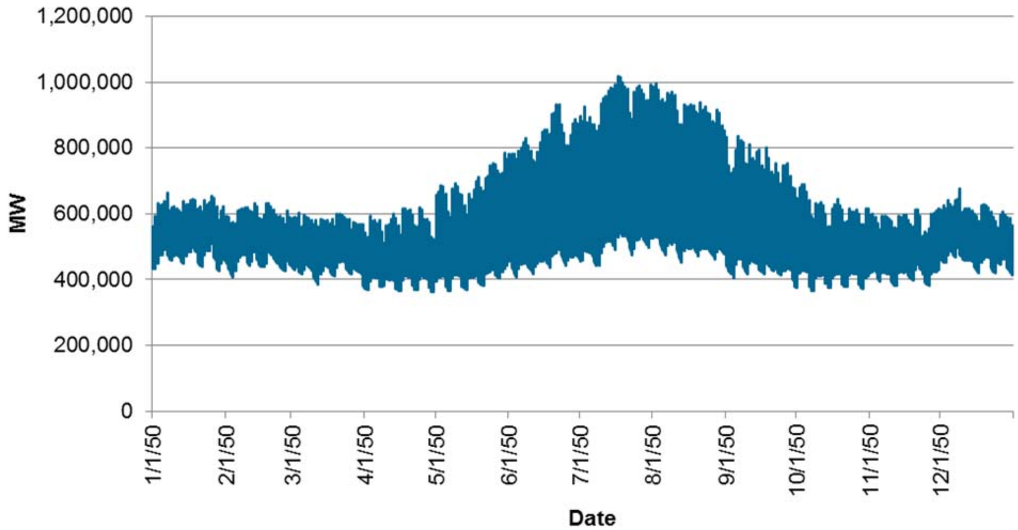

Figure 2. Non-PEV *High-Demand* hourly load profile, 2050.

[2] The underlying data used to produce these charts at the national and regional levels is available at http://www.nrel.gov/analysis/re_futures/docs/ref_demand_reporter_high.xlsb (High-Demand) and http://www.nrel.gov/analysis/re_futures/docs/ref_demand_reporter_low.xlsb (Low-Demand)

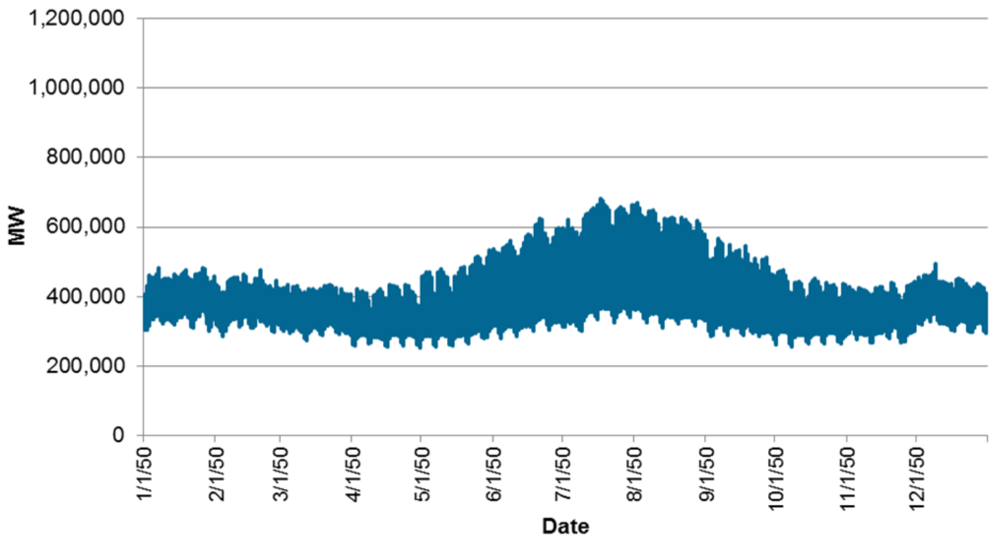

Figure 3. Non-PEV *Low-Demand* hourly load profile, 2050.

End-use projections were developed for the three primary end-use sectors: buildings (commercial and residential), industrial, and transportation. Because each of these sectors is unique, the method applied to project electricity use differed for each sector.

2.1 Buildings Sector

The buildings sector, comprising residential and commercial buildings, dominates overall electricity consumption and represents almost 75% of electricity demand in the AEO Reference Case (EIA 2010). In addition, building electrical end uses are highly heterogeneous and changing over time.

Within the buildings sector, trends that can be expected to influence future electricity use include increased market adoption of green buildings, more stringent building codes, more stringent appliance and equipment standards, and research by the DOE and others to develop ultra-efficient buildings (DOE EERE 2008). Ultra-efficient buildings are designed and operated to generate as much onsite power as the energy they consume. Some of the approaches to achieving this goal include developing and applying very high-efficiency technologies, finding ways to reduce the cost of energy-efficient technologies that have already been developed, and increasing the implementation of cost-effective technologies that are already available.

2.1.1 Projection of Electricity Consumption in the Building Sector

Because the focus of RE Futures was on the generation of electricity, the lower-demand baseline was developed using a top-down energy-intensity projection, rather than attempting to build a projection up from the various technologies and practices available within each of the end uses. Although a certain level of energy-efficiency gains are possible through the normal adoption of new energy-efficient practices and technologies, the larger gains here implicitly require more active policy and behavioral change to come to fruition. The efficiency gains within the *Low-Demand Baseline* are assumed to be feasible by sustained efforts on the part of government, businesses, and households, and to be cost-effective without major increases in electricity prices as a driver.

Due to the uncertainties regarding which end-use technologies are likely to show the greatest efficiency improvement over a 40-year future, the approach used to project total consumption has taken a generally neutral stance on the future composition of end-use consumption. There are two exceptions to this approach involving electricity—that used for air conditioning (space cooling) and that used for miscellaneous plug loads. These exceptions receive special treatment for different reasons. First, because cooling demand plays the major role in determining peak electricity demand in almost all regions of the United States, it represents a key driver of capacity expansion of the power sector and therefore necessary investment in renewable generation. Second, because RE Futures modeled the potential for cooling load shifting by deploying thermal energy storage, it was necessary for the commercial cooling load to be input separately from the other building loads.

The basic assumption of the *Low-Demand Baseline* is that new technologies (influencing both cooling equipment and the building envelope) would keep pace with improvements in other technologies affecting other major end uses. The poorly understood, amorphous, and perpetually growing plug loads, usually termed "miscellaneous," are a concern when energy forecasting for buildings. If miscellaneous electricity intensity does not decline to the same degree as all other major building end-use intensities, the future share of electricity associated with all other end uses—including cooling—will decrease in the long run.

The scenarios are generally based on the notion that future technologies will begin to have a significant impact on reducing these miscellaneous loads after the next decade. Further, while research on miscellaneous loads is starting to occur, it was assumed that future research in this area would be more focused on the commercial sector because commercial plug loads are less likely to be influenced by other factors, such as the income effect.[3] However, the inevitable development and adoption of new electricity-using devices, now unforeseen, will partially offset improvements in the efficiency of current and future devices. Therefore, based on projections of miscellaneous electricity use in the AEO (EIA 2010) in the long term, the share of total electricity consumption devoted to miscellaneous equipment is assumed to increase. Accordingly, these scenarios have the effect of slightly reducing, in relative terms, peak loads associated with cooling, and thus of flattening the building electricity hourly load profile over the coming decades.

Given this framework, the approach used here makes assumptions about the rate of decline of electricity for these miscellaneous uses in comparison to all other end uses. Because research on miscellaneous loads is just getting under way and new products are expected to enter the market, average electricity intensity for the miscellaneous end uses in the residential sector (accounting for an estimated 27% of current household electricity use) was assumed to remain constant through 2020 and then decline at 30% of the rate for overall electricity use. With this assumption, miscellaneous electricity use would increase to 36% of total electricity consumption in 2050. Given that result, the share of total electricity consumption used for cooling would decline by 12% (as would the shares for all other major end uses).

[3] The income effect refers to the change in an individual's income and how that change affects the demand for a good or service; generally, as income increases, the quantity of goods and services demanded also increases.

For the commercial sector, a similar approach was followed. Currently, electricity used for computers, office equipment, and other miscellaneous equipment is estimated to be about 25% of total commercial building electricity use. As mentioned previously regarding residential miscellaneous loads, similar factors are assumed to influence commercial miscellaneous loads, although future research is assumed to be more focused on the commercial sector. Assuming no overall reduction in this intensity occurs over the next decade, it is then assumed that commercial miscellaneous loads will decline at 50% of the rate for all other end uses. The share of total electricity consumption for miscellaneous end uses under this scenario would grow to 33% by 2050. Conversely, the shares of all other end uses, including cooling share, would fall by 11%.

2.1.2 Development of Load Profiles for the Building Sector

Once the projections of buildings-sector consumption were determined, the next task was to develop the buildings-sector loads by NEMS Electricity Market Module regions. The same regional definitions used by NEMS are used in ReEDS. For the buildings sector, RE Futures used Lawrence Berkeley National Laboratory's spreadsheet model, the Building End-Use Loads Forecaster. It applies the dimensionless NEMS end-use load-shapes extracted from the Electricity Market Module together with energy forecasts of the 10 residential and 10 commercial building end uses to deliver buildings-sector load profiles in the NEMS format for each of the 13 Electricity Market Module regions.

Applying exogenously derived energy forecasts sacrifices the numerous interactions that NEMS accounts for, but it permits modeling of arbitrary end-use energy requirements and forecasting beyond 2030. Applying the Building End-Use Loads Forecaster to extreme end-use demands (e.g., ones that might characterize diffusion of ultra-efficient buildings) can deliver scenarios that would be impossible to implement within the rigid constraints of NEMS itself.

The *Low-Demand Baseline* energy forecast was conducted independently of NEMS. In this case, the Building End-Use Loads Forecaster was used to forecast loads for the targeted end uses (cooling and miscellaneous) to match the energy forecast. The Building End-Use Loads Forecaster provided estimates of the loads and load profiles for each month for every 5 years. The intermediate years were interpolated and the load-shapes were modified to show daily variations within the month. These load profiles were combined with those of the industrial and non-PEV transportation loads, as described in Section 2.2.2.

Using the sectoral hourly loads for each month and region, hourly loads for the average weekday (Daytype 1), average weekend (Daytype 2), and peak weekday (Daytype 3) were calculated. Values were calculated for 2006, 2008, 2010, and every 5 years thereafter up to 2050. These average values for weekday and weekend are sufficient to calculate the ReEDS time slices. However, they produce the same load-shape for every day of the month they represent, and there is no variation due to weather. To create a semblance of a fluctuating load demand based on historical data, algorithms were developed to modify the loads for individual days depending on the relative system load for the region in that year. These modifications were made by calculating an adjustment factor for each hour using load profiles developed as part of a study on extended Daylight Saving Time (Belzer et al. 2008), and explained further in Section 2.2.2.. At the same time, the average for the month was formulated to still match the values calculated earlier and used in the ReEDS work.

As an example, the calculations using the residential data set for 8:00 a.m. 7/11/2020 Region 1 are as follows:

- Find the average and peak system load (Sa and Sp) for 8:00 a.m. on a weekday in July:

  Sa = Σ (8 a.m. weekday system loads)/21 weekdays = 71,701 MW

  Sp = Max (8 a.m. weekday system loads) = 81,082 MW.

- Find the average residential load for 8 a.m. on a weekday from the building data set:

  Ra = (20 x Daytype 1 from data set + Daytype3 from data set) / (20+1) = 20,946 MW

  Rp = Daytype 3 for the peak day = 23,490 MW

  R = [(S - Sa)/(Sp - Sa)] * (Rp - Ra) + Ra.

where:

R	=	Adjusted Residential Load
S	=	the system load for any weekday hour in July (70,394 MW on 7/11)
Sa	=	the average system load for that same hour in July (71,701 MW)
Sp	=	the peak system load for that same hour in July (81,082 MW)
Ra	=	average residential load for that hour (20,946 MW)
Rp	=	the peak residential load for that hour (23,490 MW)

So R = [(70394 -71701)/(81082-71701)]*(23490-20946) + 20946 = 20,592 MW.

The weekend calculations are a bit simpler (but less accurate) because peaks for the weekend values for residential and commercial are not available, just the average:

R = Adjusted Residential*(weekend) = S/Sa * Ra

So for 8 a.m. on 7/9/2020

R = Adjusted Res = [53377/59489] * 18548 = 16642 MW

Commercial calculations are done similarly.

2.2 Industrial Sector

The industrial sector, which includes manufacturing industries, along with mining, construction, agriculture, fisheries, and forestry, accounts for just over one-quarter of total U.S. electricity consumption (EIA 2010), and more than 50% of this is used to power electric motors (representing the single largest end use of electricity in the United States) (EIA 2006). Within the industrial sector, the chemicals and primary metals industries consume the most electricity, representing approximately 35% of electrical consumption (EIA 2006). The sector's electricity use will be affected by increases in the efficiency of motor drive systems and other processes, a slower growth rate of the more energy-intensive manufacturing industries, and a shift toward green supply chains. The sector is also affected by foreign competition.

In projecting industrial loads over the next 40 years, there are a number of unknowns. Industrial demands are more difficult to project because of the wider variation in the industrial sector makeup over time, as well as large differences in energy intensity across various industries. The extent of changes in the energy sector that would feed back into the industrial sector based on different renewable energy scenarios further complicates the task of projecting loads, which would ideally require iteration. Because RE Futures is a renewable energy study and not an industrial demand study, an approximation of the projected industrial demands was deemed sufficient.

2.2.1 Projection of Electricity Consumption in the Industrial Sector

The *Low-Demand Baseline* industrial demand trajectory is derived in a quite different manner than that used for the buildings sector. It was based on the EIA's HR2454Cap NEMS Case (EIA 2009a), which, as its name suggests, includes a carbon cap and trade policy roughly equivalent to the provisions of the Waxman-Markey Climate Bill of 2009. Given that this case would evoke a significant efficiency boost (ranging from 6% to 69% in 2050, depending on the specific industrial sector), the RE Futures demand team believed its consumption level represents a reasonable energy efficiency scenario and adopted it as the *Low-Demand Baseline*. Underlying the *Low-Demand Baseline* are EIA's assumptions that further standards for industrial energy efficiency will be established, an awards program for increasing efficiency in the thermal electricity generation process will be created, and the waste-to-heat energy incentives in the Energy Independence and Security Act of 2007 will be clarified. Overall, the changes in the *Low-Demand Baseline* for the industrial sector result in an approximately 23% decrease in electricity use compared to the *High-Demand Baseline*.

RE Futures compiled and ran the table-generation program (ftab.exe) provided with NEMS public use files to generate electric power projections for each NERC region. For the *Low-Demand Baseline*, the basic scenario from the EIA analysis of HR2454 (EIA 2009a) was used. Because NEMS only runs to 2030, the annual growth rate was calculated between 2020 and 2030, and that factor was applied to extrapolate to 2050. These annual growth rates were applied to three categories of factors: the net energy for load, electricity sales by sector, and electricity prices by sector. Because the NEMS report shows sectoral sales only after transmission and distribution losses, the values were raised by the ratio of the net energy for load to the sum of sectoral sales.

2.2.2 Development of Load Profiles for the Industrial Sector

Each year, utilities report their hourly loads for the previous year to the Federal Energy Regulatory Commission (FERC) in their FERC 714 report. In addition, several independent system operators provide historical hourly data on their websites. The 2006 and 2007 data were downloaded and converted for many utilities across the country as part of a study on extended Daylight Saving Time (Belzer et al. 2008). Each utility was tagged according to the North American Electric Reliability Corporation (NERC) region to which it belongs, and then the utilities' data were summed for each hour for each region. The resulting sum was then calibrated to match the regional net energy for load from the NEMS run for 2006 and then adjusted further by the growth in the net energy for load from 2006. This created an adjustment factor for each hour that would create an initial hourly system load for each region for any year.

The load factor is the ratio of the average load to the peak load. The system load factor can be derived from the hourly loads, but the load factors for each end-use demand sector can differ from this value.

Typically, the residential sector has the lowest load factor and the industrial sector has the highest. Many residences are not occupied during much of the day and have low appliance demands during the night, while industries tend to operate somewhat constantly over more hours of the day (and night, if multiple shifts). Regions with less-heavy industry may have lower load factors because night-time use may see lighter loads. Table 3.5 in the Electric Power Research Institute (EPRI) report *Assessment of Achievable Potential from Energy Efficiency and Demand Response Programs in the U.S.* (EPRI 2009) includes a table showing the 2008 residential, commercial, and industrial load factors for the four main regions of the country.

A load duration curve (LDC) rearranges the hourly loads from highest to lowest so that the curve shows the number of hours that demand exceeded the power level shown. The load factor described previously is equal to the area below the LDC divided by the peak load. For the industrial and non-PEV transportation sectors, the load factors above, along with an estimate of the fractions of the system's demand at minimum and at maximum system loads, were used to estimate the LDCs (residential and commercial inputs were developed as described in Section 1.2.2). For RE Futures, coincident loads were used in the GridView modeling. ReEDS uses fixed times for each day to define the different blocks rather than arranging them by load (although the top 40 hours of the summer are used to define the 17th block), and because each block is an average of a number of hours, the issue of coincident or non-coincident loads is not applicable to the modeling.

Total electricity sales for each sector must match the amount from NEMS, and the load factors for each sector should approximate the values defined by EPRI. (The data may not match the EPRI results because of different data years and region definitions between the studies.) Therefore, first, the fractions at system minimum and maximum loads were set for one of the sectors—in this case, the commercial sector—to be equal to one minus the fractions of the other sectors. This ensures that the sum of the sectors' loads equals the system load.

Microsoft Excel's goal seek function was then used to change the values of the maximum and minimum loads for the industrial and non-PEV sectors so that the area under their LDCs equals the total sales for that sector. Then the difference of the resulting load factor for each was compared to the target load factor from EPRI. The variance (sum of the square of the difference) of both the load factor and the electric sales was determined for each of the sectors and Microsoft Excel's Solver routine was used to minimize that variance by altering the fractions contributed by the Residential and Industrial sectors at the minimum and maximum system load values. Lastly, the minimum and maximum values were modified so the electric sales matched the NEMS values. This defined LDCs for each of the end-use sectors that matched both the LDC template from 2006 and the total sectoral sales from the NEMS run. These factors, along with the system maximum and minimum loads, can be used to calculate the hourly demand for the industrial and non-PEV transportation sectors, based on the corresponding system load.

Because the residential and commercial load profiles from the buildings analyses do not match the actual load profiles within a given day or month, the resulting system loads (residential + commercial + industrial + non-PEV transportation) do not necessarily match the 2006 load-shape template.

2.3 Transportation Sector

Although electricity use in the transportation sector is currently negligible (less than 0.2%) (EIA 2010), PEVs offer the opportunity for the transportation sector to significantly reduce petroleum consumption through electrification. Light-duty vehicles currently use more than 60% of the energy consumed in transportation, making them the primary focus of an electrification effort (DOE EERE 2011). Medium- and heavy-duty vehicles are the next largest segment (approximately 20%) and, while some portion of these could likely be electrified, it is quite difficult to compete with diesel powertrains in these applications. The likely load profile of medium- to heavy-duty vehicles is also less certain, making the development and incorporation of their associated load profiles into the models difficult. Therefore, RE Futures concentrated the transportation electrification effort in the light-duty vehicle market.

2.3.1 Projection of Electricity Consumption in the Transportation Sector

The transition to electricity as a fuel will create a new load for electricity generation. In support of the analysis of a high renewable electricity generation scenario, regional hourly load profiles for electrified vehicles within the time frame of 2010 and 2050 were created. The transportation electrical energy was determined using regional population forecast data (U.S. Census Bureau 2005), historical vehicle per capita data (FHA 2007), and market penetration growth functions to determine the number of PEVs in each analysis region. To represent a bounding case, a single market saturation scenario of 50% of sales being PEVs consuming on average approximately 6 kWh/d was considered. Results were generated for 3,109 counties and were consolidated to 134 power control areas (PCAs) for use in regional generation planning analysis tools.

2.3.2 Development of Load Profiles for the Transportation Sector

Hourly load profiles for PEVs have been presented in several locations (EPRI 2007; Scott et al. 2007; Hadley et al. 2008). For RE Futures, three scenarios defined in previous work (Parks et al. 2009; Markel et al. 2009) were applied. In the first case, the consumer is allowed to plug in and charge as soon as the vehicle ends the last trip for the day. This case is called *No Utility Control* because the vehicle load occurs on consumer demand and charges until complete or the consumer starts another trip. A second scenario is labeled *Opportunity*, and under this case, it is assumed that charging infrastructure is prevalent and the consumer will choose to plug in anytime the vehicle is parked regardless of stop duration. This scenario leads to significantly more fuel savings but also increases the daytime electric vehicle loads, total energy demands, and potential battery wear. Finally, a *Valley Fill/Managed* scenario is used. Originally, this scenario was implemented such that the utility had full control to deliver the daily energy needs in ways that best fit with the evening low point of a typical daily utility load curve. However, as it pertains to the high renewable penetration case, it may be most beneficial for a utility to charge vehicles at times scattered throughout the day. As a result, the *Valley Fill/Managed* load curve is used to create an energy demand that must be met during the day, but no constraints have been placed on it regarding when during the day it must be delivered. Both the *No Utility Control* and *Opportunity* scenarios assumed 110-V, 1.4-kW charge rates, while the *Valley Fill/Managed* curve allowed 3-kW charging to match best the energy demands with the utility valley shape.

It was assumed that over the duration of RE Futures, utilities would find managed charging of vehicles to be of value to system operations and therefore drivers would be incentivized toward participating in a managed charging program. Initially, all consumers would charge at home without utility controls and as public infrastructure is created and consumers learn to optimize the value of their investment in vehicle technology, the opportunity charging would grow. By combining the hourly load profile results from previous work and the transition assumptions over the study period, an aggregate per vehicle load profile that changes shape over time was generated.

The aggregate load shape in Figure 4 only represents the fixed load profile. The dynamic portion under utility control (Valley Fill/Managed) grows from 0% of the load in 2010 to approximately 45% of the total load in 2050.

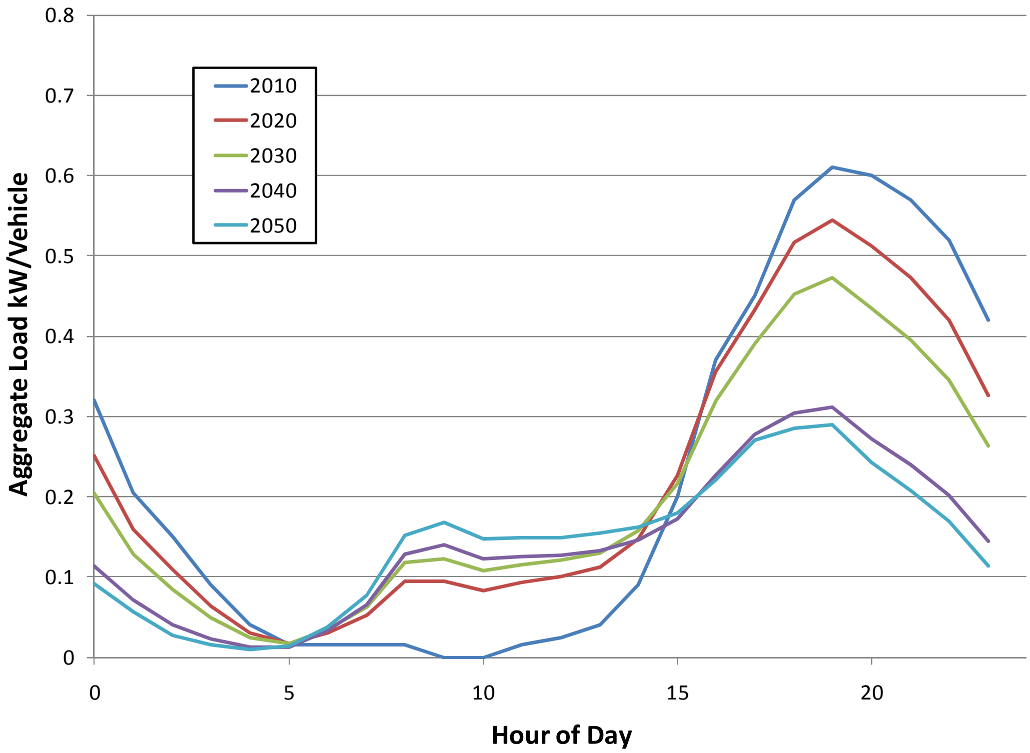

Figure 4. Shape and transition of fixed hourly aggregate load profile for PEVs.

The ReEDS model assesses energy delivery by 134 power control areas. Load profiles were generated on a county basis. A consolidation from 3,109 counties in the contiguous United States to 134 power control areas was completed.

2.4 Translation of Sector Projections to Load Schedules

Once each sector's hourly loads were calculated as described above, the hourly system load for any year and region could be calculated by summing the individual sectors. The ReEDS model uses only 17 time slices to model the system LDC – time slices by season representing morning, afternoon, evening, and nighttime, plus an additional summer peak time slice, where the top 40 hours of the summer peak are pulled out of the summer afternoon slice. These time slices allow ReEDS to consider seasonal and diurnal changes in both demand and resource availability. Once the hourly loads are known for each sector, the average amount of electricity demand in each time slice can be calculated.

Figures 5 and 6 illustrate the resulting non-PEV hourly load profiles for two of the regions. The other regional hourly load profiles can be found in the study by Hostick et al. (2012). The hourly loads from 2006 were initially used as templates for the industrial and non-PEV transportation loads. LDCs for each sector and the system as a whole were calculated, as described previously. The 2006 hourly loads were adjusted such that each sector's load requirements were fulfilled. Commercial and residential load profiles were calculated for the average weekday, peak day, and average weekend day for each month for each year. Industrial loads were calculated to maintain the overall load factor while mimicking the 2006 system load profile. The underlying data, which are further broken out by sector, are available on the RE Futures website under "Modeling and Cost Data" (www.nrel.gov/analysis/re_futures/). The use of these load profiles within the modeling effort is further documented in the RE Futures report (Mai et al. 2012).

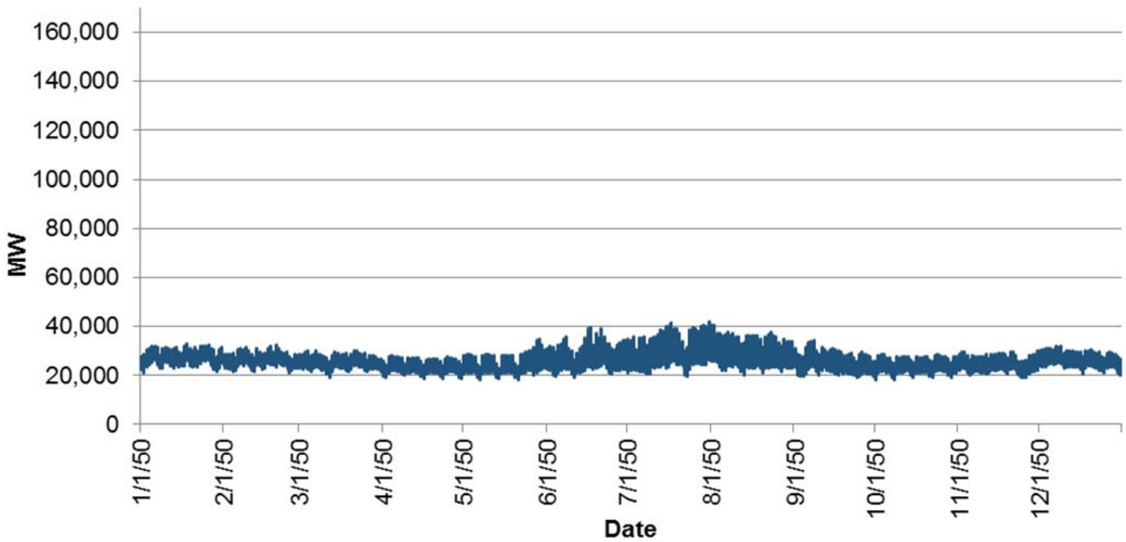

Figure 5. Non-PEV Hourly Demand in 2050, Region 4 (Mid-America Interconnected Network).

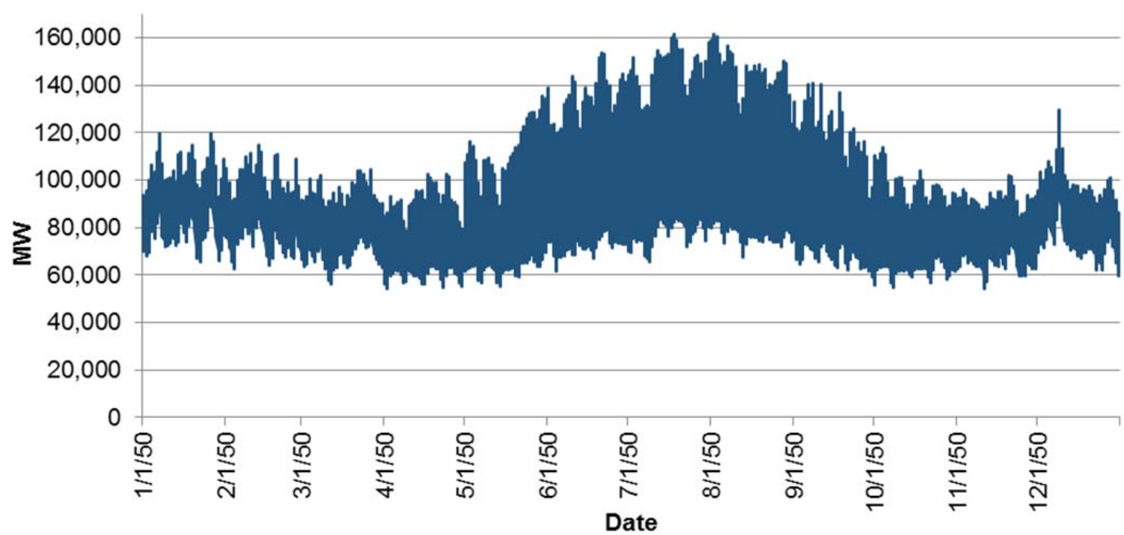

Figure 6. Non-PEV Hourly Demand in 2050, Region 9 (Southeastern Electric Reliability Council).

2.5 Comparison to Other Studies

To provide some context for the both the *High-Demand* and *Low-Demand Baselines*, the energy intensities have been compared to other studies. The comparison studies are from the University of California-Davis (McCarthy et al. 2008), EPRI (2009), EIA's analysis of Waxman-Markey (EIA 2009a), the National Academy of Sciences (NAS et al. 2009), and McKinsey and Company (Granade et al. 2009). To maintain the focus on potential energy efficiency improvement, the comparisons have been made in terms of energy intensities. For comparison purposes, the intensities were converted to index numbers normalized to be 1.0 in 2010. The McKinsey and Company report (Granade et al. 2009) was conducted assuming a much shorter time frame and greater emphasis on cost-effective potential compared to the other studies, resulting in considerably greater savings. The comparison of electricity intensities is presented by sector in Figures 7 through 9.

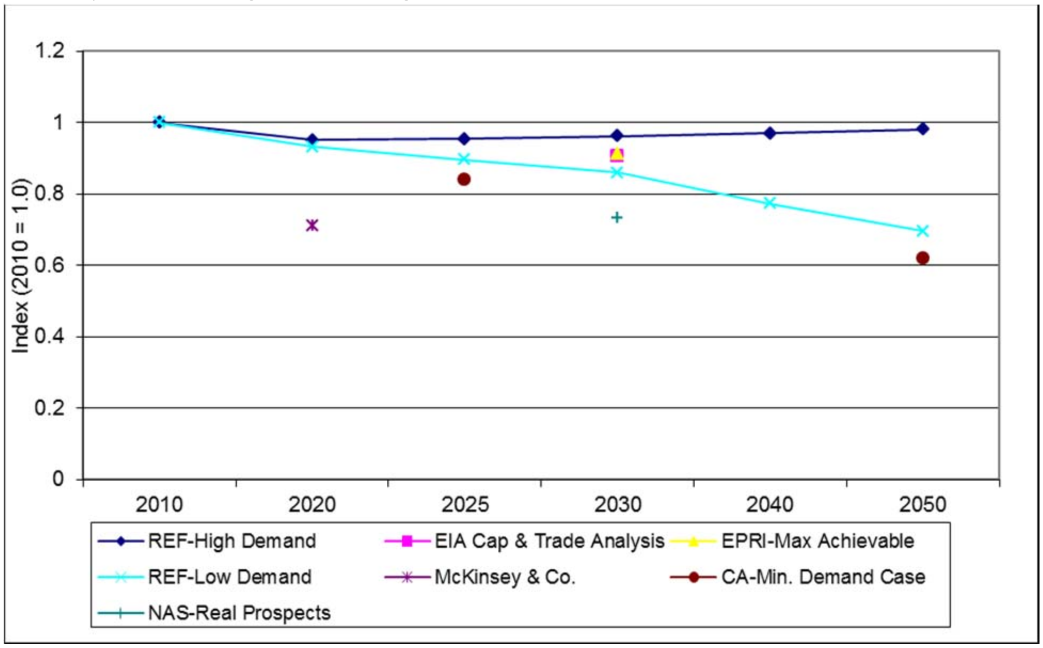

Figure 7. Comparison of residential electricity intensities from various studies.

Figure 7 shows the projected intensities for the residential sector. As a business-as-usual case, the *High-Demand Baseline* (based on the AEO 2009) shows the least decline in intensity to the year 2030. Shown only for the year 2030, the EPRI and Waxman-Markey scenarios show a modest reduction in the intensity, on the order of 10%. The minimum demand scenario developed by the University of California Davis team (CA-Min Demand Case) for the California Energy Commission extends to 2050 (McCarthy et al. 2008). When converted to an intensity, the reduction in the overall residential electricity intensity (again, on a household basis) was projected to be approximately 40% by 2050. The near-term intensity decline for 2025 was approximately 18%. As shown in Figure 7, the *Low-Demand* case falls within the range of intensity forecasts drawn from other studies.

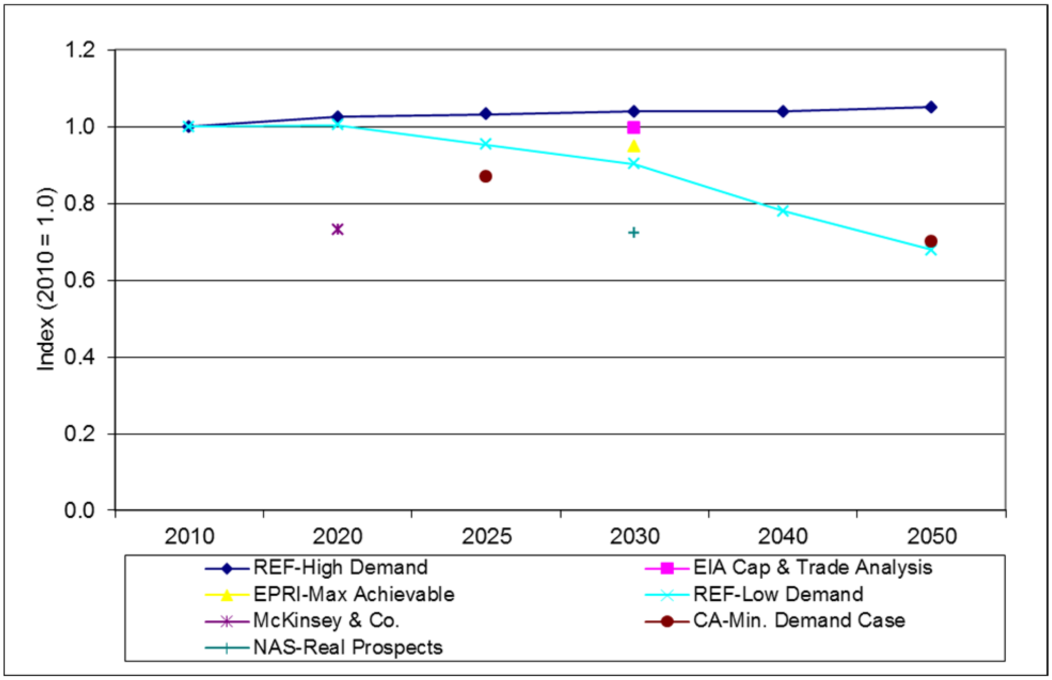

Figure 8. Comparison of commercial electricity intensities from various studies.

Figure 8 shows the scenarios from the same studies for the commercial sector. Compared to the residential sector, commercial sector electricity is expected to increase through 2030 as part of the reference projection developed by EIA (EIA 2009b), and represents the *High-Demand Baseline*. Again, the EPRI and cap-and-trade cases by 2030 showed the most modest reductions relative to the reference case.

The projections for the University of California Davis case and the high-efficiency case for RE Futures show greater reductions in intensity. RE Futures suggests a somewhat greater decline in intensity in the commercial sector than in the residential sector by 2050, in contrast to the relative declines projected by University of California Davis. By 2050, electricity intensity under the *Low-Demand* case declines by approximately 32%, compared to the California projection of an approximate 30% reduction.

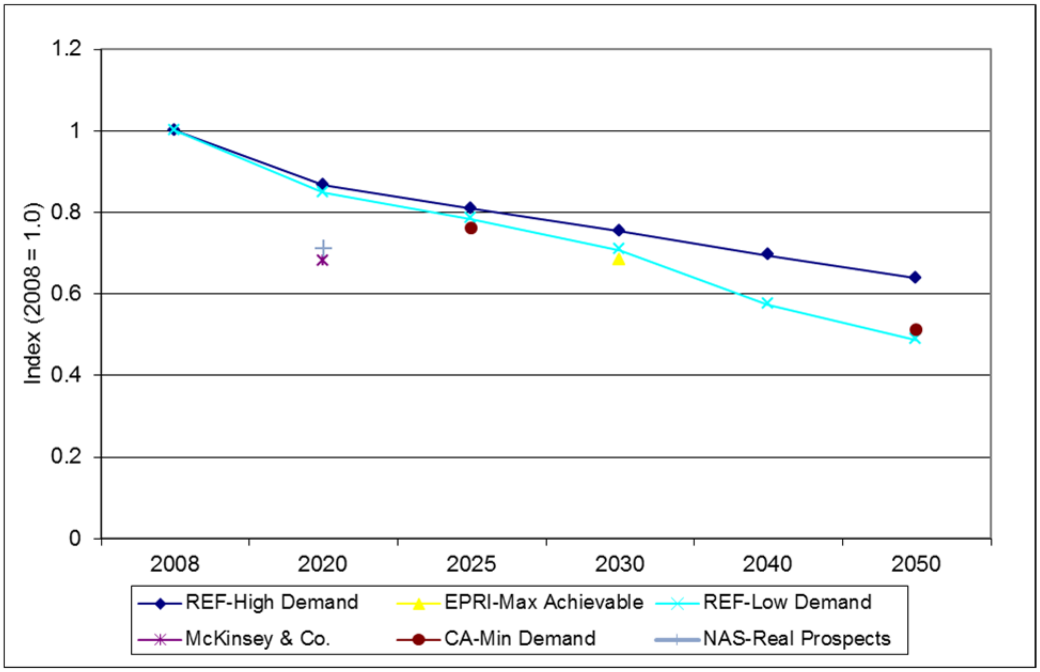

Figure 9. Comparison of industrial electricity intensities from various studies.

Figure 9 illustrates the comparison of scenarios for the industrial sector. The base year for index numbers was moved back to 2008 for the industrial sector to avoid the distortion in the intensities for 2009 and 2010 caused by the economic recession and reflected in the 2009 AEO. Both the *High-Demand and Low-Demand* baselines are taken from EIA model simulations. The *Low-Demand* case was based on the Waxman-Markey cap-and-trade analysis performed by EIA, whose results here have been extrapolated to 2050 (EIA 2009a). Figure 9 indicates that the *Low-Demand* case in this instance was reasonably close to the projections made by both EPRI and University of California Davis.

Many analyses have been conducted and papers published that include PEV market projections. EPRI and the Natural Resources Defense Council collaborated on a foundational study highlighting the nationwide greenhouse gas and pollutant emissions impacts of PEVs on the U.S. electrical grid on a regional basis (EPRI 2007). The fleet makeup assumed approximately 40% PEVs by 2030 and 60% by 2050. The market share developed in the PEV scenario is also consistent with results recently developed by Lin and Greene (2010).

3.0 Conclusions

In any study regarding the feasibility of higher percentages of renewable electricity generation, one of the key inputs is the electricity demand that is expected to be met during the analysis time frame, and the temporal profile of demand and supply. While a number of recent studies have projected energy use, few have carried those projections out to 2050. Although the load profiles developed for RE Futures are not sub-hourly, and therefore cannot be used to inform analyses or address reliability concerns at that level of detail, they represent a publicly available data set that can be used for other analysis where 8760 hourly data are adequate for modeling needs.

The demand trajectories developed for RE Futures result in a business-as-usual *High-Demand Baseline* based on EIA's AEO 2009 extended to 2050, and a *Low-Demand Baseline* reflects emerging trends that result in higher levels of energy efficiency in the buildings and industrial sectors, as well as an increase in penetration of electric vehicles.

These energy-use trajectories were converted to hourly load profiles. Within the buildings sector, adjustments were made to the load profiles to account for an assumed increase in the share of miscellaneous electricity load as a percentage of the total electricity load, and the resulting reductions in other electrical loads, specifically the cooling load, as a percentage of the total. Combined, these two effects resulted in a flattening of the overall demand profile for the non-PEV loads, as illustrated by comparing Figures 2 and 3. The resulting impact of the two demand trajectories on the supply requirements and generation mix is discussed in the full RE Futures report (NREL 2012).

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