Electricity Consumption and Peak Demand Scenarios for the Southeastern United States

Steven Nadel

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529 14th Street NW, Suite 600, Washington, DC 20045

Phone: (202) 507-4000 • Twitter: @ACEEEDC

Facebook.com/myACEEE • aceee.org

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About the Author

Steven Nadel is ACEEE's executive director. He has worked in the energy efficiency field for more than 30 years and has over 200 publications. His current research interests include utility sector energy efficiency programs and policies, state and federal energy and climate change policy, and appliance and equipment efficiency standards. He joined ACEEE in 1989 and previously served as deputy director of the organization and director of ACEEE's Utilities and Buildings programs.

Prior to ACEEE, Steve planned and evaluated energy efficiency programs for New England Electric, a major electric utility; directed energy programs for the Massachusetts Audubon Society, the state's largest environmental organization; and ran energy programs for a community organization working on housing rehabilitation in the poorest neighborhoods of New Haven, Connecticut. Steve earned a master of science in energy management from the New York Institute of Technology and a master of arts in environmental studies and a bachelor of arts in government from Wesleyan University.

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Executive Summary

In the United States, electricity consumption has been approximately flat in recent years. Increased electric end-use energy efficiency (EE) efforts have contributed to this lack of consumption growth, even as the US economy has expanded. In the southeastern US, electricity use continues to grow, but much more slowly than in earlier decades.

Looking forward, further electric efficiency gains are likely. In addition, a variety of other developments are already affecting electricity consumption and peak demand, and their impacts will only increase in the future. These developments include:

- Accelerating use of distributed power generation such as photovoltaic (PV) systems on the customer side of the meter
- Growing use of electric vehicles (EVs), considered a form of energy efficiency since the increased electricity use is outweighed by the decreased gasoline use
- The expanded use of electric heat pumps (HPs) to replace space- and water-heating equipment that burns fossil fuels, driven by the relatively high cost of heating oil and propane and by the fact that purchasing a heat pump is often less expensive than buying both a furnace and a central air conditioner
- Increasing use of demand response (DR) strategies that shift electricity use from peak to off-peak and shoulder periods.

All of these things are already happening to some extent, but looking ahead, the pace of each trend is hard to predict, and given the uncertainties, any projection made today is likely to be wrong. That said, it is useful to get a sense of how these developments might affect electricity consumption and peak demand so we can plan for the future while recognizing the large uncertainties involved. In this paper, rather than forecast the future, we explore five possible scenarios that help to define the range of potential outcomes, without taking a position on which scenario is most likely. Previously we published a set of scenarios for New England; in this report we focus on a very different region, the Southeast. Our five scenarios are:

1. *Business as usual*. We use the reference case from the *2017 Annual Energy Outlook* (AEO) prepared by the Energy Information Administration (EIA), a branch of the US Department of Energy (DOE).
2. *Accelerated*, with significantly enhanced programs and policies to promote EE, PV, EV, HP, and DR.
3. *Aggressive*, pushing the boundaries of the levels of EE, PV, EV, HP, and DR that may be achieved.
4. *Hybrid*, combining accelerated for EE, PV, and DR with aggressive for EV and HP.
5. *High energy demand,* incorporating just those practices that increase electric loads (EV and HP) but without any acceleration of load reduction practices (EE, PV, and DR) beyond what is business as usual.

Southeast electricity sales in the five scenarios are compared in figure ES1. The scenarios presented here are highly approximate; the intent is to paint a picture of what could happen, not what will happen.

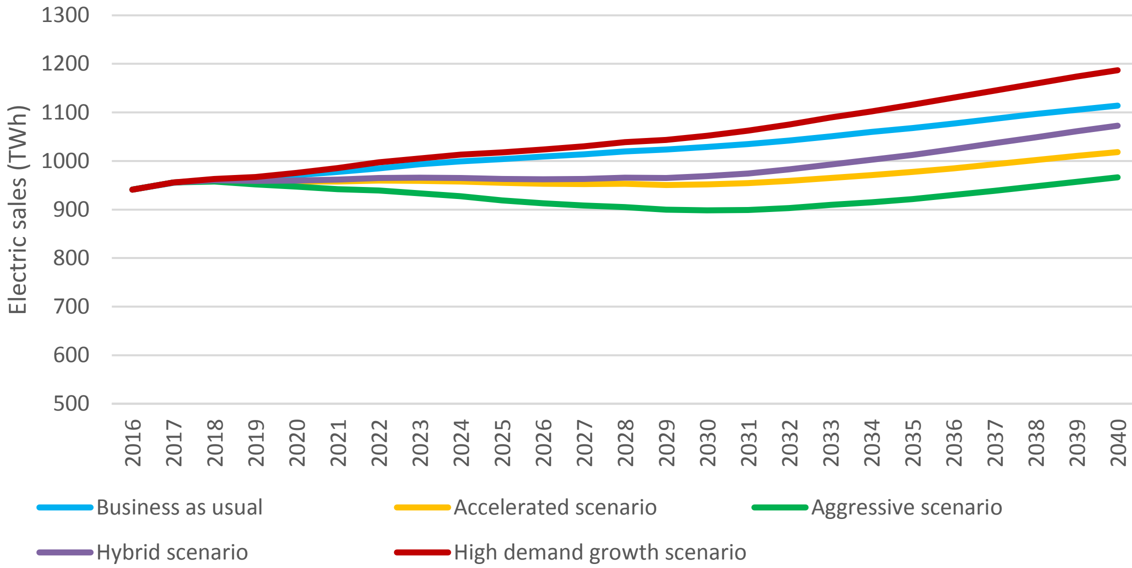

Figure ES1. Electricity sales in the five scenarios, 2016–2040

Growth in electricity sales in the different scenarios is illustrated in figure ES2. In the business-as-usual scenario, electricity sales grow modestly—about 0.7% per year. Electricity use also grows in our accelerated and aggressive scenarios, but more slowly—a compound average of about 0.3% and 0.1% per year, respectively. In the aggressive scenario, sales decline over the 2019–2030 period (due to the impacts of energy efficiency and customer solar systems) but then grow in the 2030s due to increased penetration of electric vehicles and heat pumps. The hybrid scenario lies between the business-as-usual and accelerated scenarios. And in the high energy demand scenario, sales increase by nearly 1.0% annually.

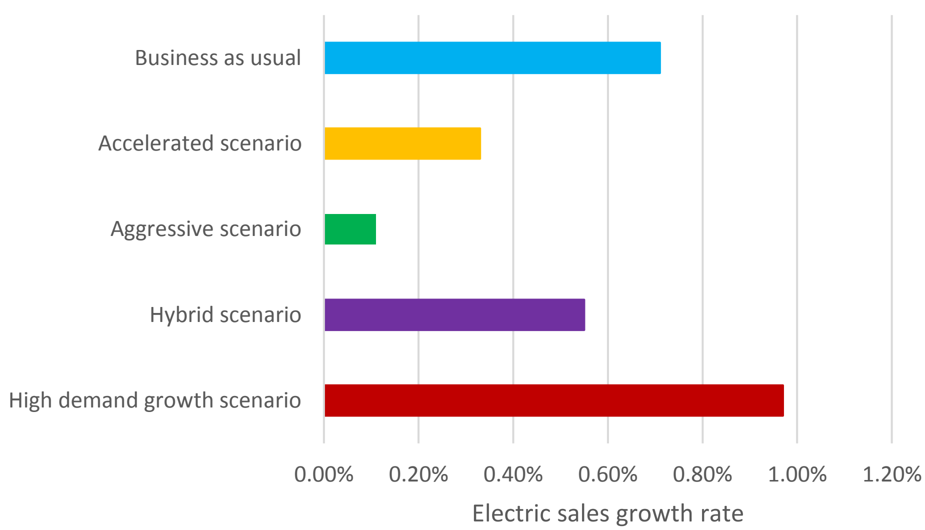

Figure ES2. Annual growth in electricity sales, 2016–2040, in the five scenarios

For peak demand, over the 2016–2040 period, the summer peak grows 29% in the business-as-usual scenario and 2–4% in the accelerated and hybrid scenarios. The slower peak growth in these scenarios is due to energy efficiency, demand response, and photovoltaics (in order of importance). The summer peak actually declines by 12% in the aggressive scenario, with the decline pronounced in the 2020s, after which slow growth resumes, due to EVs. And in the high energy demand scenario, summer peak grows by 30%. Thus, summer peak demand differs by more than 40% between our lowest and highest scenarios (aggressive and high energy demand, respectively), a difference that will have profound impact on needed investments in the electric system and hence the cost of electricity service.

Equally interesting is that in all scenarios except business as usual, the winter peak becomes the system peak, driven by photovoltaics (which can have a large impact on summer, but not on winter peaks), growth in use of heat pumps, and likely higher demand response savings in the summer than in the winter. This change to a winter peak occurs in about 2020 in most of the alternative scenarios, but early in the 2030s in the high energy demand scenario. Currently, winter peaks often occur in a few parts of the Southeast and sometimes occur in many parts of the region. Our analysis suggests that winter peaks will become significantly more common in many parts of the Southeast.

Of course, many other scenarios are also possible, although these encompass a likely range.

Thus far, the level of annual efficiency savings as a percentage of sales shown in the accelerated scenario has been achieved by Entergy Arkansas and nearly achieved by Progress Energy (North and South Carolina). These savings have also been achieved statewide in 16 states outside the Southeast. The efficiency savings shown in the aggressive scenario have not yet been achieved in the Southeast but have been proposed by the Arkansas Public Service Commission and have been achieved by Arizona as well as six other states. Likewise, the demand response savings we model have been achieved by more than ten utilities, including four in the Southeast. The levels of PV, EV, and heat pump penetration are more speculative and are subject to large uncertainty.

We recommend close observation of EE, PV, EV, HP, and DR trends over the next few years. Policies will affect the uptake of these technologies. For example, utility-administered EE programs have been increasing in several Southeast states, PV policies are being discussed in many Southeast states, and several states have been promoting EVs. Observation of market and policy developments will help to identify whether the business-as-usual, accelerated, aggressive, or hybrid scenario is most likely to happen. Such observation can also lead to refinements of these scenarios.

Our scenarios illustrate the importance of incorporating energy efficiency, as well as PV, into load forecasts. In states with active integrated resource planning (IRP) processes, some EE and PV is generally included in forecasts, although perhaps not sufficiently, given how many load forecasts have overpredicted electricity sales in recent years. But in states without IRP processes, it is unclear if EE and PV are included in forecasts. If EE and PV are not included, forecasts will be much higher, and could falsely justify generation capacity expansion, resulting in extra costs for ratepayers if the grid is designed to serve these higher expected loads. Our scenarios illustrate the importance of also including EVs and heat pumps in long-term forecasts. While the impacts of these technologies are moderate over the next 10 years, for longer time frames, they could become increasingly important. Demand response is already routinely incorporated into load forecasts, although at lower levels than we model in our scenarios.

At this point, these long-term scenarios, while based on emerging developments, contain substantial uncertainties. Still, these scenarios point out several possibilities that resource planners in the Southeast should incorporate in long-term planning. First, there is a reasonable chance that the region (or at least substantial portions) could become winter peaking rather than summer peaking, or that the winter and summer peaks will be very similar. Second, it is possible that kWh sales and summer peak demand could barely grow or grow at rates much slower than in the past. Existing power plants will retire and may need to be replaced, but significant growth in sales and resource needs above present levels may not happen in the next 25 years. Third, over the longer term (post 2040), electricity sales could grow significantly if EVs and heat pumps take off.

We are entering a dynamic period with substantial uncertainty for long-term electricity sales and peaks. Developments in energy efficiency, PV, EV, HP, and DR need to be carefully observed and analyzed over the next few years. And where public goals—such as reducing energy bills, system costs, and system emissions—will be served by these developments, policies can be adopted to encourage these trends. Resource planners should incorporate these emerging trends and policies into their long-term forecasting and planning. Such observations and analysis should provide greater clarity to resource planners and help to keep energy consumption, energy costs, and energy sector emissions down as the Southeast economy continues to grow.

Introduction

In the United States in recent years, electricity consumption has been approximately flat, even as our population and economy have grown (see figure 1). Analysis by ACEEE (Nadel and Young 2014) and others has found that energy efficiency is a significant contributor to the difference between actual consumption and what consumption would be if it grew in parallel with our economy.[1]

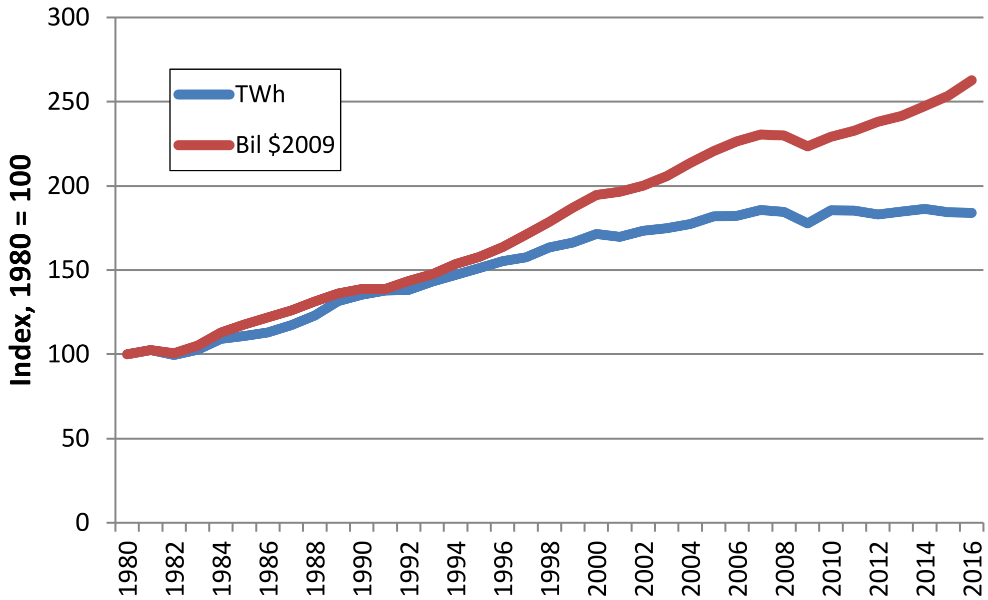

Figure 1. US electricity sales and GDP, 1980–2016 *Source:* ACEEE analysis using data from EIA 2017b, EIA 2017c, and BEA 2017.

Looking forward, further electric end-use energy efficiency gains are likely, as noted in a recent ACEEE analysis (Molina, Kiker, and Nowak 2016). In addition, a variety of other developments are already affecting electricity consumption and peak demand, and their impacts will only increase in the future. These developments include:

- Accelerating use of distributed power generation on the customer side of the meter.[2] In particular, power produced by customer-owned or leased photovoltaic (PV) systems has been growing rapidly (e.g., 17% average annual growth in residential PV over the 2012–2015 period).[3]

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1 See, for example, www.eia.gov/todayinenergy/detail.cfm?id=20031.

2 We focus on PV on the customer side of the meter as this affects the power demand a utility needs to serve. The utility meets this customer demand using a wide array of resources, including renewable energy projects that the utility may own or contract for. Utility-affiliated solar, including large-scale and community-scale projects, is becoming more common in the Southeast.

3 Derived by ACEEE from tables 10.2a and A6 in EIA 2017c.

- Growing use of electric vehicles (EVs), with several new, moderate-cost models that can go 200 miles between charges about to enter the market.[4] Recent analyses by MIT (Heywood and MacKenzie 2015) as well as by the Electric Power Research Institute (EPRI) and the Natural Resources Defense Council (NRDC) (2015) suggest that this trend can be accelerated, noting that electric vehicles generally use less energy than the most efficient gasoline-powered vehicles (including hybrids) and can also reduce greenhouse gas emissions, provided the power comes from low-emissions generation.[5]

- Expanded use of electric heat pumps (HPs) to replace space- and water-heating equipment that burns fossil fuels (mostly natural gas, propane, and fuel oil), driven by the relatively high cost of home heating oil and propane, and also by the fact that buying a heat pump is often less expensive than purchasing both a furnace and a central air conditioner. A recent ACEEE paper (Nadel 2016a) explores this issue. Recent progress on high-efficiency heat pumps, including models designed for use in cold climates, expands the opportunity to use heat pumps to replace fuel oil, propane, and in some cases natural gas.[6]

- Growing efforts to use demand response (DR) strategies to reduce peak demand. Such strategies can include time-of-use and seasonal rates, load management programs to shift loads from peak periods to other periods, and use of storage. For example, the Federal Energy Regulatory Commission (FERC) recently found that in 2014, power grid operators had identified more than 30,000 MW of available demand response resources, up 15% from 2013. More than one-third of these available resources were in Southeast Electric Reliability Council (SERC) and Florida Reliability Coordinating Council (FRCC) regions. From 2013 to 2014, available resources increased dramatically in FRCC and modestly in SERC (FERC 2016).[7]

EVs and HPs are generally more efficient than their fossil-fueled alternatives (EPRI and NRDC 2015; Nadel 2016a). Energy efficiency (EE) can be used to downsize heat pump and PV systems, which lowers their cost and also lowers the energy use of heat pumps. From just an electricity perspective, some of these trends (EE, PV, and DR) reduce the amount of power needed from the electric grid, while others (EV and HP) increase electricity use even as they decrease total energy consumption (electricity plus fossil fuels). These general trends are illustrated in figure 2. Furthermore, all of these developments can reduce US greenhouse

[4] For example, the Chevrolet Bolt and the Tesla Model 3.

[5] See www.afdc.energy.gov/vehicles/electric_emissions.php and EPRI and NRDC 2015.

[6] See www.neep.org/initiatives/high-efficiency-products/emerging-technologies/ashp/cold-climate-air-source-heat-pump.

[7] The SERC figures include the modest portion of SERC that is outside the Southeast. FERC does not break down DR resources by SERC subregion. While SERC reports these DR resources as available, there are no public data we are aware of on how much of this available resource has been actually used in recent years.

gas emissions, helping to mitigate the severity of global climate change.[8] And increased use of EE, PV, HP, and DR provides local jobs and contributes to local economic development.[9]

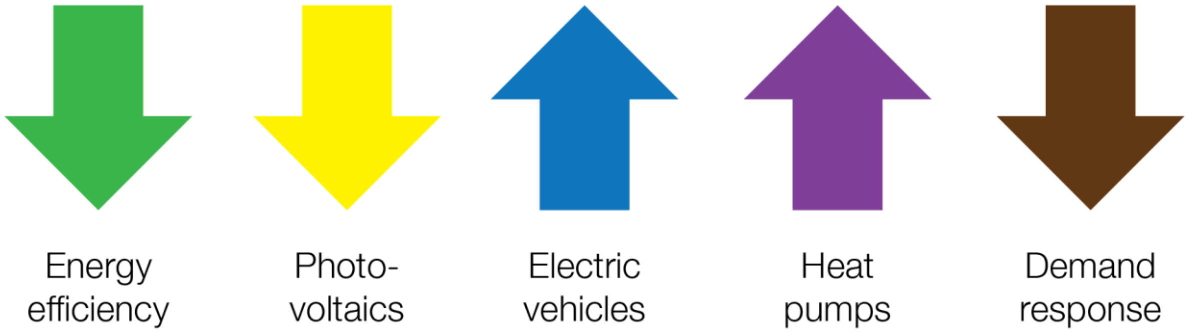

Figure 2. Typical impact of trends on electricity sales and peak demand. This chart shows direction but not magnitude (magnitudes are provided in the Scenario Results section).

Looking ahead, the pace of these trends is hard to predict, and given the uncertainties, any prediction made today is likely to be wrong. That said, it is useful to explore how these trends might affect electricity consumption and peak demand in the future so we can factor these possible impacts into electric system planning discussions, while recognizing the large uncertainties involved.

In August 2016, ACEEE published an initial paper on these issues, focusing on the New England region. Figure 3, prepared by the Independent System Operator of New England (ISO-NE) shows projected electricity consumption in New England for the next 10 years, illustrating the importance of EE and PV in their forecast.

[8] Of course, greenhouse gas emissions also depend on how electricity is generated. In the United States overall, greenhouse gas emissions per kWh are declining due to decreased use of coal and increased use of renewable energy, although these effects are partly offset by increased natural gas use and the closing of several nuclear power plants. DR can increase or decrease greenhouse gas emissions, depending on the fuel used to serve peak loads and the fuel used to serve loads that are shifted.

[9] See aceee.org/fact-sheet/ee-job-creation.

Figure 3. ISO-NE forecast. *Source:* ISO New England 2016b.

But each region is different, and therefore we selected the Southeast as the focus of our second paper on these issues. This paper was written for energy system planners, as well as policymakers and other interested parties who care about system planning issues. Rather than forecast the future, we explore five possible scenarios that define a range of potential outcomes, without judging which scenario is most likely.

We chose the Southeast for this second analysis because it is very different from New England. Unlike many regions of the United States, electricity use is still growing in the Southeast, albeit slowly (EIA 2016b). EE, PV, and EV trends are proceeding at a modest pace there, very different from the more robust pace in New England. Also, the structure of demand is very different in the Southeast, with industrial process and air-conditioning loads particularly prominent.

Our results for the Southeast may be broadly indicative for regions in the southern part of the country. The Southeast and other southern regions (the Sunbelt) have been growing in population and economic activity in recent decades, and much of the economic activity takes place in small cities and towns. However, even within the South, differences between regions mean that specific conclusions from the Southeast cannot be generalized.

Region Covered

Our analysis includes all or most of Alabama, Florida, Georgia, Kentucky, Mississippi, North and South Carolina, Tennessee, and Virginia. We include the portions of those states covered by SERC and FRCC. We do not include the Southwest Power Pool, which serves much of Arkansas and Louisiana as well as portions of Mississippi, Oklahoma, and Texas. The exact coverage of our analysis is explained further in the Methodology section. Figure 4 illustrates the region covered.

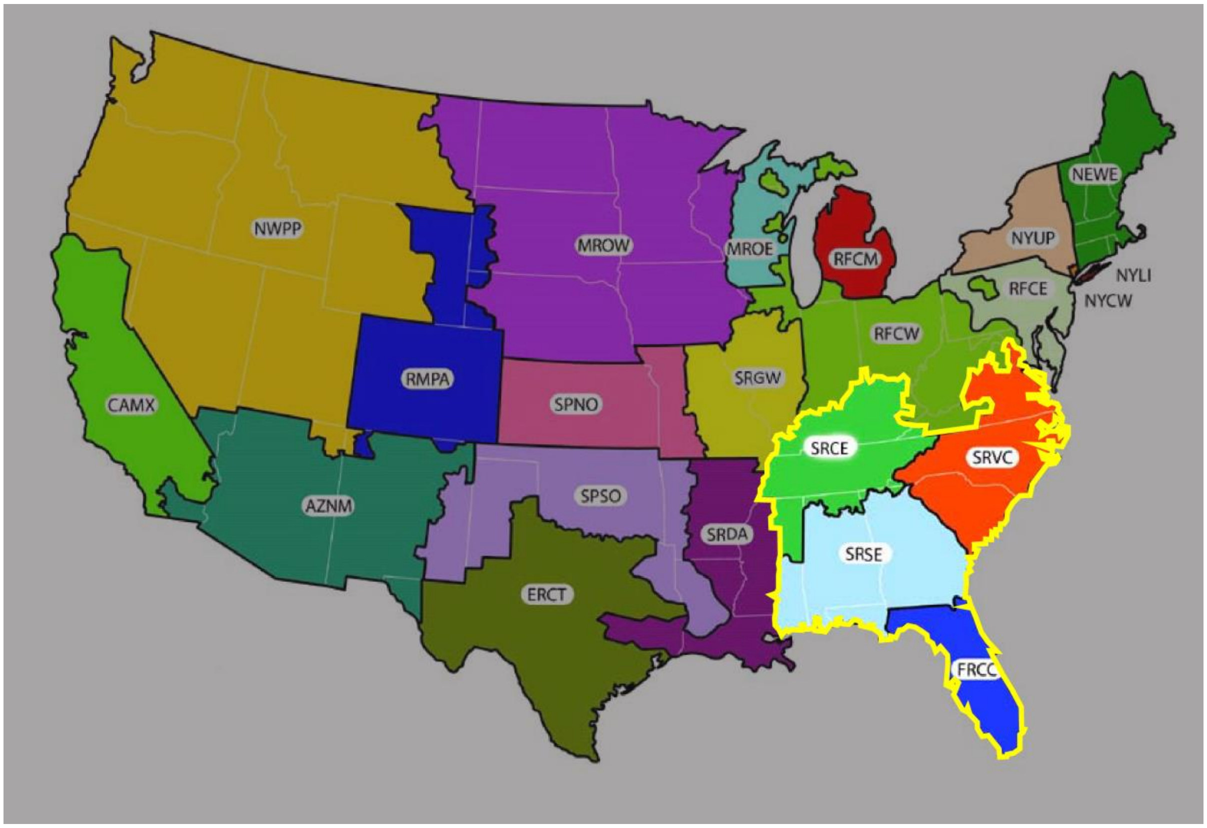

Figure 4. EIA electricity regions, with a yellow line drawn around the region covered by this study. The subregions shown are defined in Appendix A.

The Southeast states have generally not been very aggressive in pursuing energy efficiency. In ACEEE's most recent *State Energy Efficiency Scorecard* (Berg et al. 2016), all of the southeastern states were in the lower half of the rankings, with Florida and Tennessee tied for 25th, Mississippi trailing at 46th, and the other states ranging from 30th to 40th (see figure 5). This said, in prior years, Alabama, Kentucky, Mississippi, North and South Carolina, and Tennessee all received a "most improved" designation, recognizing major steps to increase their energy efficiency efforts.

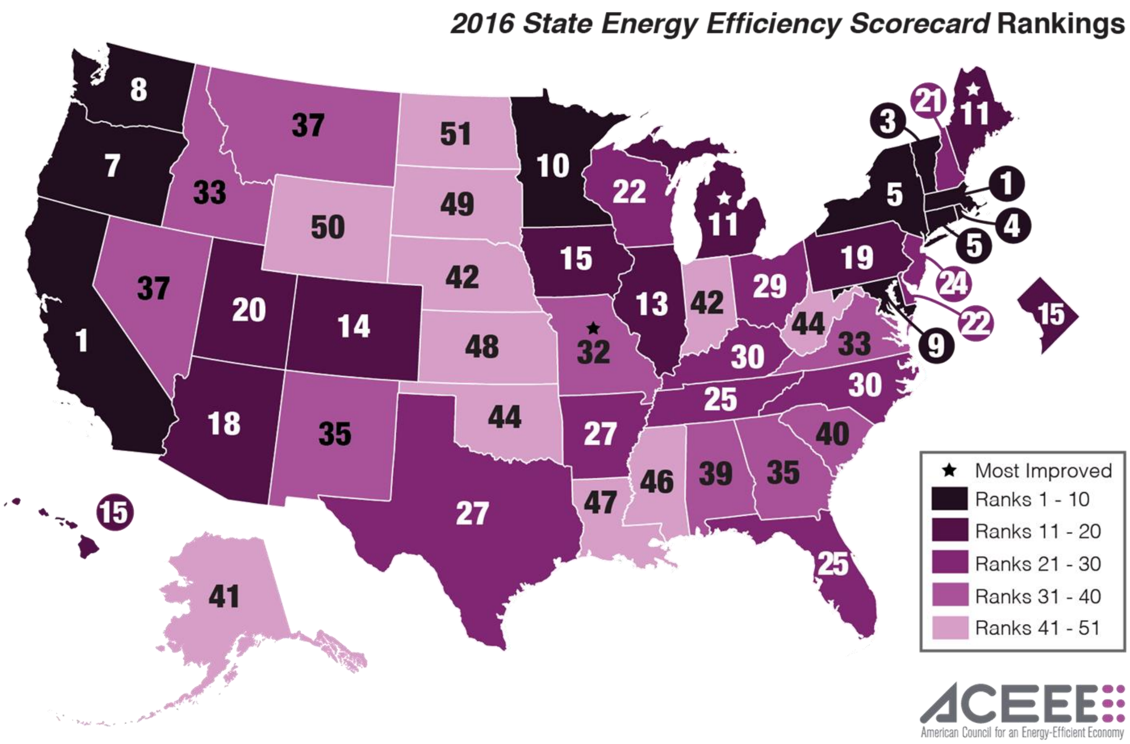

Figure 5. ACEEE *2016 State Energy Efficiency Scorecard* rank. *Source:* Berg et al. 2016.

Scenarios

For our analysis, we look at five scenarios:

1. *Business as usual*. We use the reference case from the *2017 Annual Energy Outlook* (AEO) prepared by the Energy Information Administration (EIA), a branch of the US Department of Energy (DOE) (EIA 2017a). We use this forecast rather than individual utility forecasts because the individual forecasts differ in assumptions and presentation, and most of them extend for only 15 years or so. The EIA forecast extends to 2050, although for our analysis, we go only to 2040. Also, we used the AEO for our New England analysis, which makes it easier to use the AEO to adapt our methodology to the Southeast.
2. *Accelerated*, with significantly enhanced programs and policies to promote EE, PV, EV, HP, and DR.
3. *Aggressive*, pushing the boundaries of the levels of EE, PV, EV, HP, and DR that may be achieved.[10]
4. *Hybrid*, combining accelerated for EE, PV, and DR with aggressive for EV and HP.
5. *High energy demand,* incorporating just those practices that increase electric loads (EV and HP) but without any acceleration of load reduction practices (EE, PV, and DR) beyond what is business as usual.

[10] Even greater penetration of these technologies may be possible if the region truly decides to pull out all the stops.

For our alternative scenarios, we look at levels of penetration that have been shown to be cost effective in studies on the Southeast (e.g., Eldridge et al. 2008, Elliott et al. 2007, and Neubauer et al. 2009) and in research covering other regions. From an energy efficiency perspective, the accelerated, aggressive, and hybrid scenarios are desirable.

Methodology

BUSINESS-AS-USUAL SCENARIO

We use the 2017 AEO reference case as the foundation for our analysis (EIA 2017a).[11] The AEO covers the 2014–2050 period, although we look only at the period through 2040, since the years beyond that date are extremely uncertain. The AEO reference case includes assumptions about future penetration of EE programs, PV, EV, and HP. We use these as our starting points, adding to the AEO reference case for our alternative scenarios.

EIA has not been entirely clear about how it incorporates energy efficiency in its forecasts, except explicitly stating in 2015 that at the national level about 0.5% energy efficiency savings is included in its reference forecast (EIA 2015). This assumption was based on estimated utility program savings in recent years. Given this statement, we assume the same method was employed in the 2017 forecast. We find that over the past five years, utility sector efficiency programs have achieved about 0.5% per year efficiency savings nationwide (consistent with EIA 2015), with about 0.25% per year efficiency savings in the Southeast.[12]

In the AEO 2017 reference case, EIA estimates that at the national level over the 2015–2040 period, electricity production from PV systems at customer homes and facilities will increase by an average of about 9% per year and that the number of EVs on the road will increase by an average of about 8% per year.[13] Growth rates in the overall Southeast region are slightly lower, although the distribution of PV and EVs in the Southeast is uneven, with

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[11] The reference case includes implementation of the Clean Power Plan (CPP), but this has only a small impact on our findings since our analysis is based on kWh consumption, which is barely affected by the CPP. While the CPP faces significant uncertainty, we still use the AEO reference case because there is extensive regional detail for the reference case but no regional detail for the alternative cases. At the national level, EIA estimates that the CPP will reduce the growth in electricity sales by 0.1% per year relative to an alternative case without the CPP (see the line "Electricity Supply, Disposition, Prices and Emissions" at www.eia.gov/outlooks/aeo/tables_side.cfm).

Specifically, we use EIA's electricity market region tables as the foundation of our analysis, including tables 55.2 (covering most of Florida) and 55.14-55.16 (covering SERC Southeastern, SERC Central, and VACAR). Together, these tables include all of Alabama, Florida, Georgia, and North and South Carolina as well as nearly all of Kentucky and Tennessee, most of Virginia, and the majority of Mississippi's population. For a map of these electricity market regions, see Appendix A. We supplement these data with data from tables 2.5 and 2.6 (for information on residential heating and cooling systems) and tables 39.5 and 39.6 (for information on the number of vehicles by type).

[12] ACEEE estimates 0.53% average efficiency savings in the United States and 0.25% in Southeast over the past five years, using state-specific estimates of energy efficiency program savings by year from ACEEE's annual *State Energy Efficiency Scorecard* (Berg et al. 2016 and prior editions).

[13] We include plug-in hybrid vehicles as well as all-electric vehicles.

some states leaders and other states doing much less for PV and EV.[14] Our analysis focuses on the region as a whole, not individual states. Nationally, the number of homes heated with HPs is expected to increase 2.3% per year (relative to an annual increase of only 0.8% in the total number of homes) (EIA 2017a). In table 2, below, we summarize Southeast data in the AEO on these issues.

For DR, for the business-as-usual scenario, we assume the amount of summer DR shown in the NERC *2016 Reliability Assessment* for the FRCC and SERC regions covered by our analysis (NERC 2016). We do the same for winter DR but use the NERC *2015 Reliability Assessment* (NERC 2015) since the 2016 assessment lacks details on the winter peak. It should be noted that while the Southeast is historically summer peaking, a few planning areas are predominantly winter peaking (e.g., some public and cooperative utilities in Florida, Alabama, and South Carolina), and in some years, many regions peak in winter (e.g., while Duke Energy, the Southern Company, and the Tennessee Valley Authority [TVA] are normally summer peaking, in 2014 and 2015 they peaked in the winter) (Wilson 2017). Figure 6 summarizes data on summer versus winter peaks for each planning region. The figure shows how much larger (in percentage) summer peaks are than winter peaks for summer peaking utilities and how much larger (in percentage) winter peaks are than summer peaks for winter peaking utilities.

[14] The Solar Energy Industries Association (SEIA) finds that North Carolina is third in the nation in PV installations (www.seia.org/research-resources/top-10-solar-states). And according to DOE, in 2014 Georgia was third in the nation in electric vehicle registrations per thousand people (energy.gov/eere/vehicles/fact-876-june-8-2015-plug-electric-vehicle-penetration-state-2014), due in substantial part to a since-discontinued electric vehicle tax credit.

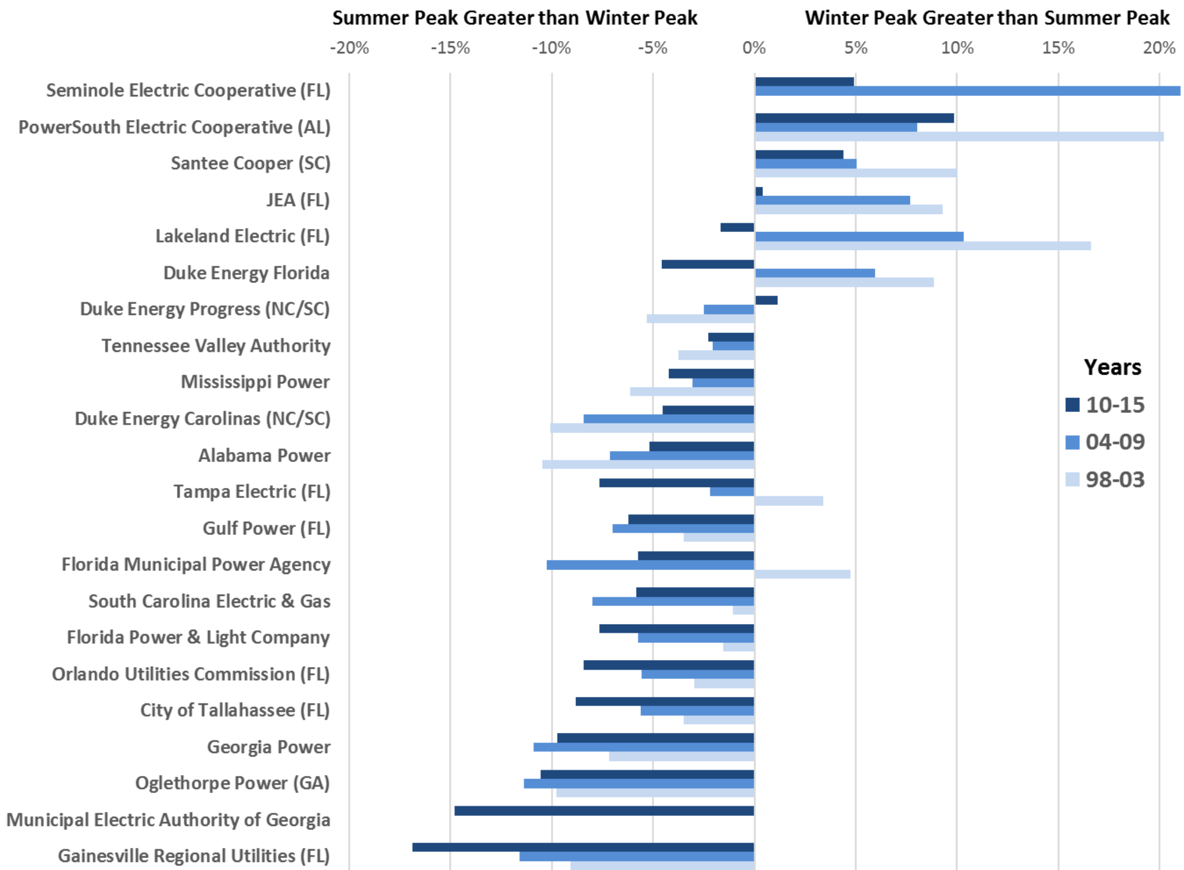

Figure 6. Summer and winter peaks for planning areas in the Southeast. *Source:* Wilson 2017.

Putting the Business-as-Usual Scenario in Context

In the 2017 AEO, electricity sales in the Southeast region covered by our analysis increase at a compound annual growth rate of 0.71%, which is a little more than for the country as a whole, for which the AEO projects a 0.56% annual growth rate. It is also useful to note that the 2017 AEO projects a lower annual growth rate for electricity sales in the Southeast (0.71%) than did the 2016 AEO (0.87%). This lower growth rate better aligns with recent history, as illustrated in figure 1.

The AEO is not the only forecast of electricity sales in the Southeast. Table 1 summarizes several recent forecasts for the region. These forecasts, which were prepared in 2015–2017, show annual growth in electricity sales ranging from 0.7% (AEO 2017) to 1.0% (from the TVA and Duke Carolinas IRPs: TVA 2015, Duke Energy 2016).[15] The median for the forecasts shown in the table is an average growth rate of about 0.9% per year. In general, more recent forecasts estimate lower growth rates than older forecasts. For example, the FRCC annual growth rate estimate declined to 0.8% in 2016, down from 1.1% the previous year. Similarly, the Duke Carolinas and Duke Progress 2016 forecasts declined from 1.2% in 2015 (for both entities) to 1.0% and 0.9%, respectively, in 2016.The AEO 2017 forecast we use

[15] This range is for the primary forecast and does not include the TVA low and high estimates.

is the most recent published forecast, and while it is a little lower than other forecasts, it is not appreciably out of line with other estimates for the region.

Table 1. Annual growth rates in electricity sales in recent Southeast forecasts.

	Month published	Forecast end year	Growth rate	Notes
AEO16	June 2016	2040	0.87%	For Southeast as defined in this report
AEO17	Jan. 2017	2050	0.71%	Same as above
SERC 2016	Sept. 2016	2025	0.91%	
FRCC 2016	July 2016	2025	0.8%	Was 1.1% in 2015 forecast
TVA IRP, current scenario	Aug. 2015	2033	1.0%	
TVA IRP, lowest scenario			0.0%	
TVA IRP, highest scenario			1.1%	
Duke Carolinas 2016 IRP	Oct. 2016	2031	1.0%	Was 1.2% in 2015 forecast
Duke Progress 2016 IRP	Oct. 2016	2031	0.9%	Was 1.2% in 2015 forecast

Sources: EIA 2016a, EIA 2017a, SERC 2016, FRCC 2016, TVA 2015, Duke Energy 2016.

ACCELERATED SCENARIO

For our accelerated scenario, we increase annual energy efficiency savings to 1.0% per year, up from the 0.25% per year weighted average for the Southeast over the past five years. We ramp in the additional 0.75% per year savings at the rate of 0.25% additional in each year over the 2018–2020 period. In 2016, 16 states achieved at least 1% annual incremental electricity savings. Several of these states have sustained this level of savings for a decade or more (Berg et al. 2016). In the Southeast, Arkansas has established a 0.9% per year savings target for 2016–2018 and a 1% per year target for 2019. And several leading southern utilities achieved or approached 1% per year savings in 2015: Entergy Arkansas (1.11%), Duke Progress NC (0.87%), and Duke Carolinas (0.76% for both North Carolina and South Carolina) (Relf, Nowak, and Baatz 2017).

For residential PVs, in our accelerated scenario we estimate that by 2040, 30% of the available roof area in the region will be covered by PVs. As discussed later, this is a substantial increase relative to the AEO reference case. We phase this in evenly over the 2018–2040 period. Available roof area by state comes from the National Renewable Energy Laboratory (Lopez et al. 2012). The 30% figure is based on the amount of PV included in some of the medium cases in TVA's *2015 Integrated Resource Plan* (TVA 2015).[16]

For EVs, we ramp up to 13% of the passenger vehicle stock by 2040 based on a national analysis prepared by researchers from the Massachusetts Institute of Technology (Heywood and MacKenzie 2015). We ramp in EVs gradually to 5% of sales in 2025 and then go from 5%

[16] Specifically, the TVA Growth Economy and De-carbonized Future scenarios. The TVA scenario extends to 2033 and includes both rooftop and utility-scale solar.

to 13% in even annual increments. EV penetration will be aided by funds that states will receive for EV charging infrastructure from the Volkswagen settlement, as well as current in-region efforts.[17]

For HPs, we assume that by 2040, 12% of homes that currently use natural gas, propane, or fuel oil as their primary fuel will switch to HPs.[18] About 16% of homes in the Southeast are heated with fuel oil or propane, so the 12% heat pump conversions we modeled represent a large portion of current fuel oil and propane systems (although to the extent that natural gas systems are converted to heat pumps, more oil and propane systems will remain). As with EVs, we start slowly through 2025 and then pick up the pace. For HPs, since conversions have barely begun, the uncertainties are probably greater than for EE, PV, and EV. Given these uncertainties, as well as a desire to keep the analysis from getting too complicated, we did not include increased use of electric heat pump water heaters in our scenarios.[19]

Finally, for DR, we ramp up from the current approximately 4% of peak demand (both summer and winter) to 8% for summer peak demand and 6.5% for winter peak demand.[20] The summer potential is midway between the business-as-usual scenario and the aggressive scenario (discussed below). For winter, we assume slightly lower savings based on concerns that reducing space heating on very cold days could be more difficult than reducing air-conditioning on very hot days.[21]

AGGRESSIVE SCENARIO

For our aggressive scenario, we further ramp up our assumptions. We take EE to 1.5% per year (six states exceeded this level in 2015, per Berg et al. 2016).[22] We increase PV to 60% of available roof area by 2040, resulting in a PV penetration in 2033 similar to that of TVA's highest case, its Distributed Marketplace scenario (TVA 2015). We ramp up EV to 32% of the

[17] Information on the Volkswagen settlement is available here: www.naseo.org/volkswagen-settlement. Current EV efforts in the region include work by Advanced Energy (www.advancedenergy.org/2016/01/25/preparing-for-electric-vehicles/) and Duke Energy (Smith 2016).

[18] This estimate is an educated guess and is double what EIA projects in its reference case.

[19] Inclusion of heat pump water heaters would increase electricity demand in the latter years of our analysis to some extent. Because water heaters generally have substantial storage capacity for hot water, there are also good opportunities to use demand response strategies to help manage the contribution of heat pump water heaters to summer and winter peak demand.

[20] Current summer projections from NERC 2016. Current winter projections from NERC 2015.

[21] This concern is discussed by Kessman (2015). There is also one small study on commercial building demand response in the Pacific Northwest that supports such a difference. In a study on five buildings, Piette, Kiliccote, and Dudley (2012) found 14% average peak reductions in winter, 16% in summer. On the other hand, our estimate of peak savings in winter could be conservative. An evaluation of a BC Hydro winter residential demand response program found average power use reductions of 13.8% during the peak period (Woo et al. 2016).

[22] This is also a level proposed in Arkansas (APSC 2013) and achieved in Arizona on average over the past five years (Berg et al. 2016 and prior editions).

vehicle stock by 2040 (on the road to 50% by 2050, as predicted by Lovins [2011])[23] and ramp up heat pump conversions to 24% in 2040.[24] For demand response, based on prior detailed ACEEE studies on Florida (Elliott et al. 2007), South Carolina (Neubauer et al. 2009), and Virginia (Eldridge et al. 2008), we gradually ramp up to 12% summer peak demand reductions. To be conservative, we reduce this to 10% for winter peak demand (see prior discussion on summer and winter relative reductions). Nadel (2017) recently identified 11 utilities with available demand response resources in 2015 of 10% or more of their peak demand, illustrating that this level of DR is achievable. Four of these utilities are in the Southeast.[25]

HYBRID AND HIGH ENERGY DEMAND SCENARIOS

As noted above, for the hybrid scenario we combine the accelerated scenario for EE, PV, and DR with the aggressive scenario for EV and HP. And for the high energy demand scenario we add aggressive EV and HP to the business-as-usual scenario.

CROSS-SCENARIO ISSUES

For all scenarios, we estimate kWh sales per year. These are sales by the utilities in the region. They *do not* include electricity generation that is used on site, but they *do* include distributed generation that is provided to the grid by customer-owned power systems. We also estimate summer and winter peak electric demand by year using the ratio of annual kWh sales to summer and winter peak demand by year, combining the SERC and FRCC regions in the NERC load forecasts.[26] For this peak analysis, we assume that the summer peak occurs at 6 p.m. and the winter peak at 8 a.m. Currently the summer peak occurs in late afternoon (3–5 p.m.) (Peavy 2017), but as consumer-owned PV increases, experience in other regions indicates that the peak will tend to move later in the day (e.g., see ISO-NE 2016a; St. John 2016). The winter peak generally occurs at about 8 a.m. (EPRI 2016; L. Peavey, SERC Reliability Corp., pers. comm., January 23, 2017). Since this is driven by electric heat in the early morning, we do not expect this peak to shift. For the alternative scenarios, deviations from the business-as-usual scenario begin in 2018. For 2017, all four scenarios are essentially the same.[27]

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[23] This scenario is also consistent with an estimate by Bloomberg New Energy Finance (2016) that electric vehicles will constitute about 35% of global new car sales by 2040.

[24] Also an educated guess. This is double the accelerated scenario for the Southeast but less than several scenarios for New England as referenced in Nadel 2016b.

[25] It should also be noted that more widespread use of smart meters with two-way communication will allow increased use of active load management that could increase DR savings above the levels we model. See Howland, Malone, and Anthony 2016 for a discussion of these issues.

[26] For summer we used NERC 2016. This does not include the winter peak, so for this information we had to use NERC 2015. These forecasts extend to 2026 and 2025, respectively. We used the average annual rate of change in these ratios over the 2015–2025 period to estimate these ratios out to 2040.

[27] Very small effects for EVs and HPs occur in the four non-business-as-usual scenarios in 2017 to allow a smoother ramp-up to the 2025 levels discussed above.

Table 2 compares some key inputs for the Southeast for the five scenarios. Detailed assumptions are documented in Appendix B.

Table 2. Comparison of key drivers for the five scenarios

	Business as usual*		Accelerated		Aggressive		Hybrid		High energy demand	
Variable	2025	2040	2025	2040	2025	2040	2025	2040	2025	2040
Incremental annual energy efficiency savings	0.25%	0.25%	1.0%	1.0%	1.5%	1.5%	1.0%	1.0%	0.25%	0.25%
Electric generation from PV (TWh)	1.61	9.83	15.89	45.69	31.78	91.38	15.89	45.69	1.61	9.83
EV share of passenger vehicle stock	3.62%	8.26%	5%	13%	8%	32%	8%	32%	8%	32%
Share of residential fossil systems converted to heat pumps	3.3%	6.0%	5%	12%	7%	24%	7%	24%	7%	24%
Demand response (as % of peak demand for summer/ winter)	3.9%/ 4.0%	3.9%/ 4.0%	8%/ 6.5%	8%/ 6.5%	11.9% / 9.5%	12%/ 10%	8%/ 6.5%	8%/ 6.5%	3.9%/ 4.0%	3.9%/ 4.0%

* ACEEE estimates derived from EIA 2017a.

Scenario Results

In this section, we examine electricity sales and summer and winter peak demand derived from our analyses of the five scenarios.

ELECTRICITY SALES

Figure 7 compares Southeast electricity sales in the five scenarios.[28] In the AEO reference case, electricity sales rise gradually; 2040 sales are 18% higher than 2016 sales, a compound average increase of 0.71% per year.

[28] This figure shows trends for the overall Southeast. Results will likely differ to some extent by state and for subregions.

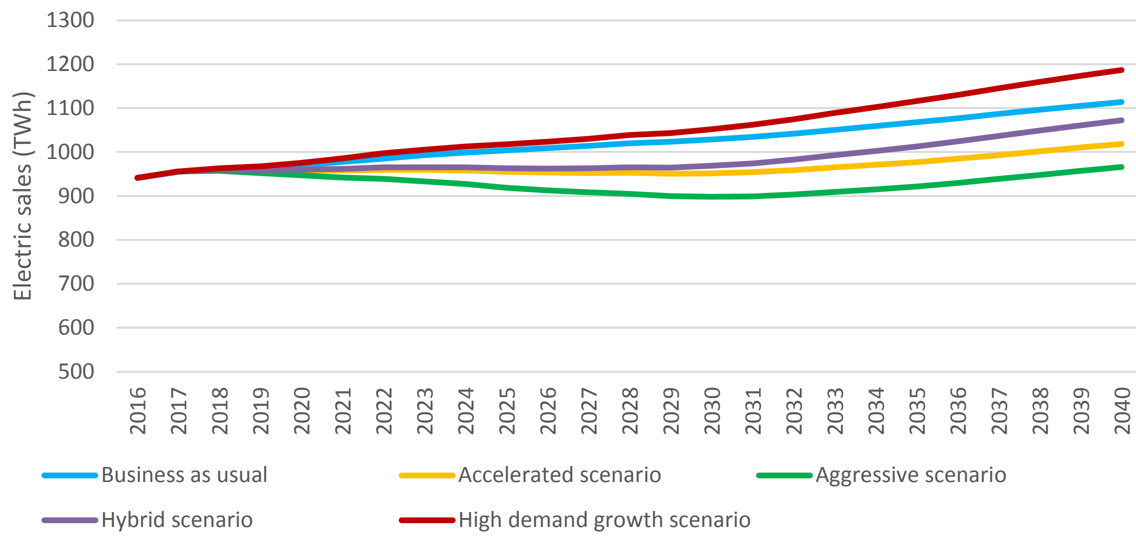


Figure 7. Electricity sales in the five scenarios, 2016–2040

In the accelerated scenario, sales also increase, but more slowly. Sales in 2040 are 8% higher than sales in 2016, a compound annual growth rate of 0.33%. Figure 8 illustrates the reasons for these changes. Enhanced energy efficiency efforts and photovoltaics both cause a decline in sales. Heat pumps and EVs both increase sales, with EVs having the larger effect relative to the business-as-usual scenario.

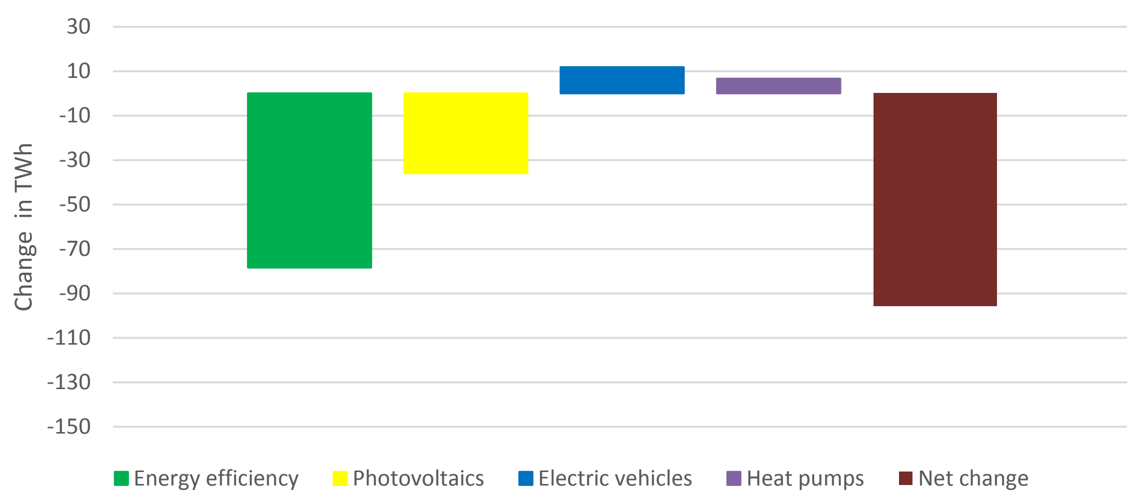


Figure 8. Changes in electricity sales in the accelerated scenario relative to the business-as-usual scenario in 2040

In the aggressive scenario, sales decline by nearly 5% from 2019–2030, but then increase nearly 8% in the subsequent decade. Sales in 2040 are about 3% higher than sales in 2016, a compound annual growth rate of 0.11%. Figure 9 compares the business-as-usual and aggressive scenarios for 2040. Sales decline due to efficiency and PV, only partially offset by growth in EVs and heat pumps. Relative to figure 8 all of the differences are more pronounced, particularly the impact of EVs in increasing electric sales.

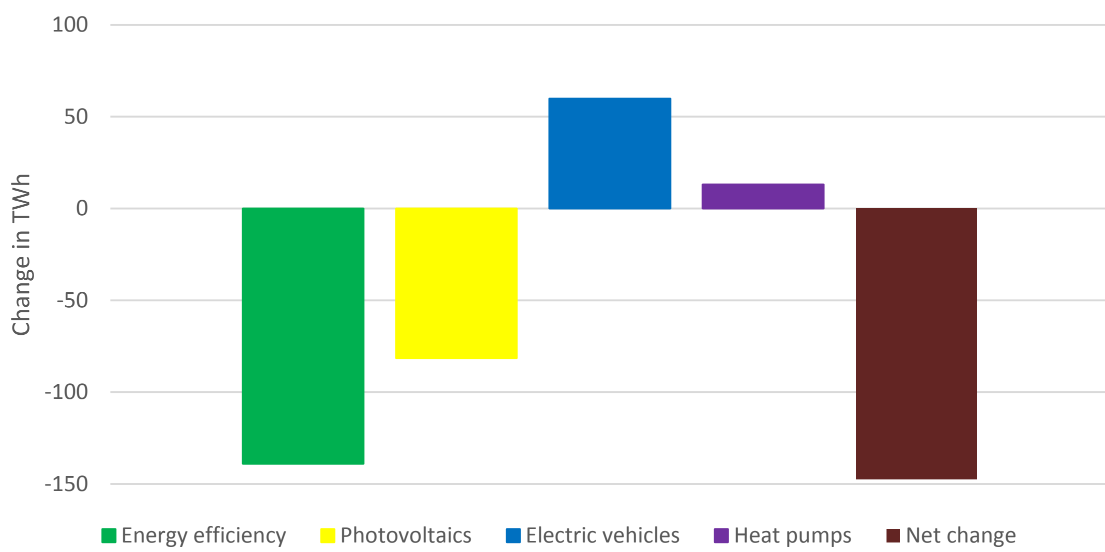


Figure 9. Changes in electricity sales in the aggressive scenario relative to the business-as-usual scenario in 2040

The hybrid scenario lies between the business-as-usual and accelerated scenarios, with electricity sales increasing 14% over the 2016–2040 period. This scenario combines the moderate EE and PV savings in the accelerated scenario with the substantial increases in electricity sales due to EVs and HPs in the aggressive scenario. The contributions of these different parameters are illustrated in figure 10, with the EV and HP sales increases offsetting much of the EE and PV sales decreases.

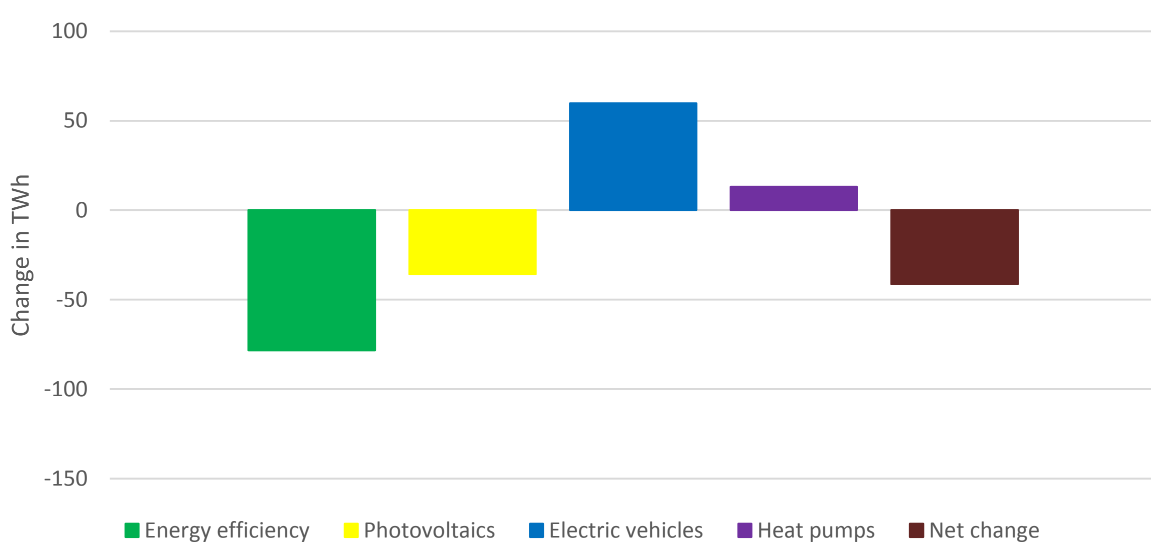


Figure 10. Changes in electricity sales in the hybrid scenario relative to the business-as-usual scenario in 2040

Finally, in the high energy demand scenario, sales increase by 26% by 2040, exceeding the sales increase in the business-as-usual case because of the additional load from EVs and heat pumps (see figure 11).

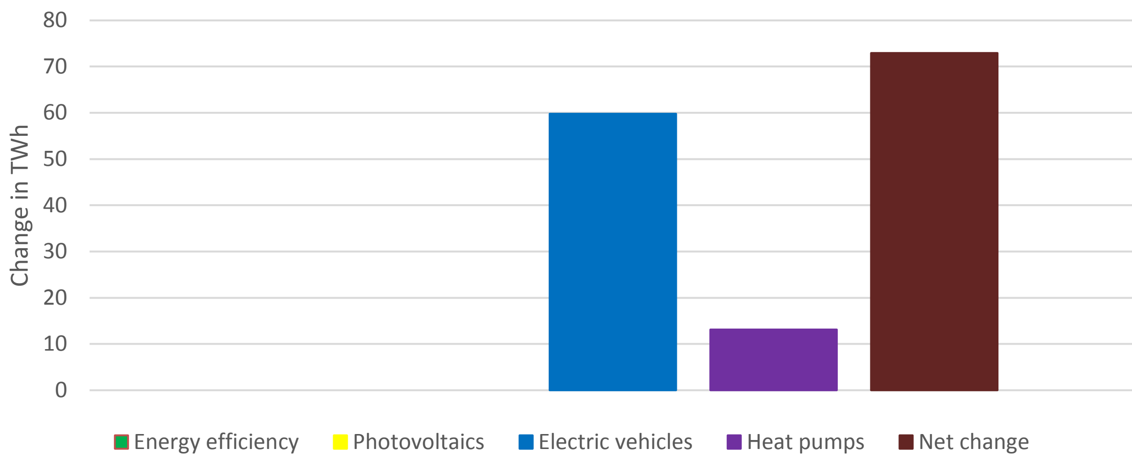


Figure 11. Changes in electricity sales in the high energy demand scenario relative to the business-as-usual scenario in 2040

Peak Demand

Trends in peak demand are shown in figures 12–15. These estimates are for average weather conditions and do not include the variability from year to year as illustrated previously in figure 6. These estimates are also very approximate as our calculations of peak impact use a variety of simple ratios, as explained in the Methodology section and Appendix B.[29] These estimates should be considered indicative and are far from definitive.

Summer peak demand trends in our five scenarios are illustrated in figure 12. In the business-as-usual scenario, summer peak demand increases by 29% over the 2016–2040 period, significantly more than the percentage increase in electricity sales in the business-as-usual scenario (18%) that was discussed earlier. In our accelerated and hybrid scenarios, summer peak demand also increases (2% and 4%, respectively) but more slowly than electricity sales growth, due primarily to the impact of demand response programs. However while summer peak grows in the accelerated and hybrid scenarios, in both scenarios peak demand is roughly level until about 2030 and then increases in the following decade due to the impact of increased EV penetration. In the aggressive scenario, summer peak demand actually declines by 12% for 2040 relative to 2016, driven by more aggressive demand response efforts. This includes a decline in the 2020s (due to EE, PV, and DR), followed by a modest increase in the 2030s (driven by EV penetration). And in the high energy demand scenario, summer peak grows by 30%. Thus, summer peak demand differs by more than 40% between our lowest and highest scenarios (aggressive and high energy

[29] For example, these estimates do not consider the impact of storage, which could have a substantial effect on peak demand. Storage could include utility-owned storage, customer-owned in-building storage, and use of electric vehicle batteries during periods when a car is parked and plugged in. These estimates implicitly assume that energy efficiency programs have about the same percentage impact on peak demand as they do on energy consumption.

demand, respectively), a difference that will have profound impact on needed investments in the electric system and hence the cost of electricity service.

The contributions of EE, PV, DR, and EV to 2040 summer peak relative to the business-as-usual summer peak are illustrated in figure 13 for the accelerated and aggressive scenarios (similar graphs for the hybrid and high energy demand scenarios can be found in Appendix C).[30]

It should be noted that even if peak demand declines overall, some investments in the grid will likely be needed to accommodate areas with above-average growth and also to replace aging equipment.

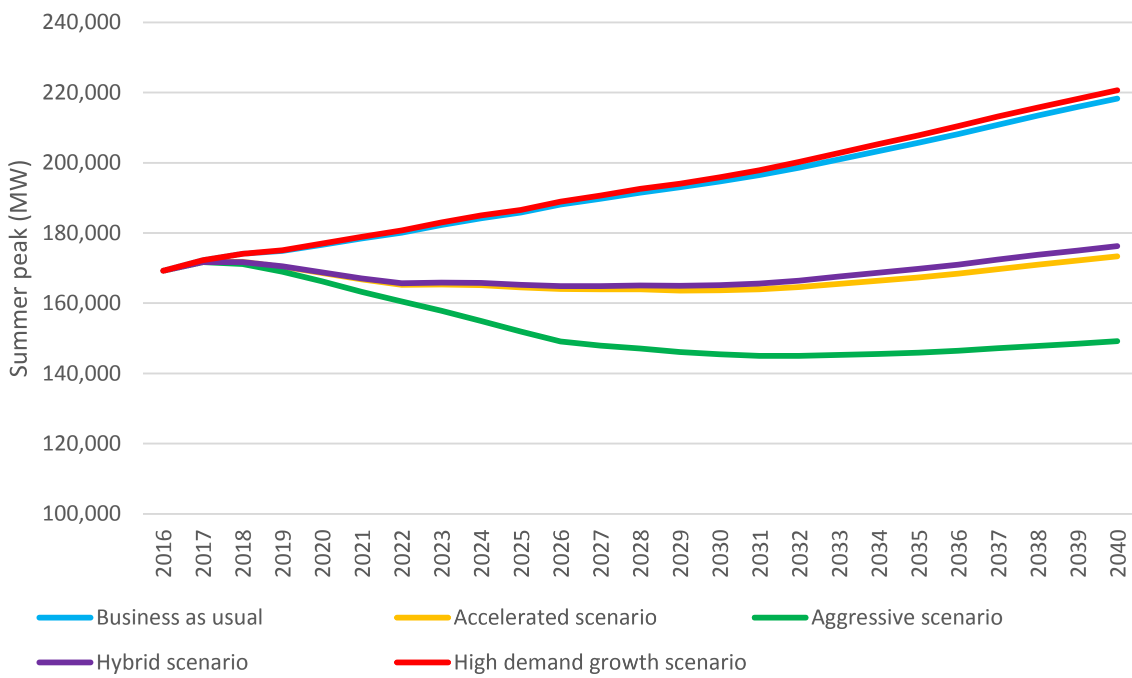


Figure 12. Estimated summer peak demand by year for each of the five scenarios

[30] We do not include any growth in heat pumps in the summer peak graphs because in the Southeast, most homes already have air-conditioning and the summer energy used by air conditioners and heat pumps is very similar. The additional incremental air-conditioning load in the small share of homes without central air-conditioning should be offset by the higher efficiency of the high-efficiency heat pumps we model in our analysis.

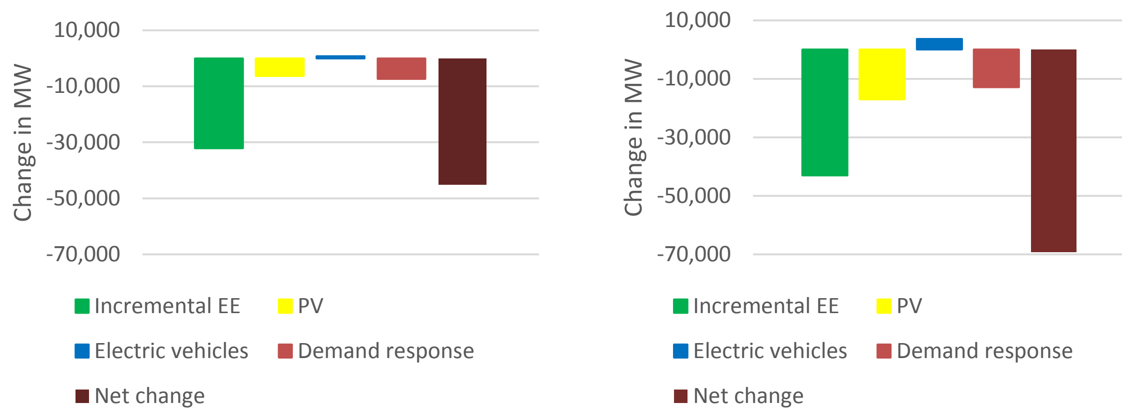
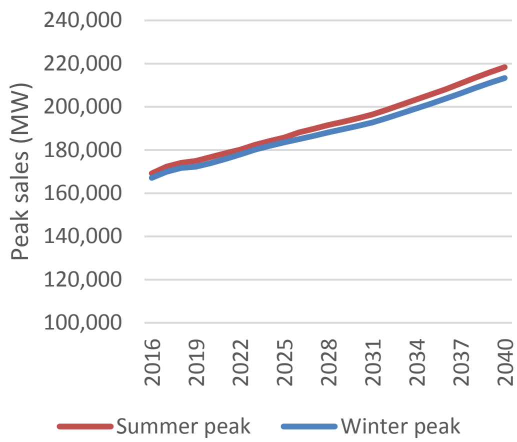
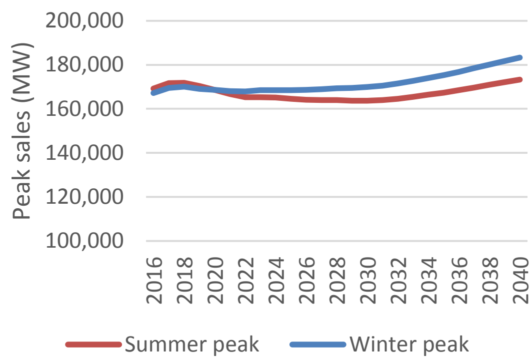


Figure 13. Changes in 2040 summer peak demand in accelerated (left) and aggressive (right) scenarios relative to business-as-usual scenario

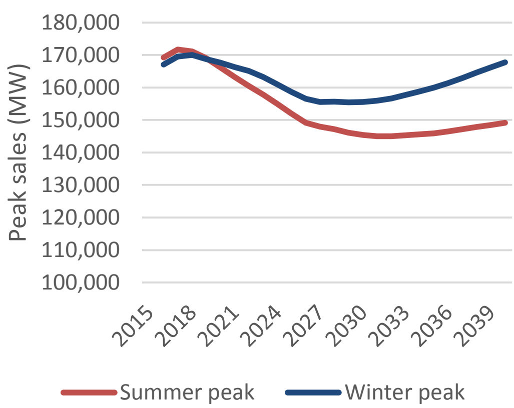
Figure 14 compares summer and winter peak demand in our five scenarios. As can be seen, summer and winter peaks are similar in the business-as-usual scenario, with summer slightly higher throughout the analysis period, consistent with the long-term trends shown in figure 6. However, in the other four scenarios, winter peak passes summer peak, with crossover happening earlier in the accelerated, aggressive, and hybrid scenarios, and later in the high energy demand scenario. In our simple analysis, the crossover point occurs in 2020 in the accelerated, aggressive, and hybrid scenarios, and in 2034 in the high energy demand scenario. While crossover occurs for the Southeast as a whole, some subregions may remain summer peaking, just as a few regions are now winter peaking as shown in figure 6. Figure 6 also lends support to future crossover for some of the planning regions: in some of the major planning regions the ratio of summer to winter peak has been declining over time.



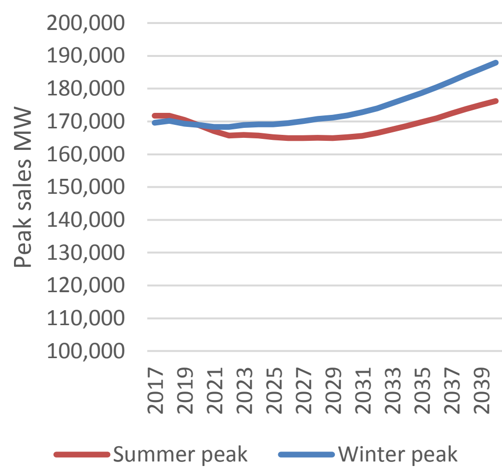
Business as usual



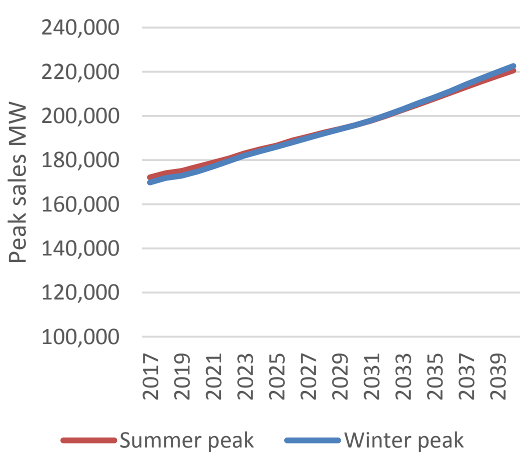
Accelerated



Aggressive



Hybrid



High energy demand

Figure 14. Peak demand trends for the five scenarios

Fortunately, some energy efficiency measures reduce both summer and winter peak demand, including building weatherization, improved HVAC controls, and more efficient heat pumps. Other measures primarily affect the summer peak and not the winter peak, such as more efficient air conditioners and commercial lighting measures.

The relative growth in winter peak is driven by greater use of heat pumps combined with the fact that PV systems reduce summer peak but not winter peak (since the winter peak occurs in the morning when the sun is low in the sky and not providing a lot of energy).[31] Relative contributions to changes in the winter peak for the accelerated and aggressive scenarios are shown in figure 15.[32]

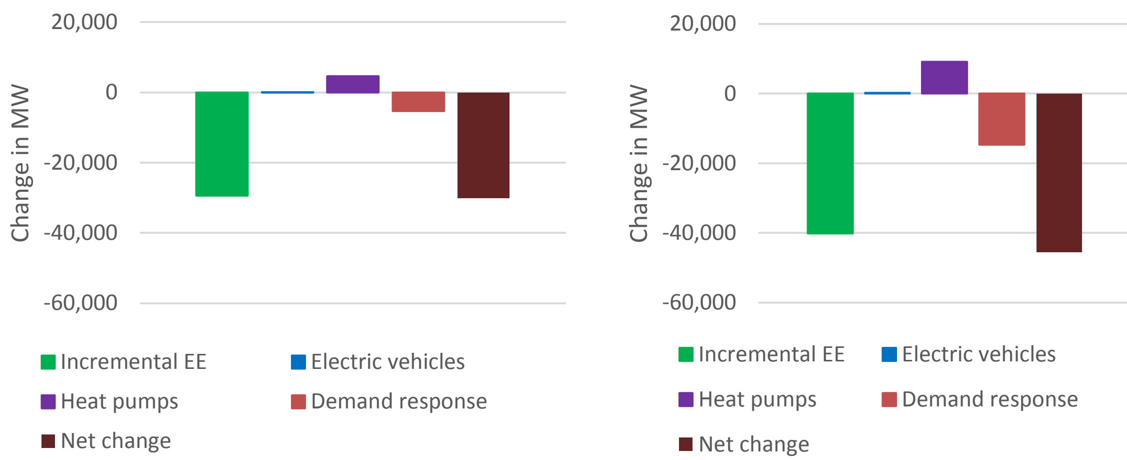


Figure 15. Changes in 2040 winter peak demand in accelerated (left) and aggressive (right) scenarios relative to business-as-usual scenario

Charts for the hybrid and high energy demand scenarios for 2040 and for all scenarios in 2030 relative to the business-as-usual scenario can be found in Appendix C.

Discussion and Conclusions

Our analysis illustrates the importance of incorporating emerging market trends, such as energy efficiency, photovoltaics, heat pumps, electric vehicles, and enhanced demand response into utility system planning. While significant uncertainty exists as to actual outcomes of these developments, not incorporating them into electric system planning can lead to mistakes that needlessly raise costs to customers or compromise reliability.

In the business-as-usual scenario, electricity sales grow modestly—about 0.7% per year. Electricity use also grows in our accelerated and aggressive scenarios but more slowly—at a

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[31] As noted earlier, we did not include storage in our analysis. Storage can be used to help manage both summer and winter peaks.

[32] These charts are for average climate; peaks will be higher in years with hot summers and cold winters and lower in years with cool summers and warm winters. Due to year-to-year weather variations, winter peaks tend to be more variable in the Southeast than summer peaks (J. Wilson, Southern Alliance for Clean Energy, pers. comm., January 17, 2017).

compound average of about 0.3% and 0.1% per year, respectively. In the aggressive scenario, sales decline over the 2019–2030 period (due to the impacts of energy efficiency and customer PV systems) but then grow in the 2030s due to increased penetration of electric vehicles and heat pumps. The hybrid scenario lies between the business-as-usual and accelerated scenarios, and the high energy demand scenario shows the most robust sales growth—nearly 1.0% per year.

For peak demand, over the 2016–2040 period the summer peak grows 29% in the business-as-usual scenario and 2–4% in the accelerated and hybrid scenarios. The slower peak growth in these scenarios is due to energy efficiency, demand response, and photovoltaics (in order of importance). The summer peak declines by 12% in the aggressive scenario, with the decline pronounced in the 2020s, before slow growth resumes in the 2030s, primarily due to EVs.

Equally interesting is that the winter peak becomes the system peak in the 2020s in all but the business-as-usual scenario, driven by photovoltaics (which have a large impact on summer but not winter peaks), growth in use of heat pumps, and potentially higher demand response savings in the summer than in the winter. A few parts of the Southeast already peak in winter.

Thus far, the rate of efficiency savings shown in the accelerated scenario has been achieved in the region by Entergy Arkansas and statewide in 16 states in other parts of the country. Several other southeastern utilities are approaching these level of savings (Duke Carolinas and Progress, both North Carolina and South Carolina). The efficiency savings shown in the aggressive scenario have not yet been achieved in the Southeast but have been proposed by the Arkansas PSC and achieved by Arizona as well as six other states. There is uncertainty about the number of years these increased savings rates can be sustained.[33] Likewise, the demand response savings we model have been achieved by more than ten utilities, including four in the Southeast. The levels of PV, EV, and heat pump penetration are more speculative and are subject to large uncertainty.

We recommend close observation of EE, PV, EV, HP, and DR trends over the next few years. Policies will affect the uptake of these technologies. For example, utility administered EE programs have been increasing in several Southeast states, PV policies are being discussed in many states in the region, and several states have been promoting EVs. Particularly if the high energy demand scenario comes to pass, substantial investments in new capacity will be needed, likely causing substantial rate increases. In such a situation, increased EE and DR investments would likely reduce costs. Likewise, if reducing emissions of air pollutants and greenhouse gases grows in importance, programs and policies to expand EE, PV, EV, and heat pumps could also be useful.

[33] Some reviewers and experts we consulted thought the levels of efficiency we modeled could be sustained, but others questioned how long these levels of annual savings could endure. The long-term potential for sustained energy efficiency savings is discussed by Baatz, Gilleo, and Barigye 2016, York et al. 2015, Nadel 2016c, and Nadel 2016d.

Our analysis illustrates the importance of incorporating energy efficiency, as well as PV, into load forecasts. ISO-New England has made a major effort to incorporate these resources into its forecast, as previously shown in figure 3. In the Southeast, some EE and PV is generally included in forecasts in states with active integrated resource planning (IRP) processes, although perhaps not sufficiently, given how many load forecasts have overpredicted electricity sales in recent years. But in states without IRP processes, it is unclear whether EE and PV are being included in forecasts. If EE and PV are not included, forecasts will be much higher and will falsely justify generation capacity expansion, resulting in extra costs for utility customers if the grid is designed to serve these higher expected loads.

Our analysis also illustrates the importance of including EVs and heat pumps in long-term forecasts. While the impacts of these technologies are expected to be modest over the next 10 years, for longer time frames these technologies will likely become increasingly important. Demand response is already routinely incorporated into load forecasts, although at lower levels than we model in our scenarios.

At this point, these long-term scenarios, while based on emerging developments, contain substantial uncertainties. Still, this analysis points out several possibilities that resource planners should consider incorporating in long-term planning. First, there is a reasonable chance that the Southeast (or at least substantial portions of the region) could become winter peaking rather than summer peaking, or that the winter and summer peaks will be very similar. Second, it is possible that kWh sales and summer peak demand could barely grow or grow at rates much slower than in the past.[34] Existing power plants will retire and may need to be replaced, but significant growth in sales and resource needs above present levels may not happen over the next 25 years. Third, over the longer term (post 2040), electricity sales could grow significantly if EVs and heat pumps take off.

We are entering a dynamic period with substantial uncertainty for long-term electricity sales and peak demand. Developments in energy efficiency, PV, EV, HP, and DR need to be carefully observed and analyzed over the next few years. Where public goals—such as reducing energy bills, system costs, and system emissions—will be served by these developments, policies can be adopted to encourage them. Resource planners should be sure to incorporate these emerging trends and policies into their long-term forecasting and planning. Such observations and analysis should provide greater clarity to resource planners and help to keep energy consumption, energy costs, and energy sector emissions down as the Southeast economy continues to grow.

[34] TVA acknowledges this possibility in its 2015 IRP; its low-growth scenario includes no growth in sales (TVA 2015).

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Appendix A. EIA Electricity Regions

1.	ERCT	TRE All	12.	SRDA	SERC Delta
2.	FRCC	FRCC All	13.	SRGW	SERC Gateway
3.	MROE	MRO East	14.	SRSE	SERC Southeastern
4.	MROW	MRO West	15.	SRCE	SERC Central
5.	NEWE	NPCC New England	16.	SRVC	SERC VACAR
6.	NYCW	NPCC NYC/Westchester	17.	SPNO	SPP North
7.	NYLI	NPCC Long Island	18.	SPSO	SPP South
8.	NYUP	NPCC Upstate NY	19.	AZNM	WECC Southwest
9.	RFCE	RFC East	20.	CAMX	WECC California
10.	RFCM	RFC Michigan	21.	NWPP	WECC Northwest
11.	RFCW	RFC West	22.	RMPA	WECC Rockies

Source: EIA 2016a

Appendix B. Detailed Analysis

Table B1. Accelerated scenario

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Electricity sales (TWh)																											
Residential	410.03	416.36	407.71	410.43	409.77	406.32	405.68	405.21	405.83	407.66	409.49	411.35	413.68	416.53	419.44	421.53	424.06	426.68	429.67	433.04	436.49	440.11	443.75	447.65	451.52	454.60	457.60
Commercial/Other	332.09	335.21	330.65	332.21	332.93	333.51	335.00	335.34	336.47	338.42	339.99	341.20	342.84	344.89	347.28	348.80	350.72	353.04	355.69	358.64	361.76	365.01	368.44	372.07	375.91	379.55	383.49
Industrial	196.78	195.08	200.62	209.86	216.72	220.67	225.71	231.58	236.45	239.54	240.86	241.20	241.35	240.57	240.01	239.57	239.19	239.37	240.28	241.92	243.21	244.13	245.38	247.02	248.40	249.81	250.92
Transportation	1.38	1.66	1.97	2.28	2.76	3.39	4.23	5.20	6.26	7.42	8.63	9.80	10.90	11.93	12.91	13.88	14.80	15.66	16.49	17.31	18.10	18.83	19.52	20.17	20.81	21.43	21.97
Total Sales	940.28	948.32	940.96	954.77	962.18	963.89	970.63	977.34	985.01	993.04	998.97	1003.55	1008.78	1013.93	1019.64	1023.78	1028.77	1034.74	1042.13	1050.90	1059.56	1068.08	1077.09	1086.91	1096.63	1105.38	1113.98
Efficiency																											
Efficiency in base			0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%
Additional efficiency (total 1%)				0.00%	0.25%	0.50%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%	0.75%
Incremental efficiency savings (TWh)				0.00	2.39	4.80	7.19	7.20	7.20	7.21	7.23	7.23	7.22	7.23	7.23	7.24	7.24	7.26	7.28	7.31	7.36	7.41	7.46	7.51	7.58	7.65	7.71
Annual efficiency savings (TWh)				-	1.2	4.7	10.5	17.2	23.5	29.4	35.0	40.3	45.2	49.8	54.0	57.8	61.3	64.4	67.2	69.7	71.9	73.7	75.2	76.4	77.3	77.9	78.4
Remaining sales (TWh)				954.77	960.99	959.16	960.14	960.18	961.54	963.61	963.93	963.24	963.57	964.16	965.68	965.97	967.48	970.30	974.89	981.20	987.71	994.39	1001.89	1010.51	1019.35	1027.48	1035.61
Photovoltaics (TWh)																											
Ramp-up to 30% of tech poten					1.99	3.97	5.96	7.95	9.93	11.92	13.91	15.89	17.88	19.87	21.85	23.84	25.83	27.81	29.80	31.78	33.77	35.76	37.74	39.73	41.72	43.70	45.69
Subtract PV already in AEO					0.28	0.49	0.74	0.92	1.11	1.25	1.39	1.61	2.01	2.37	2.71	3.06	3.49	4.04	4.56	5.09	5.64	6.24	6.91	7.60	8.27	9.02	9.83
Net PV					1.71	3.49	5.22	7.02	8.82	10.67	12.52	14.28	15.87	17.50	19.14	20.78	22.33	23.78	25.24	26.70	28.13	29.52	30.83	32.13	33.45	34.68	35.87
PV as % of basecase electric sales					0.2%	0.4%	0.6%	0.8%	1.0%	1.2%	1.4%	1.6%	1.8%	2.0%	2.1%	2.3%	2.5%	2.7%	2.9%	3.0%	3.2%	3.3%	3.5%	3.7%	3.8%	4.0%	4.1%
Electric vehicles (cars and light trucks)																											
Sales share in AEO	0.92%	1.33%	1.50%	1.62%	2.31%	2.84%	3.62%	4.36%	4.90%	5.37%	6.28%	6.48%	6.69%	6.76%	6.86%	7.17%	7.38%	7.51%	7.70%	7.90%	8.07%	8.26%	8.40%	8.50%	8.75%	8.97%	9.06%
Stock share based on sales 5 years earlier				0.34%	0.75%	0.92%	1.33%	1.50%	1.62%	2.31%	2.84%	3.62%	4.36%	4.90%	5.37%	6.28%	6.48%	6.69%	6.76%	6.86%	7.17%	7.38%	7.51%	7.70%	7.90%	8.07%	8.26%
Stock share with aggressive promotion				0.56%	1.11%	1.67%	2.22%	2.78%	3.33%	3.89%	4.44%	5.00%	5.53%	6.07%	6.60%	7.13%	7.67%	8.20%	8.73%	9.27%	9.80%	10.33%	10.87%	11.40%	11.93%	12.47%	13%
Multiplier relative to AEO				1.64	1.48	1.81	1.67	1.85	2.06	1.68	1.56	1.38	1.27	1.24	1.23	1.14	1.18	1.23	1.29	1.35	1.37	1.40	1.45	1.48	1.51	1.55	1.57
AEO EV electricity use (TWh)				1.67	1.84	2.01	2.86	3.83	4.89	6.04	7.26	8.43	9.53	10.56	11.54	12.50	13.42	14.28	15.12	15.94	16.72	17.45	18.14	18.80	19.43	20.05	20.60
Additional TWh from aggressive promotion				1.07	0.88	1.63	1.91	3.25	5.16	4.13	4.08	3.22	2.55	2.50	2.65	1.71	2.45	3.22	4.42	5.58	6.12	6.98	8.10	9.04	9.92	10.93	11.80
Heat pumps																											
Oil, propane & NG residential space heating energy use (quads			0.557	0.556	0.555	0.554	0.554	0.554	0.554	0.555	0.555	0.555	0.554	0.553	0.553	0.552	0.552	0.551	0.550	0.549	0.549	0.548	0.547	0.547	0.546	0.546	0.547
Before conversion, weatherization reduces load 20%					0.444	0.443	0.443	0.443	0.443	0.444	0.444	0.444	0.443	0.442	0.442	0.442	0.441	0.441	0.440	0.440	0.439	0.439	0.438	0.437	0.437	0.437	0.438
% converted to heat pumps in base				0.4%	0.7%	1.1%	1.5%	1.8%	2.2%	2.6%	2.9%	3.3%	3.5%	3.7%	3.8%	4.0%	4.2%	4.4%	4.6%	4.7%	4.9%	5.1%	5.3%	5.5%	5.6%	5.8%	6.0%
% converted to heat pumps					0.6%	1.2%	1.9%	2.5%	3.1%	3.7%	4.3%	5.0%	5.4%	5.9%	6.4%	6.8%	7.3%	7.8%	8.2%	8.7%	9.2%	9.7%	10.1%	10.6%	11.1%	11.5%	12%
Electricity consumption from HP conversions (TWh)					0.35	0.70	1.05	1.40	1.75	2.11	2.46	2.81	3.07	3.33	3.60	3.86	4.12	4.38	4.64	4.90	5.15	5.41	5.67	5.92	6.18	6.45	6.72
Summary (TWh)																											
AEO electric sales	940.28	948.32	940.96	954.77	962.18	963.89	970.63	977.34	985.01	993.04	998.97	1003.55	1008.78	1013.93	1019.64	1023.78	1028.77	1034.74	1042.13	1050.90	1059.56	1068.08	1077.09	1086.91	1096.63	1105.38	1113.98
Reduction from additional efficiency				0.00	-1.19	-4.73	-10.49	-17.16	-23.47	-29.43	-35.04	-40.31	-45.22	-49.77	-53.96	-57.81	-61.30	-64.44	-67.24	-69.71	-71.85	-73.68	-75.20	-76.40	-77.29	-77.91	-78.37
Remaining electric sales				954.77	960.99	959.16	960.14	960.18	961.54	963.61	963.93	963.24	963.57	964.16	965.68	965.97	967.48	970.30	974.89	981.20	987.71	994.39	1001.89	1010.51	1019.35	1027.48	1035.61
Reduction for PV				0.00	-1.71	-3.49	-5.22	-7.02	-8.82	-10.67	-12.52	-14.28	-15.87	-17.50	-19.14	-20.78	-22.33	-23.78	-25.24	-26.70	-28.13	-29.52	-30.83	-32.13	-33.45	-34.68	-35.87
Addition for EVs				1.07	0.88	1.63	1.91	3.25	5.16	4.13	4.08	3.22	2.55	2.50	2.65	1.71	2.45	3.22	4.42	5.58	6.12	6.98	8.10	9.04	9.92	10.93	11.80
Addition for HPs				0	0.35	0.70	1.05	1.40	1.75	2.11	2.46	2.81	3.07	3.33	3.60	3.86	4.12	4.38	4.64	4.90	5.15	5.41	5.67	5.92	6.18	6.45	6.72
Revised total			940.96	955.84	960.51	958.01	957.88	957.81	959.64	959.18	957.95	954.98	953.32	952.50	952.79	950.76	951.71	954.13	958.71	964.98	970.85	977.26	984.83	993.34	1001.99	1010.17	1018.26
Net change				1.07	-1.67	-5.88	-12.75	-19.53	-25.37	-33.85	-41.02	-48.57	-55.47	-61.43	-66.86	-73.02	-77.06	-80.61	-83.42	-85.93	-88.71	-90.81	-92.26	-93.57	-94.64	-95.21	-95.71
Summer Peak (MW, 6pm)																											
Predicted SERC peak -- total demand				179278				186108					195796	0.000678													
Net demand (after DR)				171698				178422					188121														
Ratio peak to sales			0.179832	0.180378	0.180923	0.181469	0.182014	0.18256	0.182799	0.183584	0.184368	0.185153	0.186483	0.187162	0.187840	0.188518	0.189197	0.189875	0.190554	0.191232	0.191910	0.192589	0.193267	0.193946	0.194624	0.195303	0.195981
Peak from sales in AEO			169214	172219	174081	174916	176668	178422	180059	182305	184178	185811	188121	189768	191530	193001	194641	196472	198582	200966	203340	205700	208167	210802	213432	215884	218318
Savings from incremental EE				-521	-1264	-2428	-4005	-5751	-7142	-9017	-10833	-12589	-14841	-16381	-17869	-19288	-20658	-21981	-23265	-24516	-25719	-26876	-27994	-29079	-30121	-31111	-32082
Remaining electric sales				171698	172816	172488	172663	172671	172916	173288	173345	173222	173280	173387	173661	173713	173983	174492	175317	176451	177621	178824	180172	181722	183311	184773	186236
Reduction for incremental PV				0	-235	-479	-717	-964	-1211	-1464	-1718	-1961	-2179	-2402	-2628	-2853	-3066	-3264	-3464	-3665	-3862	-4053	-4232	-4410	-4592	-4761	-4923
Reduction for PV in AEO				0	-38	-67	-101	-127	-152	-172	-191	-221	-276	-325	-372	-420	-479	-554	-626	-698	-774	-856	-949	-1044	-1135	-1238	-1349
Demand response (Base %)				4.2%				4.1%					3.9%														
Incremental demand response (%)				0.0%	0.5%	1.0%	2.0%	3.0%	3.9%	3.9%	3.9%	4.0%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%	4.1%
Reduction for incremental DR				0	-863	-1719	-3437	-5147	-6691	-6694	-6686	-6842	-7004	-6997	-6997	-6988	-6988	-6998	-7020	-7056	-7092	-7131	-7175	-7227	-7281	-7330	-7379
Watts per vehcile at 6pm				0.565	0.560	0.555	0.550	0.540	0.530	0.520	0.510	0.500	0.490	0.480	0.470	0.460	0.450	0.435	0.420	0.405	0.390	0.375	0.360	0.345	0.330	0.315	0.300
Addition for EVs				57	91	187	225	315	412	383	382	319	267	264	275	187	254	316	402	479	507	552	607	650	671	701	725
Addition for HPs				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total		0	169214	171755	171772	170410	168633	166748	165274	165340	165132	164517	164088	163927	163939	163640	163704	163992	164608	165511	166400	167337	168424	169691	170975	172145	173310
Net change				-463	-2309	-4506	-8035	-11674	-14785	-16965	-19046	-21293	-24033	-25841	-27590	-29361	-30937	-32480	-33974	-35455	-36940	-38363	-39743	-41111	-42457	-43739	-45008
Approx. PV nominal system MW				0	1363	2727	4090	5454	6817	8181	9544	10908	12271	13635	14998	16362	17725	19088	20452	21815	23179	24542	25906	27269	28633	29996	31360
Winter Peak (GW, 8am)																											
Predicted SERC peak -- total demand			174499				181456					191091		0.000578													
Net demand (after DR)			167115				173922					183457															
Ratio peak to sales		0.177601	0.177601	0.177997	0.178393	0.178789	0.1792	0.179909	0.180634	0.181358	0.182083	0.1828	0.1834	0.1840	0.1845	0.1851	0.1857	0.1863	0.1869	0.1874	0.1880	0.1886	0.1892	0.1897	0.1903	0.1909	0.1915
Peak from sales in AEO		168422	167115	169946	171646	172333	173922	175832	177926	180095	181895	183457	184997	186526	188168	189524	191043	192750	194729	196976	199212	201431	203754	206241	208720	211025	213309
Savings from incremental EE				-378	-974	-1985	-3401	-5303	-7155	-8957	-10701	-12384	-13866	-15290	-16662	-17965	-19218	-20423	-21587	-22714	-23794	-24826	-25817	-26772	-27683	-28544	-29384
Remaining electric sales				169568	170673	170348	170521	170529	170771	171138	171195	171073	171130	171236	171506	171558	171825	172327	173142	174262	175418	176606	177937	179468	181037	182481	183925
Demand response (Base %)			4.2%				4.2%					4.0%															
Incremental demand response (%)				0.0%	0.5%	1.0%	1.5%	2.0%	2.3%	2.3%	2.4%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Reduction for incremental DR				0	-858	-1723	-2609	-3517	-4092	-4142	-4365	-4586	-4625	-4663	-4704	-4738	-4776	-4819	-4868	-4924	-4980	-5036	-5094	-5156	-5218	-5276	-5333
Reduction for PV				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Watts per vehcile at 8am				0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020
Addition for EVs				2	3	7	8	12	16	15	15	13	11	11	12	8	11	15	19	24	26	29	34	38	41	44	48
Addition for HPs				0	244	487	730	973	1217	1461	1705	1948	2129	2311	2494	2676	2857	3037	3215	3396	3574	3753	3930	4107	4287	4471	4657
Total		168422	167115	169570	170061	169118	168651	167997	167911	168472	168549	168447	168645	168895	169308	169505	169917	170560	171508	172757	174038	175353	176807	178457	180146	181721	183298
Net change			0	-376	-1585	-3215	-5271	-7835	-10015	-11623	-13346	-15010	-16351	-17632	-18860	-20019	-21126	-22191	-23221	-24220	-25174	-26079	-26947	-27784	-28574	-29304	-30011

Notes to Table B1

- The major assumptions are discussed in the text.
- For annual efficiency savings, we assume a 10.6-year average measure life, with some measures lasting longer and some ending sooner (Molina 2014). Half of the measures are in place and saving after 10.6 years, an average loss of about 5% per year.
- For electric vehicles, we estimate that the share of EVs in the vehicle stock is equivalent to the share of EV sales five years earlier. In other words, the EV share in the stock lags the EV share in sales, since less than 10% of vehicles are replaced each year. We estimate the energy use of EVs beyond those included in the AEO by calculating a ratio of EV stock in our accelerated and aggressive scenarios to the EV stock in the AEO and multiplying EV energy use in the AEO by this ratio. Assumptions on EV miles traveled and miles/kWh are part of the AEO, and we implicitly use these same assumptions.
- We assume that transportation electricity use in 2012 was all due to public transportation and that subsequent growth in electricity used for transportation is due to EVs. This is a simplification that makes modeling much easier.
- Before or when homes are converted to heat pumps, we assume that energy efficiency measures are employed to reduce heating energy needs by 20%, allowing a smaller heat pump system.
- Heat pump performance is based on an ENERGY STAR® Most Efficient Heat Pump used in Georgia using the seasonal performance for Georgia from Nadel 2016a. We assume that, on average, the fossil fuel systems being replaced have an 83% annual fuel utilization efficiency (AFUE) based on three-quarters at 80% AFUE and one-quarter at 92% AFUE. In the Southeast, we assume most of these homes already have air-conditioning and that the small incremental air-conditioning load will be offset by the higher efficiency of the ENERGY STAR Most Efficient Heat Pump.
- We convert the kWh produced by PV systems into peak demand by dividing kWh by 1,442 kWh produced per kW of system capacity from NREL PVWatts Calculator for Atlanta using default assumptions (http://pvwatts.nrel.gov/) and then multiplying by 20%, where 20% is an estimate of the load factor of PV systems at 6 p.m. on a very hot day. (ISO-NE 2016a estimates this to be just over 20% when 8,000 MW of PV is installed; this figure is likely to be higher in the South, but we use 20% because some of the effect of PV on peak load is already reflected in the impact of PV on lowering kWh sales.)
- For EVs, we estimate that the average vehicle draws 600 W for charging at 6 p.m., ramping down to 300 W by 2040. These figures come from Hostick et al. 2012 (p. K-11) and assume that smart charging during off-peak hours will gradually become more common. We multiply this estimate of W/EV by the number of EVs, which we estimate by multiplying the incremental EV stock share (relative to the AEO [EIA 2017a]) by the number of vehicles in the stock. This latter figure we estimate by multiplying the number of new vehicles sold each year (from the AEO) by the average age of vehicles on US roads (from www.rita.dot.gov/bts/sites/rita.dot.gov.bts/files/publications/national_transportation_statistics/html/table_01_26.html_mfd).
- For heat pumps, winter peak is estimated for 8 a.m. using the EPRI Load Shape Library 4.0 (loadshape.epri.com/). We convert the annual kWh for winter space heating into peak kW using these load shapes. For winter, the EPRI load shape shows a ratio for SERC of 1.0 kW at 7 or 8 a.m. to 1,442 annual kWh (this figure is per 1 kW of load).

Table B2. Aggressive scenario

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Efficiency																											
Efficiency in base			0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%	0.25%
Additional efficiency (total 1.5%)				0.00%	0.42%	0.83%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%	1.25%
Incremental efficiency savings (TWh)				0.00	3.98	8.02	12.05	12.13	12.22	12.31	12.41	12.49	12.54	12.61	12.67	12.75	12.80	12.86	12.93	13.03	13.14	13.24	13.35	13.46	13.59	13.71	13.82
Annual efficiency savings (TWh)				-	2.0	7.9	17.5	28.7	39.4	49.6	59.2	68.4	77.0	85.0	92.5	99.4	105.7	111.5	116.7	121.3	125.5	129.0	132.0	134.5	136.4	137.9	139.0
Remaining sales (TWh)				954.77	960.19	956.00	953.10	948.61	945.60	943.45	939.73	935.17	931.81	928.93	927.18	924.40	923.05	923.25	925.43	929.56	934.10	939.06	945.05	952.39	960.19	967.50	974.95
Photovoltaics (TWh)																											
Ramp-up to 60% of tech poten					3.97	7.95	11.92	15.89	19.87	23.84	27.81	31.78	35.76	39.73	43.70	47.68	51.65	55.62	59.60	63.57	67.54	71.52	75.49	79.46	83.44	87.41	91.38
Subtract PV already in AEO					0.28	0.49	0.74	0.92	1.11	1.25	1.39	1.61	2.01	2.37	2.71	3.06	3.49	4.04	4.56	5.09	5.64	6.24	6.91	7.60	8.27	9.02	9.83
Net PV					3.70	7.46	11.18	14.97	18.76	22.58	26.42	30.18	33.75	37.37	40.99	44.62	48.16	51.59	55.03	58.48	61.90	65.28	68.58	71.86	75.17	78.39	81.56
PV as % of basecase electric sales				0.0%	0.4%	0.8%	1.2%	1.6%	2.0%	2.4%	2.8%	3.2%	3.5%	3.9%	4.3%	4.7%	5.0%	5.4%	5.7%	6.0%	6.4%	6.7%	7.0%	7.3%	7.6%	7.9%	8.2%
Electric vehicles (cars and light trucks)																											
Sales share in AEO	0.92%	1.33%	1.50%	1.62%	2.31%	2.84%	3.62%	4.36%	4.90%	5.37%	6.28%	6.48%	6.69%	6.76%	6.86%	7.17%	7.38%	7.51%	7.70%	7.90%	8.07%	8.26%	8.40%	8.50%	8.75%	8.97%	9.06%
Stock share based on sales 5 years earlier				0.34%	0.75%	0.92%	1.33%	1.50%	1.62%	2.31%	2.84%	3.62%	4.36%	4.90%	5.37%	6.28%	6.48%	6.69%	6.76%	6.86%	7.17%	7.38%	7.51%	7.70%	7.90%	8.07%	8.26%
Stock share with aggressive promotion				0.5%	1.0%	2.0%	3.0%	4.0%	5.0%	6.0%	7.0%	8.0%	9.1%	10.3%	11.6%	13.0%	14.5%	16.1%	17.8%	19.6%	21.5%	23.4%	25.2%	26.9%	28.7%	30.5%	32.3%
Multiplier relative to AEO				1.48	1.33	2.17	2.25	2.66	3.08	2.60	2.46	2.21	2.09	2.10	2.16	2.07	2.24	2.41	2.63	2.86	3.00	3.17	3.35	3.50	3.63	3.78	3.90
AEO EV electricity use (TWh)				1.67	1.84	2.01	2.86	3.83	4.89	6.04	7.26	8.43	9.53	10.56	11.54	12.50	13.42	14.28	15.12	15.94	16.72	17.45	18.14	18.80	19.43	20.05	20.60
Additional TWh from aggressive promotion				0.80	0.61	2.36	3.58	6.36	10.19	9.66	10.60	10.20	10.34	11.62	13.40	13.39	16.59	20.09	24.70	29.58	33.40	37.82	42.60	46.95	51.16	55.68	59.77
Heat pumps																											
Oil, propane & NG residential space heating energy use (quads			0.557	0.556	0.555	0.554	0.554	0.554	0.554	0.555	0.555	0.555	0.554	0.553	0.553	0.552	0.552	0.551	0.550	0.549	0.549	0.548	0.547	0.547	0.546	0.546	0.547
Before conversion, weatherization reduces load 20%					0.444	0.443	0.443	0.443	0.443	0.444	0.444	0.444	0.443	0.442	0.442	0.442	0.441	0.441	0.440	0.440	0.439	0.439	0.438	0.437	0.437	0.437	0.438
% converted to heat pumps in base				0.4%	0.7%	1.1%	1.5%	1.8%	2.2%	2.6%	2.9%	3.3%	3.5%	3.7%	3.8%	4.0%	4.2%	4.4%	4.6%	4.7%	4.9%	5.1%	5.3%	5.5%	5.6%	5.8%	6.0%
% converted to heat pumps					0.8%	1.7%	2.5%	3.3%	4.1%	5.0%	5.8%	7%	7.8%	8.9%	10.1%	11.2%	12.4%	13.6%	14.7%	15.9%	17.0%	18.2%	19.4%	20.5%	21.7%	22.8%	24%
Electricity consumption from HP conversions (TWh)					0.47	0.92	1.37	1.83	2.29	2.75	3.21	3.66	4.30	4.94	5.58	6.22	6.85	7.48	8.11	8.74	9.36	9.99	10.61	11.23	11.86	12.50	13.15
Summary (TWh)																											
AEO electric sales		948.32	940.96	954.77	962.18	963.89	970.63	977.34	985.01	993.04	998.97	1003.55	1008.78	1013.93	1019.64	1023.78	1028.77	1034.74	1042.13	1050.90	1059.56	1068.08	1077.09	1086.91	1096.63	1105.38	1113.98
Reduction from additional efficiency				0.00	-1.99	-7.89	-17.53	-28.73	-39.41	-49.58	-59.24	-68.38	-76.97	-85.00	-92.47	-99.38	-105.72	-111.50	-116.70	-121.35	-125.45	-129.02	-132.04	-134.52	-136.45	-137.89	-139.02
Remaining electric sales				954.77	960.19	956.00	953.10	948.61	945.60	943.45	939.73	935.17	931.81	928.93	927.18	924.40	923.05	923.25	925.43	929.56	934.10	939.06	945.05	952.39	960.19	967.50	974.95
Reduction for PV				0.00	-3.70	-7.46	-11.18	-14.97	-18.76	-22.58	-26.42	-30.18	-33.75	-37.37	-40.99	-44.62	-48.16	-51.59	-55.03	-58.48	-61.90	-65.28	-68.58	-71.86	-75.17	-78.39	-81.56
Addition for EVs				0.80	0.61	2.36	3.58	6.36	10.19	9.66	10.60	10.20	10.34	11.62	13.40	13.39	16.59	20.09	24.70	29.58	33.40	37.82	42.60	46.95	51.16	55.68	59.77
Addition for HPs				0	0.47	0.92	1.37	1.83	2.29	2.75	3.21	3.66	4.30	4.94	5.58	6.22	6.85	7.48	8.11	8.74	9.36	9.99	10.61	11.23	11.86	12.50	13.15
Revised total			940.96	955.57	957.58	951.82	946.87	941.83	939.32	933.28	927.12	918.86	912.70	908.12	905.16	899.39	898.33	899.23	903.20	909.39	914.96	921.58	929.68	938.71	948.04	957.29	966.32
Net change				0.80	-4.61	-12.07	-23.76	-35.50	-45.69	-59.76	-71.85	-84.69	-96.08	-105.81	-114.49	-124.39	-130.44	-135.52	-138.93	-141.52	-144.59	-146.50	-147.41	-148.20	-148.60	-148.09	-147.66
Summer Peak (MW, 6pm)																											
Ratio peak to sales			0.180	0.180	0.181	0.181	0.182	0.183	0.183	0.184	0.184	0.185	0.186	0.187	0.188	0.189	0.189	0.190	0.191	0.191	0.192	0.193	0.193	0.194	0.195	0.195	0.196
Peak from sales in AEO			169214	172219	174081	174916	176668	178422	180059	182305	184178	185811	188121	189768	191530	193001	194641	196472	198582	200966	203340	205700	208167	210802	213432	215884	218318
Savings from incremental EE				-521	-1407	-2996	-5270	-7832	-10009	-12642	-15185	-17637	-20551	-22717	-24794	-26765	-28647	-30443	-32159	-33802	-35358	-36828	-38217	-39531	-40759	-41897	-42990
Remaining electric sales				171698	172673	171920	171398	170590	170049	169663	168993	168174	167570	167051	166736	166237	165994	166030	166422	167164	167982	168872	169950	171271	172673	173987	175328
Reduction for incremental PV				0	-688	-1389	-2082	-2788	-3493	-4206	-4921	-5620	-6285	-6958	-7634	-8309	-8968	-9607	-10248	-10891	-11527	-12157	-12770	-13382	-13998	-14598	-15187
Reduction for PV in AEO				0	-51	-91	-138	-172	-207	-234	-259	-299	-374	-440	-505	-569	-650	-752	-850	-947	-1050	-1161	-1287	-1416	-1540	-1680	-1830
Demand response (Base %)				4.2%					0.0%				3.9%														
Incremental demand response (%)				0.0%	0.5%	1.0%	2.0%	3.0%	4.0%	5.0%	6.0%	7.0%	8.0%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%	8.1%
Reduction for incremental DR				0	-860	-1704	-3384	-5029	-6654	-8261	-9829	-11358	-12873	-12932	-12846	-12746	-12666	-12609	-12581	-12581	-12588	-12600	-12627	-12674	-12728	-12775	-12823
Watts per vehcile at 6pm				0.565	0.560	0.555	0.550	0.540	0.530	0.520	0.510	0.500	0.490	0.480	0.470	0.460	0.450	0.435	0.420	0.405	0.390	0.375	0.360	0.345	0.330	0.315	0.300
Addition for EVs				43	63	270	421	616	813	896	991	1011	1080	1227	1393	1470	1723	1967	2246	2539	2765	2989	3193	3374	3462	3569	3673
Addition for HPs				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total			169214	171741	171137	169006	166217	163218	160509	157858	154976	151908	149118	147948	147144	146082	145432	145029	144989	145283	145582	145944	146458	147173	147869	148505	149160
Net change				-478	-2944	-5910	-10452	-15204	-19550	-24446	-29202	-33903	-39003	-41820	-44386	-46919	-49208	-51444	-53593	-55683	-57759	-59756	-61709	-63629	-65562	-67380	-69158
Approx. PV nominal system MW				0	3699	7399	11098	14797	18497	22196	25896	29595	33294	36994	40693	44392	48092	51791	55491	59190	62889	66589	70288	73987	77687	81386	85085
Winter Peak (MW, 8am)																											
Ratio peak to sales			0.178	0.178	0.178	0.179	0.179	0.180	0.181	0.181	0.182	0.183	0.183	0.184	0.185	0.185	0.186	0.186	0.187	0.187	0.188	0.189	0.189	0.190	0.190	0.191	0.191
Peak from sales in AEO			167115	169946	171646	172333	173922	175832	177926	180095	181895	183457	184997	186526	188168	189524	191043	192750	194729	196976	199212	201431	203754	206241	208720	211025	213309
Savings from incremental EE				-378	-1115	-2546	-4650	-7357	-9986	-12537	-14999	-17369	-19505	-21547	-23500	-25349	-27109	-28780	-30371	-31886	-33314	-34654	-35913	-37095	-38189	-39196	-40156
Remaining electric sales				169568	170531	169787	169272	168474	167940	167559	166897	166088	165491	164979	164668	164175	163935	163970	164358	165090	165898	166777	167841	169146	170531	171829	173153
Demand response (Base %)			4.2%				4.2%					4.0%															
Incremental demand response (%)				0.0%	0.5%	1.0%	1.5%	2.0%	2.5%	3.5%	4.5%	5.5%	6.5%	6.9%	6.9%	6.9%	6.9%	6.9%	6.9%	6.9%	6.9%	6.9%	6.9%	6.9%	6.9%	6.9%	6.9%
Reduction for incremental DR				0	-858	-1723	-2609	-3517	-4448	-6303	-8185	-10090	-12025	-12870	-12984	-13077	-13182	-13300	-13436	-13591	-13746	-13899	-14059	-14231	-14402	-14561	-14718
Reduction for PV				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Watts per vehcile at 8am				0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020	0.020
Addition for EVs				2	2	10	15	23	31	34	39	40	44	51	59	64	77	90	107	125	142	159	177	196	210	227	245
Addition for HPs				0	325	635	952	1269	1587	1906	2224	2541	2983	3424	3868	4310	4750	5187	5622	6059	6493	6929	7359	7790	8226	8669	9117
Total			167115	169570	170000	168708	167631	166250	165110	163196	160974	158579	156493	155584	155611	155471	155579	155947	156650	157683	158788	159967	161318	162901	164564	166164	167796
Net change				-376	-1646	-3625	-6291	-9582	-12816	-16899	-20921	-24878	-28503	-30942	-32557	-34052	-35464	-36803	-38079	-39293	-40424	-41464	-42436	-43340	-44156	-44860	-45513

All notes from table B1 also apply to table B2.

Table B3. Hybrid scenario

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
AEO electric sales		948.32	940.96	954.77	962.18	963.89	970.63	977.34	985.01	993.04	998.97	1003.55	1008.78	1013.93	1019.64	1023.78	1028.77	1034.74	1042.13	1050.90	1059.56	1068.08	1077.09	1086.91	1096.63	1105.38	1113.98
Reduction from additional efficiency				0.00	-1.19	-4.73	-10.49	-17.16	-23.47	-29.43	-35.04	-40.31	-45.22	-49.77	-53.96	-57.81	-61.30	-64.44	-67.24	-69.71	-71.85	-73.68	-75.20	-76.40	-77.29	-77.91	-78.37
Remaining electric sales				954.77	960.99	959.16	960.14	960.18	961.54	963.61	963.93	963.24	963.57	964.16	965.68	965.97	967.48	970.30	974.89	981.20	987.71	994.39	1001.89	1010.51	1019.35	1027.48	1035.61
Reduction for PV				0	-1.71	-3.49	-5.22	-7.02	-8.82	-10.67	-12.52	-14.28	-15.87	-17.50	-19.14	-20.78	-22.33	-23.78	-25.24	-26.70	-28.13	-29.52	-30.83	-32.13	-33.45	-34.68	-35.87
Addition for EVs				0.80	0.61	2.36	3.58	6.36	10.19	9.66	10.60	10.20	10.34	11.62	13.40	13.39	16.59	20.09	24.70	29.58	33.40	37.82	42.60	46.95	51.16	55.68	59.77
Addition for HPs				-	0.47	0.92	1.37	1.83	2.29	2.75	3.21	3.66	4.30	4.94	5.58	6.22	6.85	7.48	8.11	8.74	9.36	9.99	10.61	11.23	11.86	12.50	13.15
Revised total			940.96	955.57	960.36	958.95	959.87	961.35	965.20	965.35	965.22	962.83	962.33	963.22	965.52	964.80	968.58	974.09	982.46	992.81	1002.34	1012.68	1024.27	1036.57	1048.91	1060.98	1072.66
Net change				0.80	-1.82	-4.94	-10.76	-15.99	-19.81	-27.69	-33.75	-40.73	-46.45	-50.71	-54.13	-58.98	-60.19	-60.65	-59.67	-58.09	-57.22	-55.40	-52.82	-50.35	-47.72	-44.41	-41.31
Summer Peak (MW, 6pm)																											
Peak from sales in AEO			169214	172219	174081	174916	176668	178422	180059	182305	184178	185811	188121	189768	191530	193001	194641	196472	198582	200966	203340	205700	208167	210802	213432	215884	218318
Savings from incremental EE				-521	-1264	-2428	-4005	-5751	-7142	-9017	-10833	-12589	-14841	-16381	-17869	-19288	-20658	-21981	-23265	-24516	-25719	-26876	-27994	-29079	-30121	-31111	-32082
Remaining electric sales				171698	172816	172488	172663	172671	172916	173288	173345	173222	173280	173387	173661	173713	173983	174492	175317	176451	177621	178824	180172	181722	183311	184773	186236
Reduction for incremental PV				0	-235	-479	-717	-964	-1211	-1464	-1718	-1961	-2179	-2402	-2628	-2853	-3066	-3264	-3464	-3665	-3862	-4053	-4232	-4410	-4592	-4761	-4923
Reduction for PV in AEO				0	-38	-67	-101	-127	-152	-172	-191	-221	-276	-325	-372	-420	-479	-554	-626	-698	-774	-856	-949	-1044	-1135	-1238	-1349
Reduction for incremental DR				0	-863	-1719	-3437	-5147	-6691	-6694	-6686	-6842	-7004	-6997	-6997	-6988	-6988	-6998	-7020	-7056	-7092	-7131	-7175	-7227	-7281	-7330	-7379
Addition for EVs				43	63	270	421	616	813	896	991	1011	1080	1227	1393	1470	1723	1967	2246	2539	2765	2989	3193	3374	3462	3569	3673
Addition for HPs				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total			169214	171741	171744	170493	168830	167049	165675	165853	165742	165209	164902	164890	165057	164922	165174	165643	166452	167571	168658	169774	171010	172416	173765	175014	176258
Net change				-478	-2337	-4423	-7838	-11373	-14384	-16452	-18437	-20601	-23219	-24878	-26473	-28079	-29467	-30829	-32130	-33395	-34682	-35926	-37157	-38386	-39666	-40871	-42060
Winter Peak (MW, 8am)																											
Peak from sales in AEO			167115	169946	171646	172333	173922	175832	177926	180095	181895	183457	184997	186526	188168	189524	191043	192750	194729	196976	199212	201431	203754	206241	208720	211025	213309
Savings from incremental EE				-378	-974	-1985	-3401	-5303	-7155	-8957	-10701	-12384	-13866	-15290	-16662	-17965	-19218	-20423	-21587	-22714	-23794	-24826	-25817	-26772	-27683	-28544	-29384
Remaining electric sales				169568	170673	170348	170521	170529	170771	171138	171195	171073	171130	171236	171506	171558	171825	172327	173142	174262	175418	176606	177937	179468	181037	182481	183925
Reduction for incremental DR				0	-858	-1723	-2609	-3517	-4092	-4142	-4365	-4586	-4625	-4663	-4704	-4738	-4776	-4819	-4868	-4924	-4980	-5036	-5094	-5156	-5218	-5276	-5333
Reduction for PV				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Addition for EVs				2	2	10	15	23	31	34	39	40	44	51	59	64	77	90	107	125	142	159	177	196	210	227	245
Addition for HPs				0	325	635	952	1269	1587	1906	2224	2541	2983	3424	3868	4310	4750	5187	5622	6059	6493	6929	7359	7790	8226	8669	9117
Total				169570	170141	169269	168880	168305	168297	168937	169092	169068	169532	170048	170729	171194	171875	172785	174002	175522	177073	178658	180380	182297	184254	186102	187954
Net change				-376	-1505	-3064	-5042	-7527	-9629	-11159	-12803	-14389	-15464	-16478	-17439	-18329	-19168	-19965	-20727	-21454	-22139	-22773	-23375	-23943	-24466	-24923	-25355

All values come from tables B1 and B2, using EE, PV, and DR from B1 and using EV and HP from B2.

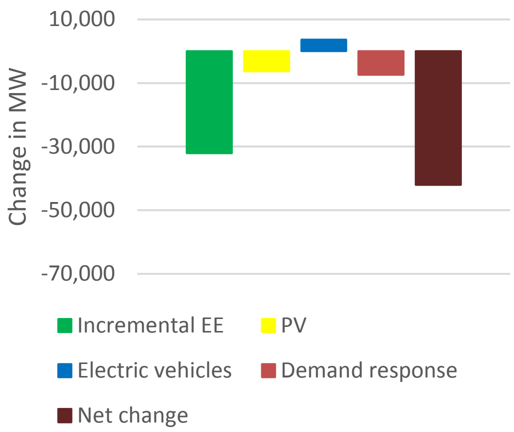
Table B4. High energy demand scenario

	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
AEO electric sales		948.32	940.96	954.77	962.18	963.89	970.63	977.34	985.01	993.04	998.97	1003.55	1008.78	1013.93	1019.64	1023.78	1028.77	1034.74	1042.13	1050.90	1059.56	1068.08	1077.09	1086.91	1096.63	1105.38	1113.98
Reduction from additional efficiency				0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Remaining electric sales				954.77	962.18	963.89	970.63	977.34	985.01	993.04	998.97	1003.55	1008.78	1013.93	1019.64	1023.78	1028.77	1034.74	1042.13	1050.90	1059.56	1068.08	1077.09	1086.91	1096.63	1105.38	1113.98
Reduction for PV				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Addition for EVs				0.80	0.61	2.36	3.58	6.36	10.19	9.66	10.60	10.20	10.34	11.62	13.40	13.39	16.59	20.09	24.70	29.58	33.40	37.82	42.60	46.95	51.16	55.68	59.77
Addition for HPs				-	0.47	0.92	1.37	1.83	2.29	2.75	3.21	3.66	4.30	4.94	5.58	6.22	6.85	7.48	8.11	8.74	9.36	9.99	10.61	11.23	11.86	12.50	13.15
Revised total			940.96	955.57	963.26	967.17	975.58	985.53	997.49	1005.44	1012.78	1017.42	1023.42	1030.48	1038.62	1043.39	1052.21	1062.31	1074.94	1089.22	1102.32	1115.88	1130.30	1145.09	1159.65	1173.57	1186.90
Net change				0.80	1.08	3.28	4.95	8.19	12.48	12.40	13.81	13.87	14.64	16.56	18.97	19.61	23.44	27.57	32.81	38.31	42.76	47.81	53.21	58.18	63.02	68.18	72.92
Summer Peak (MW, 6pm)																											
Peak from sales in AEO			169214	172219	174081	174916	176668	178422	180059	182305	184178	185811	188121	189768	191530	193001	194641	196472	198582	200966	203340	205700	208167	210802	213432	215884	218318
Savings from incremental EE				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Remaining electric sales				172219	174081	174916	176668	178422	180059	182305	184178	185811	188121	189768	191530	193001	194641	196472	198582	200966	203340	205700	208167	210802	213432	215884	218318
Reduction for incremental PV				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reduction for PV in AEO				0	-38	-67	-101	-127	-152	-172	-191	-221	-276	-325	-372	-420	-479	-554	-626	-698	-774	-856	-949	-1044	-1135	-1238	-1349
Reduction for incremental DR				0	4	8	12	12	12	12	12	12	13	13	13	13	13	13	13	13	13	13	13	13	14	14	14
Addition for EVs				43	63	270	421	616	813	896	991	1011	1080	1227	1393	1470	1723	1967	2246	2539	2765	2989	3193	3374	3462	3569	3673
Addition for HPs				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total			169214	172262	174110	175127	177000	178924	180731	183041	184992	186613	188938	190683	192563	194064	195898	197898	200214	202820	205344	207846	210424	213146	215772	218229	220656
Net change				43	29	211	332	502	673	736	813	802	817	915	1033	1063	1257	1425	1632	1854	2004	2147	2257	2344	2341	2345	2338
Winter Peak (MW, 8am)																											
Peak from sales in AEO			167115	169946	171646	172333	173922	175832	177926	180095	181895	183457	184997	186526	188168	189524	191043	192750	194729	196976	199212	201431	203754	206241	208720	211025	213309
Savings from incremental EE				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Remaining electric sales				169946	171646	172333	173922	175832	177926	180095	181895	183457	184997	186526	188168	189524	191043	192750	194729	196976	199212	201431	203754	206241	208720	211025	213309
Reduction for incremental DR				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Reduction for PV				0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Addition for EVs				2	2	10	15	23	31	34	39	40	44	51	59	64	77	90	107	125	142	159	177	196	210	227	245
Addition for HPs				0	325	635	952	1269	1587	1906	2224	2541	2983	3424	3868	4310	4750	5187	5622	6059	6493	6929	7359	7790	8226	8669	9117
Total				169948	171973	172978	174889	177124	179544	182036	184158	186038	188023	190002	192095	193897	195869	198027	200458	203161	205847	208519	211290	214226	217155	219921	222671
Net change				2	327	645	967	1292	1618	1941	2263	2581	3027	3476	3927	4374	4826	5277	5729	6184	6635	7088	7536	7985	8435	8896	9362

All values come from tables B1 and B2, using EE, PV, and DR from the business-as-usual rows of B1 and using EV and HP from B2.

Appendix C. Additional Graphs

HYBRID SCENARIO 2040 FIGURES



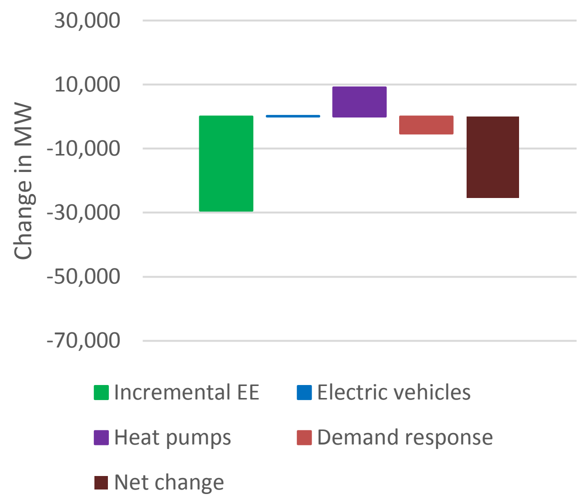
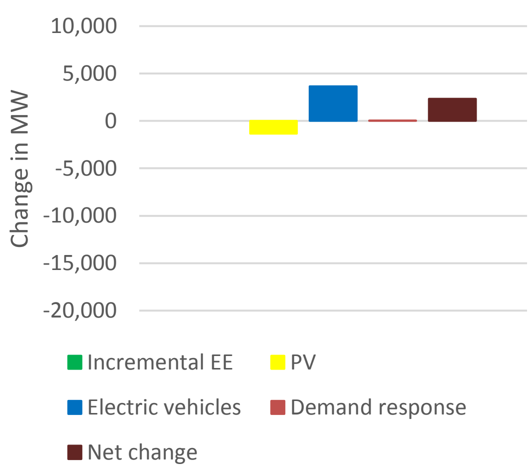


Figure C1. Comparison of 2040 summer (left) and winter (right) peak demand in hybrid scenario relative to business-as-usual scenario

HIGH ENERGY DEMAND SCENARIO 2040 FIGURES



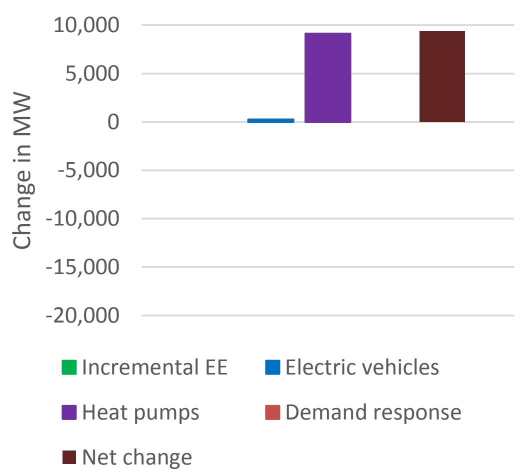


Figure C2. Comparison of 2040 summer (left) and winter (right) peak demand in high energy demand scenario relative to business-as-usual scenario

COMPARISON OF 2030 SALES AND PEAK DEMAND WITH BUSINESS-AS-USUAL SCENARIO

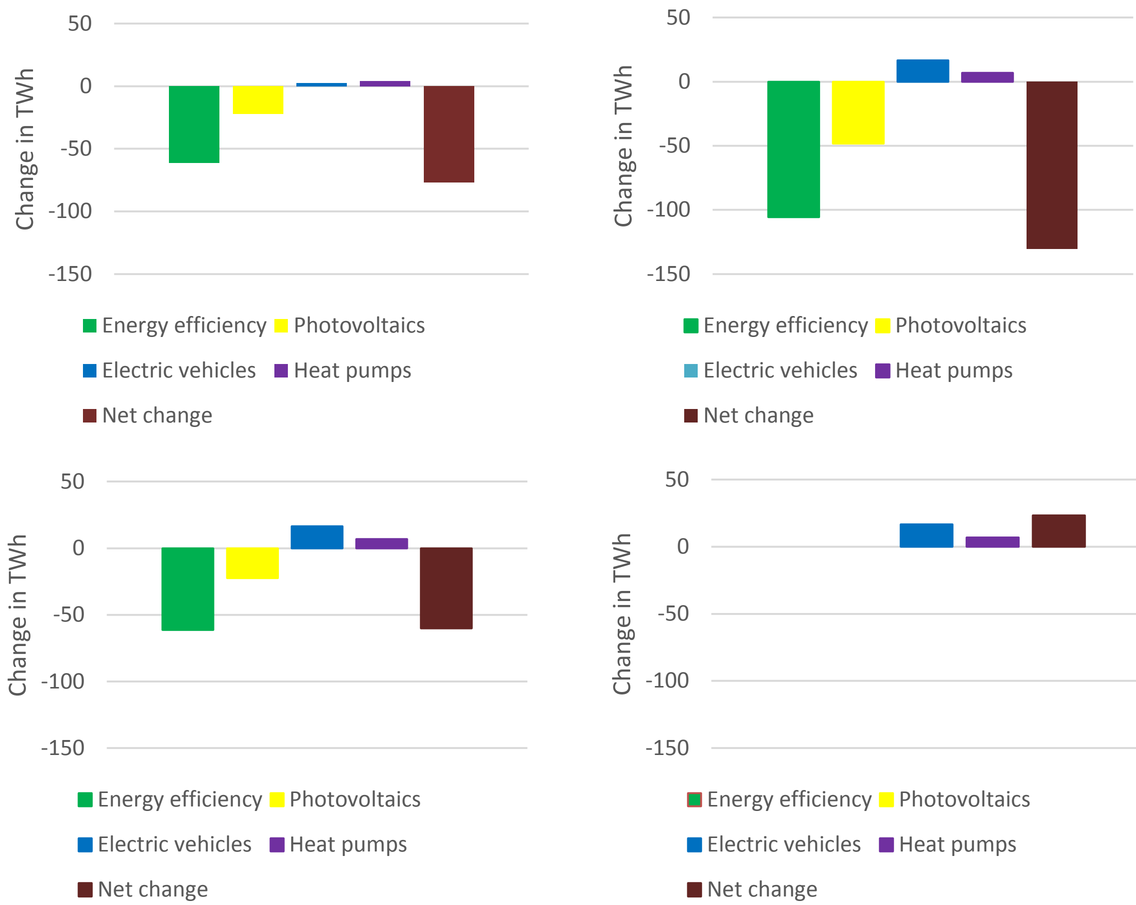


Figure C3. Comparison of 2030 sales in accelerated (upper left), aggressive (upper right), hybrid (lower left), and high energy demand (lower right) scenarios relative to business-as-usual scenario

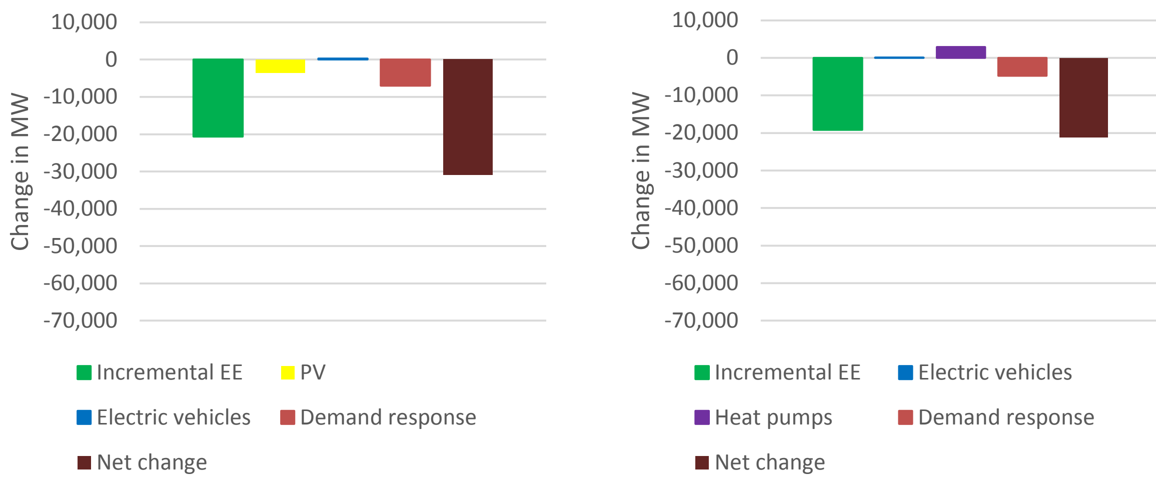


Figure C4. Comparison of 2030 summer (left) and winter (right) peak demand in accelerated scenario relative to business-as-usual scenario

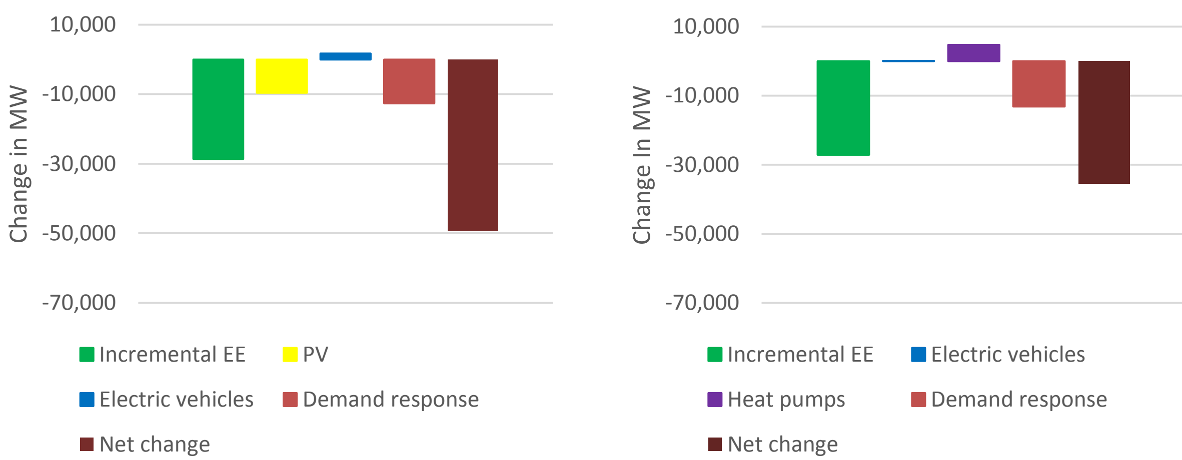


Figure C5. Comparison of 2030 summer (left) and winter (right) peak demand in aggressive scenario relative to business-as-usual scenario

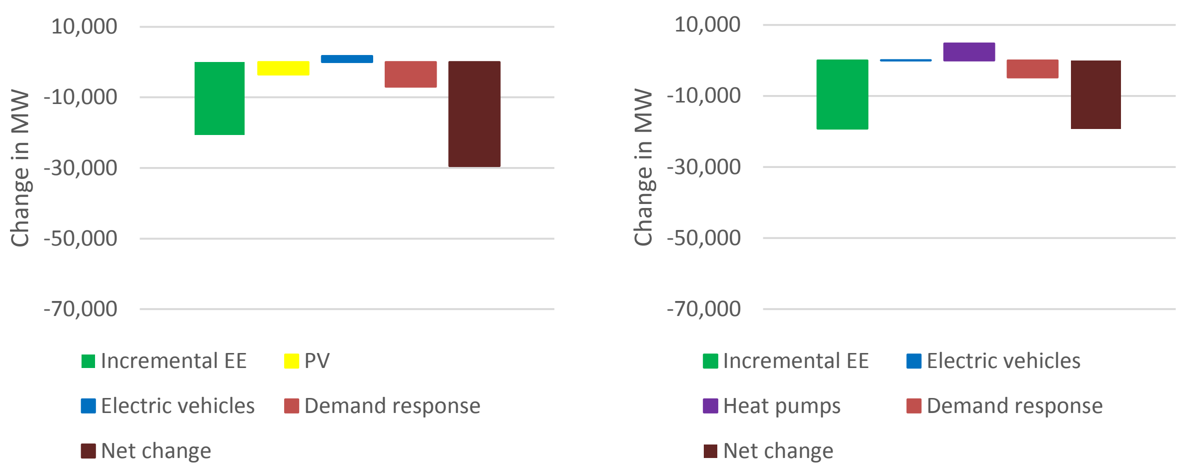


Figure C6. Comparison of 2030 summer (left) and winter (right) peak demand in hybrid scenario relative to business-as-usual scenario

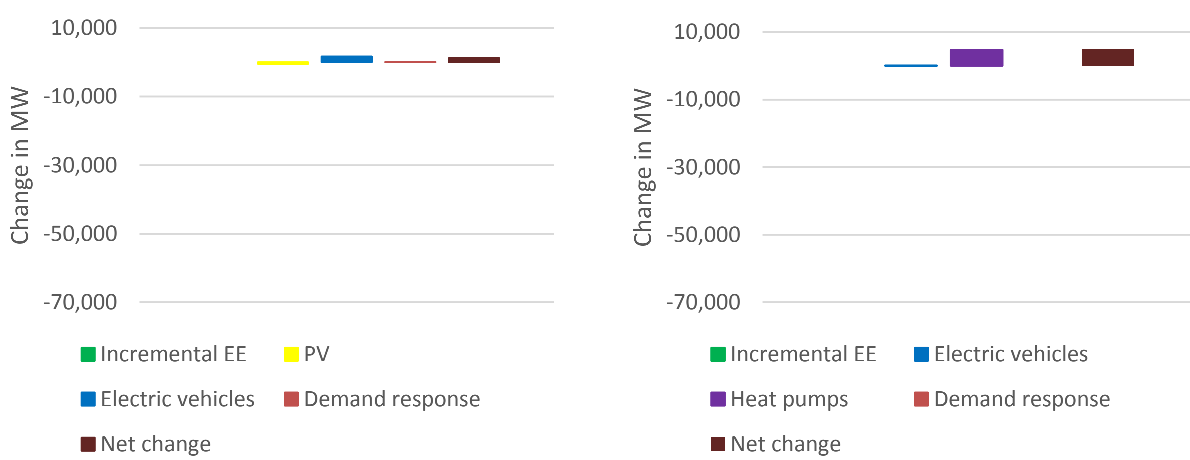


Figure C7. Comparison of 2030 summer (left) and winter (right) peak demand in high energy demand scenario relative to business-as-usual scenario