Synapse
Energy Economics, Inc.

Toward a Sustainable Future for the U.S. Power Sector:

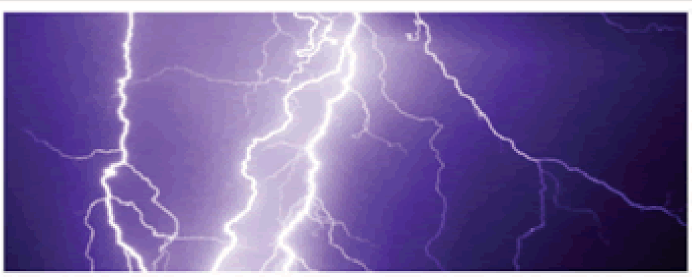
Beyond Business as Usual 2011

November 16, 2011

AUTHORS:

Geoff Keith, Bruce Biewald, Ezra Hausman, Kenji Takahashi, Tommy Vitolo, Tyler Comings and Patrick Knight

Prepared for the Civil Society Institute



485 Massachusetts Ave.
Suite 2
Cambridge, MA 02139

617.661.3248
www.synapse-energy.com

The **Civil Society Institute** (www.CivilSocietyInstitute.org) is a nonprofit and nonpartisan action oriented research center that serves as a catalyst for change by creating problem-solving interactions among people, and between communities, government and business that can help to improve society. CSI works to support local and state efforts to advance the modernization of the electric system and protect the health of citizens and their communities through advancing safe, sustainable, and affordable energy solutions.

Synapse Energy Economics, the consulting company that prepared this report, provides research, testimony and reports to regulatory commissions, consumer advocates, environmental organizations and state and federal agencies. The firm was founded in 1996 to specialize in consulting on energy, economic, and environmental issues. Synapse has a professional staff of twenty two.

Geoff Keith is a Senior Associate at Synapse. He holds an MA in environmental studies from Brown University and a BA from Tufts University. He began consulting on energy and environmental issues in 1996. Prior to Synapse, he worked at M.J. Bradley & Associates and the Rhode Island Division of Public Utilities and Carriers.

Bruce Biewald is President and Chief Executive Officer of Synapse. He has consulted on issues of energy economics and electric industry restructuring since 1980 and has testified in more than one hundred regulatory proceedings in twenty four states and two Canadian provinces. Prior to founding Synapse, Bruce worked at the Tellus Institute. He studied architecture and building technology at MIT.

Ezra Hausman, Vice President and Chief Operating Officer of Synapse, has consulted on energy and environmental issues since 1998. He holds a PhD in earth and planetary sciences, an SM in applied physics from Harvard University, an MS in civil engineering from Tufts University, and a BA from Wesleyan University. Prior to his work at Synapse, he worked with Tabors Caramanis & Associates.

Kenji Takahashi is an Associate at Synapse. He holds an MA in urban affairs and public policy, with a concentration in energy and environmental policy, from the University of Delaware and a BA in law, with a concentration in public administration, from Kansai University in Osaka, Japan.

Tyler Comings is an Associate at Synapse. He holds an MA in economics from Tufts University and a BA in mathematics and economics from Boston University. Prior to joining Synapse, he served as a senior associate at Ideas42, a think tank specializing in behavioral economics research.

Tommy Vitolo is an Associate at Synapse. He holds a PhD in systems engineering from Boston University, an MS in financial and industrial mathematics from Dublin City University, Ireland, and BS degrees in applied mathematics, computer science, and economics from North Carolina State University.

Patrick Knight, a Research Associate at Synapse, holds an MA in urban and environmental policy and planning from Tufts University and a BS in geophysics from Boston College.

Synapse wishes to thank the Civil Society Institute for funding this work, and all of our colleagues who have contributed ideas and feedback. Responsibility for errors and omissions rests entirely with Synapse and not with the Civil Society Institute.

TABLE OF CONTENTS

1. Introduction and Summary

In 2010 the Civil Society Institute released *Beyond Business as Usual, a* study evaluating a strategy for the U.S. electric industry that would provide large-scale public health and environmental benefits at a reasonable cost. The strategy, built around energy efficiency and renewable resources, would also provide substantial reductions in carbon emissions. Since then, the debate has continued over the best way forward for the electric industry. Advocates of a future based on coal with new environmental controls and carbon capture continue to make their case, as do advocates of nuclear power.

Away from this debate, new evidence has emerged that major changes in this industry are needed. Several mining tragedies globally have underscored the human toll of the coal supply chain. New EPA initiatives targeting air toxics, coal ash, and effluent releases highlight the environmental impacts of coal and the cost of addressing them with control technologies. The use of fracking in natural gas exploration is coming under scrutiny, with evidence of groundwater contamination and greenhouse gas emissions. Concerns are increasing about the vast amounts of water used at coal-fired and nuclear power plants, particularly in regions of the country facing water shortages. Events at the Fukushima nuclear plant have renewed doubts about the ability to operate large numbers of nuclear plants safely over the long term. Further, cost estimates for "next generation" nuclear units continue to climb, and lenders are unwilling to finance these plants without taxpayer guarantees.

The study compares a "business as usual" future to a scenario in which all coal-fired plants and a quarter of the nation's nuclear plants are retired by 2050. Reliance on energy efficiency and renewable resources is increased, while natural gas use is lower than under business as usual.

In addition to these troubling events, however, information has emerged over the past year suggesting that the cost of replacing coal with clean energy is falling. The current and projected price of coal has increased, and the price of photovoltaic (PV) systems has fallen sharply since 2009, a result of unprecedented growth in this sector globally. Further, the financial sector is increasingly placing risk premiums on technologies with carbon emissions, making renewable energy and efficiency more attractive in comparison. Given these trends, a revision of last year's study seemed especially timely.

For this revision, we have incorporated the price changes mentioned above, and we have revised several other assumptions based on feedback received on last year's study. We have lowered our assumed capacity factors for wind generators and increased the assumed cost of wind energy. We have increased the assumed cost of sustaining high levels of efficiency savings over the study period and revised our estimate of the cost savings that would accrue from retiring coal-fired plants rather than retrofitting them with new environmental controls.

Our methodology remains essentially the same as in the 2010 study. We use the U.S. Energy Information Administration's annual modeling work to establish a reference case, or "business as usual" (BAU) scenario. We compare this to a "Transition Scenario" in which the country moves toward a power system based on efficiency and renewable energy. In this scenario all coal-fired power plants are retired, along with nearly a quarter of the nation's nuclear fleet, by 2050.

Reliance on energy efficiency and renewable energy is significantly increased, while natural gas use is lower than under BAU. Importantly, the Transition Scenario does not rely on hoped-for breakthroughs; nearly all of demand is met throughout the study period with technologies that are commercial today.

We estimate the net costs and benefits of the Transition Scenario relative to BAU using a spreadsheet model that accounts for generating capacity, energy, fuel use, costs, emissions, and water use. We perform the analysis on a regional basis, with the country divided into ten regions. We are careful to ensure that there is sufficient generating capacity in both scenarios and that there is a reasonable mix of energy sources in each region from the perspective of power system operation. For most of our technology cost and performance assumptions we rely on the Annual Energy Outlook (AEO) 2011 data. For some resources, however, we believe that other sources provide a more accurate picture of current and expected costs, and we base our assumptions on those sources. Finally, we perform sensitivity analyses around a number of important input assumptions.

We perform the analysis on a regional basis with the country divided into ten regions. We are careful to ensure that there is sufficient capacity in each region and that regions have a reasonable mix of resources from the perspective of power system operation.

The Transition Scenario compares to BAU as follows.

- Total U.S. electricity use grows by 0.9% per year under BAU to 5,590 Terawatt-hours (TWh) in 2050. In the Transition Scenario, more aggressive energy efficiency programs across the country reduce electricity use by about 0.1% per year to 3,760 TWh in 2050.
- Under BAU, coal-fired generation grows from just over 1,860 TWh in 2010 to 2,340 TWh in 2050 – a 26% increase. In the Transition Scenario, coal-fired generation is eliminated by 2050.
- Natural gas-fired generation grows from 1,010 to 1,840 TWh under BAU, while it rises to only 1,230 TWh in the Transition Scenario.
- Nuclear generation rises from 800 to 870 TWh under BAU, due to uprates at existing plants across the country and the addition of new units totaling 6,200 MW in the Southeast. Nuclear generation falls to 618 TWh in the Transition Scenario, a reduction of 23%.
- Wind energy grows from 92 to 189 TWh under BAU, while it grows to 611 TWh in the Transition Scenario. This includes over 60 TWh from offshore wind farms.
- PV generation grows from 4 to 24 TWh under BAU, and it grows to 842 TWh in the Transition Scenario.

The results of this analysis are encouraging. We find that a transition to efficiency and renewable energy in the power sector is likely to be less expensive than BAU. Table 1 shows the net costs of the Transition Scenario relative to BAU at four points in time. These are annual costs, not cumulative. The net present value of the 40-year stream of savings and costs is a savings of $83 billion, discounted at 4.8%.

The net annual cost impacts range from savings of $18 billion in 2050 to costs of $9 billion in 2040. To put this in perspective, $18 billion is about 5% of total electric industry revenues in 2010, assuming 3,730 TWh sold at an average price of ¢10 per kWh. As seen in Table 1, when spread over all kWhs sold in the relevant year, the annual savings in 2020 are ¢0.4 per kWh consumed, and the costs in 2040 are ¢0.3 per kWh.

Table 1. The Net Annual Costs of the Transition Scenario (billion 2010$)

	2020	2030	2040	2050
Net Cost of Generation	($23)	($50)	($49)	($58)
Energy Efficiency	$19	$53	$58	$31
Demand Response	$0.1	$0.7	$2.2	$4.0
Incremental Transmission	$0.0	$0.0	$0.2	$1.1
New Energy Storage Costs	$0.0	$0.0	$0.8	$3.6
Avoided Environmental Controls	($11)	($12)	($3.2)	$0
Total	($16)	($8.2)	$9.0	($18)
Total (¢/kWh of electricity use)	(¢0.4)	(¢0.2)	¢0.3	(¢0.4)

We present several sensitivity analyses to gauge the range of uncertainty around these net savings. The variables with the largest impacts on the results are the cost of energy saved through efficiency measures, the cost of coal, and the cost of new PV capacity. However, in all of the sensitivity analyses, the Transition Scenario provides savings on an NPV basis relative to BAU.

The idea that we could capture the kind of benefits this scenario provides while also saving money is a significant change in our thinking about this industry. It reflects a fundamental shift in the cost of renewable energy relative to fossil-fueled and nuclear energy. These findings are particularly striking, given that the BAU scenario includes no carbon costs or carbon reductions. If the cost of carbon reductions were included under BAU, the savings provided by the Transition Scenario would grow dramatically. We also have not included externalized costs of pollution in our cost analysis, although we have estimated some of the health benefits of the Transition Scenario.

The results of this study are encouraging. We find that a transition to efficiency and renewable energy is likely to be less expensive than business as usual. This is particularly striking given that our business as usual scenario includes neither carbon costs nor carbon reductions.

The benefits of the Transition Scenario include the following:

- By 2020, power sector CO_2 emissions fall 25% below 2010 levels. By 2050 they are 81% below 2010 levels. Under BAU, CO_2 emissions grow by 28% through 2050.
- Other environmental and health impacts of coal-fired electricity are dramatically reduced and, by 2050, eliminated altogether. This includes the air and water impacts of generation, coal ash and other solid waste, and the impacts of mining and coal transportation.
- Cooling water withdrawals at power plants fall from 55 to 0.6 trillion gallons per year in the Transition Scenario. In 2050 they are more than 90% below BAU levels. Water consumption at power plants (via evaporation) falls from 1.5 to 0.6 trillion gallons per year, 76% below BAU levels.

- Over $450 billion in health effects related to air pollution would be avoided over the study period, based on damage factors developed by the National Research Council. (We do not include these costs in calculating the net cost of electricity production for the Transition Scenario.) This translates into roughly 55 thousand fewer premature deaths in the Transition Scenario than under BAU.
- The construction and operation of the new power plants in the first decade of the Transition Scenario creates roughly 3.1 million new job-years – the equivalent of 310,000 people employed for the entire decade.
- Over $100 billion would be saved by retiring coal-fired plants rather than retrofitting them with new environmental controls.
- The annual production of high-level radioactive waste would be reduced by nearly a quarter, and the risks associated with nuclear power generation and the nuclear fuel cycle would be reduced as well.
- Natural gas use would be lower than BAU in all years of the study period. In 2050, gas use would be below BAU by 3.7 quadrillion Btu per year, or 28%.

The study does not lay out an optimized or detailed roadmap for this industry. Rather, it explores a fundamental change in direction. The intent is to challenge assumptions and inform our energy policy debate.

It is important to note that this scenario seeks to address a wide range of problems, and we have had to make tradeoffs among competing benefits. The study does not intend to lay out an optimized or detailed roadmap for the industry. Rather, it explores a fundamental change in direction. The intent is to challenge assumptions and inform the debate about U.S. energy policy. CSI expects to continue adjusting this Transition Scenario as more information becomes available, and we hope that other groups will explore variations on it as well. In terms of further research, the study points to the following areas of uncertainty.

1. What is the most reliable and cost effective way for system operators to integrate high levels of variable generation into regional power systems? How much variable generation can a balancing area accommodate *when the other resources are predominantly flexible ones rather than inflexible, baseload plants*?
2. How will developments in the transportation sector affect the electric industry? Will transportation move to electricity on a large scale or to other fuels? If that sector does move toward electricity, how much power will it require and what kind of energy storage resource will electric vehicles offer?
3. What are the risks and carbon emissions associated with drilling in shale formations? What technologies and practices do we need to develop to minimize the use of natural gas as we phase out coal-fired generation?

Work in these areas is already underway at research labs, utilities, and government agencies globally. We hope that this study adds momentum to this and other work focused on the transition to a sustainable electric industry.

Finally, the fact that CO_2 emissions increase in our BAU scenario is important. While BAU is a useful baseline against which to compare alternative scenarios, it is not a tenable future. We must achieve significant carbon reductions over the next several decades. Therefore, the net costs and benefits of the Transition Scenario should be compared to those of other proposals that provide meaningful carbon reductions. To date we have not seen cost benefit analyses of futures built around new nuclear power or coal with carbon sequestration.

2. Methodology

The methodology of the study is laid out below, and specific input assumptions are presented in Appendix A.

A. AEO 2011 and Business as Usual

We begin with data from the 2011 Annual Energy Outlook (AEO), released by the Energy Information Administration (EIA) in April 2011. Each year EIA uses the National Energy Modeling System (NEMS) to model a "Reference Case" energy scenario. EIA then analyzes various policy proposals by modeling the policy under consideration and comparing the results to the Reference Case. The AEO 2011 simulates U.S. energy production and use through 2035. The nation's power sector is divided into the 22 NERC subregions for analysis.

We make several adjustments to the AEO 2011 Reference Case in creating our BAU scenario. First, to reduce the data requirements of the study, we aggregate the 22 regions used in the AEO into ten regions, as shown in Figure 1. Alaska and Hawaii are not included in this analysis.

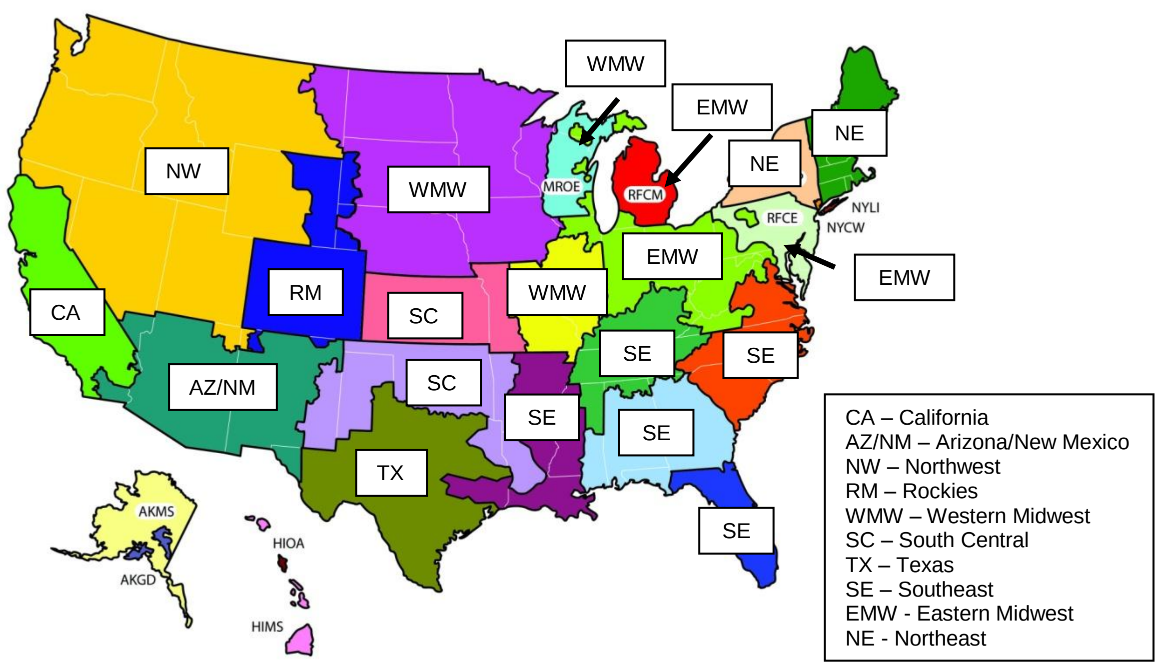


Figure 1. Aggregating the AEO Regions

Second, because the AEO extends only through 2035, we extrapolate the AEO data to 2050. This includes data on electricity demand, generation, capacity retirements and additions, and fuel use. We extrapolate demand and generation in each region based on the regional trends in the AEO data during the period 2025 through 2035 (the last ten years for which the AEO provides data). Thus, the resources that NEMS selected to meet load growth during this period continue to meet load growth through 2050. We report annual results for the years 2010, 2020, 2030, 2040, and 2050.

In extrapolating the AEO data to 2050, we add or retire capacity necessary to maintain reasonable reserve margins. Most regions of the nation currently have excess generating capacity, and the AEO 2011 projects that this excess will shrink between now and 2030. (See Table 2 on page 18) As we extrapolate the AEO data, we continue this trend: under in the BAU, reserve margins in most regions fall to 15% by 2040, and we maintain reserve margins of at least 15% through 2050.[1] In the Transition Scenario, reserve margins tend to fall to 15% faster than under BAU, but then they rise again in some regions in order to maintain enough flexible capacity to accommodate high levels of variable generation.

B. Developing the Transition Scenario

To develop the Transition Scenario, we first develop new forecasts of electricity consumption and peak load growth in each region. We do this by adjusting BAU demand to simulate the effects of more aggressive energy efficiency and demand response (DR) programs nationwide.[2] The energy use forecast in the AEO includes the effects of efficiency codes and standards in the near term; however it does not include the effects of future adjustments to codes and standards or the much larger impact of utility or third-party efficiency programs. Therefore, we adjust the AEO demand forecast based on data from efficiency programs currently being implemented across the nation and on a number of studies of energy efficiency potential. Specifically, we assume that by 2020 all regions are achieving savings equivalent to 2% of the previous year’s sales, consistent with the results of the most aggressive efficiency programs in recent years. (Several states and utilities are currently targeting savings in excess of 2%.) This level of savings is sustained throughout the study period. Each region begins the ramp up to 2% from its current average level of savings. We assume that the average cost of efficiency rises from ¢4.7 per kWh saved in the 2011-20 period to ¢7.0 per kWh in the 2040-50 period, as it becomes more expensive to maintain this level of savings over time.

To simulate a strong national commitment to energy efficiency, we assume that, by 2020, all states are achieving savings equivalent to 2% of sales, consistent with the results of the most aggressive programs in recent years.

To develop peak load forecasts for the Transition Scenario, we adjust the AEO regional peak loads to account for the effects of energy efficiency and DR programs. The effect of efficiency programs are simulated by reducing peak loads by 0.15 kW for each MWh saved. This factor is an average based on analysis of state and utility efficiency program reviews.

We simulate the growth of DR programs by reducing peak loads in each region by an increasing amount over time and attributing costs to this reduced load. We estimate the relative potential of DR in different regions based on a study performed for the Federal Energy Regulatory Commission (FERC) in 2009 (Brattle Group et al., 2009). This study includes several DR potential

[1] The Rocky Mountain region is an exception to this rule, as NEMS allows the reserve margin to fall to 10% in 2030.
[2] Demand response programs pay customers to reduce electricity demand during peak periods.

estimates for each region, based on the type of loads and generation in each region. While the study includes some very aggressive estimates of regional DR potentials, we add DR resources over time in a fairly conservative way. (See Table 3 on page 18.) We expand DR capabilities most aggressively in regions where capacity is needed most, and we expand capabilities less where capacity is not needed. The cost of DR rises in each region as higher penetration levels are achieved (see Appendix A, Section E).

In the Transition Scenario, generation from retired coal and nuclear plants is replaced with generation from the remaining power plants, new renewable resources and new gas-fired plants. The trajectory of plant retirements and additions was developed in an iterative way. Plant retirement and renewable energy development scenarios were sketched out for each region based on: the region's mix of existing power plants; electricity demand growth; historical energy transfers into and out of the region; the renewable resources available in the region; and renewable technology cost data. Coal-fired capacity was retired as rapidly as possible, while maintaining adequate reserve margins and avoiding unrealistic development scenarios for any new resource.

After a rough nationwide scenario was sketched out, we explored ways to reduce the cost of the scenario or increase the benefits by adjusting plant retirements and additions in the various regions. This process required us to make tradeoffs. For example, retiring coal-fired units faster would reduce the net savings of the Transition Scenario, but it would increase the near-term environmental and health benefits as well as CO_2 reductions.

C. Calculating Costs

Our technology cost and performance assumptions are based on a review of a number of sources, including work done by government agencies, engineering firms, utilities, financial researchers and non-governmental organizations. Wherever possible, we have compared these estimates to data from actual recent projects. As a default, we use the assumptions used in the AEO 2011. An advantage of using these data is that EIA has focused on consistency in the assumptions common to all technologies. However, for several technologies we find that data from other sources point to assumptions significantly different from those used in the AEO, and for these resources we have not used the AEO assumptions. A discussion of our cost and performance assumptions and the sources on which they are based appears in Appendix A.

To cost out the two scenarios, we first use the input assumptions presented in Appendix A to calculate the levelized cost of energy from each plant type in the BAU and Transition Scenarios. We do not include in this cost analysis the effects of direct subsidies, such as grants and tax incentives. For existing coal plants, gas-fired combined cycle plants, and combustion turbines, we calculate region-specific levelized costs based on the average capacity factor of the plants in each region and decade. For most new plants, we calculate costs with a single, nationwide capacity factor for each plant type. For new solar and wind facilities we use region-specific capacity factors. We then apply these levelized costs to the total generation from each resource type to determine total costs under BAU and in the Transition Scenario. To estimate the net cost or savings from pursuing the Transition Scenario, we subtract the total cost of generation under BAU from that of the Transition Scenario.

In addition to the cost of generation, we also calculate the cost of energy efficiency and DR, new energy storage capacity, and new inter-regional transmission capacity. We also estimate the savings the Transition Scenario would provide in avoided emission control costs.

D. Air Emissions and Water Use

The AEO reports power sector emissions of CO_2, sulfur dioxide (SO_2), oxides of nitrogen (NO_X), and mercury in each region through the analysis period. In addition, Synapse maintains a database of over 1,000 U.S. coal-fired generating units. This database includes information reported by unit owners to EIA and the Environmental Protection Agency (EPA) regarding unit type, fuels, efficiency, air emissions and emission controls, cooling system, and operating costs. We use this database and the emissions reported in the AEO to estimate emissions and water use under BAU and in the Transition Scenario. An important step in this process is the development of assumptions about the new environmental controls that existing units will be required to install over the next 10 to 20 years.

Environmental control retrofits and unit retirements are simulated using a database of over 1,000 U.S. coal-fired generating units. Units with the lowest estimated retrofit costs per MW are retrofitted first. In the Transition Scenario, units with the highest forward-going costs, including retrofit costs, are retired first.

The EPA's current work includes five major programs that are likely to affect emissions and water use at coal-fired power plants over the next several decades. Some of these programs include regulations that are currently in force, while other regulations are in various stages of development. These five programs are as follows.

- The promulgated Clean Air Visibility Rule requires a large cohort of power plants that affect visibility in national parks and other federal natural areas to reduce SO_2, NO_X and particulate emissions. This rule is currently in force, and is currently impacting plants across the Western U.S.
- The promulgated Cross State Air Pollution Rule (formerly the proposed Clean Air Transport Rule) will cap NO_X and SO_2 emissions in 2012 and 2014 across the eastern half of the U.S., excluding New England.
- The proposed Air Toxics rule will limit mercury, acid gases, and other toxic pollution from coal- and oil-fired power plants in 2015. Given the status of this proposal, we assume that the rule will be in force under BAU.
- EPA is scheduled in 2011 and 2012 to revise the current air quality standards for ozone, SO_2, NO_2, and fine particulate matter. The Agency's drafts of these standards indicate that they will be substantially lower than the current standards, and will thus require controls in counties and regions that will be out of compliance.
- The proposed Water Intake Structures rule under the Clean Water Act section 316(b) may require steam plants that use once-through cooling to reduce water withdrawals, thus effectively requiring the conversion of most plants to a recirculating cooling tower. While the details of the final rule are not yet certain, there is mounting pressure for reducing both withdrawals and thermal discharge, and it seems likely that numerous retrofits will be required.

There is considerable uncertainty in predicting the results of these regulatory proceedings in terms of the pace and scope of retrofits at coal-fired plants. Faced with lawsuits and industry pressure, delays relative to EPA's current timeframe are certainly possible. However, over the next several decades, it seems likely that EPA's commitment to large-scale public health initiatives, along with court mandates the agency faces, will result in substantial emission reductions from coal-fired plants. Therefore, for the purposes of this study we assume that under BAU these reductions will be realized, but that they will be realized over a longer timeframe than EPA is currently planning. Specifically, we assume that:

- Half of the coal-fired units over 100 MW in size and without flue-gas desulfurization (FGD) systems install these systems by 2020. The other half installs them by 2030. On average, controlled plants achieve an SO_2 emission rate of 0.2 lb per mmBtu.
- Half of the coal-fired units over 100 MW without selective catalytic reduction (SCR) systems install these systems by 2020. The other half installs them by 2030. On average, controlled plants achieve a NO_X emission rate of 0.15 lb per mmBtu.
- Half of the coal-fired units over 100 MW without mercury controls and fabric filters to capture particulate matter install these systems by 2020. The other half installs them by 2030. On average, mercury is reduced by 90% at controlled plants.
- Implementation of EPA's proposed rule on water intake structures will eventually require all large power plants in the country to have closed-loop cooling systems. We assume that half of the coal-fired plants over 100 MW with once-through cooling systems install closed-loop systems by 2020, and that the other half installs them by 2030.
- Units under 100 MW in size and gas-fired CCCTs and CTs are unaffected by these rules.

To estimate air emissions under BAU, we apply these control assumptions to the emissions from coal-fired plants. We assume that the units with the lowest per-MW retrofit costs are retrofitted first (between 2011 and 2020). These are generally the larger units. Controls on smaller units are not required until after 2020. In the Transition Scenario we apply the same retrofit assumptions along with the coal retirement strategy. Units that are retired in the same decade that they would have been retrofitted are not required to install the controls.

Total power sector emissions based on these assumptions are shown in Section 4.A. In Section 4.B we report estimated health benefits of the emission reductions achieved in the Transition Scenario relative to BAU. And in our cost analysis we include the savings realized in avoided emission control investments in the Transition Scenario.

E. Transmission and System Operation

We address the cost of new transmission and system operation constraints in the following ways. First, we consider transmission within power control areas. The NEMS model (the basis of the BAU scenario) does not recognize transmission constraints within regions or simulate power flows within regions. To approximate the cost of transmission system upgrades within regions, NEMS applies regional cost factors to peak loads. In the Transition Scenario, loads do not grow, so transmission investment would not be needed simply to move more energy, as under BAU. However, investment within control areas would be needed to maintain and expand the transmission system to accommodate more variable generation and allow new renewable energy to reach all parts of a regional grid. We make the simplifying assumption that this would cost roughly the same as the transmission investment estimated based on load growth in AEO 2011.

Turning to inter-regional transmission, the NEMS model includes transfer limits between regions, and it simulates economic power transfers within those limits. It does not simulate the addition of new transmission capacity between regions. Therefore, under BAU there is little growth in energy transfers between regions. In the Transition Scenario, however, there are increased transfers between several regions. We estimate the cost of the new transmission capacity needed to accommodate these transfers by translating energy transfers into MW of capacity needed and assuming that new capacity (high voltage DC lines) costs $1 million per MW on average. (See Section 3.D.)

Most studies of aggressive renewable energy development envision load growth and continued operation of coal and nuclear capacity on a large scale. In the Transition Scenario, demand falls slightly, and retired coal and nuclear plants would free up large amounts of existing transmission capacity.

Regarding transmission, it is important to remember that most studies of aggressive renewable energy development envision load growth and continued operation of coal and nuclear capacity on a large scale. In the Transition Scenario demand *falls* slightly over the study period, and retired coal and nuclear plants would free up large amounts of existing transmission capacity each decade. Therefore, much less new transmission would be needed than in a scenario in which renewables met growing loads on top of existing generation.

At the distribution level, the same dynamic would occur: less energy would be delivered, and most of the energy from new, distribution-connected PV systems would be replacing coal and nuclear energy in those distribution systems. Of course distribution systems would have to be upgraded to accommodate more complex energy flows, but much of this work is already being funded, so it would not be incremental spending in the Transition Scenario.[3] Therefore, we add a $2 per MWh charge to all PV energy to contribute to the distribution system work needed to accommodate the higher levels of distributed generation. By 2050 this amounts to roughly $1.7 billion annually.

We have also focused on developing flexible and robust regional power systems that can accommodate minimum and maximum load conditions and the load swings between them. On this point, note that the retirement of large amounts of inflexible capacity – coal and nuclear units – will in itself create regional power systems that can accommodate more variable generation. In addition, we have incorporated four other strategies to increase the flexibility of regional power systems.

- First, we ensure that regions with high levels of wind and PV generation also have large amounts of flexible generating capacity (primarily CCCTs and CTs) to accommodate rapid changes in wind and solar generation.

[3] Over the past several years, utilities have been authorized to collect and spend billions on distribution upgrades and other "smart grid" work.

- Second, in regions with high levels of wind generation we augment this flexible generation with energy storage capacity.
- Third, the growing DR capacity and costs that we incorporate into the Transition Scenario also increase system flexibility. Demand response programs with "dispatchable" components such as direct load control help to provide intra-day and intra-hour ramping capability to support greater levels of variable generation output. The introduction of dynamic pricing and potentially greater customer response to system ramping requirements also increases the flexibility of the system to respond to variable generation.
- And finally, we expect that current trends toward larger energy balancing areas and increased coordination across balancing areas will continue. (Larger balancing areas support the reduction of aggregate wind variability by capturing the spatial diversity of the wind resource base.) For example, the Midwest ISO region consolidated its numerous balancing areas into a single balancing area in 2009, and this has allowed for integration of wind resources without significantly increasing operating reserve requirements. The Southwest Power Pool is planning to consolidate its member utilities into a single balancing region in this decade. The Pennsylvania/New Jersey/Maryland ISO (PJM) operates as a single balancing area, as do the northeastern ISOs (NY and NE), the California ISO and ERCOT (Texas). The Western Electricity Coordinating Council is also working toward a broader "energy imbalances market" to increase coordination across much of the Western Interconnect.

F. Savings from Avoided Environmental Retrofits

We assume that multiple new EPA rules result in widespread pollution control and cooling system retrofits at existing coal-fired units. Specifically, we assume that by 2030 all units over 100 MW in size have flue gas desulfurization (FGD) systems, selective catalytic reduction (SCR) systems, fabric filters, activated carbon injection systems, and closed-loop cooling systems. We assume that this retrofit strategy is implemented in both BAU and the Transition Scenario. However, in the Transition Scenario any unit that is retired in the same decade that it would have been required to install new controls does not install the controls. Therefore, a number of retrofits are avoided in the Transition Scenario.

Many of the units retired in the first two decades of the Transition Scenario would have been required to install new environmental controls. We estimate the savings from avoided control retrofits at over $100 billion.

To target units for retrofits, we assume that the units with the lowest retrofit costs (generally the largest units) are required to install controls between 2011 and 2020 and that smaller units are controlled between 2020 and 2030. In general we target units for retirement based on each unit's forward-going costs, including any emission control costs the unit faces. However, regional energy and capacity needs override this rule in some cases. For retrofit costs, we use the cost curves developed for EPA's modeling with the Integrated Planning model. These curves, developed for EPA by Sargent & Lundy, reflect the fact that costs per MW are considerably higher at smaller units than at larger units.

This analysis yields a total avoided investment of $70 billion during the period 2011 through 2020, and $41 billion during the period 2021 through 2030. We amortize these costs over a 15-year period, consistent with cost recovery requests in a number of recent cases before utility boards. Avoided annual carrying costs are $11 billion in 2020, $12 billion in 2030 and $3.2 billion in 2040. These costs are shown in Table 5.

G. Avoided Health Impacts from Coal-Fired Generation

To estimate the health benefits of the Transition Scenario, we calculate damages and premature mortality based on the emissions and location of each coal-fired unit. We first estimate the air emissions (SO_2, NO_X, PM_{10} and $PM_{2.5}$) at each coal-fired unit. Under BAU, emissions fall at many units due to control retrofits. In the Transition Scenario emissions fall due to control retrofits at some units and retirement of other units.

We then calculate damages from each unit using a unit-specific value for damages per ton of pollution from the National Research Council's report *The Hidden Costs of Coal* (NRC, 2010). Where the NRC does not provide a value for a specific generating unit, a regional average is used in its place. These damages are converted to statistical lives using the value of a statistical life used in the NRC study ($8.2 million per life, adjusted from $2000 to $2010) and summed across all units in the nation. The difference in premature mortality between the two scenarios is the net benefit of the Transition Scenario.

H. Jobs Associated with New Plants and Energy Efficiency

Finally, we estimate the new jobs associated with the energy efficiency and new power plants in the Transition Scenario. First, we estimate the direct jobs (associated with building and operating new power plants) using technology-specific data from the National Renewable Energy Laboratory's (NREL) Jobs and Economic Development Impacts models. Second, we estimate "indirect" and "induced" jobs using the IMPLAN (IMpact analysis for PLANning) model. IMPLAN is an input-output model that relies on data sets describing the purchases of consumers and industries as well as flows of goods and services between regions. Using these relationships, and calibrating them for each region, IMPLAN is able to estimate the spin-off effects of new industry-specific activity by estimating the activity of suppliers required for that activity (indirect impacts) and the re-spending of workers' wages in the economy (induced impacts).

It is important to note that there would be other economic impacts as well: jobs created by lower cost electricity; jobs created in dismantling coal and nuclear plants and remediating the sites; and jobs lost in operating coal and nuclear plants, mining coal, and other associated activities. However, assessing all of these dynamics was beyond the scope of this work.

3. Business as Usual and the Transition Scenario

A. Electricity Demand

Electricity demand grows under BAU at about 0.9% per year. This is based on the AEO 2011 Reference Case, which includes the effects of current efficiency codes and standards, but not utility and third-party efficiency programs or any future changes to codes and standards. In the Transition Scenario, demand falls by an average of roughly 0.1% per year, as we simulate the impact of more aggressive utility and third-party efficiency programs. Figure 2 shows total U.S. electricity generation in both scenarios.

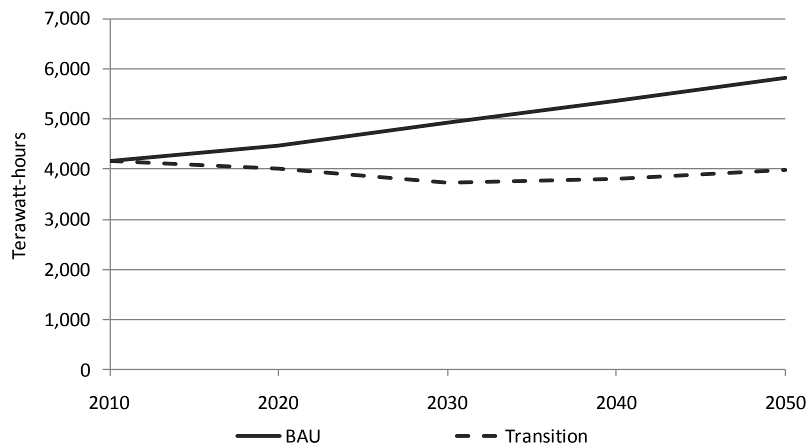


Figure 2. Total Electricity Generation in the Two Scenarios

B. The Generating Fuel Mix

Figure 3 below shows the generating fuel mixes in the two scenarios. The key differences between the two scenarios are as follows.

- Total electricity generation under BAU grows to 5,930 TWh in 2050. In the Transition Scenario generation falls slightly, to 3,960 TWh in 2050.
- Under BAU, coal-fired generation grows from 1,860 to 2,340 TWh – a 26% increase. In the Transition Scenario, coal-fired generation is eliminated by 2050.
- Natural gas-fired generation grows from 1,010 to 1,840 TWh under BAU, while it rises to only 1,230 TWh in the Transition Scenario.
- Nuclear generation rises from 800 to 870 TWh under BAU, due to uprates at existing plants across the country and the addition of new units totaling 6,200 MW in the Southeast. Nuclear generation falls to 618 TWh in the Transition Scenario, a reduction of 23%.

- Wind energy grows from 92 to 189 TWh under BAU, while it grows to 611 TWh in the Transition Scenario. This includes over 60 TWh from offshore wind farms in the Great Lakes and off the East Coast.
- PV generation grows from 4 to 24 TWh under BAU, and it grows to 842 TWh in the Transition Scenario. The majority of this is distributed PV generation.
- Large-scale biomass generation under BAU grows from 11 to 33 TWh, with all of the increase due to co-firing at coal-fired plants. In the Transition Scenario, large-scale biomass generation grows from 11 to 24 TWh, with the growth coming at new plants burning biomass only.
- In both scenarios there is substantial growth in "end-use" biomass generation, as discussed below.

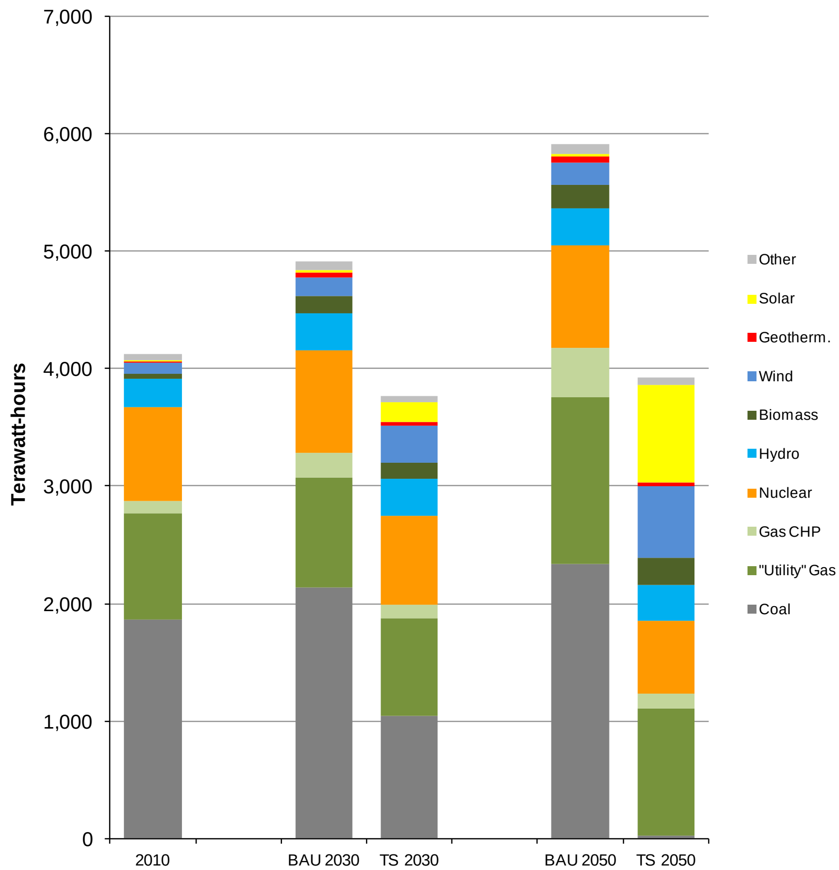


Figure 3. The Generating Fuel Mix in the Two Scenarios

While it is not evident in Figure 3, there is a shift to distributed generation in both scenarios. Under BAU, the largest increase in distributed generation is at gas-fired CHP plants; however there is a significant increase in cogeneration using biofuels as well (see below). In the Transition Scenario gas-fired CHP grows less than under BAU, but distributed PV generation grows far more. Overall, distributed generation grows faster in the Transition Scenario.

The two scenarios are the same in the growth of cogeneration using biofuels. In the AEO, strong demand for biofuels is driven by the Renewable Fuel Standard (RFS) established in the Energy Independence and Security Act of 2007. As the refining infrastructure to meet the RFS is developed, the AEO envisions increasing use of the refinery byproducts for cogeneration. By 2035, roughly 75 TWh per year are generated using these residual biofuels. We include this generation in both BAU and the Transition Scenario. Aside from this cogeneration with biofuels, there is little growth in biomass power generation in either BAU or the Transition Scenario. Under BAU, utility-scale biomass generation grows to 33 TWh in 2050, while in the Transition Scenario it grows to only 24 TWh.

The environmental impacts of biomass generation are an important consideration, and more work is needed to understand the implications of the RFS.

C. Generating Capacity

Figure 4 below shows generating capacity in both scenarios. Notable aspects of the scenarios are as follows.

- In the Transition Scenario all coal-fired plants are retired as well as all oil- and gas-fired steam plants and oil-fired combustion turbines.
- Nuclear capacity is reduced by 22,600 MW, or 23%.
- Under BAU, gas-fired combined cycle capacity grows from 198 GW in 2010 to 262 GW in 2050. In the Transition Scenario it grows to only 219 GW.
- Gas-fired CT capacity under BAU grows from 139 to 230 GW, while it grows to 200 GW in the Transition Scenario.
- Under BAU, onshore wind capacity grows from 38 to 64 GW, and offshore capacity grows from 0 to 0.2 GW. In the Transition Scenario, onshore wind grows to 162 GW, and offshore capacity grows to 16 GW (4 GW in the Great Lakes and 12 GW off the East Coast).
- PV capacity grows from 2 to 14 GW under BAU, while it grows to 384 GW in the Transition Scenario.
- Direct-fired biomass capacity grows in the Transition Scenario from 2 to 4 GW. End-use biomass capacity grows in both cases from 5 to 24 GW.

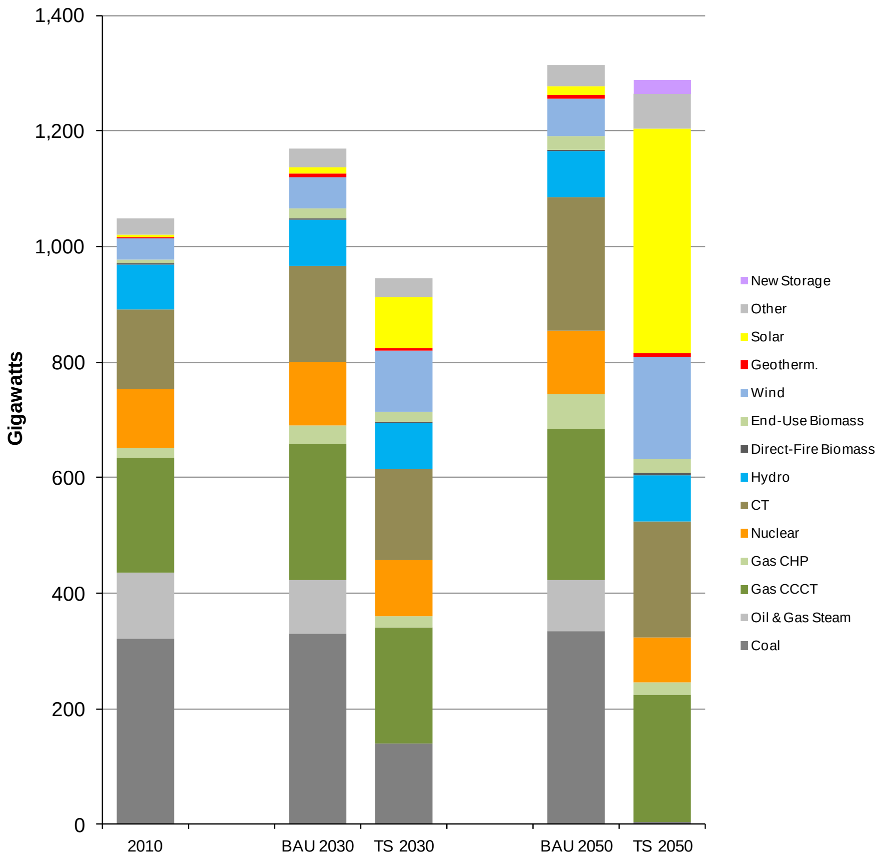


Figure 4. Generating Capacity in the Two Scenarios

To ensure that we are maintaining sufficient capacity in each region, we perform a rough reserve margin check in each decade of the study period. We estimate reserve margins by first derating wind and PV capacity and then dividing installed capacity in excess of peak load by peak load. Wind capacity is derated to 15% of its nameplate capacity, and PV is derated based on regional data compiled in Perez, et al., 2006. Table 2 below shows the results for both scenarios. As seen in the 2010 data, all regions currently have excess generating capacity relative to historical reserve margins – typically in the range of 12% to 18%. The amount of excess capacity shrinks between 2010 and 2030, based on the AEO 2011. As we extrapolate the BAU beyond 2030, we continue this trend of falling reserve margins, with margins in most regions reaching 15% by 2040. We then add or retire capacity to maintain reserve margins of at least 15%, except in the Rocky Mountains. In this region we follow the AEO and maintain a 10% margin there.

In the Transition Scenario, reserve margins fall faster than under BAU, due to aggressive retirement of coal-fired capacity. In several regions, reserve margins rise again in the last decade, as additional gas-fired and storage capacity is added to support high levels of wind and solar generation.

Table 2. Reserve Margins in the Two Scenarios

	Case	2010	2020	2030	2040	2050
AZNM	BAU	50%	29%	17%	15%	15%
	Transition	50%	25%	16%	15%	15%
RMPA	BAU	37%	17%	10%	10%	10%
	Transition	37%	15%	10%	10%	10%
NWPP	BAU	92%	69%	51%	39%	33%
	Transition	92%	80%	59%	49%	42%
CAMX	BAU	31%	25%	27%	15%	15%
	Transition	31%	33%	16%	15%	18%
NE	BAU	43%	26%	21%	15%	15%
	Transition	43%	31%	15%	15%	15%
SE	BAU	34%	32%	29%	18%	15%
	Transition	34%	21%	15%	15%	15%
EMW	BAU	36%	34%	30%	21%	15%
	Transition	36%	19%	15%	15%	15%
WMW	BAU	38%	31%	27%	19%	15%
	Transition	38%	22%	15%	16%	26%
SC	BAU	27%	18%	19%	15%	15%
	Transition	27%	15%	15%	17%	21%
ERCT	BAU	34%	25%	24%	15%	15%
	Transition	34%	15%	15%	17%	15%

We simulate the growth of DR programs by reducing peak loads in each region by an increasing amount over time and attributing costs to this reduced load to represent the payments made to customers enrolled in the programs. We estimate the relative potential of DR in different regions based on a study done for FERC in 2009 (Brattle Group et al., 2009). Table 4 shows three scenarios developed in this study, with increasing levels of DR achieved by 2019. The scenarios are called the “Expanded BAU” case (EBAU), the “Achievable Participation” case (AP), and the “Full Participation” case (FP). Table 3 compares these scenarios to the DR penetration levels in the Transition Scenario. In all regions, our assumed DR penetration in 2050 is at or below the 2019 level in the FERC study’s Achievable Participation scenario.

Table 3. Demand Response Penetration Compared to 2009 FERC Study of Potential

	FERC DR Study			Transition Scenario			
	2019 (EBAU)	2019 (AP)	2019 (FP)	2020	2030	2040	2050
Arizona/New Mexico	4%	16%	24%	1%	4%	10%	15%
Rocky Mountains	2%	9%	14%	2%	4%	7%	9%
Northwest	5%	11%	16%	1%	1%	1%	1%
California	1%	7%	11%	1%	3%	5%	7%
Northeast	3%	7%	10%	1%	3%	5%	7%
Southeast	6%	12%	19%	1%	4%	8%	10%
Eastern Midwest	5%	9%	14%	1%	4%	7%	9%
Western Midwest	4%	8%	11%	1%	3%	5%	7%
South Central	7%	13%	17%	2%	5%	10%	12%
Texas	7%	14%	20%	1%	5%	9%	14%

Note: the data from the FERC study have been adjusted to match the regions used in our analysis.

D. Transmission and System Operation

There are three areas of the country in which new transmission capacity would be needed to move additional energy between regions in the Transition Scenario.

- In the Western Interconnect, we envision an increase of roughly 27 TWh per year moving from the Northwest into the Rockies. The new transfer capacity would be needed in the final two decades of the study period. We estimate the total cost of the capacity needed to be $5 billion.
- We also envision 9 TWh per year moving from the Texas region to the Southeast by 2050. This would require a new HVDC line, added between 2040 and 2050, at an estimated cost of $1.7 billion.[4]
- After 2040, transfers would also increase from the Western Midwest to the Eastern Midwest. By 2050, an additional 27 TWh would be moving into the Eastern Midwest, and the estimated cost of the new transfer capacity is $5 billion.

Systems with little coal and nuclear capacity and large amounts of flexible capacity will be able to accommodate more variable generation than today's systems. Modeling and statistical analyses are needed to determine what kind of constraints will emerge in such systems and ultimately how much PV and wind generation can be accommodated.

These cost estimates are made based on an assumed cost of $1 million per MW of increased transfer capacity. This assumption is based on information developed for the Eastern Wind Integration and Transmission Study (EnerNex 2010), the Eastern Interconnection Planning Collaborative, and on recent cost estimates from the developers of proposed transmission projects. The total cost of the new transfer capacity listed above is $11.7 billion. We include the annualized cost of this capacity (recovered over 30 years) in our cost analysis (see Table 5).

As discussed above, we have paid careful attention to the amount of variable generation in each region. By the later decades of the Transition Scenario there is considerably less coal-fired capacity operating, and by 2050 there is no coal-fired capacity and 23% less nuclear. The removal of this inflexible capacity would make regional systems much better able to integrate variable generation than today's systems. But in addition, we have taken steps to ensure that we end up with resource mixes that can respond to all load conditions. These steps include: ensuring that regions with high levels of variable generation also have high levels of flexible generation and capacity; adding storage capacity in regions with high levels of wind generation; and including the cost of robust DR programs. We also note that current trends in system operation are likely to facilitate the integration of variable resources even under BAU. These trends include the consolidation of balancing areas and increased information sharing and cooperation among balancing areas.

[4] For comparison, developers of the "Southern Cross" line, a proposed HVDC line connecting Texas to the Southeast, estimate project costs at "well over $1 billion."

Figure 5 shows the 2050 energy mix in each region. The Arizona/New Mexico region, the South Central region and Texas have the highest levels of variable generation, all slightly above 50%. In the southwest this is primarily PV generation, while in the central regions there are high levels of wind energy too. However, all three of these regions are generating considerable amounts of energy at flexible gas-fired units (CCCTs and CTs). More importantly, Figure 6 shows that both of these regions have large amounts of flexible *capacity*. In Figure 6, flexible capacity (gas CCCTs, CTs and storage capacity) appears in various shades of grey. In all three of these regions, these resources account for over 65% of installed capacity. This capacity, most of it gas-fired units operating at relatively low capacity factors, would be available to respond quickly to steep ramping conditions and unexpected renewable generation levels. (We have not included hydro as flexible generation, because we have not determined how much hydro capacity in each region is flexible. However, in some regions hydro would provide considerable additional flexibility.)

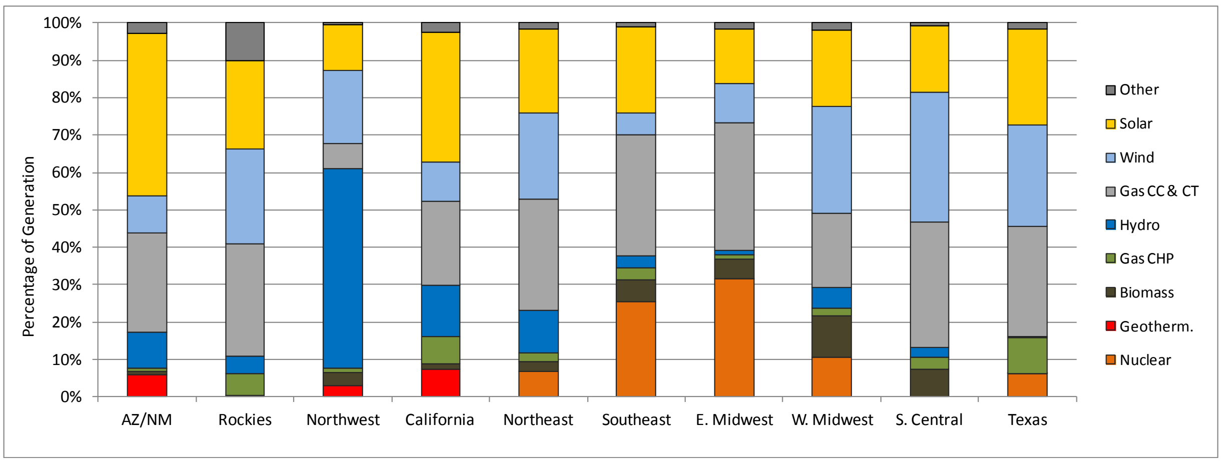


Figure 5. The Regional Generating Mixes in 2050 in the Transition Scenario

Energy storage capacity begins to come on line between 2030 and 2040. We have added this capacity primarily in regions with high levels of wind generation (the Western Midwest, South Central and Texas) to provide ancillary services and to store wind energy.

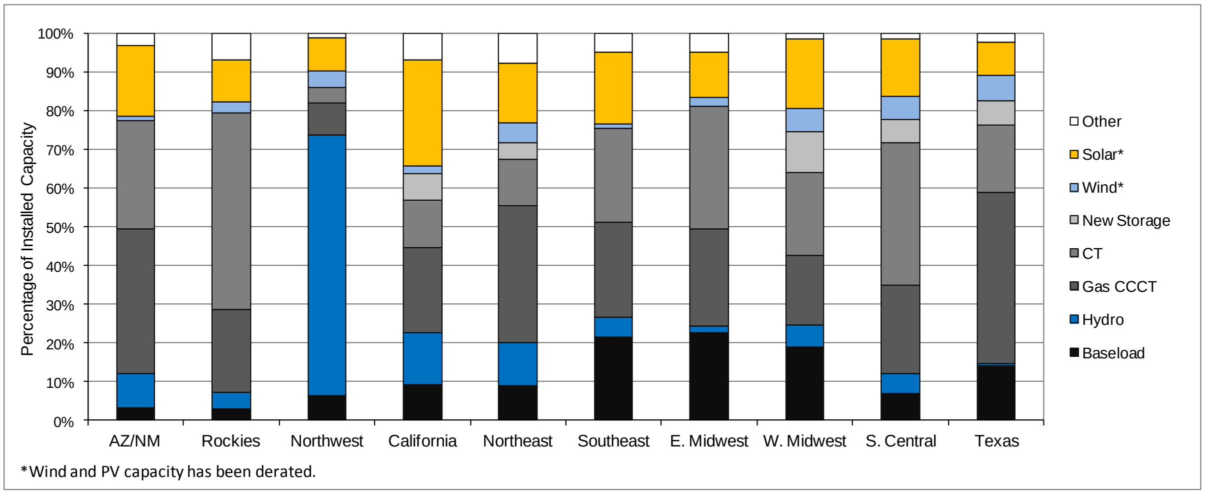


Figure 6. Installed Capacity in 2050 in the Transition Scenario

By 2050 there is 8 GW of storage capacity in the Western Midwest, 3 GW in the South Central region, 4 GW in Texas and just under 3 GW in the Northeast. (The Western Midwest, South Central and Northeast regions also have existing pumped storage capacity, included in "Other" in Figure 6.) We use an average cost of $1,200 per kW for new storage capacity (in 2040) reflecting a mix of battery, flywheel, and compressed air storage, with cost projections based on EPRI-DOE, 2004.

While we have made a number of adjustments to ensure that we have flexible and operable resource mixes, more work is needed to understand how resource mixes like these would respond to different load and generation conditions. Most of the research to date in this area has focused on adding renewable resources to regional systems that already have large amounts of inflexible baseload capacity (i.e., coal and nuclear units). Systems with little coal and nuclear capacity and large amounts of flexible capacity will be able to accommodate more variable generation. Modeling and statistical analyses are needed to determine what kind of constraints will emerge in such systems and ultimately how much PV and wind generation can be accommodated.

4. Findings

A. Air Emissions and Water Use

It is important to note that our calculations of air emissions and water use in the two scenarios are dependent on our assumptions about emission control retrofits under BAU (see Section 2.D), and there is considerable uncertainty around the pace at which control retrofits will be required in the first two decades of the study period. As EPA's regulatory initiatives progress, it will be important to revise these emissions estimates if necessary.

Under BAU, power sector CO_2 emissions rise by 28% to 3.3 billion tons per year in 2050. In the Transition Scenario, CO_2 emissions fall to just under 0.5 billion tons per year. This is a reduction of 81% from 2010 levels.

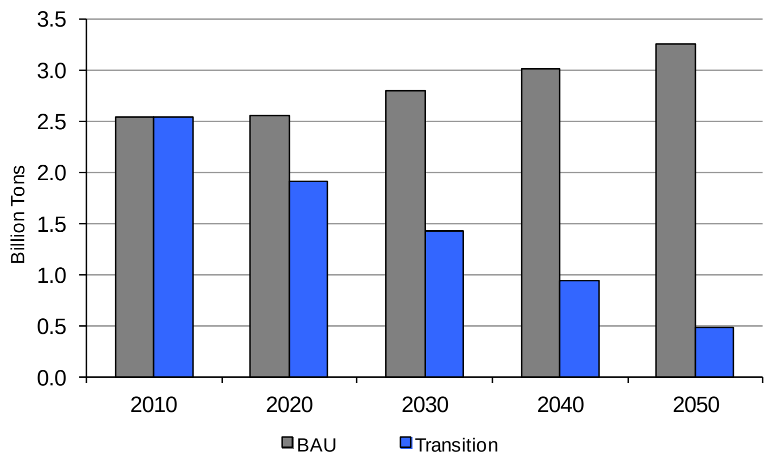


Figure 7. CO_2 Emissions in the Two Scenarios

Mercury emissions fall considerably under BAU as we assume that the entire coal fleet is controlled by 2030 and any new plants added are controlled. Emissions nationwide in 2050 are just under 5 tons under BAU. In the Transition Scenario, mercury emissions are virtually eliminated by 2050 with the elimination of coal-fired generation.

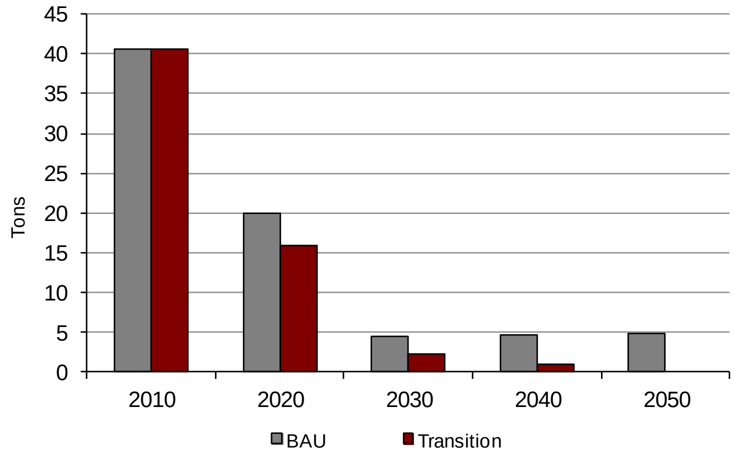


Figure 8. Mercury Emissions in the Two Scenarios

Under BAU, SO_2 emissions fall sharply by 2030, the result of widespread FGD retrofits, and then begin rising again as coal-fired generation continues to increase. Total emissions are reduced by 40% by 2050. In the Transition Scenario, SO_2 emissions are virtually eliminated by 2050 with the retirement of all coal- and oil-fired plants.

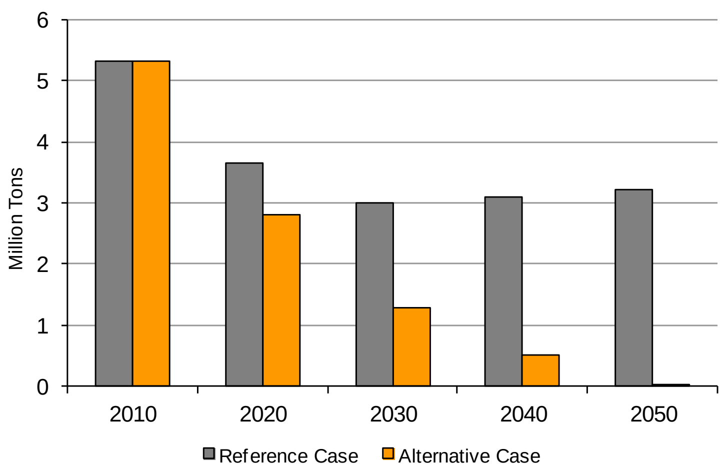


Figure 9. SO2 Emissions in the Two Scenarios

Widespread SCR retrofits reduce NO_X emissions under BAU by 36% by 2050. Overall reductions are achieved despite a considerable increase in gas-fired generation under BAU. Emissions of NO_X fall by 83% in the Transition Scenario relative to 2010 levels, as coal-fired generation is phased out and natural gas use remains lower than under BAU.

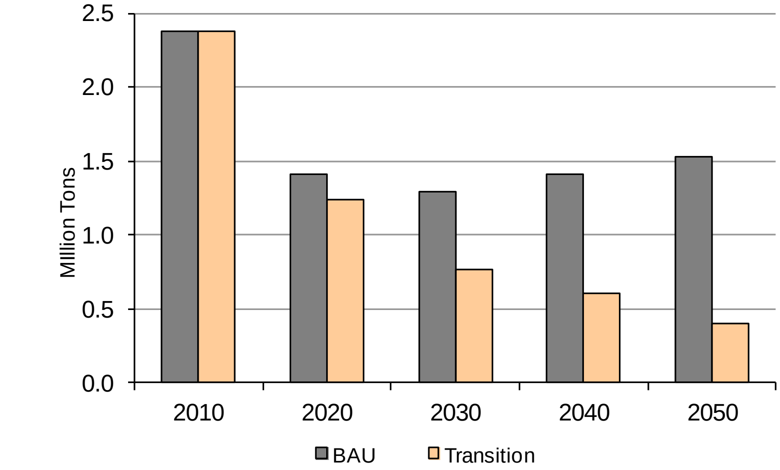


Figure 10. NOX Emissions in the Two Scenarios

Figures 11 and 12 show total power sector water withdrawals and consumption in the two scenarios. Water used for cooling and then returned to a body of water is classified as a "withdrawal," and water not returned is classified as "consumption." For coal-fired plants we estimate withdrawals and consumption using the same database of generating units used to estimate emissions and health impacts. This database includes information reported to EIA on the cooling system type for each coal-fired unit in the U.S. For other plant types, average water use assumptions were developed based on information reported by plant owners to EIA and on Stillwell, et al., 2009. Regarding cooling system retrofits, we assume that half of the coal-fired units under 100 MW in size and lacking closed-loop cooling systems install such systems by 2020. We assume that the other half installs them by 2030. (No retrofits are required at units smaller than 100 MW.) Similarly, we assume that half of the nuclear units lacking closed-cycle cooling install these systems by 2020 and the other half installs them by 2030.

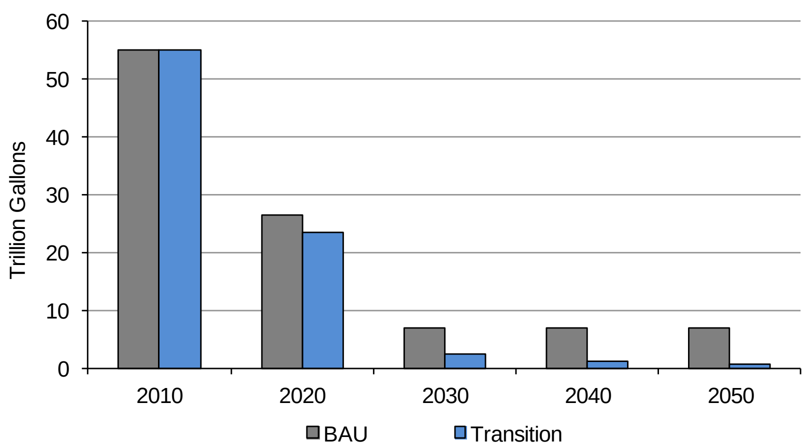


Figure 11. Water Withdrawals at Power Plants in the Two Scenarios

In both scenarios, water withdrawals fall sharply between 2010 and 2030 due to retrofits of closed-loop cooling systems at coal-fired and nuclear plants. After 2030 withdrawals begin rising again under BAU, with rising coal-fired generation. In the Transition Scenario, withdrawals continue to fall after 2030 due to coal and nuclear plant retirements.

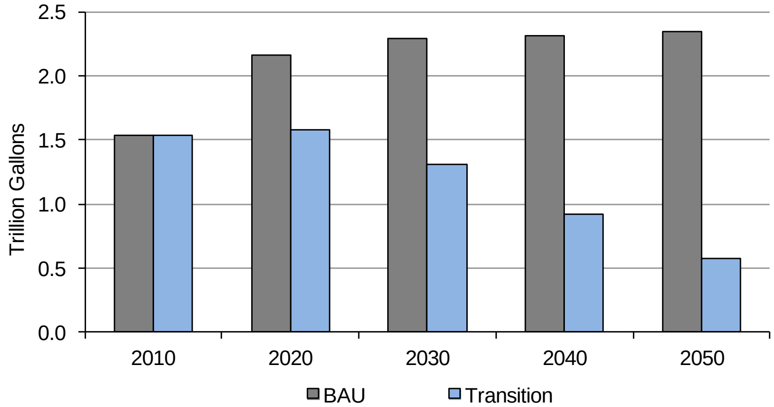


Figure 12. Water Consumption at Power Plants in the Two Scenarios

Water consumption rises under BAU, because closed-loop cooling systems lose more water via evaporation than open-loop systems. (However, note that overall consumption is an order of magnitude lower than withdrawal.) Consumption remains stable over the first decade in the Transition Scenario, as retirements offset the increased consumption at plants with new, closed-loop systems. After 2020, consumption falls steadily in the Transition Scenario, the result of coal and nuclear plant retirements.

B. Avoided Health Impacts

We estimate health effects avoided via reduced air pollution in the Transition Scenario using plant-specific damage factors developed by the National Research Council in the report *The Hidden Costs of Energy* (NRC, 2010). These damage factors represent the monetary value of statistical premature mortality due to air pollution (in monetized dollars per ton of pollutant); In Table 4 below, we show the monetized values for both scenarios as well as the estimates of statistical premature mortality. We convert monetized damages to premature mortality using the value of statistical life utilized by the NRC of $8.2 million (adjusted from $2000 to $2010.)

Table 4. Avoided Damages or Premature Mortality from Coal-Fired Plants in the Transition Scenario

	2011-2020	2021-2030	2031-2040	2041-2050	Cumulative Total
Billion dollars					
BAU	427	276	251	260	1,215
Transition	421	210	93	28	752
Difference	6	66	158	232	463
Statistical Lives					
BAU	52,000	34,000	31,000	32,000	149,000
Transition	51,000	26,000	11,000	3,000	91,000
Difference	1,000	8,000	20,000	29,000	58,000

Figures may not sum due to rounding.

Net damages are fairly small during the first decade because most of the existing coal-fired capacity without controls is controlled in both the BAU and Transition Scenario during this decade. The difference in mortality is due to a number of large units that are retired rather than controlled in the Transition Scenario and some smaller units that are retired in the Transition Scenario and not controlled under BAU. The health benefits of the Transition Scenario grow in the second decade because unit retirements continue on a large scale in the Transition Scenario, while there are far fewer control retrofits under BAU than in the first decade. After 2030 there are no further retrofits in either scenario, but the retirements continue in the Transition Scenario. Therefore, health benefits continue to increase in these decades.

These are rough estimates, and they are heavily dependent on our assumptions about the pace of control retrofits under BAU and about which coal-fired units are controlled and retired in each decade. Regarding controls, we assume that the largest uncontrolled units are controlled first – units where the cost of control is likely to be lowest in terms of dollars per MW. Regarding retirements, we assume that the least economic units are retired first, considering fuel, operating, and retrofit costs. Different assumptions about which units are controlled first and retired first would yield different estimates of avoided mortality.

C. Natural Gas Use

A key goal in our development of the Transition Scenario was to maximize our reliance on efficiency and renewable energy and thus minimize the amount of natural gas needed for the transition away from coal and nuclear power. As seen in Figure 13, annual power sector gas use is lower in the Transition Scenario than under BAU in all years of the study period. In 2020, it is 0.3 quadrillion Btu (4%) lower than under BAU, and by 2050 it is 3.7 quadrillion Btu (29%) lower than BAU.

Figure 13 shows gas use from both “central station” plants (steam units, CCCTs and CTs) and “end-use” (CHP) facilities. The NEMS model selects from a variety of CHP equipment. We represent CHP plants with the characteristics of the equipment selected most by the NEMS model in the 2011 AEO: a 10 MW CT with an overall efficiency of 76%. We allocate 40% of the cost, fuel use and emissions from this plant to electricity production and 60% to steam production. Therefore, 40% of the gas use at CHP plants is included in Figure 13, and 60% would be reported as commercial or industrial gas use.

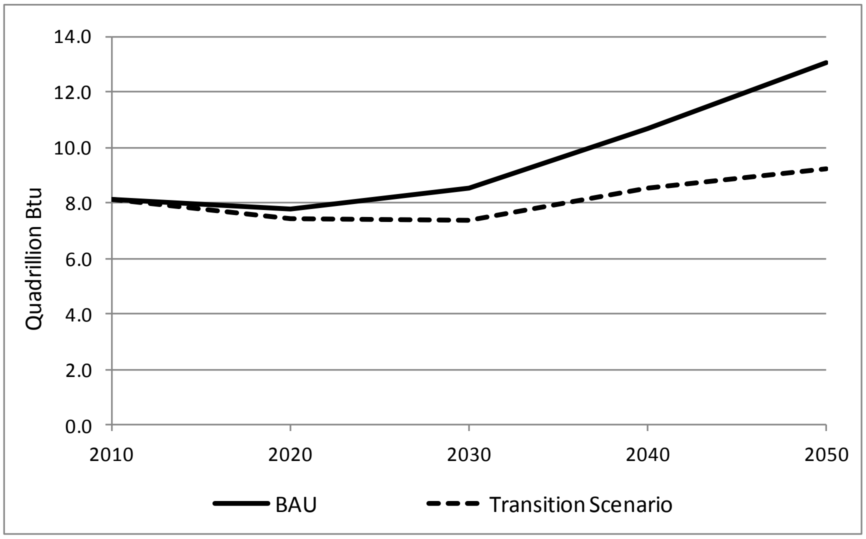


Figure 13. Power Sector Natural Gas Use in the Two Scenarios

It will be important to revisit the resource mix in the Transition Scenario as more information becomes available. Information about the cost and potential of efficiency, renewables and energy storage technologies could warrant changes to this scenario, as could information on the greenhouse gas emissions and health risks of gas drilling.

D. Net Costs

Table 5 (below) shows the net costs of the Transition Scenario relative to BAU at four points in time. Note that these are annual costs, not cumulative. Over the study period, significant savings in the cost of generating electricity offset incremental costs such that the scenario provides net savings over much of the study period. The net present value of the 40-year stream of savings and costs is a savings of $83 billion, discounted at 4.8%.

The net annual impacts range from savings of $18 billion in 2050 to costs of $9 billion in 2040. To put this in perspective, $18 billion is about 5% of total electric industry revenues in 2010, assuming 3,730 TWh sold at an average price of ¢10 per kWh. As seen in Table 5, when spread over all kWhs sold in the relevant year, the savings are ¢0.4 per kWh consumed in 2020, and the costs are ¢0.3 per kWh in 2040.

We explore several sensitivity analyses to gauge the range of uncertainty around these net savings. The variables with the largest impacts are the cost of energy efficiency, the cost of coal and the cost of new PV capacity. However, in all of the sensitivity analyses the Transition Scenario provides savings on an NPV basis relative to BAU.

Demand response costs represent the payments to customers enrolled in demand response programs. Incremental transmission represents the cost of increasing transfer capabilities between regions to accommodate the increased power exchanges in the Transition Scenario. Energy storage is the cost of building and operating storage facilities. The cost of the energy losses from storage is included in the Net Cost of Generation. Avoided emission control costs are the costs avoided by retiring coal-fired plants rather than adding the controls expected under BAU. We assume 15-year cost recovery on emission control investments (compared to 30 years for all other investments).

Table 5. The Net Annual Net Costs of the Transition Scenario (billion 2010$)

	2020	2030	2040	2050
Net Cost of Generation	($23)	($50)	($49)	($58)
Energy Efficiency	$19	$53	$58	$31
Demand Response	$0.1	$0.7	$2.2	$4.0
Incremental Transmission	$0.0	$0.0	$0.2	$1.1
New Energy Storage Costs	$0.0	$0.0	$0.8	$3.6
Avoided Environmental Controls	($11)	($12)	($3.2)	$0
Total	($16)	($8.2)	$9.0	($18)
Total (¢/kWh of electricity use)	(¢0.4)	(¢0.2)	¢0.3	(¢0.4)

In Section 4.F we present a number of sensitivity analyses to gauge the range of uncertainty around these net savings. The variables with the largest impacts on the results are the cost of energy efficiency, the cost of coal and the cost of new PV capacity. However, in all of the sensitivity analyses the Transition Scenario provides savings on an NPV basis relative to BAU.

E. Jobs Associated with New Plants

Table 6 shows the new jobs associated with the expanded energy efficiency programs and the construction and operation of new power plants in the Transition Scenario. Data in this table are reported in job-years, the equivalent of one new worker employed for a year. Total direct jobs are calculated using technology specific factors from NREL's Jobs and Economic Development Impacts models. Indirect and induced jobs are calculated using the IMPLAN model.

It is important to note that this is a limited analysis of the employment effects of the Transition Scenario. A wider analysis would be needed to assess the full, net effects of the scenario. For example, there would be additional jobs created in the Transition Scenario as a result of lower expenditures on electricity across the economy and in the decommissioning of retired power plants. There would also be significant job loss due to the retirement of coal and nuclear plants. More work is needed to develop a full picture of the economic impacts of the Transition Scenario.

Employment impacts are shown only for the first decade of the study period, because advances in technology will change not only the cost of new resources but also the amount of labor needed to install and operate them. Thus, the uncertainty around employment impacts becomes quite large in later decades.

Table 6. Employment Impacts of New Plants and Energy Efficiency in the Transition Scenario 2011-2020 (job-years)

Technology	Direct Construction	Direct O&M	Total Direct, Indirect, and Induced
Wind	138,000	22,000	932,000
CSP	5,000	1,000	18,000
Photovoltaic	130,000	55,000	1,533,000
Geothermal	5,000	4,000	26,000
Biomass	30,000	9,000	284,000
Gas CHP	2,000	0*	16,000
Energy Efficiency	134,000	0*	299,000
Total	444,000	90,000	3,108,000

**Direct O&M job-years associated with Transmission are less than 500. This is shown as zero here as figures are rounded to the nearest thousand job-years. We assume no jobs associated with operation and maintenance of efficiency measures.*

For direct construction, roughly 444,000 job-years are created, equivalent to 44,400 construction workers working full time for the entire decade. Similarly, roughly 90,000 O&M job-years are created, equivalent to about 9,000 full time workers employed over the decade. Whereas in construction the number of jobs is roughly the same each year, the O&M jobs ramp up over time. In the first year there are nearly zero jobs, because no projects have been completed. However, assuming a roughly linear rate of construction over the decade, the last year would require roughly 18,000 people full time to perform the O&M activities for the completed new projects.

Direct jobs aren't the only employment impact of these projects. They require materials and additional people to design, manufacture, and deliver those materials. Those materials in turn may require materials for their production, and so forth. These are "indirect" jobs. Further, all the workers building and operating the projects – as well as the workers manufacturing the ingredients to the projects – spend their wages in the local economy. These expenditures create "induced" jobs. It is this multiplier effect, both from indirect and induced jobs, which results in a total job-year creation in excess of 3.1 million between 2011 and 2020.

F. Sensitivity Analyses

Looking at Table 5 (above), one can identify several assumptions that do not have a large impact on the cost results. For example, doubling or tripling the cost of DR, new transmission or energy storage would not change the net costs much. We performed sensitivity analyses around the assumptions that have a larger impact. Analyses of the following input assumptions are presented below:

- The cost of energy efficiency,
- Coal and natural gas prices,
- The cost of PV systems, and
- The cost of new nuclear plants.

The Transition Scenario provides the highest net present savings ($144 billion) in the high coal price sensitivity. Savings are lowest ($21 billion) in the high PV cost scenario.

In doing these analyses, we simply changed the input assumption and observed the change in the net savings and costs of the Transition Scenario over time. We did not develop new BAU and Transition Scenarios based on the changed assumption.

To assess the cost of energy efficiency, we developed the high and low cost cases shown in the top portion of Table 7. The bottom portion shows the impact of these assumptions on the net cost of the Transition Scenario. The high-cost efficiency case brings the NPV savings down to $25 billion, while the low-cost case increases the savings to $125 billion.

Table 7. Results of Efficiency Cost Sensitivities (2010$)

	Energy Efficiency Cost Assumptions ($/MWh)				
	2020	2030	2040	2050	
High EE Case	$47	$60	$75	$90	
Base EE Case	$47	$52	$60	$70	
Low EE Case	$47	$47	$50	$50	
	Annual Net Cost of Transition Scenario (billion$)				NPV (billion$)
High EE Case	($16)	($3)	$20	($4)	($25)
Base EE Case	($16)	($8)	$9	($18)	($84)
Low EE Case	($16)	($12)	$2	($29)	($125)

We evaluated the impact of fuel prices by raising and lowering coal and gas prices (separately) by 20% relative to the base case prices. Prices reach the 20% difference by 2020 and remain there for the remainder of the study period. As seen in Table 8, higher gas prices result in higher net savings from the Transition Scenario, because less gas is burned in this scenario than under BAU. The higher assumed gas prices increase NPV savings to $103 billion, while lower gas prices reduce NPV savings to $63 billion.

Table 8. Results of Gas Price Sensitivities (2010$)

	Annual Net Cost of Transition Scenario (billion)				NPV
	2020	2030	2040	2050	(billion$)
High Gas Case	($16)	($10)	$6	($24)	($103)
Base Gas Case	($16)	($8)	$9	($18)	($84)
Low Gas Case	($15)	($7)	$12	($11)	($63)

As shown in Table 9, higher coal prices increase the savings provided by the Transition Scenario, and lower coal prices decrease them.

Table 9. Results of Coal Price Sensitivities (2010$)

	Annual Net Cost of Transition Scenario (billion)				NPV
	2020	2030	2040	2050	(billion$)
High Coal Case	($17)	($14)	($0)	($31)	($144)
Base Coal Case	($16)	($8)	$9	($18)	($84)
Low Coal Case	($14)	($3)	$18	($5)	($23)

Table 10 shows the input assumptions and results of our analysis of PV costs. The top portion of the table shows the installed costs used in our main analysis and in each sensitivity. Installed costs are shown because levelized energy costs vary across regions based on the solar resource. The low PV price case has the cost of large PV projects hitting $1.00 per W_{DC} ($1.20 per W_{AC}) sometime between 2030 and 2040. This is ten years *earlier* than in the base case but ten to fifteen years *later* than the current goal of the DOE's SunShot program. The cost of large projects does not fall further after reaching $1.20 per W_{AC}. The costs of commercial and residential projects continue to fall over the entire period, though at a diminishing rate, and they do not reach $1.20 per W_{AC}. The high PV cost case has costs falling more slowly from 2011 levels, and large systems do not reach $1.20 per W_{AC} during the study period.

These two sensitivity analyses are not symmetric around the base case. In the later decades, the high cost case is farther from base case than the low cost case. This is because in both the base case and the low cost case, we assume that PV technology hits maturity and diminishing cost reductions per year during the study period. It simply hits this point sooner in the low cost case. Thus, this assumed point of maturity, at $1.20 per W_{AC} for large projects, provides a lower bound for the low cost case, while the high cost case is not similarly constrained.

The bottom portion of Table 10 shows the impact of the two PV cost sensitivities on the total net cost of the Transition Scenario. In the high-cost PV case the NPV savings fall to $21 billion, and in the low-cost case savings rise to $136 billion.

Table 10. Inputs and Results of PV Cost Sensitivities (2010$)

	Adjustments to PV Capital Costs for Sensitivity Analyses				
	2020	**2030**	**2040**	**2050**	
Large Installations ($/$W_{AC}$)					
High PV Case	$3.55	$2.65	$2.06	$1.56	
Base PV Case	$3.30	$2.30	$1.58	$1.20	
Low PV Case	$3.05	$1.95	$1.20	$1.20	
Commercial Installations ($/$W_{AC}$)					
High PV Case	$4.60	$3.68	$3.25	$2.85	
Base PV Case	$4.30	$3.20	$2.50	$2.20	
Low PV Case	$4.00	$2.72	$1.76	$1.70	
Residential Installations ($/$W_{AC}$)					
High PV Case	$5.55	$4.71	$4.23	$3.77	
Base PV Case	$5.30	$4.10	$3.25	$2.90	
Low PV Case	$5.05	$3.50	$2.30	$2.24	
	Annual Net Cost of Transition Scenario (billion$)				**NPV (billion$)**
High PV Case	($15)	($5)	$20	$3	($21)
Base PV Case	($16)	($8)	$9	($18)	($84)
Low PV Case	($16)	($11)	($1)	($32)	($136)

Finally, Table 11 shows the impact on net costs of different assumptions about the cost of energy from new nuclear plants. In all cases, the trend of increasing energy costs from new nuclear plants is the result of increasing fuel prices. We hold the installed cost of new nuclear plants constant through the study period. The low nuclear cost case uses the cost of energy derived from the AEO 2011 cost assumptions ($114 per MWh). The high-cost case is calculated using an installed cost of $8,000 per kW. Because the new nuclear plants in the BAU scenario are added early, and only 6.2 GW are added, the effect of these changed assumptions is pronounced in the early years of the study period and it diminishes over time. The high nuclear costs increase the NPV savings to $100 billion, and the low costs decrease the NPV savings to $70 billion.

Table 11. Results of New Nuclear Cost Sensitivities (2010$)

	New Nuclear Cost Assumptions ($/MWh)				
	2020	2030	2040	2050	
High Nuclear Cost	$178	$180	$182	$183	
Base Nuclear Cost	$143	$145	$146	$148	
Low Nuclear Cost	$114	$116	$118	$119	
	Annual Net Cost of Transition Scenario (billion$)				**NPV (billion$)**
High Nuclear Cost	($17)	($10)	$7	($18)	($100)
Base Nuclear Cost	($16)	($8)	$9	($18)	($84)
Low Nuclear Cost	($14)	($7)	$11	($18)	($70)

Appendix A: Technology Cost and Performance Assumptions

The goal of our cost analysis is to compare the cost of generating electricity under BAU to the same cost in the Transition Scenario. We do not include the effects of direct subsidies such as grants and tax credits in the cost of resources. Consumers pay some costs through electricity rates and pay other costs (subsidies) through tax dollars, but either way they pay the full cost of each plant built. So it is important, wherever possible, to include the full cost of each resource. However, it is very difficult to remove the effect of indirect subsidies from the cost of new plants. These subsidies include R&D funding; subsidies for exploration, drilling, and mining; federal loan guarantees; and externalized costs of pollution. We have not attempted to remove these subsidies from our quantitative analysis, but they should be borne in mind as we compare these two scenarios.

We use cost assumptions from the AEO 2011 for all existing technologies. We use the AEO for many new technologies as well; however for PV, wind, and nuclear plants we have used assumptions based on other sources, as discussed below. Because of the considerable changes in PV costs and pricing over the past 24 months, we have been careful to base our PV assumptions on the most current information possible. In addition, given the wide range of possible PV price trajectories over the next several decades, we present a sensitivity analysis around our PV cost assumptions.

Plant cost and performance assumptions change in each decade of the study period based on: technology improvements for immature technologies, fuel costs, and increasing O&M costs to represent aging equipment. All costs are reported in 2010 dollars. Dollars have been converted from source documents where necessary.

A. Fuel Costs

In both the BAU and Transition Scenario we use the fuel costs from the AEO 2011, shown in Table 12. These figures have been adjusted from 2009 dollars in the AEO documentation.

Table 12. AEO 2011 Fuel Prices (2010$/mmBtu)

	2010	2020	2030	2040	2050
Coal	$2.29	$2.17	$2.35	$2.51	$2.69
Natural Gas	$5.13	$5.07	$6.28	$7.47	$8.82
Distillate Fuel Oil	$16.57	$20.01	$22.57	$23.98	$25.83
Residual Fuel Oil	$11.56	$14.93	$17.06	$17.13	$17.61
Biomass	$1.93	$2.58	$3.04	$3.02	$2.95
Nuclear	$0.76	$0.83	$1.03	$1.18	$1.36

B. Existing Power Plants

We include in our cost analysis all existing generating units (existing in 2010) that operate differently under BAU versus the Transition Scenario. A unit might operate differently in the two scenarios because it is retired in the Transition Scenario or because it produces more or less energy at some point. We do not analyze the costs of existing resources that operate in exactly the same way in the two scenarios, because our cost analysis focuses on the net cost of the Transition Scenario. For resources that operate in exactly the same way, the net cost in the Transition Scenario is zero. We analyze the costs of the following existing resources:

- Coal-fired plants,
- Gas-fired combined-cycle plants,
- Gas- and oil-fired combustion turbines,
- Gas- and oil-fired steam plants, and
- Nuclear plants.

To cost out energy from existing plants we use a fleet average approach. For existing coal units, combined cycle units, and combustion turbines we use the average capacity factor of the units in each region to calculate the average levelized costs in each region. For nuclear units and oil and gas steam units, we use a single capacity factor to calculate levelized costs that are applied to all plants nationwide. Fleet average heat rates for each plant type were developed based on AEO data and information reported to EIA and EPA.

EIA has developed assumptions for capital additions at fossil and nuclear plants based on historical data. For a given plant type, different costs are applied to units 30 years old or younger versus units over 30. Synapse has also reviewed data reported to FERC on capital additions and found the data for different plant types to be similar to the AEO assumptions. Therefore, we have used the AEO capital additions for fossil and nuclear units.

It is not clear from the AEO documentation how fixed and variable O&M costs increase as a given plant ages. We have treated O&M in the same way as capital additions, developing separate cost assumptions for units 30 years old or younger and units over 30. We apply these two cost factors to each regional fleet based on generating unit on-line dates.

The tables below show the cost assumptions for each existing plant type included in our cost analysis. Table 13 shows the input assumptions for existing coal-fired units. Again, regional average levelized costs were calculated using regional average capacity factors from the AEO. For the year 2010, these capacity factors range from 53% to 85%. As seen in Table 13, the 2010 levelized cost of energy from existing coal units ranges from $38 to $43 per MWh in different regions.

Table 13. Assumptions for Existing Coal-Fired Units (2010$)

Assumption	Value	Source
Fixed O&M ($/kW-yr)	$35.97	AEO 2011
Over 30 Fixed O&M ($/kW-yr)	$48.00	Synapse
Variable O&M ($/MWh)	$4.25	AEO 2011
Over 30 Variable O&M ($/MWh)	$4.68	Synapse
Capital Additions ($/kW-yr)	$16.18	AEO 2011
Over 30 Capital Additions ($/kW-yr)	$22.25	AEO 2011
Heat Rate (Btu/kWh)	10,500	Synapse
Range of 2010 Energy Costs ($/MWh)	$38-$43	Calculated

AEO data have been converted to 2010 dollars where necessary.

The 2010 levelized cost of energy from existing combined-cycle units ranges from $46 to $53 per MWh, based on capacity factors ranging from 17% to 51%. The AEO does not appear to include capital additions for CCCTs, even units over 30 years old. We include capital additions of $15.00 per kW-year to units over 30 years old.

Table 14. Assumptions for Existing Gas-Fired CCCTs (2010$)

Assumption	Value	Source
Fixed O&M ($/kW-yr)	$14.62	AEO 2011
Over 30 Fixed O&M ($/kW-yr)	$16.08	Synapse
Variable O&M ($/MWh)	$3.11	AEO 2011
Over 30 Variable O&M ($/MWh)	$3.42	Synapse
Capital Additions ($/kW-yr)	$0.00	Synapse
Over 30 Capital Additions ($/kW-yr)	$15.00	Synapse
Heat Rate (Btu/kWh)	7,700	Synapse
Range of 2010 Energy Costs ($/MWh)	$46-$53	Calculated

AEO data have been converted to 2010 dollars where necessary.

As seen in Table 15, the 2010 levelized cost of energy from existing combustion turbines ranges from $88 to $235 per MWh, based on capacity factors ranging from 0.6% to 21%.

Table 15. Assumptions for Existing Gas- and Oil-Fired Combustion Turbines (2010$)

Assumption	Value	Source
Fixed O&M ($/kW-yr)	$6.98	AEO 2011
Over 30 Fixed O&M ($/kW-yr)	$7.68	Synapse
Variable O&M ($/MWh)	$14.70	AEO 2011
Over 30 Variable O&M ($/MWh)	$16.17	Synapse
Capital Additions ($/kW-yr)	$0.00	AEO 2011
Over 30 Capital Additions ($/kW-yr)	$0.00	AEO 2011
Heat Rate (Btu/kWh)	13,500	Synapse
Range of 2010 Energy Costs ($/MWh)	$88-$235	Calculated

AEO data have been converted to 2010 dollars where necessary.

For oil and gas steam units, we use the fixed and variable O&M data for coal units from the AEO. The costs of capital additions, also from the AEO, are specific to gas and oil steam units. As noted, for oil and gas steam units we use single capacity factor and heat rate assumptions to calculate a levelized energy cost that is applied to all units nationwide. The 2010 levelized cost of energy from gas steam plants is $72 per MWh, and the cost from oil steam plants is $143.

Table 16. Assumptions for Existing Oil- and Gas-Fired Steam Plants (2010$)

Assumption	Value	Source
Fixed O&M ($/kW-yr)	$35.97	AEO 2011
Over 30 Fixed O&M ($/kW-yr)	$48.00	Synapse
Variable O&M ($/MWh)	$4.25	AEO 2011
Over 30 Variable O&M ($/MWh)	$4.68	Synapse
Capital Additions ($/kW-yr)	$8.09	AEO 2011
Over 30 Capital Additions ($/kW-yr)	$14.16	AEO 2011
2010 Energy Cost for Gas ($/MWh)	$72	Calculated
2010 Energy Costs for Oil ($/MWh)	$143	Calculated

AEO data have been converted to 2010 dollars where necessary.

As with oil and gas steam plants, single capacity factor and heat rate assumptions are used to estimate the levelized cost of nuclear energy at all plants nationwide. For nuclear plants we use a capacity factor of 90%, and the levelized cost of energy from existing nuclear units is $27 per MWh.

Table 17. Assumptions for Existing Nuclear Plants (2010$)

Assumption	Value	Source
Fixed O&M ($/kW-yr)	$88.75	AEO 2011
Over 30 Fixed O&M ($/kW-yr)	$100.00	Synapse
Variable O&M ($/MWh)	$2.04	AEO 2011
Over 30 Variable O&M ($/MWh)	$2.24	Synapse
Capital Additions ($/kW-yr)	$21.24	AEO 2011
Over 30 Capital Additions ($/kW-yr)	$53.61	AEO 2011
Heat Rate (Btu/kWh)	10,700	Synapse
2010 Nuclear Energy Cost ($/MWh)	$27	Calculated

AEO data have been converted to 2010 dollars where necessary.

In addition to these costs, we include capital costs of $3,000 per kW at all nuclear units that operate longer than 60 years (the period covered by the original license and a 20-year extension). This cost represents the substantial rebuilding of the unit that we assume will be necessary to obtain a new operating license.

Little work is publicly available about the costs that would be associated with relicensing a 60-year-old nuclear facility. The $3,000 per kW figure is slightly less than half of the cost we assume for a new "greenfield" nuclear unit. This assumption, however, has a relatively small impact on the overall results, because most units are assumed to operate past 60 years in both BAU and the Transition Scenario. Only 19 units are retired in the Transition Scenario before they reach age 60.

To discern the impact of this assumption, we evaluated scenarios with the cost of a 60-year rebuild at $1,000 per kW and $5,000 per kW. Assuming $1,000 per kW decreases the NPV savings of the Transition Scenario from $74 billion to $61 billion. Assuming $5,000 per kW increases the net savings to $86 billion.

C. New Power Plants

As in the AEO, we calculate levelized costs for all new technologies using a fixed charge rate to determine the annual carrying costs of capitalized equipment. However, the AEO includes interest during construction and other factors in its fixed charge rates, while we use these rates simply to annualize capital costs. Our fixed charge rates were developed using a cost of capital representative of a roughly equal mix of utility, merchant, and public projects. Our base fixed charge rate is 9.5%, and this is applied to the lowest risk projects (e.g., onshore wind, solar and geothermal). As in the AEO, we add a risk premium to new plants that produce CO_2, and we also add risk premiums to nuclear, biomass, and offshore wind. In sizing these risk premiums, we are guided by the levelized costs reported for the AEO, by other credible estimates of new plant costs, and by our own research.

For each technology we compare our cost assumptions to four recent estimates of new project costs. The estimates labeled “E3 Analytics” were developed by this firm for the Western Electricity Coordinating Council’s (WECC) Transmission Expansion Planning Policy Committee (E3 Analytics, 2010). Data labeled “Lazard” were released in May 2010 by the Lazard Company, a global investment bank (Lazard, 2010). Data labeled “EIA” are from the AEO 2011 assumptions (EIA, 2010), and data labeled “Black & Veatch” are from that company’s work for California’s Renewable Energy Transmission Initiative and for the company’s “Gencost” model (Black & Veatch, 2011). Data labeled “BBAU” are the assumptions used in this study. In addition, for certain technologies we compare estimates from these four sources to information from actual recent projects.

Note that some of the sources report “overnight costs,” which do not include interest during construction, while others report “installed costs,” which do include this interest.

Coal-Fired Plants

The overnight cost of new coal-fired plants in AEO 2011 is $3,167 per kW for a single unit plant and $2,844 for a dual unit plant. We use the AEO data for a single unit plant. As seen in Table 18, this figure is roughly consistent with Black & Veatch’s range, slightly higher than the E3 Analytics’ assumption, and at the lower end of Lazard’s range.

Note that all the estimates in Table 18 are for plants that burn coal directly. No coal gasification plants are added under either BAU or the Transition Scenario.

Table 18. Comparison of Cost Estimates for New Coal-Fired Units (2010$)

	E3 Analytics 2010	Lazard 2010	EIA 2010	Black & Veatch 2011	BBAU
Overnight Cost ($/kW)			$3,167		$3,167
Installed Cost ($/kW)	$3,793	$3,035-$8,497		$3,000-$4,000	$4,196
Fixed Charge Rate (%)					13%
FOM ($/kW-yr)	$50.58	$20.63-$31.96	$35.97		$35.97
VOM ($/MWh)	$3.03	$2.02-$5.97	$4.25		$4.25
Capital Additions ($/kW-yr)			$16.18		$16.18
Heat Rate (Btu/kWh)		8,960-12,000	8,800		8,800
Capacity Factor (%)	87%	93%	85%	70% to 90%	85%
Fuel Cost ($/mmBtu)		$2.53	$2.15		$2.15
Energy Cost ($/MWh)		$70-$154	$110	$86-$115	$105

Direct subsidies excluded. Figures converted to 2010 dollars from source documents where necessary.

For new coal we assume a construction period of 5 years and a construction loan at 13%. Using a capital recovery factor of 13%, we get a levelized cost of energy of $105 per MWh for the period 2011-20. We report levelized costs here using the 2016 fuel price to be consistent with EIA 2010. All new coal-fired plants operate at an 85% capacity factor.

Combined Cycle Combustion Turbines (CCCT)

Table 19 compares the estimates for new CCCTs. For gas-fired combined cycle units we use the AEO cost assumptions for an advanced unit. We assume a construction period of 3 years and a construction loan at 10%. Table 20 shows our levelized costs with a capacity factor of 60%. The cost of energy is calculated with the 2016 fuel price to be consistent with EIA 2010. The capacity factors of new CCCTs in the Transition Scenario are driven by the need for energy versus capacity in each region.

Table 19. Comparison of Cost Estimates for New Gas-Fired Combined Cycle Plants (2010$)

	E3 Analytics 2010	Lazard 2010	EIA 2010	Black & Veatch 2011	BBAU
Overnight Cost ($/kW)			$1,003		$1,003
Installed Cost ($/kW)	$1,315	$968-$1,184		$1,000-$1,600	$1,153
Fixed Charge Rate (%)					11%
FOM ($/kW-yr)	$8.09	$5.56-$6.27	$14.62		$14.62
VOM ($/MWh)	$4.96	$2.02-$3.54	$3.11		$3.11
Capital Additions ($/kW-yr)			$0.00		$0.00
Heat Rate (Btu/kWh)	7,000	6,800-7,220	6,430		6,430
Capacity Factor (%)	90%	40%-93%	87%	70%-90%	60%
Fuel Cost ($/mmBtu)		$6.07	$4.76		$4.76
Energy Cost ($/MWh)		$68-$97	$64	$95-$109	$64

Direct subsidies excluded. Figures converted to 2010 dollars from source documents where necessary.

Combustion Turbines

For gas-fired combustion turbines we use the AEO cost assumptions for an 85 MW unit. We assume no interest during construction. Table 20 shows costs with a capacity factor of 8%. The cost of energy is calculated with the 2016 fuel price to be consistent with EIA 2010. The capacity factors of new CTs in the Transition Scenario are driven by the need for energy versus capacity in each region.

Table 20. Comparison of Cost Estimates for New Gas-Fired Combustion Turbines (2010$)

	E3 Analytics 2010	Lazard 2010	EIA 2010	Black & Veatch 2011	BBAU
Overnight Cost ($/kW)			$974		$974
Installed Cost ($/kW)	$1,113	$809-$1,012		$600-$900	$974
Fixed Charge Rate (%)					11%
FOM ($/kW-yr)	$14.16	$6.88-$27.31	$6.98		$6.98
VOM ($/MWh)	$5.06	$4.75-$28.32	$14.70		$14.70
Heat Rate (Btu/kWh)	9,300	10,200-10,830	10,850		10,850
Capacity Factor (%)		10%	30%	5%-25%	8%
Fuel Cost ($/mmBtu)		$6.07	$4.76		$4.76
Energy Cost ($/MWh)		$234-$260	$125	$167-$361	$236

Direct subsidies excluded. Figures converted to 2010 dollars from source documents where necessary.

Nuclear Plants

The new nuclear projects under development continue to struggle with delays and cost overruns.

- Progress Energy's two-reactor project in Levy County, Florida was originally scheduled to be online by 2016 at a cost of $17 billion. The latest estimate is an online date of 2021 and a cost of $22.5 billion, or $10,000 per kW.
- Finland's Olkiluoto project was originally scheduled to be online in 2009 for $4.3 billion. It is now scheduled to be operating in 2013 at a cost of $8.6 billion, or $5,400 per kW.
- In late 2010, Constellation Energy scrapped plans for a new reactor at Calvert Cliffs after finding terms the U.S. Government offered for a loan guarantee unacceptable.
- The effort to develop two new reactors at the South Texas plant was scrapped in April 2011. The project was a partnership including Toshiba, and the disaster at Fukushima was cited as the key reason for the decision. However, cost escalation had put the project in a precarious position. Cost estimates had risen to $18 billion, or $6,700 per kW, and another partner, CPS Energy, had already reduced its share from 50% to 7.6%.
- To date one U.S. nuclear project has received a federal loan guarantee, the Vogtle project in Georgia. The developer's current estimate for this project is $14 billion, or roughly $6,400 per kW.

The cost estimates at some other projects remain lower. The latest from the expansion of the Sumner plant in South Carolina is $9.1 billion or $4,100 per kW. However, the escalating costs of the other projects cast some doubt on this estimate. Florida Power and Light has estimated the cost of a one-year delay for a nuclear project to be between $800 million and $1.2 billion (Scroggs, 2007).

Table 21 compares several estimates of new nuclear plant costs. The installed costs from AEO 2011 are the lowest of them – even below the low end of Lazard's considerable range. We use an installed cost of $6,584, along with the AEO assumptions for O&M and capital additions. With a

90% capacity factor, these assumptions yield a levelized energy cost of $142 per MWh. This is within the range estimated by Black & Veatch, but well above the AEO energy cost. It is worth noting that Lazard's range of energy costs appear quite low given the installed costs assumed. We conclude that there is either a subsidy included in the calculation of energy costs or there is an error.

Table 21. Comparison of Cost Estimates for New Nuclear Plants (2010$)

	E3 Analytics 2010	Lazard 2010	EIA 2010	Black & Veatch 2011	BBAU
Overnight Cost ($/kW)			$5,335		$6,000
Installed Cost ($/kW)	$7,586	$5,447-$8,293		$6,000-$8000	$6,584
Fixed Charge Rate (%)					14%
FOM ($/kW-yr)	$71.00	$12.95	$88.75		$88.75
VOM ($/MWh)	$6.07	$0.00	$2.04		$2.04
Capital Additions ($/kW-yr)			$21.24		$21.24
Heat Rate (Btu/kWh)	10,400	10,450			10,450
Capacity Factor (%)	85%	90%	90%	70%-90%	90%
Fuel Cost ($/mmBtu)		$0.51	$0.81		$0.81
Energy Cost ($/MWh)		$78-$115	$115	$100-$158	$142

Direct subsidies excluded. Figures converted to 2010 dollars from source documents where necessary.

The fact that no "next-generation" nuclear project has been successfully completed makes any estimate of costs highly uncertain, and we believe that costs could ultimately be significantly higher than our assumption here. For example, the current estimates for two of the projects discussed above (Progress Energy and South Texas) are above our new nuclear costs, and another of the estimates (Vogtle) is essentially at our assumed cost. We use this assumption for new nuclear in order to be somewhat conservative in assessing the savings from not building new nuclear plants.

Wind Plants

The cost of onshore, utility-scale wind projects reached very low levels in the middle part of the last decade, with total installed costs well below $2,000 per kW. However, strong global demand increased turbine prices late in the decade, and prices have only recently begun to come down. Table 22 compares recent estimates of wind costs. The Black & Veatch estimate takes into account the recent softening in turbine prices; the company's May 2011 estimate for the RETI process in California includes an installed cost range of $2,000 to $2,500 per kW, down from their assumptions for Phases I and II of that project. We believe that the other estimates, from 2010, do not take this recent trend into account, and therefore we use an installed cost at the midpoint of the Black & Veatch range. We use the AEO 2011 O&M costs.

Onshore wind is a fairly mature technology; however, there are likely to be moderate improvements over the next several decades. In particular, we expect onshore wind projects to continue to benefit from offshore R&D, leading to small cost reductions and capacity factor improvements. We reduce installed costs by 2% for the second decade of the study and another 2% for the third decade. We do not reduce installed wind costs after that.

Table 22. Comparison of Cost Estimates for Onshore Wind Projects (2010$)

	E3 Analytics 2010	Lazard 2010	EIA 2010	Black & Veatch 2011	BBAU
Overnight Cost ($/kW)			$2,438		$2,250
Installed Cost ($/kW)	$2,377	$2,276-$2,630		$2,000-$2,500	$2,475
Fixed Charge Rate (%)					9.5%
FOM ($/kW-yr)	$50.58	$61.00	$28.07		$28.07
VOM ($/MWh)	$0.00	$0.00	$0.00		$0.00
Capacity Factor (%)	33%	30%-40%	34%	32%-42%	33%-41%
Energy Cost ($/MWh)		$86-$131	$97	$75-$115	$74-$93

Direct subsidies excluded. Figures converted to 2010 dollars from source documents where necessary.

For offshore wind we assume an installed cost of $5,938, in line with E3 Analytics and higher than Lazard's range, but slightly lower than AEO 2011. We use the AEO O&M costs. (We have not seen offshore wind estimates from Black & Veatch.)

Table 23. Comparison of Cost Estimates for New Offshore Wind Projects (2010$)

	E3 Analytics 2010	Lazard 2010	EIA 2010	BBAU
Overnight Cost ($/kW)			$5,975	$5,600
Installed Cost ($/kW)	$6,069	$3,793-$5,058		$5,938
Fixed Charge Rate (%)				10.5%
FOM ($/kW-yr)	$91.00	$61.00-$101.00	$53.33	$53.33
VOM ($/MWh)	$0.00	$13.15-18.21	$0.00	$0.00
Capacity Factor (%)		32%-45%	34%	44%
Energy Cost ($/MWh)		$134-$258	$247	$181

Direct subsidies excluded. Figures converted to 2010 dollars from source documents where necessary.

We have revised our wind capacity factors downward significantly since the 2010 study. In that study we used data developed by Black & Veatch for the DOE's *20% Wind by 2030* study (US DOE, 2008). The capacity factors used in that study are significantly above the factors used in most other studies, including the four studies cited in Table 22. The capacity factors we use here are based on data from the Eastern Wind Integration and Transmission Study (EnerNex, 2010) and other regional data sources. Figure 14 shows EnerNex's estimated capacity factors at developable U.S. wind sites as a function of cumulative capacity.

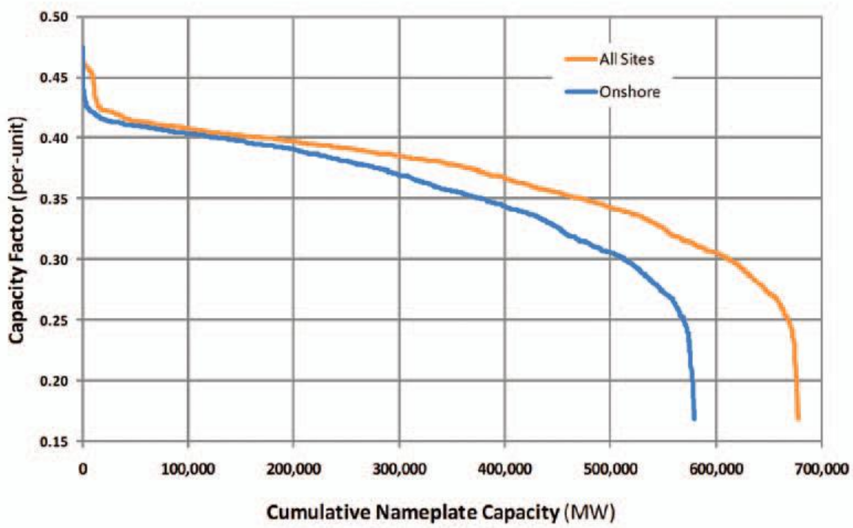


Figure 14. Capacity Factor Data from EnerNex 2010

Table 24 shows the capacity factors we apply to onshore wind plants in both the BAU and Transition Scenario. These capacity factors increase by two percentage points between the first and second decades. After 2030, capacity factors improve by half a percentage point per decade.

Table 24. Capacity Factors Used for Wind Projects

	2011-20	2021-30	2031-40	2041-50
Arizona/New Mexico	37.0%	39.0%	39.5%	40.0%
Rocky Mountains	37.0%	39.0%	39.5%	40.0%
Northwest	37.0%	39.0%	39.5%	40.0%
California	33.0%	35.0%	35.5%	36.0%
Northeast	34.0%	36.0%	36.5%	37.0%
Southeast	33.0%	35.0%	35.5%	36.0%
Eastern Midwest	34.0%	36.0%	36.5%	37.0%
Western Midwest	41.0%	43.0%	43.5%	44.0%
South Central	41.0%	43.0%	43.5%	44.0%
Texas	38.0%	40.0%	40.5%	41.0%
All Offshore	44.0%	46.0%	46.5%	47.0%

Photovoltaics

The AEO 2011 assumption for the capital cost of large PV installed in 2016 is \$4.75 per W_{AC}, and the assumption for small PV is \$6.05 per W_{AC}. Based on other data, we believe that these figures overstate the near-term cost of PV. Large project costs in the AEO fall to roughly \$3.05 per W_{AC} in 2035, and we believe this forecast is also significantly too high. As one point of comparison, a 2010 white paper written by a different office within the U.S. DOE projects that "with current market trends and cost reduction opportunities, utility-scale system costs are expected to reach

$2.20 per W_{DC} by 2016" (U.S. DOE 2010, p. 1). This is equivalent to roughly $2.65 per W_{AC}. Our PV price forecast, laid out below, is more conservative than this forecast; however, the difference in these two forecasts from the same agency underscores the range of uncertainty around long-term PV prices. Given this uncertainty, we examine the impact of high and low PV price scenarios on the results of this study.

The installed cost of large (ground mounted) PV systems has been falling since late 2009. In 2010, prices bid for large PV projects (≥5 MW) in the U.S. were in the range of $4.00 to $4.50 per W_{AC}. An offer by the Sacramento Municipality Utility District to buy renewable energy resulted in bids from projects totaling 100 MW at a price in the range of $140 per MWh. In 2011, an offer by Southern California Edison resulted in bids for 250 MW of PV at a price in the range of $130 per MWh. Factoring in the 30% grant or investment tax credit (ITC) available to these projects, these levelized energy costs are consistent with installed costs in the range of $4.00 to $4.50 per W_{AC}.

The 2010 energy bids cited above are also roughly consistent with the estimates by the U.S. DOE, Black & Veatch, and Lazard that came out in mid-2010 and 2011. E3 Analytics' estimate, in its January 2010 study for WECC, was between $4.50 to $5.70 per W_{AC}, considerably higher than the other three sources. In May of 2011, however, WECC revised this estimate to a range of $4.00 to $4.70 per W_{AC}, more in line with the other estimates (WECC, 2011). The AEO 2011 assumption (cited as EIA 2010 in Table 25) is above all the other estimates.

Table 25. Comparison of Installed Cost Estimates for Large PV Projects (2010$)

	WECC 2011	Lazard 2010	EIA 2010	US DOE 2010	Black & Veatch 2011
$ per W_{DC}		$3.50 - $3.75		$3.04	
$ per W_{AC}	$4.00-$4.70	$4.22 - $4.52	$4.75	$4.09	$3.60 - $4.00

As yet there is little publicly available information on 2011 project costs, but module price data suggests that costs have continued to fall.[5] Historically, modules have been the largest component of project costs, representing about half of total installed costs. Trends in module prices show significant declines through 2010 and 2011. At the end of 2010, both Barclay's Capital and Macquarie Capital projected module prices in the range of $1.45 per W_{DC} by the end of 2011. However, by July 2011 module prices had fallen faster than these predictions, and at least one financial research firm had reduced their fourth-quarter 2011 average module price forecast to $1.25 to $1.30 per W_{DC} (Jeffries & Co., 2011). These module prices support anecdotal evidence from California suggesting that many spring 2011 bids for large systems were in the range of $120 per MWh (Shugar 2011, Kirkpatrick 2011). If panel prices continue to fall from summer 2011 levels, this could put total installed costs on a path to reach DOE's forecast of $2.20 per W_{DC} by 2016.

However, a supply and demand imbalance is clearly driving much of the recent module price reductions. A considerable amount of both silicon and module production capacity has been added in recent years in response to strong European demand. This demand has been driven primarily by subsidies, which are now being reduced. It is likely that a number of module

[5] Module manufacturers include audited cost data as part of the information they provide to financial analysts.

manufacturers will not survive at current prices and there will be a significant consolidation in the market. Therefore, we believe that module prices are not likely to continue falling in the near term at the rate they have fallen over the past two years.

The PV prices used for this study are shown in Table 26. These 2011-20 prices are consistent with a scenario in which: a) by 2015 panel prices have fallen to a sustainable $1.20 per W_{DC} ("sustainable" meaning priced at cost plus margin); and b) BOS cost reductions are not realized as fast as panel cost reductions have been realized recently. Our 2011-20 average price is based on a panel cost of $1.45 per W_{AC} and BOS costs of $1.85 per W_{AC}. Over the long term, we assume that large PV projects achieve DOE's target of $1.00 per W_{DC} ($1.20 per W_{AC}) sometime between 2040 and 2050. This is a less aggressive forecast than DOE's current cost reduction goal ($1.20 per W_{AC} before 2020); however it is consistent with our efforts to be conservative in assessing the costs of phasing out coal-fired electricity.

Table 26. Assumed Costs of PV Systems (2010$)

	2011-2020	2021-2030	2031-2040	2041-2050
Installed Cost ($/$W_{AC}$)				
Large (≥5 MW)	$3.30	$2.30	$1.58	$1.20
Commercial (@ 1 MW)	$4.30	$3.20	$2.50	$2.20
Residential (≤5 kW)	$5.30	$4.10	$3.25	$2.90
Levelized Cost – California ($/MWh)				
Large (≥5 MW)	$146	$102	$73	$57
Commercial (@ 1 MW)	$244	$179	$141	$123
Residential (≤5 kW)	$306	$232	$186	$165
Levelized Cost – Northeast ($/MWh)				
Large (≥5 MW)	$179	$124	$88	$69
Commercial (@ 1 MW)	$285	$206	$162	$142
Residential (≤5 kW)	$356	$268	$214	$190

Like all costs in this study, these costs do not include direct subsidies. This is important to note when comparing these numbers to current market data. For example, pricing for large projects in the 2010 California market was in the range of $130 to $140 per kWh with the 30% grant or ITC. For our average 2011-20 cost of energy from California projects ($146), we assume significant cost reductions from 2010 and we do not include the subsidy.

Our near-term costs for small systems are based on discussions with companies marketing these systems. Current costs for residential scale systems appear to be in the range of $5.70 per W_{AC} (though these systems are being marketed for far less than this due to subsidies). Current costs for commercial scale systems appear to be in the range of $5.00 per W_{AC}.

The capacity factors we use for the 2011-20 period were developed using NREL's *PV Watts* tool. For large systems, we assume ground mounted, single axis tracking systems, and for residential and commercial we assume roof mounted fixed tilt systems. After the first decade, we assume that capacity factors increase by 2 percentage points over the study period. We use the same capacity factors for commercial and residential PV (labeled "small" in Table 27).

Table 27. Capacity Factors Used for PV Projects

	2011-20		2021-30		2031-40		2041-50	
	Large	Small	Large	Small	Large	Small	Large	Small
Arizona/New Mexico	32.0%	24.0%	33.0%	25.0%	33.5%	25.5%	34.0%	26.0%
Rocky Mountains	28.0%	22.0%	29.0%	23.0%	29.5%	23.5%	30.0%	24.0%
Northwest	27.0%	21.0%	28.0%	22.0%	28.5%	22.5%	29.0%	23.0%
California	27.0%	21.0%	28.0%	22.0%	28.5%	22.5%	29.0%	23.0%
Northeast	22.0%	18.0%	23.0%	19.0%	23.5%	19.5%	24.0%	20.0%
Southeast	24.0%	19.0%	25.0%	20.0%	25.5%	20.5%	26.0%	21.0%
Eastern Midwest	22.0%	17.0%	23.0%	18.0%	23.5%	18.5%	24.0%	19.0%
Western Midwest	25.0%	19.0%	26.0%	20.0%	26.5%	20.5%	27.0%	21.0%
South Central	27.0%	21.0%	28.0%	22.0%	28.5%	22.5%	29.0%	23.0%
Texas	25.0%	20.0%	26.0%	21.0%	26.5%	21.5%	27.0%	22.0%

We assume the same prices under BAU and in the Transition Scenario, based on the assumption that most of the learning and technology development will be driven by global supply and demand dynamics. That is, we assume that a scenario with higher PV penetration in the U.S. will not create dramatically lower prices than one with much lower penetration. This assumption is likely to understate the cost of PV under BAU, as the various parts of the U.S. supply chain would no doubt become more competitive and efficient in the Transition Scenario than under BAU.

Direct-Fired Biomass Plants

The four sources we compare are relatively consistent in their estimates for new biomass plants. The estimates from E3 Analytics and Lazard are for a stoker boiler, and the AEO estimate is for a bubbling fluidized bed boiler. This difference accounts for AEO's lower heat rate. We use the assumptions from the AEO, along with a fixed charge rate of 11.5%. This fixed charge rate is based on our research, which indicates that lenders view biomass, with its fuel cost risk, as considerably more risky than wind or solar.

Table 28. Comparison of Cost Estimates for New, Direct Fired Biomass Plants (2010$)

	E3 Analytics 2010	Lazard 2010	EIA 2010	Black & Veatch 2011	BBAU
Overnight Cost ($/kW)			$3,860		$3,860
Installed Cost ($/kW)	$4,299	$3,035-4,046		$3,500-$5,000	$4,362
Fixed Charge Rate (%)					11.5%
FOM ($/kW-yr)	$157.00	$96.09	$100.50		$100.50
VOM ($/MWh)	$4.05	$15.17	$5.00		$5.00
Heat Rate (Btu/kWh)	14,800	14,500	13,500		13,500
Capacity Factor (%)	85%	85%	83%	70%-90%	83%
Fuel Cost ($/mmBtu)		$1.01-$3.34	$2.20		$2.20
Energy Cost ($/MWh)		$92-$148	$114	$105-$160	$128

Direct subsidies excluded. Figures converted to 2010 dollars from source documents where necessary.

Geothermal Plants

For geothermal, we focus only on the resources in the western U.S. that can be developed with binary or flash technology. Enhanced geothermal systems, in which fracking is used to create a usable thermal resource, remain quite expensive, and they are not developed in either the AEO 2011 or in the Transition Scenario.

The cost of new conventional geothermal plants is highly site specific and can vary widely. Key variables include the depth of the resource, how rocky the soil is, and whether the resource is amenable to binary or flash technology. Petty and Porro 2007 provide a supply curve based on analysis of many potential sites across the western U.S. This work is useful in that it identifies the technology likely to be used at each site. However, Petty and Porro's estimates of project costs are considerably lower than most other sources. Table 29 compares estimates of new geothermal plant costs. The assumptions shown for the AEO 2011 are for binary systems. None of the other sources identify the technology assessed, but it seems likely that the low end of Lazard's range is binary and the high end flash.

Our cost assumptions yield levelized costs very close to AEO 2011 and at the low end of Lazard and Black & Veatch's ranges. Note that in both the AEO 2011 and the Transition Scenario, a relatively small amount of new geothermal resources is developed for electricity. In the AEO, 5.4 GW of new capacity is developed by 2050, and in the Transition Scenario 2.7 GW is developed. Thus, our cost assumption is intended to reflect the average cost of developing the most attractive sites.

Table 29. Comparison of Cost Estimates for New Geothermal Plants (2010$)

	E3 Analytics 2010	Lazard 2010	EIA 2010	Black & Veatch 2011	BBAU
Overnight Cost ($/kW)			$4,141		$4,000
Installed Cost ($/kW)	$5,563	$4,653-$7,333		$4,000-$6,000	$5,800
Fixed Charge Rate (%)					9.5%
FOM ($/kW-yr)	$182.00	$0.00	$84.27		$84.27
VOM ($/MWh)	$5.06	$30.34-$40.46	$9.64		$9.64
Capacity Factor (%)	90%	80%-90%	91%	80%-90%	85%
Energy Cost ($/MWh)		$96-$160	$101	$87-$160	$96

Direct subsidies excluded. Figures converted to 2010 dollars from source documents where necessary.

Concentrating Solar Power (CSP)

For a long time trough technology was the dominant CSP technology. However, the costs of trough projects have not come down as hoped, and tower projects now appear to be the technology of choice. Several companies are developing tower technology today, including BrightSource Energy and SolarReserve. These companies have aggressive cost reduction goals, but there is no information available about costs from actual projects.

Moreover, CSP projects face several significant challenges that PV does not face. First, CSP requires large amounts of land, and a better solar resource than PV. This makes it more difficult to site CSP near the grid, and adds transmission costs to projects. Second, CSP requires far more water than PV. All new CSP projects are likely to be required to use "dry" cooling systems, and even projects cooled in this way use much more water than PV projects. Given the global momentum behind PV today, and the projected cost reductions, it seems unlikely that CSP will play a large role in the country's energy future. However, it will be important to monitor the CSP projects under development today, and revise input assumptions as necessary.

Table 30 shows the estimates for new trough projects without storage. The addition of thermal energy storage capacity to a CSP plant does not appear to be cost effective today. We use the AEO assumptions with a higher capacity factor, consistent with the solar resource in the southwestern U.S.

Table 30. Comparison of Cost Estimates for Concentrating Solar Plants (2010$)

	E3 Analytics 2010	Lazard 2010	EIA 2010	Black & Veatch 2011	BBAU
Overnight Cost ($/kW)			$4,692		$4,692
Installed Cost ($/kW)	$5,350	$5,000-$5,300		$5,300-$5,600	$6,100
Fixed Charge Rate (%)					10.5%
FOM ($/kW-yr)	$65.00	$66.00	$64.00		$64.00
VOM ($/MWh)	$0.00	$0.00	$0.00		$0.00
Capacity Factor (%)	28%	26%-29%	18%	22%-27%	27%
Energy Cost ($/MWh)		$161-$188*	$312	$194-$245*	$304

**These estimates of energy costs include the effects of the 30% federal grant or ITC, while the others do not.*

End-Use Generation using Natural Gas

There are eight different gas-fired technologies available to the NEMS model for end-use generation, including two internal combustion engines, five combustion turbines, and a combined cycle system. We represent all end-use gas-fired generation with the characteristics of the equipment selected most often by the model in the AEO 2011: a 10-MW combustion turbine. The installed cost of this equipment is $1,090 per kW, and this cost is quite close to the weighted average of the gas-fired CHP technologies selected by the model. We also use the AEO heat rate (10,945 Btu/kWh) and O&M assumptions for this turbine. To estimate the cost of electricity and gas used for electricity generation, we allocate 40% of the costs and fuel use to electricity and 60% to steam. With the 2016 gas price of $4.76 per mmBtu, this yields a levelized cost of electricity of $35 per MWh.

D. Energy Efficiency

Table 31 compares the results of several recent energy efficiency potential studies. These studies estimate the “achievable potential” over the indicated study period. Achievable potential is a subset of economic potential. Economic potential typically includes all technically viable energy efficiency measures below the avoided cost of electricity. Achievable potential further screens the economic potential based on policy, infrastructure, funding, and consumer response limitations.

Table 31 shows the achievable potential divided by the total sales forecast over the study period. For example, in the first row of the table, GDS estimates that forecasted residential electricity sales in 2031 could be reduced by 34% with achievable energy efficiency measures. Note that all of these studies factor into their sales forecasts the lighting standards established in the Energy Independence and Security Act (EISA) of 2007. That is, the potential savings estimated are in addition to the savings associated with that standard. This is important, because the AEO 2011 Reference Case also includes the effects of that standard.

Table 31. Comparison of Efficiency Potential Studies

Author	State/region	Analysis Period	Period (yrs.)	Sector	Achievable Potential over Sales Forecast
GDS 2011	VT	2012 - 2031	20	RES	34%
GDS 2011	VT	2012 - 2031	20	C&I	19%
GDS 2011	VT	2012 - 2031	20	Combined	25%
VEIC 2011	VT	2012 - 2031	20	RES	37%
VEIC 2011	VT	2012 - 2031	20	C&I	31%
VEIC 2011	VT	2012 - 2031	20	Combined	33%
KEMA 2010	CT	2009 - 2018	10	RES	27%
KEMA 2010	CT	2009 - 2018	10	C&I	34%
KEMA 2010	CT	2009 - 2018	10	Combined	31%
NWPCC 2010	Northwest	by 2030	20	All	27%
ACEEE 2011	AR	2009 - 2025	17	All	22%
ACEEE 2009a	PA	2008 - 2025	18	All	18%
McKinsey 2009	US	2009 - 2020	20	RES	22%
McKinsey 2009	US	2009 - 2020	20	C&I	26%
Average of all studies				RES	30%
				C&I	27%
				Combined	26%

A key difference in these studies is in their treatment of new technologies. Some efficiency potential studies, including the two ACEEE studies cited in Table 31, hold technology constant. All of the other studies in the table factor in emerging technologies and/or assume technology improvement over time, and these studies found significant additional potential in lighting, primarily with emerging LED lighting. This difference in assumptions explains much of the difference in estimated potential between the ACEEE studies and the other studies.

For the Transition Scenario we assume that more aggressive efficiency programs nationwide reduce electricity use by 33.5% below BAU levels *by 2050*. Compared to the achievable potentials listed in Table 31 – in the range of 18% to 33% *over 20 years or less* – this is not a particularly aggressive assumption. Clearly, the technology will be available over the 40-year period to achieve this. However, there is wide variation among the states today in terms of the rate at which efficiency opportunities are being captured, and getting the entire country up to the level of the most aggressive states today would require a strong national commitment.

Another metric often used to measure efficiency progress is savings as a percentage of the previous year's sales. In the Transition Scenario, we assume that by 2020 the entire country is saving energy each year equal to 2% of the previous year's sales. Several years ago, this seemed like an aggressive target, as only a few utilities nationwide were capturing savings at this level.

Today, however, a broad range of states and utilities have established targets or mandates that will result in savings of at least 2% of the previous year's sales.[6]

The cost of saved energy from utility and third party efficiency programs has been well below the cost of new supply-side resources for some time. In 2009, ACEEE reviewed the cost of saved energy in utility and third party programs from fourteen leading states and concluded that average "utility costs" ranged from ¢1.5 to ¢3.4 per kWh, an average value of ¢2.5 per kWh (ACEEE 2009b). The study also found that the utility typically bears about 55% of the total energy efficiency cost, and customers bear about 45%. This implies that the total cost of energy efficiency measures, including participants' costs, is around ¢4.5 per kWh.

Another study, summarized in Figure 15, compares a number of efficiency program cost estimates from states with very aggressive programs (Synapse 2008). The average is ¢2.6 per kWh (adjusted to $2010). Again, this is the utility cost only, so total estimated costs would be in the range of ¢4.7 per kWh (again adjusted to $2010).

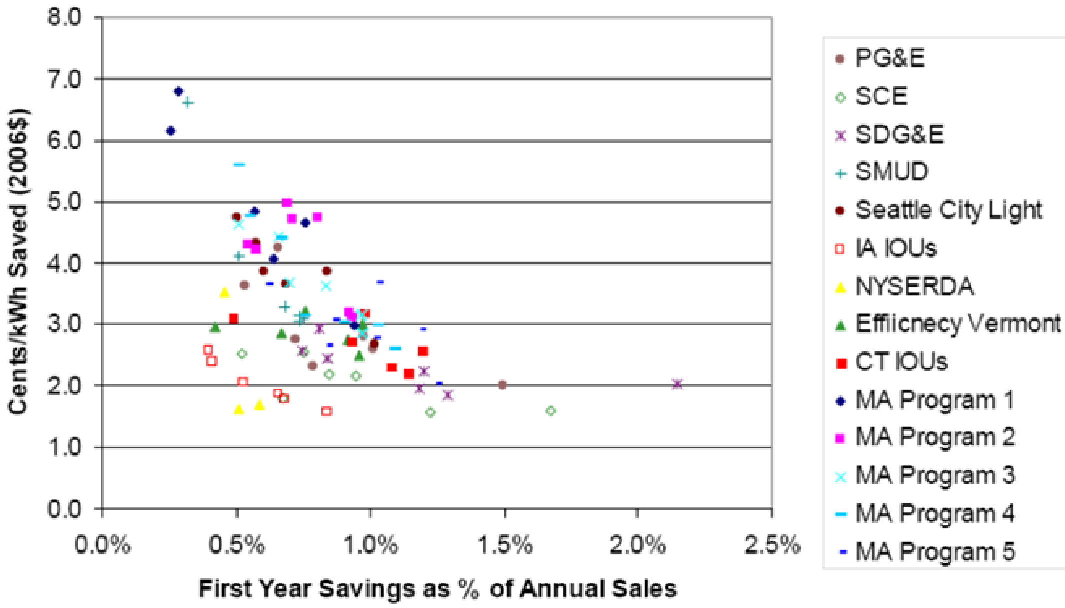


Figure 15. Comparison of Utility Program Efficiency Costs from Synapse 2008

The data in Figure 15 also suggest that there are economies of scale associated with more aggressive efficiency efforts: the highest cost savings per kWh came from programs achieving smaller overall savings, and the lowest cost savings came from the most aggressive programs.

[6] Note that savings equal to 2% of the previous year's sales do not reduce load by 2% per year. While these efficiency programs are operating, load is growing due to new buildings and increased plug loads in existing buildings. So if load were growing at 2% per year, then capturing efficiency savings of 2% per year would result in zero net load growth. If load were growing at 1% per year, these savings would result in load reductions of roughly 1% per year.

While both the Synapse and ACEEE studies are backward looking, the data compiled for Vermont by GDS show that a considerable amount of low-cost savings remain even in a state that has been aggressively pursuing efficiency. Figure 16 shows the energy efficiency supply curve for the Vermont residential sector from GDS 2011. The cost of saved energy ranges from close to zero to nearly $1.00 per kWh, but the majority of the savings are under ¢10 per kWh. As shown in Table 31 above, this study estimated an achievable potential for the residential sector of 34% of forecasted sales by 2031. The weighted average cost of achieving this potential is about ¢5.5 per kWh saved (2010$). For the commercial sector, the weighted average cost is ¢2.5 per kWh (2010$) to capture the achievable potential of 19%. Together, the cost of capturing all achievable savings in Vermont is ¢3.7 per kWh (2010$).

However, the costs presented in Figure 16 are measure costs only: they do not include program delivery costs such as operating and technical support. Efficiency Vermont's 2010 annual report indicates that 35% of the total program costs are spent for program delivery services. Based on this, the total cost of capturing the achievable potential would be about ¢5.7 per kWh (2010$).

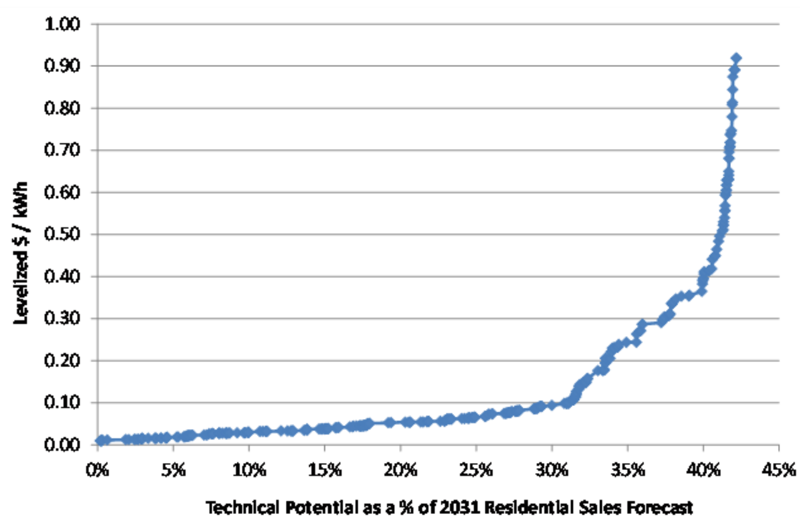


Figure 16. Residential Efficiency Supply Curve for Vermont from GDS, 2011 ($2011)

Again, this estimate of ¢5.7 per kWh is the average cost of reducing statewide energy use in 2031 by 25% below the current forecast. Program administrators will no doubt target the lower cost measures first, so savings in the initial years would cost considerably less than this. Based on this and the other data presented above, we attach a total cost of ¢4.7 per kWh to the energy saved during the first decade of the Transition Scenario. This is intended to include both provider costs ("utility costs") and customer costs ("participant costs").

Regarding the longer term, we tend to agree with studies, like the GDS study for Vermont, that assume improving technology will allow for deep savings without steep increases in the cost of saved energy. The technologies emerging today support this idea, as do many historical case studies. The cost of refrigerators, for example, has been falling steadily since about 1975, while the weighted average efficiency of the refrigerators sold has increased considerably over the same period (Goldstein 2011). However, in the interest of a conservative assessment of the cost of the Transition Scenario, we assume a rising cost of saved energy over the study period. Table 32 shows the levelized cost of saved energy in each decade of the study. Costs are recovered and levelized over a 15-year period.

Table 32. Assumed Cost of Saved Energy in the Transition Scenario (¢/kWh)

2011-20	2021-30	2031-40	2041-50
¢4.7	¢5.3	¢6.0	¢7.0

In Section 4.F we discuss our sensitivity analysis around these efficiency cost assumptions.

E. Demand Response

At low levels of demand response (DR) penetration, we use costs based on current payments and enrolled DR capacity in New England. At higher levels, we estimate costs based on discussions with vendors of technologies that enable shifting of cooling loads, the primary driver of summer peak loads.

Currently, capacity resources in New England are being paid $3.21 per kW-month, and 1,500 MW of DR cleared in the last capacity auction (ISO New England, 2011). This is roughly 5% of the peak load in New England. Therefore, the low end of our DR supply curve is based on a peak load reduction of 5% for a payment of roughly $3.00 per kW-month.

Our discussions with energy management companies indicate that higher payments would attract significantly more capacity. Technologies available today, such as ice-based energy storage, allow customers to shift summer cooling loads to off-peak periods (see, for example, www.ice-energy.com). It is not clear exactly how much consumers would need to be paid to invest in these systems, but vendors estimate that a price well under $10 per kW-month would result in significant market penetration.

Our supply curve for DR capacity resources is shown Figure 17. (The maximum DR resource achieved in any region in the Transition Scenario is a 15% reduction in peak load in Arizona/New Mexico by 2050.)

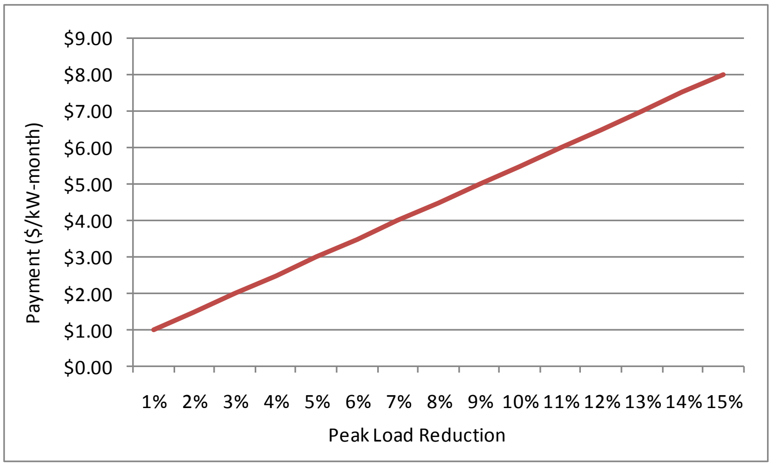


Figure 17. Demand Response Supply Curve Used in Transition Scenario

Appendix B: Data Tables

Table 33. Generation under BAU, from Figure 3 (TWh)

	2010	%	2020	%	2030	%	2040	%	2050	%
Utility-Scale										
Coal	1,841	44.6%	1,874	42.3%	2,058	41.9%	2,141	39.8%	2,231	37.7%
Oil Steam	23	0.6%	23	0.5%	23	0.5%	24	0.4%	24	0.4%
Oil CT	2	0.0%	2	0.0%	2	0.0%	2	0.0%	2	0.0%
Other Oil	7	0.2%	6	0.1%	6	0.1%	7	0.1%	9	0.1%
Gas Steam	93	2.2%	91	2.1%	91	1.9%	91	1.7%	91	1.5%
Gas CCCT	764	18.5%	699	15.8%	794	16.2%	1,022	19.0%	1,261	21.3%
Gas CT	46	1.1%	47	1.1%	47	1.0%	52	1.0%	61	1.0%
Nuclear	803	19.4%	877	19.8%	877	17.9%	873	16.2%	870	14.7%
Pumped Storage	-7	-0.2%	-7	-0.1%	-7	-0.1%	-7	-0.1%	-7	-0.1%
Other	0	0.0%	2	0.0%	4	0.1%	6	0.1%	17	0.3%
Hydropower	239	5.8%	300	6.8%	307	6.2%	309	5.7%	309	5.2%
Geothermal	17	0.4%	25	0.6%	42	0.9%	49	0.9%	51	0.9%
Waste Gases	15	0.4%	15	0.3%	15	0.3%	15	0.3%	15	0.2%
Biomass (Direct)	9	0.2%	9	0.2%	9	0.2%	9	0.2%	9	0.2%
Biomass (Co-Fire)	2	0.0%	28	0.6%	24	0.5%	24	0.5%	24	0.4%
Solar Thermal	1	0.0%	3	0.1%	3	0.1%	3	0.1%	3	0.1%
Utility PV	0	0.0%	1	0.0%	1	0.0%	2	0.0%	3	0.1%
Wind	91	2.2%	142	3.2%	156	3.2%	167	3.1%	185	3.1%
Offshore Wind	0	0.0%	1	0.0%	1	0.0%	1	0.0%	1	0.0%
Utility Subtotal	3,946		4,137		4,453		4,789		5,161	
End-Use Sited										
Liquified Fuels	23	0.6%	32	0.7%	79	1.6%	111	2.1%	111	1.9%
Petroleum	5	0.1%	5	0.1%	5	0.1%	5	0.1%	5	0.1%
Gas CHP	103	2.5%	160	3.6%	211	4.3%	297	5.5%	427	7.2%
Other	12	0.3%	16	0.4%	16	0.3%	16	0.3%	17	0.3%
Hydropower	3	0.1%	3	0.1%	3	0.1%	3	0.1%	3	0.1%
Geothermal	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Municipal Waste	3	0.1%	3	0.1%	3	0.1%	3	0.0%	3	0.0%
Biomass CHP	31	0.7%	60	1.3%	122	2.5%	139	2.6%	170	2.9%
Wind	0	0.0%	2	0.1%	2	0.0%	3	0.0%	3	0.0%
End-Use PV	3	0.1%	14	0.3%	16	0.3%	18	0.3%	21	0.4%
End-Use Subtotal	184		295		458		594		758	
Total Generation	4,130		4,432		4,911		5,383		5,919	

Table 34. Generation in the Transition Scenario, from Figure 3 (TWh)

	2010	%	2020	%	2030	%	2040	%	2050	%
Utility-Scale										
Coal	1,841	44.6%	1,481	36.8%	1,016	27.0%	488	12.8%	0	0.0%
Oil Steam	23	0.6%	11	0.3%	0	0.0%	0	0.0%	0	0.0%
Oil CT	2	0.0%	1	0.0%	0	0.0%	0	0.0%	0	0.0%
Other Oil	7	0.2%	5	0.1%	2	0.1%	1	0.0%	0	0.0%
Gas Steam	93	2.2%	46	1.2%	0	0.0%	0	0.0%	0	0.0%
Gas CCCT	764	18.5%	746	18.5%	788	20.9%	944	24.8%	1,046	26.6%
Gas CT	46	1.1%	47	1.2%	50	1.3%	51	1.3%	54	1.4%
Nuclear	803	19.4%	822	20.4%	757	20.1%	690	18.1%	618	15.7%
Pumped Storage	-7	-0.2%	-7	-0.2%	-7	-0.2%	-7	-0.2%	-7	-0.2%
Other	0	0.0%	2	0.0%	4	0.1%	6	0.2%	17	0.4%
Hydropower	239	5.8%	300	7.4%	307	8.1%	309	8.1%	309	7.9%
Geothermal	17	0.4%	22	0.5%	26	0.7%	31	0.8%	36	0.9%
Waste Gases	15	0.4%	19	0.5%	22	0.6%	23	0.6%	24	0.6%
Biomass (Direct)	9	0.2%	10	0.2%	14	0.4%	19	0.5%	24	0.6%
Biomass (Co-Fire)	2	0.0%	1	0.0%	1	0.0%	0	0.0%	0	0.0%
Solar Thermal	1	0.0%	2	0.0%	2	0.0%	2	0.1%	3	0.1%
Utility PV	0	0.0%	44	1.1%	84	2.2%	259	6.8%	495	12.6%
Wind	91	2.2%	210	5.2%	296	7.9%	436	11.4%	545	13.9%
Offshore Wind	0	0.0%	10	0.2%	22	0.6%	43	1.1%	63	1.6%
Utility Subtotal	3,946		3,770		3,383		3,297		3,229	
End-Use Sited										
Liquified Fuels	23	0.6%	23	0.6%	23	0.6%	23	0.6%	23	0.6%
Petroleum	5	0.1%	5	0.1%	5	0.1%	5	0.1%	5	0.1%
Gas CHP	103	2.5%	110	2.7%	118	3.1%	123	3.2%	126	3.2%
Other	12	0.3%	16	0.4%	16	0.4%	16	0.4%	17	0.4%
Hydropower	3	0.1%	3	0.1%	3	0.1%	3	0.1%	3	0.1%
Geothermal	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Municipal Waste	3	0.1%	3	0.1%	3	0.1%	3	0.1%	3	0.1%
Biomass CHP	31	0.7%	60	1.5%	122	3.3%	139	3.6%	170	4.3%
Wind	0	0.0%	2	0.1%	2	0.1%	3	0.1%	3	0.1%
End-Use PV	3	0.1%	34	0.9%	89	2.4%	196	5.1%	348	8.9%
End-Use Subtotal	184		256		382		510		698	
Total Generation	4,130		4,026		3,765		3,807		3,927	

Table 35. Capacity under BAU, from Figure 4 (GW)

	2010	%	2020	%	2030	%	2040	%	2050	%
Utility-Scale										
Coal	318	30.3%	318	29.3%	318	27.2%	318	26.2%	318	24.2%
Oil & Gas Steam	114	10.8%	93	8.6%	93	7.9%	89	7.3%	89	6.8%
CCCT	198	18.9%	204	18.8%	235	20.1%	244	20.2%	262	20.0%
CT/Diesel	139	13.2%	143	13.2%	166	14.2%	175	14.5%	230	17.5%
Nuclear	101	9.6%	110	10.2%	110	9.4%	110	9.1%	110	8.4%
PS/Other	22	2.1%	22	2.0%	22	1.9%	23	1.9%	25	1.9%
Other Storage	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Fuel Cells	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Distributed Gen	0	0.0%	1	0.1%	2	0.2%	3	0.3%	4	0.3%
Hydropower	77	7.3%	78	7.2%	79	6.8%	80	6.6%	80	6.1%
Geothermal	2	0.2%	3	0.3%	6	0.5%	7	0.5%	7	0.5%
MSW/LFG	3	0.3%	3	0.3%	3	0.3%	3	0.3%	3	0.3%
Biomass DF	2	0.2%	2	0.2%	2	0.2%	2	0.2%	2	0.2%
Solar Thermal	1	0.1%	1	0.1%	1	0.1%	1	0.1%	1	0.1%
Utility PV	0	0.0%	0	0.0%	0	0.0%	1	0.1%	1	0.1%
Wind	37	3.6%	49	4.5%	53	4.5%	57	4.7%	62	4.7%
Offshore Wind	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Utility Subtotal	1,014		1,028		1,091		1,113		1,195	
End-Use Sited										
Liquified Fuels	4	0.4%	5	0.5%	12	1.0%	16	1.3%	16	1.2%
Petroleum	1	0.1%	1	0.1%	1	0.1%	1	0.1%	1	0.1%
Gas CHP	18	1.7%	26	2.4%	32	2.8%	44	3.6%	60	4.6%
Other	2	0.2%	3	0.2%	3	0.2%	3	0.2%	3	0.2%
Hydropower	1	0.1%	1	0.1%	1	0.1%	1	0.1%	1	0.1%
Geothermal	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Municipal Waste	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Biomass CHP	5	0.5%	9	0.9%	17	1.5%	20	1.6%	24	1.8%
Commercial PV	1	0.1%	5	0.4%	5	0.4%	6	0.5%	6	0.5%
Residential PV	1	0.1%	5	0.4%	5	0.4%	6	0.5%	6	0.5%
Wind	0	0.0%	2	0.2%	2	0.1%	2	0.2%	2	0.2%
End-Use Subtotal	34		56		78		97		119	
Total Capacity	1,048		1,084		1,170		1,210		1,314	

Table 36. Capacity in the Transition Scenario, from Figure 4 (GW)

	2010	%	2020	%	2030	%	2040	%	2050	%
Utility-Scale										
Coal	318	30.3%	215	21.9%	137	14.5%	66	6.1%	0	0.0%
Oil & Gas Steam	114	10.8%	57	5.8%	0	0.0%	0	0.0%	0	0.0%
CCCT	198	18.9%	198	20.2%	199	21.1%	206	19.1%	219	17.3%
CT/Diesel	139	13.2%	143	14.5%	158	16.7%	182	16.9%	200	15.8%
Nuclear	101	9.6%	104	10.6%	96	10.2%	88	8.1%	78	6.2%
PS/Other	22	2.1%	22	2.2%	22	2.3%	23	2.1%	25	2.0%
Other Storage	0	0.0%	0	0.0%	0	0.0%	2	0.2%	23	1.8%
Fuel Cells	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Distributed Gen	0	0.0%	1	0.1%	2	0.2%	3	0.3%	4	0.3%
Hydropower	77	7.3%	78	7.9%	79	8.4%	80	7.4%	80	6.3%
Geothermal	2	0.2%	3	0.3%	4	0.4%	4	0.4%	5	0.4%
MSW/LFG	3	0.3%	4	0.4%	4	0.5%	5	0.4%	5	0.4%
Biomass DF	2	0.2%	2	0.2%	3	0.3%	4	0.3%	4	0.3%
Solar Thermal	1	0.1%	1	0.1%	1	0.1%	1	0.1%	1	0.1%
Utility PV	0	0.0%	19	1.9%	37	3.9%	114	10.6%	193	15.3%
Wind	37	3.6%	73	7.5%	99	10.4%	129	11.9%	160	12.6%
Offshore Wind	0	0.0%	3	0.3%	6	0.6%	11	1.0%	16	1.2%
Utility Subtotal	1,014		922		846		916		1,013	
End-Use Sited										
Liquified Fuels	4	0.4%	4	0.4%	4	0.4%	4	0.4%	4	0.3%
Petroleum	1	0.1%	1	0.1%	1	0.1%	1	0.1%	1	0.1%
Gas CHP	18	1.7%	19	1.9%	20	2.1%	21	2.0%	22	1.7%
Other	2	0.2%	3	0.3%	3	0.3%	3	0.2%	3	0.2%
Hydropower	1	0.1%	1	0.1%	1	0.1%	1	0.1%	1	0.1%
Geothermal	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Municipal Waste	0	0.0%	0	0.0%	0	0.0%	0	0.0%	0	0.0%
Biomass CHP	5	0.5%	9	1.0%	17	1.9%	20	1.8%	24	1.9%
Commercial PV	1	0.1%	13	1.3%	32	3.4%	72	6.7%	125	9.9%
Residential PV	1	0.1%	7	0.7%	18	1.9%	39	3.6%	70	5.5%
Wind	0	0.0%	2	0.2%	2	0.2%	2	0.2%	2	0.2%
End-Use Subtotal	34		59		99		163		252	
Total Capacity	1,048		981		945		1,078		1,265	

Table 37. Regional Average Capacity Factors at Coal-Fired Plants under BAU

	2010	2020	2030	2040	2050
Northeast	53%	44%	67%	73%	80%
Southeast	63%	65%	71%	75%	80%
Eastern Midwest	63%	64%	72%	76%	80%
Western Midwest	68%	65%	75%	78%	80%
South Central	72%	72%	75%	78%	80%
Texas	73%	80%	80%	80%	80%
Arizona/New Mexico	78%	77%	78%	79%	80%
Rockies	79%	80%	80%	80%	80%
Northwest	78%	74%	77%	79%	80%
California	85%	88%	89%	89%	89%

Table 38. Regional Average Capacity Factors at Coal-Fired Plants in the Transition Scenario

	2010	2020	2030	2040	2050
Northeast	53%	65%	75%	85%	--
Southeast	63%	78%	85%	85%	--
Eastern Midwest	63%	78%	85%	85%	--
Western Midwest	68%	78%	85%	85%	--
South Central	72%	80%	85%	85%	--
Texas	73%	80%	85%	85%	--
Arizona/New Mexico	78%	85%	85%	85%	--
Rockies	79%	85%	85%	85%	--
Northwest	78%	85%	85%	--	--
California	85%	85%	85%	--	--

Table 39. Regional Average Capacity Factors at CCCTs under BAU

	2010	2020	2030	2040	2050
Northeast	47%	49%	52%	58%	56%
Southeast	46%	36%	24%	38%	48%
Eastern Midwest	40%	37%	27%	37%	46%
Western Midwest	18%	16%	5%	32%	60%
South Central	51%	53%	44%	47%	48%
Texas	51%	53%	60%	63%	66%
Arizona/New Mexico	43%	38%	24%	29%	27%
Rockies	17%	9%	5%	38%	49%
Northwest	48%	4%	38%	60%	65%
California	37%	36%	39%	53%	66%

Table 40. Regional Average Capacity Factors at CCCTs in the Transition Scenario

	2010	2020	2030	2040	2050
Northeast	47%	34%	33%	33%	45%
Southeast	46%	51%	52%	61%	66%
Eastern Midwest	40%	55%	57%	70%	70%
Western Midwest	18%	54%	54%	63%	62%
South Central	51%	49%	53%	67%	66%
Texas	51%	52%	42%	39%	35%
Arizona/New Mexico	43%	23%	23%	32%	22%
Rockies	17%	18%	15%	42%	26%
Northwest	48%	15%	37%	44%	45%
California	37%	16%	35%	36%	37%

References

ACEEE 2011. American Council for an Energy Efficient Economy. “Advancing Energy Efficiency in Arkansas: Opportunities for a Clean Energy Economy.”

ACEEE 2009a. American Council for an Energy Efficient Economy. “Potential for Energy Efficiency, Demand Response, and Onsite Solar Energy in Pennsylvania.” (Available at: http://www.aceee.org/research-report/e093).

ACEEE, 2009b. American Council for an Energy Efficient Economy. “Saving Energy Cost-Effectively: A National Review of the Cost of Energy Saved Through Utility-Sector Energy Efficiency Programs.”

Black & Veatch, 2011. Ryan Pletka. “Black & Veatch’s (RETI’s) Cost of Generation Calculator.” Presentation to the California Energy Commission Cost of Generation Workshop. May 16, 2011.

Brattle Group, et al., 2009. The Brattle Group, et al., “A National Assessment of Demand Response Potential.” Prepared for the Federal Energy Regulatory Commission. June 2009. (Available at: http://www.ferc.gov/legal/staff-reports/06-09-demand-response.pdf).

E3 Analytics 2010. Energy and Environmental Economics. “Capital Cost Recommendations for 2009 TEPPC Study.” (Available at: http://www.wecc.biz/committees/BOD/TEPPC/Shared%20Documents/Forms/AllItems.aspx).

EIA, 2010. U.S. Energy Information Administration. “Updated Capital Cost Estimates for Electricity Generation Plants.” November, 2010. (Available at: http://www.eia.gov/oiaf/beck_plantcosts/).

EnerNex, 2010. EnerNex Corporation. “Eastern Wind Integration and Transmission Study.” Prepared for the National Renewable Energy Laboratory, January 2010. NREL Subcontractor Report NREL/SR-550-47078.

EPRI-DOE, 2004. Electric Power Research Institute and US Department of Energy. “EPRI-DOE Handbook Supplement of Energy Storage for Grid Connected Wind Generation Applications.”

GDS, 2011. GDS Associates, Inc. and the Cadmus Group, Inc. “Electric Energy Efficiency Potential for Vermont,” Prepared for Vermont Department of Public Service, April 2011.

Goldstein, 2011. David Goldstein. “Some dilemma: efficient appliances use less energy, produce the same level of service with less pollution and provide customers with greater savings. What’s not to like?” (Available at: http://switchboard.nrdc.org/blogs/dgoldstein/some_dilemma_efficient_applian_1.html).

ISO New England, 2011. Schiff Hardin, LLP. “ISO New England Inc., Docket No. ER11-___-000 Forward Capacity Auction Results Filing.” Filed June 27, 2011 with the Federal Energy Regulatory Commission.

Jeffries, 2011. Jefferies Group, Inc. “Alternative Energy: CORRECTION 2Q/Intersolar Preview: Price War Intensifies; Reducing Est/Ratings” July, 2011.

KEMA 2010. “Connecticut Electric Residential, Commercial, and Industrial Energy-Efficiency Potential Study,” Prepared for the Connecticut Energy Conservation Management Board (ECMB).

Kirkpatrick, 2011. Conference call including David Kirkpatrick, Vice President of enXco Corporation, May 19, 2011.

Lazard, 2010. Lazard, Ltd. “Levelized Cost of Energy Analysis – Version 4.0.” May, 2010.

McKinsey, 2009. McKinsey & Company. “Unlocking Energy Efficiency in the U.S. Economy.” (Available at: http://www.mckinsey.com/en/Client_Service/Electric_Power_and_Natural_Gas/Latest_thinking/Unlocking_energy_efficiency_in_the_US_economy.aspx).

NWPCC 2010. Northwest Power and Conservation Council. Sixth Northwest Conservation and Electric Power Plan. (Available at: http://www.nwcouncil.org/energy/powerplan/6/default.htm).

NRC, 2010. National Research Council. “Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use.” (Available at: http://www.nap.edu/catalog/12794.html).

Perez, et al. 2006. R. Perez, et al. “Update: Effective Load-Carrying Capability of PV in the U.S.” National Renewable Energy Laboratory, NREL/CP620-40068.

Petty and Porro, 2007. S. Petty and G. Porro. “Updated U.S. Geothermal Supply Characterization.” Prepared for the National Renewable Energy Laboratory. (Available at: http://www.nrel.gov/docs/fy07osti/41073.pdf).

RMI, 2010. Rocky Mountain Institute. “Achieving Low Cost Solar PV: Industry Workshop Recommendations for Neat-term Balance of System Cost Reductions.” September 2010.

Scroggs, 2007. Testimony of Steven D. Scroggs, Florida Power & Light Company, before the Florida Public Service Commission, Docket No. 070650, October 16, 2007,

Shugar, 2011. Conference call including Dan Shugar, CEO of Solaria Corporation, May 19, 2011.

Stillwell, et al., 2009. Stillwell, Ashlynn, et al. Energy Water Nexus in Texas. Produced by the University of Texas at Austin and the Environmental Defense Fund. April 2009. (Available at: http://www.edf.org/documents/9479_Energy-WaterNexusinTexasApr2009.pdf).

Synapse 2008. Synapse Energy Economics. “Costs and Benefits of Electric Utility Energy Efficiency in Massachusetts,” prepared for Northeast Energy Efficiency Council. (Available at: http://www.synapse-energy.com/Downloads/SynapseReport.2008-08.0.MA-Electric-Utility-Energy-Efficiency.08-075.pdf)

US DOE, 2010. United States Department of Energy. “$1/W Photovoltaic Systems: White Paper to Explore a Grand Challenge for Electricity from Solar.” (Available at: http://www1.eere.energy.gov/solar/sunshot/pdfs/dpw_white_paper.pdf).

US DOE, 2008. United States Department of Energy, Office of Energy Efficiency and Renewable Energy. “20% Wind Energy by 2030: Increasing Wind Energy’s Contribution to U.S. Electricity Supply.” (Available at: http://www1.eere.energy.gov/windandhydro/wind_2030.html).

US EIA. 2010. US Energy Information Administration. "Assumptions to the Annual Energy Outlook 2011." US Department of Energy. (Available at: http://www.eia.gov/forecasts/aeo/assumptions/index.cfm).

VEIC 2011. Vermont Energy Investment Corporation. "Alternative 20-Year Electric Energy Efficiency Scenarios: VEIC Analysis and Recommendations." Prepared for Vermont Public Service Board and Department of Public Service.

WECC. 2011. Heidi Pacini. "Changes Made to TEPPC Capital Cost Spreadsheet Tool." May 25, 2011 (Available at: http://www.wecc.biz/committees/BOD/TEPPC/Shared%20Documents/Forms/AllItems.aspx).