Transforming America's Power Industry:

The Investment Challenge 2010-2030

Prepared by:

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The Brattle Group

Prepared for:

The EDISON FOUNDATION

NOVEMBER 2008

The Edison Foundation is a nonprofit organization dedicated to bringing the benefits of electricity to families, businesses, and industries worldwide.

Furthering Thomas Alva Edison's spirit of invention, the Foundation works to encourage a greater understanding of the production, delivery, and use of electric power to foster economic progress; to ensure a safe and clean environment; and to improve the quality of life for all people.

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The Brattle Group

The Brattle Group provides consulting services and expert testimony in economics, finance, and regulation to corporations, law firms, and public agencies worldwide. Our principals are internationally recognized experts, and we have strong partnerships with leading academics and highly credentialed industry specialists around the world.

The Brattle Group has offices in Cambridge, Massachusetts; San Francisco; Washington, D.C.; Brussels; and London.

Detailed information about *The Brattle Group* is available at www.brattle.com.

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Executive Summary

The U.S. electric utility industry faces the greatest challenge in its history. The demand for electric services to meet the needs of our growing population and to power our increasingly digital and connected economy continues to rise. At the same time, high demand for commodities such as steel and cement is causing cost increases for building all electric infrastructure systems, including every type of new power plant, whether it's fueled by coal, nuclear power, natural gas, or renewable sources of energy. Concerns about global climate change and other environmental issues have created a new industry emphasis on more energy-efficient products and services and low-emission generation sources. New distribution end-use technologies, such as advanced automation and communications and plug-in hybrid electric vehicles (PHEVs), will dramatically change how utilities deliver electricity and how customers use it, allowing new efficiencies and greater customization of electric service.

To chart the magnitude of this challenge, The Edison Foundation asked *The Brattle Group* to examine the total investment that would be required to maintain today's high levels of reliable electric service across the United States through 2030, net of the investment that could be avoided through the implementation of more aggressive energy efficiency and demand response (EE/DR) programs.[1] In addition, the Foundation wanted *The Brattle Group* to determine the investment cost of one projected generation mix, known as the "Prism Analysis," which the Electric Power Research Institute (EPRI) developed to reduce the growth in carbon emissions.

For our research, we developed four scenarios:

1. **<u>Reference Scenario</u>**: This is similar to the Annual Energy Outlook (AEO) forecast published by the U.S. Department of Energy's Energy Information Administration (EIA), but is adjusted for higher fuel and construction costs. The Reference Scenario is a modeling benchmark and the starting point for our analysis. It does not include the impact of any new federal policy to limit carbon emissions, nor does it include the possible impacts of new industry EE/DR program efforts. The Reference Scenario should not be viewed as our "base" or "most likely" scenario, but rather is a starting point for our analysis.

2. **<u>RAP Efficiency Base Case Scenario</u>**: This scenario adds the impact of realistically achievable potential (RAP) for EE/DR programs, but does not include any new federal carbon policy. This scenario includes a forecast of likely customer behavior and takes into account existing market, financial, political, and regulatory barriers that are likely to limit the amount of savings that might be achievable through EE/DR programs. It is important to note that the RAP Efficiency Base Case

[1] For ease of exposition, we refer throughout this report to *The Brattle Group*; however, the analysis and views contained in this report are solely those of the authors and do not necessarily reflect the views of *The Brattle Group, Inc.* or its clients.

Scenario is our most likely case in the absence of a new federal carbon policy, while the Reference Scenario is simply a benchmark.

3. **MAP Efficiency Scenario**: This scenario captures the higher-end or maximum achievable potential (MAP) for EE/DR programs and assumes a more aggressive customer participation rate in EE/DR programs. It still does not include the effects of a new federal carbon policy.

4. **Prism RAP Scenario**: The final scenario assumes there is a new federal policy to constrain carbon emissions, and captures the cost of EPRI's Prism Analysis projections for generation investments (nuclear, advanced coal, renewables, etc.) that will reduce the growth in carbon emissions. This scenario further assumes the implementation of RAP EE/DR programs.

Study Findings

- **By 2030, the electric utility industry will need to make a total infrastructure investment of $1.5 trillion to $2.0 trillion.**[2] The entire U.S. electric utility industry will require investment on the order of $1.5 trillion under the RAP Efficiency Base Case Scenario. The cost could increase to $2.0 trillion under the Prism RAP Scenario.

- **Under the Reference Scenario, 214 gigawatts (GW) of new generation capacity would be required by 2030, at an investment cost of $697 billion.**[3] For the Reference Scenario, we determined that the entire U.S. electric utility industry would require an investment of $697 billion to build 214 GW of new generation capacity under existing EE/DR programs and state-level renewable programs and carbon policies. Figure 1 shows the breakdown of required new generation capacity by geographic region and generation capacity type.

- **EE/DR programs could significantly reduce, but not eliminate, the need for new generation capacity.** As shown in Figure 2, the implementation of realistically achievable EE/DR programs by electric utilities would reduce the need for new generation capacity significantly; dropping the Reference Scenario's forecast from 214 GW to an estimated 133 GW, or by 38 percent.

  In Figure 2, we also calculated the potential results for the MAP Efficiency Scenario, which represents the higher-end of the range of potential impacts of EE/DR programs. Under the MAP Efficiency Scenario, the need for new generation capacity would be reduced from 214 GW to 111 GW, or by 48 percent.

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[2] Dollar amounts have been rounded to the nearest billion or trillion dollars, and generation capacity has been rounded to the nearest gigawatt (GW) throughout the text of this report for readability.

[3] Our estimates of generation cost apply to the entire U.S. electric utility industry, including shareholder-owned electric utilities, electric cooperatives, and government-owned utilities. We assume that all segments of the industry have approximately the same capital costs and plan their systems to supply at the lowest regional cost.

Figure 1
Required New Regional Generation Capacity
Reference Scenario - No Carbon Policy (2010-2030)

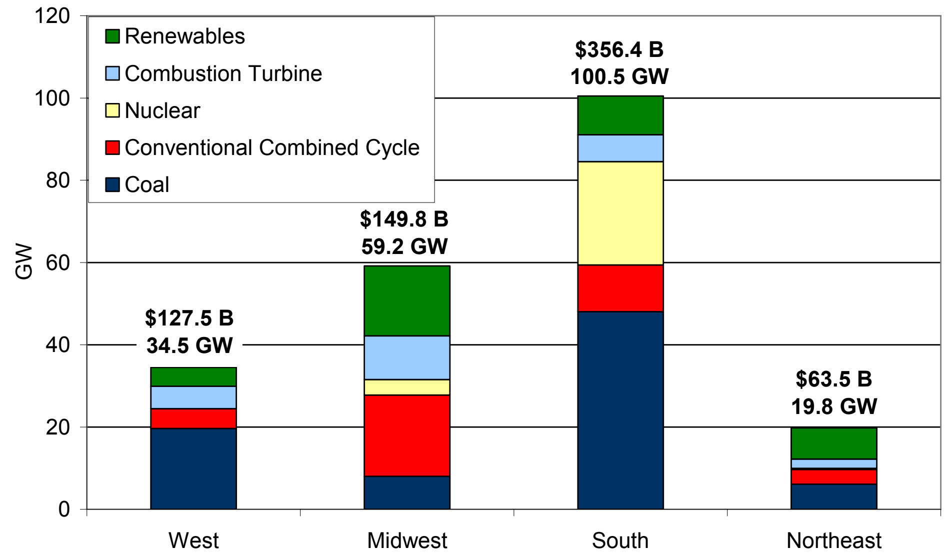
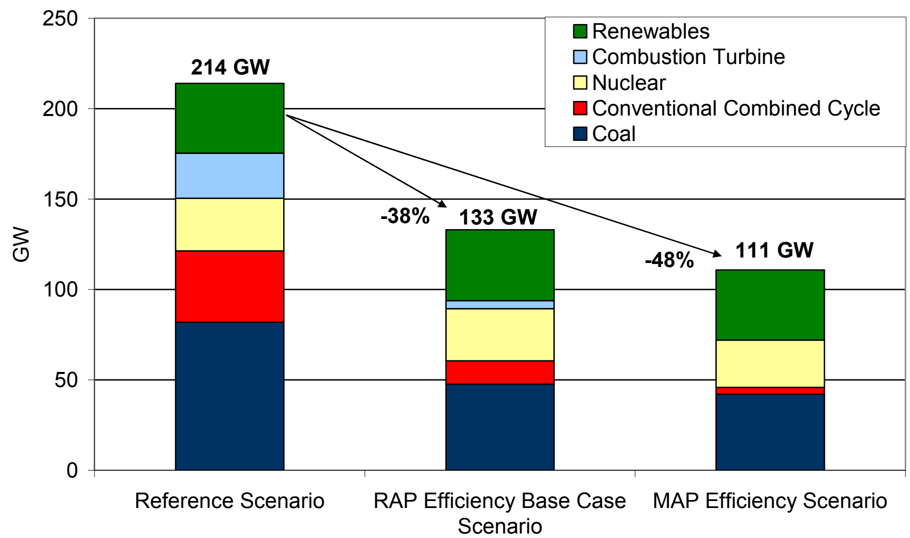


Figure 2
Impact of RAP and MAP EE/DR Programs on Reference Scenario Required Generation Capacity
No Carbon Policy (2010-2030)



Our projected demand and sales reductions from utility EE/DR programs used in this study are based on a study of energy efficiency potentials conducted by EPRI.[4] The EPRI study incorporates extensive analysis of demand response and dynamic pricing programs, as well as energy-saving technologies.

- **Reductions in generation capacity requirements do not mean an equal reduction in total investment, due in part to offsetting the cost of utility EE/DR programs.** As shown in Figure 3, the implementation of the RAP Efficiency Base Case Scenario would reduce required generation investment by $192 billion (28 percent), from $697 billion to $505 billion. Generation investment costs are not reduced in proportion to the GW reduction. This is because the bulk of capacity avoided due to the RAP Efficiency Base Case Scenario programs is comprised of lower capital cost natural gas technologies. This generation investment reduction notwithstanding, the implementation of the RAP Efficiency Base Case Scenario would require an additional investment of at least $85 billion through 2030 in both advanced metering infrastructure (AMI) and EE/DR programs. Thus, the net reduction in total investment needs between the Reference Scenario and the RAP Efficiency Base Case Scenario is $107 billion, or 15 percent.

Figure 3
Potential Avoided Investment from RAP and MAP EE/DR and AMI Programs
No Carbon Policy (2010-2030)

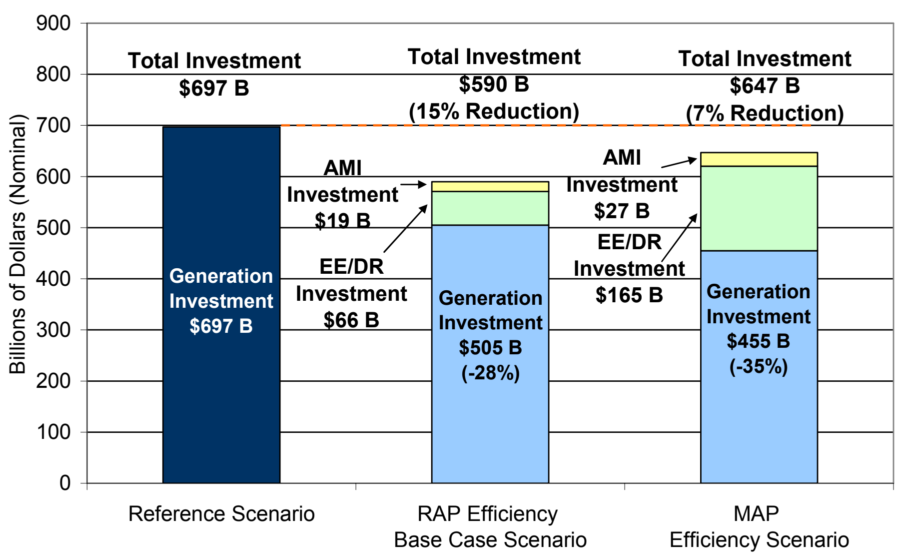


Figure 3 also shows that the more aggressive MAP Efficiency Scenario would lead to a $242-billion (35-percent) drop in the generation investment requirement, from $697 billion to $455 billion. However, this would require AMI and EE/DR program outlays of about $192 billion and, therefore, would decrease total investment needs by only $50 billion to $647 billion, which is a savings of 7 percent.

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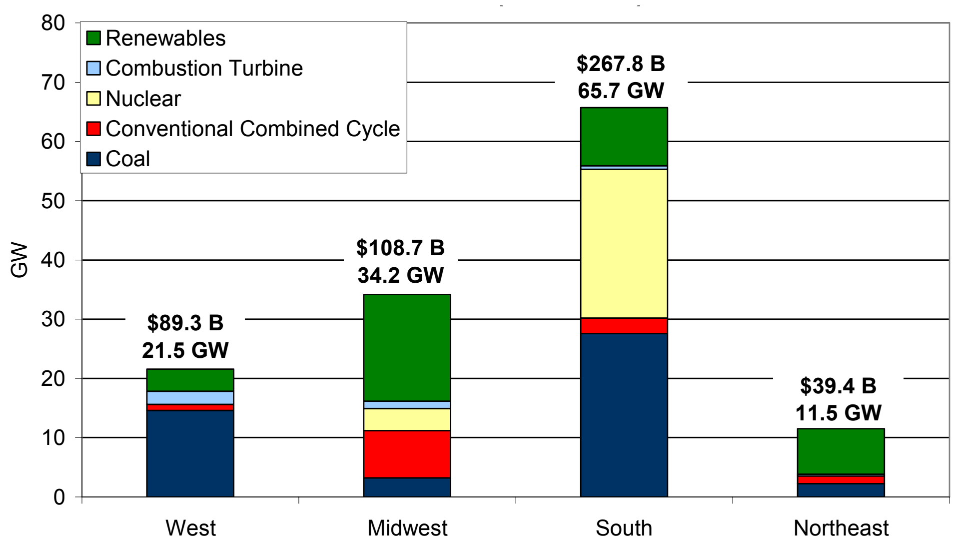
[4] A report on the results of the study, entitled *Assessment of Achievable Potential for Energy Efficiency and Demand Response in the U.S. (2010-2030)*, by the Electric Power Research Institute will be published soon.

- **All types of generation capacity are needed.** As Figure 4 illustrates, in projections through 2030, new generation investment will vary significantly in different regions of the United States, with the highest investment and load growth occurring in the South.

  For the country as a whole, every type of power plant, including those fueled by natural gas, coal, nuclear, and renewable sources will play a significant role in the projected expansion plan. Of the total new 133 GW built under the RAP Efficiency Base Case Scenario, natural gas would fuel 17 GW (13 percent), of which about 13 GW represents combined cycle and 4 GW represents combustion turbines. Coal would comprise an additional 48 GW (36 percent); nuclear would provide 29 GW (22 percent); and renewable sources (primarily wind and biomass) would provide 39 GW (29 percent). This level of renewable investment assumes the full implementation of state-level requirements in place as of August 2008.

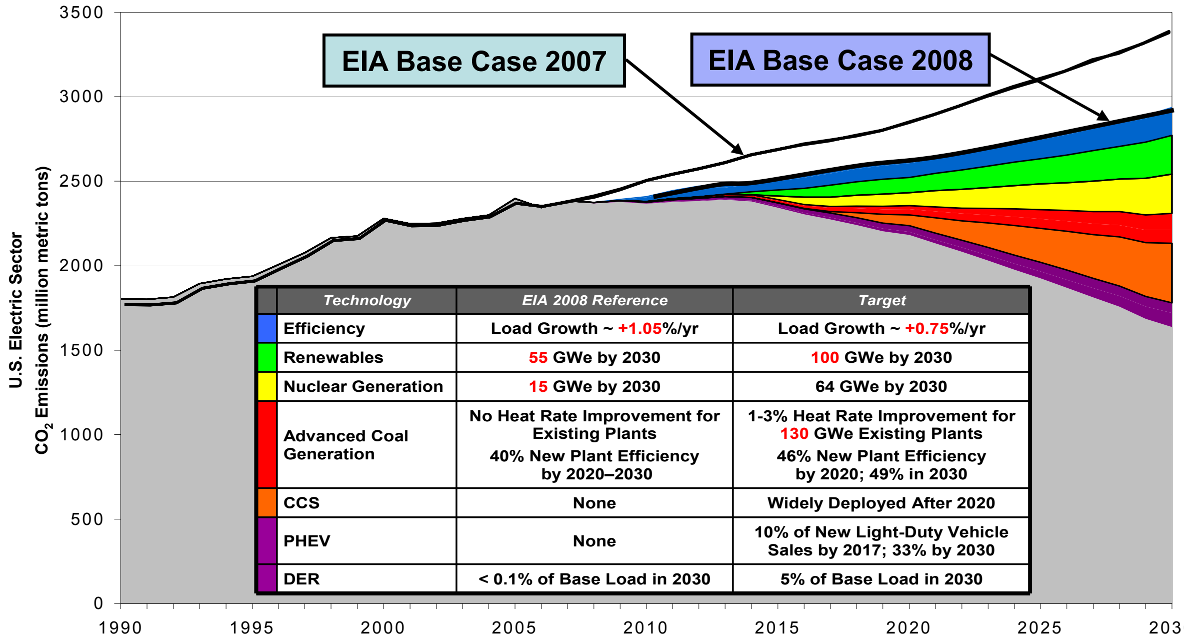
Figure 4
Required New Regional Generation Capacity for RAP Efficiency Base Case Scenario
No Carbon Policy (2010-2030)



- **Implementation of a new federal carbon policy would significantly increase the cost and change the mix of new generation capacity.** For this study, we created a simplified model of one scenario for industry adjustment to a new carbon policy. It is based on EPRI's Prism Analysis, shown in Figure 5, which incorporates both energy efficiency and generation-related technologies to reduce the growth in carbon emissions.[5] In the scenario that we developed based on EPRI's Prism Analysis (i.e., the Prism RAP Scenario), plants with advanced coal technology and full carbon capture and storage (CCS) would be the only coal-based plants deployed after 2020; some fossil-based plants would be retired prematurely; and the electric industry would increase investments in renewable energy and nuclear plants. The results of this scenario should be viewed as an illustrative example of a possible outcome rather than a definitive picture of the impacts of a U.S. carbon policy (Figure 6).

[5] Figure 5 uses "GWe" as an acronym for Gigawatt-electric. GWe is equivalent to GW.

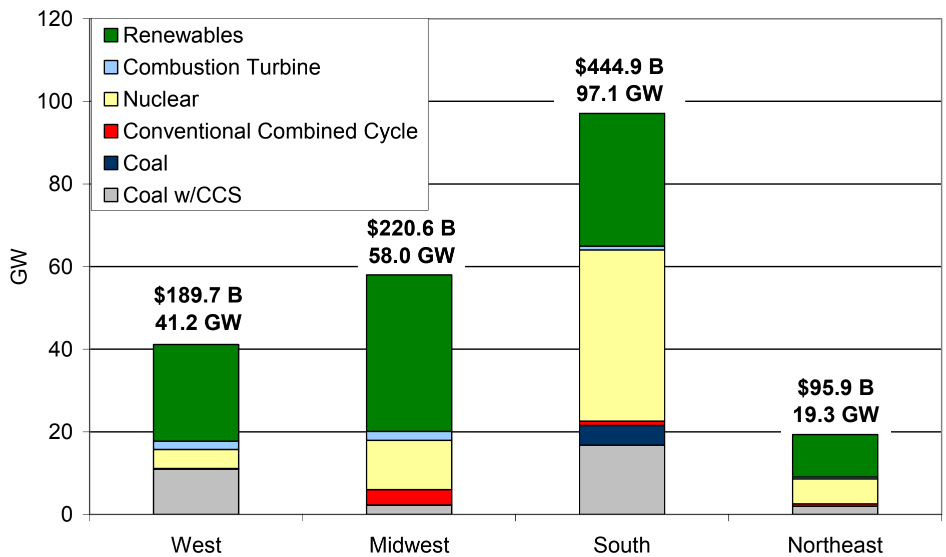
Figure 5
EPRI Prism Analysis for U.S. Carbon Policy Outcomes



Technology	EIA 2008 Reference	Target
Efficiency	Load Growth ~ +1.05%/yr	Load Growth ~ +0.75%/yr
Renewables	55 GWe by 2030	100 GWe by 2030
Nuclear Generation	15 GWe by 2030	64 GWe by 2030
Advanced Coal Generation	No Heat Rate Improvement for Existing Plants 40% New Plant Efficiency by 2020–2030	1-3% Heat Rate Improvement for 130 GWe Existing Plants 46% New Plant Efficiency by 2020; 49% in 2030
CCS	None	Widely Deployed After 2020
PHEV	None	10% of New Light-Duty Vehicle Sales by 2017; 33% by 2030
DER	< 0.1% of Base Load in 2030	5% of Base Load in 2030

Source: Based on data compiled by Electric Power Research Institute (EPRI), found at:
http://www.iea.org/Textbase/work/2008/roadmap/2a_Tyran_EPRI%20Roadmaps.pdf

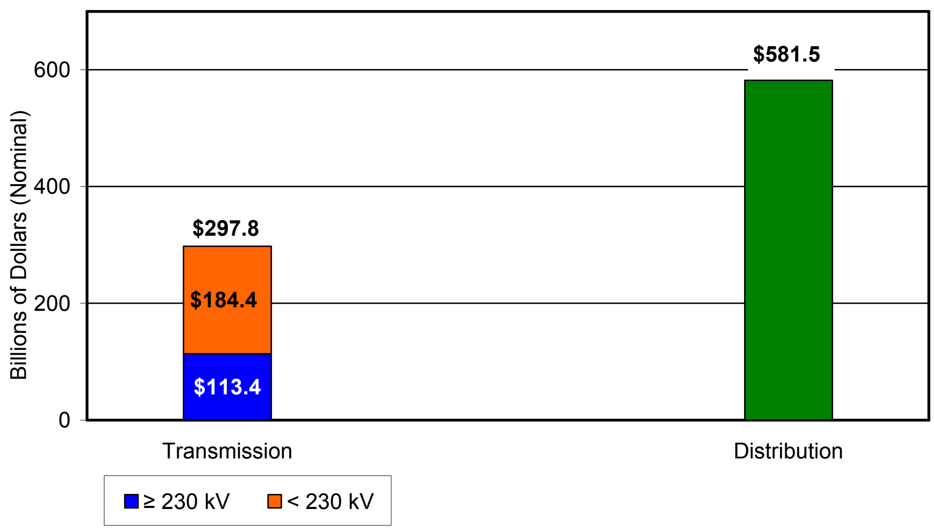
Figure 6
Regional Capacity Additions and Generation Capital Costs
In Prism RAP Scenario with Carbon Policy (2010-2030)



In the EPRI Prism Analysis, energy efficiency programs produce approximately the same reduction in demand growth as under our RAP Efficiency Base Case Scenario. However, in our Prism RAP Scenario, the generation capacity requirements will increase to 216 GW from 133 GW, which will increase the total investment cost to $951 billion from $505 billion. This capacity increase is due to several factors: the greater use of renewables; 21 GW of premature retirements of carbon-intensive generation; and a larger nuclear construction program of 64 GW.

- **Required transmission and distribution (T&D) investment could be as large as, or larger than, generation investment.** The combined investment in new T&D during this period will total about $880 billion, including $298 billion for transmission and $582 billion for distribution (Figure 7).[6] In comparison, generation investment will cost $505 billion for the RAP Efficiency Base Case Scenario. These investments will enable the industry to integrate the approximately 39 GW of renewable energy already mandated under state renewable portfolio standards (RPS) and continue the installation of a "Smart Grid."[7] These investments also will bring new efficiencies and service options to electricity customers and accommodate new end-use technologies, such as PHEVs.

Figure 7
Transmission and Distribution Investment Including Smart Grid
(2010-2030)



[6] These estimates are derived primarily from shareholder-owned electric utility expenditure data. To the extent that the data excludes T&D expenditures undertaken by electric cooperatives or government-owned utilities, these estimates are conservative.

[7] There is currently no standard definition of "Smart Grid" within the electric utility industry. It commonly refers to an array of advanced technologies for the telecommunication network and electric grid that possess two-way communication and monitoring to link all functional areas of the electric power system, including customers. The "Smart Grid" vision is that the technologies will: 1) provide customers with information and tools that allow them to be responsive to system conditions; 2) ensure more efficient use of the electric grid; and 3) enhance system reliability.

Study Methodology

This study's findings are based on EIA's AEO 2008. We modified EIA's data to reflect more recent, higher prices for electric fuels and the costs of new power plants. This resulted in an average price increase of 53 percent for natural gas (Figure 8) and 18 percent for coal (Figure 9) over the 2010 to 2020 period. The cost of constructing new power plants was based on EPRI's Technical Assessment Guide (TAG), published in July 2008 (Figure 10).

Figure 8
Comparison of U.S. Average Delivered Natural Gas Price Projections (2006 Dollars)

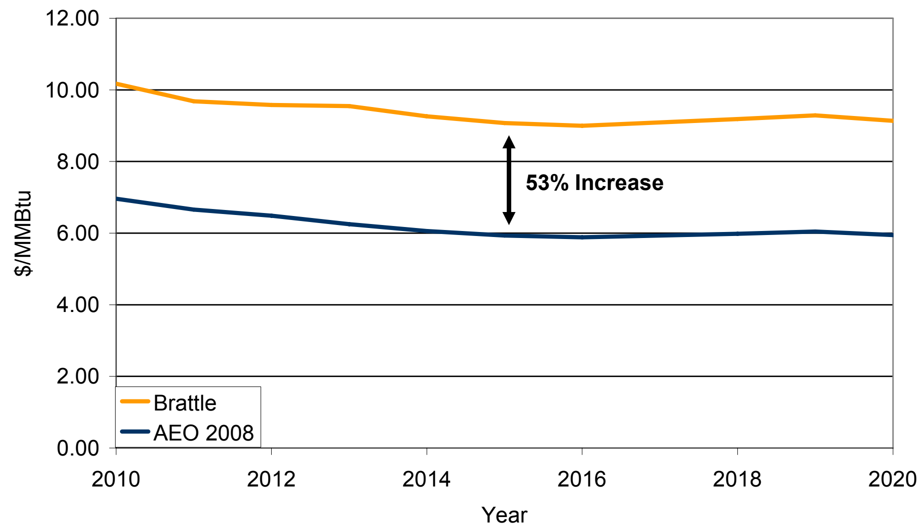


Figure 9
Comparison of U.S. Average Delivered Coal Price Projections (2006 Dollars)

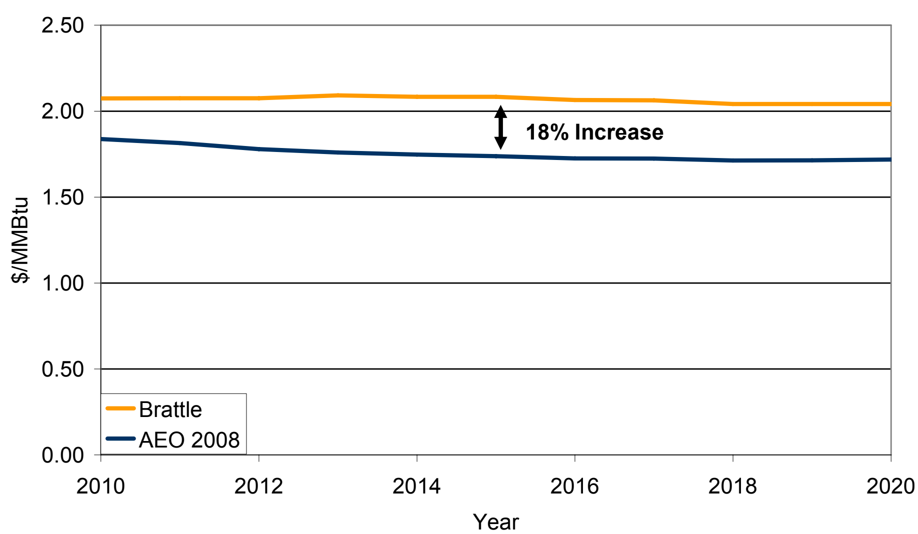
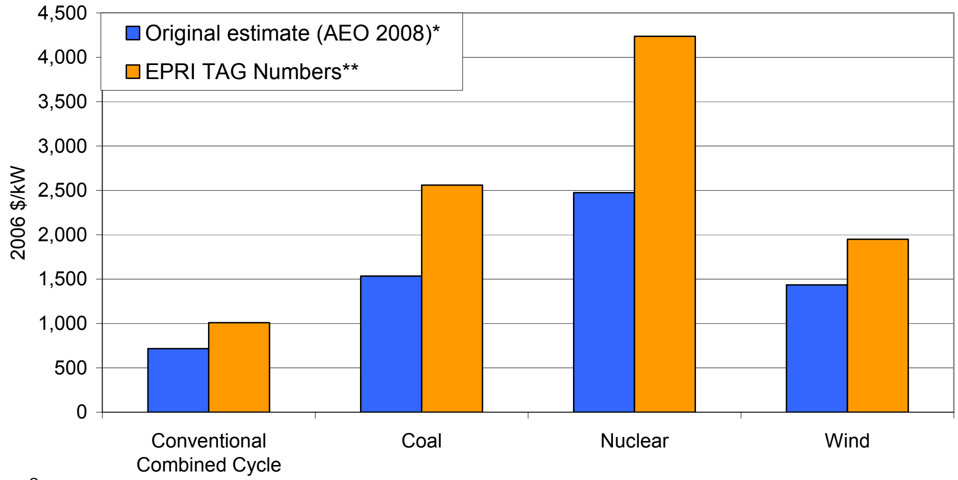


Figure 10
Updated Plant Construction Cost Estimates
(Including Construction Interest)



Sources:
* Annual Energy Outlook 2008, U.S. Department of Energy, Energy Information Administration, June 2008.
** Program on Technology Innovation: Power Generation (Central Station) Technology Options - Executive Summary, Electric Power Research Institute, July 2008.

We inserted these updated cost figures into a generation expansion planning model that *The Brattle Group* developed, the Regional Capacity Model (RECAP). This allowed us to estimate regional least-cost build-out plans through 2030.[8] RECAP uses traditional least-cost planning criteria to choose the mix of generation additions that can most economically supply the energy needs of each region that remain after energy efficiency programs reduce peak demand and energy sales. Using the readjusted EIA data in RECAP, we developed the four scenarios outlined on pages v and vi.

Summary of Results and Conclusion

The results of our study, in terms of capacity and investment costs, are summarized in Table 1.

As our starting point under the Reference Scenario, we determined that the electric industry would have to build 214 GW of new generation capacity and make a total infrastructure investment of $1.577 trillion by 2030. In the RAP Efficiency Base Case Scenario, which depicts the most likely impact of EE/DR programs under existing real-world constraints (and is therefore highlighted in Table 1), the industry still would have to build 133 GW of new generation capacity and make a total infrastructure investment of $1.470 trillion. In the MAP Efficiency Scenario, which depicts the impact of more aggressive EE/DR programs, the required new generation build still would be 111 GW, with a total infrastructure investment cost of $1.527 trillion. Finally, in the Prism RAP Scenario, which depicts the impact of a new carbon policy, the industry would have to build 216 GW of new generation capacity and make a total infrastructure investment of $2.023 trillion.

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[8] It is important to note that we did not model customer response to the increased retail rates that would accompany the higher fuel and construction costs used in RECAP. Depending on the price elasticity of demand, the reductions in future load growth could be significant.

Table 1: Model Results Overview

	Reference Scenario No Carbon Policy	RAP Efficiency Base Case Scenario No Carbon Policy	MAP Efficiency Scenario No Carbon Policy	Prism RAP Scenario Carbon Policy
Average Peak Load Growth Rate		0.70%	0.30%	0.70%
New Capacity Through 2030 (in GW)				
Renewables	38.6	39.2	38.8	103.7
Combustion Turbine	25.0	4.3	0.0	5.5
Nuclear	29.1	28.9	26.2	64.0
Conventional Combined Cycle	39.5	12.9	3.8	5.4
Coal	81.8	47.6	42.1	36.9*
Total New Capacity (GW)	**214.0**	**132.9**	**110.9**	**215.5**
Capital Investment Through 2030 (rounded to nearest billion)				
Generation	$697	$505	$455	$951
Transmission	$298	$298	$298	$298
AMI and EE/DR	$0	$85	$192	$192
Distribution	$582	$582	$582	$582
Total Capital Investment ($ Billions)	**$1,577**	**$1,470**	**$1,527**	**$2,023**

*32 GW of EPRI Prism coal generation incorporates carbon capture and storage.

No matter which scenario is implemented, total utility industry investment needs will range from approximately $1.5 trillion to $2.0 trillion by 2030.

It is important to recognize that total investment amounts are not the same as revenue requirements, rate levels, or societal costs. As a result, one cannot directly link higher investment costs with specific rate changes until fuel costs and other operating expenses are considered. For example, the implementation of RAP and MAP EE/DR programs could lead to reduced fuel expenditures or the Prism RAP Scenario could reduce the costs of complying with carbon policy mandates.

Affordable, reliable electricity is as essential to the global economy of the 21st century as it was to the American economy of the 20th century. The U.S. electric utility industry is capable of rising to this enormous investment challenge, but implementation of appropriate policies will be an essential ingredient for success.

Chapter 1: Reference Projections for New Generation Capacity 2010-2030

The electric utility industry currently faces its greatest challenge in decades as it endeavors to meet rising demand while contending with the impact of higher fuel prices and construction costs. To assist the industry in addressing this challenge, The Edison Foundation commissioned a study by *The Brattle Group* to analyze the impact of higher fuel prices and construction costs on the projected capacity mix through 2030, as well as the overall capital costs associated with this new capacity.[9] Further, *The Brattle Group* was asked to examine the impact on new generation capacity and projected overall capital costs of both an aggressive expansion of energy efficiency and demand response (EE/DR) programs and investments (see Chapter 2) and a federal climate change policy that emphasizes low-carbon investments [such as nuclear, renewables, and coal with carbon capture and storage (CCS)] in the generation sector (see Chapter 3). *The Brattle Group* used analysis for both the EE/DR and climate scenarios from the Electric Power Research Institute (EPRI).

Long-run projections of the cost of building new generation capacity are based on projections of electricity demand growth, generation fuel costs, state-level renewable energy requirements, construction costs, and retail rates. Our analysis used the U.S. Department of Energy's Energy Information Administration's (EIA's) widely used Annual Energy Outlook (AEO) forecast of U.S. electricity market growth as a starting point, but we adopt different assumptions regarding several key elements, such as generation fuel and construction costs, to reflect sustained and substantial price increases that are not reflected in the data used by EIA.

The Annual Energy Outlook

EIA's AEO is a well-known reference for a long-term national generation investment outlook that presents projections of energy supply, demand, and prices for the energy sector (not just electricity) over a 25-year horizon. The projections are based on results from the National Energy Modeling System (NEMS) and assume no changes in energy policy, such as enactment of a federal policy that limits carbon emissions. The AEO is a reliable starting point for analyzing the need for new generation capacity because of its high visibility and credibility among policy makers.

[9] For ease of exposition, we refer throughout this report to *The Brattle Group*; however, the analysis and views contained in this report are solely those of the authors and do not necessarily reflect the views of *The Brattle Group, Inc.* or its clients.

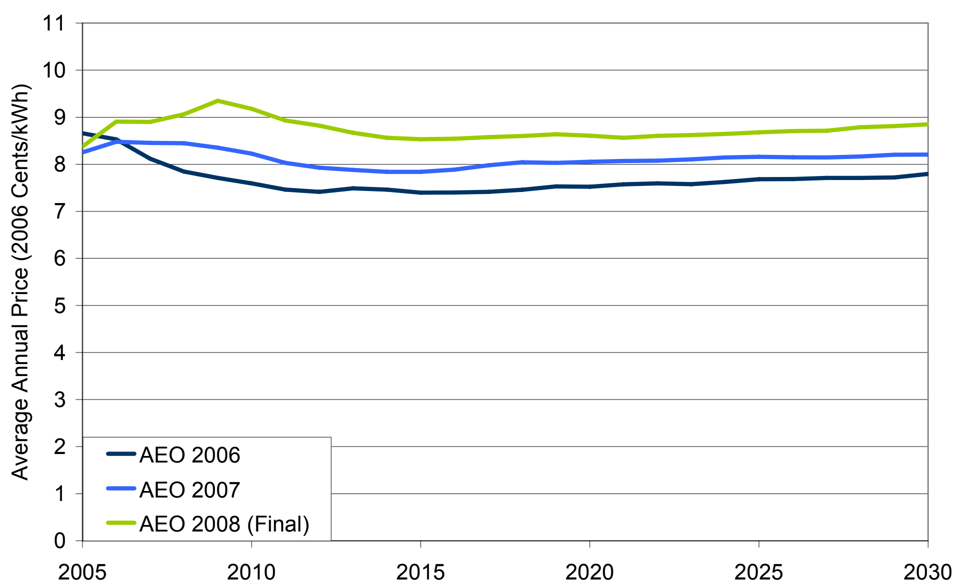
The AEO 2008 was published in June 2008.[10] As part of the AEO release, EIA makes underlying data and detailed NEMS modeling results available, which the authors of this study used to construct alternative projections of capacity builds.

AEO 2008 Load Growth

EIA projects regional and national growth in the demand for electricity through 2030, accounting for assumed economic growth and projected future energy prices. The AEO 2008 forecast projects that electricity demand growth will average about 1.1 percent per year between 2008 and 2030.

In recent versions of the AEO, EIA has projected higher retail electricity prices and lower load growth as a result of those prices (and as a result of policy changes). As the cost of the fuels used to generate electricity has risen over the past several years, customer rates have risen as well. These price increases will tend to dampen load growth.[11] Figure 1-1 shows the increased retail price projections since the AEO 2006, and Figure 1-2 shows the resulting EIA electricity growth projections.

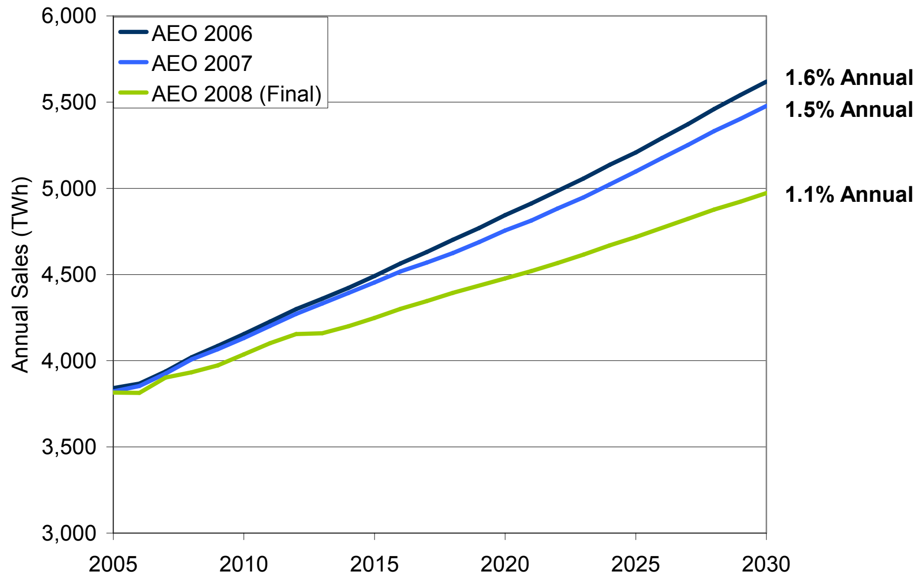
Figure 1-1
Comparison of AEO U.S. End-Use Electricity Price Forecasts



[10] Normally, the AEO is published in January, but EIA elected to postpone the release of the full document until the impacts of the Energy Independence and Security Act of 2007 (EISA) could be incorporated into the long-term projections.

[11] See *Why Are Electricity Prices Increasing? An Industry-Wide Perspective,* prepared by *The Brattle Group* for The Edison Foundation, June 2006, pages 30-31 and Appendix B.

Figure 1-2
Comparison of AEO U.S. Annual Electricity Sales Forecasts



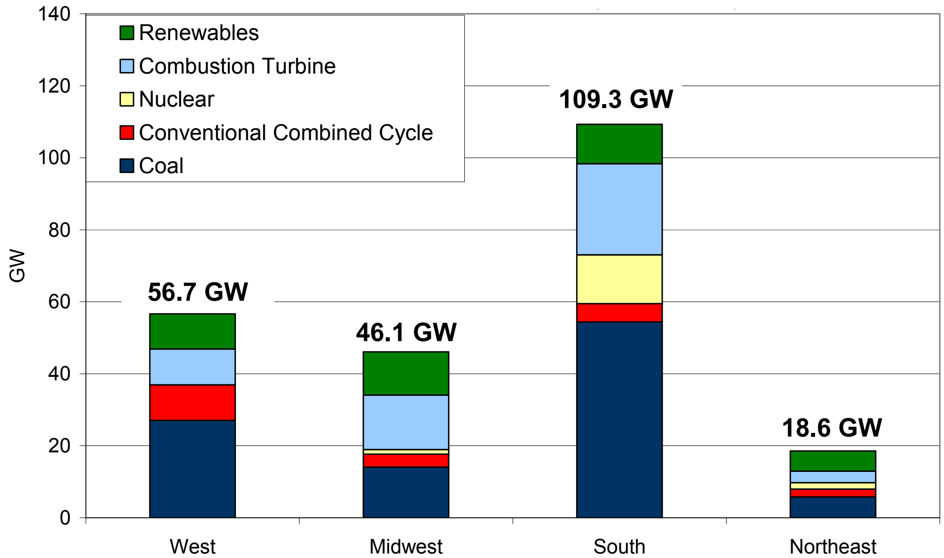
AEO 2008 Generation Investment Projections

New Generation Capacity

According to the AEO 2008, overall electricity consumption will be about five million gigawatt-hours (GWh) by 2030, which will require the addition of 231 GW of new generation capacity during the 2010 to 2030 period. EIA projects that about 101 GW, or 44 percent, of new capacity will be coal-based. Combustion turbines (CTs), which primarily are fueled by natural gas, represent the next largest category of plant, with 54 GW (23 percent) of new CTs built. EIA estimates that the nation will add 38 GW (16 percent of the total) of renewable generation capacity, primarily to comply with existing state-level renewable portfolio standard (RPS) requirements.[12] Natural gas-based combined-cycle plants (21 GW) and nuclear generation (17 GW) make up the remaining capacity additions. Figure 1-3 shows the capacity builds from 2010 to 2030 by technology type in the four main U.S. census regions.

[12] An RPS also can be referred to as a Renewable Electricity Standard (RES).

Figure 1-3
Required New Regional Generation Capacity
AEO 2008 Forecast (2010-2030)



Almost half, or 109 GW, of the cumulative new generation capacity in the AEO 2008 forecast would be located in the South census region, with about half of that as coal-based capacity. The South also accounts for the majority of nuclear capacity additions (15 GW out of a total of 17 GW) nationwide.[13] The West census region would build 57 GW of the new capacity, and the remainder will be built in the Midwest (46 GW) and the Northeast (19 GW). Coal-based capacity additions also comprise about half of the generation capacity added in the West, while capacity additions in the Midwest and the Northeast reflect a more even composition of coal, renewables, combined-cycle, and combustion turbine plants.

The regional differences in cumulative generation capacity additions appear to be largely explained by assumed growth in electricity consumption, relative fuel costs, and the assumed generation capacity retirements. In the South census region, there is significant growth expected in population, economic activity, and electricity demand. According to the AEO 2008 load forecast, roughly half of the expected increase in U.S. electricity demand between 2010 and 2030 will occur in the South.

Renewable capacity builds are primarily a function of state-level RPS requirements that will grow rapidly over the next two decades. One of the significant differences between the AEO 2007 and AEO 2008 capacity projections is the amount of renewables (particularly wind) that is expected to come online. The AEO 2007 projection showed a very small magnitude of renewable capacity additions (only 9 GW through 2030, primarily in early years) while the AEO 2008 projects 38 GW of renewable capacity between 2010 and 2030. This significant increase appears to arise from EIA's increased recognition of the impact of state-

[13] The AEO 2008 provides new generation capacity data by region through the NEMS Electricity Market Module (EMM). Projections of capacity builds in the NEMS EMM regions were mapped to census regions.

level RPS requirements, which require a rising percentage of electricity to be provided by renewable electric generation.[14]

It is important to emphasize that the AEO does not account for the likelihood of a new federal policy to constrain carbon emissions.[15] The emergence of state and regional carbon-reduction efforts and the prospects for a federal carbon policy already have affected utility capacity planning in ways that the AEO projections do not reflect. While the long-term form and intensity of such regulations are very difficult to predict, these regulations likely will have a significant impact on the cost and composition of new generation development, as well as the value of demand-side energy efficiency investments. A detailed examination of these impacts is beyond the scope of this study; however, we do explore the capital cost implications of a technology-based carbon policy on new capacity in Chapter 3.

The Brattle Group's RECAP Model Projections

In order to explore the impact of alternative assumptions and policies on the "projected" or "future" level and composition of new generation capacity builds, *The Brattle Group* used the proprietary Regional Capacity Model (RECAP). RECAP is a regional capacity expansion and economic dispatch model that can be configured to the regional detail that underlies the AEO modeling framework. It provides the optimum generation expansion plan (subject to reliability, technology, and policy constraints) under alternative assumptions regarding load growth, fuel prices, construction costs, and other inputs within the AEO modeling framework. RECAP is described in more detail in Appendix A.

When run with identical economic assumptions and constraints as the AEO 2008 forecast, RECAP projects a mix of generation plant additions (by technology type and region) that corresponds closely to the AEO 2008 projections, suggesting that RECAP provides an appropriate modeling framework to explore the impact of alternative assumptions.

The RECAP model also has the capability to estimate changes in demand for electricity from higher retail prices (i.e., RECAP can explore the implications of customer price elasticity in future load growth scenarios if retail prices change from baseline assumptions). This could occur, for example, as a result of persistently higher generation fuel prices or elevated construction costs as outlined elsewhere in this report. However, in keeping with the objective of maintaining an initial focus in this report on generation sector investment under different assumed scenarios of energy efficiency investment, such an analysis has not been prepared at this time.

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[14] As of August 2008, 27 states and the District of Columbia had RPS programs and an additional five states had renewable energy goals. While the program structure and qualifying renewable technologies for RPS programs differ from state to state, all encourage the development of renewable energy for electricity generation. The most common format is the definition of a target percentage for renewables within the state's energy portfolio during a set time frame (such as: 20 percent renewable energy either by sale or generation by 2015).

[15] The AEO is designed to provide projections under current policy, and the omission of potential carbon policy impacts is consistent with EIA's mandate. In other analyses, EIA has conducted extensive analysis of the impact of carbon policies on future outcomes in the U.S. energy sector.

Major Assumptions in *The Brattle Group's* Reference Scenario

The Brattle Group's Reference Scenario is based on altering a few key assumptions contained in the AEO 2008, particularly those relating to delivered generation fuel prices and construction costs.

Power Plant Construction Costs

In a September 2007 report prepared for The Edison Foundation, *The Brattle Group* observed that the AEO analyses from 2004 to 2007 had assumed that utility construction costs would increase at the general rate of inflation, while actual construction costs were increasing more rapidly.[16] For the AEO 2008, EIA increased the assumed real capital costs of most generation technologies by 15 to 20 percent. However, this adjustment still does not reflect recent increases in construction costs, which continue to occur. Part of this is due to the fact that the costs of many utility construction materials, such as steel, copper, aluminum, and crushed stone, continued to rise through 2007 and early 2008 because of high worldwide demand for these commodities. Many of these commodity-price increases are associated with the weak U.S. dollar, which increases the price of both imported commodities as well as those produced domestically.

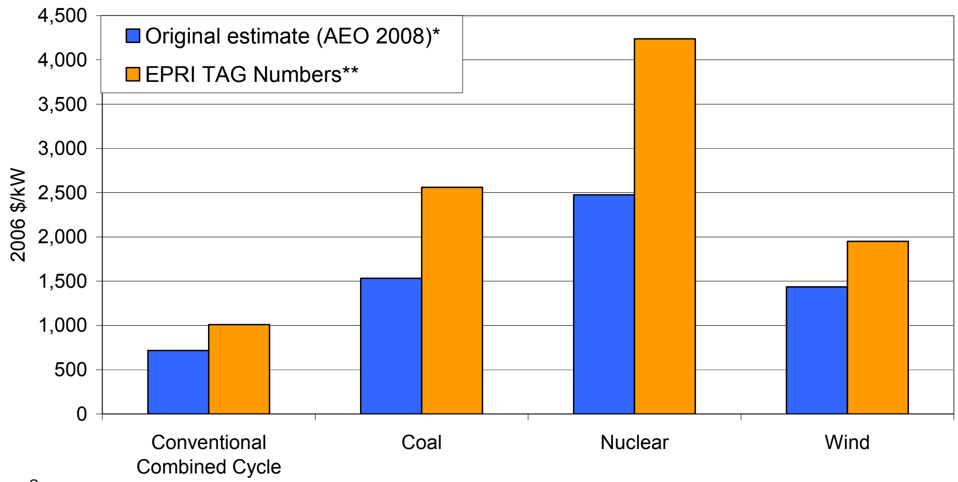
In order to reflect recent construction cost increases, *The Brattle Group* used construction cost figures developed by EPRI that were publicly released in July 2008.[17] These EPRI "Technical Assessment Guide" (TAG) estimates are substantially higher than those assumed by EIA in the AEO 2008, but in our judgment are more accurate than EIA's assumptions at this time.

Applying the EPRI data, in lieu of EIA's assumptions, has a substantial impact. Figure 1-4 compares the capital costs [in dollars per kilowatt (kW) of installed capacity] of the major generation technology types using the AEO 2008 assumptions and the recent EPRI study. As shown in this graph, EPRI's estimates of conventional coal (without CCS) and nuclear costs are about 60 percent higher than EIA's assumptions, and wind and combined-cycle costs are more than 33 percent higher than EIA's assumptions.

[16] See *Rising Utility Construction Costs: Sources and Impacts*, by Marc W. Chupka and Greg Basheda of *The Brattle Group,* prepared for The Edison Foundation, September 2007.

[17] See *Program on Technology Innovation: Power Generation (Central Station) Technology Options – Executive Summary*, Electric Power Research Institute, July 2008.

Figure 1-4
Updated Plant Construction Cost Estimates
(Including Construction Interest)



Sources:
* Annual Energy Outlook 2008, U.S. Department of Energy, Energy Information Administration, June 2008.
** Program on Technology Innovation: Power Generation (Central Station) Technology Options - Executive Summary, Electric Power Research Institute, July 2008.

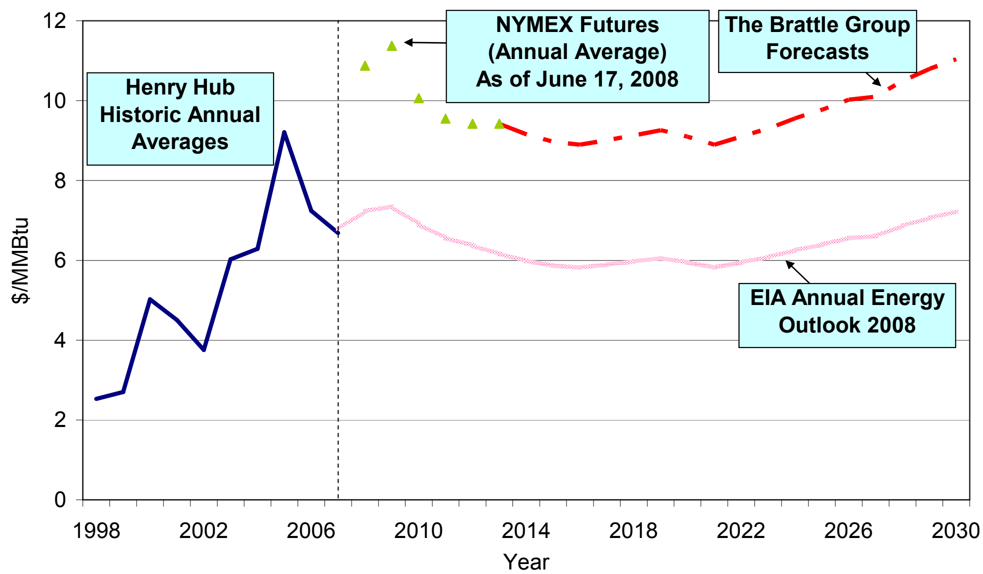
Generation Fuel Prices

The Brattle Group also assumed higher delivered generation fuel prices than EIA used in the AEO 2008. We did this because fuel prices have risen dramatically through this decade and currently are at historic highs. EIA's fuel price forecasts are based on models of long-term fuel market fundamentals, which tend to revert to historic norms and may not capture recent shifts in global markets adequately. Next, we describe how we construct alternative fuel price projections.

For natural gas and oil, *The Brattle Group* used forward prices as cited at The New York Mercantile Exchange (NYMEX), and then we assumed the EIA real price trend thereafter. The five-year forward curve in natural gas (Henry Hub) is roughly 50 percent higher than the prices projected in 2013 in the AEO 2008. Figure 1-5 compares the EIA Henry Hub natural gas fuel price forecast with *The Brattle Group's* projection based on futures market data and the long-term EIA trend.[18]

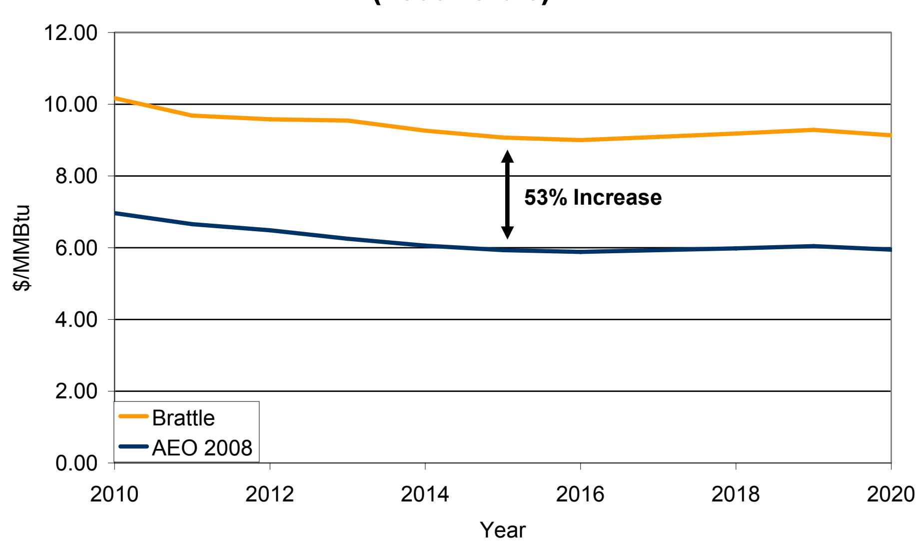
[18] For Figure 1-5, historical averages are brought into real 2006 dollars using Gross Domestic Product (GDP) deflators from the St. Louis Federal Reserve Bank. Forecasted and futures prices are converted to real 2006 dollars using EIA's AEO 2008 GDP deflator forecasts.

Figure 1-5
Historic and Forecasted Annual Average Natural Gas Henry Hub Prices (2006 Dollars)



Regional basis differentials between the Henry Hub price and delivered prices were assumed to remain constant (in real terms) as projected by EIA. Likewise, the difference between EIA crude oil prices and regional product prices (#2 distillate fuel oil and #6 residual fuel oil) also were held constant. Figure 1-6 compares the average delivered natural gas price forecast from the AEO 2008 and the Reference Scenario. *The Brattle Group's* delivered natural gas prices across the regions are 50 percent to 60 percent higher, and the average delivered price is 53 percent higher (in real dollars) than the AEO 2008 forecast prices over the forecast period.

Figure 1-6
Comparison of U.S. Average Delivered Natural Gas Price Projections (2006 Dollars)

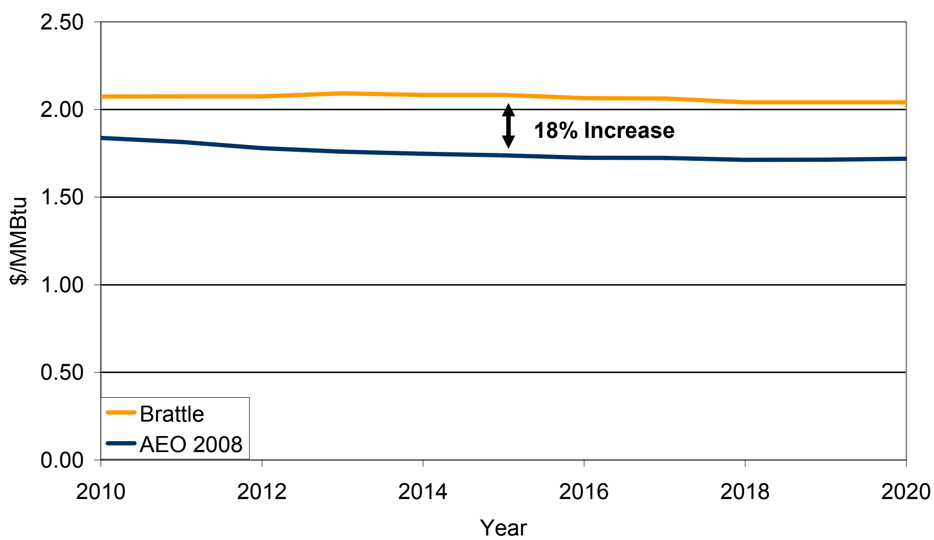


Compared to natural gas or crude oil, coal is a much more heterogeneous fuel, and futures markets for coal are far less developed than for liquid and gaseous fuel commodities. Nevertheless, coal prices clearly have risen in the past decade, in varying amounts across regions and coal types. In order to reflect these changes, *The Brattle Group's* projections for regional coal prices were increased above EIA's projected levels to reflect higher production and transportation costs, using the following assumptions:

- All minemouth prices were increased assuming that 15 percent of the minemouth price is energy-related costs, and this portion of the cost would increase by a factor equal to the difference between EIA's and *The Brattle Group's* forecasts of distillate fuel price;
- Appalachian coal minemouth price was raised by an additional 20 percent over the next 10 years to reflect increased export demand for this type of coal;
- Using origin-destination coal shipment and price data, we derived the implicit transportation costs, from which we derived cost adders assuming that 25 percent of transportation costs were fuel-related. We applied these adders to delivered prices.

As a result of these adjustments, *The Brattle Group* concluded that projected regional delivered prices for coal are roughly 10 percent to 25 percent higher than those projected by EIA in the AEO 2008 forecast. Figure 1-7 displays the average U.S. delivered coal price difference, showing that *The Brattle Group* forecast averages 18 percent higher than the AEO 2008 average forecast.

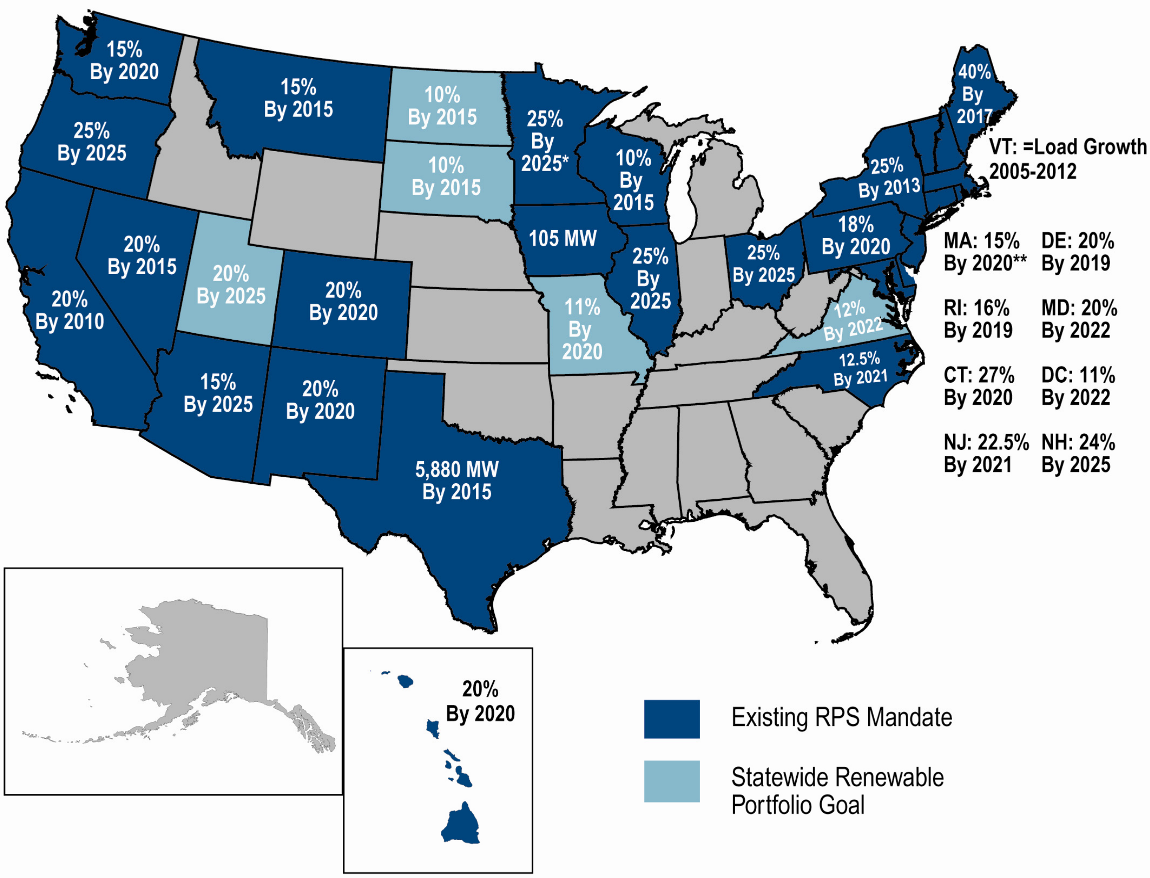
Figure 1-7
Comparison of U.S. Average Delivered Coal Price Projections
(2006 Dollars)



State Renewable Electricity Requirements

As of August 2008, 27 states and the District of Columbia had adopted RPS programs that require them to meet a percentage of the state's electricity needs with renewable generation. Another five states have instituted statewide renewable electricity goals that are not requirements. Because state RPS programs are driving investment in generation, we analyzed existing state-level RPS requirements and linked them to projections of demand growth. Figure 1-8 illustrates these renewable requirements and goals for each state. These requirements were maintained in the RECAP model.

Figure 1-8
State Renewable Portfolio Standards and Goals



*Xcel Energy: 30% By 2020 **Increasing 1% per year thereafter, with no stated expiration date

Source: Edison Electric Institute, status as of August 26, 2008.

Load Growth

As discussed earlier, we assumed the same regional load growth as in the AEO 2008 forecast. This enabled us to explicitly examine the impact of EE/DR investments on projected capacity growth without separately estimating how customers might respond to higher retail rates implied by the higher assumed fuel and construction costs.

Nuclear Limits

We placed limits on the amount of nuclear capacity that could be added in each region to reflect the lengthy regulatory process and construction schedules for new nuclear plants. For 2015, no new nuclear construction was assumed complete. For 2020, we constrained RECAP to limit nuclear construction to those projects that have applied for a Nuclear Regulatory Commission (NRC) license, representing approximately 18.5 GW of new capacity. For 2025, we limited nuclear construction to those projects that have applied or announced intentions to apply to the NRC for a license, which totals about 38.5 GW of new capacity. Between 2025 and 2030, we assumed that the industry could add between one GW and four GW of new nuclear capacity in each region, above the overall 2025 limit of 38.5 GW. This brings the total limit for 2030 to 64 GW.

The Brattle Group's Reference Scenario

As an interim step in our analysis, we created a "Reference Scenario." This scenario is similar to the AEO 2008 forecast, but reflects higher construction costs and fuel prices. The Reference Scenario should not be viewed as our "base" or "most likely" scenario, but rather a starting point for our analysis. Figure 1-9 shows the cumulative capacity built between 2010 and 2030 under the Reference Scenario. Compared to the AEO 2008 forecast of 231 GW of new capacity built, the Reference Scenario builds 214 GW of new capacity.[19] As in the AEO 2008 forecast, almost half of new generation capacity through 2030 is built in the South, followed by the Midwest and the West (Figure 1-10). New generation capacity in the Northeast constitutes less than 10 percent of nationwide capacity.[20]

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[19] Further comparisons of our Reference Scenario and AEO forecasts are shown in Appendix A, Figure A-1.

[20] The difference in the overall amount of generation capacity may be due to differences in how load is modeled, capacity availability, and transmission losses.

Figure 1-9
Cumulative New Generation Capacity
Reference Scenario - No Carbon Policy (2010-2030)

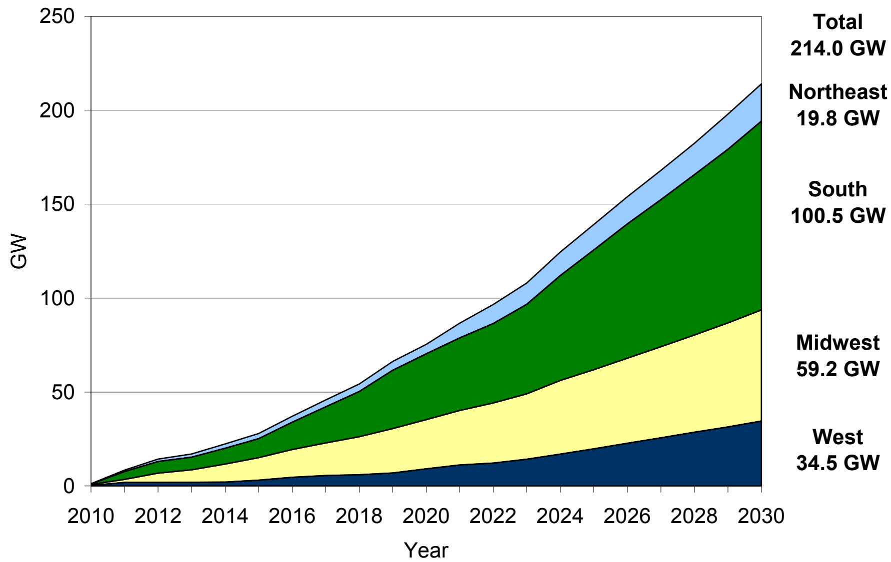
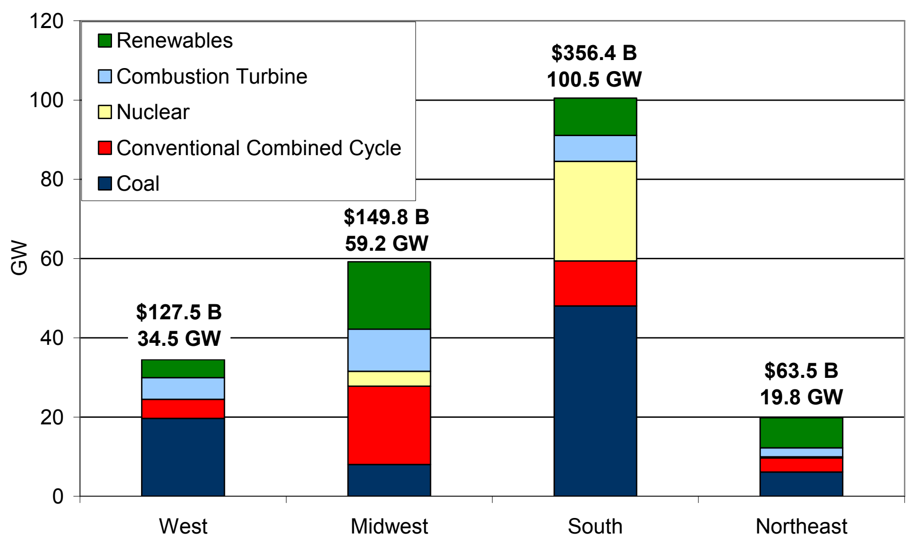


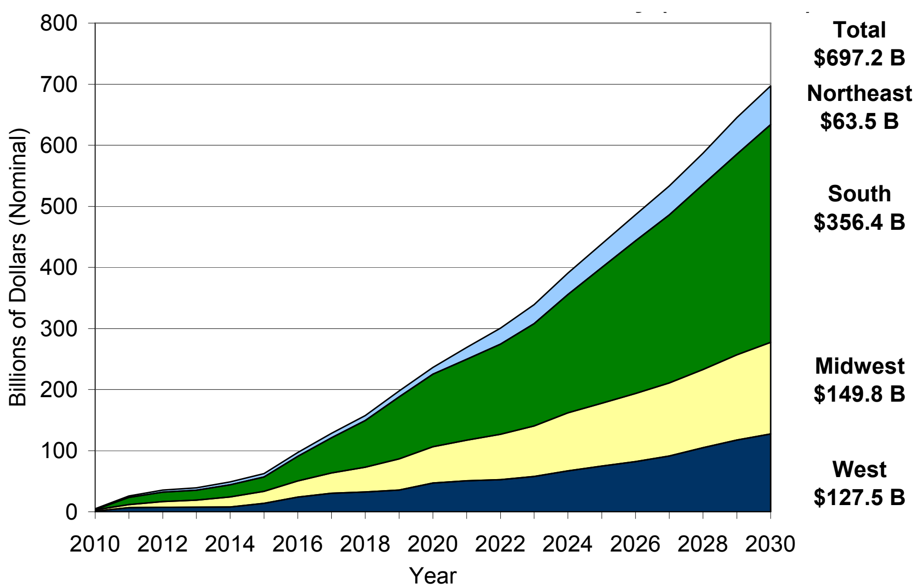
Figure 1-10
Required New Regional Generation Capacity
Reference Scenario - No Carbon Policy (2010-2030)



Generation Investment in the Reference Scenario

Under the assumed construction costs, the Reference Scenario capacity expansion would entail spending $697 billion over the 2010 to 2030 period (undiscounted, nominal, mixed-year dollars assuming a 1.9-percent annual inflation rate). Figure 1-11 shows the cumulative capital cost by region, where the South accounts for slightly more than half of the total ($356 billion). Although construction costs are somewhat lower in the South compared to the rest of the country, the cumulative capital costs reflect the prevalence of new baseload generation – coal and nuclear – that is being built in the South compared to other regions. On a cumulative installed basis, the mix of generation resources built in the South averages $3,560/kW, only slightly less expensive than capacity built in the West ($3,630/kW), higher than that built in the Northeast ($3,150/kW), and much higher than that built in the Midwest ($2,542/kW).

Figure 1-11
Cumulative Capital Requirements New Generation Capacity
Reference Scenario - No Carbon Policy (2010-2030)



Chapter 2: Energy Efficiency and Demand Response Programs and Their Impacts

For a number of reasons, there has been a strong revival of interest in utility EE/DR efforts. EE/DR generally are defined as measures that utilities undertake to reduce customer energy consumption and peak loads.[21] The Energy Independence and Security Act of 2007 (EISA) contained several initiatives to increase energy efficiency. Several states have set ambitious goals to reduce or even eliminate the growth in electricity demand. Utilities are facing increased opposition to building new power plants, in part because of public perceptions that robust efforts to intensify energy efficiency measures and rely more on renewable generation can eliminate the need for new generation capacity, particularly as a national policy to limit carbon emissions may be enacted in the next decade.

EE/DR Forecast Overview

As an increasing emphasis is placed on the importance of EE/DR as resources in the nation's energy mix, The Edison Foundation asked *The Brattle Group* to incorporate the potential peak demand and energy savings that EE/DR could provide and to estimate their impact on projected utility generation and investment requirements. *The Brattle Group* did so by relying upon a study by EPRI.[22] This study produced a regional forecast of the measure-specific potential savings that could be realized through the implementation of EE/DR programs in addition to important efficiency measures already imposed by EISA, which EIA already took into account in its AEO 2008 forecast. Specifically, the study produces two "potential" estimates.

- ***"Realistically Achievable Potential" (RAP) Efficiency Base Case Scenario***. This scenario recognizes imperfect dissemination of customer information and the real-world factors associated with utility program implementation (i.e., budgetary constraints, competing priorities, etc.). The RAP Efficiency Base Case Scenario also reflects realistic customer participation rates based on recent historical experience with EE/DR programs. These realistic customer participation rates take into account existing political and regulatory barriers that are likely to limit the amount of savings that might be achieved through EE/DR programs.

- ***"Maximum Achievable Potential" (MAP) Efficiency Scenario***. This scenario is a measure of all energy and peak demand savings that would be adopted by customers under ideal utility program conditions. The MAP Efficiency Scenario does not reach the full theoretical economic potential because there are barriers to customer adoption of measures that appear to be cost-effective that will

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[21] The usage in this paper of "energy efficiency" or "EE/DR" includes energy efficiency efforts as well as demand response.

[22] A report on the results of the study, entitled *Assessment of Achievable Potential For Energy Efficiency and Demand Response in the U.S. (2010-2030),* by the Electric Power Research Institute will be published soon.

not be overcome with utility programs (e.g., customer unwillingness to purchase certain technologies or to enroll in cost-effective programs).

The EPRI study contains substantial additional detail on the derivation of these and other potential estimates. For the purposes of this study, we examine the regional RAP Efficiency Base Case Scenario and the MAP Efficiency Scenario savings trajectories and their associated costs. ***In particular, our RAP Efficiency Base Case Scenario includes EE/DR savings as our best estimate of projected demand for electricity prior to the full modeling of price response or a national carbon policy.***

Energy Efficiency

One of the two components of the EPRI forecasts is energy efficiency (EE). The EE forecasts consider an extensive set of technologies and measures for the residential, commercial, and industrial sectors. These EE technologies and measures affect different end uses. Programs, products, and services that encourage customers to adopt EE technologies and measures come in several forms, including rebates and subsidies. Following are some of the various technologies and measures considered in the EPRI study and the end uses they affect.

- ***Residential High-Efficiency Equipment:*** The residential high-efficiency equipment categories include: central and room air conditioners, heat pumps, efficient lighting, water heating, refrigerators, freezers, clothes washers and dryers, and dishwashers. Other measures and devices include: air conditioning maintenance, ceiling and whole-house fans, ceiling and wall insulation, duct insulation and repair, external shades, foundation and wall insulation, heat pump maintenance, infiltration control, programmable thermostats, reflective roofs, storm doors, faucet aerators, pipe insulation, and low-flow showerheads. These measures affect various end uses, such as cooling, space heating, lighting, water heating, refrigeration, clothes washing and drying, and dishwashing.

- ***Commercial High-Efficiency Equipment:*** The commercial high-efficiency equipment categories include: central air conditioners, chillers, heat pumps, fans, other water heating, lighting, refrigeration, and office equipment. Other measures and devices include duct insulation, economizers, energy management control systems, fans with energy-efficient motors, variable speed control fans, programmable thermostats, variable air volume systems, variable speed drive on pumps, water temperature reset devices, outdoor daylight controls, light-emitting diode exit lighting, occupancy sensors, task lighting, photovoltaic outdoor lighting, high-efficiency compressors, anti-sweat heater controls, floating head pressure controls, glass door installations, and vending machines. These technologies and measures affect various end uses, such as cooling, space heating, ventilation, lighting, water heating, and refrigeration.

- ***Industrial High-Efficiency Equipment:*** The industrial high-efficiency equipment categories include: motors of various types and sizes; electric resistance and radio frequency devices; heating, ventilating, and air conditioning systems; and incandescent, fluorescent, and high-intensity discharge lighting. These measures include various end uses, such as process heating, machine drives, and lighting.

Demand Response

While energy efficiency technologies and measures are designed for the purpose of reducing overall electricity consumption, DR programs focus specifically on reducing peak demand. They also provide a means for cutting back load during times of system emergencies, system peaks, or high market prices. The EPRI study modeled three types of DR programs for the residential, commercial, and industrial sectors.

- ***Direct Load Control (DLC):*** Customer end uses are controlled directly by the utility through a "switch" or other comparable two-way communication-capable control device. This DLC device allows for customers' end-use settings to be automatically and remotely altered such that the loads are reduced during short "critical" event periods when the reductions are needed most. Customers commonly have the option of overriding the functionality of the DLC devices before or during events. End uses commonly controlled through DLC include air conditioners and water heaters. In exchange for participation, customers are typically awarded a payment or a rebate on their bill.

- ***Interruptible Service:*** Interruptible service programs require customers to reduce their usage by a pre-specified amount when called upon by utilities during system emergencies. These programs are generally only available for commercial and industrial (C&I) customers. For their participation, these customers generally receive a lower rate and/or a payment for the load reduction they provide.

- ***Dynamic Pricing:*** Dynamic pricing includes rate designs that are time-varying and reflect the higher cost to the utility of providing electricity during the peak period of the day. These designs go beyond the basic flat rate or even the time-of-use (TOU) rate, and can be "dispatched" during times of high market prices or system emergencies. Examples include critical peak pricing (CPP), peak time rebates (PTR), and real-time pricing (RTP). Customers must be equipped with an interval meter or "smart meter" as part of the evolving advanced metering infrastructure (AMI) to be eligible to participate in any dynamic pricing program. For CPP and RTP, customers receive an incentive equal to the potential bill savings that would come from shifting load from higher-priced (peak) periods to lower-priced (off-peak) periods. For PTR, customers receive a credit on their bill equal to the peak reduction multiplied by the pre-determined rebate amount.

In the EPRI forecast, the residential DLC programs apply to central air conditioning and water heating loads. The C&I programs target cooling, lighting, and other end uses. The interruptible service programs apply only to C&I customers and include interruptible, demand bidding, emergency, and ancillary services. The combined peak demand reduction of all of these programs produces the systemwide impact.

Load Forecast Summary for AEO 2008 and EE/DR Scenarios

The resulting annual peak and energy forecasts used by *The Brattle Group* in this analysis are shown in Figure 2-1 and Figure 2-2. By 2030, the peak reduction from the AEO 2008 load forecast is 12 percent in the RAP Efficiency Base Case Scenario and 19 percent in the MAP Efficiency Scenario (Figure 2-1).[23] Energy savings in 2030, shown in Figure 2-2, are five percent in the RAP Efficiency Base Case Scenario and eight percent in the MAP Efficiency Scenario.

[23] For a discussion of how these EE/DR projections differ from those presented in the final EPRI study, see Appendix A.

Figure 2-1
Comparison of U.S. Peak Demand Forecasts

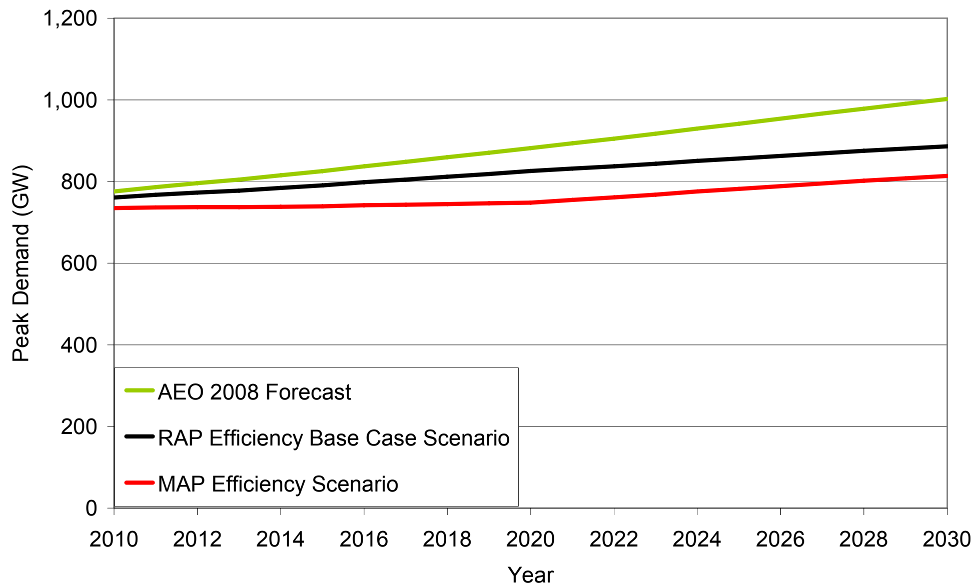
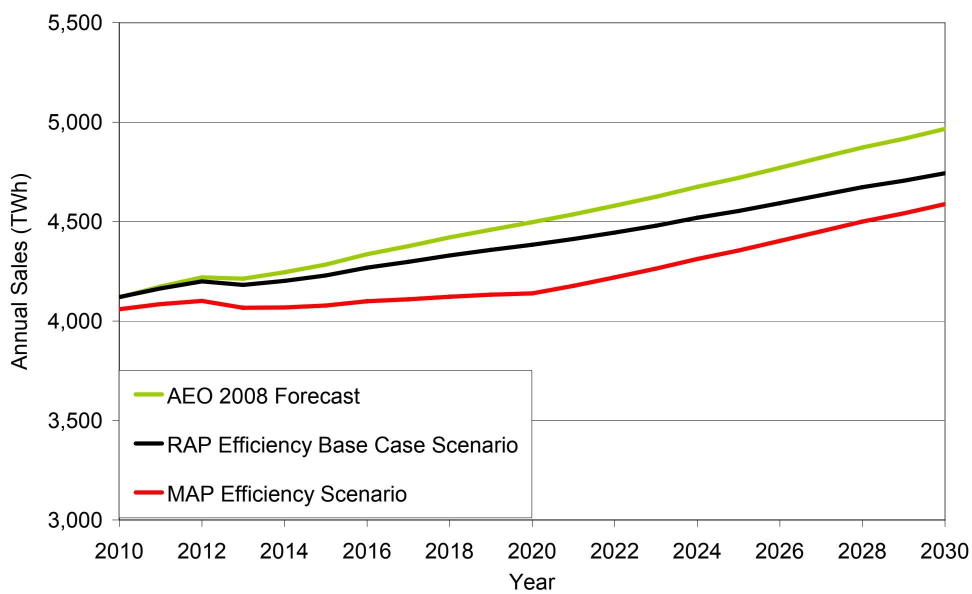


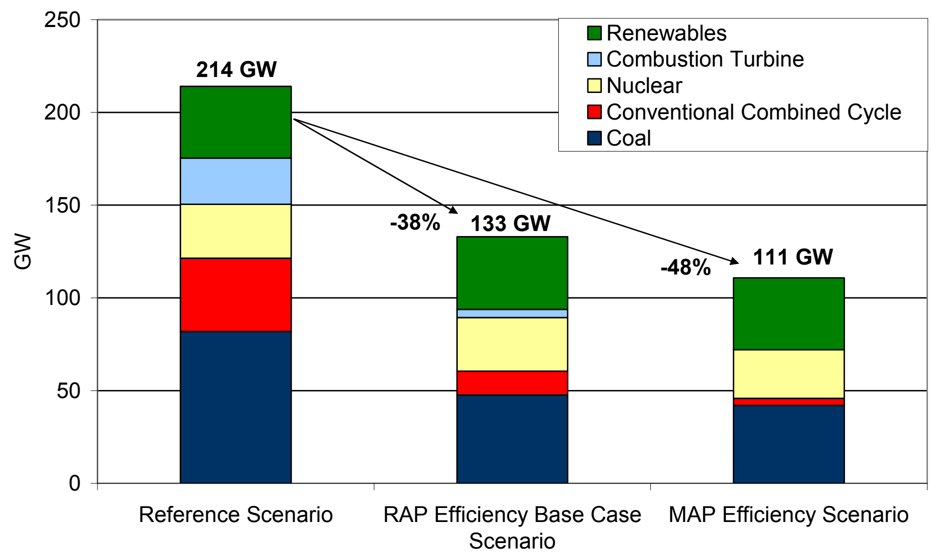
Figure 2-2
Comparison of U.S. Electricity Sales Forecasts



Impacts of EE/DR Forecasts on Capacity Expansion Projections

Relative to the Reference Scenario, the RAP Efficiency Base Case Scenario and the MAP Efficiency Scenario lead to a dramatic reduction in the amount of new generation capacity that would need to be built. Our projection of new generation capacity between 2010 and 2030 drops from 214 GW in the Reference Scenario to 133 GW in the RAP Efficiency Base Case Scenario. The amount of projected new capacity drops further to 111 GW in the more aggressive MAP Efficiency Scenario. These changes in total U.S. new generation capacity under the two energy efficiency (no carbon policy) scenarios are shown in Figure 2-3.

Figure 2-3
Impact of RAP and MAP EE/DR Programs on Reference Scenario Required Generation Capacity
No Carbon Policy (2010-2030)



The mix of new capacity also changes in the two EE/DR scenarios (no carbon policy) because they project an improving load factor for all regions of the United States. In other words, the RECAP projections for these scenarios suggest that, on a percentage basis, more peaking capacity will be avoided than baseload. As illustrated in Table 2-1, in the RAP Efficiency Base Case Scenario, new coal-based capacity decreases by 42 percent, while new combustion turbine (CT) capacity decreases by 83 percent. The load factor improvement also persists in the MAP Efficiency Scenario, where 49 percent of new coal capacity is avoided, and *all* new CT capacity is avoided. However, it is important to note that, despite the changing mix of new capacity, coal dominates the total amount of new builds across the three scenarios.

Table 2-1
Changes in New Capacity Under Energy Efficiency Scenarios

Changes in New Capacity from Reference Scenario Through 2030 (in GW)	RAP Efficiency Base Case Scenario No Carbon Policy		MAP Efficiency Scenario No Carbon Policy	
Renewables	+0.6 GW	(+ 1.5%)	+0.2 GW	(+ 0.5%)
Combustion Turbine	-20.6 GW	(-82.6%)	-25.0 GW	(-100.0%)
Nuclear	-0.2 GW	(- 0.8%)	-2.9 GW	(-10.1%)
Conventional Combined Cycle	-26.6 GW	(-67.3%)	-35.7 GW	(-90.5%)
Coal	-34.2 GW	(-41.8%)	-39.7 GW	(-48.6%)
Total Change in New Capacity (GW)	**-81.1 GW**	**(-37.9%)**	**-103.2 GW**	**(-48.2%)**

* Note: Totals may not equal sum of components due to independent rounding.

The mix of avoided generation capacity plays an important role in determining the avoided capital costs achieved through EE/DR. In the RAP Efficiency Base Case Scenario, the total cost of new capacity is projected to be $505 billion in nominal terms. This represents a 28-percent decrease from the Reference Scenario (Figure 2-4 and Figure 2-5).

Figure 2-4
Cumulative Capital Requirements for New Generation Capacity for RAP Efficiency Base Case Scenario No Carbon Policy (2010-2030)

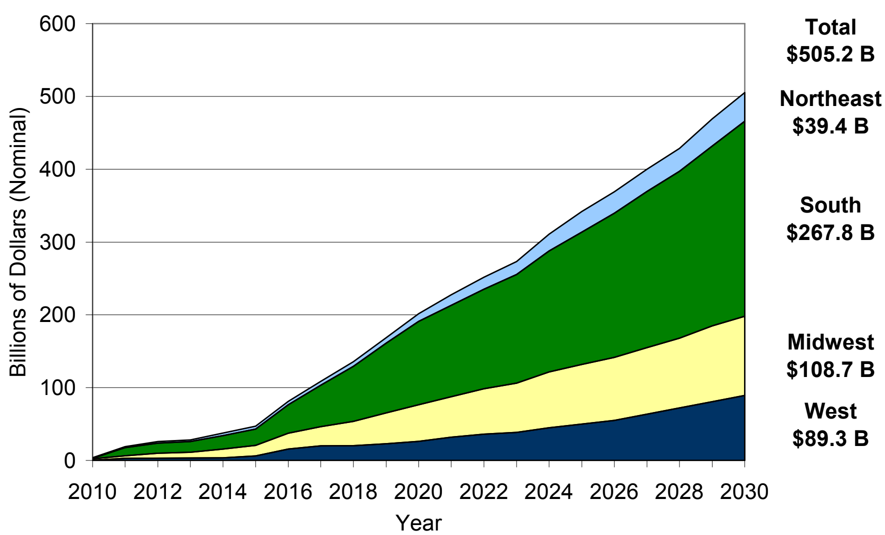
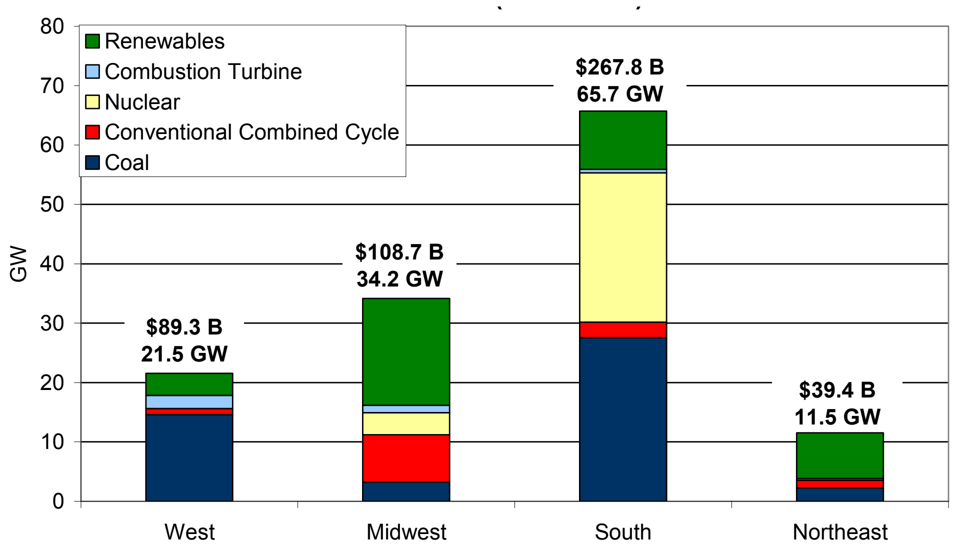


Figure 2-5
Required New Regional Generation Capacity for RAP Efficiency Base Case Scenario
No Carbon Policy (2010-2030)



The MAP Efficiency Scenario projects the total cost of new capacity to be around $455 billion in nominal terms, a 35-percent decrease from the Reference Scenario (Figure 2-6 and Figure 2-7).

Figure 2-6
Cumulative Capital Requirements for New Generation Capacity for MAP Efficiency Scenario
No Carbon Policy (2010-2030)

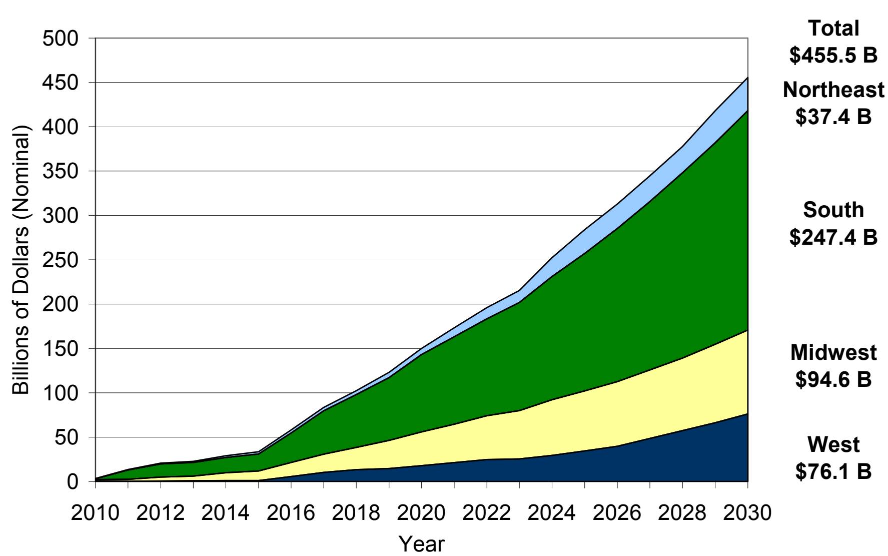
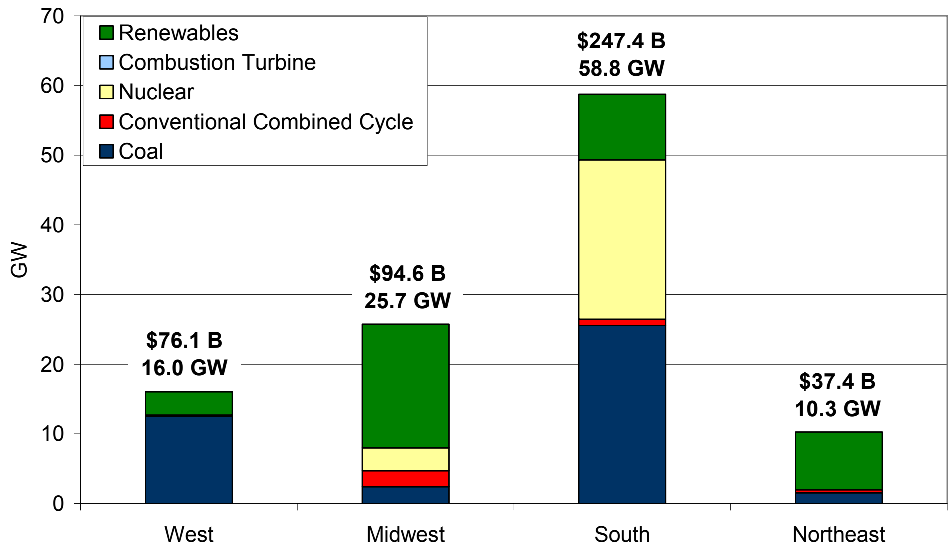


Figure 2-7
Required New Regional Generation Capacity for MAP Efficiency Scenario
No Carbon Policy (2010-2030)



The larger relative reduction in new costs in the MAP Efficiency Scenario is driven by two factors. First, the EE/DR assumptions are more aggressive, resulting in larger peak reductions and a higher level of avoided capacity. Second, a higher relative percentage of coal capacity is avoided through this scenario, further reducing the total cost. Ultimately, in nominal dollars, the RAP Efficiency Base Case Scenario leads to a $192-billion (28-percent) reduction in the capital cost of new generation, while the MAP Efficiency Scenario leads to a $242-billion (35-percent) reduction.

Costs Associated with EE/DR Programs

The EE/DR forecasts that we have analyzed in this study are composed of a number of EE/DR programs, and each of these programs has its own associated costs. For example, in a program to encourage the adoption of more energy-efficient appliances, residential customers might receive a rebate for the purchase of a new air conditioner, refrigerator, or dishwasher. Similarly, for their participation in an interruptible service program, industrial customers might receive a discounted electricity rate or a rebate for each kilowatt-hour (kWh) of reduced consumption during peak periods.

A major cost that is likely to be capitalized in the EE/DR forecast is investment in AMI, the equipment that enables dynamic pricing (as well as a wide range of operational benefits and reliability improvements). Harvesting potential gains from DR programs will require a substantial capital investment in AMI, as well as customer adoption of dynamic pricing, which is necessary to enable customers to curtail loads or shift consumption patterns away from peak periods in response to price signals. To estimate the capital cost of

DR initiatives, we separately projected the investment in AMI that likely would be necessary to support these forecasts.[24]

Our projection of AMI investment costs is driven primarily by three factors:

- **Final AMI penetration rate**: For the MAP Efficiency Scenario, we have assumed that 30 percent of residential customers and 50 percent of C&I customers would be equipped with AMI. These participation rates were reduced by roughly 60 percent to produce the RAP Efficiency Base Case Scenario.
- **AMI deployment rate over time**: We assume that AMI deployment will begin in 2010 for C&I customers and in 2015 for residential customers. Full deployment will be reached in 2030 for the RAP Efficiency Base Case Scenario. Deployment is accelerated under the MAP Efficiency Scenario, reaching full deployment in 2020.
- **Cost of AMI per customer**: Based on a review of California shareholder filings for AMI budget approval, we have estimated the full cost per residential customer to be $300. The cost per C&I customer is estimated at $1,500.

In addition to estimating the cost of AMI, the measure costs of energy efficiency also were included. Energy efficiency measure costs do not include direct program costs, such as program design, administration, marketing, and evaluation. They are the specific costs of the measure, such as equipment and installation costs. Assumed average levelized measure costs were assumed to be: $0.0188 per kWh in 2010, $0.0299 per kWh in 2020, and $0.0279 per kWh in 2030.[25] With these assumptions, we are able to project the annual investment in AMI and energy efficiency between 2010 and 2030.

Table 2-2 shows these costs on an undiscounted nominal basis. Total EE/DR outlays are about 44 percent of the avoided capacity cost in the RAP Efficiency Base Case Scenario and 79 percent of avoided capacity costs in the MAP Efficiency Scenario.

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[24] These are very rough approximations that are intended only to provide an idea as to the magnitude of DR capital costs relative to the avoided capital costs of generation from Demand Side Management (DSM). A detailed, region-specific, bottom-up study would be necessary to provide precision to these estimates.

[25] Costs provided by Global Energy Partners as inputs to the forthcoming EPRI report, *Assessment of Achievable Potential for Energy Efficiency and Demand Response in the U.S. (2010-2030),* and used as the basis of our EE/DR scenarios.

Table 2-2
Estimated EE/DR Capital Costs (2010-2030)

EE/DR Capital Costs Through 2030 (rounded to nearest billion)	RAP Efficiency Base Case Scenario No Carbon Policy	MAP Efficiency Scenario No Carbon Policy
AMI Capital Costs	$19	$27
Energy Efficiency Measure Cost	$66	$165
Total EE/DR Capital Costs, ($ Billions)	**$85**	**$192**

The Role of EE/DR in Displacing New Generation

The analysis indicates that aggressive EE/DR could be effective in displacing a significant amount of new generation capacity and in reducing overall capital requirements. However, it is equally clear that EE/DR (as modeled here) does not eliminate the need to build new generation, nor does it dramatically reduce the capital necessary to fund construction of new generating plants. The RAP Efficiency Base Case Scenario, which estimates the impact of aggressive EE/DR programs under likely real-world conditions, reduces the need for new generation capacity by about 38 percent by 2030. With correctly modeled price impacts and a national carbon policy, this percentage will be increased. However, the amount cannot be predicted due to several factors, including a number of plants already “in the pipeline” and mandated renewable capacity requirements already exceeding 39 GW.

In terms of reducing generation capital requirements, the impact of EE/DR is not proportional to the impact on reducing generation capacity. Because of the cost of implementing EE/DR programs, especially the cost of new AMI technology, the overall reduction in projected utility capital requirements is far less than the reduction in generation capacity. When EE/DR costs are factored in, overall capital requirements are reduced by seven percent under the MAP Efficiency Scenario and 15 percent under the RAP Efficiency Base Case Scenario (Table 2-3).

Table 2-3
Summary of Avoided Generation Capital Investment
Due to EE/DR (2010-2030)

Total Investment after EE/DR

	RAP Efficiency Base Case Scenario No Carbon Policy	MAP Efficiency Scenario No Carbon Policy
Total Reference Scenario investment	697	697
(Avoided) generation investment due to EE/DR	(192)*	(242)
Equals new scenario investment	505	455
Capital cost of EE/DR and AMI	85	192
Total Investment after EE/DR	**590**	**647**
Percent reduction in capital investment due to EE/DR	**-15%**	**-7%**

Net (avoided) generation investment

	RAP Efficiency Base Case Scenario No Carbon Policy	MAP Efficiency Scenario No Carbon Policy
(Avoided) generation investment due to EE/DR	(192)	(242)
Capital cost of EE/DR and AMI	85	192
Net (avoided) generation investment	**(107)**	**(50)**

* Numbers in parentheses (#) indicate negative numbers.

Chapter 3: Projecting the Capital Cost Of Carbon-Related Investments: The Prism RAP Scenario

The issue of climate change is central to any long-term projection of electricity investment, particularly in generation capacity. In fact, the prospect that federal legislation will be enacted to reduce carbon emissions in the sector already has affected utility planning and investment analysis. Although the emission targets, timing, and form of a national carbon policy have yet to be determined, most industry and political observers believe that a federal climate change policy will be enacted within the next few years.

Recognizing the importance of this issue to future generation investments, as well as the current uncertainty regarding the eventual carbon policy, The Edison Foundation asked *The Brattle Group* to evaluate one particular scenario of generation and efficiency investments that EPRI has developed, known as the "Prism Analysis." The Prism Analysis represents a suite of technologies that EPRI has concluded are feasible to deploy in the 2010 to 2030 timeframe and will lead to reduced carbon emissions in the electricity sector.[26]

The EPRI Prism Analysis technology targets are estimates of technically feasible development and deployment of technologies, but do not necessarily reflect an optimal mix that might result from responses to carbon prices. In fact, the Prism Analysis results in more low-carbon generation capacity being built by 2030 than would be needed strictly to serve increased load. Given these observations, *The Brattle Group's* analysis under the Prism RAP Scenario assumes that only certain Prism technologies are deployed, and focuses on the carbon and capital cost implications.

Prism Analysis Technology Targets

Figure 3-1 shows the EPRI Prism Analysis targets for technology deployment compared to EIA's AEO 2008 forecast. The Prism consists of seven broad types of technologies:

- Energy efficiency that reduces load growth from the AEO 2008 forecast levels to approximately the levels in our RAP Efficiency Base Case Scenario;
- Roughly double the level of renewable generation capacity over the AEO 2008 forecast levels;

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[26] See *The Power to Reduce CO_2 Emissions: The Full Portfolio*, EPRI Discussion Paper, August 2007, for a description of the primary technologies. EPRI has updated this analysis to incorporate the AEO 2008 forecast as a benchmark. EPRI also has examined the role that the Prism technologies could play in reducing the cost of carbon-reduction policies. See *The Value of Technological Advance in Decarbonizing the U.S. Economy* by Richard Richels and Geoffrey Blanford, AEI/Brookings Joint Institute for Regulatory Studies, Working Paper 07-19, November 2007.

- A tripling of nuclear capacity by 2030 over the AEO 2008 forecast levels;
- Advanced coal generation technology that enhances the efficiency of existing and new coal plants;
- CCS widely deployed after 2020;
- Plug-in hybrid electric vehicles (PHEVs) reaching a third of new vehicle sales by 2030; and
- Increased penetration of distributed energy resources (DER), including solar power.

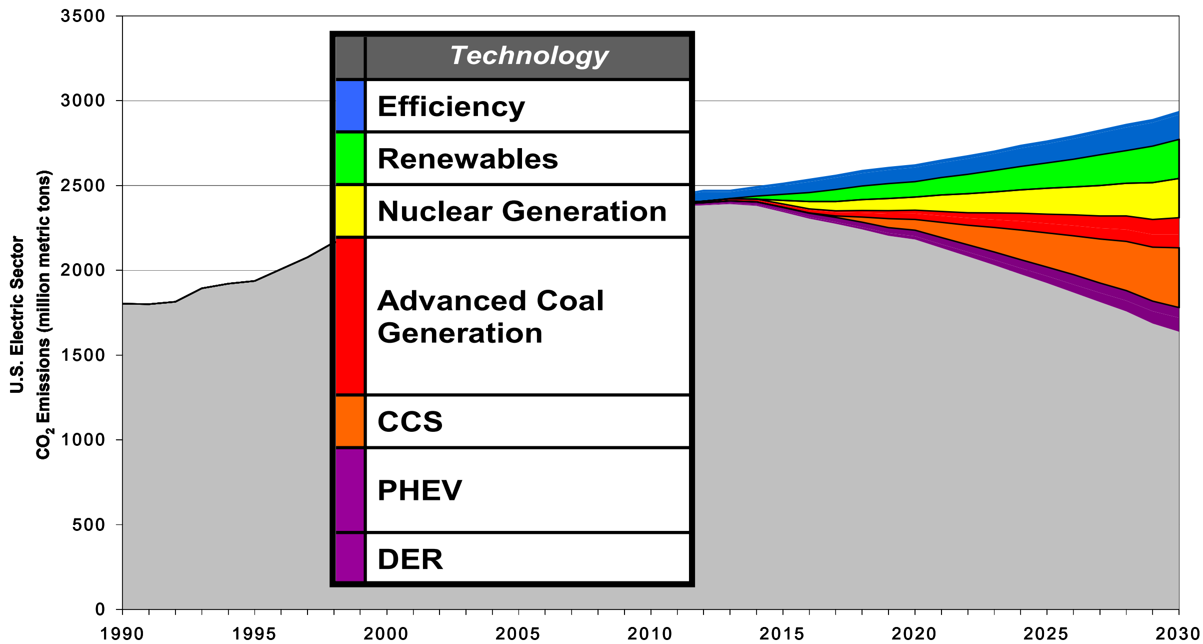
Figure 3-1
EPRI Prism Analysis Targets for Carbon-Related Technology Changes

Technology	EIA 2008 Reference	Target
Efficiency	Load Growth ~ +1.05%/yr	Load Growth ~ +0.75%/yr
Renewables	55 GWe by 2030	100 GWe by 2030
Nuclear Generation	15 GWe by 2030	64 GWe by 2030
Advanced Coal Generation	No Heat Rate Improvement for Existing Plants 40% New Plant Efficiency by 2020–2030	1-3% Heat Rate Improvement for 130 GWe Existing Plants 46% New Plant Efficiency by 2020; 49% in 2030
CCS	None	Widely Deployed After 2020
PHEV	None	10% of New Light-Duty Vehicle Sales by 2017; 33% by 2030
DER	< 0.1% of Base Load in 2030	5% of Base Load in 2030

Source: Based on data compiled by Electric Power Research Institute (EPRI), found at: http://www.iea.org/Textbase/work/2008/roadmap/2a_Tyran_EPRI%20Roadmaps.pdf.

Figure 3-2 shows the impact of these technologies on emissions from the electric generation sector of the industry, with colors of the "wedges" corresponding to the left column of Figure 3-1 (this depiction yields the "prism" effect from which the analysis draws its name). As seen in Figure 3-1, carbon emissions from electricity production would rise by about 20 percent from current levels in the AEO 2008 forecast, while the emissions resulting from the application of the Prism technologies represent about a 40-percent reduction from the AEO 2008 forecasted levels.

Figure 3-2
EPRI Prism Analysis Impacts of Technology Changes on Electric Sector CO_2 Emissions



Source: Based on data compiled by Electric Power Research Institute (EPRI), found at: http://www.iea.org/Textbase/work/2008/roadmap/2a_Tyran_EPRI%20Roadmaps.pdf.

It is also evident from Figure 3-2 that most of the reductions occur from four types of technologies: energy efficiency, CCS, nuclear, and renewables. Our analysis focuses on these technologies because they provide for the greatest emissions reductions.

Developing the Prism RAP Scenario

The four major technologies included in the Prism Analysis—energy efficiency, CCS, renewables, and nuclear—were incorporated into *The Brattle Group's* RECAP model simulations in the following manner:

- **Energy Efficiency** was included in the Prism RAP Scenario by incorporating the same EE/DR assumptions that were used in the RAP Efficiency Base Case Scenario. This scenario reduced the growth in electricity demand in a nearly identical manner as the Prism target (which reduced annual average load growth from 1.05 percent to 0.75 percent);

- **CCS** was modeled by requiring all coal builds in 2020 and after to incorporate CCS. The cost of CCS was derived from the EPRI analysis of integrated gasification combined-cycle (IGCC) with CCS capability that was 90 percent effective in capturing carbon emissions;

- **Renewables** were increased by assuming the expansion of RPS requirements between 2020 and 2030 in regions that already had such requirements, and adopting modest renewable goals after 2020 in regions that currently have no state-level requirements, to yield approximately the 100 GW capacity level in the EPRI Prism Analysis.

- **Nuclear** was introduced into the model by converting our regional nuclear build limits to requirements for nuclear construction in RECAP, as these were already at 64 GW by 2030;

Generation Capacity and Costs: The Prism RAP Scenario

The results of the Prism RAP Scenario are summarized in Figure 3-3, Figure 3-4, and Figure 3-5. The Prism RAP Scenario projects that 216 GW of new generation capacity would be built between 2010 and 2030, compared to 133 GW projected in the RAP Efficiency Base Case Scenario. This occurs primarily because the Prism RAP Scenario assumes specific investments in new low-carbon generation capacity, without regard to whether that generation mix is the least-cost way to meet the projected load growth. In fact, the investment requirements (including about 100 GW of renewables and 64 GW of nuclear) account for more capacity than the RAP Efficiency Base Case Scenario implies. Additional amounts of coal with CCS and small amounts of natural gas-based capacity are added in some regions, as required by reliability considerations for backing up renewable generation. The Prism RAP Scenario also estimates that about 20 GW of retirements (vs. 2 GW in the RAP Efficiency Base Case Scenario) would occur as a result of the nuclear, renewable, and coal with CCS investments that are assumed.

Figure 3-3
Cumulative New Generation Capacity in Prism RAP Scenario With Carbon Policy (2010-2030)

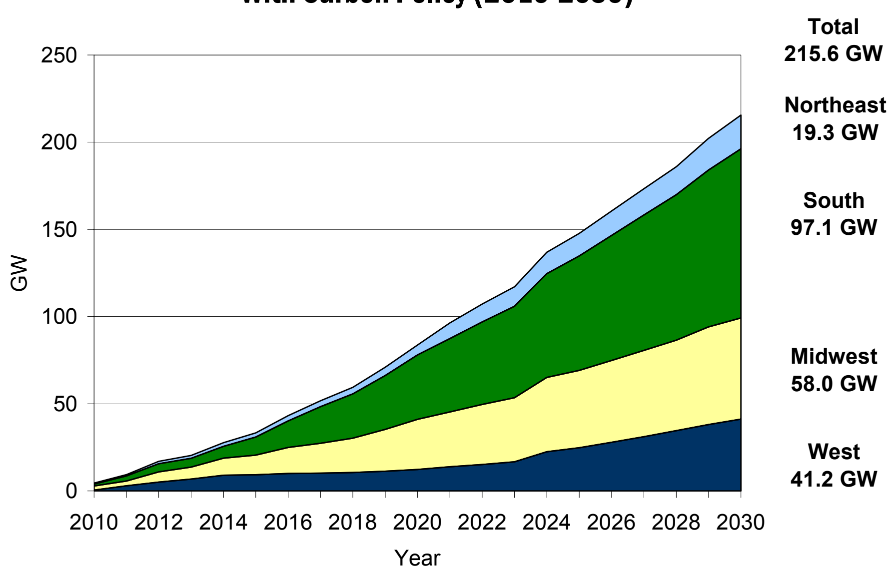


Figure 3-4
Regional Capacity Additions and Generation Capital Costs in Prism RAP Scenario With Carbon Policy (2010-2030)

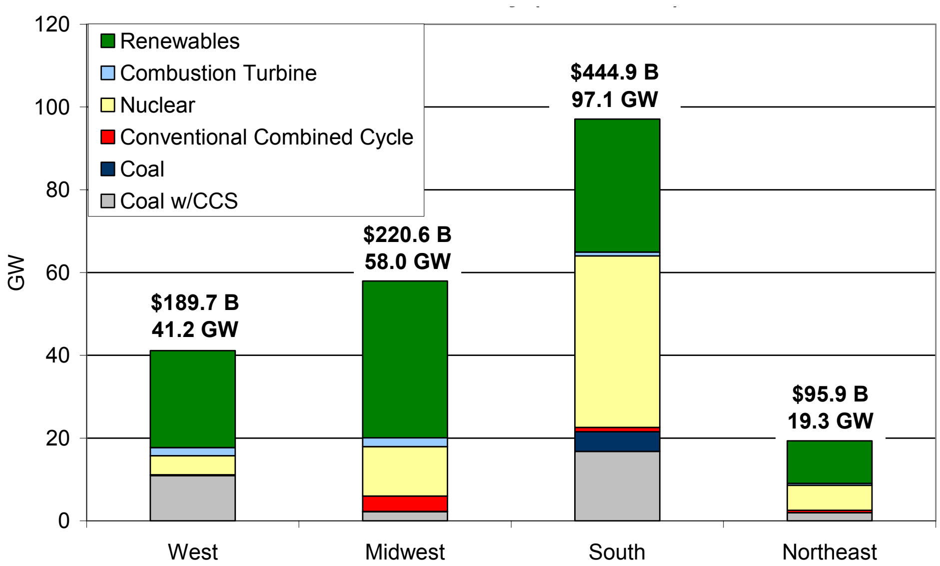
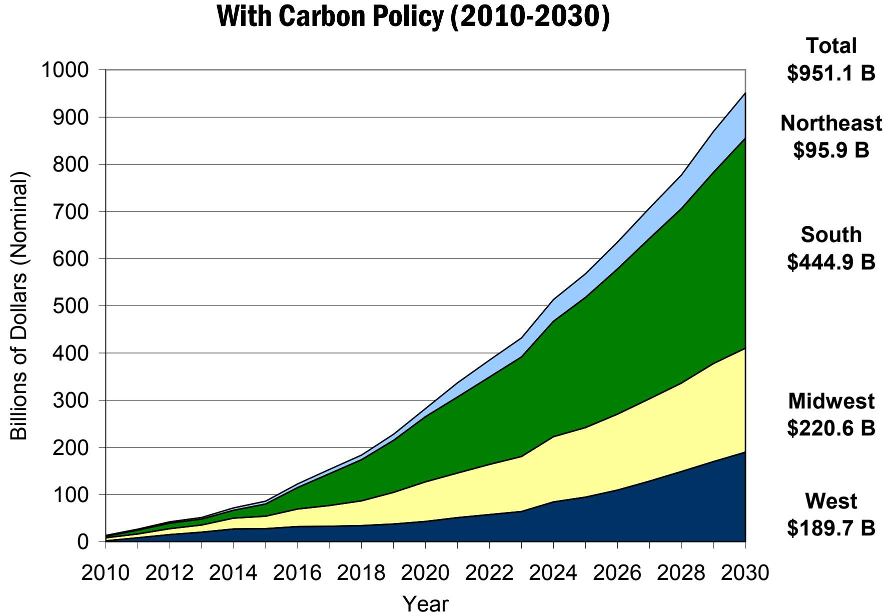


Figure 3-5
Cumulative Capital Requirements for New Generation Capacity in Prism RAP Scenario With Carbon Policy (2010-2030)



The capital cost associated with the supply investments in the Prism RAP Scenario is about $951 billion between 2010 and 2030. When AMI and program costs associated with the RAP Efficiency Base Case Scenario (a total of $85 billion) are added, the resulting figure is $1.036 trillion. This represents an increase of about 50 percent over the capital costs in the Reference Scenario and approximately a 75-percent increase above the overall capital costs of the RAP Efficiency Base Case Scenario.

Chapter 4: Projected Costs of Investments In Transmisson and Distribution Systems

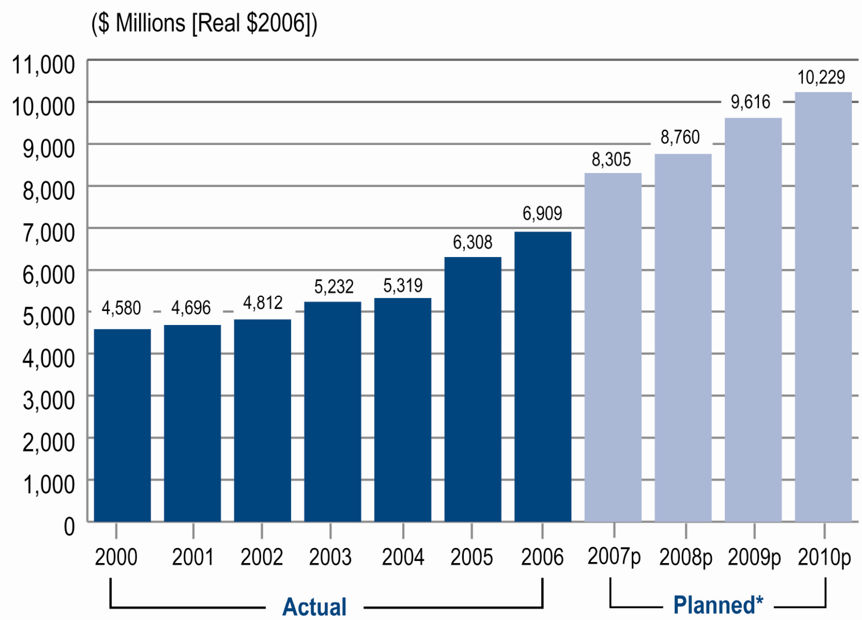
Investments in generation and EE/DR programs are the focus of much policy attention as utilities make major resource planning decisions in the face of substantial uncertainties regarding input commodity (e.g., cement, steel, and fuel) prices and emissions requirements. Utilities also will have to undertake major and growing investments in transmission and distribution systems.

Estimating future transmission capital requirements over a multi-decade horizon is extremely difficult. This is due to the variety of objectives and unique circumstances that motivate transmission investment, as well as the fact that the data available on announced projects, current transmission expenditures, and unit-level costs are neither comprehensive nor always reliable. It is particularly difficult to predict the timing or cost of major transmission additions – they are lumpy and frequently delayed or rerouted. Furthermore, proposed transmission developments exhibit a wide range of costs due to varying types of transmission lines (e.g., underground or overhead), the inclusion of different numbers of substations, the terrain crossed, and the cost of land. Finally, the recent historical pattern of new generating plants built at locations needing minimal grid build-out is shifting toward new plants in more distant, resource-rich areas. This phenomenon could considerably boost transmission miles built per installed megawatt (MW) of generation capacity, though we cannot reliably predict the magnitude of this effect.

Transmission System Costs and Data

The most detailed source of planned transmission projects is the "Coordinated Bulk Power Supply Program Report (Form EIA-411)," made publicly available by the North American Electric Reliability Corporation (NERC) through its annual Energy Supply & Demand (ES&D) database. The NERC ES&D data, which currently extend through 2015, include only announced or planned high-voltage projects [those that are rated at 230 kilovolts (kV) and above], thereby excluding investments in transmission lines of lower voltage (those that are rated below 230 kV) and other non-transmission line elements such as substations. The NERC ES&D data indicate that an additional 13,020 miles of high-voltage transmission lines will be built between 2007 and 2015. A second source of transmission data, which includes lower-voltage projects, comes from the Edison Electric Institute's "Electric Transmission Capital Budget & Forecast Survey."[27] This survey projects transmission investment from 2007 to 2010 based on responses from EEI's members. As seen in Figure 4-1, annual transmission investment by shareholder-owned electric utilities during the 2007 to 2010 period will be in the range of $8.3 billion to $10.2 billion, corresponding to approximately $37 billion in total investment (2006 dollars).

Figure 4-1
Actual and Planned Transmission Investment
By Shareholder-Owned Electric Utilities (2000-2010)



p = preliminary

Note: The Handy-Whitman Index of Public Utility Construction Costs used to adjust actual investment for inflation from year to year. The GDP Deflator used to adjust planned investment for inflation from year to year. Data represent both shareholder-owned utilities and stand-alone transmission companies.

*Planned total industry expenditures are estimated from 85% response rate to EEI's Electric Transmission Capital Budget & Forecast Survey. Actual expenditures from EEI's Annual Property & Plant Capital Investment Survey & FERC Form 1s.

Source: Edison Electric Institute, Business Information Group.

[27] The 2007 EEI "Electric Transmission Capital Budget & Forecast Survey" focuses on U.S. shareholder-owned electric utilities, including both vertically integrated and stand-alone transmission utilities. Sixty shareholder-owned electric utilities, whose stocks are publicly traded on major U.S. stock exchanges, were asked to participate. These utilities were either holding companies consisting of one or more operating subsidiaries or consolidated electric utilities. In addition, the survey also sought to capture data from 10 additional utilities that are either privately held or owned by non-U.S. corporations.

EEI's January 2008 "Transmission Projects: At a Glance" report also was used to estimate the per-unit costs of new transmission lines (i.e., investment dollar per mile and per MW-mile across various voltage classes). Our unit costs for new transmission are based on an EEI transmission project report, which contains recent estimates of project costs for a number of specific actual projects.[28] A summary of unit transmission costs based on that report is shown in Table 4-1.

Table 4-1
Recent Unit Transmission Costs
2008 Dollars

Voltage (kV)	Cost (Thousands of Dollars/Mile)	Capacity (MW)*	Cost (Millions of Dollars/GW-Mile)*
230	$2,076.5	500	$5.46
345	$2,539.4	967	$2.85
500	$4,328.2	2,040	$1.45
765	$6,577.6	5,000	$1.32

Assumptions, Sources, and Notes:

Source is EEI's "Transmission Projects at a Glance," January 2008.

Projects that use underground lines, have more than three segments, or have significantly mixed voltage levels are excluded.

The cost of projects is assumed to be given in 2007 dollars unless specified, and has been adjusted using the 2007 to 2008 percentage change in the Handy-Whitman Index.

*Based on a subset of projects where capacity was reported. Gigawatt miles are calculated by multiplying the capacity of the line (in GW) times the length of the line (in miles).

Using the dollar-per-mile figures for various voltage classes in Table 4-1 (adjusted for assumed 1.9 percent inflation), we estimate the overall nominal cost of the projects in the NERC ES&D dataset.[29] Table 4-2 shows that our estimates of transmission investments based on these data are approximately $32.5 billion through 2015.

[28] Note that these data are based on a partial sample of EEI members only.

[29] The long-run GDP deflator assumed in the AEO 2008 increases about 1.9 percent per year, a figure that we adopt to convert real dollars into future nominal dollars.

Table 4-2
Projected Cost of New Transmission 2008-2015
Millions of Dollars (Nominal)

	Voltage Level					
Year	**AC 230**	**AC 345**	**AC 500**	**AC 765**	**DC 500**	**Total AC & DC**
2008	$784.3	$421.1	$220.7	$0.0	$0.0	**$1,426.1**
2009	$1,916.4	$785.1	$2,467.7	$0.0	$0.0	**$5,169.2**
2010	$932.6	$1,346.7	$3,061.4	$0.0	$2,280.9	**$7,621.5**
2011	$816.9	$0.0	$2,662.3	$0.0	$0.0	**$3,479.2**
2012	$1,008.3	$3,776.1	$3,654.4	$0.0	$0.0	**$8,438.8**
2013	$79.0	$427.0	$2,151.2	$0.0	$0.0	**$2,657.2**
2014	$113.2	$607.1	$10.1	$0.0	$0.0	**$730.4**
2015	$176.9	$2,423.0	$410.8	$0.0	$0.0	**$3,010.7**
Total (2008-2015)	**$5,827.6**	**$9,786.1**	**$14,638.7**	**$0.0**	**$2,280.9**	**$32,533.2**

Note: Totals may not equal sum of components due to independent rounding.

Overview of Methods to Estimate Transmission Investment Through 2030

For purposes of this report, we examined two methods to estimate potential overall transmission investment through 2030 using the previously described data:

- The *Transmission Additions Method* (selected method); and
- The *Generation Additions Method.*

In simple terms, our first method (the *Transmission Additions Method)* takes the annual average number of miles of new transmission lines built or proposed between 2007 and 2015 and applies this annual average growth rate to the 2016 to 2030 time period. We then assume that future transmission line construction costs from 2016 to 2030 will reflect the dollar-per-mile costs shown in Table 4-1. Finally, we adjust these costs at the assumed rate of inflation (1.9 percent per year). This estimate assumes that recently proposed construction activity continues (in terms of miles per year and real dollars per mile) and adjusts these costs at the assumed rate of inflation, yielding a nominal dollar investment stream.

As explained in Chapters 1 to 3, we examine several generation scenarios with significant differences in the amount and type of generation constructed. Because the amount of generation varies in these scenarios, the amount of transmission investment also could vary. Accordingly, we employ a second method to estimate transmission investment, referred henceforth as the *Generation Additions Method*. This method derives the ratio of transmission miles built to MW of new generation capacity installed, and multiplies this ratio by different projections of generation capacity to estimate future miles of transmission required. We use the values reported in Table 4-1 to provide the cost of this projected transmission investment and escalate for assumed inflation. Both of these methods are explained further in the following two sections.

Resulting Transmission Investment Based on the *Transmission Additions Method*

The *Transmission Additions Method* uses different sources of data for high- and low-voltage transmission investments. This method treats the two voltage classes differently due to the dissimilarity in available data.

The NERC ES&D data for high-voltage transmission lines are fairly narrow in scope, containing primarily region, line voltage, and line length information. From these data we determine average annual total transmission line-miles (by voltage level) added or proposed between 2007 and 2015. We then multiply these average annual line-miles by their respective 2008 cost by voltage level (in dollars per mile) as shown in Table 4-1. This yields average annual transmission investments by voltage level at 2008 costs. We then assume that this level of transmission investment will remain constant (in real terms) between 2016 and 2030. Finally, we adjust these investments by the assumed rate of inflation of 1.9 percent per year. The projected amount of high-voltage transmission investment resulting from our analysis of the NERC ES&D data, combined with EEI's transmission cost figures (Table 4-1), is $113 billion (nominal) for the 2010 to 2030 period.

Because we do not have access to comparable data for low-voltage facilities, we use the following method to estimate this component of our projected total transmission investment under the *Transmission Additions Method*.

According to Table 4-2, the amount of high-voltage transmission investment for the 2008 to 2010 period is approximately $14.2 billion. EEI's 2007 "Electric Transmission Capital Budget & Forecast Survey" projects total shareholder-owned electric utility transmission investments of about $35.5 billion (nominal) during the same 2008 to 2010 period.[30] Netting out the $14.2 billion in high-voltage investments from the $35.5 billion in total transmission investments results in $21.3 billion in low-voltage investments over the three-year period, or $7.1 billion per year (nominal) of investments in low-voltage transmission facilities and other elements. Assuming that this amount of investment remains constant in real terms over the 2010 to 2030 period, the resulting amount of projected low-voltage transmission investment would be $184 billion (nominal).

Finally, we combine our low-voltage estimate with the high-voltage investment projection to reach a total annual transmission investment of $298 billion (nominal) for the 2010 to 2030 study period. Figure 4-2 shows the results from our selected method, the *Transmission Additions Method*.

In Figure 4-2, the navy blue line represents near-term estimated transmission investments from 2008 to 2015, while the pink line represents our long-term projection using the selected method, the *Transmission Additions Method*. As expected, our projected investments beyond 2015 are much smoother than the projections based directly upon forecast data from the NERC ES&D. This smooth investment from 2016 to 2030 reflects a constant level of real investment, adjusted for inflation.

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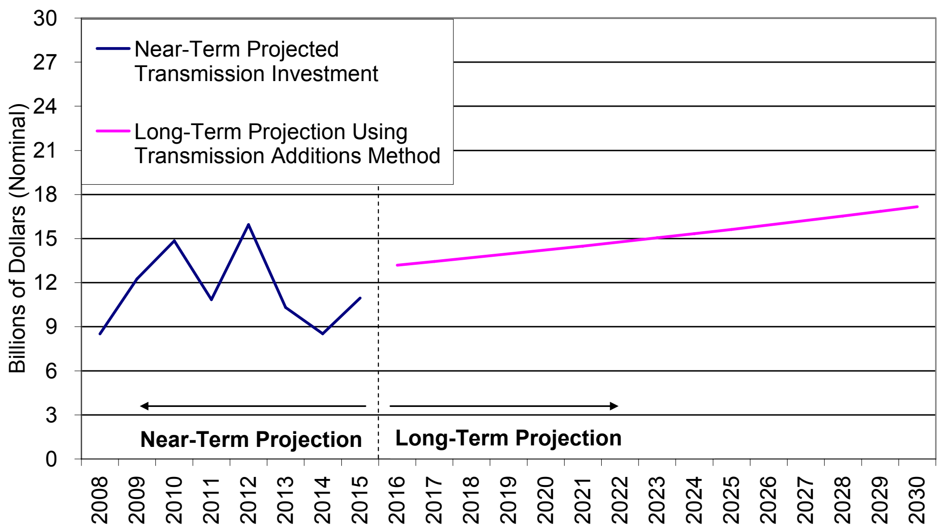
[30] Figure 4-1 shows projected transmission investment between 2008 and 2010 as $28.6 billion expressed in real 2006 dollars. Converting to nominal dollars, using the change in the Handy-Whitman Index for the years 2006 to 2008 and 1.9 percent assumed inflation thereafter, this amount increases to $35.5 billion.

Comparative Transmission Investment Based on the *Generation Additions Method*

As mentioned previously, cumulative transmission investments under our selected method, the *Transmission Additions Method*, equal $298 billion (nominal) over the 2010 to 2030 period—a figure that, by design, does not vary with the four generation scenarios covered in Chapters 1 to 3 of this report (i.e., the Reference Scenario, the RAP Efficiency Base Case Scenario, the MAP Efficiency Scenario, and the Prism RAP Scenario).

Figure 4-2
Annual Transmission Investment Projection
Transmission Additions Method (2008-2030)



The *Generation Additions Method* employs the average levels of transmission investment per MW of generation built for high-voltage transmission facilities. First, we derive the ratio of high-voltage transmission line-miles built per MW of installed capacity for the 2008 through 2015 period based on NERC ES&D data and the Reference Scenario RECAP results. Next, we use these ratios to project annual transmission line-miles built as a function of various projections of annual generation capacity builds and use the cost figures in Table 4-1 to estimate annual high-voltage transmission investments. Finally, we combine these figures with our average annual low-voltage investment estimate of $7.1 billion per year and adjust the resulting amount for inflation.

Figure 4-3 illustrates a single estimate of the annual investment costs using the *Transmission Additions Method* (pink line). It also shows three estimates of the annual investment costs using the *Generation Additions Method:* one for the RAP Efficiency Base Case Scenario (light blue line); one for the MAP Efficiency Scenario (brown line); and one for the Reference Scenario (purple line).

As one might expect, under the *Generation Additions Method*, the lower the level of projected generation capacity, the lower the level of projected transmission investment.[31] Under this method, the Reference Scenario has the highest level of generation builds followed by the RAP Efficiency Base Case Scenario and finally the MAP Efficiency Scenario.

Figure 4-3
Annual Transmission Investment Projections
All Methods (2008-2030)

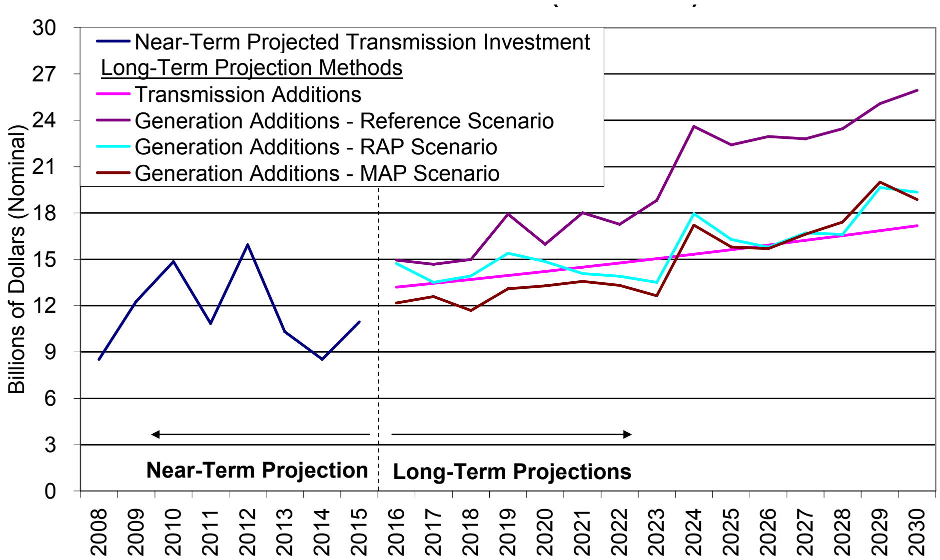


Figure 4-4 depicts four estimated cumulative projections of transmission investment for the 2010 to 2030 period: one estimate for the *Transmission Additions Method* and three estimates using the *Generation Additions Method* as applied to the three scenarios described in Chapter 1 and Chapter 2. As illustrated in Figure 4-4, the cumulative transmission investments range from a low of $295 billion under the MAP Efficiency Scenario to a high of $370 billion using the same method under the Reference Scenario.

The lower portion of each stacked bar in Figure 4-4 represents cumulative high-voltage transmission investments based on the two transmission projection methods and three of the generation scenarios. The upper portion of the bars corresponds to the low-voltage transmission investments. As discussed earlier in this chapter, estimating future transmission capital investments over a multi-decade horizon is extremely challenging due in large part to the difficulty of predicting the location and fuel characteristics of the future generation capacity requirements. For this reason, we selected the $298-billion estimated transmission requirement derived from the *Transmission Additions Method* over the three transmission investment estimates produced under the *Generation Additions Method*. Based on our analysis and the results as

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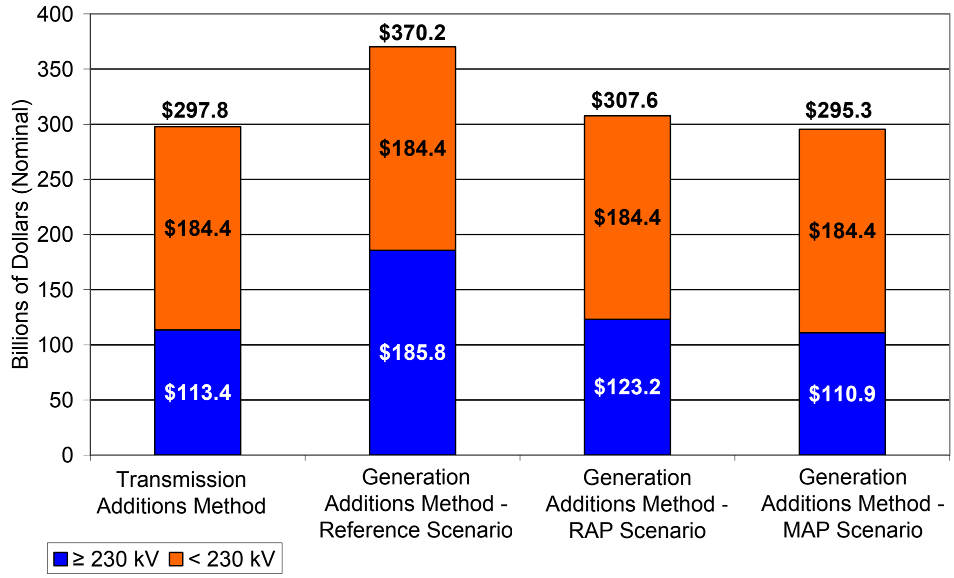
[31] The transmission investment results from the Prism RAP Scenario described in Chapter 3 are not shown because they are very similar to those shown for the Reference Scenario as a result of overall MW of generation capacity built between 2010 and 2030 being nearly identical. Note that a federal carbon policy could affect the mix of transmission projects to accommodate remote renewables and CCS sites. This potential effect was not quantified.

illustrated in Figure 4-4, we believe that our selected method produces an investment projection that is: 1) consistent and well within the range of transmission investment projections from the alternative generation-based methods, and 2) conservative, so that the results have not been influenced by uncertain future generation capacity scenarios.

Figure 4-4
Cumulative Transmission Investment Projections
(2010-2030)



Transmission and Renewable Generation

As discussed previously, gaining access to the amount of renewable generation implied by escalating RPS requirements will involve additional transmission development that may not be reflected in the recent data from NERC. While some of the projects in the NERC ES&D database and the EEI "At A Glance" report may be motivated in part by new renewable generation opportunities, it is plausible that additional transmission development beyond those projects will have to occur in order to significantly increase the contribution of renewables into the electricity supply mix.

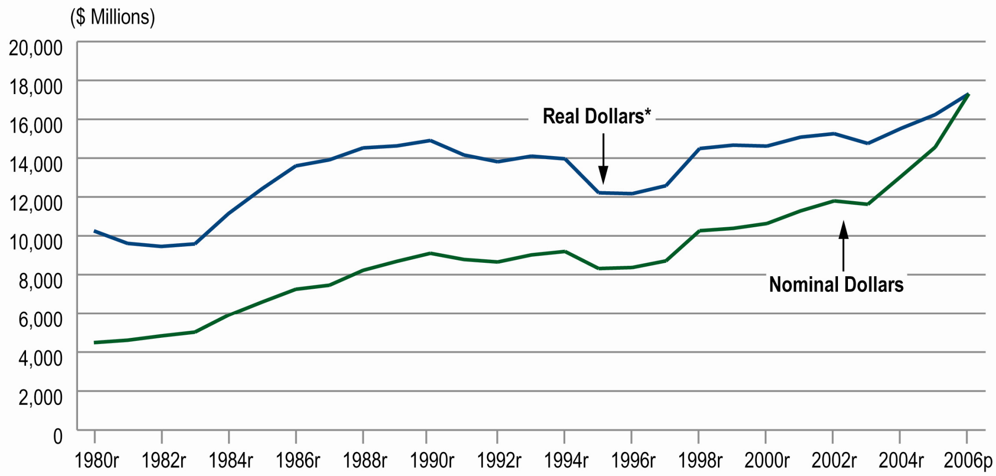
In order to provide a rough estimate of the magnitude of investment required, we assume that each GW of additional renewable capacity requires an associated transmission investment that increases slightly over time. This could occur, for example, as the most accessible resources are developed earlier, with more remote resources gradually becoming attractive as demand for renewables increases. We adopted the following rule of thumb: for each GW of renewable capacity built in 2011, we assume that 10 miles of transmission capacity are needed, and we escalate that mileage figure by 10 miles each successive year. Under this framework, renewable capacity built in 2015 needs 50 miles of transmission, renewable capacity built in 2020 needs 100 miles, renewable capacity built in 2025 needs 150 miles, and renewable capacity built in 2030 needs 200 miles. Since Table 4-1 shows that a 345-kV transmission link can support roughly one GW of power transfer and costs roughly $3 million per mile, we apply that cost to our estimated transmission builds for expanded renewable generation access.

For the amount of renewable capacity in the Reference Scenario, these assumptions would add about $15.5 billion between 2010 and 2030 in undiscounted nominal terms to account for transmission investments made in order to access increasing amounts of progressively more remote renewables. Although this is obviously a rough calculation, on the whole it is probably conservative. That is because there are many remote renewables–e.g., wind power in the central United States and northern New England–that may require transmission lines that are more than 200 miles long to connect them to the grid. While this calculation may understate the transmission costs associated with renewables, it still represents a significant capital cost that the utility sector will bear as it complies with state RPS requirements.

Distribution System Costs and Data

Shareholder-owned electric utility distribution-related construction expenditures have been rising in real and nominal terms since the mid-1990s, surpassing $17 billion per year in 2006. These investments have been made to expand distribution systems, replace aging equipment, enhance reliability, improve power quality, and to begin to integrate "Smart Grid" system elements. Figure 4-5 shows the trends of distribution investments over the past quarter-century. Distribution investments are a substantial portion of current utility capital expenditures—about 25 percent to 30 percent of overall capital expenditures—a share that is steady under current trends.

Figure 4-5
Distribution Investment by Shareholder-Owned Electric Utilities
(1980-2006)



* 2006 Dollars p = Preliminary r = Revised
Note: Real dollar results are shown using the Handy-Whitman Index of Public Utility Construction Costs to adjust for inflation from year to year.

Sources: Prior to 1999, data are from Edison Electric Institute's "Uniform Statistical Report". For 1999, data are from Edison Electric Institute's Construction Expenditures Survey, the Federal Energy Regulatory Commission (FERC Form 1), and company Annual Reports (10-K). For 2000-2006, data are from Edison Electric Institute's Annual Property & Plant Capital Investment Survey and the Federal Energy Regulatory Commission (FERC Form 1).

Some of the recent increases in distribution investment levels are attributable to the same drivers that are responsible for the construction cost increases observed in the generation and transmission segments of the industry.[32] Estimating and projecting distribution investments over a multi-decade horizon are prone to the same difficulties as those found with transmission. Discrete distribution investments are much smaller than transmission investments and are undertaken for a variety of reasons; some of these are discretionary and others are required to maintain system reliability and power quality. The industry's obligation to provide and maintain reliable electric service to its customers, combined with the prospects for "Smart Grid" investments to enable greater operating efficiencies, suggest that distribution system investment levels in the future are likely to reflect the recent growth observed in current investment trends. To explore the sensitivity of distribution investments to these key drivers and trends, we employ three methods to project distribution investments for the years 2010 to 2030, namely:

- *Real Investment Growth Rate Method:* Our selected method. This method extrapolates the recent trend in real distribution investment levels to provide a projection of nominal distribution costs from 2010 through 2030;

- *Per Capita Method*: A trend of per capita distribution expenditures based on forecasted population change. We examine nominal per capita investments under this method; and

[32] See *Rising Utility Construction Costs: Sources and Impacts*, prepared by Marc W. Chupka and Greg Basheda of *The Brattle Group* for The Edison Foundation, September 2007.

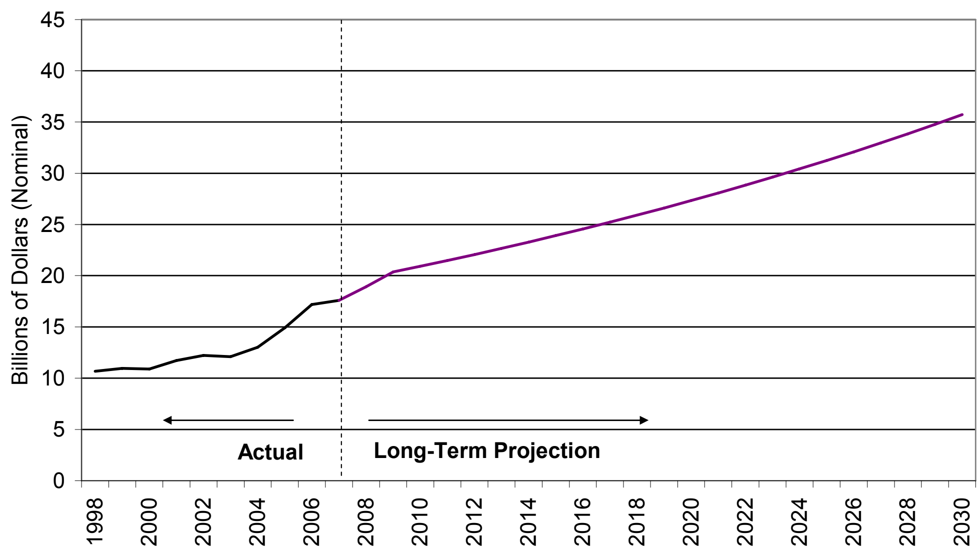
- *Nominal Growth Rate Method*: We present two nominal growth rate projections—one version that extrapolates recent growth rates in nominal distribution expenditures and another version that assumes that the 2007 distribution expenditures will grow at the assumed rate of inflation.

All three of these methods use the same basic underlying distribution investment input data to project future distribution investment requirements.

Real Investment Growth Rate Method

Historic distribution system investment figures from 1998 through 2007 were obtained from EEI's "Annual Property and Plant Capital Investment Survey."[33] The average real growth rate based on this historical data is about 0.8 percent per year. This real investment growth rate was applied to 2007 annual distribution investment expenditures and then adjusted annually at the rate of inflation (1.9 percent per year) to forecast distribution investments through 2030, as shown in Figure 4-6. The total distribution costs for the 2010 to 2030 period using the *Real Investment Growth Rate Method* are $582 billion in nominal terms. We chose this as our selected method to provide an estimate of distribution investment requirements to 2030, and used the alternative methods described next to provide comparisons to our selected method.

Figure 4-6
Annual Distribution Investment Projection
Real Investment Growth Rate Method



[33] These costs were converted from nominal dollars to 2008 dollars using the Handy-Whitman distribution cost index. Because we use the Handy-Whitman distribution cost index, the resulting growth in annual real costs should reflect increased physical investment in distribution systems.

Per Capita Method

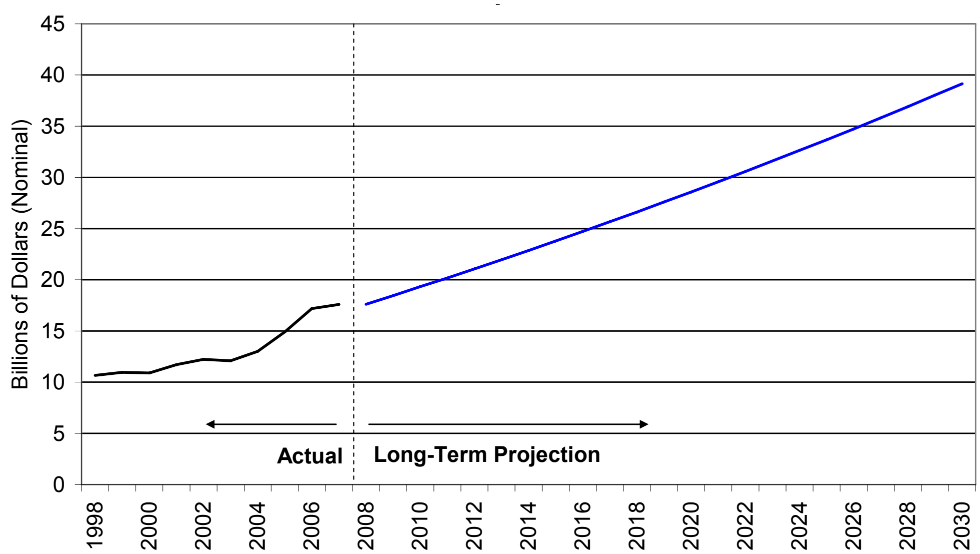
Our second method derives the historic relationship between distribution costs, time, and U.S. population, and uses population growth projections to yield a distribution investment forecast. We first calculate actual per capita distribution investment costs from 1998 through 2007 using EEI survey data and Census Bureau population data. We then project the trends in per capita distribution costs using the results of a regression that captures the relationship between per capita costs and time over the 1998 to 2007 period, where the trend equals 1 in 1998, 2 in 1999, and 3 in 2000, etc.[34]

$$\textbf{Nominal Per Capita Costs} = \mathbf{32.91 + 2.25 \times Trend}$$

$$\mathbf{R^2 = 0.83 \qquad\qquad (2.26) \quad (0.37)}$$

This method produces a linear increase in the amount of distribution investment per year per capita, and in turn allows us to project the per capita distribution investments from 2008 to 2030 using projections of U.S. population growth.[35] Figure 4-7 presents the forecast results using the *Per Capita Method*, which yields a total industry distribution investment requirement of $605 billion for the years 2010 to 2030. Because this estimate is based on the total U.S. population, it reflects estimated investments by the entire U.S. utility industry.

Figure 4-7
Annual Distribution Investment Projection
Per Capita Method



[34] Standard errors of the coefficients are shown in parentheses.

[35] We use the population projection reported in the assumption tables in the AEO 2008 for this calculation.

Nominal Growth Rate Method

This method projects distribution investment costs based on trends in total nominal distribution expenditures between 1998 and 2007. The growth rate in nominal distribution investment costs over this period averaged approximately 5.9 percent per year. This nominal growth rate was applied to 2007 distribution expenditures to project annual nominal distribution investments through 2030. An additional projection was constructed to examine an alternative possibility where 2007 distribution investments simply grow at the rate of overall inflation (assumed to be 1.9 percent per year). Implicit in this projection are the assumptions that distribution costs will grow at the rate of inflation (i.e., that trends in distribution costs will follow the overall inflation rate) and that real distribution investments will remain constant at 2007 levels.

Figure 4-8 displays the results of the two versions under the *Nominal Growth Rate Method*, which provide additional comparative projections of future distribution investments. The total investment using the historic nominal growth rate of distribution investment is $821 billion, while the general inflation-only projection results in a $475-billion investment.

Figure 4-8
Annual Distribution Investment Projections
Nominal Growth Rate Methods

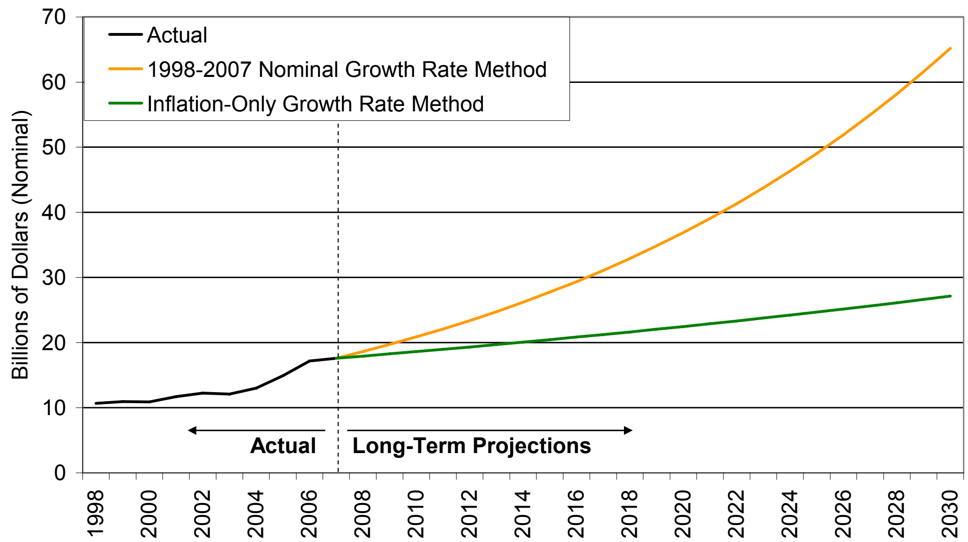


Figure 4-9 and Figure 4-10 illustrate the overall results from the three distribution investment methods, both over time and in total cumulative nominal dollars, respectively. These figures show that our selected method—the *Real Investment Growth Rate Method*—yields a distribution investment projection of $582 billion through 2030. As is the case with our transmission estimates, our selected method regarding distribution investments is solidly within the range (from nominal $475 billion to $821 billion) of the distribution investment estimates produced under the alternative methods (*Per Capita and Nominal Growth Rate Methods*) utilized in this report.

Beyond the fact that our selected method is well within the range of alternative methods, the estimated investment requirement under the *Real Investment Growth Rate Method* is strikingly close to the estimate under the *Per Capita Method*—both are approximately $600 billion through 2030—which provides us added confidence in the projections yielded from our selected method.

Figure 4-9
Annual Distribution Investment Projections
All Methods

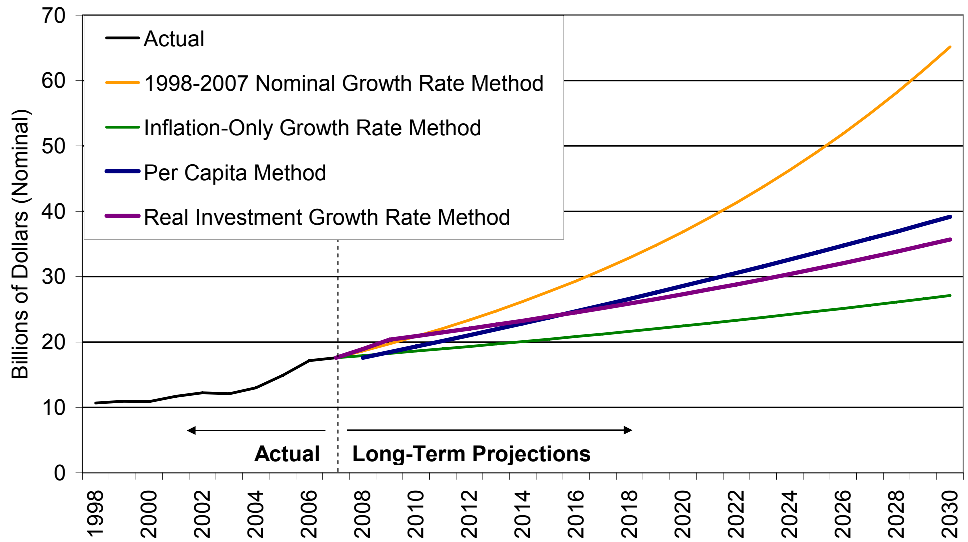
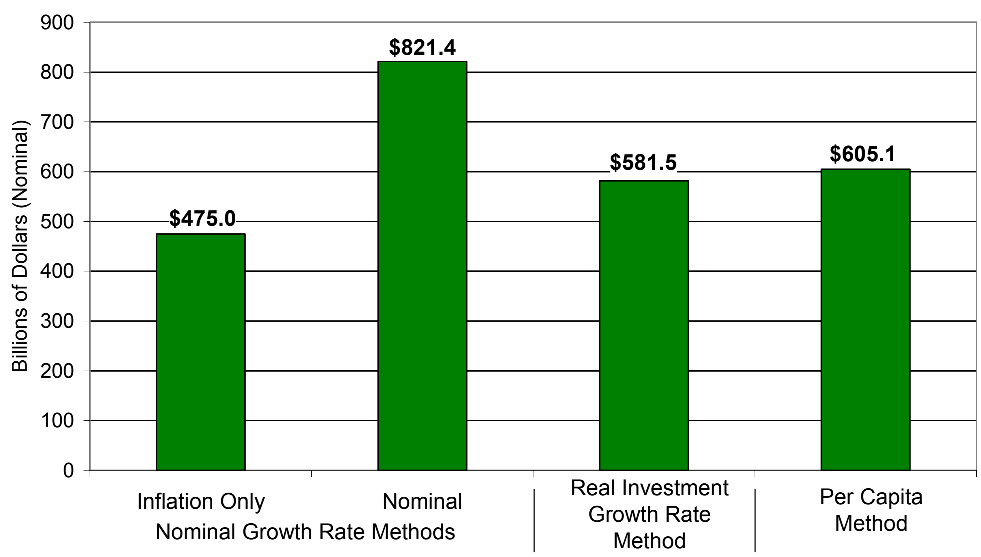


Figure 4-10
Cumulative Distribution Investment Projections
(2010-2030)

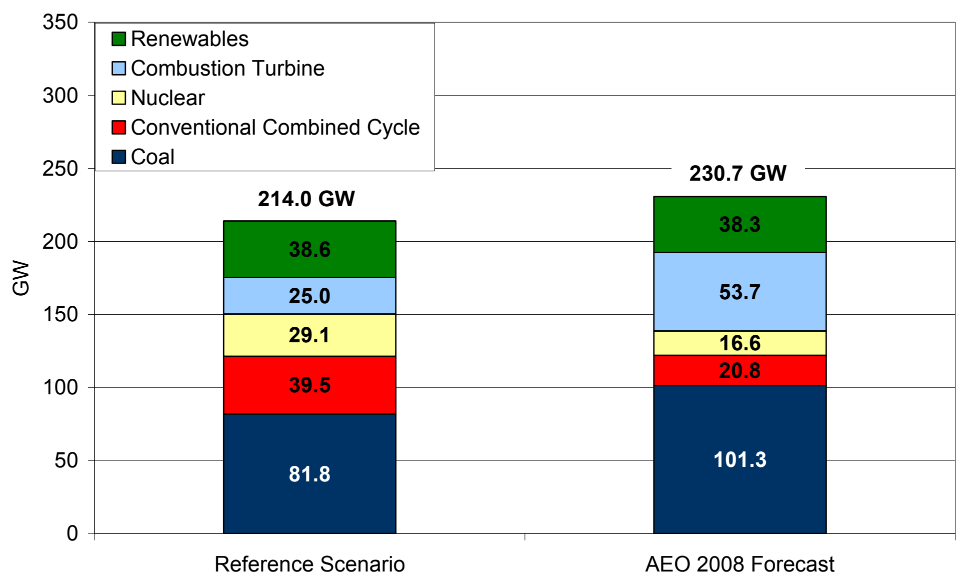


Appendix A

***The Brattle Group's* RECAP Model**

All our scenario simulations were performed with RECAP, *The Brattle Group's* least-cost generation expansion planning model. The composition of capacity builds in our Reference Scenario is similar to the AEO 2008 forecast. Figure A-1 compares the AEO 2008 forecast of capacity by type to the RECAP results. As shown on Figure A-1, the RECAP model (Reference Scenario) builds almost 20 GW less of coal-based capacity, but about 18 GW more of natural gas combined-cycle capacity than in the AEO 2008. Although natural gas prices are higher in the Reference Scenario than in the AEO 2008, the construction costs associated with coal units are much higher, which means that natural gas-based capacity is relatively more attractive. This is consistent with recent trends where utilities have scaled back plans for expensive coal-based capacity and shifted toward natural gas, a trend also influenced by concerns about carbon emissions from coal. The Reference Scenario also builds about half the capacity of combustion turbines as in the AEO 2008 (25 GW compared to 54 GW in AEO 2008), which may be due to the fact that RECAP models system peak load in greater detail than does NEMS, the model underlying the AEO 2008 forecast. Renewable capacity in the Reference Scenario is nearly identical to the AEO 2008 forecast, as most renewable capacity is built to satisfy requirements that depend on load growth, which is identical. Finally, the Reference Scenario builds more nuclear generation than in the AEO 2008 projection, possibly because the AEO 2008 forecast has stricter limits on nuclear builds. (The 17 GW of nuclear capacity built in the AEO 2008 forecast is very similar to the amount of capacity represented by the project developers that had submitted applications to the NRC at the time the AEO 2008 forecast was performed.)

Figure A-1
Comparison of New Generation Capacity



Linking EE/DR Projections in the EPRI Study to RECAP

It is important to note two ways in which the EE/DR projections that were used in this analysis differ from the impacts that are being reported through the EPRI study. These differences are driven by: 1) the impact of retail electricity prices on EE/DR cost-effectiveness and 2) the reference load forecast by which the impacts are being measured.

First, the RAP Efficiency Base Case Scenario and the MAP Efficiency Scenario estimates will be affected by the projected level of the retail electricity price. As retail prices rise, more EE/DR measures will become cost effective and the overall impact of EE/DR will increase. Our analysis accounted for this relationship by relying on region-specific EE/DR projections that were a function of the projected retail electricity rate projected by RECAP. This served as an analytic point of departure from the EPRI projections, which relied solely on the price projections implied in the AEO 2008 forecasts. Due to the higher fuel price and installation cost assumptions in *The Brattle Group's* analysis (relative to the AEO 2008 forecast), and their impact on the projected retail electricity rate, our assumed EE/DR impacts were larger than those reported in the EPRI study.

Second, the EE/DR impacts projected in the EPRI study produce potential annual peak and energy-savings forecasts for the 2010 to 2030 period. These impact estimates assume no existing EE/DR in the load forecast. In other words, they represent a percentage change from a load forecast that does not include any existing EE/DR. However, for our analysis, we are using the AEO 2008 forecast as the starting point for our load forecast. This load forecast already includes a moderate amount of EE/DR and, thus, is lower than the starting point of the EPRI forecasts. As a result, we have scaled down the EPRI numbers such that they represent changes from the AEO 2008 load forecast.

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