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Resource Portfolio Analysis

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Project Directed by

David Eaton, Ph.D.

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List of Acronyms

To be inserted later.

Forward

The Lyndon B. Johnson (LBJ) School of Public Affairs has established interdisciplinary research on policy problems as the core of its educational program. A major part of this program is the nine-month policy research project, in the course of which one or more faculty members from different disciplines direct the research of ten to thirty graduate students of diverse backgrounds on a policy issue of concern to a government or nonprofit agency. This "client orientation" brings the students face to face with administrators, legislators, and other officials active in the policy process and demonstrates that research in a policy environment demands special talents. It also illuminates the occasional difficulties of relating research findings to the world of political realities.

During the 2008-2009 academic year the City of Austin, on behalf of Austin Energy (AE), and Solar Austin co-funded a policy research project to review options for AE to achieve sustainable energy generation and become carbon neutral by 2020. The summary report evaluates different power generation technology options as well as demand-side management and other AE investment options to discourage future energy use and meet future projected energy demand. This project developed methods to evaluate future power generation options for their feasibility and cost-effectiveness. The project team assessed scenarios of alternate investments that could be made between 2009 and 2020 that would allow AE to produce and distribute the electricity its customers demand at a reasonable cost while reducing carbon dioxide emissions. This report describes a set of short-term and long-term investment options that can help AE, its customers, and be of use for developing sustainable electric utilities nationwide.

The curriculum of the LBJ School is intended not only to develop effective public servants but also to produce research that will enlighten and inform those already engaged in the policy process. The project that resulted in this report has helped to accomplish the first task; it is our hope that the report itself will contribute to the second.

Finally, it should be noted that neither the LBJ School nor The University of Texas at Austin necessarily endorses the views or findings of this report.

Admiral Bob Inman
Interim Dean
LBJ School of Public Affairs

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Executive Summary

See Volume I (Summary Report)

Chapter 1. Introduction: Assessing Resource Portfolio Options

In July 2008, Austin Energy (AE) released its proposed plan for meeting electricity demand through 2020 while meeting the goals of the Austin Climate Protection Plan, including achieving 700 megawatts (MW) of peak demand savings from energy efficiency and conservation and meeting 30 percent of all energy needs through renewable resources (including the addition of 100 MW of solar generation capacity). The proposal also included a carbon dioxide (CO_2) cap and reduction plan to limit CO_2 emissions to 2007 levels.[1] Under its proposal, AE would add 1,375 MW of new power generating capacity by 2020, with only 300 MW coming from fossil-fueled resources.[2] Since releasing this plan, AE has made considerable efforts to engage its customers in a public dialogue regarding the proposal and the future energy options for AE. With the intent of providing additional information to the public on the scope of power generating technologies and other investment opportunities currently available to electric utilities, AE and Solar Austin have tasked this project team from the Lyndon B. Johnson School of Public Affairs to articulate alternate strategies for meeting future energy needs with low-cost sources of energy that will reduce greenhouse gas (GHG) emissions. The goal of this volume of the report is to identify feasible and cost-effective investment opportunities for AE that can help contribute to the creation of a sustainable electric utility. This analysis has set the target of achieving zero net CO_2 emissions by 2020 as an interim goal towards achieving a sustainable power generation portfolio. The energy resource mix that AE implements in the future will represent a major portion of its cost of service and will be a significant contributor to either increasing or reducing AE's carbon footprint. The resources used and technologies implemented will influence how AE and Austin are perceived as a sustainable utility and a sustainable city, respectively. Furthermore, AE's future power generation mix will affect customer electricity rates and AE's capacity to contribute assets to the City of Austin budget.

In Volume II of this report, "Sustainable Energy Options for Austin Energy," substantial information was gathered on AE's power generation mix and its current efforts to handle customer demands, electric utility industry trends that may affect future planning at AE, and various power generation technologies. Our assessment of energy options for AE provides the basis for evaluating the integration of future sources of energy into AE's power generation resource portfolio. This report seeks to evaluate the benefits and consequences that these decisions could have for the future of the utility and the Austin community. New technologies continue to improve efficiency and reduce emissions from fossil-fueled and other traditional power generation options while renewable technologies continue to lower in costs and increase in attractiveness as a cleaner form of energy. New prospects for electric generation and increasing societal pressure to provide clean energy to customers have altered the playing field for power generation investment options. Having a clear and concise understanding of the current state of all electric generation technologies, as well as the ability to anticipate further advancements to these and other energy-related technologies, is crucial for making informed and intelligent investment decisions. While each power generation technology has proponents and opponents, this report seeks to provide an unbiased perspective by presenting comparative information regarding the advantages and disadvantages of each type of power generation technology.

AE makes investment decisions to ensure their power generation mix can reliably meet demand at affordable electric rates for customers. AE now also has incentives to replace current power generation facilities with cleaner forms of energy in order to meet its renewable energy and carbon reduction goals as well as the goals outlined by the Austin Climate Protection Plan. New power generation facilities can take many years to site, gain regulatory approval, and construct. Time constraints create a need for long-term planning, foresight into the future regarding costs of power generation technologies, and an awareness of the risks and uncertainties that exist in the electric utility and energy sectors. Investing in power generation technologies and facilities benefits a utility by allowing it to control its own assets, reap future profits, and meet regulatory and societal demands. Investing in relatively immature power generation technologies and facilities that use renewable forms of energy such as biomass, solar, wind or even geothermal can be made through power purchase agreements (PPA). While such agreements do not allow AE to directly control its own assets, PPAs provide a hedge against cost risks and other uncertainties facing new power generation technologies. Although it is important for AE to evaluate energy options both in the operational sense as well as for purchase, we do not go into such detail in this report. This report analyzes the costs of such technologies and facilities based upon current cost estimates for construction and operation of new generation facilities. Therefore, it is assumed that, under a PPA, these costs will be passed on to AE. Beyond investing solely in power generation technologies, AE also faces opportunities to invest in demand-side management (DSM) programs to limit its projected increase in demand and to invest in infrastructure changes that enhance power system reliability and flexibility.

Portfolio analysis has been identified as a mechanism that utilities can use to make future generation planning decisions.[3] Applying the portfolio approach allows decision makers to compare the impacts and tradeoffs that generation technologies have on different objectives. Objectives for a public utility like AE include financial stability, providing low-cost electricity to its customers, lowering emissions to protect the environment, meeting regulatory protocols, and satisfying political and public demands. Power generation technologies may satisfy some of these objectives at the expense of others. For example, while coal-fired power plants provide relatively inexpensive and reliable energy at all times of the day, this comes at the cost of high greenhouse gas emissions. While wind energy does not emit pollutants and is becoming cost competitive with coal-fired electricity, it provides an intermittent source of energy that currently faces transmission constraints, creating reliability of service concerns. The portfolio approach allows decision-makers to weigh the tradeoffs of different objectives and determine what set of options provides the greatest achievement of societal and operational objectives at the least cost to other objectives. The rationale for the portfolio approach is to analyze uncertainties and risks associated with power generation technologies, make comparisons of technologies based upon multiple objectives, and identify the ways in which technologies can complement each other within a power generation mix.[4]

In order to assess power generation resource portfolio options, we designed a user-friendly model to demonstrate the effects of power generation technology additions and subtractions made to AE's current resource mix during the years 2009 through 2020. The model is designed as a Microsoft Excel spreadsheet so that a potential user can modify new facility inputs and select tabular and graphical outputs. This model allows different resource portfolios to be compared based upon potential risks on system reliability, costs and economic impacts, and societal concerns including the emission of GHGs into the atmosphere. Specifically, this model allows the user to analyze the ability of a power generation mix to meet demand (both annually and daily during peak demand), to evaluate the CO_2 emissions profile of the mix, and determine the anticipated costs of such power generation investments. An explanation of the methodology used in the creation of the model including the assumptions and limitations that were made follows.

The chapters that follow in this volume of the report show the impacts associated with particular investment plans through a series of graphs and tables and provide a brief analysis of the impact such changes would have upon system reliability, carbon emissions, and costs of providing electricity. We first evaluated AE's proposed energy resource plan to provide a baseline scenario of AE's future power generation mix. We then look at six alternate strategies for investing in new energy sources that would further reduce AE's carbon footprint and analyze the impact that additional demand savings (beyond AE's goal of 700 MW of demand savings by 2020) would have upon the necessity of these investments. We also conducted a sensitivity analysis for specific power generation technology investments in a scenario, including associated outputs as appendices to those chapters. From these evaluations, we then made several conclusions related to designing a sustainable utility. We then provide recommendations for sustainable energy options for AE by selecting several different investment plans that would provide reliable, cleaner energy with the intent of developing a carbon neutral electric utility by 2020.

Notes

[1] Austin Energy, "Future Energy Resources and CO_2 Cap and Reduction Planning." July 2008. Online. Available: http://www.austinenergy.com/About%20Us/Newsroom/Reports/Future%20Energy%20Resources_%20July%2023.pdf. Accessed: July 24, 2008.

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[3] The National Regulatory Research Institute, "What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies Across Nine Criteria." Online. Available: http://www.coalcandothat.com/pdf/35%20GenMixStateToolsAndCriteria.pdf. Accessed: July 16, 2008. p. 62.

[4] The National Regulatory Research Institute, "What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies Across Nine Criteria." Online. Available: http://www.coalcandothat.com/pdf/35%20GenMixStateToolsAndCriteria.pdf. Accessed: July 16, 2008. p. 64-65.

Chapter 2. Austin Energy Resource Portfolio Simulator Methodology

The electric utility industry has developed an array of tools to either simulate the utility's choices or optimize relevant variables, such as cost minimization or reliability maximization. Electric utility modeling should link long-term resource and equipment planning, mid-term operations planning, and short-term real time operations.[1] Each level of the process maintains an inherent complexity that must be managed and linked together. Long-term resource planning typically involves a timeline of 5 to 40 years and involves balancing a power generation mix that can satisfy forecasted loads coupled with DSM strategies. Long-term resource planning is based upon the load-service function, construction costs and time, fuel costs and dependability, operational life and dependability, maturity, and any externalities involved with each generation technology.[2] Mid-term operations planning, typically involving a timeline of less than 5 years, involves scheduling power production and maintenance, securing fuel contracts, and deciding when to start up and shut down power generating units. Short-term real time planning involves up-to-the-minute dispatching of units and maintaining equipment by sustaining certain voltages and frequencies. The entire process of traditional electric utility planning and modeling is reflected in **Error! Reference source not found.**. Each box in the diagram represents a different model that could be constructed, while many of the individual functions can be satisfied concurrently within one model.

Based on this detailed framework, the project team developed a simplified long-term simulation model (called the "Austin Energy Resource Portfolio Simulator") to predict and analyze the reliability of AE's power system, costs for investment plans, and affects of investments on carbon emission levels, while broadly addressing pertinent mid-term operations concerns. The intent of this model was to provide snapshots of the potential risks and uncertainties associated with system reliability and costs of a power generation mix. One can then compare generation mixes and make a judgment regarding their ideal future resource portfolio. This model allows the user to quickly run alternate scenarios for further comparison. Although AE can forecasts loads on an hourly basis, this model does not have that level of accuracy. Real time planning is beyond the scope of this project, given its dynamic nature and required level of detail and information.

The resulting model is a simulation tool, not an optimization model, meaning it does not choose a power generation mix based on a certain optimized variable of interest. Optimization is beyond the scope of this project, as it would require defining a mix of power generating technologies as a function of both costs and emissions varying in time until 2020, while incorporating other long-term planning factors mentioned previously.

Model Inputs

Based on the simplified model process reflected in Figure 2.2, a procedural process was developed to determine the inputs required to develop the model. Capacity additions from conventional and alternative power generating technologies determine the system's ability to produce power, while DSM strategies can reduce forecasted demand. After a user determines the appropriate investments that allow AE to meet projected electricity demands along with other concerns, the model predicts system reliability, carbon emissions, and costs associated with the investments made. A diagram of the final model components is included in Figure 2.3. AE's forecasted yearly peak demand and power generation needs are incorporated into the model to demonstrate the ability of a power generation mix to meet demand.

The project team analyzed the availability of various energy sources and power generation technologies to determine reasonable investment opportunities through 2020. The following fuel sources and power generation technologies were included in the model:

- Coal (pulverized coal and integrated gasification combined cycle power plants with and without a carbon capture and storage system),
- Nuclear,
- Natural gas (combustion gas turbines or combined cycle gas units),
- Wind (onshore and offshore),
- Biomass (using wood waste),
- Coal co-fired with biomass (using wood waste),
- Landfill gas,
- Concentrated solar,
- Solar photovoltaic (centralized facilities and distributed systems), and
- Geothermal (binary cycle power plants).

Power plant characteristics for the Fayette Power Project, AE's exiting pulverized coal-fired power capacity, are represented as "coal" in the model. Integrated gasification power plant additions facilities also use coal, but are represented in the model by as "IGCC w/ CCS" or "IGCC w/o CCS." Natural gas is represented by AE's current existing facilities broken up by technology types in order to accurately portray capacity and carbon emission factors. Sand Hill 1-4 are combustion gas turbines, Sand Hill 5 is a combined cycle unit, Decker 1 and 2 are steam turbine units, and Decker CGT are combustion gas turbines. Power plant characteristics for the South Texas Project, AE's existing nuclear power capacity, are represented as "nuclear" in the model. Compressed air energy storage, pumped hydropower, utility-scale batteries, flywheels, and fuel cells are also included in the model as energy storage technologies or facilities.

The simulation model operates by first scheduling a mix of energy resources to be implemented to serve the electrical demand needs for AE's service area through 2020. The user can add or subtract power producing capacities each year until 2020. Long-term planning factors are included by allowing the user to manipulate assumptions of load forecasts, technology characteristics, costs, and other factors, or choose a point in time in which to introduce a new energy resource. Once the user has defined the variables and entered the scheduled additions or subtractions to AE's power generation mix through 2020, the outputs automatically generate. Figure 2.4 shows a screenshot of the scenario schedule function of the model.

A user can select availability and capacity factors for each input, defining how often a facility will operate at capacity during the course of a year. The capacity factor for intermediate and peaking power sources (primarily natural gas for AE's power system) can be adjusted after a scenario schedule is entered to help meet total yearly demand or to eliminate the necessity of a particular power generation facility. Capacity factors for each resource or technology can be adjusted by the hour to determine hourly electricity production for one peak demand day in 2020. Capacity factors for AE's natural gas facilities default to 2007 usage. We assume that all natural gas additions are made as additions of units to AE's current facilities that have the same technology characteristics as existing units.

Energy resources are assigned a carbon-equivalent emissions factor per unit of electricity produced [in metric tons of carbon dioxide equivalent per megawatt-hour of electricity generated (CO_2-eq/MWh)]. Yearly demand defaults to projections used internally by AE, but can be user-adjusted, as needed. Multiplying each resource or facility's power capacity (in MW) by the amount of time the resource is used (capacity factor × hours/year) determines the annual amount of electricity produced (in MWh/year). This can vary in time for each technology as the chosen schedule of additions and subtractions dictates. Electricity production is then adjusted with a 5 percent loss to account for system average transmission and distribution losses (except for distributed photovoltaic modules). Multiplying annual electricity produced by each resource or facility's carbon emission factor yields a direct carbon emissions profile (in metric tons/year) forecasted to 2020.

The resulting series of outputs are as follows:

- Annual power generation capacity from each resource and the overall mix through 2020,
- Annual electricity production from each resource and the overall mix through 2020,
- An hourly load profile for meeting peak demand in 2020 with electricity production from each resource and the overall mix,
- A carbon emissions profile through 2020,
- Potential annual carbon costs or profits due to impending legislation from 2014 to 2020,
- Potential costs to offset remaining carbon emissions,
- Annual capital costs of new facilities added to the mix (represented as total overnight costs),
- Annual fuel costs of the mix, and
- A range of expected increases in the cost of electricity (represented as total levelized costs of electricity) attributed to each resource and the magnitude of additions to the mix.

Model Outputs

Based on the input values, a number of calculations are performed to generate the generation capacity, electricity delivered, carbon emissions, and costs outputs for a scenario. The process by which these outputs are generated, including any calculations used, is provided below. The list of assumptions and limitations provided later in this document provides additional information on the outputs.

System Reliability

The purpose of the first set of outputs and calculations performed in the model is to confirm if the user defined a resource portfolio that allows AE to meet the peak load forecasted from 2009 through 2020. These outputs gauge the reliability of the resource portfolio. The total nameplate capacity of a particular resource in any given year is determined by summing the yearly power generation facility additions or subtractions to that point and the base year (2008) nameplate capacity of that resource. This combined nameplate resource capacity of the resource portfolio is then compared with the projected peak load with and without DSM projections forecasted by AE. AE projects that it will be able to meet its goal of an additional 700 MW of demand savings by 2020. However, it is possible that AE will achieve more or less savings. For this reason, both projection lines are included in the system reliability outputs, but the scenarios are designed to meet demand *including* DSM savings. The following outputs related to system reliability are generated to demonstrate the ability of a particular power generation mix to meet projected demand: a bar graph showing annual power generation capacity from each resource or facility and the overall mix through 2020 with projection lines of peak load with and without DSM; a bar graph showing annual electricity production from each resource or facility and the overall mix with projection lines of peak load with and without DSM through 2020; an hourly load profile for meeting demand during the peak day in 2020 with energy production from each resource or facility and the overall mix with projection lines of peak load with and without DSM; and comparison pie charts of total power generation capacity and electricity delivered by source in 2020.

The equation used for the output of electricity generation (MWh) is a summation of the nameplate capacities of the resources and facilities that compose the resource mix (MW) multiplied by the respective capacity factors for the resources and facilities multiplied by 8760 hours (number of hours in a non-leap year). Capacity factors used in the model are provided in **Error! Reference source not found.**. The calculation used for electricity generated for each resource or facility is provided as Equation 1.

$$G = \sum N_i * CF_i * 8760 \qquad \text{Equation 1}$$

Where:	G	=	total electricity generated by generation mix in one year (MWh);
	N_i	=	nameplate capacity of facility, *i* (MW);
	CF_i	=	capacity factor; and
	8760	=	hours in a non-leap year (hrs).

The actual electricity delivered to customers (in MWh) is calculated by taking the result of Equation 1 (MWh of electricity generated, *G*) and subtracting estimated transmission and distribution line losses. A 5 percent transmission loss is based on average estimates by AE and is assumed to be constant across all resources, except distributed solar PV. Total electricity delivered for a particular year is calculated by summing up the electricity generated by each resource for that particular year. The calculation used for total electricity delivery for a given year is provided as Equation 2.

$$D = G * (1 - 0.05) \qquad \text{Equation 2}$$

Where:	D	=	total electricity delivered by generation mix in one year (MWh);
	G	=	total electricity generated by generation mix in one year (MWh); and
	0.05	=	system average transmission loss rate.

Equation 1 is used to determine the MWh of electricity generated without predicting how AE will actually use the resource in a given year. Therefore, the user must adjust capacity factors for intermediate power sources that do not have limited availability (primarily natural gas for AE's power system), if necessary, to meet demand (or get as close to meeting total demand as possible). For example, if a resource mix falls 10,000 MWh short of total yearly demand for electricity, capacity factors for AE's natural gas units at either or both Decker and Sand Hill can be increased from their default 2007 values to meet this demand. Other factors that may influence the dispatch of AE's natural gas facilities such as natural gas fuel prices and the nodal market are not considered by this model. As we do not know when, how often, or for what period of time a resource will be used, the model assumes that usage will be based on a typical range of usage factors for the resource. It is also assumed that yearly capacity factor and availability factors are constant from 2009 through 2020 for resources other than natural gas.

The peak hourly load profile output (assumed to be the hottest day in the summer) demonstrates if a defined resource mix allows AE to meet the typically worst-case scenario of energy demand forecasted for AE in 2020. The peak demand hourly load profile shape for 2007 was translated from an hourly demand load curve generated by ERCOT, and scaled down to meet AE's likely needs in 2020. It is assumed that the peak demand hourly load profile shape for AE will stay the same through 2020.

Hourly capacity factors during the peak day for the following resources are assumed constant: coal, nuclear, biomass, landfill gas, geothermal, and purchased power. Hourly capacity factors for natural gas sources are manually adjusted for each hour during the peak day to serve as intermediate or backup power sources. Hourly capacity factors for wind and solar are based upon an hourly load profile for each respective resource, and pose a limitation when dealing with intermittency discussed later in this section. The ability of the resource mix to meet the peak demand hourly load in interim years, between 2009 and 2019, is not included. Figure 2.5 shows hourly load profiles used in this model.

Carbon Dioxide Emissions and Carbon Costs

Carbon dioxide (CO_2) emissions are calculated by taking the summation of the electricity generated by each resource (MWh) multiplied by that resource's carbon emission factor (CO_2-eq/MWh). These calculations are based upon the carbon emission factors referenced in **Error! Reference source not found.**. The summation of total direct CO_2 emissions is represented as a line chart of CO_2 emissions by year. The calculation used for CO_2 emissions is provided as Equation 3.

$$CE = \sum G_i * EF_i \qquad \text{Equation 3}$$

Where: C = total CO_2 emissions by resource mix in one year (metric tons);
G_i = total electricity generated by resource, *i*, in one year (MWh); and
EF_i = carbon emission factor for resource, *i* (CO_2-eq/MWh).

Again, Equation 3 does not fully take into account how AE may actually use the resource. Purchase power emissions are not included in this calculation because no scenario was designed to rely on purchased power. Omitting emissions from purchased power, however, is consistent with the California Climate Action Registry requirements for reporting carbon emissions, which AE currently uses to verify their emissions.

Estimated annual costs of offsetting AE's CO_2 emissions through 2020 is represented as a bar graph with a range of offset costs from \$13 to \$40. This range is based upon a general review of the price of offsets in voluntary carbon markets in the United States and projections of future offset costs if carbon regulation were to be implemented. It should be noted that under carbon regulation it may be stipulated that only a percentage of an entity's carbon emissions can be credited through offsets to meet emission reduction requirements. However, whether an entity wishes to purchase offsets to reduce emissions beyond allowed amounts is their discretion. The price of offsets could be influenced by carbon regulation, particularly by the structure of the allowance market (i.e. percentage of credits versus percentage auctioned). For example, if carbon regulation was passed, creating a 100 percent auction system, AE would have to purchase credits for all of their emissions, essentially replacing the offset market. Such a system would bring into question whether a utility could purchase offsets rather than credits in order to claim "carbon neutrality." The calculation used for offset costs is provided as Equation 4.

$$TOC = CE * OC \qquad \text{Equation 4}$$

Where: TOC = total costs of carbon offsets in one year (\$);
CE = total CO_2 emissions by resource mix in one year (metric tons); and
OC = carbon offset price (\$/metric ton).

Estimated annual costs or profits from CO_2 emissions are represented as a bar graph for the years 2014 through 2020. Costs or profits from CO_2 emissions would only be applicable if carbon regulation were to be passed by the federal or state government. Therefore, this output provides only a representation of the estimated impacts of carbon regulation based upon analysis of the Lieberman-Warner Climate Stewardship and Innovation Act of 2007 completed by the

Environmental Protection Agency (EPA). The percentage of credits allocated versus auctioned is based upon language in the Climate Stewardship and Innovation Act of 2007.[3] The estimated cost of allowances by year is based upon EPA analysis for the years 2015 and 2020 and interpolated by AE for the remaining years between 2014 and 2020.[4] The implementation year for carbon regulation is estimated to be 2014, two years after the proposed implementation year under the Lieberman-Warner bill filed in 2007. Under our analysis, 2005 emissions would serve as the baseline year for calculating emission reduction requirements. If AE were to emit CO_2 at levels greater than the amount provided by free credits under carbon regulation, they would have to pay for each metric ton of CO_2 emitted beyond the credited amount, multiplied by the cost of carbon determined by the auction market. However, if AE were to reduce its CO_2 emissions by an amount that exceeded that of which was required for a given year they would be able to sell their excess credits to other entities in the carbon trade market. We assume that carbon credits that AE could potentially sell would be worth the same as those purchased at auction. The calculation used for carbon allowance costs or profits is provided as Equation 5.

$$TCP = [EC - (CE * AC)] * AP \qquad \text{Equation 5}$$

Where:

	TCP	=	total costs or profits of allowances [negative value indicates cost and positive value indicates profit] ($);
	EC	=	emissions cap (metric tons);
	CE	=	total CO_2 emissions by resource mix in one year (metric tons);
	AC	=	percentage of allowance credits; and
	AP	=	carbon allowance price ($/metric ton).

Costs

Expected annual capital costs for a particular investment plan is represented by a bar graph that calculates the total overnight costs of all power generation technology investments, summed over a given year. Total overnight cost is the cost that would be incurred if a technology or power plant facility could be built instantly. Overnight costs do not factor in financing charges or escalation in construction costs incurred during the time a plant is under construction. Capital costs are assumed constant for all years through 2020 as 2008 estimates, that is, the model does not account for projections of increases or decreases in capital costs for a particular power generation technology. Therefore, it is important to recognize the year in which an investment is made and the anticipated construction time for a particular facility. The majority of capital cost estimates come from a report released by the Congressional Research Service (CRS) in November 2008, while some of the cost estimates for technologies such as energy storage come from other sources. The CRS estimates are based upon a database of 161 recent power projects.[5] Capital costs are represented in dollars per kilowatt of power generation capacity ($/kW). A potential range of values is provided based upon the maturity of the technology. Capital costs for particular power generation technologies are calculated by multiplying the power generation nameplate capacity (MW) of a technology or facility by its capital cost estimate ($/kw × 1000 kw/MW). Capital cost estimates are provided in Table 2.2 and references are provided with notes included on capital cost ranges used in the model. Since some investments are evaluated as additions to AE's current facilities (for coal, natural gas, and nuclear) these estimates may be inaccurate due to cost reductions attributed to already owning the land and other factors. It is possible that AE may invest in particular resources or power generation technologies through power purchase agreements. For these instances, it is assumed that capital costs will be capture by the contract. Additionally, profits earned through the selling of ownership in a power plant facility are not included in the model. The calculation used for capital costs is provided as Equation 6.

$$TCC = \sum CCNG_i * N_i * 1000 \qquad \text{Equation 6}$$

Where:	*TCC*	=	total capital costs of new generation facilities in a given year ($);
	$CCNG_i$	=	capital costs of new generation facility, *i* ($);
	N_i	=	nameplate capacity of facility, *i* (MW); and
	1000	=	conversion factor (1000 kW/MW).

Fuel costs for a power generation mix are represented as dollars per megawatt-hour of electricity generated ($/MWh). A potential range of fuel cost projections are primarily based upon Energy Information Administration data converted to 2008 dollars. Fuel costs for a particular power generation technology are calculated by multiplying the amount of electricity generated by the facility by its fuel cost estimate, if it exists. Fuel costs only apply to biomass, coal, natural gas, and nuclear technologies. Fuel cost estimates are provided in Table 2.2 and references are provided with notes included on fuel cost ranges used in the model. The calculation used for fuel costs is provided as Equation 7.

$$TFC = \sum FC_i * G_i \qquad \text{Equation 7}$$

Where:	*TFC*	=	total fuel costs in a given year ($);
	FC_i	=	fuel costs of generation facility, *i* ($/MWh); and
	G_i	=	total electricity generated by resource, *i*, in one year (MWh).

A dual axis bar and box-and-whiskers graph is used to demonstrate the expected increase in levelized cost of electricity by year for the overall mix due, attributed to investments in power generation technologies and facilities. The "levelized cost" of electricity is the constant annual cost of electricity that is equivalent, on a present value basis, to the actual annual costs, which are themselves variable. Components of levelized costs estimates include: the total cost of construction including financing; the cost of insuring the plant; ad valorem property taxes; fixed operation and maintenance costs; fuel costs, and variable operation and maintenance costs. By levelizing costs, one is able to compare technologies against one another more easily than by comparing annual costs. The majority of the levelized costs figures are derived from a 2007 study conducted by the California Energy Commission to compare costs of central station electricity generation technologies.[6] Levelized costs for energy storage technologies are not available in the literature, so the model has rough estimates of such costs based upon their combined usage with wind energy facilities.

The left side y-axis shows the expected increase in levelized costs of electricity in cents per kilowatt-hour (cents/kWh) to the cost of producing electricity. One can imagine that this is analogous to an increase in a customer's electric bill. The right side y-axis shows what percentage of total electricity generated in each year through 2020 comes from newly installed facility installations that have taken place since 2008. This procedure allows new facilities to be weighted against existing facilities. For instance, imagine a scenario where a completely overhauled AE replaces 95 percent of its existing facilities with new technologies through 2020. Now, imagine a scenario where a very expensive technology is installed, but on a very small scale, providing 1 percent of AE's electricity in 2020. The massively overhauled generation mix will obviously increase the levelized cost of electricity many times over that of the minor addition. Thus, expected increases in the costs of electricity are related to the amount of additions that compose a particular power generation mix. However, decreases in the costs of electricity attributed to the selling of ownership in power plant facility are not included.

Equation 8 outlines the cost estimation procedure.

$$LCOE_n = \left(\frac{\sum_{n}^{n} G_{new}}{\sum_{n}^{n} G_i} \right) * \left(\frac{\sum_{2009}^{n} LCOE_i * G_i}{\sum_{2009}^{n} G_{new}} \right) \qquad \text{Equation 8}$$

Where:	$LCOE_n$	=	levelized cost of electricity in year *n* due to additional generation facilities ($/MWh);
	n	=	year in question;
	G_{new}	=	electricity generated by new facility since 2008, *new*, in one year (MWh);
	G_i	=	total electricity generated by facility, *i*, in one year (MWh); and
	$LCOE_i$	=	levelized cost of electricity estimate of individual facility, *i* ($/MWh);

Economic Impacts

The economic impact projections for selected power generation mix scenarios were created with the IMPLAN (IMPact analysis for PLANning) input-output program marketed by the Minnesota IMPLAN Group (MIG, Inc) using industry and demographic data collected on the State of Texas.

The resulting outputs were constructed using IMPLAN's Social Accounting Matrix (SAM) function, which uses historical multipliers to project the impact of investment in diverse sectors. In addition to the impacts within a particular sector, SAM can also project indirect impacts on related industries and induced impacts driven by projected changes in household incomes[7].

The key assumptions of the IMPLAN model are constant returns to scale, unconstrained supply, fixed commodity input structure, homogenous output, and uniform industry technology.[8] IMPLAN does not have data on the unique impacts related to renewable power generation technologies. The multiplier assumptions for the electric power generation, residential maintenance and repair, and non-residential construction sectors represent industry averages and thus under represent the unique impacts of renewable power generation technologies. Given the small market share of non-conventional power generation sources there is currently no reliable method to isolate the impacts of investment in renewable power generation without manually adjusting the industry multipliers. A much less comprehensive impact analysis may be conducted using the Job and Economic Development Impact (JEDI) model, a tool that was developed as a joint venture between MIG, Inc and the National Renewable Energy Lab. The JEDI model may be used to analyze the impacts of investment in coal plants, wind energy, solar concentrating facilities, or natural gas facilities.[9]

The most important assumption regarding the inputs for each scenario run concerns the location of the projected power plants. For the purposes of inputs into IMPLAN we are modeling all investments in onshore wind and concentrated solar facilities in the counties encompassed by the Electric Reliability Council of Texas Competitive Renewable Energy Zones. All natural gas, solar photovoltaic (PV), landfill gas, and geothermal investments are modeled as being constructed in the ten counties in the Capital Area Council of Governments. Investments in integrated gasification combined cycle coal-based power generation plants with carbon capture and storage technology and nuclear facilities are modeled in Matagorda County, and investments in biomass facilities are modeled in Nagodoches County.

The impacts for each scenario are projected by year for each development region. Investments for capital outlay are assumed to take place in each of the three years prior to the addition of capacity, with the exception distributed solar PV, which is modeled as taking place in the year capacity additions are added into the scenario schedule. Operation and maintenance costs are accumulated to incur in the year in which capacity is posted on the scenario schedule as well as each successive year. In scenarios where the capacity at the Fayette Power Project coal plant is reduced we only model the loss of output and employment and do not include any potential gains incurred from the sale or lease of the facility.

Output impacts represent the total value of economic activity resulting from the grouped events. Value-added impacts isolate employee compensation, proprietary income, and other property-type income such as rents, royalties, and dividends, and indirect business taxes.[10] The monetary outputs are discounted to 2007 dollars.

Assumptions of the Model

As previously noted, this model is intended to provide a relatively simple snapshot of the impacts of making investments in power generation technologies and facilities to re-shape AE's resource portfolio by 2020. As such, many assumptions have been made due to data limitations and intent of model simplicity. General assumptions made in the model follow.

System Reliability:

- Future peak demand is assumed to follow AE projections as estimated from AE documents without specific data.
- Future annual electricity generation is calculated based upon AE projections of future peak demand, multiplied by 0.52 – a value determined empirically in the model calibration process. This implies that the average yearly demand for the entire system is, on average, about half of peak demand.
- Actual energy produced is based upon generation capacity multiplied by capacity factor multiplied by 8760 (days in a year).

- A 5 percent transmission loss is applied to all resources (except distributed solar photovoltaic modules) in calculating actual energy generated.
- Efficiencies of technologies are assumed constant and based upon current estimates.
- Hourly capacity factors for the following resources are assumed constant: coal, nuclear, biomass, landfill gas, geothermal, and purchased power.
- Hourly capacity factors for the following resources are manipulated as necessary or based upon hourly load profiles: natural gas, wind, solar, and energy storage.
- Capacity additions and subtractions are assumed to occur on the first day of the calendar year (January 1) and CO_2 emissions are reported for each calendar year.
- Peak demand hourly profile shape for 2020 is based upon current peak demand profile shape provided by the Electric Reliability Council of Texas (ERCOT) extrapolated to projected 2020 peak demand projection provided by AE. Furthermore, spot wind and solar profiles (not varying) are used to model hourly availability of these intermittent sources.
- Energy storage is not represented as additional generation capacity, but rather as a mechanism to use excess electricity during a different period of the day. This can be manipulated manually with the hourly load profile output.

Carbon Dioxide Emissions and Carbon Costs

- Carbon emission factors are assumed constant and emission factors for current facilities are based upon 2007 AE reporting.
- Costs of offsets are provided as a range of potential values assumed constant through 2020.
- Carbon regulation is assumed to become effective beginning in 2014 and costs or profits of carbon are based upon the Lieberman-Warner Climate Stewardship and Innovation Act of 2014.

Costs and Economic Impacts

- Capital, fuel, and levelized costs are assumed constant and are based upon current estimates. Cost ranges are provided to account for potential cost fluctuations.
- Capital costs are represented as total overnight costs for implementing a new technology or constructing a new power plant facility.
- The value of selling existing facilities (or ownership in existing facilities) is not represented in the model.
- Expected increases in levelized cost of electricity are calculated based upon the percentage of electricity generated from cumulative new additions as a weighted cumulative average of additions.

Limitations of the Model

Again, due to the simplicity of the model and lack of data, limitations arose during the creation of the model. The following limitations exist in the model:

System Reliability:

- Projected demand for actual energy delivered (in MWh, not peak power demand in MW) is not based upon AE projections, but determined empirically.
- Capacity factors can be adjusted yearly for the output of total electricity generation, but are particularly difficult to estimate for natural gas sources when they are used as a backup power source for solar and wind or as an intermediate power source.
- The peak demand hourly profile is provided only for the year 2020 and, therefore, does not account for potential failure to meet peak demand in previous years.
- The model only looks at the hourly load profile for peak demand during the summer and does not account for other seasonal fluctuations in demand.
- The model does not specifically deal with probabilistic failures or intermittency of wind and solar resources.
- Energy storage is currently modeled to only account for the storage of excess electricity (usually wind). Therefore, it is not necessarily modeled as it would be actually used. For example, energy storage may be used to store baseload power sources at night for use during the day due to cost incentives.

Costs and Economic Impacts

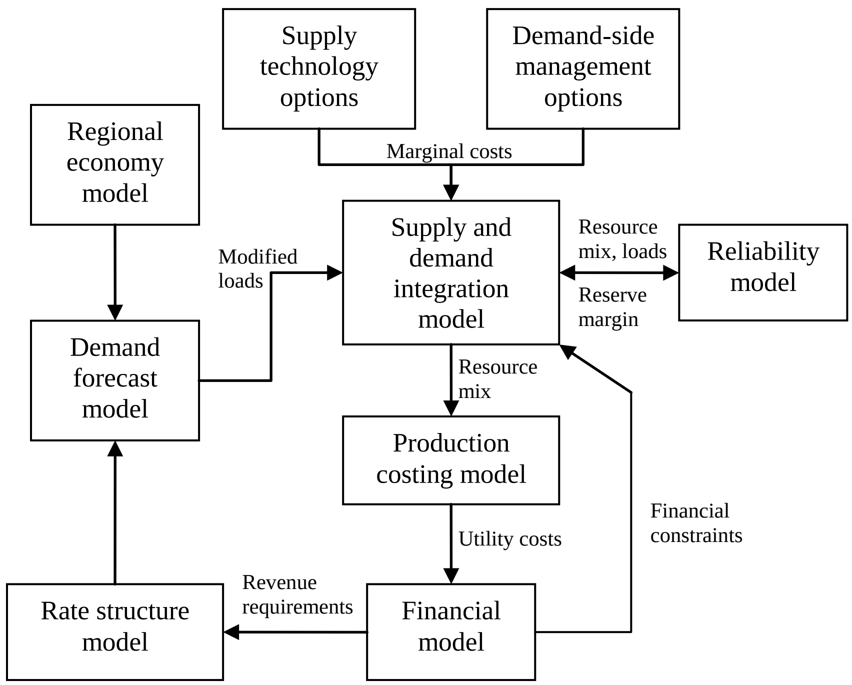
- Capital costs for additions to existing facilities use data for total overnight costs for a new facility.
- All cost projections are based upon current cost estimates and, therefore, do not account for potential future rises or drops in costs for particular technologies that are expected to exhibit such changes as they become more widely adopted or as fuel prices escalate.
- Levelized costs of electricity estimates do not account for current costs of electricity by source, but rather by taking the cumulative weighted average of additions and its expected impact on electric bills based upon percentage of overall energy generated coming from additions.
- Levelized costs of electricity for storage and DSM are not explicitly modeled. Rough storage cost estimates are made by attempting to capture how the additional capital costs, operation & maintenance costs, and any fuel costs would be passed along if storage technologies were built in conjunction with additional wind facilities. The rough estimates come from manipulating inputs to the cost estimation model obtained from the California Energy Commission.

Model Scenarios

The goal of this volume of the report is to provide a comparison of different power generation mix scenarios. The following chapters evaluate the impacts of seven different investment plans compared to AE's proposed energy resource plan. Model outputs are included in the following chapters. Because AE's use of coal accounts for about 70 percent of its CO_2 emissions and the primary intent of our project is to evaluate the options for AE to move towards a sustainable electric utility with an interim goal of reaching carbon-neutrality by 2020, the primary scenarios all involve the eventual sale or lease of AE's part ownership in the Fayette Power Project (AE's lone coal-burning power source). The seven primary scenarios evaluated include: nuclear expansion; high renewable investment; expected renewable investment; expected renewable investment with energy storage; natural gas expansion; coal with carbon capture and sequestration; and high renewables without coal and nuclear. Included with the primary scenario analyses are appendices with the outputs for each major resource investment, separately for each scenario. These appendices are intended to serve as a sensitivity analysis of each scenario. Table 2.3 lists the energy resource mix scenarios that follow in this report with sensitivity analysis shown and major investments included. A chapter evaluating what impacts DSM savings beyond AE's goal of 700 MW by 2020 would have upon these scenarios is also included.

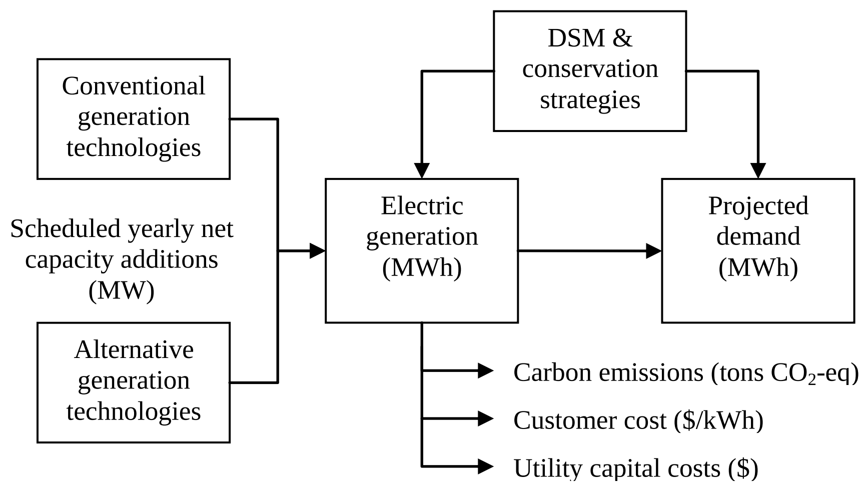
AE's proposed energy resource plan would add 1,375 additional Megawatts (MW) of generating capacity by 2020, with only 300 MW coming from fossil-fueled resources.[11] The generation capacity for 2008 includes AE's current power generation mix. Scheduled additions of natural gas and wind power generation capacity in 2009 as well as the 100 MW biomass project expected by 2012 have already been approved by the Austin City Council and contracted for purchase or operation by AE. As a resource, biomass has a capacity factor similar to that of coal and nuclear and can provide a reliable source of baseload power.[12] This generating capacity has been contracted through a PPA to provide 100 MW of energy per year over a 20 year time period at the total cost of $2.3 billion. The wind and natural gas planned additions for 2009, planned wind additions for 2011, the proposed centralized photovoltaic module system for 2010, and the biomass project expected to be available by 2012 have been included in all potential scenario runs. Cost projections for these additions are based upon general cost data for new power generation plants, rather than the contractual agreements established by AE.

Figure 2.1
Traditional Electric Utility Planning Model



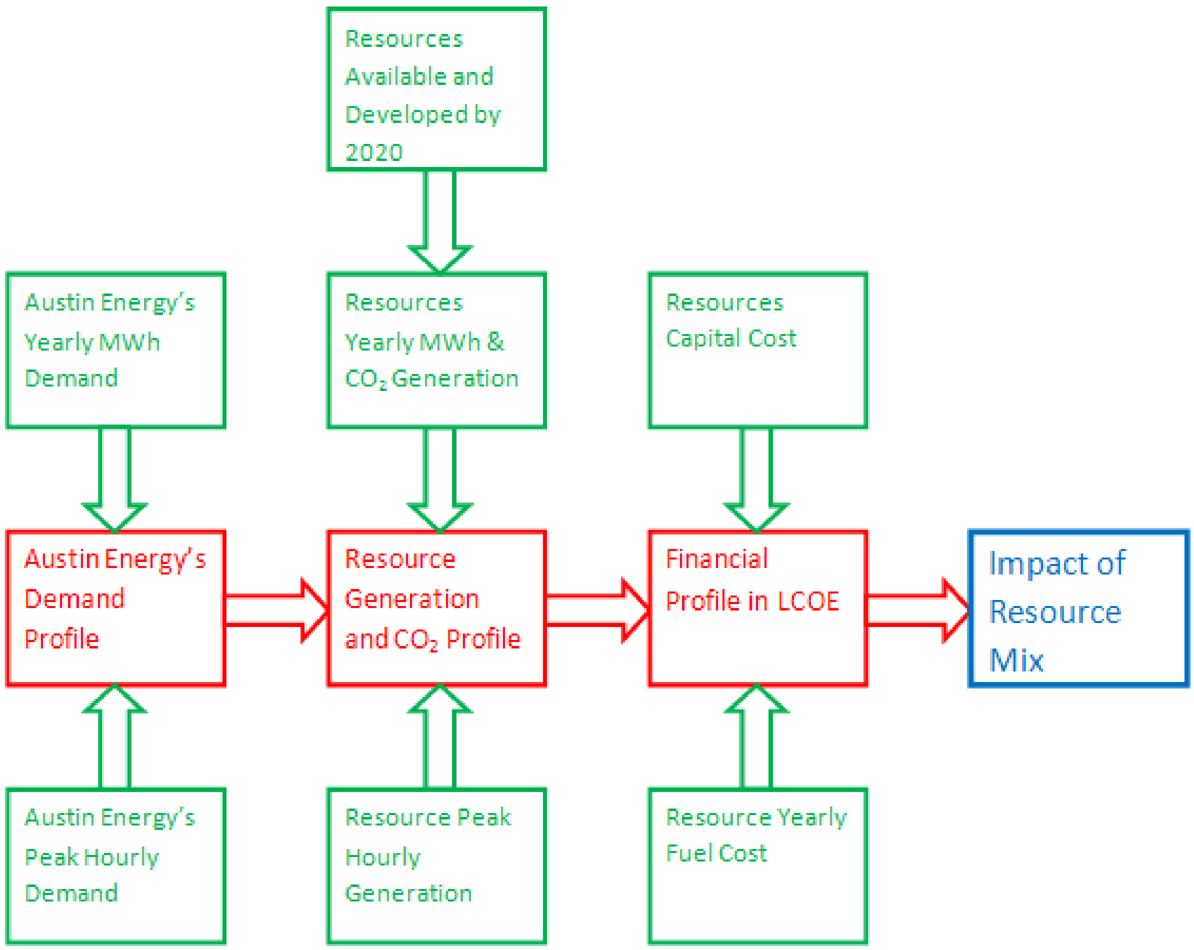
Source: Adapted from: Hobbs, Benjamin F. "Optimization Methods for Electric Utility Resource Planning." European Journal of Operational Research, vol. 83, no. 1, (May 18, 1995), pp. 1-20.

Figure 2.2
Simplified Model Process for Power Generation Mix Analysis



Source: Adapted from: Hobbs, Benjamin F. "Optimization Methods for Electric Utility Resource Planning." European Journal of Operational Research, vol. 83, no. 1, (May 18, 1995), pp. 1-20.

Figure 2.3
Diagram of Model Components



Source: Created by project team.

Figure 2.4
Screenshot of Generate Scenario Function

Schedule of power generation additions and subtractions (net MW)	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	607												-607
Nuclear	422												
Natural Gas - Sand Hill 1-4	189	100											
Natural Gas - Sand Hill 5	312						100						220
Natural Gas - Decker 1 & 2	741												
Natural Gas - Decker CGT	193												
Wind	274	165		100			100	200		526		100	220
Wind + CAES	0												
Biomass	0				100								
FPP w/ biomass co-firing	0												
Landfill Gas	12												
Solar PV - Centralized	0		30										
Solar PV - Distributed	1												
Concentrated Solar	0												
IGCC w/ CCS	0												
IGCC w/o CCS	0												
Geothermal	0												
Storage	0												
Accelerated Conservation	0												
Purchased Power	0												

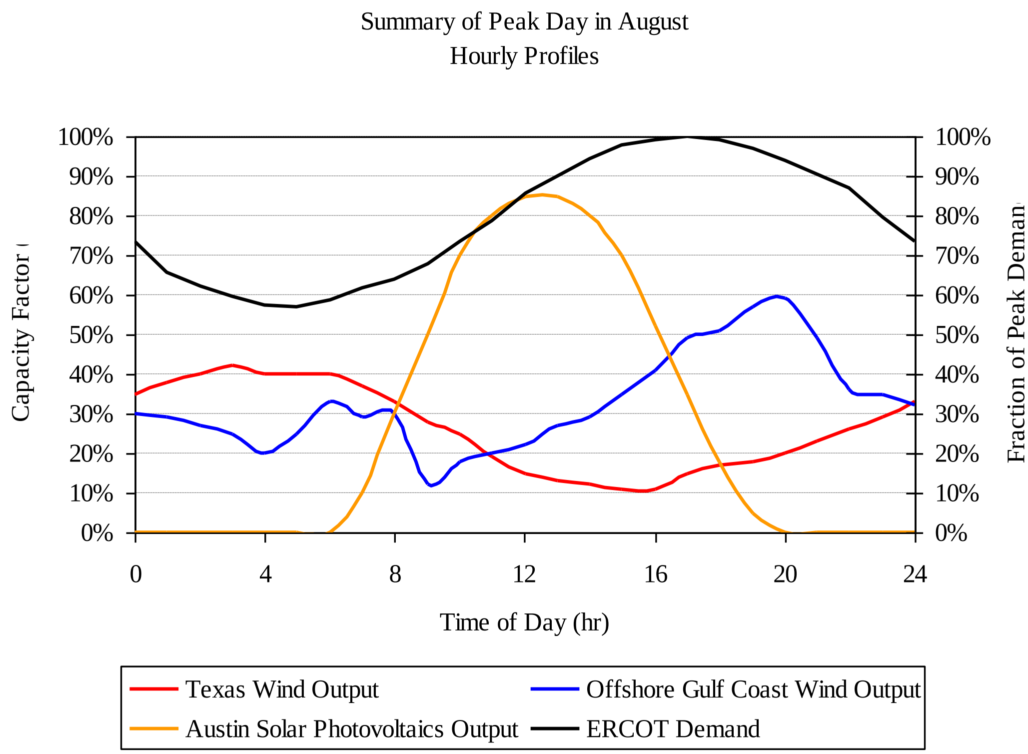
Generate Scenario2

CSP Type

Storage Type

Source: Created by project team.

Figure 2.5
Hourly Inputs for Peak Demand Hourly Profile in Model
(based on peak summer day)



Sources: See following table.

Summary of Peak Day Hourly Profiles	Reference
ERCOT Demand	2007 ERCOT Planning Long-Term Hourly Peak Demand and Energy Forecast, May 8, 2007
Texas Wind Output	Vick, B.D., Clark, R.N., Carr, D. 2007. Analysis of wind farm energy produced in the United States. In: Proceedings of the AWEA Windpower 2007 Conference, June 3-6, 2007, Los Angeles, California. 2007 CD-ROM.
Offshore Gulf Coast Wind Output	Analysis of Transmission Alternatives for Competitive Renewable Energy Zones in Texas, ERCOT, December 2006
Austin Solar Photovoltaics Output	Austin Energy Resource Guide, October 2008.
CSP Thermal Storage Output	The Value of Thermal Storage. February 20, 2003. Presentation, Platts Research & Consulting

Table 2.1
Model Inputs for Availability Factors, Capacity Factors, and Carbon Dioxide Equivalent Emission Factors

Technology	**Availability Factor**	**Capacity Factor**	**CO_2-e Emission Factor (metric tons/MWh)**
Coal	0.95[13]	0.95[14]	0.94[15]
Nuclear	0.97[16]	0.92[17]	0.00[18]
Natural gas - Sand Hill	0.96[19]	0.26[20]	0.38[21]
Natural gas - Decker	0.96[22]	0.26[23]	0.58[24]
Wind	0.95[25]	0.29[26]	0.00[27]
Offshore wind	0.95[28]	0.29[29]	0.00[30]
Biomass	0.90[31]	0.80[32]	0.10[33]
Landfill gas	0.90[34]	0.80[35]	0.00[36]
Solar PV - centralized	0.99[37]	0.17[38]	0.00[39]
Solar PV - distributed	0.99[40]	0.17[41]	0.00[42]
Concentrated solar	0.99[43]	0.17[44]	0.00[45]
IGCC w/ CCS	0.88[46]	0.95[47]	0.16[48]
Geothermal	0.92[49]	0.90[50]	0.00[51]
Fossil purchased power	1.00[52]	1.00[53]	0.59[54]

Table 2.2
Model Inputs for Capital Costs, Fuel Costs, and Total Levelized Costs of Electricity

Technology	Total Overnight Cost ($/kW)	Fuel Costs ($/MWh)	Total Levelized Costs of Electricity ($/MWh)
Coal-pulverized (w/ scrubber technology)	2,485.00[55]	14.02[56]	90.00[57]
Coal-IGCC w/CCS	4,774.00[58]	13.17[59]	134.00[60]
Coal-IGCC w/o CCS	3,359.00[61]	13.17[62]	104.00[63]
Natural gas - advanced combustion turbines	473.00[64]	75.60[65]	248.52[66]
Natural gas - advanced combined cycle	1,186.00[67]	50.37[68]	81.90[69]
Advanced nuclear	3,682.00[70]	4.89[71]	67.01[72]
Onshore wind	1,896.00[73]	n/a	60.78[74]
Offshore wind	2,872.00[75]	n/a	60.78[76]
Solar PV - centralized	5,782.00[77]	n/a	116.23[78]
Solar PV - distributed - thin film	Unavailable[79]	n/a	101.50[80]
Concentrated solar-parabolic trough	2,836.00[81]	n/a	154.86 [82]
Concentrated solar-stirling dish	3,744.00[83]	n/a	312.10[84]
Concentrated solar-power tower	3,500.00[85]	n/a	90.00[86]
Biomass	2,809.00[87]	25.37[88]	60.36[89]
Co-firing with biomass	275.00[90]	25.37[91]	20.00[92]
Landfill gas	1,897.00[93]	n/a[94]	47.86[95]
Geothermal	3,590.00[96]	n/a	67.18[97]
Pumped hydro storage	2,379.00[98]	n/a	48.01[99]
Compressed air energy storage	675.00[100]	n/a	Unavailable
Battery storage	2,322.50[101]	n/a	Unavailable
Flywheel storage	4,004[102]	n/a	Unavailable
Purchased power	Unavailable	n/a	Unavailable

Sources: See endnotes 50 through 97.

Table 2.3
Primary Scenarios Run for Analysis

	Scenario Title	Resources/Technologies with Sensitivity Analysis	Major Additions and Subtractions Through 2020
Portfolio 1	AE Resource Plan	None	Add biomass, natural gas, solar, and wind
Portfolio 2	Nuclear Expansion	Nuclear and natural gas	Nuclear replaces coal and AE resource plan additions
Portfolio 3	High Renewables	Onshore and offshore wind, concentrated solar power, centralized and distributed PV, biomass, and geothermal	Very high investments in biomass, geothermal, solar, and wind technologies to replace coal
Portfolio 4	Expected Renewables	Refer to portfolio 3 sensitivity analysis	Expected available investments in biomass, geothermal, solar, and onshore wind to replace coal
Portfolio 5	Renewables with Storage	Various energy storage technologies	Expected renewables coupled with energy storage of wind to replace coal
Portfolio 6	Natural Gas Expansion	Natural gas, co-firing biomass	Natural gas replaces half of current coal and AE resource plan additions
Portfolio 7	Cleaner Coal	IGCC without carbon capture and storage technology	IGCC with carbon capture and storage to replace Fayette Power Project and AE resource plan additions
Portfolio 8	High Renewables without Nuclear	Pulverized coal, IGCC with and without carbon capture, and natural gas	High renewables to replace coal and nuclear

Notes

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[14] Calculations from AE documents, in accordance with National Regulatory Research Institute. What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria. Columbus, OH, February 14, 2007.

[15] Calculations from AE's CCAR Emissions Computations Spreadsheet, 2007.

[16] Calculations from AE documents, in accordance with National Regulatory Research Institute. What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria. Columbus, OH, February 14, 2007.

[17] Calculations from AE documents, in accordance with National Regulatory Research Institute. What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria. Columbus, OH, February 14, 2007.

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[21] Calculations from AE's CCAR Emissions Computations Spreadsheet, 2007.

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[23] Calculations from AE Documents, including CCAR Emissions Computations Spreadsheet, 2007.

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[27] National Regulatory Research Institute. What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria. Columbus, OH, February 14, 2007.

[28] Not applicable, assumed to be similar to onshore wind.

[29] Not applicable, assumed to be similar to onshore wind.

[30] National Regulatory Research Institute. What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria. Columbus, OH, February 14, 2007.

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[34] Not applicable, assumed to be similar to biomass.

[35] Not applicable, assumed to be similar to biomass.

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[38] The Value of Distributed Photovoltaics to AE and the City of Austin, Clean Power Research LLC, March 17, 2006, in accordance with National Regulatory Research Institute. What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria. Columbus, OH, February 14, 2007.

[39] National Regulatory Research Institute. What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria. Columbus, OH, February 14, 2007.

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[43] Not applicable, assumed to be similar to solar PV.

[44] Not applicable, assumed to be similar to solar PV.

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[51] National Regulatory Research Institute. What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria. Columbus, OH, February 14, 2007.

[52] Not applicable, assumed to always be available for purchase.

[53] Not applicable, assumed to always be available for purchase.

[54] Calculations from AE's CCAR Emissions Computations Spreadsheet, 2007.

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[57] High and Low estimates are from: Lazard, "Levilized Cost of Energy Analysis-Version 2.0 (June 2008). Online. Available: http://www.narucmeetings.org/Presentations/2008%20EMP%20Levelized%20Cost%20of%20Energy%20-%20Master%20June%202008%20(2).pdf. Accessed: November 15, 2008. p. 10. Expected value estimated at lower end of the range due to estimated cost of IGCC plant.

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[60] Expected value estimate from: Lazard, "Levilized Cost of Energy Analysis-Version 2.0 (June 2008). Online. Available: http://www.narucmeetings.org/Presentations/2008%20EMP%20Levelized%20Cost%20of%20Energy%20-%20Master%20June%202008%20(2).pdf. Accessed: November 15, 2008. p. 10. High estimate assumed 30% higher than expected value and low estimate assumed 10% lower than expected value due to immaturity of technology.

[61] Stan Kaplan. Congressional Research Service, Power Plants: Characteristics and Costs. November 13, 2008. Online. Available: http://www.fas.org/sgp/crs/misc/RL34746.pdf. Accessed: December 15, 2008. High estimates assumed 30% higher and low estimates assumed 10% lower due to immaturity of technology.

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[66] Expected value estimate is from: California Energy Commission, Comparative Costs of California Central Station Electricity Generation Technologies(June 2007). Online. Available: http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SD.PDF. Accessed: November 15, 2008. p. 7. High and low estimates are from: Lazard, "Levilized Cost of Energy Analysis-Version 2.0 (June 2008). Online. Available: http://www.narucmeetings.org/Presentations/2008%20EMP%20Levelized%20Cost%20of%20Energy%20-%20Master%20June%202008%20(2).pdf. Accessed: November 15, 2008. p. 9.

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[72] Expected value estimate is from: California Energy Commission, Comparative Costs of California Central Station Electricity Generation Technologies(June 2007). Online. Available: http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SD.PDF. Accessed: November 15, 2008. p. 7. High estimate from: Lazard, "Levilized Cost of Energy Analysis-Version 2.0 (June 2008). Online. Available: http://www.narucmeetings.org/Presentations/2008%20EMP%20Levelized%20Cost%20of%20Energy%20-%20Master%20June%202008%20(2).pdf. Accessed: November 15, 2008. p. 9. Low estimate assumed 10% lower than expected value.

[73] Stan Kaplan. Congressional Research Service, Power Plants: Characteristics and Costs. November 13, 2008. Online. Available: http://www.fas.org/sgp/crs/misc/RL34746.pdf. Accessed: December 15, 2008. High estimates assumed 20% higher and low estimates assumed 10% lower due to mature technology status.

[74] Expected value estimate is from: California Energy Commission, Comparative Costs of California Central Station Electricity Generation Technologies(June 2007). Online. Available: http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SD.PDF. Accessed: November 15, 2008. p. 7. High and low estimates are from: Lazard, "Levilized Cost of Energy Analysis-Version 2.0 (June 2008). Online. Available:

http://www.narucmeetings.org/Presentations/2008%20EMP%20Levelized%20Cost%20of%20Energy%20-%20Master%20June%202008%20(2).pdf. Accessed: November 15, 2008. p. 9.

[75] Stan Kaplan. Congressional Research Service, Power Plants: Characteristics and Costs. November 13, 2008. Online. Available: http://www.fas.org/sgp/crs/misc/RL34746.pdf. Accessed: December 15, 2008. High estimates assumed 20% higher and low estimates assumed 30% lower due to immature technology status.

[76] Assumed the same as onshore wind due to lack of information. Expected value estimate is from: California Energy Commission, Comparative Costs of California Central Station Electricity Generation Technologies(June 2007). Online. Available: http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SD.PDF. Accessed: November 15, 2008. p. 7. High and low estimates are from: Lazard, "Levilized Cost of Energy Analysis-Version 2.0 (June 2008). Online. Available: http://www.narucmeetings.org/Presentations/2008%20EMP%20Levelized%20Cost%20of%20Energy%20-%20Master%20June%202008%20(2).pdf. Accessed: November 15, 2008. p. 9.

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[79] Information not available.

[80] High and Low estimates are from: Lazard, "Levilized Cost of Energy Analysis-Version 2.0 (June 2008). Online. Available: http://www.narucmeetings.org/Presentations/2008%20EMP%20Levelized%20Cost%20of%20Energy%20-%20Master%20June%202008%20(2).pdf. Accessed: November 15, 2008. p. 10. Expected value estimate is average of high and low estimate.

[81] Stan Kaplan. Congressional Research Service, Power Plants: Characteristics and Costs. November 13, 2008. Online. Available: http://www.fas.org/sgp/crs/misc/RL34746.pdf. Accessed: December 15, 2008. High estimates assumed 20% higher and low estimates assumed 20% lower due to immature technology status.

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[83] Based upon data for solar thermal. Energy Information Administration, Assumptions to the Annual Energy Outlook 2008 (June 2008). Online. Available: http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf. p. 79. High estimates assumed 20% higher and low estimates assumed 20% lower due to immature technology status.

[84] Expected value estimate is from: California Energy Commission, Comparative Costs of California Central Station Electricity Generation Technologies(June 2007). Online. Available: http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SD.PDF. Accessed: November 15, 2008. p. 7. High estimates assumed 20% higher and low estimates assumed 20% lower due to mature technology status.

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[86] Expected value estimate is from: Lazard, "Levilized Cost of Energy Analysis-Version 2.0 (June 2008). Online. Available: http://www.narucmeetings.org/Presentations/2008%20EMP%20Levelized%20Cost%20of%20Energy%20-%20Master%20June%202008%20(2).pdf. Accessed: November 15, 2008. p. 10. High estimates assumed 20% higher and low estimates assumed 20% lower due to immature technology status.

[87] Energy Information Administration, Assumptions to the Annual Energy Outlook 2008 (June 2008). Online. Available: http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf. p. 79. High estimates assumed 20% higher and low estimates assumed 10% lower due to mature technology status.

[88] This is an average of the range provided by: The National Regulatory Research Institute, What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies Across Nine Criteria. Online. Available: http://www.coalcandothat.com/pdf/35%20GenMixStateToolsAndCriteria.pdf. Accessed: July 16, 2008. p. 18-19.

[89] Expected value estimate is for wood waste from: California Energy Commission, Comparative Costs of California Central Station Electricity Generation Technologies(June 2007). Online. Available: http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SD.PDF. Accessed: November 15, 2008. p. 7. High and low estimates are unspecified biomass sources from: Lazard, "Levilized Cost of Energy Analysis-Version 2.0 (June 2008). Online. Available: http://www.narucmeetings.org/Presentations/2008%20EMP%20Levelized%20Cost%20of%20Energy%20-%20Master%20June%202008%20(2).pdf. Accessed: November 15, 2008. p. 9.

[90] High and low estimates are from: Lazard, "Levilized Cost of Energy Analysis-Version 2.0 (June 2008). Online. Available: http://www.narucmeetings.org/Presentations/2008%20EMP%20Levelized%20Cost%20of%20Energy%20-%20Master%20June%202008%20(2).pdf. Accessed: November 15, 2008. p. 9. Expected value is the average of the high and low estimates.

[91] This is an average of the range provided by: The National Regulatory Research Institute, What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies Across Nine Criteria. Online. Available: http://www.coalcandothat.com/pdf/35%20GenMixStateToolsAndCriteria.pdf. Accessed: July 16, 2008. p. 18-19.

[92] High and low estimates are from: Lazard, "Levilized Cost of Energy Analysis-Version 2.0 (June 2008). Online. Available: http://www.narucmeetings.org/Presentations/2008%20EMP%20Levelized%20Cost%20of%20Energy%20-%20Master%20June%202008%20(2).pdf. Accessed: November 15, 2008. p. 9. Expected value is the average of the high and low estimates.

[93] Energy Information Administration, Assumptions to the Annual Energy Outlook 2008 (June 2008). Online. Available: http://www.eia.doe.gov/oiaf/aeo/assumption/pdf/electricity.pdf. p. 79. High estimates assumed 20% higher and low estimates assumed 10% lower due to mature technology status.

[94] Assume fuel is tapped into at facility so no costs are incurred.

[95] Expected value estimate is from: California Energy Commission, Comparative Costs of California Central Station Electricity Generation Technologies(June 2007). Online. Available: http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SD.PDF. Accessed: November 15, 2008. p. 7. High estimate is from from: Lazard, "Levilized Cost of Energy Analysis-Version 2.0 (June 2008). Online. Available: http://www.narucmeetings.org/Presentations/2008%20EMP%20Levelized%20Cost%20of%20Energy%20-%20Master%20June%202008%20(2).pdf. Accessed: November 15, 2008. p. 9. Low estimate assumed 10% lower than expected value.

[96] Stan Kaplan. Congressional Research Service, Power Plants: Characteristics and Costs. November 13, 2008. Online. Available: http://www.fas.org/sgp/crs/misc/RL34746.pdf. Accessed: December 15, 2008. High estimates assumed 20% higher and low estimates assumed 10% lower due to mature technology status.

[97] Expected value estimate is for binary plant from: California Energy Commission, Comparative Costs of California Central Station Electricity Generation Technologies(June 2007). Online. Available: http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SD.PDF. Accessed: November 15, 2008. p. 7. Low estimate is from from: Lazard, "Levilized Cost of Energy Analysis-Version 2.0 (June 2008). Online. Available: http://www.narucmeetings.org/Presentations/2008%20EMP%20Levelized%20Cost%20of%20Energy%20-%20Master%20June%202008%20(2).pdf. Accessed: November 15, 2008. p. 9. High estimate assumed 20% higher than expected value.

[98] Expected value estimate is from: The National Regulatory Research Institute, What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies Across Nine Criteria. Online. Available: http://www.coalcandothat.com/pdf/35%20GenMixStateToolsAndCriteria.pdf. Accessed: July 16, 2008. p. 18-19. High and low estimates from: Dan Rastler, New Demand for Energy Storage, Electric Perspectives. (September/October 2008) p. 30-47. Online. Available: http://www.eei.org/magazine/editorial_content/nonav_stories/2008-09-01-EnergyStorage.pdf. Accessed: November 17, 2008.

[99] Assumed expected value estimate for conventional hydropower from: California Energy Commission, Comparative Costs of California Central Station Electricity Generation Technologies(June 2007). Online. Available: http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SD.PDF. Accessed: November

15, 2008. p. 7. High estimates assumed 20% higher and low estimates assumed 10% lower due to mature technology status.

[100] For below ground took average of high and low estimate from: Dan Rastler, New Demand for Energy Storage, Electric Perspectives. (September/October 2008) p. 30-47. Online. Available: http://www.eei.org/magazine/editorial_content/nonav_stories/2008-09-01-EnergyStorage.pdf. Accessed: November 17, 2008.

[101] Took average of low and high estimates for lead acid, sodium, and flow batteries from: Dan Rastler, New Demand for Energy Storage, Electric Perspectives. (September/October 2008) p. 30-47. Online. Available: http://www.eei.org/magazine/editorial_content/nonav_stories/2008-09-01-EnergyStorage.pdf. Accessed: November 17, 2008.

[102] Took average of low and high estimates for lead acid, sodium, and flow batteries from: Dan Rastler, New Demand for Energy Storage, Electric Perspectives. (September/October 2008) p. 30-47. Online. Available: http://www.eei.org/magazine/editorial_content/nonav_stories/2008-09-01-EnergyStorage.pdf. Accessed: November 17, 2008.

Chapter 3. Baseline Scenario: Austin Energy's Proposed Resource Plan

In July 2008 Austin Energy (AE) revealed a proposed resource plan for meeting energy demand through 2020 while remaining under a proposed carbon dioxide (CO_2) cap and reduction plan.[1] AE proposed adding 1,375 additional Megawatts (MW) of generating capacity by 2020, with only 300 MW coming from fossil-fueled resources.[2] Table 3.1 lists the planned additions to AE's resource portfolio from 2009 to 2020 by fuel source, power generation technology, or facility. The generation capacity for 2008 includes AE's current power generation mix. Scheduled additions of natural gas and wind power generation capacity in 2009, 100 MW biomass project expected by 2012, and a 30 MW centralized photovoltaic power plant located in Webberville just outside of Austin have already been approved by the Austin City Council (Council) and contracted for purchase or operation by AE. As a resource, biomass has a capacity factor similar to that of coal and nuclear and can provide a reliable source of baseload power.[3] This generating capacity has been contracted through a PPA to provide 100 MW of energy per year over a 20 year time period at the total cost of $2.3 billion. The wind and natural gas planned additions for 2009, planned wind additions for 2011, the centralized photovoltaic (PV) module system expected to be available by 2010, and the biomass project expected to be available by 2012 have been included in all eight scenario runs. Cost projections for these additions are based upon general cost data for new power generation plants, rather than the contractual agreements established by AE.

AE's proposed energy resource plan includes 200 MW of additional capacity at the Sand Hill Energy Center, proposed for 2013. This would be a combined cycle expansion project that would provide reliable energy with lower MW-hour (MWh) CO_2 emissions than coal. AE is expecting this project to cost $160 million and take three years to complete.[4] An additional 100 MW of purchased biomass generating capacity has also been recommended for 2016. AE's primary investment in new generation capacity is an addition of 775 MW of generating capacity from wind facilities. Additionally, contracts for 77 MW and 126 MW of current wind generating capacity being purchased by AE are set to expire in 2011 and 2017, respectively. AE may be able to renew these contracts at that time. AE has also proposed a gradual investment in solar energy to meet the Austin Climate Protection Plan (ACPP) goal of providing 100 MW of solar capacity by 2020. The recently approved 30 MW centralized PV solar facility will be constructed in Webberville, near Manor, Texas. This facility will also have 5 MW of capacity to test emerging solar technologies. AE is planning to invest in covering rooftop space in Austin with photovoltaic modules (PV) through public and private partnerships to help reach its solar goals. AE also may invest in a large-scale West Texas solar plant.[5] It is unclear whether the solar capacity additions for the years 2014, 2017, and 2019 are expected to come from distributed solar PVs, centralized PV power plants, or concentrated solar power plants. For the purposes of this analysis, it has been assumed that the 2014 and 2017 additions will be investments in distributed PV systems and the 2019 addition will be a concentrating solar power plant.

System Reliability

AE's proposed resource plan provides a baseline proposal for adequately meeting expected increased demand through 2020 while satisfying AE's proposed CO_2 emissions cap and reduction plan, as well as specific goals detailed by the ACPP. demonstrates that AE's power generation capacity will well exceed forecasted peak load with and without meeting conservation goals. By 2016, 1,229 MW of power generation capacity will be provided from baseload power sources (coal, nuclear, and biomass). The 100 MW biomass additions set to occur in 2012 and 2016 continue to help AE provide continuous power from traditional baseload power sources in accordance with expected baseload demand increases. Solar and wind capacity increases should provide increased renewable energy for AE customers that can be backed-up by the natural gas plants. The 300 MW of additional natural gas power generation capacity lends towards this system of dependable power that will help account for any unexpected lags in availability due to the intermittent nature of wind and solar resources.

Given the expected capacity factors for on-shore wind and solar PV (29 and 17 percent, respectively) as well as current capacity factors for AE's coal, nuclear, and natural gas facilities AE will be able to deliver electricity reliably to its customers, given that AE meets its conservation goals (see Figure 3.2). It appears that AE will be able to provide reliable service even if conservation goals are only met halfway.

Figure 3.3 details AE's expected hourly load profile for the hottest day (peak demand) in the summer of 2020. The hourly load profile follows expected solar and wind profiles and demonstrates that AE will be able to meet peak demand without purchasing power by engaging its natural gas facilities, even on the hottest day of the summer. As AE makes gradual additions to its resource portfolio from baseload, intermediate, and intermittent sources of energy, it appears that AE will be able to meet peak demand in all years between 2009 and 2020 without purchasing power. AE is currently purchasing 300 MW of power a year from the statewide electric grid. AE's planned resource portfolio allows AE to control all of its power generation resources.

Carbon Emissions and Carbon Costs

AE's proposed resource plan will increase the amount of renewable power generation capacity to about 30 percent of its resource portfolio by 2020. About 27 percent of AE's actual power generation would come from clean energy sources in 2020. As peak demand is expected to increase by about 16 percent between 2008 and 2020, the increase in clean energy power generation capacity (by about 22 percent) will not curb CO_2 emissions markedly (see Figure 3.4). The resource portfolio shift to a higher percentage of clean energy sources allows AE to meet increased demand without a concurrent rise in CO_2 emissions.

In July 2008 AE proposed a CO_2 upper limit (cap) and reduction plan through 2020.[6] AE plans to cap its CO_2 emissions at 2007 emission levels and gradually reduce emissions to 2005 levels by 2014. Most recently proposed federal carbon-related bills would set an initial 2014 goal of reducing economy-wide greenhouse gas (GHG) emissions to 2005 or 2006 levels in the first year of implementation. AE's CO_2 emissions in 2007 were roughly 6.1 million metric tons and in 2005 were roughly 5.6 million metric tons. AE will need to reduce its emissions by 745,000 million metric tons over a seven-year period while energy demands gradually rise. Their goal is to gradually reduce emissions by about 100,000 metric tons in a stair-step fashion.

While no current carbon regulation exists, many bills have been proposed by the United States Congress over the past several years. Many of these bills propose a cap-and-trade system that would give away CO_2 allowances to regulated entities to ease the burden of the regulations. However, these allowances are typically based upon recent historical emissions, so a voluntary program for curbing CO_2 emissions could reduce the number of allowances AE might receive in the future.[7] Under the Lieberman-Warner Climate Security and Stewardship Act of 2007, a portion of an entity's emissions would be accounted for by free permits, or allowances, while a portion of allowances would be auctioned.[8] Figure 3.5 estimates the costs of allowances for AE based upon the Lieberman-Warner bill and expected CO_2 emissions under AE's proposed resource plan. Since the amount of permits would gradually decline under the proposed cap and trade system, the cost of allowances would rise from almost $50 million in 2014 to almost $100 million in 2020, for a total of about $490 million in carbon allowance costs by 2020. Although the expected cost of offsets is expected to be lower than the cost of allowances, only 15 percent of an entity's CO_2 emissions could be accounted for as offsets under the Lieberman-Warner bill.[9]

AE has stated that given current economic and political considerations, the best option for reducing its carbon footprint is to generate electricity from its current sources and purchase offsets in the short-term for emissions that exceed the cap and/or replace coal-based generation with natural gas.[10] If the federal government or the State of Texas were to adopt comprehensive GHG regulations, AE will be able to make a more informed decision on these options. AE projects that costs to offset CO_2 emissions by 2014 would be $18.8 million dollars, while replacing coal generation with natural gas would cost $253.3 million.[11] Figure 3.6 provides a range of annual costs to offset emissions to zero, thus achieving carbon-neutrality. Depending on the cost of offsets, offsetting emissions to zero would range between $50 million and $250 million annually with a slight decline in costs most years.

AE's proposed resource plan presents marked improvement in delivering electricity from clean and renewable sources, which tend to have less impact on air and water quality, land, and local ecosystems. However, AE's resource plan does not plan on selling or reducing its stake in its coal or nuclear resources, so the environmental impacts associated with these resources will continue to persist. AE's coal resources currently account for 71 percent of its total CO_2 emissions. Continued use of coal prevents significant reductions in CO_2 emissions. Other harmful air and water pollutants generated by its coal facility will continue to impact the environment negatively. Nuclear waste will also continue to accumulate due to AE's nuclear resource use. Despite the remaining sustainability issues associated with AE's coal and nuclear resources, it appears that AE's proposed energy resource plan moves towards a more sustainable energy portfolio, particularly to account for increased energy demand.

Costs and Economic Impacts

The approach of the report is to project costs and economic impacts based solely upon general cost estimates for new power generation facilities. The model used here does not reflect AE's cost projections of scheduled or proposed additions to its resource portfolio, whether in the form of power purchase agreements or currently owned and operated facility expansions, the following cost estimates may not coincide with AE projections.

Figure 3.7 lists capital cost estimates for AE's scheduled and proposed additions to its power generation mix. Capital costs are expressed as the sum of total overnight costs for additions scheduled in a particular year. Total expected capital costs summed over the years until 2020 range from $2.2 to $3.0 billion. The year in which a project is proposed influences total capital costs. This study uses a range of costs, even though expected capital costs may increase or decrease during the next decade. AE's proposed energy resource plan demonstrates gradual capital investments to account for increased demand. AE has no plans to sell current power generation facilities or stakes in current facilities. The majority of AE's planned projects do not have large capital cost ranges.

Figure 3.8 details annual expected fuel costs for AE's proposed resource plan. As fossil-fueled sources do not change dramatically under this scenario, fuel costs are expected to remain fairly stable, ranging in any given year from $170 to $360 million. If carbon legislation or other fossil-fueled related regulation is implemented over the next decade, fuel costs (primarily for coal and natural gas) should move towards the high range.

Figure 3.9 estimates the expected rise in costs to produce electricity by calculating the impact of the levelized costs of new power generation resources, as a percentage of overall generation capacity. As a resource portfolio becomes composed of more new resource additions, the marginal increase in costs will rise. AE's energy resource plan calls for almost 30 percent of its 2020 resource portfolio to be comprised of new generation capacity, which leads to an increase of between 1.5 and 3 cents per kilowatt-hour between 2009 and 2020 based on new power generation investments alone. Carbon allowance costs and offset costs or any unexpected additional costs to the utility could also be passed on to the customer during this time period.

The Greater Austin Area is expected to experience significant economic stimulation from the AE resource plan due to expansion of local natural gas facilities and investment in local solar PV installation and utility-scale solar PV power plants. Figure 3.10 demonstrates an average of $90 million in additional total economic output through 2020. Economic activity will peak at approximately $180 million in 2011 and 2012 in anticipation of the completion of a 200 MW expansion to the Sand Hill natural gas facility in 2013 and solar capacity additions expected in 2014. Total economic output will rise again in 2016 to almost $130 million due to additional solar capacity additions. Figure 3.11 projects $3.6 million of total value added due to enduring economic activity.

Figure 3.12 projects an average of approximately 600 new jobs per year in the Greater Austin Area attributed to AE's resource plan.

The majority of the economic activity stimulated by the AE resource plan will be in the Competitive Renewable Energy Zones (CREZ) in West Texas for the construction of wind and concentrated solar facilities. Economic activity in the CREZ will contribute approximately $113 million of total output per year between 2009 and 2020 (see Figure 3.13). Figure 3.14 projects about $12 million of total value added each year in the CREZ region due to enduring economic activity. Figure 3.15 projects an average of approximately 60 new jobs per year in the CREZ region attributed to AE's resource plan.

Nagodoches County will also experience significant impact from the AE Resource Plan due to the addition of 200 MW of biomass power generation capacity to AE's power generation mix. Figure 3.16 demonstrates an annual total economic output of about $68 million between 2009 and 2020. Figure 3.17 projects about $10 million of total value added each year in Nacogdoches County due to enduring economic activity. Figure 3.18 projects an average of approximately 50 new jobs per year in Nacogdoches County attributed to AE's resource plan.

IMPLAN only models the effects of construction and installation of new power generation facilities, estimated activity from the installation of distributed PV units, and operations and maintenance activities associated with power generation facilities. This scenario does not take into account the possibility of attracting renewable energy manufacturing to the Austin area.

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[1] AE, "Future Energy Resources and CO_2 Cap and Reduction Planning." July 2008. Online. Available: http://www.austinenergy.com/About%20Us/Newsroom/Reports/Future%20Energy%20Resources_%20July%2023.pdf. Accessed: July 24, 2008.

[2] AE, "Future Energy Resources and CO_2 Cap and Reduction Planning." July 2008. Online. Available: http://www.austinenergy.com/About%20Us/Newsroom/Reports/Future%20Energy%20Resources_%20July%2023.pdf. Accessed: July 24, 2008.

[3] AE, "Nacogdoches Biomass Project Town Hall Meeting." August 13, 2008. Online. Available: http://www.austinenergy.com/biomassTownHallAugust2008.pdf. Accessed: August 17, 2008.

[4] AE, "Future Energy Resources and CO_2 Cap and Reduction Planning." July 2008. Online. Available: http://www.austinenergy.com/About%20Us/Newsroom/Reports/Future%20Energy%20Resources_%20July%2023.pdf. Accessed: July 24, 2008.

[5] AE, "Future Energy Resources and CO_2 Cap and Reduction Planning." July 2008. Online. Available: http://www.austinenergy.com/About%20Us/Newsroom/Reports/Future%20Energy%20Resources_%20July%2023.pdf. Accessed: July 24, 2008.

[6] Austin Energy, "Future Energy Resources and CO_2 Cap and Reduction Planning." July 2008. Online. Available:
http://www.austinenergy.com/About%20Us/Newsroom/Reports/Future%20Energy%20Resources_%20July%2023.pdf. Accessed: July 24, 2008.

[7] Austin Energy, "Austin Smart Energy." *Austin Energy Resource Guide*. Online. Available:
http://www.austinsmartenergy.com/downloads/AustinEnergyResourceGuide.pdf. Accessed: December 19, 2008, p 35.

[8] Govtrack.us. "S. 2191 [110th] Lieberman-Warner Climate Security Act of 2007." Online. Available:
http://www.govtrack.us/congress/bill.xpd?bill=s110-2191. Accessed: January 19, 2008.

[9] Govtrack.us. "S. 2191 [110th] Lieberman-Warner Climate Security Act of 2007." Online. Available:
http://www.govtrack.us/congress/bill.xpd?bill=s110-2191. Accessed: January 19, 2008.

[10] Austin Energy, "Future Energy Resources and CO_2 Cap and Reduction Planning." July 2008. Online. Available:
http://www.austinenergy.com/About%20Us/Newsroom/Reports/Future%20Energy%20Resources_%20July%2023.pdf. Accessed: July 24, 2008.

[11] Austin Energy, "Future Energy Resources and CO_2 Cap and Reduction Planning." July 2008. Online. Available:
http://www.austinenergy.com/About%20Us/Newsroom/Reports/Future%20Energy%20Resources_%20July%2023.pdf. Accessed: July 24, 2008.

Table 3.1
Austin Energy Resource Plan Scheduled Additions to Generation Mix

	Schedule of power generation additions and subtractions (net MW)												
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	607	0	0	0	0	0	0	0	0	0	0	0	0
Nuclear	422	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 1-4	189	100	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 5	312	0	0	0	0	200	0	0	0	0	0	0	0
Natural Gas - Decker 1 & 2	741	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker CGT	193	0	0	0	0	0	0	0	0	0	0	0	0
Wind	274	165	0	23	0	0	50	100	0	74	0	50	110
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	100	0	0	0	100	0	0	0	0
FPP w/ biomass co-firing	0	0	0	0	0	0	0	0	0	0	0	0	0
Landfill Gas	12	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV - Centralized	0	0	30	0	0	0	0	0	0	0	0	0	0
Solar PV - Distributed	1	0	0	0	0	0	20	0	0	20	0	0	0
Concentrated Solar	0	0	0	0	0	0	0	0	0	0	0	30	0
IGCC w/ CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
IGCC w/o CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0
Accelerated Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 3.1
Austin Energy Resource Plan Power Generation Capacity

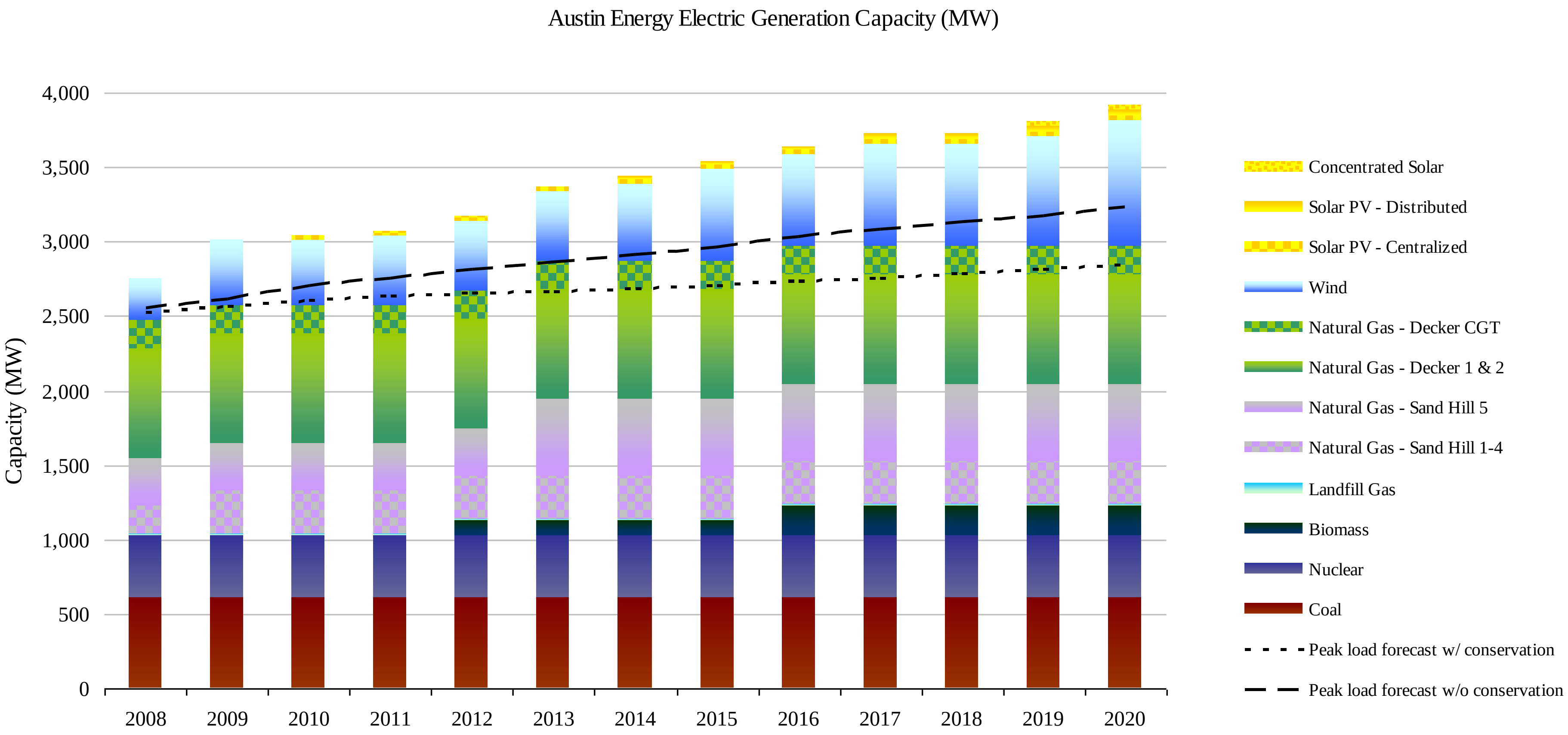


Figure 3.2
Austin Energy Resource Plan Electric Delivery

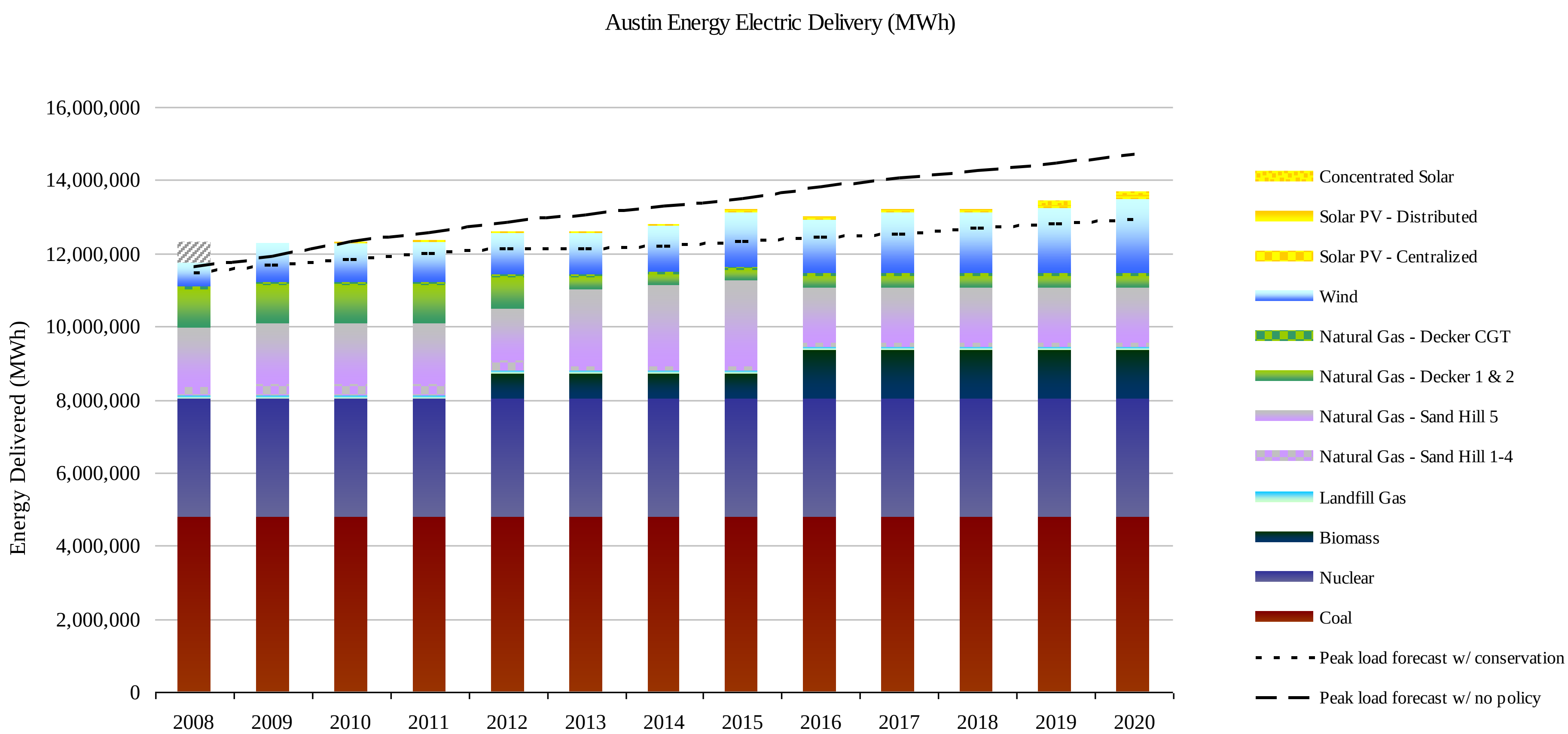


Figure 3.3
Austin Energy Resource Plan Hourly Load Profile (Peak Demand, Summer 2000)

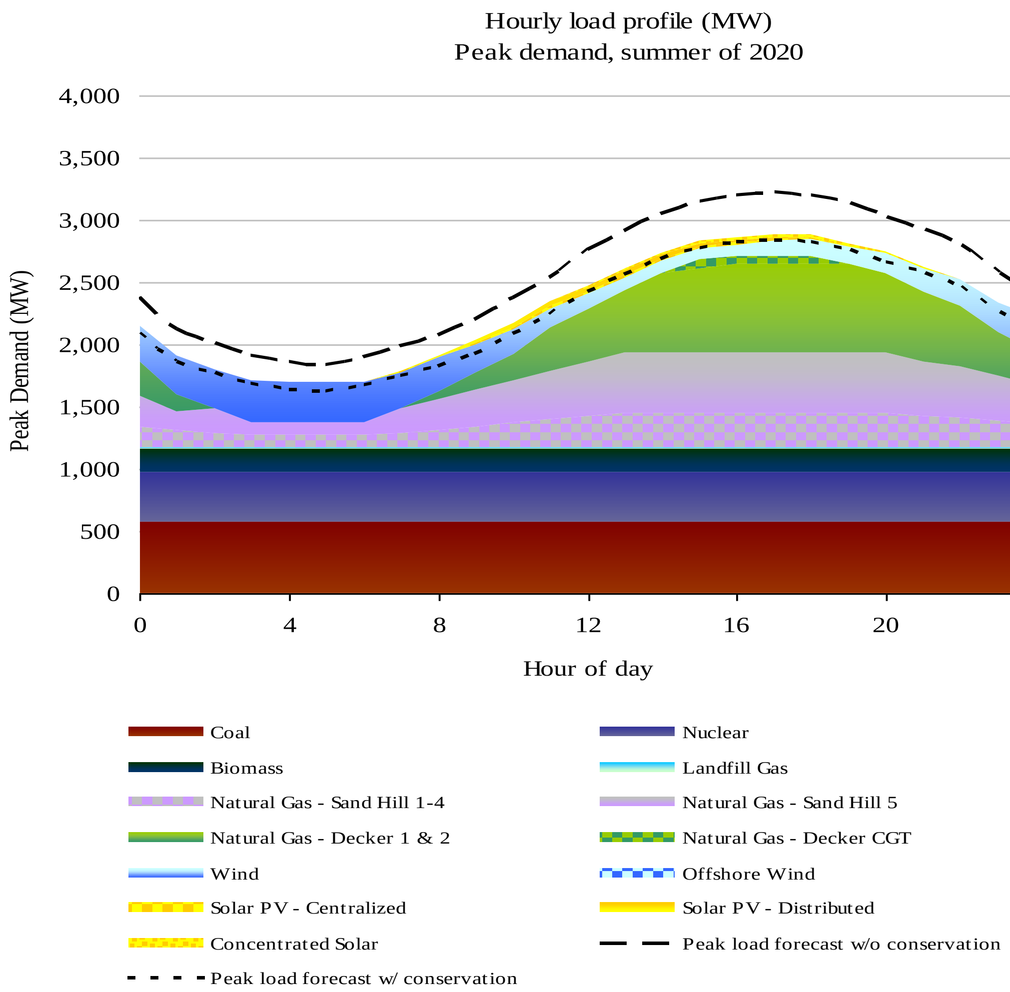


Figure 3.4
Austin Energy Resource Plan Direct Carbon Dioxide Emissions

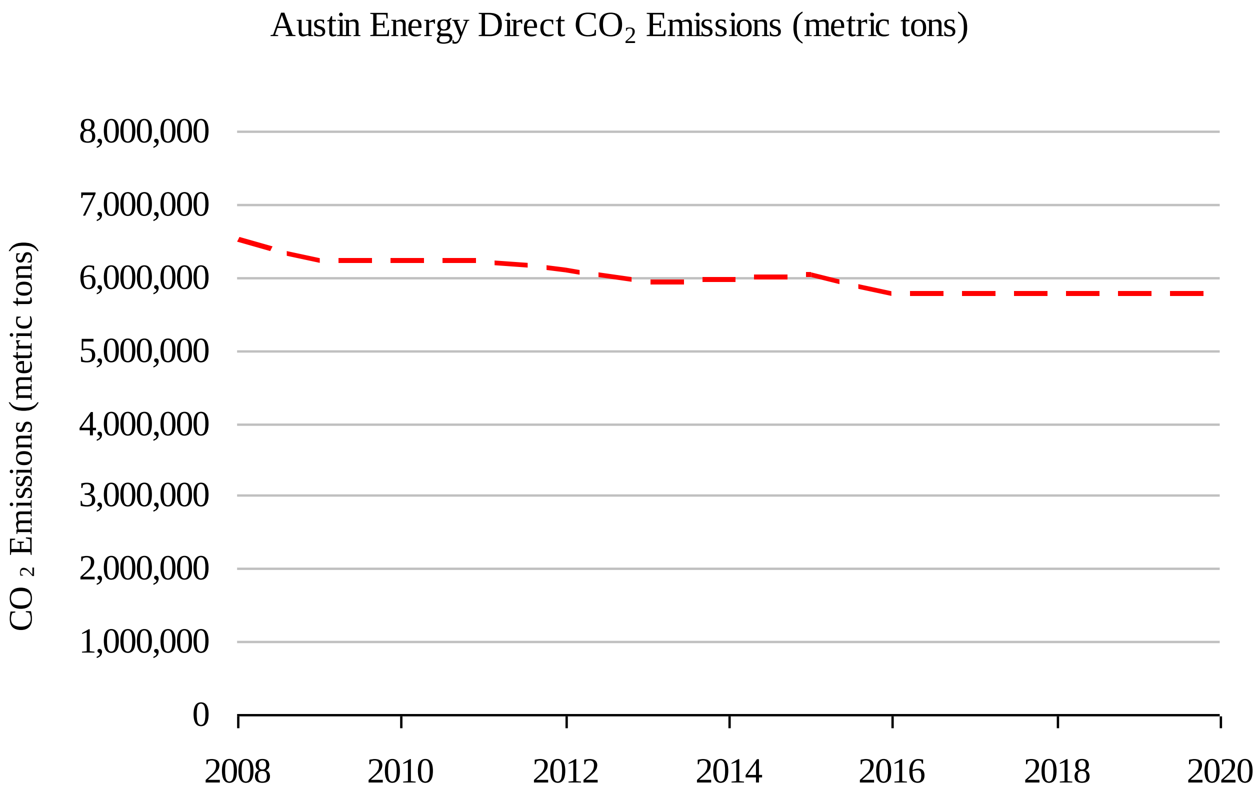


Figure 3.5
Austin Energy Resource Plan Carbon Allowance Costs

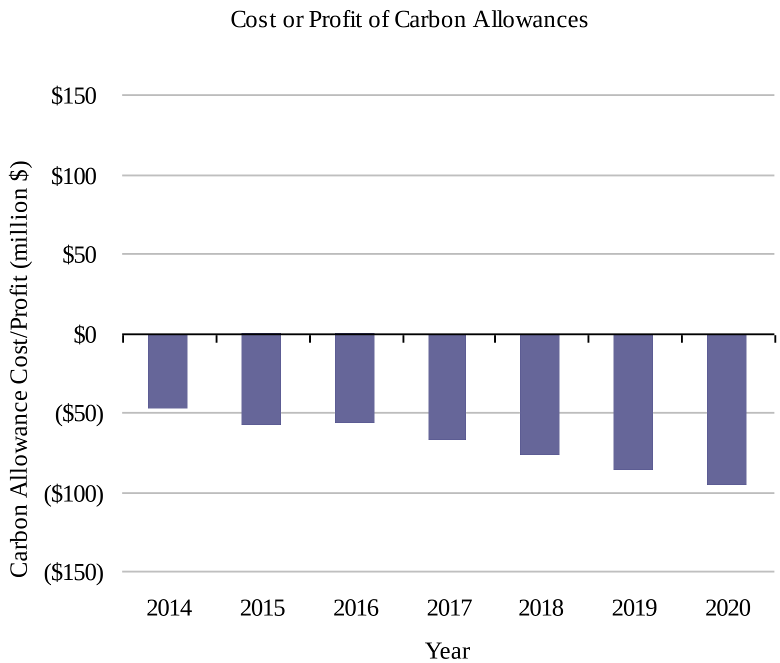


Figure 3.6
Austin Energy Resource Plan Carbon Offset Costs

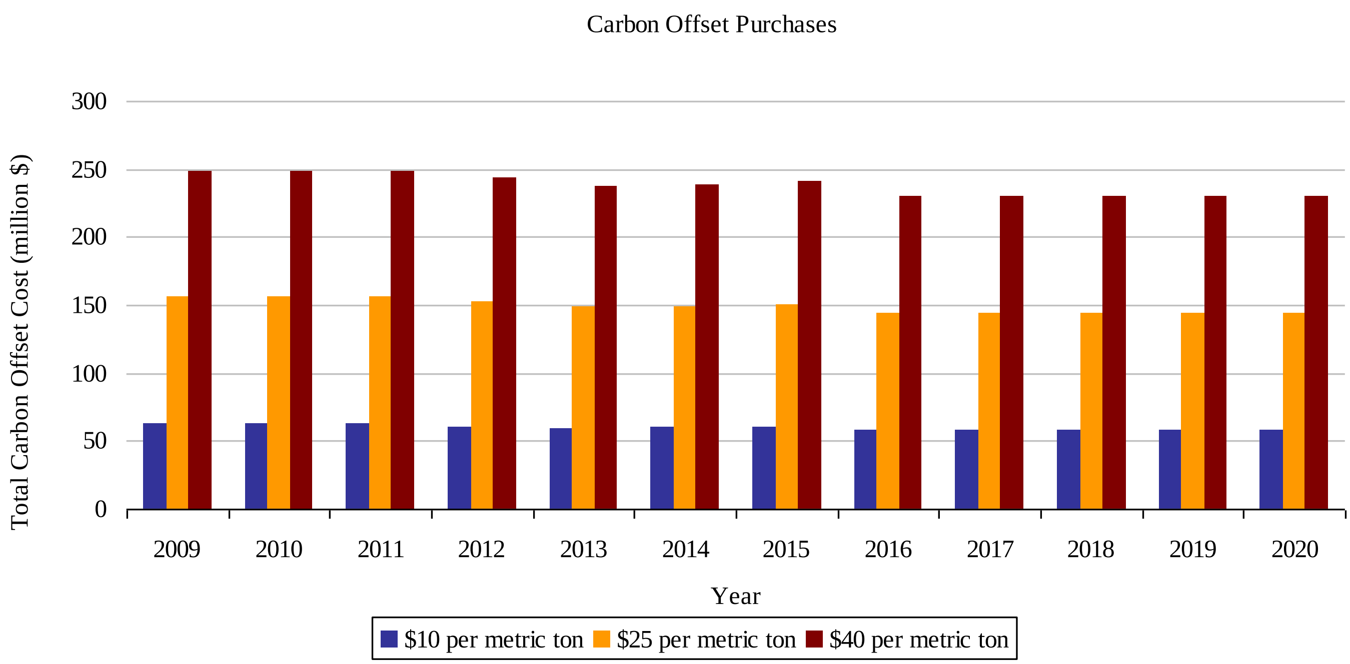


Figure 3.7
Austin Energy Resource Plan Capital Costs

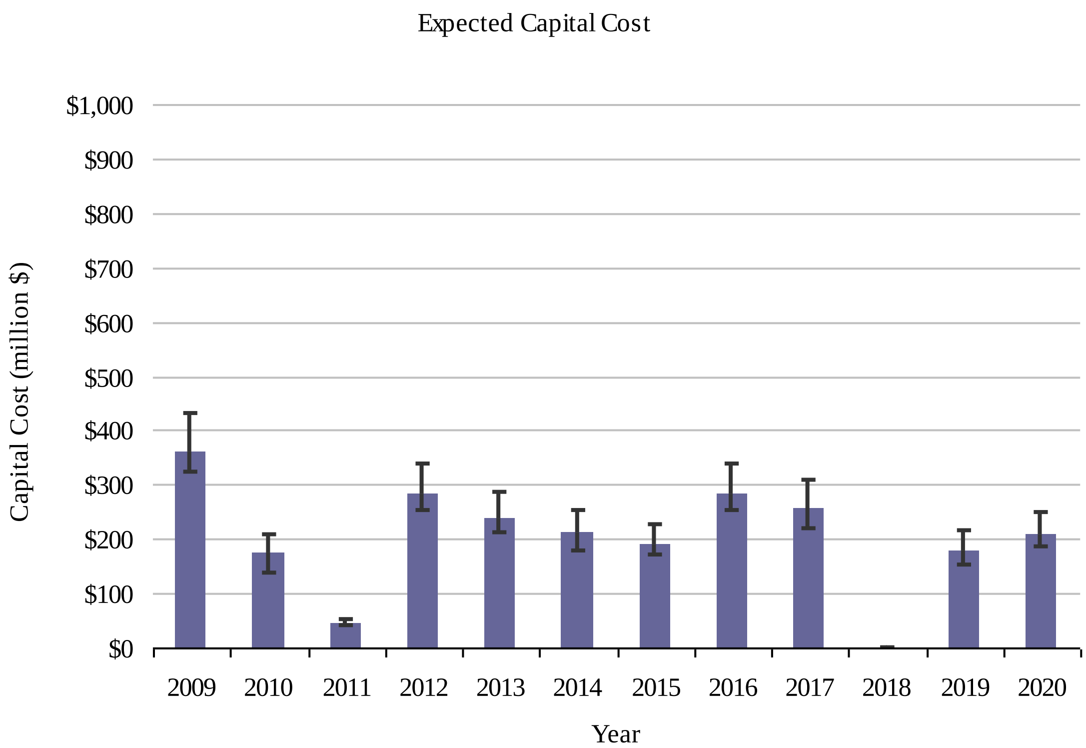


Figure 3.8
Austin Energy Resource Plan Fuel Costs

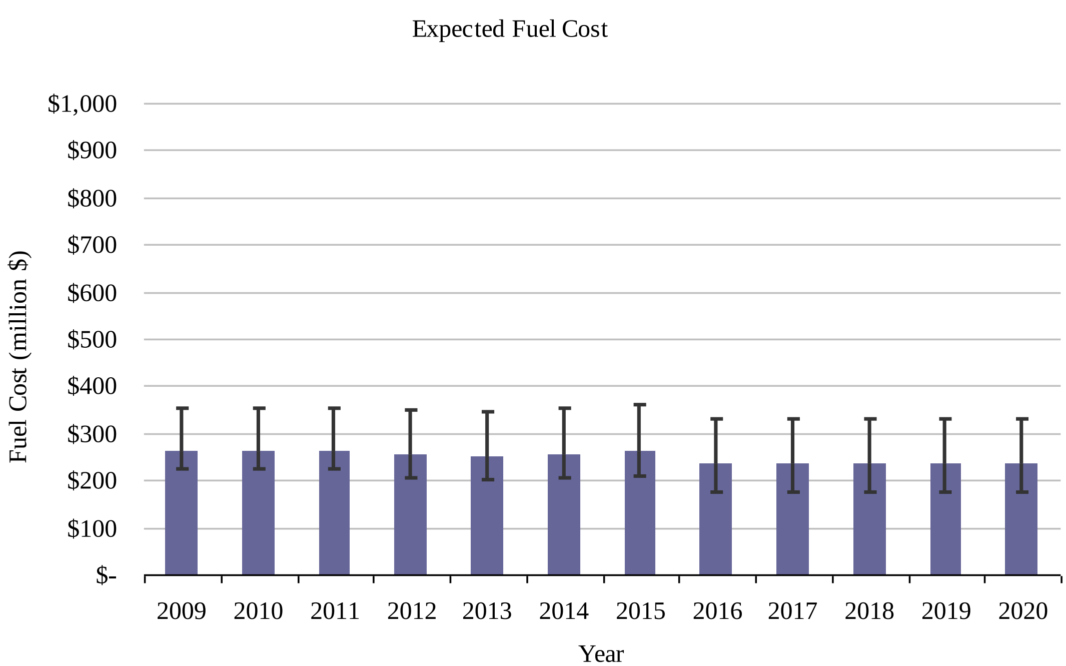


Figure 3.9
Austin Energy Resource Plan Levelized Costs

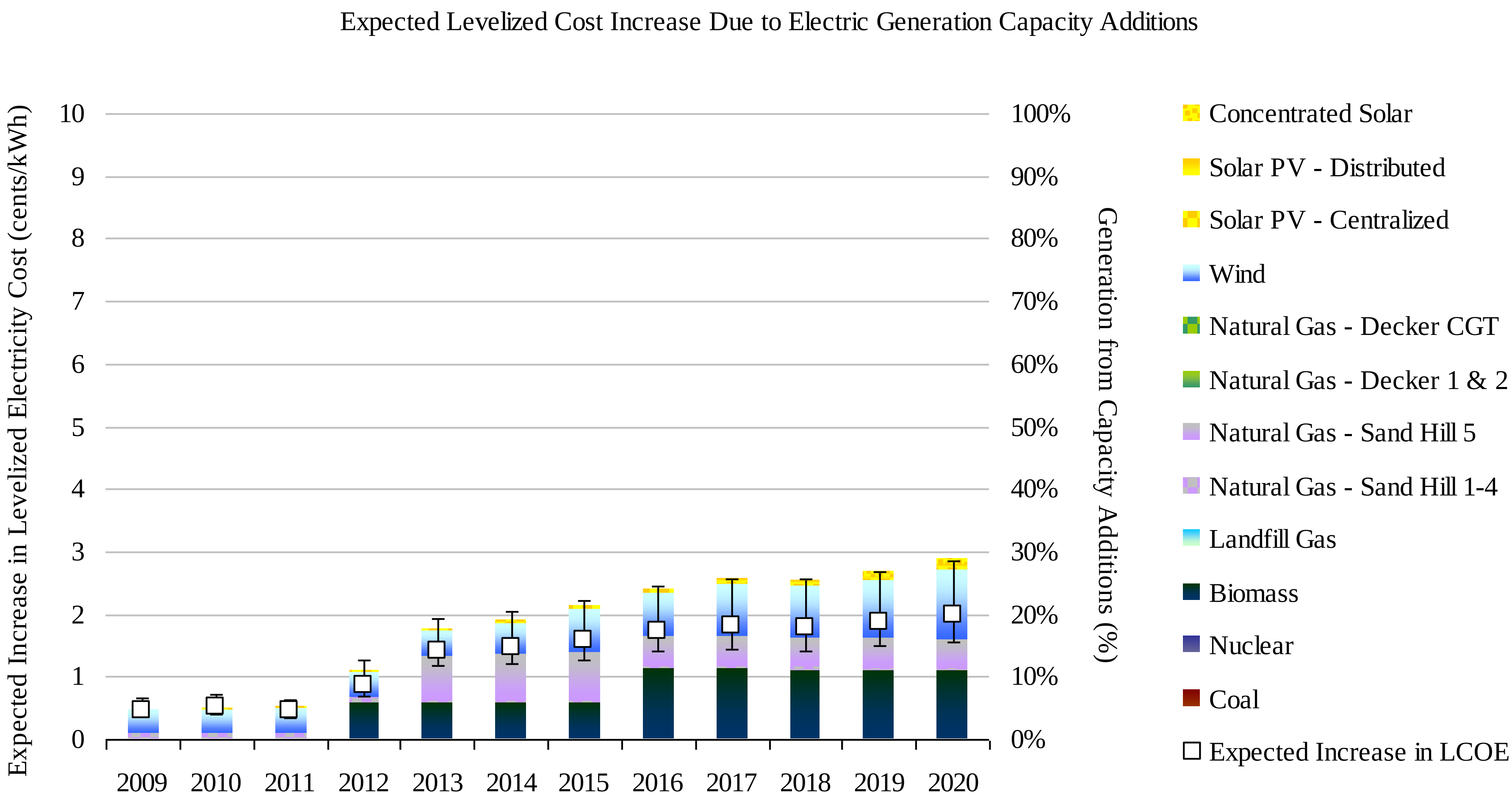


Figure 3.10
Austin Energy Resource Plan Economic Activity Greater Austin Area

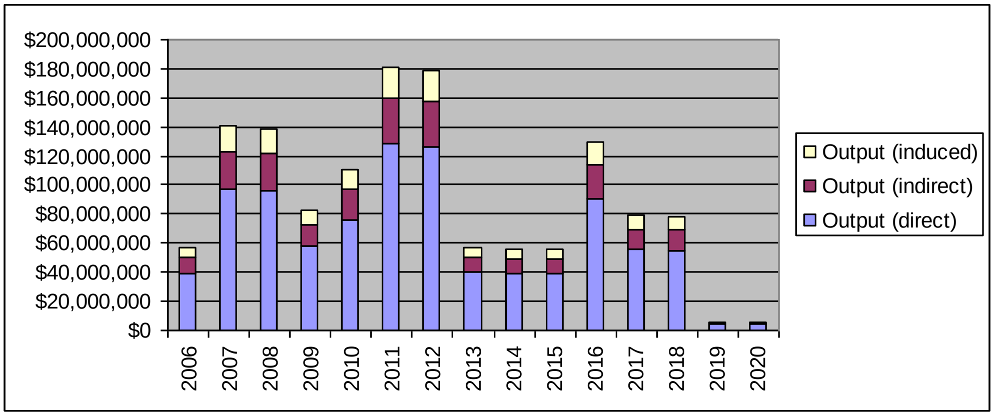


Figure 3.11
Austin Energy Resource Plan Total Value Added Greater Austin Area

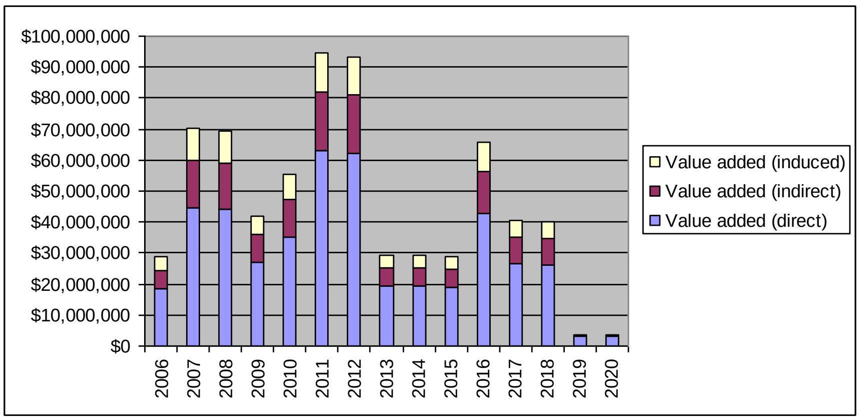


Figure 3.12
Austin Energy Resource Plan Employment Impacts Greater Austin Area

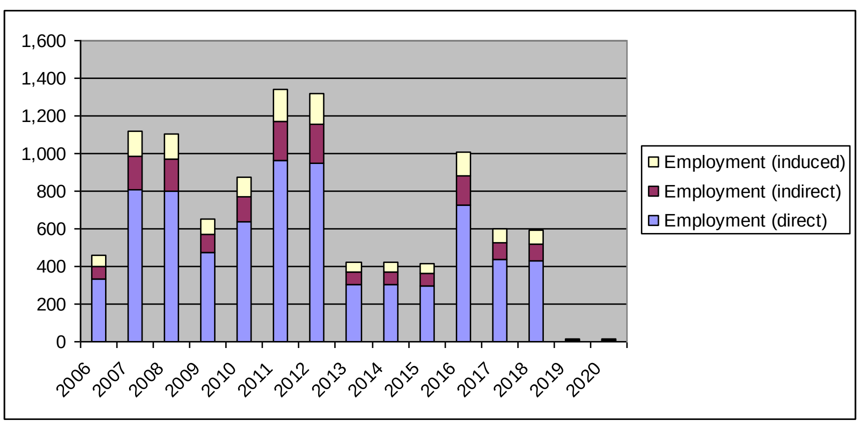


Figure 3.13
Austin Energy Resource Plan Economic Activity CREZ Region

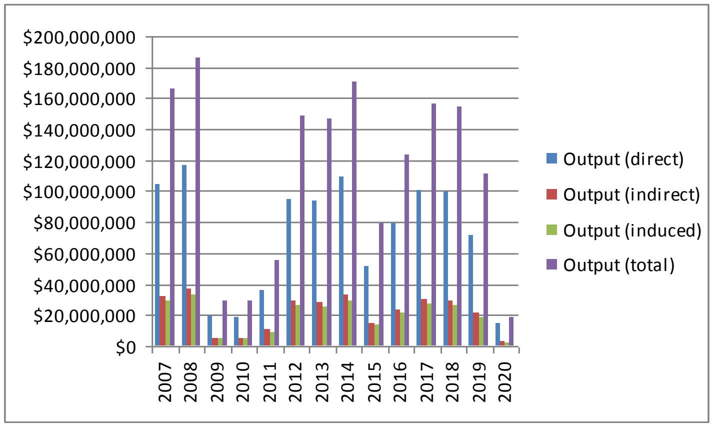


Figure 3.14
Austin Energy Resource Plan Total Value Added CREZ Region

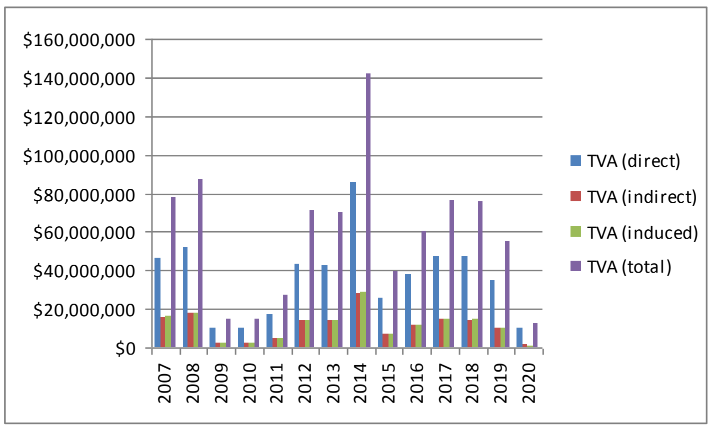


Figure 3.15
Austin Energy Resource Plan Employment Impacts CREZ Region

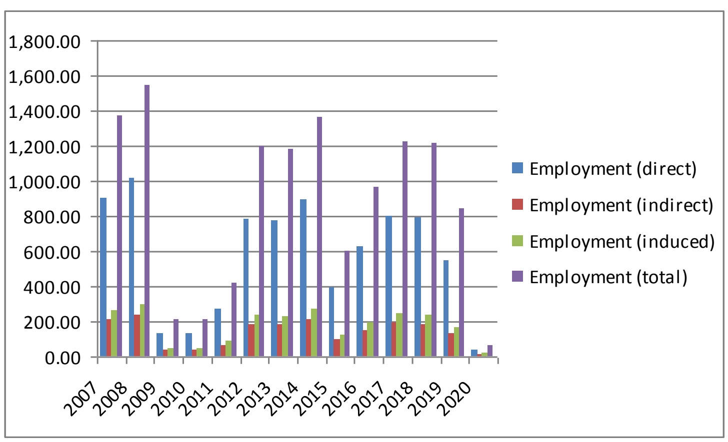


Figure 3.16
Austin Energy Resource Plan Economic Activity Nacogdoches County

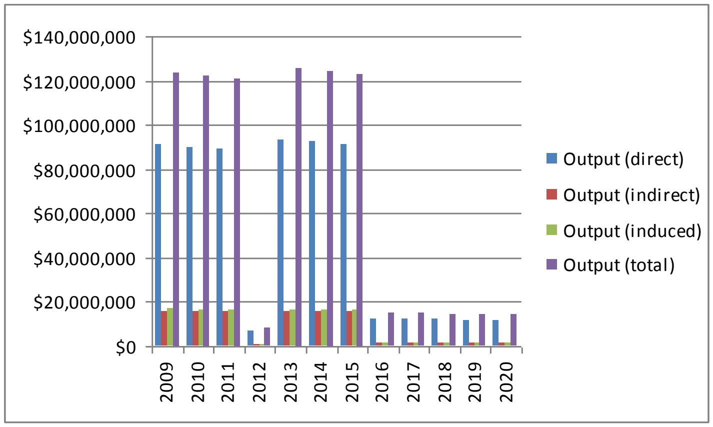


Figure 3.17
Austin Energy Resource Plan Total Value Added Nacogdoches County

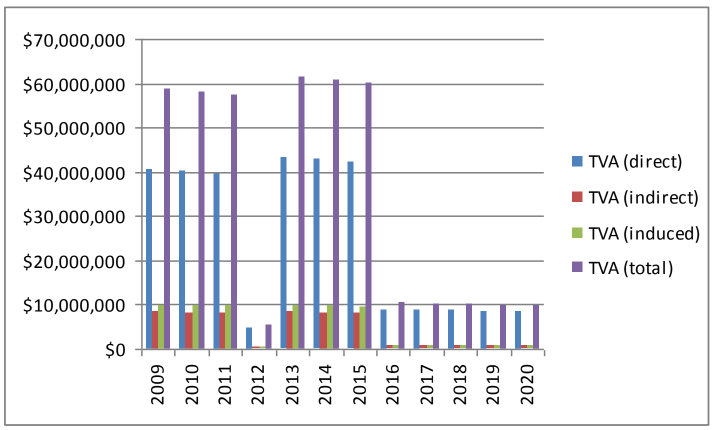
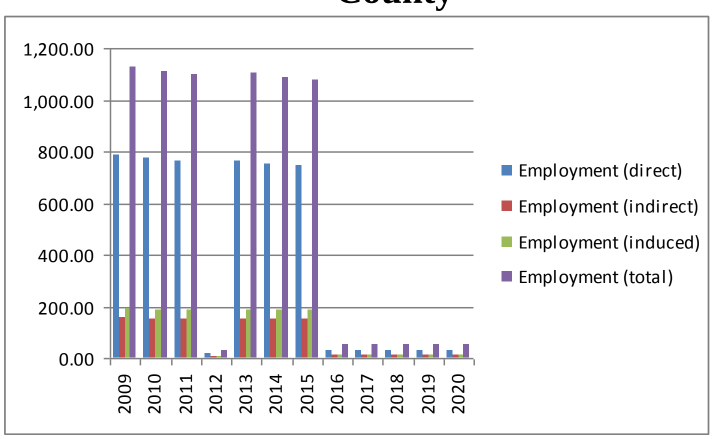


Figure 3.18
Austin Energy Resource Plan Employment Impacts Nacogdoches County



Notes

Chapter 4. Nuclear Expansion Scenario

The nuclear expansion scenario aligns with Austin Energy's (AE) proposed energy resource plan while replacing all of AE's coal resources with nuclear. Table 4.1 details the schedule of additions and subtractions to AE's power generation portfolio under this proposal. The nuclear expansion scenario would significantly reduce the carbon dioxide (CO_2) emissions of AE by relieving coal-fired power generation from AE's resource portfolio. Under this scenario 607 megawatts (MW) of coal (the current power generating capacity of AE's stake in the Fayette Power Project) is replaced in 2018 by a doubling of current nuclear energy capacity (422 MW). It is assumed that the additional units proposed for expansion at the South Texas Project (where AE's current nuclear power comes from) and other expansion proposals would come to fruition by that time to provide available nuclear capacity that could be purchased by AE beginning in 2018. The addition of additional nuclear capacity by 2018 is uncertain given the significant regulatory and political issues involved in commissioning a nuclear power plant or even expanding an existing nuclear power plant.

By adding new nuclear power generation capacity coal could be replaced with a reliable and emission-free baseload power source. However, nuclear energy raises security and environmental concerns related to nuclear waste and large coolant water requirements. This scenario demonstrates the impact and costs of replacing coal with nuclear to reduce CO_2 emissions.

System Reliability

By replacing FPP with a reliable baseload power source, system reliability is ensured. Under this scenario 1.044 MW of baseload power (nuclear and biomass power generation capacity) will be available. However, if demand rises as expected, AE may wish to invest in more nuclear capacity to entirely replace coal with nuclear capacity. This would require about 600 MW of nuclear power capacity additions. However, additions of biomass and a 200 MW combined-cycle unit expansion at Sand Hill could account for additional baseload power needs. Additionally, wind and solar power generation capacity additions are complementary energy sources that can generate power collectively at most times of the day. Solar and wind capacity increases should provide increased renewable energy for AE customers that can be backed-up by the natural gas plants. The 300 MW of additional natural gas power generation capacity lends towards this system of dependable power that will help account for any unexpected lags in availability due to the intermittent nature of wind and solar resources.

Figure 4.1 demonstrates that this scenario adequately meets the power generation capacity needs of AE's customers through 2020. Figure 4.2 demonstrates that this scenario will also be able to adequately meet the energy needs of AE customers through 2020. However, this is contingent on AE meeting its conservation goals between 2009 and 2020. If AE were to fall short of its conservation goals natural gas use could be increased accordingly. Figure 4.3 details AE's expected hourly load profile for the hottest day (peak demand) in the summer of 2020. Under this scenario AE would fall just short of meeting peak demand in 2020 (meeting 98.8 percent of energy needs at peak) without purchasing power from the electric grid. This is considering that natural gas facilities are run at full capacity during peak demand periods and follows expected wind and solar availability profiles. This demonstrates that it may be necessary for AE to add additional nuclear capacity or additional capacity from other energy sources to provide peak power in 2020.

Carbon Emissions and Carbon Costs

This scenario would cut carbon emissions by almost three quarters, primarily a result of eliminating coal from AE's resource portfolio. In 2007 AE emitted roughly 6.1 million metric tons of CO_2. Under the nuclear expansion scenario CO_2 emissions would drop to under 2 million metric tons by 2020 (see Figure 4.4). The nuclear expansion scenario demonstrates an opportunity to significantly reduce AE's carbon footprint to a level that makes offsetting emissions to zero more manageable than under AE's proposed resource plan.

Significantly reducing CO_2 emissions could present an opportunity to profit if carbon regulation were to be passed that supported a portion of allowances being given for free. Figure 4.5 indicates that AE will begin to accrue profits from carbon trading in 2018 with the transition of coal to nuclear. By 2020 AE could be profiting roughly $55 million annually from excess carbon allowances. Figure 4.6 shows the effects on the quantity of carbon offsets required for purchase by AE annually to reach zero net carbon emissions. In 2020 it would cost AE roughly $41 million annually at a offset cost of $25 per metric ton of CO_2 released to reach carbon neutrality through offsetting emissions.

Costs and Economic Impacts

The most significant cost incurred by AE under this scenario is the expansion of nuclear capacity. Nuclear facilities have high capital costs with much uncertainty. Cost estimates have escalated during the past several years as more realistic estimates for nuclear power plant projects have been released. Nuclear plant capital cost estimates range from $3,000 to $8,000 per kilowatt installed. This would mean an overnight cost of between $1.3 billion and $3.4 billion for 422 MW of nuclear power generation capacity. However, fuel costs and operating costs are lower than other energy resources given the levels of energy output from these facilities. Figure 4.7 shows a distinctive spike in capital expenditures in 2018 attributed to nuclear power generation expansion. Figure 4.8 demonstrates that under this scenario fuel costs would remain steady through 2020 because even when coal is removed natural gas would be used more heavily to account for some loss in net baseload power. It is important to recognize that although nuclear power plants require significant initial capital investment, operations and maintenance costs are more predictable and stable than other power generation technologies once the plant becomes operational.

Figure 4.9 shows the expected increase in the cost of electricity in 2017 would be about 2 cents per kWh, but would then jump to about a 4 cent per kWh increase over current rates in 2018 due to nuclear additions. If the cost of nuclear is higher than expected the cost of electricity could increase as much as 6 cents per kWh over current rates. While AE may not be directly involved in the funding of the construction of the facility from which this nuclear power would be purchased, it is assumed that the costs of capital will be accounted for in the levelized cost of electricity. This scenario and some other scenarios include the divestment of all or a portion of AE's stake in FPP. The calculation provided by Figure 4.9 for expected increase in cost of electricity does not appoint a monetary value of reducing or removing coal or any other resource from AE's resource portfolio as the methods for evaluating how much AE could receive are beyond the scope of this report. Such removal may help to alleviate the additional costs to electricity accrued from the identified resource additions. Additionally, the cost estimates provided in this model do not account for any government subsidies that may be available for the building of new nuclear power plants.

The biggest additions to AE's resource portfolio that occur in the nuclear expansion scenario are external to the Greater Austin Area. Wind and concentrated solar investments are projected to be located in the Competitive Renewable Energy Zones (CREZ) and nuclear capacity additions are projected to be located at in Matagorda Bay at the South Texas Project based upon proposals to expand this facility. Investment in local power generation will not likely offset the negative local economic impacts of divestment in AE's coal use. Figure 4.10 shows the economic output in the Greater Austin Area generated by the nuclear expansion scenario and Figure 4.11 shows the total value added to the Greater Austin Area from the investments made in the nuclear expansion scenario. The simulation projects that the average local economic development attributed to the nuclear expansion scenario prior to divestment in coal will be $125 million in economic output and 824 additional jobs per year. $150 million would be generated in both 2011 and 2012, mostly due to the 200 MW expansion project of 200 MW of new natural gas-based power generation capacity at Sand Hill in 2013. Economic output increases to over $200 million in 2014 and 2017 corresponding to the addition of 20 MW of distributed solar PV capacity in each year. Figure 4.12 shows the impacts on employment created or eliminated by the nuclear expansion scenario. Divestment in AE's stake in FPP in 2018 is expected to create a net loss of 36 jobs in the Greater Austin Area.

Table 4.1
Nuclear Expansion Scenario Scheduled Additions and Subtractions to Generation Mix

	Schedule of power generation additions and subtractions (net MW)												
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	607	0	0	0	0	0	0	0	0	0	-607	0	0
Nuclear	422	0	0	0	0	0	0	0	0	0	422	0	0
Natural Gas - Sand Hill 1-4	189	100	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 5	312	0	0	0	0	200	0	0	0	0	0	0	0
Natural Gas - Decker 1 & 2	741	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker CGT	193	0	0	0	0	0	0	0	0	0	0	0	0
Wind	274	165	0	23	0	0	50	100	0	74	0	50	110
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	100	0	0	0	100	0	0	0	0
FPP w/ biomass co-firing	0	0	0	0	0	0	0	0	0	0	0	0	0
Landfill Gas	12	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV - Centralized	0	0	30	0	0	0	0	0	0	0	0	0	0
Solar PV - Distributed	1	0	0	0	0	0	20	0	0	20	0	0	0
Concentrated Solar	0	0	0	0	0	0	0	0	0	0	0	30	0
IGCC w/ CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
IGCC w/o CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0
Accelerated Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 4.1
Nuclear Expansion Scenario Power Generation Capacity

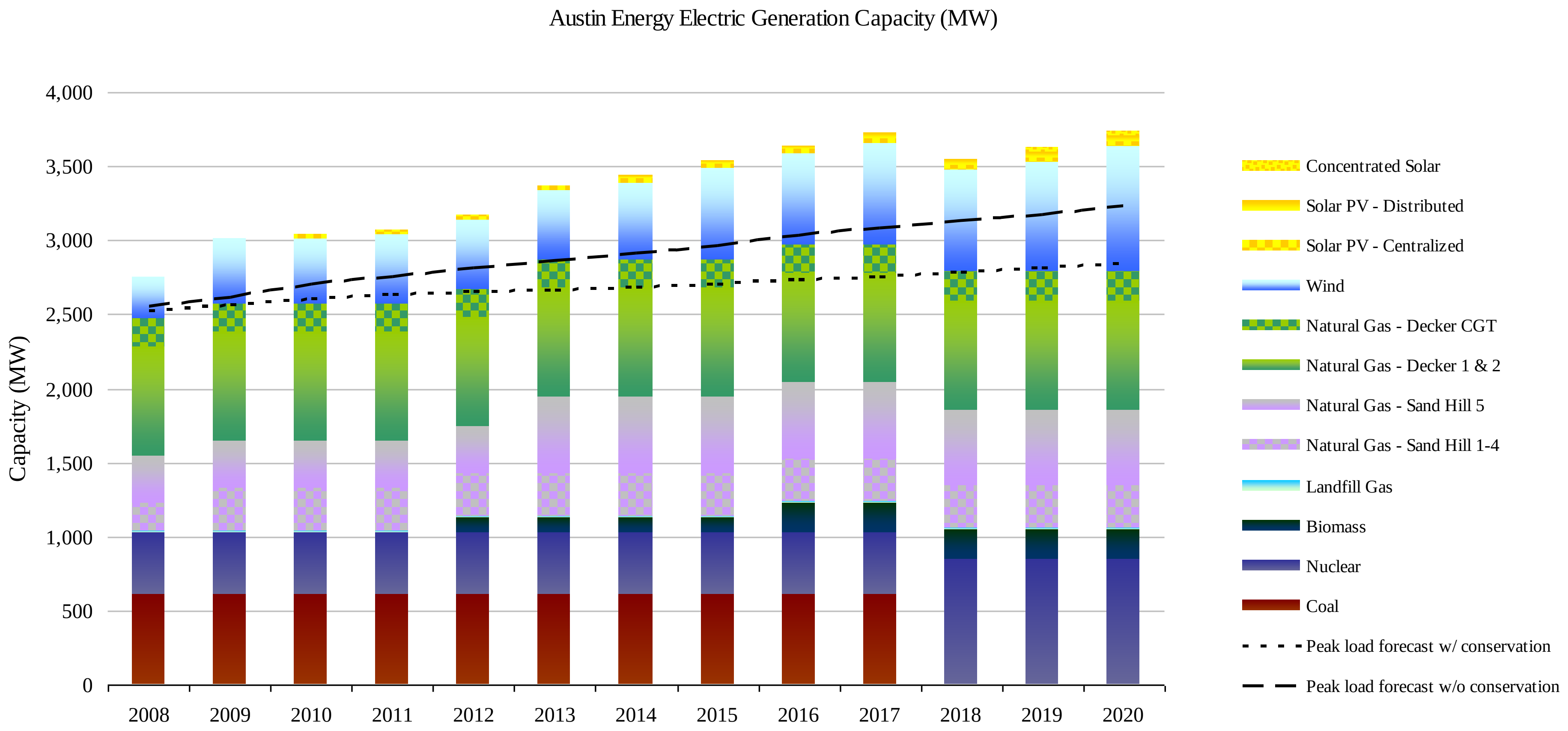


Figure 4.2
Nuclear Expansion Scenario Electric Delivery

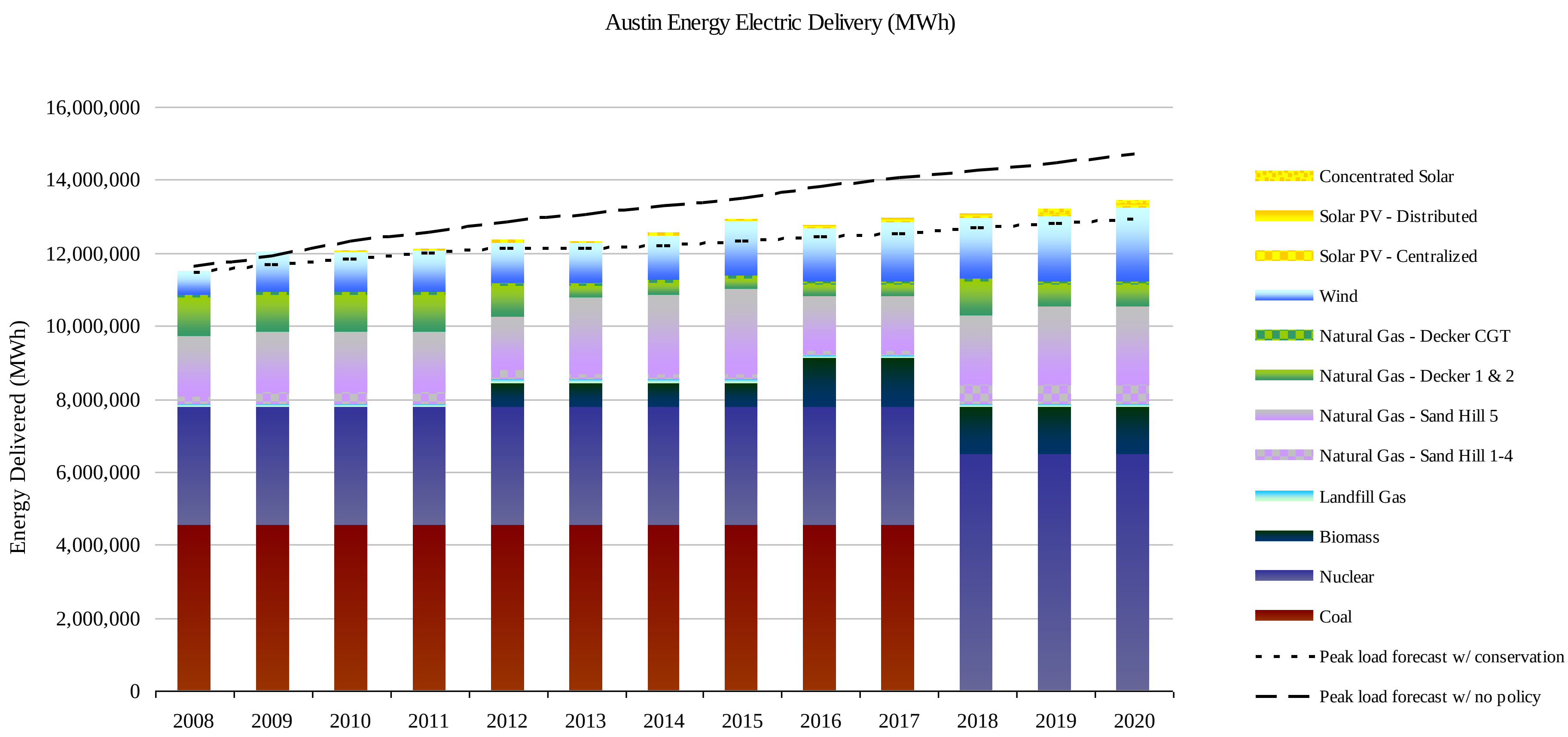


Figure 4.3
Nuclear Expansion Scenario Hourly Load Profile (Peak Demand, Summer 2000)

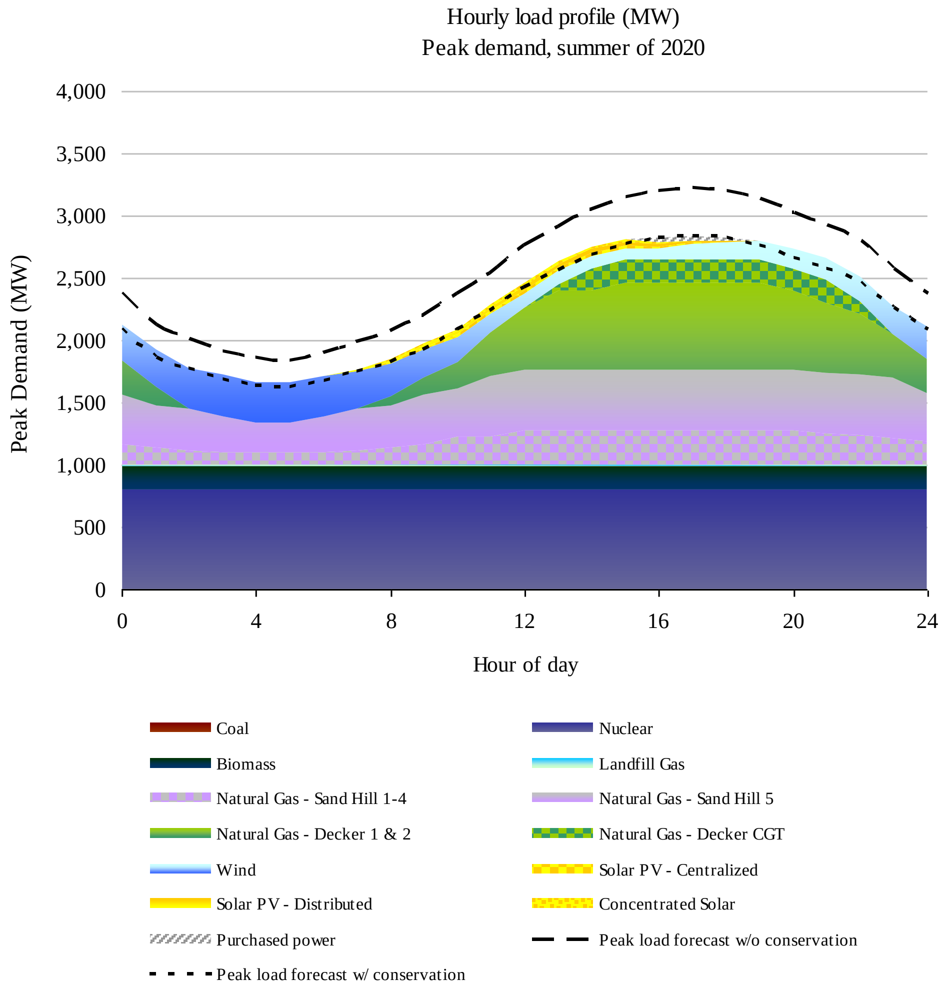


Figure 4.4
Nuclear Expansion Scenario Direct Carbon Dioxide Emissions

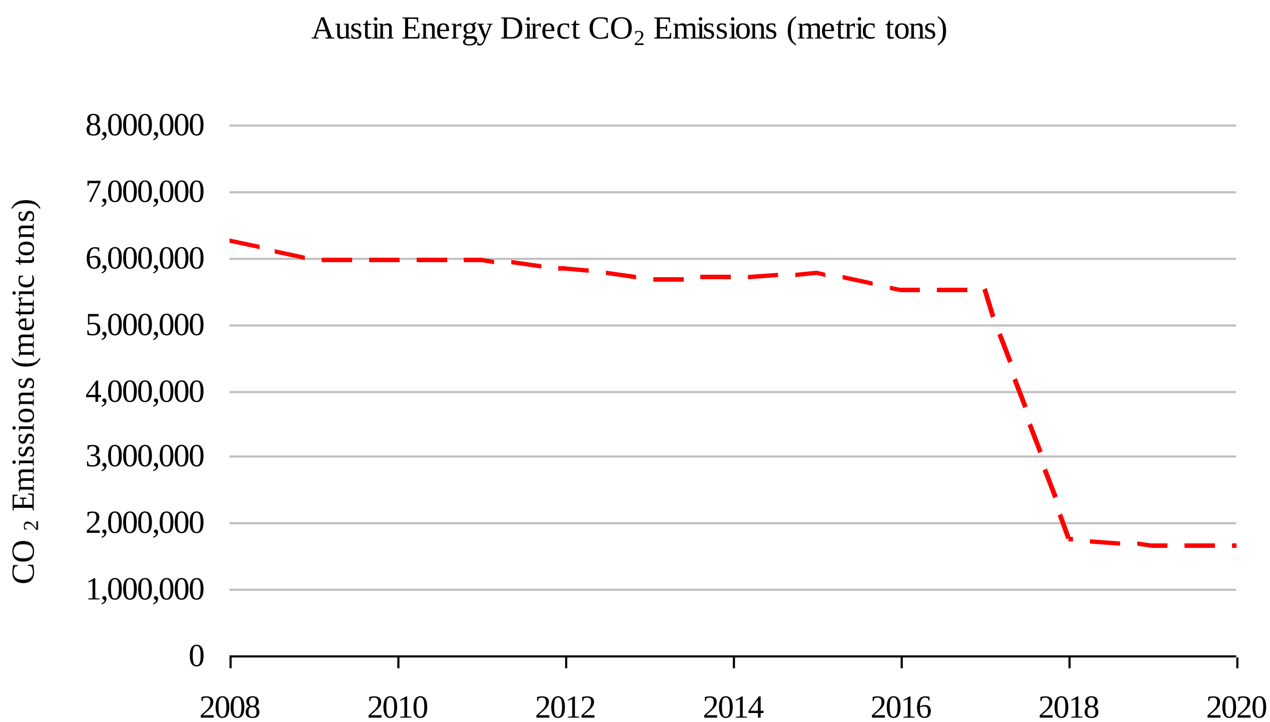


Figure 4.5
Nuclear Expansion Scenario Carbon Allowance Costs

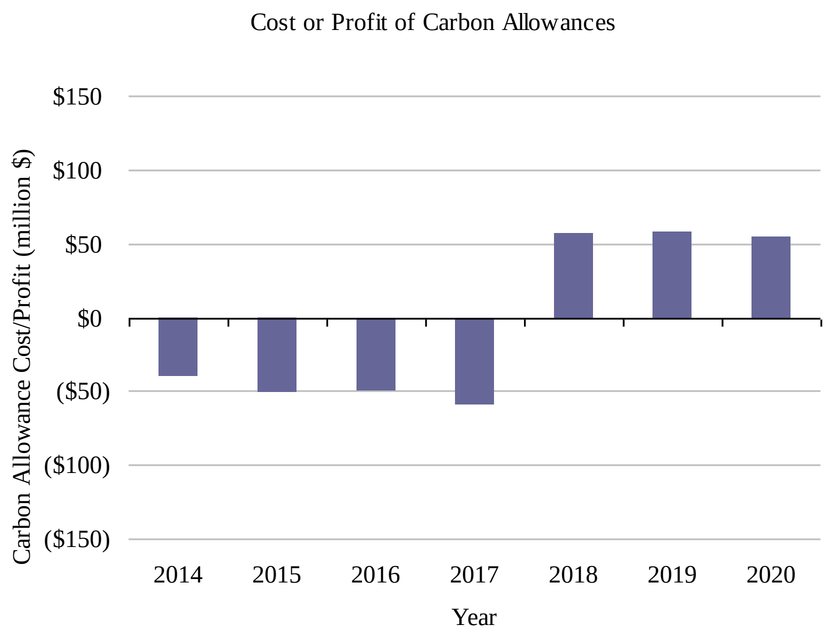


Figure 4.6
Nuclear Expansion Scenario Carbon Offset Costs

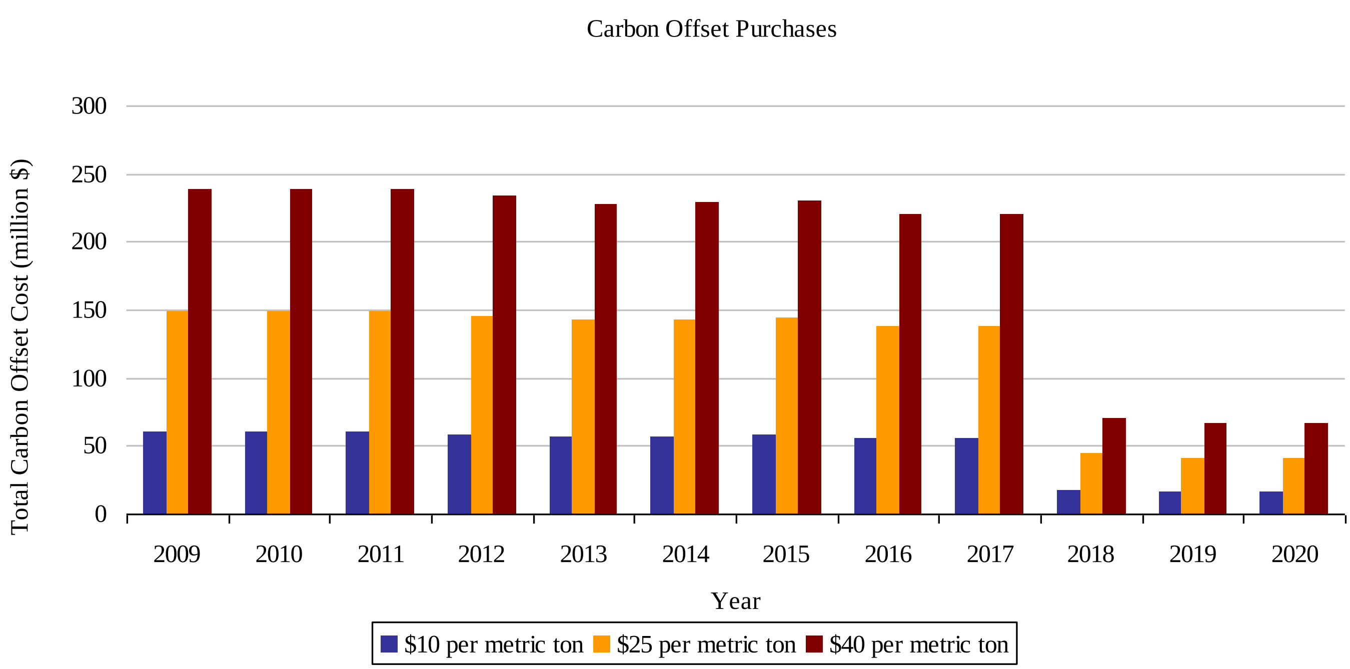


Figure 4.7
Nuclear Expansion Scenario Capital Costs

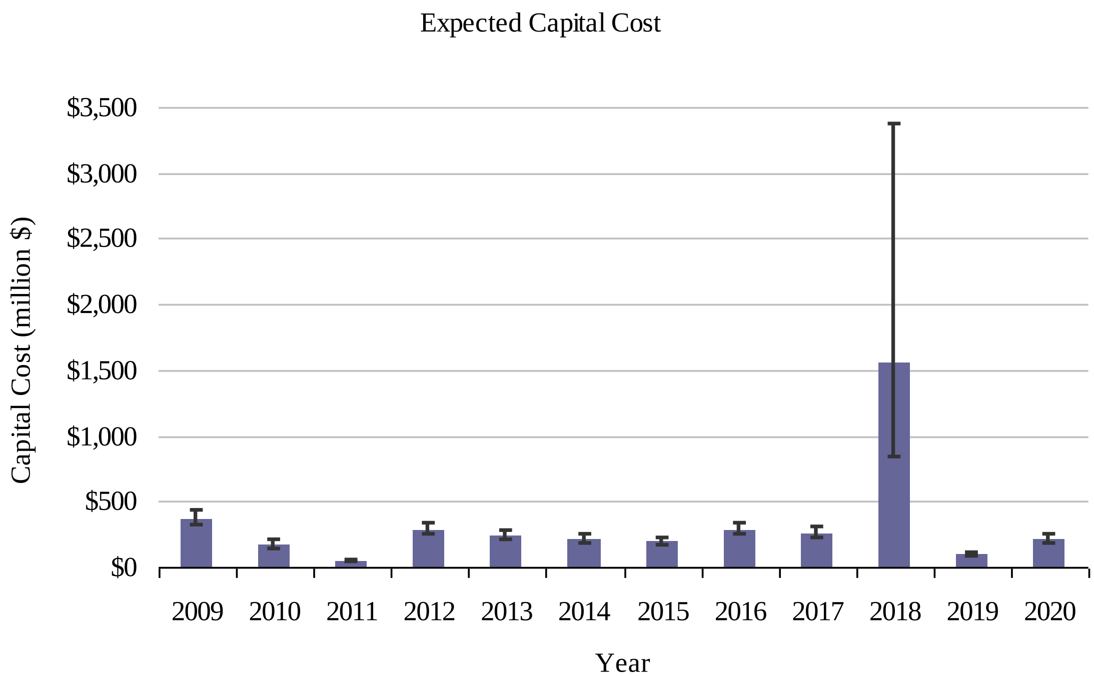


Figure 4.8
Nuclear Expansion Scenario Fuel Costs

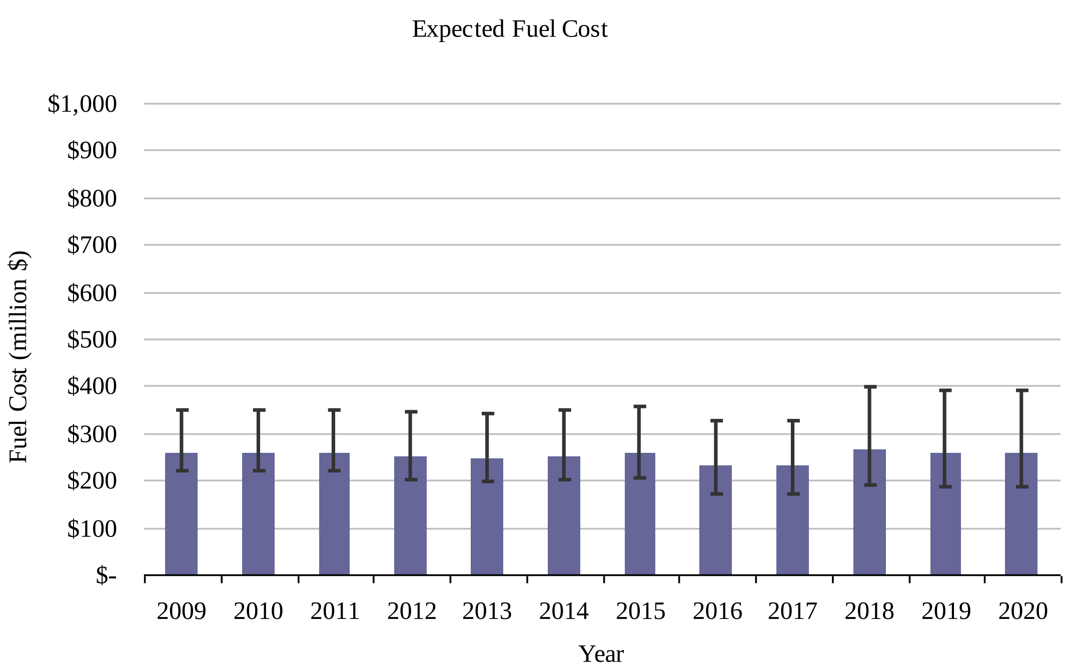


Figure 4.9
Nuclear Expansion Scenario Levelized Costs

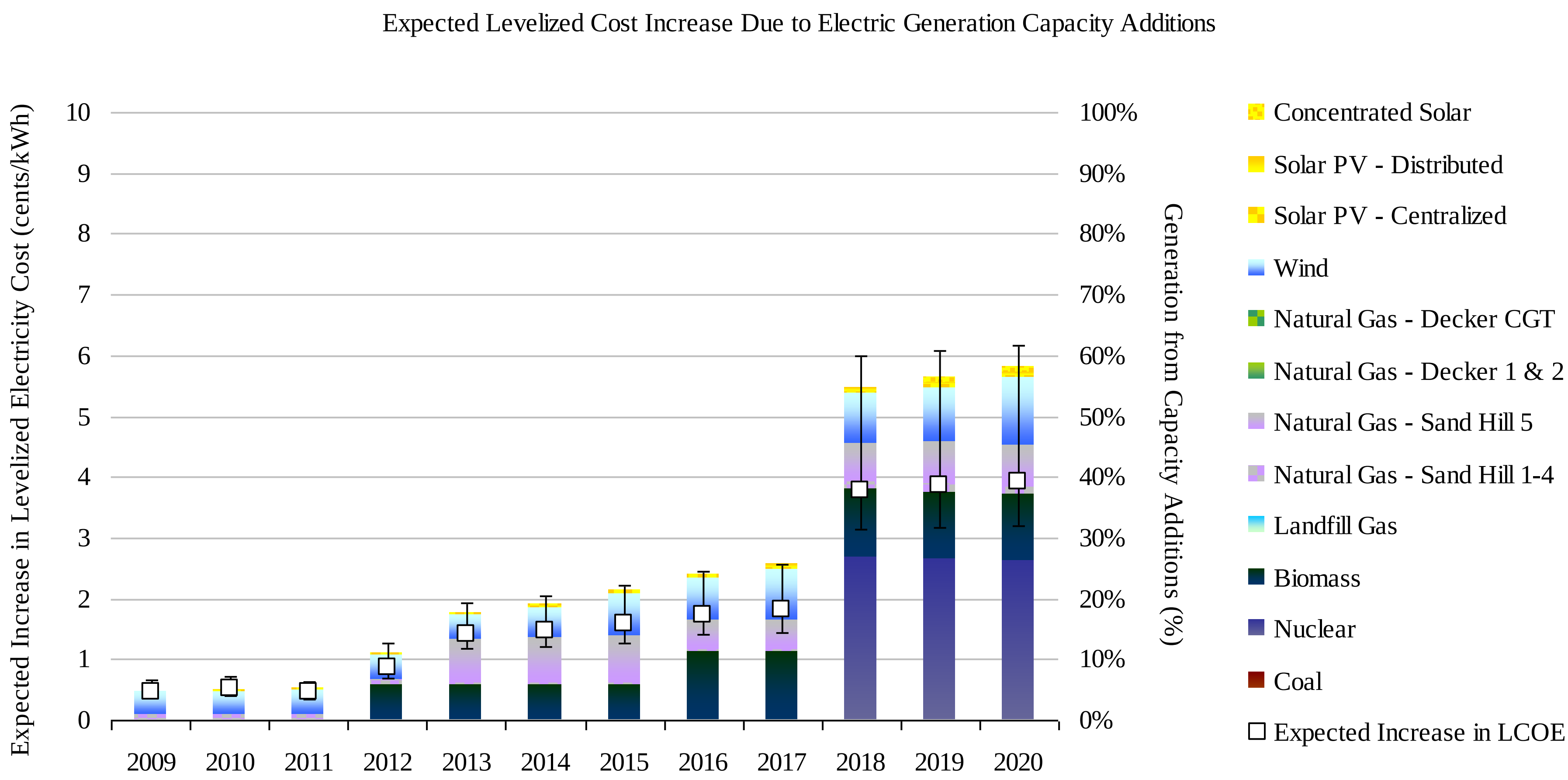


Figure 4.10
Nuclear Expansion Scenario Economic Activity

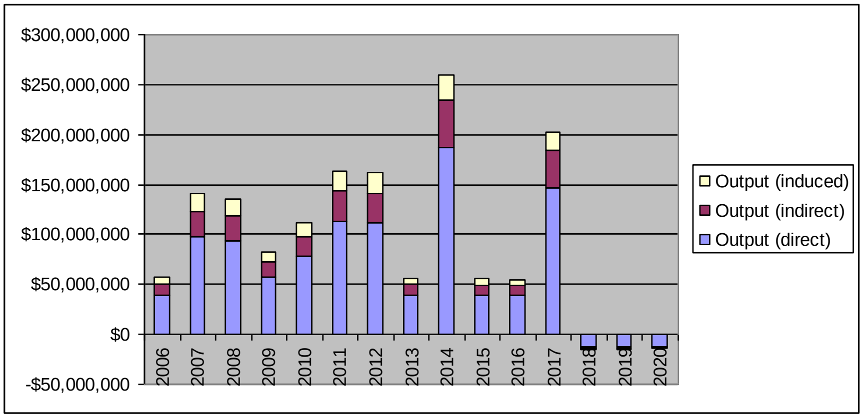


Figure 4.11
Nuclear Expansion Scenario Total Value Added

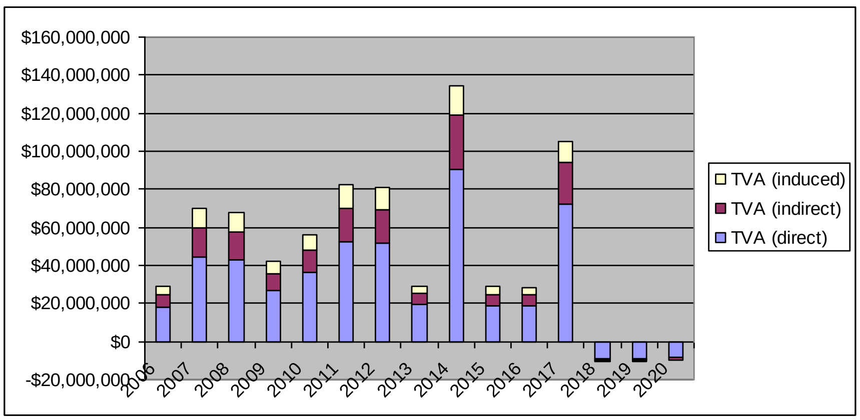
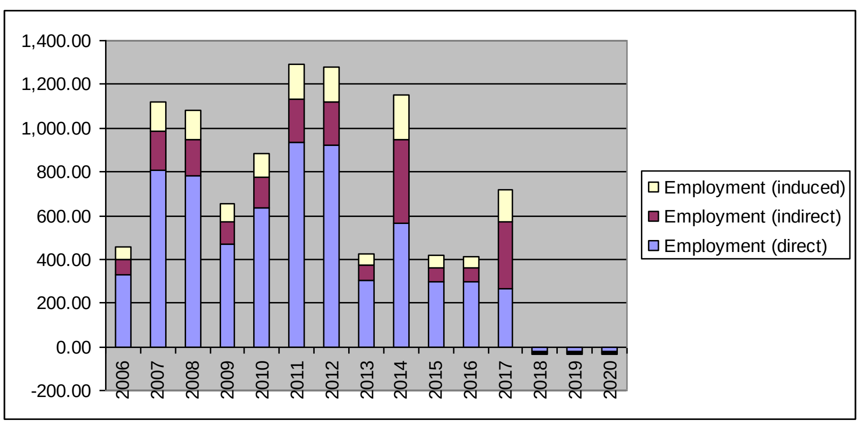


Figure 4.12
Nuclear Expansion Scenario Employment Impacts



Chapter 5. High Renewables Scenario

The high renewable resource investment scenario evaluates the shift towards a cleaner energy portfolio that eliminates the need for burning coal to generate electricity. details additions to AE's resource portfolio from 2009 to 2020 by fuel source, power generation technology, or facility, for the proposed high renewables scenario. By eliminating the necessity of burning coal for electricity, Austin Energy (AE) eliminates a resource that currently accounts for 71 percent of its carbon dioxide (CO_2) emissions while only providing 32 percent of its annual energy needs. Renewable energy technologies present a much more sustainable source of power generation than fossil fueled technologies because they utilize resources that are not depleted during the energy conversion process and do not emit harmful pollutants or by-products into the atmosphere and ecosystem. The high renewables scenario presents an extreme implementation of current renewable energy technologies to AE's power system. The renewables power generation mix presents an ambitious and optimistic presentation of renewable power options through 2020. Investments are made gradually in a manner that appears optimistically possible given current and expected advancements in these technologies and expansion in Texas' electric grid. Utility-scale solar, geothermal, and biomass facility investments are limited to current and expected capacity constraints. Wind facilities are assumed to be unconstrained by capacity, but in fact may have a penetration limit due to their inherent unreliability.

Biomass and geothermal power plants can provide baseload power that is available continuously in the same manner as coal, hydroelectric, and nuclear facilities. Therefore, biomass and geothermal plants provide a reliable source of energy as long as supplies are available. In addition to the biomass project that will begin operation in 2012, AE has proposed an additional 100 MW project to come on-line in 2016. The following scenario includes an additional 90 MW of biomass generation capacity to be added in 2020. Although no geothermal facility currently exists in Texas, there is some potential for geothermal power production. This scenario proposes a total of 100 MW of geothermal energy to be added to AE's resource portfolio with 50 MW additions occurring in 2014 and 2020, respectively. An addition of 15 MW of landfill gas power in 2016 provides an additional source of local baseload power.

Wind and solar resources provide an intermittent source of clean energy. AE is currently proposing an aggressive expansion of wind and solar assets (to 1,029 MW and 101 MW of generation capacity, respectively). The high renewables scenario makes even greater investments in wind and solar assets (to 1,990 and 913 MW of generation capacity, respectively). Solar additions include the construction of two large-scale concentrated solar facilities that use parabolic trough methods (the most advanced and least cost option for concentrated solar power generation), gradual accelerated investment in local distributed generation from solar photovoltaic (PV) panels on rooftops, and gradual investment in centralized PV systems. Onshore wind energy investments almost double that proposed by AE and a gradual addition of 305 MW of offshore wind power generation capacity is proposed in an effort to tap into wind energy availability at hours different from typical onshore wind availability.

System Reliability

Eliminating AE's stake in the Fayette Power Project coal facility creates concerns regarding system reliability, as this removes a major source of baseload power generation (607 MW of power generation capacity). In an effort to relieve such concerns, 390 MW of baseload power would be provided from geothermal and biomass facilities. However, the high renewables scenario creates a resource portfolio that becomes highly dependent upon the unreliable variable nature of wind and solar energy. Due to low capacity factors, a system so dependent on wind and solar would require much greater power generation capacity than forecasted demand. Figure 5.1 demonstrates that AE's power generation capacity would in fact greatly exceed forecasted peak load with and without conservation goals being met. This proposed system would hold 5,227 MW of power generation capacity compared to a system of 3,923 MW of power generation capacity under the AE proposed energy resource plan. By 2020, 812 MW of generation capacity will be provided from baseload power sources (nuclear, geothermal, and biomass) and 2,903 MW of power generation capacity will come from intermittent sources of energy (wind and solar). 2,324 MW of power generation capacity will come from energy resources that can provide continuous sources of power as long as the facility is in operation.

Figure 5.2 demonstrates that, given expected capacity factors for wind and solar (29 and 17 percent, respectively) as well as current capacity factors for AE's nuclear and natural gas facilities, AE will be able to reliably deliver electricity to its customers as long as AE meets its conservation goals. It appears that AE will be able to provide reliable service even if conservation goals are only met halfway, the same expected reliability of AE's proposed energy resource plan. However, because 52 percent of expected electricity delivered is dependent upon intermittent sources of energy, there is some cause for concern for system reliability given the chances that wind and solar do not meet expected production levels. However, the natural gas facilities operated by AE are expected to operate at levels much lower than capacity and would serve as reliable backup sources of power.

To demonstrate the risks of a system highly dependent on wind and solar energy, Figure 5.3 details AE's expected hourly load profile for the hottest day (peak demand) in the summer of 2020. The hourly load profile follows expected solar and wind profiles and demonstrates that AE will be able to meet peak demand without purchasing power even on the hottest day of the summer, if expected wind and solar production is met and AE meets its conservation goals. Since AE makes gradual additions to its resource portfolio from baseload, intermediate, and intermittent sources of energy, it appears that AE will be able to meet peak demand in all years between 2009 and 2020 without purchasing power. This demonstrates that it is possible to construct a power system focused on renewable resources to provide predominantly clean energy to customers.

Carbon Emissions and Carbon Costs

AE's proposed resource plan will increase the amount of clean energy power generation capacity to about 30 percent of its entire resource portfolio by 2020, the goal set by the Austin Climate Protection Plan. In comparison, the high renewables scenario will increase the amount of clean energy power generation capacity to about 63 percent of AE's resource portfolio, more than doubling what is currently being proposed by AE. Given expected capacity factors for wind and solar and adjusted capacity factors for natural gas to account for forecasted demand, about 72 percent of AE's actual power generation would come from clean energy sources in 2020 (compared to 26 percent in AE's proposed resource plan). Fifty-two percent of actual electricity delivered would come from wind and solar alone. By eliminating CO_2 emissions caused by the burning of coal and shifting to a much cleaner resource portfolio, CO_2 emissions would drop dramatically in the high renewables scenario (see Figure 5.4). AE's CO_2 emissions in 2007 were roughly 6.1 million metric tons. Under the high renewables scenario CO_2 emissions would drop to under 600,000 metric tons by 2020, a reduction of almost 90 percent. The high renewables scenario demonstrates an opportunity to significantly eliminate AE's carbon footprint by reducing CO_2 emissions to a level that makes offsetting emissions to zero very manageable.

Significantly reducing CO_2 emissions could present an opportunity to profit if carbon regulation were to be passed that supported a portion of allowances being given for free. For example, under the Lieberman-Warner Climate Security Act of 2007, a portion of an entity's emissions would be accounted for by free permits, or allowances, while a portion of allowances would be auctioned. Figure 5.5 estimates that AE could receive profits of about $216 million from 2014 to 2020 based upon allowance price estimates for the Lieberman-Warner bill and expected CO_2 emissions under the high renewables scenario. This compares to potential costs of about $490 million under AE's proposed energy resource plan.

Under the high renewables scenario, offsetting CO_2 emissions to zero also becomes much more manageable. Figure 5.6 provides a range of annual costs to offset emissions to zero, thus effectively achieving carbon-neutrality. The costs of offsets would be dramatically reduced in the years 2014 and 2020, respectively, as half of AE's stake in its coal facility would be eliminated. By 2020, annual costs would range from $6 to $23 million compared to $58 to $230 million under AE's proposed resource plan.

The high renewables scenario provides one of the most sustainable power generation scenarios conceivable for AE. This future power generation mix would rely on clean energy for almost 75 percent of customer electric needs by 2020. Natural gas facilities would serve as backup for intermittent sources of energy and as peaking units. The primary issue with sustainability then comes from arguments regarding the sustainable nature of nuclear energy. Under the high renewables scenario, AE continues its operation of just over 400 MW of power from its stake in a nuclear facility to provide baseload power. While nuclear energy does not emit greenhouse gas (GHG) emissions or other harmful air pollutants, there are serious issues regarding land use, hazardous waste, and catastrophic risks associated with producing energy through nuclear fission. Our study concludes that nuclear energy provides a more sustainable form of energy than coal due to the lack of GHG emissions and thus was kept as part of AE's resource portfolio, rather than coal, to help ensure reliable service and affordable electric rates. As renewable resources continue to advance, reliance on nuclear energy as well as natural gas could become less necessary. However, given a timeframe of only 11 years, we believe that nuclear is a necessary component to ensuring AE's ability to provide reliable energy at low costs under a high renewable energy resource mix.

Costs and Economic Impacts

It should first be noted that our model does not account for AE projections of the costs of their scheduled or proposed additions to its resource portfolio. As many of these additions come in the form of power purchase agreements or currently owned and operated facility expansions, the following cost estimates may not coincide with AE projections. The cost estimates provided below are based solely upon general cost estimates for new power generation facilities.

Figure 5.7 details the capital cost estimates for the scheduled and proposed additions in the high renewables power generation mix. Capital costs are expressed as the sum of total overnight costs for additions scheduled in a particular year. Total expected capital costs range from $6.9 to $9.5 billion (compared to $2.2 to $3.0 billion under AE's proposed resource plan). Capital costs are expressed as total overnight costs. It is important to recognize the year for which a project is proposed. On-shore wind turbines are a mature technology with relatively stable expected costs, but other renewable technologies present much uncertainty in capital costs. No geothermal, concentrated solar plant, or off-shore wind facility has ever been constructed in Texas, so cost estimates for these facilities have larger ranges. Costs for biomass plants may rise as supplies in Texas decrease. It is expected that costs to build utility-scale solar plants and to install solar PV panels will drop considerably in the next decade, but when and by how much is uncertain. In this model, costs are expressed as current estimates and ranges are determined based upon the relative maturity of the technology and expected direction by which costs are expected to flow.

Figure 5.8 details expected annual fuel costs for the high renewables scenario. Since the amount of fossil-fueled resources changes dramatically under this scenario, fuel costs are expected to drop considerably, greatly reducing the risks associated with fuel price instability. Fuel costs are expected to decrease as coal usage is reduced and eliminated. By 2020, fuel costs under this scenario would range from $67 to $172 million annually (compared to $93 to $328 million under AE's proposed resource plan).

Figure 5.9 estimates the expected rise in costs to produce electricity by calculating the impact of the levelized costs of new power generation resources as a percentage of overall generation capacity. The high renewables scenario presents an almost completely redefined power generation mix with over 75 percent actual power generation coming from additions since 2009. Therefore, the costs of these additions will have a significant impact on the costs of electricity. This model estimates that electric rates would rise by by between 4.5 and 8 cents per kilowatt-hour of electricity consumed by 2020 under the high renewables scenario, compared to between 1.5 and 3 cents per kilowatt-hour of electricity consumed under AE's proposed energy resource plan. It should be noted that this expected increase in electric rates is based solely on new power generation investments. Offset costs or any unexpected additional costs to the utility could also be passed on to the customer during this time period. Additionally, the calculation for expected increase in cost of electricity does not appoint a monetary value of reducing or removing coal or any other resource from AE's resource portfolio as the methods for evaluating how much AE could receive are beyond the scope of this report. Such removal may help to alleviate the additional costs to electricity accrued from the identified resource additions.

The high renewable scenario represents a major increase in economic activity for the Greater Austin Area attributed to investments in 250 MW of centralized photovoltaic power generation facilities, 15 MW of landfill gas capacity, and 55 MW of distributed photovoltaic power generation capacity. The most significant impact upon the local economy would be created by the rapid acceleration in solar PV modules on rooftops. This could create a vibrant local solar manufacturing and installation industry. Additionally, centralized PV systems located within the Austin region could further accelerate the solar industry in Austin.

Figure 5.10 shows the economic output in the Greater Austin Area generated by the high renewables scenario. Local economic activity peaks above $500 million in 2016. Figure 5.11 shows the total value added to the Greater Austin Area from the investments made in the high renewables scenario. Figure 5.12 shows the impacts on employment created through the high renewables scenario.

Table 5.1
High Renewables Scenario Scheduled Additions and Subtractions to Generation Mix

	Schedule of power generation additions and subtractions (net MW)												
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	607	0	0	0	0	0	-305	0	0	0	0	0	-302
Nuclear	422	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 1-4	189	100	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 5	312	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker 1 & 2	741	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker CGT	193	0	0	0	0	0	0	0	0	0	0	0	0
Wind	274	165	0	100	0	0	100	200	0	526	0	100	220
Offshore Wind	0	0	0	0	50	0	50	0	50	0	50	0	105
Biomass	0	0	0	0	100	0	0	0	100	0	0	0	90
FPP w/ biomass co-firing	0	0	0	0	0	0	0	0	0	0	0	0	0
Landfill Gas	12	0	0	0	0	0	0	0	15	0	0	0	0
Solar PV - Centralized	0	0	30	0	0	0	50	0	0	70	0	100	0
Solar PV - Distributed	1	0	5	5	5	5	5	5	5	5	5	5	5
Concentrated Solar	0	0	0	0	0	0	305	0	0	0	0	0	302
IGCC w/ CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
IGCC w/o CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	50	0	0	0	50	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0
Accelerated Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 5.1
High Renewables Scenario Power Generation Capacity

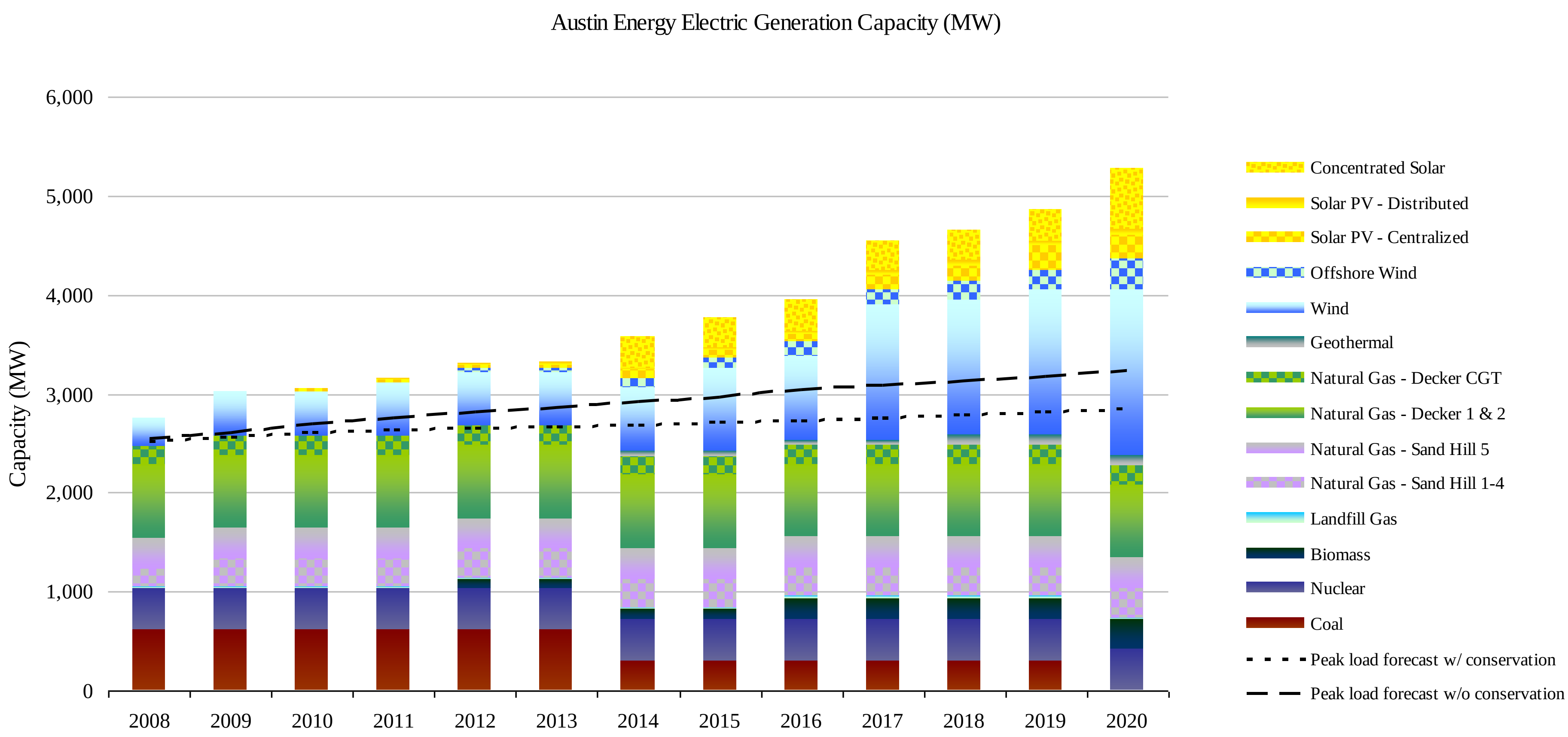


Figure 5.2
High Renewables Scenario Electric Delivery

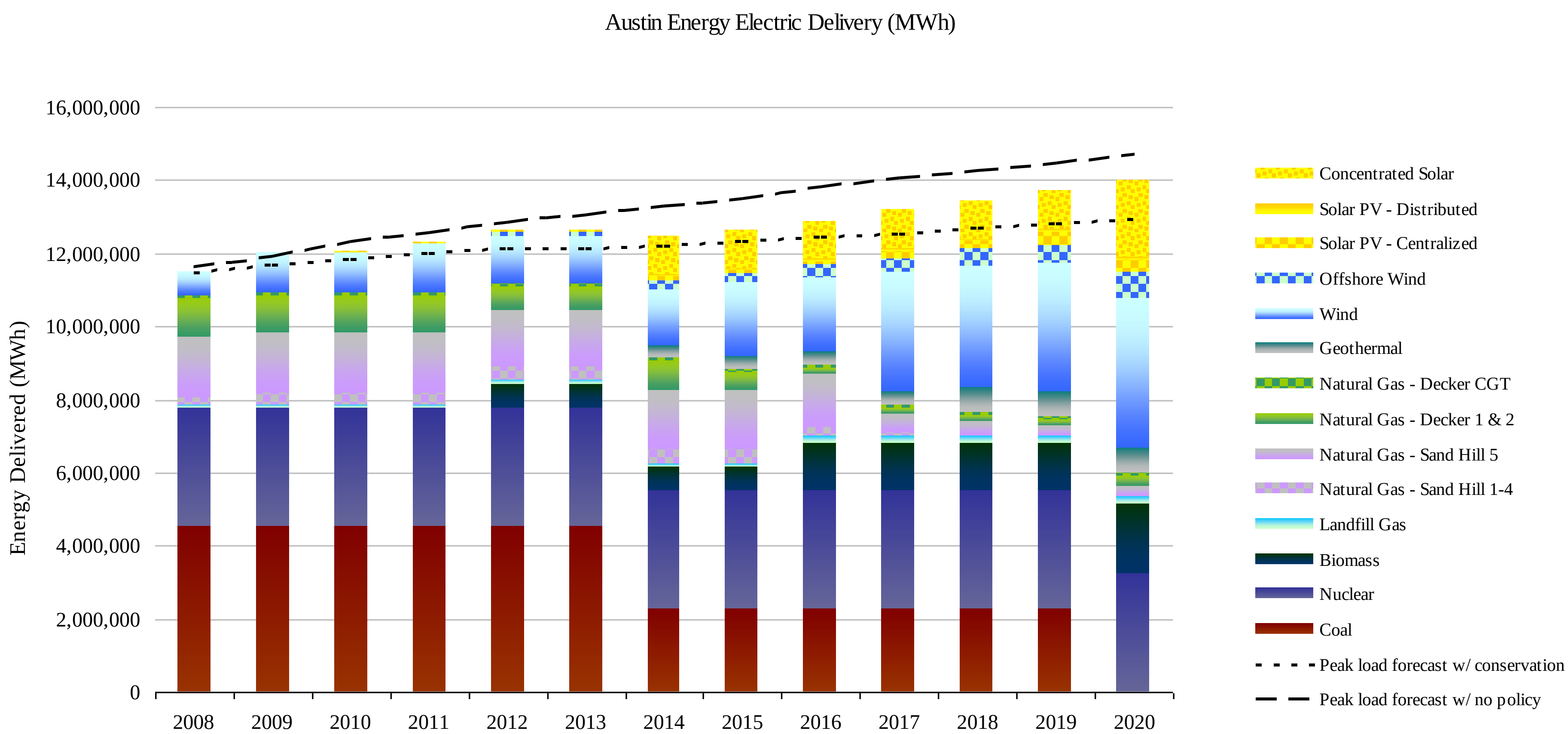


Figure 5.3
High Renewables Scenario Hourly Load Profile (Peak Demand, Summer 2000)

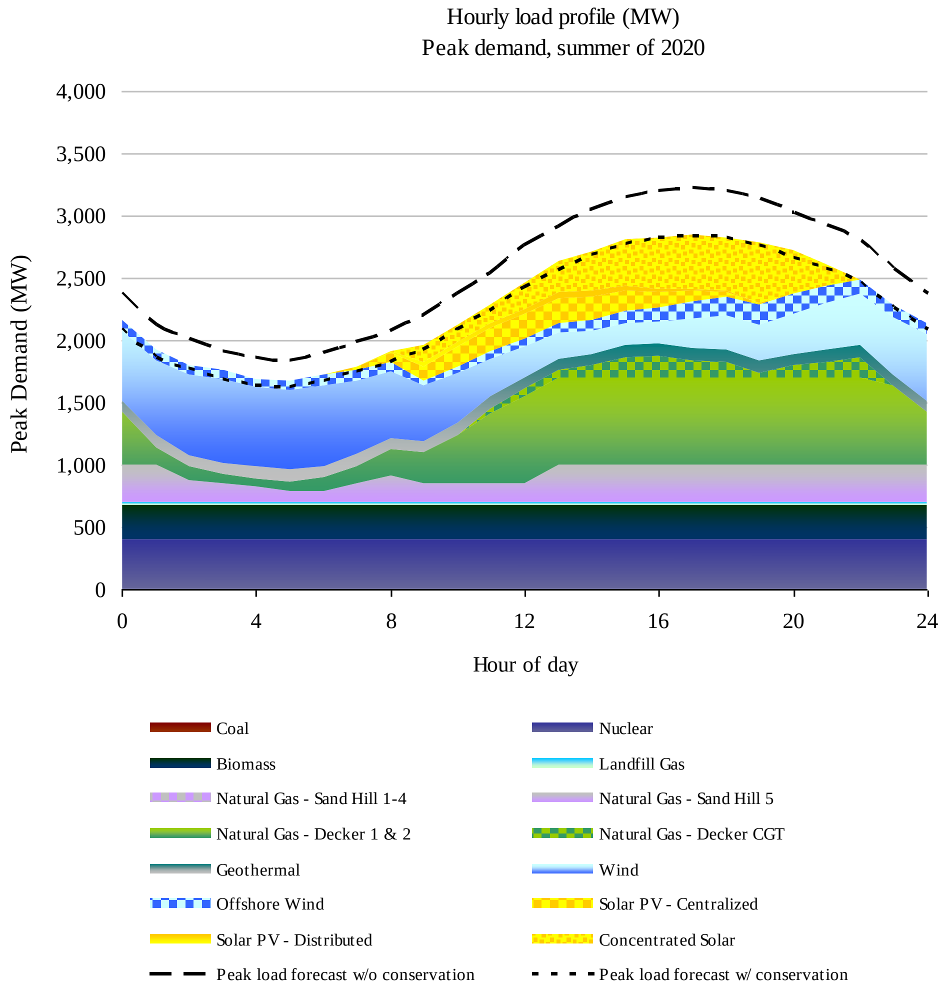


Figure 5.4
High Renewables Scenario Direct Carbon Dioxide Emissions

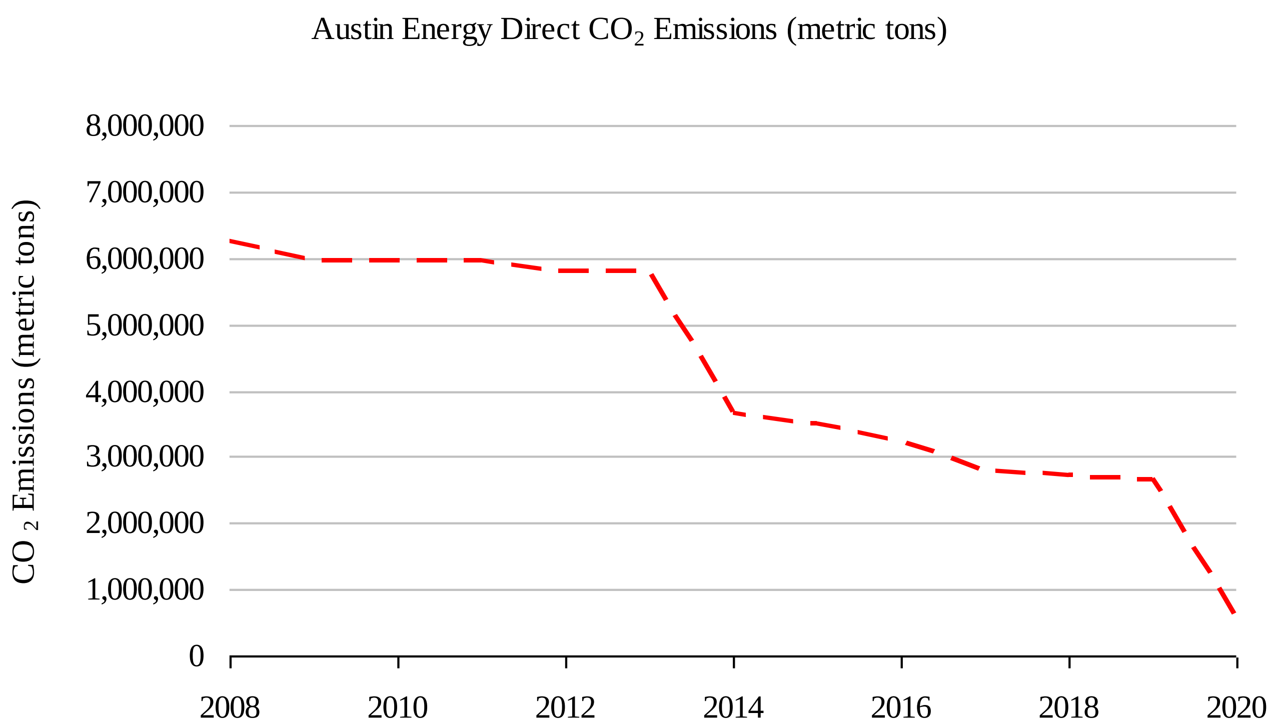


Figure 5.5
High Renewables Scenario Carbon Allowance Costs

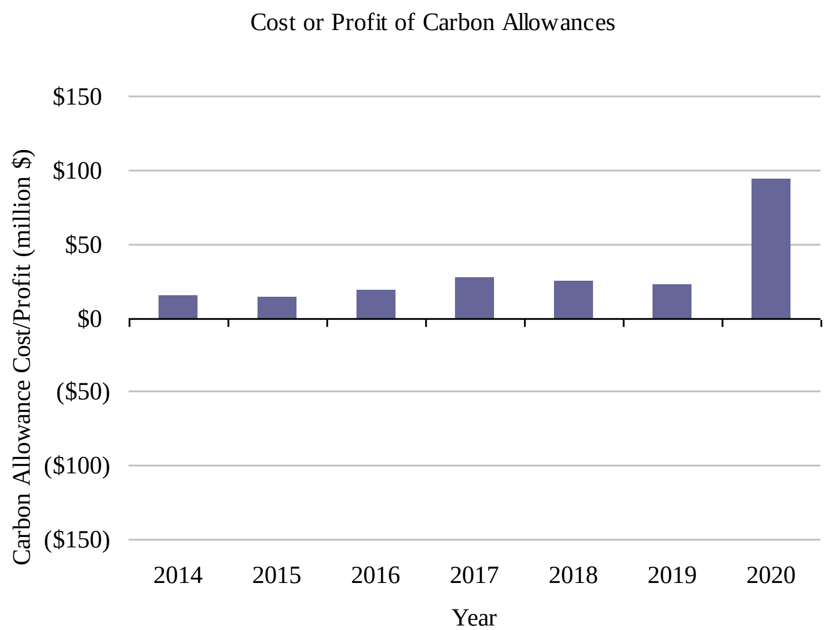


Figure 5.6
High Renewables Scenario Carbon Offset Costs

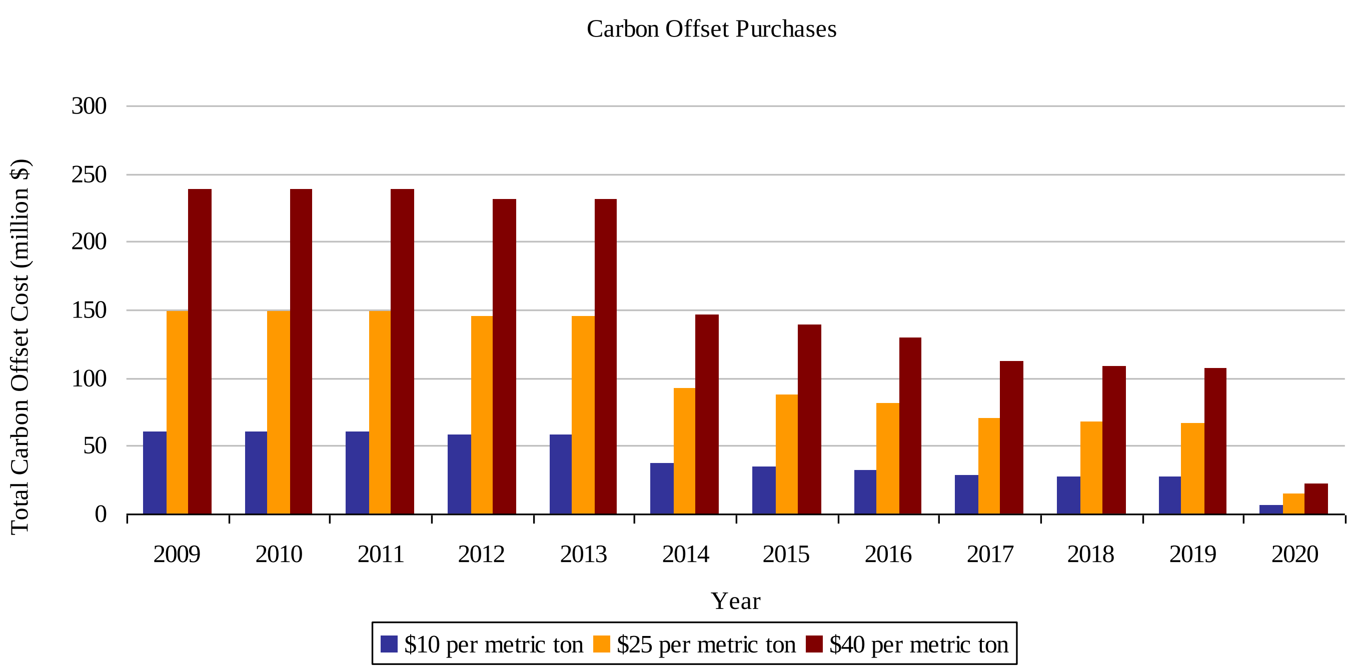


Figure 5.7
High Renewables Scenario Capital Costs

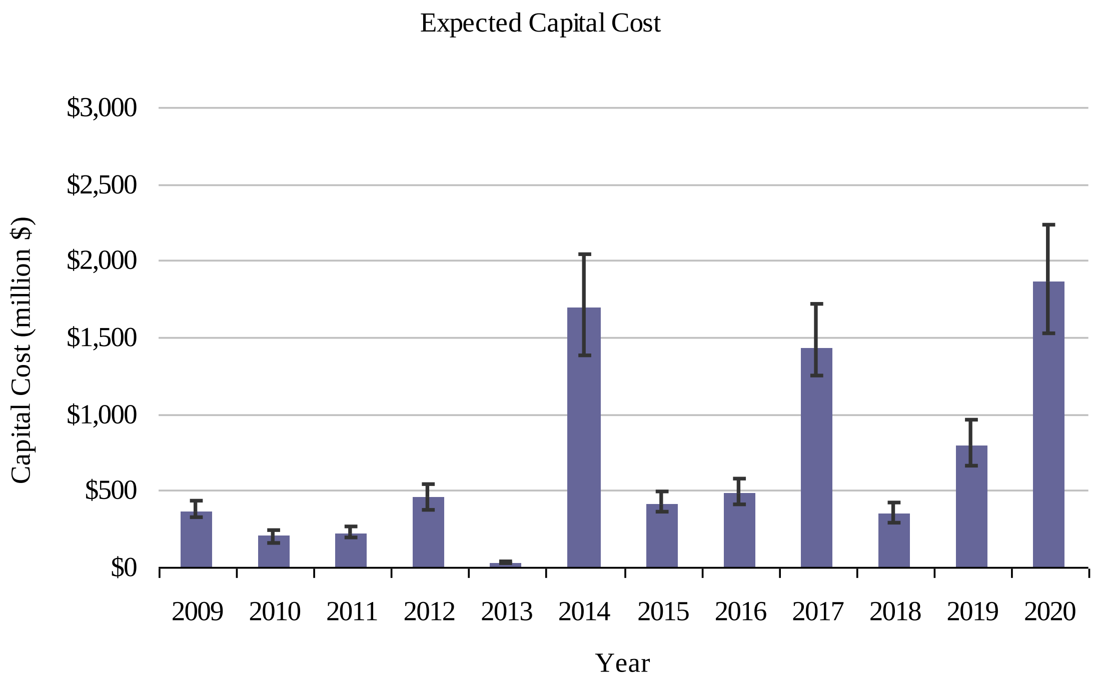


Figure 5.8
High Renewables Scenario Fuel Costs

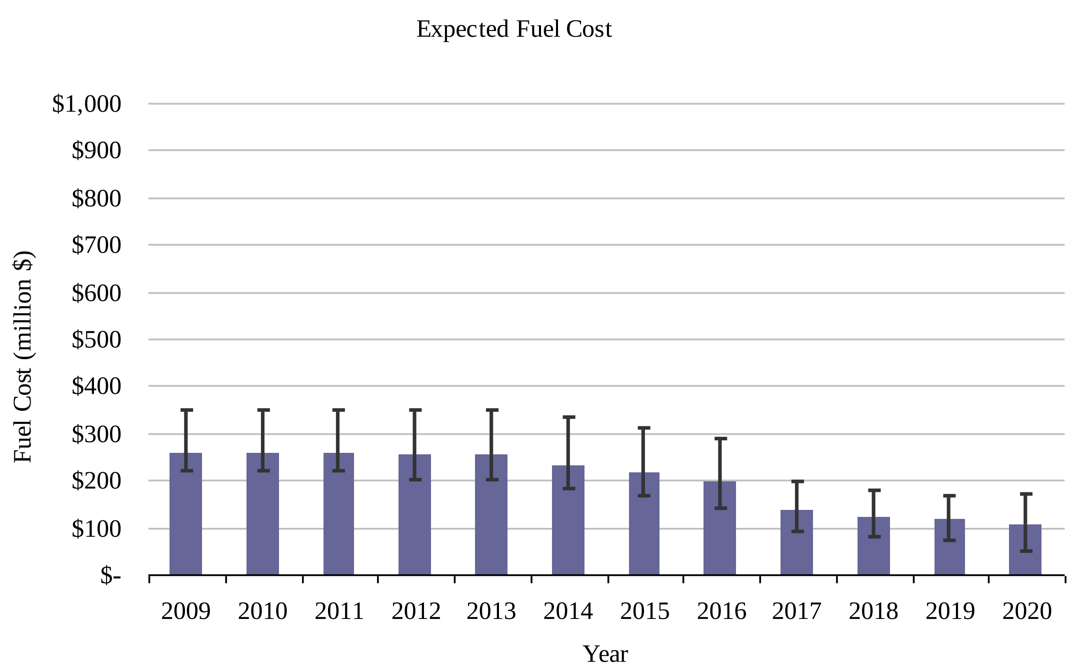


Figure 5.9
High Renewables Scenario Levelized Costs

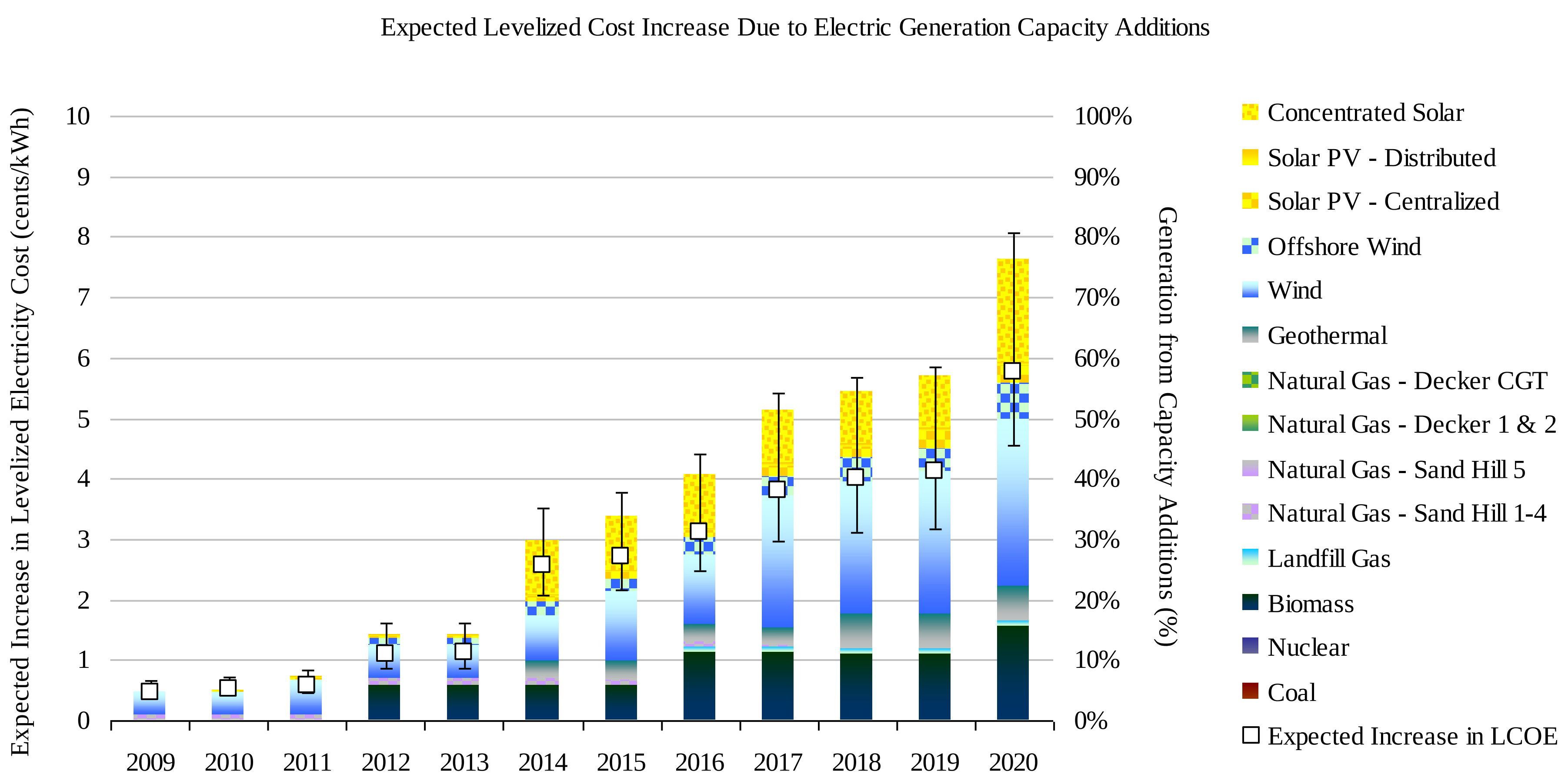


Figure 5.10
High Renewables Scenario Economic Activity

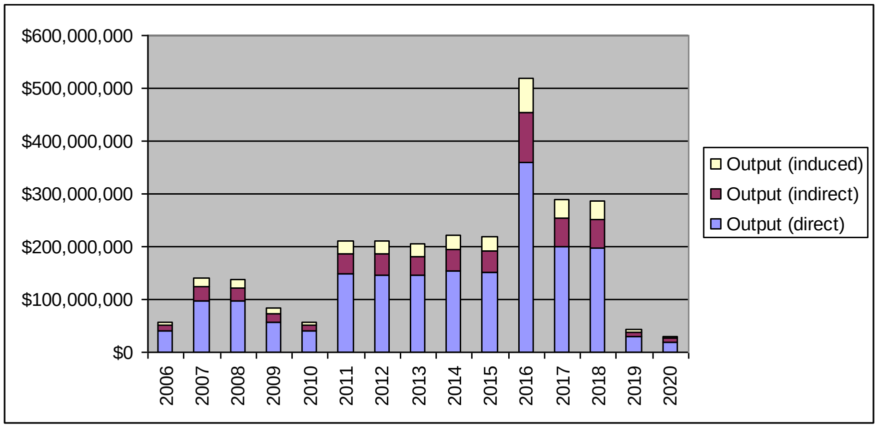


Figure 5.11
High Renewables Scenario Total Value Added

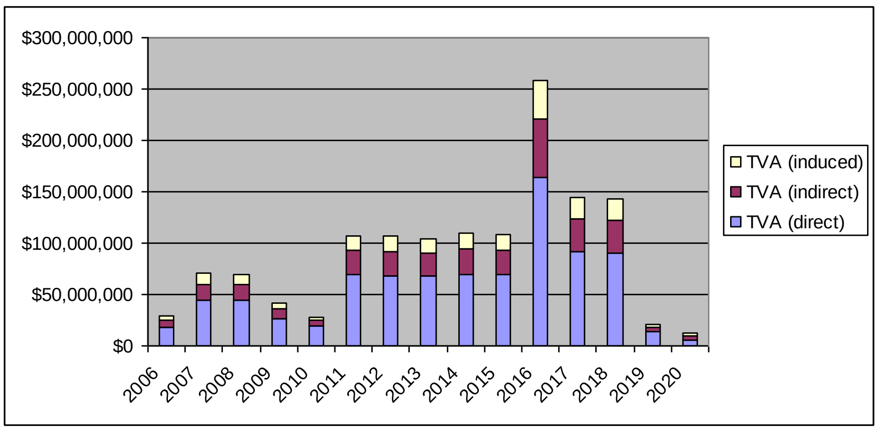
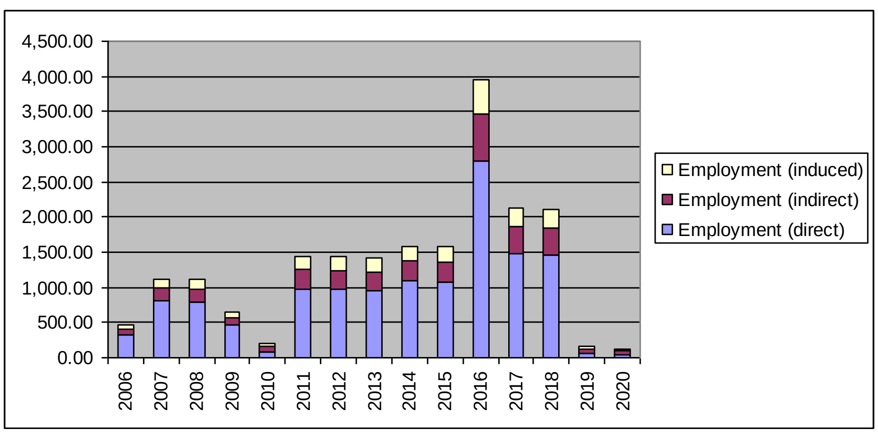


Figure 5.12
High Renewables Scenario Employment Impacts



Chapter 6. Expected Renewables Scenario

The expected renewable resource investment scenario is a compromise between Austin Energy's (AE) proposed resource plan and the high renewable resource scenario. details the proposed additions to AE's resource portfolio from 2009 to 2020. The scenario presents a schedule of investments in power generating capacity that is considered more realistic than the high renewables scenario in regards to both affordability and practicality. In this scenario, AE eliminates half of its stake in the Fayette Power Project (FPP) in 2018, thus halving its CO_2 emissions attributed to the burning of coal. To make up for lost coal baseload power, AE maintains the schedule of 572 MW of wind, 300 MW of natural gas, and 200 MW of baseload biomass additions included in AE's proposed resource plan. AE would make greater investments in solar through 2020 than what is included in the original resource plan (341 MW versus 100 MW) under this scenario, but invests in about two-thirds less than the solar investments scheduled in the high renewables scenario. In addition to the currently scheduled 30 MW centralized solar installation expected to be available by 2010, AE would install two 50 MW centralized solar photovoltaic (PV) facilities, one in 2014 and another in 2019. AE would install two 100 MW concentrating parabolic trough solar facilities, one in 2014 and the other in 2020. This scenario relies on the assumption that distributed solar PV would be installed at a rate of 1 MW per year, beginning in 2010 (considering a typical residential installation is about 3 kW and 1 MW = 1,000 kW, this would mean the installation of about 333 residential PV systems per year). Unlike the high renewables scenario, this scenario does not include the addition of any geothermal or offshore wind sources, as AE's access to these resources is limited geographically.

System Reliability

Figure 6.1 demonstrates that AE's power generation capacity would exceed forecasted peak load with and without conservation goals being met. Eliminating about half of AE's stake in FPP creates concerns regarding system reliability, as this removes a major source of baseload power generation (305 MW). In an effort to relieve such concerns, biomass facilities would provide 200 MW of baseload power. However, the expected renewables scenario creates a resource portfolio that becomes highly dependent upon the unreliable variable nature of wind and solar energy, as well as greater natural gas consumption. Due to low capacity factors and the probabilistic possibility of failure, a system so dependent on wind and solar would require much greater power generation capacity than forecasted demand. Beginning in 2018 with the removal of half of FPP, the combination of baseload and natural gas sources cannot meet demand by themselves in the presence of a failure of wind or solar. This reliance on variable wind and solar resources introduces a real concern of potential system failures.

This proposed system would hold 3,659 MW of power generation capacity compared to a system of 3,923 MW of generation capacity under the AE proposed energy resource plan. By 2020, 924 MW of power generation capacity will be provided from baseload power sources (coal, nuclear, and biomass) and 1,188 MW of power generation capacity will come from variable energy sources (wind and solar).

Figure 6.2 demonstrates that, given expected capacity factors for wind and solar (29 and 17 percent, respectively) as well as current capacity factors for AE's nuclear and natural gas facilities, AE will be able to deliver electricity to its customers as long as AE meets its conservation goals. If wind and solar do not meet expected production levels, the natural gas facilities would serve as backup sources of power. By 2020, combined cycle natural gas units at Sand Hill would be providing close to baseload levels of electricity because of the lower CO_2 emissions associated with them, while the other natural gas units at Sand Hill and Decker act as peaking and reserve capacity.

Figure 6.3 details AE's expected hourly load profile for the hottest day (peak demand day) in the summer of 2020. The hourly load profile follows expected solar and wind profiles, and demonstrates that AE will most likely have to purchase power to be able to meet peak demand in 2020 even if AE meets its conservation goals. At peak, with all the natural gas facilities operating at full capacity, AE will still have to purchase 185 MW from the grid. An additional 200 MW natural gas facility could make up this difference if AE so chose.

Carbon Emissions and Carbon Costs

AE's proposed resource plan will increase the amount of renewable power generation capacity to about 30 percent of its entire resource portfolio by 2020, the goal set by the Austin Climate Protection Plan. In comparison, the expected available renewables scenario will increase the amount of renewable power generating capacity to about 38 percent of AE's entire resource portfolio. Given expected capacity factors for wind and solar and adjusted capacity factors for natural gas to account for forecasted demand, about 33 percent of AE's actual power generation would come from clean energy sources in 2020 (compared to 26 percent in AE's proposed resource plan) with 22 percent of actual electricity delivered coming from wind and solar. By eliminating half of the CO_2 emissions caused by the burning of coal, CO_2 emissions would decrease by about 36 percent from 2008 levels in the expected renewables scenario (see Figure 6.4). The expected renewables scenario demonstrates an opportunity to reduce AE's carbon footprint substantially by 2020 with seemingly reasonable investments in additional low-carbon facilities. Although this scenario would result in the production of lower CO_2 emissions, Figure 6.6 estimates that AE would still have to pay between $29 and $48 million annually based upon carbon allowance price estimates if the Lieberman-Warner bill were to be implemented. This compares to potential annual costs of about $47 to $96 million under AE's proposed energy resource plan.

Under the expected renewables scenario, offsetting CO_2 emissions to zero becomes more manageable than in the proposed resource plan. Figure 6.6 provides a range of annual costs to offset emissions to zero, thus effectively achieving carbon-neutrality. By 2020, the annual costs for offsets would range from $40 to $160 million compared to $58 to $230 million under AE's proposed resource plan.

The expected renewables scenario provides a modest increase in renewable and low-carbon generating facilities over those included in the proposed resource plan. This power generation mix reveals practical steps toward AE's pursuit of carbon neutrality by 2020 without a tremendous cost increase over the proposed resource plan. As CO_2 emissions decline in this scenario, the issue with sustainability comes from arguments regarding the sustainable nature of nuclear energy. Under the expected renewables scenario, AE continues its operation of just over 400 MW of power from its stake in a nuclear facility to continue to provide baseload power. While nuclear energy does not emit greenhouse gases or other harmful air pollutants, there are serious issues regarding land use, hazardous waste, and catastrophic risks associated with producing energy through nuclear fission. However, given a timeframe of only 11 years, we believe that nuclear is a necessary component to ensuring AE's ability to provide reliable energy at low costs under a more renewable energy resource mix.

Costs and Economic Impacts

Figure 6.7 details the capital cost estimates for AE's scheduled and proposed additions to its power generation mix. Expected capital costs range from $2.6 to $3.7 billion (compared to $2.2 to $3.0 billion under AE's proposed resource plan). Capital costs are expressed as total overnight costs. Therefore, it is important to recognize the year for which a project is proposed. In this model, costs are expressed as current estimates and ranges are determined based upon the relative maturity of the technology and expected direction by which costs are expected to flow.

Figure 6.8 details annual fuel costs for the high renewables scenario. Fuel costs are not expected to decrease because, even though the elimination of half of FPP will reduce coal consumption, that resource is replaced by natural gas and biomass that is typically more expensive. Fuel costs would, by 2020 under this scenario, range from $205 to $413 million annually (compared to $93 to $328 million under AE's proposed resource plan).

Figure 6.9 estimates the rise in costs on electric bills by calculating the impact of the levelized costs of new power generation resources as a percentage of overall power generation capacity. The expected renewables scenario presents a modestly redefined power generation mix with about 30 percent of actual power generation coming from additions since 2009. Since this scenario is similar to the proposed resource plan, the expected costs of these additions will not have a significantly different impact on the costs of electricity. This model estimates that the cost to produce electricity would rise between 1.8 and 3.2 cents per kilowatt-hour (compared to between 1.5 and 3 cents per kilowatt-hour under AE's proposed energy resource plan). It should be noted that this expected increase in electric rates is based solely on new power generation investments. Offset costs or any unexpected additional costs to the utility could also be passed on to the customer during this time period.

Figure 6.10 shows that there would be a major spike in economic activity during the years 2011 to 2013 of over $250 million each year created by the addition of 200 MW of natural gas power generation capacity at Sand Hill in 2013 and 50 MW of centralized solar capacity in 2014. Figure 6.11 shows the total value added to the Greater Austin Area from the investments made in the expected renewables scenario. Figure 6.12 shows the impacts on employment created or eliminated by the expected renewables scenario. The consequence of employment losses created from AE's divestment in coal in the Greater Austin Area under this scenario is an enduring relative loss of output and no net gain of jobs.

IMPLAN only models the effects of construction and installation of new power generation facilities, estimated activity from the installation of distributed PV units, and operations and maintenance activities associated with power generation facilities. This scenario does not take into account the possibility of attracting renewable energy manufacturing to the Austin area.

Table 6.1
High Renewables Scenario Scheduled Additions and Subtractions to Generation Mix

	Schedule of power generation additions and subtractions (net MW)												
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	607	0	0	0	0	0	0	0	0	0	-305	0	0
Nuclear	422	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 1-4	189	100	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 5	312	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker 1 & 2	741	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker CGT	193	0	0	0	0	0	0	0	0	0	0	0	0
Wind	274	165	0	23	0	0	50	100	0	74	0	50	110
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	100	0	0	0	100	0	0	0	0
FPP w/ biomass co-firing	0	0	0	0	0	0	0	0	0	0	0	0	0
Landfill Gas	12	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV - Centralized	0	0	30	0	0	0	50	0	0	0	0	50	0
Solar PV - Distributed	1	0	1	1	1	1	1	1	1	1	1	1	1
Concentrated Solar	0	0	0	0	0	0	100	0	0	0	0	0	100
IGCC w/ CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
IGCC w/o CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0
Accelerated Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 6.1
Expected Renewables Scenario Power Generation Capacity

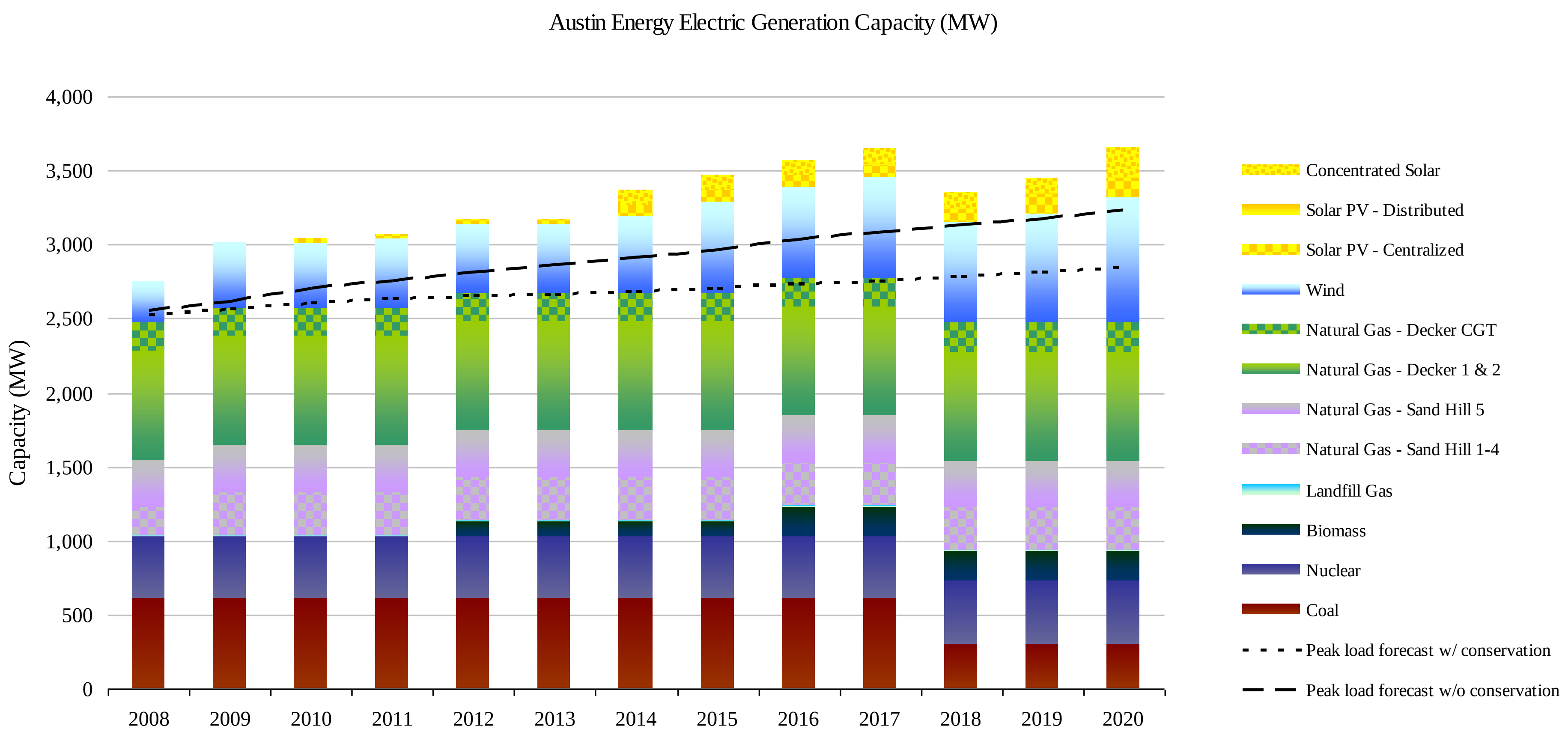


Figure 6.2
Expected Renewables Scenario Electric Delivery

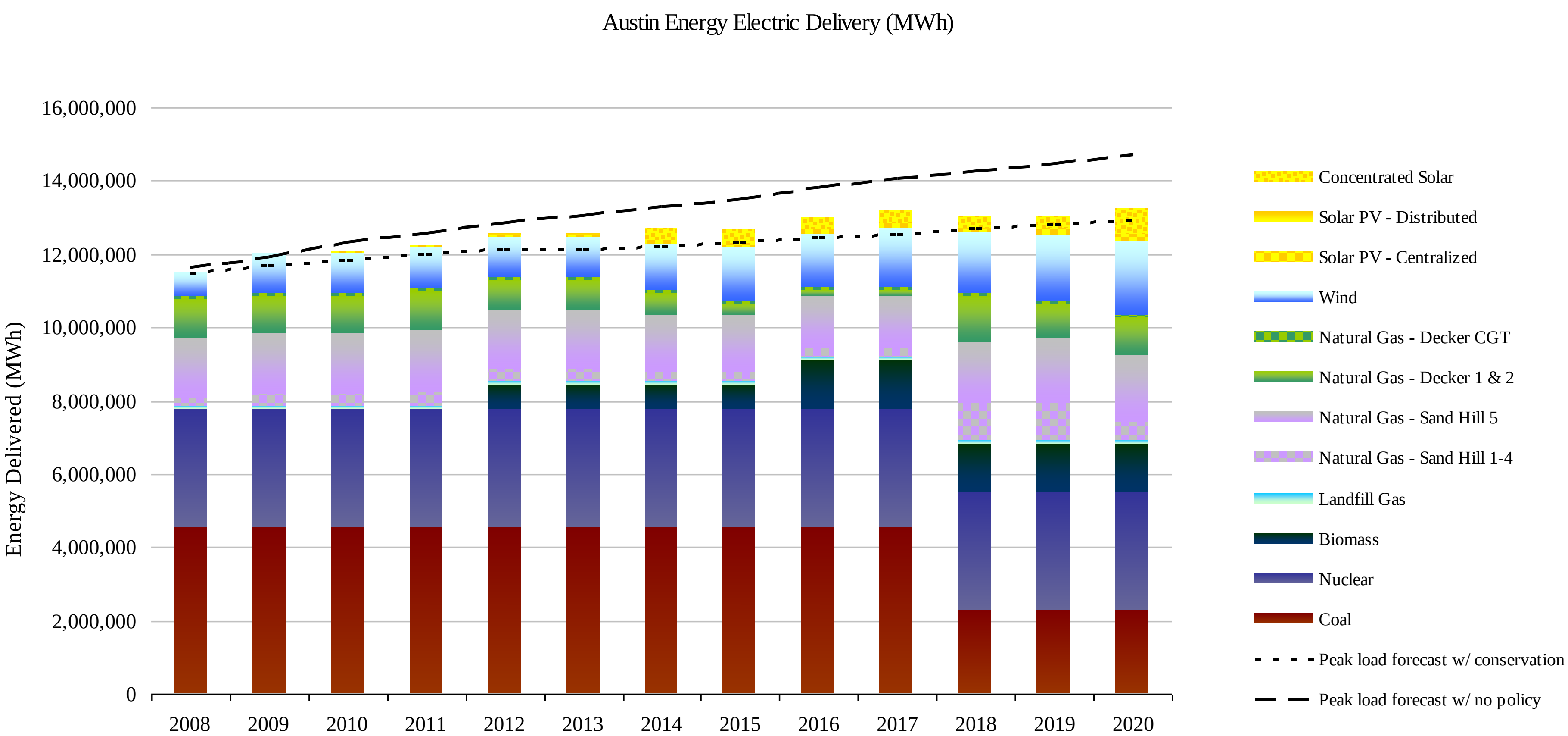


Figure 6.3
Expected Renewables Scenario Hourly Load Profile (Peak Demand, Summer 2000)

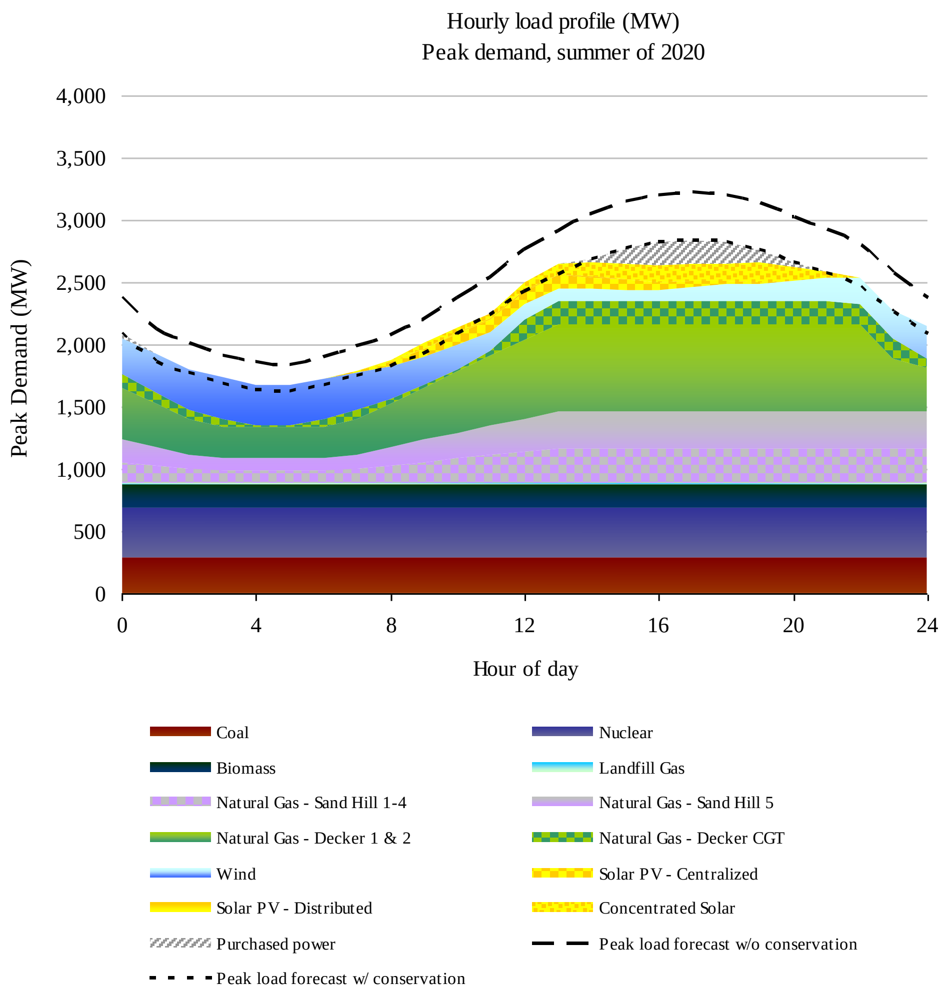


Figure 6.4
Expected Renewables Scenario Direct Carbon Dioxide Emissions

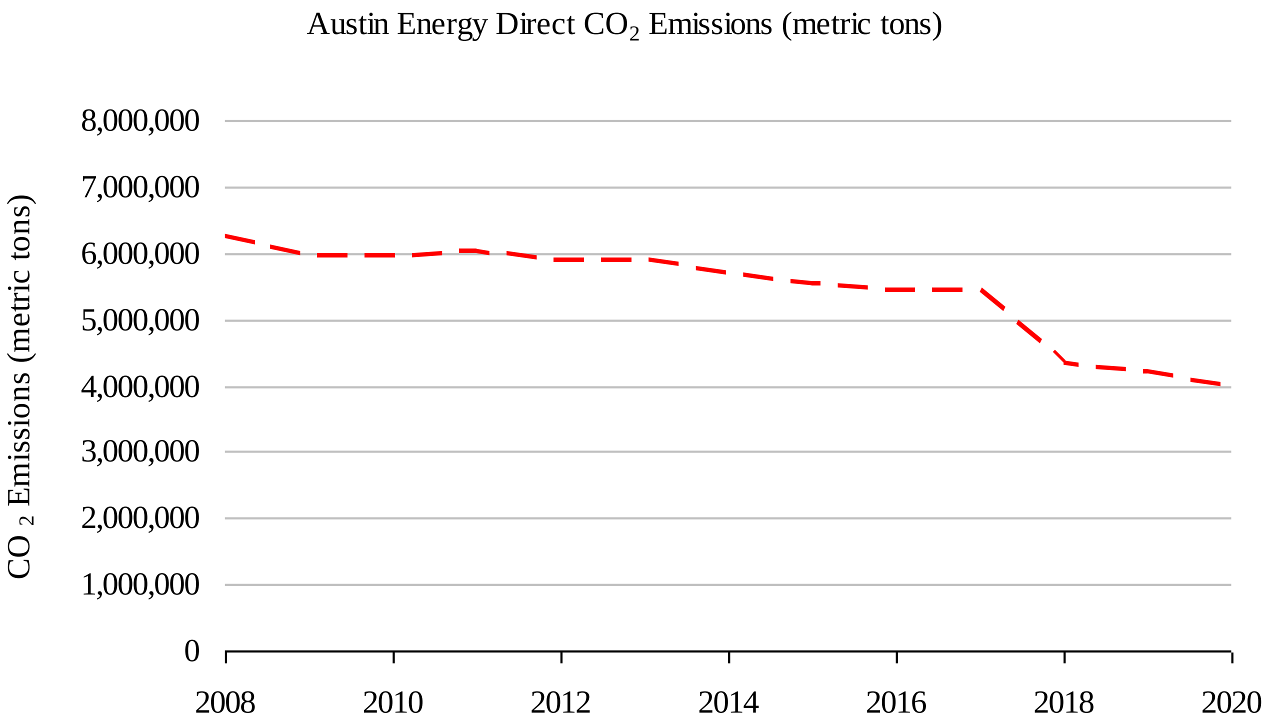


Figure 6.5
Expected Renewables Scenario Carbon Allowance Costs

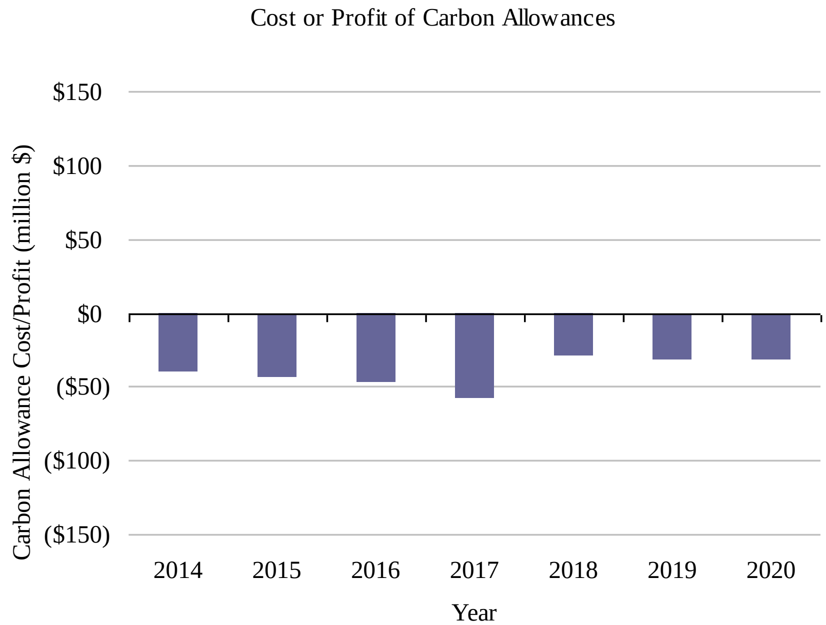


Figure 6.6
Expected Renewables Scenario Carbon Offset Costs

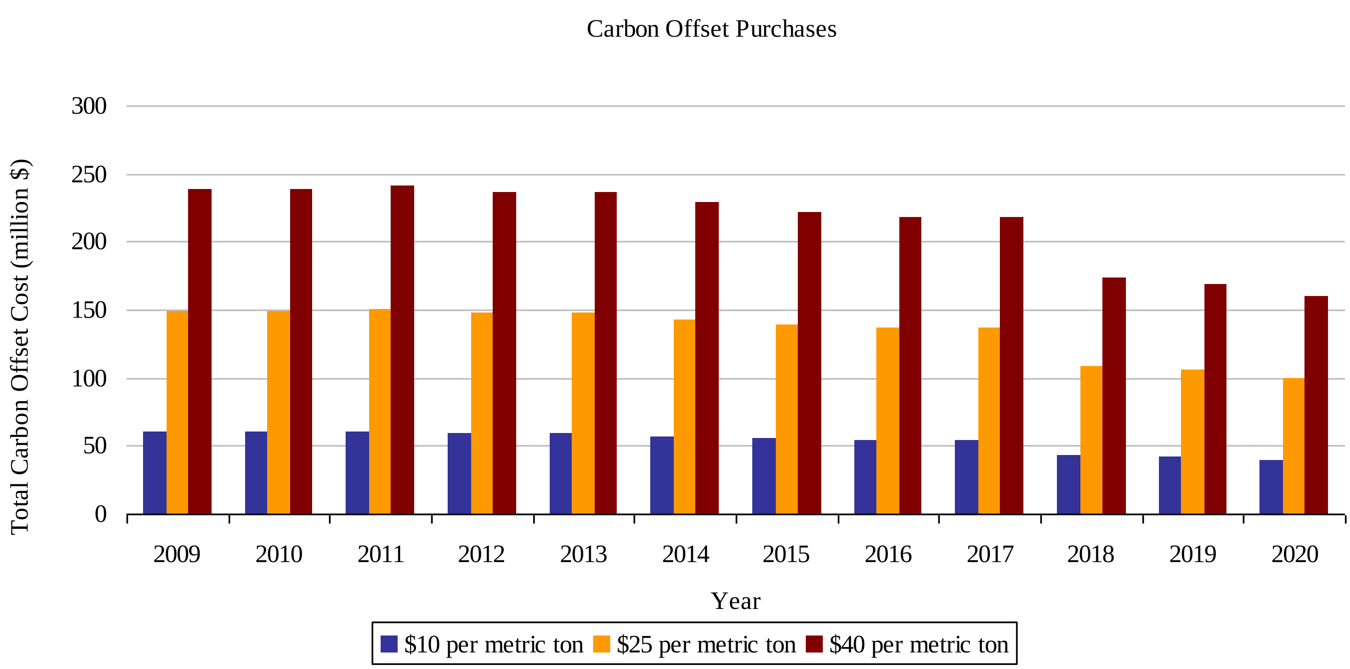


Figure 6.7
Expected Renewables Scenario Capital Costs

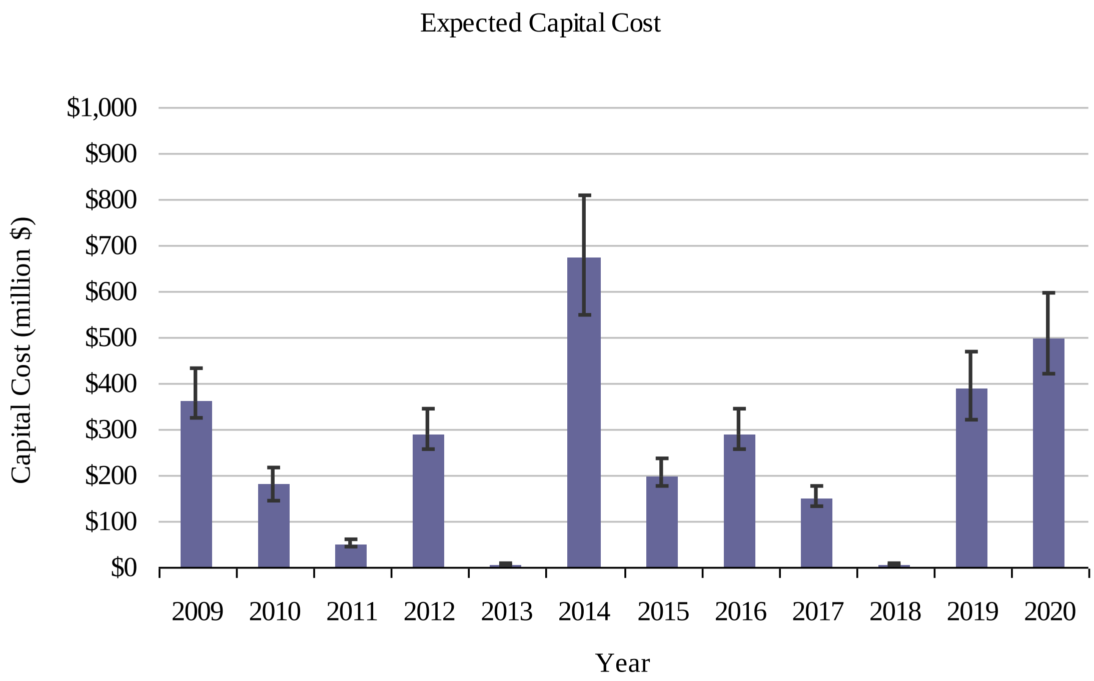


Figure 6.8
Expected Renewables Scenario Fuel Costs

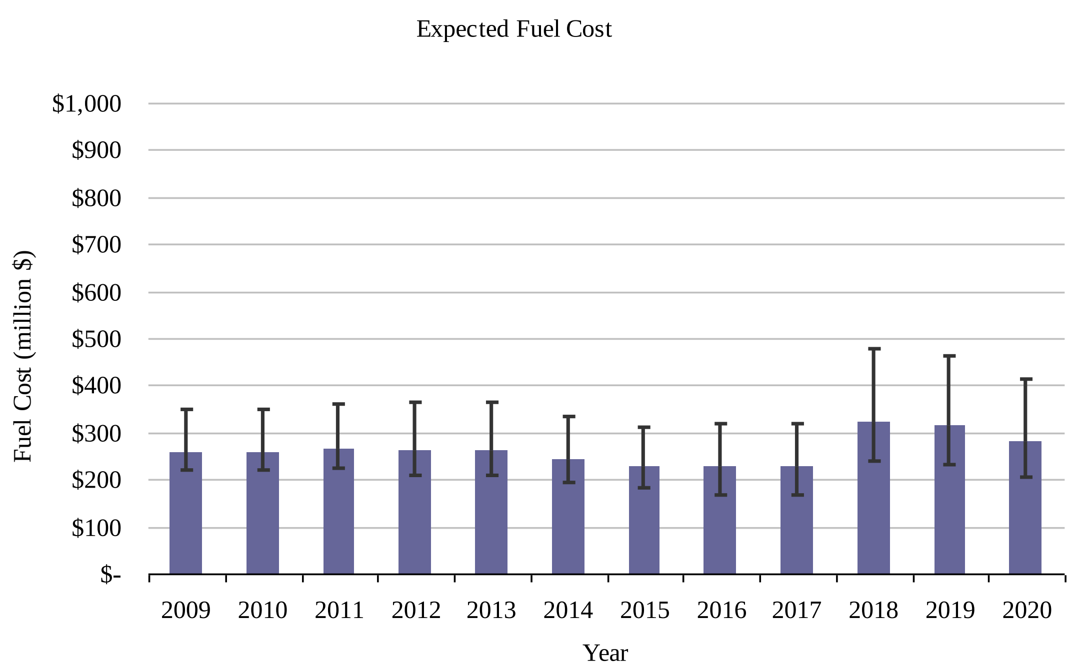


Figure 6.9
Expected Renewables Scenario Levelized Costs

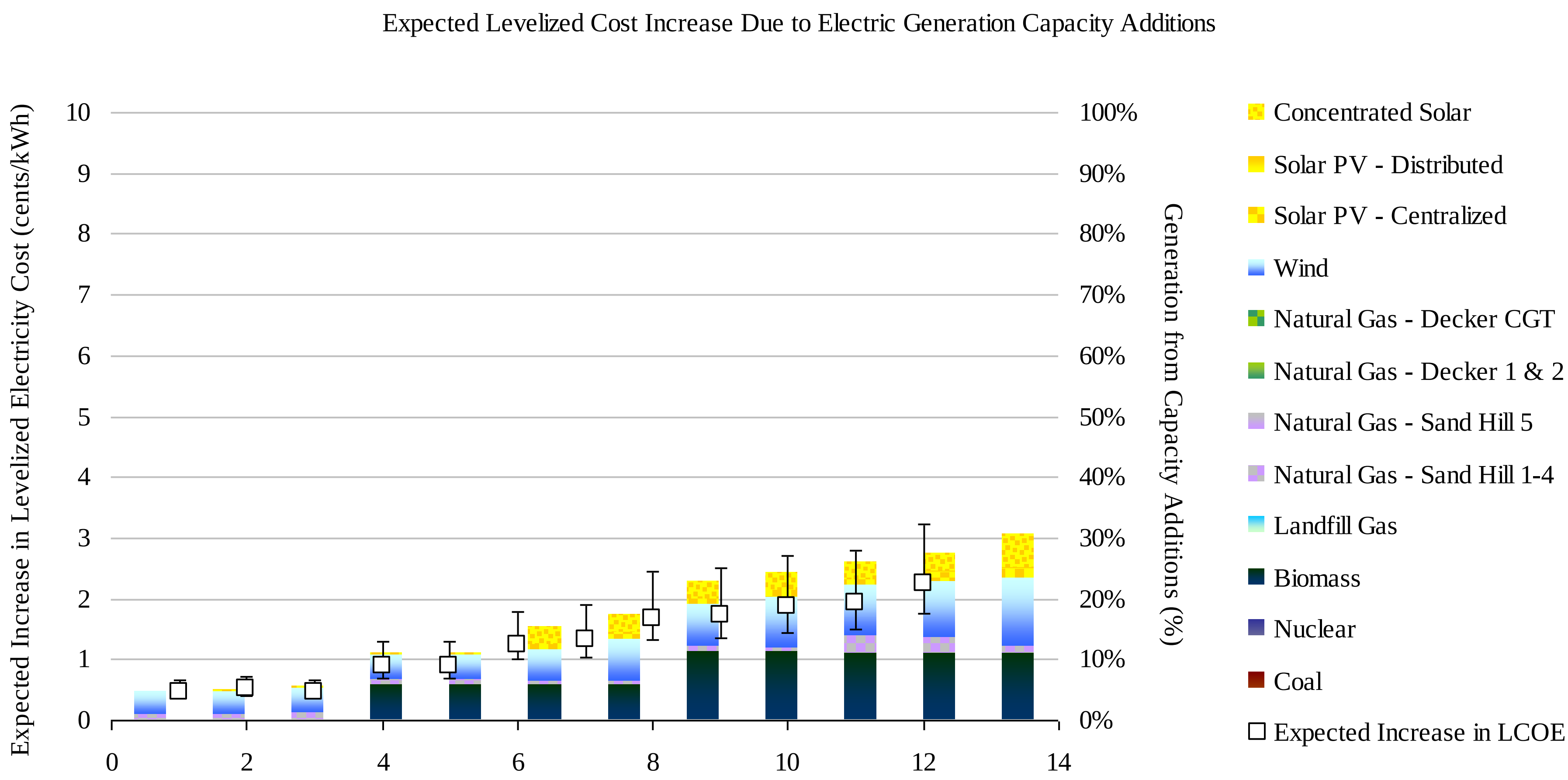


Figure 6.10
Expected Renewables Scenario Economic Activity

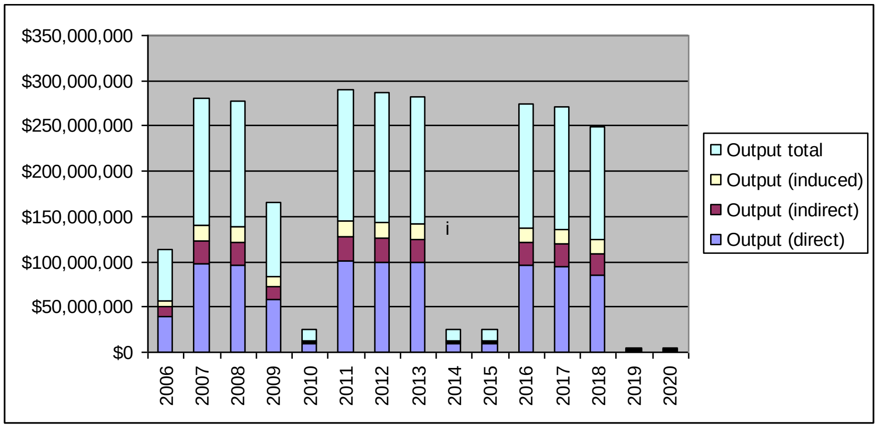


Figure 6.11
Expected Renewables Scenario Total Value Added

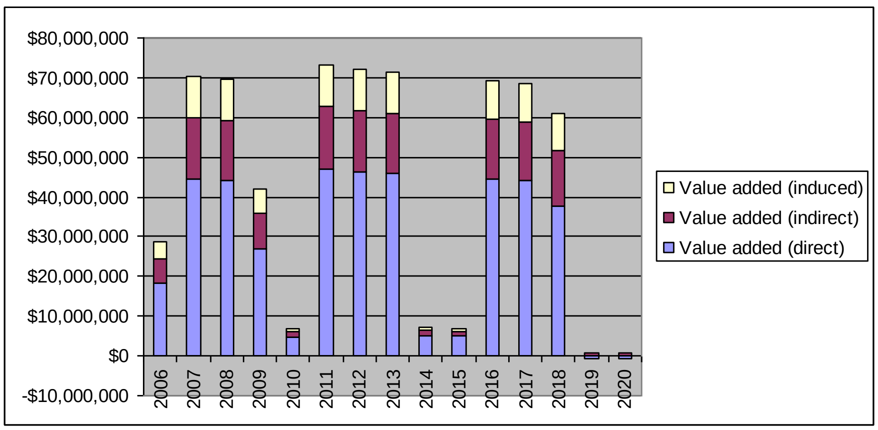
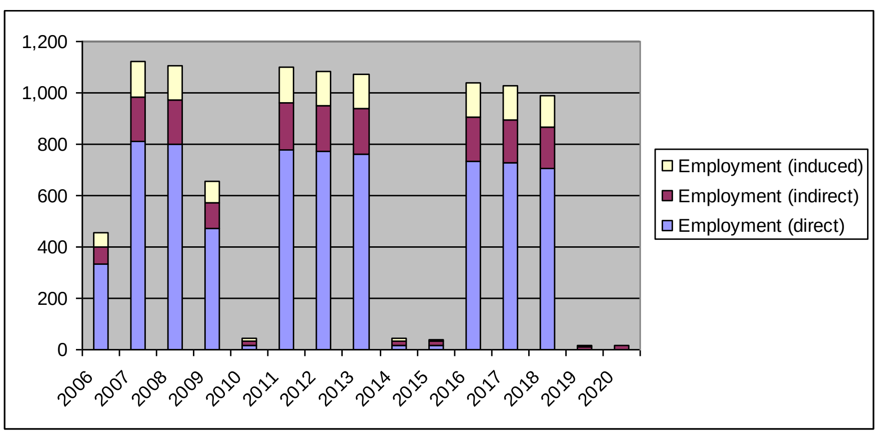


Figure 6.12
Expected Renewables Scenario Employment Impacts



Chapter 7. Expected Renewables with Energy Storage Scenario

This scenario incorporates possible energy storage capacity into the expected available renewable resources scenario. Table 7.1 details the proposed additions to AE's resource portfolio from 2009 to 2020. This scenario strives to address the two primary failings of the expected renewables scenario; a failure to meet the peak daily demand by 200 MW and the necessity to promulgate the use of a portion of AE's coal resources (302 MW). To address the peak shortage and to attempt to lower carbon emissions further, this scenario introduces 350 MW of Compressed Air Energy Storage (CAES) facility additions through 2020 (represented as Wind + CAES in the model). CAES was identified as the most likely storage technology because it has the lowest capital costs of any practical and proven utility-scale storage option. In principle, pumped storage on the Colorado River could be used as a form of energy source, but AE has yet to discuss such an option with the Lower Colorado River Authority. Upon selecting CAES, the decision was made to pair the compressed air storage technology with a power generation technology. Since Austin is in a hot climate, where electricity demand peaks during afternoons in the summer, when solar output is producing near its maximum and wind is producing near its minimum, CAES is paired with wind facilities to achieve maximum marginal gains. This system was designed to allow CAES to capture some excess nighttime electricity generated by its paired wind facilities. This allows the void during the peak afternoons and evenings to be filled by stored electricity from wind and CAES.

System Reliability

Figure 7.1 demonstrates that AE's power generation capacity would exceed forecasted peak load with and without conservation goals being met. Under this scenario AE would be able to eliminate all of its use of coal, rather than only half which was the limitation experienced by the expected renewables scenario without storage. Eliminating AE's stake in the Fayette Power Project (FPP) coal facility creates concerns regarding system reliability as this removes a major source of baseload power generation capacity (607 MW). In an effort to relieve some such concerns, biomass facilities would provide 200 MW of baseload power and natural gas would be used more often as base and intermediate providers. The expected renewables with storage scenario creates a resource portfolio that becomes highly dependent upon the unreliable variable nature of wind and solar energy, but the addition of 350 MW of energy storage capacity will help alleviate some of these concerns. Due to low capacity factors and the probabilistic possibility of failure, a system so dependent on wind and solar would require much greater power generation capacity than forecasted demand. Beginning in 2016 with the removal of half of FPP, the combination of baseload and natural gas sources cannot meet demand by themselves in the presence of a failure of wind or solar. This reliance on intermittent wind and solar sources introduces a real concern of potential system failures. It should be noted that CAES is not considered an actual power generation technology, as it simply uses some natural gas to transfer electricity from one time of day to another, with an inherent limitation on roundtrip efficiency of around 75 percent. That is to say that if a wind facility generates an excess of 1000 MWh of electricity over the course of a night to be stored in a CAES facility, the facility will transfer about 750 MWh of electricity to the grid the next afternoon, using some natural gas in the process.

This proposed system would hold 3,557 MW of power generation capacity and 350 MW of storage capacity compared to a system of 3,923 MW of generation capacity under the AE proposed energy resource plan. By 2020, 622 MW of power generation capacity would be provided from baseload power sources (coal, nuclear, and biomass) and 1,188 MW of power generation capacity would come from variable energy sources (wind and solar).

In order to demonstrate the pairing of energy storage with a particular resource a new technology is represented in the simulator: "Wind + CAES." This represents the actual electricity generated by a portion of wind facilities that is dedicated to "charging" or "re-fueling" the CAES facilities. This is considered an actual power generation technology, while "Storage" merely provides a daily buffer.

Figure 7.2 demonstrates that, given expected capacity factors for wind and solar (29 and 17 percent, respectively) as well as current capacity factors for AE's nuclear and natural gas facilities, AE will be able to deliver electricity to its customers as long as AE meets its conservation goals. If wind and solar do not meet expected production levels, the natural gas facilities would serve as backup sources of power. By 2020, combined cycle natural gas units at Sand Hill are providing close to baseload levels of electricity because of the lower CO_2 emissions associated with them, while the other natural gas combustion turbine units at Sand Hill and Decker act as peaking and reserve capacity.

Figure 7.3 details AE's expected hourly load profile for the hottest day (peak demand day) in the summer of 2020. The hourly load profile follows expected solar and wind profiles and demonstrates that AE will most likely be able to meet peak demand if AE meets its conservation goals and CAES fills the afternoon and evening gaps. The amount of wind electricity used to "charge" the CAES facilities is not shown on Figure 7.3 because it would not be actually delivered to the grid until later in the day, in the form of "Storage."

Carbon Emissions and Carbon Costs

AE's proposed resource plan will increase the amount of renewable power generation capacity to about 30 percent of its entire resource portfolio by 2020, while the expected renewables scenario with storage will increase the amount of renewable power generating capacity to about 39 percent of AE's entire resource fleet. Given expected capacity factors for wind and solar and adjusted capacity factors for natural gas to account for forecasted demand, about 30 percent of AE's actual power generation would come from clean energy sources in 2020 (compared to 26 percent in AE's proposed resource plan) with 20 percent of actual electricity delivered coming from wind and solar. By eliminating the CO_2 emissions caused by the burning of coal, CO_2 emissions would decrease by about 52 percent from 2008 levels in the expected renewables scenario (see

Figure 7.4). The expected renewables with storage scenario demonstrates an opportunity to reduce AE's carbon footprint substantially by 2020 with seemingly reasonable investments in additional low-carbon and energy storage facilities. Since this scenario produces lower CO_2 emissions, Figure 7.5 estimates that AE could earn up to $6 million annually by 2020 based upon carbon allowance price estimates from the Lieberman-Warner bill. This compares to potential costs of about $96 million in 2020 under AE's proposed energy resource plan.

Under the expected renewables with storage scenario, offsetting CO_2 emissions to zero becomes more manageable than in the proposed AE resource plan and the expected renewables scenario. Figure 7.6 provides a range of annual costs to offset emissions to zero, thus effectively achieving carbon-neutrality. By 2020, the annual costs for offsets would range from $30 to $119 million compared to $58 to $230 million under AE's proposed resource plan.

The expected renewables with storage scenario provides a modest increase in renewable and low-carbon generating facilities over those included in AE's proposed resource plan, and the addition of CAES for power generation-shifting purposes. This power generation mix reveals practical steps toward AE's pursuit of carbon neutrality by 2020 without a tremendous cost increase over the proposed resource plan.

Costs and Economic Impacts

Figure 7.7 details the capital cost estimates for AE's scheduled and proposed additions to its power generation mix. Expected capital costs range from $3.7 to $5.5 billion (compared to $2.2 to $3.0 billion under AE's proposed resource plan). Capital costs are expressed as total overnight costs, thus, it is important to recognize the year for which a project is proposed. In this model, costs are expressed as current estimates and ranges are determined based upon the relative maturity of the technology and expected direction by which costs are expected to flow.

Figure 7.8 details annual fuel costs for the expected renewables with storage scenario. Fuel costs are expected to increase because, even though the elimination of FPP will reduce coal consumption, that resource is replaced by natural gas and biomass that is typically more expensive. Additionally CAES requires the use of natural gas to operate. Fuel costs would, by 2020 under this scenario, range from $266 to $552 million annually (compared to $93 to $328 million under AE's proposed resource plan).

Figure 7.9 estimates the rise in costs on electric bills by calculating the impact of the levelized costs of new power generation resources as a percentage of overall power generation capacity. The expected renewables scenario with storage presents a substantially redefined power generation mix with about 40 percent of actual power generation coming from additions since 2009. This scenario would incur rises in costs to produce electricity similar to the expected renewables scenario without storage, but energy storage presents a largely unknown and unpredictable additional expense. Since energy storage is not the same as an energy production facility and only a few sites exist in the world, levelized cost estimates of cents per kilowatt-hour were not found in the literature. Instead, the "cost of generation" model used by the California Energy Commission was obtained and inputs were varied to get a rough estimate of how much CAES would likely add to the cost of producing electricity. Since CAES is paired with wind facilities in this scenario, we defined a new generation technology in the model – "Wind + CAES." We simply added the overnight costs and estimated fuel costs from CAES alone (the only values found in literature) to the inputs values for wind facilities alone. Fuel costs were estimated using a heat rate of CAES of 4000 BTU/kWh (about half that of natural gas facilities alone) and a hypothetical value of CAES producing 15 percent of the time that the wind facility is actually producing. The cost model produced levelized cost estimates of Wind + CAES at about 45 to 55 percent higher than wind alone. With this limited information, the cost estimates associated with this scenario should be taken as rougher estimates than the rest of the scenarios.

The simulation estimates that the cost to produce electricity would rise between 2.9 and 4.9 cents per kilowatt-hour under this scenario, compared to 1.8 and 3.2 cents per kilowatt-hour in the expected renewables scenario without storage and compared to between 1.5 and 3 cents per kilowatt-hour under AE's proposed energy resource plan. It should be noted that this expected increase in electric rates is based solely on new investments. Offset costs or any unexpected additional costs to the utility could also be passed on to the customer during this time period. Additionally, the calculation for expected increase in cost of electricity does not appoint a monetary value of reducing or removing coal or any other resource from AE's resource portfolio as the methods for evaluating how much AE could receive are beyond the scope of this report. Such removal may help to alleviate the additional costs to electricity accrued from the identified resource additions.

Figure 7.10 shows that there would be a major spike in economic activity during the years 2011 to 2013 of over $250 million each year created by the addition of 200 MW of natural gas power generation capacity at Sand Hill in 2013 and 50 MW of centralized solar capacity in 2014. Figure 7.11 shows the total value added to the Greater Austin Area from the investments made in the expected renewables scenario. Figure 7.12 shows the impacts on employment created or eliminated by the expected renewables scenario. The consequence of employment losses created from AE's divestment in coal in the Greater Austin Area under this scenario is an enduring relative loss of output and no net gain of jobs.

IMPLAN only models the effects of construction and installation of new power generation facilities, estimated activity from the installation of distributed PV units, and operations and maintenance activities associated with power generation facilities. This scenario does not take into account the possibility of attracting renewable energy manufacturing to the Austin area.

Table 7.1
Expected Renewables with Storage Scenario Scheduled Additions and Subtractions to Generation Mix

Schedule of power generation additions and subtractions (net MW)													
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	607	0	0	0	0	0	0	0	-305	0	0	0	-302
Nuclear	422	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 1-4	189	100	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 5	312	0	0	0	0	200	0	0	0	0	0	0	0
Natural Gas - Decker 1 & 2	741	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker CGT	193	0	0	0	0	0	0	0	0	0	0	0	0
Wind	274	165	0	23	0	0	0	0	0	24	0	0	10
Wind + CAES	0	0	0	0	0	0	50	100	0	50	0	50	100
Biomass	0	0	0	0	100	0	0	0	100	0	0	0	0
FPP w/ biomass co-firing	0	0	0	0	0	0	0	0	0	0	0	0	0
Landfill Gas	12	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV - Centralized	0	0	30	0	0	0	50	0	0	0	0	50	0
Solar PV - Distributed	1	0	1	1	1	1	1	1	1	1	1	1	1
Concentrated Solar	0	0	0	0	0	0	100	0	0	0	0	0	100
IGCC w/ CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
IGCC w/o CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	50	100	0	50	0	50	100
Accelerated Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 7.1
Expected Renewables with Storage Scenario Power Generation Capacity

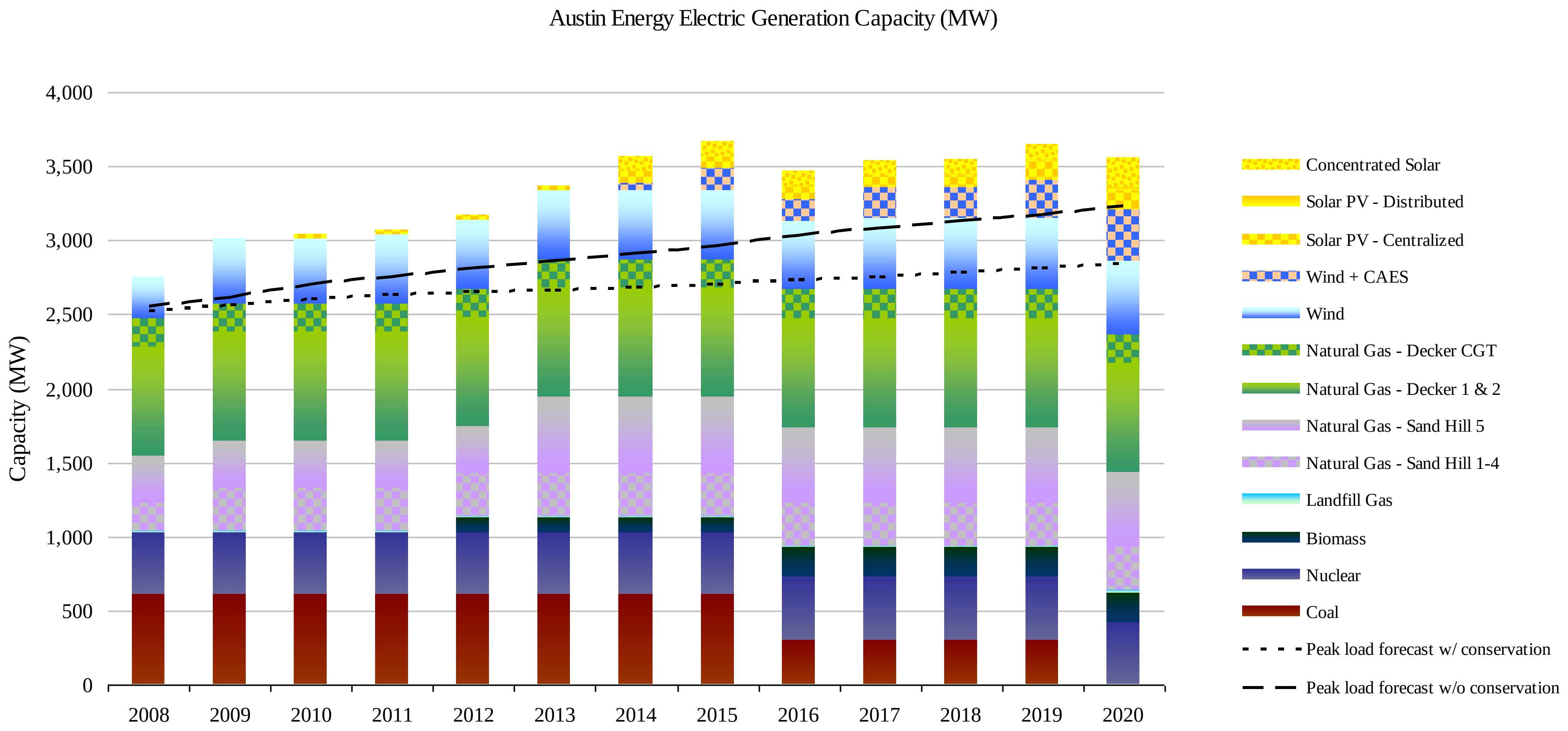


Figure 7.2
Expected Renewables with Storage Scenario Electric Delivery

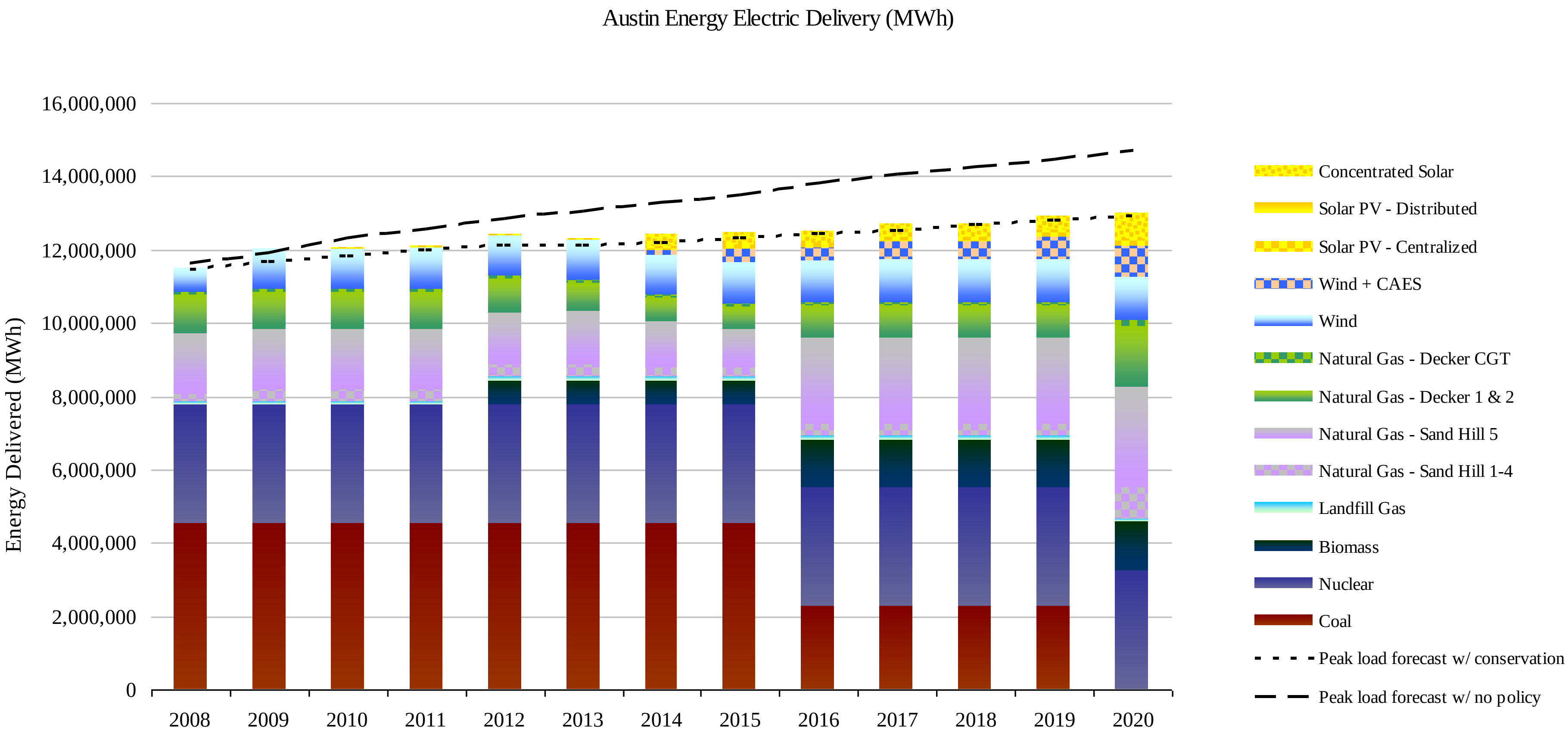


Figure 7.3
Expected Renewables with Storage Scenario Hourly Load Profile (Peak Demand, Summer 2000)

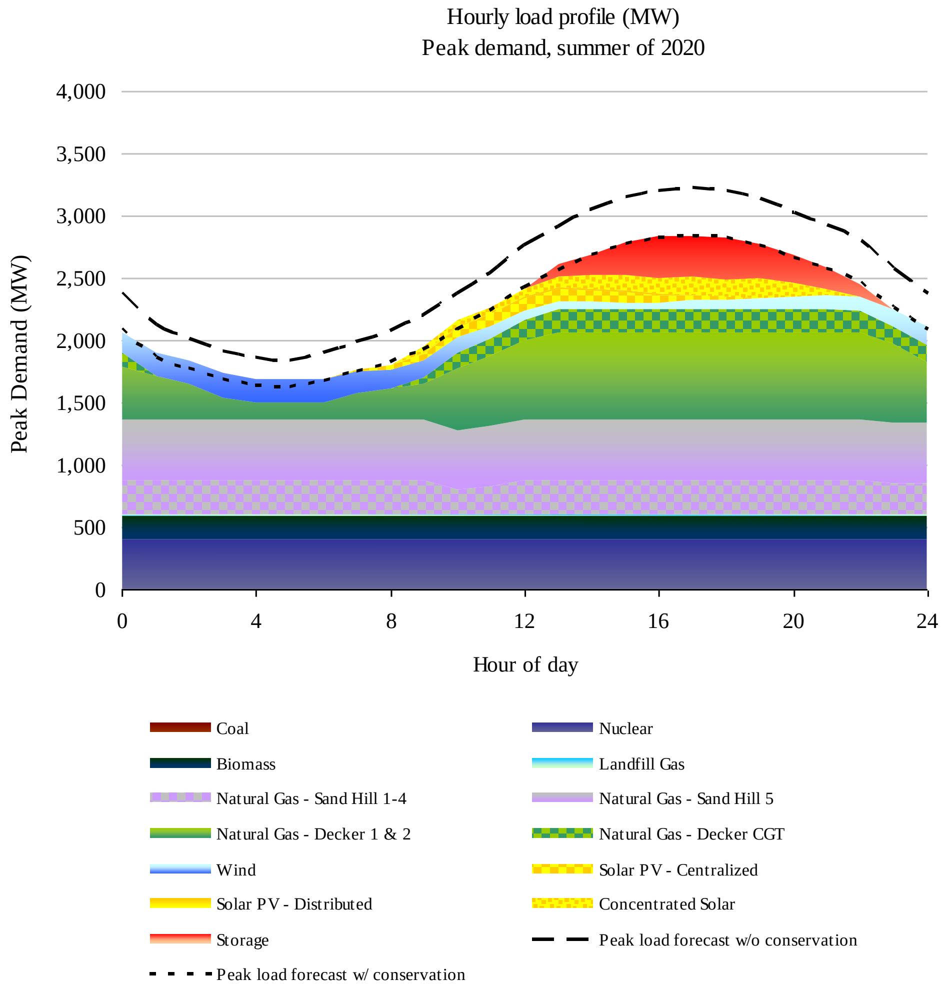


Figure 7.4
Expected Renewables with Storage Scenario Direct Carbon Dioxide Emissions

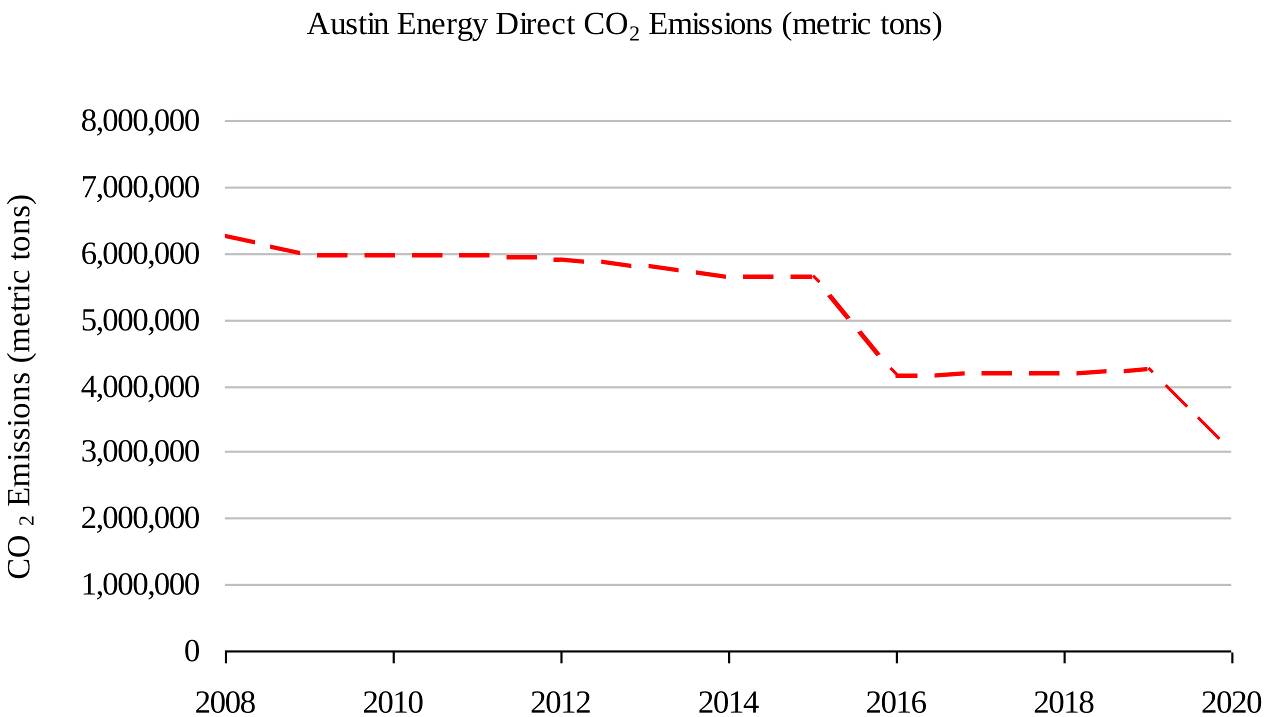


Figure 7.5
Expected Renewables with Storage Scenario Carbon Allowance Costs

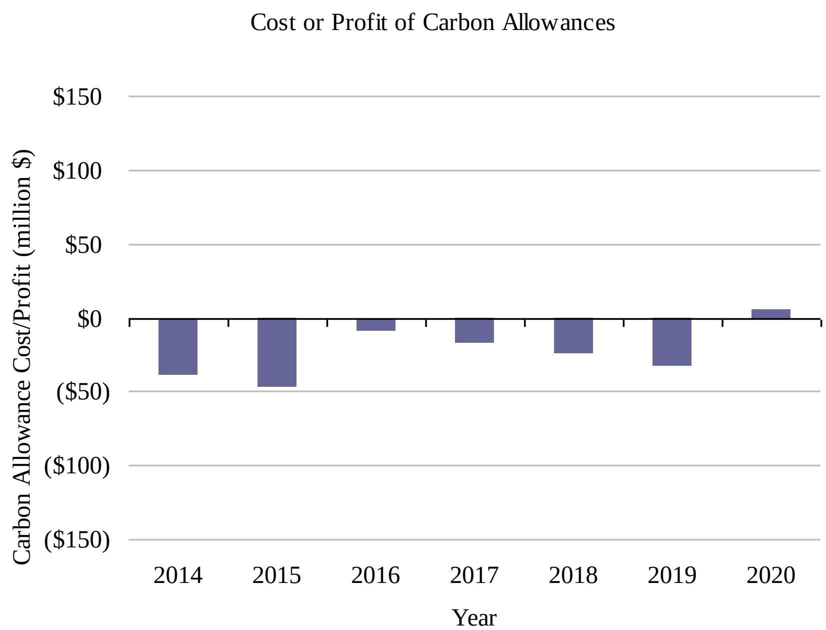


Figure 7.6
Expected Renewables with Storage Scenario Carbon Offset Costs

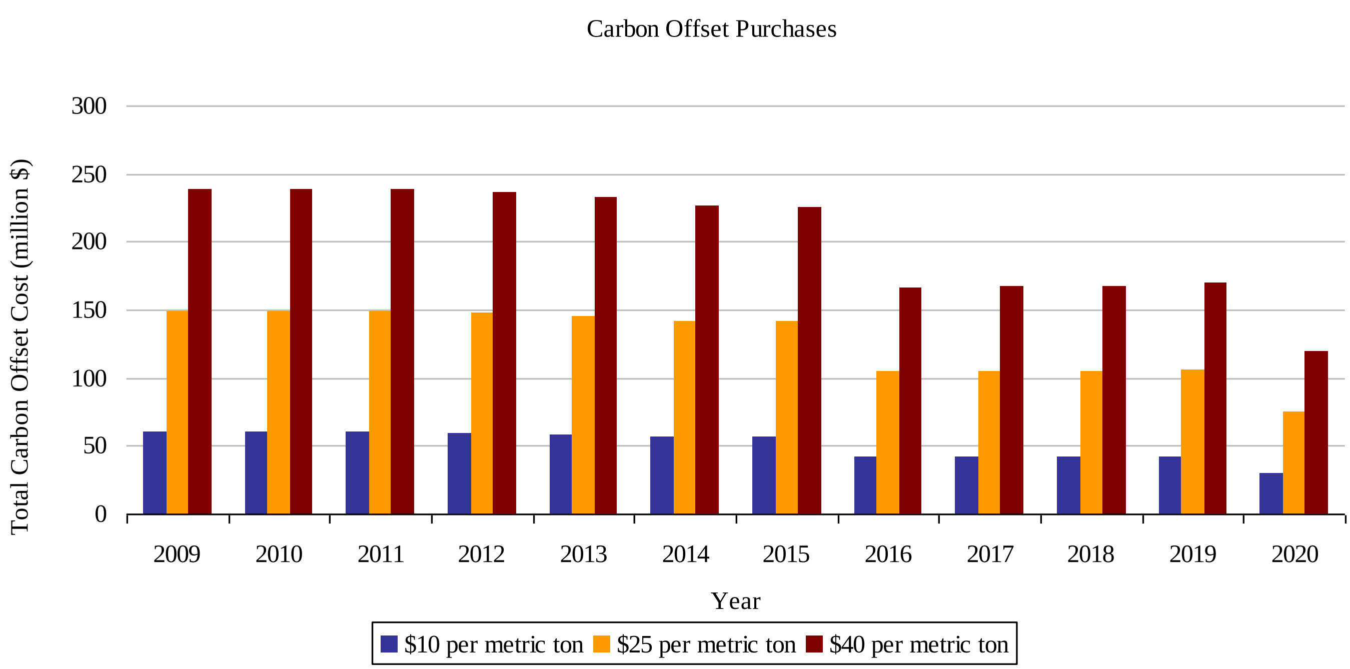


Figure 7.7
Expected Renewables with Storage Scenario Capital Costs

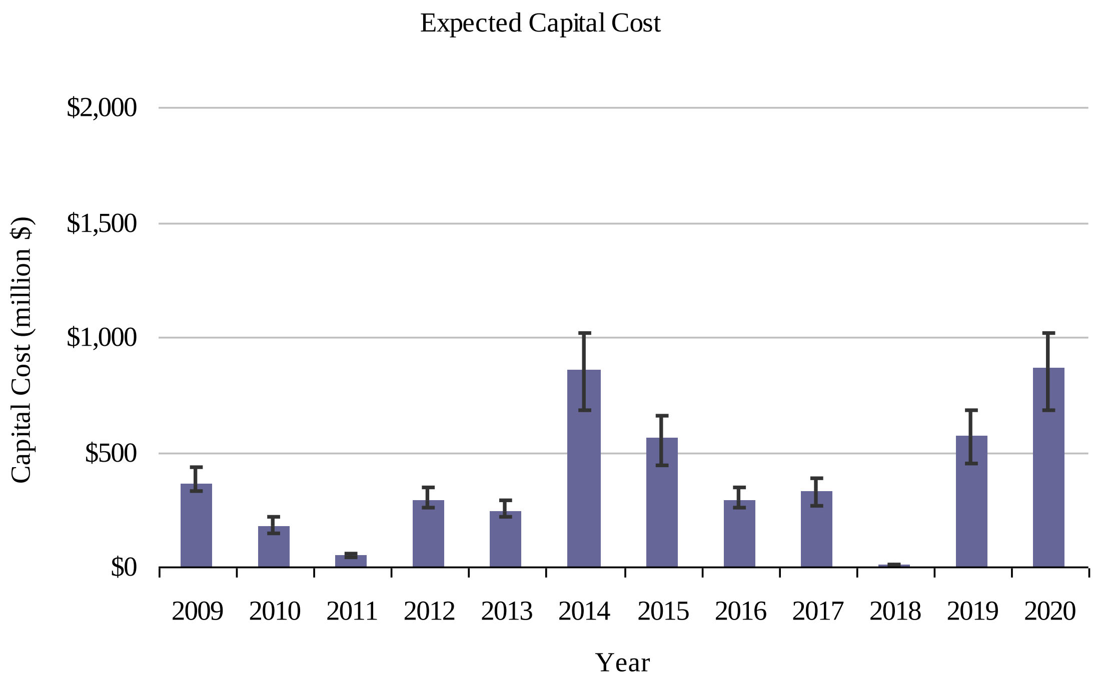


Figure 7.8
Expected Renewables with Storage Scenario Fuel Costs

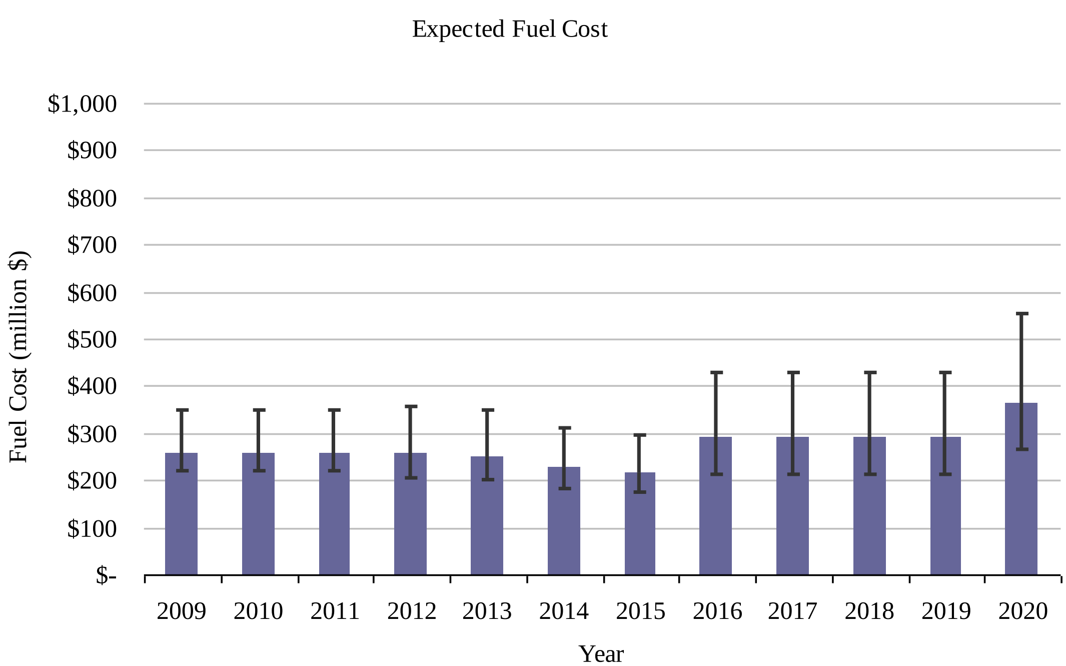


Figure 7.9
Expected Renewables with Storage Scenario Levelized Costs

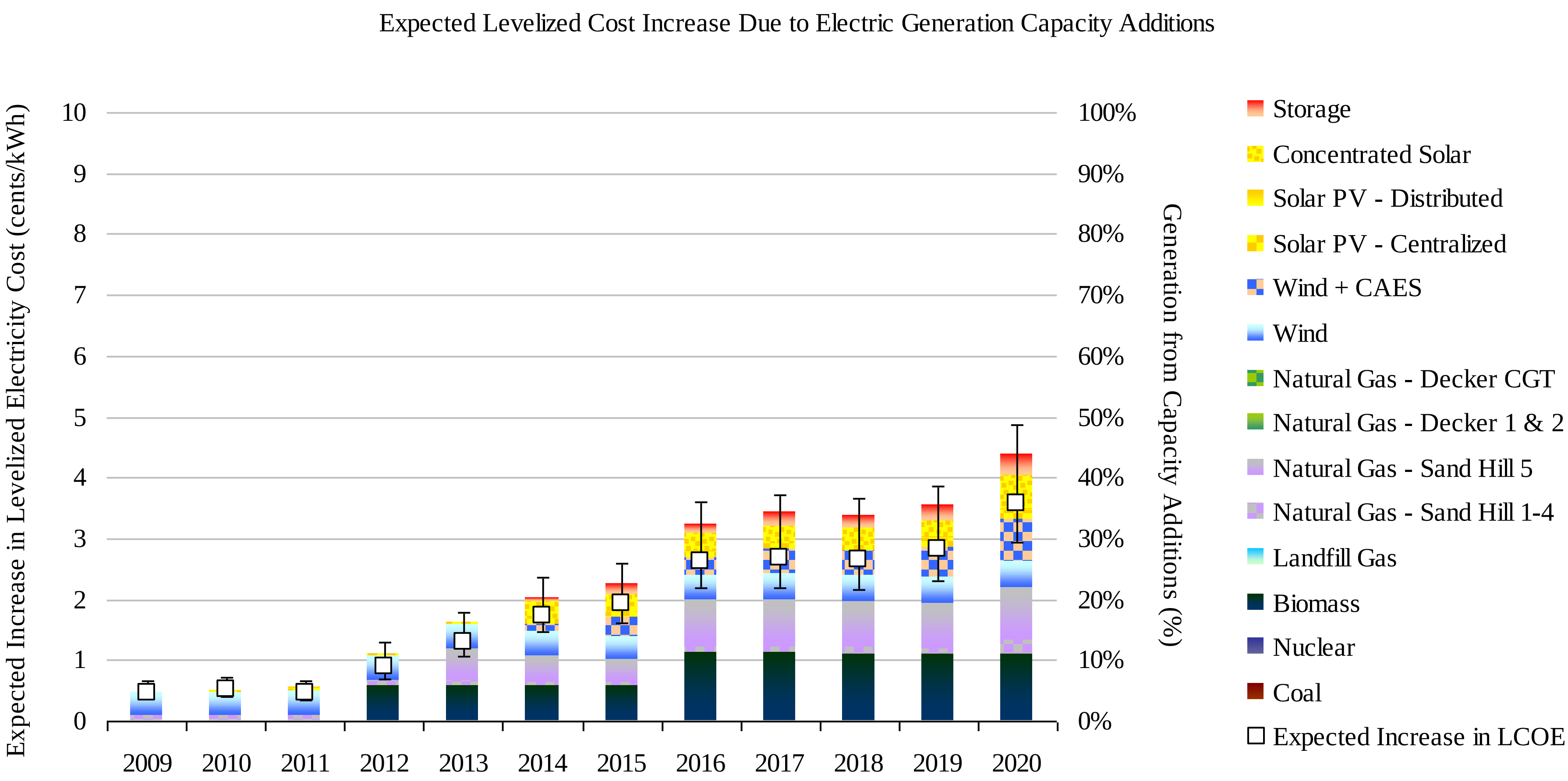


Figure 7.10
Expected Renewables with Storage Scenario Economic Activity

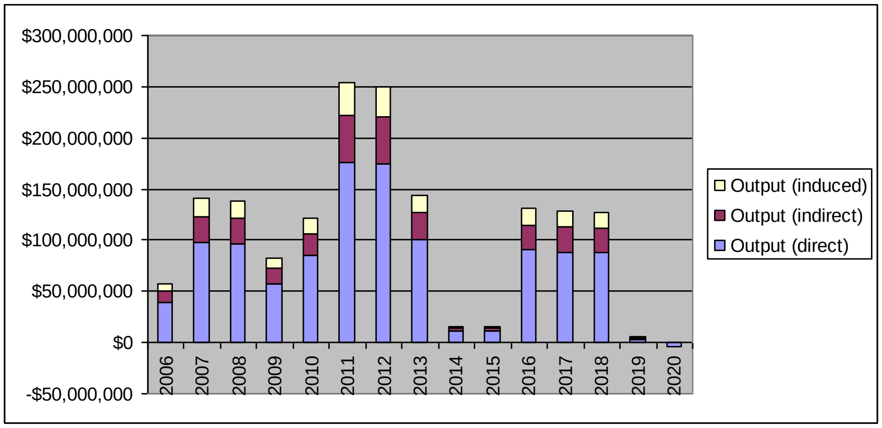


Figure 7.11
Expected Renewables with Storage Scenario Total Value Added

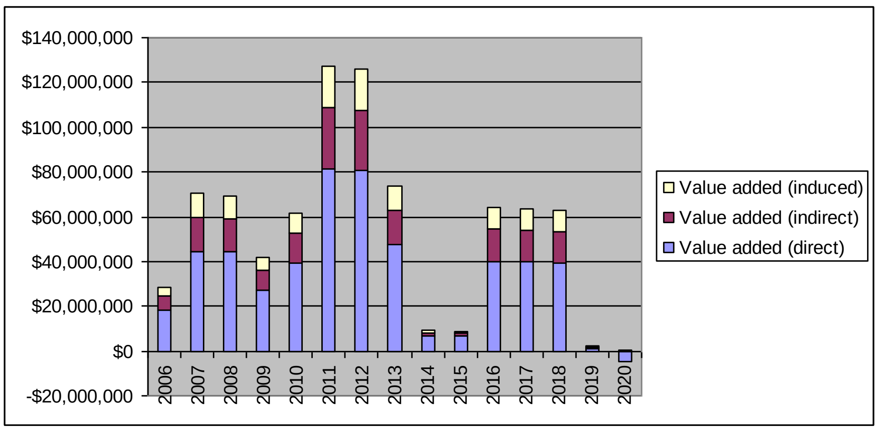
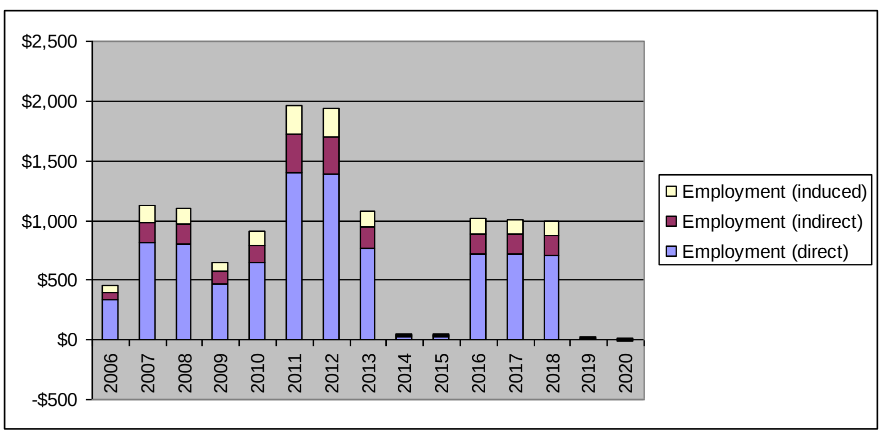


Figure 7.12
Expected Renewables with Storage Scenario Employment Impacts



Chapter 8. Natural Gas Expansion Scenario

The natural gas expansion scenario aligns with Austin Energy's (AE) proposed energy resource plan while replacing all of AE's coal resources with natural gas by 2016. The natural gas expansion scenario represents a strategy of replacing the burning of coal in AE's resource portfolio with the burning of natural gas through an expansion of its currently existing natural gas facilities. This scenario does not entirely account for possible limitations in expanding AE's natural gas facilities, but does consider some information on the capability of expansion at these facilities. Table 8.1 details the schedule of additions and subtractions to AE's resource portfolio by fuel source, power generation technology, or facility, for the proposed natural gas expansion scenario. While natural gas is a carbon emitter, it is not nearly as carbon-intensive as coal.

System Reliability

The loss of coal baseload power under this scenario raises significant concerns regarding the reliability of AE's system. Under this scenario the loss of 607 MW of coal baseload power generation capacity is compensated for by the addition of natural gas and biomass. Currently, AE uses natural gas power generation as an intermediate power source. Under this scenario a portion of natural gas capacity would have to be utilized as a baseload power source. This creates risks regarding the price volatility of natural gas as a fuel source. This scenario is also more dependent on wind and solar resources than the AE resource plan since less natural gas will be available to serve as a backup power source under this scenario. Wind and solar resources are much less reliable than conventional fuel-based power generation technologies due to the variable nature of wind and solar energy.

Figure 8.1 demonstrates that the AE's power generation capacity is adequate under this scenario to meet the needs of AE customers. Figure 8.2 also demonstrates that under this scenario AE will be able to deliver electricity to meet the needs of its customers. However, the use of AE's natural gas facilities will be much higher under this scenario than AE's proposed energy resource plan. To demonstrate the risks of a system highly dependent on natural gas, Figure 8.3 details AE's expected hourly load profile for the hottest day (peak demand) in the summer of 2020. The hourly load profile follows expected solar and wind profiles and demonstrates that AE will be able to meet peak demand without purchasing power even on the hottest day of the summer, if expected wind and solar production is met and AE meets its conservation goals. AE will have to use its natural gas facilities at full capacity in order to meet peak demand.

Carbon Emissions and Carbon Costs

The natural gas expansion scenario represents a reduction in carbon emissions by more than half (see Figure 8.4). AE's CO_2 emissions in 2007 were roughly 6.1 million metric tons. Under the natural gas expansion scenario CO_2 emissions would drop to approximately 3 million metric tons by 2020. The natural gas expansion scenario demonstrates an opportunity to significantly eliminate AE's carbon footprint by reducing CO_2 emissions to a level that makes offsetting emissions to zero more manageable than under AE's propose energy resource plan.

Significantly reducing CO_2 emissions could present an opportunity to profit if carbon regulation were to be passed that supported a portion of allowances being given for free. For example, under the Lieberman-Warner Climate Security Act of 2007, a portion of an entity's emissions would be accounted for by free permits, or allowances, while a portion of allowances would be auctioned. Figure 8.5 indicates that AE would accrue modest profits from carbon trading after the initial phase-out of coal. Figure 8.6 demonstrates that this scenario would also reduce the quantity of carbon offsets required for purchase by AE in order to reach a net zero carbon emissions.

Costs and Economic Impacts

The most significant capital costs, detailed in Figure 8.7, are incurred with the expansion of natural gas capacity sufficient to cover the energy needs necessary for reducing coal use in 2014 and eliminating coal use from AE's resource portfolio in 2016. Capital cost estimates used by the simulator are for the construction of new natural gas facilities. It is likely that capital costs would be lower if AE is expanding additional units at facilities it already operates and on land it already owns. Figure 8.8 shows a steady increase in fuel costs under this scenario through 2016, the year that the second phase of natural gas development is completed. It is important to note that natural gas is a volatile commodity and its costs cannot be predicted with any degree of accuracy, as is displayed by the extended tail on the bar graph in Figure 8.8 in 2014, the year that increased reliance on natural gas begins.

Figure 8.9 demonstrates two major jumps in the levelized cost of electricity that can both be attributed to the addition of natural gas capacity in 2014 and 2016. Assumptions about the particularly unpredictable price of natural gas aside, this scenario represents an expected increase in the price of power by about 4 cents per kilowatt-hour. The simulator model does not account for increased use in natural gas capacity in calculating the increased cost of electricity. Therefore, this estimate would likely be much higher under a natural gas expansion scenario due to the increased fuel costs attached to greater reliance on natural gas as a baseload or more commonly used intermediate power source.

Major investments in natural gas and solar technologies under the natural gas expansion scenario would result in significant economic impacts in the Greater Austin Area. Figure 8.10 shows the economic output in the Greater Austin Area generated by the natural gas expansion scenario and Figure 8.11 shows the total value added to the Greater Austin Area from the investments made in the natural gas expansion scenario. Economic output would peak between 2011 and 2013 at above $350 million in due to the buildup of additional natural gas capacity in 2013 and 2014. Figure 8.12 shows the impacts on employment created or eliminated by the natural gas expansion scenario.

This process only models the effects of construction and installation of new energy generation facilities, estimated activity from the installation of distributed photovoltaic units, and operations and maintenance activities for utility scale generation facilities. What this scenario does not take into account is the possibility of attracting renewable energy manufacturing to the Austin area.

Table 8.1
Natural Gas Expansion Scenario Scheduled Additions and Subtractions to Generation Mix

Schedule of power generation additions and subtractions (net MW)													
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	607	0	0	0	0	0	-305	0	-302	0	0	0	0
Nuclear	422	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 1-4	189	100	0	0	0	0	0	0	302	0	0	0	0
Natural Gas - Sand Hill 5	312	0	0	0	0	200	305	0	0	0	0	0	0
Natural Gas - Decker 1 & 2	741	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker CGT	193	0	0	0	0	0	0	0	0	0	0	0	0
Wind	274	165	0	23	0	0	50	100	0	74	0	50	110
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	100	0	0	0	100	0	0	0	0
FPP w/ biomass co-firing	0	0	0	0	0	0	0	0	0	0	0	0	0
Landfill Gas	12	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV - Centralized	0	0	30	0	0	0	0	0	0	0	0	0	0
Solar PV - Distributed	1	0	0	0	0	0	20	0	0	20	0	0	0
Concentrated Solar	0	0	0	0	0	0	0	0	0	0	0	30	0
IGCC w/ CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
IGCC w/o CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0
Accelerated Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 8.1
Natural Gas Expansion Scenario Generation Capacity

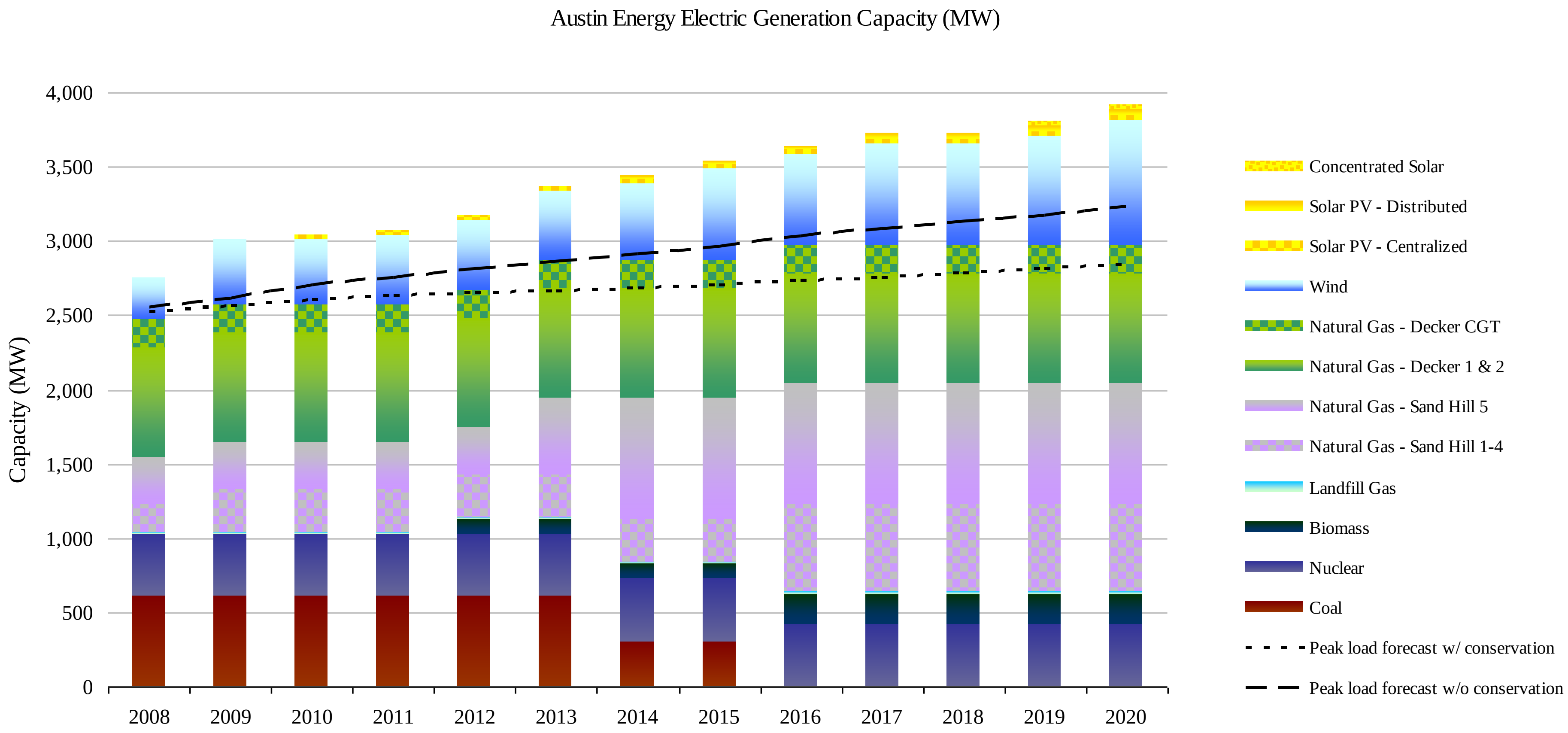


Figure 8.2
Natural Gas Expansion Scenario Electric Delivery

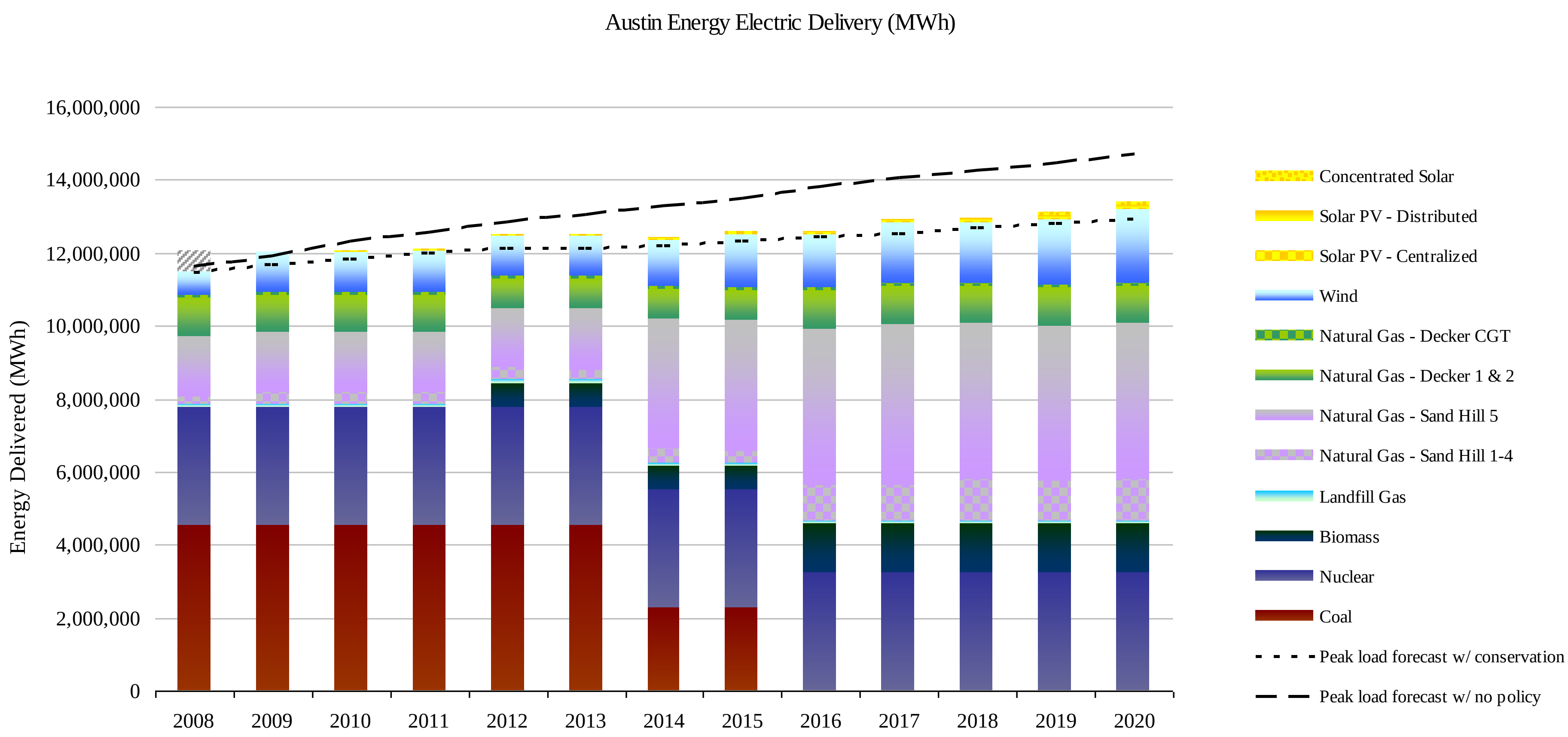


Figure 8.3
Natural Gas Expansion Scenario Hourly Load Profile (Peak Demand, Summer 2000)

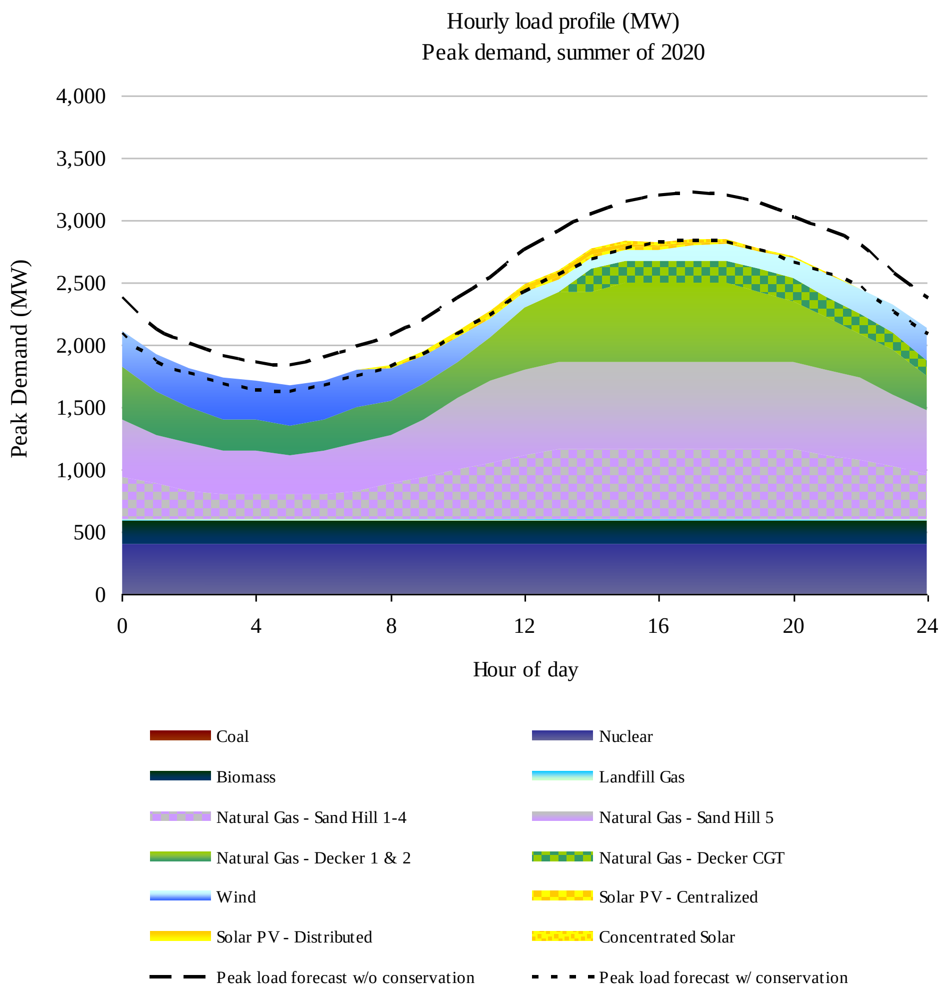


Figure 8.4
Natural Gas Expansion Scenario Direct Carbon Dioxide Emissions

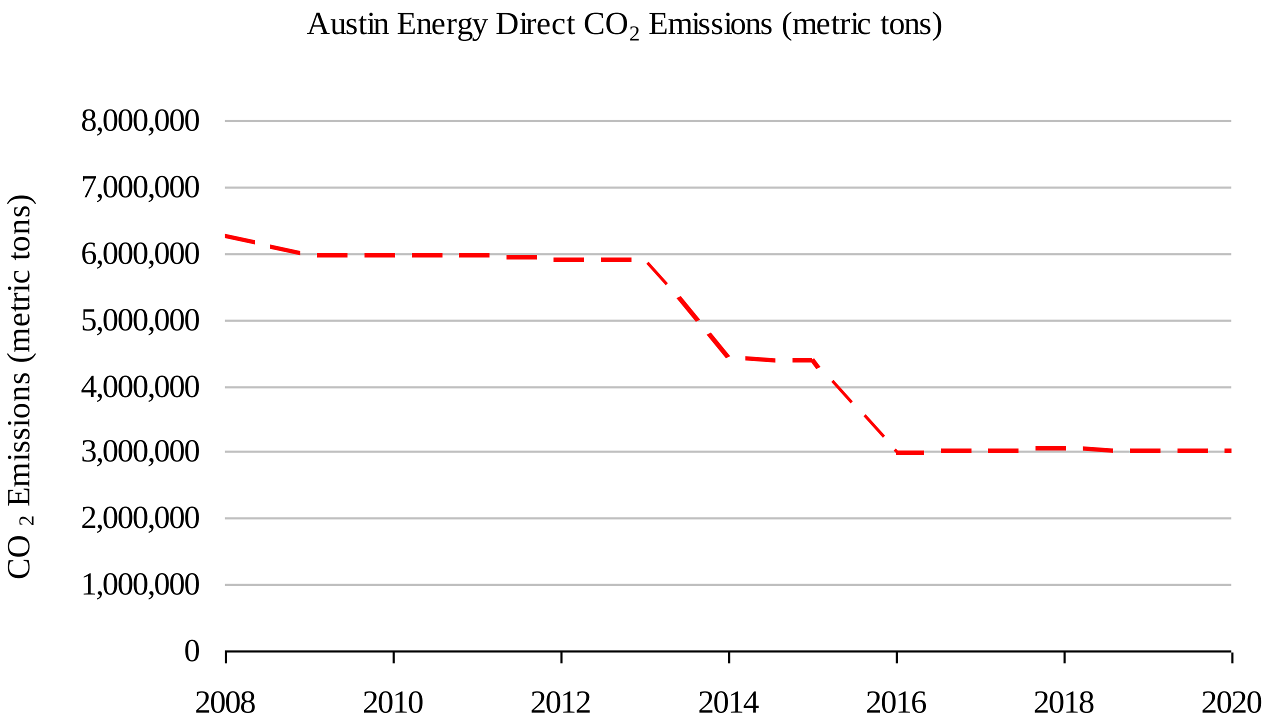


Figure 8.5
Natural Gas Expansion Scenario Carbon Allowance Costs

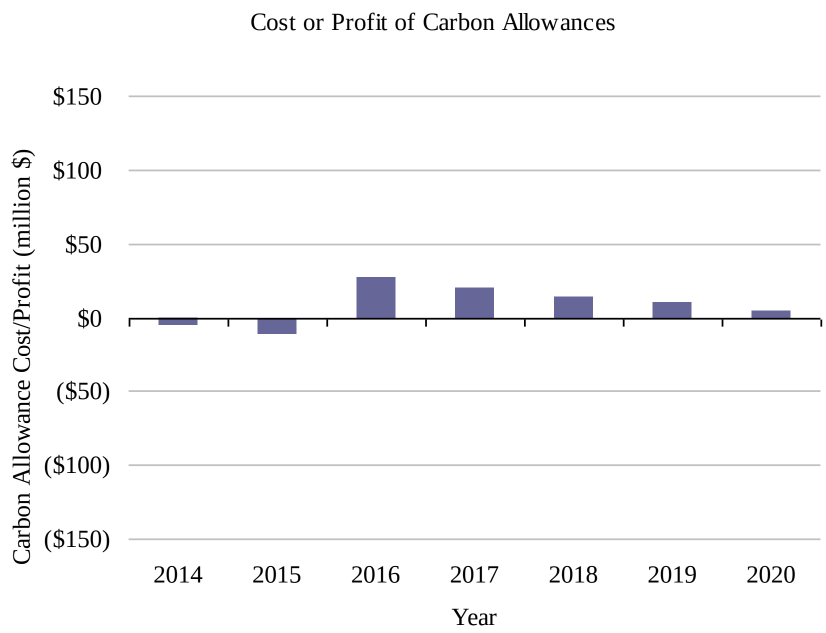


Figure 8.6
Natural Gas Expansion Scenario Carbon Offset Costs

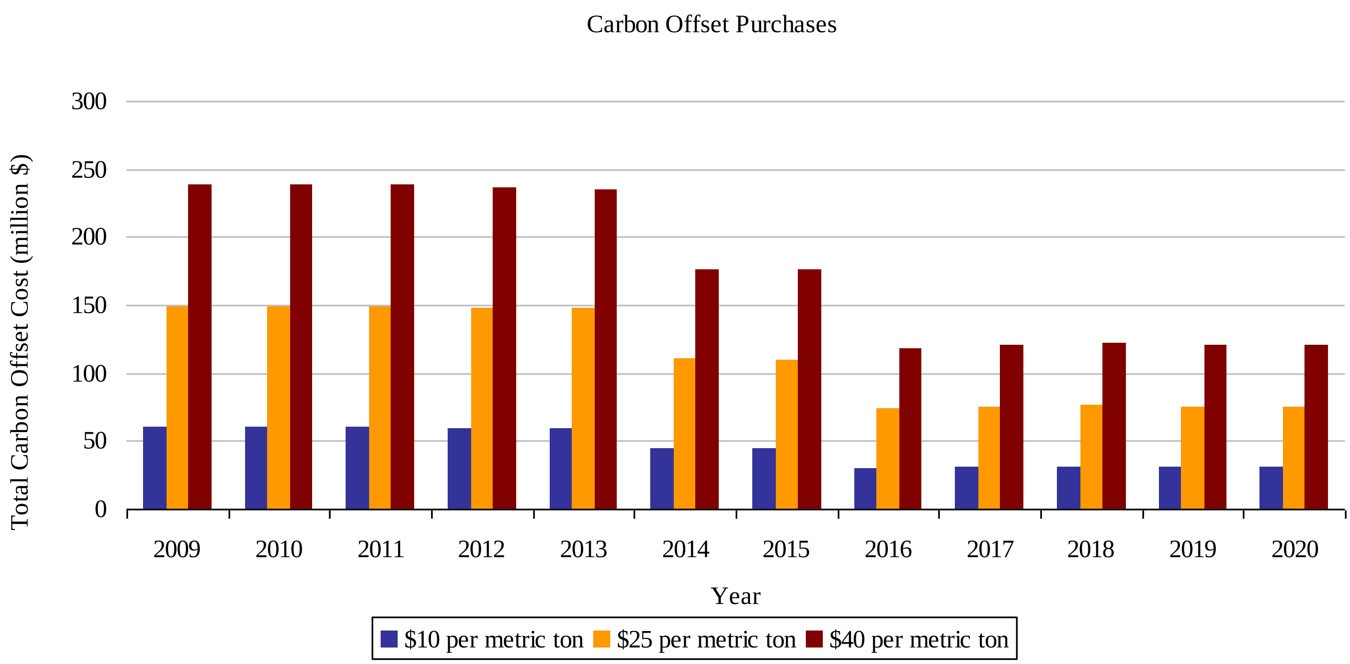


Figure 8.7
Natural Gas Expansion Scenario Capital Costs

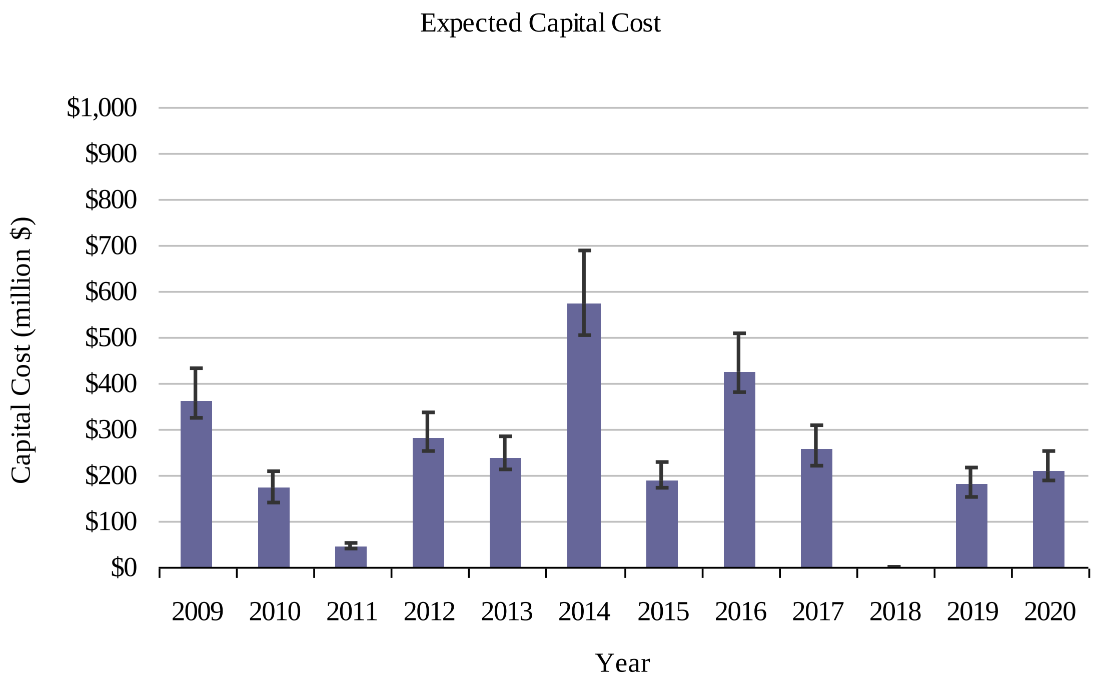


Figure 8.8
Natural Gas Expansion Scenario Fuel Costs

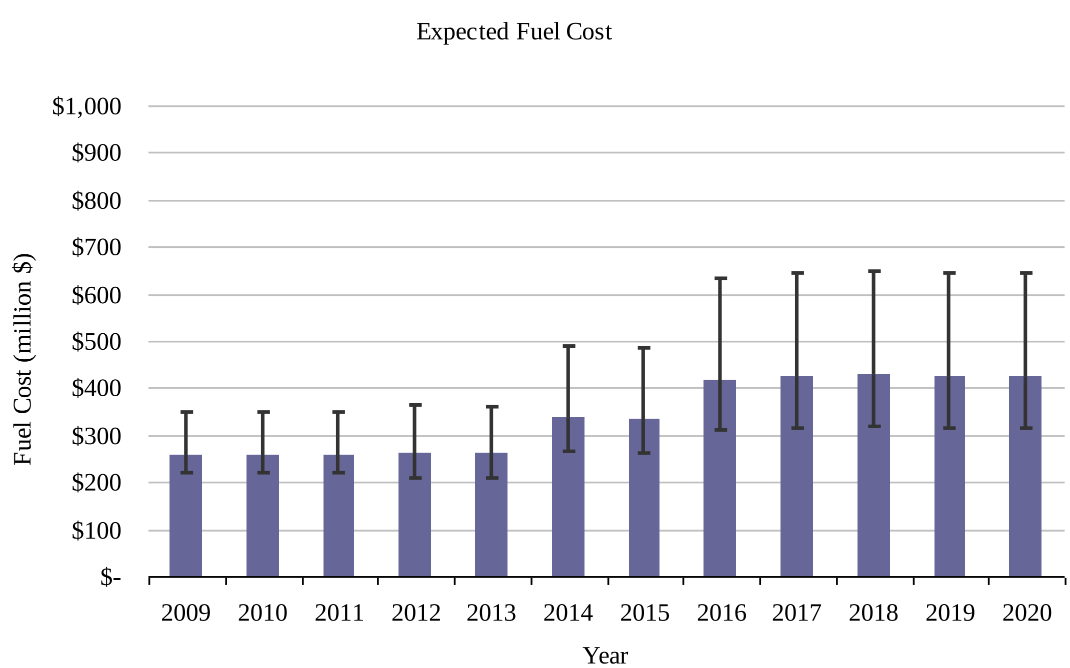


Figure 8.9
Natural Gas Expansion Scenario Levelized Costs

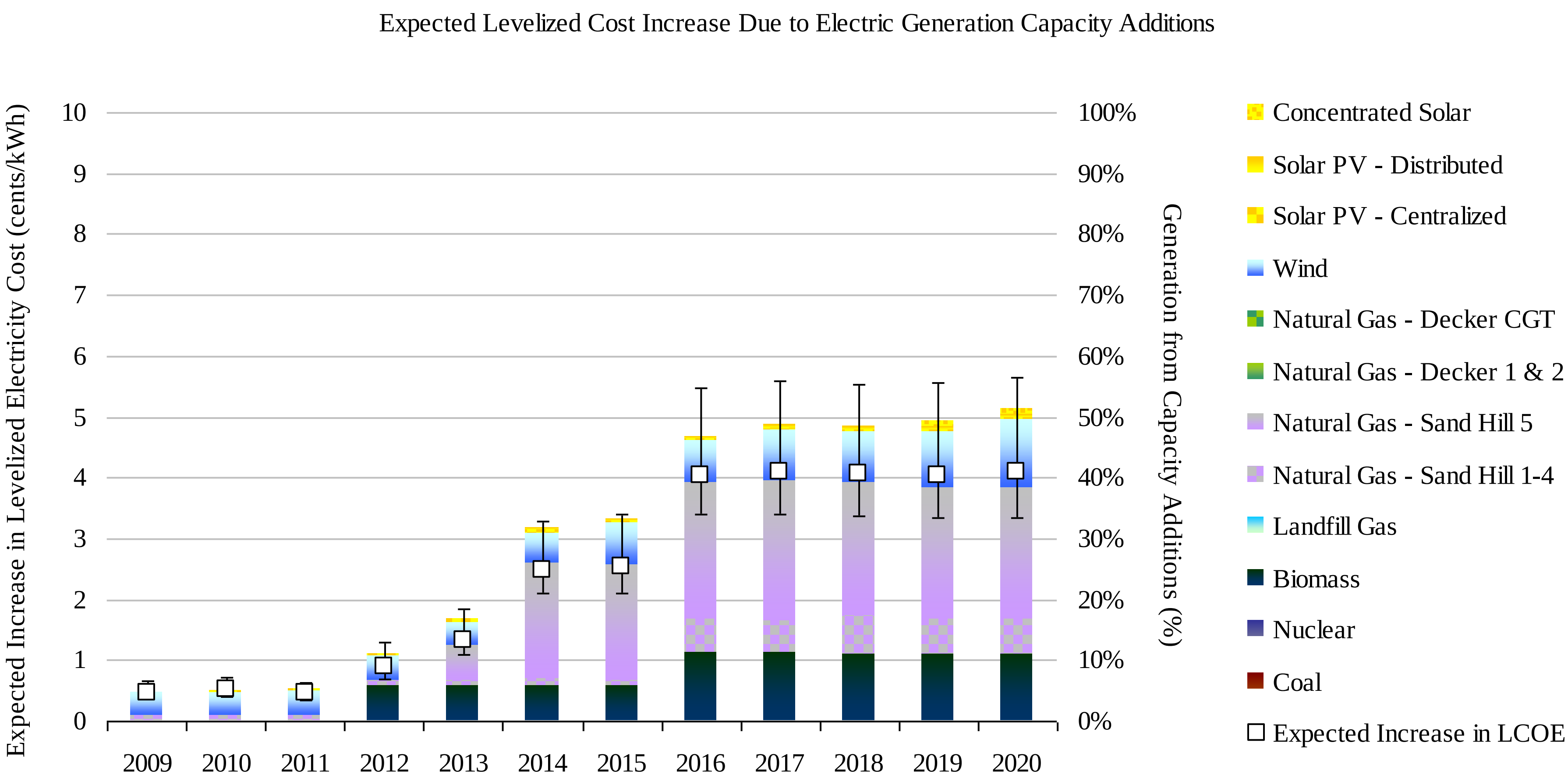


Figure 8.10
Natural Gas Expansion Scenario Economic Activity

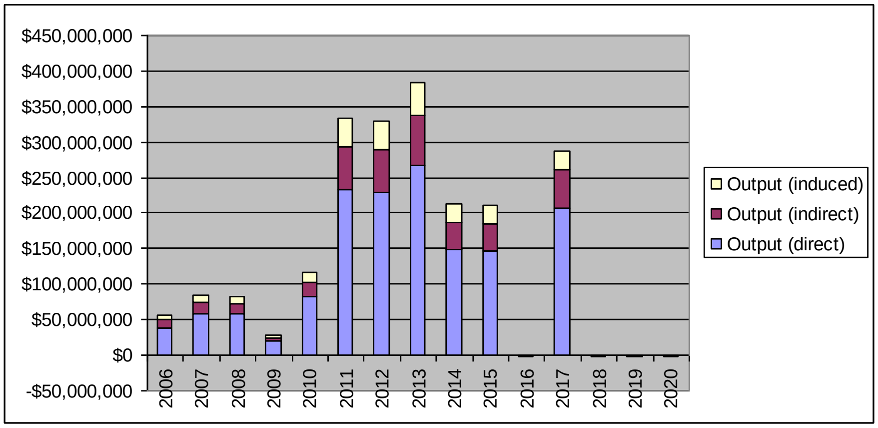


Figure 8.11
Natural Gas Expansion Scenario Total Value Added

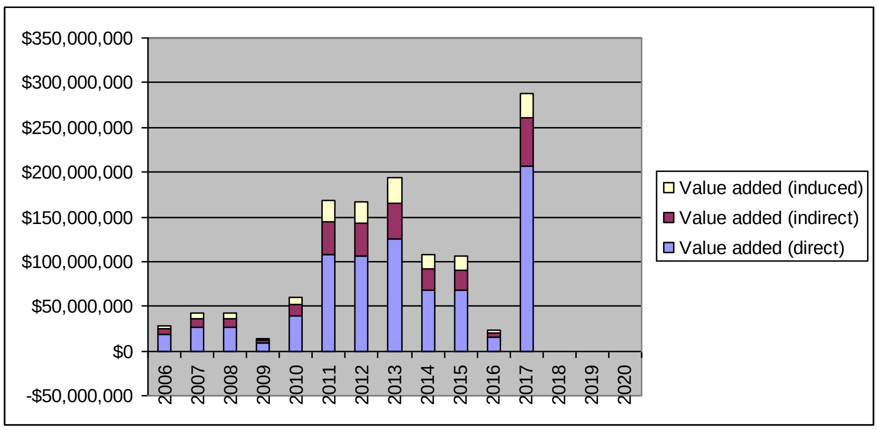
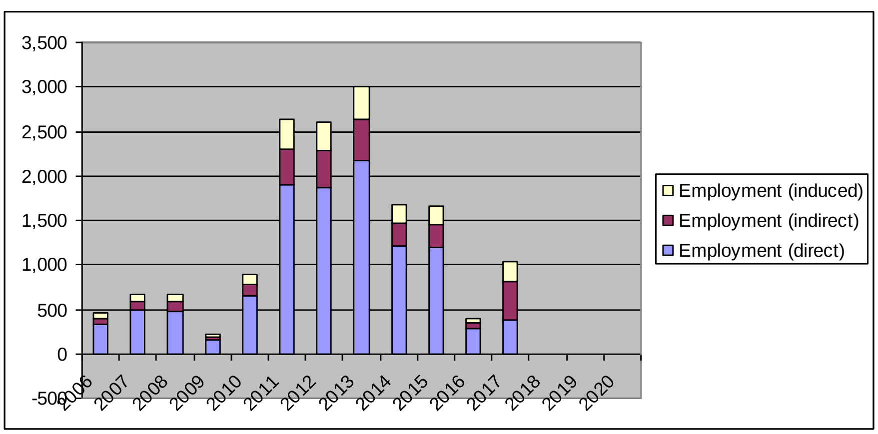


Figure 8.12
Natural Gas Expansion Employment Impacts



Chapter 9. Cleaner Coal Scenario

The cleaner coal scenario aligns with Austin Energy's (AE) proposed energy resource plan while replacing AE's stake in FPP with a cleaner coal facility in 2020. This scenario utilizes "clean coal" technologies to continue the use of coal in AE's resource portfolio, but reduces the amount of CO_2 emissions into the atmosphere attributed to the burning of coal. Under this scenario AE's would divest its interest in the Fayette Power Project (FPP) coal facility and replace the lose of power generated from this plant with coal-based power generated by an Integrated Gasification Combined Cycle (IGCC) coal coal plant with carbon capture and storage (CCS) technology. IGCC plants are more efficient that traditional pulverized coals plants, but a large amount of energy is required to operate the CCS process and it can be very costly to transport CO_2 to an available storage site. details additions to AE's resource portfolio from 2009 to 2020 by fuel source, power generation technology, or facility. IGCC plants have a capacity factor similar to that of traditional coal fired power plants and nuclear power plants, so it can provide a reliable source of baseload power. However, since an IGCC plant is designed to capture energy losses and prevent deficiency below the desired output, capital costs come at about a 45 percent increase over traditional coal plants.

Cleaner coal plants can provide a reliable source of energy as long as expenditure is sufficient for CCS technology. Implementation of carbon regulation could make IGCC plants with CCS technology much more cost competitive with traditional coal plants. Coal power generation faces other risks. Coal mining and transport costs have increased over the years and may continue to do so. Fifty coal plants have been cancelled or postponed since January 2007, illustrating the increased risk and uncertainty perceived by the public regarding coal-based power generation. Whether IGCC with CCS technology can be operational at the scale necessary to replace FPP by 2020 is uncertain.

This scenario was run to show the sensitivity of using cleaner coal expansion in AE's resource portfolio. Cleaner coal technology presents a much more sustainable source of power generation than fossil fueled technologies because they utilize coal resource that are not depleted during the energy conversion process.

System Reliability

Replacing AE's stake in the FPP with a cleaner coal facility does not create concerns regarding system reliability because this new facility can still provide baseload power generation (607 MW of power generation capacity.) Figure 9.1 demonstrates that AE's power generation capacity would exceed forecasted peak load with and without conservation goals being met. This scenario would consist of 3,923 MW of power generation capacity in 2020, the same amount of power generation capacity under AE's proposed energy resource plan.

Given the expected capacity factors for on-shore wind and solar PV (29 and 17 percent, respectively) as well as current capacity factors for AE's coal, nuclear, and natural gas facilities AE will be able to deliver electricity reliably to its customers under this scenario, given that AE meets its conservation goals (see Figure 9.2). Figure 9.3 details AE's expected hourly load profile for the hottest day (peak demand) in the summer of 2020. The hourly load profile demonstrates that AE will be able to meet peak demand without purchasing power in 2020.

Carbon Emissions and Carbon Costs

By reducing CO_2 emissions caused by the burning of coal, CO_2 emissions would drop dramatically under this scenario (see Figure 9.4). AE's CO_2 emissions in 2007 were roughly 6.1 million metric tons. Under this scenario CO_2 emissions would drop to 1.8 million metric tons by 2020, a reduction of about 70 percent.

By reducing carbon emissions AE could profit if carbon regulation were to be passed that supported a portion of allowances being given for free. Under the Lieberman-Warner Climate Security Act of 2007, a portion of an entity's emissions would be accounted for by free permits, or allowances, while a portion of allowances would be auctioned. Figure 9.5 estimates that AE could make about $50 million in 2020 based upon allowance price estimates for the Lieberman-Warner bill under this scenario.

Under this scenario, offsetting CO_2 emissions to zero also becomes much more manageable. Figure 9.6 provides a range of annual costs to offset emissions to zero, thus achieving carbon-neutrality. The costs of offsets would be dramatically reduced in 2020, when the transition to cleaner coal occurred. In 2020, annual carbon costs would decline to $18 to $72 million annually compared to $58 to $230 million under AE's proposed resource plan.

Costs and Economic Impacts

Relative to oil or natural gas, coal is currently the least expensive fossil fuel used to generate electric power. Cleaner coal technology facilitates use of coal while increasing the efficiency of generating electricity and decreasing CO_2 emissions. However, such efficiency and environmental gains come at a high cost. Figure 9.7 details the capital cost estimates for AE's scheduled and proposed additions to its power generation mix. Total expected capital costs under this scenario summed over the years 2009 to 2020 range from $5.72 to $10.09 billion (compared to $2.2 to $3.01 billion under AE's proposed resource plan). Capital costs are expressed as total overnight costs. Therefore, it is important to recognize the year for which a project is proposed.

Figure 9.8 details annual fuel costs for this scenario. As fossil-fueled sources do not change dramatically under this scenario, fuel costs are expected to remain fairly stable, ranging in any given year from $170 to $360 million which is almost the same as AE's resource plan. If carbon legislation or other fossil-fueled related regulation is implemented over the next decade, fuel costs (primarily for coal and natural gas) would likely move towards the high estimate.

Figure 9.9 estimates the expected rise in costs to produce electricity by calculating the impact of the levelized costs of new power generation resources, as a percentage of overall power generation capacity. Under this scenario customers would expect the cost of electricity to 4.5-7.3 cents per kilowatt-hour. It should be noted that this expected increase in electric rates is based solely on new power generation investments. Offset costs or any unexpected additional costs to the utility could also be passed on to the customer during this time period. Additionally, the calculation for expected increase in cost of electricity does not appoint a monetary value of reducing or removing coal or any other resource from AE's resource portfolio as the methods for evaluating how much AE could receive are beyond the scope of this report. Such removal may help to alleviate the additional costs to electricity accrued from the identified resource additions.

Figure 9.10 shows the economic output in the Greater Austin Area generated by the cleaner coal scenario. Local economic activity peaks above $200 million in 2016. Figure 9.11 shows the total value added to the Greater Austin Area from the investments made in the cleaner coal scenario. Figure 9.12 shows the impacts on employment created through the cleaner coal scenario.

Table 9.1
Cleaner Coal Scenario Scheduled Additions and Subtractions to Generation Mix

Schedule of power generation additions and subtractions (net MW)													
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	607	0	0	0	0	0	0	0	0	0	0	0	-607
Nuclear	422	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 1-4	189	100	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 5	312	0	0	0	0	200	0	0	0	0	0	0	0
Natural Gas - Decker 1 & 2	741	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker CGT	193	0	0	0	0	0	0	0	0	0	0	0	0
Wind	274	165	0	23	0	0	50	100	0	74	0	50	110
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	100	0	0	0	100	0	0	0	0
FPP w/ biomass co-firing	0	0	0	0	0	0	0	0	0	0	0	0	0
Landfill Gas	12	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV - Centralized	0	0	30	0	0	0	0	0	0	0	0	0	0
Solar PV - Distributed	1	0	0	0	0	0	20	0	0	20	0	0	0
Concentrated Solar	0	0	0	0	0	0	0	0	0	0	0	30	0
IGCC w/ CCS	0	0	0	0	0	0	0	0	0	0	0	0	607
IGCC w/o CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0
Accelerated Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 9.1
Cleaner Coal Scenario Power Generation Capacity

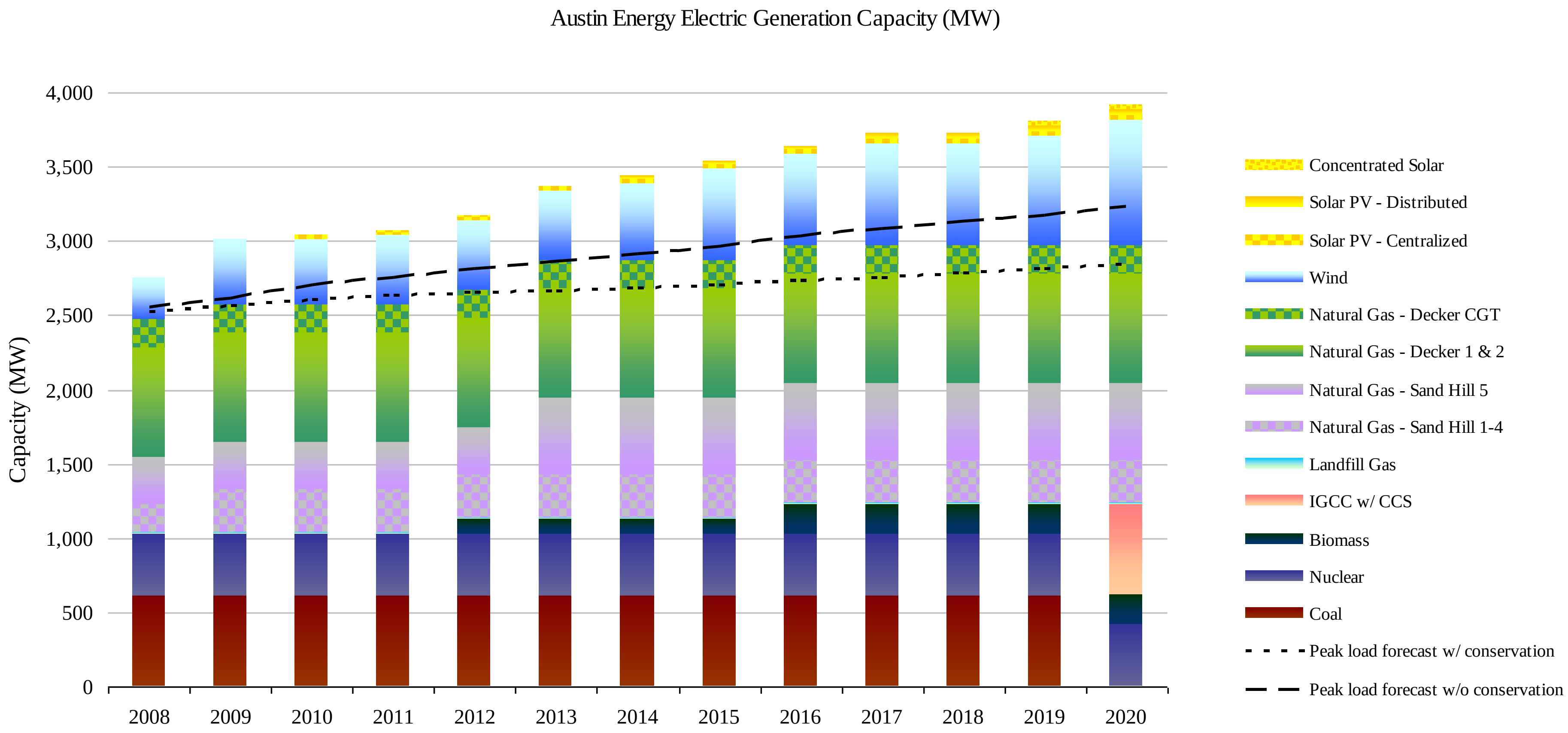


Figure 9.2
Cleaner Coal Scenario Electric Delivery

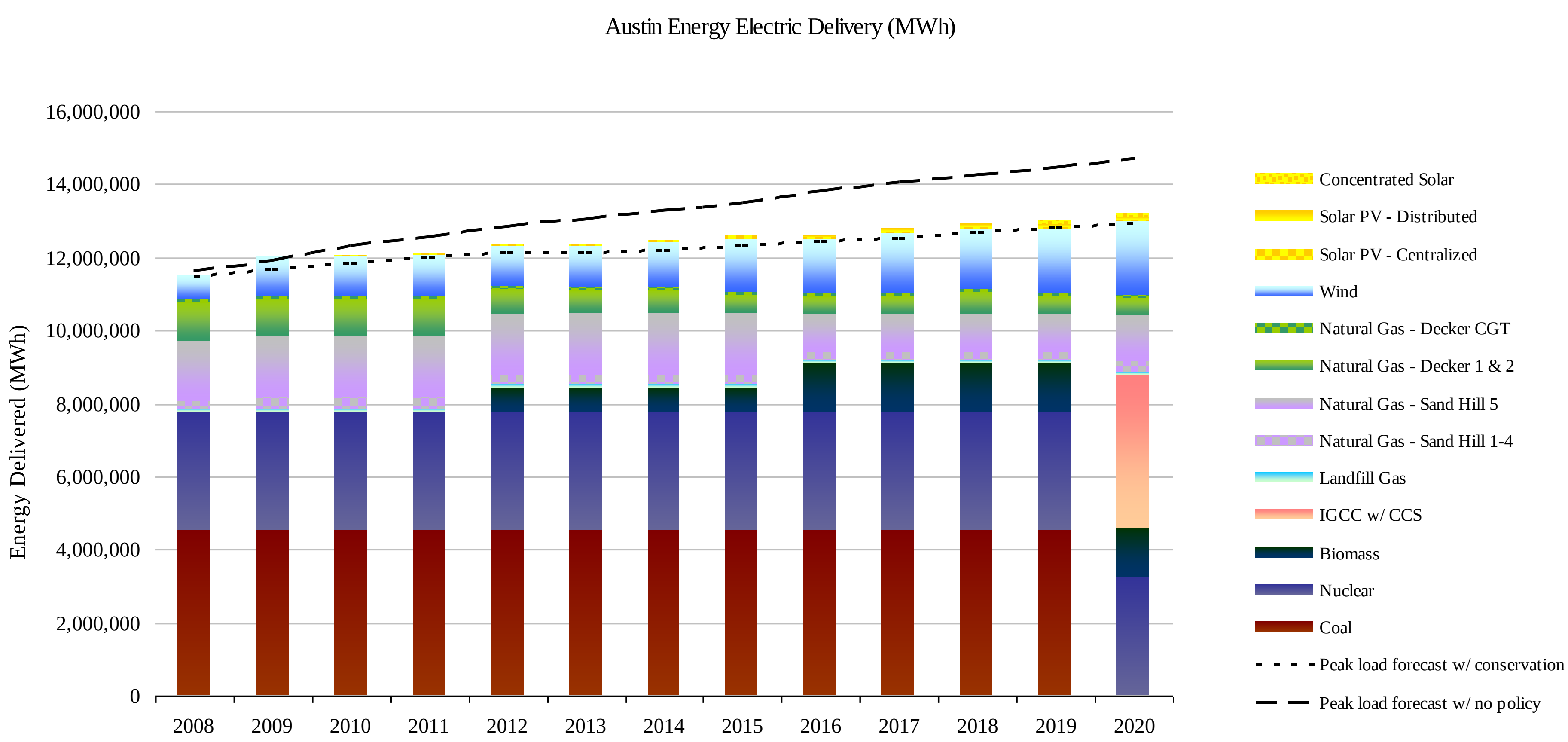


Figure 9.3
Cleaner Coal Scenario Hourly Load Profile (Peak Demand, Summer 2000)

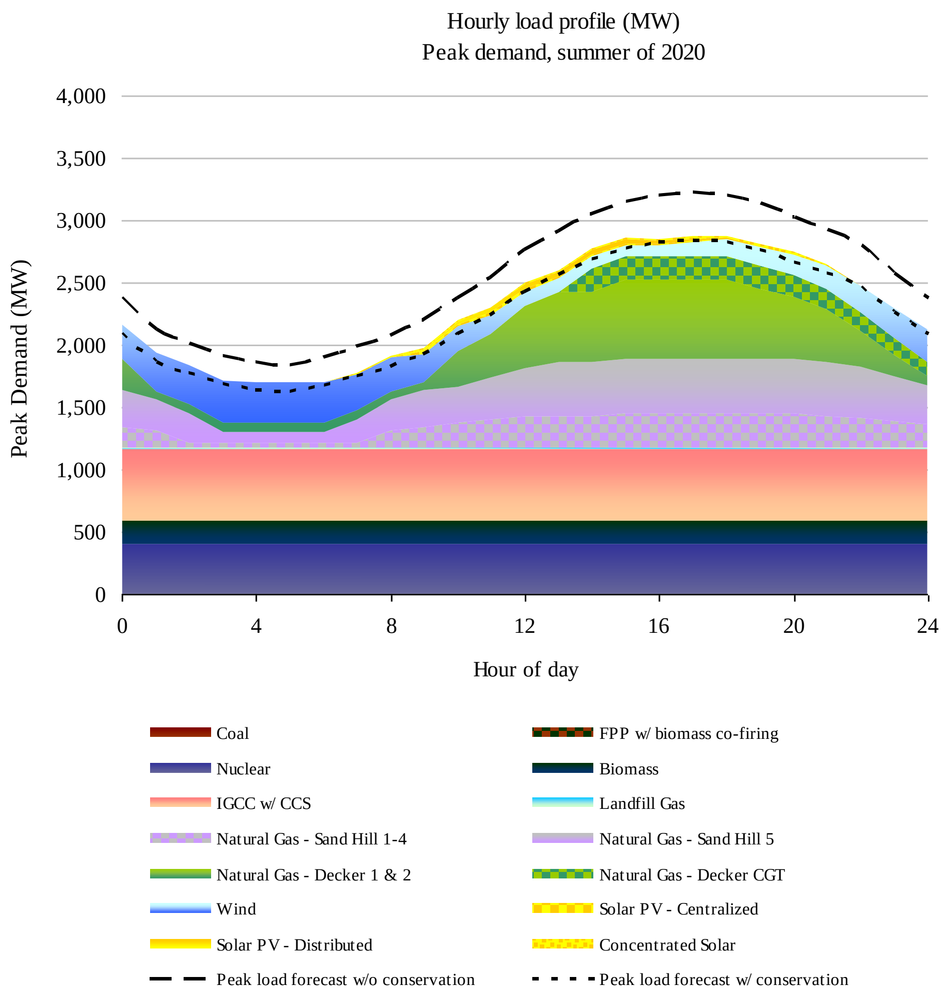


Figure 9.4
Cleaner Coal Scenario Direct Carbon Dioxide Emissions

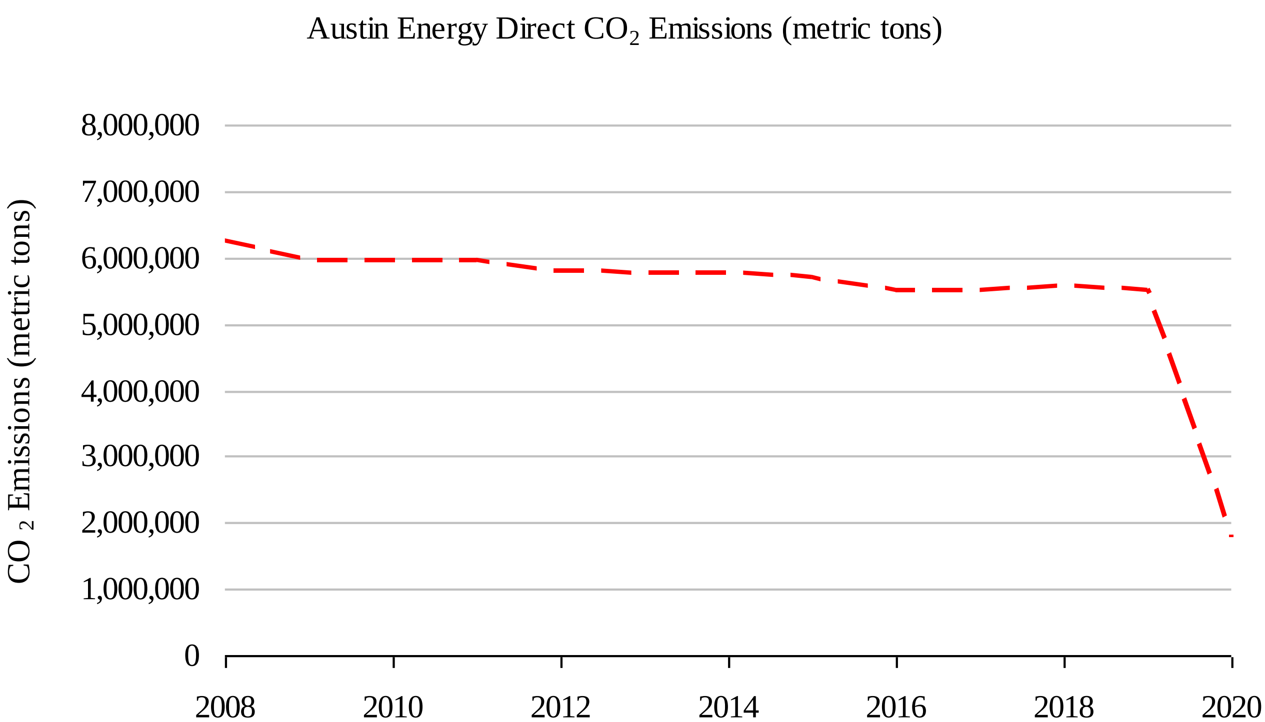


Figure 9.5
Cleaner Coal Scenario Carbon Allowance Costs

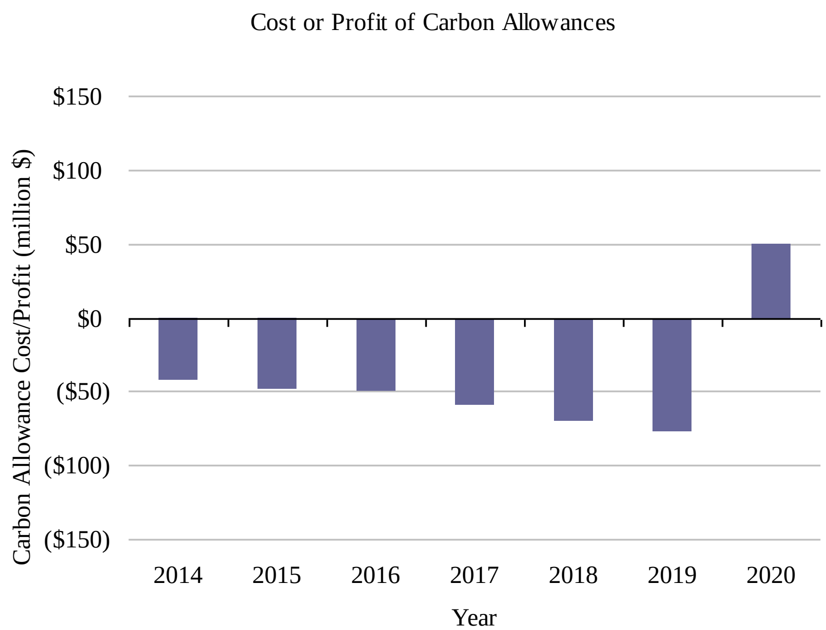


Figure 9.6
Cleaner Coal Scenario Carbon Offset Costs

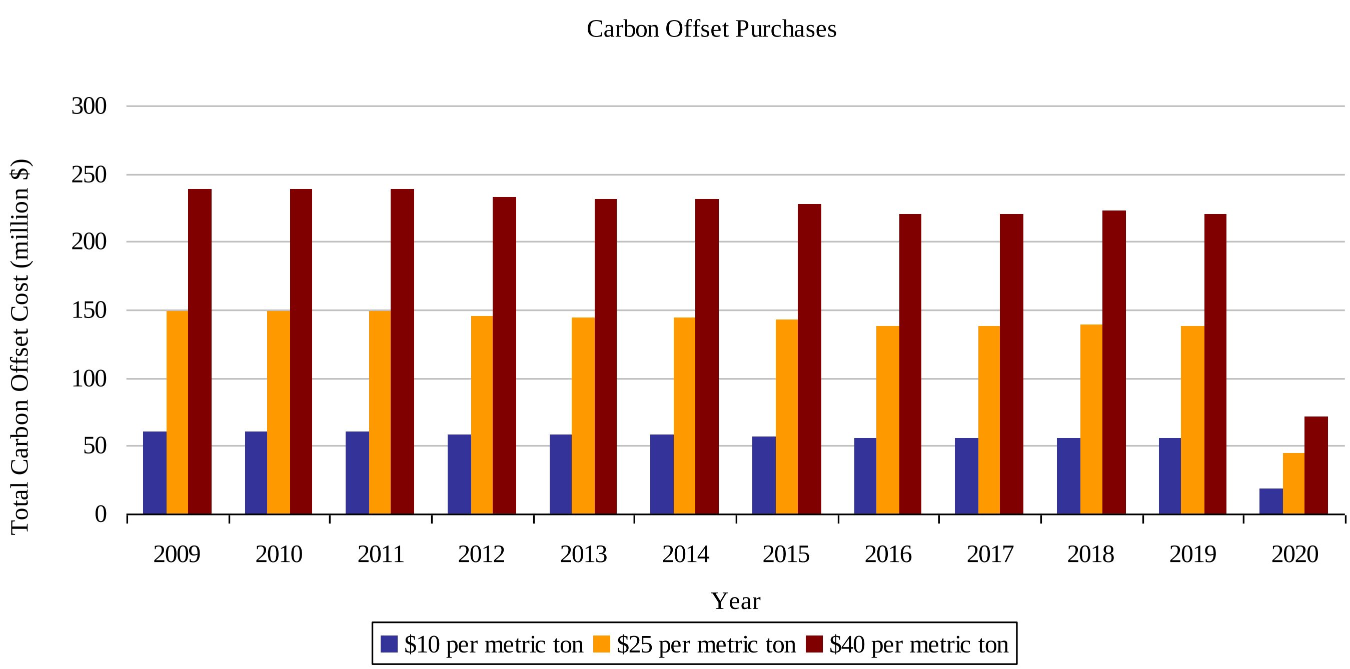


Figure 9.7
Cleaner Coal Scenario Capital Costs

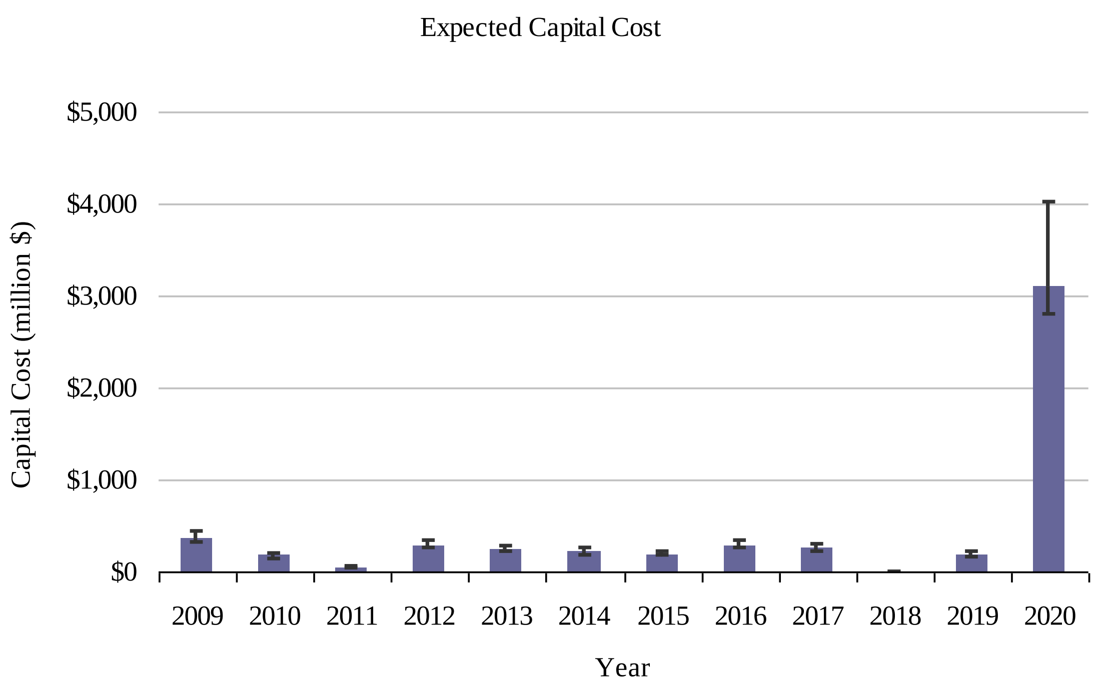


Figure 9.8
Cleaner Coal Scenario Fuel Costs

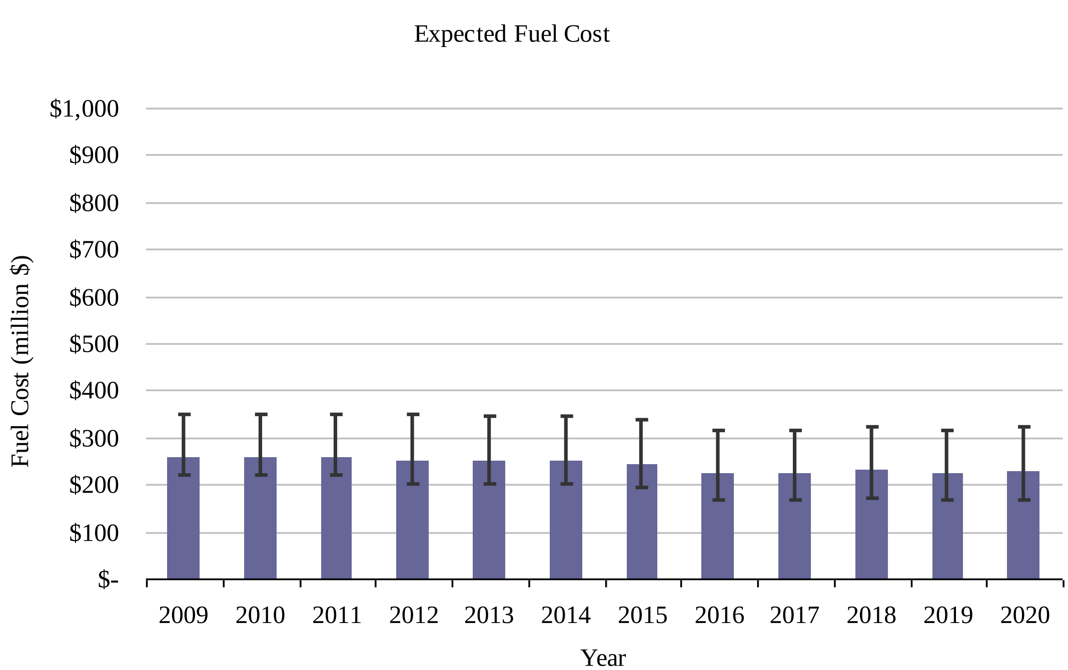


Figure 9.9
Cleaner Coal Scenario Levelized Costs

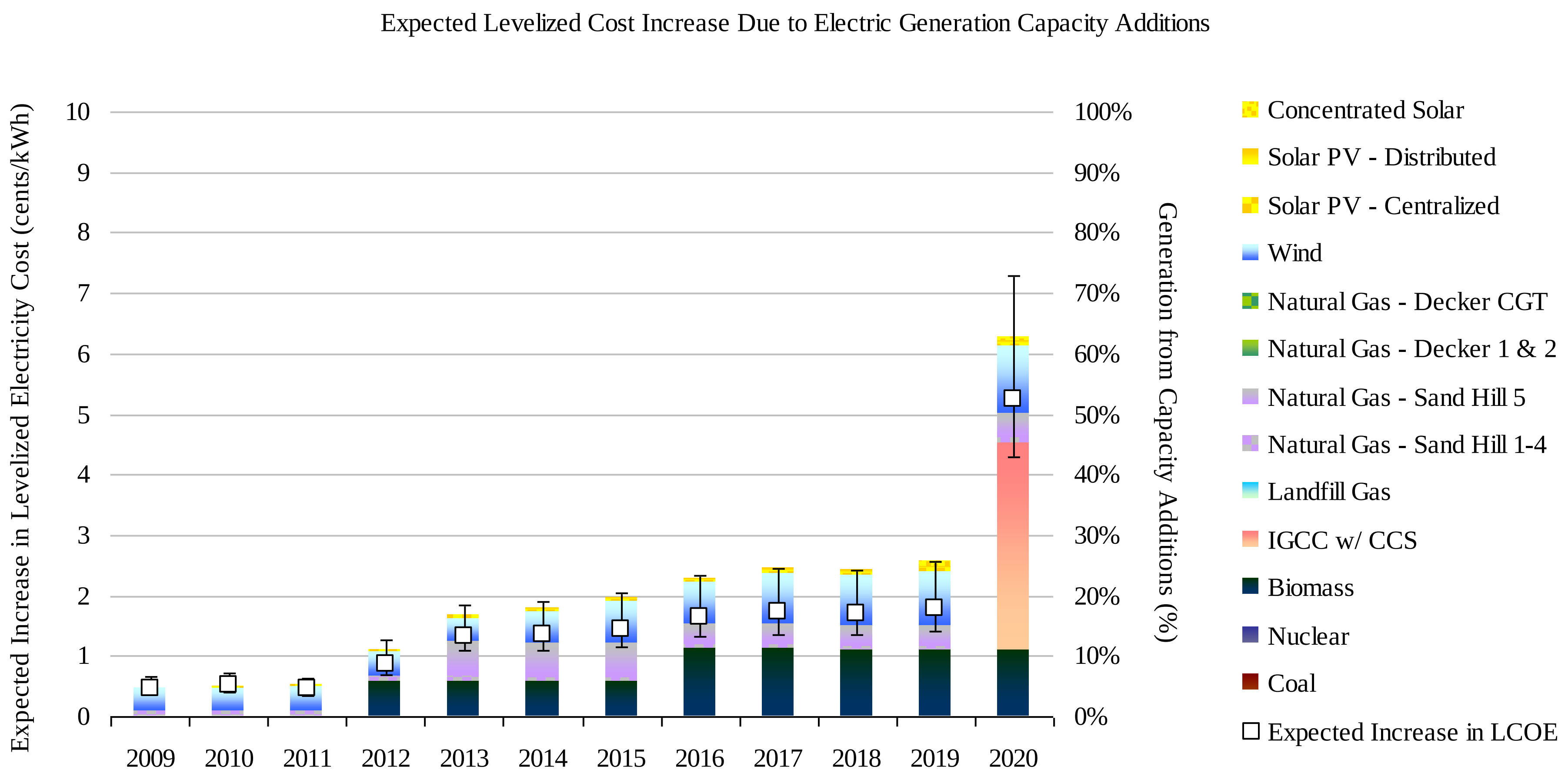


Figure 9.10
Cleaner Coal Scenario Economic Activity

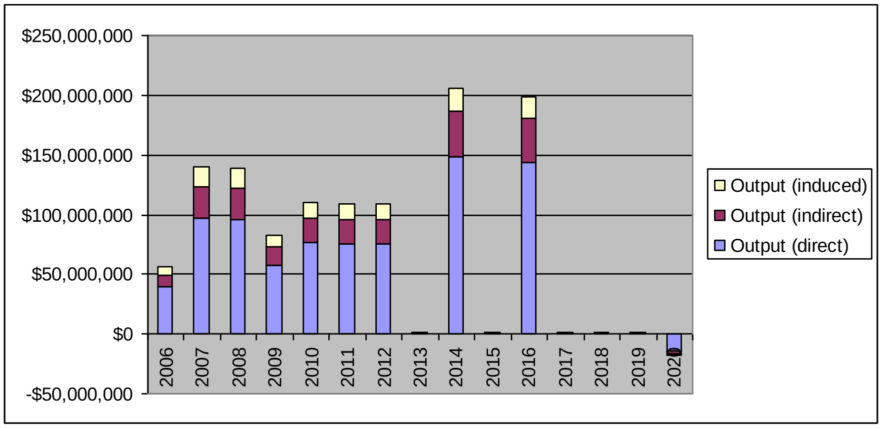


Figure 9.11
Cleaner Coal Scenario Total Value Added

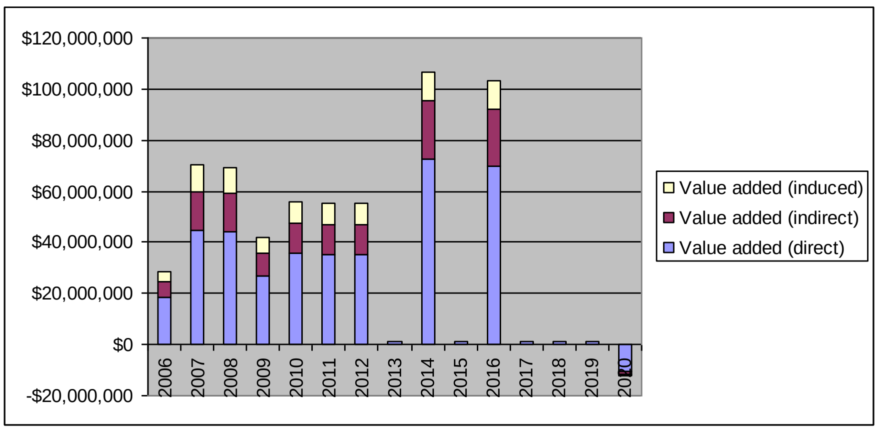
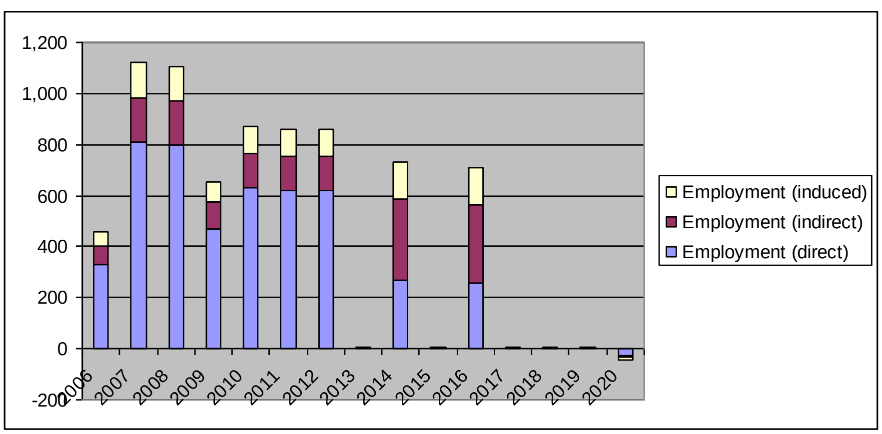


Figure 9.12
Cleaner Coal Scenario Employment Impacts



Chapter 10. High Renewables Without Nuclear Scenario

The schedule for this scenario is identical to the schedule for the high renewables scenario with three exceptions. Table 10.1 details the additions and subtractions made to AE's resource portfolio from 2009 to 2020 by fuel source, power generation technology, or facility under this scenario. This scenario includes a slight acceleration in the addition of geothermal capacity as well as a delay in divestment in coal. The more significant change is the removal of 422 MW of nuclear power (the power generating capacity of the South Texas Project, where AE generates its nuclear energy) from AE's resource portfolio. This divestment is scheduled for 2016 and represents the only net difference between this scenario and the high renewables scenario. Therefore, this scenario holds the same optimism with regards to the availability of renewable resources through 2020. One difference between this scenario and the high renewable scenario (portfolio option 3) is that with the loss of its stake in a coal and nuclear plant AE would no longer receive energy from a baseload power source of significant capacity. Rather, AE would become reliant upon technologies with variable availability.

System Reliability

Figure 10.1 demonstrates that AE's power generation capacity would exceed forecasted peak load with and without conservation goals being met. The high renewables without nuclear scenario includes 1,990 MW of wind and 913 MW of solar-based generation, including two large-scale concentrated solar facilities using parabolic troughs and gradual investment in distributed rooftop photovoltaic units. The mix of onshore and offshore wind facilities is intended to exploit the complementary availabilities of both technologies, given that onshore wind is most readily available in the evening and early morning and offshore wind is most readily available during the day.

Figure 10.2 demonstrates that, given expected capacity factors for wind and solar (29 and 17 percent, respectively) as well as current capacity factors for AE's nuclear and natural gas facilities, AE would be able to reliably deliver electricity for most days not occurring in peak months.

The loss of nuclear as a reliable baseload source of power makes AE much more vulnerable to gaps in variable resource availability and could necessitate a much greater reliance on power purchased on the spot market. To demonstrate the risks of a system highly dependent on wind and solar energy, Figure 10.3 details AE's expected hourly load profile for the hottest day (peak demand) in the summer of 2020. The hourly load profile follows expected solar and wind profiles and demonstrates that AE will be able to meet peak demand without purchasing power even on the hottest day of the summer, if expected wind and solar production is met and AE meets its conservation goals. AE would be unable to meet peak demand even if wind and solar energy meets expected levels and natural gas facilities were operated at full capacity. This demonstrates great concern over the reliability of a system that become almost entirely reliant on natural gas and renewable resources.

This scenario should satisfy opponents of nuclear energy, a technology whose "sustainability" merits can be debated. Although nuclear power production does not emit greenhouse gases (GHG) or other harmful air pollutants, there are serious issues regarding land use, hazardous waste, and catastrophic risks associated with producing energy through nuclear fission. This scenario represents a compromise of conflicting views of sustainability by increasing reliance on carbon-emitting purchased power while simultaneously divesting AE from any involvement in nuclear energy. In realistic terms, the availability factors for renewable power generation technologies are not likely to satisfy system reliability requirements for AE.

Carbon Emissions and Carbon Costs

The high renewables scenario with the elimination of coal and nuclear would increase the amount of clean energy power generation capacity to about 68 percent of AE's resource portfolio; over double what is currently being proposed by AE and 5 percent greater than the 63 percent share represented by the high renewables scenario (see Figure 10.4). A significant drawback is that the reduction in carbon emissions may be substituted by reliance on carbon-intensive purchased power that would not be accounted for in AE's carbon footprint.

Should carbon regulation be implemented, reductions in CO_2 emissions may present an opportunity for profit. Under the Lieberman-Warner Climate Security Act of 2007 a portion of an entity's emissions would be accounted for by free permits, or allowances, while a portion of allowances would be auctioned. Figure 10.5 estimates that AE would have to pay about $168.2 million between 2014 and 2020 in allowances.

Under the high renewables without nuclear scenario, ability to offset emissions to reach carbon neutrality becomes much more manageable and would require an annual cost of between $20 and $81 by 2020**.**

Costs and Economic Impacts

Figure 10.7 details the capital cost estimates for the high renewables without nuclear scenario. Expected capital costs range from $6.93 to $9.44 billion (compared to $2.2 to $3.01 billion under AE's proposed resource plan). Capital costs are expressed as total overnight costs. Therefore, it is important to recognize the year for which a project is proposed. On-shore wind turbines are a mature technology with relatively stable expected costs, but other renewable technologies present much uncertainty in capital costs. No geothermal, concentrated solar plant, or off-shore wind facility has ever been constructed in Texas. Costs for biomass plants may rise as supplies in Texas decrease. It is expected that costs to build utility-scale solar plants and to install solar PV panels will drop considerably in the next decade, but when and by how much is uncertain. In this model, costs are expressed as current estimates and ranges are determined based upon the relative maturity of the technology and expected direction by which costs are expected to flow.

Figure 10.8 details annual fuel costs under the high renewables without nuclear scenario. Since the amount of fossil-fueled resources changes dramatically under this scenario, fuel costs are expected to drop considerably, greatly reducing the risks associated with fuel price instability. Fuel costs are expected to decrease gradually as coal usage is reduced and eliminated. However, increased reliance on natural gas prevents fuel costs from dropping significantly. By 2020 fuel costs under this scenario would range from $67 to $172 million annually (compared to $93 to $328 million under AE's proposed resource plan).

Figure 10.9 estimates the rise in costs on electric bills by calculating the impact of the levelized costs of new power generation resources as a percentage of overall power generation capacity. The high renewables without nuclear scenario presents an almost completely redefined power generation mix with almost 80 percent of actual power generation coming from additions since 2009. Therefore, the costs of these additions will have a significant impact on the costs of electricity. Since renewable power generation is much more expensive than traditional fossil-fuel based power generation it is expected that electric rates would rise considerably. It is estimated that this scenario would raise the costs of electricity by 5 to 8 cents per kilowatt-hour. It should be noted that this expected increase in electric rates is based solely on new power generation investments. Offset costs or any unexpected additional costs to the utility could also be passed on to the customer during this time period. Additionally, the calculation for expected increase in cost of electricity does not appoint a monetary value of reducing or removing coal or any other resource from AE's resource portfolio as the methods for evaluating how much AE could receive are beyond the scope of this report. Such removal may help to alleviate the additional costs to electricity accrued from the identified resource additions.

Local economic development impacts could be significant under a high renewables scenario depending upon the location of new power generation facilities. The most significant impact upon the local economy would be created by the rapid acceleration in solar PVs on rooftops. This could create a vibrant local solar manufacturing and installation industry. Additionally centralized PV systems located within the Austin region could further accelerate the solar industry in Austin.

The high renewable scenario represents a major increase in economic activity for the Greater Austin Area attributed to investments in 250 MW of centralized photovoltaic power generation facilities, 15 MW of landfill gas capacity, and 55 MW of distributed photovoltaic power generation capacity. The most significant impact upon the local economy would be created by the rapid acceleration in solar PV modules on rooftops. This could create a vibrant local solar manufacturing and installation industry. Additionally, centralized PV systems located within the Austin region could further accelerate the solar industry in Austin. AE's divestment in its stake in nuclear power generated at the STP project would not directly affect the Greater Austin Area because this plant is located several hundred miles away from Austin in Matagorda Bay.

Figure 10.10 shows the economic output in the Greater Austin Area generated by the high renewables without nuclear scenario. Figure 10.11 shows the total value added to the Greater Austin Area from the investments made in the high renewables without nuclear scenario. Figure 10.12 shows the impacts on employment created through the high renewables without nuclear scenario.

Table 10.1
High Renewables Without Nuclear Scenario Scheduled Additions and Subtractions to Generation Mix

Schedule of power generation additions and subtractions (net MW)													
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	607	0	0	0	0	0	0	0	0	-302	0	0	-305
Nuclear	422	0	0	0	0	0	0	0	-422	0	0	0	0
Natural Gas - Sand Hill 1-4	189	100	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 5	312	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker 1 & 2	741	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker CGT	193	0	0	0	0	0	0	0	0	0	0	0	0
Wind	274	165	0	100	0	0	100	200	0	526	0	100	220
Offshore Wind	0	0	0	0	50	0	50	0	50	0	50	0	105
Biomass	0	0	0	0	100	0	0	0	100	0	0	0	90
FPP w/ biomass co-firing	0	0	0	0	0	0	0	0	0	0	0	0	0
Landfill Gas	12	0	0	0	0	0	0	0	15	0	0	0	0
Solar PV - Centralized	0	0	30	0	0	0	50	0	0	70	0	100	0
Solar PV - Distributed	1	0	5	5	5	5	5	5	5	5	5	5	5
Concentrated Solar	0	0	0	0	0	0	305	0	0	0	0	0	302
IGCC w/ CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
IGCC w/o CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	100	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0
Accelerated Conservation	0	0	0	0	0	0	0	0	0	0	0	0	0
Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 10.1
High Renewables Without Nuclear Scenario Generation Capacity

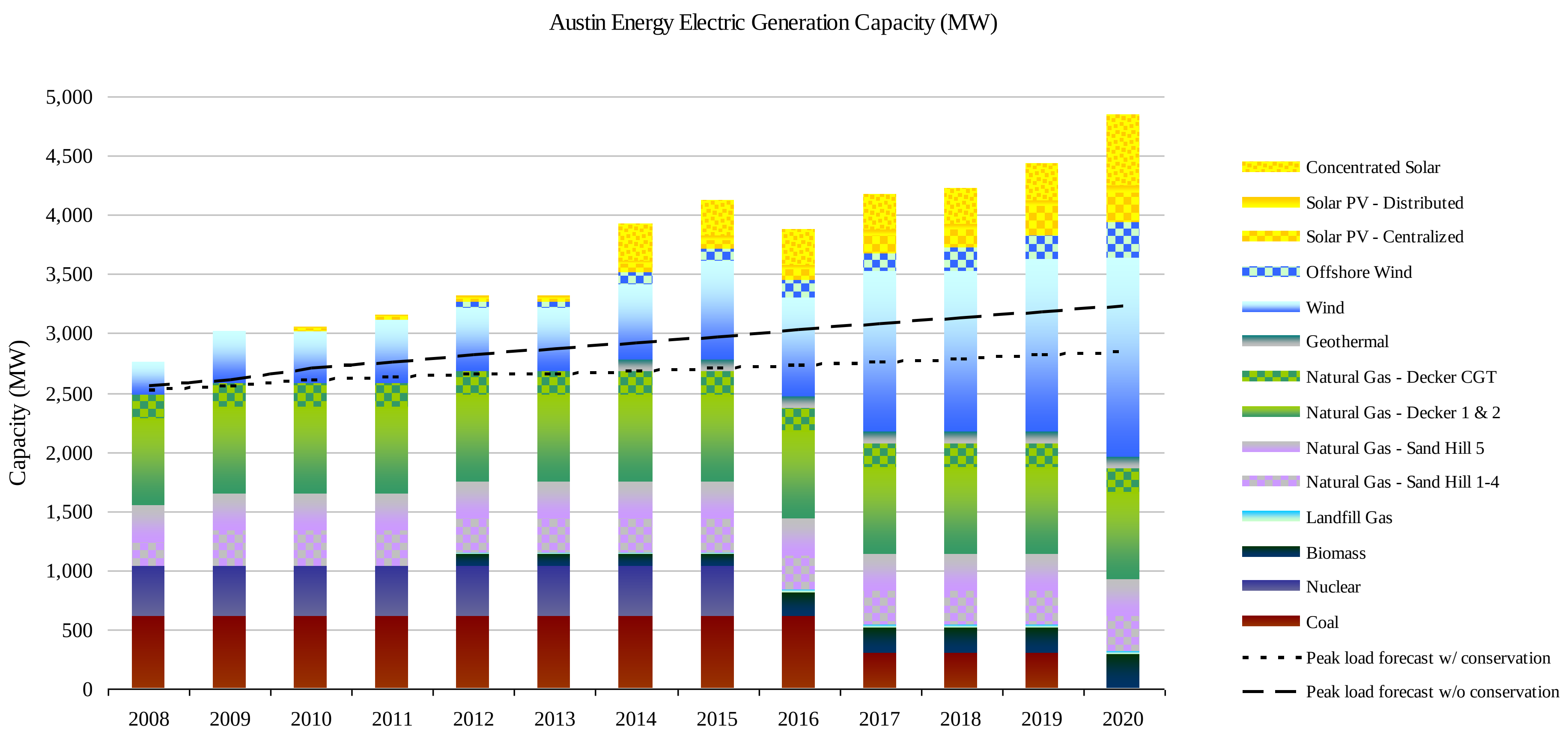


Figure 10.2
High Renewables Without Nuclear Scenario Electric Delivery

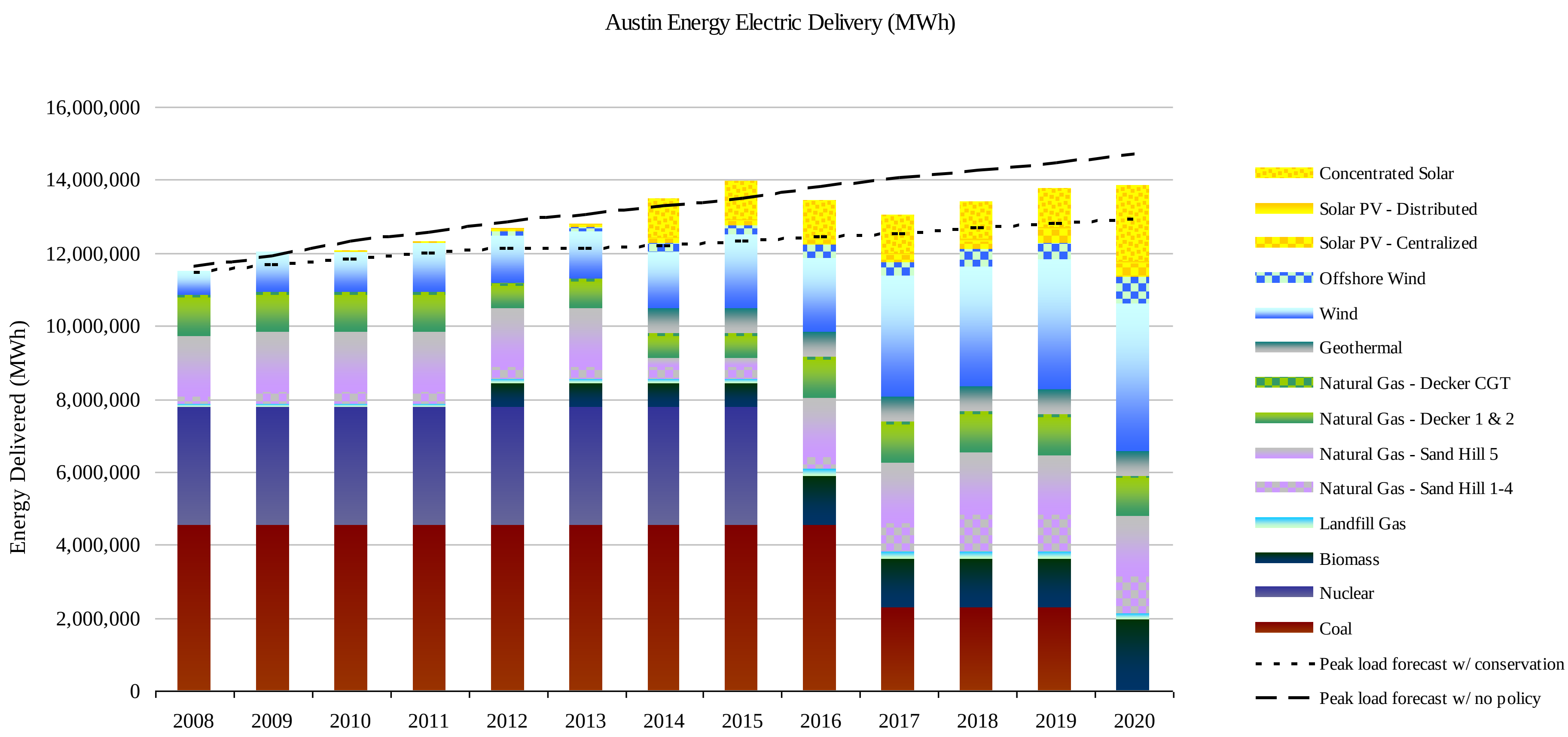


Figure 10.3
High Renewables Without Nuclear Scenario Hourly Load Profile (Peak Demand, Summer 2000)

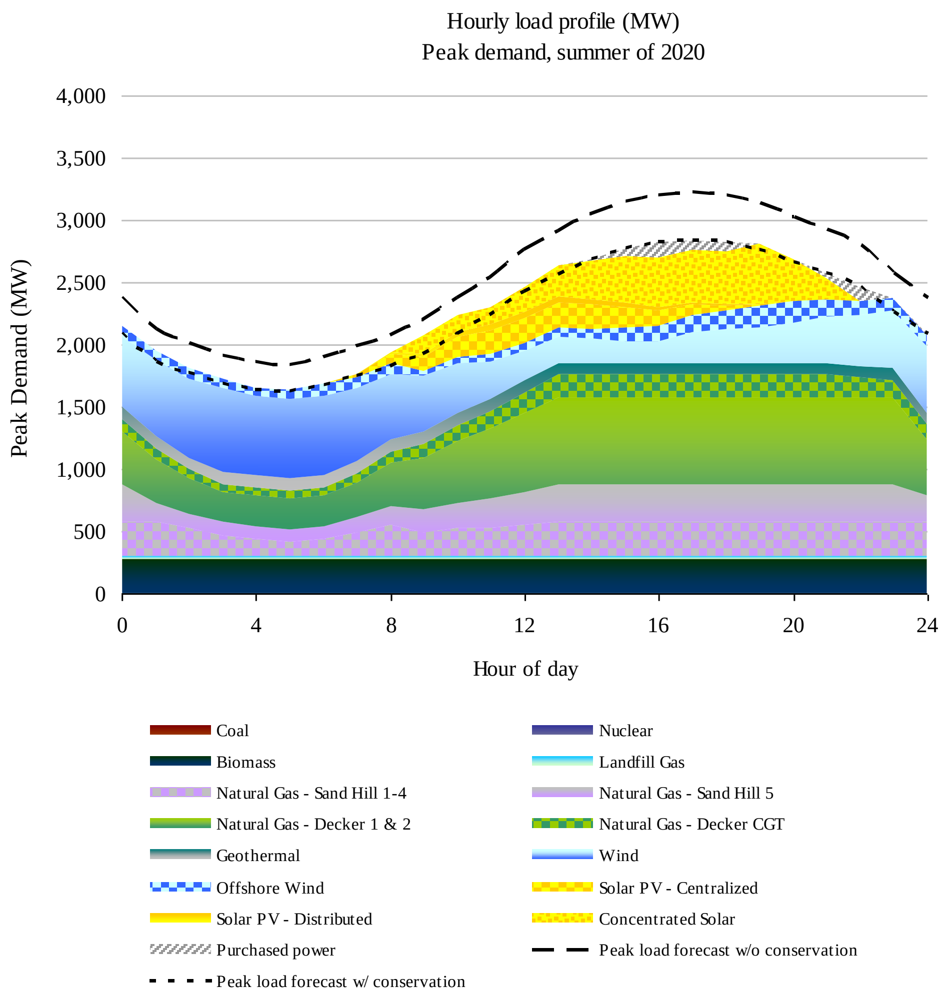


Figure 10.4
High Renewables Without Nuclear Scenario Direct Carbon Dioxide Emissions

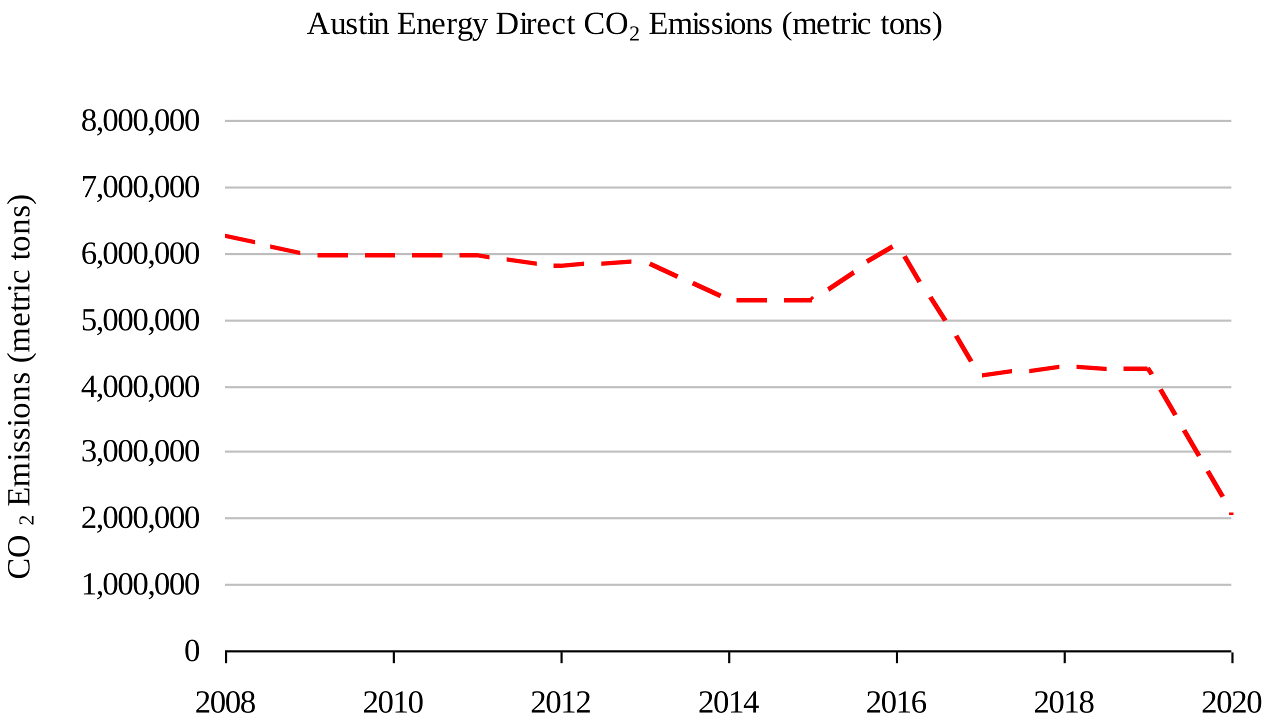


Figure 10.5
High Renewables Without Nuclear Scenario Carbon Allowance Costs

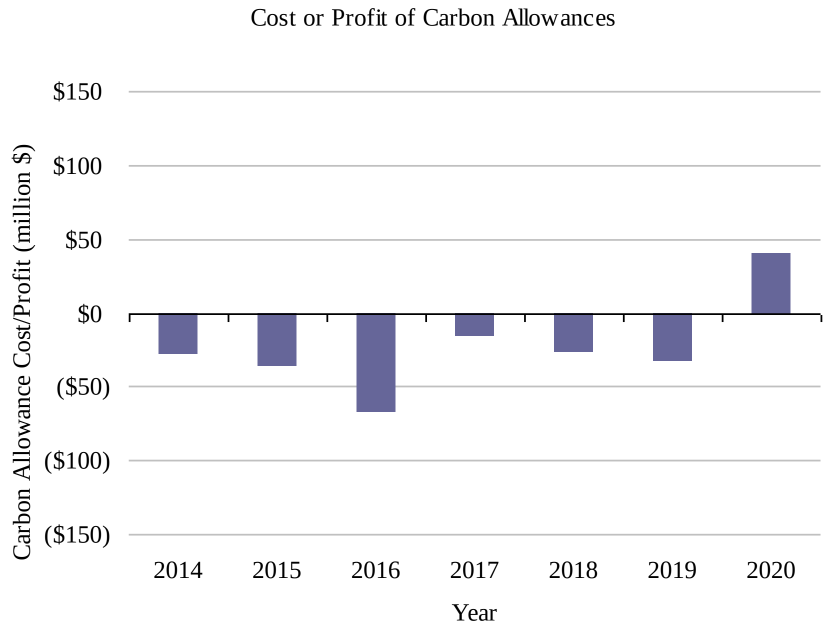


Figure 10.6
High Renewables Without Nuclear Scenario Carbon Offset Costs

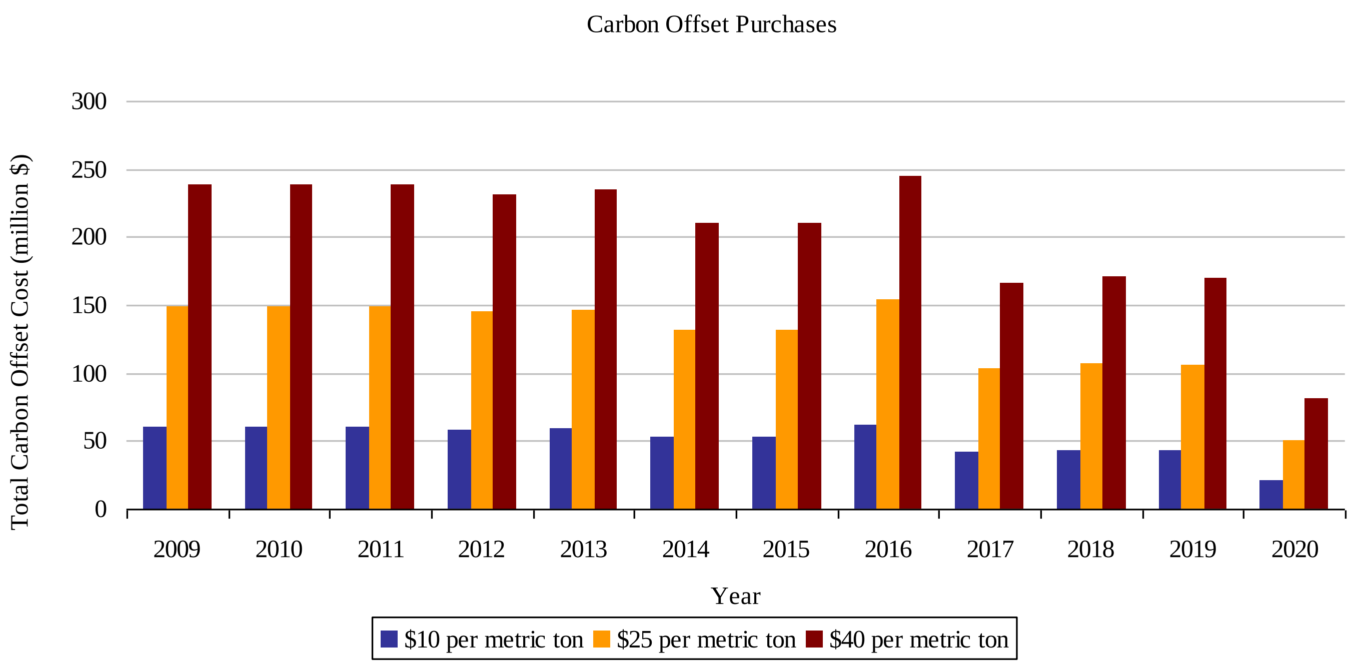


Figure 10.7
High Renewables Without Nuclear Scenario Capital Costs

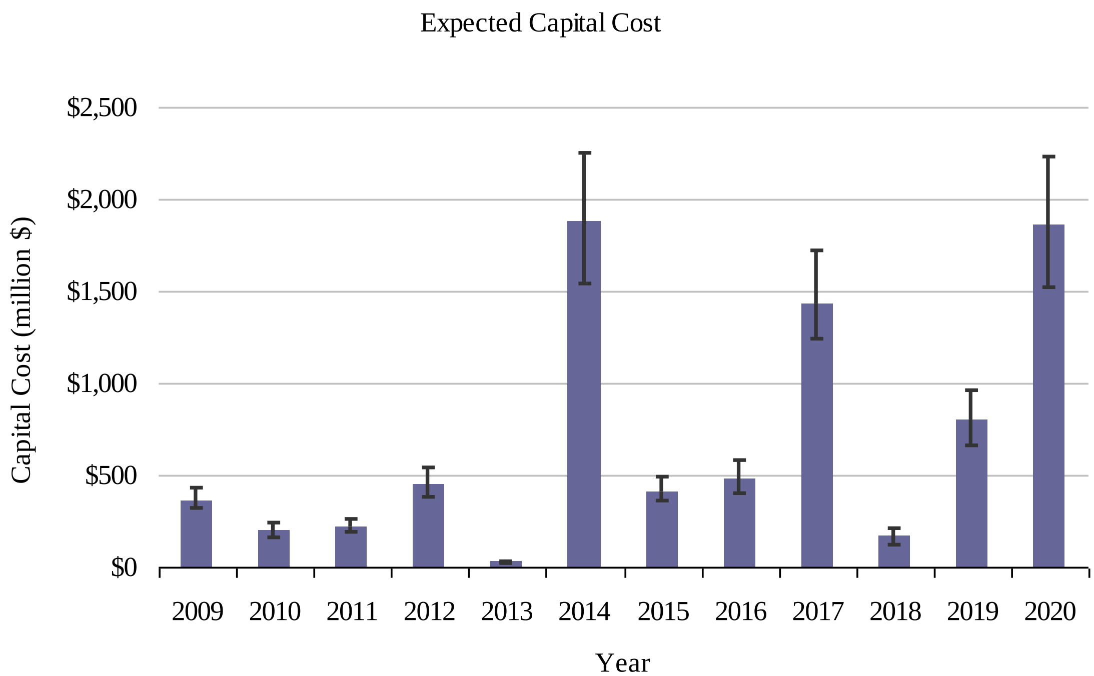


Figure 10.8
High Renewables Without Nuclear Scenario Fuel Costs

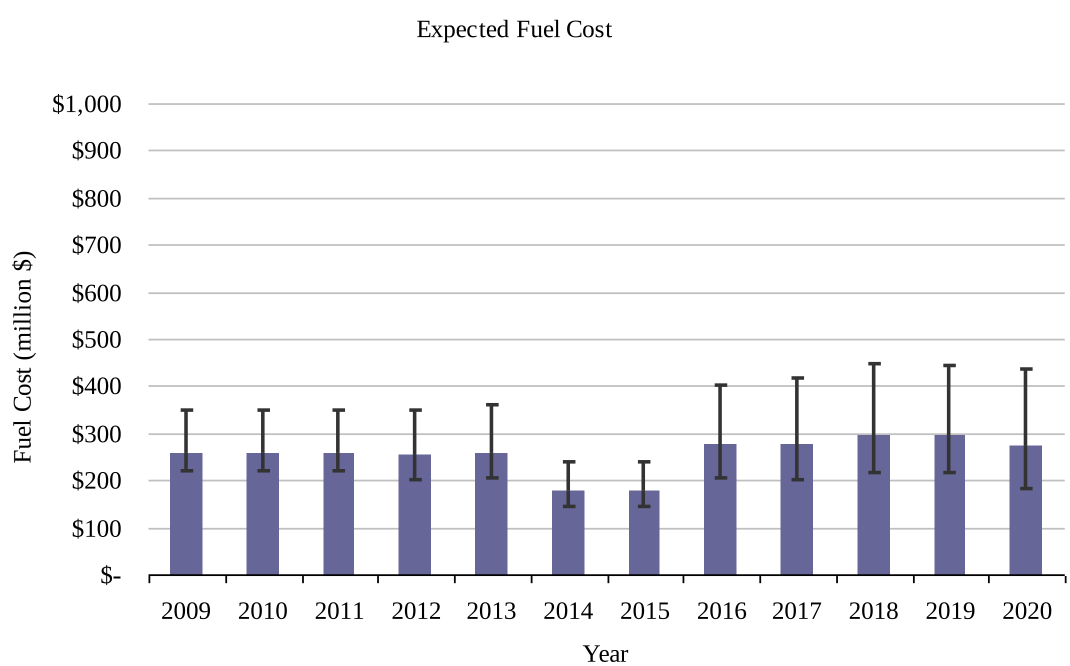


Figure 10.9
High Renewables Without Nuclear Scenario Levelized Costs

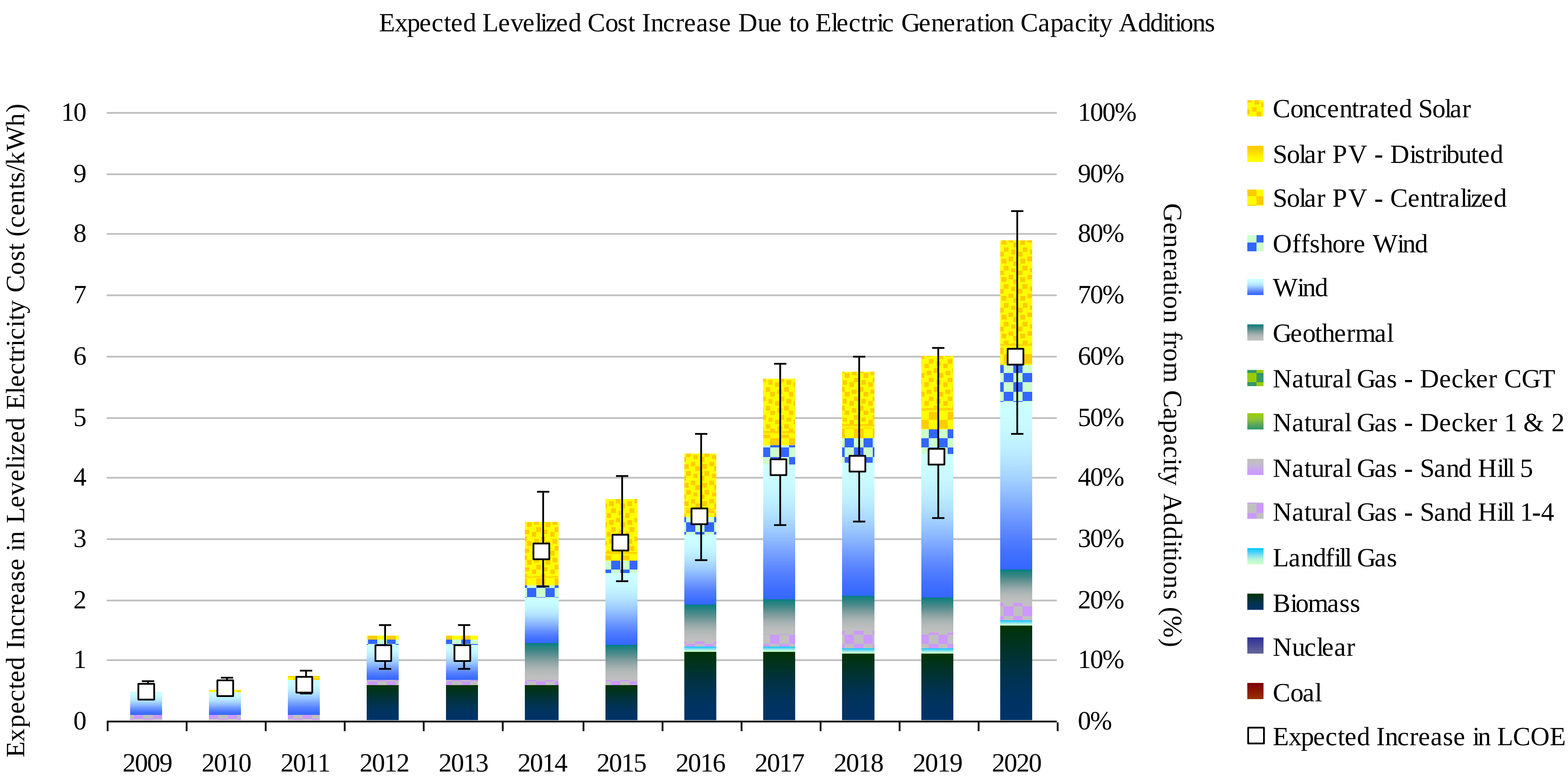


Figure 10.10
High Renewables Without Nuclear Scenario Economic Activity

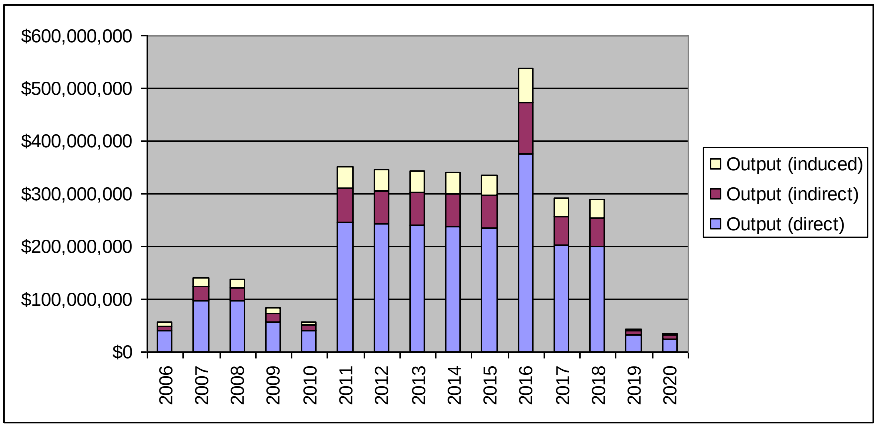


Figure 10.11
High Renewables Without Nuclear Scenario Total Value Added

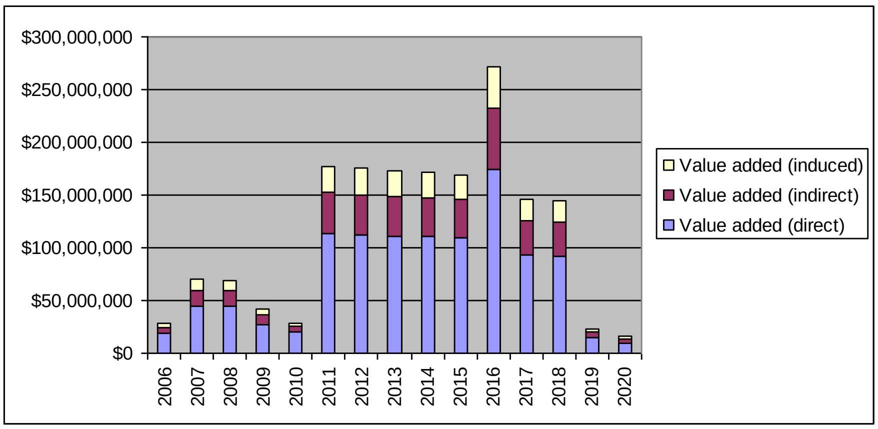
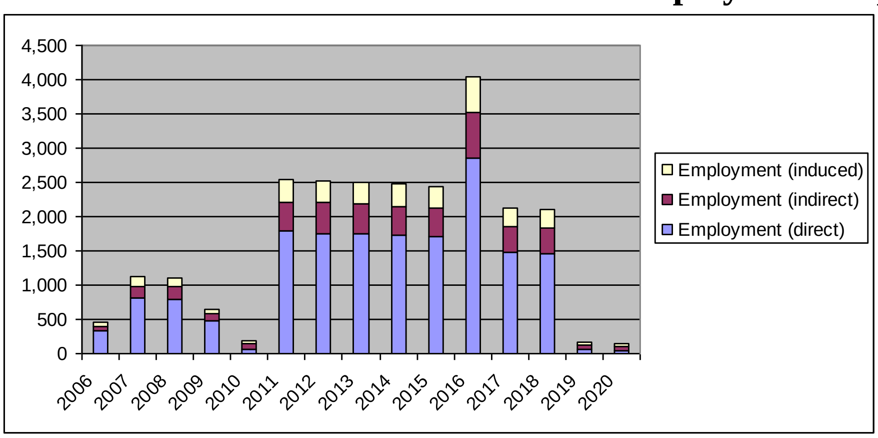


Figure 10.12
High Renewables Without Nuclear Scenario Employment Impacts



Chapter 11. Accelerated Demand-Side Management

This chapter attempts to incorporate into the model scenarios some potential ranges of demand reductions that Austin Energy (AE) could realistically achieve through accelerated conservation strategies. Measured reductions in both peak power demand and overall electricity demand due to utility-scale demand-side management (DSM), energy efficiency, and pricing mechanisms have been surveyed and documented in Chapter 3 of Volume II of this report. This chapter uses median values from those reports to obtain a rough estimate of the potential impact of conservation strategies on the AE proposed resource plan modeled scenario found in chapter 2 of this volume of the report. lists the planned additions to AE's resource portfolio from 2009 to 2020 by fuel source, power generation technology, or facility and includes demand savings by year.

Utility-scale studies have reported a wide variety of potential energy savings that stem from three basic strategies: energy efficiency, time-of-use pricing, and demand response programs. Energy efficiency strategies would implement system-wide appliance and equipment upgrades to lower overall energy demand. Time-of-use pricing and demand-response programs would achieve reductions primarily in peak power demand. Rough-estimate median values from the wide range of energy savings have been gathered to generate new load profiles from the original AE load forecast through 2020. These load profiles are provided as Figures 11.1-11.3. This chapter assumes that energy efficiency measures could achieve annual energy demand reductions of 24 percent by 2020 [in megawatt-hours (MWh)]. This chapter assumes that time-of-use pricing and demand-response programs could achieve 22 percent peak demand savings (in MW) combined, or approximately 10 percent savings in total energy demand (in MWh). The combination of these strategies could theoretical achieve peak demand savings of 40 percent (in MW) and overall demand savings of just over 30 percent (in MWh). In comparison, the demand forecast in the AE proposed energy resource plan that includes conservation efforts would reduce both peak demand and overall energy consumption by approximately 12 percent. To implement these forecasts into the model, the values were assumed to be implemented at a constant rate during each year, established by the end savings percentage used divided by approximately 11 years.

System Reliability

Pursuing very aggressive energy efficiency and DSM measures could have a substantial impact on AE's future (see Figures 11.4-11.6). Drastically reducing overall demand would allow AE to rely on fewer new power generation facilities. Demand reductions are assumed to be achieved at all hours of the year so this mix gains reliability as it does not have to rely heavily on variable power generation technologies (wind and solar) as much. The demand reductions are so large that it is no longer necessary for AE to burn coal to produce electricity by 2020. Nuclear and natural gas power sources could become the primary producers of electricity. Natural gas would be used sparingly by 2020 and offer more than enough back-up capacity for variable resources when needed.

Carbon Emissions and Carbon Costs

The modeled aggressive conservation measure eliminates the need for the Fayette Power Project coal plant by 2020. The demand reduction is so large in this scenario that carbon emissions are reduced to the levels seen only in other very high renewables and carbon-free scenarios. Figures 11.7-11.9 demonstrate the impacts of accelerated conservation on carbon emissions and carbon costs.

Costs and Economic Impacts

DSM and efficiency strategies are generally among the cheapest ways to produce, or in the case, negate the use of, energy. Figures 11.10 and 11.11 demonstrate the impact of this scenario on yearly capital and fuel costs. The capital cost requirements to achieve all these strategies are estimated to be \$4.5-\$6.1 billion through 2020 (compared to AE's proposed resource which is estimated to cost between \$2.1 and 2.9 billion in capital). Fuel costs are increased in this scenario in relation to AE's proposed resource plan from \$130-270 million in 2020 to \$155-\$340 million, primarily due to an increased reliance on natural gas facilities. Associated levelized cost of electricity values were unable to be estimated in this analysis since DSM and efficiency strategies are not technically power generation technologies.

Table 11.1
Accelerated DSM Scenario Scheduled Additions and Subtractions to Generation Mix

Schedule of power generation additions and subtractions (net MW)													
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	607	0	0	0	0	0	0	0	-100	-100	-100	-200	-107
Nuclear	422	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 1-4	189	100	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Sand Hill 5	312	0	0	0	0	200	0	0	0	0	0	0	0
Natural Gas - Decker 1 & 2	741	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas - Decker CGT	193	0	0	0	0	0	0	0	0	0	0	0	0
Wind	274	165	0	23	0	0	50	100	0	74	0	50	110
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	100	0	0	0	100	0	0	0	0
FPP w/ biomass co-firing	0	0	0	0	0	0	0	0	0	0	0	0	0
Landfill Gas	12	0	0	0	0	0	0	0	0	0	0	0	0
Solar PV - Centralized	0	0	30	0	0	0	0	0	0	0	0	0	0
Solar PV - Distributed	1	0	0	0	0	0	20	0	0	20	0	0	0
Concentrated Solar	0	0	0	0	0	0	0	0	0	0	0	30	0
IGCC w/ CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
IGCC w/o CCS	0	0	0	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0	0	0	0
Storage	0	0	0	0	0	0	0	0	0	0	0	0	0
Accelerated Conservation	0	89	184	281	383	487	595	706	826	944	1064	1187	1318
Purchased Power	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 11.1
Peak Demand Profiles for DSM Strategies

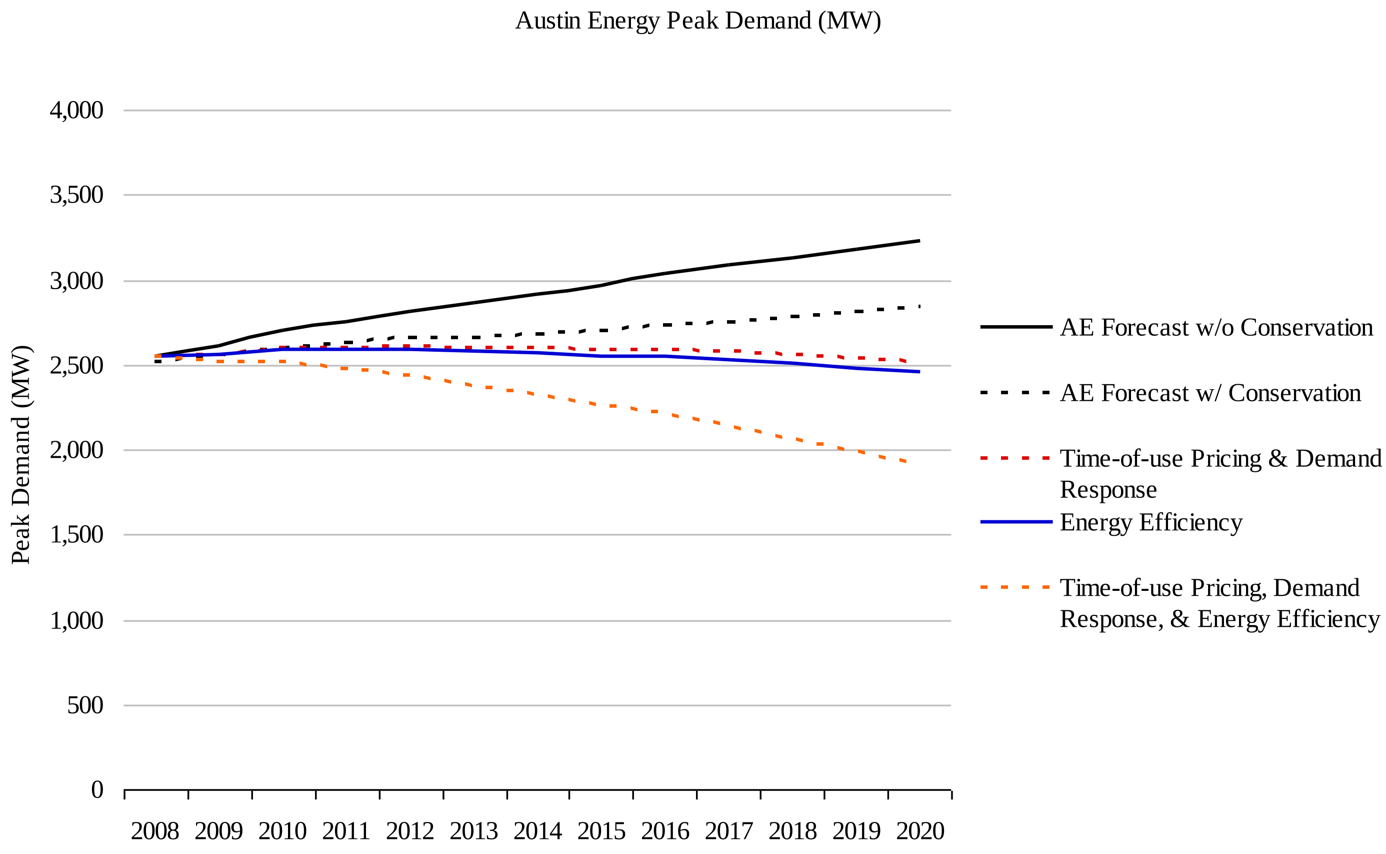


Figure 11.2
Annual Electricity Demand Profiles for DSM Strategies

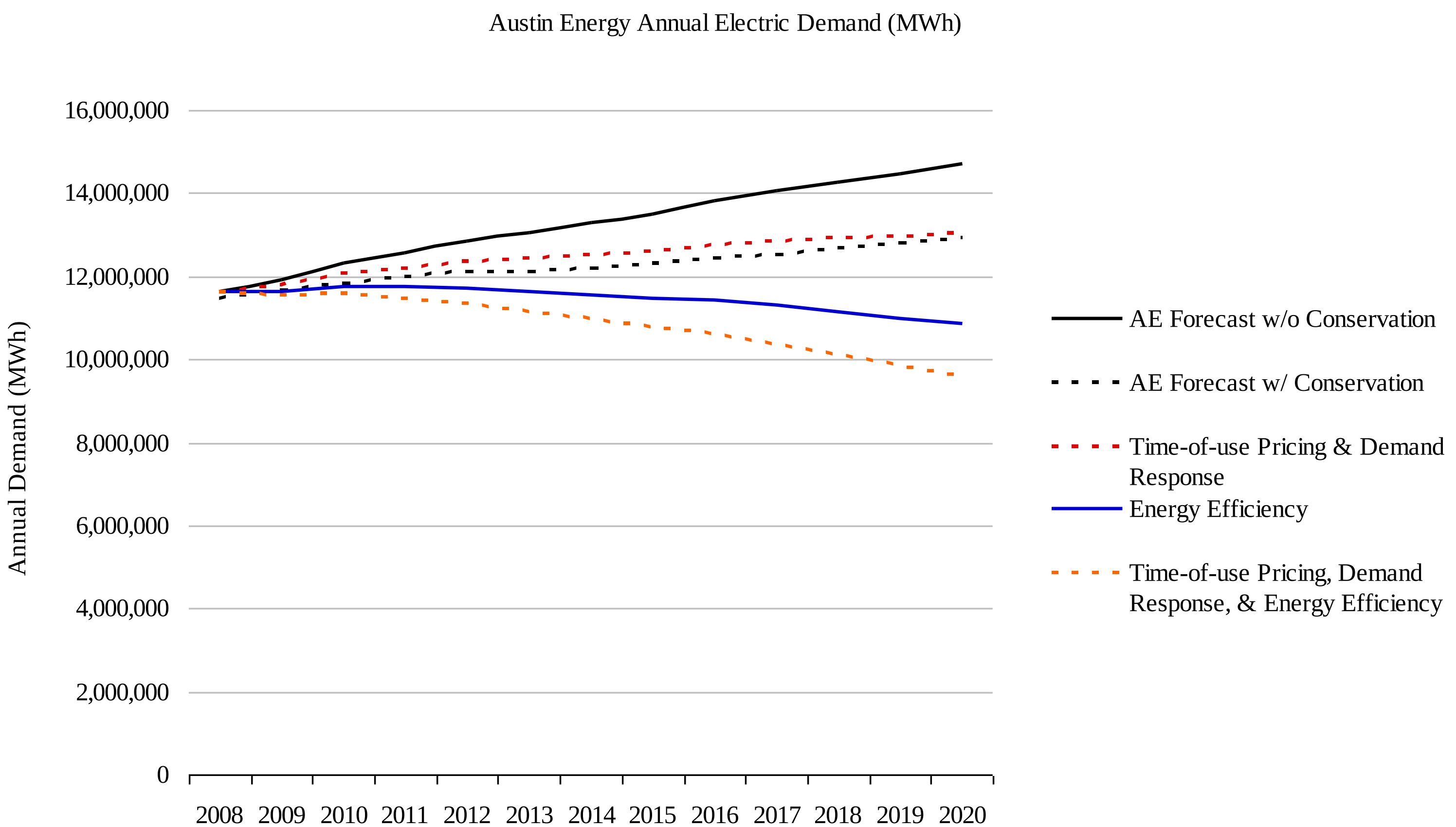


Figure 11.3
Peak Day Hourly Profile for DSM Strategies

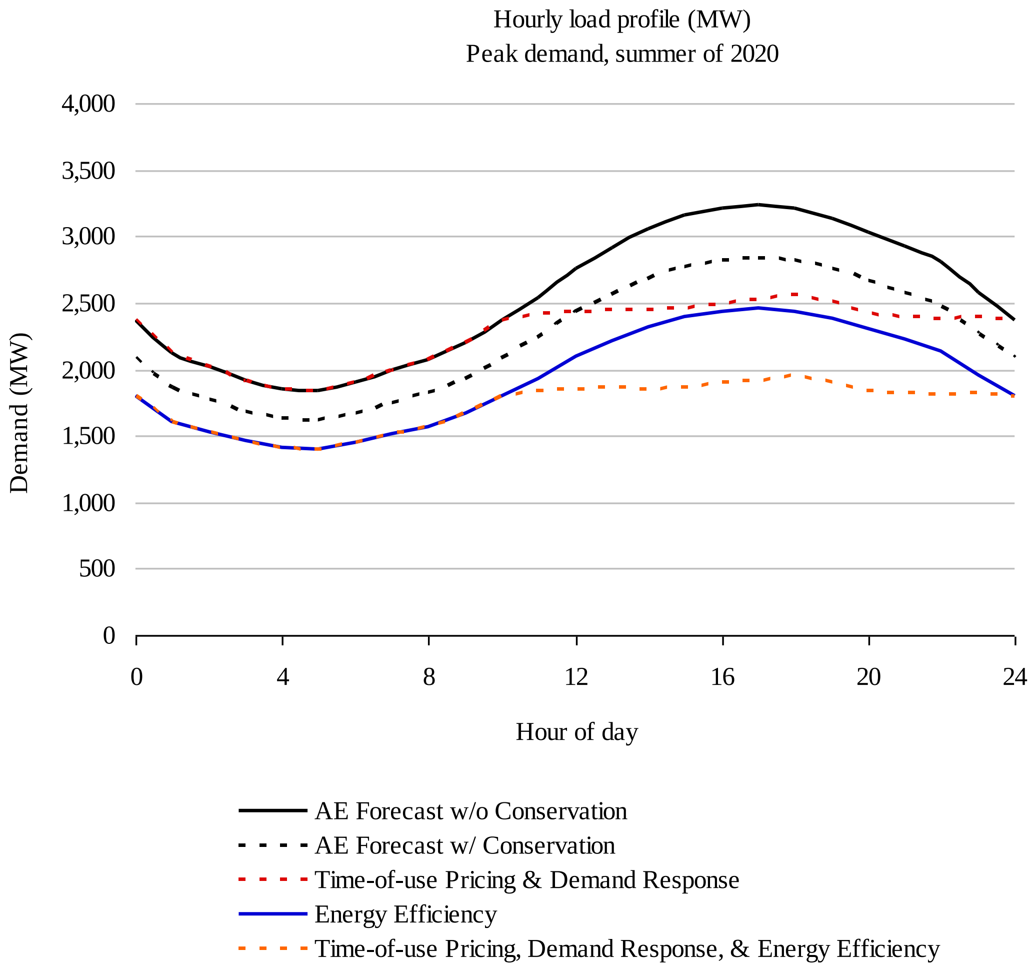


Figure 11.4
Accelerated DSM Scenario Power Generation Capacity

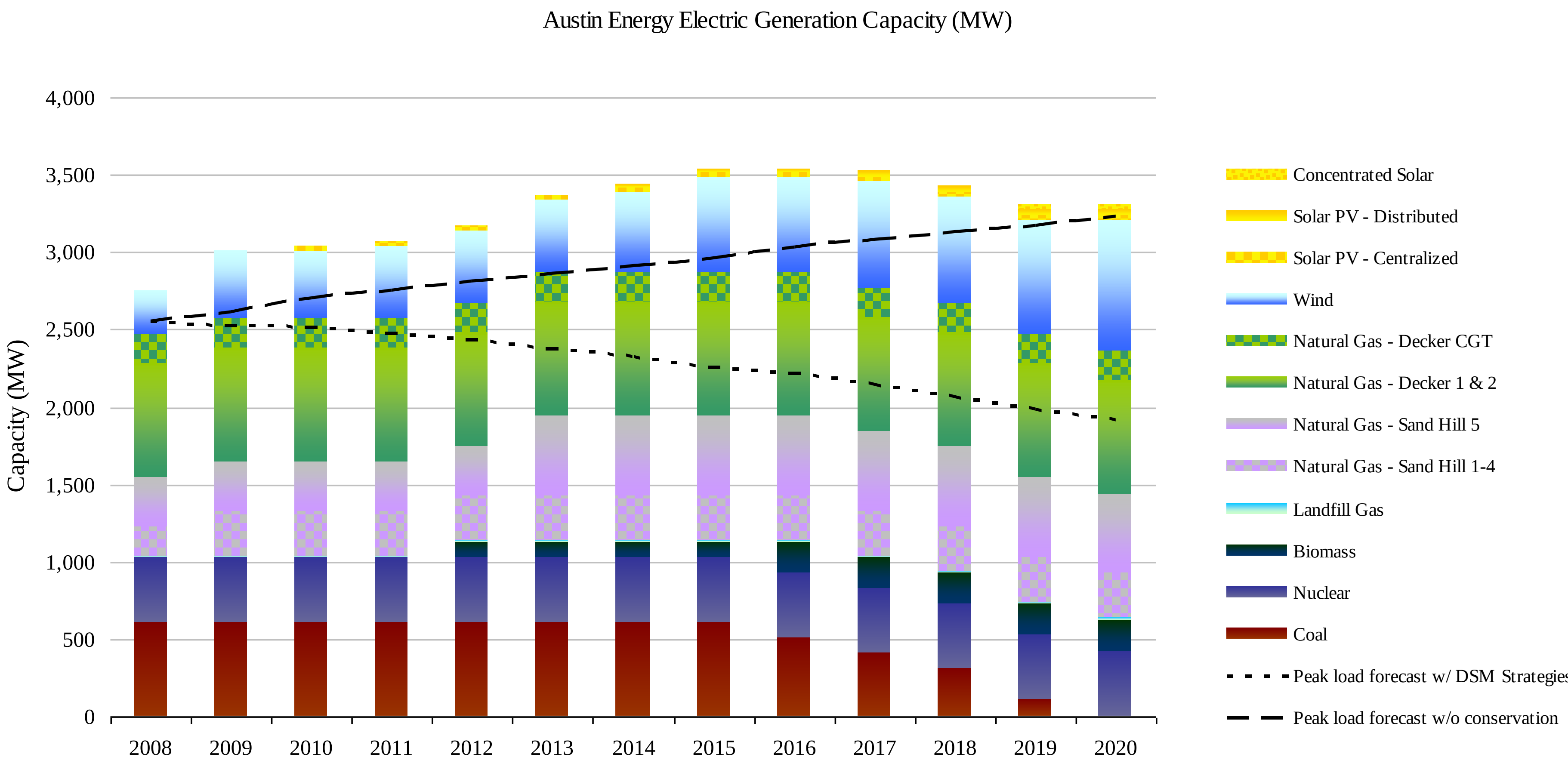


Figure 11.5
Accelerated DSM Scenario Electric Delivery

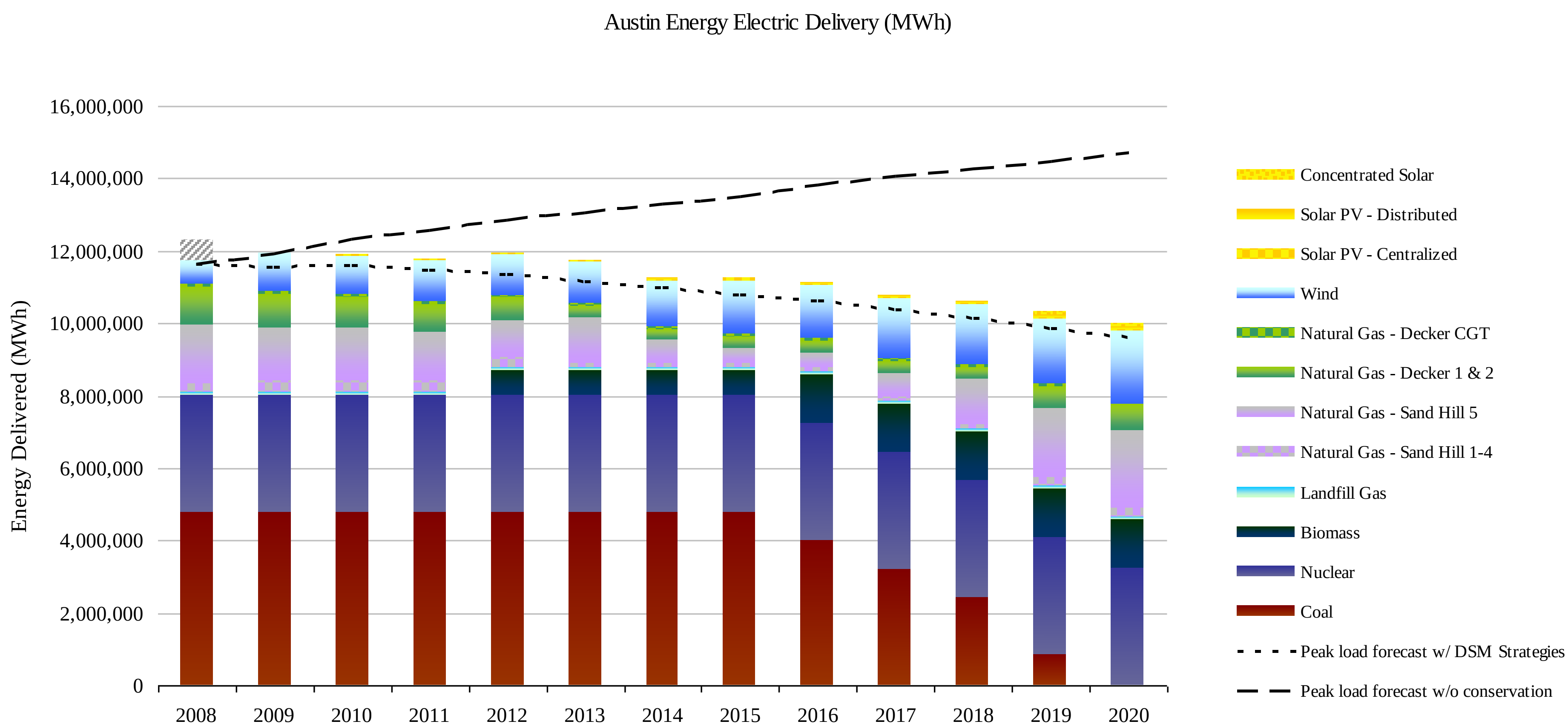


Figure 11.6
Accelerated DSM Scenario Hourly Load Profile (Peak Demand, Summer 2000)

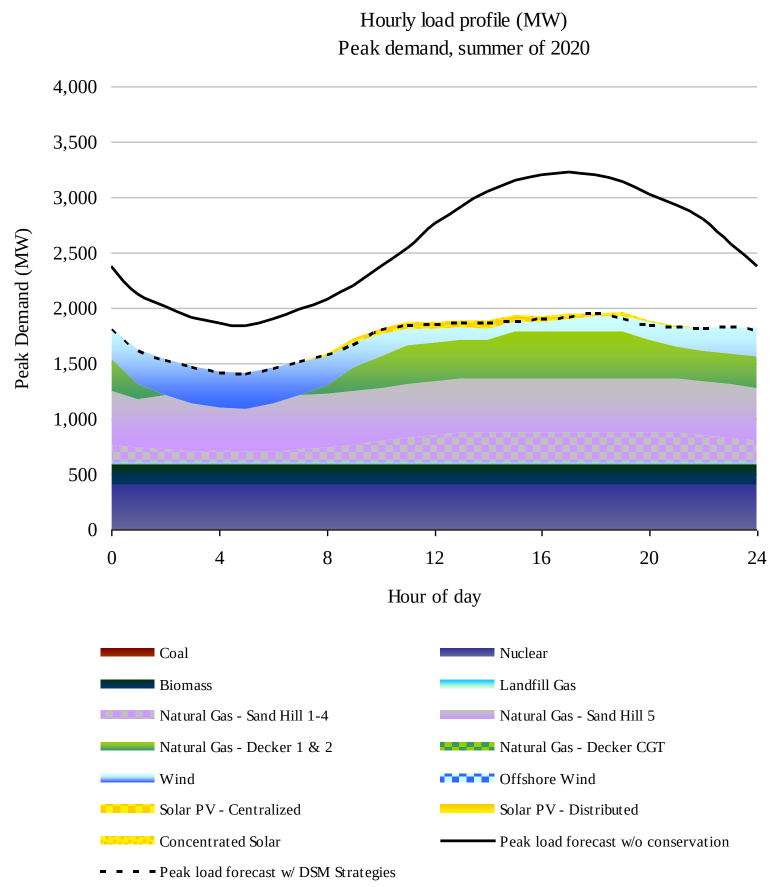


Figure 11.7
Accelerated DSM Scenario Direct Carbon Dioxide Emissions

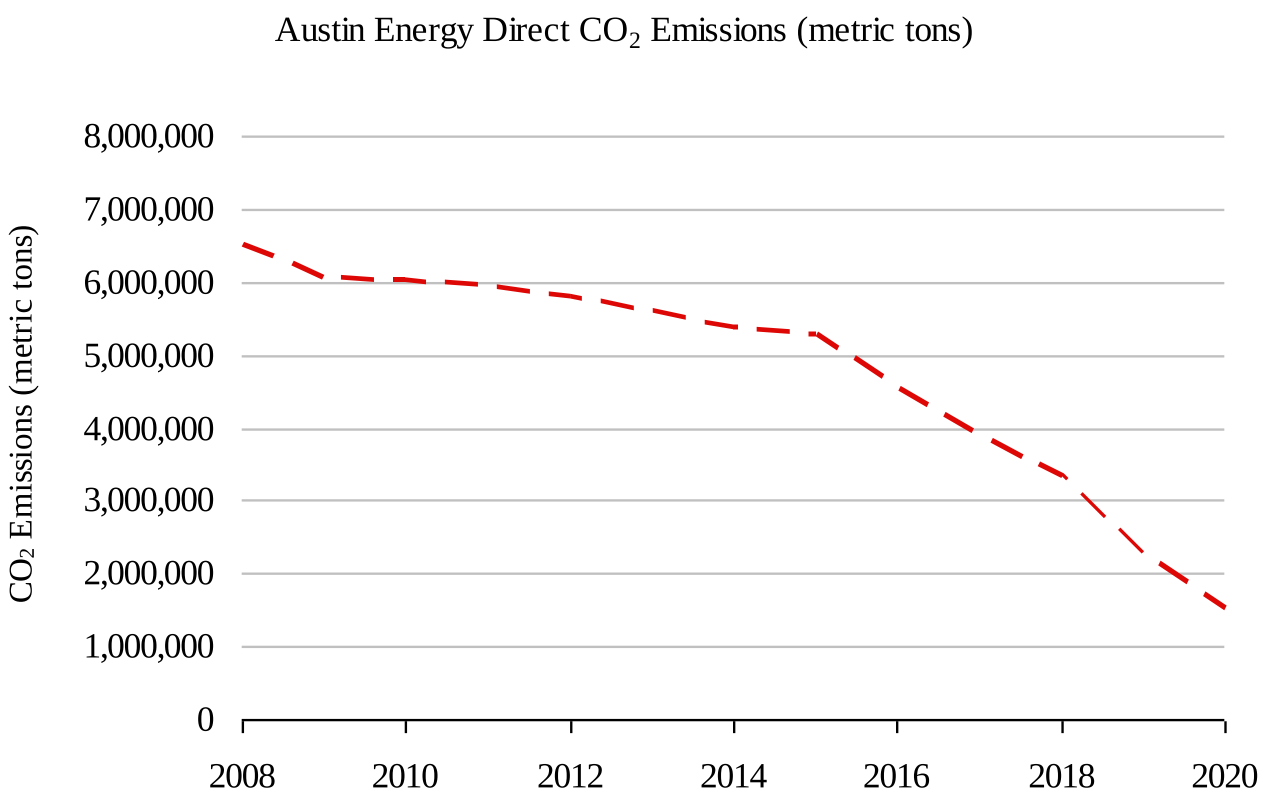


Figure 11.8
Accelerated DSM Scenario Carbon Allowance Costs

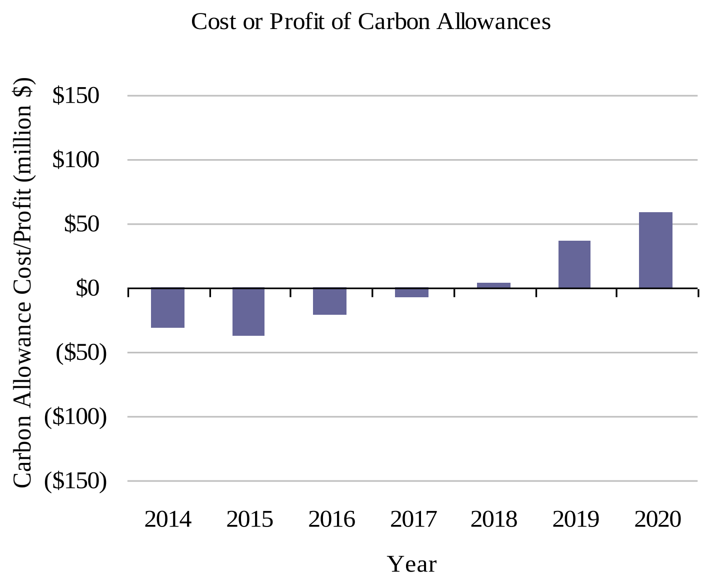


Figure 11.9
Accelerated DSM Scenario Carbon Offset Costs

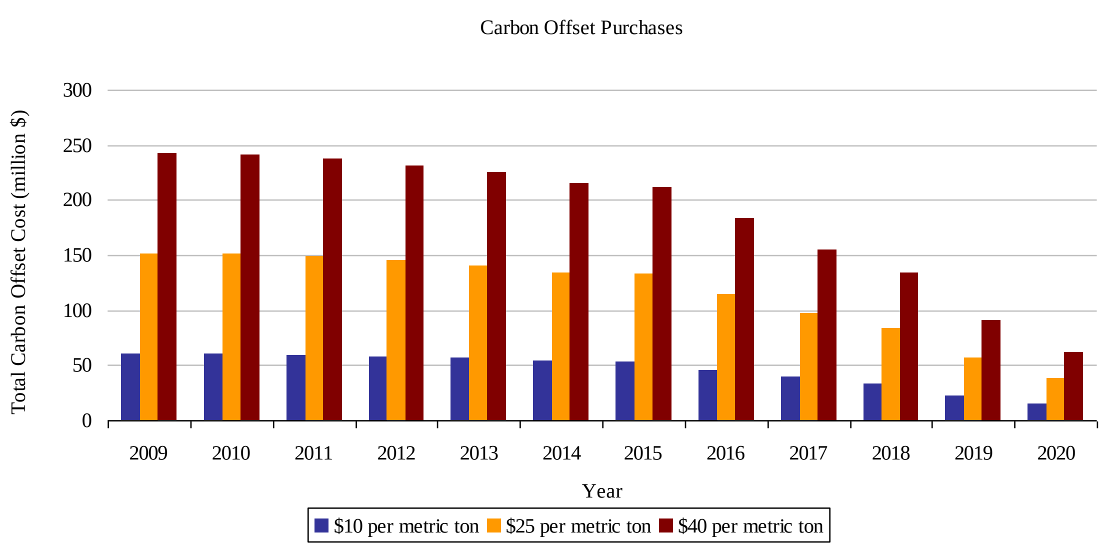


Figure 11.10
Accelerated DSM Scenario Capital Costs

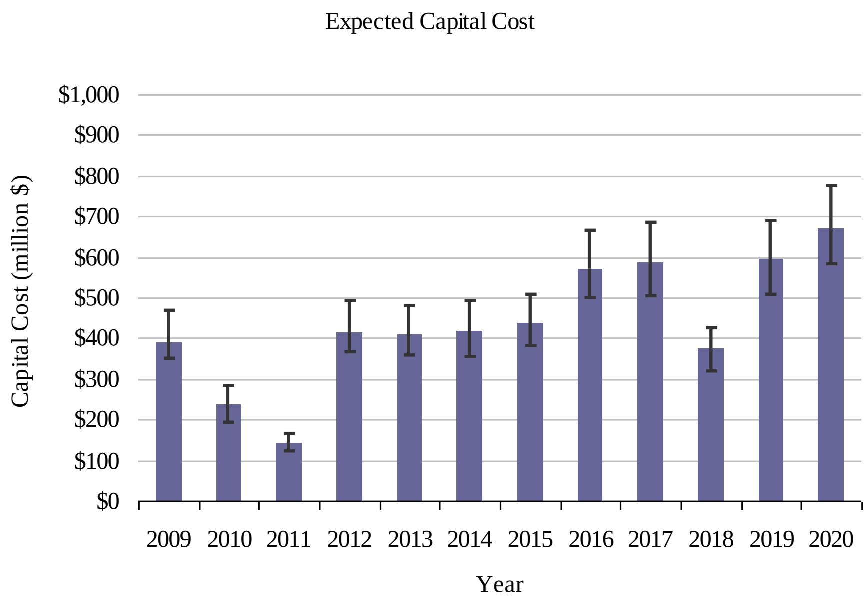
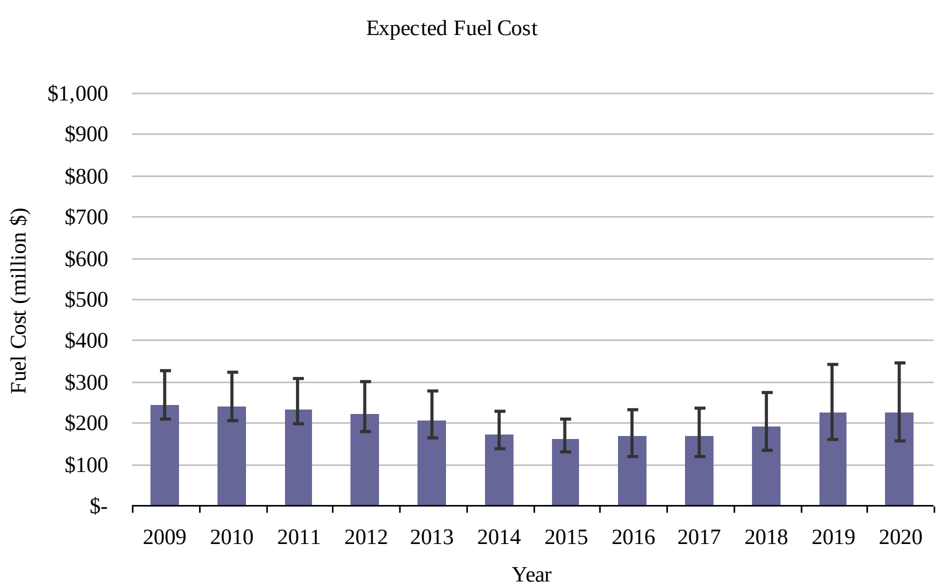


Figure 11.11
Accelerated DSM Scenario Fuel Costs



Chapter 12. Conclusions and Recommendations

The evaluation model developed by the project team allows one to compare different investment options that would reshape Austin Energy's (AE) resource portfolio by 2020. Seven primary scenarios that demonstrate the diversity of investment opportunities identified by the project team in Volume II of this report were run for comparison with AE's proposed energy resource plan. Additionally, the impact of demand-side management (DSM) savings exceeding AE's goal of 700 megawatts (MW) of demand savings by 2020 is also included in this report. The seven primary scenarios evaluated include: nuclear expansion; high renewable energy investment; expected available renewable energy investment; expected available renewable energy investment with energy storage capacity; natural gas expansion; coal with carbon capture and sequestration facility to replace current coal facility; and high renewable energy investment to replace both coal and nuclear. Included with several of the primary scenario analyses is an appendix that details the impact of each major resource or technology investment within each individual primary scenario. The appendices are intended to serve as a sensitivity analysis of each resource or technology investment made in a given scenario or other degrees of investment that could be made in a particular resource or technology. Table 12.1 lists the energy resource mix scenarios evaluated and the components of the analysis of these scenarios. The scenarios evaluated and their associated outputs are not intended to provide a complete list of all of the possible investments that could be made by AE through 2020. Rather, the intention is to evaluate a diverse range of options with a model that has the ability to easily evaluate new options as they are presented.

In this chapter, resource portfolio scenarios are compared using measures that indicate four criteria: system reliability, carbon reductions, costs and economic impacts, and risks and uncertainties. This report is intended to inform AE customers and the general public about the impact that investments in different energy resources and power generation technologies may have upon these criteria. Comparative tables with rankings based on measures identified for each of the four factors are provided in this chapter.

The primary goal of this report is to evaluate sustainable energy options for AE with the interim goal of reaching carbon neutrality by 2020. Therefore, we believe that the impact of different investments on AE's carbon footprint should have the greatest significance for the findings and recommendations provided herein. While all of the primary scenarios demonstrate reductions in AE's carbon footprint, the amount of reduction varies considerably in degree and cost. A comparative table that ranks the eight scenarios in terms of costs of carbon reductions is included in this chapter.

Comparison of Resource Portfolios

The goal of the model is to provide a simple tool for comparing different energy resource portfolios. The model created for the purposes of this evaluation has the capacity to be quickly and easily run for any investment plan identified by a user (albeit limited by the models inputs). Eight scenarios have been evaluated for comparison of their impacts upon AE's power system. In Chapters 2 through 9 of this volume of the report, the actual outputs generated by the model for each scenario are accompanied by an interpretation and analysis of each scenario. These eight scenarios are not intended to preclude the consideration or evaluation of other potential investment plans.

These eight scenarios have been identified to recognize and assess the impacts of different approaches to reducing AE's carbon footprint. These scenarios provide a diverse set of options by focusing on different types of energy resources and power generation or energy storage technologies. The intent of the comparison of these eight scenarios is to provide the reader of this report with an overview of a range of investment and divestment opportunities along with information on the impact of these investments. Almost every power generation or energy storage technology that has been identified by the project team as a feasible investment opportunity between 2009 and 2020 is included in one or more scenario. Each reader can consider the estimated consequences of investing in her or his preferred technologies. Each user can use the raw data to design an AE resource portfolio that she or he prefers.

The project team accepts that there is no easy way to compare these eight scenarios or others that could or should be developed to explore AE's diverse potential energy portfolios. The project's approach is to compare alternate scenarios based on four criteria: system reliability, costs and economic impacts, CO_2 emissions, and risks and uncertainties. The tradeoffs among criteria are clear (as discussed below), so it is important to construct a transparent comparison process as other analysts may wish to use different metrics of comparison. It is possible for AE to reach close to carbon neutrality by 2020 using any of the eight scenarios by using different approaches. The following paragraphs compare the logic involved in these tradeoffs.

In some scenarios (high renewables) AE will spend a lot of money buying new renewable energy sources in order to relieve current carbon-intensive fuels from service. Such options may be more "sustainable" in the sense that renewable resources are carbon neutral. If the US were to develop federal carbon regulations AE may be able to earn returns on these investments in the form of allowances. Fuel costs would drop, so the savings in fuel would eventually balance out the increased capital expenses. No returnable private business discount rate is likely to justify the disproportionate investment required to achieve the high renewables scenario, as the substantial annual fuel savings would require many years to compensate AE for the capital investments.

The nuclear expansion option that allows for the retirement of coal-fueled electricity is a different value judgment. Nuclear expansion can yield low-cost power and a zero carbon footprint with the potential for carbon offset payments to morph into carbon allowances that earn money for AE. The issue is whether the public is willing to accept the risks associated with nuclear energy. Risks include very high capital costs, construction delays, and political consideration of issues relating to the sustainable merits of nuclear energy due to the production of radioactive wastes. As no new nuclear power plant has been built in the US for several decades it is hard to assess whether estimated capital costs will fall within "expected" values or be even more expensive per kWh than solar power. The tradeoff is unintended risks versus expected costs, a value judgment that only elected officials have the right to make.

The third example of tradeoffs among scenarios comes from AE's base case, its resource plan, where carbon neutrality could only be reached through an annual payment of carbon offsets. One must judge whether the purchase of carbon offsets to achieve carbon neutrality truly constitutes a sustainable electric utility. While AE's resource plan has the lowest incremental capital costs per kWh of the eight scenarios it also makes the least progress towards carbon neutrality as it accepts the existing coal source and actually expands reliance on natural gas as a complement to variable solar and wind resources.

The problem with this conceptual comparison among these scenarios (which could be expanded to all eight scenarios or even other scenarios) is that is not easy to analyze such marginal changes without making a value judgment. As a result, the project team has attempted to evaluate the scenarios by identifying performance measures of interest to AE's customers. These measurements relate to certain criteria that impact investment decisions in the electric utility industry. Table 12.2 lists the criteria used to evaluate the eight primary scenarios identified by this report. For each criterion multiple measurements are used to compute an ordinal ranking of the eight resource portfolio scenarios under each criterion.

System Reliability

The primary goal of an electric utility provider is to provide reliable service by ensuring that electricity is available at all times to meet customer demands. Measurements of system reliability capture the ability of the utility to generate electricity to meet yearly and peak demand, transmit and distribute electricity, and handle unexpected weather events or technological failures. Total nameplate power generation capacity determines the system's entire capacity for generating power, but the size of the system can be deceiving in terms of ability to generate electricity when a large proportion of the capacity is attributed to variable power sources (e.g., wind and solar). Since wind and solar cannot be relied upon to generate electricity at all times, we define the total nameplate power generation capacity of all non-variable resources as a metric of reliability. Utilities focus on peak demand to determine if their resource portfolio can handle the highest level of demand expected. We define another reliability metric as the ability of a resource portfolio to meet expected peak demand in 2020 as a fraction of peak hourly demand met in 2020. Wind and solar hourly profiles are used to account for the expected amount of electricity generated by these resources on a peak demand day. As AE increases its reliance on variable resources it is important to recognize the risks and uncertainties this poses to system reliability. Power generation attributed to wind and solar is vulnerable to unavailability due to uncontrollable factors. Wind and solar power generation is constrained by the magnitude of wind velocity and solar radiation on a particular day at a particular time. One way to ensure reliable service from variable energy sources is by "backing up" these sources with natural gas facilities that can be quickly ramped up in case of expected or unexpected weather events or technological failures. The ratio of available natural gas capacity over the course of the year (after expected natural gas capacity is used) to solar and wind capacity provides an indication of the ability of AE to provide electricity when necessary to account for lower than expected variable resource power production. Reliance on natural gas is also measured to indicate the availability of natural gas resources as a backup to variable resources. The ability of AE to provide reliable electric service to its customers is not only determined by its ability to produce power. AE must also have adequate transmission and distribution infrastructure in place to ensure electricity can be transferred from its source to its end-use. Since it is expected that most utility-scale renewable power generation plants will be built in rural, scarcely populated regions of Texas, the percentage of power generation attributed to biomass, geothermal, solar, and wind is measured as an indicator of the transmission and distribution requirements necessary for a particular resource portfolio. It is assumed that coal, natural gas, and nuclear facilities would be built in areas of the state with existing adequate transmission and distribution infrastructure.

Table 12.3 summarizes the quantitative and qualitative system reliability indicators. Based upon the measurements used in this analysis, AE's energy resource plan emerges as the leading candidate for ensuring system reliability. Only three of the scenarios are able to meet peak demand without purchasing power from the electric grid: AE's energy resource plan, the high renewables scenario, and the expected available renewables with energy storage scenario. The nuclear expansion scenario comes close to being able to meet peak demand by doubling current nuclear capacity (from 422 MW to 844 MW) to replace the 607 MW of power generation capacity attributed to coal. If AE were to substitute all of the current coal power generation supply with nuclear (a 607 MW addition of nuclear power generation capacity), it would be able to meet peak demand in 2020 and would ensure system reliability similarly to AE's proposed resource plan. None of the scenarios falls dramatically short of meeting peak demand. The two high renewable scenarios appear to be the only two scenarios that face serious risks due to reliance on unreliable variable energy resources, wind and solar. Under the high renewables scenario, it appears that even if all of the expected wind and solar resources were unavailable, 50 percent of the nameplate capacity would be supported by available natural gas capacity. Since wind and solar capacity factors are already low, natural gas capacity may be able to account for the complete loss of wind and solar availability even under the high renewable scenario. The high renewables scenarios could only occur if Texas' proposed new transmission infrastructure is built. Texas is currently investing 5 billion dollar to build extensive transmission lines in West Texas to deliver electricity from wind farms to the most populous cities in Texas. It is unclear whether these investments would be able to transmit such a large investment in West Texas wind and solar resources to AE. The feasibility of the high renewables case could depend on the amount of investment by other utilities in wind and solar resources.

Carbon Emission Reductions

The primary purpose of this report is to identify investments that will help AE design a sustainable electric utility that is carbon-neutral by 2020. Carbon-neutrality has been defined by this report as eliminating AE's carbon footprint by reducing direct carbon dioxide (CO_2) emissions as low as possible and offsetting the remaining emissions to zero. Direct CO_2 emissions are measured to demonstrate the ability of different investments to reduce emissions from current levels prior to buying offsets. The expected annual cost of offsetting the remaining emissions is provided as a separate measurement. The expected annual cost or profit from buying or selling allowances under a carbon regulatory framework is also measured.

Table 12.4 summarizes the quantitative and qualitative indicators of CO_2 emissions and associated potential carbon costs. Three outputs are generated related to CO_2 emissions and associated costs for three of the portfolio options (AE's plan, nuclear expansion, and high renewable): direct CO_2 emissions by year through 2020 and expected costs or profits from carbon allowances (based upon the proposed Lieberman-Warner Climate Security Act of 2007). The three measurements are related, as the greater the reduction in CO_2 the lower the annual costs of offsets and allowances. The high renewable scenario achieves annual CO_2 reductions of over 5.5 million metric tons of CO_2 by 2020 from 2007 levels (about 6.1 million metric tons), the greatest reduction of all eight scenarios by at about 1 million metric tons. The nuclear expansion scenario achieves the second largest reduction in CO_2 emissions by 2020 and the AE resource plan achieves the lowest reduction in CO_2 emissions, reducing between 2007 and 2020 annual emissions by about 300,000 metric tons prior to the purchase of offsets. Under the high renewable scenario, it is estimated that the annual costs of offsetting emissions would be about $14 million by 2020 at an offset cost of $25 per metric ton of CO_2 emitted. The cost of offsetting emissions in the future is unclear due to the uncertainty of carbon regulation in the US. The cost of offsetting emissions is fairly low currently (at about $4-8 a metric ton of CO_2), but would likely rise if carbon regulation is implemented in the US. Under the AE resource plan, this cost would be about $144 million annually. Based upon the carbon regulatory scheme proposed by the Lieberman-Warner bill, three of the scenarios would result in the need for AE to purchase allowances in 2020: the AE resource plan (at an annual cost of about $96 million); the expected available renewables scenario (at an annual cost of about $31 million); and the natural gas expansion scenario (at an annual cost of about $31 million). The high renewable scenario would generate about $94 million annually through the sale of allowances by 2020. The nuclear expansion scenario would generate about $55 million annually through the sale of allowances. It is expected that the value of allowances would continue to increase each year after 2020.

Costs and Economic Impacts

This report indicates that making investments with the intent of reducing AE's carbon footprint can entail significant costs, so the costs and expected impacts on customer electric rates are another criteria posited by this analysis. To evaluate the total economic impacts of a resource portfolio, various cost indicators are measured along with the projected economic development impacts in Austin and surrounding counties. Total expected capital costs measures the expected capital outlay (measured as total overnight costs) that would be necessary through 2020 for a particular investment plan. Such costs can affect electric rates, AE's credit rating, and AE's ability to finance new projects.

Total expected fuel costs measures the reliance on fossil fuels and the risk of volatile fuel prices. Fuel costs may become increasingly volatile as competition for fossil fuels increases with global economic activity. Carbon regulation could also affect fuel prices, as combustion of fuels emits large amounts of CO_2. The expected increase in levelized cost of electricity attempts to capture the actual impact of investments on customer electric bills. It should be noted that throughout this analysis no "value" is imputed to the leasing or selling of AE's share of ownership in a power plant facility in the levelized cost of electricity. The calculators do not attempt to represent the flows of debts. Any sale or lease of AE's power plant ownership, such as its stake in FPP, could be used to pay for the purchase of other power sources or could contribute to a reduction in electric rates at that time.

Table 12.5 summarizes the quantitative and qualitative indicators of costs and economic impacts. The expected capital costs of the high renewable scenarios (about $8.3 million) exceed that of AE's resource plan (about $2.2 million) by a factor of almost four. While total expected fuel costs are about $600,000 lower in the high renewable scenario, lower fuel costs do not offset the capital costs incurred during this time period. Selling or leasing ownership in FPP would offset some of these costs under the high renewable scenario. The natural gas expansion scenario would entail the lowest expected capital costs (at about $1.4 million), but would have the greatest expected total fuel costs (at about $4.8 million). Annual fuel costs by 2020 would be the highest under a natural gas expansion scenario. The high renewables scenario would have the lowest annual expected fuel costs by 2020, but it would take several decades for annual fuel costs, at current prices, to offset the high capital costs. The expected increase in levelized costs of electricity attempts to account for the costs of financing power generation projects and all costs that go into the production of electricity including capital and variable costs. The current cost of electricity for AE customers is about 10 cents per kWh, but varies based upon the amount of electricity consumed during a billing period. The expected increase in the cost of electricity is about 2 cents per kWh under AE's proposed energy resource plan. The expected renewables scenario would face an expected increase in cost of electricity of 2.2 cents per kWh, but this does not capture the increased reliance on natural gas that could raise the fuel charge for customers. The high renewable scenario estimates an expected increase in the cost of electricity of about 5.8 cents per kWh by 2020. The cleaner coal scenario also demonstrates a high expected increase in cost of electricity of 5.7 cents per kWh. The natural gas scenario estimates an expected increase of 5.7 cents per kWh, but this may be misleading because much of the natural gas expansion comes in the form of combustion turbines that would be used to provide large amount of electricity. As it is unlikely that AE would operate combustion gas turbines at high levels of use, actual costs would likely be lower with the expansion of combined cycle facilities replacing combustion gas turbine expansion to be used for high levels of use. The nuclear expansion scenario provides a middle ground cost of electricity increase between AE's resource plan and the high renewable scenario with an expected increase of 3.9 cents per kWh. However, nuclear investments entail high capital cost risks and the potential for project delays that could push costs higher. The AE resource plan appears to be the least cost option followed by the expected renewable scenario and the nuclear expansion scenario. The value of the sale or lease of FPP could alter this ranking.

Risks and Uncertainties

Any future is full of uncertainties, starting with the question of whether 2020 electricity demand will be lower or relatively similar than demand in 2008 due to a prolonged depression or whether growth will push 2020 demand at or above AE forecasts. Any portfolio of power sources has risks and uncertainties associated with it. Measurements of risks include uncertain cost estimates and reliance on variable resources or immature technologies. High estimates of capital costs, fuel costs, and increases in levelized cost of electricity represent one criterion of AE cost risks. The fraction of total demand met by energy sources that vary (solar and wind) is an indicator of the risk of relying heavily on sources of energy that are dependent on weather and wind patterns as well as time of day. Reliance on new emerging technologies is another type of risks that will affect electricity availability and reliability.

Table 12.6 lists indicators of risks and uncertainties. Taking the high estimate of total capital costs, fuel costs, and increase in levelized cost of electricity does not alter the ordinal rankings of these scenarios from expected costs. For example, the nuclear expansion scenario faces the greatest capital costs and levelized cost of electricity risks due to the uncertainty of the costs that will be incurred to build the nuclear expansion. The natural gas expansion scenario faces the greatest fuel costs risk. The cleaner coal and natural gas expansion scenarios have the lowest fraction of total demand met with variable resources in 2020. The high renewables scenario places a considerable amount of dependency on variable resources at almost 60 percent of electricity generated (compared to 17 percent under AE's resource plan). No other scenario places more than 24 percent reliance on variable resources in 2020. Risks from immature technologies are greatest under the clean coal scenario, expected renewable with energy storage and the high renewable scenarios.

Table 12.7 ranks the eight resource portfolio options by assigning equal weight to all comparative measures within each criteria and then assigning equal weight to each criteria to compute an average order ranking across the four criteria. While such a measure which has no absolute meaning whatsoever, as it is an index of indices added together, it is a means to compare scenarios. Of all the ways that multiple criteria can be aggregated, this approach is used because it is transparent and simple; other users can adopt their own multi-criteria measures.

The AE proposed energy resource plan receives the highest overall ranking despite achieving the lowest reductions in CO_2 because it received the highest ranking for system reliability, costs and economic impacts, and risks and uncertainties. The nuclear expansion scenario is ranked second because of the significant reductions the scenario makes in CO_2 emissions. The high renewable scenario receives a slightly higher ranking than the expected available renewables, natural gas expansion, cleaner coal, and expected available renewable with energy storage scenarios. The high renewables without coal and nuclear scenario has by far the lowest average ranking of the eight scenarios. It appears that the nuclear expansion scenario and AE's resource plan receive comparable rankings when the factors of system reliability, CO_2 reductions, costs and economic impacts, and risks and uncertainties are all assigned equal weight. AE's resource plan is less costly, more reliable, and faces lower risks and uncertainties than the nuclear expansion scenario, but fails to make significant reductions in CO_2 emissions. The implication of this result is that if a user is comfortable with nuclear power's costs, risks and uncertainties (as compared to the value of reducing CO_2) then nuclear expansion would be favored to replace coal. If a user is troubled by nuclear energy's risks and is willing to accept the high costs and risks of relying on renewable energy sources, then the high renewables scenario appears to be the best option. The following sections include details on the measurements used to obtain scores for the four identified criteria: system reliability, CO_2 reductions, costs and economic impacts, and risks and uncertainties. Outputs generated by the model for three of these options (AE's plan, nuclear expansion, and high renewable investment) are included in each criteria section. The full-length report details the results of all eight scenarios.

This report seeks to estimate the costs and risks for AE to reach carbon neutrality by 2020. Each energy portfolio has an associated cost for reducing CO_2 emissions. Table 12.8 provides several categories for comparison that demonstrate the estimated costs to reach carbon neutrality for each resource portfolio. To estimate which scenarios have the best "bang for the buck" for reducing CO_2 emissions, two criteria have been used: metric tons of CO_2 reduced in 2020 from 2007 levels by million dollars invested in capital and by cents per kWh of expected rise in cost of electricity. The nuclear expansion scenario exhibits the greatest efficiency reductions in cents per kWh of expected rise in the cost of electricity, at about 1.14 million metric tons per cent increase (compared to 161,000 metric tons under AE's resource plan). The nuclear expansion scenario achieves the second greatest reductions of dollars of capital invested at 1,141 metric tons per dollar invested (compared to 144 metric tons under AE's resource plan). The natural gas expansion scenario achieves a reduction of 1,534 metric tons of CO_2, but this figure is deceiving because it does not account for the high fuel costs associated with natural gas expansion. It achieves the second least reductions based on metric tons of CO_2 reduced by cent per kWh of expected rise in cost of electricity at 366,800 metric tons. AE's proposed energy resource plan achieves the least reductions in CO_2 based upon these two measurements for the eight scenarios. Expected total costs of offsetting CO_2 emissions to zero through 2020, purchasing allowances, annual costs or profits of allowances, and annual costs of offsets are all lowest for the high renewables scenario, followed by the nuclear expansion scenario. AE's resource plan is last in all of these categories.

Based on a cumulative score from these carbon reduction and cost categories the nuclear expansion scenario has the lowest relative costs for reducing carbon emissions, followed by a large investment in renewables. These results follow the charts in , Figure 12.2 and Figure 12.3. These charts compare the amount of CO_2 reductions achieved with their associated costs. Scenarios lying on the left side of the axis and equal to a scenario on their right side would be the better investment option as they would meet similar reductions at lesser cost. These charts demonstrate that the AE resource plan comes at the lowest costs, but also achieves the least reduction in CO_2 emissions. The expected renewables scenarios (with and without energy storage capacity) and the natural gas expansion scenario appear to make considerable reductions in CO_2 emissions without drastically raising the cost of electricity, but it should be noted that the model does not take into account the added cost of using more natural gas. The nuclear expansion scenario appears to provide the greatest reductions in CO_2 emissions at the lowest cost if expected cost estimates are achieved. However, the range of potential costs is highest for this scenario demonstrating the risks of high capital costs for nuclear expansion. At the highest cost estimate for nuclear expansion the high renewable scenario (at expected costs) would achieve greater reductions in CO_2 emissions at lower cost.

Discussion

This report discusses a diverse range of choice of fuel sources for electricity in order to encourage Austin's citizens and elected officials to remain the final arbiters of the future based on their value judgments. Each of the eight scenarios allows AE to reach carbon neutrality by 2020 either by reducing direct CO_2 emissions or through the purchase of carbon offsets. However, there are significant differences in costs, risks, and merits of achieving sustainability associated with these options. A number of conclusions are discussed below that reflect the analysis of power generation technologies and the analysis of investment options for these technologies.

AE's proposed resource plan (portfolio option 1) appears to be a reliable, low cost, and low risk investment plan compared to the other seven scenarios. It also reduces direct CO_2 emissions the least because AE continues to burn coal at a constant rate through 2020. AE is not likely to significantly reduce its carbon footprint unless it reduces its coal use.

Several alternative technologies (nuclear, natural gas, integrated gasification combined cycle with carbon capture and storage, biomass, and geothermal power plants) can create opportunities for replacing AE's current pulverized coal-fired baseload generation capacity with cleaner forms of energy, measured in terms of direct emissions of CO_2. Wind and solar resources are not reliable baseload power generation sources due to their variable nature, but may become more reliable with the development of utility-scale energy storage. Biomass and geothermal resources face availability constraints that limit their potential to replace all of AE's current coal baseload power usage. It is not known if AE could build clean coal facilities with carbon capture and storage at the necessary scale to replace FPP on its own by 2020. Additional nuclear energy capacity or natural gas appears to be a feasible means to substitute coal baseload power generation.

Nuclear expansion (portfolio option 2) provides the least expected cost option for reducing CO_2 emissions. However, expansion of AE's nuclear power comes with the largest range of cost risks and uncertainties regarding construction length. Nuclear energy continues to face uncertainty in terms of public acceptance due to concerns related to the management of radioactive waste and safety.

AE's current nuclear capacity allows it to invest in renewable baseload power sources (biomass and geothermal) to replace coal if available to ensure reliable service to customers. It remains uncertain whether AE can purchase and implement reliable additional biomass or geothermal resources prior to 2020.

The cost of investment in the "anticipated" available renewable resources (portfolio option 4) are lower than a high investment in renewables (portfolio option 3), even if option 4 only allows for half of AE's coal use to be replaced with cleaner sources of energy, thus achieving more modest reductions in CO_2. A high investment in renewables entails high expected capital costs as well as high risks and uncertainties. While the high renewables scenario may be more sustainable in that the sources once in place can continue to be used without fuel costs and it reduces CO_2 emissions more than the other options, it may be overly ambitious about where and when these resources could come on-line.

AE must maintain sufficient natural gas capacity to backup wind and solar additions to AE's resource portfolio for any of the increased renewables scenarios. The capital costs of central solar facilities remains hard to estimate and the reliability of solar and wind remains risky.

AE's planned additions for onshore wind under its proposed energy resource plan appear to be reasonable even if these wind resources have low resource availability during peak demand. Potential investments in offshore wind achieve higher rates of reductions in CO_2 emissions by displacing more natural gas use during peak hours than equal investment in onshore wind. Offshore wind currently faces uncertainty in terms of availability and costs.

Solar energy investments permit greater reductions in CO_2 emissions than onshore wind due to higher availability of solar energy during the day, as opposed to onshore wind which is primarily available during the night and morning off-peak hours. Solar investments currently come at much higher cost per kWh then wind.

Energy storage could provide a cost-effective way to achieve significant CO_2 reductions if coupled with onshore wind investments (portfolio option 5). Energy storage allows wind power generation to be temporarily stored and shifted from times of high production (early morning hours) to times of greater demand (late afternoon hours) to displace natural gas. Energy storage does not enhance the ability for solar to achieve CO_2 reductions because it is only available during times of typically higher demand. While energy storage requires additional capital, by shifting wind generated power from off-peak to on-peak hours, storage can serve as a hedge against natural gas prices. Compressed air energy storage facilities appear to be the most mature type of energy storage technology on the market today and have the highest capacities for storing energy. AE could collaborate with the LCRA to construct pumped storage facilities close to Austin. Key uncertainties with storage are the actual costs of how it would be operated and dispatched. If storage is not used on a regular basis it could become an expensive way to achieve peak shifting.

Expansion of natural gas units (portfolio option 6), particularly an additional combined cycle unit at Sand Hill, provides a low capital cost investment to displace coal use while achieving some reductions in CO_2 emissions (albeit at much lower levels than nuclear or renewable resources). Added natural gas generation capacity creates concern over natural gas price volatility. Increased reliance on natural gas should be focused on the use of combined cycle units due to the high costs of operating combustion turbines. Additional natural gas capacity can serve as a backup source for additional investments in wind and solar, to be used primarily when these resources become unavailable. The need for natural gas expansion is contingent on the magnitude of complementary wind and solar investments as well as AE's ability to purchase supplementary power from the grid if these resources become unavailable for periods of time due to weather or cloud patterns.

While replacing FPP with an advanced clean coal facility with CCS technology (portfolio option 7) would be a symbolic act of confidence in coal, it would also represent a technical risk as there are no such large-scale plants in routine operation in the US. As an immature technology, CCS would have high costs and uncertain operating characteristics as a replacement for FPP. Even though the CCS option uses a lower-cost fuel to enhance CO_2 reductions comparable to a natural gas alternative, the CCS process can carry a high energy cost.

Removing both coal and nuclear from AE's resource mix (portfolio option 8) is a risky scenario for AE. AE would face significant expansion of natural gas facilities due to the variable nature of wind and solar and the uncertainty of availability of biomass and geothermal resources.

One uncertainty affecting each scenario is the question of whether the US will regulate carbon. Carbon regulation could offset some of the costs for cleaner energy technologies by increasing the cost of emitting carbon or allowing an electric utility to generate revenues depending on the type of carbon regulation implemented. Carbon regulation alone will not make solar power generation technologies cost competitive nor will it erase the diurnal cycles of wind and solar availability.

The cost of implementing new renewable power generating technologies, particularly solar technologies, into AE's resource portfolio would need to drop considerably between 2009 and 2020 to make a high renewable investment scenario cost competitive with AE's proposed energy resource plan. Even the optimistic scenarios of solar advocates (30 percent reduction of silicon costs over a decade) cannot make solar a cost-effective source for baseload power.

The expected available renewable resources scenario demonstrates that it is possible to reduce coal use by half and reduce the amount of natural gas expansion necessary through 2020 with utility-scale solar power plant additions at cost similar to AE's proposed energy resource plan. The cost of increased use of its natural gas facilities (not captured by these calculations) could be offset by the selling or leasing of one unit at FPP (not captured by these calculations) and the value of emission reductions under carbon regulation.

Further demand reductions beyond AE's goal of 700 MW of savings through 2020 would delay the need for additional power generation capacity additions. Accelerated DSM could ease the transition to a coal-free resource portfolio and lower the costs for replacing this lost source of baseload power.

Remaining Issues

AE has some choices as to when to act and in what energy sources to invest to maintain its record of reliable low-cost electricity service to its customers as it seeks to become a sustainable, carbon-neutral utility. AE has already taken significant risks to move towards sustainability over the past several decades, including the early adoption of energy conservation and efficiency programs, green building regulations, and substantial investment in on-shore wind, and its smart grid deployment.

There are potential advantages and disadvantages to waiting to invest in new sources of power generation or energy conservation programs. AE is already becoming a utility leader in advancing new technologies and investing in cleaner sources of energy. AE is poised to have one of the first fully operational smart grid systems in the US, to receive 100 MW of power generation capacity from biomass (by 2012), and just recently had its proposal to build the largest centralized PV solar plant in the US (by 2010) approved by Council. The question is should AE also be an initial adopter of other more immature technologies such as utility-scale energy storage, carbon capture and storage, off-shore wind, and geothermal in Texas? An early adopter may have to budget for uncertain "discount" pricing and incur cost increases or delays in construction due to technological immaturity. Early adoption and investment in immature technologies entails significant risks and uncertainties that AE and Austin citizens may wish to constrain until costs become more stabilized and technologies become more advanced.

Austin citizens must also readdress the merits of nuclear expansion as a sustainable resource with the consideration of CO_2 emissions. Nuclear energy provides the most reliable and abundant baseload power source to replace fossil fuels from AE's resource portfolio without emitting CO_2.

Despite the expected scale of investment in solar and nuclear technologies it is impossible to predict whether solar costs will fall significantly over the next decade and whether the next generation of nuclear plants can come on-line under the costs and within the time estimated. It is also difficult to determine when large-scale carbon capture and storage can become cost-effective and accepted by the public. Underlying these choices are many other risks and questions related to how the US will regulate CO_2 emissions, how Texas' Legislature and ERCOT will manage its electric industry, and how Austin's citizens will weigh the value of reaching carbon neutrality against its costs and effects upon reliability of service.

Recommendations

There are many ways for AE to reach carbon neutrality by 2020. One key issue is whether AE wishes to reach carbon neutrality by potentially paying hundreds of millions of dollars in carbon fees, taxes, or offsets, or whether it wants to invest in new sources of nuclear or renewable energy that cost more to build than its proposed energy resource plan but less to operate under a carbon regulation regime. A number of inferences can be developed based upon the analysis of power generation technologies and the analysis of investment options for these technologies. The recommendations that follow are based upon these inferences.

If AE wishes to reduce its carbon footprint significantly by 2020 one option is to reduce its reliance on FPP. If AE sells or leases its ownership in two units at FPP, it should target divestment to a year that would allow AE maximum carbon credit if carbon regulation is passed prior to the divestment. If AE divests its coal capacity; to retain system reliability AE must invest in cleaner forms of baseload power generation capacity such as nuclear, biomass, and geothermal baseload power plants.

Biomass is touted as a carbon-free source of energy even though it requires the burning of carbon. Its low carbon footprint reflects an accounting anomaly that weighs CO_2 emitted from burned residues different from energy in coal and gas. AE should monitor the reporting credibility of biomass as a carbon-free source of energy if carbon regulation is passed and should independently evaluate the merits of this resource as a form of clean energy. AE could benefit from any cost-competitive sources of biomass power generation capacity up to 300 MW of power generation capacity if it is considered a verifiable carbon-free source of energy.

AE should investigate the possibilities of investment in geothermal plants in areas of the state where geothermal sources exist. Any geothermal opportunities presented by third parties should be considered for up to 300 MW of power generation capacity. Partnerships for such an investment should be pursued if the relative costs are low and the reliability of the resource is high.

AE should monitor its wind investments as a component of its overall resource portfolio and evaluate the quality of its availability. Wind energy investments are only expected to be valuable up to a point at which infrastructure is in place to transfer wind energy over hundreds of miles from West Texas to Central Texas. Wind is likely to remain a low-cost option to meet off-peak demand (between 800-1500 MW of additional onshore wind investments). Offshore wind and energy storage facilities coupled with onshore wind can flatten AE's hourly wind supply profile. AE should consider off-shore wind and energy storage to provide wind capacity during peak demand hours. Such investments should be evaluated based upon the increased value of increasing renewable power capacity at times when electricity is most needed and most costly.

AE should monitor the costs of solar technologies, particularly utility-scale solar power plants, as the marginal per-MWH costs of these technologies are expected to fall upon an increase in their market penetration. If centralized PV module solar plants (such as the proposed Webberville facility) are built in areas close to Austin, the solar industry in and around Austin would develop valuable expertise. AE could make at least 100 MW of investment in centralized PV facilities through 2020.

AE could consider investments in concentrated solar plants (particularly parabolic trough facilities) in West Texas. Opportunities presented by third parties should be considered along with proposed partnerships for such investments. The amount of investment should reflect the marginal per-MWh cost of solar energy. Should concentrated solar energy costs fall rapidly, AE could benefit from at least 200 MW of solar capacity additions and upwards of 600 MW of capacity additions to its resource portfolio by 2020. Increased efforts should be made to add distributed PV systems to roofspace in Austin. As AE’s smart grid is deployed and costs of PV rooftop systems drop AE may be able to increase its investment and efforts for subsidizing PV systems, particularly for commercial entities.

Table 12.1
Resource Portfolio Analysis Summary

	Scenario Title	Resources/Technologies with Sensitivity Analysis	Major Additions and Subtractions Through 2020
Portfolio 1	AE Resource Plan	None	Add biomass, natural gas, solar, and wind
Portfolio 2	Nuclear Expansion	Nuclear and natural gas	Nuclear replaces coal and AE resource plan additions
Portfolio 3	High Renewables	Onshore and offshore wind, concentrated solar power, centralized and distributed PV, biomass, and geothermal	Very high investments in biomass, geothermal, solar, and wind technologies to replace coal
Portfolio 4	Expected Renewables	Refer to portfolio 3 sensitivity analysis	Expected available investments in biomass, geothermal, solar, and onshore wind to replace coal
Portfolio 5	Renewables with Storage	Various energy storage technologies	Expected renewables coupled with energy storage of wind to replace coal
Portfolio 6	Natural Gas Expansion	Natural gas, co-firing biomass	Natural gas replaces half of current coal and AE resource plan additions
Portfolio 7	Cleaner Coal	IGCC without carbon capture and storage technology	IGCC with carbon capture and storage to replace Fayette Power Project and AE resource plan additions
Portfolio 8	High Renewables without Nuclear	Pulverized coal, IGCC with and without carbon capture, and natural gas	High renewables to replace coal and nuclear

Table 12.2
Criteria and Measures for Evaluating Resource Portfolios

Criteria	Measures
Criteria #1: System Reliability in 2020	• Reliable power generation capacity (based on MW capacity of non-variable resources) • Ability to meet peak demand on the peak day in 2020 • Ratio of available natural gas capacity to solar and wind capacity. • Reliance on natural gas (based on yearly MWh) • Infrastructure requirements (based on MW capacity of biomass, geothermal, solar and wind)
Criteria #2: Carbon Profile in 2020	• Direct carbon emissions (metric tons of CO_2) • Annual cost of offsets • Annual costs or profits of allowances
Criteria #3: Costs and Economic Impacts Through 2020	• Total expected capital costs • Total expected fuel costs • Expected increase in levelized cost of electricity in 2020 • Economic development in Austin and surrounding 10 counties
Criteria #4: Risks and Uncertainties	• High estimate of total capital costs through 2020 • High estimate of total fuel costs through 2020 • High estimate of increase in levelized cost of electricity in 2020 • Fraction of total demand met with variable resources in 2020 • Technological maturity subjective ranking

Table 12.3
Measures of System Reliability (in 2020, rankings in parentheses)

	Total Power Generation Capacity of Non-Variable Resources (MW)	Fraction of Peak Hourly Demand Met (%)	Ratio of Unused Natural Gas Capacity to Wind and Solar Capacity	Fraction of Total Demand Met with Natural Gas (%)	Total Power Generation Capacity of Biomass, Geothermal, Solar and Wind (MW)
Portfolio 1-AE Resource Plan	2,976 (1)	100% (1)	1.58 (2)	14.6% (2)	1147 (1)
Portfolio 2-Nuclear Expansion	2,791 (4)	98.8% (6)	1.41 (4)	24.6% (4)	1147 (1)
Portfolio 3-High Renewables	2,374 (7)	100% (1)	0.50 (7)	4.6% (1)	3293 (7)
Portfolio 4-Expected Renewables	2,471 (6)	93.5% (8)	0.95 (5)	25.7% (5)	1388 (5)
Portfolio 5-Renewables with Storage	2,719 (5)	100% (1)	0.92 (6)	41.5% (7)	1388 (5)
Portfolio 6-Natural Gas Expansion	2,976 (1)	100% (1)	1.65 (1)	48.4% (8)	1147 (1)
Portfolio 7-Cleaner Coal	2,976 (1)	100% (1)	1.57 (3)	15.6% (3)	1147 (1)
Portfolio 8-High Renewables Without Nuclear	1,952 (8)	97.3% (7)	0.38 (8)	26.7% (6)	3293 (7)

Table 12.4
Measures of Carbon Profile (in 2020, rankings in parentheses)

	Direct Carbon Emissions (metric tons of CO_2)	Annual Costs of Offsetting Emissions to Zero ($ million)	Annual Costs or Profits of Allowances ($ million)
Portfolio 1-AE Resource Plan	5,761,000 (8)	144 (8)	-96 (8)
Portfolio 2-Nuclear Expansion	1,646,000 (2)	41 (2)	55 (2)
Portfolio 3-High Renewables	566,000 (1)	14 (1)	94 (1)
Portfolio 4-Expected Renewables	3,993,000 (7)	100 (7)	-31 (7)
Portfolio 5-Renewables with Storage	2,984,000 (5)	75 (5)	6 (5)
Portfolio 6-Natural Gas Expansion	3,021,000 (6)	76 (6)	4 (6)
Portfolio 7-Cleaner Coal	1,791,000 (3)	45 (3)	49 (3)
Portfolio 8-High Renewables Without Nuclear	2,031,000 (4)	51 (4)	41 (4)

Table 12.5
Measures of Costs and Economic Impacts (through 2020, rankings in parentheses)

	Total Expected Capital Costs ($million, through 2020)	**Total Expected Fuel Costs ($million, through 2020)**	**Expected Increase in Levelized Costs of Electricity in 2020 (cents/kWh)**	**Economic Development in Austin and Surrounding 10 Counties (measured in net job years)**
Portfolio 1-AE Resource Plan	2,241 (1)	2,977 (3)	2.0 (1)	10,270 (5)
Portfolio 2-Nuclear Expansion	3,889 (4)	3,022 (4)	3.9 (4)	3,507 (8)
Portfolio 3-High Renewables	8,286 (7)	2,398 (1)	5.8 (7)	15,720 (2)
Portfolio 4-Expected Renewables	3,076 (3)	3,142 (6)	2.2 (2)	9,456 (6)
Portfolio 5-Renewables with Storage	4,558 (6)	3,247 (7)	3.6 (3)	11,994 (4)
Portfolio 6-Natural Gas Expansion	2,925 (2)	4,077 (8)	4.1 (5)	14,751 (3)
Portfolio 7-Cleaner Coal	5,318 (5)	2,896 (2)	5.2 (6)	9,063 (7)
Portfolio 8-High Renewables Without Nuclear	8,286 (7)	3,062 (5)	6.0 (8)	20,755 (1)

Table 12.6
Measures of Risks and Uncertainties (through 2020, rankings in parentheses)

	High Estimate of Total Capital Costs ($million, through 2020)	High Estimate of Total Fuel Costs ($million, through 2020)	High Estimate of Increase in Levelized Cost of Electricity in 2020 (cents/kWh)	Fraction of Total Demand Met with Variable Resources in 2020 (%)	Technological Maturity (Subjective Ranking)
Portfolio 1-AE Resource Plan	2,905 (1)	4,102 (3)	2.8 (1)	17.0 (1)	1
Portfolio 2-Nuclear Expansion	4,373 (4)	4,259 (4)	6.2 (5)	17.3 (2)	1
Portfolio 3-High Renewables	8,770 (7)	3,382 (1)	8.1 (7)	58.5 (7)	5
Portfolio 4-Expected Renewables	3,560 (3)	4,416 (6)	3.2 (2)	22.8 (5)	4
Portfolio 5-Renewables with Storage	5,072 (5)	4,619 (7)	4.9 (3)	23.2 (6)	7
Portfolio 6-Natural Gas Expansion	3,409 (2)	5,954 (8)	5.7 (4)	17.4 (3)	1
Portfolio 7-Cleaner Coal	5,803 (6)	4,005 (2)	7.3 (6)	17.7 (4)	8
Portfolio 8-High Renewables Without Nuclear	8,770 (7)	4,370 (5)	8.4 (8)	59.3 (8)	5

Table 12.7
Comparative Ranking of Resource Portfolio Options

Portfolio Rankings	System Reliability Score	Carbon Emissions and Associated Carbon Costs Score	Costs and Economic Impacts Score	Risks and Uncertainties Score	Total Score (Average Ranking)
Portfolio 1- AE Resource Plan	7 (1)	24 (8)	10 (1)	7 (1)	48 (2.75)
Portfolio 2- Nuclear Expansion	19 (4)	6 (2)	20 (5)	16 (2)	61 (3.25)
Portfolio 3- High Renewables	23 (5)	3 (1)	17 (2)	27 (6)	70 (3.50)
Portfolio 7- Cleaner Coal	9 (2)	9 (3)	20 (5)	26 (5)	64 (3.75)
Portfolio 6- Natural Gas Expansion	12 (3)	18 (6)	18 (4)	18 (3)	66 (4.00)
Portfolio 4- Expected Renewables	29 (7)	21 (7)	17 (2)	20 (4)	87 (5.00)
Portfolio 5- Renewables with Storage	24 (6)	15 (5)	20 (5)	28 (7)	87 (5.75)
Portfolio 8- High Renewables Without Nuclear	36 (8)	12 (4)	21 (8)	33 (8)	102 (7.00)

Table 12.8
Costs of Reaching Carbon Neutrality

	Direct Carbon Emissions (metric tons of CO_2)	Total Expected Capital Costs ($million, through 2020)	Expected Increase in Levelized Costs of Electricity in 2020 (cents/kWh)	Metric Tons of CO_2 Reduced From 2007 Levels by Million Dollar Invested in Capital	Metric Tons of CO_2 Reduced From 2007 Levels by Cent per kWh of Expected Rise in Cost of Electricity	Expected Total Costs of Offsetting Carbon to Zero ($ million, through 2020)	Expected Total Costs or Profits of Allowances ($million, through 2020)	Annual Costs or Profits of Allowances ($million)	Annual Costs of Offsets ($million)	Cumulative Score and Ranking
Portfolio 2-Nuclear Expansion	1,646,000 (2)	3,889 (4)	3.9 (4)	1140.94 (1)	1.137,720 (1)	1,424 (3)	-31 (3)	55 (2)	41 (2)	22 (1)
Portfolio 3-High Renewables	566,000 (1)	8,286 (7)	5.8 (7)	665.77 (6)	951,129 (2)	1,215 (1)	216 (1)	94 (1)	14 (1)	27 (2)
Portfolio 6-Natural Gas Expansion	3,021,000 (6)	2,925 (2)	4.1 (5)	1046.83 (2)	746,825 (6)	1,339 (2)	58 (2)	4 (6)	76 (6)	37 (3)
Portfolio 5-Renewables with Storage	2,984,000 (5)	4,558 (6)	3.6 (3)	679.85 (4)	860,764 (4)	1,516 (4)	-163 (4)	6 (5)	75 (5)	40 (4)
Portfolio 7-Cleaner Coal	1,791,000 (3)	5,318 (5)	5.2 (6)	807.07 (3)	825,382 (5)	1,621 (7)	-297 (7)	49 (3)	45 (3)	42 (5)
Portfolio 4-Expected Renewables	3,993,000 (7)	3,076 (3)	2.2 (2)	679.36 (5)	949,865 (3)	1,611 (6)	-282 (6)	-31 (7)	100 (7)	46 (6)
Portfolio 8-High Renewables Without Nuclear	2,031,000 (4)	8,286 (7)	6.0 (8)	489.02 (7)	675,331 (7)	1,522 (5)	-168 (5)	41 (4)	51 (4)	51 (7)
Portfolio 1-AE Resource Plan	5,761,000 (8)	2,241 (1)	2.0 (1)	143.71 (8)	161,029 (8)	1,786 (8)	-488 (8)	-96 (8)	144 (8)	58 (8)

Figure 12.1
Metric Tons of CO_2 Reduced From 2007 Levels by Cent per kWh of Expected Rise in Cost of Electricity

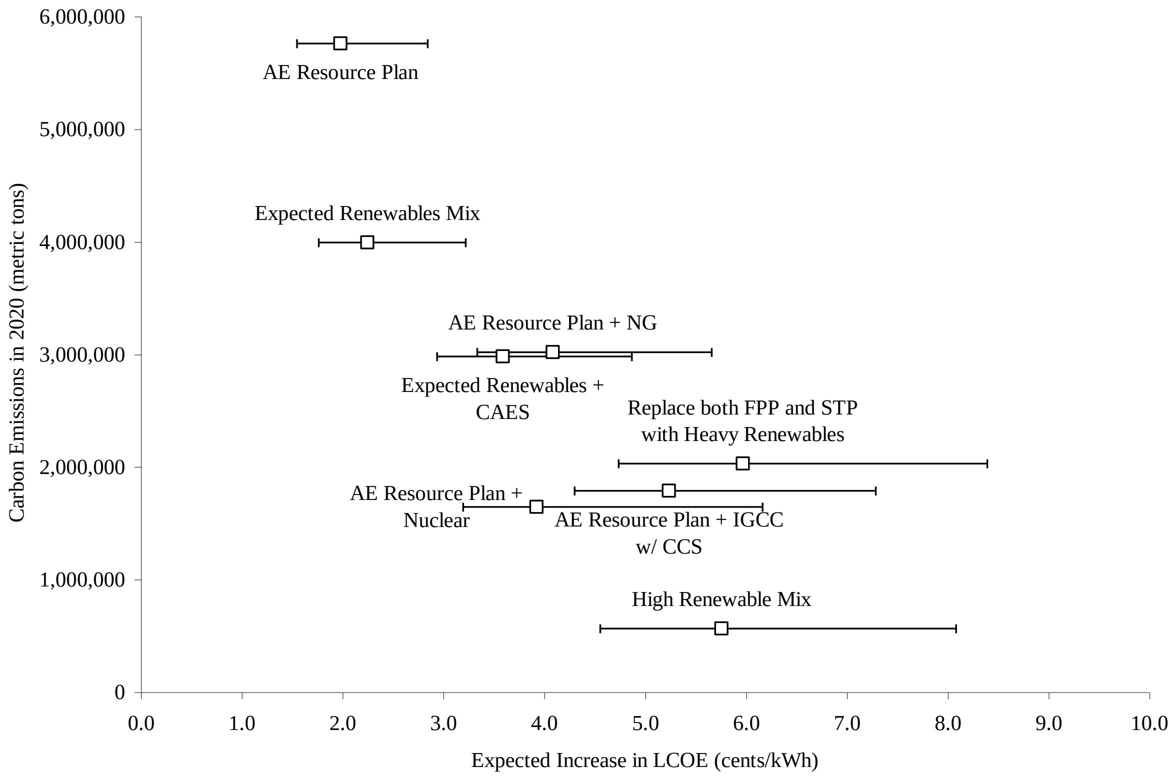


Figure 12.2
Metric Tons of CO_2 Reduced From 2007 Levels by Million Dollars Invested in Capital

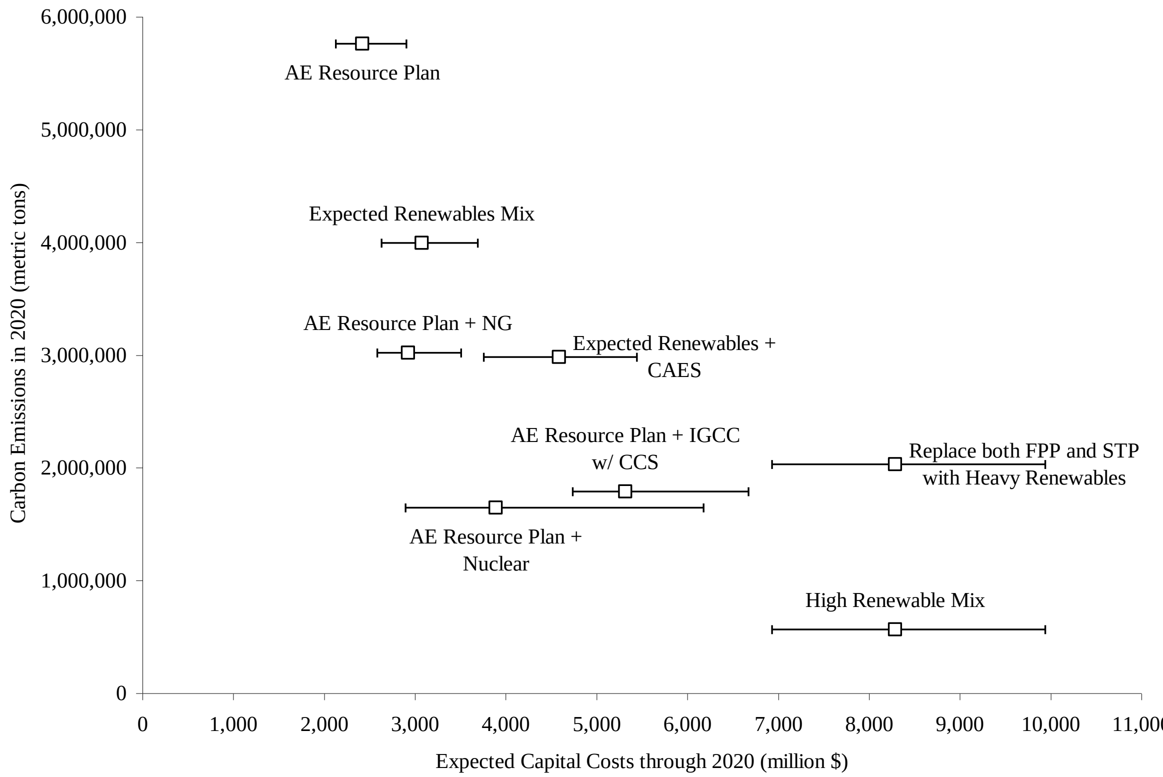


Figure 12.3
Metric Tons of CO_2 Reduced From 2007 Levels by Increase in Fuel Costs