Sustainable Energy Options for Austin Energy

Summary Report

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Future Resource Portfolio Analysis

Project directed by

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List of Acronyms and Abbreviations

ACPP	Austin Climate Protection Plan
AE	Austin Energy
Btu	British thermal unit
CAES	Compressed air energy storage
CAPCOG	Capital Area Council of Governments
CEC	California Energy Commission
CCS	Carbon capture and storage/sequestration
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
Council	Austin City Council
CSP	Concentrated solar power
CREZ	Competitive Renewable Energy Zone
CROI	Carbon return on investment
CRS	Congressional Research Service
DOE	United States Department of Energy
DSM	Demand-side management
EIA	Energy Information Administration
EPA	United States Environmental Protection Agency
EPRI	Electric Power Research Institute
ERCOT	Electric Reliability Council of Texas
FERC	Federal Electric Regulatory Commission
FPP	Fayette Power Project
FY	Fiscal Year

GHG	Greenhouse gas
IGCC	Integrated gasification combined cycle
JEDI	Jobs and Economic Development Impact
kW	Kilowatt
kWh	Kilowatt-hour
LCRA	Lower Colorado River Authority
MIG, Inc.	Minnesota IMPLAN Group, Incorporated.
Mt	Metric ton
MW	Megawatt
MWh	Megawatt-hour
NRC	Nuclear Regulatory Commission
NREL	National Renewable Energy Laboratory
NRRI	National Regulatory Research Institute
PHEV	Plug-in hybrid electric vehicle
PPA	Power purchase agreement
PUC	Public Utility Commission of Texas
PV	Photovoltaic
SAM	Social Accounting Matrix
STP	South Texas Project
US	United States

Foreword

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. This project developed methods to evaluate future power generation options for their feasibility and cost-effectiveness. The 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. 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

Acknowledgments and Disclaimer

This project would not have been possible without the financial support of Austin Energy (AE) and Solar Austin through commissioning the study. Project participants are thankful for the guidance provided by AE, Solar Austin, faculty and staff of The University of Texas at Austin (UT-Austin), and other energy experts in the Austin community.

AE staff members who contributed their time and expertise include John Baker, Bob Breeze, Andres Carvallo, Jennifer Clymer, Mark Dreyfus, Christopher Frye, Noreen Gleeson, Jerrel Gustafson, Ravi Joseph, Mark Kapner, Richard Morgan, Norman Muraya, Todd Shaw, and Fred Yebra.

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Funds for this project were managed through the Center for International Energy and Environmental Policy of the Jackson School of Geosciences and both units co-sponsored this research. The Law School of UT-Austin, the Institute for Innovation, Competition, and Capital (IC²), the Bess Harris Jones Centennial Professorship of Natural Resource Policy Studies, the Environmental Sciences Institute, and the LBJ School of Public Affairs either provided additional support for this study and/or co-sponsored a conference to present and evaluate the results of this report on March 10, 2009.

None of the sponsoring units including AE, Solar Austin, the LBJ School of Public Affairs, or other units of UT-Austin endorse any of the views or findings of this report. Christopher Smith and David Eaton, Ph.D., edited this volume of the report. Any omissions or errors are the sole responsibility of the authors and editors of this report.

Executive Summary

The City of Austin, on behalf of Austin Energy (AE), and Solar Austin commissioned this Policy Research Project with the Lyndon B. Johnson School of Public Affairs at The University of Texas at Austin to review options for Austin's electric utility, AE, to achieve sustainable power generation with an interim goal of becoming carbon neutral by 2020. This report describes feasible and cost-effective investments that would allow AE to produce and distribute the electricity it needs while simultaneously achieving zero net carbon dioxide (CO_2) emissions by 2020 using sustainable energy sources.

For Volume III of this report, "Future Resource Portfolio Analysis," a simulation tool was designed to evaluate eight different future energy resource portfolio scenarios for AE. The simulation tool 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, the direct emission of CO_2 into the atmosphere, and other risks and uncertainties. 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 to determine its anticipated costs.

An explanation of the methodology used in the creation of the model, including its assumptions and limitations, is provided in Chapter 2 of this volume of the report. Appendix A is a user's guide for the final version of the simulation software. The evaluation of the eight scenarios herein and the comparison of the scenarios represent an earlier version of the simulation software that does use, in some instances, different assumptions for capacity factors and costs of different power generation resources than the final version of the software that has been publicly released. The scenario comparison that follows does use a consistent set of assumptions. Tables included in Chapter 2 of this volume that detail different power generation technology characteristics and their estimated costs align with the evaluation and comparison of the scenarios provided in this report.

Chapters 3 through 10 of this volume evaluate eight diverse resource portfolio investment scenarios through 2020 (see Table 1). These chapters describe the impacts associated with each respective investment plan through a series of graphs, tables, and corresponding analyses of the impact those investments may have upon system reliability, carbon emissions, and costs to provide electricity. AE's "strawman" energy resource plan (July 2008) is first evaluated to provide a baseline scenario of AE's future power generation mix. Seven alternate strategies that would further reduce AE's carbon footprint are then evaluated. These eight scenarios all assume that AE meets its goal of 700 megawatts (MW) of peak energy demand savings by 2020. Chapter 11 analyzes the impact of additional demand savings. Chapter 12 analyzes the economic impacts of the eight resource portfolio scenarios.

Table 1
Primary Scenarios Run for Analysis

	Scenario Title	Major Additions and Subtractions Through 2020
Portfolio 1	AE Resource Plan	Add biomass, natural gas, solar, and wind
Portfolio 2	Nuclear Expansion	Nuclear replaces coal and AE resource plan additions
Portfolio 3	High Renewables	Very high investments in biomass, geothermal, solar, and wind technologies to replace coal
Portfolio 4	Expected Renewables	Expected available investments in biomass, geothermal, solar, and onshore wind to replace coal
Portfolio 5	Renewables with Storage	Expected renewables coupled with energy storage of wind to replace coal
Portfolio 6	Natural Gas Expansion	Natural gas replaces half of current coal and AE resource plan additions
Portfolio 7	Cleaner Coal	Advanced coal with carbon capture and storage technology to replace the Fayette Power Project and AE resource plan additions
Portfolio 8	High Renewables without Nuclear	High renewables to replace coal and nuclear

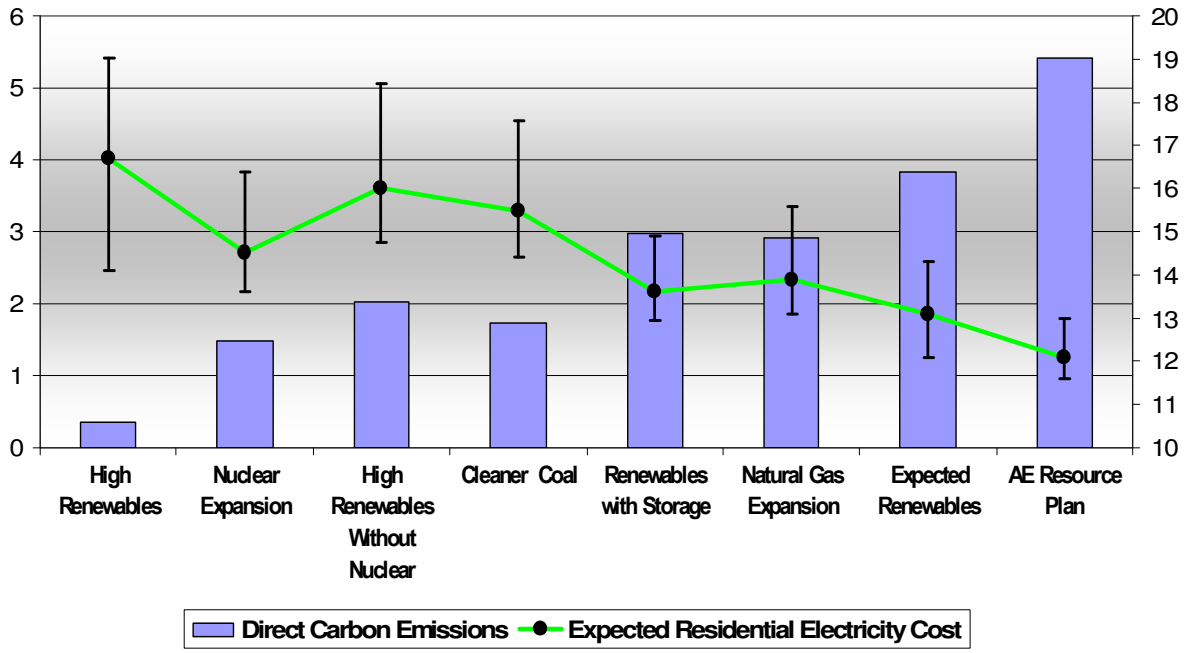
Chapter 13 compares the eight scenarios by using criteria and performance measures to compute an ordinal ranking of the eight resource portfolio scenarios under each criterion. Table 2 compares the eight scenarios using the ordinal ranking system designed by the project team. Chapter 14 discusses the potential total costs of reducing CO_2 emissions and Chapter 15 discusses future uncertainties facing the electric utility sector that must be considered within the context of this analysis. Chapter 16 concludes this analysis with a series of recommendations to AE.

Figure 1 shows the expected increase in the cost of electricity in 2020 (right y-axis) as well as the expected level of CO_2 emissions in 2020 (left y-axis) for the eight future resource portfolio scenarios. The current cost of electricity for residential customers averages about 10 cents per kilowatt-hour of electricity consumed. AE's 2007 CO_2 emissions were about 6.1 million metric tons.

Table 2
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)

Figure 1
Comparison of Eight Future Resource Portfolio Scenarios



Conclusions

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, on-shore wind investment, and smart grid deployment.

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. Of the eight scenarios evaluated by this study, 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.

This evaluation demonstrates that there are many factors that must be considered when evaluating the actual costs of achieving carbon neutral status. Future uncertainties facing the electric utility industry, particularly the possibility of future regulation of CO_2 and other greenhouse gas emissions, make it difficult for a utility to determine when and how it should act to ensure the best investment decisions are made. Beyond consideration for economic stability, AE must consider when and how to proceed in making investments to reduce its CO_2 emissions to meet Austin Climate Protection Plan and internal goals, the demands of the citizens of Austin, and maintaining a diversified generation resource portfolio.

The following conclusions were made based on the analyses conducted in this report:

- Several alternative power generation technologies (nuclear, natural gas, integrated gasification combined cycle with carbon capture and storage, biomass, and geothermal power plants) present 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.

- Of the baseload power generation technologies available, geothermal and biomass provide the greatest carbon return on investment, and, therefore, should be given priority to replace fossil fuels when available. Due to geothermal and biomass availability constraints, nuclear energy may provide the most reliable and abundant non-carbon emitting baseload power source to replace fossil fuels in AE's resource portfolio.

- Nuclear expansion (portfolio option 2) provides the least expected cost option for reducing CO_2 emissions of the eight scenarios evaluated under this study. However, potential capital cost overruns make this a high-risk option.

- AE's current nuclear power generation capacity allows the utility to invest in renewable baseload power sources (biomass and geothermal) to replace coal when

available while ensuring reliable and cost-effective service to its customers through 2020.

- The estimated cost of the "anticipated available" renewable resources scenario (portfolio option 4) is lower than a high investment in renewable resources scenario (portfolio option 3) and reduces AE's coal use by 50 percent through renewable resource additions.

- AE may want to maintain sufficient natural gas capacity to backup additional wind and solar additions to AE's resource portfolio to reduce increased risk of exposure to the volatile energy market.

- AE's planned additions for on-shore wind resources in West Texas appear to be reasonable investments given projected cost-competitiveness of this resource, expected transmission build-out to reduce congestion costs, and the ability of this resource to act as a hedge against carbon costs, even if these wind resources have relatively low resource availability during peak demand. Investment in coastal wind resources, both on-shore and off-shore, can provide additional benefits due to the complementary profile of these resources to on-shore wind resources located in West Texas.

- Solar energy investments provide a greater opportunity to reduce peak demand and thus reduce the need to build new peaking plants to meet generation needs than wind energy investments. However, wind energy investments may provide greater opportunities for CO_2 emission reductions as these resources tend to generate more electricity during off-peak hours. This allows AE's coal plant, a much more significant contributor of CO_2 emissions, to be ramped down.

- Utility-scale energy storage may provide a cost-effective way to achieve significant CO_2 reductions if coupled with wind energy investments (portfolio option 5). However, many utility-scale energy storage technologies are still in development and are not yet cost-effective or widely available.

- Expansion of natural gas units (portfolio option 6), particularly an additional combined cycle unit at AE's Sand Hill facility, provides a low capital cost investment option to displace coal use while achieving significant reductions in CO_2 emissions (albeit at much lower levels than nuclear or renewable resources).

- While replacing the Fayette Power Project (FPP) with an advanced clean coal facility that uses carbon capture and sequestration technology (portfolio option 7) would provide a hedge against potential future carbon costs, it would also represent a technical risk, as there are no such large-scale plants in routine operation in the United States (US).

- Removing both coal and nuclear from AE's resource mix (portfolio option 8) is a very high risk scenario for AE as this would result in high exposure to the volatile energy market.

- 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.

- 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, if such resources are available.

- Further demand reductions beyond AE's goal of 700 MW of savings through 2020 would delay the need for additional power generation capacity additions, but may be increasingly difficult to achieve and come at a higher cost to the utility.

- There are many factors that must be considered when evaluating the actual costs of achieving carbon neutral status.

- Carbon return on investment is a measure that can be used to determine the relative value of different resource investments for achieving carbon reductions.

- One major uncertainty affecting each scenario is the question of whether the US will regulate carbon.

- Other future uncertainties facing AE and the electric utility industry sector include local, state and federal regulation, the accuracy of load projections, nuclear risks and uncertainties, fossil fuel prices, renewable technology costs, ability to rely on variable resources, and the potential impacts of distributed generation and electric vehicles.

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 this report's 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 it must reduce its reliance on coal.

- Austin citizens ought to consider the balances of risks and costs of nuclear expansion as a sustainable resource relative to a zero carbon footprint.

- Austin citizens ought to consider what costs they are willing to accept if AE were to invest in large amounts of renewable resources.
- AE should monitor the reporting credibility of biomass as a carbon-free source of energy if carbon regulation is passed.
- AE should investigate the possibilities of investment in geothermal plants in areas of the state where potential geothermal sources exist.
- AE should monitor its wind investments as a component of its overall resource portfolio and evaluate the quality and timing of its availability.
- AE should monitor the costs of solar technologies, particularly utility-scale solar power plants, as the marginal per-MW-hour costs of these technologies are expected to fall upon an increase in their market penetration.
- AE should consider investments in concentrated solar plants in West Texas as a complementary renewable resource to wind generation.
- AE's single best electric sector investment is in energy efficiency, conservation, peak shifting, and reducing peak demand.
- The design and success of AE's plans through 2020 depends heavily on the critical assumption that 700 MW can be conserved between 2009 and 2020.

Chapter 1. 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 (ACPP), including achieving 700 megawatts (MW) of cumulative peak energy demand savings from energy efficiency, load shifting, and conservation and meeting 30 percent of all energy needs through renewable resources by 2020 (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 attributed to the burning of 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 future energy options for AE.

AE and Solar Austin have tasked a project team coordinated through 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. Volume II of this report provides information on the breadth of power generating technologies and other investment opportunities currently available to electric utilities such as AE that can help contribute to the creation of a sustainable electric utility. The project team set the target of achieving zero net CO_2 emissions by 2020 as an interim goal towards achieving a sustainable power generation portfolio. As a major component of this research, simulation software was designed by the project team to assist in the evaluation and comparison of eight diverse future resource portfolio scenarios. This volume of the report discusses the simulation software designed by the project team, evaluates and compares the eight scenarios, discusses future uncertainties, and provides recommendations for AE based upon this analysis.

Introduction

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. The project team's 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 outlined by the ACPP. 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, and geothermal can also 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 relatively 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. For the purposes of evaluation in this report, the simulation software uses current cost estimates for the construction and operation of new power 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 programs to limit its projected increase in demand and to invest in infrastructure changes that enhance power system reliability and flexibility.

Portfolio Analysis

Portfolio analysis has been identified as a mechanism that utilities can use to make future power 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 a variable 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 a mix of 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 impacts 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, the direct emission of CO_2 into the atmosphere, and other risks and uncertainties. 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 those power generation investments.

An explanation of the methodology used in the creation of the model, including its assumptions and limitations, is provided in Chapter 2 of this volume of the report. Appendix A is a user's guide for version 24 of the simulation software. The evaluation of the eight scenarios herein and the comparison of the scenarios represent an earlier version of the simulation software that does use, in some instances, different assumptions for capacity factors and costs of different power generation resources than the final version of the software that has been publicly released. The scenario comparison that follows does use a consistent set of assumptions. Tables included in Chapter 2 of this volume of the report that detail different power generation technology characteristics and their estimated costs align with the evaluation and comparison of the scenarios provided in this report.

Chapters 3 through 10 of this volume of the report evaluate eight diverse resource portfolio investment scenarios through 2020. These chapters describe the impacts associated with each respective investment plan through a series of graphs, tables and corresponding analysis of the impact those investments may have upon system reliability, carbon emissions, and costs to provide electricity. AE's "strawman" energy resource plan (July 2008) is first evaluated to provide a baseline scenario of AE's future power generation mix. Seven alternate strategies that would further reduce AE's carbon footprint are then evaluated. These eight scenarios all assume that AE meets its goal of 700 MW of peak energy demand savings by 2020. Chapter 11 analyzes the impact of additional demand savings. Chapter 12 analyzes the economic impacts of the eight

resource portfolio scenarios. Chapter 13 compares the eight scenarios by using criteria and performance measures to compute an ordinal ranking of the eight resource portfolio scenarios under each criterion. Chapter 14 discusses the potential total costs of reducing CO_2 emissions and Chapter 15 discusses future uncertainties facing the electric utility sector that must be considered within the context of this analysis. Chapter 16 concludes this analysis with a series of recommendations to AE.

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 %20 Resources_%20July%2023.pdf. Accessed: July 24, 2008.

[2] Ibid.

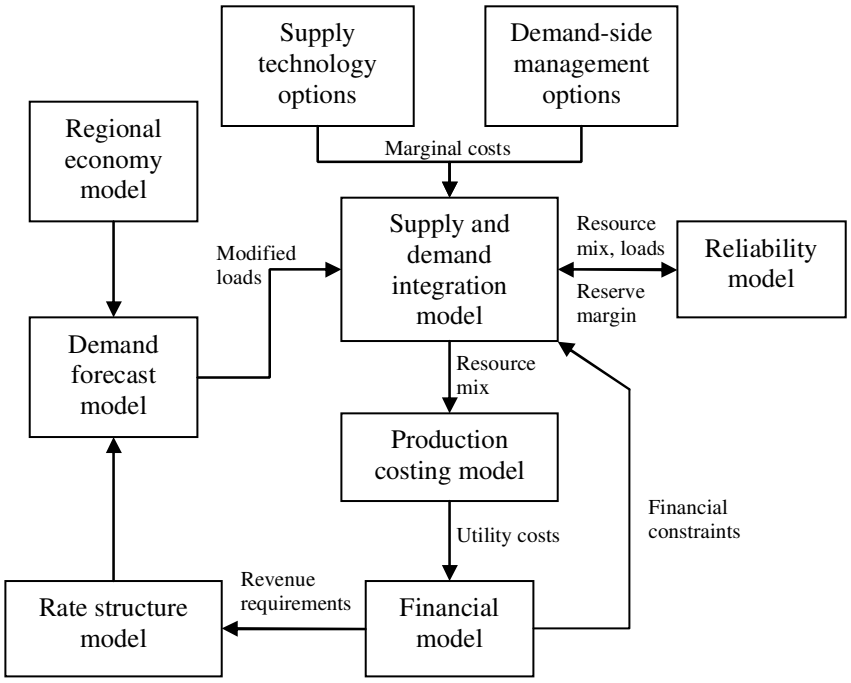
[3] The National Regulatory Research Institute, *What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies Across Nine Criteria*, p. 62. Online. Available: http://nrri.org/pubs/electricity/07-03.pdf. Accessed: March 16, 2009.

[4] Ibid., pp. 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 demand-side management (DSM) strategies. Long-term resource planning is based upon the load-service function, construction costs and time, fuel costs, operational life and dependability, maturity, and any externalities involved with each power generation technology.[2] Mid-term operations planning, typically involving a timeline of less than five 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 shown in Figure 2.1. 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.

Figure 2.1
Traditional Electric Utility Planning Model



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

Based on this detailed framework, the project team developed a simplified long-term simulation program (called the "Austin Energy Resource Portfolio Simulator") to predict and analyze the reliability of Austin Energy's (AE) power system, costs of different investment plans, and effects of investments on carbon emission levels, while broadly addressing pertinent mid-term operations concerns. This simulation software evaluates investments made between 2009 and 2020 by AE. 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 internally forecast loads on an hourly basis, this model does not have that level of accuracy. Real time and hourly planning is beyond the scope of this project, given its dynamic nature and required level of detail and information.

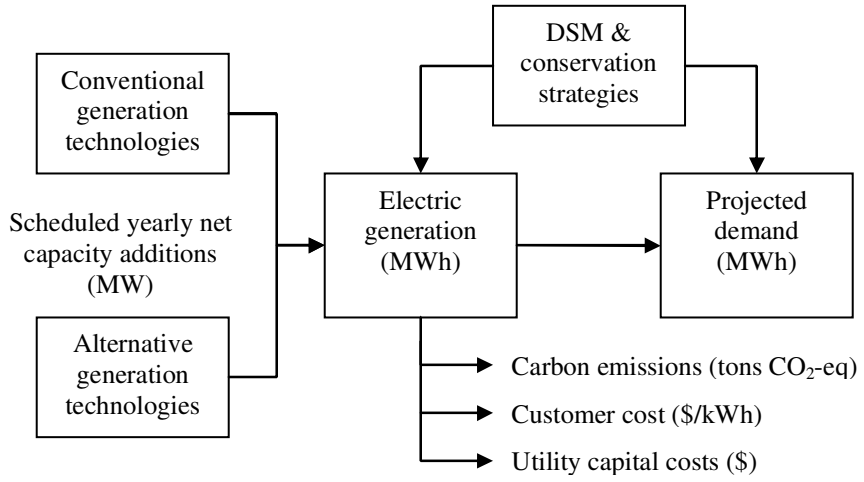
The resulting model is a simulation tool, not an optimization model, meaning it does not choose a power generation mix based on a certain optimized variable of interest. Optimization is beyond the scope of this project, as it would require defining a mix of power generating technologies as a function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

The user's guide for Version 24 of the Austin Energy Resource Portfolio Simulator is included in this volume of the report as Appendix A. Version 24 of the simulator is provided with the report as well as Version 26, an improved version of the software that includes outputs for additional environmental impacts and more accurate modeling.

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. This model does not account for AE's interaction with the energy market as this was considered beyond the scope of this study.

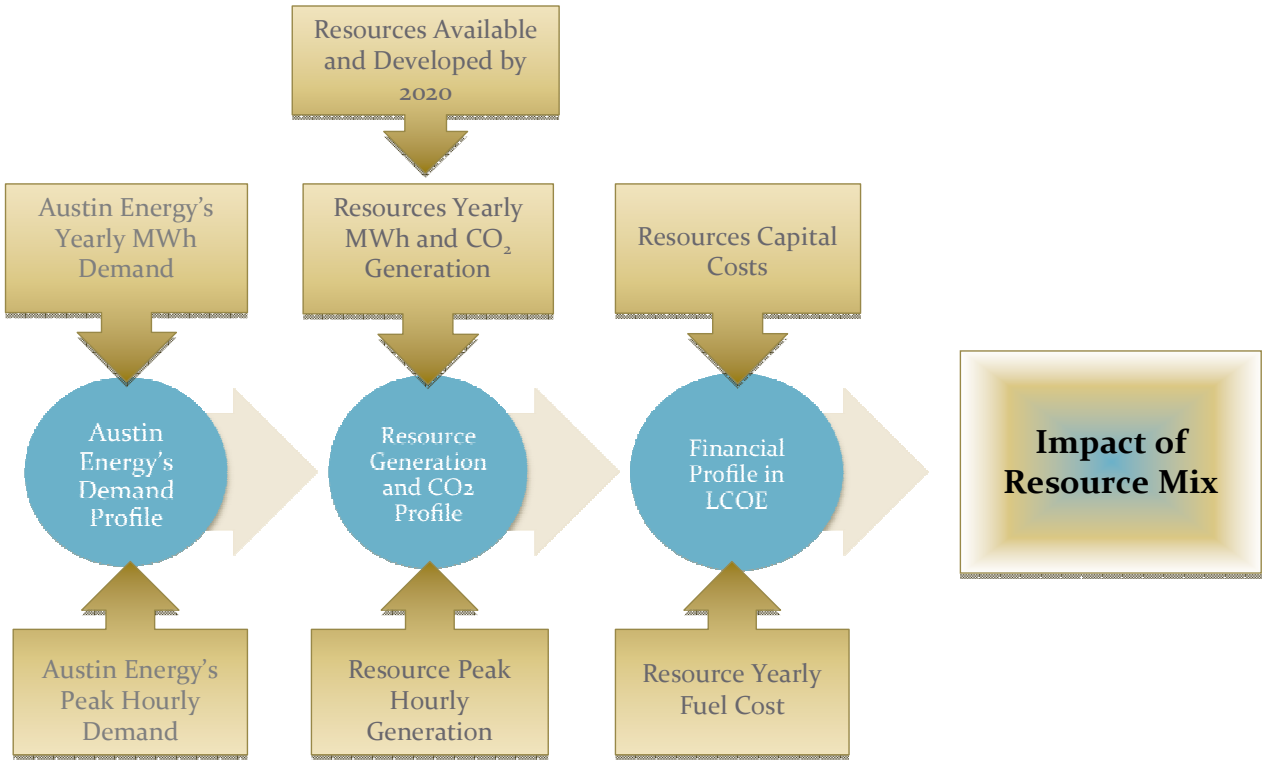
Figure 2.2
Simplified Model Process for Power Generation Mix Analysis



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

A diagram of the final model components is included in Figure 2.3. AE's forecasted yearly peak demand (with and without DSM) and power generation needs are incorporated into the model to demonstrate the ability of a power generation mix to meet demand.

Figure 2.3
Diagram of Model Components



Source: Created by project team.

The project team analyzed the availability of various energy resources and power generation technologies to determine reasonable investment opportunities through 2020. Only power generation technologies that have the potential to be readily available by 2020 are included as power generation inputs. The following fuel sources, power generation technologies, and enabling technologies are 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 and combined cycle gas units);
- Wind (onshore and offshore);
- Biomass (using wood waste);
- Coal co-fired with biomass (using wood waste);
- Landfill gas;
- Concentrated solar (parabolic trough, solar-Stirling dish, and power tower);

- Solar photovoltaic (centralized facilities and distributed systems);
- Geothermal (binary cycle power plants); and
- Energy storage (compressed air, pumped storage, flywheels, and batteries).

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 with the option of integrating a carbon capture and storage (CCS) system and are represented in the model 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 CO_2 emission factors. "Sand Hill 1-4" represents four combustion gas turbines, "Sand Hill 5" is a combined cycle unit, "Decker 1 & 2" represents two steam turbine units, and "Decker" represents several combustion gas turbines. Power plant characteristics for the South Texas Project, AE's existing nuclear power capacity, are represented as "nuclear" in the model. The project team assumes that all coal, nuclear, and natural gas additions are made as additions of units to AE's current facilities that have the same technology characteristics as existing units or new facilities with the same technology characteristics. No other units represent currently operating facilities for AE. However, the characteristics of solar PV systems and wind energy turbines resemble the characteristics for current wind and solar capacity for AE.

The simulation software 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 has the opportunity to determine investment and divestment decisions made by AE by adjusting the capacity of different power generation technologies as well as adjusting investments in DSM, or "accelerated conservation," and energy storage technologies. The user-assigned capacity additions and subtractions of conventional and alternative power generating technologies determine the system's ability to produce power. Projections of demand reduction achieved through DSM strategies allow new capacity additions to be avoided. 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.

Long-term planning factors are included by allowing the user to manipulate technology characteristics (capacity factors and CO_2 emission factors), costs (capital, fuel, and levelized cost of electricity), and demand forecast (by adjusting the "accelerated conservation" inputs), or choose a point in time in which to introduce a new energy resource. 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 or unit. 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.

Figure 2.4
Screenshot of Generate Scenario Function

Schedule of power generation additions and subtractions (net MW)

Generate Scenario2

	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												

CSP Type

Storage Type

Source: Created by project team.

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 based upon its 2008 load forecast. 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/or facility and the overall mix through 2020;
- Percentage of power generation capacity from each resource and/or facility in 2020;
- Annual electricity production from each resource and/or facility and the overall mix through 2020;

- An hourly load profile for meeting peak demand in 2020 with electricity production from each resource and/or facility and the overall mix;
- Percentage of electricity delivered from each resource and/or facility in 2020;
- A carbon emissions profile through 2020;
- Annual capital costs of new resources and/or facilities added to the mix (represented as total overnight costs);
- Annual fuel costs of the power generation mix;
- Expected increase in the cost of electricity (represented as total levelized costs of electricity) attributed to each resource;
- Potential annual costs to offset remaining CO_2 emissions; and
- Potential annual carbon costs or profits related to carbon regulation between 2014 and 2020.

Model Outputs

Based on the input values, a number of calculations are performed by the model 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 to consider when interpreting 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 by using its own generating resources, assuming full capacity if all generation resources are available on that peak day. While, in reality, other generation units within the electric grid can serve as additional options for providing power to AE customers, these outputs provide measures of 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. 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 Table 2.1. 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.

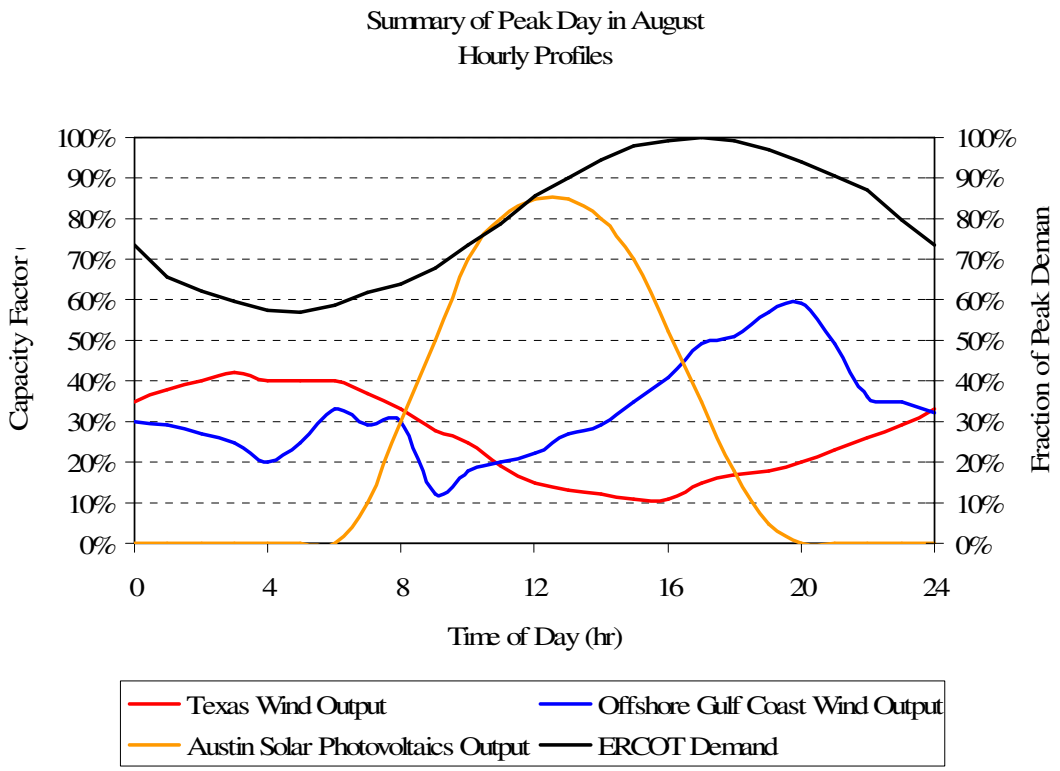
Equation 1 is used to determine the MWh of electricity generated without predicting how AE will actually use the resource in a given year. Therefore, the user must adjust capacity factors for intermediate power sources that do not have limited availability (primarily natural gas for AE's power system), 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 the Electric Reliability Council of Texas (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 variability 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.

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



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

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 Table 2.1. 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.

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 [3]	0.95[4]	0.94[5]
Nuclear	0.97[6]	0.92[7]	0.00[8]
Natural gas - Sand Hill	0.96[9]	0.26[10]	0.38[11]
Natural gas - Decker	0.96[12]	0.26[13]	0.58[14]
Wind	0.95[15]	0.29[16]	0.00[17]
Offshore wind	0.95[18]	0.29[19]	0.00[20]
Biomass	0.90[21]	0.80[22]	0.10[23]

Landfill gas	0.90[24]	0.80[25]	0.00[26]
Solar PV - centralized	0.99[27]	0.17[28]	0.00[29]
Solar PV - distributed	0.99[30]	0.17[31]	0.00[32]
Concentrated solar	0.99[33]	0.17[34]	0.00[35]
IGCC w/ CCS	0.88[36]	0.95[37]	0.16[38]
Geothermal	0.92[39]	0.90[40]	0.00[41]
Fossil purchased power	1.00[42]	1.00[43]	0.59[44]

Sources: See endnotes 9 through 50.

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. 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.[45] 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.[46] 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.[47] 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 captured by the contract. Additionally, profits earned through the selling or leasing 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).

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[48]	14.02[49]	90.00[50]
Coal-IGCC w/CCS	4,774.00[51]	13.17[52]	134.00[53]
Coal-IGCC w/o CCS	3,359.00[54]	13.17[55]	104.00[56]
Natural gas- advanced combustion turbines	473.00[57]	75.60[58]	248.52[59]
Natural gas- advanced combined cycle	1,186.00[60]	50.37[61]	81.90[62]
Advanced nuclear	3,682.00[63]	4.89[64]	67.01[65]
Onshore wind	1,896.00[66]	n/a	60.78[67]
Offshore wind	2,872.00[68]	n/a	60.78[69]
Solar PV- centralized	5,782.00[70]	n/a	116.23[71]
Solar PV- distributed - thin film	Unavailable[72]	n/a	101.50[73]
Concentrated solar-parabolic trough	2,836.00[74]	n/a	154.86 [75]
Concentrated solar-stirling dish	3,744.00[76]	n/a	312.10[77]
Concentrated solar-power tower	3,500.00[78]	n/a	90.00[79]
Biomass	2,809.00[80]	25.37[81]	60.36[82]

Co-firing with biomass	275.00[83]	25.37[84]	20.00[85]
Landfill gas	1,897.00[86]	n/a[87]	47.86[88]
Geothermal	3,590.00[89]	n/a	67.18[90]
Pumped hydro storage	2,379.00[91]	n/a	48.01[92]
Compressed air energy storage	675.00[93]	n/a	Unavailable
Battery storage	2,322.50[94]	n/a	Unavailable
Flywheel storage	4,004[95]	n/a	Unavailable
Purchased power	Unavailable	n/a	Unavailable

Sources: See endnotes 51 through 98.

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 attributed to new 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.[96] 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 or leasing of ownership in power plant facilities 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. Results of the economic impact analysis are included in Chapter 12. Appendix B provides background information on the functionality of IMPLAN.

Assumptions of the Model

As previously noted, this model is intended to provide a basic 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 CO2 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 variable resources.
- 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 variability 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 actually be 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:

- This is not an hourly dispatch model and does not account for the utility's interaction with the ERCOT energy market. Therefore, this model does not account for the costs or cost savings that can be attributed to purchasing power on the spot market or selling excess energy.
- 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 the expected impact on electric bills based upon the 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 and 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 divestment 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. Table 2.3 lists the energy resource mix scenarios that follow in this report with 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 MW of generating capacity by 2020, with only 300 MW coming from fossil-fueled resources.[97] 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 a 100 MW biomass project expected by 2012 and a 30 MW solar project expected by 2010 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.[98] 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 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.

Table 2.3
Primary Scenarios Run for Analysis

	Scenario Title	Major Additions and Subtractions Through 2020
Portfolio 1	AE Resource Plan	Add biomass, natural gas, solar, and wind
Portfolio 2	Nuclear Expansion	Nuclear replaces coal and AE resource plan additions
Portfolio 3	High Renewables	Very high investments in biomass, geothermal, solar, and wind technologies to replace coal
Portfolio 4	Expected Renewables	Expected available investments in biomass, geothermal, solar, and onshore wind to replace coal
Portfolio 5	Renewables with Storage	Expected renewables coupled with energy storage of wind to replace coal
Portfolio 6	Natural Gas Expansion	Natural gas replaces half of current coal and AE resource plan additions
Portfolio 7	Cleaner Coal	IGCC with carbon capture and storage to replace Fayette Power Project and AE resource plan additions
Portfolio 8	High Renewables without Nuclear	High renewables to replace coal and nuclear

Source: Created by project team.

Notes

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

[2] The National Regulatory Research Institute (NRRI), *What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies Across Nine Criteria.* Online. Available: http://nrri.org/pubs/electricity/07-03.pdf. Accessed: March 16, 2009.

[3] Calculations from AE documents, in accordance with NRRI, *What Generation Mix Suits Your State?* (online).

[4] Ibid.

[5] Calculations from AE's California Climate Action Registry (CCAR) Emissions Computations Spreadsheet, 2007.

[6] Calculations from AE documents, in accordance with NRRI, *What Generation Mix Suits Your State?* (online).

[7] Ibid.

[8] NRRI, *What Generation Mix Suits Your State?* (online).

[9] Calculations from AE documents, in accordance with NRRI, *What Generation Mix Suits Your State?* (online).

[10] Calculations from AE documents, including CCAR Emissions Computations Spreadsheet, 2007.

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

[12] Calculations from AE documents, in accordance with NRRI, *What Generation Mix Suits Your State?* (online).

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

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

[15] NRRI, *What Generation Mix Suits Your State?* (online).

[16] Calculations from AE documents, in accordance with NRRI, *What Generation Mix Suits Your State?* (online).

[17] NRRI, *What Generation Mix Suits Your State?* (online).

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

[19] Ibid.

[20] NRRI, *What Generation Mix Suits Your State?* (online).

[21] Ibid.

[22] Ibid.

[23] Ibid.

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

[25] Ibid.

[26] NRRI, *What Generation Mix Suits Your State?* (online).

[27] Ibid.

[28] Clean Power Research LLC, *The Value of Distributed Photovoltaics to AE and the City of Austin* (March 17, 2006) in accordance with NRRI, *What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies Across Nine Criteria.* Online. Available: http://nrri.org/pubs/electricity/07-03.pdf. Accessed: March 16, 2009.

[29] NRRI, *What Generation Mix Suits Your State?* (online).

[30] Ibid.

[31] Clean Power Research LLC, *The Value of Distributed Photovoltaics* in accordance with NRRI, *What Generation Mix Suits Your State?* (online).

[32] NRRI, *What Generation Mix Suits Your State?* (online).

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

[34] Ibid.

[35] NRRI, *What Generation Mix Suits Your State?* (online).

[36] Ibid.

[37] Not applicable, assumed to be equal to capacity factor for traditional coal.

[38] NRRI, *What Generation Mix Suits Your State?* (online).

[39] Ibid.

[40] Ibid.

[41] Ibid.

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

[43] Ibid.

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

[45] Govtrack.us, *Senate Bill 280: Climate Stewardship and Innovation Act of 2007*. Online. Available: http://www.govtrack.us/congress/bill.xpd?bill=s110-280. Accessed: January 20, 2009.

[46] United States Environmental Protection Agency, *EPA Analysis of the Lieberman-Warner Climate Security Act of 2008, S. 2191 in 110th Congress* (March 14, 2008). Online. Available: http://www.epa.gov/climatechange/economics/economicanalyses.html#s2191. Accessed : March 14, 2008.

[47] 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.

[48] Kaplan, *Power Plants* (online).

[49] NRRI, *What Generation Mix Suits Your State?* (online). High and low estimates assumed 5% higher and lower due to low volatility of coal prices.

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

[51] Kaplan*Power Plants* (online).

[51] NRRI, *What Generation Mix Suits Your State?* (online). High estimates assumed 30% higher and low estimates assumed 10% lower due to immaturity of technology.

[52] NRRI, *What Generation Mix Suits Your State?* (online). High and low estimates assumed 5% higher and lower due to low volatility of coal prices.

[53] Expected value estimate from: Lazard, *Levilized Cost of Energy Analysis* (online). High estimate assumed 30% higher than expected value and low estimate assumed 10% lower than expected value due to immaturity of technology.

[54] Lazard, *Levilized Cost of Energy Analysis* p. 10 (online). High estimates assumed 30% higher and low estimates assumed 10% lower due to immaturity of technology.

[55] NRRI, *What Generation Mix Suits Your State?* (online). High and low estimates assumed 5% higher and lower due to low volatility of coal prices.

[56] Expected value estimate is from: Lazard, *Levilized Cost of Energy Analysis*, p. 9 (online). Low estimate is from: California Energy Commission, *Comparative Costs* p. 7 (online). High estimate assumed 30% higher than expected value due to immaturity of technology.

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

[58] NRRI, *What Generation Mix Suits Your State?*, pp. 18-19 (online). High estimates assumed 50% higher and low estimates assumed 20% lower due to high volatility of natural gas prices.

[59] Expected value estimate is from: CEC, *Comparative Costs*, p. 7 (online). High and low estimates are from: Lazard, *Levilized Cost of Energy Analysis*, p. 9 (online).

[60] Kaplan, *Power Plants* (online). High estimates assumed 20% higher and low estimates assumed 10% lower due to mature technology status.

[61] NRRI, *What Generation Mix Suits Your State?*, pp. 18-19 (online). High estimates assumed 50% higher and low estimates assumed 20% lower due to high volatility of natural gas prices.

[62] Expected value estimate is from: CEC, *Comparative Costs*, p. 7 (online). High and low estimates are from: Lazard, *Levilized Cost of Energy Analysis*, p. 9 (online).

[63] Expected value estimate is from: Kaplan, *Power Plants* (online). Low estimates: Assumed 10 percent lower than expected value from: EIA, *Assumptions*, p. 79 (online). High estimates: David Schlissel and Bruce Biewald, Synapse Energy Economics, Inc., *Nuclear Power Plant Construction Costs* (July 2008). Online. Available: http://www.synapse-energy.com/Downloads/SynapsePaper.2008-07.0.Nuclear-Plant-Construction-Costs.A0022.pdf. Accessed: December 15, 2008. Rounded from highest estimate of $8,000/kw.

[64] NRRI, *What Generation Mix Suits Your State?*, pp. 18-19 (online). High and low estimates assumed 5% higher and lower due to low volatility of uranium prices.

[65] Expected value estimate is from: CEC, *Comparative*, p. 7 (online). High and low estimates are from: Lazard, *Levilized Cost of Energy Analysis*, p. 9 (online). Low estimate assumed 10% lower than expected value.

[66] Kaplan, *Power Plants* (online). High estimates assumed 20% higher and low estimates assumed 10% lower due to mature technology status.

[67] Expected value estimate is from: CEC, *Comparative Costs*, p. 7 (online). High and low estimates are from: Lazard, *Levilized Cost of Energy Analysis*, p. 9 (online).

[68] Kaplan, *Power Plants* (online). High estimates assumed 20% higher and low estimates assumed 30% lower due to immature technology status.

[69] Assumed the same as onshore wind due to lack of information. Expected value estimate is from: CEC, *Comparative Costs*, p. 7 (online). High and low estimates are from: Lazard, *Levilized Cost of Energy Analysis*, p. 9 (online).

[70] Kaplan, *Power Plants* (online). High estimates assumed 20% higher and low estimates assumed 20% lower due to immature technology status.

[71] Expected value estimate is from: CEC, *Comparative Costs*, p. 7 (online). High estimates assumed 20% higher and low estimates assumed 20% lower due to mature technology status.

[72] Information not available.

[73] High and low estimates are from: Lazard, *Levilized Cost of Energy Analysis*, p. 10 (online). Expected value estimate is average of high and low estimate.

[74] Kaplan, *Power Plants* (online). High estimates assumed 20% higher and low estimates assumed 20% lower due to immature technology status.

[75] Expected value estimate is from: CEC, *Comparative Costs*, p. 7 (online). High and low estimates are from: Lazard, *Levilized Cost of Energy Analysis*, p. 10 (online). High estimates assumed 20% higher.

[76] Based upon data for solar thermal: EIA, *Assumptions*, p. 79 (online). High estimates assumed 20% higher and low estimates assumed 20% lower due to immature technology status.

[77] Expected value estimate is from: CEC, *Comparative Costs*, p. 7 (online). High estimates assumed 20% higher and low estimates assumed 20% lower due to mature technology status.

[78] The National Renewable Energy Laboratory, *Power Technologies Energy Data Book*, pp. 18,20,22. Online. Available: http://www.nrel.gov/analysis/power_databook/docs/pdf/db_chapter02_csp.pdf. Accessed: October 28, 2008. High estimates assumed 20% higher and low estimates assumed 20% lower due to immature technology status.

[79] Expected value estimate is from: Lazard, *Levilized Cost of Energy Analysis*, p. 10 (online). High estimates assumed 20% higher and low estimates assumed 20% lower due to immature technology status.

[80] EIA, *Assumptions*, p. 79 (online). High estimates assumed 20% higher and low estimates assumed 10% lower due to mature technology status.

[81] This is an average of the range provided by: NRRI, *What Generation Mix Suits Your State?*, pp. 18-19 (online). Online. Available: http://nrri.org/pubs/electricity/07-03.pdf. Accessed: March 16, 2009.

[82] Expected value estimate is from: CEC, *Comparative Costs*, p. 7 (online). High and low estimates are unspecified biomass sources from: Lazard, *Levilized Cost of Energy Analysis*, p. 9 (online).

[83] High and low estimates are from: Lazard, *Levilized Cost of Energy Analysis*, p. 9 (online). Expected value is the average of the high and low estimates.

[84] This is an average of the range provided by: NRRI, *What Generation Mix Suits Your State?*, pp. 18-19 (online).

[85] High and low estimates are from: Lazard, *Levilized Cost of Energy Analysis*, p. 9 (online). Expected value is the average of the high and low estimates.

[86] EIA, *Assumptions*, p. 79 (online). High estimates assumed 20% higher and low estimates assumed 10% lower due to mature technology status.

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

[88] Expected value estimate is from: CEC, *Comparative Costs*, p. 7 (online). High estimate is from: Lazard, *Levilized Cost of Energy Analysis*, p. 9 (online). Low estimate assumed 10% lower than expected value.

[89] Kaplan, *Power Plants* (online). High estimates assumed 20% higher and low estimates assumed 10% lower due to mature technology status.

[90] Expected value estimate is from: CEC, *Comparative Costs*, p. 7 (online). Low estimate is from: Lazard, *Levilized Cost of Energy Analysis*, p. 9 (online). High estimate assumed 20% higher than expected value.

[91] Expected value estimate is from: NRRI, *What Generation Mix Suits Your State?* pp. 18-19 (online). High and low estimates from: Dan Rastler, "New Demand for Energy Storage," *Electric Perspectives* (September/October 2008), pp. 30-47. Online. Available: http://www.eei.org/magazine/editorial_content/nonav_stories/2008-09-01-EnergyStorage.pdf. Accessed: November 17, 2008.

[92] Assumed expected value estimate for conventional hydropower from: CEC, *Comparative Costs*, p. 7 (online). High estimates assumed 20% higher and low estimates assumed 10% lower due to mature technology status.

[93] For below ground took average of high and low estimate from: Rastler, "New Demand for Energy Storage," pp. 30-47 (online).

[94] Took average of low and high estimates for lead acid, sodium, and flow batteries from: Rastler, "New Demand for Energy Storage," pp. 30-47 (online).

[95] Took average of low and high estimates for lead acid, sodium, and flow batteries from: Rastler, "New Demand for Energy Storage," pp. 30-47 (online).

[96] California Energy Commission (CEC), *Comparative Costs of California Central Station Electricity Generation Technologies* (June 2007), pp. 4-6. Online. Available: http://www.energy.ca.gov/2007publications/CEC-200-2007-011/CEC-200-2007-011-SD.PDF. Accessed: November 15, 2008.

[97] Austin Energy (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.

[98] AE, *Nacogdoches Biomass Project Town Hall Meeting* (August 13, 2008). Online. Available: http://www.austinenergy.com/biomassTownHallAugust2008.pdf. Accessed: August 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, a 100 MW biomass project expected by 2012, and a 30 MW centralized photovoltaic (PV) 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 power purchase agreement (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 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.

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

AE is planning to invest in covering rooftop space in Austin with PV modules 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 PV systems, 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.

In April 2009, AE released a revised resource plan based upon its 2009 load forecast in which projected demand decreased by 135 MW for 2020.[6] Changes to AE's resource plan included delaying the deployment of new natural gas resources, reducing biomass by 50 MW, and reducing wind by 25 MW.[7] This analysis was conducted prior to the April 2009 revised resource plan was released and is therefore based on the original proposed resource plan. All other scenarios in which investments match that of the original proposed resource plan were also not updated based upon the revised resource plan. However, these changes are minor and should not influence the results of this analysis.

It should also be noted that the analysis of these eight scenarios is based upon a set of capacity factor and cost assumptions that are included in Chapter 2 of this volume of the report. Some of these assumptions have been updated in the final version of the simulation software (version 26). Therefore, this analysis is not based upon the released version of the software, but rather the assumptions and limitations incorporated into the simulator at the time the analysis was conducted (January 2009). However, these changes should not make a significant difference in the results of this study as the purpose is to provide a relative comparison of eight resource portfolio scenarios.

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. Figure 3.1 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 variable nature of wind and solar resources. Given the expected capacity factors for on-shore wind and solar PV 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 demand-side management (DSM) goal (see Figure 3.2). It appears that AE will be able to provide reliable service even if its DSM goal is only met halfway.

Figure 3.1
Austin Energy Resource Plan Power Generation Capacity

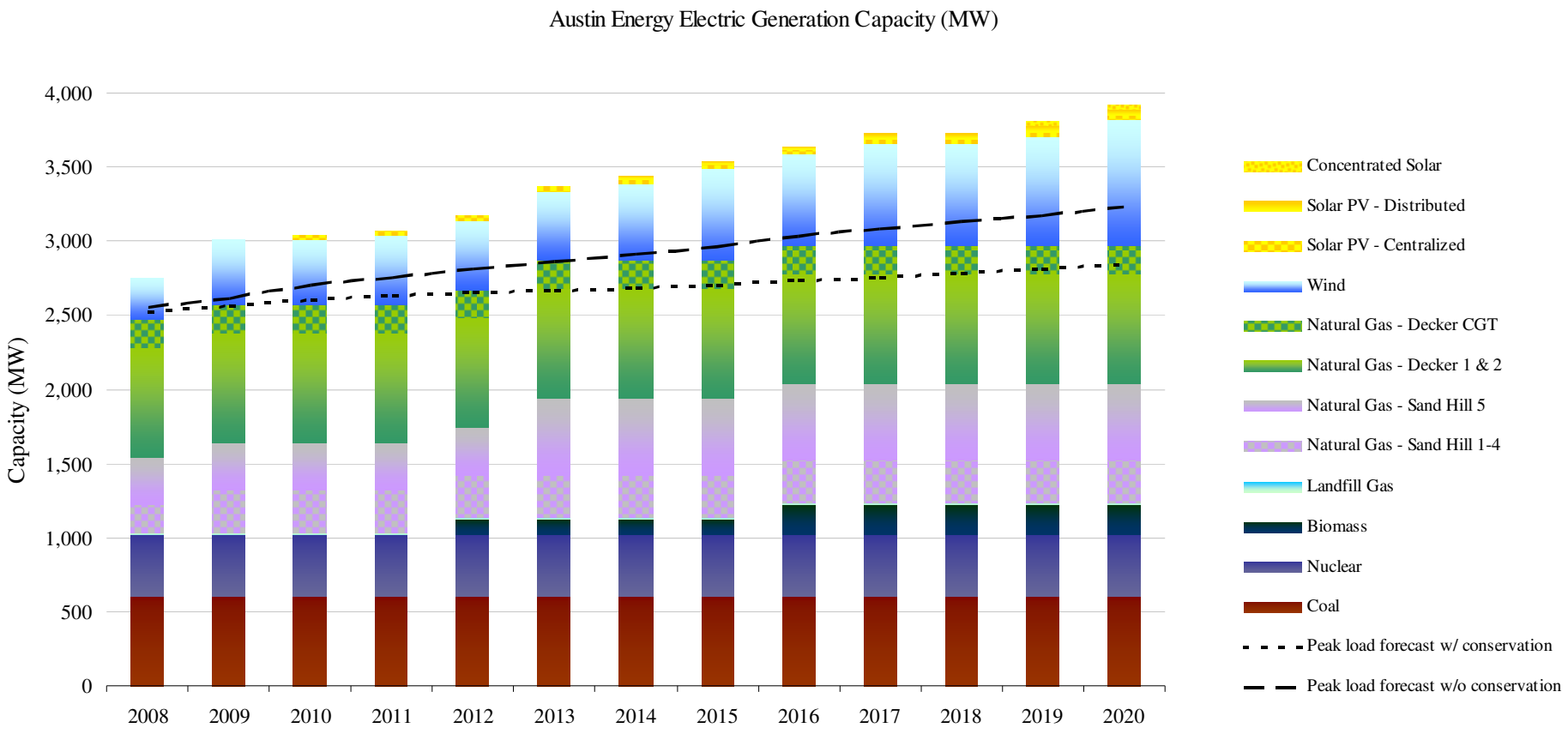


Figure 3.2
Austin Energy Resource Plan Electric Delivery

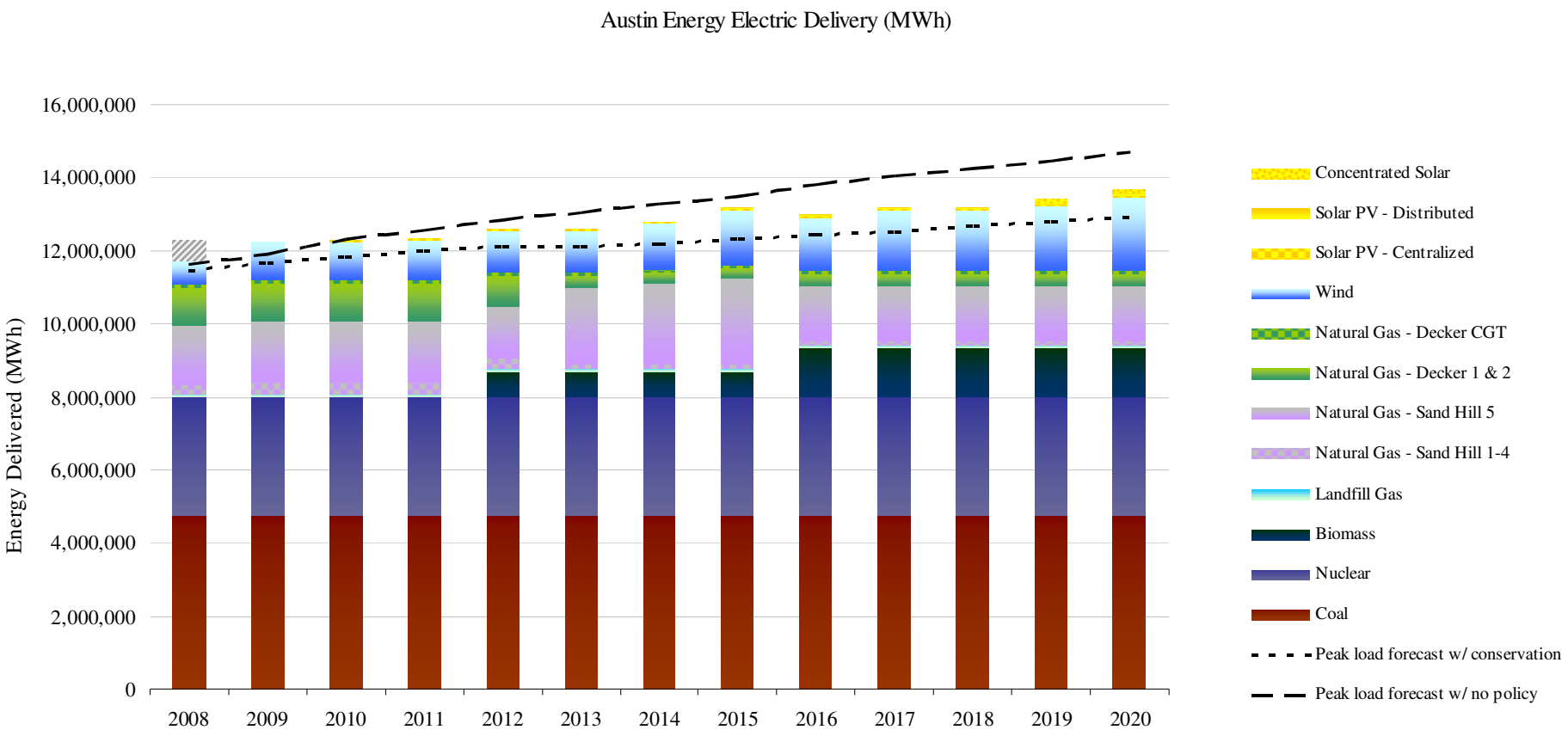
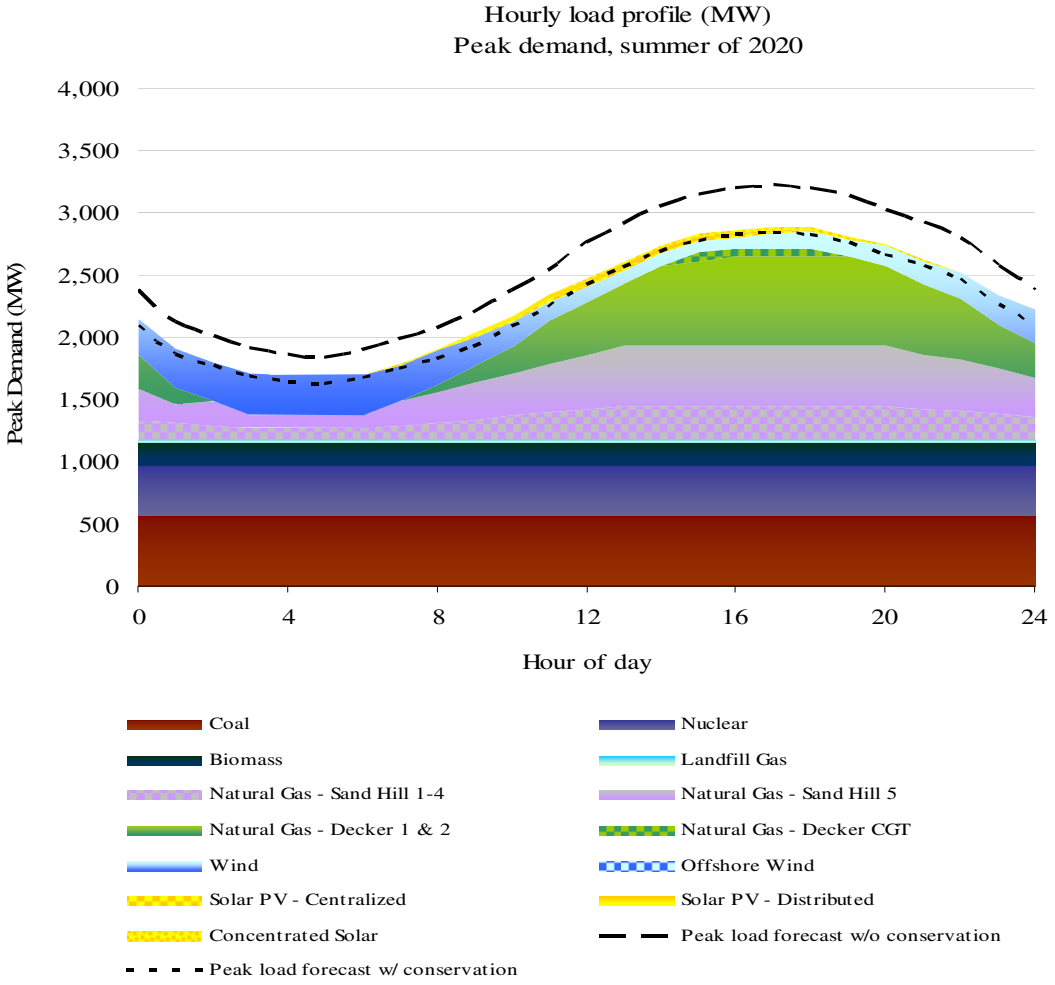


Figure 3.3 details AE's expected hourly load profile for the hottest day (peak demand) in the summer of 2020. The hourly load profile follows expected solar and wind profiles and demonstrates that AE will be able to meet peak demand without purchasing power by engaging its natural gas facilities, even on the hottest day of the summer. As AE makes gradual additions to its resource portfolio from baseload, intermediate, and variable 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.

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

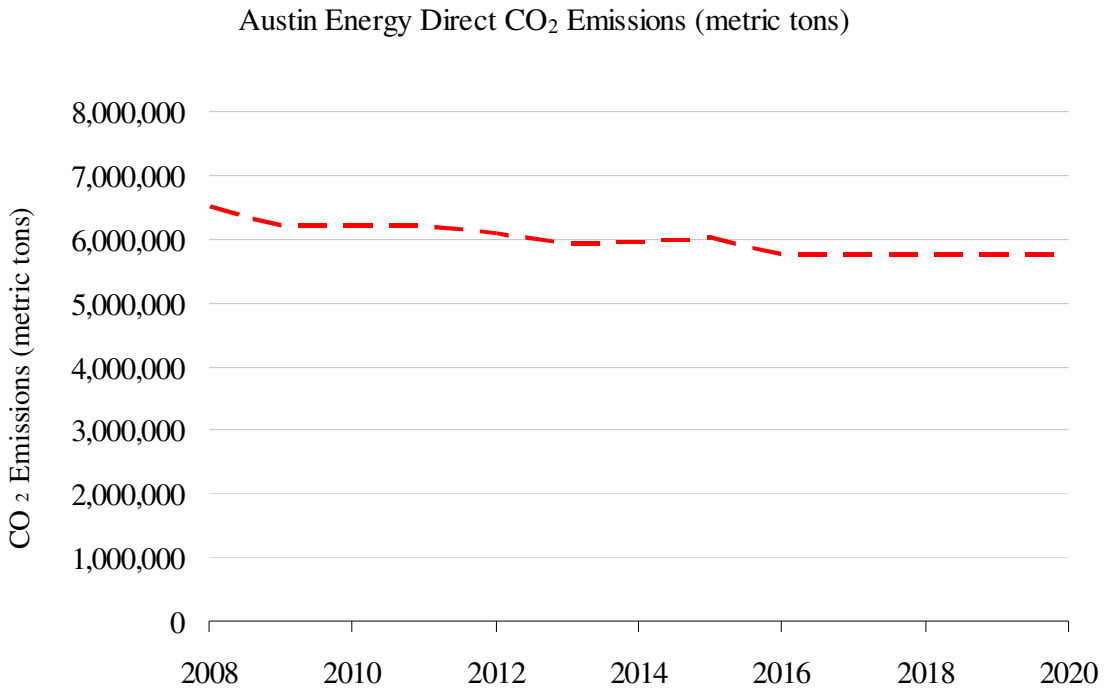


Carbon Emissions and Carbon Costs

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 renewable power generation capacity 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.

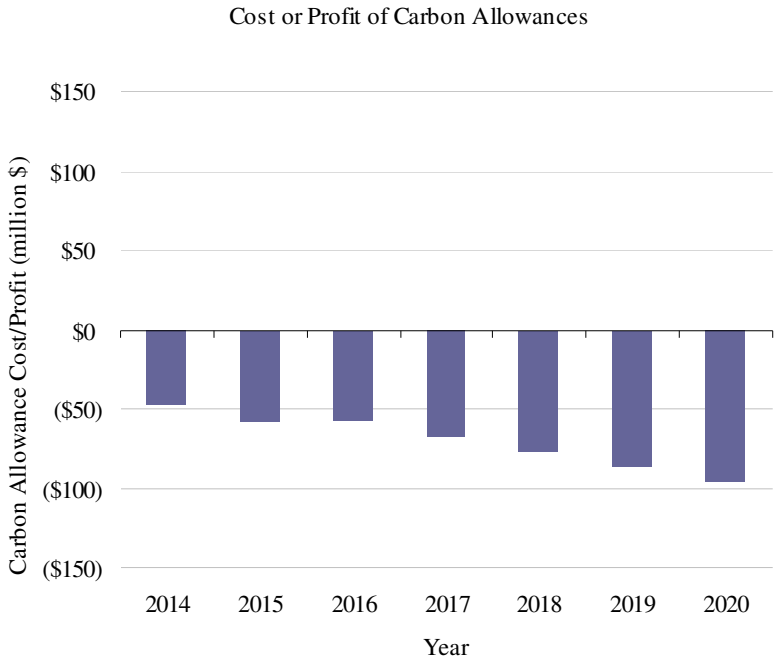
In July 2008, AE proposed a CO_2 upper limit (cap) and reduction plan through 2020.[8] AE plans to cap its CO_2 emissions at 2007 emission levels and gradually reduce emissions to 2005 levels by 2014. Most recently proposed federal carbon-related bills would set an initial 2014 goal of reducing economy-wide 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. AE's goal is to gradually reduce emissions annually by about 100,000 metric tons in a stair-step fashion.

Figure 3.4
Austin Energy Resource Plan Direct Carbon Dioxide Emissions



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.[9] 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.[10] 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.[11]

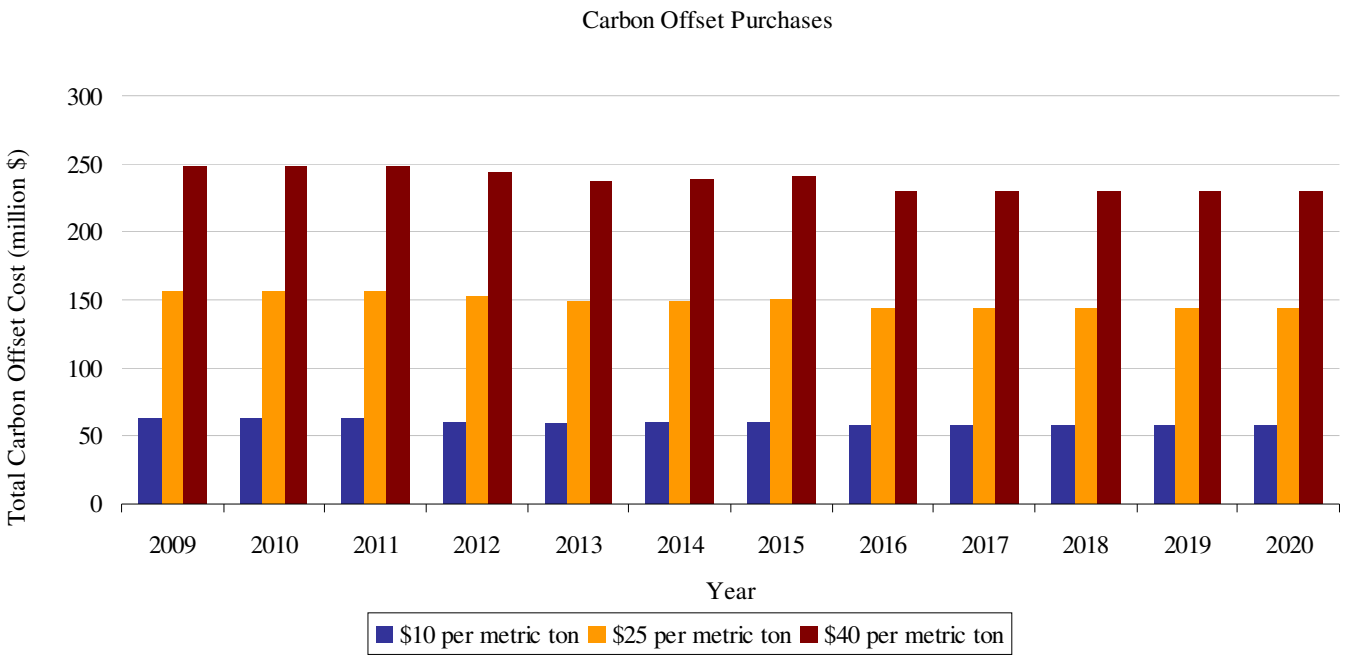
Figure 3.5
Austin Energy Resource Plan Carbon Allowance Costs



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.[12] 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.[13] 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.

Figure 3.6
Austin Energy Resource Plan Carbon Offset Costs



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 to come on-line 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 significant capital cost uncertainty.

Figure 3.7
Austin Energy Resource Plan Capital Costs

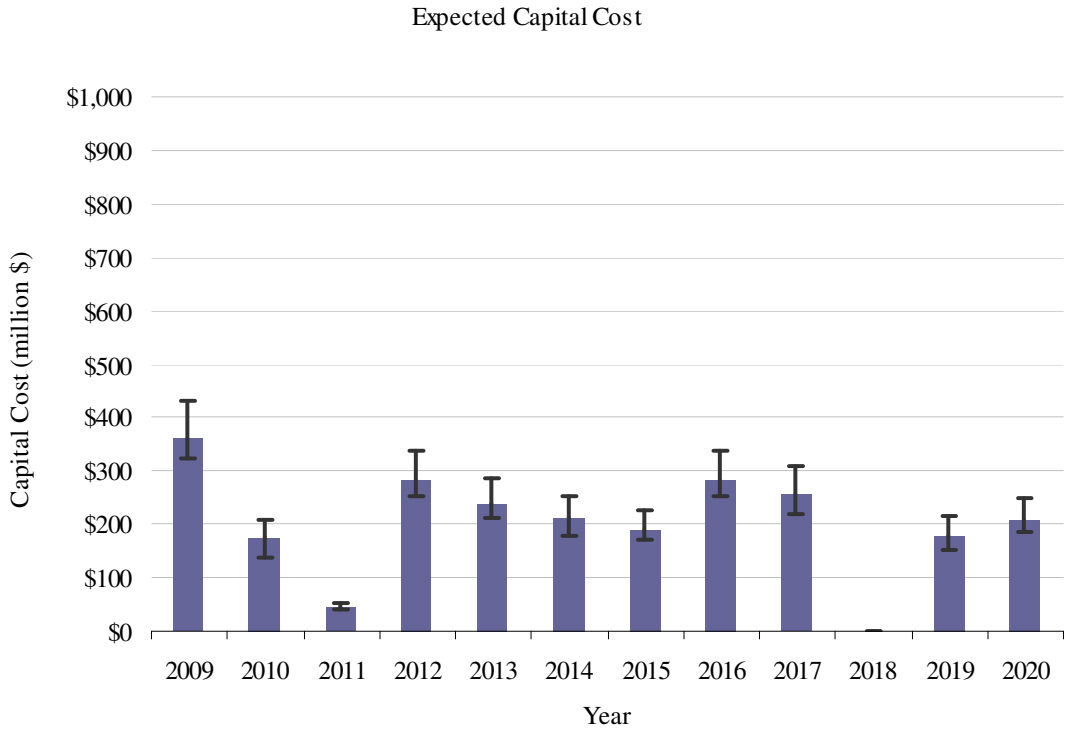


Figure 3.8 details annual expected fuel costs for AE's proposed resource plan. As fossil-fueled sources do not change dramatically under this scenario, fuel costs are expected to remain relatively stable, ranging in any given year from $170 to $360 million. If carbon

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. This expected increase in electric rates is based solely on new power generation investments. Carbon offset costs, infrastructure or regulatory costs, or any other 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 3.8
Austin Energy Resource Plan Fuel Costs

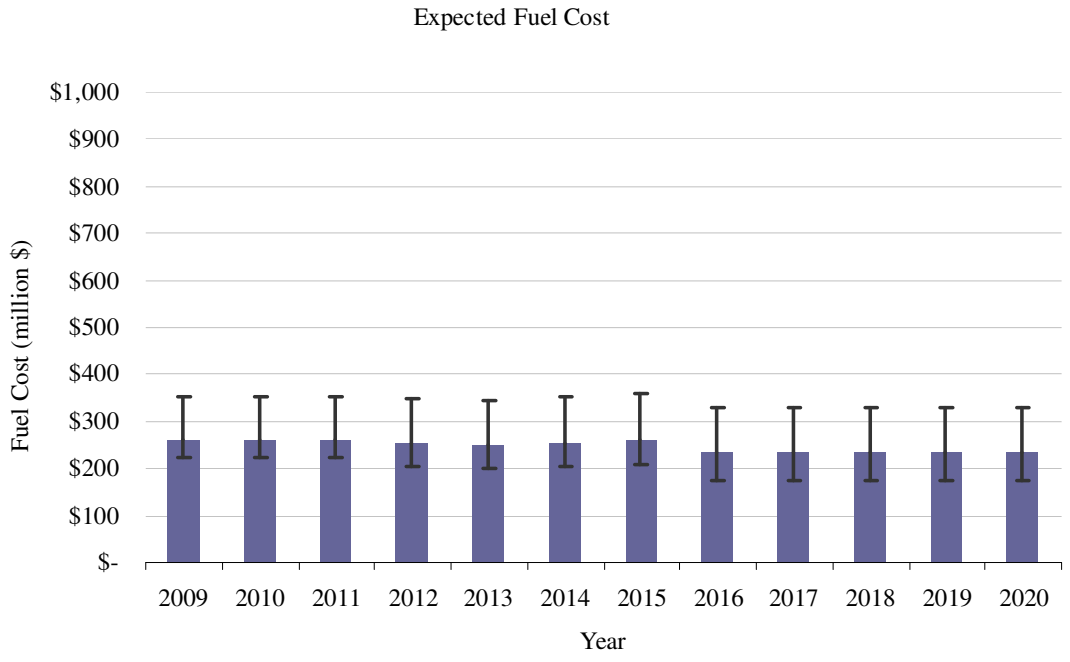


Figure 3.9
Austin Energy Resource Plan Levelized Costs

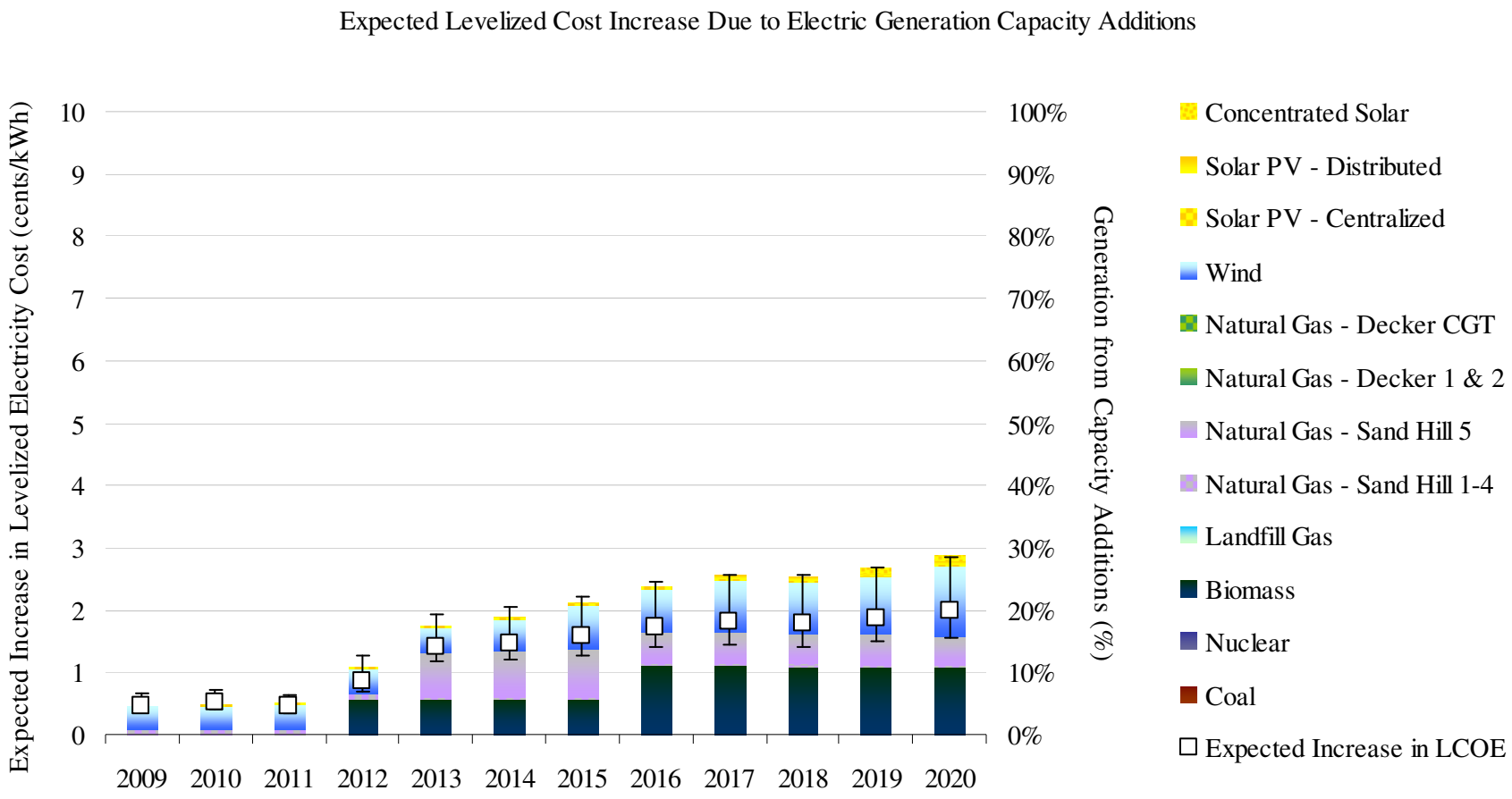


Figure 3.10
Austin Energy Resource Plan Economic Activity Greater Austin Area

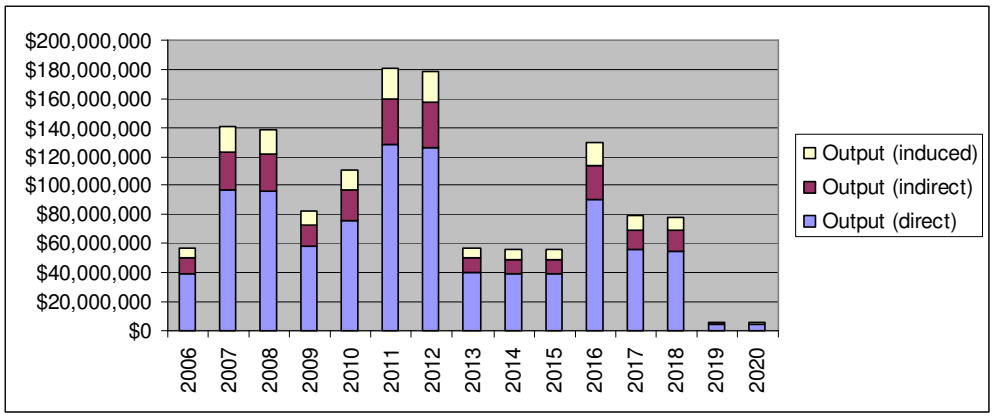


Figure 3.11
Austin Energy Resource Plan Total Value Added Greater Austin Area

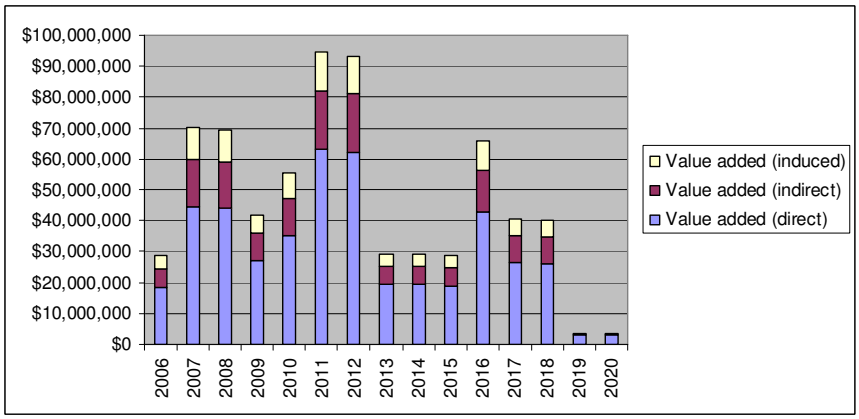


Figure 3.12 projects an average of approximately 600 new jobs per year in the Greater Austin area attributed to AE's resource plan.

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.

Figure 3.12
Austin Energy Resource Plan Employment Impacts
Greater Austin Area

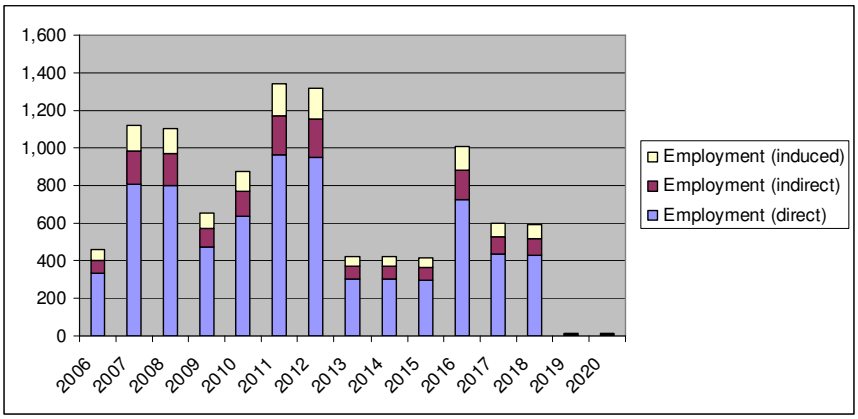


Figure 3.13
Austin Energy Resource Plan Economic Activity
CREZ Region

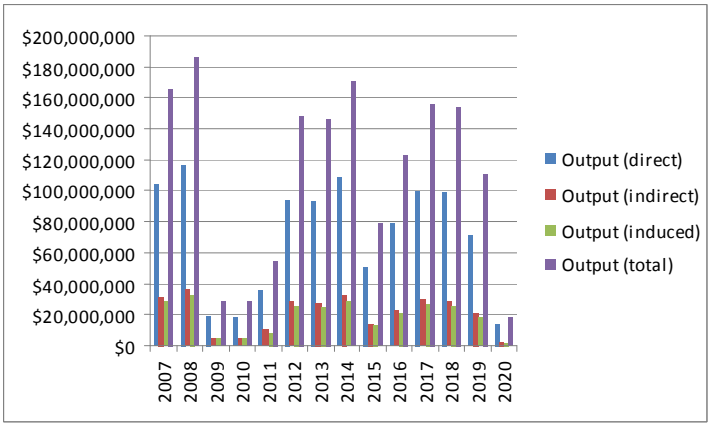


Figure 3.14
Austin Energy Resource Plan Total Value Added
CREZ Region

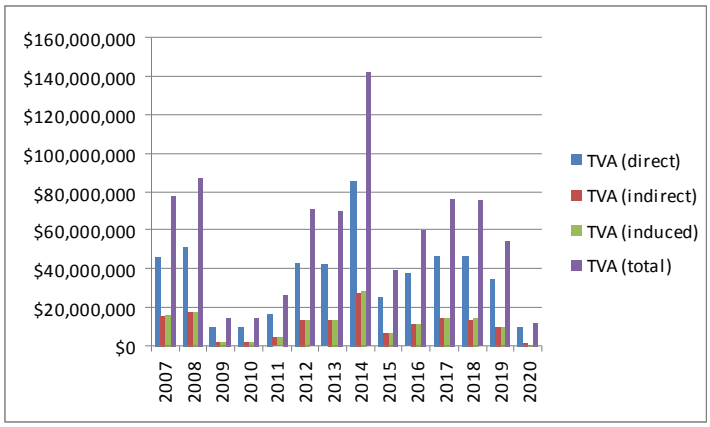
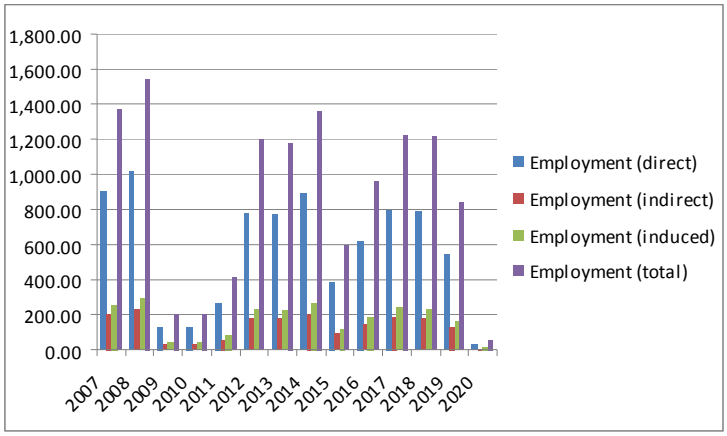


Figure 3.15
Austin Energy Resource Plan Employment Impacts
CREZ Region



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.

Figure 3.16
Austin Energy Resource Plan Economic Activity Nacogdoches County

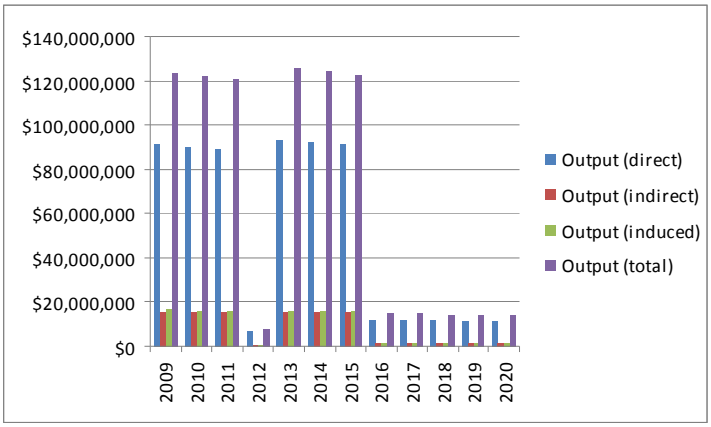


Figure 3.17
Austin Energy Resource Plan Total Value Added
Nacogdoches County

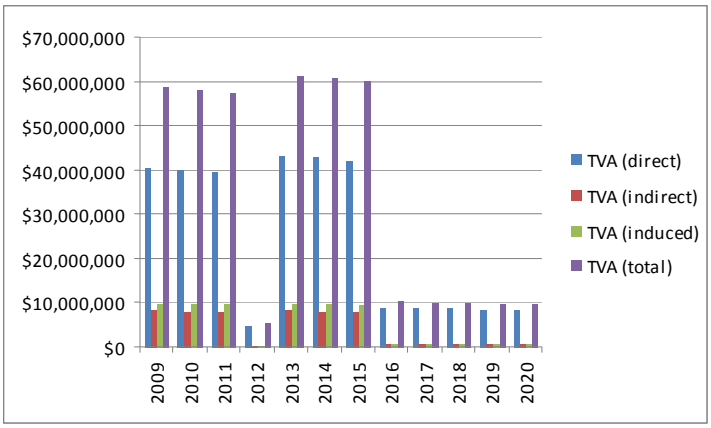
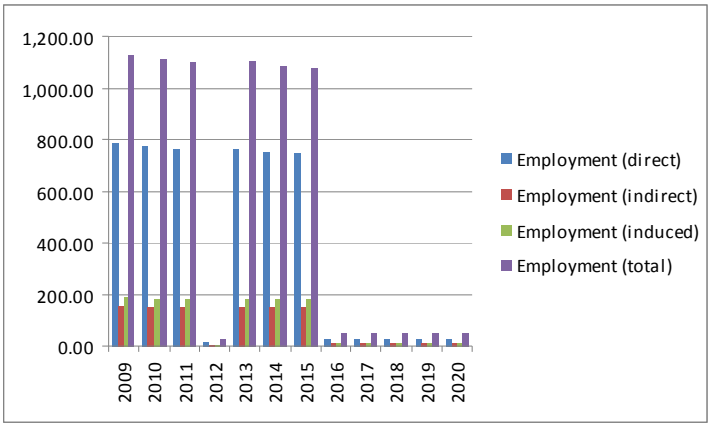


Figure 3.18
Austin Energy Resource Plan Employment Impacts
Nacogdoches County



Notes

[1]Austin Energy (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] Ibid.

[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* (online).

[5] Ibid.

[6] Presentation by Roger Duncan, General Manager, Austin Energy, *Public Participation and Resource Plan Updates*, Austin City Council, Austin, Texas, April 20, 2009.

[7] Ibid.

[8] AE, *Future Energy Resources* (online).

[9] AE, *Austin Energy Resource Guide* (October 2008), p. 35. Online. Available: http://www.austinsmartenergy.com/downloads/AustinEnergyResourceGuide.pdf. Accessed: December 19, 2008.

[10] 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.

[11] Ibid.

[12]AE, *Future Energy Resources* (online).

[13] Ibid.

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 scenario. 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 doubling 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) or 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 in 2020 (compared to 1,229 MW of baseload power generation capacity available under AE's proposed resource plan). 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 a 600 MW addition of nuclear power capacity rather than only about 400 MW. Additions of biomass and a 200 MW combined-cycle unit expansion at Sand Hill could account for additional baseload power needs. 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 variable 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 shows that this scenario will also be able to adequately meet the energy needs of AE customers through 2020.

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

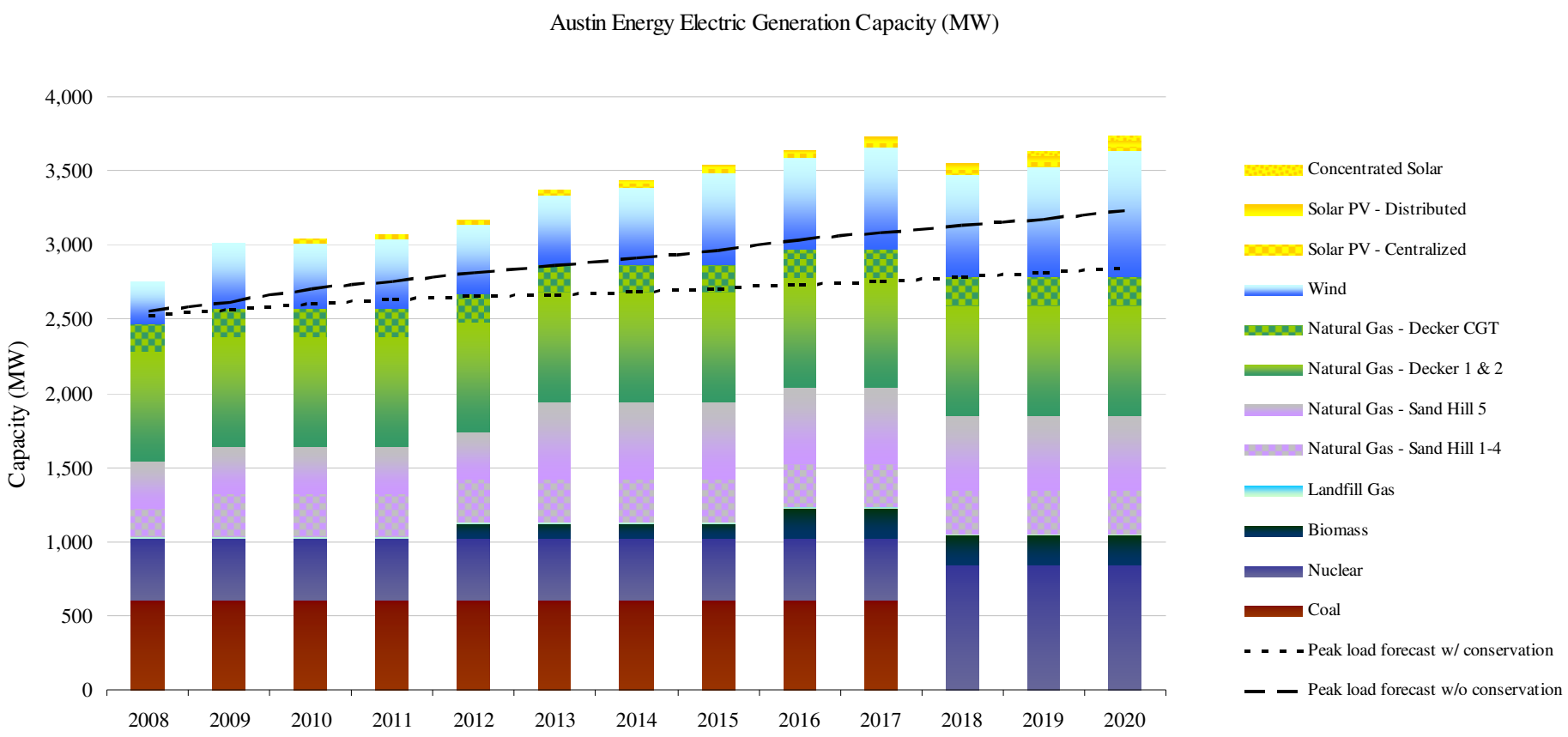
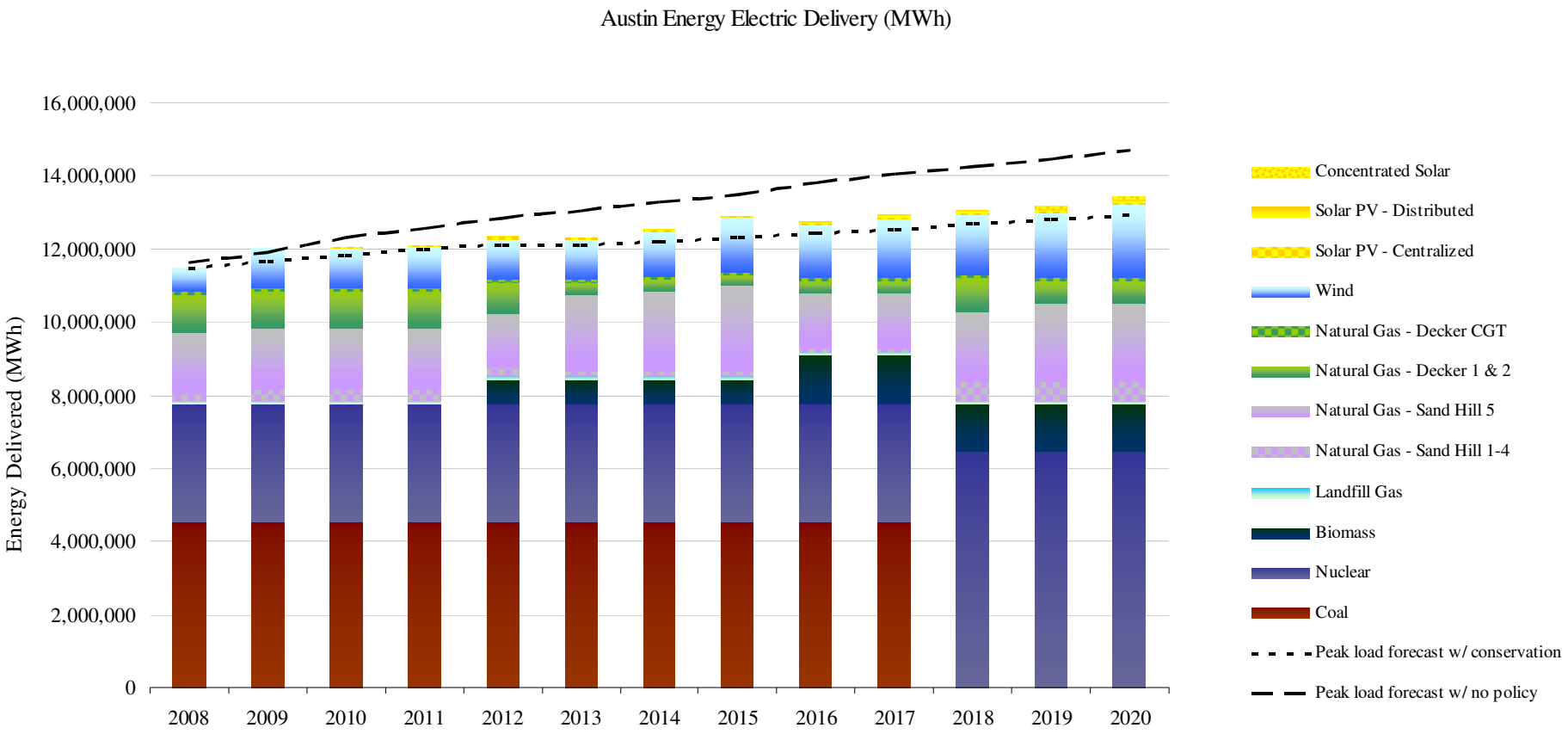
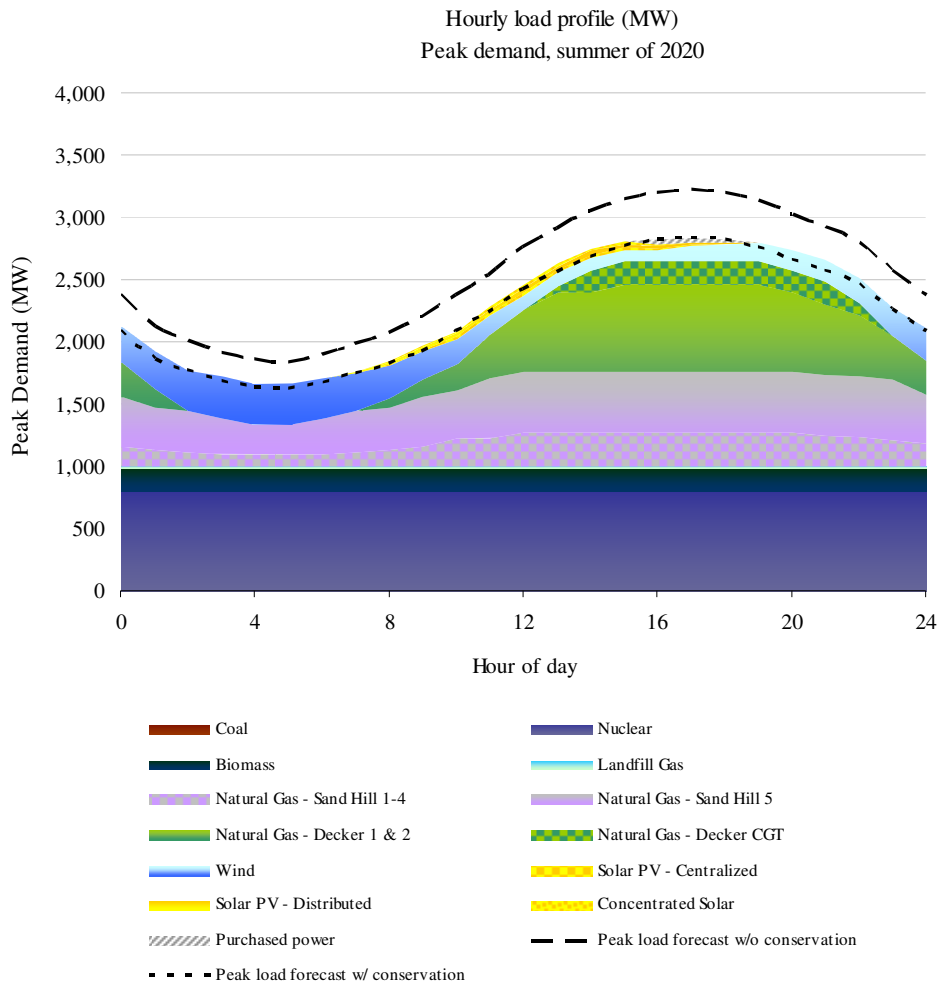


Figure 4.2
Nuclear Expansion Scenario Electric Delivery



However, this is contingent on AE meeting its demand-side management (DSM) goal between 2009 and 2020. If AE were to fall short of its DSM goal, 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 evaluation assumes that natural gas facilities are run at full capacity during peak demand periods and expected wind and solar availability profiles are achieved. 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.

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



Carbon Emissions and Carbon Costs

This scenario would cut carbon emissions by almost 75 percent, 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 for profit if carbon regulation that supported a portion of allowances being given for free is passed. 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 between $16 and $66 million annually at an offset cost ranging from $10 to $40 per metric ton of CO_2 released to reach carbon neutrality by offsetting emissions.

Figure 4.4
Nuclear Expansion Scenario Direct Carbon Dioxide Emissions

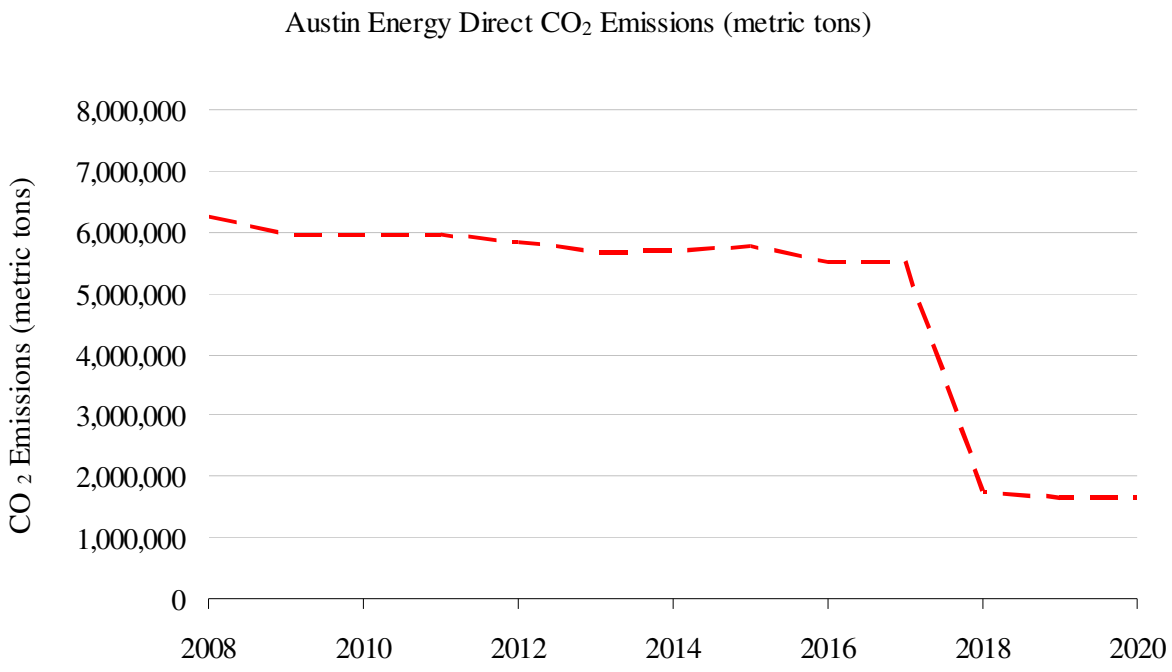


Figure 4.5
Nuclear Expansion Scenario Carbon Allowance Costs

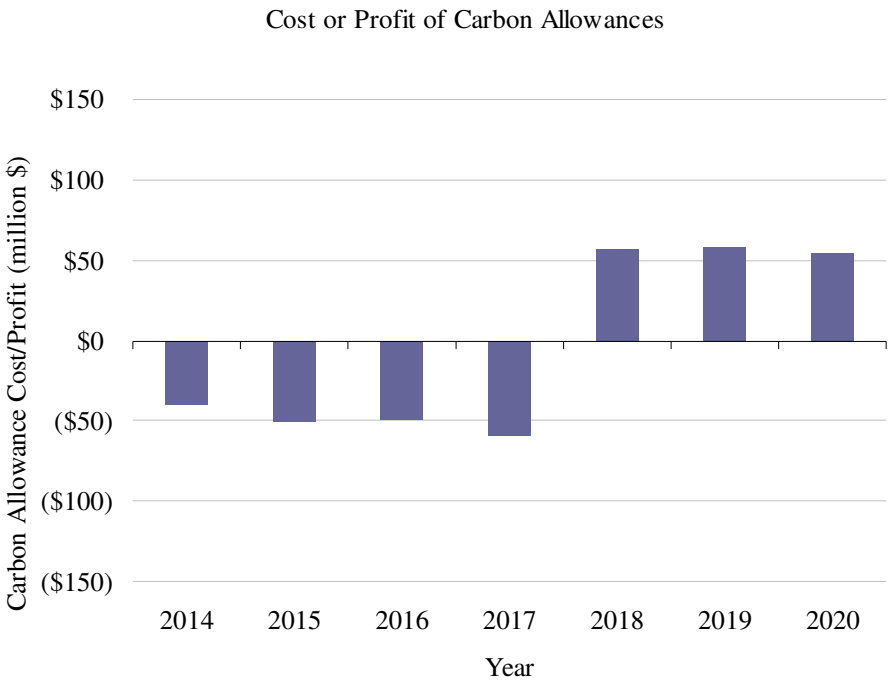
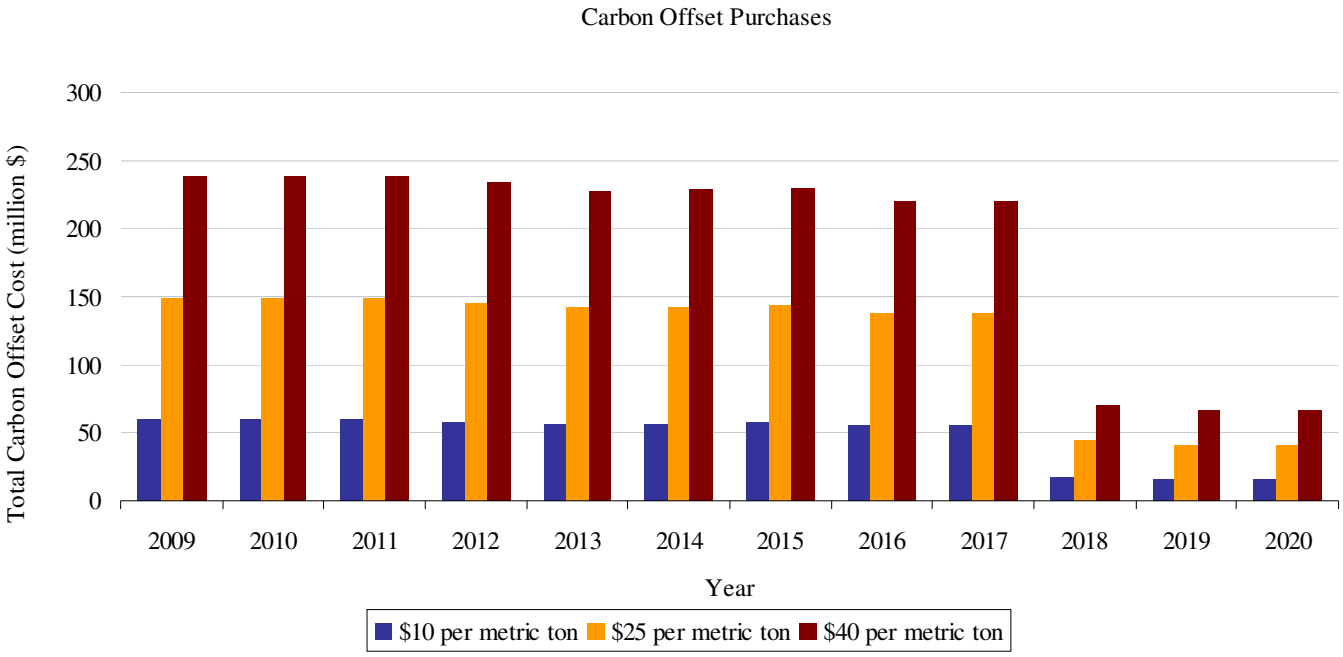


Figure 4.6
Nuclear Expansion Scenario Carbon Offset Costs



Costs

The most significant cost incurred by AE under this scenario is the capital cost associated with 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 under this scenario attributed to nuclear power generation expansion. Total expected capital costs range from $2.9 to $6.2 billion (compared to $2.2 to $3.0 billion under AE's proposed resource plan).

Figure 4.8 demonstrates that under this scenario, fuel costs would gradually increase through 2020. This is attributed to the necessity to use more natural gas, a more expensive and volatile fuel, once coal use is eliminated. By 2020, fuel costs under this scenario would range from $186 to $389 million annually (compared to $93 to $328 million under AE's proposed resource plan). It is important to recognize that while nuclear power plants require significant initial capital investment, operations and maintenance costs tend to be 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 under this scenario 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. Under this scenario, customers would expect the cost of electricity to rise 3.2-6.2 cents per kWh by 2020. 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 expected increase in cost of electricity does not include a potential sale or lease value for FPP as the methodology for determining such a value would be very difficult to develop. Such removal may help to alleviate the additional costs of electricity accrued from resource additions. The cost estimates calculated by this model also do not account for any government subsidies that may be available for the building of new nuclear power plants. The expected increase in electric rates is based solely on new power generation investments. Carbon offset costs, infrastructure or regulatory costs, or any other unexpected additional costs to the utility could also be passed on to the customer during this time period.

Figure 4.7
Nuclear Expansion Scenario Capital Costs

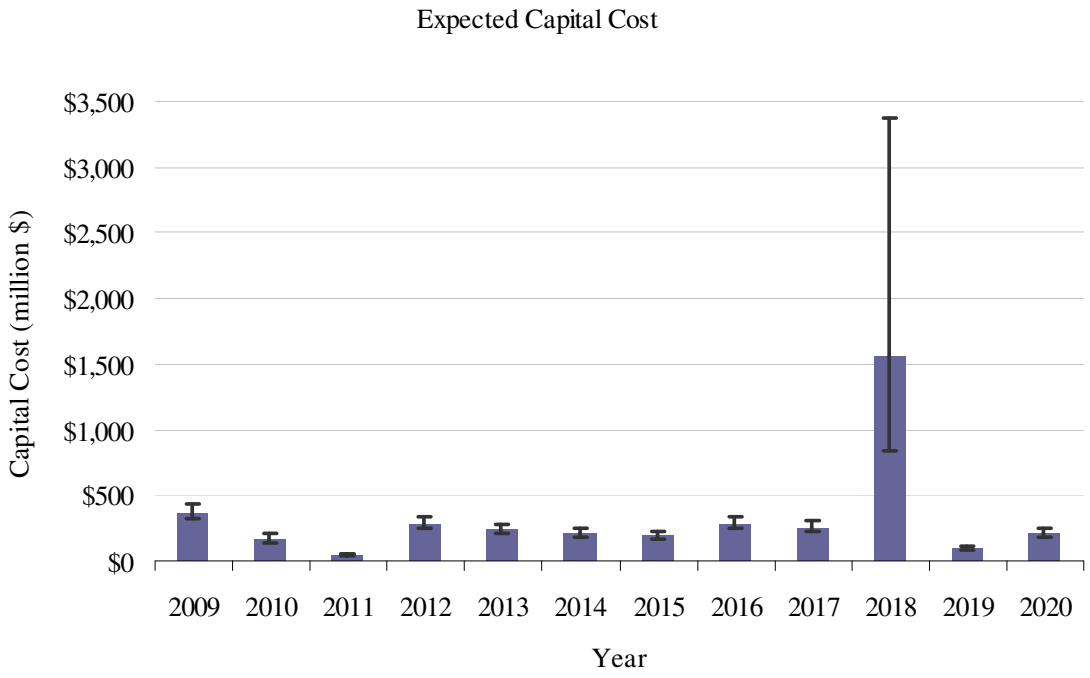


Figure 4.8
Nuclear Expansion Scenario Fuel Costs

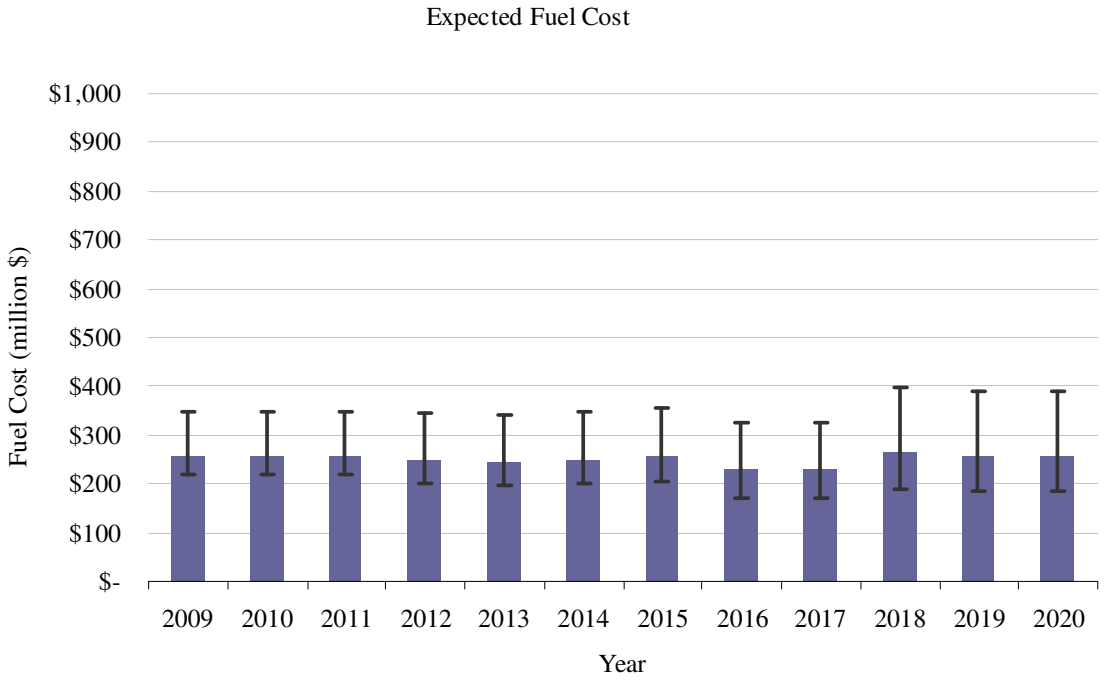
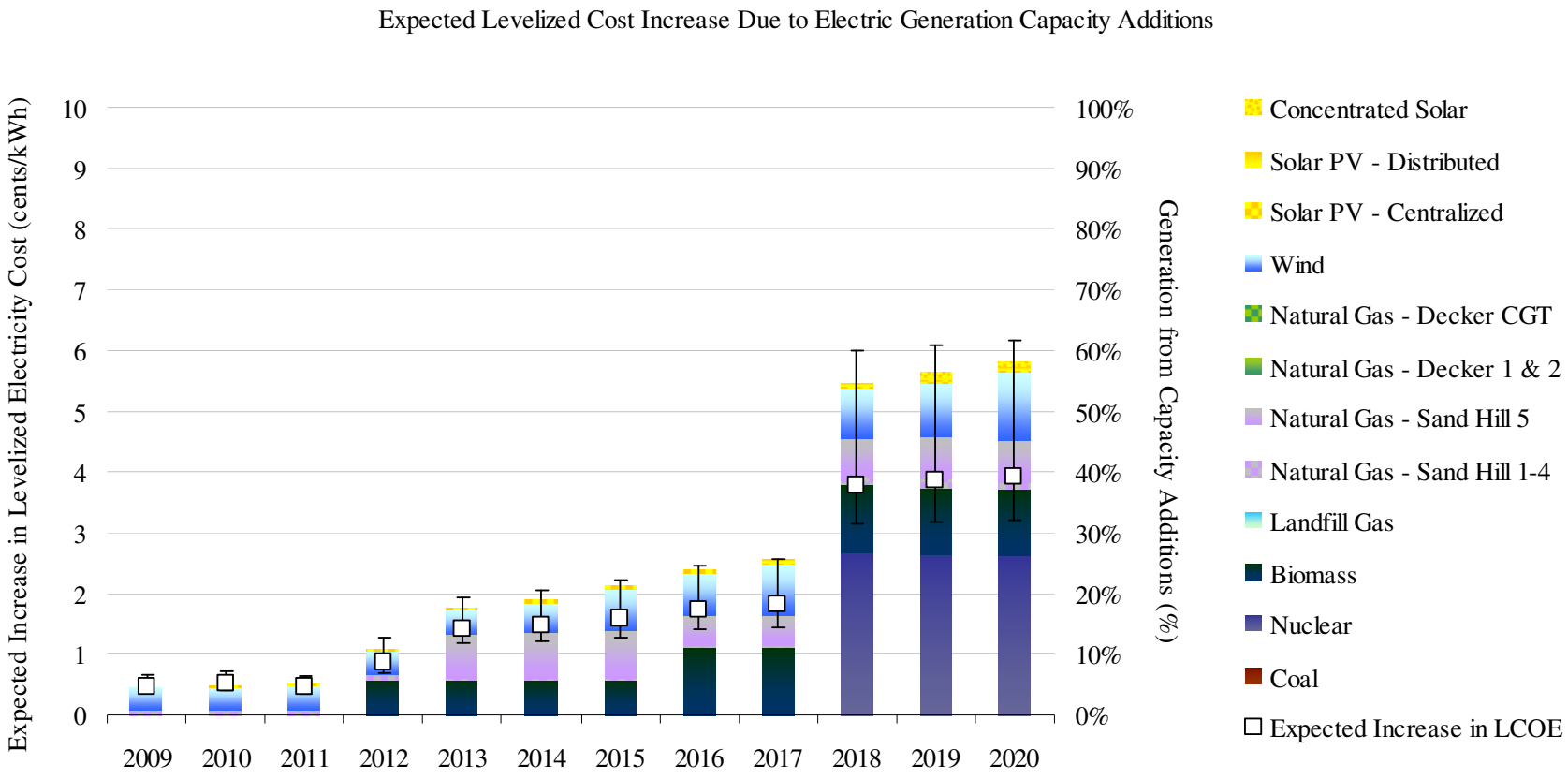


Figure 4.9
Nuclear Expansion Scenario Levelized Costs



Chapter 5. High Renewables Scenario

The high renewable resource investment scenario evaluates a significant shift towards a cleaner energy portfolio that eliminates the need for burning coal to generate electricity. Table 5.1 details the additions to Austin Energy's (AE) resource portfolio from 2009 to 2020 by fuel source, power generation technology, or facility under this scenario. By eliminating the need to burn coal for electricity, 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. Such a 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 of Texas' electric grid. Utility-scale solar, geothermal and biomass facility investments are limited to current and expected capacity and availability constraints. Wind facilities are assumed to be unconstrained by capacity, but in fact may have a penetration limit due to its inherent unreliability as a variable resource, limits to the planned transmission build-out, and continued cost-effectiveness given the operational parameters of the electric system.

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 can provide a reliable and continuous 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 megawatt (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 in the state. 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 a variable 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 (currently 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 or coastal 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 use of coal 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 the demand-side management (DSM) goal 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 variable energy sources (wind and solar). 2,324 MW of power generation capacity will come from energy resources that can provide continuous power.

Figure 5.2 demonstrates that, given assumed capacity factors for wind and solar 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 DSM goal. It appears that AE will be able to provide reliable service even if its DSM goal is only met halfway. However, because 52 percent of expected electricity delivered is dependent upon variable energy sources, there is some cause for concern for system reliability and increased exposure to the volatile energy market given the chances that wind and solar power generation capabilities do not meet expected demand levels at any given hour. 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 DSM goal. Since AE makes gradual additions to its resource portfolio from baseload, intermediate, and variable energy sources, 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.

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

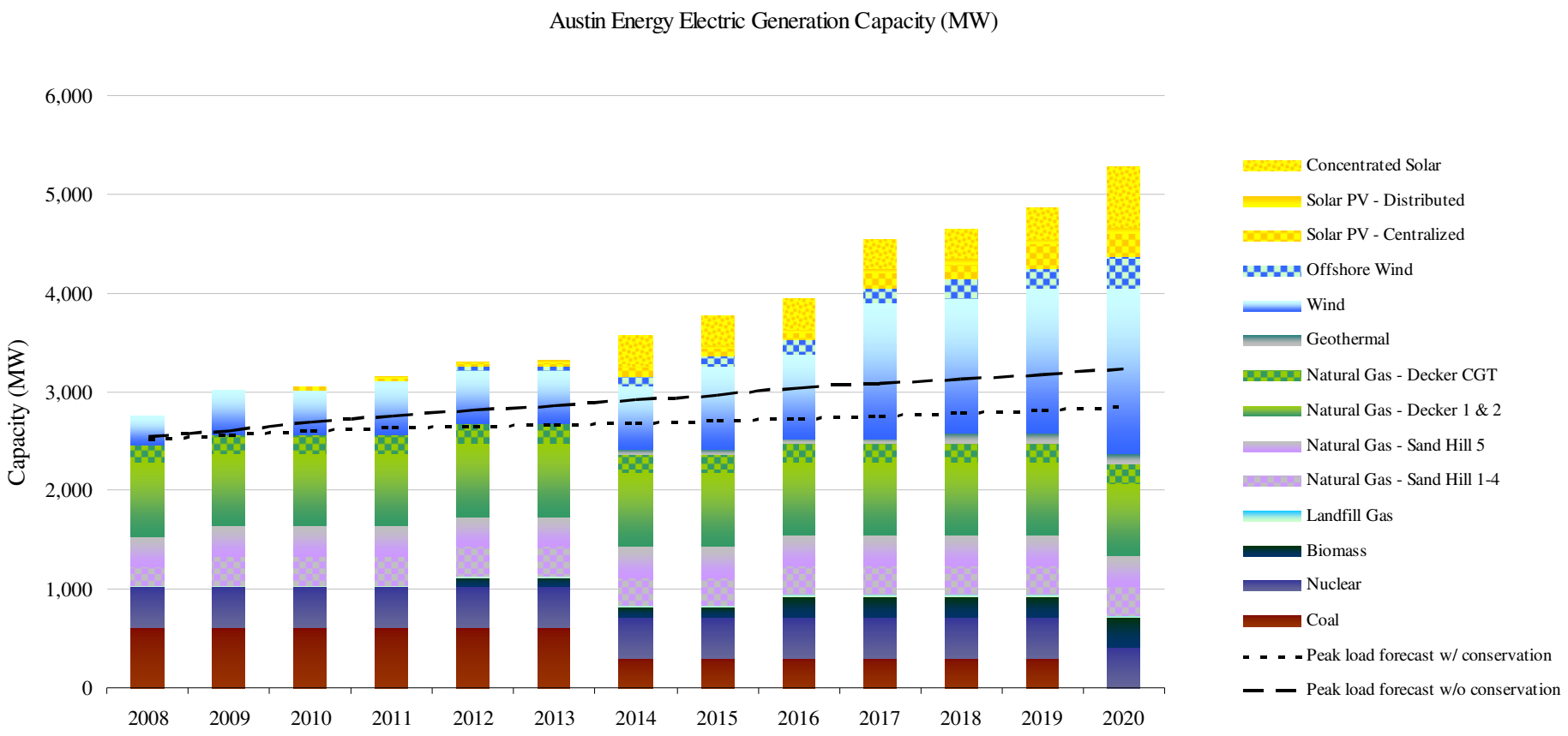


Figure 5.2
High Renewables Scenario Electric Delivery

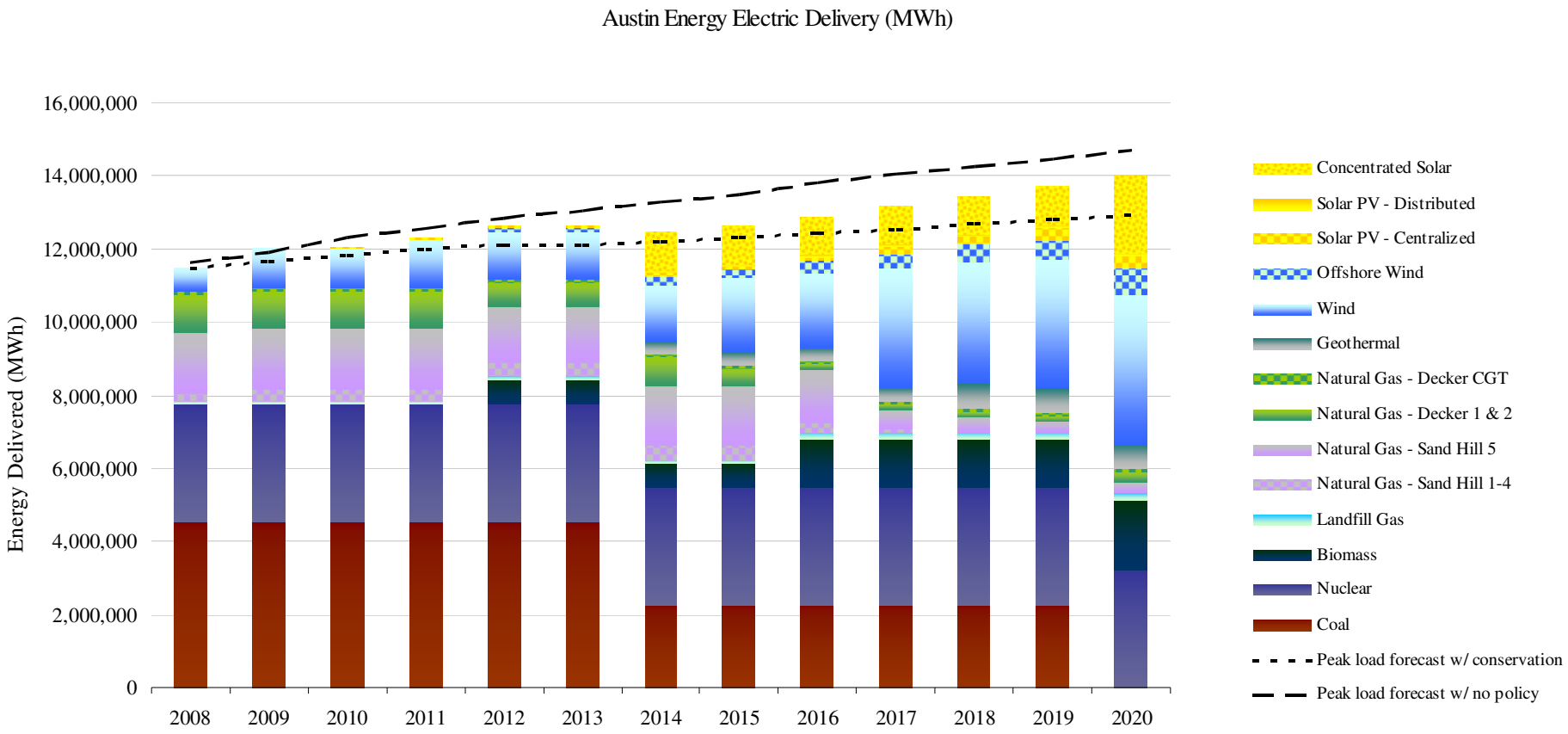
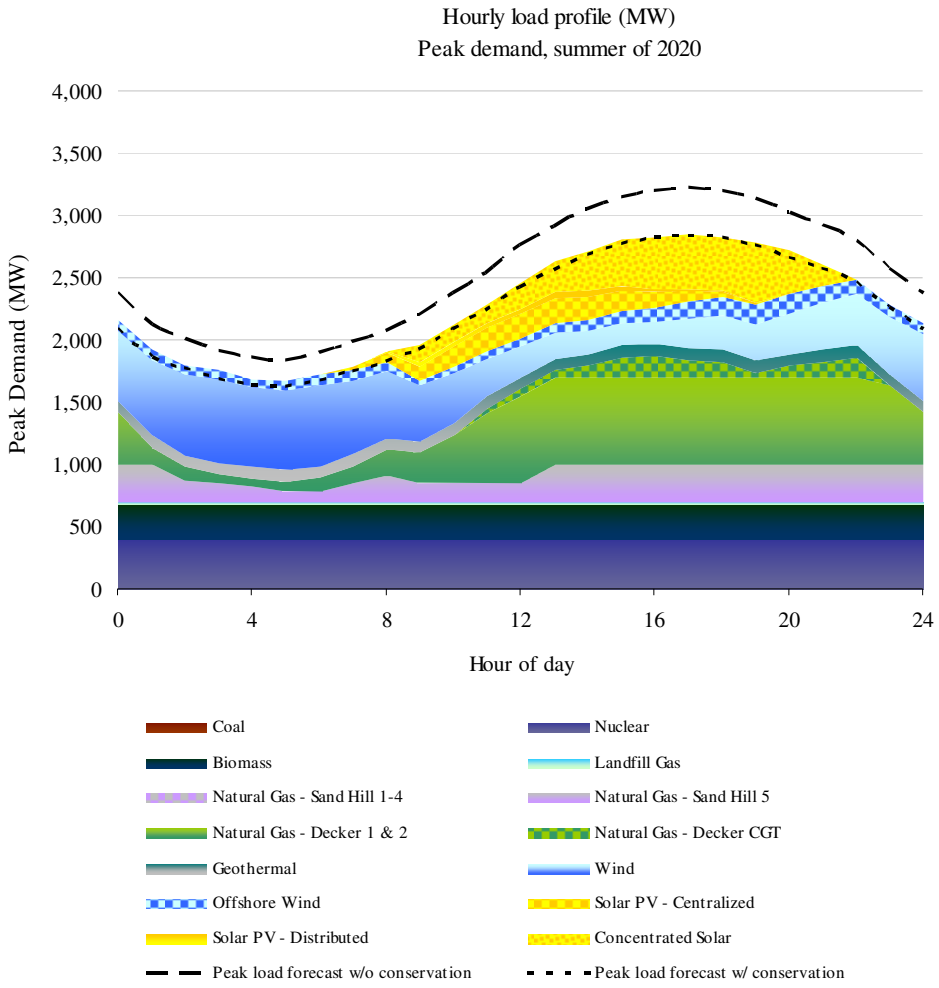


Figure 5.3
High Renewables Scenario Hourly Load Profile
(Peak Demand, Summer 2000)

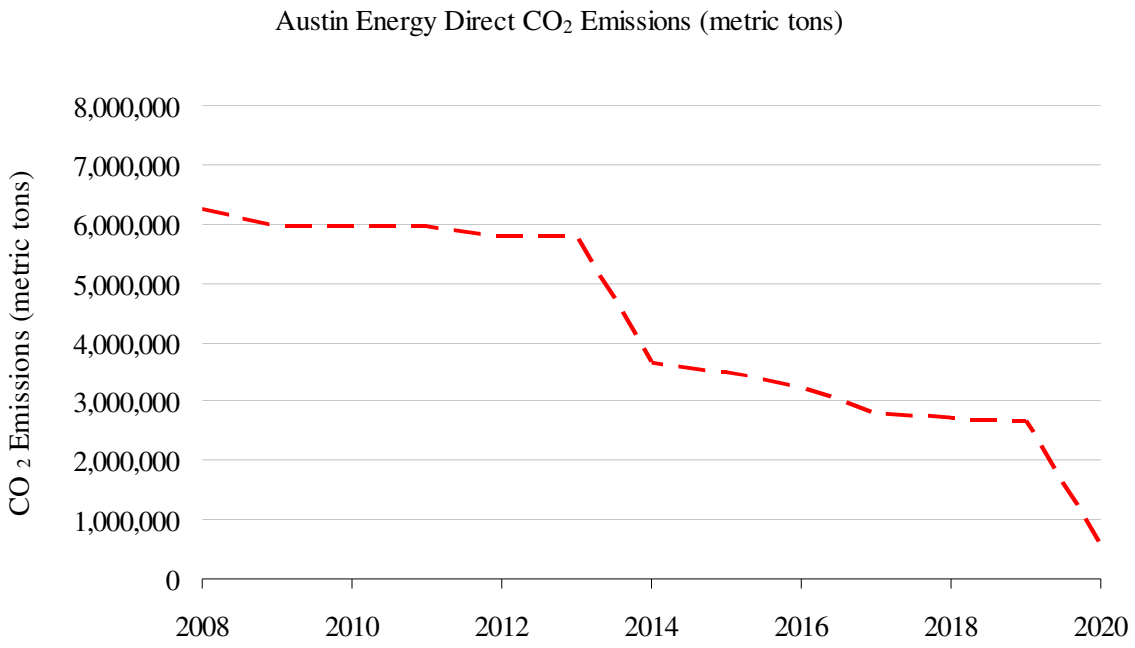


Carbon Emissions and Carbon Costs

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. 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 was first proposed by AE. Given assumed 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); 52 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

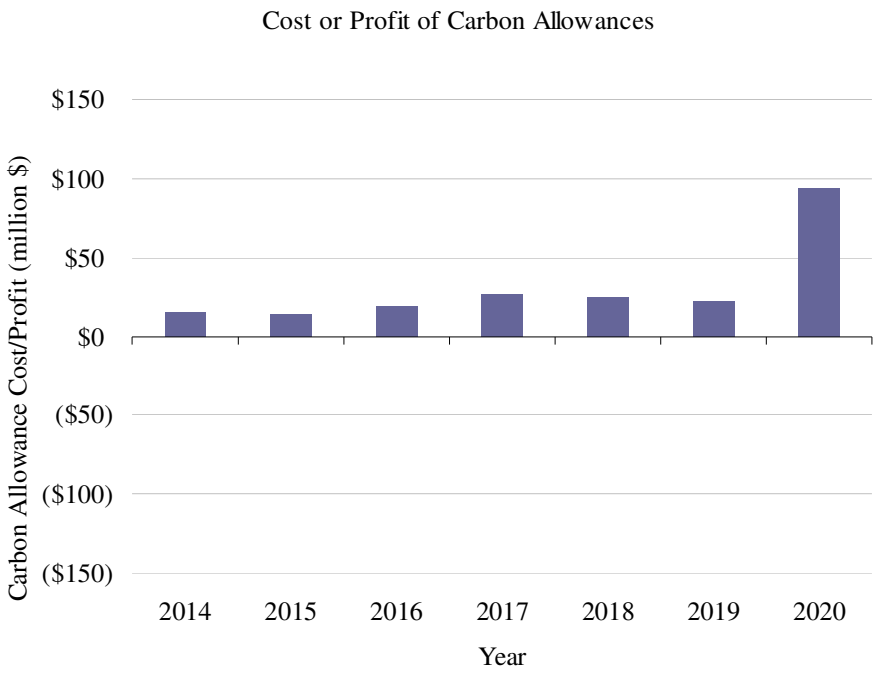
in 2007 were roughly 6.1 million metric tons. Under the high renewables scenario CO_2 emissions would drop to under 600,000 metric tons by 2020, a reduction of almost 90 percent. The high renewables scenario demonstrates an opportunity to significantly eliminate AE's carbon footprint by reducing CO_2 emissions to a level that makes offsetting emissions to zero very manageable.

Figure 5.4
High Renewables Scenario Direct Carbon Dioxide Emissions



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 allocated for free to the utility. 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.

Figure 5.5
High Renewables Scenario Carbon Allowance Costs

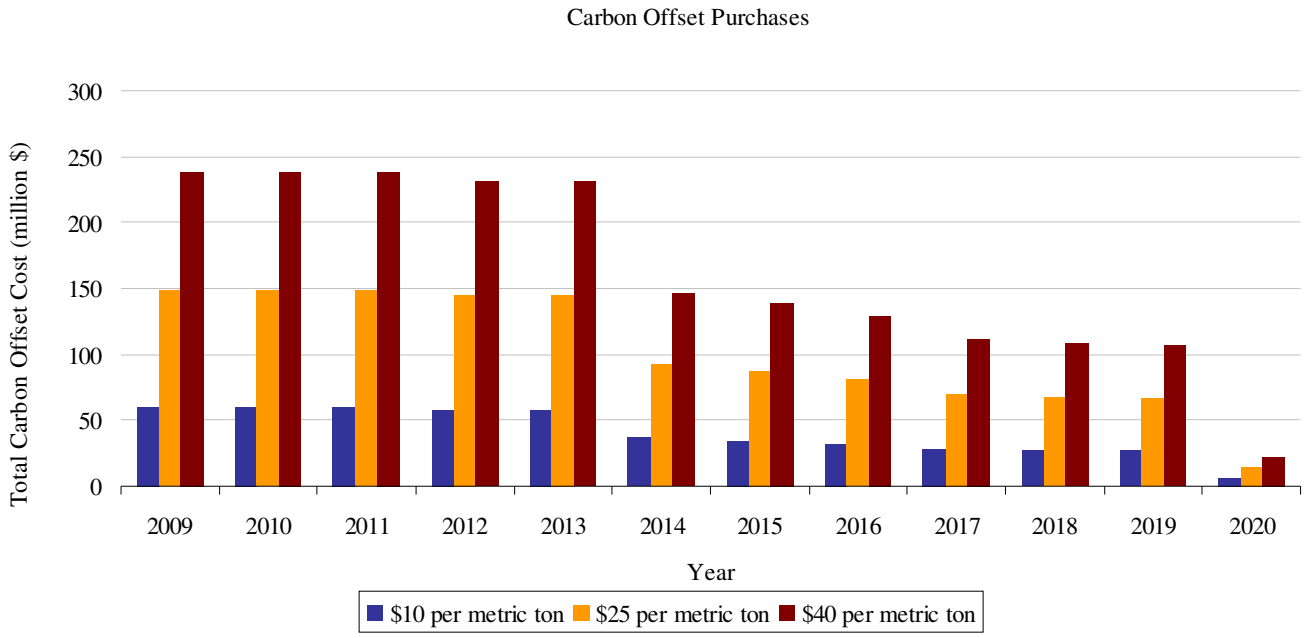


Under the high renewables scenario, offsetting CO_2 emissions to zero becomes much more manageable. Figure 5.6 provides a range of annual costs to offset emissions to zero, thus effectively achieving carbon-neutrality. The costs of offsets would be dramatically reduced in the years 2014 and 2020, respectively, as half of AE's stake in its coal facility would be eliminated in each of those years. 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 variable sources of energy and to provide peaking power. 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, it does raise 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 and lower in costs, reliance on nuclear energy

as well as natural gas could become less necessary and cost-effective. Given a timeframe of only 11 years, the project team believes that nuclear is a necessary component to ensuring AE's ability to provide reliable energy at low costs under a high renewable resource mix.

Figure 5.6
High Renewables Scenario Carbon Offset Costs



Costs

The model used in this study does not use AE projections of the costs of scheduled or proposed additions to its resource portfolio. As many of these additions may 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. The model estimates that electric rates will increase by between 4.5 and 8 cents per kilowatt-hour of electricity consumed by 2020 under this scenario, compared to between 1.5 and 3 cents per kilowatt-hour under AE's proposed energy resource plan. This expected increase in electric rates is based solely on new power generation investments. Carbon offset costs, infrastructure or regulatory costs, or any other unexpected additional costs to the utility could also be passed on to the customer during this time period. The calculation for expected increase in cost of electricity does not appoint a monetary value for reducing or removing coal or any other resource from AE's resource portfolio. Such value may help to alleviate the additional costs to electricity accrued from the identified resource additions.

Figure 5.7
High Renewables Scenario Capital Costs

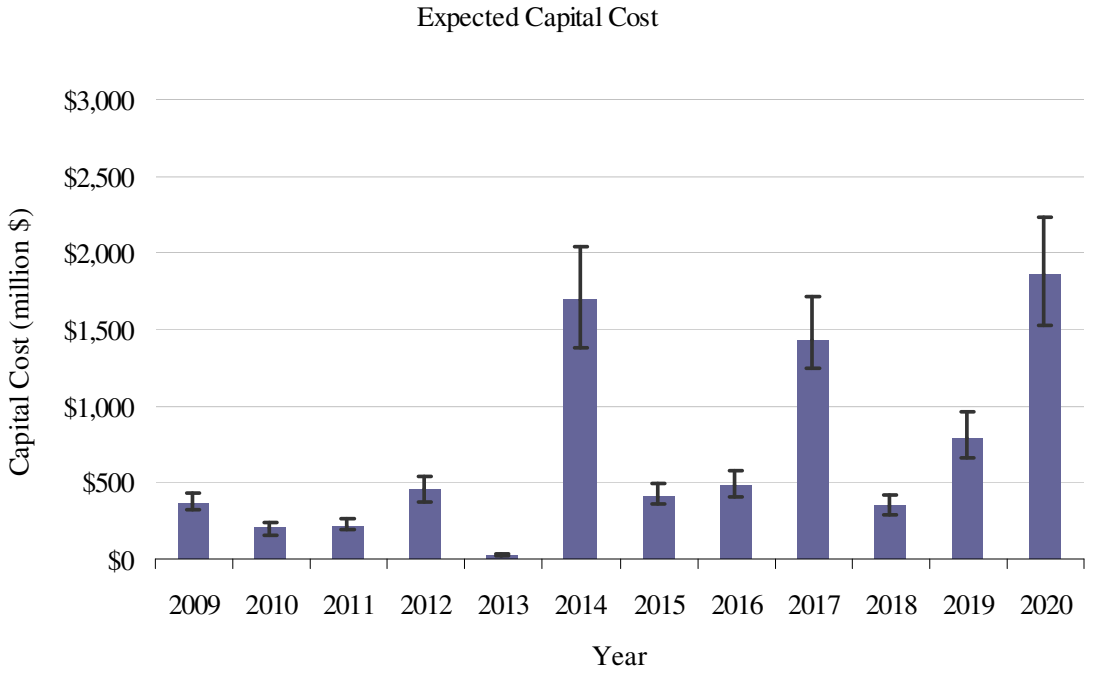


Figure 5.8
High Renewables Scenario Fuel Costs

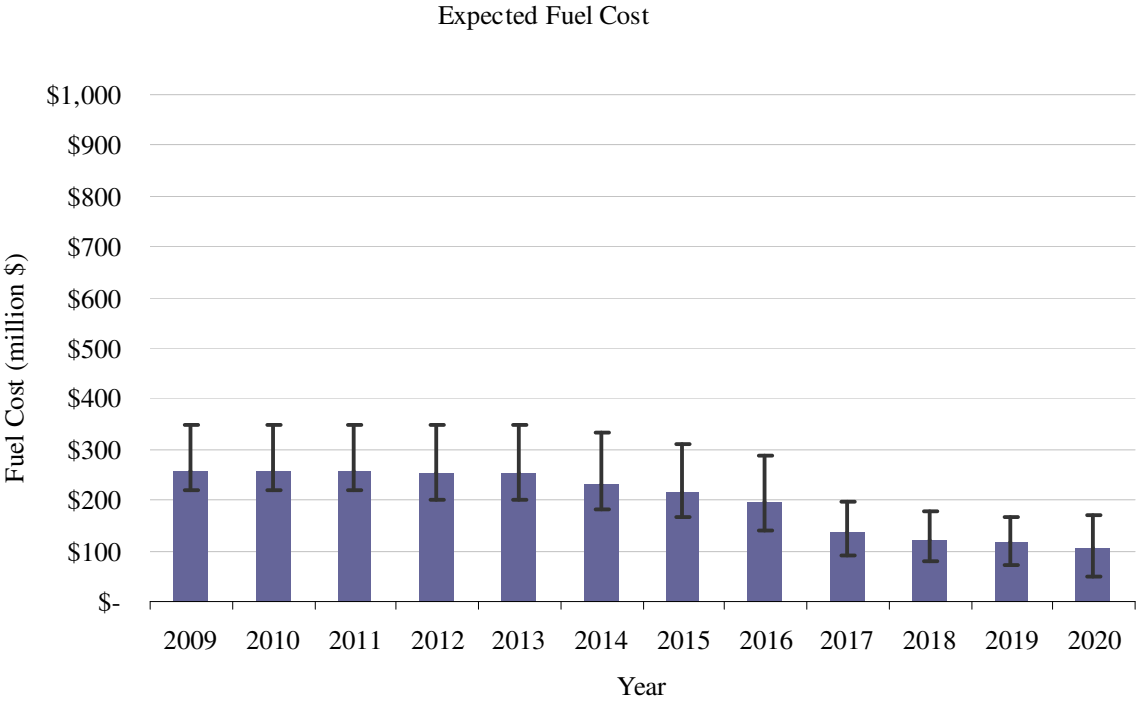
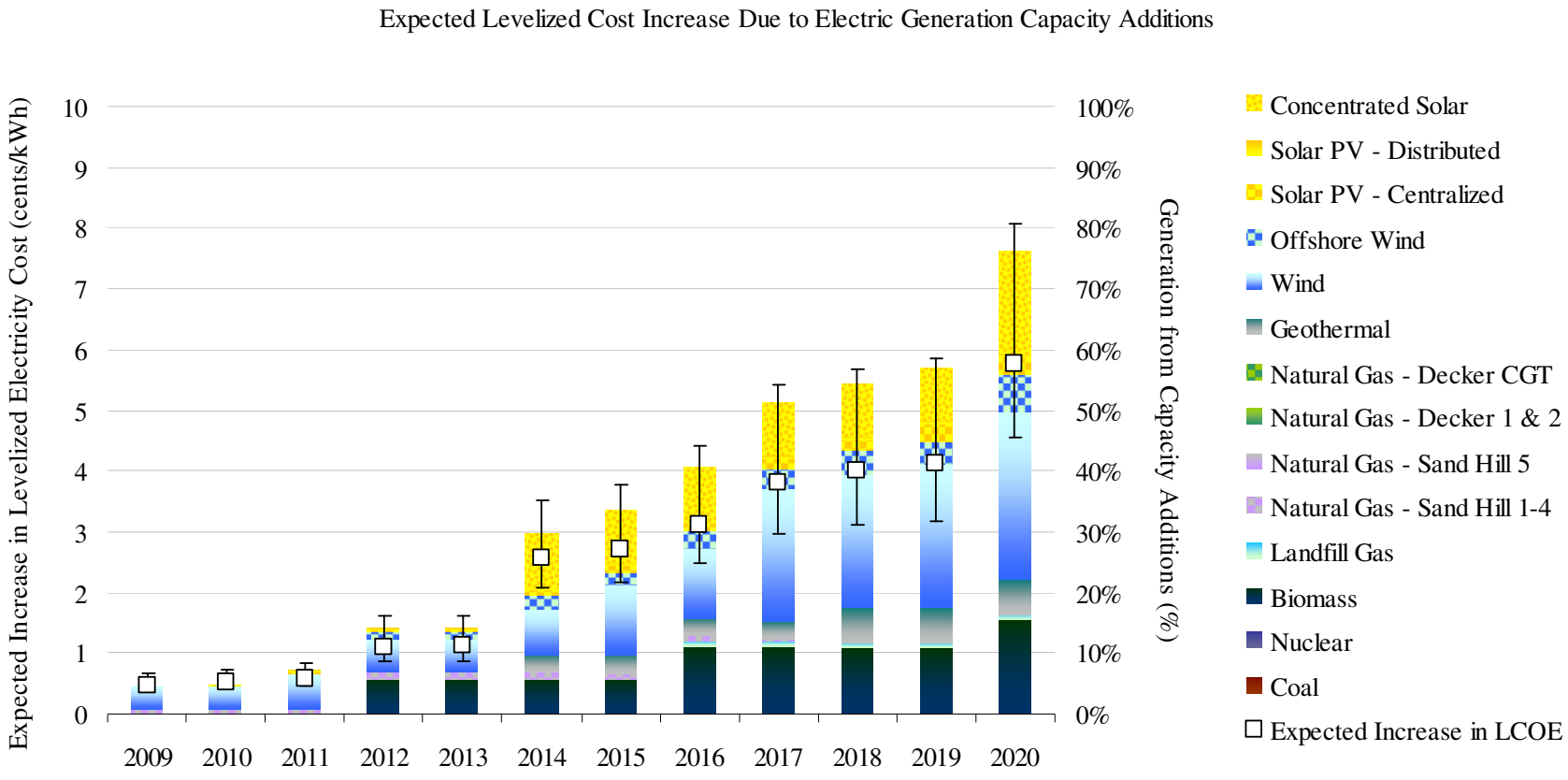


Figure 5.9
High Renewables Scenario Levelized Costs



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. Table 6.1 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 carbon dioxide (CO_2) emissions attributed to the burning of coal. To make up for lost coal baseload power, AE maintains the schedule of 572 megawatts (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 kilowatt (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 off-shore wind sources, as AE's future access to these resources is uncertain.

System Reliability

Figure 6.1 demonstrates that AE's power generation capacity would exceed forecasted peak load with and without AE's demand-side management (DSM) goal 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 or vulnerability to volatile power market prices.

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 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 DSM goal. 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 DSM goal. At peak, with all the natural gas facilities operating at full capacity, AE would still have to purchase 185 MW from the market to meet demand. An additional 200 MW natural gas facility addition could make up this difference.

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 6.5 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.

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

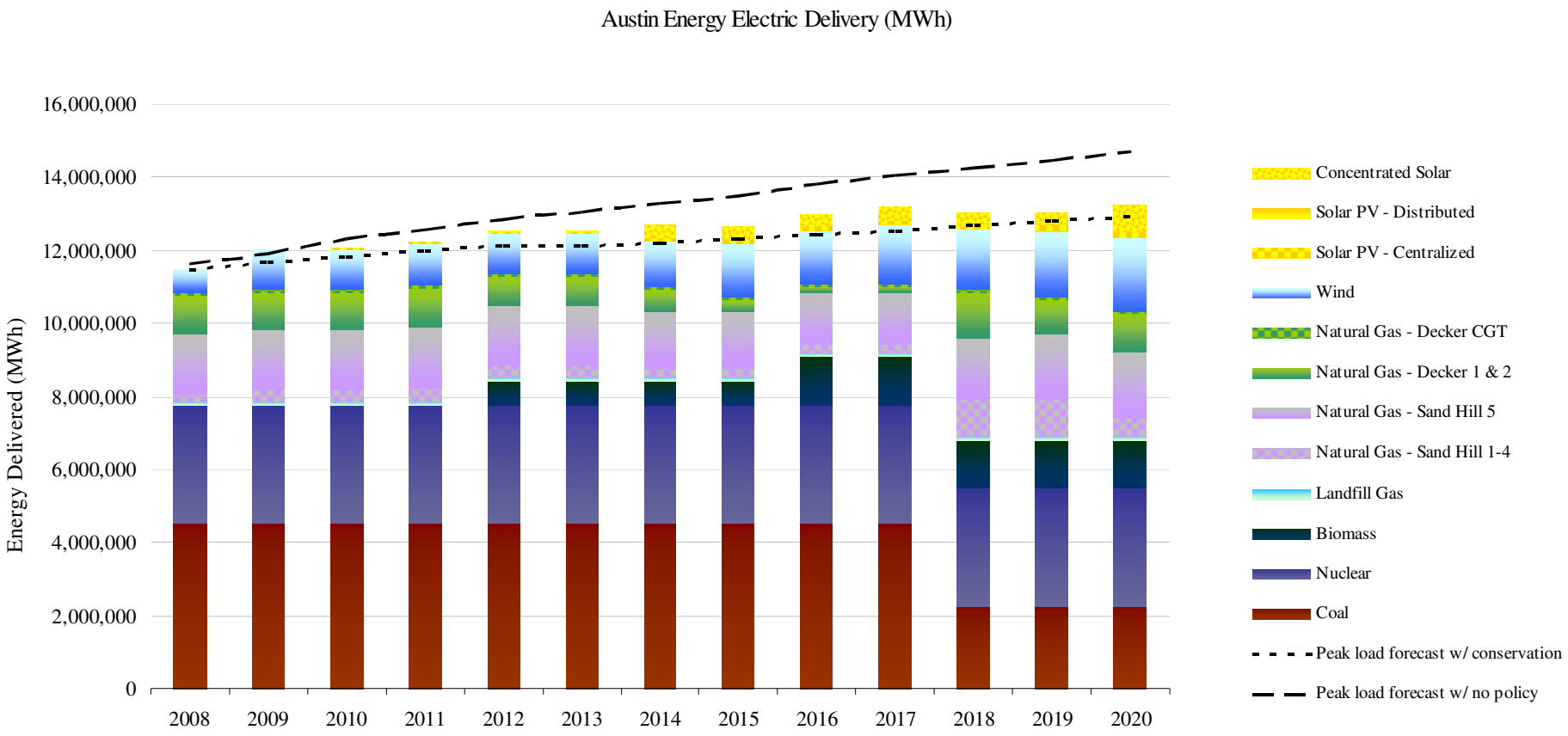


Figure 6.2
Expected Renewables Scenario Electric Delivery

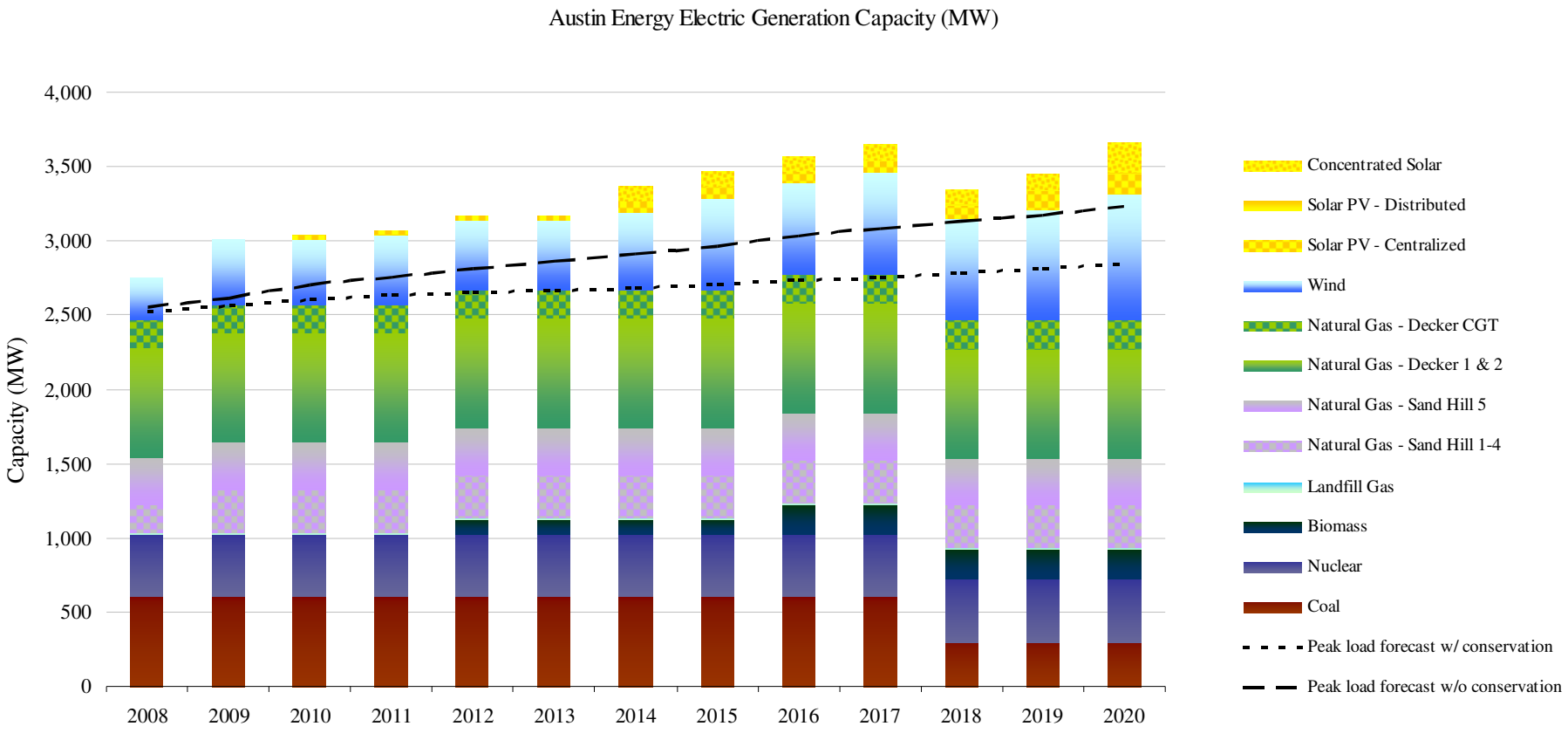


Figure 6.3
Expected Renewables Scenario Hourly Load Profile
(Peak Demand, Summer 2000)

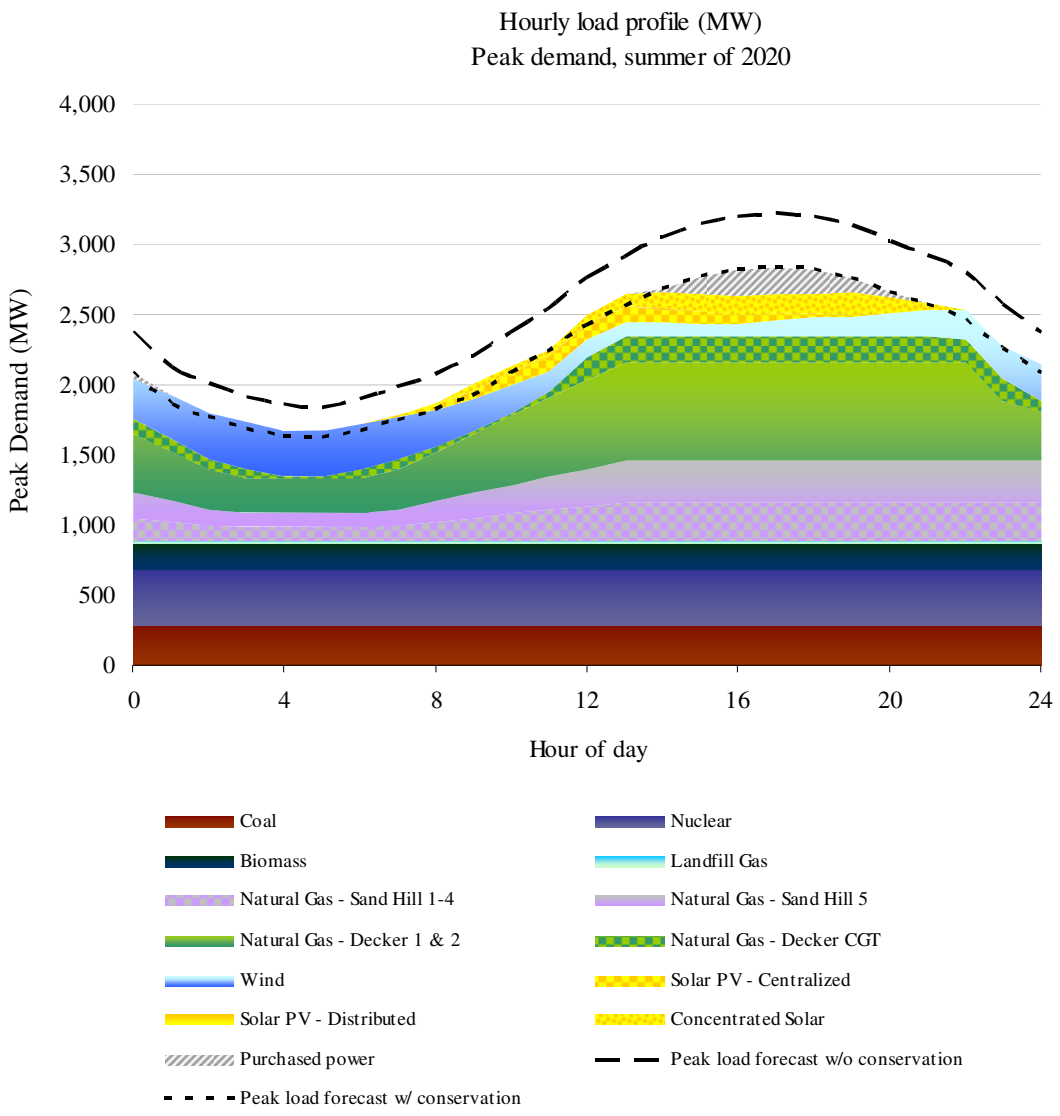


Figure 6.4
Expected Renewables Scenario Direct Carbon Dioxide Emissions

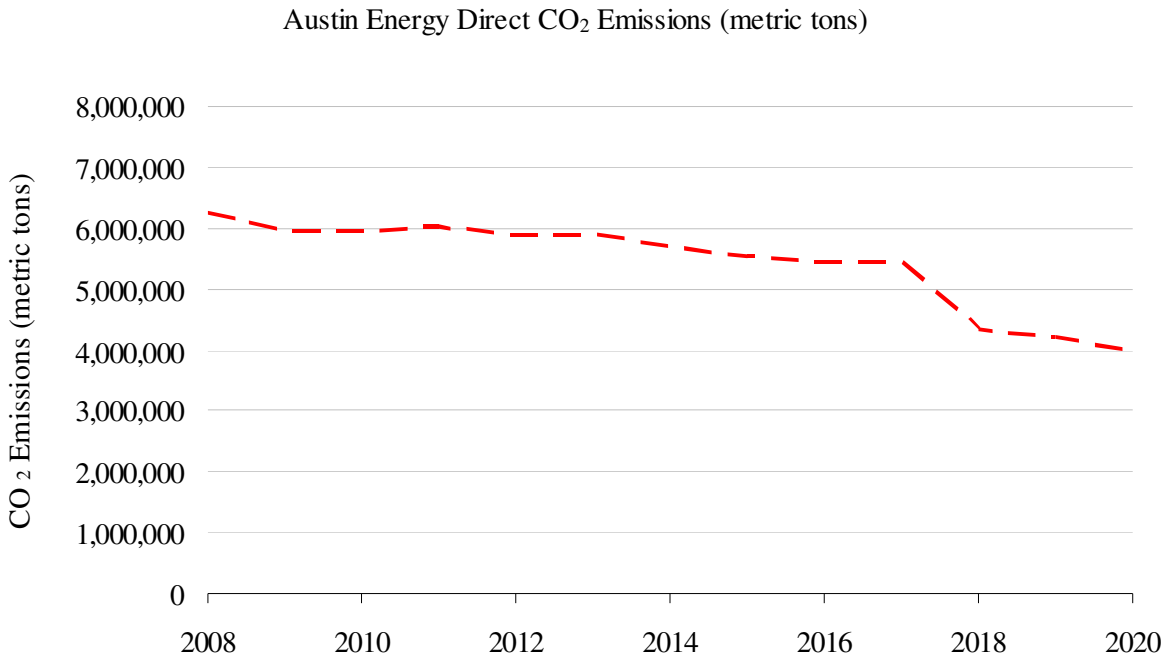
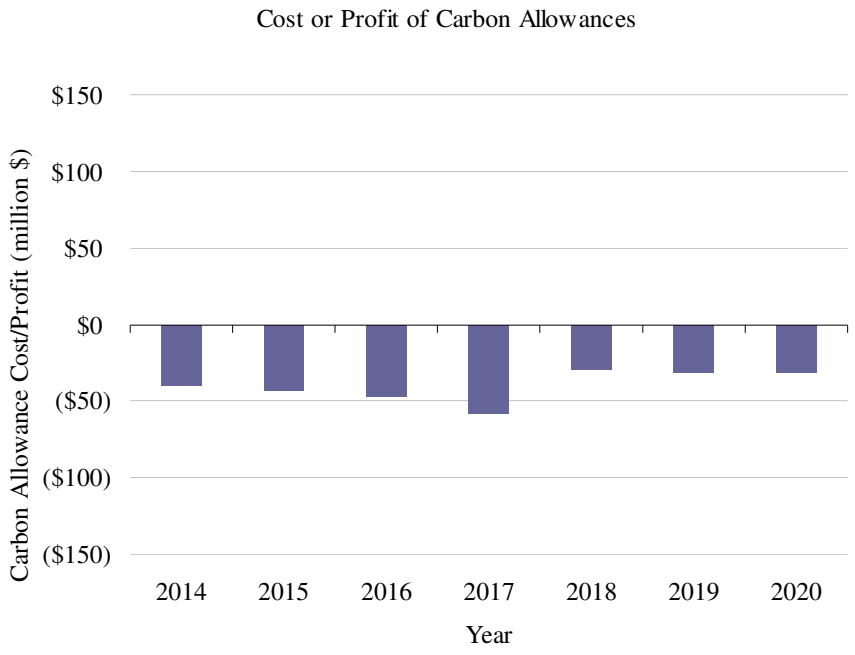


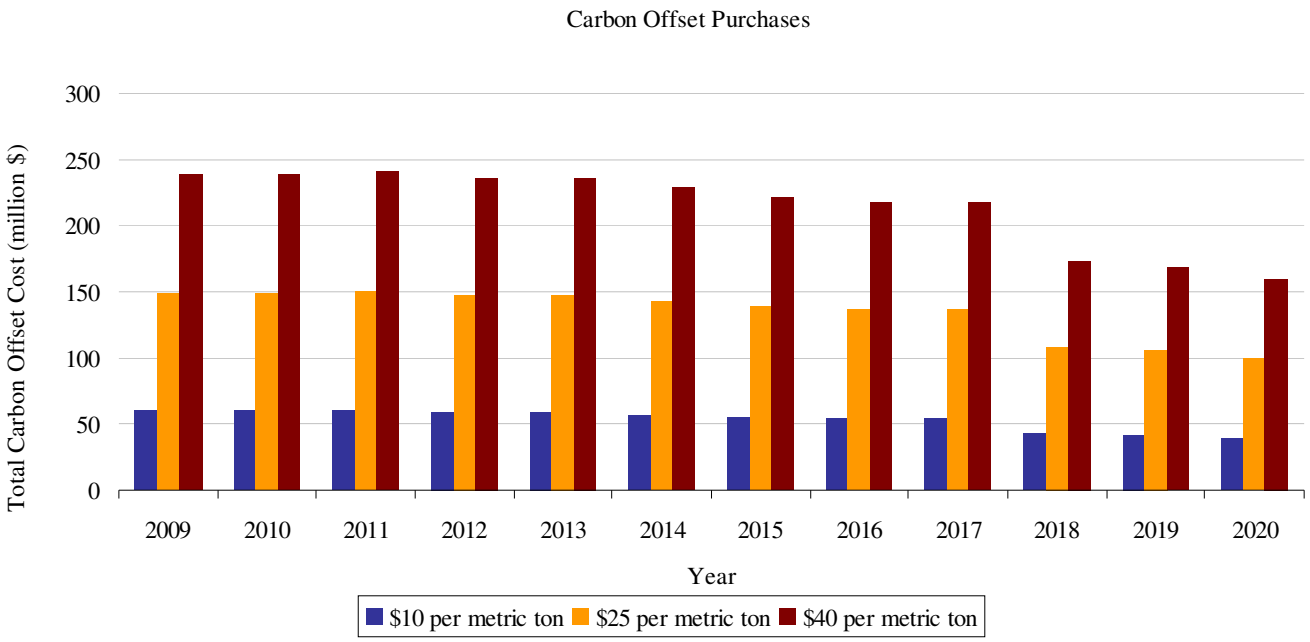
Figure 6.5
Expected Renewables Scenario Carbon Allowance Costs



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 generation mix.

Figure 6.6
Expected Renewables Scenario Carbon Offset Costs



Costs

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). This expected increase in electric rates is based solely on new power generation investments. Carbon offset costs, infrastructure or regulatory costs, or any other unexpected additional costs to the utility could also be passed on to the customer during this time period.

Figure 6.7
Expected Renewables Scenario Capital Costs

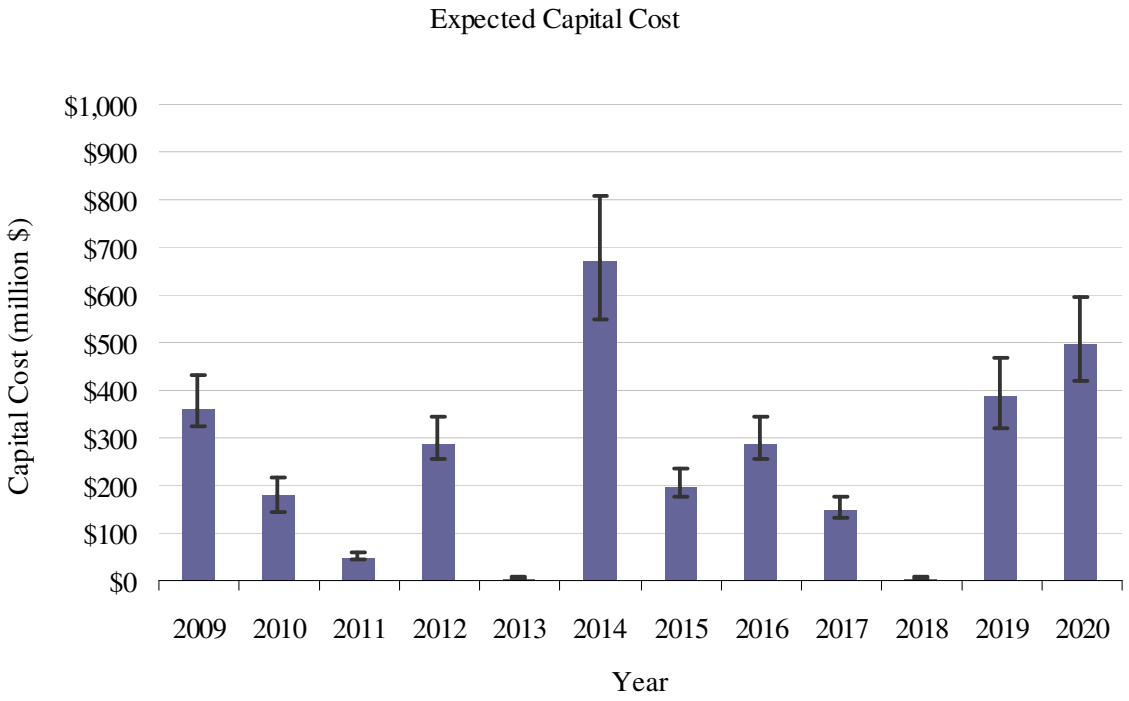


Figure 6.8
Expected Renewables Scenario Fuel Costs

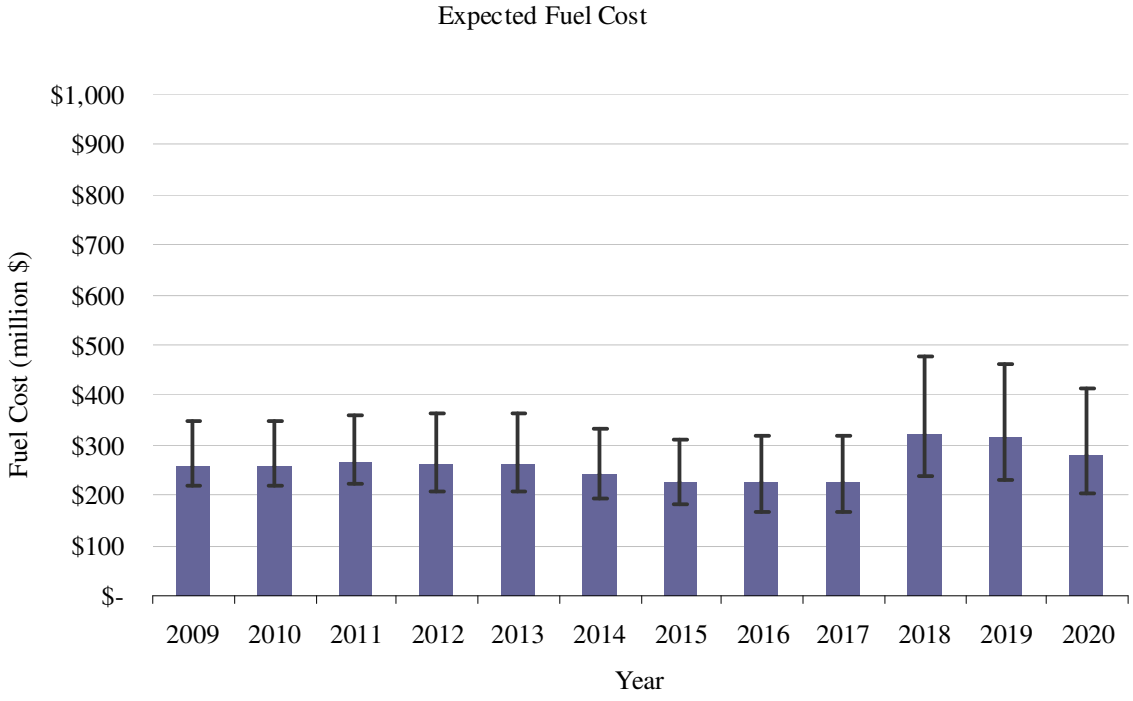
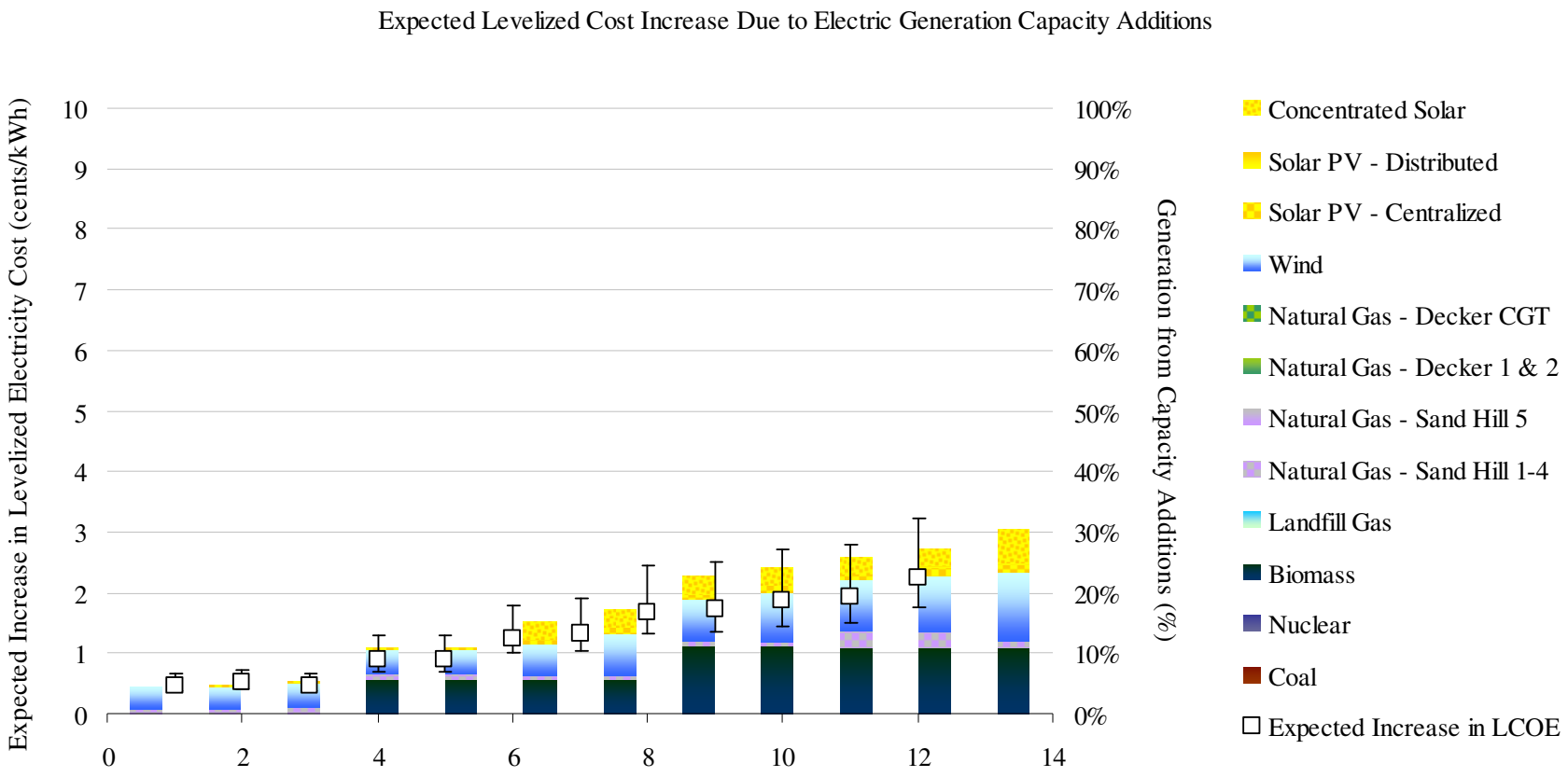


Figure 6.9
Expected Renewables Scenario Levelized Costs



Chapter 7. Expected Renewables with Energy Storage Scenario

This scenario incorporates utility-scale energy storage capacity into the expected available renewable resources scenario. Table 7.1 details the proposed additions to Austin Energy's (AE) resource portfolio from 2009 to 2020 under this scenario. This scenario strives to address the two primary failings of the expected renewables scenario; a failure to meet the peak daily demand by 200 megawatts (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 utility-scale storage technology to be deployed during this time period because it has the lowest current expected 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 storage, but it is unclear if this would be a viable and plentiful option. Upon selecting CAES, the decision was made by the project team to pair the CAES technology with a power generation technology for modeling purposes. Since Austin is in a hot climate, where electricity demand peaks during afternoons in the summer and 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 CAES stored wind energy.

System Reliability

Figure 7.1 demonstrates that AE's power generation capacity would exceed forecasted peak load with and without its demand-side management (DSM) goal 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. Completely divesting in its share of ownership in the Fayette Power Project (FPP) coal facility may create concerns regarding system reliability for AE as this removes a major source of baseload power generation capacity (607 MW). In an effort to relieve such concerns, biomass facilities would provide 200 MW of baseload power and some more efficient natural gas facilities could be used as baseload power plants during certain times of the year. 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 in the presence of a failure of wind and solar. This reliance on variable wind and

solar sources of energy introduces a real concern of potential system failures. Energy storage technologies are intended to relieve these concerns. CAES is not considered to be a power generation technology, as it uses some natural gas to transfer electricity from one time of day to another, with an inherent limitation on overall efficiency of around 75 percent. Therefore, if a wind facility generates an excess of 1000 megawatt-hours (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. In the model, the wind generators are considered actual power generation technologies, while "Storage" merely provides a daily buffer.

Figure 7.2 demonstrates that, given expected capacity factors for wind and solar 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 DSM goal. If wind and solar do not meet expected production levels, the natural gas facilities serve as backup sources of power. By 2020, combined cycle natural gas units at Sand Hill may provide 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 DSM goal and CAES fills the afternoon and evening gaps. The amount of wind electricity stored at a CAES facility at any given time is not shown on Figure 7.3 because it would not actually be delivered to the grid until later in the day, represented as "Storage" in the model.

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

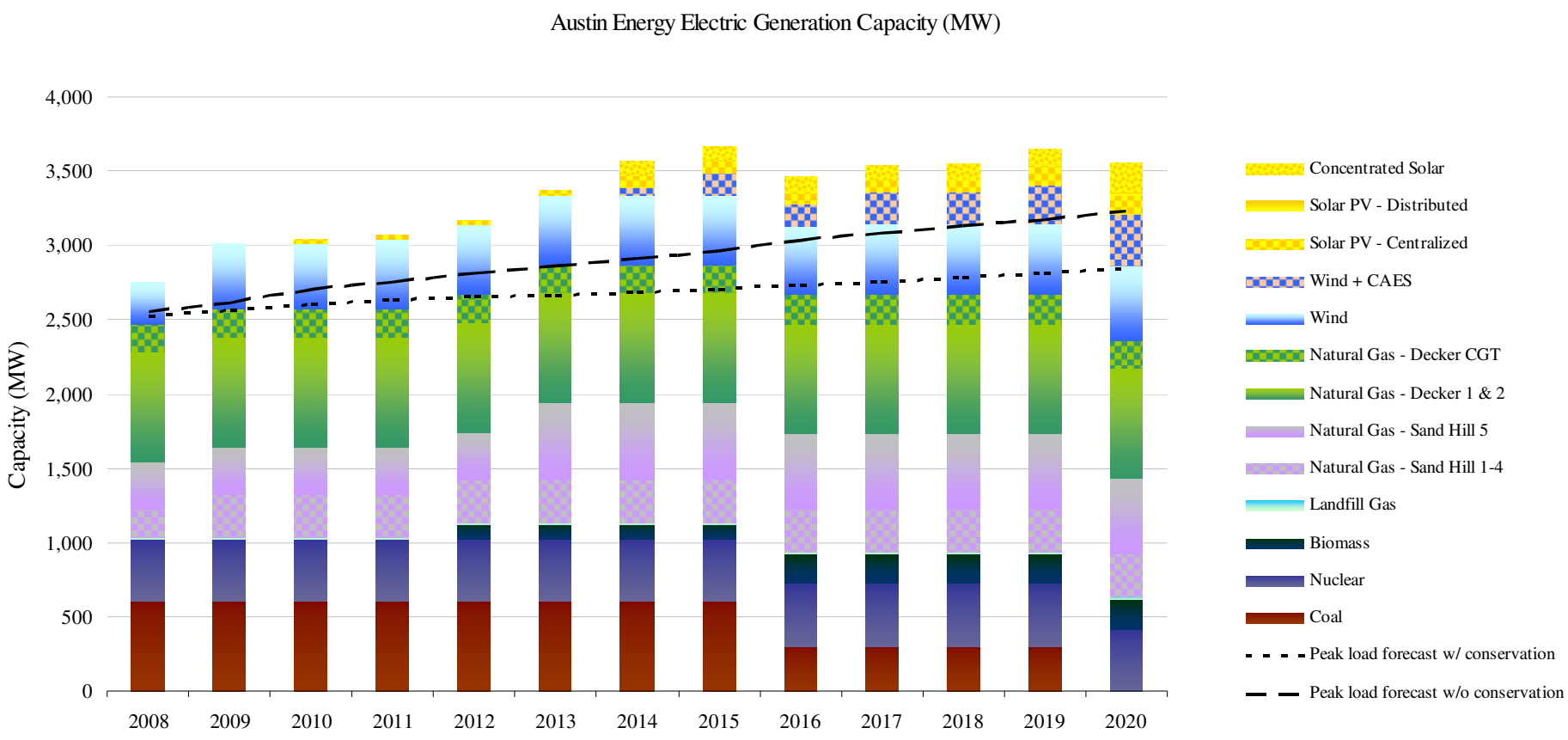


Figure 7.2
Expected Renewables with Storage Scenario Electric Delivery

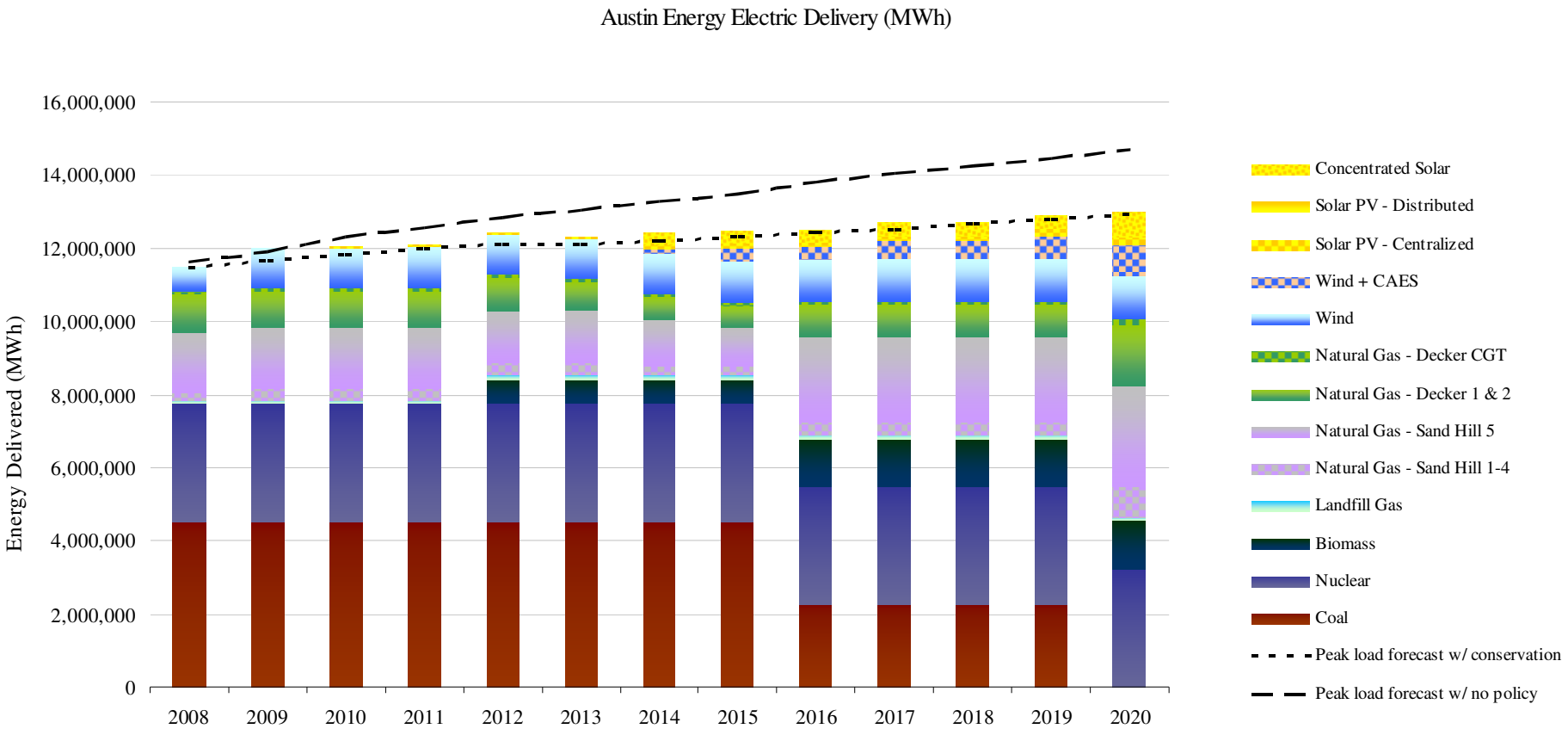
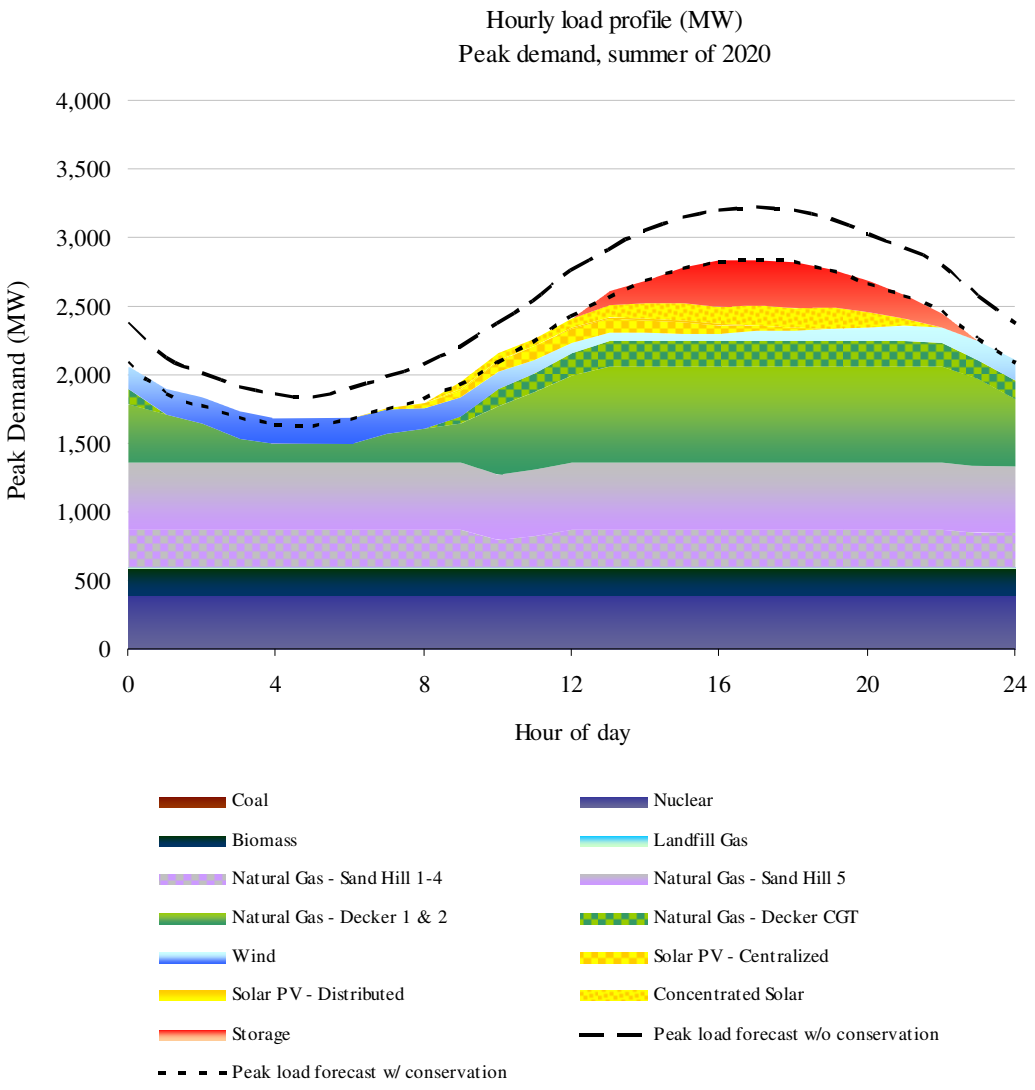


Figure 7.3
Expected Renewables with Storage Scenario Hourly Load Profile
(Peak Demand, Summer 2000)

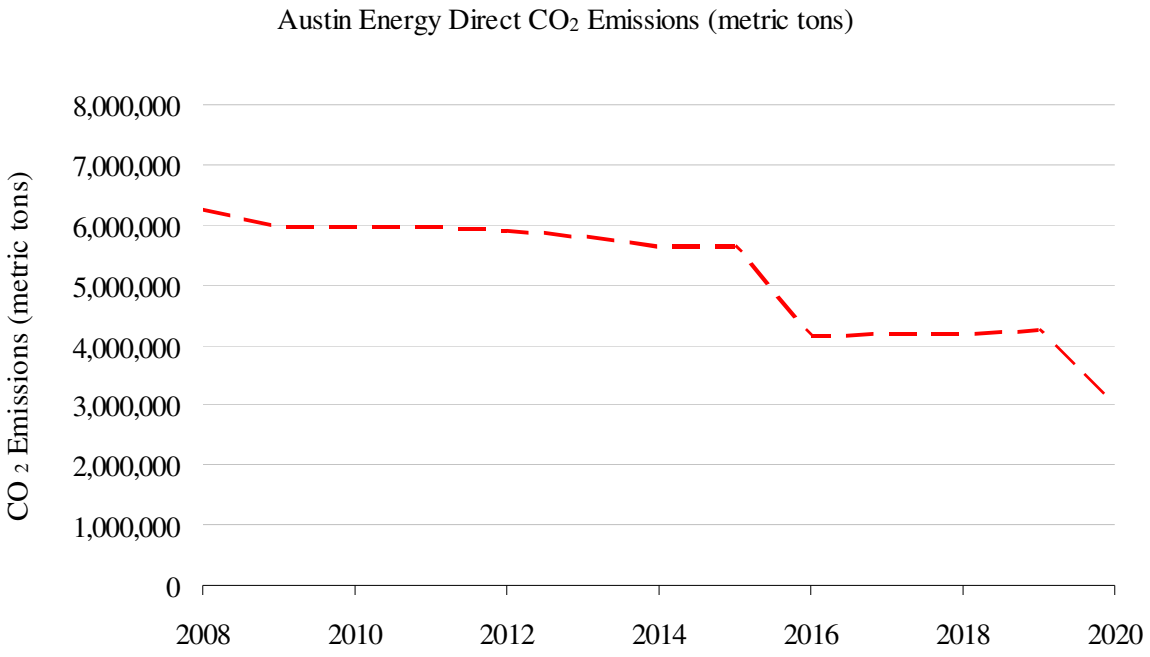


Carbon Emissions and Carbon Costs

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 carbon dioxide (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 with storage 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.

Figure 7.4
Expected Renewables with Storage Scenario Direct Carbon Dioxide Emissions



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.

Figure 7.5
Expected Renewables with Storage Scenario Carbon Allowance Costs

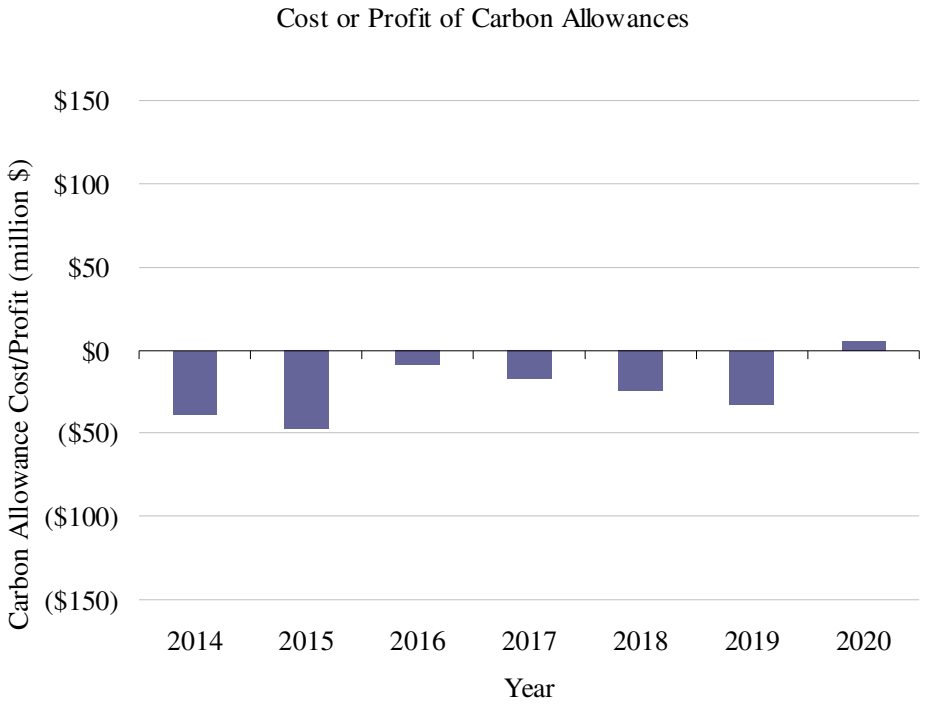
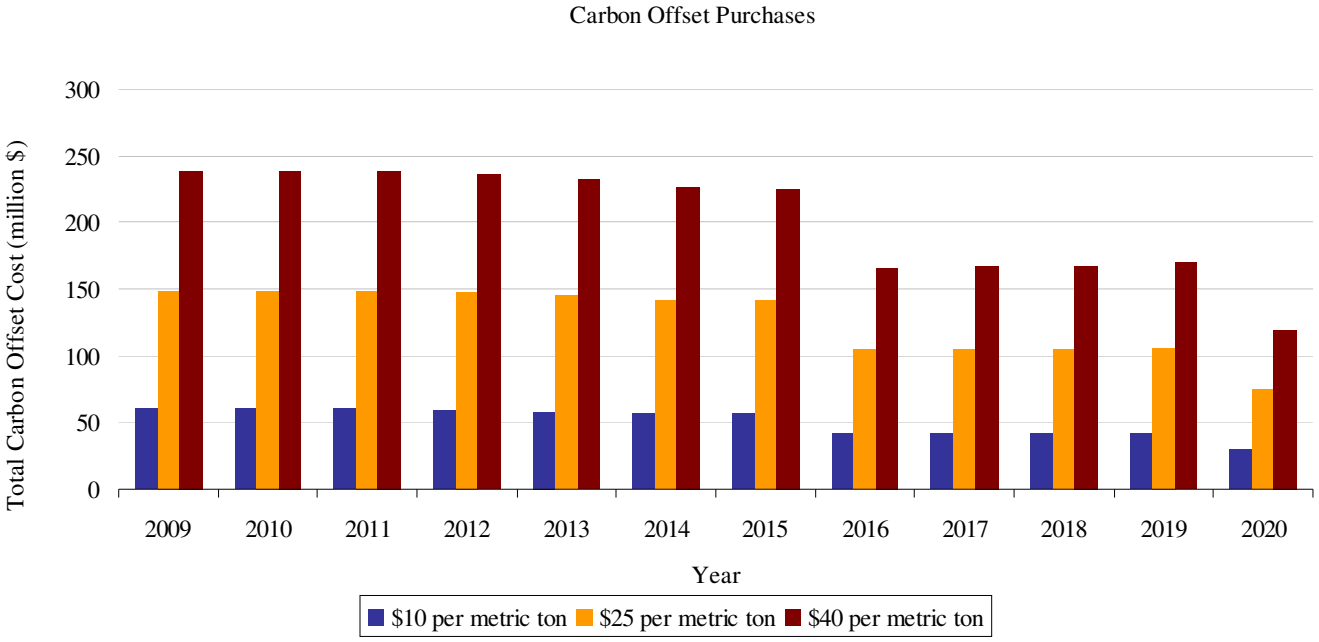


Figure 7.6
Expected Renewables with Storage Scenario Carbon Offset Costs



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

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 with storage scenario 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, the project team defined a new generation technology in the model – "Wind + CAES." The project team 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 4,000 British thermal units per kilowatt-hour (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. Given the limited information on costs of CAES facilities, 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. This expected increase in electric rates is based solely on new power generation investments. Carbon offset costs, infrastructure or regulatory costs, or any other 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 7.7
Expected Renewables with Storage Scenario Capital Costs

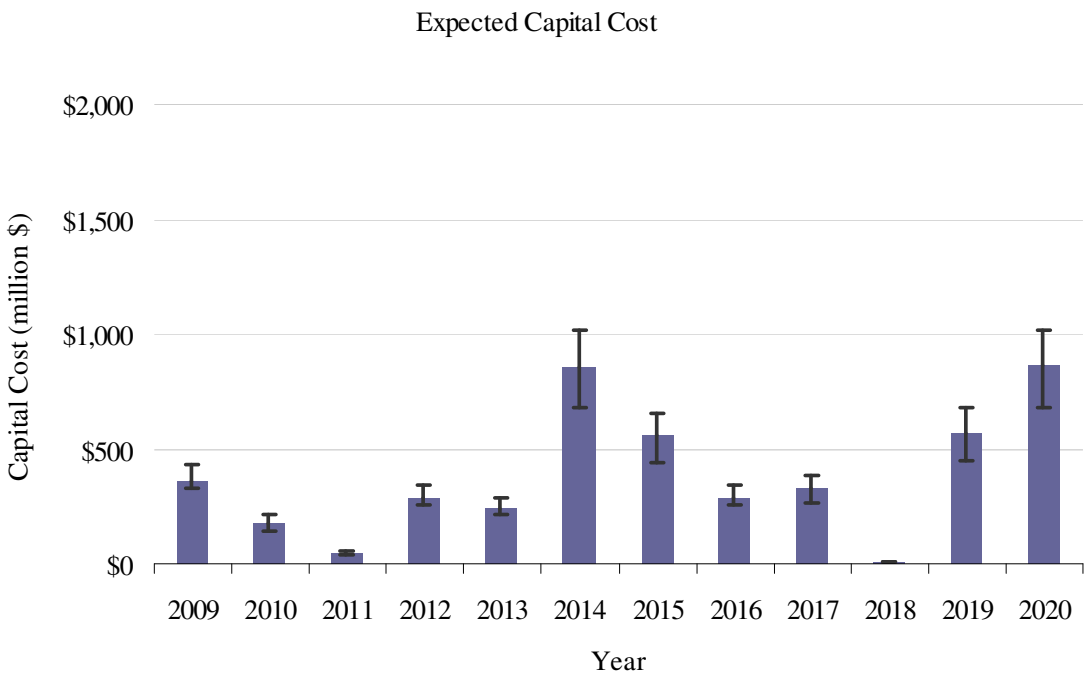


Figure 7.8
Expected Renewables with Storage Scenario Fuel Costs

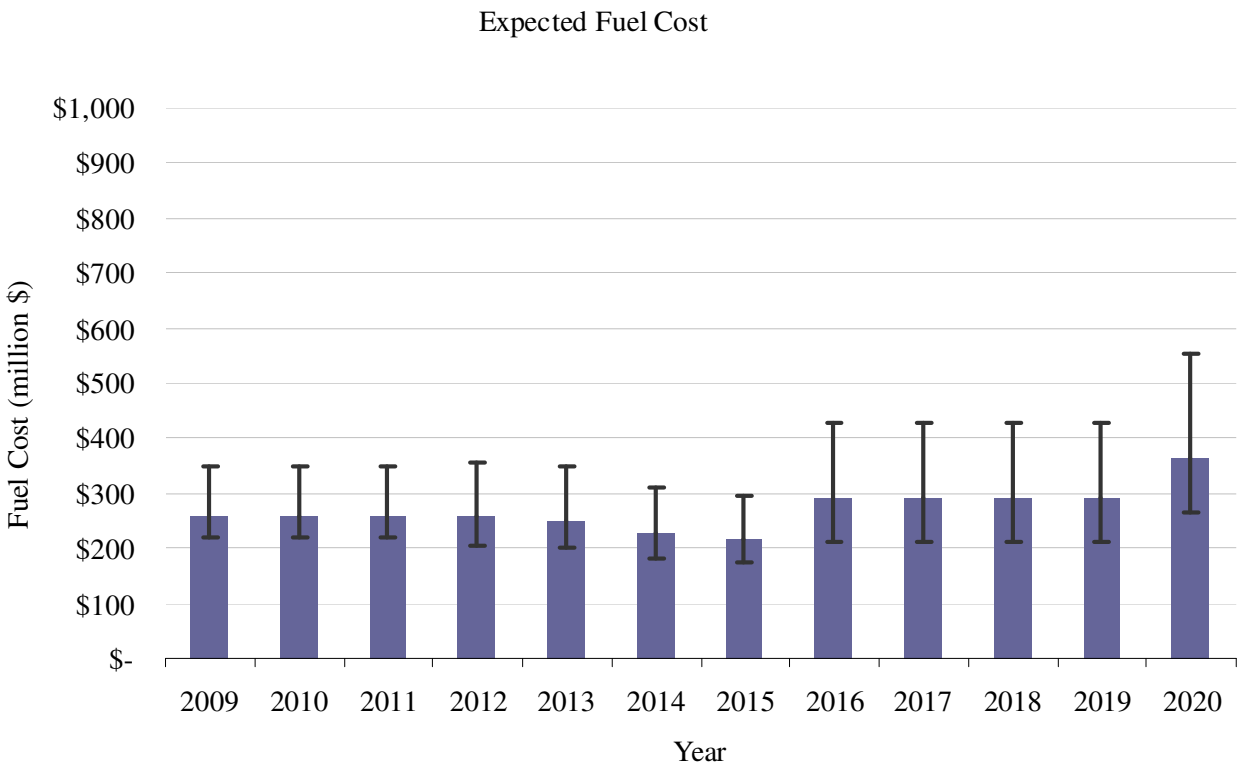
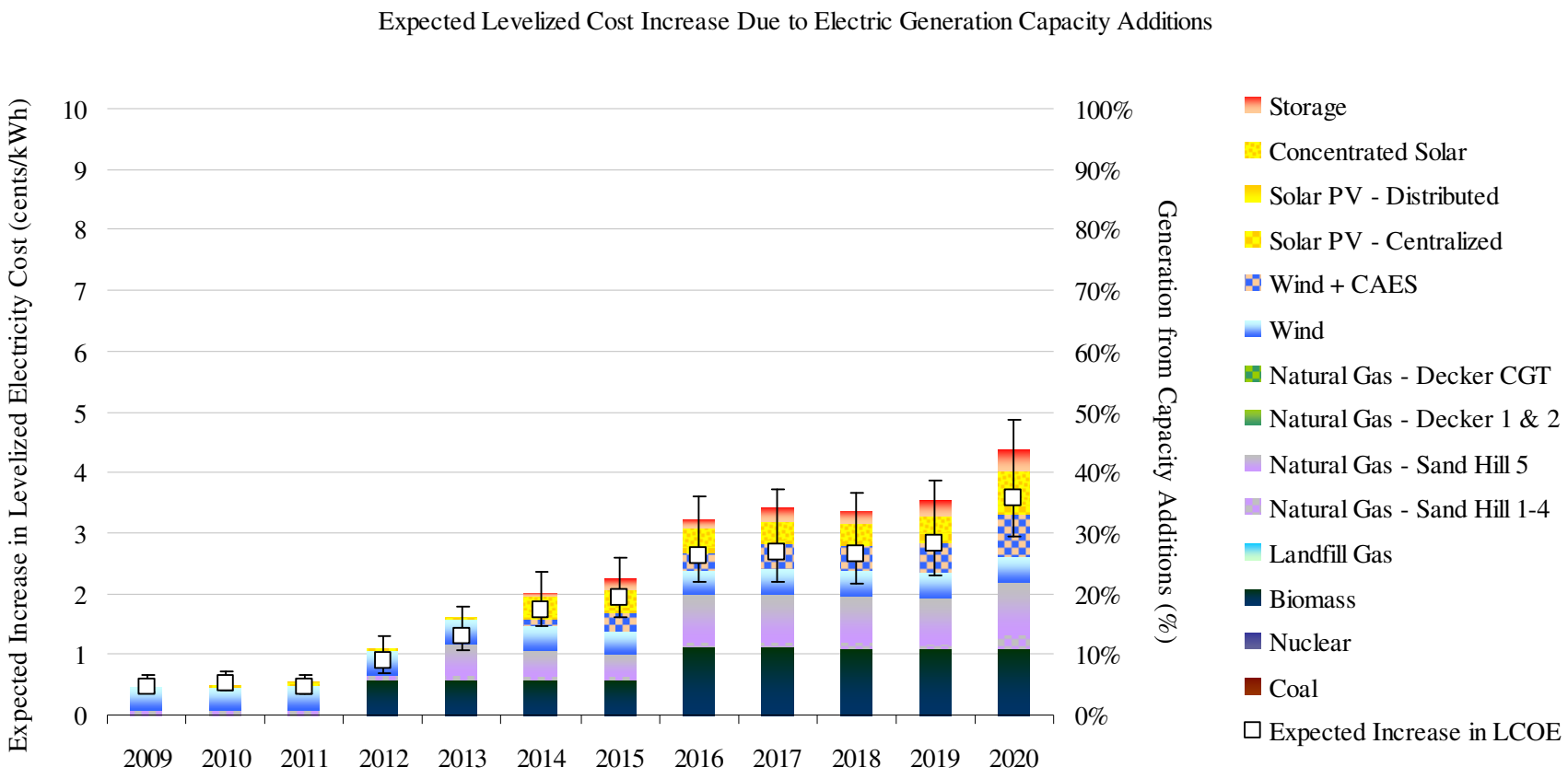


Figure 7.9
Expected Renewables with Storage Scenario Levelized Costs



Chapter 8. Natural Gas Expansion Scenario

The natural gas expansion scenario aligns with Austin Energy's (AE) original 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. In AE's proposed resource plan, 300 megawatts (MW) of natural gas is added to AE's resource portfolio. In this scenario 907 MW of natural gas is added with 505 MW of new power generation capacity from new combined cycle units at Sand Hill and 402 MW of power generation capacity from new combustion gas turbines at Sand Hill. This scenario does not account for potential limitations in expanding the Sand Hill facility, but does consider information that there is potential for some expansion at this facility. If AE were unable to expand this much capacity at the Sand Hill facility it could potentially expand capacity at Decker or build a new facility with the same types of natural gas units as Sand Hill. 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 as carbon-intensive as coal.

System Reliability

The loss of coal as a baseload power source 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 power generating units. However, natural gas is not traditionally used by AE as a baseload power source. Therefore, traditional baseload power generation capacity is nearly halved by 2016 under this scenario, dropping from 1229 MW to 622 MW (nuclear and biomass power generation capacity). 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 demonstrates that under this scenario AE will be able to deliver electricity to meet the needs of its customers. However, the relative usage of AE's natural gas facilities will be much higher under this scenario than AE's proposed energy resource plan.

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

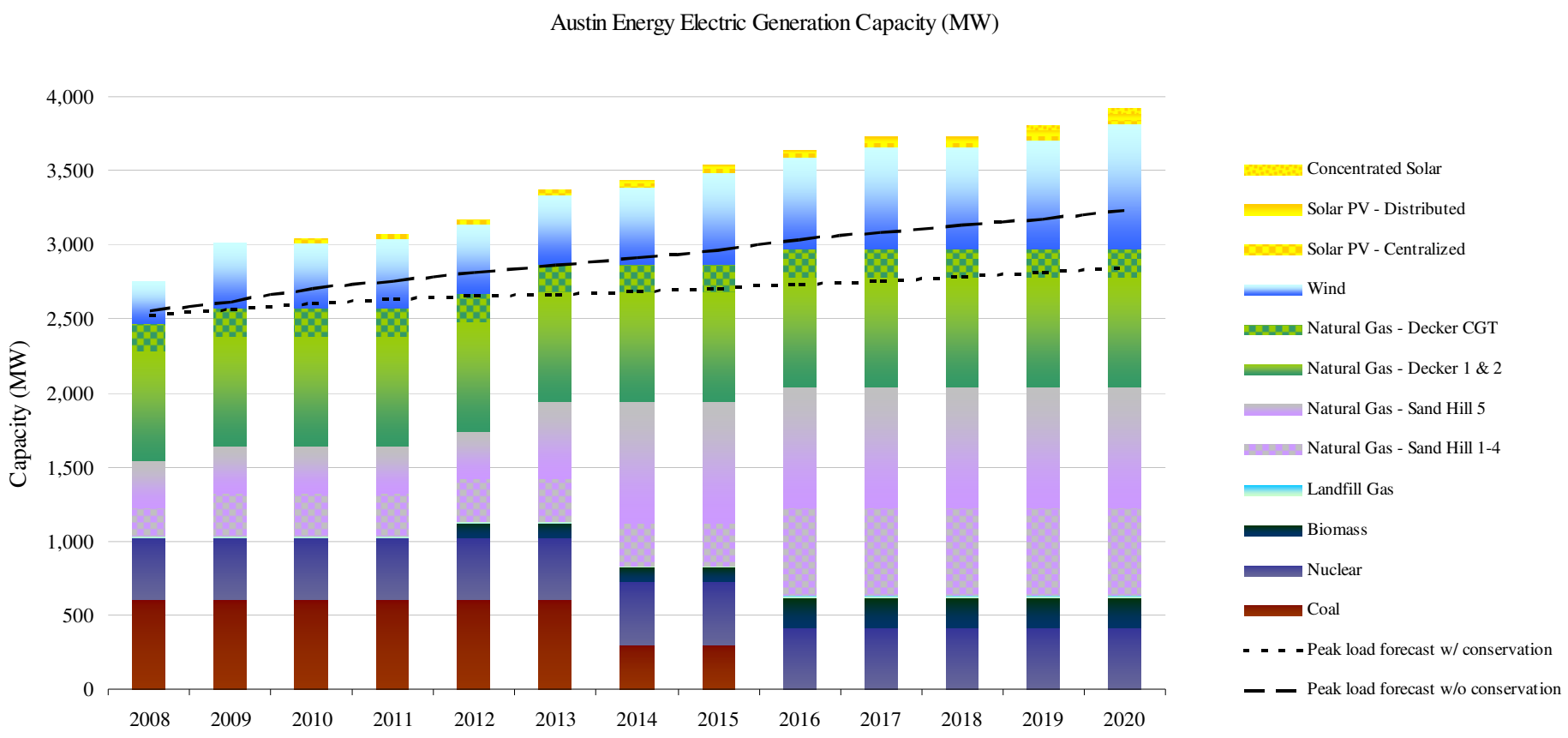
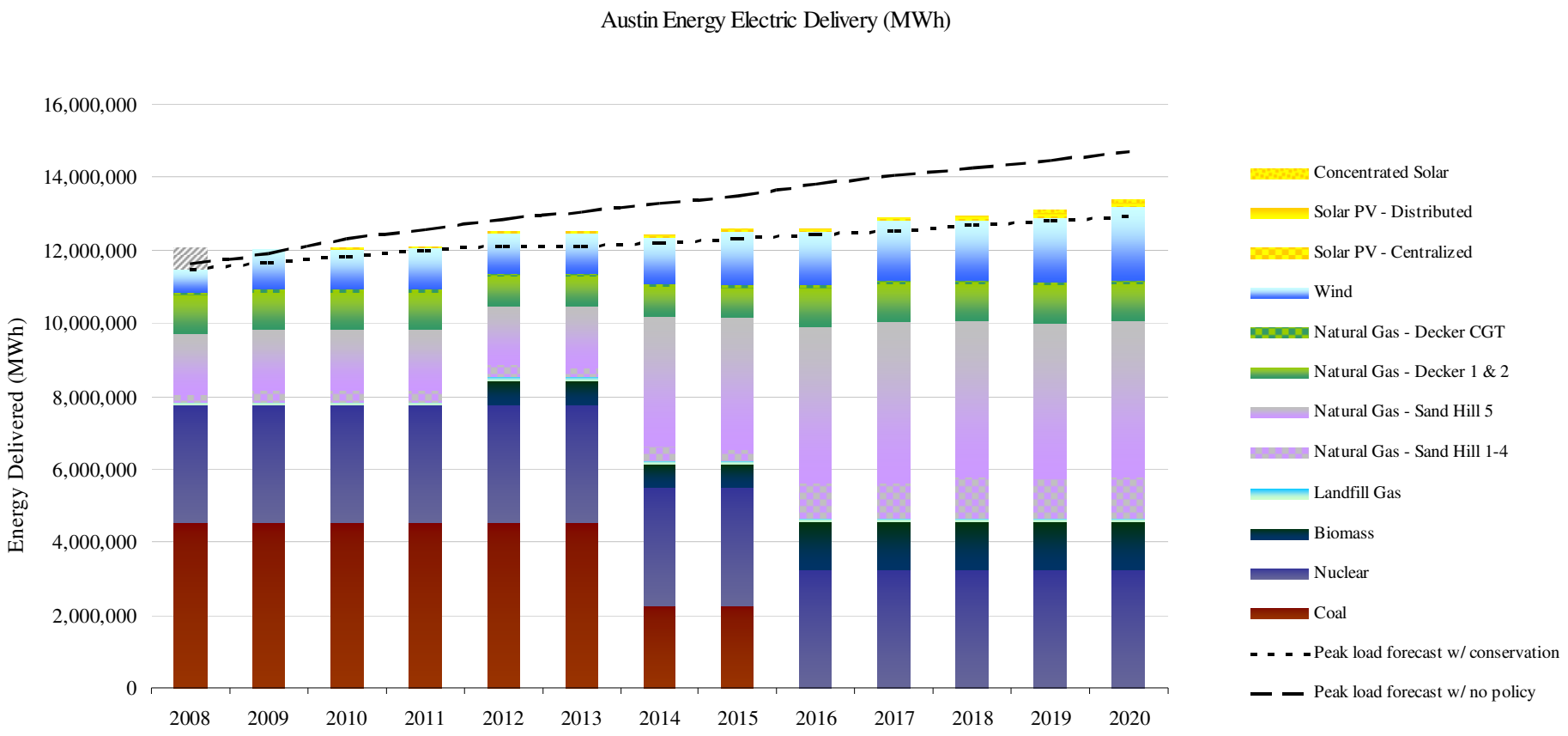
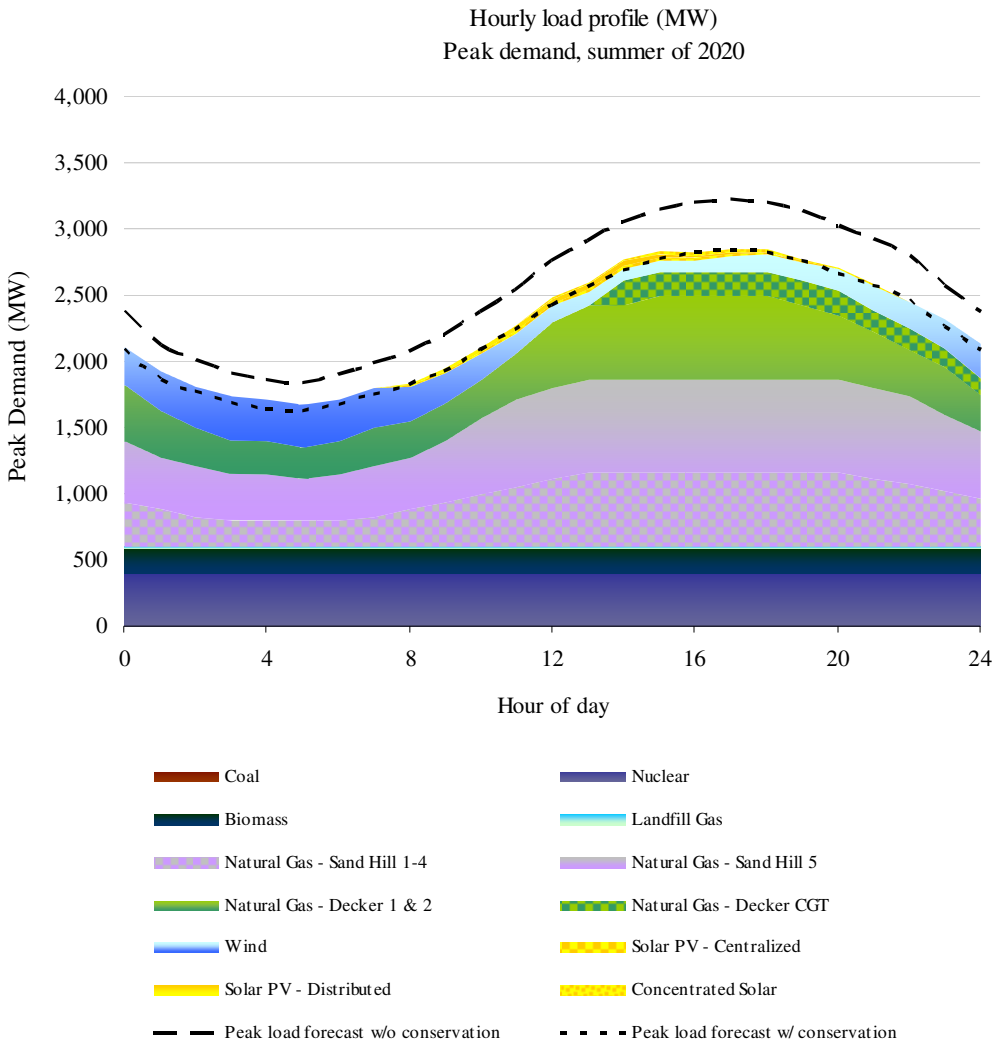


Figure 8.2
Natural Gas Expansion Scenario Electric Delivery



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 demand-side management (DSM) goal. However, AE will have to use its natural gas facilities at full capacity in order to meet peak demand. Unlike AE's proposed energy resource plan, there will no additional available natural gas capacity if needed due to a planned or unexpected outage at a generation facility.

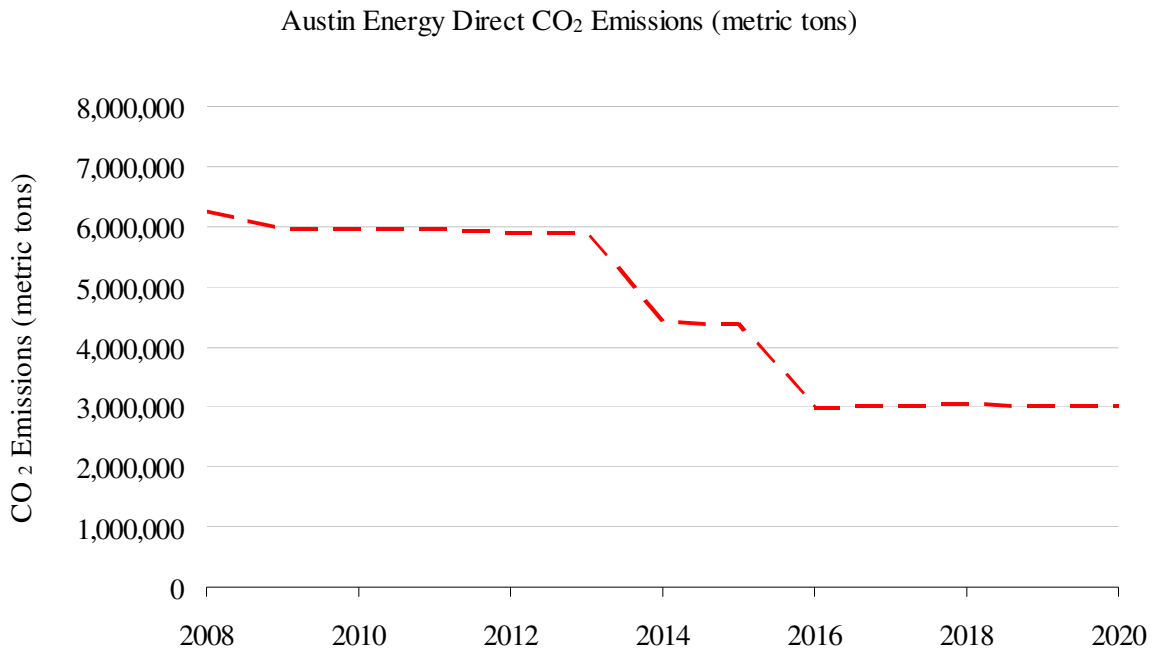
Figure 8.3
Natural Gas Expansion Scenario Hourly Load Profile
(Peak Demand, Summer 2000)



Carbon Emissions and Carbon Costs

The natural gas expansion scenario represents a reduction in carbon emissions by more than half (see Figure 8.4) as carbon emission factors for AE's natural gas facilities average about half the emission factor of burning coal. AE's carbon dioxide (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 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 proposed energy resource plan.

Figure 8.4
Natural Gas Expansion Scenario Direct Carbon Dioxide Emissions



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 allocated 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. AE could receive profits of about $4 million from 2014 to 2020 based upon allowance price estimates for the Lieberman-Warner bill and expected CO_2 emissions under this scenario. This

compares to potential costs of about $490 million under AE's proposed energy resource plan.

Figure 8.5
Natural Gas Expansion Scenario Carbon Allowance Costs

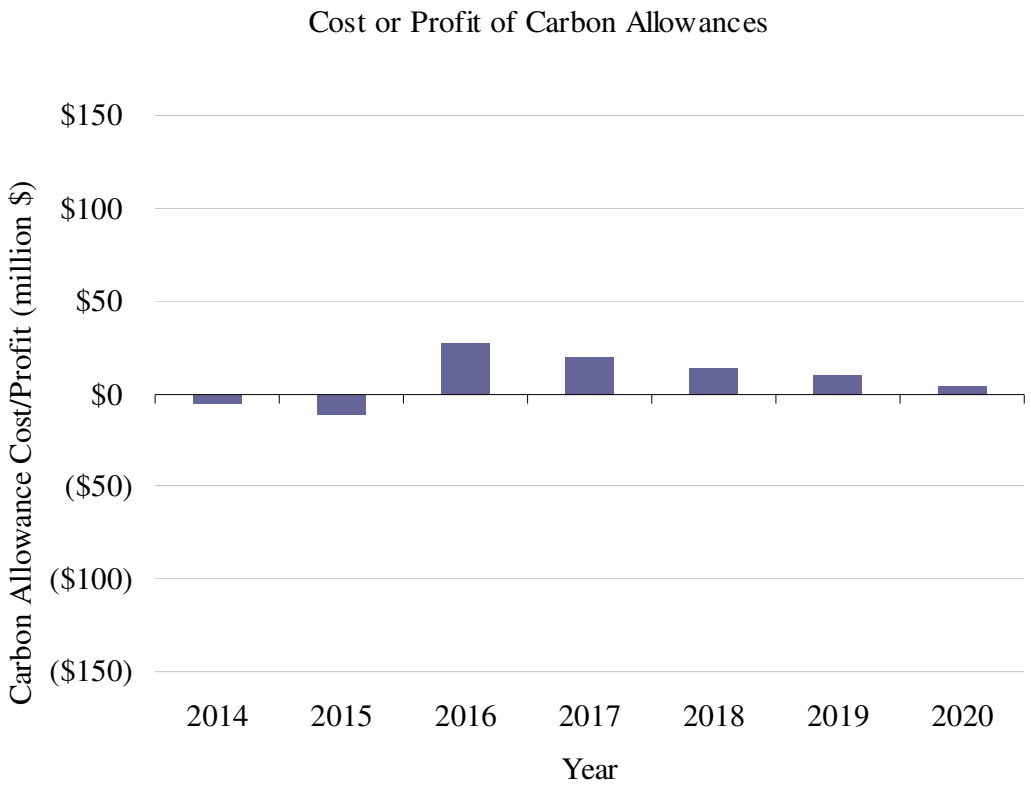
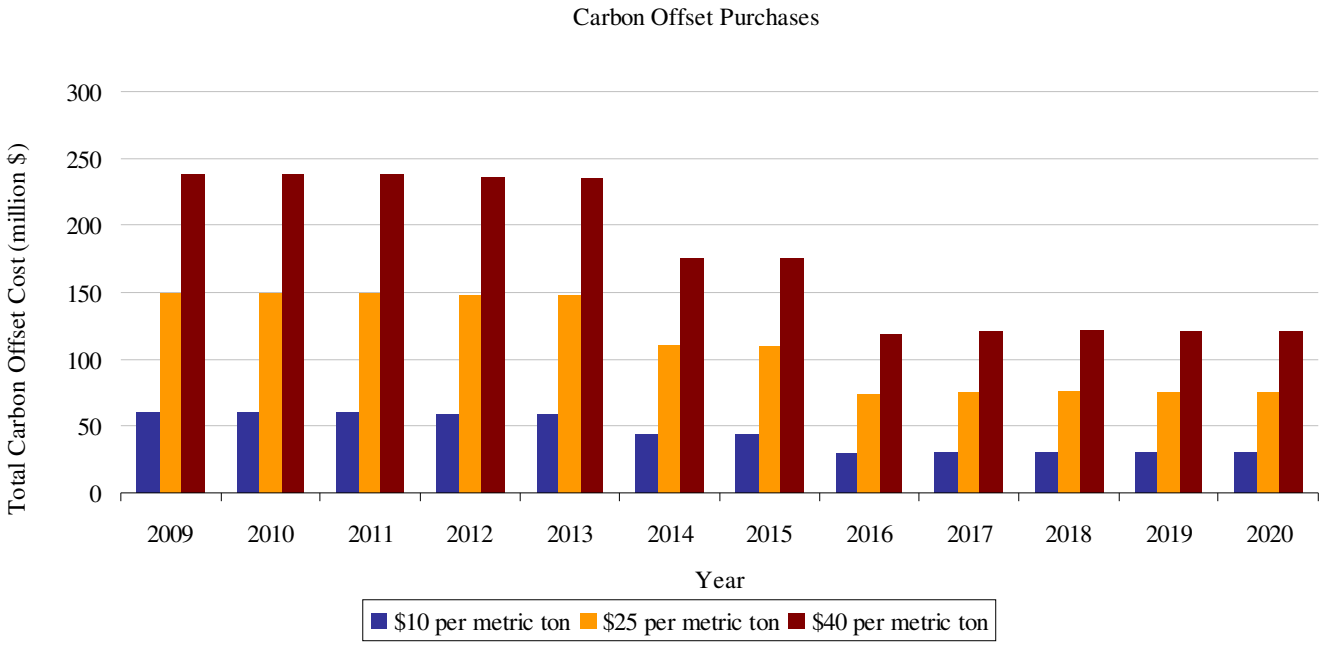


Figure 8.6 demonstrates that this scenario would reduce the quantity of carbon offsets required for purchase by AE in order to reach net zero carbon emissions. The costs of offsets would be dramatically reduced in the years 2014 and 2016, respectively, as half of AE's stake in its coal facility would be eliminated each of those years. By 2020, annual carbon offset costs would range from $30 to $121 million compared to $58 to $230 million under AE's proposed resource plan.

Figure 8.6
Natural Gas Expansion Scenario Carbon Offset Costs



Costs

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. Total expected capital costs range from $2.58 to $3.5 billion (compared to $2.2 to $3.0 billion under AE's proposed resource plan). 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 adding 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. Fuel costs are expected to increase as coal is replaced by natural gas because natural gas is a more expensive fuel. By 2020, fuel costs under this scenario would range from $316 to $645 million annually (compared to $93 to $328 million under AE's proposed resource plan). 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.

This scenario results in a power generation mix in 2020 that attributes new generation to just over half of all power generated. 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 model estimates that electric rates would rise by between 3.3 and 5.7 cents per kilowatt-hour of electricity consumed (compared to between 1.5 and 3 cents per kilowatt-hour of electricity consumed under AE's proposed energy resource plan) by 2020. The simulator 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 frequently used power source. This expected increase in electric rates is based solely on new power generation investments. Carbon offset costs, infrastructure or regulatory costs, or any other unexpected additional costs to the utility could also be passed on to the customer during this time period.

Figure 8.7
Natural Gas Expansion Scenario Capital Costs

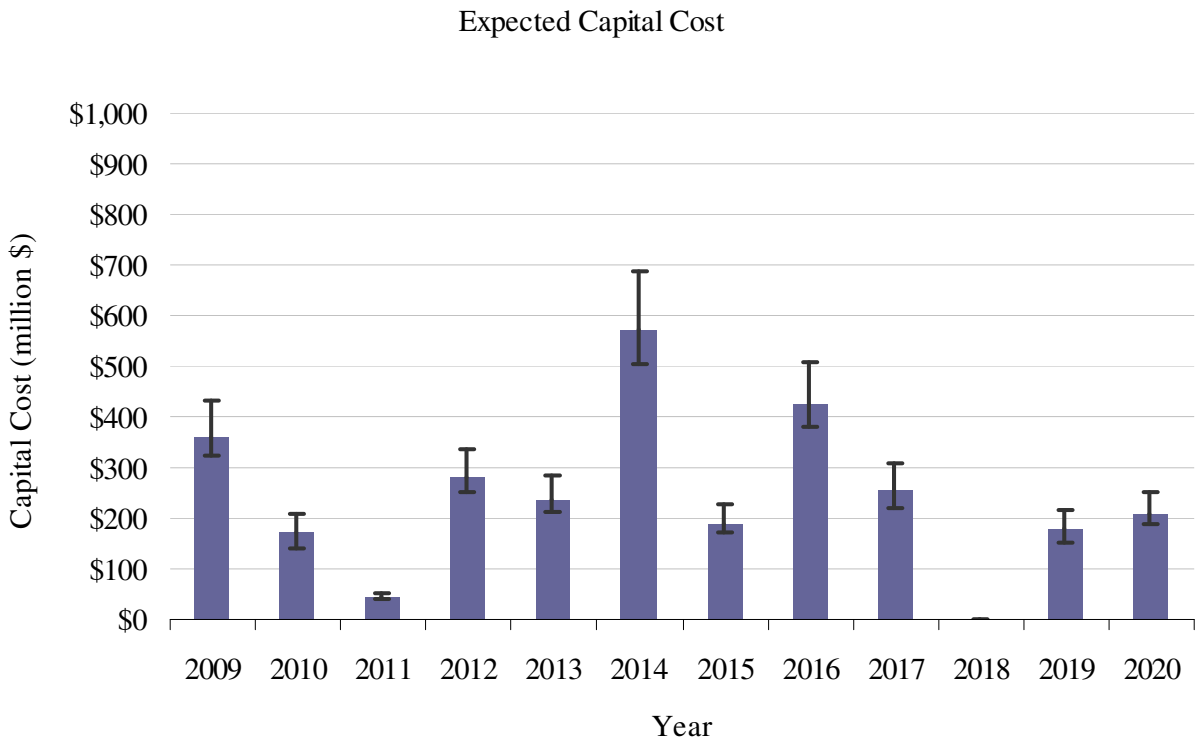


Figure 8.8
Natural Gas Expansion Scenario Fuel Costs

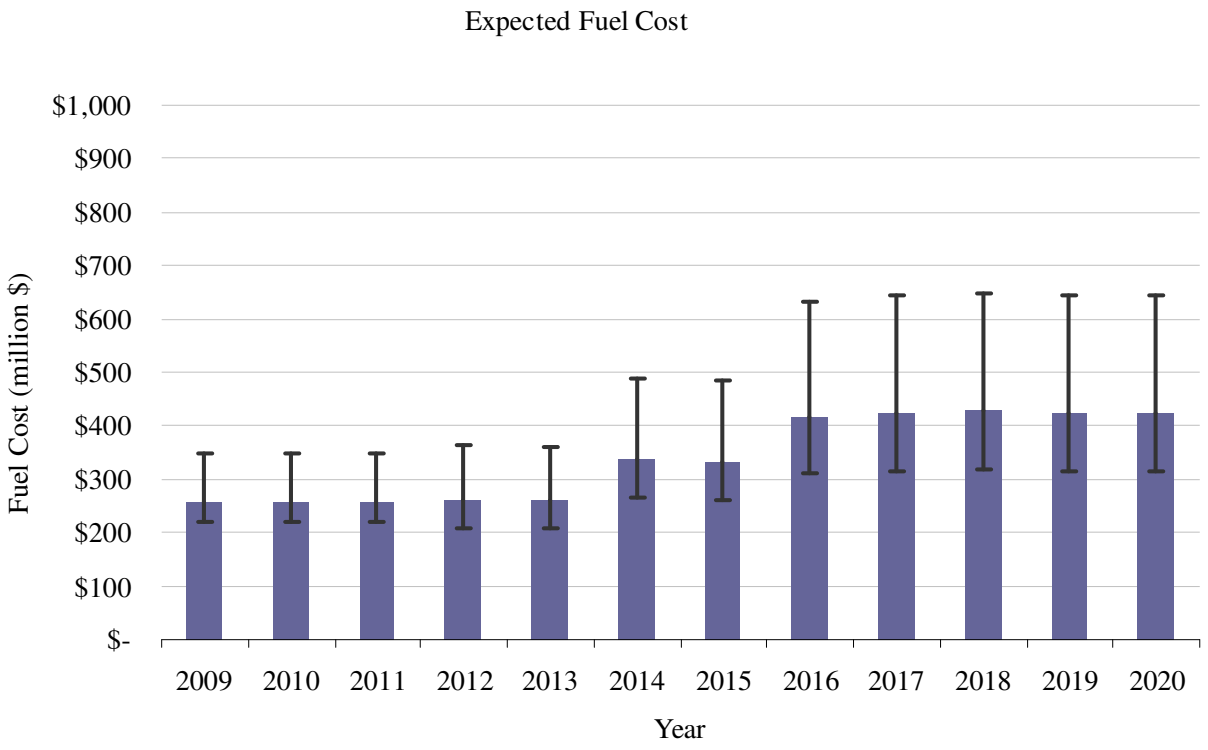
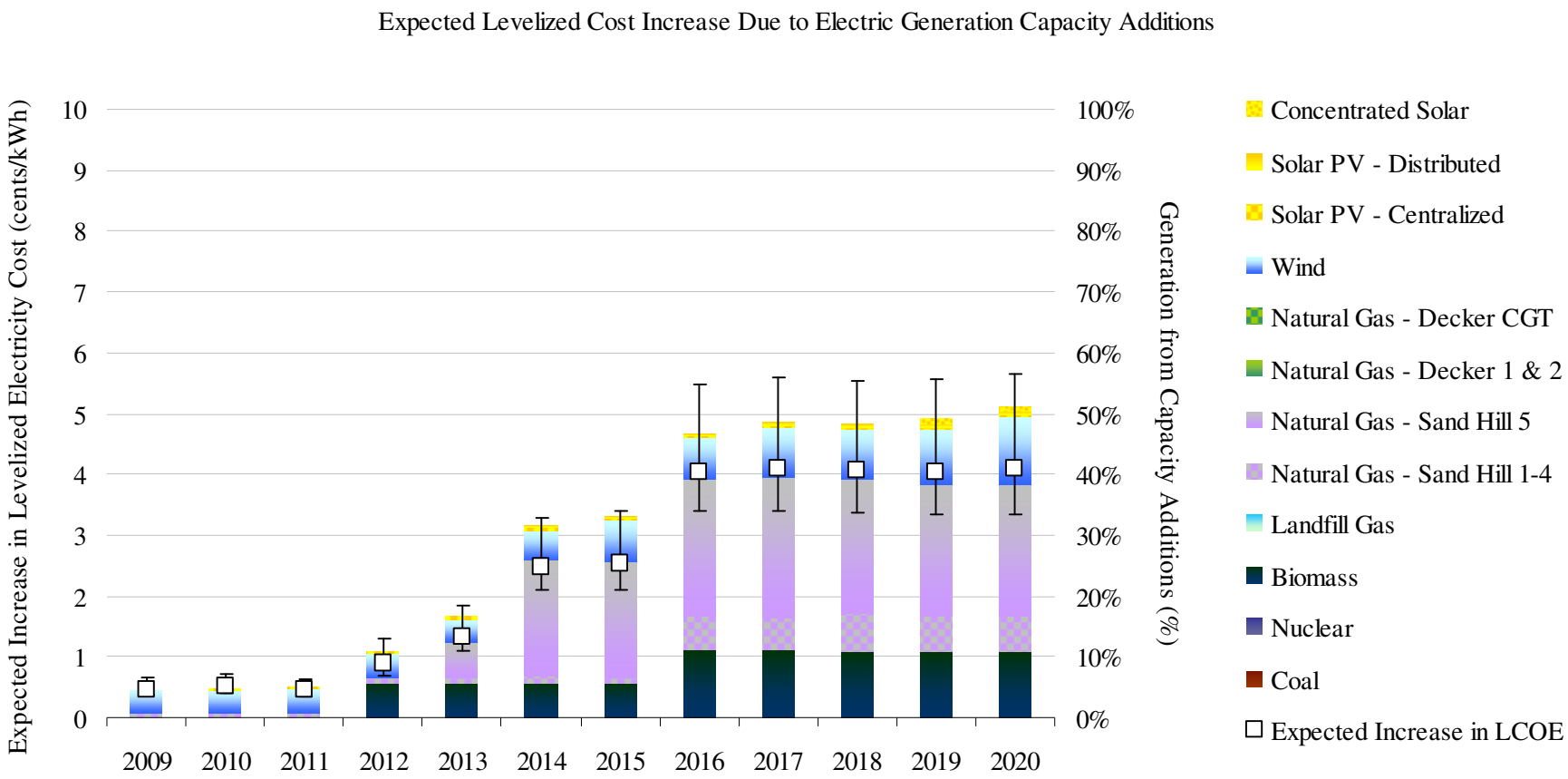


Figure 8.9
Natural Gas Expansion Scenario Levelized Costs



Chapter 9. Cleaner Coal Scenario

The cleaner coal scenario aligns with Austin Energy's (AE) original proposed energy resource plan while replacing AE's stake in the Fayette Power Project (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. AE's divestment in FPP would be simultaneously replaced with coal-based power generated at an integrated gasification combined cycle (IGCC) coal plant with carbon capture and storage (CCS) technology. IGCC plants are more efficient than 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. Table 9.1 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 demonstrate the impacts of using cleaner coal expansion in AE's resource portfolio. Cleaner coal technology present a more sustainable source of power generation than traditional coal-fired power generation technologies because a majority of the carbon dioxide (CO_2) emissions are captured and sequestered rather than released into the atmosphere and potentially contributing to global warming.

System Reliability

Replacing AE's stake in 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 AE's demand-side management (DSM) goal 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 original proposed energy resource plan.

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

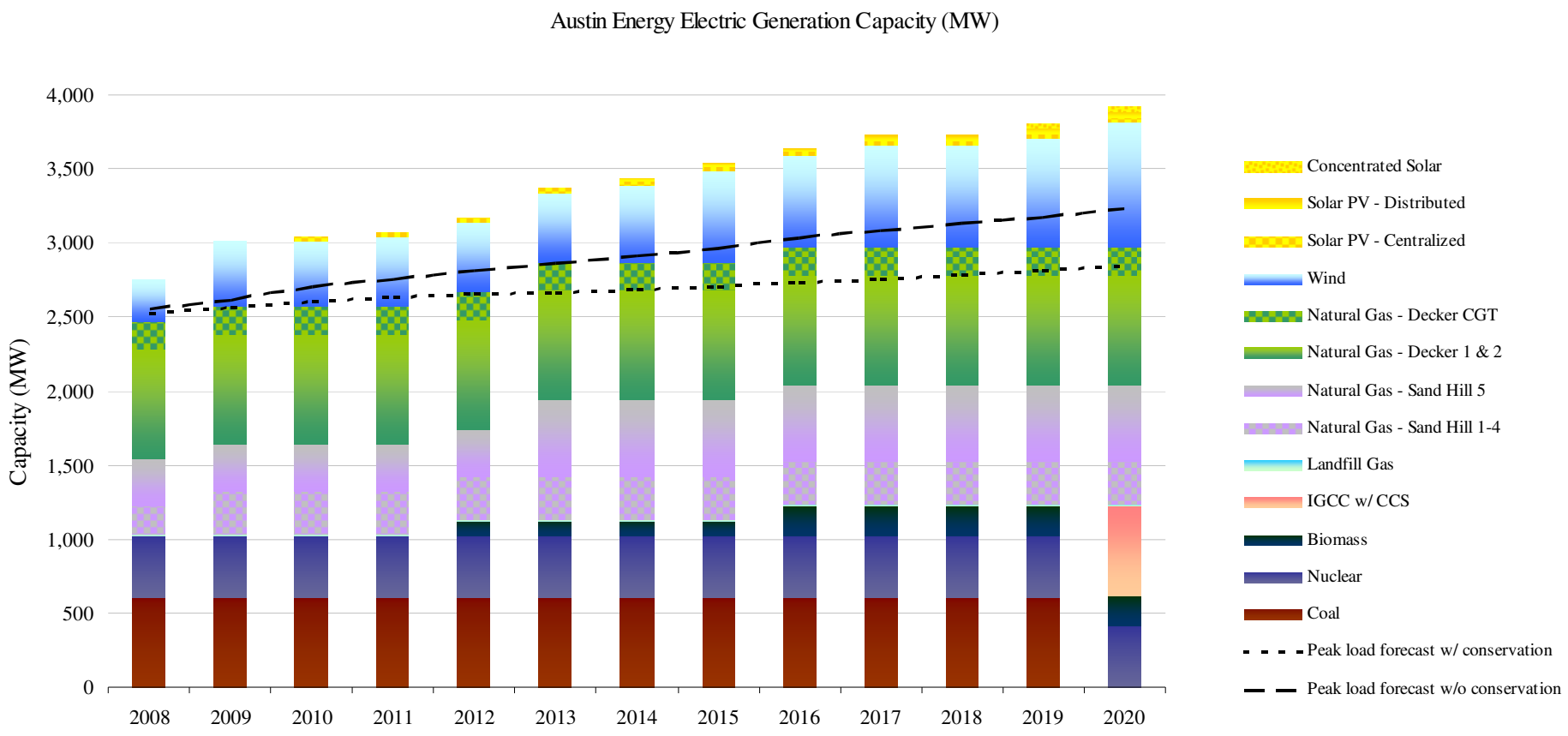
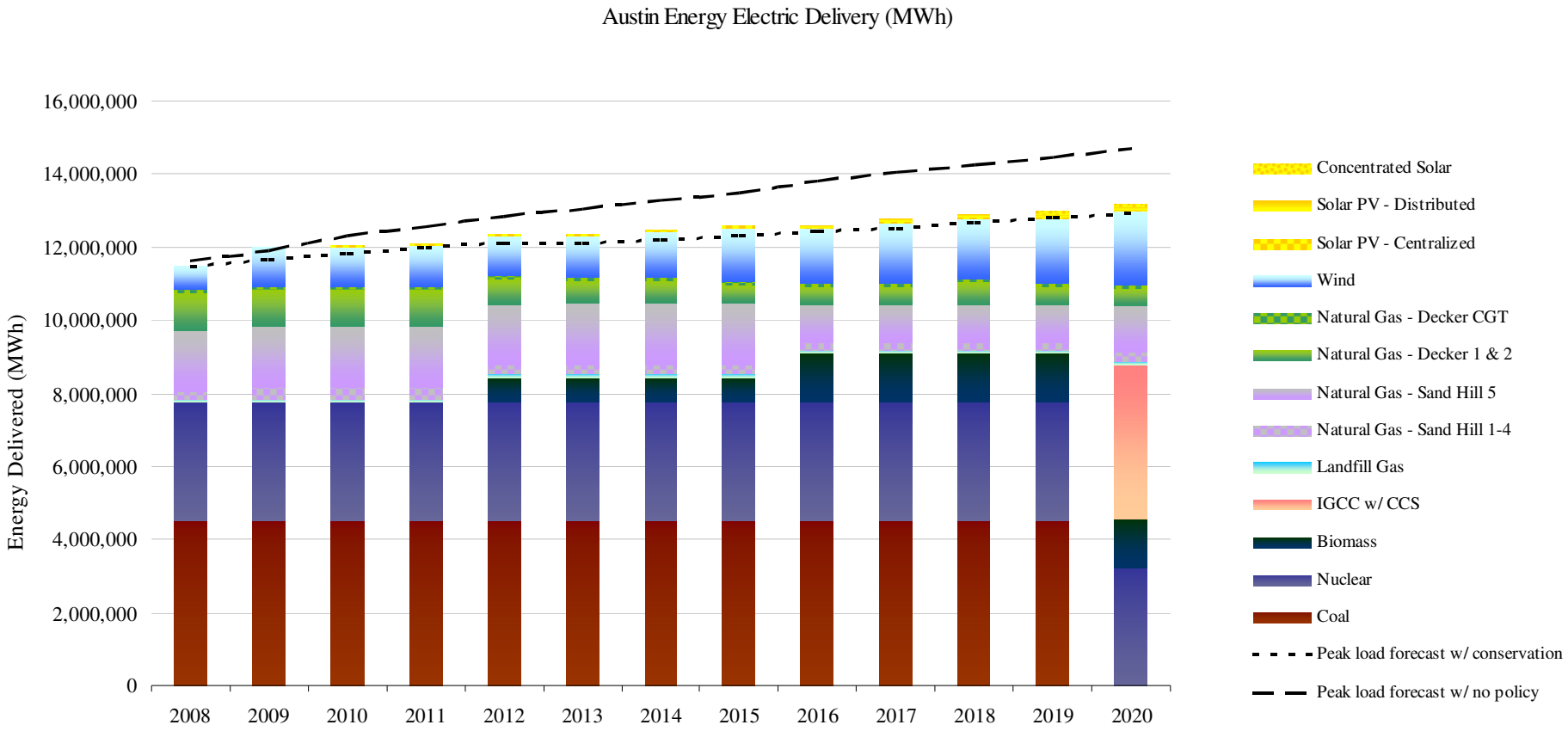
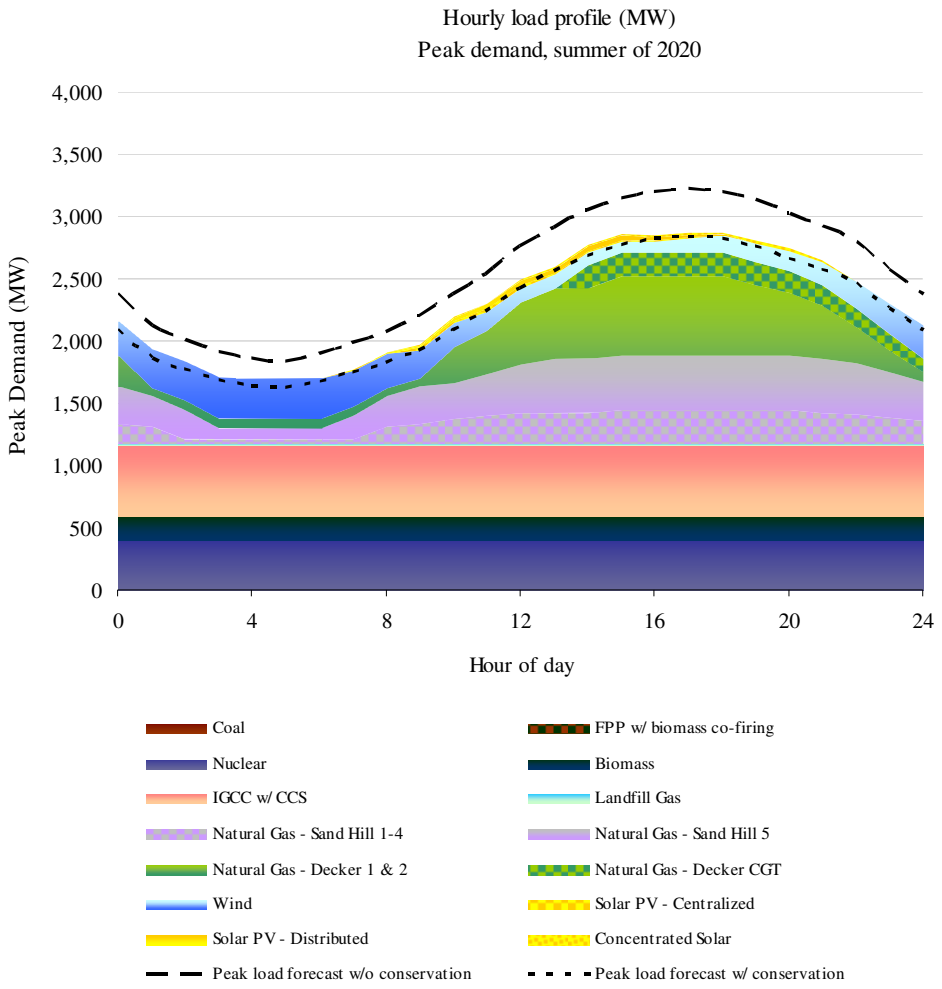


Figure 9.2
Cleaner Coal Scenario Electric Delivery



Given the expected capacity factors for on-shore wind and solar photovoltaic 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 DSM goal (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 so long as all of its facilities are fully operational and expected energy output from variable resources is met.

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



Carbon Emissions and Carbon Costs

The carbon emission factor for FPP, a traditional pulverized coal facility, is 0.94 metric tons of CO_2 emitted per megawatt-hour of energy produced. The carbon emission factors for an IGCC coal-fired plant with and without CCS are 0.86 and 0.16 metric tons of CO_2, respectively. By replacing FPP with a clean coal facility (IGCC with CCS technology), CO_2 emissions are reduced by 83 percent. Since FPP accounts for 71 percent of AE's CO_2 emissions, this scenario results in a dramatic drop in direct CO_2 emissions (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 away 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. This compares to potential costs of about $490 million under AE's proposed energy resource plan.

Under this scenario, offsetting CO_2 emissions to zero 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.

This scenario only makes one significant change to AE's original proposed resource plan, but this change makes a major impact on CO_2 emissions. While replacing a traditional coal-fired power plant with an advanced cleaner coal facility appears to be an appealing way to achieve carbon reductions while ensuring a reliable baseload power source that relies on abundantly available local fuel supplies is retained, no utility-scale IGCC plants with CCS technology currently exist in the US. The availability for AE to invest in such a facility and concerns over the reliability and sustainability merits make this scenario much more uncertain in terms of achievability.

Figure 9.4
Cleaner Coal Scenario Direct Carbon Dioxide Emissions

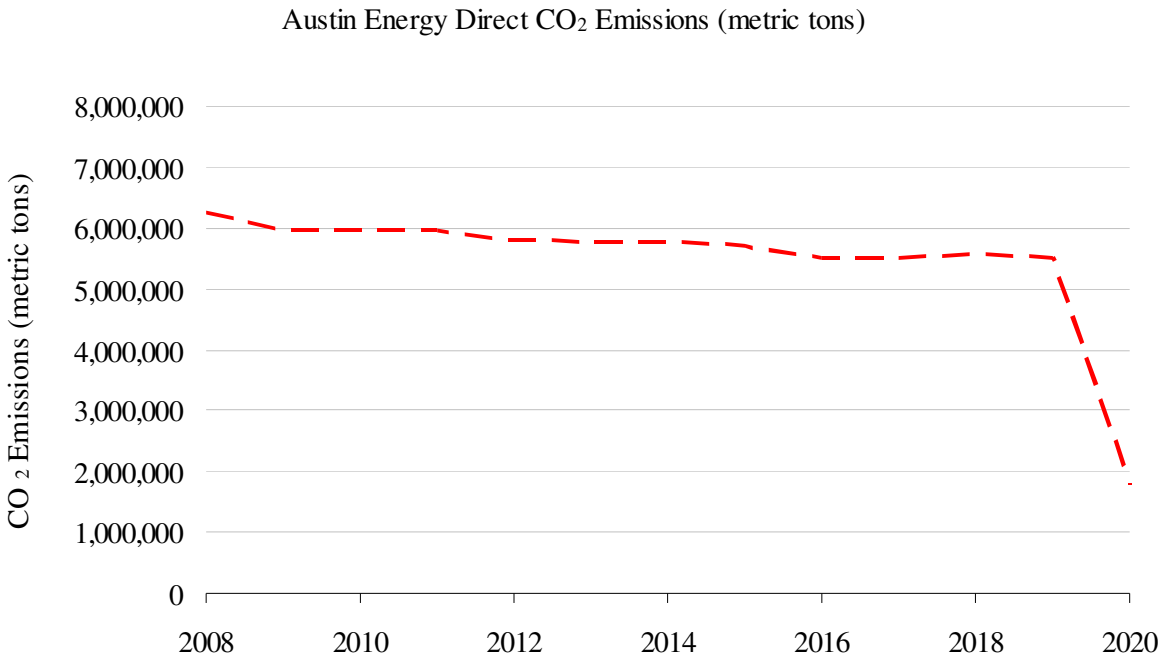


Figure 9.5
Cleaner Coal Scenario Carbon Allowance Costs

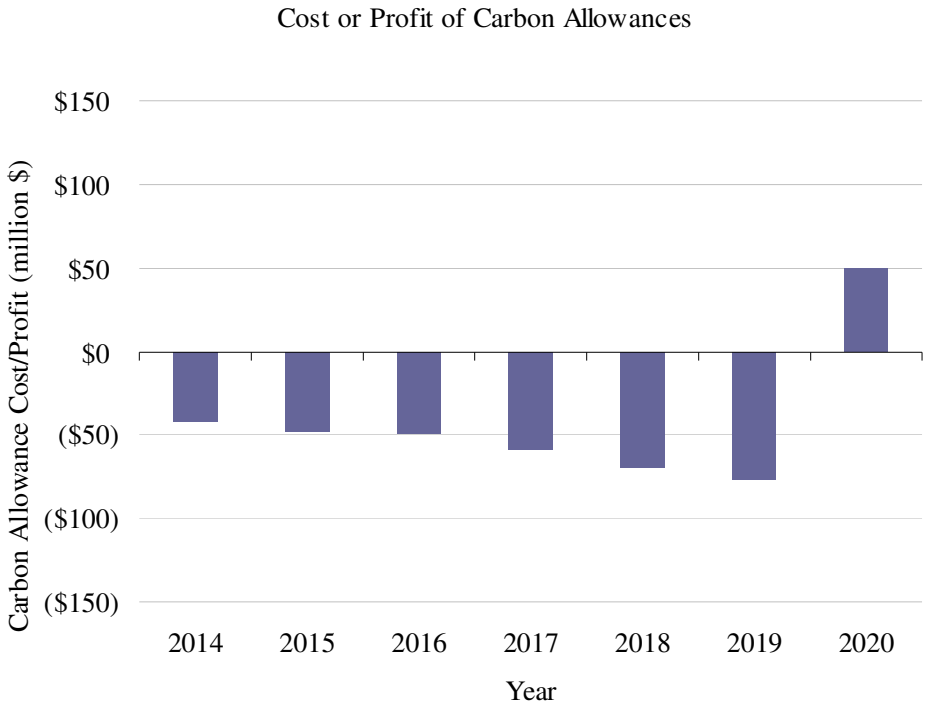
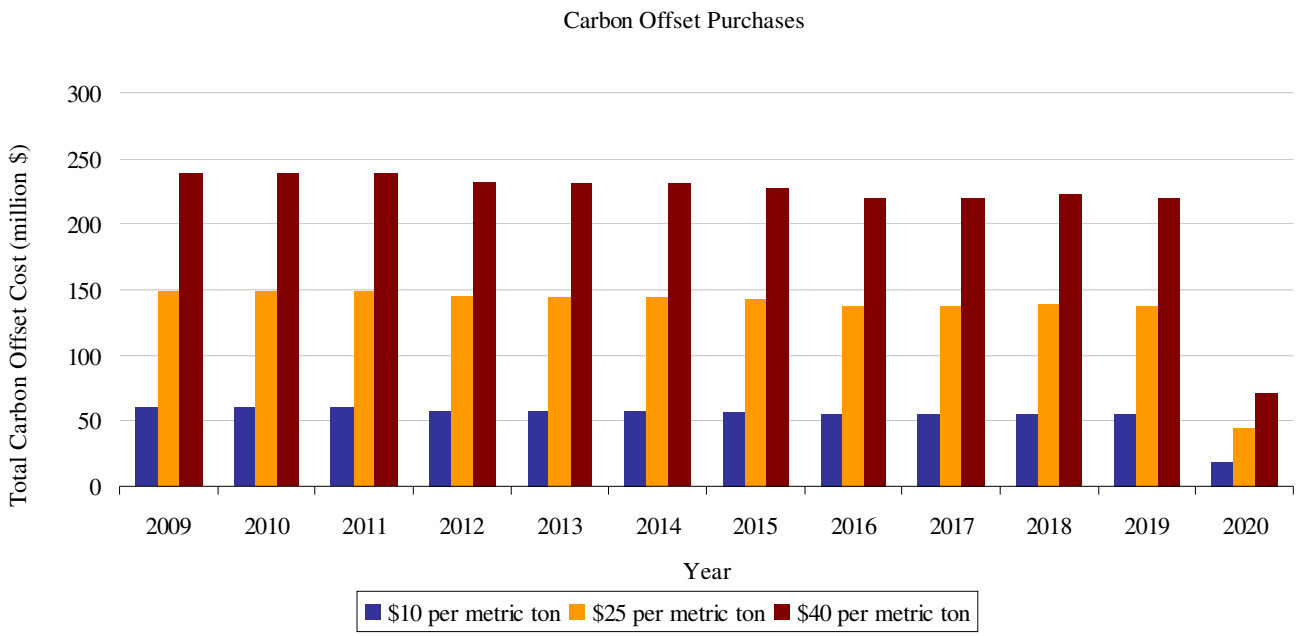


Figure 9.6
Cleaner Coal Scenario Carbon Offset Costs



Costs

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 $4.74 to $6.67 billion (compared to $2.2 to $3 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. Since cost estimates for the major expense in this scenario, the clean coal facility, are based on projections rather than actual experience with building such a plant, this cost estimate is highly unreliable. However, since this plant would not go into operation until 2020, several years of experience with the building of such plants, if such were to occur, could lower the cost of this type of facility. What this type of facility would cost at that time is unclear.

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 $167 to $324 million; 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 9.7
Cleaner Coal Scenario Capital Costs

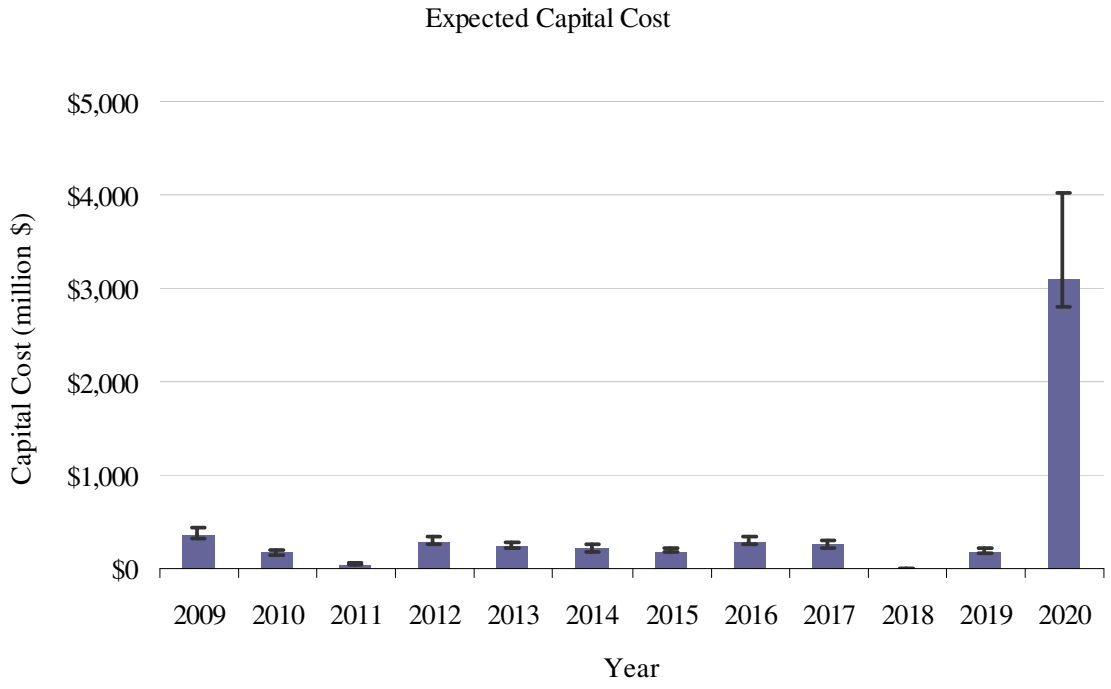


Figure 9.8
Cleaner Coal Scenario Fuel Costs

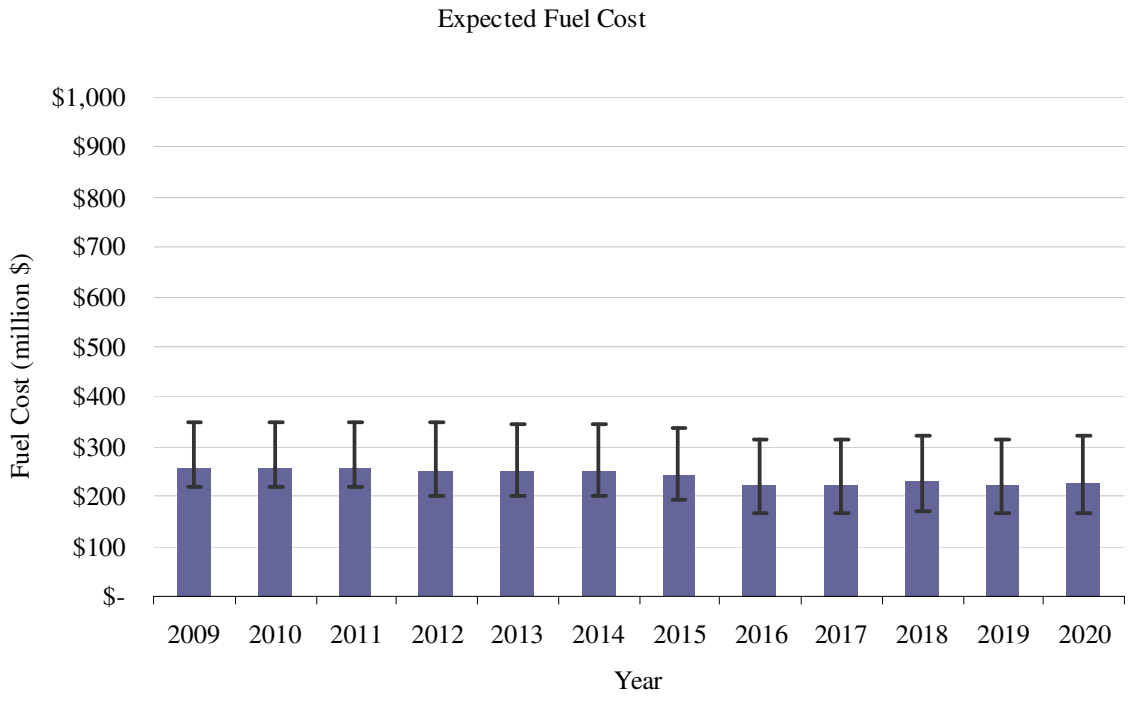
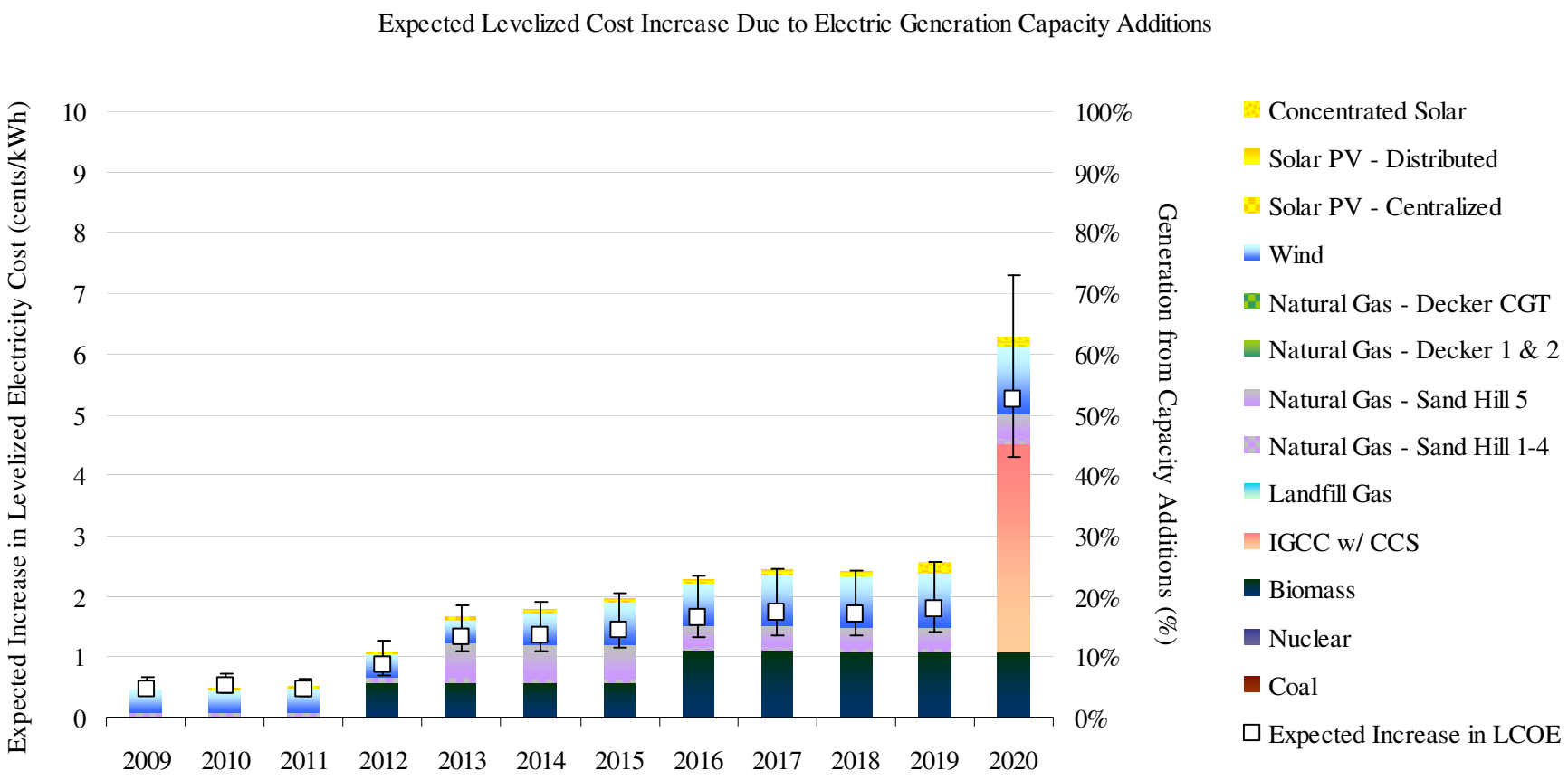


Figure 9.9 estimates the expected rise in costs to produce electricity by calculating the impact of the levelized costs of new power generation resources, as a percentage of overall power generation capacity. Under this scenario, customers would expect the cost of electricity to rise by 4.3-7.3 cents per kilowatt-hour by 2020. This expected increase in electric rates is based solely on new power generation investments. Carbon offset costs, infrastructure or regulatory costs, or any other 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 9.9
Cleaner Coal Scenario Levelized Costs



Chapter 10. High Renewables Without Nuclear Scenario

Table 10.1 details the additions and subtractions made to Austin Energy's (AE) resource portfolio from 2009 to 2020 by fuel source, power generation technology, or facility under the high renewables without nuclear scenario. The schedule for this scenario is identical to the schedule for the high renewables scenario with three exceptions. 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 megawatts (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. AE would become much more reliant upon natural gas, the volatile energy market, and renewable technologies with variable availability.

System Reliability

Under this scenario, the amount of traditional baseload power generation would decrease from 1,229 MW in the AE proposed resource plan to only 390 MW of baseload power generation capacity. Figure 10.1 demonstrates that AE's power generation capacity would exceed forecasted peak load with and without its demand-side management (DSM) goal 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 that use parabolic trough technology and gradual investment in distributed rooftop photovoltaic units. The mix of on-shore and off-shore (or coastal) wind facilities is intended to exploit the complementary profiles of this resource in the alternate locations, given that on-shore wind is most readily available in the evening and early morning and off-shore wind is most readily available during the day.

Figure 10.2 demonstrates that, given expected capacity factors for wind and solar 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 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.

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

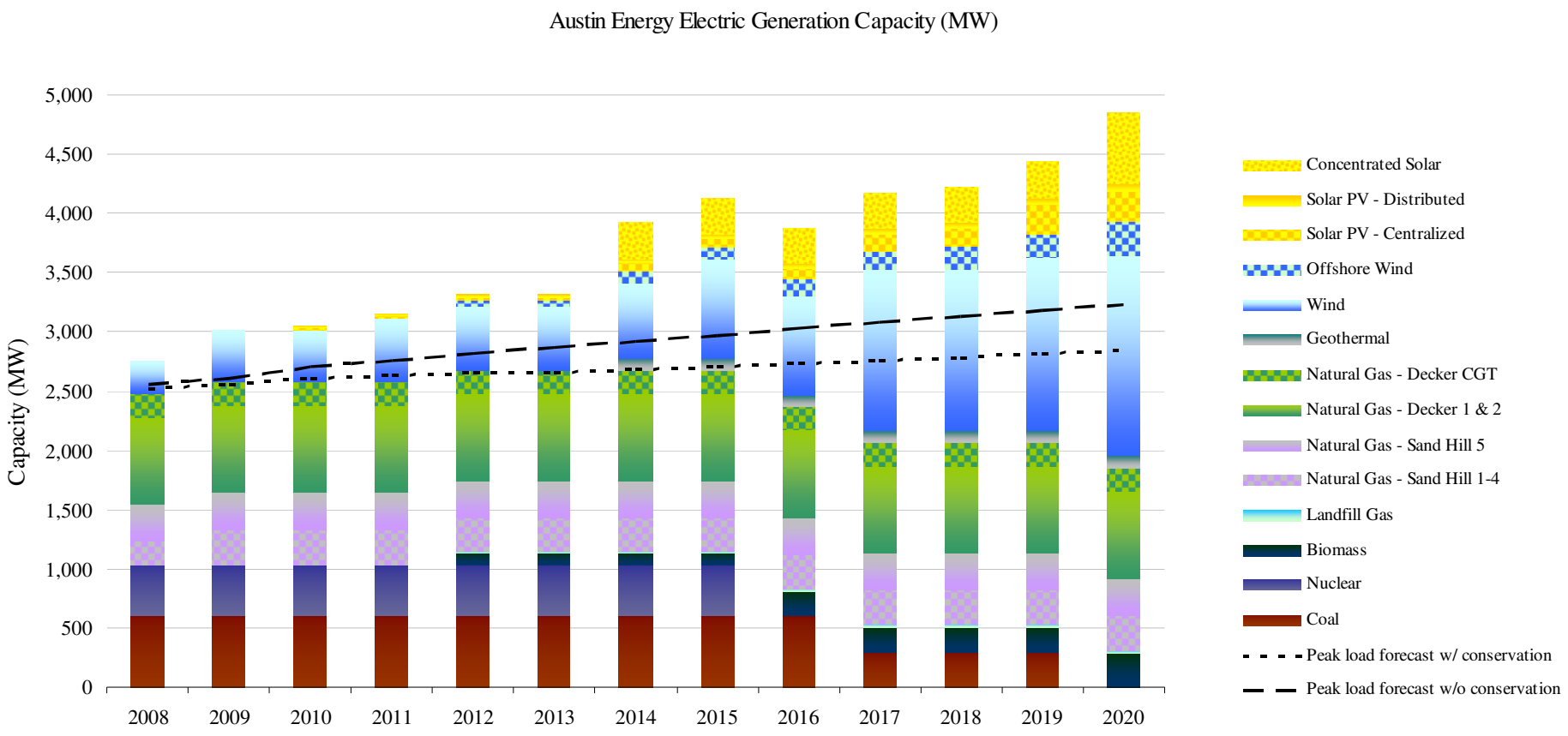
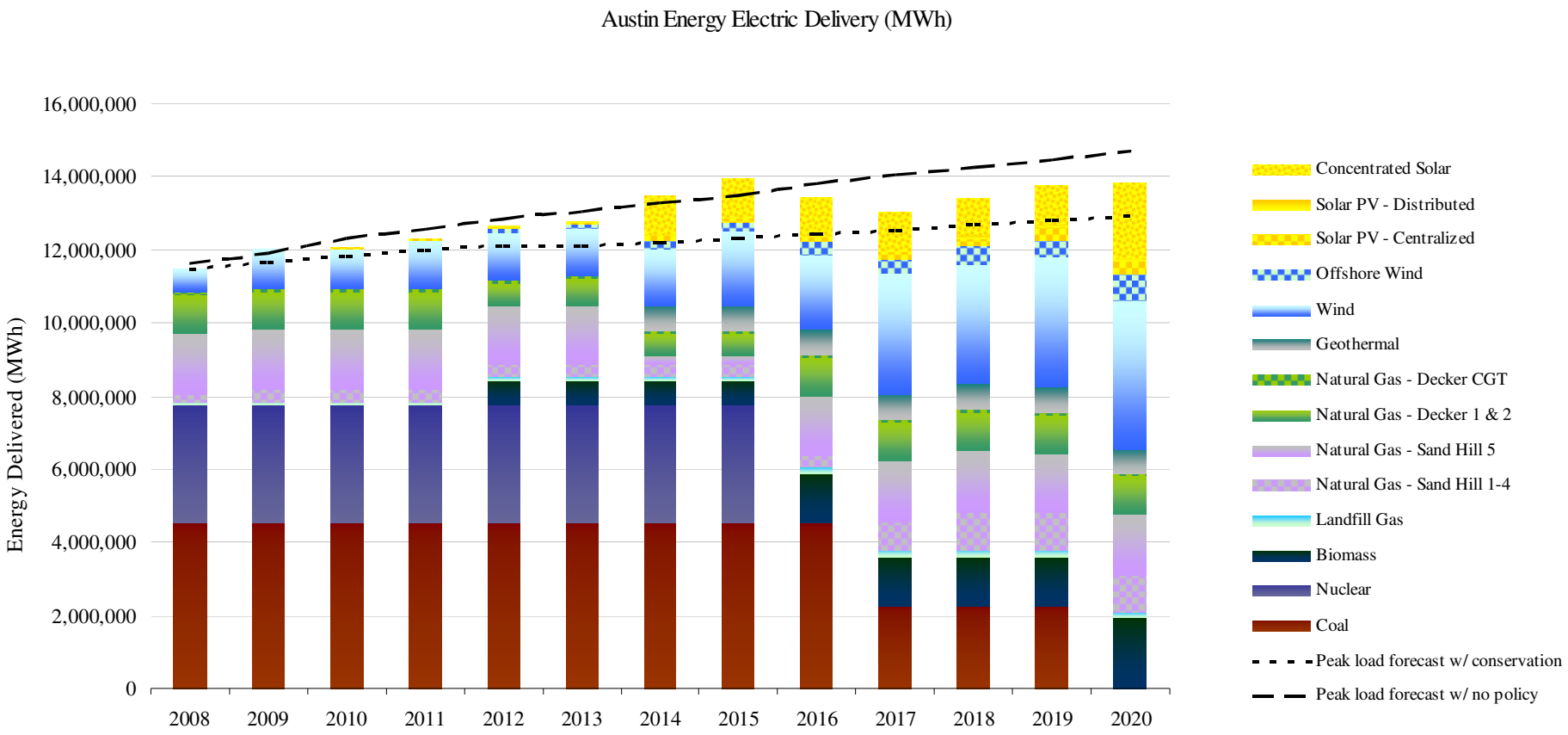


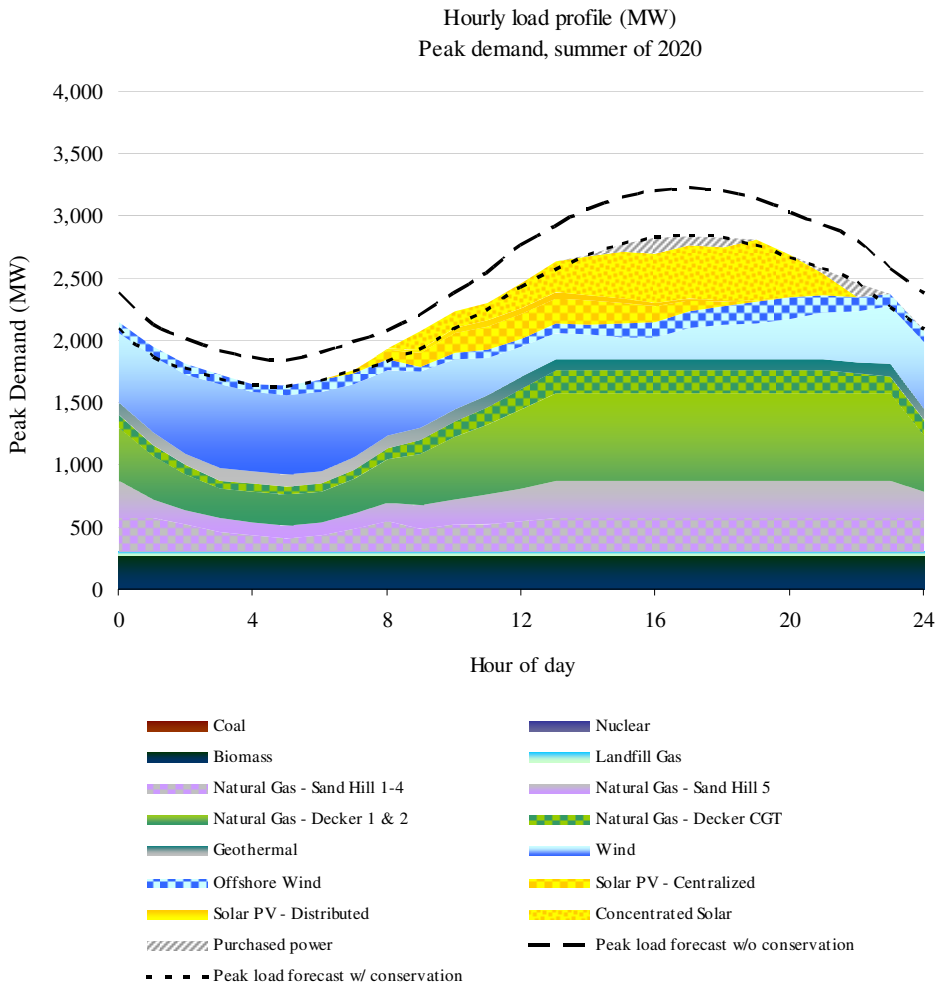
Figure 10.2
High Renewables Without Nuclear Scenario Electric Delivery



The hourly load profile follows expected solar and wind profiles and demonstrates that 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 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.

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



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 carbon dioxide 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; including $40 million in 2020 alone.

Under the high renewables without nuclear scenario, the 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**.**

Figure 10.4
High Renewables Without Nuclear Scenario Direct Carbon Dioxide Emissions

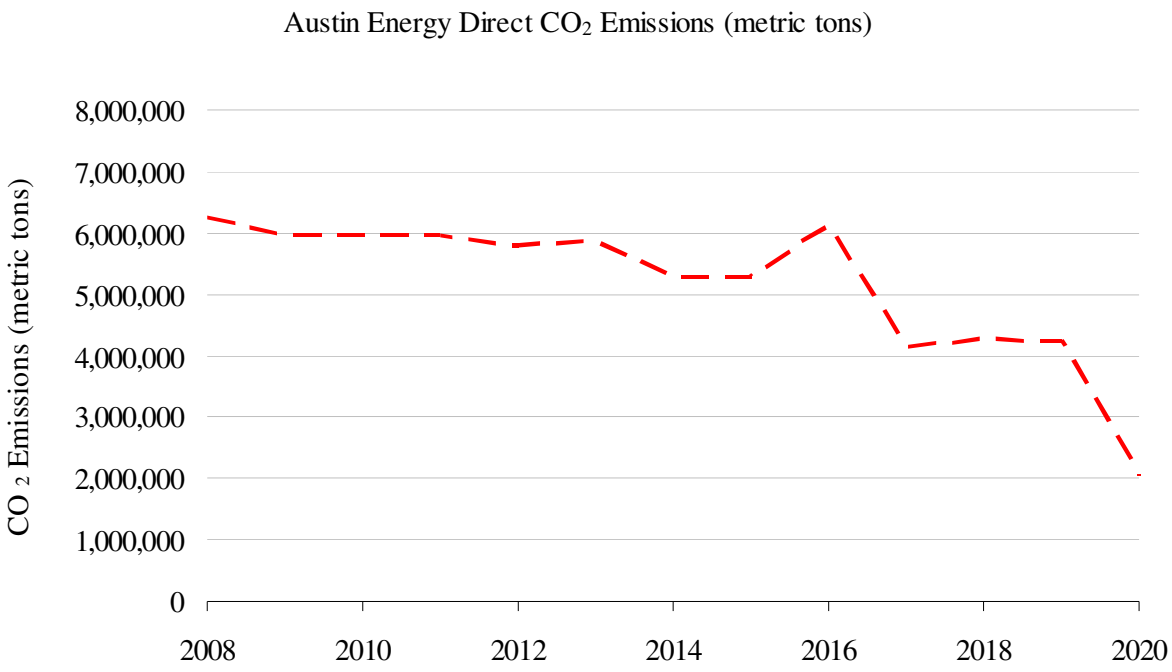


Figure 10.5
High Renewables Without Nuclear Scenario Carbon Allowance Costs

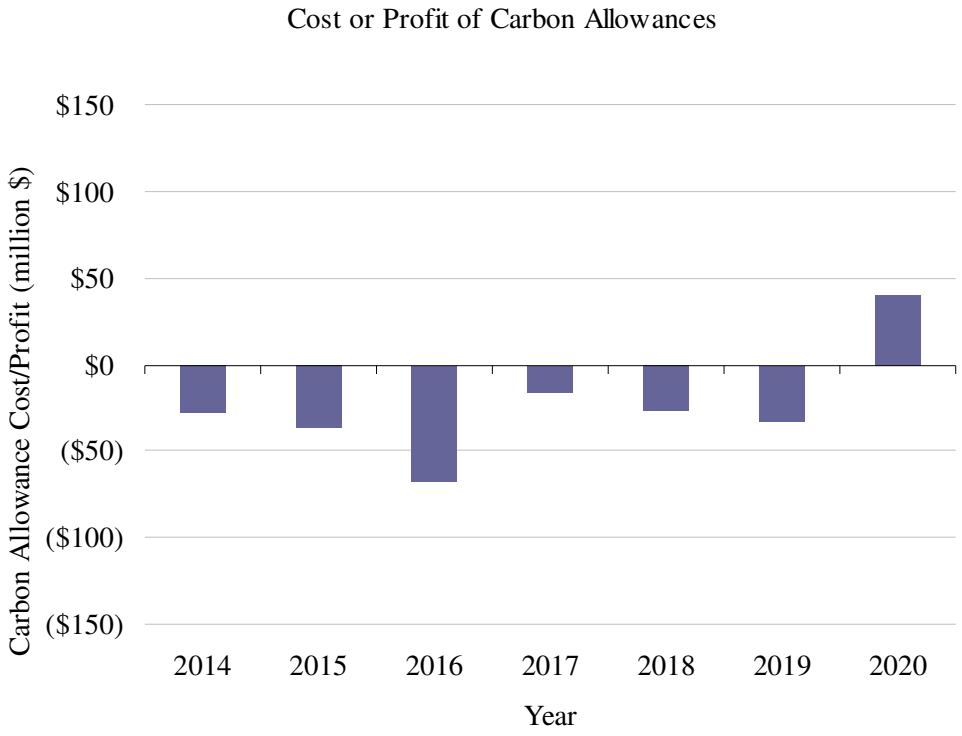
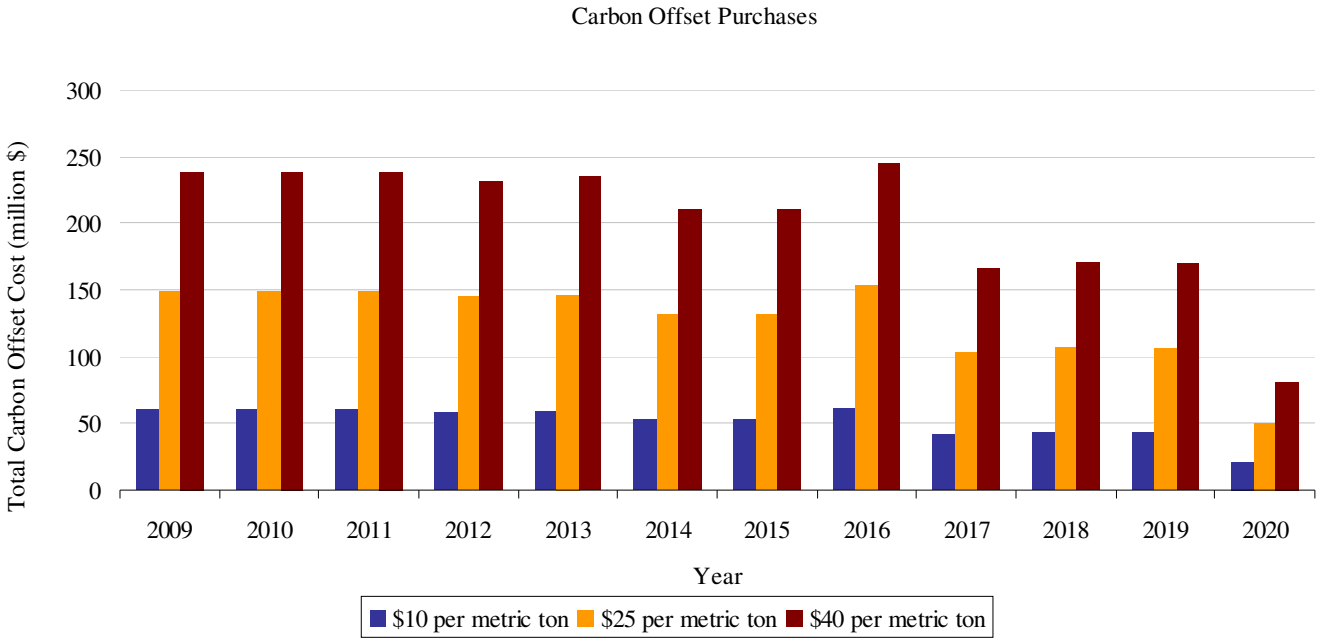


Figure 10.6
High Renewables Without Nuclear Scenario Carbon Offset Costs



Costs

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 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, 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 overall 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 4.7-8.4 cents per kilowatt-hour. This expected increase in electric rates is based solely on new power generation investments. Carbon offset costs, infrastructure or regulatory costs, or any other 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 for such a sale or lease 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 10.7
High Renewables Without Nuclear Scenario Capital Costs

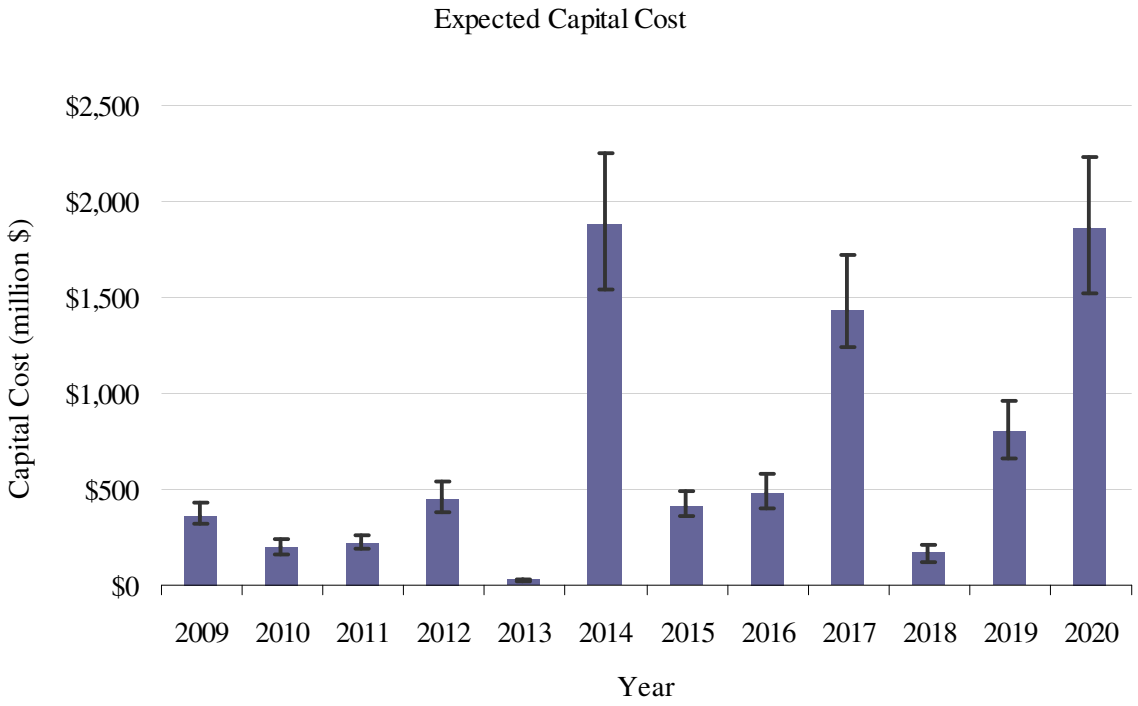


Figure 10.8
High Renewables Without Nuclear Scenario Fuel Costs

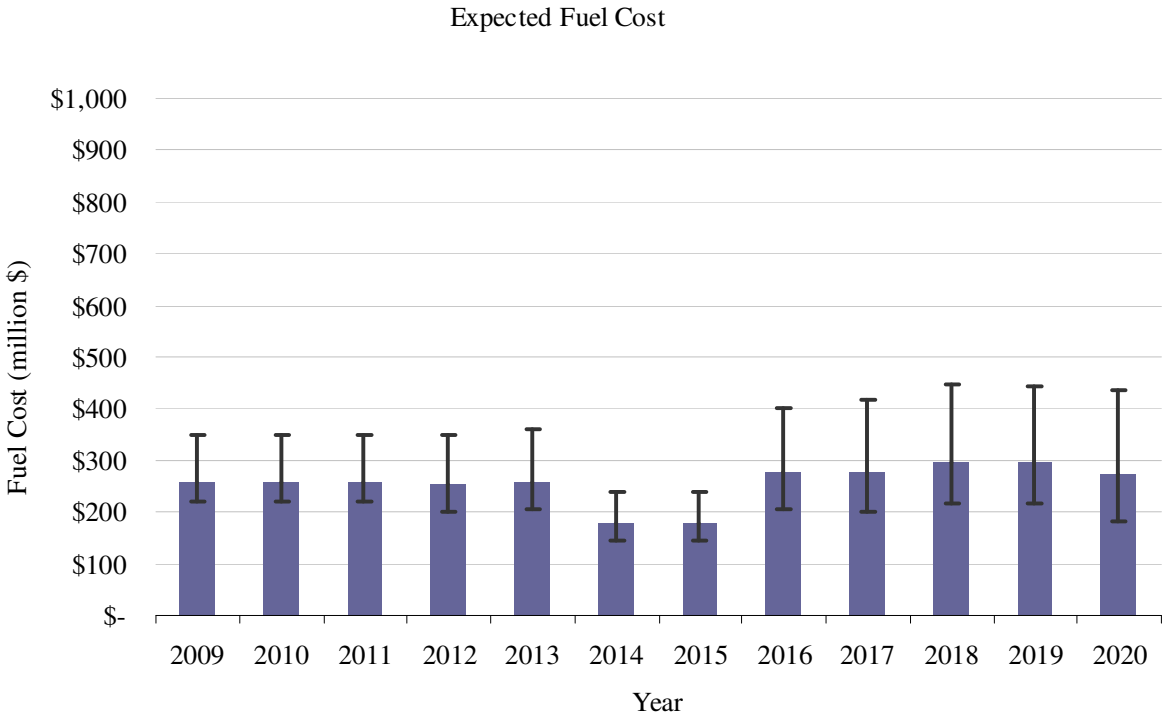
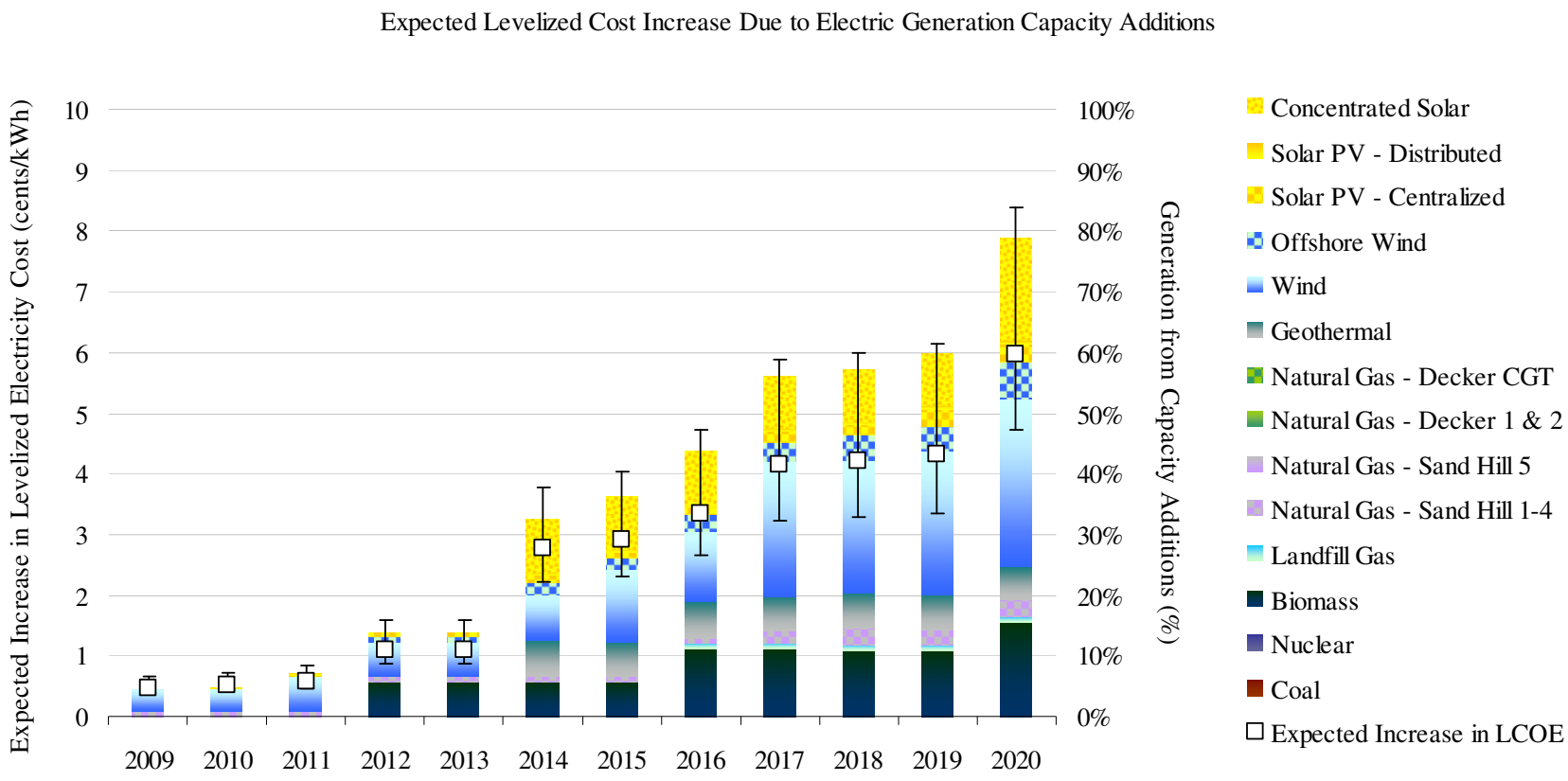


Figure 10.9
High Renewables Without Nuclear Scenario Levelized Costs



Chapter 11. Accelerated Demand-Side Management

One of the many challenges for an electric utility is accurately projecting future load, or demand. The analysis of the eight future resource portfolios assumes that Austin Energy (AE) will be able to achieve its goal of 700 megawatts (MW) of demand savings and that forecasted demand aligns with its projections. However, this analysis is based upon AE's 2008 load forecast. As a demonstration of the unpredictability of future demand, AE's 2009 load forecast predicted significantly lower demand through 2020. This change in the load forecast was based upon the expected short and long-term impacts of an economic recession. Expected demand between the 2008 and 2009 load forecast dropped by 65 MW for 2009 and 135 MW for 2020. AE updates their load forecast yearly and its strategic planning team constantly monitors trends in the electric utility industry that can impact future demand and create other planning challenges.

This chapter attempts to incorporate into the model scenarios some potential ranges of demand reductions that AE could realistically achieve through accelerated demand-side management (DSM) strategies. Measured reductions in both peak power demand and overall electricity demand due to conservation, energy efficiency, pricing mechanisms and other DSM strategies 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 DSM strategies on the AE proposed resource plan modeled scenario discussed and analyzed in Chapter 2 of this volume of the report. Table 11.1 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 under the Accelerated DSM scenario.

Utility 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 theoretically achieve peak demand savings of 40 percent (in MW) and overall demand savings of just over 30 percent (in MWh).

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

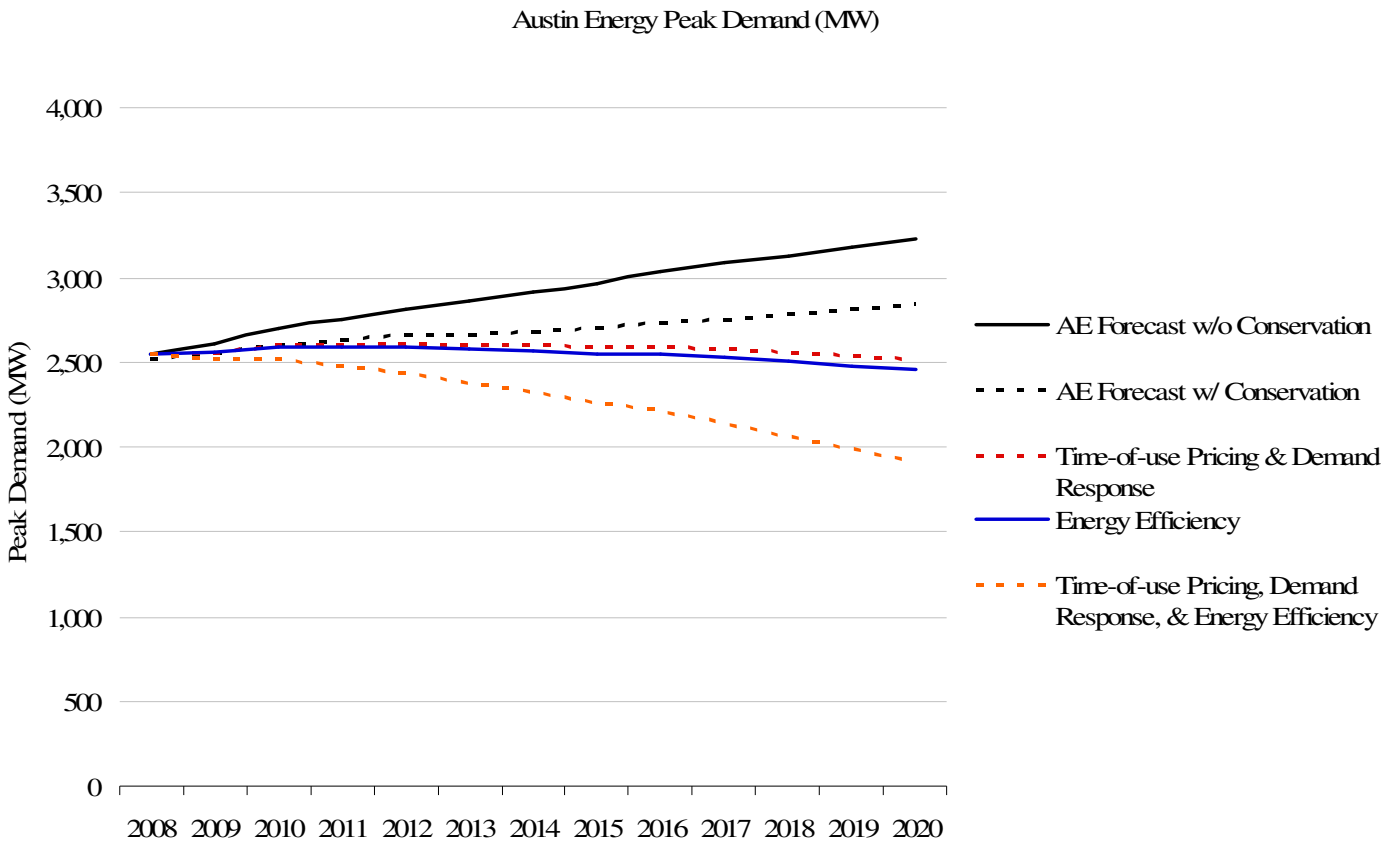
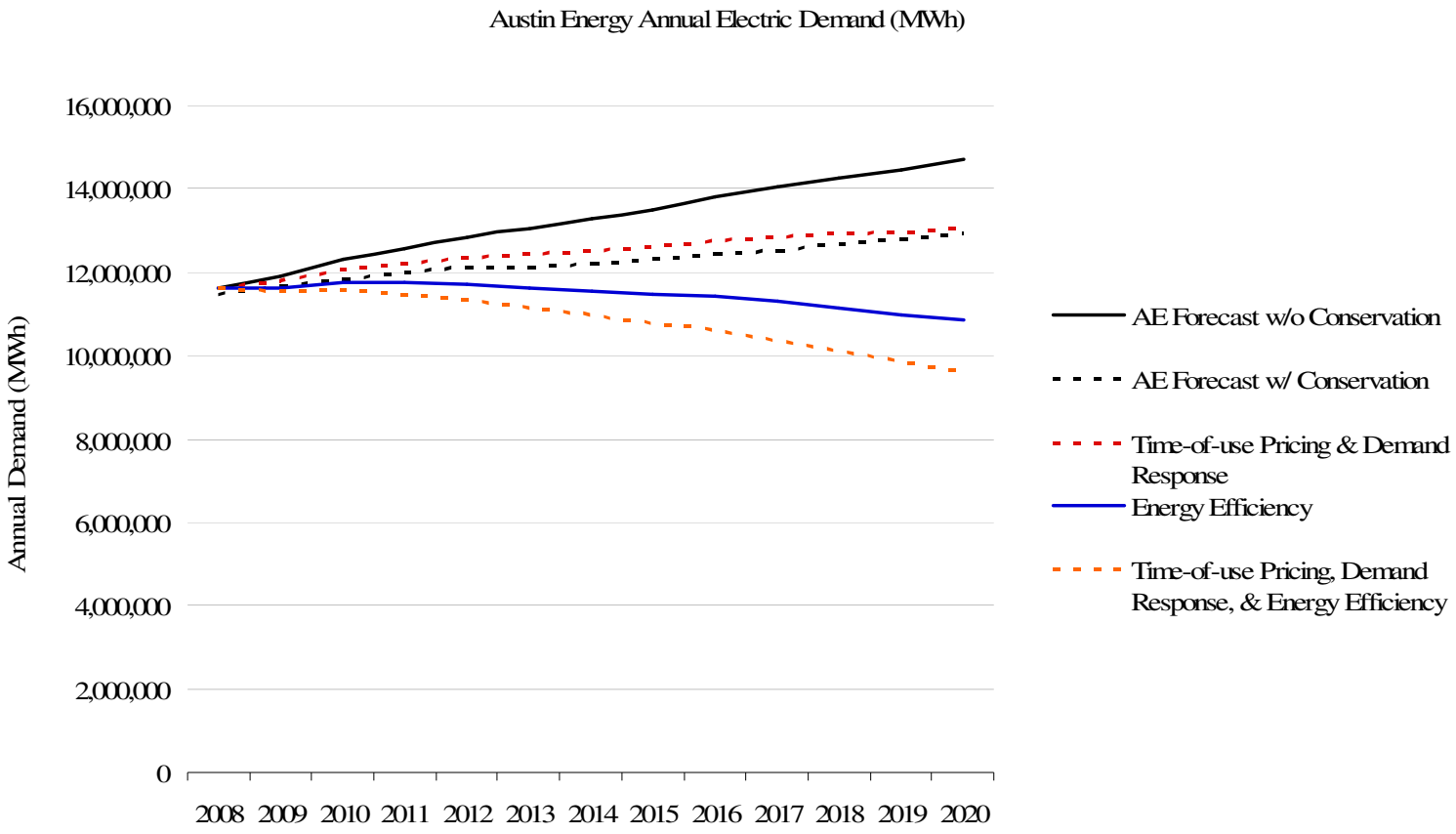
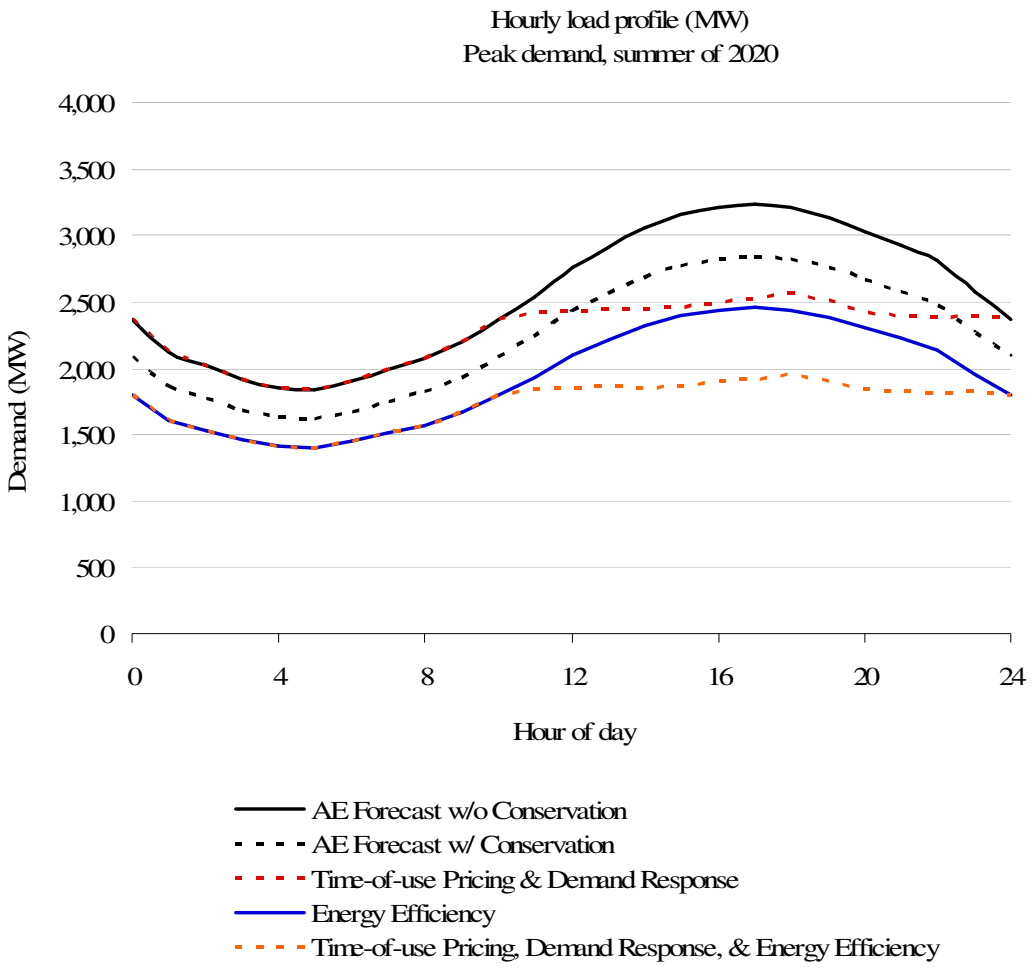


Figure 11.2
Annual Electricity Demand Profiles for DSM Strategies



In comparison, the demand forecast in the AE proposed energy resource plan that includes DSM 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.

Figure 11.3
Peak Day Hourly Profile for DSM Strategies



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 scenario achieves reliability gains as it does not have to rely as heavily on variable power generation technologies (wind and solar). The additional 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 Accelerated DSM scenario 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 renewable addition and carbon-free scenarios. Figures 11.7-11.9 demonstrate the impacts of accelerated DSM on carbon emissions and carbon costs.

Costs

Energy efficiency and conservation 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 this level of DSM is 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 technically not power generation technologies.

Figure 11.4
Accelerated DSM Scenario Power Generation Capacity

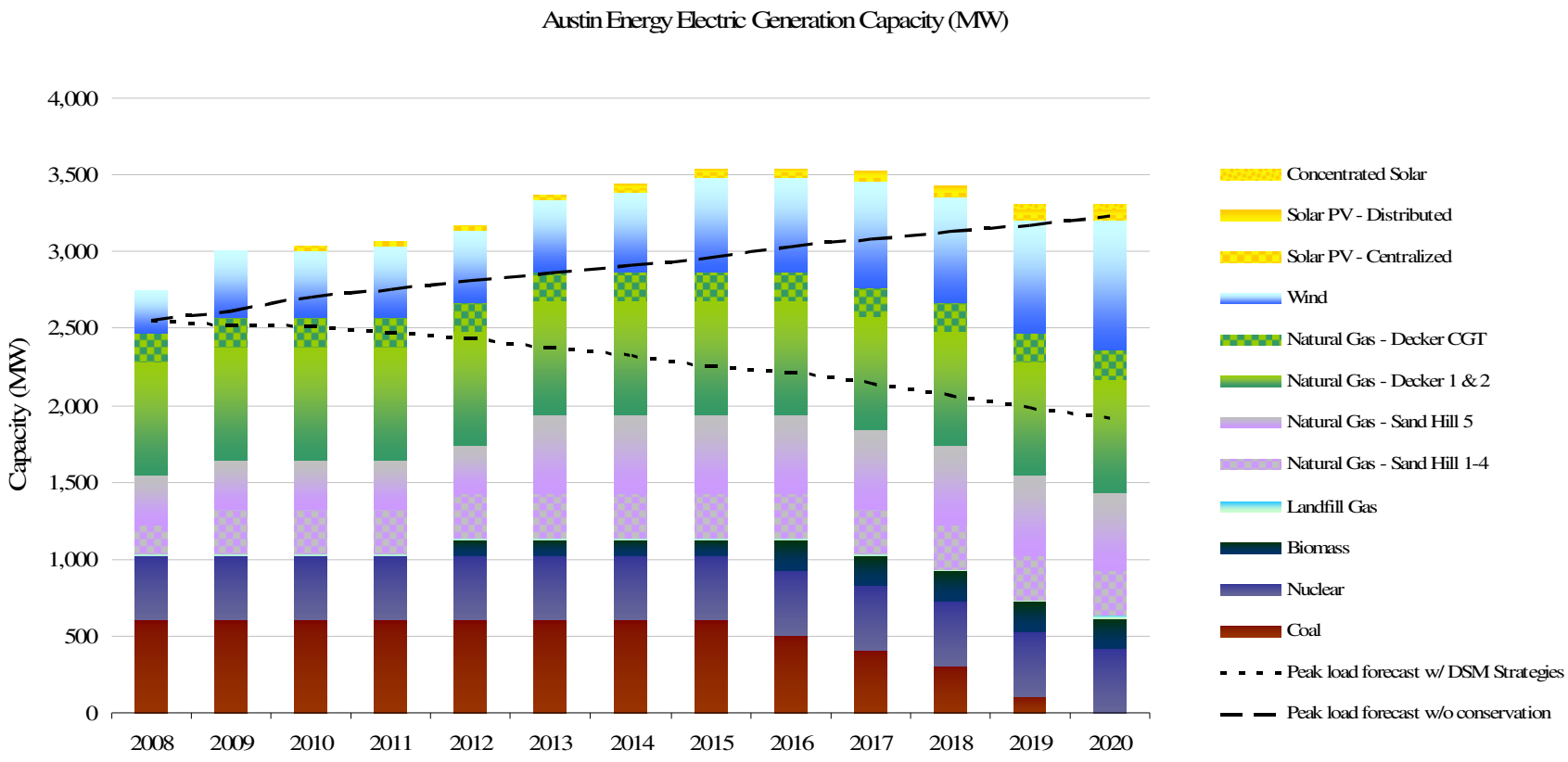


Figure 11.5
Accelerated DSM Scenario Electric Delivery

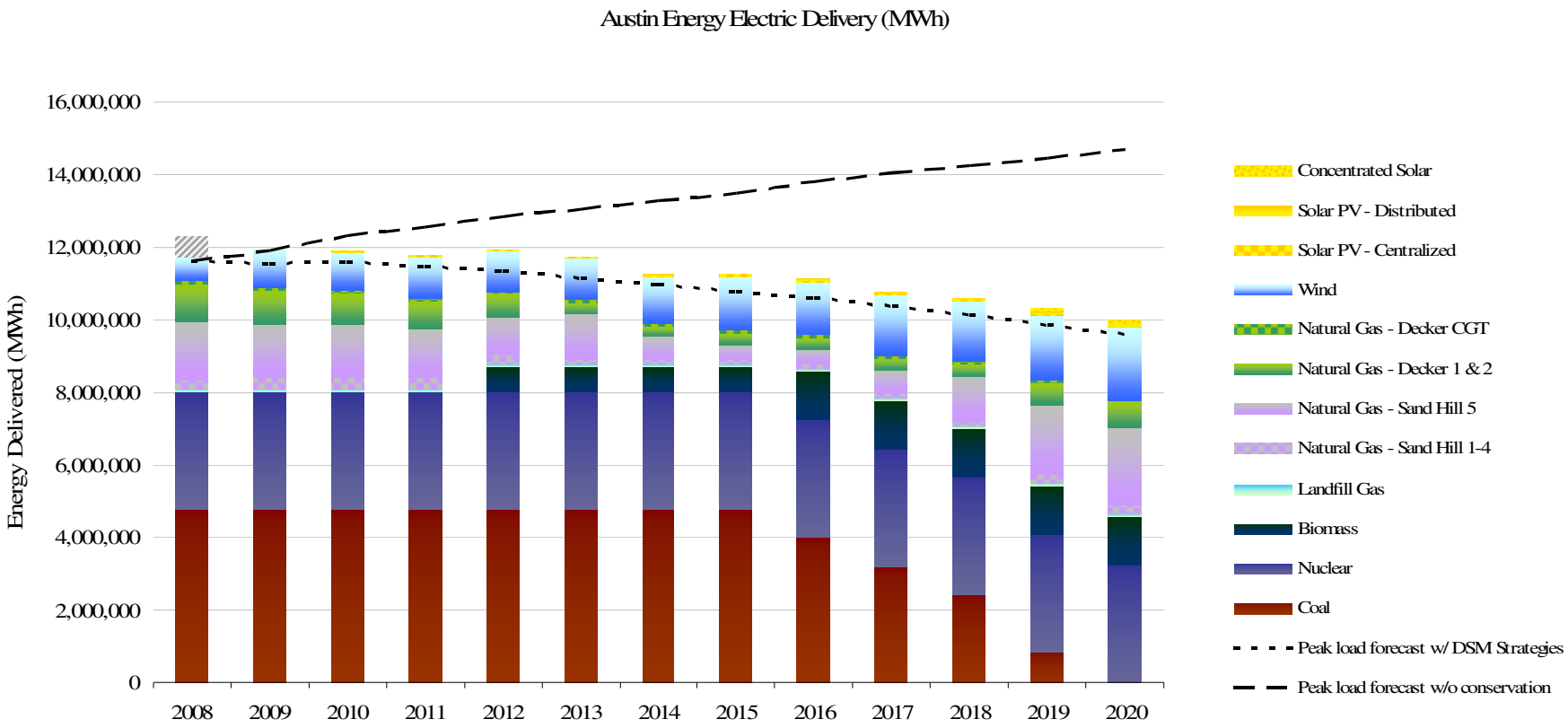


Figure 11.6
Accelerated DSM Scenario Hourly Load Profile
(Peak Demand, Summer 2000)

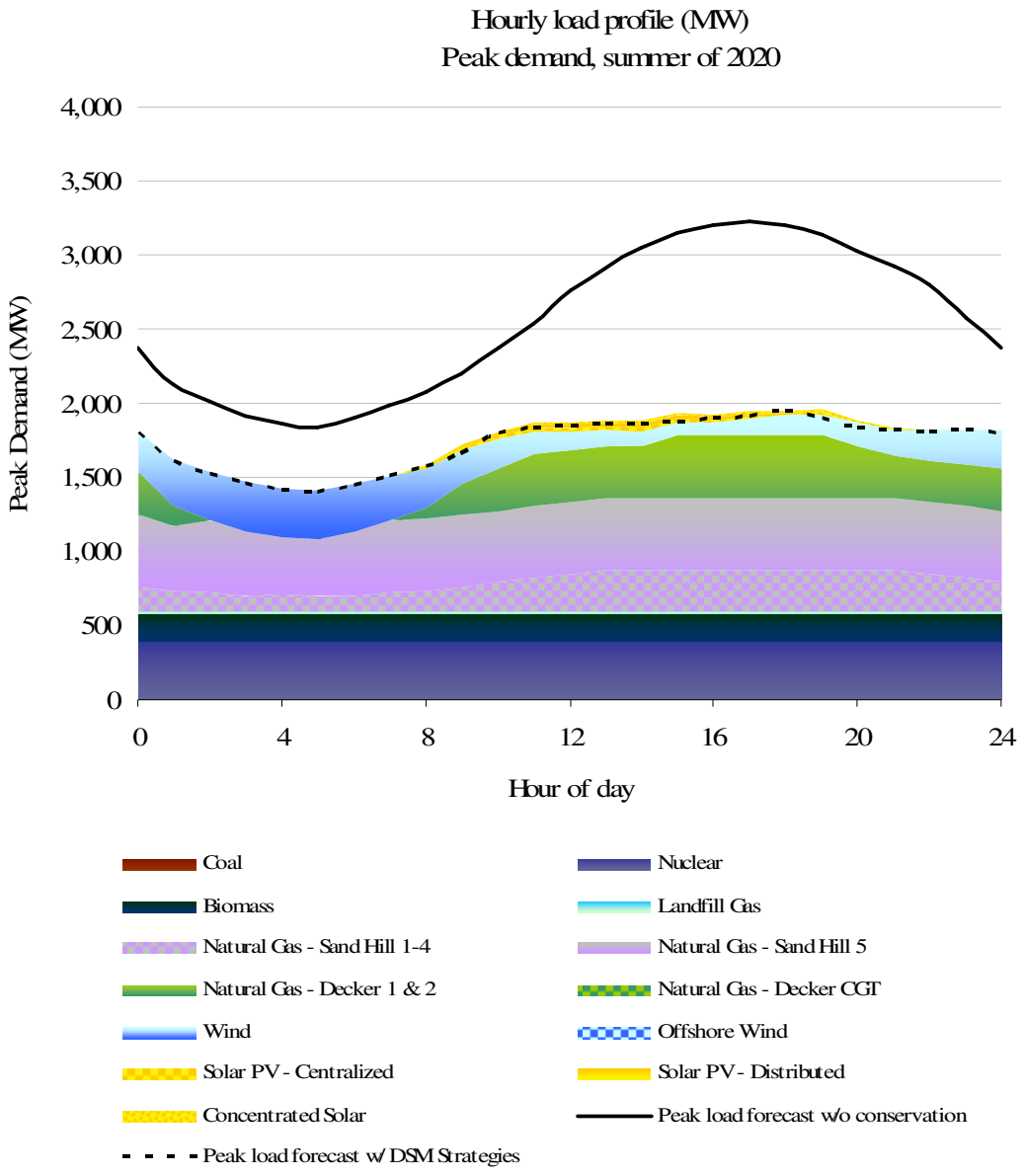


Figure 11.7
Accelerated DSM Scenario Direct Carbon Dioxide Emissions

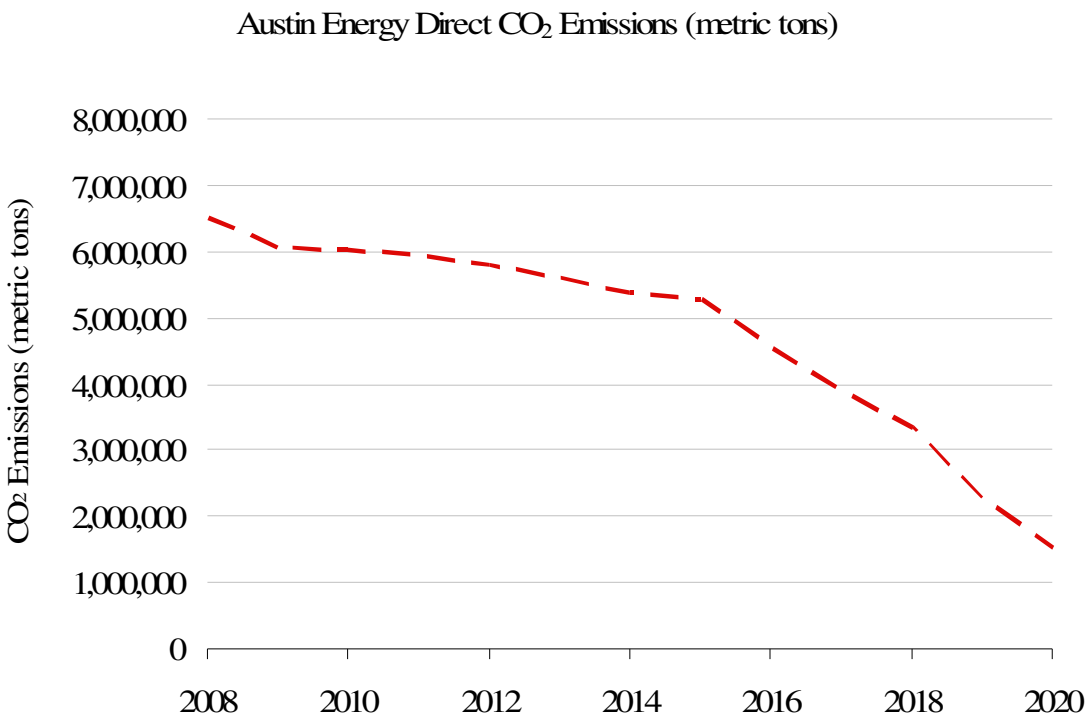


Figure 11.8
Accelerated DSM Scenario Carbon Allowance Costs

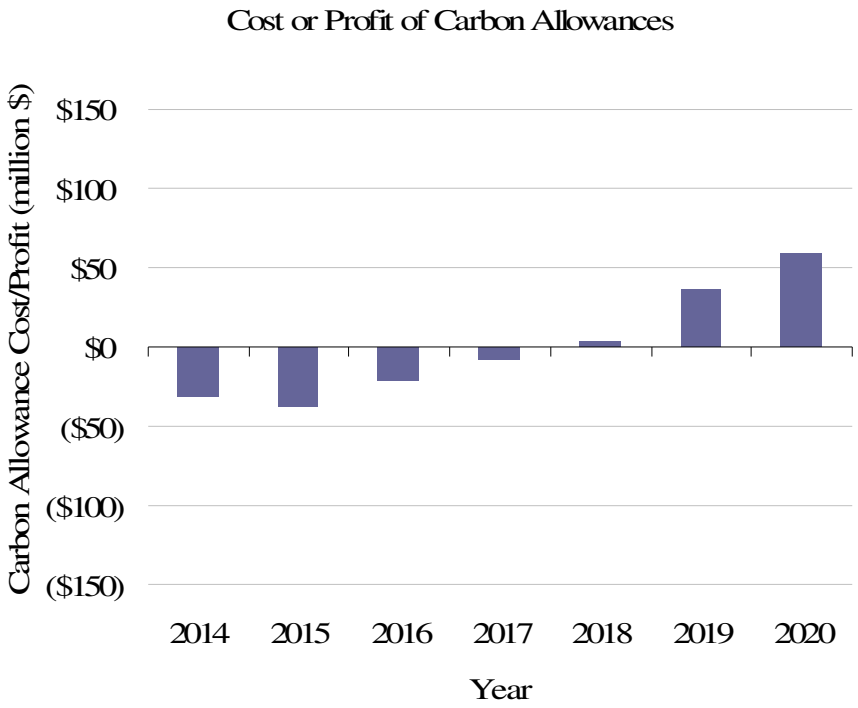


Figure 11.9
Accelerated DSM Scenario Carbon Offset Costs

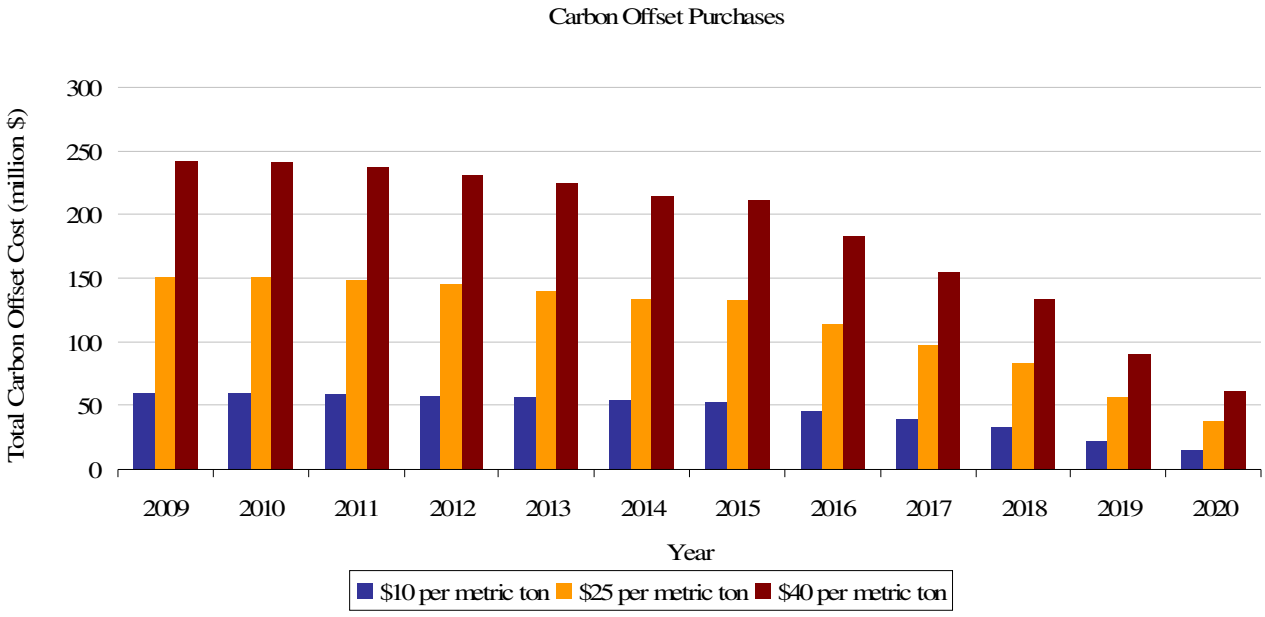


Figure 11.10
Accelerated DSM Scenario Capital Costs

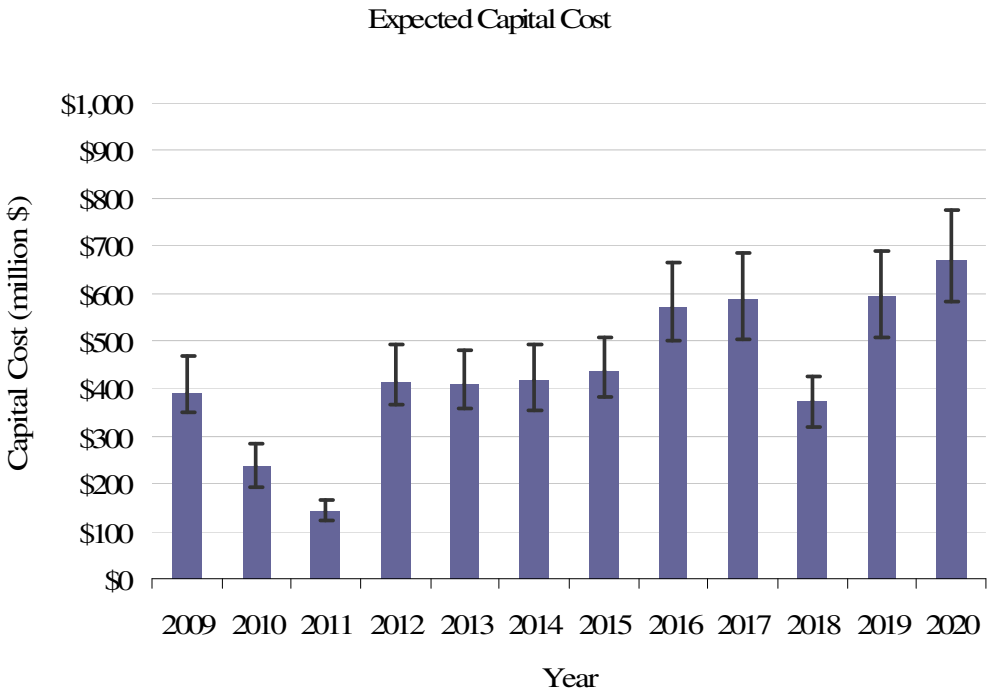
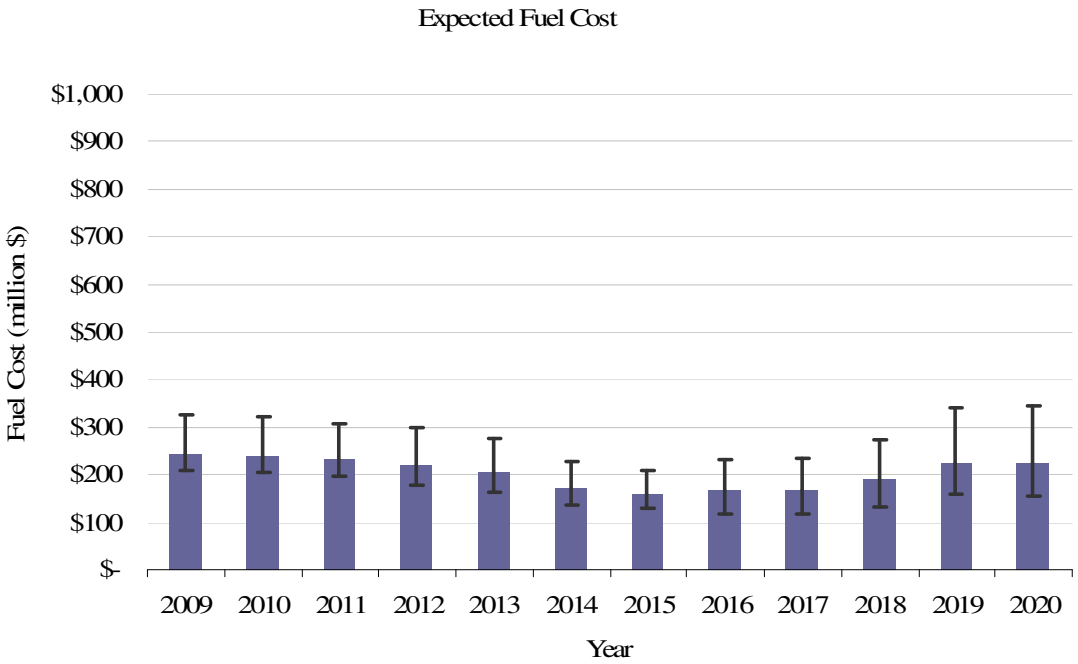


Figure 11.11
Accelerated DSM Scenario Fuel Costs



Chapter 12. Economic Development Impacts of Resource Portfolio Scenarios

The method used to estimate economic impacts is the Impact Analysis for Planning (IMPLAN) software program, developed by Minnesota IMPLAN Group (MIG), Inc.[1] IMPLAN is an input-output program which uses county-level historic industry averages to project the impact of large investments on local economies. A complete description of how IMPLAN operates and the methods used for analyzing the eight resource portfolio scenarios may be found in Appendix B of this volume of the report.

IMPLAN projects new capital flows and employment directly related to the investments in the industry sectors indicated by the user. For the purposes of this project, the project team modeled investments in the electric power generation and transmission sector, the other new nonresidential construction sector, and the maintenance and repair construction of residential structures sector. A listing of the assumptions for the location and size of investments is included in Appendix B.

A significant limitation of using IMPLAN for modeling investment in emerging technologies, which are by definition currently underrepresented in industry activity, is that historic industry averages of capital flows, hiring, and inter-industry spending do not reflect the relationships of capital, labor, and technology for changing markets. For example, impacts in an electricity market dominated by coal and natural gas power generation will not be the same as equivalent investments in a market dominated by wind and solar power generation. This limitation applies to modeling operations and maintenance costs, which is proportionately much smaller than capital costs in the 12-year period analyzed by this study. The standard professional use of IMPLAN is in a context whereby the proposed investment, purchasing, and employment data is specifically delineated by project managers, whereas our scenarios are intentionally more general. Due to these limitations, the IMPLAN outputs can be used as a basis of comparison for the short-term impacts of each scenario, but not for the long-term enduring impacts of scenarios with relatively higher investments in new technologies.

The project team was conservative with its assumptions regarding economic activity and thus did not model original economic activity outside of the direct construction and maintenance of new power generation plants. This excludes reasonable assumptions regarding the introduction of new industry activity due to an above average investment in emerging technologies. A more in-depth study of the macroeconomic sensitivities of each technology is beyond the scope of this project, but an example of this type of analysis has been conducted by the RAND Corporation for IMPLAN inputs for a fixed-array centralized photovoltaic (PV) power plant.[2] For that example, RAND recommends dividing the capital costs among the semiconductor and related industries sector, the fabricated structural metal sector, the engineering and architectural services sector, the electrical industrial apparatus sector, and the electric power generation and transmission sector. While such precise assumptions would be inappropriate for this analysis, they

could be employed for estimating the impact of a particular project, such as the 30 megawatt (MW) solar array project to be constructed in Webberville.

Figure 12.1, Figure 12.2, and Figure 12.3 show the economic development impacts of the eight scenarios evaluated in this report. Impacts include total value added, industry impacts, and employment impacts. More information on the meaning of these terms is included in Appendix B.

Figure 12.1
Total Value Added Impacts

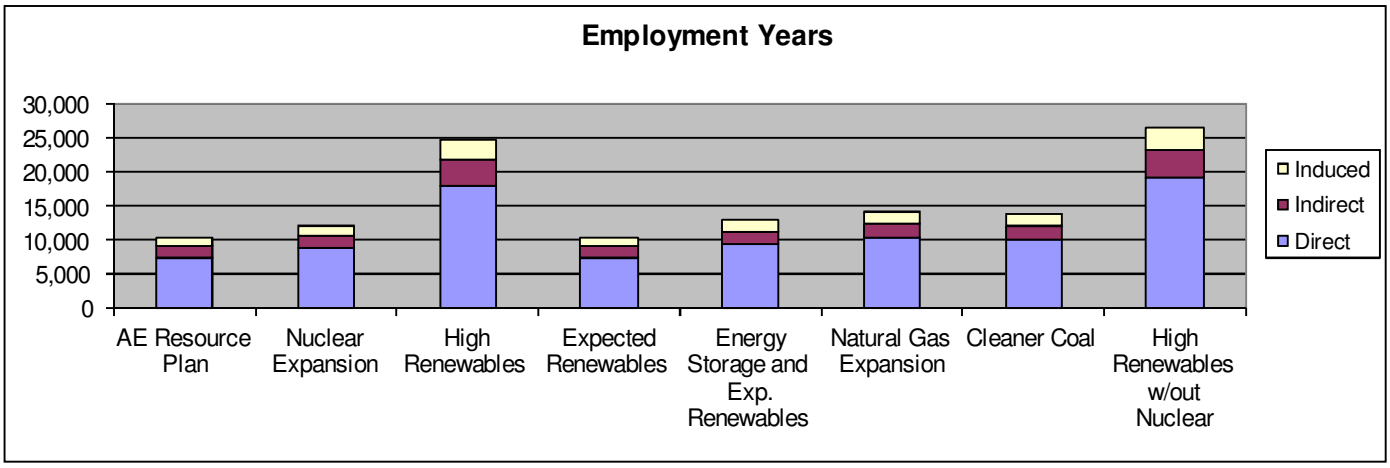


Figure 12.2
Industry Outputs

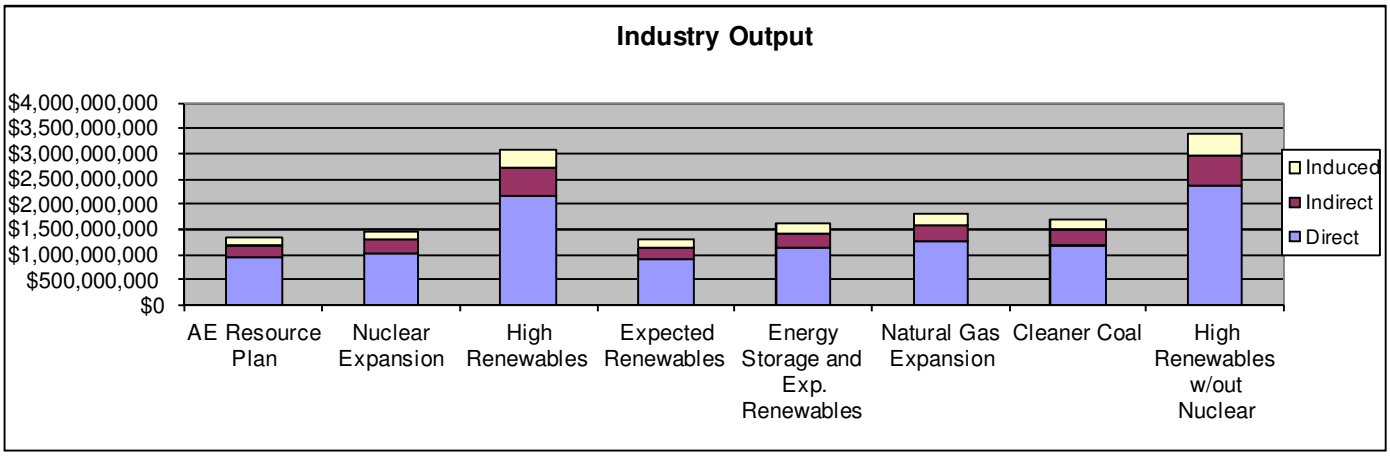
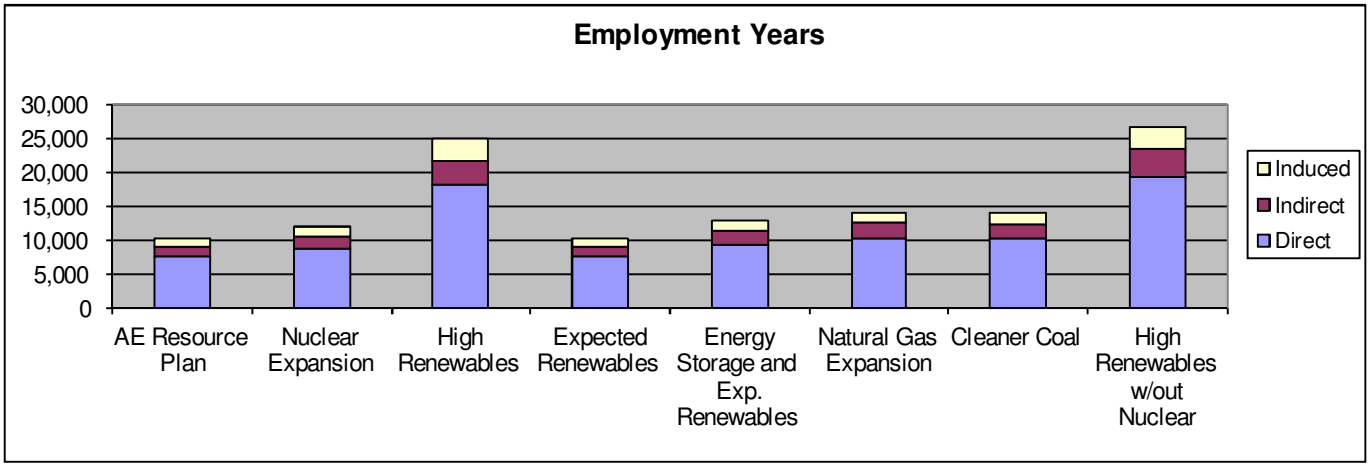


Figure 12.3
Employment Outputs



Austin Energy Resource Plan

Austin Energy's (AE) original proposed resource plan (July 2008) presents a balance of many different power generation types. Additions to the generation mix are integrated gradually from 2008 to 2020. New generation sources added in this proposal include the addition of over 300 MW of natural gas, 30 MW of concentrated solar PV, 41 MW of distributed solar PV, 30 MW of centralized solar PV, and over 800 MW of wind generation. Distributed solar and centralized solar PV investments are assumed to be located within the Capital Area Council of Governments (CAPCOG) region, while concentrated solar is expected to take place in the Competitive Renewable Energy Zones (CREZ). A moderate amount of these investments would occur within the CAPCOG region, including solar PV and natural gas expansion. The most significant economic development impacts would occur outside the AE service territory and CAPCOG region.

Jobs and local investments in construction, engineering, and utilities will have a moderate impact on the local economy. It is projected that this scenario would have a $695,451,650 effect on the CAPCOG region in total value added by 2020. This scenario produces relatively less total value added compared to the median of the eight scenarios evaluated by this study. It is projected that this scenario would produce $1,355,353,532 in local gross products and outputs by 2020. This value is relatively less than the median of the eight scenarios. This scenario would generate 10,362 years of employment for local workers in the CAPCOG area, again producing less than the median of the eight scenarios.

The direct impacts that result within the Austin CAPCOG region are $450 million in value added, $950 million in local gross product and output, and 7,500 direct employment years. The indirect impacts that result within the Austin CAPCOG region are $145 million in value added, $240 million in local gross product and output, and

1,600 employment years. The induced impacts that result within the Austin CAPCOG region are $100 million in value added, $160 million in local gross product and output, and 1,300 employment years.

Compared to the median of the eight scenarios analyzed in this study, this proposal produces money mostly spent outside the local economy and value added to communities outside the CAPCOG region. Some employment would be created locally through additions to the Sand Hill natural gas facility and distributed and centralized solar PV additions. This scenario would result in relatively less economic development than the median of the eight scenarios.

High Renewables Scenario

The key components of the high renewables scenario include adding substantially more renewable power generation resources (3,033 MW) to AE's resource portfolio and eliminating AE's use of coal (607 MW) by 2020. Investments include the addition of over 700 MW of concentrated solar PV, 55 MW of distributed solar PV, 250 MW of centralized solar PV, 100 MW of geothermal energy, almost 1,700 MW of new on-shore wind generation, and over 305 MW of off-shore wind. A significant portion of new generation added in this scenario occurs within the CAPCOG area. Under this scenario, jobs and local investments in construction, engineering, utilities, information technology, and semiconductor businesses will have a significant impact on the local economy.

The outputs of this scenario tend to be roughly double the median of the eight scenarios analyzed in this study. It is projected that this scenario will have a $1,590,901,654 effect on the Austin CAPCOG region in total value added by 2020, substantially more than the median and mean of the eight scenarios. It is also projected that this scenario would produce $3,093,616,405 in local gross products and outputs by 2020. This scenario is projected to generate 24,798 years of employment for local workers, doubling the employment years for CAPCOG area workers compared to the median of the eight scenarios.

The direct impacts that result within the Austin CAPCOG region are $1.03 billion in value added, $2.16 billion in local gross product and output, and 18,000 direct employment years. The indirect impacts that result within the Austin CAPCOG region are $330 million in value added, $555 million in local gross product and output, and 3,750 employment years. The induced impacts that result within the Austin CAPCOG region are $225 million in value added, $380 million in local gross product and output, and 3,000 employment years.

Compared to the median of the eight scenarios, this scenario produces a greater amount of money that would be spent within the local economy, greater value added to communities within the CAPCOG region, and greater employment generation. This scenario provides almost double the economic development compared to the median of the eight scenarios.

Nuclear Expansion Scenario

The key element of the nuclear expansion scenario is expansion of AE's nuclear generation capacity (422 MW) to replace coal (607 MW). For the purposes of this analysis, the project team assumed that this investment occurs at the South Texas Project plant located in Matagorda Bay, Texas, as this is where AE currently receives its nuclear energy needs from. This investment would not occur in the CAPCOG region. However, this scenario and all other scenarios include at the least the same investments in other power sources as AE's proposed energy resource plan to account for the elimination of coal and the necessity to meet increased energy demand.

Jobs and investments in construction, manufacturing, and nuclear related industries will not have significant impact on the local economy. It is projected that this scenario would have a $756,869,556 impact on the CAPCOG region in total value added by 2020, slightly below the median and mean of the scenarios. It is projected that this scenario would produce $1,466,952,819 in local gross products and outputs, slightly below the median of the eight scenarios. It is also projected that this scenario would generate 12,001 years of employment for local workers, slightly less than the amount of employment years for CAPCOG area workers when compared to the median of the eight scenarios

Direct impacts that result within the Austin CAPCOG region would be $490 million in value added, $1.02 billion in local gross product and output, and almost 8,800 direct employment years. Indirect impacts that result within the Austin CAPCOG region would be $156 million in value added, $262 million in local gross product and output, and almost 1,800 employment years. Induced impacts that result within the Austin CAPCOG region would be almost $110 million in value added, $180 million in local gross product and output, and 1,450 employment years.

Compared to the median of the eight scenarios, this scenario produces money spent mostly outside the local economy and value added and employment generated predominantly in Matagorda County and other communities outside of the Austin CAPCOG region.

Expected Renewables Scenarios

Investments in renewable power generation technologies are greater in the expected renewables scenarios than in AE's proposed resource plan, but less than the high renewables scenario. Investments include 572 MW of new wind power generation, 200 MW of biomass, 130 MW of centralized PV, 12 MW of distributed PV, and some natural gas additions. The investments in relevant industries of electrical construction and operations and maintenance for the expected renewables (with and without storage) scenarios will not have significant impact on the local economy because the most significant impacts generated by this scenario are not in the CAPCOG region, with the exception of natural gas additions and solar PV additions. The biomass additions are assumed to take place in Nagodoches County, and the wind development to occur in the

CREZ areas of West Texas. The expected renewables with storage scenario would incur more activity in the CAPCOG area due to the greater addition of natural gas, assumed to be a local investment.

For the expected renewables without storage scenario direct impacts that affect the Austin CAPCOG region are $423,487,361 in total value added activity, $902,995,552 in total output, and 7,509 employment years over the 12 year period. The indirect impacts that affect the Austin CAPCOG region are $139,490,269 for total value added, $235,006,494 for output, and 1,586 employment years. The induced impacts that affect the Austin CAPCOG area are $246,184,926 for total value added impact, $159,176,294 for output, and 1,265 for employment years. These outputs are marginally higher for the expected renewables with storage scenario due to additional investment in storage technologies that would increase natural gas usage in the CAPCOG region.

Cleaner Coal Scenario

The cleaner coal scenario aligns with the investments made in AE's proposed energy resource plan and includes the replacement of AE's use of pulverized coal with a "clean coal" plant that uses integrated gasification combined cycle and carbon capture and sequestration technologies. It is assumed that such a plant would be built in Matagorda County since AE owns land in this area. Therefore, most of the marginal benefits over the AE proposed resource plan would not occur in the CAPCOG region.

In comparison to the seven other scenarios, the cleaner coal scenario will modestly affect the CAPCOG region, with impacts slightly above the median for all scenarios. The direct impacts register at $567,763,332 for total value added activity, $1,189,592,396 for industry output, and an addition of 10,171 employment years. The indirect impacts are $182,028,305 in total value added activity, $306,735,187 for industry output, and 2,088 employment years. The induced impacts throughout the area are $126,876,711 in total value added activity, $210,821,025 in industry output, and an additional 1,676 employment years.

Natural Gas Expansion Scenario

The natural gas expansion scenario entails a significantly higher investment in natural gas, which would directly impact the CAPCOG region because these investments are assumed to be additions to current facilities owned and operated by AE which are all located in Austin. Investments included in this scenario include 807 MW of natural gas, 407 MW of new wind generation, 40 MW of distributed solar PV, and 60 MW of centralized solar PV.

In comparison to the seven other scenarios, the natural gas scenario is projected to have a greater effect on the CAPCOG region because natural gas units would be built locally. Total impacts are well above the median for the scenarios modeled. The direct impacts include $624,900,880 in total value added economic activity, $1,268,923,488 in industry output, and 10,321 employment years. The indirect impacts are $188,079,247 in total value added activity, $317,293,230 in industry output, and 2,129 additional employment

years. The induced impacts are $130,589,898 in total value added activity, $216,990,982 in industry output, and 1,725 additional employment years.

High Renewables without Nuclear Scenario

The high renewables without nuclear scenario essentially follows the investment schedule of the high renewables scenario and eliminates AE's use of nuclear as well as coal. As with the high renewables scenario, a significant portion of new generation taking place in this scenario occurs within the CAPCOG area. Under this scenario, jobs and local investments in construction, engineering, utilities, information technology, and semiconductor businesses will have a significant impact on the local economy.

It is projected that this scenario would have a $1,758,425,486 effect on the Austin CAPCOG region in total value added by 2020. This scenario produces the greatest total value added out of all eight scenarios analyzed in this study, and is substantially more than the median and mean of the scenarios. It is projected that this scenario produces $3,389,363,944 in local gross products and outputs. The outputs of this scenario are more than double the median of the eight scenarios. This scenario also would generate 26,617 years of employment for local workers in the CAPCOG region, more than double the employment years for CAPCOG region workers when compared to the median of the eight scenarios.

Direct impacts that result within the Austin CAPCOG region include $1.16 billion in value added, $2.38 billion in local gross product and output, and 19,330 direct employment years. Indirect impacts that result within the Austin CAPCOG region include $357 million in value added, $600 million in local gross product and output, and 4,000 employment years. Induced impacts that result within the Austin CAPCOG region include $250 million in value added, $400 million in local gross product and output, and 3,250 employment years.

Compared to the median of the eight scenarios, this scenario would produce a greater amount of money spent within the local economy, greater value added to communities within the CAPCOG area, and greater employment creation locally. This scenario provides more than double the economic development than the median of the eight scenarios provides.

Notes

[1] Minnesota IMPLAN Group, Inc., *IMPLAN Professional 2.0 User's Guide, Analysis Data Guide* (Stillwater, Minnesota, 2004), p. 102.

[2] The RAND Corporation, *Cost Breakdowns of Power Generation Technologies*. Online. Available: http://www.rand.org/pubs/monograph_reports/MR1604/MR1604.appc.pdf. Accessed: April 14, 2009.

Chapter 13.
Comparison of Resource Portfolio Scenarios

In this chapter, eight resource portfolio scenarios are compared using measures that indicate four criteria: system reliability, carbon reductions, costs and economic impacts, and risks and uncertainties. Table 13.1 lists the energy resource portfolio scenarios evaluated in this study. 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 Austin Energy (AE) through 2020. Rather, the intention is to evaluate a diverse range of options that move AE towards becoming a carbon-neutral utility using a model that has the ability to easily evaluate new options as they are presented. This analysis 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 included 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, the project team concluded that the impact of different investments on AE's carbon footprint should have the greatest significance for the findings and recommendations provided by this report. 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.

Table 13.1
Resource Portfolio Analysis Summary

	Scenario Title	Major Additions and Subtractions Through 2020
Portfolio 1	AE Resource Plan	Add biomass, natural gas, solar, and wind
Portfolio 2	Nuclear Expansion	Nuclear replaces coal and AE resource plan additions
Portfolio 3	High Renewables	Very high investments in biomass, geothermal, solar, and wind technologies to replace coal
Portfolio 4	Expected Renewables	Expected available investments in biomass, geothermal, solar, and onshore wind to replace coal
Portfolio 5	Renewables with Storage	Expected renewables coupled with energy storage of wind to replace coal
Portfolio 6	Natural Gas Expansion	Natural gas replaces half of current coal and AE resource plan additions
Portfolio 7	Cleaner Coal	IGCC with carbon capture and storage to replace Fayette Power Project and AE resource plan additions
Portfolio 8	High Renewables without Nuclear	High renewables to replace coal and nuclear

Comparison of Resource Portfolios

The eight scenarios included in this report were developed to analyze the relative impacts of different approaches to reducing AE's carbon footprint. These scenarios provide a diverse set of options by differentiating among the various types of energy resource and power generation or energy storage technology investments that can be made in the planning period (2009 to 2020). The intent of the comparison of these 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. The reader of the report can consider the estimated consequences of investing in her or his preferred technologies. Each user of the model developed for this analysis, the Austin Energy Resource Portfolio Simulator, 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 portfolio needs and desires. The project team's approach is to compare alternate scenarios based on four criteria: system reliability, costs and economic impacts, carbon dioxide (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 carbon mitigation approaches. The following paragraphs compare the logic involved in these tradeoffs.

In some scenarios, such as the high renewables scenario, AE would 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 United States (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 waste. 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 kilowatt-hour (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 few 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 management and customers. These measurements relate to certain criteria that impact investment decisions in the electric utility industry. Table 13.2 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.

Table 13.2
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 allowance
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

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 demand. 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 (e.g., wind and solar) or intermediate (natural gas) power sources. Since wind and solar cannot be relied upon to generate electricity at all times, the project team defined 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.

The project team defined, as another reliability metric, 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 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 adequate existing transmission and distribution infrastructure.

Table 13.3 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

unable to meet peak demand without purchasing power from the electric grid: the nuclear expansion scenario, the expected renewables scenario, and the high renewables to replace coal and nuclear scenario. The nuclear expansion scenario comes close to being able to meet peak demand by doubling current nuclear capacity [from 422 megawatts (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.

Table 13.3
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)

None of the scenarios falls dramatically short of meeting peak demand. The two high renewable scenarios appear to be the only 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 dollars 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 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 13.4 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: 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 renewables 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.

Table 13.4
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)

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 general fund transfer, 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. Throughout this analysis, no "value" is assigned to the leasing or selling of AE's share of ownership in a power plant facility in the levelized cost of electricity. The calculators embedded in the simulation do not attempt to represent the flows of debts. Any sale or lease of AE's power plant ownership, such as its stake in the Fayette Power Project (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 13.5 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 is 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.

Table 13.5
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)

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 renewables 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 amounts 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 renewables 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 the levelized cost of electricity represent one criterion of AE cost risks. The fraction of total demand met by variable energy sources (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 risk that will affect electricity availability and reliability.

Table 13.6 lists indicators of risks and uncertainties. Taking the high estimate of total capital costs, fuel costs, and increase in the 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 renewables with energy storage scenario, and the high renewables scenario.

Table 13.6
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 Renew-ables without Nuclear	8,770 (7)	4,370 (5)	8.4 (8)	59.3 (8)	5

Conclusions

Table 13.7 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 has no absolute meaning, 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 renewables scenario receives a slightly higher ranking than the expected available renewables, natural gas expansion, cleaner coal, and expected available renewables 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.

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 13.1, Figure 13.2, and Figure 13.3. 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 from existing facilities. 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 renewables

scenario, at expected costs, would achieve greater reductions in CO_2 emissions at lower cost.

Table 13.7
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)

Figure 13.1
Metric Tons of CO_2 Reduced from 2007 Levels
by Cent per kWh of Expected Rise in Cost of Electricity

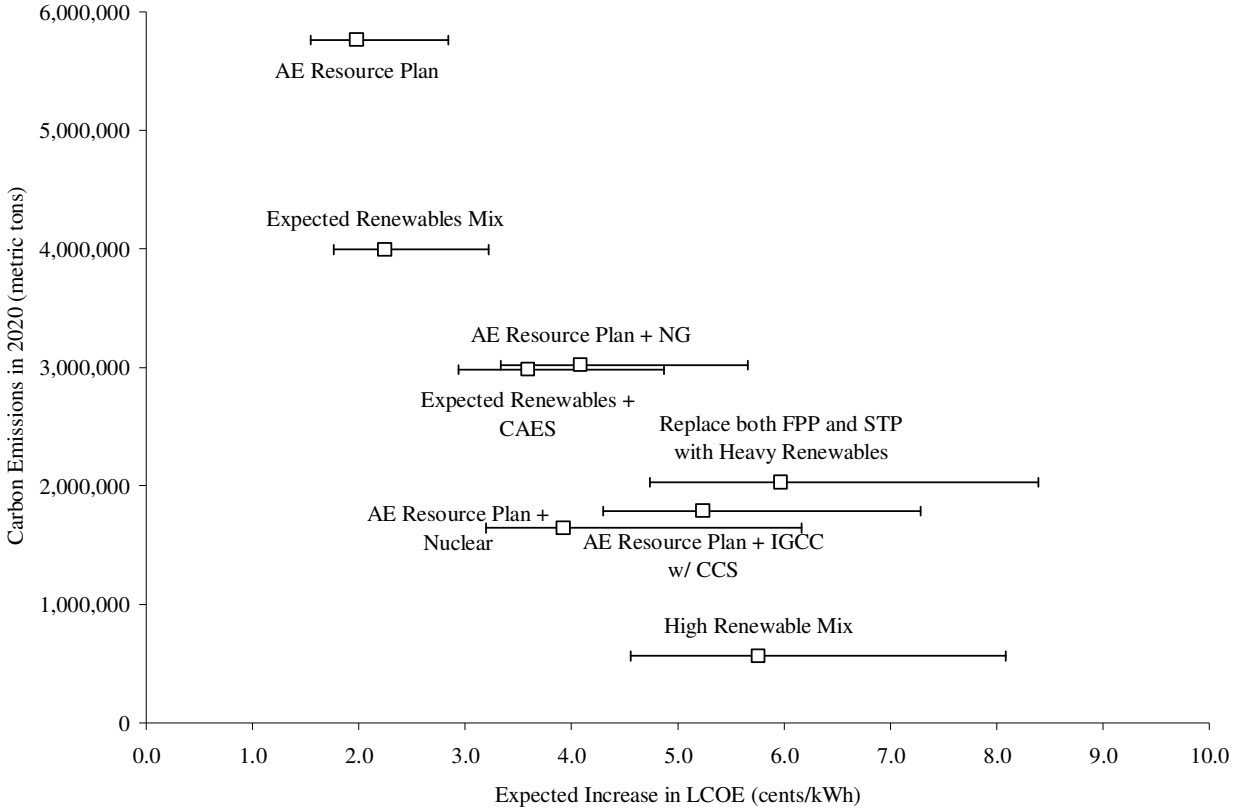


Figure 13.2
Metric Tons of CO_2 Reduced from 2007 Levels by Million Dollars Invested in Capital

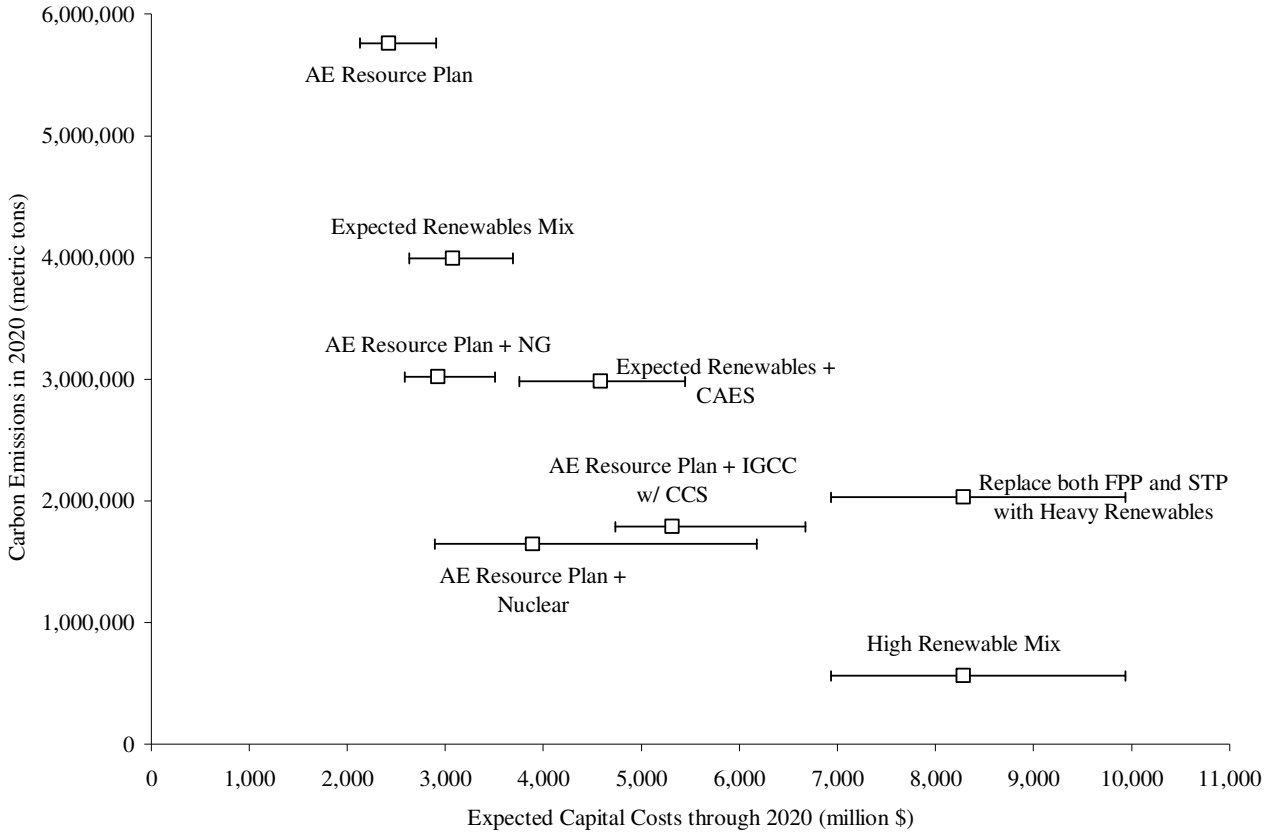
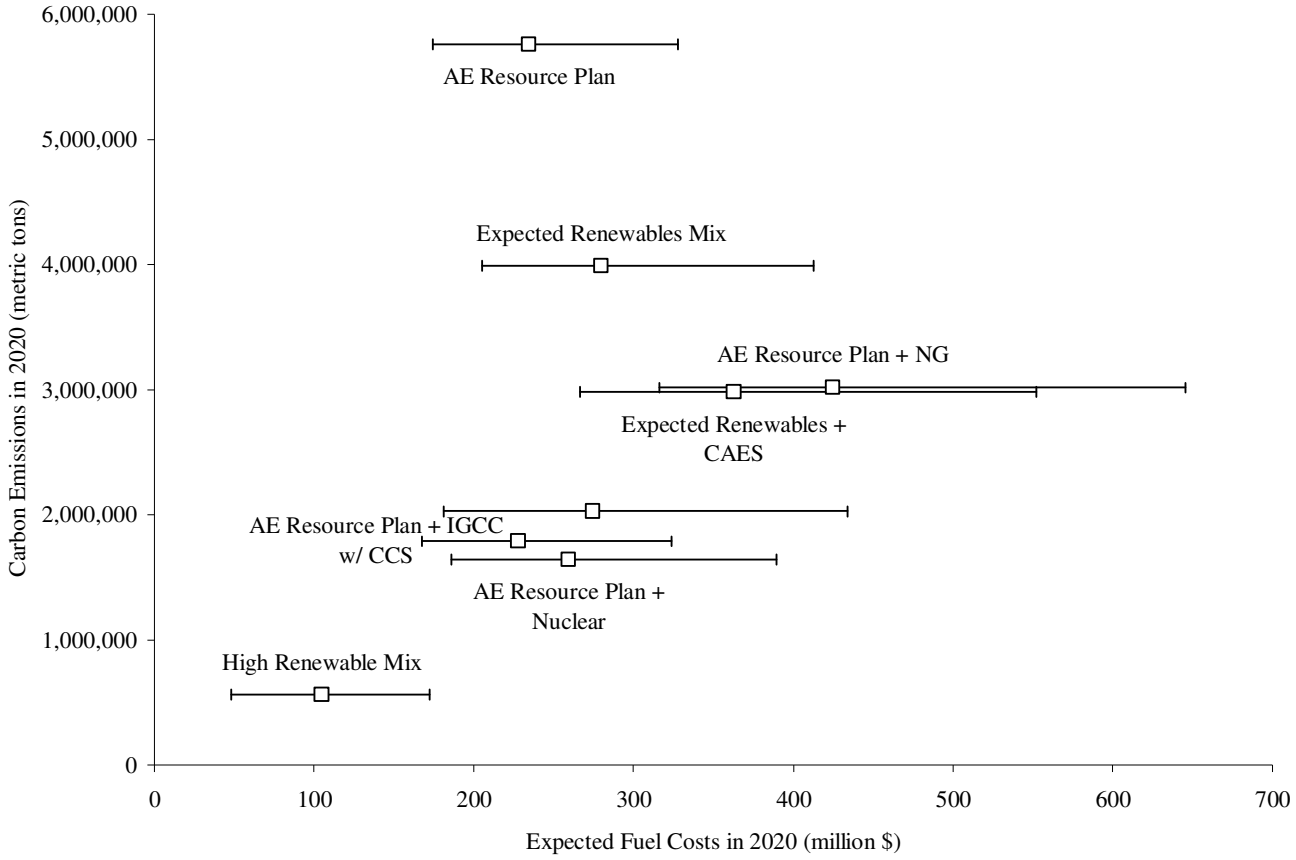


Figure 13.3
Metric Tons of CO_2 Reduced from 2007 Levels by Increase in Fuel Costs



Chapter 14. A Carbon Neutral Austin Energy

The scope of this study is to identify options for Austin Energy (AE) to achieve sustainable power generation with an interim goal of becoming carbon neutral by 2020. This goal presents a challenge as AE currently produces the majority of its power from finite fossil fuel resources. Using cleaner energy sources has many potential environmental and economic benefits. However, these benefits come at considerable costs as cleaner energy sources tend to be more expensive than traditional energy sources. This chapter provides some perspective on what the true benefits and costs of achieving a carbon-neutral utility would be for the City of Austin.

This chapter first discusses the reasons for designing a carbon neutral electric utility. A brief comparison of the costs of reducing carbon for the eight future resource portfolio scenarios evaluated in this report is provided. This is followed by a discussion of the potential challenges and true costs of developing a carbon neutral utility by 2020.

Why Reduce Carbon?

AE has four primary incentives to reduce its carbon footprint: 1) traditional fossil fuel resources that emit CO_2 and other greenhouse gases (GHGs) are finite and thus face supply constraints that can lead to price volatility and uncertainty with availability; 2) carbon regulation at the federal level continues to gain support and could be passed within the next few years; 3) carbon-free energy sources tend to be free of other pollutants and have much less impact on the environment (although solar and wind power generation technologies do tend to require large amounts of land and nuclear energy produces radioactive waste, uses large amounts of water, and faces catastrophic risk concerns); 4) societal preferences for renewable resources are increasing, particularly in Austin, as evidenced by support for the Austin Climate Protection Plan (ACPP) and attitudes recently expressed by stakeholders through AE's public participation process. These incentives are discussed in more detail below.

While the incentives to reduce its carbon footprint are many, AE must be careful in its approach to and timing for reducing CO_2 emissions as carbon regulation has yet to be defined and implemented by the federal government. Such regulation will set a baseline year that will determine the amount of CO_2 emissions by which AE and other electric utilities will have to use in meeting reduction requirements. Therefore, reducing emissions prior to the baseline year may make future reduction requirements more difficult or costly to achieve if the more cost-effective investments available to AE are initially used. If AE were to achieve carbon neutrality, this concern becomes less relevant as a carbon neutral utility, by definition, would achieve the maximum level of reduction possible anyways.

Dependence on Fossil Fuels

From its beginning, the electric utility sector has used finite fossil fuel resources to meet the majority of power generation needs. The exploitation of fossil fuel sources have always carried economic, health, and environmental risks associated with their extraction, processing, transport, combustion, and use. The development of the use of nuclear energy to generate electricity in the 1950s and 1960s provided some relief from the use of fossil fuels, but created a new host of concerns that led to very strict guidelines for building, maintaining, and decommissioning nuclear power plants. Because of the risks associated with these traditional energy sources, electric utilities have constantly had to adapt to regulation regarding the types of resources and technologies used to generate electricity. For example, concerns over the effects of acid rain on the environment led to the regulation of sulfur and nitrous oxide emissions in the 1970's. Although the electric utility sector initially resisted emission reduction regulations, claiming that such regulation would cause the cost of electricity to skyrocket and possibly bankrupt the industry, electric utilities adapted to regulation as scrubber technologies were developed to reduce pollutants.

Chapters 7 and 8 of Volume II of this report discuss concerns regarding coal and natural gas resources. Discussions of future supply concerns and fuel price volatility are included. The following chapter of this report (Chapter 15) discusses future fossil fuel price concerns in more detail. Because fossil fuels are finite resources, the amount and location of supplies influences prices and the political power of different nations. While the electric industry does not use oil at a large scale, oil prices tend to influence coal and especially natural gas prices. As conventional forms of oil and natural gas have declined in availability, advanced drilling methods have been developed to extract unconventional forms of these fuels. These fuels tend to be more expensive. Constrained local supply creates dependence on foreign sources of these fuels which may threaten national security. While local coal supplies appear to be abundant for many more decades and possibly even a few centuries, this is still a finite resource. As such, continued use at current levels is not sustainable. Additionally, the burning of coal releases the highest amount of CO_2 per unit of energy for any fuel type.[1] Thus, coal is the most vulnerable resource in regards to carbon regulation as carbon regulation could influence both the price and use of coal considerably.

Carbon Regulation

It appears that regulation of the emission of GHGs, particularly CO_2, will be the next major regulatory challenge for electric utilities. In the 2006 update to its strategic plan, AE recognized the increasing pressure on the United States (US) to begin regulating carbon. AE recognized that financial markets were beginning to take notice of "future carbon risk." Since 2006, support for carbon regulation by the US federal government has become even stronger as Congress continues to file and consider legislation for regulating carbon. Local and state governments are beginning to take their own actions as demonstrated by the passage of the ACPP by the Austin City Council (Council) in 2007.

Concerns regarding the emission of GHGs are caused by the threat of climate change. Burning fossil fuels emits large quantities of CO_2, the most widely dissipated human-induced GHG. Many scientists agree that human-induced GHG emissions are a cause of global temperature increases.[2] This rise in temperatures, termed global warming, could change the world's climate system and potentially affect the well-being of humans and other species.

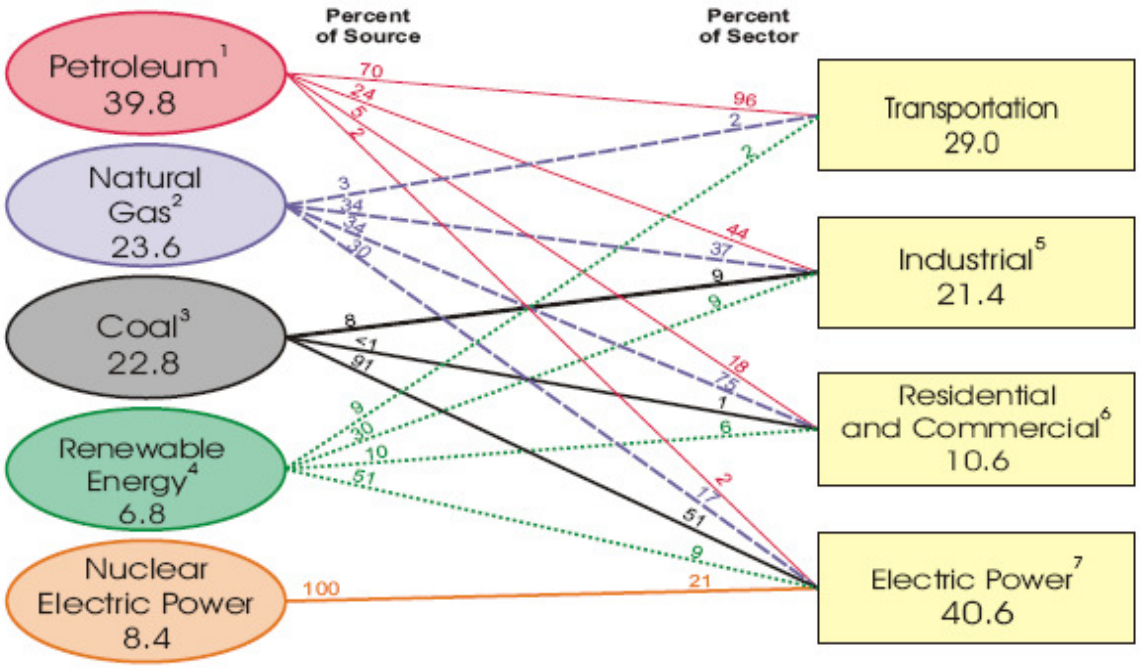
Electricity accounts for 40.6 percent of the energy consumed in the US (see Figure 14.1).[3] The electric sector also accounts for roughly 40 percent of the country's CO_2 emissions.[4] Based upon the legislative bills that have been proposed, it appears likely that electric utilities will be faced with the majority of the responsibility for reducing CO_2 emissions as it is much more difficult to regulate and control emissions from the transport sector. Although it is uncertain if and when carbon regulation will be passed by the federal government, the amount of societal and political support for such regulation has caused electric utilities to begin considering the impact of carbon regulation for future planning.

Carbon regulation would significantly impact future planning for electric utilities, as utilities currently rely heavily on carbon-emitting sources of energy (see Figure 14.1). Seventy percent of the electricity consumed in the US is generated from fossil fuel sources.[5] Carbon regulation could impact the price of fossil fuels for utilities and the cost of electricity for customers. Such regulation could spur energy market shifts that make renewable technologies and new emission reduction technologies more cost-competitive. Charges to emit CO_2 could both stimulate the economy of renewable technologies as a competitive alternative to traditional power generation technologies as well as increase the appeal of nuclear energy and carbon capture and storage technologies. AE and other electric utility providers have already begun to invest in new technologies to generate electricity in a cleaner manner and to increase efficient energy use.

Environmental Benefits

Carbon-free sources of energy tend to also achieve other environmental benefits when used to replace fossil fuels. Energy sources that do not emit CO_2 also do not emit other pollutants such as ash, carbon monoxide, mercury, particulate matter, sulfur and nitrous oxides, and volatile organic compounds. These pollutants can have local, regional, national, and even global negative health and environmental impacts. The extraction of fossil fuels tends to disrupt ecosystems and can be dangerous to the health and safety of workers. Wind and solar resources do not generate hazardous waste nor require the extraction of fuels, the transportation of fuels, or substantial amounts of water to generate electricity. Although wind and solar resources tend to use relatively large amounts of land, dual uses of the land can often be implemented.

Figure 14.1
United States Primary Energy Consumption by Source and Sector, 2007



[1]Does not include 0.6 quadrillion Btu of fuel ethanol, which is included in "Renewable Energy."
[2]Excludes supplemental gaseous fuels.
[3]Includes less than 0.1 quadrillion Btu of coal coke net imports.
[4]Conventional hydroelectric power, geothermal, solar/PV, wind, and biomass.
[5]Includes industrial combined-heat-and-power (CHP) and industrial electricity-only plants.
[6]Includes commercial combined-heat-and-power (CHP) and commercial electricity-only plants.
[7]Electricity-only and combined-heat-and-power (CHP) plants whose primary business is to sell electricity, or electricity and heat, to the public.
Note: Sum of components may not equal 100 percent due to independent rounding.
Sources: Energy Information Administration, *Annual Energy Review 2007*, Tables 1.3, 2.1b-2.1f and 10.3.

Source: Energy Information Administration, *Annual Energy Review 2007*. Online. Available: http://www.eia.doe.gov/emeu/aer/pecss_diagram.html. Accessed: May 11, 2009.

Social Preferences

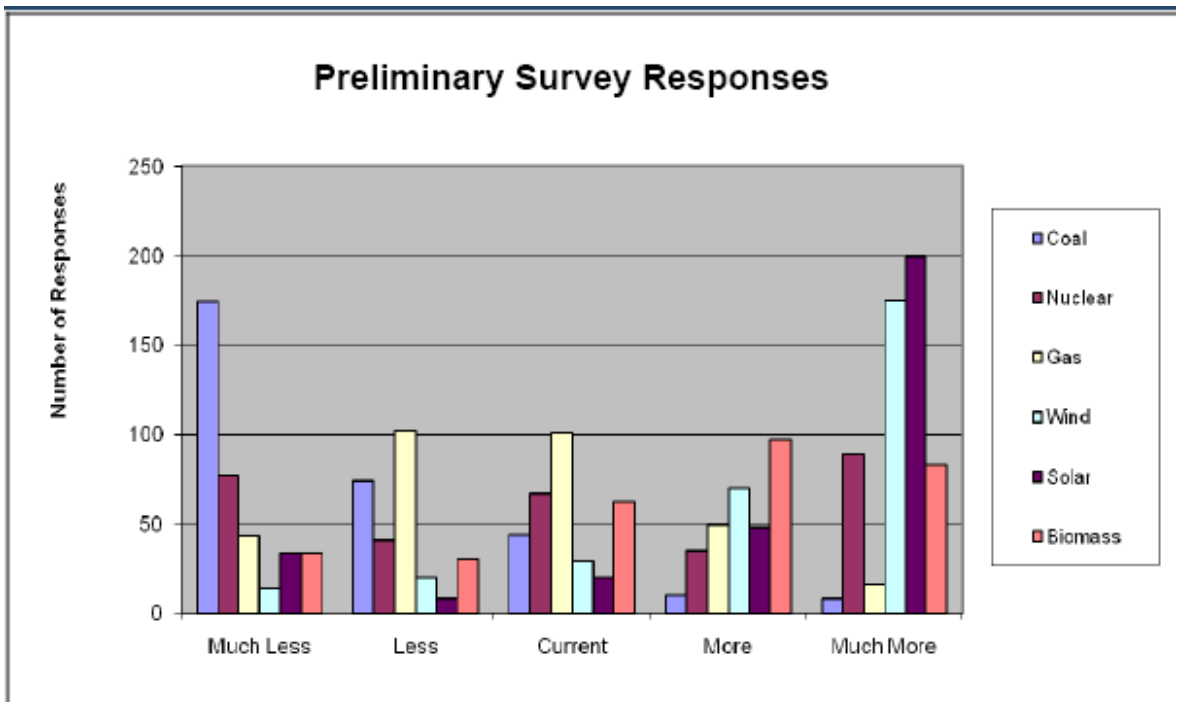
Recent actions by the City of Austin demonstrate local social preferences for reducing the city's carbon footprint and moving towards the usage of cleaner sources of energy. On February 7, 2007, City of Austin Mayor Will Wynn unveiled an ambitious plan for the city to address global warming by reducing GHG emissions. On February 15, 2007, the Council passed a resolution supporting the ACPP and setting the goal of making Austin "the leading city in the nation in the effort to reduce and reverse the negative impacts of global warming."[6] Components of the plan include a municipal plan, a utility plan, a homes and buildings plan, a community plan, and a "go neutral" plan.

The ACPP sets forth specific goals and guidelines for the development of the city's utility plan. Specific deliverables outlined by the plan include:[7]

- Establishing an upper bound on CO_2 and a carbon reduction plan for all utility emissions;
- Achieving carbon neutrality on any new power generation units through lowest-emission technologies, carbon sequestration, and offsets;
- Achieving 700 megawatts (MW) in energy savings through energy efficiency and conservation by 2020; and
- Meeting 30 percent of all energy needs through renewable resources by 2020, including 100 MW of solar power.

Recent data released by AE also indicates the increasing preference by AE customers to use cleaner energy sources. Figure 14.2 shows the preliminary responses from AE customers to polling of preferences of AE stakeholders for the future use of different energy sources. This data indicates that the majority of customers prefer that AE invest in more biomass, solar, and wind resources and use less coal. Preferences for future natural gas and nuclear usage appear to be split.[8]

Figure 14.2
Preliminary Survey Responses for Desired Resource Use of Austin Energy Customers



Source: Presentation by Roger Duncan, General Manager, Austin Energy (AE), *Public Participation and Resource Plan Updates*, Austin City Council, Austin, Texas, April 20, 2009.

The inability to sustain a system based on finite natural resources, the likely passage of carbon regulation in the near future, the collection of environmental benefits of replacing carbon-emitting energy sources with carbon-free sources, and societal preferences for cleaner energy sources all provide incentives for AE to make dramatic changes to its resource portfolio and develop a sustainable, carbon neutral utility.

Costs of Carbon-Neutrality

For the purpose of this report the project team identified the interim goal of AE reaching carbon neutral status by 2020 as a significant step towards becoming a sustainable electric utility. Carbon neutrality has been popularly defined as "making no net release of carbon dioxide to the atmosphere, especially through offsetting emissions by planting trees."[9] This study defined carbon neutrality for an electric utility as reducing CO_2 emissions to the greatest extent possible and then balancing the remaining CO_2 emissions with measurable and reliable CO_2 storage methods or by purchasing offsets.

Comparing Scenarios

Chapter 13 of this report compares eight future resource portfolio scenarios based on a series of performance measures that capture four criteria: system reliability, CO_2 emissions, costs, and risks and uncertainties. These performance measures are used to provide an objective ranking of the eight scenarios. No preference is given to a particular performance measure, as all are weighted equally. However, such decisions cannot realistically be made without making some value judgments. If AE customers are willing to pay a premium for reducing carbon emissions, it may be appropriate to apply greater weight to carbon reduction variables.

Table 14.1 provides several categories for comparison that demonstrate the estimated costs to reach carbon neutrality for each resource portfolio. To determine which scenarios achieve 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 completely 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.

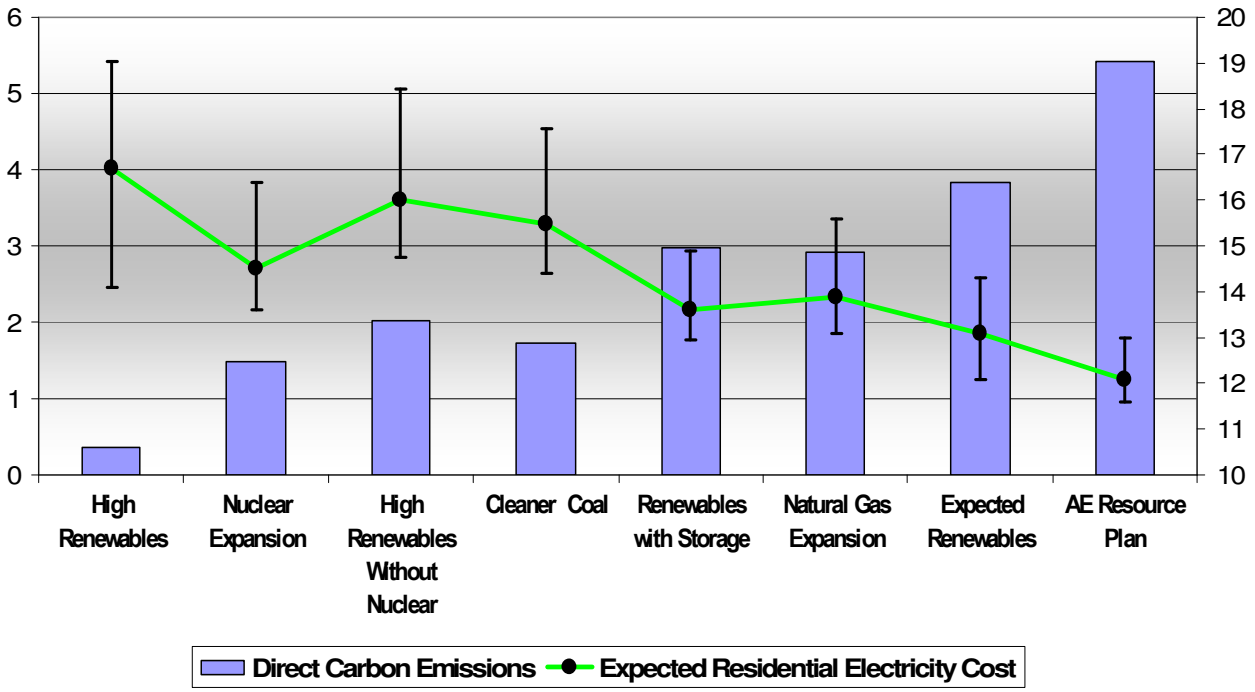
Table 14.1
Costs of Reaching Carbon Neutrality

	Portfolio 2-Nuclear Expansion	Portfolio 3-High Renewables	Portfolio 6-Natural Gas Expansion	Portfolio 5-Renewables with Storage	Portfolio 7-Cleaner Coal	Portfolio 4-Expected Renew-ables	Portfolio 8-High Renewables w/o Nuclear	Portfolio 1- AE Resource Plan
Direct Carbon Emissions (metric tons of CO_2)	1,646,000 (2)	566,000 (1)	3,021,000 (6)	2,984,000 (5)	1,791,000 (3)	3,993,000 (7)	2,031,000 (4)	5,761,000 (8)
Total Expected Capital Costs ($million, through 2020)	3,889 (4)	8,286 (7)	2,925 (2)	4,558 (6)	5,318 (5)	3,076 (3)	8,286 (7)	2,241 (1)
Expected Increase in Levelized Costs of Electricity in 2020 (cents/kWh)	3.9 (4)	5.8 (7)	4.1 (5)	3.6 (3)	5.2 (6)	2.2 (2)	6.0 (8)	2.0 (1)
Metric Tons of CO_2 Reduced from 2007 Levels by Million Dollar Invested in Capital	1140.94 (1)	665.77 (6)	1046.83 (2)	679.85 (4)	807.07 (3)	679.36 (5)	489.02 (7)	143.71 (8)
Metric Tons of CO_2 Reduced from 2007 Levels by Cent per kWh of Expected Rise in Cost of Electricity	1.137,720 (1)	951,129 (2)	746,825 (6)	860,764 (4)	825,382 (5)	949,865 (3)	675,331 (7)	161,029 (8)
Expected Total Costs of Off-setting Carbon to Zero ($ million, through 2020)	1,424 (3)	1,215 (1)	1,339 (2)	1,516 (4)	1,621 (7)	1,611 (6)	1,522 (5)	1,786 (8)
Expected Total Costs or Profits of Allowances ($million, through 2020)	-31 (3)	216 (1)	58 (2)	-163 (4)	-297 (7)	-282 (6)	-168 (5)	-488 (8)
Annual Costs or Profits of Allow-ances ($million)	55 (2)	94 (1)	4 (6)	6 (5)	49 (3)	-31 (7)	41 (4)	-96 (8)
Annual Costs of Offsets ($million)	41 (2)	14 (1)	76 (6)	75 (5)	45 (3)	100 (7)	51 (4)	144 (8)
Cumulative Score and Ranking	22 (1)	27 (2)	37 (3)	40 (4)	42 (5)	46 (6)	51 (7)	58 (8)

Source: Created by project team.

Figure 14.3 is a dual axis bar graph that shows the expected CO_2 emissions for 2020 (left y-axis) for all eight scenarios and the expected average cost of electricity [in cents per kilowatt-hour (kWh)] for residential customers in 2020 (right y-axis). The current residential rate is approximately 10 cents per kWh (9.6 cents per kWh to be exact).[10] This graph shows that increases in carbon reductions correlate with an increase in the cost of electricity. The high renewables scenario achieves the greatest reduction in CO_2 emissions by lowering emissions to about 566,000 metric tons in 2020 (compared to about 6 million metric tons currently, an over 90 percent decrease in emissions). The high renewables scenario is projected to have the greatest expected increase in the cost of electricity compared to the other seven scenarios with residential electric rates increasing by about 65 percent to 16.4 cents per kilowatt-hour. Since the goal of this project is for AE to lower its CO_2 emissions as much as possible and offset the remaining emissions in order to achieve carbon neutral status, the high renewables scenario is used in the context of what the actual costs to achieving carbon neutral status would be.

Figure 14.3
Comparison of Eight Future Resource Portfolio Scenarios



Source: Created by project team.

High Renewables Scenario

The project team's evaluation of the eight future resource portfolio scenarios concluded that the high renewables scenario would achieve the greatest reduction in CO_2 emissions, but would come at the greatest cost to the utility and its customers. However, it should be noted that our projections of the expected increase in the cost of electricity is contingent upon a number of assumptions and limitations. The assumptions and limitations of this analysis are included in Chapter 2 of this report. Several factors could increase or decrease the expected increase in the cost of electricity in 2020.

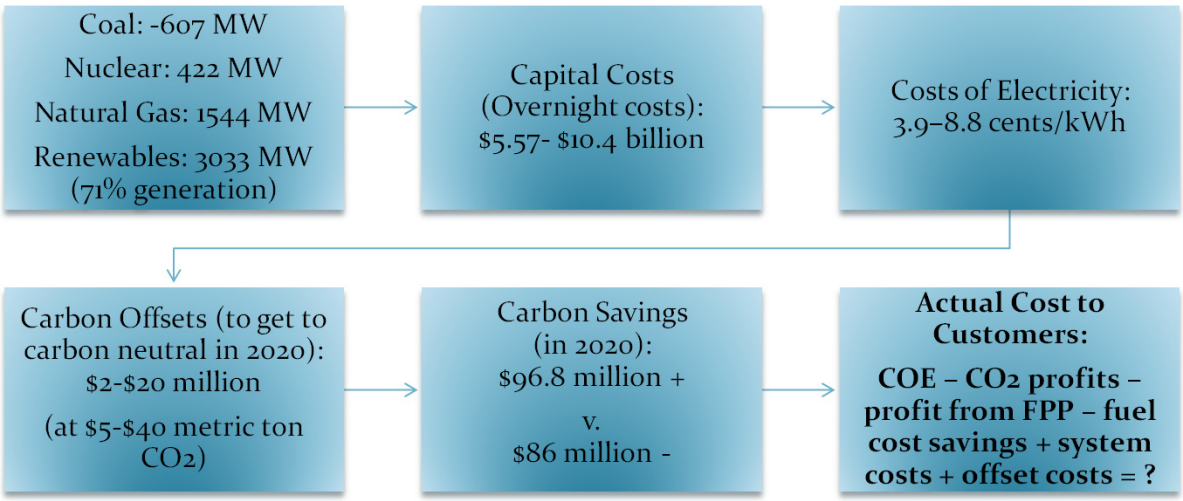
Costs of Electricity

This report calculates the expected increase in the cost of electricity by taking the expected average levelized costs of electricity for investments in new power generation technologies weighted by their expected use and applying the impact of this value based on the proportion of electricity that will be generated by new power generation additions between 2009 and 2020. The levelized costs of electricity is a calculation used by the electric utility sector to evaluate and compare the costs of power generation technologies. Levelized cost is the constant annual cost that is equivalent on a present value basis to the annual costs, which are themselves variable.[11] Components of levelized costs calculations typically include capital and financing, cost of insuring the plant, property taxes, fixed and variable operations and maintenance costs, and fuel costs.[12] These components are included in the California Energy Commission's (CEC) study on levelized costs of different power generation technologies, which was predominantly used in this study. The levelized cost figures used for technologies not evaluated by the CEC were based on various other studies or the model used by the CEC was applied for that technology by the project team. All levelized cost figures used for the evaluation of the eight scenarios are referenced in Chapter 2 of this report. Values used in the CEC study are based upon an assessment of actual power plants built in the State of California between 2001 and 2006 and values obtained from industry for technologies that had not been built during this period in California. Some of the cost components are specific to the government taxing policies of the State of California. Therefore, it is expected that these values would differ from actual costs in Texas based on this factor alone. However, the CEC study and other data used should provide a broad reflection of the comparative costs of different power generation technologies as projections for the costs of producing electricity through the use of these technologies in Texas would likely be similar.

As different technologies vary in efficiency and availability, the levelized costs of electricity calculates the actual cost of electricity produced [in cents per kWh or dollars per megawatt-hour (MWh)]. It is important not to misuse this measurement. The levelized costs of electricity does not account for other resource planning factors such as availability of a power source, impacts on the power system, environmental factors, system diversity issues, and other risk factors.[13] Again, this measurement is intended to provide a general reflection of the comparative costs of power generation technologies. Our calculation of the expected increased cost of electricity does not account for these and several other factors. Figure14.4 shows some of the factors that should be included

to calculate the actual cost of electricity in 2020 for the high renewables scenario. These factors are discussed below.

Figure 14.4
Cost Factors for Actual Cost of Electricity: AE Proposed Resource Plan



Source: Created by project team.

Profit from Fayette Power Project Sale or Lease

In the majority of the scenarios evaluated, all or a portion of AE's ownership in the Fayette Power Project (FPP), AE's lone coal-fired power plant, is sold or leased at some point between 2009 and 2020. In the high renewables scenario, about half of AE's ownership (305 MW) is divested in 2014 and the other half (302 MW) is divested in 2020. It is unclear whether AE would be able to successfully sell or lease its share in FPP and, if so, what the value of this transaction would be. As the demand for electricity is increasing in the State of Texas and coal remains one of the cheapest forms of energy, it appears likely that AE could obtain a substantial value for this facility if current trends continue. It is unclear what these savings would be. FPP has been recognized for being one of the most reliable and cost-effective coal-fired power plants in the world and has received recognition for technological renovation, safety, and performance.[14] The value of this facility is likely to change over the next several years based upon several factors, including whether carbon regulation is passed, the availability and cost of electricity from renewable resources, the price of natural gas, new supply of baseload power sources, and future demand for baseload electricity. While it is uncertain what the value of divestment

in FPP would be at any given time for AE, it would likely lower the expected increased cost of electricity. By how much would be determined by the timing of such divestment and the state of the electric sector in Texas at that time.

Future Cost Projections

For this report, the expected increase in the cost of electricity uses current estimates of the levelized costs of electricity for all power generation technologies considered in this study. The costs of investing in a particular technology do not vary by year of investment. High and low value estimates attempt to account for potential decreases or increases in the costs to generate electricity from these technologies. These estimates are based on technological maturity and published future cost projections for certain technologies. These values, along with references to this data or the rationale used by the project team, are included in the references tab of the simulation software. All outputs produced by the simulation software that include costs show the expected costs with an error bar (low to high range) by year. If one were to assume that costs of a particular investment were to be lower or higher based upon the year of investment, the cost range provided by the error bar provides an indication of what such costs might be. It is expected that traditional power generation technologies will increase in costs as fossil fuel resources become more stressed and increased regulation by the federal government is implemented. Conversely, the costs of alternative technologies, particularly solar technologies, are expected to decrease as investment in these technologies expands and economies of scale are reached. For example, the Department of Energy (DOE) projects that the average costs of producing electricity from solar photovoltaic (PV) technologies will decline to between 11 and 18 cents per kWh by 2010 and 5 to 10 cents per kWh by 2015.[15] A discussion of future cost projections for fossil fuels and renewable energy technologies is included in the following chapter of this report (Chapter 15).

Costs of Carbon Offsets

Carbon offsets are discussed in some detail in Chapter 5 of this report. The high renewables scenario represents the most feasible, albeit unlikely, scenario for maximum investment in renewable resources to replace coal and meet increased demand while maintaining AE's current investment in nuclear and natural gas resources. Heavy reliance on variable sources of energy (wind and solar) requires the use of natural gas as a backup power source that can be turned on quickly when variable resources become unavailable. Therefore, even under the high renewables scenario, AE would not be able to meet its electric generation needs without emitting some CO_2 in the process. While CO_2 emissions are reduced by over 90 percent from current levels, AE would still emit about 566,000 metric tons of CO_2 annually. In order for AE to become carbon neutral, it would need to offset these remaining emissions.

It is uncertain what portion, if any, of offsetting emissions will qualify as an emission reduction under carbon regulation. Therefore, it is important that the cost of offsetting emissions is considered after the impact of carbon regulation costs are accounted for. Under a 100 percent auction market, AE would still have to pay for its remaining CO_2 emissions. Any additional payment for offsetting CO_2 emissions would be an added cost

to AE. Under a partial allowance market, AE would likely not qualify for allowances for offsetting CO_2 emissions. Currently the cost of a carbon offset on the voluntary market varies from about $3-$12 per metric ton of CO_2 offset.[16] The cost of a carbon offset will be influenced by the type of market that exists in the future. Under a regulated market, rather than a voluntary market, the costs of offsets will likely increase.[17]

As the future cost of offsets remains uncertain, lowering actual direct CO_2 emissions reduces the potential future costs AE will have to incur if it chooses to be a carbon neutral utility. AE and the City of Austin must also consider the merits of offsetting the remainder of AE's emissions and ensure that offsets that are purchased are legitimate and verifiable. Eliminating direct CO_2 emissions from AE owned, operated, or purchased power facilities entirely may be unattainable by 2020 given the variable nature of wind and solar resources. Therefore, the legitimacy of achieving carbon neutrality (in the sense of being a truly sustainable utility) by purchasing offsets to account for the remainder of emissions must be considered.

Carbon Costs

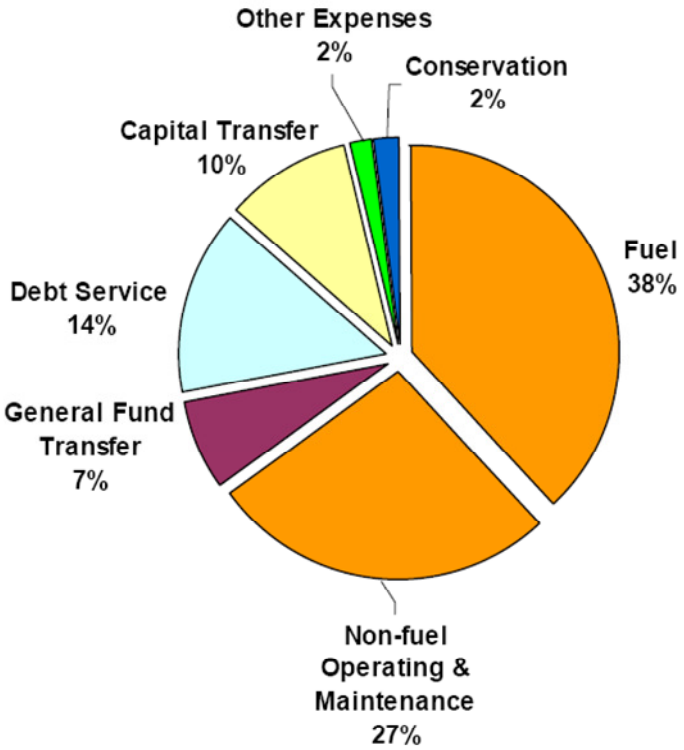
While carbon regulation at the federal level is gaining increased support and momentum, it is uncertain if and when related legislation will be passed. Carbon regulation will dramatically affect the choices that electric utilities make as the costs of various fuels and technologies will likely change in response to such regulation. While agreement on passing some form of regulation is on the rise, contention on the structure of such a system continues to be debated. A multitude of issues must be addressed in comprehensive carbon regulation such as what type of regulatory scheme (cap-and-trade versus carbon tax), who and what to regulate, what to do with money generated from such policy, and setting the baseline year for meeting emission reduction goals. While the majority of the bills that have been proposed by Congress support a cap-and-trade system there has been much debate as to how such a system should be structured. Much of the debate has been whether to provide allowances for emissions, auction off allowances, or design a mixed approach.

For the purposes of this study, the project team calculated the expected costs of carbon based upon the cap-and-trade regulatory scheme proposed by the Lieberman-Warner Climate Stewardship and Innovation Act of 2007. Under the proposed bill, implementation would have begun in 2014 using, as a baseline, 2007 emission levels. A mixed auction-allowance market was proposed with a gradual shift towards an entirely auctioned-based market. The costs of carbon projections used in this report are based upon analysis on the impacts of this bill conducted by the Environmental Protection Agency.[18] If AE were to achieve reductions beyond the goals set by federal regulation, it would receive excess allowances that it could then sell on the open market (the trade mechanism of the cap and trade system). The potential costs or profits created from the carbon market are not included in this study's analysis of the levelized costs of electricity. If AE were able to gain profits from carbon allowances, this could potentially lower the cost of electricity in 2020. However, if AE were to have to pay for carbon permits, this could increase the expected cost of electricity.

System Costs

Figure 14.5 shows the projected Fiscal Year (FY) 2009 operating requirements for AE.[19] Total operating requirements is projected to be roughly $1.38 billion for FY 2009. 38 percent of AE's costs go to fuel. If AE were to dramatically change its resource portfolio, this cost distribution chart would likely change as well. Fuel costs would account for much less of AE's costs, but system costs may rise to account for reliance on less reliable resources. Variable resources (wind and solar) would have to be carefully monitored in order to ensure that backup sources are deployed when these resources do not meet expected levels of availability. Major investments in these resources may also lead to additional transmission and distribution costs. However, the costs of building new transmission lines are shared among all electric utility members of the Electric Reliability Council of Texas electric grid.

Figure 14.5
Operating Requirements for Austin Energy (FY 2009)



Source: AE, *Fiscal Year 2008-09 Proposed Budget*, p. 28. Online. Available: http://www.ci.austin.tx.us/budget/08-09/downloads/August21BriefingsFINALAE_PW.pdf. Accessed: May 15, 2009.

As AE moves toward an advanced electric grid with smart meters and associated technologies, it is unclear what the impacts on operating the system will be. This could lead to cost savings due to better automation and control of the power system or could require more careful monitoring and increased system costs depending on the types of demand-side management (DSM) programs that are adopted in the future by AE. High penetration of distributed power generation sources, particularly solar PV, could lead to revenue erosion and increased system costs for net metering and other associated system costs. As investments are made in higher amounts of renewable energy sources to displace natural gas, this could create some loss on investment in those facilities. This is also a potential concern with replacing coal as the profits that were once made from that plant would evaporate.

Fuel Cost Savings

As 38 percent of the operating requirements for AE are attributed to fuel and fuel costs can vary, fuel cost savings hold external benefits not capture by the levelized costs data. The billing rate structure currently used by AE adds a fuel cost charge to provide the utility flexibility to increase rates when gas, coal, and uranium prices change. Thus, the fuel charge changes much more regularly than the customer and energy charges. Fuel costs are captured in the levelized cost of electricity, but fuel cost savings are not necessarily captured by the expected increase in cost of electricity as this is calculated as a percentage of new generation. When fossil fuel resources are replaced with energy sources that do not require the use of a fuel, additional fuel cost savings may be achieved. Replacing fossil fuels with non-fossil fuel sources provides a hedge against fuel price volatility and decreases the risks posed by fossil fuels.

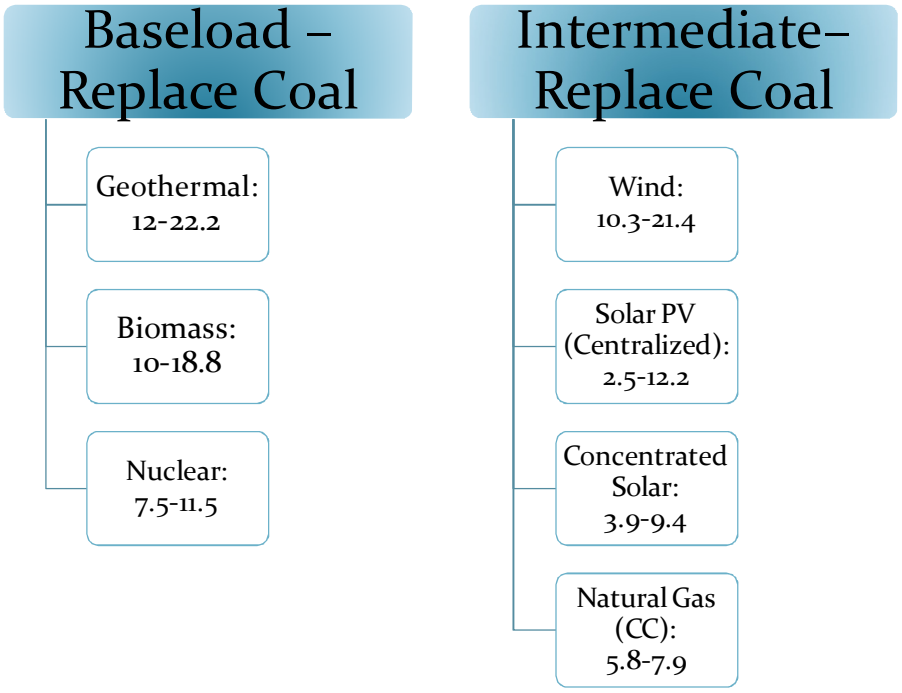
Carbon Return on Investment

As a goal of this report is to evaluate options for reducing CO_2 emissions, evaluating the carbon return on investment (CROI) for different power generation technologies can help AE make future investment decisions. CROI refers to how much CO_2 or CO_2 equivalent emissions are removed from the atmosphere, or emissions avoided, for each dollar spent.[20] AE currently uses the CROI calculation to determine the cost per ton of CO_2 per displaced dollar spent for DSM and renewable energy programs.

A simple version of the CROI calculation is (x-y)/k where x is the current amount of carbon actually being produced from a certain fuel or technology, y is the carbon expected to be produced from a certain fuel or technology, and k is the cost of the energy project.[21] One could also take into account the carbon balance (life-cycle carbon emissions) or distinguish between the marginal cost of the new technology and what it is replacing. For the purposes of this study, a carbon return on investment was conducted based upon the updated cost estimates as noted in the simulation software references tab. For this calculation, the project team took the range of cost of electricity (in dollars per MWh) of seven power generation technologies that could be used to replace coal: geothermal (binary cycle), biomass (wood waste), nuclear, wind, centralized solar PV, concentrated solar thermal, and natural gas (combined cycle unit). This analysis assumes

that each unit of energy produced from the new technology is used to replace one unit of energy of coal. Carbon emission factors for each technology (measured in metrics tons of CO_2 emitted per each MWh of energy produced) are based on the data used in the previous chapter's (Chapter 13) scenario comparison. The difference in CO_2 emissions from the new power generation source to the emission factor of coal used at FPP is divided by the range of costs of the new technology (in dollars per MWh). Figure 14.6 shows the carbon return on investment for these seven power generation technologies based on a range of costs. The lower number demonstrates a low projection for possible costs reductions achieved by 2020. The higher number demonstrates the high projection. These comparisons are divided into baseload generation sources and intermediate/peak sources because these technologies tend to be used differently by the utility.

Figure 14.6
Carbon Return on Investment



Source: Created by project team.

This analysis shows that geothermal has a higher CROI than biomass which has a higher CROI than nuclear. However, the availability of large-scale investments in geothermal and biomass is uncertain. For peak and intermediate sources of energy, wind appears to have the highest CROI followed by centralized PV solar, concentrated solar, and natural gas. While natural gas has the lowest CROI for the high cost projection, it does exhibit the smallest range in potential costs, has a better CROI than solar currently, and is a more

reliable source of energy than solar or wind. The future CROI for solar is highly dependent upon achievements in reaching economies of scale as projected by DOE and other governmental entities. If and when solar reduces it costs, it could have a higher CROI than natural gas so this should be monitored annually.

CROI provides a metric for evaluating the sustainability of different power generation technologies. However, this is only one of many criteria or metrics that can be used to evaluate investments in cleaner sources of energy. Availability of supply, transmission and distribution constraints, risks and uncertainties, and other factors must also be considered. AE is working on a CROI matrix tool that will allow the user to evaluate a group of investments with the goal of reducing carbon.[22] The tool is anticipated to be a spreadsheet-based format with transparent and updateable data sources that would allow the user to perform scenario analysis similar to that conducted in this report. However, this tool will have many more variables included such as CROI, cost factors, supply issues, water and land use, emissions, and other environmental impacts.[23]

Conclusions

There are many factors that must be considered when evaluating the actual costs of achieving carbon neutral status. Future uncertainties facing the electric utility industry, particularly the possibility of future regulation of CO_2 and other GHG emissions makes it difficult for a utility to determine when and how it should act to ensure the best investment decisions are made. Beyond consideration for economic stability, AE also must consider when and how to proceed in making investments to reduce its CO_2 emissions to meet ACPP and internal goals, the demands of the citizens of Austin, and ensure that it maintains a diversified resource portfolio.

Based upon the analysis of the CROI it appears that geothermal and biomass baseload power sources should be given priority to replace coal. However, nuclear energy provides the most reliable and abundant baseload power source to replace fossil fuels from AE's resource portfolio without emitting CO_2. Availability constraints for biomass and geothermal resources may make some investment in nuclear energy necessary to replace all of AE's existing coal-fired power generation capacity with baseload power sources.

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, 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. It will receive 100 MW of power generation capacity from biomass (by 2012) and 30 MW from

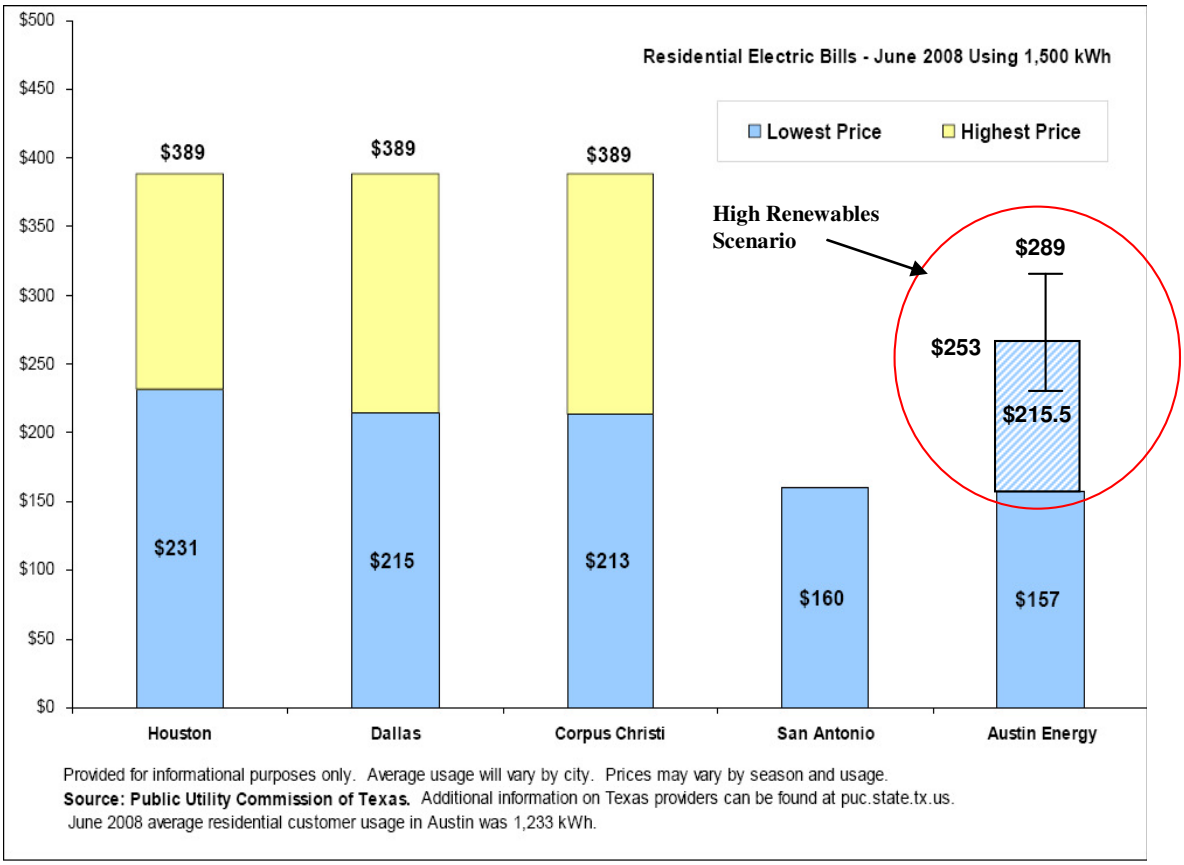
the largest centralized PV solar plant in the US (by 2010). Should AE become an initial adopter of other immature technologies such as utility-scale energy storage, carbon capture and storage, off-shore wind, and geothermal in Texas? An early adopter may take advantage of lower contract costs from vendors eager to establish utility-scale performance. Unfortunately, those same vendors may face delays in construction or demand compensation for cost over-runs if the developing technology does not meet advertised performance measures. 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.

Recommendations

Austin citizens ought to consider the balances of risks and costs of nuclear expansion as a sustainable resource relative to a zero carbon footprint. As a part of AE's public participation process for its proposed resource plan, stakeholders were asked to determine whether they felt more or less of a particular resource should be used by AE. The preliminary responses from this survey are shown in Figure 14.2. For nuclear energy, opinions were split. This indicates that it may be beneficial for AE to provide additional information on the advantages and disadvantages or nuclear energy and re-evaluate the opinions of citizens thereafter.

Austin citizens ought to consider what costs they are willing to accept if AE were to invest in large amounts of renewable resources. The evaluation of the high renewables scenario demonstrates that AE could move towards a resource portfolio that meets over 70 percent of AE's power generation needs and reduces CO_2 emissions by 90 percent by increasing electric bills by somewhere between 4 and 9 cents per kWh of electricity used (with an expected 65 percent increase in electric bills). Figure 14.7 demonstrates that relative to electric costs in some other major cities in Texas, such as Dallas and Houston, this rise in electric costs would make electric bills comparable to current rates in those cities (which are likely to increase by 2020). Because AE has kept electric rates relatively low, it is capable of making dramatic changes to its resource portfolio in an effort to reduce CO_2 emissions while staying competitive with other electric rates in Texas. Continued evaluation of social preferences for technologies that can achieve carbon reductions should be conducted by AE as social preferences for energy usage change.

Figure 14.7
Residential Bills in Texas



Source: Adapted from: AE, *Fiscal Year 2008-09 Proposed Budget*, p. 27. Online. Available: http://www.ci.austin.tx.us/budget/08-09/downloads/August21BriefingsFINALAE_PW.pdf. Accessed: May 15, 2009.

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Chapter 15. Future Uncertainties

Austin Energy (AE) must carefully evaluate future investment decisions as well as the continued use of current power generation resources, as many future uncertainties exist in the electric utility industry. Electric utilities must consider many factors when planning for the future, including: 1) reliability, costs, risks, and uncertainties for different fuels and power generation technologies; 2) system diversification; 3) regulation from local, state, and federal authorities; 4) environmental concerns; and 5) other social concerns. The electric utility sector is arguably facing greater uncertainty than ever before. Uncertainties make strategic planning for utilities difficult. Predicting the impacts that different investments will have on a utility's economic stability, its electric rates, and system reliability is a challenging task. The primary uncertainties facing the electric industry today, which are inter-related, are future costs of producing electricity for all fuels and technologies and the implementation of carbon and other environmental regulations by the federal government.

The simulation software developed by the project team is limited in its capabilities to fully evaluate future resource investments due to these risks and uncertainties. It is important for the reader of this report to evaluate future scenarios within the context of the assumptions and limitations identified in this report. Chapter 2 of this volume of the report discusses the methodology used by the project team to evaluate future resource portfolio scenarios for AE. The project team chose to assume that no changes in regulation or costs to produce electricity from different power generation technologies would occur in its "expected" cost estimates. Risks and uncertainties are recognized as possibilities rather than absolutes and are accounted for by using potential future cost ranges and separate potential cost evaluations. In this study, a range is provided for all outputs that consider costs to the utility and its customers. Measures of the impacts of carbon regulation for a given resource portfolio scenario are provided as separate outputs.

Future uncertainties facing AE and the electric utility sector are discussed in this chapter. This discussion is intended to assist the reader in determining his or her interpretation of the impacts of different resource portfolio scenarios identified by this report. This chapter discusses local, state, and federal regulatory uncertainty including carbon regulation, demand projections, nuclear risks and uncertainties, fossil fuel prices, renewable technology costs, reliance on variable resources, and the potential impacts of distributed generation and electric vehicles.

Federal Energy and Carbon Regulation

The United States (US) government influences energy policies in several ways, including providing incentives through tax cuts, rebates, and credits, imposing punishments through fines, taxes, and regulatory standards, using market mechanisms such as taxes and cap-and-trade markets to regulate emissions, restricting access to certain resources, and imposing environmental constraints. Policies set by the federal government tend to

influence the types of power generation technologies that electric utilities invest in. Many federal agencies impact the electric utility industry including the Department of Energy, the Federal Energy Regulatory Commission (FERC), the Department of Interior, and many others. The President and the US Congress, as well as state and local governments, can also develop energy policies that affect electric utilities. In Texas, the Public Utility Commission of Texas (PUCT) and the Electric Reliability Council of Texas (ERCOT), have direct influence over electric grid, industry, and energy market policies.

It appears that regulation of the emission of greenhouse gases (GHGs), particularly carbon dioxide (CO_2), in response to concern of the potential impacts of climate change, will be the next major regulatory challenge for electric utilities. The degree of scientific certainty that climate change is occurring, is human-induced, and will have significant impacts on human populations has reached a level that signals domestic action should be taken soon to advert the most drastic consequences. In 2007, the Intergovernmental Panel on Climate Change released their fourth assessment report on climate change stating that, "warming of the climate change system is unequivocal, as is now evident from observations of increases in global average air and ocean temperatures, widespread melting of snow and ice and rising global average sea levels."[1] The potential costs of the impacts of climate change appear to provide economic incentives to take action. The Stern Review on the Economics of Climate Change, released in 2006, concluded that the benefits of strong, early action on climate change outweigh the costs.[2]

While debate on the merits of scientific evidence of climate change and its potential costs and effects continues to persist in the US, contentions that concerns are unwarranted appear to be waning as public support for a national climate change policy strengthens. In May 2008, a poll commissioned by the non-partisan Presidential Climate Action Project and conducted by Harris Interactive found that 66 percent of Americans believed that the next president of the US should have a policy that addresses climate change.[3] Public support for actions on climate change, the change in presidential administrations to one favorable of such measures,[4] the increasing number of local and state climate change actions,[5] and the increasing number of climate change-related bills proposed at the federal level all demonstrate the high likelihood that the US Congress will pass and implement a comprehensive climate change policy during the next few years.

In the 109th Congress (2005-2006), 12 bills were proposed for mandatory climate regulation and during the 110th Congress (2007-2008), 15 bills were proposed related to reducing GHG emissions (considered the primary human-induced contribution to climate change).[6] Thirteen of these 15 bills proposed some form of a cap and trade system for reducing GHG emissions while the other two bills proposed a tax on emissions.[7] This follows concerns over the political unattractiveness of a carbon tax despite assertions that a tax provides a stronger market mechanism to reduce GHG emissions.[8] In 2008, the Council on Foreign Relations released a report conducted by an independent task force assigned to look at US policy on climate change. The task force acknowledged the potential major impacts that unabated climate change will have on human welfare, ecosystem stability, and national security and recommended that US policymakers

support a cap and trade system to reduce emissions significantly from 1990 levels by 2050.[9]

Although the financial crisis and subsequent economic recession has created some concern that carbon regulation will be difficult to pass in the near future, recent legislation received considerable attention and momentum in the US Congress. The Waxman-Markey bill entitled "The American Clean Energy and Security Act of 2009" was a comprehensive energy regulation bill that included the promotion of various types of "clean energy" as defined by the bill, the promotion of energy efficiency, regulation of GHGs, and mechanisms to ease the transition for industry and customers to a clean energy economy.[10] The initial draft version of the bill set a renewable portfolio standard for all retail electricity providers requiring 6 percent of electricity generated to come from renewable resources by 2012 and 25 percent of electricity generated to come from renewable resources by 2025.[11] AE currently projects it will generate at least 30 percent of its electricity from renewable resources by 2020.[12] Incentives are also included for carbon capture and sequestration deployment, clean vehicle technologies, and modernization of the electric grid. Energy efficiency standards and incentives are included for buildings, manufactured homes, appliances, transportation, and the industrial and utility sectors.

New energy efficiency resource standards would be established for electric utilities that would not likely affect AE as AE has already set relatively ambitious demand-side management (DSM) goals to be met by 2020. The bill would create several mechanisms to ease the transition to a clean energy market including programs to create green jobs, ensuring domestic competitiveness by providing rebates to sectors affected by climate change regulation, and consumer assistance. Of most importance to AE, this bill would establish a cap and trade regulatory market, called the "global warming pollution reduction program."[13] Electric utilities such as AE would be covered by this program and would have to gradually reduce their emissions in relation to 2005 baseline levels. Emissions would have to be reduced by 20 percent by 2020 from 2005 levels.[14] Several mechanisms would be implemented to allow oversight of the program by the federal government and ensure that the "price on carbon" remained manageable for covered entities. Under the discussion draft bill offsets could be counted towards emissions above allowed amounts for a given year.[15]

A key issue that is left unresolved in the discussion draft of this bill is how to allocate the tradable emissions allowances. This discussion is being addressed by the Energy and Commerce Committee of the US House of Representatives. The issue of an allowance versus an auction market (or a combined approach) has been widely debated, predominantly because the European Union's Emissions Trading Scheme faced much difficulty controlling the allowance market it created for participating countries. The design of the allocation of allowances will influence the cost to AE for emitting CO_2 emissions. Under a 100 percent allowance market, AE would have to purchase allowances for all of its emissions. If a full or partial auction market is designed, AE could potentially gain profits from emission reductions by selling excess allowances. Under either system, AE would achieve annual financial savings by reducing CO_2

emissions. How much these savings would be is uncertain. The simulation software uses projections of the cost of carbon by year based upon the Lieberman-Warner Climate Stewardship and Innovation Act of 2007.[16] While this bill was not structured identical to the Waxman-Markey bill, it does provide a general representation of the potential impact of carbon costs on AE. How carbon regulation will affect the cost of different power generation technologies and fossil fuel prices is uncertain. These potential external impacts are not reflected in the analysis of the eight future resource portfolio scenarios provided in this report. Carbon regulation will likely have a major impact on AE's future ability to provide low-cost electricity. AE must consider these issues when making investment decisions today as it takes several years for new technologies to come online and those technologies may need to operate for decades before the utility receives a return on its investment. Carbon regulation could also make divestment in current power generation technologies operated and/or owned by AE attractive. However, if AE waits until carbon regulation is imposed the value of some fossil-fueled technologies may decrease.

State and Local Regulation

Electric utilities such as AE cannot act entirely as an independent organization. Electric utilities are heavily regulated by all levels of government due to the necessity of the services they provide and the interconnectedness among electric utilities through the electric grid. However, relative to other electric utilities AE is given much independence in its operational decision-making. As a public utility, the Austin City Council and AE customers have direct influence on the utility's policies and decision-making process. Texas is also the only state that has its own electric grid, allowing it to operate nearly entirely independent of FERC and other regional electric grids.[17]

In 2001 the State of Texas deregulated the electric utility sector. Municipal utilities in Texas were given an option of whether or not to opt into the deregulated market. As of 2009, AE and all other 73 public utilities in Texas have not opted into deregulation,[18] but the City of Austin could decide to do so at any time or deregulation could be imposed by the Texas Legislature. Amidst this environment, AE has developed a competitive strategy aimed at keeping rates low by reducing operating costs, paying down debt, and paying cash for new sources of generation, when possible.

Both the PUCT and ERCOT have some regulatory authority over AE's facilities and activities. The PUC regulates all electric utilities in Texas, provides oversight to ERCOT, and adopts and enforces rules related to retail electric competition. PUC has jurisdiction over rates and quality of service of transmission and distribution utilities, sets wholesale transmission rates, and oversees wholesale and retail competitive markets. As a municipally-owned utility, AE is not subject to the PUCT's retail rate and service quality jurisdiction, but is subject to wholesale transmission rate jurisdiction and wholesale power generation market oversight. Austin City Council sets the budget and electric rates for AE.

ERCOT operates the electric grid in Texas that serves about 75 percent of the state, overseeing 70,000 megawatts (MW) of power generation capacity and 37,000 miles of transmission lines that make up the statewide electric grid.[19] As a member of ERCOT, AE pays 4 percent of ERCOT's costs to operate the state's power grid, as it represents 4 percent of the statewide power generation load.[20] ERCOT also facilitates the operation of the retail competitive market by managing transmission congestion and ensuring all power generators have equal access to the electric grid. Although AE does not participate in retail deregulation, it does participate in the ERCOT wholesale market. AE conducts the following types of transactions with ERCOT: sale of electricity; purchase of electricity; sale of ancillary services (e.g. reserve capacity, load following and frequency control); submission of transactions negotiated with other entities for approval; and ERCOT-required transactions, when necessary, to maintain system reliability or to relieve transmission congestion.[21]

In September 2003, the PUCT ordered ERCOT to transition from a zonal to a nodal market.[22] The purpose of the switch is to improve price signals, improve dispatch efficiency, and assign congestion costs to market participants responsible for the congestion.[23] Although the transition was originally scheduled for completion in December 2008, ERCOT announced in May 2008 that it would not meet the target date.[24] ERCOT now hopes to complete transition to the nodal market by December 2010. The nodal market grid is expected to consist of more than 4,000 nodes, replacing the current congestion management zones of the zonal market.[25] Although the nodal market will not affect all of ERCOT's current processes and systems, the following major components will be added: day-ahead markets; reliability unit commitment; real-time or security constrained economic dispatch; and congestion revenue rights.[26] Day-ahead markets will provide a centralized market for parties to conduct power transactions for delivery the next day.[27] Reliability unit commitment is a system that can be used to ensure that sufficient power generation capacity is being provided, while also leveraging offline resources to relieve load and transmission congestion.[28] Security constrained economic dispatch will be used to determine economical load dispatch across the grid by calculating actual shift factors.[29] A congestion revenue right is a financial instrument that ERCOT will be auctioning monthly and annually, where revenues will be returned to loads.[30]

The switch to a nodal market will affect AE's future resource planning, even though only 5 to 10 percent of AE's power sources are currently traded through the ERCOT market.[31] Under the nodal market, all power will be bid into and purchased out of the market. Under the zonal market, AE contracts to buy or sell power from other parties through bilateral contracts. With the switch to the nodal market, these bilateral true supply contracts will become ERCOT instruments that provide guaranteed prices.[32] Besides a significant change in the way power transactions are completed, AE will have to ensure their infrastructure is able to perform in the nodal market.[33] Another consideration relevant to the scope of this report is that the nodal market is based on the operating idea of reliability and cost, rather than environmental responsibility. Thus, the nodal market could impact the way in which AE's renewable resources are used.

Demand Projections

One of the many challenges for an electric utility is accurately projecting demand, or load. Accurate projections of demand are necessary for short-term, mid-term, and long-term operational planning. The use of electricity by end-users is not constant. Rather, it fluctuates given a household, building, or industry's changing needs. Demand fluctuates based upon the time of day, the season, and weather fluctuations. Electric utilities use historical demand, weather projections, and future projections of growth to estimate future demand for electricity. Miscalculating short-term demand can lead to power system failures or buying power off of the grid that can cost utilities thousands to millions of dollars. Miscalculating future demand in the long term can mislead utilities into making unnecessary investments in new power generation sources or not making the necessary investments to meet future electric demand from internal sources. Investments in new power generation sources can cost millions to billions of dollars and thus should be carefully evaluated based on future demand projections. Since new power plants and electric generation units can take several years to site, build, and begin operation, investment decisions must be made several years in advance of demand needs. For these reasons, electric utilities such as AE invest in sophisticated demand forecasting software that allows the utility to make informed investment decisions several years into the future.

Chapter 5 of Volume II of this report discusses load forecasting and details AE's 2008 load forecast. AE's load forecasting technique relies on a multitude of variables that allow it to project demand up to the hour through 2020. Of course, the further out these projections go, the less reliable they will be. Nonetheless, these demand forecasting techniques have proven reliable in the past. Expected economic and population growth in the AE service area is accounted for as well as expected technological advances in energy efficiency and appliances and improvements to building codes, among other factors. DSM projections play an uncertain, but vital role for electric utilities such as AE that make significant investments in such programs. Chapter 3 of Volume II of this report discusses the concept of DSM, AE's current DSM programs, and identifies future opportunities for energy demand savings. AE achieved on the order of 800 MW of energy demand savings between 1982 and 2008, a period of 26 years.[34] AE has a goal set by the Austin Climate Protection Plan to achieve 700 MW of peak demand savings by 2020. This is an ambitious goal that is premised on AE's previous achievements in DSM savings. AE believes that with expected advancements in the efficiency of various household technologies that use electricity, the opportunities associated with an advanced metering infrastructure, and the projected implementation of stricter building standards it can meet and possibly even exceed these goals. In FY 2008, AE reduced its peak demand by 64.1 MW; 25.3 MW through residential programs, 19.7 MW through commercial programs, and 19.2 MW through its Green Building Program.[35] This met AE's expectations. Continuing this pace of energy demand savings would allow AE to achieve the 700 MW goal.

While AE's previous achievements in energy demand savings demonstrate their commitment and ability to successfully implement energy efficiency and conservation

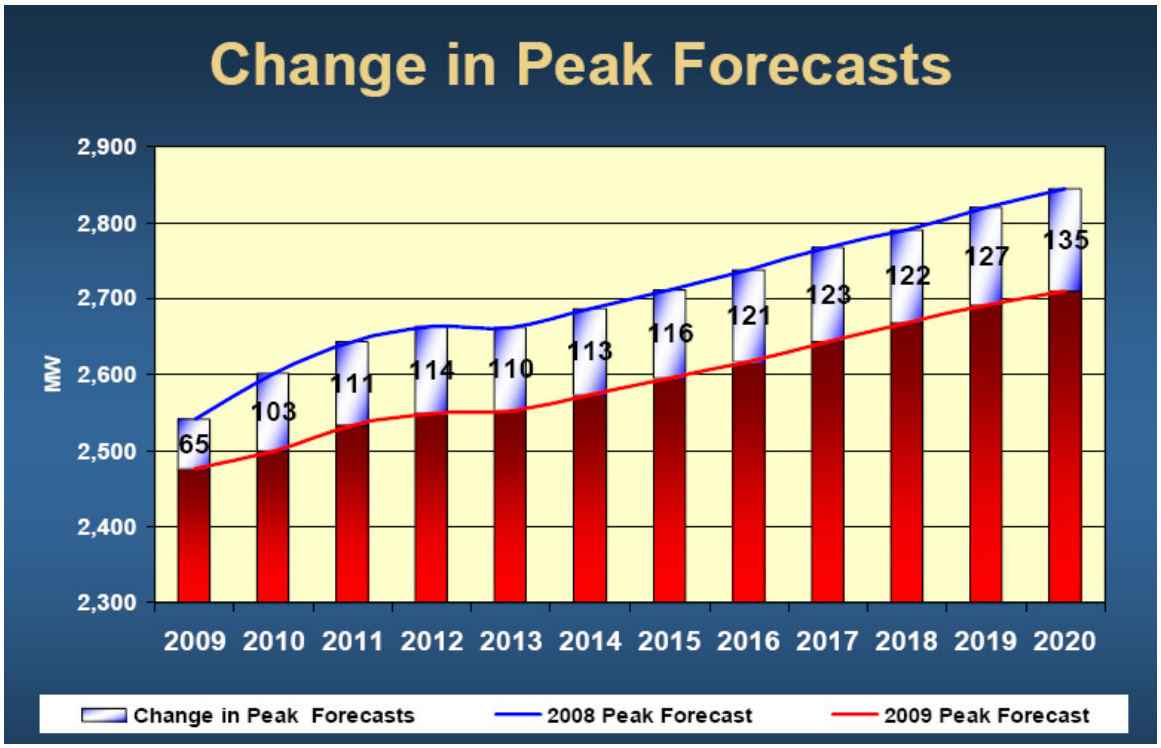
programs, AE will likely need to make some dramatic changes to achieve the 700 MW goal. Analysis conducted in Chapter 3 of Volume II of this report demonstrates that demand response and load shifting programs, particularly altering billing mechanisms to more accurately reflect the value of electricity at a given point during the day, could create significant demand reductions. Many of these programs are also premised on the willingness of customers to make investments that improve the efficiency of their energy use and adopt other technologies and programs that reduce demand. Disseminating the appropriate information to customers on the cost savings that can be achieved by reducing demand is vital for the success of these programs. The project team concluded that AE's single best electric sector investment continues to be in conservation, peak shifting, and reducing peak demand. AE uses its last 100 MW of peak resources only 43 hours per year.[36] It is uncertain if AE can significantly exceed its goals for demand savings by 2020, but efforts should not halt at meeting this goal. One of AE's top priorities should remain to lower peak demand as much as possible. Chapter 11 of this report discusses the theoretical potential for achieving further demand reductions and the impacts that further reductions could have.

The analysis of the eight future resource portfolios in this study assumes that AE will be able to achieve its goal of 700 MW of demand savings and that forecasted demand aligns with its projections. However, this analysis is based upon AE's 2008 load forecast. As a demonstration of the unpredictability of future demand, AE's 2009 load forecast predicted significantly lower demand through 2020. This was based upon the expected short and long-term impacts of the current economic recession. Figure 15.1 shows AE's load forecast for 2009 compared to its 2008 load forecast. Expected demand between the 2008 and 2009 load forecasts dropped by 65 MW for 2009 and 135 MW for 2020.[37] AE updates their load forecast yearly and its strategic planning team constantly monitors trends in the electric utility industry that can impact future demand and create other planning challenges. The simulation software used in this study has since been updated with the 2009 load forecast. Future analysis should be updated annually based upon AE's most recent load forecast and investment decisions should be carefully monitored and re-evaluated as new projections of demand are made.

Dependence on Economy

The change in AE's load forecast in response to the economic recession demonstrates that future electric demand is highly dependent on the condition of the local, state, and national economies. While electricity is characterized as an inelastic good, economic growth is a strong indicator of the rate by which electric demand increases, if at all. As the utility makes investment decisions that take several years and even decades to earn returns, it must be careful not to over-invest in new energy sources. Over-investing can lead to lost revenues and negative impacts on AE's credit rating. An economic collapse could have significant repercussions on electric utilities as their revenues are dependent upon consumer use of electricity.

Figure 15.1
Austin Energy 2009 Load Forecast



Source: Presentation by Roger Duncan, General Manager, Austin Energy, *Public Participation and Resource Plan Updates*, Austin City Council, Austin, Texas, April 20, 2009.

Future of Nuclear Power

The primary driver of renewed interest in nuclear energy comes from the resource's ability to reliably generate electricity without directly emitting CO_2. While renewable resources such as wind and solar may be more desirable from an environmental standard, the variable nature of those resources creates reliability concerns. The Energy Policy Act of 2005 created production incentives for the first 6,000 MW of new nuclear units in the form of production tax credits and federal loan guarantees.[38] Public acceptance of nuclear capacity expansion is now at an all-time high and concerns over the risks associated with nuclear power continue to decline. New reactor designs have proven successful internationally and reduce the risks of reactor failures.

The potential for expansion of nuclear power plants in Texas and the US is promising. The Nuclear Regulatory Commission is currently processing applications for 32 new nuclear reactors at 21 sites across the country.[39] Eight of these proposed new reactor units are located at the following four sites in Texas: an evolutionary power reactor near Amarillo; an advanced pressurized-water reactor near Glen Rose; a boiling-water reactor

in Victoria County; and the addition of two units of advanced boiling-water reactors at the South Texas Project (STP).[40] The City of Austin has elected not to invest in the two new reactors being built at STP based upon recommendations from AE. The Council cited the following reasons for not investing in this project: the risk of overly optimistic projected costs; permitting and construction schedules; and inherent uncertainties and risks.[41] The additional security and environmental risks associated with hazardous waste generated from nuclear energy were left unstated.

AE's formal recommendation that the City of Austin not participate in the STP expansion proposal was given in February 2008. In November 2008, NRG Energy, the lead partner in the project, submitted revised and additional information to AE. In December 2008, AE approved a $241,000 contract with a consulting firm, Worley Parsons, to analyze the proposal. On February 12, 2009, the Austin City Council voted to decline participation in the expansion of the STP as currently proposed.[42] A detailed financial analysis and risk assessment completed by Worley Parsons concluded that the potential return to the City of Austin would not outweigh the potential risks of the expansion project and its $2 billion price tag to the city.[43] The consulting firm argued that the total estimated project cost of $6 billion could potentially exceed $10 billion, reflecting STP's history of construction cost over-runs in the past.[44] During the 1970s, STP's initial two reactors were estimated to cost close to $1 billion and ended up beginning operation more than five years late at a cost of $5 billion over the initial estimate.[45] Another council concern was that the $2 billion price tag could potentially have a negative effect on AE's credit rating, thereby affecting the utility's ability to invest in other energy projects.[46]

As demonstrated by this example, the greatest uncertainty facing the nuclear power industry will be the actual cost to construct new nuclear units. The nuclear power industry has a storied history of drastically underestimating capital costs. Cost overruns have averaged about 207 percent.[47] Capital cost projections for nuclear projects have more than doubled over the past five years as new projects have conducted more accurate assessments. The Congressional Research Service conducted an evaluation of all recent cost estimates and found the average total overnight cost projection (which assumes that the plant could be built overnight) to be $3,900 per kilowatt (kW) of power generation capacity.[48] This compares to about $1,500 per kW for a new traditional coal plant. Capital costs for nuclear energy are a major component of the actual cost of electricity to customers. With such high levels of uncertainty with capital costs, estimates of the levelized costs of electricity from nuclear power ranges from 4 cents to 30 cents per kW-hour (kWh).[49] The current cost of electricity to residential customers ranges from 8-20 cents per kWh depending on the location in the US.

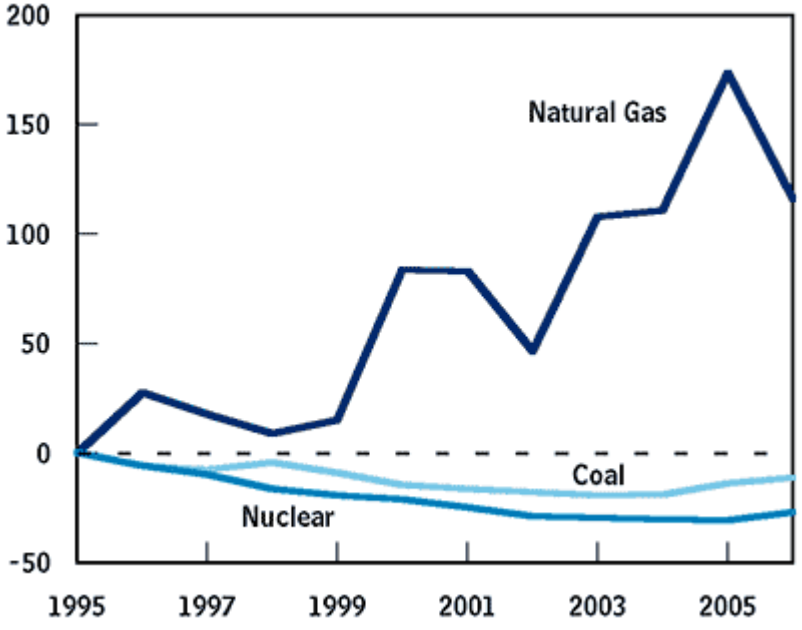
The debate for expanding the use of nuclear power essentially rests on the merits of nuclear energy as a carbon-free resource and whether society is willing to accept the cost risks and other uncertainties associated with nuclear power. The advantages of nuclear energy are many, but so are its disadvantages. It appears likely that new nuclear units will inevitably be constructed and come online over the next decade. Whether the number of units will exceed the number of units that will be de-commissioned is dependent upon whether the federal government passes carbon regulation. Public acceptance of renewed

nuclear power investment is on the rise, but future catastrophic incidents and high costs could influence those opinions.

Fossil Fuel Prices

One of the greatest concerns facing electric utilities is the future price of fossil fuels, primarily natural gas and coal. The price of oil is also important for electric utilities to monitor as it tends to correlate with other fossil fuel prices. Figure 15.2 shows historical price volatility for natural gas, coal, and uranium. Fuel costs currently constitute 38 percent of AE's operating requirements.[50] From Fiscal Year (FY) 2007 to FY 2009 system annual average fuel costs increased from 2.912 to 3.655 cents per kWh.[51] This reflected an increase in natural gas prices and higher rail transportation costs to transport coal from Wyoming to the Fayette Power Project. Natural gas prices have historically exhibited price volatility with prices fluctuating between 3 and 12 dollars per million British thermal unit between 2002 and 2008.[52] This uncertainty has caused many electric utilities, including AE, to hedge future natural gas prices by locking into long-term contracts. Coal has exhibited much less volatility as prices have stayed relatively stable for several decades. However, rail transportation costs continue to influence the price of coal. Because AE ships its coal from a significant distance (Wyoming), a minor increase in transportation costs can be significant for AE. Although coal is available in Texas, it is of lower quality and emits a greater amount of pollutants.

Figure 15.2
Historical Volatility in Fossil Fuel Prices
(Percentage Change)

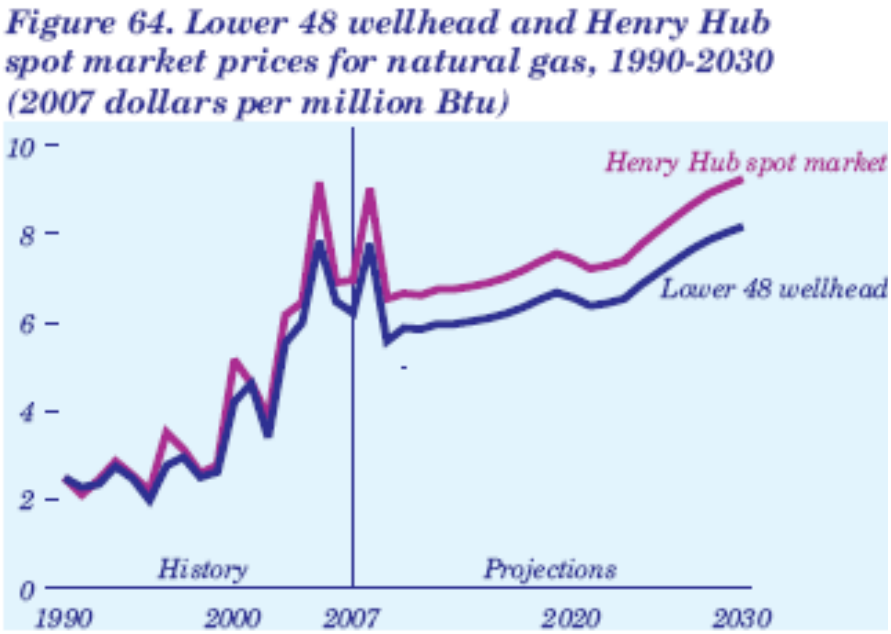


Source: Congressional Budget Office, *Nuclear Power's Role in Generating Electricity, Chapter 2* (May 2008). Online. Available: http://www.cbo.gov/ftpdocs/91xx/doc9133/Chapter2.5.1.shtml#1045449. Accessed: April 6, 2009.

Note: The percentage changes are based on prices in 2006 dollars, with adjustments for inflation made using the gross domestic product price index. Prices for all fuels equal the average cost at which those fuels are delivered to power plants, as measured by EIA.

The Energy Information Administration (EIA) expects natural gas prices to continue to increase as more expensive resources are used.[53] Other factors that will affect natural gas prices are economic and technological growth. Figure 15.3 shows EIA projections of future natural gas prices. Short-term prices tend to be affected by weather, the US economy, and gas storage levels. Long-term natural gas prices are affected by economic activity, the balance between supply and demand, and the price of oil. With increasing economic activity, growth, new businesses, and new homes, gas prices tend to rise. Therefore, the economic recession should lower the price of natural gas, as it has done for the price of oil. However, the use of more expensive domestic natural gas resources should cause the price of natural gas to increase. Unconventional production is now the largest source of US supply.[54]

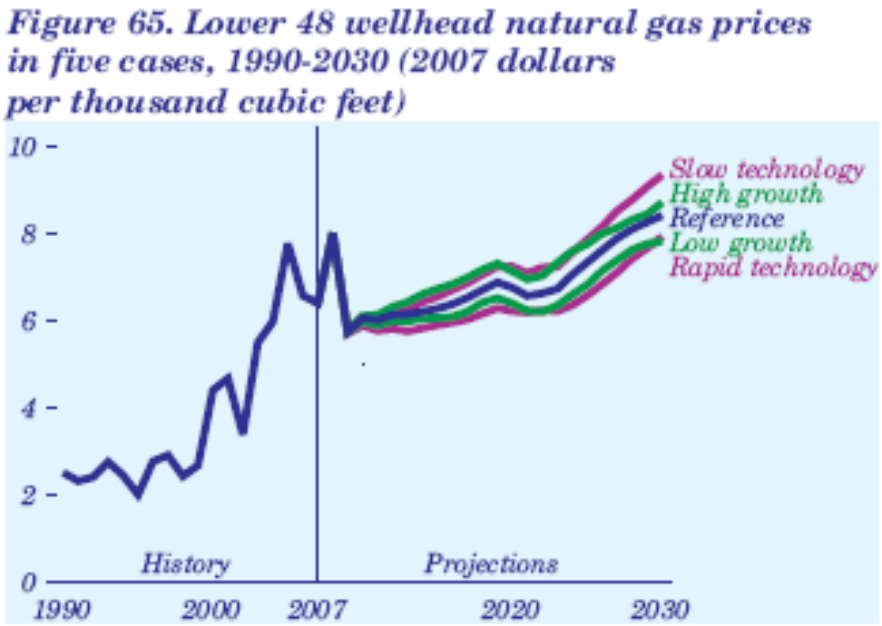
Figure 15.3
Natural Gas Price Projections Through 2030



Source: Energy Information Administration (EIA), *Annual Energy Outlook 2009*, p. 76. Online. Available: http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2009).pdf. Accessed: May 15, 2009.

Figure 15.4 shows that the future price of natural gas is heavily dependent on economic growth and technological improvements to natural gas exploration and production technologies as more expensive sources are used. Production from many older gas wells is declining rapidly and more natural gas is being used for electric generation since it produces less pollutants than coal and helps meet peak demand. Natural gas prices may decline or stabilize as new planned pipelines are completed in Alaska, but natural gas prices should continue to rise thereafter.[55] Carbon regulation could also impact the price of natural gas, but in what way is uncertain as natural gas emits high levels of CO_2, but at much lower levels than coal.

Figure 15.4
Factors Affecting Natural Gas Price Projections

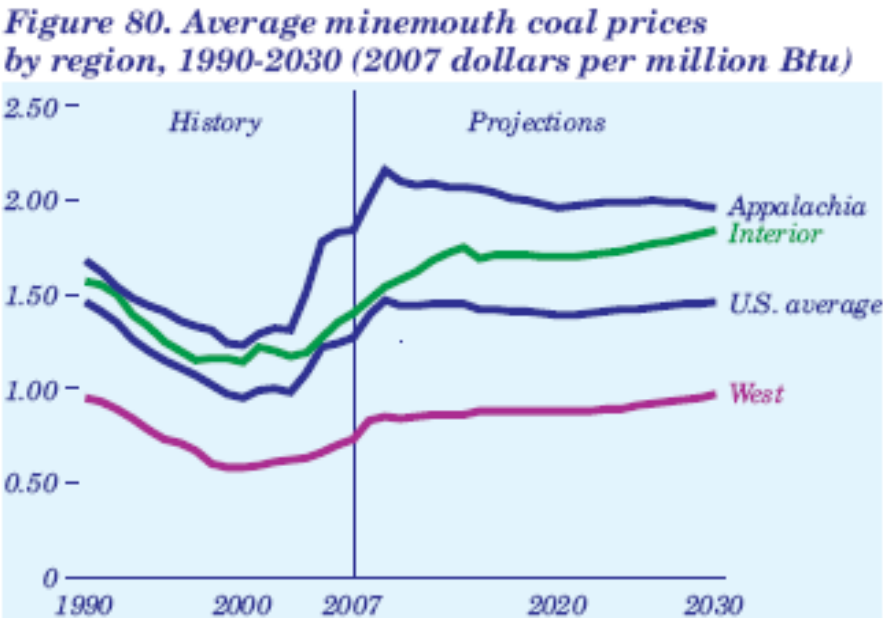


Source: EIA, *Annual Energy Outlook 2009*, p. 76. Online. Available: http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2009).pdf. Accessed: May 15, 2009.

The price of coal will likely continue to remain fairly stable during the next several decades. Carbon regulation could cause significant increases in the price of coal, but it is difficult to determine by how much as it is likely that emissions will be regulated rather than production. Deployment of clean coal technologies such as carbon capture and storage could also impact the price of coal as such technologies could increase the use of coal. Coal costs tripled between 2003 and 2008 as concerns of carbon regulation increased and problems arose with siting approval.[56] Recent increases in the cost of coal are primarily due to the rising prices of fuel, equipment, and parts and supplies at US coal mines.[57] Additionally, the cost of transporting has increased. However, it is expected that coal prices will stabilize around $26-28 per short ton produced with a price of $28.94

per short ton or $1.45 per million British thermal unit projected for 2030 due to the large supply of coal that exists in the US.[58] Figure 15.5 shows coal price projections through 2030.

Figure 15.5
Coal Price Projections Through 2030



Source: EIA, *Annual Energy Outlook 2009*, p. 84. Online. Available: http://www.eia.doe.gov/oiaf/aeo/pdf/0383(2009).pdf. Accessed: May 15, 2009.

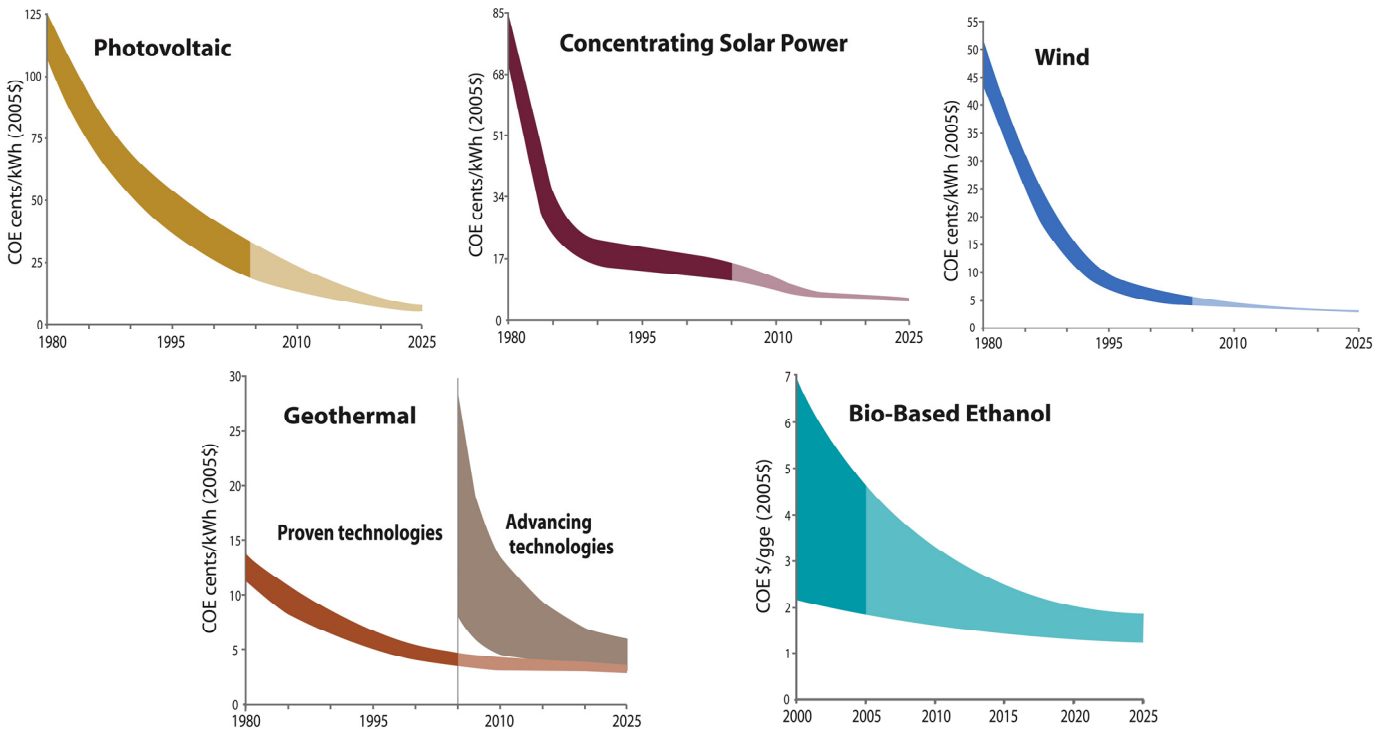
Renewable Technology Costs

Renewable energy advocates commonly tout that despite the currently high costs of renewable energy technologies, particularly for solar, these energy sources will become cost competitive with traditional technologies as market penetration increases and production costs decline with economies of scale. Additionally, continued investment in research and development for solar technologies could further decrease the costs of those technologies.

Figure 15.6 shows cost trends analyzed by the National Renewable Energy Laboratory (NREL) for five renewable energy technologies: solar photovoltaic (PV), concentrating solar technologies, wind, geothermal, and bio-based ethanol. These cost curves demonstrate that since 1980 the costs of renewable energy technologies have decreased dramatically.[59] By 2005 (the point of which this analysis was conducted), wind and geothermal technologies had reached economies of scale and were cost competitive with traditional power generation technologies based on the cost of actual electricity delivered

(levelized costs of electricity, in cents per kWh). Utility scale biomass power production facilities are also cost competitive with traditional power generation facilities. However, the availability of biomass and geothermal power production potential in Texas is uncertain. Based upon the analysis provided in Volume II of this report, it is not likely that AE could invest in much more than a few hundred MW combined from these sources of energy by 2020. Therefore, the focus of additional investment in renewable energy technologies is focused upon wind and solar technologies. As these energy sources are only available during certain periods of the day, these technologies tend to be used for intermediate or peak power needs.

Figure 15.6
Renewable Energy Cost Curves

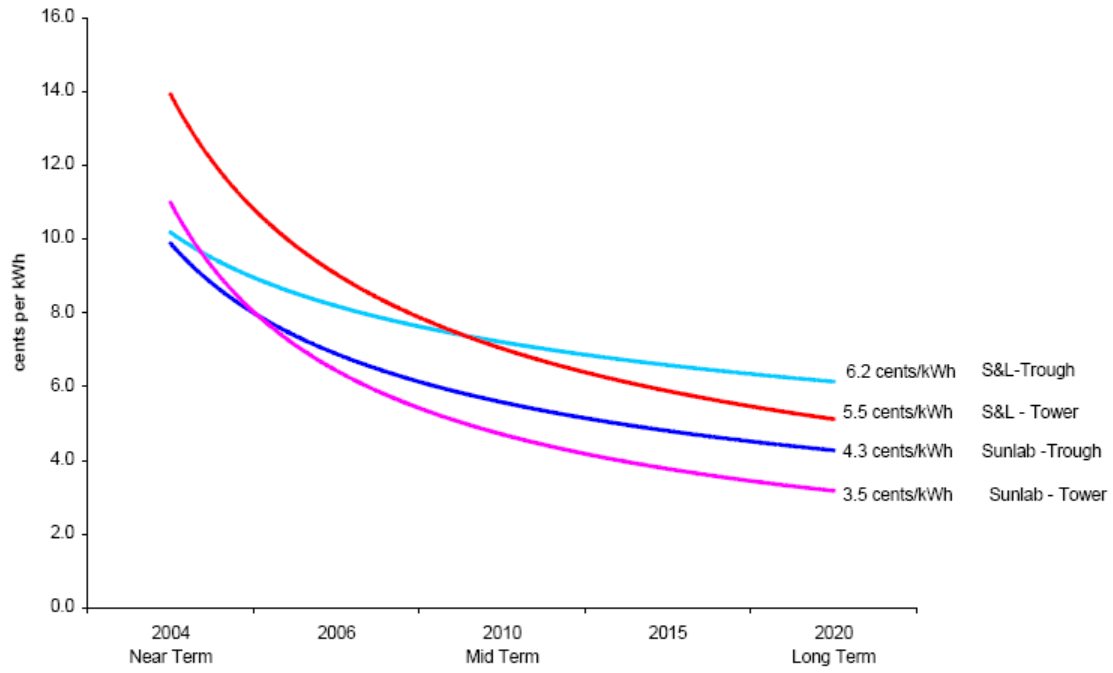


Source: National Renewable Energy Laboratory (NREL), Energy Analysis Office, *Renewable Energy Cost Trends*. Online. Available: www.nrel.gov/analysis/docs/cost_curves_2005.ppt. Accessed: May 16, 2009.

Onshore wind produced in West Texas and solar technologies demonstrate complementary profiles, making concurrent investments in both highly attractive. While wind technologies appear to have reached economies of scale and the cost of electricity produced is not likely to drop by much in the next several decades, electricity produced by solar energy is still relatively expensive and has yet to reach its low cost projections.

The costs of both solar PV and concentrated solar facilities have dropped considerably since 1980, but remain relatively expensive to other power generation technologies.[60] It is currently cheaper to provide electricity with concentrating solar technologies than solar PV arrays mainly due to the scale in the size of these facilities. Figure 15.7 shows the results of a study by NREL that concluded that concentrated solar technologies (parabolic trough and power tower) could decrease to 3.5-6.2 cents per kWh by 2020.[61]

Figure 15.7
Concentrated Solar Power Cost Projections



Source: NREL, *Executive Summary: Assessment of Parabolic Trough and Power Tower Solar Technology Cost and Performance Forecasts* (Subcontractor report, October 2003). Online. Available: http://www.nrel.gov/csp/pdfs/35060.pdf. Accessed: May 16, 2009.

If market penetration of solar technologies grows exponentially as expected in the next decade, concentrated solar costs will likely continue to decline as economies of scale are reached, making solar cost-competitive with traditional power generation technologies per unit of energy produced.[62] Figure 15.8 shows the US solar market trajectory with market penetration rates and future cost projections. Costs for residential, commercial, and utility scale solar PV systems are included.

Based on the cost curves in Figure 15.6, solar costs (both PV and concentrated solar) are projected to decrease by about 75 percent by 2025.[63] In 2009, the Lawrence Berkeley

National Laboratory published a comprehensive study of installed cost trends for solar PV systems from 1998 to 2007. This study found that capacity-weighted average installed costs declined from $10,500 per kW in 1998 to $7,600 per kW in 2007, an average annual reduction of $300 per kW, or 3.5 percent a year in real dollars.[64] However, costs remained fairly stable between 2005 and 2007. The actual cost of electricity generated from distributed solar PV systems averaged between 18 and 23 cents per kWh produced in 2006 according to the DOE.[65] The DOE projects that the average cost to produce electricity from solar PV will decline to between 11 and 18 cents per kWh by 2010 and 5 to 10 cents per kWh by 2015.[66]

While cost trends appear to support that solar power generation technologies will decrease in cost over the next several years, this is based upon the assumption that growth in these technologies will continue given current costs. However, as with wind technologies, government incentives, typically in the form of tax breaks or subsidies, will likely be necessary to encourage investment in these technologies until economies of scale are reached. Government regulation that encourages the adoption of these technologies through such market-based incentives or the passage of renewable portfolio standards at the local, state, or federal level will greatly influence the ability for low-end future cost projections of solar technologies to be achieved. Once solar technologies become cost competitive with traditional technologies, wide-scale adoption should increase. When and by how much solar costs will decline is uncertain and should play a major role in the timing of AE's decisions to invest in solar technologies. AE has already chosen to be a leader in early adoption of large-scale solar power plant facilities with its decision to invest in a 30 MW centralized solar PV facility. At what scale it will continue to invest in distributed solar PV (by providing solar rebates to customers), utility-scale centralized PV plants, and concentrated solar power facilities will largely be determined by the future uncertain costs of these technologies.

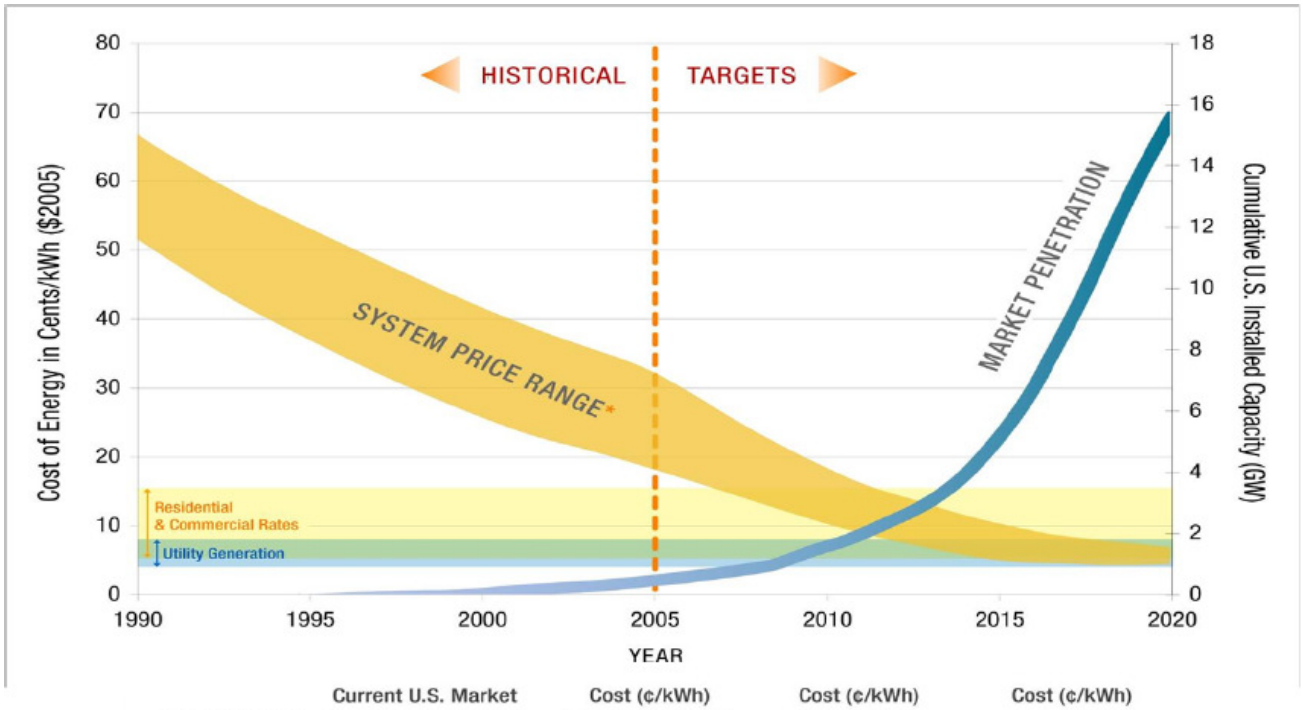
Reliance on Variable Energy Sources

As electric utilities such as AE move towards wind and solar power generation to relieve or replace traditional fossil fuel-based power generation sources, one of the biggest concerns is the impact of the variable nature of these resources on system reliability. Electric utilities and grid operators are concerned that dependence on variable resources puts communities at risk for blackouts when wind and solar supplies cannot meet instantaneous demand due to unpredictable circumstances. While fossil fuel powered plants hold the risk of unexpected plant failures, utilities generally feel more wary of reliance on weather conditions than technology.

Wind and solar resources face daily (diurnal), short-term (several days), seasonal, and annual fluctuations. However, these fluctuations can be predicated reasonably well and, since electric utilities have the capacity to carefully plan the dispatch of other resources, ensuring reliability even when a significant portion of a utility's resource portfolio is comprised of variable resources appears manageable. Figure 15.9 shows the daily and short-term fluctuations in solar availability (direct solar radiation) for a five-day period for seven Texas cities, including Austin, with the night-time hours omitted. Fluctuations

are caused by the diurnal (day/night) effect and changing atmospheric conditions, primarily cloud cover.[67] This figure purposely depicts a period of five days with a mixture of clear and non-clear days. Clear days exhibit fairly smooth hourly variations while non-clear days exhibit much more extreme short-term variations ranging from high levels of solar radiation to near-zero levels. These near-zero levels demonstrate the risks of reliance on solar power during peak demand. While diurnal variations create concerns for short-term availability, some concentrated solar plants have the ability of thermal storage to ensure constant resource availability.

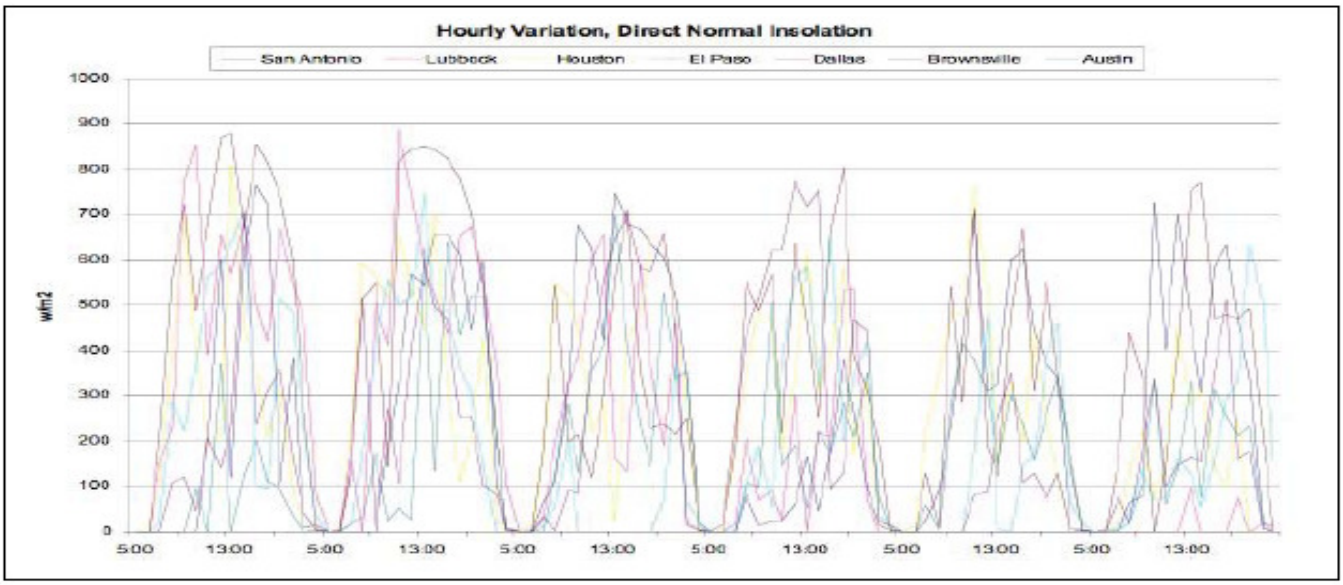
Figure 15.8
US Solar Market Trajectory

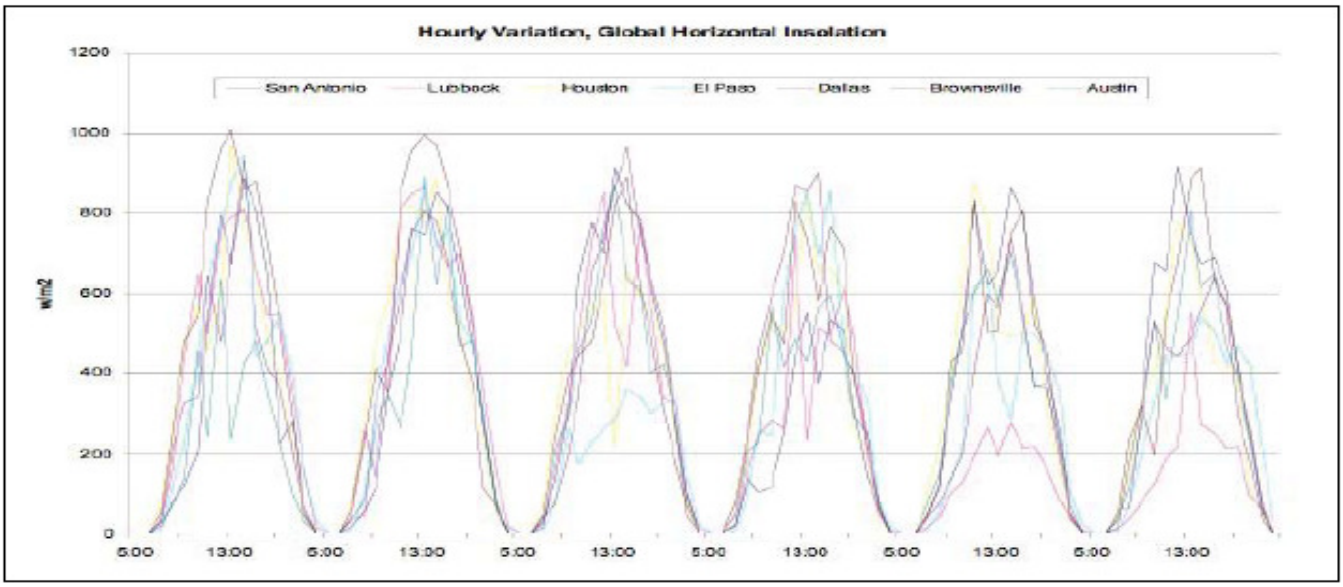


Market Sector	Current U.S. Market Price Range (¢/kWh)	Cost (¢/kWh) Benchmark 2005	Cost (¢/kWh) Target 2010	Cost (¢/kWh) Target 2015
Residential	5.8-16.7	23-32	13-18	8-10
Commercial	5.4-15.0	16-22	9-12	6-8
Utility	4.0-7.6	13-22	10-15	5-7

Source: United States Department of Energy, Solar Energy Technologies Program, *Solar Energy Industry Forecast: Perspectives on U.S. Solar Market Trajectory* (PowerPoint Presentation, June 24, 2008). Online. Available: http://www1.eere.energy.gov/solar/solar_america/pdfs/solar_market_evolution.pdf. Accessed: April 19, 2009.

Figure 15.9
Daily and Diurnal Variations in Solar Insolation: Texas, Selected Cities



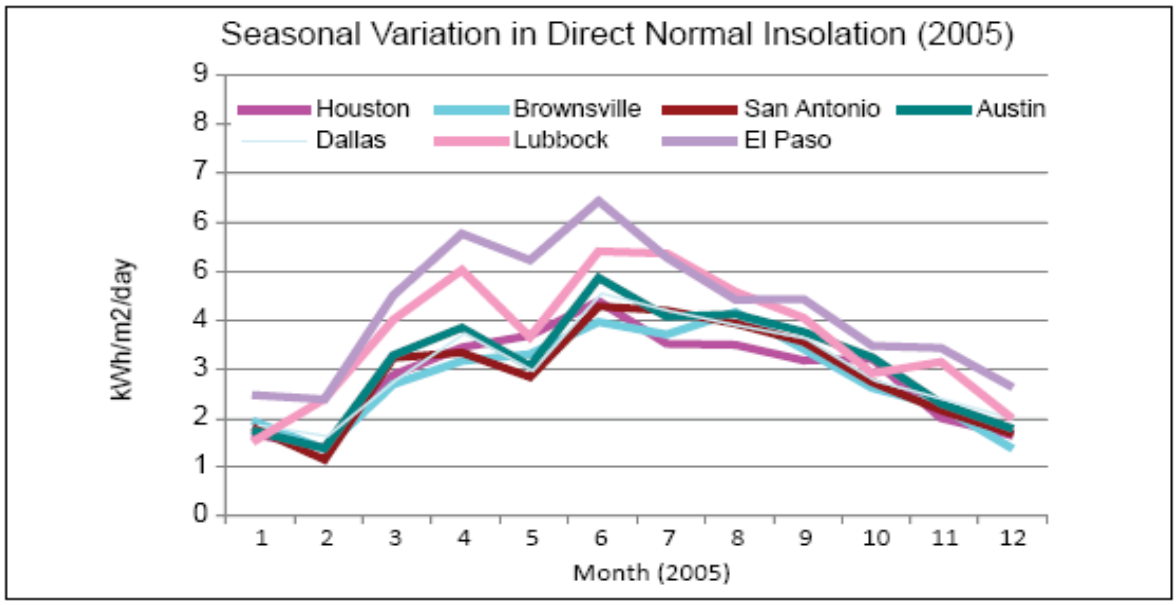


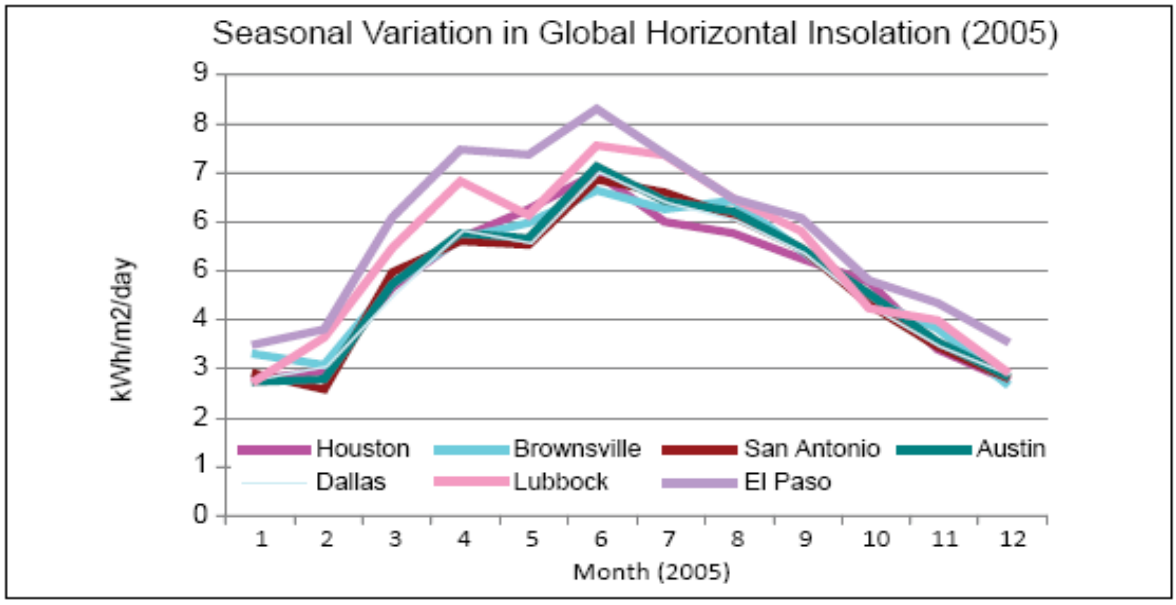
Source: Frontier Associates, LLC, Report for the State Energy Conservation Office of Texas, *Texas Renewable Energy Resource Assessment* (December 2008), p. 3-14. Online. Available: http://www.seco.cpa.state.tx.us/publications/renewenergy/pdf/renewenergyreport.pdf. Accessed: May 16, 2009.

Figure 15.10 shows seasonal variation in levels of solar insolation for the same seven cities. Summer months tend to exhibit the greatest level of solar insolation while winter months exhibit lower levels due to increased cloud cover, less exposure to the sun, and

shorter days.[68] This variation aligns with demand in Texas as demand is typically greater during the summer months than the winter months.

Figure 15.10
Seasonal Variation in Solar Insolation: Texas, Selected Cities

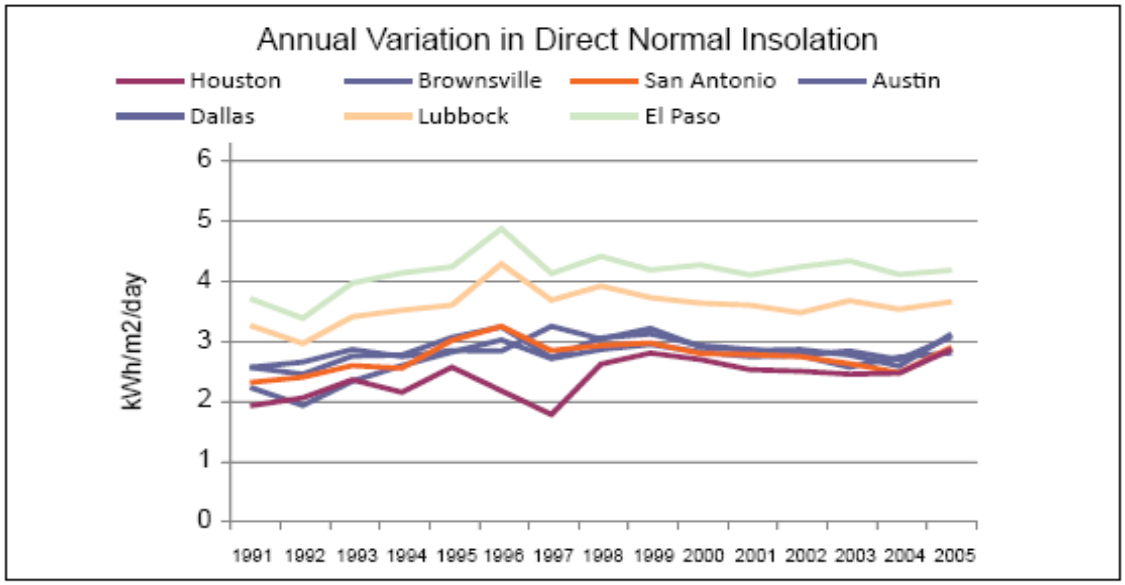


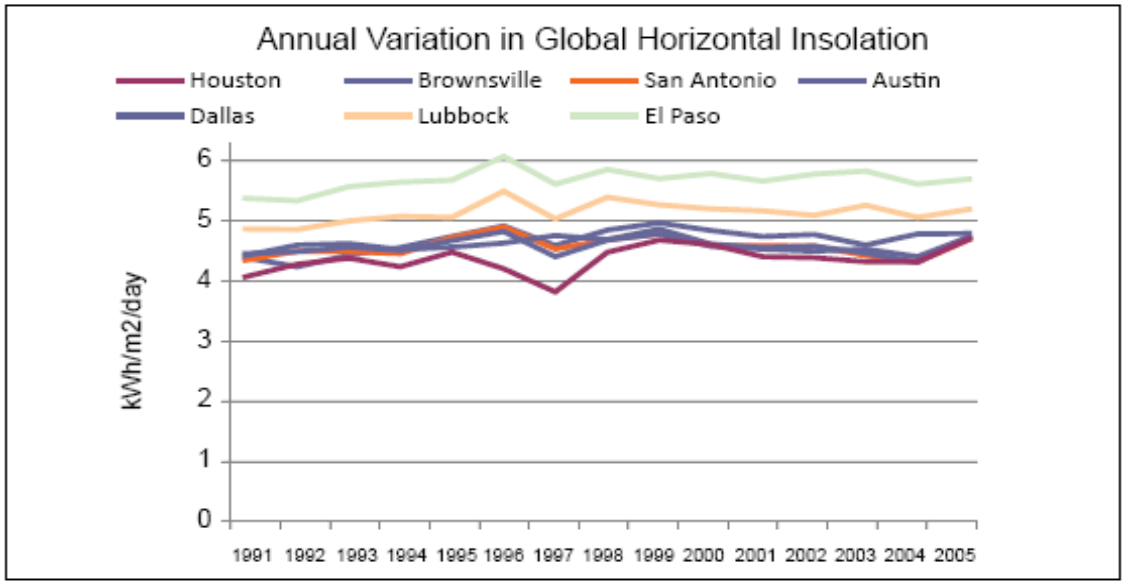


Source: Frontier Associates, LLC, Report for the State Energy Conservation Office of Texas, *Texas Renewable Energy Resource Assessment* (December 2008), p. 3-13. Online. Available: http://www.seco.cpa.state.tx.us/publications/renewenergy/pdf/renewenergyreport.pdf. Accessed: May 16, 2009.

Figure 15.11 shows annual variation in solar insolation levels from 1991 to 2005 for the same seven Texas cities. Variabilty from year to year is typically only about 15 percent, so utilities can easily plan for such variation.[69]

Figure 15.11
Annual Variation in Solar Insolation: Texas, Selected Cities

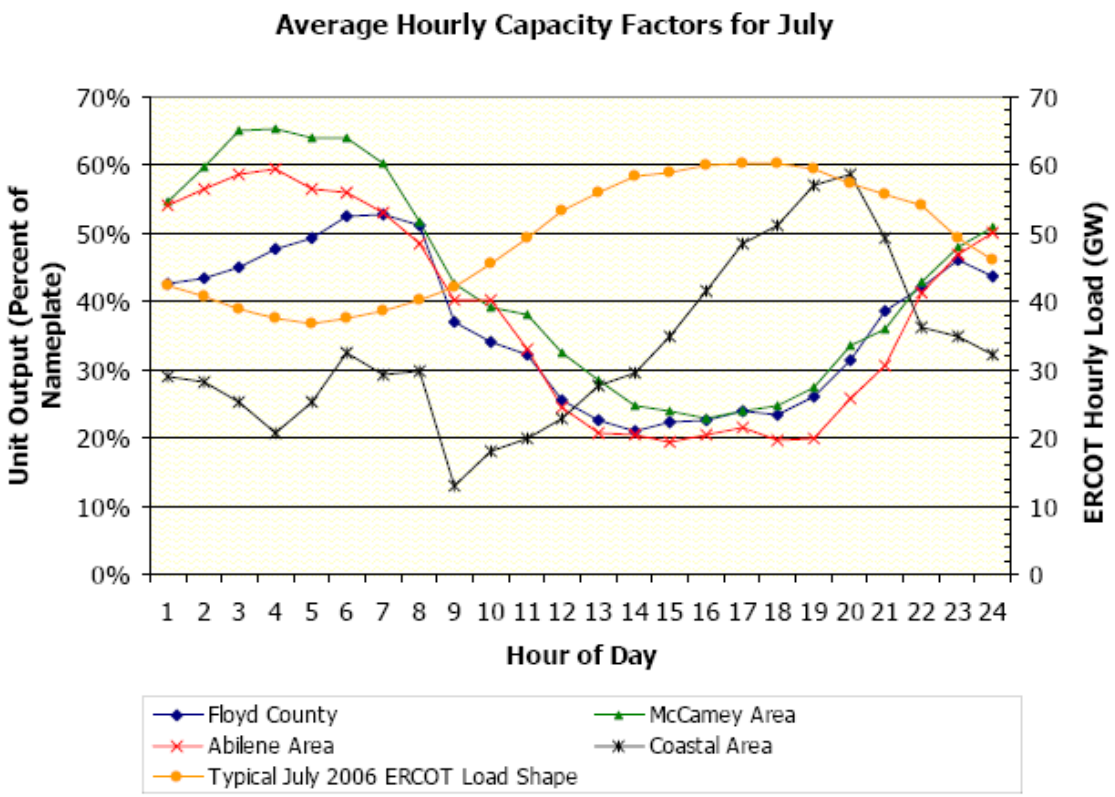




Source: Frontier Associates, LLC, Report for the State Energy Conservation Office of Texas, *Texas Renewable Energy Resource Assessment* (December 2008), p. 3-12. Online. Available: http://www.seco.cpa.state.tx.us/publications/renewenergy/pdf/renewenergyreport.pdf. Accessed: May 16, 2009.

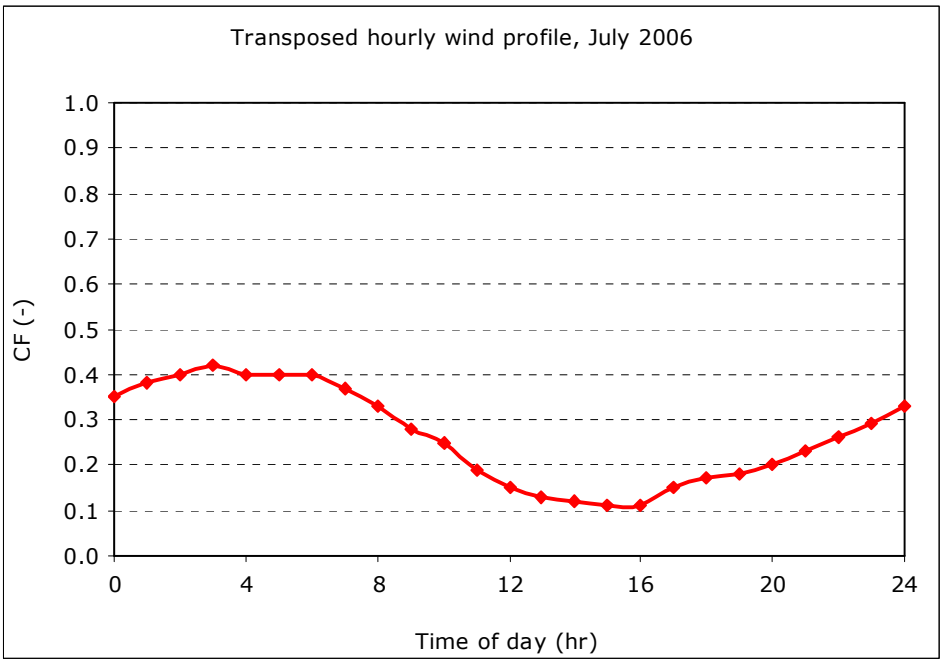
Wind profiles are fairly predictable and face similar variations as solar. However, onshore wind away from the coast exhibits a profile that is nearly opposite from that of solar. The highest levels of power production from wind are during the night and early morning hours. Figure 15.12 shows the wind profiles for four locations in Texas, three onshore locations (in West Texas) and one coastal location. Figure 15.13 shows the wind profiles transposed by the project team for use in the simulation software used in this study. These profiles exhibit the complementary characteristics of West Texas onshore wind and coastal or offshore wind. Figure 15.14 shows hourly wind profiles for onshore wind power production used by AE for one week in May 2008 compared to one week in August 2008. These profiles demonstrate not only the daily fluctuations exhibited by wind energy but also the short-term and seasonal variations.

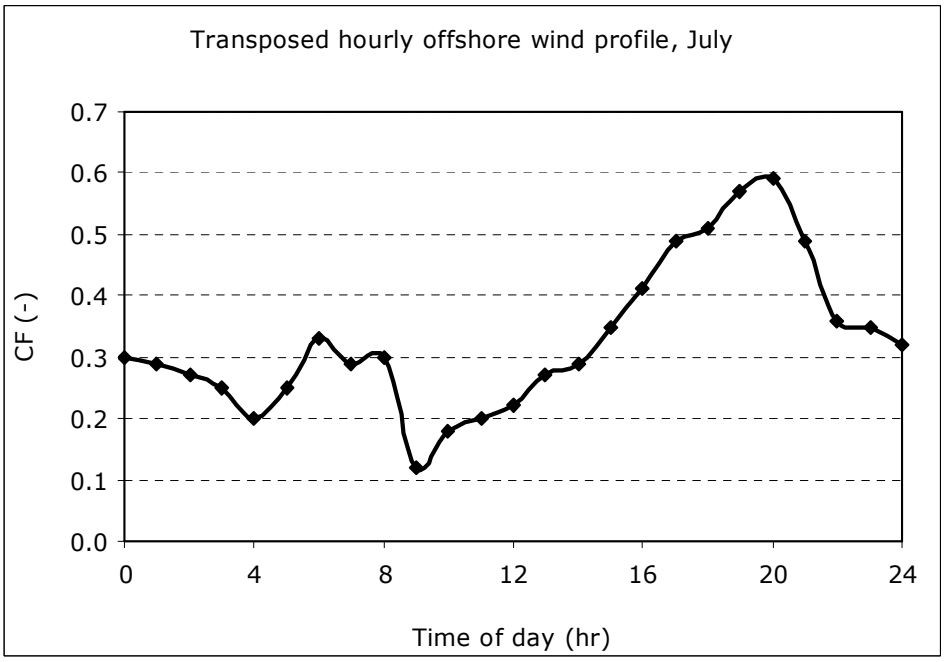
Figure 15.12
Texas Wind Profiles



Source: Electric Reliability Council of Texas, *Analysis of Transmission Alternatives for Competitive Renewable Energy Zones in Texas* (December 2006).

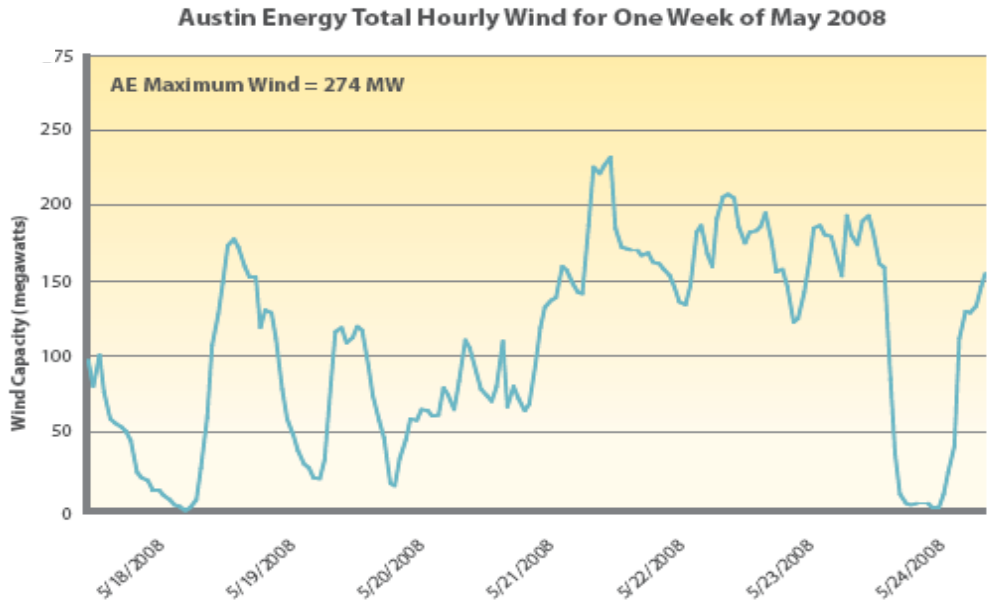
Figure 15.13
Onshore and Offshore Wind Profiles for Texas

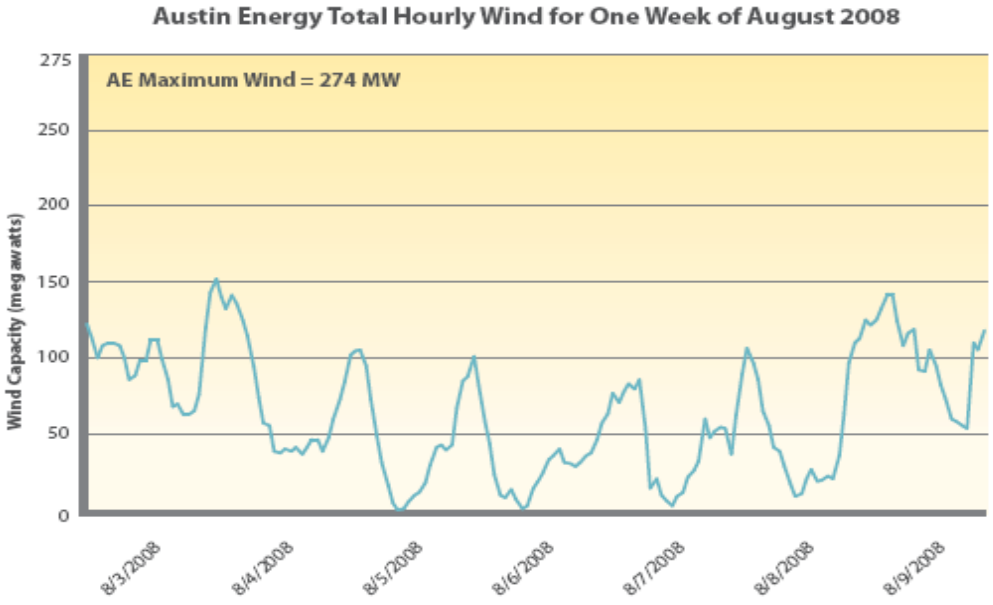




Source: Created by project team.

Figure 15.14
Austin Energy's Wind Energy Profiles





Source: Austin Energy, *Austin Energy Resource Guide* (October 2008), p. 29. Online. Available: http://www.austinsmartenergy.com/downloads/AustinEnergyResourceGuide.pdf. Accessed: November 17, 2008.

As AE determines the amount of investment and reliance on wind and solar resources it is willing to accept, it should evaluate the risks posed by the variability of these sources. Worst-case scenarios in which the wind does not blow and the sun does not shine for an extended period of time can be evaluated to determine if the resource portfolio is overly dependent on variable energy sources. Table 15.1 shows a series of system reliability performance measures that provide some indication of the ability of the eight future resource portfolio scenarios to meet the worst case scenario. In 2020, peak demand is expected to be 2,706 MW (based on 2009 AE load forecast). Column 1 in Table 15.1 shows the amount of power generation capacity of non-variable resources (wind and solar). The greater this number, the more unreliable the system would be without the availability of variable resources.

Table 15.1
Measures of System Reliability (in 2020, Rankings in Parentheses)

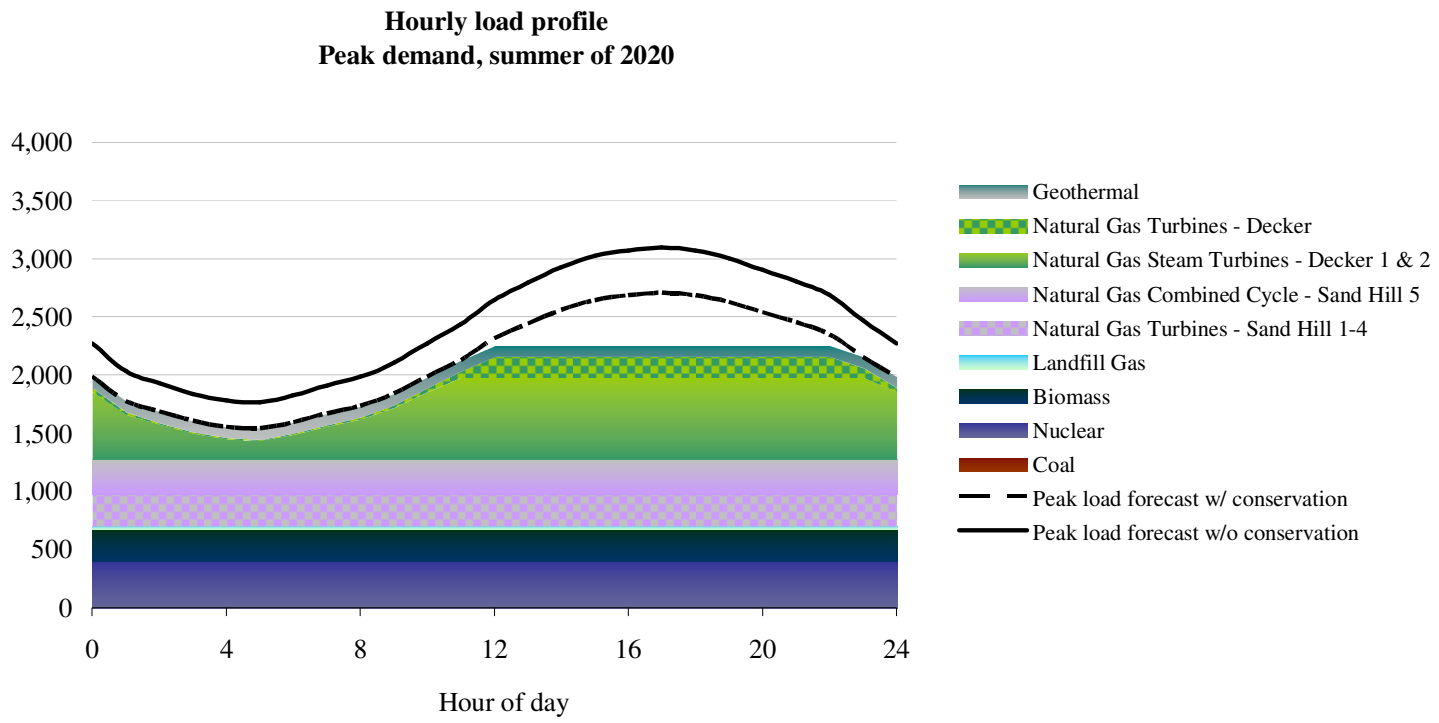
	Total Power Generation Capacity of Non-Variable Resources (MW)	Fraction of Peak Hourly Demand Met (%)	Ratio of Unused Natural Gas Capacity to Wind and Solar Capacity	Fraction of Total Demand Met with Natural Gas (%)	Total Power Generation Capacity of Biomass, Geothermal, Solar and Wind (MW)
Portfolio 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 Renew-ables Without Nuclear	1,952 (8)	97.3% (7)	0.38 (8)	26.7% (6)	3293 (7)

Source: Created by project team

Figure 15.15 shows the high renewables scenario worst-case scenario (no wind or solar resources available on the peak day) with the 2009 load forecast applied using the updated simulation software. This scenario exhibits that because of the amount of natural gas that is retained for backup purposes, 83 percent of the energy needed on the peak day

is met by the remaining non-variable resources given that all natural gas facilities could be run at maximum capacity when needed that day. This demonstrates that even given the very unlikely scenario of no wind and solar availability for the peak day, AE could still meet the majority of its energy needs with its natural gas facilities. While it is important to analyze these worst-case scenarios and plan accordingly, the likelihood of such circumstances occurring are low and would only occur occasionally.

Figure 15.15
Hourly Peak Demand Profile: High Renewables Scenario without Wind and Solar



Source: Created by project team.

The variability of wind and solar creates the necessity for more reliable sources of energy to serve as backup power sources. Natural gas power production units, particularly combustion turbines, tend to serve this need because they are the cheapest power generation facilities that can be built and have the shortest ramp-up time (the time it takes for the unit to begin operation). These units can be fired up in a matter of minutes to account for unexpected fluctuations in other resources or increased demand. It is essential that as AE increases the capacity of its wind and solar resources it evaluates the ability for natural gas to provide an adequate amount of backup power. Fortunately, AE currently has a sufficient amount of excess natural gas capacity that can serve to meet

future backup power needs as several more hundred MWs of wind and solar power generation comes online.

Energy storage can also provide a mechanism by which wind and solar power generation reliability concerns are alleviated. Energy storage technologies are discussed in Chapter 17 of Volume II of this report. Energy storage can enable excess energy, including wind and solar, to be temporarily stored and quickly dispatched at a later time to meet energy demand. This could be particularly advantageous for wind resources as excess wind is generated during off-peak periods. Off-peak wind can then be stored to be dispatched during peak periods to level the actual use of wind during a 24-hour time period, thus functioning similar to a baseload power plant. Solar resources could be used in the same manner, but such use may be less advantageous since solar is generated mostly during periods of higher demand. However, solar thermal storage can remedy concerns with short-term fluctuations in that resource's availability.

Distributed Generation Impacts

Electric utilities have traditionally built large central station power generation plants to provide electricity for customers. New technological developments with distributed generation technologies, the reliability and efficiency gains of combined heat and power facilities, and increasing affordability of solar PV systems could lead to a revolution in the structure of the modern electric grid as distributed generation resources penetrate AE's power system. AE is promoting distributed generation as a benefit for the utility as well as customers and appears poised to become an industry leader in facilitating the addition of distributed generation resources connected to the grid. In 2008, AE announced a plan to scale-up a massive amount of distributed generation and revolutionize its electric grid as a model for other electric utilities. The Pecan Street Project was initiated in October 2008 "to make the city of Austin into America's clean energy laboratory—a place for researchers and entrepreneurs to develop, test, and implement the urban power system of the future."[70] The project brings together AE, the City of Austin, researchers at The University of Texas at Austin and other universities and organizations, and private corporations such as General Electric and IBM. The four main components of the project are to: 1) develop a local, public-private consortium dedicated to research and development of clean energy technologies and distributed power generation; 2) opening up the city's electric grid to act as a lab to test emerging clean energy technologies; 3) develop a new business model to ensure AE's continued profitability; and 4) show the world how the new business and systems model can work.[71]

A primary component of the project is to integrate wide-scale distributed generation into AE's power generation and distribution system. The goal of achieving 300 MW of distributed power generation by 2020 has been stated by project founders.[72] It is likely that the majority of such power generation will come from PV panels installed on residential and commercial roof space, but other potential sources are combined heat and power, small-scale wind turbines, and solar thermal technologies. Although AE has supported distributed solar PV for several decades through its solar rebate program, distributed solar only accounts for roughly 2.9 MW of AE's over 2,400 MW power

generation mix.[73] At such a relatively small-scale, the impact of solar PV upon AE's revenues and power system is minor. However, as solar penetration increases, AE is faced with several new risks and uncertainties. AE must ensure it reaches this goal without negatively impacting profit margins. The primary concerns for AE are revenue erosion, loss of control of a major portion of its system capacity, and operational complexities that can be costly and may impose additional reliability concerns.

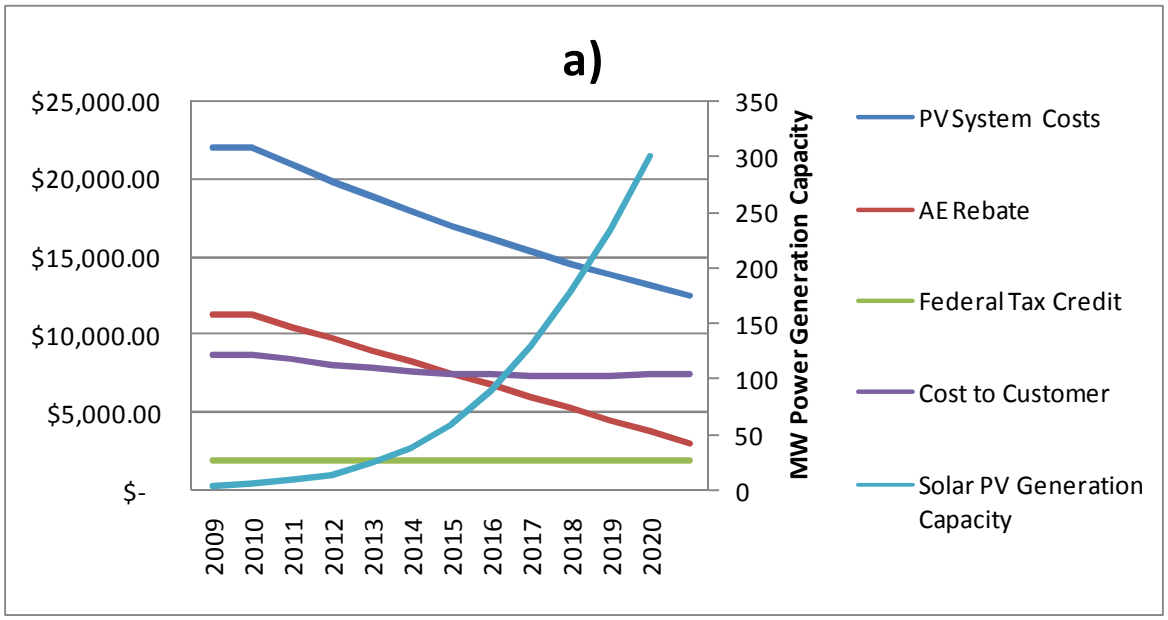
One question is whether AE can continue to sustain its solar rebate program given such high penetration rates. If AE were to continue to provide its current rebate to achieve 300 MW of residential PV by 2020 it would cost about $1.1 billion to the utility.[74] Because it is unlikely that AE could sustain such high costs, the number of solar rebates they provide each year is capped. This creates a paradox for AE in meeting the 300 MW goal. As solar costs decline, AE could adjust or eliminate its solar rebate program accordingly. Figure 15.16(a) demonstrates the projected costs of a 3 kW PV system for an AE customer by year through 2020 as installation costs decline and penetration rates increase with a steady reduction in AE's solar rebate of $250 a year beginning in 2010.

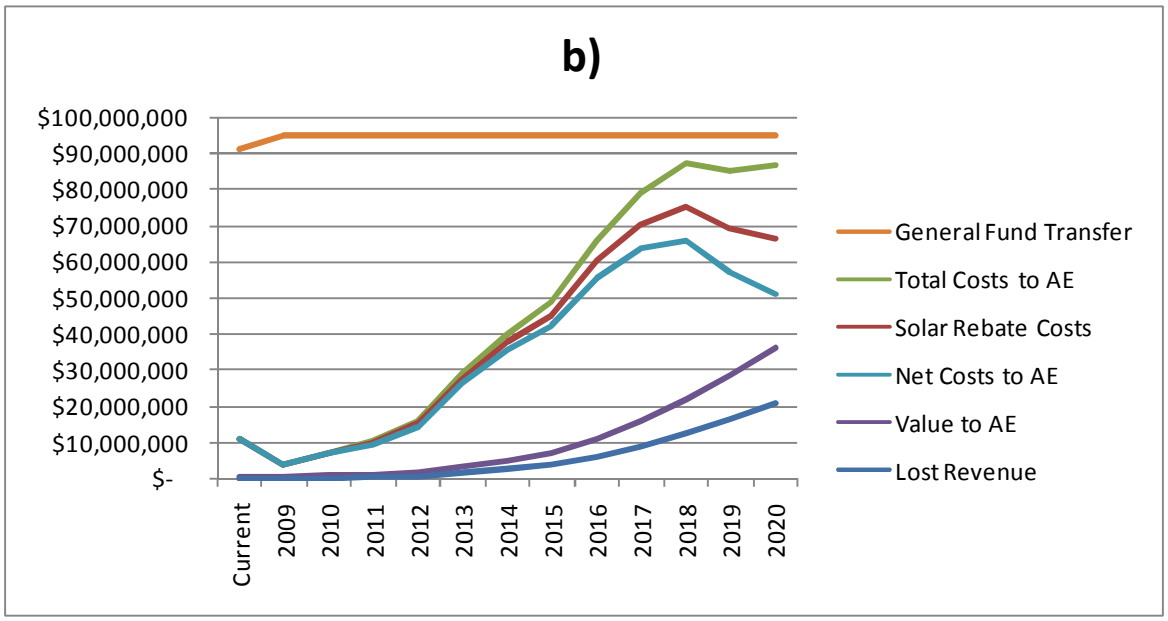
In 2006, AE solicited a study to determine the value of solar electric generation to AE. This study determined that at a 100 MW penetration rate solar PV was worth 10.7 cents per kWh due to cost savings from energy production, avoided new generation capacity, transmission and distribution capacity deferrals, reduced transformer and line losses, reactive power control, environmental savings, natural gas price hedging, and disaster recovery.[75]

Figure 15.16(b) demonstrates the revenue and cost impacts of gradually achieving 300 MW of PV on AE's power system by 2020. Projected lost revenue for AE would actually be less than the value of solar PV to AE. Total lost revenue through 2020 is about $74.9 million. Total value of solar PV through 2020 is about $130.2 million. While lost revenue may be offset by the value of solar PV, solar rebates are still very costly for AE even after implementing an annual reduction to the current rebate of $250. Total costs of providing solar rebates through 2020 is about $485.35 million (the solar rebate reduction structure proposed herein would save about $630 million). Total net costs to AE (solar rebate costs + lost revenue – value of solar) through 2020 is about $430 million.

It appears that the impact on revenue erosion can potentially be offset by the benefits of solar PV. This theoretical value of solar PV is based upon many cost saving assumptions that may become questionable at a penetration of 300 MW of PV. If new solar PV generation capacity offsets new power generation capacity needs such value may be withheld, but if new solar generation capacity exceeds rising demand in AE's service area this value may drop significantly. AE should re-evaluate the value of solar PV for 300 MW installed based upon its most recent load forecast through 2020.

Figure 15.16
Impacts of Solar PV Penetration
a) Costs of 3 kW Solar PV System for AE Customer
b) Solar PV Penetration Impacts by Year





Source: Created by project team.

The potential impacts on AE's finances along with other uncertainties related to the operation of wide-scale PV systems that rely on a variable energy source indicate the necessity for AE to develop a new business model approach to PV integration. AE currently supports PV integration by providing purchase incentives for systems connected to the grid (allowing AE operational capacity), but AE does not own these systems. Therefore, AE does not earn a return on its rebate investment. Thus, AE currently operates a business model in which revenue is lost at the added expense of the cost of the rebate.

AE should move towards a new business model in which it becomes a part or whole owner in PV systems. While it is difficult to convince homeowners to purchase a PV system, even when providing a reasonable rebate, AE understands the value of PV and has the capacity to incur high capital costs through low financing rates. Because of the value of solar to AE, customers could still receive reduced electric rates or earn a cash incentive if they agree to have the system installed on their home or property. Additionally, if lower electric rates are provided this would add value to the property. Concern that a utility would have an unfair advantage in providing value-added customer services through PV systems has created some regulatory resistance to allowing utilities to own and operate these systems.[76] AE would need to evaluate regulatory issues that may prevent such a business model approach.

While the risks and uncertainties posed by high solar PV penetration rates for electric utilities are many, so are the opportunities. AE and other electric utilities must evaluate new business model approaches to meet new renewable energy goals through solar PV and other distributed generation sources while ensuring financial stability.

Electric Vehicle Impacts on Utility

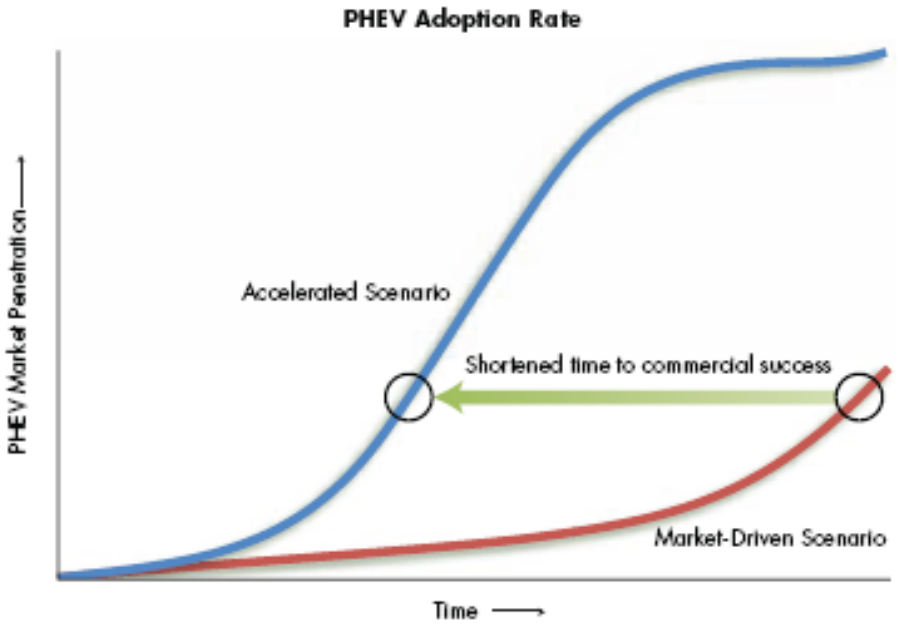
Another uncertainty facing the electric utility industry is the potential future impact of electric vehicles increasing electric demand and creating problems for managing the electric grid. However, opportunities for utilities to actually reduce the costs of electricity by lowering peak demand also exist for electric vehicles. This concept has been termed the vehicle-to-grid system. The idea behind the vehicle-to-grid system is that electric vehicles could serve as temporary storage devices to shift energy from off-peak demand hours to peak-demand hours. AE is one of the main proponents of this concept and is already beginning to test its potential. In January 2008, AE announced that it would partner with V2Green's Connectivity Module to test its automation equipment with two electric vehicles.[77] The idea behind this technology is that the vehicle-to-grid system can control the timing and extent to which the vehicles are charged and when energy is sold back onto the grid. By charging a vehicle at night, when demand is low, and selling back energy when the vehicle is plugged-in during the day, when demand is at its peak, electric vehicle customers can make money from the electricity produced while the utility can effectively shift demand from off-peak to on-peak hours. This process would effectively store energy for the utility to reduce peak demand. Vehicle to grid technology could stabilize electrical grids by consuming power

when electricity is abundant and selling electricity back to the grid when electricity is in highest demand.

The amount of emissions related to an electric vehicle is dependent upon the utility's generation mix or the generation technology linked to a particular plug-in vehicle. If a person were to plug-in their vehicle and use solar energy emissions attributed to the vehicle would be much lower than if the energy used was attributed to the utility's overall power generation mix. Furthermore, wind energy tends to be abundant during the early morning hours (2 to 6 am) when supply could be greater than demand. Prices for such energy could be very cheap for electric vehicle customers and provide clean energy for the powering of their vehicles. If this energy is sold back onto the grid later, clean energy will have been stored for the electric utility by the vehicle's battery storage component.

However, electric vehicles need to be able to penetrate the market for this type of technology to make a sizeable difference. Initial costs of purchasing electric vehicles will likely be high and subsidies may be needed to promote purchase by consumers. Incentives could be provided by the government or by the utility through agreements that the customer will provide a certain amount of electricity back to the utility during certain hours of the day when demand is the highest. Figure 15.17 demonstrates a general representation of the likely prospects of electric vehicle market penetration. This figure demonstrates that electric vehicles will take several years to make a sizeable impact on the electric grid as market penetration of new automobile technologies tends to grow slowly because of high initial cost and risks of early adoption.[78] The provision of incentives by the government and the utility along with consumer education will likely determine the rate of adoption. Due to these uncertainties the project team does not factor increased demand (or potential energy demand savings) attributed to electric vehicles through 2020. However, electric vehicle impacts should be carefully monitored, especially given AE's support to date of this technology.

Figure 15.17
Electric Vehicle Market Penetration Projections



Source: Electric Power Research Institute, "Plug-in Hybrids on the Horizon: Building a Business Case," *EPRI Journal* (Spring 2008), p. 13. Online. Available: http://mydocs.epri.com/docs/CorporateDocuments/EPRI_Journal/2008-Spring/1016422_PHEV.pdf. Accessed: May 16, 2009.

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Chapter 16. Conclusions and Recommendations

This report discusses a diverse range of choices for generating 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 evaluated in this study could potentially allow Austin Energy (AE) to reach carbon neutrality by 2020 through a combination of reducing direct carbon dioxide (CO_2) emissions and purchasing carbon offsets. However, there are significant differences in costs, risks, and merits of achieving sustainability associated with these options. A number of conclusions and recommendations are discussed below that reflect the analysis of power generation technologies and the analysis of investment options for these technologies.

Conclusions

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, on-shore wind investment, and smart grid deployment.

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. Of the eight scenarios evaluated by this study, 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) present 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 of the eight scenarios evaluated under this study. However, expansion of AE's nuclear power comes with significant 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 power generation capacity allows the utility to invest in renewable baseload power sources (biomass and geothermal) to replace coal when available while ensuring reliable and cost-effective service to its customers through 2020. However, it remains uncertain whether AE can purchase and implement reliable additional biomass or geothermal resources prior to 2020.

The estimated cost of the "anticipated available" renewable resources scenario (portfolio option 4) is lower than a high investment in renewables scenario (portfolio option 3) and reduces AE's coal use by 50 percent through renewable resource additions. A high investment in renewables entails high expected capital costs as well as high risks and uncertainties. The high renewables scenario may be more economically sustainable than other scenarios due to the reduction in uncertain and volatile fuel costs. The high renewables scenario also reduces CO_2 emissions more than the other options. However, it may be overly ambitious about where and when these resources could come on-line.

AE may want to maintain sufficient natural gas capacity to backup additional wind and solar additions to AE's resource portfolio to reduce increased risk of exposure to the volatile energy market. The variability of solar and wind resources due to when the sun shines and the wind blows means that sufficient natural gas and/or storage are necessary requirements for assuring reliable electricity service.

AE's planned additions for on-shore wind resources in West Texas appear to be reasonable investments given projected cost-competitiveness of this resource, expected transmission build-out to reduce congestion costs, and the ability of this resource to act as a hedge against carbon costs, even if these wind resources have relatively low resource availability during peak demand. Investment in coastal wind resources, both on-shore and off-shore, can provide additional benefits due to the complementary profile of these resources to on-shore wind resources located in West Texas. Potential investments in offshore or coastal 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 provide a greater opportunity to reduce peak demand and thus reduce the need to build new peaking plants to meet generation needs than wind energy investments. However, wind energy investments may provide greater opportunities for CO_2 emission reductions as these resources tend to generate more electricity during off-peak hours. This allows AE's coal plant, a much more significant contributor of CO_2 emissions, to be ramped down. Solar investments currently come at much higher cost per kWh than wind.

Utility-scale energy storage may provide a cost-effective way to achieve significant CO_2 reductions if coupled with wind energy investments (portfolio option 5).

However, many utility-scale energy storage technologies are still in development and are not yet cost-effective or widely available. Energy storage allows wind power generation and other sources of energy 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 Lower Colorado River Authority to construct pumped storage facilities close to Austin. Two uncertainties with storage are what storage capacity would cost and the rules concerning how storage 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 AE's Sand Hill facility, provides a low capital cost investment to displace coal use while achieving significant 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 the Fayette Power Project (FPP) with an advanced clean coal facility with carbon capture and sequestration (CCS) technology (portfolio option 7) would provide a hedge against potential future carbon costs, it would also represent a technical risk, as there are no such large-scale plants in routine operation in the United States. 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 (coal) to enhance CO_2 reductions comparable to a natural gas alternative, the CCS process includes a large demand for energy to capture and sequester carbon, high capital costs, and CCS still results in CO_2 discharges from parts of the process other than power generation.

Removing both coal and nuclear from AE's resource mix (portfolio option 8) is a very high risk scenario for AE as this would result in high exposure to the volatile energy market. Under this scenario, AE would need to purchase power from the market or significantly expand its natural gas power generation capacity to account for the variable nature of wind and solar as well as the uncertainty of availability of biomass and geothermal resources.

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 (75 percent reduction in 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, if such resources are available. The cost of increased use of AE's 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 megawatts (MW) of savings through 2020 would delay the need for additional power generation capacity additions, but may be increasingly difficult to achieve and come at a higher cost to the utility. Accelerated DSM demand reductions due to time-of-day pricing tied to the smart grid or peak shifting could ease the transition to a coal-free resource portfolio and lower the costs for replacing this lost source of baseload power.

One major 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.

Other future uncertainties facing AE and the electric utility industry sector include local, state and federal regulation, the accuracy of load projections, nuclear risks and uncertainties, fossil fuel prices, renewable technology costs, ability to rely on variable resources, and the potential impacts of distributed generation and electric vehicles. These risks and uncertainties must be considered as AE makes future resource investment decisions and determines its future resource portfolio mix.

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 this report's 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 it must reduce its reliance on coal. 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 and it wishes to retain or enhance system reliability, then AE must invest in cleaner forms of baseload power generation capacity such as nuclear, biomass, or geothermal baseload power plants.

AE should monitor the reporting credibility of biomass as a carbon-free source of energy if carbon regulation is passed. 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 organic residues different from energy in coal and gas. AE can 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). On-shore wind coupled with energy storage facilities and coastal or off-shore wind can flatten AE's hourly wind supply profile. AE should consider on-shore wind and energy storage to provide wind capacity during peak demand hours. Such investments should be evaluated based upon the value and risks of 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-MW-hour costs of these technologies are expected to fall upon an increase in their market penetration. If centralized photovoltaic (PV) module solar plants (such as the planned 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 in West Texas as a complementary resource to wind generation. Opportunities presented by third parties should be considered along with proposed partnerships for concentrated solar plant investments. The amount of investment should reflect the marginal per-MW-hour 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.

AE's single best electric sector investment is in energy efficiency, conservation, peak shifting, and reducing peak demand. AE uses its last 100 MW of peak resources only 43 hours per year. If that peak evaporates, the cost savings from not having to build or use 100 MW of peak power are significant. One of AE's top priorities should be to work with the Texas Legislature, the Public Utility Commission of Texas, the Electric Reliability Council of Texas, and other Texas utilities to develop pricing options that reward electricity providers to avoid, prevent, or constrain peak demand.

The design and success of AE's plans through 2020 depend on one critical assumption: that 700 MW can be conserved between 2009 and 2020. It took AE over 25 years to achieve 800 MW of demand savings, reflecting 26 different energy conservation investment programs. There are two keys to conservation success, the amount of electricity saved for each conservation investment and the fraction of AE's customer base that participates in such practices and programs. If AE hopes to achieve 700 MW or more in demand savings between 2009 and 2020, it should invest in a community-wide education program to help its customers save themselves money by helping AE trim its peak and reduce overall demand.

Appendix A.
Austin Energy Resource Portfolio Simulator Version 24
User's Guide

This document serves as a user's guide for the Austin Energy Resource Portfolio Simulator created by the policy research project team, coordinated through the Lyndon B. Johnson School of Public Affairs, tasked to look at "sustainable energy options for Austin Energy." The intent of the simulator is to provide instantaneous analysis of the potential risks and uncertainties associated with adjusting Austin Energy's (AE) future power generation mix. The simulator is designed to assist AE staff, the public, and policymakers in making energy investment decisions through 2020. The user can compare power generation mixes based on a series of charts and graphs and, in turn, make a judgment regarding his or her ideal future resource portfolio. Although AE already has the capabilities to forecast load on an hourly basis and currently does so through 2020, the intent of this model is not to replicate that level of detail. Real time planning is beyond the scope of this project and the capacity of this model given the dynamic nature of electric utility system modeling and the level of detail and information required for such modeling. Additionally, the software is not an optimization model. It does not choose a power generation mix based on an optimal value of a certain variable of interest. Optimization is considered 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. Rather, the purpose of the model is to provide the user with a snapshot of the impacts of making investments in various energy resources to generate power for AE.

The simulator created for this purpose is a Microsoft® Excel spreadsheet tool that allows users to control inputs of additions and subtractions to and from AE's resource portfolio mix through the year 2020. All values used in the model are referenced to ensure transparency. Variables including capacity factors, carbon dioxide (CO_2) emission factors, and costs can be manipulated to meet the preferences of the user. The user's guide provides information on how to use the simulator, identifies assumptions used in the modeling process, and details the capabilities and limitations of the simulator.

Section A provides a basic step-by-step guide to using the simulator. Sections B and C describe the simulator inputs and outputs, respectively. Section D provides an overview of assumptions implicit in the model, and Section E lists the limitations of the model.

A. Using the Simulator

Perform the following steps to run a scenario in the simulator:

1. Upon receipt of the simulator file, click on File → Save As and save the document as a master document. The user should open this master document each time he or she wishes to generate a new scenario.

2. Click on the *Before you Begin* tab (see Figure A.1) to review AE's current energy resource mix and the projected load for AE with and without projected demand-side management (DSM) achievements.

   Note: AE's load forecast for both 2008 and 2009 are included for reference. The model defaults to the 2009 load forecast.

3. Click on the *Choose Your Generation Mix* tab (see Figure A.2). Input the proposed power generation capacity additions and subtractions by technology and year in the chart labeled "Choose Your Generation Mix." For example, to increase onshore wind capacity by 50 megawatts (MW) in 2016 and 75 MW in 2017, enter "50" in Cell J10 and "75" in Cell K10. To remove a currently-owned resource from AE's resource mix, enter a negative number. For example, to divest in ownership or lease approximately half of AE's current stake in the coal-fired Fayette Power Plant in 2018, enter "-305" in Cell L4.

   Notes: 2008 values (Column B) indicate AE's power generation capacity as of the end of 2008 for each identified resource, technology, or facility. Only cells shaded in blue should be modified for the purposes of increasing or decreasing the power generation capacity of a particular resource. The 165 MW addition of onshore wind in 2009, the 100 MW addition of natural gas in 2010, the 30 MW solar PV project set to begin operation in 2010, and the 100 MW biomass project set to begin operation in 2012 have already been approved by the Austin City Council. Therefore, these cells should not be changed. Inputs for all cells default to AE's updated proposed resource plan released in April 2009.

4. If you have included "Concentrated Solar" (CSP) in your resource mix, click Cell Q17 to select the type of CSP facility (see Figure A.3).

5. If you have included "Storage" (an energy storage technology), click on Cell Q21 to select the type of energy storage technology (see Figure A.4). Click on Cell R21 to adjust the number of hours to be used for storage facilities.

   Notes: The amount of electricity storage [in MW-hours (MWh)] is defined as the capacity of the storage facility (in MW, also the rate of release) multiplied by the number of hours that it will be able to supply stored electricity. If you have included electricity storage, the model automatically adjusts natural gas capacity factors during the hours of midnight and 10 AM on the peak day to provide enough excess electricity to charge the storage facilities. The model then automatically adjusts natural gas usage during the peak hours between noon and 10 PM, beginning at the 5 PM peak, and dispatches electricity in increments at the rate of release (MW) each hour surrounding the peak, alternating from 5PM, to 4PM, to 6PM, to 3PM, to 7PM, etc. The result is the storage of electricity to shift generation from the peak hours to the off-peak hours.

One limitation of the model is that, since electricity storage facilities are not technically power generation facilities but *load shifting* facilities, electricity costs cannot be attributed. The model alerts the user on the "Choose Your Generation Mix" tab that it cannot calculate electricity costs. The usefulness of modeling electricity storage, however, is that it gives the user an idea of the principle of energy storage, as well as an estimate of the amount of capital investment required for the technology.

6. Click on Cell R22 and select "Yes" if you want to run the simulator assuming AE's goal for conserving energy is met, and "No" if not (see Figure A.5).

   Note: AE's proposed resource plan includes a cumulative saving of 700 megawatts (MW) of energy through DSM/conservation by 2020. Projected demand with and without this goal being met is provided in the *Before You Begin* tab for both 2008 and 2009 load forecasts (see Figure A.1). The user can model additional energy savings, or less savings, attributed to conservation by inserting the amount of savings in Row 22 (in MW of peak demand energy savings) gained or lost in relation to AE's projected cumulative savings through 2020 for each year. Once energy savings are added or subtracted for a given year these savings continue for all subsequent years.

7. Adjust capacity factors (column "O") and CO_2 emission factors (column "P") for each power source other than natural gas facilities to suit your assumptions (see Figure A.6).

   Notes: See *References* tab (see Figure A.7) to view the references and assumptions used for all default capacity factors and CO_2 emission factors. Capacity factors for coal, nuclear, all natural gas units, and onshore wind correspond with 2007 reporting for AE's facilities that use these energy sources. Capacity factors for wind and solar photovoltaic (PV) are based on AE assessment of solar PV in their service territory and AE's projections of future output. CO_2 emission factors for coal and all natural gas units correspond with 2007 reporting for AE's facilities that use these energy sources. Nuclear, wind, solar, and geothermal resources do not emit CO_2 directly and thus these values should stay unchanged. Capacity factors for natural gas in Cells O6-O9 only apply to year 2008. The model will adjust natural gas capacity factors as appropriate based on maximum and minimum values designated in Cells Q6-Q9 and R6-R9 (see Step 8).

8. Adjust maximum natural gas unit capacity factors (Cells Q6-Q9) and minimum natural gas unit capacity factors (Cells R6-R9) to determine the maximum and minimum amount of usage of the respective units (see Figure A.8).

   Notes: Default capacity factors (Cells O6-O9) for natural gas units are based on 2007 usage by AE. Maximum and minimum capacity factors default to a reasonable use of such units.

The simulation software automatically adjusts natural gas usage to meet demand based upon the assigned minimum and maximum capacity factors. These capacity factors determine the minimum and maximum amount of time that the unit will run in a given year. The maximum capacity factors are established based on the maximum amount of time the user thinks a facility could realistically function in one year. The maximum capacity factors are used primarily in determining how much the natural gas facilities will run annually. To automate scenario modeling, natural gas capacity factors are adjusted automatically according to the gap between yearly electricity demand and power production from all facilities, excluding natural gas. If that gap remains after adding all production from technologies but natural gas, the least carbon-intensive facility will attempt to make up the difference (natural gas combined cycle-Sand Hill 5). If, by running at or below its maximum capacity factor, the gap is filled, the other natural gas units are only run at the minimum capacity assigned. If more natural gas must be deployed to meet yearly demand, the next least carbon-intensive natural gas unit or set of units attempt to fill the gap. This calculation process continues until annual demand is met.

There exists some disconnection between the amount of time a unit or set of units is needed to meet the peak hourly load profile and the yearly demand profile. For example, if the hourly profile calls for a natural gas unit or set of units to operate at a 10 percent capacity factor on the peak day that does not directly translate to an accurate estimate of yearly usage. Thus, the assigned minimum capacity factors can be used as a calibration device to adjust facilities to a more realistic performance level. This also helps to accurately adjust the carbon profile.

9. Click on the *Edit Your Own Costs* tab to adjust capital costs, fuel costs, and levelized cost of electricity for each power source (see Figure A.9), if so desired. Expected, low, and high cost values can be adjusted. Click on the *References* tab to view the references and assumptions used for costs for each power source (see Figure A.7).

10. Use the "Scenario Output Summary" section of the *Choose Your Generation Mix* tab (see Figure A.2) to determine if the additions and subtractions of power sources and the changes, if made, to the capacity factors, CO_2 emission factors, and cost values meet your expectations. Adjust the inputs accordingly. Values related to system reliability, CO_2 emissions, and costs are updated automatically based on the user-adjusted inputs.

11. The user can view the calculations behind the corresponding series of charts and graphs generated by the simulation software by clicking on the *Scenario Calculation Output* tab (see Figure A.10). Numerical values can be viewed for each year represented in the following charts and graphs (outputs).

12. Once the user is satisfied with the inputs assigned, he or she can view the corresponding outputs generated in the tabs following the *Scenario Calculation Output* tab. Outputs include: *Yearly Capacity, 2020 Capacity, Yearly Electricity, 2020 Peak Hourly, 2020 Electricity, Carbon Profile, Capital Costs, Fuel Costs, Cost of Electricity, Carbon Offsets,* and *Carbon Allowances.* For a detailed description of the outputs see Section C of this guide.

13. When you have completed the steps above, click on File → Save As and save the file under a new name.

14. Because the simulator runs the simulation instantaneously as inputs are entered, the user can continue to refine the inputs after review of the outputs. To run an additional scenario, open the master document and repeat these steps.

Figure A.1
Screenshot of *Before You Begin* Tab

Microsoft Excel - prp_model[1].v21_streamlined_newcosts

Austin Energy Resource Portfolio Simulator

2009 Load Forecast Projected Load Through 2020 *Without DSM*

Year	MW	Additional MW over Previous Year Load	Additional MW over 2008 Load
2008	2550	0	0
2009	2545	-5	-5
2010	2597	52	47
2011	2644	47	94
2012	2701	57	151
2013	2755	54	205
2014	2802	47	252
2015	2849	47	299
2016	2914	65	364
2017	2962	48	412
2018	3008	46	458
2019	3048	40	498
2020	3095	47	545

2009 Load Forecast Projected Load Through 2020 *With DSM*

Year	MW	Additional MW over Previous Year Load	Additional MW over 2008 Load
2008	2520	0	0
2009	2495	-25	-25
2010	2497	2	-23
2011	2519	22	-1
2012	2541	22	21
2013	2550	9	30
2014	2567	17	47
2015	2589	22	69
2016	2609	20	89
2017	2627	18	107
2018	2658	31	138
2019	2686	28	166
2020	2706	20	186

Source: Austin Energy, *Public Participation and Resource Plan Updates (April 2009), p. 7.*

2008 Load Forecast Projected Load Through 2020 *Without DSM*

Year	MW	Additional MW over Previous Year Load	Additional MW over 2008 Load
2008	2550	0	0
2009	2610	60	60
2010	2700	90	150
2011	2755	55	205
2012	2815	60	265
2013	2865	50	315
2014	2915	50	365
2015	2965	50	415
2016	3035	70	485
2017	3085	50	535
2018	3130	45	580
2019	3175	45	625
2020	3230	55	680

2908 Load Foreast Projected Load Through 2020 *With DSM*

Year	MW	Additional MW over Previous Year Load	Additional MW over 2008 Load
2008	2520	0	0
2009	2560	40	40
2010	2600	40	80
2011	2630	30	110
2012	2655	25	135
2013	2660	5	140
2014	2680	20	160
2015	2705	25	185
2016	2730	25	210
2017	2750	20	230
2018	2780	30	260
2019	2813	33	293
2020	2841	28	321

Source: Austin Energy, *Austin Energy Resource Guide: Planning for Austin's Future Energy Resources* (October 2008).
Online. Available: http://www.austinsmartenergy.com/downloads/AustinEnergyResourceGuide.pdf.
Adapted from Figure 10

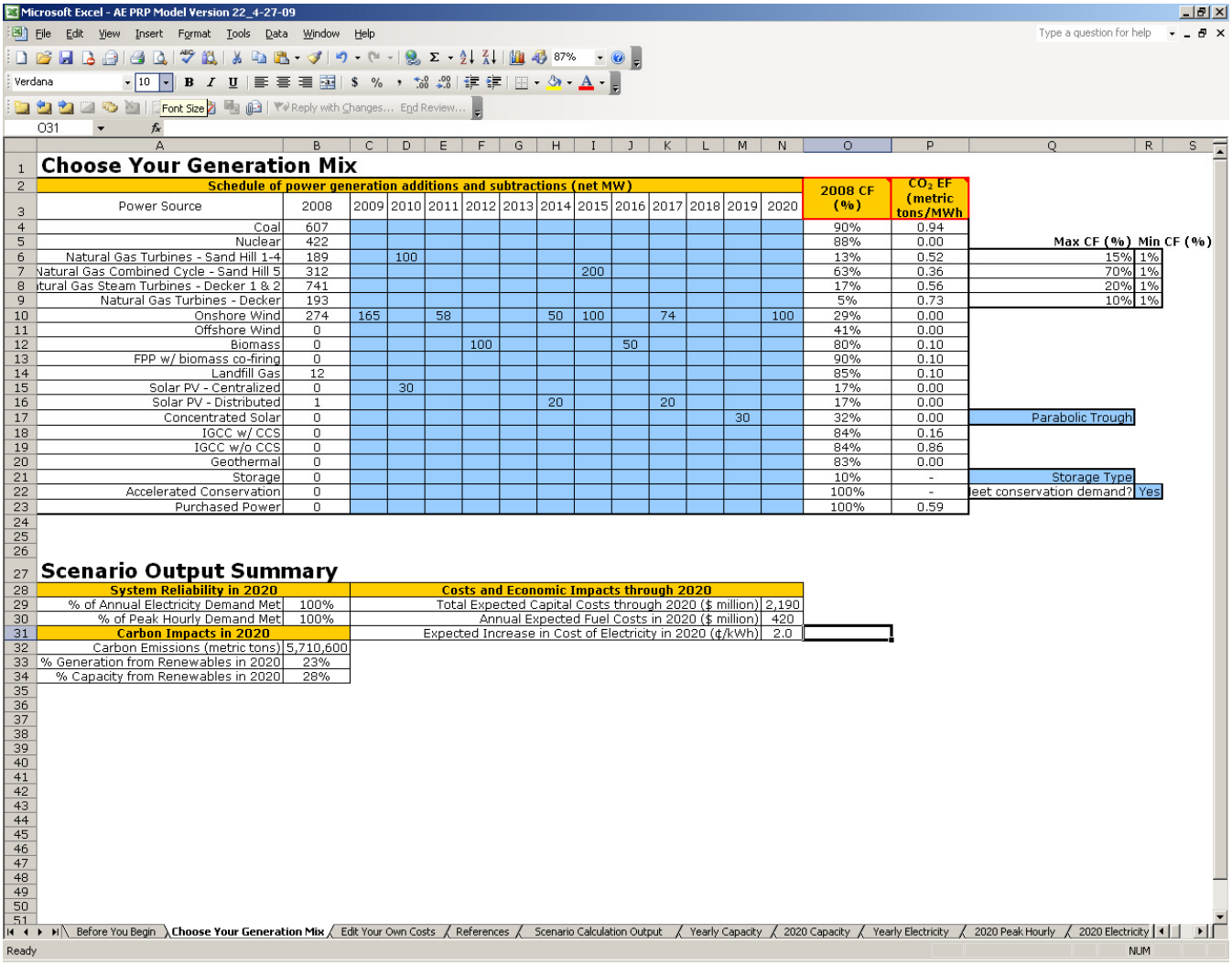
Austin Energy Current Resource Mix

Resource	Generation Capacity (MW)
Coal	607
NG Decker	934
NG Sand Hill	501
Domain & RMEC	9
Nuclear	422
Wind	274
Landfill Gas	12
Solar	1
Total	**2760**

Additional 300 MW of Purchased Power added in Summer Only
Source: *Austin Energy Resource Guide* , Figures 12 & 15

Before You Begin | Choose Your Generation Mix | Edit Your Own Costs | References | Scenario Calculation Output | Yearly Capacity | 2020 Capacity | Yearly Electricity | 2020 Peak Hourly | 2020 Electricity

Figure A.2
Screenshot of *Choose Your Generation Mix* Tab



Choose Your Generation Mix

Power Source	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2008 CF (%)	CO_2 EF (metric tons/MWh
Coal	607													90%	0.94
Nuclear	422													88%	0.00
Natural Gas Turbines - Sand Hill 1-4	189		100											13%	0.52
Natural Gas Combined Cycle - Sand Hill 5	312							200						63%	0.36
Natural Gas Steam Turbines - Decker 1 & 2	741													17%	0.56
Natural Gas Turbines - Decker	193													5%	0.73
Onshore Wind	274	165		58			50	100		74			100	29%	0.00
Offshore Wind	0													41%	0.00
Biomass	0				100				50					80%	0.10
FPP w/ biomass co-firing	0													90%	0.10
Landfill Gas	12													85%	0.10
Solar PV - Centralized	0		30											17%	0.00
Solar PV - Distributed	1						20			20				17%	0.00
Concentrated Solar	0											30		32%	0.00
IGCC w/ CCS	0													84%	0.16
IGCC w/o CCS	0													84%	0.86
Geothermal	0													83%	0.00
Storage	0													10%	-
Accelerated Conservation	0													100%	-
Purchased Power	0													100%	0.59

Schedule of power generation additions and subtractions (net MW)

	Max CF (%)	Min CF (%)
	15%	1%
	70%	1%
	20%	1%
	10%	1%

Parabolic Trough	
Storage Type	
eet conservation demand?	Yes

Scenario Output Summary

System Reliability in 2020	
% of Annual Electricity Demand Met	100%
% of Peak Hourly Demand Met	100%
Carbon Impacts in 2020	
Carbon Emissions (metric tons)	5,710,600
% Generation from Renewables in 2020	23%
% Capacity from Renewables in 2020	28%

Costs and Economic Impacts through 2020	
Total Expected Capital Costs through 2020 ($ million)	2,190
Annual Expected Fuel Costs in 2020 ($ million)	420
Expected Increase in Cost of Electricity in 2020 (¢/kWh)	2.0

Figure A.3
Screenshot of "Concentrated Solar" Selection Function

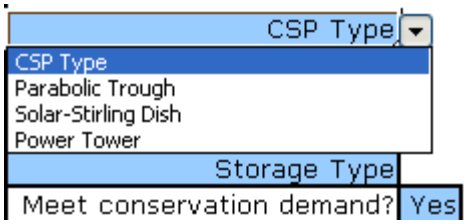


Figure A.4
Screenshot of "Storage" Selection Function

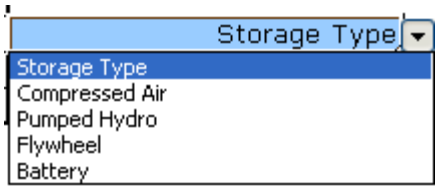


Figure A.5
Screenshot of "Meet Conservation Demand?" Selection Function

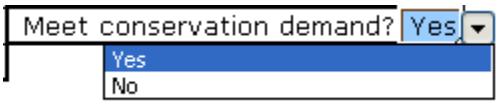
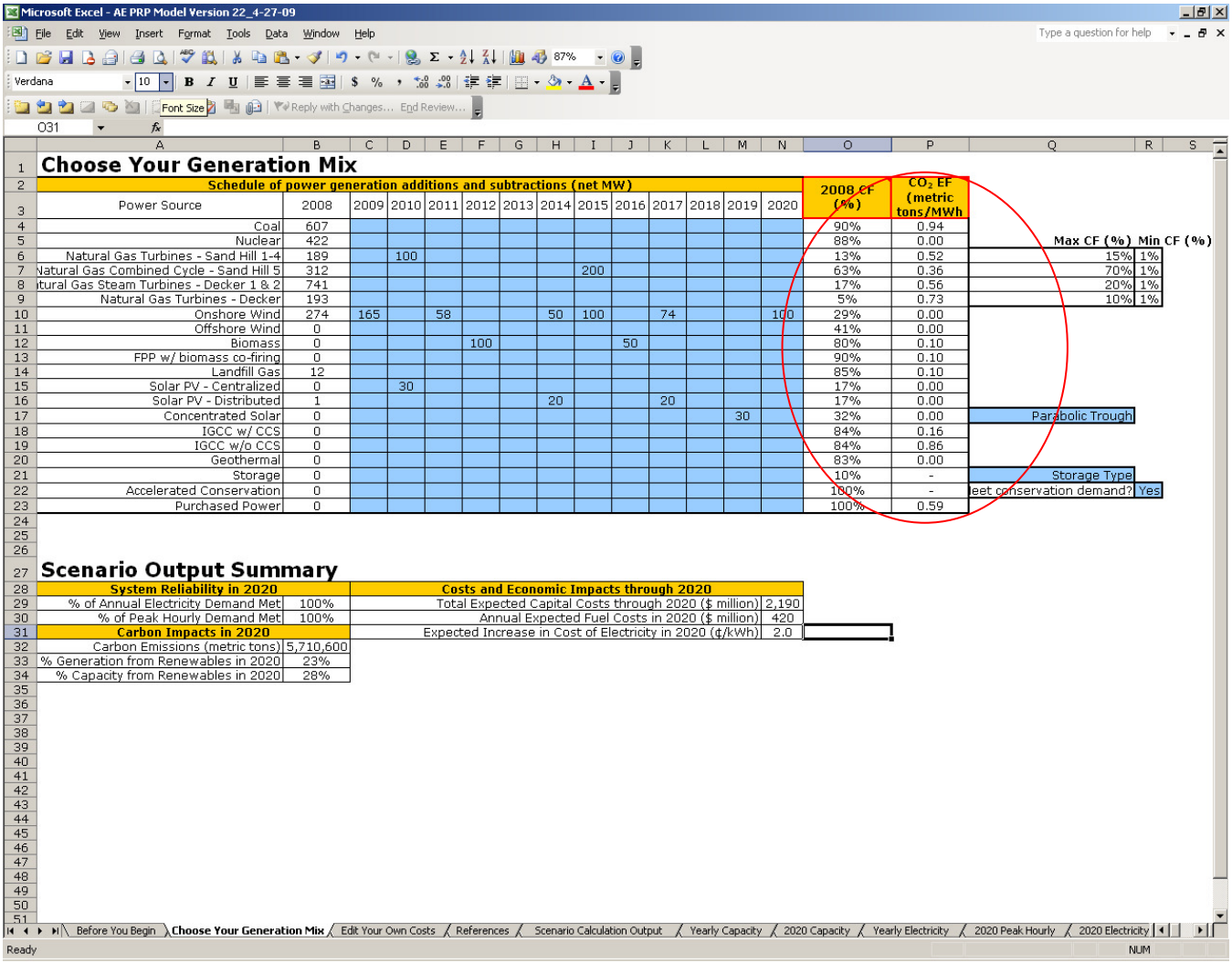


Figure A.6
Screenshot of Capacity Factor and Carbon Dioxide Emission Factor Cells



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Choose Your Generation Mix

Schedule of power generation additions and subtractions (net MW)

Power Source	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2008 CF (%)	CO_2 EF (metric tons/MWh
Coal	607													90%	0.94
Nuclear	422													88%	0.00
Natural Gas Turbines - Sand Hill 1-4	189		100											13%	0.52
Natural Gas Combined Cycle - Sand Hill 5	312							200						63%	0.36
Natural Gas Steam Turbines - Decker 1 & 2	741													17%	0.56
Natural Gas Turbines - Decker	193													5%	0.73
Onshore Wind	274	165		58			50	100		74			100	29%	0.00
Offshore Wind	0													41%	0.00
Biomass	0				100				50					80%	0.10
FPP w/ biomass co-firing	0													90%	0.10
Landfill Gas	12													85%	0.10
Solar PV - Centralized	0		30											17%	0.00
Solar PV - Distributed	1						20			20				17%	0.00
Concentrated Solar	0											30		32%	0.00
IGCC w/ CCS	0													84%	0.16
IGCC w/o CCS	0													84%	0.86
Geothermal	0													83%	0.00
Storage	0													10%	-
Accelerated Conservation	0													100%	-
Purchased Power	0													100%	0.59

	Max CF (%)	Min CF (%)
	15%	1%
	70%	1%
	20%	1%
	10%	1%

Parabolic Trough

Storage Type

eet conservation demand? Yes

Scenario Output Summary

System Reliability in 2020	
% of Annual Electricity Demand Met	100%
% of Peak Hourly Demand Met	100%
Carbon Impacts in 2020	
Carbon Emissions (metric tons)	5,710,600
% Generation from Renewables in 2020	23%
% Capacity from Renewables in 2020	28%

Costs and Economic Impacts through 2020	
Total Expected Capital Costs through 2020 ($ million)	2,190
Annual Expected Fuel Costs in 2020 ($ million)	420
Expected Increase in Cost of Electricity in 2020 (¢/kWh)	2.0

Before You Begin | Choose Your Generation Mix | Edit Your Own Costs | References | Scenario Calculation Output | Yearly Capacity | 2020 Capacity | Yearly Electricity | 2020 Peak Hourly | 2020 Electricity

Figure A.7
Screenshot of *References* Tab

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References / Assumptions

Capacity Factors and CO2-e Emission Factors	Technology	Capacity Factor	Reference	CO2-e Emission Factor (metric tons/MWh)	Reference
	Coal	0.90	Calculations from Austin Energy 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.	0.94	Calculations from Austin Energy's CCAR Emissions Computations Spreadsheet, 2007
	Nuclear	0.88	Calculations from Austin Energy 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.	0.00	National Regulatory Research Institute. What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria. Columbus, OH, February 14, 2007.
	Natural Gas - Sand Hill 1-4	0.13	Calculations from Austin Energy Documents, including CCAR Emissions Computations Spreadsheet, 2007	0.52	Calculations from Austin Energy's CCAR Emissions Computations Spreadsheet, 2007
	Natural Gas - Sand Hill 5	0.63	Calculations from Austin Energy Documents, including CCAR Emissions Computations Spreadsheet, 2007	0.36	Calculations from Austin Energy's CCAR Emissions Computations Spreadsheet, 2007
	Natural Gas - Decker 1 & 2	0.17	Calculations from Austin Energy Documents, including CCAR Emissions Computations Spreadsheet, 2007	0.56	Calculations from Austin Energy's CCAR Emissions Computations Spreadsheet, 2007
	Natural Gas - Decker CGT	0.05	Calculations from Austin Energy Documents, including CCAR Emissions Computations Spreadsheet, 2007	0.73	Calculations from Austin Energy's CCAR Emissions Computations Spreadsheet, 2007
	Wind	0.29	Calculations from Austin Energy 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.	0.00	National Regulatory Research Institute. What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria. Columbus, OH, February 14, 2007.
	Offshore Wind	0.41	N/A, assumed to be similar to onshore wind.	0.00	National Regulatory Research Institute. What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria. Columbus, OH, February 14, 2007.
	Biomass	0.80	National Regulatory Research Institute. What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria. Columbus, OH, February 14, 2007.	0.10	National Regulatory Research Institute. What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria. Columbus, OH, February 14, 2007.
	FPP co-fired w/ Biomass	0.90	N/A, assumed to be same as coal	0.10	Weighted emissions factor calculated based on the amount of biomass blended into FPP.
	Landfill Gas	0.85	Kauai Island Utility Cooperative. Renewable Energy Technology Assessments. 2005. Online. Available: http://www.kiuc.coop/pdf/KIUC%20RE%20Final%20Report%2010%20-%20Landfill%20Gas.pdf. Accessed: October 23, 2008.	0.10	N/A, assumed to be similar to biomass
	Solar PV - Centralized	0.17	The Value of Distributed Photovoltaics to Austin Energy 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.	0.00	National Regulatory Research Institute. What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria. Columbus, OH, February 14, 2007.
	Solar PV - Distributed	0.17	The Value of Distributed Photovoltaics to Austin Energy 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.	0.00	National Regulatory Research Institute. What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria. Columbus, OH, February 14, 2007.
	Concentrated Solar	0.32	NREL JEDI http://www.nrel.gov/analysis/jedi/, Accessed: March 29, 2009. Assuming West Texas Direct Solar Radiation of 6.0 kWh/m²/day	0.00	National Regulatory Research Institute. What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria. Columbus, OH, February 14, 2007.
	IGCC w/ CCS	0.84	N/A, assumed to be equal to capacity factor for traditional coal	0.16	National Regulatory Research Institute. What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria. Columbus, OH, February 14, 2007.
	IGCC w/o CCS	0.84	N/A, assumed to be equal to capacity factor for traditional coal	0.86	National Regulatory Research Institute. What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria. Columbus, OH, February 14, 2007.
	Geothermal	0.83	National Regulatory Research Institute. What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria. Columbus, OH, February 14, 2007.	0.00	National Regulatory Research Institute. What Generation Mix Suits Your State? Tools for Comparing Fourteen Technologies across Nine Criteria. Columbus, OH, February 14, 2007.
	Fossil Purchased Power	1.00	N/A, assumed to always be available	0.53	Calculations from Austin Energy's CCAR Emissions Computations Spreadsheet, 2007

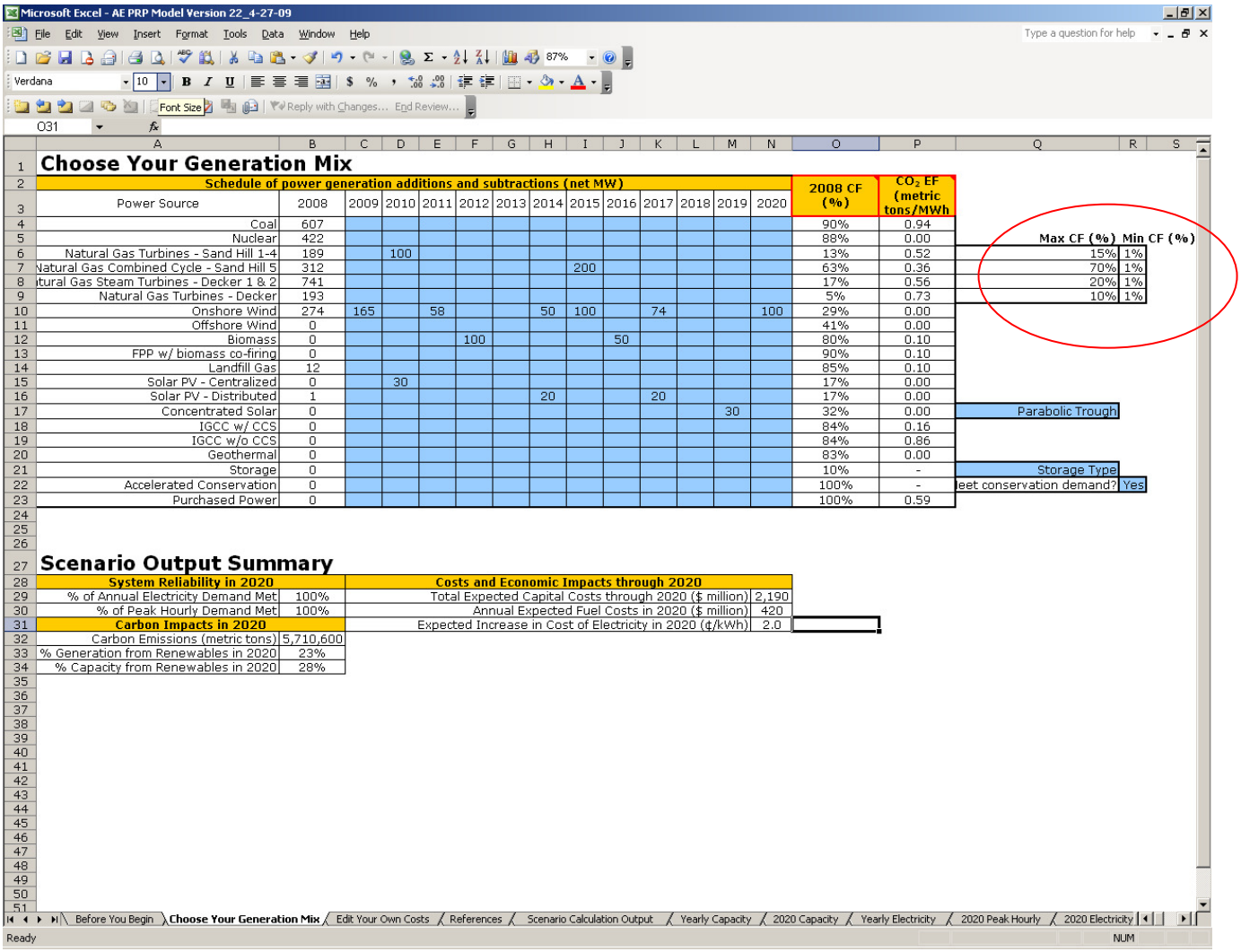
Summary of Peak Day Hourly Profiles	Reference

Summary of Peak Day in August
Hourly Profiles

Before You Begin / Choose Your Generation Mix / Edit Your Own Costs / References / Scenario Calculation Output / Yearly Capacity / 2020 Capacity / Yearly Electricity / 2020 Peak Hourly / 2020 Electricity

Ready NUM

Figure A.8
Screenshot of Minimum and Maximum Capacity Factor for Natural Gas Units



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Choose Your Generation Mix

Power Source	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2008 CF (%)	CO_2 EF (metric tons/MWh
	Schedule of power generation additions and subtractions (net MW)														
Coal	607													90%	0.94
Nuclear	422													88%	0.00
Natural Gas Turbines - Sand Hill 1-4	189		100											13%	0.52
Natural Gas Combined Cycle - Sand Hill 5	312							200						63%	0.36
Natural Gas Steam Turbines - Decker 1 & 2	741													17%	0.56
Natural Gas Turbines - Decker	193													5%	0.73
Onshore Wind	274	165		58			50	100		74			100	29%	0.00
Offshore Wind	0													41%	0.00
Biomass	0				100				50					80%	0.10
FPP w/ biomass co-firing	0													90%	0.10
Landfill Gas	12													85%	0.10
Solar PV - Centralized	0		30											17%	0.00
Solar PV - Distributed	1						20			20				17%	0.00
Concentrated Solar	0											30		32%	0.00
IGCC w/ CCS	0													84%	0.16
IGCC w/o CCS	0													84%	0.86
Geothermal	0													83%	0.00
Storage	0													10%	-
Accelerated Conservation	0													100%	-
Purchased Power	0													100%	0.59

	Max CF (%)	Min CF (%)
	15%	1%
	70%	1%
	20%	1%
	10%	1%

Parabolic Trough

Storage Type

eet conservation demand? Yes

Scenario Output Summary

System Reliability in 2020	
% of Annual Electricity Demand Met	100%
% of Peak Hourly Demand Met	100%
Carbon Impacts in 2020	
Carbon Emissions (metric tons)	5,710,600
% Generation from Renewables in 2020	23%
% Capacity from Renewables in 2020	28%

Costs and Economic Impacts through 2020	
Total Expected Capital Costs through 2020 ($ million)	2,190
Annual Expected Fuel Costs in 2020 ($ million)	420
Expected Increase in Cost of Electricity in 2020 (¢/kWh)	2.0

Before You Begin | Choose Your Generation Mix | Edit Your Own Costs | References | Scenario Calculation Output | Yearly Capacity | 2020 Capacity | Yearly Electricity | 2020 Peak Hourly | 2020 Electricity

Ready

Figure A.9
Screenshot of *Edit Your Own Costs* Tab

Microsoft Excel - AE PRP Model Version 22_4-27-09

AE Resource Portfolio Simulator Costs

Coal, Gas, and Nuclear	l-IGCC w/ CCS		Coal-IGCC w/o CCS			Natural Gas-Advanced Combustion			Natural Gas-Advanced Com		
	Expected	High	Low	Expected	High	Low	Expected	High	Low	Expected	Hi
Total Overnight Costs ($/kW)	$4,774.00	$6,206.20	$2,312.10	$2,569.00	$3,339.70	$ 549.00	$ 610.00	$ 732.00	$ 686.70	$ 763.00	$ 9
Variable O&M Costs ($/kW)	$ 4.53	$ 5.89	$ 2.68	$ 2.98	$ 3.87	$ 2.91	$ 3.23	$ 3.88	$ 1.85	$ 2.05	$
Fixed O&M Costs ($/kW)	$ 46.43	$ 60.36	$ 35.51	$ 39.46	$ 51.30	$ 9.67	$ 10.74	$ 12.89	$ 10.75	$ 11.94	$
Fuel Cost ($/MWh)	$ 27.42	$ 28.79	$ 26.05	$ 27.42	$ 28.79	$ 62.47	$ 78.09	$ 117.14	$ 48.29	$ 60.36	$
Total Levelized Cost of Electricity ($/MWh)	**$ 134.00**	**$ 174.20**	**$ 74.70**	**$ 80.72**	**$ 134.00**	**$ 144.54**	**$ 160.60**	**$ 334.00**	**$ 73.00**	**$ 81.02**	**$ 10**

Renewables (Wind & Solar)	ffshore Wind		Solar Photovoltaics (Centralized)			Solar Photovoltaics (Distributed-			Concentrated Solar-Parab		
	Expected	High	Low	Expected	High	Low	Expected	High	Low	Expected	Hi
Total Overnight Costs ($/kW)	$2,872.00	$3,446.40	$1,305.50	$5,222.00	$6,266.40	$2,408.00	$9,632.00	$10,000.00	$2,036.50	$4,073.00	$4,8
Variable O&M Costs ($/kW)	$ -	$ -	$ -	$ -	$ -	n/a	n/a	n/a	$ -	$ -	$
Fixed O&M Costs ($/kW)	$ 91.32	$ 109.58	$ 9.54	$ 11.93	$ 14.32	n/a	n/a	n/a	$ 46.35	$ 57.94	$
Fuel Cost ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$
Total Levelized Cost of Electricity ($/MWh)	**$ 96.17**	**$ 115.40**	**$ 77.02**	**$ 308.09**	**$ 369.71**	**$ 80.00**	**$ 468.87**	**$ 562.64**	**$ 99.66**	**$ 199.31**	**$ 23**

Other Renewables	ring w/ Biomass		Landfill Gas			Geothermal-Binary		
	Expected	High	Low	Expected	High	Low	Expected	High
Total Overnight Costs ($/kW)	$ 275.00	$ 500.00	$2,036.70	$2,263.00	$2,715.60	$2,904.30	$3,227.00	$ 3,872.40
Variable O&M Costs ($/kW)	n/a	n/a	$ 0.01	$ 0.01	$ 0.01	$ -	$ -	$ -
Fixed O&M Costs ($/kW)	n/a	n/a	$ 104.94	$ 116.60	$ 139.92	$ 151.21	$ 168.01	$ 201.61
Fuel Cost ($/MWh)	$ 25.37	$ 49.19	$ -	$ -	$ -	$ -	$ -	$ -
Total Levelized Cost of Electricity ($/MWh)	**$ 20.00**	**$ 37.00**	**$ 47.12**	**$ 52.36**	**$ 81.00**	**$ 42.00**	**$ 65.55**	**$ 78.66**

Storage Options	ed Air Energy Storage		Battery Storage			Flywheel Storage			Purchased Power		
	Expected	High	Low	Expected	High	Low	Expected	High	Low	Expected	Hi
Total Overnight Costs ($/kW)	$ 675.00	$ 750.00	$1,545.00	$2,322.50	$3,100.00	$3,695.00	$4,004.00	$ 4,313.00	n/a	n/a	n
Variable O&M Costs ($/kW)	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n/a	n
Fixed O&M Costs ($/kW)	n/a	n/a	n/a	$ 66.70	n/a	n/a	n/a	n/a	n/a	n/a	n
Fuel Cost ($/MWh)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	n/a	n/a	n
Total Levelized Cost of Electricity ($/MWh)											

Before You Begin / Choose Your Generation Mix / Edit Your Own Costs / References / Scenario Calculation Output / Yearly Capacity / 2020 Capacity / Yearly Electricity / 2020 Peak Hourly / 2020 Electricity

Figure A.10
Scenario Calculation Output

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Scenario Calculations

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 Turbines - Sand Hill 1-4	189	0	100	0	0	0	0	0	0	0	0	0	0
Natural Gas Combined Cycle - Sand Hill 5	312	0	0	0	0	0	0	200	0	0	0	0	0
Natural Gas Steam Turbines - Decker 1 & 2	741	0	0	0	0	0	0	0	0	0	0	0	0
Natural Gas Turbines - Decker	193	0	0	0	0	0	0	0	0	0	0	0	0
Onshore Wind	274	165	0	58	0	0	50	100	0	74	0	0	100
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	100	0	0	0	50	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

Carbon stack emission factors

	g CO2/kWh	metric tons/MWh
Coal	938	0.938
Nuclear	0	0.000
Natural Gas Turbines - Sand Hill 1-4	520	0.520
Natural Gas Combined Cycle - Sand Hill 5	360	0.360
Natural Gas Steam Turbines - Decker 1 & 2	560	0.560
Natural Gas Turbines - Decker	730	0.730
Onshore Wind	0	0.000
Offshore Wind	0	0.000
Biomass	100	0.100
FPP w/ biomass co-firing	100	0.100
Landfill Gas	100	0.100
Solar PV - Centralized	0	0.000
Solar PV - Distributed	0	0.000
Concentrated Solar	0	0.000
IGCC w/ CCS	156	0.156
IGCC w/o CCS	860	0.860
Geothermal	0	0.000
Storage	0	0.000
Accelerated Conservation	0	0.000
Purchased Power	592	0.592

Installed power generation capacity (MW)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	607	607	607	607	607	607	607	607	607	607	607	607	607
Nuclear	422	422	422	422	422	422	422	422	422	422	422	422	422
Natural Gas Turbines - Sand Hill 1-4	189	189	289	289	289	289	289	289	289	289	289	289	289
Natural Gas Combined Cycle - Sand Hill 5	312	312	312	312	312	312	312	512	512	512	512	512	512
Natural Gas Steam Turbines - Decker 1 & 2	741	741	741	741	741	741	741	741	741	741	741	741	741
Natural Gas Turbines - Decker	193	193	193	193	193	193	193	193	193	193	193	193	193
Onshore Wind	274	439	439	497	497	497	547	647	647	721	721	721	821
Offshore Wind	0	0	0	0	0	0	0	0	0	0	0	0	0
Biomass	0	0	0	0	100	100	100	100	150	150	150	150	150
FPP w/ biomass co-firing	0	0	0	0	0	0	0	0	0	0	0	0	0
Landfill Gas	12	12	12	12	12	12	12	12	12	12	12	12	12
Solar PV - Centralized	0	0	30	30	30	30	30	30	30	30	30	30	30
Solar PV - Distributed	1	1	1	1	1	1	21	21	21	41	41	41	41
Concentrated Solar	0	0	0	0	0	0	0	0	0	0	0	30	30
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
AE scheduled demand reduction	30	50	100	125	160	205	235	260	305	335	350	362	389
Accelerated Conservation	2520	2495	2497	2519	2541	2550	2567	2589	2609	2627	2658	2686	2706
Total capacity	**2751**	**2916**	**3046**	**3104**	**3204**	**3204**	**3274**	**3574**	**3624**	**3718**	**3718**	**3748**	**3848**

	Availability Factor (%)	2008 CF (%)	MAX CF (%)
Coal	95%	90%	
Nuclear	97%	88%	
Natural Gas Turbines - Sand Hill 1-4	96%	13%	15%
Natural Gas Combined Cycle - Sand Hill 5	96%	63%	70%
Natural Gas Steam Turbines - Decker 1 & 2	96%	17%	20%
Natural Gas Turbines - Decker	96%	5%	10%
Onshore Wind	95%	29%	
Offshore Wind	95%	41%	
Biomass	90%	80%	
FPP w/ biomass co-firing	95%	90%	
Landfill Gas	90%	85%	
Solar PV - Centralized	99%	17%	
Solar PV - Distributed	99%	17%	
Concentrated Solar	99%	32%	
IGCC w/ CCS	88%	84%	
IGCC w/o CCS	88%	84%	
Geothermal	92%	83%	
Storage	95%	10%	
Accelerated Conservation	100%	100%	
Purchased Power	100%	100%	

Meet conservation demand? Yes

Peak Demand (MW)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Peak load forecast w/o conservation	2550	2545	2597	2644	2701	2755	2802	2849	2914	2962	3008	3048	3095
Peak load forecast w/ conservation	2520	2495	2497	2519	2541	2550	2567	2589	2609	2627	2658	2686	2706
Peak load forecast w/ accelerated DSM	2520	2495	2497	2519	2541	2550	2567	2589	2609	2627	2658	2686	2706

Yearly Capacity Factors (%)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Coal	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%	90%
Nuclear	88%	88%	88%	88%	88%	88%	88%	88%	88%	88%	88%	88%	88%

Before You Begin / Choose Your Generation Mix / Edit Your Own Costs / References / Scenario Calculation Output / Yearly Capacity / 2020 Capacity / Yearly Electricity / 2020 Peak Hourly / 2020 Electricity

Ready NUM

B. Model Inputs

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 AE Resource Portfolio Simulator allows the user to adjust several inputs to determine the power generation mix that AE uses through 2020 based upon the performance characteristics for which the user feels are most accurate and appropriate.

AE's supply of power generation technologies must have the capabilities to meet demand in order to reliably provide power without having to purchase power from the electric grid. AE's forecasted yearly peak demand and power generation needs (based on 2009 load forecast) are incorporated into the model to demonstrate the ability of a power generation mix to meet demand. As described in the Notes section of Step 6 in Section A, the user can adjust demand by manipulating conservation. The user can also adjust demand in the "Peak Demand" section (Cells A56-O58) of the *Scenario Calculation Output*.

The user has the opportunity to determine investment and divestment decisions made by AE by adjusting the capacity of different power generation technologies as well as adjusting investments in DSM/conservation and energy storage technologies. The user-assigned capacity additions and subtractions of conventional and alternative power generating technologies determine the system's ability to produce power.

Long-term planning factors are included by allowing the user to manipulate technology characteristics (capacity factors and CO_2 emission factors), costs (capital, fuel, and levelized cost of electricity), and demand forecast (by adjusting the "accelerated conservation" inputs), or choose a point in time in which to introduce a new energy resource. 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. Capacity factors for each resource or technology can be adjusted by the hour in the "Hourly Fraction of Peak" section in cells A191-AA211 of the *Scenario Calculation Output* tab to determine hourly electricity production for one peak demand day in 2020.

Projections of demand reduction achieved through DSM strategies allow new capacity additions to be avoided. After a user determines the appropriate investments that allow AE to meet projected electricity demand while attaining the societal goals supported by the user, the model, through a series of outputs discussed in Section C, projects impacts on system reliability, direct CO_2 emissions, and costs associated with the investments made.

The project team analyzed the availability of various energy resources and power generation technologies to determine reasonable investment opportunities through 2020. Only power generation technologies that have the potential to be readily available by 2020 are included as power generation inputs. The following fuel sources, power generation technologies, and enabling technologies are 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 and combined cycle gas units);
- Wind (onshore and offshore/coastal);
- Biomass (using wood waste);
- Coal co-fired with biomass (using wood waste);
- Landfill gas;
- Concentrated solar (parabolic trough, solar-Stirling dish, and power tower);
- Solar photovoltaic (centralized facilities and distributed systems);
- Geothermal (binary cycle power plants); and
- Energy storage (compressed air, pumped storage, flywheels, and batteries)

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 with the option of integrating a carbon capture and storage (CCS) system and are represented in the model 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 CO_2 emission factors. "Sand Hill 1-4" are combustion gas turbines, "Sand Hill 5" is a combined cycle unit, "Decker 1 & 2" are steam turbine units, and "Decker" 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. The simulator assumes that all coal, nuclear, and natural gas additions are made as additions of units to AE's current facilities that have the same technology characteristics as existing units or new facilities with the same technology characteristics. No other units represent current operating facilities for AE. However, the characteristics of solar PV systems and wind energy turbines resemble the characteristics for current wind and solar capacity for AE.

C. Model Outputs

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. Each resource or facility's power generation capacity is multiplied by the amount of time the resource is used (MW × hours/year), determining 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 PV modules). The amount of electricity produced annually is multiplied by each resource or facility's CO_2 emission factor, yielding a direct CO_2 emissions profile (in metric tons/year) forecasted to 2020.

Based on the input values, a number of calculations are performed to generate power generation capacity, electricity delivered, CO_2 emissions, and costs outputs for a scenario. The process by which these outputs are generated, including any calculations used, is provided below. Sections D and E provide information on the assumptions and limitations of the model. The resulting series of outputs are as follows:

- Annual power generation capacity from each resource and/or facility and the overall mix through 2020;
- Percentage of power generation capacity from each resource and/or facility in 2020;
- Annual electricity production from each resource and/or facility and the overall mix through 2020;
- An hourly load profile for meeting peak demand in 2020 with electricity production from each resource and/or facility and the overall mix;
- Percentage of electricity delivered from each resource and/or facility in 2020;
- A carbon emissions profile through 2020;
- Annual capital costs of new resources and/or facilities added to the mix (represented as total overnight costs);
- Annual fuel costs of the power generation mix;
- Expected increase in the cost of electricity (represented as total levelized costs of electricity) attributed to each resource;
- Potential annual costs to offset remaining CO_2 emissions; and
- Potential annual carbon costs or profits related to carbon regulation between 2014 and 2020.

Calculations

The *Scenario Calculation Output* tab provides all of the numerical outputs for the model, including the following tables and calculations:

- A schedule of net power generation additions and subtractions (MW);
- Installed power generation capacity (MW);
- Projected peak demand depending on conservation and accelerated DSM (MW);
- Yearly capacity factors (%);
- Actual power generation based on capacity factors (MWh);
- Annual electricity production from each resource and the overall mix through 2020;
- A carbon emissions profile through 2020 (metric tons based on stack emissions to meet AE's laod);

- Potential annual CO_2 costs or profits related to carbon regulation between 2014 and 2020;
- Potential costs to offset remaining CO_2 emissions;
- An hourly load profile (peak demand, summer 2020) for meeting peak demand in 2020 with electricity production from each resource and the overall mix;
- Expected annual capital costs of new facilities added to the mix, represented as total overnight costs (millions and $/kW) as well as low and high estimates;
- Expected levelized cost of electricity of additions (cents per kWh) as well as low and high estimates;
- Total cost summary (low, expected, and high estimates);
- Expected fuel costs (millions and $/MWh);
- Capacity additions (MW);
- Cumulative capacity additions (MW); and
- Actual power generation from new additions (MWh and fractional).

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. 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.

Carbon Dioxide Emissions and Carbon Costs

Energy resources are assigned a carbon-equivalent emissions factor per unit of electricity produced (in metric tons of CO_2 equivalent per MWh of electricity generated). CO_2 emissions are calculated by taking the summation of the electricity generated by each resource (MWh) multiplied by that resource's CO_2 emission factor (CO_2-eq/MWh). 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 $5 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.

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.

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. The simulator assumes that carbon credits for which AE could potentially sell would be worth the same as those purchased at auction.

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. The majority of the default capital cost values are based upon values used by the California Energy Commission (CEC) in a 2007 report on the levelized cost of electricity of different power generation technologies. High and low estimates are based on assumptions of future cost projections (see *References* tab). These values were used to ensure consistency with the projections of expected increase in levelized costs of electricity. However, not all power sources were evaluated by the CEC study.

Fuel costs for a power generation mix are represented as dollars per MWh of electricity generated ($/MWh). A potential range of fuel cost projections are based upon values used in the CEC study and assumptions made regarding the potential future costs of these fuels (see *References* tab). 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.

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, 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. 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. 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. The majority of the default expected levelized cost of electricity values are based upon values used by the CEC. High and low estimates are based on assumptions of future cost projections and other studies as referenced in the *References* tab.

D. Underlying Assumptions of the Model

As previously noted, this model is intended to provide a basic 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 as estimated from AE documents with specific data.
- Actual energy produced is based upon power generation capacity multiplied by capacity factor multiplied by 8760 (hours in a year).
- A 5 percent transmission loss is applied to all resources (except distributed solar PV modules) in calculating actual energy generated.
- Efficiencies of technologies (represented within the capacity factors) 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 variable sources (see *References* tab).
- Energy storage is not represented as additional power generation capacity, but rather as a mechanism to use excess electricity during a different period of the day. This is manipulated automatically 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 or leasing existing facilities (or part 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.

E. Limitations of the Model

The following limitations exist in the model:

System Reliability

- The model is not an hourly dispatch model and, thus, does not account for purchases and sales of electricity in the electric market.
- The model does not account for potential changes to the ERCOT market with the switch to a nodal market.
- Projected demand for actual energy delivered (in MWh, not peak power demand in MW) is not based upon specific AE projections, but determined empirically from AE data.
- 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 store excess electricity between the hours of midnight and 10 AM on the peak day and dispatch the stored electricity between the hours of noon and 10 PM. The model does not have the capability to model daily usage of storage facilities nor does it have the capability to estimate the electricity cost of storage. The cost limitations exist because storage technologies do not generate electricity; they shift times of dispatch of electricity.

Costs and Economic Impacts

- Capital costs for additions to existing facilities use data for total overnight costs for a new facility.
- All expected 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. However, future cost projections are captured by the range of costs provided.
- 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 can be made only by any additional capital costs or fuel costs that are introduced, but the model displays a message to the user that levelized costs cannot be calculated when using storage technologies.

Contacts for Further Information

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Appendix B.
Economic Impact Methodology

The economic impact projections for selected power generation mix scenarios were generated with the IMPLAN (IMpact analysis for PLANning) program. IMPLAN is an input-output program that uses Keynesian multipliers. The program is marketed by the Minnesota IMPLAN Group (MIG, Inc). IMPLAN uses industry and demographic data collected on the State of Texas and particular regions within the State. Specific regions analyzed for economic impacts include the 10 county regions of the Capital Area Council of Governments (CAPCOG) for Central Texas, Nacogdoches County, Matagorda County, and the Competitive Renewable Energy Zones (CREZ) in West Texas and the Texas Panhandle.

Chapter 12 provides analysis of eight selected power generation mix scenarios that are modeled using IMPLAN's Social Accounting Matrix (SAM) function. The SAM function uses historical multipliers to project the impact of investment in diverse sectors. In addition to the impacts within a particular sector, SAM also projects indirect impacts on related industries and induced impacts created by projected changes in household incomes.[1]

The inputs needed to capture the values associated with new electricity generation sources are the name of the county in which the plant is to be built and the subsequent data from that county (information on population, land area, property tax, sales tax, etc.), the dollar amount of the investment, what industry sector the investment applies to, and the year that the investment is made. Once the inputs have been inserted in IMPLAN, there are three outputs that IMPLAN produces: total value added, total output, and employment years.

Assumptions and Calculations

The key assumptions of the IMPLAN model are constant returns to scale, unconstrained supply, fixed commodity input structure, homogenous output, and uniform industry technology.[2] IMPLAN does not have data specific to 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 unconventional 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 Jobs and Economic Development Impact (JEDI) model, a tool that was developed as a joint venture between MIG, Inc and the National Renewable Energy Lab (NREL). This tool can be used to analyze the impacts of investment in coal plants, wind energy, solar concentrating facilities, or natural gas facilities.[3]

Expected capital costs (represented as total overnight costs) and expected operations and maintenance costs used in the simulation software discussed in Chapter 2 are used as inputs to IMPLAN (see Figure B.1). Capital costs are amortized equally into the three years preceding new power generation capacity additions.[4,5] The costs for operation and maintenance begin to incur in the year in which capacity is posted on the scenario schedule and continue to occur in each successive year. Distributed photovoltaic (PV) solar, however, is an exception because it is modeled as solely taking place in the year it is added into the scenario schedule.

The most important assumptions regarding the inputs for each model concern the location of the projected power generation facilities. For the purposes of this analysis, the project team modeled all onshore wind and concentrated solar facilities in the counties encompassed by the Electric Reliability Council of Texas (ERCOT) CREZ in West Texas and the Texas Panhandle.[6] All natural gas, distributed solar PV, landfill gas, and geothermal are modeled as being constructed in the ten counties that compose the CAPCOG region (see Figure B.2). New coal and nuclear facilities are modeled in Matagorda County and biomass facilities are modeled in Nacogdoches County.

Eight scenarios are evaluated in this report. These scenarios are computed using a Microsoft® Excel spreadsheet that allowed the project team to automatically estimate the outlays in operations and maintenance costs and overnight costs for each year of a scenario schedule. Figure B.3 provides an example of a schedule of additions and subtractions for a resource portfolio scenario.

The economic impacts attributed to each scenario are projected by year for each development region, which are divided according to types of power generation: Nacogdoches County (biomass), CAPCOG (natural gas, landfill gas, geothermal, coal, distributed solar, centralized solar), Matagorda County (nuclear and clean coal facilities) and CREZ (concentrated solar and onshore wind). Figure B.4 shows an example of the calculation used for estimating annual capital costs.

Using IMPLAN

Selecting regions that will be affected economically by an investment schedule is the first step in the IMPLAN procedure (see Figure B.5). This function allows IMPLAN to interpret the specific impact on the different regions according to new types of power generation.

Figure B.6 shows an IMPLAN generated screenshot of the type of information that is included in the regional demographic and industry data. This data is then aggregated to form a model of one of the development zones. For example, in Figure B.6 ten counties were selected for the CAPCOG region and IMPLAN automatically calculates the demographic and basic industry data for the selected region.

The next step is to enter the input data on the basis of regional demographic data and IMPLAN codes (see Figure B.7). In the first column, the year and type of cost are entered under “Event Name” in order to keep track of each investment. “Sector,” the

second column, the operations and maintenance inputs for each year, are coded as sector 31 (Sector 31: Electronic power generation and transmission), capital costs are coded as sector 36 (Sector 36: Construct other new nonresidential structure), and distributed solar PV capital costs are modeled as sector 39 (Sector 39: Maintenance and repair construct of nonresidential structure). "Value," the third column, refers to total expenditures in selected industry sector. This has a positive linear relationship with new created "Employment," the fourth column. Adjusting the fifth column, "Basis," allows the user to select the type of impact. An industry impact gives the entire event amount to the industry selected.[7] In the next two columns, "Year" and "Deflator," expenditures are presented in historical dollars for a year other than the regional model data. The year of that expenditure must be specified in order to apply the correct deflator. The version of IMPLAN which we used for this project discounted all outputs to 2007 dollars. The column "Margin" is only important for commodities, so that input is left blank. The last column, "% Local," refers to local purchase coefficients. This indicates the portion of the direct expenditure that should be applied to the model. Since the project team assumed that the event is an entirely local activity, the "% Local" field equals 100 percent.

Outputs

Figure B.8 shows the outputs produced by the IMPLAN model. These outputs represent the total value of economic activity resulting from the grouped events. The marginal impacts on each IMPLAN industry are identified as direct, indirect, or induced.

Direct impacts refer to on-site or immediate effects created by expenditures. For example, if a wind plant is constructed this would refer to the on-site jobs of the contractors and crews hired to construct the plant. It would also include the jobs at the turbine manufacturing plants and the jobs at the tower and blade factories.

Indirect effects refer to the increase in economic activity that would occur when a contractor, vendor, or manufacturer receives payment for goods or services and, in turn, is able to pay others who support their business. For instance, this impact includes the banker who finances the contractor; the accountant who keeps the contractor's books, and the steel mills, electrical manufacturers, and other suppliers that provide the necessary materials.

Indirect effects refer to the change in wealth and income that is induced by the spending of those persons directly and indirectly employed by the project. This would include spending on food, clothing, or daycare by those directly or indirectly employed by the project, retail services, public transit, utilities, cars, oil, property and income taxes, medical services, and insurance.[8]

Each marginal impact can be divided into three outputs: Total Output, Total Value Added and Employment Years. Total Value Added is made up of four sub-components: employee compensation (wages and salaries of workers, benefits, and non-cash compensation); proprietary income (payments received by self-employed individuals as income); other property type income (payments for rents, royalties, and dividends); and

indirect business taxes (excise taxes, property taxes fees, licenses, and sales taxes paid by business).[9] It can be calculated the following way:

Value Added = Total Revenues - Cost of Inputs from outside sources.

Total Output is a single number represented in US dollars. The value represents total production in the selected region. Data is derived from a number of sources, including Census Bureau data, Bureau of Economic Analysis output estimates, and the Bureau of Labor Statistics employment projections.[10] Total output is comprised of total revenues, sales, or the total value of the output.

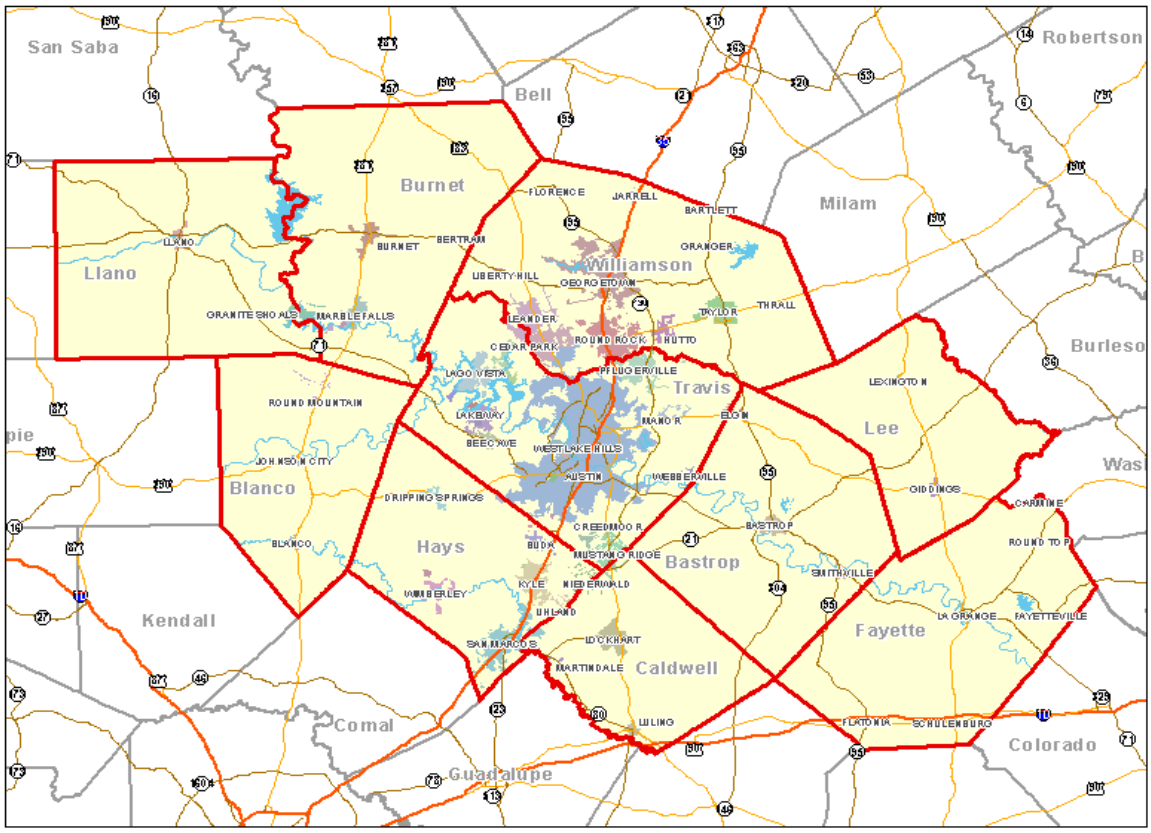
Employment Years is listed as a single number of jobs in the selected region. Data came from ES202 employment security data supplemented by county business patterns and Regional Economic Information System data.[11]

Figure B.1
Screenshot of Data Used for Cost Inputs

	A	C	D	E	F	G	H	I	J	K
1	AE Future Generation Mix Cost Modeling with Ranges									
2										
3		Coal-Pulverized (w/scrubber technology)			Coal-IGCC w/ CCS			Coal-IGCC w/o CCS		
4	Cost Analysis	Low	Expected	High	Low	Expected	High	Low	Expected	High
5	Total Overnight Costs ($/kW)	$ 2,360.75	$ 2,485.00	$ 2,982.00	$ 4,296.60	$ 4,774.00	$ 6,206.20	$ 3,023.10	$ 3,359.00	$ 4,366.70
6	Variable O&M Costs ($/kw)	$ 4.45	$ 4.68	$ 5.62	$ 4.08	$ 4.53	$ 5.89	$ 2.68	$ 2.98	$ 3.87
7	Fixed O&M Costs ($/kw)	$ 26.70	$ 28.10	$ 33.72	$ 41.79	$ 46.43	$ 60.36	$ 35.51	$ 39.46	$ 51.30
8	Fuel Cost ($/MWh)	$ 13.32	$ 14.02	$ 14.72	$ 12.51	$ 13.17	$ 13.83	$ 12.51	$ 13.17	$ 13.83
9	Total Levelized Cost of Electricity ($/MWh)	$ 74.00	$ 90.00	$ 134.00	$ 120.60	$ 134.00	$ 174.20	$ 74.70	$ 104.00	$ 135.20
10										
11	Total O&M Costs($/kW)	$31.14	$32.78	$39.34	$45.86	$50.96	$66.25	$38.20	$42.44	$55.17
12										

Source: Created by project team.

Figure B.2
Map of CAPCOG Region



Source: Capital Area Council of Governments. Online. Available: http://data.capcog.org/Information_Clearinghouse/download-interface/images/mapfordownloadscounty.png. Accessed: May 15, 2009.

Figure B.3 Example of Investment Schedule

4		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
5	Coal	607						-305		-302				
6	Nuclear	422												
7	Natural Gas - Sand Hill 1-4	189	100							302				
8	Natural Gas - Sand Hill 5	312					200	305						
9	Natural Gas - Decker 1 & 2	741												
10	Natural Gas - Decker CGT	193												
11	Wind	274	165		23			50	100		74		50	110
12	Offshore Wind	0												
13	Biomass	0				100				100				
14	FPP w/ biomass co-firing	0												
15	Landfill Gas	12		30										
16	Solar PV - Centralized	0						20			20			
17	Solar PV - Distributed	1											30	
18	Concentrated Solar	0												
19	IGCC w/ CCS	0												
20	IGCC w/o CCS	0												
21	Geothermal	0												
22	Storage	0												
23	Accelerated Conservation	0												
24	Purchased Power	0												
25														

Source: Created by project team.

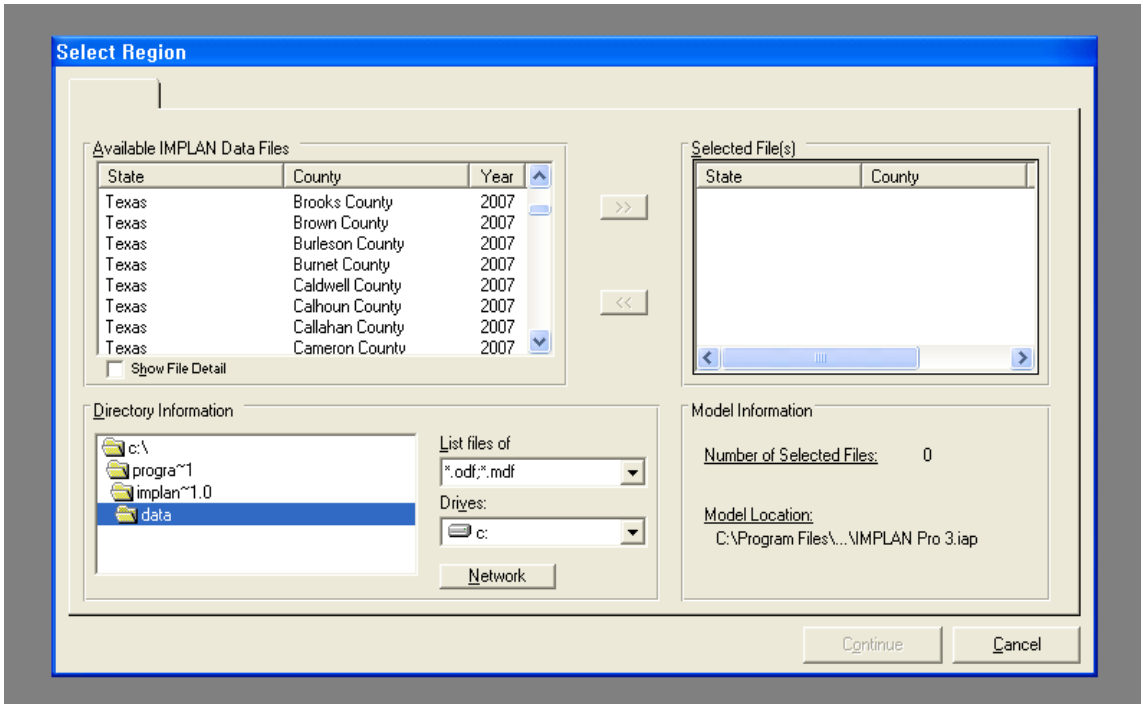
Figure B.4 Example of Calculation for Capital Costs

CapCog Expected Capital Costs	2005	2006	2007	2008	2009	2010	2011
Accrued Capital Cost				0	47	173	0
				0	15.766667	57.82	0
Amortized	0	0	0				
		15.76666667	15.766667	15.7666667			
			57.82	57.82	57.82		
				0	0	0	
					0	0	0
						0	0
							0
	0	15.76666667	73.586667	73.5866667	57.82	0	0

Matagorda Bay Expected Capital Costs	2005	2006	2007	2008	2009	2010	2011
Accrued Capital Costs				0	0	0	0
Amortized				0	0	0	0
	0	0	0				
		0	0	0			
			0	0	0		
				0	0	0	
					0	0	0
						0	0
							0

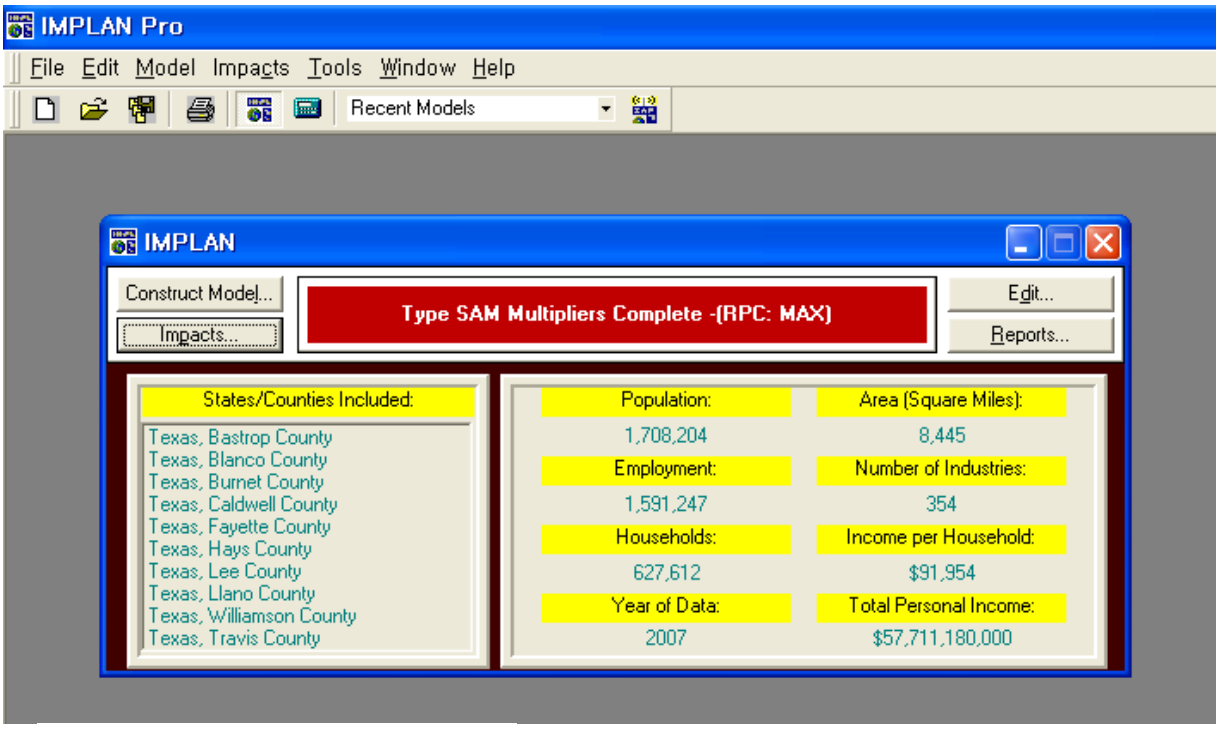
Source: Created by project team.

Figure B.5 Screenshot for Selecting Region in IMPLAN



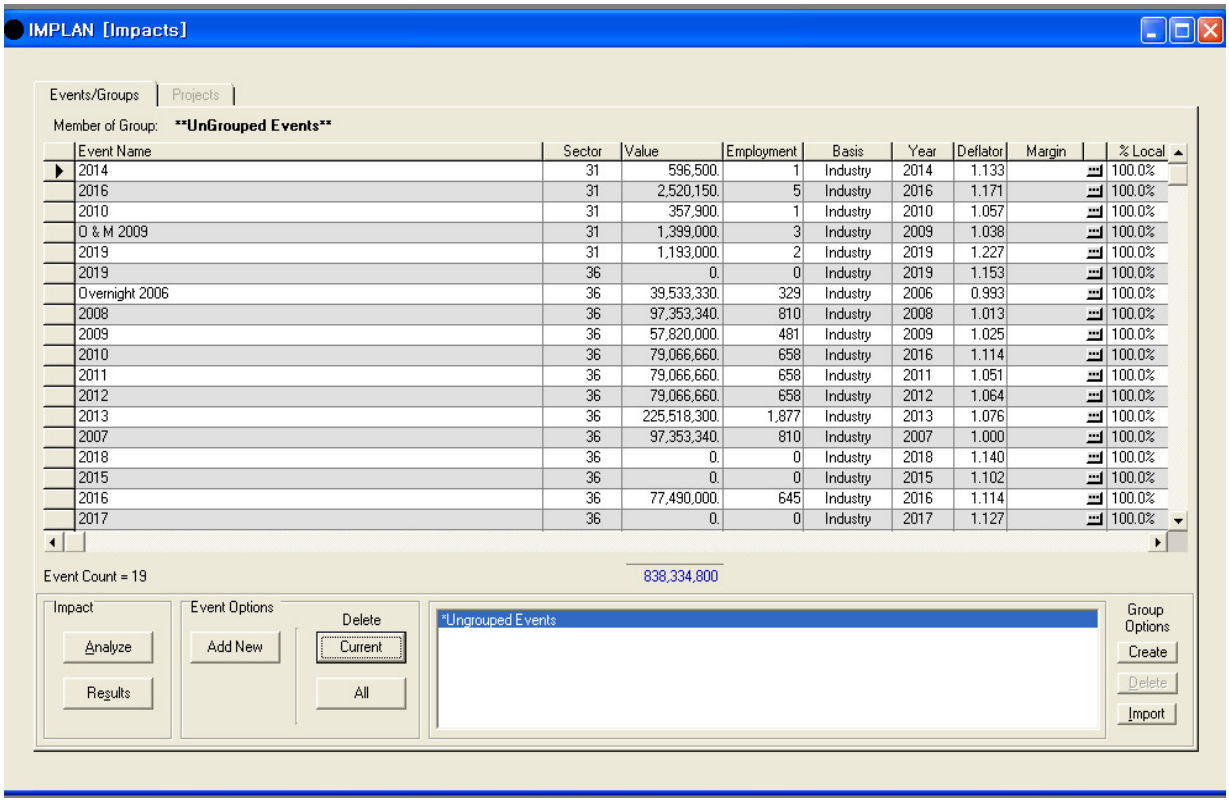
Source: Minnesota IMPLAN Group (MIG), Inc., *IMPLAN Pro 2.0*.

Figure B.6 Screenshot of Regional Demographic and Industry Data Included in IMPLAN



Source: MIG, Inc., *IMPLAN Pro 2.0*.

Figure B.7
Screenshot of Input Data in IMPLAN



Event Name	Sector	Value	Employment	Basis	Year	Deflator	Margin	% Local
2014	31	596,500.	1	Industry	2014	1.133		100.0%
2016	31	2,520,150.	5	Industry	2016	1.171		100.0%
2010	31	357,900.	1	Industry	2010	1.057		100.0%
O & M 2009	31	1,399,000.	3	Industry	2009	1.038		100.0%
2019	31	1,193,000.	2	Industry	2019	1.227		100.0%
2019	36	0.	0	Industry	2019	1.153		100.0%
Overnight 2006	36	39,533,330.	329	Industry	2006	0.993		100.0%
2008	36	97,353,340.	810	Industry	2008	1.013		100.0%
2009	36	57,820,000.	481	Industry	2009	1.025		100.0%
2010	36	79,066,660.	658	Industry	2016	1.114		100.0%
2011	36	79,066,660.	658	Industry	2011	1.051		100.0%
2012	36	79,066,660.	658	Industry	2012	1.064		100.0%
2013	36	225,518,300.	1,877	Industry	2013	1.076		100.0%
2007	36	97,353,340.	810	Industry	2007	1.000		100.0%
2018	36	0.	0	Industry	2018	1.140		100.0%
2015	36	0.	0	Industry	2015	1.102		100.0%
2016	36	77,490,000.	645	Industry	2016	1.114		100.0%
2017	36	0.	0	Industry	2017	1.127		100.0%

Source: MIG, Inc., *IMPLAN Pro 2.0.*

Figure B.8
Screenshot of IMPLAN Outputs

Impact Name

IMPLAN

Type

- Value Added (VA)
  - Labor Income
    - Employee Compensation
    - Proprietors Income
  - Other Property Type Income
  - Indirect Business Taxes
- Employment
- Output

2007 dollars (except 'Employment')

Output Results:

Sector	Direct	Indirect	Induced	Total
1: Oilseed farming	0	1	2	3
2: Grain farming	0	4,063	5,730	9,793
3: Vegetable and melon farming	0	98	13,754	13,852
4: Fruit farming	0	47	17,288	17,335
5: Tree nut farming	0	36	8,844	8,880
6: Greenhouse- nursery- and floriculture pro	0	4,965	79,295	84,260
8: Cotton farming	0	158	604	762
10: All other crop farming	0	1,235,944	30,506	1,266,450
11: Cattle ranching and farming	0	2,678	72,278	74,956
12: Dairy cattle and milk production	0	1,019	15,309	16,328
13: Poultry and egg production	0	703	92,137	92,840
14: Animal production- except cattle and pc	0	1,106	26,918	28,024
15: Forestry- forest products- and timber trac	0	67	2	69
16: Commercial logging	0	20,207	396	20,603
18: Commercial hunting and trapping	0	0	28,447	28,447
19: Support activities for agriculture and for	0	2,685	560	3,245
20: Extraction of oil and natural gas	0	3,281,288	800,855	4,082,143
25: Mining and quarrying stone	0	345,723	2,237	347,960
26: Mining and quarrying sand- gravel- clay-	0	31,133	871	32,004
27: Mining and quarrying other nonmetallic	0	131	103	234
29: Support activities for oil and gas operati	0	64,621	14,026	78,647
31: Electric power generation- transmission-	-10,822,310	1,038,407	898,861	-8,885,041
32: Natural gas distribution	0	292,988	255,943	548,931
Totals:	$778,453,531	$207,311,815	$139,590,191	$1,125,355,538

Source: MIG, Inc., *IMPLAN Pro 2.0*.

Notes

[1] Minnesota IMPLAN Group (MIG), Inc., *IMPLAN Professional 2.0 User's Guide, Analysis Data Guide* (Stillwater, Minnesota, 2004), p. 102.

[2] Ibid., p. 103.

[3] United States Department of Energy, *Job and Economic Development Impact (JEDI) Model*. Online. Available: http://www.windpoweringamerica.gov/filter_detail.asp?itemid=707. Accessed: November 11, 2008.

[4] MIG, Inc., *IMPLAN Support: Analysis Questions*. Online. Available: http://implan.com/index.php?option=com_fireboard&Itemid=76&func=view&catid=84&id=&id=237&catid=84. Accessed: November 11, 2008.

[5] Interview with Christopher Frye, Economic Development Director, Austin Energy, Austin, Texas, March 1, 2009.

[6] Bill Bojorquez, *Competitive Renewable Energy Zone (CREZ) Update*. Online. Available: http://www.ercot.com/meetings/board/keydocs/2007/B1016/Item_06_-_CREZ_Update.pdf. Accessed: November 13, 2008.

[7] MIG, Inc., *IMPLAN Professional 2.0 User's Guide,* p. 50.

[8] Ibid., p. 81.

[9] Ibid., p. 126.

[10] Ibid., p. 125.

[11] Ibid.