Modeling Report for the Draft Energy Master Plan

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Edward J. Bloustein School
of Planning and Public Policy

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I. Overview

The State of New Jersey is undertaking an extensive and comprehensive energy planning effort. New Jersey is statutorily required to adopt an Energy Master Plan addressing the production, distribution, consumption, and conservation of energy for a period of ten years and to provide updates every three years. In addition, on February 13, 2007, Governor Corzine signed Executive Order 54, setting greenhouse gas reduction objectives for the years 2020 and 2050. The New Jersey Legislature passed and the Governor signed on July 6, 2007 the Global Warming Response Act, which calls for reducing greenhouse gas emissions to 1990 levels by the year 2020 and further reducing them to 80% below 2006 levels by 2050. The New Jersey Department of Environmental Protection (DEP) is preparing a comprehensive inventory of greenhouse gases in response to Executive Order 54 and the Global Warming Response Act.

The Center for Energy, Economic and Environmental Policy (CEEEP) and the Rutgers Economic Advisory Service (R/ECON™), both located within the Edward J. Bloustein School of Planning and Public Policy of Rutgers, the State University of New Jersey, have been tasked by the New Jersey Board of Public Utilities (BPU) to provide data and modeling support for the master plan effort. The BPU chairs the New Jersey State Energy Master Plan Committee. This preliminary report describes the context, data assumptions, and preliminary calculations.

A series of prior events helped to build the foundation for this report. On December 18, 2006, CEEEP and R/ECON™ presented the modeling framework used in this report to stakeholders. On January 5 and 19, 2007, CEEEP convened two technical working groups to elicit input on electric generation and transmission. In addition, CEEEP and R/ECON™ participated extensively in many stakeholder meetings convened as part of the Energy Master Plan process from late 2006 through July 2007. CEEEP and R/ECON™ envision further collaboration with stakeholders with respect to the assumption and modeling process.

The purpose of this paper is to provide information for the review process on the draft Energy Master Plan. Section II of this report describes the role of modeling in long-term energy planning; Section III articulates the two basic scenarios that are modeled – Business as Usual (BAU) and Alternative; and Section IV reports on the preliminary results of this modeling effort. Appendix A provides the policies in the BAU and Alternative scenarios, and Appendix B provides more details on the assumptions used in the modeling. The policies assumptions and modeling results included in this paper deal with electricity, space heating, and natural gas and fuel oil use. Transportation assumptions are under development and will be included in the analysis at a later date. The results—primarily coming out of the R/ECON™ model—may change when transportation policies are added to the analysis. In addition, the assumptions used in the draft Energy Master Plan were made at the start of the process and will need to be updated prior to the publication of the final Energy Master Plan.

II. Long-term Energy Planning and Modeling

A. Energy Planning

Planning is a broad term whose meaning varies according to the context in which it is used. The role of data analysis and modeling within a planning context can also vary. In the context of the Energy Master Plan for New Jersey, planning should be an iterative process that articulates fundamental objectives, establishes measurable targets, assigns resources and responsibilities for meeting those targets, and reevaluates and adjusts the Plan's strategies over time.

The value of planning comes from both the process and the outcomes. The process provides a structure that should help policymakers and stakeholders think through implications and impacts of different strategies. The output from modeling the Plan enables policymakers and stakeholders to assess whether the Plan satisfies its objectives and allows them to evaluate its performance over time.

A cursory review of energy events over the last several decades reveals that the unexpected is the norm, not the exception. In the late 1970s and early 1980s, there were serious concerns about the possibility of prices reaching $100 per barrel of oil. During the 1990s oil and natural gas prices were at very low levels but they have increased dramatically in recent years. In the 1970s, natural gas was not permitted to be used to generate electricity. In the 1990s and until the relatively recent spike in natural gas prices starting in 2002, natural gas became the dominant fuel for new generation plants. In 1979, the meltdown at Three Mile Island precipitated a halt in the construction of new nuclear power plants. Now a possible resurgence may be occurring with the extension of licenses by twenty years and preliminary plans for building new plants. Air emissions concerns in the 1970s revolved around sulfur dioxide and nitrogen oxide; today they also include emissions of greenhouse gases like carbon dioxide and methane. Finally, new technologies are being developed and improved including those for hybrid vehicles, fuel cells, carbon sequestration, biomass, wind turbines, and solar power.

The planning process must account for the fact that the future is unknown. The process must be able to identify major uncertainties, determine when events depart substantially from what the plan assumed, and make changes as appropriate. An inappropriate response to uncertainty, however, is to assume that planning has no value. Its value is in establishing the conditions under which policies will be successful and thereby in defining the framework that would need to be adjusted if those conditions fail to materialize.

Fundamentally, the Energy Master Plan assumes that there is a critical connection between energy, environmental, and economic policies that must be addressed in a comprehensive fashion. In addition, the Plan assumes that fossil fuel prices are likely to increase, that global warming is a serious problem that requires immediate action, that energy efficiency is the most cost-effective means of addressing most of the foreseeable future increases in energy needs, and that a variety of renewable technologies should be developed and implemented for economic and environmental reasons. It is within this context that the role of modeling is discussed.

B. Energy Modeling in Support of the Energy Master Plan Process

This section reviews the modeling effort that supports the development of the Energy Master Plan. Its main points should be kept in mind when reviewing the details of the modeling effort covered in Sections III and IV below. Specifically, this section discusses the purpose and limitations of the modeling effort, the distinction between the modeling efforts and the Energy Master Plan, the difference between planning and forecasting as it relates to the Energy Master Plan, and the relationship between modeling results and implementation.

The purpose of the modeling is to inform the process, not to be dispositive. The engineering, economic, and policy issues are so complex and intertwined that there is not a single "right" solution that the modeling is supposed to calculate. Instead, by comparing alternatives, the modeling illustrates the likely differences in outcomes under a set of defensible, reasonable assumptions. It forces data collection and analysis, justification of assumptions, understanding of complexities and relationships, and rigorous means to test intuition and establish orders of magnitude. Regardless of the results, the process of modeling is extremely helpful. The modeling may narrow areas of disagreement, help to identify uncertainties that matter and those that do not given the policy choices, identify key tradeoffs, and establish the conditions under which certain outcomes can occur. Obviously, it is intended that the results themselves contribute to the planning process and discussions, but not that the model determines the specific policy design.

The Energy Master Plan should not be confused with the assumptions and policies modeled. Clearly, there is an important connection between a proposed plan and the modeling effort, but that does not mean what is modeled is "the Plan". For example, the modeling effort may assume that 1,000 mega-Watts (MW) of New Jersey off-shore wind are built by the year 2020, but the Plan, as implemented, may start with a smaller pilot facility to gain more knowledge and experience about costs and performance. The results from the pilot project will have implications regarding whether and how to continue.

Furthermore, the modeling cannot reproduce every possible policy or investment alternative because there is simply not enough time or capacity to do so. Moreover, the models may not be as sensitive to the differences between two *similar* policies that have significant implications for one stakeholder group versus another. Understandably, stakeholders are concerned about particular projects, and may infer that the inclusion or lack of inclusion of a particular project indicates that the Energy Master Plan does or does not consider that project as part of the Plan. While not every scenario can be modeled, there will be qualitative discussions of these differential impacts and additional modeling runs may be commissioned at a later time.

In addition, many stakeholders have strong views about what the future holds. Naturally, they would like to see these views embodied in the Energy Master Plan and modeling assumptions as much as possible. For instance, many stakeholders believe that a national carbon dioxide policy will be implemented during the planning horizon of the Energy Master Plan. This modeling effort considers this possibility as a sensitivity case to the BAU and Alternative scenarios. The fact that a national carbon dioxide policy is considered as a sensitivity case should not be taken to indicate that New Jersey does not think such an approach is desirable or that a national approach is unlikely. Instead, the modeling effort is based on existing or explicitly state- or regionally-driven policies, in this case, the Regional Greenhouse Gas Initiative (RGGI).

Another frequent source of misunderstanding is equating modeling with forecasting. The modeling effort compares the BAU and Alternative scenarios under a reasonable set of assumptions. Absolute errors in assumptions typically, but not always, result in smaller errors when comparing the differences between two outcomes than without such a comparison. The BAU and Alternative scenarios are meant to represent two possible energy futures for New Jersey. The BAU follows the current trajectory that New Jersey established in the 2004 base year. The Alternative scenario represents a set of energy futures that depart significantly from the current path. The purpose of the modeling effort is to provide quantitative calculations that inform decisions regarding the comparison of these two scenarios by helping to determine which policies have a relatively greater impact on the state's energy, environmental, and economic landscape than others.[1]

This is not meant to suggest that in developing the BAU and Alternative scenarios that assumptions are chosen without care. Nothing could be further from the truth. Great effort has been made to pick reasonable, credible, and objective assumptions for use in the models. Moreover, in Section IV, sensitivity analysis is also provided with the preliminary calculations. That being said, since the purpose is to compare the relative merits of two courses of action, it is the relative differences that drive the comparison, not absolute numbers. In contrast to this relative analysis, investors in projects and other stakeholders care substantially about absolute outcomes, such as the price of natural gas or the capacity factor of a wind farm. The assumptions made in this modeling effort are tailored to its context and objectives; using these assumptions in other situations may not be appropriate.

Another common misunderstanding is equating each assumption to an explicit provision of the plan. In many cases, the models require a level of detail well beyond what is appropriate for a long-term plan. For instance, in modeling future electricity prices, the model that is used calculates the amount of electricity a power plant produces in every hour in the year 2020. Clearly, one should not interpret the output of this model that New Jersey wants power plant X to produce 123 MW at 1 pm on July 23, 2020.

In other cases, a sufficient level of detail regarding a particular issue is not readily available, but assumptions have to be made. An example of this is the judicious location of energy efficiency measures, demand response, and combined heat and power facilities that may allow the postponement or avoidance of transmission and distribution (T&D) upgrades. Determining these locations requires highly specific information that is not readily available. Given this practical limitation, the modeling made generic assumptions for the potential T&D savings that could occur with judicious location of these measures.

It is also important to consider the modeling results in the context of the underlying strategies. Sometimes the relationship between policies and outcomes can get lost in all the calculations. The modeling should provide a means to test and understand the EMP's themes and strategies, not become the focus of the EMP. This document should be read in conjunction with the draft New Jersey Energy Master Plan and associated strategy documents.

The modeling process establishes many of the conditions under which policies can achieve their intended outcomes. This helps tremendously with evaluating policy implementation and understanding the conditions under which policy changes may be necessary. Some assumptions made in the modeling will be wrong. Unforeseen events will require changes in direction and policies. Planning in general and modeling in particular can help anticipate these possibilities and determine appropriate responses at the appropriate times.

In short, the Energy Master Plan must explicitly deal with uncertainty and the prospect that things will turn out differently from what was assumed. This often gets lost in the discussions as modeling is frequently assumed to be a forecasting effort with definite outcomes. The data and modeling assumptions have associated ranges of uncertainties. Even in situations in which one would think the range of uncertainty should be small, e.g., the cost of a combustion turbine, they can be surprisingly large. These uncertainties need to be considered when evaluating calculations. Although models calculate numbers to a precise value, this "precision" is a programming artifact and must be understood as such. What also should be kept in mind is that the range of uncertainty varies with specific assumptions. The uncertainty

[1] This is a typical approach in policy analysis. See, for example, *MIT Study on the Future of Coal*, 2007, pp. 8-9, available at http://web.mit.edu/coal/

in the cost of a combustion turbine is smaller than the uncertainty of the cost of off-shore wind, which is in turn smaller than the uncertainty associated with the cost of a new nuclear power plant.

A primary driver for the current modeling draft calculations is the assumptions about the cost and magnitude of energy efficiency and demand response for electricity and natural gas. If one assumes that energy efficiency and demand response are cost-effective (which numerous studies have concluded) and that state policies can successfully influence energy efficiency and demand response, then one does not need modeling to conclude that energy bills will decrease, environmental impacts will be lessened, and the New Jersey economy will not be harmed. The modeling provides the order of magnitude, confirms the intuition, and helps target policies that can help to make these outcomes more likely. Thus, the preliminary calculations to date reflect the assumptions that they are based upon.

C. Description of Models

Two major models are used as part of this effort. The first is R/ECON™, a detailed econometric time series model of the New Jersey economy. The second is DAYZER, a sophisticated model of the PJM[2] wholesale electricity power market. This model, DAYZER (Day-Ahead Locational Market Clearing Prices Analyzer), is a unit commitment and dispatch model that mimics, as closely as practical, the day-ahead wholesale electricity market that New Jersey is part of (PJM), including calculating the locational marginal prices (LMPs) that vary by location and time. The results from DAYZER, along with many other assumptions, are then provided to R/ECON™ as inputs.

1. R/ECON™ – The New Jersey State Economic Model

R/ECON is an econometric model comprised of over 300 equations, which are solved simultaneously. The equations are based on historical data for New Jersey and the US. The historical data used to produce the model covers the period from 1970 to 2005, with some sectors updated through 2006. The sectors included in the model are:

- Employment and gross state product for 40 industries
- Wage rates and price deflators for major industries
- Consumer price index
- Personal income and its components
- Population, labor force and unemployment
- Housing permits, construction contracts, and housing prices and sales
- Energy prices and usage
- Motor vehicle registrations and stocks, and
- State tax revenues by type of tax, and current and capital expenditures.

The heart of the model is a set of equations modeling employment, wages, and prices by industry. In general, employment in an industry depends on demand for that industry's output, and on the state's wages and prices relative to the nation's wages and prices. Demand can be represented by a variety of variables including (but not limited to) New Jersey personal income, NJ population, NJ sectoral output, or US employment in the sector. Growth in population is driven by total employment in the state and by state prices relative to national prices.

[2] PJM Interconnection is a regional transmission organization (RTO) that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia, and the District of Columbia

As part of this project the model was extended to include additional equations related to the energy sector. The equations in this new model sector are:

- Electric price per kilowatt hour, residential, commercial, industrial, and other;
- Electricity usage for residential, commercial, industrial, and other;
- Electric revenues in billions of dollars residential, commercial, industrial, and other;
- Natural gas price per thousand cubic feet, by sector, including the electric power sector;
- Natural gas usage by sector, including the electric power sector;
- Natural gas revenues in billions of dollars;
- Fuel oil price per million BTU, by sector;
- Fuel oil usage by sector;
- Motor fuel price and usage;
- Energy sales and corporate business taxes in millions of dollars; and
- Employment at electric utilities and other utilities.[3]

The R/ECON™ forecasting service produces four forecasts of the New Jersey economy each year. This study used the April 2007 R/ECON™ forecast as its baseline (referred hereafter as BAU).[4] The baseline forecast goes out to 2020. The data for the U.S. used in BAU comes from Global Insight, Inc., a national leader in economic forecasting.

Tables 1 and 2 list the categories of inputs and outputs of the R/ECON™ model.

[3] The employment data, like all other New Jersey employment data used in the model, comes from the New Jersey Department of Labor.
[4] The next forecast update will be in January 2008.

Table 1: R/ECON™ Inputs

Inputs	
Data Endogenous to the Model	***Data Exogenous to the Model***
New Jersey Historical Data	**US Data**
Real Estate and Construction	**Consumption**
Value of Construction Contracts	**Employment by Industry**
Residential Building Permits	**Labor Force**
Home Sales and Prices	**Population**
Building Stock	**Gross Domestic Product, Nominal & Real**
Prices	**Prices**
Deflators by Industry	*Chained Price Indices*
Consumer Price Index	*Consumer Prices*
Employment by Industry	*Producer Prices*
Population and Households	**Interest Rates**
State and Local Government	**Vehicle Sales and Prices**
Operating & Capital Expenditures	**Income**
Local Property Taxes	**Interest Rates**
State Tax Revenues	**Vehicles**
Retail Sales	**Personal Income, by type**
Before Tax Profits	**Other Exogenous Variables:**
Wage Rates	*Consumer Sentiment Index*
New Jersey	*Maximum Wage subject to Social Security*
United States	*Minimum Wage*
Personal Income, by type	*S&P 500 Index*
Labor Force and Unemployment	*Retail Sales*
Gross State Product by industry	*Employee and Self-employed paid Social Security Taxes*
Vehicles	*Proportion of residents with Health Insurance, US*
Existing Stock	
New registrations	**New Jersey Data**
Fuel Consumption and Prices	**Tax Rates**
Electricity	**Dummy variables**: seasonals, quarters, policies (RPS, tax changes)
Natural Gas	
Distillate Fuel Oil	
Diesel Fuel	**New Jersey Minimum Wage**
Motor Gasoline	**Proportion of NJ residents with Health Insurance**

Table 2: R/ECON™ Outputs

Outputs
State Level Projections
Real Estate and Construction
Value of Construction Contracts
Residential Building Permits
Home Sales and Prices
Building Stock
Prices
Deflators by Industry
Consumer Price Index
Employment by Industry
Population and Households
State and Local Government
Operating & Capital Expenditures
Local Property Taxes
State Tax Revenues
Retail Sales
Before Tax Profits
Wage Rates
New Jersey
United States
Personal Income, by type
Labor Force and Unemployment
Gross State Product by industry
Vehicles
Existing Stock
New registrations
Fuel Consumption and Prices
Electricity
Natural Gas
Distillate Fuel Oil
Diesel Fuel
Motor Gasoline

2. DAYZER – The PJM Wholesale Market Model

DAYZER calculates locational market clearing prices and the associated transmission congestion costs in competitive electricity markets.[5] This tool simulates the operation of the PJM electricity market—the dispatch procedures adopted and used by PJM—and replicates the calculations made by PJM in solving for the security-constrained, least-cost unit commitment and dispatch in the day-ahead markets. The LMP and congestion cost calculations are based on data on fuel prices, demand forecast, unit and transmission line outages, and emission permits costs. DAYZER incorporates all the security, reliability, economic, and engineering constraints on generation units and transmission system components.

DAYZER has the following features:

- Accurate security-constrained unit commitment and dispatch algorithms that mimics those used by PJM in the day-ahead market
- Accurate modeling of PJM with its own particularities (second contingency constraints, locational reserve markets, etc.)
- Captures marginal transmission losses in dispatch and clearing prices
- Captures transmission outages, transmission contingencies, nomograms, and planned and known transmission upgrades
- Models accurately phase angle regulators and loop flows
- Allows users to analyze various scenarios and quantify the impact of key variables/assumptions
- Employs random outage using Bernoulli Probability modeling
- Enables the optimization of generation maintenance schedule based on reserves
- Uses import and export schedules to account for flows to and from neighboring markets

DAYZER requires that both transmission and generation additions and retirements be input exogenously into the model.[6] The existing PJM transmission system is used in the DAYZER runs with additions as noted in Appendix A of this document.

In the current modeling effort, generation expansion plans are based on the following process: PJM's load forecasts by zone by year are used to calculate the hourly loads using PJM's 2006 load duration curve. The amount of system-wide installed capacity is calculated based on PJM's 15% reserve margin. Renewable generation that is needed to meet individual states Renewable Portfolio Standards (RPS) is then included in the expansion plan. If additional generation is needed to meet the installed reserve margin, it is added. The type (baseload, intermediate, or peaking) and the fuel (nuclear, coal, or natural gas) are determined by reviewing the PJM generation interconnection queue for each particular PJM zone. Historically, the PJM generation queue contains more generation than is actually built. DAYZER is then run using the candidate expansion plan to ensure that generation unit capacity factors are appropriate for the type of unit and to ensure there are no hours in which demand exceeds supply in each zone that DAYZER tracks. In addition, locational marginal prices and net operating revenues are checked to ensure that either retirements or new generation would not otherwise occur. Modifications to the candidate expansion plan are made as necessary, and DAYZER is re-run until a satisfactory expansion is developed.

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[5] DAYZER was developed by Cambridge Energy Solutions, http://www.ces-us.com/index.html . DAYZER was used in a recently commissioned study by PJM and Mid-Atlantic Distributed Resources Initiative on the estimating the benefits of demand response. See The Brattle Group, *Quantifying Demand Response Benefits in PJM*, January 29, 2007.

[6] Some models have the ability to construct generation expansion plans but do not have the detail locational marginal price capabilities of DAYZER.

Table 3 lists the inputs and outputs of the DAYZER model.

Table 3: DAYZER Inputs and Outputs

Inputs	Outputs
PJM Transmission System	**Utility Zone Results**
Emission Permit Prices	*Zonal LMP*
Fuel Prices	*LMP by Bus*
Natural Gas Prices	*Energy Portion of LMP*
Coal Prices	*Congestion Portion of LMP*
Oil Prices	**Unit Results**
Generation Unit Characteristics	*Unit LMP*
Plant Size (MW)	*Energy Portion of LMP*
Heat Rate	*Congestion Portion of LMP*
Fixed O&M	*Spin Price*
Variable O&M	*Unit Generation*
Emission Rates	*Spin Generation*
PJM Interface Import/Export Schedule	*Fuel Cost*
PJM Reserve Requirements	*Emission Cost*
Utility Zone Demand	*Variable O&M Cost*
	Startup Cost
	Transmission System Results
	Line Flow
	Shadow Price

III. Business As Usual and Alternative Scenarios

At this point in the development of the Energy Master Plan, two major scenarios are being evaluated during the Plan's time horizon, which ends in the year 2020. The BAU scenario represents one specific possible future whose outcomes reflect New Jersey continuing on its current course with respect to energy policy. There are, of course, many other possible outcomes that are numerically different from the specific BAU outcome that is modeled but are similar in nature.

The Alternative scenario utilizes a combination of programs designed to implement energy efficiency, renewable energy, and other actions that are intended to achieve the greenhouse gas emission limits specified in the Global Warming Response Act and the RPS requirements for 2020.

When comparing the outcomes of the BAU and Alternative scenarios, an important caveat needs to be kept in mind. Any comparison must include the reduction in greenhouse gas emissions that is anticipated in the Alternative scenario compared to the BAU scenario. Comparing the economic performance of these two scenarios without accounting for the economic value of the greenhouse gas reductions has the effect that the BAU scenario appears economically more favorable than the Alternative scenario. The difficulty is that there is a wide range of estimates regarding the negative economic impact per CO_2 ton. The IPCC's Working Group II estimates a range from $3 to $95 per ton based upon a survey of 100 estimates with a mean of $12 per metric ton.[7] The Stern Report estimates the social cost of CO_2 at $85 per ton.[8] A consensus view on the marginal damages of greenhouse gases does not exist.[9]

In 2020, the Alternative scenario is estimated to reduce CO_2 by 39 million metric tons compared to BAU. This translates in real dollars into approximately $117 million as a low estimate, $468 million as a mean estimate, and $3.7 billion as a high estimate of economic benefits in 2020 alone.[10] Table 4 lists the economic benefits of reduced CO_2 emissions from 2010 through 2020. The net present value of savings is $400 million as a low estimate, $1.6 billion as a mean estimate, and $13 billion as high estimate.[11] The economic benefits accrue to the global economy, not just New Jersey's economy, due to the nature of global warming.

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[7] Gilbert E. Metcalf, *A Proposal for a U.S. Carbon Tax Swap: An Equitable Tax Reform to Address Global Climate Change*, The Brookings Institution, Oct. 2007 citing the Intergovernmental Panel on Climate Change (IPCC), *Contribution of Working Group II to the Fourth Assessment Report*, Geneva, Switzerland, 2007.

[8] Metcalf, ibid, citing Nicholas Stern, *The Economics of Climate Change*, Cambridge, UK: Cambridge University Press, 2007.

[9] Metcalf 2007, p. 11.

[10] Complicating the comparison between the BAU and Alternative scenarios is the Regional Greenhouse Gas Initiative (RGGI), which is common to both scenarios. RGGI internalizes much of the cost of CO_2 emissions from electric power plants because it caps those emissions for units greater than 25 megawatts. See CEEEP, *Economic Impact Analysis of New Jersey's Proposed 20% Renewable Portfolio Standard*, Dec. 8, 2004 for a more detailed discussion of air emission externality costs in general and in the context of emission caps.

[11] Ruth, Coelho, Karetnikov, *The US Economic Impacts of Climate Change and the Costs of Inaction*, Center for Integrative Environmental Research, October 2007.

Table 4: Economic Benefits of Reduced CO_2 Emissions

	BAU - Alt. (Million Metric Tons)	Low Savings Estimate	Mean Savings Estimate	High Savings Estimate
2010	0	$ -	$ -	$ -
2011	3.9	$ 11,700,000	$ 46,800,000	$ 370,500,000
2012	7.8	$ 23,400,000	$ 93,600,000	$ 741,000,000
2013	11.7	$ 35,100,000	$140,400,000	$1,111,500,000
2014	15.6	$ 46,800,000	$187,200,000	$1,482,000,000
2015	19.5	$ 58,500,000	$234,000,000	$1,852,500,000
2016	23.4	$ 70,200,000	$280,800,000	$2,223,000,000
2017	27.3	$ 81,900,000	$327,600,000	$2,593,500,000
2018	31.2	$ 93,600,000	$374,400,000	$2,964,000,000
2019	35.1	$105,300,000	$421,200,000	$3,334,500,000
2020	39	$117,000,000	$468,000,000	$3,705,000,000
Total NPV (6% discount rate)		**$407,981,301**	**$1,631,925,202**	**$12,919,407,850**

The specifics of the BAU and Alternative scenarios are provided in Appendices A and B. The electricity, natural gas, and space heating tables have been posted on the New Jersey Energy Master Plan website since March 2007.[12] In addition, a listing of all of the comments and responses thereto have been posted on the same website. A high-level description of the difference between the BAU and Alternative scenarios is provided below for electricity, natural gas, and space heating.

Several sensitivity cases are evaluated and discussed in Section III. C.

A. Comparison of BAU with Alternative – Electricity Assumptions

This section describes the major similarities and differences between the BAU and Alternative scenarios. Unless noted otherwise, policies are assumed to be implemented on January 1, 2010 and escalated linearly until they achieve their final level on December 31, 2020.

Demand Growth – the BAU assumes that electricity demand growth is 1.52% per year. The specific assumptions used in the electricity model are based upon the BPU's load forecast.[13] The PJM load forecast assumes load to grow at a specific percentage in each zone by year.[14] The Alternative scenario, however, assumes that much of this increase in demand is met through energy efficiency and demand response measures not part of the BAU scenario. The Alternative scenario also assumes that 2,200 MW

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[12] Assumptions matrices are available at http://www.nj.gov/emp/home/docs/approved/assumptions.html.

[13] The BPU used a 1.52% load growth rate. This value was derived from New Jersey's historic load growth, using EIA data. See Energy Master Plan Electricity Paper. November 6, 2006. Available at http://nj.gov/emp/home/docs/pdf/061013e.pdf.

[14] PJM Capacity Adequacy Planning Department. *PJM Peak Load Forecast.* January 2007. See Jay Apt, Lee Gresham, M. Granger Morgan, and Adam Newcomer, *Incentives for Near-Term Carbon Dioxide Geological Sequestration: A White Paper prepared for The Gasification Carbon management Work Group*, Carnegie Mellon Electricity Industry Center, Oct. 9, 2007 who point out that national electricity load growth is linear not exponential.

can be shaved off the top 50 peak demand hours through the use of demand response. These assumptions were developed based on studies conducted in New Jersey and other states in the region. The assumptions are aggressive.

Renewable Generation – both scenarios assume the same Renewable Portfolio Standard (RPS). Since the RPS is based upon a percentage of demand, the amount of renewables in the BAU scenario is greater than in the Alternative scenario. Compared to the BAU scenario, the Alternative scenario assumes that New Jersey installs 650 additional MW of off-shore wind, 100 additional MW of on-shore wind, and 450 MW of additional biomass through a number of projects.

Combined Heat and Power (CHP) – the Alternative scenario assumes an additional 1,500 MW of CHP is implemented behind the meter by 2020.

Conventional Generation – Differences in conventional generation are based upon the differences in demand and generation between the two scenarios. (The development of the generation expansion plans for each scenario is discussed in Section II. C.1.)

New Transmission – New transmission is identical for both scenarios: the specific additions to the existing PJM transmission system are provided in Appendix A.[15]

Appendix B contains key wholesale electricity assumptions used in the DAYZER model of PJM.

B. Comparison of BAU with Alternative – Natural Gas and Fuel Oil Assumptions

This section describes the differences between the BAU and the Alternative scenarios for natural gas and fuel oil components of the energy master plan. These fuels are considered in two groups: space heat and non-space heat. Space heating includes natural gas and fuel oil, but does not explicitly include fuels used for water heating, cooking, or industrial processes. Under the greenhouse gas mitigation policies of the state, savings through energy efficiency are expected for non-space heat natural gas and fuel oil consumption.

The overarching difference between the two scenarios is that essentially no policies were enacted or implemented in the 2004 base year that impacted this sector. Whereas the Renewable Portfolio Standard was already an articulated policy for the electricity sector that can be included in the base case, no similar policies had been developed for space heating. Therefore, this section describes the proposed policies under the Alternative scenario affecting the heating sector.

Demand Growth – The BAU scenario assumes that demand for natural gas grows from approximately 495 trillion Btus in 2004 to 501 trillion Btus in 2020. Fuel oil, which has been declining in favor of natural gas for many years, decreases from 107 trillion Btus in 2004 to 93 trillion Btus in 2020. In the Alternative scenario due to energy efficiency gains, demand for both natural gas and fuel oil is projected to decline to about 475 trillion Btus.[16]

Energy Efficiency – The assumed decline in consumption is driven by four policies: the implementation of the EPAct 2005 appliance standards, the adoption of future appliance standards, the adoption of

[15] Other transmission lines were approved by PJM after the preliminary transmission assumptions were made, which are not reflected in the modeling.
[16] This reduction includes all savings from proposed energy efficiency policies proposed by the EMP, it does not include gas needed to meet the proposed additional MWs of Combined Heat and Power (CHP).

enhanced building codes for new construction, and the development of an energy efficiency incentive program (in the form of white tags or rebates) targeted specifically at existing building stock. The cost of the energy efficiency in existing buildings is a place holder until more programmatic details are available.

Table 5: Energy Efficiency Savings and Cost Assumptions for Natural Gas and Fuel Oil

	Savings	Equalized Cost Savings per appliance*
Appliance Standards (2005)	3.00 trillion Btu	$284 (2005$)
Future Appliance Standards	4.27 trillion Btu	$151 (2005$)

	Savings	Equalized Cost Savings per home/square foot of commercial or industrial space for all upgrades
Enhanced Building Codes	9.89 trillion Btu	$4,757 (2003$) / new home
		$0.17 / square foot

	Savings	Rebate Price / Thousand square feet of Natural Gas and / gallons of Fuel Oil (2007$)**	
EE in Existing Building Stock and Appliance Replacement	97.57 trillion Btu	*Natural Gas* $5.16	*Fuel Oil* $0.36

Notes:

* Incremental cost over average appliance life - annual savings from lower energy consumption.

** Based on historical prices per unit of energy saved through the NJ CEP program.

Alternative Fuels – In an effort to decrease reliance on traditional fossil fuels and associated greenhouse gas emissions, the Alternative scenario proposes that 5% of fuel oil be replaced with biofuel by 2020. This would save approximately 4.35 trillion Btus.

Table 6: Alternative Fuel Savings and Cost Assumptions for Heating

	Savings	Required Subsidy per gallon
5% Biofuel	4.35 trillion Btu	$1 (2007$)

C. Description of Electricity Sensitivity Scenarios

Besides the Business As Usual and Alternative scenarios, several wholesale electricity sensitivity scenarios are analyzed. They include different CO_2 allowance price cases, high fuel price cases, and cases regarding the amount of energy efficiency and demand response.

Two carbon dioxide scenarios are examined. One assumes the implementation of the Regional Greenhouse Gas Initiative (RGGI). For this scenario, based on studies conducted as part of the RGGI process, the equivalent of a $3/ton (2006$) CO_2 allowance price is added to the variable costs of generation units that emit CO_2 that are located in RGGI states within PJM.[17] These states are Delaware, Maryland, and New Jersey. In addition, a national CO_2 cap-and-trade regime is modeled using a $7/ton (2006$) CO_2 allowance price.[18] These two CO_2 sensitivity analyses are conducted in conjunction with the Business as Usual and the Alternative scenarios and are denoted "BAU-RGGI", "BAU-National", "ALT-RGGI", and "ALT-National".[19] While the $3 and $7 assumptions are grounded in studies currently available, they should not necessarily be interpreted as the likely value of carbon certificates.

A high-fuel price case is also analyzed using Global Insight's Low Growth assumptions from its February 2007 U.S. forecast. The high-fuel price case assumes that the natural gas price at Henry Hub in 2020 is 10.31/mmBTU in nominal dollars.[20] The high fuel price cases use the RGGI assumptions and are designated as "BAU-RGGI-HF" and "ALT-RGGI-HF".

Two sensitivity cases are evaluated regarding energy efficiency and demand response under the Alternative scenario. In one scenario, no demand response is assumed but the amount of energy efficiency assumed in the Alternative scenario occurs. In another sensitivity case, only 75% of the energy efficiency and demand response in the Alternative scenario occurs. These two cases are designated as "ALT-RGGI-No DR" and "ALT-RGGI-75% DR&EE". As the nomenclature indicates, these sensitivity cases are based on the RGGI assumptions.

Table 7 is a high-level description of the various sensitivity analyses.

[17] The CO_2 allowance price is translated into a $/MWh adder based on a unit's heat rate and its CO_2 emission factor.
[18] This CO_2 allowance price corresponds to HR 5049Scenarios A and C as reported on http://www.eia.doe.gov/oiaf/1605/climate.html .
[19] Recently, there has been a lot of attention and proposed legislation regarding a national CO_2 strategy and some proposals and studies contemplate and examine much higher allowance prices than $7/ton. Here, no position is taken on the likelihood of a national policy or the associated costs. See http://www.eia.doe.gov/oiaf/1605/climate.html . Also, ISO New England conducted CO_2 sensitivity cases using $3, $20 and $40 prices per allowance. See *New England Electricity Scenario Analysis*, August 2, 2007 available at http://www.iso-ne.com/pubs/whtpprs/index.html p. 29.
[20] In all scenarios and sensitivities cases, the Henry Hub price is adjusted for seasonal price effects and to account for transportation to generation units in PJM.

Table 7: Sensitivity Analysis Descriptions

Scenario Short Name	Year	CO2 Trading System	Class I RPS	Solar RPS	NJ On-Shore Wind	NJ Off-Shore Wind	Biomass	CHP	Demand Response
2010 BAU-RGGI	2010	RGGI	5.49%	0.31%	10	0	50	0	0
2015 BAU-RGGI	2015	RGGI	9.65%	0.93%	50	350	200	0	0
2020 BAU-RGGI	2020	RGGI	17.88%	2.12%	100	350	450	0	0
2010 Alt-RGGI	2010	RGGI	5.49%	0.31%	52	0	50	429	650
2015 Alt-RGGI	2015	RGGI	9.65%	0.93%	126	417	475	964	1,100
2020 Alt-RGGI	2020	RGGI	17.88%	2.12%	200	1,000	900	1,500	2,200
2015 BAU-National	2015	National	9.65%	0.93%	50	350	200	0	0
2020 BAU-National	2020	National	17.88%	2.12%	100	350	450	0	0
2015 Alt-National	2015	National	9.65%	0.93%	126	417	475	964	1,100
2020 Alt-National	2020	National	17.88%	2.12%	200	1,000	900	1,500	2,200
BAU-High CO_2 Permits	2020	High National	17.88%	2.12%	100	350	450	0	0
Alt-High CO_2 Permits	2020	High National	17.88%	2.12%	200	1,000	900	1,500	2,200
BAU-RGGI-HF	2020	RGGI	17.88%	2.12%	100	350	450	0	0
Alt-RGGI-HF	2020	RGGI	17.88%	2.12%	200	1,000	900	1,500	2,200
Alt-No DR	2020	RGGI	17.88%	2.12%	200	1,000	900	1,500	0
Alt-75% EE & DR	2020	RGGI	17.88%	2.12%	200	1,000	900	1,500	1,650

Notes:
1. RGGI trades CO2 at $3 per ton in 2006 dollars, escalated for inflation only, only in RGGI States.
2. National trades CO2 at $7 per ton in 2006 dollars, escalated for inflation only, in all PJM States.
3. High National trades CO2 at $40 per ton in 2020 dollars in all PJM States.
4. RPS percentages are the percentage of total energy that must be produced by that renewable source.
5. Wind, biomass, and CHP values are the capacity values.
6. Demand Response is the amount of Demand Response at the peak hour.

As this effort is a work in progress, additional sensitivity analyses may be conducted.

IV. Preliminary Calculations: BAU vs. Alternative Scenarios for Electricity, Natural Gas, and Fuel Oil

A. R/ECON™ Results

Assumptions pertaining to the BAU and Alternative Scenario cases were agreed upon by Energy Master Plan committee members, stakeholders, and the Governor's Office of Economic Growth. With these decisions made, the output from DAYZER and other sensitivity analyses could be fed into the R/ECON™ model to capture the macroeconomic impacts of the proposed policies. As noted above, the R/ECON™ model builds off a core model of over 300 simultaneous equations to provide a multifaceted picture of the state's economy. Input into the model are historical time series at both the state and the national level for employment sectors, wages, consumer price index, population, tax revenues and expenditures, energy consumption, and retail energy prices. These historical data provide the foundation for the estimated equations. Projections for national trends are provided on a quarterly basis by Global Insight. Based on the estimated relationship between the state and national historical trends, projections are estimated for the state's economy. However, assumptions about the state level that are different from the Business as Usual trends can be specified and the effects of these changes can be observed as to how they ripple through the New Jersey economy.

For the EMP, the additional cost to implement each proposed policy was translated into a unit that was then added to the R/ECON™ model. For example, the price impact of the proposed off-shore wind pilot project would be calculated by first determining the marginal difference in the cost of generating a unit of electricity compared to the average unit of electricity under the given generation fuel and technology mix. These calculations are determined by DAYZER. This per unit incremental cost is then multiplied by the total number of units that are expected to be produced in each given year. The total cost of this electricity generation is not paid by a single source, but rather spread over all electricity rate payers in the state. The final calculation provides a ¢/kWh value that is added to the R/ECON™ Business as Usual scenario and is understood to be the incremental cost of implementing the off-shore wind pilot project. Similar calculations for approximately 30 proposed policies touching electricity, natural gas, and space heating complete the bridge between DAYZER, spreadsheet analyses, and the R/ECON™ model. Table 8 shows an example of these final adders to the R/ECON™ baseline data.

Table 8: Sample Adders for the Business as Usual Case

	Net Adder or (Subtractor)			R/ECON™ Variable affected
	2010	2015	2020	
Electricity (RPS and pilot project implementation)				
All Sectors $/kWh Adder	$0.001	$0.002	$0.007	*Retail Electricity price*

Source: R/ECON™ adders supplied 11/28/2007. These adders fed into model output generated on 12/03/2007.

Table 9 shows some of the adders to the R/ECON™ model for the Alternative Scenario. In the cases where there are BAU adders, the value is *in addition to* the BAU.

Table 9: Sample Adders for the Alternative Scenario

	Net Adder or (Subtractor)			R/ECON™ Variable affected
	2010	2015	2020	
Electricity (Implementation of RPS, more extensive pilot projects, and energy efficiency policies)				
Residential $/kWh Adder	$0.0006	$0.0039	$0.0017	*Retail Residential electricity price*
Commercial $/kWh Adder	$0.0049	$0.0086	$0.0057	*Retail Commercial electricity price*
Industrial $/kWh Adder	$0.0039	$0.0015	$(0.0084)*	*Retail Industrial electricity price*
Natural Gas (Implementation of energy efficiency policies)				
Residential $/thousand cubic feet Adder	$0.17	$1.13	$2.31	*Retail Residential Natural Gas price*
Commercial $/thousand cubic feet Adder	$0.07	$0.43	$0.96	*Retail Commercial Natural Gas price*
Industrial $/thousand cubic feet Adder	$(0.00)	$(0.02)	$0.04	*Retail Industrial Natural Gas price*
Fuel Oil (implementation of energy efficiency and biofuel replacement policies)				
Residential $/gallon Adder	$0.00	$0.03	$0.09	*Retail Residential Fuel Oil price*
Commercial $/gallon Adder	$0.00	$0.03	$0.07	*Retail Commercial Fuel Oil price*
Industrial $/gallon Adder	$0.00	$0.01	$0.01	*Retail Industrial Fuel Oil price*

Source: R/ECON™ adders supplied 11/28/2007. These adders fed into model output generated on 12/03/2007.* The slight negative adder in the Alternative Scenario is a result of the expected energy efficiency gains from proposed EMP policies. Lower overall energy demand decreases the wholesale electricity price.

The adders provide a bridge between DAYZER output, policy and cost assumptions not related to electricity and the macroeconomic output provided by the R/ECON™ model. Other policies such as the Combined Heat and Power (CHP) program proposed by the Energy Master Plan Committee have been handled in a different manner. CHP does not reduce electricity consumption beyond the explicit energy efficiency programs in the EMP, but it does reduce the electricity consumed from traditional power plants. To capture the 1500 MW of CHP installed and in use by 2020, the R/ECON™ model reduced the tax revenue generated from electric utility operation by the same percentage as the demand for traditional electricity is replaced by onsite, behind-the-meter-CHP generated electricity. This percentage starts with about 1% in 2010 (controlling for existing CHP assumed to be reflected in the data already) and increases to about 10% in 2020.

Aggressive energy efficiency and renewable energy policies, such as large in-state pilot projects for off-shore wind, on-shore wind, and biomass imply new job creation for the state. Jobs for both the construction and operation and maintenance for these pilot projects and the employment requirements for improving energy efficiency in existing buildings in the state have been estimated and added to the model. The additional jobs from these "new" or expanded industries in the state largely off-set the impacts on employment declines as a result of higher energy prices or lower demand for energy.

The next several tables show the relative impact of the Alternative Scenario compared to the BAU. Table 10 shows the retail prices given the adders and the predicted change in consumption. The difference between the "Baseline" and the "Alternative" is not equal to the adders simply because the model uses projection data for national wholesale prices from Global Insight and the interactions between consumption and price changes may further have an impact on the price in 2020. However, the direction of the price increase is the same as anticipated from the adders.

Table 10: Retail Energy Prices Based on R/ECON™ Output

	2020 BAU	2020 Alt.	% Difference
Electricity			
Residential Price (Cents per KWH)	18.32	18.62	1.7%
Commercial Price (Cents per KWH)	16.72	17.33	3.6%
Industrial Price (Cents per KWH)	13.75	12.87	-6.4%
Natural Gas			
Residential Price ($ per TCF)	20.92	23.16	10.7%
Commercial Price ($ per TCF)	18.11	19.06	5.2%
Industrial Price ($ per TCF)	14.87	14.93	0.4%
Electricity Price ($ per TCF)	11.39	11.39	0.0%
Heating Oil			
Residential Price (Cents per Gal)	240.76	249.73	3.7%
Commercial Price (Cents per Gal)	198.16	205.39	3.7%
Industrial Price (Cents per Gal)	194.01	195.09	0.6%

Source: R/ECON™ model output generated on 3/3/2008.

The Energy Master Plan focuses heavily on reducing energy consumption through enhanced energy efficiency measures. Table 11 shows the overall energy consumption reduced by implementing targeted programs. Total natural gas usage only decrease slightly between the BAU and Alternative because of the increased natural gas consumption due to the installation of CHP units. Natural gas usage in the space heating and cooking sector decrease 19.2% between the BAU and Alternative, which achieves the goals of the Energy Master Plan.

Table 11: Energy Consumption by Fuel Based on R/ECON™ Output

	2020 BAU	2020 Alt.	%Difference
Annual Use in Million BTUs: Total	2,010,586,392	1,825,944,810	-9.2%
Electricity (all sectors)	332,753,792	270,235,193	-18.8%
Total Natural Gas	633,923,030	631,905,950	-0.3%
Residential, Commercial, and Industrial Usage	446,817,989	372,824,510	-16.6%
Behind-the-Meter CHP Usage	14,812,991	66,921,865	351.8%
Natural Gas for Electricity	172,292,050	192,159,575	11.8%
Fuel Oil (all sectors space heat)	426,890,220	377,849,065	-4.5%

Source: R/ECON™ model output generated on 3/3/2008.

The impact of higher prices and lower consumption is that the overall sectoral and per customer expenditures decline between the BAU and the Alternative scenario. Table 12 shows a summary of these differences in expenditures for electricity, natural gas, and heating oil.

Table 12: Energy Expenditures Based on R/ECON™ Output[21]

		Electricity		
	Retail PRICE $/kWh	Average kWh/Customer	Average Annual Customer Bill	Total Sector Expenditures (billions of nominal $)
2005 Baseline				
Residential	$0.12	8,970	$1,053	$3.52
Commercial	$0.11	87,335	$9,266	$4.22
Industrial	$0.10	868,014	$84,718	$1.16
TOTAL				$8.90
2020 BAU				
Residential	$0.18	9,180	$1,682	$6.48
Commercial	$0.17	93,011	$15,553	$8.38
Industrial	$0.14	743,236	$102,211	$1.60
TOTAL				$16.47
2020 Alternative				
Residential	$0.19	6,663	$1,241	$4.78
Commercial	$0.17	66,287	$11,488	$6.19
Industrial	$0.13	597,810	$76,948	$1.21
TOTAL				$12.18
		Natural Gas Without CHP		
	Retail PRICE $/mmBtu	Average mmBtu/Customer	Average Annual Customer Bill	Total Sector Expenditures (billions of nominal $)
2005 Baseline				
Residential	$14.44	95	$1,372	$3.44
Commercial	$13.52	851	$11,506	$2.37
Industrial	$11.52	9,080	$104,643	$0.89
TOTAL				$6.70
2020 BAU				
Residential	$21.57	83	$1,789	$5.88
Commercial	$18.67	610	$11,379	$2.87
Industrial	$15.33	5,480	$84,025	$0.57
TOTAL				$9.33
2020 Alternative				
Residential	$23.88	64	$1,529	$5.02
Commercial	$19.65	479	$9,420	$2.38
Industrial	$15.39	4,639	$71,399	$0.49
TOTAL				$7.89

[21] Customer count assumptions from EIA State Level Energy Data. Available at http://www.eia.doe.gov/cneaf/electricity/epa/epa_sprdshts.html.

Natural Gas With CHP				
	Retail PRICE $/mmBtu	**Average mmBtu/Customer**	**Average Annual Customer Bill**	**Total Sector Expenditures (billions of nominal $)**
2005 Baseline				
Residential	$14.44	95	$1,372	$3.44
Commercial	$13.52	851	$11,506	$2.37
Industrial	$11.52	9,080	$104,643	$0.89
TOTAL				$6.70
2020 BAU				
Residential	$21.57	83	$1,789	$5.88
Commercial	$18.67	610	$11,379	$2.87
Industrial	$15.33	5,480	$84,025	$0.57
TOTAL				$9.33
2020 Alternative				
Residential	$23.88	66	$1,585	$5.21
Commercial	$19.65	684	$13,429	$3.39
Industrial	$15.39	7,441	$114,509	$0.78
TOTAL				$9.38
Fuel Oil				
	Retail PRICE $/mmBtu	**Average mmBtu/Customer**	**Average Annual Customer Bill**	**Total Sector Expenditures (billions of nominal $)**
2005 Baseline				
Residential	$15.95	102	$1,620	$ 0.817
Commercial	$13.01	851	$11,075	$ 0.241
Industrial	$12.78	9,080	$116,053	$ 0.117
TOTAL				$1.18
2020 BAU				
Residential	$17.36	111	$1,930	$ 0.566
Commercial	$14.29	530	$ 7,579	$ 0.236
Industrial	$13.99	23,109	$323,260	$ 0.201
TOTAL				$1.00
2020 Alternative (includes EE and Biodiesel)				
Residential	$18.01	81	$1,461	$0.429
Commercial	$14.81	409	$6,057	$ 0.189
Industrial	$14.07	21,538	$302,966	$ 0.189
TOTAL				$0.81

Chart 1 shows the residential energy usage per household from 1990 through the modeling time period of 2020.

Chart 1: Residential Energy Use per Household, Baseline Compared to Alternative

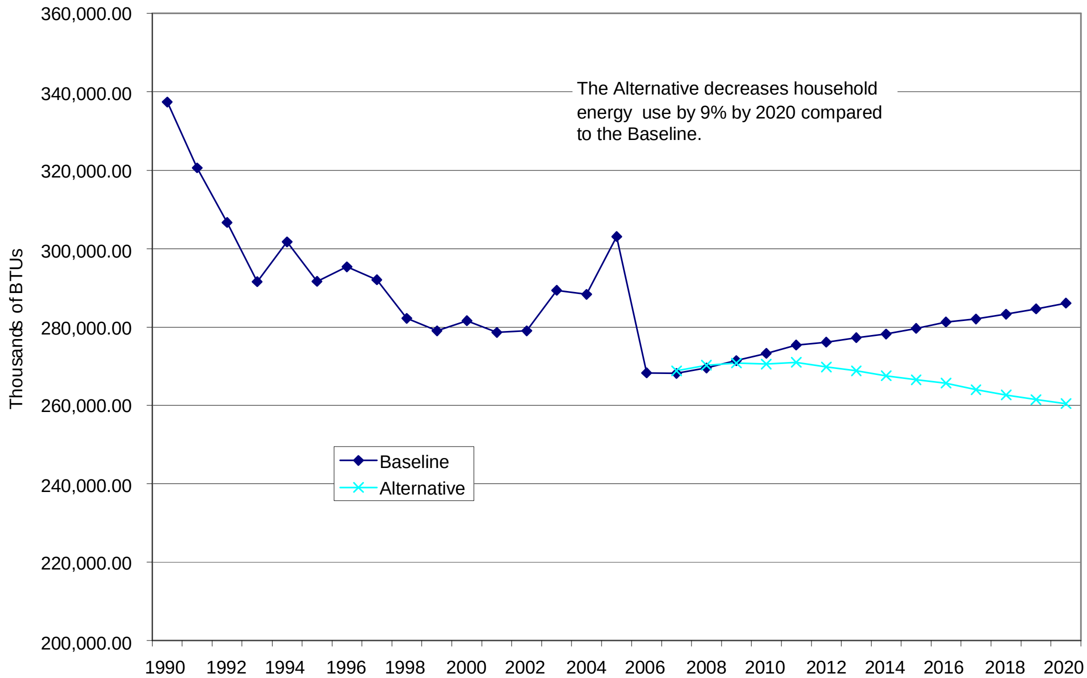


Chart 2 shows the commercial energy usage per square foot 1990 through the modeling time period of 2020.

Chart 2: Commercial Energy Use per Square Foot, Baseline Compared to Alternative

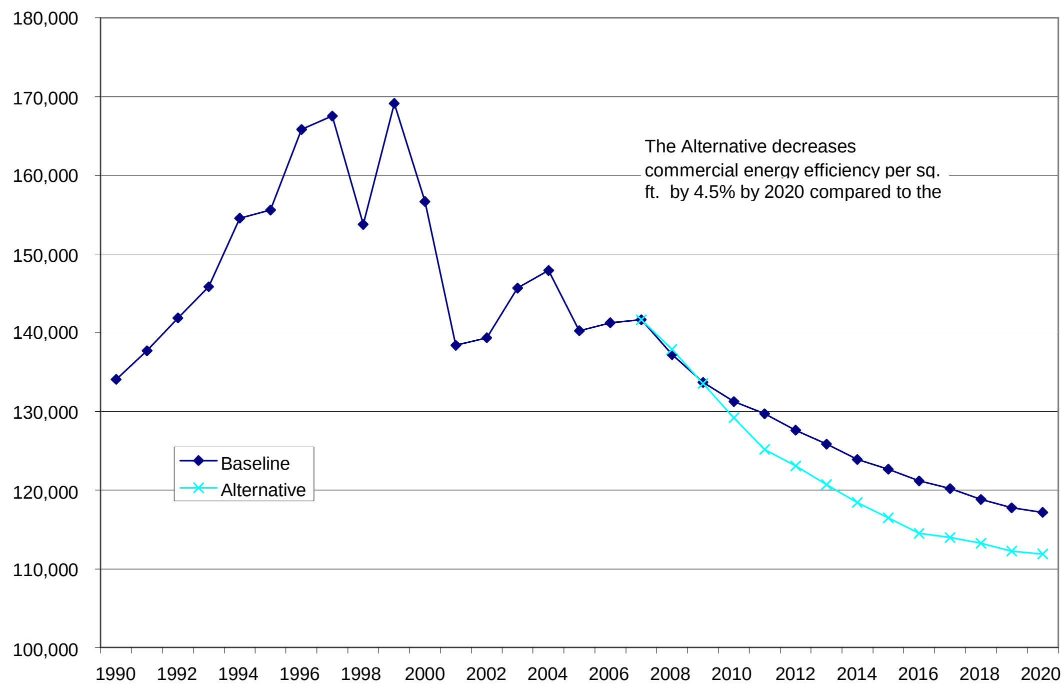
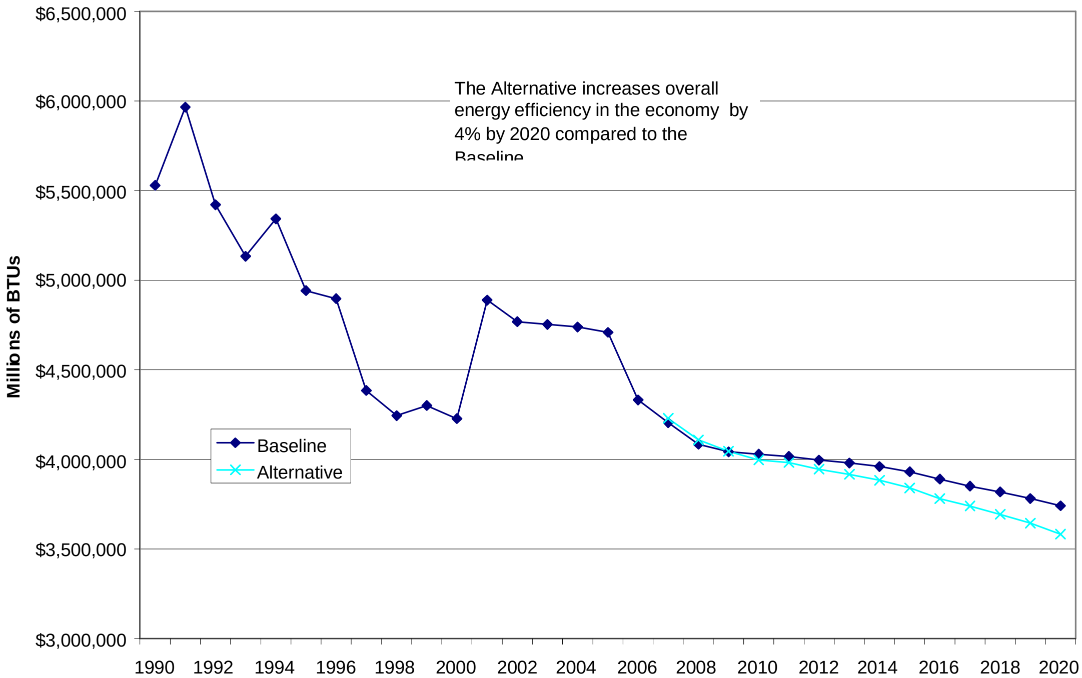


Chart 3 shows New Jersey's energy use per dollar of real gross state product from 1990 through the modeling time period of 2020.

Chart 3: New Jersey Energy Use per Dollar of Real Gross State Product, Baseline Compared to Alternative



The macroeconomic effects of changes in energy prices and consumption can be seen in Table 13. Most of the effects of the Energy Master Plan policies are marginal, with the exception of a 0.7% increase in residential building permits, 0.2% increases in construction contracts and the consumer price index, and a 0.2% decrease in the unemployment rate. Total employment, in retail sales and the gross state product all increased by 0.1%. As noted in Section III, the results below do not include the economic benefits of reducing greenhouse gasses in the Alternative Scenario. Thus, even without accounting for the greenhouse gas reduction, the economy improves slightly under the Alternative Scenario as compared to the Baseline.

Table 13: Macroeconomic Indicators Based on R/ECON™ Output

	2020 BAU	2020 Alt.	% Difference
Non-ag. Employment(thous)	4,688.1	4,695.0	0.1%
Unemployment Rate(%)	4.8%	4.7%	-0.2%
Personal Income($bill)	$814.5	$814.8	0.0%
Retail Sales($bill)	$238.4	$238.6	0.1%
New Vehicle Registrations (thousands)	710.4	710.3	0.0%
New Car Registrations	354.5	354.4	0.0%
New Light Trucks and Vans	355.9	356.0	0.0%
Residential Building Permits	32,670	32,906	0.7%
Contract Construction($mill)	$16,659	$16,690	0.2%
Consumer Price Index(1982=100)	289.5	290.0	0.2%
Gross State Product($2000 bill)	$537.3	$538.0	0.1%
Total Tax Revenues($bill)	$50.4	$50.4	0.0%

Source: R/ECON™ model output generated on 3/3/2008.

B. Electricity Results

This section presents wholesale electricity results for the two main scenarios and various sensitivity cases. In some tables of results, results already presented are repeated for ease of comparison.

Table 14 compares the wholesale electricity prices in the BAU and Alternative scenarios in the year 2020. For the Alternative scenario, two cases are presented. One assumes that the Regional Greenhouse Gas Initiative is the policy with respect to CO2 emissions; the other assumes that there is a national program. Prices that are reported are the straight hourly averages of New Jersey electricity prices ($/MWh), the load weighted average New Jersey electricity price, and the installed capacity price. The installed capacity price is determined by looking at the marginal unit in each zone and calculating the amount of revenue it would need to meet its annual going forward costs after subtracting out its net operating profits earned in the energy market. Similar calculations are performed for Class 1 renewable energy resources such as solar and on- and off-shore wind installed in New Jersey.[22] It is the delta in electricity prices between the Alternative and BAU scenarios that are provided to the R/ECON™ model. The results of the BAU and Alternative scenarios provided below should not be construed as forecast of future electricity prices but instead are the modeling results under different assumptions.

Table 14: 2020 Business As Usual and Alternative Scenarios (RGGI and National) Nominal Electricity Prices ($/MWh)

Prices	BAU-RGGI	ALT-RGGI	BAU-National	ALT-National
Straight Avg. LMP	70.36	52.95	74.78	58.10
Load Weighted LMP	74.65	57.79	79.08	62.47
Capacity Price[23]	16.55	16.55	16.55	16.55
NJ Class 1 REC	27.92	26.59	24.01	23.36
NJ On-Shore Wind Adder	21.19	28.49	20.24	26.95
NJ Off-Shore Wind Adder	51.45	49.40	47.35	44.29
NJ SREC	175.53	179.33	175.18	178.78

Note that the LMPs, both straight and load weighted, decrease slightly more than 20% between each pair of the BAU and Alternative scenarios. The capacity prices do not change in any of the scenarios because the marginal unit in all cases is a gas turbine that rarely, if ever, runs in the DAYZER simulation.[24] As a result, the going forward costs are the annual fixed operations and maintenance costs plus the annual amount needed to cover return of and on capital, which do not vary by scenario. The New Jersey on-shore wind adder and S-REC increase between the BAU and Alterative scenarios because the prices that these resources obtain in the energy market decrease between these two cases. The reverse is the situation with the New Jersey off-shore wind adder because prices increase at that location.[25]

[22] While this report was being finalized, the NJ BPU issued rule changes to its solar programs. See Summit Blue Consulting, *An Analysis of Potential Ratepayer Impact of Alternatives for Transitioning the New Jersey Solar Market from Rebates to Market-Based Incentives* prepared for New Jersey Board of Public Utilities, December 6. 2007, and State of New Jersey Board of Public Utilities, *Decision and Order Regarding Solar Electric Generation,*Docket No. EO06100744, September 12, 2007.
[23] Capacity Prices are in $/MWh. 16.55 $/MWh is equivalent to 52.90 $/MW-day in 2020.
[24] Many stakeholders noted the rising costs of power plants and the belief that these increases were not just short-term phenomenon. See Chupka and Basheda, *Rising Utility Construction Costs: Sources and Impacts,* The Brattle Group, Prepared for The Edison Foundation, September 2007.
[25] The various REC prices and wind adders should not be added to the wholesale energy and capacity prices to arrive at the total wholesale price since these resources are only a fraction of the total MWh’s sold.

Table 15 reports the results for BAU and Alternative scenarios that models CO_2 emission allowance prices at $40 per ton.

Table 15: 2020 Business As Usual and Alternative, RGGI, High CO_2 Emission Permit Prices Sensitivity Scenarios Nominal Electricity Prices ($/MWh)

Prices	BAU-RGGI	BAU-High CO_2 Permits	ALT-RGGI	Alt-High CO_2 Permits
Straight Avg. LMP	70.36	94.83	52.95	79.24
Load Weighted LMP	74.65	99.06	57.79	83.02
Capacity Price	16.55	16.55	16.55	16.55
NJ Class 1 REC	27.92	16.92	26.59	15.62
NJ On-Shore Wind Adder	21.19	14.66	28.49	20.86
NJ Off-Shore Wind Adder	51.45	40.62	49.40	37.88
NJ SREC	175.53	172.75	179.33	176.14

Table 16 reports the results for BAU and Alternative scenarios that model higher fuel prices than the standard BAU and Alternative scenarios.

Table 16: 2020 Business As Usual and Alternative, RGGI, High Fuel Price Sensitivity Scenarios Nominal Electricity Prices ($/MWh)

Prices	BAU-RGGI	BAU-RGGI-HF	ALT-RGGI	ALT-RGGI-HF
Straight Avg. LMP	70.36	80.77	52.95	60.47
Load Weighted LMP	74.65	85.66	57.79	66.08
Capacity Price	16.55	16.55	16.55	16.55
NJ Class 1 REC	27.92	26.23	26.59	24.97
NJ On-Shore Wind Adder	21.19	18.29	28.49	26.79
NJ Off-Shore Wind Adder	51.45	49.40	49.40	45.60
NJ SREC	175.53	174.06	179.33	178.52

As expected, the High Fuel cases result in higher straight average and load weighted average LMPs. Note that the relative differences are approximately 20% in both straight average LMPs and load weighted average LMPs between the BAU and Alternative scenarios with and without high fuel prices.

Table 17 reports the results for two Alternative sensitivity runs. One scenario, ALT-No DR, is the Alternative scenario without a demand response program for the 50 highest load hours. The second scenario, ALT-75% EE & DR, is the alternative scenario that only achieves 75% of the energy efficiency and demand response goals.

Table 17: 2020 Alternative Sensitivity Scenarios, No Demand Response and 75% Demand Response and Energy Efficiency, Nominal Electricity Prices ($/MWh)

Prices	ALT-RGGI	ALT-No DR	ALT-75% EE & DR
Straight Avg. LMP	52.95	53.67	54.91
Load Weighted LMP	57.79	58.39	59.75
Capacity Price	16.55	16.55	16.55
NJ Class 1 REC	26.59	26.97	26.59
NJ On-Shore Wind Adder	28.49	27.99	27.44
NJ Off-Shore Wind Adder	49.40	47.51	45.87
NJ SREC	179.33	179.07	179.02

Note that the No DR and 75% EE & DR cases result in higher electricity prices than the ALT-RGGI scenario, which is expected since demand is higher in each of these cases than in the ALT-RGGI scenario.

Table 18 reports the results for the scenarios in 2015 in nominal dollars.

Table 18: 2015 Business As Usual and Alternative Scenarios (RGGI and National) Nominal Electricity Prices ($/MWh)

Prices	BAU-RGGI	ALT-RGGI	BAU-National	ALT-National
Straight Avg. LMP	56.22	50.79	61.51	56.04
Load Weighted LMP	59.82	54.67	64.91	59.60
Capacity Price[26]	12.51	12.51	12.51	12.51
NJ Class 1 REC	17.63	17.93	15.58	15.39
NJ On-Shore Wind Adder	13.67	16.66	12.26	15.26
NJ Off-Shore Wind Adder	21.49	24.96	20.37	23.57
NJ SREC	131.35	132.64	130.67	132.05

Table 19 provides the fuel mix for New Jersey electricity generation for 2004, 2020 Business as Usual, and 2020 Alternative scenarios under the RGGI CO_2 assumptions.

[26] Capacity Prices are in $/MWh. 12.51 $/MWh is equivalent to 39.98 $/MW-day in 2015

Table 19: New Jersey Electricity Generation Fuel Mix in 2004 and 2020 Business As Usual and Alternative RGGI Scenarios (GWh)

	2004		2020 BAU-RGGI		2020 ALT-RGGI	
	Total Gen.	% by Fuel	Total Gen.	% by Fuel	Total Gen.	% by Fuel
Total Generation	57,119	100%	77,225	100%	73,483	100%
Nuclear	27,082	47%	34,155	44%	34,158	47%
Coal	10,322	18%	14,640	19%	11,345	15%
Natural Gas	16,036	28%	19,394	25%	3,876	5%
Petroleum	1,391	2%	163	0%	16	0%
On-Site	1,227	2%	1,562	2%	12,103	17%
Solar	10	0.0%	2,050	2.7%	1,397	1.9%
Wind	0	0%	4,355	6%	9,706	13%
Refuse	1,051	2%	906	1%	883	1%
Hydro	0	0%	0	0%	0	0%

Table 20 provides New Jersey electricity fuel mix in 2020 Business As Usual and Alternative RGGI Scenarios.

Table 20: New Jersey Electricity Fuel Mix in 2020 Business As Usual and Alternative RGGI Scenarios (GWh)

		2020 BAU RGGI		2020 ALT- RGGI	
		Total Gen.	% by Fuel	Total Gen.	% by Fuel
PJM Imports	**Total Imports**	23,069	24%	5,900	9%
	Nuclear	6,053	6%	1,491	2%
	Coal	12,826	13%	3,554	5%
	Natural Gas	2,810	3%	586	1%
	Wind	937	1%	179	0%
	Other*	205	0%	58	0%
NJ Generation Utilized In-State	**Nuclear**	32,558	34%	27,882	42%
	Coal	13,956	14%	9,261	14%
	Natural Gas	18,487	19%	3,164	5%
	Petroleum	155	0%	13	0%
	On-Site	1,489	2%	9,879	15%
	Solar	1,954	2%	1,140	2%
	Wind	4,151	4%	7,923	12%
	Refuse	864	1%	721	1%
	Total Demand	96,682	100%	65,883	100%

* - include petroleum, solar, refuse, and hydro

Table 21 provides the various electricity and capacity prices for 2010. Only the BAU-RGGI case is reported because there is only a slight difference between the BAU and Alternative cases in 2010. Only the RGGI case is reported because it is not anticipated that a national program would be up and running by 2010.

Table 21: 2010 Business As Usual Scenario (RGGI) Nominal Electricity Prices ($/MWh)

Prices	BAU-RGGI
Straight Avg. LMP	46.32
Load Weighted LMP	49.61
Capacity Price[27]	12.51
NJ Class 1 REC	17.02
NJ On-Shore Wind Adder	16.17
NJ SREC	133.00

Tables 22 and 23 report air emissions for 2020 and 2015 for the four major scenarios. CO_2 emissions are broken down into two different categories: emissions from in-state generation and emissions from imported electricity. In-state generation includes emission from both generators that are interconnected to the grid and localized CHP units. Imported electricity emissions were calculated using average PJM emission rates. Note that in 2015 the CO_2 emissions are greater in the Alternative than the BAU scenario because of CHP emissions. In 2020 this is not the case because the energy efficiency measures in the Alternative Scenarios are substantial enough to provide a counter effect.

Table 22: 2020 Business As Usual and Alternative Scenarios (RGGI and National) Electricity Emissions

	BAU-RGGI	ALT-RGGI	BAU-National	ALT-National
NJ CO_2 (Million Metric Tons)	21.63	19.09	23.00	20.14
Imported CO_2 (Million Metric Tons)	6.99	2.64	5.13	1.23
NJ SO_2 (Metric Tons)	61,472	49,016	64,192	51,261
NJ NO_x (Metric Tons)	29,330	21,892	30,743	23,040

Table 23: 2015 Business As Usual and Alternative Scenarios (RGGI and National) Emissions

	BAU-RGGI	ALT-RGGI	BAU-National	ALT-National
NJ CO_2 (Million Metric Tons)	15.30	16.40	16.46	17.32
Imported CO_2 (Million Metric Tons)	17.91	6.98	16.69	6.16
NJ SO_2 (Metric Tons)	54,445	48,352	58,399	52,441
NJ NO_x (Metric Tons)	24,910	21,768	26,752	23,595

[27] Capacity Prices are in $/MWh. 12.51 $/MWh is equivalent to 36.99 $/MW-day in 2010

C. Natural Gas and Fuel Oil Results

Because the natural gas and oil markets are continental and international, New Jersey has far less ability to have an impact on wholesale prices in the natural gas market with policies chosen under the Energy Master Plan than it has with electricity. Nevertheless, consumption levels and greenhouse gas emissions are affected in the Alternative scenario compared to BAU. Table 24 compares the greenhouse gas emissions from natural gas and fuel oil by sector in the BAU and Alternative scenarios. The reductions in emissions reflect a 20% reduction in consumption in all sectors, with the exception of "other combustion" for the industrial sector, which is only projected to decline by 9%.[28]

Table 24: 2020 Business As Usual and Alternative Scenario Greenhouse Gas Emissions from Natural Gas and Fuel Oil Combustion in the Residential, Commercial, and Industrial Sectors (million metric tons)[29]

Retail Prices	2004 Baseline	BAU-Natural Gas & Fuel Oil	ALT-Natural Gas & Fuel Oil	% Difference
Residential				
Space Heating	14.2	15.5	12.4	-20%
Other Combustion	3.4	3.8	3.0	-20%
Commercial				
Space Heating	6.1	5.7	4.6	-20%
Other Combustion	4.8	3.6	2.9	-20%
Industrial/Other				
Space Heating	0.7	0.4	0.3	-20%
Other Combustion	17.1	15.3	13.9	-9%

Table 25 shows the relative impact of the proposed Energy Master Plan policies on the overall greenhouse gas emissions reductions. The biggest impact will come from the energy efficiency measures in existing building stock.

Table 25: Relative Impact of Proposed Policies of the Alternative Scenario on Greenhouse Gas Emissions Reductions for the Natural Gas and Fuel Oil Sector

Policy	Approximate Percent of Total Emissions Reduction
2005 Appliance Standards	3.6%
Future Appliance Standards	5.2%
Enhanced Building Codes	11.9%
Energy Efficiency in Existing Building Stock and Appliance Replacement Program	73.6%
5% Biodiesel	5.6%
Total	100%

[28] 20% reductions are based on energy efficiency policies, such as appliance standards, enhanced building codes, and programs targeting energy efficiency investments in existing building stock; 9% reduction in the industrial sector recognizes the use of natural gas in production processes that may not have potential for efficiency gains.
[29] Reductions in Greenhouse gas emissions were estimated by the NJ Department of Environmental Protection (DEP) and the Center for Climate Strategies, draft 10/15/07.

D. Greenhouse Gas Emissions

The draft Energy Master Plan has significant impacts on all sectors of greenhouse gas emissions in New Jersey. Many Energy Master Plan initiatives have direct and indirect effects on greenhouse gas emissions. There is an overall reduction of approximately 33 percent of greenhouse gasses in the Alternative scenario compared to the BAU in 2020. The majority of the reduction is due to the reduced demand in the electricity sector and the reduced emissions from on-road gasoline as a result of draft Energy Master Plan programs. Table 26 shows a draft greenhouse gas inventory for New Jersey compiled by the New Jersey Department of Environmental Protection.

Table 26: New Jersey Greenhouse Gas Emissions Estimates and Projections[30]

Sector	Sub-sector	2004	2020 BAU	2020 With Planned Actions
Transportation	On-road gasoline	38.3	44.3	31.3
	On-road diesel	7.5	11	10.5
	Aviation	1	1	1
	Marine	1.5	1.8	1.8
	Railroad & Other	0.5	0.6	0.6
Electricity	In-state	19	21.5	18.7
	In-state, from MSW	1.3	1.3	1.3
	Imported	13.4	20.3	4.8
Residential	Space heat	14.2	15.5	12.4
	Other combustion	3.4	3.8	3
Commercial	Space heat	6.1	5.7	4.6
	Other combustion	4.8	3.6	2.9
Industrial	Space heat	0.7	0.4	0.3
	Other combustion	17.1	15.3	13.9
Halogenated gases (ex. SF_6)		3.4	8.4	8.4
Sulfur Hexafluoride		0.3	0.1	0.1
Industrial non-fuel related		0.1	0.1	0.1
Agriculture		0.5	0.4	0.4
Natural Gas T&D		2	2.1	2.1
Landfills, POTWs		6.8	6	6
Released through land clearing		1.1	1.1	1.1
Sequestered by forests		-6.8	-5.9	-5.9
Totals		**136**	**158**	**119**
1990 estimate	**120**			

Source: New Jersey DEP. DRAFT; 10/15/07. All values are estimates; 1990 and 2004 values are believed to be accurate to within 5%, 2020 projections are much less certain.

V. Conclusion

The preliminary results presented in this paper should be assessed and interpreted within the planning context described at the beginning of this paper. They are not forecasts but instead provide a means of comparing the BAU and Alternative scenarios and are provided to inform the planning process not dictate the outcome. These results are preliminary and are likely to be modified and updated as the planning process continues.

[30] Draft GHG Inventory available at http://www.state.nj.us/globalwarming/outreach/. Note: Electricity emissions differ from values previously reported in the report. NJ DEP receives electricity emission from CEEEP, and electricity emissions have been updated since the most recent draft of the GHG Inventory.

Appendix A: Business as Usual Versus Alternative Scenario

Appendix A: Business As Usual Versus Alternative Scenario

ELECTRICITY - Base Case							
Policies Included	**Collection Point**	**Sector Allocation**	**Timing**	**Comments/Caveats/ Reference**	**Starting Point (2004)**	**2020 Demand & Growth Rate w/out Alternative Scenario**	**Cost**
			Projected Usage (Demand)	Includes behind-the-meter CHP use : 2004: 1,227 GWH; 2020: 1,516 GWH	**78,530 GWh** (EIA Form 826 and 906/920, 2006; this total does not include transportation)	**100,000 GWh** (approximately 1.52% annually for all sectors) **PEAK: approximately 25,100 MW***	

22.5% RPS							
Class 1	Class 1 RECs	Electric Power Sector (**commodity**)	(in GWh) 2004 = 509; 2010 = 4,667; 2015 = 8,843; 2020 = 17,669	pilot projects = 350 MW off-shore wind (2012), 100 MW on-shore wind (10 MW by 2010, 50 MW by 2015, 100 MW by 2020), and 450 MW Biomass in State (50 MW by 2010, 200 MW by 2015, 450 MW by 2020)	**509 GWh** (NJ CEP)	**17,669 GWh** (RPS Board Order)	**Determined by DAYZER**
Solar PV	S-RECs	Electric Power Sector (**commodity**)	(in GWh) 2004 = 12; 2010 = 259; 2015 = 850; 2020 = 2,095	MW 2004 = 10 2010 = 219 2015 = 719 2020 = 1,767	**12 GWh (2004)** (NJ CEP)	**2,095 GWh** (RPS Board Order)	
Class 2	Class 2 RECs	Electric Power Sector (**commodity**)	(in GWh) 2004 = 1,940; 2010 = 2,125; 2015 = 2,291; 2020 = 2,471	existing RDFs / MSW incinerators and hydro (all In-state)	**1,940 GWh** (NJ CEP)	**2,471 GWh** (EMP Electricity Paper)	

ELECTRICITY - Base Case

Policies Included	Collection Point	Sector Allocation	Timing	Comments/Caveat/ Reference	Starting Point (2004)	2020 Demand & Growth Rate w/out Alternative Scenario	Cost
Other Policies							
RGGI	Cap-and-Trade (single clearing price)	Electric Power Sector **(commodity)**	Stabilize carbon dioxide emissions from electric power sector at approx. current levels 2009 - 2015; 2015 - 2018 emissions will decline, achieving a 10% reduction by 2019.	[Source: Based on Model RGGI Rules]; Some of the program reductions may be achieved outside the electricity sector through emissions offset projects.**	**19.80 MMT CO_2** (2003 level, starting point is 2015) (Source: NJ DEP converted from short tons, obtained 03/07)	**approx. 18.6 MMT CO_2 (RGGI)**	**Determined by DAYZER**
Nuclear Relicensing	N/A	Electric Power Sector	Assume the following plants are relicensed: Oyster Creek = 2009; Salem 1 = 2016; Salem 2 = 2020; Hope Creek = 2036	May include a 100 MW update at Hope Creek			
New Transmission Lines for <u>Exports</u>	N/A	Electric Power Sector	2007=Neptune 685 MW 2007 = Linden 330 MW 2010 = Bergen-49th Street 670 MW	Assumptions provided by PJM Transmission Meeting 1/19/07 (Does not include the 1200 MW Bergen Line Q75 in the PJM queue)			
New Transmission Lines or <u>Imports</u>	N/A	Electric Power Sector	670 MW (to offset PJM RTEP process)	(Mountaineer is not included in the Base Case)			
Transmission Line Net Import Capacity (Incl.Rerating / Upgrades)	N/A	Electric Power Sector	2006 = 5,800 MW 2011 = approx 9,500 MW	Assumptions provided by PJM Transmission Meeting 1/19/07	**5,800 MW (Import Capacity)**	**approx. 10,170 MW (Import Capacity)**	

* - the latest PJM forecasts projects NJ peak demand to be 25,046 MW; DAYZER runs accounting for solar capacity in use in peak hours projects 25,158 MW for 2020.

***The Regional Greenhouse Gas Initiative is a regional cap-and-trade program targeted at reducing greenhouse gas emissions from the electric generation sector. As such, the generators located within the participating states must off-set their carbon emissions by improving their technology or by purchasing credits produced by other, more efficient or cleaner generators. As such, there is not a* *specific target for New Jersey generators, but rather one for the participating region. The goal is: Stabilize carbon dioxide emissions from electric power sector at approximately current levels 2009 - 2015; 2015 - 2018 emissions will decline, achieving a 10% reduction by 2019. The values entered above follow these guidelines for New Jersey, but should not be considered firm targets as this is counter to how a cap-and-trade program functions.*

ELECTRICITY - Base Case

Policies Included	Collection Point	Sector Allocation	Timing	Comments/Caveats/ Reference	Starting Point (2004)	2020 Demand & Growth Rate w/out Alternative Scenario	Cost
Other Policies - Continued							
In-State Generation Expansion	N/A	Electric Power Sector	(in MW, values are cumulative): 2010 = 603 2015 = 1,745 2020 = 4,570	Under PJM RTEP (03/07) and PJM Generation queue, capacity expansion cumulatively is 1,275 MW in 2007, 4,212 MW in 2010 and 4,862 MW in 2015.			**Determined by DAYZER**
In-State Generation Retirements	N/A	Electric Power Sector	(in MW, values are cumulative): 2004 = 536 2005 = 845 2006 = 1,122 2010 = 1,575 2015 = 1,958 2020 = 2,881	Assumptions taken from PJM RTEP (03/07) and PJM Retirement queue			
In-State Generation Capacity	N/A	Electric Power Sector	(in MW based on Summer capacity) 2004 = 17,367 2010 = 17,757 2015 = 17,374 2020 = 16,450	Assumption determined from the PJM 2006 generation list + retirements between 2004 and 2006 to achieve 2004 base year. NJ projected peak load of 21500 MW in 2010, 23200 MW in 2015, 25000 MW in 2020 based on February 2007 PJM Load Forecast.	**17,367 MW** (capacity)	**16,450 MW** (capacity) (base + retirements + capacity needed to meet margin requirements)	

ELECTRICITY- Alternative Scenario *Preliminary*								
Policies Included	**Collection Point**	**Sector Allocation**	**Timing**	**Comments/Caveats/ Reference**	**Potential Savings (annual in year 2020)**	**Starting Point (2004)**	**2020 Goal w/Alternative Scenario**	**Cost**
Usage (Demand) Reduction Goal (20% off projected 2020 Demand)					20,000 GWh	78,530 GWh (EIA Form 826 and 906/920, 2006)	80,000 GWh (projected growth from BAU minus 20%) PEAK: approximately 19,500 MW*	

Demand Reduction Policies							
Appliance Standards (2005)	Manufacturers/ Consumers	Residential, Commercial, Industrial	(RESIDENTIAL) 2009-2010 = 0 GW; 2011-2015 = 412 GWh 2016-2020 = 412 GWh (COMMERCIAL) 2009-2010 = 0 GWh 2011-2015 = 182 GWh 2016-2020 = 182 GWh (INDUSTRIAL) 2009-2010 = 0 GWh; 2011-2015 = 81 GWh; 2016-2020 = 81 GWh	Source: Northeast Energy Efficiency Partnership, "Energy Efficiency Standards: A Low-Cost, High Leverage Policy for Northeast States" available at http://www.neep.org/Standards/report.html, (2004)	**1,350 GWh**		**Cost Assumptions Estimated Using Source Documents**

ELECTRICITY- Alternative Scenario *Preliminary*								
Policies Included	**Collection Point**	**Sector Allocation**	**Timing**	**Comments/Caveats/Reference**	**Potential Savings (annual in year 2020)**	**Starting Point (2004)**	**2020 Goal w/Alternative Scenario**	**Cost**
Demand Reduction Policies - Continued								
Appliance Standards (Future)	Manufacturers/ Consumers	Residential, Commercial, Industrial	(RESIDENTIAL) 2009-2010 = 0 GWh 2011-2015 = 366 GWh 2016-2020 = 366 GWh (COMMERCIAL) 2009-2010 = 0 GWh 2011-2015 = 162 GWh 2016-2020 = 162 GWh (INDUSTRIAL) 2009-2010 = 0 GWh 2011-2015 = 72 GWh 2016-2020 = 72 GWh	Source: Partially from: Steven Nadel, Andrew deLaski, Maggie Eldridge, and Jim Kliesch, "Leading the Way: Continued Opportunities for New State Appliance and Equipment Efficiency Standards" ASAP-6/ACEEE-A062 (Washington, D.C.: American Council for an Energy-Efficient Economy, March 2006); Summit Blue Consulting, LLC., Energy Efficiency Market Assessment of New Jersey Clean Energy Programs, July 20, 2006	**1,200 GWh**			**Cost Assumptions Estimated Using Source Documents**
Enhanced Building Codes*	Developers/ Property Owners	Residential, Commercial, Industrial	(RESIDENTIAL) 2009-2010 = 262 GWh 2011-2015 = 655 GWh 2016-2020 = 655 GWh (COMMERCIAL) 2009-2010 = 118 GWh 2011-2015 = 296 GWh 2016-2020 = 296 GWh (INDUSTRIAL) 2009-2010 = 6 GWh 2011-2015 =14 GWh 2016-2020 =14 GWh	Assumption based on HERS 90 for residential construction (assumes 30,000 new residential units annually); commercial sector 49 GWH/Year electricity (assumes savings at 15% of use/sq ft, and allocated as a percentage of elec,gas and oil use) (assumed additional 22 million square ft. annually)	**2,316 GWh**			

Policies Included	Collection Point	Sector Allocation	Timing	Comments/Caveats /Reference	Potential Savings (annual in year 2020)	Starting Point (2004)	2020 Goal w/Alternative Scenario	Cost
ELECTRICITY- Alternative Scenario *Preliminary*								
Demand Reduction Policies - Continued								
20% EE for existing building stock *(Above theoretically achievable appliance standards and enhanced building codes)*	a single clearing price by sector	**25% reduction**in **RESIDENTIAL 22% COMMERCIAL** and **9% reduction for INDUSTRIAL**	(RESIDENTIAL) 2009-2010 = 793 GWh 2011-2015 = 1,983 GWh 2016-2020 = 1,983 GWh (COMMERCIAL) 2009-2010 = 948 GWh 2011-2015 = 2,371 GWh 2016-2020 = 2,371 GWh (INDUSTRIAL) 2009-2010 = 114 GWh 2011-2015 = 286 GWh 2016-2020 = 286 GWh	Assumes an Energy Efficiency Portfolio Standard, however the selected method would be determined through a Board proceeding. Strategies will be targeted in congested areas to the extent possible.	**11,134 GWh**			**Cost Assumptions Estimated Using Source Documents**
Appliance Replacement			(RESIDENTIAL) 2009-2010 = 285 GWh 2011-2015 = 712 GWh 2016-2020 = 712 GWh (COMMERCIAL) 2009-2010 = 341 GWh 2011-2015 = 852 GWh 2016-2020 = 852 GWh (INDUSTRIAL) 2009-2010 = 41 GWh 2011-2015 = 103 GWh 2016-2020 = 103 GWh		**4,000 GWh**			
Total Potential Savings (Annual in 2020)					**20,000 GWh**	**78,530 GWh** (Demand)	**80,000 GWh**	

ELECTRICITY- Alternative Scenario *Preliminary*

Policies Included	Collection Point	Sector Allocation	Timing	Comments/Caveats/ Reference	Potential Savings (annual in year 2020)	Starting Point (2004)	2020 Goal w/Alternative Scenario	Cost
Other Policies								
650 additional MW for a total of 1,000 MW Off-shore Wind in NJ**	Class 1 RECs	Electric Power Sector	Phased in consistent w/ RPS requirement	This new capacity will be ***IN-STATE*** and would otherwise likely be Out-of-state		**509 GWh (NJ CEP)**	**12,861 GWh** (2,987 GWh off-shore wind; 562 GWh on-shore wind; 6,720 GWh biomass; remainder imported from PJM)	**Determined by DAYZER**
100 additional MW for a total of 200 MW On-shore Wind**	Class 1 RECs	Behind the meter (small-scale wind)	Phased in consistent w/ RPS requirement	This new capacity will be ***IN-STATE*** and would otherwise likely be Out-of-state				
450 additional MW for a total of 900 MW Biomass**	Class 1 RECs	Electric Power Sector	Phased in consistent w/ RPS requirement	This new capacity will be ***IN-STATE*** and would otherwise likely be Out-of-state				
Solar PV (same goal as base case)	S-RECs	Behind the meter	Phased in consistent w/ RPS requirement	Assumes use of SREC and no rebates, however the selected method will be determined through the ongoing Board proceeding.		**12 GWh (2004)** (NJ CEP)	**1,525 GWh**	
Class 2 (same goal as base case)	Class 2 RECs	Electric Power Sector	Phased in consistent w/ RPS requirement	existing RDFs / MSW incinerators and hydro (all In-state)		**1,940 GWh** (NJ CEP)	**1,798 GWh**	

* - includes the impacts of 2,200 MW of DR, 2,000 MW of energy efficiency, and 1,500 MW of CHP.

**Assumes pilot projects of 350 MW off-shore wind, 100 MW on-shore wind, and 450 MW Biomass are included in the Base Case

ELECTRICITY- Alternative Scenario *Preliminary*

Policies Included	Collection Point	Sector Allocation	Timing	Comments/Caveats/ Reference	Potential Savings (annual in year 2020)	Starting Point (2004)	2020 Goal w/Alternative Scenario	Cost
Other Policies - Continued								
1,500 Additional MW CHP	Direct Payment (rebate)	20% Electric Power Sector / 80% behind-the-meter	Phased in consistent w/ CHP policy implementation	Strategies will be targeted in congested areas to the extent possible. The GWh produced by CHP will be roughly between 7,000 and 10,500 in 2020; the range depends on the capacity factors of the chosen technologies.		**175 MW (2004)** (MW required to produce 1,227 GWh of behind the meter electricity assuming a 80% capacity factor)	**1,716 MW** (BAU CHP assumed to increase at 1.52% annually, so this value equals 1500 + otherwise occurring growth)	$300-$400/kW rebate would likely be required for this policy to reach its stated goal. (value based on studies conducted for Connecticut and NYSERDA)
2,000 MW Peak Load Reduction due to Energy Efficiency	Various	Residential, Commercial, Industrial	Phased in consistent w/ EE policy implementation	Includes 300 MW savings from 2005 Appliance Standards and 400 MW savings from Future Appliance Standards, with the remainder apportioned from Enhanced Building Codes and Energy Efficiency in Existing Building Stock		**17,577 MW (2004)** NJ Coincident Peak	shave **top 2,000 MW off 50 peak hours in 2020**	**Determined by DAYZER**
2,200 MW Peak Load Reduction due to Demand Response	white tag with adder for congested areas (energy efficiency)	Residential, Commercial, Industrial	Phased in consistent w/ DR policy implementation	Peak in 2005 and 2006 were significantly higher than 2004 base year. Strategies will be targeted in congested areas to the extent possible.		**17,577 MW (2004)** NJ Coincident Peak	shave **top 2,200 MW off 50 peak hours in 2020**	

Natural Gas and Heating Fuel - Base Case						
Policies Included	**Collection Point**	**Sector Allocation**	**Timing**	**Comments/Caveats**	**Starting Point (2004)**	**2020 Demand & Growth Rate w/out Alternative Scenario**
				Projected Demand	602.29 trillion Btus (495.18 = natural gas; 107.11 = heating fuel) (EIA 2006)	594.25 trillion Btus (501 = natural gas; 93.25 = heating fuel)

SPACE HEATING - Alternative Scenario *Preliminary**							
Policies Included	**Collection Point**	**Sector Allocation**	**Timing**	**Comments/ Caveats/ References**	**Potential Savings* (Annual in year 2020)**	**Starting Point (2004)**	**2020 Goal w/Alt Scenario**
				Demand Reduction Goal (20% Reduction off projected 2020 demand)	119.08 trillion Btus	602.29 trillion Btus (495.18 = natural gas; 107.11 = heating fuel) (EIA 2006)	475.17 trillion Btus
Demand Reduction Policies							
Appliance Standards (2005)	Manufacturers/ Consumers	Residential, Commercial, Industrial	**[Natural Gas]** (RESIDENTIAL) 2009-2010 = 0 TBtu; 2011-2015 = 0.99TBtu; 2016-2020 = 0.99 Tbtu (COMMERCIAL) 2009-2010 = 0 TBtu; 2011-2015 = 0.36TBtu; 2016-2020 = 0.36 Tbtu (INDUSTRIAL) 2009-2010 = 0 TBtu; 2011-2015 = 0.15TBtu; 2016-2020 = 0.15 Tbtu **[Heating Fuel]** NO IMPACTS	Source: Northeast Energy Efficiency Partnership, "Energy Efficiency Standards: A Low-Cost, High Leverage Policy for Northeast States" available at http://www.neep.org/ Standards/report.htm l, (2004)	3.00 Trillion Btu		

Assumptions based on output from R/ECON conducted February 2007.

Natural Gas and Heating Fuel - Alternative Scenario *Preliminary**

Policies Included	Collection Point	Sector Allocation	Timing	Comments/Caveats/ References	Potential Savings* (Annual in year 2020)	Starting Point (2004)	2020 Goal w/Alt Scenario
Demand Reduction Policies - Continued							
Appliance Standards (Future)	Manufacturers/ Consumers	Residential, Commercial, Industrial	**[Natural Gas]** (RESIDENTIAL) 2009-2010 = 0 TBtu; 2011-2015 = 0.99 TBtu; 2016-2020 = 1.45 Tbtu (COMMERCIAL) 2009-2010 = 0 TBtu; 2011-2015 = 0.36 TBtu; 2016-2020 = 0.53 Tbtu (INDUSTRIAL) 2009-2010 = 0 TBtu; 2011-2015 = 0.15 TBtu; 2016-2020 = 0.22 Tbtu **[Heating Fuel]** (RESIDENTIAL) 2009-2010 = 0 TBtu; 2011-2015 = 0.15 TBtu; 2016-2020 = 0.22 Tbtu (COMMERCIAL) 2009-2010 = 0 TBtu; 2011-2015 = 0.06 TBtu; 2016-2020 = 0.08 Tbtu (INDUSTRIAL) 2009-2010 = 0 TBtu; 2011-2015 = 0.02 TBtu; 2016-2020 = 0.04 TBtu	Source: Partially from: Steven Nadel, Andrew deLaski, Maggie Eldridge, and Jim Kliesch, "Leading the Way: Continued Opportunities for New State Appliance and Equipment Efficiency Standards" ASAP-6/ACEEE-A062 (Washington, D.C.: American Council for an Energy-Efficient Economy, March 2006); Summit Blue Consulting, LLC., Energy Efficiency Market Assessment of New Jersey Clean Energy Programs, July 20, 2006	4.27 Trillion Btu (3.70 Tbtu from NG and 0.57 from Heating Fuel)		

Assumptions based on output from R/ECON conducted February 2007.

Natural Gas and Heating Fuel - Alternative Scenario *Preliminary**							
Policies Included	**Collection Point**	**Sector Allocation**	**Timing**	**Comments/Caveats/ References**	**Potential Savings* (Annual in year 2020)**	**Starting Point (2004)**	**2020 Goal w/Alt Scenario**
Demand Reduction Policies - Continued							
Enhanced Building Codes	Developers /Property Owners	Residential, Commercial, Industrial	**[Natural Gas]** (RESIDENTIAL) 2009-2010 = 0.40 TBtu; 2011-2015 = 2.0 TBtu; 2016-2020 = 2.0 Tbtu (COMMERCIAL) 2009-2010 = 0.54 TBtu; 2011-2015 = 1.35 TBtu; 2016-2020 = 1.35Tbtu (INDUSTRIAL) 2009-2010 = 0.04 TBtu; 2011-2015 = 0.10 TBtu; 2016-2020 = 0.10 Tbtu **[Heating Fuel]** (RESIDENTIAL) 2009-2010 = 0.14 TBtu; 2011-2015 = 0.68 TBtu; 2016-2020 = 0.68 Tbtu (COMMERCIAL) 2009-2010 = 0.07 TBtu; 2011-2015 = 0.16 TBtu; 2016-2020 = 0.16 Tbtu (INDUSTRIAL) 2009-2010 = 0.02 TBtu; 2011-2015 = 0.04 TBtu; 2016-2020 = 0.04 TBtu	(Assumption based on HERS 90 for residential construction (assumes 30,000 new residential units annually); commercial sector 0.4 TBTU/Year natural gas) (Commercial savings at 15% of use/sq ft, and allocated as a percentage of elec,gas and oil use) (assumed additional 22 million square ft. annually)	9.88 Trillion Btu (7.89 Tbtu from NG and 1.99 from Heating Fuel)		
**Assumptions based on output from R/ECON conducted February 2007.*							

Natural Gas and Heating Fuel - Alternative Scenario *Preliminary**							
Policies Included	**Policies Included**	**Policies Included**	**Policies Included**	**Policies Included**	**Policies Included**	**Policies Included**	
Demand Reduction Policies – Continued							
20% EE for existing building stock *(Above theoretically achievable appliance standards and enhanced building codes)*	a single clearing price (white tags)	20% reduction in EACH sector w/ different white tag price	**[Natural Gas]** (RESIDENTIAL) 2009-2010 = 6.72 TBtu 2011-2015 = 16.81 TBtu 2016-2020 = 16.81 Tbtu (COMMERCIAL) 2009-2010 = 3.84 TBtu 2011-2015 = 9.59 TBtu 2016-2020 = 9.59 Tbtu (INDUSTRIAL) 2009-2010 = 0.40 TBtu 2011-2015 = 1.00 TBtu 2016-2020 = 1.00 Tbtu **[Heating Fuel]** (RESIDENTIAL) 2009-2010 = 0 TBtu 2011-2015 = 2.25 TBtu 2016-2020 = 2.25 Tbtu (COMMERCIAL) 2009-2010 = 0 TBtu 2011-2015 = 0.69 TBtu 2016-2020 = 0.69 Tbtu (INDUSTRIAL) 2009-2010 = 0 TBtu 2011-2015 = 0.10 TBtu 2016-2020 = 0.10 TBtu	Assumes an Energy Efficiency Portfolio Standard, however the selected method would be determined through a Board proceeding.	71.83 Trillion Btu (65.76 Tbtu from NG and 6.07 from Heating Fuel)		
**Assumptions based on output from R/ECON conducted February 2007.*							

Natural Gas and Heating Fuel - Alternative Scenario *Preliminary**							
Policies Included	**Policies Included**	**Policies Included**	**Policies Included**	**Policies Included**	**Policies Included**	**Policies Included**	
Demand Reduction Policies – Continued							
Appliance Replacement			**[Natural Gas]** (RESIDENTIAL) 2009-2010 = 2.41 TBtu 2011-2015 = 6.03 TBtu 2016-2020 = 6.03 Tbtu (COMMERCIAL) 2009-2010 = 1.38 TBtu 2011-2015 = 3.44 TBtu 2016-2020 = 3.44 Tbtu (INDUSTRIAL) 2009-2010 = 0.14 TBtu 2011-2015 = 0.36 TBtu 2016-2020 = 0.36 Tbtu **[Heating Fuel]** (RESIDENTIAL) 2009-2010 = 0 TBtu 2011-2015 = 0.79 TBtu 2016-2020 = 0.79 Tbtu (COMMERCIAL) 2009-2010 = 0 TBtu 2011-2015 = 0.24 TBtu 2016-2020 = 0.24 Tbtu (INDUSTRIAL) 2009-2010 = 0 TBtu 2011-2015 = 0.04 TBtu 2016-2020 = 0.04 TBtu		25.74 Trillion Btu (23.60 Tbtu from NG and 2.14 from Heating Fuel)		

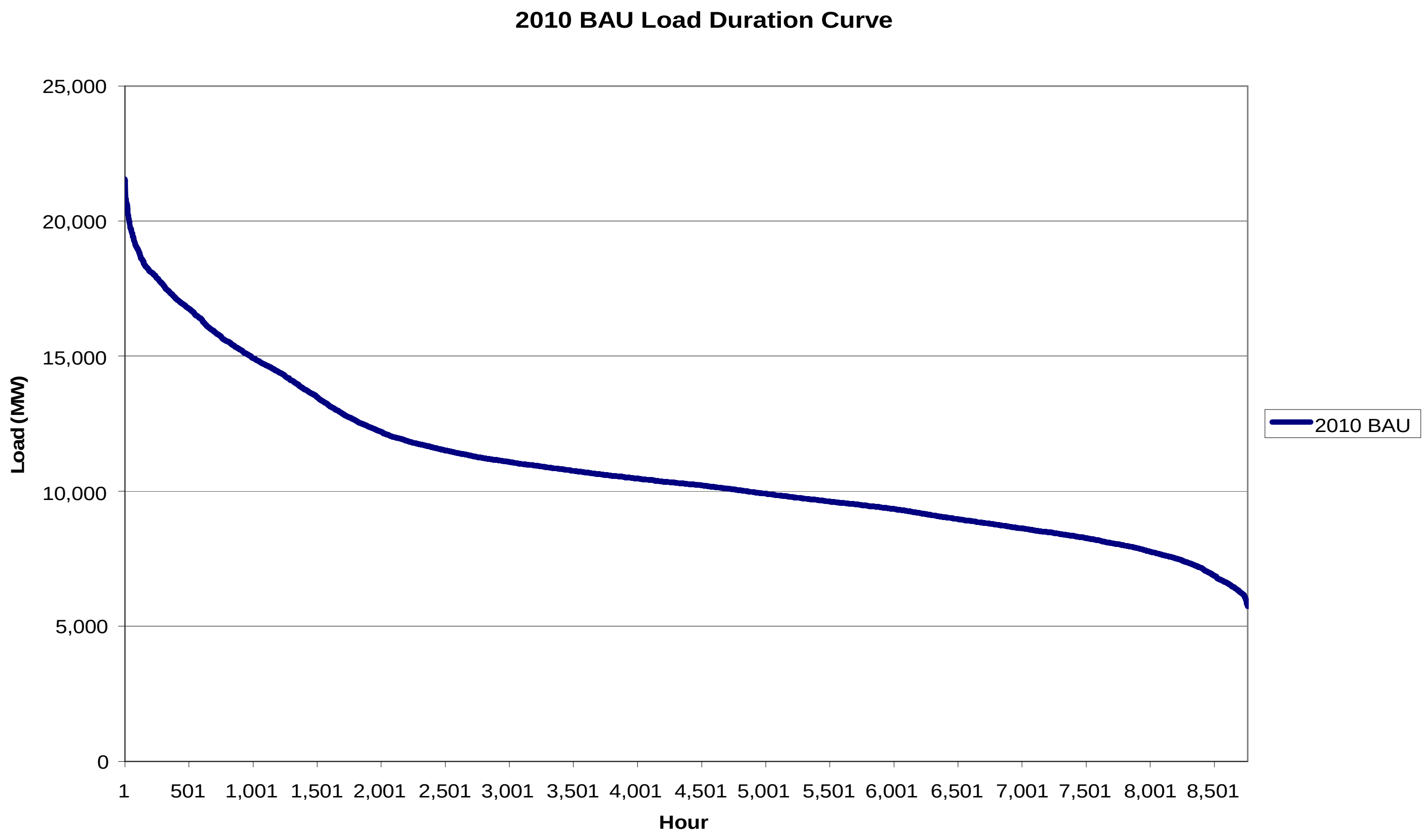
Natural Gas and Heating Fuel - Alternative Scenario *Preliminary**							
Policies Included	**Collection Point**	**Sector Allocation**	**Timing**	**Comments/Caveats/ References**	**Potential Savings* (Annual in year 2020)**	**Starting Point (2004)**	**2020 Goal w/Alt Scenario**
Demand Reduction Policies - Continued							
Replace 5% of Heating Fuel Demand with Biofuels					4.35 Tbtu	negligible	4.35 Trillion Btus
Total Potential Savings (annual in 2020)					119.08 Trillion Btus	602.29 trillion Btus	475.17 trillion Btus

Appendix B: Key Wholesale Electricity Assumptions Used in the Modeling Process

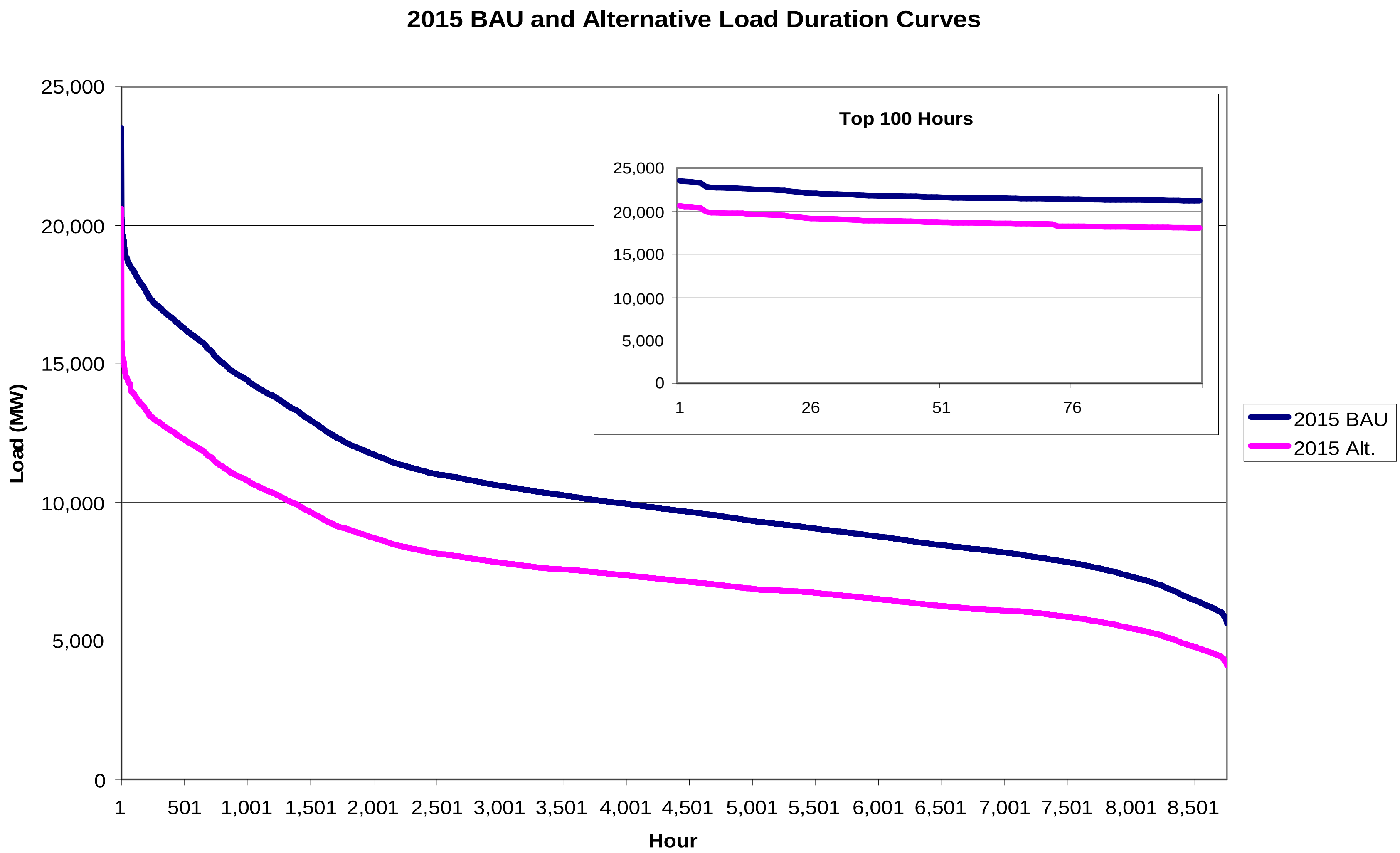
Appendix B: Key Wholesale Electricity Assumptions Used in the Modeling Process

Demand Assumptions

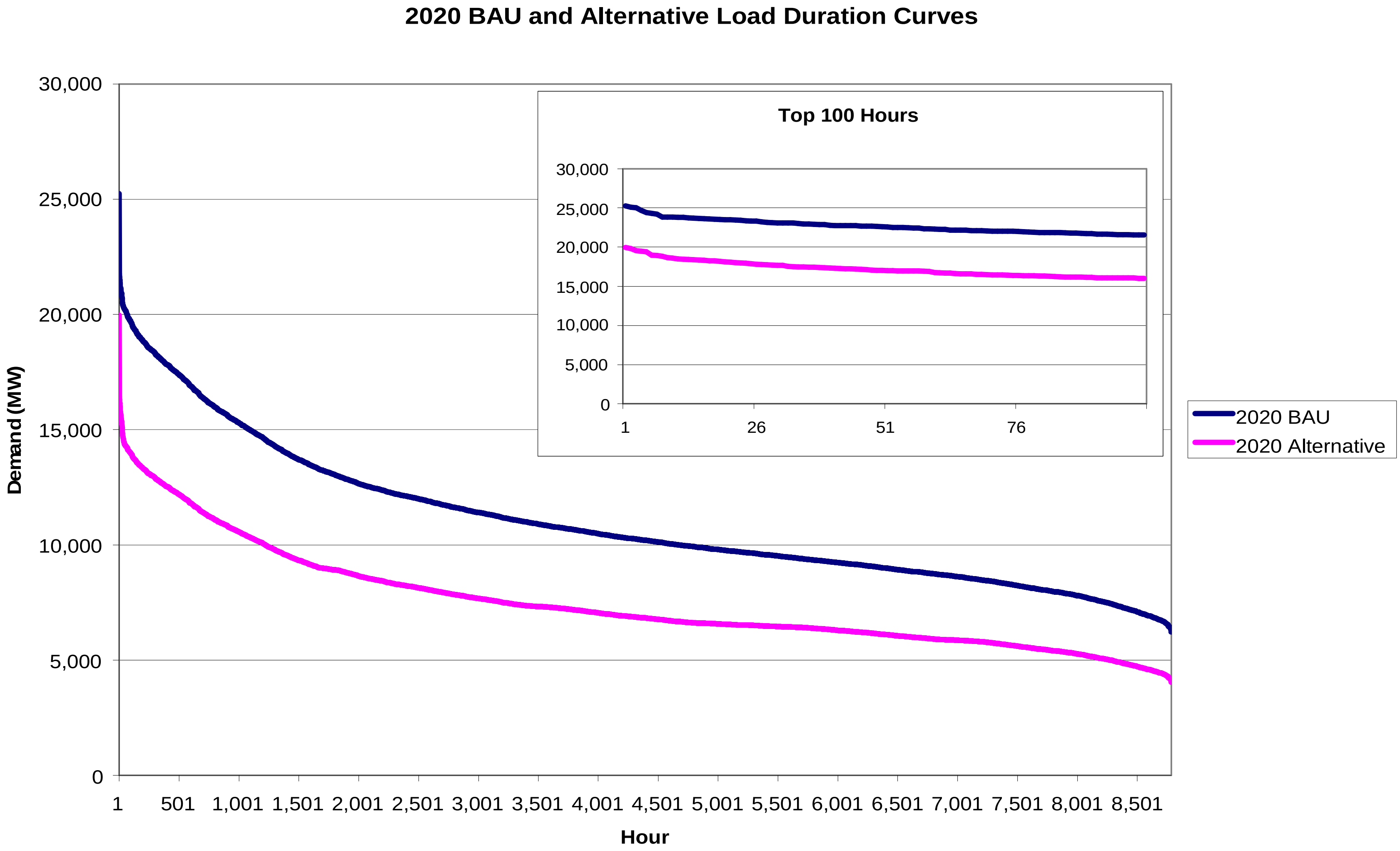
Business As Usual and Alternative 2010 Load Duration Curve



Business As Usual and Alternative 2015 Load Duration Curve



Business As Usual and Alternative 2020 Load Duration Curve



Generation Assumptions

Existing New Jersey Generation in 2004

Total (MW)	Nuclear	Gas Turbine	Combined Cycle	Coal	Oil	Steam Turbine Gas	Hydro	Other
16,869	3,889	4,800	3,990	2,063	461	1,151	0	513
	23%	28%	24%	12%	3%	7%	0%	3%

Summary of PJM Generation Outside NJ in 2004

Total (MW)	Nuclear	Gas Turbine	Combined Cycle	Coal	Oil	Steam Turbine Gas	Hydro	Other
148,070	26,806	23,209	15,810	65,081	5,769	4,340	2,229	4,826
	18%	16%	11%	44%	4%	3%	2%	3%

New Jersey Future New Generation 2010. 2015, & 2020

	Total (MW)	Combined Cycle	Gas Turbine	Wind	Biomass	Nuclear	Coal
2010	38	0	0	38	0	0	0
2015 BAU	2,295	1,645	100	400	200	0	0
2015 Alt	550	0	0	350	200	0	0
2020 BAU	5,420	2,700	1,870	450	450	0	0
2020 Alt	2,100	0	0	1,200	900	0	0

Rest of PJM Future New Generation 2010, 2015, & 2020

	Total (MW)	Combined Cycle	Gas Turbine	Wind	Biomass	Nuclear	Coal
2010	7,389	2,536	320	2,600	0	0	1,933
2015 BAU	21,266	4,841	3,476	5,716	650	0	6,583
2015 Alt	19,986	4,691	2,946	5,716	650	0	5,983
2020 BAU	34,445	5,956	4,786	10,976	750	1,594	10,383
2020 Alt	28,231	5,906	4,316	9,026	650	0	8,333

Note: The amount of generation is based upon the assumption that the PJM revenue margin of 15% is exactly met.

Generation Cost Assumptions

NJ Generation Cost Assumptions ($2006)									
	Overnight Installed Cost ($/kW)		Variable Operation & Maintenance Cost ($/MWh)		Fixed Operation & Maintenance Cost ($/kW-yr)		Heat Rate (MMBtu/kWh)	Capacity Factors	
	Min	Max	Min	Max	Min	Max	_	Min	Max
Conventional Coal	$ 1,900	$ 2,400	$ 2.20	$ 2.70	$ 18.30	$ 22.40	9,200	Determined by model	
Integrated Gas Combined Cycle (IGCC)	$ 2,400	$ 3,200	$ 1.00	$ 1.25	$ 32.00	$ 40.00	8,000		
Advanced Combined Cycle	$ 700	$ 950	$ 2.00	$ 2.50	$ 11.40	$ 14.00	6,900		
Gas Turbine	$ 500	$ 750	$ 5.00	$ 6.20	$ 6.00	$ 7.30	11,300		
Nuclear	$ 1,700	$ 3,700	$ 0.50	$ 0.60	$ 70.00	$ 80.00	n/a	85%	92%
Combined Heat and Power (CHP) (3-25 MW)**									
w/out Chillers	$ 1,000	$ 1,500	$ 4.00	$ 6.50	$ 30.00	$ 45.00	10,000	80%	
w/ Chillers	approx. $2,000						10,000	80%	
Wind									
On-shore	$ 1,500	$ 2,200	$ 1.00	$ 2.00	$ 28.00	$ 32.00	n/a	25%	35%
Off-shore	$ 2,000	$ 2,800	$ 1.00	$ 2.00	$ 28.00	$ 32.00	n/a	25%	35%
Solar	$ 7,500	$ 8,000	$ -	$ 1.00	$ 11.00	$ 12.00	n/a	12%	15%
	Min	Max							
Levelized Real Fixed Capital Charge Rate (%)	12%	15%							

Note: Costs in NJ are assumed to be 10% higher than rest of PJM

Improvements in technologies and cost reductions are modeled consistent with those in the Annual Energy Outlook and other References

** - Other cost assumptions related to Energy Efficiency (EE), and the Regional Greenhouse Gas Initiative (RGGI) are being finalized along with fuel price assumptions*

*** - Variable and Fixed O&M costs for CHP decrease with installation size; units of 20+ MW face the min. costs*

Source: Cost Generation Taskforce 2007

Solar Assumptions

Solar performance for Newark, NJ is measured using the PVWATTS model from the National Renewable Energy Laboratory (NREL). The model is available at http://rredc.nrel.gov/solar/codes_algs/PVWATTS/.

PV Hours Performance Assumptions for Newark, NJ

PVWATTS: Hourly PV Performance Assumptions			
City:	NEWARK	**Array Tilt (deg):**	40.7
State:	NJ	**Array Azimuth (deg):**	180
Lat (deg N):	40.7	**DC Rating (kW):**	1
Long (deg W):	74.17	**DC to AC Derate Factor:**	0.77
Elev (m):	9	**AC Rating (kW):**	0.77
Array Type:	Fixed Tilt	**Capacity Factor**	13.5%

Solar Average Hourly Output per Month in Newark, NJ

	Jan	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**
1	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
2	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
3	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
4	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
5	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
6	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
7	0.000	0.000	0.000	0.000	0.000	0.001	0.000	0.000	0.000	0.000	0.000	0.000
8	0.008	0.039	0.018	0.017	0.046	0.048	0.031	0.015	0.007	0.001	0.057	0.012
9	0.126	0.207	0.145	0.147	0.191	0.183	0.157	0.155	0.163	0.126	0.221	0.139
10	0.277	0.352	0.299	0.284	0.326	0.298	0.284	0.274	0.304	0.293	0.326	0.291
11	0.357	0.439	0.426	0.379	0.433	0.394	0.386	0.395	0.415	0.420	0.403	0.354
12	0.437	0.500	0.487	0.432	0.454	0.474	0.449	0.463	0.474	0.481	***0.418***	***0.378***
13	***0.471***	***0.510***	***0.496***	***0.523***	0.487	***0.502***	***0.487***	***0.492***	0.479	***0.508***	0.362	0.371
14	0.436	0.429	0.493	0.485	***0.528***	0.488	0.465	0.489	***0.497***	0.457	0.298	0.334
15	0.335	0.372	0.456	0.467	0.471	0.444	0.434	0.467	0.451	0.424	0.215	0.247
16	0.189	0.258	0.355	0.375	0.375	0.372	0.390	0.377	0.407	0.323	0.090	0.105
17	0.035	0.088	0.223	0.271	0.284	0.274	0.289	0.260	0.251	0.174	0.001	0.001
18	0.000	0.000	0.099	0.145	0.154	0.153	0.176	0.147	0.110	0.035	0.000	0.000
19	0.000	0.000	0.002	0.008	0.018	0.040	0.038	0.016	0.001	0.000	0.000	0.000
20	0.000	0.000	0.000	0.000	0.000	0.001	0.001	0.000	0.000	0.000	0.000	0.000
21	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
22	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
23	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
24	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

***Bold** indicates average peak output in each month*

Summary of Solar Performance in Newark, NJ

Annual Max (kW)	0.893	March 17, 12:00pm
Annual Average (kW)	0.135	
Standard Deviation (kW)	0.213	

Combined Heat and Power Assumptions

2004: Generation Cost Assumptions of Natural Gas Fuel Combined Heat and Power

2004: Generation Cost Assumptions of Natural Gas-Fueled Combined Heat and Power						
Technology	**Total Overnight Cost (REAL 2006 $/kW)**	**Variable Operation & Maintenance Costs (REAL $2006 /MWh)**	**Fixed Operation & Maintenance Costs (REAL $2006/kW)**	**Heat Rate nth-of-a-kind (Btu/kWhr) (HHV)**	**Recoverable Heat Rate (Btu/kHhr)**	**Capacity Factor**
Gas Engine (0-.5 MW)	$1,451	$18.14	$127.15	12,126	5,683	80%
Gas Engine (.5-1 MW)	$1,041	$11.74	$82.27	11,050	4,323	80%
Gas Turbine (1-5 MW)	$1,147	$6.40	$44.88	12,366	5,622	80%
Gas Turbine (5-20 MW)	$1,030	$6.40	$44.88	11,750	5,282	80%
Gas Turbine (>20 MW)	$747	$4.27	$33.66	9,220	3,779	80%
Source: KEMA, New Jersey Energy Efficiency and Distributed Generation Market Assessment (all technologies noted above are w/out chillers)						

2007: Generation Cost Assumptions of Natural Gas-Fueled Combined Heat and Power

2007: Generation Cost Assumptions of Natural Gas-Fueled Combined Heat and Power (CHP)			
Technology	**Total Overnight Cost (REAL 2006 $/kW)**	**Heat Rate nth-of-a-kind (Btu/kWh) (HHV)**	**Recoverable Heat Rate (Btu/kWh)**
Existing CHP facilities (assumed to be w/out chillers) (3-25 MW)	$1,601	10,000	7,000
New CHP facilities w/ Chillers (3-25 MW)	$2,134	10,000	7,000
** Costs adjusted for inflation using a CPI calculator, available a http://www.bls.gov/cpi/*			
Source: Joe Sullivan, NJ BPU 2007			

Cost of Capital Assumptions

	Nuclear	Combined Cycles*	Combustion Turbines	Pulverized Coal	IGCC	Retrofits	Renewables
Input:							
Debt Life (years)	20	20	20	20	20	15	15-20
Book Life (years)	40	30	30	40	40	20	
Nominal After Tax Equity Rate (%)	14	13	13	13	13	12	14-19
Equity Ratio (%)	50	50	50	50	50	50	40
Nominal Debt Rate (%)	9	8	8	8	8	7	8
Debt Ratio (%)	50	50	50	50	50	50	60
Income Tax Rate (%)	41.2	41.2	41.2	41.2	41.2	41.2	41
Other Taxes/Insurance (%)	2.2	2.2	2.2	2.2	2.2	2.2	2.2
Inflation (%)	2.25	2.25	2.25	2.25	2.25	2.25	2.25
Discount Rate	6.86%						
Output:							
Levelized Real Fixed Capital Charge Rate (%)	14	13.3	13.3	12.9	12.9	13.6	

* Also applies to repowering options from coal and oil/gas steam units to new combined cycle units.

NOTE: Income tax and other tax/insurance rates updated as of July 2003.

Source: IFC Consulting (RGGI Report 2006)

Energy Efficiency and Renewables Jobs Assumptions

BAU Scenario

	On-Shore Wind		Off-Shore Wind		Biomass		Solar		Conventional Generation		Total	
	1 Year Jobs	Annual O&M	1 Year Jobs	Annual O&M	1 Year Jobs	Annual O&M	1 Year Jobs	Annual O&M	1 Year Jobs	Annual O&M	1 Year Jobs	Annual O&M
2010	3	3	0	0	5	35	484	0	0	0	493	37
2011	2	5	0	0	3	54	151	0	536	55	156	59
2012	2	7	0	0	3	69	178	0	546	110	182	76
2013	2	9	0	0	3	82	218	0	556	165	223	91
2014	2	11	1,607	123	3	86	258	0	566	220	1,870	220
2015	2	13	0	124	5	110	299	0	577	275	305	246
2016	2	15	0	126	5	133	354	0	952	366	362	274
2017	2	18	0	127	5	153	409	0	970	457	416	297
2018	2	19	0	126	5	170	464	0	987	547	471	316
2019	2	22	0	129	5	205	523	0	1,005	638	530	356
2020	2	23	0	131	5	222	575	0	1,024	677	582	376

Alternative Scenario

	On-Shore Wind		Off-Shore Wind		Biomass		Solar		CHP		EE Audits		EE Installations		Total	
	1 Year Jobs	Annual O&M	1 Year Jobs	Annual O&M	1 Year Jobs	Annual O&M	1 Year Jobs	Annual O&M	1 Year Jobs	Annual O&M	1 Year Jobs	Annual O&M	1 Year Jobs	Annual O&M	1 Year Jobs	Annual O&M
2010	3	14	0	0	5	35	439	0	63	81	0	1,254	0	4,772	511	6,156
2011	3	18	0	0	9	92	129	0	81	161	0	1,254	0	4,772	222	6,298
2012	3	22	0	0	9	145	149	0	81	242	0	1,254	0	4,772	242	6,436
2013	3	26	0	0	9	196	180	0	81	323	0	1,254	0	4,772	273	6,571
2014	3	29	1,607	123	9	221	209	0	81	403	0	1,254	0	4,772	1,909	6,803
2015	3	33	632	172	9	260	237	0	81	484	0	1,254	0	4,772	962	6,975
2016	3	36	645	225	9	297	277	0	81	564	0	1,254	0	4,772	1,015	7,149
2017	3	39	648	275	9	328	314	0	81	645	0	1,254	0	4,772	1,054	7,314
2018	3	41	645	323	9	354	350	0	81	726	0	1,254	0	4,772	1,087	7,471
2019	3	44	660	381	9	418	386	0	81	806	0	1,254	0	4,772	1,139	7,677
2020	3	47	668	437	9	444	417	0	81	887	0	1,254	0	4,772	1,177	7,841

Emissions Allowances

Emission Permit Prices ($/Ton-Nominal)

	2010	2015	2020
SO-2	700	700	700
NOx	2600	2600	2600
CO2 RGGI	2.36	3.88	5.67
CO2 National	7.35	8.05	8.83
Source: RGGI Preliminary Electricity Sector Modeling Results, August 17, 2006, ICF Consulting			
U.S. Energy Information Agency Environmental Climate Change Analysis [*http://www.eia.doe.gov/oiaf/1605/climate.html*](http://www.eia.doe.gov/oiaf/1605/climate.html)			

Renewable and Energy Efficiency Job Impact Assumptions

BAU

	Annual One-Time Installation Jobs		Annual Operations and Maintenance Jobs	
	Cumulative	**2020**	**Cumulative**	**2020**
On-Shore Wind	15	1	103	17
Off-Shore Wind	1,137	0	629	93
CHP	0	0	0	0
Solar	3,913	575	0	0
Energy Efficiency	0	0	0	0

Alternative

	Annual One-Time Installation Jobs		Annual Operations and Maintenance Jobs	
	Cumulative	**2020**	**Cumulative**	**2020**
On-Shore Wind	23	2	249	33
Off-Shore Wind	3,896	473	1,374	310
CHP	888	42	789	38
Solar	3,087	417	0	0
Energy Efficiency	N/A		9,109	828

***Notes
1.) Cumulative refers to 2010 - 2020
2.) 2020 is only the job impact from the year 2020
3.) Energy Efficiency jobs are for EE Audits only, not for EE Measures.

Transmission Assumptions

Projects modeled

Name	**Size (MW)**
Neptune/Sayreville 230 kV	685
Linden 230 kV	330
Bergen	670
Source: PJM Regional Expansion Plan 2007 http://www.pjm.com/planning/reg-trans-exp-plan.html	

Projects not modeled

Name	**Size (MW)**
Bergen 230 kV	1200
Source: PJM Regional Expansion Plan 2007 http://www.pjm.com/planning/reg-trans-exp-plan.html	

New Jersey Power Plant Retirement Assumptions

Year	**Retirements**
2006	1,122
2010	1,575
2015	1,958
2020	2,881

Notes:

1.) Base Year is 2004

2.) Values are Cumulative

3.) If Unit retired after July 1 during the reported year, it was not counted as a retirement

4.) Capacities are Summer Capacity

R/ECON™ Assumptions

Baseline Scenario

(Nominal $)				
	2006	**2010**	**2015**	**2020**
Real GDP	11422.4	12848.8	14551.6	16604.2
Real GDP(% change)	3.4	3.1	2.6	2.7
GDP Deflator	2.9	2.0	1.9	1.8
Consumer Prices	3.2	1.9	1.9	1.9
Oil - WTI ($ per barrel)	66.12	61.75	56.87	60.08
Natural Gas--Henry Hub ($/mmbtu)	6.80	7.78	7.61	8.76
NJ Natural Gas ($/mmbtu)	-	-	-	-
Productivity (%change)	2.1	2.0	2.5	2.3
Unemployment Rate (%)	4.6	4.4	4.8	4.8
Payroll Employment (%change)	1.9	1.3	0.5	0.8
30-Year Fixed Mortgage Rate (%)	6.42	7.01	6.85	6.85
Fuels & Power (1982=1.0)	1.67	1.73	1.74	1.95
PPI: Coal	1.27	1.27	1.29	1.37
PPI: Gas Fuels	2.72	3.04	2.97	3.56
PPI: Electric Power	1.62	1.81	2.04	2.34
PPI: Utility Natural Gas	2.30	2.45	2.44	2.80
PPI: Crude Petroleum	1.76	1.63	1.51	1.46
PPI: Refined Petroleum Products	1.93	1.81	1.69	1.79
Global Insight 2007 February 2007.				

High Growth Scenario

(Nominal $)				
	2006	**2010**	**2015**	**2020**
Real GDP	11422.4	13194.7	15249.6	17963.1
Real GDP(% change)	3.4	3.6	3.0	3.6
GDP Deflator	2.9	1.6	1.2	1.2
Consumer Prices	3.2	1.4	1.3	1.3
Oil - WTI ($ per barrel)	66.1	58.2	50.7	52.6
Natural Gas--Henry Hub ($/mmbtu)	6.80	7.49	7.02	7.94
NJ Natural Gas ($/mmbtu)	-	-	-	-
Productivity (%change)	2.1	1.7	2.7	2.8
Unemployment Rate (%)	4.6	4.3	4.7	4.7
Payroll Employment (%change)	1.9	1.8	0.5	1.3
30-Year Fixed Mortgage Rate (%)	6.42	6.46	6.24	6.25
Fuels & Power (1982=1.0)	1.67	1.66	1.61	1.76
PPI: Coal	1.27	1.27	1.25	1.28
PPI: Gas Fuels	2.72	2.92	2.73	3.20
PPI: Electric Power	1.62	1.77	1.93	2.16
PPI: Utility Natural Gas	2.30	2.37	2.27	2.54
PPI: Crude Petroleum	1.76	1.53	1.33	1.27
PPI: Refined Petroleum Products	1.93	1.72	1.52	1.59
Global Insight 2007 February 2007.				

Low Growth Scenario

(Nominal $)				
	2006	**2010**	**2015**	**2020**
Real GDP	11422.4	12435.3	13674.7	15104.3
Real GDP(% change)	3.4	2.3	2.1	1.8
GDP Deflator	2.9	2.9	3.6	4.0
Consumer Prices	3.2	2.9	3.6	4.0
Oil - WTI ($ per barrel)	66.1	65.9	64.4	73.3
Natural Gas--Henry Hub ($/mmbtu)	6.80	8.15	8.40	10.31
NJ Natural Gas ($/mmbtu)	-	-	-	-
Productivity (%change)	2.1	1.6	1.9	1.5
Unemployment Rate (%)	4.6	4.9	5.1	5.0
Payroll Employment (%change)	1.9	0.4	0.5	0.4
30-Year Fixed Mortgage Rate (%)	6.42	7.03	7.63	8.16
Fuels & Power (1982=1.0)	1.67	1.82	1.95	2.36
PPI: Coal	1.27	1.31	1.43	1.67
PPI: Gas Fuels	2.72	3.20	3.31	4.23
PPI: Electric Power	1.62	1.88	2.28	2.89
PPI: Utility Natural Gas	2.30	2.56	2.71	3.35
PPI: Crude Petroleum	1.76	1.75	1.72	1.80
PPI: Refined Petroleum Products	1.93	1.92	1.90	2.16
Global Insight 2007 February 2007.				