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WCI Modeling Results for New Mexico

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Introduction

This testimony presents results for New Mexico from analysis conducted for the Western Climate Initiative. The WCI Economic Modeling Team (EMT) directed the region-wide analysis and engaged ICF International and Systematic Solutions, Inc. to help model the effects of the WCI's regional plan to reduce greenhouse gas (GHG) emissions. The New Mexico Environment Department engaged ICF to examine and present the projected effects specific to New Mexico, based on the regional modeling. Extensive information on the regional modeling is available on the WCI website, and this testimony will refer to that information frequently in order to avoid major duplication. It also replicates the tables that present the results for WCI, and presents that same types of results, but for New Mexico only. All WCI documents referenced here are available at http://westernclimateinitiatve.org/component/repository/Economic-Modeling-Team-Documents/. NMED-Hausker Exhibit 1.

In this and any modeling exercise, it is important to keep in mind what models can and cannot do, and the benefit that we can glean from economic and policy modeling. Generally, such models do not claim to, nor can they, "predict" the future. The economy and society at large have too many random and unpredictable elements to allow models to offer predictions with much confidence. The vagaries of economic booms and recessions, oil price gyrations, and natural gas supplies – to name just a few – mean that yesterday's prediction is invariably "wrong". Models *do* have value in giving insights into the likely effects of policies if one focuses on the "deltas", i.e., the differences between two scenarios. Most economic and policy models establish a "business-as-usual" (BAU) scenario holding constant a current policy framework, and then exploring the effects of changing that policy. Sensitivity analysis then varies the underlying assumptions to improve the robustness of the projections. This outlook guided the WCI modeling.

The granularity of the modeling is also worth noting. This testimony is based on the modeling of a huge expanse of the U.S. and Canada that encompasses all the WCI partners. Furthermore, the modeling of the electricity sector had to encompass an even larger expanse due to the interconnected nature of the power system. Therefore, the results for New Mexico are indicative but could not capture the details one might expect from a modeling exercise focused on the state alone, or even on a single utility within the state.

The WCI has conducted a multi-phase analysis and recently concluded "Phase 3" which updates previous analyses by accounting for new Partners within the WCI, the economic downturn of 2008-2009, and various model improvements identified by the EMT and WCI stakeholders. Details on the evolution of the multi-phase analysis are available in WCI's Phase 3 analysis released in July 2010, entitled *Updated Economic Analysis of the WCI Regional Cap-and-Trade Program* (hereafter "*Updated Economic Analysis*"). NMED-Hausker Exhibit 2.

Projected effects for New Mexico are expressed as differences between "reference runs" and "cap-and-trade runs". Reference runs project energy use and emissions for the state economy under a BAU scenario. Cap-and-trade runs project the energy use and emissions of the economy under a scenario of implementation of the WCI regional plan that includes a cap-and-trade program along with "complementary policies."

Complementary polices can take many forms: regulations, incentive programs, utility DSM programs, etc. All aim to reduce energy use and greenhouse gas emissions, often at a net savings to society. Effective complementary policies can lower the cost of implementing a cap-and-trade program relative to a scenario of cap-and-trade alone.

This testimony is organized as follows: Section 2 provides an overview of the ENERGY 2020 model used for the WCI analysis; Section 3 explains key assumptions used in the modeling; Section 4 describes the Modeling Cases; Section 5 presents the Modeling Results; and Section 6 presents

Conclusions. There are three appendices: Appendix A presents a glossary of terms used in this testimony; Appendix B presents the reference case results; and Appendix C presents the main policy case results.

Overview of ENERGY 2020 Model

ICF used the ENERGY 2020 model for the WCI analysis, via a subcontract with Systematic Solutions, Inc., the owner of the model. *ENERGY 2020 Inputs and Assumptions* (hereafter the "*Assumptions Book*") provides a detailed description of the model and is posted on the WCI website. NMED-Hausker Exhibit 3. Below is a brief description of the model.

ENERGY 2020 is an integrated, multi-region energy model that provides all-fuel demand and supply sector simulations. The model simulates demand by three residential categories (single family, multi-family, and agriculture/rural), over 40 NAICS commercial and industrial categories,[1] and three transportation services (passenger, freight, and off-road). There are approximately six end-uses per category and six technology/mode families per end-use. End-uses include process heat, space heating, water heating, refrigeration, lighting, air conditioning, and motors. The technology families correspond to six fuels groups (oil, gas, coal, electric, solar and biomass) and 30 fuel products. The transportation sector contains 45 modes, including various types of automobile, truck, off-road, bus, train, plane, marine and alternative-fuel vehicles. More end-uses, technologies, and modes can be added as data allow. For all end-uses and fuels, the model is parameterized based on historical, locale-specific data. The load duration curves for electricity demand are dynamically built up from the individual end-uses to capture changing conditions under consumer choice and combined gas/electric programs.

Each energy demand sector includes cogeneration, self-generation, and distributed generation simulation, including mobile-generation, micro-turbines, and fuel-cells. Fuel-switching responses are

[1] NAICS is the North America Industrial Classification System which was developed jointly by the U.S., Canada, and Mexico to provide new comparability in statistics about business activity across North America.

rigorously determined. The technology families (which can be split to portray specific technology dynamics) are aggregates that, within the model, change building shell, economic-process and device efficiencies and capital costs as prices or other information seen by decision makers change. ENERGY 2020 utilizes the historical and forecast data developed for each technology family to parameterize and disaggregate the model.

The supply portion of the model includes endogenous detailed electric supply simulation of capacity expansion/construction, rates/prices, load shape variation due to weather, a complete (but aggregate) representation of the electric transmission system, and changes in regulation. The model dispatches plants according to the specified rules whether they are optimal or heuristic and simulates transmission constraints when determining dispatch. A dispatch routine selects critical hours along seasonal load duration curves as a way to determine system generation. Peak and base hydro usage is explicitly modeled to capture hydro-plant impacts on the electric system.

In addition to modeling electricity supply, ENERGY 2020 can also model the supply of oil, natural gas, refined petroleum products, ethanol, land-fill gas, and coal. In this analysis, however, prices for these energy sources were provided exogenously to the model.

ENERGY 2020 includes pollution accounting for both combustion (by fuel, end-use, and sector) and non-combustion processes, and non-energy (by economic activity) for all GHGs that would be covered by the WCI cap-and-trade program, as well as conventional air pollutants at the state and provincial level by economic sector.

ENERGY 2020 can simulate the impacts of a wide variety of GHG mitigation policies, including regulations, demand reduction programs, taxes, and emission caps with trading. These capabilities were used in the reference runs (to reflect existing policies) and in cases involving complementary policies and the WCI cap-and-trade design. Details on specific policies included in the modeling appear in later sections and in the *Assumptions Book*. The *Updated Economic Analysis* explains how the use of GHG offsets and allowance banking was modeled with ENERGY 2020.

ENERGY 2020 is not a macroeconomic model but can be coupled with a macroeconomic model such as REMI. Therefore, ENERGY 2020 does not project economic output, household income, employment, etc. That part of the analysis has been conducted by another Department witness, Dr. Adam Rose.

Modeling Assumptions

This section highlights the major assumptions used in the modeling with an emphasis on New Mexico-specific assumptions. These assumptions are included in all modeling runs with the exception of those varied in sensitivity cases described in a later section. The *Updated Economic Analysis* and *Assumptions Book* provide full detail on all assumptions, including links to data sources.

Geographic Coverage: Historic data and projections for New Mexico and the 10 other WCI partners were used, covering a wide range of energy and economic variables. As noted earlier, the modeling also simulated the entire US and Canadian electric grid (at various levels of resolution) to account for the interconnected nature of the power grid, and to explore the potential for emission "leakage" to areas outside of the WCI program.

Sectors and Sources. The modeling included energy use in all sectors, as well as most industrial process emissions. Landfill methane emissions and non-CO2 agriculture emissions were included in the total emissions estimates, but emission reductions are not estimated for these sources. The analysis reflects WCI focus on gross, rather than net, emissions, and thus forest and soil sinks are excluded.

Population Forecast:. Energy demand and GHG emissions are driven in part by population. The modeling used official projections showing New Mexico's popultion growing from 2.0 million in 2006 to 2.5 million in 2020, comparable to the growth for WCI as a whole (85 million to 102 million).

Economic Growth. Economic output is another key driver of energy demand and GHG emissions. The modeling was conducted during a period of the worst recession in the last half century, generating uncertainty on reasonable growth projections for the next decade. After considerable discussion, the EMT settled on a projection that captured the current downturn and assumed some resumption of growth in 2010 and continuing to 2020. The resulting 2006-2020 average growth was 2.4% per year.

Energy Prices. For this critical driver, the EMT adopted the AEO 2009 Reference Case price forecast. ENERGY 2020 generated state- and province-specific retail prices from the forecast based on historical patterns, as shown in the table below. Other fuel prices appear in the *Assumptions Book.*

Table 1 - Energy Price Forecast

	2006	2012	2015	2020
World Oil Price (2007 US$/barrel)	60.70	94.84	108.52	112.05
Natural Gas Wellhead Price (2007 US$/mmBtu)	6.91	6.75	6.90	7.43
Coal Prices (2007 US$/ton)	25.29	27.69	27.77	27.38

Source: EIA Annual Energy Outlook 2009, Reference Case price series.

GHG Mitigation Options. The model simulates decisions by energy users for each end use, including: fuel choice; investment in end-use efficiency (by purchasing devices that are more efficient than the minimum required by standards); and end-use utilization (how much the device is used). End-use specific choices are simulated as needed, such as mode choice for freight movement and passenger transportation. Choices are simulated based on costs (increased capital costs versus the value of fuel saved), as well as non-price attributes (convenience and acceptance of the technology). Past purchasing behavior is used to calibrate the non-price choice parameters for each end use. Key assumptions on cost appear in the *Assumptions Book*. In addition, the EMT made the following key assumptions on technology availability:

- No new coal plants are assumed to be built by 2020 in the WECC region beyond those already planned and committed.[2] Regarding New Mexico, the modeling assumes that the Desert Rock coal plant does not go forward.
- Carbon capture and storage is assumed not feasible for any fossil-fuels electric generation through 2020.
- No new nuclear power plants are assumed to be built in the WECC region through 2020.
- No new hydropower capacity is assumed to be built in the WECC region through 2020.
- Neither all-electric vehicles nor plug-in hybrids are assumed to be available in significant numbers through 2020.

Policies. Three key policy assumptions are worth noting:

- All cases include the requirements of the Energy Independence and Security Act of 2007, including appliance and lighting energy efficiency standards, and the national renewable fuels standard (RFS). These requirements are assumed to be implemented fully in the U.S. WCI Partner jurisdictions. For the Canadian provinces, lighting, equipment and appliance standards as defined by the Canadian Standards Association[3], as well as federal "ecoENERGY" Renewable Fuels Strategy.
- All cases incorporated the Clean Car Standards through 2016, equivalent to California's Pavley I. In April, 2010, the federal government established standards for vehicle GHG emissions and CAFÉ standards which would align with the GHG emission standards previously proposed by California. As a result, a national standard was established which will require the fuel efficiency

[2] See Appendix F of the *Assumptions Book for* a list of coal plants that are assumed to be planned and committed.

[3] http://www.oee.nrcan.gc.ca/regulations/home_page.cfm.

of new passenger cars and light trucks to reach an average fleet efficiency of 35.5 mpg by 2016. The modeling assumed a fixed percentage increase in the efficiency of new vehicles each year starting in 2010 to reach the mandated level by 2016. Information relating to the cost of implementing this policy was based on estimates by the NHTSA.[4] Efficiency improvements beyond 2016 (Pavely II) are included the complementary policies runs.

- All cases incorporate the renewable portfolio standards (RPSs) currently in effect in WCI states and provinces. New Mexico's RPS increases to 20% by 2020.[5]

Cap-and-Trade Policy Assumptions. The modeling simulated the WCI program design with these assumptions:

- *Allowance Budgets*: Recommendations to the WCI Partners on setting allowance budgets are under development by the WCI Cap Setting and Allowance Distribution (CSAD) Committee. Thus the EMT had to make reasonable assumptions about the allowance budget and based these assumptions on the WCI Design Recommendations. In the modeling, the cap for 2020 is assumed to be 15% below 2005 levels (proxied by 2006 model-estimated emissions, since this is the first year for which modeling results are available). The *Updated Economic Analysis* provides an explanation of how the EMT determined assumptions for allowance budgets for the "narrow scope" compliance period (2012-2014) and the "broad scope" compliance period beginning in 2015. Compliance with the caps means that the emissions in the capped sectors, summed over 2012-2020, equals the annual allowance budgets plus offsets, summed over 2012-2020. Over-

[4] NHTSA, Corporate Average Fuel Economy Rulemaking, Document No. WP.29-145-13, June 2008. See also: NHTSA, Final Environmental Impact Statement, Corporate Average Fuel Economy Standards, Passenger Cars and Light Trucks, Model Years 2011 to 2015, October 2008.B

[5] See Appendix I of the *Assumptions Book* for details on all WCI partners.

compliance in the first two compliance periods is acceptable, and the banked allowances can be used in the final compliance period.

- *Allocation of Allowances*: The modeling was conducted without specific assumptions on the mixture of freely allocated allowances vs. auctioned allowances. Economic theory suggests that the price of allowances will affect energy prices in the same ways regardless of this mixture, and that those prices will drive abatement costs. The allocation method is largely an equity issue, and determines who benefits from the market value of the allowances. The modeling assumed that allowance prices increase energy prices in proportion to carbon content in both energy markets and in regulated utility prices.
- *Allowance Banking*: The modeling assumed that players in the allowance market recognize the time value of money, and when they bank an allowance in one time period (incurring the opportunity cost of not using it), they expect that it will have greater value in a future time period. Economic theory suggests that when banking is allowed under a cap-and-trade system, the allowance price will grow over time at a rate equal to the emitter's discount rate. The EMT chose a private sector real discount rate of 8% and also conducted senstitivity analysis at 4% and 12%. The *Updated Economic Analysis* provides more details on banking provisions.
- *Offsets*: The cap-and-trade program allows the limited use of GHG offsets. The EMT constructed an offset supply curve based on a recent U.S. EPA study of offset potential in the forestry and agriculture sectors to integrate with the use of allowance and banking (details available in the *Updated Economic Analysis*).

- *First Jurisdictional Deliverer*: All cases incorporate a proxy to represent the first jurisdictional deliverer approach described in the WCI Design Recommendations. [6] Consequently, emissions from electricity imported into the WCI Partner jurisdictions from outside the WCI Partner jurisdictions are included in the analysis.

Complementary Policies. The modeling reflected the WCI program design with these assumptions:

- *Clean Car Standards*: The modeling assumed that all WCI partners adopt the equivalent of California's Pavley II beginning in 2017. By 2020, per-mile GHG emissions from new passenger vehicles decrease by 17 percent relative to new vehicle emissions in 2016. ENERGY 2020 estimates the fuel savings and changes to device investments and increases in operation and maintenance costs. Change in vehicle costs are based on estimates from the California Air Resources Board. Additional details are available in the *Assumptions Book*.
- *Energy Efficiency*: The combined effect of energy efficiency programs recently put in place and being pursued are assumed to reduce the rate of growth in electricity and natural gas demand by 0.5% each year starting in 2012. ENERGY 2020 estimates the fuel savings and changes to investments and operation and maintenance costs. The modeling also includes program administration cost, which is $0.6 billion per year by 2020.
- *VMT Reduction*: The modeling assumed that transportation-related programs will have the equivalent effect of reducing vehicle miles traveled (VMT) by 2% from the reference case by 2020, beginning in 2008. ENERGY 2020 does not estimate the cost of reducing the VMT

[6] See http://westernclimateinitiative.org/document-archives/wci-design-recommendations.

internally. A review of the VMT reduction literature indicated both costs and savings from such programs. The EMT assumed that the magnitude of the net implementation cost is neglible.

- *Ontario Coal Phase-Out*: Ontario phases out all of its coal generation between 2009 and 2015, consistent with the province's plans.

Modeling Cases

The EMT requested six cases – that is, six families of model runs. Each family of runs consists of a reference run, a complementary policies run (i.e., the complementary policies applied to the reference run), and cap-and-trade run (i.e., an allowance price imposed on the complementary policies run).

The EMT defined a Main policy and five Sensitivity cases, which differ from the main policy case in the following ways:

- Half-effectiveness of complementary policies (shares reference run with main policy case).
- Alternative economic forecast, high economic growth, low energy prices (requires its own reference and complementary policies runs).
- High fuel price and high electricity generation cost (requires its own reference and complementary policies runs).
- A discount rate of 4% per year that drives growth in allowance price for cap-and-trade (shares reference run and complementary policies run with main policy case).
- A discount rate of 12% per year that drives growth in allowance price for cap-and-trade (shares reference run and complementary policies run with main policy case).

These cases are described more fully below.

Main Policy Case. This case simulates the effects of the WCI cap-and-trade program under the EMT's assumptions regarding future socio-economic conditions, complementary policies, and offset availability and costs. The sensitivity cases then allowed the EMT to gauge the sensitivity of the main policy case results to changes in some of these key assumptions.

Half-Effectiveness of Complementary Policies. This sensitivity case explored the effects of the energy efficiency and VMT programs achieving only half of their assumed emission reductions:

- The energy efficiency programs reduce the rate of growth in electricity and natural gas demand by 0.25% per year, starting in 2012 (rather than 0.50%).
- Vehicle miles traveled decrease by only 1% from the reference case by 2020 (rather than 2%).

The clean car standards and the Ontario coal phase-out are unchanged.

Sensitivity Case: Alternative Economic Forecast. This sensitivity case examined the implications of a different economic forecast than assumed in the main policy case. The alternative economic forecast assumes an average growth rate of 2.8% per year, higher than in the forecast used for the main policy case. The alternative forecast also uses lower energy price (equal to the average of the AEO 2009 reference-price and low-price forecasts) and assumes that the U.S does not fully meet the EISA biofuels mandate for 2020, but rather a lower level of biofuels reflected in the AEO 2009 forecast. Each of these changes has the effect of increasing GHG emissions in the reference case. The EMT considered these changes to be reasonable because the higher growth of the economy would also increase opportunities to become more energy efficient. An alternative complementary policies run would be appropriate for this sensitivity case, in which the energy efficiency programs achieve a 1% per year decrease in electricity and natural gas demand growth, starting in 2012.

Sensitivity Case: High Fuel Prices and Electricity Generation Costs. This sensitivity case explored the implications of a scenario that includes both increased energy prices and increased power generation costs as a set of conditions that could occur together in the future. In this case, energy prices are assumed to start at 2008 prices and increase in real terms by 50% by 2020, and capital and O&M costs for power generation are assumed to be 30% higher than in the main policy case. This case required its own reference and complementary policies runs.

Sensitivity Case: 4% Annual Growth In Allowance Prices. This sensitivity case examines the implications of a slow-rising allowance price trajectory. This case uses a growth rate in the allowance price of 4% per year instead of 8% per year in the cases discussed above.

Sensitivity Case: 12% Annual Growth In Allowance Prices. This sensitivity case examines the implications of a faster-rising allowance price trajectory. This case uses a growth rate in the allowance price of 12% per year instead of 8% per year in the cases discussed above.

Modeling Results

Table 2 summarizes the results of modeling for the main policy case and the five sensitivity cases. (The output variables are the same as in Table 9 in the *Updated Economic Analysis)*.

For WCI as a whole, the main policy case achieves the regional GHG emissions goal at an allowance price of $33 in 2020. With region-wide trading, of course, the same allowance price is projected for New Mexico. The abatement cost for New Mexico, summing over the years 2012-2020, is negative $440 million, indicating a small net savings to the economy (not accounting for a small addition cost for offset purchases not modeled at the state level). The net cost for WCI as a whole over the period analyzed (including offset costs) was projected at negative $102 billion. The results of the sensitivity cases suggest that reducing the effectiveness of complementary polices by half, or assuming a rapid economic recovery and low energy prices, would increase allowance prices to more than $50, but still result in net savings.[7] Conversely, Table 2 shows that allowance prices would be much lower than the main policy case if energy prices and electricity production costs in the reference case are higher than expected (and thus resulting in lower Reference Case GHG emissions).

Table 3 presents detailed cost estimates for the main policy case by sector and cost type, summed over the program period of 2012-2020. Negative costs are shown in parentheses. The cost savings result from the complementary policies. The largest single savings are attributable to the passenger transportation sector. In particular, the VMT reduction reduces expenditures on fuel and vehicle purchases.

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[7] As explained in the *Updated Economic Analysis*, modeling runs were not performed for allowance prices over $50. This price, however, achieved 94% of the emission reductions required by the cap for both sensitivity cases.

The half-effectiveness of complementary policies case achieves compliance for an allowance price trajectory that has a price higher than $50 in 2020. The alternative economic forecast case also achieves compliance for an allowance price higher than $50 in 2020. The potential for savings, however, is higher in this case than any other (at least $6.86 billion for the State). This is because the faster economic growth was assumed to create more opportunities to improve energy efficiency. Hence, complementary policies were assumed to reduce the growth rate of electricity and natural gas demand by 1 percent in each year. Nonetheless, the faster economic growth and lower fuel prices leads to greater emissions in the reference run and a greater need for emission reductions in the cap-and-trade run, requiring an allowance price greater than $50 to achieve the WCI regional goal.

The sensitivity case that assumes higher energy prices and electricity generation costs achieves compliance at a low allowance price of $13. The cost savings potential is larger than the main policy case because the low allowance price preserves a greater portion of the savings from the complementary policies.

The final two sensitivity cases imply that the discount rate used by emitters in trading of the current vs. future value allowances would have little effect on the results.

Table 2: Summary of Economic Results for Main Policy and Sensitivity Cases (savings in parentheses)

Case Description	Abatement by covered sectors, 2012-2020 (MMTCO2e)	Reduction from offsets, 2012-2020 (MMTCO2e)	Abatement cost,* 2012-2020 (2007 $B)	Offset cost, 2012-2020 (2007 $B)	Allowance price in 2020 that achieves complianc e (2007 $)	Allowance value 2012-2020 (2007 $B)
Main policy case	4.01	N/A	(0.44)	N/A	33	N/A
Sensitivity Cases						
Half the VMT reduction and energy efficiency improvements	(0.14)	N/A	< 2.91	N/A	>50	N/A
Faster economic growth & lower primary energy prices**	34.04	N/A	< (6.86)	N/A	>50	N/A
Higher energy prices and power plant construction costs	16.02	N/A	(1.70)	N/A	13	N/A
4% annual allowance price escalation	3.98	N/A	(0.40)	N/A	28	N/A
12% annual allowance price escalation	4.18	N/A	(0.44)	N/A	39	N/A

* Abatement cost reflects the negative $547 million from Table 3 plus an assumed $110 million for energy efficiency program administration.
** This case assumes greater economic growth will create more opportunities to improve energy efficiency and therefore reduce the annual growth rates by 1% per year instead of 0.5% per year.
N/A: Not Available. Use of offsets was modeled at the WCI-wide level, not at state level, therefore Reduction from Offsets and Offset Cost is not available. Allowance Value

Table 3: Economic Results for the Main Policy Case by Sector and Cost Type, 2007 Million US$ Summed Over 2012-2020 (savings in parentheses)

Sector	Fuel	Device	Process	O&M	Total
Residential	184	385	2	18	589
Commercial	564	565	6	72	1,207
Energy Intensive Industry*	987	128	8	93	1,216
Paper	12	3	0	3	18
Chemicals	90	(14)	3	11	90
Petroleum	462	139	4	77	683
Nonmetallic Minerals	317	1	1	2	321
Primary Metals	106	(1)	0	0	105
Mining Except Oil & Gas	-	-	-	-	-
Oil and Gas Extraction	-	-	-	-	-
Other Industry	529	91	3	72	695
Passenger Transportation	(1,255)	(2,447)	-	(456)	(4,158)
Freight Transportation	(94)	(2)	-	-	(96)
Agriculture	-	-	-	-	-
Waste & Wastewater	-	-	-	-	-
Total**	915	(1,280)	19	(201)	(547)

* Energy Intensive Industry is a subtotal of the seven energy-intensive sectors listed beneath it.

** Does not include allowance value, offset costs, or complementary policies administrative costs (which are estimated and reported separately).

Conclusions

The *Updated Economic Analysis* of WCI-wide effects for the regional GHG mitigation program indicate that the 2020 emissions goal could be achieved with a small negative cost, i.e., a savings to the economy. The projected effects specific to New Mexico, based on the same regional modeling exercise, indicate a similar small negative cost to the state. The main policy case suggests that New Mexico would contribute a reduction of about 4 MMTCO2e to meeting the WCI emissions reduction goal. Sector by sector results for New Mexico are different from WCI as a whole for many reasons, including differences among WCI jurisdictions in industry composition, existing power generation, and land use patterns.

The New Mexico results are similar to those for WCI as a whole in illustrating that complementary policies are key to projections of negative savings. The *Updated Economic Analysis* also highlight the importance of offsets and allowance banking as cost containment design features.

Attachment A - Glossary

2012 - the first year of the first compliance period, and the starting year of the WCI cap-and-trade program.

2015 - the first year of the second compliance period, at which point additional sectors are subject to the cap.

2020 - the final year of the third compliance period, and the end year of the economic analysis.

Abatement -means the change in emissions in covered sectors due to complementary policies and the cap-and-trade policy. Specifically, it is the difference between the emissions in a cap-and-trade run and the emissions in the reference run. Reductions through offsets, therefore, are not included in this use of the term abatement.

Abatement cost - means the resource cost to bring about abatement. In this analysis, proper quantification of total abatement costs requires that the value of allowances used in the electric power sector be subtracted from the abatement costs. This is required because electricity prices in the model were assumed to include the full market value of allowances in order to effectuate proper energy use decisions among end users in the residential, commercial, industrial, and transportation sectors. Because allowance values represent a financial transfer and not a resource (or abatement) cost, the allowance value is subtracted from the abatement cost so that it reflects the actual cost of reducing emissions.

Allowance - a permit to emit one ton of carbon dioxide equivalents (CO_2e).

Allowance budget - means the number of allowances assumed to be issued throughout the region in a given year. In the WCI cap-and-trade program, one allowance is required to emit each metric ton (Mt) of covered greenhouse gas emissions, expressed in carbon dioxide equivalents (CO_2e). For purposes of economic modeling, an allowance budget was determined for each year such that the WCI regional goal would be met in 2020 through a linear decline starting in 2012. The difference between the reference case emissions for covered sectors and the allowance budgets represents the total 9-year emission reduction that the main policy and sensitivity cases must achieve.

Allowance value - means the allowance price in a given year multiplied by the allowance budget for that year.

Banking - means that covered sources emit less than the allowance budget in one compliance period and bank the remaining allowances for use in a later compliance period. This allows covered sources to make cost-effective reductions earlier and lessen the costs later.

Broad scope - in the modeling means the narrow scope plus passenger and freight transport emissions and emissions from all remaining fossil fuel combustion, including residential, commercial, agriculture, and waste & wastewater. These emissions are covered in the second and third compliance periods. Not included in the broad scope are process emissions from agriculture, waste & wastewater, and high Global Warming Potential gases, such as refrigerants.

Cap-and-trade run - means an application of ENERGY 2020 in which an allowance price has been imposed on the reference and complementary policies conditions. All of the cap-and-trade runs include complementary policies.

Case - means a family of ENERGY 2020 runs consisting of a reference run, a complementary policies run, and a cap-and-trade run. Each case is characterized by assumptions on economic growth, energy/fuel prices, and effectiveness of complementary policies (full or half), generation cost, and allowance-price growth rate.

Complementary policies run - means an application of ENERGY 2020 in which complementary policies have been added to the reference conditions.

Compliance - means that at the end of each compliance period emissions from all covered sectors, summed over each year since 2012, must be equal to or less than the allowance budgets issued since 2012, after accounting for offsets.

Compliance period - means a three-year period at the end of which an emission source must hold a sufficient number of allowances to account for its emissions during that period. The WCI compliance periods are 2012-2014, 2015-2017, and 2018-2020.

Covered sector - means a sector of the economy whose emissions are covered by the cap-and-trade program in a given compliance period.

EMT- the Economic Modeling Team

GHG – Greenhouse Gas

Narrow scope - in modeling means emissions from electric power generation within the WCI Partner jurisdictions, emissions from electric power generation outside the WCI Partner jurisdictions for power imported into the WCI Partner jurisdictions, and emissions from industrial fuel combustion and processes within the WCI Partner jurisdictions.

Reduction - means the difference between emissions in the reference run and the allowance budgets. Reductions define the threshold for compliance with the cap-and-trade program, whereas abatement refers to the decrease in emissions from covered sectors, which will be less than the reductions to the extent that offsets are used. ***Reference run*** - means an application of ENERGY 2020 to a business-as-usual scenario (i.e., absent any cap or other GHG abatement policies not already adopted).

Uncovered sources - emission sources that are not included in the program scope in a given year.

VMT – Vehicles Miles Traveled

WCI regional goal (or target) -15% below 2005 levels by 2020 of greenhouse gas (GHG) emissions for the entire regional economy.

WECC - Western Electricity Coordinating Council

Attachment B -
Detailed Reference Run Results for New Mexico

This Attachment presents the detailed results for New Mexico for the Reference Case. All dollars shown are 2007 dollars. These tables present annual results for selected years: 2006 (the first year modeled); 2012 (when the narrow scope begins); 2015 (when the broad scope begins); 2020 (the final year modeled). The far right column shows the average annual growth rate for 2006-2020. These tables present the same output variables as Tables 11-16 in the *Updated Economic Analysis.* Below is a brief guide to the tables.

Greenhouse Gas (GHG) Emissions: GHG emissions are presented in millions of metric tons of carbon dioxide equivalent ($MMTCO_2e$). Emissions are presented by major sector.

Total Energy Use: Total energy use is reported by fuel type in units of trillion Btu per year (Tbtu/year).

Electric Sector: Outputs for the electric sector include:

- Generation capacity in units of megawatts (MW) by generation type.
- Generation output in units of gigawatt-hours per year (GWh/year) by generation type.
- Electricity sales in units of GWh/year. New Mexico is modeled as a net electricity exporter, hence imports are zero.
- Annualized generating utility costs in millions of dollars per year. (These numbers are not equivalent to the accounting costs reported by utilities.)

Transportation Sector: Outputs for the transportation sector include VMT for passenger and freight vehicles, as well as miles traveled per passenger. The fleet average efficiency and marginal efficiency (for new vehicles) are reported for four vehicle types in miles per gallon. The average vehicle market share and marginal vehicle market share are reported for passenger vehicles.

Fuel Prices: Fuel prices are reported for electricity, natural gas, coal, fuel oil, LPG, gasoline, and diesel in 2007 dollars per million Btu (2007 $/mmBtu). The prices include the forecasted energy prices as well as the estimated costs of delivering the fuels to market (but not fuel taxes). The prices reported for the cap-and-trade policy cases also include the allowance price, assuming market forces will incorporate it proportionally to carbon content of the fuel.

Fuel Expenditures: Fuel expenditures are reported by major sector. Estimates of fuel expenditures do not include the value of the allowances, although they do take into account the increase in the price of electricity driven by the allowance price.

Table 1: Reference Run Greenhouse Gas Emissions

GHG Emissions *(Mt)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Residential	2.7	2.8	3.0	3.3	1.4%
Commercial	1.7	1.5	1.5	1.5	-0.8%
Energy Intensive	25.4	21.7	22.0	22.7	-0.8%
Other Industry	1.9	1.7	1.7	1.7	-1.0%
Passenger	11.8	15.0	14.4	13.4	0.9%
Freight	5.1	4.6	4.5	4.4	-1.0%
Power Sector	16.3	15.7	16.4	17.9	0.7%
Waste	1.5	1.6	1.8	1.9	2.0%
Agriculture (non energy)	4.8	4.3	4.4	4.7	-0.2%
Imported Power	0	0	0	0	0.0%
Total	**71.4**	**68.8**	**69.6**	**71.6**	**0.0%**

Table 2: Reference Run Energy Use

Total Primary Energy Use *TBtu/year)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Aviation Fuel	14	17	17	17	1.8%
Biomass	1	3	4	4	10.7%
Coal	149	138	135	142	-0.4%
Diesel	68	67	67	67	-0.2%
Ethanol	1	13	16	22	28.1%
Landfill Gases/Waste	0	0	0	0	0.0%
LPG	22	21	21	20	-0.6%
Motor Gasoline	122	142	132	116	-0.4%
Natural Gas	249	243	266	293	1.2%
Nuclear	0	0	0	0	0.0%
Oil, Unspecified	44	41	42	43	-0.1%
Renewables	6	8	8	8	2.0%
Total	**676**	**693**	**709**	**733**	**0.6%**

Table 3: Reference Run Electric Sector Results

Generation Capacity *(MW)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**
Gas/Oil	2,583	4,059	4,059	4,059	3.3%
Coal	1,897	1,897	1,897	1,897	0.0%
Nuclear	-	-	-	-	-
Hydro	82	82	82	82	0.0%
Biomass	6	43	49	49	15.6%
Wind	494	703	703	703	2.6%
Other Renewable	-	0	1	1	-
Total	**5,062**	**6,784**	**6,791**	**6,791**	**2.1%**

Generation Output *(GWh/year)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**
Gas/Oil	4,332	5,771	8,282	10,982	6.9%
Coal	13,983	13,732	13,380	13,809	-0.1%
Nuclear	-	-	-	-	-
Hydro	198	198	198	198	0.0%
Biomass	22	248	293	293	20.3%
Wind	1,499	2,079	2,079	2,079	2.4%
Other Renewable	-	3	5	5	-
Total	**20,035**	**22,031**	**24,237**	**27,365**	**2.3%**

Sales *(GWh/year)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**
Residential	6,063	6,226	6,657	7,235	1.3%
Commercial	8,900	8,850	9,220	9,796	0.7%
Industrial	6,386	5,982	6,196	6,948	0.6%
Transportation	118	159	153	143	1.4%
Street/Misc	1,589	1,589	1,589	1,589	0.0%
Resale	-	-	-	-	-
Total	**23,057**	**22,807**	**23,816**	**25,711**	**0.8%**

Table 4: Reference Run Electric Sector Results [cont.]

Generating Utility Costs (M$/Year)	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Annualized Investments	163	109	103	35	-10.4%
Fuel Expenditures	1,051	1,051	1,629	2,095	5.1%
Operation & Maintenance	126	155	157	160	1.7%
Total	1,340	1,315	1,889	2,290	3.9%

Table 5: Reference Run Transportation Sector Results

Distance Traveled	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Passenger (billions of vehicle miles traveled)	23.1	33.0	35.8	38.8	3.8%
Freight (billions of vehicle miles traveled)	4.8	4.6	4.8	5.0	0.4%
Passenger Miles/Person	10.9	12.4	12.9	13.4	1.5%

Average Vehicle Efficiency *(miles/gallon)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Light Gasoline	23.2	26.1	29.2	35.1	3.0%
Medium Gasoline	23.2	26.1	29.2	35.1	3.0%
Heavy Gasoline	16.9	18.2	19.7	22.2	2.0%
Heavy Diesel	16.9	18.1	19.6	22.0	1.9%
Fleet Average (In-Use Vehicles)	21.2	24.6	27.5	32.7	3.2%

Marginal Vehicle Efficiency *(miles/gallon)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Light Gasoline	24.3	33.9	42.9	46.0	4.7%
Medium Gasoline	24.3	33.9	42.9	46.0	4.7%
Heavy Gasoline	17.4	20.6	23.6	24.7	2.6%
Heavy Diesel	17.3	20.5	23.4	24.5	2.5%
Fleet Average (In-Use Vehicles)	21.7	29.6	35.9	38.4	4.2%

Table 6: Reference Run Transportation Sector Results [cont.]

Average Vehicle Market Share *(Percent)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Light Gasoline	39.3	37.7	37.4	37.1	-0.4%
Medium Gasoline	35.6	35.3	35.3	35.2	-0.1%
Heavy Gasoline	25.1	27.0	27.3	27.7	0.7%

Marginal Vehicle Market Share *(Percent)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Light Gasoline	39.2	36.5	36.7	36.8	-0.4%
Medium Gasoline	35.3	34.9	35.1	35.2	0.0%
Heavy Gasoline	25.5	28.6	28.2	28.0	0.7%

Table 7: Reference Run Fuel Prices

Prices (2007 $/mmBtu)	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Residential					
Res Electricity Prices	27.9	28.3	28.1	27.2	-0.2%
Res Natural Gas Prices	10.8	11.5	11.7	12.2	0.9%
Res Oil Prices	-	-	-	-	-
Res LPG Prices	22.4	27.0	29.7	30.7	2.3%
Commercial					
Com Electricity Prices	24.7	25.1	24.9	23.9	-0.2%
Com Natural Gas Prices	9.0	9.7	9.9	10.4	1.1%
Com Oil Prices	14.1	18.7	21.4	22.3	3.3%
Com LPG Prices	19.9	24.5	27.1	28.1	2.5%
Industrial					
Ind Electricity Prices	14.9	15.6	15.5	14.9	0.0%
Ind Natural Gas Prices	8.2	8.9	9.1	9.7	1.2%
Ind Coal Prices	1.8	2.1	2.0	2.0	0.6%
Ind Oil Prices	15.2	19.8	22.5	23.4	3.1%
Ind LPG Prices	13.5	18.1	20.7	21.7	3.5%
Transportation					
Gasoline Prices	20.3	24.8	27.5	28.5	2.5%
Diesel Prices	20.2	24.8	27.5	28.4	2.5%

Table 8: Reference Run Fuel Expenditures

Fuel Expenditures ($millions/yr)					
Sector	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**
Residential	1,173	1,306	1,422	1,536	1.9%
Commercial	1,066	1,069	1,102	1,121	0.4%
Energy Intensive	1,338	1,328	1,420	1,550	1.1%
Paper	50	44	45	48	-0.3%
Chemicals	196	209	227	248	1.7%
Petroleum	622	631	687	746	1.3%
Nonmetallic Minerals	332	325	341	372	0.8%
Primary Metals	138	119	121	137	-0.1%
Mining Except Oil and Gas	-	-	-	-	-
Oil and Gas Extraction	-	-	-	-	-
Other Industry	710	785	876	938	2.0%
Passenger Transportation	3,010	4,695	4,995	4,871	3.5%
Freight Transportation	1,356	1,508	1,670	1,733	1.8%
Agriculture	-	-	-	-	-
Waste & Wastewater	-	-	-	-	-
Total	**8,654**	**10,691**	**11,486**	**11,749**	**2.2%**

* Energy Intensive Industry is a subtotal of the seven energy-intensive sectors listed beneath it.

Attachment C -
Detailed Main Policy Case Results for New Mexico

This Attachment presents the detailed results for New Mexico for the Main Policy Case. All dollars shown are 2007 dollars. These tables present annual results for selected years: 2006 (the first year modeled); 2012 (when the narrow scope begins); 2015 (when the broad scope begins); 2020 (the final year modeled). The far right column shows the percentage from the 2020 value from the Reference Case to the Main Policy Case. See p. B-1 for a brief guide to the first six tables. The tables in this Attachment present the same output variables as Tables 17-23 in the *Updated Economic Analysis.*

The seventh and last table is Annualized Costs, i.e., the change in costs from the Reference Case that is attributable to the WCI program. Costs are reported in millions of 2007 dollars per year ($M/Yr). Total costs are broken down by major sector and represent the sum of fuel expenditures, investment costs, and changes in O&M costs. Investment costs increase as more efficient devices, buildings, and processes are purchased in response to the limit on GHG emissions. The investment costs are annualized using a 5% real discount rate over the life of the equipment. The annualized costs are counted each year over the life of the equipment. In the case of passenger transportation, the complementary policies result in a negative cost, i.e., savings to the economy. Fuel expenditure savings typically offset most or all of the increased investment costs. The sub-total does not include the adjustments for program administration of the complementary policies or the allowance value of the power sector. These adjustments are added to arrive at the total cost.

Table C-1: Main Policy Case Greenhouse Gas Emissions

GHG Emissions *(MMTCO$_2$e)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**	**Change from Ref @ 2020**
Residential	2.7	2.8	3.0	3.0	0.9%	-7.0%
Commercial	1.7	1.5	1.5	1.4	-1.5%	-9.4%
Energy Intensive	25.4	21.8	22.2	23.1	-0.3%	1.6%
Other Industry	1.9	1.7	1.8	1.9	-0.3%	9.5%
Passenger	11.8	14.8	14.2	12.6	0.4%	-6.4%
Freight	5.1	4.6	4.5	4.4	-1.2%	-2.0%
Power Sector	16.3	16.3	16.3	17.4	0.5%	-3.0%
Waste	1.5	1.6	1.8	1.9	2.0%	0.0%
Agriculture (non energy)	4.8	4.3	4.4	4.7	-0.2%	0.0%
Imported Power	0	0	0	0	0.0%	0.0%
Total	**71.4**	**69.2**	**69.6**	**70.3**	**-0.1%**	**-1.9%**

Table C-2: Main Policy Case Energy Use

Total Primary Energy Use *(TBtu/year)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**	**Change from Ref @ 2020**
Aviation Fuel	14	17	17	17	1.7%	-0.6%
Biomass	1	3	4	4	10.8%	0.8%
Coal	149	133	134	140	-0.5%	-1.1%
Diesel	68	67	67	64	-0.4%	-4.0%
Ethanol	1	12	16	21	27.7%	-3.9%
Landfill Gases/Waste	-	-	-	-	-	-
LPG	22	21	21	21	-0.3%	3.2%
Motor Gasoline	122	140	130	107	-0.9%	-7.4%
Natural Gas	249	265	270	282	0.9%	-4.1%
Nuclear	-	-	-	-	-	-
Oil, Unspecified	44	41	44	48	0.6%	10.4%
Renewables	6	8	8	9	2.6%	7.5%
Total	**676**	**709**	**711**	**713**	**0.3%**	**-3.9%**

Table C-3: Main Policy Case Electric Sector Results

Generation Capacity *(MW)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**	**Change from Ref @ 2020**
Gas/Oil	2,583	4,059	4,059	4,059	3.3%	0.0%
Coal	1,897	1,897	1,897	1,897	0.0%	0.0%
Nuclear	0	0	0	0	0.0%	-
Hydro	82	82	82	82	0.0%	0.0%
Biomass	6	42	47	47	15.3%	-3.4%
Wind	494	676	676	676	2.3%	-3.9%
Other Renewable	0	0	0	1	0.0%	-13.1%
Total	**5,062**	**6,756**	**6,761**	**6,761**	**2.1%**	**-0.4%**

Generation Output *(GWh/year)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**	**Change from Ref @ 2020**
Gas/Oil	4,332	8,566	8,561	10,124	6.3%	-7.8%
Coal	13,983	13,261	13,266	13,668	-0.2%	-1.0%
Nuclear					-	-
Hydro	198	198	198	198	0.0%	0.0%
Biomass	22	246	280	280	19.9%	-4.2%
Wind	1,499	2,003	2,003	2,003	2.1%	-3.7%
Other Renewable	-	2	4	4	-	-12.4%
Total	**20,035**	**24,277**	**24,313**	**26,278**	**2.0%**	**-4.0%**

Sales *(GWh/year)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**	**Change from Ref @ 2020**
Residential	6,063	6,186	6,454	6,777	0.8%	-6.3%
Commercial	8,900	8,734	8,848	9,271	0.3%	-5.4%
Industrial	6,386	5,988	6,227	7,230	0.9%	4.1%
Transportation	118	157	148	127	0.5%	-11.3%
Street/Misc	1,589	1,589	1,589	1,589	0.0%	0.0%
Resale						-
Total	**23,057**	**22,655**	**23,267**	**24,995**	**0.6%**	**-2.8%**

Table C-3: Main Policy Case Electric Sector Results [cont.]

Generating Utility Costs (M$/Year)	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Annualized Investments	163	108	102	28	-11.8%	-19.7%
Fuel Expenditures	1,051	1,307	1,782	1,979	4.6%	-5.5%
Operation & Maintenance	126	156	156	158	1.6%	-1.3%
Total	**1,340**	**1,571**	**2,040**	**2,166**	**3.5%**	**-5.4%**

Table C-4: Main Policy Case Transportation Sector Results

Distance Traveled	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Passenger (billions of vehicle miles traveled)	23.1	32.5	35.2	37.8	3.6%	-2.6%
Freight (billions of vehicle miles traveled)	4.8	4.6	4.8	5.0	0.3%	-0.7%
Passenger Miles/Person	10.9	12.3	12.7	13.1	1.3%	-2.6%

Average Vehicle Efficiency *(miles/gallon)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Light Gasoline	23.2	26.1	29.2	36.3	3.2%	3.3%
Medium Gasoline	23.2	26.1	29.1	36.2	3.2%	3.3%
Heavy Gasoline	16.9	18.2	19.6	24.3	2.6%	9.8%
Heavy Diesel	16.9	18.1	19.5	24.1	2.6%	9.7%
Fleet Average (In-Use Vehicles)	21.2	24.5	27.5	34.5	3.6%	5.5%

Marginal Vehicle Efficiency *(miles/gallon)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Light Gasoline	24.3	33.9	42.9	53.7	5.8%	16.7%
Medium Gasoline	24.3	33.9	42.9	53.7	5.8%	16.7%
Heavy Gasoline	17.4	20.6	23.6	33.4	4.8%	35.0%
Heavy Diesel	17.3	20.5	23.4	33.0	4.7%	34.7%
Fleet Average (In-Use Vehicles)	21.7	29.6	35.9	46.9	5.7%	22.2%

Average Vehicle Market Share *(Percent)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Light Gasoline	39.3	37.7	37.4	37.0	-0.4%	-0.3%
Medium Gasoline	35.6	35.3	35.3	35.1	-0.1%	-0.3%
Heavy Gasoline	25.1	27.0	27.3	27.9	0.8%	0.8%

Marginal Vehicle Market Share *(Percent)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Light Gasoline	39.2	36.5	36.7	36.2	-0.6%	-1.8%
Medium Gasoline	35.3	34.9	35.1	34.6	-0.2%	-1.8%
Heavy Gasoline	25.5	28.6	28.2	29.3	1.0%	4.6%

Table C-5: Main Policy Case Fuel Prices

Prices (Including Allowance Value) (2007 $/mmBtu)	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Residential						
Res Electricity Prices	27.9	28.3	31.6	32.1	1.0%	18.1%
Res Nat. Gas Prices	10.8	11.5	11.7	14.4	2.1%	17.6%
Res Oil Prices	-	-	-	-	-	-
Res LPG Prices	22.4	27.0	29.7	32.2	2.6%	5.0%
Commercial						
Com Electricity Prices	24.7	25.1	28.2	28.7	1.1%	19.2%
Com Nat. Gas Prices	9.0	9.7	9.9	12.6	2.4%	20.7%
Com Oil Prices	14.1	18.7	21.4	25.1	4.2%	12.4%
Com LPG Prices	19.9	24.5	27.1	29.6	2.9%	5.4%
Industrial						
Ind Electricity Prices	14.9	15.6	18.5	19.1	1.8%	28.6%
Ind Nat. Gas Prices	8.2	8.9	10.2	11.3	2.3%	16.4%
Ind Coal Prices	1.8	2.1	3.9	4.8	7.0%	139.4%
Ind Oil Prices	15.2	19.8	24.0	25.7	3.8%	9.5%
Ind LPG Prices	13.5	18.1	22.0	23.6	4.1%	8.6%
Transportation						
Gasoline Prices	20.3	24.8	27.5	30.8	3.0%	8.2%
Diesel Prices	20.2	24.8	27.5	30.7	3.0%	7.9%

Table C-6: Main Policy Case Fuel Expenditures

Annual Fuel Expenditures ($million/yr)						
Sector	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Residential	1,173	1,296	1,461	1,559	2.1%	1.5%
Commercial	1,066	1,060	1,178	1,224	1.0%	9.2%
Energy Intensive Ind.*	1,338	1,347	1,523	1,728	1.8%	11.5%
Paper	50	45	47	48	-0.2%	1.7%
Chemicals	196	211	237	263	2.1%	6.2%
Petroleum	622	641	735	825	2.0%	10.7%
Nonmetallic Minerals	332	330	373	431	1.9%	16.0%
Primary Metals	138	120	131	160	1.0%	16.5%
Mining Except Oil and Gas	-	-	-	-	-	-
Oil & Gas Extraction	-	-	-	-	-	-
Other Industry	710	795	934	1,029	2.7%	9.7%
Passenger Transportation	3,010	4,634	4,918	4,546	3.0%	-6.7%
Freight Transportation	1,356	1,508	1,670	1,701	1.6%	-1.8%
Agriculture	-	-	-	-	-	-
Waste & Wastewater	-	-	-	-	-	-
Total	**8,654**	**10,639**	**11,685**	**11,787**	**2.2%**	**0.3%**

* Energy Intensive Industry is a subtotal of the seven energy-intensive sectors listed beneath it.

Table C-7: Main Policy Case Annualized Costs

Annualized Total Costs (2007 $million/yr)				
Sector	**2006**	**2012**	**2015**	**2020**
Residential		(5)	69	118
Commercial		1	129	239
Energy Intensive Industry*		24	124	222
Paper		0	3	2
Chemicals		2	11	14
Petroleum		15	69	123
Nonmetallic Minerals		5	32	60
Primary Metals		1	10	22
Mining Except Oil & Gas		-	-	-
Oil and Gas Extraction		-	-	-
Other Industry		13	74	122
Passenger Transportation		(308)	(453)	(578)
Freight Transportation		0	0	0
Agriculture		-	-	-
Waste & Wastewater		-	-	-
Sub-Total		**(252)**	**(65)**	**345**
Program Costs		3	9	18
Power Sector Allowance Value (subtract from sub-total)		(253)	(318)	(519)
Total		**(501)**	**(244)**	**(156)**

* Energy Intensive Industry is a subtotal of the seven energy-intensive sectors listed beneath it.

Economic Modeling Team

The Economic Modeling Team was formed in 2008 to provide WCI Partner jurisdictions with economic analysis to inform the development of the regional, multi-sector cap-and-trade program. In 2009, the Team will continue to serve as a resource to the WCI Partners and other Committees, and inform the development of cap-and-trade policy and design options.

The work of the Economic Modeling Team, continuing from 2008, is divided into the following two tasks and associated deliverables:

- Task 8: Expand the WCI Version of ENERGY 2020
- Task 9: Phase 3 Policy and Sensitivity Cases

Contact information can be found on the Committee Contacts page.

For Economic Modeling Team documents, please refer to the Economic Modeling Team Document Library.

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Western Climate Initiative

Updated Economic Analysis of the WCI Regional Cap-and-Trade Program

July 2010

Western Climate Initiative

Contents

Overview

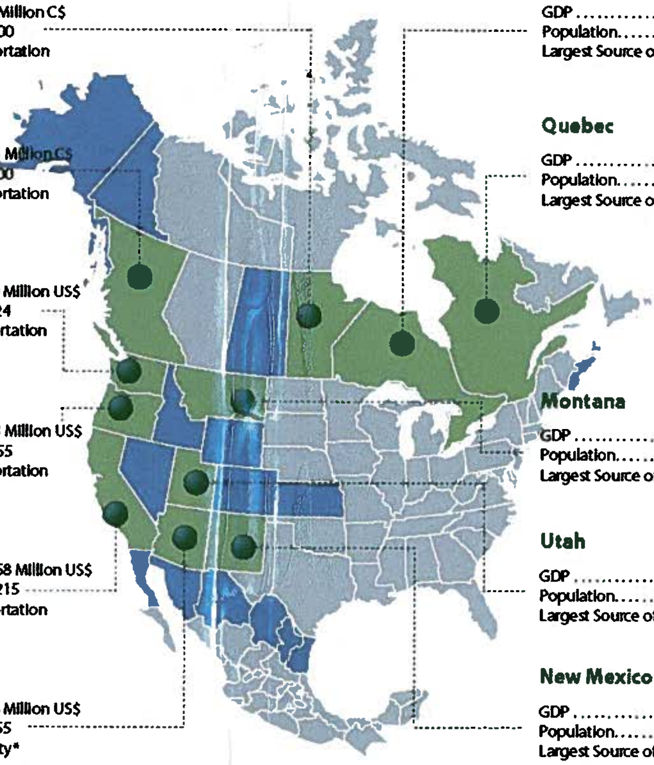
This report summarizes the results of an economic analysis conducted by the Partner jurisdictions of the Western Climate Initiative (WCI). It updates the results of a 2008 economic analysis that informed the design of the WCI regional cap-and-trade program, which will reduce greenhouse gas (GHG) emissions contributing to climate change, spur development of new clean-energy jobs and technologies, and help achieve a strong economy.

The updated analysis incorporates new data reflecting expanded WCI membership, the economic downturn of 2008–2009, and various model improvements recommended by WCI Partner jurisdictions and stakeholders. Results of the updated analysis are consistent with the results of the 2008 report:

- The WCI GHG emissions reduction goal—a reduction of 15 percent from 2005 levels by 2020—can be achieved with a net savings of about US$100 billion between 2012 and 2020.
- Complementary policies such as standards for energy efficiency and clean cars are an important part of reducing emissions and containing costs.
- Offsets and allowance banking provisions in the cap-and-trade program are important features for containing costs.
- Savings to the economy may vary depending on such factors as future economic growth, fuel prices, and effectiveness of complementary policies.

WCI Partners and Observers

U.S. Partner jurisdictions comprise 19% of the total U.S. population and 20% of the U.S. GDP
Canadian Partner jurisdictions comprise 79% of the total Canadian population and 76% of the Canadian GDP.



Manitoba

GDP .... 48,586 Million C$
Population................. 1,186,700
Largest Source of Emission .. Transportation

British Columbia

GDP .... 190,214 Million C$
Population................. 4,380,300
Largest Source of Emission .. Transportation

Washington

GDP .... 311,270 Million US$
Population................. 6,468,424
Largest Source of Emission .. Transportation

Oregon

GDP .... 158,233 Million US$
Population................. 3,747,455
Largest Source of Emission .. Transportation

California

GDP .... 1,812,968 Million US$
Population................. 36,553,215
Largest Source of Emission .. Transportation

Arizona

GDP .... 247,028 Million US$
Population................. 6,338,755
Largest Source of Emission .. Electricity*

*includes tribal lands

Ontario

GDP .... 582,019 Million C$
Population................. 12,803,900
Largest Source of Emission ... Transportation

Quebec

GDP .... 298,157 Million C$
Population................. 7,700,800
Largest Source of Emission ... Transportation

Montana

GDP .... 34,253 Million US$
Population................. 957,861
Largest Source of Emission ... Electricity

Utah

GDP .... 105,658 Million US$
Population................. 2,645,330
Largest Source of Emission ... Electricity

New Mexico

GDP .... 76,178 Million US$
Population................. 1,969,915
Largest Source of Emission ... Electricity

Partners   Observers

Observers

CANADA: Nova Scotia, Saskatchewan, Yukon; **UNITED STATES:** Alaska, Colorado, Idaho, Kansas, Nevada, Wyoming;
MEXICO: Baja California, Chihuahua, Coahuila, Nuevo Leon, Sonora, Tamaulipas

Source for US data: U.S. Census Bureau and U.S. Bureau of Economic Analysis; Source for Canadian data: Statistics Canada
U.S. and Canada population figures 2009; U.S. and Canada GDP figures 2008

The Western Climate Initiative

The Western Climate Initiative (WCI) is a coalition of seven U.S. states and four Canadian provinces working together to identify, evaluate, and implement policies to address climate change at a regional level.

Established in 2007, the WCI is a comprehensive effort to reduce GHG pollution, spur growth in new green technologies, help build a strong clean-energy economy, and reduce dependence on oil.

Through a regional cap-and-trade program and complementary policies, the WCI goal is to reduce emissions of the pollution that causes global warming to 15 percent below 2005 levels by 2020.

The WCI is one of three GHG initiatives in North America with action plans in place to achieve a transition to clean-energy economies. Others include the Regional Greenhouse Gas Initiative (RGGI) in the Northeastern and Mid-Atlantic states and the Midwestern Greenhouse Gas Reduction Accord in the midwestern United States.

A unique feature of the WCI is the consensus achieved among its 11 Partner jurisdictions in developing a GHG emissions reduction strategy that accommodates the diverse economies and interests of its members and takes into account lessons learned from existing programs.

The Imperative for Action

The WCI Partner Jurisdictions are motivated to act by four critical factors:

- The impacts of climate change already being experienced in the region
- The forecast of far more significant adverse climate change impacts if we do not act now
- The economic costs of inaction
- The economic opportunities associated with a green economy

Current climate change impacts include rising temperatures and changing precipitation patterns that are resulting in higher sea levels, longer droughts, increased flooding, more wildfires, and less water availability. Future impacts expected from unabated climate change include more extreme sea-level increases, longer heat waves, unhealthy air quality, more unpredictable water availability, and reduced biodiversity as invasions of non-native species increase and local habitat moves northward and to higher elevations. These impacts will affect a wide range of people, ecosystems, and economic sectors, including electricity generation, health care, agriculture, and tourism.

While the precise cost of inaction is uncertain, it is likely to far exceed the cost of undertaking well-conceived climate change mitigation activities. A number of Partner jurisdictions have evaluated the potential economic impact of climate change. An April 2010 report by the State of California's Climate Action Team, for example, forecast the cost of coastal flooding associated with sea-level rise in the San Francisco Bay area at $36 billion by 2050 and nearly $100 billion for all of California by 2085.[1] The report also predicted severe consequences for California's agriculture industry, with reduced crop yields and lower crop quality resulting in losses estimated at $3 billion annually by 2050. Washington State's Department of Ecology released a 2009 report indicating that inaction could cost the average Washington household $1,250 per year by 2020 and more than double that amount by 2080, due to higher energy costs, increased health-related costs, and a variety of other factors.[2]

At the same time, WCI Partner jurisdictions are taking action to reduce these costs and are realizing the benefits associated with the transition to a clean-energy economy. In the U.S., the seven WCI Partner states comprise 20 percent of the U.S. economy, yet they garnered 60 percent of venture capital investments directed toward clean-technology businesses between 2006 and 2008. In 2007, the proportion of green businesses and green jobs in the economies of WCI Partner states was 20 percent higher than in the U.S. economy as a whole.[3] British Columbia's green businesses contributed C$15.3 billion to the provincial economy in 2008, and that number is expected to grow significantly in the next decade. Jobs tied directly or indirectly to B.C.'s green economy are also forecast to increase—from nearly 166,000 jobs in 2008 to more than 225,000 in 2020.[4]

In Ontario, environmental industries represent about 40 per cent of the Canadian environmental industry sector revenues.[5]

The WCI Cap-and-Trade Program

In September 2008, following 18 months of stakeholder consultation, analysis, and Partner deliberations, the WCI Partner jurisdictions released Design Recommendations for the WCI Regional Cap-and-Trade Program. Cap-and-trade has proven to be a successful means of reducing air pollution and is considered one of the most effective strategies to reduce GHG emissions. For example, the U.S. Acid Rain Program has reduced emissions 40 percent below 1990 levels—at a fraction of the cost originally estimated by the U.S. EPA.[6] Cap-and-trade programs place a market value on emissions reductions and provide incentives for emitters and investors to seek out the lowest-cost opportunities to reduce emissions, including energy efficiency and process improvements, greater use of renewable and lower-polluting fuels, and other clean-energy innovations.

As described in the *Design Recommendations* and subsequent policy documents released by the WCI Partners, each WCI Partner jurisdiction will have

[1] See www.climatechange.ca.gov/publications/cat/index.html.
[2] See www.ecy.wa.gov/climatechange/economic_impacts.htm.
[3] See www.pewcenteronthestates.org/trends_detail.aspx?id=53588
[4] See http://www.globe-net.com/media/118121/bcge_report_feb_2010.pdf.
[5] See http://www.nrtee-trnee.com/eng/issues/programs/climate-prosperity/benchmarking/benchmarking-eng.php and http://www.ene.gov.on.ca/en/news/2008/031301.php
[6] See www.edf.org/page.cfm?tagID=1085.

an emissions allowance budget consistent with its jurisdiction-specific emissions goal, along with the flexibility to decide how to allocate its allowance budget. For example, a Partner could give allowances to emitters operating within its jurisdiction, auction the allowances to willing buyers, or provide for some combination of the two.[7] Facilities that reduce their emissions below their allowance holdings can sell the excess allowances or "bank" them for use in a later compliance period. Selling excess allowances allows covered facilities to recoup some of their emissions reduction costs, while banking allowances will lessen the costs later, as the cap becomes more stringent.

In the initial compliance period, beginning in 2012, the program will cover emissions from electricity—including electricity generated outside the WCI Partner jurisdictions but used by them—industrial combustion at large sources, and industrial process emissions for which adequate quantification methods exist. In the second compliance period, beginning in 2015, the program will expand to include fuels combusted at industrial, residential, and commercial buildings that are not otherwise covered as emissions sources, as well as transportation fuels. The first compliance period will encompass about half of the economy-wide emissions in the WCI Partner jurisdictions. Starting with the second compliance period, the program will cover about 90 percent of GHG emissions in the WCI jurisdictions.

In crafting its cap-and-trade program, the WCI Partners carefully assessed the designs and performance of programs such as the U.S. Environmental Protection Agency's Acid Rain Program, the European Union's Emission Trading System, and the Regional Greenhouse Gas Initiative.

To ensure compliance with the overall cap, the cap-and-trade program includes a rigorous emissions reporting requirement, which will be followed consistently across participating jurisdictions. Each WCI Partner will require annual emissions reports (using equivalent measurement protocols and verified by a third party) from entities and facilities covered by the cap. This element of the program is consistent with well-designed cap-and-trade programs that have had compliance rates of more than 99 percent. At the end of each three-year compliance period, facilities and entities with covered emissions will be required to submit to their state or provincial government emissions allowances and offsets equal to the amount of GHGs they released or were responsible for during that compliance period. If the facility or entity does not have sufficient emissions allowances and offsets to cover its emissions, a requirement to submit three allowances will be assessed for each one that they are short, in addition to any penalties that may be applicable in the state or province where the violation occurred.

[7] An allowance is a tradable "permit," and one allowance is required to emit each metric ton of covered greenhouse gases, measured in carbon dioxide equivalents (CO_2e).

Economic Analysis

An important consideration in crafting the WCI Design Recommendations in 2008 was an economic modeling analysis (referred to here as Phase 2) of various cap-and-trade program design options. The Phase 2 analysis[8] showed that the WCI Partner jurisdictions could achieve the goal of reducing emissions to 15 percent below 2005 levels by 2020 and could realize a modest net cost savings through an increase in energy efficiency and reduced fuel consumption. These savings would be in addition to the benefits the region would accrue from a cleaner environment and spin-offs resulting from investment and innovation in a green economy.

A Phase 3 economic analysis was recently completed to account for expansion of the WCI (to include Manitoba, Québec, and Ontario) and the economic downturn of 2008–2009. It also reflects various model improvements identified by the WCI Economic Modeling Team (EMT) and stakeholders, including updated fuel price forecasts, assumptions about offset price and availability, algorithms for allowance banking, costs of implementing complementary policies, detail of model outputs for the electric power sector, and simulation of the WCI two-phase approach to capping emissions in 2012 and 2015.

The Economic Model: ENERGY 2020

The Phase 3 analysis was conducted by the WCI Economic Modeling Team—with support from its contractors, ICF International and Systematic Solutions, Inc. (SSI)—using ENERGY 2020, a well-established and well-tested multi-region, multi-sector energy model that can simulate energy demand, energy supply, energy costs, and GHG emissions under user-defined scenarios. The basic workings of the model have been described in multiple stakeholder conference calls, workshops, and reports.

The model simulates demand in more than 40 commercial and industrial categories, three transportation services (passenger, freight, and off-road), and three residential categories. There are approximately six end uses per category and six technology/mode families per end use. For all end uses and fuels, the model is parameterized based on historical, locale-specific data. Load duration curves for electricity demand are dynamically built up from individual end uses to capture changing conditions under consumer choice and combined gas/electric programs. Technology and efficiency choices are modeled based on past experience with consumer choice rather than on a purely economic evaluation.

Additional information about the ENERGY 2020 model can be found in the appendix to this report and in WCI's *Assumptions Book for ENERGY 2020* at www.westernclimateinitiative.org/component/remository/Economic-Modeling-Team-Documents/

[8] See www.westernclimateinitiative.org/component/remository/general/design-recommendations/Design-Recommendations-Appendix-B/.

In consultation with the EMT, ICF International and Systematic Solutions Inc. used ENERGY 2020 to run a main policy case along with several "sensitivity" cases. All cases estimate the costs (and cost savings) of meeting the regional GHG reduction goal, as well as an allowance (or carbon) price required to provide sufficient incentive for the emissions reductions. The main policy case simulates the design of the WCI cap-and-trade program and expectations of future economic growth, fuel prices, the use of offset credits, and complementary policies. Because these expectations affect the potential cost of the cap-and-trade program, several "sensitivity" cases were also run to estimate the range of costs under alternative future scenarios. Specifically, the EMT looked at complementary policies being only half as effective, a faster rate of economic growth (with lower fuel prices as well), higher fuel and electricity generation costs, and alternative carbon price escalation rates over the period of the cap (2012–2020).

Offsets

The WCI cap-and-trade program design recommendations include multiple features to provide flexibility and low-cost compliance options, including the limited use of offset credits. Offsets are reductions in GHG emissions from industries outside the capped sectors, such as forestry and agriculture. Offset credits may be issued for projects that sequester carbon dioxide from the air or reduce GHG emissions, as long as they meet rigorous criteria to ensure that emissions reductions are real, verifiable, surplus/additional, permanent, and enforceable. Offset credits may be purchased and traded like allowances and used along with allowances to meet a compliance obligation. The WCI program limits the use of offsets for compliance purposes to ensure that a majority of the required emissions reductions are achieved by the sources covered by the cap-and-trade program. Assumptions about the cost and availability of compliance-grade offsets in the future are important when modeling because the more available and cost-effective they are, the more the program's overall costs will be reduced.

Complementary Policies

The WCI Partner jurisdictions recognize that other policies, working in concert with a cap-and-trade program, will address market barriers that limit the use of cost-effective technologies and help achieve the regional GHG reduction goal. Complementary policies promote cost-effective emissions reductions that would not typically be responsive to the price signal created by the cap-and-trade program. They also reduce emissions in sectors not covered by the cap, prevent emissions shifting (or leaking) to sources outside the cap or the capped region, and encourage investments in low-carbon technologies.

Examples of complementary policies include energy efficiency targets and standards, emissions performance standards for electric power, renewable energy standards, renewable/low-carbon fuels standards, transportation planning, mass transit, government procurement policies, and direct government funding and investment in key technologies. These policies are identified in state and provincial climate action plans, and many have been implemented or are in the process of being implemented.

Assumptions about the effectiveness of complementary policies are important when modeling the costs of a cap-and-trade program. To meet the regional GHG reductions goal, any emissions reductions not achieved by complementary policies will have to be achieved through the cap-and-trade mechanism. The WCI Economic Modeling Team (EMT) made the following assumptions about complementary policies in its modeling:[9]

- **Ontario Coal Phase-Out.** Ontario will be phasing out coal-fired electricity generation between 2010 and 2014.[10]
- **Clean Car Standards.** The second phase of the California Clean Car Standards (Pavley II) will be implemented regionwide in 2017, with the effect of improving the efficiency of new passenger vehicles from 35.5 mpg in 2016 to 42.5 mpg by 2020.[11]
- **Energy Efficiency.** The combined effect of energy efficiency programs recently put in place and being pursued will reduce the growth rate of electricity and natural gas demand by 0.5% each year, starting in 2012.[12]

Summary of Economic Modeling Results

- The WCI can meet its 2020 regional emissions reduction goal with modest net cost savings.
- Complementary policies such as energy efficiency and clean car standards have the potential to significantly reduce emissions and contain costs. In this analysis, complementary policies result in negative costs, or cost savings.
- Banking and offsets are also important design elements for achieving emissions reductions and limiting costs.
- Higher-than-expected fuel prices would make it less costly to achieve the emissions goal, with lower allowance prices. Conversely, lower-than-expected fuel prices, coupled with a faster economic recovery, would raise the allowance price.

[9] The cost of obtaining the emissions reductions associated with these policies is included in the modeling results. A literature review of travel demand reduction programs showed a broad range of potential planning and development costs and savings, including potential infrastructure savings. This analysis excludes these potential costs and savings, and focuses solely on the impacts on vehicle use and fuel use.

[10] See news.ontario.ca/mei/en/2009/09/ontarios-coal-phase-out-plan.html.

[11] See arb.ca.gov/cc/ccms/ccms.htm.

[12] This is less than the 1.0% assumed in the Phase 2 analysis and is reasonable as a minimum expectation considering the efficiency provisions of the American Recovery and Reinvestment Act of 2009 in addition to complementary policies identified in state and provincial climate action plans. Studies by the California Energy Commission and the Northwest Power and Conservation Council suggest that a reduction of 1.0% is achievable with currently cost-effective measures.

- **Vehicle Miles Traveled (VMT).** The combined effect of transportation and fuel programs recently put in place and being pursued is equivalent to reducing the fore-casted travel demand so that VMT in 2020 is lower by 2%, starting in 2008.

Summary of Economic Modeling

The results of the WCI economic modeling suggest that the GHG emissions reduction goal for 2020 can be achieved with a cost savings of approximately US$100 billion in the region between 2012 and 2020. While significant, these savings are relatively modest (less than 0.2%) relative to the size of the overall economy of the 11 WCI Partner jurisdictions.

The cost savings result from the complementary policies, with the largest proportion of the savings attributable to a 2% reduction in the use of personal vehicles by 2020, and to a lesser extent by the energy efficiency investments that reduce the growth rate of electricity and natural gas consumption.[13] In practice, the cap-and-trade program is expected to facilitate and ensure the cost savings of complementary policies. That is, the *combination* of the price signal and market incentives associated with the cap-and-trade program *and* their effect on production and consumption choices would enable complementary policies to have their full emissions and cost-saving effects.

Economic Modeling Scenarios	Cost Savings 2012–2020 (2007 USD)	Emissions Allowance Price in 2020 (2007 USD)
Main Policy Case	US$102 billion	US$33 per metric ton
Sensitivity Cases		
Complementary policies only half as effective as in main case	At least US$38 billion	At least US$50 per metric ton
Faster economic growth and lower primary energy prices	At least US$202 billion	At least US$50 per metric ton
Higher energy prices and power plant construction costs	US$106 billion	US$13 per metric ton

[13] The net savings include the cost of administering and achieving the reduction in annual electricity and natural gas demand growth anticipated from complementary policies. The planning and development costs and benefits associated with reducing travel demand are not included in the analysis due to modeling and data limitations, although it is not clear that these costs and benefits would significantly affect the results.

To achieve the necessary emissions reductions under cap-and-trade, WCI modeling forecasts a carbon allowance price of US$33 in 2020. This is higher than the US$24 predicted in the WCI Phase 2 modeling but on par with government analyses of the WCI and other cap-and-trade proposals. (See Page 43 in the Appendix for details.)

In addition to the main policy case, three sensitivity runs were conducted with ENERGY 2020 to determine how cost savings might change if different assumptions about complementary policies and future economic growth and energy prices are made. As shown in the table above, the WCI program would continue to deliver net cost savings, although if future economic growth and energy prices deviate substantially from what is expected, allowance prices could range from US$13 to over US$50 to fully achieve the WCI emissions reduction goal.

Emissions Reductions

Total emissions from capped sectors in the reference case (a business-as-usual modeling scenario) are projected to be 7,999 million metric tons (Mt) of carbon dioxide equivalents from 2012 to 2020. To achieve a 15% reduction below 2005 emissions levels, WCI modeling forecasts a cumulative reduction of 719 Mt. Of this total, 235 Mt of reductions would be from offsets and 484 Mt would be achieved within the capped sectors. Figure 1 shows more specifically where WCI modeling forecasts that the 719 Mt of reductions will come from.

Figure 2 shows the projected trend in emissions reductions. Rather than reducing emissions in a straight line to 15% in 2020, sources in the WCI region are predicted to "over comply" with the cap in earlier years and "bank" the excess allowances for use in 2019 and 2020. In this way, the same

Figure 1. Source of Emissions Reductions Under the Cap, Main Policy Case Relative to the Reference Case, 2012–2020

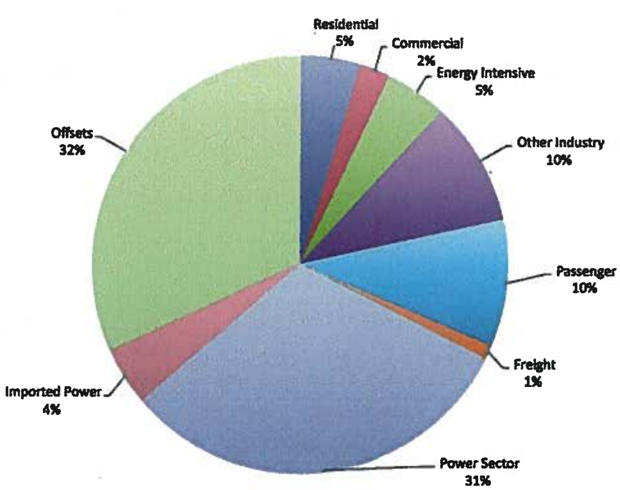
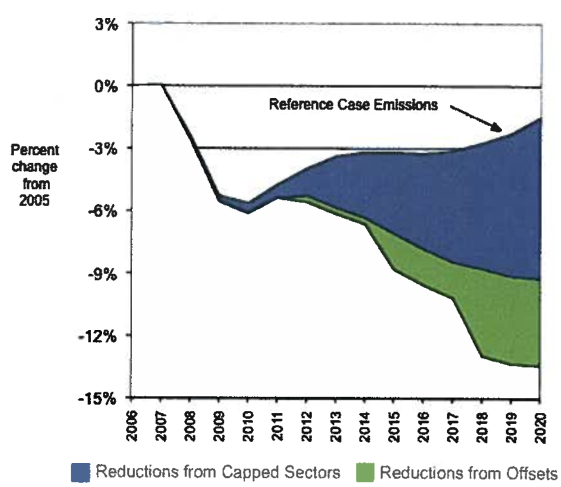


Figure 2. GHG Emissions Reductions Under the WCI Program



amount of emissions reductions is achieved, but sooner and with more flexibility at lower costs.

A Note About the Economic Analysis

Models are by necessity simplified representations of the real-world economy. They cannot predict the future, but they can shed light on important economic relationships, test the robustness of alternative policy architectures (e.g., against the uncertainty of future energy and commodity prices, technological development, etc.) and thereby help inform the design of a market-based climate change policy.[14] While ENERGY 2020 estimates the direct cost of energy use, it is not a macroeconomic model and does not estimate how direct costs (and cost savings) will translate into broader effects such as economic output, trade, employment, and government revenues. ENERGY 2020 results can be, and have been, used as inputs to macroeconomic models. But given the modest costs and savings predicted by ENERGY 2020 relative to the size of the WCI economy, such an analysis has not been conducted.

Other economic analyses, including macroeconomic analyses, however, have been conducted by individual WCI Partner jurisdictions. Some of these analyses are more detailed or are more specifically tailored to the programs and policies of the sponsoring jurisdiction. The WCI regional analysis does not replicate all aspects of these studies, nor is it a substitute.

Looking Ahead

The WCI Partner jurisdictions will be scheduling a conference call with stakeholders to review the analysis and results. Stakeholder comments are welcome and will be taken into consideration as WCI Partners continue implementing their GHG reduction policies. However, no further regional economic analysis or revisions to this report are planned by the WCI Partner jurisdictions.

The WCI Partner jurisdictions are also moving forward on several other fronts, including:

- Release of the *Detailed Program Design* in summer 2010, which will support the implementation of the cap-and-trade program by Partner jurisdictions.
- Development of policies and processes associated with the offset program.
- Establishment of carbon emissions allowance budgets for each Partner jurisdiction.
- Ongoing collaboration and development of complementary policies.
- Ongoing collaboration with other North American regional cap-and-trade programs.

For More Information:
www.westernclimateinitiative.org

[14] See www.pewclimate.org/white-paper/economic-models-are-insights-not-numbers.

Appendix: Detailed Modeling Results and Description of Analysis

Contents

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Description of Analysis

This analysis was directed by the WCI Economic Modeling Team (EMT), with support from its contractors ICF International and Systematic Solutions, Inc. The EMT first analyzed the economic impacts of a WCI cap-and-trade program in 2008 using the ENERGY 2020 model designed and applied by its contractors. The EMT refers to this analysis as the Phase 2 analysis because it supplemented preliminary (Phase 1) work with population and economic forecasts provided by some WCI states for use in lieu of nationally available data. The results of the Phase 2 analysis informed the development of the *Design Recommendations for the WCI Regional Cap-and-Trade Program* and concluded that the program could achieve the WCI emissions reduction goal with a small cost savings, equal to about 0.2 percent of the region's gross domestic product.[15]

The analysis presented here (the Phase 3 analysis) updates the results of the Phase 2 analysis to account for new Partners within the WCI, the economic downturn of 2008-2009, and various model improvements identified by the EMT and WCI stakeholders. The differences between the Phase 2 and Phase 3 modeling are summarized in Tables 1 and 2 and in Figures 1 and 2.

The EMT modeling results are expressed as differences between "reference runs" and "cap-and-trade runs". Reference runs simulate energy use and emissions of the economy under a business-as-usual forecast. Cap-and-trade runs simulate the energy use and emissions of the economy after imposing a carbon price sufficient to reduce emissions to the level of the WCI regional goal.

It is important to note that this analysis does not model the costs of climate change, and therefore the benefits of cap-and-trade and complementary policies in terms of avoided costs, nor any co-benefits (such as reduced smog and resulting health improvements, for example).

Included in the cap-and-trade runs is a set of assumptions regarding the costs and energy use impacts of complementary policies under development by the WCI jurisdictions. Complementary polices are regulations and incentive programs that reduce energy use and greenhouse gas emissions, often at a net savings to the users of fuel. The costs of a cap-and-trade program depend on the effectiveness of complementary policies because any emission reductions not achieved by the complementary policies must be met through the cap-and-trade mechanism. The EMT therefore conducted "sensitivity runs" for the cap-and-trade program in which some of the major complementary policies were assumed to be only half as effective as in the cap-and-trade runs. The EMT also conducted sensitivity runs testing assumptions about the rate of economic growth, future fuel and electricity generation costs, and carbon (or allowance) price escalation rates over the period of the cap (2012-2020).

[15] The WCI's greenhouse gas emissions reduction goal is an aggregate reduction of 15% below 2005 levels by 2020.

Table 1: Differences Between Phase 2 and Phase 3 Modeling

Issue	Type	Phase 2	Phase 3	Comment
Jurisdictions included	Model capability	8 WCI Partners in the WECC	All 11 WCI Partners	Required substantial additions to the model, including specifications for the electric sector throughout U.S. and Canada
Program scope	Program definition	Compared broad scope throughout to narrow scope throughout	Represents program design with narrow scope (2012) followed by broad scope (2015)	Required model changes to be consistent with WCI Design Recommendations
Allowance budget	Program definition	Set in 2012 and linear decline through 2020	Set in 2012 for narrow scope. Set in 2015 for broad scope, with continued reduction in 2012 scope.	Setting the Phase 3 allowance budget in 2015 required assumptions regarding the rate of decline from 2012 to 2015
Electric sector outputs	Model capability	No detailed electric sector outputs	Added electric sector outputs to show investment costs and operating costs	Response to stakeholder request
Offset limit	Program definition	5% of cap	49% of emission reductions	Phase 3 limit is more strict and consistent with the WCI Design Recommendations
Offset supply	Assumption	Unlimited supply available at $20 per metric ton	Supply curve modeled using U.S. EPA analysis of domestic offset supply over time, adjusted to include Canadian supply	Phase 3 supply assumptions remain simplistic, but are an improvement over Phase 2. Offset prices start lower but can exceed $20 per metric ton.
Economic growth forecast	Assumption	Forecast did not include the recession. Used a single forecast.	Updated forecast to include the recession. Created an alternative forecast with extra growth post 2012	Figure 1: shows the Phase 2 and Phase 3 economic forecasts. The new forecast tends to decrease costs.

Issue	Type	Phase 2	Phase 3	Comment
Fuel price forecasts	Assumption	Annual Energy Outlook 2008 High Case as Reference Case	Reference run: Annual Energy Outlook 2009 Mid Case. Alternative Reference run: Average of AEO Mid and Low Cases High Price Case: AEO High Case	Figure 2 shows the Phase 2 and Phase 3 fuel price forecasts for crude oil. The higher fuel price forecast in the reference run leads to price driven efficiency improvements.
Policies included in the reference run	Assumption	US: EISA requirements Canada: CSA standards and "ecoENERGY" Renewable Fuels Strategy Partner: RPS requirements	All Phase 2 reference case policies plus the vehicle standards agreement through 2016 (modeled as Pavley 1)	By putting the Pavley 1 standards in the reference run, the emission reductions and cost savings are in the reference run and are not counted as part of the program
Costs of efficiency improvements in devices and processes	Assumption	Included declining costs due to economies of scale so that more efficient technologies cost less than standard technologies	Requires that more efficient devices and processes always cost more than standard technologies	This change in assumption increases the cost of improving efficiency. It is a conservative assumption (i.e., may overstate costs)
O&M costs	Assumption	Not estimated	Added for Phase 3 to capture non-fuel cost impacts on O&M associated improved efficiency	This change in assumption increases the costs of improving efficiency, resulting in a better estimate
Costs of reducing vehicle emissions beyond Pavley 1	Assumption	Not estimated	Added for Phase 3 to reflect incremental costs of additional efficiency improvements	This change in assumption increases the costs of improving efficiency, resulting in a better estimate
Complementary policies included	Program definition	Energy efficiency VMT reductions Vehicle standards	Energy efficiency VMT reductions Vehicle standards post 2016	The vehicle standards through 2016 are in the reference run

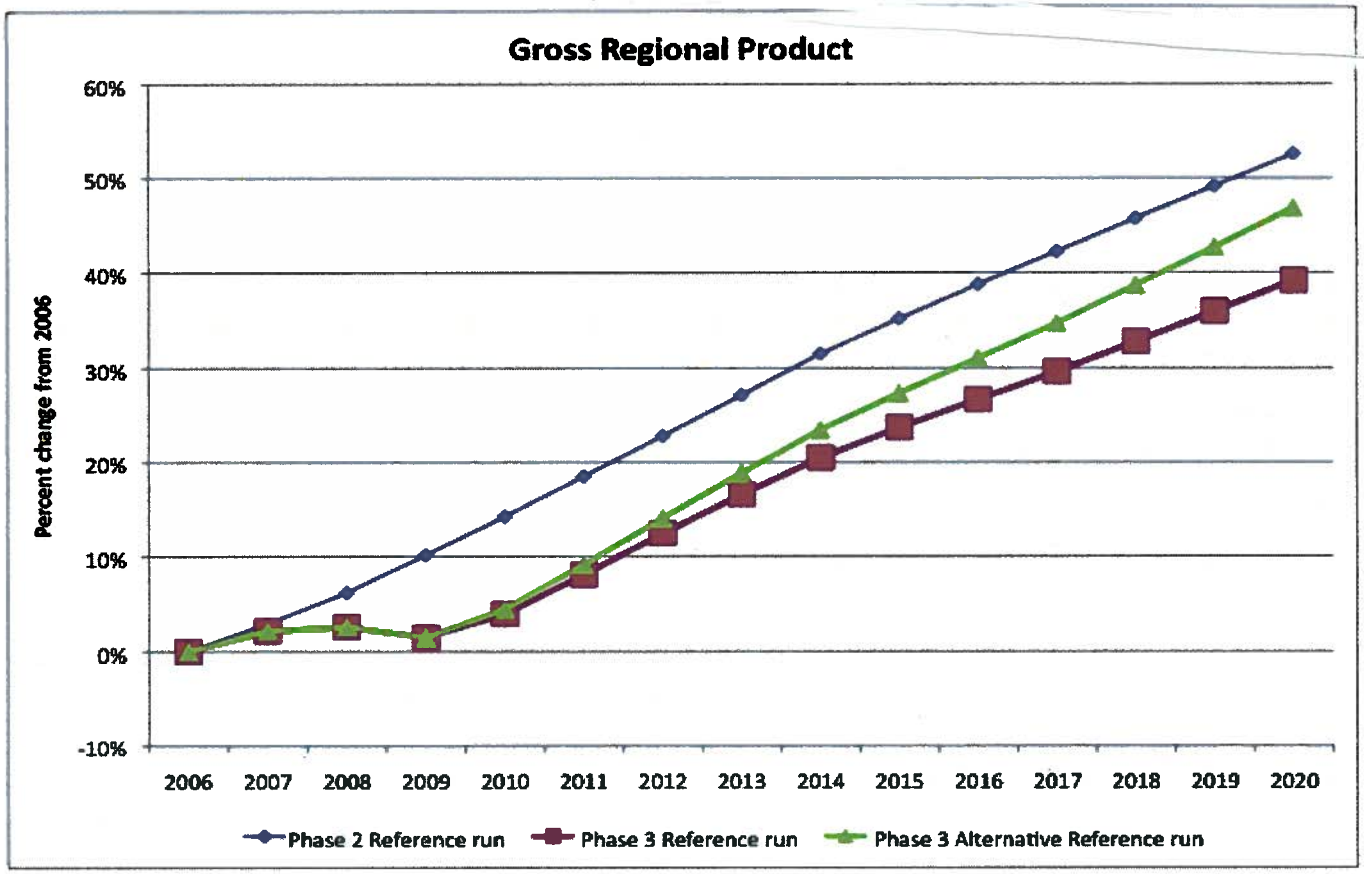
Issue	Type	Phase 2	Phase 3	Comment
Effect of energy efficiency programs	Assumption	Energy efficiency reduces rate of growth in electricity and natural gas demand by 1% each year	Energy efficiency reduces rate of growth in electricity and natural gas demand by 0.5% each year. (In the alternative economic forecast sensitivity case, 1% is assumed.)	The Phase 3 assumption regarding the effects of the EE programs makes it more costly to achieve the emissions target
Cost of administering energy efficiency programs	Assumption	Did not calculate program administration costs	Calculates program administration costs based on experience from existing electricity and natural gas programs	Phase 3 calculations add costs to the program
Banking algorithm	Model capability	Used a "rule of thumb" to approximate potential allowance banking behavior	Simulate economically rational banking behavior, namely increases in allowance prices over time that reflect the opportunity cost of banking allowances	An 8% annual increase in allowance price is assumed to reflect risk and time value of money. Sensitivity cases were analyzed using 4% and 12%.

Table 2: Summary of How Differences Between Phase 2 and Phase 3 Modeling Affect Cost Estimates

Phase 3 Aspects That Tend to Reduce Cost Estimates	Phase 3 Aspects That Tend to Increase Cost Estimates
Economic Forecast: Recession reduces emissions	Less gas-fired generation capacity build-out
Fuel Prices: 2009 forecast is higher	Phase I of the Clean Car Standards are placed in the reference run. All emission reductions (and cost savings) become part of the reference run and are not attributed to the WCI program.
	Costs for Phase II of the Clean Car Standards (2017 and beyond) were added, increasing costs
	The effect of energy efficiency programs is assumed to reduce electricity and natural gas growth by 0.5% instead of 1.0%, reducing the impact of efficiency programs increasing costs
	Costs for administering energy efficiency programs were added
	Devices exceeding energy efficiency standards are assumed to always have higher costs than standard devices, and their costs are not allowed to decrease by more than 10% over time
	Operation and maintenance costs were increased for more-efficient devices

Phase 2 and Phase 3 modeling differences that neither reduce nor increase cost estimates, or whose effects are uncertain, are not listed in this table.

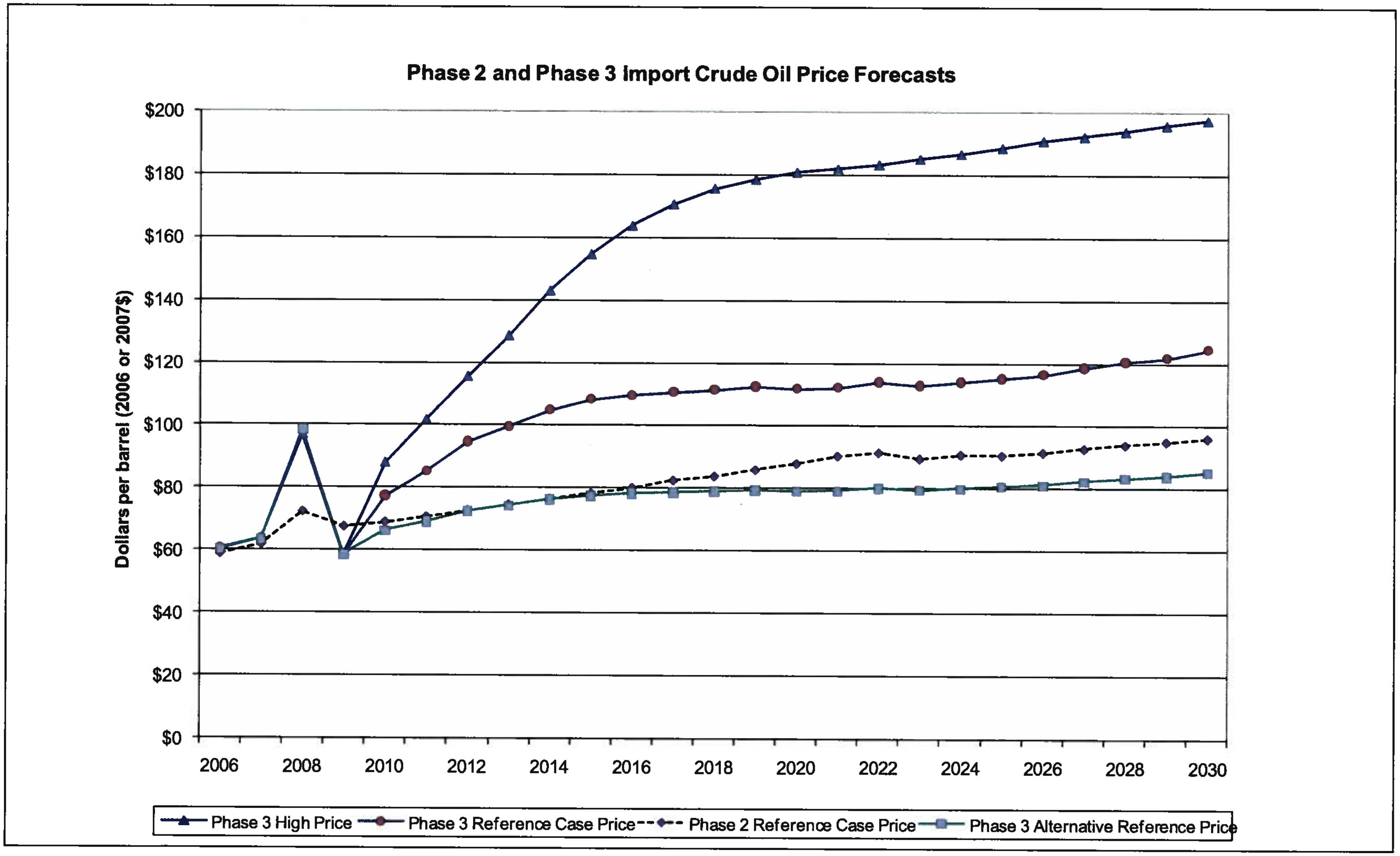
Figure 1: Economic Forecasts Used in Phase 2 and Phase 3 Modeling



Average annual growth rates from 2006 to 2020:

Phase 2 Reference run: 3.1% per year
Phase 3 Reference run: 2.4% per year
Phase 3 Alternative reference run: 2.8% per year

Figure 2: Fuel Price Forecasts Used in Phase 2 and Phase 3 Modeling



Results for all cap-and-trade and sensitivity runs include the change in emissions and net cost to covered sectors relative to the reference runs, as well as the 2020 allowance price required to achieve the WCI regional goal and the total market value of allowances over the 2012-2020 period. Additional details on the ENERGY 2020 model and the EMT's analytical approach can be found below and in the *Assumptions Book for Energy 2020* posted on the WCI website.[16]

Definitions

2012 is the first year of the first compliance period, and the starting year of the WCI cap-and-trade program.

2015 is the first year of the second compliance period, at which point additional sectors are subject to the cap.

2020 is the final year of the third compliance period, and the end year of the economic analysis.

Allowance budget means the number of allowances assumed to be issued throughout the region in a given year. In the WCI cap-and-trade program, one allowance is required to emit each metric ton of covered greenhouse gas emissions, expressed in carbon dioxide equivalents (CO_2e). For purposes of economic modeling, an allowance budget was determined for each year such that the WCI regional goal would be met in 2020 through a linear decline starting in 2012. The difference between the reference case emissions for covered sectors and the allowance budgets represents the total 9-year emission reduction that the main policy and sensitivity cases must achieve.

Allowance value means the allowance price in a given year multiplied by the allowance budget for that year.

Banking means that covered sources emit less than the allowance budget in one compliance period and bank the remaining allowances for use in a later compliance period. This banking allows covered sources to make cost-effective reductions earlier and lessen the costs later.

Compliance period means a three-year period at the end of which an emission source must hold a sufficient number of compliance instruments (allowances and offset credits) to account for its emissions during that period. The WCI compliance periods are 2012-2014, 2015-2017, and 2018-2020.

Compliance means that at the end of each compliance period emissions from all covered sectors, summed over each year since 2012, must be equal to or less than the allowance budgets issued since 2012, after accounting for offsets.

Covered sector means a sector of the economy whose emissions are covered by the cap-and-trade program in a given compliance period.

Uncovered sources are emission sources that are not included in the program scope in a given year.

[16] The posting on the WCI website is at: http://www.westernclimateinitiative.org/component/remository/Economic-Modeling-Team-Documents/

Narrow scope in the modeling means emissions from electric power generation within the WCI Partner Jurisdictions, emissions from electric power generation outside the WCI Partner Jurisdictions for power imported into the WCI Partner Jurisdictions, and emissions from industrial fuel combustion and processes within the WCI Partner Jurisdictions.

Broad scope in the modeling means the narrow scope plus passenger and freight transport emissions and emissions from all remaining fossil fuel combustion, including residential, commercial, agriculture, and waste & wastewater. These emissions are covered in the second and third compliance periods. Not included in the broad scope are process emissions from agriculture, waste & wastewater, and high Global Warming Potential gases, such as refrigerants.

Reference run means an application of ENERGY 2020 to a business-as-usual scenario (i.e., absent any cap or other GHG abatement policies not already adopted).

Complementary policies run means an application of ENERGY 2020 in which complementary policies have been added to the reference conditions.

Cap-and-trade run means an application of ENERGY 2020 in which an allowance price has been imposed on the reference and complementary policies conditions. All of the cap-and-trade runs include complementary policies.

Case means a family of ENERGY 2020 runs consisting of a reference run, a complementary policies run, and a cap-and-trade run. Each case is characterized by assumptions on economic growth, energy/fuel prices, and effectiveness of complementary policies (full or half), generation cost, and allowance-price growth rate.

Abatement means the change in emissions in covered sectors due to complementary policies and the cap-and-trade policy. Specifically, it is the difference between the emissions in a cap-and-trade run and the emissions in the reference run. Reductions through offsets, therefore, are not included in this use of the term abatement.

Abatement cost means the resource cost to bring about abatement. In this analysis, proper quantification of total abatement costs requires that the value of allowances used in the electric power sector be subtracted from the abatement costs. This is required because electricity prices in the model were assumed to include the full market value of allowances in order to effectuate proper energy use decisions among end users in the residential, commercial, industrial, and transportation sectors. Because allowance values represent a financial transfer and not a resource (or abatement) cost, the allowance value is subtracted from the abatement cost so that it reflects the actual cost of reducing emissions.

Reduction means the difference between emissions in the reference run and the allowance budgets. Reductions define the threshold for compliance with the cap-and-trade program, whereas abatement refers to the decrease in emissions from covered sectors, which will be less than the reductions to the extent that offsets are used.

WCI regional goal (or target) is 15% below 2005 levels by 2020 of greenhouse gas (GHG) emissions for the entire regional economy.

WECC is the Western Electricity Coordinating Council.

Methodology and Assumptions

This section begins with two subsections describing the ENERGY 2020 model and the general modeling assumptions and input data. Following subsections describe how banking, offsets, and complementary policies are included in the modeling, as they are key factors in the design and cost-containment of the program. The final subsection describes the remaining assumptions pertinent to the main policy case and sensitivity cases.

ENERGY 2020

ENERGY 2020 was the model used in this analysis. A detailed description of ENERGY 2020 is available in the *Assumptions Book for Energy 2020* posted on the WCI website.[17] Additional documentation is available at the California Air Resources Board (ARB) website.[18] Below is a brief description of the model.

ENERGY 2020 is an integrated, multi-region energy model that provides all-fuel demand and supply sector simulations. The model simulates demand by three residential categories (single family, multi-family, and agriculture/rural), over 40 NAICS commercial and industrial categories,[19] and three transportation services (passenger, freight, and off-road). There are approximately six end-uses per category and six technology/mode families per end-use. End-uses include process heat, space heating, water heating, refrigeration, lighting, air conditioning, and motors. The technology families correspond to six fuels groups (oil, gas, coal, electric, solar and biomass) and 30 detailed fuel products. The transportation sector contains 45 modes, including various types of automobile, truck, off-road, bus, train, plane, marine and alternative-fuel vehicles. More end-uses, technologies, and modes can be added as data allow. For all end-uses and fuels, the model is parameterized based on historical, locale-specific data. The load duration curves for electricity demand are dynamically built up from the individual end-uses to capture changing conditions under consumer choice and combined gas/electric programs.

Each energy demand sector includes cogeneration, self-generation, and distributed generation simulation, including mobile-generation, micro-turbines, and fuel-cells. Fuel-switching responses are rigorously determined. The technology families (which can be split, as an option, to portray specific technology dynamics) are aggregates that, within the model, change building shell, economic-process and device efficiency and capital costs as price or other information that the decision makers see,

[17] The posting on the WCI website is at:
http://www.westernclimateinitiative.org/component/remository/Economic-Modeling-Team-Documents/
[18] The posting on the ARB website is at:
http://www.arb.ca.gov/cc/scopingplan/economics-sp/models/models.htm.
[19] NAICS is the North America Industrial Classification System which was developed jointly by the U.S., Canada, and Mexico to provide new comparability in statistics about business activity across North America.

change. ENERGY 2020 utilizes the historical and forecast data developed for each technology family to parameterize and disaggregate the model.

The supply portion of the model includes endogenous detailed electric supply simulation of capacity expansion/construction, rates/prices, load shape variation due to weather, a complete (but aggregate) representation of the electric transmission system, and changes in regulation. The model dispatches plants according to the specified rules whether they are optimal or heuristic and simulates transmission constraints when determining dispatch. A dispatch routine selects critical hours along seasonal load duration curves as a way to determine system generation. Peak and base hydro usage is explicitly modeled to capture hydro-plant impacts on the electric system.

In addition to modeling electricity supply, ENERGY 2020 can also model the supply of oil, natural gas, refined petroleum products, ethanol, land-fill gas, and coal. In the Phase 3 modeling, however, prices for these energy sources were provided exogenously to the model.

ENERGY 2020 includes pollution accounting for both combustion (by fuel, end-use, and sector) and non-combustion processes, and non-energy (by economic activity) for all GHGs that would be covered by the WCI cap-and-trade program, as well as conventional air pollutants at the state and provincial level by economic sector.

ENERGY 2020 can simulate the impacts of a wide variety of GHG mitigation policies, including regulations, demand reduction programs, taxes, and emission caps with trading. These capabilities were used in the reference runs (to reflect existing policies) and in cases involving complementary policies and the WCI cap-and-trade design. Details on specific policies included in the modeling appear in later sections and in the *Assumptions Book*.

ENERGY 2020 is not a macroeconomic model and does not predict the downstream effect of energy prices, costs, and cost savings on factors such as economic output, household income, trade and employment, although its outputs can and have been used in such assessments.

General Modeling Assumptions

This section presents an overview of the major assumptions used in the modeling. These assumptions are included in all modeling runs, except for the assumptions on economic growth, fuel prices, and electricity generation costs, which are altered in two of the sensitivity cases. The *Assumptions Book for ENERGY 2020* includes additional detail on the assumptions and model inputs, including links to data sources.

Geographic Coverage: The Phase 3 modeling covers the lower 48 states of the U.S. and all of Canada, which includes the 11 WCI Partners. By covering the entire electric grid in addition to the energy/emissions impacts in the 11-Partner region, the impacts of the WCI programs and policies on electricity generation in the non-WCI WECC states and provinces can be examined.

Sectors and Sources: The Phase 3 modeling includes energy use in all sectors, as well as most industrial process emissions. Landfill methane emissions and non-energy agriculture emissions are included in the total emissions estimates, but emission reductions are not estimated for these sources.[20] The analysis is based on gross emissions, so that forestry emissions and sinks are excluded.

WCI Population Forecast: A key driver in the ENERGY 2020 energy demand simulations is population forecast. Table 3 shows the population growth forecast used.

Table 3: Population Forecast for WCI Partners, Selected Years (Millions)

Jurisdiction	2006	2012	2015	2020
Arizona	6.2	7.4	7.9	8.8
British Columbia	4.3	4.6	4.8	5.1
California	37.4	40.1	41.5	44.1
Manitoba	1.2	1.2	1.2	1.2
Montana	0.9	1.0	1.1	1.2
New Mexico	2.0	2.6	2.7	2.8
Ontario	12.7	13.6	14.1	14.8
Oregon	3.7	4.0	4.1	4.4
Quebec	7.6	7.8	7.9	8.1
Utah	2.6	3.1	3.3	3.7
Washington	6.4	7.0	7.3	7.7
Total	**85.1**	**92.4**	**96.0**	**101.9**

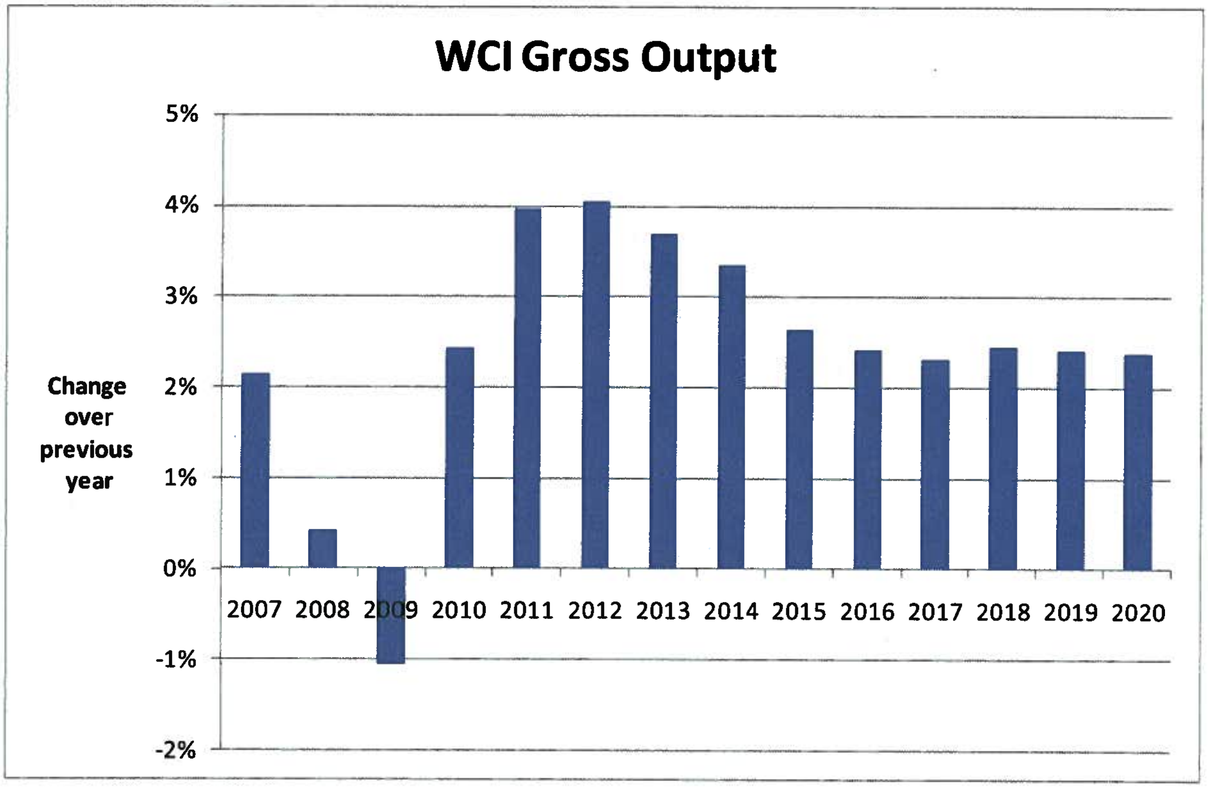
WCI Economic Growth Forecast: Another key driver in the ENERGY 2020 simulation of energy demand is sector-specific economic growth. Table 4 and Figure 3 show the gross economic output forecast for the WCI region.

Table 4: Regional Gross Economic Output Forecast for the WCI Region, Selected Years (Billion of 2007 US dollars)

2006	2009	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
5,514	5,595	6,199	6,819	7,675	2.4%

[20] Examples of non-energy agriculture emissions are methane emissions from livestock and livestock manure management, and carbon and N_2O emissions from agricultural soils.

Figure 3: Regional Gross Economic Output Forecast for WCI Partners



Emission Abatement Options: The model simulates decisions by energy users for each end use, including: fuel choice; investment in end use efficiency (e.g., by purchasing devices that are more efficient than the minimum required by standards); and end-use utilization (how much the device is used). End-use specific choices are simulated as needed, such as mode choice for freight movement and passenger transportation. Choices are simulated based on costs (increased capital costs versus the value of fuel saved) as well as non-price attributes (convenience, acceptance of the technology). Past purchasing behavior is used to calibrate the non-price choice parameters for each end use.

Energy Independence and Security Act of 2007 (EISA): The reference runs, main policy case, and sensitivity cases include the requirements of the EISA, appliance and lighting energy efficiency standards, and the renewable fuels standard (RFS). These requirements are assumed to be implemented fully in the U.S. WCI Partner jurisdictions. For the Canadian provinces, lighting, equipment and appliance standards as defined by the Canadian Standards Association[21] as well as federal "ecoENERGY" Renewable Fuels Strategy.[22]

[21] http://www.oee.nrcan.gc.ca/regulations/home_page.cfm

[22] This strategy requires 5% average renewable content based on the gasoline pool that is produced or imported, starting in 2010, and 2% average renewable content in diesel fuel and heating oil (distillate) by 2012. The Canada Gazette indicates that the 2% renewable content in diesel fuel and heating oil is equivalent to 5% renewable content in on-road diesel use. (See http://canadagazette.gc.ca/partI/2006/20061230/html/notice-e.html#i3)

Clean Car Standards: All cases incorporate the Clean Car Standards through 2016, equivalent to California's Pavley I. In April, 2010, the U.S. federal government established standards for vehicle GHG emissions and CAFÉ standards which would align with the GHG emission standards previously proposed by California. (At the same time, the Canadian federal government also announced rules that would effectively align with those in the U.S.) As a result, a national standard was established which will require the fuel efficiency of new passenger cars and light trucks to reach an average fleet efficiency of 35.5 mpg by 2016. The Phase 3 modeling assumes a fixed percentage increase in the efficiency of new vehicles each year starting in 2010 to reach the mandated level by 2016. Information relating to the cost of implementing this policy was based on estimates by the NHTSA.[23] Efficiency improvements beyond 2016 (Pavely II) are included the complementary policies runs.

Renewable Portfolio Standards: All modeling runs incorporate the renewable portfolio standards (RPSs) currently in effect in the states and provinces. See Appendix I of the *Assumptions Book for ENERGY 2020* for details.

Fuel Prices: An important variable in the modeling is the forecast of fuel prices (oil, coal, natural gas, etc.). The model calculates electricity prices internally. Table 5 shows the AEO 2009 reference-case price forecast used in the modeling. State- and province-specific retail prices are derived in the model from the prices shown in this table.

Table 5: Fuel Price Forecast

	2006	2012	2015	2020
World Oil Price (2007 US$/barrel)	60.70	94.84	108.52	112.05
Natural Gas Wellhead Price (2007 US$/mmBtu)	6.91	6.75	6.90	7.43
Coal Prices (2007 US$/ton)	25.29	27.69	27.77	27.38

Source: EIA Annual Energy Outlook 2009 reference price series.

Technology Assumptions: To conduct the analysis, assumptions are required regarding the availability, cost, and use of a range of technologies through 2020. This analysis adopts assumptions, listed below, which overall are conservative in that they tend to increase the cost of achieving the WCI emissions goal. The WCI Partner jurisdictions recognize the promise of a variety of technologies as a means of reducing emissions, and they are promoting their development in some cases. However, their near-term commercial deployment remains uncertain. These assumptions are made for modeling purposes, and do not reflect WCI policy recommendations regarding the promise or use of these technologies.

- Coal Plants: Coal plants that are already planned and committed are assumed to be completed as planned and brought into service. No additional new coal plants are assumed to be built by 2020 in the WECC region beyond those already planned and committed. See Appendix F of the

[23] NHTSA, Corporate Average Fuel Economy Rulemaking, Document No. WP.29-145-13, June 2008, see also: NHTSA, Final Environmental Impact Statement, Corporate Average Fuel Economy Standards, Passenger Cars and Light Trucks, Model Years 2011 to 2015, October 2008.

Assumptions Book for ENERGY 2020 for a list of coal plants that are assumed to be planned and committed.

- Nuclear Plants: No new nuclear power plants are assumed to be built by 2020 in the WECC region.

- Carbon capture and storage: Carbon capture and storage is assumed for this analysis to not be feasible for electric power generation through 2020.

- Hydropower: No new hydropower capacity is assumed to be built in the WECC region through 2020.

- Plug-in hybrids: Electric vehicles, including plug-in hybrids, are assumed to be not available in significant numbers through 2020.

- Electricity Generation Costs: The Phase 3 modeling uses estimates of power generation capital costs, operating costs, and heat rates developed for a recent study by the California Public Utilities Commission, summarized in Table 6.

Table 6: Summary of Power Generation Cost Inputs

Technology	Total Capital Costs $/kW	Fixed O&M ($/kW-yr)	Variable O&M ($/MWh)	Capacity Factor	Nominal Heat Rate
Biogas	$2,623	107.5	0.01	85%	11,566
Biomass	$3,836	50.18	2.96	85%	15,509
Geothermal	$3,575	154.92	-	90%	-
Hydro - Small	$2,530	13.14	3.3	50%	-
Solar - Thermal	$2,840	49.63	-	40%	-
Wind	$1,983	28.51	-	37%	-
Coal ST	$2,671	25.91	4.32	85%	8,844
Coal IGCC	$3,087	36.36	2.75	85%	8,309
Coal IGCC with CCS	$5,127	42.82	4.18	85%	9,713
Gas CCCT	$878	11.04	2.4	90%	6,917
Gas CT	$794	11.4	3.36	5%	10,807
Hydro - Large	$2,530	13.14	3.3	50%	-
Nuclear	$4,999	63.88	0.47	85%	10,400
<5MW CHP	$1,952	11.04	2.4	40.5%	9,700
>5MW CHP	$1,259	11.04	2.4	85%	9,220

Cost Basis Year = 2005.
All estimates are 2008 U.S. dollars.
Source: E3 GHG Calculator v2b, tab Gen Cost". Available at:
http://www.ethree.com/GHG/GHG%20Calculator%20v2b.zip

Allowance Banking

The EMT's methodology enables allowances to be banked when allowance prices are low and for banked allowances to be used when allowance prices are high. In its Phase 2 analysis, the EMT applied ENERGY 2020 in a mode that simulated a year-to-year clearing of the market for GHG allowances. In this mode, ENERGY 2020 applied the relevant annual emission cap and simulated emitters choosing among reduction options, offsets, and banking in response to a price for allowances. The model iterated until it found the market-clearing price for that year that met the emissions cap. This year-to-year mode required that the EMT specify a decision rule for emitters on when to bank allowances and when to withdraw them from the bank.

In its Phase 3 analysis, the EMT relied on a second approach, with stronger grounding in economic principles expected to guide banking by emitters. This approach assumes allowance prices in different years are linked by the discount rate of the allowance holders. In other words, holders of allowances recognize the time value of money so that when they bank an allowance in one time period (incurring the opportunity cost of not using it), they expect that it will have greater value in a future time period. Economic principles suggest that when banking is allowed under a cap-and-trade system, the allowance price will grow over time at a rate equal to the time value of money and investment risk.[24]

This approach was incorporated into the modeling by using ENERGY 2020 to evaluate vectors of allowance prices covering the period 2012-2020 (growing annually at a specified annual discount rate of 8%), rather than iterating a single year at a time and then moving on to the next year. Appropriate constraints were designed to reflect the limit on the use of offsets and the prohibition on borrowing of allowances.

The bank flow in any year is defined as follows:

Bank flow = Allowance budget – Capped sector emissions + Offsets used

The number of banked allowances in a given year is the sum of the annual bank flows from 2012 up to and including that year.

When a cap-and-trade system allows banking, the flexibility given to emitters means that a model can examine the <u>*cumulative*</u> cap over the relevant time period (along with allowed offsets), and iterate toward the price <u>*vector*</u> (i.e., price trajectory over the 2012-2020 period) that would result in meeting the cumulative cap. This approach assumes that emitters are likely to bank and use allowances in an economically rational manner and that the allowance price will rise over time to reflect the time value of money and investment risk.

[24] See, e.g., R. Newell et al, Managing Permit Markets to Stabilize Prices, Resources for the Future, June 2003, p.5 (http://www.rff.org/documents/RFF-DP-03-34.pdf), and P. Joskow, A.D. Ellerman et al, Emissions Trading Under the U.S. Acid Rain Program: Evaluation of Compliance Costs and Allowance Market Performance, Center for Energy and Environmental Policy Research, MIT (undated), p. 24, fn.38 (http://faculty-gsb.stanford.edu/wilson/archive/E542/classfiles/Joskow_napap.pdf).

Offsets

The modeling effort used an offset supply curve to calculate, for each year, the number of offsets available at the allowance price, as shown in Figure 4. The offset supply curve is based on a 2005 report by U.S. EPA.[25] Then the offset limit in the WCI program design is applied for each compliance period. According to Section 9.2 of the *Design Recommendations for the WCI Regional Cap-and-Trade Program*, the offset limit equals "49 percent of the total emissions reductions from 2012-2020."[26] The number of offsets actually used is the lesser of the offsets available from the offset supply curve and the offset limit.

Figure 4: Offset Supply Curves

Table 7 shows the calculation of the offset limit for the main policy case. The "reduction calculation line" is equal to the 2012 narrow scope emissions of the complementary policies run, which is 464 Mt for the main policy case and discount rate sensitivity cases. For 2015 and beyond, the reduction calculation line also includes the other covered sector emissions for 2015, which is 464 + 597 = 1,061 Mt for the main policy case and discount rate sensitivity cases. The "total emission reductions" are the difference between the reduction calculation line and the allowance budget. The offset limit is 49 percent of the reductions.

[25] U.S. EPA, Greenhouse Gas Mitigation Potential in U.S. Forestry and Agriculture, 2005, http://www.epa.gov/sequestration/pdf/greenhousegas2005.pdf

[26] The emissions reductions in this case are relative to the 2012 emissions, not the reference case projections for 2012-2020.

Table 7: Calculation of Offset Limit, Main Policy Case and Discount Rate Sensitivity Cases

Year	Complementary policies run emissions, narrow scope (Mt)	Complementary policies run emissions, other covered sectors (Mt)	Reduction calculation line (Mt)	Allowance budget (Mt)	Reductions (Mt)	Offset limit (Mt)
2012	464		464	464	-	-
2013			464	456	8	4
2014			464	449	16	8
2015		597	464+597= 1,061	1,038	23	11
2016			1,061	1,017	44	22
2017			1,061	996	66	32
2018			1,061	975	87	42
2019			1,061	953	108	53
2020			1,061	932	129	63
Total						**235**

Complementary Policies

The following assumptions were made in the complementary policy run used in the main policy case and in three of the five sensitivity cases. The assumptions are somewhat different for the two sensitivity cases examining half effectiveness of complementary policies and high fuel price and electricity generation costs. These differences are explained in the Cases Analyzed section of this appendix.

Ontario Coal Phase-Out: Ontario will be phasing-out coal-fired electricity generation between 2010 and 2014.[27]

Clean Car Standards: This is equivalent to California's Pavley II. (Pavley I is included in the reference run.) This policy starts in 2017. By 2020, per-mile GHG emissions from new passenger vehicles decrease by 17 percent relative to new vehicle emissions in 2016.[28] ENERGY 2020 estimates the fuel savings and

[27] See news.ontario.ca/mei/en/2009/09/ontarios-coal-phase-out-plan.html.

[28] This is based on emission reductions contemplated in "California Air Resources Board, Climate Change Scoping Plan: a Framework for change, December 2008 Discussion Draft." Also see "California Air Resources Board, Comparison of Greenhouse Gas Reductions for the United States and Canada under U.S. CAFÉ Standards and California Air Resources Board Greenhouse Gas Regulations – An Enhanced Technical Assessment, 25 February 25, 2008."

changes to device investments and increases in operation and maintenance costs. Change in vehicle costs are based on estimates from the California Air Resources Board.[29]

Energy Efficiency: The combined effect of energy efficiency programs recently put in place and being pursued are assumed to reduce the rate of growth in electricity and natural gas demand by 0.5% each year starting in 2012.[30] ENERGY 2020 estimates the fuel savings and changes to device and process investments and operation and maintenance costs. The modeling also includes program administration cost, which is $0.6 billion per year by 2020.[31]

VMT Reduction: The combined effect of transportation and fuel programs recently put in place and being pursued is assumed to be equivalent to reducing travel demand so that vehicle miles traveled (VMT) are lower by 2 percent from the reference case by 2020, beginning in 2008. ENERGY 2020 estimates the fuel savings and decrease in device investment and operation and maintenance costs due to less wear and tear on the vehicles. ENERGY 2020 does not estimate the planning and development costs and savings associated with reducing travel demand. A brief literature review of travel demand programs and policies indicated a broad range of potential planning and development costs and savings, including potentially significant infrastructure savings. This analysis excludes these potential planning and development costs and savings, and focuses solely on the impacts on vehicle use and fuel use.

Other Cap-and-Trade Modeling Assumptions

This section describes assumptions regarding the cap, reductions, allowance prices, and compliance. These topics are relevant only to the cap-and-trade runs and not to the reference or complementary policies runs.

Allocation of Allowances: The model does not distinguish between freely allocated allowances and auctioned allowances. Rather, it determines the change in energy use and the costs associated with that change. These abatement costs are the same regardless of whether allowances are freely allocated or auctioned. The allocation method, instead, determines who benefits from the market value of the allowances.

Allowance Budgets: Recommendations to the WCI Partners on setting allowance budgets are under development by the WCI Cap Setting and Allowance Distribution (CSAD) Committee. However, for purposes of completing this economic modeling, the EMT had to make reasonable assumptions about the allowance budget and based these assumptions on the WCI Design Recommendations.

In the modeling, the cap for 2020 is assumed to be 15% below the 2006 model-estimated emissions, since this is the first year for which modeling results are available. Ideally, model-estimated emissions for 2005 would be available as the basis for the 2020 budget, but this is not expected to have a significant effect since U.S. and Canadian emissions, as reported by the federal governments, actually

[29] California Environmental Protection Agency, Air Resources Board, Regulations to Control Greenhouse Gas Emissions from Motor Vehicles, Final Statement of Reasons, August 4, 2005.
[30] For example, electricity sales for 2017 in the reference run are 1.2 percent higher than sales for 2016. In the complementary policies run, electricity sales for 2017 are 1.2% - 0.5% = 0.7% higher than sales in 2016.
[31] The EMT assumed administration costs of $6/MWh of electricity saved and $1/MMBtu of natural gas saved.

declined slightly between 2005 and 2006. Furthermore, all reductions necessary to meet the WCI economy-wide goal are assumed to come from sectors covered by the cap, which provides a slightly conservative estimate of the cost to the covered sectors. Thus:

2020 allowance budget = 0.85 x 2006 emissions[32] – 2020 emissions from uncovered sources

For modeling purposes, the 2012 allowance budget was set as the 2012 emissions from the narrow scope estimated in the complementary policies run. Emissions associated with imported power are included in the 2012 allowance budget. The trajectory for the first compliance period is based on the rate of reduction that would be required if the broad scope were in place in 2012. For modeling purposes, the 2015 allowance budget was set in two parts. The first part was the continued trajectory of the narrow scope emissions that started in 2012. The second part was the best estimate of the emissions covered for the first time in 2015. Emissions from these newly covered sources were estimated from the complementary policies run. The total allowance budget in 2015 is the sum of these two parts. The trajectory from 2015 to 2020 is a straight line, as defined in the *WCI Design Recommendations*.

Discount Rate: A real discount rate of 5% was used in annualizing costs and calculating net present values of cost streams. As noted above, the time value of money is also used to model allowance banking and use over time. The modeling used a rate of 8% to model banking, reflecting both the discount rate and investment risk specific to holding allowances. Sensitivity cases with values of 4% and 12% were also analyzed.

Compliance: As noted above, the goal of compliance is that the emissions in the capped sectors, summed over 2012-2020, equals the annual allowance budgets plus offsets, summed over 2012-2020. (Over-compliance in the first two compliance periods is acceptable. The banked allowances can be used in the final compliance period.) The emissions are a decreasing function of allowance price and offsets are an increasing function of the allowance price, up to the offset limit.

First Jurisdictional Deliverer: All cases incorporate a proxy to represent the first jurisdictional deliverer approach described in the *WCI Design Recommendations*. Consequently, emissions from electricity imported into the WCI Partner Jurisdictions from outside the WCI Partner jurisdictions are included in the analysis.

Cases Analyzed

This report presents six cases – that is, six families of model runs. Each family of runs consists of a reference run, a complementary policies run (that is, the complementary policies applied to the reference run), and cap-and-trade run (that is, an allowance price imposed on the complementary policies run). The cases are:

- Main policy case

[32] 2006 emissions include emissions associated with power imported from non-WCI jurisdictions.

- Sensitivity cases, which differ from the main policy case in the following ways:
  - Half-effectiveness of complementary policies (shares reference run with main policy case).
  - Alternative economic forecast, high economic growth, low energy prices (requires its own reference and complementary policies runs).
  - High fuel price and high electricity generation cost (requires its own reference and complementary policies runs).
  - Allowance price growth rate of 4% per year for cap-and-trade (shares reference run and complementary policies run with main policy case).
  - Allowance price growth rate of 12% per year for cap-and-trade (shares reference run and complementary policies run with main policy case).

The allowance price applies to the narrow scope sectors in 2012-2014 and to the broad scope sectors in 2015-2020. ENERGY 2020 determines the energy use changes and GHG emissions. The number of banked allowances is calculated from the emissions, the allowance budget, and number of offsets used.

Main Policy Case

This case simulates the effects of the WCI cap-and-trade program under the EMT's primary set of assumptions regarding future socio-economic conditions, complementary policies, and offset availability and costs. The following sensitivity cases allow the EMT to gauge the sensitivity of the main policy case results to changes in some of these key assumptions.

Sensitivity Case: Half-Effectiveness of Complementary Policies

The purpose of this sensitivity case is to examine what happens if the energy efficiency and VMT programs achieve only half of their assumed emission reductions. Specifically, this case assumes that:

- The energy efficiency programs reduce the rate of growth in electricity and natural gas demand by only 0.25 percent per year, starting in 2012.
- Vehicle miles traveled decrease by only 1 percent from the reference case by 2020.
- The clean car standards are unchanged.
- The Ontario coal phase-out is unchanged.

Sensitivity Case: Alternative Economic Forecast

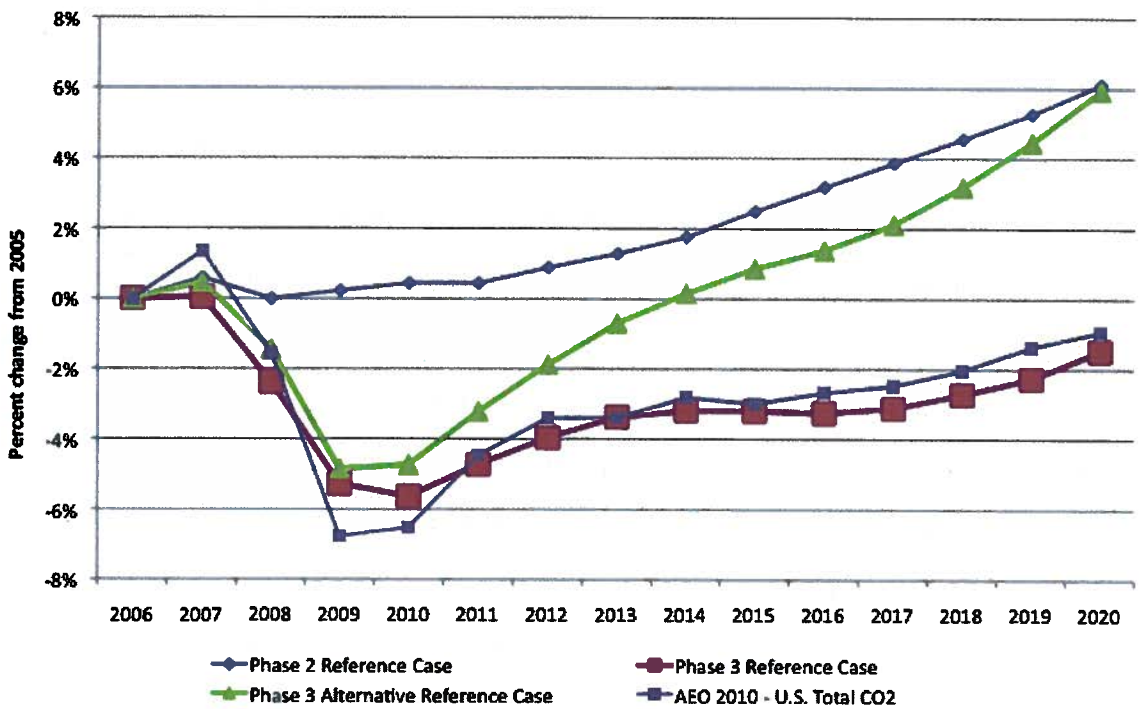
The purpose of this sensitivity case is to examine the implications of a different economic forecast than that assumed in the main policy case. The alternative economic forecast assumes a growth rate of 2.8 percent per year, about 0.5 percent per year higher than in the forecast used for the main policy case.

For energy prices, the alternative forecast uses the average of the AEO 2009 reference-price and low-price forecasts. This case also assumes that the EISA biofuels mandate will not be fully met by 2020. Instead, the case assumes the level of biofuels reflected in the AEO 2009. Each of these changes has the effect of increasing emissions in the reference case, and together, increase the challenge of meeting the WCI regional goal. Since the higher growth of the economy would also increase opportunities to become more energy efficient, an alternative complementary policies run was conducted for this sensitivity case in which the energy efficiency programs achieve a 1 percent per year decrease in the electricity and natural gas demand growth, starting in 2012. Table 8 and Figure 5 summarize the differences between the reference and alternative reference runs.

Table 8: Reference Run and Alternative Reference Run Assumptions

Assumption	Reference run	Alternative Reference run
Economic growth	Accounts for economic recession based on January 2009 Congressional Budget Office forecast	Faster economic growth to assess implications of a stronger than expected recovery
Fuel price forecast	AEO 2009 mid case	Average of AEO 2009 mid and low cases. Lower fuel prices results in more fuel consumption
Energy efficiency program impacts (used in complementary policy run)	Reduced demand for electricity and natural gas by 0.5% per year	Reduced demand for electricity and natural gas by 1.0% per year

Figure 5: Reference Run and Alternative Reference Run Emission Compared to the Latest National Forecast



Sensitivity Case: High Fuel Prices and Electricity Generation Costs

The purpose of this sensitivity case is to examine the implications of energy prices being higher than assumed in the main policy case. There has been considerable stakeholder comment that the energy price forecast in the main policy case may be too low. Additionally, some stakeholders have commented that the power generation cost assumptions may be too low, indicating that recent increases in commodity prices have had an impact on these costs. This sensitivity case includes both increased energy prices and increased power generation costs as a set of conditions that could occur together in the future. In this case, energy prices are assumed to start at 2008 prices and increase in real terms by 50% by 2020, and capital and O&M costs for power generation are assumed to be 30% higher than in the main policy case. This case required its own reference and complementary policies runs.

Sensitivity Case: 4% Annual Growth In Allowance Prices

The purpose of this sensitivity case is to examine the implications of a slow-rising allowance price trajectory. This case uses a growth rate in the allowance price of 4 percent per year instead of 8 percent per year in the cases discussed above.

Sensitivity Case: 12% Annual Growth In Allowance Prices

The purpose of this sensitivity case is to examine the implications of a faster-rising allowance price trajectory. This case uses a growth rate in the allowance price of 12 percent per year instead of 8 percent per year in the cases discussed above.

Results and Discussion

Emission Results for the Main Policy Case

Figure 6 shows the emission results of ENERGY 2020 for the main policy case. Offsets, complementary policies, and additional emission reductions caused by the cap are each important to achieving the WCI regional goal. Together, these emission reductions meet an allowance budget that decreases linearly to 15 percent below 2005 levels by 2020. Emission reductions in 2020 are predicted to be 13.4 percent below 2005 emissions due to over-compliance in earlier years and the use of banked allowances in 2019 and 2020.

Figure 6: Greenhouse Gas Emission Reductions Under the WCI Program, 2006-2020

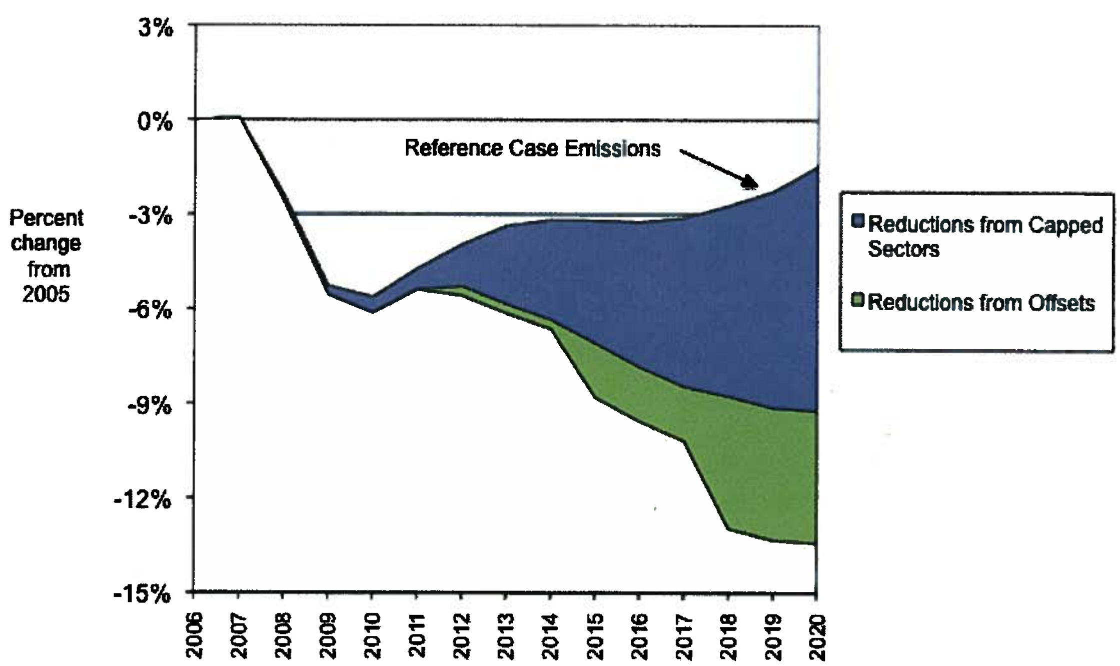
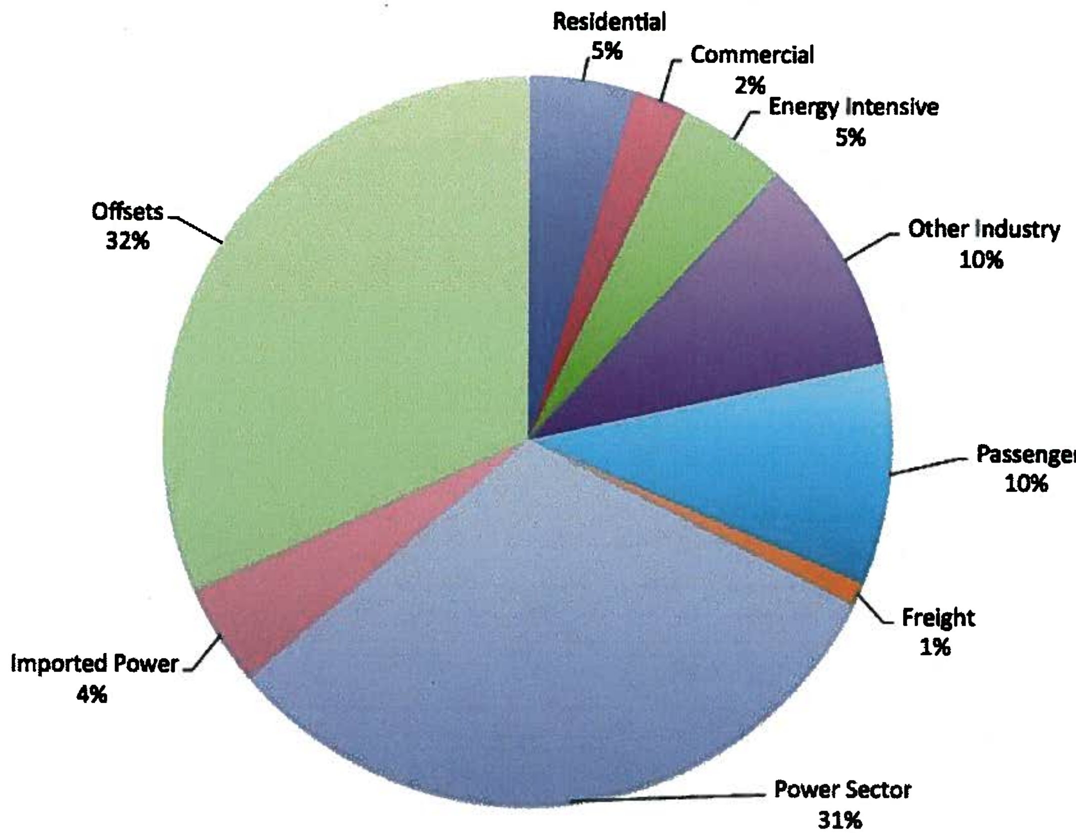


Figure 7 shows the relative amount that each type of reduction contributes to the total emissions reduced by the program over the period 2012-2020. Total emissions from capped sectors for this period in the reference run is 7,999 million metric tons (Mt) of carbon dioxide equivalents. The allowance budget described in Other Cap-and-Trade Modeling Assumptions would reduce emissions by 719 Mt over the 2012-2020 period. The contribution of each sector to this reduction is shown in Figure 8.

Figure 7: Source of Emission Reductions Under the Cap, Main Policy Case Relative to the Reference Case, 2012-2020



Economic Results for the Main Policy Case and Sensitivity Cases

Table 9 summarizes the results for the six cap-and-trade cases. The main policy case achieves the WCI regional goal at an allowance price of $33 in 2020. The net cost over the period analyzed (abatement cost plus offset cost) is -$102 billion, which represents a net cost savings. The sensitivity cases indicate that reducing the effectiveness of complementary polices by half, or assuming a rapid economic recovery and low energy prices, raise allowance prices to over $50, but still produce a net cost savings.[33] The sensitivity cases also suggest allowance prices would be much lower than the main policy case if energy prices and electricity production costs in the reference case are higher than expected.

Table 10 provides detailed cost estimates for the main policy case by sector and cost type, summed over the years 2012-2020. Negative costs (i.e., savings) are shown in parentheses. The cost savings result from the complementary policies. The largest single savings are attributable to the passenger transportation sector. In particular, the reduction in VMT reduces expenditures on fuel and on other vehicle costs. Figure 8 shows the fuel cost savings, other costs, and total costs for all sectors for the main policy case. The total savings of $102 billion, however, is modest relative to the size of the WCI

[33] Modeling runs were not performed for allowance prices over $50. This price, however, achieved 94% of the emission reductions required by the cap for both sensitivity cases.

economy (less than 0.2 percent of the combined economies of the 11 WCI Partner jurisdictions). The total market value of all allowances distributed in the main policy case is $188 billion.

Table 9: Summary of Economic Results for Main Policy and Sensitivity Cases (savings in parentheses)

Case Description	Abatement by covered sectors, 2012-2020 (Mt CO2e)	Reduction from offsets, 2012-2020 (Mt CO2e)	Abatement cost,* 2012-2020 (2007 $B)	Offset cost, 2012-2020 (2007 $B)	Allowance price in 2020 that achieves compliance (2007 $)	Allowance value 2012-2020 (2007 $B)
Main policy case	484	235	(105)	3	33	188
Sensitivity Cases						
Half the VMT reduction and energy efficiency improvements	483	243	< (38)	3	> 50	> 285
Faster economic growth & lower primary energy prices**	816	291	< (202)	4	> 50	> 287
Higher energy prices and power plant construction costs	420	208	(106)	2	13	72
4% annual allowance price escalation	484	235	(105)	3	28	179
12% annual allowance price escalation	484	235	(106)	3	39	200

* Abatement cost includes approximately $3B for energy efficiency program administration.
** This case assumes greater economic growth will create more opportunities to improve energy efficiency and therefore reduce the annual growth rates by 1% per year instead of 0.5% per year.

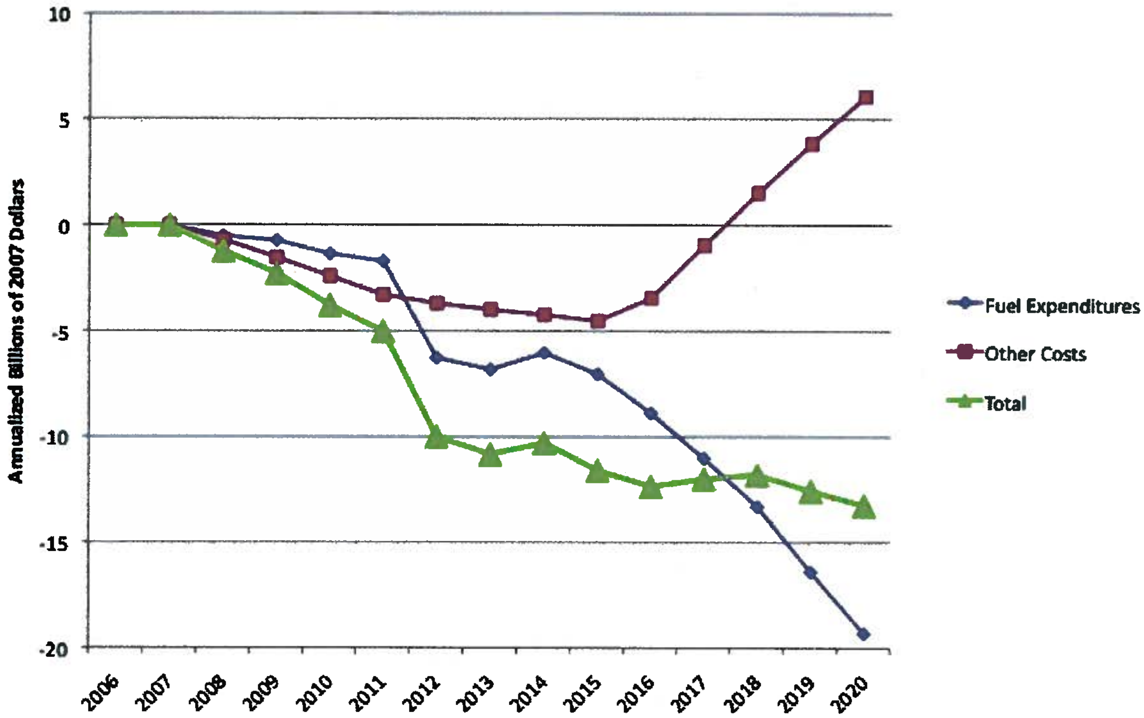
Table 10: Economic Results for the Main Policy Case by Sector and Cost Type, 2007 Million US$ Summed Over 2012-2020 (savings in parentheses)

Sector	Fuel	Device	Process	O&M	Total
Residential	(21,880)	20,830	350	2,710	2,010
Commercial	(18,020)	8,030	350	1,580	(8,060)
Energy Intensive Industry*	(14,760)	580	320	730	(13,130)
Paper	(3,540)	(710)	90	(10)	(4,170)
Chemicals	(3,000)	(410)	30	(160)	(3,540)
Petroleum	(250)	1,790	190	850	2,580
Nonmetallic Minerals	(1,050)	(170)	30	(90)	(1,280)
Primary Metals	(3,320)	(70)	0	20	(3,370)
Mining Except Oil & Gas	(2,630)	(160)	(10)	(80)	(2,880)
Oil and Gas Extraction	(970)	310	(10)	200	(470)
Other Industry	(3,300)	1,480	(330)	940	(1,210)
Passenger Transportation	(29,680)	(51,510)	0	(7,760)	(88,950)
Freight Transportation	(3,000)	30	0	9,130	6,160
Agriculture	(4,430)	(20)	(20)	(100)	(4,570)
Waste & Wastewater	0	0	0	0	0
Total**	(95,070)	(20,580)	670	7,230	(107,750)

* Energy Intensive Industry is a subtotal of the seven energy-intensive sectors listed beneath it.

** Does not include offset costs or complementary policies administrative costs, which are estimated and reported separately.

Figure 8: Economic Results for the Main Policy Case by Year, 2007 Billion US$



The half-effectiveness of complementary policies case achieves compliance for an allowance price trajectory that has a higher price than $50 in 2020. (The modeling effort did not include any runs higher than $50.)

The alternative economic forecast case also achieves compliance for an allowance price above $50 in 2020. The potential for savings, however, is higher in this case than any other (at least $198 billion). This is because the faster economic growth was assumed to create more opportunities to improve energy efficiency. Hence, complementary policies were assumed to reduce the growth rate of electricity and natural gas demand by 1 percent in each year. Nonetheless, the faster economic growth and lower fuel prices leads to greater emissions in the reference run and a greater need for emission reductions in the cap-and-trade run, requiring an allowance price greater than $50 to achieve the WCI regional goal.

The high energy price and electricity generation cost sensitivity case achieves compliance at a lower allowance price of $13. The allowance price is so low that the WCI offset limit is not reached because offset prices begin to exceed the allowance price. The cost savings potential is larger than the main policy case because the low allowance price preserves a greater portion of the savings from the complementary policies.

The final two sensitivity cases imply that the precise slope of the price trajectory (discount rate) assumed by the EMT has little effect on the economic results.

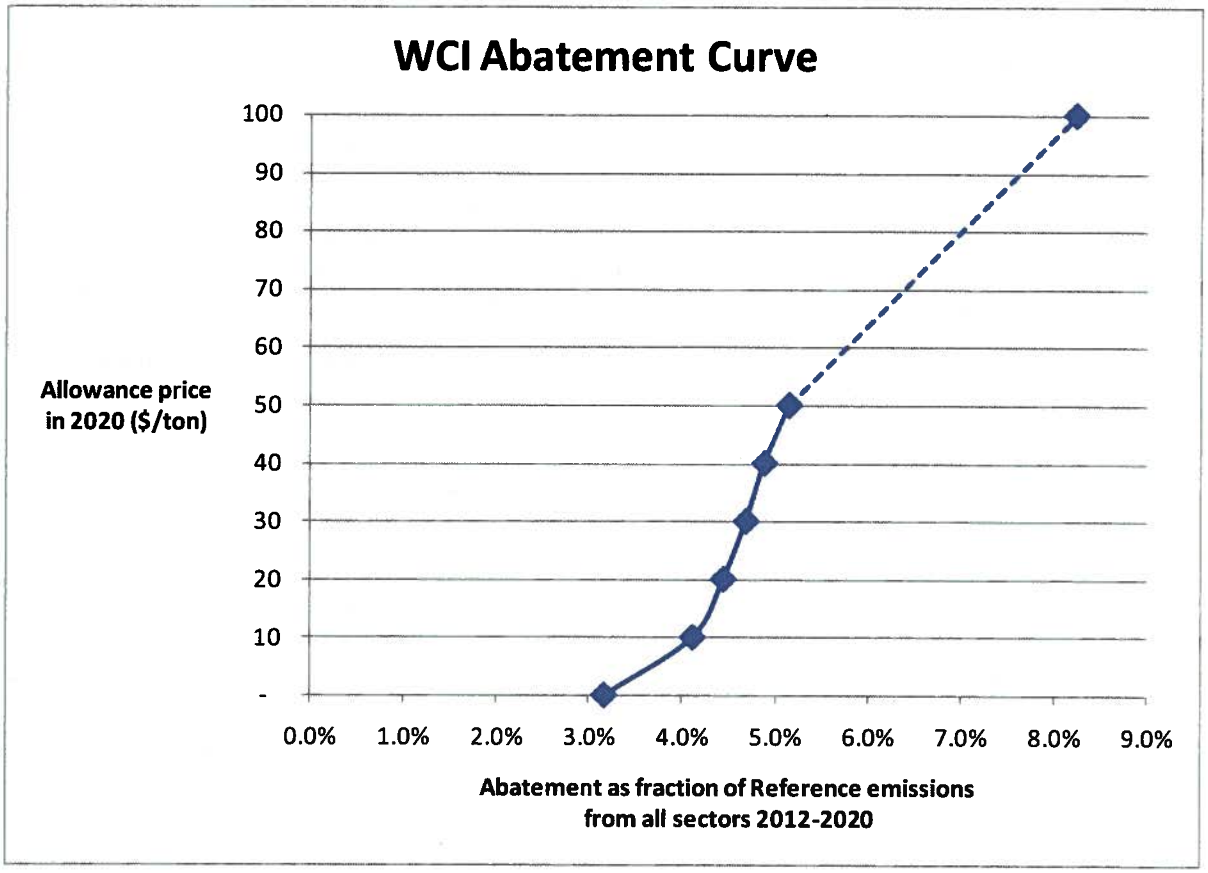
To put the results of Table 9 into some context, the 2020 allowance prices estimated in other studies are provided below. These studies differed from the EMT's analysis and from each other in their geographic scope, emission targets, time period, use of offsets, and type of computational model used.

- WCI 2008, $24 in 2020.[34]
- California Scoping Plan, $10 in 2020.[35]
- Updated Analysis of California's Scoping Plan, $21.[36]
- U.S. EPA analysis of Waxman-Markey (ACES), $20 in 2020.[37]
- Congressional Budget Office analysis of Waxman-Markey, $28 in 2020.[38]
- Energy Information Agency analysis of Waxman-Markey, $32 in 2020.[39]
- U.S. EPA analysis of Kerry-Lieberman (APA), $24 in 2020.[40]

Finally, Figure 9 shows the abatement curve for the main policy case. The curve suggests that reducing emissions from three percent below the reference case to four percent below the reference case, and from five to eight percent below the reference case, can be achieved through modest escalation of allowance prices. In the four to five percent range, however, the cost of abatement alternatives rises faster as greater emission reductions are sought within this range.

[34] http://www.westernclimateinitiative.org/component/remository/Economic-Modeling-Team-Documents/Appendix-B-Economic-Modeling-Results/
[35] http://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm
[36] http://www.arb.ca.gov/cc/scopingplan/economics-sp/economics-sp.htm
[37] http://www.epa.gov/climatechange/economics/economicanalyses.html
[38] http://energycommerce.house.gov/Press_111/20090620/cbowaxmanmarkey.pdf
[39] http://www.eia.doe.gov/oiaf/servicerpt/hr2454/pdf/sroiaf(2009)05.pdf
[40] http://www.epa.gov/climatechange/economics/economicanalyses.html

Figure 9: Abatement for the Main Policy Case



Conclusions

- The WCI emissions reduction goal for 2020 can be achieved with a net cost savings of approximately $100 billion in the WCI region over the 2012-2020 period. While significant, these savings are modest (less than 0.2 percent) relative to the economic size of the 11 WCI Partner jurisdictions.

- The allowance price predicted in 2020 to achieve the regional emission reduction goal in the main policy case is $33, which is higher than the $24 predicted in the Phase 2 modeling but comparable to the results of other independent studies.

- Complementary policies have the potential to significantly reduce emissions and contain costs. In this analysis, they produce negative costs, or cost savings. Complementary policies provide net savings because the reduction in fuel and other expenditures is greater in magnitude than the cost of the emission reductions. If complementary policies have roughly half the effect that the EMT assumed in the main policy case, then an allowance price of over $50 would be required to achieve the WCI regional goal.

- Higher-than-expected fuel prices would make it less costly to achieve the emissions goal, with lower allowance prices. Conversely, lower-than-expected fuel prices, coupled with a faster economic recovery, would raise the allowance price.

- Banking and offsets are important design elements to achieve emissions reductions and limit costs. Although no sensitivity cases were conducted to test the EMT's assumptions about offsets, it appears that none of the cases analyzed here would achieve the regional goal at an allowance price below $50 if not for the availability and price of offsets assumed in this report.

Detailed Results for the Reference Run and Main Policy Case

Description of Outputs

Table 11 through Table 16 present detailed results for the reference run used in the main policy case. Table 17 through Table 23 present detailed results for a representative cap-and-trade case. All dollars shown are 2007 dollars. These tables present annual results for selected years: 2006 (the first year modeled); 2012 (when the narrow scope begins); 2015 (when the broad scope begins); 2020 (the final year modeled). Another column shows the average annual growth rate for 2006-2020. For the cap-and-trade cases, the final column compares the 2020 value with the 2020 value from the reference run. Below are brief explanations of the model results shown in the tables.

Greenhouse Gas (GHG) Emissions: GHG emissions are presented in millions of metric tons of carbon dioxide equivalent (Mt CO_2e). Emissions for the 11 WCI Partner jurisdictions included in the analysis are presented by major sector.

Total Energy Use: Total energy use is reported by fuel type in units of TBtu/year.

Electric Sector: Outputs for the electric sector include:

- Generation capacity in units of megawatts (MW) by generation type. Note that estimated generation capacity grows due to capacity additions, but capacity retirement is not calculated. Consequently, generation capacity does not decline in the model outputs.

- Generation output in units of gigawatt-hours per year (GWh/year) by generation type.

- Electricity sales in units of GWh/year, including electricity imports into the eight WCI Partner jurisdictions in the WECC.

- Generating utility costs in $M/year, as requested by stakeholders.

Transportation Sector: Outputs for the transportation sector include VMT for passenger and freight vehicles, as well as miles traveled per passenger. The fleet average efficiency and marginal efficiency (for new vehicles) are reported for four vehicle types in miles per gallon. The average vehicle market share and marginal vehicle market share are reported for passenger vehicles.

Fuel Prices: Fuel prices are reported for electricity, natural gas, coal, fuel oil, LPG, gasoline, and diesel in 2007 dollars per million Btu (2007 \$/mmBtu). The prices include the forecasted energy prices (presented in Table 5 above for the reference run) as well as the costs of delivering the fuels to market, but not fuel taxes. The prices reported for the cap-and-trade policy cases also include the allowance price, reflecting the appropriate carbon content of the fuel.

Fuel Expenditures: Fuel expenditures are reported by major sector. Estimates of fuel expenditures do not include the value of the allowances, although they do take into account the increase in the price of electricity driven by the allowance price.

Costs and Savings: For the cap-and-trade cases, costs and savings are reported in millions of 2007 dollars per year (\$M/Yr). Total costs are reported by major sector, which are the sum of changes in fuel expenditures, changes in investment costs, and changes in O&M. Investment costs increase as more efficient devices, buildings, and processes are purchased in response to the limit on GHG emissions. The investment costs are annualized using a 5% real discount rate over the life of the equipment. The annualized costs are counted each year over the life of the equipment. The estimates of total costs include both the change in fuel expenditures and the change in investment costs. As shown in the tables below, the fuel expenditure savings typically offset most or all of the increased investment costs. The sub-total does not include the adjustments for program administration of the complementary policies or the allowance value of the power sector. These adjustments are added to get the total cost.

Reference Run

A reference run represents a business-as-usual scenario through 2020 (i.e., absent any cap or other GHG abatement policies not already adopted). Table 11 through Table 16 show model outputs for the reference run used in the main policy case. This reference run was also used in the half effectiveness complementary policies sensitivity case and the discount rate sensitivity cases. Alternative reference runs were used to assess the other two sensitivity cases, but these outputs are not included in this report.

Table 11: Reference Run Greenhouse Gas Emissions

GHG Emissions *(Mt CO_2e)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Residential	78	80	85	89	1.0%
Commercial	55	53	53	52	-0.4%
Energy Intensive	228	202	203	204	-0.8%
Other Industry	65	74	81	92	2.5%
Passenger	352	354	334	306	-1.0%
Freight	133	131	135	142	0.5%
Power Sector	200	156	162	176	-0.9%
Waste	42	48	52	57	2.1%
Agriculture (non energy)	69	71	75	81	1.2%
Imported Power	38	41	41	41	0.5%
Total	**1,260**	**1,210**	**1,219**	**1,241**	**-0.1%**

Table 12: Reference Run Energy Use

Total Primary Energy Use *(TBtu/year)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Aviation Fuel	737	781	799	836	0.9%
Biomass	681	621	660	727	0.5%
Coal	1,455	1,290	1,343	1,462	0.0%
Diesel	1,673	1,668	1,711	1,771	0.4%
Ethanol	93	200	317	494	12.7%
Landfill Gases/Waste	34	35	35	35	0.1%
LPG	668	591	579	550	-1.4%
Motor Gasoline	4,166	4,028	3,677	3,216	-1.8%
Natural Gas	5,244	4,535	4,671	4,833	-0.6%
Nuclear	1,617	1,659	1,609	1,677	0.3%
Oil, Unspecified	1,545	1,429	1,441	1,468	-0.4%
Renewables	2,026	2,188	2,277	2,375	1.1%
Total	**19,939**	**19,025**	**19,119**	**19,444**	**-0.2%**

Table 13: Reference Run Electric Sector Results

Generation Capacity *(GW)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**
Gas/Oil	71	82	83	87	1.5%
Coal	22	24	24	24	0.7%
Nuclear	24	24	24	24	0.0%
Hydro	109	113	114	114	0.3%
Biomass	3	3	4	5	3.6%
Wind	4	13	20	25	13.8%
Other Renewable	3	3	3	3	1.4%
Total	**236**	**262**	**273**	**282**	**1.3%**
Generation Output *(TWh/year)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**
Gas/Oil	153	103	112	129	-1.2%
Coal	116	104	108	116	0.0%
Nuclear	155	159	154	161	0.2%
Hydro	504	528	536	550	0.6%
Biomass	15	17	20	25	3.7%
Wind	9	33	50	64	15.1%
Other Renewable	14	14	15	15	0.8%
Total	**966**	**958**	**995**	**1,060**	**0.7%**
Sales *(TWh/year)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**
Residential	314	316	331	350	0.8%
Commercial	333	331	345	370	0.8%
Industrial	309	288	298	325	0.4%
Transportation	6	8	8	7	1.7%
Street/Misc	16	16	16	16	0.0%
Resale	-	-	-	-	#N/A
Total	**978**	**960**	**998**	**1,070**	**0.6%**
Generating Utility Costs (M$/Year)					
	2006	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**
Annualized Investments	6,595	11,448	9,204	6,501	-0.1%
Fuel Expenditures	20,583	18,387	21,831	29,671	2.6%
Operation & Maintenance	5,945	6,463	6,783	7,108	1.3%
Total	33,124	36,298	37,818	43,280	1.9%

Table 14: Reference Run Transportation Sector Results

Distance Travelled	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Passenger (billions of vehicle miles traveled)	690.3	751.9	810.8	865.0	1.6%
Freight (billions of vehicle miles traveled)	102.6	105.1	110.4	117.9	1.0%
Passenger Miles/Person	7.9	8.0	8.1	8.2	0.3%

Average Vehicle Efficiency *(miles/gallon)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Light Gasoline	23.2	25.6	28.8	34.8	2.9%
Medium Gasoline	23.2	25.6	28.8	34.7	2.9%
Heavy Gasoline	16.9	18.0	19.5	22.0	1.9%
Heavy Diesel	16.9	18.0	19.5	22.0	1.9%
Fleet Average (In-Use Vehicles)	20.9	23.0	25.9	30.7	2.8%

Marginal Vehicle Efficiency *(miles/gallon)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Light Gasoline	24.2	33.4	41.9	45.0	4.5%
Medium Gasoline	24.2	33.4	41.9	44.9	4.5%
Heavy Gasoline	17.3	20.4	23.4	24.5	2.5%
Heavy Diesel	17.3	20.4	23.4	24.4	2.5%
Fleet Average (In-Use Vehicles)	21.2	27.8	33.4	35.6	3.7%

Average Vehicle Market Share *(Percent)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Light Gasoline	36.8	36.5	36.7	37.2	0.1%
Medium Gasoline	34.1	34.2	34.6	35.1	0.2%
Heavy Gasoline	29.0	29.3	28.7	27.7	-0.3%

Marginal Vehicle Market Share *(Percent)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Light Gasoline	36.7	36.5	38.1	38.2	0.3%
Medium Gasoline	33.8	34.3	36.1	36.2	0.5%
Heavy Gasoline	29.4	29.2	25.8	25.6	-1.0%

Table 15: Reference Run Fuel Prices (2007 $/mmBtu)

Sector	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Residential					
Res Electricity Prices	27.1	26.9	27.2	27.2	0.0%
Res Natural Gas Prices	10.3	11.6	12.1	12.9	1.6%
Res Oil Prices	21.1	25.7	28.4	29.3	2.4%
Res LPG Prices	22.0	26.7	29.4	30.4	2.3%
Commercial					
Com Electricity Prices	26.4	25.7	25.9	25.8	-0.2%
Com Natural Gas Prices	9.0	10.1	10.5	11.3	1.6%
Com Oil Prices	19.6	24.3	27.0	28.0	2.6%
Com LPG Prices	20.4	25.0	27.7	28.7	2.5%
Industrial					
Ind Electricity Prices	16.4	15.9	16.0	15.7	-0.3%
Ind Natural Gas Prices	7.9	9.3	9.7	10.3	1.9%
Ind Coal Prices	2.0	2.2	2.1	2.1	0.5%
Ind Oil Prices	14.7	19.2	21.7	22.6	3.1%
Ind LPG Prices	20.1	24.8	27.4	28.4	2.5%
Transportation					
Gasoline Prices	23.0	27.5	30.3	31.4	2.3%
Diesel Prices	22.3	26.8	29.5	30.5	2.3%

Table 16: Reference Run Fuel Expenditures (2007 $billion/yr)

Sector	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020
Residential	44.9	47.5	51.1	55.1	1.5%
Commercial	41.7	42.0	44.1	46.7	0.8%
Energy Intensive Industry*	42.2	43.7	47.0	48.3	1.0%
Paper	5.7	5.2	5.3	5.3	-0.5%
Chemicals	5.9	6.4	7.0	7.7	1.9%
Petroleum	16.2	17.2	18.7	18.7	1.0%
Nonmetallic Minerals	3.4	3.5	3.8	3.9	1.1%
Primary Metals	6.6	6.7	7.2	7.8	1.2%
Mining Except Oil and Gas	1.1	1.4	1.7	1.9	4.0%
Oil and Gas Extraction	3.3	3.4	3.4	2.9	-0.9%
Other Industry	18.8	20.7	23.1	24.8	2.0%
Passenger Transportation	100.1	122.7	128.2	123.0	1.5%
Freight Transportation	39.5	47.5	54.0	59.1	2.9%
Agriculture	4.2	4.2	4.5	4.5	0.5%
Waste & Wastewater	-	-	-	-	#N/A
Total	**291.5**	**328.2**	**351.9**	**361.6**	**1.6%**

* Energy Intensive Industry is a subtotal of the seven energy-intensive sectors listed beneath it.

Main Policy Case

The following tables shows detailed results for the main policy case, which achieves compliance with an allowance price of $33 per metric ton in 2020.

Table 17: Main Policy Case Greenhouse Gas Emissions

GHG Emissions *(Mt CO_2e)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Residential	78	79	82	82	0.4%	-7.6%
Commercial	55	53	52	47	-1.1%	-9.0%
Energy Intensive	228	202	200	196	-1.1%	-3.7%
Other Industry	65	74	74	78	1.3%	-15.6%
Passenger	351	350	329	287	-1.4%	-6.2%
Freight	133	131	135	139	0.3%	-1.8%
Power Sector	199	148	137	141	-2.5%	-20.2%
Waste	42	48	52	57	2.1%	0.0%
Agriculture (non energy)	69	71	72	79	1.0%	-2.6%
Imported Power	38	38	38	36	-0.4%	-11.6%
Total	**1,260**	**1,193**	**1,170**	**1,144**	**-0.7%**	**-7.9%**

Table 18: Main Policy Case Energy Use

Total Primary Energy Use *(TBtu/year)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Aviation Fuel	737	781	799	831	0.9%	-0.6%
Biomass	681	622	653	698	0.2%	-4.0%
Coal	1,455	1,213	1,114	1,160	-1.6%	-20.7%
Diesel	1,673	1,656	1,683	1,692	0.1%	-4.4%
Ethanol	93	197	313	472	12.3%	-4.5%
Landfill Gases/Waste	34	35	35	35	0.1%	0.0%
LPG	668	595	584	526	-1.7%	-4.4%
Motor Gasoline	4,166	3,983	3,621	2,981	-2.4%	-7.3%
Natural Gas	5,244	4,496	4,484	4,343	-1.3%	-10.1%
Nuclear	1,617	1,625	1,517	1,552	-0.3%	-7.5%
Oil, Unspecified	1,545	1,417	1,428	1,474	-0.3%	0.4%
Renewables	2,026	2,193	2,300	2,430	1.3%	2.3%
Total	**19,939**	**18,813**	**18,531**	**18,193**	**-0.7%**	**-6.4%**

Table 19: Main Policy Case Electric Sector Results

Generation Capacity *(GW)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**	**Change from Ref @ 2020**
Gas/Oil	71	88	92	100	2.5%	15.7%
Coal	22	21	17	17	-1.7%	-28.7%
Nuclear	24	24	24	24	0.0%	0.0%
Hydro	109	113	116	117	0.5%	2.1%
Biomass	3	3	4	5	4.2%	8.2%
Wind	4	15	22	29	14.9%	15.3%
Other Renewable	3	3	3	3	1.2%	-2.9%
Total	**236**	**266**	**279**	**295**	**1.6%**	**4.7%**
Generation Output *(TWh/year)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**	**Change from Ref @ 2020**
Gas/Oil	153	102	102	107	-2.5%	-16.8%
Coal	116	96	86	90	-1.8%	-22.4%
Nuclear	155	156	146	149	-0.3%	-7.3%
Hydro	504	527	545	564	0.8%	2.5%
Biomass	15	17	21	25	3.8%	1.0%
Wind	9	36	55	73	16.2%	14.1%
Other Renewable	14	15	15	15	0.8%	-0.2%
Total	**966**	**949**	**970**	**1,024**	**0.4%**	**-3.4%**
Sales *(TWh/year)*	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**	**Change from Ref @ 2020**
Residential	314	311	318	328	0.3%	-6.3%
Commercial	333	325	329	347	0.3%	-6.3%
Industrial	309	284	288	308	0.0%	-5.3%
Transportation	6	8	8	7	1.3%	-6.5%
Street/Misc	16	16	16	16	0.0%	0.0%
Resale	-	-	-	-	#N/A	#N/A
Total	**978**	**945**	**959**	**1,007**	**0.2%**	**-5.9%**
Generating Utility Costs (M$/Year)	**2006**	**2012**	**2015**	**2020**	**Avg. Annual Growth Rate 2006-2020**	**Change from Ref @ 2020**
Annualized Investments	6,595	12,466	11,312	9,089	2.3%	39.8%
Fuel Expenditures	20,583	17,544	18,652	23,520	1.0%	-20.7%
Operation & Maintenance	5,945	6,558	6,938	7,358	1.5%	3.5%
Total	**33,124**	**36,568**	**36,902**	**39,967**	**1.4%**	**-7.7%**

Table 20: Main Policy Case Transportation Sector Results

Distance Travelled	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Passenger (billions of vehicle miles traveled)	690.3	742.6	797.6	845.2	1.5%	-2.3%
Freight (billions of vehicle miles traveled)	102.6	105.1	110.4	116.9	0.9%	-0.8%
Passenger Miles/Person	7.9	7.9	8.0	8.0	0.1%	-2.3%

Average Vehicle Efficiency *(miles/gallon)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Light Gasoline	23.2	25.6	28.8	35.9	3.2%	3.3%
Medium Gasoline	23.2	25.6	28.7	35.8	3.2%	3.3%
Heavy Gasoline	16.9	18.0	19.5	24.3	2.6%	10.0%
Heavy Diesel	16.9	18.0	19.5	24.2	2.6%	10.0%
Fleet Average (In-Use Vehicles)	20.9	23.0	25.8	32.5	3.2%	5.8%

Marginal Vehicle Efficiency *(miles/gallon)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Light Gasoline	24.2	33.4	41.9	52.3	5.7%	16.3%
Medium Gasoline	24.2	33.4	41.9	52.3	5.7%	16.3%
Heavy Gasoline	17.3	20.4	23.4	33.1	4.7%	34.9%
Heavy Diesel	17.3	20.4	23.4	32.9	4.7%	34.7%
Fleet Average (In-Use Vehicles)	21.2	27.8	33.4	43.7	5.3%	22.8%

Average Vehicle Market Share *(Percent)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Light Gasoline	36.8	36.5	36.7	37.1	0.0%	-0.2%
Medium Gasoline	34.1	34.2	34.6	35.0	0.2%	-0.2%
Heavy Gasoline	29.0	29.3	28.7	27.9	-0.3%	0.6%

Marginal Vehicle Market Share *(Percent)*	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Light Gasoline	36.7	36.5	38.1	37.7	0.2%	-1.3%
Medium Gasoline	33.8	34.3	36.1	35.7	0.4%	-1.3%
Heavy Gasoline	29.4	29.2	25.8	26.6	-0.7%	3.7%

Table 21: Main Policy Case Fuel Prices (2007 $/mmBtu)

Sector	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Residential						
Res Electricity Prices	27.1	26.9	28.3	28.7	0.4%	5.6%
Res Natural Gas Prices	10.3	11.6	12.1	15.1	2.8%	17.4%
Res Oil Prices	21.1	25.7	28.4	31.2	2.8%	6.3%
Res LPG Prices	22.0	26.7	29.4	31.9	2.7%	5.1%
Commercial						
Com Electricity Prices	26.4	25.7	27.0	27.3	0.2%	6.0%
Com Natural Gas Prices	9.0	10.1	10.5	13.4	2.9%	19.3%
Com Oil Prices	19.6	24.3	27.0	30.1	3.1%	7.5%
Com LPG Prices	20.4	25.0	27.7	30.2	2.8%	5.2%
Industrial						
Ind Electricity Prices	16.4	15.9	16.7	16.6	0.1%	5.5%
Ind Natural Gas Prices	7.9	9.3	10.8	11.8	2.9%	14.8%
Ind Coal Prices	2.0	2.2	3.4	3.8	4.8%	81.5%
Ind Oil Prices	14.7	19.2	23.3	25.0	3.8%	10.7%
Ind LPG Prices	20.1	24.7	28.7	30.2	3.0%	6.4%
Transportation						
Gasoline Prices	23.0	27.6	30.3	33.8	2.8%	7.5%
Diesel Prices	22.3	26.8	29.5	32.8	2.8%	7.4%

Table 22: Main Policy Case Fuel Expenditures (2007 $billion/yr)

Sector	2006	2012	2015	2020	Avg. Annual Growth Rate 2006-2020	Change from Ref @ 2020
Residential	44.9	46.8	50.5	53.5	1.3%	-2.9%
Commercial	41.7	41.4	43.9	46.0	0.7%	-1.5%
Energy Intensive Ind.*	42.2	43.5	46.5	46.7	0.7%	-3.1%
Paper	5.7	5.1	5.1	5.0	-0.9%	-5.6%
Chemicals	5.9	6.3	6.8	7.3	1.6%	-5.0%
Petroleum	16.2	17.3	18.9	18.4	0.9%	-1.4%
Nonmetallic Minerals	3.4	3.4	3.7	3.8	0.9%	-2.3%
Primary Metals	6.6	6.6	7.2	7.8	1.2%	0.3%
Mining Except Oil/Gas	1.1	1.4	1.5	1.5	2.2%	-21.9%
Oil & Gas Extraction	3.3	3.4	3.3	2.9	-1.0%	-2.5%
Other Industry	18.8	20.6	23.2	24.8	2.0%	0.0%
Passenger Transportation	100.1	121.4	126.5	115.1	1.0%	-6.5%
Freight Transportation	39.5	47.5	54.0	58.1	2.8%	-1.7%
Agriculture	4.2	4.1	4.1	3.9	-0.5%	-14.0%
Waste & Wastewater	-	-	-	-	#N/A	#N/A
Total	**291.5**	**325.2**	**348.8**	**348.1**	**1.3%**	**-3.7%**

* Energy Intensive Industry is a subtotal of the seven energy-intensive sectors listed beneath it.

Table 23: Main Policy Case Annualized Costs

Annualized Total Costs (2007 $billion/yr)				
Sector	**2006**	**2012**	**2015**	**2020**
Residential	-	0.0	1.4	3.3
Commercial	-	(0.2)	0.7	1.0
Energy Intensive Industry*	-	(0.2)	(0.3)	(1.4)
Paper	-	(0.1)	(0.2)	(0.5)
Chemicals	-	(0.1)	(0.2)	(0.5)
Petroleum	-	0.1	0.4	0.2
Nonmetallic Minerals	-	(0.0)	(0.1)	(0.2)
Primary Metals	-	(0.0)	0.0	0.0
Mining Except Oil & Gas	-	(0.1)	(0.2)	(0.5)
Oil and Gas Extraction	-	(0.0)	(0.1)	0.0
Other Industry	-	0.0	0.4	0.3
Passenger Transportation	-	(6.4)	(9.8)	(12.1)
Freight Transportation	-	(0.0)	0.0	1.5
Agriculture	-	(0.1)	(0.4)	(0.7)
Sub-Total	**-**	**(6.9)**	**(8.3)**	**(9.4)**
Program Costs	-	0.1	0.3	0.6
Power Sector Allowance Value (subtract from sub-total)	-	(3.3)	(3.9)	(5.8)
Total	**-**	**(10.1)**	**(11.9)**	**(14.6)**

* Energy Intensive Industry is a subtotal of the seven energy-intensive sectors listed beneath it.

Economic Analysis and Modeling Support to the Western Climate Initiative

ENERGY 2020 Model Inputs and Assumptions

Revision Date - 26 April 2010

Prepared for:
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Table of Contents:

Acronyms & Definitions

AEO	Annual Energy Outlook (published by EIA)
ARB	California Air Resources Board
BPA	Bonneville Power Administration
Btu	British Thermal Units
CAC	Criteria Air Contaminants (SO_x, NO_x, PM, etc.)
CFL	Compact Fluorescent Light bulb
CHP	Combined Heat and Power
CO_2e	Carbon Dioxide equivalent
GDP	Gross Domestic Product
GO	Gross Output
GWP	Global Warming Potential
DG	Distributed Generation
E3	Energy and Environmental Economics, Inc.
EIA	Energy Information Administration
EPACT	Energy Policy Act of 2005
ESCO	Energy Service Company
GHG	Greenhouse Gas
IECC	International Energy Conservation Code
IGCC	Integrated Gasification Combined Cycle
kW	Kilowatt
kWh	Kilowatt-hour
Mt	Megatonne
MW	Megawatt
MWe	Megawatt electric
Mt CO_2e	Megatonnes Carbon Dioxide Equivalent (also referred to as MTCE)
NOx	Nitrogen Oxides
OGCC	Oil/Gas Combined Cycle Turbine
OGCT	Oil/Gas Combustion Turbine
OGST	Oil/Gas Steam Turbine
PC	Pulverized Coal
REMI	Regional Economic Models, Inc.
RECS	Renewable Energy Certificates
Rest of US	Balance of systems in US
SO_x	Sulfur Oxides (including sulfur dioxide)
USEPA	United States Environmental Protection Agency
W	Watt
WCI	Western Climate Initiative
WECC	Western Electricity Coordinating Council

1 Background and Project Scope

The Western Climate Initiative (WCI) retained ICF International and its partner Systematic Solutions Inc. (SSI), to assist in modeling a cap-and-trade system for the western US and Canada. For 30 years, ICF has been known for its sophisticated models. Over that time, ICF has worked to build, enhance, and apply these tools for a variety of public and private sector clients to help answer complex questions on energy and environmental market issues. Over the same period, SSI has performed analysis to solve problems in all facets of the energy market, including electric and natural gas utilities, energy extracting industries, and the transportation sector. In addition, both firms have applied macroeconomic models in conjunction with their energy market modeling tools to address broader questions of economic impacts.

When this modeling was initiated, all eight WCI Partner jurisdictions were located within the Western Electricity Coordinating Council (WECC) region. In late 2008, ICF was authorized to expand the modeling effort to include all 11 of the current partners; including the provinces of Manitoba, Ontario and Québec. In order to properly represent the expanded geographic coverage of the WCI, the model was expanded to represent all of the US and Canada. In the process of building this expanded model, ICF took the opportunity to update some information in the model and address issues raised by the WCI Economic Modeling Team (EMT) and WCI stakeholders. The update also included revising the economic forecasts to include the effects of the economic recession.

This report describes the ENERGY 2020 model, assumptions in the analysis, and the input data and data sources.

2 Analytic Approach

This project uses ENERGY 2020 to model the business-as-usual outlook for the WCI Partner jurisdictions[1] as well as surrounding states and provinces and the impact of potential greenhouse gas (GHG) emissions reduction policies.

ENERGY 2020 is an integrated multi-region energy model that provides complete and detailed, all-fuel demand and supply sector simulations. These simulations can additionally include macroeconomic interactions to determine the benefits or costs to the local economy of new facilities or changing energy prices. The model can be used in regulated as well as deregulated and transitioning environments. GHG and criteria air contaminant pollution emissions and costs, including allowances and trading, are endogenously determined, thereby allowing assessment of environmental risk and co-benefit impacts.

The basic implementation of ENERGY 2020 for North America now contains a user-defined level of aggregation down to the 10 provincial and 50 state (and sub-state) level. ENERGY 2020 contains historical information on all generating units in the US and Canada. Data for Mexico can be incorporated as needed. ENERGY 2020 is parameterized with local data for each region/state/province as well as all the associated energy suppliers it simulates. Thus, it

[1] Arizona, California, Montana, New Mexico, Oregon, Utah, Washington, British Columbia, Manitoba, Ontario and Québec.

captures the unique characteristics (physical, institutional and cultural) that affect how people make choices and use energy. Collections of state and provincial models are currently validated from 1986 to the latest quarterly numbers.[2]

ENERGY 2020 can be linked to a detailed macroeconomic model to determine the economic impacts of energy/environmental policy and the energy and environmental impacts of national economic policy. For US regional and state level analyses, the REMI macroeconomic model is regularly linked to ENERGY 2020.[3] The Informetrica macroeconomic model is linked to ENERGY 2020 for Canadian national and provincial efforts.[4] The REMI and Informetrica macroeconomic models include inter-state/provincial, US and world trade flows, price and investment dynamics, and simulate the real-time impact of energy and environmental concerns on the economy and vice versa.

The structure of the model is well tested and has been used to simulate not only US and Canadian energy and environmental dynamics, but also those of several countries in South America, Western, Central, and Eastern Europe. These efforts include strategic and tactical analyses for both planning and energy industry restructuring/deregulation. In the 1990s, the US EPA made ENERGY 2020 available to interested states to analyze emissions, energy, and economic impacts of state-level climate change initiatives. Further, the model has been used successfully for deregulation analyses in all the US states and Canadian provinces. Many US and Canadian energy suppliers use the model for the analysis of combined electricity and gas deregulation dynamics.[5]

The default model simulates demand by three residential categories (single family, multi-family, and agriculture/rural), over 40 NAICS commercial and industrial categories[6], and three transportation services (passenger, freight, and off-road). There are approximately six end-uses per category and six technology/mode families per end-use.[7] Currently the technology families correspond to six fuels groups (oil, gas, coal, electric, solar and biomass) and 30 detailed fuel products. The transportation sector contain 45 modes including various type of automobile, truck, off-road, bus, train, plane, marine and alternative-fuel vehicles. More end-uses, technologies, and modes can be added as data allow. For all end-uses and fuels, the model is parameterized based on historical, locale-specific data. The load duration curves are dynamically built up from the individual end-uses to capture changing conditions under consumer choice and combined gas/electric programs.

Each energy demand sector includes cogeneration, self-generation, and distributed generation simulation, including mobile-generation, micro-turbines, and fuel-cells. Fuel-switching responses

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[2] Energy supplier data comes from FERC and US DOE for the US and Statistics Canada. US and Canadian fuel and demand data come from the US Department of Energy and Natural Resources Canada, respectively. US and Canadian pollution data come from US EPA and Environment Canada, respectively.
[3] Regional Economic Models, Inc. www.remi.com
[4] Informetrica Limited www.informetrica.ca
[5] ENERGY 2020 is the only model known to have simulated and predicted the dynamics that occurred in the UK electric deregulation. These include gaming, market consolidation and re-regulation dynamics.
[6] NAICS is the North America Industrial Classification System which was developed jointly by the U.S., Canada, and Mexico to provide new comparability in statistics about business activity across North America.
[7] End-uses include Process Heat, Space Heating, Water Heating, Other Substitutable, Refrigeration, Lighting, Air Conditioning, Motors, and Other Non-Substitutable (Miscellaneous). Detailed modes include: small auto, large auto, light truck, medium-weight truck, heavy-weight truck, bus, freight train, commuter train, airplane, and marine. Each mode type can be characterized by gasoline, diesel, electric, ethanol, NG, propane, fuel-cell, or hybrid vehicles.

are rigorously determined. The technology families (which can be split, as an option, to portray specific technology dynamics) are aggregates that, within the model, change building shell, economic-process and device efficiency and capital costs as price or other information that the decision makers see, change. ENERGY 2020 utilizes the historical and forecast data developed for each technology family to parameterize and disaggregate the model.

The supply portion of the model includes endogenous detailed electric supply simulation of capacity expansion/construction, rates/prices, load shape variation due to weather, and changes in regulation.[8] The model dispatches plants according to the specified rules whether they are optimal or heuristic and simulates transmission constraints when determining dispatch.[9] A sophisticated dispatch routine selects critical hours along seasonal load duration curves as a way to provide a quick but accurate determination of system generation. Peak and base hydro usage is explicitly modeled to capture hydro-plant impacts on the electric system.

ENERGY 2020 supply sectors include electricity, oil, natural gas, refined petroleum products, ethanol, land-fill gas, and coal supply. Energy used in primary production and emissions associated with primary production and its distribution is included in the model. The supply sectors included in a particular implementation of ENERGY 2020 will depend on the characteristics of the area being simulated and the problem being addressed. If the full supply sector is not needed, then a simplified simulation determines delivered-product prices.

The ENERGY 2020 model includes pollution accounting for both combustion (by fuel, end-use, and sector) and non-combustion, and non-energy (by economic activity) for SO_2, NO_2, N_2O, CO, CO_2, CH_4, PMT, $PM_{2.5}$, PM_5, PM_{10}, VOC, CF_4, C_2F_6, SF_6, and HFC at the state and provincial level by economic sector. Other (gaseous, liquid, and solid) pollutants can be added as desired. Pollution does not need to be determined directly by coefficients but can recognize the accumulation of capital investments that result in pollution emission with usage. National and international allowance trading is also included. Plant dispatch can consider emission restrictions.

The model captures the feedback among energy consumers, energy suppliers, and the economy using Qualitative Choice Theory and co-integration.[10] For example, a change in price affects demand that then affects future supply and price. Increased economic activity increases demand; increased demand increases the investment in new supplies. The new investment affects the economy and energy prices. The energy prices also affect the economy.

Finally, the system includes confidence and validity testing software that places uncertainty bounds on simulation results, quantifies confidence intervals, and ranks the contributions to uncertainty in future conditions. This feature can be used to limit data efforts to information most important to the analysis.

[8] ENERGY 2020 does include a complete, but aggregate representation of the electric transmission system. Electric transmission data is provided by FERC, the Department of Energy, and the National Electric Reliability Council. The dispatch technologies in the basic model include: Oil/Gas Combustion turbine, Oil/Gas Combined Cycle, Oil/Gas Combined Cycle with CCS, Oil/Gas Steam Turbine, Coal Steam Turbine, Advanced Coal, Coal with CCS, Nuclear, Baseload Hydro, Peaking Hydro, Small Hydro, Wind, Solar, Wave, Geothermal, Fuel-cells, Flow-Battery Storage, Pumped Hydro, Biomass, Landfill Gas, Trash, and Biogas.

[9] A 110 node transmission system is used in the default model, but a full AC load-flow bus representation model has also been interfaced with ENERGY 2020.

[10] The model has used the work of Daniel McFadden and Clive Granger since its inception in the late 1970s.

In order to assess the potential impacts of proposed policy options, a b*usiness-as-usual* scenario is developed as a point of reference. This *Reference Case* represents a scenario that is viewed as a reasonable expectation of how the economy, energy use and emissions might develop over time.

Part of the nature of developing a Reference Case is the need to address inherently uncertain issues that can have significant impacts on future energy use and emissions. No forecast is going to be *right* or *accurate* in that no one can tell today how some of the key underlying issues may develop. Given the level of uncertainty involved in any projection of a possible future, caution should be used in applying a high level of precision to the modeling results. Understanding the Reference Case, however, can be extremely useful in providing an underlying structure against which to model proposed policies, and in determining directionality and cause and effect.

Numerous assumptions are required to perform an analysis of this type across a range of topic areas, including economic developments, fuel and electric markets, and regulatory structures. Projected outcomes are only as good as the input assumptions upon which they are based, with more rigorous assumptions leading to a more rigorous analysis. The inputs and assumptions described in this document were developed to provide as accurate a representation as possible of the activities and structures underlying energy use and GHG emissions in the WCI Partner jurisdictions.

3 Reference Case Inputs

ENERGY 2020 derives energy demands, such as the demand for electricity based on economic activity and device efficiency. The following sections provide a brief overview of the data inputs and assumptions as well as the sources of data used in the Reference Case. Actual data inputs for specific elements such as generating units, emission factors, etc., can be provided separately in Excel spreadsheets as required.

As a multi-sector analytical tool, ENERGY 2020 requires data and assumptions covering a broad range of economic sectors and their interactions. In most cases, the necessary data – both historical and projected – is available from the federal government (EIA, EPA, etc.). In past analyses, ENERGY 2020 has relied heavily on these federal sources to populate and calibrate the model. In developing the model for this project, a considerable amount of state-specific information was available and has been used wherever possible.

The following sections provide an overview of the data and assumptions that are required to perform the multi-sector analysis, and list the data sources used to populate ENERGY 2020.

Data inputs for ENERGY 2020 are required in five areas: [11]

1. Population and economic
2. Fuel prices
3. Energy use and consumption
4. Emissions and air regulations
5. Electricity generation capacity and operation

[11] "Data" here refers to both historical data and assumptions and projections of future inputs.

The sections below list the key data elements required in each of these areas, along with the sources that have been used to supply these data for other analyses. Appendix B lists a number of default data sources used by the model. The sections that follow provide a more specific description of the data used for this project including state-specific data used in place of national sources.

ENERGY 2020 requires both historical data and projections to calibrate and generate forward-looking projections. Various historical data will be used for the period 1985-2005 (the last year for which certain detailed sectoral and end-use are available). Projections for the period to be modeled (e.g. through 2030) will be gathered where possible to provide points of comparison and check the reasonableness of the projection.

The implementation of ENERGY 2020 for this project began with inclusion of the states and provinces within the Western Electricity Coordinating Council (WECC); specifically Arizona, California, Montana, New Mexico, Oregon, Utah, Washington, and British Columbia. Manitoba was initially not included in this modeling due to the complexity of extending the model beyond the WECC. Since that time, new partners have joined the WCI, including Ontario and Quebec. The current phase of the project expands the modeling to include all eleven current WCI Partner jurisdictions. In order to fully represent the interactions between these jurisdictions and their neighbouring states and provinces, the model has been expanded to represent all of the US and Canada.

3.1 *Population and Economic Data*

Demographic and economic data is required to generate demands for services. The historic data for the US states was obtained from the US Bureau of Economic Analysis (BEA). For the Canadian provinces, historic data is from Statistics Canada's CANSIM.

The following data sources were used to establish the reference case for the WCI policy modeling:

Description of Data/Input	Sources	Detailed Reference
Total population, historical and growth over time	US Census Bureau	*Historic (1985-2006):* Regional Economic Information System, Bureau of Economic Analysis, U.S. Department of Commerce http://www.bea.gov/regional/spi/default.cfm?satable=summary *California:* California population taken from: CEC *California Energy Demand 2008-2018 Staff Revised Forecast*
	Statistics Canada	Statistics Canada Table 051-0001 (based on census data)
	Future	For US - Future annual population growth rates are taken from Regional Forecasts from AEO then applied to the state historical population. Annual Energy Outlook 2007 (February 2007 release). http://www.eia.doe.gov/oiaf/aeo/supplement/suptab_1.xls through suptab_9.xls For Canada: projected based on Informetrica forecast.
Population by housing type	US Census Bureau	Population Estimates Program, Population Division

Description of Data/Input	Sources	Detailed Reference
(single-family, multi-family, etc.)	Statistics Canada	Household type, Structural Type of Dwelling and housing tenure for Private Households of Canada
Households by housing type (single-family, multi-family, etc.)	US Census Bureau	Household splits (data through 2001 then held constant): *Source: U.S. Census Bureau, Housing and Household Economic Statistics Division* Last Revised: *December 16, 2005* http://www.census.gov/hhes/www/housing/census/historic/units.html **Household size** US Census Bureau, Census 2000 - assumes household size is same for all housing types in state. **Number of households** Calculated based on population, household fraction, and household size.
	Statistics Canada	Household type, Structural Type of Dwelling and Housing Tenure for Private Households of Canada
	Future	Projected based on Informetrica forecast.
Personal income	US Bureau of Economic Analysis	*Historic (1985-2006)*: Bureau of Economic Analysis, 6/24/07 http://www.bea.gov/regional/spi/default.cfm?satable=summary *California*: Estimates provided by ARB (see Appendix C).
	Statistics Canada	Statistics Canada CANSIM table 384-0012
	Future	Apply changes in historic Personal Income to Total GRP ratio and apply to future to forecast out to 2030.

Project partners were provided with the default projections proposed for use in the modeling and invited to provide alternative jurisdiction-specific projections.

Several partners elected to accept the initial model projections, including:

- Montana
- Oregon
- Utah
- British Columbia
- California

It should be noted that the economic projection for California had been provided by the state based on work done as part of a prior project.

Some partners chose to provide jurisdiction-specific projections for some of the demographic and economic data, including:

- Arizona: personal income; population (state total); and gross output (from REMI)
- New Mexico: population
- Washington: population

For all other partners data from the sources listed in the tables above was used.

Population, housing and economic output projections provided by the partners are presented in Appendix C.

3.1.1 Economic Forecast

Economic conditions changed quite dramatically over the course of this project. ENERGY 2020 requires a detailed state and provincial level sector-by-sector forecast for the US and Canadian economy as a basis for modeling future economic activity and emissions. A projection for the US economy was obtained from Regional Economic Models, Inc. (REMI). For the Canadian economy, a long term projection prepared by Informetrica Ltd., was made available by the National Energy Board. Both of these projections pre-dated the economic downturn that started in late 2008. Given the speed with which the economy has changed, we found that economic forecasts with the level of detail required by the model were not yet available at the time when the Reference Case was being prepared.

In order to provide a more realistic representation of current economic expectations, ICF/SSI in consultation with the Economic Modeling Team (EMT) sought more recent projections that would reflect current expectations of the two economies. For the US, the projection of the Congressional Budget Office[12] was selected as providing a reasonable representation of a consensus view at that time. Recognizing the strong interaction between the two national economies, we sought projections for the Canadian economy which projected comparable US conditions to those presented in the CBO forecast. The Conference Board of Canada,[13] in its Winter 2009 Outlook, provides a forecast for both the Canadian and US economy. The depth and length of the US downturn presented in the Board's US outlook were reasonably aligned with the Congressional Budget Office's expectations. Unfortunately this projection did not have the level of detail required by the model. As a result, an earlier Conference Board of Canada forecast was used which implied a less severe US recession than the CBO forecast. This Canadian forecast therefore projected less of a downturn for Canada than the projection used for the U.S. These two forecasts were used to adjust the existing more detailed projections in order to reflect the effects of the economic downturn. In the case of the Conference Board projection, considerable sector detail was available to reflect differences in these impacts between provinces. Where jurisdiction specific projections had been provided by partners, these projections were also adjusted to reflect the changes in the broader economy.

3.2 *Energy Price Data*

Energy prices can play a significant role in end user decisions on equipment, capital and operating decisions. Fuel costs can be critical in determining the costs of electric dispatch, as well as input costs of some industrial processes and home heating. ENERGY2020 calculates future electric prices based in part on these fuel costs.

[12] Congress of the United States, Congressional Budget Office, The Budget and Economic Outlook: Fiscal Years 2009 to 2019, January 2009.

[13] ICF/SSI used the Conference Board's "Provincial Long Term Database" which provided the most recent available economic forecast available. The Board published a summary of its expectations for the Canadian economy in its "Canadian Outlook Executive Summary: Global Recession Weighs Heavily on Canada, Winter 2009".

Energy prices are largely determined by international markets, although domestic demand, such as electric sector demand for natural gas can influence prices. As a result, fuel prices are treated by the model as an exogenous input.

Historic energy price data are taken from US DOE State Energy Data and Statistics Canada. The model currently uses energy price forecast data for the US from the Energy Information Administration's 2009 Annual Energy Outlook Reference Case Price scenario for 2009 to 2030.[14] For Canada, the National Energy Board's price forecast is used[15].

Biomass Cost *(per MBtu in 2006$)*	
Residential	$11.53
Commercial	$10.09
Industrial	$10.06

Biomass prices in the model are based on research completed for a previous project, shown in the table below. Unlike other fuels, biomass prices are significantly influenced by local cost and supply issues.

Power prices are calculated endogenously by the model based on generation costs and dispatch. While, the model estimates retail electricity prices, actual consumer prices may differ as a result of political, regulatory or market influences. The model can be calibrated to actual prices, within reasonable parameters, for the historic period.

Given the time and resources available for the project, the model does not account for the different regulatory regimes among the partner jurisdictions with respect to electric price regulation (i.e., cost-of-service ratemaking vs. various forms of market-driven pricing). The intent of the modeling is rather to produce reasonable estimates of retail prices at the state or provincial level based on generation costs and historical mark-ups above generation costs.

3.3 *Historic Energy Consumption Data*

ENERGY 2020 models energy use at the end-use level within each economic sector based on the existing physical stock and the efficiency of that stock. The database of device efficiencies reflects both the average efficiency of energy use for current stocks and the efficiency/energy alternatives available to consumers at the margin. Technology and efficiency choices are modeled based on past experience with consumer choice rather than on a purely economic evaluation.

Historic energy use and consumption data used in the model is derived from the federal Energy Information Administration (EIA) State Energy Data (SEDS) database. Where state-specific data were available, these data was used to replace national data sources.

Default sectoral and end-use data as well as energy intensities are based on the Residential Energy Consumption Survey (RECS), Commercial Energy Consumption Survey (CECS) and Manufacturers Consumption Energy Survey (MECS).

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[14] Energy Information Administration, Annual Energy Outlook 2008, Report #DOE/EIA-0383(2008), June 2008, http://www.eia.doe.gov/oiaf/aeo/

[15] Canada's Energy Future: An Energy Market Assessment, November 2007. http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgyftr/2007/nrgyftr2007-eng.html

Description of Data/Input	Sources Used/Available
Residential Data - Household income by housing type - No. of people per household - End-use consumption data, including fuels used for space and water heating, air conditioning, etc.	2001 EIA Residential Energy Consumption Survey (RECS), by Census Region and Division (2005 RECS in process) http://www.eia.doe.gov/emeu/recs/contents.html For Canada – Natural Resources Canada Office of Energy Efficiency Database http://oee.nrcan.gc.ca/corporate/statistics/neud/dpa/comprehensive_tables/index.cfm?attr=0
Commercial Data - Floor area by sub-sector - End-use consumption data, including fuels used for space and water heating and energy intensities	2003 EIA Commercial Buildings Energy Consumption Survey (CBECS), by Census Region and Division (2007 CBECS underway) http://www.eia.doe.gov/emeu/cbecs/contents.html For Canada – NRCan OEE Database
Industrial/Manufacturing Data - Energy use by fuel for each sub-sector and end-use	2002 EIA Manufacturing Energy Consumption Survey (MECS), by Census Region (2006 MECS underway) http://www.eia.doe.gov/emeu/mecs/contents.html For Canada – NRCan OEE Database
State/Provincial Energy Data: - Energy consumption and expenditures by sector and energy source	2004 EIA State Energy Data System (SEDS) http://www.eia.doe.gov/emeu/states/_seds.html Canada: NRCan OEE Database and CANSIM

3.4 *Historic Emission Data*

3.4.1 Emissions and Air Regulations

Historic GHG emissions are based on the Canadian national inventory published by Environment Canada and the US GHG emissions inventory as published by the EPA.[16] ENERGY 2020 is calibrated using historic information on all of the major GHG emissions including:

- Carbon dioxide (CO_2),
- Nitrous oxide (N_2O),
- Methane (CH_4),
- Sulfur hexafluoride (SF_6),
- Hydrofluorocarbons (HFCs) and
- Perfluorocarbons (PFCs).

GHG emissions are presented in CO_2 equivalent (CO_2e) terms. The global warming potentials used to convert the different greenhouse gas emissions into CO_2e terms are provided in Appendix H.

[16] EPA website: http://www.epa.gov/climatechange/emissions/usinventoryreport.html

Input	Sources Used/Available
Emissions by sector, end-use, fuel & GHG	US EPA http://www.epa.gov/climatechange/emissions/usinventoryreport.html Environment Canada http://www.ec.gc.ca/pdb/ghg/inventory_e.cfm

3.4.2 Emission Factors

Emission factors for most fuels are based on values used by ICF in developing national and state inventories. For the transportation sector however, the emission factors for CH_4 and N_20 pollutants were adapted from the Canadian National Inventory Report.[17] ENERGY 2020 calculates GHG emissions at the point of combustion for most fuels. Upstream emissions from extraction and processing are captured as part of those respective economic sectors.

Emissions associated with the use of biomass as a fuel are deemed to be biogenic and therefore not contribute to global warming. As a result, the model assumes no GHG emissions are created from the use of biomass.

Emissions from ethanol and other biofuels represent an exception from a modeling perspective. In order to capture the emissions associated with their production and distribution, the model applies full cycle emission factors for these fuels. While the combustion of ethanol and biodiesel are not deemed to result in any anthropogenic emissions, the model uses an emission factor to recognize upstream emissions.

The full-cycle emission factors used in the model for each biofuels type are shown in the table below:[18]

Corn Ethanol	76 g CO_2e / MJ
Cellulosic Ethanol	14 gCO_2e / MJ
Biodiesel	30 gCO_2e / MJ

When these fuels are used in combination with other fuels, for example in a mix of gasoline and ethanol, the emissions associated with gasoline combustion are reported as part of total gasoline-related emissions.

3.5 *Electricity Sector Data*

3.5.1 Generation Data

The electricity sector differs from other sectors in the extent to which emissions associated with power use within the state may result from emissions outside the WCI region as power is imported from or exported to other areas.

[17] Environment Canada. National Inventory Report 1990-2005, Greenhouse Gas Sources and Sinks in Canada, April 2007. (Annex 12 Emission Factors)

[18] Alexander Farrell, UC Berkeley and Daniel Sperling, UC Davis, A Low-Carbon Fuel Standard for California Part 1: Technical Analysis May 29, 2007 Table 2-3 http://www.energy.ca.gov/low_carbon_fuel_standard/UC-1000-2007-002-PT1.PDF

ENERGY 2020 contains information on every generating unit in the state or province, as well as in neighboring jurisdictions which may supply power to the state. The model tracks and uses the following information for each generating unit:

- Historic Peak Capacity (MW);
- Historic generation levels (GWh);
- Type of fuel used;
- Heat rate;
- Historic annual fuel use (PJ);
- Emissions by pollutant type;
- O&M costs;
- Capacity factors;
- Emission rates;
- Outage rates;
- State or Province;
- Physical location (latitude and longitude);
- Ownership information;
- Plant type (Hydraulic, Coal, Combined Cycle Turbine, etc.)

The data on existing and committed generating units in the US was obtained from the National Electric Energy Data System (NEEDS) 2006 database and reconciled with a list of plants from BPA. The database of plants in Canada was developed based on the Canadian IPM®[19] module, modified and updated based on information from Statistics Canada, Environment Canada and the National Energy Board.

3.5.2 Electricity Generation Capacity and Operation Data

ENERGY 2020 is populated with data describing the type, operation and performance of every generating unit in the US and Canada. In order to improve model performance, some smaller units with common characteristics have been combined (i.e. wind units at the same site, or small hydraulic units). In addition to plant-level data, the table below includes other inputs necessary to describe the electric system, including transmission capability.

Input	Sources Used/Available
Plant type	Annual Electric Generator Report: EIA Form 860 (2006) Canadian IPM® Base Case 2004[20] Natural Resources Canada, Canada's Energy Outlook: Reference Case 2006[21] Supplemented by National Energy Board info.
Plant capacity	Annual Electric Generator Report: EIA Form 860 (2006) Canada: as above
Plant historical generation	EIA Form 906/920 (2001-2006) Total generation output by plant type for California from

[19] ICF's Integrated Planning Model®.
[20] http://www.ec.gc.ca/cleanair-airpur/caol/canus/IPM_TECHNICAL/ipm_technical_report/toc_e.cfm
[21] http://www.nrcan-rncan.gc.ca/com/resoress/publications/peo/peo-eng.php

Input	Sources Used/Available
	CEC Canada: as above
Plant fuel type	Annual Electric Generator Report: EIA Form 860 (2006) Canada: as above
Plant Heat Rate	EIA Form 906/920 (2001-2006) Canada: as above
Plant fuel consumption	EIA Form 906/920 (2001-2006)
Plant emissions by pollutant	EPA CAMD (2001-2006) Environment Canada
Plant costs (operation and maintenance, variable and fixed)	CA: E3 model data Canada: as above
Plant historical capacity factor	EIA Form 906/920 (2001-2006) Statistics Canada
Plant availability (outages)	Calculated using generation data Statistics Canada
Plant owner and location	Annual Electric Generator Report: EIA Form 860 (2006) Canada: as above
Planned capacity additions and retirements	Annual Electric Generator Report: EIA Form 860 California Public Utility Commission GHG Modeling process (E3) NRCan Energy Outlook
Transmission Capability	Canada: National Energy Board, *Canadian Electricity Trends and Issues (2001)* & *Canadian Electricity Exports and Imports (2001)*; National Resources Canada, *Electric Power in Canada 1998 – 1999*; NERC, *2004 Summer Assessment* & *2004 Winter Assessment: Reliability in the Bulk Electricity Supply in North America* Western US – Additional data provided by BPA and reports from the WECC (Approved 2006 Spring OTC Limits, March 16, 2006).

This data has been compared to generation data provided as part of modeling for the California Public Utilities Commission.[22]

The resulting list of generating units was matched to emission data from the EPA and Environment Canada in order to calculate emission rates. The resulting emission rates for the targeted GHG emissions were then reviewed for reasonableness based on plant type and capacity factors, etc.

Historic generation by plant type will be calibrated with historic generation data available from the EIA.

[22] www.ethree.com/cpuc_ghg_model.html

3.5.3 Transmission Structure and Dispatch

Power flows between neighboring US states are modeled within ENERGY 2020 based on existing transmission capabilities and interconnections as obtained from NERC reports.

Appendix D describes the inter-regional transmission capabilities between model regions (or nodes) as well as the maximum capacity limit of each transmission path used in the model. Interconnection capacities and transmission nodes used in the model were based on the IPM® Model 2006[23] updated to reflect changes in the region based on past work for past clients including the Bonneville Power Administration and review by the Economic Modeling Team.

Generation is dispatched at the node level for a set of sample hours in each season. Each node is economically dispatched, selecting lowest cost generation first with the resulting clearing price determining the generation price for that node as described in Appendix A. As part of the calculation the model can utilize resources from a neighboring node within the constraints of the transfer capacity between nodes. The transfer of energy between nodes is subject to a 1% loss to represent additional transmission losses.

3.5.4 Planned Capacity Changes

As part of the modeling process, ENERGY 2020 builds new capacity endogenously as needed to meet capacity and reserve requirements or to minimize the total cost of generation (e.g., in response to allowance prices). At any given time, however, plans may already be in place to build, re-furbish, upgrade or retire generation facilities. These plans must be incorporated into the model in order to reflect decisions and commitments that have already been made.

For this project, we reviewed information on generation projects planned in the Region, with particular emphasis on planned coal facilities. This list was then reviewed with the WCI Economic Modeling Team to determine which projects were felt to be most likely to proceed based on the current status. While it is not possible to determine which specific projects will proceed, for modeling purposes we have assumed that the units listed in Appendix F will be built during the modeled period.

ENERGY 2020 can determine the need for new generation based on a pre-determined reserve requirement. Normally, this determination is based on the highest level of demand for power and the available capacity at the time of that peak. Some types of generation, such as wind or some types of hydro-electric generation however, may not be available at the time of the peak. For modeling purposes the model assumes that only 15% of installed wind capacity is available at the time of the peak.

[23] Table 3.5 of section 3 of the documentation for the EPA Base Case 2006 (v3.0) posted on the EPA website: http://epa.gov/airmarkets/progsregs/epa-ipm/index.html#docs

3.5.5 New Generation Characteristics

The costs and characteristics of new generation are based on information developed as part of the GHG modeling process for the California Public Utility Commission[24] and are shown in Appendix G.

Carbon capture and storage (CCS) is not assumed to be available until after 2020. The performance and cost assumptions for new generating units equipped with CCS are shown in Appendix G. It should be noted that these costs represent capture costs only and do not include transportation or sequestration costs.

The model assumes that no new nuclear generation capacity will come online through 2020. Ontario nuclear units returning to service after scheduled refurbishment are not considered to be "new" capacity.

3.5.6 Industrial Generation and Co-generation

ENERGY 2020 models both utility generation, which supplies the power grid, and industrial generation which supplies a particular end user. Industrial generation is defined as power generation that is within the industrial end user's facility and is not used to supply power to the grid. Industrial generation, as defined in ENERGY 2020, could also be referred to as self-generation or load displacement generation. Industrial generation may be supplied by any of the fuels listed below:

- Biomass
- Coal
- LPG
- Oil
- Solar
- Steam

Co-generation, or combined heat and power facilities, simultaneously generate electricity and supply a heat load. ENERGY 2020 recognizes that co-generation may occur either as industrial generation or as utility generation and may use any of a number of fuels.

- Within the power sector, these plants are treated as 'must run' units, meaning that they will always operate when available. Power from these units contributes to overall electricity supply. Heat from these units may be captured as part of a separate steam supply system, however, limited data is available regarding overall US steam demand.
- Within the industrial sector, co-generation capacity will run based on heating requirements. Heat produced from co-generation is used to meet industrial heat requirements based on a co-generation heat rate. Co-generated electricity is used to meet industrial power requirements, reducing net demand from the grid.

Where the heat contribution of co-generation is significant, the preferred modeling approach is to include these units in the industrial sector.

[24] www.ethree.com/cpuc_ghg_model.html

The databases used to represent electricity generation often include all significant generators, including both utility and industrial boilers and generators. By contrast, reported electricity consumption information tends to be based on metered electricity sales, and as such are net of self generation. Total electricity consumption and generation will generally be slightly higher than reported electricity sales. It is therefore important in calibrating the model with historic electricity consumption that existing generation used as industrial or self-generation be appropriately identified.

3.6 *Transportation*

ENERGY 2020 models passenger, freight and off road transportation separately, based on different underlying drivers. Transportation is assumed to be a derived demand based on levels of economic output (for freight) or personal income (for passenger). As the economic drivers (industrial gross output and personal income) grow, transportation demand increases. The amount of transportation required per unit of economic output changes over time based on historic trends.

Transportation requirements are developed for each geographic area in the model based on historic demands for transportation, consumer preferences, business requirements, and the cost for each mode of transportation. Consumers of transportation select among available modes within the model based on preferences and relative costs. Mode choices include bus, train, and various types of personal and freight vehicles. Consumers choose among modes based on consumer preferences and cost. The model uses average vehicle lifetimes to vintage the vehicle stock.

Personal vehicle choices are made in a similar manner. Consumers consider capital cost, fuel cost and efficiency as well as non-price factors in their purchase decision and seek to maximize perceived utility. Historically, non-price factors such as vehicle size, performance and appearance have dominated the choice decision with efficiency playing a relatively minor role. Costs are presented in the model in terms of the capital cost per mile traveled for different vehicle classes. Larger vehicles therefore have a higher associated capital cost as well as lower energy efficiency for the level of delivered service (miles traveled).

The transportation categories represented in the model are shown below.

E2020 Classifications				
Economic Categories	**Modes**	**Vehicle Classes** *(Personal Vehicles)*	**Fuel Types** *(Personal Vehicles)*	**Technology Types**
Passenger	Personal Vehicles	Light	Gasoline	Internal Combustion Engine
Freight	Motorcycle	Medium	Diesel	Hybrids
Off Road	Train	Heavy	Propane	Fuel Cell
	Plane		CNG	Plug-In Hybrid
	Marine		Electric	
			Ethanol	
			Hydrogen	

At present, plug-in hybrid and fuel cell options are not populated in the model. As more information on the costs and characteristics of these options becomes available these choices can be made available to transportation consumers.

Vehicle and modal efficiencies used in the model are based on the *Transportation Energy Data Book* (Edition 26, 2007)[25] published by the US Department of Energy's Oak Ridge National Laboratory. Specific data references are provided in the table below.

Input	Sources Used/Available
*All tables below are from **Transportation Energy Data Book** (Edition 26, 2007)[26] published by the US Department of Energy's Oak Ridge National Laboratory.*	
Average fuel economy	Tables 4.17 and 4.18
New Vehicle Efficiency	Tables 4.7 and 4.8
Scrap/Survival Rates	Tables 3.8, 3.9 and 3.10
Freight Truck Fuel Economy	Tables 5.1 and 5.2
Bus Efficiency	Table 2.13
Rail Efficiency – Passenger	Table 9.10 and 9.11
Rail Efficiency - Freight	Table 9.8
Marine – Freight	Table 9.5
Air Travel	Table 9.2

The model reflects the most recent changes in new passenger vehicle in CAFÉ standards, as embodied in the *Energy Independence and Security Act of 2007* (see section 4.8).

Off road transportation energy use in ENERGY 2020 is driven by activity in the Agriculture, Forestry and Construction sectors.

3.7 *Built Environment*

ENERGY2020 has been used to model energy for almost three decades. Much of the data on energy efficiency and costs was originally based on information provided by the Energy Information Administration's *Annual Report to Congress*[27] which was last published in 1980. Over the years, these data has been updated based on information gathered from clients as part of numerous projects. The resulting cost and efficiency data is used as default values in the model.

When a new model is built for a particular project, actual historic energy use is input to the model (generally from the EIA SEDS database) and allocated by sector based on census region data from the most recent energy surveys available from the EIA (e.g. Residential Energy Consumption Survey, Commercial Building Energy Consumption Survey, etc). Average and maximum device efficiencies are adjusted within the model over time in calibrating to this actual

[25] http://cta.ornl.gov/data/download26.shtml
[26] http://cta.ornl.gov/data/download26.shtml
[27] EIA, Annual Report to Congress, 1980: Volume 3. Energy Information Administration, USDOE, Report #: DOE/EIA-0173(80)/3.

energy use data. For the WCI project, ICF and SSI have subjected these data to an internal review and updated the values based on expert opinion and data from a variety of sources.

Appendix J presents the assumptions used in modeling the residential and commercial sectors, showing assumed levels of efficiency by period, maximum efficiency levels, initial and operating costs per mmBtu of energy use and device lifetimes for each end use for each fuel type. This data is used in the choice curves within the model.

Several of the jurisdictions involved in the WCI have had a long history of promoting energy efficiency and demand side management for electricity and natural gas energy use. As a result, average appliance and equipment efficiencies are expected to be higher than for the US and Canada as a whole. Where data permits, end-use data within the model has been adjusted to reflect current levels of efficiency and market saturations.

The Reference Case does not assume any increase in equipment or appliance efficiency other than the improvements due to the *Energy Independence and Security Act of 2007*, as noted in section 4.8.

3.8 *Programs/Policies Incorporated in Reference Case*

The *Energy Independence and Security Act of 2007* was passed into law in early January 2008. The following assumptions will be used to model the Act in the Reference Case:

- Renewable Fuels: The Act specifies a minimum volume of biofuels to be produced each year. For modeling purposes we have assumed that this volume of biofuels is produced and consumed in each year. The model assumes that each of the US states will use their pro-rata share of the available fuels.
- Residential Boilers and Furnace Fans: Savings estimates developed by the ACEEE for each state has been used to model this portion of the Act, using only the benefits realized by upgrades to the residential energy boilers, leaving out any energy benefits associated with reduced electricity consumption by furnace fans.
- Walk-In Coolers and Walk-In Freezers: Savings estimates developed by the ACEEE for each state has been used to model this portion of the Act.
- Electric Motor Efficiency Standards: The model will utilize the ACEEE savings projections, pro-rated to each states relative industrial electricity sales.
- External Power Supply Efficiency Standard: savings estimates developed by the ACEEE for each state have been used to model this portion of the Act.
- Energy Efficient Light Bulbs: The base assumptions are that general service lighting accounts for about 90% of residential lighting, 10% of commercial lighting and 5% of industrial lighting.
- Metal Halide Lamp Fixtures: The model assumes that 15% of commercial lighting and 60% of industrial lighting now use metal halide fixtures. For new installations the model assumes that 80% of this market would use pulse start ballasts.

On May 19, 2009, the Obama administration announced its intention to establish standards for vehicle GHG emissions and CAFÉ standards which would align with the GHG emission standards previously proposed by California. As a result, a national standard will be established which will require the fuel efficiency of new passenger cars and light trucks to reach an average fleet efficiency of 35.5 mpg by 2016. For modeling purposes we have assumed a fixed percentage increase in the efficiency of new vehicles each year starting in 2010 to reach the mandated level by 2016. Information relating to the cost of implementing this policy was based on estimates by the NHTSA[28]. We have assumed that fleet efficiency will continue to increase beyond 2016 but have included that increase in the complementary policies.

For the Canadian provinces, the model assumes that existing requirements for biofuels are met. Existing legislation requires that all gasoline sold in Canada contain 5% ethanol by 2012 and that all fuel oil and diesel contain 2% biofuels by 2010.[29]

The reference case includes Renewable Portfolio Standards for each US state as well as renewable energy targets established by Canadian provinces. Please refer to Appendix I for summaries of each jurisdiction's RPS.

3.9 Alternate Reference Case

In testing the sensitivity of the analysis to different assumptions the EMT decided to model an "Alternate Reference Case." This Alternate case involved changing three assumptions in the main Reference Case:

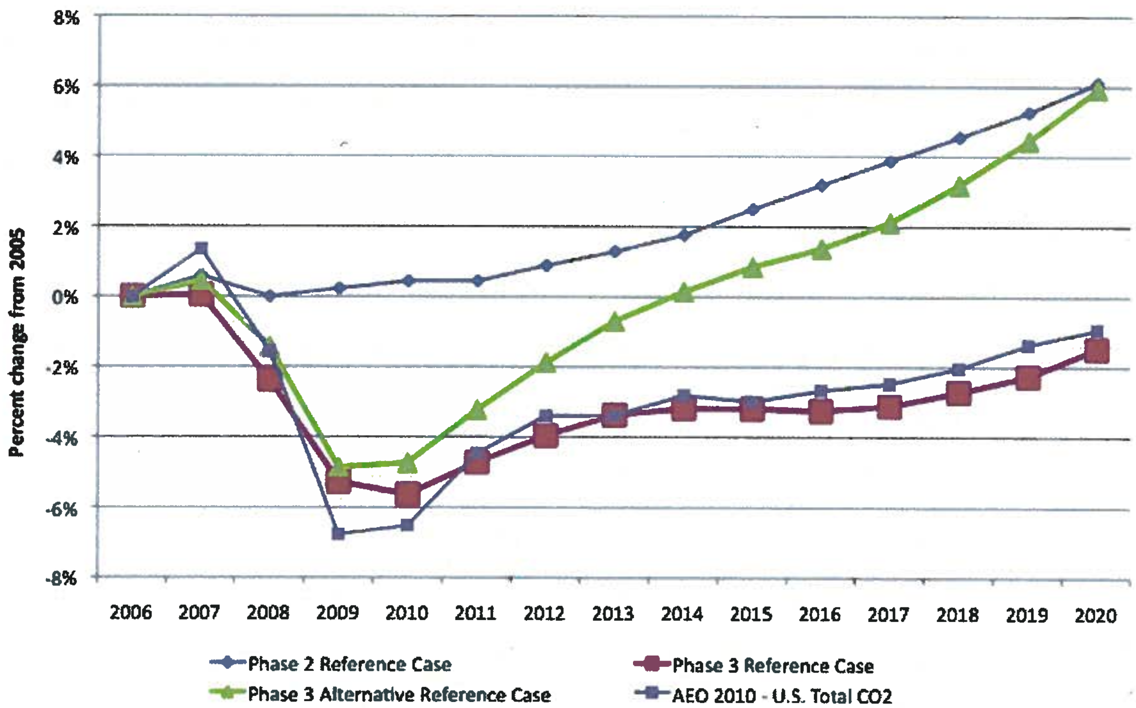
1. That the economy would grow more rapidly; adding 0.5% per year growth starting in 2010.
2. That the biofuels mandate established by the US Energy Independence and Security Act (EISA) will not be fully met by 2020. Instead, the Alternate Reference assumes the level of biofuels reflected in the US Annual Energy Outlook (AEO) 2009.
3. Given uncertainties around the future price of oil and gas, the Alternate Reference assumes that prices follow a trajectory mid-way between the reference and low energy price scenario presented in the AEO 2009.

All of these 'alternate' assumptions have the effect of increasing the base level of GHG emissions relative to the base Reference Case. The comparison between the two cases is shown below.

[28] NHTSA, Corporate Average Fuel Economy Rulemaking, Document No. WP.29-145-13, June 2008, see also: NHTSA, Final Environmental Impact Statement, Corporate Average Fuel Economy Standards, Passenger Cars and Light Trucks, Model Years 2011 to 2015, October 2008.

[29] Renewable Fuels Strategy: ecoENERGY for Biofuels. Canada Gazette: http://canadagazette.gc.ca/partI/2006/20061230/html/notice-e.html#i3

Assumption	Base Reference Case	Alternative Reference run
Economic growth	Accounts for economic recession based on January 2009 Congressional Budget Office forecast	Faster economic growth to assess implications of a stronger than expected recovery
Fuel price forecast	AEO 2009 mid case	Average of AEO 2009 mid and low cases. Lower fuel prices results in more fuel consumption
Energy efficiency program impacts (used in complementary policy run)	Reduced demand for electricity and natural gas by 0.5% per year	Reduced demand for electricity and natural gas by 1.0% per year



4 Complementary Policies

It is expected that a number of programs to increase energy efficiency and reduce energy requirements will be introduced in conjunction with any cap-and-trade system implemented. These policies would complement the cap-and-trade system to assist in meeting GHG reduction goals. While it is expected that each partner will introduce its own particular set of policies to achieve these reductions, a *Complementary Policies* scenario was modeled that includes the following WCI-wide policies. These policies are in addition to any existing policies represented in the Reference Case or Alternate Reference. Some of these policies were modeled differently for the Reference Case and the Alternate Reference, as described below:

- **Vehicle Miles Traveled** – The combined effect of transportation and fuel programs recently put in place and being pursued is assumed to be equivalent to reducing vehicle miles traveled (VMT) by 2 percent from the reference case by 2020, beginning in 2008.

- **Energy Efficiency Programs** – The combined effect of energy efficiency programs recently put into place and being pursued (affecting the use electricity, natural gas, fuel oil and propane) are assumed to reduce energy use by *one-half of one percent in each year* below the reference forecast between 2012 and 2020. This change was introduced through increases to process and device efficiencies across the residential, commercial and industrial sectors. The costs of actual equipment upgrades associated with these efficiency gains are captured in the model. However, program and administration costs are not modeled by ENERGY 2020. The costs associated with implementing such a program could be funded through auction revenues. In the **Alternate Reference case**, which includes more robust economic growth, efficiency programs are assumed to reduce growth in energy use by *one percent each year* over the same period.

    - **Efficiency Improvement** - In order to translate this policy into modeling terms, ICF/SSI assumed that the increase in efficiency would be implemented across all sectors (residential, commercial and industrial) and all end uses. Through an iterative process, operating this policy on a stand-alone basis, we determined a level of efficiency gain for marginal devices for each year that would achieve the targeted reduction in energy use. The increase in efficiency was introduced into the model through a multiplier applied evenly across processes and devices.

    - **Economies of Scale** - An assumption was made that as more efficient devices were required, the cost of devices would benefit from economies of scale; shifting the cost curve for the efficiency improvement down.

      For modeling purposes the EMT directed that the economies of scale achieved as these technologies gain market share be limited to no more than 10% reduction in cost. In addition, the model will be constrained such that this reduction does not bring the cost of more efficient devices to a level below the cost for standard devices with current levels of efficiency.

    - **Retrofits** - No retrofits, or premature retirements of existing equipment, were assumed in the modeling. The efficiency improvements required to meet the policy target were assumed to take place at the margin. In ENERGY 2020 devices and processes are each continually replaced with assumed lifetimes of less than 20 years so at least 5% of the devices and processes are replaced each year.

    - **Process Efficiency Impacts on Device Investments** – Changes in process efficiency generally reflect changes in the level of energy service required (e.g. the amount of lighting reduced due to day-lighting or improved design or water heating needs reduced due to more efficient end-use devices). To the extent the process efficiency increases, this tends to lower the level of device investment required in these end uses; as lower lighting requirements are reflected in fewer new fixtures being required. For modeling purposes, we have assumed that 30% of the efficiency gains attained under the complementary policy will come from process efficiency gains, while 70% come from device efficiency gains.

- **Vehicle Efficiency Improvements** – The efficiency improvements included in the Reference Case (described above) result in new vehicle efficiency improvements until 2016. While no further improvements beyond that time are required under current law or regulation, the EMT has assumed that all WCI Partner jurisdictions will require continued improvements in vehicle efficiency through to 2020. The assumed improvement between 2016 and 2020 is based on emission reductions currently contemplated by the California ARB in its Scoping Plan.[30] This would increase the average efficiency of new cars and light trucks to 42.5 mpg by 2020.[31] The change in vehicle costs required to meet this standard are based on estimates by the California Air Resources Board.[32]

- **Ontario Coal Phase-out** – Assumes that Ontario phases out its coal-fired electricity generation by 2015, replacing it with hydro and wind power.

5 Sensitivity Analyses

The EMT ran several sensitivity cases to test the effects of different assumptions regarding the effectiveness of the complementary policies, economic forecasts, fuel prices and electricity generation costs, and growth rate of allowance prices.

5.1 *Sensitivity Case: Half-Effectiveness of Complementary Policies*

The purpose of this sensitivity case is to examine what happens if the energy efficiency and VMT programs achieve only half of their assumed emission reductions. Specifically, this case assumes that:

- The energy efficiency programs reduce the rate of growth in electricity and natural gas demand by only 0.25 percent per year, starting in 2012.
- Vehicle miles traveled decrease by only 1 percent from the reference case by 2020.
- The clean car standards are unchanged.
- The Ontario coal phase-out is unchanged.

5.2 *Sensitivity Case: Alternative Economic Forecast*

The purpose of this sensitivity case is to examine the implications of a different economic forecast than that assumed in the main policy case. The alternative economic forecast is described in a previous section.

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[30] California Air Resources Board, Climate Change Scoping Plan: a Framework for change, December 2008 Discussion Draft, Pursuant to AB 32: The California Global Warming Solutions Act of 2006.

[31] California Air Resources Board, Comparison of Greenhouse Gas Reductions for the United States and Canada under U.S. CAFÉ Standards and California Air Resources Board Greenhouse Gas Regulations – An Enhanced Technical Assessment, 25 February 25, 2008.

[32] California Environmental Protection Agency, Air Resources Board, Regulations to Control Greenhouse Gas Emissions from Motor Vehicles, Final Statement of Reasons, August 4, 2005.

5.3 *Sensitivity Case: High Fuel Prices and Electricity Generation Costs*

The purpose of this sensitivity case is to examine the implications of energy prices being higher than assumed in the main policy case. There has been considerable stakeholder comment that the energy price forecast in the main policy case may be too low. Additionally, some stakeholders have commented that the power generation cost assumptions may be too low, indicating that recent increases in commodity prices have had an impact on these costs. This sensitivity case includes both increased energy prices and increased power generation costs as a set of conditions that could occur together in the future. In this case, energy prices are assumed to start at 2008 prices and increase in real terms by 50% by 2020, and capital and O&M costs for power generation are assumed to be 30% higher than in the main policy case. This case required its own reference and complementary policies runs.

5.4 *Sensitivity Case: 4% Annual Growth In Allowance Prices*

The purpose of this sensitivity case is to examine the implications of a slow-rising allowance price trajectory. This case uses a growth rate in the allowance price of 4 percent per year instead of 8 percent per year in the cases discussed above.

5.5 *Sensitivity Case: 12% Annual Growth In Allowance Prices*

The purpose of this sensitivity case is to examine the implications of a faster-rising allowance price trajectory. This case uses a growth rate in the allowance price of 12 percent per year instead of 8 percent per year in the cases discussed above.

Appendix A: The ENERGY 2020 Model

The Model – ENERGY 2020

ENERGY 2020 is an integrated multi-region, multi-sector energy analysis system that simulates the supply, price and demand for all fuels. It is a causal and descriptive model, which dynamically describes the behavior of both energy suppliers and consumers for all fuels and for all end-uses. It simulates the physical and economic flows of energy users and suppliers. It simulates how they make decisions and how those decisions causally translate to energy-use and emissions.

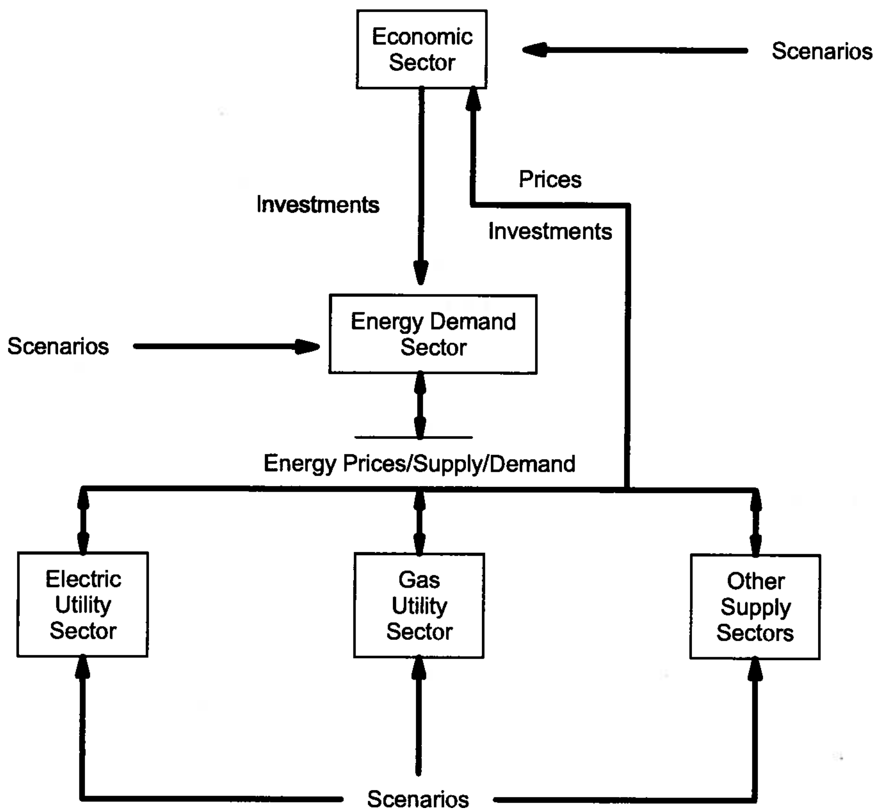
ENERGY 2020 is an outgrowth of the FOSSIL2/IDEAS model developed for the US Department of Energy (DOE) and used for all national energy policy since the Carter administration.[33] This early version of ENERGY 2020 was developed in 1978 at Dartmouth College for the DOE's Office of Policy Planning and Analysis.

Model Overview:

The basic structure of ENERGY 2020 is provided in Figure 1.1. Energy Demand sector interacts with the Energy Supply sector to determine equilibrium levels of demand and energy prices. Energy Demand is driven by the Economy sector, which in turn provides inputs to the Economy sector in terms of investments in energy using equipment and processes and energy prices. The model has a simplified Economy sector to capture the linkages between the energy system and the macro-economy. However, the model is best run with full integration with a macroeconomic model such as REMI. Given the modular nature of ENERGY 2020, additional sectors or modules from other, non-ENERGY 2020 related, models (macroeconomic, supply such as oil, gas, renewables etc.) can be incorporated directly into the ENERGY 2020 framework.

[33] *FOSSIL2 was the original version but was renamed to IDEAS a few years ago to reflect its evolutionary development since its original construction.*

Figure 1.1: ENERGY 2020 Overview



Energy Demand:

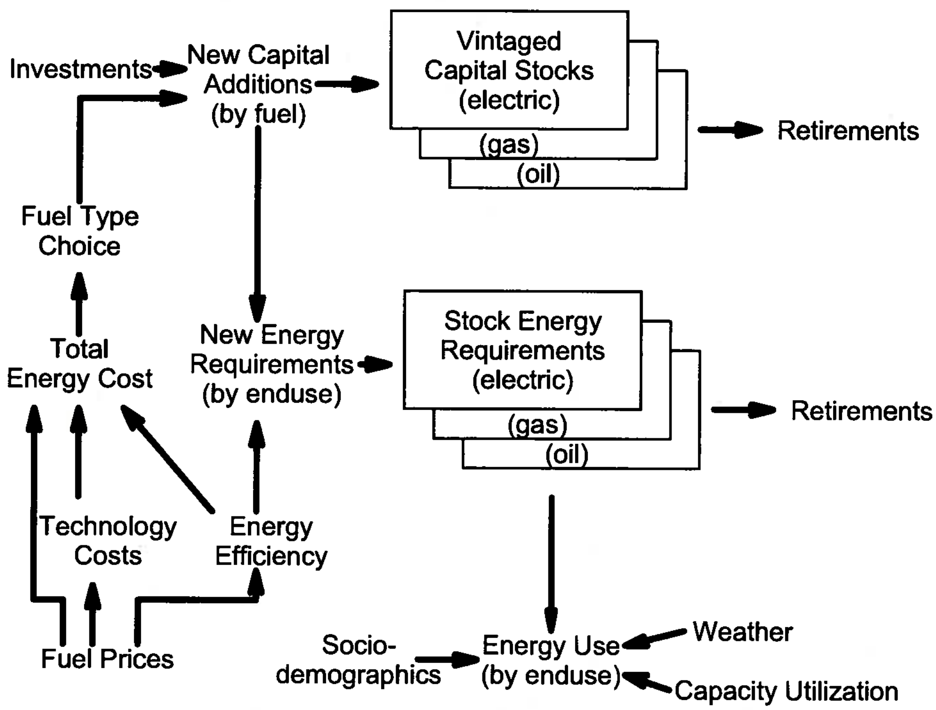
The demand sector of the model represents the geographic area by disaggregating the four economic sectors into subsectors based on energy services. As many or as few subsectors can be incorporated as required. Multiple technologies, multiple end-uses and multiple fuels are detailed. The level of detail that can be incorporated is of course subject to the data availability. The four economic sectors are:

- Residential sector which includes three classes, single family, multifamily and rural/agricultural with 8 end-uses including space heating, water heating, lighting, cooling, refrigeration, other substitutable, and other non-substitutable.
- Commercial sector which is aggregated into one class and end-uses including space heating, water heating, cooling, lighting, other substitutable, other non-substitutable.
- Industrial sector which includes 10 (23 for US) 2-digit SIC categories and is further broken down into process heat, motors, lighting, miscellaneous as the end uses.
- Transportation sector which includes several modes of transportation including automobile, truck, bus, train, plane, marine and electric vehicles. Also, each of the residential, commercial and industrial sectors has separate transportation demands.

For each of the end-uses, up to six fuels are modeled, for example, the residential space heating has the choice of a gas, oil, coal, electric, solar and biomass space heating technologies. Added end-uses, technologies and modes can be added as data allow. For all end-uses and fuels, the model is parameterized based on historical locale-specific data. The load duration curves are dynamically built up from the individual end-uses to capture changing condition under consumer choice and combined gas/electric programs.

A few basic concepts are crucial to an understanding of how the model simulates the energy system. These concepts including, the capital stock driver, the modeling of energy efficiency through trade-off curves, the fuel market share calculation, utilization multipliers and the cogeneration module are discussed below in abbreviated form. Figure 1.2 (Demand Overview) illustrates the demand sector interactions.

Figure 1.2: Demand Overview



Energy Demand as a Function of Capital Stock:

The model assumes that energy demand is a consequence of using capital stock in the production of output. For example, the industrial sector produces goods in factories, which require energy for production; the commercial sector requires buildings to provide services; and the residential sector needs housing to provide sustained labor services. The occupants of these buildings require energy for heating, cooling, and electromechanical (appliance) uses.

The amount of energy used in any end-use is based on the concept of energy efficiencies. For example, the energy efficiency of a house along with the conversion efficiency of the furnace determines how much energy the house uses to provide the desired warmth. The energy efficiency of the house is called the capital stock energy or process efficiency. This efficiency is primarily technological (e.g. insulation levels) but can also be associated with control or life-style changes (e.g. less household energy use because both spouses work outside the home.) The furnace efficiency is called the device or thermal efficiency. Thermal efficiency is associated with air conditioning, electromotive devices, furnaces and appliances.

The model simulates investment in energy using capital (buildings and equipment) from installation to retirement through three age classes or vintages. This capital represents embodied energy requirements that will result in a specified energy demand as the capital is utilized, until it is retired or modified.

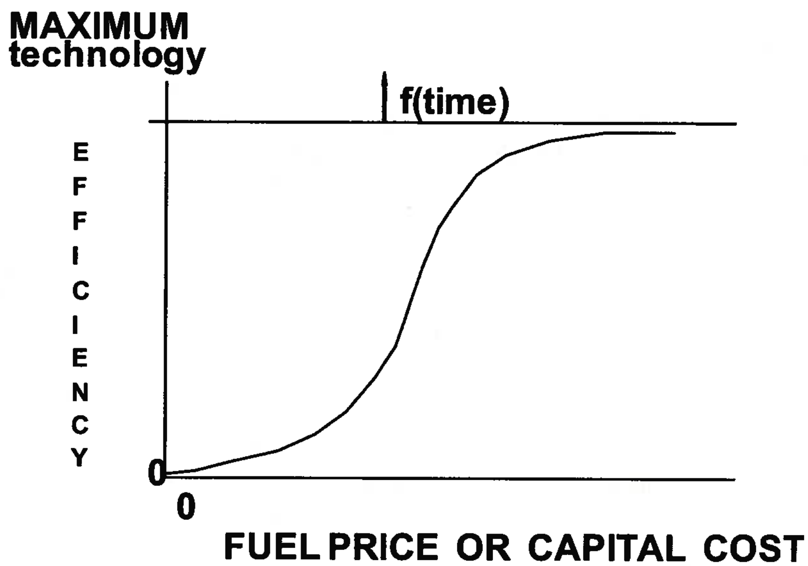
The size and efficiency of the capital stock, and hence energy demands, change over time as consumers make new investments and retire old equipment. Consumers determine which fuel and technology to use for new investments based on perceptions of cost and utility. Marginal trade-offs between changing fuel costs and efficiency determine the capital cost of the chosen technology. These trade-offs are dependent on perceived energy prices, capital costs, operating costs, risk, access to capital, regulations and other imperfect information.

The model formulates the energy demand equation causally. Rather than using price elasticities to determine how demand reacts to changes in price, the model explicitly identifies the multiple ways price changes influence the relative economics of alternative technologies and behaviors, which in turn determine consumers' demand. In this sense, price elasticities are outputs, not inputs, of the model. The model accurately recognizes that price responses vary over time, and depend upon factors such as the rate of investment, age and efficiency of the capital stock, and the relative prices of alternative technologies.

Device and Process Energy Efficiency:

The energy requirement embodied in the capital stock can be changed only by new investments, retirements, or by retrofitting. The efficiency with which the capital uses energy has a limit determined by technological or physical constraints. The trade-off between efficiency and other factors (such as capital costs) is depicted in Figure 1.3 (Efficiency/Capital Cost Trade-Off). The efficiency of the new capital purchased depends on the consumer's perception of this trade-off. For example, as fuel prices increase, the efficiency consumers choose for a new furnace is increased despite higher capital costs. The amount of the increase in efficiency depends on the perceived price increase and its relevance to the consumer's cash flow.

Figure 1.3: Efficiency/Capital Cost Trade-Off



The standard the model efficiency trade-off curves are called consumer-preference curves because they are estimated using cross-sectional (historical) data showing the decisions consumers made based on their perception of a choice's value. Many planners are now interested in measure-by-measure or least-cost curves which use engineering calculations and discount rates to show how consumers should respond to changing energy prices. Another analysis focuses on the technical/price differences in alternative technologies and the incentives needed to increase the market-share or market penetration of a specific technology. This perspective on the choice process uses market share curves. The model allows the user to select any of these three types of curves to represent the way consumers make their choices. Shared savings, rebate, subsidy programs, etc. can be tested using any of the curves.

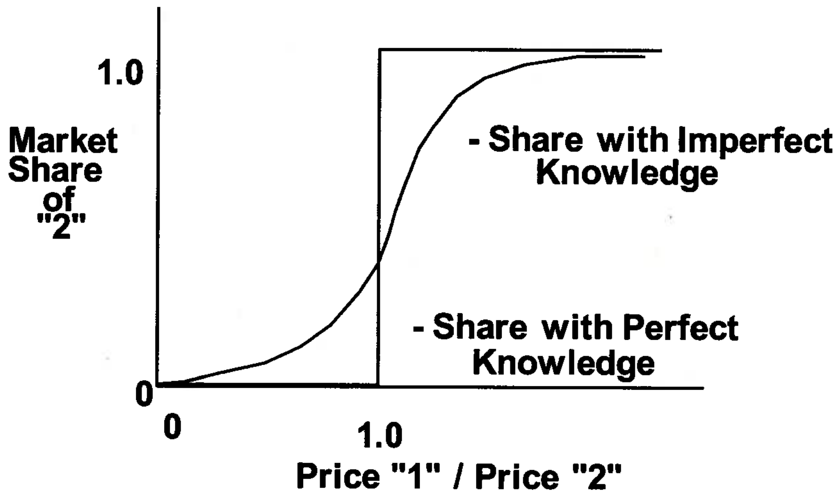
Cumulative investments determine the average embodied efficiency. The efficiency of new investments versus the average efficiency of existing equipment is one measure of the gap between realized and potential conservation savings.

The model uses saturation rates for devices to represent the amount of energy services necessary to produce a given level of output. Saturation rates may change over time to reflect changes in standard of living or technological improvements. For example, air conditioning has historically increased with rising disposable incomes. These rates can be specified exogenously or can be defined in relation to other variables within the model (such as disposable income).

The Market Share Calculation:

Not all investment funds are allocated to the least expensive energy option. Uncertainty, regional variations, and limited knowledge make the perceived price a distribution. The investments allocated to any technology are then proportional to the fraction of times one technology is perceived as less expensive (has a higher perceived value) than all others. This process is shown graphically in Figure 1.4 (Market Share Dynamics).

Figure 1.4: Market Share Dynamics



Short Term Budget Responses:

A short-term, temporary response to budget constraints is included in the model. Customers reduce usage of energy if they notice a significant increase in their energy bills. The customers' budgets are limited and energy use must be reduced to keep expenditures within those limits. These cutbacks are temporary behavioral reactions to changes in price, and will phase out as budgets adjust and efficiency improvements (true conservation) are implemented. This causes the initial response to changing prices to be more exaggerated than the long-term response, a phenomenon called "take-back" in studies of consumer behavior.

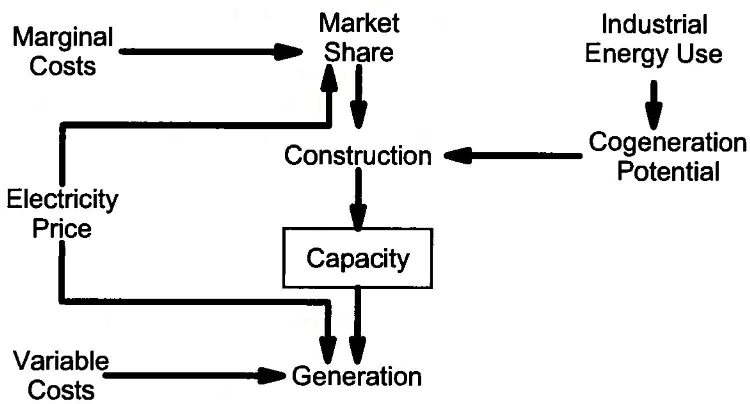
Accounting for Fungible Demand:

Some furnaces and processes can use multiple fuels. That is, they can switch almost instantaneously between, for example, gas and oil or coal and biomass as prices or the market dictates. Energy demand that is affected by this short-term fuel switching phenomena is called fungible demand. The model explicitly simulates this market share behavior.

Modeling Cogeneration:

Most energy users meet their electricity requirements through purchases from a utility. Some users (industrial and commercial) can, however, convert some of their own waste heat into usable electricity when economics warrant such action. Other users (residential and commercial) can purchase self-generation energy sources such as gas turbines, diesel-generators or fuel cells. Figure 1.5 shows a simplified overview of the cogeneration structure.

Figure 1.5: Cogeneration Concepts



In the model all energy used for heating is a candidate for cogeneration. The cost of cogeneration is the fixed capital cost of the investment plus the variable fuel costs (net of efficiency gains). This cogeneration cost is estimated for all technologies and compared to the price of electricity. The marginal market share for each cogeneration technology is based on this comparison.

Cogeneration is restricted to consumers who directly produce part of their own electricity requirement. Companies which generate power primarily for resale to the electric utility are considered independent power producers and are included in the electric supply model.

Energy Supply:

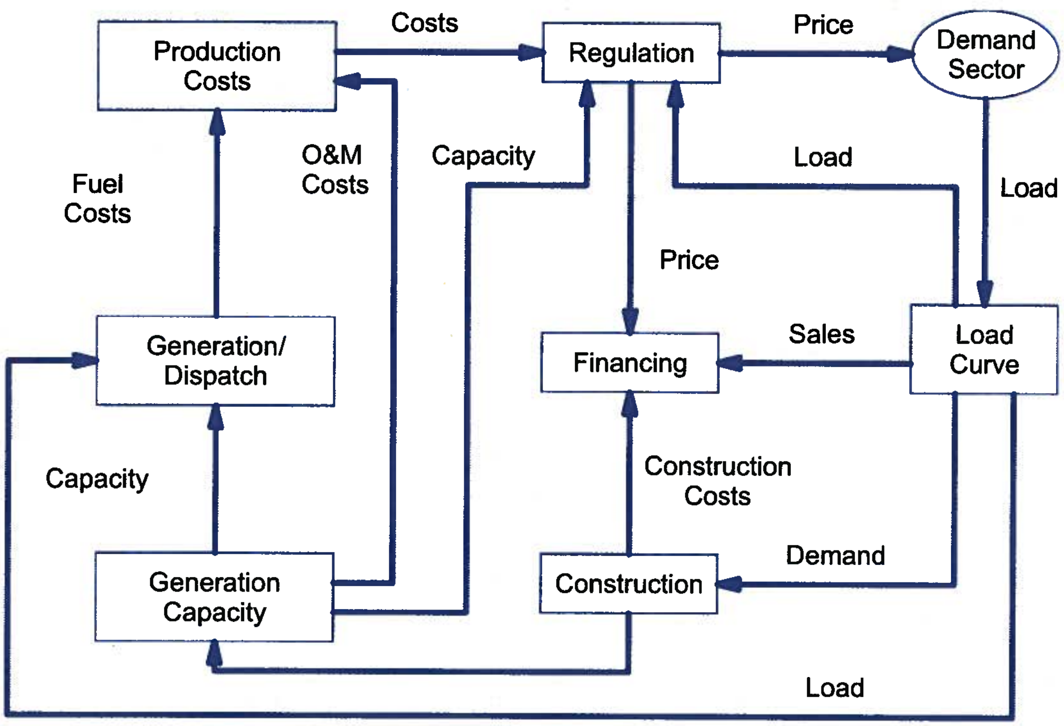
For electric and gas utilities (separate or combined), ENERGY 2020 internally and self-consistently simulates sales, load (by end-use, time-of-use, and class), production (across thirty-six dispatch types), demand-side management (by technology), forecasting, capacity expansion (new generation, independent power producers, purchases, and DSM), all important financial variables, and rates (by class, end-use, and time-of-use.)

The version currently used in this analysis only has the electricity utility sector (a full fledged natural gas utility sector for Canada is currently unavailable in the model, only a simplified natural gas supply function is used to calculate the supply price response).

With the inclusion of the electric utility sector, the generic supply model turns over the calculation of electricity prices to that sector. The model is capable of endogenously simulating the forecasting of capacity needs, as well as the planning, construction, operation and retirement of generating plants and transmission facilities. Each step is financed in the model by revenues, debt, and the sale of stock. The simulated utility, like its real world counterpart, pays taxes and generates a complete set of accounting books. In ENERGY 2020, the regulatory function is modeled as a part of the utility sector. The regulator sets the allowed rate of return, divides revenue responsibility among customer classes, approves rate base, revenues and expenses, and sets fuel adjustment charges.

The interactions in the electric utility sector are summarized in Figure 1.6

Figure 1.6: Electric Utility Structure Overview



Expansion Planning:

The utility sector endogenously forecasts future demand for electricity. From the forecast it projects the future capacity required meeting future demand by taking into account retirements and plants already under construction. Construction of additional capacity is initiated if future electricity requirements, including reserves, are forecast to exceed available capacity (using seasonal ratings).

If additional capacity is needed to meet forecasted needs, the basic capacity expansion module in ENERGY 2020 determines whether base or peaking capacity is required. The model determines the maximum number of hours that new peaking capacity can be economically operated, before it would be less expensive to construct and operate base load capacity instead. If the forecasted peaking capacity would operate more than that economic maximum, base loads units are initiated, otherwise peaking units are initiated. Any plant type including geothermal, wind, biomass and storage can be considered.

New plants, of a pre-specified minimum size, are initiated when the reserve margin would be violated if the plants were not built or if base load capacity is inadequate to serve base load energy needs at the end of the forecast period. The model does allow the minimum reserve margin to be temporarily violated at the peak if new base load capacity is scheduled to be available within the year. Peaking units are allowed to serve more than the maximum economical number of hours until base load capacity comes on-line.

Minimum plant size is exogenous. The mix of new base load plants (i.e. alternative coal technologies, hydro, or nuclear) is user-specified in the standard ENERGY 2020 configuration. The model also evaluates the financial implications of new construction, including total construction costs, cost schedules, and AFUDC/CWIP. The gross rate on AFUDC equals the weighted average cost of capital. The actual construction progress and financial impacts are simulated on a year by year basis.

ENERGY 2020 can also be configured to consider intermediate load units, firm purchases contracts, external sales, independent power producers, and demand-side options. These options can be optionally selected based on endogenous least-cost analysis or can be chosen by user-specified criteria to meet. A detailed automatic Integrated Resource Planning module that would endogenously choose (with user control) from DSM measures utility and non-utility generation and purchase alternatives using linear programming techniques is now being offered as an enhancement.

Financing:

The ENERGY 2020 utility finance sub-sector simulates the activities of a utility's finance department. It forecasts funding requirements and follows corporate policies for obtaining new funds. The model simulates borrowing and issuing of stock, and can repurchase stock or make investments if it has excess cash. Cash flows are explicitly modeled, as are any decision that affects them. Coverage ratios, intermediate- and long-term debt limits, capitalization, rates of return, new stock issues, bond financing, and short-term investments are endogenously calculated. The model keeps track of gross, net, and tax assets. It also calculates the depreciation values used for the income statement and tax obligations.

For this project, this element of the model is not used, and a simpler approach to estimating retail electricity prices is used.

Regulation:

The utility sector sets electricity prices according to regulatory requirements. The regulatory procedures use allowed rate-of-return and test year cost and demands to determine allowed revenues. Electricity prices are calculated from peak-demand fractions by allocation of costs. Any other allocation scheme can also be considered. The regulatory sub-sector of ENERGY 2020 automatically factors in a wide variety of regulatory policies and options. More importantly, the model can be readily modified to consider a wide spectrum of scenarios.

The regulatory process revolves around a test year, usually one year forward, when proposed rates will go into effect. The utility sector forecasts test year sales and peak demands by season and customer class, just as it does to determine capacity needs. These test year demand estimates are used to allocate responsibility for system peak, and therefore, generation capacity costs.

Fuel costs for the test year are estimated by dispatching the plants that will be available in the test year, using the dispatching routine explained below. Fuel costs and operating and maintenance costs are adjusted for expected inflation, and these costs are factored into the electricity rates using forecasted sales.

ENERGY 2020 calculates the utility rate-base according to a detailed conventional rate making formula. The model allows the user to adjust allowable costs, and has been used extensively to evaluate alternative rate-base scenarios for individual plants, including allowing return of, but no return on investment, and partial disallowment of construction and interest costs.

The ENERGY 2020 system also includes estimation of avoided costs, which determines when the utility may be required to purchase third party power. Environmental constraints, such as air pollution restrictions, can also be included in the model. If ENERGY 2020 is configured as a regional or state-wide system, municipal utilities, with their unique tax and rate structures, are incorporated. Similarly, regional or power pool interchange is also recognized by ENERGY 2020. As with the other sectors of ENERGY 2020, the regulatory subsector is flexible enough to accommodate any existing or hypothetical circumstance.

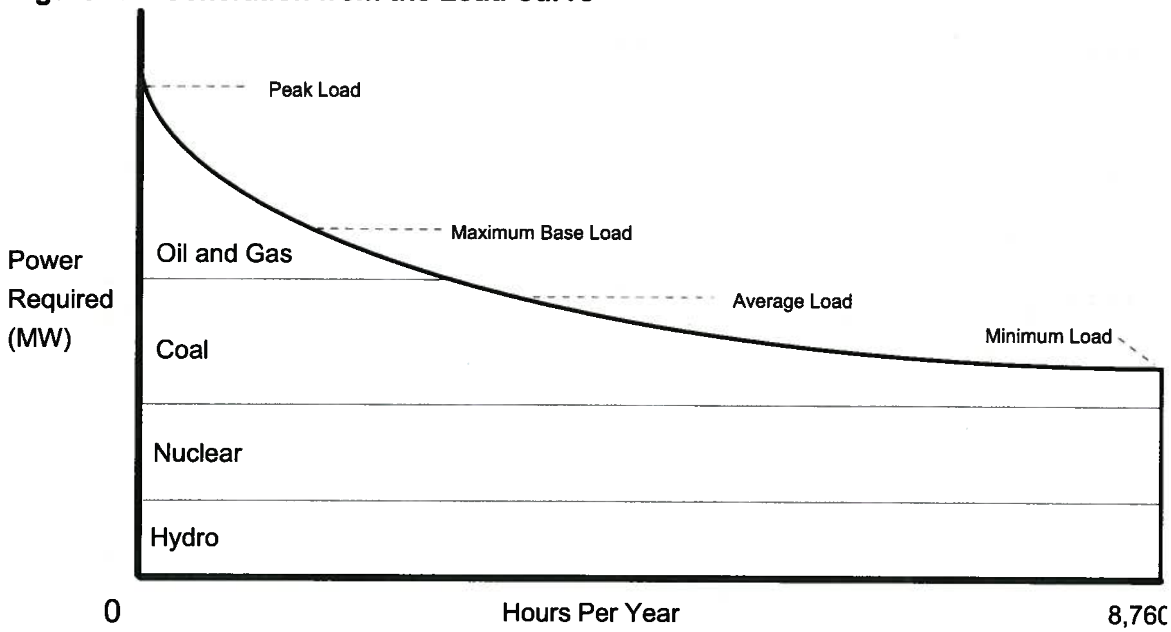
For this project, this element of the model is not used, and a simpler approach to estimating retail electricity prices is used.

Operations:

Each end-use in ENERGY 2020 has a related set of load shape factors. Typically, these factors define the relationship between peak, minimum and average load for each season. These factors when combined with the weather-adjusted energy demand by end-use and corrected for cogeneration, resale, and load management programs, form the basis of the approximated system load duration curve. Alternatively, unit hourly loads for each end-use for three days per month (average weekday, weekend and peak weekday) are used.

The standard ENERGY 2020 production subsector uses an advanced de-rating or chronological method to estimate the seasonal or hourly dispatch of plants. It purchases power externally when economic or necessary. Plant availability and generation for coal, nuclear, hydroelectric, oil and gas are currently considered, as well as pumped storage, firm purchases, interruptible load, and fuel switching and qualified facilities. Figure 1.7 also shows a typical plant dispatch schedule.

Figure 1.7: Generation from the Load Curve



The ENERGY 2020 system estimates conventional fuel costs based on the unit dispatch, heat rates, and fuel prices (from the supply sector.) Nuclear fuel costs are capitalized and depreciated throughout the re-fuelling cycle. Nuclear fuel expenses also include fuel disposal costs.

ENERGY 2020 explicitly models the costs of maintaining the transmission and distribution (T&D) system. New facility investments are scheduled and incurred endogenously. In addition, the user can specify the decision rules that dictate T&D expenditures. ENERGY 2020 also explicitly models both fixed and variable operation and maintenance costs, power pool interchanges, nuclear decommissioning costs, plant capital additions, plant cancellations, and general administration costs.

Model Applications:

The structure of the model is well tested and has been used to simulate not only US and the Canada energy and environmental dynamics but also those of several countries in Western, Central and Eastern Europe. Current efforts include strategic and tactical analyses for South America deregulation. Further, the model has been used successfully for deregulation analyses in over 50 energy suppliers and in all the US states and Canadian provinces. Several US and Canadian energy suppliers currently use the model for the analysis of combined electricity and gas deregulation dynamics.[34] The model contains confidence and validity packages that allow it to determine how to take maximal advantage of RTO rules. The ISO NE used the model to find gaps in its rules and to develop more efficient market conditions. The model was used for the CAPX/ISO to model to show, before the fact, many of the "games" played in the California market.

[34] *ENERGY 2020 is the only model known to have simulated and predicted the dynamics that occurred in the UK electric deregulation. These include gaming, market consolidation and re-regulation dynamics.*

Appendix B: Data Sources

The following describes the default data sources used in ENERGY 2020. Where these data has been replaced by jurisdiction-specific information, the jurisdiction-specific data is described in the main body of the document.

Historical Energy Prices and Demands
Historic energy prices and demands are from *State Energy Data*, Integrated Energy Statistics Divisions of the Office of Energy Markets and End Use, Energy Information Administration, USDOE. This document provides annual time series estimates of State-level energy consumption, prices, and expenditures by major economic sectors. In 2000, the *State Energy Data* replaced two former EIA reports: State Energy Data Report (SEDR) and State Energy Price and Expenditure Report (SEPER). Tables by major economic sector can be found at: http://www.eia.doe.gov/emeu/states/_states.html. New tables by energy source can be found at: http://www.eia.doe.gov/emeu/states/multi_states.html.

Future Energy Prices
To estimate future energy prices, we apply the forecasted price growth rates from the *Annual Energy Outlook (AEO) 2008* to the prices from the last historical year (obtained from *State Energy Data*). The Annual Energy Outlook 2008 presents a forecast and analysis of US energy supply, demand, and prices through 2030.
http://www.eia.doe.gov/oiaf/aeo/supplement/index.html

Note that there is a gap between the most recently reported historical year of data and the first forecast year. We resolve this by including one year's worth of price data from the AEO of the previous year.

Future Energy Demands
Future energy demands are computed by the model, but the model can calibrate to future energy demands if desired. In this project, the model projections have been compared to other forecasts but have not been calibrated to any other forecast.

Device Energy Efficiency Standards
Device efficiency standards come mainly from the *Energy Policy Act of 1992*, with some efficiencies coming from other selected sources.
http://energy.navy.mil/publications/law_us/92epact/hr776toc.htm
This initial base of efficiency standards have been updated as new regulations have come into effect. Requirements in the ***Energy Independence and Security Act*** have also been included in the Reference Case.

Device Capital Cost, Efficiency, and Device Lifetimes; Cogeneration Capital Costs, Heat Rates and Parameters
These values were originally developed from the *Annual Report to Congress, 1980: Volume 3.* Energy Information Administration, USDOE, Report #: DOE/EIA-0173(80)/3. ICF and SSI have reviewed and updated these data which is used to provide the shape of choice curves within the model based on expert opinion and data from a variety of sources. The values used are presented in Appendix J.

End-Use Load Shapes
The end use load shapes were originally based on 1995 NEPOOL published reports. Load shapes for temperature sensitive loads are modified based on actual weather data for the state/region being modeled.

Industrial Energy Splits, Industrial End Use Splits and Commercial End-Use Splits
The energy that we obtain from *State Energy Data* is a total value that needs to be split among different industries and/or uses (end use demands, cogeneration demands, feedstock demands). We obtain the splits among industries and uses from the *Manufacturing Energy Consumption Survey*, Energy Information Administration, USDOE. The Manufacturing Energy Consumption Survey is conducted every five years and provides detailed data on energy consumption in the manufacturing sector. http://www.eia.doe.gov/emeu/mecs/contents.html

Residential Devices Saturations and Market Shares
Residential devices saturations and market shares are obtained from the *Residential Energy Consumption Survey*, Energy Information Administration, USDOE.
http://www.eia.doe.gov/emeu/recs/contents.html

Inflation Rate
Historical inflation rates are calculated from the consumer price index reported by the Bureau of Labor. Projections for inflation from 2004 through 2030 are calculated from the consumer price index projections of the *Annual Energy Outlook 2008*, Energy Information Administration, USDOE. http://www.eia.doe.gov/oiaf/aeo/index.html.

Fuel Choice Variance Factors, Return on Investment, and Maximum Process Efficiency Multiplier
The fuel choice variance factors, return on investment and maximum process efficiency multiplier variables come from projections obtained from the DEMAND81 energy model. Backus, George A. 1981. DEMAND81: National Energy Policy Model. Four Volumes. AFC 7-10. School of Industrial Engineering. Purdue University. West Lafayette, Indiana. These factors are updated as part of the calibration process.

Process Capital Costs
The data was developed from the US I/O Tables by REMI in $1987 and have been updated based on work with past clients.

Residential Energy Usage Per Appliance
The average usage per appliance was originally based on *NEPOOL April 1994 Forecast for Massachusetts*. The miscellaneous end use category is computed by adding the residential energy for all miscellaneous end uses and dividing by the number of households. Average use per appliance has been updated since that time based on input from various clients and is calibrated to actual energy use as part of the process of calibrating to actual energy use.

Number of Households
The number of households comes from the United States Census, US Census Bureau.
http://www.census.gov/main/www/cen2000.html.

Appendix C: Jurisdiction specific forecasts

Arizona

Population Forecast	
Year	**Population**
2006	6,239,482
2007	6,432,007
2008	6,622,885
2009	6,812,137
2010	6,999,810
2011	7,186,070
2012	7,370,993
2013	7,554,429
2014	7,736,022
2015	7,915,629
2016	8,093,110
2017	8,268,253
2018	8,441,095
2019	8,611,507
2020	8,779,567

REMI 2006 Forecast Output - Arizona
Arizona Personal Income - Billions of Nominal $

	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Earnings by Place of Work	148	157	169	181	193	205	217	230	243	255	268	281	294	307	320
Contr for Gov Social Ins	16	18	19	20	22	23	25	27	28	30	31	33	35	37	38
Adj for Residence	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Dividends, Interest, and Rent	34	37	39	43	46	49	52	55	58	61	65	69	72	76	81
Personal Current Transfer Receipts	30	33	35	38	41	43	46	48	51	54	57	60	63	67	70
Personal Income	196	210	226	243	258	274	290	307	325	341	359	377	395	414	433
Personal Taxes	22	25	27	29	31	33	35	37	39	41	43	45	48	50	52
Disp Pers Inc	173	185	198	213	227	241	255	270	285	300	316	331	348	364	381
Personal Income Pct Change		**7%**	**7%**	**8%**	**6%**	**6%**	**6%**	**6%**	**6%**	**5%**	**5%**	**5%**	**5%**	**5%**	**5%**

REMI 2006 Forecast Output - Arizona Arizona Output by Industry - $2000															
	2006	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
Forestry, Fishing, Other	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.4	0.4	0.4	0.4	0.4	0.4	0.4	0.4
Mining	2.6	2.0	2.3	2.5	2.4	2.3	2.2	2.1	2.0	2.1	2.2	2.2	2.3	2.3	2.4
Utilities	7.0	7.0	7.2	7.4	7.6	7.7	7.9	8.0	8.2	8.4	8.7	9.0	9.2	9.5	9.7
Construction	23.4	22.9	23.9	25.9	27.0	28.1	29.2	30.2	31.4	32.3	33.1	33.9	34.5	35.2	35.7
Manufacturing	63.5	63.6	70.9	78.9	85.3	92.1	99.0	106.2	114.0	120.1	126.3	132.8	139.1	145.7	152.2
Wholesale Trade	20.1	20.8	22.9	25.3	27.4	29.6	31.9	34.4	37.2	39.0	40.9	42.8	44.7	46.7	48.6
Retail Trade	27.8	29.3	31.3	34.0	35.9	38.0	40.0	42.2	44.6	46.5	48.5	50.5	52.5	54.5	56.4
Transp, Warehousing	11.7	12.0	12.6	13.3	13.9	14.5	15.1	15.7	16.3	16.9	17.5	18.2	18.7	19.3	19.9
Information	12.7	13.2	14.0	15.1	16.1	17.1	18.1	19.2	20.5	21.4	22.3	23.3	24.2	25.1	26.1
Finance, Insurance	29.5	30.3	31.7	33.3	34.6	36.0	37.4	38.9	40.5	41.9	43.3	44.8	46.2	47.6	49.0
Real Estate, Rental, Leasing	46.2	47.4	49.7	52.5	54.7	57.1	59.4	61.9	64.5	66.7	68.8	70.9	72.9	74.9	76.8
Profess, Tech Services	16.7	17.0	18.1	19.5	20.6	21.8	23.0	24.3	25.7	26.8	28.0	29.3	30.5	31.7	32.9
Mngmt of Co, Enter	4.6	4.8	5.2	5.7	6.1	6.6	7.1	7.5	8.1	8.5	8.9	9.3	9.6	10.0	10.4
Admin, Waste Services	14.7	15.2	16.0	16.9	17.8	18.7	19.5	20.5	21.5	22.3	23.1	24.0	24.8	25.6	26.4
Educational Services	2.2	2.3	2.4	2.5	2.5	2.6	2.7	2.8	2.9	3.0	3.1	3.2	3.3	3.4	3.5
Health Care, Social Asst	22.3	23.2	24.2	25.3	26.5	27.7	28.9	30.3	31.7	33.0	34.3	35.7	37.0	38.3	39.6
Arts, Enter, Rec	3.3	3.4	3.6	3.8	3.9	4.1	4.3	4.5	4.7	4.9	5.1	5.2	5.4	5.6	5.7
Accom, Food Services	11.1	11.5	11.9	12.5	12.8	13.2	13.6	14.0	14.5	14.8	15.2	15.5	15.9	16.2	16.5
Other Services (excl Gov)	7.6	7.8	8.1	8.5	8.8	9.2	9.5	9.9	10.3	10.6	11.0	11.4	11.7	12.1	12.4
Total	**$327.5**	**$333.9**	**$356.5**	**$383.3**	**$404.4**	**$426.8**	**$449.2**	**$472.9**	**$498.8**	**$519.6**	**$540.8**	**$562.3**	**$583.0**	**$604.1**	**$624.7**
Annual Percent Change		**2.0%**	**6.8%**	**7.5%**	**5.5%**	**5.5%**	**5.3%**	**5.3%**	**5.5%**	**4.2%**	**4.1%**	**4.0%**	**3.7%**	**3.6%**	**3.4%**

California Population and Household Projections:

	B	C	D	E	F	G	H	I	J	K
14	**California**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**
15	Population (Millions)	34.6	35.0	35.5	35.8	36.2	36.5	36.9	37.2	37.6

	B	L	M	N	O	P	Q	R	S	T	U	V
14	**California**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
15	Population (Millions)	38.0	38.4	38.9	39.3	39.7	40.1	40.6	41.0	41.4	41.9	42.3

	B	C	D	E	F	G	H	I	J	K	L
66	**California Households (Thousands)**	**2001**	**2002**	**2003**	**2004**	**2005**	**2006**	**2007**	**2008**	**2009**	**2010**
67	Total	12,038	12,204	12,358	12,488	12,597	12,703	12,841	12,978	13,116	13,256
68	Single Family	7,697	7,803	7,901	7,984	8,054	8,122	8,210	8,297	8,386	8,475
69	Multi Family	3,776	3,828	3,876	3,917	3,952	3,985	4,028	4,071	4,114	4,158
70	Other Residential	565	573	580	586	591	596	603	609	616	622

	B	M	N	O	P	Q	R	S	T	U	V
66	**California Households (Thousands)**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**
67	Total	13,397	13,540	13,686	13,832	13,981	14,130	14,280	14,431	14,582	14,734
68	Single Family	8,565	8,657	8,750	8,844	8,939	9,034	9,130	9,227	9,323	9,420
69	Multi Family	4,202	4,247	4,293	4,339	4,386	4,432	4,479	4,527	4,574	4,622
70	Other Residential	629	636	643	649	656	663	670	678	685	692

California Gross Output by Industry

	B	C	D	E	F	G	H	I	J	K	L	M	N	O	P	Q	R	S	T	U	V
18	California Gross Output (Billions of 2000 $/Year)	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
19	Total	9,618	9,704	9,931	10,387	10,715	11,107	11,436	11,795	12,215	12,649	13,096	13,545	14,009	14,483	14,903	15,317	15,724	16,134	16,547	16,964
20	Single Family	781	776	786	808	831	854	879	904	929	956	983	1,011	1,039	1,069	1,099	1,130	1,162	1,195	1,229	1,264
21	Multi Family	247	246	249	256	263	271	278	286	294	303	311	320	329	338	348	358	368	378	389	400
22	Other Residential	35	35	35	36	37	38	39	40	41	43	44	45	46	48	49	50	52	53	55	56
23	Transportation Services	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2
24	Pipelines	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2
25	Communication	63	64	62	69	68	74	78	83	88	93	98	103	109	114	118	122	126	131	135	140
26	Utilities	15	21	22	23	23	23	23	23	23	23	23	23	23	23	24	24	25	26	26	27
27	Wholesale	75	75	75	77	83	89	94	99	104	110	116	122	129	136	141	146	151	156	162	167
28	Retail	122	126	128	131	134	140	147	153	158	162	167	172	177	183	188	194	200	206	212	218
29	FIRE	276	287	301	322	332	342	351	360	367	375	383	392	400	409	419	430	441	452	463	475
30	Offices - Business Services	171	166	169	177	183	192	199	207	215	223	231	240	248	257	266	274	283	292	301	311
31	Education	9	10	10	11	12	12	12	13	13	13	13	13	14	14	14	15	15	15	16	16
32	Health & Social	69	75	79	82	85	87	90	93	95	97	100	102	105	108	111	114	118	121	125	130
33	Food, Lodging, Recreation	48	50	52	55	56	58	59	61	62	63	64	65	66	67	68	70	71	73	74	76
34	Government	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2
35	Food & Tobacco	15	16	15	14	15	16	16	16	16	16	16	17	17	17	17	17	18	18	18	18
36	Textiles	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
37	Apparel	5	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	5
38	Lumber	2	2	2	2	2	2	2	2	2	3	3	3	3	3	3	3	3	3	3	3
39	Furniture	3	3	3	3	3	4	4	4	4	4	4	4	4	4	4	4	4	5	5	5
40	Paper	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3
41	Printing	22	20	20	21	22	23	25	26	27	29	31	32	34	36	37	39	41	42	44	45
42	Chemical	13	10	13	17	16	17	17	17	17	18	18	18	18	19	19	20	20	21	21	22
43	Petroleum Products	7	5	6	8	12	12	12	12	12	11	11	11	11	11	11	12	12	12	13	13
44	Rubber	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2
45	Leather	1	1	1	1	1	1	2	2	2	2	2	2	2	2	2	2	2	2	2	2
46	Nonmetallic Minerals	4	4	4	4	4	4	4	4	5	5	5	5	5	5	5	5	5	5	5	6
47	Primary Metals	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	3	3	3	3	3
48	Fabricated Metals	11	9	9	9	10	11	11	11	11	11	11	11	11	12	12	12	13	13	14	14
49	Machines	9	7	7	8	7	7	7	7	7	7	7	7	7	7	7	7	8	8	8	9
50	Computers	42	34	30	28	30	35	39	44	49	55	62	68	75	82	87	91	96	100	105	109
51	Electric Equipment	4	3	3	3	3	3	3	3	3	3	3	3	3	3	4	4	4	4	4	4
52	Transport Equipment	12	12	11	11	9	9	10	10	10	11	11	12	12	12	13	13	14	14	14	15
53	Other Manufacturing	9	9	10	10	11	11	11	12	12	12	13	13	14	14	15	15	16	16	17	18
54	Mining Except Oil & Gas	2	2	2	3	3	4	4	4	4	4	3	3	3	3	3	4	4	4	4	4
55	Oil & Gas Extraction	4	3	4	5	7	7	6	6	6	6	6	6	6	6	6	6	6	6	7	7
56	Construction	56	56	57	63	70	71	70	69	70	71	71	72	73	73	75	76	77	79	80	82
57	Forestry	6	6	6	6	6	6	6	6	6	6	6	6	6	7	7	7	7	7	7	7
58	Agriculture	11	12	14	17	15	15	15	15	15	15	15	15	16	16	16	17	17	17	18	18

New Mexico:

	B	C
12	Year	Population (Millions)
13	2001	1.82
14	2002	1.85
15	2003	1.88
16	2004	1.91
17	2005	1.95
18	2006	1.98
19	2007	2.01
20	2008	2.05
21	2009	2.08
22	2010	2.16
23	2011	2.19
24	2012	2.23
25	2013	2.26
26	2014	2.30
27	2015	2.34
28	2016	2.37
29	2017	2.41
30	2018	2.45
31	2019	2.49
32	2020	2.53

Washington: population

Year	Population (Millions)
1990	4.9
1991	5.0
1992	5.1
1993	5.3
1994	5.4
1995	5.5
1996	5.6
1997	5.7
1998	5.8
1999	5.8
2000	5.9
2001	6.0
2002	6.0
2003	6.1
2004	6.2
2005	6.3
2006	6.4
2007	6.5
2008	6.6
2009	6.7
2010	6.8
2011	6.9
2012	7.0
2013	7.1
2014	7.2
2015	7.3
2016	7.4
2017	7.5
2018	7.6
2019	7.7
2020	7.7

Appendix D: Inter-Regional Transmission Capacity for WECC as modeled in ENERGY 2020

Region From	Region To	Capacity Limit (MW)
Alberta	British Columbia	1,000
British Columbia	Alberta	1,200
Allston, OR	Olympia, WA	4,200
Olympia, WA	Allston, OR	4,200
Allston, OR	Williamet, OR	4,120
Williamet, OR	Allston, OR	4,120
Arizona	LADWP, CA	1,229
LADWP, CA	Arizona	1,229
Arizona	New Mexico	2,500
New Mexico	Arizona	2,500
Arizona	Pace, UT	600
Pace, UT	Arizona	600
Arizona	San Diego & Imperial Valley, CA	1,133
San Diego & Imperial Valley, CA	Arizona	1,133
Arizona	Southern California	2,150
Southern California	Arizona	2,150
Arizona	WAPA L.C. (AZ,NM)	9,999
WAPA L.C. (AZ,NM)	Arizona	9,999
British Columbia	North Puget, WA	2,850
North Puget, WA	British Columbia	2,000
British Columbia	Spokane, WA	200
Spokane, WA	British Columbia	200
British Columbia	West Kootenay, BC	9,999
West Kootenay, BC	British Columbia	9,999
Bonanza, UT	Bridger, WY	300
Bridger, WY	Bonanza, UT	300
Bonanza, UT	Pace, UT	785
Pace, UT	Bonanza, UT	400
Bonanza, UT	WAPA R.M., CO	650
WAPA R.M., CO	Bonanza, UT	650
Bridger, WY	Eastern Idaho	2,200
Eastern Idaho	Bridger, WY	600
Bridger, WY	WAPA R.M., CO	1,450
WAPA R.M., CO	Bridger, WY	1,450
Bridger, WY	Wyoming R.M.	400
Wyoming R.M.	Bridger, WY	400
Bridger, WY	Yellowtail, MT	625
Yellowtail, MT	Bridger, WY	400
Brownlee, ID	Lower Columbia (WA,OR)	50
Lower Columbia (WA,OR)	Brownlee, ID	50
Brownlee, ID	McNary, WA	300
McNary, WA	Brownlee, ID	300

Region From	Region To	Capacity Limit (MW)
Brownlee, ID	Oxbow, OR	1,700
Oxbow, OR	Brownlee, ID	1,700
Brownlee, ID	Southern Idaho	1,850
Southern Idaho	Brownlee, ID	1,850
Coulee, WA	Grant County, WA	2,396
Grant County, WA	Coulee, WA	2,396
Coulee, WA	Mid Columbia (WA,OR)	1,844
Mid Columbia (WA,OR)	Coulee, WA	1,844
Coulee, WA	North Puget, WA	1,451
North Puget, WA	Coulee, WA	1,451
Coulee, WA	Olympia, WA	126
Olympia, WA	Coulee, WA	126
Coulee, WA	Seattle South, WA	5,275
Seattle South, WA	Coulee, WA	5,275
Coulee, WA	Spokane, WA	1,140
Spokane, WA	Coulee, WA	1,140
Eastern Idaho	Garrison, MT	224
Garrison, MT	Eastern Idaho	337
Eastern Idaho	Idaho	400
Idaho	Eastern Idaho	270
Eastern Idaho	Pace, UT	400
Pace, UT	Eastern Idaho	630
Eastern Idaho	Southern Idaho	2,557
Southern Idaho	Eastern Idaho	2,557
Garrison, MT	WAPA U.M., MT	200
WAPA U.M., MT	Garrison, MT	200
Garrison, MT	Western, MT	1.300
Western, MT	Garrison, MT	1.300
Garrison, MT	Yellowtail, MT	2,573
Yellowtail, MT	Garrison, MT	2,573
Idaho	Ogden, UT	9,999
Ogden, UT	Idaho	9,999
Idaho	Pace, UT	9,999
Pace, UT	Idaho	9,999
Idaho	Wyoming R.M.	9,999
Wyoming R.M.	Idaho	9,999
LADWP, CA	Lower Columbia (WA,OR)	3,100
Lower Columbia (WA,OR)	LADWP, CA	3,100
LADWP, CA	Pace, UT	1,400
Pace, UT	LADWP, CA	1,200
LADWP, CA	Sierra, NV	235
Sierra, NV	LADWP, CA	235
LADWP, CA	Southern Nevada	1,841
Southern Nevada	LADWP, CA	1,841
LADWP, CA	Southern California	9,999
Southern California	LADWP, CA	9,999

Region From	Region To	Capacity Limit (MW)
LADWP, CA	WAPA L.C. (AZ,NM)	1,231
WAPA L.C. (AZ,NM)	LADWP, CA	1,231
Lower Columbia (WA,OR)	Malin, OR	1,708
Malin, OR	Lower Columbia (WA,OR)	1,708
Lower Columbia (WA,OR)	McNary, WA	1,948
McNary, WA	Lower Columbia (WA,OR)	1,948
Lower Columbia (WA,OR)	Mid Columbia (WA,OR)	5,277
Mid Columbia (WA,OR)	Lower Columbia (WA,OR)	5,277
Lower Columbia (WA,OR)	Slatt, OR	3,031
Slatt, OR	Lower Columbia (WA,OR)	3,031
Lower Columbia (WA,OR)	Williamet, OR	3,334
Williamet, OR	Lower Columbia (WA,OR)	3,334
Lower Granite Dam, WA	Mid Columbia (WA,OR)	5,560
Mid Columbia (WA,OR)	Lower Granite Dam, WA	5,560
Lower Granite Dam, WA	Spokane, WA	1,155
Spokane, WA	Lower Granite Dam, WA	1,155
Malin, OR	PG and E, CA	4,800
PG and E, CA	Malin, OR	4,800
Malin, OR	Sierra, NV	300
Sierra, NV	Malin, OR	300
Malin, OR	Southern Idaho	1,500
Southern Idaho	Malin, OR	1,500
Malin, OR	Southern Oregon	4,782
Southern Oregon	Malin, OR	4,782
McNary, WA	Mid Columbia (WA,OR)	2,000
Mid Columbia (WA,OR)	McNary, WA	2,000
McNary, WA	Slatt, OR	2,854
Slatt, OR	McNary, WA	2,854
McNary, WA	Williamet, OR	227
Williamet, OR	McNary, WA	227
Baja, Mexico	San Diego & Imperial Valley, CA	800
San Diego & Imperial Valley, CA	Baja, Mexico	800
Mid Columbia (WA,OR)	Oxbow, OR	400
Oxbow, OR	Mid Columbia (WA,OR)	400
Mid Columbia (WA,OR)	Seattle South, WA	3,700
Seattle South, WA	Mid Columbia (WA,OR)	3,700
Mid Columbia (WA,OR)	Slatt, OR	4,100
Slatt, OR	Mid Columbia (WA,OR)	4,100
Mid Columbia (WA,OR)	Spokane, WA	273
Spokane, WA	Mid Columbia (WA,OR)	273
Mid Columbia (WA,OR)	Williamet, OR	2,600
Williamet, OR	Mid Columbia (WA,OR)	2,600
N. King, WA	Seattle South, WA	526
Seattle South, WA	N. King, WA	526
New Mexico	PS Colorado	558
PS Colorado	New Mexico	558

Region From	Region To	Capacity Limit (MW)
New Mexico	WAPA L.C. (AZ,NM)	817
WAPA L.C. (AZ,NM)	New Mexico	817
New Mexico	WAPA R.M., CO	690
WAPA R.M., CO	New Mexico	690
North Puget, WA	Seattle North, WA	3,000
Seattle North, WA	North Puget, WA	3,000
North Puget, WA	Seattle South, WA	3,000
Seattle South, WA	North Puget, WA	3,000
Ogden, UT	Pace, UT	9,999
Pace, UT	Ogden, UT	9,999
Olympia, WA	Seattle South, WA	4,500
Seattle South, WA	Olympia, WA	4,500
OVERTHRS, WY	Wyoming R.M.	9,999
Wyoming R.M.	OVERTHRS, WY	9,999
Oxbow, OR	Southern Idaho	90
Southern Idaho	Oxbow, OR	50
Oxbow, OR	Spokane, WA	450
Spokane, WA	Oxbow, OR	300
Pace, UT	Scenic SW, UT	300
Scenic SW, UT	Pace, UT	300
Pace, UT	Sierra, NV	205
Sierra, NV	Pace, UT	205
Pace, UT	Station Load, WY	9,999
Station Load, WY	Pace, UT	9,999
Pace, UT	WAPA L.C. (AZ,NM)	265
WAPA L.C. (AZ,NM)	Pace, UT	265
Pace, UT	Wyoming R.M.	9,999
Wyoming R.M.	Pace, UT	9,999
PG and E, CA	Sierra, NV	160
Sierra, NV	PG and E, CA	150
PG and E, CA	Southern Oregon	30
Southern Oregon	PG and E, CA	80
PG and E, CA	Southern California	3,400
Southern California	PG and E, CA	3,000
PS Colorado	WAPA R.M., CO	9,999
WAPA R.M., CO	PS Colorado	9,999
Southern California Edison	Southern California	200
Southern California	Southern California Edison	200
Scenic SW, UT	Southern Nevada	300
Southern Nevada	Scenic SW, UT	300
Scenic SW, UT	St. George, UT	9,999
St. George, UT	Scenic SW, UT	9,999
Scenic SW, UT	Station Load, WY	26
Station Load, WY	Scenic SW, UT	26
San Diego & Imperial Valley, CA	Southern California	5,000
Southern California	San Diego & Imperial Valley, CA	5,000

Region From	Region To	Capacity Limit (MW)
Seattle North, WA	Seattle South, WA	1,690
Seattle South, WA	Seattle North, WA	1,690
Sierra, NV	Southern Idaho	262
Southern Idaho	Sierra, NV	500
Sierra, NV	Southern California	17
Southern California	Sierra, NV	17
Southern Oregon	Williamet, OR	4,495
Williamet, OR	Southern Oregon	4,495
Southern Nevada	Southern California	2,754
Southern California	Southern Nevada	2,754
Southern Nevada	WAPA L.C. (AZ,NM)	4,554
WAPA L.C. (AZ,NM)	Southern Nevada	4,554
Southern California	WAPA L.C. (AZ,NM)	1,140
WAPA L.C. (AZ,NM)	Southern California	1,140
Spokane, WA	West Kootenay, BC	200
West Kootenay, BC	Spokane, WA	200
Spokane, WA	Western, MT	1,300
Western, MT	Spokane, WA	2,200
Station Load, WY	Wyoming R.M.	9,999
Wyoming R.M.	Station Load, WY	9,999
WAPA L.C. (AZ,NM)	WAPA R.M., CO	485
WAPA R.M., CO	WAPA L.C. (AZ,NM)	485
WAPA U.M., MT	Yellowtail, MT	390
Yellowtail, MT	WAPA U.M., MT	390

Source: Federal Energy Regulatory Commission, *FERC-714 Annual Power System Reports*
http://www.transmission.bpa.gov/orgs/opi/FERC714/index.shtm

Appendix E: Data Sets Used in ENERGY 2020

This Appendix describes the initial set definitions for ENERGY 2020 used for this project. The sets are the dimensions of the variables (sometimes called indexes) which delineate the scope and detail of the model. For example, the time frame set could be defined as a base year 1990 and every 5 years.

Time Frame

The initial historical year for calibration is 1990.
Current end year of the analysis is 2020, but analysis can be extended to 2030 or beyond.
The last historic year of data will be 2005.
All data sets include annual data for each year of history and the forecast.

For some data sets, the period covered by actual data will depend on available data (e.g., emissions).

Geographical Areas

Each area in the model will represent a state or a province (no sub-state break-outs).
The model will provide separate results for the eleven WCI Partner jurisdictions. The surrounding region (the rest of the WECC) and the rest of the US and Canada are also modeled.

The states and provinces included in the WCI region for modeling purposes include:

- Arizona
- New Mexico
- Washington
- Ontario
- California
- Oregon
- British Columbia
- Quebec
- Montana
- Utah
- Manitoba

Generating Units

The list of units is based on the NEEDS database for the US plus a similar database for the units in Canada. Within the Region and the rest of the US, some of the smaller plants may be aggregated by plant type in order to allow the expedite model operation. Under these assumptions regarding aggregation, this version of the model will include approximately 3,000 units/plants.

Electric Companies

Although ENERGY 2020 can model individual utilities or groups of utilities, for the WCI project the model assumes that each state has a single aggregate utility.

Sectors and Classes

The energy demand portion of the model will simulate residential, commercial, industrial, and transportation demands. There will be an electric sales class for each sector.

Emission Only Sectors

Several sectors generate emissions, but do not have full energy demand simulations in the model. These include solid waste, waste water, incineration, and land use. It may be possible to develop a full energy demand simulation for one or more of these.

Pollutants

The model currently has the capability to cover 15 pollutants, although the final set will depend on project requirements and available data. The GHG pollutants include Carbon Dioxide, Methane, Nitrous Oxide, Sulfur-Hexafluoride, Perfluorocarbon, and Hydrofluorocarbon. The criteria air pollutants include Sulfur Dioxide, Nitrogen Oxides, Total Particulate Matter, Volatile Organic Compounds, Carbon Monoxide, Particulate Matter $_{2.5}$, Particulate Matter $_{10}$, Mercury, and Ozone.

Fuels

There are currently two sets of fuels in the model. The largest category contains 33 fuels (shown below). The second category is the list of technologies which the energy demand sectors choose from. This smaller set contains only the basic types of fuels (Electricity, Natural Gas, Oil, LPG, Biomass, Solar). The aggregate category oil is later broken out into the different types of oil (LFO, HFO, petroleum coke, etc.).

Entire List of Fuels

- Asphalt
- Aviation Fuel
- Biomass
- Coal
- Coke
- Coke Oven Gas
- Diesel
- Electric
- Ethanol
- Geothermal
- Heavy Fuel Oil
- Hydro
- Hydrogen
- Kerosene
- Landfill Gases
- Light Fuel Oil
- LPG
- Lubricants
- Motor Gasoline
- Naphtha Specialties
- Natural Gas
- Nuclear
- Oil, Unspecified
- Other Non-Energy Products
- Petrochemical Feedstocks
- Petroleum Coke
- Solar
- Steam
- Still Gas
- Wave
- Wind
- Unknown 1
- Unknown 2

Electric Generation Plants Types

The electric generation plant types are used to hold the data for future generic plants which the model will construct endogenously. The list currently includes:

- Gas/Oil Peaking
- Gas/Oil Combined Cycle
- Gas/Oil Steam
- Coal
- Coal Advanced
- Coal with CCS
- Gas CC with CCS
- Nuclear
- Base Hydro
- Peak Hydro
- Other Generation
- Biomass
- Landfill Gas
- Wind
- Solar
- Fuel Cells
- Pumped Hydro
- Small Hydro
- Wave
- Geothermal
- Other Storage
- Biogas
- Trash

Residential Sectors

The residential sector is split into housing types:

- Single Family
- Multi-Family
- Other Residential

Commercial Sectors

- Transportation Services
- Pipelines
- Communication
- Electric Utilities
- Gas Utilities
- Water & Other Utilities
- Wholesale
- Retail
- FIRE
- Offices - Business Services
- Education
- Health & Social
- Food, Lodging, Recreation
- Government

Industrial Sectors

- Food & Tobacco
- Textiles
- Apparel
- Lumber
- Furniture
- Pulp & Paper Mills
- Converted Paper
- Printing
- Petrochemicals
- Industrial Gas
- Other Chemicals
- Fertilizers
- Petroleum Products
- Rubber
- Leather
- Cement
- Glass
- Lime & Gypsum
- Other Non-Metallic
- Iron & Steel
- Aluminum
- Other Nonferrous
- Fabricated Metals
- Machines
- Computers
- Electric Equipment
- Transport Equipment
- Other Manufacturing

- Iron Ore Mining
- Other Metal Mining
- Non-metal Mining
- Light Oil Mining
- Heavy Oil Mining
- Frontier Oil Mining
- Oil Sands In-Situ
- Oil Sands Mining
- Oil Sands Upgraders
- Gas Mining
- Coal Mining
- Construction
- Forestry
- Agriculture

Transportation Sectors

- Passenger
- Freight
- Off Road

Miscellaneous Sectors

- Misc. & Street Lighting
- Electric Resale
- Utility Electric Generation
- Industry Electric Generation
- Steam Generation
- Solid Waste
- Waste Water
- Incineration
- Land Use

Residential End-Uses

- Space Heating
- Water Heating
- Other Substitutable
- Refrigeration
- Lighting
- Air Conditioning
- Other Non-Substitutable

Commercial End-Uses

- Space Heating
- Water Heating
- Other Substitutable
- Refrigeration
- Lighting
- Air Conditioning
- Other Non-Substitutable

Industrial End-uses

- Process Heat
- Electric Motors
- Other Substitutable
- Miscellaneous

Transportation End-Uses

- Ground
- Air/Water

Residential, Commercial, and Industrial Technology Types

Each technology type has its own trade-off curve which determines the efficiency and the capital cost of the technology type. These curves allow the model to contain many different technologies within these broad types.

- Electric
- Gas
- Coal
- Oil
- Biomass
- Solar
- LPG
- Steam

Transportation Technology Types

Several technology types are provided for transportation, and each of these contains a trade-off curve which allows the model to simulate even more individual technologies.

- Plug-in Hybrids
- Light Gasoline
- Light Diesel
- Light Propane
- Light CNG
- Light Electric (Plug-in)
- Light Ethanol
- Light Hybrid Gasoline
- Light Hybrid Diesel
- Light Fuel Cell Gasoline
- Light Fuel Cell CNG
- Light Fuel Cell Hydrogen
- Medium Gasoline
- Medium Diesel
- Medium Propane
- Medium CNG
- Medium Ethanol
- Medium Hybrid Gasoline
- Medium Hybrid Diesel
- Medium Fuel Cell Gasoline
- Medium Fuel Cell CNG
- Medium Fuel Cell Hydrogen
- Heavy Gasoline
- Heavy Diesel
- Heavy Propane
- Heavy CNG
- Heavy Ethanol
- Heavy Hybrid Gasoline
- Heavy Hybrid Diesel
- Heavy Fuel Cell Gasoline
- Heavy Fuel Cell CNG
- Heavy Fuel Cell Hydrogen
- Motorcycle
- Bus Gasoline
- Bus Diesel
- Bus Propane
- Bus CNG
- Bus Fuel Cell Gasoline

- Bus Fuel Cell Hydrogen
- Bus Fuel Cell Ethanol
- Train
- Plane
- Marine
- Off Road

Prices

Delivered energy prices are presented for the following fuels:

- Residential Electricity
- Residential Natural Gas
- Residential Coal
- Residential Oil
- Residential Biomass
- Residential LPG
- Residential Steam
- Commercial Electricity
- Commercial Natural Gas
- Commercial Coal
- Commercial Oil
- Commercial Biomass
- Commercial LPG
- Commercial Steam
- Industrial Electricity
- Industrial Natural Gas
- Industrial Coal
- Industrial Oil
- Industrial Biomass
- Industrial LPG
- Industrial Steam
- Gasoline
- Diesel
- Aviation Fuel
- Transportation HFO
- Transportation Natural Gas
- Transportation LPG
- Electric Utility Residual Oil
- Electric Utility Distillate Oil
- Electric Utility Natural Gas
- Electric Utility Coal
- Electric Utility Nuclear
- Electric Utility Biomass
- Ethanol
- Hydrogen

Electric Load Segments

The model dispatches for 6 different hour types (high peak, low peak, high intermediate, low intermediate, high base load, low base load) for each of the four seasons.

Appendix F: Planned or Committed Coal Plants Post-2005

State	Plant_Name	Plant Type	On-Line Year	Capacity (MW)	Fuel	HeatRate	Owner	Notes
AZ	Bowie Power Station LLC	Oil/Gas Combined Cycle	2012	500	NaturalGas	7,548	Southwestern Power Group IILLC	
AZ	Bowie Power Station LLC	Oil/Gas Combined Cycle	2010	500	NaturalGas	7,548	Southwestern Power Group IILLC	
AZ	Springerville	Coal	2010	400	Coal	10,178	Salt River Project	
CO	Comanche	Coal	2009	750	Coal	8,763	Public Service Co of Colorado	
NE	Nebraska City	Coal	2009	663	Coal	9,508	Omaha Public Power District	
NV	TS Power Plant	Coal	2008	200	Coal	10,700	Newmont Nevada Energy Investment, LLC	
TX	J K Spruce	Coal	2010	750	Coal	9,273	City of San Antonio	
WY	Wygen 2	Coal	2007	70	Coal	11,044	Cheyenne Light Fuel & Power Co	
WY	Wygen 3	Coal	2010	100	Coal		Black Hills Corporation	
CO	Lamar Plant	Oil/Gas Steam	1972	25	Natural Gas	14,500	City of Lamar	
CO	Lamar	Coal (Advanced)	2008	39	Coal	9,000	Lamar Utility Board	Repowering
NE	Public Power Generation Agency, Whelan Energy Center 2	Coal	2012	220	Coal	10,047	Public Power Generation Agency	
NM	Estancia Biomass Power Plant	Biomass	2010	25	Biomass (wood)	12,000	Western Water & Power Production LLC	
ND	Great River Energy, Spiritwood	Combined Heat & Power	2010	99		9,000		
TX	Tuminent (TXU) Oak Grove Plant	Coal (Lignite)	2009/10	1600	Lignite	9,130		
TX	Luminent (TXU) Sandow 5	Coal (Advanced)	2009	600	Coal	9,130		
TX	City Public Service, Spruce Plant	Coal	2009	750	Coal	9,000		
WY	Black Hills Corporation, Wygen II Plant	Coal	2008	95		12,500	Black Hills Corporation	
WY	Basin Electric Coop, Dry Fork	Coal (Advanced)	2011	385	Coal	9,000	Basin Electric Coop	
WY	North American Power Gp, 2 Elk Power Plant Unit 1	Coal	2010	325	Coal	9,000	North American Power Group	
WY	DKRW Energy LLC	Coal	2010	200	Coal	9,000	DKRW	

Note: These units have been included for modeling purposes only. It is not possible to determine at this time which specific projects will be completed.

Appendix G: New Generation Performance and Cost Assumptions

Table 1A. Input Values to Busbar Energy Costs - California Resources (2008 $)

Resource Technology	2020 Overnight Capital Cost ($/kW) ($/kW)		Fixed O&M Cost ($/kW-year)		Variable O&M Cost ($/MWh)		Capacity Factor
	Low (if range)	High (if range)	Low (if range)	High (if range)	Low (if range)	High (if range)	
Biogas	$3,065		$139		1.20		80%
Biomass	$4,484		$65		1.20		80%
Geothermal	$3,339	$8,131	$157	$226	1.20		90%
Hydro - Small	$2,539	$5,170	$14	$31	0.94	1.81	25% - 65%
Solar - Thermal	$3,235		$64		1.20		37% - 40%
Wind	$1,962		$37		1.20		27% - 40%
Coal ST	$2,479		$33		1.20		85%
Coal IGCC	$2,866		$47		1.20		85%
Coal IGCC with CCS	$4,101		$55		1.20		85%
Gas CCCT	$1,054		$14		1.20		90%
Gas CT	$807		$15		1.20		5%
Hydro - Large	$1,486	$2,193	$9	$13	0.63	0.89	12% - 57%
Nuclear	$3,999		$83		1.20		85%

Table 1B. Input Values to Busbar Energy Costs - Rest of WECC Resources (2008 $)

Resource Technology	2020 Overnight Capital Cost ($/kW) ($/kW)		Fixed O&M Cost ($/kW-year)		Variable O&M Cost ($/MWh)		Capacity Factor	Nominal Heat Rate (Btu/kWh)
	Low (if range)	High (if range)	Low (if range)	High (if range)	Low (if range)	High (if range)		
Biogas	$2,350	$2,835	$107	$128	0.92	1.11	80%	13,648
Biomass	$3,438	$4,148	$50	$60	0.92	1.11	80%	8,911
Geothermal	$1,582	$19,451	$157	$226	0.96	1.11	90%	n/a
Hydro - Small	$1,758	$4,782	$11	$28	0.71	1.69	22% - 65%	n/a
Solar - Thermal	$2,588	$2,939	$51	$58	0.96	1.09	36% - 39%	n/a
Wind	$1,504	$1,815	$28	$34	0.92	1.11	27% - 40%	n/a
Coal ST	$1,901	$2,293	$26	$31	0.92	1.11	85%	8,844
Coal IGCC	$2,197	$2,651	$36	$43	0.92	1.11	85%	8,309
Coal IGCC with CCS	$3,144	$3,794	$42	$51	0.92	1.11	85%	9,713
Gas CCCT	$808	$975	$11	$13	0.92	1.11	90%	6,917
Gas CT	$619	$747	$11	$14	0.92	1.11	5%	10,807
Hydro - Large	$1,122	$2,031	$5	$11	0.41	0.78	15% - 65%	n/a
Nuclear	$3,066	$3,699	$63	$76	0.92	1.11	85%	10,400

Note: Variable O&M Costs do not include fuel costs. Range of costs is similar for several of the technologies.
Source: Energy and Environmental Economics, Inc., CPUC GHG Modeling - Generation Costs (Word document), 11/16/2007.www.ethree.com/cpuc_ghg_model.html

Appendix H: Global Warming Potential

ENERGY 2020 models emissions of each of the six greenhouse gases reported under the Kyoto protocol. These emissions are then translated into equivalent quantities of CO_2 emissions (CO_2e) based on the global warming potential of each of the gases.

The Global Warming Potential (GWP) values used in ENERGY 2020 are shown in the table below.

Greenhouse Gas	Global Warming Potential
Carbon Dioxide (CO_2)	1
Methane (CH_4)	21
Nitrous Oxide (N_2O)	310
Sulfur Hexafluoride (SF_6)	23,900
Perfluorocarbons (PFC)	7,000
Hydrofluorocarbons (HFC)	1,300

These values are consistent with the Global Warming Potential values used in the 1996 Second Assessment Report based on 100-year warming potential for the individual gases. In the case of HFCs and PFCs the GWP values used in the model are based on an estimated average GWP for these gases.

Appendix I: Renewable Portfolio Standards: Partner Jurisdictions and Rest of North America

State or Prov	Target	Policy
United States		
AZ	15% of generation from renewables by 2025	Regulated electric utilities must generate 15% of their energy from renewables by 2025. By 2012, at least 30% of the standard must be derived from distributed renewable energy (4.5% of total electricity sales by regulated utilities). RES specifies what technologies qualify (Solar Water Heat, Solar Space Heat, Solar Thermal Electric, Solar Thermal Process Heat, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Geothermal Heat Pumps, CHP/Cogeneration, Solar Pool Heating (commercial only), Daylighting (non-residential only), Solar Space Cooling, Solar HVAC, Additional technologies upon approval, Anaerobic Digestion, Fuel Cells using Renewable Fuels) and allow for the addition of new technologies as they become feasible. Penalties for non-compliance. The new rules also require a growing percentage of the total resource portfolio to come from distributed generation.
CA	Major utilities 20% from renewable sources by 2010 on a retail sales basis	California's Investor-Owned Utility, Electric Service Providers, Small and Multi-Jurisdictional Utilities and Community Choice Aggregators to produce at least 20% of their electricity using renewable sources by 2010 based on renewable retail sales. Eligible technologies: Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Geothermal Electric, Municipal Solid Waste, Anaerobic Digestion, Small Hydroelectric, Tidal Energy, Wave Energy, Ocean Thermal, Biodiesel, and Fuel Cells using Renewable Fuels.

State or Prov	Target	Policy
MT	10% of generation load to be renewable by 2010; 15% by 2015	Each investor-owned and public utility should: Meet 20% of its load using renewable energy resources by 2020, increasing to 25% by 2025. The legislation contains a cost cap that encourages utilities to invest in renewable generation that is cost competitive with conventional generation. Eligible technologies: wind, solar, geothermal, existing hydroelectric projects, landfill or farm-based methane gas, wastewater-treatment gas, low-emission, nontoxic biomass, and fuel cells where hydrogen is produced with renewable fuels.
NM	10% of generation by 2011; 15% renewable by 2015; 20% by 2020	Applies to Investor-Owned Utility, Rural Electric Cooperative. IOUs: 15% power generation from renewable sources and 20% by 2020. RECs: 10% by 2020. This legislation expands on NM's current RPS requiring that 10% of the state's nergy come from such sources by 2011. IOUs must also meet: 20% of RPS from solar (4% of total sales); 20% of RPS from wind (i.e. 4% of total sales); 10% of RPS from geothermal and biomass (2% of total sales); 3% of RPS from distributed renewables (0.6% of total sales) by 2020. Eligible technologies: Solar Thermal Electric, Photovoltaics, Landfill Gas, Wind, Biomass, Hydroelectric, Geothermal Electric, Zero emission technology with substantial long-term production potential, Anaerobic Digestion, Fuel Cells using Renewable Fuels

State or Prov	Target	Policy
OR	25% of electric load must be renewable sources by 2025 (ramps up from 2015)	Largest utilities 25% of their electric load with new renewable energy sources by 2025. Interim targets of 5% by 2011; 15% by 2015; 20% by 2020; and 25% by 2025. Based on total retail sales volumes. Eligible technology: wind, solar, wave, geothermal, biomass, new hydro or efficiency upgrades to existing hydro facilities. Utilities are not required to comply with the standard if doing so will result in retail electricity price increases of more than 4%. If none of a utility's options for compliance are cost-effective, they can make an Alternative Compliance Payment (ACP) to help meet their renewable energy requirement. The level of the ACP will be determined by the PUC and will be set to provide adequate incentive for the utility company to generate qualifying renewable electricity instead of using an ACP payment to meet the RPS. The ACP will be placed into an account that can be used in the future to acquire renewable energy, invest in conservation or, for consumer-owned utilities, research and development.
UT	20% of sales by 2025 for Rocky Mountain Power and Co-ops or municipal electric utilities, if cost effective	The retail sales are adjusted by subtracting the non-carbon sources of energy (e.g. hydro, nuclear) and future carbon sequestration from the total retail sales. The 20% target would then apply to the carbon component of the utility's portfolio.Requires plans and reports concerning an electrical corporation's or municipal electric utility's progress in acquiring renewable energy.Requires the Utah Geological Survey to make rules concerning carbon capture and geological storage of captured carbon emissions.
WA	All new long term baseload facilities must meet 1,100 lbs CO_2/MWh starting July 2008	GHG performance standard for all new, long-term baseload electric power generation. Under the standard, all baseload generation for which utilities enter into long-term contracts must meet a greenhouse gas emissions standard of 1,100 pounds per MWh beginning in July 2008
WA	15% of production to be renewable by 2020 (small & low growth utilities exempt, so effectively 14%)	All utilities serving >25,000 people to produce 15% of their energy using renewable sources by 2020. Eligible technology: wind, solar, and tidal power as well as landfill-methane capture.

State or Prov	Target	Policy
CANADA		
PEI	15% by 2010	
Nfld	n/a	
NB	10% renewables by 2016	
NS	18.5% of electricity needs from renewables by 2013	
PQ	Produce 4,000 MW of electricity from wind by 2015	Additional hydro projects will begin operation by 2012, totalling 1,054 MW. The 1500Mw La Romaine facility will is projected to come on line in 2014.
ON	No coal-fired electricity generation in the province by 31 December 2014 Conserve 6,300 MW of electricity by 2025 (40% by 2010)50% increase in renewable energy capacity by 2015, including hydro; 15,700 MW by 2025 including up to 1,000 MW of renewable power to the grid by 2010	Regulation to phase out use of coal-fired generation enacted in 2007. Renewable power RFP being contracted for capacity and generation
MB	1,000 MW of wind power by 2016 Energy saving target of 842 MW of electricity by 2017	Most of Manitoba's power production is already from renewable sources. Target: 1,000 MW of wind power by 2016. The 1,000 MW will reduce GHGs by 3.5 Mt annually, and stimulate $2 billion in new investments. As a part of this, the province intends to add 300 MW of wind (starting construction in 2007-08). The 300 MW is in addition to the 99 MW St. Leon wind farm, which is already in operation.

State or Prov	Target	Policy
SK	Demand side management to reduce needs by 300 MW by 2017 New and replacement generation emissions-free or fully offset	By 2017, we commit to saving at least 300 megawatts of SaskPower's electricity generation through demand side management practices. Ensure all of SaskPower's new and replacement electricity generation facilities are either emissions-free or fully offset by emission credits
AB	By 2008, more than 12.5% of Alberta's total electricity generated will be generated from renewables	12.5% renewables, primarily wind and biomass
BC	Offset all O&G grid power emissions by 2016.	All existing natural gas and oil-fired generating facilities part of the integrated grid will need to completely offset their GHG emissions by 2016. All coal will need to use CCS, sequester or otherwise offset emissions, and all new O&G must not add to current levels of emissions50% of incremental electricity requirements to be met through conservation
BC	Maintain 90% clean sources - all new sources zero emissions.	Maintaining 90% clean power supply, including hydro. Note that no nuclear will be built in the province. Government will issue guidelines to define what sources qualify as clean or renewable and provide additional policy direction as required. In 2004, power generation accounted for only 3% of the total amount of GHG emitted.
NWT	n/a	Taltson River Hydro development (36 MW) set for construction and online by 2011 4 mini hydro possibilities
Yukon	n/a	$7M to install third turbine at Aishihik hydo plant planned to be in service between 2009 & 2012 (7 MW capacity)
Nunavut	n/a	n/a

Province or State	E2020 Description	RPS since 05/01/08	2020 RPS % Region Sales Target	State goal for renewable (% of sales)	Out of State Permitted	New Restrictions on generation location
IA	MAPP	no	0.2%	105 MW	Yes	Must own facilities located in the state or enter into long term contracts to purchase or wheel electricity from facilities located within the utility's service area
MN	MAPP	no	11.2%	Xcel Energy: 30% by 2020 All Others: 25% by 2025*	Yes	Allowed to use out of state generation - Local benefits. The commission shall take all reasonable actions within its statutory authority to ensure this section is implemented to maximize benefits to Minnesota citizens, balancing factors such as local ownership of or participation in energy production, development and ownership of eligible energy technology facilities by independent power producers, Minnesota utility ownership of eligible energy technology facilities, the costs of energy generation to satisfy the renewable standard, and the reliability of electric service to Minnesotans
ND	MAPP	no	0.7%	State Renewable Goal: 10% by 2015	%	"A portion or all of the renewable energy and recycled energy objective may be met by the purchase and retirement of renewable energy and recycled energy certificates representing credits from qualified sources and facilities as defined in section 49-02-26 and section 5 of this Act. Renewable energy and recycled energy certificates do not need to be acquired from an in-state facility."
NE	MAPP	no	N/A	N/A	N/A	N/A
SD	MAPP	yes	0.6%	Voluntary RPS 10% by 2015	N/A	N/A
E2020 Region: MAPP			12.7%			

Province or State	E2020 Description	RPS since 05/01/08	2020 RPS % Region Sales Target	State goal for renewable (% of sales)	Out of State Permitted	New Restrictions on generation location
DE	MidWest	no	0.2%	20% by 2019	No	Energy sold or displaced by a customer-sited eligible energy resource can generate renewable energy credits for RPS compliance, provided the system is sited in Delaware.
IL	MidWest	no	2.4%	25% by 2025 Tech. Min. 75% wind	Yes after 2011	Through 2011, eligible resources must be located in-state.
IN	MidWest	no	0.0%	N/A	N/A	N/A
KY	MidWest	no	0.0%	N/A	N/A	N/A
MD	MidWest	yes	1.3%	Standard: Tier 1: 20% in 2022 and beyond; Tier 2: 2.5% in 2006 through 2018 Tech. Min. 2% solar electric in 2022 as part of the Tier 1 requirement. Suppliers also receive 110% - 120% credit for wind and 110% credit for methane during a specified timeframe	Yes	Solar resources must be connected with the distribution grid serving Maryland, except that on or before December 31, 2011, solar resources not connected to the Maryland grid are eligible only if offers for solar RECs from Maryland grid sources are not made to an electricity supplier that would satisfy the RPS.
MI	MidWest	no	2.2%	20% by 2020 at least 5% must be from solar	Yes	Allowed to use out of state generation

Province or State	E2020 Description	RPS since 05/01/08	2020 RPS % Region Sales Target	State goal for renewable (% of sales)	Out of State Permitted	New Restrictions on generation location
NJ	MidWest	yes	1.8%	22.5% by 2021 (2.12% from solar; 17.88% from other Class I renewables; 2.5% from Class II or additional Class I renewables)	Yes	To qualify as "Class I" or "Class II" renewable energy, electricity must be generated within or delivered into the PJM region. "Class I" or "Class II" renewable energy delivered into the PJM region must be generated at a facility that began construction on or after January 1, 2003, in order to qualify.
OH	MidWest	yes	1.5%	25% from alt. energy resources by 2025 (12.5% renewables). Additional 12.5%of the overall 25% standard can also be met through alternative energy resources like third-generation nuclear power plants, fuel cells, energy-efficiency programs, and clean coal technology that can control or prevent CO_2 emissions	50%	At least half of this renewable energy must be generated in-state.

Province or State	E2020 Description	RPS since 05/01/08	2020 RPS % Region Sales Target	State goal for renewable (% of sales)	Out of State Permitted	New Restrictions on generation location
PA	MidWest	no	2.6%	Standard: 18% during compliance year 2020-2021 (8% Tier I and 10% Tier II) Technology Minimum: Solar PV set-aside of 0.5% for June 1, 2020 and thereafter	Yes	Allowed to use out of state generation - Energy derived only from alternative energy sources inside the geographical boundaries of this Commonwealth or within the service territory of any regional transmission organization that manages the transmission system in any part of this Commonwealth shall be eligible to meet the compliance requirements under this act. Electric distribution companies and electric generation suppliers shall document that this energy was not used to satisfy another state's renewable energy portfolio standards
WI	MidWest	no	0.7%	Requirement varies by utility (statewide target of 10% by 12/31/15)	Yes	Allowed to use out of state generation
WV	MidWest	no	0.0%	N/A	N/A	N/A
E2020 Region Code: MW			**12.7%**			

Province or State	E2020 Description	RPS since 05/01/08	2020 RPS % Region Sales Target	State goal for renewable (% of sales)	Out of State Permitted	New Restrictions on generation location
CT	NPCC	no	3.2%	*in % of sale* 27% by 2020 20% Class I resources 3% Class I or Class II resources 4% Class III resources by 2010	Yes	Electric suppliers or distribution may satisfy the requirements by: (A) purchasing Class I or II renewable sources within the jurisdiction of the regional independent system operator, or within the jurisdiction of NY, PA, NJ, MD, DE, provided the department determines such states have a renewable portfolio standard that is comparable to this section; or (B) by participating in a renewable energy trading program within said jurisdictions as approved by the Department of Public Utility Control. Eligibility for resources postponed until at least 1/1/2010
MA	NPCC	yes	1.0%	Class I Std: 4% of sales by end 2009, additional 1% of sales each year thereafter, no stated end date Class II Std: 3.6% of annual sales Alt. Energy Portfolio Std: 0.75% of sales by end 2009, reaching 5% in 2020, and an additional 0.25% of sales each year thereafter	%	In meeting the “Class I” standard, retail suppliers must provide a portion – to be determined by the DOER – of the required renewable energy from new, in-state, on-site systems of <2MW in capacity which began commercial operation after December 31, 2007.

Province or State	E2020 Description	RPS since 05/01/08	2020 RPS % Region Sales Target	State goal for renewable (% of sales)	Out of State Permitted	New Restrictions on generation location
ME	NPCC	yes	0.5%	Standard: Class I: 10% new resources by 2017 (and for each year thereafter) Class II: 30% by 2000 Tech. Min: No	N/A	NE-ISO
NH	NPCC	no	0.6%	By 2025: 16% Class I 0.3% Class II 6.5% Class III 1% Class IV	Yes	From other states in the New England control area and adjacent states
NY	NPCC	yes	12.8%	Standard: 24% by 2013 Technology Minimum: 2% of total incremental RPS requirement is set-aside for the Customer-Sited Tier, for a total of 0.1542% of customer-sited generation*	Yes	Allowed to use out of state generation - Main Tier: Limited to the electricity sold in a retail sale in NY State made by a load serving entity to a customer – self-generation is not eligible Customer-sited Tier: Only facilities located in NY are eligible – self generation is eligible Resources eligible for the Customer-Sited Tier include fuel cells, photovoltaic, wind, and methane digesters. Customer-Sited Tier systems are generally limited to the size of the load at the customer's meter.

Province or State	E2020 Description	RPS since 05/01/08	2020 RPS % Region Sales Target	State goal for renewable (% of sales)	Out of State Permitted	New Restrictions on generation location
RI	NPCC	no	0.5%	16% by 2019 and thereafter (14% must be from new sources)	Yes	Generation Units must be located in NEPOOL or in a control area adjacent, provided the associated Generation Attributes shall be applied to the RES only to the extent that the energy produced by the Generation Unit is actually delivered into NEPOOL for consumption by NE customers. The delivery of such energy from the Generation Unit into NEPOOL must be verified by: (a) a unit-specific bilateral contract for the sale and delivery of such energy into NEPOOL; (b) confirmation from ISO that the renewable energy was actually settled in the ISO Market Settlement System; and, (c) (1) confirmation through the North American Reliability Council tagging system that the import of the energy into NEPOOL actually occurred; or, (2) any such other requirements.
VT	NPCC	yes	0.4%	RPS Goals: (1) increase in retail electricity sales between 2005-2012; (2) 20% of state-wide electric retail sales and CHP by 2017; (3) 25% of all energy consumed from renewables by 2025	Yes	Allowed to use out of state generation - The public service board shall ensure that all electricity provider and provider-affiliate disclosures and representations made with regard to a provider's portfolio are accurate and reasonably supported by objective data. Further, the public service board shall ensure that providers disclose the types of generation used and whether the energy is Vermont-based, and shall clearly distinguish between energy or tradable energy credits provided from renewable and non-renewable sources and existing and new sources.
E2020 Region Code: NP			19.0%			

Province or State	E2020 Description	RPS since 05/01/08	2020 RPS % Region Sales Target	State goal for renewable (% of sales)	Out of State Permitted	New Restrictions on generation location
AK	Rest of US	no	0.0%	N/A	N/A	N/A
AL	Rest of US	no	0.0%	N/A	N/A	N/A
AR	Rest of US	no	0.0%	N/A	N/A	N/A
FL	Rest of US	no	2.9%	RPS Goal: to develop RPS by Feb. 1, 2009. Each electricity provider, except municipal utilities and rural cooperatives, must supply an as-yet unspecified amount of renewable energy to its customers. Although HB 7135 does not specify the RPS target, the Governor EO 07-127 from July 13, 2007 requires utilities to produce at least 20% of their electricity from renewables.	N/A	N/A
GA	Rest of US	no	0.0%	N/A	N/A	N/A
HI	Rest of US	yes	0.1%	*% in sales* 10% by 12/31/2010; 15% by 12/31/2015; and 20% by 12/31/2020 (including existing renewables)	N/A	

Province or State	E2020 Description	RPS since 05/01/08	2020 RPS % Region Sales Target	State goal for renewable (% of sales)	Out of State Permitted	New Restrictions on generation location
KS	Rest of US	no	0.0%	N/A	N/A	N/A
LA	Rest of US	no	0.0%	N/A	N/A	N/A
MO	Rest of US	no	0.6%	Goal: 11% by 2020*	N/A	n/a
MS	Rest of US	no	N/A	N/A	N/A	N/A
NC	Rest of US	no	1.0%	Standard: 12.5% of 2020 retail sales by 2021 for investor-owned utilities; 10% of 2017 retail sales by 2018 for electric cooperatives and municipal utilities Technology Minimum: 0.2% solar electricity and thermal energy by 2018; 0.2% swine waste by 2018; 900,000 MWh of poultry waste by 2014	25%	Obligated utilities may: "Purchase renewable energy certificates derived from in-state or out-of-state new renewable energy facilities. Certificates derived out-of-state new renewable energy facilities shall not be used to meet <25% of the requirements, provided that this limitation shall not apply to an electric public utility with less than 150,000 NC retail jurisdictional customers as of 31 December 2006." Qualifying out-of-state facilities must be in service after 2006 or hydro facilities under 10 MW.
OK	Rest of US	no	0.0%	N/A	N/A	N/A
SC	Rest of US	no	0.0%	N/A	N/A	N/A
TN	Rest of US	no	0.0%	N/A	N/A	N/A

Province or State	E2020 Description	RPS since 05/01/08	2020 RPS % Region Sales Target	State goal for renewable (% of sales)	Out of State Permitted	New Restrictions on generation location
TX	Rest of US	no	1.0%	5,880 MW by 1/1/2015 Target of at least 500 MW from renewables other than wind	No - unless direct transmission connection.	Energy delivered into a transmission system where it is commingled with electricity from non-renewable resources cannot be verified as delivered to TX customers, thus eligible out of state generation requires a dedicated transmission line.
VA	Rest of US	no	0.6%	Standard: 12% of base year (2007) sales by 2022 Technology Minimum: None, but wind and solar power receive a double credit toward RPS goals.	Yes	Out of state generation allowed. Eligible renewable energy is (i) generated/purchased in the Commonwealth or in the interconnection region of the regional transmission entity, as it may change from time to time; (ii) generated by a public utility providing electric service in the Commonwealth from a facility in which the public utility owns at least a 49 percent interest and that is located in a control area adjacent to such interconnection region; or (iii) represented by certificates issued by an affiliate of such regional transmission entity, or any successor to such affiliate, and held or acquired by such utility, which validate the generation of renewable energy by eligible sources in such region.
Total E2020 Region Code: RU			**6.2%**			

Appendix J: Efficiency and Cost Data – Built Environment

Residential:

Residential Device Standards	
Equipment	**Effective Efficiency Standard**
Gas hot water from 1990 to the final year	59%
Oil hot water from 1990 to the final year	51%
Electric hot water from 1990 to the final year (inc.tank losses)	92%
LPG hot water from 1990 to the final year	59%
Electric air conditioning for 1990	260% COP = 2.6
Electric air conditioning for 1991	261% COP = 2.61
Electric air conditioning for 1992 to 2006	265% COP = 2.65
Electric air conditioning for 2007 to the final year	344% COP = 3.44
Electric Refrigeration for 1990 to 1992	34.5%
Electric Refrigeration for 1993	40.0%
Electric Refrigeration for 1994 to 2000.	42.0%
Electric Refrigeration from 2001 to the final year	54.7%
Biomass space Heating from 1993 to the final year (wood burning equipment)	63.0%
Gas space Heating from 1993 to the final year	80.0%
Oil space Heating from 1993 to the final year	80.0%
LPG space Heating from 1993 to the final year	80.0%

Residential (cont'd.)

Maximum Device Efficiency							
(Btu/Btu)	Electric	N.Gas	Coal	Oil	Biomass	LPG	Steam
Primary Heat	278%	97%	97%	97%	78%	97%	99%
Water Heating	250%	86%	97%	97%	78%	97%	99%
Other Substitutable Loads	130%	97%	97%	97%	65%	97%	99%
Refrigerators	98%	0%	0%	0%	0%	0%	0%
Lighting	95%	0%	0%	0%	0%	0%	0%
Air Conditioning	447%	113%	0%	0%	0%	113%	0%
Other Non-Substitutable Loads	98%	0%	0%	0%	0%	0%	0%

Note – Electric heating applications include heat pumps.
Non-substitutable loads are those loads which require electricity (refrigerators, electronics, etc.).
Substitutable loads are those loads which can use multiple fuels (i.e. Range, dryers, etc.).

Device Capital Cost								
1985$/mmBtu/Year	Electric	N.Gas	Coal	Oil	Biomass	Solar	LPG	Steam
Space Heating	17.7	23.1	19.0	36.0	17.2	132.0	23.1	36.0
Water Heating	8.5	18.5	19.0	23.5	17.2	82.0	18.5	23.5
Other Substitutable Loads	65.0	85.0	19.0	85.0	17.2	-	85.0	85.0
Refrigerators	96.5	-	-	-	-	-	-	-
Lighting	0.23	-	-	-	-	-	-	-
Air Conditioning	4.4	34.1	-	-	-	-	34.1	-
Other Non-Substitutable Loads	19.8	-	-	-	-	-	-	-

Device Operating Costs								
1985 $/mmBtu	Electric	N.Gas	Coal	Oil	Biomass	Solar	LPG	Steam
Space Heat	0.018	0.024	0.011	0.020	0.013	0.012	0.024	0.030
Water Heating	-	-	-	-	-	0.010	-	-
Other Substitutable Loads	-	-	-	-	-	-	-	-
Refrigeration	-	-	-	-	-	-	-	-
Lighting	-	-	-	-	-	-	-	-
Air Conditioning	0.015	0.017	-	-	-	-	0.017	-
Other Non-Substitutable Loads	-	-	-	-	-	-	-	-

Residential (cont'd.)

Physical Life of Equipment in Years (Residential)							
	Space Heat	Water Heating	Substitutable Loads	Refrigeration	Light	Air Conditioning	Non-Substitutable Loads
Electric	18	15	13	18	6	15	10
Natural Gas	18	15	13	0	0	15	0
Coal	18	15	13	0	0	0	0
Oil	18	15	13	0	0	0	0
Biomass	18	15	13	0	0	0	0
Solar	18	15	13	0	0	0	0
LPG	18	15	13	0	0	0	0
Steam	18	15	13	0	0	0	0

Commercial:

Device Efficiency Standards (Commercial)								
Btu/Btu	Electric	N.Gas	Coal	Oil	Biomass	Solar	LPG	Steam
Space Heating (primary)	450%	97%	97%	97%	65%	1000%	97%	99%
Water Heating	400%	97%	97%	97%	65%	1000%	97%	99%
Other Substitutable Loads	130%	97%	97%	97%	65%	1000%	97%	99%
Refrigerators	140%	0%	0%	0%	0%	0%	0%	0%
Lighting	95%	0%	0%	0%	0%	0%	0%	0%
Air Conditioning	400%	240%	0%	0%	0%	0%	200%	0%
Other Non-Substitutable Loads	98%	0%	0%	0%	0%	0%	0%	0%

Device Capital Cost (Commercial)								
$/mmBtu/Year	Electric	N.Gas	Coal	Oil	Biomass	Solar	LPG	Steam
Primary Heat	9.20	7.5	42.2	19.0	25.5	138.9	22.9	42.2
Water Heating	5.20	8.9	42.2	19.0	-	138.9	22.9	42.2
Other Substitutable Loads	19.80	11.3	11.3	19.0	-	-	11.3	11.3
Refrigeration	0.21	-	-	-	-	-	-	-
Lighting	0.02	-	-	-	-	-	-	-
Air Conditioning	9.20	34.1	-	-	-	-	34.1	-
Other Non Substitutable Loads	22.00	-	-	-	-	-	-	-

Device Operating Cost Fraction ($/Year/$)								
1985 $/mmBtu	Electric	N.Gas	Coal	Oil	Biomass	Solar	LPG	Steam
Space Heating (primary)	0.02	0.03	0.01	0.03	0.01	0.01	0.03	0.04
Water Heating	0.00	0.00	0.00	0.00	0.00	0.01	0.00	0.00
Other Substitutable Loads	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Refrigeration	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Lighting	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Air Conditioning	0.01	0.02	0.00	0.00	0.00	0.00	0.03	0.00
Other Non-Substitutable Loads	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

Physical Life of Equipment in Years							
	Space Heat	Water Heating	Substitutable Loads	Refrigeration	Light	Air Conditioning	Non-Substitutable Loads
Electric	18	8	10	15	7	18	7
Natural Gas	25	8	10	0	0	18	0
Coal	18	8	10	0	0	0	0
Oil	25	8	10	0	0	0	0
Biomass	18	8	10	0	0	0	0
Solar	18	8	10	0	0	0	0
LPG	18	8	10	0	0	18	0
Steam	18	8	10	0	0	0	0