RENEWABLE ENERGY DEVELOPMENT INFRASTRUCTURE PROJECT

COLORADO CLIMATE ACTION PLAN SCENARIO ANALYSIS

FOR

COLORADO POWER SECTOR

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1 INTRODUCTION

Colorado's burgeoning population and fast-growing economy trend toward ever increasing demand for energy services. During the 1990s, Colorado's population grew by over 30%.[1] In July 2006, the state had 4.75 million residents and a population growth rate that is third in the nation. Over the next decade an additional one million new residents are projected. Demand for electric power services drives estimates of future requirements for electricity generation over time, and concomitantly, of required added power plant capacity.

In 2005, Colorado's total reported in-state electricity generation reached 49,632 GWh or 10.45 MWh of electricity usage per capita per year. The state registered 47.4 million tons of carbon dioxide (CO2), that is 955 million tons CO2 per each GWh of electricity generated. By early 2007, Colorado's renewable generation capacity (excluding hydro) amounted to only 298 MW. Recently enacted legislation in Colorado changed the trend and more renewable resources are being incorporated into the resource portfolio of electric utilities. By end of 2008, the level of installed renewable capacity in Colorado reached about 1,100 MW.

In November 2007, Colorado Governor Bill Ritter, Jr. issued the Colorado Climate Action Plan (CAP)[2] which calls for CO2 emissions reduction by 20% below 2005 level by 2020, and further reduction by 80% below 2005 levels by 2050. The CAP also calls for increased energy efficiency by all utilities – investor-owned, municipal and cooperatives – by initiating or greatly expanding their DSM efforts to achieve half of the carbon reductions targeted in the electric utility sector.

[1] Colorado Alliance for Immigration Reform., available online at: http://www.cairco.org/data/data_co.html
[2] Available online at: www.colorado.gov/energy/in/uploaded_pdf/ColoradoClimateActionPlan_001.pdf

In April 2009, U.S. Representatives Waxman and Markey proposed Climate-Change Legislation entitled the "American Clean Energy and Security Act of 2009." This bill intends to establish a mechanism to reduce U.S. CO_2 emissions to 3% below the level of CO_2 emitted in the U.S. in 2005 by 2012. The target would further increase to 20% CO_2 emissions reduction below 2005 levels by 2020, and 83% by 2050. Several mechanisms for accomplishing these reduction goals have been discussed: a cap and trade program in which all allowances are auctioned given assigned allowances based on historic emissions, and the implementation of a federal tax on carbon emissions.

The targeted CO_2 emissions reduction for both the proposed federal legislation and the Colorado CAP is the same for 2020, which is 20% CO_2 emissions reductions by 2020. Since the electric power sector contributes as high as 48% of CO_2 emissions in the state according to a 1998 inventory[3], and as low as 36% according to the CAP, meeting CO_2 emissions reduction goals for CAP or federally enacted legislations will require a significant change in the Colorado electric power sector's generation mix. In order to assess, in conjunction with the REDI project, the likely effects of CAP or proposed climate change legislation on the power sector's resource portfolio, an analysis and examination of ranges of resource options has been produced in this report.

The development of energy scenarios allows a way to analyze and examine a range of resource portfolios and policies for consideration of alternative possibilities. An important step for any system planning modelling exercise is to establish a baseline scenario that represents a reasonable progression of a system's advancement into future years taking into account certain aspects of the current and future conditions. This study provides the results of such a scenario analysis.

[3] Colorado Department of Public Health and Environment, available online at: www.cdphe.state.co.us/ap/down/climatechange.pdf, page 13.

To date there has been no statewide power sector model for Colorado integrating the various features described above. This study is the first direct statewide assessment of the new legislative mandates for more renewable and energy efficiency measures to reduce greenhouse gas emissions from the power sector while assessing pathways to meet the CAP goals by 2020. The intention is to provide utilities, policy-makers, and the public with a more detailed understanding of approaches Colorado's electric power sector could take in order to meet the CAP's 2020 carbon reduction goal.

2 SCENARIO ANALYSES

For this study, we model Colorado's statewide electric power sector while balancing economic costs and carbon reduction benefits. We developed a Reference Scenario for the Colorado power sector incorporating the statewide existing generation fleet, future generation expansion, the state's Renewable Energy Standards (RES) requirements, and the state's mandated Demand Side Management (DSM) measures to meet the forecasted energy needs. This study provides a statewide energy planning and policy evaluation that not only considers ways to respond to increased energy needs but also ways to decrease the sector's carbon footprint in response to the CAP.

2.1 Background on Colorado's Power Sector

Table 1 shows the mix of generation mix in Colorado from 1990 through 2005. Electricity generation from coal in Colorado grew at about 1.3% annually. Colorado's electricity supply was dominated by coal whose contribution to the grid's energy mix was at 90% in 1990.

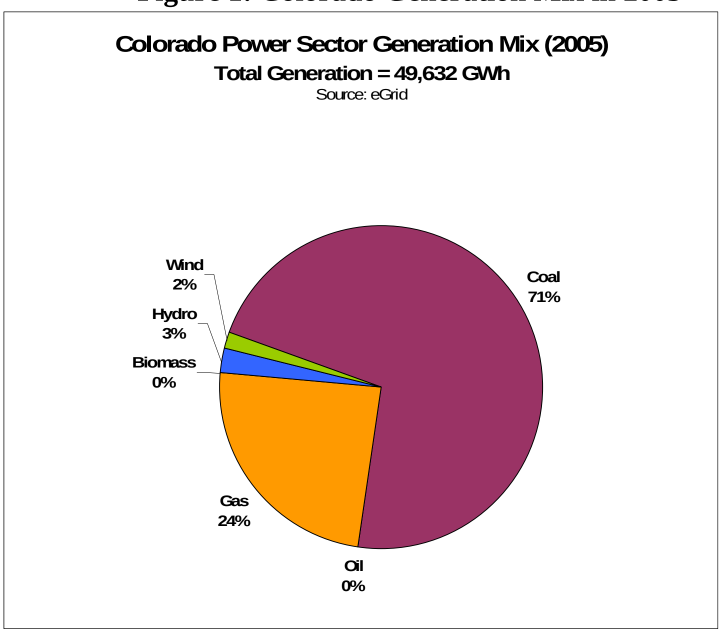
Table 1: Colorado Net Generation by Fuel Type (1990-2005)

Fuel Type	1990 (MWh)	1995 (MWh)	2000 (MWh)	2005 (MWh)	Average Annual Growth Rate (%)	1990 Share (%)	1995 Share (%)	2000 Share (%)	2005 Share (%)
Coal	29,814,983	30,492,682	35,381,219	35,570,135	1.3%	91.6%	85.6%	80.1%	71.7%
Oil	27,390	11,712	109,385	17,046	-2.5%	0.1%	0.0%	0.2%	0.0%
Natural Gas	1,290,092	2,856,788	7,157,438	11,923,290	54.9%	4.0%	8.0%	16.2%	24.0%
Other Gas	0	0	0	2,430	-	0.0%	0.0%	0.0%	0.0%
Hydro	1,419,870	2,131,189	1,454,415	1,415,296	0.0%	4.4%	6.0%	3.3%	2.9%
Renewable	28,990	32,910	17,914	810,561	179.7%	0.1%	0.1%	0.0%	1.6%
Pump Storage	-33,198	91,953	45,175	-122,063	17.8%	-0.1%	0.3%	0.1%	-0.2%
Total Generation	32,548,127	35,617,234	44,165,546	49,616,695	3.5%	100.0%	100.0%	100.0%	100.0%

Source: DOE/EIA

The last decade's expansion of gas fired generating units to meet load growth, about 24% of total generation mix, has lowered the contribution of coal in the gird mix to 71% by 2005. See Figure 1.

Figure 1: Colorado Generation Mix in 2005



In 2004, Colorado voters passed the first in the nation citizen-initiated referendum that created a RES for the State- Amendment 37. The initiative required 10% of investor-owned utilities' retail energy be produced from renewable energy resources. The initiative also placed a requirement that 4% of the RES be sourced from solar power (one-half of which must be customer-sited).

In 2006, the Colorado legislature passed a law that provided regulatory guidance to the Colorado Public Utilities Commission that encourages the development of coal-fired integrated gasification combined-cycle generation.

In 2007, House Bill 1281 doubled the amount of RES to 20% for investor-owned utilities, and added a 10% requirement for non-regulated utilities (Cooperatives and Municipalities). In addition, a separate Senate Bill 100 encouraged the development of new transmission infrastructure to support the development of new renewable energy resources. A third bill, House Bill 1037 established energy efficiency and DSM goals for the regulated utilities. And as mentioned earlier in November, 2007, the Governor Ritter released his statewide climate action plan to reduce CO2 emissions by 20% from 2005 actual emission levels by 2020 and 80% by 2050.

These new legislative actions in Colorado have opened up new opportunities for the emerging New Energy Economy. The policy changes have created challenges for both the regulators and the utilities. Most significantly, the new legislation has caused the Colorado Public Utilities Commission to replace the earlier “least-cost” and “fuel neutrality” utility planning goals with the a more practical approach of "cost effective resource planning.” This new standard was incorporated into revised Electric Resource Planning at the PUC. The cost-effective resource planning standard takes into consideration the costs and benefits of adding more renewable resources and DSM programs to the utility's resource plan for resource acquisition. In addition to legislation, recent uncertainty and volatility in natural gas prices has also affected Colorado’s future electric supply outlook. As a result, after three decades of no new coal plant construction, a new 750 MW coal-fired generating station (in Pueblo) was approved by the PUC in 2005 - it will be operational by the end of 2009.

As seen in Figure 1 above, coal and natural gas still dominate Colorado electricity supply. With price volatility in natural gas and coal at risk of future carbon regulation, renewables such as wind and solar are increasingly becoming attractive policy alternatives coupled with energy efficiency measures. However, the integration of utility-scale renewable energy resource is constrained to a considerable extent due to lack of transmission infrastructure to connect the newly developed renewable energy zones, which are in remote areas, to load. The variable nature of wind has also placed a limit on the integration of wind generation into the system (e.g., see Xcel Energy's recent wind integration study).[4]

There are 57 electric distribution utilities serving end-use customers in Colorado. Two investor-owned (IOUs) utilities (Xcel Energy doing business as Public Service Company of Colorado and Black Hills Energy) serve close to 60% of the state's electric customers. These utilities operate under the economic regulatory jurisdiction of the Colorado Public Utilities Commission. The other 40% of the state's end-use customers are served by self-regulated Municipal (17%) and Rural Electric Cooperative (23%) utilities. According to the U.S. Department of Energy's Energy Information Agency's (EIA) historical data, Colorado's electric end-use customer split consist of three main customer classes: residential (34%), commercial (41%) and industrial (25%). Legislative RES and DSM requirements impact the two types of utilities differently in Colorado. The RES results in greater carbon reduction for IOUs as compared to non-IOUs. The DSM requirements only apply to IOUs.

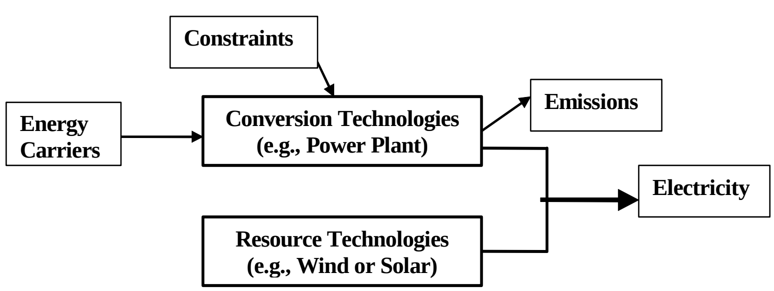
[4] Available online at:
www.nrel.gov/wind/systemsintegration/pdfs/colorado_public_service_windintegstudy.pdf

3 MODELING METHODOLOGY

We use the MARKAL modeling framework to investigate scenarios of future electric generation technologies in Colorado and their impact on the environment.[5] MARKAL is a model that represents an energy system commencing from the extraction or importation of fuels, through their conversion to useful forms (such as electric power), to meet end-users' demands. The model determines the least-cost pattern of technology investment while meeting the required energy demands and model constraints, and then calculates the resulting environmental impact such as carbon dioxide emissions.

The objective of the model is to minimize the discounted total system cost for a region (or a set of regions if multiple regions are modeled) obtained by adding the discounted periods' total annual cost. The total includes annual operating costs, annualized investment costs, and a cost representing the welfare loss incurred when demands for energy services are reduced due to their price elasticity.[6] This objective is equivalent to maximizing the total surplus (consumers' plus producers' surpluses). The building blocks depicted in Figure 2 represent the stylized power sector network, referred to as a Reference Energy System consisting of energy carriers, conversion or resource technologies, and energy services.

Figure 2: Generic Reference Energy System for Power Sector



[5] MARKAL model is a linear programming model focused strictly on the integrated assessment of energy systems.
[6] This cost is determined when Demand Elasticity is modeled.

4 MODEL DEVELOPMENT

The modeling horizon employed for this exercise is 30 years. A year is divided into three seasons with spring and fall seasons combined. Seasons are divided into three time fractions; day, night, and peak hours. Since Colorado is a net importer of electric power, power imports from neighboring states are modeled to account for utility fixed contracts and other imports under mere economic conditions.

In order to investigate scenarios of future electric generation technologies and their impact on the state's future CO_2 emissions, the following scenarios were developed and evaluated:

- Reference Scenario
- Carbon Policy Scenario
- Sensitivity Scenarios (with and without the CAP Scenario)
    - Low Energy Demand Forecast (1.4% per year) compared to the Reference Scenario of 2% per year
    - High and Low Natural Gas costs (+/- 30% of the Basecase costs)
    - Low Availability Factor for Coal-Fired Plants (20% below Basecase)

We first developed the Basecase which represents an expansion plan for Colorado incorporating the existing generation fleet while optimizing new capacity additions to meet the forecasted energy demand. We then introduced the DSM and RES scenarios to the Basecase to develop the Reference Scenario. The Reference Scenario serves as the basis for the subsequent analysis of alternate technology and policy scenarios. Table 2 shows the scenarios we analyzed for this study.

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Table 2: Descriptions of Scenarios Analyzed

Name	Scenario Descriptions
BA	Basecase
BAD	Basecase + DSM Goals (300 GWh per year)
BADR	Reference Case (Basecase + DSM + RES goals)
BADRC	Reference Case + CAP
Sensitivity Scenarios	
BADRAF	Reference Case with Coal Plants Reduced Availability Factor by 20%
BADRAFC	Reference Case with Coal Plants Reduced Availability Factor + CAP
BADRHG	Reference Case with High Gas Cost by 30%
BADRHGC	Reference Case with High Gas Cost + CAP
BADRLG	Reference Case with Low Gas Cost by 30%
BADRLGC	Reference Case with Low Gas Cost + CAP
BADRLD	Reference Case with Low Energy Demand Forecast (1.4% per year)
BADRLDC	Reference Case with Low Energy Demand Forecast + CAP

4.1 Advance Technologies

In this study a total of 6 advanced technologies are utilized. The conventional pulverized coal-fired technology is utilized but is considered to be equipped with Carbon-Capture and Sequestration (CCS) technology at 50% CO2 capture capability. The Integrated Gasification Combined Cycle (IGCC) technology is also utilized which is a power generation process that integrates a gasification system with a conventional combustion turbine combined cycle power block for generating electricity with coal or natural gas. The coal IGCC technology is considered to have 50% CCS capability while natural gas IGCC with 90% CCS capability. Advanced nuclear technology is considered and utilized since some utilities are considering nuclear generation as a viable option to reduce CO2 emissions in the future. The first availability of these advanced technologies is considered to be in 2017. Other more advanced natural gas technologies such as improvements to advanced combined cycle and combustion turbines that have higher efficiency ratings are also utilized in the model with assumed availability starting in 2014.

4.2 Demand Side Management in Colorado

Colorado's two IOUs and several non-IOU utilities have pursued DSM programs to varying degrees over past years. For example in 1993, Colorado utilities spent 0.40 percent of revenues for DSM programs with an estimated savings of 0.53 percent of sales. The DSM activities dropped in the late 1990s, mostly due to the anticipation of the introduction of retail competition in the electric utility industry restructuring era. For example in 1998, Colorado utilities spent 0.11 percent of revenues for DSM programs with an estimated savings of 1.29 percent of sales. A total of 0.29 percent negative changes from 1993 spending level.

As mentioned earlier, there are two IOUs in Colorado subject to rate regulations under the Colorado Public Utilities Commission (PUC). Both IOUs serve approximately 60% of the state's customers and electricity sales. These regulated utilities have a major role to play in energy efficiency and conservation programs. Xcel Energy has been involved in DSM programs since the 1980s as a result of PUC requirements. As part of a 2005 decision rendered in a Least-Cost Planning proceeding, the PUC ordered Xcel Energy to provide more DSM programs to its customers, accompanying the approval of Xcel's proposed first coal-fired power plant in more than two decades. [7] Xcel Energy committed to undertake a total of 320 MW of demand reduction and 800 GWh of energy savings over the 8-year period (i.e., 100 GWh per year or 0.38% of annual sales) beginning in 2006 and ending in 2013. The total cost of this undertaking was proposed for approval at $196 million (1996 dollars).

[7] See Xcel Energy's Certificate of Public Convenience and Necessity for Comanche 3 Pulverized Coal Power Plant before the CPUC, Dockets 04A-214E, 04A-215E, and 04A-216E.

In 2007, Colorado General Assembly passed a Demand Side Management bill, HB07-1037.[8] The bill required the Colorado PUC to establish energy savings and demand reduction goals (e.g., sets minimum goals) for regulated utilities (IOUs) to acquire through energy efficiency, conservation, load management, and demand response programs. The impact of these goals is to reduce the energy and capacity that the effected IOU would have traditionally planned to serve through supply-side resources. The bill also allows for utility investments in cost-effective electric DSM programs to be more profitable to the utility than any other utility investment that is not already subject to special incentives. The legislation also specifies that the goal of DSM shall be consistent with allowing all classes of customers an opportunity to participate in DSM programs and be consistent by giving due consideration to the impact of DSM programs on non-participants and on low income customers, which basically means that no rate increases should be due to increased DSM measures.

4.3 Impact of New Legislation on DSM in Colorado

In response to the new law, in 2007, Xcel Energy offered an Enhanced DSM Plan to its customers. Their application was litigated at the PUC, and the Commission approved their plans with slight modifications. For the period 2009-2020, in addition to the 2003 Least Cost Planning DSM requirements, Xcel Energy proposed to spend $738 million (2006 dollars) on more DSM programs to achieve 2,350 GWh (i.e., about 200 GWh per year) of energy savings.

In this study for the REDI project, a DSM scenario is modelled based on the assumptions that the IOUs are required by the PUC to invest in DSM measures and achieve a set amount of energy savings per year with the goal of

[8] House Bill 07-1037, "*CONCERNING MEASURES TO PROMOTE ENERGY EFFICIENCY, AND MAKING AN APPROPRIATION THEREFOR*", enacted 2007.

11% of 2006 retail energy sales.[9] In its recent report to the Colorado General Assembly, the Commission reported the rate regulated utilities (Xcel Energy and Black Hills) DSM programs will achieve total energy saving of 3,176 GWh by 2018. We have modeled a total of 3,900 GWh of energy savings by 2020 from all utilities in Colorado[10]. Our approach is based on energy savings of 300 GWh per year accumulating over the years throughout the planning horizon. The accumulated total energy savings over the planning horizon for both IOUs would be 8,400 GWh by 2035.

The cumulative annual energy savings are modeled as part of the Reference Scenario. For example, for year 2020, total energy savings of 3,900 GWh is modeled as DSM contribution to energy savings at the penetration rate of 25% Residential, 65% Commercial, and 10% Industrial. Xcel energy performed a comprehensive DSM study suggesting the DSM penetration distribution rate in Colorado is 25/75 between residential and commercial/industrial customers, respectively. [11] The annual incremental energy savings will peak at 3,900 GWh or 5.4% of total energy demand forecast in year 2020 and is assumed that investments in DSM will continue into the future years on the same rate of 300 GWh of energy savings per year. It is important to note that these DSM levels certainly are subject to change based upon the IOUs' proposals and the PUC's orders. However, for modeling purposes of a Basecase, upward or downward levels of DSM were not assumed.

In this study, DSM is modeled as a resource contributing to the reduction of total energy requirements and the system's need for fuel and new capacity over

[9] See the PUC's report to Colorado General Assembly on DSM pursuant to HB 07-1037, April 28, 2009. Also, see the PUC Docket No.07A-420E.

[10] This amount accounts by 2020 for Xcel Energy about 3500 GWh, Black Hills about 100 GWh, and the remaining 400 GWh from all other Cooperatives and Municipalities.

[11] Recent study by Xcel Energy shows a penetration rate of 75/25% for commercial and residential customers, respectively.

the life of the DSM resources. We have also utilized Xcel Energy's DSM costs reported in the 2009-2010 DSM biennial filing. We have used Xcel Energy's Program cost at Generator of $856/kW for 2009 and $895/kW for 2010 with an escalation rate of 4.6% throughout the study period as the cost of DSM/EE scenarios implementation. We adopted Xcel's DSM costs as the utility avoided costs for the cost of DSM programs since Xcel represents the largest electric utility actively pursuing DSM measures in Colorado.

Beginning in 2010, Xcel Energy will estimate the annual avoided emission costs as environmental benefits of DSM measures. In this study, the Reference Scenario internalizes the DSM avoided emissions as part of energy efficiency/conservation benefits by using less fossil fuel generation.

4.4 Renewable Energy Standards (RES) Scenario

As mentioned above, the 2004 RES (Amendment 37) applied to the two rate regulated utilities in the state, Xcel Energy (PSCo) and Black Hills. It allowed a few other Colorado covered utilities (those with 40,000 or more customers) to opt out of the RES, or an exempt utility to opt in, with a majority vote involving a minimum of 25 percent of the utility's customers. Intermountain Rural Electric Association and United Power voted to opt out. Colorado Springs Utilities voted to remain part of Amendment 37.

In 2007, HB07-1281 increased the amount of electricity a utility must generate or cause to be generated from renewable energy resources. The previous RES established by the voter-approved in 2004 Ballot Amendment 37, required utilities to meet a 10% RES by 2015 and required 4% of that standard to be obtained from solar energy sources. HB07-1281 doubled these requirements by mandating that by 2020 IOUs must meet a 20% RES. This legislation continued the requirement of Amendment 37 for the IOUs to satisfy 4% of the RES from solar resources. Also in 2007, another Bill was passed, SB07-100**,** which provided a mechanism for the designation of energy resource zones and the development of additional transmission infrastructure for delivery of renewable energy from those zones (e.g., from remote wind farms) to the load centers of the utilities. Of significance, SB07-100 does not apply to rural electric cooperatives, municipal utilities, and Colorado's sole cooperatively-owned generation and transmission utility (Tri-State Generation and Transmission Association).

Each scenario is described in the following sections with results presented in terms of a summary with major model inputs, model calibration, and presentation of reference scenario results compared to other scenarios.

5 MODEL DATABASE DEVELOPMENT

This study concentrates on the electric power system of Colorado and presents the development of a supply-side energy system incorporating Renewable Energy Standards (RES), Energy Efficiency and Demand Side Management (DSM) measures. The focus of the work is to demonstrate the current status of power sector in Colorado and to quantify the pathways for a carbon-constrained future electric power system.

5.1 Demand and Energy Forecast

Electric resource planning requires energy and demand load forecasting for those years in the planning horizon. There is no statewide long-term energy demand forecast available for Colorado that can be used for this study. Utilities in Colorado perform their own long-term forecast for their own use. The long-term forecast of the two regulated utilities (Xcel Energy and Black Hills) that serve almost 60% of the state's load is publicly available. The other 40% of the state's load is served by cooperative and municipally owned utilities with limited publicly available long-term forecasts. In order to develop a statewide energy and demand forecast for the planning horizon of 30 years, two recent studies were utilized- 1) the Rocky Mountain Area Transmission (RMATS) Study, and 2) the Colorado Energy Forum (CEF) Report.

A trend analysis was performed to curve fit historical data from the DOE/EIA, combined with the projected energy and demand data from RMATS and CEF. Results of Trend Analysis were used to build Colorado Demand and Energy requirements for each Sector. The results of Trend Analysis show an average annual growth rate of 2.0% and 1.9% for energy and demand, respectively. See Tables 3 and 4 for Colorado energy and demand forecast, respectively, utilized in the model as Reference Scenario.

Table 3: Colorado Energy Forecast (Low, Base, High)

Colorado Energy Forecast (GWh)			
Year	Low (1.4%)	Base (2.0%)	High (2.9%)
2005	48,353	48,353	48,353
2008	53,138	54,811	55,270
2011	55,565	59,271	60,395
2014	58,103	63,731	65,995
2017	60,757	68,191	72,115
2020	63,533	72,651	78,802
2023	66,435	77,110	86,109
2026	69,469	81,570	94,094
2029	72,643	86,030	102,819
2032	75,961	90,490	112,353
2035	79,431	94,950	122,771

We have used the Base energy demand forecast, as represented in Table 3, to model the statewide Reference Scenario. We have also run a sensitivity scenario with the Low energy demand forecast to assess the impacts if, in case, the statewide energy needs grew at a slower pace as a result of the recent slowdown in economic activity.

Table 4: Colorado Energy Demand Forecast (Low, Base, High)

Colorado Demand Forecast (MW)			
Year	Low (1.4%)	Base (1.9%)	High (2.4%)
2005	9,664	9,664	9,664
2008	10,114	10,390	10,417
2011	10,575	11,176	11,218
2014	11,059	11,962	12,081
2017	11,564	12,747	13,010
2020	12,092	13,533	14,010
2023	12,644	14,319	15,088
2026	13,222	15,105	16,248
2029	13,826	15,890	17,497
2032	14,457	16,676	18,842
2035	15,118	17,462	20,291

Based on this demand forecast, it is projected that Colorado will need to add - to the existing 2005 installed capacity of 11,232 MW[12] - new generation resources of 2,644 MW and 4,466MW for years 2014 and 2020, respectively.[13]

The end-use customers in Colorado are represented by three classes or "sectors": residential, commercial, and industrial sectors. The relationships of each sector to total energy requirements were developed from available historical data from EIA for 2000-2005. Table 5 shows the distribution of total energy requirement among the three sectors.

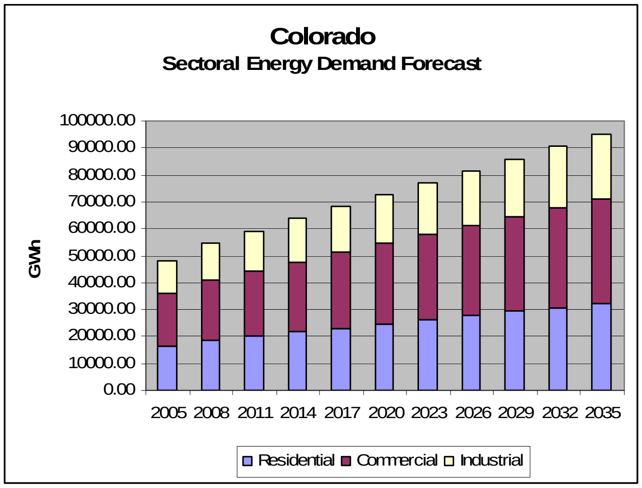
Table 5: Colorado End-Use Sectors Share of Total Energy Requirements

End-Use Percent Share of Total Energy Requirements		
Residential	**Commercial**	**Industrial**
34	**41**	**25**

[12] We use 2005 as Base-Year for the modeling purposes due to availability of public data.
[13] This need is based on the forecasted demand for each year plus a 16% reserve margin. For example, for 2014, the need of 2,644 MW is calculated by taking the forecasted demand of 11,962 MW plus 1,914 MW for reserve margin less 11,232 MW of existing installed capacity in 2005.This capacity estimate does not include any transmission and distribution losses, which usually run between 3-6%.

As discussed earlier, the demand for electric services over time serve as the primary driver for the requirements of future power plant capacity additions and electric generation to serve the expected load. The aggregated view of the energy demand composition for each sector is shown in Figure 3. The commercial sector dominates the usage followed by the residential and industrial sectors, respectively.

Figure 3: Colorado Sectoral Energy Demand

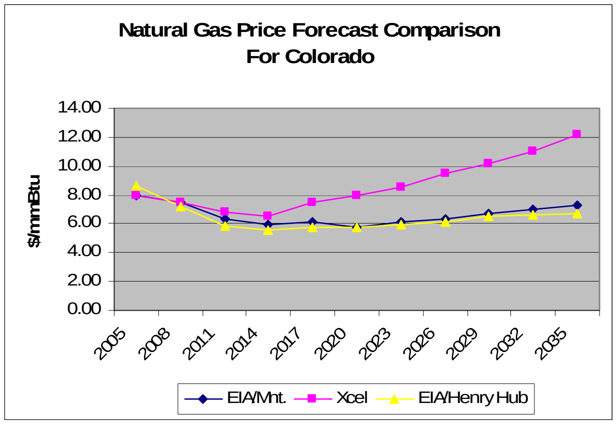


5.2 Fuel Supply Prices

Fuel supply price inputs to the model are those developed by Xcel Energy for Colorado. Data for fuel supply prices were gathered from EIA and Xcel Energy's 2007 Colorado Resource Plan. Xcel Energy uses various sources of data to compile and develop its fuel prices. For example, for gas prices, it used a blend of the New York Mercantile Exchange, the EIA, and two private industry sources. Figure 4 show the comparison of gas price projections by EIA and Xcel Energy. Natural gas price forecast developed by Xcel Energy is higher than EIA and more representative of fuel market in the region and therefore were adopted and utilized as input to this model. We also used sensitivities runs to represent price volatility of natural gas by increasing and decreasing the baseline natural gas prices by 30 percent. Natural gas price fluctuations are known to all as extremely volatile.

However, to place our projections within reasonable bounds, we confined the high and low sensitivity runs to plus/minus 30 percent.

Figure 4: Natural Gas Price Forecast



The same reasoning goes for other fuel types. For example, Xcel Energy developed coal prices for its Colorado operation using various sources as well. Both Powder River Basin, Wyoming (PRB) and Colorado-Wyoming (CO-WY) coal types are utilized in the model with prices adopted from Xcel Energy coal prices. Coal prices for both PRB and CO-WY coal resources are assumed to be the same. We did not run coal price sensitivity since coal prices are pretty much stable throughout the life of coal contracts. Recent trends indicate that coal prices in the future may be more volatile than has historically been the case. However, for modeling purposes, we have not made assumptions that the price is going to vary dramatically from longer-term historic price trend-lines.

5.3 Existing Installed Capacity

Using 2005 data, we aligned and calibrated the model's Base-Year (2005) with the total installed electric generating capacity of 11,232 MW in Colorado. This includes 5,143 MW of coal-fired plants (1,733 MW of bituminous coal, 3,410 MW of sub-bituminous coal). Colorado also had 4,226 MW of gas-fired power plants (1,760 MW of combined cycle and 2,460 MW of combustion turbine) and 107 MW gas-fired steam plants, and 276 MW of internal combustion plants. The remaining generation in 2005 includes 643 MW of hydro, 563 MW of pumped storage hydro, 265 MW of wind, and 10 MW of solid waste. The Base-Year (2005) is modeled with all the existing installed capacity and the respective operating characteristics of the plants, including availability factors, and carbon emissions.

5.4 Renewable Technologies

Renewable electricity generation encompasses a collection of technologies including:

- Wind turbines
- Solar generators;
    - Photovoltaic technology (On-site PV and central PV)
    - Concentrated Solar Power (inclusive, or exclusive of thermal storage)
- Geothermal power
- Biomass-fired generators
- Landfill methane

Each of above technologies has found different degrees of market opportunities, especially when supported by government policies and incentives. Absent government incentives, a few are able to economically compete directly with available best conventional generation technologies. The push towards more clean, domestic, renewable electric power sources over the next decade is widely expected to significantly change the cost and availability of renewable technologies. Increased demand is expected to induce more research and development that will bring many improvements in renewable technologies resulting in lower costs and better performance.

5.5 Solar

A recent report by the Western Governors' Association (WGA) projects as much as 8,000 MW of solar capacity could be installed in the Western states with a combination of distributed solar electricity systems and central concentrating solar power (CSP) plants by 2015, and an additional 2,000 MW of solar thermal systems could be installed in the same timeframe. WGA further projects by 2015, the cost of electricity from future CSP plants should be competitive with plants burning costly natural gas, and distributed systems should have declined in price to the point that they should be able to produce electricity below retail utility rates in most parts of the West.

Colorado has over 300 days of sunshine per year, making it an ideal location for solar photovoltaic and solar thermal electric power technologies. Colorado's RES for IOUs requires 4% of their RES must be from solar and 50% of that must be from "on-site" solar systems (typically a PV system) located at customers' facilities.

5.6 PV and Concentrated Solar Power

Central station solar power technologies include both solar thermal electric and photovoltaic (PV) generators. The vast majority of the central station solar projects underway or actually deployed today are concentrating solar power (CSP) technologies. Concentrating PV and flat-plate PV are increasingly be used for utility-scale systems. As PV costs decline and its market volume grows, central station flat plate PV deployment will become more commonplace. The WGA report cites a Solar Task Force survey of the CSP industry indicating capability to produce over 13 GW by 2015 if the market could absorb that much.

The WGA Solar Task Force also projects that, with a deployment of 4 GW, total nominal cost of CSP electricity would fall below 10¢/kWh. Analysis shows that CSP at 10¢/kWh is equivalent to a blended base load-peak value of natural gas generation at a fuel cost of $7/mmBtu. Achieving 4 GW of CSP deployments by 2015 from the current 354-MW base requires growth similar to that of the PV and wind industries in the past decade.

5.7 Solar Limits

For the purpose of this modeling exercising, a Rule-Based constraint is designed to capture the RES requirements in Colorado within the model. The percent requirement is modeled as a floor (i.e., a required bound since it is mandated) for the renewable generation in Colorado. The Rule Based constraint also recognizes the fact that the RES requirements for solar generation shall include 4% from solar of which a minimum of 50% of the 4% shall be from distributed solar (i.e., on-site solar). We have also modeled the expected installed capacity of CSP in the Reference Scenario to reach at a minimum to 1000 MW by 2020. There are two reasons for our modeling assumption of 1,000 MW of CSP by 2020: 1) there is a lot of interests in the development of CSP in San Luis Valley mainly due to the fact that two major utilities in the state have proposed to build high-voltage transmission lines connecting solar rich San Luis Valley to load center[14], and 2) the PUC's electric resource planning allow regulated utilities to be on a path where it is a reasonable to include and reach 1,000 MW CSP goal within their resource plans.

5.8 Wind

In 2001, the Colorado PUC ordered Xcel Energy to include a 162 MW wind plant as part of its integrated resource plan. At this point in time, Xcel is purchasing output from nearly 1,100 MW of installed wind capacity. Xcel has added 835 MW to its resource portfolio to meet the minimal non-solar levels of the RES requirements through 2020. This activity displaces what otherwise would

[14] In April 2009, Xcel Energy and Tri-State G&T filed an application before the PUC to build a double-circuit transmission lines between San Luis Valley and Pueblo, Colorado.

be fossil-fired generation, which reduces both gas and coal burning resulting in associated CO2 emission reductions. We have modeled Xcel Energy wind capacity for 2005 and 2008 as existing and planned wind capacity, respectively.

We have made a distinction in the model between the availability and capacity factor of wind generation in the Generation Development Areas (GDAs). Table 5 shows three types of wind power generation modeled with MW availability and capacity factors.

Table 5: Modeled Wind Power MW Availability and Capacity Factor

GDAs	MW	Wt. Average Capacity Factor
Wind GDA 1 & 8	2,000	42%
Wind GDA 2	1,283	36.6%
All other GDAs	18,000	34%

These numbers were calculated from the wind GDA data used in the SB07-91 report, "Connecting Colorado's Renewable Resources to the Markets.[15] The best 25% of wind resources in the GDAs were taken and a weighted average capacity factor was calculated based on remaining potential in each wind class. Our study showed that by disaggregating the wind into three types, the discounted total system cost is reduced by more than one billion dollars over the 30 years planning horizon. This is mainly due to higher capacity factor of Wind in GDA 1, 2, and 8 than just utilizing one type of wind in the model with an average 35% capacity factor.

5.9 Wind Limits

The Rule-Based constraint for renewables allows non-solar renewables to fulfill the RES mandated requirements after taking under consideration the 4%

[15] Available online at: http://www.colorado.gov/energy/index.php?/resources/category/publications

share required for solar technologies. Since other renewable technologies such as geothermal and biomass currently have limited scope and scale availability in Colorado, wind technology captures the majority of RES requirements which reaches about 16% of total electric sales by 2020. In the Reference Scenario, the RES requirement is modeled as noted in RES section earlier. For the Carbon Policy scenario, the RES requirement is considered as the floor (i.e., the lower bound) but wind penetration is capped at 33% of total electric retail sales in 2035.

The reason for capping wind penetration at 33% is primarily due to recent electric utilities' independent studies that the variable nature of wind generation could only be economically and operationally integrated into the utility system up to a certain percentage of the total utility generation. Beyond certain limits, the integration of wind generation becomes more costly, thus less economical. For example, Xcel Energy recently performed a wind integration study for wind integration of 10% (722 MW), 15% (1038 MW), and 20% (1444 MW) into Xcel energy's system in Colorado and reported different integration costs and limits for its Colorado operation. Should advances in operational integration of variable wind penetration prove successful; the 33% penetration cap will be viewed as a conservative assumption.

5.10 Near-Term Power Plants Retirements

Colorado's recent legislative mandates on the power sector industry to add more DSM programs and renewable technologies to their resource portfolio, coupled with the statewide CAP targets, and the potential of federal legislation to reduce carbon dioxide emissions, have heightened utilities' awareness regarding greenhouse gas emissions. Several utilities have started voluntarily to plan responsibly, including a strategy of retiring old coal-fired plants. In its 2007 Electric Resource Plan, Xcel Energy proposed to retire four existing generation units and make up for the lost generation through new natural gas combined cycle additions. The PUC approved this, so in the Reference Scenario, a total of 353 MW of coal-fired capacity is retired from the Base Year 2005 total installed capacity.

Xcel Energy in its Resource Plan states the retiring these four coal units and re-powering them with a 480 MW combined cycle plant is expected to reduce CO2 emissions by 1.4 million tons per year.[16] The four coal units are modeled as retired in the Reference Scenario and the decision to replace the units is made by the model which in the Reference Scenario would be the same as Xcel Energy's decision that is a replacement of equal amount of capacity with conventional combined cycle technology, however in policy scenarios the decision would be based on the economics and carbon policy constraints.

Although there may be candidates for retirements of coal generating stations in the Colorado's electric fleets that could be considered by 2020, those candidates have not been modeled in this study's scenario.

5.11 Approved and Proposed Future Power Plants

Due to uncertainty and volatility in natural gas prices, coal-fired generation has re-entered the thinking at some utilities as a viable option in the utilities' near-term resource portfolios. Xcel Energy, Holy Cross' and Intermountain's new coal-fired power plant (Comanche 3 in Pueblo) with a capacity of 750MW was approved by the PUC in 2005, with an in-service date of 2009. This new generating station is captured in the model as an investment of $1.3 billion, plus the transmission interconnection and delivery cost (i.e., $2,020/kW in 2005$). In addition, the possibility of building an additional 600MW coal-fired IGGC unit by 2017 is captured in the model. This was captured in the model because it was referenced in Xcel's Electric Resource Plan.

[16] See Xcel Energy 2007 Resource Plan at

5.12 New Power Plants

All new capacity decisions will depend on the initial capital costs, operating efficiencies, capacity values, fuel prices, carbon policy constraints, and other operational factors. Natural gas plants are generally the least expensive capacity to build with about half the CO2 emissions per MWh as coal. However, natural gas plants are characterized by comparatively much higher, and more volatile, fuel costs. Advanced technologies like IGCC, nuclear, and renewable plants are typically more expensive to build than gas plants, but have relatively lower operating costs. In addition, many advanced technologies receive tax credits, and can more readily meet low carbon policy objectives. Of course, wind and solar resources have no fuel costs, which serve as an important hedge against future price volatility.

The database for this study contains 14 generating technology options for future capacity needs consideration. The model covers a 30 year study period from 2005 to 2035 in three years increments. Table 6 shows the conventional thermal, advanced technologies, and renewable technologies utilized in the Reference Scenario and all other scenarios.

The cost and performance characteristics of some of these resources were updated from Xcel Energy's 2007 Electric Resource Plan, and internal communications with the GEO and NREL staff.[17]

5.13 Discount Rate and Inflation Rate

Utilities use financial market risk measures to determine cost of capital or the discount rate for calculation of net present value of proposed capital investment decisions. By definition the appropriate discount rate for an investment is the opportunity cost of capital – the rate of return that investors

[17] It is assumed that Xcel Energy's data is more up-to-date than other sources and therefore is adopted for some technologies in this study.

expect in capital markets for the same degree of risk as the risk associated with the project being considered.

The discount rate is considered as a global parameter within the MARKAL model to represent the time value of capital for energy systems investment from the societal point of view. The discount rate used in the Basecase is assumed to be at 7.5%. This is consistent with the largest utility in Colorado, Xcel Energy's current discount rate of 7.88% based on after-tax weighted average cost of capital. As discussed in previous sections, IOUs serve close to 60% of Colorado's electric load and are the main drivers in generation resources capital investment in Colorado. An inflation rate of 1.5% is assumed for commodity prices beyond 2005.

Table 6: Thermal and Renewable Resources Cost and Performance Data

Modeled Power Generation Technology##	Capital Cost# ($/kW)	Life	Heat Rate# (Btu/kWh)	AF (%)	VAROM ($/MWh)	FXDOM ($/kW/yr)	Emission Rates# CO2 (lb/MWh) Output	NOx (lb/MWh) Output	SO2 (lb/MWh) Output
New Biomass CC	1,634	30	10,283	80	2.99	45.04	-	-	-
New PC with 50% CCS*	3,769	40	11,343	93	10.58	46.21	1,167	0.3730	0.6191
Com3 - Xcel Energy*	2,020	40	8,672	88	3.06	15.64	2,159	0.0000	0.0000
IGCC - Xcel Energy*	4,008	40	10,202	88	3.05	17.14	1,048	0.4270	0.7048
Bit Coal Steam	N/A	40	10,618	83	2.78	15.64	2,159	3.8953	2.3873
Sub Bit Coal Steam	N/A	40	10,474	83	2.78	15.64	2,143	3.1810	3.7048
DSF Steam	N/A	35	12,916	85	0.52	0.86	2,000	2.4683	0.1952
Diesel IC	N/A	35	12,916	85	8.89	0.86	2,000	2.4683	0.1952
New Geothermal*	3,641	30	10,283	90	22.88	16.71	N/A	N/A	N/A
Hydro	N/A	45	10,283	27	4.48	14.20	N/A	N/A	N/A
Hydro PS	N/A	45	3,754	83	2.65	16.71	N/A	N/A	N/A
New Coal IGCC with 50% CCS*	4,008	40	10,202	87	3.05	17.14	1,048	0.4286	0.7064
New Adv CT	520	30	8,553	92	2.83	8.89	921	0.0873	N/A
New Adv CC*	827	30	7,281	93	3.09	9.42	865	0.0714	N/A
CC	N/A	30	7,399	94	0.49	15.75	881	0.1532	N/A
New CC*	885	30	7,463	95	2.81	13.19	889	0.3413	N/A
CT	N/A	30	10,525	94	0.10	6.51	1,278	0.5683	N/A
New CT*	659	30	10,459	98	7.95	4.31	1,246	0.5175	N/A
New Gas IGCC with 90% CCS	1,124	30	7,952	98	2.93	19.95	86	0.0794	N/A
Gas Steam	N/A	30	13,390	92	0.52	0.86	1,587	2.4151	N/A
New Adv Nuclear**	5,500	40	10,512	92	0.60	58.00	N/A	N/A	N/A
PV_Central	3,830	30	10,283	N/A	N/A	8.96	N/A	N/A	N/A
PV_On-Site	7,519	30	10,283	N/A	N/A	8.96	N/A	N/A	N/A
Solar_CSP***	3,500	30	10,283	N/A	N/A	43.55	N/A	N/A	N/A
Wind (Include PTC)*	1,690	20	10,283	N/A	N/A	23.24	N/A	N/A	N/A
Coal Based Imports#	-	-	-	-	-	-	2,159	-	-
Gas Based Imports#	-	-	-	-	-	-	881	-	-

Notes:
- CC = Combined Cycle
- CT = Combustion Turbine
- PC = Pulverized Coal
- IGCC = Integrated Gasification Combined Cycle
- Com3 = Pulverized coal unit by Xcel Energy with no SO2 and NOx impact (net of other 2 units)
- PS = Pumped Storage Hydro Facility
- AF = Availability Factor
- Heat Rate# = Renewables' heat rates are an equivalent proxy heat rate
- Capital Cost# = Updated capital costs include transmission interconnection and delivery costs. For Solar, first year cost is shown, subsequent years costs are lower.
- Emission Rates# = Source of existing power plants emissions is EPA-ETS (Emission Tracking System)
- Imports# = imports are transmission constrained at 5,100 GWh per year
- ##Sources data from DOE/EIA or EPA-NM or as noted by * from other sources
- *Xcel Energy = Operates as Public Service Company of Colorado filed its 2007 Resource Plan with Colorado PUC on Nov. 2007
- **GEO from FERC document
- ***GEO from NREL
- VAROM = Variable O&M, FXDOM = Fixed O&M

6 REFERENCE SCENARIO

The developments of energy scenarios allow a way to analyze and examine a range of resource portfolios and policies for consideration of alternative possibilities. An important step for any energy modelling exercise is to establish a baseline scenario that represents a reasonable progression of the system's advancement into the future years taking into account certain aspects of the current and future conditions. A Reference Scenario serves as the basis for the subsequent analysis of alternate technology and policy scenarios. In preparation for this study, a Reference Scenario has been established by:

- developing a state-wide energy and demand forecast for each of three sectors (residential, commercial , and industrial);
- adopting forecasts of energy supply prices from the DOE/EIA and the regulated utilities' filings before the Colorado Public Utilities Commission (PUC);
- establishing the state's existing power plants' installed capacity, coupled with the independent power producers' (IPP) installed capacity;
- establishing the state's mandated Renewable Energy Standards (RES) requirements for all IOU and non-IOU retail distribution utilities;
- establishing the state's mandated Demand-Side Management (DSM) and Energy Efficiency (EE) requirements for all IOU utilities;
- establishing known near-term power plants retirements through the state's PUC and utilities' electric resource plans;
- establishing approved and proposed future power plants through the state's PUC and utilities electric resource plans;
- establishing that 1,000 MW of concentrated solar power will be on the electric system by 2020; and,

- establishing assumptions for "guiding" model choices in situations where there are limitations on system evolution that inhibit the selection of ideal economic choices

MARKAL is a least-cost optimization model for long-term energy system planning. Therefore, it is necessary to establish within the model the resources bounds and restrict some aspects of model choices to better reflect the conditions as the most likely evolution of the state's electric power system, assuming a Reference Scenario perspective. Reference Scenario assumes a continuation of current energy policies using existing resources and adding planned and future conventional resources to meet electricity requirements of the state. Embedded within this assumption are limitations on how much the energy system will remain similar to what it is now, without intervention.

6.1 Model Output for Reference Scenario

The model is calibrated for the Base-Year (2005). The model's output closely matches the reported data by the DOE/EIA for the Colorado's electric power generation. The model's output for 2005 consists of 38,333 GWh (or 71.5%) of electricity production from coal-fired power plants; about 10,000 GWh of gas-fired generation; 4,100 GWh of hydro which also includes pumped-storage; and 833 GWh of renewable generation.

For the Reference Scenario with RES and DSM fully implemented at statewide levels, coal-fired generation provides the bulk of the electricity generation requirements in 2005 continuing into the future, 2020 and beyond, with peaking at 46,700 GWh of the state's total generation requirements. The increased coal generation from 2005 level is due to two new modeled coal fired power plants with in-service dates modeled as 2009 and 2017.[18]

Gas generation increases over the years and reaches 14,200 GWh by 2020 and doubles to 20,000 GWh by 2035. This is mainly due to the fact that all new capacity additions will be from gas fired generation either combined cycle or combustion turbines technologies. The hydro generation of 4,167 GWh in the Reference Scenario includes 2,172 GWh of generation from pumped-storage facilities in the peak hours.

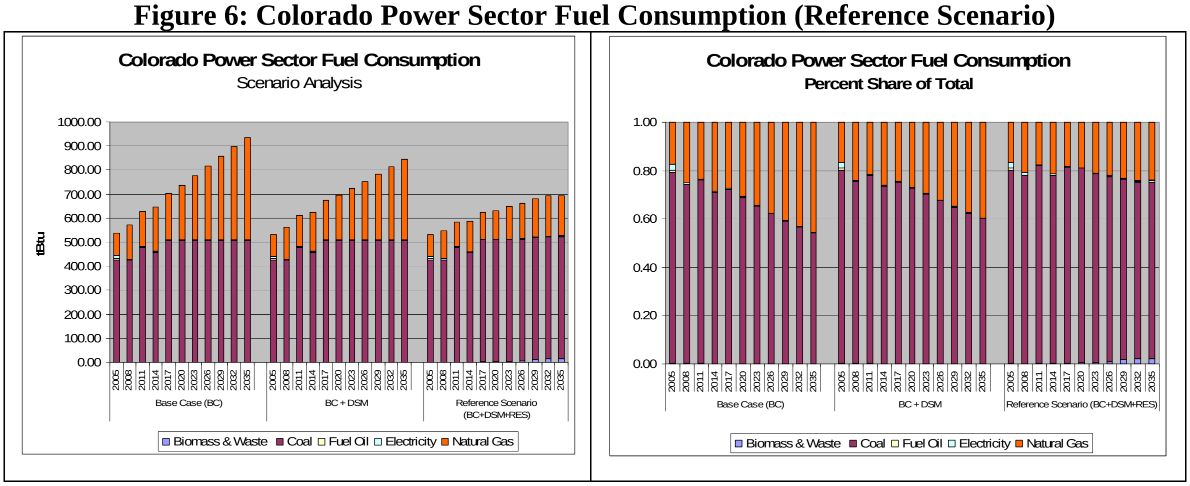
In 2005, the model's output matches the share of generation from renewables that is about 1.5%. The share of renewables consistently increases over the years where in 2020; renewables meet the intended requirements of the RES. The effective rate of RES in the state by 2020 reaches 15.7% of total generation, or 11,944 GWh of renewable generation. It should be noted that as renewable technologies costs become more competitive (e.g., solar technology in particular) compared to other conventional technologies, the model utilizes more renewables, more than RES requirements, in the out years. This is due to the fact that RES requirements were set as a floor, not as a ceiling, in the model.

The other sources of energy for electricity load are a small amount from oil-fired generation, and imported electric power (Wyoming). Oil consumption in Reference Scenario is less than 1% for electricity generation in 2005 and is mostly from small power generators owned by utilities or municipalities. Most of the imports are from existing long term utility contracts which over the years expire with the level of imports dropping from 4% in 2005 to less than 2% in 2020 and to 0% by 2035.

[18] Xcel Energy's Comanche 3 at 750 MW and the proposed Coal IGGC plant at 600 MW.

As more DSM and renewables enter the resource portfolio of Colorado's power sector by virtue of the RES and HB07-1037, the gas consumption decreases due to the fact that DSM and renewable generation displace gas generations at margin. The Basecase also accounts for 350 MW of announced old coal-fired generation to be retired between 2011-2014, and two new coal-fired power plants with the total capacity of 1,350 MW to be added in the next decade; one 750 MW of new pulverized coal-fired generation with the in-service date of 2009, and one 600 MW of IGCC technology with 50% carbon capture technology with the in-service date of 2017. This is reflected in coal consumption with an increase in 2011 for 750 MW coal plant with in-service date of 2009, then a decrease in 2014 for the retirements of 350 MW, and then an increase due to in-service date of a proposed 600 MW IGCC plant. Figure 6 below depicts Colorado's power sector fossil fuel consumption profile throughout the planning horizon. Figure 6 also depicts the coal and gas fuel consumption as a percent of total.

Figure 6: Colorado Power Sector Fuel Consumption (Reference Scenario)



Source: Saeed G Barhaghi, PhD, PE – University of Colorado Denver

6.2 Reference Scenario Projected CO2 Emissions Profile

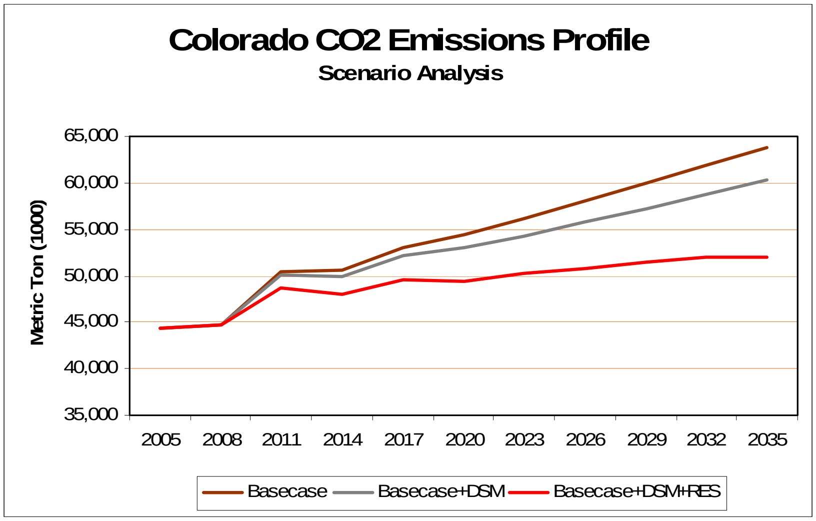
Figure 7 depicts Reference Scenario CO2 emissions profile for the existing installed and new capacity additions estimated by the model to meet the forecasted future years' energy needs. By 2020, the Basecase (i.e., no DSM or RES included) level of CO_2 emissions increases to 54,407 million metric tons (MMT). This is about 22% above 2005 CO_2 level. The increase in CO_2 emissions is mainly due to increased fossil-fueled generation to meet the demand for more energy and the addition of two new power plants, one with no carbon-capture technology and the other one, a proposed IGCC plant with 50% carbon-capture.

When mandatory DSM measures are added to the Basecase, CO_2 levels drop to 52,956 MMT, or 19% above 2005 CO_2 level, about a 3% improvement. The level of DSM energy savings reaches its maximum level by 2020 to 3,900 GWh. In this study, in order to show the impact of changes in usage driven by customers, DSM measures are modeled separately (i.e., added to the Basecase) to show, in aggregate, the cost and benefit of energy efficiency measures in terms of reduced total system costs and reduced CO_2 emissions and furthermore, to show the need for more DSM measures by the utilities and the need for detailed modeling. In later studies, detailed energy efficiency scenarios will be designed and modeled to capture the cost and benefit of DSM technologies separately (e.g., the impact of space cooling, lighting performance, efficient motors, or many others) to accomplish the goals of the CAP calling for, close to half of utilities CO_2 reductions should come from energy efficiency and DSM measures.

When mandatory RES requirements are added to the Basecase, in addition to DSM measures, CO_2 levels drop further down to 49,357 MMT CO_2 emissions by 2020, or 11% above 2005 CO_2 level, an additional 9% improvement. By 2020, the level of RES percent requirements reaches its maximum level at 15.7% effective rate. The impact of both DSM and RES legislation on Colorado's power sector, if fully implemented, would be a 12% drop in CO_2 emissions level from the level if there was not such legislation. Figure 7 shows the progression of CO_2

emissions reductions as mandatory DSM and RES requirements are implemented by the Colorado electric utilities.

Figure 7: Reference Scenario – Power Sector CO2 Emissions Profile



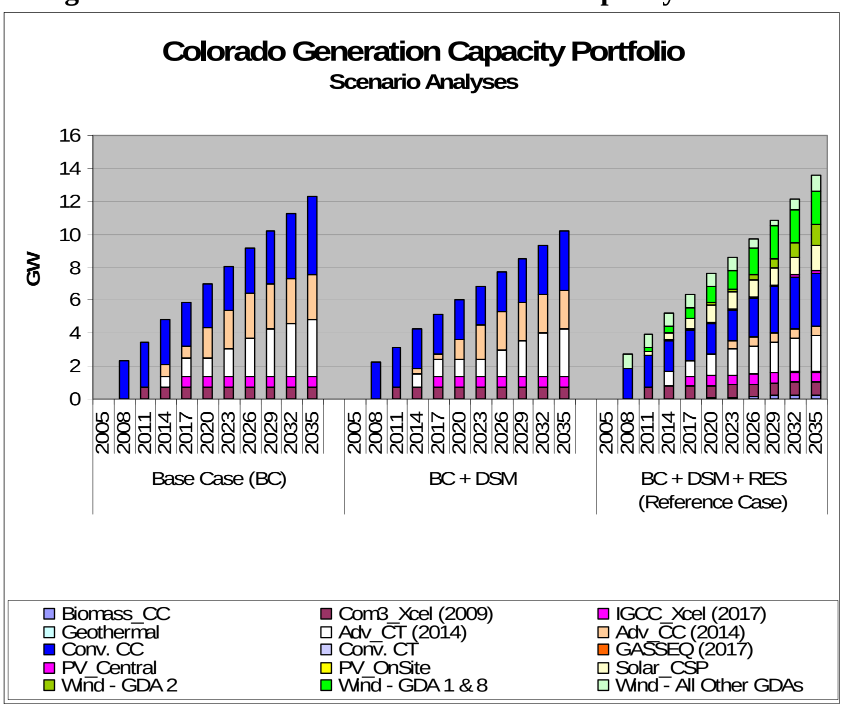
Source: Saeed G Barhaghi, PhD, PE – University of Colorado Denver

In Colorado, coal generation contributes close to 80% of CO2 emissions throughout the modeling horizon for the Reference Scenario. This is due to the fact that coal units are the most economical units to operate (i.e., low production cost) and the model utilizes all, installed and new, coal power plants to their maximum level of availability at all hours. The CO2 level for the Reference Scenario reaches 49,357 MMT and 51,965 MMT by 2020 and 2035, respectively. As the RES requirements increase over time and reach the maximum by 2020, the addition of fossil-fueled generation to meet the growing demand is reduced and is replaced by more renewable technologies. This change in generation mix does prevent the level of CO2 emissions from increasing in Colorado. However, the implementation of RES requirements alone does not make the CO2 emissions level decrease to the level of CAP goals unless other constraints, such as carbon reduction policy scenarios are introduced. In the following sections, carbon reduction policies and their impacts on the pattern of coal units utilization is discussed.

6.3 Reference Scenario New Capacity Additions

Figure 8 shows the progression of new capacity additions for the Basecase over the planning horizon to meet the forecasted energy demand. As we discussed earlier, we incrementally add the mandated DSM and RES requirements to arrive at the Reference Scenario. Figure 8 also shows the change in resource portfolio as DSM and RES requirements are added to the Basecase. Beginning in 2014, when new advanced technologies are projected to become more widely available, the model incorporates the use of more advanced combustion turbines (CT) or combined cycle (CC) technologies. With higher efficiencies and lower variable costs[19], advanced CTs and CCs can operate more efficiently than are projected for conventional CCs in the Basecase.

Figure 8: Colorado Electric Power Sector Capacity Additions



Source: Saeed G Barhaghi, PhD, PE – University of Colorado Denver

[19] Improvements in efficiency and costs for Advanced CT make it more cost effective to operate in the out years.

Once the RES requirements are added to the Basecase, the use of fossil-fuel generation is displaced by renewables generation. As noted before, we have distinguished and modeled wind by the GDAs and the model utilizes wind from the GDAs with higher capacity factor first before using wind from all other GDAs with one exception that Xcel Energy's 830 MW operational by 2008 is given to the model as wind from all other GDAs with a capacity factor of 34% (see Figure 8 above).

Table 7 shows in tabular form the amount of nameplate capacity additions for year 2020 for each technology. It should be noted that, as DSM measures are incorporated into the Basecase, the model builds less capacity (i.e., displaces CCs and CTs), about 1,000 MW less than the Basecase as intended by the DSM goals.20

Table 7: Colorado Power Sector Capacity

Technologies	CAPACITY PORTFOLIO (GW)		
	2020		
	BA	BAD	BADR
Biomass_CC	0.00	0.00	0.06
Com3_Xcel (2009)	0.75	0.75	0.75
IGCC_Xcel (2017)	0.60	0.60	0.60
Geothermal	0.00	0.00	0.04
Adv_CT (2014)	1.14	1.07	1.29
Adv_CC (2014)	1.83	1.21	0.00
Conv. CC	2.70	2.39	1.86
Conv. CT	0.00	0.00	0.00
GASSEQ (2017)	0.00	0.00	0.00
PV_Central	0.00	0.00	0.07
PV_OnSite	0.00	0.00	0.03
Solar_CSP	0.00	0.00	1.00
Wind - GDA 2	0.00	0.00	0.15
Wind - GDA 1 & 8	0.00	0.00	0.97
Wind - All Other GDAs	0.00	0.00	0.83
Total Capcity	7.02	6.02	7.65

In order to meet the requirements of the RES, electric utilities in Colorado will need to add 1,120 MW of wind in addition to all installed wind by the end of 2008 (i.e., 263 MW prior to 2008 and about 830 MW by end of 2008), and 1,100

[20] In its report to the Colorado General Assembly, the Commission established a 2020 DSM goal of 886-944 MW for Xcel Energy and 35.5 MW for Black Hills. The model's output is consistent with the DSM goal for 2020.

MW of solar technologies, which about 1,000 MW will be concentrating solar power (CSP). As noted before, with the full implementation of DSM and RES requirements, the state's CO2 emissions level drops by 12% to 49,357 MMT. The CAP calls for CO2 emissions reduction of 20% below 2005 CO2 emissions level or 35,549 MMT by 2020. This means that there is about a 28% gap in CO2 emissions reduction that needs to be achieved by other means.[21] The focus of this work is, after demonstrating the current status of CO2 emissions of power sector in Colorado, to quantify the pathways to meet the CAP's goals while developing a sustainable electric system for the out years.

7 CLIMATE ACTION PLAN SCENARIO

With recent awareness of the potential impact of greenhouse gases (GHG) on the environment, a number of states have initiated Climate Action Plans and a proposed climate-change legislation entitled the "American Clean Energy and Security Act of 2009" is currently being considered by Congress to substantially reduce C02 emissions.[22] The CAP sets a goal for the state to achieve an economy-wide reduction in CO2 emissions of 20% below 2005 levels by 2020 and 80% below 2005 levels by 2050. The plan calls for electric utilities that are estimated to produce 36% of the state's carbon emissions to reduce those emissions through a combination of DSM, changing customer behavior, and a change in the generation mix that incorporates clean energy resources. .The CAP calls for significant customer and government initiated reductions in energy usage, including improvements in lighting performance, a call for industrial users to increase efficiency, and changes in building codes.

[21] This translates into about 13,800 MMT of additional CO2 emissions reduction from the Reference Case level of 49,357 MMT.

[22] For example, see Regional Greenhouse Gases Initiatives which is a regional program by Northeastern states to reduce GHG emissions, and California recently passed the Global Warming Solutions Act of 2006, A.B. 32, aimed at reducing carbon emissions from sources within the state.

7.1 Generation and CO2 Emissions Benchmark

As discussed earlier, the model has been calibrated for Colorado's existing generation fleet for the Base-Year (2005). The model's output from the operations of existing fleet of generating facilities meet closely the energy and CO2 emissions reported by the U.S. EPA eGrid. Table 8 depicts Colorado's electric generation and CO2 and criteria pollutants emissions for 2005.

Table 8: Colorado Electric Generation Emissions (2005)

Colorado Electric Generation Emissions (2005)			
Emissions	SO2	CO2	NOx
Rate (lb/MWh)	2.5346	1,911	2.9224
Total Emissions (ton)	62,898	47,420,655	72,533
Total Emissions (metric tonne)	57,060	43,019,736	65,802
Total Generation (MWh)	49,632,186		
Source: eGrid			

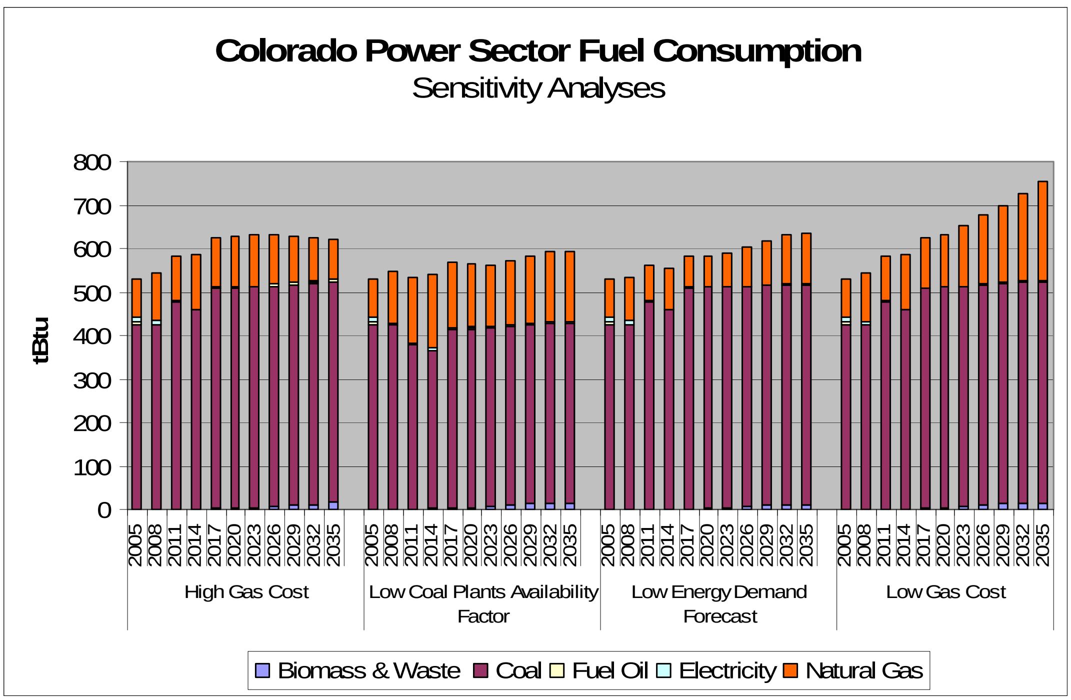
In addition, since Colorado is a net importer of electricity the model also accounts for CO2 emissions from coal or natural gas based imports from out of state. The criteria pollutants emissions are also within close range of the reported emissions.

8 SENSITIVITY SCENARIOS

Before introducing the CAP scenario, we performed a series of sensitivity analyses for the Reference Scenario to gauge the degree of uncertainties with regard to: 1) natural gas price volatility plus or minus 30% price change from the Basecase; 2) a change in energy forecast to a lower level due to recent economic indicators (i.e., 1.4% increase per year as opposed to the Basecase 2.0% per year growth in energy demand); and 3) if there is carbon regulation – either a carbon tax or cap and trade regulations – which may cause the utilities to operate their coal units in a less economical way by limiting and reducing the coal units' availability factor by 20% compared to the Reference Case. See Table 2 for the descriptions of the scenarios analyzed.

Figure 9 below depicts Colorado's power sector fossil fuel consumption profile throughout the planning horizon for the sensitivity scenarios. As seen in Figure 9, as gas prices increase the model economically selects a lower level of natural gas-fired generation. The model economically selects more gas-fired generation when gas prices drop. The level of coal consumption stays the same however, the level of coal based electricity imports increase towards out years when gas prices increase.

Figure 9: Colorado Power Sector Fuel Consumption for Sensitivity Scenarios



Source: Saeed G Barhaghi, PhD, PE – University of Colorado Denver

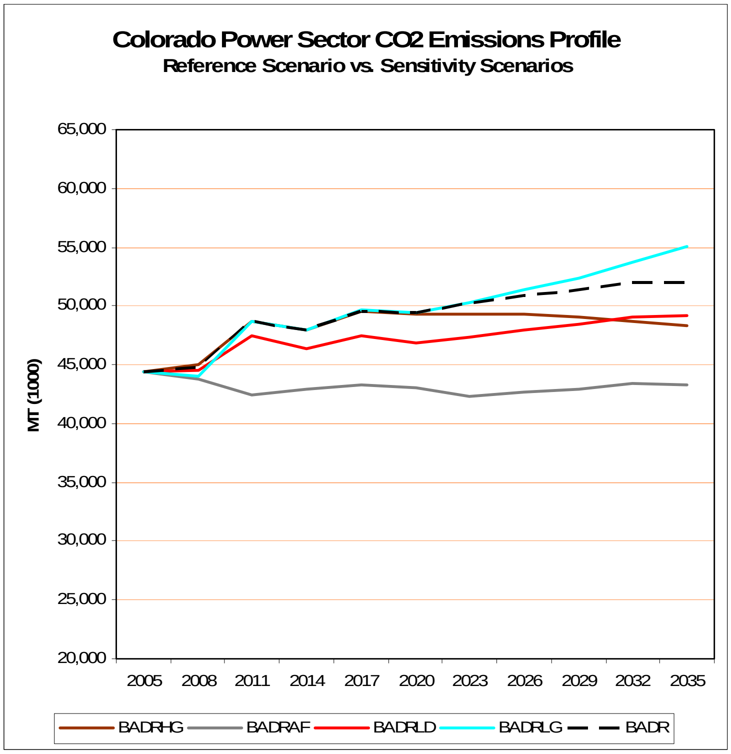
A lower availability factor for coal units suppresses the operation of coal units and therefore less coal is consumed as a result, with lower carbon emissions.

A low energy demand forecast minimizes the consumption of the natural gas since low energy demand impacts the hours of operation of CCs and CTs.

8.1 Sensitivity Scenarios CO2 Emissions Profile

Figure 10 shows CO2 emissions profile for four sensitivity scenarios compared to the Reference Scenario (BADR). As seen in Figure 10, suppressing the coal units' operations will result in less CO2 emissions than the Reference Case.

Figure 10: Colorado Electric Power Sector's CO2 Emissions Profile



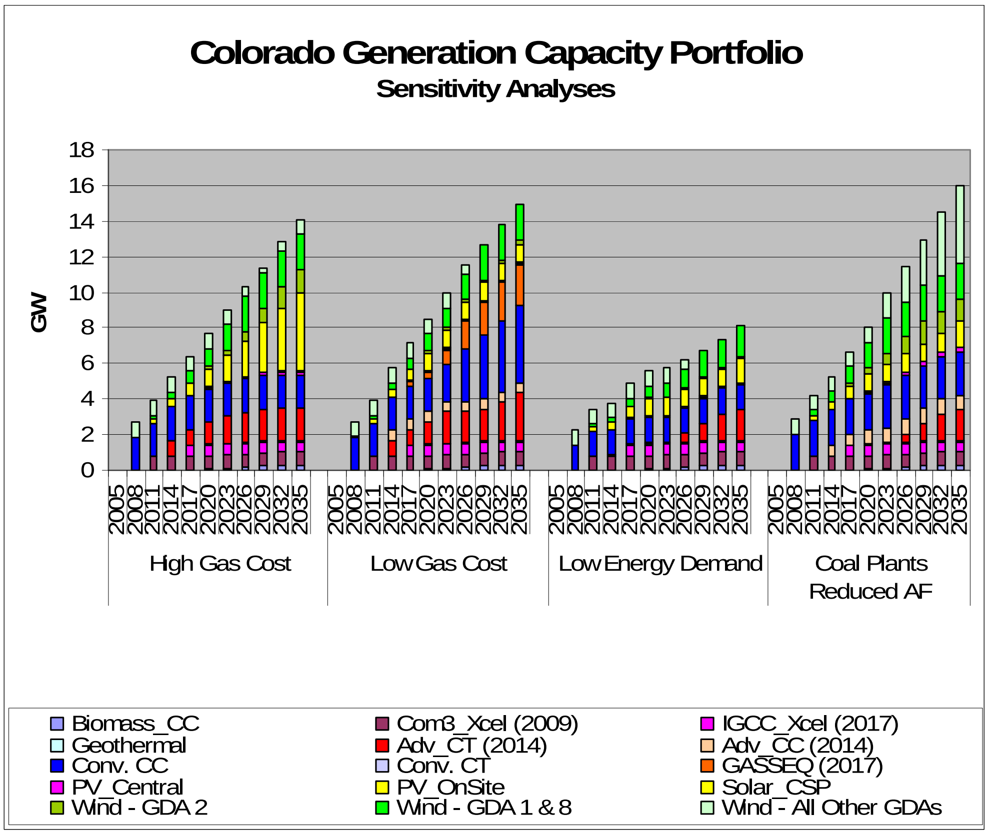
Source: Saeed G Barhaghi, PhD, PE – University of Colorado Denver

Low energy demand also results in less CO2 emissions than the Reference Case while low gas costs increases the operation of gas-fired units and the CO2 emissions. On the other hand, high gas costs decreases the operation of gas-fired units and the CO2 emissions. Total system costs of the Reference Scenario and sensitivity and CAP scenarios are discussed in the following sections.

8.2 Sensitivity Scenarios Resource Portfolio

Figure 11 shows resource portfolio for four sensitivity scenarios. As we discussed earlier, suppressing the coal units' operations will result in less CO2 emissions than the Reference Case at higher system costs of about $2.0 billion (2005$). This cost is related to building more renewables for the displaced coal units' generation.

Figure 11: Sensitivity Scenarios Capacity Portfolio



Source: Saeed G Barhaghi, PhD, PE – University of Colorado Denver

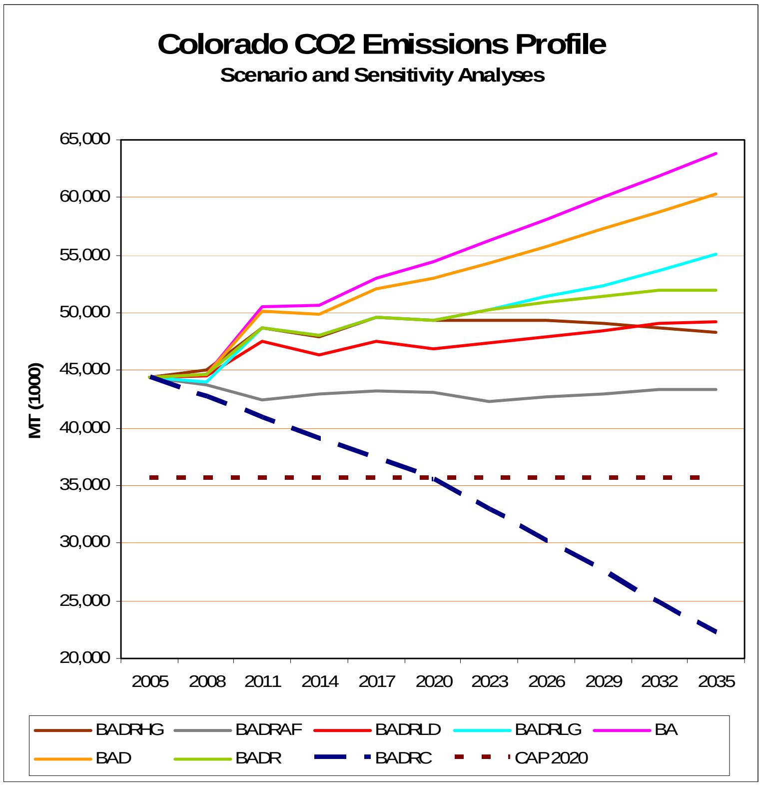
Low energy demand also results in less CO2 emissions than the Reference Case but with much less system costs because less capacity, both fossil-fueled and renewables capacity is needed to be built. Low gas costs increases the operation of gas-fired units and CO2 emissions while decreasing the system costs by building advanced gas units CCs and CTs and gas IGGC when available in 2017, but less renewable capacity. On the other hand, high gas costs decreases the operation of gas-fired units and the CO2 emissions while increasing the system costs by building more renewables in particular solar-CSP.

8.3 Climate Action Plan Scenario Results

In order to analyze the impact of the CAP, a CAP scenario was analyzed. We have also combined and analyzed the sensitivity scenarios with the CAP scenario to gauge the total impact of low energy demand forecast, natural gas cost volatility, and the existing coal-fired plant's lower availability factor on total CO2 reductions over the years.

As seen in Figure 12, there is a wide gap between the Reference Scenario (BADR) and the CAP Scenario (BADRC) CO2 emissions profile. The gap is about 28% which indicates more CO2 emissions reduction is needed, in addition to full implementation of DSM and RES requirements, in order to bring the power sector's CO2 emissions levels close to CAP calls which is 20% below 2005 CO2 emissions levels. Sensitivity scenarios also show a gap between them and the CAP Scenario but to a less degree for low availability factor of coal units and low energy demand forecast.

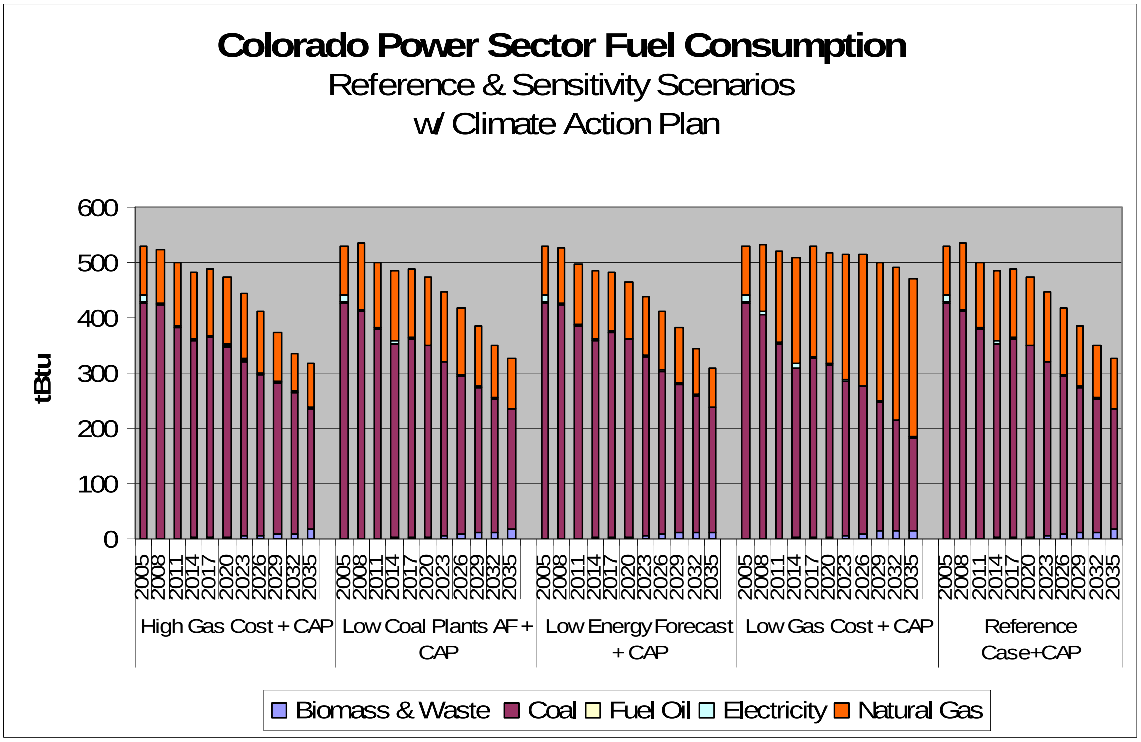
Figure 12: Sensitivity Scenarios Capacity Portfolio



Source: Saeed G Barhaghi, PhD, PE – University of Colorado Denver

Figure 13 below depicts Colorado's power sector fossil fuel consumption profile throughout the planning horizon for the sensitivity scenarios and the Reference Scenario constrained with CAP. As seen in Figure 13, when the model is constrained with the CAP requirements the pattern of the fossil-fueled generation and consumption reduces over the planning horizon except when gas prices decline, which is when gas-fired generation increases to compensate for the reduced coal-fired generation.

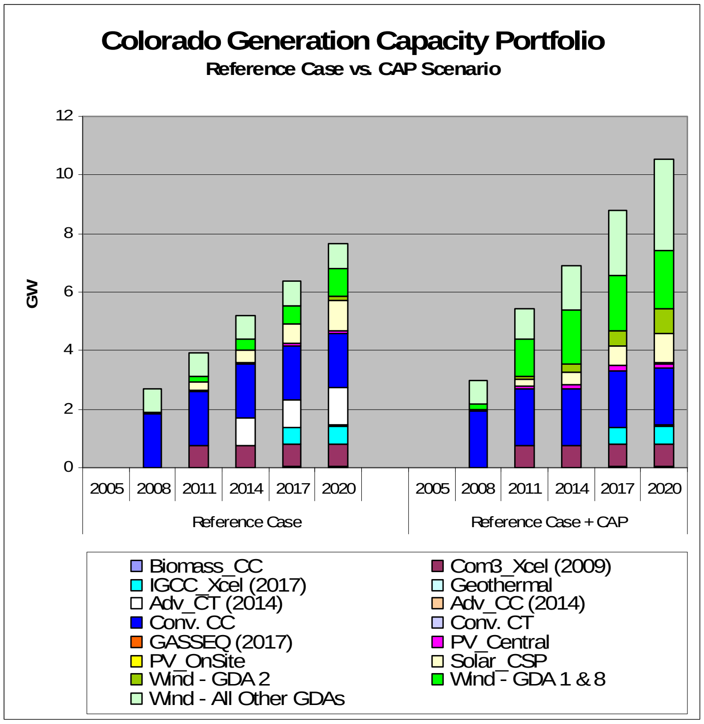
Figure 13: Colorado Power Sector CAP Constrained Fossil Fuel Consumption



Source: Saeed G Barhaghi, PhD, PE – University of Colorado Denver

Figure 14 shows resource portfolio of the Reference Scenario compared to Reference Scenario when it is constrained with the CAP requirements. When the model is constrained to meet the CAP's CO2 goals by 2020, it displaces fossil-fueled generation with more renewables, it operates less fossil-fueled generation and builds less gas-fired generation, but instead builds about 4,000 MW more wind capacity. The model does not add to solar-CSP but adds about 100 MW to the capacity of PV-solar central compared to the Reference Scenario.

Figure 14: Colorado Power Sector 2020 CAP Resource Portfolio



Source: Saeed G Barhaghi, PhD, PE – University of Colorado Denver

The projected impact of DSM and RES on Colorado power sector generation mix by fuel type is reflected on coal by lowering the contribution of coal in the grid mix from 71% in 2005 to 61% in 2020 while gas fired generation drops from 24% in 2005 to 18% in 2020. Renewable contribution in the grid mix increases from 2% in 2005 to 16% in 2020 due to the implementation of RES requirements. See Figure 15, Reference Scenario generation mix. When the Reference Scenario is constrained to meet the CAP goals by 2020, the coal contribution to the grid mix further drops to 44% while gas generation increases to 24% and renewable generation reaches 27%. See Figure 15, CAP Scenario generation mix. Hydro generation increases slightly from 3% in 2005 to 5% of the grid mix in 2020 due to limited availability of hydro generation in Colorado.

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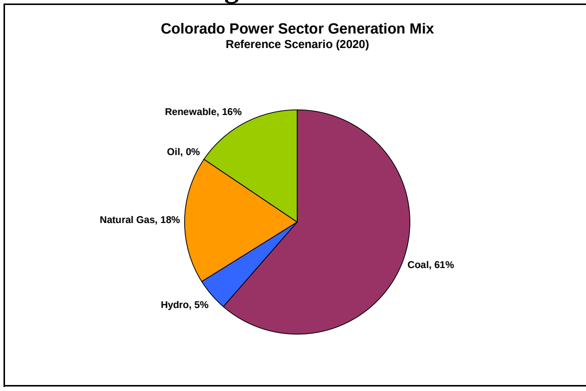
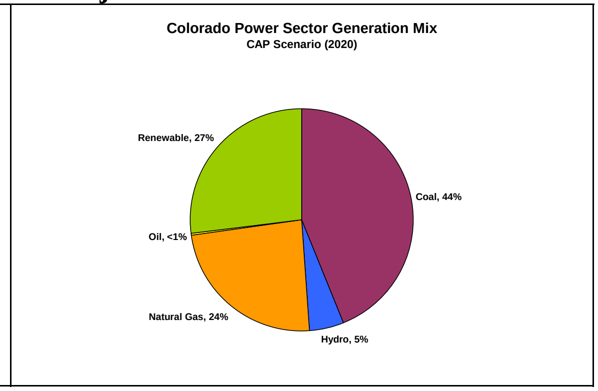
Figure 15: Colorado Power Sector Projected Grid Mix for 2020





Source: Saeed G Barhaghi, PhD, PE – University of Colorado Denver

Table 9 shows the breakdown of Reference and CAP scenarios capacity addition by technology for 2020 when the CAP's first goal is to be met. As seen in Table 9, about 1,300 MW of CT technology is not built as compared to the Reference Scenario, but instead, more wind is built. The model first utilizes the available wind capacity from GDA 1 and 8, followed by GDA 2, and then from all other GDAs based on the capacity factor.

Table 9: Colorado Power Sector 2020 Detailed CAP Resource Portfolio

Generation Technologies	Capacity (GW) 2020 BADR	Capacity (GW) 2020 BADRC
Biomass_CC	0.06	0.06
Com3_Xcel (2009)	0.75	0.75
IGCC_Xcel (2017)	0.60	0.60
Geothermal	0.04	0.04
Adv_CT (2014)	1.29	0.00
Adv_CC (2014)	0.00	0.00
Conv. CC	1.86	1.94
Conv. CT	0.00	0.00
GASSEQ (2017)	0.00	0.00
PV_Central	0.07	0.17
PV_OnSite	0.03	0.03
Solar_CSP	1.00	1.00
Wind - GDA 2	0.15	0.85
Wind - GDA 1 & 8	0.97	2.00
Wind - All Other GDAs	0.83	3.08
Total Capcity	7.65	10.52

Table 10 shows the breakdown of Reference and CAP Scenarios resource portfolio by technology type for 2020 with wind at 12.5% capacity credit. This table represents the resource portfolio as it would be represented by the utilities in their loads and resources tables to show the amount of capacity needed to meet the forecasted load plus the planning reserve margin.

Table 10: Colorado Power Sector 2020 Detailed CAP Resource Portfolio

Generation Technologies	Capacity (GW)	
	2020	
	BADR	BADRC
Biomass_CC	0.06	0.06
Com3_Xcel (2009)	0.75	0.75
IGCC_Xcel (2017)	0.60	0.60
Geothermal	0.04	0.04
Adv_CT (2014)	1.29	0.00
Adv_CC (2014)	0.00	0.00
Conv. CC	1.86	1.94
Conv. CT	0.00	0.00
GASSEQ (2017)	0.00	0.00
PV_Central	0.07	0.17
PV_OnSite	0.03	0.03
Solar_CSP	1.00	1.00
Wind* - GDA 2	0.02	0.11
Wind*- GDA 1 & 8	0.12	0.25
Wind* - All Other GDAs	0.10	0.38
Total Capcity	5.94	5.33

* Wind capacity adjusted at 12.5% capacity credi

Table 11a shows the breakdown of resource portfolio by technology type for 2020 for the Sensitivity Cases with and without CAP Scenario. Table 11b shows the breakdown of resource portfolio by technology type for 2020 with wind at 12.5% capacity credit for the Sensitivity Cases with and without CAP Scenario.

Table 11a: Sensitivity Scenarios Resource Portfolio for 2020

Technologies	CAPACITY PORTFOLIO (GW) 2020 BADRHG	BADRLG	BADRLD	BADRAF
Biomass_CC	0.06	0.06	0.06	0.06
Com3_Xcel (2009)	0.75	0.75	0.75	0.75
IGCC_Xcel (2017)	0.60	0.60	0.60	0.60
Geothermal	0.04	0.04	0.04	0.04
Adv_CT (2014)	1.28	1.29	0.08	0.00
Adv_CC (2014)	0.00	0.55	0.00	0.85
Conv. CC	1.86	1.86	1.42	2.00
Conv. CT	0.00	0.00	0.00	0.00
GASSEQ (2017)	0.00	0.32	0.00	0.00
PV_Central	0.07	0.07	0.06	0.09
PV_OnSite	0.03	0.03	0.03	0.03
Solar_CSP	1.00	1.00	1.00	1.00
Wind - GDA 2	0.15	0.15	0.04	0.35
Wind - GDA 1 & 8	1.02	0.97	0.68	1.39
Wind - All Other GDAs	0.83	0.83	0.83	0.92
Total Capcity	7.6795	8.5175	5.59	8.08

Technologies	CAPACITY PORTFOLIO (GW) Sensitivity Cases w/ CAP (2020) BADRHGC	BADRLGC	BADRLDC	BADRAFC
Biomass_CC	0.06	0.06	0.06	0.06
Com3_Xcel (2009)	0.75	0.75	0.75	0.75
IGCC_Xcel (2017)	0.60	0.60	0.60	0.60
Geothermal	0.04	0.04	0.04	0.04
Adv_CT (2014)	0.36	0.00	0.00	0.00
Adv_CC (2014)	0.00	0.55	0.00	0.00
Conv. CC	1.56	1.84	1.41	1.94
Conv. CT	0.00	0.00	0.00	0.00
GASSEQ (2017)	0.00	0.32	0.00	0.00
PV_Central	0.18	0.11	0.10	0.17
PV_OnSite	0.03	0.03	0.03	0.03
Solar_CSP	1.00	1.00	1.00	1.00
Wind - GDA 2	0.85	0.28	0.48	0.85
Wind - GDA 1 & 8	2.00	1.91	1.50	2.00
Wind - All Other GDAs	3.26	1.25	1.25	3.09
Total Capcity	10.68	8.74	7.22	10.53

Table 11b: Sensitivity Scenarios Resource Portfolio for 2020 (wind at 12.5%)

Technologies	CAPACITY PORTFOLIO (GW) Sensitivity Cases (2020) BADRHG	BADRLG	BADRLD	BADRAF
Biomass_CC	0.06	0.06	0.06	0.06
Com3_Xcel (2009)	0.75	0.75	0.75	0.75
IGCC_Xcel (2017)	0.60	0.60	0.60	0.60
Geothermal	0.04	0.04	0.04	0.04
Adv_CT (2014)	1.28	1.29	0.08	0.00
Adv_CC (2014)	0.00	0.55	0.00	0.85
Conv. CC	1.86	1.86	1.42	2.00
Conv. CT	0.00	0.00	0.00	0.00
GASSEQ (2017)	0.00	0.32	0.00	0.00
PV_Central	0.07	0.07	0.06	0.09
PV_OnSite	0.03	0.03	0.03	0.03
Solar_CSP	1.00	1.00	1.00	1.00
Wind* - GDA 2	0.02	0.02	0.01	0.04
Wind* - GDA 1 & 8	0.13	0.12	0.09	0.17
Wind* - All Other GDAs	0.10	0.10	0.10	0.12
Total Capcity	5.93	6.81	4.23	5.75

Technologies	CAPACITY PORTFOLIO (GW) Sensitivity Cases w/ CAP (2020) BADRHGC	BADRLGC	BADRLDC	BADRAFC
Biomass_CC	0.06	0.06	0.06	0.06
Com3_Xcel (2009)	0.75	0.75	0.75	0.75
IGCC_Xcel (2017)	0.60	0.60	0.60	0.60
Geothermal	0.04	0.04	0.04	0.04
Adv_CT (2014)	0.36	0.00	0.00	0.00
Adv_CC (2014)	0.00	0.55	0.00	0.00
Conv. CC	1.56	1.84	1.41	1.94
Conv. CT	0.00	0.00	0.00	0.00
GASSEQ (2017)	0.00	0.32	0.00	0.00
PV_Central	0.18	0.11	0.10	0.17
PV_OnSite	0.03	0.03	0.03	0.03
Solar_CSP	1.00	1.00	1.00	1.00
Wind* - GDA 2	0.11	0.04	0.06	0.11
Wind* - GDA 1 & 8	0.25	0.24	0.19	0.25
Wind* - All Other GDAs	0.41	0.16	0.16	0.39
Total Capcity	5.33	5.72	4.39	5.33

* Wind at 12.5% Capacity Credit

As seen in Tables 10 and 11b, the total capacity built to meet the load by 2020 ranges between 4.2 and 5.9 GW, accounting for wind at 12.5% capacity credit, depending on the type of sensitivity scenarios. For example, when we impose low availability factor for the existing coal-fired units, the model compensate for less generation from coal units by building more gas-fired units and renewables. When we constrain the low availability sensitivity with CAP scenario, the model optimizes the use of fossil fuel by building more renewables such as wind or solar.

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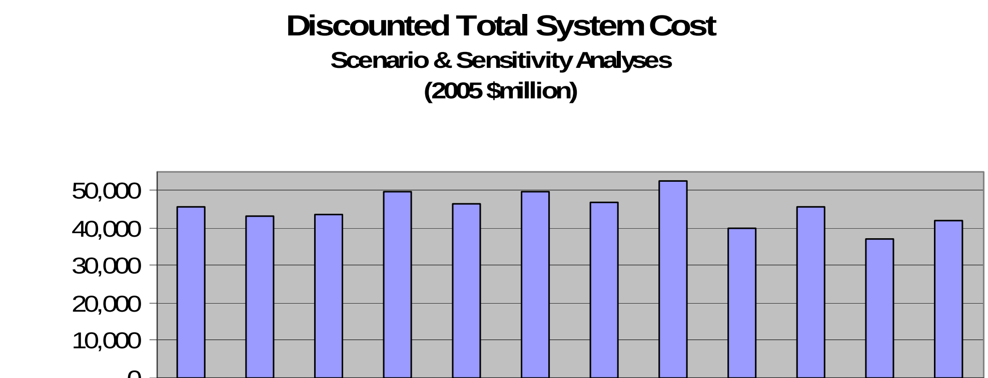
The variation in resource portfolio due to various sensitivity runs and the CAP scenario is reflected in the discounted total system cost shown in Figure 15. For example, when we constrain the Reference Scenario with the CAP requirements, the discounted total system costs for the 30 years planning horizon increases by 14% but the CO2 level drops by 57%.[23] The increase in costs is due to building and utilizing less fossil-fueled generation, and building and utilizing more renewable technologies. The discounted total system cost is the lowest for the low energy demand forecast sensitivity and the highest when high gas cost sensitivity is constrained with the CAP requirements. Figure 16 below lists the discounted total system cost for all scenarios.

Figure 16: Colorado CAP Scenario Analyses System Cost



	BA	BAD	BADR	BADRC	BADRAF	BADRAFC	BADRHG	BADRHGC	BADRLG	BADRLGC	BADRLD	BADRLDC
Disc. Cost (2005$M)	45,606	43,014	43,493	49,699	46,415	49,725	46,690	52,709	39,980	45,810	37,226	42,054

9 SUMMARY AND CONCLUSION

The analyses documented in this report is intended to provide a general overview of resource portfolio and policy options for the Colorado electric power sector in meeting the goals of Colorado Climate Action Plan to limit carbon

[23] We have modeled the CAP's CO2 reduction goals for 2020 and 2050 with immediate attention to 2020 goals. Drop in CO2 emissions by 57% in 2035 means that the model was constrained to achieve CO2 emissions reduction from 20% below 2005 level in 2020 to 80% below 2005 level in 2050, and by 2035 the model has achieved 57% CO2 emissions reduction below 2005 level.

emissions by 2020. Numerous assumptions and modeling techniques were used to produce the analyses included in this report.

For this study, we used the MARKAL modeling platform to optimize statewide power sector's generation while balancing economic costs and environmental benefits. We developed a Reference Scenario for Colorado power sector analyzing impacts of statewide Renewable Energy Standards (RES) requirements, Energy Efficiency and Demand Side Management (DSM), and the Colorado Climate Action Plan.

Following are summary of the study and major results of the analysis:

- We first developed the Basecase which represents an energy plan for Colorado incorporating the existing generation fleet while optimizing new capacity additions to meet the forecasted energy demand. We estimated, by 2020, the Basecase (i.e., no DSM or RES included) level of CO2 emissions would increases to 54,407 million metric tons (MMT) which is about 22% above 2005 CO2 level.
- We then developed the reference scenario which incorporated the Basecase with DSM and RES requirements. The reference case served as the basis for the subsequent analyses of alternate technology and policy scenarios.
- When mandatory DSM measures were added to the Basecase, we estimated CO2 levels drop to 52,956 MMT, or 19% above 2005 CO2 level, about a 3% improvement from the Basecase. The level of DSM energy savings reached their maximum level, 3,900 GWh by 2020.
- When mandatory RES requirements were added to the Basecase, in addition to DSM measures, we estimated CO2 levels drop further down to 49,357 MMT CO2 emissions by 2020, or 11% above 2005 CO2 level, an

additional 9% improvement. By 2020, the level of RES percent requirements reached its effective rate of 15.7% of total energy needs.

- We estimated the impact of both DSM and RES legislation on Colorado's power sector, if fully implemented; to be a 12% drop in CO2 emissions level from the level if there was not such legislation.
- We estimated new capacity additions for the reference case by 2020 to be in the order of :
  - Comanche 3(2009) 750 MW
  - IGCC (2017) 600 MW
  - Biomass 60 MW
  - Geothermal 40 MW
  - CT 1,290 MW
  - CC 1,860 MW
  - PV Central 70 MW
  - PV Onsite 30 MW
  - Solar-CSP 1,000 MW
  - Wind GDA 2 150 MW
  - Wind GDA 1 & 8 970 MW
  - Wind All other GDAs 830 MW

- We estimated that there will be a gap of about 28% between the reference case and the CAP goals which indicated more CO2 emissions reduction were needed, in addition to full implementation of DSM and RES requirements, in order to bring the power sector's CO2 emissions levels close to CAP calls which is 20% below 2005 CO2 emissions levels.
- In order to analyze the impact of the CAP, we developed a CAP scenario and estimated new resource portfolio for the CAP scenario for 2020 to be in the order of:
  - Comanche 3(2009) 750 MW
  - IGCC (2017) 600 MW
  - Biomass 60 MW
  - Geothermal 40 MW
  - CT 0 MW
  - CC 1,940 MW
  - PV Central 170 MW
  - PV Onsite 30 MW
  - Solar-CSP 1,000 MW
  - Wind GDA 2 850 MW

- Wind GDA 1 & 8 2000 MW
- Wind All other GDAs 3080 MW

- When we constrained the reference case with the CAP requirements, the discounted total system costs for the 30 years planning horizon increased by 14% but the CO_2 level dropped by 57%.
- We also performed a series of sensitivity analyses for the reference case to gauge the degree of uncertainties with regard to:
  1) Natural gas price volatility plus or minus 30% price change from the Basecase;
  2) Low Energy demand forecast due to recent economic indicators (i.e., 1.4% growth per year as opposed to the Basecase 2.0% per year growth in energy demand); and
  3) Coal units low availability factor, what if scenario, if there is carbon regulation – either a carbon tax or cap and trade regulations – which may cause the utilities to operate their coal units in a less economical way by limiting and reducing the coal units' availability factor by 20% compared to the reference case.

- We also constrained the sensitivity scenarios with the CAP to arrive at an estimated cost and resource portfolio for the sensitivity scenarios. We estimated the total capacity built to meet the load by 2020 for the sensitivity cases ranged between 4.2 GW and 5.9 GW, accounting for wind at 12.5% capacity credit, depending on the type of sensitivity scenarios. We also estimated the discounted total system cost to be the lowest when the energy demand forecast was low and the highest when the natural gas prices were highest and sensitivity cases were constrained with the CAP requirements.

The results of this study provide a general overview of a statewide energy planning and policy evaluation for the Colorado electric power sector that not only considers ways to respond to increased energy demand forecast needs but also ways to decrease the electric power sector's carbon footprint.