ATTACHMENT G

DRAFT Energy Baseline Report

Submitted to City of Boulder

Submitted By Nexant

Opinion Dynamics Corporation

First Tracks Consulting Service Inc

Iron Mountain Consulting

May 4, 2011

---Draft ---

Nexant

CONTENTS

1.1 PREFACE TO MAY 4 DRAFT

This draft report provides a "snapshot" of the Energy Baseline project as of May 3. A final report is scheduled to be completed in preparation for the June 14 City Council Study Session.

This draft provides results for data collection and analyses that have been completed to date. Draft results address all of the major topics that will be covered in the final report. However, some results are preliminary and may be updated for the final report based on feedback from city staff and ongoing data collection. In addition, the report includes a handful of sections that have not yet been completed. To demonstrate the range of topics that will be addressed in the final report, these sections have been included as placeholders in this draft. However, these placeholders simply identify content as "to be developed."

This project is a data intensive exercise, and for the snapshot provided in this draft, we have focused on providing as much data as possible. While data are placed in context where possible, descriptions of analyses used and conclusions that can be drawn have not been finalized. The final report will likely contain additional information to provide further background and context.

Finally, again in the interest of providing as much information as possible, data presented in this draft has not yet been fully edited for consistency of format and style. For example, a range of different graphic formats have been used by different authors responsible for different sections. The final report will undergo additional editing to clean up these style differences.

1.2 ORGANIZATION OF THIS REPORT

The report is organized into the following chapters:

Chapter 2 addresses **Boulder Electric Spending and Rates** to understand how much money Boulder residents and businesses spend on electricity; how spending, average utility bills and average rates vary by customer segment within the city and compare to spending at other utilities; and how spending is projected to increase in the future.

Chapter 3 addresses **Xcel Underlying Electric Costs and Profitability** to understand the cost components that drive rates and revenues (including costs required to support earnings to Xcel's shareholders); how profitability varies by customer sector and segment within the city; and how key costs are projected to increase in the future.

Chapter 4 addresses **Boulder Electric Sales and Loads** to understand how much electricity Boulder residents and business consume; how usage varies by customer segment within the city; and how usage drives the city load shape variation across hours of the day and seasons of the year.

Chapter 5 addresses **Xcel Generation Systems** to understand the plants that currently provide electricity to Xcel's customers; the difference in Boulder's generation mix due to Windsource purchases and on-site solar installations; the greenhouse gases associated with Boulder's current electrical system; and how the generation mix is projected to change in the future.

Chapter 6 addresses Xcel's **Transmission and Distribution** systems, including analyses of current system configurations, constraints, and statewide policies affecting the current and future system.

Chapter 7 addresses **Sustainable Energy Programs**—including energy efficiency, demand response, and renewable energy programs offered by Xcel to Boulder customers—to understand the investments Xcel is making in customer facilities, and how Xcel's programs compare to programs at other utilities.

Chapter 8 addresses **Reliability** to understand the frequency and duration of outages on the Boulder regional distribution system, and how those compare to other portions of the Xcel system, as well as to other utilities.

Chapter 9 provides a **Comparison to Benchmark Cities** that matches key data for Xcel's system to similar information from utilities serving other cities with large universities and similar populations.

2 BOULDER ELECTRIC SPENDING AND RATES

This chapter provides information on the amount of money Boulder electric customers spend on electricity, including total spending as well as spending per customer (i.e., average utility bills) and spending per unit of energy consumption (i.e., average rates).

To place the data in context, a number of comparisons are provided, including:

- By customer sector (e.g., residential vs. business) and segment (e.g., office buildings compared to electronics factories within the business sector);
- Between Boulder and the rest of Xcel's Colorado system;
- Between Xcel's Colorado system and utilities in Colorado and across the United States;
- Over time, including historical data going back to 1990 and, for average rates, Xcel's forecasts going out to 2030.
- Additional comparisons to Boulder's benchmark cities are provided in Chapter 9.

In the body of this chapter, data are presented in graphical format. Data tables supporting the graphs are presented in the Appendix and in additional spreadsheets provided to city staff.

Key data references for this chapter include:

- Annual reports that Xcel provided to the city under its franchise agreement through 2009;
- Monthly reports that Xcel provides to Boulder to document collection of the Climate Action Program (CAP) tax;
- Annual reports that Xcel files with the Federal Energy Regulatory Commission (FERC) documenting finances and operations;
- Annual reports that Xcel files with the Energy Information Administration (EIA) of the U.S. Department of Energy (USDOE) documenting sales and revenues;
- Similar reports filed with FERC and IEA by comparison utilities;
- A detailed analysis of the rate tariffs offered by Xcel to all of its Colorado electric customers;
- A detailed segmentation analysis of Boulder's customer base, drawing on data city staff provided on buildings, households, and businesses in the city; public data from Xcel regarding energy characteristics for different customer segments; Xcel's current rate tariffs; and public data from Xcel documenting its underlying costs of generating and delivering electricity;
- The plan that Xcel developed in response to the Colorado Clean Air-Clean Jobs Act that has been approved by the Colorado Public Utilities Commission (PUC).

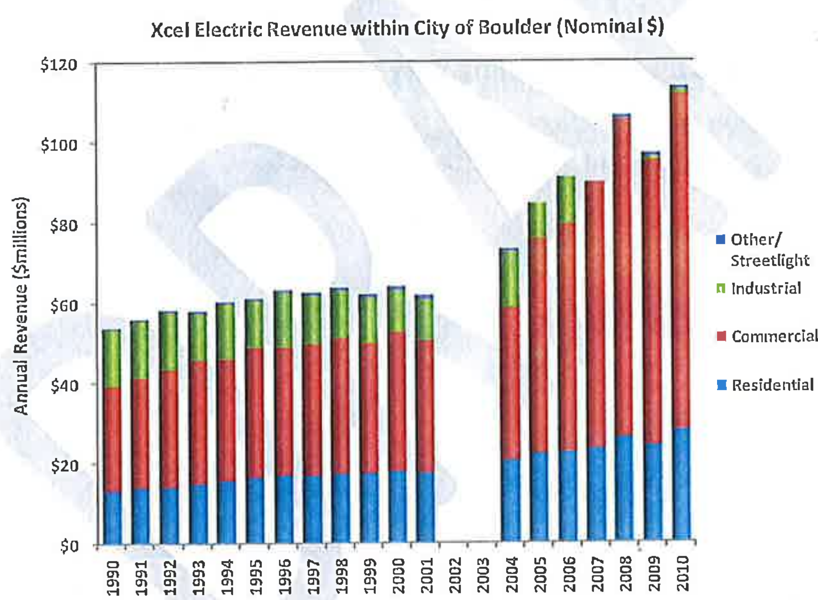
2.1 BOULDER ELECTRIC SPENDING

The annual reports that Xcel provided to the city under the franchise agreement document overall spending, including breakdowns by customer class. Although Xcel did not provide an annual report for 2010, spending could be estimated based on overall sales (documented from Xcel's CAP Tax reports) and Xcel's system-wide average rate increase from 2009 to 2010. Xcel Annual reports for 2003 and 2004 were unavailable for this draft report. They will be included for the final report.

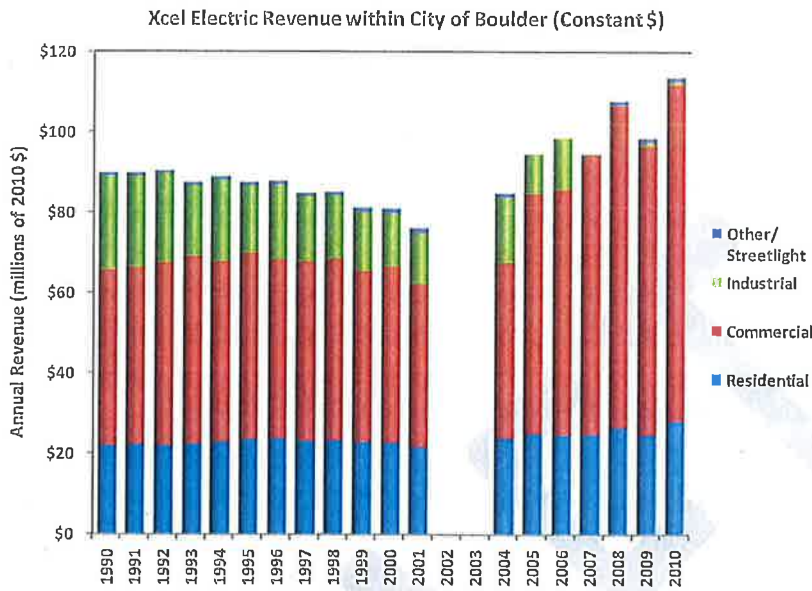
The data breaks down business spending for commercial and industrial customers. These designations reflect the volume of customer electricity purchases rather than underlying business activity (i.e., commercial designates smaller customers, regardless of whether those customers operate retail stores or a manufacturing plants). Changes in the mix of commercial to industrial spending over time, especially in recent years, reflects Xcel's changing definition of "large" vs. "small" customers, rather than a more fundamental shift in Boulder's underlying business base.

2.1.1 How Much Does Boulder Spend on Electricity?

Data presented here reflect nominal dollars, or dollars actually spent in each year, without adjustment for underlying inflation. Changes in spending over time reflect growth in overall customers, changes in sales per customers, and changes in average rates



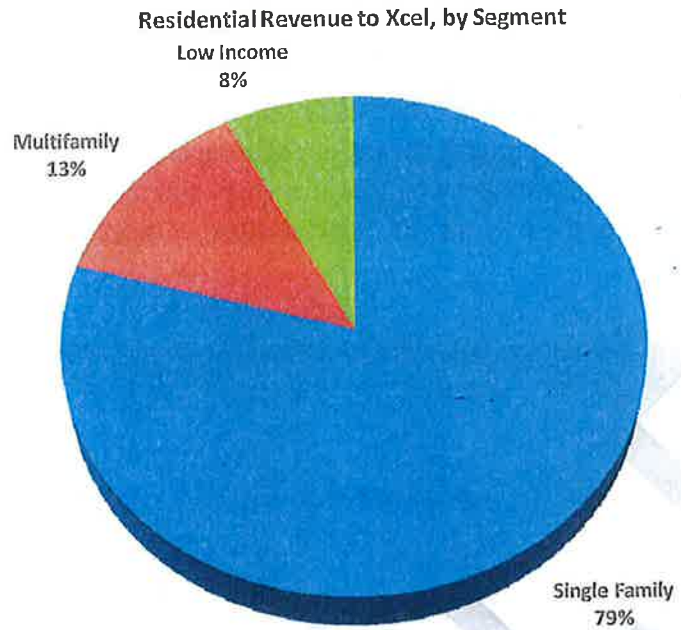
Data presented below are in constant 2010 dollars, with spending for past years increased to equivalent 2010 dollars using consumer price index estimates developed by the U.S. Department of Labor.



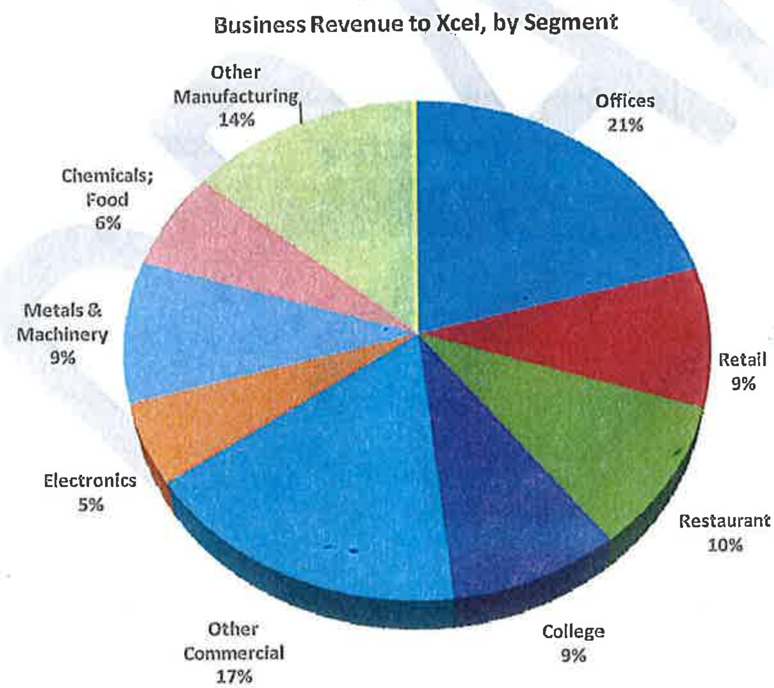
2.1.2 How Does Electric Spending Vary by Customer Segment?

The segmentation analysis disaggregates recent residential spending by housing type, and business spending by commercial and manufacturing business type.

2.1.2.1 How Does Residential Spending Vary By Customer Segment?



2.1.2.2 How Does Business Spending Vary By Customer Segment?

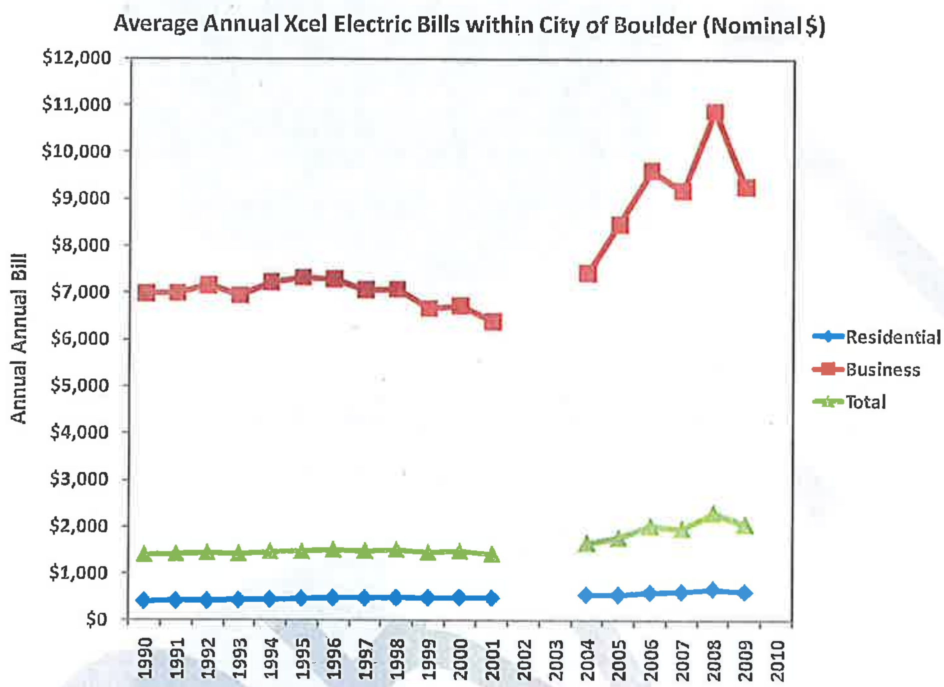


2.2 BOULDER AVERAGE ELECTRIC BILLS

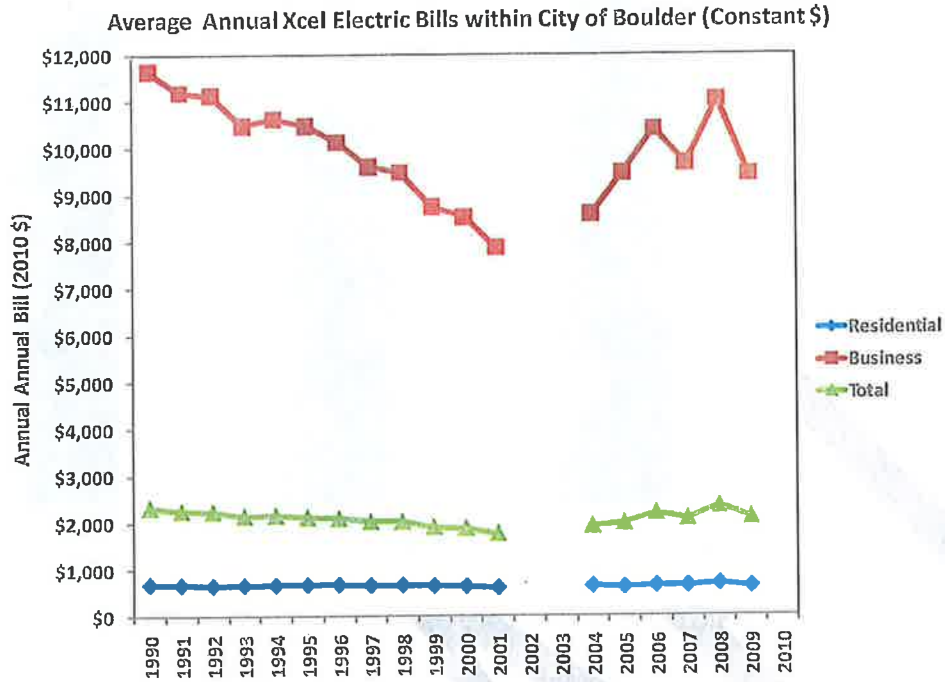
Average annual electric bills are calculated as the ratio of annual spending to total electric customers, which is also provided in Xcel's annual reports through 2009.

2.2.1 What are Average Electric Bills in Boulder?

Data presented here reflect nominal dollars, or dollars actually spent in each year, without adjustment for underlying inflation. Changes in average bills over time control for changes in the number of customers in the city, but still reflect changes in usage per customer as well as average rates.



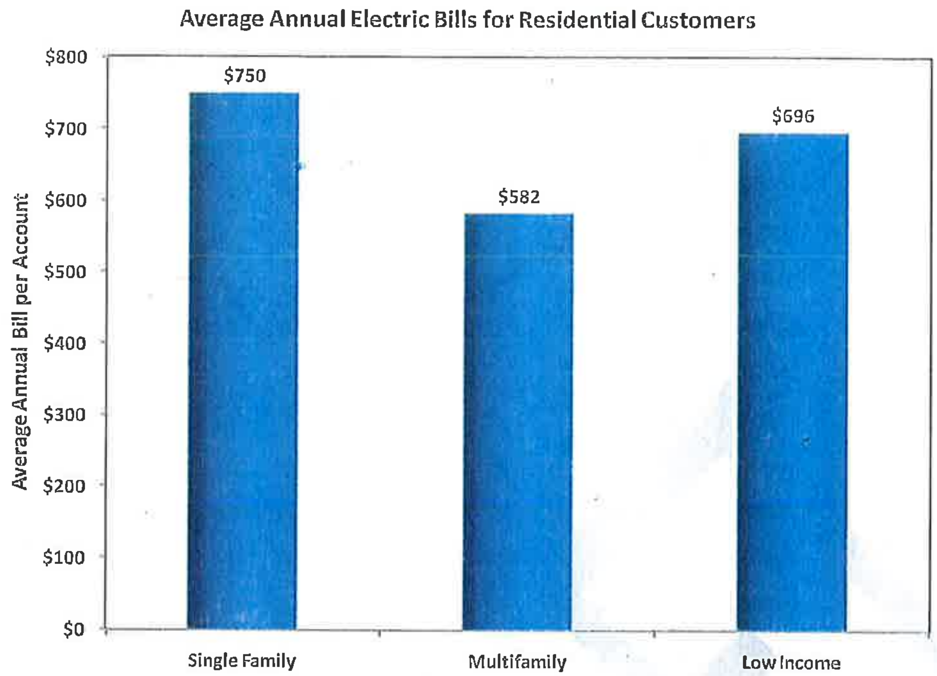
Data presented below are in constant 2010 dollars, with spending for past years increased to equivalent 2010 spending using consumer price index estimates developed by the U.S. Department of Labor.



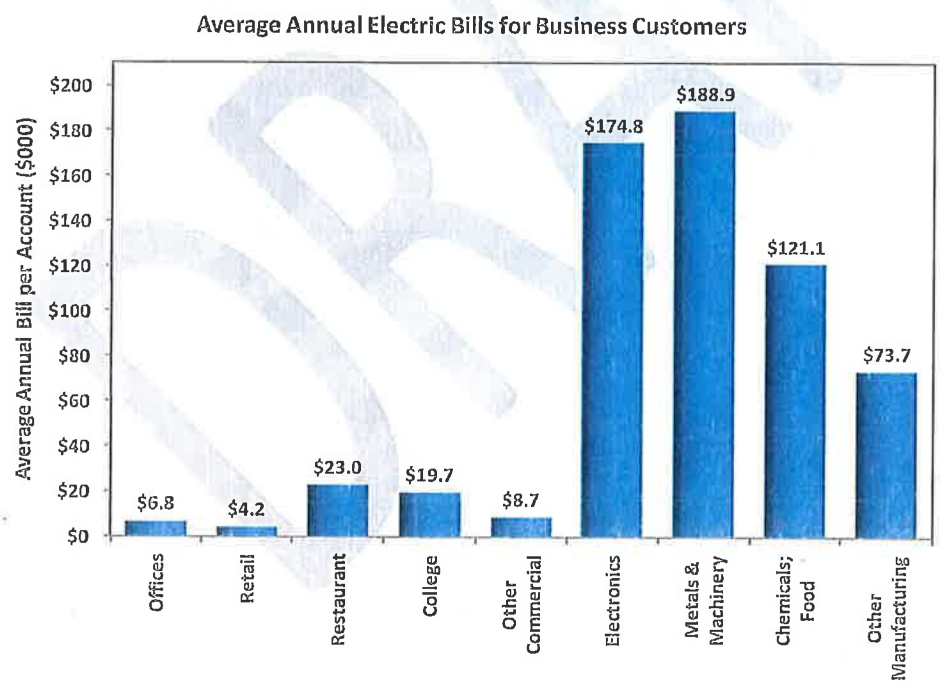
2.2.2 How Do Electric Bills Vary By Customer Segment?

The segmentation disaggregates recent residential spending by housing type, and business spending by commercial and manufacturing business type.

2.2.2.1 How Do Average Residential Bills Vary By Customer Segment?



2.2.2.2 How Do Average Business Bills Vary By Customer Segment?



2.2.3 What Proportion of Total Customer Spending Is Consumed by Electricity

An "energy burden" analysis will be conducted to compare household spending on electricity to disposable household income, and to compare business spending to underlying business costs.

2.2.3.1 How Much Of Low-Income Household Income Is Devoted To Electricity?

Section to be completed for final report.

2.2.3.2 How Much Of Business Operating Cost Is Devoted To Electricity?

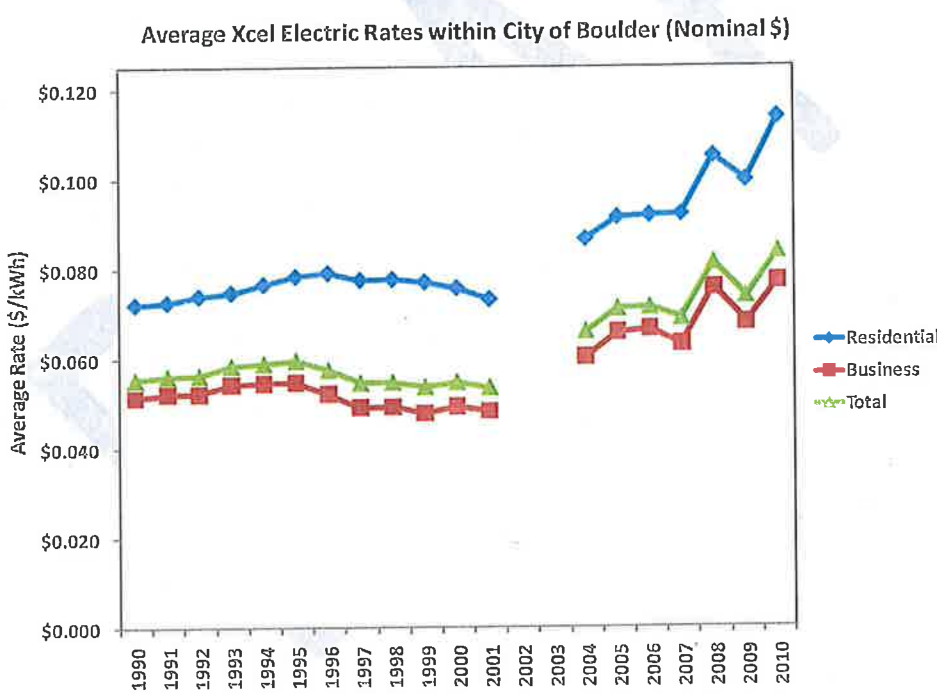
Section to be completed for final report.

2.3 BOULDER AVERAGE ELECTRIC RATES

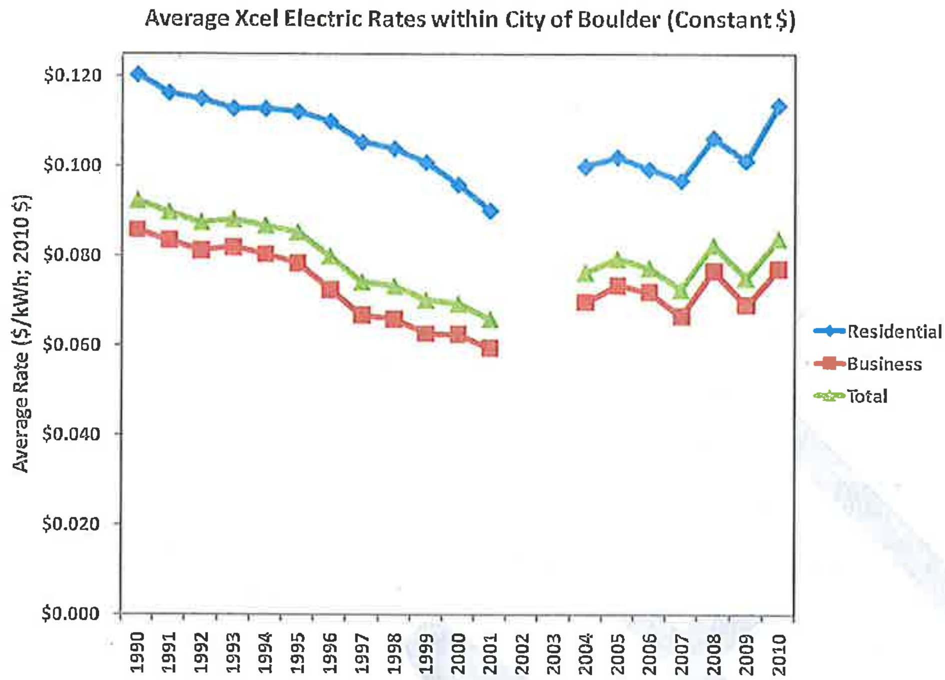
Average annual electric rates are calculated as the ratio of annual spending to annual energy consumption (which is presented in Section 4.1).

2.3.1 What Are Average Electric Rates In Boulder?

Data presented here reflect nominal dollars, or dollars actually spent in each year, without adjustment for underlying inflation. Changes in average rates reflect changes in the underlying price of electricity, controlling for changes in the number of customers and usage per customer.



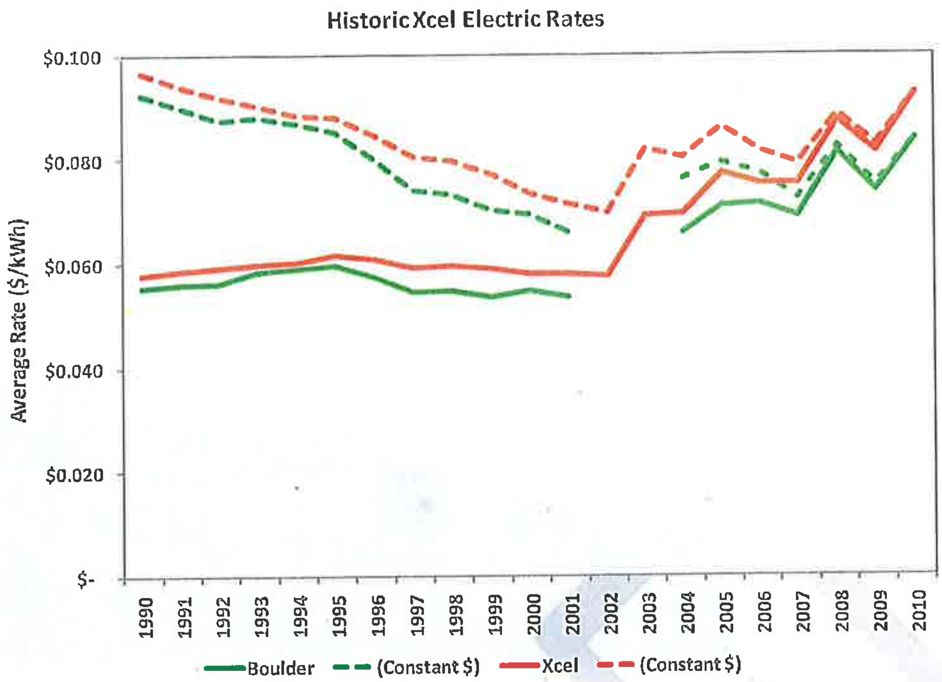
Data presented below are in constant 2010 dollars, with rates for past years increased to equivalent 2010 dollars using consumer price index estimates developed by the U.S. Department of Labor.



Average rates were stable in nominal terms throughout the 1990s, but have increased by over 50 percent since 2002. Adjusted for inflation, rates declined in constant dollars throughout the 1990s, and so the more recent increases still leave 2010 rates approximately 9 percent below 1990 levels.

2.3.2 How Do Boulder's Rates Differ From Xcel's Overall Rates for Colorado?

Xcel's overall rates for its Colorado system were calculated from the reports it files with FERC and EIA. Average rates in Boulder are approximately 10 percent below Colorado totals. This reflects the higher concentration of business customers in Boulder, which represent approximately 80 percent of Boulder sales, but less than 70 percent of Xcel's Colorado total sales. Average business rates are lower than average residential rates because business customers tend to use larger volumes of electricity and to have higher load factors (the ratio of average energy usage to peak usage), which spread out fixed customer and demand charges over more kilowatt-hours.

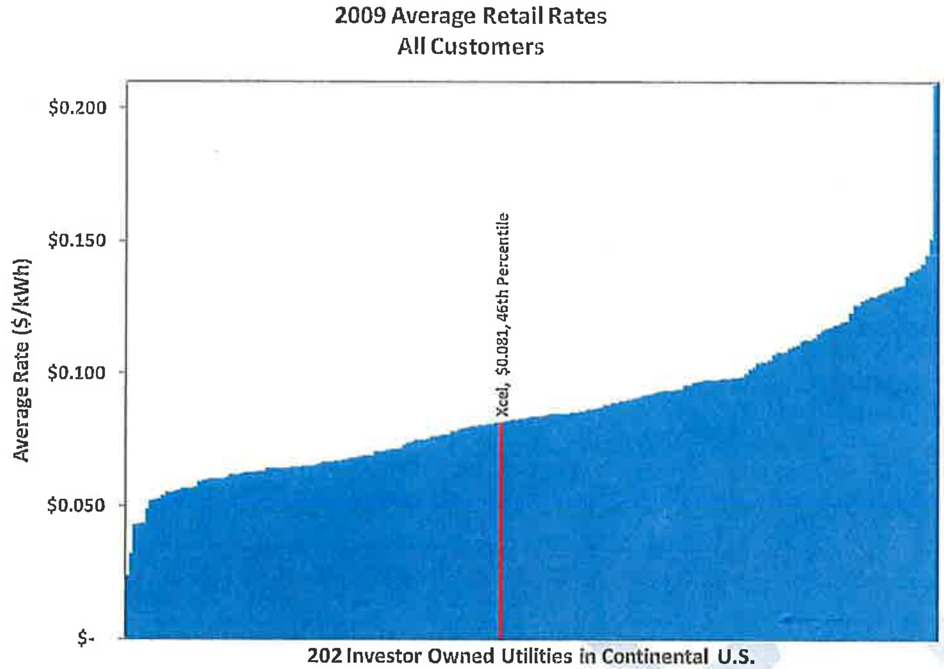


2.3.3 How Do Xcel's Colorado Rates Differ From Rates at Other Investor Owned Utilities?

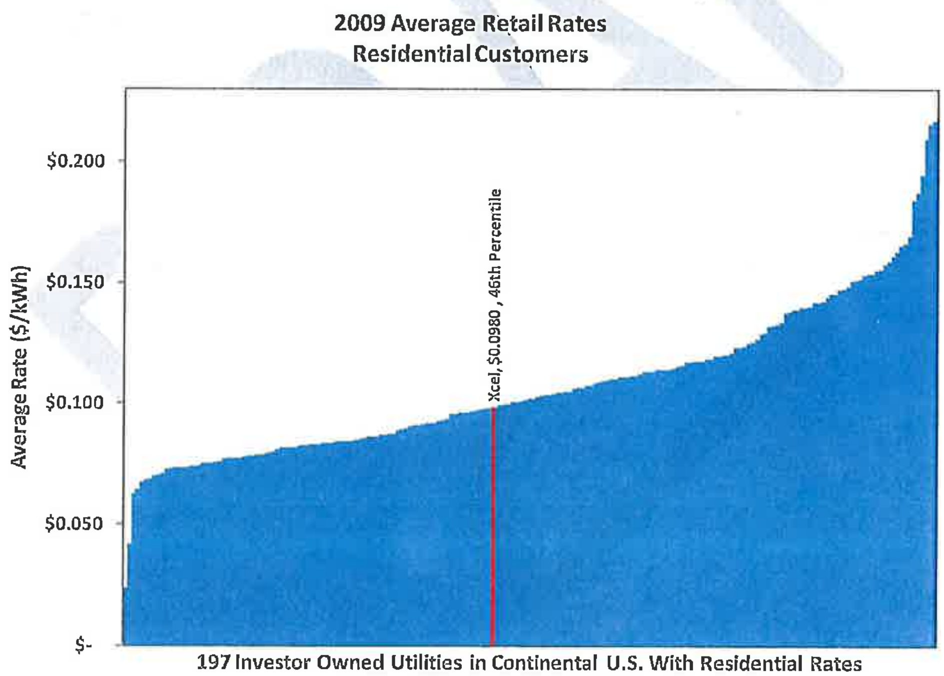
Xcel's average rates on its Colorado system could be compared to rates at other investor-owned utilities in the United States using data utilities file with EIA. Xcel's overall rates, as well as its rates to individual customer classes, are just below the medians for all utilities.

At approximately 8 cents per kilowatt-hour, Xcel's 2009 average rates were slightly over half as high as the highest rates in the country, which exceed 15 cents, and more than 50 percent above the lowest rates, which are just over 5 cents.

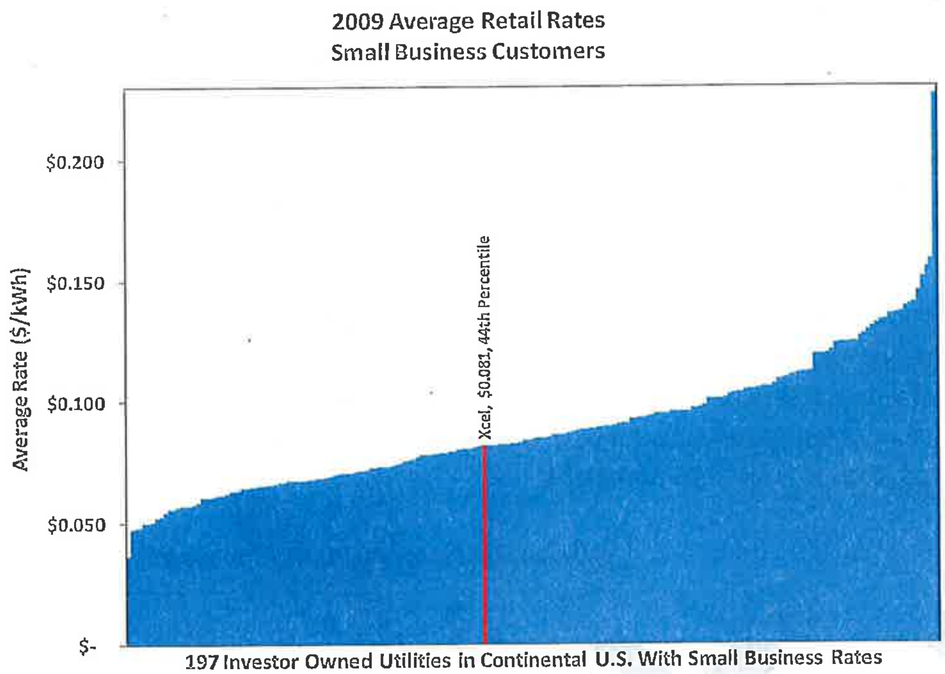
2.3.3.1 How Do Xcel's Overall Rates Differ From Rates at Other Utilities?



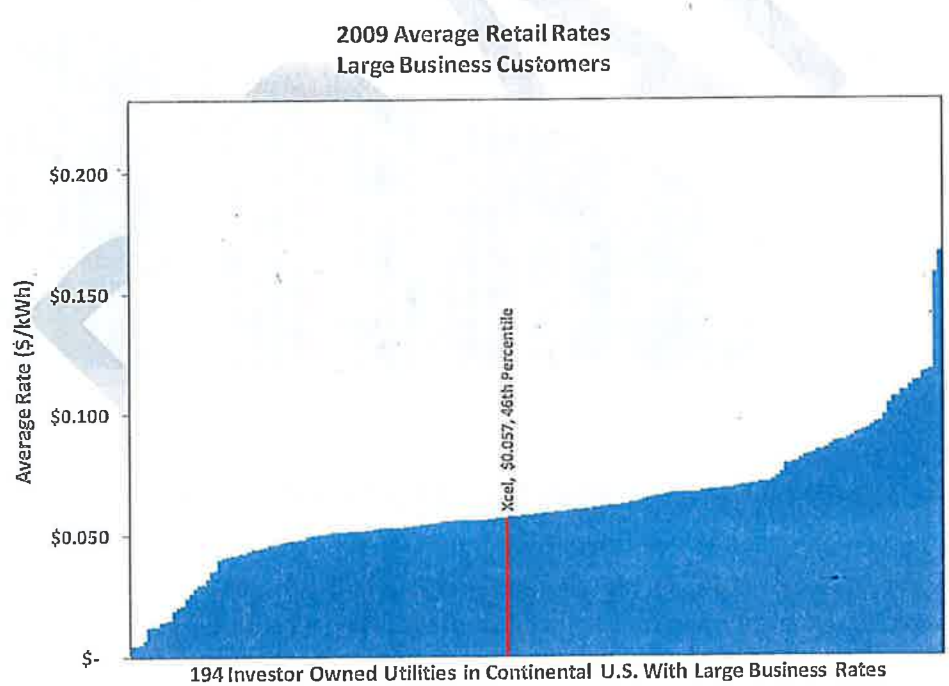
2.3.3.2 How Do Xcel's Residential Rates Differ From Rates at Other Utilities?



2.3.3.3 How Do Xcel's Small Business Rates Differ From Rates at Other Utilities?



2.3.3.4 How Do Xcel's Large Business Rates Differ From Rates at Other Utilities?

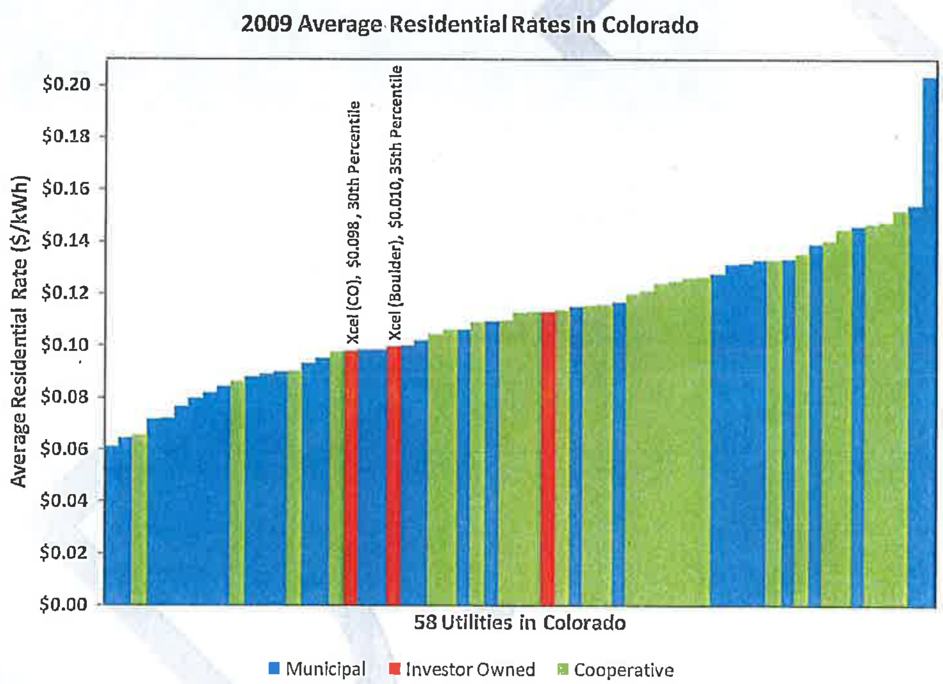


2.3.4 How Do Xcel's Residential Rates Compare To Rates at Other Colorado Utilities?

The EIA data could also be used to compare Xcel's residential rates to rates at other Colorado utilities. Residential rates were used as so that the mix of business to residential customers, which differs widely across Colorado utilities, would not affect the comparison.

Xcel's Colorado rates rank in the thirtieth percentile (i.e., the 18th lowest rates out of 58 utilities). Xcel's average rates within the city are slightly higher than Xcel's Colorado average, probably reflecting the relatively small average consumption of Boulder customers, who are more likely to live in apartments than Xcel's average Colorado customer.

Utilities with the lowest rates tend to be municipally owned, serving relatively compact service territories. Utilities with the highest rates tend to be cooperatively owned, serving relatively dispersed rural service territories. Both municipal and cooperative utilities have access to relatively inexpensive federal power; and both utility types do not incur costs needed to support earnings and related taxes for utility shareholders.

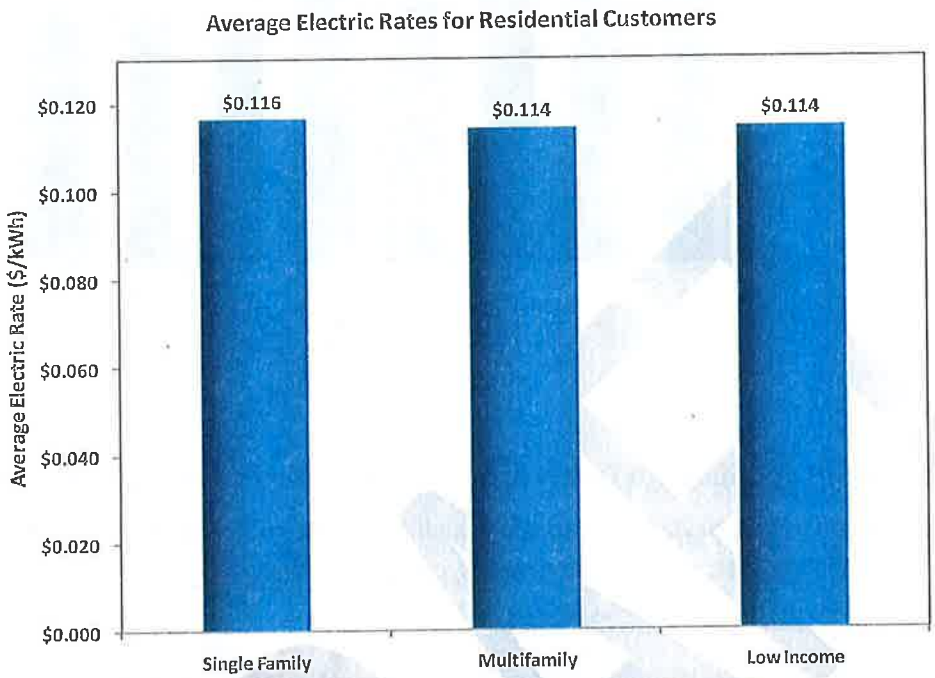


2.3.5 How Do Boulder's Average Rates Vary By Customer Segment?

The segmentation analysis calculated average rates for each customer segment by applying Xcel's 2011 Colorado rate tariffs to energy usage characteristics for each segment (e.g., energy and demand requirements; summer and winter usage; on-peak and off-peak usage).

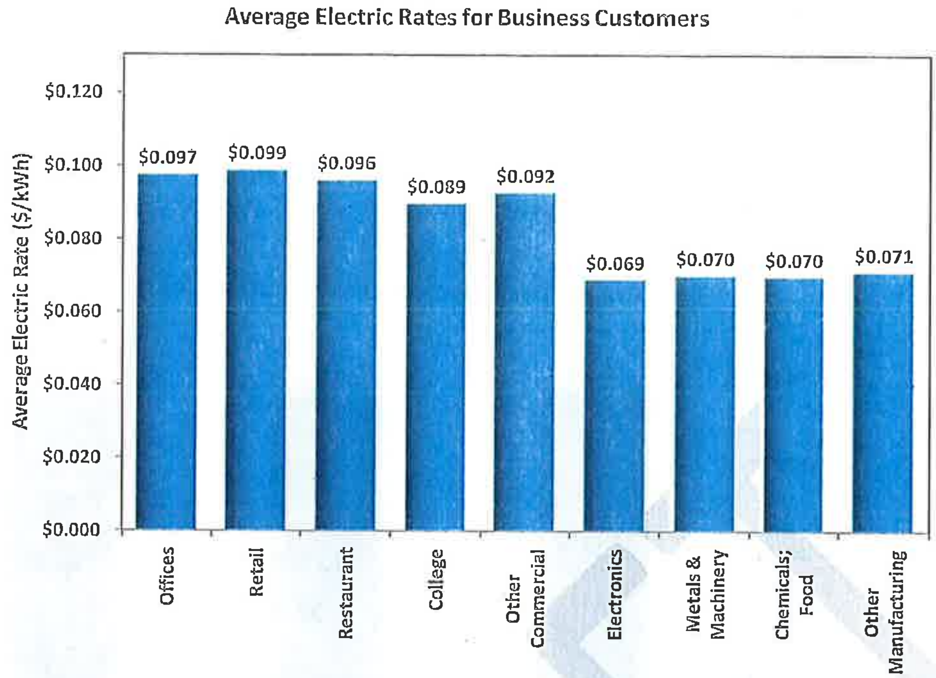
2.3.5.1 How Do Average Residential Rates Vary By Customer Segment?

Average rates paid by different residential segments shows small variation, reflecting only small differences in underlying usage patterns. Xcel recently changed its price structure to charge much higher rates for consumption over 500 kilowatt-hours per month, and so the largest residential customers pay substantially higher average rates.



2.3.5.2 How Do Average Business Rates Vary By Customer Segment?

Manufacturing business segments pay lower average rates than commercial segments. Manufacturing segments include customers with higher overall usage and higher load factors (the ratio of average energy usage to peak usage). Electric bills for these customers spread out fixed customer and demand charges over more kilowatt-hours, resulting in lower average rates.



2.3.6 Which Specific Rate Tariffs Are Available to Xcel's Colorado Customers?

A detailed analysis of all 2011 rate tariffs available to Xcel's Colorado customers was performed to compare the customer, energy, and demand charges that apply to each specific rate offering. Depending on the specific tariff, charges can vary by:

- **Usage level:** residential tariffs charge higher rates for usage exceeding 500 kilowatt-hours per month in the summer;
- **Season:** many tariffs charge higher rates in summer months and lower rates in the winter;
- **Usage period:** customers with special meters that track usage for on-peak and off-peak periods are charged higher rates for usage during the middle of day on weekdays (on peak) and lower rates for usage during the night and on weekends and holidays (off peak);
- **System charges:** rates for larger business customers segregate charges for the underlying costs of the distribution system from those for the generation and transmission system.

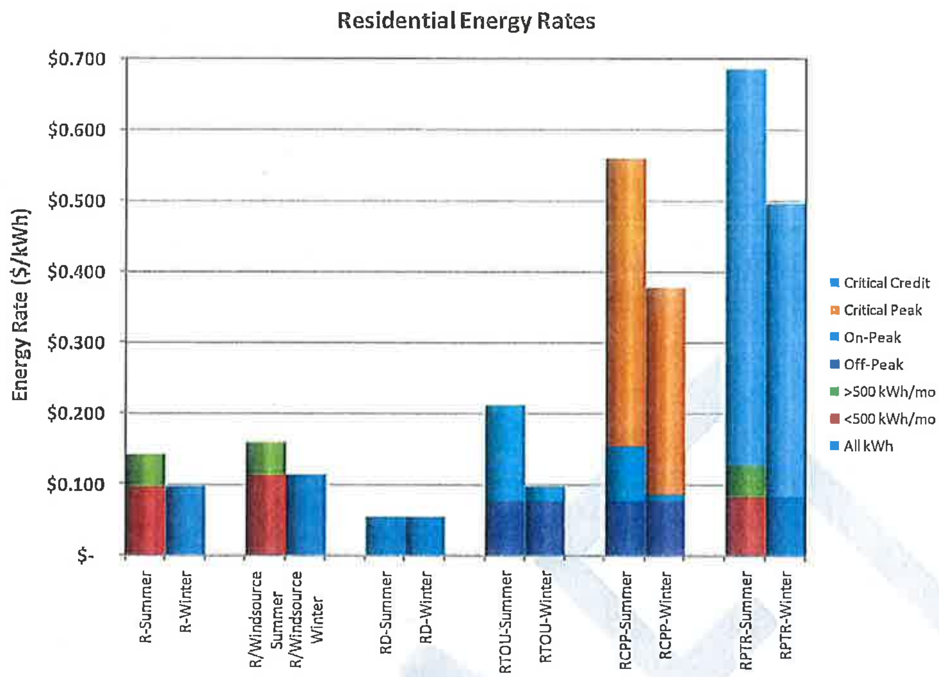
Customers choosing to participate in certain sustainable energy programs also receive different rates, including:

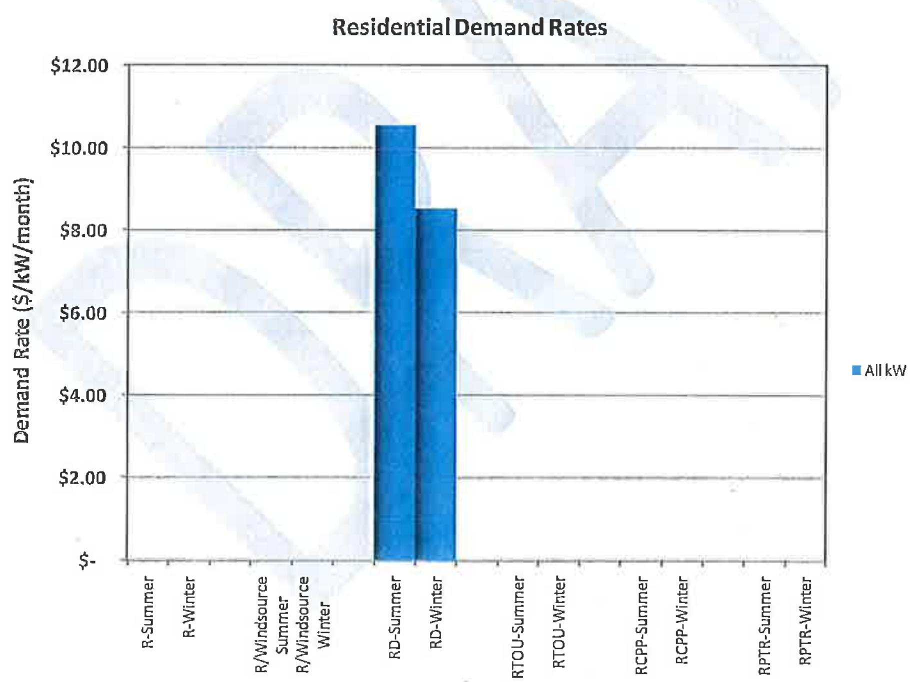
- **Windsource:** residential and business customers participating in this program pay an additional 2.16 cents per kilowatt-hour on all energy purchases (see section 7.3.1 for additional analysis of Windsource);

- **Interruptible service:** very large business customers who agree to interrupt or otherwise lower usage during Xcel's hours of highest demand receive discounts on demand charges that vary from $6 to $16 per kilowatt per month depending on the frequency, duration, and response speed for interruptions.

In addition, residential customers on Xcel's SmartGrid City program in Boulder are eligible for two additional tariff options that are only offered in Boulder. These rates (Residential Critical Peak Pricing or RCPP and Residential Peak Time Rebate or RPTR) provide customers with incentives to reduce usage during critical-peak periods (Xcel's hours of highest system demand) in response to real-time signals provided on the SmartGrid City system.

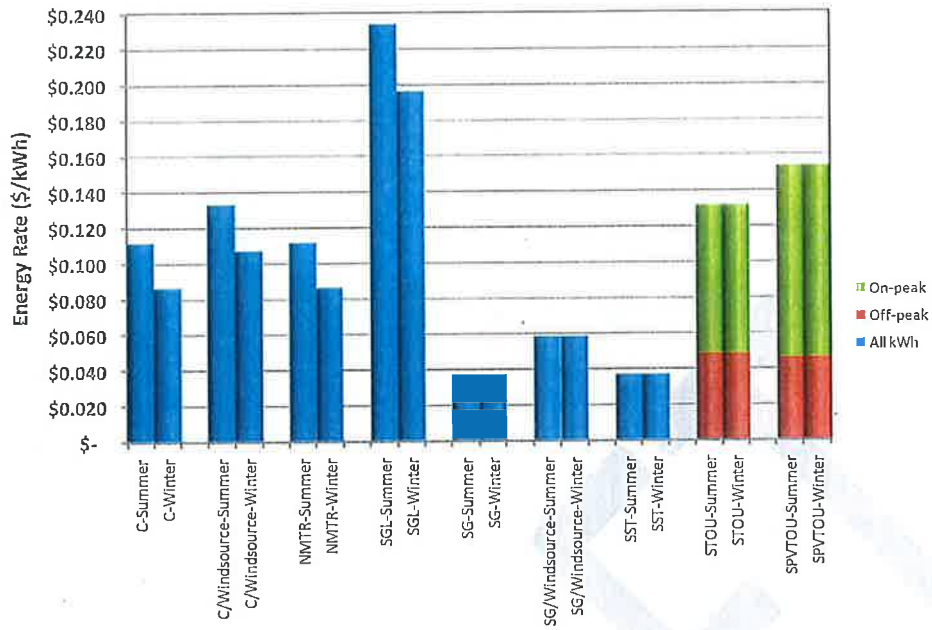
2.3.6.1 Which Rate Tariffs Are Available To Residential Customers?



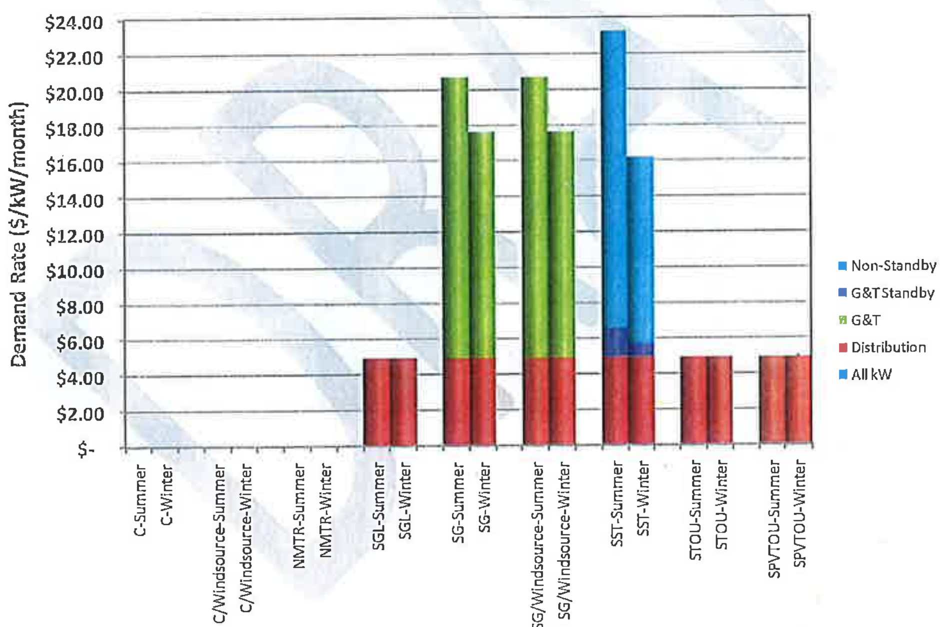


2.3.6.2 Which Rate Tariffs Are Available To Small Business Customers?

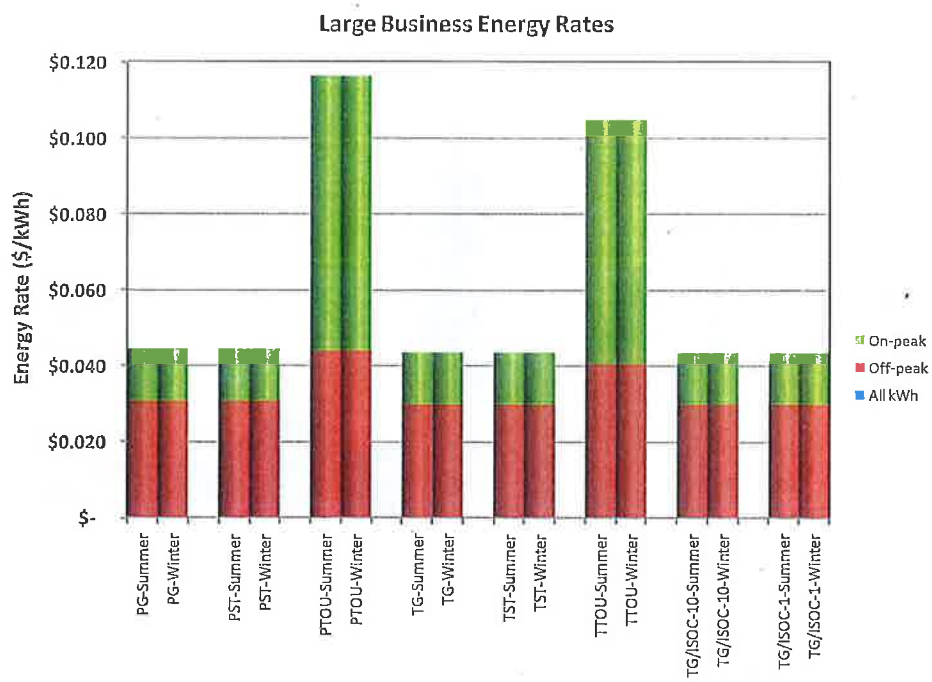
Small Business Energy Rates

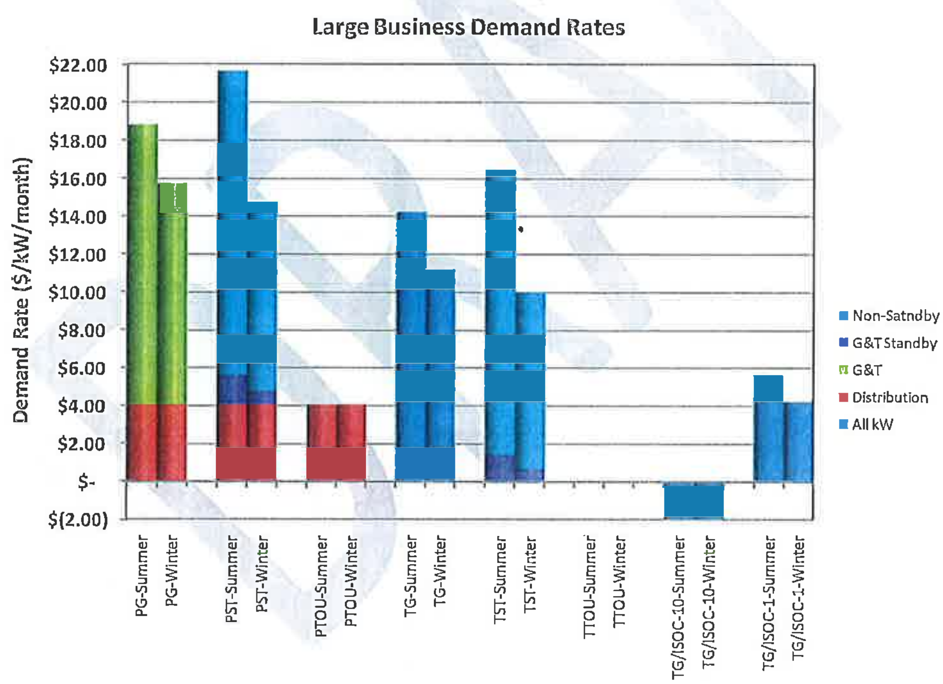


Small Business Demand Rates



2.3.6.3 Which Rate Tariffs Are Available To Large Business Customers?



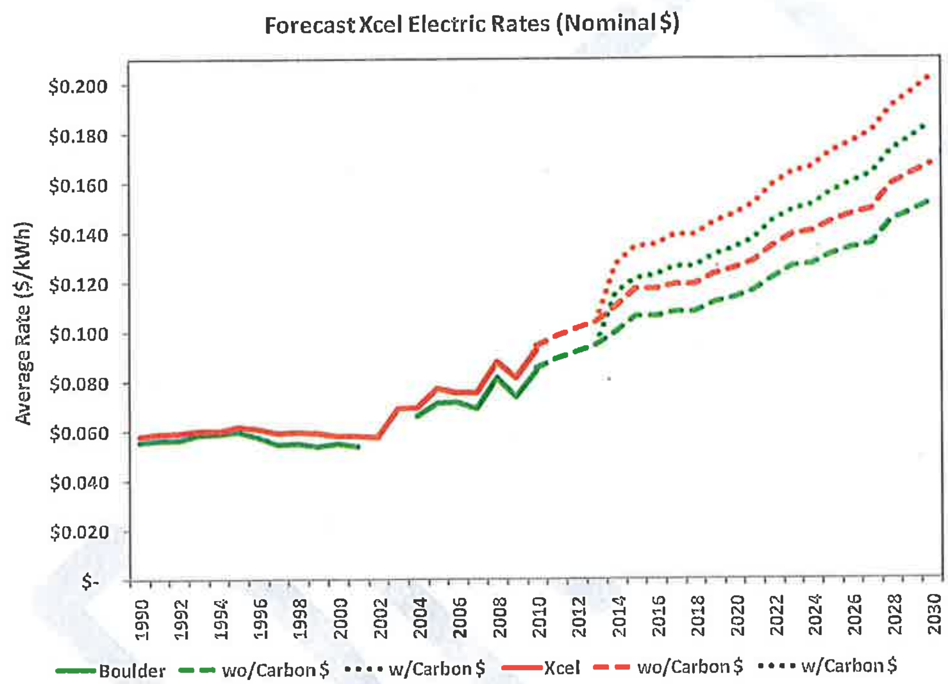


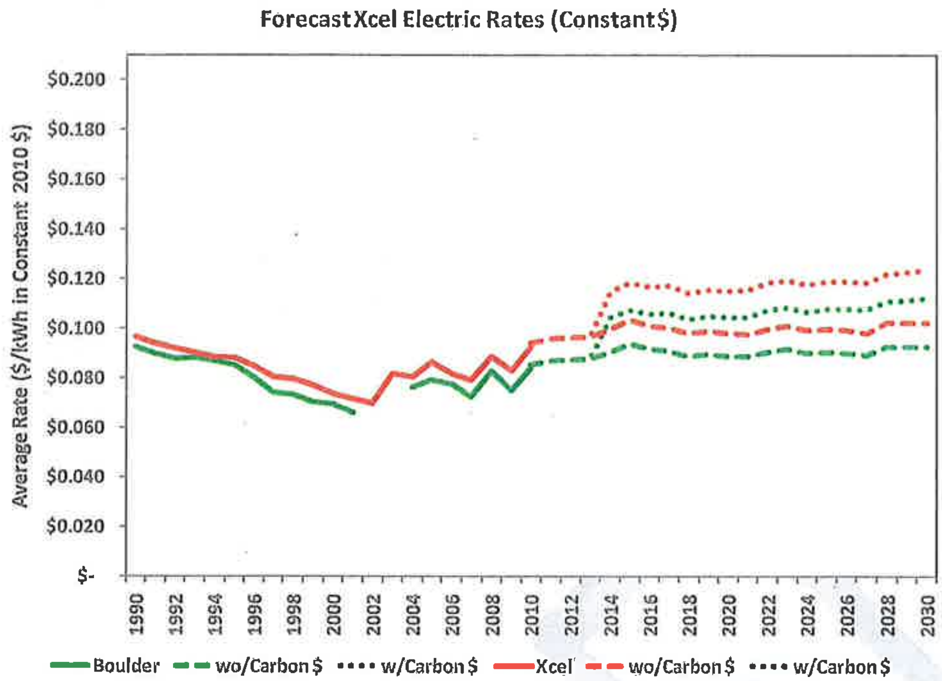
2.3.7 How Are Rates Projected To Increase In The Future?

The plan that Xcel developed in response to the Colorado Clean Air-Clean Jobs Act that has been approved by the Colorado Public Utilities Commission (PUC) includes forecasts of average rates.

Not taking into account any potential new taxes or other regulations that might create a price on carbon emissions, Xcel projects rates to increase by about 4 percent in constant dollars by 2020 (33 percent after inflation) and about 8 percent by 2030 (78 percent after inflation). However, if carbon prices do come into play, Xcel projects much higher rate increases: approximately 22 percent by 2020 (56 percent after inflation) and 31 percent by 2030 (115 percent after inflation).

Xcel's rate forecasts rely on a number of assumptions regarding the costs of building new natural gas and renewable generation plants as well as the future prices of coal and natural gas. Additional analysis of Xcel's fuel price projections are provided in Section 3.2.2.




Forecast Xcel Electric Rates (Constant $)
Average Rate ($/kWh in Constant 2010 $)
$0.200
$0.180
$0.160
$0.140
$0.120
$0.100
$0.080
$0.060
$0.040
$0.020
$-
1990
1992
1994
1996
1998
2000
2002
2004
2006
2008
2010
2012
2014
2016
2018
2020
2022
2024
2026
2028
2030
Boulder
wo/Carbon $
w/Carbon $
Xcel
wo/Carbon $
w/Carbon $

3 XCEL UNDERLYING COSTS AND PROFITABILITY

This chapter provides information on the underlying costs that drive customer spending and average rates on Xcel's Colorado system, including information on the expenses and financing costs Xcel incurs to build and operate its electric system, as well as the profit and related taxes that flow to Xcel's shareholders.

In the body of this chapter, data are presented in graphical format. Calculations and data tables supporting each graph will be provided in spreadsheet format to city staff.

Key references for this chapter include:

- Annual reports that Xcel files with FERC documenting finances and operations;
- The plan that Xcel developed in response to the Colorado Clean Air-Clean Jobs Act that was approved by the Colorado PUC;
- Utility fuel price forecasts developed by the U.S. Department of Energy (USDOE) in its 2011 Annual Energy Outlook;
- A detailed allocation analysis that distributed common costs, assets, liabilities, and earnings for Xcel's consolidated Colorado operations to each of its three operating utilities (electric, natural gas and steam); allocated total electric costs to generation, transmission, distribution, and general activities; and allocated generation costs among plants of different fuel types;
- A detailed segmentation analysis of Boulder's customer base, drawing on data city staff provided on buildings, households, and businesses in the city; public data from Xcel regarding energy characteristics for different customer segments; Xcel's current rate tariffs; and public data from Xcel documenting its underlying costs of generating and delivering electricity.

3.1 XCEL COLORADO OPERATIONS

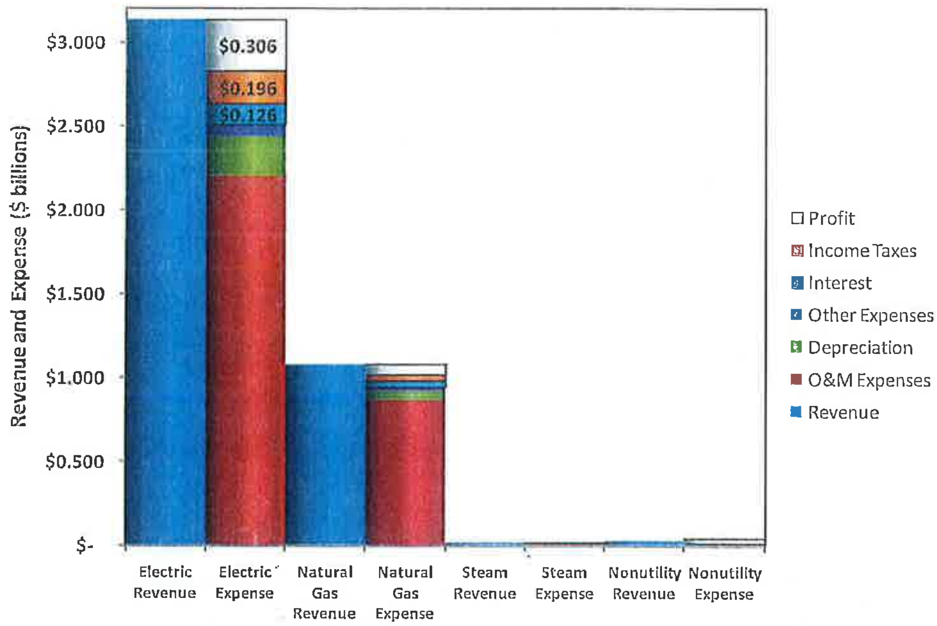
3.1.1 Xcel Overall Operating Income

Information from Xcel's 2010 FERC filing was used to estimate revenue and expenses for each of Xcel's three Colorado utilities (electric, natural gas, and steam) as well as Xcel's small nonutility operations. Since Xcel finances its overall operations with consolidated debt and equity, an analysis was required to assign financing and tax costs to each utility. In addition, electric revenue and expenses reflect retail sales to Colorado customers, as well as additional wholesale transactions which represent approximately 14 percent of 2010 electric revenue.

3.1.1.1 How Do Xcel's Colorado Revenue and Costs Vary by Utility?

Xcel's electric utility represents over 70 percent Colorado revenue and expenses. In 2010, electric revenues exceeded direct expenses by approximately $627 million (on revenues of over $3.1 billion), which was used to pay for interest on debt, as well as net income and related taxes to equity shareholders.

Xcel 2010 Revenue and Expenses from Colorado Operations



3.2 XCEL ELECTRIC COSTS

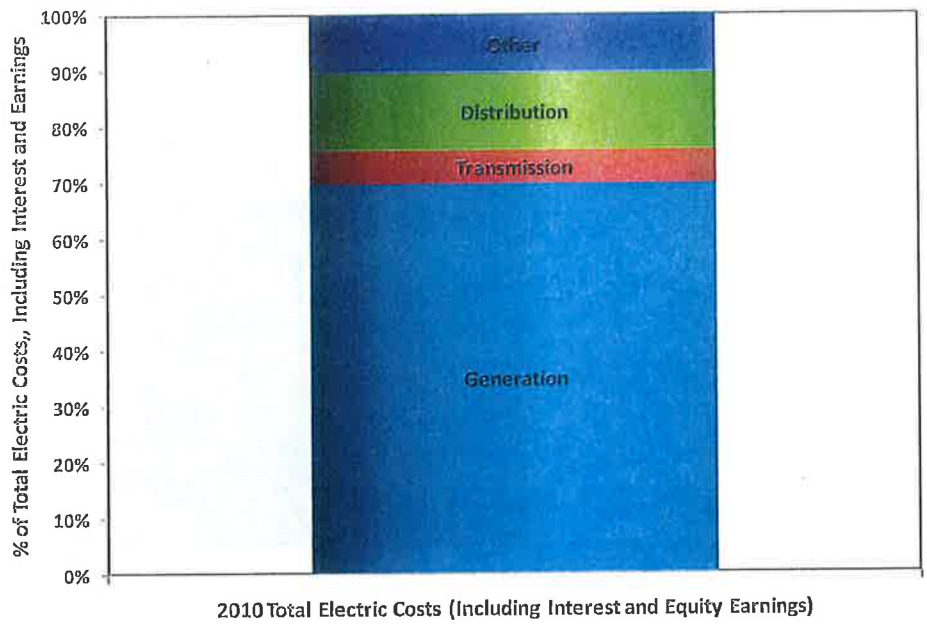
3.2.1 Xcel Electric Costs

An analysis was performed to allocate Xcel's overall 2010 electric costs, including expenses as well as financing costs required to fund plant investment, to its generation, transmission, distribution, and general operations, and then to further disaggregate generation costs among plants of different fuel types.

3.2.1.1 How do Xcel's Colorado Electric Expenses and Financing Costs Vary by Asset Type?

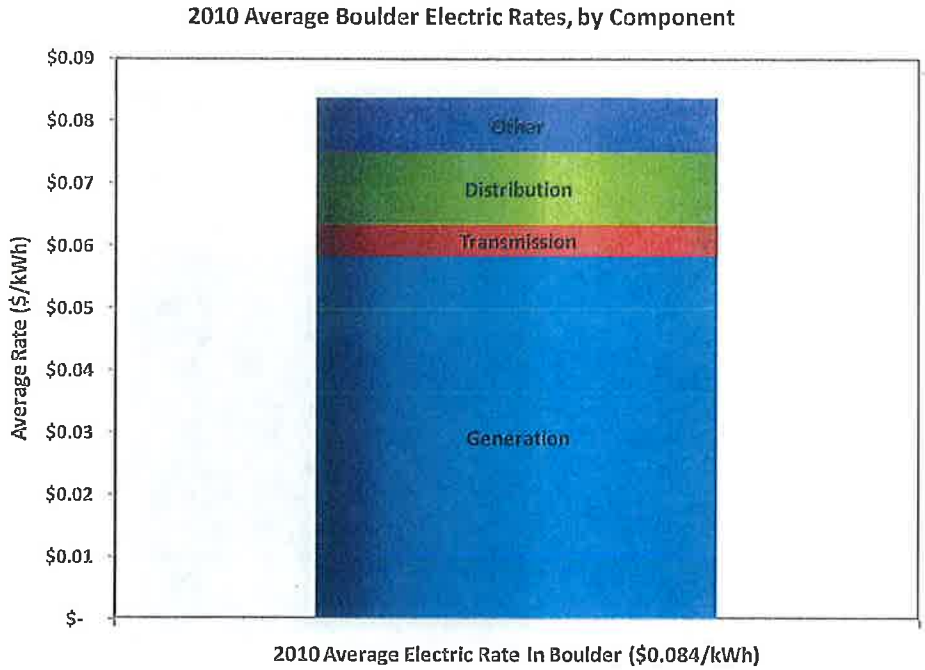
About 70 percent of Xcel's costs from its Colorado electric operations support its generation system, with another 6 percent for transmission, 14 percent for distribution, and 10 percent for general operations.

2010 Xcel Colorado Electric Costs, by Component



3.2.1.2 How do Xcel's Costs Translate to Boulder Electric Rates?

Applying these shares to Boulder's city-wide 2010 average electric rates results in average rates of approximately 5.8 cents per kilowatt-hour to support generation, 0.5 cents for transmission, 1.2 cents for distribution, and 0.9 cents for general activities.



3.2.1.3 How do Xcel Generation Costs Vary by Fuel Type?

To be developed for final report.

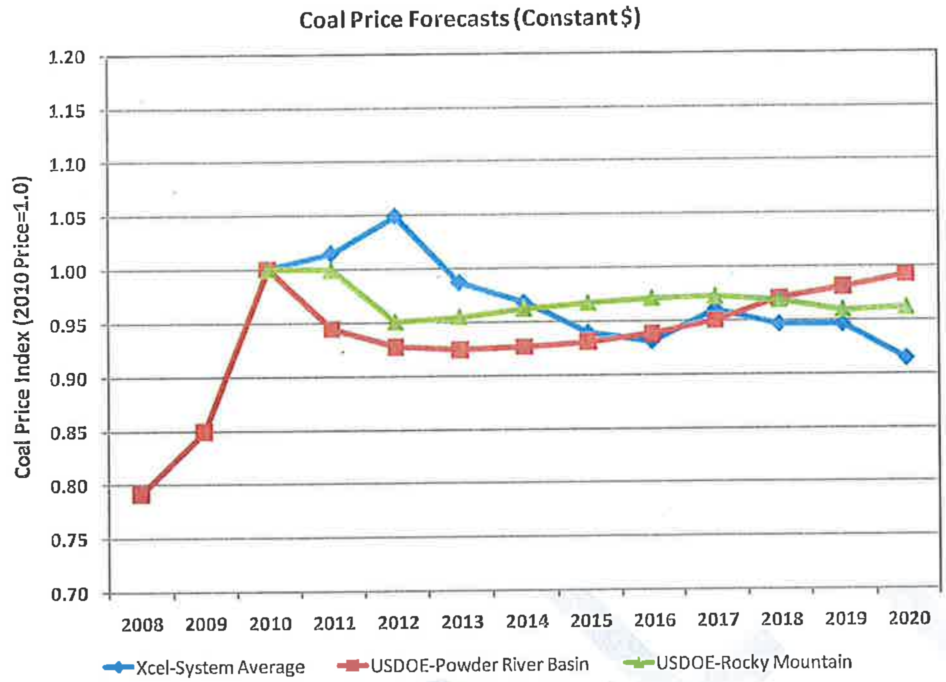
3.2.2 Xcel Fuel Price Projections

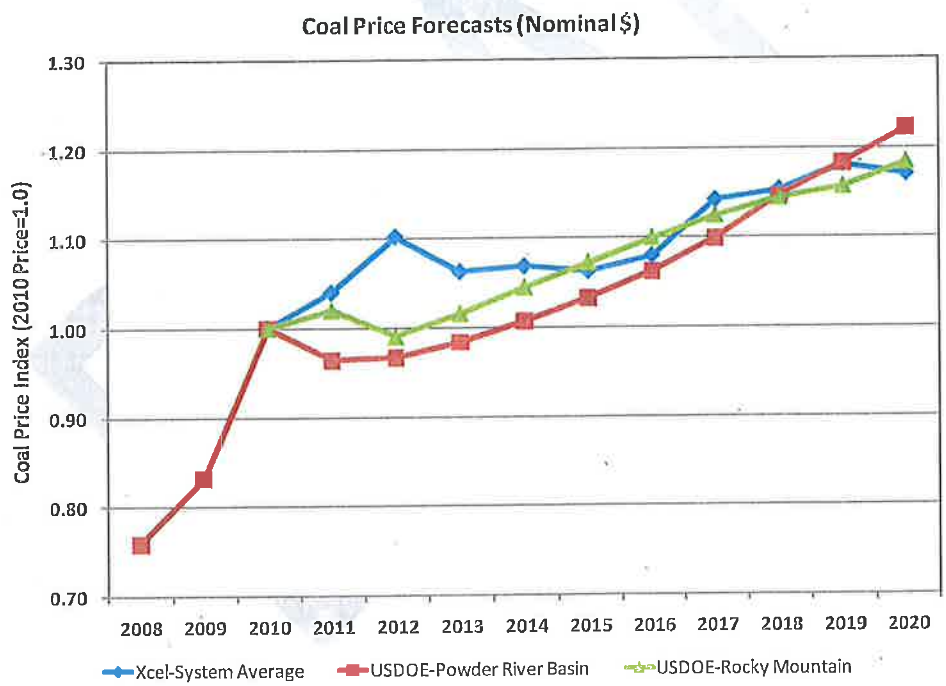
The plan that Xcel developed in response to the Colorado Clean Air-Clean Jobs Act that has been approved by the Colorado Public Utilities Commission (PUC) includes forecasts of underlying coal and natural gas prices. These forecasts were compared to recent changes in utility fuel prices, as well as to forecasts developed by USDOE in its 2011 Annual Energy Outlook.

Xcel's projects coal prices to increase at approximately 1.6 percent per year in nominal dollars (which translates into a 0.9 percent annual decrease after inflation) and natural gas prices to increase at approximately 6.3 percent per year in nominal dollars (3.8 percent after inflation).

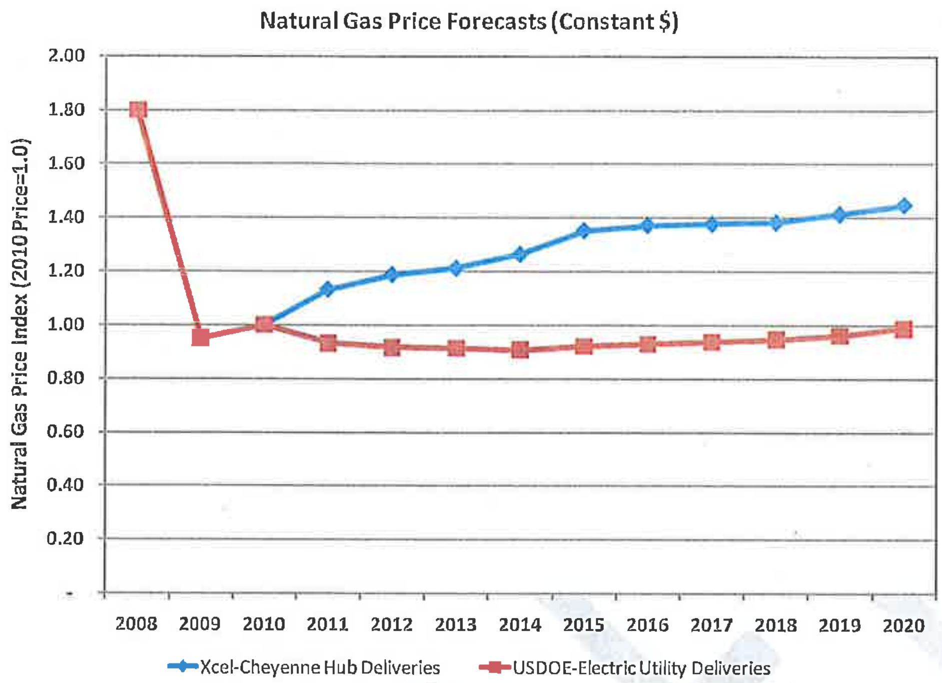
Xcel's plan was developed amidst extreme volatility in utility fuel markets, with coal prices increasing by over 25 percent and natural gas prices declining by over 40 percent between 2008 and 2010. While Xcel's coal forecast is well below recent price increases, it is generally in line with USDOE's projections. Xcel's natural gas price forecast is substantially higher than USDOE's forecast, which projects no real increase in natural gas prices over and above inflation between 2010 and 2020.

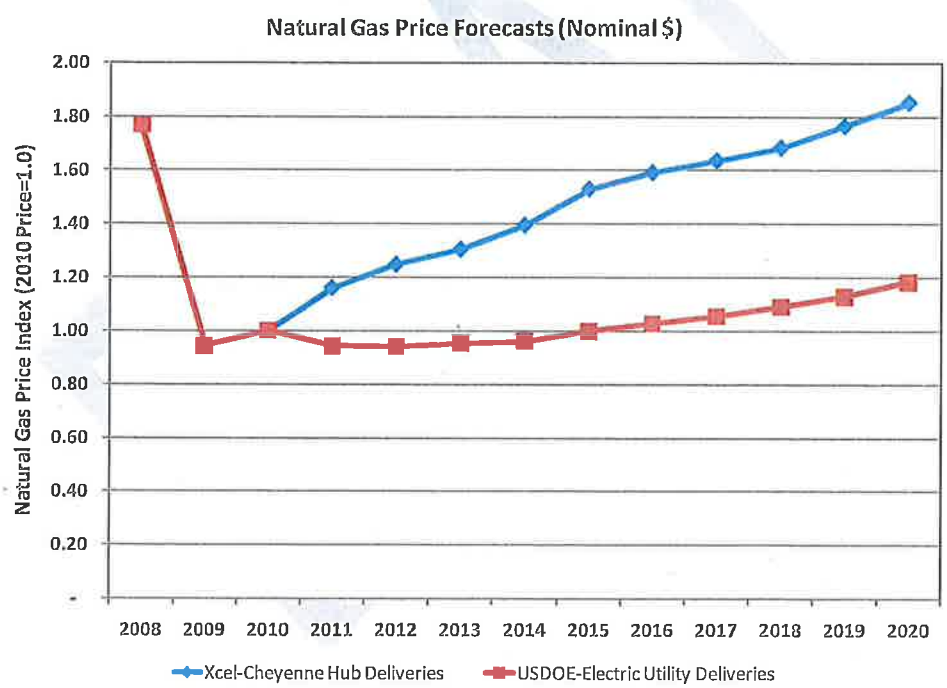
3.2.2.1 How Are Xcel's Coal Prices Projected To Increase In The Future?





3.2.2.2 How Are Xcel's Natural Gas Prices Projected To Increase In the Future?



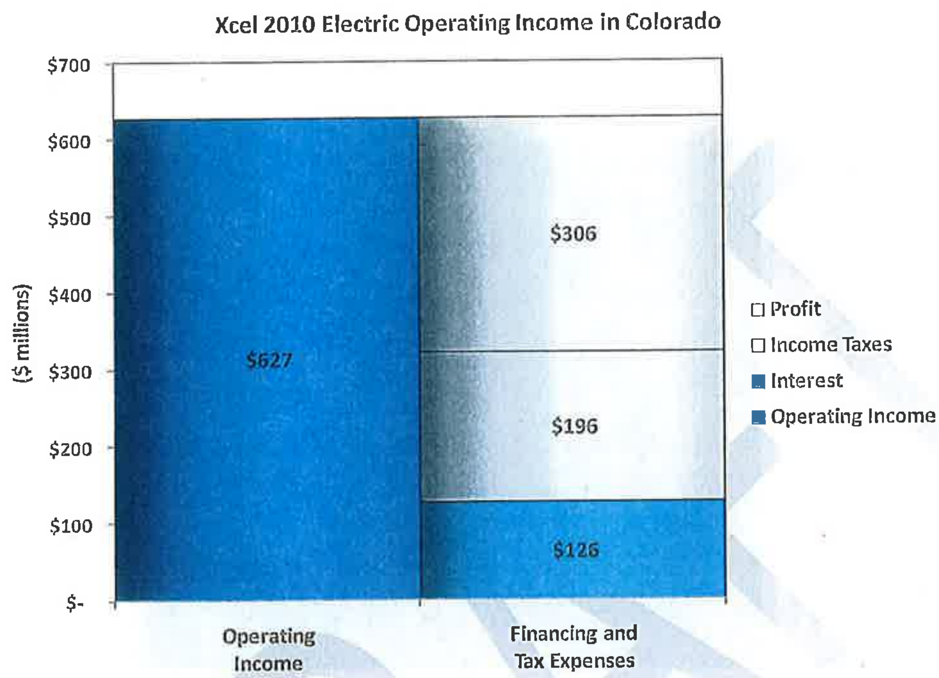


p

3.3 XCEL'S COLORADO ELECTRIC OPERATING INCOME

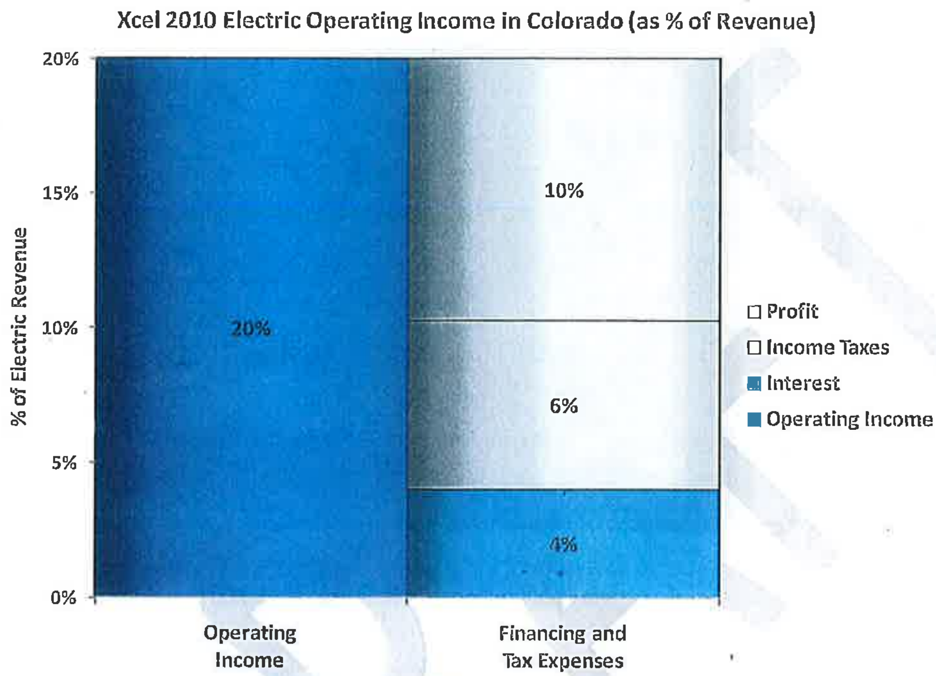
3.3.1.1 How Does Electric Operating Income Fund Debt Interest and Equity Returns?

This graph isolates Xcel's 2010 operating income on its Colorado electric operations (shown previously in section 3.1.1), and shows how revenues in excess of expenses fund debt interest, earnings for equity shareholders, and taxes on those earnings.



3.3.1.2 How Does Electric Operating Income Compare to Electric Revenue?

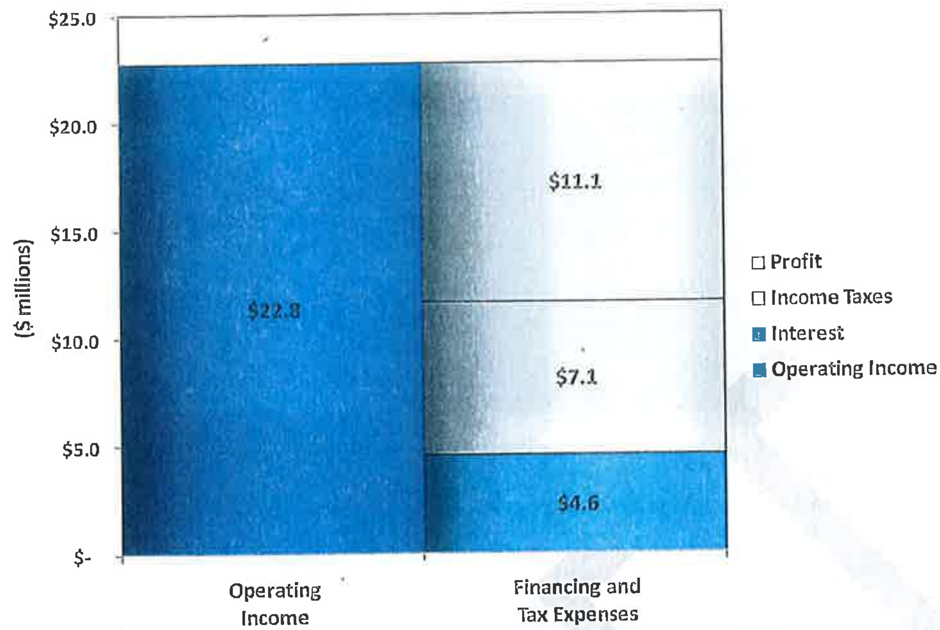
This graph uses the information shown in Section 3.3.1.1, to express values as a percentage of total electric revenue. Approximately 10 percent of Xcel's 2010 revenue went to fund shareholder earnings, with another 6 percent going to fund taxes on those earnings. (These values show earnings and taxes as a percentage of revenue, and are not the same as rates of return on outstanding equity shares or rates of return on utility plant-in-service, which are alternative metrics used to set utility rates and to gauge shareholder earnings performance.)



3.3.1.3 How Much Electric Operating Income Does Xcel Earn in Boulder?

This graph applies the percentages calculated in Section 3.3.1.2 to Xcel's 2010 electric revenue from Boulder customers, to provide general estimates of the contributions Boulder customers made to Xcel's interest payments, shareholder earnings, and taxes on those earnings.

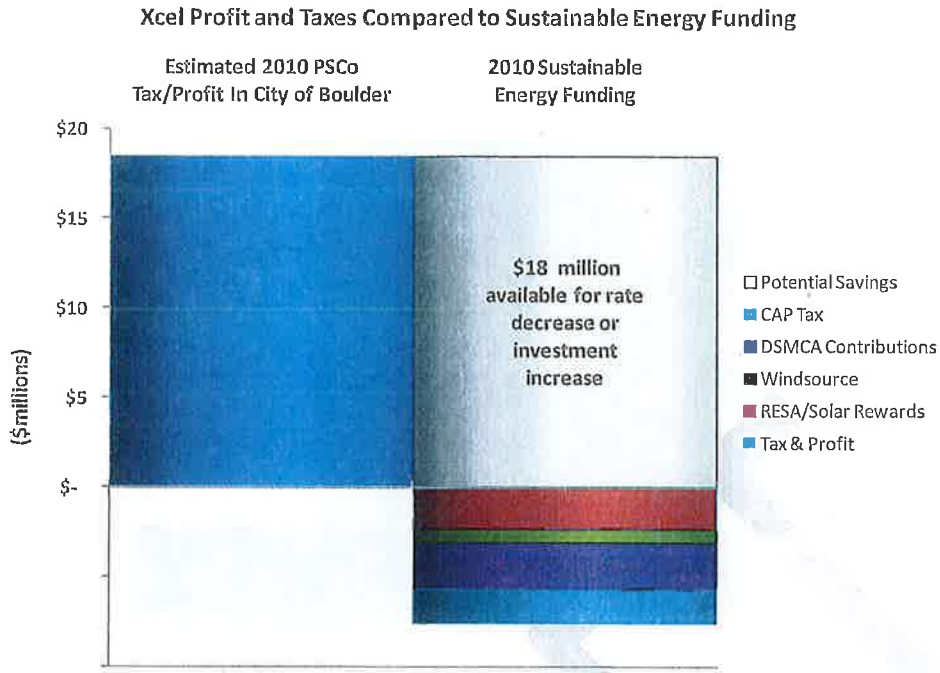
Estimated Xcel 2010 Electric Operating Income in Boulder



3.3.1.4 How Does Xcel Profit and Income Taxes Collected in Boulder Compare to Sustainable Energy Spending in 2010?

To place Boulder contributions in context, the approximately $18 million dollars that went to fund shareholder earnings and taxes in 2010 represents approximately 2.4 times the amount Boulder customers contributed towards Xcel's and the city's sustainable energy investments in 2010. These sustainable investments included:

- Revenues that funded Xcel's renewable generation required under Colorado's Renewable Energy Standard (which also funds on-site photovoltaic installations through Xcel's Solar Rewards program);
- Revenues that funded Xcel's DSM programs;
- Revenues from Boulder's Windsource participants;
- Revenues from Boulder's CAP tax, which fund city sustainability initiatives.



3.3.2 Xcel's Investor Returns

3.3.2.1 What Levels of Returns are Earned by Xcel's Investors?

Section to be completed for final report.

3.3.3 Xcel's Operating Margins by Customer Segment

3.3.3.1 How Do Operating Margins Vary by Residential Customer Segment

Section to be completed for final report.

3.3.3.2 How Do Operating Margins Vary by Business Customer Segment

Section to be completed for final report.

4 BOULDER ELECTRIC SALES AND LOADS

This chapter provides information on the amount of electricity Boulder customers purchase from Xcel, as well as data on the city's overall load shape that show fluctuation in loads across the hours of the day and seasons of the year.

To place the data in context, a number of comparisons are provided, including:

- By customer sector (e.g., residential vs. business) and segment (e.g., office buildings compared to electronics factories within the business sector);
- Between Boulder and the rest of Xcel's Colorado system;
- Over time from 1990 through 2010;
- Additional comparisons to Boulder's benchmark cities are provided in Chapter 9.

In the body of this chapter, data are presented in graphical format. Data tables supporting the graphs are presented in the Appendix and in additional spreadsheets provided to city staff.

Key references for this chapter include:

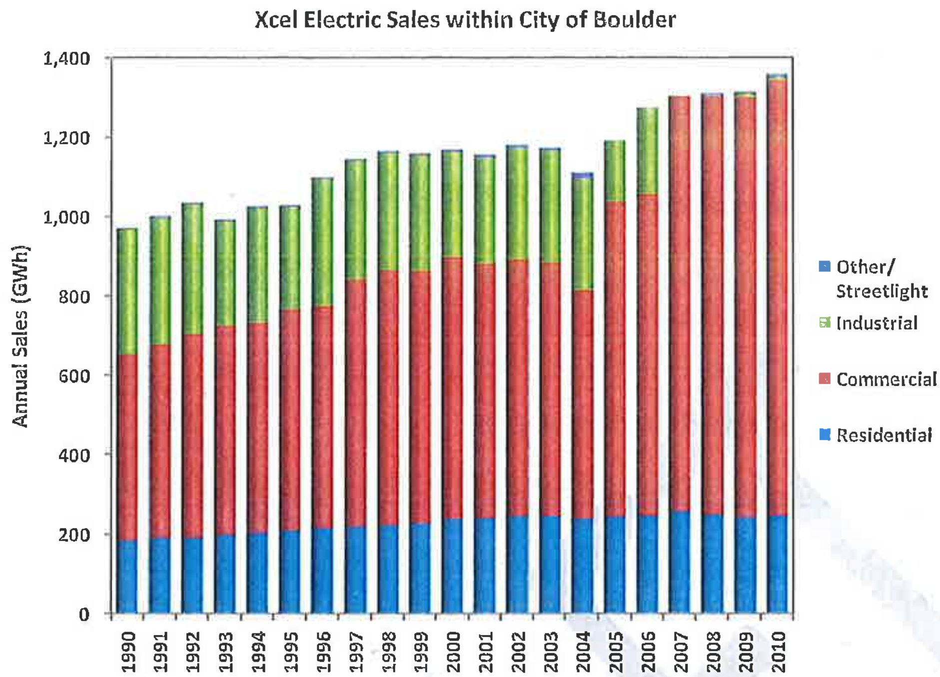
- Annual reports that Xcel provided to the city under its franchise agreement through 2009;
- Monthly reports that Xcel provides to Boulder to document collection of the CAP tax;
- The greenhouse gas (GHG) emissions inventory that the City completed in 2009;
- Annual reports that Xcel files with EIA documenting sales, revenues, and customers;
- A detailed segmentation analysis of Boulder's customer base, drawing on data city staff provided on buildings, households, and businesses in the city; public data from Xcel regarding energy characteristics for different customer segments; Xcel's current rate tariffs; and public data from Xcel documenting its underlying costs of generating and delivering electricity.

4.1 BOULDER ELECTRIC SALES

Overall sales are documented by Xcel's annual reports, the GHG inventory, and Xcel's 2010 monthly CAP tax reports.

Again, while the data breaks down business sales for commercial and industrial customers, these designations reflect the volume of customer electricity purchases rather than underlying business activity (i.e., commercial designates smaller customers, regardless of whether those customers operate retail stores or manufacturing plants). Changes in the mix of commercial and industrial spending over time, especially in recent years, reflects Xcel's changing definition of "large" vs. "small" customers, rather than a more fundamental shift in Boulder's underlying business base.

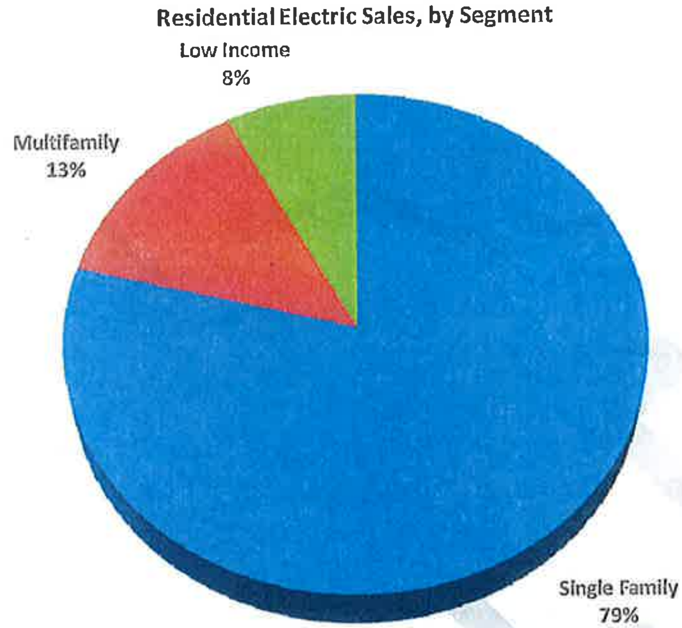
4.1.1 How Much Electricity Does Xcel Sell To Boulder Customers?



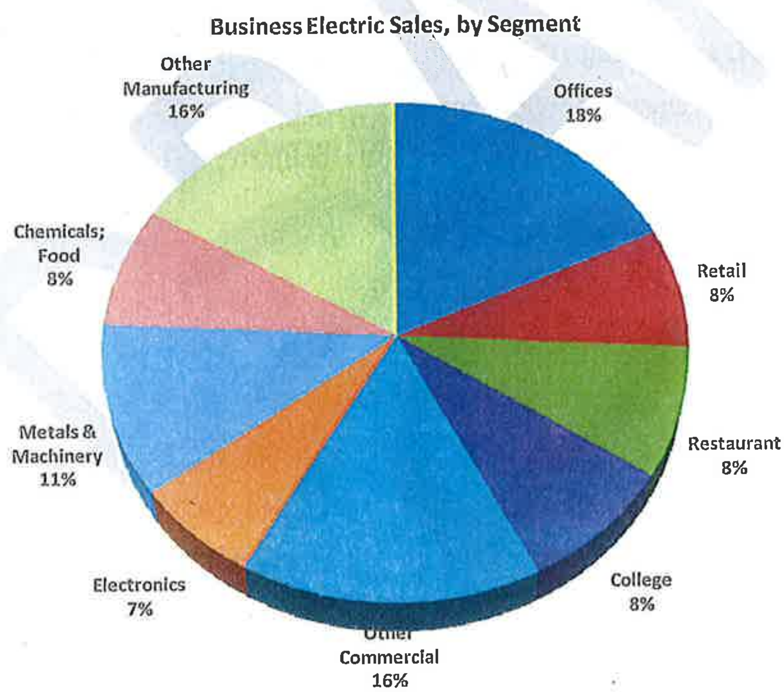
4.1.2 How Do Boulder Sales Vary by Customer Segment?

The segmentation analysis provides a breakdown of recent residential usage by housing type, and business usage by commercial and manufacturing business type.

4.1.2.1 How Do Residential Sales Vary by Customer Segment?

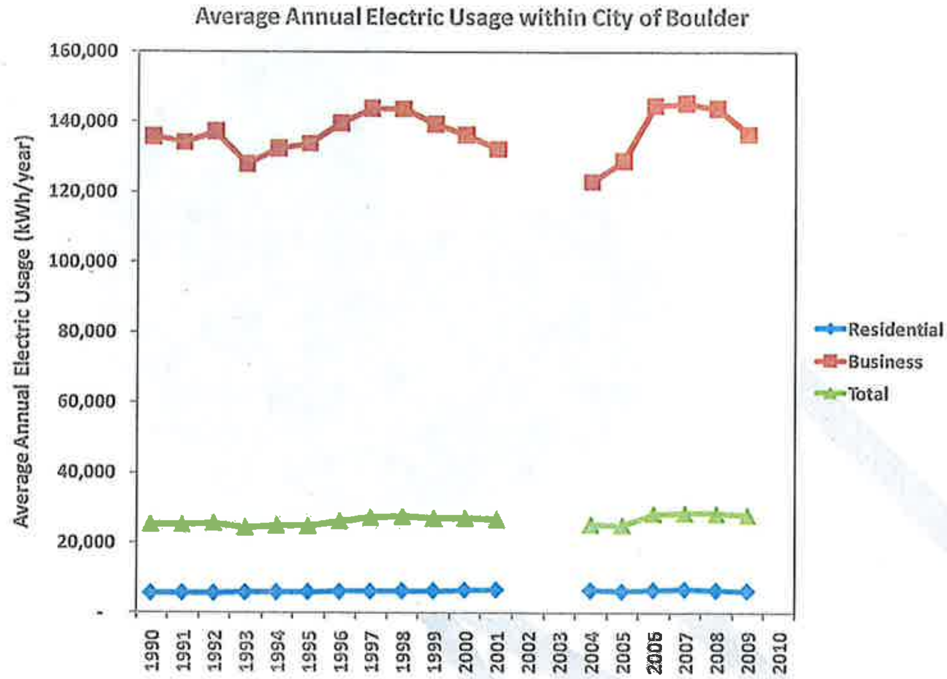


4.1.2.2 How Do Business Sales Vary by Customer Segment?



4.1.3 How Much Electricity Does the Average Boulder Customer Consume?

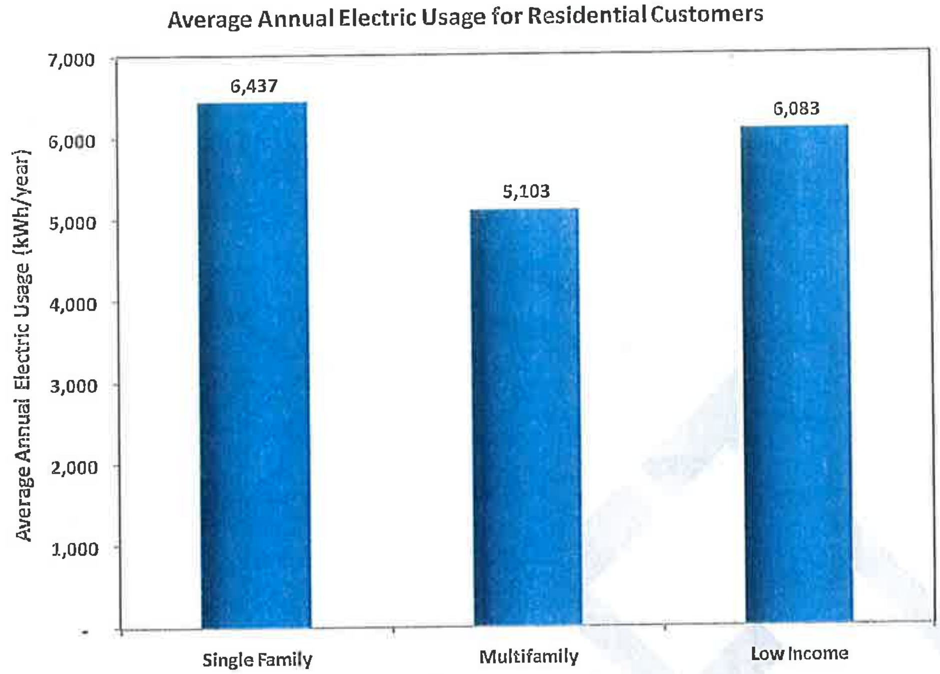
For years where annual reports were available, average usage per customers could be calculated as the ratio of sales to customers.



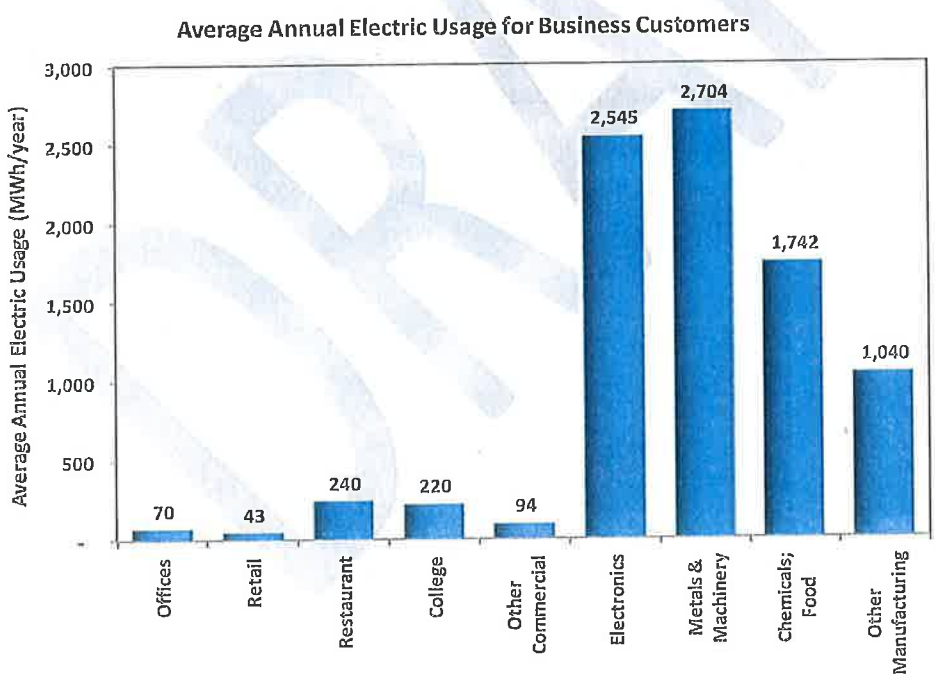
4.1.4 How Does Average Consumption Vary by Customer Segment?

The segmentation analysis provides comparisons of average usage per customer by housing type, and average business usage by commercial and manufacturing business type.

4.1.4.1 How Does Average Consumption Vary by Residential Segment

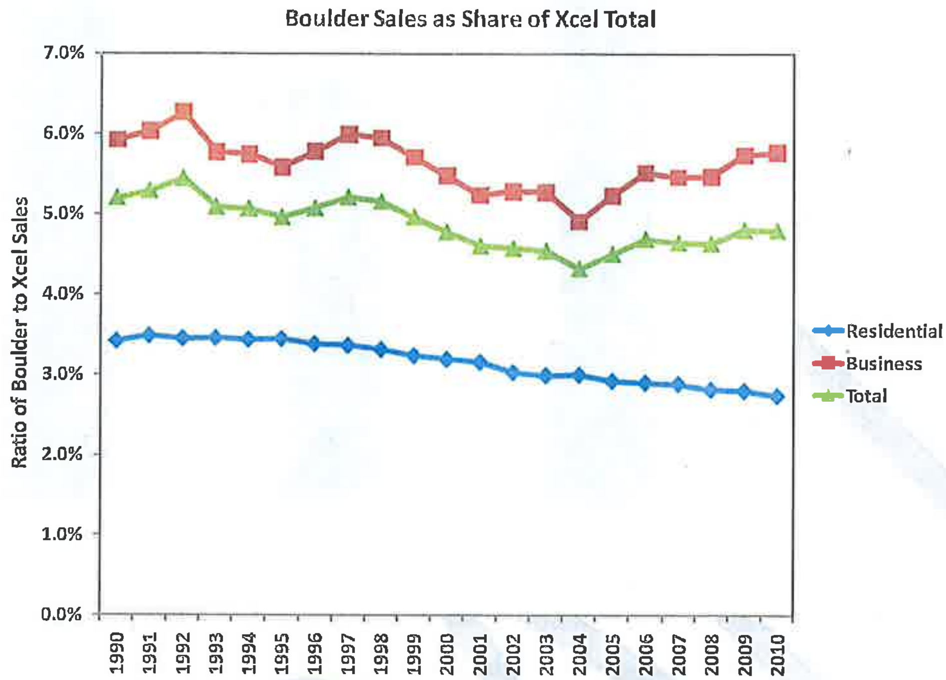


4.1.4.2 How Does Average Consumption Vary by Business Segment?



4.1.5 How Do Boulder Sales Compare to Sales for the Rest of Xcel?

The proportion of Xcel's overall Colorado sales represented by Boulder customers has declined only slightly since 1990. In 2010, Boulder customers represented 4.8 percent of overall sales, 2.7 percent of residential sales, and 5.8 percent of business sales.



4.1.6 How Fast Have Sales Increased?

From a 1990 starting point, Boulder's sales increased exactly in step with Xcel's overall Colorado sales through the late 1990s, but grew more slowly in this century.

4.2 BOULDER ELECTRIC LOADS

4.2.1 Load Shapes

The figures in sections 4.2.1.1 and 4.2.1.2 depict Boulder's load shape in both average day-types and overall annual load, respectively. The daily load shapes display a 24-hour load shape for the following significant day-types:

- Average Winter Weekday
- Average Winter Weekend Day
- Average Summer Weekday
- Average Summer Weekend Day
- The Vernal Equinox
- The Autumnal Equinox
- The System Peak Day

Each figure displays the city-wide system load for that day and the two sector loads that make up the system load: business and residential.

The City-wide System Load Shapes in Section 4.2.1.2 depict the overall load for the city based on 8,760 hours of load data (one full year).

4.2.1.1 Daily Load Shapes

Figure 4-1 displays the hourly load during an average weekday in the winter. Winter, in this case, is defined in line with Xcel Energy's definition as October 1st through May 31st.

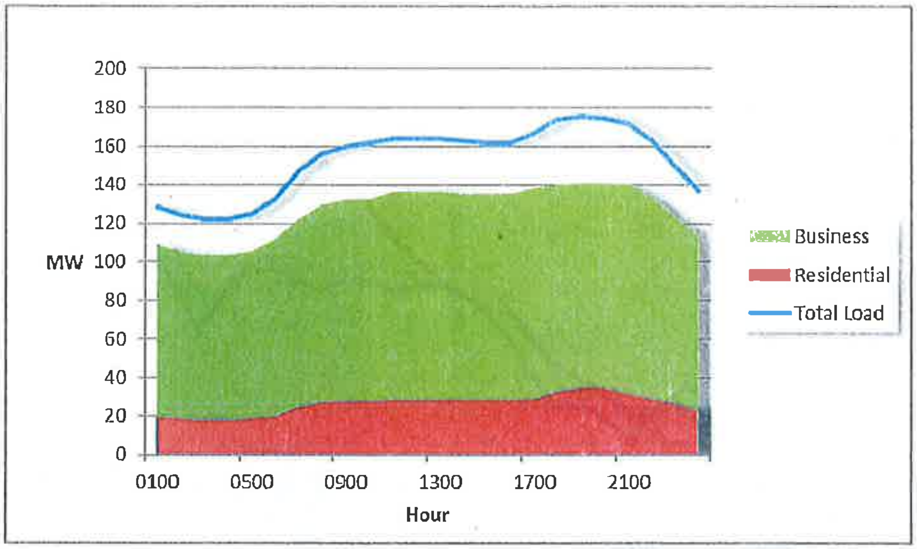


Figure 4-1: Average Winter Weekday

Figure 4-2 displays the hourly load during an average weekend day in the winter.

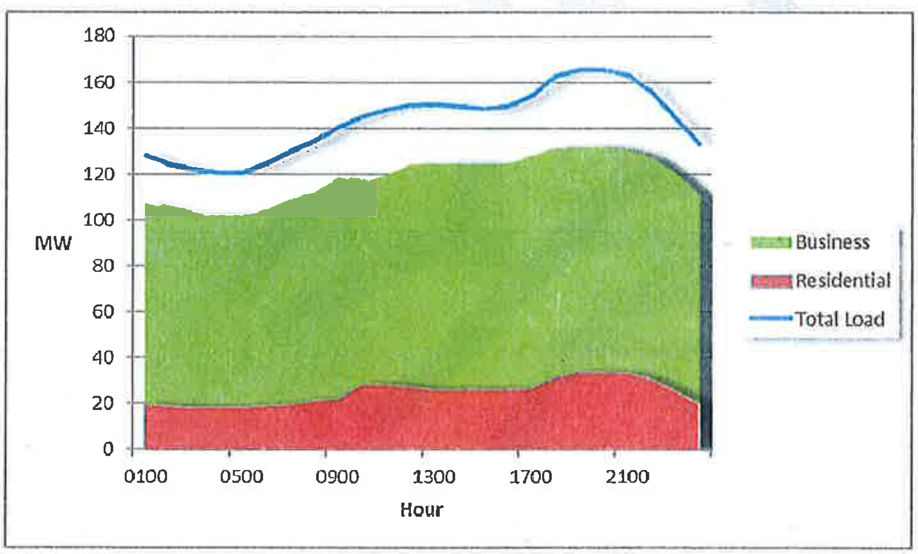


Figure 4-2: Average Winter Weekend Day

Figure 4-3 displays the hourly load during an average weekday in the summer. Summer, in this case, is defined in line with Xcel Energy's definition as June 1st through September 30th.

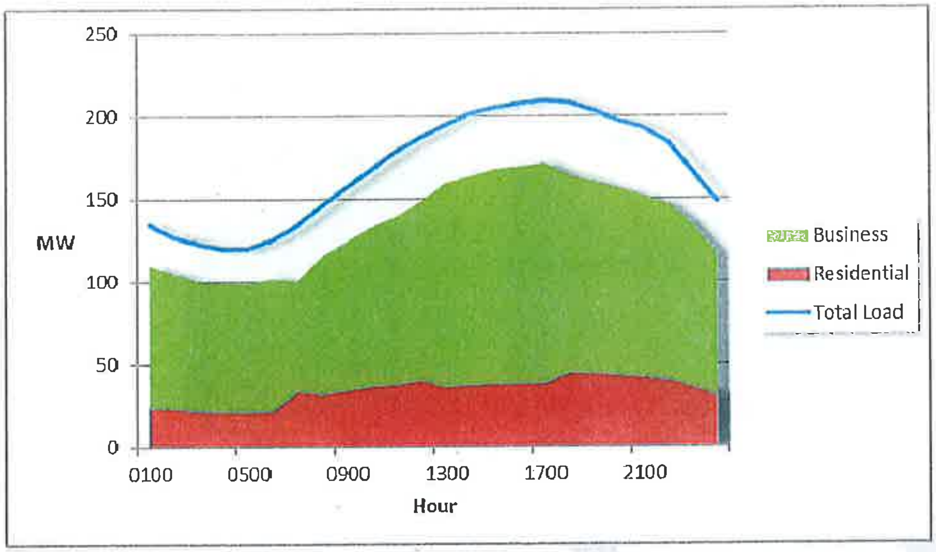


Figure 4-3: Average Summer Weekday

Figure 4-4 displays the hourly load during an average weekend day in the summer.

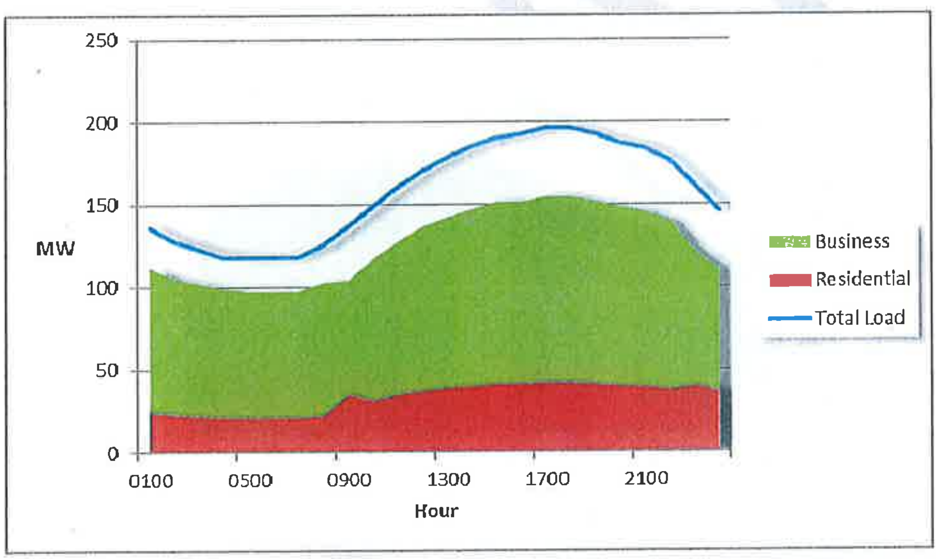


Figure 4-4: Average Summer Weekend Day

Figure 4-5 displays the hourly load on the Vernal Equinox which typically occurs around March 20th. This load shape is representative of a typical load shape during the spring "shoulder" season.

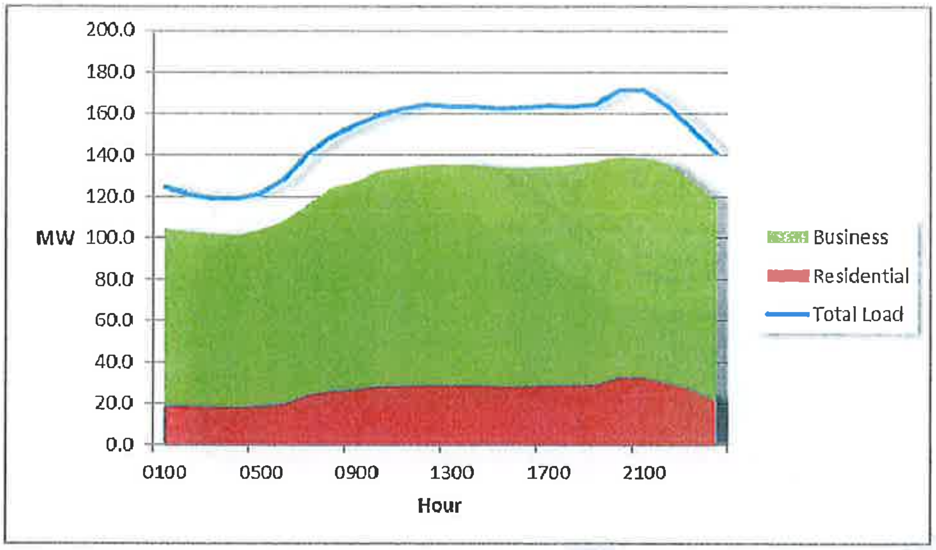


Figure 4-5: Vernal Equinox (~March 20th)

Figure 4-6 displays the hourly load on the Autumnal Equinox which typically occurs around September 23rd. This load shape is representative of a typical load shape during the fall "shoulder" season.

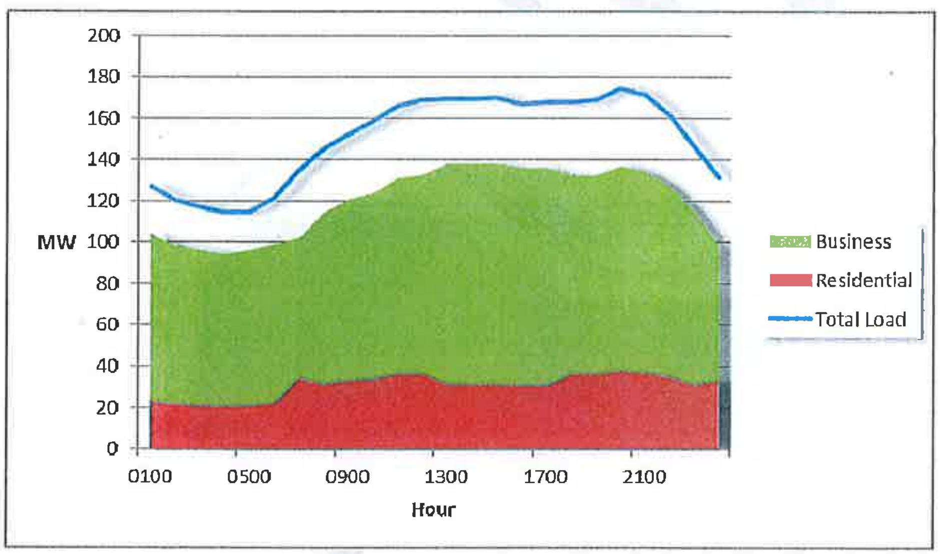


Figure 4-6: Autumnal Equinox (~September 23rd)

Figure 4-7 displays the hourly load on the city-wide system peak day. The day within which the system peak occurs will vary from year to year.

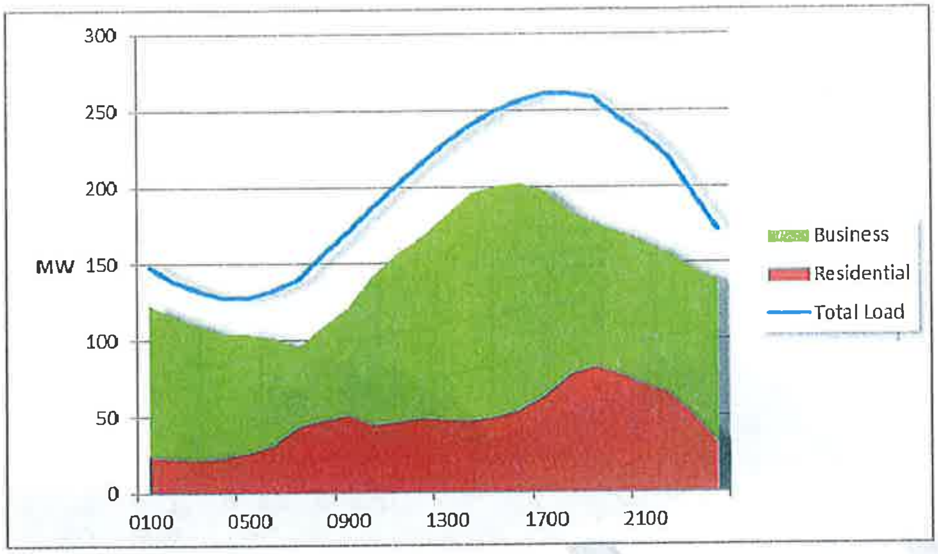


Figure 4-7: Peak Day

4.2.1.2 City-wide System Load Shapes

Figure 4-8 displays a 3-dimensional visualization of Boulder's annual load shape. From left to right on the chart, 365 days of the year are represented. From front to back a 24-hour "slice" shows the load for a given day. The result is a load shape representing all 8,760 hours of the year.

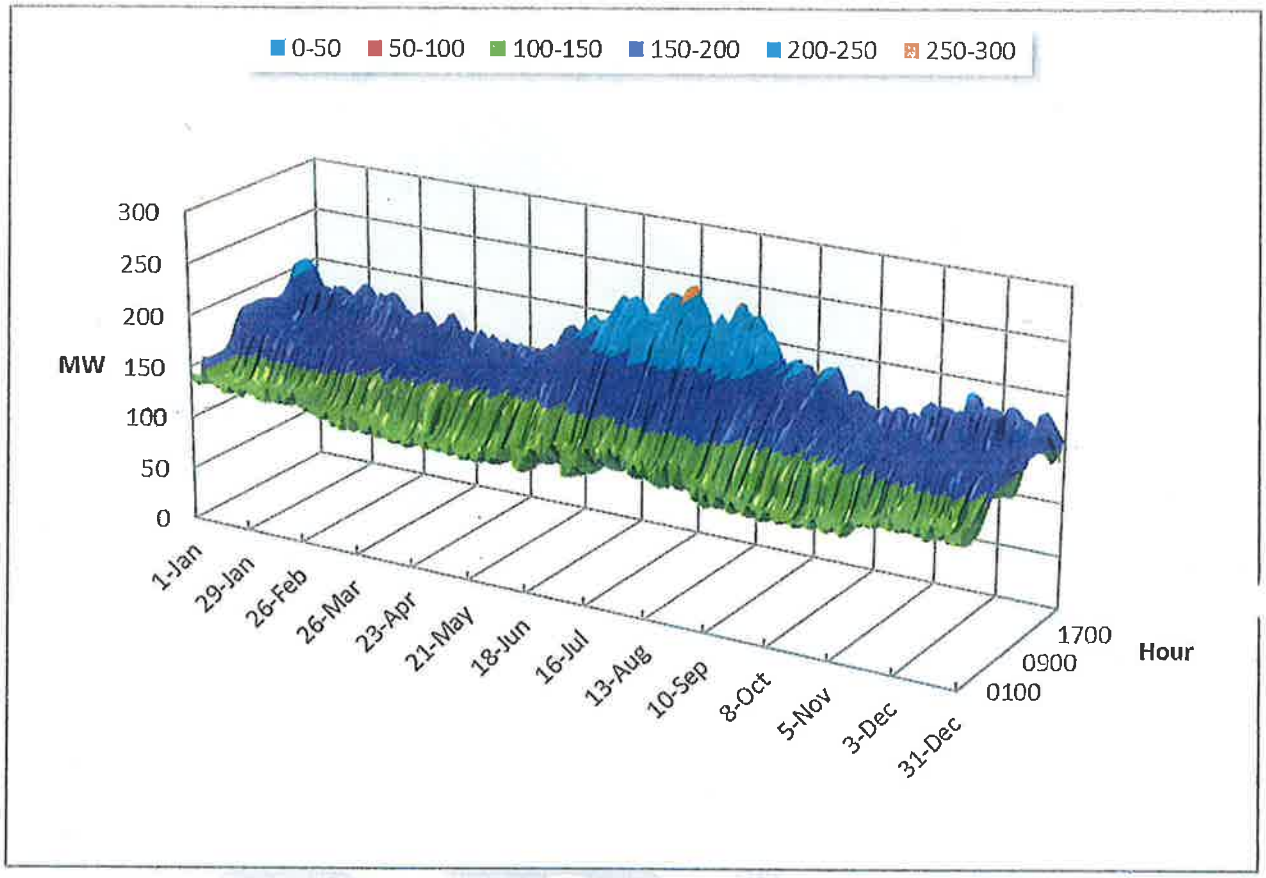


Figure 4-8: Annual Load – 365 Days of 24-Hour Loads (MW)

Figure 4-9 represents three metrics for each day of the year: the peak load for that day, the minimum load for that day, and the average of the hourly loads over all 24 hours of that day.

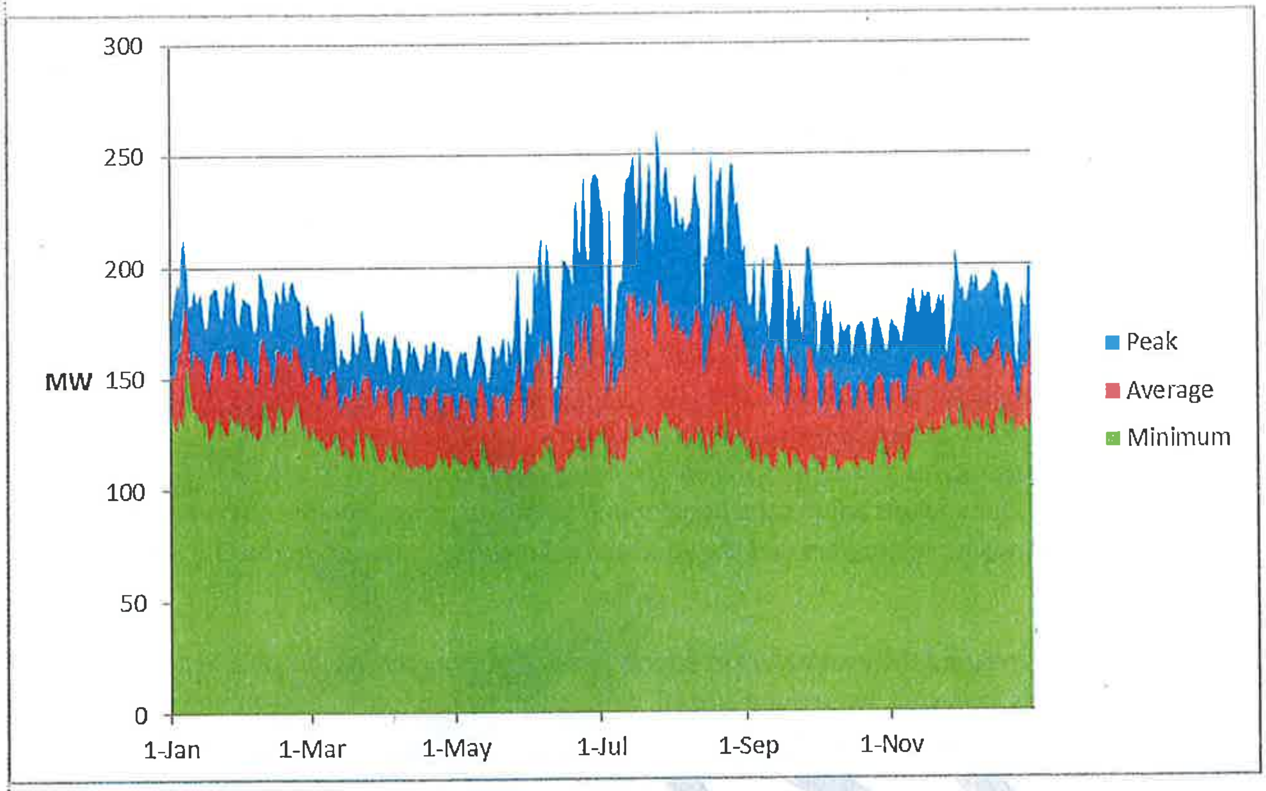


Figure 4-9: Daily Load – Peak, Average, and Minimum Loads (MW)

4.2.2 Key Load Characteristics Findings

- Boulder's estimated summer peak falls at 260 MW with an estimated fluctuation of 10 MW above or below this value.
- The daily peak tends to be under 200 megawatts during the winter and shoulder months.
- Boulder's average minimum load is approximately 120 megawatts, and the absolute minimum load over the course of the year falls just above 100 megawatts.

5.1 DATA SOURCES AND ANALYSIS

Nexant has reviewed Boulder's current electricity generation portfolio, analyzing the production, consumption and electricity purchase history of Xcel Energy Public Service Company of Colorado (PSCo) using data provide by the utility to the City as well as information filed with the Colorado Public Utility Commission including the 2009 Corporate Responsibility Report , information filed with the Federal Energy Regulatory Commission, and Continuous Emissions Monitoring System (CEM) data from the US Environmental Protection Agency (EPA). In addition to these primary sources, for this analysis Nexant queried data from the Energy Velocity database licensed by Ventyx, an ABB company.

Consistent with PSCo's December 17, 2010 response to the City's Information Request, our analysis assumes that absent other factors, the City's consumption matches the energy mix of the PSCo system from PSCo generation and energy purchases. To the extent that data are available, our analysis disaggregates and adjusts the annual energy mix to conform to the City's historical monthly load shape. Our analysis adjusts the Boulder energy mix to reflect Boulder customer's participation in PSCo's WindSource program and the wind and solar energy supplied to the City under that program.

Nexant has analyzed the breakdown of energy generation sources attributable to meeting Boulder's energy needs from coal, natural gas and oil, wind, solar, hydroelectric, nuclear and other for 1995, 2000, 2005 and 2009, based on available historical data. In addition to the annual breakdown, sufficient data are available for 2005 and 2009 to analyze the monthly energy mix. Adequate historical data are not available to analyze differences in the energy mix between on-peak and off-peak hours.

At the request of the City, Nexant has projected the energy mix analysis forward and forecast the energy mix for PSCo and Boulder annually for 2010 through 2018. This is the period covered by the plan to reduce emissions submitted by PSCo in compliance with the Colorado Clean Air Clean Jobs Act and approved by the Colorado Public Utilities Commission in December, 2010. Under this plan PSCo plans to close three coal units at its Cherokee plant in Denver, one coal unit in the Arapahoe plant in Denver, and the coal unit at the Valmont plant in Boulder. It also plans to construct a new natural-gas fired unit at the Cherokee site, convert a coal-fired unit at Arapahoe, and a coal unit at Cherokee to natural gas generation.

The energy mix forecast takes into account the requirement for PSCo under Colorado's updated Renewable Energy Standard (RES) per Colorado House Bill 1001, signed in March 2010, a RES of 12% from 2010 through 2014, 20% from 2015 through 2019, and reaching 30 % in 2020.

An accompanying Excel "workbook" computer file provided to the City contains the results shown in the tables and figures of this section along with calculations and with additional annual and monthly details.

5.2 GENERATION PORTFOLIO

Based on the available data and our analysis described in the previous section, the following information regarding the total energy mix from generation and purchases was calculated and presented here in tables and figures:

- PSCo and Boulder's historical annual energy mix, 1995, 2000, 2005, and 2009.
- PSCo and Boulder's forecast annual energy mix for years 2010 through 2018.
- The annual energy mix for PSCo's own generation and PSCo energy purchases separately, historical for 1995, 2000, 2005, and 2009 and forecast for years 2010 through 2018.
- Boulder's historical monthly energy mix for 2009 (and for 2005 in accompanying Excel file).

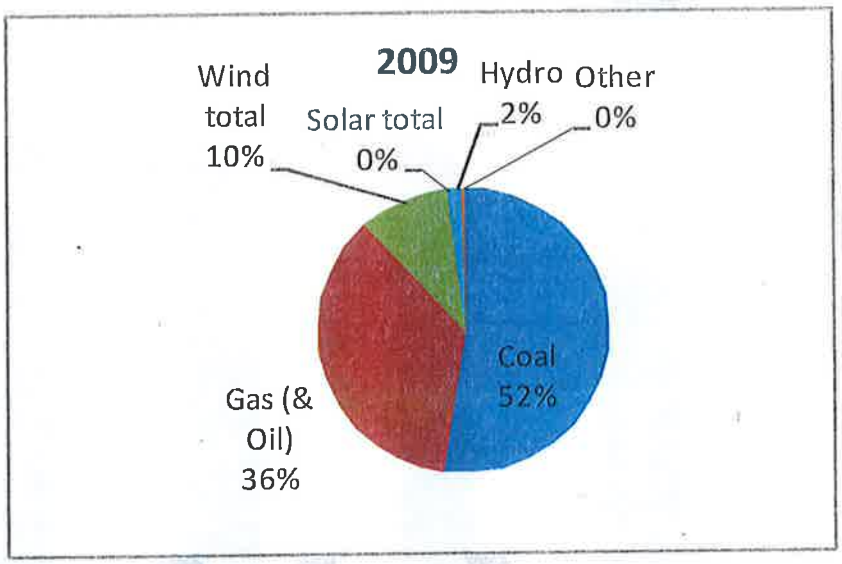


Figure 5-1: PSCo Energy Mix 2009

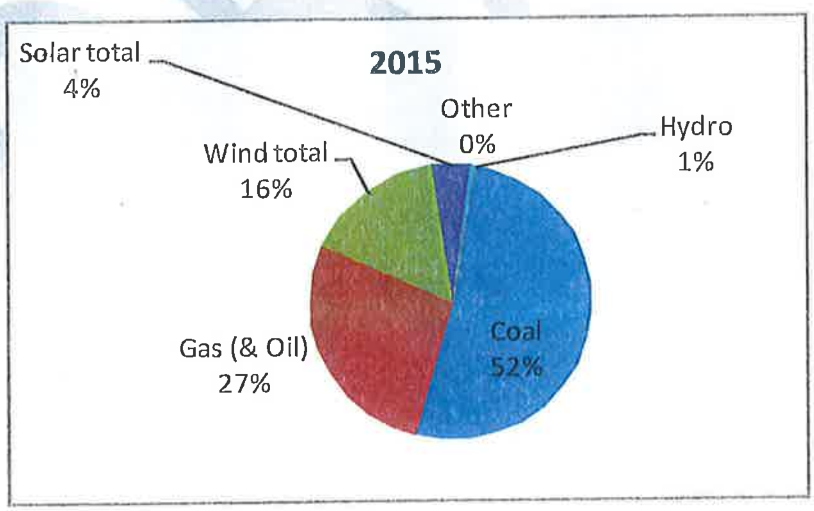


Figure 5-2: PSCo Forecast Energy Mix 2015

Table 5-1 PSCo Historical Energy Mix (MWh)

PSCo	1995	2000	2005	2009
Coal	19,604,402	35,734,434	29,296,261	19,248,572
Gas (& Oil)	5,140,851	13,114,673	13,628,216	13,233,173
Wind total	6,850	486,399	930,132	3,677,163
Solar total	0	0	0	16,813
Hydro	415,842	1,013,333	994,778	613,248
Other	15,454	233,108	423,555	17,427
TOTAL ENERGY	25,183,399	50,581,947	45,272,943	36,806,396

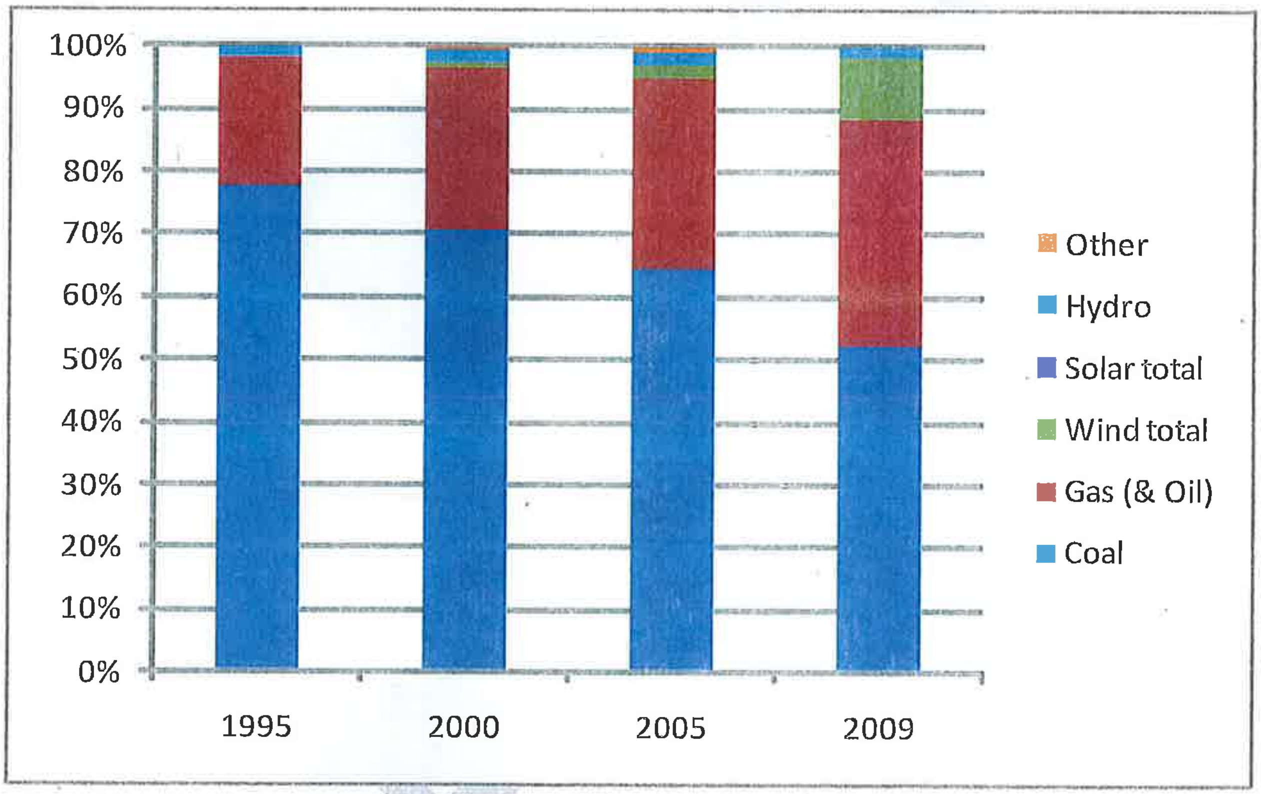


Figure 5-3 PSCo Historical Total Energy Mix

Table 5-2 PSCo Forecast Energy Mix (MWh)

PSCo	2010	2011	2012	2013	2014	2015	2016	2017	2018
Coal	21,706,296	22,232,926	20,849,206	20,167,180	19,280,469	18,622,736	18,253,386	18,437,386	16,374,774
Gas Oil	12,513,709	11,415,070	12,309,075	10,380,188	10,021,101	9,897,970	9,816,083	9,816,083	11,670,742
Wind	3,827,152	4,433,350	4,104,910	5,169,015	5,169,015	5,773,906	5,773,906	5,773,906	6,773,906
Solar	219,000	473,040	473,040	473,040	1,568,040	1,568,040	1,568,040	1,568,040	1,568,040
Hydro	245,402	234,890	234,890	234,890	229,634	224,378	724,585	724,585	682,537
Other	0	0	0	0	0	0	0	0	0
TOTAL	38,511,559	38,789,276	37,971,121	36,424,314	36,268,260	36,087,030	36,136,000	36,320,000	37,070,000

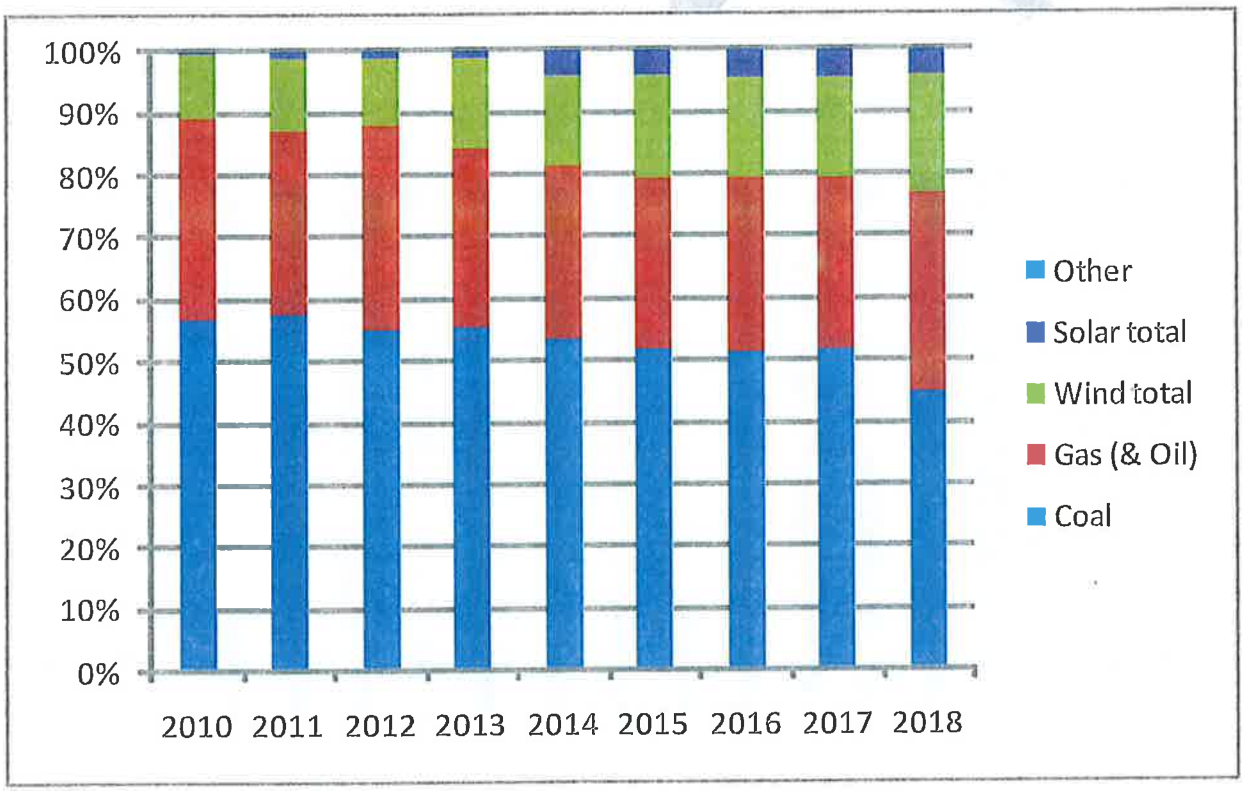


Figure 5-4 PSCo Forecast Total Energy Mix

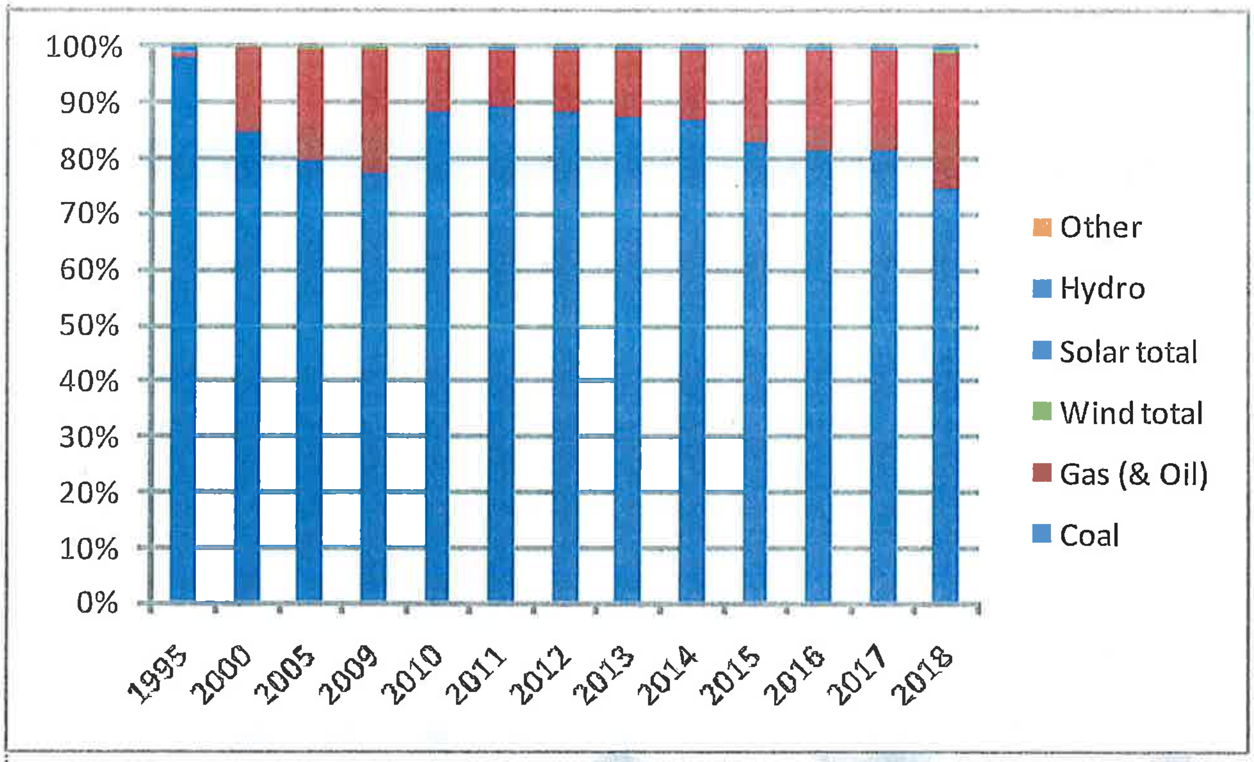


Figure 5-5 PSCo's Own Generation Historical and Forecast

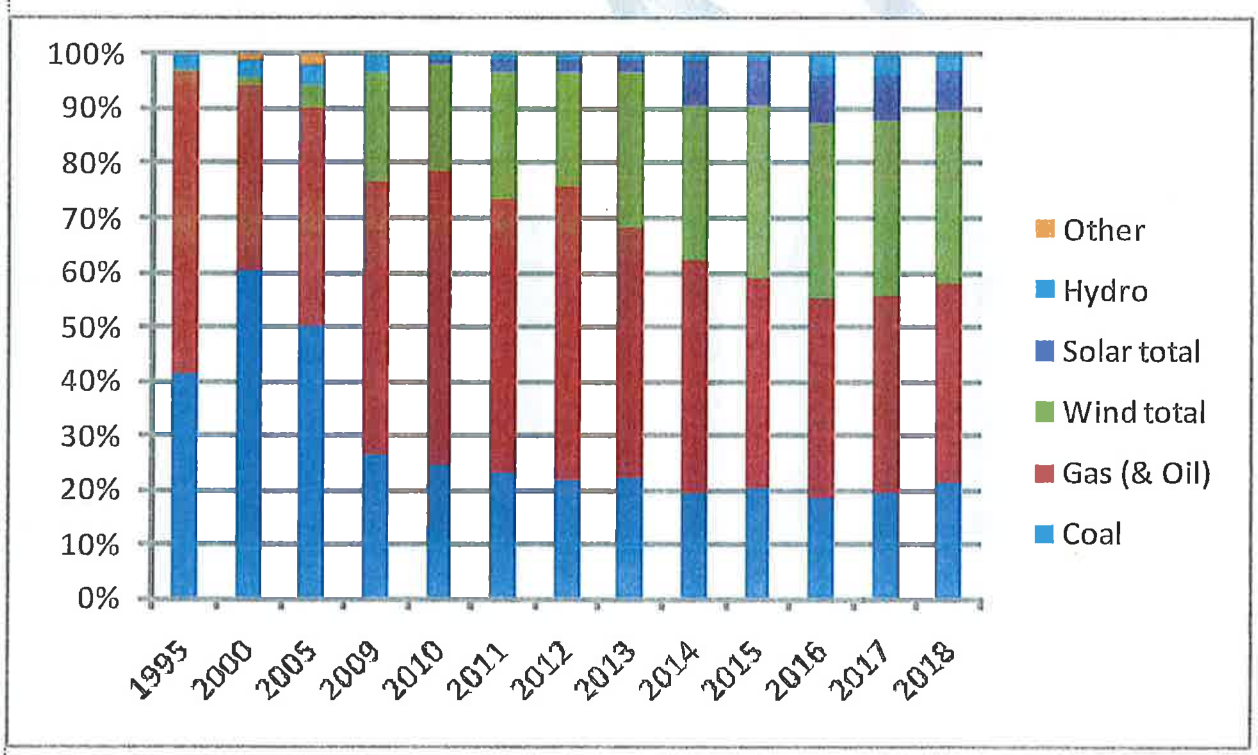


Figure 5-6 PSCo Purchases Historical and Forecast

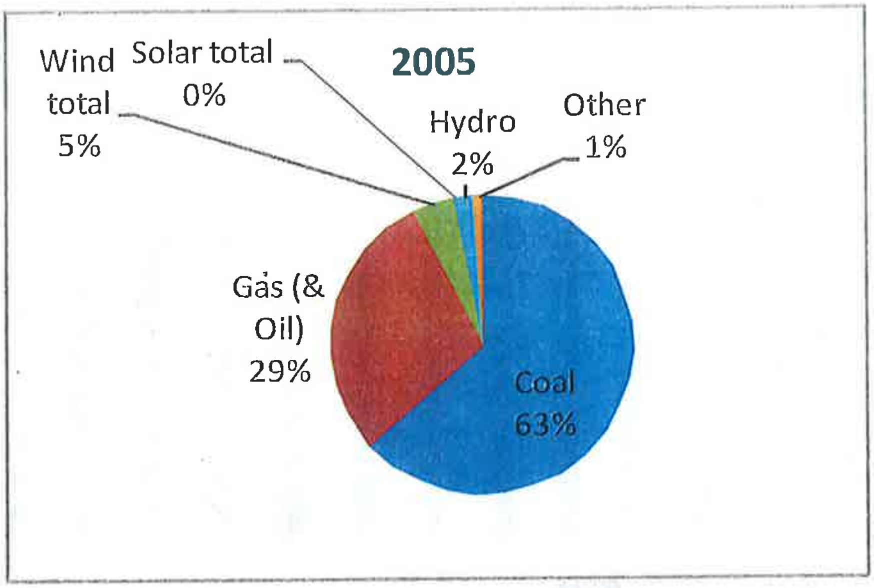


Figure 5-7 Boulder Energy Mix 2005

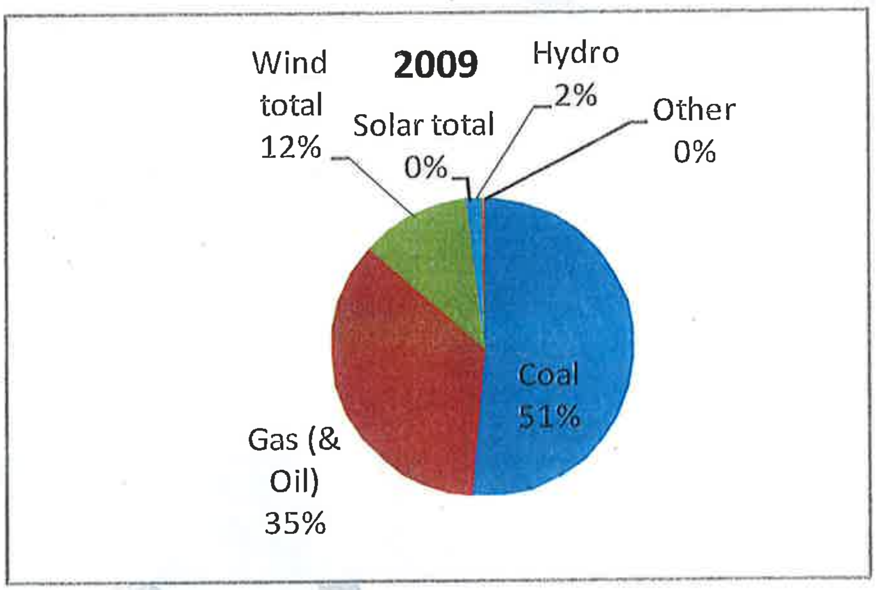


Figure 5-8 Boulder Energy Mix 2009

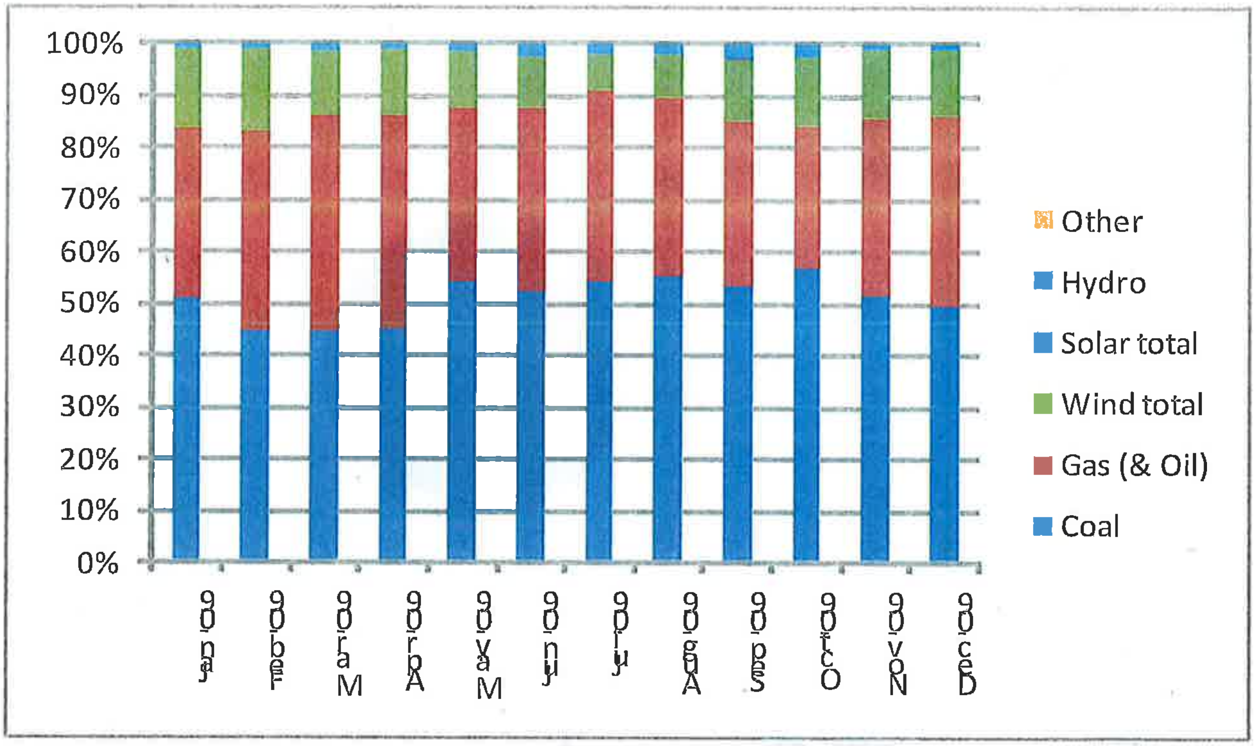


Figure 5-9 Boulder Monthly Energy Mix 2009

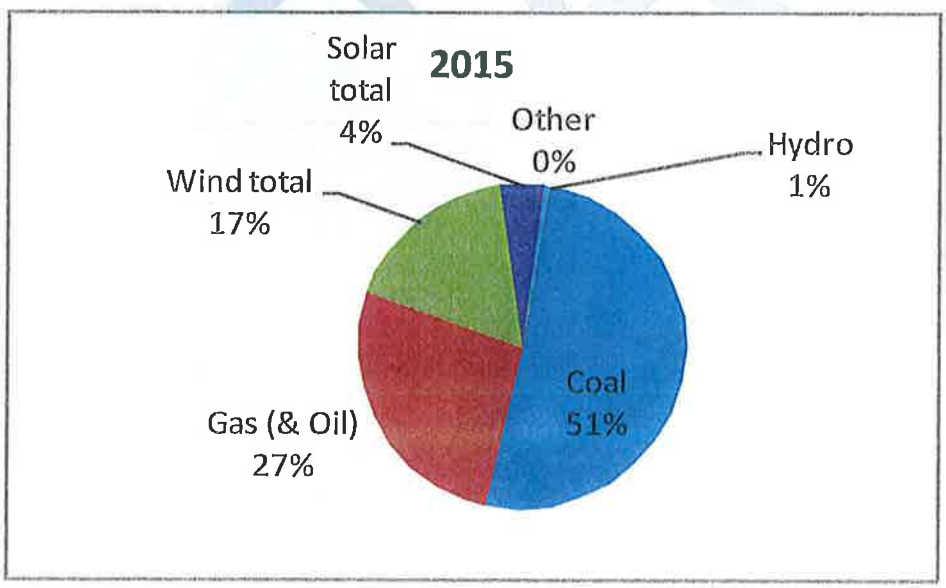


Figure 5-10 Boulder Forecast Energy Mix 2015

Table 5-3 Boulder Historical Energy Mix (MWh)

COB	1995	2000	2005	2009
Coal	799,383	804,454	752,951	672,738
Gas (& Oil)	209,622	295,238	348,529	461,609
Wind total	279	41,624	53,386	154,706
Solar total	0	0	0	1,066
Hydro	16,956	22,812	25,254	21,705
Other	630	5,248	10,772	607
TOTAL ENERGY	1,026,870	1,169,376	1,190,892	1,312,431

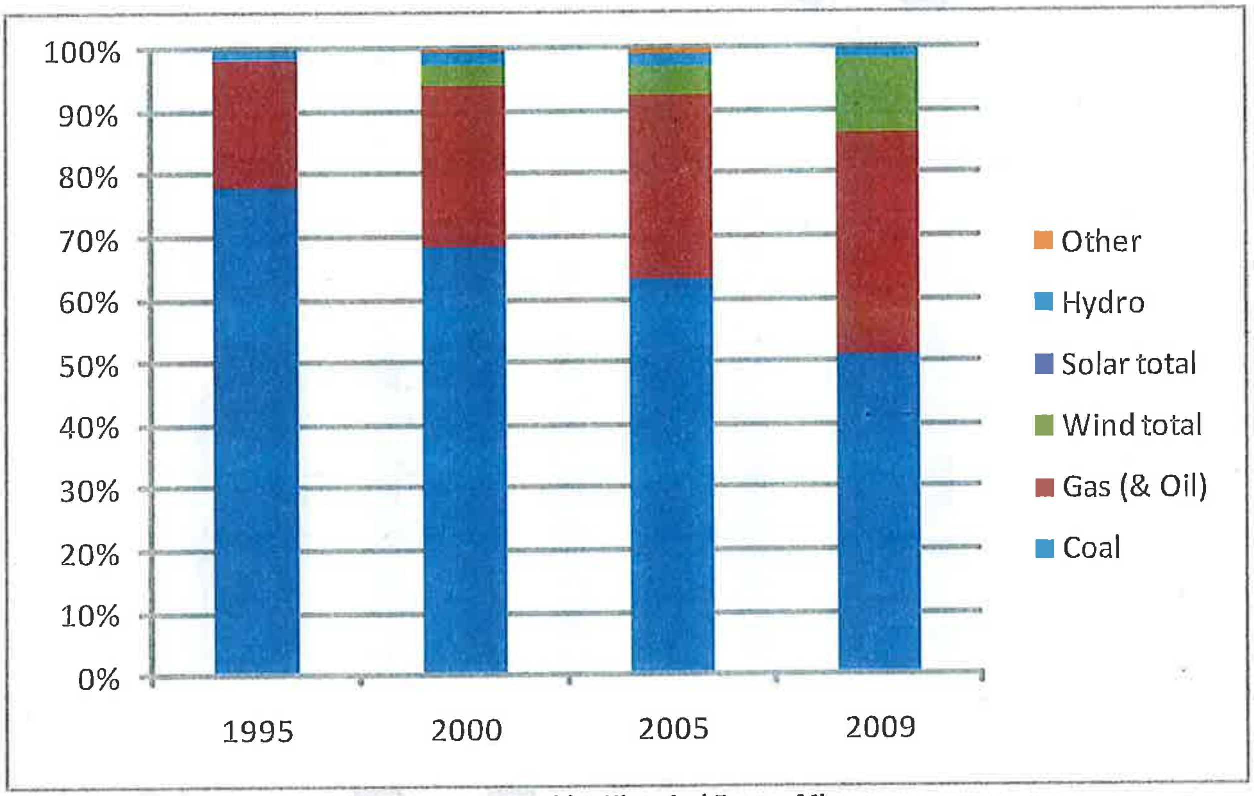


Figure 5-11 Boulder Historical Energy Mix

Table 5-4 Boulder Forecast Energy Mix (MWh)

COB	2010	2011	2012	2013	2014	2015	2016	2017	2018
Coal	738,643	760,212	737,172	759,402	744,723	736,904	735,221	755,373	666,517
Gas	425,829	390,316	435,216	390,869	387,073	391,664	395,378	402,161	475,045
Wind	156,612	178,196	171,753	221,010	226,072	254,938	259,131	263,226	302,725
Solar	7,933	16,660	17,211	18,293	61,048	62,530	63,643	64,728	64,318
Hydro	8,351	8,032	8,305	8,845	8,870	8,879	29,185	29,686	27,782
Other	0	0	0	0	0	0	0	0	0
TOTAL	1,337,367	1,353,416	1,369,657	1,398,419	1,427,786	1,454,914	1,482,557	1,515,174	1,536,386

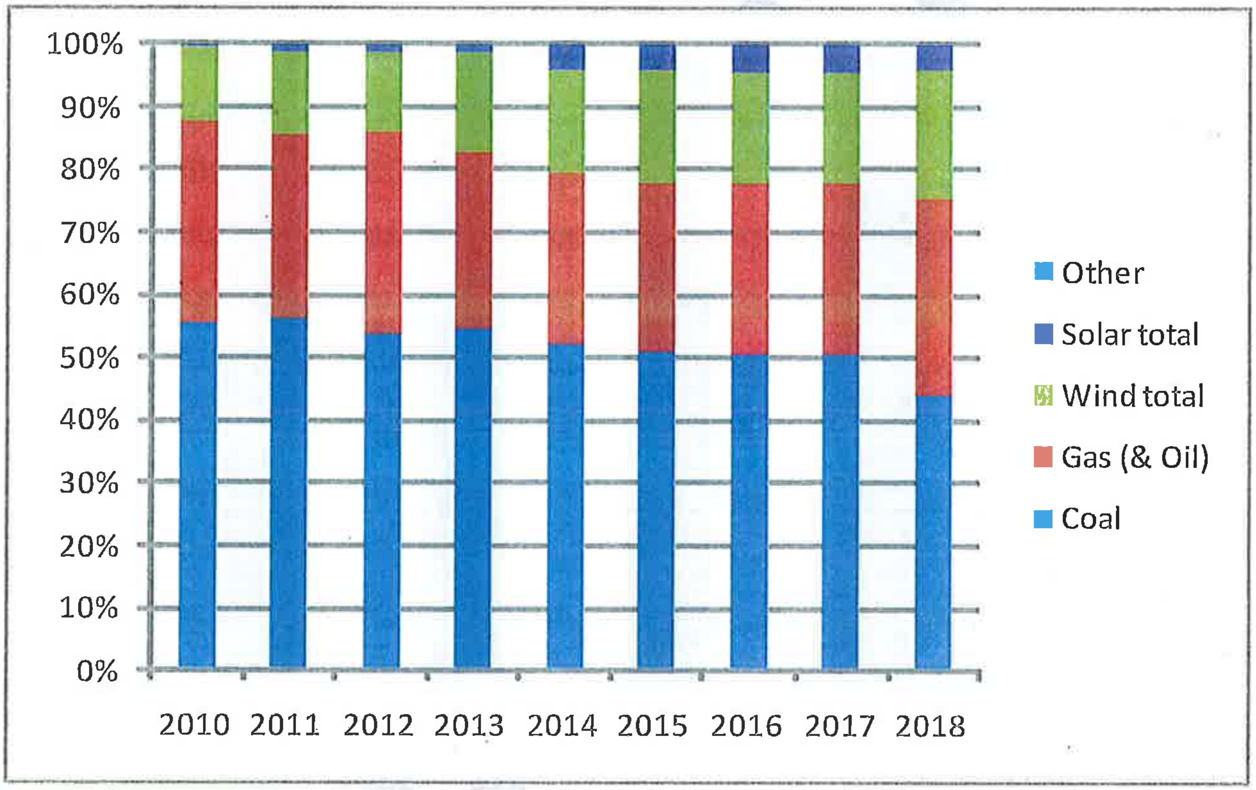


Figure 5-12 Boulder Forecast Energy Mix

The above tables and figures show the following.

Tables 4-1 and 4-2 and Figures 4-1, 4-2, 4-3, and 4-4 illustrate the following trends:

- The proportion of coal in the total energy mix has declined from approximately 75% in 1995 to approximately 55% today, and it is projected to decline to approximately 45% by 2018.
- Natural gas (& oil) has increased from approximately 20% of the total in 1995 to over 30% today and it is projected to decline to between 25% and 30% by 2018.
- Renewable energy has increased from 2% of the total in 1995 to approximately 12% today, and it is projected to increase to approximately 20% to 25% by 2018.
- The forecast energy mix is uncertain. While the forecast mix of PSCO's own generation is well grounded in PSCo's plan filed with the Colorado PUC, the forecast energy mix of purchased energy is highly uncertain. In contrast to the results of our analysis, PSCo projected in its response to the questions from the City that coal energy would be from 50% and above 60% of the energy mix through 2020, and natural gas energy would decline to 16% in 2015 and increase thereafter.

Tables 4-3 Figures 4-7 through 4-12 illustrate the following:

- Boulder has a higher proportion of renewable energy than PSCo as a result of greater participation in the WindSource program, which covers 2.6% of Boulder load in 2009 and less than 1% for PSCo. Wind and Solar represent 12% of the Boulder energy mix for 2009 compared to 10% for PSCo.

Figures 4-5 and 4-6 illustrate the following:

- Coal represents a higher percent of PSCo's own generation and gas and renewable energy represent a lower percent of PSCO's own generation than of PSCO's purchases. Historically, PSCo's generating capacity has been primarily coal-fueled.
- The proportion of coal in PSCo's own generation has declined from 98% in 1995 to between 85% and 90% today, and it is projected to decline to approximately 75% by 2018. PSCo coal generation increases in 2010 and 2011 reflecting energy generated by the Comanche 3 coal unit with 521 MW Summer Capacity, which came on-line in May 2010.
- Generation from natural gas has increased from less than 1% of PSCo's own generation in 1995 to over 20% in 2009 declining to near 10% in 2010 with Comanche 3 coal unit coming online. Natural gas is expected to increase to between 20% and 25% of PSCo's own generation by 2018.
- Renewable energy has remained at approximately 1% of PSCO's own generation from 1995 to today and is projected to remain so through 2018

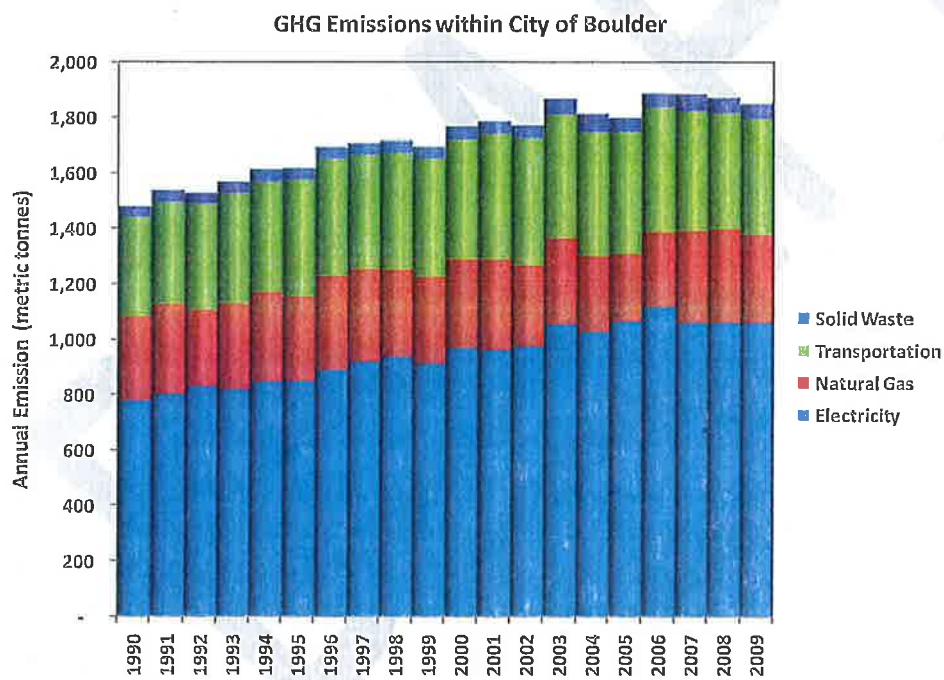
- The proportion of coal in purchased energy has declined from over 40% in 1995 and 50% in 2000 to approximately 25% today and is projected to decline to near 20% by 2018.
- Energy from Natural gas has ranged between about 35% and 55% of purchased energy. It is approximately 55% today and is forecast to decline to between 35% and 40 % of purchased energy by 2018.
- Renewable energy has increased from approximately 3% of purchased energy to over 20% today and is projected to increase to between 40% and 45% of purchased energy by 2018 for compliance with Colorado's HB 1001.

5.3 GREENHOUSE GAS EMISSIONS

Boulder's GHG emissions were documented in the GHG inventory that the city developed as part of its 2009 Climate Action Program Assessment.

5.3.1 How Much of Boulder's Overall Emissions Come From Electricity?

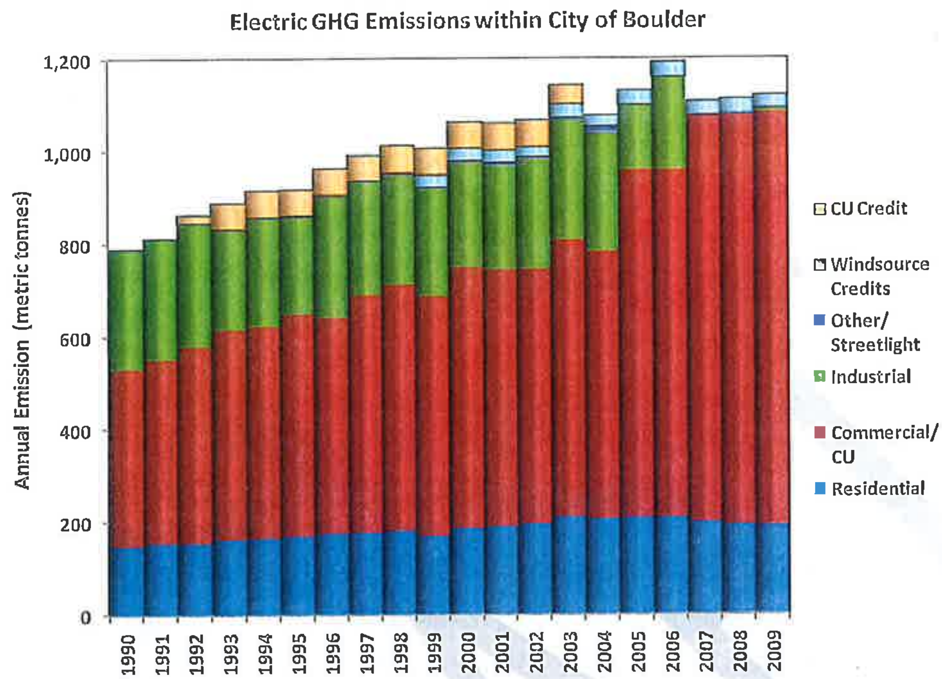
Electricity accounts for over half of the City's overall GHG emissions (approximately 57 percent of total emissions in 2009).



5.3.2 How Do Boulder's Electric Emissions Vary by Sector?

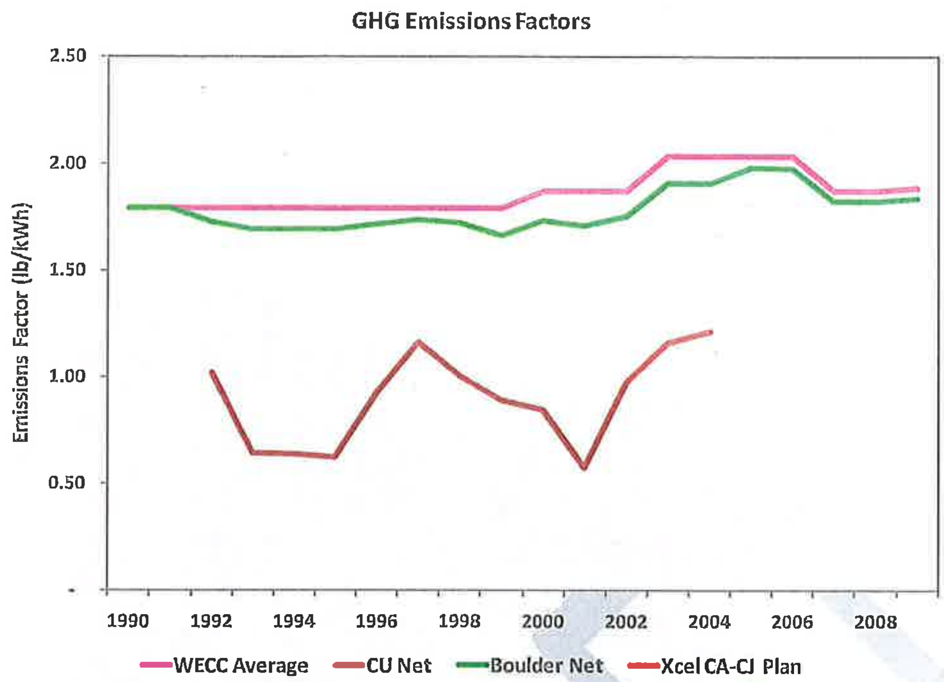
The business sector, with over 80 percent of electric consumption, represents over 80 percent of electric GHG emissions.

Windsource purchases lower city-wide electric emissions by 2.7%. The cogeneration system that provided electricity as well as heating to the University of Colorado (CU) campus created additional emissions offsets throughout the 1990s. However that system has not operated in recent years.



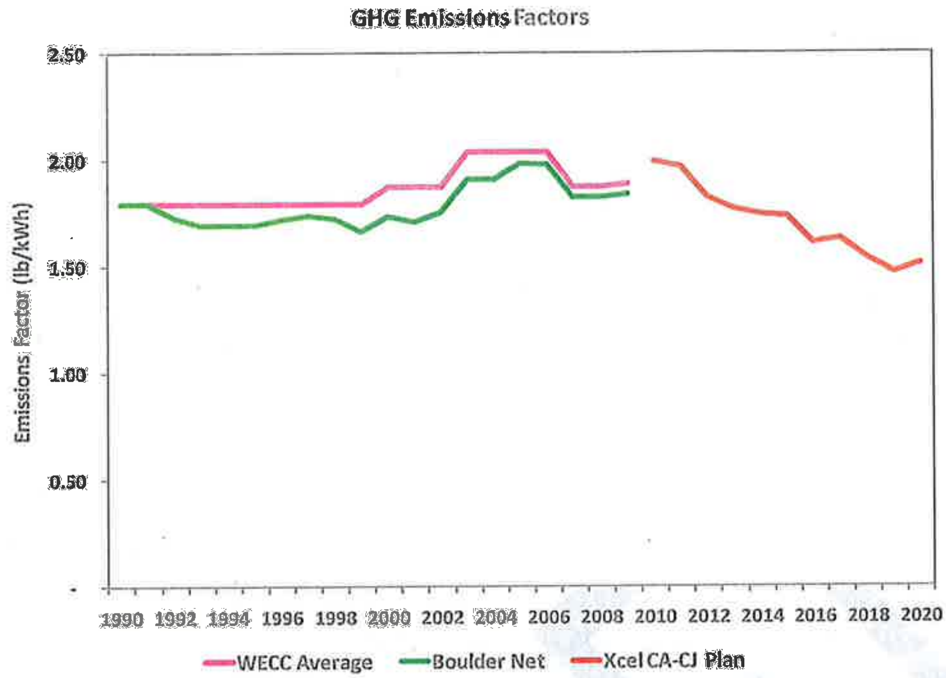
5.3.3 What Are Boulder's Unit Emissions per kWh of Electricity?

Consistent with the World Resources institute protocol for tracking greenhouse gas emissions, the inventory tracks electric carbon emissions based on the carbon intensity of the entire western U.S. electric grid (the Western Electric Coordination Council, or WECC). With Windsource purchases and CU's cogeneration, Boulder's net emissions per kilowatt-hour of electricity is lower than the WECC system average.



5.3.4 How is Xcel Projecting Emissions Rates to Change in the Future?

The plan that Xcel developed in response to the Colorado Clean Air-Clean Jobs Act provides forecasts of emissions rates into the future. Xcel's Colorado emissions were slightly higher than the WECC average in 2010. Xcel projects emissions per kilowatt-hour to decrease by about 24 percent between 2010 and 2020 through the replacement of existing coal generation with natural gas units, and the continued addition of renewable generation to the system in compliance with Colorado's Renewable Energy Standard.


GHG Emissions Factors
Emissions Factor (lb/kWh)
2.50
2.00
1.50
1.00
0.50
-
1990 1992 1994 1996 1998 2000 2002 2004 2006 2008 2010 2012 2014 2016 2018 2020
WECC Average
Boulder Net
Xcel CA-CJ Plan

6 BOULDER TRANSMISSION AND DISTRIBUTION SYSTEM

6.1 DATA SOURCES AND ANALYSIS

This section, which encompasses how energy is delivered from point of generation to point of use in Boulder, describes the Colorado transmission network including Xcel Energy Public Service of Colorado within the WECC, the place of Boulder within that network, and delivery of energy from generation resources within this network to Boulder.

Xcel Energy /PSCo owns and operates about 4,000 miles of transmission facilities at 115 kV and above in the State of Colorado. PSCo also owns and operates certain facilities rated at distribution voltage level. PSCo is located in the Western Interconnection and is a member of the Western Electricity Coordinating Council ("WECC"). The WECC does not presently offer transmission services under a regional Open Access Transmission Tariff (OATT), and there is presently no functioning Regional Transmission Organization (RTO) for the PSCo system.

PSCO provides point-to-point service and Network Integration Transmission Service ("network service"), and charges customers rates accepted for filing by the Commission, pursuant to the Joint OATT. Transmission planning costs are recovered for PSCo in part under the joint OATT that includes transmission plant and O&M expenses, grandfathered transmission contracts, Colorado retail base rates, and a Colorado retail Transmission Cost Adjustment Rider for new transmission plant in service that is not in the retail rates.

For any transmission project wholly within the PSCo local transmission system that is undertaken for economic reasons or congestion relief at the request of a single Requester, the project costs will be allocated to that Requester.

6.2 TRANSMISSION AND DISTRIBUTION LOSSES

Xcel Energy, PSCo filed a revised loss analysis to Colorado Public Utility Commission (CoPUC) in 2006 to calculate appropriate transmission and distribution loss factors. Prior to this analysis the PSCo system transmission loss factor was 3.0 percent, and there was no additional loss factor for transmission provided at distribution voltage level. In the loss analysis submitted in March 2006 to CoPUC, the transmission loss factor was calculated to be 2.56 percent and the primary distribution loss factor was calculated to be 2.35 percent.

Xcel Energy's current tariff per published report dated July 2010 reconfirms the above loss factors.[1] Absent other factors, Boulder's transmission and distribution loss profile follows the PSCo transmission and distribution system loss profile shown in Table 6-1 below.

---

[1] CoPUC docket No.02A-541E;
Xcel Energy Operating Companies Joint Open Access Transmission Tariff Public Service Company of Colorado: Change in Real Power Losses Rates and Billing Calculation for Network Integration Transmission Service (Docket

Table 6-1 PSCo Historical System Losses

Year	Total Source MWh	Energy Losses MWh (Transmission and Distribution)	Historical System Loss %	System Loss % per FERC Tariff[2]
1995	25,183,299	1,494,508	5.9%	
2000	50,581,947	1,441,054	2.8%	
2005	45,272,943	1,439,691	3.2%	
2009	36,806,394	1,781,894	4.8%	4.91

6.3 BOULDER AREA TRANSMISSION NETWORK

This section provides (i) an overview of Boulder area's transmission network; (ii) an overview of PSCo's future transmission projects for Denver-Boulder area; and (iii) a summary of transmission related issues based on publicly available information and a high level power flow and contingency analysis using a WECCC model.

A geographical map showing Denver-Boulder area transmission network and their interconnection with the rest of PSCo's transmission network is shown in Figure 6-1.

No. ER09-___-000) dated 10/31/2008 - http://www.xcelenergy.com/SiteCollectionDocuments/docs/PSCo-Network-Service-Billing-Filing.pdf;
Xcel Energy Operating Companies FERC Electric Tariff, Second Revised Volume No. 1 (Xcel Energy Operating Cos Joint OATT Version: 0.0.0 Effective 7/30/2010) – Page 40
http://www.xcelenergy.com/SiteCollectionDocuments/docs/OATT.pdf

2 Xcel Energy Operating Companies FERC Electric Tariff, Second Revised Volume No. 1 (Xcel Energy Operating Cos Joint OATT Version: 0.0.0 Effective 7/30/2010) – Page 40
http://www.xcelenergy.com/SiteCollectionDocuments/docs/OATT.pdf

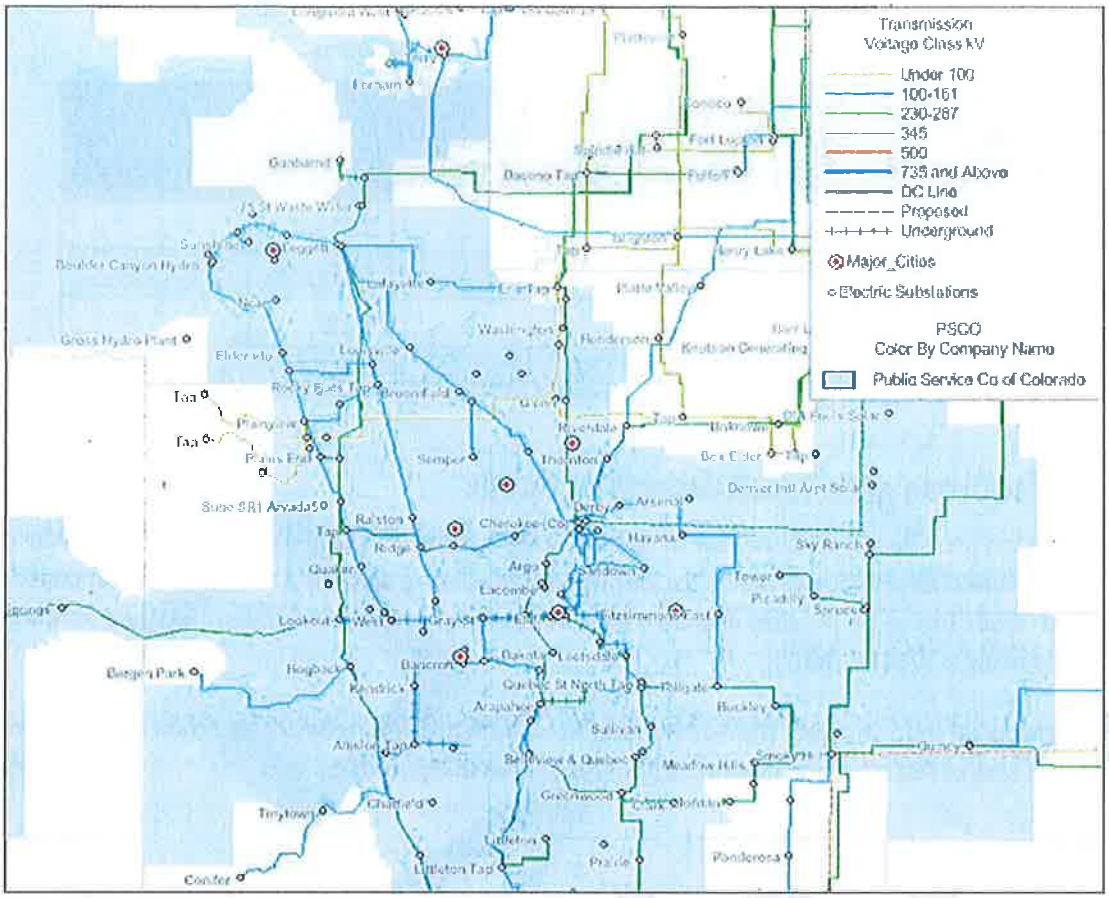


Figure 6-1 Transmission Overview

Source: Energy Velocity

The Boulder area transmission network comprises of 230 kV and 115 kV transmission lines. The following is a list of key substations in Boulder's area:

- Boulder Terminal (115 kV)
- Sunshine (115 kV)
- Ncar (115 kV)
- Gunbarrel (230 kV)
- Niwot (230 kV)
- Leggett (115 kV)

A single line drawing showing interconnections of the key Boulder area 115 kV and 230 kV substations is shown in Figure 6-2. This single line drawing is based on the information included in WECC 2012 model.

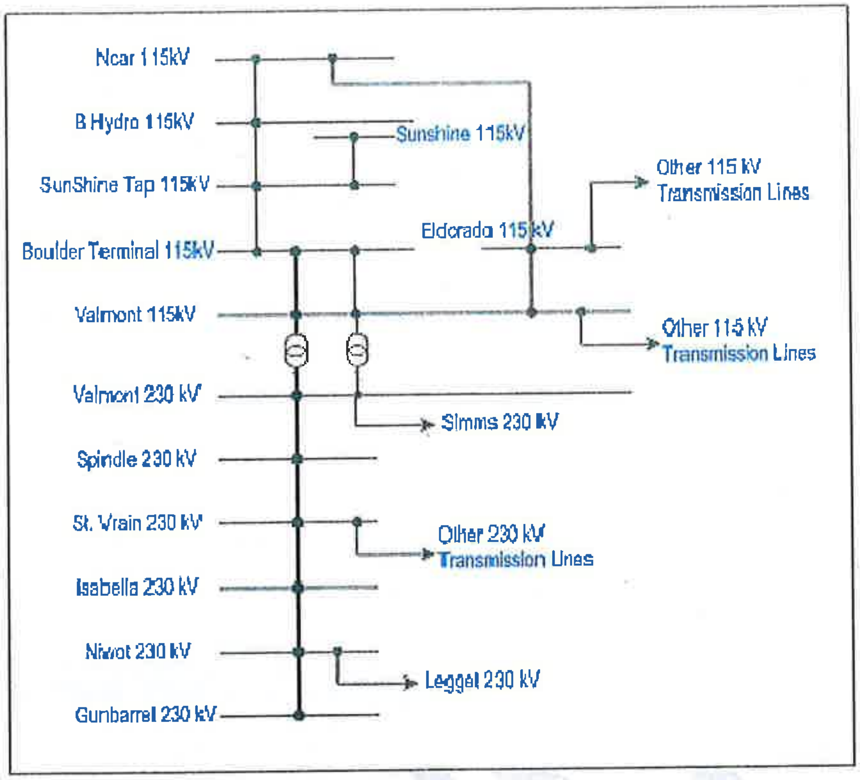


Figure 6-2 Single Line Diagram of Boulder's Transmission Network

Source: WECC and Nexant

6.3.1 PSCo Planned Transmission Projects for Denver-Boulder Area

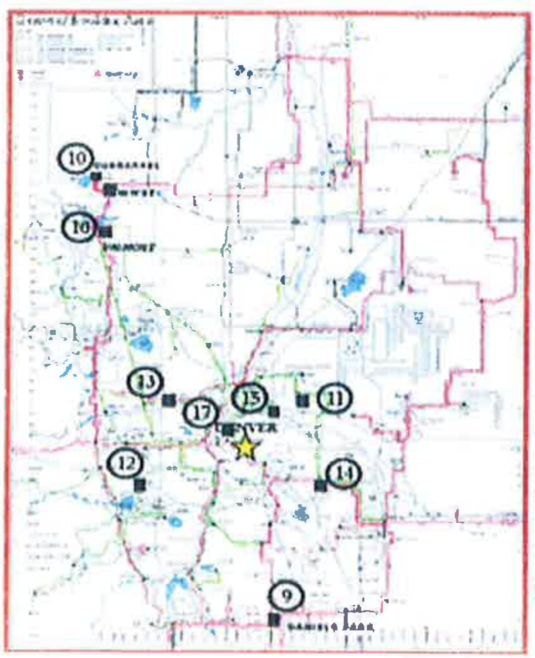
In a report released by PSCo titled "PSCo 10-Year Plan / 20-Year Scenario Assessment"[3], dated December 2010, PSCo provided a list of planned transmission projects in Denver-Boulder area for 2010-2015. No plans for the Denver-Boulder area beyond 2015 are included in this report.

The planned 2010-2015 projects are shown in Figure 6-3 through Figure 6-5. Project # 7, 10, 16, and 20 shown in these figures have direct benefit to the Boulder area due to their proximity to the Boulder area transmission (# 7: Eldorado Plainview; # 10: Gunbarrel - Niwot 230 kV; #16: Barker Sub; and # 20: Gunbarrel Interconnection).

[3] http://www.xcelenergy.com/SiteCollectionDocuments/docs/PSCO201010yearplanL12-01-2010.pdf

#	Project	Comments	ISD*	Drivers
1	Sandown – Leetsdale Line	New 7 mile 115kV underground line for reliability	Completed	Reliability
2	IREA Missile Site	Construct a new 115 kV termination for IREA	5/2013	Wholesale Customer
3	IREA Green Valley	Construct a new 115 kV termination for IREA	5/2013	Wholesale Customer
4	Fairgrounds (Todd Creek) 115 kV Delivery Point	Provide a load delivery interconnection for TSG&T on Cherokee-Ft. Lupton 115 kV	6/2011	Transmission Service
5	Powhaton	New Powhaton substation on the Spruce – Smoky Hill 230 kV line	Completed 6/2010	Distribution
6	Marcy	Add third 230/13.8 kV transformer at Marcy substation	Completed 6/2010	Distribution
7	Eldorado – Plainview	Replace existing 115 kV line with new single – circuit, 115 kV structures and line rated for 150 MVA	12/2010	Reliability
8	Chambers	Final phase of upgrades tying the 230 kV outer belt network to the 115 kV load serving transmission system between the Tower substation and the Cherokee – East 115 kV lines	11/2010	Reliability

Figure 6-3 PSCo's Planned Projects in Denver-Boulder Area



#	Project	Comments	ISD*	Drivers
9	Daniels Park 230/115 kV 280 MVA	Replace existing 230/115 kV 150 MVA transformer with 230/115 kV 280 MVA transformer	Completed 6/2010	Reliability
10	GunBarrel – Niwot 230 kV	2.3 mile Underground 230 kV line to Niwot, second circuit	11/2011	Retail Customer
11	Havana	Add a 115/13.8 kV transformer at Havana substation	6/2013	Distribution
12	Russell	Add a 115/13.8 kV transformer at Russell substation	6/2014	Distribution
13	Tollgate	Add a 230/13.2 kV transformer at Tollgate substation	4/2012	Distribution
14	RTD Fas Tracks	RTD load interconnection at the Sandown substation. Move underground North – California and North – Capitol Hill circuits	P1 11/2011 P2 5/2013	Retail Customer
15	Valmont – Ridge Line	Install intermediate 115 kV structures to existing 115 kV circuit for increased line to ground clearance and uprate of line rating to 150 MVA	12/2010	Reliability
16	Barker Sub	Install two new 50 MVA 230/13.8 kV transformers at Barker Substation site	5/2015	Distribution

Figure 6-4 PSCo's Planned Projects in Denver-Boulder Area (cont.)

#	Project	Comments	ISD*	Drivers
18	Brantner	Construct a new 115/13.2 kV substation near 128th and Holly	7/2014	Distribution
19	Capitol Hill	Add a third 115/13.8 kV transformer at Capitol Hill substation	5/2014	Distribution
20	Gun barrel Interconnection	Install a new 230/24.9 kV transformer for delivery to Poudre Valley REA	6/2011	Distribution
21	North	Add a third 115/13.8 kV transformer at North substation	5/2015	Distribution
22	Sandown	Add a third 115/13.8 kV transformer at Sandown substation	11/2011	Distribution
23	Bancroft	Add a third 115/13.2 kV transformer at Bancroft substation	1/2013	Distribution
24	University	Add a third 115/13.8 kV transformer at University substation	10/2012	Distribution
25	Federal Heights	Add a third 115/13.8 kV transformer at Federal Heights substation	3/2013	Distribution
26	Lacombe	Add a third 230/13.8 kV transformer at Lacombe substation	5/2013	Distribution
27	Jewell	Add a third 230/13.8 kV transformer at Jewell substation	3/2013	Distribution

Figure 6-5 PSCo's Planned Projects in Denver-Boulder Area (cont.)

Source: PSCo

6.3.2 WECC 2012 Summer Peak Case Assessment

A high level analysis was performed to determine the line loading of the 115 kV and 230 kV transmission lines using WECC 2012 summer peak model.

Table 6-2 summarizes the line loadings in the WECC 2012 summer peak model under normal system conditions for the Boulder area transmission lines shown in Figure 6-2.

As shown in the following table, the two transmission lines between Boulder Terminal and Valmont 115 kV substation and the transmission lines between Valmont and Eldorado are loaded to approximately 50% of their rating. Other transmission lines have adequate unused capacity.

In order to assess the potential impact of outage of either of the two transmission lines between Boulder Terminal and Valmont and the transmission line between Eldorado and Valmont (the 115 kV transmission lines that are loaded to approximately 50% of their normal rating), (n-1) contingency analysis was performed using WECC 2012 base case. The outage of either of the two 115 kV circuits between Boulder Terminal and Valmont increases the loading of the second circuit to 110% of its normal rating. The outage of Eldorado to Valmont 115 kV line does not cause any overload in the Boulder area's 115 kV transmission network.

Table 6-2 2012 WECC Base Case Transmission Line Loading

From BUS #	Name	BASE KV	To BUS #	Name	BASE KV	CKT	LOADING (MVA)	RATING (MVA)	PERCENT Loading
70058	B.HYDRO	115	70295	NCAR	115	1	41	120	34%
70058	B.HYDRO	115	70424	SUNSHTAP	115	1	20.1	109	18%
70059	BO_TERM	115	70424	SUNSHTAP	115	1	39.8	109	37%
70059	BO_TERM	115	70444	VALMONT	115	1	70.6	120	59%
70059	BO_TERM	115	70444	VALMONT	115	2	71	138	51%
70164	ELDORADO	115	70295	NCAR	115	1	18.7	120	16%
70164	ELDORADO	115	70322	PLAINVW	115	1	39	102	38%
70164	ELDORADO	115	70346	RALSTON2	115	1	21.2	102	21%
70164	ELDORADO	115	70444	VALMONT	115	1	49.8	102	49%
70213	GUNBARRE	230	70297	NIWOT	230	1	30.3	287	11%
70261	LEGGETT	230	70297	NIWOT	230	1	148.8	558	27%
70297	NIWOT	230	70544	ISABELLE	230	1	213.8	558	38%
70423	SUNSHINE	115	70424	SUNSHTAP	115	1	20.7	108	19%

The limited power flow analysis discussed above indicates that there is a need to review PSCo's detailed analysis of any transmission issues in the Boulder area, with focus on these lines in particular, before drawing firm conclusions.

6.3.3 Impact of Retirement of Valmont Coal Fired Unit #5

As part of its plan to reduce emissions, Xcel is planning to retire several coal fired units currently operating at Cherokee, Arapahoe, and Valmont.

Xcel Energy has performed analysis to determine the impact of the retirements of Cherokee and Arapahoe coal fired generators on Denver-metro area's real power generation and voltage support needs. Xcel's future plan to mitigate the impact of shutdown of Cherokee and Arapahoe coal fired generators is shown in Figure 6-6.

Based on the limited power flow analysis, it appears that there is a need to review the PSCo's detailed analysis of any existing transmission issues in the Boulder area before drawing firm conclusions.

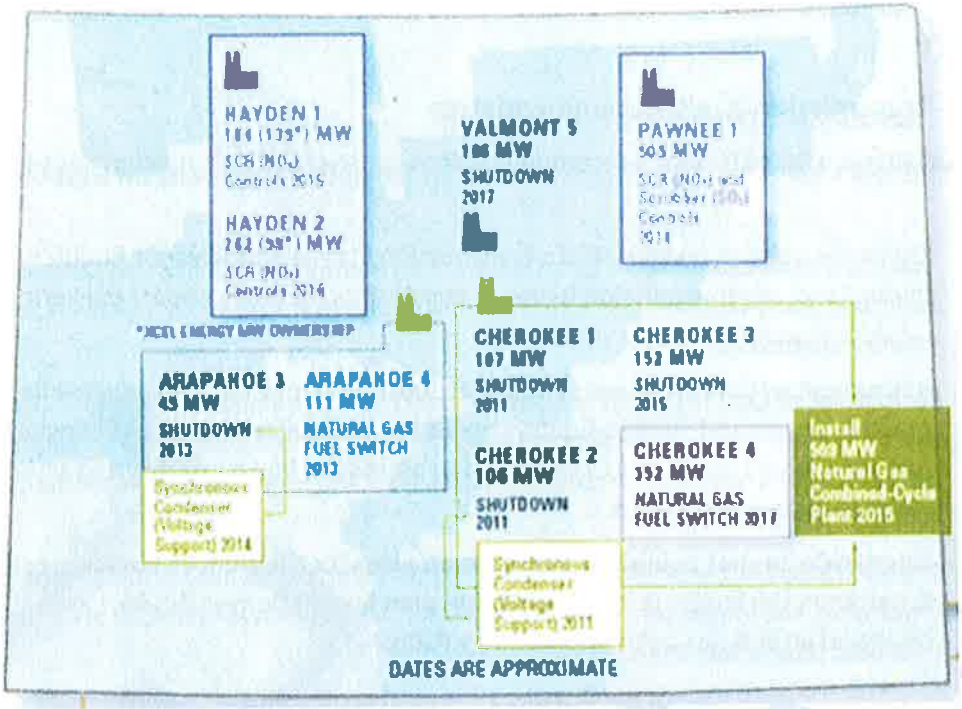


Figure 6-6 Xcel Energy Emission Reduction Plan[4]

Source: PSCo

The Valmont generators are located in close proximity to Boulder and provide generation to customers in that area. Retirement of Valmont Unit #5 coal-fired generating unit will have a direct impact on Boulder area's reactive power requirements.

Some analysis has been performed by Public Service Company of Colorado of the impact of retirement of Valmont generator for Boulder area load. According to the information included in Transmission Report for the Clean Air – Clean Jobs Act, dated October 8, 2010[5], in order for Valmont unit #5 to be retired from coal-fired operation, PSCo concludes that the following measures must be taken to ensure adequate voltage and system support at Valmont.

1. The existing Valmont unit #6 gas-fired plant must remain on-line and capable of operation under peak loading periods.
2. The existing 90 MVARs of shunt capacitors must remain in service at Valmont.
3. Measures may need to be taken to reduce potential contingency loading on the Valmont 230/115kV transformers. It is recommended that this be achieved by:
    a. Allowing up to 115% loading under contingency conditions, or
    b. Implementing operating procedures to mitigate potential overloads.

[4] http://www.xcelenergy.com/SiteCollectionDocuments/docs/10-12-303.pdf

[5] Source: http://www.xcelenergy.com/SiteCollectionDocuments/docs/10M-245E_Green%20Exhibit%20No.%20TWG-1.pdf

4. Additional studies should be performed to fully assess any necessary upgrades at the Valmont site.

6.3.4 Transmission Study Recommendation

The following is a list of Nexant's recommendations for study of transmission issues in the Boulder area:

- There is a need to review PSCo's Transmission Planning Studies for Boulder area to fully understand any transmission issues or constraints that may impact delivering power to Boulder customers.
- Retirement of Coal fired unit at Valmont substation may have an adverse impact on the reactive power and voltage support needs for Boulder area loads. As concluded by Xcel, further analysis needs to be conducted to assess the impact of this retirement and identify suitable mitigation options.
- Since PSCo has not published transmission plans for the Denver-Boulder area beyond 2015 timeframe, the longer term transmission plan for the Denver-Boulder area should be reviewed after it has been published by PSCo.

6.4 BOULDER DISTRIBUTION SYSTEM

6.4.1 Distribution System Impact of On Site Generation

Colorado enacted the Bill HB 1001 in 2010 which increases the Renewable Electricity Standard (RES) to 30 percent by 2020. According to HB1001, the electric utilities will have to increase the proportion of electricity sourced from renewable energy as indicated in Table 6-3. The utilities will also have to provide a growing proportion of power from Distributed Generation (DG) as shown in Table 6-4 below.[6][7]

Table 6-3 Colorado RES

Year	Colorado RES
2007	3%
2008 - 2010	5%
2011-2012	12%
2013-2014	12%
2015-2016	20%
2017-2019	20%
>=2020	30%

6 http://www.epa.gov/statelocalclimate/documents/pdf/on-site_generation.pdf

7 HB 10-1001 http://www.leg.state.co.us/CLICS/CLICS2010A/csl.nsf/fsbillcont3/47C157B801F26204872576AA00697A3F?Open&file=1001_01.pdf

Table 6-4 Distributed Generation Requirement

Year	% Retail Sales from DG
2008 - 2010	0.50%
2011 - 2012	2%
2013- 2014	2%
2015 2016	3%
2017 - 2019	3%
>= 2020	3.50%

As defined in HB 1001, distributed generation is renewable energy resources that can be connected to the existing transmission or distribution grid without the need for new substation or transmission facilities other than an inverter, meter, transformer, or associated cable connection. Retail distributed generation is interconnected on the customer side of the utility meter providing energy to serve customer load.

Distributed generation per HB 1001 includes renewable energy resources such as rooftop and other small solar, wind, geothermal, biomass, new hydroelectricity with a nameplate rating of ten MW or less, and hydroelectricity in existence on January 1, 2005 with a nameplate rating of thirty MW or less owned by individuals, small businesses, and communities.

Distributed Generation programs provide incentives for on-site (renewable) resource installations. Under HB 1001, the retail electric customers are entitled to receive a standard rebate offer from the utility for the installation of eligible solar electric generation of up to 100 kW on customer's premises. The Bill is designed to reimburse the customer for on-site generation in excess of its own consumption.

Distributed Generation is intended to save ratepayers money by avoiding the costs of building new transmission facilities and power plants and the accompanying profit margins for utilities. Small scale renewable distributed generation built closer to the point of consumption bridges the gap between projected electricity demand growth and lack of transmission infrastructure to support the transportation of power from the source to sink.

6.4.2 Effect of DG's on the distribution system

The development of Distributed Generation is a current issue being confronted in the technical design of electric distribution systems. National and state standards and guidelines have been developed for the interconnection of DG. Per a paper on standards for interconnecting DG by NREL, when properly integrated with the grid DG has potential benefits such as reduced electric line loss; grid/ electric power system (EPS) investment deferment and improved grid/EPS asset utilization; improved reliability; ancillary services such as voltage support or stability, VARs, contingency reserves, and black start capability; clean energy; lower-cost electricity; reduced price volatility; greater reliability and power quality; energy and load management.[8]

"An interconnect standard is necessary for DG to operate in parallel with the utility power system. It is the single most important technical issue in most DG projects. Typically, each utility sets the protection requirement guidelines to connect distributed generators to the utility grid. These guidelines generally cover smaller distributed generators of capacity 10 MW or less connected to the utility system at the subtransmission and distribution level. These utility circuits are designed to generally supply radial loads. Introduction of on-site generation provides a source for redistribution of the fault current on the feeder circuit potentially causing the loss of relay coordination and overvoltages. Individual states as well as the IEEE have been actively involved in in an effort to develop standards and guidelines for the interconnection of DG that can be ultimately consolidated as single standard of technical requirements for DSG interconnection." [9]

A "ten-point action plan" for reducing barriers to distributed generation has been provided in the paper "DISTRIBUTED GENERATION INTERCONNECTIONS: PROTECTION, MONITORING, AND CONTROL OPPORTUNITIES" (Donald L. Hornak, Basler Electric Company, N. H. "Joe" Chau, Florida Power and Light Company) is shown here.[10]

Ten-point Action Plan for Distributed Generation

A. Reduce technical barriers

(1) Adopt uniform technical standards for interconnecting distributed power to the grid.

(2) Adopt testing and certification procedures for interconnection equipment.

(3) Accelerate development of distributed power control technology and systems.

B. Reduce business practice barriers

(4) Adopt standard commercial practices for any required utility review of interconnection.

(5) Establish standard business terms for interconnection agreements.

(6) Develop tools for utilities to assess the value and impact of distributed power at any point on the grid.

C. Reduce regulatory barriers

(7) Develop new regulatory principles compatible with distributed power choices in both competitive and utility markets.

(8) Adopt regulatory tariffs and utility incentives to fit the new distributed power model.

---

8 IEEE 1547 National Standard for Interconnecting Distributed Generation: How Could It Help My Facility? http://www.nrel.gov/docs/fy04osti/34875.pdf

9 A Tutorial on the Impact of Distributed Generation (DG) on Distribution Systems - An IEEE paper by C. J. Mozina (Beckwith Electric), April 2008

10 http://www.basler.com/downloads/disgen_interc2.pdf

(9) Establish expedited dispute resolution processes for distributed generation project proposals.

(10) Define the conditions necessary for a right to interconnect.

CoPUC adopted net metering standards in 2005 that apply to utilities with 40,000 or more customers including cooperative and municipally owned utilities. In 2008, HB 1160 was enacted requiring municipally owned utilities with 5,000 customers or more to adopt interconnection rules similar to the PUC's. Per SB51, the PUC adopted new rules in 2009 that changed Colorado's net metering policies, relaxed some of the insurance requirements for interconnection, and addressed utility concerns for highly seasonal circuits and voltage flickers. The Colorado interconnection rule permits dispute resolution. Also permitted is interconnection to area network with systems up to 300 kW capacity.[11]

Based on FERC standard, Colorado's three tiered interconnection rules include:

1. Inverter based systems with maximum capacity of 10 kW complying with IEEE 1547 and UL 1741 standards in level 1
2. Systems with maximum capacity of 2 MW in level 2 that must be connected to a portion of the distributed system and subject to the utility's tariff. It must also comply with IEEE 1547 and UL 1741 standards.
3. Systems with capacity up to 10 MW in level 3 that do not qualify for level 1 or level 2 interconnection procedures. Level 3 interconnections may require studies regarding project scope, feasibility, impact, and facilities.

6.4.3 Distribution Study Recommendation

In its study of PSCo's plans and implementation of the SmartGrid City project for the Boulder distribution system, the City should take into account the interconnection rules for Distributed Generation adopted by the PUC and review the following:

- Technical standards for interconnecting distributed power to the grid.
- Testing and certification procedures adopted for distributed generation interconnection equipment.

6.4.4 Distribution Investment

Available data on distribution investments, depreciation, and remaining book lives of Xcel/PSCo's existing distribution system within the City has been reviewed. While Xcel's FERC Form 1 does not separately report distribution investments within Boulder, this data is provided in the annual franchise reports to the City. The estimated book value for the city of Boulder, distribution lines and facilities for 2005, 2008, and 2009 in Table 6-5 have been calculated based on those reports for 2006 and 2009.

[11] http://dsireusa.org/incentives/incentive.cfm?Incentive_Code=CO28R&re=1&ee=1

Table 6-5 Boulder Distribution System Book Value

Boulder	2005	2008	2009
Distribution lines and facilities	$109,171,000	$123,146,000	$129,111,000
Local System Common Property	$2,910,544	$3,250,375	$3,387,567
Gross Total Local Distribution Plant	$112,081,544	$126,396,375	$132,498,567
Accumulated Depreciation	($34,029,791)	($34,486,021)	($35,999,497)
Net Local Distribution Plant Investment	$78,051,753	$91,910,354	$96,499,070

The book values shown in this table for Distribution Lines and facilities and for Local System Common Property are taken directly from the franchise report Local System values, lines 17 and 18 on page 3 Input Plant Investment Electric. The Integrated System book values in the franchise reports lines 13 through 15 list values for Boulder facilities which include Distribution substations, General and common, and Intangible – Electric, as well as for Generation and Transmission facilities.

The 2009 Boulder distribution system book value shown of $96.5 Million does not include the cost of subsequent investment by PSCo in the experimental Boulder SmartGrid City project. Those costs have been estimated by PSCo at over $44.5 Million, recovery of which investment was capped at $27.9 Million by the CoPUC on January 5, 2011.

7 SUSTAINABLE ENERGY PROGRAMS

This chapter provides information on the sustainable energy programs that Xcel operates throughout its Colorado service territory, and documents participation in these programs by Xcel's Boulder customers. The data address Xcel program spending, as well as the savings and renewable energy generated through the programs.

To place the data in context, a number of comparisons are provided, including:

- By customer sector (e.g., residential vs. business);
- Between Boulder and the rest of Xcel's Colorado system;
- Between Xcel's Colorado system and other investor-owned utilities in the United States.
- Additional comparisons to Boulder's benchmark cities are provided in Chapter 9.

In the body of this chapter, data are presented in graphical format. Data tables supporting the graphs are presented in the Appendix and in additional spreadsheets provided to city staff.

Key references for this chapter include:

- Annual reports that Xcel files with the Colorado PUC documenting its DSM program activities.
- Annual reports that Xcel files with EIA documenting its DSM program and green pricing program activities, and similar reports filed by comparison utilities.
- Reports that Xcel provides to the city documenting CAP tax collections, which also document participation by Boulder customers in Windsource.
- Data that Xcel has provided to the city documenting participation in DSM programs and Solar Rewards.
- A long range plan for increasing DSM investments that Xcel has filed with the Colorado PUC and which formed the basis for the plan it developed in response to the Colorado Clean Air-Clean Jobs Act that has been approved by the Colorado PUC.

7.1 OVERVIEW OF XCEL'S SUSTAINABLE ENERGY PORTFOLIO

Xcel operates four types of sustainable energy programs that can be organized into two broad groups:

- Demand-Side Management (DSM) Programs
  - Energy Efficiency Programs
  - Load Management Programs
- Renewable Energy Programs

- Green Pricing Program (Windsource)
- On-Site Renewable Program (Solar Rewards)

Xcel's DSM Programs include both energy efficiency and load management programs. Energy efficiency programs increase the overall efficiency of the equipment powered by Xcel's electric generation; examples of energy efficiency activities include programs that help customers design efficient buildings, purchase efficient lighting and cooling systems when they replace equipment, and install control systems and insulation to improve the efficiency of existing equipment. Load management programs encourage customers to use less electricity during the days and hours when Xcel is experiencing annual peak demand. Examples of load management programs include Xcel's direct load control program, which remotely controls residential air conditioners during system peak hours, and interruptible service, through which Xcel pays large customers to reduce loads during system peak hours.

Xcel's renewable energy programs include green pricing and on-site renewable programs. Windsource, Xcel's green pricing program, allows customers to spend a premium in return for Xcel providing them with renewable generation above and beyond that Xcel provides to all customers in compliance with Colorado's Renewable Energy Standard. Solar Rewards, Xcel's on-site renewable program, provides rebates and, in some cases, ongoing payments to customers that install solar photovoltaic systems. To further support on-site generation, Xcel also allows "net metering," that allows customers to use solar generation to reduce net purchase throughout entire billing cycles, even though, in some hours, on-site generation may exceed on-site power requirements.

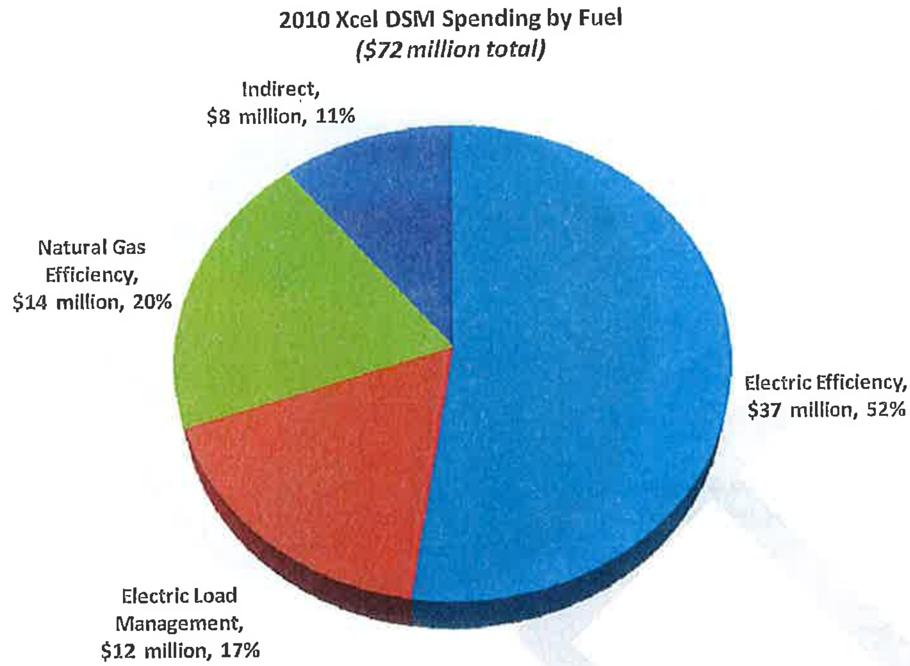
7.2 XCEL ENERGY DEMAND-SIDE MANAGEMENT PROGRAMS

Xcel's 2010 DSM report to the Colorado PUC documents spending and savings for its entire portfolio, including electric energy efficiency, electric load management, natural gas energy efficiency, and indirect activities (which include energy audits, education, and other market transformation activities).

7.2.1 Overall DSM Spending

7.2.1.1 How Much Does Xcel Spend On All DSM Activities (Including Natural Gas)?

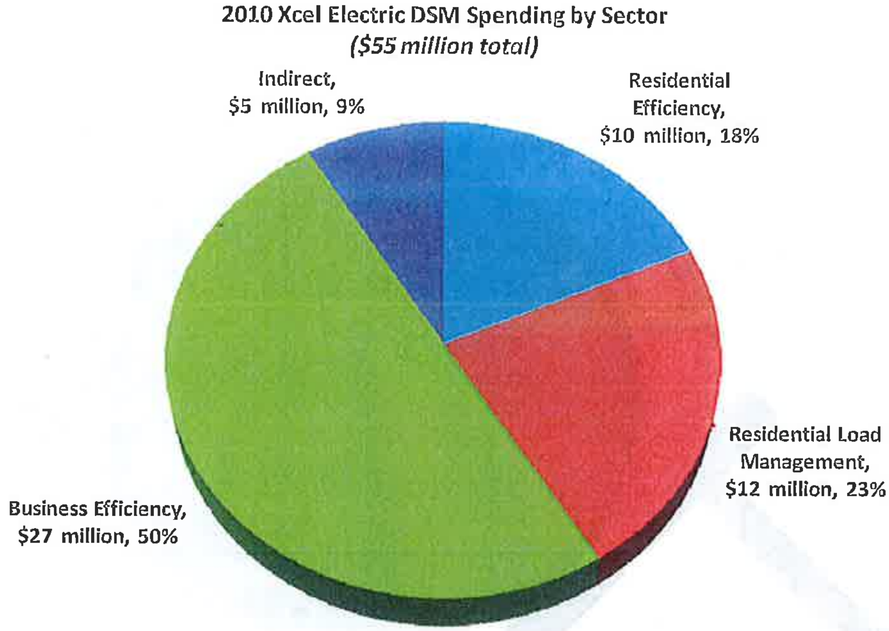
Xcel spent approximately $72 million on all DSM activity in 2010, with almost two thirds funding direct electric activities, 20 percent funding direct natural gas activities, and 11 percent funding indirect electric and natural gas activities.



7.2.1.2 How Much Does Xcel Spend On Electric DSM?

Of the $55 million spent on electric activities, half went to business programs, 41 percent went to residential programs (including both efficiency and load management), and nine percent funded indirect activities.

Xcel does not include costs or performance in its annual DSM report for its interruptible service program that provides load management options for business customers.

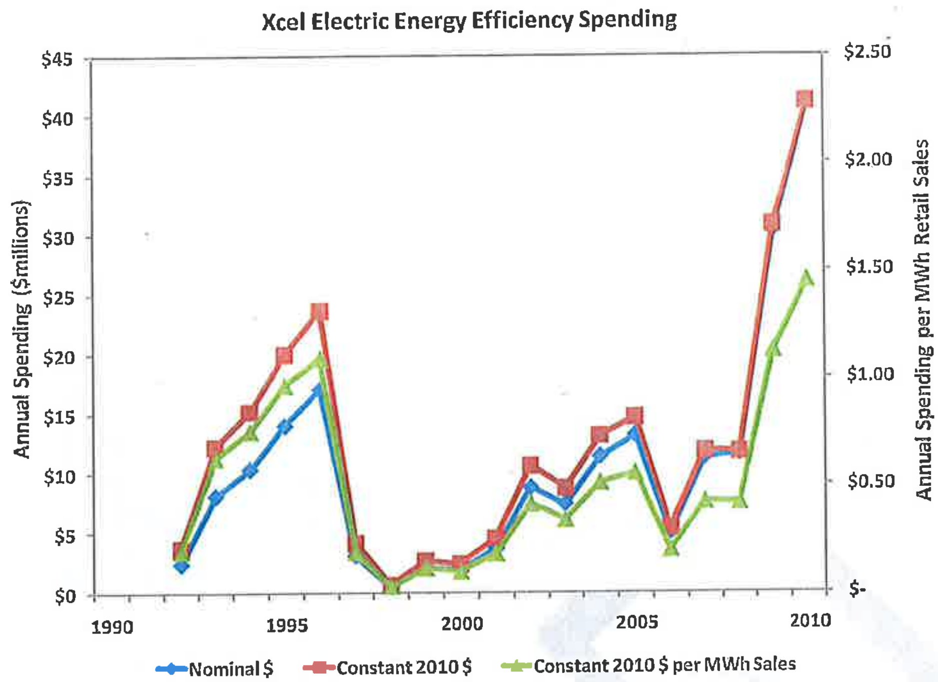


7.2.2 Xcel Electric Energy Efficiency

Information in this section addresses Xcel's energy efficiency programs alone; additional information on load management programs is provided in Section 7.2.3.

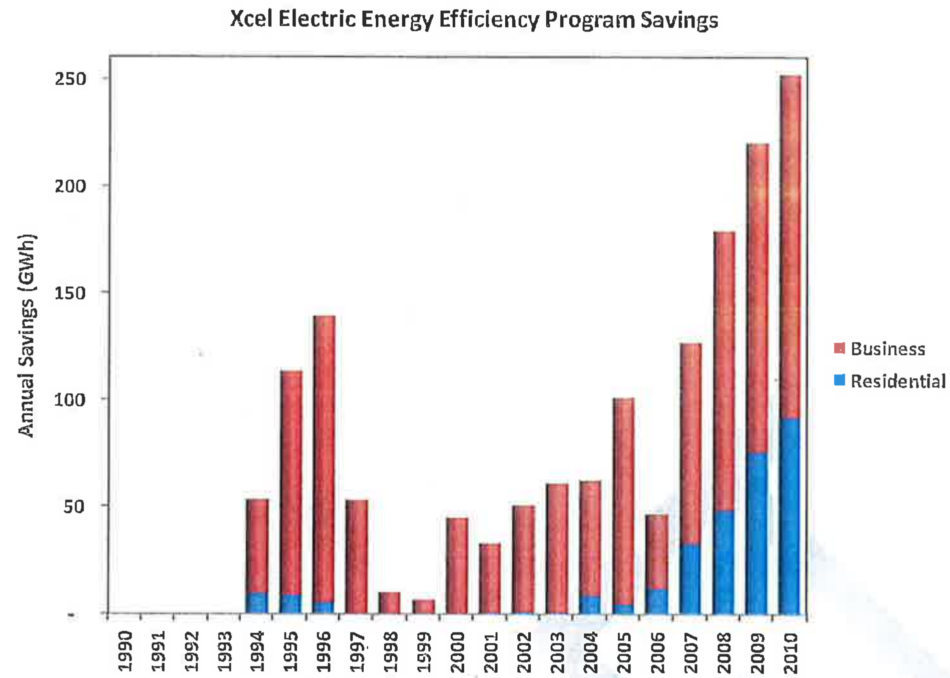
7.2.2.1 How Much Does Xcel Spend On Electric Energy Efficiency?

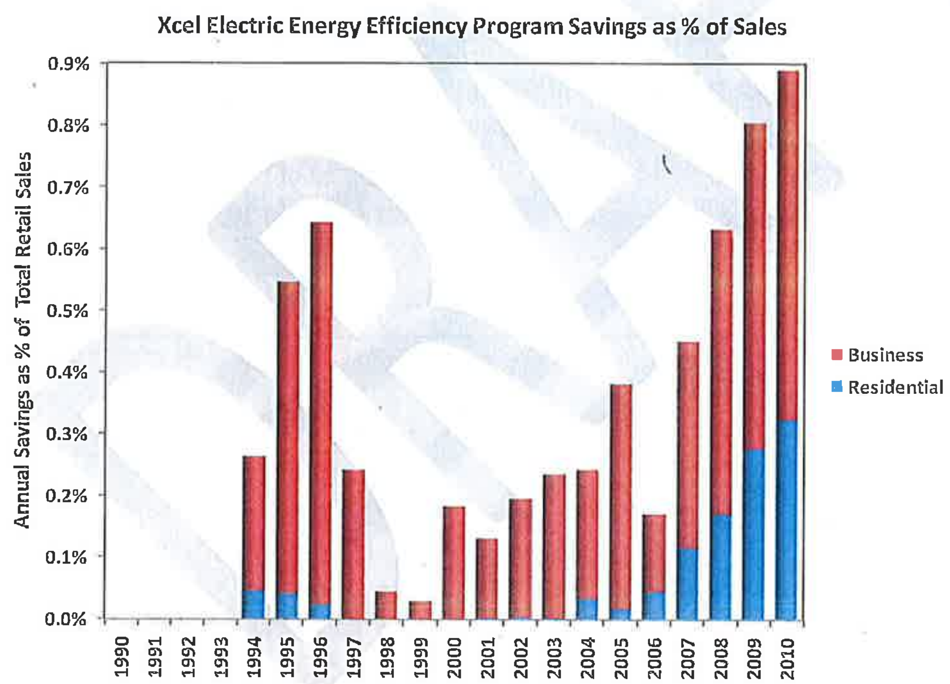
Xcel launched a set of electric energy efficiency programs in the 1990s, but then greatly reduced activity in 1997. With program expansion in recent years, Xcel exceeded 1996 spending (normalized to constant dollars and per megawatt-hour of system sales for comparison) by 2009, and again increased spending in 2010. Xcel spent over $40 million on electric energy efficiency activities in 2010 (including some indirect activities).



7.2.2.2 What Does Xcel Save From Electric Energy Efficiency?

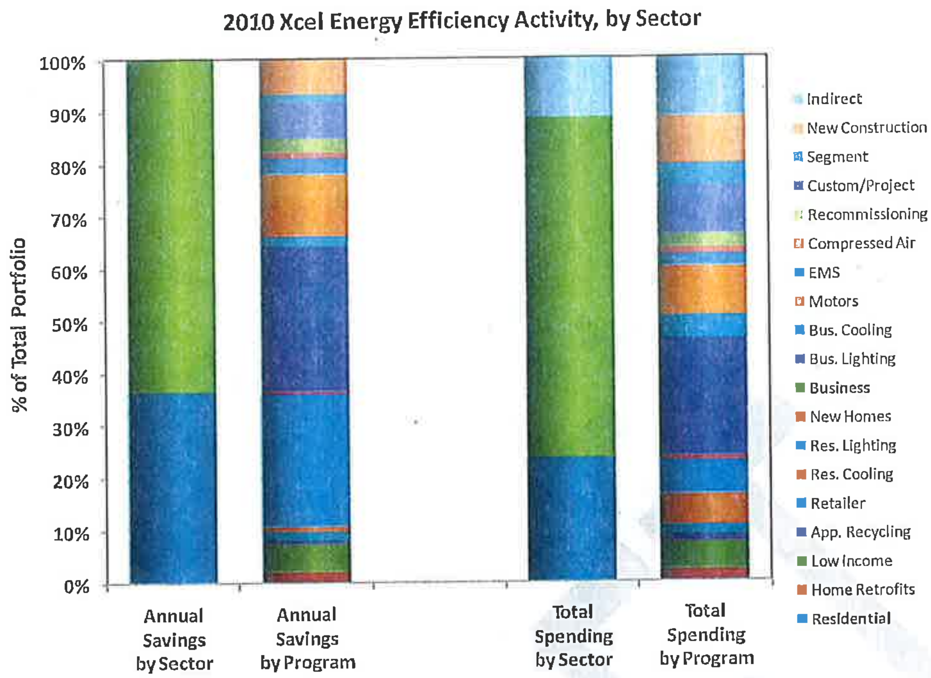
The majority of savings come from business programs, with over 60 percent of 2010 savings coming from business customers. Overall savings generated by each year's activity (rather than cumulative savings that take into account the long terms persistence of program measures installed in customer facilities) reached approximately 0.9 percent of retail sales in 2010.





7.2.2.3 How Does Electric Energy Efficiency Vary by Sector and Program?

In 2010, Xcel's largest programs in terms of both savings and spending included the residential lighting and low income programs, as well as the business lighting, motors, and custom programs. Over half of portfolio savings in 2010 came from the two lighting programs.



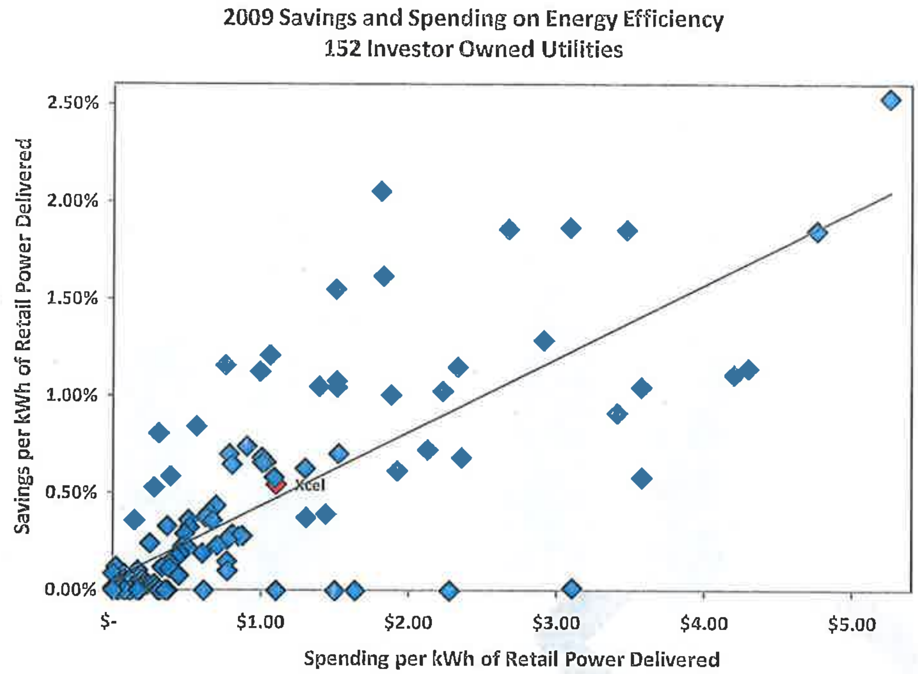
7.2.2.4 How Does Xcel's Energy Efficiency Performance Compare To Other Utilities'?

Xcel's spending and savings performance in 2009—as measured per kilowatt-hour of retail power deliveries for comparison to other utilities—placed it near the 75th percentiles among the 152 investor-owned utilities reporting to EIA. Since around half of reporting utilities show very little activity, this places Xcel's performance near the median for utilities with substantial portfolios.

However, in absolute terms, Xcel's spending and savings is well below the most aggressive utility portfolios. The most aggressive utilities have spending and annual savings levels that are three to five times greater than Xcel's 2009 results.

When comparing savings per unit of spending (i.e., the trend line shown in the following figure), Xcel's performance is very close to the overall trend for all reporting utilities.

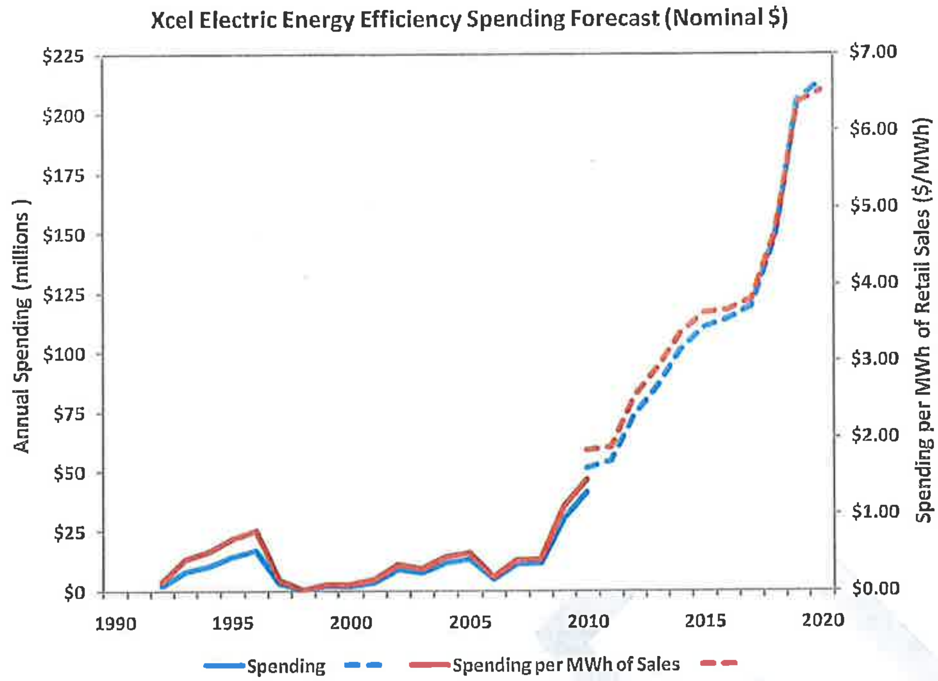
Since Xcel is still ramping up its program portfolio, increases in Xcel's spending and savings between 2009 and 2010 was likely to have outpaced those at other utilities with more established portfolios. That is, Xcel's spending and savings are likely to be closer to the top portfolios in 2010 than they were in 2009.

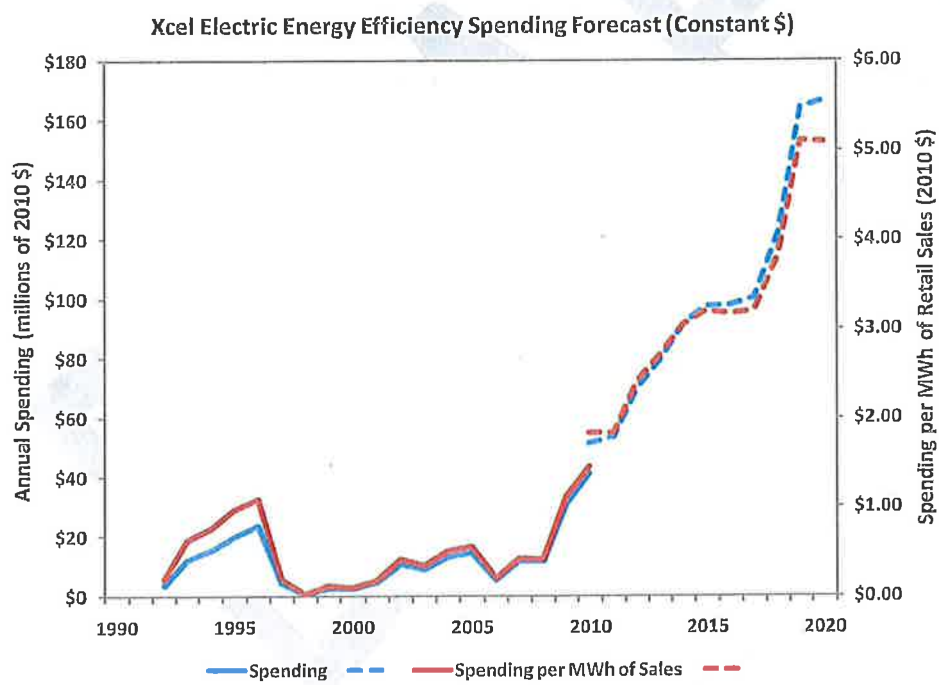


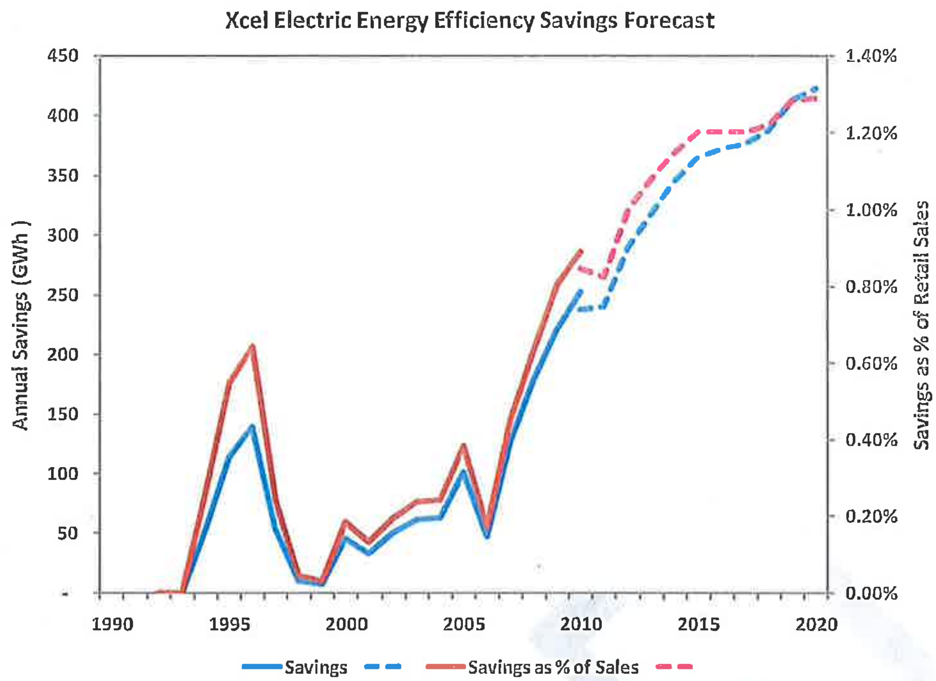
7.2.2.5 How is Xcel Projecting Energy Efficiency to Increase In The Future?

In a proceeding before the Colorado PUC, Xcel has proposed to greatly increase its electric DSM spending and savings, and this proposal formed the basis for the resource plan it developed to comply with the Colorado Clean Air-Clean Jobs Act.

Xcel's proposal would quadruple spending from 2010 levels (in constant dollars), and increase annual savings by approximately two thirds. (Note that Xcel's plan combines energy efficiency and residential load management projections; an estimate that isolated energy efficiency programs was developed for the following graphs.)

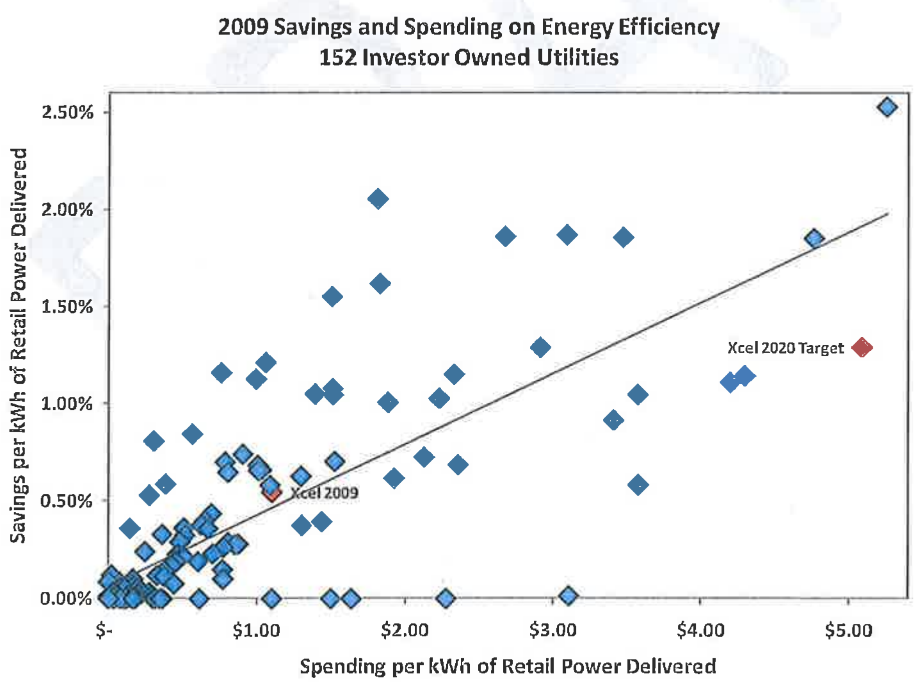

Xcel Electric Energy Efficiency Spending Forecast (Nominal $)
Annual Spending (millions)
Spending per MWh of Retail Sales ($/MWh)
$0
$25
$50
$75
$100
$125
$150
$175
$200
$225
$0.00
$1.00
$2.00
$3.00
$4.00
$5.00
$6.00
$7.00
1990
1995
2000
2005
2010
2015
2020
Spending
Spending per MWh of Sales


Xcel Electric Energy Efficiency Spending Forecast (Constant $)
Annual Spending (millions of 2010 $)
Spending per MWh of Retail Sales (2010 $)
$0
$20
$40
$60
$80
$100
$120
$140
$160
$180
$0.00
$1.00
$2.00
$3.00
$4.00
$5.00
$6.00
1990
1995
2000
2005
2010
2015
2020
Spending
Spending per MWh of Sales



7.2.2.6 How Does Xcel's Plan Compare To Current Performance at Other Utilities?

Xcel's proposed expansion would place its energy efficiency portfolio among the leaders in energy efficiency spending and performance when compared to 2009 portfolios delivered by other utilities.

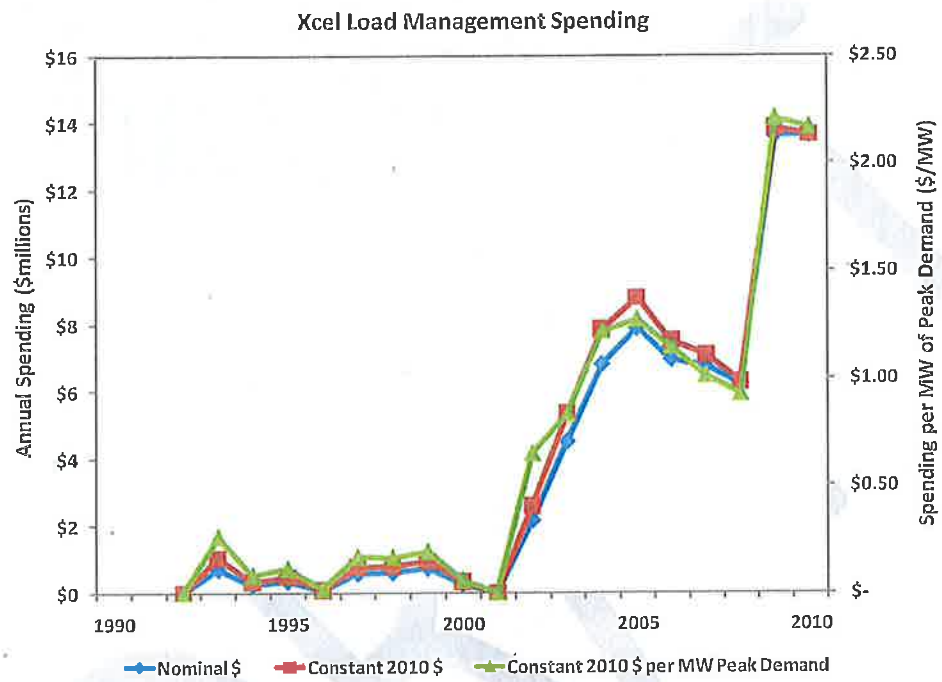


7.2.3 Xcel Load Management Programs

Information in this section addresses Xcel's load management programs, including residential direct load control and business interruptible service, using data that Xcel reports to EIA.

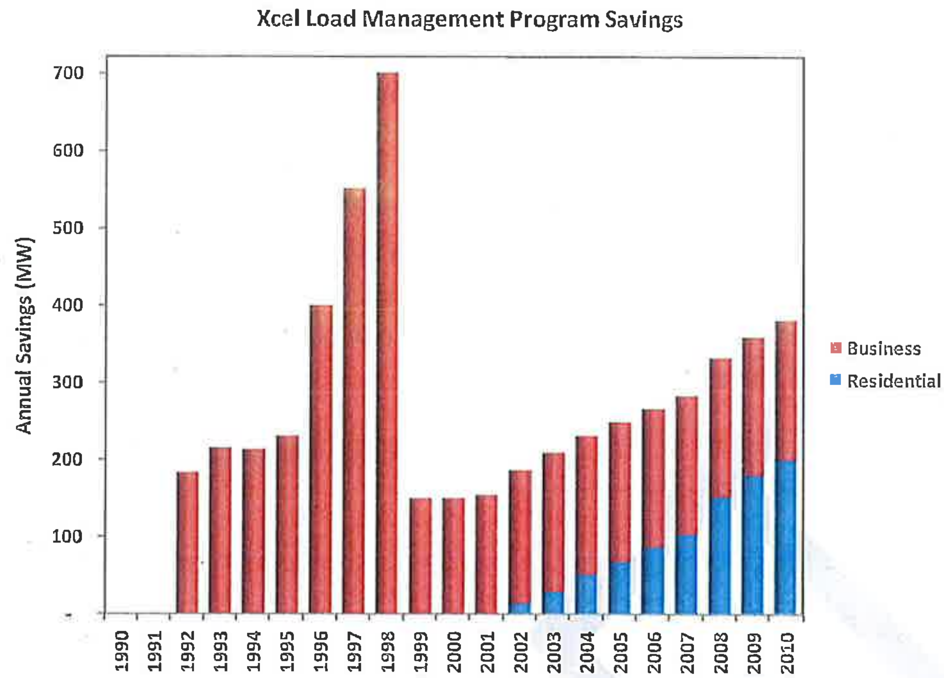
7.2.3.1 How Much Does Xcel Spend On Load Management?

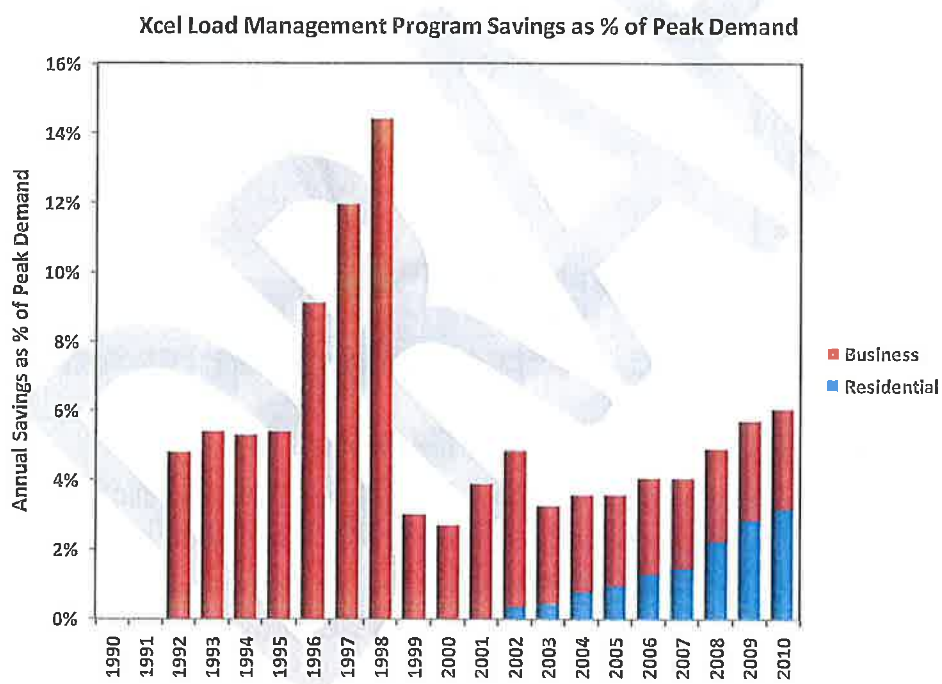
Xcel spent approximately $14 million on its load management activities in 2010. Note that Xcel does not track the incentives it pays to interruptible participants as costs. Since these incentives are paid in the form of rate discounts, they are tracked as reduced revenues rather than costs, and so are not included in the following graph.



7.2.3.2 What Does Xcel Save From Load Management?

Xcel load management participants have the capacity to save almost 380 MW during system peak demand, representing approximately 6 percent of peak load. Slightly more than half of these savings in 2010 came from the residential program.





7.2.3.3 How Does Xcel's Load Management Performance Compare To Other Utilities'?

Section to be completed in final report.

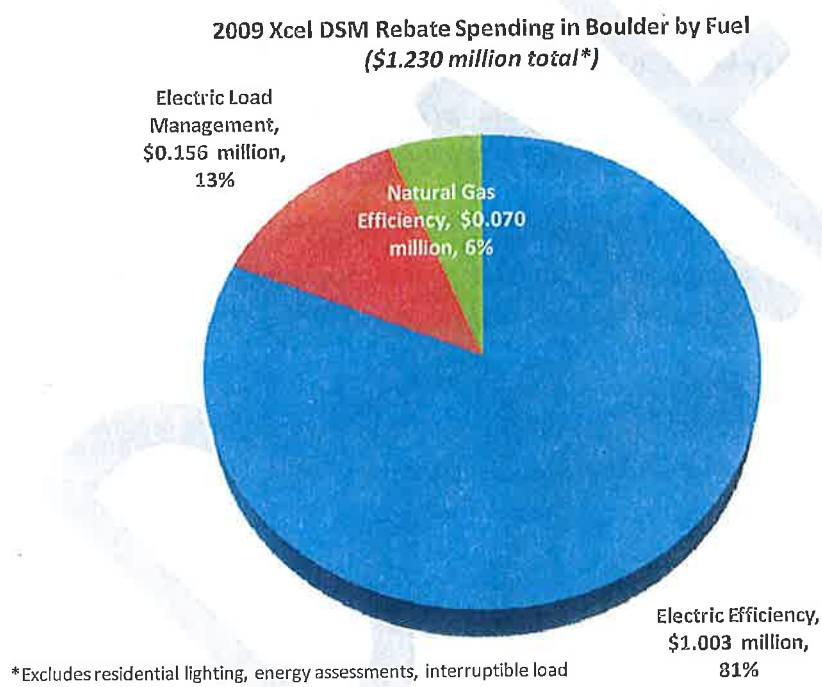
7.2.4 Xcel DSM Rebate Spending in Boulder

Xcel has provided data to Boulder to document 2009 rebate spending, savings, and participation from by Boulder customers. Note that costs in this section represent only costs spent directly on rebates to Boulder customers. These rebate costs are not directly comparable to Xcel's total costs described in previous section, because the Boulder rebate totals exclude:

- Overhead costs required to administer, market, and evaluate programs;
- Indirect programs that provide energy audits, education, and similar activities;
- "Upstream" rebates that are paid directly to retailers to reduce prices for compact fluorescent lamps (CFLs) purchased by Boulder customers.

7.2.4.1 How Much Does Xcel Spend In Boulder On All DSM Rebates (Including Natural Gas)?

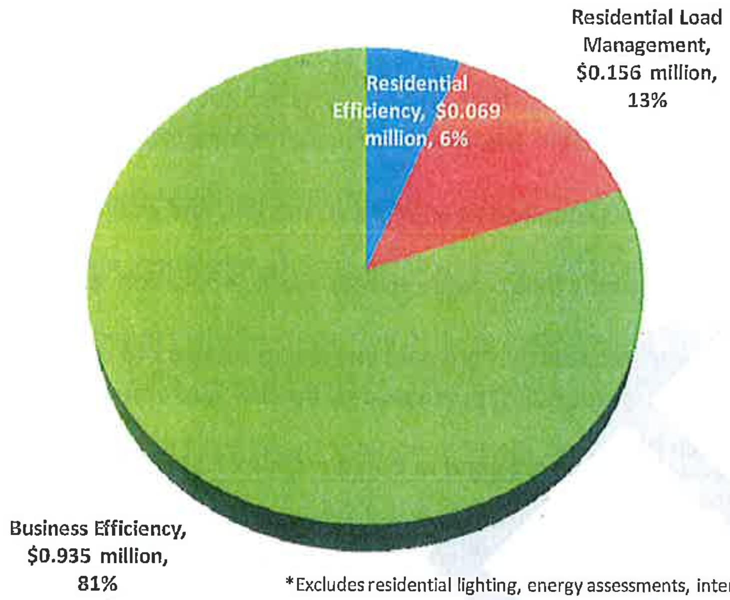
In 2009, Xcel provided $1.2 million in direct rebates to Boulder customers. Over 80 percent of the total went to electric efficiency programs, and only 6 percent went to natural gas programs.



7.2.4.2 How Much Does Xcel Spend In Boulder On Electric DSM Rebates?

Of the $1.1 million in electric rebates, over 80 percent went to business customers. About two thirds of the residential rebates went to participants in the load management program. (However, keep in mind that these rebate totals exclude upstream rebates from Xcel's residential lighting program, which is Xcel's largest residential efficiency program.)

2009 Xcel Electric DSM Rebate Spending in Boulder by Sector
($1.159 million total*)



*Excludes residential lighting, energy assessments, interruptible load

7.2.5 Xcel Energy Efficiency in Boulder

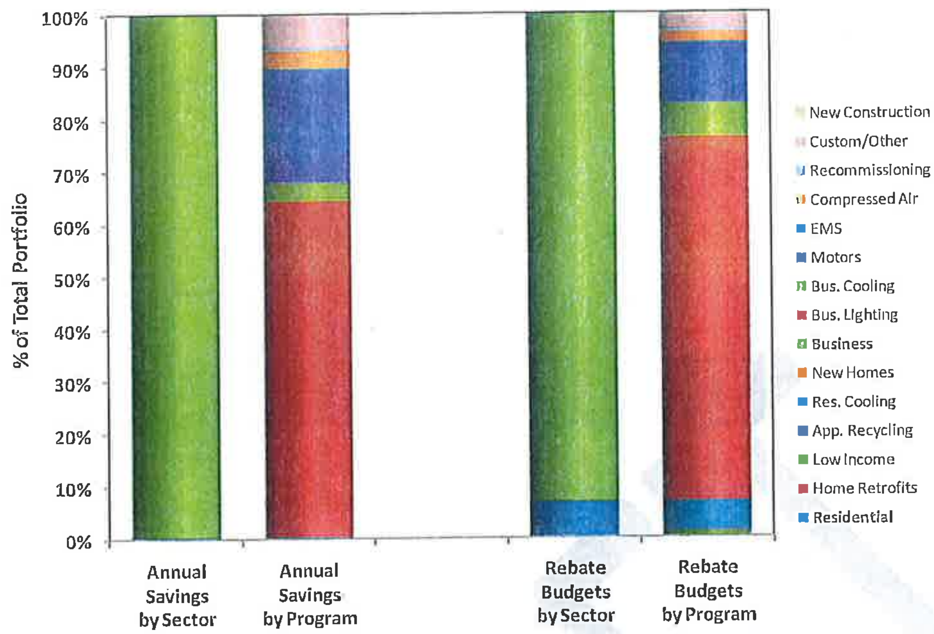
This section isolates activity from Xcel's energy efficiency programs in Boulder; Section 7.2.6 addresses the load management program separately.

7.2.5.1 How Much Does Xcel Spend in Boulder on Rebates for Individual Programs?

Virtually all of 2009 savings came from the business programs. (Again, these figures exclude savings from the upstream residential lighting program, which is Xcel's largest residential efficiency program)

Over two thirds of reported savings came from the business lighting program and over 90 percent of savings came from three business programs: lighting, motors, and custom.

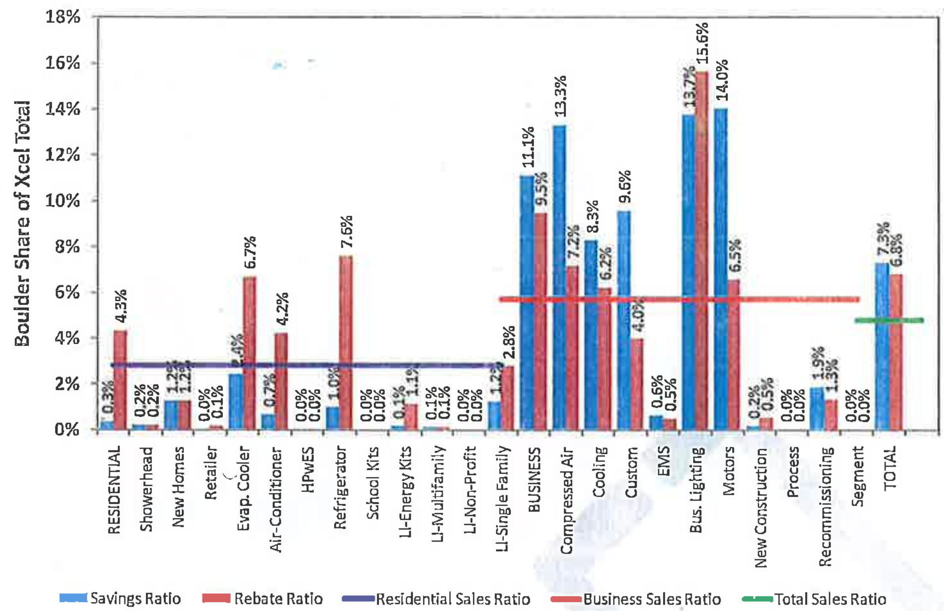
2009 Xcel Electric Energy Efficiency Activity in Boulder



7.2.5.2 How Does Boulder Participation Compare to Participation in the Rest of Xcel?

Overall, Boulder customers, who consume less than 5 percent of Xcel's Colorado sales, represented around 7 percent of Xcel's 2009 savings and rebate spending. Boulder business customers, who consume under 6 percent of sales, represent over 11 percent of total savings and almost 10 percent of rebate spending. Residential customers, who consume less than 3 percent of total sales, represent over 4 percent of rebate spending, but less than one percent of savings.

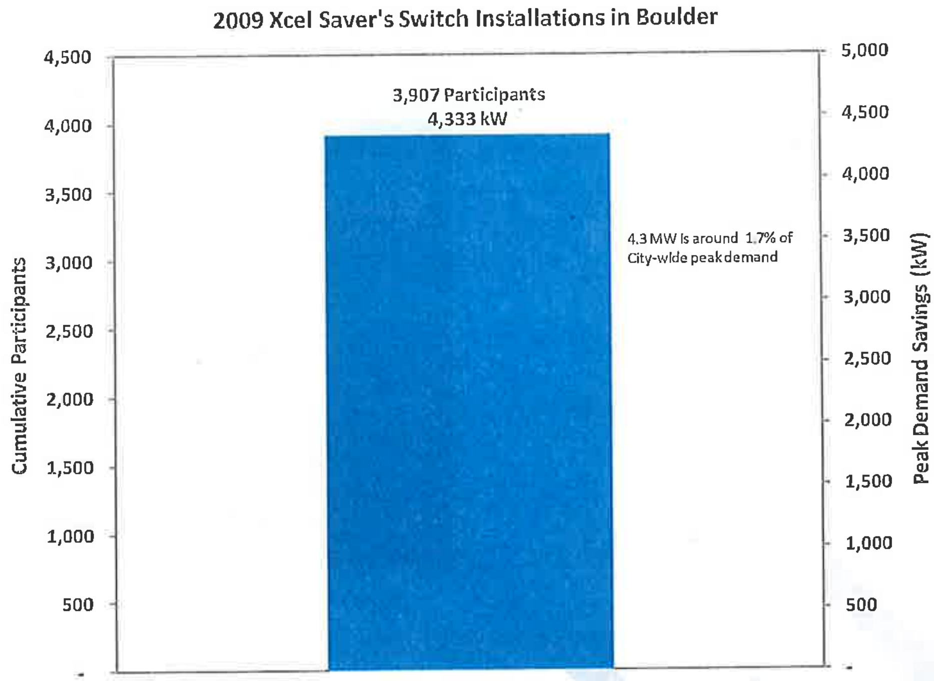
2009 Boulder Electric Energy Efficiency Activity as Share of Xcel Total
(Excludes Residential Lighting; Energy Assessments)



7.2.6 Xcel Load Management in Boulder

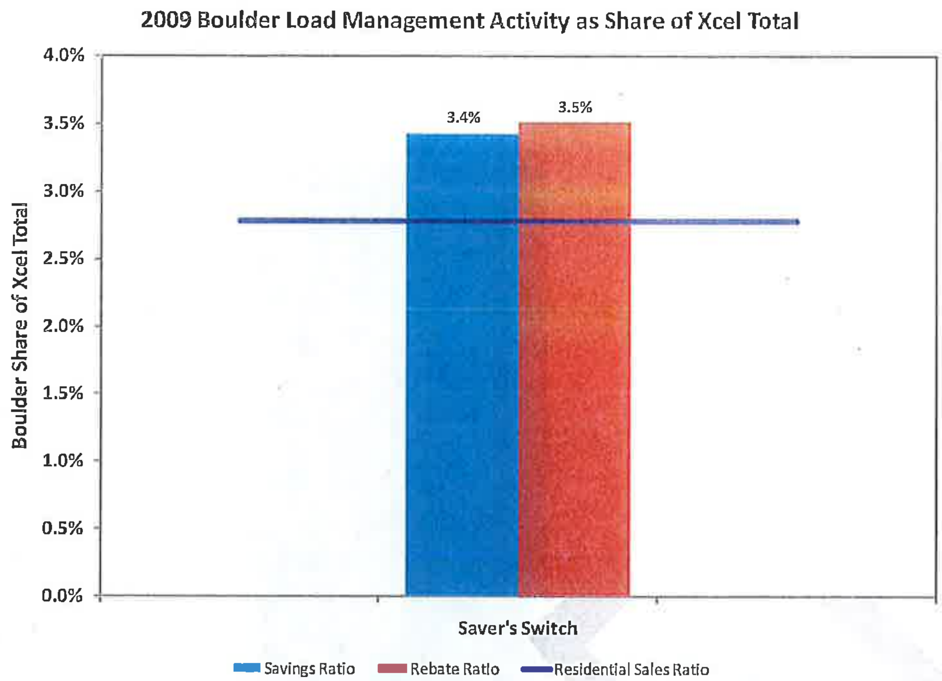
7.2.6.1 How Much Residential Load Management Is Installed In Boulder?

In 2009, over 3,900 customers participated in Saver's Switch, Xcel's residential load management program, creating the potential to provide over 4.3 MW in system peak savings.



7.2.6.2 How Does Boulder Participation Compare to Participation in the Rest of Xcel?

Residential customers, who consume less than 3 percent of total sales, represent over 3 percent of Xcel's Saver's switch participants.



7.3 RENEWABLE ENERGY PROGRAMS

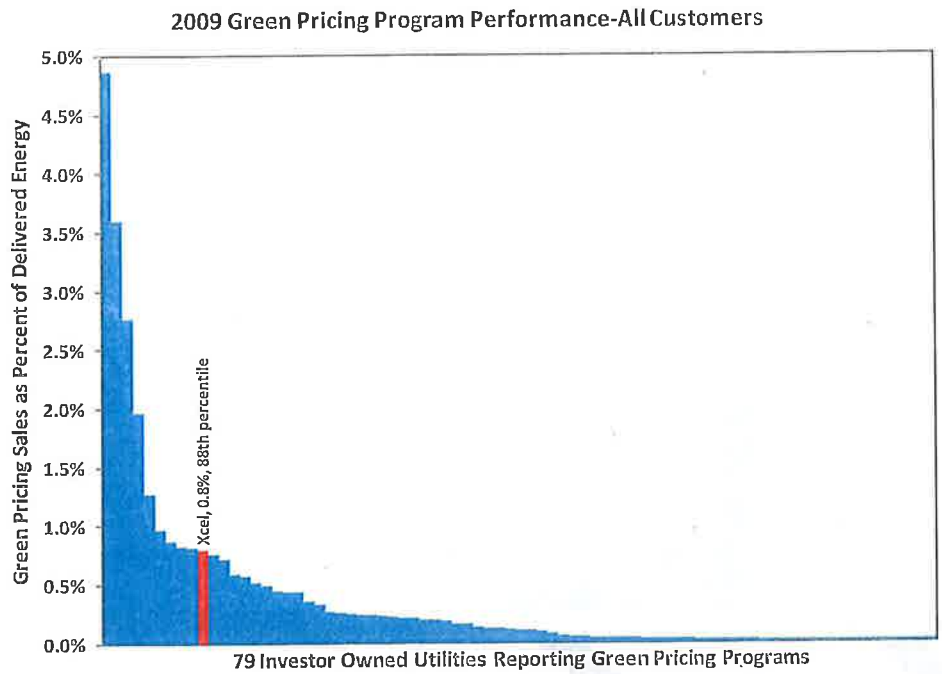
7.3.1 Windsource, Xcel's Green Pricing Program

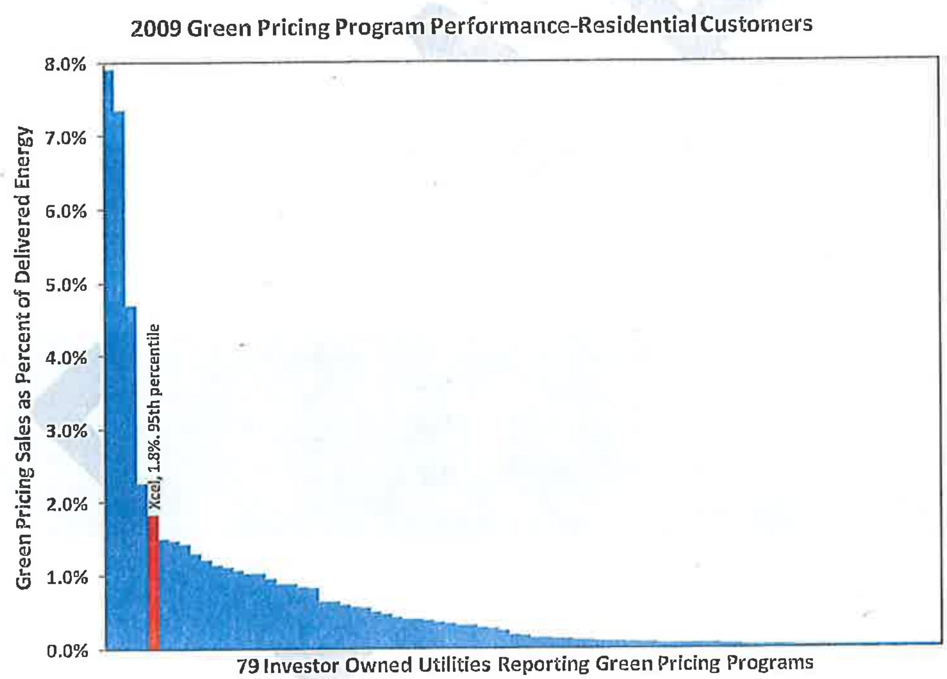
7.3.1.1 How Much of Xcel's Sales Come from Windsource?

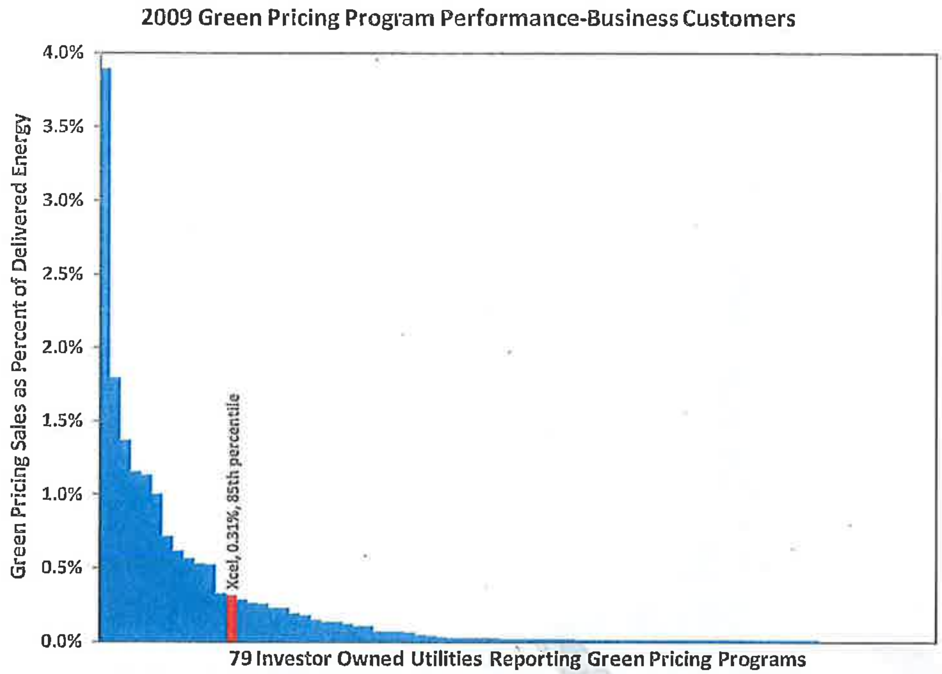
Section to be completed in final report, including a time series of Windsource savings.

7.3.1.2 How Does Windsource Compare to Green Pricing Programs at Other Utilities?

Reports that utilities file with EIA identified 79 investor-owned utilities that offered green pricing programs like Xcel's Windsource program in 2009. Participants in Xcel's program purchased 0.8% of Xcel's total retail sales, which ranked tenth among all reported programs (88^{th} percentile). Xcel's residential program ranked fifth (95^{th} percentile).


2009 Green Pricing Program Performance-All Customers
5.0%
4.5%
4.0%
3.5%
3.0%
2.5%
2.0%
1.5%
1.0%
0.5%
0.0%
Green Pricing Sales as Percent of Delivered Energy
Xcel, 0.8%, 88th percentile
79 Investor Owned Utilities Reporting Green Pricing Programs


2009 Green Pricing Program Performance-Residential Customers
8.0%
7.0%
6.0%
5.0%
4.0%
3.0%
2.0%
1.0%
0.0%
Green Pricing Sales as Percent of Delivered Energy
Xcel, 1.8%. 95th percentile
79 Investor Owned Utilities Reporting Green Pricing Programs



7.3.2 Solar Rewards, Xcel's On-Site Renewable Program

In response to a data request from the city, Xcel provided information on participation in the Solar Rewards program through November of 2010.

7.3.2.1 How Many Solar Installations Does Xcel have on its Colorado System?

Near the end of 2010, Xcel's Solar Rewards program included 7,239 systems with over 48 megawatts of installed capacity. These systems have the capacity to generate over 0.2% of Xcel's 2010 retail sales.

	Installed Systems[1]	Installed MW	Expected Annual Generation (MWh)	Total Customer Sales (MWh)	PV Generation as % of Sales
Xcel Total					
Small Customer Owned	6,669	34	48,240		
Small Third Party	349	2	2,774		
Medium	221	12	16,041		
Total	7,239	48	67,055	28,298,643	0.2%

7.3.2.2 How Does Solar Rewards Compare to On-Site Renewable Programs at Other Utilities?

Section to be completed for final report.

7.3.3 Boulder Renewable Energy Programs

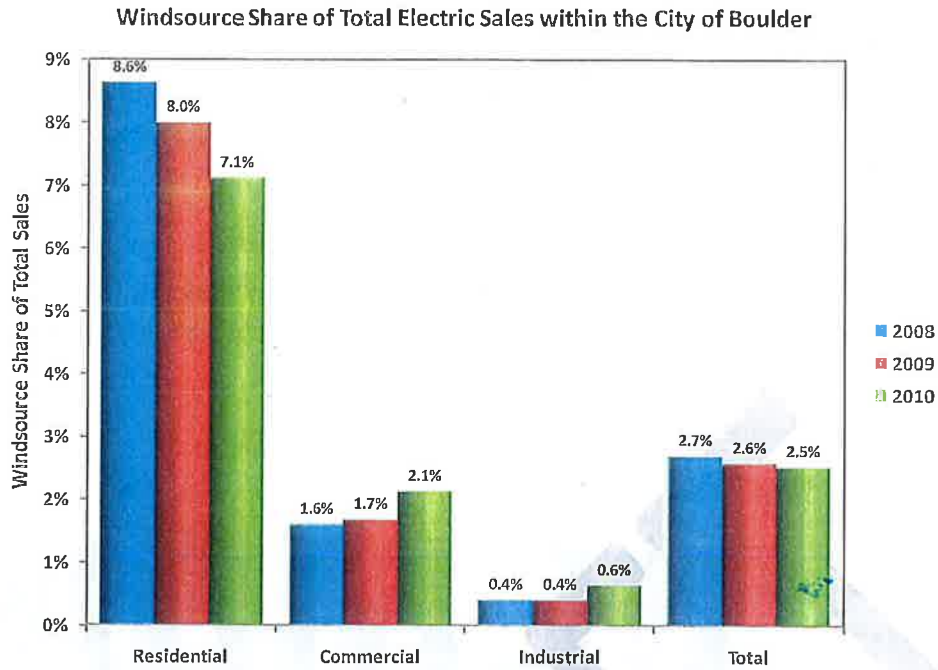
Boulder's GHG inventory documents overall participation in Windsource going back to 1990. In more recent years, Xcel provides additional detail on Windsource participation in its monthly CAP tax reports.

7.3.3.1 How Much of Boulder's Sales Come From Windsource?

Windsource purchases represent between 2 and 3 percent of Boulder's total sales going back to 1999, the first year of program operation. In 2010, Windsource participants purchased 2.5 percent of city-wide sales.

7.3.3.2 How do Boulder Windsource Sales Vary by Sector?

Residential Windsource participants represent a much higher percentage of retail sales, purchasing over 7 percent of residential sales in 2010.



7.3.3.3 How Does Boulder's Windsource Participation Compare to Xcel Overall Participation?

Section to be completed for final report.

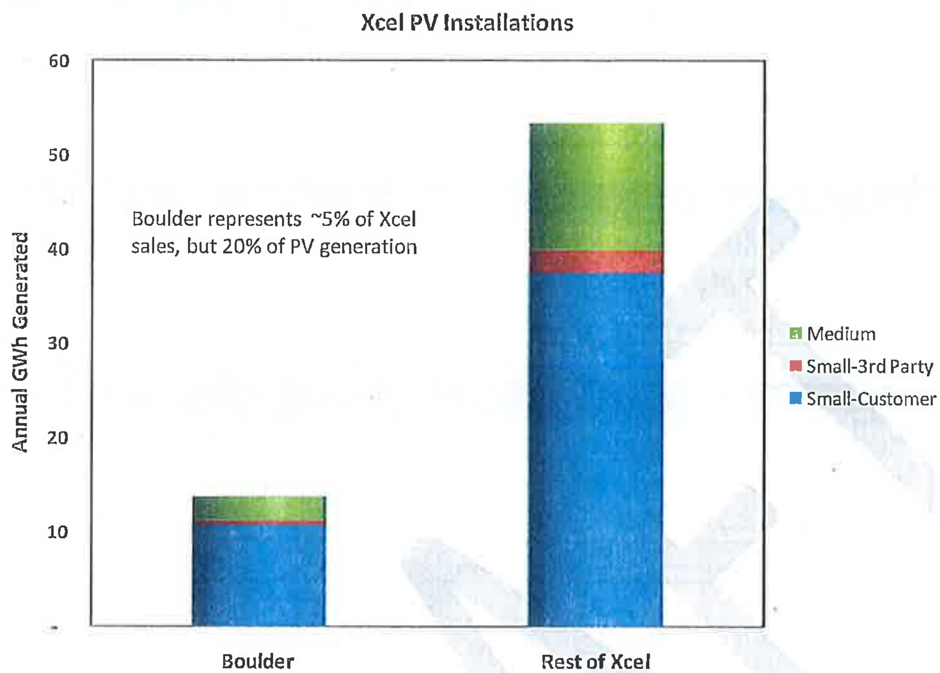
7.3.3.4 How Do Boulder's Solar Rewards Installations Compare to Total Sales?

Through November 2010, almost 1,700 solar systems had been installed on Boulder customer facilities through the Solar Rewards program, representing 10 MW of installed capacity. These systems have the capacity to generate over 1 percent of Boulder retail sales.

	Installed Systems[1]	Installed MW	Expected Annual Generation (MWh)	Total Customer Sales (MWh)	PV Generation as % of Sales
Xcel Total					
Small Customer Owned	6,669	34	48,240		
Small Third Party	349	2	2,774		
Medium	221	12	16,041		
Total	7,239	48	67,055	28,298,643	0.2%
Boulder					
Small Customer Owned	1,610	8	10,758		
Small Third Party	35	0	374		
Medium	43	2	2,589		
Total	1,688	10	13,721	1,355,984	1.0%
Boulder as % of Total					
Small Customer Owned	24%	23%	22%		
Small Third Party	10%	14%	13%		
Medium	19%	16%	16%		
Total	23%	21%	20%	5%	

7.3.3.5 How Do Boulder Installations Compare to Installations in the Rest of Xcel?

Overall, Boulder customers, who consume less than 5 percent of Xcel's Colorado sales, represent over 20 percent of Xcel's Solar Rewards energy generation.



8.1 OVERVIEW OF RELIABILITY MEASUREMENTS AND METRICS

The electric utility industry has developed several performance measures of reliability based on outage duration, frequency of outages, system availability, and response time. System reliability depends on sustained interruptions and momentary interruptions. For the assessment of PSCo's system reliability, the following performance measures were used; SAIDI, SAIFI, CAIDI, ECT, and ERT.

8.1.1 SAIDI

SAIDI is the system average interruption duration index. It indicates average minutes of interruption/customer. According to IEEE, "SAIDI is the best indicator of system stresses beyond those that utility's staff builds, design, and operate to minimize."

SAIDI is calculated as SUM TOTAL OF CUSTOMER MINUTES INTERRUPTED/TOTAL NUMBER OF CUSTOMERS SERVED. It is generally calculated on monthly or annual basis. However, it can also be calculated daily, or for any other time period.

PSCo uses SAIDI–ODI (ordinary distribution interruptions) as a reliability index. SAIDI – ODI represents those events that utility staff can respond to without crisis mode operations. It conforms to IEEE 1366-2003 . By excluding the major events from the SAIDI, the SAIDI-ODI ensures that the utility is tracking the real changes in the reliability indices, and not chasing unusual events like hurricanes, tornadoes, and floods.

PSCo benchmarks the SAIDI-ODI values for its nine regions against a Reliability Warning Threshold (RWT) based on historical SAIDI-ODI values calculated for each region, per docket 05A-288E. PSCo calculates and reports SAIDI-ODI monthly and annually, and updates the RWT annually . A warning is triggered when the SAIDI-ODI value exceeds the RWT in a year. SAIDI-ODI exceeding the RWT two years in a row triggers bill credits for the affected region. In this section, all references to SAIDI indicate SAIDI-ODI, with the SAIDI value given in minutes.

8.1.2 SAIFI

SAIFI is the system average interruption frequency index. It measures how often an average customer experiences a sustained interruption. SAIFI is calculated as TOTAL NUMBER OF SUSTAINED INTERRUPTIONS/TOTAL NUMBER OF CUSTOMERS SERVED.

8.1.3 CAIDI

CAIDI is the customer average interruption duration index. Once an outage occurs, CAIDI provides the average time to restore service. CAIDI is calculated as TOTAL DURATION OF SUSTAINED INTERRUPTIONS/TOTAL NUMBER OF SUSTAINED INTERRUPTIONS. By definition, CAIDI equals SAIDI/SAIFI.

8.1.4 ECT

ECT is the electric continuity threshold. It measures the total number of customers experiencing more than 5 sustained electric service interruptions (SESI) excluding major event day interruptions (MEDI) and public damage interruptions (EPUBI) in a calendar year. PSCo will pay a single bill credit of $50 to each customer experiencing interruptions in excess of the ECT.

8.1.5 ERT

ERT is the electric restoration threshold. It measures the number of customers experiencing a sustained electric service interruption larger than 24 hours in duration in a calendar year, not counting the MEDI and EPUBI. PSCo pays a bill credit of $50 for each occurrence to each customer experiencing an interruption in excess of the ERT.

8.2 HISTORICAL RELIABILITY DATA

While lower values of these reliability indices generally indicate better system reliability, the numerical performance measures may not necessarily be significant by themselves. They are significant in terms of identifying a trend and relative performance when comparing a system against other utilities and industry average. To provide meaningful information, reliability data was collected from several utilities that include investor owned utilities and public power companies in Colorado and outside of Colorado. The IEEE benchmark reliability indices were reviewed for a comparison against Xcel Energy and other utilities across the nation. The American Public Power Association (APPA), an organization of 2,000 municipal and other publicly owned electric utilities, compiles reliability data for its members from data submitted to the U.S. Department of Energy, Energy Information Administration (EIA). In addition, publicly available APPA data which represents the mean of reliability indices for the 214 largest public power systems, was also reviewed.

These reliability index data are summarized in Table 8-1. Data pertaining to Colorado utilities in Table 8-1 are based on Xcel Energy PSCo's Electric Quality of Service Monitoring And Reporting Plan (QSMRP) for 2008 and 2009. The data sources for other utilities and benchmarks are developed from various resources including from IEEE and APPA , as listed in the Excel workbook provided as an attachment to this report.

The PSCo QSMRP reports reliability data for nine service areas in Colorado regions – namely, Boulder, Denver, Front Range, Greely, High Plains, Mountain, Northern Region, San Luis Valley, and Western Region. As requested by the City of Boulder, reliability data from Colorado Springs Utilities, Fort Collins, and Longmont are provided in Table 8-3. Also included is data on small medium and large size investor owned utilities and municipal/public power companies in this table for a national benchmark in Table 8-2. Additionally, these numbers are compared to IEEE and APPA benchmarks for 2009.

Table 8-1 Historical Reliability Indices

			2008					2009				
Entity	# of Customers	Ownership	SAIDI	SAIFI	CAIDI	ECT	ERT	SAIDI	SAIFI	CAIDI	ECT	ERT
Boulder Region	116,737	IOU (PSCO)	88.8	0.8	108.3	504.0	-	98.6	0.8	117.4	2,195.0	18
Colorado Springs	202,901	Muni	31.4	0.7				47.7	1.0			
DenverRegion	928,352	IOU (PSCO)	66.9	0.8	89.2	2,874.0	254.0	71.3	0.7	99.0	2,888.0	688
Fort Collins	70,410	Muni	10.0	0.3				11.0	0.5			
Longmont	45,000	Muni	29.2	0.4				23.8	0.3			
Front Range	16,811	IOU (PSCO)	98.6	1.0	97.6	0	0	124.1	0.8	165.5	0	0
Greely	54,634	IOU (PSCO)	29.4	0.4	75.4	0	0	48.2	0.6	77.7	0	0
High Plains	11,193	IOU (PSCO)	40.9	0.6	71.8	0	0	42.8	0.6	71.3	0	0
Mountain	34,274	IOU (PSCO)	97.1	0.8	117.0	0	0	79.1	0.8	94.2	0	0
Northern Region	26,329	IOU (PSCO)	96.5	1.1	86.2	37.0	0	62.8	0.6	106.4	37.0	0
San Luis Valley	22,125	IOU (PSCO)	36.4	0.3	140.0	0	0	47.6	0.5	99.2	0	0
Western Region	64,022	IOU (PSCO)	39.4	0.5	87.6	372.0	0	73.9	1.1	69.1	1,652.0	0
Bryan Texas Utility	46,718	Muni	22.9	0.3				13.6	0.3			
Portland General Electric	820,266	IOU						79.8	1.5	120.0		
Otter Tail Power Co.	129,500	IOU						74.0	1.3	56.9		
Pacific Power & Light	1,719,000	IOU						168.0	1.5	120.0		
APPA								69.0	0.9			
IEEE Median (Large Respondent)								118.5	1.0	107.6		
IEEE Median (Medium Respondent)								119.2	1.2	102.8		
IEEE Median (Small Respondent)								109.5	1.3	88.4		

8.3 RELIABILITY INDEX COMPARISON

The size of customer base and area are useful in the reliability analysis since the problems encountered in a large area with more diverse customer base are more complex compared to the smaller areas with smaller number of customers. Per IEEE definition, a small size utility typically has less than 100,000 customers, a medium size utility has customers more than 100,000 but less than a million. A large size utility generally is considered to have more than a million customers.

In Table 8-2 the Boulder region of PSCo is compared to four other medium sized utility regions, Colorado Springs, Denver, Portland General Electric, and Otter Tail service territories, and to median IEEE data on medium sized utility regions.

- SAIDI and SAIFI values for Boulder region are lower than the IEEE medians. SAIDI values for the Boulder region are higher than the four other medium sized utilities in this comparison table.

Table 8-2 2009 Reliability Comparison for Medium Sized Utility Regions

Entity	# of Customers	Ownership	SAIDI	SAIFI	CAIDI	ECT	ERT
Boulder Region	116,737	IOU (PSCO)	98.6	0.8	117.4	2,195.0	18
Colorado Springs	202,901	Municipal Utility	47.7	1.0			
DenverRegion	928,352	IOU (PSCO)	71.3	0.7	99.0	2,888.0	688
Portland General Electric	820,266	IOU	79.8	1.5	120.0		
Otter Tail Power Co.	129,500	IOU	74.0	1.3	56.9		
IEEE Median (Medium Respondent)	>100,000<1,000,000	National	119.2	1.2	102.8		

Table 8-3 2008 - 2009 Reliability Comparison for Colorado Utility Regions

Entity	# of Customers	Ownership	SAIDI08	SAIFI08	CAIDI08	ECT08	ERT08	SAIDI09	SAIF091	CAIDI09	ECT09	ERT09
Fort Collins	70,410	Muni	10.0	0.3				11.0	0.5			
Longmont	45,000	Muni	29.2	0.4				23.8	0.3			
Greely	54,634	IOU (PSCO)	29.4	0.4	75.4	0	0	48.2	0.6	77.7	0	0
Colorado Springs	202,901	Muni	31.4	0.7				47.7	1.0			
San Luis Valley	22,125	IOU (PSCO)	36.4	0.3	140.0	0	0	47.6	0.5	99.2	0	0
Western Region	64,022	IOU (PSCO)	39.4	0.5	87.6	372.0	0	73.9	1.1	69.1	1,652.0	0
High Plains	11,193	IOU (PSCO)	40.9	0.6	71.8	0	0	42.8	0.6	71.3	0	0
DenverRegion	928,352	IOU (PSCO)	66.9	0.8	89.2	2,874.0	254.0	71.3	0.7	99.0	2,888.0	688
Boulder Region	116,737	IOU (PSCO)	88.8	0.8	108.3	504.0	-	98.6	0.8	117.4	2,195.0	18
Northern Region	26,329	IOU (PSCO)	96.5	1.1	86.2	37.0	0	62.8	0.6	106.4	37.0	0
Mountain	34,274	IOU (PSCO)	97.1	0.8	117.0	0	0	79.1	0.8	94.2	0	0
Front Range	16,811	IOU (PSCO)	98.6	1.0	97.6	0	0	124.1	0.8	165.5	0	0

Table 8-3 provides comparison of reliability indices between the nine PSCo service regions (including Boulder) and the three public power companies (municipalities) in Colorado: Fort Collins, Longmont, and Colorado Springs.

- Boulder region's SAIDI reliability measure is in the middle three of Colorado's nine regions in 2008 and the high three regions for SAIDI in 2009.
- The three Colorado public power companies (municipalities) have lower SAIDI reliability measures in 2008 than all but one of the nine Colorado service regions and they have lower SAIDI reliability measures in 2009 than all nine service regions. This observation may be explained by pro-active measures taken by municipal utilities to maintain their distribution system.
- The reliability indices presented in this report represent the status of these indices for a period of two years. These data are not adequate for establishing historical trends.

Fort Collins Utilities reliability indices are the lowest in Colorado. The company's approach to reliability is to schedule mitigation measures when failures under a single protective device exceed 2 instances in a 2-year period as a means of supporting their SAIFI number. Fort Collins reviews the outages and protective device counts monthly. Their approach is designed to take care of problems on a tap level so that the reliability extends up to the system level. Fort Collins distribution system is 99% underground.

Longmont Power and Communications (LPC) has been an APPA award winner for safety and reliability among the public power companies over the years. It has the lowest SAIDI and SAIFI values only second to Fort Collins. LPC has a goal to restore service within one hour. From 2008 to date, the company has not had any interruptions lasting more than 24 hours. LPC tracks its SAIDI and SAIFI indices on a weekly basis and reports it to the management every month.

LPC analyzes unusual materials failures to determine the cause and takes steps to replace the material if a failure is found to adversely affect the reliability indices. LPC also replaces old devices on all three phases when one of them fails, particularly if the device is old. Numbers of cable failures (typically 10 to 12 a year) are closely monitored and replaced as needed. New materials and products are routinely reviewed to see if they have characteristics that make them less likely to fail.

Colorado Springs Utilities has an operational target for SAIDI to be under 50 and SAIFI to be less than 1. All the three public power companies are reported to have zero ECT and ERT. Five sustained interruptions in a calendar year are unusually high for them.

Numerous factors can contribute to differences in reliability indices between regions: Geographic location, population density, type of terrain, climate and weather differences are some of these factors, in addition to differences in transmission and distribution system design, age, and maintenance.

For example, long lines over rough terrain and stormy weather increase exposure to outages and affect reliability; a cause of long outages could be falling trees and branches or ice-weighted branches causing short circuits. The use of recloser/breaker with a reclosing relay at the substation has been demonstrated to reduce the SAIDI and SAIFI values in a paper by ABB on "The Effect of Loop Reconfiguration and Single Phase Tripping on Distribution System Reliability".[12]

Figure 8-1 and Figure 8-2 provide a visual comparison for SAIDI and SAIFI values of different utilities and industry medians. Lower SAIDI and SAIFI would appear to indicate improved performance in terms of both duration and frequency of interruptions. Caution should be observed when interpreting these indices. A larger CAIDI in indicates a longer average duration customer outage during an interruption. However, a smaller CAIDI does not rule out the possibility that the average customer may be experiencing many short duration outages, as would be shown by SAIDI and SAIFI.

[12] http://www05.abb.com/global/scot/scot235.nsf/veritydisplay/ce0cc4f93ec4e17f85256c41006a527f/$file/distribution%20system%20reliability.pdf

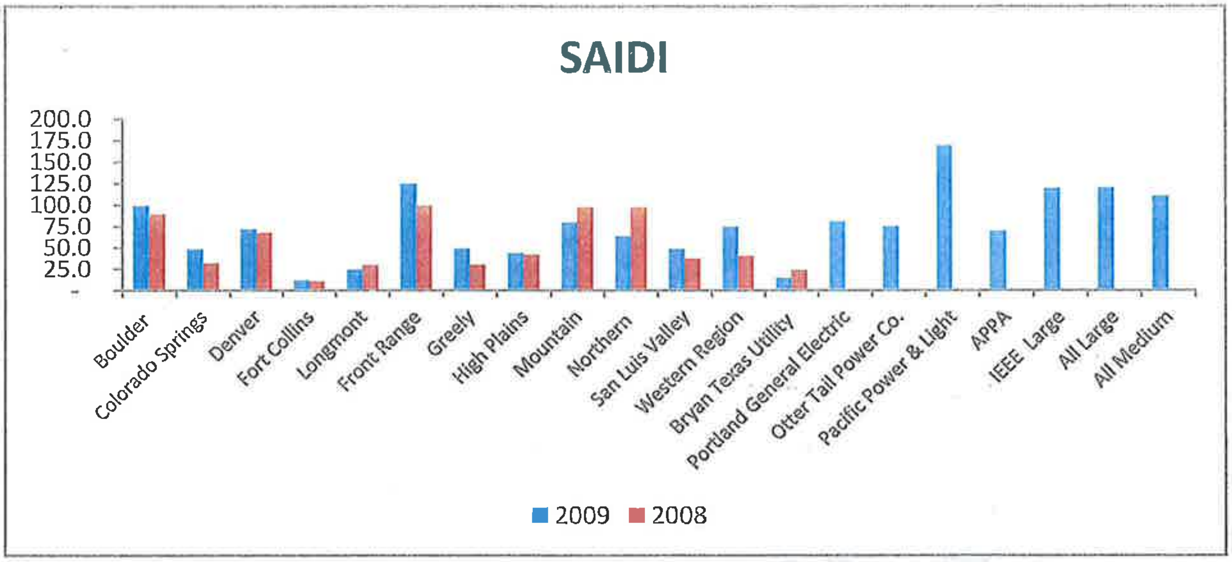


Figure 8-1 Utilities 2008 – 2009 SAIDI Comparison

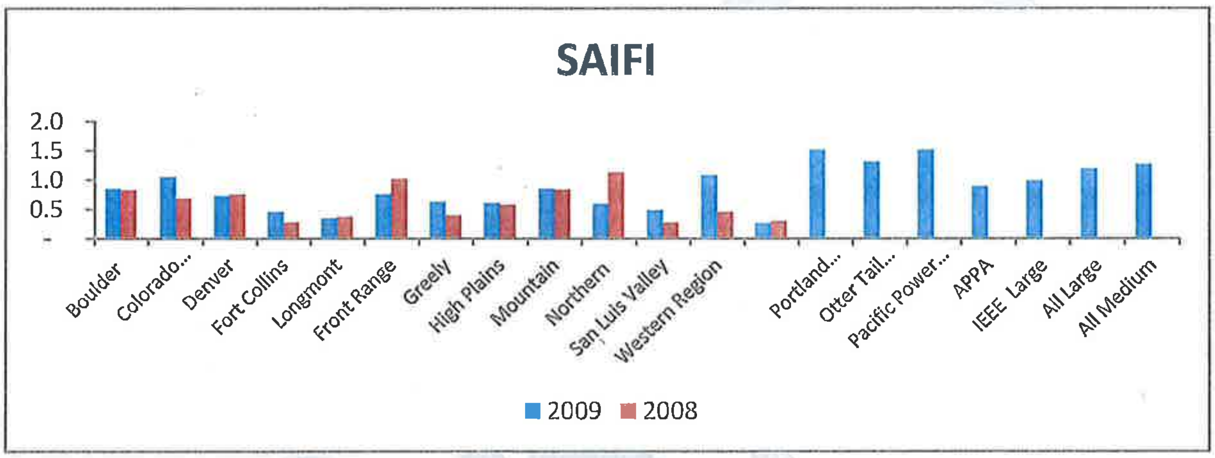


Figure 8-2 Utilities 2008 – 2009 SAIFI Comparison

9 COMPARISONS TO BENCHMARK CITIES

9.1 BOULDER BENCHMARK CITIES

To use as benchmarks in comparing city programs, resources, and other activities, Boulder has identified 10 other U.S. cities that contain large universities and which have similar populations. In this section, we compare electricity characteristics for Xcel's overall Colorado service territory to those for utilities serving Boulder's benchmark cities. As described in previous sections, data for Xcel's Colorado service territory may not be representative for the city of Boulder itself. However, this data represents the fairest comparison to other cities, especially other cities that are also served by large utilities. (For example, while we have documented in previous chapters that Boulder customers are more likely to participate in sustainable energy programs than other Xcel customers, it may also be true that customers from Santa Cruz, California are more likely to participate in sustainable energy programs than other PG&E customers.)

Where data was readily available, comparison data were developed for all 10 of the utilities serving the benchmark cities. However, where substantial data collection and analysis were required, benchmark data was limited to 8 comparison cities: each of the cities included in Table 9-1, with the exception of Provo, Utah, and Tempe, Arizona. Provo was excluded because there was relatively little data available. Tempe was excluded because its climate and electricity use characteristics are much different from Boulder's.

Table 9-1: Boulder Benchmark Cities

Benchmark City	Electric Utility	Acronym	Utility Ownership
Boulder, Colorado	**Xcel Energy**	**Xcel**	**Investor Owned**
Ann Arbor, Michigan	Detroit Edison	DECo	Investor Owned
Madison, Wisconsin	Madison Gas & Electric	MG&E	Investor Owned
Norman, Oklahoma	Oklahoma Gas & Electric	OG&E	Investor Owned
Santa Barbara, California	Southern California Edison	SCE	Investor Owned
Santa Cruz, California	Pacific Gas & Electric	PG&E	Investor Owned
Eugene, Oregon	Eugene Water & Electric Board	N/A	Municipal
Fort Collins, Colorado	Fort Collins Utilities	N/A	Municipal
Palo Alto, California	Palo Alto Utilities	N/A	Municipal
Provo, Utah	Provo Utilities	N/A	Municipal
Tempe, Arizona	Salt River Project	SRP	State Corporation

In the body of this chapter, data are presented in graphical format. Data tables supporting the graphs are presented in the Appendix and in additional spreadsheets provided to city staff.

Key references for this chapter include:

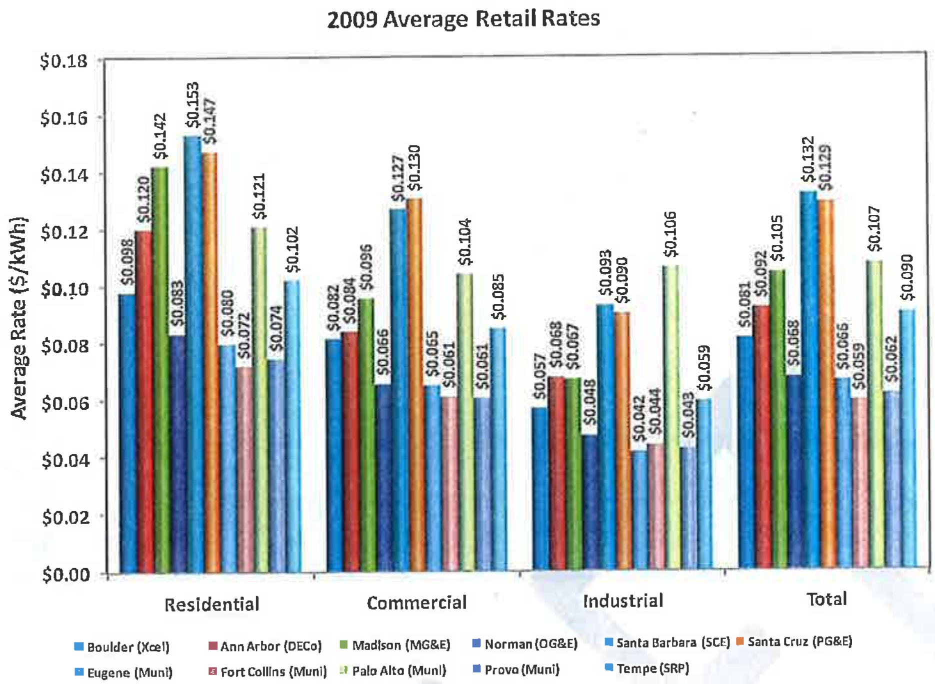
- Annual reports that Xcel and other utilities file with FERC;
- Annual reports that municipal utilities develop to document their operations and finances;
- Climate action plans for individual cities;
- An analysis to estimate the greenhouse gas emissions for each utility based on generation output from different fuel sources.

9.2 REVENUES, RATES, AND SALES

9.2.1 How Do Xcel's Electric Rates Compare to Utilities' Serving Benchmark Cities?

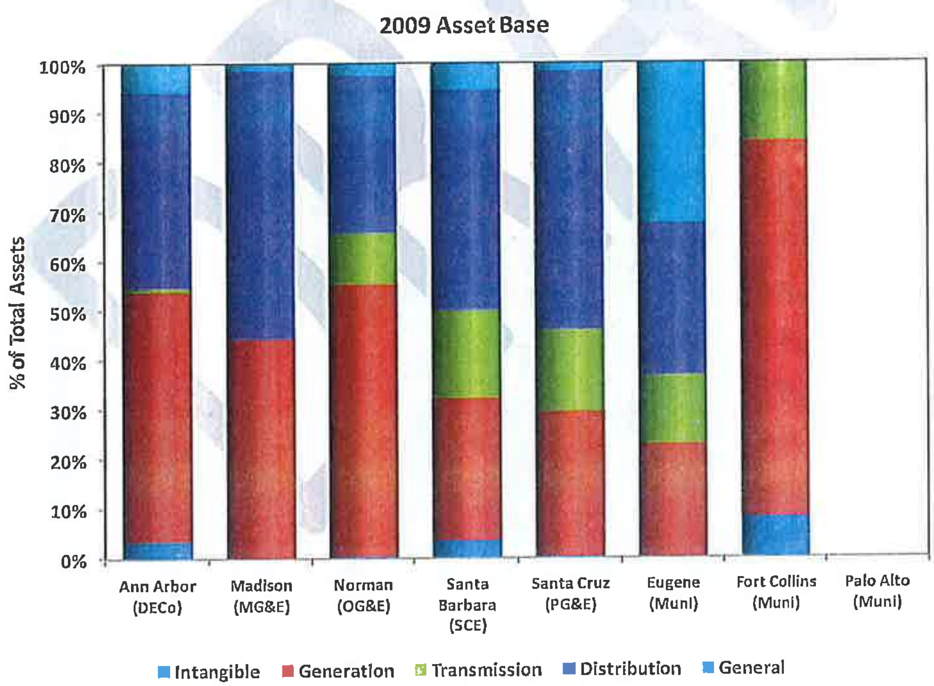
9.2.1.1 How Do Total Rates Compare?

9.2.1.2 How Do Rates Compare by Sector?



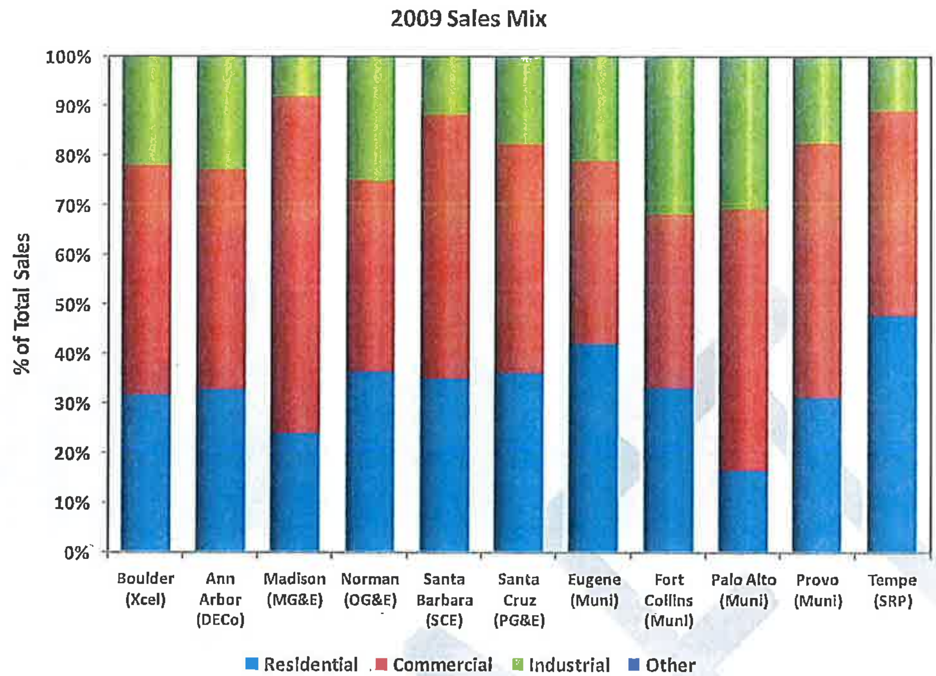
9.3 UNDERLYING COSTS

9.3.1 How Are Total Assets Distributed At Utilities Serving Benchmark Cities?



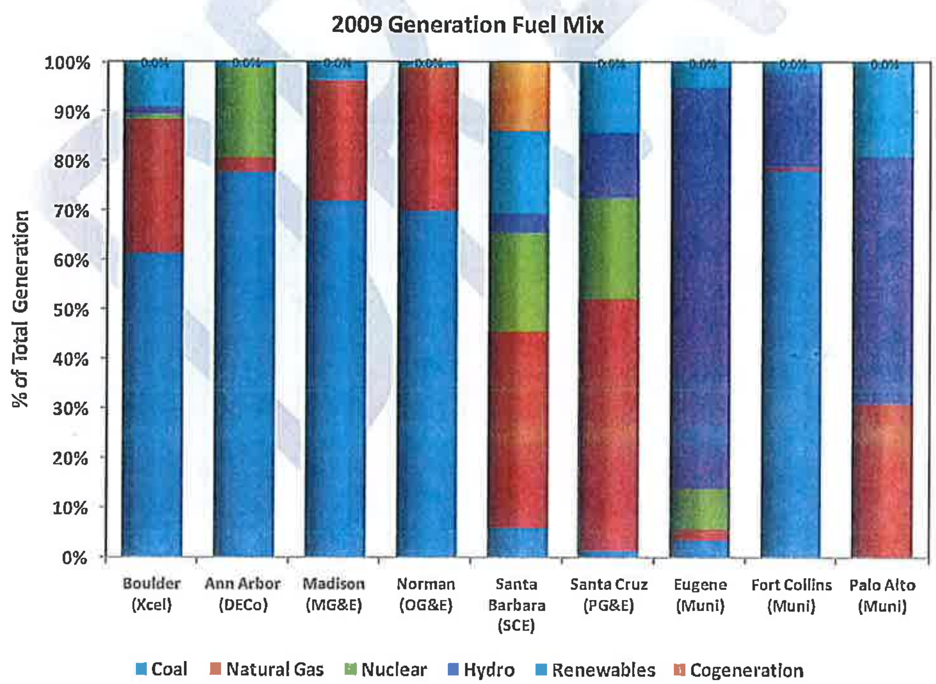
9.4 SALES AND LOADS

9.4.1.1 How Does Xcel's Sales Mix Compare to Utilities' Serving Benchmark Cities?

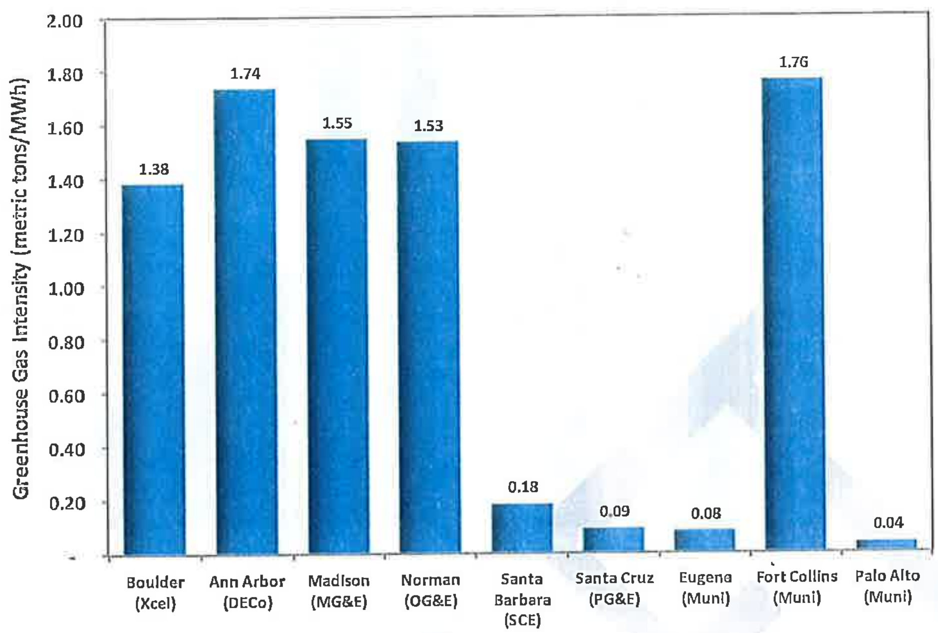


9.5 GENERATION SYSTEM

9.5.1 How Does Xcel's Fuel Mix Compare to Utilities' Serving Benchmark Cities?



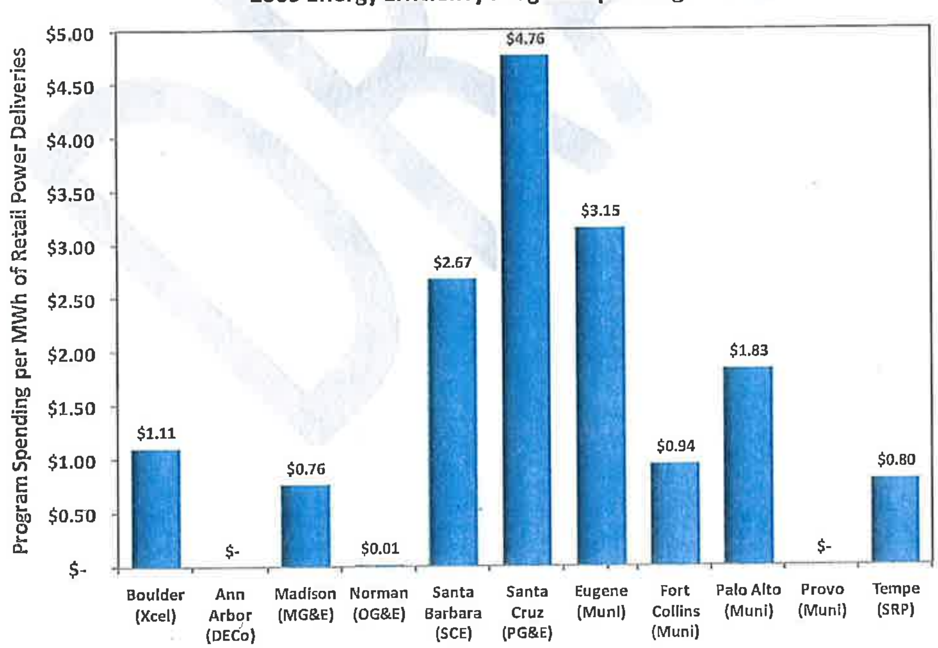
9.5.2 How Do Xcel's GHG Emissions Compare to Utilities' Serving Benchmark Cities?



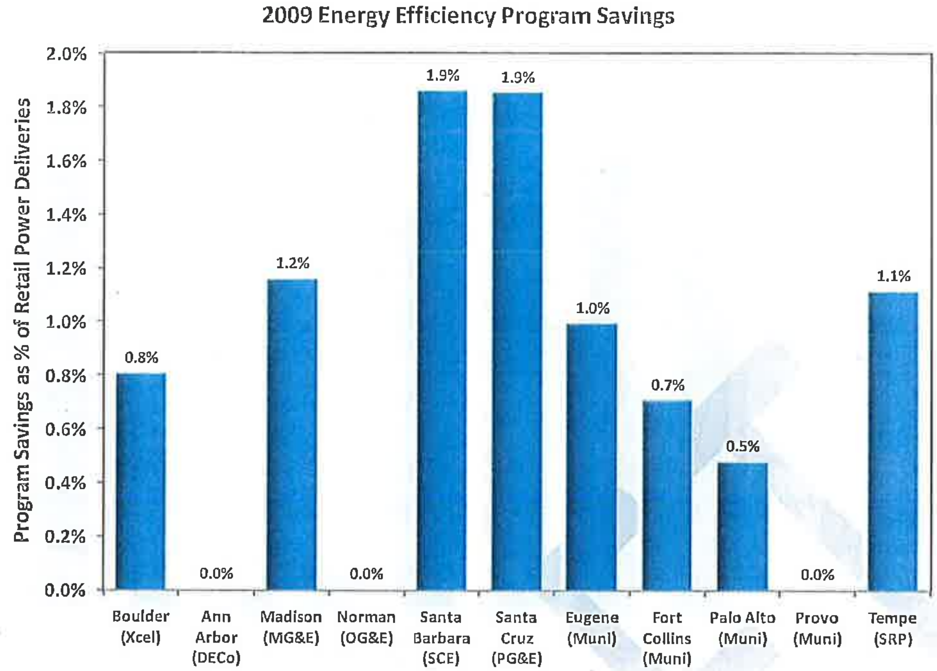
9.6 SUSTAINABLE ENERGY PROGRAMS

9.6.1 Energy Efficiency Programs

9.6.1.1 How Does Xcel's Program Spending Compare to Utilities' Serving Benchmark Cities?

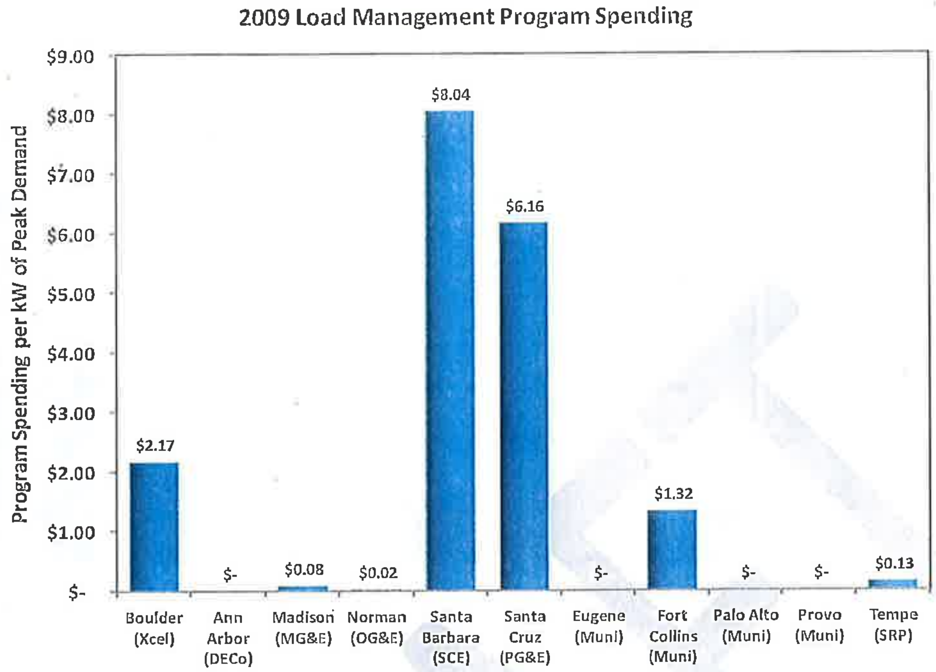


9.6.1.2 How Do Xcel's Program Savings Compare to Utilities' Serving Benchmark Cities?

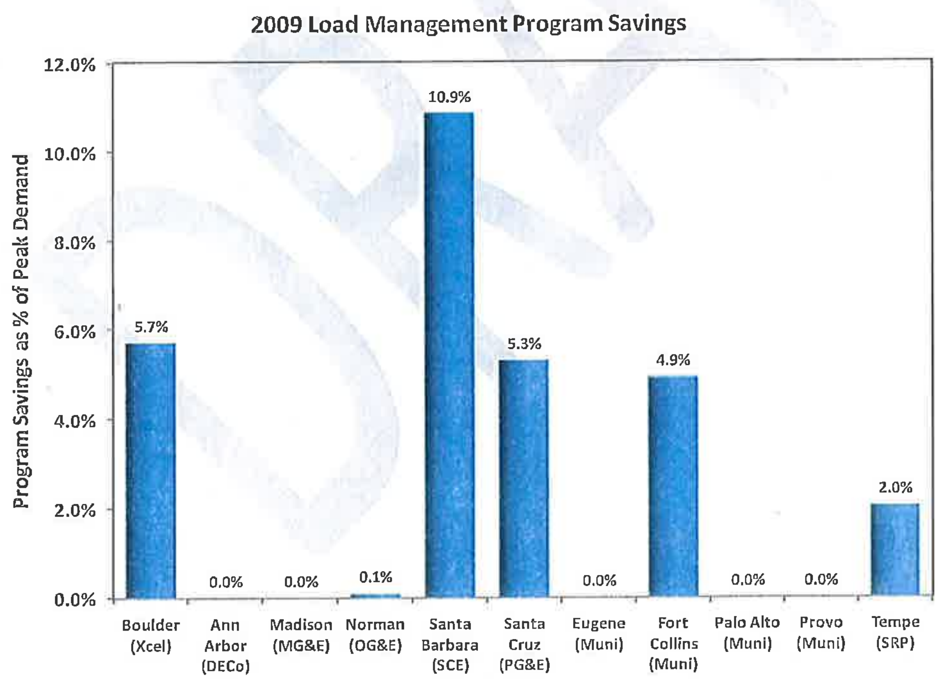


9.6.2 Load Management Programs

9.6.2.1 How Does Xcel's Program Spending Compare to Utilities' Serving Benchmark Cities

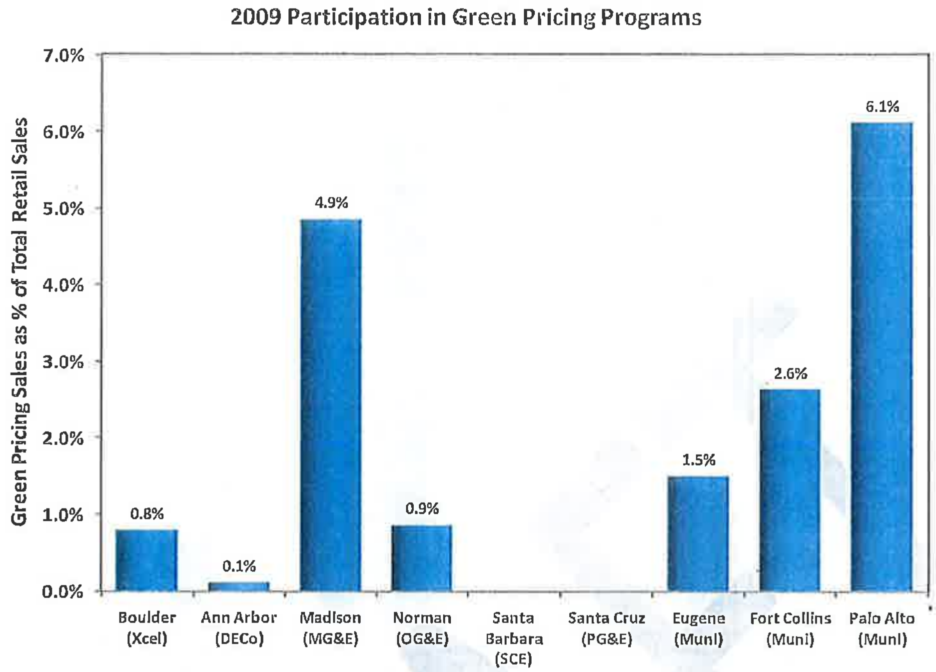


9.6.2.2 How Does Xcel's Program Savings Compare to Utilities' Serving Benchmark Cities



9.6.3 Green Pricing Programs

9.6.3.1 How Does Xcel's Program Participation Compare to Utilities' Serving Benchmark Cities



Appendix A — DETAILED DATA TABLES

This appendix provides a range of data used to develop the graphics presented in the body of the report. Additional data and calculations that are too voluminous to present here, but are being provided to city staff in spreadsheet format, include data and calculations supporting:

- Segmentation analysis developed to allocate total Boulder sales to residential and business customer segments, and to calculate average rates, bills, marginal costs, and operating margins for each segment.
- Tariff analysis developed to estimate energy and demand charges for each Xcel retail rate offering.
- Cost analysis developed to allocate Xcel's Colorado costs, assets, liabilities, and earnings among its three utility subsidiaries.
- Load shape analysis developed to estimate Boulder's overall load shape from component load shapes for each customer segment.
- Detailed data on costs and savings from Xcel's DSM programs in 2009 and 2010, including costs and savings from Boulder customers participating during 2009.
- Data used to compare Xcel's Colorado operations to those at investor-owned utilities located throughout the Unites States.

A.1 BOULDER ELECTRIC REVENUE, SALES, CUSTOMERS, RATES, BILLS, AND USAGE

Table A-1: Xcel Electric Revenue from the City of Boulder (thousands of nominal $)

	Residential	Commercial	Industrial	Other/ Streetlight	Business Total	Total
1990	$13,213	$26,208	$13,829	$478	$40,515	$53,728
1991	$13,926	$27,471	$14,136	$486	$42,093	$56,019
1992	$14,181	$29,214	$14,229	$531	$43,974	$58,155
1993	$14,909	$30,947	$11,558	$545	$43,050	$57,959
1994	$15,582	$30,476	$13,735	$588	$44,799	$60,381
1995	$16,396	$32,592	$11,521	$628	$44,741	$61,137
1996	$17,121	$31,990	$13,315	$689	$45,994	$63,115
1997	$17,029	$32,838	$11,881	$727	$45,445	$62,474
1998	$17,377	$33,779	$11,717	$813	$46,308	$63,685
1999	$17,559	$32,422	$11,182	$884	$44,488	$62,047
2000	$18,056	$34,541	$10,339	$1,031	$45,911	$63,967
2001	$17,689	$32,846	$10,154	$1,120	$44,120	$61,809
2002	N/A	N/A	N/A	N/A	N/A	N/A
2003	N/A	N/A	N/A	N/A	N/A	N/A
2004	$20,595	$37,948	$13,870	$869	$52,686	$73,281
2005	$22,353	$53,404	$8,813	$0	$62,217	$84,570
2006	$22,728	$56,645	$11,629	$0	$68,275	$91,003
2007	$23,593	$66,199	$0	$1	$66,200	$89,792
2008	$26,233	$79,168	$0	$981	$80,148	$106,382
2009	$24,218	$70,944	$706	$999	$72,649	$96,867
2010	$28,189	$83,487	$828	$1,134	$85,449	$113,638

Source: Xcel annual reports to city of Boulder

Sources:

Table A-2: Xcel Electric Revenue from the City of Boulder (thousands of constant 2010 $)

	Residential	Commercial	Industrial	Other/ Streetlight	Business Total	Total
1990	$22,043	$43,725	$23,072	$797	$67,594	$89,638
1991	$22,296	$43,981	$22,631	$779	$67,390	$89,686
1992	$22,041	$45,405	$22,115	$825	$68,344	$90,385
1993	$22,498	$46,700	$17,442	$823	$64,965	$87,462
1994	$22,927	$44,842	$20,209	$865	$65,915	$88,842
1995	$23,460	$46,632	$16,485	$898	$64,016	$87,476
1996	$23,794	$44,459	$18,505	$957	$63,921	$87,716
1997	$23,136	$44,613	$16,141	$988	$61,742	$84,878
1998	$23,246	$45,188	$15,674	$1,088	$61,950	$85,196
1999	$22,983	$42,436	$14,636	$1,157	$58,229	$81,211
2000	$22,864	$43,739	$13,092	$1,305	$58,137	$81,001
2001	$21,780	$40,442	$12,502	$1,379	$54,323	$76,103
2002	N/A	N/A	N/A	N/A	N/A	N/A
2003	N/A	N/A	N/A	N/A	N/A	N/A
2004	$23,774	$43,805	$16,010	$1,003	$60,818	$84,592
2005	$24,957	$59,627	$9,840	$0	$69,467	$94,424
2006	$24,583	$61,269	$12,579	$0	$73,848	$98,431
2007	$24,812	$69,620	$0	$1	$69,620	$94,432
2008	$26,569	$80,180	$0	$993	$81,173	$107,742
2009	$24,615	$72,108	$717	$1,016	$73,841	$98,455
2010	$28,189	$83,487	$828	$1,134	$85,449	$113,638

Source: Xcel annual reports to city of Boulder; historic inflation adjustments from U.S. Department of Labor.

Table A-3: Xcel Electric Sales to the City of Boulder (thousands kilowatt-hours)

	Residential	Commercial	Industrial	Other/ Streetlight	Business Total	Total
1990	183,317	470,549	314,332	3,721	788,602	971,919
1991	191,869	486,594	317,216	3,780	807,589	999,458
1992	191,739	513,848	324,569	3,869	842,286	1,034,025
1993	199,442	527,345	262,100	3,919	793,364	992,807
1994	203,447	529,453	287,879	3,942	821,274	1,024,721
1995	209,325	556,682	256,805	4,058	817,545	1,026,870
1996	216,500	558,171	319,876	4,022	882,068	1,098,569
1997	219,623	622,706	298,832	4,283	925,821	1,145,444
1998	223,748	643,921	291,216	5,230	940,367	1,164,115
1999	227,929	636,797	287,329	5,253	929,379	1,157,308
2000	238,545	659,504	264,393	6,933	930,831	1,169,376
2001	241,764	640,883	264,804	7,728	913,416	1,155,179
2002	245,836	647,815	278,192	8,078	934,084	1,179,920
2003	246,376	639,663	279,308	7,983	926,954	1,173,330
2004	237,882	578,076	278,376	16,056	872,508	1,110,390
2005	244,648	792,582	153,662	0	946,244	1,190,892
2006	247,551	808,557	218,468	0	1,027,025	1,274,576
2007	256,288	1,047,028	0	2	1,047,031	1,303,319
2008	250,034	1,053,907	0	4,372	1,058,278	1,308,313
2009	243,173	1,057,197	7,649	4,412	1,069,258	1,312,431
2010	248,150	1,095,337	7,925	4,572	1,107,834	1,355,984

Source: Xcel annual reports to city of Boulder; Xcel CAP Tax reports to city of Boulder.

Table A-4: Xcel Electric Customers in the City of Boulder

	Residential	Commercial	Industrial	Other/ Streetlight	Business Total	Total
1990	32,873	5,791	7	8	5,806	38,679
1991	33,923	6,010	7	8	6,025	39,948
1992	34,368	6,123	9	10	6,142	40,510
1993	34,837	6,183	9	10	6,202	41,039
1994	35,094	6,184	11	10	6,205	41,299
1995	35,511	6,087	13	11	6,111	41,622
1996	35,812	6,294	14	6	6,314	42,126
1997	35,790	6,416	13	7	6,436	42,226
1998	35,826	6,521	13	10	6,544	42,370
1999	36,230	6,646	13	10	6,669	42,899
2000	36,611	6,804	13	12	6,829	43,440
2001	36,649	6,880	13	12	6,905	43,554
2002	N/A	N/A	N/A	N/A	N/A	N/A
2003	N/A	N/A	N/A	N/A	N/A	N/A
2004	37,189	7,071	13	11	7,095	44,284
2005	40,556	7,340	8	0	7,348	47,904
2006	37,978	7,101	4	0	7,104	45,083
2007	38,567	7,207	0	1	7,208	45,775
2008	38,903	7,348	0	12	7,360	46,263
2009	39,260	7,820	2	13	7,835	47,095
2010	N/A	N/A	N/A	N/A	N/A	N/A

Source: Xcel annual reports to city of Boulder.

Table A-5: Xcel Average Electric Rates in the City of Boulder (nominal $/kWh)

	Residential	Commercial	Industrial	Other/ Streetlight	Business Total	Total
1990	$0.072	$0.056	$0.044	$0.128	$0.051	$0.055
1991	$0.073	$0.056	$0.045	$0.129	$0.052	$0.056
1992	$0.074	$0.057	$0.044	$0.137	$0.052	$0.056
1993	$0.075	$0.059	$0.044	$0.139	$0.054	$0.058
1994	$0.077	$0.058	$0.048	$0.149	$0.055	$0.059
1995	$0.078	$0.059	$0.045	$0.155	$0.055	$0.060
1996	$0.079	$0.057	$0.042	$0.171	$0.052	$0.057
1997	$0.078	$0.053	$0.040	$0.170	$0.049	$0.055
1998	$0.078	$0.052	$0.040	$0.155	$0.049	$0.055
1999	$0.077	$0.051	$0.039	$0.168	$0.048	$0.054
2000	$0.076	$0.052	$0.039	$0.149	$0.049	$0.055
2001	$0.073	$0.051	$0.038	$0.145	$0.048	$0.054
2002	N/A	N/A	N/A	N/A	N/A	N/A
2003	N/A	N/A	N/A	N/A	N/A	N/A
2004	$0.087	$0.066	$0.050	$0.054	$0.060	$0.066
2005	$0.091	$0.067	$0.057	N/A	$0.066	$0.071
2006	$0.092	$0.070	$0.053	N/A	$0.066	$0.071
2007	$0.092	$0.063	N/A	$0.271	$0.063	$0.069
2008	$0.105	$0.075	N/A	$0.224	$0.076	$0.081
2009	$0.100	$0.067	$0.092	$0.226	$0.068	$0.074
2010	$0.114	$0.076	$0.105	$0.248	$0.077	$0.084

Source: Calculated from annual revenues and sales.

Table A-6: Xcel Average Electric Rates in the City of Boulder (constant 2010 $/kWh)

	Residential	Commercial	Industrial	Other/ Streetlight	Business Total	Total
1990	$0.120	$0.093	$0.073	$0.214	$0.086	$0.092
1991	$0.116	$0.090	$0.071	$0.206	$0.083	$0.090
1992	$0.115	$0.088	$0.068	$0.213	$0.081	$0.087
1993	$0.113	$0.089	$0.067	$0.210	$0.082	$0.088
1994	$0.113	$0.085	$0.070	$0.219	$0.080	$0.087
1995	$0.112	$0.084	$0.064	$0.221	$0.078	$0.085
1996	$0.110	$0.080	$0.058	$0.238	$0.072	$0.080
1997	$0.105	$0.072	$0.054	$0.231	$0.067	$0.074
1998	$0.104	$0.070	$0.054	$0.208	$0.066	$0.073
1999	$0.101	$0.067	$0.051	$0.220	$0.063	$0.070
2000	$0.096	$0.066	$0.050	$0.188	$0.062	$0.069
2001	$0.090	$0.063	$0.047	$0.179	$0.059	$0.066
2002	N/A	N/A	N/A	N/A	N/A	N/A
2003	N/A	N/A	N/A	N/A	N/A	N/A
2004	$0.100	$0.076	$0.058	$0.062	$0.070	$0.076
2005	$0.102	$0.075	$0.064	N/A	$0.073	$0.079
2006	$0.099	$0.076	$0.058	N/A	$0.072	$0.077
2007	$0.097	$0.066	N/A	$0.285	$0.066	$0.072
2008	$0.106	$0.076	N/A	$0.227	$0.077	$0.082
2009	$0.101	$0.068	$0.094	$0.230	$0.069	$0.075
2010	$0.114	$0.076	$0.105	$0.248	$0.077	$0.084

Source: Historic inflation from U.S. Department of Labor.

Table A-7: Average Annual Xcel Electric Bills in the City of Boulder (nominal $/customer/year)

	Residential	Commercial	Industrial	Other/ Streetlight	Business Total	Total
1990	$402	$4,526	$1,975,560	$59,742	$6,978	$1,389
1991	$411	$4,571	$2,019,371	$60,812	$6,986	$1,402
1992	$413	$4,771	$1,580,982	$53,069	$7,160	$1,436
1993	$428	$5,005	$1,284,227	$54,525	$6,941	$1,412
1994	$444	$4,928	$1,248,604	$58,772	$7,220	$1,462
1995	$462	$5,354	$886,264	$57,081	$7,321	$1,469
1996	$478	$5,083	$951,093	$114,757	$7,284	$1,498
1997	$476	$5,118	$913,917	$103,838	$7,061	$1,480
1998	$485	$5,180	$901,290	$81,299	$7,076	$1,503
1999	$485	$4,878	$860,151	$88,393	$6,671	$1,446
2000	$493	$5,077	$795,321	$85,907	$6,723	$1,473
2001	$483	$4,774	$781,068	$93,366	$6,390	$1,419
2002	N/A	N/A	N/A	N/A	N/A	N/A
2003	N/A	N/A	N/A	N/A	N/A	N/A
2004	$554	$5,367	$1,066,891	$78,990	$7,426	$1,655
2005	$551	$7,276	$1,101,659	N/A	$8,467	$1,765
2006	$598	$7,977	$3,322,695	N/A	$9,610	$2,019
2007	$612	$9,185	N/A	$668	$9,184	$1,962
2008	$674	$10,774	N/A	$81,719	$10,890	$2,299
2009	$617	$9,072	$352,902	$76,865	$9,272	$2,057
2010	N/A	N/A	N/A	N/A	N/A	N/A

Source: Calculated from annual revenues and customers.

Table A-8: Average Annual Xcel Electric Bills in the City of Boulder (constant 2010 $/customer/year)

	Residential	Commercial	Industrial	Other/ Streetlight	Business Total	Total
1990	$671	$7,551	$3,295,966	$99,672	$11,642	$2,317
1991	$657	$7,318	$3,233,010	$97,359	$11,185	$2,245
1992	$641	$7,415	$2,457,182	$82,480	$11,127	$2,231
1993	$646	$7,553	$1,937,948	$82,280	$10,475	$2,131
1994	$653	$7,251	$1,837,150	$86,475	$10,623	$2,151
1995	$661	$7,661	$1,268,078	$81,673	$10,476	$2,102
1996	$664	$7,064	$1,321,807	$159,486	$10,124	$2,082
1997	$646	$6,953	$1,241,651	$141,074	$9,593	$2,010
1998	$649	$6,930	$1,205,715	$108,760	$9,467	$2,011
1999	$634	$6,385	$1,125,816	$115,695	$8,731	$1,893
2000	$625	$6,428	$1,007,112	$108,783	$8,513	$1,865
2001	$594	$5,878	$961,698	$114,958	$7,867	$1,747
2002	N/A	N/A	N/A	N/A	N/A	N/A
2003	N/A	N/A	N/A	N/A	N/A	N/A
2004	$639	$6,195	$1,231,561	$91,181	$8,572	$1,910
2005	$615	$8,124	$1,230,022	N/A	$9,454	$1,971
2006	$647	$8,628	$3,593,916	N/A	$10,395	$2,183
2007	$643	$9,660	N/A	$703	$9,659	$2,063
2008	$683	$10,912	N/A	$82,764	$11,029	$2,329
2009	$627	$9,221	$358,690	$78,126	$9,424	$2,091
2010	N/A	N/A	N/A	N/A	N/A	N/A

Source: Historic inflation from U.S. Department of Labor.

Table A-9: Average Annual Electric Consumption in the City of Boulder (kilowatt-hours/customer/year)

	Residential	Commercial	Industrial	Other/ Streetlight	Business Total	Total
1990	5,577	81,255	44,904,600	465,101	135,825	25,128
1991	5,656	80,964	45,316,514	472,525	134,040	25,019
1992	5,579	83,921	36,063,189	386,937	137,136	25,525
1993	5,725	85,289	29,122,244	391,910	127,921	24,192
1994	5,797	85,617	26,170,825	394,185	132,357	24,812
1995	5,895	91,454	19,754,256	368,935	133,783	24,671
1996	6,045	88,683	22,848,281	670,265	139,700	26,078
1997	6,136	97,055	22,987,075	611,824	143,850	27,127
1998	6,245	98,746	22,401,248	523,043	143,699	27,475
1999	6,291	95,817	22,102,243	525,336	139,358	26,978
2000	6,516	96,929	20,337,936	577,784	136,306	26,919
2001	6,597	93,152	20,369,573	643,971	132,283	26,523
2002	N/A	N/A	N/A	N/A	N/A	N/A
2003	N/A	N/A	N/A	N/A	N/A	N/A
2004	6,397	81,753	21,413,509	1,459,637	122,975	25,074
2005	6,032	107,981	19,207,789	N/A	128,776	24,860
2006	6,518	113,867	62,419,362	N/A	144,561	28,272
2007	6,645	145,279	N/A	2,467	145,260	28,472
2008	6,427	143,428	N/A	364,300	143,788	28,280
2009	6,194	135,191	3,824,402	339,421	136,472	27,868
2010	N/A	N/A	N/A	N/A	N/A	N/A

Source: Calculated from annual sales and customers.

A.2 XCEL ELECTRIC REVENUE, SALES, CUSTOMERS, RATES, BILLS, AND USAGE

Table A-10: Annual Electric Revenue in Colorado (thousands of nominal $)

	Residential	Business	Total
1990	$379,184	$701,679	$1,080,863
1991	$391,460	$717,165	$1,108,625
1992	$402,117	$722,068	$1,124,185
1993	$422,672	$746,012	$1,168,684
1994	$442,650	$774,008	$1,216,658
1995	$465,817	$810,115	$1,275,932
1996	$494,957	$823,603	$1,318,560
1997	$496,540	$806,866	$1,303,406
1998	$514,235	$829,747	$1,343,982
1999	$529,463	$846,136	$1,375,599
2000	$551,758	$869,136	$1,420,894
2001	$571,308	$886,787	$1,458,095
2002	$585,034	$899,977	$1,485,011
2003	$686,628	$1,097,917	$1,784,545
2004	$672,496	$1,116,917	$1,789,413
2005	$760,920	$1,282,405	$2,043,325
2006	$756,701	$1,291,498	$2,048,199
2007	$801,162	$1,308,956	$2,110,118
2008	$914,531	$1,558,926	$2,473,457
2009	$853,318	$1,373,359	$2,226,677
2010	$1,013,188	$1,601,200	$2,614,388

Source: EIA Form 861; PSCo 2010 FERC Form 1.

Table A-11: Annual Electric Revenue in Colorado (thousands of constant 2010 $)

	Residential	Business	Total
1990	$632,619	$1,170,660	$1,803,280
1991	$626,727	$1,148,180	$1,774,907
1992	$624,975	$1,122,247	$1,747,222
1993	$637,828	$1,125,761	$1,763,589
1994	$651,299	$1,138,847	$1,790,146
1995	$666,497	$1,159,124	$1,825,621
1996	$687,880	$1,144,624	$1,832,504
1997	$674,601	$1,096,212	$1,770,813
1998	$687,927	$1,110,008	$1,797,935
1999	$692,993	$1,107,473	$1,800,466
2000	$698,688	$1,100,583	$1,799,271
2001	$703,428	$1,091,865	$1,795,293
2002	$709,117	$1,090,858	$1,799,975
2003	$813,714	$1,301,127	$2,114,841
2004	$776,293	$1,289,309	$2,065,602
2005	$849,581	$1,431,828	$2,281,410
2006	$818,468	$1,396,919	$2,215,387
2007	$842,561	$1,376,594	$2,219,154
2008	$926,225	$1,578,859	$2,505,084
2009	$867,315	$1,395,886	$2,263,201
2010	$1,013,188	$1,601,200	$2,614,388

Source: Historic inflation from U.S. Department of Labor.

Table A-12: Annual Electric Sales in Colorado (megawatt-hours)

	Residential	Business	Total
1990	5,371,137	13,320,362	18,691,499
1991	5,512,784	13,392,145	18,904,929
1992	5,561,513	13,441,874	19,003,387
1993	5,776,320	13,746,764	19,523,084
1994	5,926,072	14,301,927	20,227,999
1995	6,085,375	14,636,292	20,721,667
1996	6,403,685	15,267,507	21,671,192
1997	6,539,488	15,448,373	21,987,861
1998	6,760,764	15,821,906	22,582,670
1999	7,052,920	16,284,687	23,337,607
2000	7,485,830	17,002,623	24,488,453
2001	7,673,558	17,451,786	25,125,344
2002	8,128,867	17,685,551	25,814,418
2003	8,251,118	17,594,844	25,845,962
2004	7,954,565	17,793,599	25,748,164
2005	8,389,592	18,091,213	26,480,805
2006	8,557,673	18,640,845	27,198,518
2007	8,903,904	19,181,983	28,085,887
2008	8,905,338	19,365,982	28,271,320
2009	8,704,558	18,654,680	27,359,238
2010	9,086,993	19,211,650	28,298,643

Source: EIA Form 861; PSCo 2010 FERC Form 1.

Table A-13: Electric Customers in Colorado

	Residential	Business	Total
1990	842,072	115,390	957,462
1991	848,446	115,634	964,080
1992	859,561	116,534	976,095
1993	868,596	148,484	1,017,080
1994	875,725	193,869	1,069,594
1995	895,957	196,124	1,092,081
1996	919,405	199,869	1,119,274
1997	939,583	203,422	1,143,005
1998	956,180	207,288	1,163,468
1999	981,590	213,257	1,194,847
2000	1,008,211	218,365	1,226,576
2001	1,030,031	222,359	1,252,390
2002	1,049,670	208,431	1,258,101
2003	1,066,468	211,057	1,277,525
2004	1,084,722	212,715	1,297,437
2005	1,086,358	209,842	1,296,200
2006	1,103,578	207,968	1,311,546
2007	1,120,333	208,595	1,328,928
2008	1,133,153	208,465	1,341,618
2009	1,146,242	209,773	1,356,015
2010	1,156,123	210,025	1,366,148

Source: EIA Form 861; PSCo 2010 FERC Form 1.

Table A-14: Average Electric Rates in Colorado (nominal $/kWh)

	Residential	Business	Total
1990	$0.071	$0.053	$0.058
1991	$0.071	$0.054	$0.059
1992	$0.072	$0.054	$0.059
1993	$0.073	$0.054	$0.060
1994	$0.075	$0.054	$0.060
1995	$0.077	$0.055	$0.062
1996	$0.077	$0.054	$0.061
1997	$0.076	$0.052	$0.059
1998	$0.076	$0.052	$0.060
1999	$0.075	$0.052	$0.059
2000	$0.074	$0.051	$0.058
2001	$0.074	$0.051	$0.058
2002	$0.072	$0.051	$0.058
2003	$0.083	$0.062	$0.069
2004	$0.085	$0.063	$0.069
2005	$0.091	$0.071	$0.077
2006	$0.088	$0.069	$0.075
2007	$0.090	$0.068	$0.075
2008	$0.103	$0.080	$0.087
2009	$0.098	$0.074	$0.081
2010	$0.111	$0.083	$0.092

Source: Calculated from revenues and sales.

Table A-15: Average Electric Rates in Colorado (constant 2010 $/kWh)

	Residential	Business	Total
1990	$0.118	$0.088	$0.096
1991	$0.114	$0.086	$0.094
1992	$0.112	$0.083	$0.092
1993	$0.110	$0.082	$0.090
1994	$0.110	$0.080	$0.088
1995	$0.110	$0.079	$0.088
1996	$0.107	$0.075	$0.085
1997	$0.103	$0.071	$0.081
1998	$0.102	$0.070	$0.080
1999	$0.098	$0.068	$0.077
2000	$0.093	$0.065	$0.073
2001	$0.092	$0.063	$0.071
2002	$0.087	$0.062	$0.070
2003	$0.099	$0.074	$0.082
2004	$0.098	$0.072	$0.080
2005	$0.101	$0.079	$0.086
2006	$0.096	$0.075	$0.081
2007	$0.095	$0.072	$0.079
2008	$0.104	$0.082	$0.089
2009	$0.100	$0.075	$0.083
2010	$0.111	$0.083	$0.092

Source: Calculated from revenues and sales.

Table A-16: Average Annual Electric Bills in Colorado (nominal $/customer/year)

	Residential	Business	Total
1990	$450	$6,081	$1,129
1991	$461	$6,202	$1,150
1992	$468	$6,196	$1,152
1993	$487	$5,024	$1,149
1994	$505	$3,992	$1,137
1995	$520	$4,131	$1,168
1996	$538	$4,121	$1,178
1997	$528	$3,966	$1,140
1998	$538	$4,003	$1,155
1999	$539	$3,968	$1,151
2000	$547	$3,980	$1,158
2001	$555	$3,988	$1,164
2002	$557	$4,318	$1,180
2003	$644	$5,202	$1,397
2004	$620	$5,251	$1,379
2005	$700	$6,111	$1,576
2006	$686	$6,210	$1,562
2007	$715	$6,275	$1,588
2008	$807	$7,478	$1,844
2009	$744	$6,547	$1,642
2010	$876	$7,624	$1,914

Source: Calculated from revenues and customers.

Table A-17: Average Annual Electric Bills in Colorado (constant 2010 $/customer/year)

	Residential	Business	Total
1990	$751	$10,145	$1,883
1991	$739	$9,929	$1,841
1992	$727	$9,630	$1,790
1993	$734	$7,582	$1,734
1994	$744	$5,874	$1,674
1995	$744	$5,910	$1,672
1996	$748	$5,727	$1,637
1997	$718	$5,389	$1,549
1998	$719	$5,355	$1,545
1999	$706	$5,193	$1,507
2000	$693	$5,040	$1,467
2001	$683	$4,910	$1,433
2002	$676	$5,234	$1,431
2003	$763	$6,165	$1,655
2004	$716	$6,061	$1,592
2005	$782	$6,823	$1,760
2006	$742	$6,717	$1,689
2007	$752	$6,599	$1,670
2008	$817	$7,574	$1,867
2009	$757	$6,654	$1,669
2010	$876	$7,624	$1,914

Source: Calculated from revenues and customers.

Table A-18: Average Annual Electric Consumption in Colorado (kWh/customer/year)

	Residential	Business	Total
1990	6,378	115,438	19,522
1991	6,498	115,815	19,609
1992	6,470	115,347	19,469
1993	6,650	92,581	19,195
1994	6,767	73,771	18,912
1995	6,792	74,628	18,974
1996	6,965	76,388	19,362
1997	6,960	75,942	19,237
1998	7,071	76,328	19,410
1999	7,185	76,362	19,532
2000	7,425	77,863	19,965
2001	7,450	78,485	20,062
2002	7,744	84,851	20,519
2003	7,737	83,365	20,231
2004	7,333	83,650	19,845
2005	7,723	86,213	20,430
2006	7,754	89,633	20,738
2007	7,948	91,958	21,134
2008	7,859	92,898	21,073
2009	7,594	88,928	20,176
2010	7,860	91,473	20,714

Source: Calculated from sales and customers.

A.3 DATA FROM XCEL CLEAN AIR-CLEAN JOBS PLAN

Table A-19: Xcel Projections from Clean Air-Clean Jobs Plan

	Generation (GWh)	Sales (GWh)	Emissions (thousand tons)	Emissions (lb/kWh sales)	Average Rates w/ Carbon (cents/kWh)	Average Rates wo/ Carbon (cents/kWh)
2010	33,398	32,038	31,860	1.989	9.4	9.4
2011	33,224	31,871	31,315	1.965	9.8	9.8
2012	31,980	30,678	27,963	1.823	10.1	10.1
2013	32,292	30,977	27,325	1.764	10.4	10.4
2014	32,673	31,343	27,289	1.741	11.0	12.7
2015	33,328	31,971	27,683	1.732	11.7	13.4
2016	33,836	32,458	26,085	1.607	11.7	13.5
2017	34,320	32,922	26,827	1.630	11.9	13.9
2018	35,070	33,642	25,872	1.538	11.9	13.9
2019	35,461	34,017	24,992	1.469	12.3	14.4
2020	36,199	34,725	26,181	1.508	12.5	14.7
2021			26,221		12.8	15.1
2022			26,265		13.4	15.9
2023			23,702		13.9	16.4
2024			24,054		14.0	16.6
2025			23,853		14.4	17.2
2026			23,745		14.7	17.6
2027			24,443		14.9	18.0
2028			23,472		15.9	19.0
2029			23,184		16.3	19.6
2030			23,572		16.7	20.2

Source: PSCo Clean Air-Clean Jobs Emissions Reduction Plan.

A.4 DATA FROM BOULDER GREENHOUSE GAS EMISSIONS INVENTORY

Table A-20: Total Greenhouse Gas Emissions in the City of Boulder (metric tonnes)

	Electricity	Natural Gas	Transportation	Solid Waste	Total
1990	780,298	304,790	353,617	39,829	1,478,534
1991	801,513	328,145	364,863	40,960	1,535,480
1992	831,563	276,918	379,345	42,090	1,529,916
1993	820,653	310,413	394,965	43,221	1,569,252
1994	846,946	323,350	396,928	44,351	1,611,575
1995	850,192	307,141	414,599	45,064	1,616,995
1996	891,347	340,234	416,017	45,606	1,693,204
1997	920,233	333,425	409,421	45,004	1,708,082
1998	940,498	312,082	418,314	45,058	1,715,952
1999	911,929	314,483	422,191	45,433	1,694,036
2000	971,381	317,759	428,423	49,079	1,766,642
2001	961,872	327,987	449,024	49,206	1,788,088
2002	978,238	290,415	454,046	49,345	1,772,044
2003	1,055,610	310,096	443,092	58,272	1,867,070
2004	1,027,142	275,030	444,120	68,479	1,814,771
2005	1,064,721	246,430	437,101	49,814	1,798,066
2006	1,119,635	269,224	444,896	53,398	1,887,152
2007	1,060,705	330,095	432,269	61,500	1,884,569
2008	1,061,705	336,596	416,553	56,164	1,871,017
2009	1,060,617	319,570	413,602	55,540	1,849,329
2010	N/A	N/A	N/A	N/A	N/A

Source: Boulder Greenhouse Gas Inventory, 2009.

Table A-21: Electric Greenhouse Gas Emissions in the City of Boulder (metric tonnes)

	Residential	Commercial	Industrial	Other/ Streetlight	CU	Total	Windsource Credit	CU Wholesale Sale Credit
1990	149,007	323,616	255,501	3,024	58,865	790,014	0	0
1991	155,958	327,261	257,845	3,073	68,261	812,399	0	0
1992	155,853	381,141	263,822	3,145	40,906	844,867	0	-17,147
1993	162,115	426,901	213,045	3,186	26,713	831,960	0	-56,449
1994	165,370	428,378	233,999	3,204	27,564	858,515	0	-57,222
1995	170,147	450,390	208,741	3,299	27,788	860,366	0	-57,605
1996	175,980	422,320	260,008	3,269	43,154	904,730	0	-59,025
1997	178,518	454,499	242,902	3,481	56,091	935,492	0	-56,034
1998	181,871	478,180	236,712	4,251	51,171	952,185	0	-61,328
1999	169,551	471,928	232,498	4,264	44,487	922,728	-25,567	-57,691
2000	186,310	519,048	223,658	5,885	44,104	979,005	-26,736	-56,311
2001	189,042	524,826	224,007	6,559	30,166	974,599	-26,736	-58,768
2002	195,961	499,050	235,530	6,856	50,880	988,276	-21,007	-57,478
2003	209,895	538,292	257,062	7,371	59,562	1,072,181	-29,083	-41,126
2004	205,325	505,180	256,353	14,824	71,902	1,053,583	-23,670	0
2005	208,025	687,726	141,044	0	63,208	1,100,004	-29,538	0
2006	209,223	654,192	200,808	0	95,441	1,159,665	-31,991	0
2007	199,745	877,246	-816	2	0	1,076,177	-29,132	0
2008	193,743	882,655	-849	3,707	0	1,079,257	-30,287	0
2009	191,080	891,338	5,589	3,768	0	1,091,776	-29,046	0
2010	N/A	N/A	N/A	N/A	N/A	N/A	N/A	N/A

Source: Boulder Greenhouse Gas Inventory, 2009.

Table A-22: Windsource Sales in the City of Boulder

	Windsource Sales (kWh)	% of Retail Sales
1990	0	0.0%
1991	0	0.0%
1992	0	0.0%
1993	0	0.0%
1994	0	0.0%
1995	0	0.0%
1996	0	0.0%
1997	0	0.0%
1998	0	0.0%
1999	31,500,000	2.7%
2000	31,500,000	2.7%
2001	31,500,000	2.7%
2002	24,750,000	2.1%
2003	31,500,000	2.7%
2004	25,637,000	2.3%
2005	31,993,000	2.7%
2006	34,649,484	2.7%
2007	34,350,480	2.6%
2008	35,713,332	2.7%
2009	34,011,630	2.6%
2010	34,225,001	2.5%

Source: Boulder Greenhouse Gas Inventory, 2009; Xcel CAP Tax reports to city of Boulder.

Table A-23: Greenhouse Gas Emissions Factors (lb/kWh)

	WECC Average	CU Net of Cogeneration Heating	City Net of Windsource and CU
1990	1.792	1.792	1.792
1991	1.792	1.792	1.792
1992	1.792	1.017	1.729
1993	1.792	0.640	1.694
1994	1.792	0.639	1.694
1995	1.792	0.624	1.690
1996	1.792	0.929	1.716
1997	1.792	1.160	1.736
1998	1.792	1.004	1.720
1999	1.790	0.891	1.663
2000	1.872	0.847	1.730
2001	1.872	0.571	1.705
2002	1.872	0.973	1.751
2003	2.036	1.158	1.904
2004	2.036	1.213	1.905
2005	2.036	1.939	1.977
2006	2.036	1.940	1.973
2007	1.870	N/A	1.821
2008	1.870	N/A	1.819
2009	1.883	N/A	1.834

Source: Boulder Greenhouse Gas Inventory, 2009.

A.5 DATA FOR BENCHMARK CITIES

Table A-24: 2009 Average Annual Rates ($/kWh)

	Residential	Commercial	Industrial	Total
Boulder (Xcel)	$0.098	$0.082	$0.057	$0.081
Ann Arbor (DECo)	$0.120	$0.084	$0.068	$0.092
Madison (MG&E)	$0.142	$0.096	$0.067	$0.105
Norman (OG&E)	$0.083	$0.066	$0.048	$0.068
Santa Barbara (SCE)	$0.153	$0.127	$0.093	$0.132
Santa Cruz (PG&E)	$0.147	$0.130	$0.090	$0.129
Eugene (Muni)	$0.080	$0.065	$0.042	$0.066
Fort Collins (Muni)	$0.072	$0.061	$0.044	$0.059
Palo Alto (Muni)	$0.121	$0.104	$0.106	$0.107
Provo (Muni)	$0.074	$0.061	$0.043	$0.062
Tempe (SRP)	$0.102	$0.085	$0.059	$0.090

Source: Form EIA-861.

Table A-25: 2009 Electric Plant in Service (millions)

	Intangible	Generation	Transmission	Distribution	General	Total
Boulder (Xcel)	$41	$2,866	$1,228	$3,346	$129	$7,611
Ann Arbor (DECo)	$488	$7,377	$86	$5,808	$831	$14,589
Madison (MG&E)	$0	$353	$0	$434	$11	$799
Norman (OG&E)	$30	$4,583	$860	$2,641	$216	$8,331
Santa Barbara (SCE)	$1,061	$8,850	$5,447	$13,745	$1,640	$30,743
Santa Cruz (PG&E)	$115	$9,957	$5,647	$18,017	$562	$34,298
Eugene (Muni)	$0	$149	$88	$200	$209	$646
Fort Collins (Muni)	$93	$865	$180	$0	$0	$1,138
Palo Alto (Muni)	N/A	N/A	N/A	N/A	N/A	N/A

Source: FERC Form 1, Utility Annual Reports

Table A-26: 2009 Sales by Customer Class (% of total sales)

	Residential	Commercial	Industrial	Other
Boulder (Xcel)	32%	46%	22%	0%
Ann Arbor (DECo)	33%	44%	23%	0%
Madison (MG&E)	24%	68%	8%	0%
Norman (OG&E)	36%	39%	25%	0%
Santa Barbara (SCE)	35%	53%	12%	0%
Santa Cruz (PG&E)	36%	46%	17%	0%
Eugene (Muni)	42%	37%	21%	0%
Fort Collins (Muni)	33%	35%	32%	0%
Palo Alto (Muni)	17%	53%	31%	0%
Provo (Muni)	31%	51%	17%	0%
Tempe (SRP)	48%	41%	11%	0%

Source: Form EIA-861.

Table A-27: 2009 Electric Generation by Fuel

	Coal	Natural Gas	Nuclear	Hydro	Renewable	Cogen-eration
Boulder (Xcel)	61.0%	27.0%	1.0%	1.5%	9.0%	0.0%
Ann Arbor (DECo)	77.0%	3.0%	18.0%	0.0%	1.0%	0.0%
Madison (MG&E)	71.8%	24.3%	0.0%	0.0%	3.7%	0.0%
Norman (OG&E)	70.0%	29.0%	0.0%	0.0%	1.0%	0.0%
Santa Barbara (SCE)	6.0%	40.0%	20.0%	4.0%	17.0%	14.0%
Santa Cruz (PG&E)	1.3%	50.0%	20.0%	13.0%	14.0%	0.0%
Eugene (Muni)	3.4%	2.3%	8.0%	81.6%	5.1%	0.0%
Fort Collins (Muni)	79.5%	0.7%	0.0%	19.4%	2.1%	0.0%
Palo Alto (Muni)	0.0%	31.0%	0.0%	50.0%	19.0%	0.0%

Source: FERC Form 1, Utility Annual Reports

Table A-28: 2009 Energy Efficiency Program Statistics

	Residential Savings per kWh of Sales	Business Savings per kWh of Sales	Total Savings per kWh of Sales	Total Spending per kWh of Sales
Boulder (Xcel)	0.9%	0.8%	0.8%	$1.11
Ann Arbor (DECo)	0.0%	0.0%	0.0%	$0.00
Madison (MG&E)	2.6%	0.7%	1.2%	$0.76
Norman (OG&E)	0.0%	0.0%	0.0%	$0.01
Santa Barbara (SCE)	2.3%	1.6%	1.9%	$2.67
Santa Cruz (PG&E)	1.7%	1.9%	1.9%	$4.76
Eugene (Muni)	1.0%	1.0%	1.0%	$3.15
Fort Collins (Muni)	0.3%	0.9%	0.7%	$0.94
Palo Alto (Muni)	0.8%	0.4%	0.5%	$1.83
Provo (Muni)	0.0%	0.0%	0.0%	$0.00
Tempe (SRP)	1.7%	0.6%	1.1%	$0.80

Source: Form EIA-861.

Table A-29: 2009 Load Management Program Statistics

	Residential Savings per kW of Total Peak Demand	Business Savings per kW of Total Peak Demand	Total Savings per kW of Total Peak Demand	Total Spending per MW of Peak Demand
Boulder (Xcel)	2.9%	2.9%	5.7%	$2.17
Ann Arbor (DECo)	0.0%	0.0%	0.0%	$0.00
Madison (MG&E)	0.0%	0.0%	0.0%	$0.08
Norman (OG&E)	0.0%	0.1%	0.1%	$0.02
Santa Barbara (SCE)	2.9%	7.9%	10.9%	$8.04
Santa Cruz (PG&E)	0.8%	4.5%	5.3%	$6.16
Eugene (Muni)	0.0%	0.0%	0.0%	$0.00
Fort Collins (Muni)	0.8%	4.2%	4.9%	$1.32
Palo Alto (Muni)	0.0%	0.0%	0.0%	$0.00
Provo (Muni)	0.0%	0.0%	0.0%	$0.00
Tempe (SRP)	1.7%	0.3%	2.0%	$0.13

Source: Form EIA-861.

Nexant

Nexant, Inc.
1401 Walnut St
Suite 400
Boulder, CO, 80302
T) 303 402 2480
F) 303 440 6644
www.nexant.com