THE IMPACT OF A RENEWABLE ENERGY PORTFOLIO STANDARD ON RETAIL ELECTRIC RATES IN COLORADO

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EXECUTIVE SUMMARY

Introduction

In its 2004 session, the Colorado General Assembly is considering legislation (HB 1273) to require Colorado's investor-owned electric utilities to acquire a specified minimum amount of electric power from renewable energy sources.

The purpose of this report is to estimate the impact that such a legislative mandate will have on the price of electricity sold by Colorado's investor-owned utilities. The report will also consider other economic impacts of a "renewable portfolio standard" (RPS) for Colorado. Specifically, this report addresses the following questions:

- What effect will HB 1273 have on the electric rates paid by Colorado consumers?
  - What factors affect the cost of renewable and non-renewable energy sources in Colorado?
  - How sensitive are the conclusions about rate impact to changes in federal tax policy and future natural gas prices?
- What fraction of the Colorado retail market will be served by the renewable resources required under HB 1273?
- What other effects will an RPS have in Colorado?
- How does the proposed Colorado RPS compare to similar laws in other states?

The cost of electricity from renewable resources has fallen in recent years. Electric power generated by wind turbines in large "wind farms," for example, is now price competitive with power produced using traditional fuels. But renewable and non-renewable energy sources differ in many important respects, including their reliability, environmental impacts and their potential to affect rural economic development.

This report examines the distinctions between renewable and fossil fuel electric production and estimates the rate impact of requiring utilities to use a specified level of renewable resources. It is hoped that this report will provide legislators and other policy makers with a useful analytical tool to assist them in considering the Renewable Portfolio Standard in HB 1273.

Major Findings

- **The Renewable Portfolio Standard in HB 1273 will have a modest effect on utility bills in Colorado. The most likely outcome is lower electric bills for consumers of the investor-owned utilities:**

    - The RPS is expected to result in a savings of $ 218 million for customers of Xcel Energy. This is a reduction of 20 cents per month for the average residential consumer over the period 2004-2023.

    - Under less likely assumptions, the RPS would save $ 337 million for Xcel consumers, producing monthly bill savings of 31 cents for the average residential consumer during the period 2004-2023,

    - Using much less likely worst-case assumptions, the RPS would increase electric rates by about 8 cents per month for the average Xcel residential customer over the 20-year period.

- **Renewable energy sources can save consumers money by acting as a "hedge" against spikes in natural gas prices.** Renewable sources such as wind will result in consumer savings of 52¢ to 75¢ per month (in addition to other savings) in years when natural gas prices spike as they did in 2000 and 2003.

- **The expansion of renewable energy capacity mandated by the Colorado RPS will have positive benefits for water use, air quality, and rural economic development.**

    - The RPS mandate could save between 27,000 and 53,000 acre-feet of water that would otherwise be consumed by energy production. This upper bound is equivalent to the combined storage of the Gross, Marston, Ralston and Strontia Springs reservoirs.

    - By substituting renewables for a portion of generation from fossil fuels, the RPS can significantly reduce emissions from Colorado power plants. Depending on the mix of the avoided fuel, emissions of the greenhouse gas carbon dioxide would be reduced by between 16 million and 27 million tons of CO_2.

    - Renewable resources can affect rural economic growth, offering rural counties opportunities for an increased tax base and landowners opportunities for income from leases to wind generators.

Other Findings

- **Colorado utilities had developed about 300 MW of renewable power by January 2004, representing about 1.8% of the electricity generated in the state. Coal and natural gas remain the dominant fuel sources with 77% and 20% of the market, respectively.**

- **Thirteen states have adopted Renewable Portfolio Standards through legislation or regulatory rules, as shown on the following map. The experience of these states appears to show that an RPS can be effective in increasing both the supply and demand for renewable energy without increasing electric rates.**

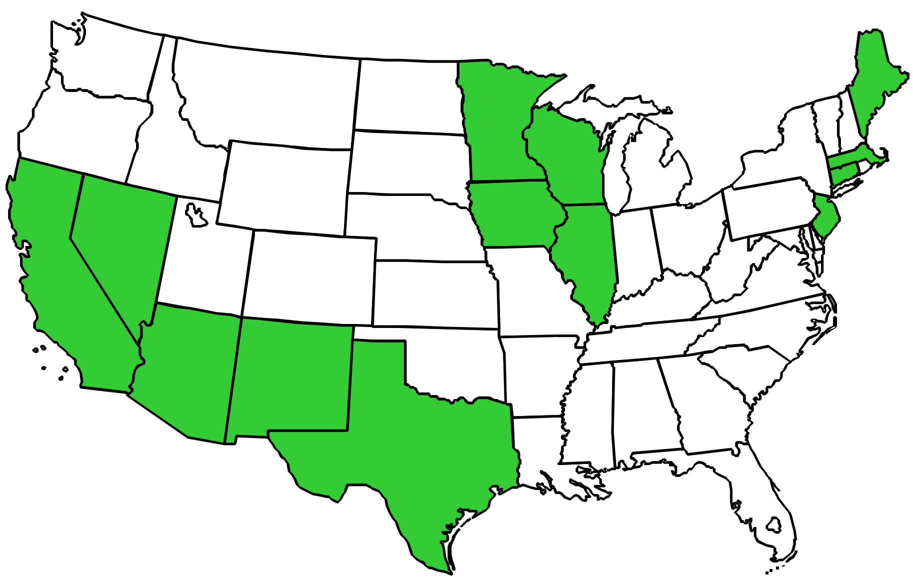

Figure 1 -- Renewable Portfolio Standards in 13 States

- **The proposed Colorado legislation would place Colorado in the middle of the thirteen states with respect to its RPS target. In terms of energy (kilowatt-hours), the RPS will require that Colorado's two investor-owned utilities add new renewable resources equal to about 4.5% of their energy portfolios by 2011 and 11.2% by 2021.**

- **The most important factors affecting the relative cost of renewable and non-renewable resources are:**
  - The future price of natural gas;
  - The future of the federal Production Tax Credit (PTC);

- Improvements in the efficiency of both fossil-fueled plants and wind generation.

- **The 2004 estimate of <u>future natural gas costs</u> published by the U.S. Department of Energy (DOE), projects that natural gas prices will remain above $3.50/Mcf in the near term, increasing to prices that remain <u>consistently above $4.00/Mcf in the longer term</u>.**

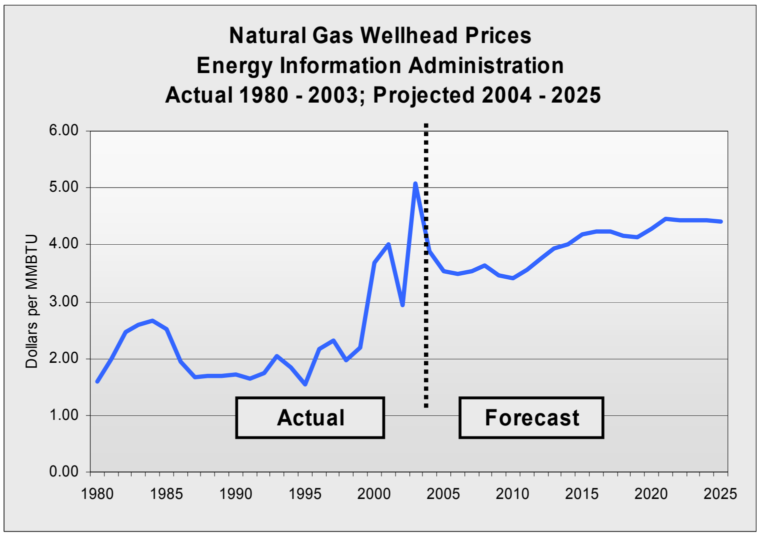

Figure 2 - Forecast Natural Gas Prices

- **Colorado has a relatively large potential renewable energy resource in wind power, ranking 11th among the 50 states. The state has significant Class 4 and Class 3 wind areas, suitable for commercial wind generation.**

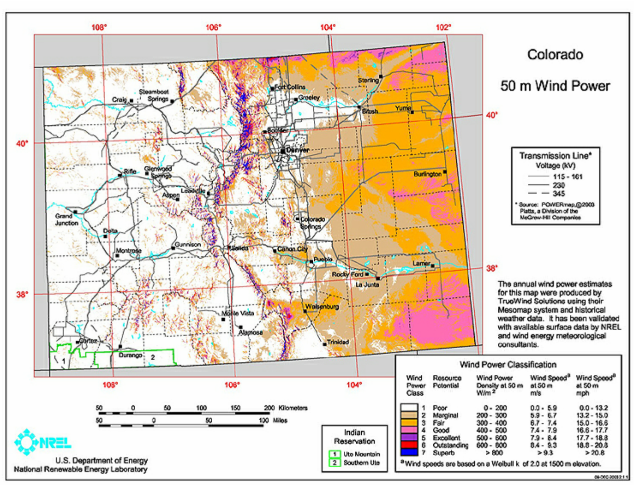

Figure 3 -- Colorado Wind Resource Map

INTRODUCTION

Across the country, many state legislatures and state public utilities commissions are considering whether to mandate that electric utilities acquire a minimum amount electric power produced using renewable energy resources. By 2004, thirteen states had adopted "Renewable Portfolio Standards" (RPS).

Some of the legislative mandates have been adopted as part of an electric industry restructuring plan (e.g., Texas); others were adopted as stand-alone proposals (e.g., Iowa, Minnesota).

Among the reasons cited for adopting an RPS are these:

- Renewable energy, especially wind power, biomass generation, and geothermal energy has caught up with traditional fossil fueled generation in cost;
- Renewable energy is still fairly unfamiliar to utilities; legislative mandates will speed up adoption of technologies which are (or soon will be) cost effective;
- Renewable energy has environmental benefits compared to the use of fossil fuels;
- Renewable energy is often "home-grown" and will produce economic development advantages for a state, especially in rural areas;
- There is strong public support for the use of renewable energy;
- Federal tax policy encourages the use of renewable energy through the Production Tax Credit (PTC);
- The price of natural gas, which powers most of the generating plants built in recent years, is subject to considerable uncertainty and fluctuation. Some renewable resources (e.g., wind and solar) can stabilize consumer energy prices since they have little or no marginal (fuel) cost.

Purpose of this Report

The primary purpose of this report is to estimate the effect that an RPS will have on the retail rates of the affected Colorado utilities.

Using the RPS requirements contained in HB 1273, introduced in the 2004 Colorado General Assembly, this report first estimates the amount of renewable energy that would be obtained by Colorado's two investor owned utilities over the next twenty years. The report then compares the cost of renewable energy with new fossil-fueled generation to estimate the effect that the RPS requirement will have on retail electric rates.

The report examines the degree to which renewable resources can act as a hedge against price fluctuations is the natural gas market. Finally, the report explores other likely effects of an RPS, such as its environmental and economic development aspects.

It is well known that the cost of electricity produced using renewable resources has fallen in recent years. Electric power generated by wind turbines in large "wind farms," for example, is now price competitive with power produced using traditional fuels. At the same time, the price of electricity produced from fossil fuels has generally increased and fluctuated as the price of natural gas has risen in recent years.

While the cost per kilowatt-hour of renewable and fossil-fueled electricity may be growing closer together, there are other important distinctions between the two energy sources. Energy from traditional fossil resources is usually more predictable than power produced by wind or solar resources since the availability of these renewable resources varies naturally. On the other hand, wind and solar systems have essentially zero fuel cost, so that the price of their electrical output is unaffected by fluctuations in domestic natural gas markets and regional electric power markets.

These two energy sources differ importantly in their environmental impact as well. Fossil-fueled electric resources can contribute substantial amounts of carbon dioxide (CO_2), sulphur oxides (SO_x), nitrogen oxides (NO_x), and mercury to the environment. Thermal electric plants also have relatively high requirements for the consumptive use of water, needed for cooling. Renewable resources such as wind generation do not produce emissions and do not require cooling water. Of course, there are a variety of renewable resources and some, such as burning biomass, may not have the same environmental benefits as solar and wind.

In addition to the positive environmental effects, proponents of renewable energy also point to two other external benefits that may distinguish them from more traditional energy sources: 1) economic development opportunities, especially in rural areas and 2) reduced risk of future energy price fluctuations.

The differing character of renewable and non-renewable power sources makes comparing their future costs a complex task. This report is intended to provide legislators and other policy makers with analytical tools to assist them as they consider the Renewable Portfolio Standard for Colorado proposed in HB 1273.

Methodology

In preparing this report, the author employed two methodologies. First, he conducted extensive research of the research literature on energy price forecasts, on renewable portfolio standards, including studies from other states that estimated the rate impact of an RPS, and on the current state of generation technologies.

Second, the author models the 20-year future of retail electric prices for Colorado's investor-owned utilities, estimating the avoided cost against which the estimated future costs of renewable energy can be compared. The report computes the difference between the future price of renewables (assumed to be wind power for analytic purposes) and the future cost of electricity produced with fossil fuels (assumed to be advanced combined cycle natural gas-fired generation).

In addition to offering point estimates of the impact of renewable portfolio standard on retail electric rates, the report also examines the sensitivity of the analysis to certain key variables, including the cost of natural gas and changes in federal tax policy. Finally, the report simulates the change in electric prices caused by spikes in natural gas prices similar to those that occurred in 2000 and 2003. This last analysis permits measurement of the "hedge" value of some renewable resources.

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About the Author

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THE COLORADO ELECTRIC UTILITY INDUSTRY

Colorado ranks 29th in size among the 51 state jurisdictions, measured by energy sold in 2001, at 46.9 million megawatt-hours. Ninety percent of the energy generated in Colorado in 2001 was produced by regulated utilities; ten percent was produced by non-utility generators.

To put the Colorado industry in perspective, the retail electric market in Colorado is about twice the size of the retail market in Utah or Nebraska, but only one-seventh of the size of the Texas retail electric market, the country's largest.

Colorado Utilities

The state's load is served by 60 utilities, including 2 investor-owned companies (Xcel Energy and Aquila); 30 municipal utilities (including Colorado Springs, Fort Collins and Loveland) and 28 rural electric cooperatives.

The following chart shows the relative size of these three sectors of the Colorado electric industry, measured by megawatt-hours sold in 2001:

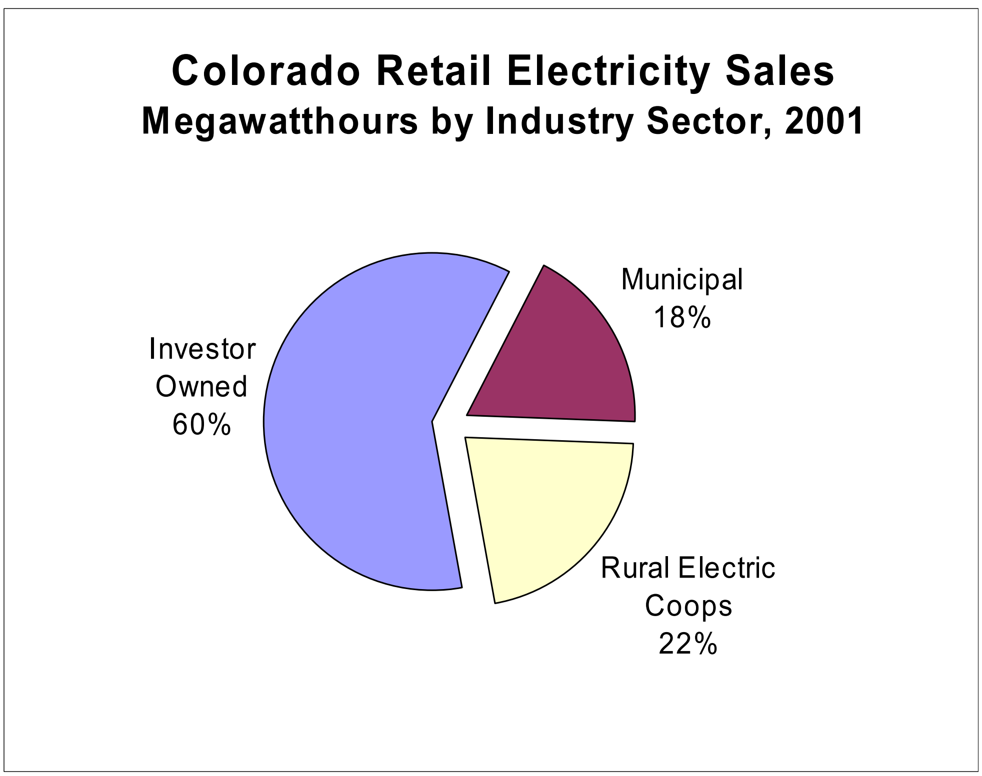


Figure 4 -- Market Share of Colorado Utilities

Fuel Used for Generation in Colorado

Across the state's utility and non-utility generators, coal is the predominant fuel used in Colorado, accounting for 77% of the electric energy produced. Next is natural gas with 20% of the market; hydroelectric power comprises about 3% of total generation; all other sources, including renewable energy, accounted for less than 1% of the electricity generated in the state in 2001, as reported by the Energy Information Administration.

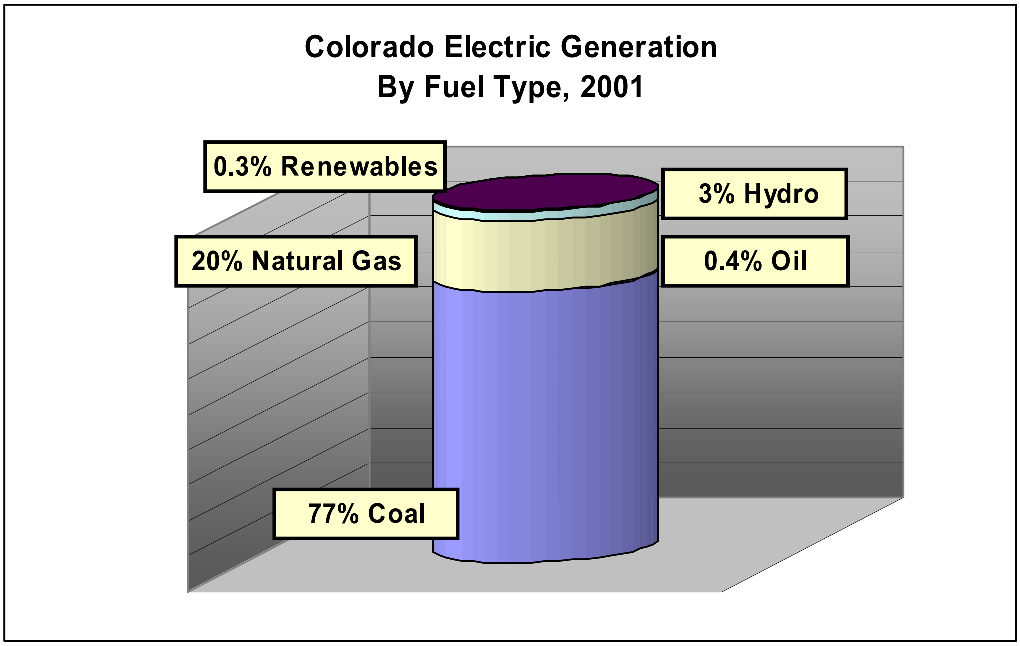


Figure 5 -- Fuel Mix of Colorado Electric Generation

As in most other states, the fuel mix in Colorado has been changing, with the relative use of natural gas as a fuel for electric generation increasing sharply in recent years. Natural gas fired power plants are the technology of choice for independent power producers because of the lower capital costs and shorter lead times associated with gas turbine technology.

The percentage of Colorado generation fueled by natural gas has grown sharply in the past decade. In 1993 natural gas produced 4.4% of the state's electricity; a decade later, natural gas use had quadrupled to 19.8% of the market – an annual growth rate of 22%.

The Retail Price of Electricity in Colorado

Overall, Colorado's utilities rank 38th in the country for the average price of electricity per kilowatt-hour. In other words, electricity is more expensive in 37 states; it is less expensive in 12 states. The following table shows the average retail price of electricity for three customer classes, segregated by utility type:

Colorado Retail Electric Rates, 2002			
Sector	**Residential Price/KWh**	**Commercial Price/KWh**	**Industrial Price/KWh**
Total State	7.37	5.67	4.52
Investor-Owned Utilities	7.21	5.36	4.12
Municipal Utilities	6.63	5.76	4.55
Rural Cooperatives	8.19	7.06	5.23

Figure 6 -- Retail Electric Rates by Class of Ownership and Customer Class

Current Utility Use of Renewable Energy in Colorado

In January 2004, Colorado was home to three wind farms; a fourth wind farm supplies power to Colorado consumers from its location just north of the Colorado-Wyoming border in Arlington, Wyoming.

Thus, Colorado utilities were producing or purchasing renewable energy (from wind and small hydro) totaling 299 megawatts from instate sources and an additional 110 from a wind farm in southwestern Kansas owned by Aquila.

Wind Power Sites Supplying Energy to Colorado, 2004			
Facility	**Location**	**Rating**	**Date**
Ponnequin	Weld County, CO	30 MW	1998
Arlington	Albany County, WY	25 MW	1999
Peetz	Logan County, CO	30 MW	2001
Lamar	Prowers County, CO	162 MW	2003

Figure 7 -- Colorado Wind Generation in 2004

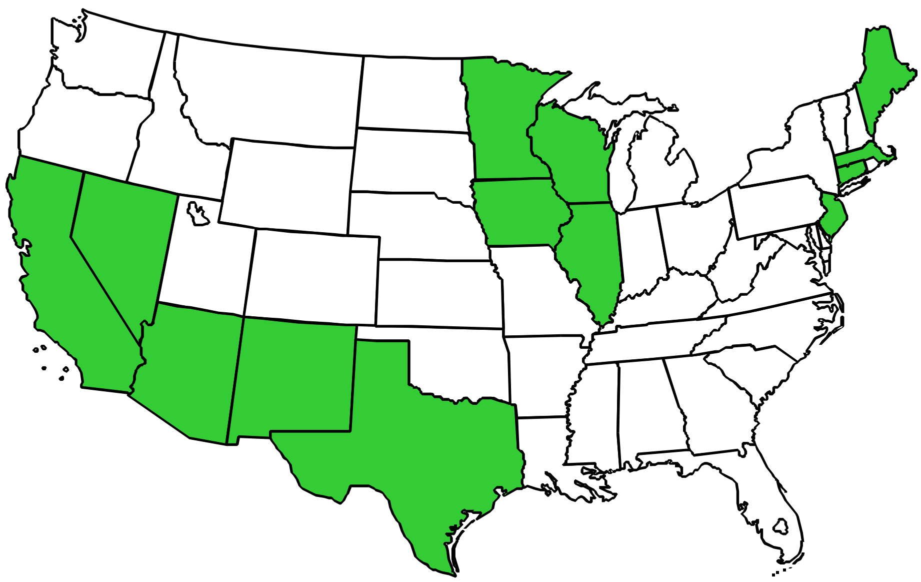
With the addition in 2003 of the 162 MW wind farm in Lamar, the level of renewable generation (as defined in the proposed legislation) in Colorado has risen significantly since 2001. However, generation from all renewable sources comprises only about 1.8% of total generation in the state in 2004.

The Lamar wind farm (also known as Colorado Green), was the subject of a decision of the Colorado Public Utilities Commission in February 2001, following an extensive evidentiary proceeding. The PUC made detailed findings about the production costs of the facility, its capacity value, and the costs of integrating the facility into Xcel Energy's bulk power system. The results of the PUC's analysis will be referenced below in discussing the costs of wind power.

The proposed Colorado RPS legislation defines renewable energy sources to include existing small hydroelectric facilities (less than 20 MW capacity) and new small hydroelectric facilities (less than 10 MW capacity). In 2004, Xcel Energy could count approximately 52 MW of existing hydroelectric generation capacity in this category.

RENEWABLE PORTFOLIO STANDARDS IN OTHER STATES

By 2003, thirteen states had adopted a renewable portfolio standard either through legislation or rule making by the state utility regulatory agency. Here is a map of the states that have adopted an RPS:



The RPS standards vary somewhat from state to state, but share the common feature of requiring utilities to acquire a targeted amount or percentage of capacity or energy from renewable resources by specific dates. Here is a brief summary of the standards adopted in the states that have taken action on the issue by the end of 2003:

State	Adopted	Renewable Energy Standard
Arizona	1998	1% in 2005; 1.05% in 2006; 1.1%/year 2007 to 2012
California	2002	At least 1%/year; 20%, by 2017
Connecticut	1998	10% by 2010
Illinois	2001	5% by 2010; 15% by 2020
Iowa	1991	105 average MWs
Maine	1999	30% of sales including high efficiency cogeneration
Massachusetts	1997	4% new renewables on 7% base by 2009; 1%/year thereafter
Minnesota	2003	10% of 2015 sales

Nevada	2001	5% in 2003, increasing to 15% of retail sales by 2013
New Jersey	2001	4% by 2012
New Mexico	2002	10% of sales by 2011
Pennsylvania	1998	Limited renewable requirements for one utility
Texas	1999	2880 MW by 2009, approx 3% of sales
Wisconsin	1999	0.5% by 12/31/01, increasing to 2.2% by 12/31/11

Figure 8 -- Renewable Portfolio Standards in Other States

How the Proposed Colorado RPS Compares to Others

The proposed Colorado Renewable Portfolio Standard, discussed in the next section, requires the state's two investor-owned utilities to acquire 500 MW of renewable capacity by 2007; 900 MW by 2011; and 1800 MW by 2021. In meeting the standard, the utilities may count existing renewable capacity toward the RPS requirement. When translated to megawatt-hours using an appropriate capacity factor, the RPS requirement equates to the following schedule of new additions and total renewable resources.

Benchmark Date	Renewable Capacity Required	Renewable Capacity		New as Percent of Total Load	RPS as Percent of Total Load
		Existing	New*		
1/1/2007	500 MW	431 MW	69 MW	0.7%	5.0%
1/1/2011	900 MW	455 MW	445 MW	4.5%	8.6%
1/1/2021	1800 MW	507 MW	1293 MW	11.2%	15.0%
*In actual practice, the "New" requirement may be smaller: we have assumed that the RPS requirements are met without the use of the capacity "multipliers" permitted by the legislation for certain renewable resources.					

Figure 9 -- Colorado's RPS Requirements as Percentage of Total Resources

As can be seen by comparing the standards in these two tables, HB 1273 will put Colorado in the middle of the pack with respect to the requirements that states have adopted for their renewable portfolio standards.

THE PROPOSED COLORADO LEGISLATION

Overview of the Legislation

HB 1273 was introduced in the Colorado General Assembly in January 2004. The legislation establishes an electric resource standard for renewable energy that applies to the state's two investor-owned utilities. Here is a list of the major features of the legislation with explanatory comments:

- **Requires the Public Utilities Commission to adopt rules requiring the state's investor-owned utilities to generate or acquire a specified amount of renewable energy each year. The state-wide standard is as follows:**

  - **500 MW by December 31, 2006**
  - **900 MW by December 31, 2010**
  - **1800 MW by December 31, 2020**

Comment: *The bill applies to two investor-owned utilities. Municipal utilities and rural electric cooperatives, which provide 40% of the state's electricity, are exempted. The following chart show the estimated level of new renewable resources required under the law, compared to expected levels of existing renewables and non-renewable sources.*

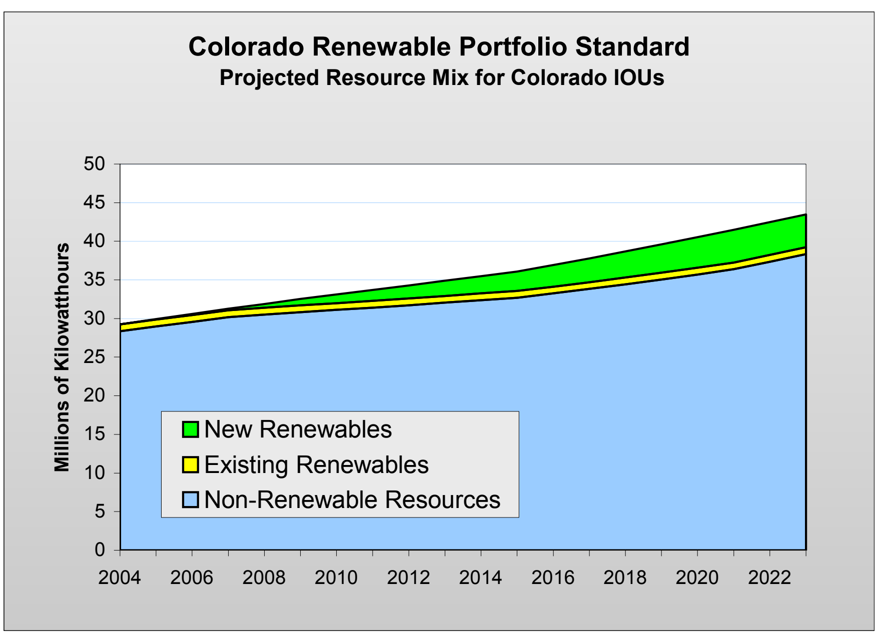


Figure 10 -- Impact of Renewable Portfolio Standard on MWh

- **Defines renewable energy to include biomass, geothermal, solar, small hydroelectric, wind, and hydrogen derived from renewable energy sources.**

Comment: *The bill permits small hydroelectric facilities to qualify as renewable resources for purposes of the requirement. The bill also includes various "multipliers" that allow utilities to count certain types of resources (e.g., solar facilities or those built in an enterprise zone) with greater weight toward meeting the standard.*

- **Permits qualifying renewable resources existing at the time of enactment to count toward the renewable energy standard.**

Comment: *At the time of enactment, Xcel Energy can count approximately 402 MW of renewable capacity (chiefly existing wind capacity) in satisfaction of the standard. Aquila, which owns a large wind farm in Kansas, can count up to 110 MW towards satisfaction of the standard.*

- **Expresses the legislative intent that competitive acquisition should generally be used to acquire renewable energy resources to balance cost, benefit and risk.**

***Comment**: Although the requirement for competitive bidding is not absolute, the bill gives guidance to the Commission to consider the least cost resources when approving a utility's resource plan. However, the language is not so strict that the Commission could not approve, for example, higher cost resources designed to provide power in peak periods in which fossil fuel generation costs are also higher.*

- **Authorizes the Colorado Public Utilities Commission to adopt rules to establish a system of tradable renewable energy credits.**

Comment: *Implementation details are left to the PUC, but the bill allows for the creation and trading of permits to ensure that renewable resources are acquired at* *least cost. Such a system could be aligned with a west-wide credit trading system being created by the Western Governors' Association.*

- **Authorizes the Colorado PUC to exempt providers from the resource standard if sufficient renewable resources are not available or if transmission costs are not reasonable.**

Comment: *Colorado is thought to have significant potential renewable resources, especially wind and solar resources. However, this provision also acknowledges that transmission access is an important prerequisite for economic renewable resources.*

- **The bill exempts wholesale customers of utilities from paying for mandated renewable resources unless the wholesale customer opts to include the cost of renewables in its wholesale rate.**

- **Requires each affected utility to file an annual report detailing its compliance with the renewable resource requirement.**

- **Authorizes the Colorado Public Utilities Commission to establish fines for non-compliance.**

THE COST OF WIND ENERGY IN COLORADO

The renewable portfolio standard in HB 1273 defines a variety of resources as qualifying renewable resources for purposes of meeting the standard:

- Biomass
- Geothermal Energy
- Solar Energy
- Small Hydroelectricity
- Wind Energy
- Hydrogen derived from other Renewable Energy sources
- Qualified Energy Recovery Systems

Colorado will undoubtedly be home to many, if not all, of these renewable resources in future years. However, in 2004 wind energy is the most economical and most widely deployed of these resources, with about 250 MW already in place. In addition, scientists rank Colorado as the 11th "windiest" state in the nation for suitable resources for generating electricity from wind.

For these reasons, this report makes the simplifying assumption, *for estimate purposes only*, that the state's investor-owned will meet their entire renewable resource requirements by the use of wind energy. In practice, other renewable sources are likely to compete successfully with wind during a competitive bidding process in which renewable energy sources are acquired by the utility. This means that, in practice, the actual costs might be lower than those derived in this report.

Colorado's Wind Resources

Wind power engineers classify geographic areas according to the average speed and "density" of the wind at each location. Wind quality classifications vary from 1 to 7 and are defined as follows:

Wind Power Class	10 Meters		50 meters	
	Wind Power Density (watts/m^2)	**Wind Speed** (mph)	**Wind Power Density** (watts/m^2)	**Wind Speed** (mph)
1	<100	<9.8	<200	<12.5
2	100 – 150	9.8 - 11.5	200 - 300	12.5 - 14.3
3	150 – 200	11.5 - 12.5	300 - 400	14.3 - 15.7
4	200 – 250	12.5 - 13.4	400 - 500	15.7 - 16.8
5	250 – 300	13.4 - 14.3	500 - 600	16.8 - 17.9
6	300 – 400	14.3 - 15.7	600 - 800	17.9 - 19.7
7	>400	>15.7	>800	>19.7

Figure 11 -- Wind Resource Classification

At the present state of wind generation technology, wind power classes of 4, 5 and 6 are the most desirable for electric power generation, although significant research efforts are being expended to lower the cost of generating power economically in Wind Power Class 3. The Department of Energy is devoting a significant amount of research to “Low Wind Speed Technologies” (LWST) designed to improve the commercial value of sites that are Class 3 and below.

Class 4 areas are usually described as “good”; class 5 areas are “excellent” and Class 6 areas are described as “outstanding.”

Turning to the “wind map” of Colorado, we see that the eastern portion of the state contains significant areas of Class 4 wind power as well as large areas of Class 3 wind power. This map is of recent vintage and shows wind power at a “hub height” of 50 meters. This relatively higher hub height reflects the move toward wind machines with higher hubs and larger blades at a height where wind power is more consistent. All these factors contribute to the higher efficiency output of new turbines.

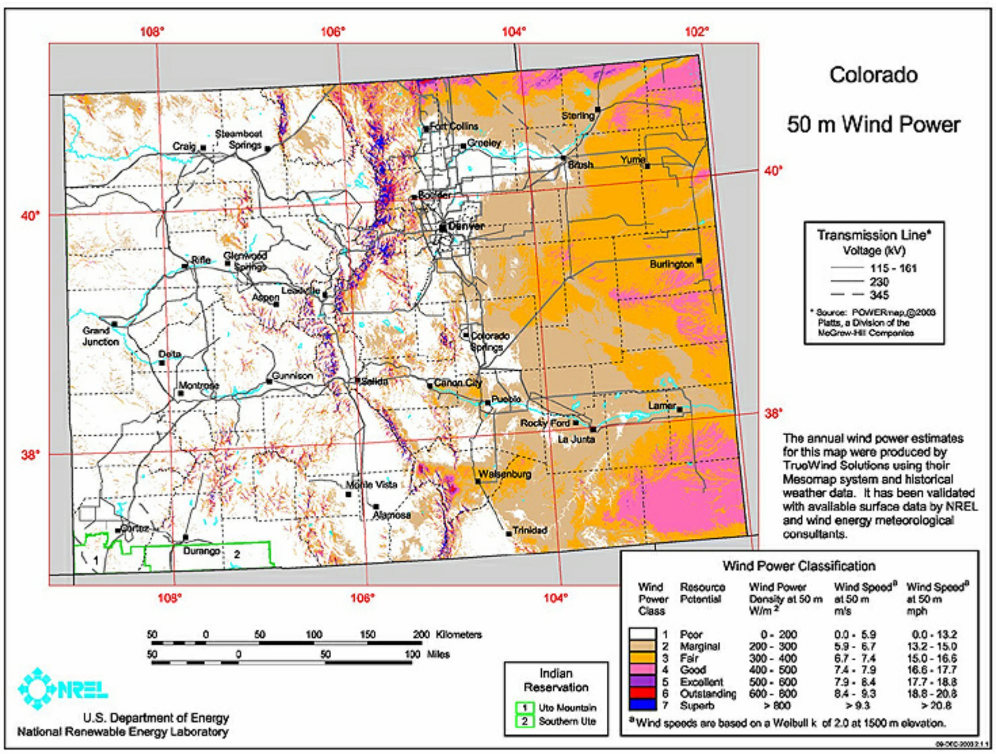


Figure 12 -- Colorado Wind Resource Map

The wind resources available in Colorado make it one of the better states in the country for wind power prospects. Here is a ranking of the top twenty states in country by potential for wind energy production:

THE TOP TWENTY STATES for wind energy potential, as measured by annual energy potential in the billions of kWhs, factoring in environmental and land use exclusions for wind class of 3 and higher.

1	North Dakota	1,210	11	Colorado	481
2	Texas	1,190	12	New Mexico	435
3	Kansas	1,070	13	Idaho	73
4	South Dakota	1,030	14	Michigan	65
5	Montana	1,020	15	New York	62
6	Nebraska	868	16	Illinois	61
7	Wyoming	747	17	California	59
8	Oklahoma	725	18	Wisconsin	58
9	Minnesota	657	19	Maine	56
10	Iowa	551	20	Missouri	52

Source: *An Assessment of the Available Windy Land Area and Wind Energy Potential in the Contiguous United States, Pacific Northwest Laboratory, 1991.*

Figure 13 -- Top Twenty States for Wind Energy Potential

Modeling the Cost of Wind Power

The cost of wind power has fallen dramatically in the past twenty years. The Department of Energy reports that the cost was 40¢ per kilowatt-hour in the 1980s. The DOE's research and development program estimates that the (unsubsidized) cost of wind power in Class 4 areas is about 5¢ per KWh currently; the agency has as its goal a decline to 3¢ per KWh in 2012. (All values in constant 2002 dollars).

For purposes of this report, we use the following values for the cost of wind power production:

Unsubsidized cost per KWh: 5.0 cents per KWh in 2004 decreasing linearly to 3.5 cents per KWh in 2023.

The initial value appears to be conservative. A 15-year wind contract was offered in late 2003 in Oklahoma for a (PTC subsidized) price of 2.48¢ per KWh. Assuming that the levelized, pre-tax value of the PTC is 2.0¢ per KWh, this implies an unsubsidized rate of about 4.5¢ per KWh for this project.

The (PTC subsidized) cost of the Lamar Wind project was estimated to be 3.2¢ per KWh before adding 0.2¢ in ancillary costs. The capital costs of wind systems have declined in real terms since the Colorado PUC's decision three years ago, so that it is reasonable to assume the 2004 cost would be close to 5¢ per KWh.

Finally, the DOE's Wind Energy Program Multi Year Technical Plan estimates that generation in Class 4 wind regimes costs at about 4.3-5.0 cents/KWh currently.

The terminal cost of 3.5¢ per KWh is also likely to be conservative. The Department of Energy's goal for Low Wind Speed Technology costs is 3.0¢ per KWh in 2012, a much more optimistic goal that the assumption made here. The 3.5¢ per KWh assumption used in this report is equivalent to a capital investment of approximately $750 per KW at a 40% capacity factor, values that appear to be easily achievable by 2023 given current progress in wind technology.

Wind Capacity Factor: 35% in 2004 increasing to 40% in 2023. The 35% value at the beginning of the analytical period is commonly used to characterize wind projects built in Wind Class 4 areas today. The 40% capacity factor at the end of the twenty-year period reflects the fact that wind regimes are becoming increasingly better characterized, and that blade, rotor and generator design continue to improve.

Wind Integration Costs: 0.4¢ per KWh, decreasing over 20 years to 0.35¢ per KWh. This is likely a conservative assumption given recent research and regulatory findings on the subject. In 2001, the Colorado Public Utilities Commission determined that the integration costs of the Lamar wind project were approximately 0.2¢ per KWh; research on the BPA system estimates that its "firming and shaping" costs are approximately 0.6¢ per KWh. Recent research by Xcel Energy reportedly concludes that 0.2¢ per KWh represents the integration costs in Minnesota over a range of wind capacity additions. Other research in Wisconsin and Michigan estimates integration costs in the range of 0.2¢ to 0.3¢ per KWh. Thus, the 0.4¢ used in this report is in the upper middle the range of values. The slight decline over twenty years is due to the assumed marginal increase in capacity factor of wind generators.

The Production Tax Credit

Beginning in 1992, Congress approved a Production Tax Credit (PTC) of 1.5¢ per KWh for electricity produced from a renewable resource project in the first ten years of the project life. The PTC was indexed for inflation, so that its 2003 value was approximately 1.8¢ per KWh.

The original PTC expired in 1999 and was extended (retroactively with no break) through 2003. Congress did not act on a comprehensive energy bill in 2003, with the result that the PTC has again expired. Legislation has been introduced to extend the PTC through 2006 and most observers expect the PTC to be reestablished.

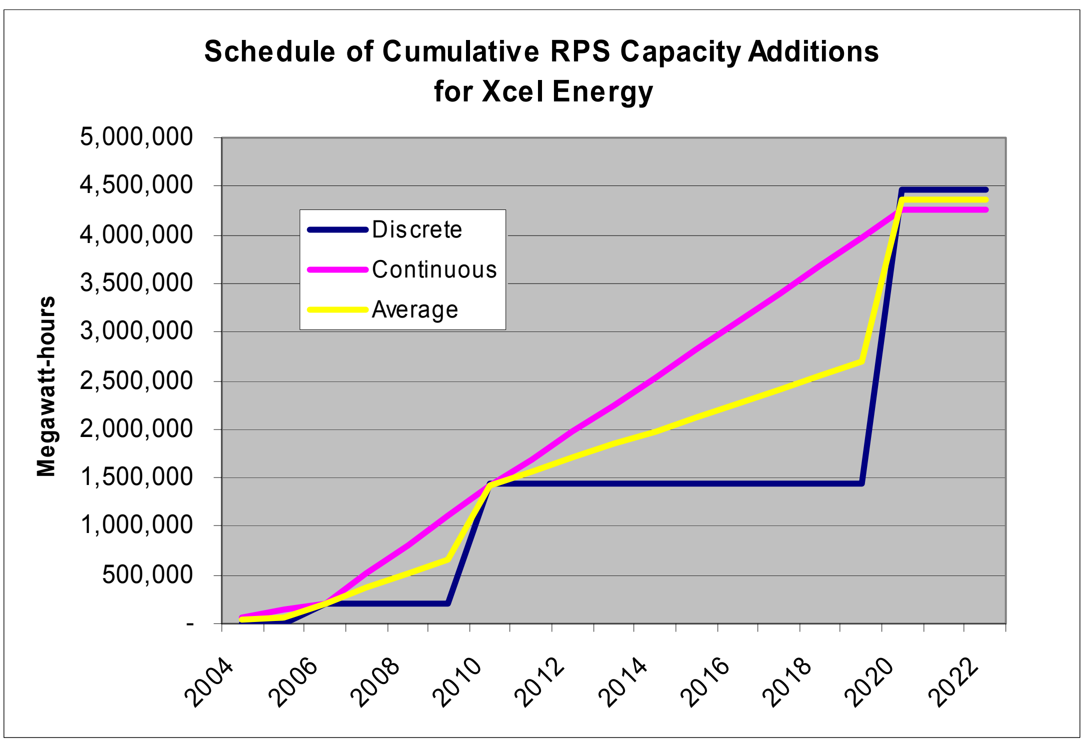
The 2003 PTC has an after tax value of 1.8¢ per KWh produced in 2004 dollars. Assuming a firm faces a 35% marginal federal tax rate, this means that the PTC has a pre-tax value of 2.8¢ per KWh for energy produced in the first ten years of a project. Levelized over a 20-year project life, this pre-tax number is equivalent (on a net present value basis) to a 2.0¢ per KWh value for all energy produced over a 20-year project life. It is this value – 2.0¢ per KWh – that we use in this report.

At 2.0¢ per KWh, the PTC is obviously very important to an analysis of the rate impact of an RPS. Since the status of the PTC is not known with certainty, this report includes analyses conducted under different assumptions about status of the PTC.

Rate of Renewable Power Acquisition under the Colorado RPS

As discussed above, the proposed RPS requires utilities to acquire specified amounts of electricity from renewable energy by specific dates. It is not possible to predict the exact schedule and rate of the utilities' compliance with the requirements. A utility could, for example, acquire the full amount of its RPS required capacity in the month immediately before a benchmark date (discrete addition). Alternatively, the utility could obtain the capacity gradually over the entire period between benchmark dates (continuous addition).

For purposes of the cost modeling in this report, we have presumed a middle ground between the continuous and discrete strategies. Specifically, we have used an acquisition schedule that is an average of the "last minute" discrete strategy and the "gradual" continuous strategy. For the case of Xcel Energy, the assumed average acquisition rate is shown in the following chart as the middle of the three curves.



THE FUTURE COST OF ELECTRICITY FROM FOSSIL FUELS

Production Costs of Coal and Natural Gas Plants

In Colorado, the most likely traditional power sources for meeting growth in electric demand are fossil-fueled plants powered by coal or natural gas. Colorado's utilities will acquire such power by either constructing the capacity themselves or purchasing the power in the market. The utilities will answer the "build or buy" question in a decision that balances the availability of capital, assessment of risk, environmental considerations and other factors.

But whether the companies build or buy, the cost of the power will be driven by the familiar components of utility generation costs: capital costs, operating costs and fuel costs. Purchased power is subject to the additional influence of market pressures, with prices responding to market demand.

For this report, we assume that the "avoided cost" facing the utilities is the cost of power produced by an advanced combined cycle natural gas plant. Plants of this design are the preferred choice of third-party power producers given their lower capital costs. During the past decade, natural gas plants provided two-thirds of new capacity in Colorado.

The per-kilowatt-hour costs of an advanced coal plant and an advanced combined cycle gas turbine plant are projected to be relatively close, as demonstrated by the following table, which shows the most recent estimates of the Department of Energy. The values in this table were not used in this report, but are presented here as a check on the costs developed in the model used here.

	2010		2025	
Costs	Advanced coal	Advanced combined cycle	Advanced coal	Advanced combined cycle
	2002 mills per kilowatthour			
Capital	33.77	12.46	33.62	12.33
Fixed	4.58	1.36	4.58	1.36
Variable	11.69	32.95	11.74	37.91
Incremental transmission	3.38	2.89	3.26	2.78
Total	**53.43**	**49.65**	**53.20**	**54.38**

Figure 14 -- Cost of New Fossil Generation

Cost of New Fossil Generation
From *2004 Energy Outlook,* Energy Information Administration

Each technology has its advantages and disadvantages. As can be seen, coal plants have a significantly higher capital cost, but lower variable operating costs, due mainly to the relatively lower cost of coal. Gas plants are cheaper and faster to build but have significantly higher operating costs due to the higher cost of natural gas per kilowatt-hour produced.

These two types of plant differ in other characteristics, including fuel conversion efficiency (heat rates), emissions, water use, etc. But the bottom line is that per-KWh costs are similar under current projections for coal and gas prices. It is a reasonable to assume that the avoided cost faced by Colorado utilities is the cost of an advanced combined cycle gas plant.

Model Assumptions

Capital Costs: For this report, we assume that the marginal plant is an advanced combined cycle gas plant with a capital cost of $550/KW that remains constant (in real terms) over the study period.

Heat Rate: We assume a heat rate of 8100 BTU/KWh, slightly better than the average of the nation's top 50 combined cycle plants in 2003, improving continuously to 6900 BTU/KWh in 2023.

Fuel Cost: For the base case cost of natural gas, we used the most recent projections by the Department of Energy, contained in the *Annual Energy Outlook 2004*, adjusted for lower gas transportation charges in the region.

As discussed *infra*, we also established an alternate High Gas Cost case, in which the historic DOE downward bias in gas prices was removed. In addition, we created a Low Gas Cost case in which future gas costs were adjusted downward from the current DOE estimate by about 10%, phased in over 10 years. Finally, we created a Spike Gas Cost scenario to measure the hedge value of renewable resources in the portfolio. See the discussion of these alternative Gas Cost cases on page 25 below.

Operation and Maintenance Costs: Variable O&M Expenses are assumed to be 2.8 mills/KWh, remaining constant (in real terms) over the study period.

The combination of these assumptions yields the following series of costs for gas-fired electricity shown in the following chart. The costs are approximately 6% lower than the DOE assumptions in its *Annual Energy Outlook 2004* (see Figure 14 on page on page 22 above). The lower cost in Colorado is likely due to our assumption about lower regional gas transportation costs.

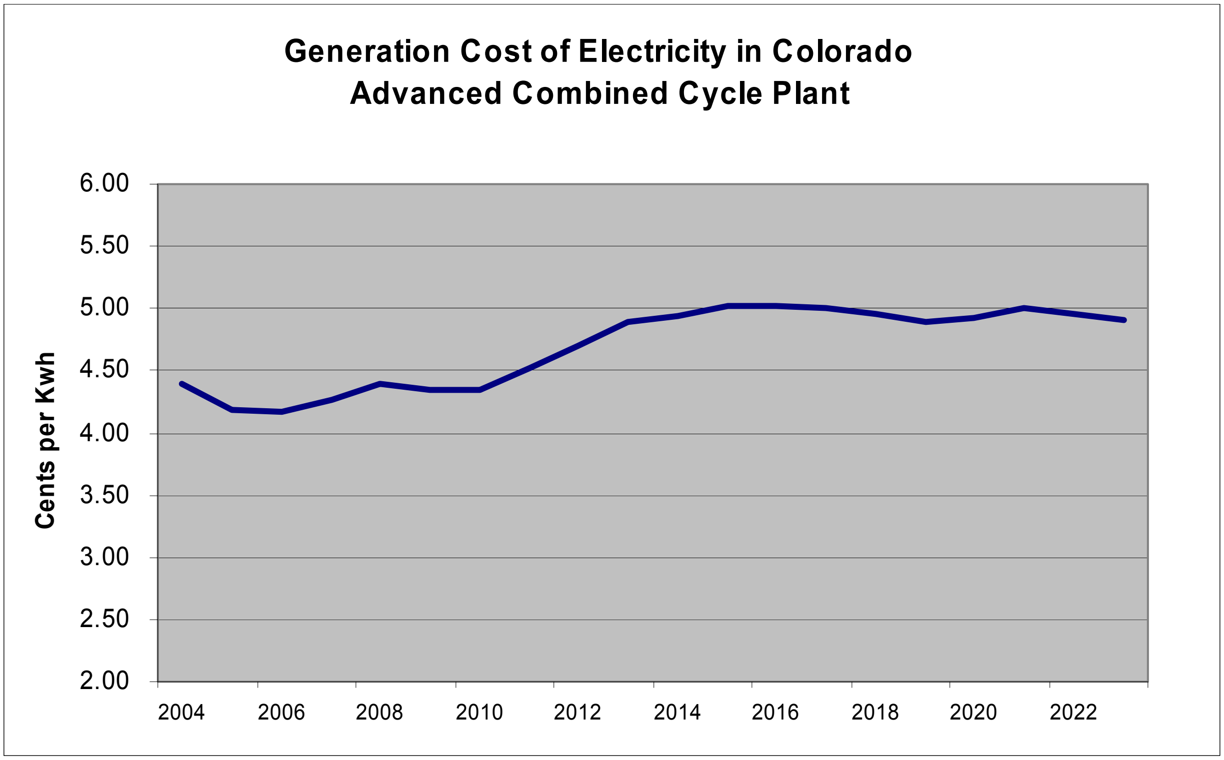


Figure 15 -- Per KWh Cost of Combined Cycle Generation, 2004-2023

The Future Cost of Natural Gas

One of the more vexing challenges facing an analyst of the U.S. utility industry is making assumptions about the future price of natural gas. This premium fuel has become the fuel of choice of non-utility electric generators. In Colorado, the use of natural gas as a generator fuel grew by 498% from 1993 to 2002, an annual growth rate of 22%. During the same period, the energy produced using coal in Colorado increased only 15%, about 1.6% each year from 1993 to 2002. In brief, the cost of natural gas has become an important determinant of generation costs and the price of electricity in western markets.

For the base case estimate in this report, we adopt the current projections provided by the Department of Energy for gas prices to 2025. Here is a graph showing actual wellhead natural gas prices to 2003 together with DOE's estimates from 2004 to 2025.

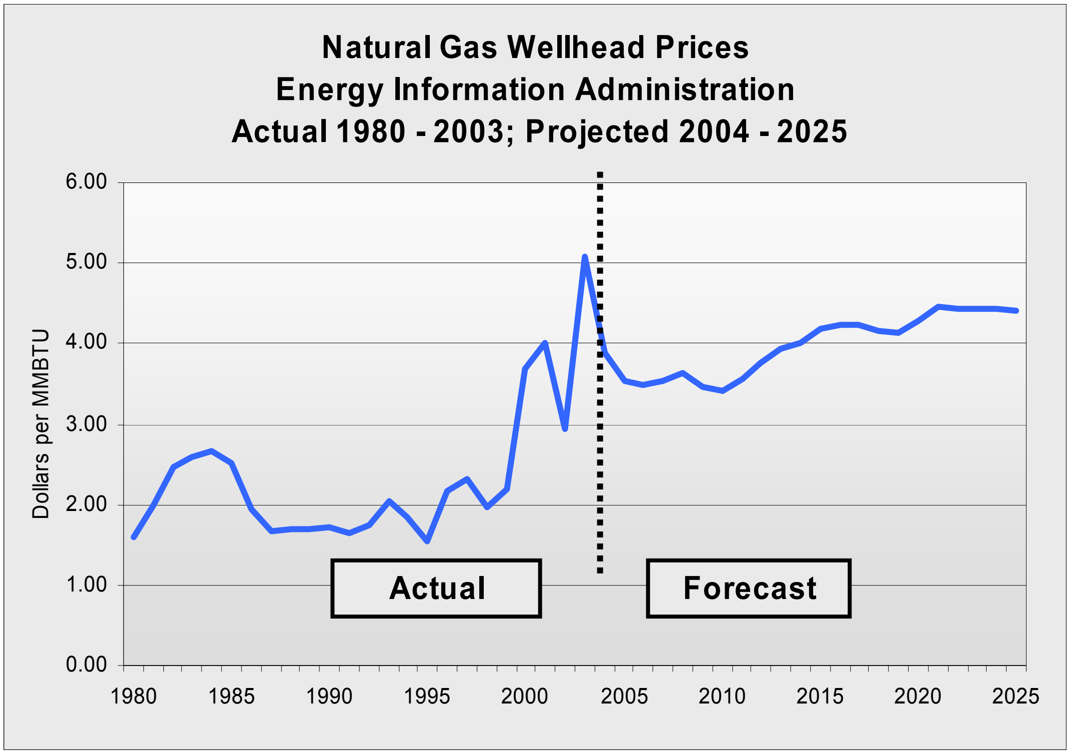


Figure 16 -- Actual and Forecast Natural Gas Prices

There are two important observations about the DOE's estimates of future natural gas prices:

- Each year for the past ten years, the DOE estimate of natural gas prices has superceded the previous year's estimate by *increasing* the estimate of future prices; and
- For the past five years, DOE's estimate has shown a downward bias when compared to commodity futures prices. The bias is estimated to be between $0.40 and $0.60 per MMBTU when the current forecast DOE is compared to the nearest-in-time futures contract.

As a result of this observed downward bias and the fact that EIA price forecasts have been revised upward each year, we have created a "High Gas Cost" scenario (depicted in the following chart) in which an assumed downward bias of $0.50 per Mcf is corrected over the first ten years of the forecast.

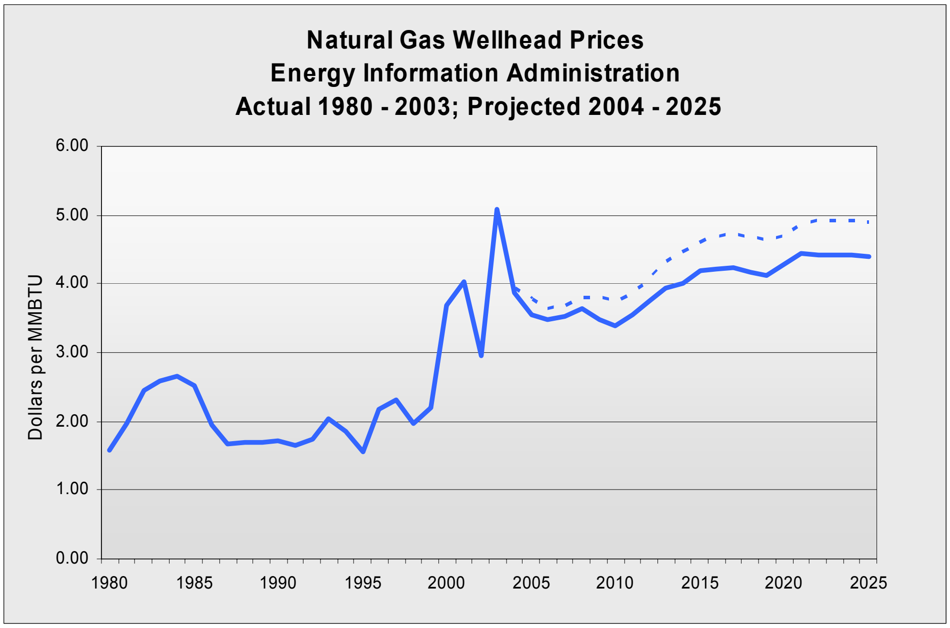


Figure 17 -- Forecast Natural Gas Prices with High Cost Case

As can be seen by inspection, removing the EIA downward bias in projected natural gas prices yields a plausible scenario that will be referred to as the "High Gas Cost" case. In a later section of this report, we will also model the occurrence of sharp price "spikes" such as the price excursions that occurred in 2000 and 2003.

To model the unlikely scenario that gas prices will fall below the EIA estimate, we have also created a "Low Gas Cost" case in which actual prices are $0.50/Mcf below the most recent EIA forecast (with the difference phased in over ten years). The following chart illustrates the High, Base and Low Gas Cost cases that are used in the balance of the analysis. In this chart, the three cases are presented in terms of the cost of gas delivered to the utility.

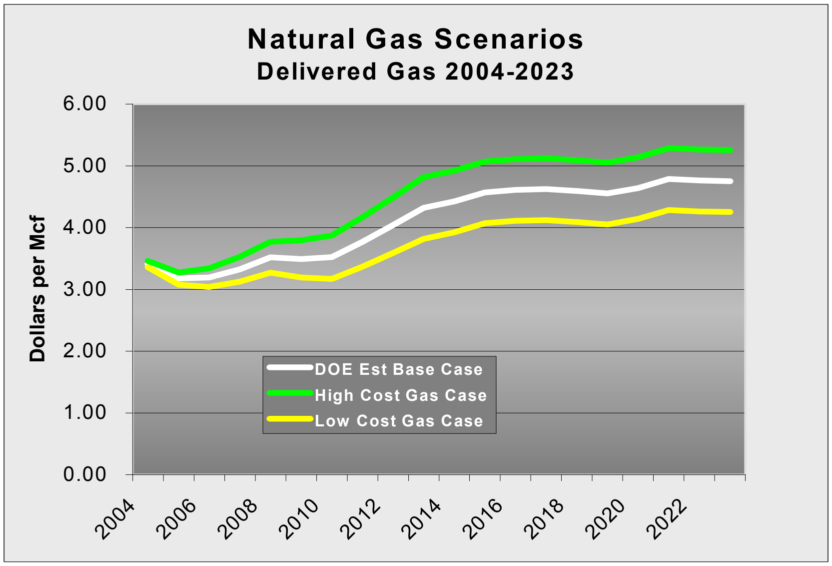


Figure 18 -- Base Cost, High Cost and Low Cost Gas Cases

Rate Impact of an RPS in Colorado

We are now able to estimate the impact that an RPS mandate would have on retail electric rates in Colorado. Since the result is dependent on the choice of input factors, we will distinguish six cases, differing on the assumptions about the future price of natural gas and the status of the federal Production Tax Credit.

Later we will also examine the impact of large short-term price excursions in the price of natural gas to measure the value of renewable energy resources as a price hedge.

Six Scenarios

The first two cases assume the accuracy of the Energy Information Administration's estimate of natural gas prices for the twenty-year period 2004-2023.

Scenario 1: Assume base gas costs; assume that the Production Tax Credit (PTC) is extended retroactively from December 31, 2003 to December 31, 2009.

Scenario 2: Assume base gas costs; assume that the PTC is not extended following its expiration on December 31, 2003.

The next two cases assume higher gas costs by removing the observed downward bias of the EIA gas price projections.

Scenario 3: Assume high gas costs; assume that the PTC is extended for six years until December 31, 2009.

Scenario 4: Assume high gas costs; assume that the PTC is not extended following its expiration on December 31, 2003.

The last two cases assume gas prices are lower than forecast by approximately 11%, with the discount phased in over ten years.

Scenario 5: Assume low gas costs; assume that the PTC is extended for six years until December 31, 2009.

Scenario 6: Assume low gas costs; assume that the PTC is not extended following its expiration on December 31, 2003.

Summary of Effects by Scenario

The following table summarizes the effects of the RPS on retail electric rates under the six scenarios just described.

Following the scenario description in Column A of the table, the (nominal) total 20-year change in Xcel's revenue requirement is shown in Column B, followed by the discounted net present value of the annual effects in Column C. A negative number signifies a reduction in the revenues required by Xcel.

The next three columns show the monthly bill impact for the average residential customer of Xcel Energy in Colorado. Column D states the average monthly bill change over the 20-year period 2004-2023. A negative number signifies a reduction in the monthly bill.

Columns E and F report the range in changes in the monthly bills over the twenty year period. Thus, for example, under the assumptions of Scenario 1, Column D shows the average residential bill will decrease by an average of 20 cents per month. The largest monthly reduction would be 47 cents per month (Column F); the smallest reduction would be 1 cent (Column E) in some months during the twenty year period 2004-2023.

Rate Impact of Colorado RPS for 2004-2023: Six Scenarios

	Xcel Total 20 Year Effect		***Impact on Average Residential Monthly Bill***		
Senario Description	Nominal Effect	NPV Effect	Overall	Range	
Col A	Col B	Col C	Col D	Col E	Col F
Base Gas Case, PTC to 2010	(214,189,504)	(56,145,729)	(0.20)	(0.01)	(0.47)
Base Gas Case, No PTC	(46,573,309)	1,417,352	(0.03)	0.17	(0.31)
High Gas Case, PTC to 2010	(337,474,603)	(96,032,976)	(0.31)	(0.01)	(0.72)
High Gas Gas Case, No PTC	(169,858,408)	(32,713,588)	(0.15)	0.09	(0.55)
Low Gas Case, PTC to 2010	(90,904,404)	(27,487,628)	(0.08)	0.04	(0.23)
Low Gas Gas Case, No PTC	76,711,791	35,831,761	0.08	0.24	(0.06)

Notes:
1) Base Gas Case uses the EIA Annual Energy Outlook 2004 projections for wellhead natural gas prices.
2) High Gas Case removes EIA downward price bias.
3) PTC is the federal Production Tax Credit for renewables -- 1.5 cents/kwh for first 10 years production, adjusted for inflation.

Figure 19 -- Rate Effect of RPS Under Six Scenarios

Probability of the Scenarios

Based on the Department of Energy's consistent under-estimates of natural gas costs, it is reasonable to assume that the probability of the High Gas scenario occurring is 50% and that the probability of the Low Gas Cost scenario occurring is 20%. This implies a 30% probability that the Base Gas Cost case will occur.

It also appears likely that Congress will extend the PTC for renewable energy. For purposes of computing an expected value, it is reasonable to assign a probability of 20% that the PTC will not be extended at all; an 80% probability that the PTC will be extended for six years.

Assigning a probability of 80% of extension for the PTC through 2009 has less effect on the result as might appear: we can assume that, as has occurred in past periods, utilities and wind developers will accelerate acquisition of wind resources in order to take advantage of a PTC if it were scheduled to expire. In other words, the assumption of an extension through, say, 2007 might have the same effect as an extension through 2009. This report does not adjust the rate of acquisition of renewable resources based on the timing of expiration of the PTC.

Under this assignment of probabilities, here is the likelihood of each of the six scenarios occurring:

Scenario Probabilities		
Scenario 1:	Base Gas, PTC to 2010	24%
Scenario 2:	Base Gas, No PTC	6%
Scenario 3:	High Gas, PTC to 2010	40%
Scenario 4:	High Gas, No PTC	10%
Scenario 5:	Low Gas Case, PTC to 2010	16%
Scenario 6:	Low Gas Case, No PTC	4%

Figure 20 -- Scenario Probabilities

Using these probability weightings, we arrive at the following conclusions about the savings associated with wind resources in the portfolio:

- It is likely that the Renewable Portfolio Standard will reduce the revenue requirement of Xcel Energy over the 20-year period 2004-2023. The expected value of the reduction is approximately $ 218 million in 2004 dollars. The discounted net present value of the savings stream is $ 58 million.
- It is likely that the Renewable Portfolio Standard will lower monthly electric bills for residential customers over the 20-year period 2004-2023. The expected reduction for the average residential customer is about 20 cents per month. In some years, the bill reduction could be as large as 51 cents per month.

- Of all the scenarios considered, the single most likely case (with probability 40%) is that residential bills will be reduced by about 31 cents per month. In this case, the revenue requirement of Xcel Energy would decrease by $ 337 million over the 20-year period 2004-2023.

- A much less likely scenario (with 4% probability) is that monthly bills could increase slightly, by about 8 cents per month.

Renewable Resources as a Hedge on Natural Gas Prices

As mentioned earlier, the wellhead price of natural gas has generally increased over the past 25 years, with wide fluctuations observed, especially in the past ten years. In 2003, for example, a spike sent wellhead prices up 72% over 2002 levels.

The estimates of future natural gas costs made by the Department of Energy suggest that prices will trend upward relatively smoothly over the next twenty years. (See first chart below) The DOE estimates do not project price spikes, since these are, by definition, not knowable future events.

Since some renewable resources (e.g., wind and solar) have essentially zero "fuel" costs, these resources can serve as a hedge or insurance against price spikes such as those observed in 2000 and 2003. While it is not possible to predict price spikes, it is possible to model the mitigation of their impact with the presence of renewable energy systems in the resource mix.

The economy is replete with examples of hedges against price fluctuation. Individuals assign a value to predictability in prices: consumers will often select fixed-rate options even when a market-rate or variable-rate option might be advantageous, simply to reduce the risk of price fluctuations. Similarly, firms often hedge their risk by purchasing various types of financial options. Importantly, these options are valuable even if they do not "pay off" in the sense of actually functioning in the case of fluctuations.

While it may be difficult to obtain a precise value of the hedge when applied to renewable electric energy resources, we can simulate the "pay off" value of renewables as a hedge by assuming that natural gas prices take unexpected spikes in the future.

The chart on the left shows the most recent estimates of future natural gas prices published by the Energy Information Administration in its *Annual Energy Outlook 2004.* The chart on the right illustrates the effect of two hypothetical price spikes in 2010 and 2017, and in the "shoulder" years of 2011 and 2018. From inspection of the chart, these price spikes are seen to be plausible, if not predicable.

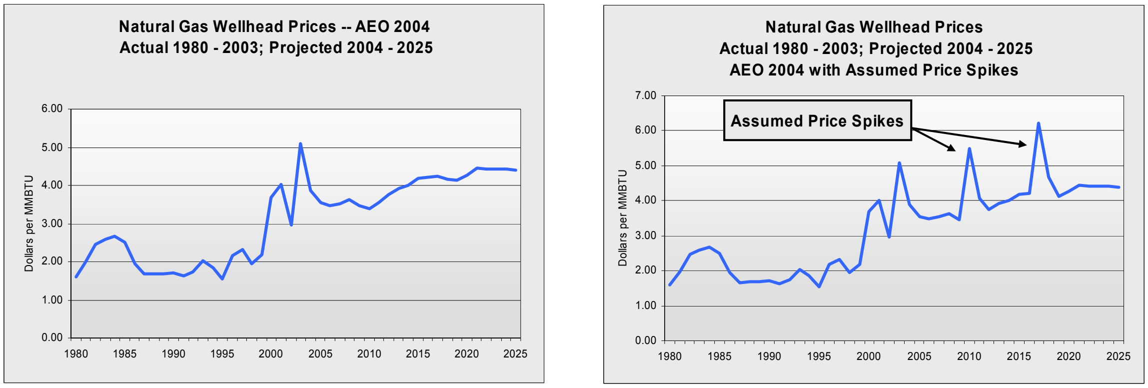


Figure 21 -- Natural Gas Price Spike Assumptions

To illustrate the hedge value of the proposed Renewable Portfolio Standard, we calculated the costs difference between renewables and gas turbine costs under the Base Gas Cost case (the chart on the left) and then made the same calculation using the gas prices shown in the Spike Gas Cost case (chart on the right). The difference of these to results was then calculated. Since fixed costs and base gas costs were included in each case, the difference represents the marginal value of the renewable resources under the assumption of the hypothetical price spikes.

The results are striking. Under the gas price assumptions illustrated in the graph above, the presence of wind resources on the Xcel system at the level required by the RPS would save Colorado consumers $28.3 million and $41.2 million respectively during the two years of the assumed price spike. This equates to monthly savings of $0.57 and $0.72 for residential customers during those two years. These savings are in addition to the savings identified earlier.

Of course, the hedge value for commercial and industrial customers would be much larger. The estimated savings, for example, to a commercial customer with a 500 KW demand and 60% load factor would be approximately $200 per month in a year in which natural gas prices spiked as illustrated in this example.

OTHER EFFECTS OF AN RPS IN COLORADO

Water Use

Thermal electric generating plants such as coal-fired and gas-fired generators use a large amount of water in the production process. The water used in electricity production can be permanently lost to the state (*consumptive use)* or it can be withdrawn and replaced, usually with a temperature differential (which can have environmental consequences in some cases). Focusing on the consumptive use of water in generation plants, that use is approximately 250 gallons per MWh for gas plants and 490 gallons per MWh for coal plants.

By displacing the need for a portion of new gas-fired or coal-fired generation, some renewable energy sources can reduce the consumptive use of water in generation. For example, energy produced using wind turbines requires no water. Other renewable resources, e.g. co-firing biomass, require water for cooling and will not have this impact.

The following table illustrates the water savings of the proposed Colorado RPS assuming the renewable resources (e.g., wind or solar) do not require water for consumptive use and displace gas generation.

Impact of RPS on Consumptive Water Use		
Total Impact 2004-2023		
MWh	**Gallons Saved**	**Acre-Feet Saved**
35,545,037	8,886,259,157	27,281
Average Annual Impact 2004-2023		
MWh	**Gallons Saved**	**Acre-Feet Saved**
1,777,252	444,312,958	1,364

Figure 22 --Impact of an RPS on Consumptive Water Use

If renewable generation replaces coal generation only, the water savings would be much greater: approximately 53,000 acre-feet of water would be saved from consumptive use over 20 years in this case.

To put these numbers in perspective, 53,000 acre-feet of water is the *combined* capacity of four reservoirs used by Denver Water: the Gross, Marston, Ralston and Strontia Springs reservoirs.

Air Quality Effects

If the Renewable Portfolio Standard were met with near-zero-emissions energy sources such as wind or solar sources, there would be a substantial positive impact on Colorado air quality and a reduction in greenhouse gas emissions.

To calculate the rate impact of the RPS, this report assumed that the RPS resources would replace generation from natural gas-fired turbine generators. While these remain the most likely avoided capacity installations or purchases, actual system operations may include displacement of some coal generation, depending on the system considerations at the time. Obviously, the emissions profile of gas and coal as fuel sources differ considerably.

Focusing on carbon dioxide emissions, and assuming the avoided capacity is a combined cycle natural gas plant, we calculate that the avoided CO_2 emissions are approximately 16 million tons over 20 years. The corresponding value if coal-fired production is displaced is 27 million tons of CO_2.

It is beyond the scope of this report to estimate the reduction in emissions of sulphur oxides (SO_x), nitrogen oxides (NO_x), and mercury, since the level of these pollutants will depend upon the quality of fuels and the mix of coal and gas generation actually displaced by renewable resources. In general, though, the RPS would be expected to reduce emissions of these pollutants. Over the next 20 years, the RPS will require new renewable resources to supply 36 million MWh of electricity, about 5.5% of all the electricity sold in the state during that period.

Rural Economic Development Opportunities

Another of the impacts of developing renewable power (especially wind generation) cited by its advocates is the impact on rural communities. Because wind resources are typically found outside of densely populated areas, there is a natural connection between this resource and the economies of rural areas. The economic impact has two elements:

- Increased revenues for local governments related to increased tax base;
- Income for rural landowners from leasing land to wind site developers.

The National Conference of State Legislatures released a briefing paper in January 2004, *Tax and Landowner Revenue from Wind Projects* that discusses these aspects of wind power and rural economies. NCSL quotes data that shows that landowners are receiving between $750 and $4000 per wind turbine per year in payments for the use of their land.

If the 2021 RPS requirement were met entirely with wind resources in Colorado, up to 1300 wind turbines would be required, yielding an annual payment of $1 million to $5 million to landowners. NCSL points out that wind turbines are usually compatible with other uses of the land, so that these payments would be in addition to any gain realized from farming or ranching.

The NCSL report also includes numerous anecdotal examples of county governments and school districts across the country collecting substantial revenues from wind projects. In some cases, the counties are receiving payments in lieu of taxes for tax-exempt projects.

Finally, Western Resource Advocates reports that the addition of a wind farm similar to the Lamar wind farm would increase the tax base of many eastern Colorado counties by percentages ranging from 20% to 50%.

CONCLUSIONS

It is reasonable for policy makers to ask about the impact on utility bills of the Renewable Portfolio Standard proposed in HB 1273. Despite the strong public support for increased use of renewable energy, there might be a negative reaction among consumers if the RPS caused electric rates to rise significantly.

Fortunately for Colorado, the RPS requirement of HB 1273 is likely to *lower* utility bills, not raise them.

This report finds that the RPS proposed in HB 1273 for Colorado is unlikely to affect consumer rates much in either direction. The expected value of the RPS effect in Colorado is that residential consumers would experience a modest average reduction of 20 cents in monthly electric bills during the twenty year period 2004-2023.

Under a slightly more favorable (but very probable) set of assumptions, the average bill reduction would be about 31 cents per month. Finally, adopting much less likely worse-case assumptions (lower natural gas prices and no federal production tax credit), the RPS could cause a small increase of 8 cents per month in the monthly bill for the average residential customer of Xcel Energy.

The following chart shows the cumulative dollar savings from the Colorado Renewable Portfolio Standard over the first twenty years of its application under two scenarios.

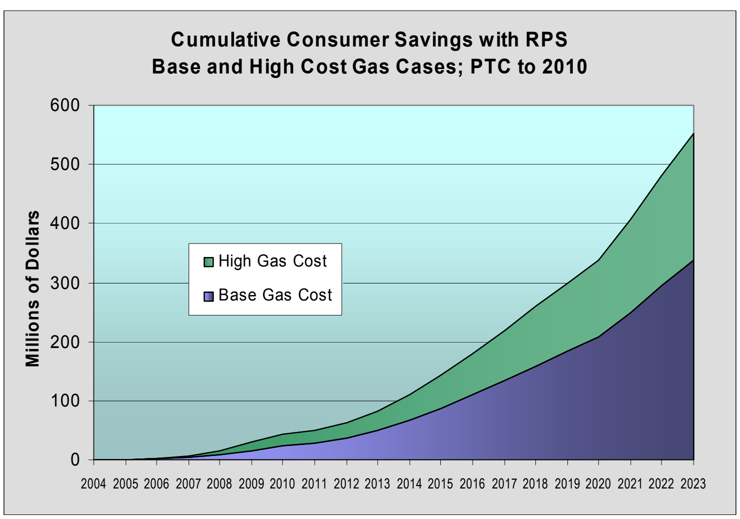


Figure 23 -- Cumulative RPS Savings

In addition to the likely favorable impact on rates, this report identifies two other impacts of a Renewable Portfolio Standard: the impact on Colorado's rural economies and a reduction in emissions from the state's power plants.

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