Appendix F
Energy Supply
Policy Recommendations

Summary List of Policy Recommendations

	Policy Recommendation	GHG Reductions ($MMtCO_2e$)			Costs (Savings) 2007–2020 (Million $)	Cost-Effective-ness ($/t$CO_2$e)	Climate Action Panel Action
		2012	2020	Total 2007–2020			
ES-1	Tax credits and incentives to finance renewable energy generation facilities.	Benefits are quantified in policy ES-2.					Unanimous Consent
ES-2	Increase renewable portfolio standards to 30% for investor-owned electric utilities and 15% for municipal and co-op utilities, with no more than 85% of renewable energy from centralized wind power.	1.9	4.9	34	$524	$16/ton	Super Majority (3 objections) (1 qualified approval)
ES-3	Consider adoption of Xcel's clean energy portfolio standard on a state, regional, or national basis.	Non-specific policy was not quantified					Majority (9 objections)
ES-4	Require all electric utilities to plan cooperatively for electricity transmission infrastructure investments that support renewable resources.	Non-quantitative policy proposal analyzed					Unanimous Consent
ES-5	Consider applying a price to CO_2 emissions (such as cap and trade or tax) on a state, regional, or national basis.	Non-specific policy not quantified					Super Majority (1 objection) (1 qualified approval)
ES-6	Assess a public benefit charge on all electric utility bills to fund renewable energy programs.	Policy not quantified					Super Majority (3 objections) (1 qualified approval)
ES-7	Adopt structural changes to facilitate large businesses and universities to invest in combined heat and power (CHP) and distributed generation (DG) systems.	0.4	1.1	7.3	$110	$15/ton	Unanimous Consent
ES-8	Work with neighboring states to form a regional CO_2 transportation and sequestration collaborative.	Non-quantitative proposal not quantified					Unanimous Consent
ES-9	Low interest loans to Colorado companies and universities for research and development of carbon emissions reduction technology, funded at $100M/yr through surcharge on all electricity bills.	R&D benefits not quantified					Unanimous Consent
ES-10	Evaluate and, if appropriate, seek funding for advanced fossil fuel generation with carbon capture demonstration project.	Non-specific policy not quantified					Unanimous Consent
ES-11	Statewide mapping & development of small hydro-power, geothermal, and biomass renewable power sources.	0.0	0.8	3.1	$123	$40/ton	Unanimous Consent
ES-12	Review costs and emission reduction potential of nuclear power.	Non-specific policy not quantified					Unanimous Consent
ES-13	Adopt policies to promote a 2% increase in efficiency of existing power generators by 2020.	Costs not quantified – savings ca. 1 $MMtCO_2$/yr by 2020					Unanimous Consent
ES-14	Reduce GHG emissions from oil and gas operations 35% by 2020.	0.8	2.6	16	$12	$0.8/ton	Unanimous Consent
ES-15	Establish a CO_2 emissions performance standard of no more than 1,100 lbsCO_2/MWh for new non-peaking power plants and those older than 60 years.	0.5	2.3	13	–$14	–$1/ton	Super Majority (5 objections)
	Sector totals of **6 analyzed policies** (including ES-13) after adjusting for overlaps among policies	3	9	59	N/A	N/A	
	Sector totals of **5 policies with cost estimates** (not including ES-13) after adjusting for overlaps				$526	$10/ton	

GHG = greenhouse gas; $MMtCO_2e$ = million metric tons of carbon dioxide equivalents; MWh = megawatt hours.

Negative cost numbers indicate cost *savings*. The cost (savings) shown are calculated as in terms of net present value in constant 2005 dollars using a 5% annual real discount rate for the period 2008 through 2020. Capital investments are represented in terms of levelized or amortized costs through 2020.

ES-1. Renewable Energy Incentives

Policy Option Description

Resource maps of renewable energy in Colorado developed by the U.S. Department of Energy's (US DOE's) National Renewable Energy Laboratories (NREL), based in Golden, Colorado, show that Colorado is well-endowed with renewable resources. Wind is prevalent in the northeast and southeast corners of the state. Biomass is available in the northeast. Photovoltaics can be deployed throughout the state. Concentrating solar power can be tapped in the San Luis Valley. Deep geothermal resources exist in the southern portion of the state. Solar and wind alone may have the potential to produce 100 times the electricity currently used in Colorado, even after reasonable filters are applied. However, renewables are generally more costly than today's conventional energy supplies. Financial incentives can greatly accelerate the deployment of renewables and allow time for learning curves, economies of scale, and R&D to lower their costs.

Mechanisms include an investment tax credit, an energy production tax credit, a tax incentives, and incentives to help support financing of projects. Production tax credits are generally preferred by renewable energy providers that can produce electricity at under about 10 cents per kWh (wind and geothermal), whereas investment tax credits are generally preferred for more expensive technologies (concentrating solar power). Key to the success of these incentives is that they be guaranteed for a period of at least 5 years to allow time to raise financing and build projects.

Financial incentives that encourage utilities to deploy or purchase renewable energy should also be considered. Finally, R&D aimed at solving Colorado-specific issues can be funded at state universities and NREL. These issues include resource assessment and performance-cost analysis.

Policy Option Design

Goal: Financing and/or tax incentives to meet goals in ES-2

Timing: 2009

Coverage: First 2000 MW capacity in state

Other: Not applicable.

Implementation Mechanisms

SBC or other funds are distributed as investment tax credits, production tax credits and/or other financial incentives.

Related Policies/Programs in Place

Federal production tax credit for wind energy and investment tax credit for photovoltaic (PV) systems.

Type(s) of GHG Reductions

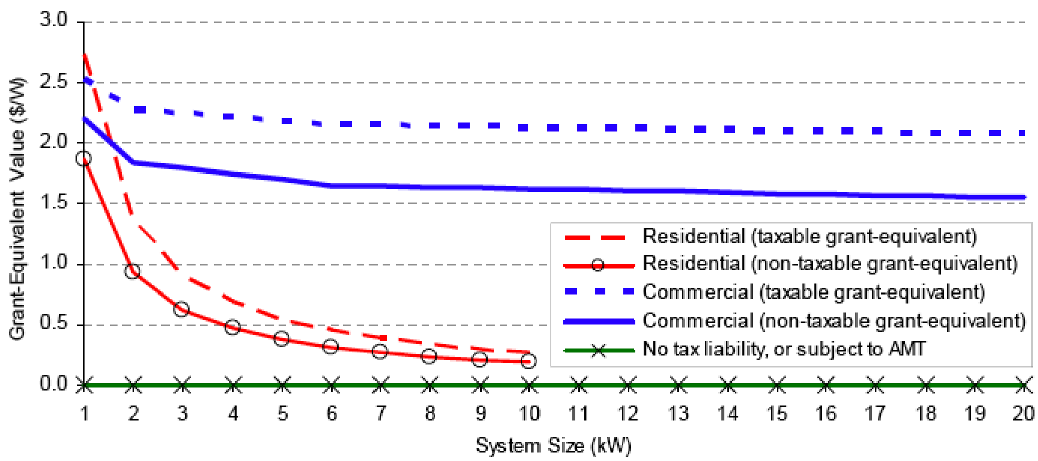
Decreased fossil generation resulting from replacement with renewable generation.

Estimated GHG Savings and Costs per $MtCO_2e$

Benefits are quantified in companion policy ES-2.

We found one attempt specifically to quantify the benefits of investment incentives—in the report, *Exploring the Economic Value of EPAct's PV Tax Credits* by Bolinger, *et al.* In this report, the authors use a cash-flow model to calculate the "grant-equivalent benefit" to PV owners of the EPAct 2005 investment tax credit for PV. As seen in their chart (below), they find the benefit to be equivalent to grants in the range of $1.75 to $2.75 per Watt for very small systems. The value falls rapidly with increasing system size for residential owners, but much less rapidly for commercial owners. (Graphic taken from Bolinger, Wiser and Ing, page 8.)

Figure F-1. The Benefits of the EPAct Tax Credit for Photovoltaic Owners



Data Sources:

Bolinger, Wiser, and Ing, *Exploring the Economic Value of EPAct's PV Tax Credits*, Lawrence Berkeley National Laboratory, February, 2007.

Cameron Brooks, et al., *A Guidance Document on Debt and Equity Investment Mechanisms for the Clean Energy States Alliance*, November, 2003.

Brooks, Milford and Schumacher, *Global Clean Energy Markets: the Strategic Role of Public Investment and Innovation*, a report for the Clean Energy Group, May 2004.

Quantification Methods:

Quantified with companion policy proposal ES-2.

Key Assumptions

None identified.

Key Uncertainties

None identified.

Additional Benefits and Costs

None identified.

Feasibility Issues

None identified.

Status of Group Approval

Unanimous consent of those CAP members present and voting.

Level of Group Support

No objections.

ES-2. Mandated Portfolio Standards

Policy Option Description

A Renewable Portfolio Standard (RPS) is a requirement that utilities must supply a certain percentage of electricity from an eligible renewable energy source(s). For example, an RPS of 5% would mean that for every 100 kWh that a utility supplies, 5 kWh must be generated from renewable resources. About 20 states currently have an RPS, including Colorado. Colorado's current RPS requires investor-owned utilities to provide 20% renewable energy by 2020 and other load serving entities to provide 10%, also by 2020. In some states, utilities can also meet their RPS (or EPS) by purchasing certificates from eligible energy projects, typically referred to as Renewable Energy Certificates (RECs).

Policy Option Design

Goal: 30% of total energy for Investor-Owned Utilities (IOUs), and 15% for municipal utilities and cooperatives, to come from renewables; no more than 85% of this from utility-scale wind projects. The requirement may be satisfied through the purchase of RECs following the guidelines of the existing Colorado RPS, except that in-state RECs shall be weighted equally to out-of-state RECs.

Eligibility of efficiency improvements at large hydropower projects for generating RECs should be considered.

Wildlife values and sustainability issues should be taken into account for siting of new wind and hydro facilities.

Timing: by 2020

Coverage: All retail electric suppliers, including municipally owned and co-ops.

Implementation Mechanisms

Mandate applicable to all IOUs, municipal utilities and cooperatives.

Related Policies/Programs in Place

The existing RPS in Colorado requires 20% renewables for IOUs and 10% renewables for cooperatives and municipal utilities (with +40,000 customers) by 2020. IOUs must meet 4% of their annual target with solar, half of which must be located on-site at customers' facilities.

In-state renewable resources receive favorable treatment. Each kilowatt-hour (kWh) from eligible in-state renewable projects receives 125% credit for RPS-compliance purposes. Certain community-based projects can receive 150% credit under cooperatives and eligible municipal utilities, and solar projects online by 2015 receive 300% credit.

Utilities are entitled to recover prudent cost of complying RPS through retail rates. Utilities may comply with the RPS by purchasing RECs.

Type(s) of GHG Reductions

Reductions come from reduced fossil-fueled generation relative to the reference case.

Estimated GHG Savings and Costs per $MtCO_2e$

		GHG Reductions ($MMtCO_2e$)			Gross NPV Cost 2007–2020 (Million $2005)	NPV Savings 2007–2020 (Million $2005)	Net Present Value 2007–2020 (Million $2005)	Cost-Effectiveness ($2007/$tCO_2e$)
ES-2	Mandated Portfolio Standards	2	5	34	$1,992	$1,468	$524	$16

Note also that costs shown include only the projected costs of the renewable energy and avoided cost of displaced generation; we have not included any administrative costs.

Data Sources:

Data from the following sources were used in this analysis.

Black and Veatch; research performed for the US DOE, NREL and American Wind Energy Association, unpublished draft report.

Colorado Springs Utilities, unpublished research on biomass fuel and technology costs in Colorado.

KEMA 2006. Colorado DSM Market Potential Assessment, March 31, 2006.

NREL, Comparison of Cost-Based U.S. Operational Impact Studies, 2007.

Synapse Energy Economics and Tellus Institute, A Balanced Energy Plan for the Interior West, a report for Western Resource Advocates, 2004. Available at: www.westernresourceadvocates.org.

Stoddard, et. al., Economic, Energy and Environmental Benefits of Concentrating Solar Power in California, NREL, May 2005–April 2006, NREL/SR-550-39291.

US EIA, Annual Energy Outlook 2007, Assumptions to the AEO, Electricity Market Module. Available at: http://www.eia.doe.gov/oiaf/aeo/assumption/index.html.

Western Governor's Association (WGA) Solar Task Force, Clean and Diversified Energy Initiative, Western Governor's Association, January, 2006.

Wiser and Bolinger, Report Summary, Annual Report on U.S. Windpower Installation, Cost and Performance Trends, 2006, US DOE, May 2007.

Wiser, et. al., Letting the Sun Shine on Solar Costs: An Empirical Investigation of Photovoltaic Cost Trends in California, LBL, January, 2006, LBNL-59282.

Quantification Methods:

The PWG working group provided the following guidelines:

- Large wind projects could not account for more than 85% of the renewable energy requirement,
- Each of the following resources provides three percent of the renewable energy requirement: solar thermal, small scale solar PV, small hydro, biomass and geothermal.

We first reviewed a number of sources to develop cost assumptions for each of the eligible renewable technologies over the study period. We next calculated the amount of each type of new renewable technology needed to meet the policy goal in 2020, and interpolated the growth of each technology from current levels to the 2020 levels. (See discussion of this below.) We balanced supply and demand in each year by backing off coal- and gas-fired generation in a ratio of 75% coal and 25% gas. We first backed off any fossil generation added in that year, and when new generation reached zero, we began backing off generation from existing fossil units.[1] Generation from existing coal-fired plants was reduced by 2% in 2008 and 6% in 2020. Generation from existing gas-fired plants was reduced by 2% in 2008 and 7% in 2020. As a final step we calculated avoided GHG emissions as a result of the decreased fossil fuel generation.

We calculated the cost of the RPS by calculating total costs for each technology in each year. When the cost of a technology changed over time, previously installed capacity continued to operate at its original levelized cost, while new capacity from that point forward used the updated levelized cost. The total cost of the new renewable energy was then summed for each year and compared to the total avoided cost, calculated with a real avoided cost figure of $56 per MWh throughout the study period. This avoided cost figure is based on from Xcel's 2006 DSM market assessment.

Key Assumptions:

Although the policy would only place a single constraint on the types of renewable energy sources that are eligible (no more than 85% of the requirement to be met from large wind sources), the PWG determined that for analysis purposes, a much more detailed requirement for distribution of technologies would be assumed as shown in Table F-1. This required mix of generating technologies fundamentally drives the cost of this option. A similar RPS program with looser technological diversity requirements might have significantly lower costs.

Major assumptions affecting this analysis are

- the mix of renewable technologies meeting the RPS;
- the cost of these technologies;
- the avoided cost of fossil fuel generation; and
- the type of generation displaced by new renewable generation.

The percentage of total RPS energy generated from each renewable technology is shown in Table F-1 along with total renewable generation. The figures for 2007 are based on projected

[1] Generation from existing coal-fired plants was reduced by 2% in 2008 and 6% in 2020. Generation from existing gas-fired plants was reduced by 2% in 2008 and 7% in 2020.

2007 generation from existing renewable facilities, and the RPS is assumed to take effect in 2008. We assume that 10% of existing hydro generation is eligible to meet the RPS.

Table F-1. Assumed mix of generation meeting the proposed RPS

	2010	2015	2020
Wind	91%	87%	84%
Solar PV	1%	3%	3%
Solar Thermal	1%	3%	3%
Existing Hydro	5%	2%	2%
New Hydro	0%	0%	1%
Biomass Co-firing	1%	3%	3%
Other Biomass	2%	1%	1%
Geothermal	0%	2%	3%
Total RPS GWh	2,800	10,200	16,000

Percentages may not sum to 100 due to rounding.

The levelized cost of each technology over the study period is shown in Table F-2 along with relevant sources. Note that the costs used are reported net of the federal production tax credit and investment tax credit. The production tax credit is assumed to extend through 2014, while the investment tax credit is assumed to extend through the study period.

Table F-2. Assumed levelized cost of renewable technologies (2005$/MWh)

	2010	2015	2020	Relevant Sources
Wind	50	72	68	Wiser and Bolinger; Black and Veatch
Solar PV	263	177	135	PWG assumption.
Solar Thermal	133	94	89	Stoddard *et al.,* WGA solar task force
Small Hydro	---	105	105	PWG assumption.
Biomass Co-firing	1	20	20	Colorado Springs; Synapse
Other Biomass	48	63	63	Colorado Springs; Synapse
Geothermal	---	71	71	Scaled up from EIA; Black and Veatch

Wiser and Bolinger. These costs were compared to a number of other estimates, most notably the data recently developed by Black & Veach for DOE, NREL and AWEA. Current costs are high based on high demand for equipment. The PV costs used are consistent with residential scale PV systems—in the range of 2 kW in size. Capital costs are assumed to be $6,000/kW through 2014. falling to $4,000/kW through 2019, and $3,000/kw in 2020. The capacity factor is assumed to be 20%.

Small hydro is assumed to cost $3,000/kW with total O&M costs of $5.00/MWh. The assumed capacity factor is 35%. Projects are depreciated over 40 years; the capital recovery factor is 10.2%.

Biomass co-firing costs are estimated to range from $15 to $25 per MWh depending on fuel costs and whether or not fuel handling equipment is purchased. Fuel costs are the key driver of costs and they appear to vary widely—from around $1.00/mmBtu to over $2.00/mmBtu. We assume $20/MWh throughout the study period. However, because this resource is eligible for the PTC, the net cost is $1/MWh prior to 2015.

Other biomass energy is assumed to be provided by fluidized bed plants with capital costs of $2,400/kW, total O&M of $28.50/MWh. The assumed capital recovery factor is 12.6%. Capital costs are assumed to fall 5% by 2015 due to technology development and learning.

The geothermal cost estimate used here is highly speculative. We found very little data on the cost of developing deep geothermal resources such as those in Colorado. We have taken the EIA's estimate for developing shallow resources and scaled it up to account for the depth and untested nature of the Colorado resource. EIA's capital cost is $2,260/kW: we assume capital costs of $4,000/kW and use EIA's O&M cost of $77/kW-yr. Capital costs are assumed to fall by 10% in 2015 due to technological improvements and learning.

In addition to these costs, we added system integration costs to wind energy. These costs rise as wind generation becomes a larger portion of total, as shown in Table F-3. These assumed costs are based on an NREL review of wind integration cost studies.

Assumed Wind Integration Costs (2005$)

Wind integration costs are indicated in Table F-3. See the discussion under "Key Uncertainties" for more detail.

Table F-3. Wind integration costs

Wind Integration Costs ($/MWh)					
Penetration Threshold (% energy)	0%	5%	10%	15%	20%
Cost per MWh:	$1	$3	$5	$8	$11

Key Uncertainties

In terms of emissions, the key uncertainty is what fuels are backed off as new renewable generation is added to the system. We have assumed that both new plant additions are deferred and existing plants are utilized less in the ratio of 75% coal and 25% gas. In reality, each new resource type will affect the system differently, based on its pattern of generation, and the dynamics differ significantly in the short run and the long run. Further, the ability of new renewable resources to meet peak load requirements in the state must be assessed.

Hourly dispatch modeling might help to shed more light on these dynamics in this study.

In terms of cost, the costs assumed for wind energy and the avoided cost have the largest impact on estimated RPS costs. There are large uncertainties in these costs, and there may be some distortion associated with using values from dissimilar sources. For example, avoided costs of new generation were based on EIA forecasts, whereas costs for renewable resources were based on other sources as noted.

Wind Integration Costs

One significant area of uncertainty in projecting a large role for nondispatchable, variable output resources such as wind power is the additional cost imposed on the system in order to maintain reliability standards in the face of their unpredictable output. With current technology and experience, many believe that these "wind integration" costs could reach up to $20/MWh or higher as wind penetration levels approach 25% of system capacity. However, there are a number of factors that might mitigate against such high cost as the system and operating practices adjust to accommodate higher contribution of wind. Some of these include:

- Participation in a larger control or balancing area with active energy markets, such as WestConnect
- Better technology for new generating resources used for ramping, including better heat rates, wider operating ranges, and better quick start capabilities
- Changed operation of existing hydro resources, including those operated by Western Area Power Authority, to accommodate wind
- Better wind forecasting

PWG members provided the following sample trajectories for possible wind integration costs on their system with increasing contribution of wind to total energy production. However, PWG members do not consider these trajectories to span the entire range of possible costs (i.e., the high and low cases do not represent maximum and minimum), nor do they represent these as indicative of costs for all of or any particular region of Colorado.

Table F-4.

Wind Integration Costs ($/MWh)					
	Penetration Threshold (% energy)				
	0-4%	5-9%	10-14%	15-19%	20-25%
Low Case:	$ -	$ 1	$ 2	$ 3	$ 5
Mid Case:	$ 1	$ 3	$ 5	$ 8	$ 11
High Case:	$ 1	$ 4	$ 9	$ 12	$ 17

Choosing a row from this range of integration cost trajectories would impact the results of this analysis as indicated in Table F-5.

Table F-5.

	GHG Reductions ($MMtCO_2e$)			Gross NPV Cost 2007–2020 (Million $2005)	NPV Savings 2007–2020 (Million $2005)	Net Present Value 2007–2020 (Million $2005)	Cost-Effectiveness ($2007/$tCO_2e$)
	2012	2020	Total 2007–2020				
Low Case	1.9	4.9	34	$1,836	$1,468	$367	$11
Mid Case	1.9	4.9	34	$1,992	$1,468	$524	$16
High Case	1.9	4.9	34	$2,123	$1,468	$655	$19

Additional Benefits and Costs

Transmission costs for serving wind resources are not included in this analysis. (See discussion in ES-4.)

Policy would have other air emissions benefits and water use savings benefits not quantified here.

Feasibility Issues

Current RPS requirement for municipal utilities and cooperatives is lower than for IOUs—10% by 2020. This policy may be especially burdensome for these entities.

Status of Group Approval

Approved by CAP members present and voting with three objections.

Level of Group Support

One objection concerned the 85% ceiling on central station wind.

Two objections were that Colorado should gain experience with the existing RPS program before increasing the requirement. One of those two objectors also included concerns about the lack of any state’s experience with a 30% standard, lack of cost studies for integration of renewables at that level, and a belief that government should not be mandating fuel supply.

One CAP member’s vote of approval was qualified, on the basis that additional analysis is needed on the quantification of costs.

Barriers to Consensus

None identified.

ES-3. Clean Energy Portfolio Standards

Policy Option Description

This is a variant on the portfolio standard that is more broadly defined to include energy efficiency, clean coal, new nuclear resources, and carbon offsets, as well as renewable energy, and is based on a proposal by Xcel energy for a nationwide portfolio standard. Xcel's analysis and that of EIA can provide insight into the potential of a Colorado-only program.

Policy Option Design

Goal: Consider Xcel's proposed "clean energy portfolio standard" on a state, regional, or national basis.

Timing: Not specified.

Coverage: Not specified.

Implementation Mechanisms

Implementation following Xcel proposal.

Related Policies/Programs in Place

RPS program in Colorado.

Type(s) of GHG Reductions

Avoided emissions based on displaced conventional fossil fuel generation.

Estimated GHG Savings and Costs per MtCO$_2$e

Non-specific policy was not quantified.

Data Sources:

EIA, ICF

Quantification Methods:

Not quantified as part of this process; however, this has been quantified as a possible national policy initiative by the U.S. Energy Information Administration (EIA), which projected a total cost of $7.8 billion NPV from 2006 through 2030, and reductions of 186 MMtCO$_2$ in 2020, on a national basis.

Key Assumptions:

- Other assumptions as contained in Xcel proposal and/or EIA analysis.
- Costs of generating technologies in the NEMS electricity model

Key Uncertainties

- Uncertainties in the projected costs of new nuclear and IGCC units are substantial.
- Safety valve cost cap renders emissions reductions uncertain
- Cost estimates from NEMS for nuclear technologies are considered highly optimistic by several members.

Additional Benefits and Costs

None identified.

Feasibility Issues

None identified.

Status of Group Approval

Accepted by CAP with simple majority, with 9 objections out of 22 members present and voting.

Level of Group Support

The following are some of the objections:

- Could get in the way of other, more effective policies.
- Not pertinent for this panel to even consider something that was so controversial on national level.
- Uncertainty of emissions reduction under this plan, given the “safety valve” price.
- Would be more acceptable if undertaking in concert with a national or regional cap.
- Concerns about inclusion of nuclear energy, considering waste issues and potentially very high cost.

Barriers to Consensus

Those CAP members raising objections expressed strong opinions in opposition to the policy, as reflected in the objections listed above.

ES-4. Transmission Infrastructure for Renewables

Policy Option Description

SB 100 provides that utilities regulated by the Public Utilities Commission are required to file maps of generation resource areas that need transmission, and transmission plans to serve those areas, for approval by the PUC by October 31 of each odd-numbered year. This new law changes the goal of transmission planning and investments by requiring planning and investment for transmission to serve resource areas, rather than for single generators as had been the case in the past. This will break the "chicken and egg" dilemma for new renewable energy projects in the state, where transmission to serve potential wind-power resources could not be built without generators to serve, but no wind project developer could develop a project in an area without transmission already in place.

The mitigation option proposed here is to expand the coverage of SB 100 to all Colorado utilities to achieve a seamless, coordinated transmission network solution to support renewable resources statewide, instead of limiting transmission planning to areas served by investor owned and PUC regulated utilities.

The proposed solution is to plan for phased expansion based on the magnitude of the wind resource, along with attention to engineering, cost, statewide and regional transmission needs, and benefits associated with transmission investments including consumer savings from adding diverse resources to utility generation portfolios.

As a guide, this proposal includes full implementation of the National Wind Coordinating Collaborative (NWCC)/Western Governors' Association (WGA) Leadership Forum Draft Action Plans: Implementing Transmission Recommendations in the West. Information on these plans can be found on the following Web sites:

- Press release: http://www.westgov.org/wga/press/plenary1-pr.htm
- Policy resolution: http://www.westgov.org/wga/policy/06/clean-energy.pdf
- Report: http://www.westgov.org/wga/meetings/am2006/CDEAC06.pdf
- General Web site: http://nationalwind.org/events/transmission/western/2006/default.htm

Policy Option Design

Goal: Require joint planning and cooperation and to design "expandable" transmission to serve renewable energy resource zones (i.e., providers & renewable energy developers working together.)

Timing: Pass legislation amending SB 100 in the 2008 legislative session.

Coverage: Statutory changes will directly affect utilities and renewable resource developers regulated by the Public Utilities Commission (PUC). Locally controlled and regulated utilities and federal power marketing agencies will be encouraged to participate.

Implementation Mechanisms

Requirement on transmission providers as discussed above.

Renewable energy technologies face a barrier to development that conventional fossil-fuel energy technologies do not—namely, many renewable energy technologies (e.g. wind, geothermal) must be built where the energy source is best which is often far from existing transmission lines and load centers. Under current Federal Energy Regulatory Commission (FERC) rules, interconnecting generators, such as new wind farm developers, pay the full cost of the tie-lines from the generator to the first point of interconnection with the grid.[2]

FERC rules also determine who pays for upgrades needed for the transmission grid to serve new renewable energy generators:

> Network upgrades are defined as the additions, modifications, and upgrades to the transmission system at or beyond the point of connection to the grid to accommodate generators to the system. The full cost of network upgrades for generator interconnection is borne by and rolled into transmission rates of transmission owners. Transmission owners, however, may require interconnecting generators to provide upfront funding for network upgrades and then credit the funds, with interest, back to generators over time following commercial operation of generators.[3]

Some states—notably Texas, Minnesota, and California—have adopted policies to reduce the transmission barriers to renewable energy development. All three states provide cost recovery incentives for utilities or financing options for smaller power plant owners to facilitate construction of transmission to meet renewable portfolio standards goals. A similar policy would have to be adopted in Colorado before this policy could be cost effective.

Related Policies/Programs in Place

SB 100.

Type(s) of GHG Reductions

Lower CO_2 emissions associated with displaced fossil fuel-based electricity generation.

Estimated GHG Savings and Costs per $MtCO_2e$

Non-quantitative policy proposal not amenable to analysis.

Quantification Methods:

Not applicable.

Key Assumptions:

The following sources could be used to support an assumption of between $1,000 to $2,000/MW-mile for the cost of transmission infrastructure for renewables:

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[2] Western Governors' Association (WGA) Clean and Diversified Energy Initiative. *Draft Report of the Transmission Task Force*. March 2006. Available on the Internet at: www.awea.org/policy/regulatory_policy/transmission_documents/WGA_TransmissionReport_3-2-06.pdf

[3] WGA. *Draft Report of the Transmission Task Force*, ibid

For its Wind Deployment System (WinDS) Model, NREL assumes a $1,000/MW-Mile cost of transmission with scenarios for $700 and $1,400/MW-Mile as well. This data is available at: http://www.nrel.gov/analysis/winds/transmission_cost.html.

The report Tackling Climate Change in the US: Potential Carbon Emission Reductions from Energy Efficiency and Renewable Energy by 2030 also uses $1,000/MW-Mile as the cost assumption for new transmission in its modeling. This report is available at: http://www.ases.org/climatechange/climate_change.pdf.

The report by the Western Governors' Association's Geothermal Task Force Report assumes a transmission cost of $1,000/MW-Mile with an alternate case assumption of $2,000/MW-Mile. This report is available at: http://www.westgov.org/wga/initiatives/cdeac/Geothermal-full.pdf.

The presentation *Wind Power in the US to 2030: An Industry Perspective* in Texas.

The Western Governors' Association's Wind Task Force Report assumes a cost for new transmission of $1,000/MW-Mile. This report is available at: http://www.westgov.org/wga/initiatives/cdeac/Wind-full.pdf.

Key Uncertainties

Location of and cost of providing transmission access to wind resource areas in the state

Additional Benefits and Costs

Ancillary benefits of expanded transmission infrastructure; economic opportunities and employment in Colorado.

Feasibility Issues

PUC does not have the authority to compel municipal utilities and cooperatives to participate.

Status of Group Approval

Unanimous consent of those CAP members present and voting.

Level of Group Support

No objections.

Barriers to Consensus

None identified.

ES-5. Cost for CO_2 Emissions (Cap-and-Trade or Tax)

Policy Option Description

Establishing a cost for CO_2 emissions is an alternative, and complementary, GHG-control method relative to direct regulations such as energy efficiency standards. The concept is to internalize the externality, allowing the marketplace find the most efficient reductions. Pricing CO_2 emissions has two primary effects. First, it increases the cost of carbon-based energy to encourage conservation and energy efficiency. Second, it provides an economic advantage to non-carbon-based or lower emissions energy technologies.

There are two basic approaches: cap and trade (C&T) and carbon taxes. The cap and trade approach has largely been based on the success of the C&T system for acid rain in the United States. A cap is placed on total GHG emissions, with each unit of emissions represented by a permit that can be traded to find the lowest cost compliance. Typically the caps begin somewhat high (close to current emissions levels) and ratchet down on a pre-determined schedule.

Under the carbon tax approach, the government collects a tax per unit of GHG emissions. The tax collection can be done either upstream (e.g., wellhead, power plant) or downstream (e.g., gas pump, electricity bill). A carbon tax can be designed to be net revenue neutral. That is, the carbon tax revenue collected would be offset dollar-for-dollar by a reduction of some other tax. The revenue offset can be designed to mitigate impact on lower income or vulnerable ratepayers without negating the incentive for conservation.

Hybrid schemes are possible, such as a tax and trade system where an entity facing a large tax liability could offset their taxes through investments in reducing the GHG footprint of another with no or low liability.

Policy Option Design

Goal: Consider applying a price to carbon emissions on a state, regional or national basis.

Timing: 2007

Coverage: United States.

Implementation Mechanisms

There are a number of possible implementation mechanisms for this policy:

- Join a regional, market-based initiative (such as the Western Climate Initiative) to reduce carbon emissions
- Implement a statewide carbon tax
- Advocate for national market-based greenhouse gas regulations or a carbon tax with science-based reduction targets

Related Policies/Programs in Place

There are currently no mandatory carbon pricing policies affecting Colorado. Colorado consumers can and do participate in voluntary programs such as the Chicago Climate Exchange. (http://www.chicagoclimatex.com/)

Type(s) of GHG Reductions

Most economically efficient emissions reductions to be identified by marketplace in response to highly focused economic signals.

Estimated GHG Savings and Costs per $MtCO_2e$

Factors that affect projections of carbon cost
Results from a range of studies highlight certain factors that affect projections of future carbon emissions prices. In particular, the studies provide insight into whether the factors increase or decrease expected costs, and to the relationships among different factors. A number of the key assumptions that affect policy cost projections (and indeed policy costs) are discussed in this section, and summarized in Table F-6.

Here we only consider these factors in a qualitative sense, although quantitative meta-analyses do exist.[4] It is important to keep these factors in mind when attempting to compare and survey the range of cost/benefit studies for carbon emissions policies so the varying forecasts can be kept in the proper perspective.

1. Base case emissions forecast

Developing a business-as-usual case (in the absence of federal carbon emission regulations) is a complex modeling exercise in itself, requiring a wide range of assumptions and projections which are themselves subject to uncertainty. In addition to the question of future economic growth, assumptions must be made about the emissions intensity of that growth. Will growth be primarily in the service sector or in industry? Will technological improvements throughout the economy decrease the carbon emissions per unit of output?

In addition, a significant open question is the future generation mix in the United States. Throughout the 1990s most new generating investments were in natural gas-fired units, which emit much less carbon per unit of output than other fossil fuel sources. Today many utilities are looking at baseload coal due to the increased cost of natural gas, implying much higher emissions per MWh output. Some analysts predict a comeback for nuclear energy, which despite its high cost and unsolved waste disposal and safety issues has extremely low carbon emissions.

A business-as-usual case which included several decades of conventional base load coal, combined with rapid economic expansion, would present an extremely high emissions baseline. This would lead to an elevated projected cost of emissions reduction regardless of the assumed policy mechanism.

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[4] See, *e.g.*, Carolyn Fischer and Richard D. Morgenstern, *Carbon Abatement Costs: Why the Wide Range of Estimates?* Resources for the Future, September, 2003. http://www.rff.org/Documents/RFF-DP-03-42.pdf

2. Complementary policies

Complementary energy policies, such as direct investments in energy efficiency, are a very effective way to reduce the demand for emissions allowances and thereby to lower their market price. A policy scenario which includes aggressive energy efficiency along with carbon emissions limits will result in lower allowances prices than one in which energy efficiency is not directly addressed.[5]

3. Policy implementation timeline and reduction target

Most "policy" scenarios are structured according to a goal such as achieving "1990 emissions by 2010" meaning that emissions should be decreased to a level in 2010 which is no higher than they were in 1990. Both of these policy parameters have strong implications for policy costs, although not necessarily in the intuitive sense. A later implementation date means that there is more time for the electric generating industry to develop and install mitigation technology, but it also means that if they wait to act, they will have to make much more drastic cuts in a short period of time. Models which assume phased-in targets, forcing industry to take early action, may stimulate technological innovations so that later, more aggressive targets can be reached at lower cost.

4. Program flexibility

The philosophy behind cap and trade regulation is that the rules should specify an overall emissions goal, but the market should find the most efficient way of meeting that goal. For emissions with broad impacts (as opposed to local health impacts) this approach will work best at minimizing cost if maximum flexibility is built into the system. For example, trading should be allowed across as broad as possible a geographical region, so that regions with lower mitigation cost will maximize their mitigation and sell their emission allowances. This need not be restricted to CO_2 but can include other GHGs on an equivalent basis, and indeed can potentially include trading for offsets which reduce atmospheric CO_2 such as reforestation projects. Another form of flexibility is to allow utilities to put emissions allowances "in the bank" to be used at a time when they hold higher value, or to allow international trading as is done in Europe through the Kyoto protocol.

One drawback to programs with higher flexibility is that they are much more complex to administer, monitor, and verify. [6] Emissions reductions must be credited only once, and offsets and trades must be associated with verifiable actions to reduce atmospheric CO_2. A generally accepted standard is the "five-point" test: "at a minimum, eligible offsets shall consist of actions that are real, surplus, verifiable, permanent and enforceable."[7] Still, there is a clear benefit in terms of overall mitigation costs to aim for as much flexibility as possible, especially as it is

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[5] A recent analysis by ACEEE demonstrates the effect of energy efficiency investments in reducing the projected costs of the Regional Greenhouse Gas Initiative. Prindle, Shipley, and Elliott; *Energy Efficiency's Role in a Carbon Cap-and-Trade System: Modeling Results from the Regional Greenhouse Gas Initiative*; American Council for an Energy Efficient Economy, May 2006. Report Number E064.

[6] An additional consideration is that greater geographic flexibility reduces potential local co-benefits, discussed below, that can derive from efforts to reduce greenhouse gas emissions.

[7] Massachusetts 310 CMR 7.29.

impossible to predict with certainty what the most cost-effective mitigation strategies will be in the future. Models which assume higher flexibility in all of these areas are likely to predict lower compliance costs for reaching any specified goal.

5. Technological progress

The rate of improvement in mitigation technology is a crucial assumption in predicting future emissions control costs. This has been an important factor in every major air emissions law, and has resulted, for example, in the pronounced downward trend in allowance prices for SO_2 and NO_x in the years since regulations of those two pollutants were enacted. For CO_2, looming questions include the future feasibility and cost of carbon capture and sequestration, and cost improvements in carbon-free generation technologies. Improvements in the efficiency of coal burning technology or in the cost of nuclear power plants may also be a factor.

6. Reduced emissions co-benefits

Most technologies which reduce carbon emissions also reduce emissions of other criteria pollutants, such as NO_x, SO_2, and mercury. This results in cost savings not only to the generators who no longer need these permits, but also to broader economic benefits in the form of reduced permit costs and consequently lower priced electricity. In addition, there are a number of co-benefits such as improved public health, reduced premature mortality, and cleaner air associated with overall reductions in power plant emissions which have a high economic value to society. Models which include these co-benefits will predict a lower overall cost impact from carbon regulations, as the cost of reducing carbon emissions will be offset by savings in these other areas.

Table F-6.

Assumption	Increases Prices if…	Decreases Prices if…
"Base case" emissions forecast	Assumes high rates of growth in the absence of a policy, strong and sustained economic growth	Lower forecast of business-as-usual" emissions
Complimentary policies	No investments in programs to reduce carbon emissions	Aggressive investments in energy efficiency and renewable energy independent of emissions allowance market
Policy implementation timeline	Delayed and/or sudden program implementation	Early action, phased-in emissions limits.
Reduction targets	Aggressive reduction target, requiring high-cost marginal mitigation strategies	Minimal reduction target, within range of least-cost mitigation strategies
Program flexibility	Minimal flexibility, limited use of trading, banking and offsets	High flexibility, broad trading geographically and among emissions types including various GHGs, allowance banking, inclusion of offsets perhaps including international projects.
Technological progress	Assume only today's technology at today's costs	Assume rapid improvements in mitigation technology and cost reductions
Emissions co-benefits	Ignore emissions co-benefits	Includes savings in reduced emissions of criteria pollutants.

Because of the uncertainties and interrelationships surrounding these factors, forecasting long-range carbon emissions price trajectories is quite complicated and involves significant uncertainty. Of course, this uncertainty is no greater than the uncertainty surrounding other key variables underlying future electricity costs, such as fuel prices, although there are certain characteristics that make carbon emissions price forecasting unique.

One of these is that the forecaster must predict the future political climate. As documented throughout this paper, recent years have seen a dramatic increase in both the documented effects of and the public awareness of global climate change. As these trends continue, it is likely that more aggressive and more expensive emissions policies will be politically feasible. Political events in other areas of the world may be another factor, in that it will be easier to justify aggressive policies in the United States if other nations such as China are also limiting emissions.

Another important consideration is the relationship between early investments and later emissions costs. It is likely that policies which produce high prices early will greatly accelerate technological innovation, which could lead to prices in the following decades which are lower than they would otherwise be. This effect has clearly played a role in NO_x and SO_2 allowance trading prices. However, the effect would be offset to some degree by the tendency for emissions limits to become more restrictive over time, especially if mitigation becomes less costly and the effects of global climate change become increasingly obvious.

Data Sources:

Synapse Energy Economics, "Climate Change and Power: Carbon Dioxide Emissions Costs and Electricity Resource Planning," Revised as of June 2006. http://www.synapse-energy.com/Downloads/SynapsePaper.2006-06.0.Climate-Change-and-Power.A0009.pdf

Energy Information Administration, Analysis of S. 139, the Climate Stewardship Act of 2003, EIA June 2003, SR/OIAF/2003-02; Energy Information Administration, Analysis of Senate Amendment 2028, the Climate Stewardship Act of 2003, EIA May 2004, SR/OIAF/2004-06

Sergei Paltsev, John M. Reilly, Henry D. Jacoby, A. Denny Ellerman, Kok Hou Tay. Emissions Trading to Reduce Greenhouse Gas Emissions in the United States: the McCain-Lieberman Proposal. MIT Joint Program on the Science and Policy of Global Change; Report No. 97; June 2003.

Bailie et al., Analysis of the Climate Stewardship Act, July 2003; Bailie and Dougherty, Analysis of the Climate Stewardship Act Amendment, Tellus Institute, June 2004. Available at http://www.tellus.org/energy/publications/McCainLieberman2004.pdf

Utility resource planning that incorporate carbon prices (e.g., Xcel Energy, Idaho Power, and Pacificorp)

Quantification Methods:

We will review and summarize these policy developments and literature relating to the costs and benefits of cap and trade and carbon tax regulation options in the United States.

There have been numerous federal GHG emission reduction policies proposed in Congress over the past 3 to 4 years. There are studies that estimate the impact of some of the federal proposals including price per ton of carbon.

There are also state and regional initiatives such as California's Global Warming Solutions Act, Regional Greenhouse Gas Initiative (RGGI) in the Northeast, and Western Regional Climate Action Initiative. Further, some utilities are predicting and incorporating carbon prices in their resource planning.

Key Assumptions:

None.

Key Uncertainties

Not applicable.

Additional Benefits and Costs

None identified.

Feasibility Issues

Imposition of a carbon tax in Colorado would face a statewide ballot initiative.

Status of Group Approval

Approved by those CAP members present and voting with one objection .

Level of Group Support

- One member objected as being philosophically opposed to such approaches; and that a cost mechanism would drive up the cost of electricity; citizens tend to oppose any new taxes; an emissions cap in the absence of a technology to capture and store carbon drives electricity generation to more natural gas, increasing risk of volatile gas prices and uncertain supply; and higher costs under a cap and trade system could have greater impact on the poor, according to a Congressional Budget Office study.
- One member's vote of approval was qualified because of a concern about the high costs associated with such programs.

Barriers to Consensus

None identified.

ES-6. Public Benefit Charge Funds

Policy Option Description

A system benefits charge (SBC) is a small monthly fee assessed on utility bills. The money that is collected is used to fund "public benefits," which typically include low-income weatherization programs, appliance efficiency rebates, renewable energy rebates, energy efficiency programs, and demand-side management programs. More than twenty states currently assess such charges under a variety of names, including system and public benefits charge, wires charge, access charge, universal service charge and distribution charge. The current proposal is focused on using SBC funds to support renewable energy development.

The goal of SBCs, in the context of climate policy, is be to accelerate the implementation of cost effective efficiency measures and the deployment of renewable resources. The charge may range from one to five percent of the monthly bill. In Europe, more than 50 municipal utilities collect fees to promote solar energy installations. In Germany, which has adopted a goal of achieving 20% of its electricity from renewable energy, a typical household may pay up to $15 more each month. In the United States these charges have typically been much smaller.

In Wisconsin, for example, Madison residential customers pay about 10 cents a day, or $3 per month. Wisconsin's public benefits charge collects about $70 million statewide each year. For small business customers, the charge is a maximum of $6 per month per meter. For more information on the Wisconsin program see www.focusonenergy.com

In Colorado, some utilities already assess SBCs to fund energy efficiency programs, and the proposal is to expand this. Natural gas utilities can also collect such funds, and a bill to require this has been introduced in the Colorado legislature in past sessions.

Policy Option Design

Goal: 2 ($0.002) or 4 mills ($0.004)/kWh charge. Each mil corresponds to about $10 per capita per year, or just under $48 million/yr. Money to be spent on renewable energy resources.

Timing: 2008

Coverage: All retail electric bills.

Implementation Mechanisms

SBCs can be assessed as a percentage of the monthly bill, or as a fixed monthly fee that varies by customer class. The funds can be managed by the utilities that collect them, by a nonprofit set up to do so, or by a state agency.

A public benefits charge funding renewable energy has a goal very similar to that of a renewable portfolio standard (RPS). Thus, it is important to consider the strengths and weaknesses of these two tools—and ways they might complement one another or result in an inefficient use of resources.

An RPS establishes a target amount of new renewable energy and relies on market forces to determine which specific projects are developed. Projects receive the subsidy retrospectively (i.e., after they begin generating energy), and cost caps are often included to limit RPS costs to ratepayers. With an SBC, funds are collected and distributed, based on project milestones, by a centralized office. The strengths and weaknesses of the two policies are summarized below.

Table F-7. Conceptual comparison of RPS and SBC approaches

Characteristic	RPS	SBC
Ability to define/control the amount of new renewable energy targeted.	Strength	Weakness
Ability to define/control the cost of the subsidy to ratepayers. Originally, this was seen as a strength of SBC funding, but with the advent of RPS cost caps it is no longer a significant distinction.	—	—
Use of market forces to distribute funds. In SBC programs, bid review and project selection take up a considerable portion of the administrative budget. Further, centralized processes are subject to the abuse of unfair influence or access to decision makers.	Strength	Weakness
Funding certainty. With an RPS the funding level is uncertain until after completion of project. Project developers—and potential lenders and investors—must rely on estimates. With an SBC the developer knows early on how much will be paid at each project milestone	Weakness	Strength
Ability to support pre-commercial technologies and non-cost barriers to renewables.	Weakness	Strength

Based on these strengths and weaknesses, the RPS should target market-ready technologies, while the SBC should target pre-commercial technologies and other market barriers.[8] Experience to date suggests that significant barriers to renewables remain even in the context of an RPS. For example, perceived risks and other dynamics often raise the cost of capital to renewable energy developers considerably. Subsidies targeting the financing stage can play a critical role. (Financial incentives for renewable energy are also proposed under ES-1.)

Related Policies/Programs in Place

City of Boulder currently has a Public Benefits Charge in place.

Type(s) of GHG Reductions

Reductions would come from displaced fossil-fueled generation.

Estimated GHG Savings and Costs per $MtCO_2e$

We have not quantified the potential impacts of ES-6.

A number of studies focus on SBC implementation issues and the kind of investments states have made (e.g., different types of loans versus equity positions in projects); however few of

[8] There is considerable literature documenting the funding challenges facing technologies past the basic R&D stage but not yet market ready. See for example: Murphy and Edwards, *Bridging the Valley of Death: Transitioning from Public to Private Sector Financing*, NREL, May 2003, NREL/MP-720-34036.

these studies attempt to quantify the impacts of SBC funding. One useful data point comes from a review of 10 state clean energy funds by Bolinger and Wiser.[9] Table F-8 shows data from this study on the amount of funding currently committed by each state and the number of MWs represented by recipient projects.

Table F-8. SBC funding and project MW by state

State	Funding (million$)	MW	$/kW
CA	190.0	1,227	155
IL	8.4	113	74
MA	32.8	52	631
ME	5.6	19	295
MN	107.7	252	427
NH	2.7	50	54
NJ	14.7	18	817
NY	10.5	50	210
OR	3.8	122	31
PA	21.4	347	62
Total	**397.5**	**2,249**	**177**

From Bolinger and Wiser's data (in the first three columns) we have calculated the cost per kW of new capacity. The ratios range from $817/kW in New Jersey to $31 in Oregon. The ratio across all states is $177/kW. However, these numbers only include funds committed to projects—they do not include administrative costs of the SBC program. Further work would be needed to identify administrative costs in each state and add them to these numbers. Thus $177/kW dollars appears to be a low boundary of potential SBC impacts.

The analysis of the RPS proposed in ES-2 is a useful reference point in gauging the potential effects of an SBC without an RPS in Colorado. GHG reductions from ES-2 are estimated to cost $16/tCO_2e$. However, this comparison ignores administrative costs and program ramp-up periods. As discussed above, the administrative costs of an SBC are likely to be higher than those of an RPS, while program ramp rates are likely to be longer with an SBC than with an RPS.

Finally, note that the cost of either approach will be driven by the assumption about the mix of new renewable technologies built or supported under the policy. To use these numbers as a benchmark one must assume that each would result in the same mix of new renewable energy resources.

Data Sources:

Bolinger and Wiser, The Impact of State Clean Energy Fund Support for Utility-Scale Renewable Energy Projects, Lawrence Berkeley Laboratory, May 2006.

Bolinger and Wiser, Utility-Scale Renewable Energy Projects: A Survey of Clean Energy Fund Support, Lawrence Berkeley Laboratory, 2002, LBNL-496667.

[9] Bolinger and Wiser, *The Impact of State Clean Energy Fund Support for Utility-Scale Renewable Energy Projects*, Lawrence Berkeley Laboratory, May 2006. Data shown here are taken from Table 1.

Brooks, et al., A Guidance Document on Debt and Equity Investment Mechanisms for the Clean Energy States Alliance, prepared for the Clean Energy States Alliance, November 2003.

NJ PIRG Law and Policy Center, Renewables Work: Job Growth from Renewable Energy Development in the Mid-Atlantic, Spring 2004.

Quantification Methods:

Not quantified at this time. Cost is expected to be comparable to ES-2 on a per-ton CO_2e basis.

Key Assumptions:

None identified.

Key Uncertainties

The amount of new renewable capacity and generation produced by a given amount of SBC funding.

Additional Benefits and Costs

Several reports have been published investigating the local employment impacts of renewable energy.[10]

Feasibility Issues

Local control issues may be of concern.

Status of Group Approval

Approved by those CAP members present and voting with three objections.

Level of Group Support

Objections include:

- Too high of a goal in terms of charges.
- Uncertainty in how the funds would be used.

One member's affirmative vote was qualified, on the belief that decisions such as this are better made at the local level.

Barriers to Consensus

None identified.

[10] NJ PIRG Law and Policy Center, Renewables Work: Job Growth from Renewable Energy Development in the Mid-Atlantic, Spring 2004.

ES-7. Incentives for CHP and DG

Policy Option Description

Financial incentives for combined heat and power (CHP) and distributed generation (DG) can include: (1) direct subsidies for purchasing/selling systems given to the buyer/seller; (2) tax credits or exemptions for purchasing/selling systems given to the buyer/seller; (3) tax credits or exemptions for operating systems; (4) feed-in tariff, which is a direct payment to CHP/DG owners for each kWh of electricity or Btu of heat generated from a qualifying system; and (5) tax credits for each kWh or Btu generated from a qualifying system.

In addition, the availability of net metering would substantially increase the value of certain kinds of DG resources, as any excess energy produced could effectively be sold to the grid at the retail price to offset the cost of purchasing power when additional energy is needed.

Barriers to these resources include inadequate information, institutional barriers, high transaction costs for small projects, high financing costs because of lender unfamiliarity and perceived risk, "split incentives" between building owners and tenants, and utility-related policies like interconnection requirements, high standby rates, and exit fees. The lack of Standard Offer or long-term contracts, payments at avoided cost levels, and lack of recognition of the value of reduced carbon emissions also create obstacles to widespread implementation.

Policies to remove these barriers include:

- Improved interconnection rules,
- Improved pricing and rates policies, including net metering,
- Streamlined permitting,
- Procurement policies, and
- Education/outreach.

Policy Option Design

Goal: Ramp up CHP/DG to 2% of total fossil fuel generation; ½ CHP and ½ other DG

Timing: Achieve 2% by 2020

Coverage: Large industrials, commercial, universities, or anyone with a heating or steam load

Implementation Mechanisms

The following implementation mechanisms suggested for related policy RCI-9 are recommended for adoption here.

Implement (modified) WGA's recommendations to states to promote CHP implementation:

1. PUC undertakes a thorough review of policies affecting CHP.
2. Adopt recently enacted FERC standards for interconnection agreements.
3. Seek CHP solutions to Transmission-constrained areas.
4. Undertake a review of electricity rates, including standby rates, to make sure they are not discriminatory toward CHP. Incorporate policies that will appropriately promote CHP in state utility Least Cost Planning and Integrated Resources Plans.
5. Consider adding CHP to Demand Side Management and other energy efficiency programs.
6. Consider decoupling or other mechanisms to remove utility disincentives for CHP.
7. Adopt simplified, streamlined, and consistent permitting for CHP systems. Offer state-funded training and technical assistance programs for local code officials.
8. Ensure that renewable portfolio standards, environmental portfolio standards, advanced energy portfolio standards, and other renewable energy laws include the full range of renewable CHP options, including waste heat recovery and spent pulping liquor.
9. Call on CHP Regional Application Centers (DOE) for help in policy, programs, and analysis.
10. Wherever possible, adopt consistent, region-wide policies. (WGA 2006).

Related Policies/Programs in Place

Colorado Net Metering Law:

Colorado has 2 MW capacity limit on system size under its statewide net metering law, which applies to utilities with +40,000 customers. The information is available at: http://www.dsireusa.org/library/includes/incentivesearch.cfm?Incentive_Code=CO26R&Search=TableType&type=Net&CurrentPageID=7&EE=0&RE=1

Some municipal utilities also have established their own net metering rules. See http://www.dsireusa.org/library/includes/statesearch2.cfm?State=CO&back=fintab&CurrentPageID=7&Search=TableState&EE=0&RE=1

Type(s) of GHG Reductions

Improved energy use efficiency associated with expanded use of CHP and increased generation by renewable DG systems which include PV, landfill gas, biomass, and biogas-based DG systems.

Estimated GHG Savings and Costs per $MtCO_2e$

	Policy Option	GHG Reductions ($MMtCO_2e$)			Gross NPV Cost 2007–2020 (Million $2005)	NPV Savings 2007–2020 (Million $2005)	Net Present Value 2007–2020 (Million $2005)	Cost-Effectiveness ($2007/$tCO_2e$)
		2012	2020	Total 2007–2020				
ES-7	Incentives for CHP, DG, Smart Grid	0.4	1.1	7.3	$557	$447	$110	$15

Data Sources:

CHP Technical Potential

- **WGA 2006**. Combined Heat and Power White Paper to the Clean and Diversified Energy Initiative of the Western Governors Association, January 2006, available at http://www.westgov.org/wga/initiatives/cdeac/CHP-full.pdf.
- This report estimated 1,578 MW of technical CHP potential in Colorado. The report mentions that the appendix to the report details this analysis. (However, the appendix is not available on their website http://www.westgov.org/wga/initiatives/cdeac/cdeac-reports.htm#TaskForceReports).

Cost and Performance of CHP and DG:

- **San Diego Regional Energy Office 2007**. "Statewide Self-Generation Incentive Program Data" (updated April 2007, 2.3 MB XLS), available at http://www.energycenter.org/ContentPage.asp?ContentID=279&SectionID=276&SectionTarget=35
- The database has cost/kW installed data for several DG technologies. It is not clear from the database that those technologies are used for CHP applications.
- **GRI and NREL 2003**, Gas-Fired Distributed Energy Resource Technology Characterizations—Bringing you a prosperous *future where energy is clean, abundant, reliable, and affordable*, available at http://www.eea-inc.com/dgchp_reports/TechCharNREL.pdf.
- This is the most comprehensive report (although it is getting outdated) on cost and performance of gas-fired CHP technologies.
- **Western Resource Advocate 2004**. A Balanced Energy Plan for the Interior West, prepared by Synapse Energy Economics and Tellus Institute, available at http://www.westernresourceadvocates.org/energy/bep.php
- **Navigant Consulting 2006**. "Energy Cost Savings Module for customer-sited DG" prepared for the Massachusetts DG Collaborative, available at http://masstech.org/renewableenergy/public_policy/DG/EnergyCostSavingsModule-Jan202006.zip (5.5 MB zip file)
- This workbook provides cost and performance data for several CHP applications including gas turbines, reciprocating engines and micro-turbines.
- **Colorado Office of Consumer Counsel 2005**. Initial Comments of the Colorado Office of Consumer Counsel under Docket No. 05R-112E in the Matter of the Proposed Rules

Implementing Renewable Energy Standard 4 CCR 72303, available at http://www.dora.state.co.us/occ/Cases/05R-112E_Amendment37_Rulemaking/InitialCommentsFinal.pdf

- **Synapse 2005.** *Feasibility Study of Alternative Energy and Advanced Energy Efficiency Technologies for Low-Income Housing in Massachusetts*, prepared for The Low-Income Energy Affordability Network, Action for Boston Community Development, and Action Inc.

Quantification Methods:

Estimate annualized cost of CHP and DG systems

Deduct cost savings associated with reduced fuel use for space and water heating and avoided cost of electricity;

Estimate emission reductions associated with greater energy use efficiency at end-use and with renewable energy generation.

Key Assumptions:

The many assumptions regarding cost, technical parameters, and technology choices that were required to analyze this policy include

- Average capacity factor of 60% for all CHP systems
- Avoided cost of electricity: $56/MWh. This includes energy & capacity costs. Based on KEMA 2006. Xcel's Colorado DSM Market Potential Assessment, March 2006.
- Avoided cost of natural gas: $7.42/MMBtu. The simple average of commercial and industrial natural gas prices for Mountain region in AEO2007 The industrial sector uses more natural gas than the commercial sector. However, because more CHP potential exists in the commercial sector, we use the simple average of fuel prices for CHP applications.
- Avoided cost of coal: $1.7/MMBtu from AEO 2007 forecast for Industrial users in the Mountain region.
- Avoided cost of fuel oil: $12.5/MMBtu. The simple average of commercial and industrial distillate oil price forecasts from AEO 2007 forecast for the Mountain region.
- Allocation of DG system capacity is as follows:

Residential PV Systems	35%
Commercial and Industrial (C&I) PV Systems	35%
Customer-sited Landfill Gas	10%
Customer-sited Biomass	15%
Customer-sited Biogas	5%

- Average net heat rate by fuel (Btu fuel input/kWh electricity output):

Natural Gas	10,000
Biomass	13,000

This is a placeholder estimate. Heat rates vary by the type of generator and other factors.

- Fraction of CHP heat output displacing thermal energy by fuel

Natural Gas	80%
Biomass	0%
Coal	4%
Electricity	10%
Oil	6%

Fraction of fuel usage was developed based on the following two tables.

Fuel consumption for commercial space and water heating (trillion Btu) for Mountain Region (average between 2005 and 2020)

	Consumption	Share
Electricity	14	6%
Natural Gas	196	89%
Fuel Oil	9	4%
	219	100%

Source: These tables were created based on the table for EIA, AEO2007 National Energy Modeling System run AEO2007.D112106A. The original data was obtained from Erin Boedecker at the Commercial Energy Demand Division at EIA

Fraction of industrial fuel use for process heat and HVAC for West Census Region

Electricity	13%
Fuel Oil	1%
Natural Gas	71%
LPG	1%
Coal	13%

Source: EIA 2002 Energy Consumption by Manufacturers. Table 5.8 - By Region with Total Consumption of Electricity (trillion Btu), available at http://www.eia.doe.gov/emeu/mecs/mecs2002/data02/shelltables.html

- Net efficiency of displaced boiler/heater thermal energy by fuel

Natural Gas	85%
Biomass	80%
Coal	80%
Electricity	92%
Oil	80%

- Usable cogenerated heat output as a fraction of fuel energy input is assumed to be 40% for both natural gas and biomass fired CHP
- Fraction of usable heat output replacing space/water/process heat use is assumed to be 90%
- Estimated average non-fuel operating and maintenance costs by system type ($/MWh)

Natural Gas	$10.00
Biomass	$20.00

Source: Rough Estimates of O&M costs: O&M costs for natural gas systems are based on GRI and NREL 2004. Gas-Fired Distributed Energy Resource Technology Characterizations. O&M for other fuels are assumed to be higher than natural gas.

- Capital costs for CHP are incremental to the cost of regular space and water heating systems because CHP systems are assumed to replace space or water heating systems or both. The costs of regular space and water heating systems are assumed to be around $1500. Incremental costs for natural gas systems are assumed to be $1300 and to decrease to $1040 by 2020. The incremental costs for biomass DG systems (including wood and biomass) is assumed to be $2000 and decrease to $1400 by 2020. The cost reduction the study period is around 20% based on EIA's DG cost projection in AEO2007. The capital costs in 2010 are close to the weighted average capital cost of equivalent DG systems in "Self-Generation Incentive Program Data" by San Diego Regional Energy Office.

	2010	**2020**
Natural Gas	$1300	$1040
Biomass	$2000	$1400

- Capital cost for renewable DG systems are as follows:

	2010	**2020**
PV	$6,000	$3,000
Landfill Gas	$3,000	$2,400
Biomass	$3,300	$2,640
Biogas	$4,000	$3,200

The costs of PV systems are taken from the appendix to Western Resource Advocate 2004. Estimated capital costs for landfill gas and biogas based DG by 2010 are close to weighted average of the capital costs for these systems in the Self-Incentive Generation Program Data by San Diego Regional Energy Office. The cost of biomass based DG system (for wood) is assumed to be around the midpoint cost between natural gas system and biogas system. The costs are assumed to decrease by 20% by 2020. This cost reduction is based on EIA's assumption on DG costs in its AEO2007.

- Capacity factors for these technologies are

Residential PV Systems	25%
Commercial and Industrial (C&I) PV Systems	25%
Customer-sited Landfill Gas	90%
Customer-sited Biomass	85%
Customer-sited Biogas	90%

PV capacity factor of 25% is from Colorado Office of Consumer Counsel 2005. Capacity factors for other systems are based on RPS cost impact studies in other states.

- Renewable DG systems are assumed to have the following power generation share in each year:

Residential PV Systems	15%
Commercial and Industrial (C&I) PV Systems	15%
Customer-sited Landfill Gas	20%
Customer-sited Biomass	30%
Customer-sited Biogas	20%

More wood biomass generation is assumed because its potential should be larger than other landfill gas and biogas sources. PV generation is set at only slightly lower rates because their capacity factor is lower but it has significant potential.

- Economic lifetimes of all systems are 20 years.
- Interest rates: 7% for residential customers and 8% for commercial and industrial customers
- The Federal Solar Investment Tax Credits (ITC) (applied to system cost) is set at 30% for solar PV investments. See http://www.seia.org/getpdf.php?iid=21. We assume the Solar Tax Credits will be extended until the end of the study period.
- The Federal Production Tax Credits (PTC) are set at $10/MWh for landfill gas plants and $19/MWh for biomass and biogas plants. Renewable generators that become online prior to 2015 receive PTC for the first 10 year operation.
- Value of avoided energy purchases.

Key Uncertainties

While we have set allocations among different renewable DG systems, the technology composition of currently installed DG systems is unknown. The performance and financial characteristics we have assumed are also subject to a wide range of uncertainty.

Additional Benefits and Costs

DG provides additional benefits in terms of security of supply and reduced load on the transmission & distribution system. Other benefits include economic opportunities and diversity of supply.

Feasibility Issues

None identified.

Status of Group Approval

Unanimous consent of those CAP members present and voting.

Level of Group Support

No objections.

Barriers to Consensus

None identified.

ES-8. CO_2 Capture and Transport Infrastructure

Policy Option Description

Carbon dioxide capture and sequestration (CCS) in conjunction with advanced fossil fuel generation may represent one option to significantly reduce the carbon dioxide emissions associated with electricity generation in the future. One barrier to implementation of CCS on a wide scale is the absence of a pipeline infrastructure to carry carbon dioxide to suitable sequestration sites. Another barrier to CCS implementation is regulatory uncertainty in key areas such as ownership of underground sequestration resources, regulations, and long-term liability against carbon dioxide leakage. There are also uncertainties and concerns over potential adverse environmental impacts of carbon dioxide capture, transportation and storage. This policy recommendation seeks to address these barriers through policies to encourage the investigation of a regional pipeline infrastructure for CO_2 transport to suitable sequestration sites, and to reduce regulatory uncertainties that today hinder the planning and development of CCS projects.

Policy Option Design

Goal: Work with neighboring states and the Western Governors' Association (WGA) to analyze options for a regional CO_2 transportation and sequestration collaborative. Create a workshop process resulting in a written report by state agencies to address various regulatory and environmental uncertainties associated with CCS.

Timing: As soon as possible. This has to start soon as utilities are making plans for new coal plants and should be able to count on CCS if it will become a reality.

Coverage: Governor's office, legislature, state agencies.

Implementation Mechanisms

The Climate Action Panel recommends that Governor Ritter assign the Oil and Gas Conservation Commission and the Colorado Department of Health and the Environment to investigate major regulatory and environmental issues related to CCS and to pipeline development necessary for implementation of CCS. These issues include but are not limited to appropriate government agencies to regulate sequestration sites, ownership of pore space for sequestration, regulations needed to protect public health and the environment from the full range of impacts associated with CCS and pipeline development, long-term liability for CO2 storage, appropriate methods and procedures to monitor the fate of the captured and sequestered carbon dioxide, unitization of ownership of pore space rights, possibility of eminent domain for pipelines, the possible need for a state or regional carbon dioxide pipeline authority, and other issues. The agencies could consider whether and how federal EPA Underground Injection Control provisions might apply to CO2 and how state agencies could implement them. The agencies could also consider a Joint Review process to streamline approvals across multiple state agencies. The agencies should be required to write a report to the Governor with its recommendations.

Related Policies/Programs in Place

None.

Type(s) of GHG Reductions

Facilitate CO_2 capture and permanent storage before reaching atmosphere, thus reducing the impact of coal combustion on the atmosphere.

Estimated GHG Savings and Costs per $MtCO_2e$

This is a non-quantitative policy proposal.

Data Sources:

School of Mines report on CCS opportunities in Colorado;

MIT study on "the Future of Coal" (http://web.mit.edu/coal/)

Quantification Methods:

This option will not be quantified as it relates only to a regional infrastructure research initiative.

Key Assumptions:

Existence of significant potential for cost-effective, permanent CO_2 storage in region; cost and economic feasibility of constructing transport infrastructure to access these sites.

Key Uncertainties

Cost and extent of infrastructure needed, ultimate potential for permanent CO_2 storage in region. Also:

- Ownership of "pore space" or the right to sequester carbon dioxide underground
- Regulatory authority for key questions related to CCS, including appropriate government agencies to regulate sequestration sites, ownership of pore space for sequestration, long-term liability for CO_2 storage, unitization of ownership of pore space rights, possibility of eminent domain for pipelines, and other issues.
- Environmental and public health impacts of carbon capture, transportation and storage.
- Permanence of underground carbon dioxide storage.

Additional Benefits and Costs

None identified.

Feasibility Issues

None identified.

Status of Group Approval

Unanimous consent of those CAP members present and voting.

Level of Group Support

No objections.

Barriers to Consensus

None identified.

ES-9. R&D for Carbon Emissions Reducing Generating Technology

Policy Option Description

Research and development (R&D) funding can be targeted toward a particular technology or group of technologies as part of a state program with a mission to build an industry around that technology in the state and/or to set the stage for adoption of the technology for use in the state. For example, an agency could be established to help develop and deploy energy storage technologies. R&D funding can be made available to any renewable or other advanced technology through an open bidding procedure (driven by bids received rather than by a focused strategy to develop a particular technology). Funding can also be given for demonstration projects to help commercialize technologies that have already been developed but are not yet in widespread use.

Policy Option Design

Goals: 0.2 cent/kWh charge = $20/capita-year, $100 million for low-interest loans to Colorado research companies and universities, toward carbon emissions reducing technology.

Timing: First funding cycle in 2009; Requests for Proposals (RFPs) circulated in 2008

Coverage: Colorado universities and businesses

Implementation Mechanisms

Low-interest loans to CO research companies & universities to be funded by a per-kWh charge on electricity use, to be made available for in-state R&D on low- or non-carbon emitting sources of electricity, such as advanced solar, fuel cells, wind power, etc. The fund would *not* be available support to generating technologies which depend on carbon capture and sequestration to become low-emitting.

Related Policies/Programs in Place

SB 246, just passed by the state legislature, provides funding for renewables and efficiency R&D.

Type(s) of GHG Reductions

GHG reductions would occur over time as the enhanced R&D led to faster market penetration of GHG-reducing technologies.

Estimated GHG Savings and Costs per $MtCO_2e$

R&D benefits not quantified.

Data Sources:

Committee on Benefits of DOE R&D on Energy Efficiency and Fossil Energy, *Energy Research at DOE: Was It Worth It? Energy Efficiency and Fossil Energy Research 1978 to 2000*, National Academy Press, Washington D.C., 2001.

Quantification Methods:

We have not attempted to quantify the emissions benefits of investments in energy R&D in Colorado. However, one useful framework for this type of quantification was developed by a National Research Council committee (the committee) formed in 2000 to assess the benefits of DOE spending on R&D. The committee assessed benefits in three areas: economic, environmental and security. They reviewed 17 energy efficiency programs, (representing $1.6 billion of the total $7.3 billion energy efficiency R&D expenditures) and 22 fossil energy RD&D programs (representing nearly $11 billion of the $15 billion appropriated to the Office of Fossil Energy for RD&D between 1978 and 2000).

The committee came to a number of qualitative and quantitative conclusions. Among the quantitative findings were the following (all costs given in 1999$):

- Total net realized economic benefits associated with the energy efficiency programs reviewed were approximately $30 billion, compared to the roughly $7 billion in total energy efficiency R&D investment over the 22-year life of the programs. (In the energy efficiency area, most of the realized economic benefits to date are attributable to three relatively modest projects in the building sector carried out in the late 1970s and 1980s and continuing into the 1990s.)
- Economic benefits of fossil programs instituted from 1986 to 2000 were estimated to be $7.4 billion, compared to the $4.5 billion cost of the programs during that period. Benefits associated with fossil energy programs instituted from 1978 to 1986, estimated at $3.4 billion, were less than the cost of this period's fossil energy programs ($6.0 billion).
- The committee had difficulty assigning a monetary value to environmental benefits, but "conservatively" estimated the environmental benefits of both R&D programs at $60 to $90 billion.
- The committee did not quantify security benefits.

In addition to these conclusions, the committee emphasized that the benefits of programs varied considerably across the programs studied. The committee writes: "by an order of magnitude, the largest apparent benefits were realized as (1) avoided energy costs in the buildings sector in energy efficiency and (2) avoided environmental costs from the NOx reductions achieved by a single program in fossil energy. This result is not surprising given the balanced research portfolio, which also includes its share of failures and modest successes."[11]

Key Assumptions:

Not applicable.

[11] Committee on Benefits of DOE R&D, page 6.

Key Uncertainties

The areas of R&D that should be subsidized and the eventual benefits of these subsidies.

Additional Benefits and Costs

An added benefit of enhancing R&D and building a renewable energy industry is the creation of jobs in Colorado. A report published in February 2007 (Madsen, et al. *"Energy for Colorado's Economy: Creating Jobs and Economic Growth with Renewable Energy"*, Environment Colorado Research & Policy Center) shows that doubling Colorado's renewable energy standard (RPS) to 20% will create a net increase of 4,100 person-years of employment through 2020. It will benefit total wages paid to workers in the state by a net cumulative total of $570 million over this timeframe. This is four times the employment impact and twice the wage impact of the original Amendment 37. Augmenting this report is a July 2007 study from The Union of Concerned Scientists that states that a 20% renewable standard would create 4,100 new jobs in Colorado from renewable energy development bringing $2.5 billion in new capital investment and $331 million in income to farmers, ranchers and rural landowners. Consumer savings are estimated to be $510 million in lower electricity and natural gas costs to Colorado consumers.

In addition to the in-state benefit, Colorado has the opportunity to become the leading state for renewable energy development and *training* of the national technical workforce required to meet U.S. renewable energy and energy efficiency goals. A 2007 report from the American Solar Energy Society shows that a moderate (mid-range) estimate of national renewable energy employment created by 2030 would be 3.1 million new jobs with a national annual revenue of $227 billion (Bezdek, R.H., *SOLAR 2007*, Cleveland, OH). Colorado could seek to capture the education and training of this national workforce to its positive economic benefit; capturing even a few percent of this workforce demand in-state could possibly double the impact from the current RPS.

Feasibility Issues

Feasibility of additional per-kWh charges on customer bills. May have to be approved by voters of CO.

Status of Group Approval

Unanimous consent of those CAP members present and voting.

Level of Group Support

No objections.

Barriers to Consensus

None identified.

ES-10. Promote Advanced Fossil Fuel Generation With Carbon Capture, Including IGCC

Policy Option Description

Advanced fossil fuel generation technologies, in combination with carbon dioxide capture and sequestration (CCS), may offer one option to reduce the carbon dioxide emissions associated with fossil-fuel based electricity generation. While coal-based generation is the largest source of carbon dioxide emissions in the state, CCS may provide a cost-effective pathway to reduce carbon emissions from coal power plants while continuing to rely on an abundant, domestic source of energy. Coal generation with CCS could be based on integrated gasification combined cycle (IGCC) technology, pulverized coal technology, or some other approach yet to be determined.

Under this proposal, the Climate Action Panel recommends that:

- Governor Ritter carefully consider and evaluate the costs, GHG emission reductions, and other aspects of the Colorado IGCC with CCS project as reflected in Xcel Energy's application the Colorado Public Utilities Commission and, based on this evaluation, support such a project if appropriate.
- Governor Ritter and Colorado's federal legislators work to obtain meaningful federal funding for the Colorado IGCC with CCS project. Federal funding would leverage the benefits of advanced coal with CCS for the entire nation, mitigate the technology risk of the project borne by Colorado utilities and ratepayers, and directly benefit Colorado's electric customers by reducing the cost of an IGCC with CCS project to ratepayers.

Policy Option Design

Goals: In addition to the goals outlined above,

- Direct PUC to re-evaluate rules for demonstration projects and technology commercialization.
- Involve the state's research universities.
- Broaden policy to include advanced technologies, not just IGCC.

Timing: Xcel Energy is expected to propose an IGCC with CCS project in 2007 that would be operational sometime between 2013 and 2015.

Coverage: One generating plant

Implementation Mechanisms

State study and, if appropriate, support for proposed project and efforts to secure federal funding to help offset the cost to state ratepayers.

Related Policies/Programs in Place

This option is somewhat covered by existing legislation that already directs the PUC to consider approval of an IGCC plant, and to waive some of its rules on seeking least cost production.

HB 06-1281 concerns the establishment of a program to demonstrate the use of breakthrough advanced coal technology to promote low-emitting coal-fueled electricity generation.

Type(s) of GHG Reductions

If the project is built and successfully implements permanent sequestration of a significant portion of CO_2 from the effluent stream, GHG reduction would be the avoidance of adding these emissions to the overall atmospheric burden.

Estimated GHG Savings and Costs per $MtCO_2e$

Not quantified.

Data Sources:

Not applicable.

Quantification Methods:

The costs and emissions benefits for this have not been quantified.

Key Assumptions

Existence of significant potential for cost-effective, permanent CO_2 storage in region.

Key Uncertainties

Significant uncertainty in cost and benefits; potential for permanent storage of CO_2 in region also unknown. In addition, proposal requires infrastructure to transport CO_2 to suitable sequestration site (addressed in policy ES-8).

Additional Benefits and Costs

Economic and employment benefits in the state, including R&D benefits associated with early implementation of technology.

Feasibility Issues

- Additional risk of power plant development related to use of western coals with IGCC
- Additional risk of IGCC at higher altitude
- Additional risk of operational reliability of IGCC with CCS
- Uncertainties surrounding the permanence of the captured carbon dioxide being sequestered from the atmosphere and any potential adverse environmental impacts from geologically sequestering carbon dioxide.

Status of Group Approval

Unanimous consent of those CAP members present and voting.

Level of Group Support

No objections.

Barriers to Consensus

None identified.

ES-11. Small New Hydro and Efficiency Improvements at Existing Hydro, Identifying Other Small Renewables and Removing Barriers Thereto

Policy Option Description

Currently, existing hydroelectric plants in Colorado produce about 1,200 GWh of electric energy per year. This energy is produced from plants built in the early 1920s and before as well as relatively newer units. Older plants present opportunities for improvements in efficiency and production including more efficient turbines, upgraded generator windings and replacement of mechanical controls with solid state equipment. The improvement in efficiency and plant production can range from 1%–2% to as high as 25%–30%.

In addition, several studies have suggested there may be 1000 MW or more of hydroelectric potential in Colorado at existing dams and water impoundments, diversions and conveyance structures. Research suggests that the capacity and generation efficiency of many existing hydro projects could be increased. The U.S. Bureau of Reclamation has uprated 50 units since beginning its uprate program in 1978, at an average cost of $68 per new kW.[12] In addition to this capacity, we believe the potential for new, small hydroelectric projects is considerable, but more work needs to be done to characterize this resource. Sites for potential projects include existing impoundments and diversions as well as networks such as municipal water systems. Most municipal water systems include numerous pressure release valves, and these valves can be replaced by small turbines that generate electricity.

Depending on site-specific factors, small hydroelectric projects may be cost competitive with both fossil-fueled and other renewable power sources. With the recent enthusiastic acceptance of wind energy programs, it is reasonable to expect that small hydroelectric energy programs based on local resources would also be favorably received by customers.

There are also sites in Colorado suitable for developing pumped storage hydro facilities, which allow off-peak generation to be shifted to peak periods. However, from the perspective of GHG emissions it is important to consider both the loss of efficiency associated with pumped storage and what energy source is used to power the pumping. If coal, the effective emission rate of the pumped storage energy is actually *higher* than that of the coal plant due to pumping losses. However, storage of renewable energy in a pumped storage facility could be an effective GHG mitigation strategy. Use of pumped storage to take full advantage of intermittent wind generation is particularly attractive.

The primary barrier to development of hydroelectric facilities is that the water facilities are owned and operated by entities without expertise in power production. Also, the generation potential of each site is usually small and often overlooked by power providers. In fact, all small renewable resources face barriers similar to these: the site owner rarely has experience in power generation, and power production per site is relatively small, making it more difficult to justify

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[12] U.S. Bureau of Reclamation, Generator Power Uprate Program Report, July 2000. Available at: www.usbr.gov/power/data/uprate/uprate.html.

the investment in feasibility studies and other up-front costs. However, when considered as a whole, these small sites may represent a significant amount of zero-carbon energy. More research is needed to identify and remove barriers to small, distributed renewable generators.

Policy Option Design

Goals: Begin with statewide mapping of unexploited potential of geothermal, small hydro, and biomass (expanded SB-91). Follow with:

- Address institutional barriers to small renewables;
- Seek to add 50 MW of new, small hydro resources per year beginning in 2014;
- Consider transferring oversight from FERC to the state in order to streamline permitting. Permitting should include environmental certification, based on models DOE already has in place.

Establish a work group to research barriers to small renewable energy facilities and propose solutions.

Timing: Mapping and small renewables work group to begin immediately.

Coverage: Statewide.

Implementation Mechanisms

Mapping could be coordinated by the Governor’s Energy Office—utilizing experts from State agencies, federal agencies, water resource groups, consulting firms and/or small hydro owners/operators. Developers of small hydro projects would have access to any subsidies that are established and revenue from energy credits under an RPS. The small renewables work group could be led by the Governor’s Energy Office.

Related Policies/Programs in Place

SB-91: Existing statewide mapping program.

The U.S. Bureau of Reclamation has uprated 50 units since beginning its uprate program in 1978, at an average cost of $68 per new kW.

Type(s) of GHG Reductions

CO_2 emissions reductions associated with avoided fossil-fueled generation.

Estimated GHG Savings and Costs per $MtCO_2e$

	Policy Option	GHG Reductions ($MMtCO_2e$) 2012	2020	Total 2007–2020	Gross NPV Cost 2007–2020 (Million $2005)	NPV Savings 2007–2020 (Million $2005)	Net Present Value 2007–2020 (Million $2005)	Cost-Effectiveness ($2007/$tCO_2e$)
ES-11	Small New Hydro and Efficiency Improvements at Existing Hydro, Identifying Other Small Renewables and Removing Barriers	0.0	0.8	3.1	$264	$141	$123	$40

The PWG agreed to assume a cost of $3,000/kW for all new small hydro resources in the state and a capacity factor of 35%. We assume a 40-year economic life for these facilities and a capital recovery factor of 10.2%, yielding a nominal cost of $105/MWh. The sensitivity of the cost of these resources to these assumptions is shown in Table F-9 under "Key Assumptions," below.

We evaluated the addition of 50 MW per year of small hydro between 2014 and 2020. Assuming that 75% of the energy from these projects displaces coal-fired generation and 25% of it displaces gas-fired generation, each 50-MW block of capacity would eliminate roughly 111,000 metric tons of CO_2 emissions annually. In 2020, the entire 350-MW block would be displacing approximately 774,000 tons annually—or about 1.5% of total state emissions in the reference case.

The NPV (2007) of the cost of this program is calculated as $123 million, and the total avoided emissions during this period would be 3 $MMtCO_2e$. This yields a per-ton avoided cost of approximately $40 through 2020.

Data Sources:

Hydro mapping efforts at the national level include the following:

- US DOE, Feasibility Assessment of the Water Energy Resources of the United States for New Low Power and Small Hydro Classes of Hydroelectric Plants, DOE-ID-11263, January, 2006,
- Idaho National Engineering and Environmental Laboratory, Estimation of Economic Parameters of U.S. Hydropower, INEEL/EXT-03-00662, June 2003.
- James Francfort, U.S. Hydropower Resource Assessment for Colorado, DOE/ID-10430, May 1994.

However, these studies use GIS databases and other models to estimate the developable hydro capacity within a state. They provide little of the information needed to assess the cost and feasibility of a site for a small hydro project. Thus, a state mapping effort, using tools that can provide this information, is critical.

Quantification Methods:

- Start with the revised reference case;
- Use "small hydro" as a proxy for all unexploited small renewable resources;
- Add in 50 MW per year of hydro capacity at $3000 per kW and a 35% capacity factor;
- Assume the hydro energy displaces 75% new coal-fired generation and 25% new gas-fired generation and that the long term avoided cost of generation is $56/MWh.

Key Assumptions:

- The assumptions of a "flat supply curve" at $3,000 per kW and a 35% capacity factor drive the cost estimate in this analysis. For context, the cost matrix below shows the estimated cost of a two-MW hydro energy at different capital cost points and capacity factors.

Table F-9.

		Capacity Factor			
		30%	50%	70%	90%
	MWh/yr:	5,256	8,760	12,264	15,768
Cost ($/kW)	**Principal ($M)**	**Levelized Cost ($/MWh)**			
$1,000	$2.00	$43.91	$28.35	$21.68	$17.97
$2,000	$4.00	$82.82	$51.69	$38.35	$30.94
$3,000	$6.00	$121.73	$75.04	$55.03	$43.91
$4,000	$8.00	$160.65	$98.39	$71.71	$56.88

- We assume that 350 MW of small hydro capacity can be installed at certified environmentally acceptable sites by 2020, at existing federal and non-federal impoundments and diversions
- We assume the existence of up to 500 MW of accessible but unexploited small hydro.
- We assume institutional, structural, and jurisdictional barriers can be overcome at reasonable cost.

Key Uncertainties

Total capacity is available at feasible, undeveloped sites

Supply curve of small hydro and other small renewables capacity—i.e., how much capacity is available at what price?

Distribution of capacity factors and operating costs of actual small hydro and other small renewable projects.

Additional Benefits and Costs

Small hydro and other small renewable energy projects provide landowners with an additional revenue stream; other economic benefits including employment benefits.

Feasibility Issues

What would a mapping project that could provide the needed information look like? Who is best suited to do it?

Actual technical and economic potential of small renewables on CO;

Jurisdictional, ownership, and zoning issues;

Transmission availability and access for small power projects.

Status of Group Approval

Unanimous consent of those CAP members present and voting.

Level of Group Support

No objections.

Barriers to Consensus

None identified.

ES-12. Nuclear Energy

Policy Option Description

In 2005, electricity generation accounted for 37% of Colorado's gross greenhouse gas emissions on a consumption basis, or about 43 million metric tons on a CO_2-equivalent basis ($MMtCO_2$). Of that, coal-fired plants emit 35 $MMtCO_2e$. Since nuclear plants also produce base load power, they are potentially a direct replacement for coal-fired plants.

Nuclear power provides about 20% of U.S. electricity, and is the largest single source of low-carbon power in the electric sector. During operation, nuclear plants generate no GHGs, although there are GHG emissions associated with the mining, refining, and transport of nuclear fuel and the construction and decommissioning of plants. The feasibility of new nuclear power plants in the U.S. clouded by several serious and interrelated issues relating to costs, safety, management of radioactive waste and the proliferation of nuclear materials. Colorado's sole nuclear reactor, located at St. Vrain, operated between 1976 and 1989. Due to frequent outages and reliability problems, it was decommissioned in 1992. In 1996, the St. Vrain plant was refurbished with natural gas turbines.

Worldwide, there are about 435 nuclear power plants. Electric utilities in the U.S. are contemplating building new reactors at existing power plant sites in the South, but no incumbent Colorado utility currently has any plans to add nuclear capacity. Since it has been decades since a new reactor was ordered in the United States, the costs of building one are highly uncertain. Estimates are that it might take at least ten years to design, site, permit, finance, and construct a new nuclear power plant.

Some 30 new reactors are under construction in various countries around the world. The price of their uranium fuel has soared in recent years, from $7 a pound in 2000 to more than $120 in 2007. Since Colorado is relatively rich in uranium ore, a number of companies are actively prospecting for uranium on the Western Slope. One new mine has also been proposed in Weld County.

Although Colorado's experience with nuclear power was costly, the facts are clear: to stabilize atmospheric concentrations of carbon dioxide, global emissions must eventually fall to the level of U.S. emissions today. Achieving this in the face of continued population and economic growth will be a monumental challenge and all potentially viable options deserve consideration.

In any "wedge" analysis of possible reduction opportunities, nuclear power must be evaluated as one option, since it currently provides the largest share of low-emitting power. The CAP, like the public at large, is divided about the benefits and liabilities of nuclear power. However, since the scale of total carbon reductions needed is so monumental, since future technological developments are uncertain, and since the electric sector will be central to any successful resolution of the climate challenge, policymakers should not discard the nuclear option until we learn more about the cost, viability and contribution that other low-emitting options can make, including carbon capture and sequestration, solar photovoltaics, wind, energy storage, transmission enhancements, conservation, and improvements in energy efficiency.

Policy Option Design

Goals: literature review of costs of new nuclear power plants

Timing: Not applicable.

Coverage: Not applicable.

Implementation Mechanisms

Not applicable.

Related Policies/Programs in Place

Not applicable.

Type(s) of GHG Reductions

New nuclear generation in Colorado would reduce the operation of existing coal-fired plants and/or defer the need for new ones.

Estimated GHG Savings and Costs per $MtCO_2e$

Non-specific policy not quantified.

Data Sources:

Massachusetts Institute of Technology, *The Future of Nuclear Power: An Interdisciplinary MIT Study*, 2003, ISBN: 0-615-12420-8.

The Keystone Center, *Nuclear Power Joint Fact-Finding*, June 2007.

U.S. Energy Information Association, *Assumptions to the Annual Energy Outlook, 2007*, April 2007, Report #: DOE/EIA-0554(2007).

Quantification Methods:

We have not quantified potential costs and emission reductions associated with this policy due to considerable uncertainties around the cost and feasibility of new nuclear capacity. We found two studies that assess the potential costs of new nuclear capacity in the U.S. and the uncertainties surrounding it. The first is an interdisciplinary study from the Massachusetts Institute of Technology (MIT study), and the second is the report of a stakeholder research group brought together by the Keystone Center (Keystone study). Both studies focus on uncertainties in four main areas. The MIT authors write:

- Costs—nuclear plants have higher overall lifetime costs than gas- and coal-fired plants;
- Safety—nuclear power has perceived adverse safety, environmental and health effects;
- Proliferation—nuclear power entails potential security risks; and

- Waste—nuclear power has unresolved challenges in the long-term management of radioactive wastes.[13]

Estimates of the cost of energy from new nuclear units are highly uncertain. Table F-10 shows three cost estimates. The first estimate is from the MIT study; the second is from the Keystone study; and the third is the cost that the U.S. Energy Information Agency (EIA) uses in its energy modeling. (The levelized cost of energy in the EIA model falls from 6.3 to 5.8 ¢/kWh over the period 2015 to 2030.) The MIT Study assumes a capacity factor or 85% and assumes that non-fuel O&M costs for a new plant can be reduced by 25% relative to the current fleet average. Since their O&M costs are quite close, it seems that EIA has made a similar assumption about O&M costs.

Table F-10. Projected costs of new nuclear energy in the United States (2005$)

	MIT Study[14]	U.S. EIA[15]	Keystone Center
Overnight cost ($/kW)	2,100	2,081	3,420–3,800
Debt/Equity ratio	50/50	unknown	50/50
Cost of debt/equity	8%/15%	unknown	8%/15%
Construction period (yrs)	5	6	5–6
Economic life (yrs)	25–40	40	30–40
Fuel (¢/kWh)	unknown	0.5–0.6	1.2–1.6
O&M (¢/kWh)	unknown	0.9	2.3–3.0
Fuel + O&M (¢/kWh)	1.6	1.4–1.5	3.5–4.7
Levelized energy cost (¢/kWh)	7.0–7.4	6.3–5.8	7.9–0.6

Costs are presented in 2005 dollars. Dollars from the MIT and Keystone studies have been converted from 2003 and 2007, respectively.

While there is some uncertainty around all cost components, the uncertainty around the terms of plant financing is particularly large. The current fleet of nuclear plants in the U.S. was built within a heavily regulated industry, and as the MIT authors note, “many of the risks associated with construction costs, operating performance, fuel price changes and other factors were borne by consumers rather than suppliers.” It is unclear whether capital markets will be willing to take on the perceived risks of merchant nuclear plants in today’s competitive bulk power markets—and if they are, they may well demand risk premiums considerably higher than those assumed in the MIT study.

However, as the Keystone study notes, “competitiveness cannot be gauged entirely by comparing financial numbers,” and questions about nuclear costs may prove to be small compared to concerns about safe plant operation, safety of the fuel cycle and the proliferation of nuclear materials represent major barriers. In a post-9/11 world, concerns about the security of nuclear plants and fuel processing facilities may loom as large in the public mind as concerns about reactor safety and waste containment. In short, is not at all clear that these issues could be resolved to the satisfaction of public officials and the public at large. Further, the resolution of

[13] Massachusetts Institute of Technology, *The Future of Nuclear Power: An Interdisciplinary MIT Study*, 2003, ISBN: 0-615-12420-8, p. 2.

[14] Massachusetts Institute of Technology, p. 42-43.

[15] U.S. EIA, Table 38, p. 72.

these issues might well place additional costs on prospective plant owners, adding to the economic challenge.

Finally, when considering nuclear energy as a GHG-reduction strategy, the issue of lifecycle emissions becomes important. There is considerable fossil fuel combustion in the mining, enriching and transportation of nuclear fuel and the decommissioning of plants, and this fuel use is not well documented. Nuclear fuel-cycle emissions probably constitute a fraction of the per-kWh emissions from a coal-fired plant, but more work needs to be done to quantify these emissions.

Key Assumptions

Costs and emission reductions not quantified.

Key Uncertainties

- The cost of a new nuclear plant in Colorado.
- The actual emissions benefit of nuclear energy over coal-fired generation fossil, accounting for emissions associated with fuel processing.

Additional Benefits and Costs

None identified.

Feasibility Issues

- Can a new nuclear plant be sited and licensed in Colorado? The siting and licensing proceedings (and potentially voter referenda) will be the battleground for safety, proliferation and waste management issues.
- Are capital markets willing to invest in a merchant nuclear plant at terms that do not impose unacceptable costs?
- Waste storage issues.

Status of Group Approval

Unanimous consent of those CAP members present and voting.

Level of Group Support

No objections

Barriers to Consensus

None identified

ES-13. Efficiency Improvements for Existing Generators (Includes Heat Recovery)

Policy Option Description

Making efficiency improvements at existing generation stations has a number of benefits such as offsetting the rising cost of fuel, reducing overall emissions and improving plant reliability. This can be done through improvements in both the combustion and steam cycles, as well as with waste heat recovery.

Efficiency improvements at existing generating stations may be hampered by federal regulation, lawsuits and uncertainty. New Source Review (NSR) and New Source Performance Standard (NSPS) regulations need to be clarified and should encourage, not discourage, efficiency improvements such as turbine upgrades, motor, pump, fan and drive improvements, control system upgrades and recovery of waste heat. Though these are Federal programs, the State of Colorado may be able to help mitigate potential regulatory issues associated with such improvements. Public policy could specifically encourage the State to utilize its regulatory discretion to streamline the process of evaluating a plant's NSR and NSPS requirements. Reform of NSR could be addressed in any carbon control regulations to encourage plant efficiency. One option is to reinstate the pollution control project (PCP) exemption and broaden it to include significant plant upgrades such as turbine replacements. Another option is to require issuance of construction permits for efficiency projects on a more timely basis (e.g. permits processed within 12 months).

Efficiency improvements at existing generating stations may also be hampered by lack of regulatory cost recovery certainty for regulated investor-owned utilities under the jurisdiction of the Colorado Public Utilities Commission (PUC). Public policy could specifically encourage the PUC to allow for the recovery of costs for efficiency improvements at existing generators. These efficiency improvements could reduce customer energy costs as well as carbon dioxide emissions.

Policy Option Design

Goals: Adopt policies that would result in a 2% overall improvement in generator efficiency by 2020

Timing: Utilities report total heat input/total MWh output in 2008; first year of reduction is 2011. Use imputed value for purchases unless specific data are provided.

Parties involved: All generation owners in CO.

Other: As needed, identify incentives that encourage plant efficiency improvements and utilization of new technology to reduce emissions.

Implementation Mechanisms

No specific implementation mechanism for this policy option has been identified.

Related Policies/Programs in Place

None specified.

Type(s) of GHG Reductions

Efficiency improvements on plants; replacement of coal with gas over time.

Estimated GHG Savings and Costs per $MtCO_2e$

This policy would avoid about 1 $MMtCO_2$ emissions per year by 2020.

Data Sources:

Colorado Inventory & Forecast as source for business as usual (BAU) generation sources in Colorado.

Quantification Methods:

Assume policy achieves 2% reduction in CO_2 emissions from fossil generating plants in Colorado.

Key Assumptions:

Costs not to include additional costs associated with NSR regulations, if applicable.

Technical and economic feasibility of reaching goal.

Key Uncertainties

- Potential for and cost of efficiency improvements at existing plants.
- Heat rates of future generating technologies.
- Efficiency improvements at existing generating stations may be hampered by federal regulation, lawsuits and uncertainty
- New Source Review (NSR) regulations could raise the cost of meeting this goal.
- Availability and price of natural gas

Additional Benefits and Costs

Lower overall cost of producing electricity at more efficient plants; economic opportunities and employment.

Feasibility Issues

The Policy Work Group estimates that a 2% improvement for existing generators is possible over this time period.

Status of Group Approval

Unanimous consent of those CAP members present and voting.

Level of Group Support

No objections

Barriers to Consensus

None identified

ES-14. Oil and Gas Operations

Policy Option Description

There are a number of ways in which Greenhouse Gas (GHG) emissions in the oil and gas industry, particularly CO_2 and methane, can be mitigated. Methane is a potent GHG, so any leaks during production, processing, and transportation/distribution should be addressed. Eliminating these leaks can be economically beneficial because it prevents the waste of valuable product. The EPA Natural Gas STAR program offers numerous methods of preventing leaks.

Policy Option Design

Goals: 35% reduction below 2004 levels in GHG emissions from methane relative to baseline case.

Also reduce uncertainty in methane losses (target for increased accuracy)

Timing: Achieve level of reduction by 2020

Parties involved: Colorado oil and gas permittees.

Implementation Mechanisms

This policy aims to reduce methane emissions from gas and oil operation gradually, starting in 2009 and reaching a 35% reduction relative to 2004 emission by 2020.

The CAP recommends that Colorado focus attention on reducing GHG emissions from fuel combustion in the oil and gas industry through education, financial incentives, mandates and/or standards—coupled with cost and investment recovery mechanisms, if appropriate.

Related Policies/Programs in Place

In 2006, EnCana installed emission control units to control VOC flash emissions associated with condensate storage tanks. The company installed 172 emissions control units at $20,000 per unit. The company has not finished its emission inventory, and thus has not identified the amount of methane reduction from this measure. EnCana reported that this measure reduced its VOC emissions from 2004 to 2006 by approximately 40%. (Personal communication with PWG member Chris Williams of EnCana in July 2007)

Type(s) of GHG Reductions

Reduced methane emissions from oil & gas operations.

Estimated GHG Savings and Costs per $MtCO_2e$

	Policy Option	GHG Reductions ($MMtCO_2e$) 2012	2020	Total 2007–2020	Gross NPV Cost 2007–2020 (Million $2005)	NPV Savings 2007–2020 (Million $2005)	Net Present Value 2007–2020 (Million $2005)	Cost-Effectiveness ($2007/$tCO_2e$)
ES-14	Oil and Gas Operations	0.8	2.6	16	$12	$0	$12	$0.8

Data Sources:

Cost of Methane Reduction:

- U.S. EPA. "EPA Natural Gas STAR Program," available at: www.epa.gov/gasstar/ and http://www.epa.gov/gasstar/techprac.htm

Quantification Methods:

Cost of reduced methane based on the data available from US EPA's Natural Gas Star Program is used to estimate the level of investment that is necessary to achieve the policy target.

Key Assumptions:

Table F-11.

Parameter	Value	Notes
Cost of Saved Methane	$0.487 per Mcf of methane	This figure is based on (1) 20 year average lifetime of methane reduction measures, (2) 5% real discount rate, and (3) the average cost of saved methane based on performance by a number of methane reduction projects under US EPA Gas Star Program.
Methane Emission Rate	0.404 ton of CO_2e per Mcf of CH_4	US EPA. Natural gas methane unit converter, available at www.epa.gov/gasstar/pdf/unitconverter_final.pdf

Mcf = million cubic feet

Key Uncertainties

Cost and feasibility of reaching target.

Additional Benefits and Costs

Recovery of valuable product.

Avoidance of methane emissions to the atmosphere, which contributes to the production of pollutants such as NO_x and O_3.

Feasibility Issues

Further study and analysis of the approaches recommended above by the Colorado Department of Public Health and Environment and other appropriate agencies may suggest changes in goals and determinations regarding the economic and technical feasibility of these approaches.

Status of Group Approval

Unanimous consent of those CAP members present and voting.

Level of Group Support

No objections.

Barriers to Consensus

None identified.

ES-15. CO_2 Emissions Standards for Power Plants

Policy Option Description

A carbon dioxide emissions performance standard is an emissions standard requiring that all new non-peaking power plants located in Colorado or serving Colorado electricity customers have carbon dioxide emission no greater than 1,100 pounds of CO_2 per megawatt-hour. In addition, to ensure that power providers have the necessary incentives to invest in new low- carbon dioxide emitting facilities rather than continue to operate aging high-carbon dioxide emitting plants the standard would also apply to existing facilities once they reach 60 years of age. The 1,100 pounds per megawatt-hour standard is based on the level of emissions of a new efficient natural gas plant.

Mitigation Option Design

Goal: Establish a power plant carbon dioxide emission standard of 1,100 pounds CO_2 per megawatt-hour for non-peaking plants. (Peaking is defined as having a capacity factor of less than 10%) Applies to new power sold in the state of Colorado, or 60+ year-old plants

Timing: As soon as possible.

Coverage: Would apply to all new non-peaking power plants, or those that have operated for 60 year or more, that are located in Colorado or that provide power to Colorado electricity customers.

Implementation Mechanisms

Implementation to be in the form of a regulatory requirement to all producers or purchasers of wholesale electricity in the state that no new power plant shall be built or operated, and no plants in excess of 60 years old shall be operated, unless it can achieve a total emissions rate of no more than 1,100 pounds of CO_2 per MWh output. This means that for any new coal plant to be built or operated it will have to be coupled with some form of operating, permanent carbon capture and storage technology. The same requirement applies to any power purchased from out of state from new resources. There is to be no provision for offsets for meeting this requirement.

This requirement does not apply to new power plants that have an annual average capacity factor of less than 10%.

This regulation is to be adopted as a regulation at the state level.

Given the lead time of constructing new fossil fuel plants, a standard established today would impact new plants that come on-line after 2011 and any that have been in operation for 60 years or more.

Related Policies/Programs in Place

None identified.

Type(s) of GHG Reductions

Displaced emissions associated with overall improvement of generating fleet efficiency relative to baseline scenario..

Estimated GHG Savings and Costs per $MtCO_2e$

	Policy Option	GHG Reductions ($MMtCO_2e$)			Gross NPV Cost 2007–2020 (Million $2005)	NPV Savings 2007–2020 (Million $2005)	Net Present Value 2007–2020 (Million $2005)	Cost-Effectiveness ($2007/$tCO_2e$)
		2012	2020	Total 2007–2020				
ES-15	CO_2 Emission Standards for Power Plants	0.5	2.3	13	N/A	N/A	($14)	($1)
ES-15a	Assuming Central Station Solar as alternative	0.9	4	23			$297	$13

Note that capital cost savings from building natural gas instead of coal plants more than offsets the higher cost of natural gas relative to coal, according to EIA technology cost projections. As an alternative, the cost of implementing this policy by replacing coal with concentrating solar thermal stations is shown above. In this case the emissions reductions would be significantly greater, as would the cost per avoided ton of CO_2 emissions.

Data Sources:

Colorado Inventory & Forecast (I&F), industry standard estimates of delivered plant costs. EIA Annual Energy Outlook for 2007.

Quantification Methods:

Policy design is to replace all new coal plants in baseline I&F, as well as all plants over 60 years old, with a portfolio of resources including energy efficiency, renewables, perhaps some gas and IGCC or other advanced coal technologies that meets the emission standard.

The analysis shown is limited to estimating cost and emissions impact of replacement of all new coal generation (heat rate 9000 Btu/kWh) in the reference case with natural gas combined cycle generation (heat rate 7000 Btu/kWh).

The EIA projections for the all-in, levelized cost of new natural gas and coal plants are as follows:

	Inputs					
		2007	2008-10	2011-14	2015-19	2020
	Cost of new coal ($/MWh)	56.07	56.07	56.07	56.1	56.1
	Cost of new gas ($/MWh)	55.24	55.24	55.24	55.2	55.2
	Cost of New Solar Thermal ($/MWh)	133	133	133	94	89

Source: EIA Annual Energy Outlook 2007.

The costs for new coal and gas are from Table 16 in AEO 2007:

Table 16. Costs of producing electricity from new plants, 2015 and 2030

	2015		2030	
Costs	Advanced coal	Advanced combined cycle	Advanced coal	Advanced combined cycle
	2005 mills per kilowatthour			
Capital	32.64	12.16	28.71	11.12
Fixed	4.89	1.44	4.89	1.44
Variable	14.82	37.97	16.49	41.17
Incremental transmission	3.72	3.67	3.64	3.49
Total	**56.07**	**55.24**	**53.73**	**57.22**

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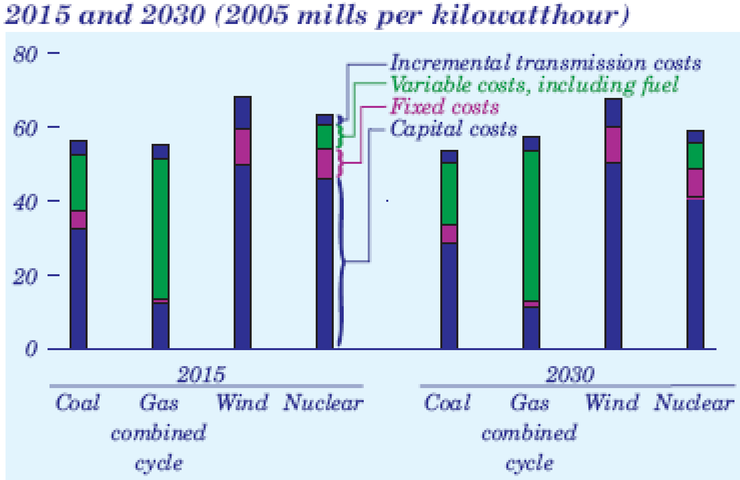
The cost of solar thermal technology is as discussed under ES-2.

The following graph from the same page compares a larger set of technologies:

Figure 56. Levelized electricity costs for new plants, 2015 and 2030 (2005 mills per kilowatthour)



Although not stated explicitly, these levelized costs are implicitly based on, and consistent with, the assumptions and energy price forecasts associated with AEO 2007.

The assumptions used for the concentrating solar analysis are based on technology cost data from the MARKAL model, as provided by SGB Engineering Consulting, LLC.

An alternative approach is to meet the policy goal through energy efficiency initiatives. This would be consistent with policy RCI-1 considered and analyzed by the Residential, Commercial and Industrial Working Group, which found a net *savings* of $32 per avoided ton of CO_2 emissions.

Key Assumptions

Cost of new plants & fuel unaffected by altered investment strategy.

Key Uncertainties

Future costs of natural gas and coal; availability and cost of generating technology..

Additional Benefits and Costs

None identified.

Feasibility Issues

Trying to apply this standard to non-Colorado facilities may violate interstate commerce clause. This may be rectifiable if the requirement is for portfolio of power purchased by LSEs. (This issue has been discussed extensively in the RGGI process.)

Status of Group Approval

Approved by those CAP members present and voting with five objections:

Level of Group Support

Objections include:

- as designed, policy is too rigid;
- would drive state towards increased natural gas use, and it is too premature for “clean coal,”
- not market based;
- premature, doesn’t consider availability of gas and cost; and
- policy is short-sighted, does not recognize need for additional generation between now and time “clean coal” from plants with carbon capture is available.

Barriers to Consensus

The noted objections reflect positions that are not conducive to reaching consensus.