Appendix H
Agriculture, Forestry, and Waste Management Policy Recommendations

Summary List of Policy Recommendations

	Policy Recommendation	GHG Reductions ($MMtCO_2e$)			Costs (Savings) 2007–2020 (Million $)	Cost-Effectiveness ($/tCO_2e$)	Climate Action Panel Action
		2012	2020	Total 2007–2020			
AFW-1	Achieve no-till operation of half of croplands by 2020 and increase nitrogen fertilizer efficiency by 20%.	0.57	0.78	7.7	–$57	–$7/ton	Unanimous Consent
AFW-2	Implement methane capture and energy recovery on manure management projects on 80% of animal feeding operations by 2020.	0.01	0.32	1.8	$66	$36/ton	Unanimous Consent (1 qualified approval)
AFW-3	Reduce on-farm petro-diesel use 20% by 2020, and reduce electricity use from fossil fuels 40% through energy efficiency and on-site renewable sources generation.	0.14	0.64	3.8	–$150	–$40/ton	Unanimous Consent
AFW-4	Incentives for the production of biodiesel fuel from oilseed crops, waste vegetable oil, or other sources to offset 40% of fossil diesel fuel use by 2020.	0.02	0.22	1.1	$13	$12/ton	Unanimous Consent (3 qualified approvals)
AFW-5	Increase in-state ethanol production, using GHG-superior feedstocks and production methods, to 400 million gallons per year above BAU by 2020.	0.39	3.1	15	$58	$3/ton	Unanimous Consent (3 qualified approvals)
AFW-6	Preserve forest lands (line 1) and grasslands (line 2) to reduce the rate of conversion to developed uses by 25% by 2020.	0.10 0.05	0.24 0.14	1.7 1.0	$44 $31	$26/ton $32/ton	Unanimous Consent
AFW-7	Increase the use of biomass from forest health and fire risk treatment for energy production, using 20% of harvested wood by 2020.	0.08	0.20	1.4	–$104	–$75/ton	Unanimous Consent
AFW-8	Divert 75% of wastes from landfills by 2020 through source reduction, enhanced recycling, and composting programs.	0.48	4.6	24	$311	$13/ton	Unanimous Consent
AFW-9	Control or capture landfill methane to achieve 50% reduction from BAU by 2020.	0.33	1.2	7.5	–$0.1	–$0.02/ton	Unanimous Consent
AFW-10	Plant 3.4 million new trees statewide by 2020 through expanded urban forestry programs.	0.03	0.08	0.59	$40	$79/ton	Unanimous Consent (1 qualified approval)
	Sector Total of Analyzed Policies After Adjusting for Overlaps	2.2	11.5	66	$252	$4 /ton	

Negative 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.

AFW-1. Agricultural Crop Management

Policy Option Description

The amount of carbon stored in the soil can be increased by crop management practices that increase carbon inputs to soil and/or reduce soil organic matter decomposition rates. Adoption of conservation tillage, in particular no-till, can increase soil carbon stocks. Reducing mechanical soil disturbance reduces the oxidation of soil carbon compounds and allows more stable aggregates to form. Other benefits of conservation tillage include reduced wind and water erosion, improved soil structure and crop water use, reduced fuel consumption, and improved wildlife habitat. On non-irrigated cropland, increased cropping frequency to reduce or eliminate summer fallow goes hand in hand with adopting no-till practices. Improved nutrient management (e.g., better timing, application rates based on soil test, and advanced fertilizer formulations) of both fertilizer and manure can increase nutrient use efficiency and reduce addition rates, thereby reducing nitrous oxide emissions and potentially fossil fuel use. For some production systems, organic farming practices result in lower net GHG emissions. Application of biochar (i.e., stable organic residues from biomass pyrolysis) to soils is a potential practice to capture and sequester atmospheric carbon dioxide (CO_2).

Policy Option Design

Goals:

- **No-till goal:** approximately 15% of total annual cropland is currently managed under no-till (most with reduced summer fallow). Achieve 50% no-till by 2020.
- **Nutrient goal:** Increase nitrogen fertilizer efficiency by 20% through the use of best management practices by 2020.

Timing:

- **No-till goal:** 30% no-till on annual croplands by 2012; achieve the full goal by 2020.
- **Nutrient goal:** Increase fertilizer efficiency by 10% by 2012; achieve the full goal by 2020.

Parties Involved: Colorado Dept. of Agriculture, Rocky Mountain Farmer's Union, Colorado State University (CSU) Agriculture Extension.

Other: Current (2005) Colorado cropland: 1,923,000 hectare (ha) dryland; 924,000 ha Conservation Reserve Program (CRP); 1,000,000 ha irrigated cropland (~50% as hay).[1]

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[1] Data provided to Center for Climate Strategies (CCS) by Keith Paustian (Colorado State University) of the Agriculture, Forestry, and Waste Management (AFW) PWG. 2005 data.

Implementation Mechanisms

- Increased extension/outreach (a good field-day program for dryland systems, through CSU researchers. This program has been developed over the past several years and could benefit from more resources). Extend the program to include nutrient management.
- State incentives—for example, favorable property tax rating for "high conservation management."
- Research and development (R&D) support for cropping systems research—for example, selection/field studies on profitable oil seeds for inclusion in dryland rotation (cross reference to biodiesel incentives).
- Incentives for water conservation/more flexible water allocation could likely play in some way.

Related Policies/Programs in Place

- Federal Conservation Compliance programs (but probably don't specifically award for no-till and reduced summer fallow); possible upcoming provisions in US Farm Bill.
- Market-based incentives—e.g., Chicago Climate Exchange (CCX) project with the Rocky Mountain Farmer's Union (RMFU).
- CDPHE, EPA and the NPS are participating in developing a Rocky Mountain National Park Nitrogen Deposition Reduction Plan.

Types of GHG Reductions

CO_2: Reducing tillage and soil disturbance slows the breakdown of plant material on the soil surface and in the root zone, accelerating the microbial processes that stabilize carbon and protecting carbon from oxidation, inhibiting the release of carbon back into the atmosphere. Additionally, reducing the amount of nitrogen fertilizer needed will reduce CO_2 emissions that result from the fertilizer manufacturing process.

N_2O (n**itrous oxide):** Increasing the efficiency of nitrogen fertilizer application is expected to reduce N_2O emissions.

Improved cultivation methods will reduce all GHG emissions that result from the combustion of distillates and other fossil fuels related to the use of farm equipment. This reduction is captured under this option, rather than AFW-3. AFW-3 examines energy efficiency measures, rather than fuel conservation techniques, such as no-till cultivation.

Estimated GHG Savings and Costs per $MtCO_2e$

GHG Reduction Potential in 2012, 2020 ($MMtCO_2e$):

- Total: 0.57, 0.78
- No-till: 0.64, 0.69
- Nitrogen fertilizer efficiency: 0.06, 0.10

Net Cost per $MtCO_2e$ (note that negative numbers are *cost savings*):

- Total: –$7.33
- No-till: –$4.37
- Nitrogen fertilizer efficiency: –$27.62

Note: The metric unit hectare (ha) is used in the analysis of this option, rather than the standard unit, acres. The GHG reductions above and costs below do not reflect the organic production incentives elements of this option. Because agricultural soils will only accumulate carbon up to a certain level before tapering off, the GHG benefit related to no-till soil carbon accumulation decreases in the post-2020 period before ceasing in 2025. The remaining benefit, which is permanent, is associated with lower fossil fuel consumption under no-till management practices compared to conventional tillage. It is also important to note that the estimates for fertilizer efficiency programs do not capture the full life-cycle benefits.

Data Sources:

Quantification of the no-till portion of this option is based upon 2,923,000 ha of agricultural land in Colorado (referenced above). This land is comprised of dryland and irrigated land. Using standard unit conversions, the soil carbon accumulation rate of 1.37 $MtCO_2$/ha-year was calculated from the midpoint of the range provided by Naderman et al.[2] The estimated cost savings ($14.33/ha) related to the adoption of no-till farming was derived from an article by Tim McAlvay of Texas A&M.[3] The reduction in fossil diesel fuel use from the adoption of conservation tillage methods is 3.5 gallons/acre.[4] From the Colorado Inventory & Forecast (Colorado I&F), the fossil diesel GHG emission factor is 10.07 $MtCO_2e$/1,000 gallons.

The historical quantity of fertilizer used is consistent with the Agriculture module of the Colorado Draft Inventory & Forecast. This forecast also provides the resulting N_2O emissions and carbon equivalent emissions. Data regarding the cost savings associated with an increase in the efficiency of fertilizer use is taken from an average of the cost of common fertilizers in the spring of 2004.[5]

Quantification Methods:

No-till Cultivation

Based on the policy design parameters, the schedule for acres to be put into conservation tillage/no-till cultivation are shown in Table H-1. The mid-point of the estimated range for carbon sequestration–2.47 Metric tons carbon per hectare (MtC/ha)–in agricultural soils was used to estimate the total amount of carbon to be sequestered. Based on the Naderman et al.

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[2] G. Naderman, B.G. Brock, G.B. Reddy, and C.W. Raczkowski, “Long Term No-Tillage: Effects on Soil Carbon and Soil Density Within the Prime Crop Root Zone,” Project Report, January 2006.

[3] Tim McAlvay. AgNews News and Public Affairs: Texas A&M University System Agriculture Program, April 27, 2005, accessed July 11, 2007 from http://agnews.tamu.edu/dailynews/stories/AGEC/Apr2705a.htm. Actual estimate is –$5.80 per acre. Converted here to metric units.

[4] Reduction associated with conservation tillage compared to conventional tillage, at www.ctic.purdue.edu/Core4/CT/CRM/Benefits.html, accessed August 2006.

[5] 2004 Fertilizer Use and Cost. Accessed on July 19, 2007 from www.ers.usda.gov/Data/FertilizerUse/Tables/Fert%20Use%20Table%207.xls.

study referenced above, it was further assumed that this additional carbon would be sequestered in the soil over a period of 6 years (after 6 years, no further carbon is stored). The resulting annual carbon accumulation rate was converted into its CO_2 equivalent yielding 1.37 $MtCO_2$/ha-year.

To estimate carbon stored each year, the annual accumulation rate was multiplied by the number of acres in the policy program each year. After 6 years, the crop acres that entered the program were assumed to not store additional carbon. Results are shown in Table H-1.

Additional GHG savings from reduced fossil fuel consumption were estimated by multiplying the fossil diesel emission factor and diesel fuel reduction per acre estimate provided above. Results are shown in Table H-1 along with a total estimated benefit from both carbon sequestration and fossil fuel reductions.

Table H-1. GHG benefits for no-till cultivation

Year	Hectares in Program	Hectares Still Accumulating Carbon	$MMtCO_2e$ Sequestered	Diesel Saved (1,000 gal)	$MMtCO_2e$ From Diesel Avoided	Total $MMtCO_2e$ Saved
2008	87,690	87,690	0.120	758	0.0076	0.1277
2009	175,380	175,380	0.240	1,516	0.0153	0.2554
2010	263,070	263,070	0.360	2,274	0.0229	0.3831
2011	350,760	350,760	0.480	3,032	0.0305	0.5109
2012	438,450	438,450	0.600	3,790	0.0382	0.6386
2013	511,525	511,525	0.700	4,422	0.0445	0.7450
2014	584,600	496,910	0.680	5,054	0.0509	0.7313
2015	657,675	482,295	0.660	5,686	0.0573	0.7177
2016	730,750	467,680	0.640	6,317	0.0636	0.7040
2017	803,825	453,065	0.620	6,949	0.0700	0.6904
2018	876,900	438,450	0.600	7,581	0.0763	0.6767
2019	949,975	438,450	0.600	8,213	0.0827	0.6831
2020	1,023,050	438,450	0.600	8,844	0.0891	0.6895

Costs savings were estimated by multiplying the estimated savings per acre cited above ($14.33) by the number of acres in the program each year. This savings estimate takes into account budget changes for the cost of fuel, labor, chemicals, and equipment. Two studies that cited the need to provide a financial incentive to generate more widespread adoption of no-till cultivation—despite the expected cost savings of the practice—were consulted. The midpoint ($7.9/ha) of the incentive needed for wheat ($4/acre)[6] and corn ($2.4/acre)[7] was multiplied by the total quantity of land entering the cultivation program each year. The resulting cost-effectiveness of no-till cultivation is a cost savings of –\$4.37/$MtCO_2e$. The result is a net cost savings for the no-till cultivation program with a net present value of –$36.48 million.

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[6] S. Brooks and R.N. Elliot. “Agricultural Energy Efficiency Infrastructure: Leveraging the 2002 Farm Bill and Steps for the Future. *American Council for an Energy Efficient Economy*. Report No. IE072. July 2007.

[7] L. Kurkavola, C. Kling, and J. Zhao. “Green Subsidies in Agriculture: Estimating the Adoption Costs of Conservation Tillage from Observed Behavior.” *Center for Agricultural and Rural Development; Iowa State University*. Working Paper 01-WP 286. April 2003

The projected business-as-usual (BAU) fertilizer use is determined by extrapolating the trend in historical fertilizer use (1990–2002) with Excel's projection tool. The application of this tool results in a projected moderate annual growth in fertilizer use in Colorado. The target efficiency improvements laid out in this policy are applied to the BAU fertilizer use projection to determine how much fertilizer use will be avoided for the years 2007–2020.

Nitrogen Fertilizer Efficiency

The nitrous oxide emission factor for fertilizer use is calculated by multiplying the carbon equivalent emissions in the Colorado Draft I&F by the standard carbon to CO_2 conversion of 44/12. Then, the CO_2e emission factors for the years 1990–2002 are averaged to provide an estimated emission factor (5.47×10^{-9} $MMtCO_2e/kg$ N) that is used to calculate the avoided GHG emissions from the proposed increase in fertilizer efficiency. The results of the calculations detailed in the preceding discussion are displayed in Table H-2. Note that this approach does not capture the avoided life cycle GHG reductions that would occur through fertilizer efficiency programs (emissions associated with the production, transport, and energy consumption during application).

Table H-2. Fertilizer reduction targets and avoided emissions

Year	Total BAU Fertilizer Use (kg N)	Policy Target	Target Fertilizer Reduction (kg N)	Avoided GHG Emissions ($MMtCO_2e$)
2007	117,844,490	0%	–	–
2008	115,837,438	2%	2,316,749	0.01
2009	113,830,386	4%	4,553,215	0.02
2010	111,823,334	6%	6,709,400	0.04
2011	109,816,282	8%	8,785,303	0.05
2012	107,809,230	10%	10,780,923	0.06
2013	105,802,178	11%	11,902,745	0.07
2014	103,795,127	13%	12,974,391	0.07
2015	101,788,075	14%	13,995,860	0.08
2016	99,781,023	15%	14,967,153	0.08
2017	97,773,971	16%	15,888,270	0.09
2018	95,766,919	18%	16,759,211	0.09
2019	93,759,867	19%	17,579,975	0.10
2020	91,752,815	20%	18,350,563	0.10

The cost savings associated with using less fertilizer is calculated by multiplying the total fertilizer reduction in each year by the average cost of fertilizer in the spring of 2004.[8] The non-discounted cost savings from 2007 to 2020 of this option is $40 million.

The program costs of nutrient management were estimated as the sum of fertilizer savings (negative cost); costs for soil testing; costs for staff, overhead, and travel; and guidance document preparation costs. Soil testing would be required for each crop field once every 4 years. The total number of harvested hectares were divided by the assumed average field size of 75 acres (30.3 ha) and divided by 4. The cost for each soil test was estimated to be $10, for a

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[8] 2004 Fertilizer Use and Cost. Accessed on July 19, 2007, from www.ers.usda.gov/Data/FertilizerUse/Tables/Fert%20Use%20Table%207.xls.

total cost of $241,000/year for soil testing. Costs for 2 full-time equivalents (FTEs) of additional staff, overhead, travel, lab, and associated costs was estimated at $250,000/year, and preparation of guidance documents was assumed to be $75,000 in the first year.[9]

The net cost of programs to increase fertilizer efficiency has a net present value of cost savings at –$24 million over the course of the policy period. The total net cost of AFW-1 is a cost savings of –$7.33/MtCO$_2$e with a net present value of –$56.52 million. Table H-3 provides a summary of the data used to calculate the program costs and cost-effectiveness.

Table H-3. Fertilizer efficiency program costs and cost-effectiveness

Year	Total Cost Savings ($MM)	Total Avoided GHG Emissions (MMtCO$_2$e)	Cost of Programs ($MM)	Discounted/ Levelized Cost ($MM)	Discounted/Levelized Cost-Effectiveness ($Mt)
2008	–$ 1.86	0.01	$1.26	–$ 0.60	
2009	–$ 3.70	0.15	$1.88	–$ 1.73	
2010	–$ 5.51	0.29	$2.57	–$ 2.67	
2011	–$ 7.31	0.43	$3.26	–$ 3.50	
2012	–$ 9.09	0.57	$3.96	–$ 4.22	
2013	–$ 10.43	0.70	$4.53	–$ 4.62	
2014	–$ 11.75	0.82	$5.11	–$ 4.95	
2015	–$ 13.06	0.81	$5.69	–$ 5.24	
2016	–$ 14.36	0.80	$6.27	–$ 5.48	
2017	–$ 15.65	0.79	$6.84	–$ 5.68	
2018	–$ 16.92	0.78	$7.42	–$ 5.83	
2019	–$ 18.18	0.77	$8.00	–$ 5.95	
2020	–$ 19.43	0.78	$8.58	–$ 6.04	
Totals		7.72	$ 65.37	–$ 56.52	–$ 7.33

Key Assumptions: The cultivation portion of the option does not explicitly differentiate between no-till and conservation tillage. Estimates of the GHG reduction potential and cost-effectiveness for GHG-superior cultivation practices are based on no-till cultivation. The nutrient management portion of this option only specifically applies to nitrogen fertilizer, and does not account for any other potential GHG implications of other elements of fertilizer. Since N_2O emission data is limited (and difficult to collect), CCS assumed that the N_2O emission factor would be consistent with emission factors displayed by the Colorado I&F.

Key Uncertainties

- Data on N_2O emissions is still sparse; current estimates do not account for life cycle fertilizer reduction savings (those associated with fertilizer production, transport, and energy use during application).
- Need for low-intensity “in field” soil carbon monitoring to decrease uncertainty (i.e., benchmark sites) in soil carbon sequestration estimates.
- The increased need for energy-intensive herbicides and chemicals may be necessary to maintain crop output under a no-till cultivation strategy. The quantity and selection of

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[9] Brian Hurd, NMSU Agricultural Economics, personal communication with H. Lindquist, CCS, June 2006.

chemicals is uncertain and therefore the life cycle energy content of these chemicals cannot be included in this analysis.
- The current landscape of Colorado agriculture is subject to change in the near future, as water compacts with neighboring states may cause an adjustment in the types of crops produced in the state.

Additional Benefits and Costs

- Erosion reduction, air and water quality, wildlife habitat, increased net returns.

Feasibility Issues

Although research shows that a net savings to farmers is to be expected, surveys and literature show a risk aversion to altering cultivation and fertilization practices in the absence of a financial incentive. Additionally, concerns over water rights with neighboring states may change the landscape of Colorado agriculture in the future, making a long-term change in farming practices less attractive.

Status of Group Approval

Complete.

Level of Group Support

Unanimous consent of those CAP members present and voting.

Barriers to Consensus

Not applicable.

AFW-2. Manure Management and Energy Programs

Policy Option Description

The methane emissions inherent from the anaerobic decomposition process of manure and other wastes may be captured and used as an energy source. Methane and nitrous oxide emissions can occur at several different places in the manure management process. Management techniques can also reduce GHG emissions and, with energy recovery, offset fossil-based energy. This option covers producer incentives to adopt programs to increase the number of methane capture and energy recovery projects or other manure management techniques that reduce methane and nitrous oxide emissions.

Policy Option Design

Goals: Implement manure management and energy programs (where feasible for adoption by the facility) on 80% of animal feeding operations (AFOs) by 2020.

Timing: Implement programs on 10 AFOs by 2012; achieve the full goal by 2020.

Parties Involved: Department of Natural Resources, Colorado Department of Agriculture, Colorado Livestock Association.

Other: Currently, one housed commercial swine feeding operation utilizes a methane digester to produce power for facility use and one additional AFO is developing a manure energy recovery strategy.

Implementation Mechanisms

- Work with the Governor's Energy Office to develop a pilot program to help fund manure energy recovery systems that are specific to the site and the operation. The pilot program would include a confined animal feeding operation (CAFO), a dairy and a swine operation.
- Development of net metering programs to provide a financial incentive and long-term risk reduction to CAFO operators undertaking electricity generation programs.
- Create a market for “green” natural gas by allowing CAFO operators to scrub captured methane and insert it into natural gas pipelines, where feasible.

Related Policies/Programs in Place

- Colorado Department of Public Health and Environment (CDPHE), U.S. Environmental Protection Agency (EPA), and the National Park Service (NPS) are participating in developing a Rocky Mountain National Park Nitrogen Deposition Reduction Plan. Part of the plan utilizes current best management practices (BMPs), as well as ongoing research into additional BMPs that can be used to reduce nitrogen emissions from livestock operations.

- Recent state legislation that requires local cooperatives to purchase power generated from renewable resources could provide markets for energy generated from CAFOs.

Types of GHG Reductions

Methane (CH_4): methane is captured and typically combusted in an energy recovery system or flare. Small amounts of N_2O and CH_4 are emitted from the combustion process.

CO_2: carbon dioxide is reduced when the methane is converted to energy and that energy is used to offset fossil-based energy (e.g., electricity, natural gas). Small amounts of N_2O and CH_4 are also reduced from the fossil-based energy that is offset.

Estimated GHG Savings and Costs per $MtCO_2e$

GHG Reduction Potential in 2012, 2020 ($MMtCO_2e$): 0.01, 0.32

Net Cost per $MtCO_2e$: $36

The cost per ton is the weighted average for dairy ($25) and swine ($58). For beef feedlots, the cost-effectiveness estimate is much higher ($1,500; due to much lower methane emissions/head), so the Policy Work Group (PWG) does not recommend adopting this policy to address feedlots. These cost estimates include the effects of grants for renewable energy projects from the Federal Farm Bill but do not include the effects of other existing federal and state tax incentives.

Data Sources: Colorado GHG I&F data, digester and engine generator set cost data from US EPA and the literature, assume 75% of methane generated at AFO is collected, value of generated electricity ($0.05/kW-hr). The total number of animal feeding operations for dairy, beef feedlots, and swine were provided by the Colorado Livestock Association.[10] In 2005, there were 660 dairy operations, 260 beef feedlots, and 700 swine AFOs.

Quantification Methods:

GHG Benefit

Methane emissions data from the Draft Colorado I&F were used as the starting point to estimate the GHG benefits of capturing and controlling the volumes of methane targeted by the policy and to add in the additional benefit of electricity generation using this captured methane (through offsetting fossil-based generation). For 2012 and 2020, the GHG benefit for capturing methane was estimated by multiplying the methane emissions from dairy, feedlot, and swine operations by the applicable goal and then by an assumed collection efficiency of 75%,[11] and converting to CO_2e. The goal was expressed as a fraction of the population, based on the average number of livestock in each category of CAFO (dairy, feedlot, or swine).

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[10] Livestock Industry Practices. Information provided by PWG member M. Collins to B. Strode, CCS, on July 19, 2007.

[11] The collection efficiency is an assumed value based on engineering judgment. No applicable studies were identified that provided information on methane collection efficiencies achieved using manure digesters (as it relates to collection of entire farm-level emissions).

The second portion of the GHG benefit for offsetting fossil-based electricity generation was estimated by converting the methane captured in each year to its heat content (in British thermal units [Btu's]) and then multiplying by an energy recovery factor of 17,100 Btu/kW-hr to estimate the electricity produced (assumes a 25% efficiency for conversion to electricity in an engine and generator set). The CO_2e associated with this amount of electricity in each year was estimated by converting the kW-hrs to MW-hrs and then multiplying this value by the Colorado-specific emission factor for electricity production from EIA data (0.877 Mt/MW-hr).[12]

The total GHG benefit was estimated as the sum of both portions of the benefit described above.

Costs

For swine, costs were estimated using annualized costs for the Barham Farm study, which was part of the North Carolina State University (NCSU) technology determinations referenced in the footnote below. Data from this study indicate a range of annualized costs from $18 to $45/head to cover installation and operation of a digester and an engine-generator set/flare. Annual operations and maintenance costs from this study were $8/head. These costs provide an estimate for the implementation of digester and energy projects at swine farms toward the upper end of the range for U.S. projects with documented costs.[13] Capital costs per head were about $72 for Barham Farm compared to an average of $52/head for seven U.S. swine digester-to-energy projects.

For dairies and feedlots, data from the US EPA methane-to-markets report and Gallo Farms studies referenced below provided an average cost of $450/head for digesters and engine-generator sets (dairies >1,000 head). From the New Mexico Dairy Producers report, capital costs for regional digesters (those serving multiple nearby operations) were estimated to be $190/head. It is not clear based on available data how well regional digesters could be implemented in Colorado, as they require several dairies in close proximity. Therefore, the average of $450/head was used.

CCS assumed that the 25% Farm Bill grant would be available to each project initiated as a result of this policy.[14] After adjustment of the capital costs, annualized costs per head were estimated assuming a 5% interest rate and a 15-year project life, annual operations and maintenance costs of $38/head were taken from the Gallo Farms Study, and the value of the electricity produced was assumed to be $0.05/kW-hr. Additional incentives to the farmer from the Renewable Energy Production Incentives were not included but could have a small effect on the estimated costs (about $1/$MtCO_2e$ reduced). The annualized per head cost estimates were multiplied by the head of livestock to be controlled in each year to estimate total costs.

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[12] Emission factor derived from "2002 Voluntary Greenhouse Gas Reporting Program"; accessed July 24, 2007, at www.eia.doe.gov/oiaf/1605/e-factor.html

[13] M. Moser, "A Dozen Successful Swine Waste Digesters," RCM Digesters, Inc., accessed February 2007 at http://rcmdigesters.com/images/PDF/ADozenSuccessfulSwineWasteDigesters.pdf

[14] More information on the program is also available at www.rurdev.usda.gov/rbs/farmbill/index.html. The application of this grant incentive was considered a reasonable assumption based on CCS discussions with EPA AgSTAR Program staff; Kurt Roos, personal communication with S. Roe, CCS, March 2007.

Key Assumptions: That the cost data for the studies cited is representative of actual costs: 75% collection efficiency for farm-level methane emissions for the digester. Farm Bill grant will be available to all projects in subsequent cycles of the Farm Bill through 2020. The $0.05/kW-hr is the assumed value to the farmer for the electricity produced (either to offset on-farm use or to sell back to the grid); this is a conservative estimate. Higher values for this electricity would translate into a lower cost-effectiveness estimate and a faster return on investment for the farmer.

Key Uncertainties

- The minimum cost for developing a manure energy recovery system on an AFO facility is one million dollars. Without significant federal or state government assistance (50%–100%) in developing the generation infrastructure, developing an energy recovery system for an AFO is not feasible for most operators.
- The operator needs to have a buyer for the power generated or needs to receive a price per kilowatt for the power generated that provides an reasonable rate of return on the investment.

Additional Benefits and Costs

Reductions in emissions of ammonia, volatile organic compounds, and odors (sulfur compounds) are achievable. Reductions occur when anaerobic digesters and energy utilization are used to capture emissions that would have occurred from the lagoon surface. Note that these reductions occur at the lagoon surface and that there is a potential for increased ammonia emissions during application of digester effluent to fields due to high ammonium concentrations, if measures are not taken to avoid these emissions. Ammonia emissions are important in the formation of fine particulate matter and nitrogen deposition to sensitive water sheds. Also, there will be an increase in emissions of nitrogen and sulfur oxides during the combustion of biogas. Both of these pollutants are also fine particulate matter precursors, and oxides of nitrogen are a precursor of ozone.

Measures to reduce both air and water pollution impacts could include the use of nitrifying/denitrifying systems to reduce the ammonium concentration prior to application. In these systems, ammonium is converted to nitrogen, which is released instead of ammonia. (Care must be taken to avoid excessive nitrous oxide emissions, however.) The other option is to identify and produce marketable products from the digester effluent, which would have to be trucked off the farm. The increased GHG emissions associated with transporting any such products have not been factored in to the analysis conducted for this option.

Feasibility Issues

The current lack of net metering in Colorado removes an incentive for CAFO operators to implement electricity generation technologies that is currently available in other states. The analysis shows that CAFO energy utilization programs have a long return on investment, which is exacerbated by poor grid interconnection availability.

Status of Group Approval

Complete.

Level of Group Support

Unanimous consent of those CAP members present and voting. One CAP member’s vote of approval was qualified on the basis of uncertainty about the implementation of net metering by cooperative rural electric associations.

Barriers to Consensus

Not applicable.

AFW-3. Reductions in On-Farm Fossil Energy Use

Policy Option Description

This option seeks to develop and implement cost-effective programs for renewable energy (biofuels, renewable electricity generation) and energy efficiency technologies for farmers and ranchers. Reductions in fossil fuel consumption reduce emissions of carbon dioxide, methane, nitrous oxide, and black carbon.

Policy Option Design

Goals:

- **Fossil fuel reduction goal:** 20% reduction in petro-diesel use by 2020.
- **Electricity reduction goal:** 40% includes reductions from electricity efficiency and on-site generation using renewable energy (solar, wind, hydro).

Timing:

- **Fossil fuel reduction goal:** Achieve 5% reduce consumption by 2012. Achieve the full policy goal by 2020.
- **Electricity reduction goal:** Achieve 10% reduce consumption by 2012. Achieve the full policy goal by 2020.

Parties Involved: Colorado Rural Electric Associations (REAs), State agriculture organizations, Governor's Energy Office, Colorado Department of Agriculture, businesses providing energy efficiency and renewable energy equipment.

Other: As needed, identify incentives that encourage the growing and supply of feedstocks, and the utilization of ethanol in transportation markets across the state.

Implementation Mechanisms

Colorado state government and others should work with rural electric associations in developing programs or businesses for services and products to increase energy efficiency and conservation. Develop group purchasing options and coordinate installation of products to lower costs.

Develop state standards for ownership renewable energy credits (RECs) to be utilized by rural electric associations for upfront incentives in the form of rebates (e.g., $2 per watt of installed renewable energy generation on a farm or ranch). The REA's ownership of RECs would allow REAs to count the production over the life of the project toward the 10% renewable energy standard under HB 1281.

Develop three or four case studies of energy efficiency measures taken on various agriculture operations (e.g., farm, ranch, feedlot, dairy) to present around the state.

Colorado state government should create incentives to upgrade REA distribution systems to "smart grid" technologies that can better take advantage of the benefits of distributed generation installed on farms and more sophisticated energy tracking devices on farms and businesses.

REAs, Tri-State, and Colorado state government should consider and develop net metering standards above 25 kW in capacity that ensures the economic viability of REAs.

Related Policies/Programs in Place

- Colorado Department of Agriculture's Renewable Energy Grant Program under the Colorado Agriculture Development Authority. Provides grants to agriculture producers for on-farm renewable energy production. Includes grants for implementation up to $100,000 and feasibility study grants up to $25,000.
- US Department of Agriculture (USDA) Farm Bill 9006 Renewable Energy/Energy Efficiency Grant and Guaranteed Loan Program. Provide grants up to 25% of the cost for renewable energy, biofuels production, and energy efficiency products.
- CCX methane offset allows producers with anaerobic digester generating power to receive income from sell of credits based on $MtCO_2$ equivalent for methane collection and combustion. The global warming potential of methane is 21 [Intergovernmental Panel on Climate Change (IPCC) Second Assessment Report]. At the current price of an $MtCO_2$ on the exchange at $3.30, a metric ton of methane would sell for more than $69.
- Net metering up to 25 kW with REA service territories and new interconnection standards for all 22 REAs from HB 07-1169.

Types of GHG Reductions

CO_2: GHG reductions that occur as a result of a decline in on-farm energy use are largely composed of CO_2, which is the byproduct of combustion of diesel fuel to run farm equipment, such as tractors, and the indirect byproduct of the generation of electricity that is used for irrigation pumps, lighting, food processing, and other agricultural processes.

CH_4 and N_2O: These gases are also emitted through the different forms of combustion that create energy for use on farms. The greenhouse effects of these gases are normalized and included in the GHG reduction potential calculations that are expressed as CO_2e.

Estimated GHG Savings and Costs per $MtCO_2e$

GHG Reduction Potential in 2012, 2020 ($MMtCO_2e$):

- Total: 0.14, 0.64
- Diesel: 0.02, 0.07
- Electricity: 0.12, 0.56

Net Cost per $MtCO_2e$:

- Total: -$39.67
- Diesel: -$82.23
- Electricity: -$33.47

Data Sources: Consumption of distillate fuel by the agriculture sector in Colorado was projected from historical data provided by the Energy Information Administration (EIA).[15] The petro-diesel emissions factor used is consistent with the Colorado I&F (10.07 $MtCO_2e$/1,000 gal). The agricultural sector electricity consumption was derived from the National Agriculture Statistics Service (NASS)[16] and historical electricity prices from the EIA.[17] The cost-effectiveness estimates are based on various sources throughout the literature. Colorado-specific data and case studies were used whenever possible.

Quantification Methods:

The BAU distillate fuel use for the Colorado agricultural sector was projected from historical (1984–2005) data retrieved from the EIA. Based upon the projected BAU distillate use, the target distillate reduction was calculated. Multiplying the target GHG reduction by the life cycle GHG emissions factor for distillate fuel yielded the incremental GHG benefit from a reduction in the use of distillate fuel.

The baseline electricity consumption on farms in Colorado was estimated by dividing the total expenditures on electricity in 2005 by the 12-month average of the monthly average retail price of electricity in Colorado.[18] The projected on-farm electricity use is based on the projections of total Colorado electricity consumption found in the Colorado I&F. Assuming that the electricity used by the agricultural sector will grow at the same rate as the total electricity consumption, the baseline on-farm electricity consumption estimate for 2005 is multiplied in each year by the annual change in total projected energy use to yield BAU electricity consumption projection.

The Colorado electricity emission factor (EF) is calculated using the same methods as AFW-2. This EF is multiplied by the target electricity reduction (the product of the target efficiency increase and BAU electricity consumption) to determine the incremental GHG benefit.

The results of these analyses are displayed in Table H-4.

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[15] Energy Information Administration. “Colorado Total Distillate Sales/Deliveries to Farm Consumers.” 1984–2005. Accessed on July 17, 2007, at http://tonto.eia.doe.gov/dnav/pet/hist/kd0vfmsco1a.htm

[16] National Agricultural Statistics Service. “Colorado Agriculture: A Profile.” 2005 data. Accessed on August 20, 2007, at www.nass.usda.gov/Census/Pull_Data_Census

[17] Energy Information Administration. “Current and Historical Monthly Retail Sales, Revenues, and Average Retail Price by State and by Sector (Form EIA-826).” Table accessed on July 17, 2007, at www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls.

[18] See notes 16 and 17 for references.

Table H-4. On-farm energy reduction targets and associated GHG savings

Year	BAU Distillate Use (1,000 gal)	Target Distillate Reduction	Incremental GHG Benefit from Distillate Reduction ($MMtCO_2e$)	BAU Electricity Consumption (MWh)	Target Electricity Reduction	Incremental GHG Benefit from Electricity Reduction ($MMtCO_2e$)
2007	49,047	0	0.000	1,213,459	–	–
2008	48,135	445	0.004	1,243,401	27,263	0.024
2009	47,222	890	0.009	1,273,343	54,527	0.048
2010	46,310	1,335	0.013	1,303,285	81,790	0.072
2011	45,397	1,779	0.018	1,333,227	109,054	0.096
2012	44,485	2,224	0.022	1,363,169	136,317	0.120
2013	43,572	2,876	0.029	1,393,111	199,413	0.175
2014	42,660	3,527	0.036	1,423,053	262,508	0.230
2015	41,747	4,179	0.042	1,452,995	325,604	0.286
2016	40,835	4,831	0.049	1,482,937	388,699	0.341
2017	39,922	5,482	0.055	1,512,879	451,795	0.396
2018	39,010	6,134	0.062	1,542,821	514,891	0.452
2019	38,098	6,785	0.068	1,572,763	577,986	0.507
2020	37,185	7,437	0.075	1,602,705	641,082	0.562

The following paragraphs explain how the net cost of reducing on-farm petro-diesel use was estimated. These calculations are based on a suite of energy efficiency strategies that reduce the amount fuel necessary to accomplish the same tasks as before implementation of this option.

The cost savings related to the reduction in on-farm diesel fuel use (Table H-5) was calculated by multiplying the annual target diesel (used interchangeably with the term “distillate”) reduction by the projected average annual price of distillate fuel.[19] In order to reach this target, three cost-effective practices to reduce the diesel fuel consumed on farms are considered: optimization of tractor tire pressure, increased efficiency of diesel irrigation pumps, and reducing the revolutions per minute (rpm) on tractors running at less-than-full capacity by using a lower gear (known as “Gear-Up, Throttle-Down” [GUTD]).

Tire Pressure: The diesel savings that result from a reduction in average tractor tire pressure from 20 pounds per square inch (psi) to 10 psi were cited to be 0.614 gallons/acre.[20] The total number of acres were found in the 2002 Agriculture Census conducted by the USDA. Based on the annual reduction in harvested cropland shown by the Colorado National Resources Inventory (NRI) data, the total number of acres from the 2002 Census were reduced by 1.01% annually until 2020.[21] This annual total was multiplied by the number of acres to determine the maximum diesel reduction that could be achieved through a program to promote optimal tire pressure for

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[19] Energy Information Administration. *Annual Energy Outlook Projection of Petroleum Prices to 2030.* Accessed on August 30, 2007, at http://www.eia.doe.gov/oiaf/aeo/excel/aeotab_12.xls

[20] J. Fyck, *Farmers Can Save Big Money on Fuel*, Agtech Innovator, Alberta Government, April 23, 2001. Accessed on August 30, 2007, at http://www1.agric.gov.ab.ca/$department/newslett.nsf/all/agin147

[21] National Resources Inventory; National Resources Conservation Service. 1982–2003 data. Accessed and inserted by K. Bickel. Consistent with data used in AFW-6.

farm tractors (Table H-6). The cost savings of the program is imbedded in the total cost savings calculation described above. The administration cost of this program is assumed to be 1 FTE at $75,000/year, increasing by 5% annually. This salary (assumed to include benefits and office space) is used to administer an education program to disseminate information regarding the large potential cost savings that is possible through a simple adjustment of their tractor's tire pressure.

Table H-5. Cost savings from reduced on-farm diesel use

Year	Target	Projected Commercial Diesel Price ($/gal)	Annual Cost Savings ($MM)
2007	–	$2.12	$–
2008	444,849	$1.99	$(0.89)
2009	889,698	$1.86	$(1.65)
2010	1,334,548	$1.75	$(2.34)
2011	1,779,397	$1.65	$(2.94)
2012	2,224,246	$1.56	$(3.48)
2013	2,875,840	$1.50	$(4.30)
2014	3,527,435	$1.47	$(5.19)
2015	4,179,030	$1.48	$(6.18)
2016	4,830,624	$1.50	$(7.24)
2017	5,482,219	$1.51	$(8.26)
2018	6,133,814	$1.52	$(9.32)
2019	6,785,408	$1.56	$(10.56)
2020	7,437,003	$1.56	$(11.64)

Diesel Pumping: Dividing the total fuel expenses for diesel irrigation pumps in 2003 ($2.4 million)[22] by the 2003 price of diesel in Colorado ($1.058/gal) yields the gallons used in 2003 (2,237,240 gal). The gallons used for irrigation pumping in each year of the policy period are projected assuming that diesel irrigation pumping maintains a constant share of on-farm diesel use in the BAU scenario. The quantity of diesel consumed by irrigation pumps in each year is multiplied by the expected efficiency improvement (41.4%) after retrofit.[23] The diesel reduction from irrigation pumping does not exceed the difference between the target and the reduction from tire pressure for the years 2014 through 2020. Therefore, the assumed reduction for pumping is equal to this difference, or the maximum reduction potential, whichever is less. The assumed pumping reduction is multiplied by the annual cost per gallon saved

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[22] USDA; National Agricultural Statistics Service. *2003 Farm and Ranch Irrigation Survey*. Table 20: Energy Expenses for On-Farm Pumping of Irrigation Water by Water Source and Type of Energy: 2003 and 1998. Accessed on August 29, 2007, at http://www.agcensus.usda.gov/Publications/2002/FRIS/tables/fris03_20.pdf

[23] J. Weddington and P. Canessa. "Diesel Pumping Efficiency Program: Final Project Report." California State University Fresno, Center for Irrigation Technology. October 31, 2006. Accessed on September 2, 2007, at http://www.pumpefficiency.org/About/literature/Final%20Diesel%20Pumping%20Efficiency%20Report,%20USEPA.doc

($1.53/gallon).[24] The sum of this number and the annual cost of pump tests (250 per test, test every 5 years) to determine the program cost.[25] The cost savings are imbedded in the total cost savings for on-farm diesel fuel reduction calculated above.

Table H-6. Reductions in on-farm diesel fuel consumption from efficiency improvements

Year	Target Diesel Fuel Reduction (gal)	Max tire pressure improvement (gal)	Assumed tire pressure improvement (gal)	Max pumping reduction (gal)	Assumed Pumping Reduction (gal)	Assumed Tractor consumption reduction (gal)
2007	–	2,536,940	–	–	–	–
2008	444,849	2,511,317	444,849	985,656	–	–
2009	889,698	2,485,952	889,698	966,971	–	–
2010	1,334,548	2,460,844	1,334,548	948,286	–	–
2011	1,779,397	2,435,990	1,779,397	929,601	–	–
2012	2,224,246	2,411,386	2,224,246	910,916	–	–
2013	2,875,840	2,387,031	2,387,031	892,231	488,809	–
2014	3,527,435	2,362,922	2,362,922	873,546	873,546	290,967
2015	4,179,030	2,339,057	2,339,057	854,861	854,861	985,112
2016	4,830,624	2,315,432	2,315,432	836,176	836,176	1,679,016
2017	5,482,219	2,292,046	2,292,046	817,491	817,491	2,372,682
2018	6,133,814	2,268,897	2,268,897	798,806	798,806	3,066,111
2019	6,785,408	2,245,981	2,245,981	780,121	780,121	3,759,306
2020	7,437,003	2,223,296	2,223,296	761,436	761,436	4,452,270

Tractors (GUTD): The GUTD estimation assesses the diesel fuel savings potential gleaned by running the engine at a lower power and higher gear when not operating at the full rated capacity of the engine. The baseline tractor fuel consumption was found by taking the product of the number of farms with tractors in Colorado (25,564),[26] the hours per year a tractor operates (411),[27] the weighted average potential power output for tractors in Colorado [69.21 power take-off (PTO)-hp],[28] the average fuel consumption (0.048 gal/hr/PTO-hp),[29] and the average percentage of maximum horsepower used (60%).[30] The maximum annual fuel consumption was

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[24] J. Weddington and P. Canessa. "Diesel Pumping Efficiency Program: Final Project Report." California State University Fresno, Center for Irrigation Technology. October 31, 2006. Accessed on September 2, 2007, at http://www.pumpefficiency.org/About/literature/Final%20Diesel%20Pumping%20Efficiency%20Report,%20USEPA.doc

[25] Ibid.

[26] USDA; National Agricultural Statistics Service. "2002 Census of Agriculture." Vol. 1, Chapter 1: Colorado State Level Data. Table 45: Selected Machinery and Equipment on Operation: 2002 and 1997. Accessed on August 30, 2007, at http://www.nass.usda.gov/census/census02/volume1/co/st08_1_045_046.pdf

[27] M. Wang, C. Saricks, and H. Lee. "Fuel-Cycle Energy and Emission Impacts of Ethanol–Diesel Blends in Urban Buses and Farming Tractors." *Center for Transportation Research; Argonne National Laboratory*. July 2003. Accessed on September 2, 2007, at http://www.transportation.anl.gov/pdfs/TA/280.pdf

[28] Weighted average from estimates provided in note above: 2002 Census of Agriculture, Table 45.

[29] H.W. Downs and R.W. Hansen. "Estimating Farm Fuel requirements." *Colorado State University Extension–Agriculture*. No. 5006. Updated on June 25, 2007. Accessed on August 30, 2007, at http://www.ext.colostate.edu/pubs/farmmgt/05006/html

[30] Ibid.

found by multiplying the baseline tractor fuel consumption by the efficiency improvement resulting from GUTD (25%).[31] As before, assumed fuel reduction is the lesser of the target that has not been met and the maximum annual fuel reduction. After GUTD has been implemented in 2014, no further efficiency measures are needed to achieve the target. The cost of the program is assumed to be 1 FTE ($75,000; increasing by 5% annually), as in the tire pressure program.

The reduction in on-farm electricity use suggested by this option is achieved through improved efficiency of electric irrigation pumps, improved lighting fixtures, and on-site renewable electricity generation. The calculations for the cost of these individual programs are detailed below in their respective sections. The cost savings for reduced on-farm electricity consumption is calculated by multiplying the variable price of electricity by the quantity of electricity that the farmer does not have to buy from the grid. This variable price is different, however, depending on whether the electricity is being used for irrigation, buildings and houses, or other farm-related uses. Most farmers pay a demand charge that is based on the capacity that must be online to meet their historical demand. Farmers then pay a per kW-hr fee. It is this variable fee that is considered in the cost savings calculation, as the demand charge is assumed to be a fixed cost. The variable electricity cost in this calculation is $0.045 per kW-hr for irrigation and $0.065 per kW-hr for lighting.[32] It is assumed that any electricity generated on-site from renewable sources yields $0.045 per kW-hr. Energy costs are assumed to escalate at 5.5% per year.[33] The cost savings calculations are detailed in Table H-7.

Table H-7. Cost savings from reduced fossil-based on-farm electricity consumption

Year	Efficiency from Lighting (MW-hr)	Cost for lighting	Efficiency from Pumping (MW-hr)	Cost for Pumping	Renewable generation (MW-hr)	Cost savings renewable	Net cost renewable ($MM)
2008	3,730	$85,468	23,533	$988,941	–	$–	$–
2009	3,820	$87,526	50,707	$1,521,047	–	$–	$–
2010	3,910	$89,584	77,880	$2,053,154	–	$–	$–
2011	4,000	$91,643	105,054	$2,585,260	–	$–	$–
2012	4,090	$93,701	132,227	$3,117,366	–	$–	$–
2013	4,179	$95,759	195,233	$4,351,131	–	$–	$–
2014	4,269	$97,817	258,239	$5,584,897	–	$–	$–
2015	4,359	$99,875	321,245	$6,818,662	–	$–	$–
2016	4,449	$101,933	354,637	$7,472,534	29,614	$(2.16)	$(0.36)
2017	4,539	$103,991	361,797	$7,612,749	85,459	$(6.57)	$(1.40)
2018	4,628	$106,049	368,958	$7,752,964	141,305	$(11.46)	$(2.94)
2019	4,718	$108,108	376,118	$7,893,178	197,150	$(16.87)	$(5.00)
2020	4,808	$110,166	383,279	$8,033,393	252,995	$(22.84)	$(7.65)

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[31] R. Grisso and R. Pitman. “Gear Up and Throttle Down—Saving Fuel” *Virginia Cooperative Extension*. Publication No: 442-450, posted October 2001. Accessed on August 29, 2007, at http://www.ext.vt.edu/pubs/bse/442-450/442-450.html

[32] These numbers are reasonable assumptions based on the rural electric rates provided by the Southeast Colorado Power Association (http://www.secpa.com/rates.htm) and the Highline Electric Association (http://www.hea.coop/billing.htm).

[33] Personal communication from T. Frank of the Rocky Mountain Farmer’s Association and B. Strode, CCS. August 27, 2007.

Table H-8. Annual price of electricity ($/kW-hr)

Year	Escalated pumping cost/ renewable savings	Escalated lighting cost
2007	$0.045	$0.065
2008	$0.047	$0.069
2009	$0.050	$0.072
2010	$0.053	$0.076
2011	$0.056	$0.081
2012	$0.059	$0.085
2013	$0.062	$0.090
2014	$0.065	$0.095
2015	$0.069	$0.100
2016	$0.073	$0.105
2017	$0.077	$0.111
2018	$0.081	$0.117
2019	$0.086	$0.124
2020	$0.090	$0.130

Lighting: Lighting is assumed to account for 1% of total farm electricity consumption.[34] The cost of electricity for lighting (different cost than irrigation pumping) is assumed to be $0.065/kW-hr.[35] The annual cost of upgrades is $0.023/kW-hr (72 W for conventional fixture (24 hr/day, 365 days/year); $20 per fixture for upgrade. Replace bulbs every 2 years).[36] The efficiency improvement for advanced lighting is 30%.[37] As the most cost-effective option for renewable, this option was assumed to be adopted to its maximum potential, reducing 4,808 MWh by 2020 (Table H-9).

Electric irrigation pumping: The MWh used for irrigation pumping was determined by taking the quotient of the total 2002 electricity expenses for irrigation pumping ($52 million)[38] and the average retail electricity price for that year ($67.6/MWh).[39] The annualized capital cost of retrofits was found to be $0.020/kW-hr. This figure was calculated based on an estimated retrofit cost of $12,000 per pump, annualized over the policy period, divided by the average potential

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[34] E. Brown and R.N. Elliott. “On-Farm Energy Use Characterizations.” *American Council for an Energy-Efficient Economy*. Report No: IE052. Accessed on August 15, 2007, at http://www.aceee.org/pubs/ie052full.pdf

[35] Based on the rural electric rates provided by the Southeast Colorado Power Association (http://www.secpa.com/rates.htm) and the Highline Electric Association (http://www.hea.coop/billing.htm).

[36] Alliant Energy; T8 Fluorescents: Overview. Accessed on June 30, 2007, at http://www.alliantenergy.com/docs/groups/public/documents/pub/p012398.hcsp

[37] Ibid.

[38] USDA; National Agricultural Statistics Service. *2003 Farm and Ranch Irrigation Survey*. Table 20: Energy Expenses for On-Farm Pumping of Irrigation Water by Water Source and Type of Energy: 2003 and 1998. Accessed on August 29, 2007, at http://www.agcensus.usda.gov/Publications/2002/FRIS/tables/fris03_20.pdf

[39] Energy Information Administration. “Current and Historical Monthly Retail Sales, Revenues, and Average Retail Price by State and by Sector (Form EIA-826).” Table accessed on July 17, 2007, at www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls

savings of retrofits.[40] The cost savings is based on an assumed variable cost of electricity (the cost exceeding the demand charge) of $0.045/kW-hr.[41] The electric irrigation pumping strategy described here is assumed to be implemented to meet the remaining target reduction after the maximum lighting efficiency is reached. In year 2014, the maximum potential reduction from electric irrigation pumping efficiency is reached. From this point forward, the maximum reduction potential for electric irrigation pumping efficiency is applied.

Table H-9. Reductions in on-farm electricity use

Year	Electricity Savings Target (MWh)	Efficiency From Lighting (MWh)	Efficiency From Pumping (MWh)	Renewable Generation
2007	–	–	–	–
2008	27,263	3,730	23,533	–
2009	54,527	3,820	50,707	–
2010	81,790	3,910	77,880	–
2011	109,054	4,000	105,054	–
2012	136,317	4,090	132,227	–
2013	199,413	4,179	195,233	–
2014	262,508	4,269	258,239	–
2015	325,604	4,359	321,245	–
2016	388,699	4,449	354,637	29,614
2017	451,795	4,539	361,797	85,459
2018	514,891	4,628	368,958	141,305
2019	577,986	4,718	376,118	197,150
2020	641,082	4,808	383,279	252,995

Renewable Generation: The renewable generation sources that are assumed to have potential on farms in Colorado are wind, solar photovoltaics (PV), solar thermal, and geothermal. The tables below demonstrate the cost (before any incentives) and assumed market share of each technology.[42] CCS used these shares to determine how much generation would be needed from each resource in order to meet the target remaining after pumping and lighting efficiency measures have been implemented. Renewable generation is assumed to have a value of $0.05/kW-hr, consistent with the value used in AFW-2. Tables H-10 and H-11 depict the annualized cost of each generation technology, and the share of generation from each source.

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[40] J.C. Loftis and D.L. Miles. "Irrigation Pumping Plant Efficiency." *Colorado State University Extension–Agriculture.* No. 4.712. Accessed on August 24, 2007, at http://www.ext.colostate.edu/PUBS/crops/04712.html

[41] Midpoint of variable rates exceeding the demand charge provided by Southeast Colorado Power Association (http://www.secpa.com/rates.htm) and the Highline Electric Association (http://www.hea.coop/billing.htm). Figure confirmed by T. Frank via personal communication with B. Strode on August 29, 2007.

[42] The figures in these tables are consistent with data and assumption used by the ES PWG in their analysis of ES-2.

Table H-10. Annualized cost of renewable generation

Year	Annualized Wind Cost (2005$/MW-hr)	Annualized PV Cost (2005$/MW-hr)	Annualized Solar Thermal Cost (2005$/MW-hr)	Annualized Geothermal Cost (2005$/MW-hr)
2010	50	576	254	–
2011	49	543	252	–
2012	48	509	250	–
2013	47	476	247	–
2014	46	442	245	–
2015	45	409	243	78
2016	45	409	243	77
2017	45	409	243	76
2018	45	409	243	76
2019	45	409	243	75
2020	45	409	243	74

Table H-11. Assumed mix of generation

Year	Share of Wind	Share of Solar PV	Share of Solar Thermal	Share of Geothermal
2007	83%	0%	1%	0%
2008	86%	0%	1%	0%
2009	88%	1%	1%	0%
2010	91%	1%	1%	0%
2011	90%	1%	1%	0%
2012	90%	2%	2%	1%
2013	89%	2%	2%	1%
2014	89%	3%	3%	2%
2015	88%	3%	3%	2%
2016	87%	3%	3%	2%
2017	87%	3%	3%	2%
2018	86%	3%	3%	3%
2019	86%	3%	3%	3%
2020	85%	3%	3%	3%

The estimated net present value (NPV) of this option is a savings of –$150 million, with a levelized cost-effectiveness of about $40 per MMtCO$_2$e.

Key Assumptions: This analysis assumed that the most cost-effective strategies of reducing on-farm fossil energy use through efficiency measures would be implemented to their full potential, with less cost-effective strategies implemented thereafter to meet the policy goal. The other major assumption is that on-farm renewable generation use the same share of resources as predicted by the ES PWG. This analysis does not take into account any potential benefits from the sales of excess electricity generated through a net metering program.

Key Uncertainties

With regard to the irrigation pumping aspect of this analysis, it is unknown what the availability of water will be for the remainder of the policy period (see Key Uncertainties for AFW-1).

Additional Benefits and Costs

- Reduced grid demand and therefore a reduction in other non-GHG pollutants related to electricity generation.
- Reduced non-GHG pollutions caused by the combustion of diesel fuel.
- Many of the strategies discussed in this section are shown to save water, labor hours, and equipment wear.

Feasibility Issues

Improving the availability of information to farm operators regarding the adjustments in equipment or practices that can have a large impact on fuel savings (i.e., tire pressure). Some of the strategies that require initial capital investment may prove difficult to implement if financing and/or incentives are not made available.

Status of Group Approval

Complete.

Level of Group Support

Unanimous consent of those CAP members present and voting.

Barriers to Consensus

Not applicable.

AFW-4. Biodiesel Production

Policy Option Description

Provide incentives for the production of biodiesel from oilseed crops, waste vegetable oil, or other sources. Biodiesel use will offset diesel fuel derived from petroleum and will lead to decreased fossil fuel-based CO_2 emissions.

Policy Option Design

Goals: Produce enough biodiesel fuel to offset 20% of the state diesel fuel demand by 2020 using GHG-superior feedstocks.

Timing: Produce enough in-state biodiesel to offset 2% of Colorado's petro-diesel consumption by 2012 and 20% by 2020.

Parties Involved: Governor's Energy Office, Colorado Department of Agriculture, Rocky Mountain Farmers Union, Colorado Farm Bureau, Colorado Livestock Association.

Other: Colorado's distillate fuel usage in 2002 was 0.73 billion gallons and is projected to be 1.25 billion gallons by 2020 (transportation diesel use was 0.57 billion gallons in 2002; 1.0 billion gallons by 2020).

Implementation Mechanisms

Colorado agriculture producers and private industry should be encouraged to build and operate biodiesel facilities within Colorado using local resources and providing locally-available product.

Colorado state government should actively evaluate the benefits and costs of incentive programs for new businesses entering the state for biodiesel production [For example, a particular plant may plan to use soybean oil not produced in the state and would likely need to be transported 1,000 miles or more to the site]. The costs should include the impacts to the environment as a whole as the fuel production cycles change, also the impacts to local and regional agricultural businesses (farming, feedlots, dairies) as the demand for feedstock crops increase and additional meal cake for livestock is available. In short, biodiesel production incentives should be established with consideration for the life cycle of the fuel source in economic and environmental terms.

Colorado state government should consider a renewable fuels standard (RFS) by volume of retail sales beginning at 2% and escalating to 5% in the short term. Increases in the RFS could be based upon local production levels.

Colorado state government should consider a retail tax credit for sale of B20 fuel. The tax credit value could increase with great retail volume sold [similar to Iowa retail incentive].

Implementation will likely require that oilseed crops be produced on land already in cultivation. Some conversion of idle land to new cropland could also occur which could decrease the overall carbon benefit to be gained from producing biodiesel [as soil organic carbon and soil nitrogen (as N_2O), both GHG sources, will be lost to the atmosphere when the land is converted to new cultivation].

Related Policies/Programs in Place

- Colorado Department of Agriculture's Renewable Energy Grant Program under the Colorado Agriculture Development Authority for grants up to $100,000 for new biodiesel production facilities; $25,000 for biodiesel feasibility studies; and $50,000 for research. grants funded through 2009.
- The Colorado Clean Energy Fund under the Governor's Energy Office with [$7 million in annual revenue] for project development.
- The renewable fuels standard from the Energy Policy Act of 2005 requires 7.5 billion gallons of renewable fuel in the U.S. by 2012, including biodiesel.
- USDA Farm Bill grant and guaranteed loan program for biodiesel facilities and research.

Types of GHG Reductions

CO_2: Life cycle emissions are reduced to the extent that biodiesel is produced with lower carbon than conventional (fossil) diesel fuel. Feedstocks used for producing biodiesel can be made from crops, which contain carbon sequestered during photosynthesis (e.g., biogenic or short-term carbon). The primary feedstocks are vegetable oils (e.g., soy, canola, sunflower, algal) and alcohols (either methanol or ethanol). From a recent report by Hill et al. (2006),[43] biodiesel from soybeans contains 93% more useable energy than its petroleum equivalent and reduces life cycle GHG emissions by as much as 41%. Higher oil production potential of different feedstocks (e.g., other oil crops, algae) will likely adjust the lifecycle GHG emissions further downward as they are developed as biodiesel sources. Local production of biodiesel also decreases the embedded CO_2e of biodiesel compared to importation of out of state vegetable oil supplies.

Estimated GHG Savings and Costs per $MtCO_2e$

GHG Reduction Potential in 2012, 2020 ($MMtCO_2e$): 0.02, 0.22

Net Cost per $MtCO_2e$: $12

Data Sources:

Data from the Colorado Draft I&F were the starting point for quantifying the benefits of offsetting fossil diesel consumption with biodiesel produced within the state (these do not incorporate future reductions in consumption due to TLU options). Fossil diesel consumption estimates are shown in Table H-12 (under BAU).

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[43] Hill et al., "Environmental, Economic, and Energetic Costs and Benefits of Biodiesel and Ethanol Biofuels," *Proceedings of the National Academy of Sciences*, 103:11206–10, July 25, 2006.

Table H-12. BAU diesel consumption

Year	Diesel Consumption (MMgal/year)
2012	828
2020	1,009

The policy design calls for 2% of the fossil diesel consumption to be offset by 2012 from in-state production and 20% offset by 2020. In-state BAU production is estimated to be 6 MMgal/year in 2012 and 9.5 MMgal/year in 2020. Therefore, incremental in-state biodiesel production targets are as shown in Table H-13.

Table H-13. Biodiesel production needed to meet policy goals

Year	Biodiesel Production Needed (MMgal/year)	
2012	(828 MMgal – 6 MMgal) x 0.02	16.4
2020	(1,009 MMgal – 9.5 MMgal) x 0.20	200

The BAU biodiesel production is based upon the current and planned biodiesel capacity of Colorado. A capacity factor of 50% is assumed. See Table H-14 for the existing and planned facilities in Colorado.[44]

Table H-14. Current and planned biodiesel production facilities in Colorado

Facility Name	Status	Capacity (1,000 gal)	Feedstock
American Agri-Diesel	In-production	6000	O-S Soy
Bio Energy of America	In-production	10000	O-S Soy
Bio Energy of America	In-production	8000	O-S Soy
San Juan Biodiesel	Planned	5000	Veg Oil (Sunflower)
San Luis Valley	Planned	1000	Veg Oil (Canola)
Kiowa County	Planned	1000	Veg Oil, I-S Soy
Rocky Mountain Sustainable Enterprises	Planned	5000	Waste Grease, I-S Soy
Holyoke Community Biodiesel	Planned	2000	I-S Soy

The CO_2e emission factor for fossil diesel used in the inventory and forecast is 10.04 Mt/1,000 gallons. The life cycle fossil diesel emission factor is 12.3 Mt/1,000 gallons.[45]

Quantification Methods:

GHG Reductions

A new study on life cycle GHG benefits for biodiesel production and use was used to estimate the CO_2e reductions for this option.[46] This study covered biodiesel production from soybean production, which is currently the predominant feedstock source for biodiesel production in the

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[44] Personal communication from T. Frank to B. Strode. E-mail sent on July 24, 2007.

[45] Hill et al., 2006.

[46] Ibid.

United States and is assumed to remain that way for the purposes of this analysis (it is also the predominant feedstock of biodiesel production in Colorado). Life cycle CO_2e reductions (via displacement of fossil diesel with soybean-derived biodiesel) were estimated by Hill et al. to be 41%. This value is being used by the TLU Policy Work Group (PPWG) to estimate the benefit of the biodiesel component of the TLU biofuels option. Hence, this analysis focuses on incremental benefits of in-state feedstocks production with the focus on vegetable oils.

For this option, the incremental benefit of in-state production is derived from the lower carbon content of biodiesel feedstocks (vegetable oil) avoided from having to transport the feedstocks from their likely source region. For this assessment, the likely source regions for soybean or canola oil are the U.S. midwest or northern plains regions. Using South Dakota as a potential source region, rail transport would require shipments to central North Carolina of about 650 miles.[47] Rail fuel consumption is about 400 ton-miles/gallon.[48] The density of vegetable oil is about 3,700 tons/MMgal. From these inputs, a GHG emission rate of 130 $MtCO_2$/MMgal oil was calculated.

When combined with the other feedstocks needed to produce biodiesel (e.g., either methanol or ethanol),[49] a gallon of vegetable oil will produce slightly more than one gallon of biodiesel. For the purposes of this estimate, each gallon is assumed to produce one gallon of biodiesel.

In addition to soybean oil, other oil feedstocks included in this analysis include animal oils (yellow grease, poultry fat, lard, and tallow), canola, and algal oils. It is assumed that technology advances will occur during the policy period that will allow for commercial scale production of algal oil to make up the shortfall (e.g., in the post-2015 period). With sufficient technology advancement, another option could be Fischer-Tropsch biodiesel from cellulose.

For oil sources other than soybean oil, the benefit for substituting in-state biodiesel for fossil diesel is estimated starting with the life cycle soybean emission factor (7,261 $MtCO_2e$/MMgal from the Hill et al. study). As mentioned previously, the benefits of the biodiesel component of the TLU biofuels option is based on displacement with soybean-based biodiesel. Hence, this analysis was designed to only account for the incremental benefit of in-state feedstock (oil) production using GHG preferential feedstocks. These include vegetable oils that produce greater volumes of oil per unit of energy input (e.g., canola), animal fats, and, in the future, algal oils.

Canola produces oil at 127 gallons/acre compared with soybeans at 48 gallons/acre. Assuming canola production energy inputs are not significantly greater than soy, the life cycle emission rate for canola would be 7,261 × 48/127 or 2,744 $MtCO_2e$/MMgal. So the incremental benefit of canola over soy is 7,261 – 2,744 = 4,517 $MtCO_2e$/MMgal.

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[47] Mapquest directions, North Dakota to Colorado; www.mapquest.com

[48] U.S. National Atlas, at http://nationalatlas.gov/articles/transportation/a_freightrr.html

[49] While the analysis here focuses on the primary feedstock for biodiesel, vegetable oil, the policy should also promote the production and use of alcohol feedstocks produced from renewable resources (e.g., starch or cellulosic ethanol, renewable methane to methanol).

For animal fats and algal oils, CCS assumes that these have negligible embedded energy. So the incremental benefit over soy equals the lifecycle fossil diesel EF (12,306 MtCO_2e/MMgal) minus the soybean based EF (7,261 MtCO_2e/MMgal), which is 5,045 MtCO_2e/MMgal.

Table H-15 provides the mix of oil feedstocks assumed in this analysis to meet the in-state production goals for 2012 and 2020. The assumed mix relies heavily on new technologies (e.g., algal oil) to produce feedstocks in the post-2012 period.

Table H-15. Assumed mix of oil feedstocks*

Year	Oil Feedstock	Fraction of New Production	MMgal/year Needed
2012	Soy (out-of-state)	0.63	10.2
2012	Soy	0.13	2.1
2012	Canola	0.17	2.8
2012	Animal	0.07	1.1
2012	Algal	0	0
2012 Total			**16**
2020	Soy (out-of-state)	0	0
2020	Soy	0.35	69.3
2020	Canola	0.20	39.6
2020	Animal	0.20	39.6
2020	Algal	0.25	49.5
2020 Total			**198**

*Excludes BAU production estimated to be 6,000 MMgal/year in 2012 and 9,500 MMgal/year in 2020.

GHG reductions were estimated by multiplying the production of each oil feedstock by the applicable incremental benefit (e.g., by oil type). Total reductions in each year were estimated by summing the incremental benefit for each oil type.

Costs

Costs were estimated using information from an analysis of biodiesel production costs from the U.S. Department of Energy (US DOE).[50] The value of incentives needed is assumed to be equivalent to the difference in the costs of producing fossil diesel and soy-based biodiesel ($0.34/gallon). This value is very close to the incentive offered in a State of Missouri incentives program.[51] This program offers production incentives of $0.30/gallon to producers up to 15 million gallons of production/year. The incentive grants last for 5 years. Hence, CCS only applied the incentives costs to the first 5 years of the policy period.

CCS assumed a similar incentive structure and that these would cover the costs of all grants or tax incentives associated with this policy (all other implementation mechanisms are assumed to be achieved within existing programs). The cost estimates are based on multiplying the amount of biodiesel produced in each year by the production incentive. This assumes that all production occurs at production facilities of less than 15 million gallons/year. The production incentive runs out after 5 years of production.

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[50] See www.eia.doe.gov/oiaf/analysispaper/biodiesel/index.html; accessed January 2007.

[51] Information on the Missouri Program from www.newrules.org/agri/mobiofuels.html#biodiesel, accessed January 2007.

Key Assumptions: Life cycle GHG emission factors utilized/derived for this analysis are representative for each feedstock and for fossil diesel. Production incentives offered by this option are sufficient to drive production of GHG-superior feedstocks (e.g., superior to soybeans) and to increase the level of research and development needed for non-crop based feedstocks (e.g., algal biodiesel, Fischer-Tropsch biodiesel).

Key Uncertainties

Similar to the ethanol production option (AFW-5), the key uncertainties associated with the level of benefits estimated for this option relate to its linkage to the low carbon fuel standard option in the TLU sector. To estimate the benefits for in-state production of biodiesel using GHG-superior feedstocks, one must make an assumption of what the source of low carbon fuel will be to lower the carbon content of diesel-powered vehicles within the policy period. For the purposes of this analysis, CCS assumed that soybean based biodiesel will remain the primary feedstock for supplying the low carbon fuel to lower the carbon content of fuels consumed by diesel vehicles. Hence, the benefits of this option are based on the incremental GHG reductions achieved by production of feedstocks with lower carbon (i.e., higher oil producing crops).

Additional Benefits and Costs

Increased in-state economic activity; new opportunities for farmers (oilseeds as rotational crop); increased transportation energy security with shorter transport distances and on-farm use of fuel produced; reduced reliance on imported petroleum.

Feasibility Issues

Sourcing of feedstocks and the size and location of facilities (both crushing and biodiesel production) must be addressed for optimization and planning. Trade-offs between food and fuel crops will be an important issue. For example, canola may be one of the crops with higher value markets than for biodiesel. Canola oil has very favorable nutritional and culinary qualities. As demand for trans-fat-free vegetable oils increases, demand for canola oil and other healthy oils grown in Colorado will increase.

There may be an overlap among agricultural options that seek to increase/maintain crop acreage in no-till production or in conservation management programs. This could be in conflict with the higher levels of crop production proposed in this option.

Global warming may also impact the choice of oilseed crops and the relative amounts of oil that can be produced. Additional warning could favor warmer climate crops like sunflower and safflower to replace the cold climate crops, but these crops need more water which may not be available.

Status of Group Approval

Complete.

Level of Group Support

Unanimous consent of those CAP members present and voting. The CAP expressed concern that the policy option is not market-based. While this policy option description used an assumed mix of crop oil production and emerging technology to meet the policy goals, the policy should not be seen as favoring one feedstock/production approach over another. Incentive programs should be developed to reward producers based on the carbon content of the biodiesel or other biofuel produced. Three CAP members' votes of approval were qualified because of concerns that development of some starch-based feedstock sources might tend to convert high value plant and wildlife habitat into croplands.

Barriers to Consensus

Not applicable.

AFW-5. Ethanol Production

Policy Option Description

Trees, crops and other plants convert atmospheric carbon to carbohydrate or fiber stocks that can be converted to liquid fuels, such ethanol. The use of these renewable, biological fuels can offset fossil fuel use and reduce associated net carbon dioxide emissions. Production incentives for the conversion of crops, forest sources, animal waste and other sources to ethanol through existing or new technologies can increase the level of ethanol use in future markets. In-state production of ethanol using GHG-superior feedstocks and processes (e.g., cellulosic technologies) offer the highest GHG benefits and complement policies to increase ethanol consumption (e.g., TLU-5).

Policy Option Design

Goals: Increase in-state ethanol production using GHG-superior feedstocks and production methods to 400 million gallons/year above BAU by 2020.

Timing: Add additional ethanol production capacity of 50 million gallons/year by 2012 and achieve the full policy goal by 2020.

Parties Involved: Suppliers of feedstocks, ethanol producers and distributors.

Other: Colorado’s gasoline consumption was 1.9 billion gallons in 2002 and is projected to be 2.2 billion gallons by 2020.

Implementation Mechanisms

Pilots and Demonstrations: Pilot projects on the use of different forestry and agriculture residues for ethanol production are needed.

Provide Tax Incentives: Incentives to reduce the capital costs of ethanol production and transport. This could include tax reductions in state sales tax for a wide variety of biomass-related equipment, including but not limited to biomass harvesting/collection and production equipment. Gross receipts exemptions for ethanol production facilities, project construction and related equipment and materials are also recommended.

Source Reduction: Reduce the amount of open slash pile burning on all land ownerships and/or provide viable alternatives to open burning. Discourage open burning through alternatives to burning provided under the BACT as defined in the Administrative Rules of Colorado, through revised DEQ Air Quality Permits when permits are needed, and by using local programs to encourage alternatives to burning.

Financial Assistance: Tax breaks or grants for ethanol producers.

Research and Development: Focusing on feedstock supplies (biomass from agricultural residues, municipal solid waste, forestry residue) and production processes (cellulosic processes or starch-based processes achieving similar net GHG benefits).

Information and Education: For target audiences.

- Education programs for livestock producers to utilize feed co-products;
- Education programs for feedstock producers;
- Consumer education programs to link demand-side mechanisms under TLU-6 to the benefits associated with fuels produced in-state (e.g., fossil fuel dependence, benefits for in-state agriculture).

Permitting Process: Streamlined permitting process with coordination between all entities issuing permits for land, water and air impacts for production facilities.

Business Development: Recruitment of cellulosic/advanced starch-based ethanol producers to locate facilities in Colorado.

Related Policies/Programs in Place

None identified.

Types of GHG Reductions

CO_2: Life cycle emissions are reduced to the extent that ethanol is produced with lower carbon than conventional (fossil) gasoline. Feedstocks used for producing ethanol can be made from crops or other biomass, which contain carbon sequestered during photosynthesis (i.e., biogenic or short-term carbon). There are two different methods for producing ethanol based on two different feedstocks. Starch-based ethanol is derived from corn or other starch/sugar crops. Cellulosic ethanol is made from the cellulose contained in a wide variety of biomass feedstocks, including agricultural residue (e.g., corn stover), forestry waste, purpose grown crops (e.g., switchgrass), and municipal solid waste. Local production of ethanol also decreases the embedded CO_2e of ethanol compared to importation from the current U.S. primary ethanol producing regions. Current research indicates cellulose-based ethanol production provides up to 72%–85% reduction in GHGs compared to gasoline, whereas an 18%–29% reduction is measured from starch-based ethanol production compared to gasoline.[52]

Estimated GHG Savings and Costs per $MtCO_2e$

GHG Reduction Potential in 2010, 2020 ($MMtCO_2e$): 0.2, 3.1

Net Cost per $MtCO_2e$: $3

Data Sources: The target for ethanol production requires a fixed quantity of production above BAU, rather than a percentage increase. Therefore, it is not necessary to project the BAU ethanol production in Colorado to quantify the cost-effectiveness and GHG reduction potential of

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[52] Well-to-Wheels Analysis of Advanced Fuel/Vehicle Systems—A North American Study of Energy Use, Greenhouse Gas Emissions, and Criteria Pollutant Emissions, General Motors, Argonne National Lab, and Air Improvement Resource, Inc., May 2005.

AFW-5. The targets set forth in this option (50 MMgal/year by 2012, 400 MMgal/year by 2020) are reached by increasing the quantity of ethanol produced in Colorado by equal increments in the years leading up to the target years. The in-state production targets are shown in Table H-16.

Table H-16. In-State ethanol production targets

Ethanol Production Schedule (MMgal/year)	
2007	–
2008	10
2009	20
2010	30
2011	40
2012	50
2013	75
2014	100
2015	150
2016	200
2017	250
2018	300
2019	350
2020	400

Emission factors from gasoline, starch-based ethanol and cellulosic ethanol are based on the Argonne National Laboratory (ANL) Greet Model.[53] The production cost differential for cellulosic versus starch-based ethanol is derived from analysis completed by the Energy Information Administration (EIA).[54]

Quantification Methods:

GHG Reductions

The benefits for this option are dependent on developing in-state production capacity that achieves benefits above the levels of existing and planned (BAU) starch-based production in the U.S. (the benefits of using ethanol from starch-based production are already accounted for under TLU-5). Emission factors for reformulated gasoline, starch-based ethanol, and cellulosic ethanol were taken from a General Motors/ANL study.[55] These emission factors incorporate the GHG emissions during the entire life cycle of fuel production (e.g., for gasoline: extraction, transport, refining, distribution, and consumption; for ethanol: crop production, feedstock transport, processing, distribution, and consumption). These life cycle emission factors are referred to as "well-to-wheels" emission factors:

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[53] Ibid.

[54] DOE EIA analysis can be found at www.eia.doe.gov/oiaf/analysispaper/biomass.html, accessed January 2007.

[55] *Well-to-Wheels Analysis*.

Table H-17. Life cycle emission factors for gasoline and ethanol

Fuel	Emission Factor (grams CO_2e/mi)
Reformulated gasoline	552
Starch-based ethanol	451
Cellulosic ethanol	154

In addition to cellulosic ethanol production, the other types of ethanol production processes targeted by this option include starch-based processes that achieve similar levels of life cycle GHG reductions to cellulosic ethanol. These would be starch-based plants that use renewable fuels, such as biomass, biogas, landfill gas, or other renewable fuels. While CCS is not aware of any lifecycle emission factors for these types of plants (although several have been proposed in the United States), CCS assumes that reductions similar to cellulosic ethanol can be achieved.

Based on the emission factors shown in Table H-17, the incremental benefit of the production targeted by this policy over conventional starch-based ethanol is 66% (reduction of CO_2e by offsetting gasoline consumption). This value was used along with the life cycle emission factor for gasoline[56] and the production in each year to estimate GHG reductions.

Costs

Costs for the incentives needed by this policy option are based on the difference in estimated production costs between conventional starch-based ethanol and cellulosic ethanol. The DOE EIA estimated that the cost to produce starch-based ethanol is $1.10/gal compared to $1.29/gal, or a difference of $0.19/gal (in $1998).[57] In 2006 dollars, the difference is $0.23/gal. These incentives are considered necessary in the near term (up to 2015) to help commercialize technologies that produce ethanol from cellulose or produce starch-based ethanol using renewable fuels. The incentives should also help to establish the infrastructure to deliver biomass to biorefineries, since producers will seek the local feedstocks or renewable fuels for their operations.

By 2015, it is assumed that advances in cellulosic ethanol production (e.g., enzyme costs, production processes) will make cellulosic ethanol production cost competitive with starch-based production. Hence, the incentives are discontinued beginning in 2015. Note that there is currently federal legislative proposal to offer cellulose an incentive of $0.765/gallon compared to the $0.51/gallon currently offered for ethanol production.[58] If enacted, this $0.255/gallon premium could cover the additional incentives that are assumed to be needed by the State of Colorado. Obviously, the federal incentives do not assure that production facilities would locate in Colorado. These federal incentives have not been factored into the cost estimates for this option.

The costs for this option were estimated using the $0.23/gal incentive multiplied by the production needed in each year. By 2015, it is assumed that these incentives will no longer be

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[56] In the study mentioned above, the average fuel economy used was 21.3 miles/gallon or 100 miles/4.7 gallons. Multiplying this value by the emission factor of 552 grams/mile yields 11,745 grams/gallon.

[57] DOE EIA analysis can be found at www.eia.doe.gov/oiaf/analysispaper/biomass.html, accessed January 2007.

[58] D. Morris, *Making Cellulosic Ethanol Happen: Good and Not So Good Public Policy*, Institute for Local Self-Reliance, January 2007, at www.newrules.org/agri/cellulosicethanol.pdf, accessed January 2007.

needed as cellulosic ethanol technologies become fully commercialized. Below is the assumed schedule for these incentives:

Table H-18. Incentives cost and benefits for ethanol production

Year	New Capacity (MMgal)	Incentives Cost (MM 2006$)	GHG Benefit ($MMtCO_2e$)
2007	–	$0.00	0
2008	10	$2.3	0.08
2009	20	$4.6	0.15
2010	30	$6.9	0.23
2011	40	$9.2	0.31
2012	50	$11.5	0.39
2013	75	$17.3	0.58
2014	100	$23.0	0.77
2015	150	$0.0	1.16
2016	200	$0.0	1.55
2017	250	$0.0	1.93
2018	300	$0.0	2.32
2019	350	$0.0	2.71
2020	400	$0.0	3.09

After discounting and leveling the costs from 2007–2020, the cost-effectiveness is just under $3.50/$MtCO_2e$ and the NPV of the 2007–2020 costs is $58 million.

Key Assumptions: Starch-based ethanol production using renewable fuels achieves equivalent GHG lifecycle benefits as cellulosic ethanol; cellulosic production or starch-based production with renewable fuels can achieve the production levels in the near term (2014 production of 310 MMgal/year) required by this policy option; Federal tax incentives do not preclude the need for the additional state incentives assumed for the cost estimate.

Key Uncertainties

The key uncertainty with this option is in estimating the incremental benefit above what is achieved with the low carbon fuel standard. To estimate benefits for in-state production of ethanol using GHG-superior technologies and feedstocks, one must make critical assumptions about what types of fuels will supply the low carbon fuel standard within the policy period. For the purposes of this analysis, CCS has assumed that the primary low carbon fuel that will be used to lower the carbon content of gasoline-powered vehicles will be starch-based ethanol. The incremental benefit is based on the higher GHG benefits associated with producing ethanol in-state using cellulosic ethanol technology and feedstocks. To the extent that this technology is widely employed within the policy period and acts as a significant supplier of fuel to meet the low carbon standard, the incremental benefits estimated here could be overstated.

Additional Benefits and Costs

Economic opportunities for ethanol producers in Colorado; additional value added in agricultural crops or crop residue; stimulation of potential markets for other biomass feedstocks (forest treatment biomass, municipal solid waste fiber).

Feasibility Issues

Implementation of this option requires additional research and development in cellulosic ethanol production methods, development of feedstock collection and delivery infrastructure, successful negotiations with cellulosic technology leaders to establish pilot and commercial-scale plants in the state. Also, both AFW-4 and AFW-5 could result in additional crop acres coming into production from lands that are currently in conservation programs or in natural cover; however water availability is expected to limit the amount of land conversion.

Status of Group Approval

Complete.

Level of Group Support

Unanimous consent of those CAP members present and voting. The CAP expressed concern that the policy option is not market-based. While this policy option description used cellulosic ethanol as an example to meet the policy goals, the policy should not be seen as favoring one feedstock/production approach over another. Incentive programs should be developed to reward producers based on the carbon content of the ethanol or other biofuel produced. Three CAP members' votes of approval were qualified because of concerns that development of some starch-based feedstock sources might tend to convert high value plant and wildlife habitat into croplands.

Barriers to Consensus

Not applicable.

AFW-6. Preserve Lands with Carbon Storage Value

Policy Option Description

Reduce the rate at which high carbon lands (i.e., existing grassland and forested land) are converted to developed uses. The carbon stored in soils and aboveground biomass is typically higher in these lands than in developed land uses. Each year, developed areas also typically sequester less carbon dioxide than forested areas. Policies are needed to protect working farms and forests from unwise and unplanned development. Indirectly, this option also supports important policies in the transportation and land use sector by promoting more efficient development patterns (e.g., TLU-1).

Reduce the rate at which permanent grassland in the USDA Conservation Reserve Program is converted to cultivated cropland (not quantified). Soil carbon stored in retired agricultural land that has been maintained as grassland is reversed when lands are put back to cultivation, resulting in net carbon emissions.

Policy Option Design

Goals:

- Reduce the rate of conversion of high carbon value lands by 25% by 2020 (high carbon value lands include forests and grasslands).

Timing: Reduce the rate of conversion of high carbon value lands by 10% by 2012. Achieve the full goal by 2020.

Parties Involved: State Agencies (e.g., Department of Wildlife and Department of Parks and Recreation), County and local governments (e.g., Open space programs), and statewide and local land trusts.

Other: Data from the Natural Resources Conservation Service (NRCS) National Resources Inventory (NRI) show the following losses of lands between 1982 and 1997 to the "urban built-up" and "rural transportation" categories (Table H-19).[59] In addition, data provided by CSU experts indicate that 1,011,090 acres will be converted to developed uses from 2000–2030, or approximately 33,703 acres/year (Dr. David Theobald, personal communication with PWG member).

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[59] See www.co.nrcs.usda.gov/technical/nri/tables/table5.pdf for conversion rates between 1982 and 1997. The NRI annual acreage lost to development can be compared to an estimate from David Theobald of CSU of 33,700 acres/year on average from 2000 to 2030.

Table H-19. Loss of crop and forest lands, 1982–1997

Land Cover/Use	10^3 Acres Lost 1982–1997	Annual Average Loss (10^3 acres)
Cultivated cropland	89.9	6.0
Non-cultivated cropland	36.1	2.4
Pastureland	46.9	3.1
Rangeland	176.9	11.8
Forest land	66.6	4.4
Totals	416	27.7

Implementation Mechanisms

Additional funding above current levels for land protection.

Incentives that reward protection of high carbon land:

- Establish a fund to provide additional incentives (e.g., tax credits) above those currently granted for donated portions of easements, based on the avoided carbon emissions potential of the development rights being retired. Easement transactions include an appraisal of the value of the development rights forgone. Based on the amount of land disturbance associated with those rights, and the carbon storage value of the land in question, an avoided carbon emission value can be calculated. The fund would provide additional incentives based on the amount of avoided emissions associated with the transaction, thus rewarding landowners who protect the highest amount of carbon (or avoid highest potential carbon emissions). The value of the incentive can be set based on a portion of the value of a ton of avoided carbon emissions based on current markets for offsets (only a portion is appropriate since landowner has already been compensated for a portion of their donation of an easement from existing sources).
- Establish a fund to pay for contracts with landowners who are not able to get expiring CRP acres back in to the system to maintain grass cover on their expired CRP acres. Least-cost policy mechanism would be for a bid-in process with contracts awarded in terms of CO_2e cost-benefit (presuming some lands have higher carbon values associated with maintenance of grass cover). If there is not a significant difference in carbon value, contracts would be evaluated solely on basis of cost and length of contract.

Linking land protection to growth policies:

- Ramping up the pace of land protection by increasing funding sources, combined with coordinated growth management strategies, could significantly reduce the pace of land conversion in the state. Land conservation organizations in Colorado have identified an additional 3 million acres of land as priorities for protection in the next ten years. Meeting this goal would require additional funding above existing sources. Targeting these acres in ways that maximized both the conservation values (e.g., open space, wildlife habitat) and growth management strategies (e.g., maintaining buffers between communities, protecting untilled landscapes on urban fringe, consolidating public lands holdings) would change baseline projections of land conversion associated with future population growth.

- In conjunction with growth management strategies developed as part of a climate strategy, identify priorities for land protection that would help implement those strategies. Direct a significant portion of new resources to those priorities, by making climate mitigation and growth management priorities of state funding sources.

Incentives to prevent land in the CRP from reverting back to cultivation:

- Colorado currently has 2,469,041 acres of land under CRP contract. 1,690,190 acres of those contracts are due to expire by 2011. Some percentage of these lands will be ineligible for a new contract (due to new rules and limits at the national level for CRP) or will have an economic incentive to re-convert to dry-land crops rather than re-enroll in CRP (particularly if dry-land biofuel crops become a feasible land use in Colorado). The cost of paying landowners to maintain permanent grass cover, particularly if grazing is permitted as a land use providing some economic return, is likely to be low, with demonstrable carbon benefits. This policy would create a program to target either permanent or long-term contracts to maintain expired CRP acres in grass cover either with or without use as grazing lands. (Note: this portion of the option is not quantified explicitly; some benefits may be captured under the quantification for avoided conversion of grasslands to developed uses).

Related Policies/Programs in Place

Great Outdoors Colorado (GOCO); http://www.goco.org/

Local open space programs

Programs led by private land trusts, e.g., the Colorado Coalition of Land Trusts (CCLT); http://www.cclt.org/

State income tax credit for land preservation (see CCLT Web site for more details)

Types of GHG Reductions

- Avoided emissions from land use change
- Maintenance of annual carbon sequestration potential

Estimated GHG Savings and Costs per $MtCO_2e$

GHG Reduction Potential in 2012, 2020 ($MMtCO_2e$):

- Grassland: 0.05, 0.14
- Forests: 0.04, 0.11
- Total: 0.10, 0.24

Net Cost per $MtCO_2e$:

- Grassland: $32
- Forests: $17
- Total: $26

Data Sources: Natural Resources Conservation Service data on CRP acres expiring during the policy period, NRI data on agricultural/range/forest land lost to urban development, data on above and below ground soil carbon levels from CSU, US Forest Service (USFS), and the scientific literature, costs for conservation easements on ag/range/forest land in Colorado.

Data Sources (Forests): "USFS Methods for Calculating Forest Ecosystem and Harvested Carbon with Standards Estimates for Forest Types of the US," General Technical Report NE-343 (also published as part of the US DOE Voluntary GHG Reporting Program). Data on forest conversion to developed uses from NRCS NRI data. Data on forest types from USFS Forest Inventory Analysis. T.F. Strong, 1997, "Harvesting Intensity Influences the Carbon Distribution in a Northern Hardwood Ecosystem," USFS Research Paper NC-329. "The Intersection of Land Use History and Exurban Development: Implications for Carbon Storage in the Northeast" Master's Thesis, K. Austin, 2006).

Quantification Methods:

Grasslands. The analysis for grasslands is displayed in Tables H-20 below. CCS used the baseline conversion estimates of 14,396 acres/year. These conversion estimates are multiplied by the targets (10% by 2012 and 25% by 2020) to yield the averted conversion in the target years. Conservation programs are assumed to increase at a linear pace to reach the targets. The carbon value of grasslands that is lost due to conversion is 0.023 MMtC/1,000 acres. The cost of easements for both forests and grasslands is assumed to be $1,960/acre.

Table H-20. Benefits and costs for grassland protection

Year	Grassland Saved (Acres)	MMtCO$_2$e Saved	Costs	Discounted Costs	Levelized Cost-effectiveness
2007	0	0.000	$–	$0	
2008	260	0.011	$510,384	$510,384	
2009	521	0.022	$1,020,768	$972,160	
2010	781	0.033	$1,531,152	$1,388,800	
2011	1,042	0.044	$2,041,536	$1,763,556	
2012	1,302	0.055	$2,551,920	$2,099,471	
2013	1,546	0.065	$3,030,405	$2,374,402	
2014	1,790	0.075	$3,508,890	$2,618,388	
2015	2,034	0.085	$3,987,375	$2,833,753	
2016	2,279	0.095	$4,465,860	$3,022,670	
2017	2,523	0.106	$4,944,345	$3,187,169	
2018	2,767	0.116	$5,422,830	$3,329,147	
2019	3,011	0.126	$5,901,315	$3,450,377	
2020	3,255	0.136	$6,379,800	$3,552,511	
Totals	**23,111**	**1.0**		**$31,102,787**	**$2.32**

Forests

Baseline rates of forest conversion to developed uses during 2008–2020 were estimated to be 5,368 acres/year, based on data from NRI and data provided by CSU. NRI data give a total annual rate of land conversion to developed uses (including all land uses) of 27,700 acres/year and an annual rate of forest conversion to developed uses of 4,400 acres/year for 1982–1997.

Data provided by CSU project that 33,703 acres/year (including all land uses) will be converted to developed uses from 2000–2030 (33,703 acres/year). The CSU estimate is 22% greater than the NRI estimate for all land converted to development, which probably reflects an increasing rate of development pressure more recently and into the future. The baseline amount of forest conversion to developed uses for 2008–2020 was inferred by scaling up the NRI estimate of 4,400 acres/year by 22%. Applying the goal levels to this baseline rate of forest conversion to developed uses amounts to avoiding the conversion of 536 acres/year by 2012 and 1,342 acres/year by 2020 of forests to developed uses.

Carbon savings from this option were estimated from two sources: the amount of carbon that would be lost as a result of forest conversion to developed uses (i.e., "avoided emissions"); and the amount of annual carbon sequestration in the forest area that is not converted to development under this option (i.e., "protection of carbon sequestration potential").

The forest carbon stocks (tons of carbon/acre) and annual carbon flux (annual change in tons of carbon/acre) data are based on default carbon sequestration values for lodgepole and ponderosa pine forest types in the Southern Rocky Mountain Region (USFS GTR-343). These forest types were chosen because of there relative dominance in Colorado. For both forest types, average forest carbon stocks (including biomass and soils) were based on coefficients for 65-year-old stands and annual rates of carbon sequestration (tons of carbon sequestered per year) were calculated by subtracting total carbon stocks in forest biomass of 65-year-old stands from total carbon stocks in forest biomass of new stands and dividing by 65. An average for 65-year-old stands was used to take reflect the average age structure of forests. Soil carbon density was assumed constant and is not included in the annual carbon flux calculations because default values for soil carbon density are constant over time in USFS GTR-343.

Table H-21. Carbon stocks and annual sequestration rates for lodgepole pine and ponderosa pine forests in the Southern Rocky Mountain Region

	Stand Age (year)	Biomass Stock (MtC/acre)	Soils Stock (MtC/acre)
Lodgepole pine			
	0	16.1	10.9
	65	30.3	10.9
	Annual flux (MtC/acre/year)	0.22	0.00
Ponderosa pine			
	0	15.5	9.8
	65	31.7	9.8
	Annual flux (MtC/acre/year)	0.25	0.00

MtC – Metric tons of carbon

Loss of forests to developed uses results in a large one-time loss of carbon. In this case, it was assumed that 53% of carbon stocks in biomass and 35% of carbon stocks in soils would be lost in the event of forest conversion, with no appreciable carbon sequestration in soils or biomass following development. The biomass loss assumption is based on research that shows heavy levels of individual tree removal results in the harvesting of 53% of carbon in aboveground biomass (Strong, 1997). The soil carbon loss assumption was based on a study that shows about a 35% loss of soil carbon when woodlots are converted to developed uses (Austin, 2006). Therefore, to estimate avoided emissions, the total number of acres protected in a year for each forest type was multiplied by the percent-adjusted carbon stock value for loss of biomass and soil carbon stocks. It was assumed that the area protected was 50% lodgepole and 50% ponderosa pine. Results were converted to units of million metric tons CO_2 equivalent ($MMtCO_2e$) and are provided in Table H-22.

Table H-22. Summary of carbon savings from avoided emissions

Year	Forest acres not converted to development	Lodgepole (tons carbon)		Ponderosa (tons carbon)		Total (tons carbon)	Total avoided emissions ($MMtCO_2e$)
		Biomass	Soils	Biomass	Soils		
2008	107	862	205	902	184	2,153	0.01
2009	215	1,724	410	1,804	368	4,306	0.02
2010	322	2,586	614	2,706	552	6,459	0.02
2011	429	3,448	819	3,608	736	8,611	0.03
2012	537	4,310	1,024	4,509	921	10,764	0.04
2013	637	5,118	1,216	5,355	1,093	12,782	0.05
2014	738	5,927	1,408	6,200	1,266	14,801	0.05
2015	839	6,735	1,600	7,046	1,438	16,819	0.06
2016	939	7,543	1,792	7,891	1,611	18,837	0.07
2017	1,040	8,351	1,984	8,737	1,784	20,856	0.08
2018	1,141	9,159	2,176	9,582	1,956	22,874	0.08
2019	1,241	9,967	2,368	10,428	2,129	24,892	0.09
2020	1,342	10,776	2,560	11,273	2,302	26,910	0.10

Forests that are protected from conversion in one year continue to sequester carbon in subsequent years, which is carbon sequestration that would not have occurred under business as usual rates of forest conversion to development. Thus, annual sequestration estimates are based on the cumulative forest acres that were not converted to development as a result of the policy. Annual carbon sequestration was calculated each year by multiplying cumulative acres by the average annual carbon flux for lodgepole and ponderosa pine, assuming 50% of each forest type is not converted to development (Table H-23).

Table H-23. Summary of carbon savings from protecting the annual carbon sequestration potential in forests

Year	Cumulative Acres	Lodgepole (tons carbon/year)	Ponderosa (tons carbon/year)	Total (tons carbon/year)	Annual Carbon Sequestered ($MMtCO_2e$)
2008	107	12	13	25	0.0001
2009	322	35	40	75	0.0003
2010	644	70	80	151	0.0006
2011	1,074	117	134	251	0.0009
2012	1,610	176	201	377	0.0014
2013	2,248	246	280	526	0.0019
2014	2,986	326	372	698	0.0026
2015	3,825	418	477	894	0.0033
2016	4,764	520	594	1,114	0.0041
2017	5,804	634	723	1,357	0.0050

Year	Cumulative Acres	Lodgepole (tons carbon/year)	Ponderosa (tons carbon/year)	Total (tons carbon/year)	Annual Carbon Sequestered ($MMtCO_2e$)
2018	6,945	759	865	1,624	0.0060
2019	8,186	894	1,020	1,914	0.0070
2020	9,528	1,041	1,187	2,228	0.0082

Costs of implementing the option were assumed to be $1,960 for every acre not converted, based on average costs of conservation easements in New Mexico. The analysis does not take into account potential cost savings from forest products revenue on working forest lands that are protected under this policy. Annual costs were estimated by multiplying the number of forest acres protected from conversion to development by the cost per acre. Annual discounted costs were then estimated using a 5% interest rate. The sum of annual discounted costs provides an estimate of the NPV of this option, which amounts to $12.8 million. The cumulative cost-effectiveness of the total program was calculated by dividing the NPV by cumulative carbon sequestration, yielding $17/ton CO_2e (Table H-24).

Table H-24. Summary of carbon savings and costs for forests

Year	Acres Protected	Avoided emissions	Annual Sequestration	Total carbon Savings ($MMtCO_2e$)	Cost	Discounted costs
2008	107	0.01	0.0001	0.01	$210,426	$210,426
2009	215	0.02	0.0003	0.02	$420,851	$400,811
2010	322	0.02	0.0006	0.02	$631,277	$572,587
2011	429	0.03	0.0009	0.03	$841,702	$727,094
2012	537	0.04	0.0014	0.04	$1,052,128	$865,588
2013	637	0.05	0.0019	0.05	$1,249,402	$978,939
2014	738	0.05	0.0026	0.06	$1,446,676	$1,079,532
2015	839	0.06	0.0033	0.06	$1,643,950	$1,168,325
2016	939	0.07	0.0041	0.07	$1,841,224	$1,246,213
2017	1,040	0.08	0.0050	0.08	$2,038,498	$1,314,034
2018	1,141	0.08	0.0060	0.09	$2,235,772	$1,372,570
2019	1,241	0.09	0.0070	0.10	$2,433,046	$1,422,552
2020	1,342	0.10	0.0082	0.11	$2,630,320	$1,464,661
Total	**9,528**			**0.74**	**$18,675,272**	**$12,823,330**

- **Key Assumptions:** 53% and 35% of biomass and soil carbon, respectively, is lost when forests are converted to developed uses; no appreciable carbon sequestration occurs post-development. Distribution of forest types protected is assumed based on forest dominance.

Key Uncertainties

The analysis of potential GHG benefits is sensitive to the assumed baseline rate of land use conversion to developed uses. There are multiple resources and types of data that could be used to establish this baseline. For instance, a recent estimate from Theobald at CSU suggests 147,000 acres/year of natural lands will be converted to non-natural uses in the future. This estimate does not specify how much of the non-natural land is would be for developed purposes, however it suggests potentially higher future rates of land use change to development than are assumed in this analysis.

Additional Benefits and Costs

Protects wildlife habitat, outdoor recreation opportunities, and open space

Land protection and land use planning can play an important role in adapting to a changing climate

Feasibility Issues

Land conservation strategies alone are unlikely to alter the general rate of land conversion, but can play a role in determining which lands are protected from conversion. It is likely that significantly more land would need to be placed under protection than is targeted by the goals for this option in order to achieve an overall reduction in the rate of land use conversion.

For this policy to achieve full benefits, forest and grassland conversion rates would need to be reduced in absolute levels across the entire state, without shifting land conversion activities to other locations.

Status of Group Approval

Complete.

Level of Group Support

Unanimous consent of those CAP members present and voting.

Barriers to Consensus

Not applicable.

AFW-7. Forest Health & Biomass Feedstocks for Energy Production

Mitigation Option Description

A specific focus of this option is on the potential synergistic objectives of forest fire risk management and bioenergy production. Forest management methods that decrease wildfire risk to communities remove biomass from forest to reduce biomass density. The biomass harvested is typically of low economic value and therefore generally is underutilized. This option proposes using this biomass as a feedstock for energy production to yield GHG reduction benefits. Woody biomass feedstocks may also come from other types of forest health management programs such as pest and disease prevention.

This option focuses explicitly on forest fire risk mitigation in communities at risk of wildfires in the wildland–urban interface (WUI) of the Front Range Region of Colorado. The focus was chosen in part because of the significant potential benefits, in terms of avoided costs and other losses, from preventing wildfires in communities. Also, the best available information is for this region of Colorado.

Mitigation Option Design

Goal: Increase the use of biomass from fire risk treatments to produce energy (specifically institutional heating) by 10% of harvested wood in 2012 and by 20% of harvested wood in 2020.

Timing: See above.

Parties involved: Colorado State Government, Colorado Department of Forestry, universities, extension/outreach specialists

Other: Current levels of biomass energy production are low in Colorado. There is no biomass utilized to produce electricity and there is one known biomass heating system in Boulder County, which consumes about 850–1000 tons of biomass per year. Additional biomass heating systems are planned for CSU, NREL, and Gilpin County for this winter. On other project in progress is in Jackson County/Walden that might produce some electricity as well as heat when it becomes operational.

The Front Range Roundtable developed recommendations for forest management priorities in the Front Range of Colorado focusing on ecological restoration and fire risk mitigation. The Roundtable recommends that about 1.5 million acres of forests are may be in need of treatment over the next 40 years and that fire management in Lower Montane forests of the Front Range be a high priority because of extensive overlap between forest restoration and community fire risk reduction objectives. The Roundtable further recommended that, to the extent possible, biomass removed during fire mitigation be used for heating institutional buildings such as schools and government buildings to offset treatment costs. This option assumes that under business as usual, the Roundtable’s priority recommendations for fire risk mitigation will be implemented in

Colorado, but the lack of bioenergy infrastructure currently in place will limit the extent to which the resulting biomass will be used to generate energy.

Implementation Mechanisms

Funding mechanisms or incentives/market-based mechanisms: mechanisms that increase the rate at which the by-products of forest thinning at the wildland–urban interface are used to generate institutional heat, such as

- Provide tax incentives to reduce the capital costs of transporting biomass for use in heating of institutional buildings. This could include tax reductions in state sales tax for a wide variety of biomass-related equipment.
- Subsidize the installation of bioheating systems in new public facilities and replacement of old boilers with bioheating systems in existing facilities.

Education/Outreach: extension services and local universities could develop partnerships that bring together potential suppliers and consumers

Related Policies/Programs in Place

State Fire Assistance Programs (Federal program)

National Fire Plan

Healthy Forest Restoration Act

Federal Energy Policy Act

Community-based cost sharing for slash/mulch services

Type(s) of GHG Reductions

Displaces emissions from fossil fuel combustion

Estimated GHG Savings and Costs per $MtCO_2e$

GHG Reduction Potential in 2012, 2020 ($MMtCO_2e$): 0.08, 0.20

Cumulative GHG reduction potential, 2007–2020 ($MMtCO_2e$): 1.4

Net Cost per $MtCO_2e$: –$75

Data Sources: Forest Inventory Analysis 2005, USFS GTR NE-343; Front Range Fuels Treatment Partnership Roundtable Final Report 2006, Forest Biomass Removals for Fossil Fuel Offsets, Nelson, Kashian, and Ryan, unpublished report 2007. Michael Ryan, USFS, personal communications; McNeil Technologies Report: Western Regional Biomass Energy Program, Final Report, Evaluating Biomass Utilization Options for Colorado: Summit and Eagle Counties, 2003.

Quantification Methods: The starting assumptions of this analysis are that fire risk mitigation treatments will generally follow the Roundtable recommendations during the time period of analysis of 2008–2020 and that none of the biomass removed will be used for energy production. The policy option will gradually increase the proportion of biomass used for energy production as it seeks to increase the demand and capacity for using biomass to heat institutional buildings during 2008–2020.

It is assumed that about 1.1 million acres of Lower Montane forests may need fire risk mitigation (i.e., thinning treatments and prescribed burning) over the next 40 years (see Table on Page 8 of the Roundtable Report). This amounts to thinning and burning about 27,500 acres/year on average initially. However, the Roundtable did not take into account future expansion of the WUI due to continued development growth. Thus, this analysis makes a rough assumption that the amount of forest classified as being in the WUI will expand by about 3% per year, and thus the area in need of treatment will also expand by this much annually, such that by 2020 more than 39,000 acres/year will need thinning for fire risk mitigation. Data were not available on forest areas in the WUI outside of the Front Range that are at risk for wildfires. Thus, the 3% expansion may also serve to capture areas outside of the Front Range in the analysis.

The amount of biomass removed from thinning was calculated using published carbon coefficients for common forest species in Lower Montane forests in the Southern Rocky Mountain Region of the United States (USFS GTR NE-343) (Table H-25). It was assumed that the thinned areas were comprised of 72% ponderosa pine and 28% Douglas fir. These are dominant species in the Lower Montane elevation range (5,000–8,000 feet) and the percentages were calculated from USFS Forest Inventory data for these types in that elevation range across Colorado. It was also assumed that thinning treatments would remove 45% of biomass carbon (based on a range of 30%–60% from Nelson et al.).

Table H-25. Carbon coefficients for forest types targeted for treatment

Forest Type	Biomass Carbon Stocks in 65-Year-Old Stands (tons carbon/acre)
Ponderosa pine (PP)	31.7
Douglas fir (DF)	56.3

Table H-26 shows the total number of acres in need of fire mitigation during 2008–2020, which increases due to an assumed 3% growth in the WUI, the number of acres thinned per year (by forest type), and the amount of carbon removed as a result of thinning. These trends are assumed constant in both the baseline and policy scenarios. Data are provided here primarily to illustrate the potential supply of biomass feedstocks for energy production as a result of fire risk management. It is important to note that the carbon removed from the forest is not likely to be replaced by future growth because the forest management goal is to reduce the biomass density of the forests permanently. Thus, in both the baseline and policy scenarios the forest experiences a net loss of carbon stocks of roughly the same magnitude.

Table H-26. Summary of forest treatments and annual carbon removed, 2008–2020

Year	Acres Needing Fire Treatment	Acres Treated With Thinning Per Year		Tons of Carbon Removed From Thinning		
		PP	DF	PP	DF	Total
2008	1,100,000	19,797	7,703	282,401	195,161	477,562
2009	1,133,000	20,391	7,934	290,873	201,016	491,889

		Acres Treated With Thinning Per Year		Tons of Carbon Removed From Thinning		
2010	1,166,990	21,002	8,172	299,599	207,047	506,646
2011	1,202,000	21,632	8,418	308,587	213,258	521,845
2012	1,238,060	22,281	8,670	317,845	219,656	537,501
2013	1,275,201	22,950	8,930	327,380	226,246	553,626
2014	1,313,458	23,638	9,198	337,201	233,033	570,234
2015	1,352,861	24,348	9,474	347,317	240,024	587,341
2016	1,393,447	25,078	9,758	357,737	247,225	604,962
2017	1,435,251	25,830	10,051	368,469	254,641	623,110
2018	1,478,308	26,605	10,352	379,523	262,281	641,804
2019	1,522,657	27,403	10,663	390,909	270,149	661,058
2020	1,568,337	28,225	10,983	402,636	278,253	680,890

The impacts of this policy option are based on increasing the use of biomass for institutional heating starting in 2008. Table H-27 shows the modeled increase in use of biomass assuming that 10% of biomass removed is used for heat production by 2012 and 20% is used for heat production by 2020 with gradual increases in intervening years. In the absence of the policy option it is assumed that none of the biomass would be used for institutional heating.

The energy content of biomass was calculated using a conversion factor of 16.4.

MMBtu/ton biomass. Emission reductions were calculated using the difference between biomass energy emissions and natural gas emissions based on the following emission factors: biomass energy yields 0.007 tons CO_2e/MMBtu, natural gas yields 0.053 tons CO_2e/MMBtu.

Table H-27. Policy impacts of increased biomass use for energy production (assuming a baseline of zero utilization)

Year	Total Carbon Removed From Thinning (tons carbon)	Proportion of biomass used to produce energy under policy scenario	Amount of biomass used for energy production (tons biomass)*	Energy generated from biomass used for energy production (MMBtu)	Emission reductions from energy offsets ($MMtCO_2$)
2008	477,562	0.02	19,102	313,281	0.01
2009	491,889	0.04	39,351	645,359	0.03
2010	506,646	0.06	60,797	997,079	0.05
2011	521,845	0.08	83,495	1,369,322	0.06
2012	537,501	0.10	107,500	1,763,002	0.08
2013	553,626	0.11	124,566	2,042,878	0.09
2014	570,234	0.13	142,559	2,337,961	0.11
2015	587,341	0.14	161,519	2,648,910	0.12
2016	604,962	0.15	181,488	2,976,411	0.14
2017	623,110	0.16	202,511	3,321,179	0.15
2018	641,804	0.18	224,631	3,683,954	0.17
2019	661,058	0.19	247,897	4,065,506	0.19
2020	680,890	0.20	272,356	4,466,636	0.20
Total	**7,458,467**				**1.40**

*Biomass calculated as 2 times the weight of carbon (i.e., carbon content of biomass is 50%)

MMBtu – is a standard measure of the heat value of fuels, representing a thousand thousand British thermal units.

There are a number of potential costs and costs savings associated with using more biomass for institutional heating. For example, revenue from the sale of extracted biomass to consumers for heat production can offset the costs of treatment, transportation, and disposal of biomass that is extracted and not used for energy (e.g., the Roundtable estimates that biomass extraction without utilization costs $654/acre compared to a cost of $364/acre for biomass extraction with utilization, which is a cost savings of $290/acre treated). In addition, cost savings can occur when fuel wood replaces more costly fossil fuels (e.g., the Roundtable estimates that wood fuel costs $2/MMBtu, compared to a cost of $7/MMBtu for natural gas). However, there are also infrastructure costs associated with upgrading or installing new boilers for using biomass. The up-front cost of a biomass combustion system can be greater than a traditional system; however the fuel can be far less expensive, such that, over time, fuel savings can more than offset upfront costs. The magnitude of these types of costs is difficult to predict under the policy scenario as data are limited on existing systems and needed upgrades to meet the capacity demands of this option.

This option assumes that the cost savings associated with revenue generated from the sale of biomass for heating purposes would roughly offset the costs associated with developing the infrastructure for using the biomass. Thus, the quantified costs savings shown in Table H-28 are based solely on the cost savings associated with lower fuel prices for wood, compared to natural gas (cost savings of $5/MMBtu of heat produced).

Costs savings were calculated each year by multiplying the energy produced from biomass by a cost savings of $5/MMBtu. Annual discounted costs were calculated using a 5% interest rate. An NPV of –$104 million was calculated for this option as the sum of annual discounted costs over the timeframe of analysis (negative values indicate cost savings). In addition, a cost-effectiveness of –$75/ton CO_2e was calculated by dividing NPV by the cumulative GHG savings of the option from 2008–2020.

Table H-28. Summary of estimated cost savings

Year	Energy generated from biomass heating (MMBtu)	Emission reductions from energy offsets ($MMtCO_2$)	Cost Savings from Biomass Utilization	Discounted Costs
2008	313,281	0.01	–$1,566,404	–$1,566,404
2009	645,359	0.03	–$3,226,793	–$3,073,136
2010	997,079	0.05	–$4,985,395	–$4,521,900
2011	1,369,322	0.06	–$6,846,609	–$5,914,358
2012	1,763,002	0.08	–$8,815,009	–$7,252,130
2013	2,042,878	0.09	–$10,214,392	–$8,003,243
2014	2,337,961	0.11	–$11,689,804	–$8,723,111
2015	2,648,910	0.12	–$13,244,548	–$9,412,653
2016	2,976,411	0.14	–$14,882,055	–$10,072,761
2017	3,321,179	0.15	–$16,605,893	–$10,704,307
2018	3,683,954	0.17	–$18,419,768	–$11,308,140
2019	4,065,506	0.19	–$20,327,529	–$11,885,085
2020	4,466,636	0.20	–$22,333,179	–$12,435,950
Total		**1.40**		**–$104,873,178**

Key Assumptions: Risk reduction treatments are the same under business as usual and policy implementation. None of the biomass by-products from risk reduction treatments would be used to produce energy under business as usual. WUI increases at a rate of 3% per year, leading to increased need for thinning treatments. Demand and capacity for using biomass to heat institutional buildings will increase at the pace needed to achieve the goals of this option.

Key Uncertainties

The demand and capacity for using biomass to heat buildings will match the assumptions of the analysis. Biomass supply is estimated using general carbon stock coefficients and coarse assumptions about thinning practices; actually supply potential could be quite different in reality. The GHG reduction is measured against the use of natural gas for heating. The actual fuel offset by biomass heating will vary by facility.

The additional GHG emissions associated with any pelletizing of biomass for use in certain commercial/residential applications has not been quantified. These emissions are expected to result in a slight reduction to the overall benefits estimated for this option. In addition, the additional transportation related emissions associating with moving biomass to consumers is not taken into account and would result in a reduction to the overall benefits.

The scenario assumes that the balance of carbon fluxes, the thinning treatments applied, and fire frequency within the forest area covered by the option are the same under the policy scenario and business as usual.

Additional Benefits and Costs

Protection of residential and or municipal lands from fire risk

Healthier forests

Protection of watersheds, wildlife and wildlife habitat, and improvements in air quality (e.g., lower air emissions occur from energy utilization compared to open burning)

Potential expansion of markets for industrial producers of renewable energy use

Creation of jobs in the associated forestry management industries

Forest fire mitigation is a potentially important strategy for adapting to future climate change

Feasibility Issues

It may not be feasible to implement treatment on the total number of acres targeted by this option.

Status of Group Approval

Complete.

Level of Group Support

Unanimous consent of those CAP members present and voting.

Barriers to Consensus

Not applicable.

AFW-8. Source Reduction, Enhanced Recycling and Composting Programs

Policy Option Description

Solid waste that is normally buried in landfills generates methane through decomposition processes. By preventing this source of methane, GHG emissions are reduced. Waste can be diverted through a variety of actions including composting, source reduction, recycling, and reuse. Alternatives to landfilling unprocessed organic material (food wastes, agricultural wastes, biosolids, lawn & garden wastes, or other organic materials) include composting and anaerobic digestion. Both alternatives reduce net GHG emissions and anaerobic digestion can also provide a source of renewable energy (methane). Source reduction and recycling also reduce product life cycle GHG emissions, including extraction and processing of raw materials, product manufacture, transport, and final disposal.

Policy Option Design

Goals: Divert 75% of wastes from landfilling by source reduction, recycling and composting.

Timing: Divert 25% by 2012; achieve the full goal by 2020.

Parties Involved: Municipal governments, waste management companies, waste generators.

Other: Not applicable.

Implementation Mechanisms

Colorado will explore all reasonable options that increase the recovery of waste materials and put them to beneficial use. Opportunities may be implemented through

- Education and public involvement
  - Colorado Association for Recycling may play an important role
  - Other non-profits can also be relied upon for advocacy/outreach
  - Leverage public desire to protect the natural beauty of Colorado
- Economic support
  - Target job development
  - Improve Colorado’s processing infrastructure
  - Public/private partnerships will be encouraged that lead to development and construction of new recycling and composting processing facilities.

    Mechanisms that have proved successful in other states will be evaluated for use in Colorado, such as low-interest financing packages; long-term contracts; guaranteed supplies of materials (e.g., from “clean stream” collection processes).

  - Landfill surcharges are the financial bridge to transition us away from a dominant landfill system to a 75% recovery system; therefore, additional surcharges on tipping fees will be evaluated for appropriate levels to achieve programmatic goals.

— This approach is used across the country, going as high as $6/yard at a landfill in California. For perspective, Colorado recently created its first recycling surcharge of ten cents/yard.

- Technical research and assistance
  - Evaluate state and local resources (data based)
- Relationship to transportation-reduction goals and policies
  - Evaluate ways to improve trash collection efficiencies
  - Apply purchasing guidelines

— Local product procurement objectives

— Source reduction limitations to discourage excessive packaging

- Legislative actions
  - Review successful programs that have helped other states increase diversion
  - Leverage grant opportunities from landfill surcharges
  - Adopt bans on landfill disposal for certain materials
  - Increase number of communities that apply pay-as-you-throw trash rates
  - When communities reach urban population thresholds of 50,000 or more, the state will require comprehensive discards collection plans that require Clean Stream (i.e., three separated materials modeled after San Francisco's Fantastic Three program) technology to be used.
- State agencies will lead by example

Related Policies/Programs in Place

- Adopted in 2007, the Sustainable Resource Economic Opportunity Bill establishes a 7- to 10-cent surcharge per ton of landfilled trash, which will create a source of funding to: provide grants for the sustainable use and economic development of discarded resources; pay for additional staff at the Colorado Department of Public Health & Environment to implement solid waste reduction programs; and offer financial rewards to communities that divert more waste.
- Also adopted in 2007, the Environmentally Preferable Products Act enables state agencies to award contracts to bidders who offer environmentally preferable products or services that may exceed the price of the lowest bid. In 2005, SB 141 was passed making it illegal to dispose of used oil, tires, and batteries in Colorado landfills.

Types of GHG Reductions

Methane reductions from avoided methane emissions from waste placed into landfills; GHG reductions from lower energy consumption associated with a reduction of wastes generated (e.g., energy used to create products or packaging); GHG reductions from lower energy consumption associated with utilizing recycled materials for production versus raw (virgin) materials.

Estimated GHG Savings and Costs per $MtCO_2e$

GHG Reductions ($MMtCO_2e$) in 2012, 2020: 0.48, 4.64

Net Cost ($/Mt): $13

Data Sources: Waste-in-placement data is consistent with the Colorado GHG Emissions Inventory and Forecast. Baseline recycling and composting estimates were derived from data presented in a joint study by BioCycle and the Earth Engineering Center of Columbia University.[60] Current source reduction programs—and reductions from those programs—were identified through private communication with Dr. L. Skumatz of Skumatz Economic Research Associates.[61] Cost information was provided by members of the AFW PWG.[62]

Quantification Methods:

GHG Reductions

The baseline estimate for the municipal solid waste (MSW) disposed in landfills was projected from the data used in the Colorado GHG Emissions Inventory and Forecast. The MSW disposed in landfills in Colorado was 3,771,823 tons in 2004. The historical data used in the I&F—provided to CCS by the CDPHE—was projected to increase at the same rate that the waste disposal increased between 2000 and 2004: 1.3%.

The availability of source-specific recycling and composting data in Colorado is extremely limited. Based on a study from BioCycle and Cornell University, CCS assumed a diversion rate (not including source reduction) of 12.5%, 17.3% of which is composted organics. Based on these figures, the 2005 baseline recycling and organic composting figures were calculated to be 445,614 tons and 93,218 tons, respectively.

The estimate for BAU source reduction was developed through data provided by Lisa Skumatz of Skumatz Economic Research Associates, Inc (SERA).[63] All source reduction is assumed to occur through pay-as-you-throw (PAYT) programs. Currently, there are 615,000 people utilizing PAYT programs in Colorado. The standard estimate used by SERA is that those participating in the PAYT programs reduce their waste disposal by 6%. Therefore, assuming a BAU per capita waste disposal rate of 0.91 tons/person/year, the BAU source reduction was calculated to be 14,483 tons (Table H-29).

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[60] P. Simmons, N. Goldstein, S.M. Kaufman, N.J. Themelis, and J. Thompson, Jr. "The State of Garbage in Amercia." *BioCycle*. April 2006. Accessed on August 24, 2007, at http://www.seas.columbia.edu/earth/wtert/sofos/Simmons_SOG06.pdf

[61] Personal Memorandum sent by L. Skumatz to B. Strode via e-mail on August 28, 2007. CCS extends special thanks to SERA for their input on this option.

[62] Personal communication from E. Lombardi and S. Gordon to B. Strode between July 2007 and September 2007.

[63] Personal Memorandum sent by L. Skumatz to B. Strode via e-mail on August 28, 2007.

Table H-29. BAU waste disposal and diversion in Colorado (tons)

Waste Management Method	Year				
	2005	2010	2012	2015	2020
MSW landfilled	3,771,823	4,023,449	4,128,739	4,291,862	4,578,181
MSW recycled	445,614	475,342	487,781	507,053	540,879
Organics composted	93,218	99,437	102,039	106,070	113,146
Source reduction	14,483	15,450	15,854	16,480	17,580
Diversion rate	12.8%	12.8%	12.8%	12.8%	12.8%

The policy goal set for waste diversion in the State of Colorado is 25% diversion by 2012 and 75% diversion by 2020. According to a member of the AFW PWG, industry expects that any long-run diversion plan will be met with equal parts recycling and organic composting.[64] Therefore, the breakdown of tonnage of waste diverted under this policy option was estimated by assuming that 75% of all citizens not currently under a PAYT program will be participating in such a program by 2020. The remainder of diversion needed to meet the 2020 75% waste diversion target is assumed to be made up of equal parts recycling and organic composting. Tables H-30 and H-31 display the total waste disposed and diverted under the policy scenario, as well as the incremental diversion expected (above and beyond BAU diversion):

Table H-30. Policy goal waste disposal and diversion in Colorado (tons)

Waste Management Method	Year				
	2005	2010	2012	2015	2020
MSW landfilled	3,771,823	3,676,397	3,550,809	2,768,324	1,312,447
Total diversion	553,315	937,280	1,183,603	2,153,141	3,937,340
MSW recycled	445,614	523,378	567,447	1,042,061	1,917,237
Organics composted	93,218	378,731	567,447	1,042,061	1,917,237
Source reduction	14,483	35,171	48,710	69,018	102,866
Diversion rate	12.8%	20.3%	25.0%	43.8%	75.0%

Table H-31. Incremental waste diversion in Colorado (tons)

Incremental Waste Diversion	Year				
	2005	2010	2012	2015	2020
Total diversion	–	347,052	577,929	1,523,538	3,265,735
MSW recycled	–	48,036	79,666	535,009	1,376,358
Organics composted	–	279,294	465,408	935,991	1,804,091
Source reduction	–	19,721	32,856	52,538	85,286

The GHG reductions for recycling are calculated by entering the 2012 and 2020 incremental recycling values displayed above into the EPA Waste Reduction Model (WARM). WARM allows the user to input values for the recycling of multiple materials. However, since data in Colorado regarding the type of materials recycled is unavailable at this time, the total quantity of incremental recycling under the policy scenario was entered into WARM under "mixed recycling." The results showed a GHG benefit of 200,731 MtCO$_2$e in 2012 and 3,540,431 MtCO$_2$e in 2020.

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[64] Personal communication from E. Lombardi to B. Strode on September 5, 2007.

By composting organic material, the CH_4 emissions that would have been generated via anaerobic decomposition in a landfill are avoided. Landfill methane avoided for the incremental (2012 and 2020) organics material diversion was estimated using an estimate of the degradable organic carbon (DOC) content from the United Nations Framework Convention on Climate Change (UNFCC).[65]

For this assessment, landfill gas generated at the applicable landfills in Colorado is assumed to be collected and controlled. The US EPA default methane collection efficiency of 75% is applied. Also, the default assumption of 10% oxidation of CH_4 as it diffuses through the landfill soil cover is applied. The 2012 incremental landfill methane avoided is (see footnote for additional details):

$$\begin{gathered}\text{Incremental 2012 } CH_4 = (465{,}408 \text{ tons of organics}) \times (0.21) \times (0.50) \times (0.907 \text{ Mt/ton}) \\ \times (16/12) \times 21 \times (1 - 0.75) \times (1 - 0.10) \\ = 279{,}236 \text{ MtCO}_2\text{e}\end{gathered}$$

The same method was used to calculate the methane avoided using the higher levels of organics to be composted in 2020 (1,804,091). The incremental benefit of increased organic material composting is 200,731 $MtCO_2e$ in and 1,082,419 $MtCO_2e$ in 2020.

WARM was also utilized to determine the GHG benefit from the incremental increase in source reduction as well. As WARM does not allow source reduction as an input for the “Mixed MSW” cell, an alternative approach to calculating GHG reductions with WARM was adopted. For years 2012 and 2020, the WARM model was run for the BAU MSW disposed in landfills (4,128,739 tons in 2012 and 4,578,181 tons in 2020). The model was run again for the 2012 and 2020 MSW disposal in landfills that would be expected after incremental source reduction only (4,095,883 tons in 2012 and 4,492,895 tons in 2020). The results of the second WARM run (625,118 $MtCO_2e$ in 2012 and 685,710 $MtCO_2e$ in 2020) are subtracted from the results of the first WARM run (630,132 $MtCO_2e$ in 2012 and 698,727 $MtCO_2e$ in 2020) to yield the total incremental GHG benefit attributed to source reduction (5,014 $MtCO_2e$ in 2012 and 13,017 $MtCO_2e$ in 2020).

The resulting GHG reductions were found to be quite high, likely due to the large diversion prescribed by this policy. The estimated GHG reduction for 2012 is 0.48 $MMtCO_2e$/year and 4.64 $MMtCO_2e$/year in 2020. The reductions from each diversion strategy are displayed in Table H-32.

Table H-32. Incremental GHG reductions from policy goal waste diversion ($MMtCO_2e$)

Year	2012	2020	Cumulative
Recycling	0.200	3.540	
Organic Composting	0.279	1.082	
Source Reduction	0.005	0.013	
Total Incremental Diversion	0.485	4.636	24.01

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[65] UNFCC, CDM–Executive Board, “Approved baseline and monitoring methodology AM0039,” September 29, 2006. The average DOC content for lawn and garden, food, and wood/straw waste is 21%. Default CH_4 content of landfill gas is 50%. 16/12 is the ratio of molecular weights of carbon and methane. 21 is the global WARMing potential of methane.

Costs

The cost of increasing recycling rates in Colorado is calculated by taking the difference of the sum of the capital cost and collection cost and the cost saved through avoided landfill tipping fees. The capital costs are determined on a per-household basis, with the figure of $129 per household derived from input given to a similar state climate change planning process in Vermont.[66] The total capital cost for additional recycling facilities in Colorado is estimated to be a total of $213.4 million over the life of the program, which is the equivalent of $12 million/year over the course of the policy period (given a 5% interest rate). The annual cost of collection per household is assumed to be $60/year ($5 per month per household).[67] The tipping fee for recycling is assumed to be the sum of the fee paid to haulers and the avoided landfill tipping fee. The payment from recycling facilities to haulers is assumed to be $30/ton and the landfill tipping fee is currently $15/ton, expected to double by 2020.[68] The results show that, beginning in 2014, this policy will have a net savings to society (Table H-33; Note: $MM stands for million dollars).

Table H-33. Cost of recycling program

Year	Tons Reduced	Households in Program	Annual Capital Cost ($MM)	Annual Costs for Collection ($MM)	Tipping Fee ($)	Avoided Disposal Cost ($MM)	Net Policy Cost (Recycling) ($MM)
2007	–	–	$–	$–		$–	$–
2008	16,090	5,371	$12.04	$0.32	$45.00	$-0.72	$11.64
2009	32,102	10,717	$12.04	$0.64	$46.25	$-1.48	$11.20
2010	48,036	16,037	$12.04	$0.96	$47.50	$-2.28	$10.72
2011	63,891	21,330	$12.04	$1.28	$48.75	$-3.11	$10.20
2012	79,666	26,596	$12.04	$1.60	$50.00	$-3.98	$9.65
2013	227,507	75,952	$12.04	$4.56	$51.25	$-11.66	$4.94
2014	379,263	126,614	$12.04	$7.60	$52.50	$-19.91	$-0.28
2015	535,009	178,609	$12.04	$10.72	$53.75	$-28.76	$-6.00
2016	694,823	231,962	$12.04	$13.92	$55.00	$-38.22	$-12.26
2017	858,784	286,699	$12.04	$17.20	$56.25	$-48.31	$-19.07
2018	1,026,972	342,848	$12.04	$20.57	$57.50	$-59.05	$-26.44
2019	1,199,469	400,435	$12.04	$24.03	$58.75	$-70.47	$-34.40
2020	1,376,358	459,488	$12.04	$27.57	$60.00	$-82.58	$-42.97

The cost of organic composting systems is based upon the annualized capital cost, which is $8 million per 100,000 tons of organics composted (assuming 5% interest).[69] The annual operation and maintenance cost is assumed to be $15 per ton.[70] The cost savings is the difference between the avoided landfill tipping fee (noted above) and the tipping fee paid to organic

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[66] P. Calabrese, Cassella Waste Management, personal communication with S. Roe, CCS, April 26, 2007.

[67] Personal communication from E. Lombardi to B. Strode on September 5, 2007.

[68] Ibid.

[69] P. Calabrese, Cassella Waste Management, personal communication with S. Roe, CCS, June 5, 2007. Transmitted via e-mail to B. Strode by S. Roe. Confirmed by E. Lombardi.

[70] Personal communication from E. Lombardi to B. Strode on September 5, 2007.

composters ($15/ton, not assumed to escalate over time).[71] The cost analysis of the organic composting program predicts a net cost over time, largely due to high initial capital cost. Some of these costs may be defrayed through the construction of larger facilities, but high levels of centralization may lead to increased transportation costs.

Table H-34. Cost of composting program

Year	Annual Cost O&M ($/ton)	Capital Cost ($/ton)	Cost Savings ($/ton)	Total Annual Cost (2007$/ton)	Annual Collection Cost ($MM)	Households in Program	Tons of Waste Composted	Net Policy Cost (Composting) (MM$)
2007	–	$–	0	$–	$–	–	–	$–
2008	30.00	$–	$–	$30.00	$1.87	31,086	93,114	$4.66
2009	30.00	$4.14	$-1.25	$32.89	$3.73	62,166	186,212	$9.85
2010	30.00	$5.52	$-2.50	$33.02	$5.59	93,241	279,294	$14.82
2011	30.00	$6.21	$-3.75	$32.46	$7.46	124,310	372,359	$19.55
2012	30.00	$6.62	$-5.00	$31.62	$9.32	155,373	465,408	$24.04
2013	30.00	$7.48	$-6.25	$31.23	$12.38	206,403	618,264	$31.69
2014	30.00	$6.96	$-7.50	$29.46	$15.53	258,762	775,099	$38.36
2015	30.00	$7.41	$-8.75	$28.66	$18.75	312,474	935,991	$45.57
2016	30.00	$7.70	$-10.00	$27.70	$22.05	367,568	1,101,018	$52.55
2017	30.00	$7.28	$-11.25	$26.03	$25.44	424,068	1,270,260	$58.51
2018	30.00	$7.47	$-12.50	$24.97	$28.92	482,002	1,443,797	$64.98
2019	30.00	$7.60	$-13.75	$23.85	$32.48	541,398	1,621,713	$71.17
2020	30.00	$7.69	$-15.00	$22.69	$36.14	602,284	1,804,091	$77.07

O&M = operation and maintenance.

The cost of increased source reduction programs is based upon the annual cost of the program, less the avoided landfill tipping fee. The cost of a source-reduction program is estimated to be $2 per household per year. This cost applies to all households not currently under PAYT program, as it is assumed that these funds are already spent on households currently enrolled in a PAYT program. The total annual cost is $2.15 million. It is also assumed that PAYT does not cost any more to administer than a traditional trash collection program. The avoided landfill tipping fee is the same as described above. The analysis estimates that source reduction presents a net cost, until the end of the policy period (2019) when the cost savings associated with avoided tipping fees overtake the cost of implementation.

The total incremental cost of waste diversion programs to meet the 75% diversion goal by 2020 is estimated to have a net present value of $310.67 million. The levelized cost-effectiveness of this option is estimated to be $12.94/MtCO$_2$e (Table H-36).

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[71] Ibid.

Table H-35. Cost of source reduction program

Year	Tons Reduced	Avoided Landfill Tipping Fee ($)	Avoided Disposal Cost ($MM)	Implementation Costs ($MM)	Program Costs ($MM)
2007	–		$–		
2008	6,576	$15.00	$-0.10	$2.15	$2.05
2009	13,150	$16.25	$-0.21	$2.15	$1.93
2010	19,721	$17.50	$-0.35	$2.15	$1.80
2011	26,290	$18.75	$-0.49	$2.15	$1.65
2012	32,856	$20.00	$-0.66	$2.15	$1.49
2013	39,419	$21.25	$-0.84	$2.15	$1.31
2014	45,980	$22.50	$-1.03	$2.15	$1.11
2015	52,538	$23.75	$-1.25	$2.15	$0.90
2016	59,093	$25.00	$-1.48	$2.15	$0.67
2017	65,646	$26.25	$-1.72	$2.15	$0.42
2018	72,195	$27.50	$-1.99	$2.15	$0.16
2019	78,742	$28.75	$-2.26	$2.15	$-0.12
2020	85,286	$30.00	$-2.56	$2.15	$-0.41

Table H-36. Cost of diversion program

Year	Avoided Emissions ($MMtCO_2e$)	Annualized Costs (MM$)	Discounted Costs (MM$)	Levelized & Discounted Cost-effectiveness
2007	–	–	–	
2008	0.10	18.34	$17.47	
2009	0.19	22.98	$20.85	
2010	0.29	27.34	$23.62	
2011	0.39	31.40	$25.84	
2012	0.48	35.18	$27.57	
2013	1.00	37.94	$28.31	
2014	1.52	39.20	$27.86	
2015	2.04	40.47	$27.39	
2016	2.56	40.96	$26.41	
2017	3.08	39.87	$24.48	
2018	3.60	38.70	$22.63	
2019	4.12	36.65	$20.41	
2020	4.64	33.69	$17.86	
Totals	**24.0**	**$443**	**$311**	**$ 13**

Key Assumptions: Assumptions used in the EPA WARM modeling include the use of the "current mix" of recycled and virgin material inputs to production (i.e., new products are not produced with 100% virgin materials); landfill gas is recovered for energy purposes; 75% collection efficiency for landfill gas (LFG); default distance to the landfill and recycling facilities (20 miles). Another key assumption is the ability of the N_2O composting emission factor to represent emissions from MSW organic materials composting.

Key Uncertainties

These include the input data to the WARM model on current levels of recycling activity and default WARM model selections (distance to material recovery facilities; landfill gas collection efficiency; and other model default selections). Cost data are also key inputs with some level of uncertainty, including the assumed tipping fees, costs for source reduction programs, and the cost of composting systems.

Additional Benefits and Costs

Reduction in other air and water pollutant emissions associated with product manufacturing and transport.

Feasibility Issues

The State legislature needs to pass a resolution that sets waste diversion goals for Colorado. The newly elected governor has already showed leadership on environmental issues. The state's reputation as an incubator for renewable energy policies and technology is growing, and greater amounts of recycling will further enhance Colorado's identity as a "green" state.

Composting, recycling and waste reduction are important tools for citizens because they can take personal action to reduce global WARMing at the household level—and in their workplaces and schools. The public is receptive and eager to reduce/reuse/recycle. Demonstrated success at reducing volumes of trash at landfills is relatively attainable and provides motivation/encourages people to strive for even greater attempts to contribute to climate protection.

Nationally, Colorado ranks among the lowest in costs for landfill disposal (between $10 and $18 per ton, compared with $60 to $90 in many other parts of the country); the public would be likely to absorb new increases in landfill fees if revenues were used to provide greater opportunities to recycle and compost waste materials.

Status of Group Approval

Complete.

Level of Group Support

Unanimous consent of those CAP members present and voting.

Barriers to Consensus

Not applicable.

AFW-9. Landfill Methane Reduction Programs

Policy Option Description

Provide incentives that will result in an increase in the recovery of landfill methane for use as an energy source. Increasing the recovery of landfill methane will reduce emissions of this GHG and will offset the use of fossil fuels for commercial/industrial heat/steam generation or electricity production.

Policy Option Design

Goals: Implement controls or waste management options at municipal solid waste landfills such that 50% of the methane emissions that would be generated under business as usual conditions are avoided by 2020. This can be done through development of additional landfill gas to energy (LFGTE) projects, flaring, reducing the amount of biodegradable waste being landfilled, or possibly other methods.

Timing: By 2012, implement controls or management strategies at 12 sites not currently using these technologies; by 2020, achieve full implementation of the policy (50% coverage of generated methane).

Parties Involved: Municipal governments, landfill operators, landfill gas to energy project developers.

Other: This policy is meant to cover sites that would not be expected to trigger the Federal New Source Performance Standards/Emission Guidelines (NSPS/EG) for landfills (and would be required to capture and control methane). According to the Colorado GHG I&F, the landfills in Table H-37 currently employ LFG controls.

Table H-37. Colorado landfills with gas controls

Site Name	County	Control
County Line Landfill	Arapahoe	Flare
Fountain Landfill	El Paso	Flare
Foothills Landfill	Jefferson	Flare
Denver Regional North Landfill	Weld	Flare
Denver Regional South Landfill	Weld	Flare
Tower Landfill	Adams	Flare
Denver – Arapahoe	Arapahoe	LFGTE
Boulder Landfill	Boulder	Flare
Larimer County Landfill	Larimer County	Flare

Implementation Mechanisms

Colorado will explore all reasonable options that will decrease the amount of biodegradable waste sent to landfill, as well as increase the recovery of “bio” waste materials and put them to beneficial use. Opportunities may be implemented through

- Education and public involvement
  - The State would provide good education about the need for waste separation systems so that “clean streams” of materials are available for reuse/recycling/composting.
- Economic support
  - Improve Colorado’s processing infrastructure for discarded materials. The private sector is likely to come in and build facilities if State and local government sets the direction for how materials will be separately collected.
- Technical research and assistance
  - Evaluate state and local resources (data based)
- Relationship to transportation reduction goals and policies
  - Apply government purchasing guidelines
- Legislative actions
  - Review successful programs that have helped other states increase diversion
  - Leverage grant opportunities from landfill surcharges
  - Adopt bans on landfill disposal for certain materials
  - Increase number of communities that apply pay-as-you-throw trash rates
  - State agencies will lead by example
  - Every landfill in the state will be required to develop a methane reduction and mitigation program by end of 2008, with financial assistance available from the State for planning purposes

— Funds will be created to assist landfill planning using new surcharges that will be applied to solid waste disposal in landfills

— The State will provide financial assistance to small landfills to install methane flaring systems.

- Large landfills that meet the US EPA’s Federal New Source Performance Standards/Emissions Guidelines (NSPS/EG) are required to install methane collection systems.

Related Policies/Programs in Place

- Federal NSPS/EG for municipal solid waste landfills (require landfill collection and control for landfills of specific sizes and pollutant emission levels).
- Adopted in 2007, the Sustainable Resource Economic Opportunity Bill establishes a 7- to 10-cent surcharge per ton of landfilled trash, which will create a source of funding to: provide grants for the sustainable use and economic development of discarded resources; pay for additional staff at the Colorado Department of Public Health and Environment to

implement solid waste reduction programs; and offer financial rewards to communities that divert more waste.

- Also adopted in 2007, the Environmentally Preferable Products Act enables state agencies to award contracts to bidders who offer environmentally preferable products or services that may exceed the price of the lowest bid. In 2005, SB 141 was passed making it illegal to dispose of used oil, tires, and batteries in Colorado landfills.

Types of GHG Reductions

- Methane reductions via collection and control (via flaring, or preferentially via energy utilization).
- Reduction of fossil fuels and associated GHGs through the use of landfill methane.

Estimated GHG Savings and Costs per MtCO$_2$e

GHG Reductions (MMtCO$_2$e) in 2012, 2020: 0.3, 1.2

Costs ($/Mt): –$0.02

Data Sources:

GHG reductions. Information on current and forecast landfill emissions levels comes from the Colorado GHG I&F for both flared and uncontrolled landfill categories. A life cycle emission factor for natural gas consumption (120.2 lb CO$_2$e/MMBtu) was calculated from the I&F emission factor for natural gas combustion (116.7 lb CO$_2$e/MMBtu) plus an estimated emission factor that covered natural gas extraction, processing, transmission and distribution using estimates in US EPA’s 2001 national emission estimates for that sector (3.5 lb CO$_2$e/MMBtu);

Costs. US EPA model LFGcost-Web, which estimates the costs to implement different types of landfill gas controls (including LFGTE); assumptions on the types of controls to be applied (flare, LFGTE plant type) to estimate costs.

Quantification Methods:

GHG reductions come from two components—landfill methane controlled through this option and fossil fuel offset with the use of collected landfill methane. The methane controlled was calculated from the uncontrolled landfill category in each year of the policy period. In 2012, 20% of the generated methane is to be collected and used for energy purposes. In 2020, 50% is to be collected and used.

The CO$_2$e emissions reductions achieved from collecting and using this methane were added to the emissions from fossil fuel that would be avoided from using the energy in the collected landfill methane. The methane to be collected from both flared and uncontrolled sites was added in each year and then converted to MMBtu. Then, the lifecycle natural gas emission factor provided above was applied to estimate GHG reductions from avoided natural gas use.

EPA’s LFGcost-Web model is used to estimate a range of costs for implementing LFG controls based on different technologies; this model handles large or small engines, and direct LFG use. The fractional reductions are referenced to data on US EPA’s Landfill Methane Outreach Program (LMOP) Web site and are displayed in Table H-38.

H-38. Calculation of cost-effectiveness for landfill methane collection and utilization

Blended Cost-effectiveness (CE)	Fraction of CO_2e Reduced	Fractional CE ($/Mt$CO_2e$)	Overall Cost-effectiveness
Scenario 1. Direct use (0.5 mi pipeline)	0.24	$-0.20	
Scenario 2. Small engine	0.02	$0.05	
Scenario 3. Standard engine	0.74	$0.11	
		$-0.03	Blended CE Estimate

The costs are determined by multiplying the total reductions by the blended CE estimate. The CE estimate includes the value of energy exports, the value of natural gas offset, the operation and maintenance (O&M) costs for LFG facilities, and annualized capital costs for these facilities.

Key Assumptions: Current reduction estimates include benefits of offset natural gas consumption. To the extent that other higher carbon fossil fuels are offset, the benefit could be greater. The refined analysis will incorporate reductions associated with electricity produced using landfill gas, since that is the most likely and common use for this energy source.

Key Uncertainties

The key uncertainty associated with this analysis is whether future landfill diversion programs (such as shown in AFW-8) will significantly alter BAU landfilling practices. If significant diversion is achieved within the policy period, lower levels of methane will be generated towards the end of the policy period than are estimated here. This would lead to lower benefits than estimated above. The extent of overlap between AFW-8 and 9 was beyond the scope of this analysis.

Additional Benefits and Costs

Lower emissions of other air pollutants including volatile organic compounds and toxic air pollutants.

Feasibility Issues

The State legislature needs to pass a resolution that sets landfill methane reduction goals for Colorado. The newly elected governor (Governor Bill Ritter) has already shown leadership on environmental issues. The state’s reputation as an incubator for renewable energy policies and technology is growing, and greater amounts of recycling will further enhance Colorado’s identity as a “green” state.

Composting, recycling, and waste reduction are important tools for citizens because they can take personal action to reduce global WARMing at the household level—and in their workplaces and schools. The public is receptive and eager to reduce/reuse/recycle. Demonstrated success at reducing volumes of trash at landfills is relatively attainable and provides motivation/encourages people to strive for even greater attempts to contribute to climate protection.

Nationally, Colorado ranks among the lowest states in costs for landfill disposal (between $10 and $18/ton, compared with $60 to $90/ton in many other parts of the country); the public would be likely to absorb new increases in landfill fees if revenues were used to provide greater opportunities to recycle and compost waste materials.

Status of Group Approval

Complete.

Level of Group Support

Unanimous consent of those CAP members present and voting. One CAP member’s vote of approval was qualified on the basis of uncertainty about the implementation of net metering by rural cooperative electric associations.

Barriers to Consensus

Not applicable.

AFW-10. Urban Forestry Programs

Mitigation Option Description

Urban forest cover protection and management offers a potentially cost-effective mechanism to reduce energy use and to store/sequester carbon. Strategic planting of trees to shade houses and AC units can yield energy savings of 15% to 50% on cooling costs.[72] Planting of shade trees can reduce summer heating costs, with only marginal increases in winter heating costs, particularly in mild climates. In addition, depending on local conditions, tree planting can reduce wind-speed and further reduce energy costs. This option seeks to expand existing urban tree planting and maintenance programs, such as Denver's Tree Initiative.[73]

Mitigation Option Design

Goals: Expand urban tree planting and maintenance programs statewide such that 3.4 million new trees are planted by 2025.

Timing: Initiate tree planting programs in 2008, achieve the full goal by 2025.

Parties involved: Colorado State Forest Service, local government planning agencies, developers, residential and commercial property owners, Colorado urban forestry organizations, electricity providers.

Other: Initiated in 2006, the Denver Tree Initiative aims to plant 1 million new trees by 2025 in the Denver metropolitan area. Based on the area of Denver metro region (661 square miles) and the area of developed land in Colorado (2,921 square miles), expanding this Denver program statewide would result in a total of 4.4 million trees in Colorado's urban areas. Subtracting the already established Denver program goals yields the policy goal of 3.4 million new trees.

Implementation Mechanisms

- Use incentives to encourage developers to retain trees and green space on new construction sites. (Incentives could include density credits, priority during approval/permitting process, and utility credits). Require developers to retain a minimum of canopy cover and those that retain more than that receive incentives. Minimum canopy cover and nature of incentives to be determined.
- Promote the creation of proper tree preservation and protection ordinances in communities across the state.
- Provide recognition to communities that increase their canopy cover percent (e.g., through CO_2 crediting in emerging programs). Consider other crediting mechanisms,

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[72] Cooling Our Cities, US EPA PM-221.

[73] More information on this program can be found at http://www.greenprintdenver.org/trees/index.php

such as allowing municipalities and/or homeowners to direct the benefits of CO_2 sequestration via trees to their budget or charity of their choice, respectively.

- Install trees as part of green roofs on state buildings—green roofs reduce urban heat islands by providing shade and the cooling effects of evapotranspiration, absorb air pollution, collect airborne particulates, and store carbon, and insulate a building from extreme temperatures (reducing energy costs).
- Support the use of consulting arborists by developers/contractors in the planning and review process prior to building permit submission.
- Empower the State Forest Service to increase seedling availability to urban tree planting programs. Expand the interaction with community groups and environmental organizations.
- Enhance existing programs to educate and cost-share tree planting programs for urban or residential plantings.
- Increase level of support/education to municipalities in order to ensure proper maintenance and care of an increased urban forest.
- Work with electricity providers to establish/expand demand side management programs to include urban tree programs.

Related Policies/Programs in Place

- Denver Tree Initiative

Type(s) of GHG Reductions

- Increased carbon sequestration in urban trees
- Avoided emissions by reduced energy use in heating and cooling
- Improved retention of soil carbon (not quantified)
- Potential for carbon sequestration in the form of durable wood products and fossil fuel offsets from forest based energy (not quantified)

Estimated GHG Savings and Costs per $MtCO_2e$

GHG Reduction Potential in 2012, 2020 ($MMtCO_2e$): 0.03, 0.08

Net Cost per $MtCO_2e$: $79

At full implementation in 2025, the annual GHG reductions would be 0.12 $MMtCO_2e$*/year and the cost-effectiveness would drop to $36/Mt.*

Data Sources: From the policy goals, 3.4 million new trees are to be planted in Colorado’s developed (urbanized) areas. For assessing emissions avoided due to lower energy demand, electricity consumption emission factors for Colorado were obtained from the Energy Supply PWG. The long-term (2013–2020) peak emission factor is 0.791 Mt/MW-hr. Additional information on sequestration rates and other default analysis inputs came from a 1999 USFS report referenced in the footnote below (McPherson and Simpson).

Quantification Methods: CCS used methods outlined by the USFS to estimate net GHG benefits for urban tree programs. A 1999 USFS guidance document was used to develop an energy reduction factor for tree shading.[74] For carbon sequestration, summary data from the USFS on Colorado's urban forests was used to derive an average sequestration rate per tree (0.022 Mt CO_2/year/tree).[75]

To use the USFS methods for energy reduction, the following information is needed about the trees to be planted: total number, fraction to be planted near buildings (within 50 ft. to provide shade benefits), number of deciduous versus evergreen trees (evergreens are best for wind protection purposes). For the purposes of this analysis, CCS assumed that one third of the trees would be targeted for near building planting and, of those trees, half would be evergreen and half would be deciduous trees. For the remaining two thirds to be planted in parks and other urban areas away from buildings, CCS assumed that half would be deciduous and the other half evergreen.

Table H-39. Assumptions about urban tree types and locations

Location	Number of Deciduous Trees	Number of Evergreen Trees	Totals
Near buildings	556,750	556,750	1,113,500
Other urban areas	1,113,000	1,113,500	2,226,500
Totals	1,669,750	1,669,750	3,400,000

CCS further assumed that all of the trees planted would be considered large trees at maturity (at least 50 feet). Using data from the 1999 study, the shade effects energy reduction for large deciduous trees is 0.0089 Mt CO_2/year-tree. Because the electricity emission factor used by the USFS (0.908 $MtCO_2$/MW-hr) is higher than the emission factor provided by the Energy Supply PWG, the emission factor was adjusted downward by a factor of 0.791/0.908 = 0.871 to reflect a value specific to the CAP process. The resulting emission factor used to estimate energy reduction benefits for this option is 0.0076 $MtCO_2$/year-tree.

For large evergreen trees, the energy reduction emission factor from the 1999 study is 0.0761 $MtCO_2e$/year-tree. After adjustment, the factor becomes 0.066 $MtCO_2$/year-tree.[76]

The energy reduction benefits achieved by this policy at full implementation would then be

$$0.0076\ MtCO_2/\text{year-tree} \times 556{,}750\ \text{deciduous trees} = 4{,}231\ MtCO_2/\text{year}$$

plus

$$0.066\ MtCO_2/\text{year-tree} \times 556{,}750\ \text{evergreen trees} = 36{,}746\ MtCO_2/\text{year}.$$

The carbon sequestration benefit by 2025 would be

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[74] *Carbon Dioxide Reduction Through Urban Forestry: Guidelines for Professional and Volunteer Tree Planters,* E. Gregory McPherson and James R. Simpson, USFS, General Technical Report PSW-GTR-171, January 1999.

[75] http://www.fs.fed.us/ne/syracuse/Data/State/data_CO.htm

[76] The shade effects energy reduction for deciduous trees planted near buildings is the net of energy saving from reduced summer cooling energy consumption plus an increase in winter heating energy consumption. For evergreen trees, a reduction in wind effects energy consumption is added to the summer cooling/winter heating energy net reduction. This leads to a larger CO_2 reduction estimated for evergreen trees.

$$0.022\ \text{MtCO}_2\text{/year-tree} \times 3{,}400{,}000\ \text{trees} = 74{,}800\ \text{MtCO}_2\text{/year.}$$

Hence, the total benefit by 2025 is

$$4{,}231 + 36{,}746 + 74{,}800 = 115{,}777\ \text{MtCO}_2\text{/year} = 0.12\ \text{MMtCO}_2\text{e/year.}$$

Costs were estimated by assuming that each tree costs $75 to install and care for over the first 2 years. The literature suggests a wide range of costs for urban tree planting and maintenance costs. One recent study suggested a range of $10–$570/tree (average of $220/tree; including maintenance costs over 40 years). Important variables in the costs include whether paid or volunteer labor is used to plant the trees and whether young and relatively inexpensive trees are used compared to large container trees.[77] CCS assumed that much of the labor could be provided via volunteer labor (e.g., homeowners, volunteer organizations) and that smaller trees would be favored, so a value toward the lower end of the range was selected.

Cost savings are achieved as the trees mature when energy reductions yield savings in electricity costs to the building owners. The 2007 residential retail electricity price in Colorado is $0.0925/kW-hr.[78] This value was used to estimate the net costs associated with this policy.

Key Assumptions: It is assumed that the trees are all planted in accordance with distribution shown above for deciduous and evergreen trees and the number near buildings. It is assumed that the trees planted near building are oriented to offer the appropriate shading effects or wind reduction effects, such that the energy reduction estimates are achieved.

Key Uncertainties

The representativeness of the sequestration and energy reduction estimates in the USFS data sources cited above to actual levels that can be achieved in Colorado's urban areas.

Additional Benefits and Costs

Urban aesthetics, air quality benefits, reductions in soil erosion.

Feasibility Issues

Actual future carbon sequestration benefits will be influenced, in part, by future climate impacts, which are difficult to predict and could include increases in infestations by pests such as the bark beetle.

Status of Group Approval

Complete.

Level of Group Support

Unanimous consent of those CAP members present and voting.

Barriers to Consensus

Not applicable.

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[77] M.R. McHale, E.G. McPherson, and I.C. Burke, "The Potential of Urban Tree Plantings To Be Cost-effective in Carbon Credit Markets," *Urban Forestry & Urban Greening*, 6:49–60, 2007.

[78] http://www.eia.doe.gov/cneaf/electricity/epm/table5_6_b.html