Colorado Climate Project

the ROCKY MOUNTAIN CLIMATE Organization

www.coloradoclimate.org

Agriculture, Forestry, and Waste Management Technical Work Group
Summary List of Draft Priorities for Analysis

	Policy Option	GHG Reductions (MMtCO$_2$e)			Net Present Value 2007–2020 (Million $)	Cost-Effective-ness ($/tCO$_2$e)	Level of Support
		2012	2020	Total 2007 2020			
AFW-1	Agricultural Crop Management	0.57	0.78	7.7	-57	-7	TBD
AFW-2	Manure Management and Energy Utilization	0.01	0.32	1.8	66	36	TBD
AFW-3	Reductions in On-Farm Energy Use	0.14	0.64	3.8	-150	-40	TBD
AFW-4	Biodiesel Production	0.02	0.22	1.1	156	143	TBD
AFW-5	Ethanol Production	0.39	3.09	15.3	58	3	TBD
AFW-6	Preserve Lands with Carbon Storage Value	0.10	0.24	1.71	26	44	TBD
AFW-7&8	Forest Health and Biomass Feedstocks for Energy Production	0.08	0.20	1.40	34	24	TBD
AFW-9	Source Reduction, Enhanced Recycling and Composting Programs	1.22	7.11	39.94	83	2	TBD
AFW-10	Landfill Methane Reduction Programs	0.33	1.16	7.5	0	0	TBD
	Sector Total After Adjusting for Overlaps						
	Reductions From Recent Actions (table to be added below)						
	Sector Total Plus Recent Actions						

Highlights in yellow represent new additions to POD.

Highlights in blue represent matters that need to be addressed by the PWG.

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 C inputs to soil and/or reduce soil organic matter decomposition rates. Adoption of conservation tillage, in particular no-till, can increase soil C 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 (i.e., better timing, application rates based on soil test, advanced fertilizer formulations, etc.) 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 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: To be determined (TBD).

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

Implementation Mechanisms

- Increased extension/outreach (a good field-day program for dryland systems, through CSU researchers. has been developed over the past several years—could benefit from more resources). Extension related to nutrient management. ??

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[1] Data provided to CCS by AFW PWG. 2005 data.

- State incentives—e.g., favorable property tax rating for "high conservation management." ?
- R&D support for cropping systems research—e.g., 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 Farm Bill (US or CO?).
- Market-based incentives—e.g., CCX (Chicago Climate Exchange) project with the Rocky Mountain Farmer's Union (RMFU).

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: 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 $MtCO_2e$

Note: The Metric unit "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.

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 $MtCO_2e$:

- Total: -$7.33

- No-till: -\$4.37
- Nitrogen fertilizer efficiency: -\$27.62

Data Sources:

Quantification of the no-till portion of this option is based upon 2,923,000 hectares 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-yr was calculated from the midpoint of the range provided by Naderman et al.[2] The estimated cost savings (\$14.33 per hectare) 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 CO Inventory & Forecast, 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 CO 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:

Based on the policy design parameters, the schedule for acres to be put into conservation tillage/no-till cultivation are shown in the table below. The mid-point of the estimated range for carbon sequestration (2.47 tC/ha) in agricultural soils was used to estimate the total amount of carbon to be sequestered. Based on the Naderman et al. study referenced above, it was further assumed that this additional carbon would be sequestered in the soil over a period of six years (after six 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-yr.

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

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.

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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. 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.

Results are shown in the table below along with a total estimated benefit from both carbon sequestration and fossil fuel reductions.

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. 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.

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.

The life-cycle emission factor of fertilizer use is calculated by multiplying the carbon equivalent emissions in the CO Draft I&F by the standard C to CO_2 conversion of 44/12. Then, the CO_2-equivalent 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

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[6] Brooks, S 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] Kurkavola, L., Kling, C., 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 Usniversity.* Working Paper 01-WP 286. April 2003

from the proposed increase in fertilizer efficiency. The results of the calculations detailed in the preceding discussion are displayed in the table below:

Year	Total BAU Fertilizer Use (kg N)	Policy Target	Target Fertilizer Reduction (kg N)	Avoided GHG Emissions (MMtCO$_2$e)
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 total cost of $241,000 per year for soil testing. Costs for 2 FTEs of additional staff, overhead, travel, lab, and associated costs was estimated at $250,000 per 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 is a savings of $27.62 per MtCO$_2$e. The net present value of the cost savings is $24 million. 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. See the table below for detailed annualized cost savings:

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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.

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

Year	Total Cost Savings ($MM)	Total Avoided GHG Emissions (MMtCO2e)	Cost of Programs ($MM)	Discounted/ Levelized Cost ($MM)	D/L CE
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 CO I&F.

Key Uncertainties

- Data on N_2O emissions is still sparse; current estimates do not account for lifecycle fertilizer reduction savings.
- Need for low-intensity “in field” soil C monitoring to decrease uncertainty (i.e., benchmark sites) in soil C sequestration estimates.

Additional Benefits and Costs

- Rocky Mountain National Park N-Deposition MOU
- Erosion reduction, air and water quality, wildlife habitat, increased net returns.

Feasibility Issues

TBD

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

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: TBD

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 Colorado Office of Energy 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 CAFO, a dairy and a swine operation.

Related Policies/Programs in Place

- CDPHE, EPA and the 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 on-going 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

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, etc.). 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: CO GHG Inventory & Forecast (I&F data), digester and engine generator set cost data from 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 CO 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).

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 BTUs) 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

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[10] Livestock Industry Practices. A presentation to the RMNP Subcommittee Meeting. Provided via personal communication (e-mail) by M. Collins to B. Strode 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).

kW-hrs to MW-hrs and then multiplying this value by the CO-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 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 CO, 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 $1/MtCO$_2$e reduced). The annualized per head cost estimates were multiplied by the head of livestock to be controlled in each year to estimate total costs.

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/kWh 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.

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[12] Emission factor derived from "2002 Voluntary Greenhouse Gas Reporting Program"; accessed July 24, 2007, from 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 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

TBD

Feasibility Issues

TBD

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

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, State Agriculture Organizations, Governors Office of Energy Management and Conservation, 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 3-4 case studies of energy efficiency measures taken on various agriculture operations (farm, ranch, feedlot, dairy, etc) 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 insures 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.
- 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.
- Chicago Climate Exchange Methane Offset allows producers with anaerobic digester generating power to receive income from sell of credits based on MTCO2 Equivalent for Methane trapping and combustion. Metric ton of methane valued at 18 MtCO2. At current price of a mtCO2 on the exchange at $3.30, a metric ton of methane would sell for more than $59.
- Net metering up to 25 kW with REA service territories and new interconnection standards for all 22 REAs from HB07-1169.

Types of GHG Reductions

CO_2: GHG reductions that occur as a result of a decline in on-farm energy use are largely comprised 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 units of CO_2e (carbon dioxide equivalent).

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 $MtCO_2e$/1000gal). 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 business as usual (BAU) distillate fuel use for the CO 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 lifecycle 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 CO electricity consumption found in the CO 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 CO electricity emission factor 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 the table below:

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[15] Energy Information Administration. “Colorado Total Distillate Sales/Deliveries to Farm Consumers.” 1984-2005. Accessed on July 17, 2007 from 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 from: 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 from: www.eia.doe.gov/cneaf/electricity/page/sales_revenue.xls.

[18] See notes 16 and 17 for references.

Year	BAU Distillate Use (1000 gal)	Target Distillate Reduction	Incremental GHG Benefit from Distillate Reduction (MMtCO$_2$e)	BAU Electricity Consumption (MWh)	Target Electricity Reduction	Incremental GHG Benefit from Electricity Reduction (MMtCO$_2$e)
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 cost savings related to the reduction in on-farm diesel fuel use 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: increased efficiency of diesel irrigation pumps, assuring that tractor tires are inflated to the proper pressure, and reducing the revolutions per minute (rpm) on tractors running at less-than-full capacity by using a lower gear (called "Gear-Up, Throttle-Down").

The diesel savings that result from a reduction in average tractor tire pressure from 20 psi (pounds per square inch) to 10 psi were cited to be 0.614 gallons per acre.[20] The total number of acres were found in the 2002 Agriculture Census conducted by the US Dept. of Agriculture. 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. 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 farm tractors. 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 (full time equivalent) at $75,000 per 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.

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[19] Energy Information Administration. *Annual Energy Outlook Projection of Petroleum Prices to 2030.* Accessed on August 30, 2007 from 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 from http://www1.agric.gov.ab.ca/$department/newslett.nsf/all/agin147.

NOTE TO PWG: The remainder of this quantification methods section will be presented in a brief, skeleton form. There will be limited reference and tables, but hopefully will provide a sense of the methods used. A complete version of the POD will be posted to the AFW PWG web page prior to COB Wednesday, Sept. 5.

- Diesel Pumping: Dividing the total fuel expenses for diesel irrigation pumps in 2003 ($2.4 million) by the 2003 price of diesel in Colorado ($1.058/gal) yields the gallons used in 2003. Multiply the gallons used (time-series developed by assuming constant ratio to total farm diesel use) by the efficiency improvement (41.4%). The diesel reduction from irrigation pumping does not exceed the difference between the target and the reduction from tire pressure. 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 ($1.53 per gallon). The sum of this number and the annual cost of pump tests (250 per test, test every 4 years) to determine the program cost. The cost savings are imbedded in the total cost savings for on-farm diesel fuel reduction calculated above.
- Tractors (GUTD): The gear-up, throttle-down (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 CO (25,564), the hours per year a tractor operates (411), the weighted average potential power output for tractors in CO (69.21 PTO-hp), the average fuel consumption (0.048 gal/hr/PTO-hp), and the average percentage of max horsepower used (60%). The maximum annual fuel consumption was found by multiplying the baseline tractor fuel consumption by the efficiency improvement resulting from GUTD (25%). 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, as in the tire pressure program.

Year	**Target Distillate 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

Year	**Target Distillate 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)**
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

- 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) and the average retail electricity price for that year ($67.6/kWh). The annualized capital cost of retrofits was found to be $0.020 per kWh and an incentive program of $0.067 per kWh is assumed (similar to a program in CA). The cost savings is based on an assumed variable cost of electricity (the cost exceeding the demand charge) of $0.045/kWh.
- Lighting: Lighting is assumed to account for 1% of total farm electricity consumption. The cost of electricity for lighting (different cost than irrigation pumping) is assumed to be $0.065/kWh. The annual cost of upgrades is $0.023/kWh (72 W for Conventional fixture (24 hr/day, 365 day/yr); $20 per fixture for upgrade. Replace bulbs every 2 years). The efficiency improvement for advanced lighting is 30%.
- Renewable Generation: The renewable generation sources that are assumed to have potential on farms in Colorado are wind, solar PV, solar thermal, and geothermal. The tables below demonstrate the cost (before any incentives) and assumed market share of each technology. 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.

Annualized Cost of Renewable Generation

Year	Annualized Wind Cost (2005$/MWh)	Annualized PV Cost (2005$/MWh)	Annualized Solar Thermal Cost (2005$/MWh)	Annualized Geothermal Cost (2005$/MWh)
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

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%

Key Assumptions: TBD

Key Uncertainties

TBD

Additional Benefits and Costs

TBD

Feasibility Issues

TBD

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

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 Office of Energy Management and Conservation, Colorado Dept. 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 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 N2O), 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: Lifecycle emissions are reduced to the extent that biodiesel is produced with lower embedded fossil-based 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 (soy, canola, sunflower, algal, etc.) and alcohols (either methanol or ethanol). From a recent report (Hill et al. 2006),[21] biodiesel from soybeans contains 93% more useable energy than its petroleum equivalent and reduces lifecycle 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 $MtCO_2e$: $143

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

Data Sources:

Data from the CO Draft Inventory & Forecast 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 (under business as usual):

Year	Diesel Consumption (MMgal/yr)
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/yr in 2012 and 9.5 MMgal/yr in 2020 (see below). Therefore, incremental in-state biodiesel production targets are:

Year	Biodiesel Production Needed (MMgal/yr)
2012	0.02*828 – 6
2020	0.20*1009 – 9.5

The BAU biodiesel production is based upon the current and planned biodiesel capacity of CO. A capacity factor of 50% is assumed. See the table below for the existing and planned facilities in CO:[22]

Facility Name	Status	Capacity (1000 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

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

The CO_2e emission factor for fossil diesel used in the inventory and forecast is 10.04 Mt/1,000 gallons. The lifecycle fossil diesel emission factor is 12.3 Mt/1,000 gallons.[23]

Quantification Methods:

GHG Reductions

A new study on lifecycle GHG benefits for biodiesel production and use was used to estimate the CO_2e reductions for this option.[24] This study covered biodiesel production from soybean production, which is currently the predominant feedstock source for biodiesel production in the US and is assumed to remain that way for the purposes of this analysis (it is also the predominant feedstock of biodiesel production in CO). Lifecycle 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 TWG 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 embedded GHG 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. mid-west 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.[25] Rail fuel consumption is about 400 ton-miles/gallon.[26] 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),[27] 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 lifecycle 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

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[23] Hill et al 2006.

[24] Ibid.

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

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

[27] 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).

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

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 $MtCO_2e/MMgal$.

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

Year	Oil Feedstock	Fraction of New Production	MMgal/yr Needed
2012	Soy (out-of-state)	0.63	10.2
2012	Soy	0.13	2.[illegible]
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 6000 MMgal/yr in 2012 and 9500 MMgal/yr 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 US DOE.[28] The value of incentives needed is assumed to be equivalent to the difference in the

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

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.[29] This program offers production incentives of $0.30/gallon to producers up to 15 million gallons of production/yr. The incentive grants last for five years.

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/yr. The production incentive runs out after five years of production.

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

TBD

Additional Benefits and Costs

TBD

Feasibility Issues

TBD

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

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

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 per year above BAU by 2020.

Timing: Add additional ethanol production capacity of 50 million gallons/yr 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

TBD

Related Policies/Programs in Place

TBD

Types of GHG Reductions

CO_2: Lifecycle emissions are reduced to the extent that ethanol is produced with lower embedded fossil-based 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.[30]

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

Assumed Ethanol Production Schedule (MMgal/yr)	
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 ANL Greet Model.[31] The production cost differential for cellulosic versus starch-based ethanol is derived from analysis completed by the Energy Information Administration (EIA).[32]

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[30] *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.

[31] Ibid.

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

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 Option 5). Emission factors for reformulated gasoline, starch-based ethanol, and cellulosic ethanol were taken from a General Motors/Argonne National Lab study.[33] 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:

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 U.S.), CCS assumes that reductions similar to cellulosic ethanol can be achieved.

Based on the emission factors shown above, 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 lifecycle emission factor for gasoline[34] 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).[35] 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

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

[34] 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.

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

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

Year	New Capacity (MMgal)	Incentives Cost (MM 2006$)	GHG Benefit (MMtCO$_2$e)
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 $3.50/MtCO$_2$e and the net present value of the 2007-2020 costs are $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

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[36] 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.

with renewable fuels can achieve the production levels in the near term (2014 production of 310 MMgal/yr) 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

TBD

Additional Benefits and Costs

TBD

Feasibility Issues

TBD

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

AFW-6. Preserve Lands with Carbon Storage Value

Policy Option Description

Reduce the rate at which existing crop/pasture and forested lands 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. 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

The rate of land conversion (from undeveloped to developed) in Colorado is estimated to be at least 100,000 acres per year. These lands include a mix of former cropland, untilled grassland, forests, and western slope shrublands. Land conservation strategies alone (absent significant growth management policy) are unlikely to alter the general rate of land conversion, but can play a role in determining which lands are protected from conversion. Further, land conservation is a generally expensive means of preventing carbon emissions, unless targeted toward highest return strategies. Colorado has an advanced program of land protection with a system of transferable tax credits for land-owners, dedicated public funding, and numerous local and statewide private land trusts. At present, the carbon storage value of lands protected is an uncompensated additional benefit that comes with the open space and wildlife habitat protection values of protecting lands. Additional incentives targeted toward the carbon storage value of land, over and above existing compensation for retiring development rights, would in theory drive more land protection toward high carbon value lands, and compensate landowners for the additional societal benefit of avoided carbon emissions. This policy would create a program to provide additional tax incentives for landowners donating development rights as part of an easement transaction for the carbon storage value of their land. In all likelihood this policy would focus on protecting forest lands from conversion, but some more mesic untilled grasslands might also qualify.

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.

Goals:

- Reduce the rate of conversion of high carbon value lands by 25% by 2020.

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

Parties Involved: TBD

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[37]:

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

Establish a fund to provide additional incentives (likely 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 (would need a simple method for evaluating carbon storage value based on existing land cover and condition), 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

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[37] 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/yr on average from 2000 to 2030.

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_2-equivalent cost-benefit (presuming some lands have higher carbon values associated with maintenance of grass cover). If there is not significant difference in carbon value, contracts would be evaluated solely on basis of cost and length of contract.

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 (open space, wildlife habitat, etc.) and growth management strategies (maintaining buffers between communities, protecting untilled landscapes on urban fringe, consolidating public lands holdings, etc.) 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.

Related Policies/Programs in Place

TBD

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 2010, 2020 ($MMtCO_2e$):

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

Net Cost per $MtCO_2e$:

- Grassland: $32.15
- Forests: $17.29

- Total: $26

Data Sources: Natural Resources Conservation Service data on Conservation Reserve Program 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, USFS, and the scientific literature, costs for conservation easements on ag/range/forest land in CO.

Quantification Methods:

NOTE TO PWG: The remainder of this quantification methods section will be presented in a brief, skeleton form. There will be limited reference and tables, but hopefully will provide a sense of the methods used. A complete version of the POD will be posted to the AFW PWG web page prior to COB Wednesday, Sept. 5. ***Note that the methodology for this method and option design have changed since the last version of this report.***

The analysis for both forests and grasslands (CRP) is displayed below. CCS used the baseline conversion estimates of 14,396 acres per year for grasslands and 5,368 acres per year for forests. 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 forest lands is incorporated in the carbon density of biomass. The carbon value of grasslands that is lost due to conversion is 0.023 MMtC/1000 acres. The cost of easements for both forests and grasslands is assumed to be $1,960 per acre.

Grasslands

Year	Grassland Acres Saved	MMtCO2e Saved	Costs	CE	Discounted Costs	Levelized Cost
2007	0	0.000	$ -		$0	
2008	260	0.011	$ 510,384	$ 46.82	$510,384	
2009	521	0.022	$ 1,020,768	$ 46.82	$972,160	
2010	781	0.033	$ 1,531,152	$ 46.82	$1,388,800	
2011	1,042	0.044	$ 2,041,536	$ 46.82	$1,763,556	
2012	1,302	0.055	$ 2,551,920	$ 46.82	$2,099,471	
2013	1,546	0.065	$ 3,030,405	$ 46.82	$2,374,402	
2014	1,790	0.075	$ 3,508,890	$ 46.82	$2,618,388	
2015	2,034	0.085	$ 3,987,375	$ 46.82	$2,833,753	
2016	2,279	0.095	$ 4,465,860	$ 46.82	$3,022,670	
2017	2,523	0.106	$ 4,944,345	$ 46.82	$3,187,169	
2018	2,767	0.116	$ 5,422,830	$ 46.82	$3,329,147	
2019	3,011	0.126	$ 5,901,315	$ 46.82	$3,450,377	
2020	3,255	0.136	$ 6,379,800	$ 46.82	$3,552,511	32.15
	23,111	**1.0**			**$31,102,787**	

Forests

	Acres Protected	Avoided emissions	Annual Sequestration	Total C Savings (MMTCO2e)	Cost	Cost Effectiveness CE ($/ton)	Discounted costs	Levelized CE
2008	107	0.01	0.00	0.01	$210,426	$26.35	$210,426	

2009	215	0.02	0.00	0.02	$420,851	$26.20	$400,811	
2010	322	0.02	0.00	0.02	$631,277	$26.05	$572,587	
2011	429	0.03	0.00	0.03	$841,702	$25.90	$727,094	
2012	537	0.04	0.00	0.04	$1,052,128	$25.76	$865,588	
2013	637	0.05	0.00	0.05	$1,249,402	$25.60	$978,939	
2014	738	0.05	0.00	0.06	$1,446,676	$25.46	$1,079,532	
2015	839	0.06	0.00	0.06	$1,643,950	$25.31	$1,168,325	
2016	939	0.07	0.00	0.07	$1,841,224	$25.17	$1,246,213	
2017	1,040	0.08	0.00	0.08	$2,038,498	$25.03	$1,314,034	
2018	1,141	0.08	0.01	0.09	$2,235,772	$24.89	$1,372,570	
2019	1,241	0.09	0.01	0.10	$2,433,046	$24.75	$1,422,552	
2020	1,342	0.10	0.01	0.11	$2,630,320	$24.62	$1,464,661	
				0.74			$12,823,330	$17.29

Background Data on Land Use Conversion Rates:

- Acres converted to development annually: ~33,703 acres per year (Dr. David Theobald of CSU projects that 1,011,090 acres will be converted to developed uses from 2000-2030)
- Approximately 22,286 acres of forest converted to other uses annually, based on historical forest losses calculated from NRI data (1982-2003) for CO. NRI does not include Federal land. See table below.
- Approx. 4,400 acres of forest converted to developed uses per year (1982-1997 NRI), see Other section above
- Approximately 137,081 acres/yr of cultivated cropland enrolled in the CRP program

Land Use	Area 1982 (acres)	Area 2003 (acres)	Annual Change (acres/yr)	Annual Change (% of land use/yr)	Annual Change (% of total/yr)
Cropland	10,603,500	8,348,000	-107,405	-1.01%	-0.26%
CRP land	0	2,193,300	137,081	--	0.33%
Pastureland	1,164,700	1,001,800	-7,757	-0.67%	-0.02%
Rangeland	25,053,600	24,790,600	-12,524	-0.05%	-0.03%
Forest land	3,757,000	3,289,000	-22,286	-0.59%	-0.05%
Other rural land	876,000	1,006,000	6,190	0.71%	0.01%

Total	41,454,800	40,628,700	-39,338		-0.09%

Key Assumptions: TBD

Key Uncertainties

TBD

Additional Benefits and Costs

TBD

Feasibility Issues

TBD

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

AFW-7&8. 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 for 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: TBD

Other: Current levels of biomass energy production are low in CO. 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 electricity and thermal 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. E.g.,

- 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

TBD

Types(s) of GHG Reductions

Displaces emissions from fossil fuel combustion

Estimated GHG Savings and Costs per MtCO$_2$e

GHG reduction potential in 2012, 2020 (MMtCO$_2$e): 0.08, 0.20
Cumulative GHG reduction potential, 2008-2020 (MMtCO2e): 1.4

Net Cost per MtCO$_2$e: $24

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, USDA FS, 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 over

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 US (USFS GTR NE-343) (Table 1). 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 CO. 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 1. Carbon coefficients for forest types targeted for treatment

	Biomass Carbon Stocks in 65-yr old Stands (tons C/ac)
Ponderosa Pine (PP)	31.7
Douglad Fir (DF)	56.3

Table 2 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 2. Summary of forest treatments and the amount of carbon removed annually from 2008-2020.

	Acres Needing Fire Treatment	PP Acres treated with thinning per year	DF Acres treated with thinning per year	Carbon removed from thinning PP (tons C)	Carbon removed from thinning DF (tons C)	To re th C
2008	1,100,000	19,797	7,703	282,401	195,161	
2009	1,133,000	20,391	7,934	290,873	201,016	
2010	1,166,990	21,002	8,172	299,599	207,047	
2011	1,202,000	21,632	8,418	308,587	213,258	
2012	1,238,060	22,281	8,670	317,845	219,656	

2013	1,275,201	22,950	8,930	327,380	226,246
2014	1,313,458	23,638	9,198	337,201	233,033
2015	1,352,861	24,348	9,474	347,317	240,024
2016	1,393,447	25,078	9,758	357,737	247,225
2017	1,435,251	25,830	10,051	368,469	254,641
2018	1,478,308	26,605	10,352	379,523	262,281
2019	1,522,657	27,403	10,663	390,909	270,149
2020	1,568,337	28,225	10,983	402,636	278,253

The impacts of this policy option are based on increasing the use of biomass for institutional heating starting in 2008. Table 3 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 CO2e/MMbtu, natural gas yields 0.053 tons CO2e/MMBtu.

Table 3. Policy impacts of increasing the amount of biomass used for energy production (assuming a baseline of zero utilization)

	Total Carbon removed from thinning (tons C)	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 energ offsets (MMtCO2
2008	477,562	0.02	19,102	313,281	
2009	491,889	0.04	39,351	645,359	
2010	506,646	0.06	60,797	997,079	
2011	521,845	0.08	83,495	1,369,322	
2012	537,501	0.10	107,500	1,763,002	
2013	553,626	0.11	124,566	2,042,878	
2014	570,234	0.13	142,559	2,337,961	
2015	587,341	0.14	161,519	2,648,910	
2016	604,962	0.15	181,488	2,976,411	
2017	623,110	0.16	202,511	3,321,179	
2018	641,804	0.18	224,631	3,683,954	
2019	661,058	0.19	247,897	4,065,506	
2020	680,890	0.20	272,356	4,466,636	
l	7,458,467				

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

Costs of implementing this options were assessed based on reported costs of transporting biomass to facilities within a 25-mile radius of treated forest area ($108/ton biomass) (Western Region Biomass Energy Program). A 25-mile radius was chosen because the targeted treatment areas are in the WUI, which by definition is close to developed infrastructure. Cost savings were also assessed based on the relative costs of heating a building with wood versus natural gas; $2/MMBtu for wood and $7/MMBtu for natural gas (Roundtable Report). Costs and costs savings were calculated each year and combined for a net cost estimate. Annual discounted costs were calculated using a 5% interest rate. A net present value (NPV) of $33 million was calculated for this option as the sum of annual discounted costs over the timeframe of analysis. A cost effectiveness of $24/ton CO2e was calculated by dividing NPV by the cumulative GHG savings of the option from 2008-2020. Cost estimates are summarized in Table 4.

Table 4. Summary of costs and cost savings

	Costs of transporting biomass	Cost Savings from Biomass Utilization	Net Costs	Discounted Costs
2008	$2,063,069	$1,566,404	$496,665	$496,665
2009	$4,249,922	$3,226,793	$1,023,129	$974,409
2010	$6,566,130	$4,985,395	$1,580,735	$1,433,773
2011	$9,017,485	$6,846,609	$2,170,876	$1,875,284
2012	$11,610,012	$8,815,009	$2,795,003	$2,299,456
2013	$13,453,101	$10,214,392	$3,238,710	$2,537,614
2014	$15,396,327	$11,689,804	$3,706,523	$2,765,865
2015	$17,444,038	$13,244,548	$4,199,491	$2,984,500
2016	$19,600,756	$14,882,055	$4,718,700	$3,193,802
2017	$21,871,177	$16,605,893	$5,265,283	$3,394,049
2018	$24,260,182	$18,419,768	$5,840,414	$3,585,508
2019	$26,772,844	$20,327,529	$6,445,314	$3,768,442
2020	$29,414,431	$22,333,179	$7,081,252	$3,943,106
Total				$33,252,471

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.

Additional Benefits and Costs

Protection of residential and or municipal lands from fire risk.
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.

Feasibility Issues

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

Status of Group Approval

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

AFW-9. 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 re-use. 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: TBD

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 7-10 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

TBD

Estimated GHG Savings and Costs per $MtCO_2e$

GHG Reductions ($MMtCO_2e$) in 2012, 2020: 1.22, 7.11

Net Cost ($/Mt): $8.38

Data Sources: State-level data on current (BAU) recycling levels from the Colorado Department of Public Health and the Environment;[38] CO State or TWG estimates of waste reduction opportunities by WARM waste category (possibly from existing municipal programs like Fort Collins); current landfilling rates from CO I&F; data from CO municipalities or the literature on the capital and annual costs for source reduction, recycling, and composting programs.

Quantification Methods:

WARM provides estimates of the lifecycle GHG emissions avoided via source reduction, recycling, and composting. The 2005 CO waste generation rate was 3,771,823 tons.

The WARM model is run two times for recycling: one for a 2012 policy scenario, and one for a 2020 policy scenario. In each case, the incremental recycling (above BAU) is input into the model as "mixed recycling."

The availability of recycling data in Colorado was 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. The estimate for BAU source reduction was developed through data provided by Lisa Skumatz of Skumatz Economic Research Associates, Inc. All source reduction is assumed to occur through pay-as-you-throw (PAYT) programs. In order to achieve the 75% by 2020 waste diversion, a multiplier was used for each year that scaled up the targeted diversion due to recycling, composting, and source reduction annually.

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 1.22 $MMtCO_2e$/year and 7.11 $MMtCO_2e$/year in 2020.

The cost of recycling programs is based on the difference of $150 annual cost per household for collection, a savings of $22.52 per ton in tipping fees, and $12 million per year in annualized capital costs.

The cost of organic composting systems is based upon the annualized capital cost, which is $8 million per 100,000 tons of organics composted, each incremental investment annualized over 15 years at 5% interest. The cost savings is $22.52 per ton, the assumed tipping fee in CO.

The cost of increased source reduction programs is based upon the annual cost of the program, which is $9.94 per household (a 1997 program in Iowa added a service charge of $8 per household. Again, the savings is $22.52 per ton diverted.

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[38] Colorado Department of Public Health and Environment, "Annual Reporting Data Received—What We've Learned," 2005, accessed July 11, 2007, at www.cdphe.state.co.us/hm/recycling2006rpt.pdf.

Key Assumptions: TBD

Key Uncertainties

TBD

Additional Benefits and Costs

TBD

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 $10–18 per ton, compared with $60–90 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

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD

AFW-10. 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: TBD

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). Per the Colorado GHG Inventory & Forecast, the following landfills currently employ LFG controls:

Site Name	County	Control
County Line LF	Arapahoe	Flare
Fountain LF	El Paso	Flare
Foothills LF	Jefferson	Flare
Denver Regional North LF	Weld	Flare
Denver Regional South LF	Weld	Flare
Tower LF	Adams	Flare
Denver – Arapahoe	Arapahoe	LFGTE
Boulder LF	Boulder	Flare
Larimer County LF	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 EPA's Federal New Source Performance Standards/Emissions Guidelines NSPS/EG) are required to install methane collection systems.

Related Policies/Programs in Place

- Federal New Source Performance Standards/Emission Guidelines 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 7-10 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 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 CO GHG I&F for both flared and uncontrolled landfill categories. An lifecycle 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 EPA's 2001 national emission estimates for that sector (3.5 lb CO$_2$e/MMBtu);

Costs. EPA model LFGcost-Web, which estimates the costs to implement different types of landfill gas controls (including LFG to energy); 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 EPA's LMOP (Landfill Methane Outreach Program) website and are displayed in the following table:

Blended Cost Effectiveness	**Fraction of CO2e reduced**	**Fractional CE ($/MtCO2e)**	
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 O&M for LFG facilities, and annualized capital costs for these facitlities.

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

TBD

Additional Benefits and Costs

TBD

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 $10-18 per ton, compared with $60-90 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

TBD

Level of Group Support

TBD

Barriers to Consensus

TBD