Appendix M

Control Option 41-Point Source Ammonia Controls

data_year	emission_process_description	county_fips	facility_name	pollutant_name	unit_emis_	air_prograr
2001	SIZE REDUCTN/CONCENTRAT	065	ASARCO INC LEADVILLE UNIT	AMMONIA	0	SM
2003	MK 82 BOMB TEST	101	TRANSPORTATION TECHNOLOGY CEN	AMMONIA	0	
2003	FUGITIVE AMMONIA EMISSIOI	123	WESTERN SUGAR CO	AMMONIA	0	A
2004	(14) WARTSILA. 20V34SG ENC	059	PLAINS END, LLC	AMMONIA	0	A
2004	AMMONIACAL ETCHING OF PI	059	CORETEC DENVER, INC.	AMMONIA	0	
2004	VARIOUS CHEMICAL USAGE	101	AIR PRODUCTS AND CHEMICALS, INC.	AMMONIA	0	SM
2004	CYANIDE LEACHING OF ORE	119	CRIPPLE CREEK & VICTOR GOLD MINI	AMMONIA	0	SM
2005	ABEC FERMENTOR	013	AMGEN BOULDER INC	AMMONIA	0	
2005	SOLVENT EVAP PLT 1 CENTE	013	ROCHE COLORADO CORP	AMMONIA	0	A
2005	SOLVENT EVAP PLT 1 SOUTH	013	ROCHE COLORADO CORP	AMMONIA	0	A
2005	HEAT TREAT FURNACE	031	TOOLS FOR BENDING INC	AMMONIA	0	
2005	SPACE SUPPORT BLDG GRO	059	LOCKHEED MARTIN SPACE SYSTEMS	AMMONIA	0	SM
2005	CEMENT CLINKER PRODUCEI	101	GCC RIO GRANDE - PUEBLO CEMENT	AMMONIA	0	A
2005	BLDG C40,C41,C42,C43,C46	123	EASTMAN KODAK CO	AMMONIA	0	A
2005	C29 PRINT ROOM EXHAUST	123	EASTMAN KODAK CO	AMMONIA	0	A
2005	CHEMICAL USEAGE	123	EASTMAN KODAK CO	AMMONIA	0	A
2005	WAUKESHA F-2895GU 500HP	123	DUKE ENERGY FIELD SERVICES - JOH	AMMONIA	0	
2005	WAUKESHA L7042 794HP	123	ENCANA OIL & GAS (USA) INC. - FRED	AMMONIA	0	SM
2006	ACID STATIONS	041	INTEL CORP (WAS ROCKWELL & UNITI	AMMONIA	0	SM
2006	AMMONIA PROCESSES	041	INTEL CORP (WAS ROCKWELL & UNITI	AMMONIA	0	SM
2006	TOTAL CHEMICAL USAGE	041	INTEL CORP (WAS ROCKWELL & UNITI	AMMONIA	0	SM
2006	#3 KILN - COAL & COKE	069	HOLCIM (US) INC - FORT COLLINS TERI	AMMONIA	0	
2006	2- CARBONIZATION FURNACE	101	GOODRICH CORPORATION	AMMONIA	0	SM
2006	ANHYDROUS AMMONIA STOF	125	M & M COOPERATIVE, INC	AMMONIA	0	
2006	ANHYDROUS AMMONIA STOF	125	M & M COOPERATIVE, INC VERNON PI	AMMONIA	0	
2004	WE BEIGE DTM	101	TRANE CO	AMMONIA	0.001775	SM
2004	QUALITY TESTING PRODUCTS	101	AIR PRODUCTS AND CHEMICALS, INC.	AMMONIA	0.004	SM
2003	AMMONIA REFRIGERATION	069	ANHEUSER BUSCH INC	AMMONIA	0.025	A
2004	<64WT% NH4F PRODUCED	101	AIR PRODUCTS AND CHEMICALS, INC.	AMMONIA	0.0345	SM
2004	NH4OH PRODUCED - 4 TANKS	101	AIR PRODUCTS AND CHEMICALS, INC.	AMMONIA	0.0415	SM
2000	AMMONIA REPACKAGING	031	KIK CORPORATION	AMMONIA	0.106288	
2004	FINAL PRODUCT FILLING	101	AIR PRODUCTS AND CHEMICALS, INC.	AMMONIA	0.128	SM
2006	TOTAL CHEMICAL USAGE	041	INTEL CORP (WAS ROCKWELL & UNITI	AMMONIA	0.2	SM
1996	LIQUID FERTILIZER	777	CENEX LAND OLAKES AGRONOMY CE	AMMONIA	0.3	
1996	FUGITIVES	031	SAFEWAY MILK PLT	AMMONIA	0.35	
2001	SEPTAGE	045	GARFIELD CNTY LANDFILL	AMMONIA	0.516444	
2005	END COMPOUND	059	BALL METAL BEVERAGE CONTAINER	AMMONIA	0.598	A
1998	STORAGE & REPACK NH3	123	DPC INDUSTRIES INC	AMMONIA	0.60975	
2000	CHEMICAL USAGE	069	AVAGO TECHNOLOGIES US, INC.	AMMONIA	0.8	SM
2000	POUNDS OF AMMONIA	005	CAIN T SQUARE	AMMONIA	0.9	
2000	AMMONIA REFRIG. SYSTEM	123	MEADOW GOLD DAIRY	AMMONIA	0.9375	
2005	BOTTLE LABEL GLUE APPLIC	059	COORS BREWING CO VALLEY COMPL	AMMONIA	0.961583	A
1999	AMMONIA EMISSIONS FROM	059	ADVANCED SURFACE TECHNOLOGIES	AMMONIA	1	
2005	SEWAGE TREATMENT PLANT	013	BUTTERBALL, LLC	AMMONIA	1	
2003	ELEC FURNACE-TUNGSTEN I	059	HONEYWELL, INC. (WAS ALLIED SIGN/	AMMONIA	1.031	
2002	BOTTLE FILLING	069	NEW BELGIUM BREWING COMPANY, I	AMMONIA	1.125	
2004	AL101B	069	VISION GRAPHICS	AMMONIA	1.129419	
2004	AL101B/W	069	VISION GRAPHICS	AMMONIA	1.129419	
2004	AL3048N	069	VISION GRAPHICS	AMMONIA	1.129419	
2004	ALC165N	069	VISION GRAPHICS	AMMONIA	1.129419	
2004	HOUSEHOLD AMMONIA	069	VISION GRAPHICS	AMMONIA	1.129419	
2004	POTW	069	CITY OF LOVELAND	AMMONIA	1.17	
1998	BLUEPRINTING -ANHYDROUS	005	ABADAN REPROGRAPHICS INC	AMMONIA	1.23	
2005	NATURAL GAS COMBUSTION	101	DAVIS WIRE PUEBLO CORP.	AMMONIA	1.25	
2001	END SEALANT	059	COORS BREWING CO ENDLINE PLT	AMMONIA	1.301435	
2002	NH4OH SOLUTION USED	059	CERAMED CORP	AMMONIA	1.45	
2005	REFRIGERATION-NH3 & CFC'S	059	COORS BREWING CO VALLEY COMPL	AMMONIA	1.6695	A
2004	AMMONIACAL ETCHANT	013	SAE CIRCUITS COLORADO INC	AMMONIA	1.71	
2000	28% NH3 SOLUTION	031	RJR CIRCUITS INC	AMMONIA	1.792	
2005	COATINGS	001	PACKAGING CORPORATION OF AMER	AMMONIA	2.00294	
2005	RESINS	001	PACKAGING CORPORATION OF AMER	AMMONIA	2.00294	
2005	WATER BASE INKS	001	PACKAGING CORPORATION OF AMER	AMMONIA	2.00294	
2000	FERTILIZER PRODUCTION	777	MONTE VISTA COOPERATIVE	AMMONIA	2.16	
2004	(20) NATURAL GAS ENGINES	059	PLAINS END, LLC	AMMONIA	2.2562	A
2004	"LAZER" SOLUTION	031	WRIGHT & MCGILL CO	AMMONIA	2.2865	
1998	FUGITIVE EQUIP LEAKS	031	CITY ICE COMPANY	AMMONIA	2.5	
2002	GEN. FOOD & AGRICULTURE	005	MEADOWGOLD DAIRIES INC	AMMONIA	2.5	
2002	AMMONIA	101	PCL PACKAGING	AMMONIA	2.5	
2006	POLYACRYLONITRILE USED	101	GOODRICH CORPORATION	AMMONIA	3.025	SM
1997	WAFERS PRODUCED-FABS2,	041	ATMEL CORP	AMMONIA	3.089	
2006	TOTAL CHEMICAL USAGE	041	INTEL CORP (WAS ROCKWELL & UNITI	AMMONIA	3.5	SM
2003	PURIFIED AMMONIUM PARAT	059	HONEYWELL, INC. (WAS ALLIED SIGN/	AMMONIA	3.51	
2003	AMMONIUM PARATUNGSTATE	059	HONEYWELL, INC. (WAS ALLIED SIGN/	AMMONIA	3.639	
2006	AMMONIA EMISSION	031	JACKSON ICE CREAM CO INC	AMMONIA	3.75	
2005	URANIUM OXIDE FUME CALC	043	COTTER CORP CANON CITY MILL	AMMONIA	3.8325	A
2004	CYANIDE LEACHING	119	CRIPPLE CREEK & VICTOR GOLD MINI	AMMONIA	4.9815	SM
1996	FERTILIZER PIPE REACTOR	777	POOLE CHEMICAL CO	AMMONIA	5.04	
1996	APP FERTILIZER PRODUCTIOI	777	REACTOR INC	AMMONIA	5.55	
2002	APP FERTILIZER PRODUCTIOI	777	BLICKS PHOSPHATE CONVERSIONS, I	AMMONIA	6.25	
2005	AMMONIA	041	SINTON DAIRY FOODS CO	AMMONIA	6.25	
1999	CHEMICAL USAGE	013	CIRCUIT IMAGES, INC	AMMONIA	6.4795	
2004	DRUMS RECYCLED	101	AIR PRODUCTS AND CHEMICALS, INC.	AMMONIA	6.6525	SM
2003	TUNGSTEN POWDER PRODUI	059	HONEYWELL, INC. (WAS ALLIED SIGN/	AMMONIA	7.302	
1996	APP FERTILIZER PRODUCTIOI	777	MEARS FERTILIZER, INC. - UNIT 1	AMMONIA	7.4	
1996	LIQUID AMMONIUM POLYPHO	777	MEARS FERTILIZER, INC. - UNIT 3	AMMONIA	7.4	
2005	TURBINE T004	123	PUBLIC SERVICE CO FORT SAINT VRA	AMMONIA	12.248	A
2001	WASTE H20 TREATMENT PLA	041	SECURITY SANITAION DIST	AMMONIA	20.945	
2005	5-STAGE PRECALCINER KILN	043	HOLCIM (US) INC. PORTLAND PLANT	AMMONIA	30.2948	A
2002	SUGAR BEET PROTEIN BREA	087	WESTERN SUGAR CO	AMMONIA	32.105	A
2005	ZIRCONIUM PRODUCT BUILDII	043	COTTER CORP CANON CITY MILL	AMMONIA	37.23	A
2005	POND WATER TREATMENT	043	COTTER CORP CANON CITY MILL	AMMONIA	57.4	A
2004	NAT GAS COMBUSTION	123	ROCKY MOUNTAIN ENERGY CENTER,	AMMONIA	124.8	A
2004	NATURAL GAS COMBUSTION	123	ROCKY MOUNTAIN ENERGY CENTER,	AMMONIA	124.8	A
2004	WASTEWATER PROCESSING	001	SO ADAMS CNTY WATER & SANITATIC	AMMONIA	241.0004	
				Total:	816.6	tons
				Number of Ammonia Sources:	94	

Appendix N

Control Option 42

Control Options Analysis for Rocky Mountain National Park Initiative

Proposed Implementation of expansion of 1-hour VOC RACT requirements to the entire 8-hour EAC area

Purpose

Purpose: This analysis presents the pros and cons of expanding the applicability of Regulation No. 7's Reasonably Available Control Technology (RACT) requirements to the 8-hour ozone control area from the current Denver 1-hour ozone attainment/maintenance area would require that the rule requirements apply to existing and new facilities in order to achieve reductions in current and future emissions.

Cost/Benefit

Costs: The RACT requirements in the 1-hour ozone attainment/maintenance area are applied to VOC sources with potential emissions of over 100 tons per year. Sources can take synthetic minor requirements (production, hourly limitation, and controls) to avoid RACT and be under the 100 tpy threshold. The 1-hour ozone area does not include the counties of Weld, Larimer, and eastern sections of Adams and Arapahoe that are included in the 8-hour EAC area.

Costs: Expanding the RACT area would capture 51 miscellaneous VOC sources over 25 TPY (actuals) and 14 miscellaneous VOC sources over 100 TPY. In addition, 832 tank batteries over 25 tpy would be in this additional area. Of these tanks, 357 are uncontrolled. If these tanks were subject to RACT (assuming RACT for a tank battery is a flare and control efficiency is 95%), about 12, 850 tpy could be reduced for a cost range of $2.5 - $5.2 million dollars. Please see VOC details (miscellanous and tank batteries) sheets for more information.

Costs: RACT for the other miscellaenous VOC sources include the use of low or no-VOC solvent coatings, the use of high-transfer efficiency equipment, and the implementation of good housekeeping practices. RACT for these sources will have to be made on a case-by-case basis. However, typically RACT can reduce VOC emissions on average 40 - 50%. The total VOC emissions from miscellaneous sources subject to the expansion is 19,800 tpy uncontrolled and 3,950 tpy controlled. Therefore, if a 40% RACT (on average) were applied to these sources, a reduction of 1,580 tpy could be achieved. A thorough cost analysis could not be conducted due to case-by-case situtations. On average, VOC reductions per ton for RACT is about $2000. Therefore, the cost can be estimated at approximately $3.2 million dollars.

Disadvantages: RACT beyond tank batteries will have to be examined on a case-by-case basis and moderate controls and inspections will have to be required to ensure sufficient VOC reductions. However, since there are only 51 miscellaneous VOC sources and only 14 sources over 100 tpy, this should take moderate effort undertaken by both industry and the APCD and is not unreasonable.

Implementation

Expanding RACT requirements could achieve overall VOC emission reductions up to 14,500 tpy for a cost range of $6 - $8.5 million dollars. RACT

Viability

The realistic implementation date for the VOC RACT expansion will take several years due to regulation changes and case-by-case examination of larger miscellaneous VOC sources. However, once regulations are set in place, the expansion should be relatively straightforward and implementable.

Appendix O

Control Option 43

Control Options Analysis for Rocky Mountain National Park Initiative

Proposed Implementation of Stage II Vapor Recovery Statewide and in the North Front Range

Purpose

Purpose: This analysis presents the pros and cons of implementing Stage II Vapor Recovery on gasoline dispensing facilities (GDFs) statewide. Gasoline vapor recovery systems are categorized under two stages. Stage I gasoline vapor recovery systems capture the vapors expelled from the underground storage tanks at gas stations when being refilled by tank trucks. Stage II systems capture gasoline vapors that would otherwise be vented during individual vehicle refueling at gas stations. There are two basic types stage II vapor recovery systems on the market. The "balance" system utilizes a double hose with rubber boot on the dispensing nozzle that provides seal between the nozzle and the vehicle gasoline filler opening. As gasoline in transfered via the inner hose into the vehicle tank the vapors are forced to the rubber boot which forces the vapors to travel in the outer hose back to gasoline dispensing facility storage tank. The "vacuum assist or bootless nozzle" system also utilizes a double hose but the outer edge of the dispensing nozzle tip has small holes that draw the vapors under a vacuum back to the gasoline dispensing facility storage tank.

Cost/Benefit

Costs: Both stage II vapor recovery systems require changes to existing GDF underground plumbing systems unless the facility was pre-plumbed in anticipation of future stage II requirements. Based on information from the New Hampshire Department of Environmental Services, the cost of stage II installation can range from $18k to $30K with yearly maintanance costs from $1k-$4k depending on the size and site characteristics. In Montana, two GDFs were retrofit with stage II for $123k. In Las Vegas, the typical cost to retrofit a GDF ranged from $40k-$60k. On average, the stage II retrofit cost is probably around $50k per GDF and the cost of building stage II into a new GDF is probably less than $30k.

Benefits: When properly installed and maintained, a stage II vapor recovery system can reduce VOC emissions by about 95% but AP-42 estimates efficiencies more in the range of 88% - 92%. However, the long-term viability of stage II vapor recovery systems are in doubt because the EPA adopted regulations in 1994 that require automakers to equip new vehicles with "onboard refueling vapor recovery" systems (ORVR). ORVR systems are required to meet a refueling emission standard of 0.20 grams per gallon of dispensed fuel, which will yield a 95 % emission reduction over uncontrolled levels. This rule essentially transfers the control of gasoline refueling vapors to to vehicle rather than at the GDF. The full implementation of ORVR systems was realized in 2006 model year. Presently, the ORVR fleet penetration in Colorado is about 45%.

Implementation

Based on a query of the permit system, there are approximately 2988 GDFs in Colorado and 2166 in North Front Range

Number of GDF's Statewide (2006):		**2988**	
Average GDF Retrofit Cost :	$	50,000	
Annual Maintenance Cost on Stage II Systems:	$	2,000	
Total Cost to Retrofit Existing GDF's with Stage II (Statewide):	$	149,400,000	[$/year/GDF] (one time cost)
Annual Maintenance on Stage II Systems (Statewide):	$	5,976,000	[$/year/GDF]
Number of GDF's in North Front Range (2006):		**2166**	
Average GDF Retrofit Cost :	$	50,000	
Annual Maintenance Cost on Stage II Systems:	$	2,000	
Total Cost to Retrofit Existing GDF's with Stage II (NFR):	$	108,300,000	[$/year/GDF] (one time cost)
Annual Maintenance on Stage II Systems (NFR):	$	4,332,000	[$/year/GDF]

Viability

Statewide Gasoline Throughput (2002):		5,700,000	[gallons/day]
If we assume Stage II Vapor Recovery is installed on all GDFs in Colorado			
[1]Vehicle Refueling Displacement Emission Factor (uncontrolled):		0.0110	[pounds/gallon]
[1]Vehicle Refueling Displacement Emission Factor (controlled-Stage II):		0.0011	[pounds/gallon]
Estimated Statewide Rule Effectiveness Factor:		80%	
Estimated Statewide VOC Emission Reduction:		45,144	[pounds/day]
Estimated Statewide VOC Emission Reduction:		**22.6**	**[tons/day]**
Estimated Statewide VOC Emission Reduction:		8,239	[tons/year]
Annualized Costs (assuming 15 year life):	$	44,635,656	[annual]
Cost per ton of VOC reduced (assume 15 year life):	**$**	**5,418**	**[$/VOC ton]**
If we assume Stage II Vapor Recovery is installed on all GDFs in North Front Range			
Estimated North Front Range Market Share of Statewide Gasoline Throughput (2002):		72%	
Estimated North Front Range VOC Emission Reduction:		32,725	[pounds/day]
Estimated North Front Range VOC Emission Reduction:		**16.4**	**[tons/day]**
Estimated Statewide VOC Emission Reduction:		5,972	[tons/year]
Annualized Costs (assuming 15 year life):	$	32,356,370	[annual]
Cost per ton of VOC reduced (assume 15 year life):	**$**	**5,418**	**[$/VOC ton]**

Additional Details

[1]Source AP-42, Table 5.2-7, 5th Edition

The regulatory costs to administer and inspect a Stage II program are not included

Appendix P

Control Option 44

EAC Area Flash Controls

Control Options Analysis for Rocky Mountain National Park Initiative

Proposed Implementation of Additional Condensate Tank Flash Controls in EAC Area

Purpose

Purpose: This analysis presents the pros and cons of implementing further controls on flash emissions from condensate tanks within the ozone Early Action Compact (EAC) area (North Front Range Area). Production or "flash" emissions result when liquids under pressure are exposed to atmospheric pressure and the gases within the liquid volatizes (e.g. opening a soda bottle). Flash emissions primarily occur at condensate storage tanks where light oils are separated from production water. Further control of flash emissions in Eastern Colorado are needed to maintain compliance with the ozone standard and could be used to further reduce emissions and make other strategies less necessary. The Division has proposed changes to Regulation 7 that would require emission controls on all EAC condensate tanks that exceed 11 tons per year on a projected uncontrolled basis (Attachement B - Initial Economic Impact Analysis of the Proposed Revisions to the Section XII of the "Emissions of Volatile Organic Compounds" Regulation). Assuming the proposed 11 tpy threshold is adopted under Regulation XII, this analysis considers the possible further lowering of the threshold to 6 tons per year.

Cost/Benefit

Costs: Control of flash emissions from condensate tanks is accomplished through either thermal oxidation with a flare device or capture of the vapors with a vapor recovery unit (VRU). A flare device comes in several sizes depending on the number of condensate tanks manifolded together and the size of each tank. The total cost (capital & installation) for an average flare device (30" diameter, rated at 1MMBTU) is about $10,600.

Benefits: Based on the Division's analysis (Attachement B - Initial Economic Impact Analysis of the Proposed Revisions to the Section XII of the "Emissions of Volatile Organic Compounds" Regulation) establishing a proposed 6 tpy control threshold would result in an additional 30,913 tpy reduction in VOC emissions. Using the 2005 data currently available, establishing a 6 tpy threshold would require controls on an additional 2,314 tanks. Using the cost data discussed above the initial cost to control these tanks will be $24,528,400. Using a 10% rate of return and a 15 year equipment life, the total cost will be $102,686,785 over 15 years or $6,845,786 per year for emission controls on condensate tanks. Dividing this number by the projected emission reductions of 30,913 tpy yields a cost per ton of VOCs reduced of $221 per ton.

Implementation

Implementation: Based on available information it does not appear that there are either any direct costs to the general public or additional implementation costs for the Division as a result of the proposed revisions.

Viability

Viability: Reductions in ozone precursors (VOC) directly reduce the potential to form ozone. Particulates are not impacted by this proposal.

Control Options Analysis for Rocky Mountain National Park Initiative

Proposed Implementation of Additional Condensate Tank Flash Controls Statewide

Purpose

Purpose: This analysis presents the pros and cons of implementing further controls on flash emissions from condensate tanks throughout Colorado outside of the ozone Early Action Compact (EAC) area. Production or "flash" emissions result when liquids under pressure are exposed to atmospheric pressure and the gases within the liquid volatizes (e.g. opening a soda bottle). Flash emissions primarily occur at condensate storage tanks where light oils are separated from production water. The Division has proposed changes to Regulation 7 that would require emission controls on statewide (excluding EAC Area) condensate tanks that exceed 20 tons per year on a projected uncontrolled basis (Attachement B - Initial Economic Impact Analysis of the Proposed Revisions to the Section XVII of the "Emissions of Volatile Organic Compounds" Regulation). Assuming the proposed 20 tpy threshold is adopted under Regulation 7, this analysis considers the possible further lowering of the threshold to 10 tons per year.

Cost/Benefit

Costs: Control of flash emissions from condensate tanks is accomplished through either thermal oxidation with a flare device or capture of the vapors with a vapor recovery unit (VRU). A flare device comes in several sizes depending on the number of condensate tanks manifolded together and the size of each tank. The total cost (capital & installation) for an average flare device (30" diameter, rated at 1MMBTU) is about $10,600. The total cost (capital & installation) for an average vapor recovery unit is about $35,000.

Benefits: Based on the Division's analysis (below) establishing a proposed 10 tpy control threshold would result in an additional 1,457 tpy reduction in VOC emissions. Establishing a 10 tpy threshold would require controls on an additional 105 tanks. Using the cost data discussed above the initial cost to control these tanks will be $1,113,000. Using a 10% rate of return and a 15 year equipment life, the total cost will be $4,649,277 over 15 years or $309,952 per year for emission controls on condensate tanks. Dividing this number by the projected emission reductions of 1,457 tpy yields a cost per ton of VOCs reduced of $213 per ton.

Implementation

Implementation: Based on available information it does not appear that there are either any direct costs to the general public or additional implementation costs for the Division as a result of the proposed revisions.

Viability

Viability: Reductions in ozone precursors (VOC) directly reduce the potential to form ozone. Particulates are not impacted by this proposal.

Appendix Q

Control Option 45

Reformulated Gasoline (VOCs and NOx)

Reformulated gasoline (RFG) is gasoline that is blended such that, on average, it significantly reduces Volatile Organic Compounds (VOC) and air toxics emissions relative to conventional gasoline. These reductions can help limit ozone formation. EPA could be petitioned to require reformulated gasoline for the Front Range urban counties, and fewer VOC and toxic (e.g, benzene) emissions would result. See EPA's RFG web page: http://www.epa.gov/otaq/rfg.htm

The Clean Air Act provides that upon the application of a Governor, EPA shall apply the prohibition against selling conventional gasoline in "any area in the State classified under subpart 2 of Part D of Title I as a Marginal, Moderate, Serious or Severe" ozone non-attainment area. Section 211(k)(6)(A) of the Act, stipulates that the effective program date must be no "later than January 1, 1995 or 1 year after [the Governor's] application is received, whichever is later." Although the Act provides EPA discretion to establish the effective date for this prohibition to apply to such areas, and allows EPA to consider whether there is sufficient domestic capacity to produce RFG in establishing the effective date, EPA does not have discretion to deny a Governor's request.

Benefits:

This control strategy can reduce mobile source VOC emissions. However, without more specific information on the reformulation it is unknown how much, if any, NOx emissions would be reduced.

Feasibility:

If the Denver EAC area violated the 8-hour ozone standard and was designated nonattainment, the area would most likely continue to be a "subpart 1" area, as is currently shown in 40 CFR 81.306, and reformulated gasoline is not required for those areas. As per our Phase 1 8-hour ozone policy (see 69 FR 23951, April 30, 2004), an 8-hour ozone nonattainment area would only be classified as a subpart 2 area if the 1-hour ozone design value was greater than 121 ppb.

If Denver did get a non-attainment designation, the State could opt-in to a reformulated gasoline program only if the area also falls under subpart 2 for ozone.

The State could pursue a voluntary-implementation reformulated gasoline program with the applicable refiners.

Appendix R

Control Option 47

Reduced Gasoline Volatility (VOCs)

Reducing fuel volatility is one means of reducing mobile source VOC emissions. At the current time, Federal Clean Air Act requirements limit Denver area summertime gas to 7.8 psi RVP. EPA could be petitioned to reduce this limit.

<u>Benefits:</u>

Reduced VOC emissions. However, this control strategy does not directly control NOx emissions, so it is unknown what the anticipated impact would be to the RNMP's nitrogen deposition rate. Additional mobile source modeling would need to be conducted to determine possible emission reductions from this control strategy.

<u>Feasibility:</u>

Under section 211(c)(4)(A) of the Act, "no State or political subdivision" can prescribe non-identical motor vehicle fuel regulations. EPA can waive this preemption if it approves the otherwise preempted fuel standard into a SIP subject to the State making a "necessity" showing. See Section 211(c)(4)(C)(i) of the Act.

Under the Energy Policy Act (EPAct) Amendments to the Clean Air Act, Colorado would be allowed to adopt a 7.0 psi low RVP program in their SIP provided they met the required "necessity" showing. The controlling language here is "... a necessity showing." The likely "need" used here would probably be that the Denver EAC area violates the 8-hour ozone standard in 2007 and is designated non-attainment. It could be anticipated that all other potential conventional control strategies would be implemented first. For example; lowering the threshold level of tons per year necessary for sources to apply RACT, increasing the stringency of the I/M program so that more vehicles are found and repaired, lowering the threshold of non-attainment NSR and/or increasing the offset ratio, etc.

If, however, the Denver EAC area attains the 8-hour ozone standard in 2007 and EPA designates the area as attainment in April, 2008, a "need" for these more stringent standards may be hard to demonstrate. EPA's Office of Transportation and Air Quality (OTAQ) and Office of General Counsel (OGC) have advised that States' authority to adopt more stringent RVP programs (or other fuel controls), under section 211(c)(4)C) of the Act, for EAC areas remains unconstrained subject of course to a showing of necessity under section 211(c)(4)(C)(i) of the Act, and now the restrictions placed by the EPAct.

Additional restrictions on EPA's authority to waive preemption have been placed by the EPAct Amendments of August 2005. One pertinent restriction is the Petroleum Administration for Defense District (PADD) restriction under section 211(c)(4)(c)(v)(V) of the Act, which precludes EPA from approving a State's request to adopt a fuel if that fuel is not already approved into a SIP in the applicable PADD. The 7.0 psi RVP program is exempt from this restriction. OTAQ and OGC have been discussing both the "necessity" showing requirement under section 211(c)(4)(C)(i) of the Act, and the new EPAct restrictions in our proposed approval of the 7.0 psi program for the Southeast MI nonattainment area. See 71 FR 46879 (August 15, 2006). States generally adopt low-RVP controls for purposes of addressing the ozone NAAQs. EPA is not aware of a low-RVP program being used as a control for "nitrogen deposition."

Finally, Colorado could pursue a voluntary-implementation low-RVP gasoline program with the applicable refiners (lower than 7.0 psi). This was actually done previously when, by an EPA waiver, the allowable metro-Denver summer time RVP was 9.0 psi and the State was able to gain the cooperation of the refining industry to instead market a summer time RVP of 8.5 psi.

Appendix S

Control Option 48

Repeal Ethanol Waiver (VOCs)

Currently there are no restrictions on blending ethanol in gasoline. If the industry chooses to blend ethanol they are allowed a one-pound RVP waiver. This waiver increases the RVP cap from 7.8 psi to 8.8 psi and increases emissions. Eliminating this waiver could reduce emissions.

<u>Benefits:</u>

Reduced VOC emissions. However, this control strategy does not directly control NOx emissions, so it is unknown what the anticipated impact would be to the RNMP's nitrogen deposition rate. Additional mobile source modeling would need to be conducted to determine possible emission reductions from this control strategy.

<u>Feasibility:</u>

Section 211(h)(5) of the Clean Air Act allows for an exemption from the 1 psi ethanol waiver where the Governor of a State submits a notification for the exemption with documentation showing that the 1 psi waiver will increase emissions that contribute to air pollution in any area in the State. It also requires EPA to review such a notification and promulgate applicable regulations within 90 days of the date of receipt of the notification. As a general matter, the effective date of an exemption shall be either the later of the first day of the high ozone season for the area that begins after the date of receipt of the notification or 1 year after the date of receipt of the notification. Lack of the "necessary regulatory language" would not appear to preclude a State from seeking this exemption. (See section 211(h)(5)(B) of the Act, "The Administrator shall promulgate regulations under (A) not later than 90 days after the date of receipt of a notification from a Governor under that subparagraph.") If EPA determines that waiving the 1 psi allowance would cause insufficient supplies the Administrator can extend the effective start date for up to 3 years total.

Colorado could pursue a voluntary-implementation requirement to not allow the 1.0 psi RVP waiver for gasoline blended with ethanol.