Davis Graham & Stubbs LLP

July 21, 2008

Via U.S. Mail and E-Mail

Ms. Theresa Amoroso
Air Pollution Control Division
Colorado Department of Public Health and Environment
4300 South Cherry Creek Drive
Denver, Colorado 80246

Re: Comments of Anadarko Petroleum, Noble Energy, Williams Production and Whiting Petroleum on the Ozone SIP Development Process and Proposed Statewide Controls Specific to Oil and Gas Industry Sources of VOC and NOx

Dear Ms. Amoroso:

We are writing on behalf of our clients Anadarko Petroleum Corporation ("Anadarko"), Noble Energy, Inc. ("Noble"), Williams Production RMT Company ("Williams") and Whiting Petroleum Corporation ("Whiting") (collectively hereafter the "Commenters"). The Commenters appreciate this opportunity to submit their concerns, suggestions and questions regarding aspects of the ongoing ozone SIP development process and possible statewide emission control strategies that will be the subject of formal rulemaking. The Commenters appreciate the hard work of the Air Pollution Control Division ("APCD" or "Division") staff, the Air Quality Control Commission and the Regional Air Quality Council thus far in their efforts to develop a proposed SIP for possible adoption and EPA review and approval.

This letter and the enclosed materials are organized to first address a general comment of all the Commenters with the SIP development process thus far. Commenters Anadarko and Noble then deal more specifically with proposed control strategies and related photochemical modeling comments specific to the ozone non-attainment area covering Denver and the North Front Range ("NFR"), in the comments attached to this letter at Tab A. Commenters Williams, Whiting and Noble address their concerns with possible statewide control strategies in comments attached to this letter at Tab B.

Because of the tight time schedule since recent meetings and reports on photochemical modeling, these comments are not comprehensive. Some or all of the Commenters may supplement them in future written submissions, and through verbal remarks at future stakeholder, RAQC and AQCC meetings leading up to formal rulemaking this fall.

GENERAL COMMENT

Timing of Source Apportionment: The Commenters do not support, and are troubled by the Division's stated intention to begin, the modeling of emission control strategy packages prior to completing the ozone source apportionment work. Source apportionment was specifically intended to inform the selection of emission control strategies and packages for modeling. While these Commenters appreciate the tight time schedule and difficulties that APCD, the RAQC and their contractors have faced in performing the work to date, we do not endorse or condone the modeling of specific control packages prior to the completion of ozone source apportionment. To do so will simply repeat the error committed in the performance of early action compact photochemical modeling in 2004, the source apportionment results from which were not obtained until after rulemaking had concluded. While these Commenters certainly appreciate the need to adhere to federal deadlines for the preparation and submission of Clean Air Act-mandated SIPs, we think it more important to produce as good a SIP as possible. If that means slightly delaying the schedule by a matter of a few weeks to properly utilize the source apportionment results in the selection of control strategies for modeling, that would be a better result than timely submitting an inferior or flawed SIP to the legislature in December of this year, in our view.

We once again thank the APCD, the RAQC, and their respective their staffs for this opportunity to comment on the ozone SIP development process and on and possible statewide emission control strategies that will be the subject of formal rulemaking later this year. We remain very interested and concerned about this process, and look forward to participating in future ozone stakeholder meetings and ultimately the rulemaking to be conducted by the Colorado Air Quality Control Commission.

Sincerely,

John R. Jacus
for
DAVIS GRAHAM & STUBBS LLP

cc: Ken Lloyd, RAQC

TAB A

TAB A

COMMENTS OF ANADARKO AND NOBLE ON OZONE CONTROL STRATEGY EVALUATION AND PHOTOCHEMICAL MODELING FOR THE DENVER 8-HOUR OZONE NON-ATTAINMENT AREA

Anadarko and Noble incorporate by their reference the General Comments in the cover letter transmitted with this Tab A attachment.

A. General Modeling Comments

1. The Modeling Report[1], reported on certain sensitivity tests that were conducted for mobile source emissions in the NAA, with VOC emissions from this group increased by factors of 2 and 3 (2X and 3X, respectively). See Section 5.4 of that report. The modeling report suggested that this increase provided more accurate VOC/NOx ratios, and that the model performance improved. This is a critical component of demonstrating attainment. If the mobile source emissions are not accurate (for the specific time of day, etc.), the modeling results and conclusions are suspect, as well. For developing a set of design values, the potential benefits of reducing emissions from mobile sources should be further reviewed, and its potential for achieving attainment brought into focus. The modeling review should address the characterization of emissions and impacts, and consider its effect as a component of developing design values, based on possible higher existing mobile source emission rates than are included in the final 2006 and 2010 base case simulations. The same report concludes that the "sensitivity of the 2010 control strategy to mobile source VOC emissions is something that should be investigated." We strongly endorse that conclusion, and request such investigation be performed as part of SIP development.

2. Back-Trajectory Analyses: The report provided by Mr. Patrick Reddy of APCD to various stakeholders at the July 14, 2008 meeting indicated that there was a NOAA Hysplit back-trajectory analysis conducted indicating that impacts in the Denver area were not clearly affected by emissions from Weld County, but that impacts at Fort Collins West were probably affected on those days by such emissions. The back-trajectory analyses that led to those conclusions should be made available to all stakeholders, especially if APCD is contemplating their use in the weight of evidence ("WOE") analysis required by EPA for the ozone SIP or in the evaluation of any statewide, state-only controls. Additionally, some of these Commenters previously asked whether the photochemical modeling contractors would be employing NOAA Hysplit back-trajectory analyses in their work, and their response was in the negative. We reiterate this request, but direct it to APCD. Please explain whether and to what extent such air parcel modeling analyses will be employed in the development of the ozone SIP, including its use in the WOE analysis of modeling results.

3. Modeling of Control Packages: In light of the recently obtained results of certain sensitivity analyses with respect to NAA controls on VOCs and NOx, we suggest the Division and the RAQC include in one of the two modeling packages of combined controls the 90% system wide control of condensate tanks in the NAA This would deliver still more VOC

---

[1] Morris, R., *et al.*, 2008: *Draft Final Report, Initial Ozone Model Performance Evaluation of the June-July 2006 Denver Ozone Episode and Diagnostics Testing and Analysis,* Environ International Corporation, Novato, CA

emission reductions while providing operator flexibility and an incentive to over control. It also is consistent with recent conclusions that minor VOC reductions may be less beneficial than regional NOx reductions in controlling ozone formation in the NAA. To the extent that time and/or other resources prevent this control strategy from being modeled, Anadarko and Noble have expressed their willingness to supplement available funding for the ongoing modeling effort to enable the inclusion of this strategy. See letter dated July 8, 2008 to Paul Tourangeau from John R. Jacus, copy attached at Tab A-1.

B. Source Apportionment Modeling Results

1. The selection of mandatory controls should be consistent with the VOC speciation and source apportionment results of the ongoing modeling effort. A number of proposed strategies do not appear to distinguish between VOCs with greatly varying photoreactivity. This has led to past reliance on control of stationary sources of VOCs with lower relative photoreactivity, and less additional control of higher reactivity VOCs, especially those from mobile sources. The ongoing photochemical modeling effort is designed to help in evaluating the relative contribution of such disparate source groups and VOC types, and we support a continued focus on speciation and source apportionment in the modeling work.

2. The source apportionment work should include a focus on mobile sources in Larimer and Weld Counties, separately, as suggested in the stakeholder discussions on July 14, 2008. Specifically, the contribution of motor vehicle emissions to ozone formation at the Fort Collins West monitor should be addressed. Any proposed emission reduction should also evaluate the potential air quality benefits of a return to required vehicle inspection and maintenance in that portion of the 8-hour ozone non-attainment area ("NAA").

3. Oil and gas emissions from Larimer and Weld Counties should also be assessed as a separate component of the OSAT effort, again as suggested on July 14. The contribution of this source category, both VOC and NOx emissions, with a potential for separate reductions from oil and gas components (flash emissions) on the Fort Collins West monitor as well as other monitors should be evaluated, with separate depictions for VOC and NOx reductions, as well as a combined strategy.

C. Ozone Stakeholder Meetings:

1. We greatly appreciate the opportunity to participate in these meetings and the effort of APCD and RAQC staff to organize and conduct them. That said, we have become concerned of late that these meetings are not as open to stakeholder participation as they perhaps should be, especially with regard to stakeholder opportunity to respond to staff reports and conclusions. For example, one of the Commenters recently asked to project a table of condensate composition data at a meeting addressing greenhouse gas impacts of VOC combustion. The data were directly relevant to the staff's presentation, and there was ample time at the meeting to engage in a brief review and discussion. The staff's unwillingness to allow such a response in that forum is unfortunate and, we think, unnecessary.

D. Comments on Proposed Oil & Gas Source Surveillance

1. The proposed provisions requiring the installation of an autoigniter and an electronic surveillance system on combustion systems controlling condensate tank emissions appears to be driven by the Division's concerns about burner downtime. By its very design, an autoigniter should provide for essentially continuous operation of the burner, unless the well/tank battery and burner are shut down by operating personnel. By contrast, the electronic surveillance system only tracks on-line time/down time and provides no direct air quality benefit.

2. Electronic surveillance systems will be costly to install (approximately $3,600/site is Noble's current estimate) and will also require significant operating labor. Because Noble (as well as many other operators, and particularly the smaller ones) do not have automated tank batteries, the collection of electronic surveillance data from each location and the management of those data will be a monumental task. Assuming approximately ½ hr/week/site for an estimated 1792 control devices on tank batteries > 2 tpy, and a rate of $100/hr (reflecting fully loaded internal labor costs), Noble has estimated that its cost is on the order of $4.66 million/year just for the data collection and management.

3. Additionally, assuming that the electronic surveillance will require recordkeeping (e.g., recording on/off every 15 minutes) comparable to other continuous monitoring devices found in other air quality regulations, then Noble will generate approximately 1.2 million data points per week for recording and submitting to the Division, creating a considerable burden for both the operator as well as Division staff in handling these data.

4. Anadarko's estimates of cost to install electronic surveillance on 2500 control devices in the DJ Basin are also quite significant, and are presented in the chart below:

ANADARKO ESTIMATE OF ELECTRONIC SURVEILLANCE COSTS	
EQUIPMENT DESCRIPTION	COST PER UNIT
Radio communicator to transmit signal back to Evans office	$1,250 per ECD
Thermocouple and associated wiring	$1,750 per ECD
Data acquisition system to store and decipher information from field (SCADA)	$15,000 total
Labor for installation	5 hours per ECD at $75 per hour
Total Systemwide Install Cost	$8,452,500

5. In light of these significant capital and operating costs, as well as the negligible air quality benefit of using electronic surveillance, Noble and Anadarko believe that use of autoigniters alone will address the Division's concerns in a more cost-effective and less burdensome manner.

E. Re-frac as a Modification

The proposed provisions require the installation of controls for the first 90 days following re-fracturing of wells. Anadarko and Noble disagree with this for the following reasons:

1. In its previous guidance, the Division has established that re-fracturing is *not* a modification. To date, the Division has not offered any clear basis for reversing its previous policy determination, and has cited no other jurisdiction where such an approach has been taken to oil and gas well permitting.

2. From a technical standpoint, re-fracing is used on existing wells to increase production, but the production is typically below the original production of the well when it was first brought on-line. As a result, the originally permitted throughput, unless it has been amended downward, should still cover the well after the re-frac. In an air quality context, bringing a source whose emissions have declined back up to a production rate that is closer to its originally permitted rate is not a modification.

3. From a practical perspective, the proposed requirements for installing controls on all tanks > 2 tpy by 2012 means that virtually every well that is being re-fraced will already have a control installed. This is because 2 tpy equates to only 0.8 bbl/day of production, and wells below that threshold are typically so close to the end of their producing life that they are not candidates for re-fracing. Re-fracs are normally performed on wells with much higher production than 0.8 bbl/day. As a result, the potential air quality benefits of including re-fracing as a modification will be short-term only (conceivably for 2009-2011 only, with the benefit declining each year).

F. 95 vs. 98 Percent Efficiency of Control Devices

Currently, Regulation No. 7 requires that control devices at each site achieve at least a 95% reduction in emissions. Although performance tests have shown that the burners typically used at many of the sites may achieve destruction efficiencies exceeding 99.5%, the industry was concerned during the initial rulemaking in 2003-04 about the capture efficiency for control devices in operation, especially because of the potential for occasional pressure relief valve venting at unmanned facilities, as well as the challenges in maintaining a tight seal around the thief hatch on the tank. Because test measurements indicated that these possible leaks were relatively small in those instances where they did occur, these Commenters were comfortable that a combined capture and destruction efficiency of 95% was achievable. We believe that this remains a more appropriate level of control device efficiency, reflecting both capture and destruction efficiencies, rather than 98%. Additionally, we note that: (i) the Division has not presented any compelling reasons for changing their previously established 95% policy, and (ii) pending COGCC regulations for use of identical devices for odor control on the exact same source propose a 95% level of control.

G. Additional Cost Information Regarding Proposed Control Strategies

Attached at Tab A-2 is a list of cost estimates from Noble regarding the Division's proposals.

H. Pneumatic Controllers

Natural gas-driven pneumatic devices are used for numerous gas production control functions including flow, temperature, liquid level, and pressure control. For estimating emissions, natural gas-driven pneumatics have historically been categorized as continuous bleed or intermittent bleed devices; although the categories high-bleed and low/no-bleed are becoming more common. The terms throttling and snap are also heard, causing further confusion between the various terminologies. To understand these terms it must be recognized that a pneumatic device contains two major components, a controller and an actuator valve. While both of these components contribute to the overall vent rate, the controller is the primary factor.

1. The terms continuous and intermittent refer to the action of the controller. Either type of device has an actuating and a non-actuating vent rate. In both cases, the actuating vent rate is determined by the actuation frequency, supply gas pressure, and the volume of the actuator bonnet including any associated supply gas tubing. When the valve needs to actuate, the controller will either apply or vent the pressure on the actuator, thus allowing the valve to change position. For an intermittent controller, the non-actuating vent rate is designed to be minimal and the primary venting would be the actuating rate. Conversely, a continuous bleed has a significant continuous non-zero bleed rate even when the valve is not actuating.

2. The terms throttling and snap refer to the action of the actuator valve itself. A throttling valve can have infinite position settings in order to vary the controlled parameter. For instance, a flow controller can be full open, 3/4 open, 1/2 open, 0.27825 open, closed, etc in order to choke the flow and control it to the desired value. On the other hand, a snap valve is either open or closed with no intermediate values. An intermittent device can be either throttling or snap just as a continuous can be either throttling or snap.

3. As controller primarily controls the bleed rate, we suggest the use of this term through the proposed regulation.

4. The EPA Natural Gas STAR Program defines a high bleed pneumatic as any pneumatic that bleeds in excess of 6 scfh. A more precise definition would be any pneumatic that is designed to have a constant non-actuating bleed rate in excess of 6 scfh. Almost all continuous bleed devices would be high bleed. Conversely, a low bleed would be any pneumatic that is not a high bleed. Most, if not all, intermittent controllers (i.e., the non-actuating bleed rate is minimal by design) will be low bleed.

5. Information from the Gas STAR program indicates that around 80% of high bleed devices can be replaced or retrofitted with low bleed devices. In E&P operations in general, and specifically for the Wattenberg area, this percentage will be much higher as most high bleed pneumatics are dump valves associated with separators and are easily retrofitted. Using Noble's existing high bleed pneumatic device inventory as an example, a 95% high-bleed replacement/retrofit program will reduce high-bleed pneumatic VOC emissions by 88%. This replacement/retrofit program will allow for a significant emission reduction in a manner that is cost effective.

6. The APCD's proposed rule language allows for high bleed devices to remain in service if warranted by safety or process purposes provided that extensive maintenance, monitoring, and recordkeeping is performed. While the value of replacing or retrofitting high-bleed controllers has been well documented, the documented benefit of pneumatic maintenance is anecdotal at best. The Gas STAR Program estimates that cleaning and tuning, in addition to repairing leaking gaskets, tubing fittings, and seals can save 5 to 10 scfh per device. Yet, these benefits and associated cost can very greatly based on the type of installation (i.e., high pressure transmission, versus low pressure E&P/midstream or large versus small facility, controller type, etc.) However, there are no specifics provided by Gas Star on the number and models of controllers evaluated, monitoring frequency, or actual cost of a maintenance program for different scenarios. Thus it is impossible to fully determine the cost of the proposed enhanced maintenance program and it is improper to unilaterally require a maintenance program for all high-bleed devices at this time.

7. Furthermore, the incremental emission reduction is minimal. Assuming the Gas Star values are appropriate, for high bleed devices that could not be replaced or retrofitted, an enhanced maintenance program, would only contribute an additional 1% reduction in VOC emissions (89% vs 88%). Given the minimal incremental benefit when compared to the replacement/retrofit program that reduces the bleed rate substantially, Noble believes that this required maintenance, monitoring, and recordkeeping is unduly burdensome and unnecessary.

Emissions based on Existing High bleed Pneumatic Inventory

	Per Device			Total		
	scfd	scfh	tpy	Count	tpy	tpd
Intermittent	50	2	0.08	0	0	0.00
Continuous	654	27	1.00	1875	1877	5.14
			Total	1875	1877	5.14

Emissions if 95% of high bleeds converted to low bleed

	Per Device			Total			
	scfd	scfh	tpy	Count	tpy	tpd	% Reduction
Intermittent	50	2	0.08	1781	136	0.37	
Continuous	654	27	1.00	94	94	0.26	
			Total	1875	230	0.63	88%

Emissions if high bleed rate is reduced by 25% via O&M/R&R

	Per Device			Total			
	scfd	scfh	tpy	Count	tpy	tpd	% Reduction
Intermittent	50	2	0.08	1781	136	0.37	
Continuous	491	20	0.75	94	70	0.19	
			Total	1875	207	0.57	89%

8. Attached at Tab A-3 are Noble and Anadarko's suggested changes to the Division's proposed Pneumatics language.

I. Potential Non-O&G Control Strategies

1. In addition to the oil and gas controls being considered, there is a critical need to look beyond the oil and gas production sector for controls that will deliver ozone

benefits. The Early Action Compact ("EAC") delivered very significant VOC reductions (i.e., at a minimum a 75% reduction) from the oil and gas production sector, with little or no change in monitored ozone levels. This is a real-world example that should be closely considered when selecting current ozone control strategies. Doing "more of the same" will likely lead to more of the same: increasingly strict controls at an extremely high cost with little or no measurable improvement in ozone levels. In order to convincingly demonstrate attainment with the current 8-hour standard and in order to make strides toward the new, lower standard, the APCD must, in our opinion, take a closer look at mobile sources and fuels.

2. Anadarko and Noble believe that a credible (i.e., EPA approvable) ozone SIP cannot fail to include an inspection and maintenance ("I/M") program and/or an effective high emitter program in the NAA, including the NFR. Although mobile sources are, admittedly, one of the more difficult sectors to target, this sector cannot be ignored in the SIP, especially when the Governor has directed RAQC and APCD to work toward achieving the new, lower standard.

3. The Division has expressed its preference that any I/M program in the NFR be a statewide only plan, not included in the SIP because it asserts that an I/M program cannot be up and running until 2011, which is too late to receive credit in this SIP. However, the state's I/M program contractor, Envirotest, has stated that it is capable of providing an enhanced vehicle I/M program in the NFR by June 1, 2009. This possibility has apparently been disregarded to date, and should be further evaluated. While the selection of an I/M program in the NFR is a decision impacting local communities, the failure to implement an I/M program also significantly impacts the entire NAA and the health of all of the citizens in the entire NAA. These are factors that should not be ignored, and APCD should work closely with the NFR to ensure that an I/M program is implemented in the NFR as expeditiously as possible so that it can be included in the SIP.

4. The Commenters would like to commend the Division on its dedication to the remote sensing and high emitter programs, and would like to encourage the Division to continue its efforts in this area, and move quickly from pilot program to full-scale high emitter identification and enforcement in an expanded I/M program area.

5. Representatives of Suncor publicly stated that it would be capable of producing 7.6 RVP gas (with the ethanol waiver), in an effort to help with ozone attainment. Since making this comment, there has been little further discussion of this possible control strategy. We believe that this the benefits of this strategy should be further evaluated.

6. We acknowledge that requiring Stage II Vapor Recovery systems at all existing gas stations does not appear to be a cost-effective strategy; however, we also maintain that this strategy should not be treated as an "all or nothing" strategy. Requiring Stage II vapor Recovery at all newly constructed or significantly modified stations, and at stations that are currently plumbed for Stage II, would result in emissions reductions that would be beneficial to ozone while providing additional health benefits from reduced exposure during refueling, and may be much more cost-effective. Notably, cost information for such an approach does not appear to have been provided to participating stakeholders.

7. At an earlier ozone stakeholder meeting, enforcement of Stage I Vapor Recovery systems was discussed. At that time APCD acknowledged that it did not have funds for Stage I enforcement, and that OIS was the responsible agency. APCD representatives also indicated that OIS lacked funds for Stage I enforcement activities. Based on these statements, it occurs to the Commenters that there may be a lack of data regarding Stage I enforcement, and a resulting lack of data regarding actual emissions from gas station operations. The Commenters suggest that that the Division consider and evaluate Stage I enforcement as a potential control strategy that could result in reduced emissions of such sources of more photochemically reactive VOCs, even without any Stage II controls.

TAB A-1

Davis Graham & Stubbs LLP

July 8, 2008

Via E-Mail and U.S. Mail (paul.tourangeau@state.co.us)

Mr. Paul Tourangeau, Director APCD
Air Pollution Control Division
4300 Cherry Creek Drive South
Denver, CO 80246-1530

Re: Ozone Modeling of Control Strategy Packages

Dear Mr. Tourangeau:

We would like to take this opportunity to thank you and your staff for the hard work spent to date in developing an ozone State Implementation Plan ("SIP"). We appreciate your efforts and look forward to working with you through the rest of the stakeholder process and during the formal rulemaking later this fall. As you are well aware, our clients, Anadarko Petroleum Corporation and Noble Energy, Inc. (the "Companies"), have been substantially involved in and concerned about the ozone SIP development process.

As a part of their involvement in this important process, the Companies are interested in funding ENVIRON/Alpine Geophysics to conduct limited additional modeling of ozone control packages. The Companies recognize, of course, that any additional modeling would be conducted only after your contractors finished modeling packages selected by the Regional Air Quality Council ("RAQC") and the Air Pollution Control Division ("APCD"). The Companies believe that modeling one or more additional control packages would provide the APCD, the RAQC, and other stakeholders with valuable information that would assist in developing an effective and cost-efficient SIP that will bring the area back into attainment. We are currently working to develop a scope of work that we will present to the APCD and the RAQC very shortly for review and comment. However, in order to craft control packages that will add value to the two Environ will already be modeling, it would be beneficial to know what will be included in these two control packages, as soon as the Division and the RAQC make this determination.

John R. Jacus . 303 892 7305 . john.jacus@dgslaw.com

1550 Seventeenth Street · Suite 500 · Denver, Colorado 80202 · 303 892 9400 · fax 303 893 1379
www.dgslaw.com

Once again, thank you for your time and hard work on the ozone SIP process. Please do not hesitate to contact me if you have any questions or concerns related to this matter.

Sincerely,

John R. Jacus
for
DAVIS GRAHAM & STUBBS LLP

/ajg

cc: Mr. Ken Lloyd, RAQC Director
Mr. Jerry Dilley, RAQC
Phillip Schlagel, Anadarko
Curtis Rueter, Noble Energy

TAB A-2

TAB A-2

AUTO-IGNITER AND ELECTRONIC SURVEILLANCE COST ESTIMATES OF NOBLE ENERGY, INC.

- Noble has installed VRU packages at 113 locations at an average of $30,000 (capital and installation costs). Annual maintenance costs are $6,000 per year per unit.

- Noble utilizes a 48 inch Tornado Tech-4 flare with capital and installation costs of $17,000 per site, and an annual maintenance cost of $1200 per flare.

- Noble employee costs associated with flare installations is estimated at $400 per unit.

- Auto-igniters will cost an additional $1400 per flare (capital + install), and electronic surveillance an additional $3600 per flare (capital + install).

- As of June 16, 2008, Noble has installed 1166 burners. To install auto-igniters on the existing units, Noble estimates it will cost $1.6 MM.

- To install electronic surveillance on all exiting tank batteries, Noble estimates it will cost $4.2MM.

- Noble currently operates 626 uncontrolled tank batteries with emissions above 2.0 tpy. To install flares with electronic surveillance and auto-igniters on all existing batteries, Noble estimates it will cost $14.0MM.

- Annual operating and maintenance costs will increase with the installation of autoigniters and electronic surveillance. Noble estimates monthly maintenance of the equipment and weekly management of the data collected will add 1/2 man-hour per week per location to operating/maintenance costs. Assuming all existing (1166 locations) and 626 uncontrolled batteries above 2.0 tpy will have auto-igniters and electronic surveillance, and based on $100/man-hr, this **increases** annual operating expenses by:

  (1792 batteries) x (1/2 man-hr/wk) x ($100/man-hr) x (52 wks/yr) = **$4.66MM/year**

TAB A-3

TAB A-3

PROPOSED NAA PNEUMATIC LANGUAGE

XIII.I. NATURAL GAS-ACTUATED PNEUMATIC ~~DEVICES~~CONTROLLERS ASSOCIATED WITH OIL AND GAS OPERATIONS

XIII.I.1. APPLICABILITY

THIS SECTION APPLIES TO PNEUMATIC ~~DEVICES~~CONTROLLERS LOCATED AT EXPLORATION AND PRODUCTION (E&P) AND MID-STREAM FACILITIES LOCATED WITHIN AN OZONE NON-ATTAINMENT AREA.

XIII.I.2. DEFINITIONS

XIII.I.2.A. ~~*ENHANCED MAINTENANCE* SHALL INCLUDE CLEANING, TUNING, AND REPAIRING LEAKING GASKETS, TUBING FITTINGS, AND SEALS, AND INCLUDES TUNING TO OPERATE OVER A BROADER RANGE OF PROPORTIONAL BAND; AND ELIMINATING UNNECESSARY VALVE POSITIONERS.~~

XIII.I.2.B. *HIGH-BLEED ~~DEVICE~~CONTROLLER* SHALL MEAN A PNEUMATIC ~~DEVICES~~CONTROLLER~~S~~ THAT ~~EMIT~~ARE~~S~~ DESIGNED WITH A CONSTANT NON-ACTIVATING BLEED RATE IN EXCESS OF 6 STANDARD CUBIC FEET OF NATURAL GAS PER HOUR (SCFH) TO THE ATMOSPHERE.

XIII.I.2.C. *LOW-BLEED ~~DEVICE~~CONTROLLER* SHALL MEAN A PNEUMATIC ~~DEVICE~~CONTROLLER THAT ~~EMITS LESS THAN 6 SCFH TO THE ATMOSPHERE .~~IS NOT A HIGH-BLEED CONTROLLER. A HIGH-BLEED CONTROLLER RETROFITTED TO LIMIT THE CONSTANT NON-~~ACTIVATING~~ACTUATED BLEED RATE BELOW 6 STANDARD CUBIC FEET OF NATURAL GAS PER HOUR (SCFH) TO THE ATMOSPHERE IS CONSIDERED A LOW-BLEED CONTROLLER.

XIII.I.2.D. *PNEUMATIC ~~DEVICE~~CONTROLLER* SHALL MEAN AN INSTRUMENT THAT IS ACTUATED USING NATURAL GAS PRESSURE AND USED TO CONTROL OR MONITOR PROCESS PARAMETERS SUCH AS ~~LIQUID~~ LEVEL, ~~GAS LEVEL,~~ PRESSURE, ~~VALVE~~ POSITION, ~~LIQUID~~ FLOW, ~~GAS FLOW~~ AND TEMPERATURE.

XIII.I.3. EMISSION REDUCTION REQUIREMENTS

THE OWNERS AND OPERATORS OF AFFECTED OPERATIONS SHALL REDUCE EMISSIONS OF VOLATILE ORGANIC COMPOUNDS FROM PNEUMATIC ~~DEVICES~~CONTROLLERS ASSOCIATED WITH AFFECTED OPERATIONS BY THE DATE~~S~~ LISTED BELOW. EMISSION REDUCTIONS

SHALL BE REQUIRED FOR NEW, MODIFIED AND EXISTING PNEUMATIC ~~DEVICES~~CONTROLLERS AS FOLLOWS:

XIII.I.3.A. ALL HIGH-BLEED PNEUMATIC ~~DEVICES~~CONTROLLERS SHALL BE REPLACED WITH LOW-BLEED ~~DEVICES~~CONTROLLERS BY MAY 1, 2009, UNLESS SUBJECT TO XIII.I.3.B.

XIII.I.3.B. HIGH-BLEED PNEUMATIC ~~DEVICES~~CONTROLLERS THAT MUST REMAIN IN SERVICE IF WARRANTED BY PROCESS OR SAFETY PURPOSES ~~MUST HAVE DIVISION APPROVAL AND~~MUST COMPLY WITH ~~S~~SECTIONS XIII.I.4. ~~AND XIII.I.5.~~

XIII.I.4. RECORDKEEPING~~MONITORING~~

XIII.I.4.A. EACH HIGH-BLEED PNEUMATIC ~~DEVICE~~CONTROLLER SUBJECT TO XIII.I.3.B. SHALL BE PHYSICALLY TAGGED IDENTIFYING IT WITH A UNIQUE HIGH-BLEED PNEUMATIC ~~DEVICE~~CONTROLLER NUMBER THAT IS ASSIGNED AND TRACKED BY THE OWNER/OPERATOR EFFECTIVE MAY 1, 2009.

~~XIII.I.4.B. EACH NEW HIGH-BLEED PNEUMATIC DEVICE~~CONTROLLER ~~SUBJECT TO XIII.I.3.B. SHALL BE INSPECTED ON A MONTHLY BASIS. ENHANCED MAINTENANCE SHALL BE PERFORMED ON A MONTHLY BASIS EFFECTIVE MAY 1, 2009.~~

~~XIII.I.5. RECORDKEEPING~~

XIII.I.~~5.A~~4.B. THE OWNER OR OPERATOR SHALL MAINTAIN A LOG OF ~~THE TOTAL NUMBER OF~~ HIGH-BLEED PNEUMATIC ~~DEVICES~~CONTROLLERS SUBJECT TO SECTION XIII.I.3.B. THE LOG SHALL INCLUDE THE CONTROLLER NUMBER, FACILITY, LOCATION, AND ~~PER FACILITY, THE TOTAL NUMBER OF HIGH-BLEED PNEUMATIC DEVICES PER COMPANY AND~~ THE ASSOCIATED REASONING THAT THE HIGH-BLEED PNEUMATIC ~~DEVICES~~CONTROLLERS MUST BE USED PURSUANT TO SECTION XIII.I.3.B. THE LOG SHALL BE UPDATED AS APPLICABLE ON A ~~MONTHLY~~QUARTERLY BASIS.

~~XIII.I.5.B. RECORDS OF ENHANCED MAINTENANCE SHALL INCLUDE, AT A MINIMUM INSPECTION DATES, THE DATE OF THE MAINTENANCE ACTIVITY, HIGH-BLEED PNEUMATIC DEVICE NUMBER, DESCRIPTION OF THE MAINTENANCE PERFORMED, RESULTS AND DATE OF ANY CORRECTIVE ACTION TAKEN, AND THE PRINTED NAME AND SIGNATURE OF THE INDIVIDUAL PERFORMING THE MAINTENANCE.~~

~~XIII.I.5.c. Records of enhanced maintenance of pneumatic devices shall be maintained for a minimum of three years and readily made available to the division upon request.~~

TAB B

TAB B

COMMENTS OF WILLIAMS, WHITING, AND NOBLE ON POSSIBLE STATEWIDE VOC AND NOX EMISSION CONTROLS SPECIFIC TO THE OIL AND GAS INDUSTRY

A. General Comments

1. Unless and until it is shown that statewide controls will significantly reduce ozone in the NAA, the proposed ozone State Implementation Plan ("SIP") should be specific to the non-attainment area ("NAA")—not the entire state of Colorado. See the prior comment memorandum to Ken Lloyd and Andrew Spielman of the RAQC dated May 20, 2008, of Anadarko and Noble a copy of which is attached at Tab B-1. Williams and Whiting endorse that prior comment and incorporate it by this reference in their comments.

2. The Division has not established that statewide controls are necessary or will contribute to ozone attainment in the NAA. The statewide modeling sensitivity testing has not yet been completed, and the Division has not otherwise demonstrated statewide VOC or NOx controls are necessary or effective in contributing to ozone attainment in the NAA. In addition, the Division has explained that it would evaluate statewide NOx control strategies in early 2009 as a part of the Regional Haze Reasonable Progress ("RH RP" process) process. The Division should continue with this planned schedule to ensure that statewide NOx control strategies are based on the best data available and that any proposed strategies are fully considered by the relevant stakeholders. Even if the Air Pollution Control Division ("APCD") ultimately decides to propose statewide oil and gas controls, APCD and AQCC should decouple the statewide rulemaking process from the ozone SIP process.

3. It is not reasonable or scientific to use poor data to make an evaluation. IPAMS Phase III emissions inventory for oil and gas sources in the Piceance Basin is currently under development. APCD should wait for the results of this important inventory so that it can be working from the most current, up-to-date information. Not waiting for this inventory would, in our opinion, be failing to use a very significant tool that will better inform and guide any statewide rulemaking specific to oil and gas industry sources. Waiting for the results of the IPAMS Phase III inventory will allow for a science-based approach that may result in more effective and cost-efficient regulations.

4. Many oil and gas operators outside the NAA have not paid much attention to the ozone stakeholder process because of their understanding that the ozone SIP dealt exclusively with operations in the NAA. Until just recently, there has been little involvement in the development of proposed statewide regulations by the majority of these operators, and the relevant stakeholders have not been fully involved. Accordingly, Williams, Whiting, and Noble appreciate the Division's plans to hold a stakeholder meeting in Grand Junction on August 14th.

B. Cost Effectiveness of Proposed Statewide Strategies

APCD's cost estimates for the implementation of tank controls are significantly underestimated.

1. The emissions and the emissions factors that APCD used in its economic impact analysis are inflated. Extensive field studies have shown that there are typically no more than 4 to 6 lbs of VOC per barrel of condensate produced in the Piceance Basin. In addition, the Division's estimated costs for combusters/enclosed flares were greatly underestimated, in the view of these Commenters. Actual vendors' bids show there would be an initial capital investment of at least $20,000 per unit, plus $5,000 annually for operating and maintenance expenses. In addition to these costs, under the Division's onerous "98% control, 99% of the time" approach, operators will incur significant costs for the automated surveillance that would be required to monitor these tanks. Even if automated surveillance is not required, an operator would still incur substantial costs with having to hire at least one full time employee for every twenty wells in order to conduct manual inspections, as estimated by Williams.

2. Please refer to the chart at Tab B-2 with Williams' Estimated Cost Impacts in the Piceance from 5 tpy or APEN Threshold Controls on Tanks. As you will note, under the Division's proposal Williams anticipates incurring $6.25 million in 2009, $2.5 million in 2010, and $2.5 million in 2011. In all, Williams expects to incur approximately $11.25 million over the next three years under the Division's proposal.

3. Whiting appreciates Williams cost estimates, but is concerned that it will not be able to purchase controls at such a low cost per unit. In addition, Whiting notes that it would be required to purchase a significantly larger number of control units, which would increase its costs substantially beyond Williams' total estimates.

4. Whiting would also like to express a concern over the availability of flares if the controls are required statewide. Whiting proposes suggesting that any statewide rule, if promulgated, would provide that, if a flare is not reasonably available, an operator will have some safe harbor from enforcement until such control becomes reasonably available in the market.

5. These costs are very high, and APCD has not demonstrated that resulting emission reductions will provide any measurable benefit to ozone or any other applicable state or federal air quality standard.

6. The Division should also keep in mind that, under its proposed 98% control, 99% of the time approach, operators will face increased compliance issues—which will create an additional burden on both industry and on the Division. These burdens have not been estimated or evaluated.

C. Pneumatics

The proposed regulation should include language allowing for operators to use high-bleed pneumatic controllers if the operating conditions render use of low-bleed controllers infeasible. Some operators have experienced significant problems with low-bleed pneumatic controllers in remote areas with extremely low winter season temperatures. In these conditions, the low-bleed pneumatic controller may freeze and fail in the open position, resulting in a spill. This risk of environmental harm must be weighed against the air quality benefit of employing low-bleed controllers. In order to avoid such problems, any proposed language requiring low-

bleed pneumatic controllers should only require them "as long as it is technically and operationally feasible to install a low-bleed controller." This clarification should specifically be added to the "safety purposes" exception allows for the limited use of high bleed devices.

D. Statewide Requirement on New Drills

1. Noble is concerned about the proposed statewide requirement for controlling the first 90 days of production from new and modified wells (the previous comments about re-fracs under the NAA are also applicable here), since not every new well that produces condensate has emissions > 5 tpy, even at first production.

2. Noble currently has 156 producing wells located in Mesa and Garfield counties, most of which were drilled in the past 2-3 years. There are approximately 60 tank batteries associated with these wells. Average production field wide is between 20-25 barrels of oil per day ("BOPD") (i.e., 0.4 BOPD per battery, or 0.16 BOPD per well). VOC emissions from only nine batteries have exceeded 2 tpy, only three batteries have exceeded 5 tpy, and none have exceeded 10 tpy. Of the three batteries that exceeded 5 tpy, all have had 4 or more wells feeding the battery.

3. As currently written, the Division's proposal would require Noble to control wells for the first 90 days, even when the average well produces < 60 bbl/year of condensate and would thus have emissions significantly less than 0.4 tpy, based on the Garfield County emission factor. The 90 days of control may capture on the order of 200 lb (0.1 tons) of emissions, which would not even be cost-effective considering the typical $2,000/site installation cost, without even accounting for equipment capital cost.

4. Because the Piceance basin is an attainment area and primarily a natural gas production rather than a condensate production region, we believe that a period of up to 90 days after a well is drilled, fractured, or completed is necessary to evaluate production and determine if emissions will exceed the threshold requiring a control device (as is currently required/allowed under Regulation No. 7 in the NAA). Allowing time for this evaluation is not expected to significantly impact air quality in this ozone attainment area.

5. Whiting also suggests that operators be afforded 60 days beyond the 90 days from date of first production to install controls, if they are required.

TAB B-1

Davis Graham & Stubbs LLP

MEMORANDUM

TO: Ken Lloyd –RAQC
Andrew Spielman –RAQC

CC: Paul Tourangeau –APCD
Curtis O. Rueter –Noble Energy
Phillip Schlagel –Anadarko Petroleum

FROM: John Jacus and Abby Gaffney

DATE: May 20, 2008

RE: Comments of Anadarko Petroleum and Noble Energy on the Role of Non-attainment Boundaries in Ozone SIP Development

We are writing to you on behalf of our clients Noble Energy and Anadarko Petroleum concerning ongoing ozone State Implementation Plan ("SIP") development for the Denver 8-hour Ozone Non-attainment Area. This memorandum contains preliminary research in response to the Air Pollution Control Division's suggestions for implementing statewide ozone controls on the oil and gas industry, as opposed to implementing controls strictly within the ozone non-attainment area. More specifically, this memorandum considers the Clean Air Act ("CAA") provisions and related guidance concerning how non-attainment area boundaries are determined and how those boundaries are related to the control measures outlined in a state's SIP. We appreciate your extensive efforts in the ozone SIP development process, and look forward to working together to develop an approvable ozone SIP.

Clean Air Act Definition:

The CAA defines a non-attainment area as "any area that does not meet (or that contributes to ambient air quality in a nearby area that does not meet) the national primary or secondary ambient air quality standard for the pollutant." CAA §107(D)(1)(A)(i). Under the CAA, when an area is designated non-attainment for ozone the State must submit a state implementation plan to EPA demonstrating how the area will come back into attainment within a certain timeframe. There is an implicit connection between a non-attainment area and the resulting controls that are needed to bring the area back into attainment: controls that are not connected to or contributing to the non-attainment area's violations are irrelevant to an area's demonstration of how it intends to conform to the federal ozone NAAQS.

EPA's Boundary Guidance on Air Quality Designations for the 8-Hour Ozone National Ambient Air Quality Standards

EPA has issued guidance explaining how to define the boundaries of a non-attainment area. *Boundary Guidance on Air Quality Designations for the 8-Hour Ozone National Ambient Air Quality Standards (NAAQS or Standard,"* dated March 28, 2000 from John S. Seitz to Air Directors, Regions I-X ("Boundary Guidance"). Based upon the CAA's definition for non-attainment areas, the Boundary Guidance explains: "EPA believes any county with an ozone monitor showing a violation of the NAAQS and any nearby contributing area needs to be designated as nonattainment." Boundary Guidance, at 3. According to the Boundary Guidance, the presumptive boundary for a non-attainment area should be the Metropolitan Statistical Area or the Consolidated Metropolitan Statistical Area ("C/MSA"). *Id.* EPA acknowledges that there may be some instances when it is appropriate for the non-attainment area to be smaller or larger than the C/MSA. *Id.*

In these instances, EPA lists eleven factors that the state should consider. *Id.* at 4. These factors are:

- Emissions and air quality in adjacent areas;
- Population density and degree of urbanization including commercial development (significant difference from surrounding areas);
- Monitoring data representing ozone concentrations in local areas and larger areas (urban or regional scale);
- Location of emission sources (emission sources and nearby receptors should generally be included in the same non-attainment area;
- Traffic and commuting patterns;
- Expected Growth (including extent, pattern and rate of growth);
- Meteorology (weather/transport patterns);
- Geography/topography (mountain ranges or other air basin boundaries);
- Jurisdictional boundaries (e.g., counties, air districts, existing 1-hour non-attainment areas, Reservations, etc.);
- Level of control of emission sources; and
- Regional emission reductions (e.g., NOx SIP call or other enforceable regional strategies).

Colorado's Ozone Non-attainment Boundary History:

On June 30, 2003, Colorado provided EPA with its recommendations for designating areas within the State for the 8-hour ozone standard. In its letter to EPA, Colorado recommended that all areas of the state be designated attainment for ozone. EPA disagreed, indicating that preliminary measurements at three monitors in the Denver metro area were in violation of the 8-hour standard. *Letter to Governor Owens from EPA Region 8 Administrator Robert E. Roberts*, Ref: 8P-AR. EPA explained that it intended to modify Colorado's recommended designation with respect to the Denver metropolitan area and to a non-attainment boundary. *Id.* EPA wrote:

> In the case of the Denver metropolitan area, the CMSA should be the starting point for considering the nonattainment boundary. This would include the following boundaries: Adams, Arapahoe, Boulder, Broomfield, Denver, Douglas, Jefferson, and Weld. In addition we recommend that Elbert, Larimer, and Morgan counties also be added. While these counties are outside the CMSA, they are adjacent to the Denver-Boulder-Greeley CMSA and may be contributing to 8-hour ozone violations.

Id. Colorado responded with a letter of its own. The Governor's office wrote:

> The Clean Air Act defines a nonattainment area as any area that does not meet or that contributes to ambient air quality in a nearby area that does not meet a national air quality standard. It is important that the boundary of the area capture those areas that are experiencing or significantly contributing to the problem. It is not clear from the information developed to date that all of the areas EPA is proposing need to be within the nonattainment area under those criteria. In particular, there are areas within the proposed boundary that do not contain significant sources of ground-level ozone precursors, or that due to topography, meteorology, or other factors do not contribute to the problem. Areas that do not contribute to the problem should not be subject to the burdens of a possible nonattainment designation.

Letter from Douglas Benevento, responding for Governor Owens, to Mr. Robert E. Roberts regarding the Proposed 8-hour Ozone Standard Nonattainment Boundary, dated February 5, 2004.

As an alternative to EPA's suggested non-attainment boundary, Colorado suggested a non-attainment area consisting of all of Broomfield, Boulder, Denver, Douglas, and Jefferson counties, parts of Adams, Arapahoe, Larimer, and Weld counties, and none of Morgan and Elbert counties. *Id.* In an enclosure to its letter, Colorado further explained that certain portions of EPA's recommendation "should be excluded from the nonattainment area due to the lack of sources that emit ozone precursor emissions, and due to terrain features that logically exclude these areas from being considered as part of the airshed." *Id.* In the words of Colorado, "It is

important that the boundary of the area capture those areas that are experiencing or significantly contributing to the problem." *Id.*

In the final non-attainment area listed in the Federal Register, EPA heeded Colorado's concerns by including all of Adams, Arapahoe, Boulder, Broomfield, Denver, Douglas, and Jefferson counties, and parts of Larimer and Weld counties. 69 Fed. Reg. 23858, 23890. Colorado's experience with the Denver Metropolitan Area's ozone non-attainment boundary underscores that the non-attainment area and the resulting controls on ozone precursors should only be imposed on areas that are actually contributing to the violations of the NAAQS.

Louisiana Environmental Action Network v. EPA, 382 F. 3d 575 (5th Cir. 2004).

In addition to the CAA definitions, the EPA Boundary Guidance, and the correspondence between EPA and the State of Colorado concerning the ozone non-attainment boundary, existing case law further demonstrates the need for controls included in a State's ozone SIP to be reasonably shown to aid the non-attainment area in coming into compliance with the NAAQS. In *Louisiana Environmental Action Network*, an environmental group challenged EPA's approval of Louisiana's ozone SIP because the SIP contained a substitute contingency measure for a facility located outside the non-attainment area. More specifically, the group claimed that reductions outside the Baton Rouge non-attainment area could not qualify as a contingency measure in the SIP without a finding that such reductions would actually improve air quality within the non-attainment area. *Id.* at 584-85. The court explained that EPA's "naked assertion" that emissions reductions from the facility would reasonably aid the non-attainment area "in its quest for attainment" was insufficient to justify the approval of the SIP. *Id.* Because there was no record to demonstrate that reductions from outside the non-attainment area would reasonably aid the area in coming into attainment, the court remanded the case back to the agency for further investigation. This case demonstrates how controls implemented as a part of a state's ozone SIP must have a connection with the non-attainment area, and how controls imposed on a source outside the non-attainment area must be shown to be contributing to the non-attainment area's violation of the NAAQS.

We appreciate the opportunity to provide these comments on behalf of Anadarko and Noble, and we welcome your response, if any, to them.

jts

TAB B-2

TAB B-2

Estimated Cost Impacts to Williams in the Piceance from 5 tpy or APEN Thresholds Controls on Tanks

Cimarron December 2006 Quote for a VOC Emission Control Device with the following Specifications:				Estimated Rules Impact over the first 3 years		
	2 MMBTU/HR	**1 Unit**		250 Units in 2009	50 Units in 2050	50 Units in 2011
	48" x 10 feet Vertical	$ 11,280.00	Unit Capitol Cost	$ 5,000,000.00	$ 1,000,000.00	$ 1,000,000.00
	1-34" Burner					
	1/2" Pilot Regulator					
	48" Flame cell					
	Guardian Reignitor	$ 1,250.00				
Other Associated Costs						
	Shipping Each	$ 500.00				
	24x48 Drip Pot	$ 2,070.00				
	Piping + Installation	$ 2,500.00				
	Inflation / Supply Adjustment	$ 2,400.00				
Total Unit Estimated Cost		**$ 20,000.00**				
Operation & Maintenance Cost includes fuel, labor, monitoring, recordkeeping and limited amount of automation						
	Annual Operation, Monitoring, Recordkeeping & Reporting per unit	$ 5,000.00		$ 1,250,000.00	$ 1,500,000.00	$ 1,500,000.00
Cost to Williams in 2009, 2010 and 2011				**$ 6,250,000.00**	**$ 2,500,000.00**	**$ 2,500,000.00**