PROPOSED MODIFICATIONS

IPANM's proposed modifications to NMED's proposed rules, 20.2.50. NMAC, are shown with additions underlined and deletions indicated by strikethrough.

20.2.50.2 SCOPE:

A. This Part applies to sources located within areas of the state under the board's jurisdiction that, as of the effective date of this ~~rule or anytime thereafter are causing or contributing to~~ Part have ambient ozone concentrations based on data submitted by the department to EPA's Air Quality System that exceed ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated and based on data from one or more department monitors. As of the effective date, sources located in the following counties are subject to this Part: Dona Ana, Eddy, Lea, Sandoval, San Juan, and Valencia.

B. If at any time after the effective date, an area of state identified in paragraph A above has a design value based on data from one or more department monitors to be less than ninety-five percent of the national ambient air quality standard for ozone, the department shall request that the board revise this rule to remove the area from this rule.

C. If at any time after the effective date, an area of state not identified in paragraph A above has a design value based on data from one or more department monitors to be greater than ninety-five percent of the national ambient air quality standard for ozone, the department shall request that the board revise this rule to add the area to this rule.

D. Once a source becomes subject to this rule, the requirements of the rule are ~~irrevocably~~ effective unless the source obtains ~~a~~ federally enforceable air permit conditions limiting the potential to emit of the source to below ~~such~~ the applicability thresholds established in this Part or the area is removed pursuant to paragraph B of this section.

20.2.50.7 DEFINITIONS: In addition to the terms defined in 20.2.2 NMAC - Definitions, as used in this Part, the following definitions apply.

XX, **"Design value"** means the 3-year average of the annual fourth-highest daily maximum 8-hour average ozone concentration.

EE. **"Pneumatic controller"** means ~~any instrument that is actuated using pressurized gas and used to control or monitor process parameters such as liquid level, gas level, pressure, valve position, liquid flow, gas flow, and temperature~~ a device that monitors a process parameter, such as liquid level, pressure, or temperature and uses pressurized gas (which may be released to the atmosphere during normal operation to send a signal to a control valve in order to control the process parameter. Controllers that do not utilize pressurized gas are not pneumatic controllers.

OO. **"Small business facility"** means for the purposes of this Part, a source that is independently owned or operated by a company that is not a subsidiary or a division of another business, that employs no more than 10 employees at any time during the calendar year, and that has a gross annual revenue of less than $250,000. Employees include part-time, temporary, or limited service workers.

20.2.50.111 APPLICABILITY:

A. This Part applies to certain crude oil and natural gas production and processing equipment ~~and~~ associated with operations that extract, collect, separate, dehydrate, store, process, transport, transmit, or handle hydrocarbon liquid or produced water in the areas specified in 20.2.50.2 NMAC and are located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations, up to the point of the local distribution company custody transfer station. Part 50 applies only in areas of the State specified in 20.2.50.2 NMAC.

B. In determining if any ~~source~~ unit is subject to this Part, ~~including a small business facility as defined in this Part~~, the owner or operator shall calculate the Potential to Emit (PTE) of such source ~~and shall have the PTE calculation certified by a qualified professional engineer~~. The calculation shall be kept on file for a minimum of five years and shall be provided to the department upon request.

C. An owner or operator of a small business facility as defined in this Part shall comply with the requirements of this Part as specified in 20.2.50.125 NMAC.

D. Oil ~~refinery~~ refineries and transmission pipelines are not subject to this Part.

20.2.50.112 GENERAL PROVISIONS:

A. **General requirements:**

(1) Sources subject to emissions standards and requirements under this Part shall be operated and maintained consistent with manufacturer specification, and good engineering and maintenance practices. The owner or operator shall keep manufacturer specifications and maintenance practices on file and make them available upon request by the department. For sources constructed prior to 1980 for which no manufacturer specifications and maintenance practices are available, the owner or operator shall develop and follow a maintenance schedule sufficient to operate and maintain such units in good working order. The owner or operator shall keep such maintenance schedules on file and make them available to the department upon request.

~~(2) Sources subject to emission standards or requirements under this Part shall be operated to minimize emissions of air contaminants, including VOC and NOx.~~

~~(3) Within two years of the effective date of this Part, owners and operators of a source requiring an Equipment Monitoring Tag (EMT) shall physically tag each unit with an EMT, the format of which shall be either RFID, QR, or bar code such that, when scanned it provides a unique identifier of the source. This unique identifier shall act as an index to the~~

~~source's record of the data required by this Part. The EMT shall be maintained by the owner or operator, and data in the EMT shall provide at a minimum, the following information:~~

~~(a) unique unit identification number;~~

~~(b) location of the source;~~

~~(c) type of source (e.g., tank, VRU, dehydrator, pneumatic controller, etc.);~~

~~(d) for each source, the VOC (and NOx, if applicable) PTE in lbs./hr. and tpy;~~

~~(e) for a control device, the controlled VOC and NOx PTE in lbs./hr. and tpy;~~

~~(f) make, model, and serial number; and~~

~~(g) a link to the manufacturer's maintenance schedule or repair recommendations~~

~~(4) The EMT shall be installed and maintained by the owner or operator of the facility.~~

~~(5) The EMT shall be of a format scannable by an owner or operator's authorized required by this Part.~~

~~(6) The owner or operator shall manage the source's record of data in a database that is able to generate a Compliance Database Report (CDR). The CDR is an electronic report generated by the owner or operator's database and submitted to the department upon request. The format of the CDR shall be determined by the department.~~

~~(7) The CDR is a report distinct from the owner or operator's database. The department does not require access to the owner or operator's database, only the CDR.~~

~~(8) If read by the owner or operator's authorized representative, the EMT shall access the owner or operator's database record for that source.~~

~~(9) The owner or operator shall contemporaneously track each compliance event for each source subject to the EMT requirements of this Part, and shall comply with the following:~~

~~(a) data gathered during each monitoring or testing event shall be contemporaneously uploaded into the database as soon as practicable, but no later than three business days of each compliance event.~~

~~(b) data required by this Part shall be maintained in the database for at least five years.~~

~~(10) The department may request that an owner or operator retain a third party at their own expense to verify any data or information collected, reported, or recorded pursuant to this Part, and make recommendations to correct or improve the collection of data or information. The owner or operator shall submit a report of the verification and any recommendations made by the third party to the department by a date specified and implement the recommendations in the manner approved by the department.~~

B. **Monitoring requirements:**

(1) Sources subject to emission standards and monitoring (e.g. inspection, testing, parametric monitoring) requirements under this Part shall be inspected monthly to ensure proper maintenance and operation unless a different schedule is specified in the Section applicable to that source type. If the equipment is shut down at the time of required periodic testing, monitoring, or inspection, the owner or operator shall not be required to restart the unit for the sole purpose of performing the testing, monitoring, or inspection, but shall note the shut down in the records kept for that equipment for that monitoring event.

(2).Such requests shall be made on an application form provided by the department. The department shall issue a letter approving or denying the requested alternative monitoring strategy. An owner or operator shall comply with the default monitoring requirements required under the applicable Section and shall not operate under an alternative monitoring strategy until it has been approved by the department.

~~(3) Each monitoring event (e.g. testing, inspection, parametric monitoring) shall be initiated by an initial scanning of the EMT, the results of which shall then be directly uploaded into the database or temporarily into the handheld or other device. Upon completion of the monitoring event, a final scanning of the EMT shall terminate the monitoring event. At a minimum, the uploaded data shall include:~~

~~(a) date and time of the testing, monitoring, or inspection event;~~

~~(b) name of the personnel conducting the testing, monitoring, or inspection;~~

~~(c) identification number and type of unit;~~

~~(d) a description of any maintenance or repair activity conducted; and~~

~~(e) results of testing, monitoring, or inspection as required under this Part.~~

C. **Recordkeeping requirements:**

(1) Within three business days of a monitoring event, an electronic record shall be made of the monitoring event and shall include the following data:

(a) date and time of the testing, monitoring, or inspection event;

(b) name of the personnel conducting the testing, monitoring, or inspection;

(c) identification number and type of unit;

(d) a description of any maintenance or repair activity conducted; and

(e) results of any testing, monitoring, or inspections required under this Part.

(2) The owner or operator shall keep an electronic record required by this Part for five years. The department may treat loss of data or failure to maintain a record, including failure to transfer a record upon sale or transfer of ownership or operating authority, as a failure to collect the data.

(3) Before the transfer of ownership of equipment subject to this Part, the current owner or operator shall conduct and document a full compliance evaluation of such equipment. The documentation shall include a certification by a responsible official as to whether the equipment is in compliance with the requirements of this Part. The compliance determination shall be conducted no earlier than three months before the transfer of ownership. The owner or operator shall keep the full compliance evaluation and certification by the responsible official for five years.

D. **Reporting requirements:** Within 24 hours of a request by the department, the owner or Operator shall for each unit subject to the request, provide the requested information either by electronically submitting a CDR to the department's Secure Extranet Portal (SEP), or by other means and formats specified by the department in its request.

20.2.50.117 NATURAL GAS WELL LIQUIDS UNLOADING:

A. **Applicability:** Manual liquids unloading operations ~~including down-hole well maintenance events~~ resulting in the venting of natural gas at natural gas wells are subject to the requirements of 20.2.50.117 NMAC. Manual liquids unloading operations that do not result in the venting of natural gas are not subject to this part. This 20.2.50.117 NMAC applies only in areas of the State specified in 20.2.50.2 NMAC and the emissions standards, monitoring, testing and inspection requirements, recordkeeping requirements and reporting requirements in this 20.2.50.117 NMAC apply only to the manual liquids unloading described in this 20.2.50.117.A NMAC.

B. **Emission standards:**

(1) The owner or operator of a natural gas well shall use best management practices during the life of the well to avoid the need for manual liquids unloading.

(2) The owner or operator of a natural gas well shall use the following best management practices during manual liquids unloading to minimize emissions, consistent with well site conditions and good engineering practices:

(a) reduce wellhead pressure before blowdown/;

(b) monitor manual liquid unloading in close proximity to the well or via remote telemetry; and

(c) close well head vents to the atmosphere and return the well to normal production operation as soon as practicable.

~~(3) The owner or operator of a natural gas well shall use one of the following methods to reduce emissions during an unloading event:~~

~~(a) installation and use of a plunger lift;~~

~~(b) installation and use of an artificial lift engine; or~~

~~(c) installation and use of a control device.~~

~~(4) The owner or operator of a natural gas well shall install an EMT on the natural gas well in accordance with 20.2.50.112 NMAC.~~

C. **Monitoring requirements:**

(1) The owner or operator shall monitor the following parameters during manual liquids unloading:

(a) wellhead pressure;

(b) flow rate of the vented natural gas (to the extent feasible); and

(c) duration of venting to the storage vessel or atmosphere.

(2) The owner or operator shall calculate the volume and mass composition of VOC vented during a manual liquids unloading event.

~~(3) A liquid unloading event shall include the scanning of the EMT and monitoring data entry in accordance with the requirements of 20.2.50.112 NMAC.~~

~~(4) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.~~

D. **Recordkeeping requirements:**

(1) The owner or operator shall keep the following records for manual liquids unloading:

(a) identification number and location of the well;

(b) date the manual liquids unloading was performed;

(c) wellhead pressure;

(d) flow rate of the vented natural gas (to the extent feasible). If not feasible, the owner or operator shall use ~~the maximum potential~~ estimated flow rate in the emission calculation);

(e) duration of venting to the storage vessel or atmosphere;

(f) a description of the management practice used to minimize release of VOC emissions before and during the manual liquids unloading; and

(g) ~~the type of control device used to control VOC emissions during the liquid unloading; and~~

~~(h)~~ a calculation of the VOC emissions ~~vented~~ emitted during the manual liquids unloading based on the duration, volume, and ~~mass~~ gas composition of the ~~VOC~~ natural gas produced.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. **Reporting requirements**: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

20.2.50.122 PNEUMATIC CONTROLLERS AND PUMPS:

A. **Applicability:** Natural gas-driven pneumatic controllers and diaphragm pumps permanently located at ~~wellhead sites~~ well production facilities, tank batteries, gathering and boosting sites, and natural gas processing plants, ~~and transmission compressor stations~~ are subject to the requirements of 20.2.50.122 NMAC, except pumps that operate less than 90 days per calendar year**.**

B. **Emission standards:**

(1) A new ~~natural gas-driven pneumatic controller or pump~~ well production facility, tank battery, gathering and boosting site, or natural gas processing plant shall comply with the requirements of 20.2.50.122 NMAC upon startup.

(2) ~~An existing natural gas-driven pneumatic pump shall comply with the requirements of 20.2.50.122 NMAC within three years of the effective date of this Part~~ A new well production facility, tank battery, gathering and boosting site, or natural gas processing plant shall have non-emitting controllers installed, except as allowed in Paragraph (5) of Subsection B of 20.2.50.122 NMAC.

(3) An existing well production facility and tank battery with four or more natural gas-driven pneumatic controller shall comply with the requirements of 20.2.50.122 NMAC according to the ~~following~~ schedule in Table 1 below:

Table 1 – WELLHEAD SITES, TANK BATTERIES, GATHERING AND BOOSTING FACILITIES

Total Historic ~~Percentage of~~ Non-Emitting ~~Controllers~~ Facility Percent Production	Total Required ~~Percentage of~~ Non-Emitting ~~Controllers~~ Facility Percent Production byJanuary 1, 2024	Total Required ~~Percentage of~~ Non-Emitting ~~Controllers~~ Facility Percent Production byJanuary 1, 2027	Total Required ~~Percentage of~~ Non-Emitting ~~Controllers~~ Facility Percent Production byJanuary 1, 2030
> 75 %	80%	85%	90%
> 60-75 %	80%	85%	90%
> 40-60 %	65%	70%	80%
> 20-40 %	45%	70%	80%
0-20 %	25%	65%	80%

(a) For purposes of this section, a "Non-Emitting Facility" means a facility with only Non-Emitting Controller except as allowed under Paragraph (5) of Subsection B of 20.2.50.122 NMAC.

(b) Except as provided in 20.2.50.122.B(3)(c) or (d) NMAC, owners or operators of existing well production facilities and associated tank batteries shall by January 1, 2023:

(i) Determine the Historic Facility Production for each existing well production facility by summing the total liquids productions (summing total barrels of oil and water produced through the well production facility) for the calendar year 2020. For a well production facility that does not have a full calendar year of data, then the owner or operator may use 2021 data or an estimate of the anticipated yearly production for the facility based on industry accepted calculation methodologies.

(ii) Calculate the Total Historic Production for the owner or operator by summing the Historic Facility Production for all existing well production facilities that commenced construction prior to the effective date.

(iii) Calculate the Facility Percent Production for each existing facility by dividing the Historic Facility Production by the Total Historic Production.

(iv) Determine the Total Historic Non-Emitting Facility Percent Production by summing the Facility Percent Production for each Non-Emitting Facility as defined in Subparagraph (5)(a) of Subsection B of 20.2.50.122 NMAC. The Total Historic Non-Emitting Facility Percent Production determines an owner or operator's January 1, 2024, January 1, 2027 and January 1, 2030 Total Required Non-Emitting Facility Percent Production as set forth in Table 1, except as provided in subparagraphs (c) or (d) of this Paragraph (3).

(v) Owners and operators must demonstrate compliance with Table 1's January 1, 2024, January 1, 2027 and January 1, 2030 Total Required Non-Emitting Facility Percent Production through retrofitting well production facilities (and associated tank batteries) to use non-emitting controllers.

(vi) if an owner or operator's pneumatic controllers are not cost-effective to retrofit, the owner or operator shall submit a cost analysis of retrofitting those remaining units to the department. The department shall review the cost analysis and determine whether those units qualify for a waiver from meeting additional retrofit requirements.

(c) In lieu of the demonstration required by 20.2.50.122.B.(3)(b) NMAC, an owner or operator may demonstrate that its total oil and natural gas production subject to Part 50 averages fifteen barrels of oil equivalent (using a 6 mcf to 1 barrel oil equivalent for natural gas) or less per well per day annual average. To calculate total oil and natural gas production subject to Part 50, an owner or operator must sum all affected oil and natural gas production in calendar year 2020 in barrels of oil equivalent, divide by 365, and divide by the number of affected wells producing hydrocarbons that the owner or operator operated in 2020.

(d) If an owner or operator meets at least seventy-five percent Total Non-Emitting Facility Percent Production by January 1, 2025, table 1 of Paragraph (3) of Subsection B of 20.2.50.122 NMAC does not apply and the owner or operator shall maintain the Total Non-Emitting Facility Percent Production at seventy-five percent or greater thereafter.

(e) If on-site electrical grid power is not available and a non-emitting pneumatic controllers are not technically and economically feasible, the operator shall utilize a gas-driven pneumatic controllers that emit natural gas emissions in an amount equal to or less than a low-bleed pneumatic controller, except as allowed under Paragraph (5) of Subsection B of 20.2.50.122 NMAC.

(f) For the purpose of 20.2.50.122.B(3)(e), the owner or operator may instead utilize a natural gas-driven intermittent pneumatic controller.

(4) Pneumatic controllers at existing gathering and boosting sites and natural gas processing plants with one or more natural gas-driven pneumatic controllers as of the effective date shall meet the required percentage of non-emitting controllers according to the schedule outlined in Table 2 below:

Table 2 ~~– NATURAL GAS COMPRESSOR STATIONS~~ GATHERING AND BOOSTING SITES AND GAS PROCESSING PLANTS

Total Historic Percentage of Non-Emitting Controllers	Total Required Percentage of Non-Emitting Controllers by January 1, 2024	Total Required Percentage of Non-Emitting Controllers by January 1, 2027	Total Required Percentage of Non-Emitting Controllers by January 1, 2030
> 75 %	80%	95%	98%
> 60-75 %	80%	95%	98%
> 40-60 %	65%	95%	98%
> 20-40 %	50%	95%	98%
0-20 %	35%	95%	98%

~~(4) Standards for natural gas-driven pneumatic controllers.~~

(a) ~~new pneumatic controllers shall have a n emission rate of zero.~~

~~(b) existing pneumatic controllers with access to commercial line electrical power shall have an emission rate of zero.~~

~~(c)~~ existing~~ pneumatic controllers~~ gathering and booster sites and natural gas processing plants shall meet the required percentage of non-emitting controllers within the deadlines in ~~tables~~ table ~~1 and~~ 2 of Paragraph (~~3~~4) of Subsection B of 20.2.50.122 NMAC, and shall comply with the following, except as provided in Paragraph 5 of Subsection B of 20.2.50.122 NMAC:

(i) by January 1, 2023, the owner or operator shall determine the total controller count for all controllers at all of the owner or operator's ~~affected facilities~~ gathering and boosting sites and natural gas processing plants that commenced construction before the effective date of this Part. The total controller count must include all emitting natural gas-driven pneumatic controllers and all non-emitting ~~pneumatic~~ controllers of any type (e.g. mechanical, electric, instrument air-driven, natural gas-driven routed to a combustion device etc), except that natural gas-driven pneumatic controllers ~~necessary for a safety or process purpose that cannot otherwise be met without emitting natural gas~~ allowed under Paragraph 5 of Subsection B of 20.2.50.122 NMAC shall not be included in the total controller count.

(ii) determine which controllers in the total controller count are non-emitting and sum the total number of non-emitting controllers and designate those as total historic non-emitting controllers.

(iii) determine the total historic non-emitting percent of controllers by dividing the total historic non-emitting controller count by the total controller count and multiplying by 100.

(iv) based on the percent calculated in (iii) above, the owner or operator shall determine which provisions of ~~tables 1 and~~ table 2 of Paragraph (~~3~~4) of Subsection B of 20.2.50.122 NMAC ~~apply~~ applies and the retrofit or replacement schedule the owner or operator must meet.

(v) if an owner or operator meets at least seventy-five percent total non-emitting controllers by January 1, 2025, ~~the owner or operator has satisfied the~~

~~requirements of tables 1 and~~ table 2 of Paragraph (~~3~~4) of Subsection B of 20.2.50.122 NMAC does not apply.

~~(vi) if after January 1, 2027, an owner or operator's remaining pneumatic controllers are not cost-effective to retrofit, the owner or operator shall submit a cost analysis of retrofitting those remaining units to the department. The department shall review the cost analysis and determine whether those units qualify for a waiver from meeting additional retrofit requirements.~~

~~(d)~~(5) ~~a pneumatic controller with a bleed rate greater than six standard cubic feet per hour is permitted when the owner or operator has demonstrated that a higher bleed rate is required based on functional needs, including response time, safety, and positive actuation. An owner or operator that seeks to maintain operation of an emitting pneumatic controller must prepare and document the justification for the safety or process purposes prior to the installation of a new emitting controller or the retrofit of an existing controller. The justification shall be certified by a qualified professional engineer~~ Pneumatic controllers that emit natural gas to the atmosphere meeting any of the following conditions are not subject to the requirements of Paragraphs (3) or (4) of Subsection B and are not required to be retrofit to count the facility or controller as non-emitting for compliance with Tables 1 and 2 of Subsection B of 20.2.50.122 NMAC.

(a) a natural gas pneumatic controller is permitted when the owner or operator has demonstrated that it is required based on functional needs, including response time, safety, and positive actuation. An owner or operator that seeks to maintain operation of an emitting pneumatic controller must prepare and document the justification for the safety or process purposes prior to the installation of a new emitting controller or the retrofit of an existing controller. The justification shall be certified by qualified maintenance or engineering staff.

(b) pneumatic controllers that emit natural gas located or temporary or portable equipment that is used for well abandonment activities or used prior to or through end of flowback.

(c) pneumatic controllers that emit natural gas located on temporary or portable equipment that is on-site and in use for 60 days or less.

(~~5~~6) Standards for natural gas-driven pneumatic diaphragm pumps.

(a) new pneumatic diaphragm pumps located at a natural gas processing plants shall have ~~an~~ a designed natural gas emission rate of zero.

(b) new pneumatic diaphragm pumps located at ~~a wellhead sites~~ well production facilities, tank batteries, gathering and boosting sites, or transmission compressor stations with access to commercial line electrical power shall have a designed natural gas emission rate of zero.

(c) existing pneumatic diaphragm pumps located at a natural gas processing plant shall have a designed natural gas emission rate of zero within 3 years of the effective date of this rule.

(d) existing pneumatic diaphragm pumps located at a well production facility, storage vessel gathering and booster site, or transmission compressor station with access to commercial line electrical power shall have a natural gas emission rate of zero within 3 years of the effective date of this rule.

(~~c~~e) ~~owners and operators of~~ existing pneumatic diaphragm pumps located at ~~wellhead sites~~ well production facilities, tank batteries, or gathering and boosting sites, ~~or transmission compressor stations~~ without access to commercial line electrical power shall reduce VOC emissions from the natural gas driven pneumatic diaphragm pumps by ninety-five percent if it is technically feasible to route emissions to a control device, fuel cell, or process. If there is a control device available onsite but it is unable to achieve a ninety-five percent emission reduction, and it is not technically feasible to route the pneumatic pump emissions to a fuel cell or process, the owner or operator shall route the pneumatic pump emissions to the control device. The rerouting or control device installation must be accomplished within 3 years.

(7) If an owner or operator's remaining natural gas pneumatic controllers, or if two years after the effective date, an owners or operator's existing natural gas pneumatic diaphragm pumps at a site without commercial line power, are not cost-effective to retrofit, the owner or operator shall submit a cost analysis of retrofitting those remaining units to the department. The department shall review the cost analysis and determine whether those units qualify for a waiver from meeting additional retrofit requirements.

~~(6) The owner or operator of a pneumatic controller or pump shall install an EMT on the controller or pump in accordance with 20.2.50.112 NMAC.~~

C. **Monitoring requirements:**

(1) Non-emitting pneumatic controllers or diaphragm pumps ~~with a natural gas bleed rate equal to zero~~ are not subject to the monitoring requirements in Subsection C of 20.2.5.122 NMAC.

(2) The owner or operator of a facility with one or more natural gas-driven pneumatic ~~controller~~ controllers subject to the deadlines set forth in Tables 1 and 2 of Paragraph (3) and (4) of Subsection B of 20.2.50.122 NMAC shall monitor the compliance status of each subject pneumatic controller at each facility.

(3) The owner or operator of a natural gas-driven pneumatic controller ~~with a bleed rate greater than zero~~ shall, on a monthly basis, ~~scan the controller and~~ conduct an AVO or OGI inspection, and shall also inspect the pneumatic controller, perform necessary maintenance ~~(such as cleaning, tuning, and repairing a leaking gasket, tubing fitting and seal; tuning to operate over a broader range of proportional band; eliminating an unnecessary valve positioner), and~~

~~maintain~~ on the natural gas-driven pneumatic controller according to manufacturer specifications to ensure that the VOC emissions are minimized.

(4) ~~The EMT shall be linked to a database that contains the following~~ For any natural gas-driven pneumatic controller remaining in operation after January 1, 2030, the owner or operator shall maintain an inventory of natural gas driven pneumatic controllers containing the following:

(a) natural gas-driven pneumatic controller identification number;

(b) type of controller (continuous or intermittent);

(c) if continuous, design continuous bleed rate in standard cubic feet per hour;

(d) if intermittent, bleed volume per intermittent bleed in standard cubic feet; and

(e) design annual bleed in standard cubic feet per year.

(5) The owner or operator of a natural gas-driven pneumatic diaphragm pump ~~with a bleed rate greater than zero shall~~ that emits natural gas to the atmosphere, on a monthly basis, ~~scan the pump and~~ conduct an AVO or OGI inspection and ~~shall also inspect the pneumatic pump and~~ perform necessary maintenance ~~and maintain the pneumatic pump according to manufacturer specifications~~ to ensure that the VOC emissions are minimized.

(6) The owner or operator shall monitor liquids production through each well production facility or tank battery.

(7) The owner or operator shall monitor total oil and gas production through each well production facility.

(~~6~~8) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. **Recordkeeping requirements:**

(1) Pneumatic controllers and pumps with a natural gas designed bleed rate equal to zero are not subject to the recordkeeping requirements in Subsection D of 20.2.5.122 NMAC.

(2) The owner or operator shall maintain a record of each existing well production facility and associated tank battery, its total liquids production, the total oil and gas production at all existing well production facilities subject to Part 50, whether the well production facility and associated tank battery is a Non-Emitting Facility, and the 2020 liquid throughput for each well production facility and associated tank battery. An owner an operator

complying with Table 1 of Paragraph (3) of Subsection B shall, beginning in calendar year 2022 each year through calendar year 2031, calculate its Non-Emitting Facility Percent Production as set forth in Paragraph (3)(b) of Subsection B except substituting the calendar year's production for the 2020 production. The owner or operator of existing well production facilities complying with the limitation on daily average per well production set forth in Paragraph (3)(c) of Subsection B shall calculate its daily average production using the procedures in Paragraph (3) substituting the calendar year for 2020.

(3) The owner or operator shall maintain a record for each existing gathering and boosting site and natural gas processing plant of the total controller count ~~for all controllers at all of the owner's or operator's affected facilities that commenced operation before the effective date of this Part. The total controller count must include~~ of all emitting and non-emitting pneumatic controllers. An owner or operator shall calculate the percentage of non-emitting controllers for each calendar year from 2022 through 2031, excluding controllers under Paragraph (5) or (7) of Subsection B of 20.2.50.122 NMAC.

(~~3~~4) The owner or operator shall maintain a record of the total count of natural gas driven pneumatic controllers ~~necessary for a safety or process purpose that cannot otherwise be met without emitting VOC~~ allowed under Paragraphs (5) or (7) of Subsection B of 20.2.50.122 NMAC.

(~~4~~5) The owner or operator of a natural gas driven pneumatic controller subject to the requirements in tables 1 and 2 of ~~Paragraph~~ Paragraphs (3) and (4) ~~of~~ shall generate a schedule for meeting the compliance ~~deadlines for each pneumatic controller~~. ~~The owner or operator shall keep a record of the compliance status of each subject controller.~~

(~~5~~6) The owner or operator shall maintain an electronic record for each natural gas driven pneumatic controller with a natural gas bleed rate greater than zero. The record shall include the following:

(a) pneumatic controller identification number;

(b) inspection dates;

(c) name of the personnel conducting the inspection;

(d) AVO or OGI inspection result;

(e) ~~AVO level discrepancy in continuous or intermittent bleed rate;~~

~~(f)~~ maintenance date and maintenance activity; and

(~~g~~f) a record of the justification and certification required in Subparagraph (d) of Paragraph (4) of Subsection B of 20.2.50.122 NMAC.

(~~6~~7) The owner or operator of a natural gas-driven pneumatic controller allowed under Paragraph (5) of 20.2.50.122 NMAC ~~with a bleed rate greater than six standard~~

~~cubic feet per hour~~ shall maintain ~~a record in the EMT database~~ of the pneumatic controller documenting ~~why a bleed rate greater than six scf/hr is necessary~~ <u>the justification</u>, as required in Subsection B of 20.2.50.122 NMAC.

(~~7~~<u>8</u>) The owner or operator shall maintain a record ~~in the EMT database~~ for a natural gas-driven pneumatic diaphram pump with an emission rate greater than zero and the associated pump number at the facility. The record shall include:

(a) for a natural gas-driven pneumatic <u>diaphragm</u> pump in operation less than 90 days per calendar year, a record for each day of operation during the calendar year.

(b) a record of any control device designed to achieve at least a ninety-five percent emission reduction, including an evaluation or manufacturer specifications indicating the percentage reduction the control device is designed to achieve.

(c) records of the engineering assessment and certification by a qualified <u>in-house</u> professional engineer that routing pneumatic pump emissions to a control device, fuel cell, or process is technically infeasible.

(~~8~~<u>9</u>) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

<u>(10) The owner or operator of an existing facility subject to Table 1 or Table 2 of Subsection B of 20.2.50.122 NMAC must retain records of its calculations until 2 years after compliance with the January 2030 requirements in Table 1 or Table 2, as applicable, is achieved and reported to the department.</u>

E. **Reporting requirements:** The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

20.2.50.124 WELL WORKOVERS

A. **Applicability**: Workovers performed at oil and natural gas wells are subject to the requirements of 20.2.50.124 NMAC as of the effective date of this Part.

B. **Emission standards**: The owner or operator of an oil or natural gas well shall use the following best management practices during a workover to minimize emissions, consistent with the well site condition and good engineering practices:

(1) reduce wellhead pressure before blowdown to minimize the volume of natural gas vented;

(2) monitor manual venting at the well until the venting is complete; and

(3) route natural gas to the sales line, if possible.

C. **Monitoring requirements**:

(1) The owner or operator shall monitor the following parameters during a workover:

(a) wellhead pressure;

(b) flow rate of the vented natural gas (to the extent feasible); and

(c) duration of venting to the atmosphere.

(2) The owner or operator shall calculate the <u>estimated</u> volume and mass of VOC vented during a workover.

(3) The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC.

D. **Recordkeeping requirements**:

(1) The owner or operator shall keep the following record for a workover:

(a) identification number and location of the well;

(b) date the workover was performed;

(c) wellhead pressure;

(d) flow rate of the vented natural gas to the extent feasible, and if measurement of the flow rate is not feasible, the owner or operator shall use the maximum potential flow rate in the emission calculation;

(e) duration of venting to the atmosphere;

(f) description of the management practices used to minimize release of VOC before and during the workover; and

(g) calculation of the <u>estimated</u> VOC emissions vented during the workover based on the duration, volume, and ~~mass~~ <u>gas composition</u> of VOC.

(2) The owner or operator shall comply with the recordkeeping requirements in 20.2.50.112 NMAC.

E. **Reporting requirements**

(1) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC.

~~(2) If it is not feasible to prevent VOC emissions from being emitted to the atmosphere from a workover event, the owner or operator shall notify by certified mail all residents located within one-quarter mile of the well of the planned workover at least three calendar days before the workover event.~~

STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF:

PROPOSED NEW REGULATION,
20.2.50 NMAC – OIL AND GAS
SECTOR –OZONE PRECURSOR POLLUTANTS

No. EIB 21-27 (R)

DIRECT TESTIMONY OF JEFFREY "RYAN" DAVIS
ON BEHALF OF THE INDEPENDENT PETROLEUM
ASSOCIATION OF NEW MEXICO

July 28, 2021

IPANM EXHIBIT 2

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. My name is Jeffrey Ryan Davis. My business address is 610 Reilly Ave., Farmington, New Mexico 87401.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING DIRECT TESTIMONY?

A. The Independent Petroleum Association of New Mexico ("IPANM"). I am currently the President of IPANM.

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am employed by Merrion Oil & Gas Corporation in Farmington, New Mexico. At Merrion, I am the Operations Manager.

Q. PLEASE DESCRIBE YOUR PAST EMPLOYMENT HISTORY.

A. I have been employed by Merrion since July 2008. From 2008 until December 2012, I was a production engineer at Merrion. In January 2013, I became Operations Manager.

Q. WHAT ARE YOUR RESPONSIBILITIES AS OPERATIONS MANAGER?

A. I manage all of our operated properties throughout the Rockies, including our New Mexico assets in the San Juan Basin. My responsibilities include overseeing all of field operations, engineering, production reporting, and regulatory compliance.

Q. PLEASE DESCRIBE YOUR EXPERIENCE WITH THE OZONE PRECURSOR POLLUTANTS OF THE OIL AND GAS SECTOR PROPOSED FOR REGULATION UNDER 20.2.50 NMAC.

A. I participated in the stakeholder engagement process as a member of the Methane Advisory Panel (MAP) and provided oral and written comments on behalf of IPANM to the NMED regarding the proposed regulation under 20.2.50 NMAC.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL EXPERIENCE.

A. In 2008, I received a Bachelor of Science degree in Mechanical Engineering from the New Mexico Institute of Mining and Technology. A copy of my resume is attached as **IPANM Exhibit 3.**

Q. HAVE YOU PREVIOUSLY TESTIFIED IN STATE OR FEDERAL REGULATORY PROCEEDINGS, INCLUDING TESTIMONY ON OZONE PRECURSOR POLLUTANTS?

A. No, not specifically on NOx or VOC, ozone precursor pollutants. I provided testimony to the Office of Management and Budget on the 2016 Bureau of Land Management Venting and Flaring Rule in 2018. I also testify on the NMOCD Waste Rule Hearing January 2021

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide IPANM's perspective on NMED's proposed regulations, including their applicability, and to specifically address requirements in the proposal for natural gas liquids unloading, pneumatic controllers and pumps, well workovers, and impacts on small operators/businesses.

III. IPANM'S EVALUATION OF NMED'S PROPOSED REGULATIONS

Q. PLEASE IDENTIFY THE REGULATIONS PROPOSED BY NMED THAT YOU ARE ADDRESSING IN THIS TESTIMONY.

A. I will be addressing the following sections:

- 20.2.50.2 NMAC -- Scope
- 20.2.50.7 NMAC – Definitions of "Pneumatic controller" and "Small business facility"
- 20.2.50.111 NMAC – Applicability;

- 20.2.50.117 NMAC – Natural Gas Liquid Unloading
- 20.2.50.122 NMAC – Pneumatic Controllers and Pumps;
- 20.2.50.124 NMAC – Well Workovers
- 20.2.50.125 NMAC – Small Business Facilities

Q. HAVE YOU REVIEWED NMED'S PROPOSED REGULATIONS AND STATEMENT OF REASONS FOR THESE PROPOSED REGULATIONS, FILED AS ATTACHMENTS 2 AND 3 TO NMED'S PETITION FOR REGULATORY CHANGE?

A. Yes.

Q. HAVE YOU REVIEWED IPANM'S COMMENTS TO NMED'S INITIAL PROPOSED OIL AND GAS SECTOR REGULATIONS?

A. Yes. The comments highlighted that the pre-proposal draft of the regulations had a much more balanced approach to the impacts on smaller operators. The pre-proposal draft had a stripper well and low potential to emit provision that provided necessary flexibility for operators with marginal production. The pneumatics provisions considered whether a site had access to line power and focused on securing reduction on sites without line power through the elimination of high bleed controllers. Overall, the pre-proposal draft reflected the input from industry during the Methane Advisory Committee (MAP) stakeholder engagement process.

1. **<u>NMED'S PROPOSED REGULATIONS SCOPE SECTION (20.2.50.2 NMAC)</u>**

Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF NMED'S PROPOSED SCOPE OF THE REGULATIONS?

A. My understanding is that the regulations are intended to regulate NOx and VOC emissions, ozone precursors, in New Mexico counties with an ozone design value greater than 95 percent of the federal ozone NAAQS, or 65.5 ppb. I have been advised that NMED ozone monitors in Dona Ana, Eddy, Lea, Sandoval, San Juan, and Valencia Counties have a design value that currently exceeds 95 percent of the federal Ozone NAAQS.

Q. WHAT IS YOUR POSITION ON NMED'S PROPOSAL OF 20.2.50.2 NMAC?

A. IPANM opposes 20.2.50.2 NMAC as currently written. IPANM does not oppose regulations necessary to assure that areas with a design value greater than 95 percent of the federal ozone NAAQS do not exceed the NAAQS. However, it does not believe that the regulation of VOC emissions from the oil and gas sector alone is necessary or appropriate to accomplish that task. We understand that ozone in Southeast New Mexico (Eddy and Lea Counties) and Northwest New Mexico (San Juan) are mostly NOx limited. That is, the reduction of ozone formation in those areas is controlled by reducing NOx emissions, not VOCs. Our review of the proposed regulations indicates that the regulations are primarily directed at reducing VOC emissions. We do not believe that a reduction in VOC emissions will lower ozone concentrations in the Southeast and Northwest or assure that the areas do not become nonattainment areas for Ozone.

We also point out that NMED has not produced a plan to control ozone beyond the proposed regulations at issue in this matter. Without understanding NMED's plan for control, it is impossible to effectively evaluate the need for the proposed regulations and recommend action by the Environmental Improvement Board ("EIB"), the body charged under the New Mexico Air Quality Control Act, Section 74-2-5.C (2021), with adopting "a plan, including rules, to control emissions of oxides of nitrogen and volatile organic compounds to provide for attainment and maintenance of the [ozone] standard."

Q. ARE YOU RECOMMENDING CHANGES TO NMED'S PROPOSAL?

A. Yes.

Q. PLEASE EXPLAIN THE BASIS FOR THIS PROPOSED CHANGE.

A. If the proposed regulations (or amendments to the regulations) are to be adopted by the Board, IPANM believes that the scope should be limited to those areas with a design value of greater than 95 percent of the federal ozone NAAQS and that it should be the Board's responsibility to add or delete areas subject to the regulations, based on future monitored ozone concentrations.

2. NMED'S PROPOSED REGULATIONS APPLICABILITY SECTION (20.2.50.111 NMAC)

Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF NMED'S PROPOSAL OF 20.2.50.111 NMAC.

A. As drafted, 20.2.50.111 NMAC states that the regulations apply "to crude oil and natural gas production and processing equipment and operations that extract, collect, separate, dehydrate, store, process, transport, transmit, or handle hydrocarbon liquid or produced water in the areas specified in 20.2.50.2 NMAC and are located at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations, up to the point of the local distribution company custody transfer station." Additionally, the section requires that sources subject to the rules, "calculate the Potential to Emit (PTE) of such sources" and have the calculations "certified by a qualified professional engineer." The rule requires the calculation be kept on file for at least 5 years and be provided to NMED "upon request."

Q. WHAT IS YOUR POSITION ON NMED'S PROPOSAL OF 20.2.50.111 NMAC?

A. IPANM has two concerns with the applicability section. First, not all sections in the rule require the calculation of PTE. Secondly, it seems unnecessary to require a qualified professional engineer certify the PTE calculation. Most operators have engineers or other staff that conduct these types of PTE evaluations and may not meet the requirements of this section.

Q. ARE YOU RECOMMENDING CHANGES TO NMED'S PROPOSAL?

A. Yes.

Q. PLEASE EXPLAIN THE BASIS FOR THIS PROPOSED CHANGE.

A. The requirement of having certification by a qualified professional engineer is not appropriate and creates an unnecessary burden to operators. In-house engineers are not required to be licensed as a professional engineer. New Mexico Board of Licensure for Professional Engineers and Professional Surveyors states that "An engineer employed by a business entity who performs only the engineering services involved in the operation of the business entity's business shall be exempt from the provisions of the Engineering and Surveying Practice Act; provided that neither the employee nor the business entity offers engineering services to the public" (Section 61-23-22 of the NM Engineering and Survey Practice Act).

3. NMED'S PROPOSED REGULATIONS NATURAL GAS LIQUID UNLOADING SECTION (20.2.50.117 NMAC)

Q: CAN YOU DESCRIBE YOUR WORK EXPERIENCE RELATED TO LIQUIDS UNLOADING?

A: The first four years of my time with MOG I worked as the production engineer for the company. My responsibility included artificial lift evaluation and implementation as well as the associate field work supervision. I evaluated the economics and procedures for artificial lift installations and supervised the rig work for implementation.

Q. **HAVE YOU REVIEWED THE PROVISIONS FOR LIQUIDS UNLOADING IN THE NMED PROPOSED OZONE PRECURSOR RULE?**

A. Yes

Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF NMED'S PROPOSAL OF 20.2.50.117 NMAC.

A. As I understand it, the intent of this section is to reduce VOC emissions associated with manual liquids unloading events through the use of best management practices during the life of the well and during the manual liquids unloading activities. The section also has monitoring, recordkeeping and reporting requirements for manual liquids unloading.

Q. WHAT IS YOUR POSITION ON NMED'S PROPOSAL OF 20.2.50.117 NMAC?

A. IPANM is supportive of the use of best management practices to reduce the emissions associated with manual liquids unloading. IPANM is concerned with the prescriptive natural of paragraph 3 of subsection B. IPANM is opposed to the equipment monitoring tracking (EMT) throughout the proposed regulation.

Q. ARE YOU RECOMMENDING CHANGES TO NMED'S PROPOSAL?

A. Yes.

Q. PLEASE EXPLAIN THE BASIS FOR THIS PROPOSED CHANGE.

A. The purpose of manual liquids unloading is to maximize the differential pressure on the wellbore to purge accumulated liquids out of the wellbore. The use of a control device would impede the manual liquids process and could create a safety concern. When performing manual liquids unloading the well is opened to the atmosphere through a low pressure (16 ounces or less) storage tank. The flow from the well is a multiphase flow stream and the tank serves to capture the liquids while venting the natural gas to the atmosphere. The sales configuration can be seen below in Figure 5 (Figure 5: Production Scenario with liquids loading. From *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquids Unloadings*, by David Allen, 2013. Retrieved from http://dept.ceer.utexas.edu/methane2/study/ https://www.youtube.com/watch?v=tup1SICEXGY&feature=youtu.be)

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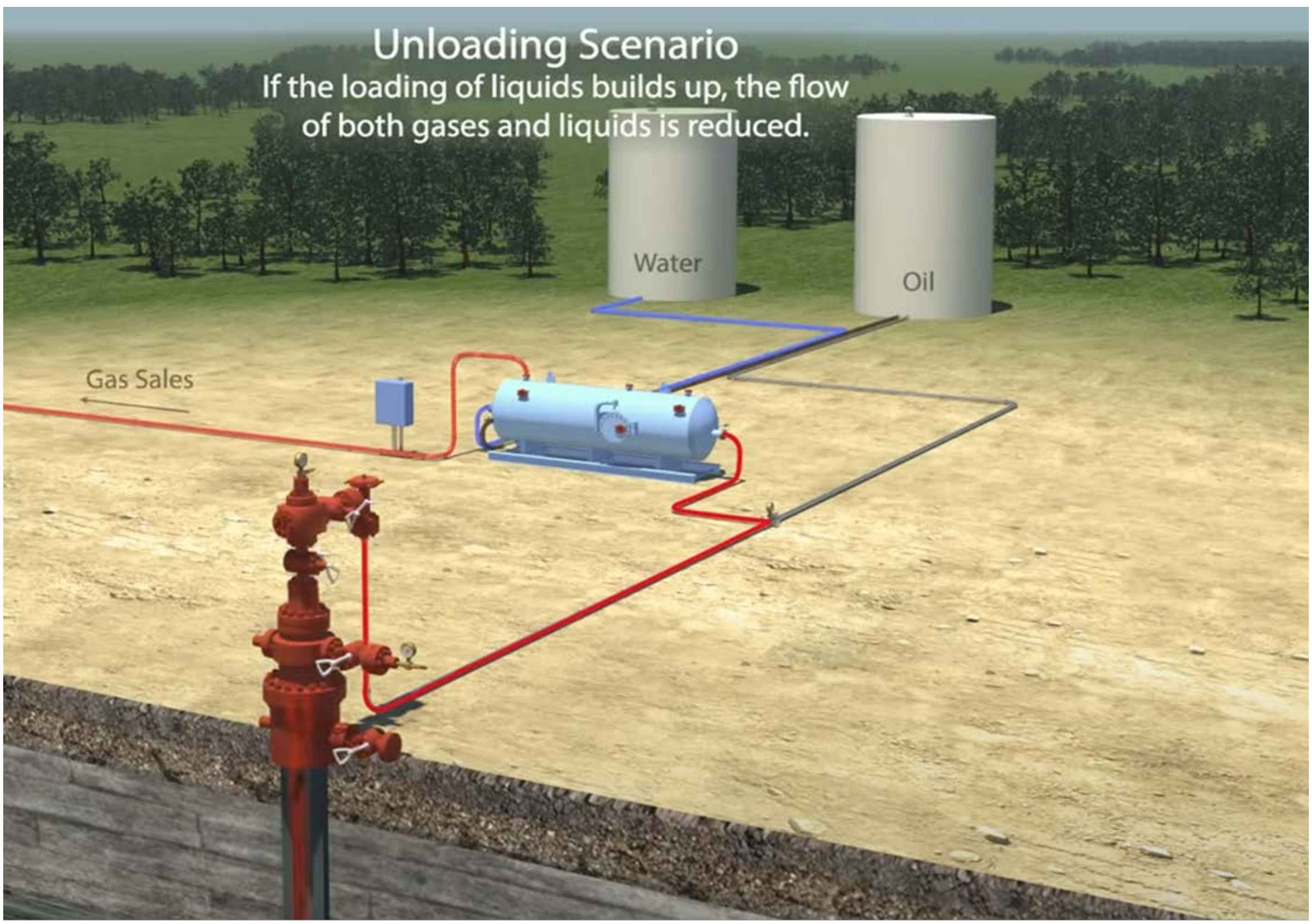

Figure 5: Production Scenario with liquids loading

The manual liquids unloading configuration is shown in Figure 6 (Figure 6: Unloading Scenario. From *Methane Emissions from Process Equipment at Natural Gas Production Sites in the United States: Liquids Unloadings*, by David Allen, 2013. Retrieved from http://dept.ceer.utexas.edu/methane2/study/ https://www.youtube.com/watch?v=tup1SICEXGY&feature=youtu.be) below illustrating the multiphase flow being directed to the storage tank.

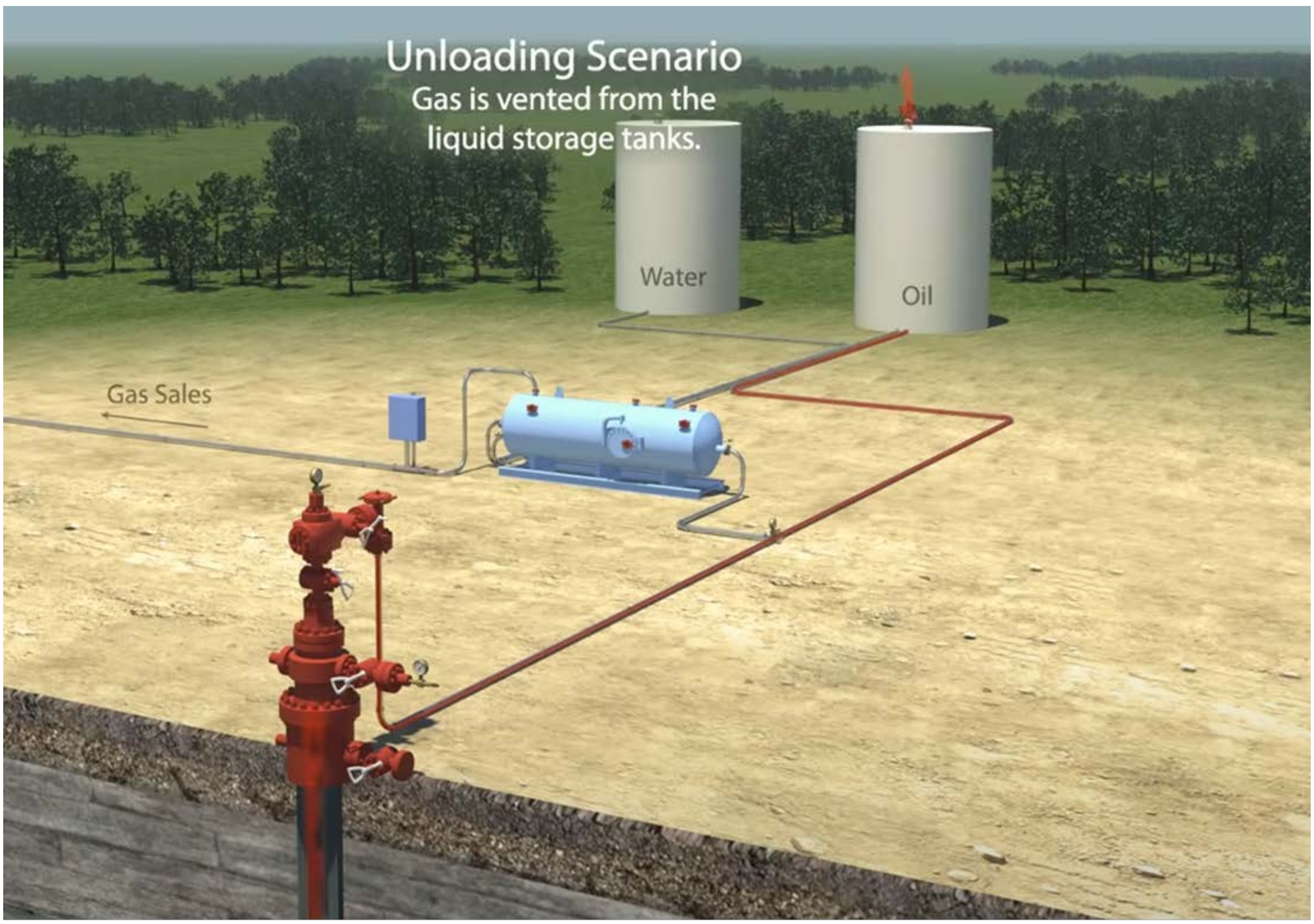

Figure 6: Unloading Scenario

Liquids unloading is a necessary process to maintain optimal production and maximize the recovery of natural gas. If the liquid loading is not addressed, it will lead to unstable flow regimes such as churn and slug flow which make a wells production sporadic and the operation of that well difficult resulting in less than optimal production and overall less resource (oil and natural gas) recovered and sent to sales. Ultimately, the hydrostatic pressure from the accumulated fluid will become equal to the reservoir pressure. This equalized condition results in the well being incapable of producing. This flow regime progression is illustrated below in Figure 2 (Figure 2: Gas Well Flow Regimes. From *Study of Identifying Liquid Loading in Gas Wells and Deliquification Techniques*, by Subhashini Sankar, S. Arul karthi, 2019. Retrieved from https://www.ijert.org/research/study-of-identifying-liquid-loading-in-gas-wells-and-deliquification-techniques-IJERTV8IS060708.pdf)

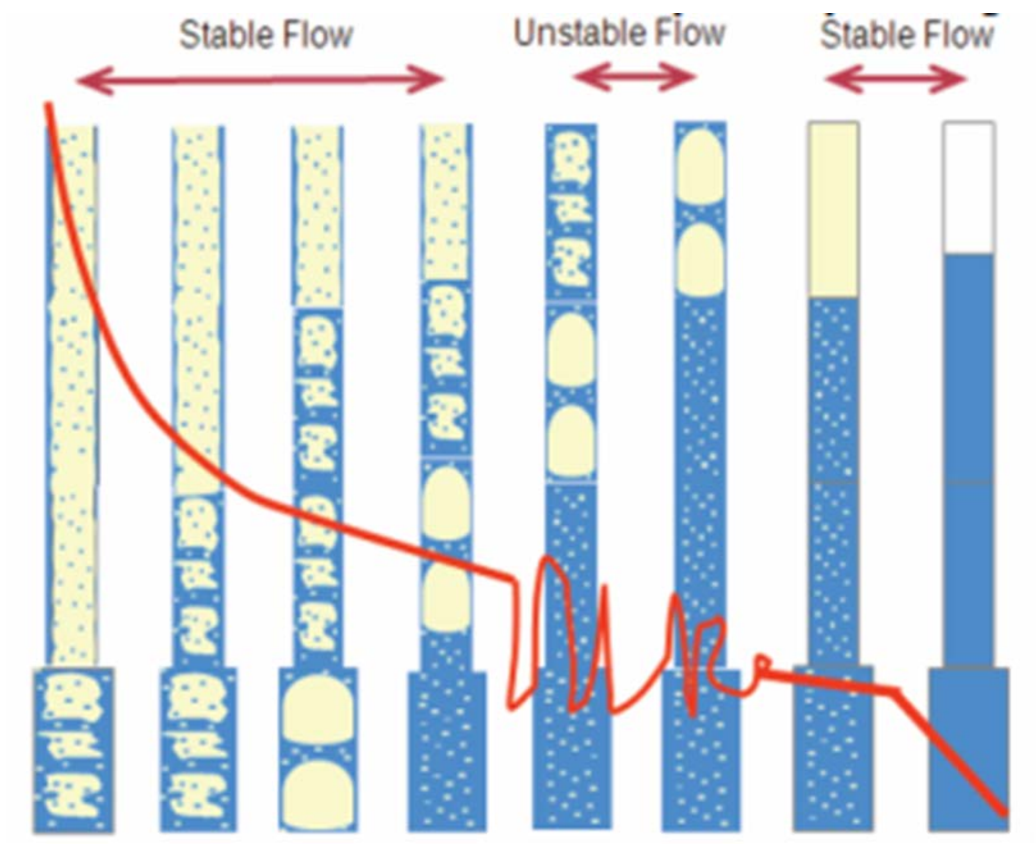

Figure 2: Gas Well Flow Regimes[1]

Most, if not all wells, have liquid production associated with the natural gas production. These liquids include produced water, natural gas condensate or crude oil. A well experiences liquid loading when the gas rate falls below the critical velocity. The critical velocity is the gas velocity required to suspend a droplet of liquid in flow. This is illustrated below in Figure 1.

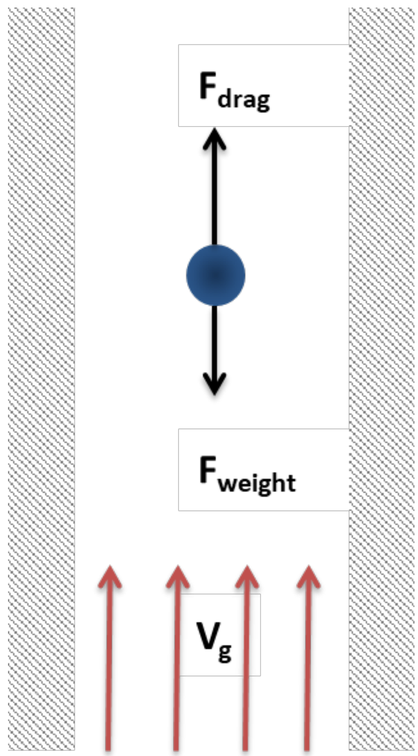

Figure 1: Critical Gas Velocity

A natural gas well's critical velocity is dependent on the tubing size and flowing tubing pressure. Some wells will come online flowing above the critical velocity but due the natural decline of the well over time, the gas rate can fall below the critical rate. Since the critical velocity is dependent on the flowing tubing pressure, a gas well can experience liquids loading when there is an increase in the flowing tubing pressure. There are various reasons for an increase in the flowing tubing pressure, but one of the primary reasons is an increase in sales line pressure due to a midstream upset. These upset conditions could include gathering compression outage, liquid condensation and accumulation in the line or line pigging operations, which is beyond the control of the operator. Operators will apply appropriate artificial lift over the life of the well to prevent the need for manual liquids unloading. Artificial lift application is an engineered solution based on individual well characteristics and site parameters. Plunger lift is not a one size fits all solution for deliquefying gas wells. The application of plunger lift is dependent of the wellbore and wellhead configuration, the gas to liquid ratio, the pressure build rate and operating pressures of the well. Other factors could limit the operator's ability to apply plunger lift such as tubing size and condition as well as the production equipment capacity and capability. Based on my experience, an artificial lift engine is a gas-powered engine that used as a prime mover on a pumping unit. An artificial lift engine is not a stand-alone piece of equipment. I do not see how the installation and use of an artificial lift engine will result in any VOC emission reductions regarding manual liquids unloading.

4. NMED'S PROPOSED REQUIREMENTS FOR PNEUMATIC CONTROLLERS AND PUMPS (20.2.50.122 NMAC)

Q. PLEASE SUMMARIZE YOU UNDERSTANDING OF NMED'S PROPOSAL TO REGULATE PNEUMATIC CONTROLLERS AND PUMPS (20.2.50.122 NMAC)?

A. It is my understanding that NMED intends to secure VOC emission reductions from natural gas-driven pneumatic controllers and diaphragm pumps. The reduction in VOC emissions from pneumatic controllers is to be accomplished by setting natural gas-driven pneumatic emission rates of zero for new pneumatic controllers and existing pneumatic controllers with access to commercial line power while transitioning all other gas-driven pneumatics to non-emitting over time. A similar approach is proposed with natural gas-driven pneumatic diaphragm pumps by setting natural gas emissions rates of zero for natural gas-driven pneumatic diaphragm pumps at natural gas processing plants and wellhead sites, tank batteries, gathering and boosting sites, or transmission compressor stations with access to commercial line power. The existing natural gas-driven pneumatic diaphragm pumps located at wellhead sites, tank batteries, gathering and boosting sites, or transmission compressor stations without access to commercial line power must reduce VOC emissions by 95% by routing emissions to a control device, fuel cell, or process.

Q. WHAT IS YOUR POSITION ON NMED'S PROPOSAL OF 20.2.50.122 NMAC?

A. Pneumatic controllers are a vital device employed in the oil and gas field separation and processing. These devices monitor crucial process parameters such as temperature, pressure or liquid level and use a pneumatic signal to control the field separation or processing. The pneumatic actuation is critical for the safe and efficient operation of process equipment in remote areas.

As an operations engineer for a small independent oil and gas operator I have found it difficult to cost effectively replace gas-driven pneumatics utilized in our field operations. In terms of performance and reliability, instrument air is the best solution to eliminate natural gas emissions from pneumatics. The issue we have in the San Juan Basin related to instrument air installations is the lack of available line power on the majority of our sites. The cost to bring power to the site and the cost of the instrument air systems are cost prohibitive. The installation of instrument air is an involved process. It isn't just a simply plug and play type retrofit. The process starts with selection of a compressed air system that incorporates an air compressor, filtration system and air dryer. The system also needs to have the appropriate enclosures, controls and storage capacity. Once you have an instrument air package there is modification that must take place on the site to separate the instrumentation supply system from the fuel system on the process equipment. This includes rerouting supply lines and pressure regulators to incorporate the use of compressed air on the instrumentation and control devices. The systems require wiring and trenching for proper installation. The instrument air skid must be placed with the appropriate setback from other equipment on location to ensure the safe operation of the system. When you consider all of the cost associate with the installation of instrument air it is difficult if not impossible to justify on an individual well economics standpoint. Where line power is not available and on single well sites with few pneumatic devices it is cost prohibitive as an option to eliminate natural gas emissions from pneumatic devices. We have spec'd out systems for future development and they do tend to make sense on new multi-well sites where line power is available

We have utilized other means to eliminate emissions from pneumatic devices in the past with very little success. We have installed solar powered instrument air systems and the reliability of these systems coupled with the maintenance cost forced us to return to natural gas as the motive fluid on our pneumatic devices. The solar power requirements also make solar cost prohibitive. We conducted a pilot project with rotary electric actuators here in the San Juan. We had many issues of which some we were able to address through the pilot project. Ultimately the two issues we were unable to address were the power consumption issues during winter month operations and the increase of emissions to the tank. The solar power systems were challenged during the cloudy/stormy periods and we ended up with a significant number of malfunctions do to loss of power during the winter. The actuation response of the rotary electric lead to an increase in the amount of gas being sent to the tanks due to the actuators not being able to close quickly enough. We concluded the pilot project and changed all of the liquid level controllers and actuators back to gas-driven pneumatics. As part of a voluntarily effort to reduce our greenhouse gas emissions we eliminated all of our continuous bleed liquid leveler controllers and replaced them with intermittent bleed controllers. We have utilized many cost-effective conversions to go from high bleed to intermittent bleed. I have significant concerns about the cost of retrofitting our pneumatic controls to zero bleed especially when there is an opportunity to secure reductions with this source in a more cost-effective manner. There are a few applications of continuous bleed controller for process and safety control purposes this would include the need to throttle a process such as in gas dehydration where it is critical to maintain a liquid level in the absorber or contact tower while also maintaining a minimum flow to feed the circulation pumps. Overall there are still opportunities to retrofit to an intermittent controller in the general separation and processing equipment to secure meaningful reductions in natural gas emissions.

If we look at what Colorado has done with Regulation 7 on pneumatics, you will see that they have implemented regulations to phase out gas-driven pneumatics with a percentage of liquid production approach. If you couple this approach with the use of intermittent bleed pneumatic controls you strike a cost-effective balance to reduce emissions with the pneumatics sources in NM. Although it is difficult to define a specific emission rate for intermittent bleed device there is data and peer review studies that indicate the emission from a properly functioning intermittent bleed device is lower than a low bleed threshold of 6 scf/hr. The emission factor for intermittent controllers used by NMED was 13.5 scf/hr.

While this emission factor is utilized by EPA in the greenhouse gas reporting process, it is outdated and overstated. There have been more recent studies that incorporated hundreds of measurements in comparison to the 26 measurements collected by EPA more than 25 years ago. These recent studies have shown the emissions from intermittent pneumatic controllers ranging from 0.32 scf/hr to 2.2 scf and routinely at the bottom end of that range. The Colorado Air Quality Control Commission recently utilized an emission factor of 3.5 scf/hr. The other point to mention here is that the intermittent bleed rate/volume is dependent on liquid production. Thus, if the NMED were to encourage the use of intermittent bleed devices and phase of gas driven pneumatics based on liquid production, the department could maximize the reductions of emissions while not overburdening operators in the state with the cost of compliance. There is also a need to provide some relief for operators of marginal or stripper wells. The Colorado regulations provides such relief by allowing flexibility for operators who have a company-wide average daily production rate per well of 15 boe or less. This is another important consideration when considering the impact on smaller operators whose margins do not support the expenditure of retrofitting to non-bleed controllers. This is very crucial to prevent the premature plugging and abandonment of wells in the state. The premature plugging and abandonment of wells would negatively impact the local communities and the state by eliminating jobs and revenue. I would strongly encourage the EIB to consider a more balanced approach when it comes to securing emission reductions related to gas-driven pneumatic devices.

Q. ARE YOU RECOMMENDING CHANGES TO NMED'S PROPOSALS?

A. Yes

Q. PLEASE EXPLAIN THE BASIS FOR THIS PROPOSED CHANGE.

A. The first basis for the proposed changes is the concern that the cost of compliance to retrofit natural gas driven pneumatic controllers being greater than the future producing reserve value on many wells in the state. The future producing reserve value is the forecasted future production revenue, less operating expenses, in present value. When we look at the options that NMED considered for pneumatic VOC reductions the upfront our estimated capital requirements are $63,360 to $316,950 for instrument air on sites with line power, $133,527 to $387,117 for instrument air on sites without power, and $43,071 for a solar electric conversion. These are significant capital expenditures specifically for single well sites with three to four gas-driven pneumatic controllers and less than 15 boe per day of production. Secondly when we look at the cost-effectiveness of the reductions it doesn't appear to be cost effective per ton. Changing the intermittent bleed emission factor to 3.5 scf/hr from 13.5 scf/hr takes the cost per ton of VOC from $2,745/ton to $7,213/ton. This does not include any consideration on the cost used by the NMED for the control technologies. If we used current industry cost, the cost per ton ranges from $7,904/ton for sites with line power to $23,829/ton for sites without access to line power. These costs per ton are very high and when you couple that with the very small potential impact on ambient ozone concentrations it seems only reasonable for there to be appropriate flexibility within the regulation, so the regulation doesn't overburden the industry without any benefit in terms of ozone reductions.

5. <u>NMED'S PROPOSED REGULATION OF WELL WORKOVERS (20.2.50.124 NMAC)</u>

Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF NMED'S PROPOSAL OF 20.2.50.124 NMAC.

A. My understanding is that the NMED intends to secure VOC reductions associated with well workovers. The proposed regulation accomplishes this through the use of best management practices, while depressurizing or blowing down wellbores for downhole maintenance or repairs. These best management practices include reducing the wellhead pressure prior to blowdown, monitoring the blowdown and routing to sales if possible.

Q. WHAT IS YOUR POSITION ON NMED'S PROPOSAL OF 20.2.50.124 NMAC?

A. It has been my experience that being able to move a rig onto location in a timely fashion to perform routine downhole maintenance is crucial for industry. When we have a workover rig working in an area and a well in close proximity goes down we may need to be able to move the rig to location within 24 hours to avoid having the rig leave the area and return later. If we are required to notify all residents within a quarter mile via certified mail three days prior would delay the process of restoring production and taking advantage of using a rig in the area. This unnecessary delay would drive the cost of workovers up and result in more miles traveled by workover rigs to perform routine downhole maintenance.

Q. CAN YOU DESCRIBE YOUR WORK EXPERIENCE RELATED TO WELL WORKOVERS?

A. The first four years of my time with Merrion I worked as the production engineer for the company. My responsibility included well workover analysis and field work supervision. I evaluated the economics and procedures for downhole well workovers and supervised the rig work associate with the well workovers.

Q. HAVE YOU REVIEWED THE PROVISIONS FOR WELL WORKOVERS IN THE NMED PROPOSED OZONE PRECURSOR RULE?

A. Yes

Q. DO YOU HAVE ANY CONCERNS WITH THE PROVISIONS? CAN YOU EXPLAIN THOSE CONCERNS?

A. Yes. IPANM has concerns about the notification provisions in 20.2.50.124.E. NMAC. The three-day prior notification using certified mail has the potential of creating delays with routine downhole maintenance activities that are necessary to restore production. It also would lead to inefficiencies related to moving workover rigs in the field. For example, Merrion has wells, in the San Juan Basin, that are 120 miles from the well service rig yard locations. There are instances where we or another operator may have a rig working in an area and we have a well go down due to a pump failure, rod pump or other needed downhole repair; it is the most efficient practice to use that rig while it is in close proximity. This reduces the travel time, mileage and emissions associated with the rig mobilization and ensures we can restore production quickly. The requirement to notify the adjacent residents via certified mail three days prior would delay the repair and restoration of production while making the activities less efficient and ultimately not result in any reduction of VOC emissions.

6. NMED'S PROPOSED REGULATIONS TO SMALL BUSINESS FACILITIES (20.2.50.7.OO NMAC AND 20.2.50.125 NMAC)

Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF NMED'S PROPOSAL OF 20.2.50.7.OO AND 20.2.50.125 NMAC.

A. I understand that the NMED proposal is intended to reduce the requirements applicable to small businesses, as defined by the regulations. The regulations define "small business facility" as "a source that is independently owned or operated by a company that is not a subsidiary or a division of another business, that employs no more than 10 employees at any time during the calendar year, and that has a gross annual revenue of less than $250,000. Employees include part-time, temporary, or limited service workers."

Q. WHAT IS YOUR POSITION ON NMED'S PROPOSAL OF 20.2.50.125 AND 20.2.50.7(OO) NMAC?

A. While IPANM supports reducing requirements applicable to small businesses, it does not believe that the proposal effectively accomplishes that objective. As drafted, the definition of "small business facility" is so limiting that few, if any, oil and gas operators in New Mexico could qualify. IPANM is concerned that the 10 employee cutoff is too limiting and will exclude most small businesses in this sector. Additionally, the gross income threshold is too limiting. The gross revenue of an oil and gas producer is tied to the price of oil and gas in the market. Increases or decreases in the price of oil or gas cannot be passed on by the producer nor can an increase in cost. Moreover, the gross annual revenue is not a measure of the business's profitability. The upfront costs of drilling a well and the infrastructure needed to move the product to a processing facility as well as the ongoing operating expenses are not factored into gross revenues. IPANM believes that other measures are a more appropriate gauge for determining whether a business should be subject to these regulations and what requirements should apply.

Q. ARE YOU RECOMMENDING CHANGES TO NMED'S PROPOSALS?

A. Yes, IPANM recommends that the proposed small business facility definition and the requirements in 20.2.50.125 NMAC not be adopted and an alternative approach that will allow truly small businesses to be exempted from many or most of the requirements of these rules. IPANM is not proposing specific language at this time to accomplish that end, but believes that NMED's initial draft, which excluded certain operations, is more in keeping with IPANM's objective to assure that small businesses are not unduly burdened by these rules, but still provide appropriate environmental protection.

Q. PLEASE EXPLAIN THE BASIS FOR THIS PROPOSED CHANGE.

A. As I explained, the proposed rule for small business facilities may not provide any regulatory relief to truly small oil and gas operations. IPANM believes that an approach that is more consistent with NMED's initial draft, may provide the necessary protections. The need for the appropriate relief or flexibility for small business facilities is very important to preserve the opportunity for small independent operators to continue to operate in New Mexico and provide good paying jobs as well as revenue to the state. IPANM estimates that there are thousands of wells that will not be able to burden the cost of compliance associated with this proposed regulation. This is especially true for the low volume and low decline rate gas wells here in the San Juan Basin and across the state. These low volume gas wells with low decline rates still have a significant amount of reserves associated with them and ultimately provide a consistent and stable production base in the state. It is also important to note that the provisions that have recently been adopted by the New Mexico Oil Conservation Commission in the new waste prevention rule have requirements for all wells in the state that reduce the amount of natural gas being vented or flared. It is essentially for the EIB to consider a balanced approach when considering the impacts on small business in the oil and gas sector.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

Jeffrey "Ryan" Davis

2400 N. Wagner Ave.
Farmington, NM 87401

505-215-3292 **rdavis@merrion.bz**

Experience	**Drilling, Completion and Production Operations Management: January 2013 – Present** Operations Manager, Merrion Oil & Gas Corporation ▪ Economic forecasting, decline curve analysis and budget preparation ▪ Contract Negotiation (Gas gathering, crude oil sales, service agreements) ▪ Safety and Insurance Compliance (Safety program development and implementation for field employees and contractors, Insurance limits for field activities) ▪ Personnel Management (Scheduling and resource management) ▪ Project Management (Coordinate regulatory and engineering tasks to ensure success of project) **Production and Field Operations Optimization: July 2008 – December 2012** Production Engineer, Merrion Oil & Gas Corporation ▪ Well optimization- Artificial Lift Selection, Lease operating expense optimization, Well workover analysis and supervised field work ▪ Regulatory Compliance- Coordinate and ensure state and federal regulatory compliance with field operations (Production reporting, activity permitting and notification, air quality permitting)
Education	**New Mexico Institute of Mining and Technology – Socorro, NM – Bachelor of Science in Mechanical Engineering** May 2008 ▪ 2005-2008: Worked at the National Radio Astronomy Observatory (NRAO) as a student engineer (3D Modeling, prototype development and final design implementation) ▪ 2007-2008: Participated in the Society of Automotive Engineers (SAE) Mini-Baja for two years as junior and senior design project.
Communication	2019 Desk and Derrick Industry Appreciation Dinner Keynote Speaker
Leadership	▪ 2021 Independent Petroleum Association of New Mexico (IPANM) President ▪ Class of 2016 Leadership San Juan Graduate ▪ NMT Team captain for the 2008 Baja SAE® Illinois. Placed 17th overall out of 115 schools.

IPANM EXHIBIT 3

Skills & Abilities	Mechanical background, Production Engineering (Production optimization, decline curve analysis, artificial lift application), Management (Budgeting, project management, gas scheduling and marketing)

STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF:

PROPOSED NEW REGULATION,
20.2.50 NMAC – OIL AND GAS
SECTOR –OZONE PRECURSOR POLLUTANTS

No. EIB 21-27 (R)

DIRECT TESTIMONY OF DAVID R. BROWN, DJR OPERATING, LLC ON BEHALF OF THE INDEPENDENT PETROLEUM ASSOCIATION OF NEW MEXICO

July 28, 2021

IPANM EXHIBIT 4

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. David R. Brown. My business address is DJR Operating, LLC, 1 Road 3263, Aztec, New Mexico 87410.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING DIRECT TESTIMONY?

A. The Independent Petroleum Association of New Mexico

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I have been employed by DJR Operating, LLC ("DJR Operating") since 2018. I am the Manager of Regulatory, Government, and Public Affairs for DJR Operating.

Q. PLEASE DESCRIBE YOUR PAST EMPLOYMENT HISTORY.

A. From 1977 to 2000, I worked at various locations for the Amoco Production Company. From 2000 to 2010, I was employed by BP America Production Company and was stationed at various locations. Then, from 2010 to 2018, I was employed with Airswift Worldwide (Consulting Services) and provided consulting services to BP America, Chesapeake Energy, Fidelity Exploration and Production, and Ward Petroleum.

Q. WHAT ARE YOUR RESPONSIBILITIES AS MANAGER OF REGULATORY, GOVERNMENT, AND PUBLIC AFFAIRS FOR DJR OPERATING?

A. [INSERT]

Q. PLEASE DESCRIBE YOUR EXPERIENCE PARTICIPATING IN EFFORTS TO ADDRESS OZONE PRECURSOR POLLUTANTS OF THE OIL AND GAS SECTOR PROPOSED FOR REGULATION UNDER 20.2.50 NMAC.

A. I was an industry participant in the Four Corners Air Quality Task Force and assisted in drafting technical papers directed at reducing ozone precursors.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL EXPERIENCE.

A. I obtained a bachelor's of science degree in Business Administration at Oral Roberts University in Tulsa, Oklahoma. I then earned master's degree in Environmental Management and Policy from the University of Denver in Denver, Colorado. A copy of my resume is attached as **IPANM Exhibit 5.**

Q. HAVE YOU PREVIOUSLY PARTICIPATED IN STATE OR FEDERAL REGULATORY PROCEEDINGS ON OZONE PRECURSOR POLLUTANTS?

A. No, but I was an industry participant in the Four Corners Air Quality Task Force.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide IPANM's position on NMED's proposed requirement in 20.2.50.112(A)(2)-(10) and (B)(3) NMAC that owners or operators of sources subject to the proposed regulations mandating an Equipment Monitoring Tag ("EMT") to physically tag each unit and specify the format of each tag. My testimony also relates to EMT requirements throughout the proposed Part 50, including the following Sections: 20.2.50.113(B)(9), (C)(7), (D)(1)(a), and (D)(2)(a); 20.2.50.114(B)(5); 20.2.50.115(B)(3)-(4), (C)(2)(d), (D)(2)(c), and (E)(2)(b); 20.2.50.117(B)(4) and (C)(3); 20.2.50.118(B)(3)(d); 20.2.50.119(B)(4) and (C)(4); 20.2.50.122(B)(6), (C)(4), and (D)(6)-(7), and; 20.2.50.123(B)(8) and (C)(4).

III. IPANM'S EVALUATION OF NMED'S PROPOSED REGULATIONS

Q. PLEASE IDENTIFY THE REGULATIONS PROPOSED BY NMED THAT YOU ARE ADDRESSING IN THIS TESTIMONY.

A. I will be addressing the following sections:

- 20.2.50.112 NMAC –General Provisions;
- 20.2.50.113 NMAC –Engines and Turbines;
- 20.2.50.114 NMAC –Compressor Seals;
- 20.2.50.115 NMAC –Control Devices;
- 20.2.50.117 NMAC –Natural Gas Well Liquid Unloading;
- 20.2.50.118 NMAC –Glycol Dehydrators;
- 20.2.50.119 NMAC –Heaters;
- 20.2.50.122 NMAC –Pneumatic Controllers and Pumps, and;
- 20.2.50.123 NMAC –Storage Vessels

Q. HAVE YOU REVIEWED NMED'S STATEMENT OF REASONS FOR THESE PROPOSED REGULATIONS, FILED AS ATTACHMENT 3 TO NMED'S ORIGINAL PETITION [PDF 37-48]?

A. Yes.

Q. HAVE YOU REVIEWED IPANM'S COMMENTS TO NMED'S INITIAL PROPOSED OIL AND GAS SECTOR REGULATIONS?

A. Yes.

1. NMED'S PROPOSED REGULATIONS TO GENERAL PROVISIONS SECTION (20.2.50.111 NMAC)

Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF NMED'S PROPOSAL OF 20.2.50.111 NMAC.

A. This section requires the owner/operator to manage the sources record of data in a database capable of generating a Compliance Database Report (CDR), which can be submitted to the New Mexico Environment Department ("NMED" or "Department") upon request. The rule goes on to say the CDR format shall be determined by the Department. Further the rule allows for the Department to possibly request that an owner/operator retain a third party at its expense to verify any data of information collected, reported, or recorded and make recommendations to correct or improve the collection of data or information.

Q. WHAT IS YOUR POSITION ON NMED'S PROPOSAL OF 20.2.50.111 NMAC?

A. IPANM has serious concerns with the proposal that requires companies to implement an EMT. Owners and operators of a source are required to physically tag each unit with an EMT in a format that is either RFID (Radio Frequency Identification), QR (Quick Response), or a bar code, such that, when scanned, it provides a unique identifier of the source. Using one of these systems requires an owner/operators of emission sources to store information regarding: the location; type of source being regulated; emission thresholds for NOx and VOC potential to emit (PTE), and the same information when a control device is being used; make, model and serial number and a link to a manufacturer's maintenance schedule, and; repair recommendations and tracking compliance events information, such as stack testing no later than three business days after the event.

Q. ARE YOU RECOMMENDING CHANGES TO NMED'S PROPOSAL?

A. Yes. The concerns highlighted in my answer to the question below leaves IPANM to conclude that the technology challenges and costs—and the lack of any evidence EMT will reduce ozone precursor pollutants—simply does not justify an EMT program as part of this rule. IPANM therefore recommends eliminating the following subsections: 20.2.50.112(A)(2)-(10) and (B)(3) NMAC, and any reference to EMT in the remainder of the proposed rule.

Q. PLEASE EXPLAIN THE BASIS FOR THIS PROPOSED CHANGE.

A. The EMT requirements will be overwhelming for small oil and gas operators. It is unclear if the Department has analyzed the technical complexity such an approach will have on small business owners involved in the oil and gas industry, much less the cost. To demonstrate, I have evaluated the implications of Monitoring Tag Options and Costs, and how they will impact small oil and gas business owners.

(i) Monitoring Tag Options

While this approach has been used in refineries and major facilities, IPANM is unaware of its use for unmanned dispersed sites covering thousands of square miles in New Mexico, which constitute upstream oil and gas activities. The three options presented in the rulemaking, RFID (Radio Frequency Identification), QR (Quick Response) codes and bar codes will require frequent monitoring to ensure they remain intact considering weather condition and the normal scratching and smudging that occurs over time. It should be noted that RFID tags are much more expensive than QR and bar codes.

Since these tagging options have not be used at dispersed oil and gas sites before, smaller companies do not have the experience to choose which tagging option is technical preferable. In addition, it is not clear if tagging will be required for units such as tanks, VRU, dehydrator, pneumatic controllers, or if it includes components subject to leak detection and repair (LDAR). If all LDAR components are included (valves, connectors, etc.), the complexity of installing tags increases dramatically. Small businesses do not have the financial resources or staffing to implement tagging requirements that do not appear to have a practical application in conditions where upstream oil and gas activities occur.

(ii) Costs

(a) Tagging. The costs incurred for installing a type of monitoring code on operational equipment cannot be ignored. IPANM contacted an air quality consultant who was requested to provide a preliminary quote on placing a barcode system at a multi-well site based upon the consultant's reading of the current proposal. The costs were almost $2,000. However, if you include LDAR components to the tagging, the cost increase in a range between $41,000 to $48,000, depending upon the type of tagging option chosen. This is due to the large increase in having to tag a few dozen units to over 2,300 for a multi well pad if LDAR components are included

(b) System Implementation. Tagging the equipment is only the initial step of the proposed regulatory process. Next, a system must be purchased and implemented so the owner or operator can manage the source's information in a database that can generate a Compliance Database Report ("CDR"), as required by the proposed regulations. The only way this can be achieved is to have a computer-based record system to compile the information. IPANM contacted a company involved in environmental management systems, and the preliminary quote provided to us based on its review of the proposed rule was a range of $95,000 to $145,000. That does not include annual maintenance fees which could be in the range of $10,000 annually. In addition, cyber security of any operating system is mandatory and will be a major consideration regarding accessibility and access to the data. . IPANM was unable to anticipate what the Department considers an adequate CDR, so the costs could rise even more depending upon Department increases.

(c) Independent Verification of Data. The proposed rule allows the Department to have a third party audit an operator's EMT at the expense of the operator.

Upon contacting an environmental consulting firm, they indicated the type of review contemplated in the rules would be approximately $5,000 for a single vertical well site which would include field audit of the site, desktop audit (verify tag function and linking) and desktop audit for compliance verification. For a multi-well horizontal well pad the costs would be approximately $7,600 for conducting a field audit and desk top audits.

(d) **Staffing**. IPANM anticipates additional staffing or contractor assistance will be needed to meet the requirements of EMT. This includes tagging all the units or emission points and uploading data and information into the management system to generate a CDR report. Based upon the current rule, it appears to upload required data and information to the operating system would require as much as a full-time equivalent person likely in the form of a contractor and at least half the time of another contractor to initially tag all the equipment subject to the rule and inspect locations afterwards to ensure the tags are intact. This could vary depending upon the number of wells and facilities, but the costs for contractors to implement this program is likely to exceed $150,000 annually which will be a significant cost burden for independent oil and gas companies.

(e) **Total Costs**. The costs IPANM has compiled will be a significant expense for independent oil and gas owners and operators. This analysis leads to one conclusion: EMT implementation is going to have a major impact on small oil and gas business operators and the members of IPANM for a benefit which cannot be clearly identified to reduce ozone precursor pollutants.

A one-size fits all prescriptive tagging and database system is not necessary. What is wrong with the current system of record keeping that individual companies currently use? If the Department requests verification on monitoring or record-keeping, the information can be provided by the operators upon request.

We are unaware the current approach is not working. While there are costs in responding to agency requests for information, those pale in comparison to the costs small businesses will be forced to absorb and implement EMT. In addition, these costs, which must be incurred as operating expenses, will not only impact profitable wells, but will place at risk marginal and stripper wells across the state, resulting in pre-mature abandonment and eliminating an important source of revenue to federal, state, and local government.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

David R. Brown
DJR Operating, LLC
1 Road 3263
Aztec, NM 87410

Professional Experience

Mr. Brown has over forty years of regulatory and field experience in oil and gas exploration and production. He has worked in California, Colorado, New Mexico, Wyoming, Utah, Montana, and North Dakota which includes eleven National Forests and numerous BLM offices as well as tribal nations. His specific job titles have included Field Environmental Coordinator, Regulatory Advisor, Manager-Regulatory Affairs and Director-Government and Public Affairs. Mr. Brown is currently the Manager of Regulatory, Government and Public Affairs for DJR Operating, LLC in Aztec, NM.

Professional Employment History

DJR Operating, LLC-New Mexico	2018-Present
Airswift Worldwide (Consulting Services) Clients	2010-2018

- BP America
- Chesapeake Energy
- Fidelity Exploration and Production
- Ward Petroleum

BP America Production Company – various locations	2000-2010
Amoco Production Company – various locations	1977-2000

Specific Employment Experiences

Air issues
- Industry participant in the Four Corners Air Quality Task Force.
- Air permit preparation and compliance for field and facility operations.
- Former Colorado Air Quality Control Commissioner.
- Preparation of air quality related monitoring programs.

Federal experience
- Managed Federal land use planning analysis and comment preparation
- Managed National Environmental Policy Act (NEPA) environmental assessments and environmental impact statements for public land projects

Waste Management/Remediation
- Prepared waste management plans and waste site audits.
- Prepared and implemented stormwater management plans

Water
- Researched and developed pilot testing of coalbed methane produced water treatment technologies
- Conducted baseline domestic water well testing program in various operational areas. .
- NPDES surface discharge permit preparation, implementation and monitoring.

IPANM EXHIBIT 5

Education

University of Denver, Denver, CO

- MS Environmental Management and Policy

Oral Roberts University, Tulsa, OK

- BS Business Administration

Professional Affiliations

- Former Colorado Appointee, Interstate Oil and Gas Compact Commission
- Former Co-Chair-Environmental Affairs Committee; New Mexico Oil and Gas Association
- Former Board Member, New Mexico Oil and Gas Association
- Former Chairman, Public Lands Committee; Petroleum Association of Wyoming
- Former Board Member; Public Lands Advocacy
- Former Chairman, Public Lands Committee; Rocky Mountain Oil and Gas Association

STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF:

PROPOSED NEW REGULATION,
20.2.50 NMAC – OIL AND GAS SECTOR –OZONE PRECURSOR POLLUTANTS

No. EIB 21-27(R)

DIRECT TESTIMONY OF DOUG N. BLEWITT, AIR QUALITY RESOURCE MANAGMENET ON BEHALF OF THE INDEPENDENT PETROLEUM ASSOCIATION OF NEW MEXICO

July 28, 2021

IPANM EXHIBIT 6

Direct Testimony of Doug N. Blewitt
No. EIB 21-27 (R)

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Doug N. Blewitt. My business address is 6077 Highwood Park Court, Naples Florida 34110.

Q. ON WHOSE BEHALF ARE YOU SUBMITTING DIRECT TESTIMONY?

A. The Independent Petroleum Association of New Mexico

Q. BY WHOM ARE YOU EMPLOYED AND WHAT IS YOUR POSITION?

A. I am a Certified Consulting Meteorologist (379). Since 1999, I have been employed by Air Quality Resource Management.

Q. PLEASE DESCRIBE YOUR PAST EMPLOYMENT HISTORY.

A. From 1980 to 1999, I was employed by Amoco/BP and provided in-house air quality expertise to all Amoco operating companies (refining, chemical, production, and minerals). In addition, during my time at Amoco/BP, I was instrumental in obtaining many PSD and minor source air permits, participated in air quality research programs and control technology evaluation.

In 1999, I was appointed by the Governor of Colorado to the Colorado Air Quality Control Commission, where I served as Technical Secretary. I served in that capacity until 2005.

Q. WHAT ARE YOUR RESPONSIBILITIES AS A CERTIFIED CONSULTING METEROLOGIST?

A. In general, I develop technical solutions for industry when it encounters challenging air quality and process safety problems. The items listed below are representative of typical projects that I have undertaken as a Certified Consulting Meteorologist:

- Advocacy support regarding EPA National Ambient Air Quality Standards which illustrated technical issues for the ozone NAAQS determinations from stratospheric intrusion in elevated terrain which could result in exceedance of the NAAQS for ozone
- As part of that analysis it was found that the down welling algorithms in regional models overstated downward mixing.
- Detailed analyses were developed and communicated that outlined technical deficiencies in the proposed NOx and SOx secondary standard or an urban visibility standard
- Co-authored peer review papers on background ozone.
- Developed a screening methodology concept for NO2 modeling that has been adopted by EPA
- Developed a hazard response system for accidental releases from Oil and Gas operations
- Directed a scientific field program for release of HF at the Nevada Test Site
    - Results aided in the development of air quality models for accidental releases at an actual facility
    - Directed a research program to assist in the design of HF mitigation systems for oil refineries and a chemical plant
- Conducted regional air quality analyses for Oil and Gas operation EISs utilizing photochemical modeling for AQRVs (deposition and visibility) and NAAQS including ozone.
- Submitted detailed technical comments on FLAG and Regional Haze Rule

- Participated in the development and implementation of the WRAP WestJump Project to build regional modeling databases for agencies and EIS analyses
- Provided air quality impact analyses for the BP Gulf of Mexico oil spill.
- Designed a WRAP field program for evaluating accuracy of NO2 modeling for drilling rigs
- Participated in the evaluation and understanding of Wyoming winter ozone phenomena
- Participated in air quality technical expert review panels
- Participated and helped direct the Four Corners Regional Air Quality Study

Q. PLEASE DESCRIBE YOUR EXPERIENCE WITH THE OZONE PRECURSOR POLLUTANTS OF THE OIL AND GAS SECTOR PROPOSED FOR REGULATION UNDER 20.2.50 NMAC.

A. I have been involved in western air quality since 1995, both from an air quality perspective (both modeling and monitoring), as well as the evaluation and implementation of controls for oil and gas sources. I helped develop the presumptive BACT approach by the state of Wyoming. That work included the developed of an approach for evaluating presumptive BACT for sources with variable emission rates, as a result of production decline.

I have also been involved in research to address the accuracy of the quantification of methane emissions using ambient monitoring and inverse modeling.

Q. PLEASE SUMMARIZE YOUR EDUCATIONAL EXPERIENCE.

A. In 1969, I obtained a Bachelor of Arts degree in chemistry and physics from Milton College. From 1969 to 1970, I completed graduate coursework in the Department of Water Chemistry at the University of Wisconsin. A copy of my resume is attached as **IPANM Exhibit 7.**

Q. HAVE YOU PREVIOUSLY TESTIFIED IN STATE OR FEDERAL REGULATORY PROCEEDINGS ON OZONE PRECURSOR POLLUTANTS?

A. I have testified in EPA Clean Air Scientific Advisory Committee (CASAC) hearings for NAAQS rule making revisions. I have testified and commented many times to EPA regarding air quality modeling scientific issues, methodology and policy issues.

II. PURPOSE OF TESTIMONY

Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY?

A. The purpose of my testimony is to provide IPANM's position on NMED's proposed scope of Part 50 in 20.2.50.2 NMAC.

III. IPANM'S EVALUATION OF NMED'S PROPOSED REGULATIONS

Q. PLEASE IDENTIFY THE REGULATIONS PROPOSED BY NMED THAT YOU ARE ADDRESSING IN THIS TESTIMONY.

A. I will be addressing the following section:

- 20.2.50.2 NMAC—Scope

Q. HAVE YOU REVIEWED NMED'S STATEMENT OF REASONS FOR THESE PROPOSED REGULATIONS, FILED AS ATTACHMENT 3 TO NMED'S ORIGINAL PETITION [PDF 37-48]?

A. Yes.

1. NMED'S PROPOSED REGULATIONS TO SCOPE SECTION (20.2.50.2 NMAC)

Q. PLEASE SUMMARIZE YOUR UNDERSTANDING OF NMED'S PROPOSAL OF 20.2.50.2 NMAC.

A. NMED's proposal applies to sources located within areas of the state under the Board's jurisdiction that, as of the effective date of the proposed rule or anytime thereafter, are causing or contributing to ambient ozone concentrations that exceed ninety-five percent of the national ambient air quality standard for ozone, as measured by a design value calculated and based on data from one or more department monitors as specified in the EPA ozone NAAQS. The rule further states that once a source becomes subject to the rule, the requirements of the rule are irrevocably effective, unless the source obtains a federally enforceable air permit limiting the potential to emit to below such applicability thresholds established in Part 50.

Q. WHAT IS YOUR POSITION ON NMED'S PROPOSAL OF 20.2.50.2 NMAC?

A. I believe it is premature to regulate NOx and VOC emissions from oil and gas facilities until NMED addresses the many technical issues and uncertainties associated with the modeling, baseline emission inventories associated with base case, and providing documentation regarding future year inventories that were used to predict future year impacts. Further, the way that the modeling was conducted, it is not possible to identify ozone benefits from NOx control compared to VOC controls. Combining results for NOx and VOC emissions precludes identification control benefits for NOx and VOCs resulting from non-linear ozone chemistry. If reductions in ozone are deemed necessary, control strategies should be developed on a regional basis (by county) to ensure that focused regional emissions will produce meaningful ozone reductions. Many of the ozone monitors have design values below the threshold level specified in the draft regulation and should be exempt from the installation of new controls.

Q. ARE YOU RECOMMENDING CHANGES TO NMED'S PROPOSAL?

A. Yes. Based on my analysis of (a) relative source contribution to monitored ozone impacts, (b) emission inventory uncertainties, and (c) proposed emission reductions for oil and gas operations, IPANM generally opposes additional proposed oil and gas controls because they result in an insignificant improvement in ambient ozone concentrations.

Q. PLEASE EXPLAIN THE BASIS FOR THIS PROPOSED CHANGE.

A. My analysis of the impacts from NMED's proposed rules that are the subject of this hearing are included in my PowerPoint Presentation, **IPANM Exhibit 8.**

(a) Relative Source Contribution to Monitored Ozone Impacts

I computed the ozone design value for the following: (a) Bloomfield, Navajo Lake, and Sub-Station Monitors and determined the ozone-source contribution to San Juan Monitors; (b) Dona Ana Monitors (La Union, Sunland Park, Chaparral, Desert View, Santa Teresa, Solano), and (c) Carlsbad City Monitor.

I reviewed the NMED ozone monitoring data and modeling. The contribution to ozone design values from New Mexico sources: for: (a) Navajo Lake, Bloomfield, and the Substation is 5.6 ppb, 4.8 ppb and 6.4 ppb, respectively; (b) Dona Ana Monitors is 3.4 ppb, and; (c) Carlsbad City Monitor is 1.9 ppb. The remainder of ozone impacts derive from sources outside the State of New Mexico.

IPANM Exhibit 8, slide 7 contains a bar diagram of predicted ozone contributions that derive impacts from sources outside the borders of the State of New Mexico. For all monitors, New Mexico source impacts are a small fraction of total ozone. In fact, sources beyond New Mexico are responsible for the majority of ozone. The Desert View monitor reported the largest measured ozone design value. The largest predicted source category ozone impacts (0.9 ppb) are from electric generating unit emissions. The combined predicted total Oil and Gas ozone impacts are only 0.5 ppb. Reported Oil and Gas ozone contributions are from combined NOx and VOC emissions. Because of ozone formation non-linear chemistry, Oil and Gas ozone impacts, and ozone impacts from NOx emissions, must be separated from VOC impacts.

As a result of this analysis, I have concluded that the majority of ozone detected within New Mexico is transported from sources located outside of the boundaries of the state. The State of New Mexico has no regulatory authority to regulate ozone reductions beyond its borders. New Mexico is not the only state facing this issue, as other states have similar ozone-compliance issues with the NAAQS. As control strategies for those areas and regions are developed, ozone transport into New Mexico will be reduced.

I have also used the modeling results to calculate current ozone design values and projected zone concentrations for future cases. The monitored ozone design values from the 2012 to 2016 period (period used in the Technical Support Document, "TSD") were compared to design values in the case for year 2028. The 2028 year case considered growth in emissions and future controls. A controlled 2028 case was developed with additional controls applied on Oil and Gas sources for both NOx and VOC emissions. The controlled 2028 case results indicate the design value, as well as the change in monitored and predicted ozone. The predicted Oil and Gas results combine both monitoring and modeling. This combination is appropriate considering the analyses conducted.

I computed and analyzed ozone concentrations for different emission scenarios at the San Juan ozone monitors. At the Navajo Lake monitor (dv=67 ppb), the 2028 future year base case predicted impacts are 64.8 ppb and a reduction of 2.2 ppb (no additional controls on Oil and Gas). If additional Oil and Gas controls are implemented, the 2028 design value is reduced to 63.3 ppb (a decrease of 1.5 ppb). Results indicate future case compliance with the 70 ppb NAAQS and the 66.5 ppb safety factor threshold. Compliance is therefore demonstrated without the implementation of additional Oil and Gas controls.

I also examined the modeled and analyzed changes in ozone concentrations for different emission scenarios at the Dona Ana ozone monitors. At the Desert View monitor (dv=72 ppb), the 2028 future year base case predicted impacts are 67 ppb and a reduction of 5 ppb (no additional controls on Oil and Gas). If additional Oil and Gas controls are implemented, the 2028 design value is reduced to 66.7 ppb (a decrease of 0.3 ppb). These results demonstrate future case compliance with the 70 ppb NAAQS. Compliance with the 66.5 ppb safety factor threshold is demonstrated. The results indicate future case compliance with the 70 ppb NAAQS and the 66.5 ppb safety factor threshold. Most significantly, compliance is therefore demonstrated without the implementation of additional Oil and Gas controls. Implementing the Oil and Gas control strategy results in an insignificant improvement in ozone (decrease of 0.3 ppb).

From my study of ozone from the 2028 future year base case using the 2012-2016 data, I have concluded the following: (a) for the 2012-2016 timeframe, the only monitors that have a design value above the NAAQS are Desert View and Santa Teresa 72.0 and 71.3 ppb, respectively; (b) the Carlsbad monitors are the only monitors with design values above 66.5 ppb (95 % of the 70 ppb NAAQS); (c) for the 2028 base case, all modeled design values are below 66 ppb, which suggests that the 2028 base case ambient ozone levels are in compliance with the threshold of 95 % of the NAAQS, and (d) if different years are used for the design value, slightly different conclusions are found. According to the TSD, the use of the 2012-2016 baseline follows EPA guidance.

From my study of ozone from the 2028 future year base case using the 2012-2016 data, I have made the following conclusions. First, for the 2015-2019 timeframe, the Chaparral, Desert View, Santa Teresa, Carlsbad and Carlsbad Cavern monitors have a design value above the 70 ppb NAAQS. Second, for the 2015-2019 time frame, the Foot Hills (located in Albuquerque), La Union, Solano, and Navajo Lake monitors have a design value in excess of 66.5 ppb (95 % of the 70 ppb NAAQ) threshold.

Third, for the 2028 base case, all monitors are below the 70 ppb ozone NAAQS except Carlsbad. The 2028 control base case reduces the design value from 73.7 ppb to 71.2 ppb (reduction of 2.5 ppb). The implementation of the Oil and Gas control strategy (NOx and VOC combined) reduces the design value to 70.9 ppb (a reduction of 0.3 ppb). The modeling demonstrates that the Oil and Gas control strategy is ineffective in reducing ozone at this monitor.

Fourth and finally, for the 2028 base case, only the Desert View and Santa Teresa monitors have concentrations above 66.5 ppb (95% of the 70 ppb NAAQS). The implementation of the Oil and Gas control strategy (NOx and VOC combined) reduces the design value by a maximum of 0.2 ppb. Thus, it follows that controls on Oil and Gas sources is a largely inefficient method and means of reducing ozone at this critical monitor.

(b) Emission Inventory Uncertainties

The NMED TSD does not contain data regarding the derivation of the base case emission inventory, and results in insufficient data to verify the base case modeling. The 2028 future year base case provides no documentation for emission calculations, emission growth (by source category), as well as assumptions regarding emission reductions that will be implemented as a result of new control requirements that are required by the proposed promulgated regulation or other programs, including regional haze.

Growth assumptions for Oil and Gas sources are critical because growth for many sources is contingent on production levels, as well as rate of drilling for new wells. A review of the Mancos Farmington Mancos Gallup Draft Resource Management Plan Amendment and Environmental Impact Statement identified numerous issues with the Mancos modeling inventories. The Mancos analysis is directly related to the New Mexico O3 Attainment Initiative Photochemical Modeling Study.

Electric generating units ("EGU") represent a large power-plant emission source in New Mexico, and large EGU sources exist beyond NM borders that impact New Mexico ozone levels. The TSD developed provides limited documentation on EGU sources included in the inventory, as well as information supporting the 2028 emission reductions. The Technical Support Document presents the following NOx emission data for EGUs: (a) EGU 2014 base case NOx emissions 43,071 t/yr; (b) EGU 2028 future year case NOx emissions 13,389 t/yr; (c) Difference -29,682 t/yr; (d) EGU 2014 EIA NOx emissions are listed as 60,158 t/yr; (e) difference between NOx modeling and EIA inventories is approximately 17,000 t/yr; (f) no documentation is provided regarding how the 2014 EGU modeling inventory was developed and why it is vastly different than the 2014 EIA inventory, and (g) several EGU facilities have announced closure of coal-fired plants and the only statement made in the TSD is that Units 4 and 5 will continue to operate at the Four Corners Power Plant in 2028.

For Oil and Gas emission inventories, documentation is lacking on the underlying assumptions used to formulate Oil and Gas emissions for the 2014 base, 2028 growth, and

2028 Oil and Gas control cases. For NOx emissions, there is approximately a 34 % increase in emissions between the 2014 base case and the 2028 growth case, while, for VOCs, the difference between the 2014 base case and the 2028 growth base case indicates a 42% decrease. It does not seem reasonable that there is substantial growth in NOx sources while there is a simultaneous reduction in VOC emissions from the same sources. Assumptions used in developing the NOx and VOC inventories do not appear to be consistent. The production decline will result in emission reductions for some NOx and VOC emissions.

All production from Oil and Gas wells will exponentially decrease over time. Production decline is offset by drilling new wells, which slows the rate of overall decline. As well production declines, some Oil and Gas emissions from selected sources will be reduced (e.g., compressors (NOx), dehydrators (NOx and VOCs) and tanks (VOCs). The reduction in emissions from decline occurs for both NOx and VOCs. In most Oil and Gas inventories for existing wells, decline is not accounted for. Typically, in future year inventories, new well emissions at initial production are added to existing wells at initial production and result in substantially overstating actual emissions. The lack of documentation regarding Oil and Gas inventories prevents confirmation of values used in the modeling.

As an example of production decline, new wells are drilled in a basin to replace declining production in existing wells. Emissions from sources which are dependent on production rate will be reduced as production declines (compressors, dehydrators, tank emissions, liquid unloading etc.). *See* IPANM Exhibit 8, slide 21. In addition, IPANM Exhibit 8, slide 22 shows examples of changes over time in well head equipment and emissions. IPANM Exhibit 8, slide 23 highlights the importance of decline in wellhead compressor emissions. The example is based on the high rate of development case from Mancos RMP over a 10-year drilling program, which indicates a 500 t/yr reduction in projected emissions over a ten year period.

For the changes in NOx emissions in the Mancos maximum development case, the total reduction in NOx over a non-decline case shows gas reductions in gas and oil and for 1,075 t/yr and 1,447 t/ty. Table 2-10 on IPANM Exhibit 8, slide 25 shows the changes in Mancos VOC emissions for Maximum Development Case by incorporating decline. Figure 2.8 on IPANM Exhibit 8, slide 26 charts the comparison of VOC flashing emissions from draft and actual well design being implemented in Mancos for BLM wells. Figure 2.9 on IPANM Exhibit 8, slide 27 plots produced VOC emissions from BLM wells with and without production decline.

(c) Proposed Emission Reductions for Oil and Gas

Under the procedure for heaters, the San Juan basin application of the proposed rule to existing sources for heaters would affect only five sources and reduce NOx emissions by 19 t/yr. Retrofitting heaters for NOx controls in the San Juan basin will have an insignificant effect on local ozone concentrations. Furthermore, the installation of low NOx burners for a 10 MMBtu/hr heater will result in the following: (a) Assume 50% control; (b) 30 ppm emission standard based on CARB BACT, and; (c) for new 10 MMBtu/hr heaters, the proposed regulation using low NOx burners at 100% load would reduce emissions from 4.4 t/yr to 2.2 t/yr.

First, in my summary of emission reductions and control cost effectiveness for a new 10 MMBtu/hr heating under the proposed regulations, the application of NOx controls for heaters with a threshold of 10 MMBtu/hr is not cost effective (90 % load control costs are estimated to be $9,185/ton). Second, actual load may be closer to 50% and control costs are approaching $16,533/ton. Third, the emission standard of 30 ppm is based on CA BACT analysis (equivalent to LAER in the rest of US). Fourth, it is recommended that NMED consider a capacity threshold of 50 MMBtu/hr. Fifth and finally, the use of the CARB cost effective control based on CARB BACT (LAER other portions of US) at $2,200/ton is a reasonable cost effective threshold. However, NMED should consider establishing an emission threshold resulting in a reduction in ozone. A reduction of 19 t/yr on heaters in the San Juan basin is not a meaningful NOx reduction to reduce ozone.

In comparing ozone reductions from NOx and VOC controls, controls for NOx and VOCs do not have the same effect on reducing ozone concentrations. Typically, a reduction in NOx emissions will be more effective than a reduction in VOC emissions (most areas are NOx limited). The ozone analysis combines NOx and VOC emission reductions for Oil and Gas; consequently, it is not possible to determine the effectiveness of VOC control in a NOx limited region. The NOx and VOC source impacts must be separated to evaluate the effectiveness of NOx versus VOC controls. The modeling displayed on Exhibit B-32 indicates that ozone formation is dominated by NOx emissions (NOx limited), which means that NOx controls are more efficient in controlling ozone concentrations, as opposed to VOC controls.

Thus, I conclude that monitoring and modeling analyses presented in the TSD do not support the need for additional controls on Oil and Gas sources. The emission inventories used in the modeling lack documentation for verification. The emission inventories for Oil and Gas do not include production decline, and likely overstate actual emissions (this will likely affect cost effective control evaluations). The modeling strongly indicates that ozone formation is NOx limited; however, the modeling cannot separate the effectiveness of NOx versus VOC controls.

IV. CONCLUSION

Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

A. Yes.

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Naples, FL 34110

Doug Blewitt
Certified Consulting Meteorologist (Number 379)

Experience

Air Quality Resource Management 1999-to Present
Developed technical solutions for industry for challenging air quality and process safety problems

Typical projects

- Advocacy support regarding EPA National Ambient Air Quality Standards – Developed comments that resulted in EPA not adopting a reduced ozone standard during the reconsideration of the standard
- Advocacy support regarding EPA National Ambient Air Quality Standards that resulted in EPA not adopting a NOx and SOx secondary standard nor an urban visibility standard
- Co-authored peer review papers on background ozone
- Developed a screening methodology concept for NO2 modeling that has been adopted by EPA
- Developed a hazard response system for accidental releases from oil and gas operations
- Assisted in the design of HF mitigation systems and consequence analysis for a chemical plant
- Conducted air quality analyses for oil and gas operation EISs
- Conducted industry support for oil and gas EIS analyses
- Developed the concept and participated in the development and implementation of the WRAP WestJump Project to build regional modeling databases for EIS analyses
- Provided air quality impact analyses for the BP Gulf of Mexico oil spill
- Designed a WRAP field program for evaluating accuracy of NO2 modeling for drilling rigs
- Participated in the evaluation and understanding of Wyoming winter ozone phenomena
- Participated in air quality technical expert review panels
- Participated and helped direct the Four Corners Regional Air Quality Study

Colorado Air Quality Control Commission 1999 to 2005

- Appointed by the Governor of Colorado
- Served as Technical Secretary
- Provided technical air quality experience and expertise to the Commission that developed Colorado air quality regulations

Amoco/BP 1980 to 1999

- Provided in house air quality expertise to all Amoco operating companies (refining, chemical, production and minerals)
- Lead project scientist for Amoco HF dispersion experiments (HF was released at the Nevada Test Site to understand the consequences of a loss of HF containment from a process unit)
- Co-author of HGSYSTEM suite of accidental release models that simulate a release of HF or other hazardous chemicals
- Designed HF mitigation systems for Amoco HF units (based on boundary layer and mathematical modeling)
- Developed an Auto Start Detection System that initiates mitigation in the event of an accidental release of HF
- Participated in hazard assessments of HF units
- Participated in the SIP development for Lake County, Indiana (a region with a refinery, three integrated steel mills, two coal fired power plants and many other industries)
- Instrumental in obtaining many PSD and minor source air permits
- Published numerous papers on advanced air quality analyses and emission controls

Education

Milton College BA 1969 Major Chemistry and Physics

University of Wisconsin 1969-1970 Department of Water Chemistry

IPANM EXHIBIT 7

Proposed Ozone Rule Comments

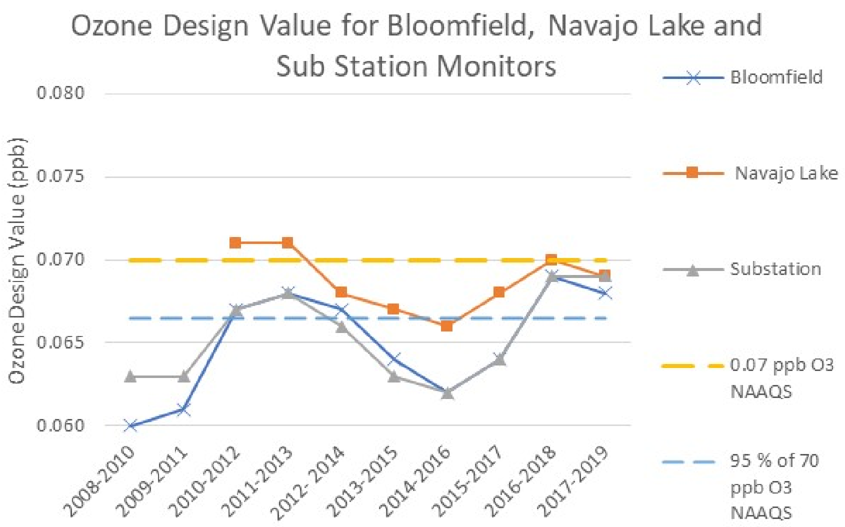
Doug N. Blewitt
Certified Consulting Meteorologist
Air Quality Resource Management (AQRM)
July 24, 2021

IPANM EXHIBIT 8

Topics of discussion

- Relative source contribution to monitored O3 impacts
- Emission inventory uncertainties
- Proposed emission reductions for Oil and Gas
- Conclusions

Relative Source Contribution to Monitored O3 Impacts



	Ozone Source Contribution to San Juan Monitors (ppb)							
Monitor	Oil pt	Oil non-pt	EGU	Non EGU	On Rd Mobile	Non Rd Mobile	Remain Anthro	Total from NM sources
Najavo Lake	0.8	2.1	1.7	0.1	0.4	0.3	0.2	5.6
Bloomfield	0.7	1.4	1.9	0	0.4	0.2	0.2	4.8
Substation	0.6	1.5	3.1	0.1	0.5	0.3	0.3	6.4

Modeling Assumptions

1) Oil point are mid stream sources
2) Oil non-point are production units
3) O3 contribution is for combined NOx and VOC emissions

Total O3 contribution from NM sources (NOx+VOC) at Navajo Lake 5.6 ppb, Bloomfield 4.8 ppb and Substation 6.4 ppb Remainder of O3 impacts from sources outside NM

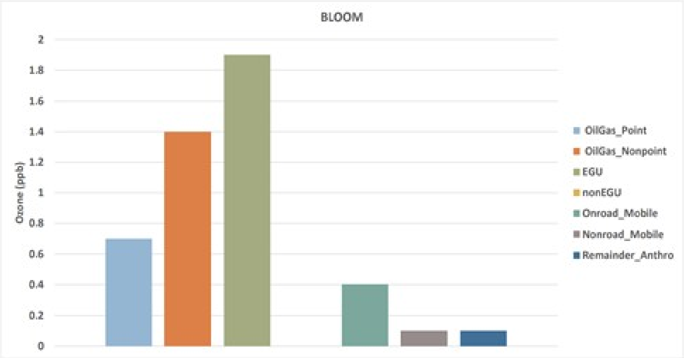


Figure 10-4. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at Bloomfield in San Juan County.

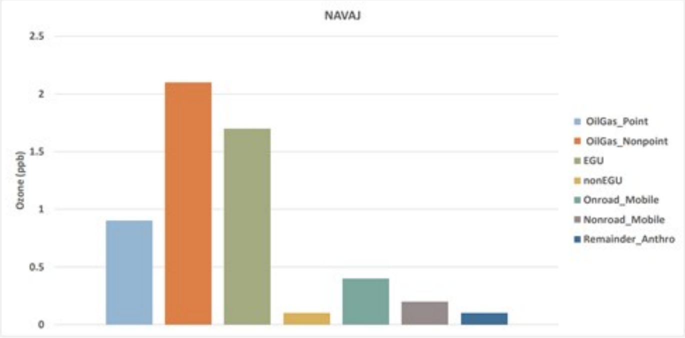


Figure 10-3. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at Navajo Lake in San Juan County.

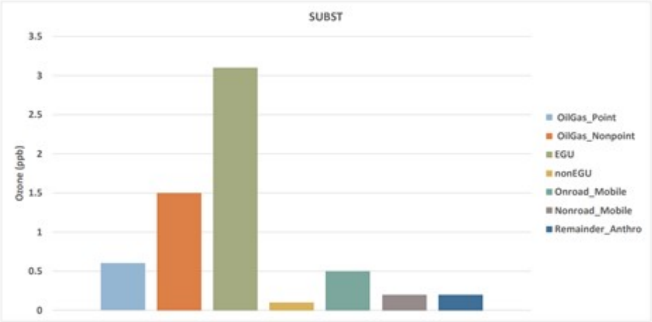
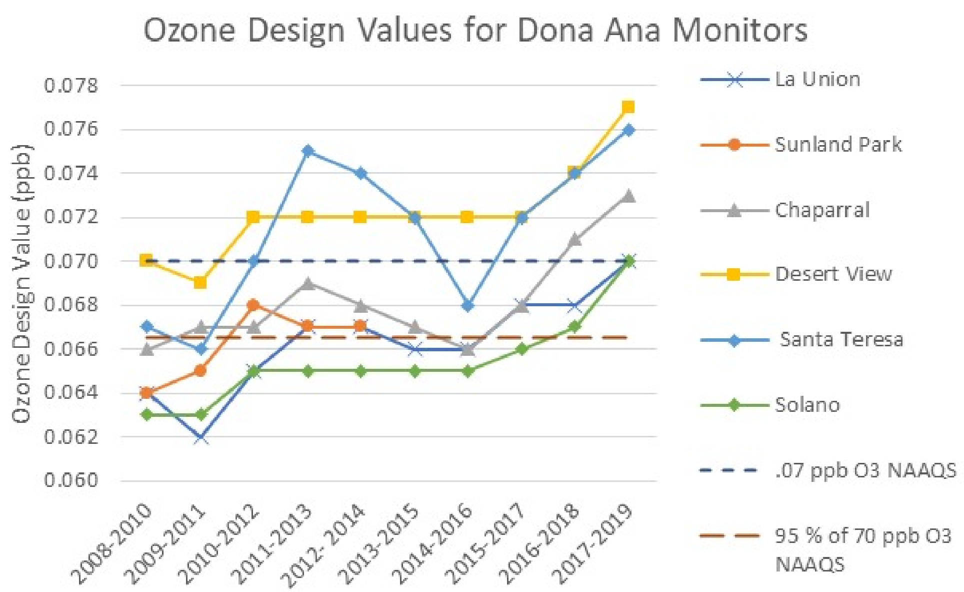


Figure 10-5. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at Substation in San Juan County.



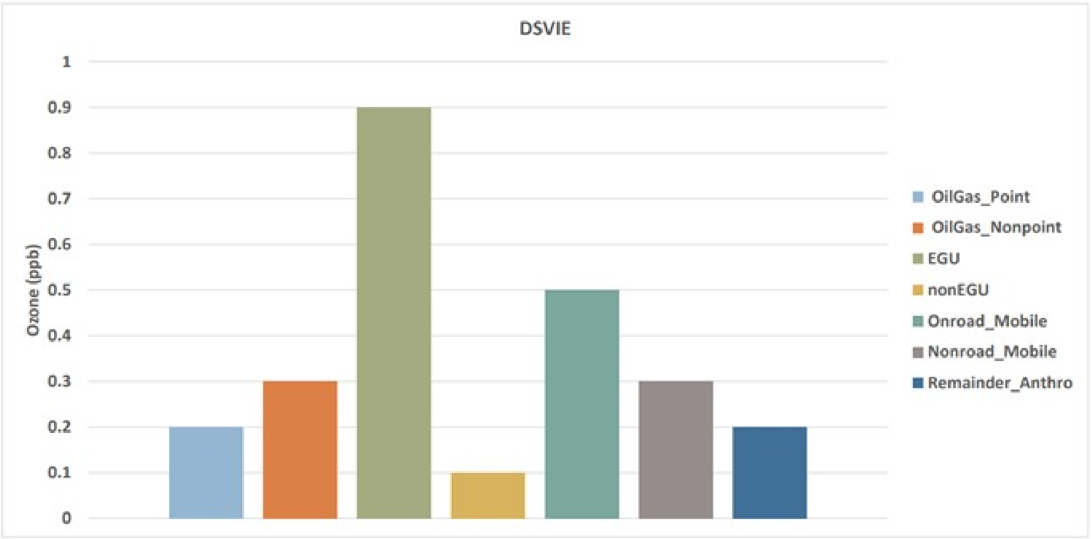
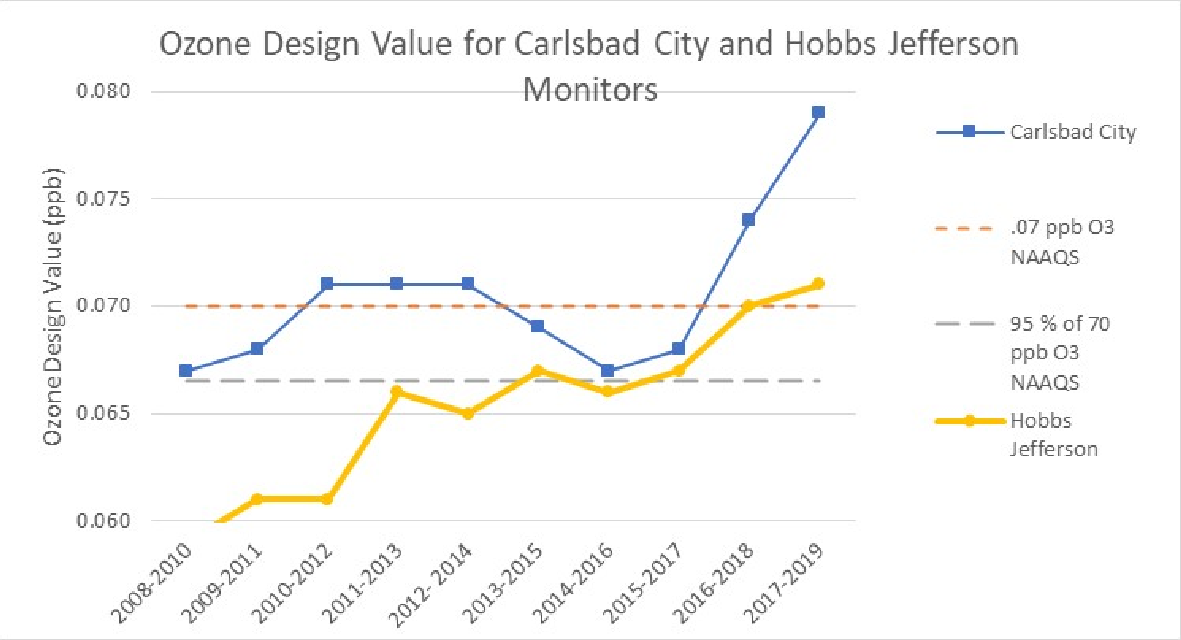


Figure 10-13. Contributions of New Mexico anthropogenic emissions from 7 Source Sectors to projected 2028 ozone DVFs at Desert View in Doña Ana County in southern New Mexico.

	Ozone Source Contribution to Dona Ana Monitors (ppb)							
Monitor	Oil pt	Oil non-pt	EGU	Non EGU	On Rd Mobile	Non Rd Mobile	Remain Anthro	Total from NM sources
Desert View	0.2	0.3	0.9	1	0.5	0.3	0.2	3.4

Modeling Assumptions
1) Oil point are mid stream sources
2) Oil non-point are production units
3) O3 contribution is for combined NOx and VOC emissions

Total O3 contribution from NM sources (NOx+VOC) 3.4 ppb.
Remainder of O3 impacts from sources outside NM



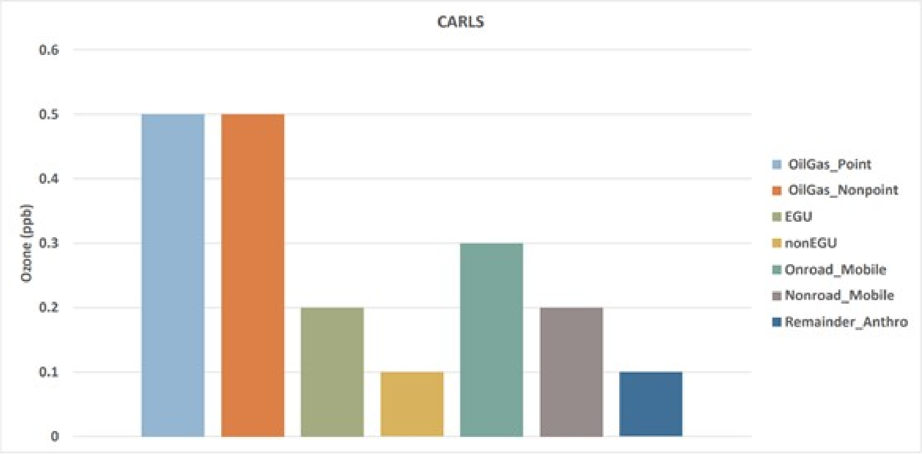


Figure 10-17. Contributions of New Mexico anthropogenic emissions for 7 Source Sectors to projected 2028 ozone DVFs at Carlsbad in Eddy County in southeastern New Mexico.

	Ozone Source Contribution to Carlsbad Monitor (ppb)							
Monitor	Oil pt	Oil non-pt	EGU	Non EGU	On Rd Mobile	Non Rd Mobile	Remain Anthro	Total from NM sources
Carlsbad City	0.5	0.5	0.2	0.1	0.3	0.2	0.1	1.9

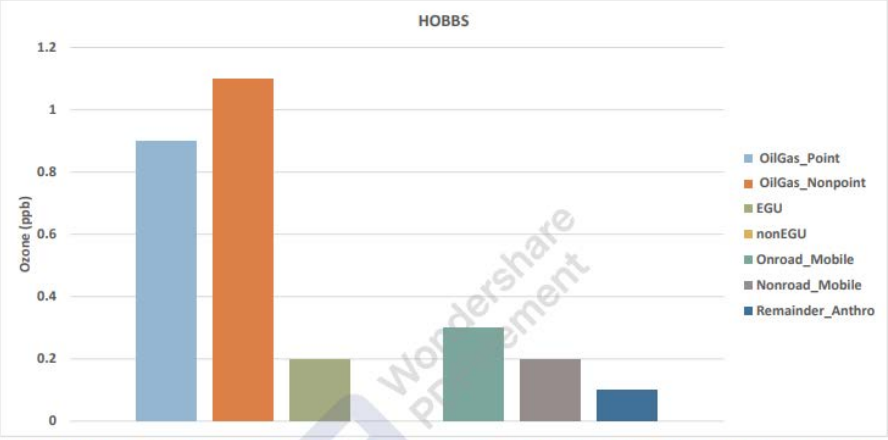


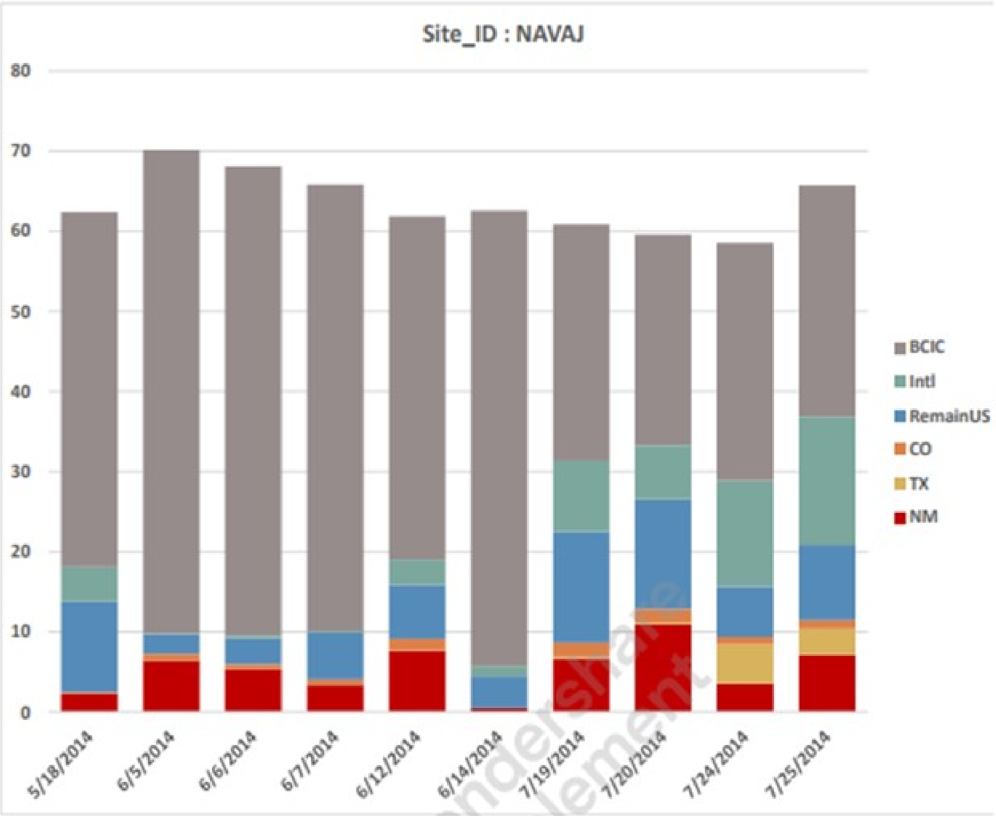
Figure 10-18. Contributions of New Mexico anthropogenic emissions for 7 Source Sectors to projected 2028 ozone DVFs at Hobbs in Lea County in southeastern New Mexico.

Modeling Assumptions
1) Oil point are mid stream sources
2) Oil non-point are production units
3) O3 contribution is for combined NOx and VOC emissions

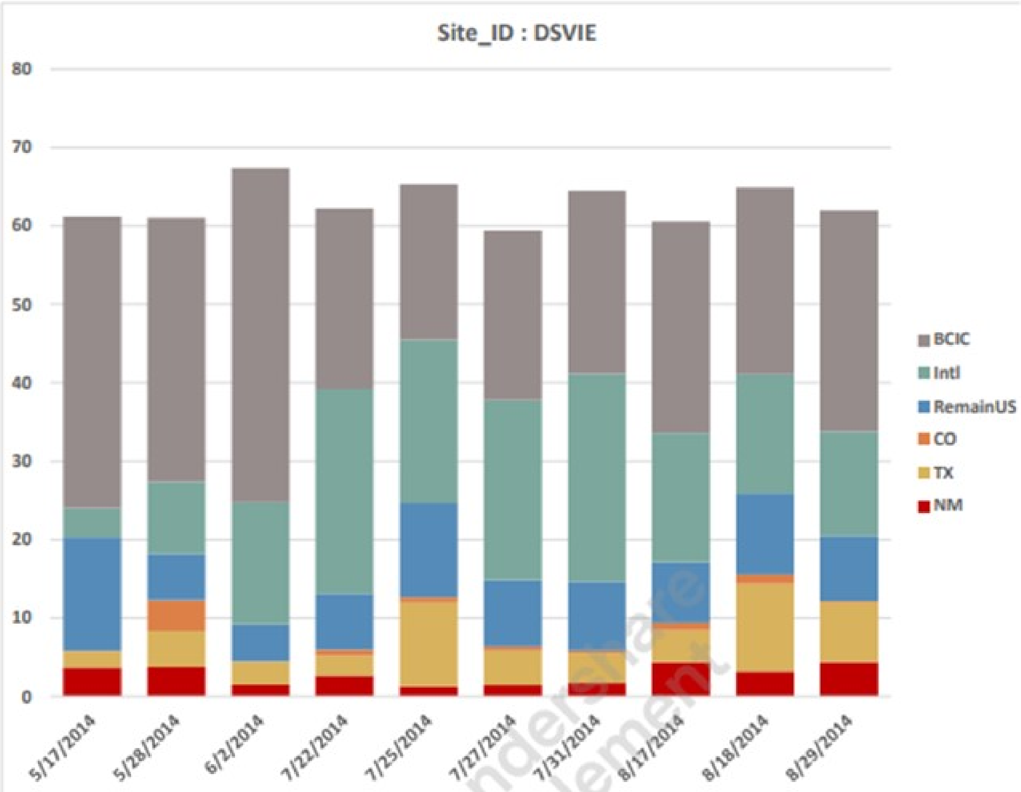
Total O3 contribution from NM sources (NOx+VOC) 1.9 ppb.
Remainder of O3 impacts from sources outside NM

O3 contributions from sources beyond New Mexico

Navajo Lake Monitor



Desert View Monitor



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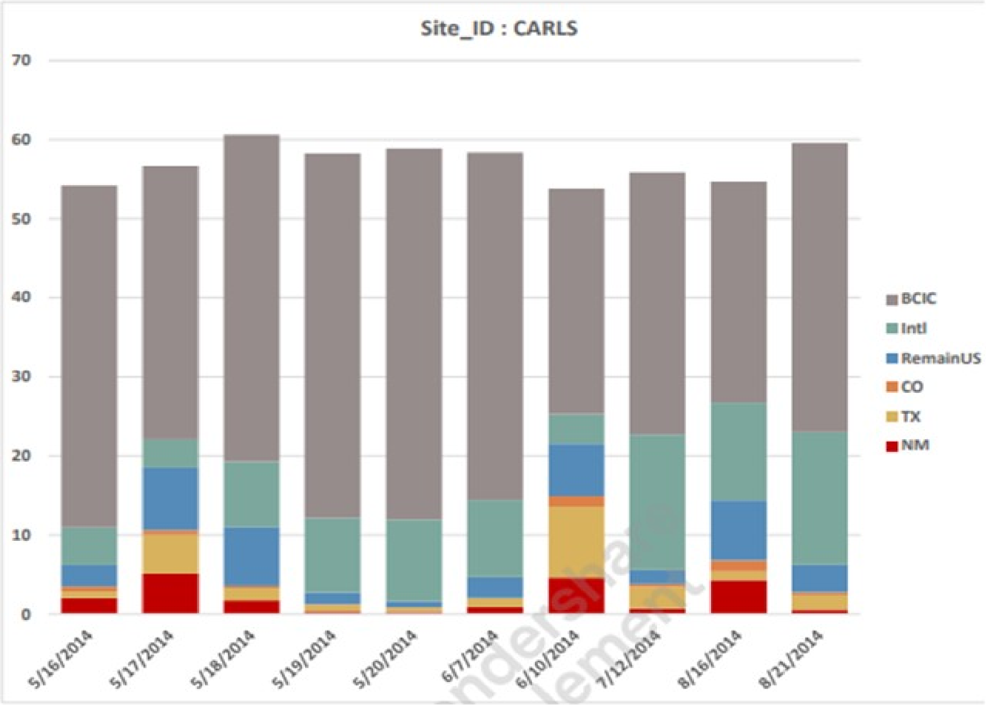
O3 contributions from sources beyond New Mexico



- Majority of O3 is transported from outside of New Mexico
- New Mexico has no regulatory authority for requiring reductions beyond its borders
- Other states have similar O3 compliance issues with the NAAQS and as control strategies for those areas are developed, O3 transport into New Mexico will be reduced

Note: 1) O3 contributions at the Hobbs Jefferson O3 monitor from sources beyond New Mexico are not provided in the TSD
2) The Hobbs Jefferson monitor, located on the New Mexico and Texas border, is likely influenced by Texas sources

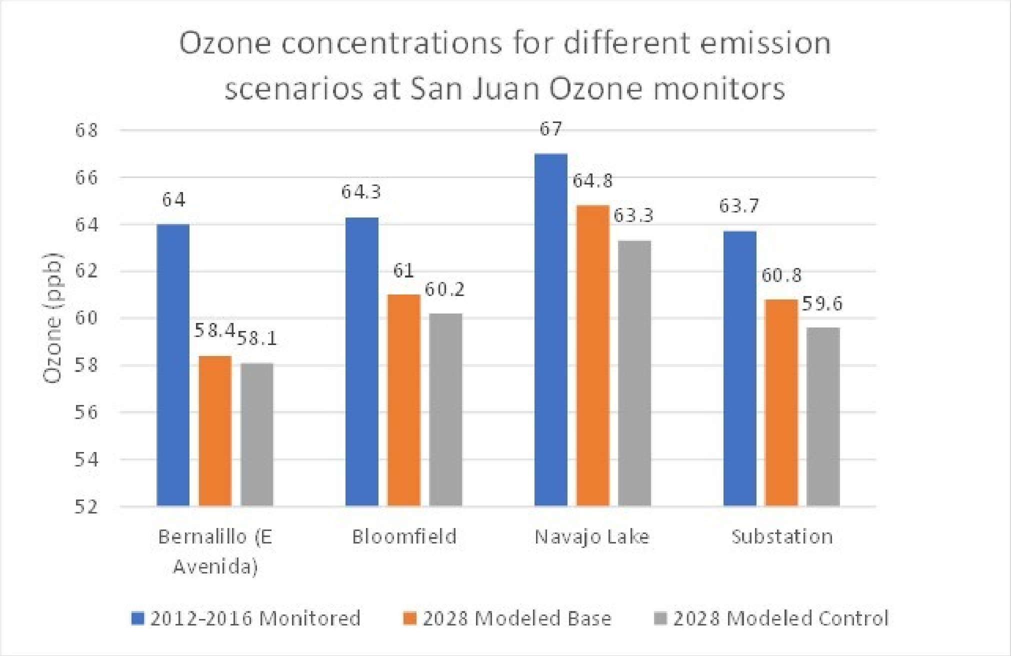
Source culpability findings

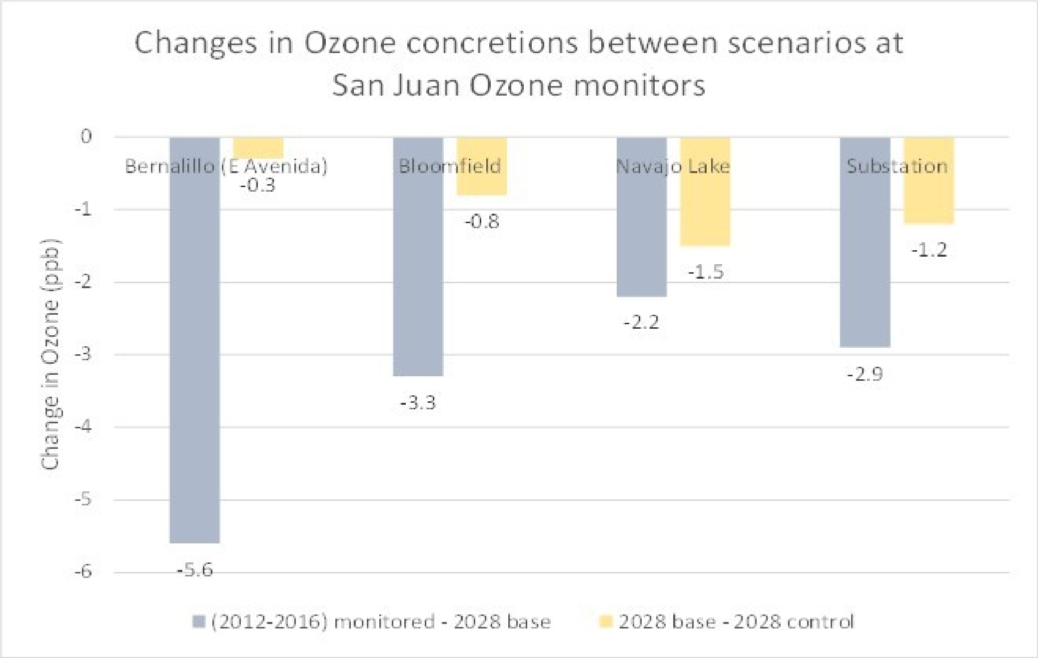
- For all monitors, New Mexico source impacts are a small fraction of total O3
- Sources beyond New Mexico are responsible for the majority of O3
- The Desert View monitor reported the largest measured O3 design value
  - The largest predicted source category O3 impacts (0.9 ppb) are from EGU emissions
  - The combined predicted total Oil and Gas O3 impacts are only 0.5 ppb
- Reported Oil and Gas O3 contributions are from combined NOx and VOC emissions
- Because of O3 formation non-linear chemistry, Oil and Gas O3 impacts and O3 impacts from NOx emissions must be separated from VOC impacts

Current O3 design values and projected O3 concentrations for future cases

- Monitored O3 design values for the period 2012 – 2016 (period used in TSD) were compared to design values in the 2028 year case
- The 2028 year base considered growth in emissions and future controls
- A controlled 2028 case was developed with additional controls applied on Oil and Gas sources for both NOx and VOC emissions
- The controlled 2028 case results indicate the design value as well as the change in monitored and predicted O3
- Predicted Oil and Gas results combine monitoring and modeling
    - This combination is appropriate considering the analyses conducted

Changes in O3 concentrations for alternate scenarios (San Juan monitors)





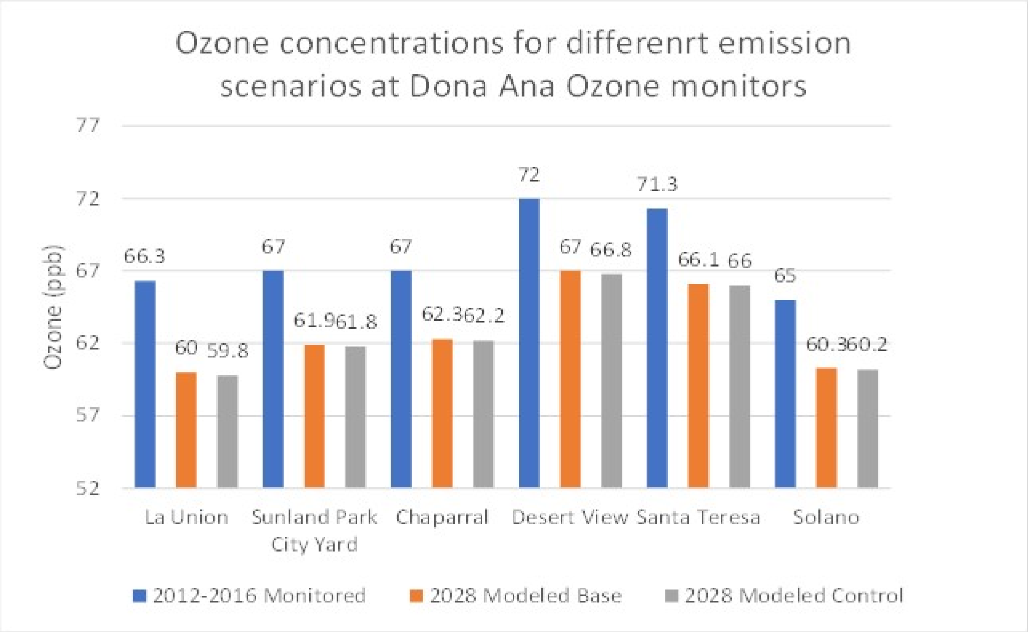
Notes:

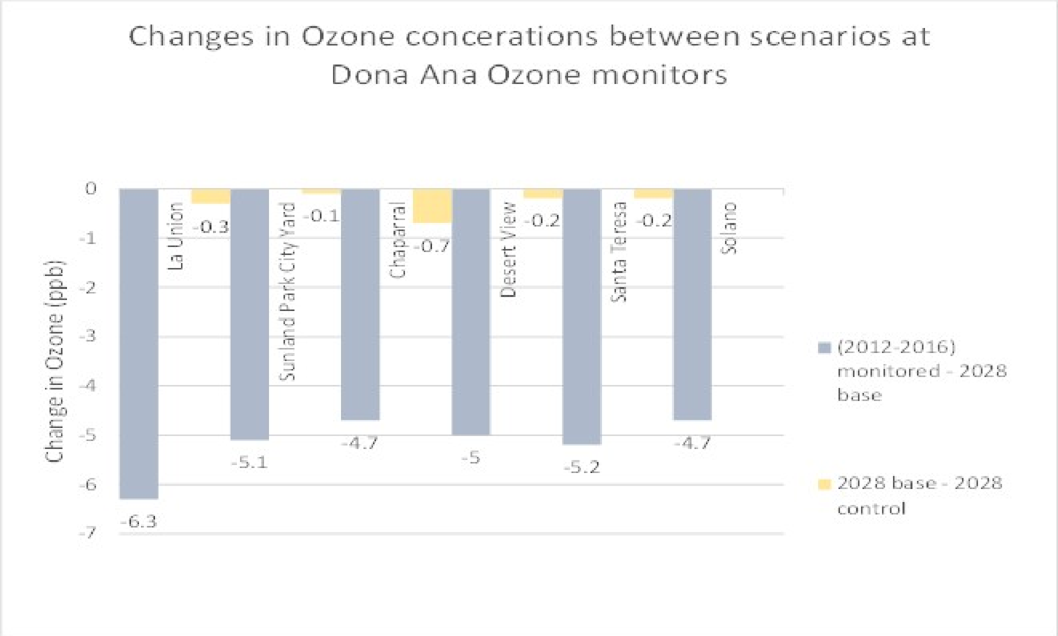
- NOx and VOC emission changes are combined
- 2012-2016 impacts are monitored not modeled

Conclusions

- **At the Navajo Lake monitor (dv=67 ppb) the 2028 future year base case predicted impacts are 64.8 ppb, a reduction of 2.2 ppb (no additional controls on Oil and Gas)**
- **If additional Oil and Gas controls are implemented, the 2028 design value is reduced to 63.3 ppb (a decrease of 1.5 ppb)**
- **Results indicate future case compliance with the 70 ppb NAAQS and the 66.5 ppb safety factor threshold**
- **Compliance is therefore demonstrated without the implementation of additional Oil and Gas controls**

Changes in O3 concentrations for alternate scenarios (southern NM monitors)





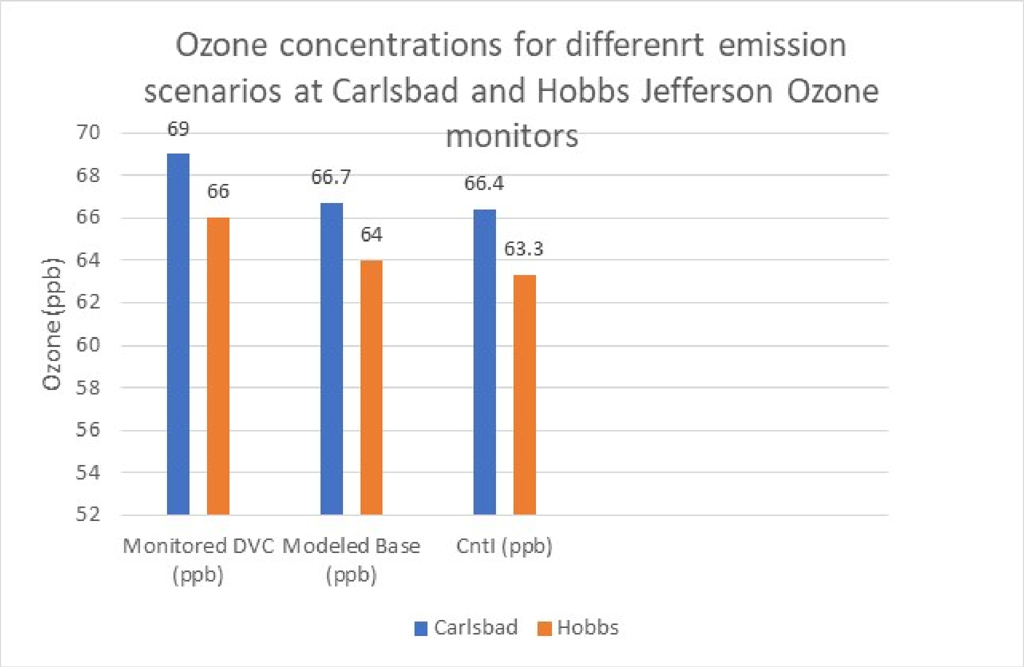
Notes:

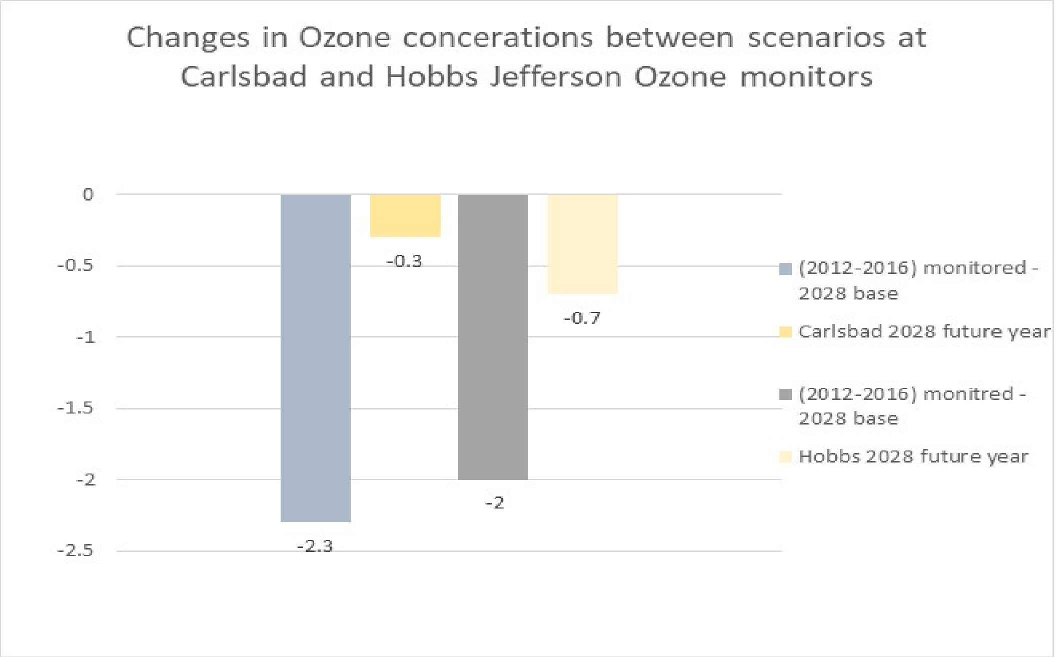
- NOx and VOC emission changes are combined
- 2012-2016 impacts are monitored not modeled

Conclusions

- **The Desert View monitor has dv of 72 ppb and the 2028 future year base case predicted impacts are 67 ppb, a reduction of 5 ppb (no additional controls on Oil and Gas)**
- **If additional Oil and Gas controls are implemented, the 2028 design value is reduced to 66.7 ppb (a decrease of 0.3 ppb)**
- **These results demonstrate future case compliance with the 70 ppb NAAQS**
- **The Desert View 2028 base case has a 67 ppb design value (0.5 ppb above the 95 % threshold)**
- **The Oil and Gas 2028 control strategy reduces the 2028 case to 66.8 ppb (reduction of 0.2 ppb) which is above the 66.5 ppb threshold**
- **Oil and Gas controls provide insignificant additional benefits for reducing O3 impacts at this monitor**

Changes in O3 concentrations for alternate scenarios Carlsbad and Hobbs Jefferson O3 monitors





Notes:
- NOx and VOC emission changes are combined
- 2012-2016 impacts are monitored not modeled

Conclusions
- **The Carlsbad monitor has a dv 69 ppb and the 2028 future year base case predicted impacts are 66.7 ppb, a reduction of 2.3 ppb (no additional controls on Oil and Gas)**
- **If additional Oil and Gas controls are implemented, the 2028 design value is reduced to 66.4 ppb (a decrease of 0.3 ppb)**
- **Implementing the Oil and Gas control strategy results in an insignificant improvement in O3**
- **The Hobbs Jefferson monitor dv is below the 66.5 ppb threshold**

Summary of changes in O3 from the 2028 future year base case using 2012 – 2016 data (time period follows EPA guidance)

Table 8-1. Observed ozone $DVC_{2012\text{-}2016}$ and projected 2028 ozone DVFs for the 2028 Base Case and 2028 O&G Control strategy and differences in the 2028 ozone DVFs ($DVF_{Cntl} - DVF_{Base}$).

AQS_ID	2012-16 DVC (ppb)	Projected 2028 DVF Base (ppb)	Cntl (ppb)	Cntl - Base	Site Name	State	County
Northern New Mexico							
350390026	64.0	60.8	60.0	-0.8	Coyote Ranger District	NM	Rio Arriba
350431001	64.0	58.4	58.1	-0.3	Bernalillo (E Avenida)	NM	Sandoval
350450009	64.3	61.0	60.2	-0.8	Bloomfield	NM	San Juan
350450018	67.0	64.8	63.3	-1.5	Navajo Lake	NM	San Juan
350451005	63.7	60.8	59.6	-1.2	Substation	NM	San Juan
350490021	64.3	60.6	60.4	-0.2	Santa Fe Airport	NM	Santa Fe
Bernalillo County							
350010023	66.3	60.9	60.7	-0.2	Del Norte HS	NM	Bernalillo
350010024	68.0	62.3	62.0	-0.3	South East Heights	NM	Bernalillo
350010029	66.0	61.0	60.5	-0.5	South Valley	NM	Bernalillo
350010032	67.0	62.6	62.1	-0.5	Westside	NM	Bernalillo
350011012	65.0	59.1	58.8	-0.3	Foothills	NM	Bernalillo
Southern New Mexico							
350130008	66.3	60.0	59.8	-0.2	La Union	NM	Doña Ana
350130017	67.0	61.9	61.8	-0.1	Sunland Park City Yard	NM	Doña Ana
350130020	67.0	62.3	62.2	-0.1	Chaparral	NM	Doña Ana
350130021	72.0	67.0	66.8	-0.2	Desert View	NM	Doña Ana
350130022	71.3	66.1	66.0	-0.1	Santa Teresa	NM	Doña Ana
350130023	65.0	60.3	60.2	-0.1	Solano	NM	Doña Ana
350151005	69.0	66.7	66.4	-0.3	Carlsbad	NM	Eddy
350171003	62.0	59.0	58.9	-0.1	Chino Copper Smelter	NM	Grant
350250008	66.0	64.0	63.3	-0.7	Hobbs Jefferson	NM	Lea
350290003	66.0	62.7	62.5	-0.2	Deming Airport	NM	Luna
350610008	66.3	62.2	62.0	-0.2	Los Lunas (Los Lentes)	NM	Valencia

<u>Legend</u>: Red highlight 2012-2016 design value is above O3 NAAQS of 70 ppb
Yellow highlight 2012-2016 design value is above 95% of O3 NAAQS or 66.5 ppb

Conclusions

1) For the 2012-2016 time frame the only monitors that have a design value above the NAAQS are Desert View and Santa Teresa 72.0 and 71.3 ppb respectively

2) The Navajo Lake, Carlsbad, South East Heights, Westside, Sunland Park City Yard, and Carlsbad monitors have design values for the 2012-2016 base case above 66.5 (95 % of the 70 ppb NAAQS)

3) For the 2028 base case all modeled design values are below 66.5 ppb except at Desert View and Carlsbad monitors

4) At Desert View the 2028 base case design value 67 ppb and is 0.5 ppb above the threshold value

5) Additional Oil and Gas controls reduce impacts for the Desert View monitor 0.2 ppb (total O3 66.8 ppb which is still above the 66.5 ppb threshold)

6) At the Carlsbad monitor the 2028 base case is 66.7 ppb (0.2 ppb above the 66.5 ppb threshold) and Oil and Gas controls reduce the design value by an additional 0.3 ppb (66.4 ppb)

6) Combined Oil and Gas controls are a very ineffective way to reduce impacts below 66.5 ppb

7) If different years are used for the dv, slightly different conclusions are found. According to the TSD the use of the 2012-2016 baseline follows EPA guidance

Summary of changes in O3 2028 future year base case using 2015 – 2019 data (Sensitivity Case)

Table 9-1. Projected 2028 ozone DVFs for the 2015-2019 current year design value $DVC_{2015-2019}$ sensitivity analysis.

AQS_ID	2015-19 DVC (ppb)	Projected 2028 DVF Base (ppb)	Cntl (ppb)	Cntl - Base	Site Name	County
350010023	69.0	63.4	63.1	-0.3	Del Norte HS	Bernalillo
350010029	66.0	61.0	60.5	-0.5	South Valley	Bernalillo
350011012	69.0	62.7	62.4	-0.3	Foothills	Bernalillo
350130008	68.7	62.1	62.0	-0.1	La Union	Doña Ana
350130020	70.7	65.7	65.7	0.0	Chaparral	Doña Ana
350130021	74.3	69.1	68.9	-0.2	Desert View	Doña Ana
350130022	74.0	68.6	68.5	-0.1	Santa Teresa	Doña Ana
350130023	67.7	62.9	62.7	-0.2	Solano	Doña Ana
350151005	73.7	71.2	70.9	-0.3	Carlsbad	Eddy
350153001	71.0	69.3	69.3	0.0	Carlsbad Caverns NP	Eddy
350250008	69.3	67.2	66.5	-0.7	Hobbs Jefferson	Lea
350390026	66.3	63.0	62.2	-0.8	Coyote Ranger Dist	Rio Arriba
350431001	67.0	61.2	60.9	-0.3	Bernalillo (E Avenida)	Sandoval
350450009	67.0	63.6	62.8	-0.8	Bloomfield	San Juan
350450018	69.0	66.7	65.2	-1.5	Navajo Lake	San Juan
350451005	67.3	64.2	62.9	-1.3	Substation	San Juan
350490021	65.0	61.2	61.0	-0.2	Santa Fe Airport	Santa Fe
350610008	66.7	62.6	62.3	-0.3	Los Lunas (Los Lentes)	Valencia

Legend: Red highlight 2012-2016 design value is above O3 NAAQS of 70 ppb
Yellow highlight 2012-2016 design value is above 95% of O3 NAAQS or 66.5 ppb

Conclusions

1) For the 2015-2019 time frame, the Chaparral, Desert View, Santa Teresa, Carlsbad and Carlsbad Cavern monitors have a design value above the 70 ppb NAAQS
2) For the 2015 -2019 time frame, the Del Norte HS, Foot Hills, La Union, Solano, and Navajo Lake monitors have a design value in excess of 66.5 ppb (95 % of the 70 ppb NAAQS) threshold
3) For the 2028 base case, all monitors are below the 70 ppb O3 NAAQS except Carlsbad
   - The 2028 control base case reduces the design value from 73.7 ppb to 71.2 ppb (reduction of 2.5 ppb)
   - The implementation of the Oil and Gas control strategy (NOx and VOC combined) reduces the design value to 70.9 ppb (a reduction of 0.3 ppb) but still above the 70 ppb NAAQS
4) For the 2028 base case only the Chaparral, Desert View, Santa Teresa, Hobbs Jefferson and Carlsbad monitors have concentrations above 66.5 ppb (90% of the 70 ppb NAAQS)
5) The dv at the Hobbs Jefferson monitor using the 2015-2019 data is larger than the 2012 -2016 data
   - The dv at the Hobbs Jefferson monitor (69.3 ppb) is below the NAAQS but above the 66.5 ppb threshold
   - For the Hobbs Jefferson monitor the implementation of the Oil and Gas control strategy (NOx and VOC combined) reduces the design value by a maximum of 0.7 ppb and reduces the dv to 66.5
   - The implementation of Oil and Gas controls reduces the dv equal to the threshold, but is not an efficient method of achieving O3 reductions
   - The modeling does not provide analyses to separate NOx and VOC impacts by source region and therefore it is impossible to evaluate the efficiency of controls
   - If the 2015 - 2019 data is used to evaluate controls, then the emission inventory should be updated to be consistent with the monitoring data
6) For the Carlsbad monitor the implementation of the Oil and Gas control strategy (NOx and VOC combined) reduces the design value by a maximum of 0.3 ppb

Emission Inventory Uncertainties

Issues with emission inventories used in the modeling

- The Technical Support Documentation does not contain data regarding the derivation of the base case
- The 2028 future year base case provides no documentation for emission calculations, emission growth (by source category) as well as assumptions regarding emission reductions that will be implemented as a result of new control requirements that are required by promulgated regulation
- Growth assumptions for Oil and Gas sources are critical because growth for many sources is contingent on production levels as well as rate of drilling for new wells
- A review of the Farmington Mancos-Gallup Draft Resource Management Plan Amendment and Environmental Impact Statement identified numerous issues with the Mancos modeling inventories
  - The Mancos analysis is directly related to the New Mexico O3 Attainment Initiative Photochemical Modeling Study

Power Plant Emissions

- Electric Generating Units (EGU) are a very large emission source in New Mexico and large EGU sources exist beyond NM borders that impact New Mexico O3 levels
- The TSD developed provides limited documentation on EGU sources included in the inventory as well as information supporting the 2028 emission reductions
- The Technical Support Document presents the following NOx emission data for EGUs
  - EGU 2014 base case NOx emissions 43,071 t/yr
  - EGU 2028 future year case NOx emissions 13,389 t/yr
  - Difference -29,682 t/yr
  - EGU 2014 EIA NOx emissions are listed as 60,158 t/yr
  - Difference between NOx modeling and EIA inventories is approximately 17,000 t/yr
  - No documentation is provided regarding how the 2014 EGU modeling inventory was developed and why it is so different than the 2014 EIA inventory
  - Several EGU facilities have announced closure of coal fired plants and the only statement made in the TSD is that Units 4 and 5 will continue to operate at the Four Corners Power Plant in 2028

Oil and Gas emission inventories

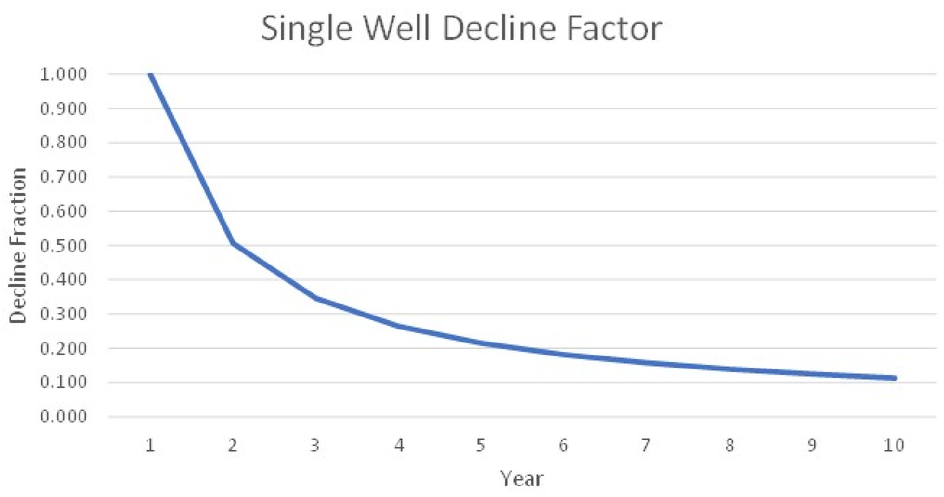
New Mexico NOx and VOC Oil and Gas emissions for 2014 base case, 2028 growth case and 2028 control case												
	NOx Emissions (t/yr)						VOCx Emissions (t/yr)					
Case	2014 Base	2028 growth	Difference 2014 base and 2028 growth	Difference 2014 base and 2028 growth (%)	2028 Control		2014 Base	2028 Growth	Difference 2014 base and 2028 growth	Difference 2014 base and 2028 growth (%)	2028 Control	
Non-Point	45,476	61,245	15,769	35	33,144		321,608	181,252	-140,356	-77	85,564	
Point	31,125	41,066	9,941	32	22,872		40,744	30,340	-10,404	-26	19,608	
Total	76,601	102,311	25,710	34	56,016		362,352	211,592	-150,760	-42	105,172	

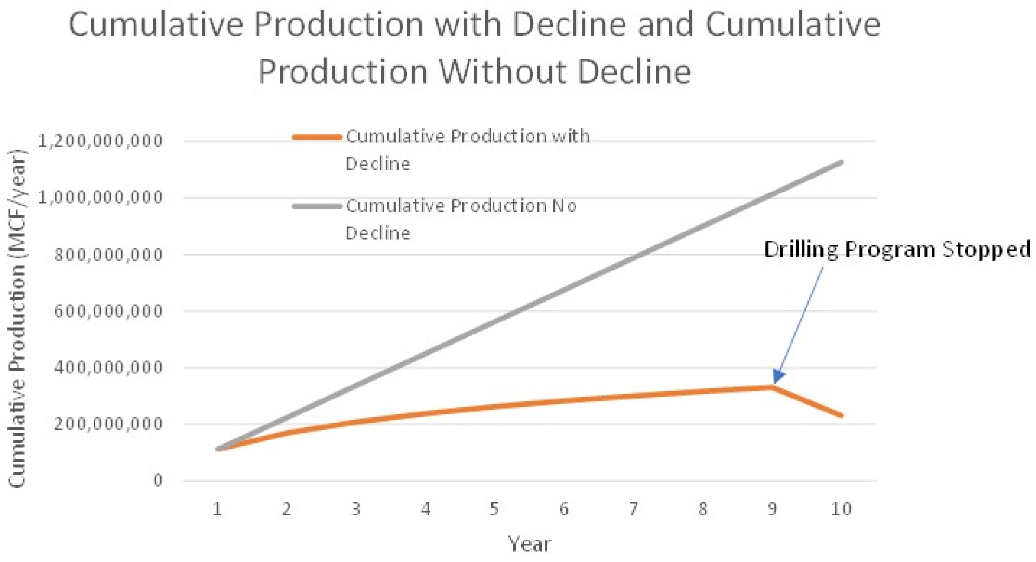
- Documentation is lacking on the underlying assumptions used to formulate Oil and Gas emissions for the 2014 base, 2028 growth and 2028 Oil and Gas control cases
- For NOx emissions there is approximately a 34 % increase in emissions between the 2014 base case and the 2028 growth case, while for VOCs the difference between the 2014 base case and the 2028 growth base case indicates a 42 % decrease
- It does not seem reasonable that there is substantial growth in NOx sources while there is a simultaneous reduction in VOC emissions from the same sources
- **Assumptions used in developing the NOx and VOC inventories do not appear to be consistent**

Production decline will result in emission reductions for some NOx and VOC emissions

- All production from Oil and Gas wells will exponentially decrease over time
- Production decline is offset by drilling new wells which slows the rate of overall decline
- As well production declines, some Oil and Gas emissions from selected sources will be reduced (e.g., compressors (NOx), dehys (NOx and VOCs) and tanks (VOCs)
- The reduction in emissions from decline occurs for both NOx and VOCs
- In most Oil and Gas inventories for existing wells decline is not accounted for
- Typically, in future year inventories new well emissions at initial production are added to existing wells at initial production and result in substantially overstating actual emissions
- The lack of documentation regarding Oil and Gas inventories prevents confirmation of values used in the modeling

Example of production decline





- New wells are drilled in a basin to replace declining production in existing wells
- Emissions from sources which are dependent on production rate will be reduced as production declines (compressors, dehys, tank emissions, liquid unloading etc.)

ɔurce: 2020, D.N. Blewitt, Technical Review of the Farmington Mancos-Gallup Draft ɛsource Management Plan Amendment and Environmental Impact Statement

Example of changes over time in well head equipment and emissions

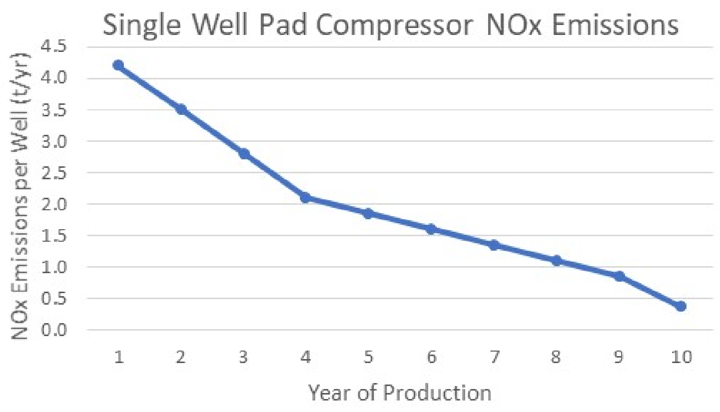
Table 2-8. Summary of Compression Equipment and Associated Emissions Mancos Oil Well Using Gas Lift Technology

Year	Gas Lift Engines	Capacity Engine 1 and 2 (hp)	Well Pad Compressor NOx Emissions (t/yr)	VRU Engines	NOx Emissions Other Sources	Total NOx Emissions per 3 Well Pad	NOx Emissions per Well (t/yr)
1	2 Engines Max Capacity	1093	4.2	2 Engines Max Capacity	0.9	5.1	1.7
2	Interpolate Emissions		3.5	2 Engines Max Capacity	0.9	4.4	1.47
3	Interpolate Emissions		2.8	1 Engine Max Capacity	0.6	3.4	1.13
4	Reduce Capacity to 1 Engine	546	2.10	1 Engine Max Capacity	0.6	2.7	0.90
5	Interpolate Emissions		1.85	1 Engine Max Capacity	0.3	2.1	0.70
6	Interpolate Emissions		1.60	Remove VRU	0.3	1.9	0.62
7	Interpolate Emissions		1.35		0.3	1.6	0.54
8	Interpolate Emissions		1.11		0.3	1.4	0.46
9	Interpolate Emissions		0.86		0.3	1.1	0.37
10	Reduce Engine Size	100*	0.36		0.3	0.6	0.21

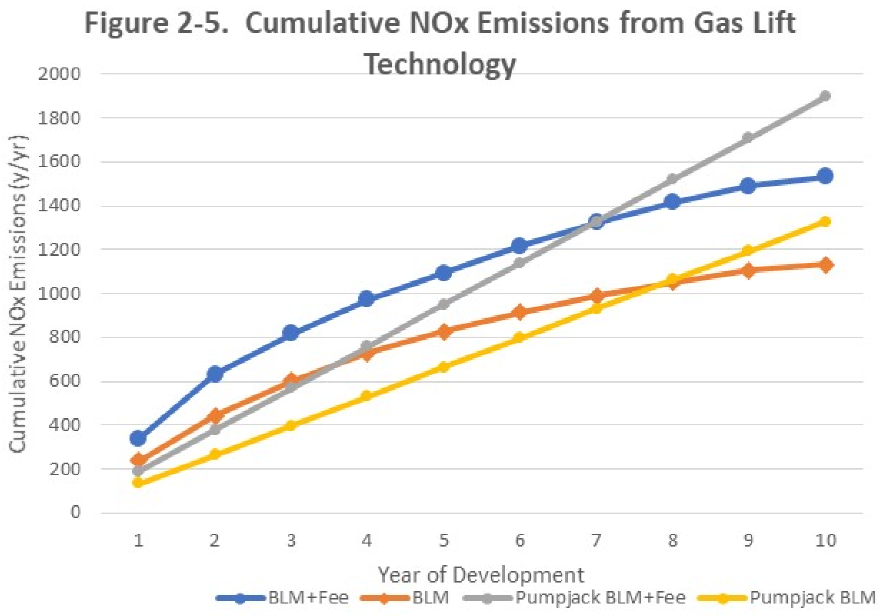
*Dependent upon pipeline pressures. Actual pressure could vary by site.

Source: 2020, D.N. Blewitt, Technical Review of the Farmington Mancos-Gallup Draft Resource Management Plan Amendment and Environmental Impact Statement

Importance of decline in wellhead compressor emissions



- Example is based on the high rate of development case from Mancos RMP over a 10-year drilling program
- Example indicates a 500 t/yr reduction in projected emissions over a 10-yr period



Source: 2020, D.N. Blewitt, Technical Review of the Farmington Mancos-Gallup Draft Resource Management Plan Amendment and Environmental Impact Statement

Changes in NOx emissions for Mancos maximum development case

Table 2-4a. Total (BLM+Fee) Well Revisions Based on Revised Engineering Data to NOx Emissions for Maximum Oil Development Case

						Original[1]		Revised		
Key	Year	Tab Name	Source Description	General Source	Source Type	NOx	% of Total	Revised NOx (t/yr)	% of Total	Chan Emiss (t/yr)
1	2025	Cn_HEq_Exh	Drilling Equip	Drilling Equip	dsl eqt exh	291.6	9.4	268.1	10.3	-23
3	2025	Cn_HEq_Exh	Completion Equip	Completion Equip	dsl eqt exh	325.1	10.4	325.1	12.5	0.
5	2025	Cn_HEq_Exh	Const Equip - Well Pad	Const Equip	dsl eqt exh	2.8	0.1	2.8	0.1	0.
6	2025	Cn_HEq_Exh	Const Equip - Well Pad Access Road	Const Equip	dsl eqt exh	2.4	0.1	2.4	0.1	0.
7	2025	Cn_HEq_Exh	Const Equip - Pipeline	Const Equip	dsl eqt exh	1.1	0.0	1.1	0.0	0.
8	2025	Cn_CV_Exh	Drilling Traffic	Drilling Traffic	dsl veh exh	11.5	0.4	11.5	0.4	0.
11	2025	Cn_CV_Exh	Well Completion & Testing	Completion Traffic	dsl veh exh	2.7	0.1	2.7	0.1	0.
27	2025	Ops_Well WO	Workover Equip	Workover Equip	dsl eqt exh	118.6	3.8	118.6	4.6	0.
40	2025	Misc_Engines_Exh	Misc. Engines	Misc. Engines	dsl eqt exh	1,898.0	60.9	0.0	0.0	-189
41	2025	Condensate Tanks & Traffic	Produced Condensate Hauling Traffic - Exhaust	Production Traffic	dsl veh exh	101.5	3.3	101.5	3.9	0.
45	2025	Condensate Tanks & Traffic	Produced Water Hauling Traffic - Exhaust	Production Traffic	dsl veh exh	35.6	1.1	35.6	1.4	0.
47	2025	Ops_Road Maint	Road Maintenance Traffic - Exhaust	Production Traffic	dsl veh exh	1.7	0.1	1.7	0.1	0.
57	2025	Heaters and Flaring	Flaring	Completion Flaring	flaring	2.1	0.1	2.1	0.1	0.
58	2025	Heaters and Flaring	Heaters	Heaters	ng ext comb	321.2	10.3	174.9	6.7	-14
64	2025	Well pad compression					0.0	1,549.0	59.6	154
					Total	3,117	100	2,598.5	100.0	-5

[1] From Draft EIS spreadsheets

Table 2-5a. Total Source (BLM+Fee) Revisions Based on Revised Engineering Data to NOx Emissions for the Maxi Development Case

						Original[1]		Revised		
Key	Year	Tab Name	Source Description	General Source	Source Type	NOx	% of Total	Revised NOx (t/yr)	% of Total	Ch Em (t/
1	2025	Cn_HEq_Exh	Drilling Equipment	Drilling Equipment	dsl eqt exh	1,271.8	66.5	197.1	23.5	-
2	2025	Cn_HEq_Exh	Completion Equipment	Completion Equipment	dsl eqt exh	59.7	3.1	59.7	7.1	
8	2025	Cn_CV_Exh	Drilling Traffic	Drilling Traffic	dsl veh exh	9.8	0.5	9.8	1.2	
11	2025	Cn_CV_Exh	Well Completion & Testing	Completion Traffic	dsl veh exh	24.1	1.3	24.1	2.9	
12	2025	Cn_CV_Exh	Well Pad and Access Road Construction Traffic	Construction Traffic	dsl veh exh	1.4	0.1	1.4	0.2	
27	2025	Ops_Well WO	Workover Equipment	Workover Equipment	dsl eqt exh	39.7	2.1	39.7	4.7	
49	2025	Compressor_Engines	Wellhead Compressor Engines	Wellhead and Lateral Compressor Engines	ngrb eng exh	369.9	19.3	369.9	44.2	
55	2025	Others Traffic	Fuel Haul Truck Traffic - Exhaust	Production Traffic	dsl veh exh	114.5	6.0	114.5	13.7	
58	2025	Heaters and Flaring	Heaters	Heaters	ng ext comb	17.0	0.9	17.0	2.0	
						1,912	**100**	**838**	**100**	-

[1] From Draft EIS spreadsheets

Total reduction in NOx over non decline case
Gas 1,075 t/yr
Oil 1,447 t/ty
Total 2,522

Source: 2020, D.N. Blewitt, Technical Review of the Farmington Mancos-Gallup Draft Resource Management Plan Amendment and Environmental Impact Statement

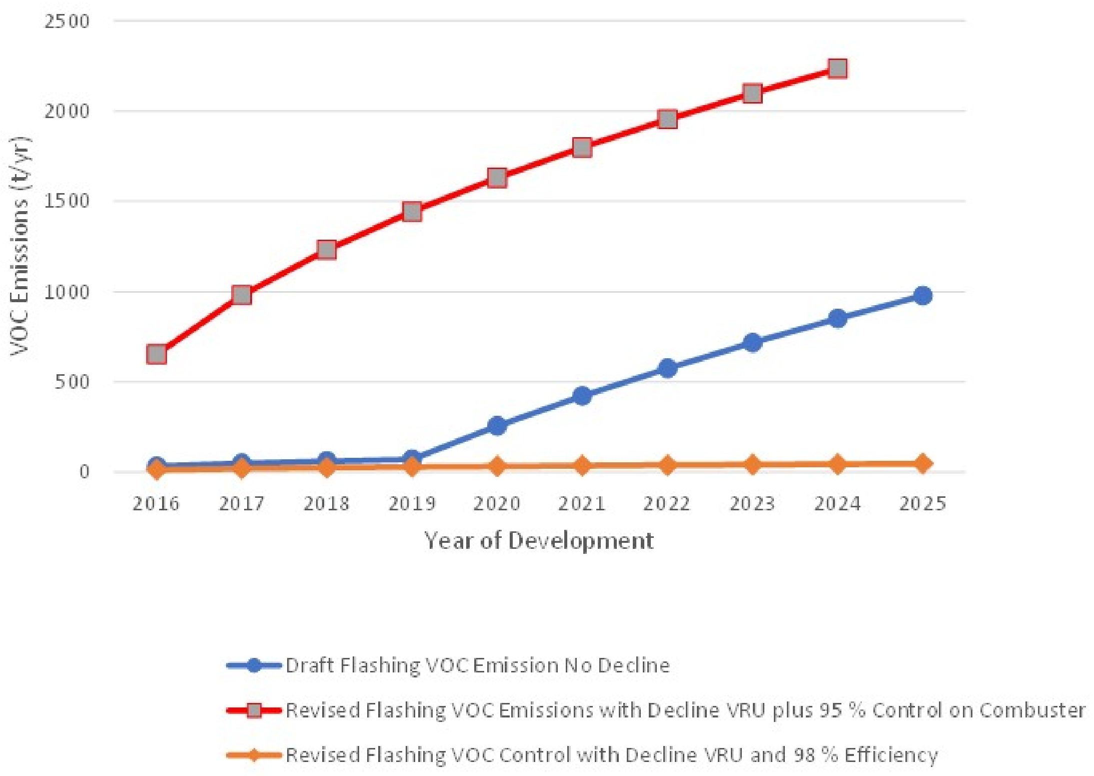
Changes in Mancos VOC emissions for Maximum Development Case by incorporating decline

Table 2-10. Changes to VOC Emissions from BLM Wells and Total Wells

Scaler	Type of Emission	VOC (t/yr)	(% Contribution)	Revised Emissions based on More Accurate Engineering VOC (t/yr)	(% Contribution)	Reduction (t/yr)	% Reductic
Annual condensate production	Flashing	2297.2	36.6	814	27	-1483	-65
Active well counts	Water tanks	2017.4	32.2	360	12	-1658	-82
Active well counts	Venting	831.8	13.3	832	27	0	0
Annual condensate production	Working/ breathing	734.0	11.7	734	24	0	0
Active well counts	Dsl eqt exh	206.6	3.3	207	7	0	0
Active well counts	Venting	107.1	1.7	107	4	0	0
	Total	**6,271**		**3,054**		**-3141**	

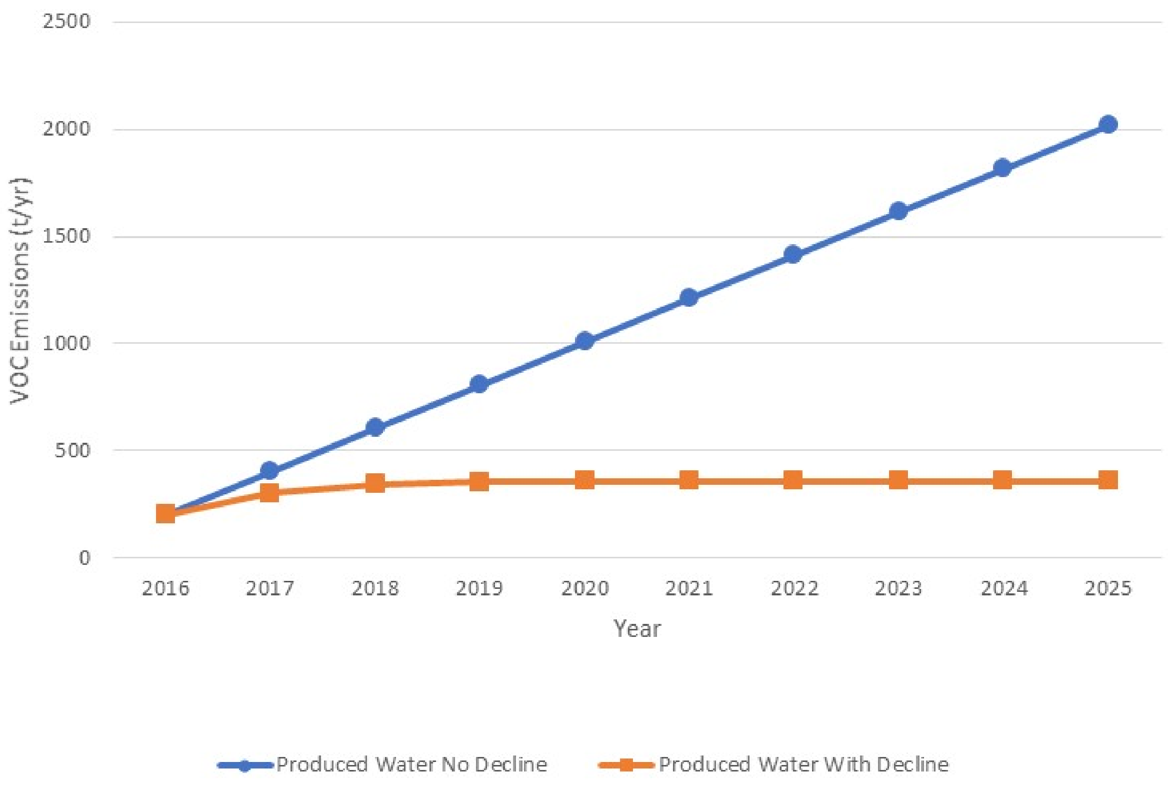
Source: 2020, D.N. Blewitt, Technical Review of the Farmington Mancos-Gallup Draft Resource Management Plan Amendment and Environmental Impact Statement

Figure 2-8. Comparison of VOC Flashing Emissions from Draft and Actual Well Design Being Implemented in the Mancos For BLM Wells



Source: 2020, D.N. Blewitt, Technical Review of the Farmington Mancos-Gallup Draft Resource Management Plan Amendment and Environmental Impact Statement

Figure 2-9. Produced Water VOC Emissions from BLM Wells With and Without Production Decline



Source: 2020, D.N. Blewitt, Technical Review of the Farmington Mancos-Gallup Draft Resource Management Plan Amendment and Environmental Impact Statement

Proposed Emission Reductions for Oil and Gas

Procedure for Heaters

- The San Juan basin application of the proposed rule to existing sources for heaters would affect 5 sources and reduce NOx emissions by 19 t/yr.
    - Retrofitting heaters for NOx controls in the San Juan basin will have an insignificant effect on local O3
- The installation of low NOx burners for a 10 MMBtu/hr heater will result in the following
    - Assume 50% control
    - 30ppm emission standard based on CARB BACT
    - For new 10 MMBtu/hr heaters, the proposed regulation using low NOx burners at 100% load would reduce emissions from 4.4 t/yr to 2.2 t/yr

Summary of emission reductions and control cost effectiveness for a new 10 MMBtu/hr heater under proposed regulation

Cost to control

	Emission reductions and cost effectiveness for low NOx burners on 10 MMBtu/hr heater						
Percent load	Low NOx burner controlled emissions assume 50% control (t/yr)	Control cost 1991 ($)	Control cost 2019 ($)	Control cost 2021 ($)		Cost to control 2019 ($/ton)	Cost to control 2021 ($/ton)
100	2.19	9,250	15,553	18,104		7,102	8,267
90	1.97	9,250	15,553	18,104		7,891	9,185
75	1.64	9,250	15,553	18,104		9,469	11,022
50	1.10	9,250	15,553	18,104		14,204	16,533
25	0.55	9,250	15,553	18,104		28,407	33,067

Heater conclusions

- The application of NOx controls for heaters with a threshold of 10 MMBtu/hr is not cost effective (90 % load control costs are estimated to be $9,185/ton)
- Actual load may be closer to 50% and control costs are approaching $16,533/ton
- Emission standard of 30 ppm is based on CA BACT analysis (equivalent to LAER in the rest of US)
- It is recommended that NMED consider a capacity threshold of 50 MMBtu/hr
- Cost effective control based on CARB BACT (LAER other portions of US) $2,200/ton

Comparison of O3 reduction from NOx vs VOC controls

- Controls for NOx and VOCs do not have the same effect on reducing O3 concentrations
- Typically, a reduction in NOx emissions will be more effective than a reduction in VOC emissions (most areas are NOx limited)
- The O3 analysis combines NOx and VOC emission reductions for Oil and Gas, consequently it is not possible to determine the effectiveness of VOC control in a NOx limited region
- The NOx and VOC source impacts must be separated to evaluate the effectiveness of NOx versus VOC controls

Modeling indicates that O3 formation is dominated by NOx emissions (NOx limited)

Summary of NOx vs VOC contribution from anthropogenic sources						
Monitor	County	Total O3 (ppb)	Boundary Conditions (%)	In domain emissions Pie (ppb)	O3 NOx (%)	O3 VOC (%)
Sub Station	San Juan	63.7	67	4.7	87	13
Southeast Heights	Bernalillo	60.7	58	4.7	92	8
Desert View	Doña Ana	63.1	44	2	95	5
Carlsbad	Eddy	57.3	67	1.6	96	4
				Maximum	96	13
				Average	92.5	7.5
				Standard Deviation	4.0	4.0
				Minimum	87	4

This means that NOx controls are more efficient in controlling O3 than VOC controls

Conclusions

- Monitoring and modeling analyses presented in the TSD do not support the need for additional controls on Oil and Gas sources
- The emission inventories used in the modeling lack documentation for verification
- The emission inventories for Oil and Gas do not include decline and likely overstate actual emissions (this will affect cost effective control evaluations)
- The modeling strongly indicates that ozone formation is NOx limited, however, the modeling cannot separate the effectiveness of NOx versus VOC controls
- The information presented in the TSD does not provide sufficient data to develop an O3 control strategy
- Modeling should be conducted so that source apportionment results are provided by region (Oil and Gas impacts should be parsed by basin) and pollutant

Technical Review of the Farmington Mancos-Gallup Draft Resource Management Plan Amendment and Environmental Impact Statement

Prepared by
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Certified Consulting Meteorologist
Air Quality Resource Management

September 25, 2020

IPANM EXHIBIT 9

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1. Executive Summary

The Bureau of Land Management (BLM) Farmington Field Office and Bureau of Indian Affairs Navajo Regional Office (BIA) have conducted an air quality analysis as part of the Farmington Mancos-Gallup draft Resource Management Plan Amendment (RMPA) Environmental Impact Statement (EIS). The analysis, in general, provides a conservative determination that there will not be any significant air quality effects from the proposed development. Based on a thorough review of the documentation and supporting data, there are several areas of the analysis that should undergo additional refinement in order to more accurately and realistically define potential air quality impacts.

Emission Estimates

The review of the Draft EIS (DEIS) found that quantification of emissions from the proposed development were overstated and that the assumptions regarding types of equipment that would be used does not match actual equipment used in development. Suggested revisions to the emission calculations to correct the identified deficiencies were made as part of this review.

Recommended changes to the emission calculations include:

- Changes in drilling emissions for NOx for both oil and gas well emissions based on actual drilling data.
- Changes in well head engine emissions for NOx for oil wells based on production decline.
- Changes in NOx well heater emissions to incorporate duty cycle.
- Changes in VOC emissions during early production that account for the installation of vapor recovery units (VRUs).
- Changes in VOC emissions for produced water which include decreasing produced water over time as the production declines.

Revisions in emissions were based on actual equipment currently being employed in the field, as well as refinements in engineering data regarding the application of equipment being used.

When corrected, the revisions in the emission calculations indicated projected emissions for the High Development Case for NOx and VOC are actually analogous to the level of emissions reported for the Medium Development Case (case with additional mitigation applied presented in the Draft EIS). **Therefore, because the corrected projected emissions for the High Development Case are comparable to the uncorrected emissions for the Medium Development Case, the air quality modeling presented in the Draft EIS for the Medium Development Case represents air quality impacts for the High Development Case**. Accordingly, the revisions in emissions do not suggest the modeling needs to be redone. No new CAMx modeling is required. **BLM simply needs to define that the Medium Development Case results portray potential impacts for the High Development Case.**

National Ambient Air Quality Standards (NAAQS)

The discussion of predicted air quality modeling results in the Draft EIS indicates that within the modeling domain in Colorado and New Mexico, there are predicted concentrations for NO_2, SO_2, O_3, PM_{10} and $PM_{2.5}$ that are above the levels of the NAAQS. The Draft EIS states the modeled exceedances are a result of wildfires. This presentation of such results is incomplete and portrays a very inappropriate representation of air quality levels in the region that are above the level of health-based air quality standards. Correct analysis of the modeling results indicates that development in conjunction with existing sources will not result in new exceedances of the NAAQS or significantly contribute to existing exceedances of the NAAQS.

EPA excludes exceptional events (e.g., natural emission such as wildfires) from NAAQS compliance demonstrations. While such natural event exclusions generally pertain to monitoring data, the same logic applies to modeling analyses.[1] The modeling discussion of results needs to be modified to exclude exceptional events. The discussion regarding compliance with the NAAQS in the Draft EIS needs to be revised to address exceptional event emissions.

The modeling discussion states that PSD increments are being exceeded and this is totally incorrect because of exceptional events emissions. Compliance with PSD increment can only be performed using modeling because only a subset of increment consuming emission sources is included in the modeling. Exceptional event sources DO NOT consume PSD increment. The Draft EIS needs to recognize the conservative nature of the modeling for the RMP.

The Draft EIS defines a significant O_3 concentration as 1 ppb (a reasonable significance threshold). Based on the O_3 modeling and other data, it can be concluded that the Maximum Gas Development Case does not pose a "significant" contribution to existing O_3 levels and does not create a new predicted exceedance to the 70 ppb O_3 NAAQS. Further, because the emission calculations are overstated from actual development, actual impacts will be less than those presented in the report.

Visibility

The visibility analysis is conservative and indicates no degradation in visibility from the proposed development. The RMPA/EIS analyzed contributions to visibility impairment at Class I and II Areas using FLAG (2010) and, for the Maximum Development Scenario, determined that (1) modeled impacts in adjacent Class I Areas indicate there are no days with predicted impacts in excess of 1.0 deciview or 0.5 deciview; and (2) Aztec Ruins, NM was the only Class II Sensitive Area with predicted impacts in excess of 0.5 deciview, with a maximum impact of 2.6 deciview (occurred on 1/7/2011). For this location, the analysis predicted 80 days in excess of 1.0 deciview and 261 days in excess of 0.5 deciview. Aztec Ruins is only approximately 2.6 square kilometers. Because of the short sight path, no accumulation of fine particles will reduce the clarity of the scenic view. In addition, the change in visibility is calculated based on a clean reference condition of approximately 70 kilometers and is not applicable to this area. The area is also in a suburban or small-town setting and background levels of particulates are generally higher and there is less opportunity for impairment from the project. Overall, based on a review of the size and location of the Aztec Ruins NM, visibility should not be considered an Air Quality Related Value at this location and no mitigation should be required.

Deposition

The modeled deposition impacts for Class I Areas do not indicate the need for additional mitigation. Deposition monitoring data in the vicinity of the Mancos Development indicate a dramatic decline in sulfur deposition over the period of record (approximately 30 years). In addition, deposition monitoring surrounding the Mancos development area indicates that deposition is improving over the past 30 years. For Class I Areas, the predicted nitrogen deposition for the Mancos development area was above the Deposition Analysis Threshold (DAT) (0.005 kg/ha/yr) at Mesa Verde and the Weminuche Wilderness

[1] Emissions for wildfires were appropriately included in the CAMx model evaluation where model predictions were compared to monitoring data to assess model accuracy.

Area. *See* RMPA/EIS at Table 3-12, 3-25. However, based on the analysis of cumulative impacts, the impacts are below the guideline critical nitrogen loading. Therefore, no additional mitigation should be considered as part of the RMPA/EIS for Class I areas.

For Class II Areas, four sensitive Class II Areas had modeled deposition impacts above the DAT and had cumulative impacts above the critical load guidance. All these sensitive Class II Areas are very small in size and the modeling coordinate system is likely expanding the size of the sensitive area. Since the size of the areas are so small, the mass of nitrates and sulfates deposited on the ground will be relatively small compared to a Class I Area comprised of very large surface areas. Because of the small size (especially Aztec Ruins) deposition should not be considered an important Air Quality Related Value. In addition, there is no regulatory requirement established for deposition limits for these Class II Areas. Accordingly, no additional mitigation is needed for the Mancos Proposed Action because of modeled deposition impacts.

Mitigation

Most of the mitigation options presented in the Draft were not analyzed in terms of emission reductions, cost, or incremental cost effectiveness. Without any data to support the additional mitigation strategies, it is inappropriate for BLM to incorporate such measures in a ROD.

A detailed analysis was conducted regarding the feasibility of replacing 50 percent of new well compression with electricity instead of using natural gas engines considering indirect emissions from electricity generation. This study indicated there would be an increase in NOx and CO_2 emissions when the emissions from electricity generation are included into total emissions (no environmental benefit). For a 3 well pad the cost of electricity over natural gas is estimated to be approximately $545,000 a year and results in absolutely no environmental benefit. Capital equipment costs would be approximately $75,000,000.

The additional mitigation strategy of electrification of natural gas compressor engines at considerable cost provides no environmental benefit and should be rejected.

2. Emission Calculation Estimates

2.1 Recommended Revisions to Emission Calculations

Based on a review of the emission calculations of NOx and VOCs, it was found that emissions were significantly overstated in the Draft EIS. Overall, as detailed below, BLM/BIA need to revise the emission inventories based on more accurate assumptions regarding actual processes, equipment, and development.

2.1.1 Revisions to NOx Emission Calculations

A detailed review of NOx emissions was performed for the largest NOx emission sources for both oil and gas wells, which revealed that some of the engineering assumptions used did not represent actual development. Revised emission calculations using more appropriate engineering data were then performed. BLM/BIA needs to revise the Draft EIS emission calculations to reflect actual development.

Table 2-3a presents the change in NOx emissions using actual engineering data compared to the calculations presented in the spreadsheets. The refinements result in a reduction in NOx emissions for

BLM wells plus Fee wells for the Maximum Development Case of 1,593 tons/year and 1,115 tons/year for just BLM wells.

Table 2-3a. Summary of the Revisions to the NOx Emission Calculation for the High Development Case

Case	DRAFT EIS NOx (t/yr)	Revised NOx (t/yr)	Difference NOx (t/yr)
BLM+Fee Gas	**1,912**	838	-1,075
BLM Gas	**1,339**	587	-752
BLM+Fee Oil	**3,117**	2,598	-519
BLM Oil	2,182	1,819	-363
BLM+Fee	5,030	3,436	-1,593
BLM	3,521	2,406	-1,115

Table 2-3b compares the revised NOx calculations for the Maximum Development Case NOx emission levels in the Draft for the high, medium, and low development cases. This comparison shows that the revised High Development Case is only 261 tons/year (8 percent) greater than the Medium Development Case including mitigation that was reported in the Draft EIS. Thus, the air quality impacts presented in the Draft EIS for the Medium Development Case actually represent impacts for the Maximum Development Case if using refined engineering data on emissions. **This means that the projected air quality impacts related to NOx emissions for the Maximum Development Case are reflected in the modeling for the Medium Development Case. The reduction in projected impacts were obtained without the application of any new mitigation options (Table 2-2 in the Draft EIS).**

Table 2-3b. Comparison of Revised NOx Emissions to Draft EIS Scenario Case

	Draft EIS Mancos Shale Wide			Revised Emissions High Development Case		
	Federal	Fee	Total	BLM + Fee		
Case	NOx Emissions (t/yr)			Revised High NOx Emissions (t/yt)	Difference in Emissions Between Medium Development Case and High Development Case (t/yr)	Percent Difference
High	3,184	1,364	4,548			
Med	1,811	1,364	3,175	3,436	-261	-8.2
Low	1,592	682	2,274			

The finding that NOx emissions from the Maximum Development Case being equivalent to the Medium Development Case means that the CAMx modeling results for the medium are representative of the maximum case and does not warrant revising the modeling and re-running the model.

Table 2-4a presents corrected NOx changes in emissions to the Maximum Development Case for BLM+Fee wells and Table 2-4b presents corrected emissions in the NOx emissions calculations for oil wells for the High Development Case for sources related to BLM wells. Tables 2-5a and 2-5b present a summary of revisions to the maximum gas case for BLM plus Fee wells and BLM (respectively). These tables were derived from the corresponding oil and gas maximum development spreadsheets using the BLM and Total Emissions tabs. In these tables "original" is the data contained in the spreadsheets developed by BLM and used in the Draft EIS. The data in the tables were filtered for all sources and the year 2025 (year of maximum development). The corresponding tables in this report present only NOx emissions that were greater than 1 ton/year. The changes in the revised emissions reported in these tables represent changes in emissions related to engineering changes reflecting actual operations for emission sources for gas (vertical) and oil (horizontal) wells.

The resulting NOx emissions in the year 2025 using more appropriate engineering data results in emission reductions for wells on BLM plus Fee land of 1,447 tons/year for oil wells and 1,075 tons/year for gas wells for a total overestimation (oil plus gas) of 2,522 tons/year.

Emissions reductions of NOx from BLM wells for the High Development Case were 519 tons/year for oil wells and 752 tons/year for gas wells for a total overestimation of 1,271 tons/year.

Only emissions for the larger source categories (drill rigs, compressors, and heaters) were reviewed using appropriate engineering data representative of actual operations. No review was conducted for NOx emissions for other sources and it was not determined if additional conservatism (over estimation of actual emissions) has occurred in the Draft EIS calculations.

The following subsections discuss the methodology used to refine emissions reported in the Maximum Development Case spreadsheets provided by BLM.

Table 2-4a. Total (BLM+Fee) Well Revisions Based on Revised Engineering Data to NOx Emissions for the Maximum Oil Development Case

						Original[2]		Revised		
Key	**Year**	**Tab Name**	**Source Description**	**General Source**	**Source Type**	**NOx**	**% of Total**	**Revised NOx (t/yr)**	**% of Total**	**Change in Emissions (t/yr)**
1	2025	Cn_HEq_Exh	Drilling Equip	Drilling Equip	dsl eqt exh	291.6	9.4	268.1	10.3	-23.5
3	2025	Cn_HEq_Exh	Completion Equip	Completion Equip	dsl eqt exh	325.1	10.4	325.1	12.5	0.0
5	2025	Cn_HEq_Exh	Const Equip - Well Pad	Const Equip	dsl eqt exh	2.8	0.1	2.8	0.1	0.0
6	2025	Cn_HEq_Exh	Const Equip - Well Pad Access Road	Const Equip	dsl eqt exh	2.4	0.1	2.4	0.1	0.0
7	2025	Cn_HEq_Exh	Const Equip - Pipeline	Const Equip	dsl eqt exh	1.1	0.0	1.1	0.0	0.0
8	2025	Cn_CV_Exh	Drilling Traffic	Drilling Traffic	dsl veh exh	11.5	0.4	11.5	0.4	0.0
11	2025	Cn_CV_Exh	Well Completion & Testing	Completion Traffic	dsl veh exh	2.7	0.1	2.7	0.1	0.0
27	2025	Ops_Well WO	Workover Equip	Workover Equip	dsl eqt exh	118.6	3.8	118.6	4.6	0.0
40	2025	Misc_Engines_Exh	Misc. Engines	Misc. Engines	dsl eqt exh	1,898.0	60.9	0.0	0.0	-1898.0
41	2025	Condensate Tanks & Traffic	Produced Condensate Hauling Traffic - Exhaust	Production Traffic	dsl veh exh	101.5	3.3	101.5	3.9	0.0
45	2025	Condensate Tanks & Traffic	Produced Water Hauling Traffic - Exhaust	Production Traffic	dsl veh exh	35.6	1.1	35.6	1.4	0.0
47	2025	Ops_Road Maint	Road Maintenance Traffic - Exhaust	Production Traffic	dsl veh exh	1.7	0.1	1.7	0.1	0.0
57	2025	Heaters and Flaring	Flaring	Completion Flaring	flaring	2.1	0.1	2.1	0.1	0.0
58	2025	Heaters and Flaring	Heaters	Heaters	ng ext comb	321.2	10.3	174.9	6.7	-146.2
64	2025	Well pad compression					0.0	1,549.0	59.6	1549.0
					Total	3,117	100	2,598.5	100.0	-519

[2] From Draft EIS spreadsheets

Table 2-4b. BLM Well Revisions Based on Revised Engineering Data to NOx Emissions for the Maximum Oil Development Case

						Original[3]		Revised		
Key	**Year**	**Tab Name**	**Source Description**	**General Source**	**Source Type**	**NOx**	**% of Total**	**Revised NOx (t/yr)**	**% of Total**	**Change in Emissions (t/yr)**
1	2025	Cn_HEq_Exh	Drilling Equip	Drilling Equip	dsl eqt exh	204.1	6.5	187.7	7.2	-16.4
3	2025	Cn_HEq_Exh	Completion Equip	Completion Equip	dsl eqt exh	227.6	10.4	227.6	12.5	0.0
5	2025	Cn_HEq_Exh	Const Equip - Well Pad	Const Equip	dsl eqt exh	1.9	0.1	1.9	0.1	0.0
6	2025	Cn_HEq_Exh	Const Equip - Well Pad Access Road	Const Equip	dsl eqt exh	1.7	0.1	1.7	0.1	0.0
7	2025	Cn_HEq_Exh	Const Equip - Pipeline	Const Equip	dsl eqt exh	0.7	0.0	0.7	0.0	0.0
8	2025	Cn_CV_Exh	Drilling Traffic	Drilling Traffic	dsl veh exh	8.1	0.4	8.1	0.4	0.0
11	2025	Cn_CV_Exh	Well Completion & Testing	Completion Traffic	dsl veh exh	1.9	0.1	1.9	0.1	0.0
27	2025	Ops_Well WO	Workover Equip	Workover Equip	dsl eqt exh	83.0	3.8	83.0	4.6	0.0
40	2025	Misc_Engines_Exh	Misc. Engines	Misc. Engines	dsl eqt exh	1328.6	60.9	0	0	-1328.6
41	2025	Condensate Tanks & Traffic	Produced Condensate Hauling Traffic - Exhaust	Production Traffic	dsl veh exh	71.0	3.3	71.0	3.9	0.0
45	2025	Condensate Tanks & Traffic	Produced Water Hauling Traffic - Exhaust	Production Traffic	dsl veh exh	24.9	1.1	24.9	1.4	0.0
47	2025	Ops_RoadMaint	Road Maintenance Traffic - Exhaust	Production Traffic	dsl veh exh	1.2	0.1	1.2	0.1	0.0
57	2025	Heaters and Flaring	Flaring	Completion Flaring	flaring	1.5	0.1	1.5	0.1	0.0
58	2025	Heaters and Flaring	Heaters	Heaters	ng ext comb	224.8	10.3	122.5	6.7	-102.4
64	2025	Well pad compression						1084.3	59.6	1084.3
						2,182	**97**	**1,819**	**37**	**-1,447**

[3] From Draft EIS spreadsheets

Table 2-5a. Total Source (BLM+Fee) Revisions Based on Revised Engineering Data to NOx Emissions for the Maximum Gas Development Case

						Original[4]		Revised		
Key	**Year**	**Tab Name**	**Source Description**	**General Source**	**Source Type**	**NOx**	**% of Total**	**Revised NOx (t/yr)**	**% of Total**	**Change in Emissions (t/yr)**
1	2025	Cn_HEq_Exh	Drilling Equipment	Drilling Equipment	dsl eqt exh	1,271.8	66.5	197.1	23.5	-1074.7
2	2025	Cn_HEq_Exh	Completion Equipment	Completion Equipment	dsl eqt exh	59.7	3.1	59.7	7.1	0.0
8	2025	Cn_CV_Exh	Drilling Traffic	Drilling Traffic	dsl veh exh	9.8	0.5	9.8	1.2	0.0
11	2025	Cn_CV_Exh	Well Completion & Testing	Completion Traffic	dsl veh exh	24.1	1.3	24.1	2.9	0.0
12	2025	Cn_CV_Exh	Well Pad and Access Road Construction Traffic	Construction Traffic	dsl veh exh	1.4	0.1	1.4	0.2	0.0
27	2025	Ops_Well WO	Workover Equipment	Workover Equipment	dsl eqt exh	39.7	2.1	39.7	4.7	0.0
49	2025	Compressor_Engines	Wellhead Compressor Engines	Wellhead and Lateral Compressor Engines	ngrb eng exh	369.9	19.3	369.9	44.2	0.0
55	2025	Others Traffic	Fuel Haul Truck Traffic - Exhaust	Production Traffic	dsl veh exh	114.5	6.0	114.5	13.7	0.0
58	2025	Heaters and Flaring	Heaters	Heaters	ng ext comb	17.0	0.9	17.0	2.0	0.0
						1,912	**100**	**838**	**100**	**-1,075**

4 From Draft EIS spreadsheets

Table 2-5b. BLM Well Revisions Based on Revised Engineering Data to NOx Emissions for the Maximum Gas Development Case

						Original		Revised		
Key	**Year**	**Tab Name**	**Source Description**	**General Source**	**Source Type**	**NOx (t/yr)**	**% of Total**	**NOx (t/yr)**	**% of Total**	**Change in Emissions (t/yr)**
1	2025	Cn_HEq_Exh	Drilling Equipment	Drilling Equipment	dsl eqt exh	890.3	66.5	138.1	23.5	-752.2
2	2025	Cn_HEq_Exh	Completion Equipment	Completion Equipment	dsl eqt exh	41.8	3.1	41.8	7.1	0.0
8	2025	Cn_CV_Exh	Drilling Traffic	Drilling Traffic	dsl veh exh	6.9	0.5	6.9	1.2	0.0
11	2025	Cn_CV_Exh	Well Completion & Testing	Completion Traffic	dsl veh exh	16.9	1.3	16.9	2.9	0.0
12	2025	Cn_CV_Exh	Well Pad and Access Road Construction Traffic	Construction Traffic	dsl veh exh	1.0	0.1	1.0	0.2	0.0
27	2025	Ops_Well WO	Workover Equipment	Workover Equipment	dsl eqt exh	27.8	2.1	27.8	4.7	0.0
49	2025	Compressor_ Engines	Wellhead Compressor Engines	Wellhead and Lateral Compressor Engines	ngrb eng exh	258.9	19.3	258.9	44.1	0.0
55	2025	Others Traffic	Fuel Haul Truck Traffic - Exhaust	Production Traffic	dsl veh exh	80.2	6.0	80.2	13.7	0.0
58	2025	Heaters and Flaring	Heaters	Heaters	ng ext comb	11.9	0.9	11.9	2.0	0.0
					Total	**1,339**	**100**	**587**	**100**	**-752**

2.1.1.1 Drilling Rig NOx Emissions for Gas and Oil Wells

2.1.1.1.1 Drilling Rig NOx Emissions for Gas Wells

The Draft EIS assumes drilling rig emissions for NOx were based on four 1,468 hp (total capacity of 5,872 hp) diesel engines operating at 50 percent load for 24 hours per day for 24 days. The corresponding emissions for this scenario were 8.4 tons/well. Based on actual drilling data, the revised NOx emissions are only 1.3 tons/well.

Table 2-6 below provides actual drilling emission data for a three well pad developed by DJR Energy LLC based on EPA Tier 2 Diesel NSPS emission standard. Hourly NOx emissions were determined for each engine using the manufacturer's data sheet adjusted for actual load. Cumulative NOx emission from drilling for the maximum year of development (2025) for gas BLM wells was calculated to be 138 tons/year compared to 890 tons/year reported in the Draft EIS.

Current EPA emission control technology has advanced to Tier 4 level and over time, drilling rig emissions will decrease as Tier 4 engines will replace Tier 2 engines.

The discussion regarding revisions of NOx emissions for oil and gas drilling rigs has been combined because the same data are being used for revising emission estimates for both types of wells. Identical drilling rigs are currently being used for oil and gas wells and it was assumed that the data presented in Table 2-6 is applicable to both types of wells. This is conservative because the time to drill a gas well is less than an oil well since the well bore depth is shorter for a gas well (vertical) than an oil well (horizontal). A shallower depth reduces the drilling time for each gas well and hence the actual emissions for gas wells are less than indicated in Tables 2-5a and 2-5b.

In addition, the revised emissions in Table 2-6 are likely overestimated. First, the engine capacity rating (hp) is at sea level and no reduction in capacity or emissions has been applied (a conservative assumption resulting in over-estimating emissions) because of the engine installation in elevated terrain. Second, data were collected on the number of hours per month each engine was operating at load as well as hours per month when it was idling. These data were then used to calculate engine load. Engine run time was calculated assuming each well was adding the hours at idle and hours under load and this sum was divided by the number of hours in a month. There is likely additional downtime for relocating the rig to a new well pad that is not included in annualized emissions.

2.1.1.1.2 Drilling Rig NOx Emissions for Oil Wells

The same engineering data were used for drilling oil wells as gas wells because the same drilling rigs are used for both types of wells. The revised NOx emissions are estimated to be 188 tons/year. Use of current engineering data reduced total NOx levels by 16 tons/year.

Table 2-6. Oil Well Drilling Rig Data for Mancos Shale Project[5]

DJR Energy

Mancos Horizontal Drilling Program

Item #	Engine or generator	Make & model	Serial #	Nominal power (HP)	Tier	at idle (hrs)	under load (hrs)	total hours/mo	hrs/mo	runtime	load	lbs/hr at load	hrs/yr	lbs/well	tons/well
1	Draw works engine	Cat C18	WJH07258	700	II	410	274	684	720	0.95	0.40	1.3	8322	222.3	0.1
2	Pump #1 engine	Cat C32	TLD01543	1,350	II	381	303	684	720	0.95	0.44	4.00	8322	684.0	0.3
3	Pump #2 engine	Cat C32	TLD00448	1,200	II	585	99	684	720	0.95	0.14	2.00	8322	342.0	0.2
4	Generator #1	Cat C18	P1L00146	861	II	342	342	684	720	0.95	0.50	2.94	8322	502.7	0.3
5	Generator #2	Cat C18	P1L00147	861	II	342	342	684	720	0.95	0.50	2.94	8322	502.7	0.3
6	HPU for top drive	Cat C15	JRE01088	475	II	406	278	684	720	0.95	0.41	2.5	8322	427.5	0.2
			Total					**5,447**				**15.7**		**2681.3**	**1.3**

NOTES

Well duration is 7.125 days/four wells per month

Eliminated construction equipment, those emissions are counted elsewhere

[5] Provided by DRJ Energy LLC

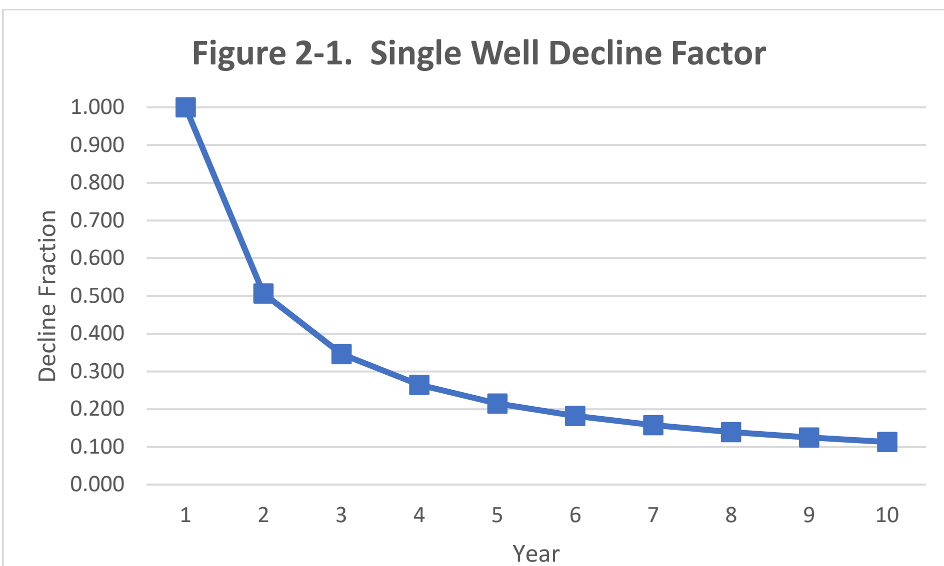
2.1.1.2 Compressor Engine Emissions

2.1.1.2.1 Compressor Engine NOx Emissions for Gas Wells

No changes were made to the Draft EIS emission estimates for well head compression, which were based on a 100 hp engine. It was assumed that this engine would be shared for 5 wells and that each gas well would consume 20 hp of the 100 hp.

For the Maximum Development Case (2025), it was assumed the cumulative well count would be 718 wells, which translates into 36 compressor locations having 100 hp capacity. NOx emissions resulting from these assumptions would be 259 tons/year using rich burn uncontrolled engines having an emission factor of 8.0 g/hp-hr.[6] It was also assumed that 100 hp engines would be used because they are below the EPA NSPS threshold for control. It is very likely that larger engines would be used requiring additional controls (e.g., 2.0 g/hp-hr or lower compared to 8.0 g/hp-hr).[7]

The Draft EIS did not include production decline related to production NOx emissions which is very important in evaluating cumulative emissions. The amount of compression needed is directly related to the amount of gas being processed. Wells drilled in the first year of development will decline by 50 percent in the second year compared to the first year (Figure 2-1). By the 10th year production is approximately 10 percent of the original production estimate. The decline data indicates that the compression needed to produce the well by the second year is only half of the compression needed compared to the first. In the Draft EIS estimated NOx emissions for compressors, it was assumed that the compressor engines would run continuously (8,760 hours/year) at 100 percent capacity and compression would not decrease as the well declined. This assumption greatly overestimated emissions from these sources.

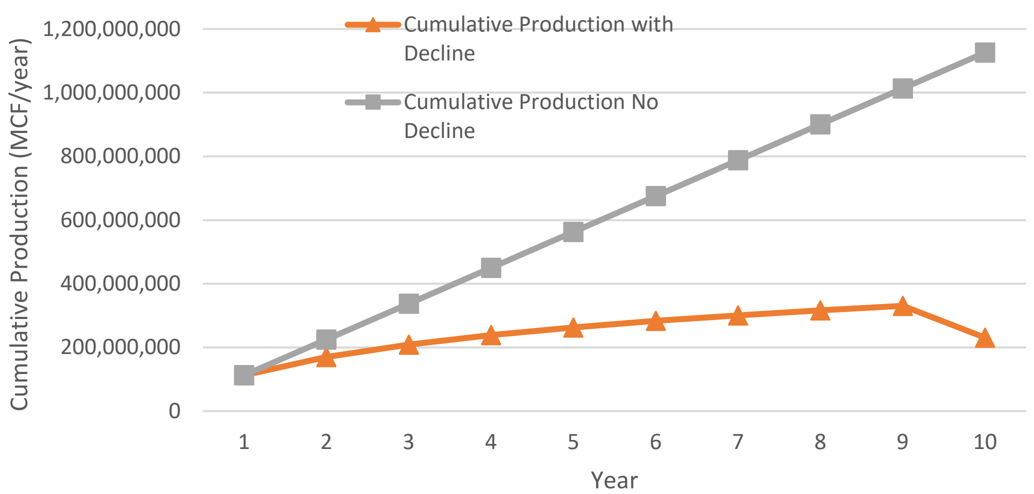


[6] Ramboll MANCOSShale_GasWells_High_Scenario_26July2016.xlsm Compressor_Engines tab

[7] Controlled emission factor was obtained from Ramboll maximum gas spreadsheet and translates to approximately a 75 percent reduction in NOx emissions.

Figure 2-2 presents cumulative gas production over a 10-year period using the data in the Draft EIS maximum gas spreadsheet data. This figure presents cumulative production volume with and without decline and illustrates that there is approximately a factor of 5 overestimate of production for the no decline case compared to the actual production accounting for decline. If decline is not factored into cumulative production estimates, extreme conservatism (overstating actual compression needs) will be factored into estimates of compressor emissions needed to fully develop the field.

Figure 2-2. Single Well Production with Decline, Cumulative Production with Decline and Cumulative Production Without Decline



2.1.1.2.2 Compressor Engine NOx Emissions for Oil Wells

The Draft EIS assumed that all oil wells would utilize 100 hp pumpjack engines. Pumpjacks are used in a small percentage of Mancos-Gallup wells but are common in vertical oil well production in the Mancos Shale region. The removal of NOx emissions for this source type resulted in a reduction of 1,329 tons/year for this source category.

Rather than using pumpjack engines to produce oil wells, oil production is accomplished using gas lift technology. With gas lift technology, more horsepower and more engines are needed at the start of production. As production declines over time, engines will be removed or de-rated. This results in fewer emissions than a pumpjack over time.

To illustrate how well pads are currently being permitted, Table 2-7 illustrates a portion of a New Mexico air permit that lists emissions for an existing 3 well pad, including engines (ENG-1-4).[8]

[8] NMED General Construction Permit (GCP-Oil and Gas) Registration Form North Alamito J31-2307

Table 2-7. NMED Permit for a 3 Well Pad for Mancos Shale Development

JR Operating, LLC North Alamito Unit J31-2307 Application Date: 3/27/2020

Table 2-D: Maximum Emissions (Consider federally enforceable controls under normal operating conditions)

This table must be filled out

Maximum Federally Enforceable Emissions are the emissions at maximum capacity with only federally enforceable methods of reducing emissions. Calculate the hourly emissions using the worst case hourly emissions for each pollutant. For each pollutant, calculate the annual emissions as if the facility were operating at maximum facility capacity without pollution controls for 8760 hours per year. Account for federally enforceable controls, such as an NSPS or MACT regulation. Consider federally enforceable controls due to permitting. List Hazardous Air Pollutants (HAP) in Table 2-I. Unit & stack numbering must be consistent throughout the application package. Fill all cells in this table with the emission numbers or a "-" symbol. A "-" symbol indicates that emissions of this pollutant are not expected. Numbers shall be expressed to at least 2 decimal points (e.g. 0.41, 1.41, or 1.41E-4).

Unit No.	NOx		CO		VOC		SOx		PM_{10}[1]		$PM_{2.5}$[1]	
	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr	lb/hr	ton/yr
ENG-1	1.2	5.28	2.41	10.55	1.14	4.98	0	0	0.05	0.2	0.05	0.2
ENG-2	1.2	5.28	2.41	10.55	1.14	4.98	0	0	0.05	0.2	0.05	0.2
ENG-3	0.18	0.77	0.18	0.77	0.11	0.46	0	0	0.01	0.06	0.01	0.06
ENG-4	0.18	0.77	0.18	0.77	0.11	0.46	-	-	0.01	0.06	0.01	0.06
GEN-1	0.03	0.11	0.07	0.3	0.02	0.1	0	0	0.01	0.06	0.01	0.06
GEN-2	0.03	0.11	0.07	0.3	0.02	0.1	0	0	0.01	0.06	0.01	0.06
HT-1 - HT-9	0.42	1.85	0.36	1.56	0.03	0.12	0	0	0.03	0.13	0.03	0.13
TK-1 - TK-6	-	-	-	-	0.42	1.86	-	-	-	-	-	-
FUG-1	-	-	-	-	4.93	21.57	-	-	-	-	-	-
ECD-1	0.02	0.09	0.05	0.2	0.08	0.33	0	0	-	-	-	-
ECD-2	0.02	0.09	0.05	0.2	0.08	0.33	0	0	-	-	-	-
SSM	-	-	-	-	-	10	-	-	-	-	-	-
Malfunction	-	-	-	-	-	10	-	-	-	-	-	-
Totals	3.28	14.35	5.78	25.2	8.08	55.29	0	0	0.17	0.77	0.17	0.77

[1] From Draft EIS spreadsheets

However, as presented in Table 2-8, changes in equipment operation and makeup occur over the life of the well. As a result, the emissions decrease for a single well over time, as depicted in Figure 2-4. Compared to the pumpjack technology, the gas lift technology results in fewer emissions (Figure 2-5). After year 7 or 8 of development, the importance of the inclusion of decline in the gas lift technology is demonstrated with the gas lift technology having lower emissions than pumpjack emissions.

Table 2-8. Summary of Compression Equipment and Associated Emissions Mancos Oil Well Using Gas Lift Technology

Year	Gas Lift Engines	Capacity Engine 1 and 2 (hp)	Well Pad Compressor NOx Emissions (t/yr)	VRU Engines	NOx Emissions Other Sources	Total NOx Emissions per 3 Well Pad	NOx Emissions per Well (t/yr)
1	2 Engines Max Capacity	1093	4.2	2 Engines Max Capacity	0.9	5.1	1.7
2	Interpolate Emissions		3.5	2 Engines Max Capacity	0.9	4.4	1.47
3	Interpolate Emissions		2.8	1 Engine Max Capacity	0.6	3.4	1.13
4	Reduce Capacity to 1 Engine	546	2.10	1 Engine Max Capacity	0.6	2.7	0.90
5	Interpolate Emissions		1.85	1 Engine Max Capacity	0.3	2.1	0.70
6	Interpolate Emissions		1.60	Remove VRU	0.3	1.9	0.62
7	Interpolate Emissions		1.35		0.3	1.6	0.54
8	Interpolate Emissions		1.11		0.3	1.4	0.46
9	Interpolate Emissions		0.86		0.3	1.1	0.37
10	Reduce Engine Size	100*	0.36		0.3	0.6	0.21

*Dependent upon pipeline pressures. Actual pressure could vary by site.

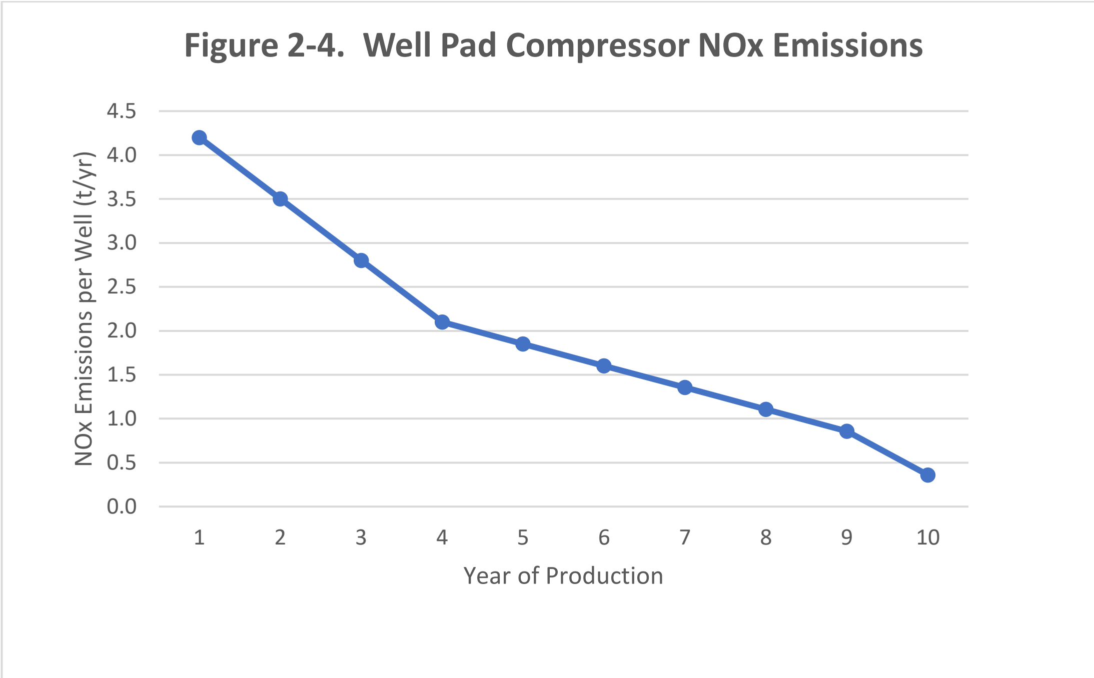


Figure 2-4. Well Pad Compressor NOx Emissions
4.5
4.0
3.5
3.0
2.5
2.0
1.5
1.0
0.5
0.0
NOx Emissions per Well (t/yr)
1
2
3
4
5
6
7
8
9
10
Year of Production

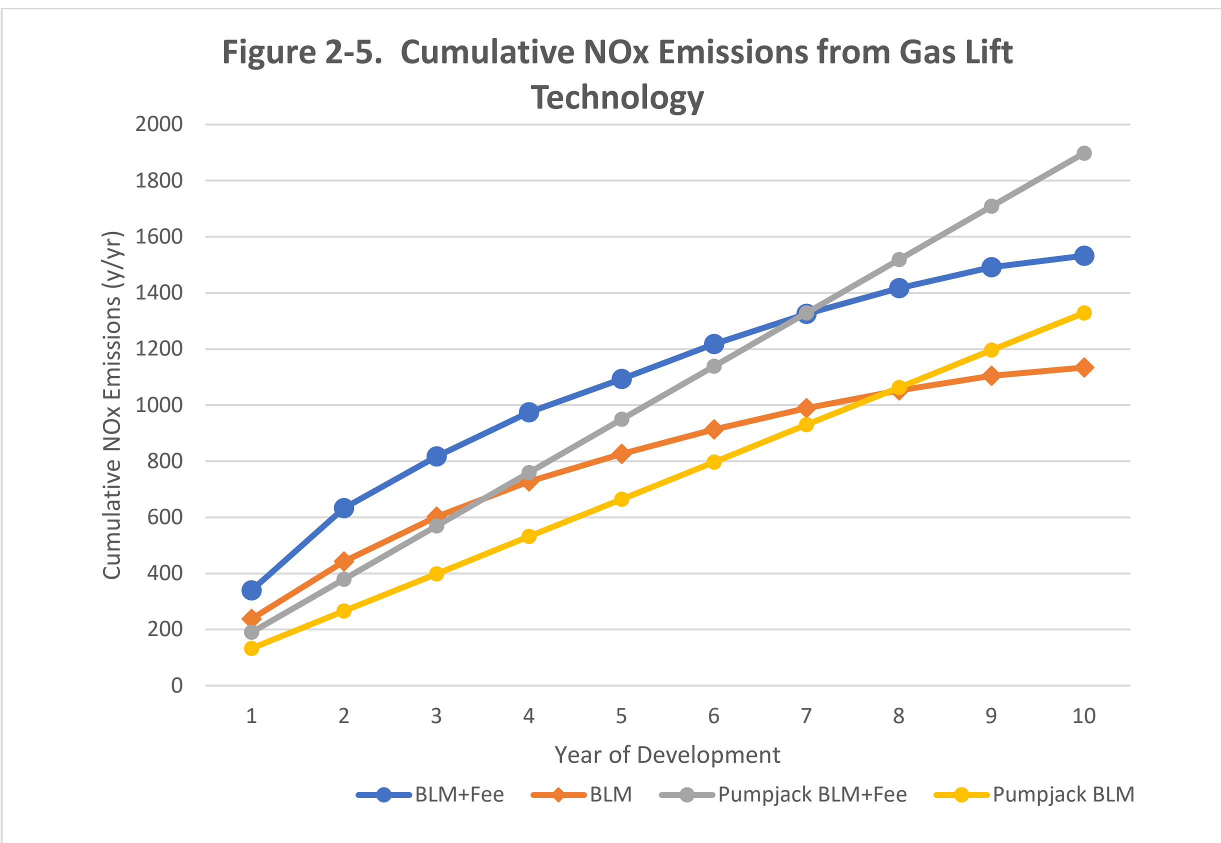


Figure 2-5. Cumulative NOx Emissions from Gas Lift Technology
2000
1800
1600
1400
1200
1000
800
600
400
200
0
Cumulative NOx Emissions (y/yr)
1
2
3
4
5
6
7
8
9
10
Year of Development
BLM+Fee
BLM
Pumpjack BLM+Fee
Pumpjack BLM

IPANM_0120

2.1.1.3 Heater NOx Emissions from Oil Wells

NOx emissions from heaters were revised by including a duty factor of 50 percent. The Draft EIS assumed these sources operated continuously over a 6-month period. These heaters are equipped with a temperature sensor that regulates when the burner is lit. This revision resulted in a reduction of 102 tons/year.

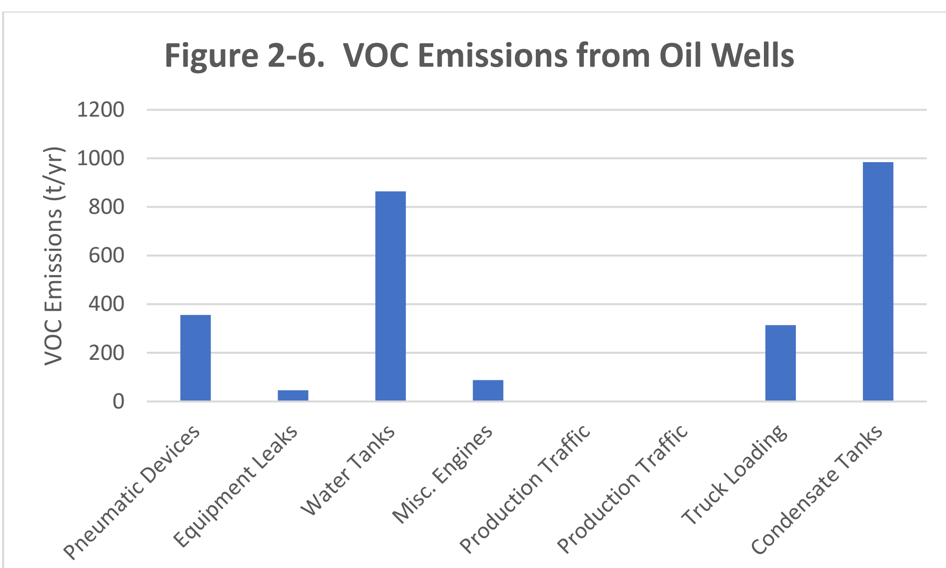
2.1.2 Revisions to VOC Emission Calculations

Table 2-9 presents a summary of VOC emissions associated with the Maximum Development Case for BLM wells and total wells (BLM plus Fee wells) as presented in the Draft EIS. This table shows that 95 percent of the VOC emissions are from oil wells. Figure 2-6 presents the distribution of VOC emissions from oil wells and shows that the four largest sources are: 1) flashing losses (37 percent); 2) produced water(33 percent); 3) pneumatic controllers (13 percent); and 4) tank working and breathing losses (12 percent).

Table 2-9. Summary of Draft EIS Reported VOC Emissions from BLM and Fee Wells

Case		VOC Emissions (t/yr)	% of Total
VOC Gas	BLM	296	5
	Total (BLM+Fee)	422	5
VOC Oil	BLM	6,271	95
	Total (BLM+Fee)	8,958	95

Total	BLM	6,566
	Total (BLM+Fee)	9,380



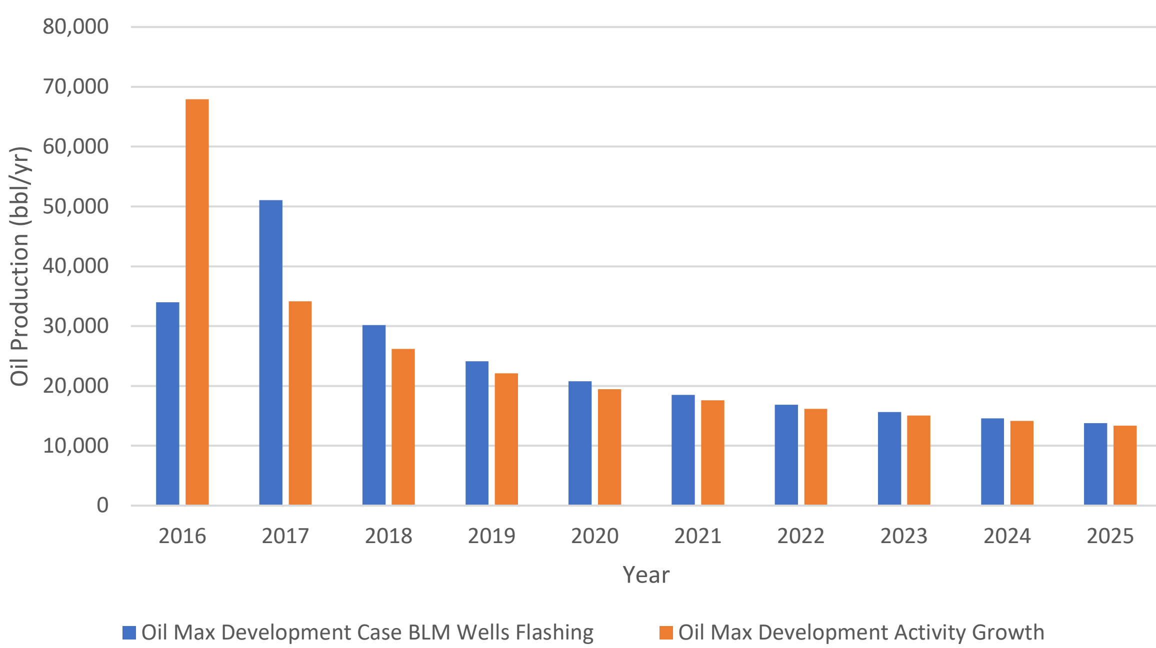
The emission calculations for flashing and produced water in the Draft EIS were based on an emission factor that is then scaled by annual condensate production and annual produced water. However, the Draft EIS did not account for the inclusion of additional emission control devices that are integrated into production equipment design. In addition, the produced water emissions inaccurately assumed that the amount of produced water remained constant over the 10-year production window. These actions overestimate emissions from these sources.

2.1.2.1 Flashing Emissions

The Draft EIS estimated flashing emissions from BLM wells and total wells (BLM+Fee) were 2,297 tons/year and 3,281 tons/year, respectively. These emissions were based on an uncontrolled emission factor of 2.7 lbs/bbl of condensate produced, scaled by annual condensate production, and routing the flash gas to a combustor that controls flash gas emissions by 95 percent.

The annual condensate production was adjusted for production decline. However, the condensate production rate used is not consistent within the document. Figure 2-7 presents the condensate production rate assumed in the activity growth tab of the MANCOSShale_OilWells_High_Scenario_26July2016 spreadsheet and the annual condensate production used in the emission calculations from the same spreadsheet. As illustrated in Figure 2-7, there is a considerable discrepancy between the two estimates of oil production for the first three years of development. There is no discussion in the Draft EIS or the spreadsheet that clarifies the difference of production rate.

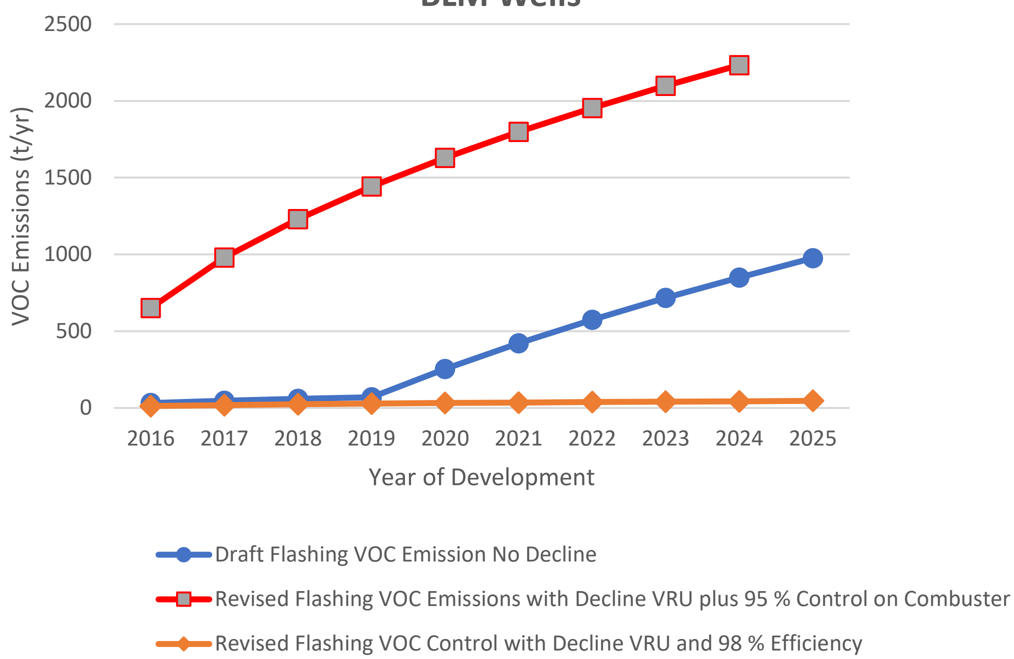
Figure 2-7. Condensate Production Reported in the Draft



The Draft EIS also did not consider that during early years of production, typical pad wells utilize vapor recovery units (VRU) that recover flash gas which is routed to sales or incorporated into oil production using gas lift technology. The 5 percent of the flash gas not controlled by the VRU is routed to the combustor. For VOC emissions reported in the Draft EIS, 100 percent (all) of the flash gas was routed to the combustor having an assumed control efficiency of 95 percent. In reality, because of the VRU, only 5 percent of the flash gas goes to the combustor (having 95 percent control efficiency).

Figure 2-8 presents a comparison of flash VOC emissions as reported in the Draft EIS and the revised emissions based on current engineering for BLM wells. This figure demonstrates that estimated VOC emissions in the worst-case year 2025 are reduced by 1,483 tons/year (65 percent) because of the additional controls in place as well as oil production decline. Two cases for controlled VOCs with decline are presented. The first presents inclusion of the VRU and 95 percent control on the residual VRU gas. The control efficiency of 95 percent is based on permit conditions. The second case is the same as the first case but a control efficiency of 98 percent was used consistent with manufacturer data and test data.

Figure 2-8. Comparison of VOC Flashing Emissions from Draft and Actual Well Design Being Implemented in the Mancos For BLM Wells



Note: Reduction resulted from inclusion decline and VRU controls plus combustor

In the year 2016 the difference between the two cases is a result of the inclusion of the additional reduction in emissions from the VRU. The difference in slope for the two cases between 2017 and 2020 is the cumulative effect of the VRU and oil production decline. It was assumed in 2020 that oil production had declined to the point where the inclusion of the VRU was no longer viable because of insufficient gas to operate the VRUs. The slope of the revised case becomes similar to what was reported in the Draft EIS, but the magnitude of emissions is substantially lower. The 98 percent control case shows no increase in VOC emissions after the VRUs are removed because of insufficient gas to operate them.

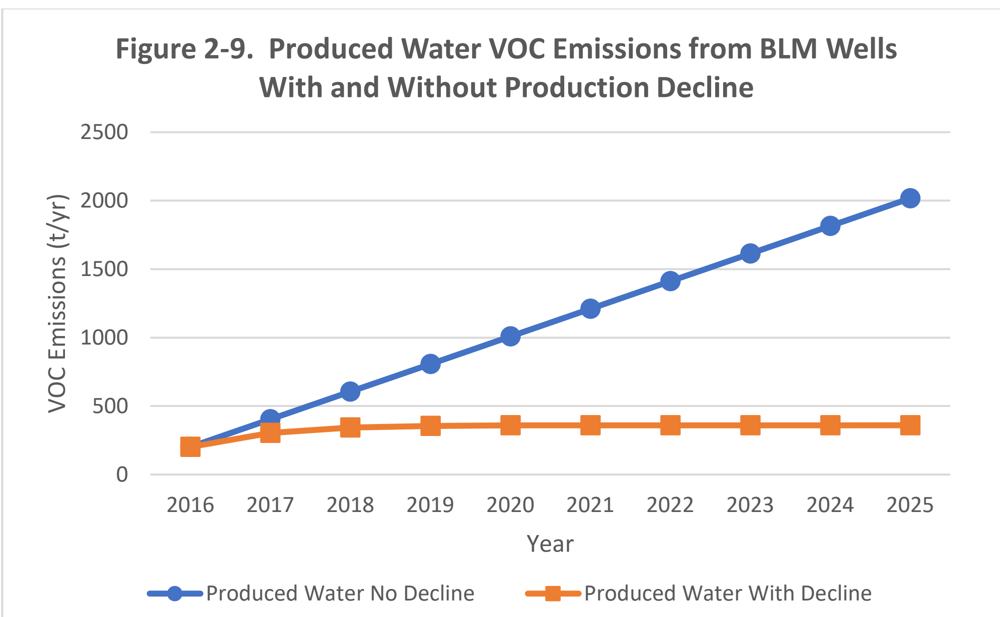
The assumption that combustors operate at 95 percent destruction efficiency is also very conservative. Appendix A presents actual field-testing data for combustors operating in Wyoming that indicate a destruction efficiency of 99 percent can be achieved. Thus, actual VOC emissions will be substantially less than indicated in the revised engineering calculations.

2.1.2.2 Produced Water

Produced water VOC emissions were calculated in a similar manner to flashing VOC emissions. The Draft EIS assumed an uncontrolled emission factor of 0.262 lb of VOC/bbl or water produced and a constant water production rate of 11,000 bbl/year/well.[9] VOC emissions for the year 2025 reported in the Draft EIS for BLM wells were 2,017 tons/year. This is based on an assumption that produced water production remains constant.

Yet, as well production (oil and gas components) declines over time, produced water will also decline. To account for this, it was assumed the rate of decline for water was the same as hydrocarbon components. The amount of produced water (11,000 bbl/year) was scaled by the well decline factor used in the Draft EIS.

Figure 2-9 illustrates the importance of the inclusion in decline in the produced water calculations. VOC emissions were reduced from 2,017 tons/year to 360 tons/year (82 percent reduction). These calculations are conservative because they do not assume that produced water emissions are routed to the combustor.



- Reduction in VOC emissions resulted from inclusion of decline in produced water
- Draft EIS assumed a constant 11,000 bbl/year/well

[9] Source Data Tab of MANCOSShale_OilWells_High_Scenario_26July2016 spreadsheet

2.1.2.3 Other VOC Sources

Because flashing and produced water emissions dominated the VOC calculations, detailed review of other VOC emission sources was not conducted. Additional review is needed on the larger emission sources to ensure that emissions are based on current practices in use in the area.

2.1.2.4 Summary of VOC Changes

Table 2-10 presents a summary of corrections in VOC emissions for the high development scenario for BLM wells and total wells, respectively.

Table 2-10. Changes to VOC Emissions from BLM Wells and Total Wells

Scaler	Type of Emission	VOC (t/yr)	(% Contribution)	Revised Emissions based on More Accurate Engineering VOC (t/yr)	(% Contribution)	Reduction (t/yr)	% Reduction
Annual condensate production	Flashing	2297.2	36.6	814	27	-1483	-65
Active well counts	Water tanks	2017.4	32.2	360	12	-1658	-82
Active well counts	Venting	831.8	13.3	832	27	0	0
Annual condensate production	Working/ breathing	734.0	11.7	734	24	0	0
Active well counts	Dsl eqt exh	206.6	3.3	207	7	0	0
Active well counts	Venting	107.1	1.7	107	4	0	0
	Total	**6,271**		**3,054**		**-3141**	

2.1.3 Revisions to Greenhouse Gas (CO_2 and CH_4) Emissions

GHG Emissions in the Draft EIS were calculated using screening emission factors and overstate actual GHG emissions and need to be revised.

2.1.3.1 Production (Downstream/End-Use) Greenhouse Gas Emissions Alternative

The end of Appendix J[10] to the Draft EIS presents a listing of estimated oil and gas production and cumulative CO_2 emissions (MMt CO_2) for the years 2018 through 2037. Greenhouse gas emissions were calculated from oil production based on a screening emission factor of 0.43 metric tons CO_2 per barrel of oil produced; gas combustion based on an screening emission factor of 0.0551 metric tons CO_2 per mcf (https://www.epa.gov/energy/greenhouse-gases-equivalencies-calculator-calculations-and-references). It is assumed that the GHG emissions represent CO_2 and not CO_2 eq (including CH_4) because the text does not provide any indication that emissions represent CO_2 eq. The URL link provided in the tables does not contain the emission factors used in the calculations in Appendix J.

Tables J1 through J13 were based on a screening level emission factor solely on production rate and is independent of actual equipment installed. Table 2-11 summarizes GHG emissions extracted from the oil and gas spreadsheet that were directly calculated based on equipment that would be used as part of calculation development.

The calculation of emissions based on actual equipment usage will more accurately reflect actual annual average emissions than screening calculations reported in Tables J1 through J13. Table 2-11 compares GHG emissions using both approaches. It is recommended that the screening calculations referenced in Tables J1 through J13 should be replaced with the more refined emission calculations based on equipment.

The gas spreadsheet dates used are not consistent with the dates in the oil spreadsheet. The dates used in the Maximum Development Oil Spreadsheet Emission Summary tab (as well as other tabs) run from 2016 through 2025. In the corresponding gas spreadsheet, the start date is 2019 and the end date is 2025. It seems very unlikely that gas drilling would start 3 years after oil development.

It is assumed that emissions presented in the gas spreadsheet in 2025 represent emissions after 10 years of development.

Table 2-11 indicates that for the Maximum Development Case for BLM wells in the year 2025 case, CO_2 emissions from oil and gas are 728,246 tons/year and CH_4 emissions are 20,284 tons/year. In Table J13 for the Maximum Development Case for BLM wells indicates 9.37 MMt/year (metric tons) which equals 728,246 short tons/year.

[10] No section number is provided. Table numbers J1 through J13 are presented

Table 2-11. Comparison of CO_2 Emissions Based on Typical Equipment Used in Oil and Gas Production in the Mancos Field

Case	Oil and Gas Spreadsheets Year 2025			Screening CO_2 Emissions from Table J13 Year 2025		
BLM	CO_2 Emissions (t/yr)	CH_4 Emissions (t/yr)		CO_2 Emissions MMt/yr	CO_2 Emissions (t/yr)	CO_2 Difference (t/yr)
Gas spreadsheet	170,151	11,278				
Oil spreadsheet	558,095	9,006				
Total	**728,246**	**20,284**		**9.37**	**10,328,654**	**-9,600,408**
BLM+Fee						
Gas spreadsheet	243,072	16,112				
Oil spreadsheet	763,269	12,866				
Total	**1,006,341**	**28,978**		**15.16**	**16,534,665**	**-15,528,324**

Note: CO_2 and CH_4 emissions based on actual equipment are what is published in the oil and gas spreadsheets and do not include changes made based on NOx and VOC sources using refined engineering data

The differences presented in Table 2-11 are attributed to the different methodology used to calculate emissions using a bottom up approach compared to a screening emission factor simply based on production. For total wells (BLM+Fee) CO_2 emissions are 1,006,341 tons/year compared of 15.16 MMt/year or 16,534,665 tons/year.

The Draft EIS should remove the screening GHG estimates and replace them with the bottom up calculation that was developed as part of the emission calculation spreadsheets.

The discussion of changes in NOx and VOCs indicated that substantial revisions are necessary to improve the accuracy of those emission inventories. The engineering refinements used for NOx and VOC will result in additional reductions in CO_2 and CH_4. Those reductions have not been quantified because of the discrepancies found in the GHG emission calculations.

2.1.4 Assumed Control Requirements

Based on a review of the tables from the Input Tab of MANCOSShale_OilWells_High_Scenario_26July2016 spreadsheet listing the base case and future year control requirements, electrification was never considered. Except for drilling emissions and completion emissions (diesel engines), all new wells were assumed to have future year controls in place over the development period. For diesel engines it was assumed that Tier 2 engines would be used until 2025 and then it was assumed that 60 percent Tier 2 Engines and 40 percent Tier 4 engines would be used. There is no technical basis for the transition from Tier 2 to Tier 4 engines. Since diesel engine emissions are regulated by New Source Performance

Standards (NSPS), any new engine or "reconstructed" engine would require a Tier 4 engine. Thus, the transition from Tier 2 to Tier 4 will occur earlier than 2025.

This table should include in place existing regulatory requirements (State and Federal) regarding emission control and be included in the Technical Support Document (Appendix J).

2.1.5 Projected Oil and Gas Emissions in the Mancos Shale Development

Detailed emission calculations were not provided in the Draft and it is very difficult to review and confirm the resulting emission estimates. The Draft document only presents a summary total for NOx, VOCs and GHG emissions by region. The Draft must be revised to provide additional documentation on how emissions were calculated

Appendix J (Attachments A and B) of the Draft presents limited details on the calculation methodology used to estimate projected emissions and resulting air quality impacts for oil and gas development in the Mancos region. Unfortunately, these sections do not provide sufficient detail to determine how emissions were calculated for each type of source. Also, for fired sources no discussion of fuel type was provided. The information in Attachments A and B only provides input to a computer program that was used to calculate emissions based on assumptions and engineering data but not the resulting calculations. No references were provided in the Draft to document emission calculations. The Draft references the CARMMS 2.0 study, but a review of that document indicated similar deficiencies regarding the lack of documentation for emission calculations.

The only quantification of emissions in the Draft EIS lists project emission totals (Table 2-1) and indicates that for the Mancos Shale proposed development for the Maximum Development Case, NOx emissions from both oil wells and gas wells on federal land has maximum total NOx emissions of 2,895 tons/year (year 2025). Projected total NOx emissions on Federal and Fee land are reported to be 4,136 tons/year. No information is provided on individual source contribution and it is difficult to determine the individual source type contributions to the total that was provided in the Draft. Without these data it is difficult to confirm the assumptions which were made in estimating emissions and to make refinements to the estimated emissions for each individual source using actual engineering data currently employed in the field. Further, some of the data included in Attachments A and B are incomplete.[11]

AQRM requested copies of the emission calculator spreadsheets that were used to compute emissions in the Draft.[12]

The spreadsheets present very complex calculations documenting how emissions were calculated and should be integrated into the Draft in an electronic form. Also, a summary of emissions by pollutant and source type from the spreadsheets should be included in the Draft.

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[11] Attachment A is missing gas compressor engine emission factor.

[12] BLM provided the following spreadsheets:

1) "MANCOSShale_OilWells_High_Scenario_26July2016";
2) "MANCOSShale_GasWells_High_Scenario_26July2016";
3) "MANCOSShale_OilWells_High_Scenario_26July2016"; and
4) "MANCOSShale_GasWells_Low_Scenario_26July2016".

AQRM conducted a detailed review of the Ramboll spreadsheets entitled

"MANCOSShale_OilWells_High_Scenario_26July2016" and
"MANCOSShale_GasWells_High_Scenario_26July2016".

The emission totals from the spreadsheets were then compared to the emission totals reported in Table 2-1.

The emission totals for the maximum development year (2025) from the oil and gas spreadsheets for NOx and VOC are presented in Table 2-2 for BLM wells and Fee wells. These totals were obtained by using the high gas and oil spreadsheets and selecting the maximum development year and summing NOx and VOC emissions.

Table 2-1. Summary of NOx and VOC Emissions by Scenario[13]

Scenario	NOx Emissions (TPY)			VOC Emissions (TPY)		
	Federal	**non-Fed**	**Total**	**Federal**	**non-Fed**	**Total**
Mancos Shale-wide						
High	3,184	1,364	4,548	6,469	2,772	9,242
Medium	1,811	1,364	3,175	2,751	2,772	5,523
Low	1,592	682	2,274	3,235	1,386	4,621
Mancos Shale, New Mexico only						
High	2,895	1,241	4,136	6,395	2,741	9,135
Medium	1,716	1,241	2,957	2,704	2,741	5,444
Low	1,448	620	2,068	3,197	1,370	4,568
Percent of Mancos Shale-wide Emissions in New Mexico						
High	91%	91%	91%	99%	99%	99%
Medium	95%	91%	93%	98%	99%	99%
Low	91%	91%	91%	99%	99%	99%

[13] **Table 2-3.** in **the Draft**

Table 2-2. Differences in High Oil and Gas Emissions between the Spreadsheets and Draft Reported for NOx and VOC Emissions

	Spread Sheet Emissions			Draft Table 2-3	
NOx	Oil Emissions (t/yr)	Gas Emissions (t/yr)	Total (t/yr)	High NOx Emissions (t/yr)	Difference Between Spreadsheet and Draft Reported NOx Emissions (t/yr)
BLM Wells	2,182	1,339	3,521	3,184	337
BLM + Fee Wells	3,117	1,912	5,030	4,548	482

VOC	Oil Emissions (t/yr)	Gas Emissions (t/yr)	Total (t/yr)	High VOC Emissions (t/yr)	Difference Between Spreadsheet and Draft Reported VOC Emissions (t/yr)
BLM Wells	6,271	289	6,560	6,469	91
BLM + Fee Wells	8,958	422	9,380	9,242	138

Comparison of the emission data from the spreadsheets and Table 2-1 and Table 2-2 (spreadsheet values) do not agree.

NOx emissions (oil and gas wells) for BLM sources from the spreadsheets were 3,521 tons/year. Table 2-1 (Table 2-3 in the Draft) lists NOx emissions for the same scenario to be 3,184 tons/year, a difference of 337 tons/year. For all sources (BLM and Fee sources) the difference is 482 tons/year. The spreadsheet lists 5,030 tons/year and Table 2-1 (Table 2-3 in the draft) lists 4,548 tons/year.

For VOC emissions for BLM wells emissions were 6,560 tons/year from the spreadsheets and 6,469 tons/year in the Draft (difference of 91 tons/year). For BLM + Fee wells the difference between the spreadsheets and those reported in the Draft was 138 tons/year.

It is assumed that the NOx emissions listed in the spreadsheet are correct and Table 2-3 in the Draft needs to be corrected.

There is also a major discrepancy between the Maximum Development Case spreadsheet for oil and the spreadsheet for gas. The maximum development oil spreadsheet indicates that development started in 2016 and the gas spreadsheet indicates that development began in 2019. It seems improbable that gas development would start 3 years after oil development. The spreadsheets need to be examined to determine if this difference is real or an error in the spreadsheet.

In terms of the worst-case year for emissions and air quality impacts (2025 or 10 years of development), the discrepancy is not important because the year 2025 represents maximum development.

There is an inconsistency between passing data between tabs in the Maximum Development Case gas spreadsheet. For the gas spreadsheet, CO_2 data from the BLM tab filtered by the year 2025 sums to a total of 169,556 tons/year while the emission BLM tab for 2025 sums to 153,146 tons/year. The totals between the two tabs should be identical. The comparison between spreadsheet totals and the totals in the report is presented to indicate that the Draft needs to be corrected to be consistent with the spreadsheets.

In the next sections it will be demonstrated that because of incorrect assumptions and lack of refined engineering data, emission calculations presented in the spreadsheets substantially over-state emissions related to actual development.

Comparisons were not made between other pollutants to determine if similar discrepancies exist.

2.2 Regulatory Analysis

The air quality analysis contained in the Draft EIS must provide a regulatory review of EPA and NMED air quality regulations that are applicable to the proposed project.

The Draft EIS does not provide any analysis of regulatory applicability and it is not possible to project what controls will be required on new and reconstructed emission sources (baseline level of emission control). Additional mitigation should not be evaluated for this project until the applicable emission control requirements are defined.

For example, Tier 4 engines are currently required for new diesel engines. Tier 2 engines could be used on existing drilling rigs, but these engines have a limited life span and any replacement will require the implementation of the latest emission control technology. The transition of Tier 2 engines to Tier 4 engines will be accomplished over a relatively short period of time through natural attrition.

Overall, the Draft EIS does not provide a regulatory applicability analysis that defines the minimum level of control legally required for development. The minimum level of control is defined as both State and Federal regulatory requirements. The Draft EIS should discuss the applicable regulations for new and reconstructed[14] emission sources as well as implementation of future controls that have been promulgated.

2.3 Mitigation

The Draft EIS provides a table of medium case scenario potential additional control assumptions but provides no documentation on the amount of mitigation reduction that would occur because of implementation and engineering feasibility.

2.3.1 Additional Applied Mitigation Measures

Until the regulatory analysis is completed, it is premature to evaluate additional mitigation options. Table 2-2 from the Draft EIS presents a list of mitigation options that could be considered for the medium development scenario (Table 2-13). Additional emission controls (see Table 2) were implemented consistent with additional controls applied in several Colorado BLM Field Offices.[15] Development of extensive additional mitigation options simply based on an email that is not available and without any economic and environmental benefits is inappropriate.

[14] NSPS definition of reconstruction has an economic threshold when capital expenditures on an existing source require the source to be considered as a new source and required to meet current NSPS emission standards.

[15] Per Forrest Cook (BLM Colorado) comments provided to Ramboll Environ in a 6/16/16 email.

Further, the definition of additional mitigation is the responsibility of NMED and can only be implemented through appropriate rulemaking. It is not the appropriate for BLM to insert additional mitigation in the ROD which has not been demonstrated necessary through ambient air quality analyses.

Table 2-13. From Draft EIS[16] Table 2-2 in the Draft EIS

Table 2-2. Medium scenario additional control assumptions.

Emission Source Category	Medium Scenario Controls
Stationary engines	50% electric engines (50% natural gas-powered)
Pneumatic devices	50% no-bleed (50% low-bleed)
Drilling	Tier 4 gen-set standards for all engines with a horsepower >750; final Tier 4 standards for all engines with horsepower <750
Completion/Fracking	
Blowdowns	25% gas captured and routed to VRUs or flares (75% vented)
Liquids removal system (all produced liquids)	25% taken away by pipeline (75% by truck) not ana
Pneumatic pumps	Unchanged from the High Scenario except in cases where less than 25% of pneumatic pumps emissions are controlled; if less than 25% of pneumatic pumps emissions are controlled then the percentage of pneumatic pumps which are controlled is set to 25%
Unpaved roads dust	80% fugitive dust control
Construction fugitive dust	50% fugitive dust control
Condensate Tanks (all produced liquids)	100% of emissions are captured and controlled by VRU or flare
Truck loading emissions	100% of emissions are captured and controlled by VRU or flare
VRUs	50% of emission control devices are assumed to be VRUs (50% flares)

Neither the Draft EIS nor the emission calculation spreadsheets provide any technical basis regarding magnitude of emission reduction resulting from these additional mitigation options over the base case.[17] The viability of these mitigation options should be determined by analysis of the following: 1) environmental benefits[18]; 2) the cost of implementation/operation; and 3) calculation of incremental[19] cost effectiveness ($/ton of pollutant removed). Without such analyses, it is not possible consider these options as potentially viable. The following presents a technical discussion of the technical viability of these options.

2.3.2 Viability of Other Mitigation Options Listed in Draft EIS Table 2-2

Table 2-14 Illustrates that most mitigation options presented in the Draft EIS were not analyzed in terms of emission reductions, cost, or incremental cost effectiveness. Without any data to support the additional mitigation strategies, it is inappropriate for BLM to incorporate such measures in a ROD.

[16] Farmington MANCOS-Gallup Draft Resource Management Plan Amendment and Environmental Impact Statement Volume 2, Appendix J, Section 2.1.2 page 5.

[17] The amount of emission reduction should be evaluated from the current regulatory floor as opposed to uncontrolled conditions.

[18] Environmental benefit should not require additional modeling and can consider incremental emission reduction from the regulatory floor, as well as qualitative analyses indicating the air quality benefit from such action.

[19] Incremental cost is defined as the cost of implementation from the regulatory floor not uncontrolled conditions.

Table 2-14. Mitigation Options Considered in Draft EIS for Future Year with Growth and Mitigation[20]

Mitigation Case	Type of Mitigation Considered	Emission Inventory Action Taken
Stationary engines	50% electric engines (50% natural gas-powered)	Not analyzed
Pneumatic devices	50% no-bleed (50% low-bleed)	90 % low bleed 10 % no bleed
Drilling	Tier 4 gen-set standards for all engines with a horsepower >750; final Tier 4 standards for all engines with horsepower	Assume 60% Tier II and 40% Tier IV starting in 2025
Completion/Fracking		
Blowdowns	25% gas captured and routed to VRUs or flares (75% vented)	Not analyzed[1]
Liquids removal system (all produced liquids)	25% taken away by pipeline (75% by truck) not ana	Not analyzed
Pneumatic pumps	Unchanged from the High Scenario except in cases where less than 25% of pneumatic pumps emissions are controlled; if less than 25% of pneumatic pumps emissions are controlled then the percentage of pneumatic pumps which are controlled is set to 25%	Assumed level of control 100%
Unpaved roads dust	80% fugitive dust control	Not analyzed
Construction fugitive dust	50% fugitive dust control	Assumed level of control 50%
Condensate Tanks (all produced liquids)	100% of emissions are captured and controlled by VRU or flare	Assumed level of control
Truck loading emissions	100% of emissions are captured and controlled by VRU or flare	Not analyzed
VRUs	50% of emission control devices are assumed to be VRUs (50% flares)	Not analyzed but in practice for oil wells

2.3.2.1 Stationary Engine Electrification

Table 2-2 in the Draft EIS presents the concept that additional emission reductions could be achieved by using 50% electric engines and the remaining 50% of the engines would be natural gas-powered. There is no information presented to quantify the environmental benefit nor the associated costs. As indicated in the previous subsection, electrification of compressors was not addressed in the Draft EIS nor emission

[20] From emission spreadsheet

inventory calculations. This suggested mitigation option has important ramifications that are critical to any evaluation of this option which are presented below.

This mitigation approach would be very difficult to implement and very costly because the majority of the project area is not electrified. To implement this option an entire electrical infrastructure would have to be designed, constructed and operated which needs to be factored into any analysis. Beyond the cost of electrification, the cost of electricity used to power the electric compressor motors needs to be included in an evaluation of this option.

In evaluating the environmental benefit for the conversion of 50 percent of the needed compression to electric from natural gas, the resulting emissions from generation of electricity to power the electric compressors must be included. Electric generation in the region is based on a mixture of coal (41 percent), natural gas (35 percent), wind (19 percent) and solar (4 percent).[21] Electrical generation based on this mixture of energy sources results in NOx emissions of 1.1 lbs/mw-hr.[22] It is estimated that electrical demand for a 3 well pad is 1.5 MW.[23] This translates to indirect NOx emissions for a single 3 well pad related to electrical generation of 7.1 tons/year.

Annual NOx emissions for a similar well pad using natural gas compression are 5 ton/year. **Thus, shifting from natural gas compression to electric compression results in a 2.1 ton/year increase in NOx emissions.**

Electric CO_2 emissions reported by EGRID are 1,333 lbs/mwh[24] compared to CO_2 emissions from natural gas of 1,138 lbs/mwh[25] and results in an increase in CO_2 emissions of approximately 1,264 tons/year.

It has been demonstrated that the conversion of natural gas fired compressor engines to electric would result in increases of NOx and CO_2 emissions. The cost of this conversion would be excessive as indicated in Table 2-15.

This table presents the increase in fuel cost (electrical cost versus well head natural gas cost) as well a scoping cost estimate on infrastructure needed to electrify the region.

Conversions of natural gas engines to electric would increase the fuel cost (electricity compared to natural gas) for a 3 well pad by $545,000 and $25,000,000 for 100 wells. This estimate includes the well head value of natural gas for gas fired compressors.

Capital cost for using electricity for 100 wells would be $34,500,000 and the total cost for 100 wells fuel plus capital becomes $75,000,000 and produces no environmental benefit.

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[21] EGRID summary tables
[22] EGRID summary tables
[23] Electric capacity was assumed to be equal to that of a 3 well pad plus a safety factor for line loss and contingency.
[24] EGRID summary tables
[25] Four Corners Air Quality Task Force Report of Mitigation Options, 2007, Appendix A Four Corners Task Force Report Mitigation Options

Table 2-15. Energy Cost and O/H Line Estimate

Assumptions:

Energy Rate	0.08	c/KWH
Connected Load in HP per well pad	1651	HP

Electric Energy Cost Calculation:

	3 wells/pad		100 Wells	
Connected Load in HP	1,651	HP	165,100	HP
Operating Load in HP (90% Load Factor)	1,486	HP	148,590	HP
Electric Load in KW (90% Eff.)	1,232	KW	123,165	KW
Electric Load in KVA (0.85 p.f.)	1,449	KVA	144,900	KVA
Average Continuous Loads in operation (75%)	924	KW	92,373	KW
Energy consumption per day (24 Hours)	22,170	KWH	2,216,963	KWH
Daily Energy Cost	**$1,774**		**$177,357**	
Yearly Energy Cost (365 Days)	**$647,353**		**$64,735,314**	
Electric Line Size and Cost:				
KW Load with Contingency (~20%)	**1,478**	**KW**	**258,646**	**KW**
KVA Load with Contingency (~20%)	1,739	KVA	304,289	KVA
Line voltage Assumed	21.6	KV	230.0	KV
Line current	46	A	764	A
Minimum Wire Size (AWG or kcmil)	4	AWG	1,272	kcmil

Electric O/H Line Cost Calculation:

	1 Well pad		100 Well pads	
Megawatts needed to completely electrify a 3 well pad	**1.48**	**MW**	**258.65**	**MW**
Electric cost at the site vs. using natural gas	**$647,353**		**$64,735,314**	

Natural Gas cost for compressor engines per year:

	1 Well pad		100 Well pads	
Savings for Natural Gas not used @$2.20/MCF	$ 122,591		$ 24,518,120	

	1 Well pad		100 Well pads	
Electricity Cost for Compressors - Natural Gas Cost for Compressors	**$ 524,763**		**$ 40,217,194**	
Electric Infostructure Cost	Approximately **$650K** per mile (from past project) – approx. 80 miles for 1/2 planned gathering system = $52MM for power distribution.		For 100 well pads, the load increases lot and the electric O/H line voltage needs to be higher (230KV) range. Additionally, Sub-station or Switchyard is also required	

Electric Equipment Calculation:

	1 Well pad		100 Well pads	
Additional cost for electrically powered equipment		$ 45,000		$ 4,500,000

Switchyard Cost:

	1 Well pad		100 Well pads	
Electric switchyard				$ 30,000,000

	1 Well pad		100 Well pads	
Equipment Cost		**$45,000**		**$ 34,500,000**
Annual Capital Cost				**$74,717,194**

Notes:
1) 3 wells per pad extrapolated from 4 wells per pad data
2) Draft mitigation option assumed 1/2 engines would be electric

2.4 Specific Emission Comments

2.4.1 Methane

Page 3-18[26] of the Draft EIS states the following:

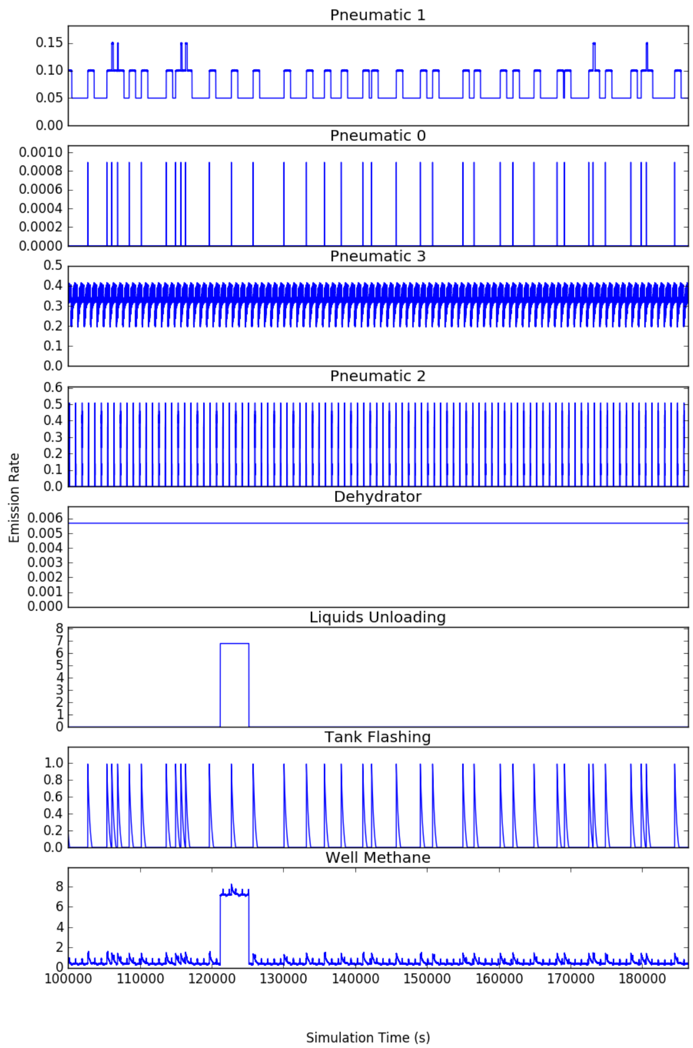
> "Methane is a GHG pollutant of concern in the planning area. In 2014, satellite imaging identified high methane concentrations over the Four Corners region, including the northern portion of the planning area. The imaging identified elevated methane concentration levels but not the sources of the methane. Methane is emitted during oil and gas well completions and from process equipment, such as pneumatic controllers and liquid unloading at oil and gas production sites, though other sources of methane may contribute to the methane hotspot. More information on the Four Corners methane hotspot may be found in the Air Resources Technical Report for Oil and Gas Development (BLM 2018c), which the BLM New Mexico State Office updates annually. Information on methane may also be found in a new interactive mapping tool launched by New Mexico in 2019. This tool shows methane hotspot information and information on methane permits."

Oil and gas operations emit CH_4 and the Draft EIS contains information regarding estimates of annual emissions and should be considered a policy inventory.[27] Ambient measurements by contrast represent an ambient concentration at a single location and a single point in time. Unless emissions are constant over time, it is impossible to estimate annual average emissions that can be used to estimate a policy inventory. Also, the uncertainty in inverse modeling is very large. Appendix A contains information regarding the uncertainty of inverse modeling.

Figure 2-10 presents the changes in well emissions for different types of sources. This figure presents short-term emissions from various components located on a production well pad and indicates the variability in short-term emissions. Ambient measurements are very dependent on the random nature of short-term emissions from the well pad. Combined emissions from the well pad (bottom panel) indicate emissions can vary from 0 to approximately 8 over a short time period (approximately 1 day). The peak emission rate of 8 is related to a liquid unloading event. If inverse modeling using ambient data is based on a liquid unloading event, the resulting emission estimate will not be representative of longer-term emissions since such emissions are episodic in nature.

[26] Appendix J
[27] A policy inventory represents annual average or long-term average emissions. Such long-term inventories are what EPA and States use to make policy decisions for environmental improvement.

Figure 2-10. Modeled Time Series of Methane Emissions for Different Types of Equipment[28]



The Draft EIS presents information regarding satellite hotspot monitoring in the Four Corners Region and attributes the hotspot impacts to oil and gas emissions. There are natural sources of CH_4 seeps in the coal bed methane (CBM) region of southern Colorado and northern New Mexico[29,30] and these natural sources may also significantly contribute to the hotspot measurements and should be recognized in the Final RMP.

[28] Downey, Nicole 2020, Personal Communication

[29] The Biggest Methane Leak in America Is in New Mexico; Scientific American https://www.scientificamerican.com/article/the-biggest-methane-leak-in-america-is-in-new-mexico/

[30] Varon, D. J., Jacob, D. J., Jervis, D., & McKeever, J. (2020). Quantifying Time-Averaged Methane Emissions from Individual Coal Mine Vents with GHGSat-D Satellite Observations. *Environmental Science & Technology*. https://pubs.acs.org/doi/10.1021/acs.est.0c01213

2.4.2 Formaldehyde from Flares

The Draft EIS assumed that emissions from the flares are 20 percent by weight formaldehyde and this assumption is not justified as explained in the following. The speciation of VOC emissions from flares being 20 percent by weight formaldehyde is based on the EPA SPECIATE Database. However, no documentation is provided on the basis for this assumption in the SPECIATE Database. The VOC emissions from flaring consists of the VOCS that are flared and not combusted and destroyed, meaning the 2 percent of the total waste streams going to the flares from the tanks, dehydration units, and pneumatic controllers. The composition of the VOC emissions from flare would therefore be the composition of the flash gas from the condensate tanks, working and breathing losses from the condensate tanks, the regenerator overhead stream from the dehydration unit, and the natural gas vented from the pneumatic pumps. However, the composition that BLM used from the EPA SPECIATE data base is shown in Table 2-15. The only documentation provided regarding the origin of the profile in SPECIATE is the following note: "Information based on composite survey data, engineering evaluation of literature data." Also, the analytical methods used, and uncertainty are listed as unknown. With all the percentages based on multiples of 10, the uncertainty would seem to be quite high.

Table 2-15. Gas Flaring taken from the SPECIATE 3.2 database[31]

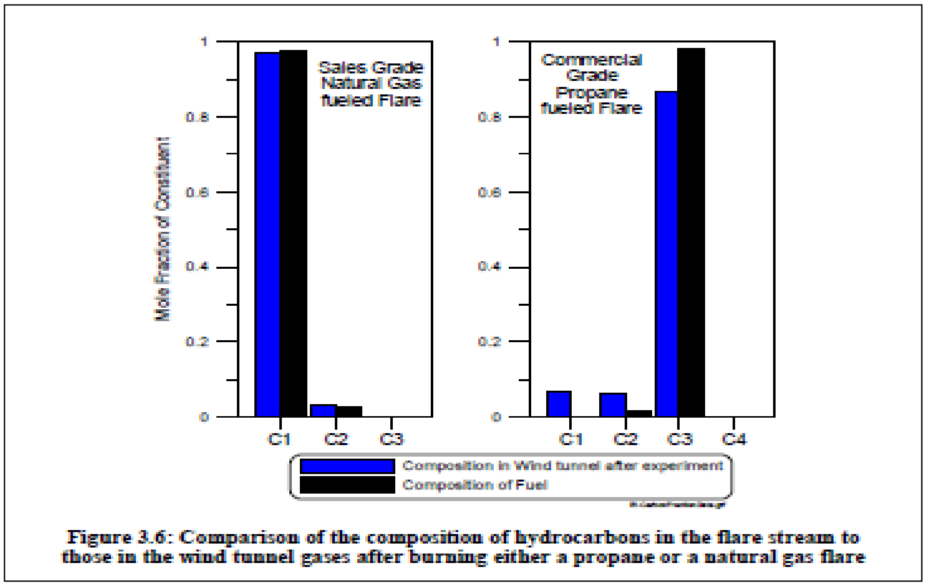
Name	Weight percent
Methane	20
Ethane	30
Formaldehyde	20
Propane	30

The University of Alberta did a flare study from 1996-2004 that looked at the combustion efficiencies and emissions from flaring at oil batteries in Alberta, Canada (Kostiuk, et al., 2004).[32] The study found that no formaldehyde is produced from flares. Kostiuk, et al. found that the gases found downwind of the flare were mainly unburned fuel, not products of incomplete combustion (Figure 2-11). Samples of the gas for aldehydes showed a maximum emission rate of 1 mg/kg of gas flared. Formaldehyde was not estimated from this amount. However, this study does show that the flare emissions are typically waste combusted gases, not products of incomplete combustion such as formaldehyde.

[31] http://cfpub.epa.gov/si/speciate/ehpa_speciate_browse_details.cfm?ptype=G&pnumber=0051

[32] Kostiuk, L.W., M.R. Johnson, and G. Thomas, 2004. "University of Alberta Flare Research Project Final Report November 1996 – September 2004". Combustion and Environment Group, Department of Mechanical Engineering, University of Alberta. September.

Figure 2-11. Comparison of Composition of Hydrocarbons in Flare Streams to Those in the Wind Tunnel Gases after Burning Either a Propane or Natural Gas Flare (Kostiuk et al., 2004)



2.4.3 Power Plant Emissions

The Arizona Public Services Electric Company owns most of the Four Corners Power Plant. It released its integrated resource plan in April 2017 (Arizona Public Services Electric Company 2017). Under this plan, it would continue operations at Four Corners Power Plant but would reduce emissions by installing selective catalytic reduction technology in 2018. It also would replace older gas-fired turbines with new turbines and modernized air pollution controls in 2019.

The Draft EIS provided:

> Overall, air pollutant concentrations, such as ozone, nitrogen oxides, and particulate matter, increased as recently as 2006. These increases negatively influenced air resources in the region, including increased deposition rates of mercury and nitrogen and reduced visibility near Class I areas. Since 2006 this trend has reversed, largely due to new regulations limiting emissions from oil and gas development and coal-fired power plants and changing technologies. This trend of decreased air pollutant emissions and continued improvement in AQRVs would likely continue due to the planned actions at area power-generating facilities described above and reductions in gas production predicted to continue through 2021; however, the rate or direction of this trend may slow or reverse if production of oil and gas development were to increase in the planning area for other reasons, such as favourable economic conditions or continued new technological advancement in the industry, or if there were changes in the state or federal regulatory environment."[33]

[33] Farmington Mancos-Gallup Draft Resource Management Plan Amendment and Environmental Impact Statement Volume 1, 2020, Page 3-16

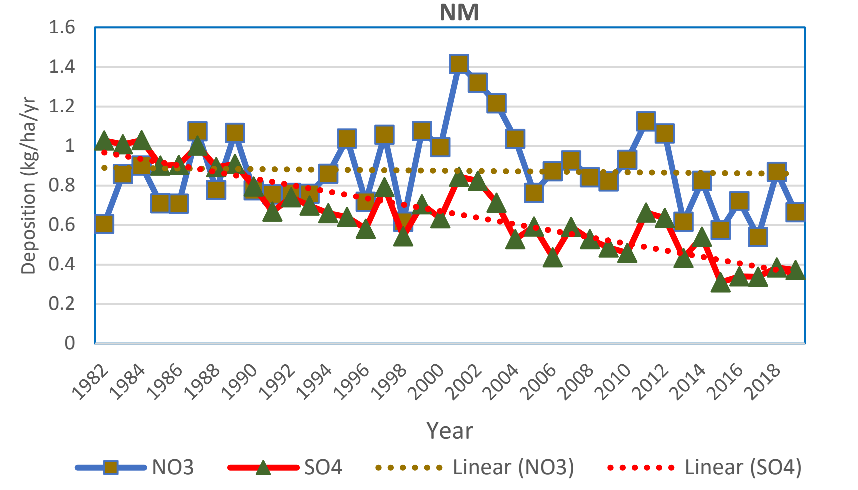
The changes in air quality in the Four Corners Region will substantially improve because of changes in operation and emission control levels from these power plants. The Draft EIS should quantify and include the actual magnitude of the emission reductions as well as the timetable for the reductions.

The conclusion reached in the Draft EIS regarding power plant emissions is that air pollutant concentrations, such as ozone, nitrogen oxides, and particulate matter, increased as recently as 2006. These increases negatively influenced air resources in the region, including increased deposition rates of mercury and nitrogen.

The conclusion that deposition and visibility has increased as recently as 2006 is not supported by ambient monitoring data.

In terms of nitrogen deposition, monitoring data from Molas Pass, CO, Mesa Verde, CO and Badlander, NM[34] indicate substantial decreases in deposition data from 1990 through 2013 (Figures 2-12 and 2-13 respectively).

Figure 2-12. Measured Wet Deposition Trends at Badlander, NM



[34] http://nadp.slh.wisc.edu/data/sites/siteDetails.aspx?net=NTN&id=NM07

IPANM_0140

Figure 2-13. Measured Wet Deposition Trends at Molas Pass

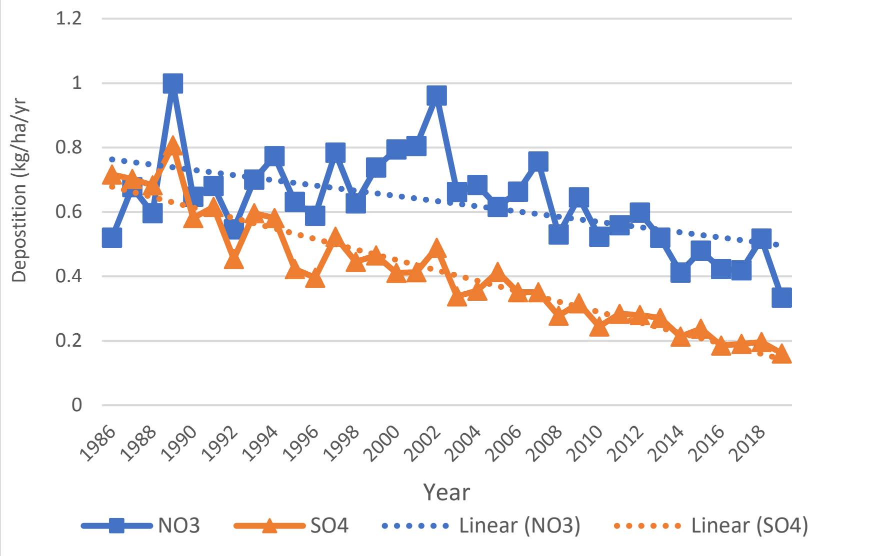
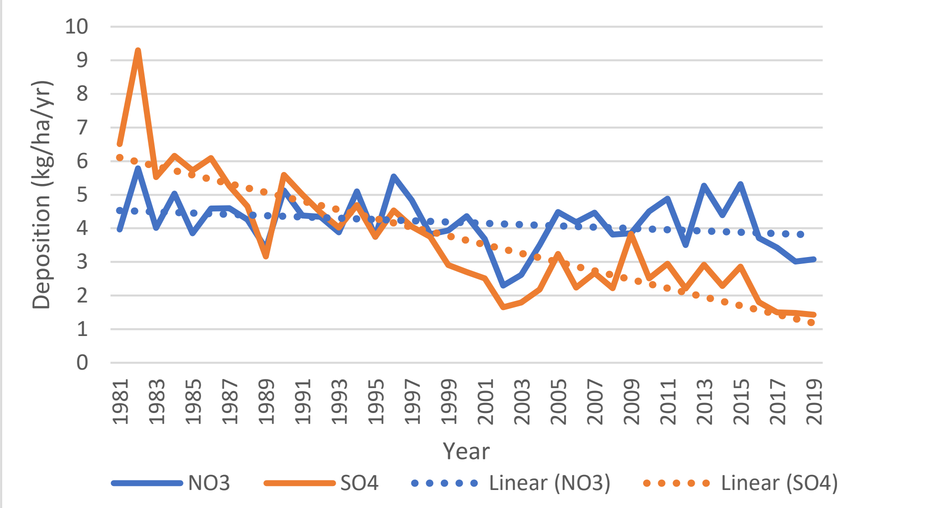


Figure 2-14. Measured Wet Deposition Trends at Mesa Verde



These figures do not illustrate the increase in deposition indicated in the Draft EIS prior to 2006. Rather, over the period of record at these three sites there has been a dramatic decrease in SO4 deposition and a slight decrease in NO_3 deposition.

Figure 2-15 presents IMPROVE measured NO_2 concentrations at Mesa Verde between 1988 through 2018. This figure does not illustrate any trend in NO_3 ambient concentrations. It does appear that peak concentrations have tended to be smaller from 2014 until 2018 than for the period 2000 through 2014. From 1988 until 2014 peak concentrations appear similar to those measured in 2014 until 2018.

Figure 2-15. Improve Measured 24-hour Average NO_3 concentrations at Mesa Verde, CO

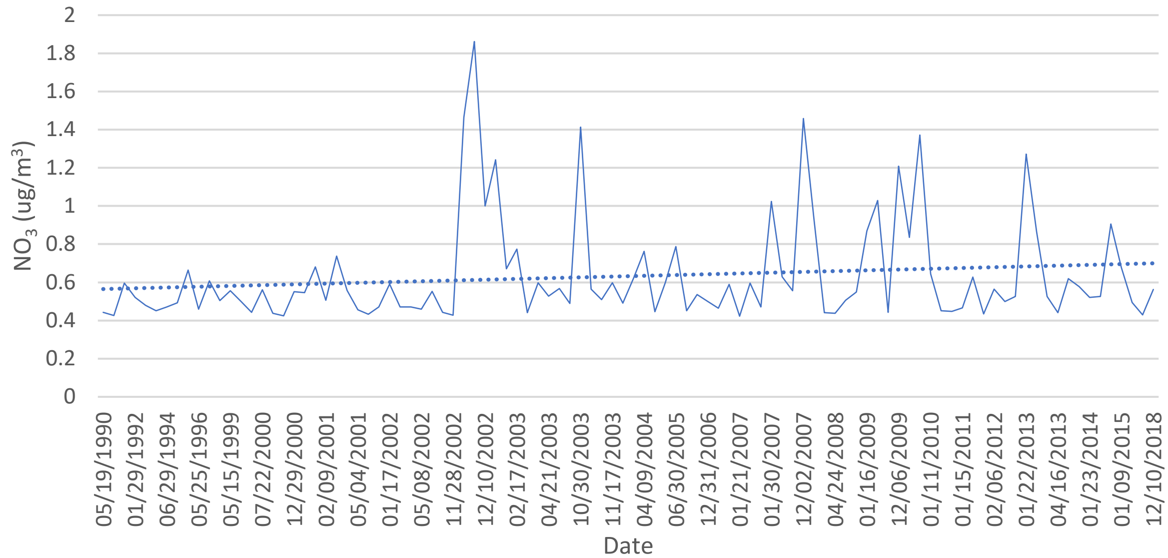
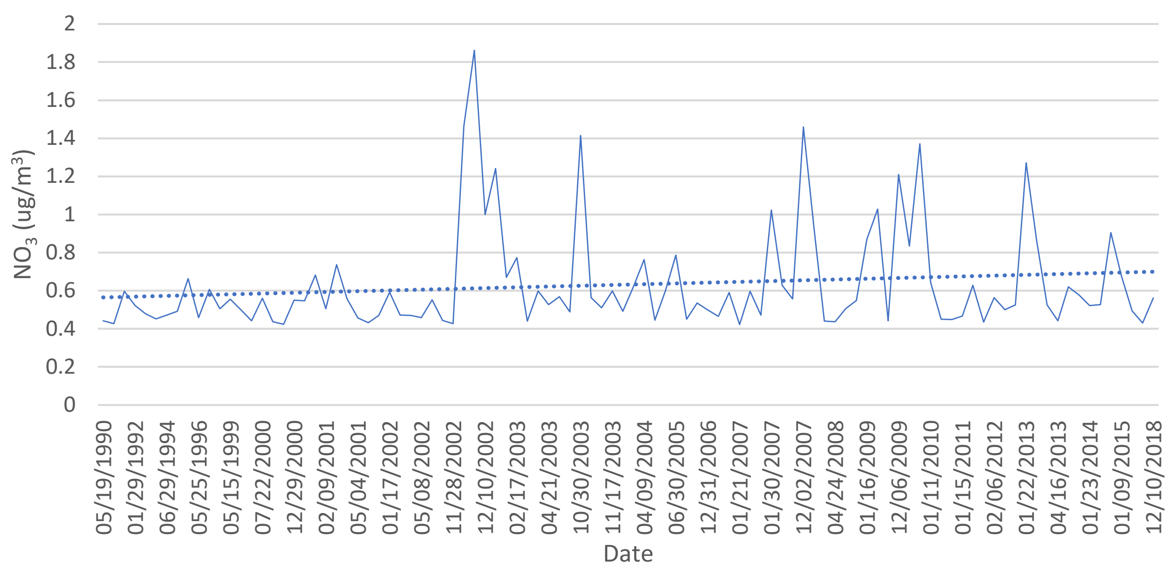


Figure 2-16 presents the top 100 measured concentrations over the period of record at Mesa Verde. There is no apparent change in maximum concentrations after controls were installed on the power plants in 2016.

Figure 2-16. Improve Maximum 100 Measured 24-hour Average NO3 concentrations at Mesa Verde, CO



Concentrations of NO_3 are being presented as a surrogate for visibility and this particle has the potential for causing visibility reductions from NOx emissions.

The monitoring data do not suggest after controls on the power plants were installed that it resulted in an improvement in deposition or visibility. To suggest oil and gas emissions could slow the rate of improvement or reverse it is without any basis. The suggestion of further degradation of AQRVs is total speculation without any quantitative basis.

This conclusion regarding increases in ambient concentrations should be removed from the document.

As part of the analysis, BLM should provide, at a minimum, an emission net analysis based on actual emission reductions achieved from changes in operation at the power plants. The changes in power plant emissions should be compared to the changes in oil and gas emissions projected in these comments. Such an analysis will provide a net change in regional emissions and will provide decision makers with tools to forecast emission changes over time.

3. NAAQS Comparisons

3.1 Ozone NAAQS Analysis Using the Absolute Modeling Results

Based on the ozone modeling and other data, it can be concluded that the maximum oil and gas development case does not pose a "significant" contribution to existing ozone (O_3) levels and does not create a new predicted exceedance to the 70 ppb O_3 NAAQS. Further, because the emission calculations are overstated from actual development, actual impacts will be less than those presented in the report for the Maximum Development Case. Impacts for the Maximum Development Case will approximate those developed for the Medium Case.

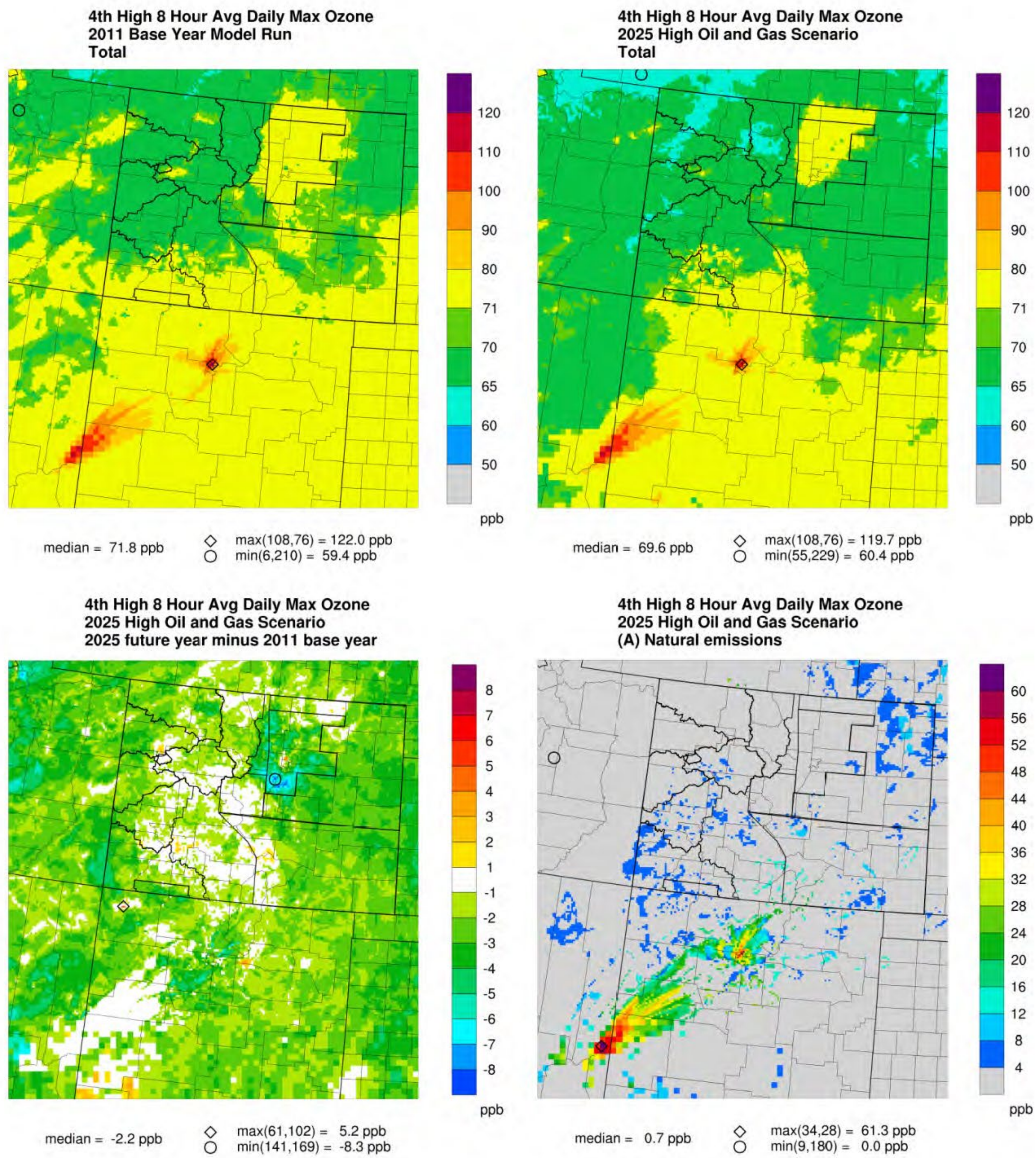
The Draft EIS provides very minimal analysis of both the modeling results and modeled exceedances of the ozone NAAQS. The modeled excursions were caused by wildfires (exceptional events) and EPA would not consider these for a determination regarding evaluation of compliance for the ozone standard.

3.1.1 Cumulative Ozone

It is recommended that the Draft EIS provide additional interpretation of the projected impacts.

The Draft EIS provides very little interpretation of the ozone modeling results and the predicted concentrations need to be placed into proper perspective. Figure 3-1 (Figure 3-1 from Appendix J) presents maps of ozone predicted impacts over the modeling domain.

Figure 3-1.



Fourth highest daily maximum 8-hour ozone concentrations for the 2011 Base Case (top left), 2025 High Development Scenario (top right), 2025 High minus 2011 differences (bottom left) and Natural Emissions (bottom right).

The absolute 4th highest ozone impacts are in the range of 71 to 80 ppb (just above the standard). It is important to note that these plots present concentrations independent of time (i.e., the plot does not represent predicted ozone concentrations on a specific day).

The top left plot is for the 2011 Base Case. It is apparent in the figure that there are two major emission sources, one in northern New Mexico and the other on the border of New Mexico and Arizona, and these result in large isolated ozone impacts. The report states that these large impacts were a from natural sources (wildfires).

The upper right plot presents cumulative impacts for the maximum oil and gas scenario for the year 2025. It is apparent in this figure that the 4th highest ozone concentration in the western portion of the grid (Mancos Shale area) has lower impacts than the base case. The bottom left figure presents the difference between the 2025 maximum oil and gas development case and the baseline case. This figure presents overall predicted ozone impacts from the maximum oil and gas development case which are projected to decrease (improvement in air quality) compared to the baseline simulation.

The improvement in ozone levels is further supported in the bottom left figure that presents the difference in predicted ozone between the maximum oil and gas case and the baseline and indicates that for the majority of the modeling domain, ozone concentration decreased between 1 and 4 ppb. There is a very small isolated area in northwest New Mexico where there is a 5 ppb increase in ozone. The report indicates that the largest increase in the maximum oil and gas case over the base case is 1.4 ppb. Therefore, the predicted 5 ppb increase is not caused solely by the Mancos sources.

The bottom right figure presents the 4th highest ozone concentrations resulting from natural sources. This figure indicates the strong dominance of natural sources on the Arizona and New Mexico border as well as in the northern portion of central New Mexico. The figure suggests that natural sources may be responsible for the 5 ppb increase in northwest New Mexico.

Based on review of the emission calculations conducted as part of this study, predicted ozone impacts are overstated because the modeling was based on unrealistic high estimates of NOx emissions from oil and gas sources for the three development cases. The corrected maximum development case NOx emissions are more representative of NOx emissions from the mid-level case and hence projected ozone impacts will be lower than stated in the Draft EIS.

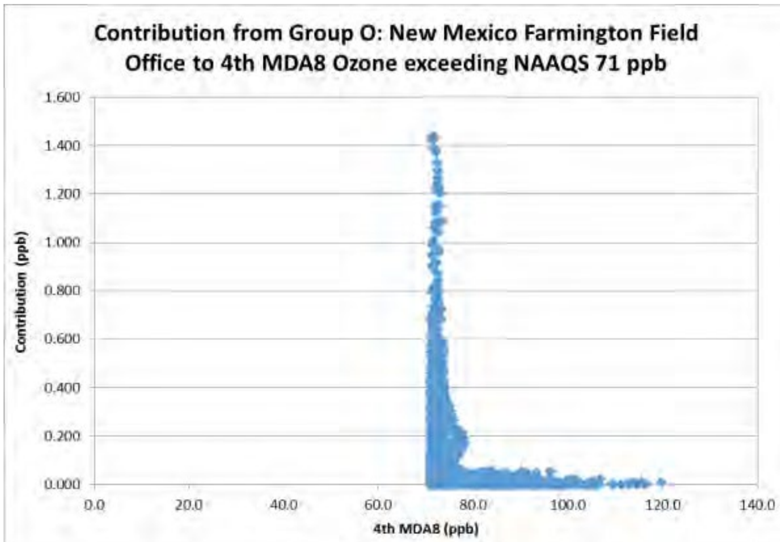
3.1.2 Incremental Ozone Impacts

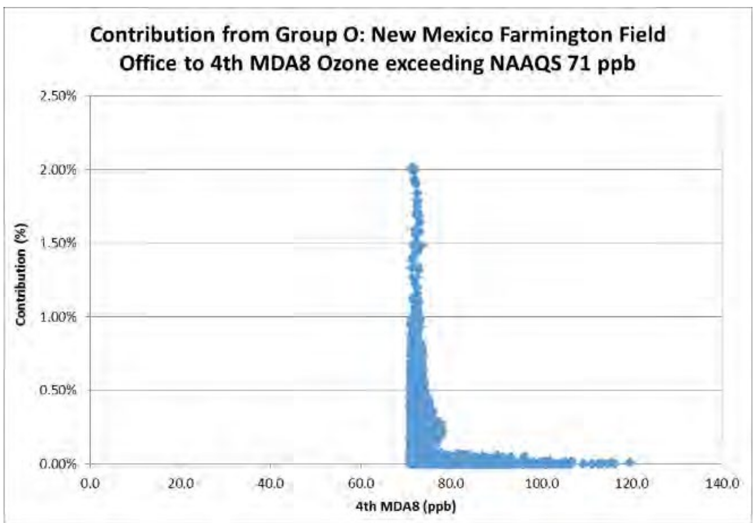
Figure 3-2 presents the contribution of the maximum oil and gas case for MDA8[35] concentrations above 71 ppb (a modeled exceedance of the NAAQS).[36] These plots provide the incremental increase in predicted ozone compared to total ozone for the same event.

[35] MDA8 is the maximum daily 8 hour average concentration and is in the form of the ozone NAAQS.

[36] Figure 3-5 Appendix J

Figure 3-2.





The information included in these figures is incomplete because it provides no information on the number of grid cells that have total MDA8 concentrations above 71 ppb or the frequency distribution for maximum oil and gas impacts. The figure does indicate that as total predicted ozone concentration increases above 71 ppb, the oil and gas impact decreases.

The largest predicted contribution of incremental ozone from the Maximum Development Oil and Gas Case is 1.4 ppb. Because of positive bias introduced in the modeling emission calculations from incorrect engineering data used in the emission calculations, actual incremental ozone impacts will be less than indicated in these figures. Since emissions for the maximum development case are closer in magnitude to the mid-level case, the incremental increase would be 0.7 ppb[37] and would be considered insignificant.

[37] Table 3-5. Maximum contribution to the annual average $PM_{2.5}$ concentrations (ug/m^3) for each of the Natural Source Group, Total Source Groups and New Mexico FFO 2025 High, Low and Medium Development Scenarios.

The Draft EIS suggests an incremental increase in ozone of 1 ppb is a reasonable concentration level to be used as a test for significant contribution for ozone. Further, EPA has issued guidance that developed a significance concentration of 1 ppb.[38]

There is no significant difference between a modeled concentration of 1.0 ppb and 1.4 ppb. It is recommended that the rounding convention used by EPA for testing compliance with the standard should be used in this case (i.e., 70.47 ppb rounds to 70 ppb and is not an exceedance of the NAAQS). Therefore, the projected incremental increase of 1.4 ppb is not an exceedance of the suggested significance threshold.

The revised Maximum Development Case emissions are very similar to what was modeled for the Medium-Level case, the projected incremental increase of for the Medium-Level Case is 0.8 ppb and is not an exceedance of the suggested significance threshold. The conclusion becomes that the Mancos Development has insignificant impacts on total ozone.

It is important to remember that these projected impacts overstate the actual impacts because of accuracy issues with the emission calculations for oil and gas.

3.1.3 Cumulative Source Attribution

An important source of ozone precursor pollutants that can inhibit compliance with the ozone standard in the West is stratospheric-tropospheric exchange (STE). STE refers to the transport of material across the tropopause. STE has direct implications on the distribution of atmospheric ozone, in particular, the decrease of lower stratospheric ozone and the increase of tropospheric ozone (Cordero, et al). STE is also known as stratosphere-to-troposphere transport (STT) or stratospheric intrusion.

Langford, et al examined STE along Colorado's Front Range during the spring of 1999 (Langford, et al, 2009) using lidar and surface measurements. "A deep tropopause fold brought ~215 ppb of ozone to within 1 km of the highest peaks in the Rocky Mountains on 6 May 1999. One-minute average ozone mixing ratios exceeding 100 ppb were subsequently measured at a surface site in Boulder, and daily maximum 8-hour ozone concentrations greater or equal to the 2008 NAAQS ozone standard of 0.075 ppm were recorded at 3 of 9 Front Range monitoring stations." This study showed that the stratospheric contribution to surface ozone is significant and can lead to exceedances of the ozone NAAQS. A study by Hocking, et al using wind profiler radars found "numerous intrusions of ozone from the stratosphere into the troposphere in southeastern Canada. On some occasions, ozone is dispersed at altitudes of two to four kilometers, but on other occasions it reaches the ground, where it can dominate the ozone density variability" (Hocking, et al, 2007). Higher elevations, as found in Colorado or other areas in the West, are at greater risk of having ozone from the stratosphere reach the ground.

A review of the CASTNET ozone monitoring data indicates that a large percentage of the monitored values in elevated terrain with concentrations above 0.065 ppm occur during the spring as shown on the Table 3-1 from the presentation "O_3 Trends in the Rural Intermountain West" (Blewitt, 2009) (Appendix C). Figure 3-1 presents the occurrence of ozone concentrations in excess of 0.065 ppm for spring and summer

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[38] EPA, 2018, Guidance on Significant Impact Levels for Ozone and Fine Particulates in the Prevention of Significant Deterioration Permitting Program.

events at the Gothic CASTNET site (located in elevated terrain in rural Colorado). Apart from 2000, 2002 and 2003, the majority of the concentrations in excess of 0.065 ppm have occurred in the spring. Additionally, this monitoring site has no local ozone precursor sources in the vicinity. The conclusion reached by such events is that the elevated ozone concentrations are a result of STE.

Table 3-1

Table 2: CASTNET Occurrence of the 4th Highest Ozone in Spring in Elevated Terrain (Blewitt, 2009)

Site	Percent of the 4th Highest 8-hour Ozone >65 ppb and in Spring	Comments
Canyonland, UT	33	No measurements in March and April
Centennial, WY	46	No measurements in April
Mesa Verde CO	77	
Pinedale, WY	44	
Rocky Mountain, CO	21	
Gothic, CO	62	
Yellowstone, WY	73	

Figure 3-1.

Figure 9: Seasonal Ozone 8-Hour Daily Maximum Greater Than 65 ppb at the Gothic, CO CASTNET Monitor

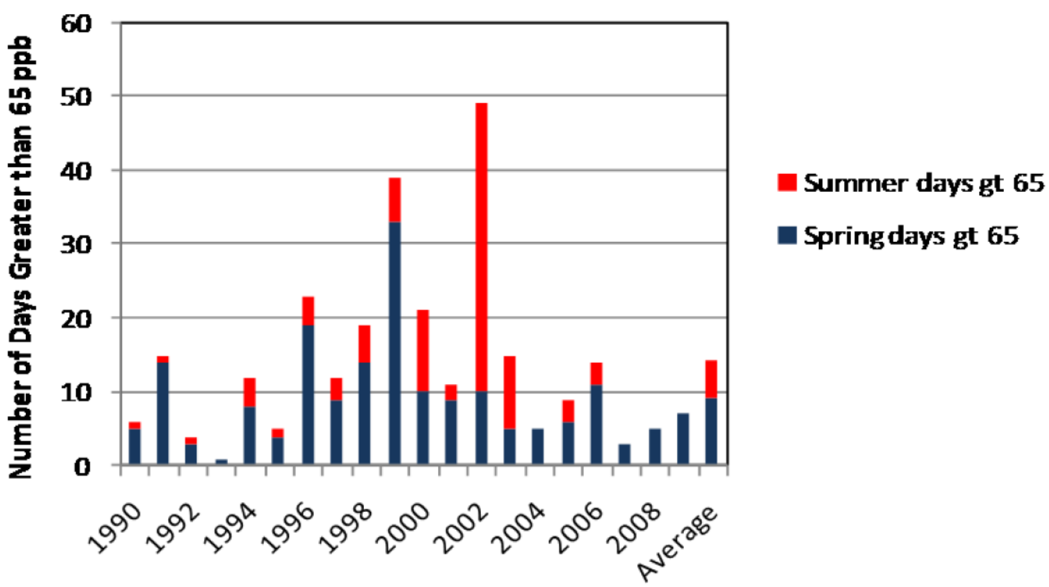
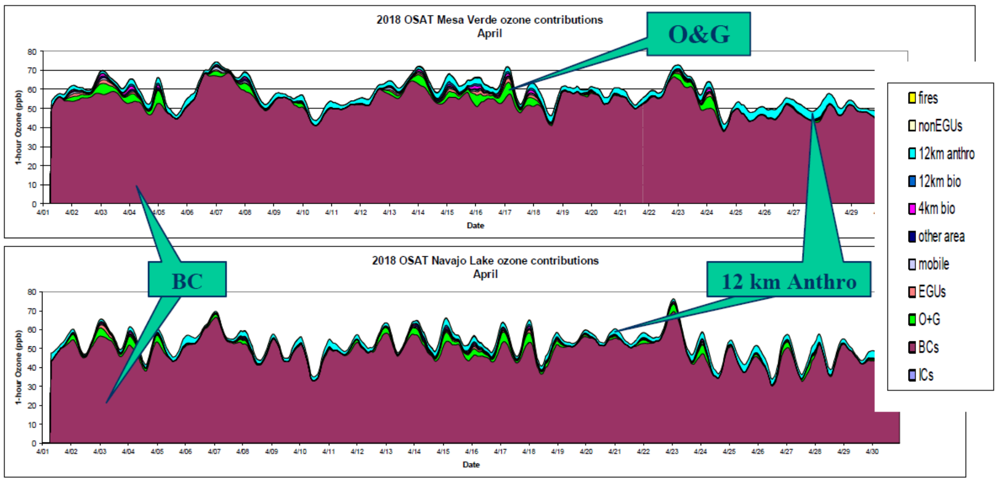


Figure 3-2 presents source apportion modeling results that were prepared as part of the 4 Corners Air Quality Modeling Analyses and indicates for Mesa Verde in Colorado and Navajo Lake in New Mexico that during April the majority of the predicted ozone is a result of boundary conditions including STE and the contribution to total ozone from oil and gas during the spring is relatively small.[39]

[39] CUMULATIVE EFFECTS SECTION Four Corners Air Quality Task Force Report of Mitigation Options November 1, 2007

Figure 3-2.

Figure 15: Source Apportionment Results for 8-Hour Average Ozone at Mesa Verde and Navajo Lake in April (Stoeckenius, 2010)



BC = Boundary Conditions

The concept of STE is important in the context of the Mancos EIS. Historical ozone monitoring data in the Draft EIS are presented and compared to the 70 ppb ozone NAAQS. That comparison does not provide the date when the highest MDA8 concentrations were measured. The time of occurrence is important because in the spring, at higher topographical elevations, stratospheric intrusion events (STE) are prevalent and the elevated concentrations may be a result of a large contribution of STE.

Table 3-2 and Figure 3-2 presents that spring was when a large fraction of the five highest ozone concentrations were measured at the Sub Station Monitor in New Mexico. STE is likely to have occurred and oil and gas had very low culpability for the largest measured ozone events.

Table 3-2. Maximum Five Highest MDA8 Ozone Concentrations at NM Sub Station Ozone Monitor

2019				2018				2017			
Date	Wind Speed	Wind Dir	O_3	Date	Wind Speed	Wind Dir	O_3	Date	Wind Speed	Wind Dir	O_3
	m/s	Deg	ppm		m/s	Deg	ppm		m/s	Deg	ppm
6/8/2019	4.7	245.8	0.065	6/25/2018	4.3	275.4	0.068	6/3/2017	4.5	247.8	0.071
5/19/2019	5.6	223.1	0.06	7/25/2018	3.6	258.7	0.067	4/22/2017	3.3	255	0.069
10/2/2019	3.5	259.4	0.06	4/17/2018	10.5	293.8	0.065	4/21/2017	7.8	290.2	0.066
4/15/2019	3.1	249.1	0.059	5/27/2018	4.2	260.7	0.065	4/9/2017	7.2	276.4	0.065
4/16/2019	5	230.8	0.059	6/19/2018	4.3	303.4	0.065	5/29/2017	4.3	290.4	0.065

3.2 $PM_{2.5}$ NAAQS Analysis

There are no air quality concerns regarding $PM_{2.5}$ for any of the proposed development plans. The Draft EIS needs to exclude any discussion of wildfires in conjunction with compliance with the $PM_{2.5}$ NAAQS. EPA would consider these impacts as exceptional events.

The proposed development for the maximum case will not result in or contribute to any new exceedances of the NAAQS. Further, $PM_{2.5}$ impacts are conservative (overstate actual impacts) and actual impacts will be less than those indicated in the Draft EIS.

The Draft EIS provides very limited analysis of $PM_{2.5}$ modeling results and predicted impacts from natural sources introduces erroneous information regarding air quality levels in the basin and results in a negative conclusion that air quality has degraded (from natural sources) when in fact measurements in the region are well below the NAAQS.

3.2.1 24-Hour Averaging Period

Table 3-3 presents a summary from the Draft EIS for $PM_{2.5}$ modeling for the High, Low and Medium development cases. The Draft EIS states, "The maximum 8th high 24-hour $PM_{2.5}$ in 2011 (421.3 ug/m^3) and 2025 High, Low and Medium Development Scenarios (420.9 ug/m^3) far exceed the 35 ug/m^3 NAAQS (top panels). These high values occur on the AZ/NM border and are largely due to emissions from wildfires (406.5 ug/m^3), as shown from the maps of contributions by Natural Emissions (bottom right panels). The greater Denver area shows exceedances in 2011 Base case and all three 2025 Scenarios."

The quote above portrays a very negative indication of air quality in the region with maximum concentrations well in excess of the 35 ug/m^3 24-hour $PM_{2.5}$ NAAQS. The very high modeled $PM_{2.5}$ impacts result from natural sources (wildfires) and EPA would consider such events as exceptional events and exclude them from an evaluation of the $PM_{2.5}$ NAAQS. The Draft EIS should be changed to discuss the exclusion of these natural source impacts for evaluation of compliance with the 35 ug/m^3 24-hour NAAQS.

It is important that the modeled levels from all three of the development cases are below the lower end of the proposed EPA significant threshold of 1.2 ug/m^3.[40] This is an important finding and should be stressed in the document. The total concentrations presented in Table 3-4 do not represent the sum of the sources listed.

Table 3-3. Maximum contribution to the 8th high 24-hour $PM_{2.5}$ concentrations (ug/m^3) for each of the Natural Source Group, Total Source Groups and New Mexico FFO 2025 High, Low and Medium Development Scenarios

Source Group	High (ug/m^3)	Low (ug/m^3)	Medium (ug/m^3)
Natural Emissions	406.5	406.5	406.5
New Mexico FFO	0.8	0.4	0.4
2011 Total	421.3	421.3	421.3
2025 Total	420.9	420.9	420.9

3.2.2 Annual Averaging Period

The Draft EIS concludes the following regarding compliance with the annual $PM_{2.5}$ NAAQS of 12 ug/m^3: "The highest annual average $PM_{2.5}$ concentration is about 23.5 ug/m^3 for the 2011 Base Case, and 21.1, 20.9, and 21.0 ug/m^3 in the 2025 High, Low, and Medium Development Scenarios. Compared to 2011, 2025 annual $PM_{2.5}$ concentrations are reduced in most of the domain, but increase in a number of regions,

[40] EPA, 2018, Guidance on Significant Impact Levels for Ozone and Fine Particulates in the Prevention of Significant Deterioration Permitting Program.

including near Denver, where about 10 ug/m^{3}of increase in annual $PM_{2.5}$ occurs for the High and Medium Development Scenarios."

As stated for the 24-hour $PM_{2.5}$ NAAQS, the natural events impact would be considered an exceptional event and would not be included in any determination of the NAAQS. It is recommended that the Draft EIS be revised to remove natural impacts for comparison with the annual NAAQS. The 10 ug/m^3 increase in $PM_{2.5}$ concentrations near Denver for the high and medium development cases is not attributable to the Mancos sources. This is illustrated in Table 4 (Table 3-5 from Appendix J) which presents the maximum $PM_{2.5}$ impacts for the three development cases. Actual impacts in Denver from the Mancos region will be considerably less than the values listed in Table 3-4. Table 3-4 summarizes the $PM_{2.5}$ modeling results for the annual case.

Table 3-4. Maximum contribution to the annual average $PM_{2.5}$ concentrations (ug/m^3) for each of the Natural Source Group, Total Source Groups and New Mexico FFO 2025 High, Low and Medium Development Scenarios

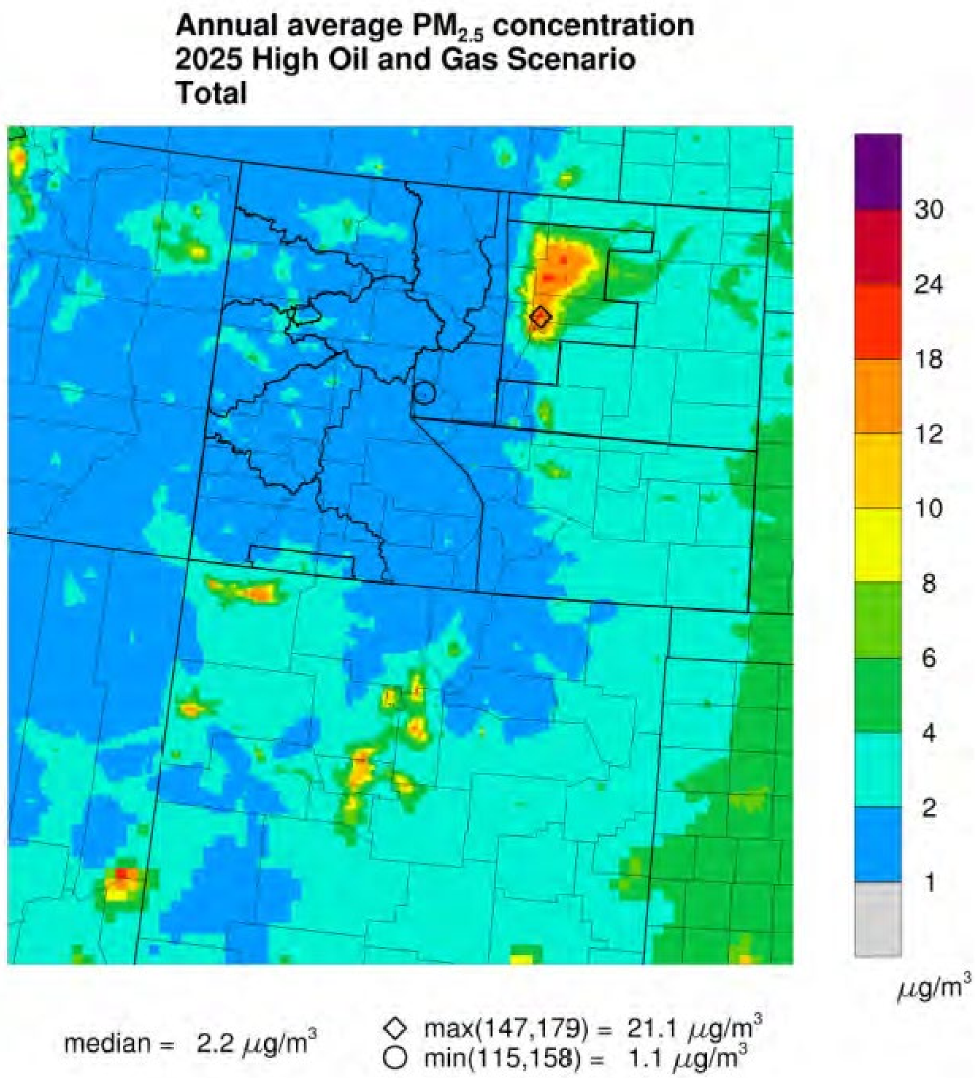
Source Group	High (ug/m^3)	Low (ug/m^3)	Medium (ug/m^3)
Natural Emissions	17.4	17.4	17.4
New Mexico FFO	**0.3**	**0.1**	**0.1**
2011 Total	23.5	23.5	23.5
2025 Total	21.1	21.1	21.1

The total impacts for 2011 and 2025 in Table 3-4 from Appendix J do not represent the sum of the individual source impacts and should be corrected.

EPA has published a significant threshold for the annual $PM_{2.5}$ of 0.2 ug/m^3.[41] Thus, the low and medium cases are below that threshold. The high case impact was 0.3 ug/m^3 and is only slightly above the proposed EPA threshold. Two things need to be considered: 1) review of the annual modeling plots (Figure 3-5) indicate compliance with the standard except in areas where the natural emissions occurred, and 2) because of the previously discussed bias in the NOx calculations, actual impacts will reduce NO_3 formation (a $PM_{2.5}$ species).

[41] https://www.epa.gov/sites/production/files/2018-04/documents/sils_policy_guidance_document_final_signed_4-17-18.pdf

Figure 3-5. (From Figure 3-13 in Appendix J)



In conclusion, there are no air quality concerns regarding $PM_{2.5}$ for any of the proposed development plans considered. Further, $PM_{2.5}$ impacts are conservative (overstate actual impacts).

3.3 PM_{10} NAAQS Analysis

There are no air quality concerns regarding PM_{10} **for any of the proposed development plans being considered. The Draft EIS needs to exclude any discussion of wildfires in conjunction with compliance with the** PM_{10} **NAAQS. EPA would consider these impacts as exceptional events.**

The Draft EIS provides very limited analysis of the modeling results and the treatment of natural impacts introduces erroneous information regarding air quality levels in the basin.

3.3.1 24-Hour Averaging

The discussion on PM_{10} impacts states, "Much of the discussion on 24-hour $PM_{2.5}$ also holds for 24-hour PM_{10}, although there appear to be more exceedances of the 24-hour PM_{10} NAAQS. Extremely large highest second high PM_{10} concentrations occur in the 2011 and 2025 emissions scenarios that exceed 1,000 ug/m^3 (Figure 3-17, top panels), which are largely due to natural emissions from wildfires near the AZ/NM border." Impacts in excess of 1000 ug/m^3 are clearly not due to routine emissions.

The analysis of modeled PM_{10} impacts suffers from the same deficiencies as was indicated for $PM_{2.5}$. Modeled exceedances are indicated arising from natural sources. The discussion of such impacts should exclude natural or exceptional event sources as these would not be included in any NAAQS PM_{10} evaluation. Table 3-5 summarizes the presented modeling impacts and illustrate the magnitude of the wildfire impacts.

Table 3-5. Maximum contribution to the 2nd highest daily average $PM_{2.5}$ concentrations (ug/m^3) for each of the Natural Source Group, 5Source Groups and New Mexico FFO 2025 High, Low and Medium Development Scenarios. NAAQS = 150 ug/m^3

Source Group	**High (ug/m^3)**	**Low** (ug/m^3)	**Medium (ug/m^3)**
Natural Emissions	1030.6	1030.6	1030.6
New Mexico FFO	2.7	1.3	1.1
2011 Total	1045.2	1045.2	1045.2
2025 Total	1045.2	1045.2	1045.2

Table 3-5 indicates that none of the PM_{10} impacts exceed the PM_{10} modeling significant level of 10 ug/m^3 and impacts are therefore insignificant.

3.4 SO_2 NAAQS Analysis

<u>There are no air quality concerns regarding SO_2 for any of the proposed development plans considered.</u>

The Draft EIS provides limited analysis of the modeling results and the treatment of natural impacts introduces erroneous information regarding air quality levels in the basin. The inclusion of natural events in the modeling presents an erroneous indication that SO_2 concentrations in the region have degraded when in fact SO_2 levels in the region are well within applicable standards.

The discussion on SO_2 in Appendix J states, "The 1-hour SO_2 NAAQS is 75 ppb and it is exceeded when the colors in Figure 5-18 are yellow or hotter. Natural emissions from wildfires are the primary cause for the two exceeding areas in Arizona and New Mexico. 1-hour SO_2 is overall below 30 ppb in most places and shows reduction from the 2011 base year to the 2025 High Development Scenario throughout most of the domain. Similarly, 3-hour, 24-hour and annual average SO_2 are all well below the corresponding NAAQS/CAAQS/NMAAQS, except for small areas affected by extreme wildfires, and all of them show a reduction from the 2011 base year to the 2025 High Development Scenario throughout most of the domain."

It is inappropriate to include the impacts of natural events in an evaluation of SO_2 NAAQS because EPA defines such impacts as exceptional events which would not be included in any compliance determination. The inclusion of predicted impacts from wildfires implies that air quality has been degraded in the region.

3.5 NO_2 NAAQS Analysis

<u>There are no air quality concerns regarding NO_2 for any of the proposed development plans considered.</u>

The Draft EIS provides limited analysis of the modeling results and the treatment of natural impacts introduces erroneous information regarding air quality levels in the basin. The inclusion of natural events in the modeling presents an erroneous indication that NO_2 concentrations in the region have degraded when in fact NO_2 levels in the region are well within applicable standards.

3.5.1 1-Hour Analysis

The 1-hour modeling results suffer from the same deficiencies as the other criteria pollutants. The inclusion of wildfires in the NAAQS analysis portrays a very negative picture of air quality in the region that resulted from an episodic natural event. The analysis should exclude these natural events.

Because of the spatial scale of the plots in the report, it is not possible to accurately determine the 1-hour NO_2 concentrations in the Mancos region. If the differences between the base case and the 3 development cases are examined (Figure 3-6), there is indication that the area of maximum impact is in Colorado and likely not affected by Mancos sources. It appears there is a slight increase in NO_2 impacts for the three alternatives compared to the base case. Figure 3-7 presents the contribution from Mancos sources for the three development cases and the maximum NO_2 impacts are:

- High Development Case = 5.8 ppb
- Low Development Case = 3.0 ppb
- Medium Development Case = 3.2 ppb

These projected impacts are conservative (overstate actual impacts) because the emissions used in the emission calculations were overstated as discussed in Section 2 of this report.

Figure 3-6.

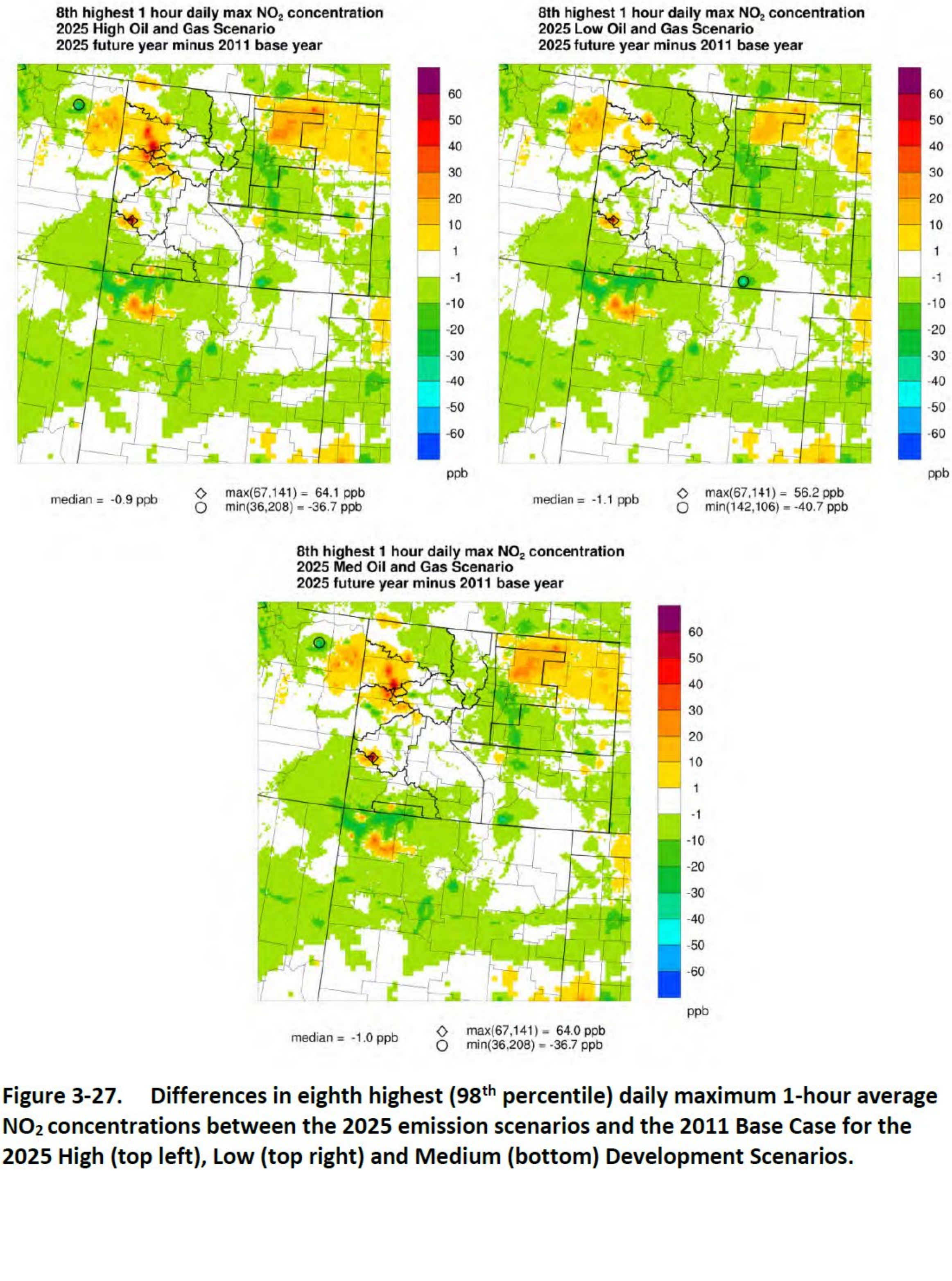


Figure 3-27. Differences in eighth highest (98th percentile) daily maximum 1-hour average NO_2 concentrations between the 2025 emission scenarios and the 2011 Base Case for the 2025 High (top left), Low (top right) and Medium (bottom) Development Scenarios.

Figure 3-7.

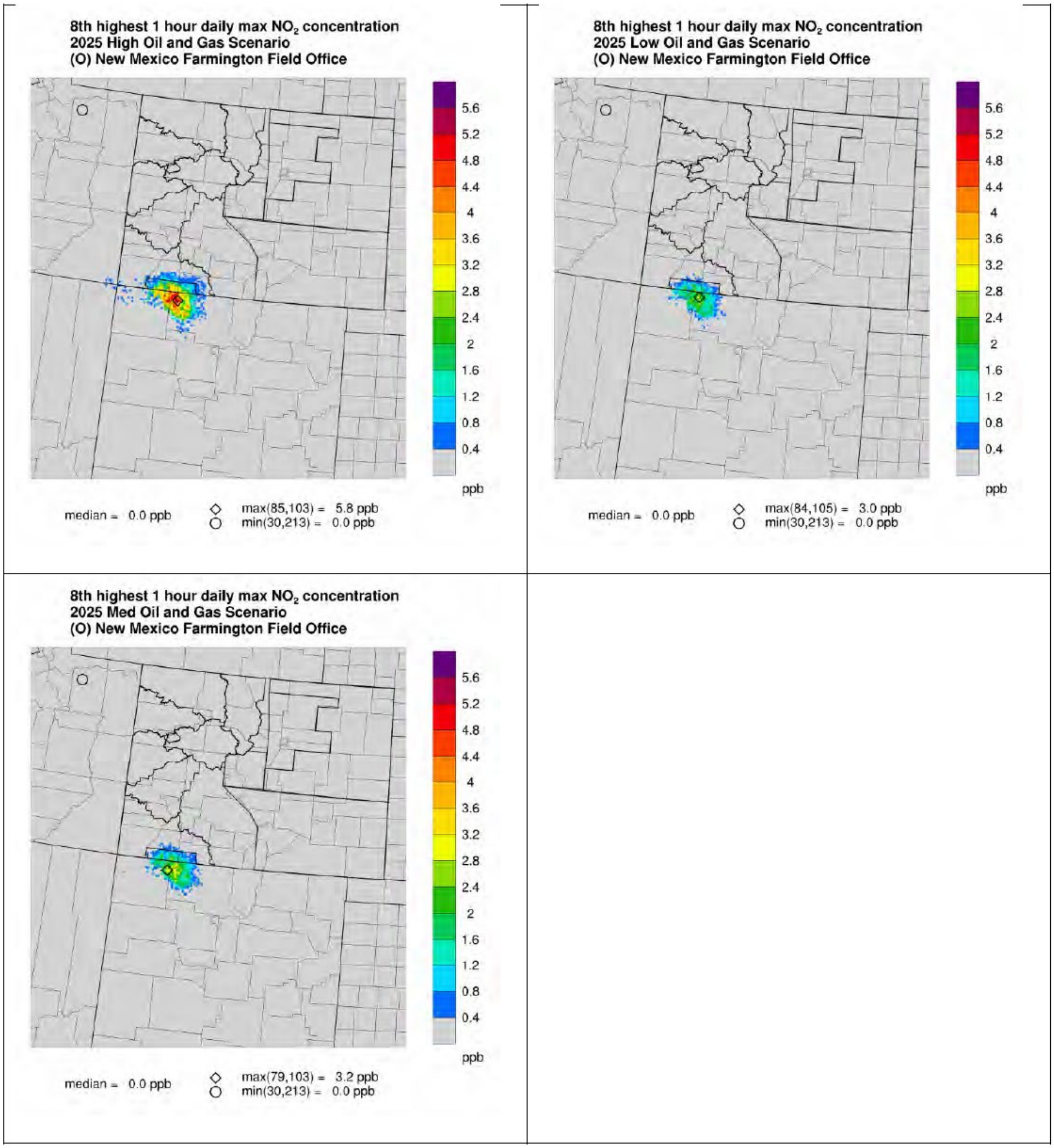


Figure 3-28. Contributions from New Mexico FFO to the eighth highest (98th percentile) daily maximum 1-hour average NO_2 concentrations in the 2025 High (top left), Low (top right) and Medium (bottom) Development Scenarios.

4. PSD Pollutant Concentration Impacts at Class I and Sensitive Class II Areas

Wildfires do not consume PSD increment and when these are removed from the modeling, no exceedances of increment were observed.

Tables 4-1 and 4-2 summarize the PSD increment analysis for applicable pollutants. The increment consumption tables were summarized from Tables 4-4 through 4-11 in Appendix J. These tables were directly copied from Appendix J. It also appears that the PSD Class II modeling results for PM_{10} annual averaging time appear to be incorrect and are shaded in light gray.

PSD sources consume increment after the baseline was established. Natural Sources (wildfires) are **NOT** increment sources. The predicted increment analyses represented in Tables 4-1 and 4-2 are incorrect as they describe potential increment exceedances for sources that do not consume increment.

The tables do indicate that the three proposed development cases have deminimus impacts in Class I and Class II Areas.

Table 4-1. Summary of PSD Class I Increment Analysis for NO_2, SO_2, $PM_{2.5}$ and PM_{10}

	Pollutant															
	NO_2-Annual				SO_2- Annual				SO_2- 24-Hour				SO_2-3 Hour			
	Increment (ug/m^3)	Predicted Impact (ug/m^3)	% increment	Class I Area where Max occurred	Increment (ug/m^3)	Predicted Impact (ug/m^3)	% of Increment	Class I Area where Max occurred	Increment (ug/m^3)	Predicted Impact (ug/m^3)	% of Increment	Class I Area where Max occurred	Increment (ug/m^3)	Predicted Impact (ug/m^3)	% of Increment	Class I Area where Max occurred
Natural emissions	**2.5**	5.562	222	Bandelier	**2**	2.7	136	Bandelier	**5**	210	4200	Bandelier	**25**	588	2351	Bandelier
Farmington Field Office: High	**2.5**	0.033	1.3	Mesa Verde	**2**	0.0	0.0	Mesa Verde	**5**	0.001	0.0	Mesa Verde	**25**	0.002	0.0	Mesa Verde
Farmington Field Office: Low	**2.5**	0.016	0.6	Mesa Verde	**2**	0.0	0.0	Mesa Verde	**5**	0	0.0	Mesa Verde	**25**	0.001	0.0	Mesa Verde
Farmington Field Office: Medium	**2.5**	0.019	0.8	Mesa Verde	**2**	0.0	0.0	Mesa Verde	**5**	0.001	0.0	Mesa Verde	**25**	0.002	0.0	Mesa Verde
2025 Total: High	**2.5**	6.097	244	Bandelier	**2**	2.9	144	Bandelier	**5**	211.072	4221	Bandelier	**25**	587	2348	Bandelier
2025 Total: Low	**2.5**	6.088	244	Bandelier	**2**	2.9	144	Bandelier	**5**	211.072	4221	Bandelier	**25**	587	2348	Bandelier
2025 Total: Medium	**2.5**	6.093	244	Bandelier	**2**	2.9	144	Bandelier	**5**	211.072	4221	Bandelier	**25**	587	2348	Bandelier
2011 Total	**2.5**	7.986	319	Petrified Fores	**2**	3.0	149	Bandelier	**5**	211.109	4222	Bandelier	**25**	587	2348	Bandelier

Table 4-1. (continued)

	Pollutant															
	$PM_{2.5}$-Annual				$PM_{2.5}$-24-hour				PM_{10}-Annual				PM_{10}-24 Hour			
	Increment (ug/m^3)	Predicted Impact (ug/m^3)	% of Increment	Class I Area where Max occurred	Increment (ug/m^3)	Predicted Impact (ug/m^3)	% of Increment	Class I Area where Max occurred	Increment (ug/m^3)	Predicted Impact (ug/m^3)	% of Increment	Class I Area where Max occurred	Increment (ug/m^3)	Predicted Impact (ug/m^3)	% of Increment	Class I Area where Max occurred
Natural emissions	1	7.833	783	Bandelier	**2**	593	29650	Bandelier	4	9.282	232	Bandelier	25	588	2351	Bandelier
Farmington Field Office: High	1	0.006	0.6	Mesa Verde	**2**	0.063	3.2	Mesa Verde	4	0.022	0.6	Mesa Verde	25	0.002	0.0	Mesa Verde
Farmington Field Office: Low	1	0.003	0.3	Mesa Verde	**2**	0.032	1.6	Mesa Verde	4	0.011	0.3	Mesa Verde	25	0.001	0.0	Mesa Verde
Farmington Field Office: Medium	1	0.003	0.3	Mesa Verde	**2**	0.033	1.7	Mesa Verde	4	0.009	0.2	Mesa Verde	25	0.002	0.0	Mesa Verde
2025 Total: High	1	9.724	972	Bandelier	**2**	609	30438	Bandelier	4	16.212	405	Bandelier	25	587	2348	Bandelier
2025 Total: Low	1	9.72	972	Bandelier	**2**	609	30438	Bandelier	4	16.201	405	Bandelier	25	587	2348	Bandelier
2025 Total: Medium	1	9.722	972	Bandelier	**2**	609	30438	Bandelier	4	16.205	405	Bandelier	25	587	2348	Bandelier
2011 Total	1	9.781	978	Bandeli	2	609	30438	Bandeli	4	13.893	347	Bandeli	25	587	2348	Bandeli

Table 4-2. Summary of Sensitive PSD Class II Increment Analysis

	Pollutant															
	NO_2-Annual				SO_2-Annual				SO_2-24-Hour				SO_2-3 Hour			
Case	Increment (ug/m^3)	Predicted Impact (ug/m^3)	% of Increment	Class II Area where Max occurred	Increment (ug/m^3)	Predicted Impact (ug/m^3)	% of Increment	Class II Area where Max occurred	Increment (ug/m^3)	Predicted Impact (ug/m^3)	% of Increment	Class II Area where Max occurred	Increment (ug/m^3)	Predicted Impact (ug/m^3)	% of Increment	Class II Area where Max occurred
Natural emissions	25	4.281	17	Bear Wallow	20	2.002	0	Bear Wallow	91	108.145	119	Bear Wallow	512	337.323	66	Dome
Farmington Field Office:	25	1.674	7	Aztec Ruins	20	0.003	0	Aztec Ruins	91	0.008	0	Aztec Ruins	512	0.013	0	Aztec Ruins
Farmington Field Office:	25	0.828	3	Aztec Ruins	20	0.001	0	Aztec Ruins	91	0.004	0	Aztec Ruins	512	0.007	0	Aztec Ruins
Farmington Field Office:	25	0.947	4	Aztec Ruins	20	0.003	0	Aztec Ruins	91	0.008	0	Aztec Ruins	512	0.012	0	Aztec Ruins
2025 Total:	25	9.901	40	Aztec Ruins	20	2.27	0	Bear Wallow	91	108.266	119	Bear Wallow	512	337.436	66	Dome
2025 Total: Low	25	8.33	33	Aztec Ruins	20	2.27	0	Bear Wallow	91	108.266	119	Bear Wallow	512	337.436	66	Dome
2025 Total:	25	8.783	35	Aztec Ruins	20	2.27	0	Bear Wallow	91	108.266	119	Bear Wallow	512	337.436	66	Dome
2011 Total	25	23.059	92	Aztec Ruins	20	2.502	0	Bear Wallow	91	108.726	119	Bear Wallow	512	338.092	66	Dome

Table 4-2. (continued)

	Pollutant															
	NO_2-Annual				SO_2-Annual				SO_2-24-Hour				SO_2-3 Hour			
Case	Increment (ug/m^3)	Predicted Impact (ug/m^3)	% of Increment	Class II Area where Max occurred	Increment (ug/m^3)	Predicted Impact (ug/m^3)	% of Increment	Class II Area where Max occurred	Increment (ug/m^3)	Predicted Impact (ug/m^3)	% of Increment	Class II Area where Max occurred	Increment (ug/m^3)	Predicted Impact (ug/m^3)	% of Increment	Class II Area where Max occurred
Natural emissions	25	4.281	17	Bear Wallow	20	2.002	10	Bear Wallow	91	108.145	119	Bear Wallow	512	337.323	66	Dome
Farmington Field Office :	25	1.674	7	Aztec Ruins	20	0.003	0	Aztec Ruins	91	0.008	0	Aztec Ruins	512	0.013	0	Aztec Ruins
Farmington Field Office:	25	0.828	3	Aztec Ruins	20	0.001	0	Aztec Ruins	91	0.004	0	Aztec Ruins	512	0.007	0	Aztec Ruins
Farmington Field Office:	25	0.947	4	Aztec Ruins	20	0.003	0	Aztec Ruins	91	0.008	0	Aztec Ruins	512	0.012	0	Aztec Ruins
2025 Total: High	25	9.901	40	Aztec Ruins	20	2.27	11	Bear Wallow	91	108.266	119	Bear Wallow	512	337.436	66	Dome
2025 Total: Low	25	8.33	33	Aztec Ruins	20	2.27	11	Bear Wallow	91	108.266	119	Bear Wallow	512	337.436	66	Dome
2025 Total: Medium	25	8.783	35	Aztec Ruins	20	2.27	11	Bear Wallow	91	108.266	119	Bear Wallow	512	337.436	66	Dome
2011 Total	25	23.059	92	Aztec Ruins	20	2.502	13	Bear Wallow	91	108.726	119	Bear Wallow	512	338.092	66	Dome

Table 4-2. (continued)

Pollutant

	PM$_{2.5}$-Annual				PM$_{2.5}$-24-hour				PM$_{10}$-Annual				PM$_{10}$-24 Hour			
Case	Increment (ug/m^3)	Predicted Impact (ug/m^3)	% of Increment	Class II Area where Max occurred	Increment (ug/m^3)	Predicted Impact (ug/m^3)	% of Increment	Class II Area where Max occurred	Increment (ug/m^3)	Predicted Impact (ug/m^3)	% of Increment	Class II Area where Max occurred	Increment (ug/m^3)	Predicted Impact (ug/m^3)	% of Increment	Class II Area where Max occurred
Natural emissions	4	6.155	154	Bear Wallow	**9**	332.52	3695	Bear Wallow	17	9.167	54	Sevilleta NWR	30	372.753	1243	Bear Wallow
Farmington Field Office:	4	0.183	5	Aztec Ruins	**9**	0.595	7	Aztec Ruins	17	0.828	5	Aztec_Ruins	30	2.129	7	Aztec_Ruins
Farmington Field Office:	4	0.092	2	Aztec Ruins	**9**	0.306	3	Aztec Ruins	17	0.416	2	Aztec_Ruins	30	1.076	4	Aztec_Ruins
Farmington Field Office:	4	0.095	2	Aztec Ruins	**9**	0.316	4	Aztec Ruins	17	0.324	2	Aztec_Ruins	30	0.862	3	Aztec_Ruins
2025 Total: High	4	12.14	304	Valledor	**9**	342.2	3802	Bear Wallow	17	70.901	417	Valle_De_Oro_NWR	30	383.645	1279	Bear_Wallow
2025 Total: Low	4	12.132	303	Valledor	**9**	342.2	3802	Bear Wallow	17	70.89	417	Valle_De_Oro_NWR	30	383.645	1279	Bear Wallow
2025 Total: Medium	4	12.137	303	Valledor	**9**	342.2	3802	Bear Wallow	17	70.897	417	Valle_De_Oro_NWR	30	383.645	1279	Bear_Wallow
2011 Total	4	11.197	280	Valledor	**9**	342.84	3809	Bear Wallow	17	58.983	347	Valle_De_Oro_NWR	30	384.256	1281	Bear Wallow

5. Visibility

The visibility analysis is conservative and indicates no degradation in visibility as a result of the proposed development. BLM did not provide any interpretation of the modeling results. The following comments indicate that conservative visibility modeling does not pose any issues in Class I Areas and sensitive Class II Areas.

BLM and Forest Service have established a level of concern regarding source impacts and visibility. It is important for the public and the decisionmaker to understand the basis for estimating the just noticeable change (JNC) in visual range as specified by EPA and used in the analysis. The following presents a discussion of those procedures. One basis of the JNC is the National Acidic Precipitation Program (NAPAP) Report. A review of the information provided in the NAPAP Report indicates that the JNC was based on the Quadratic Detection Model proposed by Carlson and Cohen that was used to predict thresholds of perceived image sharpness in video type image displays.[42] While the theory used for defining a JNC threshold in a video monitor may be applicable to air quality visibility issues, neither EPA nor the NAPAP Report have provided any supporting evidence that the JNC threshold in video monitors is in any way applicable to determining changes in visual ranges in the atmosphere over long sight paths.

5.1 Universal Applicability of JNC Over Long Sight Paths

The NAPAP reference raises several important questions regarding the JNC threshold over long sight paths. First, there is no clear definition of what the statement "a change in extinction coefficient of approximately 5% will evoke a just noticeable change **in most landscapes**" means. Second, it is also unclear how universally applicable this threshold could be over a large range of sight paths. This suggests that the establishment of a human perceivable JNC threshold may be dependent on the longest sight path within a Class I Area and that the establishment of a single JNC threshold might not be appropriate and therefore contrary to what EPA has proposed.

5.2 Deciview Visibility Unit of Measure

An additional reference provided regarding a human JNC threshold is an Atmospheric Environment paper written by Pitchford and Malm.[43] This paper outlines the concept of the deciview visibility unit of measure in which the authors conclude, based on what appears to be a sensitivity analysis, "From this it seems **reasonable to presume** that a fractional change in extinction coefficient between 5 and 20% would produce a JNC in a scene."[44] The use of what appears to be a **presumptive** sensitivity analysis to develop a JNC threshold is not appropriate. The authors also conclude "a 1 to 2 deciview change corresponds to a small, visibility perceptible change in a scene appearance **where the assumptions used in developing the deciview scale are met**."[45] This would translate to a change of 10 to 20 percent in extinction. Because a 1 to 2 deciview change is perceivable only if the assumptions used to develop the deciview scale are met, it is important to review the assumptions that were made in the development of the deciview scale

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[42] Carlson and Cohen. 1978. Image Descriptors for Displays: Visibility of Displayed Information. RCA Laboratories, Princeton, NJ.
[43] Pitchford M. L. and W. C. Malm, 1994 "Development and Applications of a Standard Visual Index" Atmospheric Environment Vol. 28, No. 5 pp. 1049-1054
[44] Pitchford M. L. and W. C. Malm, 1994 "Development and Applications of a Standard Visual Index" Atmospheric Environment Vol. 28, No. 5 pp. 1049-1054
[45] Pitchford M. L. and W. C. Malm, 1994 "Development and Applications of a Standard Visual Index" Atmospheric Environment Vol. 28, No. 5 pp. 1049-1054

because they define the limitations on universal applicability of this visibility unit of measure. The deciview scale assumptions are:

1) Contrast is a good indicator of visibility. The apparent contrast of an element of a scene can be used to estimate whether the element can be perceived and, when it can be perceived, the apparent contrast can also be used to evaluate the visual quality of its appearance.
2) The magnitude of the change in apparent contrast of a distant terrain feature against the horizontal sky required for a JNC is proportional to the apparent contrast of the terrain feature.
3) The apparent contrast of a distant terrain feature against the horizontal sky is given by the following equation:

$$C=C_o \exp(-r\, B_{ext})$$

Where: C is the apparent contrast
C_o is the initial contrast
B_{ext} is the average extinction coefficient for the sight path
r is the distance to a distant terrain feature

The first assumption regarding contrast being an indicator of visibility is generally accepted. Inherent in the second assumption is that, for a change to be noticeable, the magnitude of the change is proportional to the change in contrast as stated in the following equation.

$$\text{delta } C_{JNC} = L\, C$$

Where: L is a constant that depends on spatial frequency but not contrast

The work of Carlson and Cohen has shown that this equation is not generally considered valid, but may provide a reasonable approximation in viewing environments, such as a view of a terrain feature against the horizontal sky.[46] As such, this assumption could be considered in development of a JNC threshold.

The third assumption is valid if the horizontal sky radiance has the same value at each end of the sight path. Further, it can be regarded as a restriction that the use of the deciview index or extinction applies to terrain features against the sky. In general, the use of the deciview index only applies to the special case where the sight path is equal to the visual range. This assumption is also applicable to the manner in which the 5 percent change in extinction was defined as a JNC threshold. This is a significant oversimplification of the proposed JNC threshold.

In a review of the aforementioned Pitchford and Malm deciview scale, Richards indicated, "For example, more than a 40% change (more than 4 – deciview change) in regional haze is required for the change to be perceptible in sight paths shorter than 20% of the visual range."[47] Richards also states that in some cases a 5 percent change in contrast can be perceivable but it is commonly assumed that features with only a 2 percent change in contrast can be perceived. Using this information, Richards shows that the Pitchford and Malm equations can be rewritten as follows:

[46] Carlson, C.R. and R.W. Cohen 1978 "Visibility of displayed information. Image descriptors for displays" RCA Laboratories, Princeton N.J.
[47] Richards, L.W., 1999, "Use of the Deciview Haze Index as an Indicator for Regional Haze", AWMA

For a 2 percent case

delta b_{JNC} =0.4 /r

and a 5 percent case

delta b_{JNC} =0.32 /r

These equations apply to sight paths of any length less than or equal to the visual range and give the value for delta b_{JNC} equal to those calculated by the Pitchford and Malm work when the sight path is equal to the visual range.

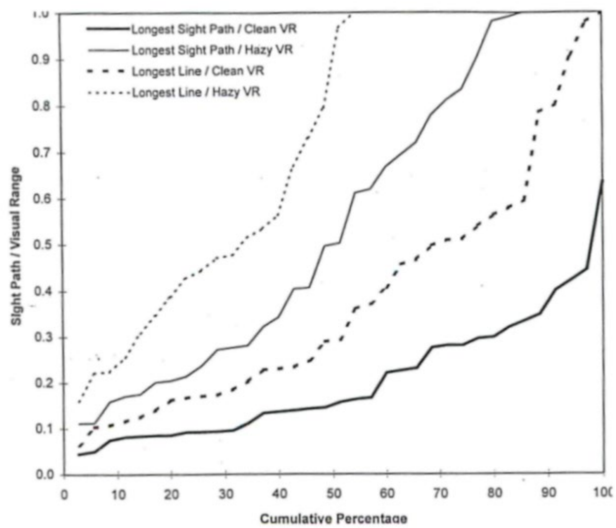
Based on the importance of the inclusion of sight path in the determination of the JNC, it seems imperative that EPA incorporates this approach into the JNC threshold determination. This would require that the JNC threshold be site specific for each Class I Area and that individual states would be required to develop their own JNC threshold for each Class I Area. Incorporation of this approach would ensure that the JNC threshold would be based on the "best science."

5.3 Practical Perspective of the Deciview Assumptions

It is important to place the assumptions used by Pitchford and Malm into practical perspective. Figure 5-1 presents a comparison of the longest lines that can be drawn within 35 Class I Areas as well as the estimated lengths of the longest visual range sight paths within these areas.[48] The visual ranges were calculated from the average light extinction coefficient for the 20 percent of the days that were the least impaired (clean) as well as the 20 percent of the days that were the most impaired (hazy). A point on a line indicates the percentage of the parks that have a ratio equal to or smaller than the value at that point. Most ratios are less than 1 and therefore sight paths are typically shorter than the visual range and contrary to the assumptions used in the development of the deciview index. This indicates that for a vast number of Class I Areas, the basic assumption of the deciview calculation has not been met. Thus, assuming that the sight path is equal to the visual range simply adds a layer of unnecessary additional conservatism to the calculation.

[48] Richards, L.W., 1999, "Use of the Deciview Haze Index as an Indicator for Regional Haze", AWMA

Figure 5-1. Comparison of Lengths of the Longest Lines for 35 National Parks and the Estimated Sight Path Within These Parks[49]



Also, FLAG (a guideline, not a regulation) considers a 0.5 deciview change in visibility significant for a single source and 1.0 deciview significant for a cumulative analysis. Based on the above information, the public and the decision makers should not consider the Forest Service LOC of 0.5 deciview as a decision point for this analysis. Further, based on the information presented in these comments, it is important to keep in mind the conservative nature of a 1.0 deciview threshold.

FFO Contributions to Visibility Impairment at Class I and II Areas using FLAG (2010)

Modeling results for BLM sources indicate the following for the Maximum Development Case:

- **Class I Areas:** Modeled impacts in adjacent Class I Areas indicate there are no days with predicted impacts in excess of 1.0 deciview or 0.5 deciview.
- **Sensitive Class II Areas:** Aztec Ruins, NM was the only Class II Sensitive Area with predicted impacts in excess of 0.5 deciview. The maximum impact was 2.6 deciview (occurred on 1/7/2011). The number of days in excess of 1.0 deciview was 80 and 261 days were predicted to have impacts above 0.5 deciview.

For the Medium Development Case:

Class I Areas: Modeled impacts in adjacent Class I Areas indicate there are no days with predicted impacts in excess of 1.0 deciview or 0.5 deciview.

- **Sensitive Class II Areas**: Aztec Ruins, NM was the only Class II Sensitive Area with predicted impacts in excess of 0.5 deciview. The maximum impact was 1.5 deciview (occurred on 1/7/2011). The number of days in excess of 1.0 deciview was 9 and 84 days were predicted to have impacts above 0.5 deciview.

[49] Richards, L.W., 1999, "Use of the Deciview Haze Index as an Indicator for Regional Haze", AWMA

For the Low Development Case:

- **Class I Areas:** Modeled impacts in adjacent Class I Areas indicate that there are no days with predicted impacts in excess of 1.0 deciview or 0.5 deciview.
- **Sensitive Class II Areas:** Aztec Ruins, NM was the only Class II Sensitive Area with predicted impacts in excess of 0.5 deciview. The maximum impact was 1.5 deciview (occurred on 1/7/2011). The number of days in excess of 1.0 deciview was 6 and 82 days were predicted to have impacts above 0.5 deciview.

The visibility modeling analysis indicates that none of the three development cases will adversely impact visibility in the 26 adjacent Class I Areas.

Aztec National Monument is the only sensitive Class II Area where the proposed Mancos development predicted any visibility impairment in excess of 1.0 or 0.5 deciview. The visibility predictions at this location must be considered in the context of size and location of this National Monument. This area is located approximately 15 miles northwest of Farmington, New Mexico, approximately 40 miles south of Durango, Colorado and adjacent to the town of Aztec, New Mexico. The physical size of the National Monument is only 160 acres (largest linear size is slightly larger than 1 mile).

Because of the small size of the National Monument and its location in a suburban area, visual range is not an important AQRV. The Aztec National Monument is a very important cultural resource that requires environmental protection; however, modeled visibility impairment is not appropriate for this location.

Because this area is very close to the Mancos Development Area (maximum distance is 76 miles), the transformation of NOx emissions in the form of NO will be transformed into NO_2 (reaction with ambient ozone) and then converted into particulate NH_3NO_3 which causes light scattering and affects visibility. The maximum predicted visibility reduction occurred on January 7, 2011 and no other information was provided on the time of occurrence for other periods when visibility reductions of 1.0 or 0.5 deciview occurred. In January ambient ozone is likely to be very low and hence the conversion of NO into NO_2 will be equivalent to the ambient concentration of ozone. Hence, the rate of conversion will be relatively small and complete conversion will occur at relatively large distances downwind.

The Clean Air Act (CAA) has established regulations to protect visibility in PSD Class I Areas. The CAA has not established any form of visibility protection for PSD Class II Areas including regions that are designated by FLMs as Sensitive Class II Areas. Any level of protection claimed by FLMs for Class II Areas has not undergone a formal rulemaking process and any suggestion of protection is only guidance not mandated by regulation.

5.4 Cumulative Visibility

Cumulative visibility modeling results indicate that none of the development scenarios result in a reduction in visual impairment and no additional mitigation is required.

Section 5.3 of Appendix J presents cumulative visibility results for Class I and Sensitive Class II Areas where IMPROVE monitors are located. The monitoring data were used to calculate over a 5-year period the visual range in deciview for the best 20 percent of the days and the worst 20 percent of the days. These monitoring results were then used to scale the visibility monitoring results in order to improve the accuracy of the model predictions. This procedure is very appropriate.

The exact mechanics of how the calculations were performed is not completely clear. For example, was the scaling performed using measured particulate concentrations (e.g., NO_3, SO_4) and visibility was reconstructed from the scaled particulate concentrations or was the scaling was done in terms of deciview? The procedures used need to be clarified.

There is no discussion or conclusions drawn regarding the results presented in this section. Review of the results presented indicates that at none of the Class I or Sensitive Class II Areas does the proposed action for any of the development cases result in any reduction in visibility.

6. Deposition

The deposition modeling results indicate predicted deposition in sensitive areas is minimal and does not merit additional mitigation.

National Park Service (NPS) and Fish and Wildlife Service (FWS) have defined a Deposition Analysis Threshold (DAT) as the additional amount of nitrogen (N) or sulfur (S) deposition within a Class I Area below which estimated impacts from a proposed new or modified source are considered insignificant. This definition, however, does not define what level constitutes a significant impact. The lack of a definition of significance is problematic in the context of model predicted impacts in excess of the screening level DAT and from such an analysis, drawing any conclusions regarding potential mitigation requirements to reduce deposition impacts is not appropriate.

6.1 Formulation of DAT

The DAT that BLM reported in the Draft EIS represents the modeled incremental increase in deposition from the Mancos project. The N DAT represents total N, including both wet and dry deposition and includes NO, NO_2, HNO_3, NO_3, NH_3, and NH_4 species. The S DAT represents total S deposition. NPS and FWS chose total N and total S species in order to be consistent with conventions used in deposition loading to represent the total amount of N and S inputs received in an ecosystem and to be compatible with CALPUFF or other model outputs.

The framework for calculating both the N and S DATs is:

DAT = Natural Background Deposition * Variability Factor * Cumulative Factor.

6.2 Natural Background

The background N values for natural background by NPS and FWS were selected from a range of natural background deposition values published in peer-reviewed scientific literature and were established at 0.50 kg/ha/yr for the East and 0.25 kg/ha/yr for the West. NPS and FWS feel "these values represent the low end of the regional range of values that are presented in estimates of regional natural background deposition and feel that this conservatism is necessary in order to fulfill the mandate to err on the side of resource protection and to protect air quality and AQRVs within Class I Areas."

6.3 Use of a Variability Factor in the DAT Process

The FLMs selected what fraction of incremental deposition could be added to existing natural and anthropogenic deposition amounts within an ecosystem and still be considered insignificant (it is important to note that this is defined in terms of insignificant rather than significant). "The NPS and FWS selected very conservative natural background numbers from the range of values presented in scientific literature and have determined that all combined anthropogenic sources could contribute up to 50% of the deviation of conservative natural background."

"Once natural background deposition numbers are determined, FLMs have a responsibility to determine what fraction of this deposition could be added to existing natural and anthropogenic deposition amounts within an ecosystem and still be considered insignificant. The NPS and FWS selected very conservative natural background numbers from the range of values presented in scientific literature and have determined that all combined anthropogenic sources could contribute up to 50% of this conservative natural background value without triggering concerns regarding resource impacts. Rationale for this decision came from looking at the modeled historical deposition scenarios in the scientific literature, where the range of estimates for any given area are often + or – 50% or more between various studies. Furthermore, the range of natural variability associated with annual natural background deposition at any given site is unknown, but 50% above or below the historical mean is plausible during any given year due to fluctuations in climate, biotic productivity, bacterial decomposition, lightning occurrence, fire, volcanic activity, sea spray, and other factors."

"The NPS and FWS have determined that a total increase in deposition, from all sources over time, greater than fifty percent of natural background deposition would trigger management concerns. Therefore, the natural background value (BN or BS) is multiplied by 0.5, or 50%."

6.4 Use of a Cumulative Factor

There is an FLM concern that, over time, cumulative deposition from emission sources may produce impacts upon Class I Areas. It is beneficial to the FLMs, the permitting authority and the applicant to determine what amount, if any, a new source could contribute to total deposition while having a reasonable assurance that cumulative deposition from all new sources would not exceed 50% of natural background.

In developing the 1996 proposal for New Source Review Reform, the U.S. Environmental Protection Agency (EPA) determined that, as long as no individual source contribution exceeds 4% of a Class I increment, it is unlikely that the accumulation of sources over time will exceed that increment.

The FLMs have applied the proposed 4% value used in Class I increment significant impact levels to the deposition analysis thresholds. By incorporating this value into the DAT equations, new sources whose modeled deposition amounts are below the DATs are not likely to significantly contribute to cumulative impacts from N or S deposition.

Deposition Analysis Threshold Equation

The DAT for a specific Class I Area in the West is calculated as:

Nitrogen DAT = B_N (0.5) * 0.04
= 0.25 kg/ha/hr * 0.5 * 0.04
= 0.005 kg/ha/yr

Sulfur DAT = B_S (0.5) * 0.04
= 0.25 kg/ha/hr * 0.5 * 0.04
= 0.005 kg/ha/yr

This equation incorporates a 0.5 Variability Factor and a 0.04 Cumulative Factor and the value of 0.04 represents a four percent safety factor to protect Class I Areas from cumulative deposition impacts.

The NPS and FWS define that "The DAT is a deposition threshold, not necessarily an adverse impact threshold. **The DAT is the additional amount of deposition that triggers a management concern, not necessarily the amount that constitutes an adverse impact to the environment."**

The DAT guidance indicates that adverse impact determinations will be considered on a case-by-case basis for modeled deposition values that are higher than the DAT.

As indicated in the above, the DAT begins with a very conservative defined level of deposition and then safety factors are applied and result in compounding levels of conservatism. **The DAT represents only 2 percent of the natural background level.**

In addition, the FLM defines, in a conservative manner, what modeled predictions in excess of the DAT mean – as the additional amount of N or S deposition within a Class I Area, below which estimated impacts from a proposed new or modified source are considered insignificant. Further, the DAT is the additional amount of deposition that triggers a management concern, not necessarily the amount that constitutes an adverse impact to the environment. Based on the FLM basis of the DAT, it is not reasonable to use in model predictions "in excess of the DAT" to be the basis of additional mitigation for the Mancos project.

6.5 Deposition Modeling Accuracy

Because incremental changes in deposition cannot be modeled, model accuracy or bias is a concern in the application of the DAT. It is also important to ensure model accuracy is tested for the time scale consistent with that of the level of concern of the AQRV. In the case of deposition, that time scale is the amount of annual deposition. The data presented for deposition model accuracy is from the model performance evaluation that BLM performed for the Continental Divide EIS. This CAMx analysis had essentially the same modeling domain as the Mancos modeling. This is information is being presented to illustrate the concerns regarding CAMx accuracy for deposition.

BLM, as part of the model evaluation of CAMx, evaluated the accuracy of various components that comprise dry and wet deposition, however, BLM did not conduct an analysis regarding measured deposition and modeled deposition over an annual period.

Based on the BLM analysis it is difficult to determine deposition model performance. BLM evaluated model performance by comparing individual nitrogen and sulfur species related to deposition as individual measurements. In addition, model performance for all Western CASTNet Monitoring was combined into a single evaluation. Thus, it is not possible to determine the accuracy of deposition for a specific Class I Area. This level of model performance is very useful for evaluating model physics but does not address if CAMx accurately simulates monitored deposition in Class I Areas over an annual period.

The model performance indicates considerable scatter in comparing modeled and monitored deposition species. Figure 6-1 presents an example of NO_3 comparisons for CASTNet monitors.[50] This figure indicates considerable model over prediction in the winter and a slight model under prediction in the summer. It is important to note that NO_3 concentrations are very low during the summer so model under prediction is not as important as model over prediction when NO_3 concentrations are higher.

[50] Appendix A Model Performance Evaluation of the CD-C CAMx 2005 and 2006 Base Case Simulations From Continental Divide Model Evaluation https://eplanning.blm.gov/public_projects/nepa/58344/72128/79126/Appendix_A_Model_Performance_Evaluation_of_the_CD-C_CAMx_Simulations_04-2016_Full.pdf

Figure 6-1. NO_3 CAMx and Monitor Comparisons[51]

APPENDIX A – MODEL PERFORMANCE EVALUATION OF THE
CD-C CAMX 2005 AND 2006 BASE CASE SIMULATIONS

NADP – NO3 wet deposition

CD-C

Hiawatha

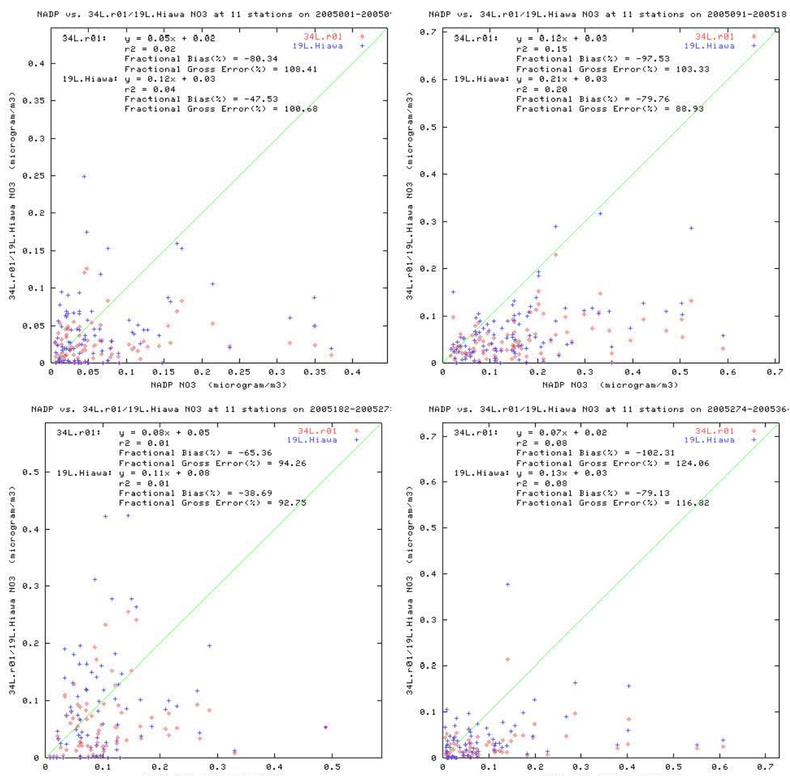


Figure A5-5h. Comparison of predicted and observed weekly average NO3 wet deposition for NADP sites in the CD-C 12 km domain for 2005 and Q1 (top left), Q2 (top right), Q3 (bottom left) and Q4 (bottom right).

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[51] Appendix A Model Performance Evaluation of the CD-C CAMx 2005 and 2006 Base Case Simulations From Continental Divide Model Evaluation https://eplanning.blm.gov/public_projects/nepa/58344/72128/79126/Appendix_A_Model_Performance_Evaluation_of_the_CD-C_CAMx_Simulations_04-2016_Full.pdf

By making comparisons between model predictions and annual deposition measurements, very limited model performance statistics can be calculated. Essentially, such an evaluation is comparing two numbers for each Class I Area. Because model performance was evaluated for 2005 and 2006, it is recommended that such a comparison can be made for both years.

While CASTNet measurements are not made at all Class I Areas, it is possible to look at CASTNet measurements in adjacent areas to infer model accuracy. It is recommended that BLM develop a correlation table so that model accuracy can be evaluated at all areas of concern.

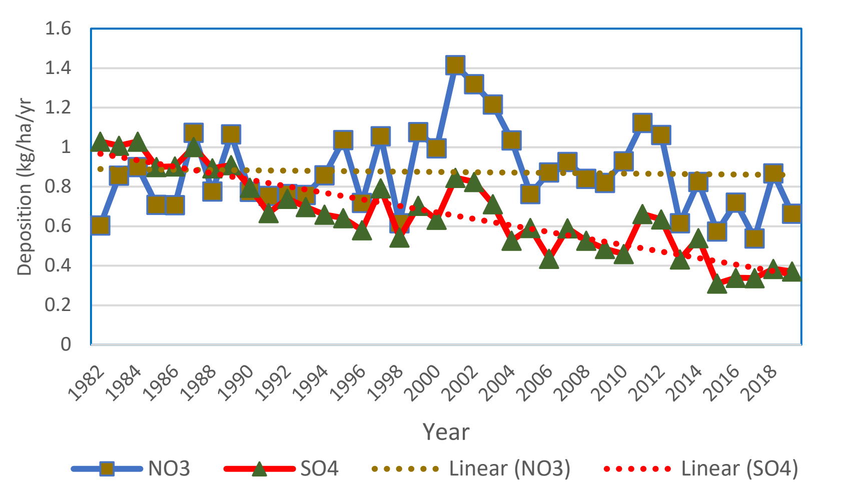
It is important to use model accuracy estimates in conjunction with estimated incremental changes in deposition. Model bias in annual deposition should be addressed or included in the evaluation of deposition impacts. This is especially true in the case of model over prediction because of the safety factors that are compounded into the establishment of the DAT. Any model over prediction adds additional conservatism to an already conservative analysis.

6.6 Cumulative Deposition

Deposition Monitoring Trends

Figures 6-2 through 6-4 present nitrogen and sulfur deposition trends at CASTNet monitors in the vicinity of Mancos Shale Development.

Figure 6-2. Measured Wet Trends at Badlander, NM



IPANM_0173

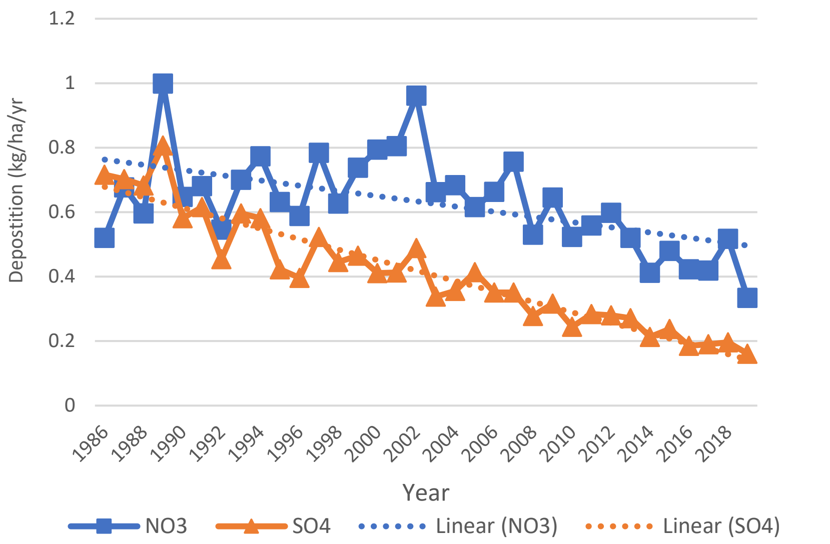


Figure 6-3. Measured Wet Deposition Trends at Molas Pass

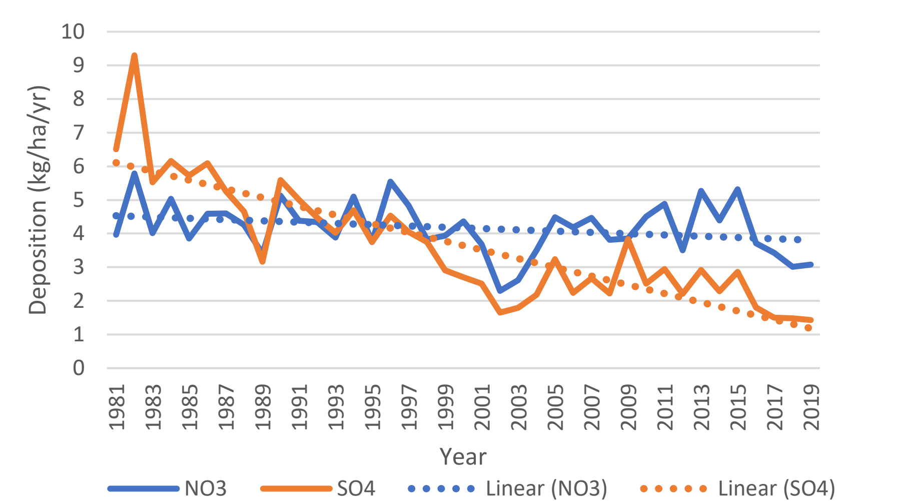


Figure 6-4. Measured Wet Deposition Trends at Mesa Verde

These figures indicate the dramatic decline in sulfur deposition over the period of record (approximately 30 years) at all three areas and also a decline in nitrogen deposition at all three sites. These figures clearly indicate that deposition to sensitive areas has been reduced over the last 30 years.

6.6.1 Changes in Modeled Deposition

Table 6-1 presents the change in predicted cumulative nitrogen deposition for 2025 for Class I Areas for the Medium-Level Case. This table indicates there will not be an increase above the nitrogen DAT (in this context the increase is considered as insignificant). The only exceptions to this were for Mesa Verde National Park where Mancos sources resulted in an increase of 0.0153 kg/ha/yr and Weminuche

Wilderness Area where an increase of 0.009 was predicted. Deposition at these two locations will be analyzed further in the cumulative deposition discussion.

Table 6-2 present a summary for predicted deposition for all sensitive Class II Areas and Table 6-3 presents a summary of predicted deposition impacts that were above the conservative DAT threshold. The information in Table 6-2 will be discussed further in the cumulative deposition section.

Table 6-1. FFO Sulfur and Nitrogen Deposition Impacts at Class I Areas for Medium Development Scenario

	Nitrogen- Max	**Nitrogen- Avg**	**Sulfur- Max**	**Sulfur- Avg**
	(kgN/ha)	(kgN/ha)	(kgS/ha)	(kgS/ha)
Arches NP	0.0012	0.0010	0.0000	0.0000
Bandelier Wilderness	0.0042	0.0038	0.0001	0.0000
Black Canyon of the Gunnison Wilderness	0.0020	0.0018	0.0000	0.0000
Bosque del Apache	0.0006	0.0005	0.0000	0.0000
Canyonlands NP	0.0029	0.0011	0.0000	0.0000
Capitol Reef NP	0.0007	0.0003	0.0000	0.0000
Dinosaur NM	0.0004	0.0003	0.0000	0.0000
Eagles Nest Wilderness	0.0012	0.0009	0.0000	0.0000
Flat Tops Wilderness	0.0010	0.0008	0.0000	0.0000
Gila Wilderness	0.0002	0.0001	0.0000	0.0000
Great Sand Dunes Wilderness-nps	0.0048	0.0039	0.0001	0.0000
La Garita Wilderness	0.0051	0.0041	0.0001	0.0001
Maroon Bells-Snowmass Wilderness	0.0018	0.0014	0.0000	0.0000
Mesa Verde NP	0.0195	0.0153	0.0002	0.0001
Mount Baldy Wilderness	0.0002	0.0002	0.0000	0.0000
Mount Zirkel Wilderness	0.0007	0.0006	0.0000	0.0000
Pecos Wilderness	0.0063	0.0046	0.0001	0.0000
Petrified Forest NP	0.0002	0.0002	0.0000	0.0000
Rawah Wilderness	0.0008	0.0006	0.0000	0.0000
Rocky Mountain NP	0.0009	0.0006	0.0000	0.0000

	Nitrogen- Max	Nitrogen- Avg	Sulfur- Max	Sulfur- Avg
	(kgN/ha)	(kgN/ha)	(kgS/ha)	(kgS/ha)
Salt Creek Wilderness	0.0004	0.0004	0.0000	0.0000
San Pedro Parks Wilderness	0.0068	0.0052	0.0001	0.0000
Weminuche Wilderness	0.0186	0.0091	0.0004	0.0002
West Elk Wilderness	0.0019	0.0015	0.0000	0.0000
Wheeler Peak Wilderness	0.0057	0.0047	0.0001	0.0001
White Mountain Wilderness	0.0006	0.0005	0.0000	0.00

Table 6-2. FFO Sulfur and Nitrogen Deposition Impacts at Class II Areas for Medium Development Scenario

	Nitrogen- Max	Nitrogen- Avg	Sulfur- Max	Sulfur- Avg
	(kgN/ha/yr)	(kgN/ha/yr)	(kgS/ha/yr)	(kgS/ha/yr)
Alamosa National Wildlife Refuge	0.0049	0.0045	0.0001	0.0001
Aldo Leopold Wilderness	0.0002	0.0002	0.0000	0.0000
Apache Kid Wilderness	0.0003	0.0003	0.0000	0.0000
Aztec Ruins NM	0.0807	0.0786	0.0012	0.0012
Baca National Wildlife Refuge	0.0039	0.0033	0.0000	0.0000
Bear Wallow Wilderness	0.0001	0.0001	0.0000	0.0000
Bitter Lake National Wildlife Refuge	0.0004	0.0004	0.0000	0.0000
Blue Range Wilderness	0.0002	0.0002	0.0000	0.0000
Bosque Del Apache National Wildlife Refuge	0.0006	0.0005	0.0000	0.0000
Browns Park National Wildlife Refuge	0.0002	0.0002	0.0000	0.0000
Canyon de Chelly NM	0.0008	0.0005	0.0000	0.0000

	Nitrogen-Max	Nitrogen-Avg	Sulfur- Max	Sulfur- Avg
	(kgN/ha/yr)	(kgN/ha/yr)	(kgS/ha/yr)	(kgS/ha/yr)
Capitan Mountains Wilderness	0.0006	0.0006	0.0000	0.0000
Chaco Culture NHP	0.0026	0.0022	0.0000	0.0000
Chama River Canyon Wilderness	0.0206	0.0140	0.0002	0.0001
Chimney Rock NM	0.0409	0.0409	0.0004	0.0004
Colorado NM	0.0014	0.0012	0.0000	0.0000
Cruces Basin Wilderness	0.0156	0.0134	0.0003	0.0002
Curecanti NRA	0.0018	0.0014	0.0000	0.0000
Dark Canyon Wilderness	0.0035	0.0028	0.0000	0.0000
Dinosaur NM	0.0005	0.0003	0.0000	0.0000
Dome Wilderness	0.0038	0.0036	0.0000	0.0000
El Malpais NM	0.0009	0.0006	0.0000	0.0000
Escudilla Wilderness	0.0002	0.0002	0.0000	0.0000
Flaming Gorge	0.0003	0.0001	0.0000	0.0000
Florissant Fossil Beds NM	0.0012	0.0012	0.0000	0.0000
Fossil Ridge Wilderness	0.0021	0.0019	0.0000	0.0000
Glen Canyon NRA	0.0065	0.0011	0.0000	0.0000
Great Sand Dunes National Park	0.0050	0.0039	0.0001	0.0000
Great Sand Dunes National Preserve	0.0054	0.0047	0.0001	0.0001
Greenhorn Mountain Wilderness	0.0039	0.0034	0.0001	0.0000
High Uintas Wilderness	0.0002	0.0001	0.0000	0.0000
Holy Cross Wilderness	0.0012	0.0010	0.0000	0.0000
Hovenweep NM	0.0074	0.0071	0.0000	0.0000
Hunter-Fryingpan Wilderness	0.0015	0.0012	0.0000	0.0000

	Nitrogen-Max	Nitrogen-Avg	Sulfur- Max	Sulfur- Avg
	(kgN/ha/yr)	(kgN/ha/yr)	(kgS/ha/yr)	(kgS/ha/yr)
Las Vegas National Wildlife Refuge	0.0021	0.0017	0.0000	0.0000
Latir Peak Wilderness	0.0054	0.0047	0.0001	0.0001
Lizard Head Wilderness	0.0054	0.0048	0.0001	0.0001
Lost Creek Wilderness	0.0014	0.0012	0.0000	0.0000
Manzano Mountain Wilderness	0.0038	0.0032	0.0000	0.0000
Maxwell National Wildlife Refuge	0.0018	0.0016	0.0000	0.0000
Monte Vista National Wildlife Refuge	0.0056	0.0046	0.0001	0.0001
Mount Evans Wilderness	0.0012	0.0010	0.0000	0.0000
Mount Sneffels Wilderness	0.0042	0.0038	0.0001	0.0001
Natural Bridges NM	0.0035	0.0032	0.0000	0.0000
Navajo NM	0.0005	0.0005	0.0000	0.0000
Petroglyph NM	0.0021	0.0019	0.0000	0.0000
Powderhorn Wilderness	0.0038	0.0032	0.0001	0.0001
Raggeds Wilderness	0.0015	0.0013	0.0000	0.0000
Rio Mora National Wildlife Refuge and Conservation Area	0.0024	0.0021	0.0000	0.0000
Sandia Mountain Wilderness	0.0035	0.0025	0.0000	0.0000
Sangre de Cristo Wilderness	0.0063	0.0041	0.0001	0.0001
Savage Run Wilderness	0.0004	0.0003	0.0000	0.0000
Sevilleta National Wildlife Refuge	0.0013	0.0009	0.0000	0.0000

	Nitrogen-Max	Nitrogen-Avg	Sulfur- Max	Sulfur- Avg
	(kgN/ha/yr)	(kgN/ha/yr)	(kgS/ha/yr)	(kgS/ha/yr)
South San Juan Wilderness	0.0273	0.0193	0.0005	0.0004
Spanish Peaks Wilderness	0.0048	0.0044	0.0001	0.0001
Uncompahgre Wilderness	0.0042	0.0030	0.0001	0.0001
Valle De Oro National Wildlife Refuge	0.0012	0.0012	0.0000	0.0000
Withington Wilderness	0.0004	0.0003	0.0000	0.0000

Table 6-3. Summary of Modeled Deposition Where Predicted Impacts for Sensitive Class II Areas are Above the Nitrogen DAT

Location	DAT (kg/ha/yr)	Medium Modeled Deposition (kgN/ha/yr)	Difference between modeled deposition and Dat (kg/ha/yr
Aztec Ruins NM	0.005	0.081	0.0757
Chama River Canyon Wilderness	0.005	0.021	0.0156
Chimney Rock NM	0.005	0.041	0.0359
Cruces Basin Wilderness	0.005	0.016	0.0106
Glen Canyon NRA	0.005	0.007	0.0015
Hovenweep NM	0.005	0.007	0.0024
Sangre de Cristo Wilderness	0.005	0.006	0.0013
South San Juan Wilderness	0.005	0.027	0.0223

6.6.2 Class I Areas

Table 6-4 summarizes the cumulative and DAT deposition modeling results for Mesa Verde National Park and Weminuche Wilderness Area. This table indicates that while modeling for Mancos sources predicted impacts were above the DAT (Average nitrogen predicted deposition for both areas were 0.01 kg/ha/yr) cumulative predicted deposition was less that the recommended critical load of 2.3 kg/ha/yr. At Mesa

Verde the cumulative nitrogen deposition was 2.02 kg/ha/yr and for the Weminuche Wilderness Area the cumulative impact was 1.62.[52]

[52] Impacts for the High Development Case

Table 6-4. Summary of Deposition in Class I Areas

		High Development		Medium Development		Low Development						
Location	Critical Load Threshold (kgN/ha/yr)	Nitrogen Deposition (kgN/ha/yr)	Result	Nitrogen Deposition (kgN/ha/yr)	Result	Nitrogen Deposition (kgN/ha/yr)	Result	Maximum Diff Between Cases (kgN/ha/yr)	Average Deposition 3 Cases (kgN/ha/yr)	% Diff	DAT (kgN/ha/yr)	Modeled DAT Med Case (kgN/ha/yr)
Mesa Verde NP	2.3	2.02	Modeling Less Than Threshold	1.99	Modeling Less Than Threshold	1.96	Modeling Less Than Threshold	0.06	1.99	3.1	0.005	0.01
Weminuche Wilderness	2.3	1.62	Modeling Less Than Threshold	1.60	Modeling Less Than Threshold	1.58	Modeling Less Than Threshold	0.04	1.60	2.5	0.005	0.01

6.6.3 Class II Areas

An analysis of modeled cumulative deposition (for all sources) and proposed action impacts relative to the DAT for sensitive Class II Areas are presented in Table 6-5. The results are for sensitive Class II Areas that have modeled impacts above critical loads recommended by FLMs as referenced in the Draft EIS. In addition, modeled impacts that were above the DAT are also listed. Thus, this table presents sensitive Class II Areas where the critical load was exceeded, and the proposed action modeled impacts were not insignificant. A total of 58 nearby sensitive Class II Areas were analyzed for deposition impacts and only 4 areas resulted in modeled impacts above the critical load and where proposed action impacts were above the DAT. It must be remembered that both the critical load and the DAT are extremely conservative, and these levels are not enforceable through regulation.

The modeling results in the following four areas meeting the above criteria:

- Aztec Ruins National Monument
- Dome Wilderness
- Manzano Mountain Wilderness
- Spanish Peaks Wilderness

The location of Aztec Ruins National Monument was discussed in the Class II Area visibility analysis. This monument is a very small area located adjacent to suburban Aztec, New Mexico. Given the nature of this area, deposition is not an AQRV.

The Dome Wilderness Area was created by Congress in New Mexico in 1980. The wilderness area is around 5,200 acres or approximately 8 square miles (21 square kilometers) in the Jemez Ranger District of the Santa Fe National Forest and borders the Bandelier Wilderness in Bandelier National Monument. Because this area is adjacent to Bandelier National Monument, modeling results should be considered together. The cumulative critical loading for Bandelier was 2.95 kg/ha/yr and the proposed action DAT was below the 0.005 kg/ha/yr threshold (0.0035 kg/ha/yr). The modeled critical loading for the Dome Wilderness was 3.04 kg/ha/yr and modeled DAT was 0.006 kg/ha/yr.

The basic modeling structure for CAMx in this portion of the modeling domain is based on a 4-kilometer grid formulation. The size of the Dome Wilderness Area is approximately 21 square kilometers or a square having a length of 4.6 kilometers on a side. This means that if the CAMx modeling grid matched the size of the Dome Wilderness Area modeled deposition would be a result of a single grid square. If the grids did not match (the most likely case), then the modeling grid would have four grid cells around the wilderness area. However, the modeling approach would more than double the size of the wilderness area and that expansion would double count impacts in Bandelier.

Manzano Wilderness is about 17 miles (28 km) long and 3–5 miles (5–8 km) wide, covering both the eastern and western slopes of the Manzano Mountains which run north-south. It is very likely that the modeling grid system has greatly enhanced the area of modeled impacts as discussed above.

The Spanish Peaks Wilderness is a 19,226 acres (77.80 km^2) wilderness area in Huerfano County and Las Animas County, Colorado and has an equivalent square area of 9 kilometers. Because of the small size of this areas, the modeling grid system has expanded the area size of deposition results over a much larger area than simply the Sensitive Class II Area.

One other aspect regarding the modeling results is that modeled deposition is very insensitive to changes in Mancos Development emission scenarios. The maximum difference between the High Emission Case and the Low Emission Case for Aztec Ruins was 0.135 kg/ha/yr or a 3 percent change in impacts. The change in emissions between the high and low cases was 2274 tons/year or 50 percent.

For the other areas of concern the change in impacts between the High and Low Cases was less than 0.053 kg/ha/yr or less than a 1 percent change. While deposition results do not scale linearly with changes in emissions, these results suggest that if additional mitigation to Mancos sources was required the emission reductions would not have beneficial impacts for reducing deposition in these Sensitive Class II Areas.

Table 6-5. Comparison of Critical Loading Deposition and Proposed Action DAT on Sensitive Class II Areas

		Max Dev		Med Dev		Low Dev							
Class II Area	**Critical Loading**	**Modeled Impact (kg/ha/yr)**	**Result**	**Modeled Impact (kg/ha/yr)**	**Result**	**Modeled Impact (kg/ha/yr)**	**Result**	**Diff in Modeled Deposition Between High and Low Case (kg/ha/yr)**	**Ave Modeled Deposition All Emiss Cases (kg/ha/yr)**	**% Diff between High and Low Case**	**Nitrogen DAT (kg/ha/yr)**	**Modeled DAT (kg/ha/yr)**	**Result**
Aztec Ruins NM	2.3	3.62	Greater than threshold	3.52	Greater than threshold	3.4815	Greater than threshold	0.135	3.549	3.8204	0.0050	0.1376	Greater than threshold
Dome Wilderness	2.3	3.04	Greater than threshold	3.03	Greater than threshold	3.0204	Greater than threshold	0.017	3.10	0.5644	0.0050	0.0063	Greater than threshold
Manzano Mountain Wilderness	2.3	4.10	Greater than threshold	4.10	Greater than threshold	4.0825	Greater than threshold	0.022	4.10	0.5446	0.0050	0.0056	Greater than threshold
Spanish Peaks Wilderness	2.3	2.35	Greater than threshold	2.34	Greater than threshold	2.2984	Less than threshold	0.053	2.33	2.2703	0.0050	0.0078	Greater than threshold

6.7 Deposition Summary

Specific Conclusions

- Deposition monitoring in the vicinity of the Mancos Development indicates that deposition is improving over the period of record (30 years).
- For Class I Areas the predicted nitrogen deposition for the Mancos Development was above the DAT (0.005 kg/ha/yr) at nearby Mesa Verde and Weminuche Wilderness Area, however, cumulative impacts were below the guideline for critical nitrogen loading. Therefore, no additional mitigation should be considered as part of the ROD for Mancos Development.
- There were 4 sensitive Class II Areas that had Mancos modeled deposition impacts above the DAT and had cumulative impacts above the critical load guidance.
  - All these sensitive Class II Areas are very small in size and the modeling coordinate system is likely expanding the size of the sensitive area.
  - Because of the small size (especially Aztec Ruins) deposition should not be considered an important AQRV.
  - There is no regulatory requirement established for deposition limits for these Sensitive Class II Areas.
  - No additional mitigation is needed for the Mancos Proposed Action because of modeled deposition Impacts.

Mitigation Measures are Unnecessary to Address Nitrogen Deposition Impacts

No justification of additional mitigation is necessary in light of BLM's overly conservative approach to analyzing deposition impacts and it would be inappropriate to impose nitrogen emission mitigation measures on the project.

BLM takes a two-prong approach to analyzing the CAMx model results: (1) BLM compares modeled deposition from the project to a Deposition Analysis Threshold or "DAT" established by the Federal Land Managers ("FLMs"); and (2) BLM then compares the modeled deposition from the project and all emission sources in the region to a "critical load threshold" that BLM contends is representative of each of the Class I and Sensitive Class II Areas.[53] When analyzing the results of the modeling, BLM takes a conservative approach and uses "maximum" annual deposition values from "any grid cell that intersects a Class I or Class II receptor area" as representative of deposition for the entire area. *Id*. at 4-99. BLM presents the "average annual deposition values of all grid cells that intersect" the Class I or Class II area, but the impact analysis is based on the maximum not the average deposition values. *Id.* In the context of deposition, the average value over the entire sensitive area should be used.

As discussed further below, the DEIS's analysis of nitrogen deposition does not support a requirement for mitigation of NOx emissions because the application of the modeling results and selection of the critical load threshold are overly conservative.

[53] AQTSD at 4-99 through 4-102

<u>The DAT is a Conservative Screening Tool that does not Represent a Threshold for Adverse Impacts</u>

The AQTSD cites the FLAG (2010) guidance as a basis for using a DAT screening level to assess potential impacts from nitrogen deposition. In the western United States, the DAT for nitrogen is set at 0.005 kilograms per hectare per year (kg/ha/yr).[54] *See also* 2008 Deposition Guidance at 4; 2011 Deposition Guidance at 3. The DAT threshold is "conservative" and "represent[s] the low end of the regional range of values" based on estimates of regional natural background deposition.

This threshold was arrived at through compounding conservatism. First, the DAT is based on the naturally occurring level of nitrogen deposition—with no anthropogenic contribution—which then is reduced by half to account conservatively for variability.[55] The second instance of conservatism in the DAT is the multiplication of the previous estimate of one-half of naturally occurring levels of nitrogen deposition by a 4% value which is designed to account for new sources that might increase deposition over time (regardless of whether those sources exist or are actually constructed).[56] Based on this methodology, "new sources whose modeled deposition amounts are below the DAT are not likely to significantly contribute to cumulative impacts from N [nitrogen] or S [sulfur] deposition."[57]

As a result of this conservative methodological approach, "if the new or modified source has a predicted N or S deposition impact below the respective DAT, the FLM will consider that impact to be negligible, and no further analysis would be required for that pollutant."[58] An exceedance of the DAT for a particular project, however, does not by itself indicate that the deposition resulting from the project would cause an adverse impact. Rather, if the DAT is exceeded, the FLM guidance indicates that a refined analysis should be done to determine whether there will in fact be any adverse impact on AQRVs. The refined analysis should consider elements specific to the Class I Area at issue, including an analysis of whether overall deposition levels exceed a critical load (discussed further below). *Id*. at 5.

While mitigation measures should not be imposed simply because the DAT is exceeded, when results indicate that the DAT will *not* be exceeded, no further analysis or mitigation is necessary.[59] In this case, the Draft EIS compares modeled nitrogen deposition at adjacent Class I and sensitive Class II Areas to the DAT for nitrogen of 0.005 kg/ha/yr.

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[54] FLAG (2010) at 66

[55] 20011, Guidance on Nitrogen and Sulfur Deposition Analysis Thresholds http://www.nature.nps.gov/air/Pubs/pdf/flag/nsDATGuidance.pdf (Deposition Guidance at 3)

[56] 2011, Guidance on Nitrogen and Sulfur Deposition Analysis Thresholds http://www.nature.nps.gov/air/Pubs/pdf/flag/nsDATGuidance.pdf (Deposition Guidance at 3)

[57] 2011, Guidance on Nitrogen and Sulfur Deposition Analysis Thresholds http://www.nature.nps.gov/air/Pubs/pdf/flag/nsDATGuidance.pdf (Deposition Guidance at 3)

[58] 2011, Guidance on Nitrogen and Sulfur Deposition Analysis Thresholds http://www.nature.nps.gov/air/Pubs/pdf/flag/nsDATGuidance.pdf (Deposition Guidance at 3)

[59] 2011, Guidance on Nitrogen and Sulfur Deposition Analysis Thresholds http://www.nature.nps.gov/air/Pubs/pdf/flag/nsDATGuidance.pdf (Deposition Guidance at 3)

Appendix A
Unquantifiable Uncertainties in a Comparison of Top Down and Bottom Up Emission Inventories

Doug Blewitt, CCM

Earth System Sciences LLC

Unquantifiable Uncertainties in Top Down and Bottom Up Emission Inventory Comparisons

- Top down uncertainties in inverse modeling
  - Drive by single well site with no tracer
  - Drive by single well with tracer
- Uncertainties in bottom up inventories
  - Differences in time scales bottom up versus top down inventories
  - Temporal variations in well site emissions (measurements compared to annual inventories)
  - Other uncertainties

Top Down Uncertainties in Inverse Modeling Drive by Single Well Site (no tracer)

- **Ultimate test of accuracy of top down inventory is to perform tracer test and evaluate known release rate to calculated release rate**
- To assess the level of uncertainty in the plume traversing results, a number of experiments were performed where CH4 was released from a cylinder of compressed gas at a known rate while traverses were made downwind of the source.
- These controlled release measurements were made at a site near the CSIRO Laboratories in Newcastle, Australia where there were no other sources of CH4 present.
- Traverses were made between 15 m and 50 m downwind of the controlled release point.
- Two initial experiments using a higher release rate of approximately 3.5 g min-1 and up to 50 m downwind overestimated the actual emission rate by about 100 % and 60 % respectively.

Source: **CSIRO ENERGY TECHNOLOGY**

Inverse Tracer Experiment Results

- Controlled release experiments were conducted on several occasions with CH4 release rates between 0.7 g min-1 and 0.8 g min-1
- Traversing distances between 15 m and 30 m downwind of the release point
- Between 6 to 10 traverses were made
- The error bars show the minimum and maximum individual results of individual traverses
- **Illustrates the large uncertainty in a single realization of inverse modeling**

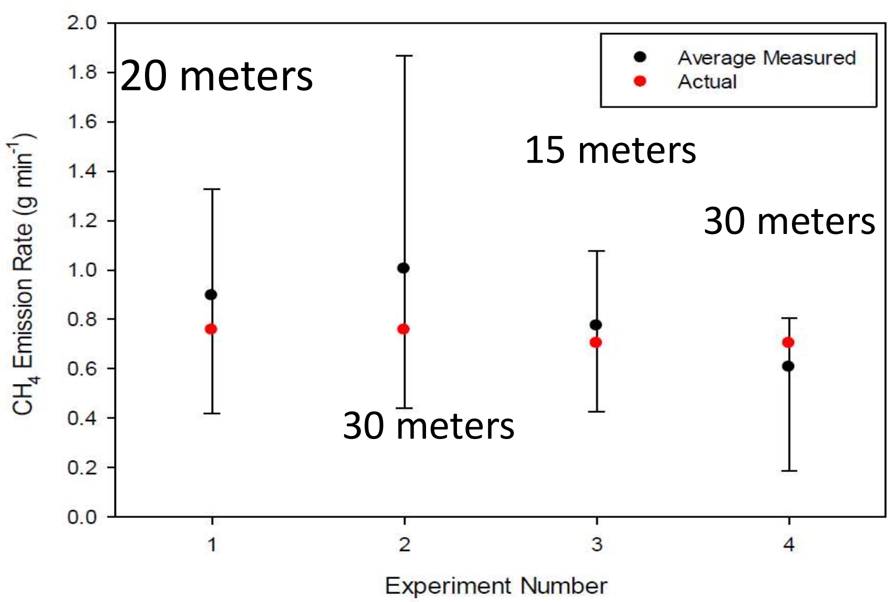


Figure 4.1. Summary of the controlled release experiments showing the CH_4 release rate determined by plume traversing and the actual release rate. Downwind distances were: Exp No 1 = 20 m; Exp No2 = 30 m; Exp No 3 = 15 m; Exp No 4 = 30 m. The error bars represent the range of emission rates measured during each set of six traverses.

Releases do not include the effects of nearby structures that can influence local dispersion

Tracer Test Results and Conclusions

		Single realization					
Distance (m)	Known release rate (g/min)	Inversion maximum (g/min)	Maximum error (%)	Inversion minimum (g/min)	Minimum error (%)	Average inversion (g/min)	Average error (%)
15	0.7	1.1	57	0.4	-43	0.75	7
20	0.75	1.3	73	0.4	-47	0.95	27
30	**0.75**	**1.9**	**153**	**0.4**	**-47**	**1**	33
30	**0.7**	**0.8**	**14**	**0.2**	**-71**	**0.6**	-14

Conclusions

1) Inverse model accuracy is very sensitive to the number of passes though the plume
2) Inversion accuracy is more accurate closer to the release – local structures could change this conclusion
3) Reproducibility between results at 30 meters downwind indicates very different results and suggests that uncertainty is larger than indicated by these experiments
4) Applicable to regional studies?

Plume Time Averaging Needs to be Considered in Inversion Calculations

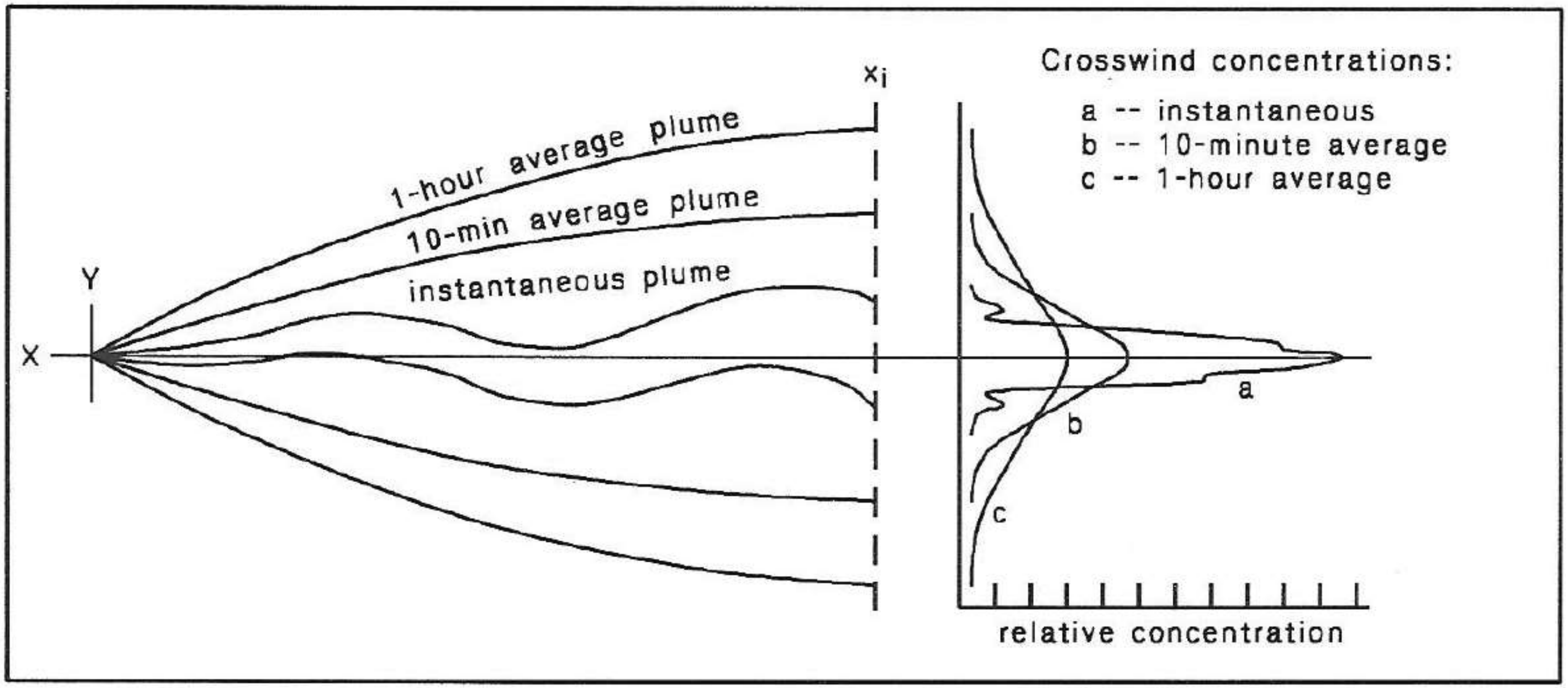


FIGURE 27

TIME-AVERAGED PLUMES

Making multiple passes through a plume and using ensemble average concentrations results in improved accuracy over a single realization

Top Down Uncertainties in Inverse Modeling Drive by Single Well Site (with tracer)

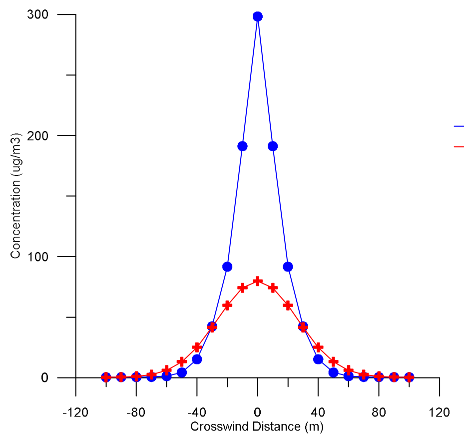
- Using a tracer in conjunction with ambient measurements can result in accurate inversion calculations
- Tracer must undergo similar dispersion to unknown sources
  - It becomes more important the closer the ambient measurements are made to the well site
  - Differences in location, release height and local structures can influence results

Modeling Experiments Were Conducted to Illustrate the Importance of Similar Dispersion

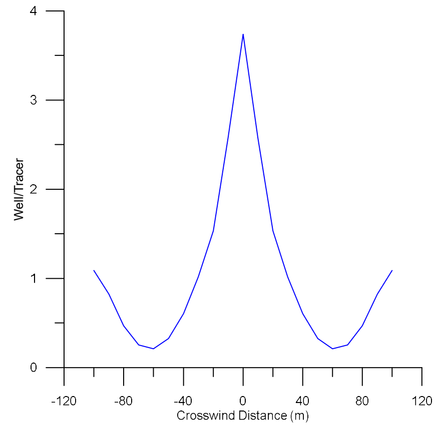
- AERMOD was used to model the difference in dispersion between a well and a tracer
  - Well emissions were modeled by releasing emissions horizontally at the top of the tank
  - The effects of local structures (downwash) were include by using actual tank dimensions
  - Tracer was modeled at the edge of the well pad (upwind and crosswind)
  - Well and tracer emission rates were modeled at 1g/s – thus differences in projected concentrations are only a result of dispersion

Crosswind Modeling Results for Well and Tracer Emissions

Tracer is upwind from tank

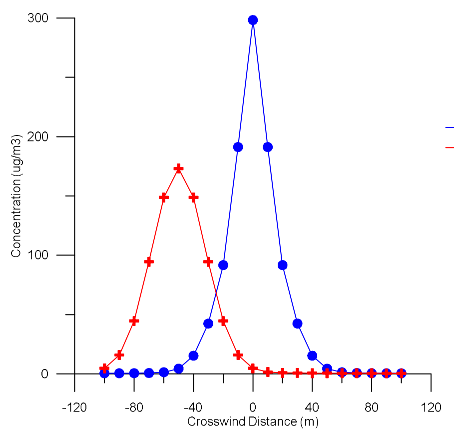


Well and tracer impacts 100 meters downwind elevation 1 meter
tracer up wind of well

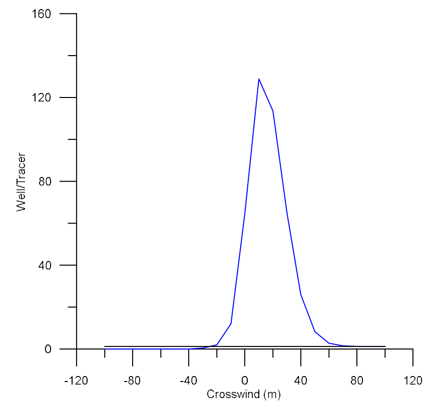


Ratio of Well Concentration/Tracer Concentration 100 m downwind 1 m elevation
Well and tracer emission rates are identical
Tracer located upwind of well pad

Tracer is crosswind from tank

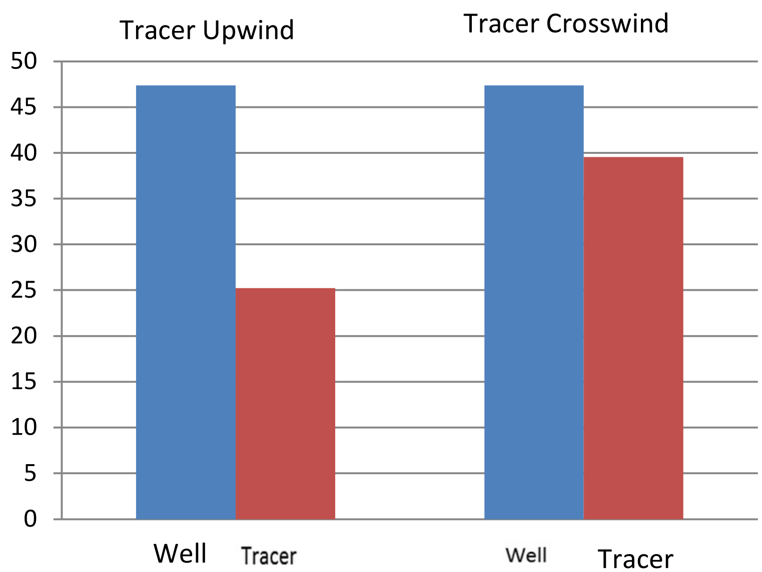


Well and tracer impacts 100 meters downwind elevation 1 meter
tracer cross wind of well

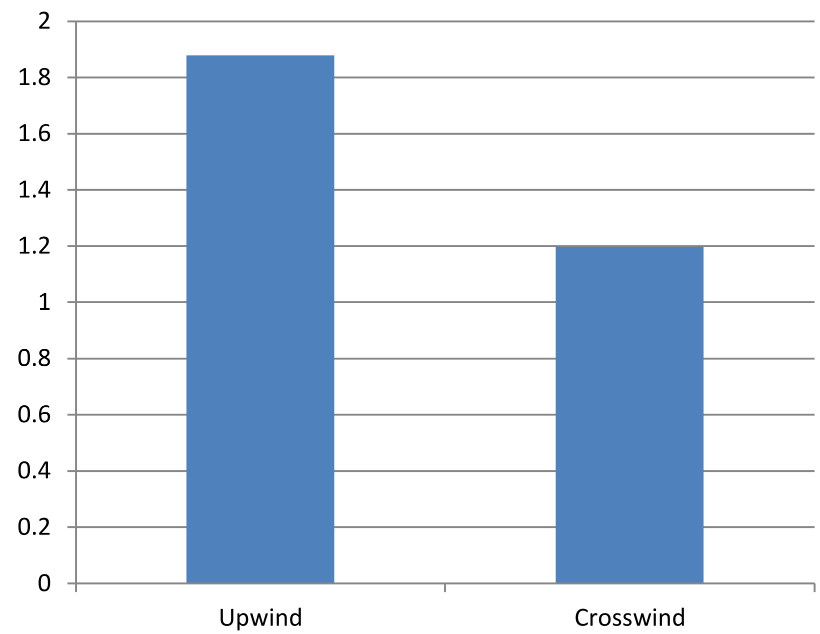


Ratio of Well Concentration/Tracer Concentration 100 m downwind 1 m elevation
Well and tracer emission rates are identical
Tracer located crosswind from well pad

Crosswind Average Concentrations for Well and Tracer Emissions



Crosswind average concentrations from wells and tracer
100 m downwind, 1 m receptor elevation



Crosswind average ratio from wells and tracer
100 m downwind, 1 m receptor elevation

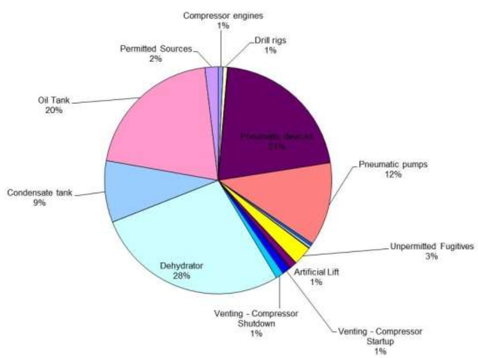
Time Scale of Bottom Up and Top Down Emission Inventories

Bottom Up

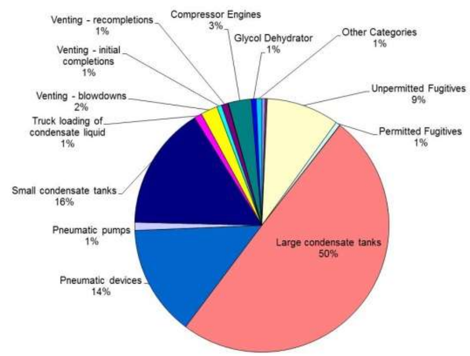
- Inventories represent annual emissions
- The temporal nature of oil and gas emissions makes it impossible to estimate short term emissions
  - Short term emissions do not necessarily equal annual emissions/8760 (hours per year)
  - From annual inventories it is difficult to estimate actual short term emissions – temporal nature of emissions
  - In modeling of oil and gas impacts, the inability to quantify short term emissions is a modeling limitation addressed through model performance evaluations and the use of models in a relative mode

Relative VOC Source Attribution for Five Production Basins

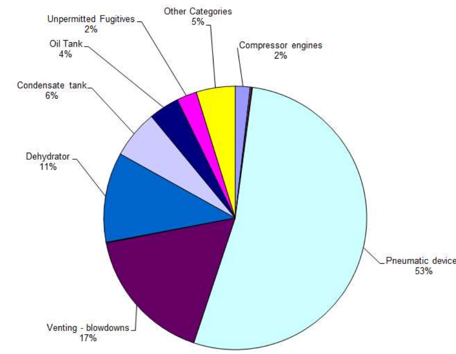
Uinta Basin, UT



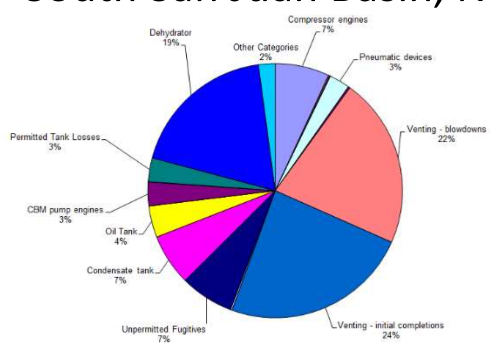
D.J. Basin, CO



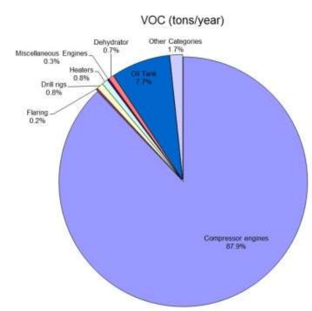
Wind River Basin, WY



South San Juan Basin, NM



North San Juan Basin, CO



Note: THC from Engines

Conclusion: Source attribution is very basin specific

Source: WRAP Phase III Inventory

Time Scale of Ambient Measurements Used for Inversion Calculations

Assume:

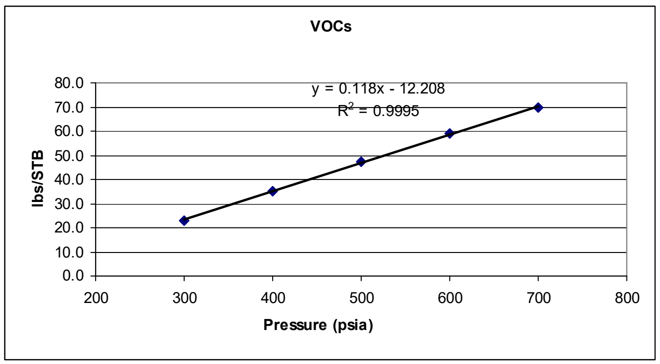
- 10 min average plume width at 50 m downwind is 50 m
- Sampling vehicle travels at 5 mph

Results:

- If sampler observes average plume width of 50 meters, the sampler is exposed to the plume for less than 1 minute
- The actual instantaneous plume width that the sampler measures may be less and thus the actual atmospheric representation will be less
- Even without temporal changes in emissions, representing annual emissions based on an atmospheric sample of a duration less than 1 minute to represent annual emissions has a large unquantifiable uncertainty
- Temporal changes in emissions from tank flashing (liquid unloading or similar sources) further complicate any comparison

Important Time Scale Issues that Must be Considered Between Top Down and Bottom Up Inventories

- Flashing tank emissions are determined by calculating an emission factor based on site specific flash properties



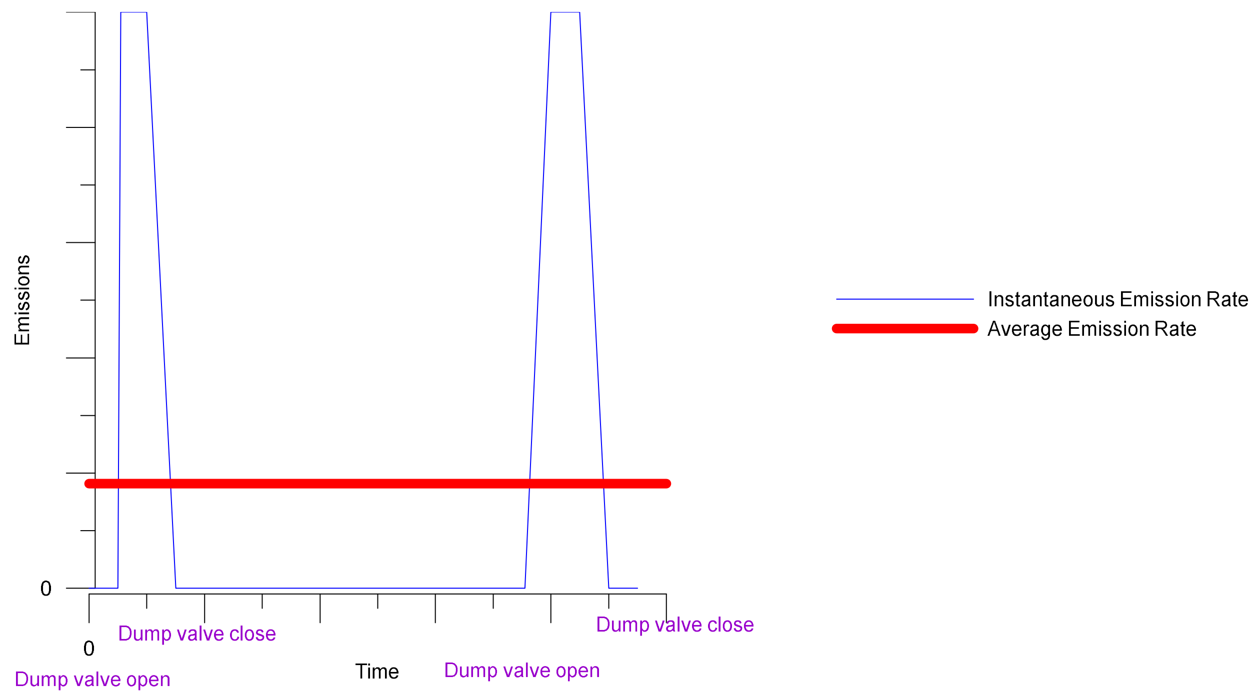
- Determine annual emissions

Emissions(t/yr)=emission factor (lbs/stb) * annual condensate production/2000 lbs/ton

Do for each individual well and then totaled

- Annual emissions are assumed to be uniform over all time periods
- However, short term tank emissions have a temporal profile

Hypothetical Tank Emission Profile



Hypothetical Instantaneous and Ave rage Emission Rates

Notes:

- Average emission rate represents the average of periods when emissions occur and when there are no emissions – annual average inventory to be used for policy consideration
- Instantaneous emissions represent time series of emissions measured at a tank
- Top down emissions based on ambient measurements and inverse modeling represent instantaneous emissions (may be present or not) and are not directly comparable to annual emission inventories

Conclusions

- There are unquantifiable uncertainties between top down and bottom up inventories
- Large uncertainties are introduced with drive by sampling unless multiple transects through the plume are made
- Uncertainties are introduced in tracer experiments if the tracer does not undergo similar dispersion to emissions of concern
- There are uncertainties in time scales between top down and bottom up inventories that must be considered