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STATE OF NEW MEXICO
BEFORE THE ENVIRONMENTAL IMPROVEMENT BOARD

IN THE MATTER OF:

PROPOSED NEW REGULATION **No. EIB 21-27 (R)**
20.2.50 Oil and Gas Sector – Ozone Precursor Pollutants
Hearing Date: September 20, 2021

NOTICE OF INTENT TO PRESENT TECHNICAL TESTIMONY OF KINDER MORGAN, INC. AND ITS SUBSIDIARIES AND AFFILIATES, EL PASO NATURAL GAS COMPANY, L.L.C., TRANSCOLORADO GAS TRANSMISSION CO., LLC, AND NATURAL GAS PIPELINE COMPANY OF AMERICA, LLC

Kinder Morgan, Inc. and its subsidiaries and affiliates, El Paso Natural Gas Company, L.L.C. ("EPNG"), TransColorado Gas Transmission Co., LLC ("TransColorado"), and Natural Gas Pipeline Company of America, LLC ("NGPL," and together with EPNG and TransColorado, "Kinder Morgan") submit this notice of intent to present technical testimony at the public hearing in the above-captioned matter pursuant to 20.1.1.302.A. NMAC (the "Notice").

1. **Entity for whom the witnesses will testify**: Kinder Morgan.

2. **Identity of witnesses**: Kinder Morgan will call the following witnesses at the hearing to present technical testimony: (1) Leslie R. Nolting, Air Permitting and Compliance Manager for Kinder Morgan, (2) Vincent L. Brindley, Technical Supervisor for Kinder Morgan, and (3) James R. Trent, Staff Engineer for Kinder Morgan. A copy of Ms. Nolting's resume is attached as **Exhibit I**. A copy of Mr. Brindley's resume is attached as **Exhibit II**. A copy of Mr. Trent's resume is attached **Exhibit III**.

Given the length and complexity of proposed 20.2.50 NMAC – Oil and Gas Sector – Ozone Precursor Pollutants (the "Proposed Rules"), we summarize in Table 1, below, the assignment of technical testimony to be provided by Ms. Nolting, Mr. Brindley, and Mr. Trent by Proposed Rule section and topic, and the anticipated duration of such testimony. As indicated in the far left column of Table 1, the relevant narrative technical testimony is provided in an exhibit to this Notice.

Table 1: Assignment of Technical Testimony

Exhibit	Rule Section	Topic	Direct Testimony Witness(es)	Anticipated Duration of Testimony	Additional Witnesses[1]
IV	N/A	Introduction and Witness Qualifications	Leslie Nolting Vincent Brindley James Trent	5 minutes	None
V	N/A	Introduction to Kinder Morgan	Leslie Nolting	10 minutes	Vincent Brindley James Trent
VI	Section 113	Introduction to Engines and Turbines	Vincent Brindley	10 minutes	Leslie Nolting James Trent
		Case-Specific Technical and Cost Considerations	James Trent	20 minutes	Leslie Nolting Vincent Brindley
		Cost Considerations For Turbines Below 4,000 bhp	James Trent	15 minutes	Leslie Nolting Vincent Brindley
		Compliance Schedule for Existing Turbines	James Trent	15 minutes	Leslie Nolting Vincent Brindley
		Emergency Engines Exemption	Leslie Nolting	5 minutes	Vincent Brindley James Trent
		Manufacturer's Recommended Maintenance Schedules	Leslie Nolting	5 minutes	Vincent Brindley James Trent
VII	Section 116	Leak Detection and Repair	Leslie Nolting	15 minutes	Vincent Brindley James Trent
VIII	Section 121	Pig Launching and Receiving	Leslie Nolting	10 minutes	Vincent Brindley James Trent
IX	Section 114	Compressor Seals	Vincent Brindley	10 minutes	Leslie Nolting James Trent
			Total Anticipated Duration:	120 minutes	

3. **List of Exhibits**: A list of exhibits that Kinder Morgan intends to offer into evidence in this matter is attached to this Notice. Kinder Morgan reserves the right to introduce and move for admission of any other exhibit in support of rebuttal or additional direct testimony at the hearing.

[1] Available for questions and cross-examination.

Respectfully submitted this 28th day of July, 2021.

By: */s/ Ana Maria Gutiérrez*

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Counsel for Kinder Morgan, Inc., El Paso Natural Gas Company, L.L.C., TransColorado Gas Transmission Co., LLC, and Natural Gas Pipeline Company of America, LLC

EXHIBIT LIST

Exhibit I	Resume of Leslie R. Nolting
Exhibit II	Resume of Vincent L. Brindley
Exhibit III	Resume of James R. Trent
Exhibit IV	Introduction and Witness Qualifications
Exhibit V	Introduction to Kinder Morgan
Exhibit VI	Section 113: Engines and Turbines
Exhibit VII	Section 116: Leak Detection and Repair
Exhibit VIII	Section 121: Pig Launching and Receiving
Exhibit IX	Section 114: Compressor Seals
Exhibit X	Redline of Proposed Rule

EXHIBIT I

RESUME OF LESLIE R. NOLTING

Leslie Nolting

2 North Nevada Avenue, Colorado Springs, Colorado 80903

Telephone: (719) 520-4652

Email: Leslie_Nolting@KinderMorgan.com

EDUCATION/TRAINING

University of Wyoming – Laramie, Wyoming

Bachelor of Science – Chemistry, December 1991

PROFESSIONAL EXPERIENCE

6/08 – Present **Kinder Morgan, Inc. (and predecessor company El Paso Corporation),** Colorado Springs, Colorado

EHS Specialist/EHS Manager – Air Permitting and Compliance

Managed team of 8 professionals (scientists and engineers) in maintaining air quality compliance for Kinder Morgan's natural gas transmission network. Reviewed capital projects in states across the country for air permitting costs and control technology requirements. Participated in preparation of Prevention of Significant Deterioration (PSD), minor source New Source Review (NSR), and Title V operating permit applications. Reviewed and negotiated permit conditions. Prepared annual emission inventories for facilities in multiple states. Prepared air quality compliance reports including review of monitoring data. Reviewed and provided comments on new regulations proposed under the Federal Clean Air Act, numerous State Implementation Plans (SIPs), and a tribal minor source permitting program. Responded to compliance issues arising from agency inspections or operational malfunctions. Worked closely with agencies to negotiate Settlement Agreements to resolve Notices of Alleged Violation. Participated in audits of a natural gas gathering system and natural gas processing plant focusing on air quality compliance. Provided training to operations and technical and mechanical services groups to promote compliance with air permits, company policies, consent orders, and other regulatory requirements

11/04 – 6/08 **Environmental Services, Inc. (contracted to El Paso Corporation),** Colorado Springs, Colorado

Environmental Scientist – Air Permitting and Compliance

Provided support for El Paso Corporation's Western Pipeline Environmental Department on a contract basis including air quality permitting and compliance tasks described above.

3/03 – 11/04 **JBR Environmental Consultants,** Salt Lake City, Utah

Environmental Scientist – Air Permitting and Compliance

Completed NSR and Title V permit applications for industrial facilities in Wyoming, Idaho, Nevada, and Utah. Performed compliance audit of and updated a Risk Management Plan pursuant to the Chemical Accident Prevention Provisions of the Clean Air Act.

3/98 – 3/03 **Environmental Services, Inc.,** Las Vegas, Nevada

Environmental Scientist – Air Permitting and Compliance

Prepared PSD, minor source NSR, and Title V permit applications for a variety of industrial facilities in New Mexico and Nevada. Performed compliance audits of natural gas production, gathering, and transmission systems. Participated in due diligence audit for a coal-fired power plant.

3/97 – 3/98 **Academy Corporation,** Albuquerque, New Mexico

Environmental Health and Safety Manager

Responsible for general environmental health and safety compliance for a silver recovery and reclamation facility including air permit compliance, waste water discharge monitoring and reporting, storm water discharge monitoring and reporting, hazardous waste management, and Occupational Safety and Health Administration (OSHA) compliance. Developed and implemented a Confined Space Entry Program in accordance with federal regulations. Developed and implemented and employee safety incentive program.

7/93 – 3/97 **Environmental Services, Inc.,** Albuquerque, New Mexico

Environmental Technician

Prepared NSR and Title V permit applications for facilities in New Mexico including the oil and gas, mining, and manufacturing industries. Developed a customized spill response and reporting compliance manual with reporting flowchart. Developed an agency-approved protocol and procedure for compliance testing of natural gas compressors using portable analyzers. Participated in compliance and due diligence audits of natural gas production, gathering, and processing facilities.

12/92 – 7/93 **Rapley Engineering Services, Inc.,** Rock Springs, Wyoming

Engineering Clerk/Technician

Developed a regulatory document filing system for a natural gas pipeline to assist in Department of Transportation compliance demonstrations.

12/91 – 12/92 **Wyoming Analytical Laboratories, Inc.,** Laramie, Wyoming

Chemist

Performed quantitative analyses on coal, water, and environmental samples using ASTM and EPA methods.

EXHIBIT II

RESUME OF VINCENT L. BRINDLEY

Vincent L. Brindley, EIT

2 North Nevada Ave, Colorado Springs, CO 80903

Telephone: (719) 520-4487

Email: vincent_brindley5@kindermorgan.com

EDUCATION

University of California, Santa Barbara

Bachelor of Science – Chemical Engineering, June 1989

PROFESSIONAL EXPERIENCE

03/00 – Present **Kinder Morgan, Inc. (and predecessor companies El Paso Corporation; Colorado Interstate Gas Company (Coastal)),** Colorado Springs, Colorado

Technical Supervisor

Direct supervisor to 4 Engine Technicians and 3 Controls Specialists. Duties the same as Mechanical Testing (below) with the addition of Controls Specialists who maintain and develop station and unit control PLC programming, provide SCADA support, electrical power support and training. Provided direct support to compression facilities including clean air retrofit work; proctored progression testing for E&C Technicians; assisted Operations with maintaining compliance with air permits; reviewed air permit renewals; reviewed engine analyses and maintenance work to ensure engine reliability and availability.

Supervisor, Mechanical Testing

Direct supervisor to 12 Reliability Specialists who performed engine analyses, portable emission testing, greenhouse gas measurement and engine troubleshooting. Maintained and supported compliance with corporate operational policies and air permit requirements. Provided technical guidance and problem resolution for direct reports for the operation and maintenance of natural gas compression facilities. Interacted extensively with all levels of Operations and other support groups in addressing plant issues. Supported review of equipment performance and identified opportunities for improvements through development of enhanced operating/maintenance procedures and corporate policies. Interacted with management personnel in other groups such as Clean Air Team, Facility Design, Automation Design, Gas Operations on various projects and issues related to plant operations and design.

<u>Corporate Air Engineer</u>

Represented Company during rulemakings with agencies. Participated in project planning/strategy meetings and provided input on location and timing impacts from air regulations. Chair of Interstate Natural Gas Association of America Task Group for MACT and NSPS. Identified and obtained necessary air permits for existing stations and new construction (NSR, PSD, Title V, Minor Sources). Evaluated applicability of new rules (NESHAP, NSPS, State level). Prepared Air and Noise Resource Report 9 for FERC filings. Coordinated 112(j), RICE, Turbine and Boiler MACTs across Western Pipelines Group. Participated on Corporate level, cross-disciplined team to establish internal policies on clean air issues. Developed numerous corporate policies and processes that were implemented across the Pipeline Group. Represented Corporation at trade group meeting as an air meeting facilitator and presenter

<u>Compliance Engineer</u>

Performed compliance duties for all environmental media - Air, Waste, Water, Oil, & Noise. Provided technical assistance to other departments on environmental issues relating to projects. Performed calculations and maintained compliance records for seven compressor stations' Title V Operating Permits. Evaluated need for Spill Prevention, Control and Countermeasure (SPCC) plans and oversaw consultant as plan was developed. Managed disposal of hazardous and non-hazardous waste per RCRA requirements. Performed site audits to assess facility compliance status and made recommendations to ensure compliance. Reviewed analytical data (PCBs, hydrostatic test, asbestos) and determined proper course of action to maintain compliance. Drafted internal policy memos on environmental considerations needed during project design.

05/97 – 03/00 **CDPHE - Air Pollution Control Division**, Denver, Colorado

Permit Engineer (Construction and Operating Permit Units)

Conducted engineering reviews and drafted permits for Construction and Title V applications using standardized and unique review procedures. Analyzed technical data, reports, and calculated emissions for a multitude of source types. Interpreted State and Federal air regulations (NSPS, NESHAP, PSD, and NSR) and determined applicability. Evaluated proposed emissions control equipment per established standards. Determined compliance status of sources and participated in violation negotiations. Performed screening models to determine ambient impacts. Created computer templates to assist permit group with emissions analysis and permit generation.

03/94 – 03/97 **United States ARMY**, Colorado Springs, CO

Combat Engineer (12B)

Administrative Noncommissioned Officer for the Fort Carson Chief of Staff's office. Maintained and managed regulations and duty roster for Fort Carson. Received, reviewed, coordinated, and maintained inquiries for Commanding General's open door policy. Served as line soldier in South Korea.

04/93 - 02/94 **Baldwin Environmental, Inc.**, Reno, Nevada

Product Development Engineer

Developed a Total Hydrocarbon Analyzer using the Flame Ionization Detector method. This included designing using CAD, testing, and coordinating with the Electronic Developer to accomplish prototype construction. Designed and fabricated custom environmental sampling equipment to customer specifications. Updated all CAD drawings for sales and production.

02/90 – 03/93 **Clean Air Engineering, Inc.** (and predecessor company Exemplar Design Engineering, Inc.), Carpinteria, California

Business / Production Manager

Accountable for the manufacture of emissions sampling equipment. This included all aspects of production, business administration, employee supervision/training, technical support, and client contact. Designed production assemblies using CAD. Assisted in daily operation of California office and performed duties of a Facilities Manager. Performed in-house consulting, Beta testing, and redesign on CAE's pre-production research projects.

Project Engineer

Performed site inspections and supervision of contractors during consulting work. Conducted experiment to determine worker exposure to adhesive vapors for OSHA compliance. Assisted in the research, design, construction, and evaluation of pilot burner for a computer controlled locomotive turbocharger, test stand. Responded to RFPs with cost estimations and quotations.

SPECIFIC PROJECT AND PERMITTING WORK

- Project manager for multiple engine/compressor foundation replacement projects.
- Negotiated and obtained all air related permits for construction and operation of the $3 billion Ruby Pipeline project.
- Coordinated Routine Maintenance, Repair and Replacement policy for Pipeline Group.
- NSR air permitting for construction of grassroots natural gas compressor stations: CIG Trinidad, CIG Kim, CIG Fort Lupton, EPNG Cimarron, EPNG Tom Mix, EPNG Picacho, WIC Snake River.
- Led MACT Implementation Team to standardize compliance methodologies across five pipeline systems for Federal Engine NESHAP.
- EPNG Line 2000 Power Up. Two grassroots facilities and one Title V permit modification to install fired turbine compression.
- Cheyenne Plains Gas Pipeline Company. PSD modification to existing facility. Permitted 36,000 HP of compression and a 300 MMscfd Amine Treatment plant.
- Prepared permit modifications for CIG Front Range Expansion and Fort Morgan Additional Compression.
- Drafted numerous NSR Construction Permits for sources ranging from gasoline service stations to peaking power turbines.
- Drafted Title V Operating permits for sources such as natural gas compressor stations, molybdenum mine and cogeneration power plant.

EXHIBIT III

RESUME OF JAMES TRENT

JAMES R. TRENT

1001 Louisiana St, Houston, TX 77002

(713) 420-4434

E-mail: james_trent@kindermorgan.com

EDUCATION

Texas A&M University, College Station, TX

Bachelor of Science, Mechanical Engineering, December 2000

PROFESSIONAL EXPERIENCE

11/20 - Present **Kinder Morgan Inc. – Engineering Design – Staff Engineer**

Currently work as a staff engineer in the engineering design group focusing on developing scopes for emissions retrofit projects and compression expansion/replacement projects on all KM interstate systems. Also work as part of a companywide team finding solutions to new emissions rules in New Mexico, Utah, Arizona, New York, Pennsylvania, and Colorado.

10/13 – 11/20 **Kinder Morgan Inc. – Engineering & Technical Services – Engineering Manager**

Worked as the Manager of the Compression Engineering and Emissions Compliance Testing group overseeing a total of 20 employees consisting of engineers, degreed professionals, and contractors located in 5 locations. Responsibilities included all of the responsibilities listed under the KMI Engineering Supervisor job (below) plus overseeing the scoping of new business develop projects, which included, without limitation, selecting the type of HP that will be scoped/ installed on these projects; overseeing emissions control technology projects; working with legal, operations and EHS to solve emissions issues that develop on the system; being responsible for the handling and directing of questions to the appropriate employees concerning COMET; developing of FERC Form 2 data; and undertaking special projects assigned by the departments director. Responsible for the budgeting of 2 RC's.

05/12 – 10/13 **Kinder Morgan Inc. – Engineering & Technical Services – Engineering Supervisor**

Supervisor of the Emissions Compliance Testing group overseeing three engineers, five specialist, and 2 truck drivers located in Houston and Colorado Springs. Responsibilities included all of the responsibilities listed under the El Paso Supervising job (below), and scheduling all work for the team members across all of KMI pipes; creating complete budget for the group broken down in as many as 21 entities and many sub-classifications; conducting monthly budget forecasting and variance reporting; taking care of groups vendor invoicing; providing training for team members and helping solve emissions issues in the field; providing input and data analysis for new unit selection.

06/09 – 05/12 **El Paso Pipeline Group – Mechanical Testing Group – Supervisor, Houston, TX**

Worked as the Supervisor of the Mechanical Testing Compliance and Performance Group overseeing nine engineers, four technicians, and 2 truck drivers located in Houston, El Paso and Colorado Springs. Responsibilities included working with the groups planner to schedule work for the team members across all of El Paso's pipes; creating individual development plans for the team members; evaluating team members performance; providing training for team engineers and the Reliability team; providing input and data analysis for new unit selection; using compressor expertise to work with manufactures to test and improve reciprocating engine compressor valves;

helping develop O&M and Capitol budgets for the testing group; and participating as a member of the Eastern Pipes ECHO team 2005-2012 and the GMRC Analyzer workshop planning committee since 2006.

01/08 – 06/09 **Southern Natural Gas an El Paso Company – Operations Planning, Birmingham, AL**

Job duties were centered on savings SNG fuel by improving fuel efficiency on gas engines and finding ways to reduce known losses and pressure drops on the system. Additional responsibilities included: identifying and proposing solutions for horsepower replacement opportunities; leading SNG's monthly fuel meeting; researching new processes and products to help the system run efficient; giving input from an operations stand point on proposed projects; and working with the environmental group to better understand the impact of certain air regulations on SNG units.

12/06 – 01/08 **El Paso Corp – Mechanical Testing Group – Performance Lead, Houston, TX**

Worked as the lead of the Mechanical Testing Group Performance team overseeing four engineers, a senior plant specialist, and a contract engineer located in Houston, El Paso and Colorado Springs. A member of the West Pipes Western Fuel Initiative team since the team's inception in 2006. Additional responsibilities as the Performance Testing Lead included: scheduling work for the team members across all of El Paso's pipes; creating development plans for the team members; evaluating team members performance; providing training for performance team engineers and the Reliability team; creating the 2005-2009 yearly O&M and Capitol budgets for the Performance and Reliability teams; managing and negotiating the purchase and upkeep of the company's entire fleet of equipment from Windrock and Dynalco; and frequently creating presentations for Plant Service's Director.

12/00 – 12/06 **El Paso Corp – Mechanical Testing Group - Principle Engineer, Houston, TX**

Worked as a Mechanical Testing Group Performance team member. Responsibilities included: reciprocating and centrifugal performance testing; noise testing for FERC and OSHA compliance; pipeline flow testing; working on efficiency studies; developing new testing equipment; undertaking upkeep and repairs of testing equipment; evaluating new field equipment; studying and resolving the compressor valve and vibration issues found on high speed reciprocating units; supporting field personnel with compressor issues; evaluating compressor loading issues; training new testing engineers; and creating and presenting papers/trainings at industry conferences.

06/98 – 12/00 **Self Employed, College Station, TX**

Worked as an AutoCAD draftsman on a contract basis for an industrial refrigeration company. Responsibilities were the same as performed at MYCOM (described below). Also contracted to provide quotation drawings for a sales office in York, Pennsylvania.

01/96 – 06/98 **MYCOM San Antonio Manufacturing, Selma, TX**

Computer draftsman / designer for an industrial refrigeration company. Responsible for laying out industrial refrigeration skid equipment and piping and making production drawings for these units. Also responsible for laying out all pressure vessel designs to be used in the refrigeration units.

05/95 – 03/96 **TOMCO$_2$ Equipment Company, Selma, TX**

Junior draftsman responsible for creating piping diagrams, instrument diagrams, and pressure vessel drawings for industrial refrigeration units using CO_2.

06/94 – 05/95 **Fort Sam Houston Public Works, Fort Sam Houston, TX**

Worked as an intern in many engineering departments to learn about engineering.

ACHIEVEMENTS: Co-Authored GMC papers titled "A Comparative Study of Performance and Efficiency of High Speed Compressor Valves," "Reciprocating Compressor Thermodynamic Capacity without the Thermo," and "Case Study of a Slow Speed Gas Transmission Reciprocating Compressor." Co-Authored an article called "Analyzing High-Speed Compressor Valves" published in the April 2007 edition of Pipeline & Gas Journal. Received the El Paso ACE award for fuel saving work.

EXHIBIT IV

INTRODUCTION AND WITNESS QUALIFICATIONS

Q. Ms. Nolting, please describe your professional and educational qualifications.

A. My name is Leslie Nolting, and I am an Air Permitting and Compliance Manager for Kinder Morgan. I have a background in chemistry and 30 years of professional experience with environmental analysis and regulatory compliance in the mineral development industry, primarily in air quality matters in the oil and gas sector. I have worked for Kinder Morgan and its predecessor company for the past 13 years, during which time I was promoted from Environmental, Health, and Safety ("EHS") Specialist to EHS Manager for Air Permitting and Compliance. As EHS Manager, I managed a team of eight scientists and engineers to ensure air quality compliance across Kinder Morgan's natural gas pipeline network. This involves a variety of responsibilities including reviewing project air permitting costs and control technology requirements; preparing Prevention of Significant Deterioration, minor source New Source Review, and Title V operating permit applications; and preparing annual emission inventories for facilities across multiple states. A full description of my educational and professional qualifications is included on my resume, included with this testimony as **Exhibit I**.

Q. Mr. Brindley, please describe your professional and educational qualifications.

A. My name is Vincent Brindley, and I am a Technical Supervisor for Kinder Morgan. I have a background in chemical engineering and have over 30 years of professional experience, the bulk of which has focused on air quality matters. I have worked for Kinder Morgan and its predecessor companies since 2000. During this time, I have been promoted several times, and currently serve as Technical Supervisor. In this position, I supervise four engine technicians and three controls specialists, and, among other things, provide direct support to the company's compression facilities (including clean air retrofit work) and review engine analyses and maintenance work to ensure engine reliability and availability. Prior to my employment with Kinder Morgan and its predecessor companies, I was a Permit Engineer with the Colorado

Department of Public Health and Environment in the construction and operating permit units. A full description of my educational and professional qualifications is included on my resume, included with this testimony as **Exhibit II**.

Q. Mr. Trent, please describe your professional and educational qualifications.

A. My name is James Trent, and I am a Staff Engineer in the Engineering Design Group for Kinder Morgan. I have over 20 years of professional experience as a mechanical engineer in the oil and gas transmission sector. Much of my work over the course of my career has focused on compressor stations, and the engines and turbines that drive compressor stations. This has included conducting performance testing, studying and resolving compressor valve and vibration issues on reciprocating engines, overseeing and scoping new projects (including evaluating the type of horsepower to be installed on these projects), overseeing emissions control technology projects, as well as researching and publishing studies and papers regarding the same. A full description of my educational and professional qualifications is included on my resume, included with this testimony as **Exhibit III**.

I, James, together with my colleagues, Leslie and Vincent, present this testimony on behalf of Kinder Morgan for the public hearing regarding the Proposed Rules.

This testimony is supplemental to Kinder Morgan's Pre-Filed Non-technical Statement (the "Non-technical Statement"), which Kinder Morgan has filed concurrently with this submission and under separate cover. The primary purpose of this testimony is to offer the Board insight into Kinder Morgan's unique transmission operations in the state of New Mexico, and to address in detail certain technical and economic matters arising from the Proposed Rules. In particular, we will testify on behalf of Kinder Morgan to address the topics outlined in Table 1, above.

EXHIBIT V

INTRODUCTION TO KINDER MORGAN AND ITS OPERATIONS IN NEW MEXICO

Q. Ms. Nolting, please describe Kinder Morgan's operations in New Mexico that are relevant to this rulemaking.

A. Kinder Morgan transports and stores natural gas in a safe, efficient, and environmentally responsible manner for the benefit of individuals, communities, and businesses. Our operations are integral to the health and welfare of New Mexico and its communities because we deliver affordable and dispatchable pipeline quality natural gas both to industrial users and to local distribution companies. Local distribution companies are the city gates for natural gas to be delivered to people's homes for use in heating, stoves, water heaters, and for other purposes. In New Mexico, we operate roughly 3,595 miles of transmission pipelines and we own assets in 23 counties throughout the state, including in counties that are the subject of the Proposed Rules.[2] To manage the New Mexico operations, Kinder Morgan employs approximately 180 individuals, maintains a payroll of over $16.6 million, and pays approximately $8.8 million annually to local and state taxing bodies.

In New Mexico, Kinder Morgan operates in the transmission segment of the oil and gas supply chain. To illustrate the function of transmission operations in relation to other segments of the gas supply chain, I, Leslie, have included a figure as ATTACHMENT A,[3] which shows an overview of the natural gas supply chain. The transmission segment is identified at numbers 6 and 7.

Transmission is part of the downstream segment of the oil and gas supply chain.[4] As a transmission operator, our operations are distinct from upstream operations (identified at numbers

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[2] Kinder Morgan operates assets in the following New Mexico Counties: Chaves, Cibola, Curry, De Baca, Doña Ana, Eddy, Grant, Guadalupe, Hidalgo, Lea, Lincoln, Luna, McKinley, Otero, Quay, Roosevelt, Sandoval, San Juan, Santa Fe, Socorro, Torrance, Union and Valencia.

[3] For the avoidance of doubt, all attachments are incorporated into Kinder Morgan's technical testimony by reference, and Kinder Morgan reserves the right to present the attachments as exhibits during its hearing testimony.

[4] The transmission segment is sometimes referred to as midstream, however, the critical point is that the transmission segment follows (and is not a part of) the natural gas gathering and boosting and natural gas processing segments.

1 & 2 on ATTACHMENT A), and from midstream gathering and boosting and processing operations (identified at numbers 3, 4, and 5 on ATTACHMENT A) in a number of ways.

First, we transport pipeline quality natural gas. This "sweet" natural gas has already been processed and has a much lower volatile organic compound ("VOC") content than the gas that is produced, transported, and processed at well production facilities, natural gas gathering and boosting compressor stations, and natural gas processing plants. To illustrate this point, we have attached gas composition data from five of our compressor stations. *See* ATTACHMENT B. This data was gathered over the past year from gas chromatographs ("GCs"). EPNG and NGPL operate approximately 40 GCs in New Mexico that continuously monitor our natural gas at all receipt points, some delivery points, and other key junctures along the transmission system.[5] These GCs take about two to three samples every hour, which are then averaged to get one numerical block-hour average.

The attached sheets show each day's average mole percentages for the components that comprise VOCs. A mole is a standard unit ($6.02214076 \times 10^{23}$) in chemistry for measuring large quantities of very small things such as atoms, molecules, and other compounds. Using this data, we converted the mole percentages for the various VOC components to a VOC content by weight percent of total gas composition. You will see in the attached that the average annual VOC content at all evaluated stations is less than 1%, and can be as low as 0.206%. *See id.* at PDF p.2 (Summary of Annual Average VOC Content). In contrast, the VOC content of the gas processed and moved through well production facilities, natural gas gathering and boosting compressor stations, and natural gas processing plants is typically higher.

Our day-to-day operations in the transmission segment also differ significantly from the other industry segments. For example, we pig our transmission pipelines much more infrequently than operators in the midstream sector pig their gathering pipelines. As discussed further later in

[5] Throughout the Permian and San Juan Basins—*i.e.*, including its Texas operations—EPNG and NGPL operate a total of approximately 108 GCs.

this testimony, our transmission pipelines are pigged at the most annually for maintenance, and typically only once every five to seven years using a "smart pig" to check the integrity of the pipeline. By contrast, gathering pipelines can be pigged as often as daily or weekly. This is because transmission pipelines contain far fewer liquids than midstream gathering lines due to the fact that the gas being transported in transmission pipelines has typically already been processed, and, even if it has not, it is pipeline quality natural gas.

Another aspect of our operations that is unique to the transmission sector is that, because we transport natural gas in interstate commerce, we are regulated by the Federal Energy Regulatory Commission ("FERC"). As a result, to be able to construct and operate a natural gas pipeline and/or a new transmission compressor station, Kinder Morgan typically, depending on the costs, scope, and potential impact to the environment, must obtain a certificate, *i.e.*, a permit, from FERC.[6] This is a lengthy and involved process that "includes consulting with stakeholders, identifying environmental issues through scoping, and preparing environmental documents such as Environmental Assessments or Environmental Impact Statements." *See* FERC, "Natural Gas Pipeline & Storage Permitting Processes," available at https://www.ferc.gov/industries-data/resources/ferc-processes (last updated March 15, 2021). There are three stages of this process: our initial application planning process, the application process, and the construction process.

During our planning process, we assess market needs, develop a proposed pipeline route or transmission compressor station site, negotiate easements with landowners located on the proposed route or site, hold public meetings regarding the proposal, begin any necessary surveys, and complete any necessary resource reports. *See* FERC, "Application Planning Process," available at https://www.ferc.gov/media/application-planning-process (last updated May 29,

[6] Projects that are limited in scope and overall footprint, and that are under a certain cost limit, are generally authorized by a company blanket authorization issued by FERC. However, any projects authorized for construction under blanket authority must be reported to FERC on an annual basis.

2020). Only after we've taken these steps will we file a certificate application with FERC and concurrently pursue necessary federal, state, or local authorizations.

Once we file our application with FERC, FERC is required to comply with the National Environmental Policy Act ("NEPA") by completing either an Environmental Assessment or an Environmental Impact Statement, and there are multiple opportunities for public input on the proposed project. *See* FERC, "Application Process," available at https://www.ferc.gov/media/application-process (last updated May 29, 2020). If FERC approves the project, we must then obtain authorization from FERC to proceed with construction of the project, which is contingent on Kinder Morgan receiving, as applicable, Clean Water Act, Clean Air Act, and other federal and state permits (if not already received) before proceeding. *See id.*

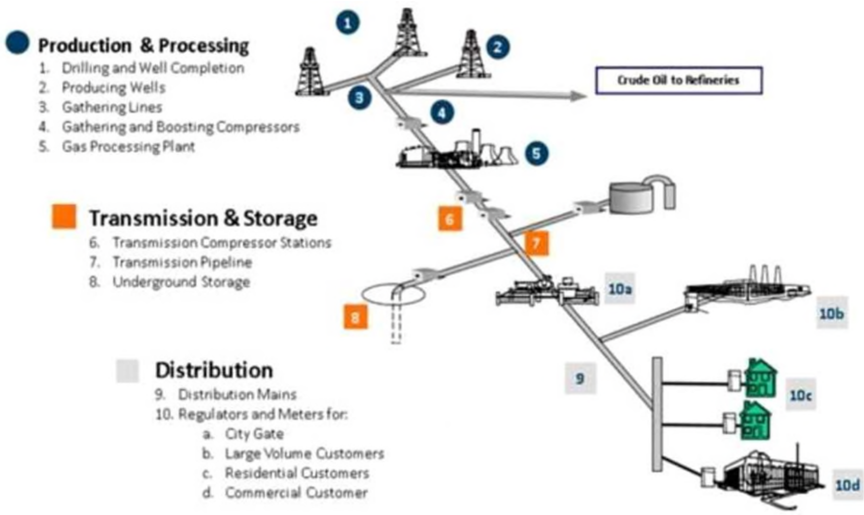
Following FERC approval of the project, Kinder Morgan's acquisition of the necessary environmental permits, completion of any outstanding property rights acquisitions from landowners, and receipt of FERC authorization to proceed with construction, we construct the pipeline and/or transmission compressor station, and restore right-of-way areas.[7] *See* FERC, "Construction Process," available at https://www.ferc.gov/media/construction-process (last updated May 29, 2020). After taking all of these steps, we begin operation of the pipeline and/or transmission compressor station subject to (1) the terms of our FERC certificate, (2) other federal, state, and local permits, and (3) the safety requirements promulgated by the Pipeline and Hazardous Materials Safety Administration ("PHMSA"). *See id.*

***Note**: At the hearing, Mr. Brindley and Mr. Trent will also be available to testify and answer any questions regarding Kinder Morgan's transmission operations.*

[7] Even after the pipeline and/or transmission compressor station is placed into service, Kinder Morgan is required by FERC to file quarterly post-construction monitoring reports for at least two years to document that the right-of-way and/or construction area has been restored and that proper revegetation is taking place.

ATTACHMENT A

Schematic of the Natural Gas Supply Chain



Source: Adapted from the American Gas Association and EPA Natural Gas STAR Program.

<u>ATTACHMENT B</u>

Gas Composition Analyses

[enclosed]

EXHIBIT VI

SECTION 113: ENGINES AND TURBINES

Q. Mr. Brindley, please provide an overview of reciprocating engines and combustion turbines used in the transmission sector.

A. The portion of the Proposed Rules that has the potential for greatest impact on Kinder Morgan's operations is Section 113, relating to emissions from reciprocating engines and combustion turbines.

Collectively, Kinder Morgan operates approximately 15 reciprocating engines and 15 combustion turbines that it anticipates will be subject to the Proposed Rules as of the effective date. We use these reciprocating engines and combustion turbines at compressor stations to compress the natural gas that we transport. We compress natural gas, *i.e.*, increase the pressure of the gas, for two reasons. First, compression reduces the size of the natural gas, which, in turn, increases the volume of natural gas that can be transported at one time. Second, compression increases the pressure of the natural gas, which enables the natural gas to move along the pipeline system. Compressor stations are typically spaced about 40 to 100 miles apart, depending on topography, pipeline routes, and other factors. The natural gas is re-compressed at each station to enable its movement to the next station, ultimately arriving at (1) the facilities of industrial consumers, (2) underground storage facilities for storage until demand increases (*i.e.*, during winter months), or (3) local distribution companies for distribution to residential, commercial, and other industrial consumers. Engines and turbines drive transmission compressor stations and are, therefore, critical to keeping gas flowing to where it needs to go.

Engines and turbines are very expensive and very large. To illustrate the size of these machines, I, Vincent, have provided a picture of an engine, as ATTACHMENT C, and a picture of a turbine, as ATTACHMENT D. The price of a new engine typically ranges from less than $300,000 for a less than 1,000 HP engine to as much as $7 million for an engine larger than 5,000 HP. The price of a new turbine ranges from typically ranges from close to $7 million for a turbine of approximately 10,000 HP to more than $10 million for a turbine of approximately 30,000 HP turbine (in each case not including engineering and installation costs).[8] Due to their size and complexity, it takes months and sometimes years from the time an engine or turbine is ordered until the time it is received, installed, and ready for operation.

***Note**: At the hearing, Ms. Nolting and Mr. Trent will also be available to testify and answer any questions regarding Kinder Morgan's engines and turbines.*

Q. Mr. Trent, please describe the data collection and analysis efforts that Kinder Morgan has undertaken related to this rulemaking.

A. In connection with this rulemaking, Kinder Morgan undertook a formal process to assess the potential impact of the Proposed Rules on four of its transmission compressor stations: EPNG's Caprock transmission compressor station ("Caprock"), EPNG's Rio Vista transmission compressor station ("Rio Vista"), EPNG's Monument transmission compressor station ("Monument"), and EPNG's Washington Ranch transmission compressor station ("Washington Ranch"). I will discuss each of these in turn.

Caprock runs on two General Electric ("GE") combustion turbines in the 5,000-7,000 HP range. To control these two turbines to comply with the proposed nitrogen oxides ("NO_x") standard for existing turbines of this size set out in Proposed Rules, Kinder Morgan would need to install Selective Catalytic Reduction ("SCR").[9] The reason that the turbines used at Caprock would require SCR can be explained in part by their age. These are older units and GE has not developed (and almost certainly will not develop) combustion technology to reduce NO_x emissions from them. The result is that SCR is the only available technology to reduce even a small amount of emissions from these turbines without first upgrading them to be compatible with existing combustion control technology, which effectively amounts to mechanically

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[8] The prices that Kinder Morgan pays for new engines and turbines is confidential business information ("CBI"). If it would be useful to NMED and the Board, and upon request, we would be willing to provide more detailed information about these prices, provided that NMED and the Board treat any such information as CBI.
[9] SCR is described in more detail, below.

modifying the turbine to make it a new turbine. Upgrading these types of turbines would cost upwards of $10,000,000, which does not make economic sense considering that an operator would need to install combustion control technology to reduce emissions after the initial upgrade is complete.

Rio Vista runs on two combustion turbines manufactured by Solar that are approximately 1,000 HP. These units would also require SCR to meet the Proposed Rules' standards. Similar to the GE turbines, Solar has not developed control technology for this horsepower of turbine. Thus, there is no alternative to SCR for these units to achieve the proposed standards.

Monument runs on 5 two-stroke lean burn reciprocating engines, manufactured by Cooper Bessemer. These engines are approximately 1,000 HP. To meet the Proposed Rules' standards, they would need to be controlled through retrofits with low NO_x emission combustion technology. Washington Ranch runs on 2 two-stroke lean burn reciprocating engines, also manufactured by Cooper Bessemer. The Washington Ranch units are approximately 4,500 HP, and, like the Monument units, would need to be controlled through retrofits with low NO_x emission combustion technology.

For each of these stations, Kinder Morgan gathered data to determine the costs associated with controlling each station's engines or turbines, as applicable. Summaries of the results of this effort for each station are attached to this testimony. *See* ATTACHMENT E.[10] The vendor quotes for Caprock, Rio Vista, and Monument, which inform each station's cost estimate are also attached. *See* ATTACHMENT F (Caprock); ATTACHMENT G (Rio Vista); ATTACHMENT H (Monument).[11] We were unable to procure a formal vendor quote for Washington Ranch prior to this filing, however, the vendor was able to provide informed estimates.[12] Based on this data, we then analyzed the cost of each control measure relative to the emissions reductions to

[10] Confidential information has been redacted from this attachment.
[11] Confidential information has been redacted from these attachments.
[12] The vendor estimated that purchase of the core control technologies would cost approximately $450,000 per engine. This total cost comprises $175,000 for an electronic pre-combustion chamber system; $75,000 for Trapped Equivalency Ratio; and $200,000 for turbocharger re-aero.

determine each measure's cost-effectiveness. *See* ATTACHMENT I (Caprock); ATTACHMENT J (Rio Vista); ATTACHMENT K (Monument); ATTACHMENT L (Washington Ranch).[13]

The process that Kinder Morgan undertook to produce the attached case study-analyses was extensive. To build a cost estimate for adding controls to an engine or turbine, we take the following steps:

- The project lead submits a request for an estimate.
- We organize an internal kick-off meeting with all involved departments (*e.g.*, Operations, Project Management, Environmental, Land, etc.) to discuss and establish project scope. During this meeting, each department is assigned one or more areas of responsibility for obtaining cost estimates. For example, the Engineering department is tasked with obtaining vendor quotes.
- Each department completes its cost assignment. This process usually takes about **<u>two to three weeks</u>**.
- Each department submits the results of its assignment to the estimating group, which compiles and synthesizes all of the inputs, and adds in certain standard costs (*e.g.*, Company labor).
- The estimating group then submits the estimate to the project manager.
- The project manager reviews the estimate, and once she is satisfied with it, submits the estimate to the director of project management.
- The director of project management then reviews, and subsequently submits the estimate to the vice president of project management.

[13] Note that the approximate shelf life of these estimates is 6 months. Thus, Kinder Morgan will need to reassess this information likely prior to the Proposed Rules becoming effective.

- Once approved by the vice president of project management, the estimate is considered final. The compilation, review, and approval process takes about **two to three weeks**, which means that the whole estimating process takes approximately **four to six weeks**.

For purposes of this rulemaking, we then used the final estimate to analyze the cost-effectiveness of the required controls, which takes additional time and resources.

I, James, personally oversaw this data collection and analysis process for the four transmission compressor stations that Kinder Morgan assessed in connection with this rulemaking, investing approximately 120 hours of my time over the past 3 months on this specific effort.

***Note**: At the hearing, Ms. Nolting and Mr. Brindley will also be available to testify and answer any questions regarding Kinder Morgan's case studies for this rulemaking.*

Q. Mr Trent, please summarize the results of the data collection and analysis performed.

A. For Rio Vista, as demonstrated in the attached vendor quote, the cost to purchase the core equipment for SCR on the two 1,051 bhp turbines that drive Rio Vista to achieve the 50-ppmvd NO_x standard would be $1,170,000. *See* ATTACHMENT G, at 5.[14] This does not include all of other costs associated with installing SCR on these turbines, which, including the costs described in the vendor quote, total $8,418,002, or about $4,200,000 per unit. *See* ATTACHMENT E, at PDF p.3. When compared against the resulting reductions down to the 50-ppmvd standard, the cost-effectiveness of that installation would be approximately $974,508 per ton of NO_x reduced for one unit and approximately $830,527 per ton of NO_x reduced for the other. *See* ATTACHMENT J, at PDF p.2. On top of that, we would then need to install an oxidation catalyst to meet the CO and NMNEHC standards in Table 3. Similarly, the cost to install SCR in order to achieve the 25-ppmvd NO_x standard for new combustion turbines would be comparable

[14] Note that this price does not include the price of certain ancillary items that would be purchased from the vendor, which remain confidential.

if not higher than the costs shown on ATTACHMENT E.

For Caprock, the vendor quoted us $6,200,000 for the core SCR equipment for the two GE turbines that power that station, including all optional hardware and services. *See* ATTACHMENT F, at 5.[15] Accounting for all other associated costs, the total cost of installing SCR at Caprock would be $20,321,412. *See* ATTACHMENT E, at PDF p.2. On a cost per ton basis, this translates to a cost of approximately $80,398 per ton of NO_x reduced for one turbine and approximately $54,935 per ton of NO_x reduced for the other. *See* ATTACHMENT I, at PDF p.2.

For Monument, the vendor quoted us a total of $2,491,143 for the primary control equipment on two of the engines—Units 4 and 5—at that station. *See* ATTACHMENT H, at 12. The total cost for this installation would be approximately $6,665,866. *See* ATTACHMENT E, at PDF p.4. On a cost per ton basis, this translates to approximately $72,527 per ton of NO_x reduced for Unit 4 and approximately $125,428 per ton of NO_x reduced for Unit 5. *See* ATTACHMENT K, at PDF p.2.

For Washington Ranch, the vendor estimated that purchase of the necessary control technologies would cost approximately $450,000 per engine. This cost comprises $175,000 for an electronic pre-combustion chamber system; $75,000 for Trapped Equivalency Ratio; and $200,000 for turbocharger re-aero. Total, the cost of installing this technology would be approximately $3,733,414. *See* ATTACHMENT E, at PDF p.5. On a cost per ton basis, this translates to approximately $10,392 per ton of NO_x reduced for one engine and $30,395 per ton of NO_x reduced for the other. *See* ATTACHMENT L, at PDF p.2.

***Note**: At the hearing, Ms. Nolting and Mr. Brindley will also be available to testify and answer any questions regarding the results of Kinder Morgan's data collection and analysis efforts.*

[15] Note that this price does not include the price of certain ancillary items that would be purchased from the vendor, which remain confidential.

Q. Mr. Trent, based on the analysis you described and your experience, are there any case-specific technical and cost considerations that Kinder Morgan believes should be accounted for in Section 113 of the Proposed Rules? If so, please describe them.

A. Yes, Kinder Morgan is concerned that it may be technically impracticable or economically unreasonable to retrofit certain of its existing reciprocating engines or combustion turbines to achieve the emissions standards set out in Table 1 and Table 3. For a legal and policy discussion regarding the Board's statutory responsibility to consider the technical practicability and economic reasonableness of the Proposed Rules, I refer the board to Kinder Morgan's Non-technical Statement.

The technical practicability and economic reasonableness of installing controls on any individual engine or turbine will vary and will depend, in part, on site-specific considerations such as space for the installation of the control and the availability of sufficient power. For example, insufficient space may exist to install controls because other equipment is located outside the exhaust point of an engine. In such a circumstance, the entire engine site would need to be reconfigured to accommodate the control technology. This type of reconfiguration has the potential to be extremely expensive. It may also be technically impracticable. A compressor reciprocating engine typically weighs at least 100,000 pounds, and can weigh as much as 365,000 pounds. Similarly, a combustion turbine can weigh more than 165,000 pounds. Kinder Morgan does not have the capability to move a machine of this size without completely disassembling it, which, in most cases, also requires demolishing the eight-foot deep concrete block underlying the unit (and hauling away multiple hundreds of yards of concrete), among other significant construction activities.

As another example, certain of Kinder Morgan's units are very close to operating at the standard set out in the Proposed Rules, such that adding controls to close the remaining gap would be cost-prohibitive. This is the case at Monument and Washington Ranch. As mentioned above, controlling the two-stroke lean burn units at Monument and Washington Ranch to the Proposed Rules' standards would require installation of low NO_x emission combustion technology. As discussed above, the cost analyses for these units show that such installation at Monument would cost $72,527 per ton of NO_x reduced for one unit and $125,428 per ton of NO_x reduced at the other, to achieve the emissions thresholds for NO_x. *See* ATTACHMENT K. Likewise, installing this technology at Washington Ranch to achieve the NO_x standard would cost $10,392 per ton of NO_x reduced for one engine and $30,395 per ton of NO_x reduced for the other. *See* ATTACHMENT L. This illustrates that, although low NO_x emission combustion technology may not be cost-prohibitive in all cases, its application in certain circumstances (*i.e.*, where the emission reductions necessary to achieve a certain standard are very small) can become unreasonably expensive.

Further, while the Proposed Rules permit an owner or operator to reduce the operating hours of an engine in lieu of achieving the standards for NO_x and VOC set out in the Proposed Rules, this alternative compliance option is not be feasible for Kinder Morgan's operations.[16] *See* Section 113.B.(2)(d) ("[I]n lieu of meeting the emission standards for an existing natural gas-fired spark ignition engine, an owner or operator may reduce the annual hours of operation of an engine such that the annual NO_x and VOC emissions are reduced by at least ninety-five percent per year."). As a natural gas transmission company, we cannot, in all circumstances, limit operation of our units in lieu of achieving the emissions reductions contemplated by the Proposed Rules. Reducing annual engine operating hours to achieve the emissions standards could mean that we have to shut down one or more compressor stations that those engines drive and/or could limit our ability to run engines when needed to meet periodic high demand (*e.g.*, during cold weather). As mentioned previously, local utilities, individuals, public institutions, and businesses rely on the gas that Kinder Morgan transports to meet certain basic and essential needs: heat and cooking, among

[16] Notably, the Proposed Rules omit this provision in the portion of Section 113 addressing turbines, without explanation. In its redline of the Proposed Rules (**Exhibit X**), however, Kinder Morgan has added an equivalent mechanism in the turbine section.

others. Reducing engine hours could compromise meeting the needs of these downstream users. It could also result in breach of Kinder Morgan's FERC-regulated transportation obligations.

Under the current drafting of the Proposed Rules, therefore, if retrofitting one or more of its engines or turbines is technically impracticable or even infeasible, Kinder Morgan would be at risk of either enforcement action from the Department or running afoul of its obligations to FERC to transport natural gas in interstate commerce safely and reliably. If retrofitting is unreasonably expensive relative to the amount of emission reductions, Kinder Morgan would be forced to pay the costs—no matter how exorbitant—to avoid the same consequences. For these reasons, we request that the Board include a mechanism in the Proposed Rules by which an owner or operator could be relieved of the obligation to comply with Table 1, and the portion of Table 3 applicable to existing combustion turbines, upon a showing (and determination by the Department) that compliance would be technically impracticable or economically unreasonable, on a case-by-case basis. Kinder Morgan has proposed language to this effect in the redline attached as **Exhibit X**.[17] To be clear, the mechanisms that we propose in the attached redline addressing circumstances of technical infeasibility or economic unreasonableness apply only to ***existing*** engines and turbines for which these concerns might arise. We would only seek relief under these mechanisms if absolutely necessary to ensure reliable and safe service to our customers.

***Note**: At the hearing, Ms. Nolting and Mr. Brindley will also be available to testify and answer any questions regarding the technical practicability and economic reasonableness of controlling emissions from engines and turbines.*

[17] Kinder Morgan also supports NMOGA's revisions to Table 1 in Section 113 to change the NO_x standard for two-stroke lean burn engines greater than 1,000 bhp to 3.0 g/bhp-hr. As demonstrated by Kinder Morgan's case studies for Monument and Washington Ranch (described in detail above), controlling two-stroke lean burn reciprocating engines greater than 1,000 bhp to the proposed standard of 0.50 g/bhp-hr is economically unreasonable. As noted, these amounts are in excess of any of the cost-effectiveness benchmarks employed by other regulatory agencies that Kinder Morgan has been able to identify, as described in more detail below.

Q. Mr. Trent, please describe Kinder Morgan's comments pertaining to the emissions thresholds proposed for existing and new combustion turbines below 4,000 bhp.

A. The Proposed Rules would require existing combustion turbines with a rating greater than or equal to 1,000 bhp and less than 5,000 bhp to achieve (1) NO_x and CO emissions standards of 50 ppmvd @ 15% O2, and (2) an NMNEHC emission standard, as propane, of 9 ppmvd @ 15% O2. *See* Section 113.B., Table 3. New units of this size would be required to achieve NO_x and CO emissions standards of 25 ppmvd @ 15% O2, and the same NMNEHC standard as for existing units. *See id*. For units with ratings below 4,000 bhp, achieving these standards would be unreasonably expensive relative to the amount of emissions reductions.

Achieving the Table 3 NO_x standards—for both existing and new units—would require installation of SCR. SCR on existing units is necessary because there is currently no combustion technology available to achieve a 50-ppmvd NO_x standard on Model-A GE Frame 3 combustion turbines or Solar Saturn combustion turbines, which are the models of turbines that Kinder Morgan operates.[18] Installing SCR would also be necessary on new units (in the 1,000-3,999 bhp range) because, to my knowledge, no manufacturer sells turbines of this size that meet the 25-ppmvd NO_x standard.

SCR is a type of post-combustion control system. The key difference between SCR and combustion control technologies (*e.g.*, low NO_x emission combustion) is that SCR is applied after combustion occurs in the turbine. In other words, it is an add-on control system that removes NO_x from the exhaust gas of a turbine. SCR removes NO_x from exhaust by causing a chemical reaction between NO_x and ammonia gas. The ammonia gas is added prior to the exhaust reaching the SCR catalyst, and the chemical reaction occurs as the exhaust passes through the catalyst chamber. The

[18] Note also that GE has indicated that it would require a $20,000 engineering study to determine if a Model-F upgrade with dry low emission technology is possible to achieve this standard.

result is that NO_x in the exhaust gas is transformed into nitrogen gas and water vapor—both harmless.

As discussed above, the cost to purchase core equipment for SCR for the two 1,051 bhp turbines that drive Rio Vista to achieve the 50-ppmvd NO_x standard would be $1,170,000. *See* ATTACHMENT G. This does not include all of other costs associated with installing SCR on these turbines, which total $8,418,002, or about $4,200,000 per unit. *See* ATTACHMENT E, at PDF p.3. When compared against the resulting reductions down to the 50-ppmvd standard, the cost-effectiveness of that installation would be approximately $974,508 per ton of NO_x reduced for one unit and approximately $830,527 for the other. *See* ATTACHMENT J. On top of that, we would then need to install an oxidation catalyst to meet the CO and NMNEHC standards in Table 3. Similarly, the cost to install SCR in order to achieve the 25-ppmvd NO_x standard for new combustion turbines would be comparable if not higher than the costs shown on ATTACHMENT E.

While we acknowledge that determining whether a certain cost is economically reasonable is not an exact science, a cost of well over $800,000 per ton of VOC and/or NO_x is excessive. For this rulemaking, we researched cost-effectiveness benchmarks employed by other regulatory agencies. The following benchmarks provide the Board and the Department with guidance for determining what is and is not economically reasonable:

<u>NO_x and NO_x/VOC Combined Benchmarks</u>

- In the recent New Mexico regional haze planning process, the Department anticipated that an appropriate cost-effectiveness threshold for requiring controls was $7,000 per ton of pollutant reduced, including NO_x. *See* Excerpt of NMED, Regional Haze Stakeholder Outreach Webinar #2, Slide 12, attached as ATTACHMENT M.
- The section of Colorado's Regulation No. 7 addressing control of emissions from engines exempts rich burn reciprocating internal combustion engines constructed

before February 1, 2009 for which retrofit technology cannot be installed for less than $5,000 per ton of combined VOC and NO_x reduced (as adjusted for inflation for future applications) from certain control requirements. *See* 5 CCR 1001-9:E.I.D.4.a.(ii). $5,000 in 2009 dollars is equal to approximately $6,400 today.[19]

- In 1994, the New York State Department of Environmental Conservation established a threshold of $3,000/ton of NO_x reduced to define economic feasibility, and stated that an emission source would not be required to implement emission mitigation systems that exceed that cost threshold, as adjusted for inflation. *See* New York State Department of Environmental Conservation, DAR-20: Economic and Technical Analysis for Reasonably Available Control Technology (RACT) Networks (Aug. 8, 2013), at 1, available at https://www.dec.ny.gov/docs/air_pdf/dar20.pdf. As adjusted, $3,000 in 1994 is now equal to approximately $5,500.[20]
- In a recent rulemaking, the Pennsylvania Department of Environmental Protection established cost-effectiveness benchmarks for installing Reasonably Achievable Control Technology-level controls of $3,750 per ton of NO_x reduced and $7,500 per ton of VOC reduced. *See* Technical Support Document for Proposed Rulemaking (Additional RACT Requirements for Major Sources of NOx and VOCs for the 2015 Ozone NAAQS RACT III)), at 12.[21]

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[19] Calculated using the Bureau of Labor Statistics' online calculator: https://www.bls.gov/data/inflation_calculator.htm.

[20] Calculated using the Bureau of Labor Statistics' online calculator: https://www.bls.gov/data/inflation_calculator.htm.

[21] File available at available at https://files.dep.state.pa.us/PublicParticipation/Public%20Participation%20Center/PubPartCenterPortalFiles/Environmental%20Quality%20Board/2021/May%2019/02_7-561_RACT%20III%20Major%20Source/04b_7-561_RACT%20III%20VOC_Proposed_TSD%20w%20APPENDICES.pdf.

VOC Benchmarks

- Similar to the exemption for rich burn reciprocating internal combustion engines for which combined VOC and NO_x control costs exceed $5,000, Colorado's Regulation No. 7 also includes a $5,000 cost-effectiveness-threshold for VOC control costs for lean burn reciprocating internal combustion engines constructed before February 1, 2009. *See* 5 CCR 1001-9.E.I.D.4.b.(ii) ("Any lean burn reciprocating internal combustion engine constructed or modified before February 1, 2009, for which the owner or operator demonstrates to the Division that retrofit technology cannot be installed at a cost of less than $5,000 per ton of [VOC] emission reduction (this value shall be adjusted for future applications according to the current day consumer price index) is exempt [from] complying with Section I.D.4.b.(i)."). Again, $5,000 in 2009 dollars is equal to approximately $6,400 today.[22]
- The Environmental Protection Agency ("EPA") determined in 2007 that a cost of $5,700/ton of VOC emissions reduced was not cost-effective. 72 Fed. Reg. 64,860, 64,864 (Nov. 16, 2007). The Obama Administration EPA cited this $5,700/ton threshold in its proposed amendments to the new source performance standards ("NSPS") for the oil and gas sector. *See* 80 Fed. Reg. 56,593, 56,636 (Sept. 18, 2015) ("Under the multipollutant approach, the cost of control for VOC based on quarterly monitoring is $6,751 per ton, and $6,334 per ton of VOC reduced if savings [of the natural gas recovered] are considered. In a previous NSPS rulemaking [72 FR 64864 (November 16, 2007)], we had concluded that a VOC control option was not cost-effective at a cost of $5,700 per ton. In light of the above, we find that the cost of monitoring/repair based on quarterly monitoring at

[22] Calculated using the Bureau of Labor Statistics' online calculator: https://www.bls.gov/data/inflation_calculator.htm.

well sites using OGI is not cost-effective for reducing VOC and methane emissions under either approach."); *see also* 81 Fed. Reg. 35,824, 35,855 (June 3, 2016) (concluding in the NSPS final rule that "the control cost, using OGI, based on quarterly monitoring is not cost-effective").

- Previously, EPA determined in the context of developing NSPS OOOO that costs in the amount of $5,299 per ton of VOC reduced or greater for application of pollution prevention requirements for wet seal centrifugal compressors were unreasonable, and, therefore, rejected that regulatory option. *See* NSPS OOOO Technical Support Document, at 6-28 (July 2011) ("The VOC control effectiveness for the processing and transmission/storage segments were $5,299 and $31,133 respectively. Therefore, Regulatory Option 3 was rejected due to high VOC cost effectiveness.").

These benchmarks serve as useful points of reference, and Kinder Morgan encourages the Board and the Department to consider them when evaluating the economic reasonableness of any rule or rule application.

Kinder Morgan recognizes that controlling emissions from combustion turbines is generally expensive, and we are supportive of reasonable regulation of turbines to achieve meaningful reductions. Because the costs to control smaller turbines to meet the Department's proposed standards would be exorbitant in all cases, however, Kinder Morgan requests that the Board change the standards applicable to new and existing 1,000-5,000 bhp units to apply only to 4,000-5,000 bhp units. This proposal is reflected in the attached redline.

***Note**: At the hearing, Ms. Nolting and Mr. Brindley will also be available to testify and answer any questions regarding the costs associated with retrofitting smaller turbines consistent with the Proposed Rules.*

Q. Mr. Trent, please describe difficulties with bringing existing combustion turbines into compliance with Table 3 on the timetable contemplated by the Proposed Rules.

A. Section 113 of the Proposed Rules sets out a phased compliance schedule, which allows owners or operators to retrofit their natural gas-fired spark-ignition engines over a period of six years. *See* Section 113.B.(2). This is a useful approach that reflects the realities of the huge amount of work that will be required to retrofit existing reciprocating engines to comply with the Proposed Rules. Kinder Morgan believes that a similar approach should be applied to combustion turbines instead of the current requirement that all existing turbines comply with the Table 3 standards within two years of the rule's effective date. *See* Section 113.B., Table 3 ("For each natural gas-fired combustion turbine constructed or reconstructed and installed before the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emissions standards no later than two years from the effective date of this Part.").

A phased compliance schedule for turbines is necessary for two primary reasons. First, Kinder Morgan operates roughly the same number of combustion turbines as it does reciprocating engines within the areas that will be subject to the Proposed Rules on the effective date. This means that it will need to retrofit approximately the same number of existing turbines as existing engines to comply with Section 113.[23] In other words, to the extent that the longer lead-time for retrofitting engines might have been justified by the simple fact that operators have more engines to retrofit, this is not the case for Kinder Morgan's operations. Second, Kinder Morgan is unaware of any difference between combustion turbines and reciprocating engines that would explain requiring retrofitting all existing turbines within two years of the effective date of the rule. As explained previously, turbines are just as large and complex as engines. As a result, the

[23] Even if the Board adopts Kinder Morgan's proposal to exclude turbines less than 4,000 bhp, a phased compliance schedule is still necessary for the reasons set out in this section.

modifications that would be necessary to achieve the Table 3 standards for existing turbines are equally time-intensive and costly.

For Kinder Morgan's existing turbines that it assessed for purposes of this rulemaking, meeting the standards of Table 3 would require installation of SCR. We consulted with a manufacturer regarding the time that it would take to install SCR on the turbines located at six of our compressor stations that would be subject to the Proposed Rules on the effective date. Assuming that Kinder Morgan will not be the manufacturer's only customer and taking into account that each of the SCR systems are custom-designed and can require as many as 130 business days to install per unit, the manufacturer estimated that if Kinder Morgan submits its turbine order for six compressor stations on January 3, 2022, installation of SCR on all of the turbines would not be completed until October 16, 2028. *See* ATTACHMENT N.

The phased installation schedule provided by the manufacturer on ATTACHMENT N reflects two practical realities. First, there are only a few companies that design, manufacture, and install SCR for GE and Solar Saturn turbines. These are third-parties that are unaffiliated with GE and Solar. Moreover, each SCR system is custom-designed for the relevant turbine and the manufacturer can only work on one SCR system at a time. The combination of few available vendors and an intensive and individualized design, manufacturing, and installation process means that it is not possible to install multiple of these systems at once.

Second, even if a vendor were able to install multiple systems at once, Kinder Morgan cannot shut down an entire compressor station for the up to six-month period that may be required to install SCR on all of the combustion turbines (typically two to three turbines) located at that station at one time in order to speed up the process. As already discussed in this testimony, downstream customers are relying on our deliveries of gas, and compressor stations are the reason that gas moves along transmission pipelines to the end user. To continue its operations without interruption, Kinder Morgan must install the required SCR systems one-by-one. This simply takes time.

Installing SCR is also extremely costly, and it is not reasonable to expect a company to absorb the costs of turbine retrofit necessary to achieve compliance with the Proposed Rules on a two-year timetable. For example, the total cost of installing SCR at Caprock would be $20,321,412. *See* ATTACHMENT E, at PDF p.2. As explained above, two turbines, which I'll refer to as Unit 1 and Unit 2, drive Caprock. The cost to install SCR on Unit 1 would be a total of $7,180,921. *See id*. The costs quoted from the vendor are incorporated into the cost of materials. *See id*.; ATTACHMENT F. Some of the other costs associated with installing SCR on Unit 1 come from company labor costs ($37,100); project management, engineering, and other internal expenses ($3,100); primary construction contractor costs ($1,916,500); and secondary contractor costs ($182,900). *See* ATTACHMENT E, at PDF p.2. The cost to install SCR on Unit 2 is higher than Unit 1, with a total cost of $11,430,361. *See id*. Again, the vendor quote is incorporated into the costs of materials, and the other costs are roughly the same as for Unit 1. *See id*.; ATTACHMENT F. The higher cost for retrofitting Unit 2 with SCR is due to the fact that the regenerator on Unit 2 must be replaced in order to allow the SCR add-on to function properly.[24]

The total SCR-installation cost for both Units at Caprock also accounts for the $1,710,130 risk of reservation credits while each Unit is out of operation for a minimum of three months during the installation process. *See* ATTACHMENT E, at PDF p.2. Reservation credits are unique to the transmission sector and can be explained through a bus analogy. Kinder Morgan, like other transmission companies, sells its pipeline services through firm transportation contracts. Part of a firm transportation contract to move gas from Point A to Point B is that the customer pays a reservation charge on the pipeline capacity it may or may not end up needing. This is like reserving a seat on the bus every day, whether you ride the bus or not. On the days that you want to ride the bus and the bus is broken, the price that you paid to reserve your seat will be refunded. Where one of Kinder Morgan's pipelines is not contracted at capacity, we may have the ability to move

[24] A regenerator is a heat exchanger; it recovers energy from exhaust before the exhaust is vented and uses that energy in process.

required volumes by relying on one turbine unit while SCR is being installed on the other, thereby avoiding the risk of reservation credits. This would be akin to having a back-up bus ready in case the other breaks down. But, this is not an option at Caprock. We are contracted at capacity through Caprock, which requires consistent operation of both Unit 1 and Unit 2. Thus, while one unit is down for SCR installation, we are at risk of a demand for reservation credits if a customer wants to "ride" the bus because we will not be able to provide the reserved capacity.

We operate approximately 15 combustion turbines that would require SCR to comply with the Proposed Rules.[25] While the costs associated with installing SCR on each turbine will vary based on site-specific factors, the cost to install SCR on the turbines at Caprock illustrates the magnitude of this process.

For these reasons, we respectfully request that the Board implement the phased compliance schedule to retrofit turbines set out in the redline attached as **Exhibit X**.

***Note**: At the hearing, Ms. Nolting and Mr. Brindley will also be available to testify and answer any questions regarding the time and costs associated with retrofitting turbines consistent with the Proposed Rules.*

Q. Ms. Nolting, please describe Kinder Morgan's comments regarding the emergency engines exemption.

A. The Proposed Rules currently exempt emergency use engines that are operated for fewer than 100 hours per year from the standards set out in Section 113. Section 113.B(10) ("The owner or operator of an emergency use engine that is operated less than 100 hours per year is not subject to the emissions standards in this Part but shall be equipped with a non-resettable hour meter to monitor and record any hours of operation."). Kinder Morgan supports this approach and has

[25] For any other turbines that do not require SCR to meet the proposed standard, we expect to need to exercise our ability, through an arrangement to the manufacturer, to exchange (*i.e.*, trade in) a component part of the turbine with a replacement that lowers overall emissions from the unit. The requisite component part costs approximately $2.5MM. Under this arrangement, it is to Kinder Morgan's benefit to do the exchange at the end of the life of the component part to maximize the value to Kinder Morgan under the arrangement. Thus, exchanging the part early—as Kinder Morgan would be required to do to come into compliance with the Proposed Rules—would result in significant value-loss and indirect costs to the Company.

proposed technical revisions in the attached redline to clarify the meaning and application of emergency use engines.

Emergency engines serve a vital function in Kinder Morgan's operations. Just like residential users of the electric power grid, sometimes we lose commercial power at our compressor stations unexpectedly. This can happen because of inclement weather or electric grid equipment failures. When we lose commercial power, we use our emergency engines to sustain our most essential system needs such as providing power for control rooms, lights, and safety and security systems, until power is restored. These systems are necessary to protect company personnel, the public, and the environment. Their continued operation during emergencies is critical.

Consistent with these limited, but essential uses, we operate our emergency engines in only three scenarios. First, to test the engine to ensure it is ready to operate in the event of an emergency. For these tests, we are subject to the limitation on the number of hours of operation allowed by federal regulation, discussed below. Second, to run the engine periodically—and typically as required by law—to ensure proper maintenance has been completed or to complete an emission test. Again, running an engine for this purpose is subject to the federal time limit. Or, third, during an emergency event. Because our emergency engines are used infrequently and because of their small size, they are responsible for a very limited amount of emissions.

We think the Proposed Rules, as drafted, recognize that it is not reasonable to subject emergency engines to the Section 113 standards—because of the purpose of emergency engines and because of their limited emissions—and intend to exempt emergency engines. However, Section 113's limitation on the time (100 hours) that emergency engines may be operated to remain exempt from the state requirements is at odds with their critical emergency-response function and with federal law. As described in the Non-technical Statement, federal law does not set a time limit on the use of emergency engines during emergencies. *See* 40 C.F.R. § 60.4211(f)(1); 40 C.F.R. § 60.4243(d)(1). Rather, the 100-hour limit applies only to ***non-emergency*** uses of emergency engines (*e.g.*, maintenance and testing). *See* 40 C.F.R. § 60.4211(f)(2); 40 C.F.R. § 60.4243(d)(2). From the operator's perspective, this is important because a cap on overall operating time could discourage an operator from running its emergency engines when it is necessary to do so (*i.e.*, in an emergency).

***Note**: At the hearing, Mr. Brindley and Mr. Trent will also be available to testify and answer any questions regarding emergency engines.*

Q. Ms. Nolting, please describe Kinder Morgan's comments regarding the requirement to comply with manufacturer's recommended maintenance schedules in Section 113.

A. The Proposed Rules require that maintenance and repair of engines and turbines "meet the minimum manufacturer recommended maintenance schedule." Section 113.C(1). We propose a minor edit to this provision to permit operators to conduct maintenance and repair consistent with good engineering and maintenance practices, as an alternative to complying with manufacturers' recommended maintenance schedules.

Limiting an operator to conducting maintenance and repair consistent with minimum manufacturer recommended schedules is problematic because the manufacturer recommendations for many older engines may be either unavailable or outdated. Many of Kinder Morgan's reciprocating engines are over 50 years old. Some of the manufacturers of these engines are no longer in business, and the maintenance specifications written when these engines were new may no longer be applicable. For these reasons and consistent with applicable permit conditions, Kinder Morgan has developed its own maintenance and repair protocols that it uses for certain of its engines and turbines. *See,* ATTACHMENT O, New Mexico Air Quality Bureau, NSR & TV: IC Engines Monitoring Protocol – Permit Template Language, Version: May 23, 2016, at 1 ("Maintenance and repair shall meet the minimum manufacturer's or permittee's recommended maintenance schedule."); ATTACHMENT P, New Mexico Air Quality Bureau, NSR & TV: Turbine Monitoring Protocol – Permit Template Language, Version: May 23, 2016, at 1 (same).

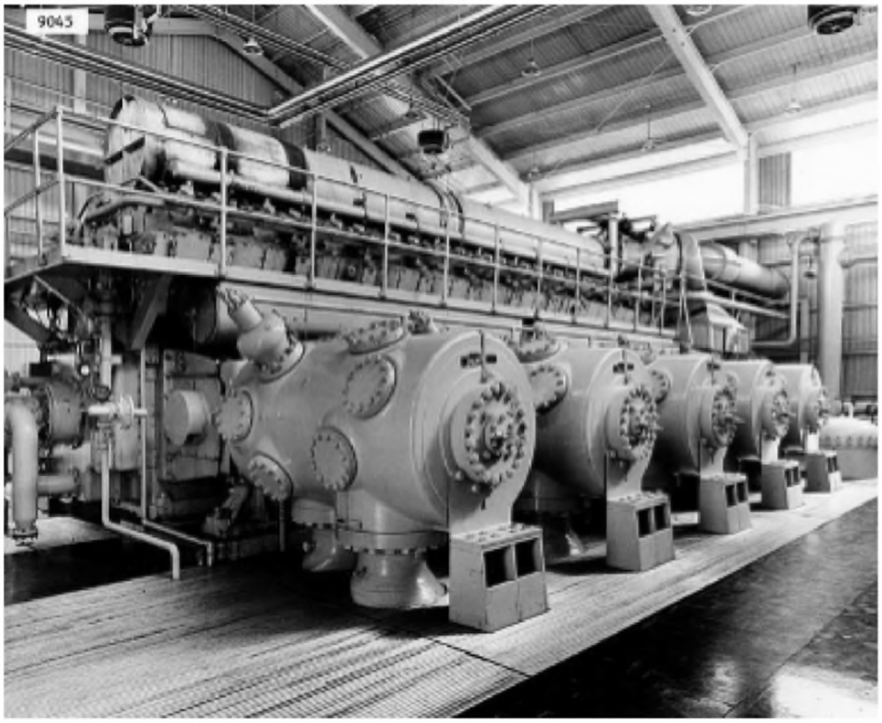
These protocols are carefully crafted and followed, consistent with good engineering and maintenance practice.

Furthermore, as described in the Non-technical Statement, Kinder Morgan's proposal is consistent with Colorado's more flexible approach to standards for required maintenance.

***Note**: At the hearing, Mr. Brindley and Mr. Trent will also be available to testify and answer any questions regarding use of manufacturers' recommended maintenance schedules.*

<u>ATTACHMENT C</u>

Image of natural gas-fired compressor engine.



<u>ATTACHMENT D</u>

Image of natural gas-fired combustion turbine.

<u>ATTACHMENT E</u>

Summaries of Cost Estimates for Case Studies

[enclosed]

<u>ATTACHMENT F</u>

Caprock Vendor Quote

[enclosed]

<u>ATTACHMENT G</u>

Rio Vista Vendor Quote

[enclosed]

ATTACHMENT H

Monument Vendor Quote

[enclosed]

ATTACHMENT I

Caprock Cost-Effectiveness Analysis

[enclosed]

ATTACHMENT J

Rio Vista Cost-Effectiveness Analysis

[enclosed]

ATTACHMENT K

Monument Cost-Effectiveness Analysis

[enclosed]

ATTACHMENT L

Washington Ranch Cost-Effectiveness Analysis

[enclosed]

<u>ATTACHMENT M</u>

Excerpt of Regional Haze Stakeholder Outreach Webinar #2[26]

[enclosed]

[26] A complete version of this document can be accessed here: https://www.env.nm.gov/air-quality/wp-content/uploads/sites/2/2017/01/NMED_EHD-RH2_8_25_2020.pdf.

ATTACHMENT N

Turbine SCR Installation Schedule

[enclosed]

ATTACHMENT O

Excerpt of Engines Monitoring – Permit Template Language[27]

[enclosed]

[27] A complete version of this document can be accessed at https://www.env.nm.gov/air-quality/permitting-section-procedures-and-guidance/ (scroll down and click on "Monitoring IC Engines").

<u>ATTACHMENT P</u>

Excerpt of Turbines Monitoring – Permit Template Language[28]

[enclosed]

[28] A complete version of this document can be accessed at https://www.env.nm.gov/air-quality/permitting-section-procedures-and-guidance/ (scroll down and click on "Monitoring Turbines").

EXHIBIT VII

SECTION 116: LEAK DETECTION AND REPAIR

Q. Ms. Nolting, please describe Kinder Morgan's comments on the leak detection and repair provisions set out in Section 116.

A. As discussed in detail in Kinder Morgan's Non-technical Statement, Congress recently used the Congressional Review Act to reinstate the methane oil and gas standards for new sources that EPA developed under President Obama and reinstate the application of these standards to th e transmission and storage sector.[29] Kinder Morgan believes that this change in the law should inform how the Board proceeds with its leak detection and repair regulation of transmission sources. Further, while the reinstated Obama-era rules apply only to new sources, EPA will be issuing a proposed rule in September 2021 to regulate existing sources in the oil and gas sector.[30] The result is that, as of June 30, 2021, sources constructed or modified after September 2015 within the transmission sector returned to being subject to the rigorous VOC and methane requirements, including leak detection requirements, set out in Subpart OOOOa. We expect that these requirements will be extended to sources constructed before September 2015 in the upcoming EPA rulemaking.

In light of these changes, we request that the Board revise the Proposed Rules to state that compliance with NSPS OOOO, OOOOa, or another NSPS subpart, as each may be revised,

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[29] S.J. Res. 14, available at https://www.congress.gov/bill/117th-congress/senate-joint-resolution/14/text; *see also* EPA, *Congressional Review Act Resolution to Disapprove EPA's 2020 Oil and Gas Policy Rule: Questions and Answers* (June 30, 2021), at 2–3, available at https://www.epa.gov/sites/production/files/2021-06/documents/qa_cra_for_2020_oil_and_gas_policy_rule.6.30.2021.pdf [hereinafter "EPA Q&A"].

[30] EPA Q&A, at 2. This action was brought on by an executive order signed by President Biden on his first day in office. *Executive Order on Protecting Public Health and the Environment and Restoring Science to Tackle the Climate Crisis* (Jan. 20, 2021), available at https://www.whitehouse.gov/briefing-room/presidential-actions/2021/01/20/executive-order-protecting-public-health-and-environment-and-restoring-science-to-tackle-climate-crisis/ (directing EPA to consider "proposing new regulations to establish comprehensive standards of performance and emission guidelines for methane and [VOC] emissions from existing operations in the oil and gas sector including the exploration and production, transmission, processing, and storage segments, by September 2021").

satisfies the requirements of Section 116. We have proposed a revision to Section 116 to this effect in the attached redline.

Our proposed revision is necessary for operational implementation reasons. It is extremely resource-intensive (with little to no emissions benefit) to manage compliance with two leak detection programs with differing requirements. This is because leak detection programs—including both the federal program and the Department's proposed Section 116—have numerous elements, each of which can differ in large and small ways from one program to the next. To illustrate, the following program details will almost certainly vary between leak detection programs: (1) the scope of the facilities that are subject to the program, (2) the effective date(s) of the program, (3) the list of approved monitoring instruments and the process for approving new technologies, and (4) fugitive emissions definitions, monitoring frequencies, repair and resurvey timelines, delay of repair provisions, and recordkeeping and reporting requirements. As a result, even if the federal program and a state program have the same monitoring frequencies, or if the state requires less frequent monitoring than the federal program, the difficulties of managing varying elements of the two programs creates significant work for operators with little to no emissions reduction benefit. This is not an efficient outcome.

Because of the technical difficulties in implementing two different and competing leak detection programs, we request that the board adopt rule language that allows a company to comply with NSPS OOOO or OOOOa (or the new NSPS developed this fall)—which again, I fully anticipate being more stringent than current regulation—to satisfy the requirements of Section 116.

Further, as I discussed earlier, Kinder Morgan's emissions profile is unique in industry. This is because the VOC content in our natural gas is lower. In turn, VOC emissions from fugitive sources at transmission compressor stations are de minimis. Kinder Morgan's fugitive VOC emissions from its compressor stations are typically below 1 tpy. For example, in the permit application for its Blanco Compressor Station A, which I, Leslie, have attached as ATTACHMENT Q, EPNG (a subsidiary of Kinder Morgan, Inc.) calculated that its fugitive VOC emissions from that compressor station were 0.057 tpy. ATTACHMENT Q, at Section 6.a (Fugitive Emissions (Insignificant Activity)). After adding a 100% safety factor to this figure, the total fugitive VOC PTE at this site was 0.13 tpy. *Id.* The resulting permit, which I have attached as ATTACHMENT R, lists the total facility-wide VOC PTE as 64.6 tpy. ATTACHMENT R, at Table 301.A. 54.3 tpy of that total is attributable to engines. *Id.* at PDF pp. 7–8, Table 305.A. Only 0.3 tpy are attributable to insignificant sources of emissions, comprising fugitive emissions (0.13 tpy), *see* ATTACHMENT Q, at Section 6.a (Fugitive Emissions (Insignificant Activity)), scrubber blowdown (0.15 tpy), *see id.* at Section 6.a (Scrubber Blowdown (Insignificant Activity)), and small heaters (0.01 tpy), *see id.* at Table 2-B.[31] The permit for this facility does not require Kinder Morgan to take action as to these fugitive emissions, underscoring their overall insignificance.

Given the stringency of the federal program and the low-VOC emissions profile of transmission sources, dedication of resources to comply with a New Mexico-specific leak detection program for the transmission segment is unnecessary. We respectfully request that the Board adopt the proposed revision to Section 116.A. of the redline attached as **Exhibit X**.

***Note**: At the hearing, Mr. Brindley and Mr. Trent will also be available to testify and answer any questions regarding leak detection and repair.*

[31] The total of 0.475 MMBtu/hr for these heaters translates to 0.01 tpy of VOC emissions by using AP-42 emission factor of 5.5 lb/MMscf and an assumed heat value of 900 Btu/scf.

ATTACHMENT Q

Blanco Compressor Station A Permit Application

[enclosed]

<u>ATTACHMENT R</u>

Blanco Compressor Station A Permit

[enclosed]

EXHIBIT VIII

SECTION 121: PIG LAUNCHING & RECEIVING

Q. Ms. Nolting, please describe Kinder Morgan's comments on Section 121 of the Proposed Rules.

A. Kinder Morgan supports NMOGA's comment that Section 121 should be removed in its entirety from the Proposed Rules because its inclusion is not supported by the Department's own emissions reductions data. Additionally, certain unique aspects of transmission operations that make the potential monthly monitoring requirement particularly ill-suited for such operations. *See* Section 121.C.(4) ("The owner or operator shall comply with the monitoring requirements in 20.2.50.112 NMAC."); Section 112.B.(1) ("Sources subject to emission standards and 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.").[32]

Kinder Morgan uses "mechanical cleaning" pigs to remove liquids that may accumulate in the pipelines that transport natural gas, and, as required by PHMSA, uses "smart pigs" to detect anomalies and the integrity of its pipelines. As discussed above, because transmission lines move pipeline quality natural gas, which contains fewer liquids, transmission lines are pigged infrequently. This is different from midstream gathering lines, which contain more liquids than transmission lines. Gathering lines in some areas might be pigged on a weekly or even a daily basis. By contrast, Kinder Morgan sometimes mechanically pigs its pipelines annually, and at least every three years, for maintenance purposes. Typically, we also do an in-line "smart pig" inspection once every five to seven years. As a result, monthly monitoring of our pigging operations is unnecessary and would be cost-ineffective.

To reflect the fact that different operations conduct pigging at very different frequencies, and to the extent that the Board retains Section 121, Kinder Morgan proposes revised frequencies

[32] Whether the incorporation of Section 112 is intended to impose a monthly monitoring requirement is unclear. Our proposed changes in **Exhibit X** are intended to improve the clarity of this section.

for audio, visual, and olfactory; EPA reference method 21; or optical gas imaging inspections of pig launching and receiving sites. These revisions are reflected in **Exhibit X**.

***Note**: At the hearing, Mr. Brindley and Mr. Trent will also be available to testify and answer any questions regarding pig launching and receiving.*

EXHIBIT IX

SECTION 114: COMPRESSOR SEALS

Q. Vincent Brindley, please describe Kinder Morgan's comments on Section 114, relating to compressor seals.

A. Kinder Morgan supports NMOGA in its request and recommendation that Section 114, addressing compressor seals, be removed from the Proposed Rule. According to technical analysis produced by NMED's consultant, VOC emissions from compressor seals is estimated 13 tpy, comprising at 0.006% of the total VOC emissions from the sources evaluated. Draft Memorandum from Mike Pring, Brian Palmer, and Stephen Treimel of Eastern Research Group, Inc. to Elizabeth Kuehn, of NMED Air Quality Bureau dated June 4, 2021 regarding Emissions Inventory Reductions, at 2, tbl. 2. In turn, application of the Proposed Rules is estimated to reduce the 13 tpy total VOC emissions by 6 tpy. *Id*. We recognize that the NMED cites to the limitations of the state's inventory to explain these low values. It is unclear, however, what improvements in methodology or what additional data would result in a level of VOC emissions from compressor seals that justifies regulation.

Furthermore, data indicates that well-maintained wet seals will have an emission rate that is comparable to or less than dry seals. A recent paper published by Pipeline Research Council International, Inc. provides a current best-estimate of transmission and storage compressors emissions, in an effort to update emission estimates in the EPA Annual GHG Inventory Report, and to provide EPA with an analysis of measured compressor emissions for Subpart W. The paper compiled centrifugal compressor methane emissions from wet seal systems measured as required per the Greenhouse Gas Reporting Rule between 2011 and 2016. The analysis found emissions from centrifugal units with wet seal systems were vastly lower than historical estimates, resulting in 7,730 scf of natural gas per day. *See* T. McGrath et al., *PRCI White Paper: Methane Emission Factors for Compressors in Natural Gas Transmission and Underground Storage based on*

Subpart W Measurement Data, Catalogue No.PR-312-18209-E01, at 47, Tbl. 4-1 (Oct. 17, 2019), available for purchase at https://www.prci.org/Research/CompressorPumpStation/CPSProjects/CPS-17-01A/142206/171289.aspx. Based on a representative average VOC content of less than 1% by weight in the transmission segment, this equates to 0.6 tons of VOC released per year/unit. Because wet seal and dry seal systems are similarly situated, regulation of wet seals in the transmission segment as proposed by NMED is unsupported, and NMED provides no data supporting its proposed performance standards for these units.

Compounding the fact that compressor seals are a de minimis source of potential emissions, the cost estimates for replacing wet seals with dry seals (which would be the likely outcome for Kinder Morgan's assets) are unreasonable. Kinder Morgan evaluated the cost to add dry gas seals to Solar Saturn Units at two locations that would be subject to the Proposed Rules. The conversion would require detailed engineering, upgrading the compressor, upgrading control systems, making skid modifications, procuring the necessary interconnect hardware, and installing and commissioning labor. The conversion totals approximately $1,400,000 per unit. That value as compared to the anticipated emissions reductions is cost-ineffective.

Finally, conversion of a wet seal to a dry seal can cause potential negative implications that generate additional costs. In particular, one of the benefits of a wet seal system is that it maintains built-in damping for the compressor seals to limit or eliminate vibrations. When the unit is converted to a dry seal, the damping benefit is lost. As a result, Kinder Morgan would have to evaluate and study the system and potentially make other modifications to the compressor to avoid unsafe vibration issues. Kinder Morgan respectfully requests the Board strike Section 114 from the Proposed Rules, or, in the alternative, that the Board eliminate transmission compressor stations from the applicability of this section.

***Note**: At the hearing, Ms. Nolting and Mr. Trent will also be available to testify and answer any questions regarding compressor seals.*

EXHIBIT X

PROPOSED REDLINE

[attached]

TITLE 20 ENVIRONMENTAL PROTECTION
CHAPTER 2 CHAPTER 2 AIR QUALITY (STATEWIDE)
PART 50 OIL AND GAS SECTOR – OZONE PRECURSOR POLLUTANTS

20.2.50.1 ISSUING AGENCY: Environmental Improvement Board. [20.2.50.1 NMAC–N, XX/XX/2021]

20.2.50.2 SCOPE: 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~~ Part~~or anytime thereafter~~, have ~~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 of the effective date, sources located in the following counties of the state are subject to this Part: Dona Ana, Eddy, Lea, Rio Arriba, Sandoval, San Juan, and Valencia.

A. If, at any time after the effective date, any area any area in the state is determined by the department to have exceeded 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, the department shall revise this rule to incorporate such areas consistent with Sections 74-1-9 and 74-2-6 NMSA. The notice of proposed rulemaking shall be published no less than one hundred and eighty (180) days before the sources in the affected area will become subject to this Part and shall include the monitoring, testing, or inspection data, and all other technical information, that demonstrate that the area or areas that is (are) the subject(s) of the proposed rulemaking exceed ninety-five percent of the national ambient air quality standard for ozone.

(1) The proposed rule revision shall include, in addition to the requirements of 20.1.1.301.B. NMAC .

(a) a list of the areas that the board proposes to become subject to this Part, and the date upon which the sources in the relevant area (or areas) will become subject to this Part; and

(b) proposed implementation dates, consistent with the time provided in the phased implementation schedules provided for in each Section of this Part, for sources within the area or areas that is (are) the subject(s) of the proposed rulemaking to come into compliance with each Section of this Part

B. Once a source becomes subject to this rule based upon potential to emit, any of the requirements of the rule based on potential to emit are irrevocably effective unless the source obtains a federally enforceable, or legally and practically enforceable limit on ~~air permit limiting~~ the potential to emit to below such applicability thresholds established in this Part, or the relevant section contains a threshold below which the requirements no longer apply. [20.2.50.2 NMAC-N, XX/XX/2021].

[The above revision to Section B is intended to (1) ensure consistency with the federal interpretation of federal enforceability; and (2) remedy contradictions with other rule sections that state a unit is not subject to the rule if it falls below the enumerated threshold.]

20.2.50.3 **STATUTORY AUTHORITY**: Environmental Improvement Act, Section 74-1-1 to 74-1-16 NMSA 1978, including specifically Paragraph (4) and (7) of Subsection A of Section 74-1-8 NMSA 1978, and Air Quality Control Act, Sections 74-2-1 to 74-2-22 NMSA 1978, including specifically Subsections A, B, C, D, F, and G of Section 74-2-5 NMSA 1978 (as amended through 2021). [20.2.50.3 NMAC-N, XX/XX/2021]

20.2.50.4 **DURATION**: Permanent. [20.2.50.4 NMAC-N, XX/XX/2021]

20.2.50.5 **EFFECTIVE DATE**: Month XX, ~~2021~~2022, except where a later date is specified in another Section. [20.2.50.5 NMAC-N, XX/XX/2021]

20.2.50.6 **OBJECTIVE**: The objective of this Part is to establish emission standards for volatile organic compounds (VOC) and oxides of nitrogen (NOx) for oil and gas production, processing, and natural gas transmission sources. [20.2.50.6 NMAC-N, XX/XX/2021]

[In addition to the revisions included in the following Proposed Rule section (20.2.50.7 – Definitions), Kinder Morgan supports and incorporates by reference the revisions to definitions submitted by NMOGA.]

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.

C. "**Approved instrument monitoring method**" means an optical gas imaging, United States environmental protection agency (U.S. EPA) reference method 21 (RM21) (40 CFR 60, Appendix B), or other instrument-based monitoring method or program approved by the department in advance and in accordance with 20.2.50 NMAC.

D. "**Auto-igniter**" means a device that automatically attempts to relight the pilot flame in the combustion chamber of a control device in order to combust VOC emissions, or a device that will automatically attempt to combust the VOC emission stream.

E. "**Bleed rate**" means the rate in standard cubic feet per hour at which natural gas is continuously or intermittently vented from a pneumatic controller.

F. "**Calendar year**" means a year beginning January 1 and ending December 31.

G. "**Centrifugal compressor**" means a machine used for raising the pressure of natural gas by drawing in low-pressure natural gas and discharging significantly higher-pressure natural gas by means of a mechanical rotating vane or impeller. Screw, sliding vane, and liquid ring compressor is not a centrifugal compressor.

H. "**Closed vent system**" means a system that is designed, operated, and maintained to route the VOC emissions from a source or process to a process stream or control device with no loss of VOC emissions to the atmosphere.

I. **"Commencement of operation**" means for an oil and natural gas wellhead, the date any permanent production equipment is in use and product is consistently flowing to a sales lines, gathering line or storage vessel from the first producing well at the stationary source, but no later than the end of well completion operation.

J. "**Component**" means a pump seal, flange, pressure relief device (including thief hatch or other opening on a storage vessel), connector or valve that contains or contacts a process stream with hydrocarbons, except for components where process streams consist solely of glycol, amine, produced water or methanol.

K. "**Connector**" means flanged, screwed, or other joined fittings used to connect pipe line segments, tubing, pipe components (such as elbows, reducers, "T's" or valves) to each other; or a pipe line to a piece of equipment; or an instrument to a pipe, tube or piece of equipment. A common connector is a flange. Joined fittings welded completely around the circumference of the interface are not considered connectors for the purpose of this Part.

L. “**Construction**” means fabrication, erection, installation or relocation of a stationary source, including but not limited to temporary installations and portable stationary sources.

M. “**Custody transfer**” means the transfer of oil or natural gas after processing or treatment in the producing operation, or from a storage vessel or automatic transfer facility or other processing or treatment equipment including product loading racks, to a pipeline or any other form of transportation.

N. “**Control device**” means air pollution control equipment or emission reduction technologies that thermally combust, chemically convert, or otherwise destroy or recover air contaminants. Examples of control devices include but are not limited to open flares, enclosed combustion devices (ECDs), thermal oxidizers (TOs), vapor recovery units (VRUs), fuel cells, condensers, air fuel ratio controllers (AFRs), catalytic converters (oxidative, selective, and non-selective), or other emission reduction equipment. A control device may also include any other air pollution control equipment or emission reduction technologies approved by the department to comply with emission standards in this Part.

O. “**Department**” means the New Mexico environment department.

P. “**Downtime**” means the period of time when equipment is not in operation, or when a well is producing, and the control device is not in operation.

Q. “**Enclosed combustion device**” means a combustion device where gaseous fuel is combusted in an enclosed chamber. This may include, but is not limited to an enclosed flare, reboiler, and heater.

R. “**Existing**” means constructed or reconstructed before the effective date of this Part and has not since been modified or reconstructed.

S. “**Gathering and boosting ~~station~~site**” means a permanent combination of equipment located downstream of a well production facility that collects or moves natural gas prior to the inlet of a natural gas processing plant or prior to a natural gas transmission pipeline or transmission compressor station if no gas processing is performed~~,~~ ~~crude oil, condensate, or produced water between a wellhead site and a midstream oil and natural gas collection or distribution facility, such as a storage vessel battery or compressor station, or into or out of storage~~. A gathering and boosting site also means a permanent combination of equipment located downstream of a well production facility that collects, moves, or stabilizes crude oil or condensate prior to an oil transmission pipeline or other form of transportation.

T. “**Glycol dehydrator**” means a device in which a liquid glycol absorbent, including ethylene glycol, diethylene glycol, or triethylene glycol, directly contacts a natural gas stream and absorbs water.

U. “**Hydrocarbon liquid**” means any naturally occurring, unrefined petroleum liquid and can include oil, condensate, and intermediate hydrocarbons.

V. “**Liquid unloading**” means the removal of accumulated liquid from the wellbore that reduces or stops natural gas production.

W. “**Liquid transfer**” means the loading and unloading of a hydrocarbon liquid or produced water between a storage vessel and tanker truck or tanker rail car for transport.

X. “**Local distribution company custody transfer station**” means a metering station where the local distribution (LDC) company receives a natural gas supply from an upstream supplier, which may be an interstate transmission pipeline or a local natural gas producer, for delivery to customers through the LDC’s intrastate transmission or distribution lines.

Y. “**~~Natural gas~~Transmission compressor station**” means any permanent installation of one or more compressors that move ~~designed to compress~~pipeline quality natural gas at increased pressures from production fields or ~~well pressure to gathering system pressure before the inlet of a~~ natural gas processing plants, ~~or to move compressed natural gas~~ through a transmission pipeline for ultimate delivery to the local distribution company custody transfer station, into underground storage, or to other industrial end users.

Z. "**Natural gas-fired heater**" means an enclosed device using a controlled flame and with a primary purpose to transfer heat directly to a process material or to a heat transfer material for use in a process.

AA. "**Natural gas processing plant**" means the processing equipment engaged in the extraction of natural gas liquid from natural gas or fractionation of mixed natural gas liquid to a natural gas product, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

BB. "**New**" means constructed or reconstructed on or after the effective date of this Part.

CC. "**Operator**" means the person or persons responsible for the overall operation of a stationary source.

DD. "**Optical gas imaging (OGI)**" means an imaging technology that utilizes a high-sensitivity infrared camera designed for and capable of detecting hydrocarbons.

EE. "**Owner**" means the person or persons who own a stationary source or part of a stationary source.

FF. "**Permanent pit**" means a pit used for collection, retention, or storage of produced water or brine and is installed for longer than one year.

GG. "**Pneumatic controller**" means an 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.

HH. "**Pneumatic diaphragm pump**" means a positive displacement pump powered by pressurized natural gas that uses the reciprocating action of flexible diaphragms in conjunction with check valves to pump a fluid. A pump in which a fluid is displaced by a piston driven by a diaphragm is not considered a diaphragm pump. A lean glycol circulation pump that relies on energy exchange with the rich glycol from the contactor is not considered a diaphragm pump.

II. "**Potential to emit (PTE)**" means the maximum capacity of a stationary source to emit an air contaminant under its physical and operational design. The physical or operational limitation on the capacity of a source to emit an air pollutant, including air pollution control equipment and a restriction on the hours of operation or on the type or amount of material combusted, stored or processed, shall be treated as part of its design if the limitation is federally enforceable. The PTE for nitrogen dioxide shall be based on total oxides of nitrogen.

JJ. "**Produced water**" means a fluid that is an incidental byproduct from drilling for or the production of oil and gas.

KK. "**Produced water management unit**" means a recycling facility or a permanent pit that is a natural topographical depression, man-made excavation, or diked area formed primarily of earthen materials (although it may be lined with man-made materials), which is designed to accumulate produced water and has a design storage capacity equal to or greater than 50,000 barrels.

LL. "**Qualified Professional Engineer**" means an individual who is licensed by a state as a professional engineer to practice one or more disciplines of engineering and who is qualified by education, technical knowledge, and experience to make the specific technical certifications required under this Part.

MM. "**Reciprocating compressor**" means a piece of equipment that increases the pressure of process gas by positive displacement, employing linear movement of a piston rod.

NN. "**Reconstruction**" means a modification that results in the replacement of the components or addition of integrally related equipment to an existing source, to such an extent that the fixed capital cost of the new components or equipment exceeds fifty percent of the fixed capital cost that would be required to construct a comparable entirely new facility.

OO. "**Recycling facility**" means a stationary or portable facility used exclusively for the treatment, re-use, or recycling of produced water and does not include oilfield equipment such as separators, heater treaters, and scrubbers in which produced water may be used.

PP. "**Responsible official**" means one of the following:

(1) for a corporation: president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of the corporation if the representative is responsible for the overall operation of the source.

(2) for a partnership or sole proprietorship: a general partner or the proprietor, respectively.

QQ. "**Small business facility**" means, for the purposes of this Part, a source that is independently owned or operated by a company that is a 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.

RR. "**Startup**" means the setting into operation of air pollution control equipment or process equipment.

SS. "**Stationary Source**" or "**source**" means any building, structure, equipment, facility, installation (including temporary installations), operation, process, or portable stationary source that emits or may emit any air contaminant. Portable stationary source means a source that can be relocated to another operating site with limited dismantling and reassembly.

TT. "**Storage vessel**" means a single tank or other vessel that is designed to contain an accumulation of hydrocarbon liquid or produced water and is constructed primarily of non-earthen material including wood, concrete, steel, fiberglass, or plastic, which provide structural support, or a process vessel such as a surge control vessel, bottom receiver, or knockout vessel. A well completion vessel that receives recovered liquid from a well after commencement of operation for a period that exceeds 60 days is considered a storage vessel. A storage vessel does not include a vessel that is skid-mounted or permanently attached to a mobile source and located at the site for less than 180 consecutive days, such as a truck railcar, or a pressure vessel designed to operate in excess of 204.9 kilopascals without emissions to the atmosphere.

UU. "**Well workover**" means the repair or stimulation of an existing production well for the purpose of restoring, prolonging, or enhancing the production of hydrocarbons.

VV. "**Wellhead site**" means the equipment directly associated with one or more oil wells or natural gas wells upstream of the natural gas processing plant. A wellhead site may include equipment used for extraction, collection, routing, storage, separation, treating, dehydration, artificial lift, combustion, compression, pumping, metering, monitoring, and product piping. [20.2.50.7 NMAC-N, XX/XX/2021]

20.2.50.8 SEVERABILITY: If any provision of this Part, or the application of this provision to any person or circumstance is held invalid, the remainder of this Part, or the application of this provision to any person or circumstance other than those as to which it is held invalid, shall not be affected thereby. [20.2.50.8 NMAC-N, XX/XX/2021]

20.2.50.9 CONSTRUCTION: This Part shall be liberally construed to carry out its purpose. [20.2.50.9 NMAC-N, XX/XX/2021]

20.2.50.10 SAVINGS CLAUSE: Repeal or supersession of prior versions of this Part shall not affect administrative or judicial action initiated under those prior versions. [20.2.50.10 NMAC-N, XX/XX/2021]

20.2.50.11 COMPLIANCE WITH OTHER REGULATIONS: Compliance with this Part does not relieve a person from the responsibility to comply with other applicable federal, state, or local laws, rules or regulations, including more stringent controls. [20.2.50.11 NMAC-N, XX/XX/2021]

20.2.50.12 DOCUMENTS: Documents incorporated and cited in this Part may be viewed at the New Mexico environment department, air quality bureau. [20.2.50.12 NMAC-N, XX/XX/2021] [The Air Quality Bureau is located at 525 Camino de los Marquez, Suite 1, Santa Fe, New Mexico 87505.]

0.2.23.13-20.2.23.110 [RESERVED]

0.2.50.111 APPLICABILITY:

A. This Part applies 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 but not including the local distribution company custody transfer station.

B. In determining if any source 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 and transmission pipelines are not subject to this Part. [20.2.50.111 NMAC-N, XX/XX/2021]

20.2.50.112 GENERAL PROVISIONS:

[Kinder Morgan supports and incorporates by reference the proposed revisions to 20.2.50.112 (General Provisions) submitted by NMOGA.]

* * *

20.2.50.113 ENGINES AND TURBINES:

[In addition to the revisions included in the following Proposed Rule section (20.2.50.113 – Engines and Turbines), Kinder Morgan supports and incorporates by reference the revisions submitted by NMOGA.]

A. Applicability: Portable and stationary natural gas-fired spark ignition engines, compression ignition engines, and natural gas-fired combustion turbines located in areas of the State specified in 20.2.50.2 NMAC at wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations, with a rated horsepower greater than the horsepower ratings of Table 1, 2, and 3 of 20.2.50.113 NMAC are subject to the requirements of 20.2.50.113 NMAC.

B. Emission standards:

(1) The owner or operator of a portable or stationary natural gas-fired spark-ignition engine, compression ignition engine, or natural gas-fired combustion turbine shall ensure compliance with the emission standards by the dates specified in Subsection B of 20.2.50.113 NMAC.

(2) The owner or operator of an existing natural gas-fired spark-ignition engine shall complete an inventory of all existing engines subject to this Part 50 by January 1, 2023, and shall prepare a schedule to ensure that each existing engine does not exceed the emission standards in table 1 of Paragraph (2) of Subsection B of 20.2.50.113 NMAC as follows:

(a) by January 1, 2025, the owner or operator shall ensure at least thirty percent of the company's existing engines meet the emission standards.

(b) by January 1, 2027, the owner or operator shall ensure at least an additional thirty-five percent of the company's existing engines meets the emission standards.

(c) by January 1, 2029, the owner or operator shall ensure that the remaining thirty-five percent of the company's existing engines meets the emission standards.

(d) in lieu of meeting the emission standards for an existing natural gas-fired spark ignition engine, an owner or operator may reduce the annual hours of operation of an engine such that the annual PTE for NOx and VOC emissions are reduced to achieve an equivalent allowable ton per year emission as set forth in Table 1 of Paragraph (2) of Section B of 20.2.50.113 NMAC or by at least ninety-five percent per year.

(e) Owners or operators of an existing natural gas-fired spark-ignition engine are not required to comply with the emissions standards specified in table 1 of Subsection B of 20.2.30.113 NMAC if the owner or operator demonstrates that the emissions standard is technically impracticable or economically unreasonable. Installation and maintenance costs and the best information available for determining technically practicable retrofit technology and control efficiency shall be considered. Owners or operators that seek to rely on this exemption must submit a justification for the technical impracticability or economic unreasonableness to the department for approval no less than ninety (90) days prior to the applicable compliance date set forth in the schedule in Paragraph (2) of Subsection B of 20.2.50.113 NMAC. If the department does not respond to the justification within forty-five (45) days after submission of the justification, the justification will be deemed approved.

(f) Any of the effective dates for the emissions standards set forth in Paragraph (2) of Subsection B of 20.2.50.113 NMAC may be extended at the Department's discretion for good cause shown.

Table 1 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES CONSTRUCTED OR~~,~~ RECONSTRUCTED~~, OR INSTALLED~~ BEFORE THE EFFECTIVE DATE OF 20.2.50 NMAC.

~~Engine Type~~	~~Rated bhp~~	~~NOx~~	~~CO~~	~~NMNEHC (as propane)~~
~~Lean-burn~~	~~>1,000~~	~~0.50 g/bhp-hr~~	~~47 ppmvd @ 15% O2 or 93% reduction~~	~~0.70 g/bhp-hr~~
~~Rich-burn~~	~~>1,000~~	~~0.50 g/bhp-hr~~	~~0.60 g/bhp-hr~~	~~0.70 g/bhp-hr~~

Maximum Engine BHP	Emission Standards (g/bhp-hr)		
	NOx	CO	VOC
4 Stroke Lean Burn engines >1000 bhp (4-stroke)	2.0	2.0	0.7

2-Stroke Lean Burns >1000 bhp	3.0	2.0	0.7
All Rich Burn engines > 1000 bph	0.5	0.6	0.7

(3) The owner or operator of a new natural gas-fired spark ignition engine shall ensure the engine does not exceed the emission standards in table 2 of Paragraph (3) of Subsection B of 20.2.50.113 NMAC upon startup.

Table 2 - EMISSION STANDARDS FOR NATURAL GAS-FIRED SPARK-IGNITION ENGINES CONSTRUCTED~~,~~ OR RECONSTRUCTED~~,~~ ~~OR INSTALLED~~ AFTER THE EFFECTIVE DATE OF 20.2.50 NMAC.

~~Engine Type~~	~~Rated bhp~~	~~NOx~~	~~CO~~	~~NMNEHC (as propane)~~
~~Lean-burn~~	~~>500 - <1,000~~	~~0.50 g/bhp-hr~~	~~0.60 g/bhp-hr~~	~~0.70 g/bhp-hr~~
~~Lean-burn~~	~~≥1,000~~	~~0.30 g/bhp-hr uncontrolled or 0.05 g/bhp-hr with control~~	~~0.60 g/bhp-hr~~	~~0.70 g/bhp-hr~~
~~Rich-burn~~	~~>500~~	~~0.50 g/bhp-hr~~	~~0.60 g/bhp-hr~~	~~0.70 g/bhp-hr~~

Engine Type	Engine (bhp)	Emissions (g/bhp-hr)		
		NOx	CO	VOC
4-Stroke Lean Burn engines	>1000 bhp and ≤ 2370	0.7	2.0	0.7
4-Stroke Rich Burn engines	>1000 bhp and ≤ 2370	0.5	2.0	0.7
All engines	>2370 bhp	0.3	2.0	0.7

(4) The owner or operator of a natural gas-fired spark ignition engine with NOx emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(5) The owner or operator of a compression ignition engine shall ensure compliance with the following emission standards:

(a) a new portable or stationary compression ignition engine with a maximum design power output equal to or greater than 500 horsepower that is not subject to the emission standards under Subparagraph (b) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC shall limit NOx emissions to not more than nine g/bhp-hr upon startup.

(b) a stationary compression ignition engine that is subject to and complying with Subpart IIII of 40 CFR Part 60, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, is not subject to the requirements of Subparagraph (a) of Paragraph (5) of Subsection B of 20.2.50.113 NMAC.

(6) The owner or operator of a portable or stationary compression ignition engine with NOx emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

(7) The owner or operator of a stationary natural gas-fired combustion turbine with a maximum design rating equal to or greater than 1,000 bhp shall comply with the applicable emission standards for an existing, new, or reconstructed turbine listed in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC.

(a) The owner or operator of an existing stationary natural gas-fired combustion turbine shall complete an inventory of all existing turbines subject to this Part 50 by July 1, 2022, and shall prepare a schedule to ensure that each subject existing turbine does not exceed the emission standards in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC except as approved through an alternative Compliance Plan per 20.2.50.113 B.9 as follows:

(i) by January 1, 2025, the owner or operator shall ensure at least thirty percent of the company's existing turbines meet the emission standards.

(ii) by January 1, 2027, the owner or operator shall ensure at least an additional thirty-five percent of the company's existing turbines meets the emission standards.

(iii) by January 1, 2029, the owner or operator shall ensure that the remaining thirty-five percent of the company's existing turbines meets the emission standards.

(iv) in lieu of meeting the emission standards for an existing stationary natural gas-fired combustion turbine, an owner or operator may reduce the annual hours of operation of a turbine such that the annual PTE for NOx and VOC emissions are reduced to achieve an equivalent ton per year emission reduction as set forth in table 3 of Paragraph (7) of Subsection B of 20.2.50.113 NMAC or by at least ninety-five percent per year.

(v) Owners or operators of an existing natural gas-fired combustion turbine are not required to comply with the emissions standards specified in table 3 of Subsection B of 20.2.30.113 NMAC if the owner or operator demonstrates that the emissions standard is technically impracticable or economically unreasonable. Installation and maintenance costs and the best information available for determining technically practicable retrofit technology and control efficiency shall be considered. Owners or operators that seek to rely on this exemption must submit a justification for the technical impracticability or economic unreasonableness to the department for approval no less than ninety (90) days prior to the applicable compliance date set forth in the schedule in Paragraph (7)(a) of Subsection B of 20.2.50.113 NMAC. If the department does not respond to the justification within forty-five (45) days after submission of the justification, the justification will be deemed approved.

(vi) Any of the effective dates for the emissions standards set forth in Paragraph (7) of Subsection B of 20.2.50.113 NMAC may be extended at the Department's discretion for good cause shown.

Table 3 - EMISSION STANDARDS FOR STATIONARY COMBUSTION TURBINES

<table>
<tr><td colspan="4">For each natural gas-fired combustion turbine constructed or reconstructed and installed before the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards no later than the schedule set forth in Paragraph (7)(a) of Subsection B of 20.2.50.113 NMAC:</td></tr>
<tr><td>Turbine Rating (bhp)</td><td>NOx (ppmvd @15% O2)</td><td>CO (ppmvd @ 15% O2)</td><td>NMNEHC (as propane, ppmvd @15% O2)</td></tr>
<tr><td>≥~~1~~4,000 and <5,000</td><td>50</td><td>50</td><td>9</td></tr>
<tr><td>≥5,000 and <15,000</td><td>50</td><td>50</td><td>9</td></tr>
<tr><td>≥15,000</td><td>50</td><td>50 or 93% reduction</td><td>5 or 50% reduction</td></tr>
<tr><td colspan="4">For each natural gas-fired combustion turbine constructed or reconstructed and installed on or after the effective date of 20.2.50 NMAC, the owner or operator shall ensure the turbine does not exceed the following emission standards upon startup:</td></tr>
<tr><td>Turbine Rating (bhp)</td><td>NOx (ppmvd @15% O2)</td><td>CO (ppmvd @ 15% O2)</td><td>NMNEHC (as propane, ppmvd @15% O2)</td></tr>
</table>

≥~~1~~4,000 and <5,000	25	25	9
≥5,000 and <15,900	15	10	9
≥15,900	9.0 Uncontrolled or 2.0 with NOx Control post-combustion	10 Uncontrolled or 1.8 with NOx Control post-combustion	5

~~(7)~~(8) The owner or operator of a stationary natural gas-fired combustion turbine with NOx emission control technology that uses ammonia or urea as a reagent shall ensure that the exhaust ammonia slip is limited to 10 ppmvd or less, corrected to fifteen percent oxygen.

~~(8)~~(9) The owner or operator of an engine or turbine shall install an EMT on the engine or turbine in accordance with 20.2.50.112 NMAC.

~~(9)~~(10) The owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675~~that is operated less than 100 hours per year~~ is not subject to the emissions standards in this Part but shall be equipped with a non-resettable hour meter to monitor and record any hours of operation.

C. Monitoring requirements:

(1) Maintenance and repair for a spark-ignition engine, compression-ignition engine, and stationary combustion turbine subject to an emission standard in Subsection B of 20.2.50.113 shall be consistent with ~~meet~~ the minimum manufacturer recommended maintenance schedule or good engineering and maintenance practices. The following maintenance, adjustment, replacement, or repair events for engines and turbines shall be documented as they occur:

(a) routine maintenance that takes a unit out of service for more than two hours during any 24-hour period; and

(b) unscheduled repairs that require a unit to be taken out of service for more than two hours during any 24-hour period.

(2) Catalytic converters (oxidative, selective and non-selective) and AFR controllers shall be maintained according to good engineering and maintenance practices or manufacturer or supplier recommended maintenance schedules, including replacement of oxygen sensors as necessary for oxygen-based controllers. During periods of catalytic converter or AFR controller maintenance, the owner or operator shall shut down the engine or turbine until the catalytic converter or AFR controller can be replaced with a functionally equivalent spare to allow the engine or turbine to return to operation.

(3) For equipment operated for 500 hours per year or more, compliance with the emission standards in Subsection B of 20.2.50.113 NMAC shall be demonstrated by performing an initial emissions test, followed by annual tests, for NOx, CO, and non-methane non-ethane hydrocarbons (NMNEHC) using a portable analyzer or U.S. EPA reference method. For units with g/hp-hr emission standards, the engine load shall be calculated using the following equations:

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (scf/hr) x Measured fuel heating value (LHV btu/scf)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

$$\text{Load (Hp)} = \frac{\text{Fuel consumption (gal/hr) x Measured fuel heating value (LHV btu/gal)}}{\text{Manufacturer's rated BSFC (btu/bhp-hr) at 100\% load or best efficiency}}$$

Where: LVH = lower heating value, btu/scf, or btu/gal, as appropriate; and
BSFC = brake specific fuel consumption. If the manufacturer's rated BSFC is not available, an operator may use an alternate load calculation methodology based on available data

[Regarding the above proposed revision, in Kinder Morgan's experience, this specific manufacturer's data is not available for most units older than 2000. Thus, an alternate calculation must be allowed. BSFC is regularly determined through current engineering practices and does not rely on manufacturer's rate.]

(a) emissions testing events shall be conducted at ninety percent or greater of the unit's capacity. If the ninety percent capacity cannot be achieved, the monitoring and testing shall be conducted at the maximum achievable capacity or load under prevailing operating conditions. The load and the parameters used to calculate it shall be recorded to document operating conditions at the time of testing and shall be included with the test report.

(b) emissions testing utilizing a portable analyzer shall be conducted in accordance with the requirements of the current version of ASTM D 6522. If a portable analyzer has met a previously approved department criterion, the analyzer may be operated in accordance with that criterion until it is replaced.

(c) the default time period for a test run shall be at least 20 minutes.

(d) an emissions test shall consist of three separate runs, with the arithmetic mean of the results from the three runs used to determine compliance with the applicable emission standard.

(e) during emissions tests, pollutant and diluent concentration shall be monitored and recorded. Fuel flow rate shall be monitored and recorded if stack gas flow rate is determined utilizing U.S. EPA reference method 19. This information shall be included with the periodic test report.

(f) stack gas flow rate shall be calculated in accordance with U.S. EPA reference method 19 utilizing fuel flow rate (scf) determined by a dedicated fuel flow meter and fuel heating value (Btu/scf). The owner or operator shall provide a contemporaneous fuel gas analysis (preferably on the day of the test, but no earlier than three months before the test date) and a recent fuel flow meter calibration certificate (within the most recent quarter) with the final test report. Alternatively, stack gas flow rate may be determined by using U.S. EPA reference methods 1 through 4 or through the use of manufacturer provided fuel consumption rates.

(g) upon request by the department, an owner or operator shall submit a notification and protocol for an initial or annual emissions test.

(h) emissions testing shall be conducted at least once per calendar year. Emission testing required by Subparts GG, IIII, JJJJ, or KKKK of 40 CFR 60, or Subpart ZZZZ of 40 CFR 63, may be used to satisfy the emissions testing requirements if it meets the requirements of 20.2.50.113 NMAC and is completed at least once per calendar year.

(4) The owner or operator of equipment operated less than 500 hours per year shall monitor the hours of operation using a non-resettable hour meter and shall test the unit at least once per 8760 hours of operation in accordance with the emissions testing requirements in Paragraph (3) of Subsection C of 20.2.50.113 NMAC.

(5) An owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675 ~~operated for less than 100 hours per year~~ shall monitor the hours of operation by a non-resettable hour meter.

(6) An owner or operator limiting the annual operating hours of an engine to meet the requirements of Paragraph (2) or Paragraph (7) of Subsection B of 20.2.50.113 NMAC shall monitor the hours of operation by a non-resettable hour meter.

(7) Prior to monitoring, testing, inspection, or maintenance of an engine or turbine, the owner or operator shall scan the EMT, and the monitoring data entry shall be made in accordance with the requirements of 20.2.50.112 NMAC.

D. Recordkeeping requirements:

(1) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain a record in accordance with 20.2.50.112 NMAC for the engine or turbine. The record shall include:

(a) the make, model, serial number, and EMT for the engine or turbine;

(b) a copy of the maintenance and repair schedule for the engine, turbine, or control device as recommended by the manufacturer ~~recommended maintenance and repair schedule~~or as developed consistent with good engineering and maintenance practices;

(c) all inspection, maintenance, or repair activity on the engine, turbine, and control device, including:

(i) the date and time of an inspection, maintenance or repair;

(ii) the date a subsequent analysis was performed (if applicable);

(iii) the name of the personnel conducting the inspection, maintenance or repair;

(iv) a description of the physical condition of the equipment as found during the inspection;

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

(vi) the results of the inspection and any required corrective actions.

(2) The owner or operator of a spark ignition engine, compression ignition engine, or stationary combustion turbine shall maintain records of initial and annual emissions testing for the engine or turbine. The records shall include:

(a) the make, model, serial number, and EMT for the tested engine or turbine;

(b) the date and time of sampling or measurements;

(c) the date analyses were performed;

(d) the name of the personnel and the qualified entity that performed the analyses;

(e) the analytical or test methods used;

(f) the results of analyses or tests;

(g) for equipment operated less than 500 hours per year, the total annual hours of operation as recorded by the non-resettable hour meter; and

(h) operating conditions at the time of sampling or measurement.

(3) The owner or operator of an emergency use engine as defined by 40 C.F.R. §§ 60.4211, 60.4243, or 63.6675 ~~operated less than 100 hours per year~~ shall record the total annual hours of operation as recorded by the non-resettable hour meter.

(4) The owner or operator limiting the annual operating hours of an engine to meet the requirements of Paragraph (2) or Paragraph (7) of Subsection B of 20.2.50.113 NMAC shall record the hours of operation by a non-resettable hour meter. The owner or operator shall calculate and record the annual NOx and VOC emission calculation, based on the engine's actual hours of operation, to demonstrate the ninety-five percent emission reduction requirement is met.

(5) An owner or operator claiming an exemption under Paragraph 2(e) or Paragraph (7)(a)(v) of Subsection B of 20.2.50.113 must maintain records for each engine or turbine, as applicable, demonstrating that the exemption applies.

~~**(4)**~~**(6)** An owner operator that received an extension of the effective dates for an emissions standards set forth in Paragraph (2) or Paragraph (7) of Subsection B of 20.2.50.113 NMAC must maintain records of the extension for good cause shown.

E. Reporting requirements: The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC. [20.2.50.113 NMAC-N, XX/XX/2021]

20.2.50.114 COMPRESSOR SEALS:

[Kinder Morgan requests the Board strike Section 114 from the Proposed Rules, or, in the alternative, that the Board eliminate transmission compressor stations from the applicability of this section.]

* * *

20.2.50.115 CONTROL DEVICES:

[In addition to the revisions included in the following Proposed Rule section (20.2.50.115 – Control Devices), Kinder Morgan supports and incorporates by reference the revisions submitted by NMOGA.]

A. Applicability: These requirements apply to control devices as defined in 20.2.50.7 NMAC and used to comply with the emission standards and emission reduction requirements in this Part.

B. General requirements:

(1) Control devices used to demonstrate compliance with this Part shall be installed, operated, and maintained consistent with manufacturer specifications, and good engineering and maintenance practices.

(2) Control devices shall be adequately designed and sized to achieve the control efficiency rates required by this Part and to handle fluctuations in emissions of VOC or NOx.

~~**(3)** The owner or operator of a control device used to comply with the emission standards in this Part shall install an EMT on the control device in accordance with 20.2.50.112 NMAC.~~

~~**(4)**~~**(3)** The owner or operator shall inspect visually, or consistent with federally-approved inspection methods, control devices used to comply with this Part at least monthly to ensure proper maintenance and operation. Prior to an inspection or monitoring event, the owner or operator shall scan the EMT and the required monitoring data shall be electronically captured in accordance with this Part.

~~**(5)**~~**(4)** The owner or operator shall ensure that a control device used to comply with emission standards in this Part operates as a closed vent system that captures and routes VOC emissions to the control device, and that unburnt gas is not directly vented to the atmosphere.

~~**(6)**~~**(5)** The owner or operator of a closed vent system for a centrifugal compressor wet seal fluid degassing system, reciprocating compressor, pneumatic controller or pump, or storage vessel using a control device or routing emissions to a process shall:

(a) ensure the control device or process is of sufficient design and capacity to accommodate all emissions from the affected sources;

(b) conduct an assessment to confirm that the closed vent system is of sufficient design and capacity to ensure that all emissions from the affected equipment are routed to the control device or process; and

(c) have the closed vent system certified by a qualified professional engineer or an in-house engineer with expertise regarding the design and operation of the closed vent system in accordance with Paragraphs (c)(i) and (ii) of this Section.

(i) The assessment of the closed vent system shall be prepared under the direction or supervision of a qualified professional engineer or an in-house engineer who signs the certification in Paragraph (c)(ii) of this Section.

(ii) the owner or operator shall provide the following certification, signed and dated by a qualified professional engineer or an in-house engineer: "I certify that the closed vent system design and capacity assessment was prepared under my direction or supervision. I further certify that the closed vent system design and capacity assessment was conducted, and this report was prepared pursuant to the requirements of this Part. Based on my professional knowledge and experience, and inquiry of personnel involved in the assessment, the certification submitted herein is true, accurate, and complete."

~~**(7)**~~**(6)** The owner or operator shall keep manufacturer specifications for all control devices on file. The information shall include:

(a) manufacturer name, make, and model;

(b) maximum heating value for an open flare, ECD, or TO;

(c) maximum rated capacity for an open flare, ECD/TO, or VRU;

(d) gas flow range for an open flare, ECD, or TO; and

(e) designed destruction or vapor recovery efficiency.

C. **Requirements for open flares:**

(1) Emission standards:

(a) the flare shall combust the gas sent to the flare and combustion shall be maintained for the duration of time that gas is sent to the flare. The owner or operator shall not send gas to the flare in excess of the manufacturer maximum rated capacity.

(b) the owner or operator shall equip each new and existing flare (except those flares required to meet the requirements of Paragraph (C) of this Subsection) with a continuous pilot flame, an operational auto-igniter, or require manual ignition, and shall comply with the following:

(i) a flare with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure the flare is operated with a flame present at all times when gas is being sent to the flare.

(ii) the owner or operator of a flare with manual ignition shall inspect and ensure a flame is present upon initiating a flaring event.

(iii) a new flare controlling a continuous gas stream shall be equipped with a continuous pilot flame upon startup.

(iv) an existing flare controlling a continuous gas stream constructed before the effective date of this Part shall be equipped with a continuous pilot no later than one year after the effective date of this Part.

(c) an existing flare located at a site with an annual average daily production of equal to or less than 10 barrels of oil per day or an average daily production of 60,000 standard cubic feet of natural gas shall be equipped with an auto-ignitor, continuous pilot, or technology (e.g. alarm) that alerts the owner or operator of a flare malfunction, if replaced or reconstructed after the effective date of this Part.

(d) the owner or operator shall operate a flare with no visible emissions, except for periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The flare shall be designed so that an observer can, by means of visual observation from the outside of the flare or by other means such as a continuous monitoring device, determine whether it is operating properly.

(e) the owner or operator shall repair the flare within three business days of any alarm activation.

(2) Monitoring requirements:

(a) the owner or operator of a flare with a continuous pilot or auto igniter shall continuously monitor the presence of a pilot flame, or presence of flame during flaring if using an auto igniter, using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department;

(b) the owner or operator of a manually ignited flare shall monitor the presence of a flame using continuous visual observation during a flaring event;

(c) the owner or operator shall, at least quarterly, and upon observing visible emissions, perform a U.S. EPA method 22 observation while the flare pilot or auto igniter flame is present to certify compliance with visible emission requirements. The observation period shall be a minimum of 15 consecutive minutes;

(d) prior to an inspection or monitoring event, the EMT on the flare shall be scanned and the required monitoring data shall be electronically captured during the event in accordance with the monitoring requirements of 20.2.50.112 NMAC; and

(e) the owner or operator shall monitor the technology that alerts the owner or operator of a flare malfunction and any instances of technology or alarm activation.

(3) Recordkeeping requirements: The owner or operator of an open flare shall keep a record of the following:

(a) any instance of alarm activation, including the date and cause of alarm activation, action taken to bring the flare into a normal operating condition, the name of the personnel conducting the inspection, and any maintenance activity performed;

(b) the results of the U.S. EPA method 22 observations;

(c) the monitoring of the presence of a flame on a manual flare during a flaring event as required under Subparagraph (b) of Paragraph (2) of Subsection C of 20.2.50.115 NMAC;

(d) the results of the gas analysis for the gas being flared, including VOC content and heating value; and

(e) any instance of technology or alarm activation of a malfunctioning flare, including the date and cause of the activation, the action taken to bring the flare into normal operating condition, date of repair, name of the personnel conducting the inspection, and any maintenance activities performed.

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

D. Requirements for enclosed combustion devices (ECD) and thermal oxidizers (TO):

(1) Emission standards:

(a) the ECD/TO shall combust the gas sent to the ECD/TO. The owner or operator shall not send gas to the ECD/TO in excess of the manufacturer maximum rated capacity.

(b) the owner or operator shall equip an ECD/TO with a continuous pilot flame or an auto-igniter. Existing ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter no later than one year after the effective date. New ECD/TO shall be equipped with a continuous pilot flame or an auto-igniter upon startup.

(c) ECD/TO with a continuous pilot flame or an auto-igniter shall be equipped with a system to ensure that the ECD/TO is operated with a flame present at all times when gas is sent to the ECD/TO. Combustion shall be maintained for the duration of time that gas is sent to the ECD/TO.

(d) the owner or operator shall operate an ECD/TO with no visible emissions, except for periods not to exceed a total of 30 seconds during any 15 consecutive minutes. The ECD/TO shall be designed so that an observer can, by means of visual observation from the outside of the ECD/TO or by other means such as a continuous monitoring device, determine whether it is operating properly.

(2) Monitoring requirements:

(a) the owner or operator of an ECD/TO with a continuous pilot or an auto igniter shall continuously monitor the presence of a pilot flame, or of a flame during combustion if using an auto-igniter, using a thermocouple equipped with a continuous recorder and alarm to detect the presence of a flame. An alternative equivalent technology alerting the owner or operator of failure of ignition of the gas stream may be used in lieu of a continuous recorder and alarm, if approved by the department.

(b) the owner or operator shall, at least quarterly, and upon observing visible emissions, perform a U.S. EPA method 22 observation while the ECD/TO pilot flame or auto igniter flame is present to certify compliance with the visible emission requirements. The period of observation shall be a minimum of 15 consecutive minutes.

(c) prior to an inspection or monitoring event, the EMT on the unit shall be scanned and the required monitoring data shall be electronically captured during the monitoring event in accordance with the monitoring requirements of 20.2.50.112 NMAC.

(3) Recordkeeping requirements: The owner or operator of an ECD/TO shall keep records of the following:

(a) any instance of an alarm activation, including the date and cause of the activation, any action taken to bring the ECD/TO into normal operating condition, the name of the personnel conducting the inspection, and any maintenance activities performed;

(b) the result of the U.S. EPA method 22 observation; and

(c) the results of gas analysis for the gas being combusted, including VOC content and heating value.

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

E. Requirements for vapor recover units (VRU):

(1) Emission standards:

(a) the owner or operator shall operate the VRU as a closed vent system that captures and routes all VOC emissions directly back to the process or to a sales pipeline and does not vent to the atmosphere.

(b) the owner or operator shall control VOC emissions during startup, shutdown, maintenance, or other VRU downtime with a backup control device (e.g. flare, ECD, TO) or redundant VRU.

(2) Monitoring Requirements:

(a) the owner or operator shall comply with the standards for equipment leaks in 20.2.50.116 NMAC, or, alternatively, shall implement a program that meets the requirements of Subpart OOOOa of 40 CFR 60.

(b) prior to a VRU inspection or monitoring event, the EMT on the unit shall be scanned and the required monitoring data shall be electronically captured during the monitoring event in accordance with the monitoring requirements of 20.2.50.112 NMAC.

(3) Recordkeeping requirements: For a VRU inspection or monitoring event, the owner or operator shall record the result of the event in accordance with 20.2.50.112 NMAC, including the name of the personnel conducting the inspection, and any maintenance or repair activities required. The owner or operator shall record the type of redundant control device used during VRU downtime.

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

F. **Recordkeeping requirements:** The owner or operator of a control device shall maintain a record of the following:

(1) the certification of the closed vent system as required by this Part; and

(2) the information required in Paragraph (7) of Subsection B of 20.2.50.115 NMAC.

G. **Reporting requirements:** The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC. [20.2.50.115 NMAC-N, XX/XX/2021]

20.2.50.116 EQUIPMENT LEAKS AND FUGITIVE EMISSIONS:

A. **Applicability:** Wellhead sites, tank batteries, gathering and boosting sites, gas processing plants, transmission compressor stations, and associated piping and components are subject to the requirements of 20.2.50.116 NMAC. Equipment leak and fugitive emissions monitoring required by New Source Performance Standards, including but not limited to Subpart OOOO and Subpart OOOOa, 40 C.F.R. Part 60, as each may be revised, may be used to satisfy the requirements of this 20.2.50.116 NMAC.

B. **Emission standards:** The owner or operator of oil and gas production and processing equipment located at wellhead sites, tank batteries, gathering and boosting sites, gas processing plants, or transmission compressor stations shall demonstrate compliance with this Part by performing the monitoring, recordkeeping, and reporting requirements specified in 20.2.50.116 NMAC.

C. **~~Default~~ Monitoring requirements:** Owners and operators shall comply with the following monitoring requirements and the monitoring requirements in 20.2.50.112 NMAC:

(1) The owner or operator of a facility with an annual average daily production of greater than 10 barrels of oil per day or an average daily production of greater than 60,000 standard cubic feet per day of natural gas shall, at least weekly, conduct audio, visual, and olfactory (AVO) inspections of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify defects and leaking components as follows:

(a) conduct a visual inspection for: cracks, holes, or gaps in piping or covers; loose connections; liquid leaks; broken or missing caps; broken, cracked or otherwise damaged seals or gaskets; broken or missing hatches; or broken or open access covers or other closure or bypass devices;

(b) conduct an audio inspection for pressure leaks and liquid leaks;

(c) conduct an olfactory inspection for unusual or strong odors;

(d) any positive detection during the AVO inspection shall be considered a leak; and

(e) a leak discovered by an AVO inspection shall be tagged with a visible tag and reported to management or their designee within three calendar days.

(2) The owner or operator of a ~~facility~~ well production facility or tank battery with an annual average daily production of equal to or less than 10 barrels of oil per day or an average daily production of equal to or less than 60,000 standard cubic feet per day of natural gas shall, at least monthly, conduct an audio, visual, and olfactory (AVO) inspection of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify a defect and leaking component as specified in Subparagraphs (a) through (e) of Paragraph (1) of Subsection (C) of 20.2.50.116 NMAC.

(3) The owner or operator of ~~the following facilities~~a well production facility or tank battery shall conduct an inspection using U.S. EPA method 21 or optical gas imaging (OGI) of thief hatches, closed vent systems, pumps, compressors, pressure relief devices, open-ended valves or lines, valves, flanges, connectors, piping, and associated equipment to identify leaking components at a frequency determined according to the following schedules:

(a) for wellhead sites or tank battery facilities:

(i) annually at facilities with a PTE less than two tpy VOC;

(ii) semi-annually at facilities with a PTE equal to or greater than two tpy and less than five tpy VOC; and

(iii) quarterly at facilities with a PTE equal to or greater than five tpy VOC.

(b) for gathering and boosting sites, gas processing plants, and transmission compressor stations:

(i) ~~quarterly~~ semi-annually at facilities with a PTE less than 25 tpy VOC; and

(ii) ~~monthly~~ quarterly at facilities with a PTE equal to or greater than 25 tpy VOC.

(4) Inspections using U.S. EPA method 21 shall meet the following requirements:

(a) the instrument shall be calibrated before each day of its use by the procedures specified in U.S. EPA method 21;

(b) the instrument shall be calibrated with zero air (less than 10 ppm of hydrocarbon in air), and a mixture of methane or n-hexane and air at a concentration near, but no~~r~~ more than, 10,000 ppm methane or n-hexane; and

(c) a leak is detected if the instrument records a measurement of 500 ppm or greater of hydrocarbon and the measurement is not associated with normal equipment operation, such as pneumatic device actuation and crank case ventilation.

(5) Inspections using OGI shall meet the following requirements:

(a) the instrument shall comply with the specifications, daily instrument checks, and leak survey requirements set forth in Subparagraphs (1) through (3) of Paragraph (i) of 40 CFR 60.18;

(b) a leak is detected if the emission images recorded by the OGI instrument are not associated with normal equipment operation, such as pneumatic device actuation or crank case ventilation.

(6) Components that are difficult, unsafe, or inaccessible to monitor, as determined by the following conditions, are not required to be inspected until it becomes feasible to do so:

(a) difficult to monitor components are those that require elevating the monitoring personnel more than two meters above a supported surface, or that cannot be reached via a wheeled scissor-lift or hydraulic type scaffold that allows access to components up to seven and six tenths meters (25 feet) above the ground;

(b) unsafe to monitor components are those that cannot be monitored without exposing monitoring personnel to an immediate danger as a consequence of completing the monitoring; and

(c) inaccessible to monitor components are those that are buried, insulated, or obstructed by equipment or piping that prevents access to the components by monitoring personnel.

D. Alternative equipment leak monitoring plans: As an equivalent means of compliance with Subsection C of 20.2.50.116 NMAC, an owner or operator may comply with the equipment leak requirements through an alternative monitoring plan as follows:

(1) An owner or operator may comply with an individual alternative monitoring plan, subject to the following requirements:

(a) the proposed alternative monitoring plan shall be submitted to and approved by the department prior to conducting monitoring under that plan.

(b) the department may terminate an approved alternative monitoring plan if the department ~~funds~~ finds that the owner or operator failed to comply with a provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

(c) upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements under Subsection C of 20.2.50.116 NMAC within 15 days.

(2) An owner or operator may comply with a pre-approved monitoring plan maintained by the department, subject to the following requirements:

(a) the owner or operator shall notify the department of the intent to conduct monitoring under a pre-approved monitoring plan, and identify which pre-approved plan will be used, at least 15 days prior to conducting monitoring under that plan.

(b) the department may terminate the use of a pre-approved monitoring plan by the owner or operator if the department finds that the owner or operator failed to comply with the provision of the plan and failed to correct and disclose the violation to the department within 15 calendar days of identifying the violation.

(c) upon department denial or termination of an approved alternative monitoring plan, the owner or operator shall comply with the default monitoring requirements under of Subsection C of 20.2.50.116.0 NMAC within 15 days.

E. Repair requirements: For a leak detected pursuant to monitoring conducted under 20.2.50.116 NMAC:

(1) the owner or operator shall place a visible tag on the leaking component until the component has been repaired;

(2) leaks shall be repaired within 15 days of discovery, except for leaks detected using OGI, which shall be repaired within seven days of discovery;

(3) the equipment must be re-monitored no later than 15 days after discovery of the leak to demonstrate that it has been repaired; and

(4) if the leak cannot be repaired within 15 days of discovery, or within seven days for a leak detected using OGI, without a process unit shutdown, the leak may be designated "Repair delayed." and must be repaired before the end of the next process unit shutdown.

F. Recordkeeping requirements:

(1) The owner or operator shall keep a record of the following for all AVO. RM21, OGI, or alternative equipment leak monitoring inspection conducted as required under 20.2.50.116 NMAC, and shall provide the record to the department upon request:

(a) facility location;

(b) date of inspection;

(c) monitoring method (e.g. AVO, RM 21, OGI, alternative method approved by the department);

(d) name of the personnel performing the inspection;

(e) a description of any leak requiring repair or a note that no leak was found; and

(f) whether a visible flag was placed on the leak or not;

(2) The owner or operator shall keep the following record for any leak that is detected:

(a) the date the leak is detected;

(b) the date of attempt to repair;

(c) for a leak with a designation of "repair delayed" the following shall be recorded:

(i) reason for delay if a leak is not repaired within the required number of days after discovery;

(ii) signature of the authorized representative who determined that the repair could not be implemented without a process unit shutdown;

(d) date of successful leak repair;

(e) date the leak was monitored after repair and the results of the monitoring; and

(f) a description of the component that is designated as difficult, unsafe, or inaccessible to monitor, an explanation stating why the component was so designated, and the schedule for repairing and monitoring the component.

(3) For a leak detected using OGI, the owner or operator shall keep records of the specifications, the daily instrument check, and the leak survey requirements specified at 40 CFR 60.18(i)(1)-(3).

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

G. Reporting requirements:

(1) The owner or operator shall certify the use of an alternative equipment leak monitoring plan under Subsection D of 20.2.50.116 NMAC to the department annually, if used.

(2) The owner or operator shall comply with the reporting requirements in 20.2.50.112 NMAC. [20.2.50.116 NMAC-N, XX/XX/2021]

20.2.50.117 NATURAL GAS WELL LIQUID UNLOADING:

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20.2.50.118 GLYCOL DEHYDRATORS:

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20.2.50.119 HEATERS:

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20.2.50.120 HYDROCARBON LIQUID TRANSFERS:

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20.2.50.121 PIG LAUNCHING AND RECEIVING:

[In addition to the revisions included in the following Proposed Rule section (20.2.50.121 – Pig Launching and Receiving, Kinder Morgan supports and incorporates by reference the revisions submitted by NMOGA.]

A. Applicability: Pipeline pig launching and receiving ~~operations~~sites with a PTE greater than or equal to one tpy of VOC located within or outside of the property boundary of wellhead sites, tank batteries, gathering and boosting sites, natural gas processing plants, and transmission compressor stations are subject to the requirements of 20.2.50.121 NMAC.

[Regarding the above proposed revision in Section A, above, as with other sections of the Proposed Rule, a PTE threshold is appropriate.]

B. Emission standards:

(1) Owners and operators of pipeline pig launching and receiving operations with a PTE equal to or greater than one tpy of VOC shall capture and reduce VOC emissions by at least ninety-eight percent, beginning on the effective date of this Part.

(2) The owner or operator conducting the pig launching and receiving operation shall:

(a) employ best management practices to minimize the liquid present in the pig receiver chamber and to prevent emissions from the pig receiver chamber to the atmosphere after receiving the pig in the receiving chamber and before opening the receiving chamber to the atmosphere;

(b) employ a method to prevent emissions, such as installing a liquid ramp or drain, routing a high-pressure chamber to a low-pressure line or vessel, using a ball valve type chamber, or using multiple pig chambers;

(c) recover and dispose of receiver liquid in a manner that ~~prevents~~ minimizes emissions to the atmosphere; and

(d) ensure that the material collected is returned to the process or disposed of in a manner compliant with state law.

(3) The emission standards in Paragraphs (1) and (2) of Subsection B of 20.2.50.121 NMAC cease to apply to a pipeline pig launching and receiving operation if the uncontrolled actual annual VOC emissions of the operation are less than one half ton per year of VOC.

(4) An owner or operator complying with Paragraph (2) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the control device requirements in 20.2.50.115 NMAC.

C. Monitoring requirements:

(1) The owner or operator of pig launching and receiving operations shall monitor the type and volume of liquid cleared.

(2) The owner or operator of an affected pig launching and receiving ~~operations~~ site shall inspect the equipment for ~~a~~ leaks using either AVO, RM 21 or OGI on either, as applicable:

(a) a monthly basis if pigging operations at a site occur on a monthly basis or more frequently; or

~~**(a)**~~**(b)** prior to commencement ~~immediately before the commencement~~ and ~~immediately~~ after the conclusion of the pig launching or receiving operation~~, and according to the requirements in 20.2.50.116 NMAC~~.

(3) The monitoring procedures shall be performed using the methodologies outlined in Paragraphs (2) through (4)) of Subsection (C) of 20.2.50.116 NMAC as applicable, and at the frequency outlined in Paragraph (2) of Subsection (C) of 20.2.50.121.

~~**(2)**~~**(4)** An owner or operator complying with Paragraph (1) of Subsection B of 20.2.50.121 NMAC through use of a control device shall comply with the monitoring requirements in 20.2.50.115 NMAC.

~~**(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 of pig launching and receiving operations shall maintain a record of the following:

(a) the pigging operation, including the date and time of the pigging operation and the type and volume of liquid cleared;

(b) the data and methodology used to estimate the actual emissions to the atmosphere and used to estimate the PTE; and

(c) the type of control device and its location, make, and model.

(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. [20.2.50.121 NMAC-N, XX/XX/2021]

20.2.50.122 PNEUMATIC CONTROLLERS AND PUMPS:

[Kinder Morgan adopts and incorporates by reference the rule revisions proposed by NMOGA to reconcile NMED's pneumatics proposal with the Colorado Rule, including with respect to the scope and applicability that excludes transmission compressor stations.]

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20.2.50.123 STORAGE VESSELS:

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20.2.50.124 WELL WORKOVERS:

* * *

20.2.50.125 SMALL BUSINESS FACILITIES:

* * *

20.2.50.126 PRODUCED WATER MANAGEMENT UNITS:

* * *

20.2.50.127 PROHIBITED ACTIVITY AND CREDIBLE INFORMATION PRESUMPTION:

[Kinder Morgan supports and incorporates by reference the proposed revisions to 20.2.50.127 NMAC submitted by NMOGA.]

HISTORY OF 20.2.50 NMAC: [RESERVED]

CERTIFICATE OF SERVICE

I hereby certify that on July 28, 2021, a true and correct copy of the foregoing **NOTICE OF INTENT TO PRESENT TECHNICAL TESTIMONY OF KINDER MORGAN, INC. AND ITS SUBSIDIARIES AND AFFILIATES, EL PASO NATURAL GAS COMPANY, L.L.C., TRANSCOLORADO GAS TRANSMISSION CO., LLC, AND NATURAL GAS PIPELINE COMPANY OF AMERICA, LLC** was served via electronic mail to the following:[33]

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[33] This list reflects the Board, the Department, and persons that have entered an appearance in this matter as posted to the Environmental Improvement Board's website as of 2:00 PM Mountain Time on July 28, 2021.

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