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Out in Front: State and Federal Regulation of Air Pollution Emissions from Oil and Gas Production Activities in the Western United States

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ABSTRACT

As oil and gas development increases in western states, states are responding at different speeds to protect human health and the environment. Colorado and Wyoming are recognized as having taken relatively early action to regulate air pollution emissions from oil and gas development, with Wyoming adopting its first sector-specific requirements in 1999. In contrast, New Mexico and Utah have been relatively slow to act. Furthermore, the U.S. Environmental Protection Agency did not adopt emissions standards for most oil and gas production activities until 2012, when it relied on Colorado and Wyoming as proving grounds for control technology. The regulatory history in these four western states shows that concern about ozone nonattainment was an important driver for control requirements in Colorado and Wyoming. These two states also have a history of relatively stringent pre-construction permitting requirements for small sources. In some areas, National Environmental Policy Act requirements for cumulative impact assessment drove adoption of tighter controls to mitigate impacts of growth. Moving forward, federal emissions standards will even out control requirements for new sources across the western states. However, control efforts that go beyond the 2012 federal standards will likely be needed in ozone nonattainment areas in western Wyoming, northeastern Utah, Colorado's Front Range, and in Indian Country. Further efforts will also be needed to address greenhouse gas emissions including methane.

I. INTRODUCTION

Development of unconventional oil and gas resources is expanding rapidly across the U.S., made viable in new locations by hydraulic fracturing and horizontal drilling. There is broad consensus on

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the need for effective regulation to ensure that these activities do not harm human health or the environment.[1] However, it is less clear which level of government ought to regulate oil and gas production to mitigate environmental risks.[2] In practice, local, state, tribal, and federal entities all play some role, but their relative influence depends on the location and stage of activity at issue, and is evolving as energy development expands into new areas. This article compares the evolution of air pollution emissions regulations for oil and gas production at the federal level and in four western states: Colorado, New Mexico, Utah, and Wyoming. The article examines the drivers for and barriers to state-level regulation, and illustrates how state, tribal, and federal actions have interacted to shape the states' contrasting regulatory situations.

Emissions from oil and gas exploration, drilling, production, and processing[3] contribute to a number of air quality problems across the interior West, including: health risks from hazardous air pollutants (HAPs), particulate matter (PM), and ozone; visibility degradation; and emissions of methane and other greenhouse gases. The Clean Air Act[4] (CAA) obligates states, the US Environmental Protection Agency (EPA), and federal land managers to require emissions control measures to address these concerns if they become severe enough. In some cases, independent state or tribal laws or local ordinances may require additional emissions controls or impose siting restrictions to protect air quality. In addition to establishing control requirements, government agencies also conduct inspections and enforce regulations, develop emissions inventories, and monitor air quality to determine whether ambient standards are being met, and undertake studies to improve scientific understanding of air quality issues.

This study focuses on control requirements for volatile organic compound (VOC) emissions, because VOC emissions are precursors to ozone formation and controls that capture VOCs effectively reduce methane, a potent greenhouse gas. Colorado and Wyoming are recognized as having some of the most stringent air pollution control requirements for oil and gas operations in the country, whereas requirements in

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1. *See, e.g.*, INT'L ENERGY AGENCY, GOLDEN RULES FOR A GOLDEN AGE OF GAS 103–105 (2012), http://www.worldenergyoutlook.org/media/weowebsite/2012/goldenrules/WEO2012_GoldenRulesReport.pdf; U.S. DEP'T OF ENERGY, SHALE GAS PRODUCTION SUBCOMMITTEE SECOND NINETY DAY REPORT 1, 11–12 (2011), http://energy.gov/sites/prod/files/90day_Report_Second_11.18.11.pdf.

2. *See* Charles Davis, *The Politics of "Fracking": Regulating Natural Gas Drilling Practices in Colorado and Texas*, 29 REV. POL'Y RES. 177 (2012).

3. The term "production" is used hereinafter to denote activities at the exploration, drilling, completions, gathering, compression, and processing stages of operations.

4. Clean Air Act of 1963, 42 U.S.C. §§ 7401–7671 (2000).

New Mexico and Utah are viewed as relatively lax.[5] Federal regulations for *new* VOC sources in the oil and gas production category largely caught up to requirements in Colorado and Wyoming when EPA issued new standards in 2012. This study identifies the drivers that led Colorado and Wyoming to move ahead of the federal government and the reasons why New Mexico and Utah lagged behind. The study concludes by discussing the future challenges and opportunities the four states face in their efforts to protect air quality in the face of new energy development.

II. TRENDS IN OIL AND GAS PRODUCTION IN WESTERN STATES

Figures 1a-c show trends in natural gas and oil production and the number of producing wells in Colorado, New Mexico, Utah, and Wyoming from 1990 to 2011. In 2011, these states were respectively ranked 5th, 7th, 9th, and 3rd in the nation in natural gas production.[6] Compared to natural gas, these four states have generally seen relatively flat or declining trends in oil production over the period from 1990 to 2011, although levels have been recovering since about 2000 in Colorado and Utah and since about 2006 in New Mexico.

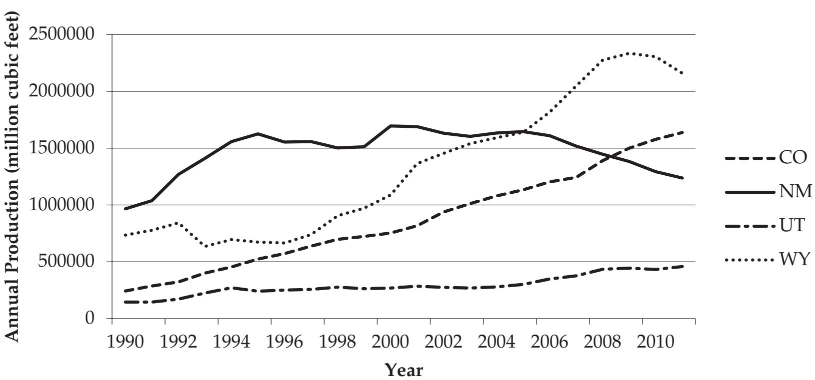

FIGURE 1A. Marketed natural gas production in Colorado, New Mexico, Utah and Wyoming from 1990 to 2011.[7]

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5. *See* U.S. GOV'T ACCOUNTABILITY OFFICE, GAO-11-34, FEDERAL OIL AND GAS LEASES: OPPORTUNITIES EXIST TO CAPTURE VENTED AND FLARED NATURAL GAS, WHICH WOULD INCREASE ROYALTY PAYMENTS AND REDUCE GREENHOUSE GASES 21, 49 (2010), *available at* http://www.gao.gov/assets/320/311826.pdf.

6. *Rankings: Natural Gas Marketed Production, 2011*, U.S. ENERGY INFO. ADMIN. (2011). Texas (1), Louisiana (2), Oklahoma (4), Pennsylvania (6), Alaska (8) and West Virginia (10) round out the top ten.

7. *Natural Gas: Natural Gas Gross Withdrawals and Production*, U.S. ENERGY INFO. ADMIN., http://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_VGM_mmcf_a.htm.

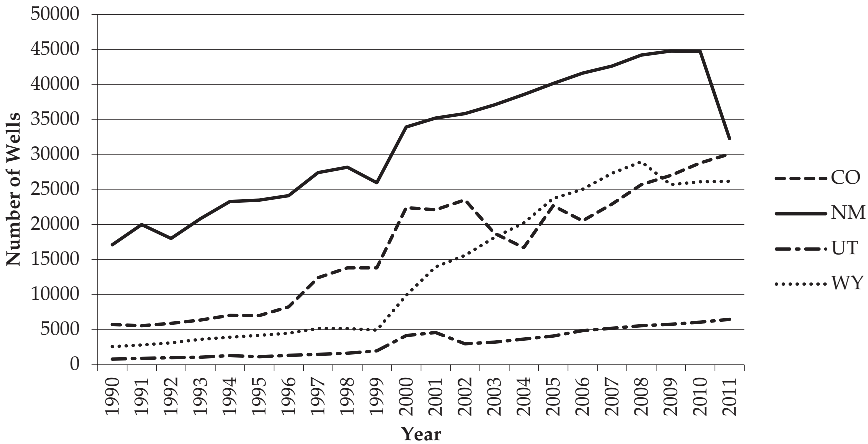

FIGURE 1B. Number of producing natural gas wells in Colorado, New Mexico, Utah, and Wyoming from 1990 to 2011.[8]

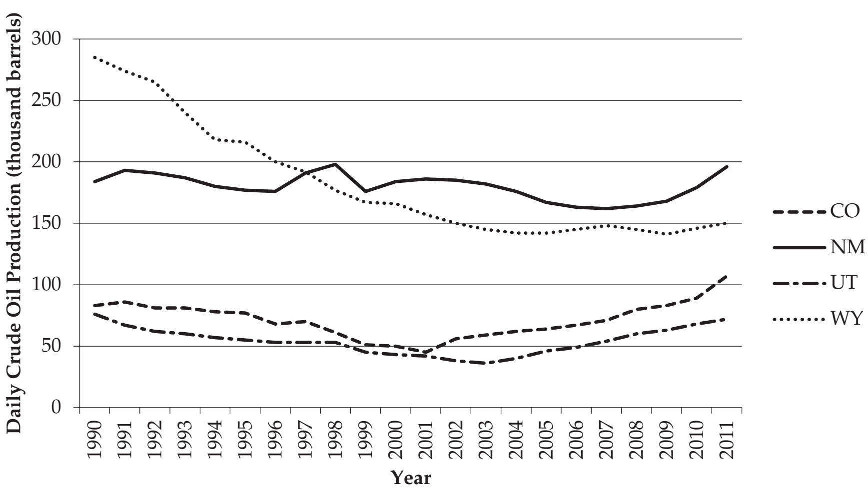

FIGURE 1C. Crude oil production in Colorado, New Mexico, Utah, and Wyoming from 1990 to 2011.[9]

8. *Natural Gas: Number of Producing Gas Wells*, U.S. ENERGY INFO. ADMIN., http://www.eia.gov/dnav/ng/ng_prod_wells_s1_a.htm.

9. *Petroleum & Other Liquids: Crude Oil Production*, U.S. ENERGY INFO. ADMIN., http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbbl_m.htm.

III. EMISSIONS FROM OIL AND GAS PRODUCTION

Equipment and operations involved in oil and gas production are significant sources of VOCs[10] and nitrogen oxides (NOx), which react in the presence of sunlight to form ground-level ozone. The sector also contributes emissions of sulfur dioxide, carbon monoxide, and PM, though generally in smaller quantities compared to other sources of these pollutants. VOCs associated with oil and gas operations include a number of compounds designated under the CAA as HAPs, including formaldehyde, benzene, toluene, ethyl benzene, and xylenes.[11] Nitrogen oxides from oil and gas equipment react to form nitric acid and ammonium nitrate (a component of PM) in addition to ozone. Oil and gas operations are also significant sources of the greenhouse gases methane and carbon dioxide.

The Western Regional Air Partnership (WRAP) was founded in 1997 to assist states, tribes, local agencies, EPA, and federal land managers in addressing regional haze and other air quality issues.[12] Recognizing that oil and gas operations were becoming significant emissions sources, the WRAP began efforts to compile detailed inventories for this sector in the early 2000s. Initial inventories were completed in 2005, followed by more refined inventories in 2007. A "Phase III" effort began in 2007 with support from the Western Energy Alliance, an oil and gas trade organization.[13] Table 1 shows estimated VOC and NOx emissions from the WRAP's Phase III inventories, comparing emissions for 2006 in the major basins in Colorado, New Mexico, Utah, and Wyoming.[14] As indicated in Table 1, the highest estimated NOx emissions are for the

10. The term volatile organic compounds or VOCs refers to all gas- or vapor-phase organic compounds that readily evaporate under normal environmental conditions, and includes alkanes, alkenes, aromatics, aldehydes, and alcohols. EPA's definition of VOC excludes methane and ethane, as having "been determined to have negligible photochemical reactivity." 40 C.F.R. § 51.100(s)(1) (2014).

11. 42 U.S.C. § 7412(b)(1) (2012).

12. Western Regional Air Partnership, *About WRAP*, http://www.wrapair2.org/About.aspx (last visited Sept. 6, 2014).

13. LEE GRIBOVICZ, ANALYSIS OF STATES' AND EPA OIL & GAS AIR EMISSIONS CONTROL REQUIREMENTS FOR SELECTED BASINS IN THE WESTERN UNITED STATES 7 (2012), available at http://www.wrapair2.org/pdf/2012-01_Final%20WRAP%20OG%20Analysis%20(01-08).pdf.

14. For rough comparison with the total emissions in Table 1, EPA reports in its National Emissions Inventory (NEI) that total emissions from anthropogenic sources in Colorado, New Mexico, Utah, and Wyoming in 2008 were 750,000 tons and 611,000 tons for NOx and VOC, respectively. *The 2008 Natl. Emissions Inventory*, U.S. ENVTL. PROT. AGENCY, http://www.epa.gov/ttnchie1/net/2008inventory.html (last updated Dec. 2, 2013). EPA's 2008 NEI is believed to underestimate emissions from oil and gas production activities. RICK BEUSSE ET AL., EPA, REPORT NO. 13-P-0161, EPA NEEDS TO IMPROVE AIR EMISSIONS

South San Juan Basin in northern New Mexico, which ranked second among the basins in natural gas production. The highest estimated VOC emissions are for the Green River Basin in western Wyoming, which ranked first in natural gas production and second for oil and condensate.

TABLE 1. Estimated annual NOx and VOC emissions from oil and gas production in 2006.[15]

Basin	NOx (tons)	VOC (tons)	Oil and Condensate Production (barrels)	Natural Gas Production (million ft^3)
Denver-Julesburg, CO	20,783	81,758	14,242,088	234,631
Uinta, UT	13,093	71,546	11,528,121	331,844
Piceance, CO	12,390	27,464	7,158,305	421,359
N San Juan, CO	5,700	2,147	32,529	443,829
S San Juan, NM	42,075	60,697	2,636,811	1,020,015
Wind River, WY	1,814	11,981	3,043,459	198,190
Powder River, WY	21,086	21,557	19,662,896	452,814
Green River, WY	21,569	94,013	16,109,992	1,468,167
Total	138,510	371,163	74,414,131	4,570,845

The emissions contributions from different processes and equipment vary somewhat across basins, but for NOx the largest contributors are generally drill rig and compressor engines.[16] Natural gas production and transmission operations often use large, natural gas-fired, reciprocating internal combustion engines for compression and pumping operations. In addition to NOx, the engines also emit VOCs, carbon monoxide, particulate matter, carbon dioxide, and methane. Drill rigs used in oil and gas operations are typically operated on diesel fuel and emit particulate matter, VOCs, NOx, and sulfur dioxide.

The oil and gas activities and equipment contributing most to VOC emissions include flashing losses from crude oil and condensate

DATA FOR THE OIL AND NATURAL GAS PRODUCTION SECTOR 16-17 (2013), *available at* http://www.epa.gov/oig/reports/2013/20130220-13-P-0161.pdf.

15. *See* GRIBOVICZ, *supra* note 13, at 31; AMNON BAR-ILAN ET AL., ENVIRON INT'L CORP., DEVELOPMENT OF BASELINE 2006 EMISSIONS FROM OIL AND GAS ACTIVITY IN THE SOUTHWEST WYOMING (GREATER GREEN RIVER) BASIN ES-3 (2012), available at http://www.wrapair2.org/pdf/2006_Baseline_Emiss_SWWY_Basin_120712.pdf.

16. GRIBOVICZ, *supra* note 13, at 34, 37, 41, 45, 48, 52, 56.

storage tanks,[17] fugitive emissions from leaks in valves, fittings and other equipment, venting of hydrocarbons from completions and blowdowns,[18] venting from glycol dehydration units,[19] and natural gas-driven pneumatic devices. The relative contributions from these sources vary widely across basins, depending on the characteristics of the oil and gas formations, production operations, and control requirements in each locale. For example, natural gas wells in the Denver-Julesburg Basin have relatively high VOC emissions due to the large quantity of condensate produced along with the gas. In contrast, the coal bed methane wells in the Northern San Juan Basin produce very little associated condensate and correspondingly low VOC emissions.

IV. DIRECT EPA REGULATION OF OIL AND GAS PRODUCTION SOURCES UNDER THE CAA

Under the cooperative federalism structure of the CAA, EPA generally sets minimum standards for ambient air quality and emissions, while the states are responsible for ensuring those standards are met. National Ambient Air Quality Standards (NAAQS) for "criteria" pollutants are the centerpiece of this framework. The CAA requires EPA to establish NAAQS and to periodically review and revise them as needed to protect public health and welfare.[20] The NAAQS for ozone is most relevant to oil and gas production, and was revised in 1997 to an 8-hour average concentration of 0.08 ppm[21] and then lowered to 0.075 ppm in

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17. Natural gas condensate (or natural gas liquids) is comprised of hydrocarbons that are volatile liquids at ambient temperatures and pressures, and readily evaporate. Condensate storage tanks release VOCs to the atmosphere mainly through flash emissions, which occur when a volatile hydrocarbon liquid flows from a pressurized vessel to one with lower pressure, for example, in transferring condensate from a separation unit into a storage vessel.

18. Completing a well refers to the stage after drilling, but before the gas is piped into a sales line, when the well-bore is cleaned out by producing fluids at a high enough rate to clear out sand, cuttings, and liquids. Traditionally, the fluids have been released to a pit or tank where sand, cuttings, and liquids are collected for disposal, while gas has been vented to the atmosphere or flared. Reduced emissions completions or "green" completions use specialized equipment to separate natural gas from the accompanying sand and liquids, and accelerate tying the well into a sales pipeline.

19. Natural gas conditioning involves separation processes to remove impurities, including natural gas liquids and water. In glycol dehydration, natural gas containing water and other contaminants is contacted with a glycol compound that absorbs the contaminants. The contaminated glycol is then regenerated at elevated temperature, releasing the water and other contaminants.

20. 42 U.S.C. § 7409 (2012).

21. 40 C.F.R § 50.10 (2014).

2008.[22] EPA's Clean Air Scientific Advisory Committee has recommended lowering the standard again to between 0.060 and 0.070 ppm.[23]

States with areas where the NAAQS are not met must develop State Implementation Plans (SIP) for achieving and maintaining compliance.[24] Once approved, the SIPs are jointly enforceable by the state and EPA. The CAA also requires states to prevent "significant deterioration" of air quality in areas that are currently meeting the NAAQS,[25] and to take steps to protect ecosystems and improve visibility in many national parks and wilderness areas.[26]

The NAAQS are established as ambient standards, affording states flexibility to decide how best to meet them. In contrast, other sections of the CAA require EPA to directly set emissions standards for specific categories of sources. For example, section 111 of the CAA requires EPA to set New Source Performance Standards (NSPS) for stationary sources.[27] The statute requires EPA to review the NSPS every eight years, unless the agency deems review unwarranted. Over time, new control technologies, developed voluntarily or to meet state-level requirements, are expected to advance the NSPS.

EPA listed oil and natural gas production as a source category requiring NSPS in 1979[28] and issued two narrowly targeted standards for the category in 1985. The first standard required use of Leak Detection and Repair (LDAR) practices to reduce VOC emissions from leaking components at natural gas processing plants.[29] The second standard addressed emissions of sulfur dioxide from sweetening units at gas

22. 40 C.F.R § 50.15.

23. Letter from Rogene Henderson, Chair, Clean Air Scientific Advisory Committee, to Honorable Stephen L. Johnson, Administrator, EPA, Re: CASAC Peer Review of the Agency's 2nd Draft Ozone Staff Paper (Oct. 24, 2006), http://nepis.epa.gov/Exe/ZyPDF.cgi/P1000WO7.pdf?Dockey=P1000Wo7.pdf; Letter from Jonathan M. Samet, Chair, Clean Air Scientific Advisory Committee to Honorable Lisa P. Jackson, Administrator, EPA, Re: Review of EPA's proposed Ozone National Ambient Air Quality Standard (Feb. 19, 2010), http://yosemite.epa.gov/sab/sabproduct.nsf/610BB57CFAC8A41C852576C]F007076BD/$File/EPA-CASAC-10-007-unsigned.pdf.

24. 42 U.S.C. § 7410 (2012).

25. 42 U.S.C. §§ 7470–79 (2012).

26. 42 U.S.C. §§ 7475, 7491–92 (2012).

27. A stationary source is defined as "any building, structure, facility, or installation which emits or may emit any air pollutant." 42 U.S.C. § 7411(a)(3) (2012). The NSPS must reflect "the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated." 42 U.S.C. § 7411(a)(1).

28. 44 Fed. Reg. 49,222–23 (Aug. 21, 1979) (codified at 40 C.F.R § 60.16 (2014)).

29. 50 Fed. Reg. 26,122 (June 24, 1985).

processing plants.[30] As discussed below, no other NSPS were established for the source category until 2012.

Section 112 of the CAA (as amended in 1990) requires EPA to establish National Emissions Standards for Hazardous Air Pollutants (NESHAP) based on maximum achievable emissions reductions for "major" sources[31] and generally achievable reductions for smaller "area" sources.[32] Section 112 requires EPA to review the standards every eight years and revise them "as necessary."[33] As with the NSPS, EPA can tighten the NESHAP over time to reflect progress in control technology. Unlike the NSPS, NESHAP apply to both new and existing sources.

EPA listed oil and natural gas production facilities as a source category under section 112 of the CAA in 1992[34] and added natural gas transmission and storage facilities in 1998.[35] The agency established NESHAP for these categories in 1999, limiting emissions of benzene, toluene, ethyl benzene, xylenes, and n-hexane from process vents on glycol dehydration units; storage vessels with flash emissions; and equipment leaks at natural gas processing plants.[36] The 1999 requirements only applied to emissions from facilities that were major sources of Hazardous Air Pollutants (HAP). In 2007, the agency added a NESHAP addressing benzene emissions from tri-ethylene glycol dehydration units.[37,38]

Since 1993, EPA has also engaged the oil and gas industry in a voluntary partnership to encourage methane emissions reductions. This program, called Natural Gas STAR, recommends technologies and practices for limiting emissions from compressors and engines, dehydrators, and pneumatic devices, among other sources. One featured technology is

30. 50 Fed. Reg. 40158 (Oct. 1, 1985).

31. Section 112 defines major sources of HAP as those having the potential to emit 10 TPY or more of a single HAP or 25 TPY of any combination of HAP. 42 U.S.C. § 7412(a)(1) (2012).

32. 42 U.S.C. § 7412(d).

33. 42 U.S.C. § 7412(d)(6).

34. 57 Fed. Reg. 31,576, 31,591 (July 16, 1992).

35. 63 Fed. Reg. 7155, 7160 (Feb. 12, 1998).

36. 64 Fed. Reg. 32,610, 32,613 (June 17, 1999).

37. 72 Fed. Reg. 26-01, 28 (Jan. 3, 2007).

38. Separate from its actions for oil and gas production, transmission, and storage, in 2004 EPA established NESHAPs for reciprocating internal combustion engines. Though also used in other applications, these engines are important pollution sources in the oil and gas production sector. EPA's engine regulations were based primarily on concern about emissions of formaldehyde, a probable human carcinogen, and eye and respiratory tract irritant. 69 Fed. Reg. 33,474, 33,475 (June 15, 2004).

reduced emissions completions (RECs or green completions), which some Natural Gas STAR partners have used since 2000.[39]

While voluntary efforts to reduce methane moved forward, EPA's mandatory emissions standards for oil and gas sources grew increasingly out-of-date. In 2009, two environmental groups—Wild Earth Guardians and San Juan Citizens Alliance—sued EPA, alleging the agency failed to meet its statutory obligations to review and revise the NSPS and NESHAPs for the oil and natural gas source categories.[40] On February 4, 2010, the U.S. District Court for the District of Columbia entered a consent decree requiring EPA to review the standards and take final action by February 28, 2012.[41] EPA's response to the consent decree led to significantly expanded regulations, which were published in August 2012.[42]

Among other new requirements, the 2012 NSPS for oil and gas production require that flowback emissions from hydraulically fractured gas wells be flared between 2012 and 2015, and that after 2015 RECs be used to further limit these emissions.[43] Effective October 2012, the NSPS rule imposes equipment and work practice requirements to reduce VOC emissions from centrifugal and reciprocating compressors.[44] For storage vessels that would otherwise release more than 6 Tons Per Year (TPY) of VOCs, the rule requires that emissions must be reduced by 95 percent, generally within 60 days of startup.[45] Also effective in October 2013, no-bleed devices must be used for pneumatic controllers at gas processing plants and low-bleed devices for controllers between the wellhead and gas processing plant or oil pipeline.[46] Additionally, the rule tightens requirements for detecting and repairing leaks at natural gas processing

39. EPA, LESSONS LEARNED FROM NATURAL GAS STAR PARTNERS: REDUCED EMISSIONS COMPLETIONS FOR HYDRAULICALLY FRACTURED NATURAL GAS WELLS 1 (2011), http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf. In a reduced emissions completion or "green completion," special equipment separates gas and liquid hydrocarbons from the flowback that comes from the well as it is being prepared for production. As a consequence the gas and liquid hydrocarbons can be recovered for use or sale more quickly, avoiding the need to vent or flare some of the gas associated with the flowback sand and liquids.

40. Wild Earth Guardians v. Jackson, No. 1:09-CV-00089-CKK (D.D.C., Jan. 14, 2009) (Complaint).

41. Wild Earth Guardians v. Jackson, No. 1:09-CV-00089-CKK (D.D.C., Feb. 5, 2010) (Consent decree).

42. 77 Fed. Reg. 49490 (Aug. 16, 2012).

43. 40 C.F.R. § 60.5375 (2013).

44. 40 C.F.R. §§ 60.5380, 60.5385.

45. 40 C.F.R. § 60.5395.

46. 40 C.F.R. § 60.5390

plants.[47] The NSPS rule does not directly regulate methane, but considers reductions in methane as a co-benefit of measures to reduce VOC emissions. EPA states that it will "continue to evaluate the appropriateness" of directly regulating emissions of methane and other greenhouse gases from oil and gas production.[48]

EPA revised the NESHAP for the oil and natural gas production and natural gas storage and transmission source categories at the same time that it revised the NSPS. The new NESHAP rule establishes standards for smaller glycol dehydration units than were previously regulated.[49] The NESHAP took effect for new units in October 2012, with compliance required for existing units in October 2015.[50]

In the preamble accompanying the proposed rules, EPA indicated it had identified control options by reviewing state and local requirements and voluntary measures reported to the Natural Gas STAR program.[51] The agency highlighted regulations in Colorado and Wyoming as especially instructive.[52] A 2012 study assessing the likely impact of EPA's proposed rules concluded that the requirements for well completions, pneumatics, storage tanks, and dehydration units would be similar to those already being applied in all or parts of Colorado and Wyoming.[53] On the other hand, the same study concluded Utah and New Mexico lacked comparable requirements to any of the proposed NSPS or NESHAPs.[54]

V. STATE AND TRIBAL REGULATION OF OIL AND GAS PRODUCTION SOURCES UNDER THE CAA

A. State Regulation

With the NSPS and NESHAP, the CAA requires EPA to directly set nationwide emissions standards. Other provisions of the CAA require states to set their own standards or otherwise regulate sources under their jurisdiction, as needed to ensure local air quality meets the NAAQS and other goals. Section 110(a)(2) of the CAA sets forth requirements for SIPs including the requirement that each plan "include enforceable emission limitations and other control measures, means, or techniques as may be necessary or appropriate to meet the applicable

47. 40 C.F.R. § 60.5400.
48. 77 Fed. Reg. 49,490, 49,513 (Aug. 16, 2012).
49. 40 C.F.R. § 63.760 (2013).
50. 77 Fed. Reg. 49,490, 49,502 (Aug. 16, 2012); 40 C.F.R. § 63.760(f)(7).
51. 76 Fed. Reg. 52,738, 52,757 (Aug. 23, 2011).
52. *Id.*
53. GRIBOVICZ, *supra* note 13, at 5.
54. *Id.* at 25, 26.

requirements of this chapter."[55] Section 110(a)(2) further requires states to regulate the "modification and construction of any stationary source within the areas covered by the plan as necessary to assure that national ambient air quality standards are achieved, including a permit program as required in parts C and D of this subchapter."[56] Part C contains requirements designed to prevent significant deterioration of air quality in areas that meet the NAAQS, while part D applies for areas where the NAAQS are not being met.[57]

The preconstruction review requirements that are specified in CAA Parts C and D focus on "major" stationary sources, generally those with the potential to emit more than 100 to 250 TPY of any air pollutant.[58] However, the general preconstruction review requirement in section 110 also encompasses smaller, "minor" sources as well. While pre-construction review requirements for major sources are specified in some detail in the CAA and EPA's implementing regulations, there is wider latitude for states to design their own programs for minor sources.[59]

Requirements for states to regulate emissions can cover existing sources as well as new ones. In fact, states must regulate existing sources in areas that are out of compliance with the NAAQS, where remedial measures may help achieve the standards. Under the CAA, existing sources located in nonattainment areas are required at a minimum to install Reasonably Available Control Technology (RACT).[60]

Whether a source is deemed minor or major for purposes of preconstruction review and permitting prompts the question of how "major" and "minor" sources are defined, i.e., whether emissions from multiple pieces of equipment at a facility are aggregated together to comprise a single source or counted as multiple distinct sources.[61] This issue has been controversial for natural gas production facilities, as systems of pipelines physically connect wells, processing, and storage equipment across large distances.[62] EPA regulations specify that a cluster of emissions release points should be treated as a single source when they (1)

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55. 42 U.S.C. § 7410(a)(2)(A) (2012).

56. 42 U.S.C. § 7410(a)(2)(C). Regulations implementing the statutory requirements are found at 40 C.F.R. §§ 51.160–64 (2013).

57. Although the language and specifics of section 110 were amended in 1977 and again in 1990, the 1970 CAA included the essential requirements for SIPs to provide for enforceable emissions limits or other measures to ensure the NAAQS are met, and to include some form of preconstruction review for stationary sources.

58. 42 U.S.C. §§ 7479(1), 7602(j), 7602(z) (2012).

59. 40 C.F.R. §§ 51.160–66 (2013).

60. 42 U.S.C. § 7502 (2012).

61. Ala. Power Co. v. Costle, 636 F.2d 323, 396–97 (D.C. Cir. 1979).

62. Steven H. Lord Jr., *Aggregation Consternation: Clean Air Act Source Determination Issues in the Oil &Gas Patch*, 29 PACE ENVTL. L. REV. 645, 651–52 (2012).

belong to the same industrial grouping, (2) are located on one or more contiguous or adjacent properties, and (3) are under common ownership or control.[63] Western states have generally interpreted those conditions to restrict aggregation of oil and gas production facilities.[64] Consequently, while some facilities, like large gas processing plants and compressor stations, have high enough emissions to be treated as major sources for permitting purposes, a large fraction of emissions from oil and gas production, including those from operations and equipment at most well sites, are treated as coming from minor sources.

B. Tribal Regulation

A significant amount of oil and gas activity in Colorado, New Mexico, and especially Utah occurs in Indian Country, where states generally lack jurisdiction.[65] The 1990 CAA Amendments and EPA's implementing regulations establish a legal framework for federally enforceable tribal regulation of sources within reservation boundaries, including sources on non-Indian-owned fee land.[66] However, most tribes lack the resources needed to develop comprehensive air quality management programs.[67]

EPA has historically administered permits for most major sources in Indian Country, but until recently lacked a program for pre-construction review of minor sources. Finally, on July 1, 2011, EPA issued a Federal Implementation Plan (FIP) for Indian Country, including a program to register and permit minor sources.[68] The program includes requirements for public notice of permit applications, monitoring, record keeping and reporting, and provision for the permitting authority to require air quality impact analysis and/or installation of control technology if local conditions so require. The FIP sets permitting thresholds that depend on the pollutant and the area's attainment status. In areas that are meeting the NAAQS, permits are required for new sources with the potential to emit more than 10 TPY for NOx and 5 TPY for VOC emissions.

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63. 40 C.F.R. § 52.21(b)(6) (2013).

64. Lord Jr., *supra* note 62, at 649.

65. Worcester v. Georgia, 31 U.S. 515 (1832) (holding invalid a Georgia law that required state licensing for non-Indians to reside on Cherokee land). WILLIAM D. RUCKELSHAUS, EPA POLICY FOR THE ADMINISTRATION OF ENVIRONMENTAL PROGRAMS ON INDIAN RESERVATIONS (Nov. 8, 1984), *available at* http://www.epa.gov/tp/pdf/indian-policy-84.pdf.

66. Jana B. Milford, *Tribal Authority Under the Clean Air Act: How is it Working?* 44 NAT. RESOURCES J. 213, 213 (2004).

67. *Id.* at 215.

68. 76 Fed. Reg. 38,748 (July 1, 2011) (Codified at 40 C.F.R. pts. 49 & 51).

Corresponding thresholds for nonattainment areas are 5 and 2 TPY.[69] The FIP required owners and operators of existing minor sources in Indian Country to register their sources by March 1, 2013.[70] The requirement to obtain a permit before constructing new minor sources in the oil and gas industry goes into effect March 2, 2016.[71] Once implemented, this program is expected to have a significant effect on emissions in the San Juan and Uinta Basins.[72]

Among the tribes in the Rocky Mountain region with significant oil and gas activity, the Southern Ute Indian Tribe has moved forward most actively to assume responsibility for regulating emissions. In 2006, nearly 380,000 million ft^3 of natural gas was produced on Southern Ute Indian tribal lands, primarily from coal bed methane formations.[73] The Tribe has conducted air quality monitoring since the early 1980s[74] and completed an emissions inventory for oil and gas sources in 2002.[75] Based on the Tribe's monitoring data, EPA has designated the reservation as meeting the 0.075 ppm 8-hour ozone standard.[76] In March 2012, EPA approved the Tribe's operating permits and inspection program for large stationary sources.[77] The Tribe is moving forward to assume responsibility for implementing NSPS and NESHAPs requirements and to develop a minor source permit program.[78]

69. 40 C.F.R. § 49.153 (2013).

70. 40 C.F.R. § 49.151(c)(1)(iii)(A).

71. 40 C.F.R. § 49.151(c)(1)(iii)(B). EPA originally set the effective date for the construction permit requirement as September 2, 2014, for minor sources in all industrial sectors. 76 Fed. Reg. 38,748, 38,751 (July 1, 2011). In June, 2014, EPA extended the permit deadline for the oil and natural gas industry to March 2, 2016, retaining the original deadline for all other sectors. 79 Fed. Reg. 34,231 (June 16, 2014).

72. GRIBOVICZ, *supra* note 13, at 37, 39, 46, 48, 50.

73. AMNON BAR-ILAN ET AL., ENVIRON INT'L CORP., DEVELOPMENT OF BASELINE 2006 AND MIDTERM 2012 EMISSIONS FROM OIL AND GAS ACTIVITY IN THE NORTH SAN JUAN BASIN 6 (2009), http://www.wrapair.org/forums/ogwg/documents/NSanJuanBasin/2009-09_06_Baseline_and_12_Midterm_Emissions_N_San_Juan_Basin_Technical_Memo_09-01.pdf.

74. *Ambient Monitoring*, S. UTE INDIAN TRIBE, www.southernute-nsn.gov/air-quality/ambient-monitoring (last visited Sept. 13, 2014).

75. *Emissions Inventory*, S. UTE INDIAN TRIBE, www.southernute-nsn.gov/air-quality/emissions-inventory (last visited Sept. 13, 2014).

76. 77 Fed. Reg. 30,088, 30,089, 30,110 (May 21, 2012). The formal designation is "unclassifiable/attainment," meaning the area is meeting the standard or expected to be meeting the standard despite a lack of monitoring data.

77. 77 Fed. Reg. 15,267 (Mar. 15, 2012).

78. S. UTE INDIAN TRIBE/STATE OF COLO. ENVTL. COMM'N, MINOR SOURCE PROGRAM (March 1, 2012) (Draft Report), *available at* http://www.southernute-nsn.gov/wp-content/uploads/2013/05/DRAFT-Minor-Source-Program-FLowchart-2012-03-01.pdf.

VI. FEDERAL REQUIREMENTS TO CONSIDER AIR QUALITY IMPACTS UNDER NEPA

The Bureau of Land Management (BLM) is responsible for leasing federal lands for oil and gas production, as well as leasing on state and private lands where mineral rights have been retained by the federal government.[79] Figure 2 shows the history of drilling under federal leases (on federal and split estate lands) in Colorado, New Mexico, Utah, and Wyoming from 1990 to 2011. In FY 2012, the federal government earned more than $600 billion in revenues from oil and gas royalties, lease rents, and bonus payments in Wyoming alone.[80]

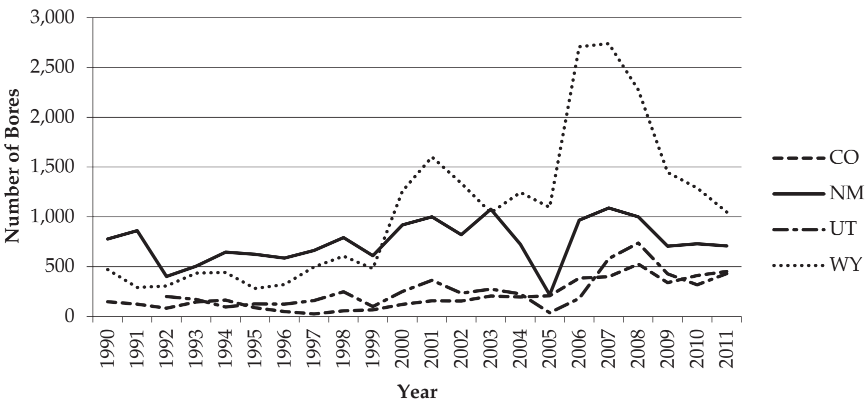

FIGURE 2. Number of well bores started on federal lands in Colorado, New Mexico, Utah, and Wyoming.[81]

BLM's role in oil and gas leasing invokes National Environmental Policy Act (NEPA)[82] requirements for assessment of environmental impacts whenever an agency proposes a "major federal action significantly affecting the quality of the human environment."[83] This occurs at several stages in the oil and gas development process. First, lands must be designated as available for leasing in resource management plans, the development of which requires NEPA review. Review is also required when oil and gas producers propose to develop resources in a particular field.

79. BLM does not lease minerals under tribal lands.

80. *Statistical Information*, OFFICE OF NATURAL RES. REVENUE, http://statistics.onrr.gov (last visited Sept. 13, 2014).

81. *Oil & Gas Statistics*, BUREAU OF LAND MGMT., www.blm.gov/wo/st/en/prog/energy/oil_and_gas/statistics.html (last updated Apr. 18, 2014).

82. National Environmental Policy Act of 1969, 42 U.S.C. §§ 4321-70 (2012).

83. 42 U.S.C. § 4332(C).

At this stage, projects are proposed in sufficient detail regarding location, timing, and operating plans to allow analysis and quantification of specific impacts, alternative actions, and potential mitigation measures. Large projects require a full environmental impact statement (EIS), with opportunities for public input in scoping potential issues and reviewing at least one draft. Supplementation may be required if significant new information becomes available before BLM announces its final action in a Record of Decision (ROD). Subsequent to project approval, additional NEPA review is required before BLM can issue permits to drill.[84]

For large project proposals, NEPA requires BLM to assess and report the air quality impacts (along with other environmental and cultural consequences) anticipated from the project and from proposed project alternatives, as well as cumulative impacts of the project together with other "reasonably foreseeable development." Beyond disclosing these effects, BLM must identify appropriate measures to minimize adverse impacts.[85] BLM must also ensure that a proposed project complies with its duty under the Federal Land-Use Planning and Management Act (FLPMA), which mandates that its land-use plans "provide for compliance with applicable pollution control laws, including State and Federal air, water, noise, or other pollution standards or implementation plans . . ."[86] Furthermore, the CAA requires federal agencies to ensure their actions "conform" to applicable SIPs, demonstrating they will not cause or contribute to violations or delay attainment of NAAQS.[87] These "general conformity" requirements have recently come into play in western Wyoming, where federal oil and gas leasing is occurring in an area where the NAAQS for ozone has been violated.

VII. REGULATION OF OIL AND GAS PRODUCTION SOURCES IN WYOMING

A. Production Trends

As shown in Figure 1, crude oil production in Wyoming declined from almost 300,000 barrels per day in 1990 to about 150,000 barrels per day in 2010.[88] In contrast, over the same period natural gas production rose by more than a factor of three,[89] and the number of producing natu-

84. *See generally* 43 C.F.R. §§ 46.10, 46.100 (2013).
85. 40 C.F.R. §§1502.14(f), 1502.16(h) (2013).
86. 43 U.S.C. § 1712(c)(8) (2012).
87. 42 U.S.C. § 7506(c)(1)(A), (B) (2012); 40 C.F.R. § 51.851 (2013).
88. *Petroleum & Other Liquids: Crude Oil Production*, *supra* note 9.
89. *Natural Gas: Natural Gas Gross Withdrawals and Production*, *supra* note 7.

ral gas and condensate wells increased by a factor of ten.[90] Much of the growth has been concentrated in Sublette County in the western part of the state, which currently accounts for about half of Wyoming's natural gas production.[91] Pinedale (population ~2,000) is the center of much of the activity.

B. Air Quality Issues

Wyoming is known for wide-open spaces and wind—conditions usually linked with good air quality. However, as oil and gas production activity in western Wyoming expanded in the late 1990s, citizens, environmental groups, and public officials began to express concern about potential impacts on visibility and atmospheric deposition in the nearby Bridger and Fitzpatrick Wilderness Areas. These areas are given special protection as Class I areas under the CAA. Furthermore, by 2004, Pinedale area residents were registering complaints with Wyoming's Department of Environmental Quality (WDEQ) about obvious haze and occasionally heavy black smoke from oil and gas operations.[92]

In the late 1990s and early 2000s, the NEPA review process was an important forum for consideration of air quality impacts in western Wyoming. EISs published in the mid-1990s for the Fontenelle and Moxa Arch projects, each proposing about 1,300 new wells, projected noticeable visibility reductions in the Bridger Wilderness Area on numerous days each year due to cumulative impacts of oil and gas development.[93] The 1999 draft EIS for the Pinedale Anticline Oil and Gas Exploration Project stated the U.S. Forest Service had "determined that the cumulative impacts from the Pinedale Anticline Project, combined with other recently proposed projects in southwest Wyoming, are significant in increasing visibility impairment in the Bridger Wilderness Area."[94] In response, one of the project proponents helped finance new control equipment at a nearby power plant to help offset emissions of haze-causing NOx.[95] However, those reductions were quickly outpaced by increased emissions from natural gas production. Projections of frequent

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90. *Natural Gas: Number of Producing Gas Wells*, *supra* note 8.

91. Wyo. Oil and Gas Conservation Comm'n, *2012 County Report*, http://wogcc.state.wy.us/CountyReportYear.cfm (select 2012 and click "Go").

92. Bruce Pendery, Wyo. Outdoor Council, Evidence of Impairment of Air Quality Related Values in the Bridger Wilderness Area, Wyoming 4-11, 17-18 (2007) (on file with author).

93. *Id.* at 15-16.

94. Bureau of Land Mgmt, Pinedale Field Office, Draft Environmental Impact Statement for the Pinedale Anticline Oil and Gas Exploration and Development Project Sublette County, Wyoming, 19 (1999) (on file with author).

95. *Id.* at 20.

and significant visibility impacts remained a prominent issue in the NEPA reviews of the large infill projects proposed for the Jonah field (3,100 new wells)[96] and the Pinedale Anticline (4,400 new wells) in the mid- to late-2000s.[97]

A new concern arose after ozone monitoring started in Sublette County in 2005. Due to the role of sunlight and influence of temperature, elevated ozone levels are normally a summertime problem.[98] However, ozone concentrations well above the NAAQS were observed at multiple monitoring sites in Sublette County in the winters of 2005, 2006, 2008, and 2011.[99] Oil and gas emissions, stagnant atmospheric conditions and extensive snow cover that reflects sunlight and enhances photolysis contribute to this phenomenon, which also occurs in the Uinta Basin. In March 2009, Governor Dave Freudenthal recommended nonattainment status with respect to the ozone NAAQS for the Upper Green River Basin (UGRB), including Sublette County and parts of Sweetwater and Lincoln Counties.[100] EPA accepted the recommendation and published this designation in April 2012.[101] The designation took effect on July 20, 2012.[102]

C. Regulatory Authority and Structure

Air quality regulations in Wyoming are promulgated by the Environmental Quality Council and administered by the Wyoming Department of Environmental Quality's Air Quality Division. WDEQ was

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96. BUREAU OF LAND MGMT., PINEDALE & ROCK SPRINGS FIELD OFFICES, FINAL ENVIRONMENTAL IMPACT STATEMENT, JONAH INFILL DRILLING PROJECT, SUBLETTE COUNTY, WYOMING 4-7, app. J-13 (2006), *available at* http://www.blm.gov/wy/st/en/info/NEPA/documents/pfo/jonah.html.

97. BUREAU OF LAND MGMT, PINEDALE FIELD OFFICE, FINAL SUPPLEMENTAL ENVIRONMENTAL IMPACT STATEMENT FOR THE PINEDALE ANTICLINE OIL AND GAS EXPLORATION AND DEVELOPMENT PROJECT SUBLETTE COUNTY, WYOMING 4-73 to 4-98 (2008), *available at* http://www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA/pfodocs/anticline/fseis.Par.30367.File.dat/vol1_ea.pdf.

98. Russell C. Schnell et al., *Rapid Photochemical Production of Ozone at High Concentrations in a Rural Site During Winter*, 2 NATURE GEOSCIENCE 120, 120 (2009).

99. METEOROLOGICAL SOLUTIONS INC., ENVIRON INTL. CORP. & T&B SYS., FINAL REPORT 2011 UPPER GREEN RIVER OZONE STUDY 1-1, 4-7, *available at* http://deq.state.wy.us/aqd/Resources-Ozone/Resources%20-Sub-%20Ozone-Winter/Technical%20Documents/Final_UGWOS_2011_Ozone_Study_Report_Text_and_Appendices.pdf.

100. Letter from Dave Freudenthal, Governor of Wyo., to Carol Rushin, Acting Reg'l Adm'r, EPA, Region 8, *Wyoming 8-Hour Ozone Designation Recommendation* (Mar. 12, 2009), *available at* http://www.fossil.energy.gov/programs/gasregulation/authorizations/2012_applications/sierra_exhibits_12-77-LNG/Ex._36_-_Rushin_Letter.pdf.

101. 77 Fed. Reg. 30,157–58 (May 21, 2012).

102. *Id.*

established in 1973. The state has required new facilities or sources to obtain permits prior to construction since May 1974.[103] Among other requirements to obtain a construction permit, the applicant must demonstrate that the proposed facility will utilize the Best Available Control Technology (BACT).[104] On their face, the construction permit requirements apply to facilities of any size. However, Wyoming regulations provide that construction permits will not be required for "such other minor sources which the Administrator determines to be insignificant in both emission rate and ambient air quality impact."[105] The size of oil and gas production sources deemed to be insignificant has evolved over time.

WDEQ's Air Quality Division has two permit engineers who currently process about 700 construction permit applications a year for oil and gas production facilities. The state has about 10 air emissions inspectors statewide, who handle inspections at oil and gas facilities and at other sources.[106] This is a small number of staff compared to the thousands of well sites and other emitting facilities in Wyoming.

D. Regulatory Timeline

In October 1995, the administrator of WDEQ's Air Quality Division, Charles A. Collins, notified the state's oil and gas producers of a change in policy on construction and operating permits, stating:

> [T]he fact that there are unpermitted sources of VOCs (post May 1974) is not surprising because of the evolution of determining the significance of these emissions. However, the time has come and gone since these sources, especially the major sources, should have been controlled to insignificant levels or permitted.[107]

Collins' 1995 memo states that construction permit requirements would be waived for minor sources based on the oil and gas operators' suggested insignificance levels: less than 50 TPY (of uncontrolled emis-

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103. *See* WYO. DEPT. OF ENVTL. QUALITY, AIR QUALITY DIV., STANDARDS AND REGULATIONS, PERMITTING REQUIREMENTS, Chapter 6, Section 2(a)–(b) *available at* http://soswy.state.wy.us/Rules/RULES/9296.pdf.

104. *Id.* at Section 2(c)(v).

105. *Id.* at Section 2(k)(viii).

106. E-mail from Heather Bleile, Air Quality Engineer, Wyo. Dept. of Envtl. Quality (June 13, 2013) (on file with author).

107. Memorandum from Charles A. Collins, Adm'r, Wyo. Dept. of Envtl. Quality, Air Quality Division, to Wyo. Oil & Gas Producers, Re: Air Quality Permit for Oil & Gas Production Facilities (Revision) (Oct. 23, 1995) (on file with author).

sions) for regulated pollutants, less than 5 TPY for individual HAPs, and less than 12.5 TPY for total HAPs.

In May 1997, Collins wrote to the oil and gas producers again, announcing that the state was rescinding the permitting waiver for sources with less than 50 TPY of emissions.[108] In rescinding the waiver, Collins wrote:

> [P]rospects of increased natural gas development in Southwest Wyoming and other parts of the state . . . has caused the Division to take another look at its current permit waiver policy. While emissions from a small number of production facilities may still be insignificant by themselves, the prospect of thousands of production facilities emitting at 50 TPY or less is not insignificant.[109]

The state has subsequently taken the position there is no threshold below which BACT does not need to be considered for oil and gas production facilities. However, that stance has been tempered by guidance on "presumptive" BACT, which does incorporate thresholds for control requirements. In its presumptive BACT guidelines, WDEQ specifies control or work practice requirements that it will automatically accept as the BACT for a particular type of equipment. Oil and gas producers can use presumptive BACT to avoid the need for case-by-case consideration of control options. In January 1999, WDEQ issued presumptive BACT for flashing losses from condensate and crude oil pressure vessels and storage tanks at new or modified well-site facilities.[110] Wyoming expanded its requirements in August 2001, requiring controls with 98 percent effectiveness for storage tanks and pressure vessels with projected VOC emissions above 40 TPY, individual HAP emissions above 10 TPY or combined HAP emissions above 25 TPY.[111] At that time, the state also required controls with 90 percent effectiveness for new well-site glycol dehydration units with projected VOC emissions above 15 TPY or HAP emissions above 7 TPY.[112]

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108. Memorandum from Charles A. Collins, Adm'r, Wyo. Dept. of Envtl. Quality, Air Quality Division, to Wyo. Oil and Gas Producers, Re: Rescinding Waiver Thresholds for Production Facilities (May 22, 1997), *available at* http://deq.state.Wyoming.us/aqd/Oil%20and%20Gas/052297.pdf.

109. *Id.*

110. Memorandum from Dan Olson, Adm'r, Wyo. Dept. of Envtl. Quality, Air Quality Division, to Wyoming Oil and Gas Producers, Re: Oil and Gas Production Facilities Section 21 Permitting Guidance (Revision) (Jan. 6, 1999).

111. WYO. DEPT. OF ENVTL. QUALITY, AIR QUALITY DIV., OIL AND GAS PRODUCTION FACILITIES, CHAPTER 6, SECTION 2 PERMITTING GUIDANCE 8-13 (2001) (on file with author).

112. *Id.* at 18–25.

In July 2004, WDEQ acted to address new development in the Jonah Field and Pinedale Anticline, stating, "[i]ntensified production activity, increased concentration of gas/condensate production equipment and consequential air quality impact due to proposed infill drilling and tight well spacing . . . warrants revisiting of the current emission control strategy."[113] For new equipment in these specific gas fields, the state shortened the time allotted for installation of controls and lowered the thresholds for requiring controls.[114] For multiple well pads in the Jonah and Pinedale Anticline Development Areas (JPDA), the new requirements included continuous monitoring of pilot flame status for emissions control flares. In June 2007, WDEQ tightened the thresholds and timelines for installing controls on new tanks and glycol dehydration units, maintaining separate requirements for the JPDA versus the rest of the state.[115] Presumptive BACT requirements were added for pneumatic pumps in the Jonah and Pinedale areas.

WDEQ issued comprehensive revisions to its oil and gas permitting guidance in March 2010, creating separate requirements issued for the Jonah/Pinedale area, a seven-county "concentrated development area" (CDA) in southwest Wyoming, and the rest of the state.[116] The guidance included presumptive BACT for new or modified sources in all three areas for flashing emissions, dehydration units, pneumatic pumps, pneumatic controllers, and blowdown/venting operations. For both the CDA and the JPDA, presumptive BACT was also specified for produced water tanks and gas well completions. The completions guidance calls for "Best Management Practices" for green completions.[117]

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113. WYO. DEPT. OF ENVTL. QUALITY, AIR QUALITY DIV., JONAH & PINEDALE ANTICLINE GAS FIELDS: ADDITIONS TO OIL AND GAS PRODUCTION FACILITY EMISSION CONTROL AND PERMITTING REQUIREMENTS 1 (2004) (on file with author)

114. The 2004 guidance did not affect existing facilities operating under permit or waiver unless and until they were modified. *Id.*

115. WYO. DEPT. OF ENVTL. QUALITY, AIR QUALITY DIV., OIL AND GAS PRODUCTION FACILITIES CHAPTER 6, SECTION 2 PERMITTING GUIDANCE (2007). The 2007 requirements were effective only for new wells or facilities modified after Sept. 1, 2007.

116. WYO. DEPT. OF ENVTL. QUALITY, AIR QUALITY DIV., OIL AND GAS PRODUCTION FACILITIES CHAPTER 6, SECTION 2 PERMITTING GUIDANCE 4-21 (2010) (on file with author). Requirements in the 2010 guidance apply to wells spud and facilities modified after Aug. 1, 2010.

117. The accompanying example permit states that "[t]he operator shall follow the operational plan for Best Management Practices described in the application for this permit to eliminate to the extent practicable emissions of volatile organic compounds and hazardous air pollutants associated with flaring and venting of hydrocarbon fluids recovered during well completion/re-completion activities." Wyo. Dept. of Envtl. Quality, Air Quality Div., Example Well Completions ("Green Completions") Permit (2010), *available at* http://deq.state.wy.us/aqd/Resources-New%20Source%20Review/Application%20Forms/ExampleWellCompletionsPermit%20March2010.pdf.

WDEQ revised its guidance again in September 2013, this time distinguishing four areas. Requirements are most stringent for the JPDA and adjacent "Normally Pressured Lance" project areas (JPDA/NPL), followed by those for the UGRB, the remainder of the CDA, and the rest of the state. For the JPDA/NPL and UGRB, the 2013 guidance adds a requirement for new or modified sources with fugitive VOC emissions estimated to exceed 4 TPY to adopt protocols for LDAR, requiring instrument-based inspections on at least a quarterly basis.[118]

In parallel with WDEQ's permitting guidance, decisions made under NEPA also advanced control requirements and practices in parts of Wyoming. The draft EIS for the Jonah Infill project, issued in February 2005, does not mention control requirements for well completions.[119] However, the supplement to the draft EIS, which was issued in August 2005, lists flareless completions as a mitigation option for limiting impacts on visibility.[120] Air quality modeling in the supplemental EIS assumes that up to 80 percent of completions in the Jonah Infill project would be flareless, green completions.[121] The Q & A document accompanying the supplement explains the change as follows:

> In February 2004 flaring from the completion of a gas well occurred outside of Pinedale. The flare temporarily created visibility impacts to Pinedale and nearby communities. Industry resolved to employ "green completions" (flareless) and new technology as soon as practical.[122]

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118. WYO. DEPT. OF ENVTL. QUALITY, AIR QUALITY DIV., OIL AND GAS PRODUCTION FACILITIES Chapter 6, Section 2 Permitting Guidance 22 (2013), *available at* http://deq.state.wy.us/aqd/Resources-New%20Source%20Review/Guidance%20Documents/September%202013%20FINAL_Oil%20and%20Gas%20Revision_UGRB.pdf.

119. BUREAU OF LAND MGMT., PINEDALE & ROCK SPRINGS FIELD OFFICES, DRAFT ENVIRONMENTAL IMPACT STATEMENT, JONAH INFILL DRILLING PROJECT, SUBLETTE COUNTY, WYOMING (2005), *available at* http://www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA/pfodocs/jonah.Par.7974.File.dat/31deis.pdf.

120. *See* BUREAU OF LAND MGMT., PINEDALE & ROCK SPRINGS FIELD OFFICES, JONAH INFILL DRILLING PROJECT, DRAFT ENVIRONMENTAL IMPACT STATEMENT, AIR QUALITY IMPACT ANALYSIS SUPPLEMENT 21 (2005), *available at* http://www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA/pfodocs/jonah.Par.2443.File.dat/53deis_aqsupplement.pdf (noting that emissions can be reduced by 80 percent by having all drill rigs emit at Tier 2 levels and no completion flares).

121. TRC ENVTL. CORP., JONAH INFILL DRILLING PROJECT, DRAFT AIR QUALITY TECHNICAL SUPPORT DOCUMENT SUPPLEMENT 21 (2005), *available at* http://www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA/pfodocs/jonah.Par.7211.File.dat/54aqtsd_supplement.pdf.

122. *Jonah Infill Drilling Project, Air Quality Impact Analysis Supplement Q & As*, BUREAU OF LAND MGMT., PINEDALE FIELD OFFICE, http://www.blm.gov/wy/st/en/info/NEPA/documents/pfo/jonah/QandAs.html (last updated Jan. 25, 2011). The February 2004 flaring incident was also cited in a March 2005 article in the Casper Star-Tribune as a trigger for

The Record of Decision for the Jonah Infill Drilling Project, issued in March 2006, includes the administrative condition:

> [O]perators will utilize flareless completions for all wells within the JIDPA [Jonah Infill Drilling Project Area] unless proven to the satisfaction of the authorized officer . . . that flareless completion operations would not be technically or economically feasible or would be unsafe, and that WDEQ has issued a permit to conduct well completion flaring for that specific well.[123]

Later that year, the draft supplemental EIS for the Pinedale Anticline Project Area listed the assumption that "all completions . . . would be 'green completions' with no flaring other than for upset/emergency conditions."[124]

BLM's NEPA analyses in the mid-2000s also considered control requirements for NOx emissions from drill rigs and compressor engines that would go beyond then-existing state or EPA regulations. The ROD for the Jonah Infill project specified that, in order to address projected visibility impacts, Tier 2 or equivalent[125] diesel engine emissions control technologies would be required "for all drill rigs at the earliest possible date." The ROD, which was issued in March 2006—after elevated ozone

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WDEQ to start requiring operators in the Pinedale area to apply for permits to use flaring in well completion operations. Whitney Royster, *DEQ Begins to Regulate 'Flaring,'* CASPER STAR-TRIB., Mar. 23, 2005, *available at* http://trib.com/news/state-and-regional/deq-begins-to-regulate-flaring/article_1d2cd291-33b6-5791-8b39-484ef8940ddd.html. The incident was captured in a photograph taken by Pinedale resident William Belveal, which showed a large black smoke plume against a snow-covered landscape. *Id.*

123. ROBERT A. BENNETT, BUREAU OF LAND MGMT., RECORD OF DECISION FOR JONAH INFILL DRILLING PROJECT, ENVTL IMPACT STATEMENT A-7 (2006), *available at* http://www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA/pfodocs/jonah.Par.2901.File.dat/00rod.pdf. WDEQ had required reporting of well flaring or venting events, including those associated with well completions, since 1986. Memorandum from Dan Olson, Adm'r, Wyo. Dept. of Envtl. Quality, Air Quality Div., to Oil and Gas Production Companies Operating in Wyoming, Re: Reporting Guidelines for Well Flaring or Venting (Dec. 7, 1999), *available at* http://deq.state.wy.us/aqd/Resources-New%20Source%20Review/Guidance%20Documents/ventmem.pdf.

124. TRC ENVTL. CORP., DRAFT SUPPLEMENTAL PINEDALE ANTICLINE OIL AND GAS EXPLORATION AND DEVELOPMENT, ENVIRONMENTAL IMPACT STATEMENT, AIR QUALITY IMPACT ANALYSIS TECHNICAL SUPPORT DOCUMENT 9 (2006), *available at* http://www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA/pfodocs/anticline/seis.Par.58477.File.dat/27vol1_aqtsd.pdf.

125. EPA has adopted successive "tiers" of emissions standards for non-road engines. 40 C.F.R. § 89.112 (2013). Tier 2 standards were the second round to be established, and applied to engines manufactured in the early-to-mid 2000s (with the specific model years of application depending on the engine size). *Id.* BLM requirements thus essentially called for drill rigs used in the Jonah Infill area to comply with the latest standards for new engines.

concentrations had been observed that winter and the winter before—also specified that BLM would work with WDEQ and EPA on expanding ozone monitoring in the area.[126]

The September 2008 ROD for the Pinedale Anticline project adopted an adaptive management approach, with the goals of eliminating days when the project caused significant visibility impairment at the Bridger Wilderness Area, and ensuring "continued attainment of the Wyoming Ambient Air Quality Standards" for ozone. If needed, mitigation measures could include natural gas-fired drill rig engines, electrification of drilling rigs and compressors, application of selective catalytic reduction to drill rig engines, and reducing the pace of development.[127]

In 2012, WDEQ initiated a citizen's task force to assist in developing a strategy to bring the UGRB into attainment with the ozone NAAQS. The task force announced near-term elements of the strategy in March 2013,[128] which include increased monitoring and ozone chemistry field studies and promoting voluntary emissions reductions during "action days" with potential for high ozone. The state is also instituting specified federal requirements for nonattainment areas that include more stringent new source review requirements for major sources, evaluating RACT for existing sources, and general conformity requirements for federal actions. Finally, WDEQ also committed to extend its JPDA BACT requirements to the whole Upper Green River Basin nonattainment area, and to incorporate EPA's new NSPS and NESHAPs into state regulations. The revised guidance issued in September 2013 partially addressed these commitments.[129]

Looking forward, Wyoming faces the challenge of managing air quality impacts from extensive new projects on top of those from its existing oil and gas activity. In the nonattainment area, proposed projects include 3,500 wells in an area adjacent to the Jonah Field (the Normally Pressured Lance Natural Gas Development Project), and the 840 well LaBarge Platform Exploration and Development Project. Proposed new projects outside of the nonattainment area include a 4,250 well project in

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126. Bennett, *supra* note 123, at A-3.

127. C. STEPHEN ALLRED, BUREAU OF LAND MGMT., RECORD OF DECISION FOR THE SUPPLEMENTAL ENVIRONMENTAL IMPACT STATEMENT, PINEDALE ANTICLINE OIL AND GAS EXPLORATION AND DEVELOPMENT PROJECT 25–26 (2008), *available at* http://www.blm.gov/pgdata/etc/medialib/blm/wy/information/NEPA/pfodocs/anticline/rod.Par.50775.File.dat/00ROD.pdf.

128. WYO. DEPT. OF ENVTL. QUALITY, AIR QUALITY DIV., UPPER GREEN RIVER BASIN OZONE STRATEGY 1 (2013), *available at* http://deq.state.wy.us/aqd/Resources-Ozone/Resources%20-Sub-%20Ozone-Winter/Technical%20Documents/WDEQAQD_UGRB_OzoneStrategy_031113.pdf.

129. WYO. DEPT. OF ENVTL. QUALITY, *supra* note 118.

the center of the state, and a 9,000 well project in the south-central part of the state.[130] Monitoring data presented in the Draft EIS for this last project, known as the Continental Divide-Crestone project, indicate that ozone concentrations across much of the project area are already in the range of 0.06 to 0.07 ppm,[131] which is the range EPA's Clean Air Scientific Advisory Committee has recommended as the revised standard.[132]

VIII. REGULATION OF OIL AND GAS PRODUCTION SOURCES IN COLORADO

A. Production Trends

Natural gas production in Colorado increased by more than a factor of six from 1990 to 2010 (Figure 1a).[133] The state's oil production declined in the late 1990s, but then increased by about 80 percent from 2000 to 2010 (Figure 1c).[134] Colorado currently has over 49,000 active oil and gas wells.[135] More than 19,000 of them are located in Weld County in northeastern Colorado, with nearly 10,000 more located in Garfield County, in the northwestern part of the state.[136] Approximately 500 drilling permits were issued in Weld County in 2000; the number peaked at 2,340 in 2008.[137] A little over 200 drilling permits were issued for Garfield County in 2000; the number there peaked at 2,888 in 2008.[138]

B. Air Quality Issues

The Denver area gained notoriety for its air pollution in the 1970s and 1980s, due in part to its very visible "brown cloud." More recently, the area has struggled to meet the NAAQS for ozone.[139],[140] A nine-county

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130. BUREAU OF LAND MGMT.,WYO. STATE OFFICE, NEPA HOTSHEET: WINTER QUARTER 2013, 4–5 (2014) (on file with author).

131. BUREAU OF LAND MGMT., RAWLINS FIELD OFFICE, DRAFT ENVIRONMENTAL IMPACT STATEMENT, CONTINENTAL DIVIDE-CRESTON NATURAL GAS DEVELOPMENT PROJECT (2012), *available at* http://www.blm.gov/wy/st/en/info/NEPA/documents/rfo/cd_creston.html.

132. Letter from Rogene Henderson, *supra* note 23.

133. *Natural Gas: Natural Gas Gross Withdrawals and Production*, *supra* note 7.

134. *Petroleum & Other Liquids: Crude Oil Production*, *supra* note 9.

135. COLO. OIL AND GAS CONSERVATION COMM'N, COLORADO WEEKLY & MONTHLY OIL & GAS STATISTICS (Sept. 7, 2012).

136. *Id.*

137. COLO. OIL & GAS CONSERVATION COMM'N, STAFF REPORT, 15 (Jan. 7, 2013), *available at* http://cogcc.state.co.us/ (click STAFF RPT from left side menu).

138. *Id.*

139. The NAAQS for ozone is currently set at 0.075 ppb, with compliance assessed based on the 4th highest 8-hour average value each year, averaged over a three-year period.

area including and surrounding Denver is currently designated "nonattainment" for ozone, based on violations that occurred in 2008–2010.[141] The nonattainment area includes part of Weld County, which is the center of oil and gas production activities in the Denver-Julesburg Basin.

In 2009, the state considered nonattainment designation for southwest Colorado, based in part on high ozone concentrations measured just across the state line at Navajo Lake, NM.[142] The state's analysis found that "gas field development and production accounts for a large percent of the total ozone precursor emissions in the broader Four Corners area," with most of the development located in New Mexico.[143] The state also examined data for northwest Colorado.[144] No violations were recorded for this region for 2006–2008, although spatial coverage of monitoring sites was relatively limited. EPA accepted the state's recommendation that the areas in western Colorado be classified as "attainment/ unclassifiable."[145]

In addition to addressing the NAAQS, Colorado has also directed control efforts toward protecting its 12 Class I areas, which include Rocky Mountain, Mesa Verde, and Sand Dunes National Parks. The state's 2011 Visibility and Regional Haze State Implementation Plan cites statewide emission control requirements for oil and gas sources as one of the programs in place to help improve and protect visibility in Class I areas.[146]

C. Regulatory Authority and Structure

Air quality regulations in Colorado are adopted by the Air Quality Control Commission (AQCC) and administered by the Air Pollution

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140. Since 1990, at the monitors that tend to record the highest ozone values, the 4th maximum 8-hour average concentrations in the Denver metropolitan area have varied year-to-year from less than 0.070 ppm to about 0.095 ppm. COLO. DEPT. OF PUB. HEALTH & ENV'T, TECHNICAL SUPPORT DOCUMENT FOR RECOMMENDED 8-HOUR OZONE DESIGNATIONS 10–11 (2009), *available at* www.colorado.gov/cs/Satellite/CDPHE-AP/CBON/1251594862560.

141. EPA, COLORADO AREA DESIGNATIONS FOR THE 2008 OZONE NATIONAL AMBIENT AIR QUALITY STANDARD (2012), *available at* http://www.epa.gov/groundlevelozone/designations/2008standards/tsd.htm.

142. COLO. DEPT. OF PUB. HEALTH & ENV'T, *supra* note 140, at 38.

143. *Id.* at 41.

144. *Id.* at 67.

145. EPA, *supra* note 141, at 1.

146. COLO. DEPT OF PUB. HEALTH & ENV'T, AIR POLLUTION CONTROL DIV., COLORADO VISIBILITY AND REGIONAL HAZE STATE IMPLEMENTATION PLAN FOR THE TWELVE MANDATORY CLASS I FEDERAL AREAS IN COLORADO 9 (2011), *available at* https://www.colorado.gov/pacific/sites/default/files/AP_PO_Regional-Haze-State-Implementation-Plan-January-2011_0.pdf.

Control Division (APCD) of the Colorado Department of Public Health and Environment.[147] Colorado sources emitting above specified thresholds must file Air Pollutant Emissions Notices (APEN).[148],[149] Since 1993, the APEN threshold for criteria pollutants (including VOCs) has been 1 TPY for sources located in nonattainment areas and 2 TPY for sources in attainment or maintenance areas.[150] Since 1972, Colorado has required construction permits for new or modified sources with potential emissions above specified thresholds.[151] For VOC and NOx emissions, respectively, the current permitting thresholds are 2 and 5 TPY if the source would be located in a nonattainment area, and 5 and 10 TPY if the source would be located in an attainment or maintenance area.[152] Minor sources of VOCs, NOx and other criteria pollutants must apply RACT, whether they are locating in or outside of nonattainment areas.[153] New, modified, and existing oil and gas production equipment is also covered by the AQCC's Regulation 7, which addresses emissions of ozone precursors from "permanent" stationary sources.[154] Temporary sources such as well completion activities are exempted from AQCC reporting and permitting requirements and instead are regulated by the Colorado Oil and Gas Conservation Commission (COGCC).

The APCD issued 3,200 permits for oil and gas equipment in 2012,[155] and in spring 2013 had eight inspectors focus on the oil and gas sector. Their efforts were augmented by inspection activities of local public health agencies and the COGCC, which employed 16 field inspectors.[156] Similar to the situation in Wyoming, Colorado has a small number of inspectors compared to the very large number of oil and gas facilities located in the state.

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147. COLO. REV. STAT. ANN. § 25-7-101 (West 1992).

148. COLO. CODE REGS. § 1001-5.A.II.A (2014).

149. For oil and gas exploration and production operations Colorado Regulation provides that:

> [o]il and gas exploration and production operations (well site and associated equipment) shall provide written notice to the Colorado Oil and Gas Conservation Commission of proposed drilling locations prior to commencement of such operations. Air Pollutant Emission Notices are not required until after exploration and/or production drilling, work overs, completions, and testing are finished.

COLO. CODE REGS. § 1001-5.A.II.D.1.III

150. COLO. CODE REGS. § 1001-5.A.II.B.3.a.

151. COLO. CODE REGS. § 1001-5.B.I.A.

152. COLO. CODE REGS. § 1001-5.B.II.D.2.a; II.D.3.a.

153. COLO. CODE REGS. § 1001-5.B.III.D.2.a.

154. COLO. CODE REGS. § 1001-9 (2014).

155. Mark McMillan, Col. Air Pollution Control Div., *The Basics of Oil & Gas Regulation in Colorado* (Mar. 21, 2013).

156. *Id.*

D. Regulatory Timeline

Specific control requirements for oil and gas equipment were first introduced in March 2004, applicable only in the Denver ozone nonattainment area. At that time, the AQCC required owners or operators of condensate storage tanks[157] with total uncontrolled emissions above 30 TPY[158] to reduce their overall average ("system-wide") emissions by up to 47.5 percent; new and existing glycol dehydration units emitting more than 15 TPY to reduce emissions by at least 90 percent; and *existing* gas processing plants to implement leak detection and repair systems.[159] The AQCC also adopted emissions limits for new and existing reciprocating internal combustion engines.[160] The 2004 regulations, which were deemed to be equivalent to or better than RACT, were adopted as part of Denver's Ozone Action Compact to attain the 8-hour ozone standard by December 2007.[161]

In December 2006, the AQCC tightened the system-wide requirements for condensate storage tanks in the nonattainment area[162] after concluding that unanticipated growth was leading to VOC emissions from the sector that would exceed the overall limits required by the Ozone Action Compact. The 2006 revisions also added new inspection, record keeping and reporting requirements for operators. In addition, the COGCC extended control requirements statewide for condensate storage tanks and glycol dehydrators with uncontrolled VOC emissions greater than 20 and 15 TPY, respectively.[163] The statewide requirements were adopted in response to growth in oil and gas drilling activity in western Colorado, leading to concerns about air quality in the Four Corners area, air pollution transport to the Front Range, and local impacts in the counties where drilling was occurring. The statement of basis and purpose for the regulations indicates they were adopted as a "proactive measure designed to eliminate air emissions that could threaten attainment . . . or adversely affect visibility in Class I areas." They were not required by federal law and as such were only subject to state-level enforcement.[164]

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157. The rule did not address crude oil or produced water tanks.

158. Emissions are summed across all the tanks under the control of a given owner or operator for comparison with the threshold.

159. COLO. CODE REGS. § 1001-9.XII.A, XII.H (2004).

160. COLO. CODE REGS. § 1001-9.XVI.A.

161. COLO. CODE REGS. § 1001-9.XIX.G; COLO. AIR QUALITY CONTROL COMM'N, EARLY ACTION COMPACT, OZONE ACTION PLAN: PROPOSED REVISION TO THE STATE IMPLEMENTATION PLAN (2004), http://raqc.org/postfiles/sip/ozone_8hr/EAC_SIP_031204-aqcc.pdf.

162. COLO. CODE REGS. § 1001-9.XII.

163. COLO. CODE REGS. § 1001-9.XVII.

164. COLO. CODE REGS. § 1001-9.X1X.I.

The AQCC took further action in December 2008, when it again tightened system-wide control requirements for tanks in the nonattainment area and added new requirements for pneumatic controllers located there.[165] The AQCC also added statewide emissions limits for reciprocating internal combustion engines.[166] The 2008 requirements were adopted as part of the state's new Ozone Action Plan. Although modeling indicated the new provisions were not necessary to attain the then-applicable 8-hour standard of 0.08 ppm, they were included on a state-only basis to help ensure attainment of that standard, advance efforts to meet the revised standard of 0.075 ppm, and address a July 2007 directive from Governor Bill Ritter to "proactively and pragmatically reduce ozone levels."[167]

Alongside the AQCC, the COGCC undertook broad revisions to its rules in 2008, in response to 2007 amendments to the Colorado Oil and Gas Conservation Act.[168] The COGCC held more than 20 hearings, with 85 individuals or organizations admitted to party status for the rulemaking.[169] More than 1,500 people attended five meetings held in impacted communities in January 2008, where odor complaints were prominent concerns. The COGCC modified its Odors and Dust regulation, Rule 805,[170] to require controls on all new and existing condensate tanks, crude oil and produced water tanks, glycol dehydrators, and pits with the potential to emit more than 5 TPY of VOCs and located within 1/4 mile of occupied buildings and outside activity areas in three western counties. The COGCC also required use of no-bleed or low-bleed valves with new, replaced, or repaired pneumatic devices, and required operators statewide to use green completions wherever specified conditions were met.[171]

The COGCC revised its rules again in February 2013, adopting new setback provisions to help limit the impact of drilling near occupied buildings.[172] Effective August 1, 2013, the setbacks for new oil and gas

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165. COLO. CODE REGS. § 1001-9.XII, XVIII (2004).

166. COLO. CODE REGS. § 1001-9.XVII. This requirement was made federally enforceable as part of the state's Regional Haze State Implementation Plan in January 2011. COLO CODE REGS. § 1001-9.XIX.L.

167. COLO. CODE REGS. § 1001-9.XIX.K.

168. Colo. House Bills 07-1298 and 07-1341 (2007).

169. COLO. OIL & GAS CONSERVATION COMM'N, STATEMENT OF BASIS, SPECIFIC STATUTORY AUTHORITY, AND PURPOSE: NEW RULES AND AMENDMENTS TO CURRENT RULES OF THE COLORADO OIL AND GAS CONSERVATION COMMISSION, 2 CCR §404-1 (2008), http://cogcc.state.co.us/.

170. COLO. CODE REGS. § 404-1.805.b (2008).

171. COLO. CODE REGS. § 404-1.805.b.2.D, .3.A.

172. COLO. OIL AND GAS CONSERVATION COMM'N, 2 CCR 404-1, STATEMENT OF BASIS, SPECIFIC STATUTORY AUTHORITY, AND PURPOSE: NEW RULES AND AMENDMENTS TO CURRENT

operations were increased from 350 feet in high-density areas and 150 feet elsewhere to a uniform distance of 500 feet, with exceptions allowed in some circumstances.[173] The new rules prohibit uncontrolled venting during completion operations conducted within 1,000 feet of a single high occupancy unit or a dense group of individual building units.[174] Reflecting increased concern about drilling activity in more populated areas of the Front Range, COGCC also amended Rule 805 to extend statewide the control requirements it adopted in 2008 for the three western counties.[175]

In December 2012, the APCD initiated a new stakeholder process to work toward adopting the federal NSPS and NESHAPS that EPA promulgated in 2012, and to consider other revisions to its oil and gas regulations and its broader APEN and construction permit programs. In November 2013, the APCD officially proposed a set of rule revisions developed in collaboration with the Environmental Defense Fund and three energy companies: Anadarko, Encana, and Noble Energy. There were 60 parties to the rulemaking process.[176] More than 10,000 written comments were received during the stakeholder process and formal rulemaking; more than 150 members of the public made comments in person.[177] Final rule revisions were adopted by the AQCC in February 2014, after a day of public comment and three days of party testimony.

The new regulations apply statewide and explicitly address the greenhouse gas methane, along with VOC emissions.[178] The revisions incorporate and then go beyond the federal NSPS and NESHAPs. They require all (new and existing) condensate, crude oil, and produced water storage tanks with uncontrolled VOC emissions exceeding 6 TPY to control hydrocarbon emissions by 95 percent.[179] Existing glycol dehydrators capable of emitting more than 6 TPY of VOC are required to achieve 95 percent control; the threshold drops to 2 TPY for new dehydrators and those located within a quarter mile of an occupied building.[180] Low-bleed pneumatic devices are required statewide.[181] Best management practices

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RULES OF THE COLORADO OIL AND GAS CONSERVATION COMMISSION (Feb. 11, 2013), *available at* http://cogcc.state.co.us/.

173. COLO. CODE REGS. § 404-1.604 (2013).

174. COLO. CODE REGS. § 404-1.604.c.(2).C.ii.

175. COLO. CODE REGS. § 404-1.805.

176. E-mail from Theresa Martin, Air Quality Control Comm'n Program Coordinator, Colo. Dept. of Public Health & Env't. to author (May 20, 2014) (on file with author).

177. *Id.*

178. COLO. CODE REGS. § 1001-9, Statements of Basis, Specific Statutory Authority and Purpose, Sections II, XII, and XVIII (2014), *available at* http://www.colorado.gov.

179. COLO. CODE REGS. § 1001-9.XVII.

180. *Id.*

181. COLO. CODE REGS. § 1001-9.XVIII.

are required to limit emissions from well maintenance and liquids unloading.[182] Finally, LDAR programs are required for well production facilities as well as gas processing plants.[183]

Going forward, Colorado faces the challenge of ongoing nonattainment in the Denver/Front Range area as oil and gas development in the Denver-Julesburg Basin continues to expand. Control requirements imposed over the past decade have progressively tightened limits on emissions from individual sources in the oil and gas sector, but the overall number of sources has grown. Improved understanding of the magnitude and timing of emissions from oil and gas processes and equipment, and the effectiveness of control requirements, is needed to help address the area's nonattainment problem. Better understanding of meteorological conditions and transport patterns in the complex flow situation of the Front Range is also needed. Colorado may face issues with winter ozone, as the widespread occurrence of high concentrations in the Uinta Basin extends across the Utah-Colorado border.[184] In addition, greater attention to local health risks associated with emissions of hazardous air pollutants may be needed as oil and gas operations increasingly intersect more densely populated areas.

IX. REGULATION OF OIL AND GAS PRODUCTION ACTIVITIES IN NEW MEXICO

A. Production Trends

Natural gas production in New Mexico increased by about 50 percent from 1990 to 1995, held steady for the next decade, then declined somewhat from 2006 to 2011 (Figure 1).[185] In 2012, New Mexico had about 27,000 producing oil wells and about 30,000 natural gas wells.[186] About two-thirds of New Mexico's natural gas production occurs in the South San Juan Basin, in the northwest corner of the state. In 2006, natural gas production in this basin was roughly split evenly between con-

182. COLO. CODE REGS. § 1001-9.XVII.

183. *Id.*

184. Based on preliminary data for winter 2013, the monitoring site in Rangely, CO has recorded exceedances of the ozone NAAQS. Utah Dept. of Envtl. Quality, *Uintah Basin Air Quality Meeting* (Apr. 29, 2013), *available at* www.deq.utah.gov/locations/uintahbasin/docs/2013/Apr/OGMtg42913.pdf.

185. *Natural Gas: Natural Gas Gross Withdrawals and Production*, *supra* note 7.

186. N.M. ENERGY, MINERALS & NATURAL RES. DEP'T, ANNUAL REPORT 42 (2012), *available at* http://www.emnrd.state.nm.us/ADMIN/publications.html.

ventional gas and coal bed methane.[187] About five percent of the natural gas production in this area occurred on lands of the Jicarilla Apache and Ute Mountain Ute tribes, with the balance on non-tribal lands.[188] Oil production in New Mexico is even more concentrated than natural gas production, with more than 90 percent occurring in Lea and Eddy counties in the state's southeast corner.[189] New Mexico reports that 246 gas wells and 1,148 oil wells were drilled and completed in 2011.[190]

The WRAP Phase III study for the South San Juan Basin estimated 84 percent of NOx emissions were from compressor engines located at the wellhead.[191] Venting from completions, well blowdowns, and dehydrators accounted for 65 percent of the estimated VOC emissions.[192] Operator surveys reported no significant use of flaring or vapor recovery units for controlling tank emissions, but some use of flares to reduce emissions from dehydrators and completions.[193]

B. Air Quality Issues

In the Four Corners area, Arizona, Colorado, New Mexico, and Utah include the tribal lands of the Navajo, Hopi, Ute Mountain Ute, Southern Ute, and Jicarilla-Apache. The area contains prominent scenic and cultural resources including Mesa Verde and Grand Canyon National Parks. In November 2005, New Mexico and Colorado joined with tribal and federal partners to convene the Four Corners Air Quality Task Force. The formation of the Task Force was motivated by concerns that emissions from expanding energy development activities would combine with those from existing power plants to exacerbate regional haze and ozone pollution. The Task Force's 2007 report recommended a number of mitigation measures directed at the oil and gas sector.[194] A working group that replaced the Task Force after 2007 credits New Mexico

187. AMNON BAR-ILAN, ET AL., ENVIRON INT'L CORP., DEVELOPMENT OF BASELINE 2006 EMISSIONS FROM OIL AND GAS ACTIVITY IN THE SOUTH SAN JUAN BASIN, FINAL REPORT 5 (2009).

188. *Id.* at 2, 5.

189. N.M. ENERGY, MINERALS & NATURAL RES. DEP'T, *supra* note 186, at 43.

190. *Id.*

191. BAR-ILAN, ET AL., *supra* note 187, at 40, 43.

192. *Id.*

193. *Id.* at 9, 25–26

194. FOUR CORNERS AIR QUALITY TASK FORCE, REPORT OF MITIGATION OPTIONS 1–155 (2007) http://www.nmenv.state.nm.us/aqb/4C/Docs/4CAQTF_Report_FINAL.pdf.

with imposing tighter limits on NOx emissions from engines used in oil and gas operations in response to Task Force recommendations.[195]

As New Mexico assessed its status with respect to the new ozone standard in the 2009–2010 timeframe, it appeared that San Juan County might be headed toward nonattainment. However, ozone concentrations there dipped in the next few years. In October 2011, New Mexico recommended to EPA that the whole state be designated attainment/unclassifiable for ozone, based on 2008–2010 monitoring data. EPA made this designation in April 2012.[196]

C. Regulatory Authority, Structure, and Timeline

The New Mexico Environmental Improvement Board was created in 1971.[197] The founding legislation established a seven-member board with responsibility for a wide range of health and environmental issues, including adopting air pollution control regulations consistent with the New Mexico Air Quality Control Act.[198] The New Mexico Environment Department (NMED) Air Quality Bureau implements the EIB's regulations.[199]

NMED regulations require a Notice of Intent (NOI) to construct any source with the potential to emit more than 10 TPY of "any regulated air contaminant."[200] The state requires construction permits for all sources with the potential of emitting more than 25 TPY of "any regulated air contaminant for which there is a National or New Mexico Ambient Air Quality Standard."[201] NMED currently interprets VOCs to be included in the NOI requirement as a regulated contaminant, but excluded from the minor source construction permit requirement, because there are no NAAQS or NMAAQS for VOCs.[202] This approach contrasts with EPA and other states' regulations, which generally encompass VOCs because they are precursors of ozone, for which a NAAQS exists. New Mexico's permitting threshold for VOCs is thus effectively the ma-

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195. *See* Four Corners Air Quality Group, Update on Recent Agency Activities 4, 6 (2012), http://www.nmenv.state.nm.us/aqb/4C/Documents/4CAQGAgency_Update_May2012_final.pdf.

196. 77 Fed. Reg. 30,088, 30,136 (May 21, 2012).

197. N.M. Stat. Ann. § 74-1-1 (1978).

198. *Id.* §§ 74-2-1 to -17.

199. Air quality management for the City of Albuquerque and Bernalillo County is conducted independently, through the Albuquerque-Bernalillo County Air Quality Control Board and Air Quality Division. N.M. Code R. § 20.11.1 (1971).

200. N.M. Code R. § 20.2.73.200(A)(1) (1995).

201. N.M. Code R. § 20.2.72.200(A)(1).

202. E-mail from Mary Uhl, Environmental Protection Specialist, N.M. Bureau of Land Mgmt. to author (Apr. 8, 2013) (on file with author).

jor new source review threshold of 100 TPY,[203] unless the source is subject to state NSPS or Emissions Standards for Hazardous Air Pollutants.[204]

In New Mexico, minor source permit applicants must demonstrate they will not contribute to violations of national or state air quality standards or PSD increments, certify compliance with all federal requirements including applicable NSPS and NESHAPs, and describe any pollution controls that will be employed. Beyond meeting federal limits, no additional controls (such as RACTs or BACTs) are generally required. By law, New Mexico permit conditions cannot be more stringent than: "(a) [t]he extent necessary to meet the requirements of the Air Quality Control Act and the federal act; or (b) [t]he emission rate specified in the permit application."[205] However, the regulations allow use of streamlined and/or general permits, whereby applicants accept additional permit conditions in exchange for expedited processing.

NMED has offered streamlined permitting for engines and turbines located at oil and gas facilities (primarily compressor stations) since 1990.[206] To take advantage of the most common streamlined option (Level 1), applicants must certify that they are using low-NOx engines with total potential to emit less than 40 TPY for all engines at the facility, and that emissions from ancillary equipment will be less than 40 TPY for VOC and less than 25 TPY for other pollutants. Facilities must also be located more than 1 km away from any occupied structures. NMED developed its first general construction permit for oil and gas compressor stations in 1999, which applies if the facility will be more than 0.25 miles from the nearest occupied structure, ensures total emissions will be less than major source thresholds, and will comply with specified NOx and CO emissions rate limitations for reciprocating engines and turbines.[207] In 2003, NMED issued a second general construction permit for compressor stations, which again included restrictions on siting, limited emissions of NOx, CO, and VOC to as low as 40 TPY each, and specified

203. *See* N.M. CODE R. § 20.2.74.

204. N.M. CODE R. § 20.2.72.200(A)(3). New Mexico NSPS and Emissions Standards for Hazardous Air Pollutants are generally those incorporated by reference from federal NSPS and NESHAP. N.M. CODE R. § 20.2.77-.78.

205. N.M. CODE R. § 20.2.72.210(B)(1); N.M. STAT. ANN. § 74-2-7(D)(1)(b) (1972).

206. N.M. ENV'T DEPT., IMPROVING ENVIRONMENTAL PERMITTING 9 (2012), http://www.nmenv.state.nm.us/aqb/documents/AQB_Final%20Report%201_10_13.pdf; N.M. CODE R. §§ 20.2.72.301-.306 (1995).

207. N.M. Env't Dept., *Construction Permit No. GCP-1, Level One Oil and Gas Installations*, 7 (Feb. 18, 1999), http://www.nmenv.state.nm.us/aqb/permit/documents/GCP-1_Permit_signed.pdf; N.M. CODE R. § 20.2.72.220.

monitoring and reporting requirements.[208] These general construction permits have not been as widely used as state officials hoped, and have been recognized as needing to be updated.[209]

New Mexico incorporated the 2012 federal NSPS/NESHAPs into state law in December 2013.[210] To help reduce the burden of the corresponding minor source permitting requirements, the state also developed a new general construction permit for storage vessels, which limits their VOC emissions to 6 TPY. The general construction permit would ensure that storage vessels fall below the applicability threshold for the NSPS.[211]

BLM's environmental protection obligations have led to expanded control requirements in New Mexico, although they have not been as extensive as in Wyoming. In 2003, the Farmington Field Office finalized an updated Resource Management Plan (RMP) for public lands and minerals in northwest New Mexico.[212] The RMP proposed full field development for the Southern San Juan Basin, with a projection that nearly 10,000 new wells would be drilled in the ensuing 20 years. Based on concerns about NOx emissions impacts on ozone, NO_2 (another criteria pollutant) and visibility, the mitigation measures in the Record of Decision (ROD) included emissions limits for new and replacement compressor engines located at wellheads and compressor stations. The ROD also recorded New Mexico BLM's commitment to participating in the Four Corners Task Force.

In 2009, the New Mexico legislature passed House Bill 195, which allows the state to adopt control requirements that are more stringent than federal standards in areas where air pollution levels are within 95 percent of violating a NAAQS.[213] In response, NMED proposed to develop a plan to address ozone levels in San Juan County, where 2006–2008 monitoring data indicated ozone levels were close to the 0.075 ppm 8-hour average standard. Among other options, NMED officials suggested they would consider new control requirements for produced

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208. N.M. Env't Dept., *Construction Permit No. GCP-4, Combustion Sources and Related Equipment*, 6 (Oct. 20, 2003), http://www.nmenv.state.nm.us/aqb/permit/documents/GCP-4_20Oct03_signed.pdf.

209. *See* N.M. ENV'T DEPT., *supra* note 206.

210. E-mail from Rita Bates, Planning Section Chief, N.M. Env't Dept., Air Quality Bureau, to author (May 21, 2014) (on file with author).

211. N.M. Env't Dept., *Construction Permit No. GCP-6, Storage Vessels*, 7 (Jan. 14, 2014), http://www.nmenv.state.nm.us/aqb/permit/Permit_Apps/documents/GCP-6.pdf.

212. BUREAU OF LAND MGMT., FARMINGTON FIELD OFFICE, RECORD OF DECISION: FARMINGTON PROPOSED RESOURCES MANAGEMENT PLAN AND FINAL ENVIRONMENTAL IMPACT STATEMENT 1 (2003), http://www.blm.gov/pgdata/etc/medialib/blm/nm/field_offices/farmington/farmington_planning/ffo_prmp_docs.Par.89022.File.dat/Farmington_ROD.pdf.

213. N.M. STAT. ANN. § 74-2-5.3(A)–(B) (2009).

water and condensate storage tanks.[214] The ozone design value for the area fell to 0.066 ppm for 2008–2010, however, so no action was taken.[215] More recently, EPA reported that the 2010–2012 design value for San Juan County was 0.071 ppm, which is 94.7 percent of the NAAQS.[216]

In summary, New Mexico significantly lags behind Colorado and Wyoming in imposing control requirements for oil and gas sources, in part because state law restricts regulation from going beyond federal requirements, and because NMED has determined that VOCs are not included in the state's requirement for minor source permitting. Oil and gas basins in New Mexico currently meet the ozone standard, so federal requirements mandating the state to act to achieve the NAAQS have not come into play. Colorado and Wyoming have also faced pressure to tighten emissions rate limits in order to accommodate new oil and gas development, but in contrast, New Mexico has seen relatively flat or declining trends in oil and gas production in recent years. In a 2009 study projecting emissions in the South San Juan Basin to 2012, the WRAP estimated that total VOC emissions in the basin would decrease by about 8 percent compared to 2006 levels due to declining oil and gas production and drilling activity, while NOx emissions would increase by about 2 percent due to increased demands on compressors.[217] These conflicting projections for precursor emissions make it difficult to forecast what will happen with ozone levels. Consequently, NMED will need to carefully monitor the situation.

X. REGULATION OF OIL AND GAS PRODUCTION ACTIVITIES IN UTAH

A. Production Trends

Utah trails Colorado, New Mexico, and Wyoming in production of oil and gas, but still ranks high nationally. Natural gas production in Utah increased in the early 1990s, held steady for the next decade, and then increased by more than 60 percent from 2004 to 2011 (Figure 1a). The number of wells producing natural gas and natural gas liquids in-

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214. Mary Uhl, Bureau Chief, N.M. Env't Dept., Air Quality Bureau, PowerPoint presentation at the San Juan County Ozone Reduction Initiative Stakeholder Meeting: Keeping within the Federal Air Quality Standards (May 14, 2009), http://www.nmenv.state.nm.us/aqb/Control_Strat/documents/OzoneReductionInitiative_May2009.pdf.

215. *AirData, Air Quality Statistics Report*, EPA, http://www.epa.gov/airdata/ad_rep_con.html (last visited Sept. 27, 2014).

216. *Air Trends, Design Values - Archives*, EPA, http://www.epa.gov/airtrends/values_previous.html (last visited Sept. 27, 2014).

217. BAR-ILAN ET AL., *supra* note 187.

creased from 800 in 1990 to about 6,500 in 2011 (Figure 1b).[218] Crude oil production in Utah declined from 1990 through about 2003, but then recovered over the next decade (Figure 2). In 2012, 76 percent of the state's oil came from Duchesne or Uintah Counties in northeastern Utah,[219] with two-thirds of the natural gas from Uintah County.[220] In 2006, about two-thirds of the oil production and more than 85 percent of the non-CBM natural gas production in the Uinta Basin occurred on tribal lands, primarily those of the Ute Indian Tribe.[221]

The WRAP Phase III study for the Uinta Basin found that in 2006, 82 percent of NOx emissions and 98 percent of VOC emissions from the Basin's oil and gas activity were from sources emitting below the major source thresholds of 100 TPY, with most of the sources located on tribal lands.[222] This is significant because at the time, EPA lacked a minor-source permitting program for Indian Country. The WRAP's survey of producers turned up only one report of a vapor recovery unit installed in the Uinta Basin at that time, with flares used for some condensate tanks, dehydration units, and initial completions.[223]

B. Air Quality Issues

The longest continuous monitoring record in eastern Utah is for Canyonlands National Park, which has measured ozone levels approaching, but not violating, the current NAAQS during several years from the late 1990s onward.[224] In July 2009, EPA established two ozone monitors in the Uinta Basin, leading to observation of very high ozone during periods with extensive snow cover.[225] Concentrations at both monitors exceeded the 0.075 ppm standard on 10 or more days during January 2010 alone. Driven by those findings, special air quality monitoring studies were conducted in the basin during each of the following three winters. Elevated ozone concentrations were observed across the basin in winter

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218. *Natural Gas: Number of Producing Gas Wells*, *supra* note 8.

219. *See Utah Oil Production-by County (past 5 years)*, UTAH OIL & GAS (March 2014), http://oilgas.ogm.utah.gov/Statistics/PROD_Oil_county.cfm.

220. *Id.*

221. RON FRIESEN, ET AL., ENVIRON INTL. CORP., FINAL REPORT: DEVELOPMENT OF BASELINE 2006 EMISSIONS FROM OIL AND GAS ACTIVITY IN THE UINTA BASIN 4 (2009).

222. *Id.* at 5.

223. *Id.* at 34.

224. NAT'L PARK SERV., NATURAL RES. PROGRAM CENTER, AIR QUALITY IN NATIONAL PARKS: 2009 ANNUAL PERFORMANCE & PROGRESS REPORT 30 (2010).

225. UTAH DIV. OF AIR QUALITY, *2012 Annual Report* 29–30 (2012), http://www.airquality.utah.gov/Public-Interest/annual-report/.pdf/2012Annual%20Report.pdf.

2010–2011 when snow was abundant,[226] but not during the milder winter of 2011–2012.[227] High levels of ozone returned with extensive snow cover in 2012–2013.[228] Researchers have concluded that snow cover and strong temperature inversions are critical elements of the winter episodes of elevated ozone, and that local oil and gas activities emit most of the VOC and NOx emissions that produce the ozone.[229]

C. Regulatory Authority, Structure, and Timeline

Air quality regulations in Utah are issued by the Utah Air Quality Board[230] and implemented by the Division of Air Quality (UDAQ) of the Department of Environmental Quality. Since 1969, new air pollution sources in Utah have been required to obtain approval orders before starting construction.[231] Utah's permitting rule includes an exemption for sources emitting less than 5 TPY of PM_{10}, SO_2, CO, NOx and VOC, and less than 500 lbs per year of any individual HAP or 2000 lbs per year of any combination of HAPs.[232] In contrast to other states that assess permit requirements based on uncontrolled emissions, Utah's thresholds are based on "actual" emissions, taking account of any planned controls. According to UDAQ, many of the emissions sources in Utah's oil and gas production industry have historically fallen below these thresholds.[233] However, without a permit requirement based on uncontrolled emissions, UDAQ lacks a mechanism to ensure that the industry installs and operates the controls necessary to reduce emissions to below permitting thresholds.

For sources above UDAQ's threshold level, the process of obtaining an approval order is initiated when the source files a notice of intent, including a description of the source, analysis of BACT, and as-

226. RANDALL MARTIN ET AL., UTAH STATE UNIV., FINAL REPORT: UINTAH BASIN WINTER OZONE AND AIR QUALITY STUDY 39 (2011), http://rd.usu.edu/files/uploads/ubos_2010-11_final_report.pdf.

227. UTAH STATE UNIV., FINAL REPORT: 2012 UINTAH BASIN WINTER OZONE & AIR QUALITY STUDY 81 (Seth Lyman & Howard Shorthill, Eds. 2013), http://rd.usu.edu/files/uploads/ubos_2011-12_final_report.pdf.

228. UTAH DEP'T OF ENVTL QUALITY, DIV. OF AIR QUALITY, Information Sheet: Ozone in the Uintah Basin 2 (2013), http://www.deq.utah.gov/locations/U/uintahbasin/docs/2013/09Sep/ozone2013.pdf.

229. UTAH STATE UNIV., *supra* note 227.

230. The Utah Air Quality Board was authorized by the Utah Conservation Act. UTAH CODE ANN. §§ 19-2-101 to -207 (1990).

231. *See* UTAH ADMIN CODE r. 307-401-5(1) (2014).

232. UTAH ADMIN. CODE r. 307-401-9(1)(a)–(b).

233. UTAH DEP'T OF ENVTL. QUALITY, DIV. OF AIR QUALITY, RURAL AIR QUALITY AND OIL/GAS DEVELOPMENT IN UTAH FACT SHEET 4 (2010) www.deq.utah.gov/locations/uintahbasin/docs/2012/Feb/June2010-_Air_Issues.pdf.

sessment of compliance with federal and state requirements including the NAAQS. UDAQ cannot issue approval orders unless the degree of pollution control is at least BACT, which UDAQ determines on a case-by-case basis.[234] UDAQ issued about 350 approval orders to oil and gas sources between 2008 (when their electronic database was started) and spring 2013, with tank batteries and compressor stations among the most frequently permitted sources.[235] During this period, BACT for tank batteries generally required venting to a flare.[236]

High ozone concentrations observed in the Uinta Basin during the winter of 2010 led to delays for new drilling projects in the area, as BLM considered and ultimately imposed new mitigation requirements for project applicants. In May 2011, BLM's Vernal, UT office issued a supplement to the 2010 Draft EIS for the Greater Natural Buttes Gas Development Project, an infill project that was initially proposed in 2007 and would drill about 3,700 new wells in a previously developed area that included federal, state, and tribal lands and minerals.[237] BLM issued the supplement in part to reconsider the project's potential air quality impacts. After working with EPA and the applicant to develop mitigation options, BLM approved the development project in May 2012, but with a number of conditions. These conditions included: electrification of approximately 50 percent of the compression capacity; installation of controls on existing condensate tanks with potential to emit more than 20 TPY of VOCs and on new tanks with potential to emit more than 5 TPY; use of low emission drill rig engines, low-emission glycol dehydrators, and low-bleed pneumatic devices; and finally, use of green completions for all well completion activities. In addition, the applicant must work with BLM to develop and implement an adaptive management strategy if ozone levels are found to exceed the NAAQS.[238] A month later, BLM imposed similar requirements for use of "best management practices"

234. UTAH ADMIN. CODE r. 307-401-2, 401-8(1)(a).

235. E-mail from Timothy Andrus, New Source Review Section Manager, Utah Dep't of Envtl. Quality, Div. of Air Quality to author (June 14, 2013) (on file with author).

236. *Id.*

237. BUREAU OF LAND MGMT., VERNAL FIELD OFFICE, GREATER NATURAL BUTTES SUPPLEMENT TO THE DRAFT ENVIRONMENTAL IMPACT STATEMENT 1-1 (2011). Surface ownership in the 160,000 acre project area is approximately 54 percent federal land, 20 percent state land and 24 percent land owned by the Ute Tribe. BUREAU OF LAND MGMT., VERNAL FIELD OFFICE, GREATER NATURAL BUTTES FINAL ENVIRONMENTAL IMPACT STATEMENT (2012).

238. BUREAU OF LAND MGMT., VERNAL FIELD OFFICE, GREATER NATURAL BUTTES RECORD OF DECISION 6 (2012), http://www.blm.gov/pgdata/etc/medialib/blm/ut/vernal_fo/planning/greater_natural_buttes/record_of_decision.Par.86388.File.dat/Cover_ROD.pdf.

and adaptive management to address air quality impacts of Gasco Energy Inc.'s proposal for 1,300 new wells in the Uinta Basin.[239]

Utah's control requirements for oil and gas sources are in a state of flux. In early 2013, UDAQ issued new permitting guidance for the Uinta Basin that barred approval of new or modified stationary sources of VOC emissions in Duchesne or Uintah County, "unless the owner or operator has provided a satisfactory determination that the source will not contribute to a potential violation of the ozone NAAQS."[240] The guidance indicated offsetting VOC emissions at a 1:1 ratio was expected to be the primary means of making the required demonstration. After the guidance was issued, applications for approval orders nearly ceased.[241] The guidance was withdrawn in summer 2013. Since then, UDAQ has proposed new rules for existing pneumatic controllers, use of bottom-fill or submerged loading for tank trucks, and use of auto-igniters with all flares. Additionally, UDAQ has been considering further "intermittent" measures to be deployed during the winter or when ozone episodes are forecast.[242] UDAQ is also working to develop a non-mandatory General Approval Order (GAO) that would replace case-by-case pre-construction permitting determinations with pre-specified control requirements for crude oil tank batteries and natural gas well sites.[243] The proposed GAO is only available for wells expected to produce less than 50,000 barrels per year of condensate or crude oil, with capture of co-produced gas. It requires tanks and dehydrators to be connected to control devices with at least 98 percent control efficiency, use of low-bleed pneumatics, submerged loading of tanker trucks, and application of LDAR.[244]

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239. BUREAU OF LAND MGMT., VERNAL FIELD OFFICE, RECORD OF DECISION FOR THE GASCO ENERGY INC. UINTA BASIN NATURAL GAS DEVELOPMENT PROJECT 18 (2012), http://www.blm.gov/pgdata/etc/medialib/blm/ut/vernal_fo/planning/gasco_eis/gasco_rod.Par.41068.File.dat/Gasco%20ROD%2006152012.pdf.

240. Memorandum from Regg Olsen, Permitting Branch Manager, Utah Dep't Envtl. Quality, Div. of Air Quality, to New Source Review Section, Re: Uintah Basin Permitting Guidance (2013), http://www.deq.utah.gov/locations/U/uintahbasin/docs/2013/02Feb/UintahBasinPermittingGuidance.pdf.

241. E-mail from Timothy Andrus, *supra* note 235.

242. *Uintah Basin: Outreach Meetings*, UTAH DEP'T OF ENVTL. QUALITY (July 30, 2013), http://www.deq.utah.gov/locations/U/uintahbasin/meetings.htm#2013. As of May 2014, the new rules had not yet been adopted, but UDAQ was planning to bring them to its Air Quality Board at their June 2014 meeting. E-mail from Colleen Delaney, Environmental Scientist, Utah Dep't Envtl. Quality, Div. of Air Quality, to author (May 20, 2014) (on file with author).

243. *Uintah Basin: Outreach Meetings*, UTAH DEP'T OF ENVTL. QUALITY (Aug. 12, 2013), http://www.deq.utah.gov/locations/U/uintahbasin/meetings.htm.

244. *General Approval Order: Crude Oil and Natural Gas Well Site and Tank Battery*, UTAH DEP'T OF ENVTL. QUALITY, http://www.deq.utah.gov/Permits/GAOs/oilgas/oilgasgao.htm (last updated July 10, 2014).

Looking forward, Utah faces a major challenge in its need to address wintertime ozone pollution in the Uinta Basin. The state has been collaborating with federal, tribal, and other partners on a multi-million dollar study of the problem, and is beginning to act on its findings in anticipation of a nonattainment designation. To date, UDAQ has focused on requirements for controls that promise cost savings, improved operation and maintenance of existing equipment, temporary measures that can be operated during forecast ozone episodes, and ways to encourage voluntary efforts.[245] If the Uinta Basin receives a nonattainment designation, additional mandatory measures are likely to be required for existing sources as well as new ones. Progress on reducing emissions and ozone in the Uinta Basin will also require action by EPA and the Ute Indian Tribe to implement minor new source review and NSPS/NESHAPS requirements for sources under their jurisdiction.

XI. DISCUSSION: PAST DRIVER AND FUTURE DIRECTIONS

A. Drivers for Regulation

Comparing how regulatory agencies in Colorado, New Mexico, Utah, and Wyoming have addressed air quality impacts from oil and gas production highlights several drivers for regulation, which have played out differently in each state. First, the CAA requires states to institute pre-construction review for new sources, including "minor" sources common in oil and gas production. The stringency of these programs varies dramatically from state-to-state and even within states, including through specification of different emissions thresholds for requiring permits. Colorado and Wyoming have historically had relatively low permitting thresholds, thus bringing a larger number of individual sources under state regulation than in New Mexico and Utah. In fact, Wyoming eliminated permitting thresholds in 1997, although it still employs thresholds for specific control requirements in its presumptive BACT guidelines.[246] EPA's 2011 rule for permitting of minor sources in Indian Country includes permitting thresholds that are similar to those currently applied in Colorado.

245. *Uintah Basin Air Quality Meeting*, UTAH DEP'T OF ENVTL. QUALITY (Apr. 29, 2013), http://www.deq.utah.gov/locations/U/uintahbasin/docs/2013/04Apr/OGMtg42913.pdf.

246. For example, Wyoming requires new and modified storage tanks in the JPDA and CDA to use controls to initially reduce VOC emissions by 98 percent, but these controls can be removed after one year if emissions will be kept below 8 TPY. *See* WYO. DEPT. OF ENVTL QUALITY, *supra* note 118, at 8, 11.

Violations of the NAAQS for ozone have driven relatively tight regulation of oil and gas sources in Colorado and Wyoming, and may soon have a similar effect in Utah. Colorado first adopted specific control requirements for new and existing sources in the oil and gas production sector in 2004 as part of its strategy to attain the ozone standard in the Denver/Front Range area. Colorado has strenghthened these requirements over the past decade as oil and gas drilling activity has increased and violations of the ozone standard have persisted. In Wyoming, observation of elevated winter ozone levels led to more stringent control requirements for sources in the JPDA than anywhere else in the region, with further restrictions on emissions rates anticipated as part of the area's new attainment strategy. While the Uinta Basin in Utah has not yet received a nonattainment designation because the monitoring record is too short, it appears that significant new control efforts are needed to reduce ozone levels there. Similarly, even though New Mexico cancelled an initiative to strengthen control requirements for the South San Juan Basin after ozone concentrations declined, more recent ozone data suggest the initiative may need to be revived.

Ozone pollution was not the only concern that prompted control requirements. The NEPA requirement that BLM analyze cumulative air quality impacts of reasonably foreseeable development has, in some cases, caused BLM to include emissions reduction measures in operator agreements and conditions of approval for operations on federal lands. As one example, NEPA analyses showing significant impacts of oil and gas emissions on visibility in Class I areas accelerated imposition of new requirements in western Wyoming, including the use of flareless green completions. Colorado has also cited regional haze abatement as a rationale for controlling emissions from the oil and gas production sector. Concerns about odors and hazardous air pollutant emissions were prominent in the Colorado Oil and Gas Conservation Commission's 2007–2008 rulemaking hearings.

In effect, actual or projected violations of air quality standards operate as a rough constraint on further emissions increases in a given air basin. In this situation, more stringent control requirements are pursued in part to make "room" for more oil and gas development activity, as well as in an effort to improve air quality. This motive is apparent in the adaptive management schemes that BLM has adopted to allow major energy projects to go forward in the face of elevated ozone levels in Wyoming and Utah, as well as the VOC offset requirements that Utah temporarily adopted in early 2013. To date, however, neither Wyoming nor Utah has identified the overall *reductions* in emissions (of VOCs or NOx, or both) that will be needed for the Upper Green River and Uinta Basins to meet the ozone NAAQS.

Up until this year, the states considered here had not specifically identified concerns about methane's impact as a greenhouse gas as a basis for regulation, although Colorado recognized methane reductions as a co-benefit of some of its programs.[247] In 2014, the Colorado Air Quality Control Commission broke new ground by directly citing the need to limit methane emissions as part of the rationale for its revised rules.[248] The other western states examined here are unlikely to follow suit anytime soon. However, in March 2014 the White House released a plan to reduce methane emissions from oil and gas production, among other sources.[249] As part of this effort, EPA is considering the need for additional regulations and BLM is developing new requirements to limit flaring and venting from wells on public land.[250]

B. Future Directions

Along with different drivers for adopting new regulations, Colorado, New Mexico, Utah, and Wyoming have also faced different challenges in addressing air quality impacts from oil and gas development. In some areas, effective regulation has been impeded by lack of information and scientific understanding about emissions impacts. Elevated wintertime ozone levels in the Uinta and Upper Green River basins may well have occurred before monitoring commenced in these areas, which highlights the importance of robust monitoring networks for air quality protection. State agencies in Utah and Wyoming continue to work with federal and academic researchers and consultants to better understand and model how wintertime ozone is produced and identify what emissions sources to prioritize for controls. Field studies are also being conducted in Colorado's western slope and Front Range basins, with a primary focus on improving emissions estimates. Colorado, Utah, and Wyoming are also collaborating with EPA and federal land management agencies on a "Three-State Study" to provide more consistent emissions inventories and modeling tools that can be used in NEPA analyses and other assessments.[251]

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247. COLO. CODE REGS. § 1001-9.XIX.K (2008).

248. *Id.*

249. THE WHITE HOUSE, CLIMATE ACTION PLAN: STRATEGY TO REDUCE METHANE EMISSIONS (Mar. 2014), http://www.whitehouse.gov/sites/default/files/strategy_to_reduce_methane_emissions_2014-03-28_final.pdf.

250. *Id.*

251. *See* Tom Moore, WRAP Air Quality Program Manager, PowerPoint presentation at WESTAR & University of Nevada - Ozone Transport Conference: Western Regional Technical Air Quality Studies: Support for Ozone Air Quality Planning in the West (October 11, 2012), http://www.westar.org/12%20Tech%20Conf/Presentations/Moore.pdf.

As indicated above, most of the oil and gas production in the Uinta Basin occurs in Indian Country, where the Ute Tribe has not taken regulatory action and the state of Utah lacks jurisdiction. Although EPA has authority to regulate sources operating in Indian Country, until recently it has focused limited resources on emissions from major sources, and has consequently neglected smaller sources even though they can collectively have a significant impact. This situation will likely change with new NSPS and NESHAP requirements and EPA's new minor source NSR rule for Indian Country. However, lack of resources and personnel to implement these rules remain an obstacle. EPA needs to increase the assistance it provides to tribes to regulate air pollution from oil and gas production activities. Over time, tribes with oil and gas resources should follow the lead of the Southern Ute Indian Tribe and develop their own capacity for regulating air emissions.

EPA was slow to institute cost-effective control requirements for oil and gas production sources, until a lawsuit compelled action. Given the size of the sector and challenges posed by its dispersed nature, many states would benefit from EPA moving forward more quickly to follow up the 2012 NSPS and NESHAPs with guidance on implementation, compliance assistance and enforcement options. EPA's own Inspector General recently criticized the agency for serious deficiencies in its oil and gas production sector emissions data, which continues to hinder sound decision-making.[252]

As suggested in the 2014 White House strategy,[253] further EPA action is also needed to address methane emissions. The Agency's Natural Gas STAR program has helped promote voluntary efforts and advanced the dissemination of new technologies and practices to reduce methane, and the 2012 NSPS promise significant reductions in methane emissions from new or recompleted wells and new production equipment. However, past lax emissions control practices in some states have left a legacy of excessive methane leakage from existing wells and equipment.[254] EPA should consider promulgating additional requirements for reducing methane emissions, including for plunger lift systems, fugitive methane leak detection and repair systems, and replacement of existing high-bleed pneumatic valves.[255]

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252. RICK BEUSSE ET AL., EPA, OFFICE OF INSPECTOR GENERAL, EPA NEEDS TO IMPROVE AIR EMISSIONS DATA FOR THE OIL AND NATURAL GAS PRODUCTION SECTOR 16–17 (2013).

253. THE WHITE HOUSE, *supra* note 249.

254. *See* U.S. GOV'T ACCOUNTABILITY OFFICE, *supra* note 5; Anna Karion et al., *Methane Emissions Estimate from Airborne Measurements over a Western United States Natural Gas Field*, 40 GEOPHYSICAL RESEARCH LETTERS 4393 (2013).

255. James Bradbury et al., *Clearing the Air: Reducing Upstream Greenhouse Gas Emissions from U.S. Natural Gas Systems* 6 (World Resources Institute, Working Paper, Apr. 2013).

Wyoming, Colorado, New Mexico, and Utah are all facing further expansion of oil and gas development activities. Trends in the region include increased density of development associated with infill projects and greater incursion of energy development into relatively densely populated suburban areas. The trend towards greater use of multi-well pads offers emissions reduction benefits through reduced truck traffic and economies of scale in use of some control technologies, but may also extend the duration of relatively heavy pre-production impacts at a given site. While infill development can increase the density of potential emissions sources, it also improves some emissions reduction opportunities; for example, through use of field gas instead of diesel for drill rigs and electrification for compressors. State, tribal, and federal regulators need to collaborate with industry to gain a better understanding of emissions trade-offs associated with these trends. To examine the effects of trends in production activity, states should consider adopting cumulative impacts analysis requirements for development occurring on state and private lands, paralleling those that apply to federal actions under NEPA.

Finally, the four states addressed here need to measure emissions reductions achieved by new regulations, and develop improved systems for compliance assurance. Enhanced leak detection and repair and telemetry systems for remote monitoring of production and control equipment could aid in both system maintenance and regulatory compliance. Colorado and Wyoming have recently adopted requirements for LDAR at well pads, although those in Wyoming are only applicable at some new or modified facilities in part of the state. Both states should collect and carefully analyze data from LDAR activities to assess program effectiveness and then refine their programs if necessary. New Mexico, Utah, and the federal agencies working within these states should consider similar requirements. State and federal agencies should continue to collaborate with industry and other researchers in field studies at well-site and basin-wide scales, in order to evaluate and reconcile emissions inventories and assess progress in reducing emissions.