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Defending the West www.westernlaw.org

Western Environmental Law Center

May 28, 2014

Sent via Electronic Mail (scoping comments only) and Certified Mail (comments and exhibits)

U.S. Bureau of Land Management
Farmington Field Office
Attn: Lindsey Eoff, RMP Project Manager
6251 College Blvd., Suite A
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Re: Scoping Comments – Farmington Resource Management Plan Amendment

Dear Mr. Torres:

The Western Environmental Law Center, along with Amigos Bravos, Chaco Alliance, Diné Citizens Against Ruining our Environment, Earthworks, Natural Resources Defense Council, San Juan Citizens Alliance, Sierra Club, and WildEarth Guardians (together “Conservation Groups”), submit the following Scoping Comments regarding the Bureau of Land Management (“BLM”) Farmington Field Office (“FFO”) Resource Management Plan Amendment (“RMPA”) and associated Environmental Impact Statement (“EIS”) encompassing approximately 4 million acres, and an analysis area of approximately 6 million acres, in northwest New Mexico. The RMPA is intended to analyze impacts of additional oil and gas development in the Mancos Shale/Gallup Formation that were not anticipated in the 2002 Reasonable Foreseeable Development (“RFD”) Scenario or considered in the 2003 Farmington RMP/EIS.

Given the critical and fundamental role that the RMPA plays in determining land use values for the area, and specifically the FFO’s management of oil and gas resources, we appreciate the opportunity to participate in Scoping, as well as the FFO’s commitment to integrate of the following concerns into the forthcoming Draft RMPA/EIS. *See* 43 C.F.R. § 1610.2; 42 U.S.C. § 4332.

The **Western Environmental Law Center** (“WELC”) uses the power of the law to defend and protect the American West’s treasured landscapes, iconic wildlife and rural communities. WELC combines legal skills with sound conservation biology and environmental science to address major environmental issues in the West in the most strategic and effective

manner. WELC works at the national, regional, state, and local levels; and in all three branches of government. WELC integrates national policies and regional perspective with the local knowledge of our 100+ partner groups to implement smart and appropriate place-based actions.

Amigos Bravos is a statewide river conservation organization guided by social justice principles. Amigos Bravos' mission is to protect and restore the waters of New Mexico, and ensure that those waters provide a reliable source of clean water to the communities and farmers that depend on them, as well as a safe place to swim, fish, and go boating. Amigos Bravos works locally, statewide, and nationally to ensure that the waters of New Mexico are protected by the best policy and regulations possible.

The **Chaco Alliance** is a grassroots citizens group dedicated to protecting and preserving Chaco Culture National Historical Park.

Diné Citizens Against Ruining our Environment ("Diné C.A.R.E.") is an all-Navajo organization comprised of a federation of grassroots community activists in Arizona, New Mexico and Utah who strive to educate and advocate for our traditional teachings derived from our Diné Fundamental Laws. Our goal is to protect all life in our ancestral homeland by empowering local and traditional people to organize, speak out, and determine the outlook of the environment through civic involvement and engagement in decision-making process relating to tribal development.

Earthworks is a nonprofit organization dedicated to protecting communities and the environment from the adverse impacts of mineral and energy development while promoting sustainable solutions. Earthworks stands for clean air, water and land, healthy communities, and corporate accountability. We work for solutions that protect both the Earth's resources and our communities.

The **Natural Resources Defense Council** ("NRDC") is a non-profit environmental membership organization with more than 440,000 members throughout the United States. Approximately 5,000 of these members reside in New Mexico. NRDC members use and enjoy public lands in New Mexico, including lands managed by the Bureau of Land Management within the Farmington Field Office planning area. NRDC members use and enjoy these lands for a variety of purposes, including: recreation, solitude, scientific study, and conservation of natural resources. NRDC has had a longstanding and active interest in the protection of public lands in New Mexico, the responsible development of oil and gas resources, and the protection of public health from environmental threats.

Founded in 1986, **San Juan Citizens Alliance** ("SJCA") organizes people to protect our water and air, our lands, and the character of our rural communities in the San Juan Basin. SJCA focuses on four program areas, including the *San Juan Basin Energy Reform Campaign*, which ensures proper regulation and enforcement of the oil, gas, and coal industry and transitioning to a renewable energy economy. SJCA has been active in BLM and National Forest oil and gas issues in the San Juan Basin since the early 1990s, and has commented on virtually every multi-well drilling program, lease sale, and programmatic environmental review conducted in the region by the federal land management agencies since the early 1990s. SJCA's members live, work, and

recreate throughout the San Juan Basin and San Juan Mountains. SJCA's members' health, use and enjoyment of this region is directly impacted by the decisions identified in this protest.

The **Sierra Club** was founded in 1892 and is the nation's oldest grassroots environmental organization. The Sierra Club is incorporated in California, and has approximately 600,000 members nationwide and is dedicated to the protection and preservation of the environment. The Sierra Club's mission is to explore, enjoy and protect the wild places of the earth; to practice and promote the responsible use of the earth's ecosystems and resources; and to educate and enlist humanity to protect and restore the quality of the natural and human environments. The Sierra Club has a New Mexico chapter, known as the Rio Grande chapter, with members that live in and use this area for recreation such as hiking, climbing, backpacking, camping, fishing and wildlife viewing, as well as for business, scientific, spiritual, aesthetic and environmental purposes.

WildEarth Guardians protects and restores wildlife, wild places, and wild rivers in the American West. As part of its Climate and Energy Program, Guardians works to advance clean energy and expose the true cost of fossil fuels. Guardians works to protect and restore the San Juan Basin in northwestern New Mexico in order to safeguard its cultural heritage, natural values, communities, and open spaces.

I. BLM's RMPA Planning and Management Obligations and Opportunities.

As provided in BLM regulations, the RMP process presents an opportunity to consider the resources within a field office, ensure public participation in BLM processes, and guide future management decisions.

The objective of resource management planning by the Bureau of Land Management is to maximize resource values for the public through a rational, consistently applied set of regulations and procedures which promote the concept of multiple use management and ensure participation by the public, state and local governments, Indian tribes and appropriate Federal agencies. Resource management plans are designed to guide and control future management actions and the development of subsequent, more detailed and limited scope plans for resources and uses.

43 C.F.R. § 1601.0-2. The RMPA process allows the FFO a critical opportunity to consider its obligations and role as steward of public lands. As discussed throughout these Scoping Comments, this opportunity is of particular importance now given the mounting impacts and threats to our public lands from the virtually unfettered oil and gas development that has occurred in the planning area to date. Conservation Groups' comments are focused on these impacts and, specifically, are concerned with impacts to air quality, greenhouse gas ("GHG") emissions, water resources, human health and livable communities, as well as other land use values in the planning area.

II. The BLM is Required to Suspend All Oil and Gas Leasing and Development in the Planning Area so long as the Farmington RMPA and EIS Remains Uncompleted.

Where, as here, there is a pending programmatic revision to the RMPA/EIS for the Mancos Shale/Gallup Formation – updating the out-of-date 2003 RMP and 2002 RFD for the planning area – NEPA establishes a duty “to stop actions that adversely impact the environment, that limit the choice of alternatives for the EIS, or that constitute an ‘irreversible and irretrievable commitment of resources.’” *Conner v. Burford*, 848 F.2d 1441, 1446 (9th Cir. 1988). When an EIS is underway, as here, NEPA regulations established by the Council of Environmental Quality (“CEQ”) prohibit an agency from taking any actions that would significantly impact the environment. 40 C.F.R. § 1506.1(c) (1997). Pursuant to these CEQ regulations:

While work on a required program environmental impact statement is in progress and the action is not covered by an existing program statement, agencies shall not undertake in the interim any major Federal action covered by the program which may significantly affect the quality of the human environment unless such action:

- (1) Is justified independently of the program;
- (2) Is itself accompanied by an adequate environmental impact statement;
- and
- (3) Will not prejudice the ultimate decision on the program. Interim action prejudices the ultimate decision on the program when it tends to determine subsequent development or limit alternatives.

40 C.F.R. §§ 1506.1(c)(1)-(3).

Proceeding with the October 2014 Lease Sale – or any other major Federal action impacting resources in the planning area – is impermissible due to the inherent prejudice that this action will cause to the pending RMPA/EIS. Revision of the RFD for the planning area is fundamental to the public land use decision-making process in the FFO and beyond – creating the foundation upon which all mineral resource management decisions are made – and, as explained by the agency’s Federal Register Notice, the FFO’s 2003 RMP/EIS is incapable of performing this function:

The RMP amendment is being developed in order to analyze the impacts of additional development in what was previously considered a fully developed oil and gas play within the San Juan Basin in northwestern New Mexico. The Mancos Shale/Gallup Formation was analyzed in the 2002 Reasonable Foreseeable Development (RFD) Scenario and current Farmington Field Office 2003 RMP/EIS. Subsequent improvements and innovations in horizontal drilling technology and multi-stage hydraulic fracturing have enhanced the economics of developing this stratigraphic horizon. With favorable oil prices, the oil play in the southern part of the Farmington Field Office boundary has drawn considerable interest and several wells are planned and being drilled. As fullfield development occurs, especially in the shale oil play, additional impacts may occur that previously were not anticipated in the RFD or analyzed in the current 2003 RMP/EIS, which will require an EIS-level plan amendment and revision of the RFD for complete analysis of the Mancos Shale/Gallup Formation.

79 FED. REG. 10548 (Feb. 25, 2014) (emphasis added).

The whole point of NEPA is to study the impact of an action on the environment before the action is taken. *See Conner*, 848 F.2d at 1452 (NEPA requires that agencies prepare an EIS before there is “any irreversible and irretrievable commitment of resources”). Where “[i]nterim action prejudices the ultimate decision on the program,” NEPA forbids it. 40 C.F.R. §§ 1506.1(c)(1)-(3). Action prejudices the outcome “when it tends to determine subsequent development or limit alternatives.” *Id.* Continuing to approve oil and gas leasing and development during the pendency of this RMPA/EIS limits the alternative available to the agency, thus violating NEPA. *Id.*

As provided, while CEQ regulations require a moratorium on any further oil and gas leasing and development until the RMPA/EIS process is completed, such a decision is also well within the discretion of the FFO. As provided in BLM Instruction Memorandum No. 2010-117 (May 17, 2010):

As outlined in the Land Use Planning Handbook (H-1601-1), the Resource Management Plan (RMP) underlies fluid minerals leasing decisions. Through RMP effectiveness monitoring and periodic RMP evaluations, state and field offices will examine resource management decisions to determine whether the RMPs adequately protect important resource values in light of changing circumstances, updated policies, and new information (H-1601-1, section V, A, B). The results of such reviews and evaluations may require field office resource information updates and land use plan maintenance, amendment, or revision. In some cases state and field office staff may determine that the public interest would be better served by further analysis and planning prior to making any decision whether or not to lease.

(emphasis added). There can be no better example than the present situation of where the public interest would be better served by completing the RMPA/EIS *before* deciding whether it is appropriate to lease or develop additional public lands in the planning area. According to BLM oil and gas statistics, there are currently 5,027,750 acres of leased land that is “in effect” in New Mexico; but only approximately 70% of which is in production. *See* BLM, Oil and Gas Statistics by Year for Fiscal Years 1988 – 2012 (attached as Exhibit 120). Before additional public lands are sold and developed by the oil and gas industry, the agency must understand the additional impacts of developing the Mancos Shale/Gallup formation.

Critically, BLM’s Taos Field Office recently deferred 16 parcels and 13,300 acres of public lands in the same Mancos Shale formation – parcels that are contiguous to 26 parcels at issue, here. The Taos parcels were also scheduled to be offered at the same October 2014 lease sale. However, at least in part due to the FFO’s pending RFD scenario, which, “[o]nce

completed, the information provided by this study will help to BLM to make future decisions regarding leasing in this area[.]” the Taos Field Office decided to defer the sale.¹

This type of reasoned approach should similarly be employed with regard to the 26 parcels in the FFO. Such an approach is not only commonsense, but, as discussed above, is also required given the resulting prejudice to the Mancos Shale RMP and EIS that *any* sale and subsequent development would create. Under these circumstances, NEPA plainly prohibits undertaking any action that would limit alternatives, as proceeding in the sale of 26 parcels certainly would. 40 C.F.R. §§ 1506.1(c)(1)-(3).

III. The BLM Must Take a Hard Look at the Direct, Indirect and Cumulative Impacts of Oil and Gas Development on Certain Resource Values in the Planning Area.

The National Environmental Policy Act (“NEPA”), 42 U.S.C. § 4321 *et seq.*, and its implementing regulations, promulgated by the Council on Environmental Quality (“CEQ”), 40 C.F.R. §§ 1500.1 *et seq.*, is our “basic national charter for the protection of the environment.” 40 C.F.R. § 1500.1. Recognizing that “each person should enjoy a healthful environment,” NEPA ensures that the federal government uses all practicable means to “assure for all Americans safe, healthful, productive, and esthetically and culturally pleasing surroundings,” and to “attain the widest range of beneficial uses of the environment without degradation, risk to health or safety, or other undesirable and unintended consequences,” among other policies. 43 U.S.C. § 4331(b).

NEPA regulations explain, in 40 C.F.R. §1500.1(c), that:

Ultimately, of course, it is not better documents but better decisions that count. NEPA’s purpose is not to generate paperwork – even excellent paperwork – but to foster excellent action. The NEPA process is intended to help public officials make decisions that are based on understanding of environmental consequences, and take actions that protect, restore, and enhance the environment.

Thus, while “NEPA itself does not mandate particular results, but simply prescribes the necessary process,” *Robertson v. Methow Valley Citizens Council*, 490 U.S. 332, 350 (1989), agency adherence to NEPA’s action-forcing statutory and regulatory mandates helps federal agencies ensure that they are adhering to NEPA’s noble purpose and policies. *See* 42 U.S.C. §§ 4321, 4331.

NEPA imposes “action forcing procedures ... requir[ing] that agencies take a *hard look* at environmental consequences.” *Methow Valley*, 490 U.S. at 350 (citations omitted) (emphasis added). These “environmental consequences” may be direct, indirect, or cumulative. 40 C.F.R. §§ 1502.16, 1508.7, 1508.8. A cumulative impact – particularly important here – is defined as:

¹ *See* BLM, Taos Field Office, *October 2014 Oil and Gas Lease Sale*, available at: http://www.blm.gov/nm/st/en/fo/Taos_Field_Office/tafo_og_sale_october.html.

the impact on the environment which results from the incremental impact of the action when added to other past, present, and reasonably foreseeable future actions regardless of what agency (Federal or non-Federal) or person undertakes such other actions. Cumulative impacts can result from individually minor but collectively significant actions taking place over a period of time.

40 C.F.R. § 1508.7.

Federal agencies determine whether direct, indirect, or cumulative impacts are significant by accounting for both the “context” and “intensity” of those impacts. 40 C.F.R. § 1508.27. Context “means that the significance of an action must be analyzed in several contexts such as society as a whole (human, national), the affected region, the affected interests, and the locality” and “varies with the setting of the proposed action.” 40 C.F.R. § 1508.27(a). Intensity “refers to the severity of the impact” and is evaluated according to several additional elements, including, for example: unique characteristics of the geographic area such as ecologically critical areas; the degree to which the effects are likely to be highly controversial; the degree to which the possible effects are highly uncertain or involve unique or unknown risks; and whether the action has cumulatively significant impacts. *Id.* §§ 1508.27(b).

Furthermore, the Federal Land Policy and Management Act (“FLPMA”), 43 U.S.C. § 1701 *et seq.*, directs that “the public lands be managed in a manner that will protect the quality of [critical resource] values; that, where appropriate, will preserve and protect certain public lands in their natural condition; that will provide food and habitat for fish and wildlife and domestic animals; and that will provide for outdoor recreation and human occupancy and use.” 43 U.S.C. § 1701(a)(8). This substantive mandate requires that the agency not elevate the development of oil and gas resources above other critical resource values in the planning area. To the contrary, FLPMA requires that where oil and gas development would threaten the quality of critical resources, that conservation of these resources should be the preeminent goal. BLM must incorporate this mandate into the agency’s RMPA decision-making, consistent with the concerns to the planning area’s resource values, as provided herein.

A. The BLM Must Take a “Hard Look” at Impacts to Air Quality.

The BLM must take a hard look at the air quality impacts from oil and gas development in the planning area. Much of air pollution from oil and gas development and operations, which is specifically discussed, below, also degrades visibility. Section 169A of the Clean Air Act (“CAA”), 42, U.S.C. § 7401 *et seq.* (1970) sets forth a national goal for visibility, which is the “prevention of any future, and the remedying of any existing, impairment of visibility in Class I areas which impairment results from manmade air pollution.” Congress adopted the visibility provisions in the CAA to protect visibility in “areas of great scenic importance.” H.R. Rep. No. 294, 95th Cong. 1st Sess. at 205 (1977). In promulgating its Regional Haze Regulations, 64 Fed. Reg. 35,714 (July 1, 1999), the U.S. Environmental Protection Agency (“EPA”) provided:

Regional haze is visibility impairment that is produced by a multitude of sources and activities which emit fine particles and their precursors and which are located across a broad geographic area. Twenty years ago, when initially adopting the

visibility protection provisions of the CAA, Congress specifically recognized that the “visibility problem is caused primarily by emission into the atmosphere of SO₂, oxides of nitrogen, and particulate matter, especially fine particulate matter, from inadequate[ly] controlled sources.” H.R. Rep. No. 95-294 at 204 (1977). The fine particulate matter (PM) (e.g., sulfates, nitrates, organic carbon, elemental carbon, and soil dust) that impairs visibility by scattering and absorbing light can cause serious health effects and mortality in humans, and contribute to environmental effects such as acid deposition and eutrophication.

The visibility protection program under sections 169A, 169B, and 110(a)(2)(J) of the CAA is designed to protect Class I areas from impairment due to manmade air pollution. The current regulatory program addresses visibility impairment in these areas that is “reasonably attributable” to a specific source or small group of sources, such as, here, air pollution resulting from oil and gas development and operations authorized by the RMPA. *See* 64 Fed. Reg. 35,714.

Moreover, EPA finds the visibility protection provisions of the CAA to be quite broad. Although EPA is addressing visibility protection in phases, the national visibility goal in section 169A calls for addressing visibility impairment generally, including regional haze. *See e.g., State of Maine v. Thomas*, 874 F.2d 883, 885 (1st Cir. 1989) (“EPA’s mandate to control the vexing problem of regional haze emanates directly from the CAA, which ‘declares as a national goal the prevention of any future, and the remedying of any existing, impairment of visibility in Class I areas which impairment results from manmade air pollution.’”) (citation omitted).

Here, there are numerous Class I areas within or near the project area that may be impacted by the proposed development, including: Bandelier National Monument, Wheeler Peak Wilderness, San Pedro Parks Wilderness, Cruces Basin Wilderness, Chama River Canyon Wilderness and Pecos Wilderness in New Mexico, as well as Weminuche Wilderness, La Garita Wilderness, South San Juan Wilderness, Great Sand Dunes National Park, and Mesa Verde National Park in Colorado.

In addition to impacts from the proposed development, cumulative air quality impacts from sources in and around the proposed development area may result in serious impairments. For example, there is substantial oil and gas development already taking place in the San Juan Basin consisting of more than 23,000 current active wells, as well as significant emissions from the two mine-to-mouth coal-fired power plants in the planning area – San Juan Mine and San Juan Generating Station, and Navajo Mine and Four Corners Power Plant.

The current status of air quality in an area is a fundamental consideration for analysis in the agency’s NEPA analysis. Background monitored concentrations of all pollutants should be reviewed. Given the increasing development in the area, there may be higher concentrations that should be reflected. In particular, elevated monitored levels for the 8-hour ozone National Ambient Air Quality Standard (“NAAQS”) in this area in recent years are very concerning. Exposure to ozone is a serious concern as it can cause or exacerbate respiratory health problems, including shortness of breath, asthma, chest pain and coughing, decreased lung function and even long-term lung damage, as discussed in greater detail below. *See also*, EPA’s National Ambient Air Quality Standards for Particulates and Ozone, 62 FR 38,856 (July 18, 1997). According to a

recent report by the National Research Council (“NRC”): “short-term exposure to current levels of ozone in many areas is likely to contribute to premature deaths.”² Even ozone concentrations at levels as low as 60 ppb can be considered harmful to human health and the FFO should consider this when evaluating the air impacts that would result from the oil and gas development under the RMPA.

Elevated ozone concentrations have been recorded in recent years at eight monitors in the Four Corners Area. For example, the background value given for Mesa Verde is 142 $\mu\text{g}/\text{m}^3$, which is just under the NAAQS.³ Thus, the increased oil and gas development that will take place under the proposed action – and, particularly the shale oil play threatening to outpace the existing RFD – would be an important contributor to the ozone problem in the area. There is no room for growth in emissions that contribute to these harmful levels of ozone pollution in the area – namely, nitrogen oxides (“NO_x”) and volatile organic compounds (“VOCs”). Any increase in emissions of ozone precursors will exacerbate the negative health effects of ozone in the region, as discussed below, and is almost certain to threaten the area’s compliance with EPA’s the ozone standard.

Critically, given the *decades* in which the FFO will rely upon the RMPA in their decision-making, the agency must also include an alternative that considers stricter EPA ozone standards. In January of 2010, EPA proposed stricter ozone standards, between 60 and 70 ppb. *See* 73 FED. REG. 16436 (May 27, 2008), and 75 FED. REG. 2938 (January 19, 2010). Although we don’t yet know how low the new ozone standards will be set, it is almost certain that the current value of 71 ppb in the planning area will no longer be in attainment once a new standard is determined, and therefore any analysis relying on the current 75 ppb standard would be quickly outdated.

The FFO must also consider significant new information that demonstrates emissions associated with oil and gas development are significantly higher than what the 2003 Farmington RMP contemplated. According to recent inventory data prepared by the Western Regional Air Partnership (“WRAP”), the 2003 Farmington EIS underestimates emissions of VOCs from oil and gas operations by nearly 30-fold. In 2003, BLM estimated that within 20 years, VOC emissions would amount to 2,008.5 tons/year. According to the most recent WRAP inventory, VOC emissions from oil and gas activities in San Juan and Rio Arriba Counties were estimated to be nearly 60,000 tons/year in 2006 and projected to be more than 55,000 tons per year by 2012.⁴ The table below illustrates this discrepancy between the amount of VOC emissions

² National Research Council, *Link Between Ozone Air Pollution and Premature Death Confirmed*, (April 2008), available at: <http://www8.nationalacademies.org/onpinews/newsitem.aspx?RecordID=12198>.

³ The 75 ppb 8-hour ozone standard of 75 ppb translates to 150 $\mu\text{g}/\text{m}^3$.

⁴ *See* ENVIRON, *Final Report: Development of 2012 Oil and Gas Emissions Projections for the South San Juan Basin* (Dec. 2009) (attached as Exhibit 121); ENVIRON, *Final Report: Development of Baseline 2006 Emissions from Oil and Gas Activity in the South San Juan Basin* (Nov. 2009) (attached as Exhibit 122).

projected in 2003 and the most recent estimates.

| Source of Emission Inventory | VOC Emission Estimate (tons/year) |
|---|--|
| RMP 20-Year Projection (RMP EIS at J-11) | 2,008.5 |
| WRAP Phase III 2006 Inventory for San Juan/Rio Arriba Counties | 59,933 |
| WRAP Phase III 2012 Projection for San Juan/Rio Arriba Counties | 55,049 |

Indeed, current oil and gas emissions likely outpace even these considerable projections, placing emphasis on the critical importance that the RMPA/EIS include detailed modeling and analysis of not only current air quality conditions in the San Juan Basin, but the cumulative impact that increased emissions from projected shale oil boom will have on when added to this baseline.

The discrepancy between 2003 RMP/EIS and the WRAP projections also indicates that the emissions data currently relied upon to approve oil and gas leasing and development in the San Juan Basin – and, in particular the EA for the October 2014 lease sale, which shows dramatically lower VOC emissions in San Juan and Rio Arriba Counties, EA at 26-27 – is seriously flawed. For example, the lease sale EA indicates that EPA emission inventory data from 2011 was utilized in reporting overall emissions in San Juan and Rio Arriba Counties. However, the EPA’s inventory data does not reflect the actual emission inventory data presented by the WRAP as it relies solely on point source inventory data submitted by the New Mexico Environment Department.⁵ Yet, as the WRAP data indicates, the vast majority of oil and gas-related VOC emissions are non-point source emissions. In other words, the emissions data BLM presents in the EA fails to accurately account for oil and gas emissions, raising further concerns that the EA is inadequate and fails to justify a finding of no significant impact. As discussed above, BLM must suspend all oil and gas leasing and development until the RMPA/EIS is completed and sufficient emissions data is available.

Of course, the RMPA/EIS must also analyze the impacts of developing the projected shale oil boom to a number of national ambient air quality standards (“NAAQS”). In particular, the agency must analyze the direct, indirect, and cumulative air quality impacts in the context of NAAQS most recently promulgated. These NAAQS include the 1-hour nitrogen dioxide NAAQS (promulgated in 2010), the 1-hour sulfur dioxide NAAQS (also promulgated in 2010), the 8-hour ozone NAAQS (promulgated in 2008), the 24-hour PM_{2.5} NAAQS (promulgated in 2006), and the annual PM_{2.5} NAAQS (promulgated in 2012). Specifically, we are concerned over

⁵ See EPA, *2011 National Emissions Inventory, version 1, Technical Support Document DRAFT* (Nov. 2013) at 160, available at: http://www.epa.gov/ttn/chief/net/2011nei/2011_neiv1_tsd_draft.pdf (attached as Exhibit 123).

the impacts to the 1-hour NO₂ NAAQS given that short-term NO₂ concentrations are linked to near-field, near ground-level emissions, including compressor engines exhaust stacks and other combustion sources.

Notably, even if current air quality monitoring data suggests that impacts to the NAAQS will not be significant, the fact that current monitoring does not indicate the region is violating any NAAQS does not mean that the NAAQS will never be violated. The U.S. District Court for the District of Colorado in fact rejected a similar analysis prepared by the BLM in support of an oil and gas drilling plan in the Roan Plateau area of western Colorado. In that case, the BLM asserted that the lack of ozone violations indicated that future impacts would not be significant. In her ruling, Judge Krieger stated: “The mere fact that the area has not exceeded ozone limits in the past is of no significance when the purpose of the EIS is to attempt to predict what environmental effects are likely to occur in the future[.]” *Colo. Envtl. Coal. v. Salazar*, 875 F. Supp. 2d 1233, 1257 (D. Colo. 2012).

Additionally, PM_{2.5} is another potential area of major health impacts in the area. PM_{2.5} can become lodged deep in the lungs or can enter the blood stream, worsening the health of asthmatics and even causing premature death in people with heart and lung disease. Even PM_{2.5} concentrations lower than the current NAAQS are a concern for human health. While background PM_{2.5} values are not at the level of the NAAQS currently, it is likely that those levels will increase with continued development in the area. Elevated wintertime concentrations could become an issue as they have in other areas of concentrated oil and gas development in the West, such as in the Uinta Basin in Utah.⁶

Also critical to the BLM’s analysis of air quality impacts is the relationship to human health. Logically, adherence to NAAQS would have a positive relationship to human health, however, the agency cannot rely on these standards or other indicators such as the Air Quality Index (“AQI”) or National Air Toxics Assessment (“NATA”) and assume that this alone would satisfy the FFO’s hard look NEPA obligations – in particular given the poor baseline air quality conditions due to prevailing impacts in the planning area.

Research indicates a strong correlation between oil and gas development and increased ozone concentrations – particularly in the summer when warm, stagnant conditions yield an increase in O₃ from oil and gas emissions.⁷ Particularly in areas of significant existing oil and gas development – such as the San Juan Basin, which was the focus of research here – summertime “peak incremental O₃ concentration of 10 ppb” have been simulated. *Id.* at 1118. This study

⁶ Several very high values of PM_{2.5} were recorded in Vernal, Utah starting in 2007, including six exceedances of the 24-hour PM_{2.5} NAAQS and a maximum 24-hour average PM_{2.5} concentration of 63 µg/m³. In 2009, there were three recorded exceedances of the 24-hour average PM_{2.5} NAAQS in Roosevelt, Utah with 24-hour average concentrations reaching 42 µg/m³ and four recorded exceedances in Vernal with 24-hour average concentrations as high as 60.9 µg/m³.

⁷ Marco A Rodriguez, et al., *Regional Impacts of Oil and Gas Development on Ozone Formation in the Western United States*, JOURNAL OF AIR & WASTE MANAGEMENT ASSOCIATION (Sept. 2009) (attached as Exhibit 1).

indicates a “clear potential for oil and gas development to negatively affect regional O₃ concentrations in the western United States, including several treasured national parks and wilderness areas in the Four Corners region – particularly Mesa Verde and the Weminuche Wilderness. “It is likely that accelerated energy development in this part of the country will worsen the existing problem.”⁸ Additionally, oil and gas production in the mountain west has recently been linked to *winter* ozone levels that greatly exceed the NAAQS.⁹

As the Endocrine Disruption Exchange has noted:

In addition to the land and water contamination issues, at each stage of production and delivery tons of toxic volatile compounds, including benzene, toluene, ethylbenzene, xylene, etc., and fugitive natural gas (methane), escape and mix with nitrogen oxides from the exhaust of diesel-driven, mobile and stationary equipment to produce ground-level ozone. Ozone combined with particulate matter less than 2.5 microns produces smog (haze). Gas field produced ozone has created a serious air pollution problem similar to that found in large urban areas, and can spread up to 200 miles beyond the immediate region where gas is being produced. Ozone not only causes irreversible damage to the lungs, it is equally damaging to conifers, aspen, forage, alfalfa, and other crops commonly grown in the West. Adding to this is the dust created by fleets of diesel-driven water trucks working around the clock hauling the constantly accumulating condensate water from well pads to central evaporation pits.¹⁰

Increases in ground-level ozone not only impact regional haze and visibility, but can also result in dramatic impacts to human health. According to the EPA:

Breathing ground-level ozone can result in a number of health effects that are observed in broad segments of the population. Some of these effects include:

- Induction of respiratory symptoms
- Decrements in lung function
- Inflammation of airways

⁸ See Rodriguez at 1118 (attached above as Exhibit 1).

⁹ See Gail Tonnesen and Richard Payton, EPA Region 8. *Winter Ozone Formation: Results from the Wyoming Upper Green River Basin Studies and Plans for the 2012, Uintah Basin Study* (seminar abstract) (Jan. 2012), available at: <http://www.esrl.noaa.gov/csd/seminars/2012/TonnesenPayton.html> (citing, *inter alia*, Schnell, et. al., *Rapid photochemical production ozone at high concentrations in a rural site during winter*, 2 Nature Geosci. 120-122 (2009) (attached as Exhibit 2).

¹⁰ The Endocrine Disruption Exchange. Undated. *Chemicals In Natural Gas Operations: Health Effects Spreadsheet and Summary*, available at: <http://www.endocrinedisruption.com/chemicals.multistate.php> (attached as Exhibit 3).

Respiratory symptoms can include:

- Coughing
- Throat irritation
- Pain, burning, or discomfort in the chest when taking a deep breath
- Chest tightness, wheezing, or shortness of breath

In addition to these effects, evidence from observational studies strongly indicates that higher daily ozone concentrations are associated with increased asthma attacks, increased hospital admissions, increased daily mortality, and other markers of morbidity. The consistency and coherence of the evidence for effects upon asthmatics suggests that ozone can make asthma symptoms worse and can increase sensitivity to asthma triggers.¹¹

Oil and gas development is one of the largest sources of VOCs, ozone, and sulfur dioxide emissions in the United States. The relationship between air quality and human health must be analyzed in the agency's NEPA analysis. "The agency must examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'" *Motor Vehicle Mfrs.*, 463 U.S. at 43 (1983).

B. The BLM Must Take a "Hard Look" at Climate Change.

If we are to stem the impacts of climate change and manage for sustainable ecosystems, not only must the BLM take a hard look at greenhouse gas ("GHG") emissions stemming from the development authorized by the RMPA, but the agency's decision must be reflective of the challenges we face.

The EPA has determined that human emissions of greenhouse gases are causing global warming that is harmful to human health and welfare. *See* 74 Fed. Reg. 66,496 (Dec. 15, 2009), *Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act*. The D.C. Circuit has upheld this decision as supported by the vast body of scientific evidence on the subject. *See Coal. for Responsible Regulation, Inc. v. E.P.A.*, 684 F.3d 102, 120-22 (D.C. Cir. 2012). Indeed, EPA could not have found otherwise, as virtually every climatologist in the world accepts the legitimacy of global warming and the fact that human activity has resulted in atmospheric warming and planetary climate change.¹² The world's

¹¹ EPA, *Health Effects of Ozone in the General Population*, available at: <http://www.epa.gov/apti/ozonehealth/population.html> (attached as Exhibit 4).

¹² *See, e.g., See INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, The Science of Climate Change* (1995) (attached as Exhibit 5); U.S. Climate Change Science Program, *Abrupt Climate Change* (Dec. 2008) (attached as Exhibit 6); James Hansen, et. al., *Global Surface Temperature Change*, REVIEWS OF GEOPHYSICS, 48, RG4004 (June 2010) (attached as Exhibit 7); *see also*, Richard A. Muller, *Conversion of a Climate Change Skeptic*, NEW YORK TIMES, July 28, 2012 (attached as Exhibit 8) (citing Richard A. Muller, et. al., *A New Estimate of the Average Earth*

leading minds and most respected institutions – guided by increasingly clear science and statistical evidence – agree that dramatic action is necessary to avoid planetary disaster.¹³ GHG concentrations have been steadily increasing over the past century,¹⁴ and our insatiable consumption of fossil fuels is pushing the world to a tipping point where, once reached, catastrophic change will be unavoidable.¹⁵ In fact, the impacts from climate change are already being experienced, with drought and extreme weather events becoming increasingly common.¹⁶

Surface Temperature, Spanning 1753 to 2011, (attached as Exhibit 9); Richard A. Muller, et. al., *Decadal Variations in the Global Atmospheric Land Temperatures* (attached as Exhibit 10)).

¹³ See, e.g., Rob Atkinson, et. al., *Climate Pragmatism: Innovation, Resilience, and No Regrets* (July 2011) (attached as Exhibit 11); Veerabhadran Ramanathan, et. al., *The Copenhagen Accord for Limiting Global Warming: Criteria, Constraints, and Available Avenues* (Feb. 2010) (attached as Exhibit 12); UNITED NATIONS, INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, *Climate Change 2007: Synthesis Report* (2007) (attached as Exhibit 13); A.P. Sokolov, et. al., *Probabilistic Forecast for Twenty-First-Century Climate Based on Uncertainties in Emissions (without Policy) and Climate Parameters*, MASSACHUSETTS INSTITUTE OF TECHNOLOGY (MIT) (Oct. 2009) (attached as Exhibit 14); UNITED NATIONS, FRAMEWORK CONVENTION ON CLIMATE CHANGE, *Report of the Conference of the Parties* (Dec. 2011) (attached as Exhibit 15); Bill McKibben, *Global Warming's Terrifying New Math*, ROLLING STONE, July 19, 2012 (attached as Exhibit 16); Elizabeth Muller, *250 Years of Global Warming*, BERKLEY EARTH, July 29, 2012 (attached as Exhibit 17); Marika M. Holland, et. al., *Future abrupt reductions in summer Arctic sea ice*, *Geophysical Research Letters*, Vol. 33, L23503 (2006) (attached as Exhibit 18).

¹⁴ See Randy Strait, et. al., *Final Colorado Greenhouse Gas Inventory and Reference Case Projections: 1990-2020*, CENTER FOR CLIMATE STRATEGIES (Oct. 2007) (attached as Exhibit 19); Robin Segall et. al., *Upstream Oil and Gas Emissions Measurement Project*, U.S. ENVIRONMENTAL PROTECTION AGENCY (attached as Exhibit 20); Lee Gribovicz, *Analysis of States' and EPA Oil & Gas Air Emissions Control Requirements for Selected Basins in the Western United States*, WESTERN REGIONAL AIR PARTNERSHIP (Nov. 2011) (attached as Exhibit 21).

¹⁵ See, e.g., James Hansen, *Tipping Point: Perspective of a Climatologist*, STATE OF THE WILD 2008-2009 (attached as Exhibit 22); GLOBAL CARBON PROJECT, *A framework for Internationally Co-ordinated Research on the Global Carbon Cycle*, ESSP Report No. 1 (attached as Exhibit 23); INTERNATIONAL ENERGY AGENCY, *CO₂ Emissions from Fuel Combustion, Highlights 2011* (attached as Exhibit 24); GLOBAL CARBON PROJECT, *10 Years of Advancing Knowledge on the Global Carbon Cycle and its Management* (attached as Exhibit 25); Malte Meinshausen, et. al., *Greenhouse-gas emission targets for limiting global warming to 2° C*, *NATURE*, Vol. 458, April 30, 2009 (attached as Exhibit 26).

¹⁶ See, e.g., UNITED NATIONS, INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, *Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation* (2011) (attached as Exhibit 27); Aiguo Dai, *Increasing drought under global warming in observations and models*, *NATURE: CLIMATE CHANGE* (Aug. 2012) (attached as Exhibit 28); Stephen Saunders, et. al., *Hotter and Drier: The West's Changed Climate* (March 2008) (attached as Exhibit 29).

Renowned NASA climatologist, Dr. James Hansen, provides the analogy of loaded dice – suggesting that there still exists some variability, but that climate change is making these extreme events ever more common.¹⁷ In turn, climatic change and GHG emissions are having dramatic impacts on plant and animal species and habitat, threatening both human and species resiliency and the ability to adapt to these changes.¹⁸ According to experts at the Government Accountability Office (“GAO”), federal land and water resources are vulnerable to a wide range of effects from climate change, some of which are already occurring. These effects include, among others, “(1) physical effects, such as droughts, floods, glacial melting, and sea level rise; (2) biological effects, such as increases in insect and disease infestations, shifts in species distribution, and changes in the timing of natural events; and (3) economic and social effects, such as adverse impacts on tourism, infrastructure, fishing, and other resource uses.”¹⁹

Despite the strength of these findings, the BLM in general, and FFO in particular, have historically failed to take serious action to address these impacts. This type of dismissive approach fails to satisfy the guidance outlined in Department of Interior Secretarial Order 3226, discussed below, or the requirements of NEPA. “Reasonable forecasting and speculation is ... implicit in NEPA, and we must reject any attempt by agencies to shirk their responsibilities under NEPA by labelling any and all discussion of future environmental effects as ‘crystal ball inquiry.’” *Save Our Ecosystems v. Clark*, 747 F.2d 1240, 1246 n.9 (9th Cir. 1984 (quoting *Scientists’ Inst. for Pub. Info., Inc. v. Atomic Energy Comm.*, 481 F.2d 1079, 1092 (D.C. Cir. 1973)).

As noted above, NEPA imposes “action forcing procedures ... requir[ing] that agencies take a *hard look* at environmental consequences.” *Methow Valley*, 490 U.S. at 350 (citations

¹⁷ See, James Hansen, et. al., *Climate Variability and Climate Change: The New Climate Dice* (Nov. 2011) (attached as Exhibit 30); James Hansen, et. al., *Perception of Climate Change* (March 2012) (attached as Exhibit 31); James Hansen, et. al., *Increasing Climate Extremes and the New Climate Dice* (Aug. 2012) (attached as Exhibit 32).

¹⁸ See Fitzgerald Booker, et. al., *The Ozone Component of Climate Change: Potential Effects on Agriculture and Horticultural Plant Yield, Product Quality and Interactions with Invasive Species*, J. INTEGR. PLANT BIOL. 51(4), 337-351 (2009) (attached as Exhibit 33); Peter Reich, *Quantifying plant response to ozone: a unifying theory*, TREE PHYSIOLOGY 3, 63-91 (1987) (attached as Exhibit 34).

¹⁹ GAO Report, *Climate Change: Agencies Should Develop Guidance for Addressing the Effects on Federal Land and Water Resources* (2007) (attached as Exhibit 35); see also Committee on Environment and Natural Resources, National Science and Technology Council, *Scientific Assessment of the Effects of Global Climate Change on the United States* (2008) (attached as Exhibit 36); Melanie Lenart, et. al. *Global Warming in the Southwest: Projections, Observations, and Impacts* (2007) (attached as Exhibit 37) (describing impacts from temperature rise, drought, floods and impacts to water supply on the southwest).

omitted) (emphasis added). These “environmental consequences” may be direct, indirect, or cumulative. 40 C.F.R. §§ 1502.16, 1508.7, 1508.8. BLM is required to take a hard look at those impacts as they relate to the agency action. “Energy-related activities contribute 70% of global GHG emissions; oil and gas together represent 60% of those energy-related emissions through their extraction, processing and subsequent combustion.”²⁰ Even if science cannot isolate each additional oil or gas well’s contribution to these overall emissions, this does not obviate BLM’s responsibility to consider oil and gas development in the action area from the cumulative impacts of the oil and gas sector. In other words, the BLM cannot ignore the larger relationship that oil and gas management decisions have to the broader climate crisis that we face. Here, the agency’s analysis must include the full scope of GHG emissions. *See Neighbors of Cuddy Mountain v. U.S. Forest Service*, 137 F.3d 1372, 1379 (9th Cir. 1998) (“To ‘consider’ cumulative effects, some quantified or detailed information is required. Without such information, neither the courts nor the public, in reviewing the [agency’s] decisions, can be assured that the [agency] provided the hard look that it is required to provide.”). If we are to stem climate disaster – the impacts of which we are already experiencing – the agency’s decisionmaking must be reflective of this reality and plan accordingly.

BLM is, at the end of the day, responsible for the management of 700 million acres of federal onshore subsurface minerals.²¹ Indeed, “the ultimate downstream GHG emissions from fossil fuel extraction from federal lands and waters by private leaseholders could have accounted for approximately 23% of total U.S. GHG emissions and 27% of all energy-related GHG emissions.”²² This suggests that “ultimate GHG emissions from fossil fuels extracted from federal lands and waters by private leaseholders in 2010 could be more than 20-times larger than the estimate reported in the CEQ inventory, [which estimates total federal emissions from agencies’ operations to be 66.4 million metric tons]. Overall, ultimate downstream GHG emissions resulting from fossil fuel extraction from federal lands and waters by private leaseholders in 2010 are estimated to total 1,551 [million metric tons of CO₂ equivalent (“MMTCO₂e”)].” *Id.* In 2010, the GAO estimated that BLM could eliminate up to 40% of methane emissions from federally authorized oil and natural gas development, the equivalent of eliminating 126 Bcf or 46.3 MMTCO₂e of GHG pollution annually and equivalent to roughly 13 coal-fired power plants.²³ To suggest that the agency does not, here, have to account for GHG

²⁰ International Investors Group on Climate Change, *Global Climate Disclosure Framework for Oil and Gas Companies* (attached as Exhibit 38).

²¹ *See* DOI-BLM, *Mineral and Surface Acreage Managed By BLM*, available at: http://www.blm.gov/wo/st/en/info/About_BLM/subsurface.html.

²² Stratus Consulting, prepared for: The Wilderness Society, *Greenhouse Gas Emissions from Fossil Energy Extracted from Federal Lands and Waters*, Feb. 1, 2012 (attached as Exhibit 39).

²³ GAO, *Federal Oil & Gas Leases: Opportunities Exist to Capture Vented and Flared Natural Gas, Which Would Increase Royalty Payments and Reduce Greenhouse Gases*, GAO-11-34 at 12 (Table 1)(October 2010) (attached as Exhibit 46). This GHG equivalence assumes a CH₄ warming potential of 72 (20-year warming period) as per the Intergovernmental Panel on Climate Change’s Fourth Assessment Report and using EPA’s GHG equivalencies calculator.

pollution from oil and gas development authorized by the RMPA, would be to suggest that the collective 700 million acres of subsurface mineral estate is not relevant to protecting against climate change. This sort of flawed, reductive thinking would be problematic, and contradicted by the agency's very management framework that provides a place-based lens to account for specific pollution sources to ensure that the broader public interest is protected. Therefore, even though climate change emissions from the RMPA may look minor when viewed on the scale of the global climate crisis we face, when considered cumulatively with all of the other GHG emissions from BLM-managed land, they become significant and cannot be ignored.

The 2014 Inventory of U.S. Greenhouse Gas Emissions reports that natural gas systems alone, including production, processing, and transmission and storage, emitted over 100 MMTCO_{2e} of methane in 2012.²⁴

Research conducted by the National Research Council has confirmed the fact that the negative impacts of energy generation from fossil fuels are not represented in the market price for such generation.²⁵ In other words, failing to internalize the externalities of energy generation from fossil fuels – such as the impacts to climate change and human health – has resulted in a market failure that requires government intervention. Not only should the agency be mindful of this cost failure as they evaluate our nation's dependence on dirty energy from oil and gas in the RMPA/EIS – particularly as it relates to other incompatible resource values deserving protection in the planning area – but the agency is *obligated* to include this type of analysis pursuant to BLM Instruction Memorandum No. 2013-131 (Sept. 18, 2013). Specifically, IM No. 2013-131 is reflective of the BLM's attempt to internalize these costs:

All BLM managers and staff are directed to utilize estimates of nonmarket environmental values in NEPA analysis supporting planning and other decision-making where relevant and feasible, in accordance with the attached guidance. At least a qualitative description of the most relevant nonmarket values should be included for the affected environment and the impacts of alternatives in NEPA analyses....

Nonmarket environmental values reflect the benefits individuals attribute to experiences of the environment, uses of natural resources, or the existence of particular ecological conditions that do not involve market transactions and

²⁴ See U.S. EPA, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2012*, at 3-63 (April 2014) (attached as Exhibit 125).

²⁵ See, e.g., National Research Council, *Hidden Costs of Energy: Unpriced Consequences of Energy Production and Use* (2010) (attached as Scoping Exhibit 40); Nicholas Muller, et. al., *Environmental Accounting for Pollution in the United States Economy*, AMERICAN ECONOMIC REVIEW at 1649-1675 (Aug. 2011) (attached as Scoping Exhibit 41); see also, Generation Investment Management, *Sustainable Capitalism*, (Jan. 2012) (advocating a paradigm shift to *Sustainable Capitalism*; “a framework that seeks to maximize long-term economic value creation by reforming markets to address real needs while considering *all* costs and stakeholders.”) (attached as Scoping Exhibit 42).

therefore lack prices. Examples include the perceived benefits from hiking in a wilderness or fishing for subsistence rather than commercial purposes. The economic methods described in this guidance provide monetary estimates of nonmarket values. Several non-economic, primarily qualitative methods can also be used to characterize the values attributed to places, landscapes, and other environmental features. Guidance on qualitative methods for assessing environmental values, including ethnography, interviews, and surveys, is in preparation.

Ideally, economic analysis for resource management should consider all relevant values, not merely those that are easy to quantify. Utilizing nonmarket values provides a more complete picture of the consequences of a proposed activity than market data alone would allow. The BLM's Land Use Planning Handbook, Appendix D encourages inclusion of information on nonmarket values, but does not provide detail.

Moreover, the federal working group addressing the social cost of carbon ("SCC") has released new estimates that revise significantly upward the costs associated with GHG pollution, with median impacts pegged at \$43 and \$65 per ton.²⁶ The RMPA must consider the SCC in the agency's NEPA analysis. To date, the BLM has effectively assumed a price of carbon that is \$0 by failing to consider the social, economic, and environmental costs of leasing and development altogether. Failure to take these impacts into account violates NEPA by relying on a partially disclosed amount of greenhouse gas pollution from foreseeable oil and gas development, and fails to take the essential next step required for a hard look: disclosing the impacts that such pollution would have.

It is well settled that where an agency action causes greenhouse gas pollution, NEPA mandates that agencies analyze and disclose the impacts of that pollution. As the Ninth Circuit has held:

[T]he fact that climate change is largely a global phenomenon that includes actions that are outside of [the agency's] control ... does not release the agency from the duty of assessing the effects of its actions on global warming within the context of other actions that also affect global warming.

Ctr. for Biological Diversity v. Nat'l Highway Traffic Safety Admin., 538 F.3d 1172, 1217 (9th Cir. 2008) (quotations and citations omitted); *see also Border Power Plant Working Grp. v. U.S. Dep't of Energy*, 260 F. Supp. 2d 997, 1028-29 (S.D. Cal. 2003) (finding agency failure to disclose project's indirect carbon dioxide emissions violates NEPA). The need to evaluate such impacts is bolstered by the fact that "[t]he harms associated with climate change are serious and well recognized," and environmental changes caused by climate change "have already inflicted significant harms" to many resources around the globe. *Massachusetts v. EPA*, 549 U.S. 497, 521

²⁶ See Interagency Working Group on the Social Cost of Carbon, United States Government, *Technical Support Document: Technical Update on the Social Cost of Carbon for Regulatory Impact Analysis – Under Executive Order 12866* (May 2013) (attached as Scoping Exhibit 43).

(2007); *see also id.* at 525 (recognizing “the enormity of the potential consequences associated with manmade climate change.”).

The FFO must “consider every significant aspect of the environmental impact of a proposed action.” *Baltimore Gas & Elec. Co. v. Natural Resources Defense Council*, 462 U.S. 87, 107 (1983) (quotations and citation omitted). To fulfill this mandate, the agency must disclose the “ecological[,] ... economic, [and] social” impacts of a proposed action. 40 C.F.R. § 1508.8(b). Here, BLM failed to satisfy this threshold requirement.

Agency decision-making must be reflective of this broader reality of climate change, and the agency’s failure to account for the full lifecycle of oil and gas production would represent a fundamental deficiency in its NEPA analysis. As discussed more fully below, BLM not only has the authority, but an obligation to address GHG emissions and methane waste. Furthermore, the agencies must consider not only the cumulative impact of the GHG emissions authorized by the proposed action, it must also consider those emissions combined with other activity in the area. As noted above, “[t]he impact of greenhouse gas emissions on climate change is precisely the kind of cumulative impacts analysis that NEPA requires agencies to conduct.” *Ctr. for Biological Diversity*, 538 F.3d 1172, 1217. The agency must assess cumulative impacts, particularly, as here, the cumulative impacts of climate change. Failure to do so would “impermissibly subject[s] the decisionmaking process contemplated by NEPA to ‘the tyranny of small decisions.’ ” *Kern*, 284 F.3d at 1078 (citation omitted).

a. Methane Emissions and Waste

The agency must take a hard look, and meaningful action, to address the serious issue of methane (“CH₄”) emissions and waste in the oil and gas production process. Such action must include an estimate of the projected methane emission rates from drilling and production activities authorized by the proposed action, as well as detailed analysis of measures employed to mitigate such emissions.

Methane emission rates can differ quite dramatically from one oil and gas field to the next, and, depending on the type of mitigation and emission controls employed, emissions can range anywhere from 1% to 12% of production.²⁷

²⁷ *See, e.g.*, David T. Allen, et. al., *Measurements of methane emissions at natural gas production sites in the United States*, PNAS (Aug. 19, 2013) (finding emissions as low as 1.5% of production at select sites) (attached as Exhibit 66); Anna Karion, et. al., *Methane emissions estimate from airborne measurements over a western United States gas field*, GEOPHYSICAL RESEARCH LETTERS (Aug. 27, 2013) (finding emissions of 6 to 12 percent, on average, in the Uintah Basin) (attached as Exhibit 67). *See also*, Joe Romm, *Study of Best Fracked Wells Finds Low Methane Emissions But Skips Super-Emitters*, CLIMATE PROGRESS (September 19, 2013), available at: <http://thinkprogress.org/climate/2013/09/19/2646881/study-fracked-wells-methane-emissions-super-emitters/>. *See also* GAO-11-34 (2010) at 25 (using a conversion factor of .4045 MMTCO₂e/Bcf for vented gas) (attached above as Exhibit 46).

Assuming a lower-bound leak rate of 1% – which is approximately one-third lower than the EPA estimate of methane emissions in the Inventory of U.S. GHG Emissions and Sinks: 1990-2011²⁸ – methane emissions from gas production by the proposed action could represent a meaningful contribution of emissions over the life of the developed field.²⁹ Assuming an upper-bound leak rate of 12%, the high end of the rate found in a 2012 study using air sampling over the Uinta Basin,³⁰ methane emissions from gas could be truly significant indeed. Although there is substantial variability between the 1% and 12% emission leak rates – and, even without specific data from the proposed action, we can assume leakage somewhere between these two extremes – even at the low end emissions would not be trivial.

Even setting aside the issue of climate change, every ton of methane emitted to the atmosphere from oil and gas development is a ton of natural gas *lost*. Every ton of methane lost to the atmosphere is therefore a ton of natural gas that cannot be used by consumers. Methane lost from federal leases may also not yield royalties otherwise shared between federal, state, and local governments. This is particularly problematic in New Mexico, where data from the U.S. Office of Natural Resources Revenue (“ONRR”), which tracks and collects royalties due from companies that mine resources on public lands, shows:

the amount of gas lost to unauthorized flaring and venting increased more than 20-fold from 2010 through 2013 ... The sharp increase, particularly starting in 2012, comes primarily from New Mexico. The state lacks infrastructure to handle the gas associated with oil development, according to the BLM, and the gas itself is poor quality that cannot go directly into a pipeline.³¹

This lost gas reflects serious inefficiencies in how BLM oil and gas leases are developed. Energy lost from oil and gas production – whether avoidable or unavoidable – reduces the ability of a lease to supply energy, increasing the pressure to drill other lands to supply energy to satisfy demand. 40 C.F.R. §§ 1502.16(e)-(f). In so doing, inefficiencies create indirect and cumulative environmental impacts by increasing the pressure to satisfy demand with new drilling. 40 C.F.R. §§ 1508.7, 1508.8(b).

i. Mineral Leasing Act’s duty to prevent waste.

²⁸ See U.S. Environmental Protection Agency, *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011* (April 2013) (attached as Exhibit 51).

²⁹ See U.S. Environmental Protection Agency, *Greenhouse Gas Equivalencies Calculator*, available at: <http://www.epa.gov/cleanenergy/energy-resources/calculator.html>.

³⁰ See Brian Maffly, *Uinta Basin gas leakage far worse than most believe*, THE SALT LAKE TRIBUNE (Aug 05, 2013), available at: <http://www.sltrib.com/sltrib/news/56692751-78/basin-carbon-emissions-gas.html.csp> (“Between 6 percent and 12 percent of the Uinta Basin’s natural gas production could be escaping into the atmosphere.”).

³¹ See Christina Nunez, *Oil Drillers’ Burning of Natural Gas Cost Millions in Revenue*, NATIONAL GEOGRAPHIC, May 22, 2014 (attached as Exhibit 126).

Conservation Groups, and in particular WELC, have been urging field offices throughout the West to adopt common sense and economical measures to address the issue of fugitive methane waste. The agencies have expansive authority – and, indeed, the responsibility and opportunity – to prevent the waste of oil and gas resources, in particular methane, which is the primary constituent of natural gas. The Mineral Leasing Act of 1920 (“MLA”) provides that “[a]ll leases of lands containing oil or gas ... shall be subject to the condition that the lessee will, in conducting his explorations and mining operations, use all reasonable precautions to prevent waste of oil or gas developed in the land....” 30 U.S.C. § 225; *see also* 30 U.S.C. § 187 (“Each lease shall contain...a provision...for the prevention of undue waste....” As the MLA’s legislative history teaches, “conservation through control was the dominant theme of the debates.” *Boesche v. Udall*, 373 U.S. 472, 481 (1963) (citing H.R.Rep. No. 398, 66th Cong., 1st Sess. 12-13; H.R.Rep. No. 1138, 65th Cong., 3d Sess. 19 (“The legislation provided for herein...will [help] prevent waste and other lax methods....”))).

BLM’s implementing regulations, reflecting these provisions, currently provide that “[t]he objective” of its MLA regulations in 43 C.F.R. Subpart 3160 “is to promote the orderly and efficient exploration, development and production of oil and gas. 43 C.F.R. § 3160.0-4. In part, “orderly and efficient” operations are ensured through unitization or communitization agreements. 43 C.F.R. §§ 3161.2, 3162.2-4(b) (BLM authority to require lessees unitization or communitization agreements); 43 C.F.R. Subpart 3180 (general rules pertaining to drilling unit agreements). Such unit agreements, because they may limit BLM authority in subsequent stages, are therefore important tools for preventing waste. *See William P. Maycock et al.*, 177 IBLA 1, 20-21 (Dec. Int. 2008) (“BLM is not required to analyze an alternative that is [n]ot feasible because it is inconsistent with the basic presumption of the Unit Agreement and BLM cannot legally compel the operator to adopt that alternative under the terms of the Unit Agreement”).

Critically, subpart 3160 specifically requires BLM officials to ensure “that all [oil and gas] operations be conducted in a manner which protects other natural resources and the environmental quality, protects life and property and results in the maximum ultimate recovery of oil and gas with minimum waste and with minimum adverse effect on the ultimate recovery of other mineral resources.” 43 C.F.R. § 3161.2 (emphasis added). The lease owner and or operator is, similarly, charged with “conducting all operations in a manner which ensures the proper handling, measurement, disposition, and site security of leasehold production; which protects other natural resources and environmental quality; which protects life and property; and which results in maximum ultimate economic recovery of oil and gas with minimum waste and with minimum adverse effect on ultimate recovery of other mineral resources.” 43 C.F.R. § 3162.1(a) (emph. added). Waste is defined as “(1) A reduction in the quantity or quality of oil and gas ultimately producible from a reservoir under prudent and proper operations; or (2) avoidable surface loss of oil or gas.” 43 C.F.R. § 3160.0-5. Avoidable losses of oil or gas are currently defined as including venting or flaring without authorization, operator negligence, failure of the operator to take “all reasonable measures to prevent and/or control the loss,” and an operator’s failure to comply with lease terms and regulations, order, notices, and the like. *Id.*

In many respects, we think that BLM’s current rules can be tightened. Regardless, it is clear that BLM’s expansive authority, responsibility, and opportunity to prevent waste must

permeate the agency's full planning and decisionmaking processes for oil and gas. The agency must ensure that any development authorized by the proposed action take advantage of not only proven, often economical technologies and practices to prevent methane waste, but, further, the agency's tools to ensure the orderly and efficient exploration, development, and production of oil and gas through controls placed on the very scale, pace, and nature of development. Moreover, it is clear that BLM's authority, responsibility, and opportunity extends to both existing and future oil and gas development. BLM, ultimately, manages the federal – i.e., publicly owned – onshore oil and gas resource in trust for the American people.

On November 19, 2013, a coalition of over 90 environmental, health, and sporting organizations submitted an open letter to Secretary Jewell of the U.S. Department of Interior and Administrator McCarthy of the U.S. Environmental Protection Agency calling for action to substantially reduce emissions of methane from the oil and gas industry on public and private lands, as well as from offshore oil operations. The coalition called on Secretary Jewell to reduce emissions from oil and gas operations on public lands by updating decades-old BLM rules on waste of mineral resources. Further, we asked Administrator McCarthy to directly regulate methane emissions from the oil and gas industry using existing Clean Air Act authority and to develop nationwide curbs on GHG emissions.

Notably, BLM is currently undertaking federal rulemaking pertaining to Onshore Oil and Gas Order No. 9, Waste Prevention and Use of Produced Oil and Gas for Beneficial Purposes. *See* 43 C.F.R. § 3164.1 (authorizing the Director to issue Onshore Oil and Gas Orders to implement or supplement regulations).

In a statement regarding Order No. 9, the agency provided:

This new order would establish standards to limit the waste of vented and flared gas and to define the appropriate use of oil and gas for beneficial use. This order would, among other things, delineate which activities qualify for beneficial use, minimize the amount of venting and flaring that takes place on oil and gas production facilities on Federal and Indian lands, and establish standards for determining avoidable versus unavoidable losses.

Office of Information and Regulatory Affairs, Unified Agenda and Regulatory Plan, RIN: 1004-AE14. The BLM must consider the pending federal rulemaking on Order No. 9, and the implications that this rule would have on place-based action and planning level decision-making for the RMPA/EIS. Such consideration in the agency's NEPA analysis is critical, here, given the immense level of existing oil and gas development in the Basin and the anticipated shale oil boom on the horizon.

The Western Environmental Law Center and our partners also recently submitted what we have identified as "Core Principals" that should help guide BLM's new order, and which are aimed to constructively inform the contours of BLM's rulemaking process. These Core Principals are incorporated herein, attached hereto as Exhibit 117, and must also be considered by the FFO when undertaking the RMPA planning process. *See* 40 C.F.R. § 1502.9(c)(1)(ii).

ii. President Obama’s Climate Action Plan and Secretarial Order 3289.

President Obama’s June Climate Action Plan explains that “[c]urbing emissions of methane is critical to our overall effort to address global climate change.” *See* Climate Action Plan at 10. The President’s call for action ties in nicely with BLM’s authority and responsibilities, beyond the MLA, to reduce methane emissions – and further reinforce the importance of incorporating required methane reduction measures into the RMPA.

The starting point is the Federal Land Policy and Management Act of 1976 (“FLPMA”). Pursuant to FLPMA, the agency must manage the public lands:

in a manner that will protect the quality of scientific, scenic, historical, ecological, environmental, air and atmospheric, water resource, and archeological values; that, where appropriate, will preserve and protect certain public lands in their natural condition, that will provide food and habitat for fish and wildlife and domestic animals; and that will provide for outdoor recreation and human occupancy and use.

43 U.S.C. § 1701(a)(8) (emphasis added). The BLM, as a multiple use agency, must also manage the public lands and the oil and natural gas resource to “best meet the present and future needs of the American people” and to ensure that management “takes into account the long-term needs of future generations for...non-renewable resources, including...minerals.” 43 C.F.R. § 1702(c). Put differently, the driving force behind agency-authorized oil and gas development is the long-term, and broad, public interest – not the often short-term, and narrow, interest of oil and gas companies. The agency’s duty to prevent waste must account for this driving force.

Here, BLM must ensure that these objectives and duties are adhered to through the completion its NEPA analysis, which must, *inter alia*, “use and observe the principles of multiple use and sustained yield” and “weigh long-term benefits to the public against short-term benefits.” *See* 43 U.S.C. § 1712(c)(1), (7). Thus, the FFO has a substantive duty to consider the enduring legacy of oil and gas development in land management decision-making, which is to be balanced against other critical multiple use resource values.

Additionally, the BLM, as an agency within the U.S. Department of Interior, is subject to Secretarial Order 3289 (Dept. Int. Sept. 14, 2009). Secretarial Order 3289, in section 3(a), provides that BLM “must consider and analyze climate change impacts when undertaking long-range planning exercises, setting priorities for scientific research and investigations, developing multi-year management plans, and making major decisions regarding potential use of resources under the Department’s purview.” Section 3(a) of Secretarial Order 3289 also reinstated Secretarial Order 3226 (January 19, 2001). Secretarial Order 3226 commits the Department of the Interior to address climate change through its planning and decisionmaking processes. As the Order explains, “climate change is impacting natural resources that the Department of the Interior (Department) has the responsibility to manage and protect.” Sec. Or. 3226, § 1. The Order therefore “ensures that climate change impacts are taken into account in connection with Department planning and decision making.” *Id.* The Order obligates BLM to “consider and

analyze potential climate change impacts” in four situations: (1) “when undertaking long-range planning exercises”; (2) “when setting priorities for scientific research and investigations”; (3) “when developing multi-year management plans, and/or” (4) “when making major decisions regarding the potential utilization of resources under the Department’s purview.” *Id.* § 3. The Order specifically provides that “Departmental activities covered by this Order” include “management plans and activities developed for public lands” and “planning and management activities associated with oil, gas and mineral development on public lands.” *Id.* (emphasis added). BLM’s oil and gas decisions are thus contemplated by and subject to section 3 of the Order.

These authorities and responsibilities can be properly exercised through effective use of NEPA. To comply with NEPA, the BLM must take a hard look at direct, indirect, and cumulative impacts, as discussed above. 40 §§ C.F.R. 1502.16(a), (b); 1508.25(c). In evaluating impacts, the agency must discuss “[e]nergy requirements and conservation potential of various alternatives and mitigation measures,” “[n]atural or depletable resource requirements and conservation potential of various alternatives and mitigation measures,” and “[m]eans to mitigate adverse environmental impacts (if not fully covered under 1502.14(f)).” 40 C.F.R. §§ 1502.16(e), (f), (h).

We emphasize, here, the “heart” of the NEPA process: BLM’s duty to consider “alternatives to the proposed action” and to “study, develop, and describe appropriate alternatives to recommended courses of action in any proposal which involves unresolved conflicts concerning alternative uses of available resources.” 42 U.S.C. §§ 4332(2)(C)(iii), 4332(2)(E); 40 C.F.R. § 1502.14(a). Alternatives are critical because, “[c]learly, it is pointless to ‘consider’ environmental costs without also seriously considering action to avoid them.” *Calvert Cliffs’ Coordinating Comm., Inc. v. U.S. Atomic Energy Commn.*, 449 F.2d 1109, 1128 (D.C. Cir. 1971). Operating in concert with NEPA’s mandate to address environmental impacts, BLM’s fidelity to alternatives analysis helps “sharply defin[e] the issues and provid[e] a clear basis for choice among options by the decision maker and the public.” 40 C.F.R. § 1502.14. An agency must, accordingly, “[r]igorously explore and objectively evaluate all reasonable alternatives” and specifically “[i]nclude the alternative of no action.” 40 C.F.R. §§ 1502.14(a), (d). Even where impacts are “insignificant,” BLM must still consider alternatives. *Bob Marshall Alliance v. Hodel*, 852 F.2d 1223, 1229 (9th Cir. 1988) (agency’s duty to consider alternatives “is both independent of, and broader than,” its duty to complete an environmental analysis); *Greater Yellowstone Coalition v. Flowers*, 359 F.3d 1257, 1277 (10th Cir. 2004) (duty to consider alternatives “is ‘operative even if the agency finds no significant environmental impact’”).

iii. Methane mitigation measures should be adopted and analyzed.

There are several widely recognized best management practices (“BMPs”) for mitigating methane emissions that, as discussed above, must be considered by BLM in its analysis of the proposed action. We believe that most, if not all of these measures should be considered and adopted, both because they can reduce methane emissions from significant emissions sources and because they have also been shown to have very quick paybacks from the sale of captured methane, even at today’s low gas prices. The most important of these measures include:

- Centralized Liquid Gathering Systems and Liquid Transport Pipelines
- Reduced Emission Completions/Recompletions (green completions)
- Low-Bleed/No-Bleed Pneumatic Devices on all New Wells
- Dehydrator Emissions Controls
- Replace High-bleed Pneumatics with Low-Bleed/No-Bleed or Air-Driven Pneumatic Devices on all Existing Wells; and
- Electric Compression
- Liquids Unloading (using plunger lifts or other deliquification technologies)
- Improved Compressor Wet Seal Maintenance/Replacement with Dry Seals
- Vapor Recovery Units on Storage Vessels
- Pipeline Best Management Practices; and
- Leak Detection and Repair

These and other mitigation measures are included among BMPs that have been identified by BLM, EPA, the State of Colorado, and other organizations, as detailed below.³²

Here, BLM has already approved a number of Mancos Shale oil projects in the lower San Juan Basin – specifically in the Lybrook and Counselors areas – which have resulted in significant, un-assessed flaring operations contributing to waste and loss of royalties. BLM has failed to sufficiently analyze these projects, and, in particular, have not explained its rationale for why flaring is needed. As discussed above, BLM should suspend all such development during the pendency of the RMPA/EIS. Additionally, the agency must account for all existing shale oil development in the Basin that has outpaced the current 2003 RMP and 2002 RFD, and provide analysis for the void of existing infrastructure in the southern Basin necessary to handle this development, and detail how the agency plans to mitigate and reduce flaring and waste in this new oil play.

Another area of concern to Conservation Groups is the effectiveness of the mitigation measures adopted to ensure that the methane captured is able to make it to market for sale and the realization of rapid payback. Such considerations must be included in the agency’s NEPA analysis. This includes, *inter alia*, how the agency will require operators on private and public

³² See also BLM, Best Management Practices for Fluid Minerals, available at: http://www.blm.gov/pgdata/etc/medialib/blm/wo/MINERALS__REALTY__AND_RESOURCE_PROTECTION_/bmps.Par.60203.File.dat/WO1_Air%20Resource_BMP_Slideshow%2005-09-2011.pdf (attached as Exhibit 115).

lands to coordinate development to ensure that centralized liquids gathering and treatment investments are made prior to the appraisal and field development phase when production increases dramatically. The FFO should identify and describe the mechanisms they plan to employ to achieve this desirable outcome.

The second issue is how gas (as opposed to liquids) captured by implementation of the mitigation measures will enter sales gas lines and make it to market, as opposed to simply being flared and wasted. Conservation Groups believe that the FFO should spell-out whether all of the gas captured by the mitigation measures adopted is expected to have similar access to a sales line, or whether some or all of it will be sent to flares and wasted. If the latter, Conservation Groups believe that additional mitigation measures should be instituted, comparable to the measure adopted for liquids, requiring planning and timely development of gas gathering and treatment infrastructure to ensure that GHG emissions are reduced, that revenues from gas sales are maximized for the realization of paybacks for operators, royalty payments for the federal and state governments, and that waste of waste of this important resource is minimized.

Critically, the FFO must mandate the use of mitigation technologies not only on new oil and gas leases – which, here, would result in only a marginal GHG benefit, as approximately 90% of the planning area is already leased – but on *all* future development authorized in the FFO. This can be accomplished through required conditions of approval (“COAs”) on all new well approvals, and should be defined in the RMPA. While BLM does not have authority to modify the lease stipulations in pre-existing oil and gas contracts, the agency can impose new restrictions that are not explicitly provided for, such as COAs and other mitigation measures.³³ Moreover, 43 C.F.R. § 3101.1-2 permits BLM to use “reasonable measures” to minimize adverse impacts to public resources, reserving the authority to impose COAs on oil and gas leases. The regulation cites various measures that are per se reasonable, but the BLM can implement stricter measures at its discretion, which fall under the agency’s “reserved rights” inherent in all modern oil and gas leases. *See Yates Petroleum Corp.*, 176 IBLA 144, 156 (2008). A party challenging a COA, such as a leaseholder, must show “by a preponderance of the evidence that such a requirement is excessive.” *Grynberg Petroleum Co.*, 152 IBLA 300, 307 (2000). Thus, so long as the COAs can be characterized as reasonable measures to minimize adverse environmental impacts – such as necessary mitigation measures to reduce methane pollution – the BLM has the authority and, indeed, responsibility, to require these additional measures under 43 C.F.R. § 3101.1-2.

Notably, several BLM Field Offices have already taken pioneering steps to address methane emissions and waste through mandatory mitigation measures at the RMP stage. In a joint Land and Resource Management Plan (“LRMP”), BLM: 1610 (CO-933), adopted by BLM Colorado’s Tres Rios Field Office (“TRFO”) and the San Juan National Forest (“SJNF”), the agencies broke new and essential ground in both acknowledging that significant GHG pollution would result from oil and gas development on TRFO lands, and then establishing required

³³ *See Decision Record and Approved Coordinated Activity Plan for the Big Piney/La Barge Area*, BUREAU OF LAND MGMT. 11 (Aug. 1991), available at: https://archive.org/stream/decisionrecordap00unit/decisionrecordap00unit_djvu.txt.

methane mitigation standards at the planning stage that will bind future leases and permits to drill to comply with these measures. As provided in the Final EIS for the LRMP:

NEPA analysis is typically conducted for oil and gas leasing and when permits are issued. **This FEIS is the first NEPA analysis where lands that could be made available for lease are identified and stipulated.** In a subsequent analysis stage, when there is a site-specific proposal for development, additional air quality impact analysis would occur. This typically occurs when an application for a permit to drill is submitted. Based on the analysis results, additional mitigation or other equally effective options could be considered to reduce air pollution.

Final EIS at 372 (emphasis added). The TRFO set a new standard by recognizing that the climate change impacts from oil and gas industry activities are cumulative and that methane losses from business-as-usual industry practices at the field office level contribute significantly to climate change and must be mitigated. In the Final EIS, the TRFO also recognized that methane emissions represent waste of a key natural resource that belongs to all U.S. citizens, and the failure to control such waste robs the U.S. and state treasuries of royalty revenues. Accordingly, the TRFO adopted six important methane mitigation measures, which include:

- Centralized Liquid Gathering Systems and Liquid Transport Pipelines
- Reduced Emission Completions/Recompletions (green completions)
- Low-Bleed/No-Bleed Pneumatic Devices on all New Wells
- Dehydrator Emissions Controls
- Replace High-bleed Pneumatics with Low-Bleed/No-Bleed or Air-Driven Pneumatic Devices on all Existing Wells; and
- Electric Compression

Id. at 376.

More recently, the Colorado River Valley Field Office (“CRVFO”), in its Proposed RMP/FEIS at 4-28 to 29, also identified several mitigation measures that would address methane emissions and waste:

- Reduce emissions of VOCs associated with federal oil and gas wells by requiring that operators install and maintain measures to achieve at least 90 percent control on glycol dehydrators and storage vessel and tank vents ... [resulting in methane emissions reductions as a co-benefit].
- Require that oil and gas operators use reduced-emission completion technologies (i.e. “green” completions) as defined in COGCC Rule 805 and the New Source Performance Standards for Crude Oil and Natural Gas

Production at 40 CFR Part 63 subpart OOOO for all wells on BLM lands and wells that access federal minerals.

- Consider electrification of engines at compressor stations as a possible mitigation measure in areas where it is feasible.

These Field Offices have established important precedents in requiring the control of methane waste and emissions from oil and gas development. They have adopted subsets of mitigation measures that presumably address the major sources of methane waste and emissions in their planning areas, which must be considered by the FFO here. *See* 40 C.F.R. § 1502.9(c)(1)(ii). As the FFO conducts its analysis for the RMPA/EIS, we urge the agency to consider the full range of methane waste and emissions mitigation technologies and practices described herein, and to adopt the widest possible set of measures tailored to the future levels of industry activity described in the RFD. Historically, the dismissive approach the agency has taken on climate change, and failure to adequately address methane emissions altogether, is plainly incompatible with the climate impacts of oil and gas development. It is incumbent upon the FFO to confront the issues of climate change and methane emissions head-on, which must be accomplished through field office level decision-making that is reflective of challenges we face.

Moreover, and in addition to both national rulemaking and precedent-setting action at the local field office level, BLM's Colorado State Office has recently adopted its Comprehensive Air Resources Protection Protocol ("CARPP"), which, as provided by the agency:

[D]escribes the process and strategies the BLM will use when authorizing activities that have the potential to adversely impact air quality within the state of Colorado. This protocol also outlines specific measures that may be taken to address BLM-approved activities with the potential to cause significant adverse impacts to air resources ... within any planning area []. Further, the purposes of this protocol are to address air quality issues identified by the [BLM], or public scoping, in its analysis of potential impacts on air resources for BLM Colorado [RMPs] and [EIS']; and clarify the mechanisms and procedures that BLM will use to achieve the air resources goals, objectives, and management actions set forth in BLM Colorado RMPs.

While the BLM Colorado CARPP is not binding on the Farmington Field Office, it nevertheless provides an important state-of-the-art resource to guide the agency's analysis of GHG mitigation measures applicable to the October 2014 lease sale. In particular, Table V-I identifies Best Management Practices and Air Emission Reduction Strategies for Oil and Gas Development. The CARPP is attached hereto as Exhibit 116, and must be considered by BLM in its decision-making regarding the FFO's RMPA/EIS. *See* 40 C.F.R. § 1502.9(c)(1)(ii).

The FFO must also consider the use of new nitrogen fracking techniques, which, notably, are already being employed in the planning area. The use of nitrogen foam in the fracking process initially results in upwards of 60% nitrogen content in produced gas, which must be flared for an average of 60-90 days until the nitrogen content is reduced to 10% or less before the

gas can enter a pipeline. As discussed below, the use of nitrogen creates a problematic tradeoff between water conservation and impacts to air quality and GHG emissions. Moreover, depending on the strength of measures required in BLM's impending methane rulemaking, the use of this technology might, in fact, be prohibited given the necessity for flaring. Regardless, the FFO must take a hard look at the impacts and tradeoffs implicit in methane fracking in the RMPA/EIS.

iv. The capture of methane is critical due to its global warming potential.

Ensuring compliance with the agency's methane waste obligations through proper analysis and documentation in the NEPA process is important: technologies and practices change, and the BLM's duty to prevent degradation and waste cannot be excused just because the agency apparently lags behind the technological curve. The GAO's 2010 report noted that BLM's existing waste prevention guidance – Notice to Lessees and Operators (“NTL”) 4a – was developed in 1980, well before many methane reduction technologies and practices were developed and understood. GAO also found that NTL 4a does not “enumerate the sources that should be reported or specify how they should be estimated.”³⁴ Problematically, GAO noted “that [BLM] thought the industry would use venting and flaring technologies if they made economic sense,” a perspective which assumes – wrongly – that markets work perfectly in the absence of necessary regulatory signals and is belied by the lack of information about the magnitude of methane waste and the documented, if still poorly understood, barriers to the deployment of GHG reduction technologies and practices. *Id.* at 20-33. Compounding the problem, GAO also “found a lack of consistency across BLM field offices regarding their understanding of which intermittent volumes of lost gas should be reported to [the Oil and Gas Operations Report].” *Id.* at 11. BLM, to its credit, conceded: “existing guidance was outdated given current technologies and said that they were planning to update it by the second quarter of 2012.” *Id.* at 27.

Indeed, a Report released by NRDC identified that “[c]apturing currently wasted methane for sale could reduce pollution, enhance air quality, improve human health, conserve energy resources, and bring in more than \$2 billion of additional revenue each year.”³⁵ Moreover, the Report further identified ten technically proven, commercially available, and profitable methane emission control technologies that together can capture more than 80 percent of the methane currently going to waste. *Id.* Such technologies must also be considered in BLM's alternatives analysis.

Preventing GHG pollution and waste is particularly important in the natural gas and oil context, where there is an absence of meaningful lifecycle analysis of the GHG pollution emitted by the production, processing, transmission, distribution, and combustion of natural gas.

³⁴ See GAO-11-34 (2010) at 11, 27 (attached above as Exhibit 46).

³⁵ Susan Harvey, et al., *Leaking Profits: The U.S. Oil and Gas Industry Can Reduce Pollution, Conserve Resources, and Make Money by Preventing Methane Waste* (March 2012) (attached as Exhibit 47).

Although natural gas is often touted as a ‘cleaner’ alternative to dirty coal, recent evidence indicates that this may not, in fact be the case – and, at the least, indicates that we must first take immediate, common sense action to reduce GHG pollution from natural gas before it can be safely relied on as an effective tool to transition to a clean energy economy³⁶ (a noted priority of this Administration). A recent report by Climate Central addresses the leak rates estimated by various sources and the impacts of this new information on assertions that natural gas is a cleaner fuel than coal, ultimately concluding that given the losses from oil and gas sources it would be decades before switching electricity generation from coal to natural gas could bring about significant reductions in emissions.³⁷

Oil and natural gas systems are the biggest contributor to methane emissions in the United States, accounting for over one quarter of all methane emissions.³⁸ In light of serious controversy and uncertainties regarding GHG pollution from oil and gas development, the agencies quantitative assessment should account for methane’s long-term (100-year) global warming impact and, also, methane’s short-term (20-year) warming impact using the latest peer-reviewed science to ensure that potentially significant impacts are not underestimated or ignored. *See* 40 C.F.R. § 1508.27(a) (requiring consideration of “[b]oth short- and long-term effects”).

EPA’s GHG Inventory – which BLM has historically relied upon in its analysis – assumes that methane is 21 times as potent as carbon dioxide (“CO₂”) over a 100-year time horizon,³⁹ a global warming potential (“GWP”) based on the Intergovernmental Panel on Climate Change’s (“IPCC”) Second Assessment Report from 1996.⁴⁰ However, the IPCC recently updated their 100-year GWP for methane, substantially increasing the heat-trapping

³⁶ Robert W. Howarth, *Assessment of the Greenhouse Gas Footprint of Natural Gas from Shale Formations Obtained by High-Volume, Slick-Water Hydraulic Fracturing* (Rev’d. Jan. 26, 2011) (attached as Exhibit 48). *See also* Robert W. Howarth et al., *Venting and Leaking of Methane from Shale Gas Development: Response to Cathles et al.* (2012) (attached as Exhibit 49); Eric D. Larson, PhD, Climate Central, *Natural Gas and Climate Change* (May 2013) (attached as Exhibit 50).

³⁷ *See* Larson, attached above as Exhibit 50.

³⁸ *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011* (attached above as Exhibit 51).

³⁹ *See* 78 Fed.Reg. 19802, April 2, 2013 (EPA proposal to increase methane’s GWP to 25 times CO₂).

⁴⁰ INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, *Second Assessment Report* (1996) (attached as Exhibit 52); *see also* U.S. Environmental Protection Agency, *Methane*, available at: <http://www.epa.gov/outreach/scientific.html>.

effect to 34.⁴¹ A Supplementary Information Report (“SIR”), prepared for BLM’s oil and gas leasing program in Montana and the Dakotas, further explains that GWP “provides a method to quantify the cumulative effect of multiple GHGs released into the atmosphere by calculating carbon dioxide equivalent (CO₂e) for the GHGs.” SIR at 1-2.⁴² However, substantial questions arise when you calibrate methane’s GWP over the 20-year planning and environmental review horizon used in the SIR and, typically, by BLM. *See* SIR at 4-1 thru 4-45 (discussing BLM-derived reasonably foreseeable development potential in each planning area). Over this 20-year time period, the IPCC’s new research has calculated that methane’s GWP is 84⁴³ – yet another substantial increase from its earlier estimate of 72, which was still over three times as potent as otherwise assumed by the SIR.⁴⁴

However, peer-reviewed science demonstrates that gas-aerosol interactions amplify methane’s impact such that methane is actually 105 times as potent over a twenty year time period.⁴⁵ This information suggests that the near-term impacts of methane emissions have been significantly underestimated. *See* 40 C.F.R. § 1508.27(a) (requiring consideration of short and long term effects). Further, by extension, BLM has also significantly underestimated the near-term benefits of keeping methane emissions out of the atmosphere. 40 C.F.R. §§ 1502.16(e), (f); *id.* at 1508.27. These estimates are important given the noted importance of near term action to ameliorate climate change – near term action that scientists say should focus, *inter alia*, on preventing the emission of short-lived but potent GHGs like methane while, at the same time, stemming the ongoing increase in the concentration of carbon dioxide.⁴⁶ These uncertainties

⁴¹ *See* INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, *Working Group I Contribution to the IPCC Fifth Assessment Report Climate Change 2013: The Physical Science Basis*, at 8-58 (Table 8.7) (Sept. 2013) (attached as Exhibit 68).

⁴² BLM, *Climate Change, Supplementary Information Report, Montana, North Dakota and South Dakota* (2010) available at: www.blm.gov/mt/st/en/prog/energy/oil_and_gas/leasing/leasingEAs.html (attached as Exhibit 53).

⁴³ *See* IPCC *Physical Science Report*, attached above as Exhibit 68.

⁴⁴ *See* INTERGOVERNMENTAL PANEL ON CLIMATE CHANGE, *Fourth Assessment Report, Working Group 1, Contribution of Working Group I to the Fourth Assessment Report of the Intergovernmental Panel on Climate Change*, Ch. 2, p. 212, Table 2.14, available at: www.ipcc.ch/publications_and_data/ar4/wg1/en/ch2s2-10-2.html (attached as Exhibit 54).

⁴⁵ Drew Shindell et al., *Improved Attribution of Climate Forcing to Emissions*, *SCIENCE* 2009 326 (5953), p. 716, available at: www.sciencemag.org/cgi/content/abstract/326/5953/716 (attached as Exhibit 55).

⁴⁶ *See, e.g., Limiting Global Warming: Variety of Efforts Needed Ranging from 'Herculean' to the Readily Actionable, Scientists Say*, *SCIENCE DAILY* (May 4, 2010), available at: <http://www.sciencedaily.com/releases/2010/05/100503161328.htm>; *see also*, Ramanathan, et. al., (attached above as Exhibit 12).

necessitate analysis. 40 C.F.R. §§ 1508.27(a), (b)(4)-(5).

Additional, serious, yet unaddressed uncertainties pertain to the magnitude of methane pollution from oil and gas emissions sources. As provided in the most recent EPA Inventory of Emissions and Sinks: 1990-2011, “[f]urther research is needed in some cases to improve the accuracy of emission factors used to calculate emissions from a variety of sources;” specifically citing the lack of accuracy in emission factors applied to methane sources.⁴⁷ A lack of data reliability has resulted in notable variation in methane emissions reporting from year to year. For example, in a Technical Support Document (“TSD”) prepared for EPA’s mandatory GHG reporting rule for the oil and gas sector for 2012, EPA determined that several emissions sources were projected to be “significantly underestimated.”⁴⁸ EPA thus provided revised emissions factors for four of the most significant underestimated sources that ranged from ten times higher (for well venting from liquids unloading) to as many as 3,500 and 8,800 times higher (for gas well venting from completions and well workovers of unconventional wells).⁴⁹ When EPA accounted for just these four revisions, it more than doubled the estimated GHG emissions from oil and gas production, from 90.2 million metric tons of CO₂ equivalent (“MMTCO₂e”) to 198.0 MMTCO₂e.⁵⁰ However, these emission estimates are based on an outdated GWP of 21. Using the IPCC’s new 100-year GWP for methane of 34, that is 320.5 MMTCO₂e, and, considering a 20-year GWP of 84, that is 792.0 MMTCO₂e – or, respectively, the equivalent emissions from 90.7 or 224 coal fired power plants that is wasted annually. These upward revisions were based primarily on EPA’s choice of data set, here, having replaced Energy Information Administration (“EIA”) data with emissions data from an EPA and Gas Research Institute (“GRI”) study. In the current year, EPA relied on yet another set of data; this time from an oil and gas industry survey of well data conducted by the American Petroleum Institute (“API”) and the American Natural Gas Alliance (“ANGA”).⁵¹ The API/ANGA survey was conducted in response to EPA’s upward adjustments in the previous GHG inventory, noting that “[i]ndustry was alarmed by the upward adjustment,” and focused specifically on emissions from liquids unloading and unconventional

⁴⁷ *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011*, at 1-19 (attached above as Exhibit 51).

⁴⁸ U.S. Environmental Protection Agency, *Greenhouse Gas Emissions Reporting From The Petroleum And Natural Gas Industry Background Technical Support Document*, at 8, available at: <http://www.epa.gov/climatechange/emissions/subpart/w.html> (attached as Exhibit 56).

⁴⁹ *Id.* at 9, Table 1; see also *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011* (attached above as Exhibit 51).

⁵⁰ See EPA, *GHG Emissions Reporting* at 10, Table 2 (attached above as Exhibit 56).

⁵¹ *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011*, at 3-63 (attached above as Exhibit 51).

gas well completions and workovers.⁵² Overall, the survey found that revising emissions from these two sources alone would reduce EPA oil and gas methane emissions estimates, which resulted in reported oil and gas production emissions at 100 MMTCO₂e pursuant to the EPA's GHG Reporting Program.⁵³

To provide a specific example of these differing data sets, EPA previously used an emissions factor of 3 thousand standard cubic feet ("Mcf") of gas emitted to the atmosphere per well completion in calculating its GHG inventory. EPA determined that this figure was significantly underestimated and that a far more accurate emissions factor was 9,175 Mcf per well.⁵⁴ The API/ANGA study suggested that this emission factor is 9,000 Mcf.⁵⁵ However, these emissions factors are simply broad, generalized estimates for well emissions across the nation, and can vary significantly from one geologic formation to the next. For example, emissions reported in the Piceance Basin are as high as 22,000 Mcf of gas per well.⁵⁶

Despite this variability in methane pollution data, what remains clear is that inefficiencies and leakage in oil and gas production results in a huge amount of avoidable waste and emissions, and, conversely, a great opportunity for the BLM to reduce GHG emissions on our public lands. Many of these uncertainties and underestimates, as EPA has explained, are a result of the fact that emissions factors were "developed prior to the boom in unconventional well drilling (1992) and in the absence of any field data and does not capture the diversity of well completion and workover operations or the variance in emissions that can be expected from different hydrocarbon reservoirs in the country." *Mandatory GHG Reporting Rule*, 75 FED. REG. 18608, 18621 (April 12, 2010). These underestimates are also caused by the dispersed nature of oil and gas equipment – rather than a single, easily grasped source, such as a coal-fired power plant, oil and gas production consists of large numbers of wells, tanks, compressor stations, pipelines, and other equipment that, individually, may appear insignificant but, cumulatively, may very well be quite significant. While dispersed, oil and gas development is nonetheless a massive, landscape-scale industrial operation – one that just happens to not have a single roof. BLM, as the agency charged with oversight of onshore oil and gas development, therefore has an opportunity to

⁵² API/ANGA, *Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production: Summary and Analysis of API and ANGA Survey Responses*, Sept. 2012, at 1 (attached as Exhibit 57).

⁵³ See EPA, *Petroleum and Natural Gas Systems: 2011 Data Summary (for 2013 GHG Reporting)*, at 3 (attached as Exhibit 58).

⁵⁴ See EPA, *GHG Emissions Reporting*, attached above as Exhibit 57 at Appendix B at 84-87.

⁵⁵ *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2011*, at 3-69 (attached above as Exhibit 51).

⁵⁶ See, e.g., EPA, *Natural Gas STAR Program, Recommended Technologies and Practices for Wells*, available at: www.epa.gov/gasstar/tools/recommended.html; see also EPA, *Natural Gas STAR Program, Reduced Emissions Completions*, Oct. 26, 2005, at 14 (attached as Exhibit 59).

improve our knowledge base regarding GHG emissions from oil and gas production, providing some measure of clarity to this important issue by taking the requisite “hard look” NEPA analysis as part of its decision-making for the RMPA/EIS.⁵⁷

Convincing evidence also exists to support the consideration of alternatives that would attach meaningful stipulations to areas open to oil and gas development. As a prime contributor to short-term climate change over the next few decades, methane is a prime target for near-term GHG reductions. In fact, there are many proven technologies and practices already available to reduce significantly the methane emissions from oil and gas operations, as detailed above. These technologies also offer opportunities for significant cost-savings from recovered methane gas. Moreover, new research indicates that tropospheric ozone and black carbon (“BC”) contribute to both degraded air quality and global warming, and that emission control measures can reduce these pollutants using current technology and experience.⁵⁸ Employment of these strategies will annually avoid a substantial number of premature deaths from outdoor air pollution, as well as increase annual crop yields by millions of metric tons due to ozone reductions. Indeed, reducing methane emissions is important not only to better protect the climate, but also to prevent waste of the oil and gas resource itself and the potential loss of economic value, including royalties. BLM should evaluate these technologies, analyzing the benefits of technological implementation versus current agency requirements.

These benefits – as well as the proven, cost-effective technologies and practices that achieve these benefits – are documented by EPA’s “Natural Gas STAR” program, which encourages oil and natural gas companies to cut methane waste to reduce climate pollution and recover value and consolidates the lessons learned from industry for the benefit of other companies and entities with oil and gas responsibilities such as BLM.⁵⁹ EPA has identified well over 100 proven technologies and practices to reduce methane waste from wells, tanks, pipelines, valves, pneumatics, and other equipment and thereby make operations more efficient.⁶⁰ Though underutilized, EPA’s Natural Gas STAR suggests the opportunity to dramatically reduce GHG pollution from oil and gas development, *if* its identified technologies and practices were implemented at the proper scale and supported by EPA’s sister agencies, such as BLM. For calendar year 2010, EPA estimated that this program avoided 38.1 million tons CO₂ equivalent, and added revenue of nearly \$376 million in natural gas sales (at \$4.00/Mcf) – revenue which

⁵⁷ In this context, the 2010 SIR, while providing a basic literature review of GHG emissions sources, is merely a starting point for BLM’s responsibility to take a hard look at GHG emissions in the context of foreseeable drilling operations in the geologic formations proposed for leasing.

⁵⁸ Drew Shindell, et al., *Simultaneously Mitigating Near-Term Climate Change and Improving Human Health and Food Security*, SCIENCE 2012 335, at 183 (attached as Exhibit 60).

⁵⁹ See generally, EPA, Natural Gas STAR Program, available at: www.epa.gov/gasstar/.

⁶⁰ See EPA, Natural Gas STAR Program, *Recommended Technologies and Practices*, available at: www.epa.gov/gasstar/tools/recommended.html.

translates into additional royalties to federal and state governments for the American public.⁶¹ BLM must identify emission reduction strategies in its NEPA analysis for the RMPA/EIS, both to address impacts of the proposed action, as well as to satisfy the requirements of SO 3226, FLPMA, and the MLA.

b. The RMPA Planning Process Provides Opportunities for the FFO to Reduce Waste by Employing Methane Mitigation Technologies.

As introduced above, methane is vented, flared, and leaked throughout oil and natural production, gathering and boosting, and processing systems, representing a critical opportunity for the FFO to take strong action in the RMPA/EIS. According to the Federal Register Notice, the focus of the RMPA/EIS is: "... the oil play in the southern part of the Farmington Field Office boundary [which] has drawn considerable interest and several wells are planned and being drilled." 79 FED. REG. 10548. Initial evidence from increased flaring in the area indicates that natural gas will be produced in association with oil development in this region. In addition to venting and leaking of methane from oil and gas equipment, Conservation Groups are concerned that the infrastructure to gather, process and send associated gas to market may be under-developed or missing in the area of interest.

Without such infrastructure, associated gas is likely to be wasted through venting or flaring and contribute to global warming, as provided above. Yet while the Federal Register Notice states that, based on the RMPA: "Decisions will be made related to impacts from oil and gas for the following resources and resource uses in the planning area" that includes "Air resources (air quality and climate change)," it does not include methane waste within the scope. *Id.* at 10549. Yet haphazard development in the Bakken play of North Dakota, for example, has led to the waste of the associated gas produced, with flaring rates still in excess of 35% or over 300 MCFD, and set an example that must not be replicated in the San Juan Basin.⁶² Fortunately, proven technologies and practices are readily available to capture methane for beneficial use. Our comments seek to ensure that the FFO gives full consideration to these capture technologies and practices, to the use of BLM's existing planning tools to ensure that the gas produced makes it to market, and to the development of alternatives to minimize methane waste and methane emissions.

⁶¹ See EPA, Natural Gas STAR Program, *Accomplishments*, available at: www.epa.gov/gasstar/accomplishments/index.html#three (attached as Exhibit 61). BLM should also take a look at EPA's more detailed program accomplishments to provide a measure of what BLM could itself accomplish, and to understand the nature of the problem and opportunities. Also of interest, for calendar year 2008, EPA estimated that its program avoided 46.3 million tons of CO₂ equivalent, equal to the annual GHG emissions from approximately 6 million homes per year, and added revenue of nearly \$802 million in natural gas sales. To speculate, the calendar year 2009 declines are likely associated with ongoing economic and financial stagnation and the low price of natural gas that has slowed natural gas drilling and production.

⁶² See North Dakota Industrial Commission, NDPC Flaring Task Force Report, (January 2014) (attached as Exhibit 127).

i. The RMPA must include Reasonably Foreseeable Development Scenarios of adequate range and scope.

In the Federal Register Notice, the BLM states: “The Field Office is developing an RFD to predict future levels of development.” *Id.* The Interagency Reference Guide document titled “Reasonably Foreseeable Development Scenarios and Cumulative Effects Analysis For Oil and Gas Activities On Federal Lands In the Greater Rocky Mountain Region”⁶³ provides guidance for development of RFD scenarios and summarizes the overall purpose of an RFD. According to the IRG:

A Reasonable Foreseeable Development Scenario (RFD):

- Is a reasonable technical and scientific approximation of anticipated oil and gas activity based on the best available information.
- Includes all interrelated and interdependent oil & gas activities in a defined area regardless of land ownership or jurisdiction.
- The scenario should be scientifically credible and presented in a technical report that may be subject to professional peer review.

Further, according to the IRG: “A scientifically based and well-documented RFD scenario is the critical component of information necessary for performing thorough cumulative effects analysis of oil and gas activities that could occur as a result of leasing.” IRG at 12 (emphasis original). The IRG also notes that “an RFD is a vital and necessary tool for serving as a context for more localized site-specific decisions on proposed exploration or development projects.” IRG at 12. In this case, localized site-specific decisions would include future Applications for Permits to Drill and Mineral Development Plans in the Mancos Shale/Gallup Formation in the FFO planning area, which the FFO will need to consider in the context of this RMPA.

In developing RFD scenarios, the FFO must utilize the most recent and best information available from energy companies conducting exploratory drilling to date in Mancos Shale/Gallup formation emerging play, from companies that will provide transport for oil production, and from midstream companies that are expected to provide gathering, boosting and processing infrastructure for natural gas production. In addition to data provided directly by companies, the FFO should also look at additional data made available through conferences, papers, presentations, public reports or statements filed by operators, and media coverage.

⁶³ See BLM, FS, EPA, and FWS Interagency Reference Guide, *Reasonably Foreseeable Development Scenarios and Cumulative Effects Analysis For Oil and Gas Activities On Federal Lands In the Greater Rocky Mountain Region* (June 2003) (attached as Exhibit 124) [hereinafter “IRG”].

As of March 2013, 27 exploratory wells had been drilled in the Mancos Shale/Gallup Formation.⁶⁴ By September 2013, WPX Energy had six producing oil wells in the Gallup Sandstone,⁶⁵ and the company announced that it would invest \$160 million to drill 29 new wells in 2014.⁶⁶ Other reports indicate that WPX and LOGOS Resources have plans to invest \$260 million for oil exploration and production in the area.⁶⁷ And Encana has announced plans to invest up to \$400 million in 2014.⁶⁸ Clearly, industry interest in these plays remains strong and the RFD must reflect the plans of these and other oil and gas companies.

The RFD must identify the number of oil and gas wells expected to be drilled on federal lands under various development scenarios over next 20 years. It should also identify the general location and quantities of recoverable oil and gas resources that are anticipated. It should forecast oil and gas production from these wells, as well as identifying associated gas that has already been produced from oil discovery wells that have been completed. In addition to wells, the RFD should also inventory and map existing gathering and processing infrastructure, as well as forecast additional infrastructure that may be needed to get the oil and gas produced to market.

As the IRG states: “Gas production rates in excess of local gathering and transmission capacity may require the construction of pipelines and associated infrastructure” and, as noted above, the RFD must address “all interrelated and interdependent oil & gas activities in a defined area regardless of land ownership or jurisdiction.” IRG at 11. That is, in addition to pipelines, the RFD must address additional infrastructure including pneumatic devices, dehydrators, storage tanks, compressors and gas processing facilities that may be needed to minimize waste. As discussed in the next section, this entire infrastructure includes equipment and practices that can be sources of methane waste and emissions.

ii. The RMPA must provide a reasonable range of forecasts of methane waste and emissions.

The approach to estimating methane waste and emissions from oil and gas activities established by EPA and adopted by BLM in its air resource analyses of greenhouse gas

⁶⁴ See April Reese, *Mancos Shale could spur Southwest drilling revival*, ENERGY AND ENVIRONMENT DAILY, March 19, 2013 (attached as Exhibit 128).

⁶⁵ See Leigh Black Irvin, *WPX Energy optimistic about continued oil development in the Gallup Sandstone*, FARMINGTON DAILY TIMES, September 7, 2013 (attached as Exhibit 129).

⁶⁶ See Phil Taylor, *BLM to revise northwest N.M. plan as shale drilling ramps up*, ENERGY AND ENVIRONMENT DAILY, February 25, 2014 (attached as Exhibit 130).

⁶⁷ See Erny Zah, *BLM holds meetings for input on land use plan in the Mancos and Gallup play areas*, FARMINGTON DAILY TIMES, March 19, 2014 (attached as Exhibit 131).

⁶⁸ See Taylor (attached above as Exhibit 130).

emissions is to estimate counts of sources of methane waste and emissions and then apply emissions factors to these equipment and operating practice counts.⁶⁹

The emissions factors used come primarily from a 1996 study conducted by EPA and the Gas Research Institute, although some emissions factors have been updated periodically as new information has become available.⁷⁰ BLM, EPA and industry have identified numerous sources of methane emissions from oil and gas development.⁷¹

These sources, all of which may occur on FFO lands as a result of Mancos Shale/Gallup Formation development, include:

- Well completions, recompletions and workovers
- Well/production testing
- Associated gas
- Casing-head gas
- Liquids unloading
- Compressors
- Pneumatic devices
- Dehydrators
- Storage vessels and tanks
- Equipment leaks
- Pipelines

For its RMPA/EIS, the FFO will need to estimate the future counts of these methane waste and emissions sources from the RFD and then apply emissions factors to them to forecast total methane waste and emissions. The NM ARTR provides an estimate of total 2011 oil and

⁶⁹ See BLM SIR (attached above as Exhibit 53); see also BLM, *Air Resources Technical Report for Oil and Gas Development, New Mexico, Oklahoma, Texas and Kansas* (February 2014) [hereinafter “NM ARTR”] (attached as Exhibit 132); EPA, *Emissions and Sinks: 1990-2012*, at ANNEX 3 Methodological Descriptions for Additional Source or Sink Categories (attached above as Exhibit 123).

⁷⁰ U.S. Environmental Protection Agency, Gas Research Institute, *Methane Emissions from the Natural Gas Industry* (1996), available at: http://www.epa.gov/gasstar/documents/emissions_report/1_executiveummary.pdf (attached as Exhibit 133).

⁷¹ See BLM, Venting and Flaring *Public Outreach* (March 19, 2014), available at: http://www.blm.gov/pgdata/etc/medialib/blm/wo/MINERALS_REALTY_AND_RESOURCE_PROTECTION/_energy/oil_and_gas.Par.72011.File.dat/VFoutreach.pdf (attached as Exhibit 134); EPA, *Petroleum and Natural Gas Systems* (Aug. 2012), available at: <http://www.epa.gov/ghgreporting/documents/pdf/infosheets/OnshorePetroleumNaturalGasSystems.pdf> (attached as Exhibit 135); EPA, *Proposed Gas STAR Gold Protocols*, available at: <http://www.epa.gov/gasstar/gold/protocols/index.html>.

gas field production methane emissions in the San Juan Basin of 1,222,860 MTCO₂e for gas and 6200 MTCO₂e for oil. *See* NM ARTR, Table 7 at 48.

But according to the NM ARTR at 36:

Methane (CH₄) releases from gas well development result from venting of natural gas during the well completion process, actuation of gas operated valves during well operations, and fugitive gas leaks along the infrastructure required for the production and transmission of gas.

It appears that the analysis in the NM ARTR does not include many of the potential sources of methane waste and emissions listed above which can reasonably be expected to either occur on federal lands or occur as interrelated and interdependent oil and gas activities in areas of other land ownership or jurisdiction. Importantly, this includes associated gas venting and flaring from oil wells, which is the type of development expected in the Mancos Shale/Gallup Formation. The FFO must analyze all relevant potential sources in forecasting methane waste and emissions from the activity levels identified in the RFD.

In addition to the obligation to address all potential sources of methane waste and emissions under the RFD, we also believe the FFO has an obligation to address the substantial body of recent scientific research that has found that estimates of methane waste and emissions from the oil and gas industry have been significantly underestimated by the EPA, as detailed above. The methane loss rate associated with EPA inventory figures is around 1%. However, in contrast to the EPA's "bottom up" inventory approach using equipment counts and emissions factors, recent "top down" peer-review studies of methane emissions based on aircraft and other atmospheric sampling have reported *substantially higher* methane loss rates associated with oil and natural gas activity.

An analysis conducted by the National Oceanic and Atmospheric Administration ("NOAA") and University of Colorado in 2011 found methane loss rate from oil and gas development in Colorado's Denver-Julesberg Basin from 2.3-7.7%.⁷² A May 2014 follow-up study of this area found that during two days of airborne measurements oil and gas operations leaked nearly three times as much methane as predicted based on inventory estimates.⁷³

A 2013 study of Utah's Uintah Basin found methane loss rates from 6- 12 %.⁷⁴ A 2013 study analyzing air samples collected from tall towers and research aircraft found that oil and gas

⁷² Gabrielle Pétron, *et al.*, *Hydrocarbon emissions characterization in the Colorado Front Range: A pilot study*, JOURNAL OF GEOPHYSICAL RESEARCH, Vol. 117, (Feb. 2012) (attached as Exhibit 137).

⁷³ *See* CIRES, *Airborne measurements confirm leaks from oil and gas operations* (May 7, 2014), available at: <http://cires.colorado.edu/news/press/2014/airbornemeasurements.html>.

⁷⁴ *See* Karion *et. al.*, (attached above as Exhibit 67).

methane emissions may be fifty-percent higher than EPA estimates.⁷⁵ A study published in March 2014, also based on aircraft sampling, found methane emissions at natural gas drilling sites in Pennsylvania from 100 to 1000 times greater than EPA estimates.⁷⁶ And a new study led by researchers at Duke also found that emissions are likely higher than current U.S. EPA estimates.⁷⁷

The evidence from these studies all point to methane waste and emissions levels from oil and gas development greater, and perhaps far greater, than estimates generated by “bottom-up” inventories and emissions factors. Accordingly, in its consideration of methane waste and greenhouse gas pollution that can be expected from Mancos Shale/Gallup Formation development, the FFO has duty to look not just at “bottom-up” forecasts using such methods, but must also consider the range of potential methane waste and emissions indicated by the current science.

iii. The RMPA must consider methane waste and emissions mitigation measures and best practices currently in use by industry and identified in the literature.

There is a growing body of literature that documents measures and best management practices currently available to and in use by the oil and gas industry to reduce methane waste and emissions, as discussed above. The FFO must take a hard look at these technologies and practices and, since virtually all types of waste and emissions sources will accompany Mancos Shale/Gallup Formation oil and gas development, adopt them as mitigation measures in the RMPA to reduce waste and emissions. While some methane waste and emissions sources are covered by EPA’s 21012 NSPS rule revisions,⁷⁸ many are not. A partial listing of mitigation measures targeting the methane waste and emissions sources that were identified in the prior section includes:

- Well completions and workovers: reduced emissions completions
- Liquids unloading: plunger lifts
- Compressors: dry seals or replacement rod packing
- Pneumatic devices: no-bleed, low-bleed, instrument air, electric
- Dehydrators: TEG dehydrator emissions controls or dessicant dehydrators
- Storage vessels and tanks: vapor recover units

⁷⁵ Scott M. Miller, *et al.*, *Anthropogenic emissions of methane in the United States* (2013) (attached as Exhibit 136).

⁷⁶ Dana Caulton, *et al.*, *Toward a better understanding and quantification of methane emissions from shale gas development* (2014) (attached as Exhibit 138).

⁷⁷ Richard G. Newell and Daniel Raimi, *Implications of Shale Gas Development for Climate Change*, ENVIRONMENTAL SCIENCE AND TECHNOLOGY, April 2014 (attached as Exhibit 139).

⁷⁸ See EPA, *Oil and Natural Gas Air Pollution Standards*, available at: <http://www.epa.gov/airquality/oilandgas/>.

- Equipment leaks: leak detection and repair programs
- Pipeline maintenance and repair: re-route gas for capture

Sources of information about these and other measures, which are available to the FFO, are detailed above and must be considered in the RMPA/EIS.

Given the ready availability of this information, and the fact that these mitigation measures are technically feasible, commercially available, and profitable to implement in most situations, it is incumbent upon the FFO to assess them and adopt them in the RMPA.

iv. The FFO should forecast potential reductions in methane waste and emissions that would result from adoption of the mitigation measures.

Using the methane waste and emissions estimates developed in the RFD, it should be relatively straightforward for the FFO to estimate the waste and emissions reductions that could be achieved by adoption of the mitigation technologies and best practices, identified above. Most of the reduction technologies, and the experience of companies deploying them, are described by the EPA Natural Gas Star Program.⁷⁹ Moreover, the Leaking Profits study provides a useful summary, based on the Gas Star program, of methane waste and emissions reductions achievable with the adoption of these technologies and best practices.⁸⁰ Estimates of potential waste and emissions reductions would provide valuable information about the quantity of the resource that can be preserved that would otherwise be lost, and about the monetary value of this resource and the royalties it could generate.

v. The FFO should apply methane waste and emissions mitigation measures to both new and existing leases and APDs targeting the Mancos Shale/Gallup Formation.

According to the Federal Register Notice: “The RMP amendment is being developed in order to analyze the impacts of additional development in what was previously considered a fully developed oil and gas play within the San Juan Basin in northwestern New Mexico.” 79 FED. REG. 10548. And, approximately 90 percent of FFO lands are already under lease.⁸¹ Since so much oil and gas development that has already occurred in this area, the FFO’s analysis of the Mancos Shale/Gallup Formation play must to identify all areas that have already been leased and areas that have not yet been leased. The FFO must also identify all APDs that have been approved for exploratory drilling in the play, any other approvals for oil and gas-related activities, and the timing of these approvals. Further, the FFO should identify any lease

⁷⁹ See EPA, *Natural Gas STAR Program – Accomplishments*, available at: <http://www.epa.gov/gasstar/accomplishments/index.html>.

⁸⁰ See Harvey, Table 4 at 18 (attached above as Exhibit 47).

⁸¹ See Taylor (attached above as Exhibit 130).

stipulations or conditions of approval applied to these actions that address methane waste or emissions.

Stipulations attached to existing leases may fall short of preventing methane waste and emissions and may not reflect current conditions, changed circumstances, and new science. Where this is the case, the FFO must commit to consistently ensuring that the protective measures in the RMPA's new stipulations with respect to methane waste and emissions are applied to all development proposals that could adversely impact resource conservation or climate change, as discussed above.

BLM has the authority to bring existing leases up to standards mandated by the RMPA. For example, the CRVFO Proposed RMP/FEIS states:

Federal oil and gas regulations prevent the BLM from being able to apply new or additional lease stipulations to existing leases. However, federal regulations allow the BLM to apply other protection measures in conjunction with planning and implementing oil and gas projects. These measures include applying stipulations consistent with the most recent land use plan as terms and conditions for discretionary approvals (e.g., ROW actions) and applying COAs to augment protections related to lease activities.

Proposed RMP/FEIS at 4-317.

Further, with respect to existing APDs, the Oil and Gas Appendix in the CRVFO Proposed RMP/FEIS states:

Approval of an APD is valid for two years. If drilling does not begin within two years, the conditions of approval can be revised before extending the APD for a maximum of two additional years.

Id. at Appendix P-6.

Therefore, for expiring APDs – as it can for new APDs – the FFO can and should impose COAs requiring methane waste and emissions mitigation measures as a condition for such APDs to be extended.

vi. Steep decline curves for associated gas production in the Mancos Shale/Gallup Formation would indicate a need for early application of methane mitigation measures.

The FFO should take a close look at data on associated gas production decline curves from exploratory wells in the Mancos Shale/Gallup Formation. Steep production decline curves, which are commonly found for shale resources, would indicate that a significant amount of natural gas resources could be lost if mitigation measures are not in place when oil or gas wells are completed.

Steep production decline curves have been observed in other shale oil and gas formations. For example, typical horizontal shale oil well production in the Permian Basin declined by 66% after the first year and by 83% over three years.⁸² Typical horizontal shale oil well production in the Bakken play declined by 70% in the first year and by 84% over three years.⁸³

If production declines by comparable amounts in the Mancos Shale/Gallup Formation, and if associated gas production volume follows oil production, mitigation measures must be in place before field development commences to avoid large waste of the resource.

c. Gas Capture and Marketing Planning is Critical to the RMPA/EIS.

i. The FFO has the planning tools it needs to minimize methane waste and emissions from oil and gas development in the Mancos Shale/Gallup Formation.

Capturing methane with the mitigation measures recommended for adoption above, only to have that methane combusted in a flare, constitutes waste and emissions that would contribute to climate change. Rather, with adequate front-end planning, the FFO can ensure that the methane captured by emissions control technologies is beneficially used or able to make it to market for sale. BLM has the planning tools available through the RMPA, and such tools must be considered in the agency's analysis. This includes, *inter alia*, how the agency will require operators on public, tribal and private lands to coordinate development to ensure that natural gas is beneficially used and/or that gathering, boosting, and processing investments are made prior to field development when production increases dramatically. The agency should identify and describe the planning tools they plan to employ to achieve this desirable outcome.

An example of the type of planning that can be applied, even at the exploration stage – and needed to avoid chaotic development of the Mancos Shale/Gallup Formation and the impermissible waste of methane that would result – can be found in the CRVFO's Proposed RMP/FEIS:

In areas of federal and mixed mineral ownership, an exploratory unit can be formed before a wildcat exploratory well is drilled. The boundary of the unit is based on geologic data and attempts to consolidate the interests in an entire structure or geologic play. The developers of the unit enter into an agreement to develop and operate as a single entity, regardless of separate lease ownerships. Costs and benefits are allocated according to agreed-upon terms. Development in

⁸² See J. David Hughes, *The Shale Revolution, Myths and Realities*, FIRST ENERGY CAPITAL ENERGY GROWTH CONFERENCE (Nov. 2013) at slide 50, available at: <http://legacy.firstenergy.com/UserFiles/HUGHES%20First%20Energy%20Nov%2019%202013.pdf> (attached as Exhibit 140).

⁸³ *Id.* at Slide 54; see also J. David Hughes, *Drill Baby Drill*, POST-CARBON INSTITUTE (Feb. 2013), available at: <http://www.postcarbon.org/drill-baby-drill/report> (attached as Exhibit 141).

a unitized field can proceed more efficiently than in a field composed of individual leases because competition between lease operators and drainage considerations is not a primary concern. Unitization also can reduce surface use requirements because all wells are operated as though under a single lease, and operations can be planned for more efficiency. Duplication of field processing facilities is eliminated, and consolidation of facilities into more efficient systems is probable. Unitization can also involve wider spacing than usual, or spacing based on reservoir factor rather than a set rule, which could result in fewer wells and higher recovery efficiency. Through planning, access roads are usually shorter and better organized, facilities are usually consolidated, and well efficiency is maximized to a degree not seen in individual lease operations.

CRVFO Proposed RMP/FEIS, Appendix P at 9-10 (emphasis added).

Front-end planning is critical to avoiding the waste of large amounts of associated gas from oil development, which is currently the focus of interest in the Mancos Shale/Gallup Formation.

ii. The FFO should consider and adopt the EPA Natural Gas Gold Star standard for addressing waste and emissions from natural gas produced in association with oil.

The EPA recently launched a new Natural Gas Gold Star Program to recognize leading companies and current best practices in methane control. The program includes proposed protocols for companies to follow to achieve Gold Star status. The protocol for established for associated gas is to:

Recover for beneficial use all associated gas produced from the reservoir, regardless of well type, except for gas produced from wildcat and delineation wells or as a result of system failures and emergencies. Beneficial use does not include flaring.⁸⁴

In addition to the mitigation measures discussed above, the FFO should adopt this protocol in the RMPA to avoid unacceptable levels of methane waste and emissions in the Mancos Shale/Gallup Formation.

iii. The FFO should consider and adopt gas capture and marketing planning in the RMPA as a prerequisite for future Mineral Development Plans and Applications for Permit to Drill.

To address excessive flaring in the Bakken region of North Dakota, that state's oil and

⁸⁴ See EPA, Gas STAR Gold Program: Proposed Framework (May 8, 2014), available at: http://www.epa.gov/gasstar/documents/Gas_STAR_Gold_proposedframework.pdf (emphasis added) (attached as Exhibit 142).

gas industry early this year came forward with recommendations that gas capture plans be required from operators before permits can be issued for drilling.⁸⁵ Gas capture planning is also being considered by the BLM as it updates its methane waste rule, NTL4-a.⁸⁶

The FFO should consider and require gas capture planning before field development commences and oil or gas production moves beyond the exploration and delineation phase and increases significantly. Under these plans, oil and gas producers seeking drilling permits or related approvals would be required to inform the FFO of the location(s) of proposed drill site(s), the timing of production, forecasts of the amounts of gas to be produced, information about existing and planned gathering and processing infrastructure to serve the site, and the proposed time frame for connection or increases in compression. While gas capture plans may focus specifically on individual wells/well pads, plans should also include identification of the operator's activities in the entire field under development. This is an essential element of gas capture planning because gathering and processing infrastructure requires adequate scale to support its development, and costs associated with individual wells/well pads are dependent on the bigger picture.

A subsequent step in the gas capture planning process would be for the FFO to aggregate individual plans and make field-wide information on the location, timing, and amounts of gas production forecast to be available to midstream companies. This information would need to be updated on a regular basis to incorporate new data and ensure that midstream companies have the up-to-date information they need to secure throughput and finance and build gathering and processing infrastructure. Also, midstream companies should be encouraged, or required when approvals are needed from the FFO, to provide regular reporting on planning and construction of gathering lines, compressors and processing facilities to inform future activities of the FFO's and oil and gas producers. Further, we believe that public disclosure of the results of such planning should be required so that the interested public can engage in an informed manner in the FFOs planning and approval processes, and as required by NEPA. *See* 40 C.F.R. § 1506.6.

Capturing methane waste and emissions with mitigation measures is just the first of the FFO's obligations. The FFO must also ensure that methane will enter a sales gas line and make it to market or be used beneficially in the field, as opposed to simply being vented or flared and wasted. As an alternative to venting, flaring, and waste, the FFO must take a hard look at gas capture planning tools to ensure either field use of the resource or that gathering, boosting and processing infrastructure is in place prior to development activities, as discussed above.

iv. The FFO should require consideration of alternatives to flaring in gas capture and marketing plans.

⁸⁵ *See* North Dakota Petroleum Council, *News Release: Industry to increase natural gas capture to 85 percent within two years and 90 percent in six years* (January 2014), available at: <http://www.ndoil.org/latest-news/news-release-industry-to-increase-natural-gas-capture-to-85-percent-within-two-years-and-90-percent-in-six-years/> (attached as Exhibit 146).

⁸⁶ *See* BLM, *Venting and Flaring* at slides 17-19 (attached above as Exhibit 134).

In a recently released White Paper⁸⁷ on strategies to reduce the flaring of associated gas, the EPA has identified several field uses and other measures to reduce flaring and waste. Much of the information in the White Paper was drawn from the University of North Dakota's Energy and Environmental Research Center. The alternatives to flaring described include small-scale field compression of natural gas for transport, methane re-injection, electric power generation for on-site use or connection to the grid, and gas liquefaction. Additional field use of gas includes use as fuel for engines, compressors and other field equipment.⁸⁸

The FFO should review the EPA paper and other sources, assess which alternatives to flaring are appropriate for the Mancos Shale/Gallup Formation play, and ensure that those alternatives are addressed in gas capture plans.

- v. The FFO should consider and adopt the recommendations of the North Dakota Petroleum Council's Flaring Task Force regarding enforcement of gas capture plans.**

As part of its recommendations for gas capture plans to be a prerequisite for drilling permits, the NDPC also recommended a set of enforcement penalties for failure to submit a plan or failure to conform to a submitted plan. Penalties recommended for failure to submit a gas capture plan included suspension or denial of a permit for new wells and production curtailments where no there is no detriment to the well or reservoir. Penalties recommended for failure to comply with a gas capture plan included production curtailment with mitigating circumstances allowing for extension of time to comply. The FFO should consider and adopt these industry recommendations to ensure that gas capture planning has teeth and results in reduced methane waste and emissions in the Mancos Shale/Gallup Formation play.⁸⁹

- vi. There is tremendous support for Gas Capture Planning in North Dakota.**

Many oil and gas companies in North Dakota are supporting gas capture planning as a way to reduce excessive flaring, which must be recognized and considered by the FFO in the RMPA/EIS process. Testimony by industry at an April 22, 2014 hearing of the North Dakota Industrial Council demonstrates this level of support.⁹⁰

⁸⁷ EPA, Office of Air Quality Planning and Standards, *Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production* (April 2014) <http://www.epa.gov/airquality/oilandgas/pdfs/20140415completions.pdf> (attached as Exhibit 143);

⁸⁸ See, e.g., Energy & Environmental Research Center, Center for Oil and Gas, available at: <http://www.undeerc.org/Expertise/Center-for-Oil-and-Gas.aspx>.

⁸⁹ See NDIC Flaring Task Force at Slide 26 (attached above as Exhibit 127).

⁹⁰ See North Dakota Industrial Council Hearing, April 22, 2014 (attached as Exhibit 159).

North Dakota Petroleum Council (500 member industry organization)

- Upstream, Midstream, Surface Owners and Government Agencies must work together to achieve the [flaring reduction] goal.
- Statewide capture targets can be achieved through proper planning and stakeholder cooperation.
- Midstream companies will have increased pressure for investment to meet the targets, but will have much improved forecasts for planning and obtaining capital.

ConocoPhillips

- Several years ago, ConocoPhillips established an ongoing dialogue with third party mid-stream companies to provide specific well location and flowrate estimates during the planning process, before applying for drill permits, to minimize flaring as the wells were brought on line. As a result of these proactive, cooperative initiatives, ConocoPhillips has established an internal goal for having 100% of our Bakken operated wells tied into a gas gathering system prior to first production through permanent facilities. We have also established a process and built necessary equipment to capture initial gas volumes during well clean-up and flow-back, with temporary tie-ins to the gas gathering system. We strongly support the reduction of flared gas volumes within the Bakken, and have worked with our competitors, through the North Dakota Petroleum Council's leadership, to submit an action plan to the NDIC for achieving this goal. We believe the action plan establishes reasonable targets and timelines for the industry and balances the reality of infrastructure construction lead-time with the urgency to reduce flaring.

Enerplus Resources

- For a company without specifically owned Midstream assets, like Enerplus, this requires operators and gas gatherers to work closely together to calculate the demand and build out the necessary infrastructure to handle the supply

Hess Oil

- Hess applauds the NDIC for adopting the Gas Capture Plan recommendation put forth by the Flaring Task Force earlier this year. We believe this will be a powerful tool for regulators, while also promoting greater accountability for operators and midstream service providers. One of the most important aspects of Gas Capture Plan required for any new permit to drill is that it will ensure that operators are communicating with midstream providers before any new wells come on line ... Over the long term, we believe the Gas Capture Plans will have a dramatic effect on infrastructure planning and increase the industry's efficiency for capturing gas.

Oneok Partners [Midstream]

- The Flaring Task Force has facilitated increased communication between producers and midstream companies, which will result in better planning in the years to come. The rapid development of the Bakken/Three Forks play has challenged existing midstream infrastructure, and it will take some time to build out the necessary facilities in these early years of the development. Increased visibility into producers'

plans and projections for the area allow midstream companies to get out front and better understand timing and capacity needs.

Petro-Hunt [Midstream]

- As a midstream gatherer and processor, upon obtaining a party's drilling plans, we review (with that party) the location and number of wells (single/multiple) to be drilled, the proposed spud dates, and how much volume we might expect at each connection point. We then model the throughputs to quantify the existing gathering line(s) and field and plant compression capacities. After modeling, we prepare a cost estimate for the gathering line(s) and other appurtenant facilities, and when necessary, obtain quotes from (multiple) compressor companies and the closest electric power provider. Once all the information is compiled, (this process takes up to two (2) months), we submit the cost estimate for the project to and discuss the information with the producer. Upon reaching a mutual agreement regarding the estimated costs, we place an order for all required facilities that we do not have in inventory and commence right of way acquisition. (Right of way acquisition averages three (3) months.) On average, we connect ninety percent (90%) of the wells prior to first production.

Petro-Hunt, L.L.C. [Exploration & Production]

- All of our North Dakota leases are now dedicated under gas processing contracts with three (3) midstream companies. We provide these companies our drilling schedules up to three (3) years in advance and our fracking schedules one (1) month in advance. This is done to allow these companies to model their systems and have our wells connected in a timely manner.

SM Energy

- Collaboration between the NDIC, operators and midstream companies is essential
- SM Energy proposes that the best way to manage gas capture targets is on a system basis
 - Limitations on the drilling of new wells, or curtailment of production, should be managed on a system (area) basis
 - A system is defined as a booster station(s) and associated gathering facilities

Statoil

- Support NDPC's proposal, so let the GCP's work

Whiting Petroleum

- Reduce the number of APD's that are approved to operators that are continuing to flare their gas contrary to their GCP's.

WPX Energy

- Our commitment to capturing gas drove us to construct our own gathering system on the Van Hook peninsula at investment cost of over \$50 million. In addition we have made a \$10 million investment for well-head compression as well as investing over \$100 million in well connections.

- Although we have many constraints WPX does support the use of the Gas Capture Plan for flaring reduction.
- WPX is confident that the GCP program can be successful in reducing gas flaring.

vii. The FFO should consider and adopt controls over the phasing and location of oil and gas development to minimize methane waste and emissions.

The FFO has available additional tools beyond mitigation measures and planning that the agency can use to minimize methane waste and emissions. The agency also has the authority to impose controls on the timing, location and pace of development – i.e., “phased development.” Such controls “promote the orderly and efficient exploration, development and production of oil and gas,” and should be considered and adopted by the FFO in the RMPA. *See* 43 C.F.R. § 3160.0-4. Specifically, the CARPP, as detailed above, includes reducing the pace of development and requiring phased development as one of the measures available to Field Offices to geographically limit or time the approval of MDPs and APDs to correspond with the ability to use gas in the field or the presence of infrastructure to ensure beneficial use. *See* CARPP at 19 (attached above as Exhibit 116).

In addition, the CRVFO’s Proposed RMP/FEIS states that:

The authorized officer has the authority to relocate, control timing, and impose other mitigation measures under Section 6 of the Standard Lease Form. This authority is invoked when lease stipulations are not attached to the lease, or new resources are discovered on a lease.

CRVFO RMP/FEIS, Appendix P at 4 (Oil and Gas Operations).

Such controls, if employed here, can reduce the footprint of oil and gas production infrastructure in the Mancos Shale/Gallup Formation play and thus reduce the number of potential methane pollution and waste sources. Such controls can also help to coordinate and harmonize the FFO’s waste prevention efforts with the agency’s broader set of responsibilities to protect the climate, ecological health and connectivity, water and air quality, public health, and wildlife. Thus, the FFO should not only take efforts to reduce the footprint of oil and gas development to prevent methane pollution and waste, but also locate and constrain such development to avoid conflicts with other resources. This should, notably, extend beyond public lands to avoid conflicts with private farms, ranches, and communities.

viii. Finally, the FFO should recognize that “adaptive management” is not a viable approach to addressing methane emissions and waste.

Adaptive management was adopted to address all air resources issues in the CRVFO’s Proposed RMP/FEIS:

The Proposed RMP would include an adaptive management approach to implementing the range of development scenarios and mitigation measures

modeled in the ARTSD and evaluated in the Draft RMP. The purpose of the CARPP in Appendix L is to address air quality issues identified by BLM in its analysis of potential impacts to air quality resources for the CRVFO RMP/EIS. In addition, the plan further clarifies the air resources goals, objectives, and management actions set forth in Table 2-2 of the Proposed RMP/Final EIS. The CARPP is an adaptive management approach to implementing air resources decisions and outlines BLM's commitments for managing air resources. The CARPP considers a range of emissions levels and air quality impacts from the mitigation and development scenarios in the ARTSD and future modeling efforts to make implementation-level decisions. The Proposed RMP includes a level of development and mitigations scenarios within the range of alternatives in the Draft RMP/Draft EIS implemented with an adaptive management plan (CARPP).

CRVFO RMP/FEIS at 4-29.

The CRVFO's Proposed RMP/FEIS explained the relationship of implementation and monitoring to adaptive management:

Adaptive management is a structured, iterative process for continuously improving implementation practices based on achieving goals and objectives established in the resource management plan (RMP). **Adaptive management is not possible without effective monitoring and evaluation because monitoring data show whether progress is being made toward achieving RMP objectives.** If not, implementation practices are adjusted and improved.

CRVFO RMP/EIS Appendix S at 1 (emphasis added).

However, the CRVFO seemed to ignore the fact that methane emissions and waste are not monitored in the same manner and to the same degree as criteria and hazardous air pollutants. According to the EPA, reporting is only required of:

... sources that in general emit 25,000 metric tons or more of carbon dioxide equivalent per year in the United States. Smaller sources ... are not included in the Greenhouse Gas Reporting Program.⁹¹

EPA has identified many small sources that can be expected to be located in the Mancos Shale/Gallup formation play but that would not exceed the reporting threshold and would, in the absence of additional monitoring and reporting requirements, go unmeasured. These include:

⁹¹ EPA, *Fact Sheet: Greenhouse Gas Reporting Program Implementation*, available at: <http://www.epa.gov/ghgreporting/documents/pdf/2009/FactSheet.pdf> (attached as Exhibit 144).

venting from workovers, pneumatic devices, liquids unloading, and small compressors, and equipment leaks throughout natural gas systems.⁹²

Therefore, reliance on adaptive management to address methane emissions and waste are “not possible” because of a lack of requirements for monitoring of smaller – but cumulatively significant – sources of such waste in the oil and gas production process. The FFO cannot simply cite the CARPP, or some other monitoring program, as a tool for future adaptive management. Rather, the agency must adopt the methane mitigation technologies, BMPs and planning tools identified in these scoping comments to address future development authorized under the RMPA, and to apply them not just to development on new leases but as RMP authorized stipulations on *all* new oil and gas development in the planning area.

d. Managing for Community and Ecosystem Resiliency.

Resilience is “an ability to recover from or adjust easily to misfortune or change.” MERRIAM-WEBSTER COLLEGIATE DICTIONARY (11th ed. 2008). In the context of climate change and the many resultant impacts, such as the alteration to the biosphere and impairments to human health, the resiliency of our landscapes and a community’s ability to respond and adapt to these changes takes on a new magnitude of importance.

As noted above, according to the GAO, federal land and water resources are vulnerable to a wide range of effects from climate change, some of which are already occurring. These effects include, among others: “(1) physical effects, such as droughts, floods, glacial melting, and sea level rise; (2) biological effects, such as increases in insect and disease infestations, shifts in species distribution, and changes in the timing of natural events; and (3) economic and social effects, such as adverse impacts on tourism, infrastructure, fishing, and other resource uses.”⁹³ It is critical that the FFO take a hard look at these growing impacts and analyze, as an alternative, employing climate mitigation measures to enable landscape and human resiliency and their ability to adapt and respond to climate change impacts.

However, beyond simply mitigating climate change impacts by reducing contributions of GHG pollution to the atmosphere, the BLM can also help promote ecological resiliency and adaptability by reducing external anthropogenic environmental stresses – like oil and gas development – as a way of best positioning public lands and the communities that rely on those public lands to withstand what is acknowledged ongoing and intensifying climate change degradation. In other words, in order to satisfy the agency’s multiple use mandate and protect the broadest range of public resources, both now and for future generations, it might be necessary to forego additional oil and gas development on public lands altogether – an action that should be considered in the FFO’s alternatives analysis. It is crucial for the BLM to close the gap in their

⁹² EPA, *Petroleum and Natural Gas Systems* (Aug. 2012), available at: <http://www.epa.gov/ghgreporting/documents/pdf/infosheets/OnshorePetroleumNaturalGasSystems.pdf> (attached as Exhibit 145).

⁹³ GAO Report (2007) (attached above as Exhibit 35).

decision-making regarding the cumulative contribution of oil and gas development authorized in the proposed action, particularly given the conflict between such authorization and the agency's responsibility to manage for healthy, resilient ecosystems. Quite simply, continuing to manage our public lands in a manner that allows for the virtually unabated extraction of mineral resources is incompatible with principals of ecosystem resilience. Agency decision-making in the RMPA/EIS must be reflective of the climate challenges we now face.

The BLM must consider the resilience of our communities and their ability to adapt and respond to climate change in its NEPA analysis. Although not specifically in the context of climate change, Congress has recognized the value that farmlands play in the welfare of people and our communities. *See* 7 U.S.C.A. §§ 4201(a)(1) (“the Nation’s farmland is a unique natural resource and provides food and fiber necessary for the continued welfare of the people of the United States”); (a)(3) (“continued decrease in the Nation’s farmland base may threaten the ability of the United States to produce food and fiber in sufficient quantities to meet domestic needs”); and (a)(5) (“Federal actions, in many cases, result in the conversion of farmland to nonagricultural uses where alternative actions would be preferred”). Any action taken that undermines a community’s welfare and capacity to provide for itself in the face of recognized changes to climate – such as the largely unabated development of oil and gas resources – fails to realize the agency’s multiple use mandate under FLPMA, and, further, is indefensible pursuant to BLM’s mandate to act as stewards of our public lands.

The myriad impacts that will result from the agency’s decision-making must be considered within the context of resiliency. Although the FFO may recognize the threat of climate change, the agency’s decision-making must also be reflective of this harm and take the many necessary and meaningful steps to ameliorate the impacts to communities, landscapes, species, and our atmosphere. As discussed above, climate change is dramatically altering the relationship between human kind and the environment in which we live. It is incumbent on the agency to not only takes steps to stem the pace of climate change through the practical implementation of mitigation technologies but, also, to position communities in a way that allows them to adjust and recover from the climate change impacts that they are already experiencing. Such critical consideration of agency decisionmaking is required if we are to meaningfully respond to the vast scale of impacts that we face.

C. The BLM Must Take a “Hard Look” at Hydraulic Fracturing.

Although advances in oil and gas extraction techniques – namely hydraulic fracturing, or “fracking” – have undoubtedly resulted in a growth of domestic production, the wisdom of these advances with regard to other resource values and human health is still very much in question.⁹⁴ As described in detail below, there is a wealth of information and reports stressing the dangers of fracking that must be considered in the agency’s subject NEPA analysis. Of course, given the national attention and debate that fracking is generating, significant sources of new information

⁹⁴ *See, e.g.,* A.R. Ingraffea, et. al., *Natural Gas, Hydraulic Fracking and a Bridge to Where?* (April 2011) (attached as Exhibit 62).

and research are being consistently published warning against the dangers and impacts that fracking can produce, which must also be considered by the agency in the RMPA/EIS.

For example, as discussed in more detail below, hydraulic fracturing was identified as one of several causes of methane contamination of drinking water and a subsequent explosion at a home in Bainbridge Township, Ohio. Spills of hydraulic fracturing fluid into the Acorn Fork Creek in Kentucky resulted in a fish kill, including the threatened Blackside Dace. Also, one study modeled that chemically concentrated fracking fluids can migrate into groundwater aquifers within a matter of years – calling into question industry claims that rock layers separating aquifers are impervious to these pollutants.⁹⁵ Claims that there has never been a documented case of groundwater contamination from fracking was challenged by EPA’s research in Pavillion, Wyoming. Indeed, a second round of testing in the Pavillion area was recently performed by the U.S. Geological Survey, which supported EPA’s preliminary findings that hydraulic fracturing resulted in groundwater contamination.⁹⁶ Even in draft form, the Pavillion Report and its troubling findings as well as incidents described above and other evidence of fracking related contamination from around the country underscore the need for thorough analysis to be performed by the FFO in the RMPA/EIS.

The dangers and impacts of fracking can be found at every stage of the oil and gas production process. For example, fracking’s waste stream can result in dramatic impacts – requiring onsite waste injection, trucking used frack fluids (“flowback”) offsite, and in some cases even the direct release of fracking waste into watercourses – the impacts of which can be compounded by ineffective or nonexistent regulation.⁹⁷ As detailed herein, natural gas production itself can be inefficient and wasteful – with practices such as the venting of methane,⁹⁸ and the use of vast quantities of water in the fracking process.⁹⁹ In addition to being wasteful, these practices can also be quite harmful to human health and the environment.

⁹⁵ See, Abrahm Lustgarten, *New Study Predicts Frack Fluids can Migrate to Aquifers Within Years*, PROPUBLICA, May 1, 2012 (attached as Exhibit 63); Josh Fox, *The Sky is Pink: Annotated Documents* (attached as Exhibit 64).

⁹⁶ Peter Wright, et. al., U.S. Geological Survey, *Groundwater-Quality and Quality-Control Data for Two Monitoring Wells near Pavillion, Wyoming*, April and May 2012 (attached as Exhibit 65).

⁹⁷ See Abrahm Lustgarten, *The Trillion Gallon Loophole: Lax Rules for Drillers that Inject Pollutants Into the Earth*, PROPUBLICA, Sept. 20, 2012 (attached as Exhibit 69); Earthworks, *The Crisis in Oil & Gas Regulatory Enforcement*, September 2012 (attached as Exhibit 70).

⁹⁸ Energy Policy Research Foundation, *Lighting up the Prairie: Economic Considerations in Natural Gas Flaring*, Sept. 5, 2012 (attached as Exhibit 71); see also, James Hansen, et. al., *Greenhouse gas growth rates*, PNAS, vol. 101, no. 46, 16109-16114, Sept. 29, 2004 (curtailing methane waste is seen as a “vital contribution toward averting dangerous anthropogenic interference with global climate.”) (attached as Exhibit 72).

The wisdom of the natural gas boom is further brought into question by the underlying economics driving domestic growth, with a historically low cost of natural gas and a vast number of approved wells that industry has allowed to expire – all of which questions the imminent need for additional public lands to be made available for oil and gas development, often at the expense of other important resource values at stake in an area. However, a closer look at some of the economics motivating the oil and gas industry’s push for greater production reveals sheer industry greed and speculation – driven by huge capital investment.¹⁰⁰ These factors cannot be ignored by BLM as it undertakes the RMPA/EIS, and must help to inform the resource values the agency elevates in its minerals management program.

a. Impacts From Hydraulic Fracturing are Well Documented and Must be Sufficiently Analyzed in the RMPA/EIS.

The potential impacts that may result from hydraulic fracturing are myriad and significant, and include, among others: impacts to water quality and supply, impacts to habitat and wildlife, impacts to human health, as well as impacts on greenhouse gas emissions and air quality.¹⁰¹ Although industry often asserts that hydraulic fracturing is safe and doesn’t result in contamination or harm to people and the environment, a NEW YORK TIMES investigation uncovered a 1987 U.S. Environmental Protection Agency (“EPA”) report to Congress which found, among other things, that fracking can cause groundwater contamination, and cites as an example a case where hydraulic fracturing fluids contaminated a water well in West Virginia.¹⁰²

⁹⁹ See GAO, *Energy-Water Nexus: Coordinated Federal Approach Needed to Better Manage Energy and Water Tradeoffs* (Sept. 2012) (attached as Exhibit 73); Nicholas Kusnetz, *The Bakken oil play spurs booming business – in water*, High Country News, Sept. 5, 2012 (attached as Exhibit 74).

¹⁰⁰ See Deborah Rogers, *In Their Own Words: Examining Shale Gas Hype*, Energy Policy Forum (April 2012) (attached as Exhibit 75).

¹⁰¹ See, e.g., National Wildlife Federation, *No More Drilling in the Dark: Exposing the Hazards of Natural Gas Production and Protecting America’s Drinking Water and Wildlife Habitats* (2011), available at: <http://www.nwf.org/News-and-Magazines/Media-Center/Reports/Archive/2011/No-More-Drilling-in-the-Dark.aspx> (attached as Exhibit 76); see also United States Forest Service, *Chloride Concentration Gradients in Tank-Stored Hydraulic Fracturing Fluids Following Flowback* (Nov. 2010), available at: <http://nrs.fs.fed.us/pubs/38533/> (last visited Dec. 20, 2011) (attached as Exhibit 77).

¹⁰² See U.S. Environmental Protection Agency, Report to Congress, *Management of Wastes from the Exploration, Development, and Production of Crude Oil, Natural Gas, and Geothermal Energy* (Dec. 1987), at Ch. IV, Damages Caused by Oil and Gas Operations (attached as Exhibit 78); see also *Drilling Down, Documents: A Case of Fracking Related Contamination*, THE NEW YORK TIMES ONLINE, available at: http://www.nytimes.com/interactive/us/drilling-down-documents-7.html?_r=1&.

The EPA report was further summarized and reviewed in an Environmental Working Group report,¹⁰³ and demonstrates the long-known dangers of employing this technology to extract mineral resources.

Fracking fluid is a conglomeration of many highly toxic chemicals and compounds. The Endocrine Disruption Exchange (“TEDX”) has documented nearly 1,000 products energy companies inject into the ground in the process of extracting natural gas. Many of these products contain chemicals that are harmful to human health. According to TEDX:

In the 980 products identified...[for use during natural gas operations], there were a total of 649 chemicals. Specific chemical names and CAS numbers could not be determined for 286 (44%) of the chemicals, therefore, the health effects summary is based on the remaining 362 chemicals with CAS numbers...Over 78% of the chemicals are associated with skin, eye or sensory organ effects, respiratory effects, and gastrointestinal or liver effects. The brain and nervous system can be harmed by 55% of the chemicals. These four health effect categories...are likely to appear immediately or soon after exposure. They include symptoms such as burning eyes, rashes, coughs, sore throats, asthma-like effects, nausea, vomiting, headaches, dizziness, tremors, and convulsions. Other effects, including cancer, organ damage, and harm to the endocrine system, may not appear for months or years later. Between 22% and 47% of the chemicals were associated with these possibly longer-term health effects. Forty-eight percent of the chemicals have health effects in the category labeled ‘Other.’ The ‘Other’ category includes such effects as changes in weight, or effects on teeth or bones, for example, but the most often cited effect in this category is the ability of the chemical to cause death.¹⁰⁴

A Congressional Report issued in April 2011 reveals that energy companies have injected more than 30 million gallons of diesel fuel or diesel mixed with other fluids into the ground nationwide in the process of fracking to extract natural gas between 2005 and 2009.¹⁰⁵ In Colorado, 1.3 million gallons of fluids containing diesel fuel was used in fracking natural gas wells.¹⁰⁶ The EPA has stated that “the use of diesel fuel in fracturing fluids poses the greatest

¹⁰³ See Environmental Working Group, *Cracks in the Façade: 25 Years ago, EPA Linked “Fracking” to Contamination* (Aug. 2011) (attached as Exhibit 79).

¹⁰⁴ TEDX, *Chemicals In Natural Gas Operations* (attached above as Exhibit 3).

¹⁰⁵ U.S. CONGRESS, HOUSE OF REPRESENTATIVES, COMMITTEE ON ENERGY AND COMMERCE, *Chemicals Used in Hydraulic Fracturing* (April 2011), at 10 (attached as Exhibit 80); see also Memorandum from Chairman Henry A. Waxman and Subcommittee Chairman Edward J. Markey, to Committee on Energy and Commerce, *Examining the Potential Impact of Hydraulic Fracturing* (Feb. 28, 2010) (attached as Exhibit 81).

¹⁰⁶ Karen Frantz, *States probe use of diesel fuel*, DURANGO HERALD, February 5, 2011, available at: <http://www.durangoherald.com/article/20110206/NEWS01/702069922/-1/s>.

threat” to underground sources of drinking water.¹⁰⁷ According to Congresswoman Diana DeGette of Colorado, fracking with diesel fuel was done without permits in apparent violation of the Safe Drinking Water Act.¹⁰⁸

In 2012, a former staffer responsible for investigating and managing groundwater contamination for New York State warned that allowing the controversial hydraulic fracturing practices would lead to contamination of the state’s aquifers and poison its drinking water. In staffer Paul Hetzler’s letter to an upstate New York newspaper, he provided:

I’m familiar with the fate and transport of contaminants in fractured media, and let me be clear: hydraulic fracturing as it’s practiced today will contaminate our aquifers.

Not *might* contaminate our aquifers. Hydraulic fracturing *will* contaminate New York’s aquifers. If you were looking for a way to poison the drinking water supply, here in the north-east you couldn’t find a more chillingly effective and thorough method of doing so than with hydraulic fracturing.¹⁰⁹

Despite the energy industry’s explanation that a thick layer of bedrock safely separates the gas-containing rock layer being fractured from ground-water used for drinking and surface water sources, evidence is emerging which warns that contaminants from gas wells are making their way into groundwater. In particular, the anticipated use of nitrogen foam in fracking applications in the planning area is of concern. In meetings, FFO employees have referenced the higher permeability of nitrogen gas, resulting in a greater likelihood of contamination. The RMPA/EIS must include detailed analysis and data regarding the use of fracking technology in

¹⁰⁷ David O. Williams, *U.S. House probe alleges Halliburton, others illegally used diesel in gas fracking*, COLORADO INDEPENDENT, February 1, 2011, available at: <http://coloradoindependent.com/73593/u-s-house-probe-alleges-halliburton-others-illegally-used-diesel-in-gas-fracking>.

¹⁰⁸ Letter from U.S. CONGRESS, HOUSE OF REPRESENTATIVES, COMMITTEE ON ENERGY AND COMMERCE, Representatives Henry A. Waxman, Edward J. Markey, & Diana DeGette, to Lisa Jackson, Administrator, U.S. ENVIRONMENTAL PROTECTION AGENCY (Jan. 31, 2011), available at: http://degette.house.gov/index.php?option=com_content&view=article&id=1048:energy-a-commerce-committee-fracking-investigation-reveals-millions-of-gallons-of-diesel-fuel-injected-into-ground-across-us&catid=76:press-releases-&Itemid=227 (attached as Exhibit 82); *see also* Environment News Service, *Toxic Diesel Fuel Used Without Permits in Fracking Operations*, February 4, 2011, available at: <http://www.ens-newswire.com/ens/feb2011/2011-02-04-092.html>.

¹⁰⁹ Karen McVeigh, *Damning New Letter from NY State Insider: ‘Hydraulic Fracturing as It’s Practiced Today Will Contaminate Our Aquifers,’* THE GUARDIAN, January 6, 2012, available at: http://www.alternet.org/water/153684/damning_new_letter_from_ny_state_insider%3A_%27hydraulic_fracturing_as_it%27s_practiced_today_will_contaminate_our_aquifers%27/.

general, and nitrogen foam fracking in particular. Evidence suggesting contaminants from hydraulic fracturing drilling operations have migrated towards the surface, include:

- In March 2004, gas was discovered bubbling up in West Divide Creek and a few nearby ponds in Garfield County. The Colorado Oil and Gas Conservation Commission (“COGCC”) took samples of the water and discovered they contained benzene, toluene, and m- & p-xylenes at concentrations of 99, 100, and 17 micrograms per liter (mg/l), respectively. This indicated that the gas seeping into West Divide Creek probably was not biogenic methane gas (gas made by the decomposition of organic matter by methanotrophic bacteria), but rather thermogenic gas. Further testing indicated that the gas seeping into West Divide Creek was thermogenic gas from the Williams Fork Formation where EnCana had been drilling for natural gas.¹¹⁰ EnCana was subsequently fined \$371,000 as a result of contaminating West Divide Creek.
- The COGCC investigated complaints from Weld County, Colorado that domestic water wells were allegedly contaminated from oil and gas development. The COGCC concluded after investigation that the Ellsworth’s well contained a mixture of biogenic and thermogenic methane (from gas drilling operations) that was in part attributable to oil and gas development. Ms. Ellsworth and the operator reached a settlement in that case.¹¹¹
- In 2007, EPA hydrologists sampled a pristine drinking water aquifer under the Jonah Well Field near Pinedale, Wyoming. They found high levels of benzene, a known carcinogen, in 3 wells and low levels of hydrocarbons in an additional 82 wells (out of the 163 wells sampled).¹¹² These contaminated wells are located in an area stretching across 28 miles in an undisturbed landscape in which the only industry that exists is natural gas extraction.
- In Pavillion, Wyoming, EPA found 11 of 39 water samples collected from domestic wells were contaminated with chemicals linked to local natural gas fracking

¹¹⁰ Colorado Oil and Gas Conservation Commission, *Mamm Creek Gas Field - West Divide Creek Gas Seep – April 14, 2004 Update* (2004), available at: http://cogcc.state.co.us/Library/PiceanceBasin/WestDivide4_14_04summary.htm; see also Margaret Ash, Environmental Protection Supervisor, Colorado Oil and Gas Conservation Commission, *Investigation into Complaint of New Gas Seep, West Divide Creek, 2007-2008* (attached as Exhibit 83).

¹¹¹ Letter from David Neslin, Director, Colorado Oil and Gas Conservation Commission, to Mr. and Mrs. Ellsworth (August 7, 2009) (attached as Exhibit 84).

¹¹² BLM Wyoming News Release, *BLM, Wyoming DEQ Require Test of Water Wells Within the Pinedale Anticline and Jonah Fields* (April 26, 2007), available at: http://www.blm.gov/wy/st/en/info/news_room/2007/04/26pfo-DEQ-BLMwatertests.html.

operations. The EPA found arsenic, methane gas, diesel-fuel-like compounds and metals including copper and vanadium. Of particular concern were compounds called adamantanes – a natural hydrocarbon found in natural gas – and a little-known chemical called 2-butoxyethanol phosphate, or 2-BEp. 2-BEp is closely related to 2-BE, a substance known to be used in fracking fluids.¹¹³

- Pennsylvania state regulators have uncovered more than 50 cases where methane and other contaminants have exploded out of wells or leaked underground into drinking water supplies.¹¹⁴

Known and suspected adverse effects of drilling operations include:

- Garfield County, Colorado, Commissioners recently expressed their health and safety concerns regarding natural gas drilling by stating in a legal filing that, “No agency...can guarantee Garfield County residents that exposures to oil and gas emissions will not produce illness or latent effects, including death.” They cited the cases of three people – Chris Mobaldi, Verna Wilson, and Jose Lara – who died after suffering from drilling-related illnesses in Garfield County.¹¹⁵
- In April 2008, a nurse at a hospital in Durango, Colorado, became critically ill and almost died of organ failure as a result of second-hand chemical exposure acquired while treating a drill rig worker who had fracking fluid on his clothes.¹¹⁶
- In Texas, which now has approximately 93,000 natural-gas wells, up from around 58,000 a dozen years ago, a hospital system in the six counties with some of the heaviest drilling reported in 2010 a 25 percent asthma rate for young children, more than three times the state rate of about 7 percent.¹¹⁷

¹¹³ See Neslin (attached above as Exhibit 84).

¹¹⁴ See Robert B. Jackson, et al., *Increased stray gas abundance in a subset of drinking water wells near Marcellus shale gas extraction*, PNAS, December 17, 2012 (attached as Exhibit 85).

¹¹⁵ David O. Williams, *GarCo officials blast state gas drilling rules in case requesting more well density*, THE COLORADO INDEPENDENT, January 19, 2011, available at: <http://coloradoindependent.com/72246/garco-officials-blast-state-gas-drilling-rules-in-case-requesting-more-well-density>.

¹¹⁶ Eric Frankowski, *Gas industry secrets and a nurse's story*, HIGH COUNTRY NEWS, July 28, 2008, available at: <http://www.hcn.org/wotr/gas-industry-secrets-and-a-nurses-story>.

¹¹⁷ Ian Urbina, *Regulations Lax as Gas Well's Tainted Waters Hits Rivers*, THE NEW YORK TIMES, February 26, 2011, available at: <http://www.nytimes.com/2011/02/27/us/27gas.html?pagewanted=all>.

- A house in Bainbridge, Ohio exploded on November 15, 2007. The Ohio Department of Natural Resources attributed the explosion to a methane leak from a nearby hydraulic fractured well. The faulty cement casing of the well developed a crack allowing methane to seep underground and fill the couple's basement.¹¹⁸

Abraham Lustgarten, an investigative reporter with ProPublica, who has won the George Polk Award for Environmental Reporting for his work on the dangers of natural gas drilling, writes:

Dennis Coleman, a leading international geologist and expert on tracking underground migration, says more data must be collected before anyone can say for sure that drilling contaminants have made their way to water or that fracturing is to blame. But Coleman also says there's no reason to think it can't happen. Coleman's Illinois-based company, Isotech Laboratories, has both the government and the oil and gas industry as clients. He says he has seen methane gas seep underground for more than seven miles from its source. If the methane can seep, the theory goes, so can the fluids.¹¹⁹

However, perhaps the most thorough evidence of groundwater contamination from hydraulic fracturing is found in a newly released EPA draft report investigating ground water contamination near Pavillion, Wyoming ("Pavillion Report").¹²⁰ Among its findings, the Pavillion Report provides:

Elevated levels of dissolved methane in domestic wells generally increase in those wells in proximity to gas production wells. Pavillion Report, at xiii.

Detection of high concentrations of benzene, xylenes, gasoline range organics, diesel range organics, and total purgeable hydrocarbons in ground water samples from shallow monitoring wells near pits indicates that pits are a source of shallow ground water contamination in the area of investigation. Pits were used for disposal of drilling cuttings, flowback, and produced water. There are at least 33 pits in the area of investigation. When considered separately, pits represent potential source terms for localized ground water plumes of unknown extent.

¹¹⁸ See Ohio Department of Natural Resources, Division of Mineral Resources Management, *Report on the Investigation of the Natural Gas Invasion of Aquifers in Bainbridge Township of Geauga County, Ohio* (September 1, 2008) (attached as Exhibit 86); see also Joan Demirjian, *Insurance company [sues] driller over home explosion*, CHAGRIN VALLEY TIMES, January 7, 2010, available at: <http://www.chagrivalleytimes.com/NC/0/1571.html>.

¹¹⁹ Abraham Lustgarten, *Hydrofracked? One Man's Mystery Leads to a Backlash Against Natural Gas Drilling*, PROPUBLICA, February 25, 2011, available at: <http://www.propublica.org/article/hydrofracked-one-mans-mystery-leads-to-a-backlash-against-natural-gas-drill/single>.

¹²⁰ EPA Draft Report, *Investigation of Ground Water Contamination Near, Pavillion, Wyoming* (Dec. 2011) (attached as Exhibit 87).

When considered as whole they represent potential broader contamination of shallow ground water. *Id.* at 33 (emphasis added).

The explanation best fitting the data for the deep monitoring wells is that constituents associated with hydraulic fracturing have been released into the Wind River drinking water aquifer at depths above the current production zone. *Id.* (emphasis added).

Although some natural migration of gas would be expected above a gas field such as Pavillion, data suggest that enhanced migration of gas has occurred to ground water at depths used for domestic water supply and to domestic wells. *Id.* at 37 (emphasis added).

A lines of reasoning approach utilized at this site best supports an explanation that inorganic and organic constituents associated with hydraulic fracturing have contaminated ground water at and below the depth used for domestic water supply.... A lines of evidence approach also indicates that gas production activities have likely enhanced gas migration at and below depths used for domestic water supply and to domestic wells in the area of investigation. *Id.* at 39 (emphasis added).

Although the Pavillion Report was never finalized, the EPA has shared preliminary data with, and obtained feedback from, Wyoming state officials, EnCana, Tribes, and Pavillion residents, prior to release. Even in draft form, the Pavillion Report and its troubling findings – as well as other evidence of fracking related contamination from around the country – must be considered in the FFO’s RMPA/EIS.

Historically, BLM has been dismissive of possible impacts to water quality from hydraulic fracturing. However, given the weight of both new and old evidence documenting the risk of water contamination from gas drilling across the country, BLM’s approach is becoming increasingly untenable, in particular given the absence of any scientific analysis that conclusively finds that these documented problems do not exist in the planning area. Indeed, even an industry report prepared for Gunnison Energy Corporation – a major oil and gas developer – has acknowledged the potential for significant impacts to water resources from fracking.¹²¹ The simple fact of the matter is that natural gas development has the potential for poisoning our water with toxic, hazardous, and carcinogenic chemicals as well as naturally occurring radioactive radium, and BLM must provide a thorough hard look analysis of these potentially significant impacts in its analysis for the RMPA/EIS.

Moreover, recent reporting from New Mexico has acknowledged a proliferation of “frack hits,” or “downhole communication,” where new horizontal drilling for oil is communicating

¹²¹ See Gunnison Energy Corporation, *Analysis of Potential Impacts of Four Exploratory Natural Gas Wells to Water Resources of the South Flank of the Grand Mesa, Delta County, Colorado* (March 2003) at 42, 56 (attached as Exhibit 88).

with both historic and active vertical wells.¹²² This is a significant development that could result in well blowouts, contamination of resources, and issues over who is responsible for liabilities and costs of such impacts. BLM has a significant responsibility to include a hard look analysis of frack hits in the RMPA/EIS.

The bottom line is this – energy companies have told us, ‘Trust us, our fracking ingredients and process for extracting natural gas are harmless.’ We now know they have not been truthful and cannot be trusted. Without implementation of a precautionary approach to these risks, BLM will continue to place the health of our community and our environment at risk.

b. Current Disclosure Rules are Insufficient.

One basic purpose of NEPA is to assure that the public and policy makers are aware in advance of the potential environmental consequences of proposed actions. 40 C.F.R. § 1500.1(a). Furthermore, the presence of uncertain or unknown risks may compel an agency to prepare a more thorough EIS, in lieu of an EA. 40 C.F.R. § 1508.27(b)(5). Currently, there are significant uncertainties about the different chemicals that are being used in hydraulic fracking, though, as mentioned above, it is clear that toxic, hazardous, and carcinogenic chemicals are used throughout the fracking process. Current, disclosure of fracking chemicals, via FracFocus, is insufficient to adequately protect the public from potentially toxic, hazardous, and/or carcinogenic chemicals.¹²³ In preparing its NEPA analysis for the RMPA/EIS, BLM must catalogue the substances that will be used or are reasonably likely to be used in fracking on the parcels made available. In order to make this information accessible to the public, BLM should categorize these substances as hazardous, toxic, carcinogenic, or benign.

c. BLM Must Take a Hard Look at Wastewater Disposal.

BLM must take a hard look at wastewater disposal in the RMPA/EIS, including a comparative analysis of the different alternatives for disposal. The agency should analyze fully the wastewater disposal methods, without assuming that treatment can and will be adequate and take care of the problem. For example, *see* Brian D. Lutz, *et al.*, *Generation, Transport, and Disposal of Wastewater Associated with Marcellus Shale Gas Development*, WATER RESOURCES RESEARCH (February 8, 2013) (attached as Exhibit 157).

Contrary to current perceptions, Marcellus wells produce significantly less wastewater per unit gas recovered (approximately 35%) compared to conventional natural gas wells. Further, well operators classified only 32.3% of wastewater from Marcellus wells as flowback from hydraulic fracturing; most wastewater was

¹²² *See, e.g.*, Gayathri Vaidyanathan, *In N.M., a sea of ‘frack hits’ may be tilting production*, E&E News, (March 18, 2014) (attached as Exhibit 118); Tina Jensen, *Fracking fluid blows out nearby well*, KQRE (October 19, 2013) (attached as Exhibit 119).

¹²³ Kate Konschnik *et al.*, *Legal Fractures in Chemical Disclosure Laws: Why the Voluntary Chemical Disclosure Registry FracFocus Fails as a Regulatory Compliance Tool*, Harvard Law School, Evtl. Law Program, Apr. 2013 (attached as Exhibit 89).

classified as brine, generated over multiple years. *Despite producing less wastewater per unit of gas, developing the Marcellus shale has increased the total wastewater generated in the region by approximately 570% since 2004, overwhelming current wastewater disposal infrastructure capacity.* *Id.* at 1 (emphasis added).

d. The BLM Must Consider Traffic Impacts that will Result from Increased Oil and Gas Development.

The RMPA/EIS must include analysis of impacts from increases in vehicle traffic that authorized development would induce. For example, cases have required NEPA analyses of proposed casino projects to include impacts of increases in vehicle traffic the projects would induce. *See Michigan Gambling Opposition v. Kempthorne*, 525 F.3d 23, 29 (D.C. Cir. 2008); *Taxpayers of Michigan Against Casinos v. Norton*, 433 F.3d 852, 863 (D.C. Cir. 2006).

As noted above, fracking requires huge amounts of water, and consequently a great number of tanker truck trips to transport this water and chemicals to the site and to transport waste from the site. Given that fracking can require *thousands* of round trips by heavy trucks when developing *each* well – the impacts of which are compounded exponentially for development of an entire oil and gas field – it is clear that this heavy industrial transport activity will result in dramatic impacts.

This analysis must include the quantification of air quality impacts from increased truck traffic, estimate increased maintenance demands, consider safety costs for increased roadway use, increased traffic accidents and associated medical impacts and burdens on local hospitals, burdens on first responders and the criminal justice system, or to even project where or how many miles of access roads will be constructed.

A recent and comprehensive 2013 study by Boulder County, Colorado of the impacts of fracking-related truck traffic (hereafter “Boulder Study”),¹²⁴ concluded that the hydraulic fracturing process for a single well would require an average of 1,400 one-way truck trips just to haul water to and from the site. *See Boulder Study* at 8. Using national data, the study also finds that taking into account the full development process (construction, drilling, and completion), the average fracked well requires 2,206 one-way truck trips. *Id.* at 10. This figure does not include production phase trips, which could add an additional 730 truck trips per year depending on various factors including the success of the well and whether it is re-fracked. *Id.*

The Boulder Study serves as an example of what BLM should analyze in its RMPA/EIS. The Study uses this trip generation data to analyze the impacts of oil and gas development on the

¹²⁴ *See Colorado Public Radio, Drilling for oil and gas drives Colo. trucking boom* (April 9, 2014) available at: <http://www.cpr.org/news/story/drilling-oil-and-gas-drives-trucking-boom> (referencing this study by Boulder County, Colorado: *boulder county oil and gas roadway impact study* (Jan 2013), available at: <https://www.bouldercounty.org/doc/landuse/dc120003oilgasroadwaystudy20130114.pdf> [hereinafter “Boulder Study”] (attached as Exhibit 160)).

county's roadway system and, ultimately, to quantify these impacts in terms of maintenance and safety costs. *Id.* at 4. To establish a baseline, the Study inventoried current roadways including surface conditions, traffic volumes, and shoulder widths. In addition to the number of truck trips, the Study also examined the vehicle classification, load, origin, and destination of the trips. Finally, road deterioration and safety costs are calculated under three development scenarios, resulting in an average cost of \$36,800 per well over 16 years. *Id.* at 55. The Boulder Study is just one example of the type of quantitative analysis of oil and gas related traffic that can be completed with currently available information, and must be included in the FFO' analysis for the RMPA/EIS.

e. The BLM Must Consider Impacts from Pipelines.

Related to the issue of transportation impacts from development of well-sites is the paradoxical relationship this has to pipelines for transporting fracking fluid, flowback, produced water, or condensates, in that as more pipelines are constructed, arguably less trucks would be required, and vice versa.

The RMPA/EEIS must provide a clear assessment on what pipelines are actually to be required, what pipelines are "feasible," whether they would be limited in what they transport, how many barrels per day they would transport, and how much truck traffic this would displace (if any, since the pipelines ultimately are transferring product to trucks). This should include estimates of how many pipelines will be constructed, how many miles of pipe will be laid, what their diameter would be, how many water-bodies they would cross, or where they will be located. Moreover, and as noted above in regard to road traffic, the RMPA/EIS must not use uncertainty as a shell-game to defer to future planning, and thus entirely fail to provide sufficient analysis of pipeline impacts. This analysis is fundamental to satisfying the agency's hard look requirement.

However, reducing truck traffic through the installation of pipelines introduces different impacts to the environment that must be accounted for in the agency's analysis. For example, there is the potential risk of pipeline ruptures, but simply identifying that risk is insufficient. The agency must quantify and analyze this risk respective to the amount of pipeline projected in the planning area over the life of the RMPA. Further, there exists the potential for contamination of soils, surface water, and groundwater as a result of spills, and there must be analysis concerning the possible spill volumes or consideration of various spill scenarios given pipeline volume, emergency procedures, and mitigation requirements.

f. Seismic Impacts

The scientific communities recognition of the relationship between hydraulic fracturing and seismic activity is not new. Indeed, the USGS freely admits, "earthquakes induced by human activity have been documented."¹²⁵ The largest and perhaps most widely known incident to date

¹²⁵ See USGS, Earthquakes Hazards Program, FAQs, available at: <http://earthquake.usgs.gov/learn/faq/?categoryID=1&faqID=1>.

resulted from fluid injection at the Rocky Mountain Arsenal near Denver, Colorado, in 1967, where an earthquake of magnitude 5.5 followed a series of smaller earthquakes. Further, in a 1990 report studying the incident, the USGS confirmed, “the link between fracking fluid injection and the earlier series of earthquakes was established.”¹²⁶

Recently, “[a] northeast Ohio well used to dispose of wastewater from oil and gas drilling almost certainly caused a series of 11 minor quakes in the Youngstown area since last spring, a seismologist investigating the quakes said.”¹²⁷ After the latest and largest quake Saturday, December 31, 2011, which registered at 4.0 magnitude, “state officials announced their beliefs that injecting wastewater near a fault line had created enough pressure to cause seismic activity. They said four inactive wells within a five-mile radius of the Youngstown well would remain closed.”¹²⁸ As Andy Ware, deputy director of the Ohio Department of Natural Resources, which regulates gas drilling and disposal wells, stated, “the state asked on Friday that injection at the well be halted after analysis of the 10th earthquake, a 2.7-magnitude temblor on Dec. 24, showed that it occurred less than 2,000 feet below the well.”¹²⁹

The events in Youngstown unfortunately don’t seem to be isolated. “A string of mostly small tremors in Arkansas, Oklahoma, Texas, British Columbia and other shale-gas-producing areas suggest that [fracking] may lead, directly or indirectly, to a dangerous earthquake.”¹³⁰ The commonality of circumstances suggests that a strong correspondence between seismic activity and development techniques used by the oil and gas industry does indeed exist. For example, “[t]he number and strength of earthquakes in central Arkansas have noticeably dropped since the shutdown of two injection wells in the area.”¹³¹ Scott Ausbrooks, the Geohazards Supervisor for

¹²⁶ Craig Nicholson and Robert Wesson, *Earthquake Hazard Associated with Deep Well Injection – A report to the U.S. Environmental Protection Agency*, U.S. Geological Survey Bulletin 1951 (1990), at 74 (attached as Exhibit 90) (also citing other well-documented examples of seismic activity induced by fluid injection, including: Denver, Colorado; Rangely, Colorado; southern Nebraska; western Alberta and southwestern Ontario, Canada; western New York; New Mexico; and Matsushiro, Japan).

¹²⁷ Thomas J. Sheeran, *Ohio Earthquakes Caused by Drilling Wastewater Well, Experts Say*, HUFFINGTON POST, January 2, 2012, available at: http://www.huffingtonpost.com/2012/01/02/ohio-earthquakes-caused-by-wastewater-well-drilling_n_1180094.html.

¹²⁸ *Id.*

¹²⁹ Henry Fountain, *Disposal Halted at Well After New Quake in Ohio*, THE NEW YORK TIMES, Jan. 1, 2012, available at: <http://www.nytimes.com/2012/01/02/science/earth/youngstown-injection-well-stays-shut-after-earthquake.html?scp=3&sq=fracking%20earthquake&st=cse>.

¹³⁰ *Id.*

¹³¹ Sarah Eddington, *Ark. Quakes Decline Since Injection Well Closures*, HUFFINGTON POST, March 14, 2011, available at: <http://www.huffingtonpost.com/huff-wires/20110314/us-arkansas-earthquakes/>.

the Arkansas Geological Survey, provided, “[w]e have definitely noticed a reduction in the number of earthquakes, especially the larger ones. It’s definitely worth noting.”¹³²

Moreover, the U.S. Geological Survey (“USGS”) has recently released a report that links a series of earthquakes in Oklahoma, in January 2011, to a fracking operation underway there. The USGS determined after analyzing earthquake data that “the character of seismic recordings indicate that they are both shallow and unique.”¹³³ The report continues, providing: “Our analysis showed that shortly after hydraulic fracturing began small earthquakes started occurring, and more than 50 were identified, of which 43 were large enough to be located. Most of these earthquakes occurred within a 24-hour period after hydraulic fracturing operations had ceased.”¹³⁴

In August 2011, an earthquake measuring 5.3-magnitude near Trinidad, Colorado, was the largest in more than 40 years.¹³⁵ However, seismic activity near Trinidad is not new. Indeed, a September 2001 swarm of earthquakes near Trinidad prompted a U.S. Geological Survey investigation. The USGS report provided, “In recent years, a large volume of excess water that is produced in conjunction with coal-bed methane gas production has been returned to the subsurface in fluid disposal wells in the area of the earthquake swarm;” and later continues, “Because of the proximity of these disposal wells to the earthquakes, local residents and officials are concerned that the fluid disposal might have triggered the earthquakes.”¹³⁶ The USGS investigation concluded: “the characteristics of the seismicity and the fluid disposal process do not constitute strong evidence that the seismicity is induced by the fluid disposal, though they do not rule out this possibility.”¹³⁷

The threat of seismic activity induced from oil and gas development practices must be considered in the BLM’s analysis of the October 2014 lease sale. As noted above, Ohio officials placed a five-mile buffer around waste injection wells. Given the recognized correlation between oil and gas development practices and the inducement of earthquakes, taking such a

¹³² *Id.*

¹³³ Austin Holland, Oklahoma Geological Survey, Examination of Possibly Induced Seismicity from Hydraulic Fracturing in Eola Field, Garvin County, Oklahoma (Aug. 2011), at 1 (attached as Exhibit 91).

¹³⁴ *Id.*

¹³⁵ Jordan Steffen, *5.3 quake in Trinidad, Colo., area unnerves regions residents*, DENVER POST, August 24, 2011, available at: http://www.denverpost.com/news/ci_18744329.

¹³⁶ Mark E. Mermonte, et al., USGS, *Investigation of an Earthquake Swarm Near Trinidad, Colorado, August – October 2001* (2002), available at: <http://pubs.usgs.gov/of/2002/ofr-02-0073/ofr-02-0073.html> (attached as Exhibit 92).

¹³⁷ *Id.*

precautionary approach, here, through required stipulations are prudent and would help stem potential future impacts. At the very least, however, BLM must take a hard look at possible seismicity impacts from the proposed action.

g. Oil and Gas Best Management Practices

As identified herein, oil and gas development can result in serious impacts to the environment and human health. The technology used in oil and gas production has evolved rapidly but, unfortunately, regulation has not kept pace. The BLM's and New Mexico's current regulations are insufficient to protect public health and the environment. The use of Best Management Practices ("BMPs") can greatly reduce the risks presented by oil and gas development by incorporating processes and technologies that are readily available.

NEPA was enacted to promote efforts that will prevent or eliminate damage to the human environment. BMPs help "mitigate" environmental impacts. "Mitigation" is defined in CEQ regulations as measures to help, avoid, reduce or compensate for environmental impacts. 40 CFR 1508.20. BLM's failure to analyze the potential benefits of requiring these BMPs in alternatives does not satisfy NEPA's hard look mandate and frustrates the purpose of preparing an EIS. *See* 40 CFR 1502.1 (providing that the purpose of preparing an EIS is to "...provide full and fair discussion of significant environmental impacts and [] inform decisionmakers and the public of the reasonable alternatives which would avoid or minimize adverse impacts or enhance the quality of the human environment."). The FFO must analyze and implement the following BMPs in the RMPA, which are necessary to account for the inherent risks of development to resources in the planning area:

i. Site Characterization and Corrective Action

Detailed site characterization and planning and baseline testing prior to any oil and gas development are crucial. Site characterization and planning must take into account cumulative impacts over the life of a project or field.

1. Geologic Suitability

Operators of wells that will be hydraulically fractured must demonstrate to the satisfaction of the regulator that the wells will be sited in a location that is geologically suitable. In order to allow the regulator to determine suitability, the owner or operator must provide:

1. A detailed analysis of regional and local geologic stratigraphy and structure including, at a minimum, lithology, geologic facies, faults, fractures, stress regimes, seismicity, and rock mechanical properties;
2. A detailed analysis of regional and local hydrology including, at a minimum, hydrologic flow and transport data and modeling and aquifer hydrodynamics; properties of the producing and confining zone(s); groundwater levels for relevant formations; discharge points, including springs, seeps, streams, and wetlands; recharge rates and primary zones, and; water balance for the area including estimates of recharge, discharge, and pumping;

3. A detailed analysis of the cumulative impacts of hydraulic fracturing on the geology of producing and confining zone(s) over the life of the project. This must include, but is not limited to, analyses of changes to conductivity, porosity, as well as permeability, geochemistry, rock mechanical properties, hydrologic flow, and fracture mechanics; and
4. A determination that the geology of the area can be described confidently and that the fate and transport of injected fluids and displaced formation fluids can be accurately predicted through the use of models.

Wells that will be hydraulically fractured must be sited such that a suitable confining zone is present. The operator must demonstrate to the satisfaction of the regulator that the confining zone:

1. Is of sufficient areal extent to prevent the movement of fluids to USDWs, based on the projected lateral extent of hydraulically induced fractures, injected hydraulic fracturing fluids, and displaced formation fluids over the life of the project;
2. Is sufficiently impermeable to prevent the vertical migration of injected hydraulic fracturing fluids or displaced formation fluids over the life of the project;
3. Is free of transmissive faults or fractures that could allow the movement of injected hydraulic fracturing fluids or displaced formation fluids to USDWs;
4. Contains at least one formation of sufficient thickness and with lithologic and stress characteristics capable of preventing or arresting vertical propagation of fractures; and
5. The regulator may require operators of wells that will be hydraulically fractured to identify and characterize additional zones that will impede or contain vertical fluid movement.

2. Area of Review

Operators must delineate an “area of review,” which is the region around a well or group of wells that will be hydraulically fractured where USDWs may be endangered. It should be delineated based on 3D geologic and reservoir modeling that accounts for the physical and chemical extent of hydraulically induced fractures, injected hydraulic fracturing fluids and proppant, and displaced formation fluids and must be based on the life of the project. The physical extent would be defined by the modeled length and height of the fractures, horizontal and vertical penetration of hydraulic fracturing fluids and proppant, and horizontal and vertical extent of the displaced formation fluids. The chemical extent would be defined by that volume of rock in which chemical reactions between the formation, hydrocarbons, formation fluids, or injected fluids may occur, and should take into account potential migration of fluids over time. The model must take into account all relevant geologic and engineering information including but not limited to:

1. Rock mechanical properties, geochemistry of the producing and confining zone, and anticipated hydraulic fracturing pressures, rates, and volumes;
2. Geologic and engineering heterogeneities;
3. Potential for migration of injected and formation fluids through faults, fractures, and manmade penetrations; and
4. Cumulative impacts over the life of the project.

As actual data and measurements become available, the model must be updated and history matched. Operators must develop, submit, and implement a plan to delineate the area of review. The plan should include the time frame under which the delineation will be reevaluated, including those operational or monitoring conditions that would trigger such a reevaluation. Within the area of review, operators must identify all wells that penetrate the producing and confining zones and provide:

1. A list of all such wells, including but not limited to wells permitted but not yet drilled, drilling, awaiting completion, active, inactive, shut-in, temporarily abandoned, plugged, and orphaned;
2. A description of each well's type, construction, date drilled, location, depth, record of plugging and/or completion, and any additional information the Division may require;
3. An assessment of the integrity of each well identified;
4. A plan for performing corrective action if any of the wells identified are improperly plugged, completed, or abandoned;
5. An assessment to determine the risk that the stimulation treatment will communicate with each well identified;
6. For each well identified as at-risk for communication, a plan for well control, including but not limited to:
 - a. A method to monitor for communication;
 - b. A determination of the maximum pressure which the at-risk well can withstand;
 - c. Actions to maintain well control;
 - d. If the at-risk well is not owned or operated by the owner/operator of the well to be stimulated, a plan for coordinating with the offset well operator to prevent loss of well control;
7. The location, orientation, and properties of known or suspected faults, fractures, and joint sets;
8. An evaluation of whether such features may act as migration pathways for injected fluids or displaced formation fluids to reach protected water or the surface;
9. An assessment to determine the risk that the stimulation treatment will communicate with such features; and
10. If such features may act as migration pathways and are at-risk for communication, the stimulation design must be revised to ensure that the treatment will not communicate with such features or the well must be re-sited.

This information should be provided with the stimulation permit application. Communication between offset wells during stimulation is a serious problem, risking blowouts in adjacent wells and/or aquifer contamination during well stimulation. A New Mexico oil well recently experienced a blowout, resulting in a spill of more than 8,400 gallons of fracturing fluid, oil, and water. The blowout occurred when a nearby well was being hydraulically fractured and the fracturing fluids intersected this offset well.¹³⁸ The incident led the New Mexico Oil

¹³⁸ Tina Jensen, *Fracking fluid blows out nearby well; Cleanup costs, competing technologies at issue*, KASA.COM. (Oct. 18 2013).

Conservation Division to request information about other instances of communication between wells during drilling, completion, stimulation or production operations.¹³⁹ Incidents of communication between wells during stimulation have been documented in British Columbia¹⁴⁰, Pennsylvania,¹⁴¹ Texas, and other states across the country.¹⁴²

The Alberta Energy Regulator (“AER”), the oil and gas regulator in Alberta, Canada, recognized that communication between wells during fracturing is a serious risk to well integrity and groundwater after a number of spills and blowouts resulted from communication between wells during fracturing. As a result, AER created requirements to address the risk of communication and reduce the likelihood of occurrence.¹⁴³ Similarly, Enform, a Canadian oil and gas industry safety association, published recommended practices to manage the risk of communication.¹⁴⁴ We recommend that the BLM review these rules and incorporate similar requirements.

3. Baseline Water Testing

Operators must submit to the regulator a statistically significant sample, as determined by the regulator, of existing and/or new geochemical analyses of each of the following, within the area of review:

1. Any and all sources of water that serve as underground sources of drinking water (“USDWs”) in order to characterize baseline water quality. This data must be made publically available through an online, geographically-based reporting system. The

¹³⁹ State of New Mexico, Energy, Minerals and Natural Resources Department, *Aztec District III-Request for information*, n.p., (Oct. 22, 2013).

¹⁴⁰ “BC Oil and Gas Commission, *Safety Advisory 2010-03, May 20, 2010: Communication During Fracture Stimulation*, n.p. (May 20 2010).

¹⁴¹ See, e.g. Scott Detrow, *Perilous Pathways: How Drilling Near An Abandoned Well Produced a Methane Geyser*, State Impact Pennsylvania, NPR (October 9, 2012); Pennsylvania Department of Environmental Protection, Bureau of Oil and Gas Management, *Draft Report - Stray Natural Gas Migration Associated with Oil and Gas Wells* (October 28, 2009).

¹⁴² Gayathri Vaidyanathan, *When 2 wells meet, spills can often follow*, ENERGYWIRE (Aug. 5, 2013).

¹⁴³ Alberta Energy Board, *Directive 083: Hydraulic Fracturing – Subsurface Integrity* (May 2013) at 15, available at: <http://www.aer.ca/documents/directives/Directive083.pdf> (attached as Exhibit 162).

¹⁴⁴ Enform Canada, *Interim IRP 24: Fracture Stimulation: Interwellbore Communication; An Industry Recommended Practice For The Canadian Oil And Gas Industry*, Interim Volume 24, 1st Edition (Mar. 27, 2013).

sampling methodology must be based on local and regional hydrologic characteristics such as rates of precipitation and recharge and seasonal fluctuations. At a minimum, characterization must include:

- a. Standard water quality and geochemistry;¹⁴⁵
- b. Stable isotopes;
- c. Dissolved gases;
- d. Hydrocarbon concentration and composition. If hydrocarbons are present in sufficient quantities for analysis, isotopic composition must be determined;
- e. Chemical compounds or constituents thereof, or reaction products that may be introduced by the drilling or hydraulic fracturing process. The use of appropriate marker chemicals is permissible provided that the operator can show scientific justification for the choice of marker(s);

Operators should also consider testing for environmental tracers to determine groundwater age;

2. Any hydrocarbons that may be encountered both vertically and really throughout the area of review;
3. The producing zone(s) and confining zone(s) and any other intervening zones as determined by the regulator. At a minimum, characterization must include:
 - a. Mineralogy;
 - b. Petrology; and
 - c. Major and trace element bulk geochemistry.

The site characterization and planning data listed above does not have to be submitted with each individual well application as long as such data is kept on file with the appropriate regulator and the well for which a permit is being sought falls within the designated area of review.

ii. Water Use and Disposal Planning

Operators must submit to the regulator a plan for cumulative water use over the life of the project. The plan should take into account other activities that will draw water from the same sources, such as agricultural or industrial activities; designated best use; seasonal and longer timescale variations in water availability; and historical drought information. Elements of the plan must include but are not limited to:

¹⁴⁵ Including: Turbidity, Specific Conductance, Total Solids, Total Dissolved Solids, pH, Dissolved Oxygen, Redox State, Alkalinity, Calcium, Magnesium, Sodium, Potassium, Sulfate, Chloride, Fluoride, Bromide, Silica, Nitrite, Nitrate + Nitrite, Ammonia, Phosphorous, Total Organic Carbon, Aluminum, Antimony, Arsenic, Barium, Beryllium, Boron, Bromide, Cadmium, Chromium, Cobalt, Copper, Cyanide, Iron, Lead, Manganese, Mercury, Molybdenum, Nickel, Selenium, Silver, Strontium, Thallium, Thorium, Uranium, Vanadium, Zinc, Cryptosporidium, Giardia, Plate Count, Legionella, Total Coliforms, and Organic Chemicals including Volatile Organic Compounds (VOCs).

1. The anticipated source, timing, and volume of withdrawals and intended use;
2. Anticipated transport distances and methods (e.g. pipeline, truck) and methods to minimize related impacts including, but not limited to: land disturbance, traffic, vehicle accidents, and air pollution;
3. Anticipated on-site storage methods;
4. A description of methods the operator will use to maximize the use of non-potable water sources including reuse and recycling of wastewater;
5. An evaluation of potential adverse impacts to aquatic species and habitat, wetlands, and aquifers, including the potential for the introduction of invasive species, and methods to minimize those impacts; and
6. Anticipated chemical additives and chemical composition of produced water, with particular attention to those chemicals that would hinder the reuse or recycling of wastewater or pose a challenge to wastewater treatment.

Operators must submit to the regulator a proposed plan for handling wastewater, such as flowback and produced fluids. Elements of the plan must include, but are not limited to:

1. Anticipated cumulative volumes of wastewater over the life of the project, reported in three categories: reuse, recycle, and disposal;
2. Anticipated on-site temporary storage methods;
3. Anticipated transport distances and methods (e.g. pipeline, truck) and methods to minimize related impacts including, but not limited to: land disturbance, traffic, vehicle accidents, and air pollution; and
4. An assessment of currently available and anticipated disposal methods, *e.g.* disposal wells, wastewater treatment facilities, etc. This assessment must enumerate the disposal options available and evaluate the ability of those options to handle projected wastewater volumes. In the case of wastewater treatment facilities, the assessment must also evaluate the ability of those facilities to successfully treat the wastewater such that it would not pose a threat to water supplies into which it is discharged.

iii. Well Design and Construction

Proper well construction is crucial to ensuring protection of USDWs. The first step to ensuring good well construction is ensuring proper well drilling techniques are used. This includes appropriate drilling fluid selection, to ensure that the wellbore will be properly conditioned and to minimize borehole breakouts and rugosity that may complicate casing and cementing operations. Geologic, engineering, and drilling data can provide indications of potential complications to achieving good well construction, such as highly porous or fractured intervals, lost circulation events, abnormally pressured zones, or drilling “kicks” or “shows.” These must be accounted for in designing and implementing the casing and cementing program. Reviewing data from offset wellbores can be helpful in anticipating and mitigating potential drilling and construction problems. Additionally, proper wellbore cleaning and conditioning techniques must be used to remove drilling mud and ensure good cement placement. Hydraulic fracturing requires fluid to be injected into the well at high pressure and, therefore, wells must be appropriately designed and constructed to withstand this pressure. The casing and cementing program must:

- Properly control formation pressures and fluids;
- Prevent the direct or indirect release of fluids from any stratum to the surface;
- Prevent communication between separate hydrocarbon-bearing strata;
- Protect freshwater aquifers/useable water from contamination;
- Support unconsolidated sediments;
- Protect and/or isolate lost circulation zones, abnormally pressured zones, and any prospectively valuable mineral deposits.

Casing must be designed to withstand the anticipated stresses imposed by tensile, compressive, and buckling loads; burst and collapse pressures; thermal effects; corrosion; erosion; and hydraulic fracturing pressure. The casing design must include safety measures that ensure well control during drilling and completion and safe operations during the life of the well. The components of a well that ensure the protection and isolation of USDWs are steel casing and cement. Multiple strings of casing are used in the construction of oil and gas wells, including: conductor casing, surface casing, production casing, and potentially intermediate casing. For all casing strings, the design and construction should be based on Good Engineering Practices (“GEP”), Best Available Technology (“BAT”), and local and regional engineering and geologic data. All well construction materials must be compatible with fluids with which they may come into contact and be resistant to corrosion, erosion, swelling, or degradation that may result from such contact.

1. Conductor Casing

Depending on local conditions, conductor casing can either be driven into the ground, or a hole drilled and the casing lowered into the hole. In the case where a hole is excavated, the space between the casing and the wellbore – the annulus – should be cemented to surface. A cement pad should also be constructed around the conductor casing to prevent the downward migration of fluids and contaminants.

2. Surface Casing

Surface casing setting depth must be based on relevant engineering and geologic factors, but be shallower than any hydrocarbon-bearing zones, and at least 100 feet but not more than 200 feet below the deepest protected water. If shallow hydrocarbon-bearing zones are encountered when drilling the surface casing portion of the hole, operators must notify regulators and take appropriate steps to ensure protection of protected water.

Surface casing must be fully cemented to surface by the pump and plug method. If cement returns are not observed at the surface, remedial cementing must be performed to cement the casing from the top of cement to the ground surface.

3. Intermediate Casing

Depending on local geologic and engineering factors, one or more strings of intermediate casing may be required. This will depend on factors including, but not limited to: the depth of the well, the presence of hydrocarbon-or fluid-bearing formations, abnormally pressured zones, lost

circulation zones, or other drilling hazards. Casing setting depth must be based on local engineering and geologic factors and be set at least 100 feet below the deepest protected water, anomalous pressure zones, lost circulation zones, and other drilling hazards. Intermediate casing must be set to protect groundwater if surface casing was set above the base of protected water, and/or if additional protected water was found below the surface casing shoe.

When intermediate casing is installed to protect groundwater, the operator shall set a full string of new intermediate casing to a minimum depth of at least 100 feet below the base of the deepest strata containing protected water and cement to the surface. The location and depths of any hydrocarbon strata or protected water strata that is open to the wellbore above the casing shoe must be confirmed by coring, electric logs, or testing, and shall be reported as part of the completion report.

When intermediate casing is set for a reason other than to protect strata that contain protected water, it must be fully cemented to surface unless doing so would result in lost circulation. Where this is not possible or practical, the cement must extend from the casing shoe to 600 feet above the top of the shallowest zone to be isolated (*e.g.* productive zone, abnormally pressured zone, etc). Where the distance between the casing shoe and shallowest zone to be isolated makes this technically infeasible, multi-stage cementing must be used to isolate any hydrocarbon or fluid-bearing formations or abnormally pressured zones and prevent the movement of fluids. An excess of 25% cement should be mixed unless a caliper log is run to more accurately determine necessary cement volume.

4. Production Casing

If both surface casing and intermediate casing are used as water protection casing, or if intermediate casing is not used, a full string of production casing is required. A production liner may be hung from the base of the intermediate casing and used as production casing as long as the surface casing is used as the water protecting casing, and intermediate casing is set for a reason other than isolation of protected water. When the production string does not extend to the surface, at least 200 feet of overlap between the production string and next larger casing string should be required. This overlap should be cemented and tested by a fluid-entry test at a pressure that is at least 500 psi higher than the maximum anticipated pressure to be encountered by the wellbore during completion and production operations to determine whether there is a competent seal between the two casing strings.

When intermediate casing is not used, production casing must be fully cemented to surface unless doing so would result in lost circulation. If not cemented to the surface, production casing shall be cemented with sufficient cement to fill the annular space from the casing shoe to at least 600 feet above fluid-bearing formations, lost circulation zones, oil and gas zones, anomalous pressure intervals, or other drilling hazards. Where the distance between the casing shoe and shallowest zone to be isolated makes this technically infeasible, multi-stage cementing must be used to isolate any hydrocarbon or fluid-bearing formations or abnormally pressured zones and prevent the movement of fluids. Sufficient cement shall also be used to fill the annular space to at least 100 feet above the base of the freshwater zone, either by lifting

cement around the casing shoe or cementing through perforations or a cementing device placed at or below the base of the freshwater zone.

5. General

For surface, intermediate, and production casing, at a minimum, centralizers are required at the top, shoe, above and below a stage collar or diverting tool (if used), and through all protected water zones. In non-deviated holes, a centralizer shall be placed every fourth joint from the cement shoe to the ground surface or to within one joint of casing from the bottom of the cellar, or casing shall be centralized by implementing an alternative centralization plan approved by the BLM. In deviated holes, the BLM may require the operator to provide additional centralization. All centralizers must meet API Spec 10D (Recommended Practice for Casing Centralizers – for bow string centralizers), or API Spec 10 TR4 (rigid and solid centralizers) and 10D-2 (Petroleum and Natural Gas Industries, Equipment for Well Cementing, Part 2, Centralizer Placement and Stop Collar Testing).

All cemented casing strings must have a uniformly concentric cement sheath of at least 1" (*i.e.* minimum difference of 2" between wellbore diameter and casing outside diameter). An excess of 25% cement should be mixed unless a caliper log is run to more accurately determine necessary cement volume.

For any section of the well drilled through fresh water-bearing formations, drilling fluids must be limited to air, fresh water, or fresh water based mud, and exclude the use of synthetic or oil-based mud or other chemicals.

In areas where the depth to the lowest protected water is not known, operators must estimate this depth and provide the estimate with the application for a permit to drill. This depth should then be verified by running petrophysical logs, such as resistivity logs, after drilling to the estimated depth. If the depth to the deepest protected water is deeper than estimated, an additional string of casing is required. Surface casing must be of sufficient diameter to allow the use of one or more strings of intermediate casing. All instances of protected water not anticipated on the permit application must be reported, including the formation depth and thickness and water flow rate, if known or estimated.

All cement must have a 72-hour compressive strength of at least 1200 psi and free water separation of no more than two milliliters per 250 milliliters of cement, tested in accordance with the current API RP 10B. Cement must conform to API Specification 10A and gas-blocking additives must be used. Cement mix water chemistry must be proper for the cement slurry designs. At a minimum, the water chemistry of the mix water must be tested for pH prior to use, and the cement must be mixed to manufacturer's recommendations. An operator's representative must be on site verifying that the cement mixing, testing, and quality control procedures used for the entire duration of the cement mixing and placement are consistent with the approved engineered design and meet the cement manufacturer recommendations, API standards, and the requirements of this section.

Compressive strength tests of cement mixtures without published performance data must be performed in accordance with the current API RP 10B and the results of these tests must be provided to the regulator prior to the cementing operation. The test temperature must be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of cement. A better quality of cement may be required where local conditions make it necessary to prevent pollution or provide safer operating conditions.

Prior to cementing, the hole must be prepared to ensure an adequate cement bond by circulating at least two hole volumes of drilling fluid and ensuring that the well is static and all gas flows are killed. Top and bottom wiper plugs and spacer fluids must be used to separate drilling fluid from cement and prevent cement contamination. Casing must be rotated and reciprocated during cementing when possible and when doing so would not present a safety risk. Cement should be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus. During placement of the cement, operator shall monitor pump rates to verify they are within design parameters to ensure proper displacement efficiency. Throughout the cementing process operator shall monitor cement mixing in accordance with cement design and cement densities during the mixing and pumping.

All surface, intermediate, and production casing strings must stand under pressure until a compressive strength of 500 psi is reached before drilling out, initiating testing, or disturbing the cement in any way. In no case should the wait-on-cement (“WOC”) time be less than 8-hours. All surface, intermediate, and production casing strings must be pressure tested. Drilling may not be resumed until a satisfactory pressure test is obtained. Casing must be pressure tested to a minimum of 0.5 psi/foot of casing string length or 1500 psi, whichever is greater, but not to exceed 80% of the minimum internal yield. If the pressure declines more than 10% in a 30-minute test or if there are other indications of a leak, corrective action must be taken.

A formation integrity test (“FIT”) must be performed immediately after drilling out of all surface and intermediate casing. The test should demonstrate that the casing shoe will maintain integrity at the anticipated pressure to which it will be subjected while drilling the next section of the well, no flow path exists to formations above the casing shoe, and that the casing shoe is competent to handle an influx of formation fluid or gas without breaking down. If any FIT fails, the operator must contact the BLM and remedial action must be taken to ensure that no migration pathways exist. The casing and cementing plan may need to be revised to include additional casing strings in order to properly manage pressure.

Cement integrity and location must be verified using cement evaluation tools that can detect channeling in 360 degrees. If fluid returns, lift pressure, displacement and/or other operations indicate inadequate cement coverage, the operator must: (i) run a radial cement evaluation tool, a temperature survey, or other test approved by the Division to identify the top of cement; (ii) submit a plan for remedial cementing to the Division for approval; and (iii) implement such plan by performing additional cementing operations to remedy such inadequate coverage prior to continuing drilling operations. Cement evaluation logging must be performed on all strings of cemented casing that isolate protected water, potential flow zones, or through which stimulation will be performed.

When well construction is completed, the operator should certify, in writing, that the casing and cementing requirements were met for each casing string.

iv. Well Logs

After drilling the well but prior to casing and cementing operations, operators must obtain well logs to aid in the geologic, hydrologic, and engineer characterization of the subsurface. Open hole logs, *i.e.* logs run prior to installing casing and cement, should at a minimum include:

Gamma Ray Logs:

Gamma ray logs detect naturally occurring radiation. These logs are commonly used to determine generic lithology and to correlate subsurface formations. Shale formations have higher proportions of naturally radioactive isotopes than sandstone and carbonate formations. Thus, these formations can be distinguished in the subsurface using gamma ray logs.

Density/Porosity Logs:

Two types of density logs are commonly used: bulk density logs, which are in turn used to calculate density porosity, and neutron porosity logs. While not a direct measure of porosity, these logs can be used to calculate porosity when the formation lithology is known. These logs can be used to determine whether the pore space in the rock is filled with gas or with water.

Resistivity Logs:

These logs are used to measure the electric resistivity, or conversely conductivity, of the formation. Hydrocarbon and fresh water-bearing formations are resistive, *i.e.* they cannot carry an electric current. Brine-bearing formations have a low resistivity, *i.e.* they can carry an electric current. Resistivity logs can therefore be used to help distinguish brine-bearing from hydrocarbon-bearing formations. In combination with Darcy's Law, resistivity logs can be used to calculate water saturation.

Caliper Logs:

Caliper logs are used to determine the diameter and shape of the wellbore. These are crucial in determining the volume of cement that must be used to ensure proper cement placement.

These four logs, run in combination, make up one of the most commonly used logging suites. Additional logs may be desirable to further characterize the formation, including but not limited to Photoelectric Effect, Sonic, Temperature, Spontaneous Potential, Formation Micro-Imaging ("FMI"), Borehole Seismic, and Nuclear Magnetic Resonance ("NMR"). The use of these and other logs should be tailored to site-specific needs.

v. Core and Fluid Sampling

Operators of wells that will be hydraulically fractured should also obtain whole or sidewall cores of the producing and confining zone(s) and formation fluid samples from the producing zone(s). At a minimum, routine core analysis should be performed on core samples representative of the range of lithology and facies present in the producing and confining

zone(s). Special Core Analysis (“SCAL”) should also be considered, particularly for samples of the confining zone, where detailed knowledge of rock mechanical properties is necessary to determine whether the confining zone can prevent or arrest the propagation of fractures. Operators should also record the fluid temperature, pH, conductivity, reservoir pressure and static fluid level of the producing and confining zone(s). Operators should prepare and submit a detailed report on the physical and chemical characteristics of the producing and confining zone(s) and formation fluids that integrates data obtained from well logs, cores, and fluid samples. This must include the fracture pressure of both the producing and confining zone(s). This data does not need to be gathered for every well but operators should obtain a statistically significant number of samples.

vi. Mechanical Integrity

Operators must maintain mechanical integrity of wells at all times. Mechanical integrity should be periodically tested by means of a pressure test with liquid or gas, a tracer survey such as oxygen activation logging or radioactive tracers, a temperature or noise log, and a casing inspection log. The frequency of such testing should be based on-site, with operation specific requirements and be delineated in a testing and monitoring plan prepared, submitted, and implemented by the operator.

Mechanical integrity and annular pressure should be monitored over the life of the well. Instances of sustained casing pressure can indicate potential mechanical integrity issues. The annulus between the production casing and tubing (if used) should be continually monitored. Continuous monitoring allows problems to be identified quickly so repairs may be made in a timely manner, reducing the risk that a wellbore problem will result in contamination of USDWs.

vii. Operations and Monitoring

Each hydraulic fracturing treatment must be modeled using a 3D geologic and reservoir model, as described in the Area of Review requirements, prior to operation to ensure that the treatment will not endanger USDWs. Prior to performing a hydraulic fracturing treatment, operators should perform a pressure fall-off or pump test, injectivity tests, and/or a mini-frac. Data obtained from such tests can be used to refine the hydraulic fracture model, design, and implementation.

Prior to well stimulation, all casing and tubing to be used by the operator to perform the stimulation treatment must be pressure tested. For cemented completions, the test pressure must be at least 500 psi greater than the anticipated maximum surface pressure to be experienced during the stimulation operation or the life of the completion operation. For non-cemented completions, the test pressure must be a minimum of: (i) 70% of the lowest activating pressure for pressure actuated sleeve completions; or (ii) 70% of formation integrity for open-hole completions, as determined by a formation integrity test. A failed test is one in which the pressure declines more than 10% in a 30-minute test or if there are other indications of a leak.

In the event of a failed test, the operator must:

1. Orally notify the authorized officer as soon as practicable but no later than 24 hours following the failed test, and;
2. Perform remedial work to restore mechanical integrity.

Stimulation operations may not begin until a successful mechanical integrity test is performed and the results are submitted to the regulator. If mechanical integrity cannot be restored, the well must be plugged and abandoned.

During the well stimulation operation, the operator must continuously monitor and record the pressures in each well annuli, surface injection pressure, slurry rate, proppant concentration, fluid rate, and the identities, rates, and concentrations of all additives (including proppant).

If during any stimulation operation the annulus pressure:

1. increases by more than 500 pounds per square inch as compared to the pressure immediately preceding the stimulation; or
2. exceeds 80% of the API rated minimum internal yield on any casing string in communication with the stimulation treatment;

the operation must immediately cease, and the operator must take immediate corrective action and orally notify the authorized officer immediately following the incident. Within one week after the stimulation operations are completed, the operator must submit a report containing all details pertaining to the incident, including corrective actions taken.

If at any point during the hydraulic fracturing operation the monitored parameters indicate a loss of mechanical integrity or if injection pressure exceeds the fracture pressure of the confining zone(s), the operation must immediately cease. If either occurs, the operator must notify the regulator within 24 hours and must take all necessary steps to determine the presence or absence of a leak or migration pathways to USDWs. Prior to any further operations, mechanical integrity must be restored and demonstrated to the satisfaction of the regulator and the operator must demonstrate that the ability of the confining zone(s) to prevent the movement of fluids to USDWs has not been compromised. If a loss of mechanical integrity is discovered or if the integrity of the confining zone has been compromised, operators must take all necessary steps to evaluate whether injected fluids or formation fluids may have contaminated or have the potential to contaminate any unauthorized zones. If such an assessment indicates that fluids may have been released into a USDW or any unauthorized zone, operators must notify the regulator within 24 hours, take all necessary steps to characterize the nature and extent of the release, and comply with and implement a remediation plan approved by the regulator. If such contamination occurs in a USDW that serves as a water supply, a notification must be placed in a newspaper available to the potentially affected population and on a publically accessible website and all known users of the water supply must be individually notified immediately by mail and by phone.

The use of diesel fuel and related products, BTEX compounds, and 2-BE in well stimulation fluids should be prohibited.

Techniques to measure actual fracture growth should be used, including downhole tiltmeters and microseismic monitoring. These techniques can provide both real-time data and, after data processing and interpretation, can be used in post-fracture analysis to inform fracture models and refine hydraulic fracture design. Tiltmeters measure small changes in inclination and provide a measure of rock deformation. Microseismic monitoring uses highly sensitive seismic receivers to measure the very low energy seismic activity generated by hydraulic fracturing.

Hydraulic fracturing fluid and proppant can sometimes be preferentially taken up by certain intervals or perforations. Tracer surveys and temperature logs can be used to help determine which intervals were treated. Tracers can be either chemical or radioactive and are injected during the hydraulic fracturing operation. After hydraulic fracturing is completed, tools are inserted into the well that can detect the tracer(s). Temperature logs record the differences in temperature between zones that received fracturing fluid, which is injected at ambient surface air temperature, and in-situ formation temperatures, which can be in the hundreds of degrees Fahrenheit.

Operators should develop, submit, and implement a long-term groundwater quality monitoring program. Dedicated water quality monitoring wells should be used to help detect the presence of contaminants prior to their reaching domestic water wells. Placement of such wells should be based on detailed hydrologic flow models and the distribution and number of hydrocarbon wells. Baseline monitoring should begin at least a full year prior to any activity, with monthly or quarterly sampling to characterize seasonal variations in water chemistry. Monitoring should continue a minimum of 5 years prior to plugging and abandonment.

viii. Reporting

At a minimum, operators must report:

- All instances of hydraulic fracturing injection pressure exceeding operating parameters as specified in the permit;
- All instances of an indication of loss of mechanical integrity;
- Any failure to maintain mechanical integrity;
- The results of:
 - Continuous monitoring during hydraulic fracturing operations;
 - Techniques used to measure actual fracture growth; and
 - Any mechanical integrity tests;
- The detection of the presence of contaminants pursuant to the groundwater quality monitoring program;
- Indications that injected fluids or displaced formation fluids may pose a danger to USDWs;
- All spills and leaks; and
- Any non-compliance with a permit condition.

The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a minimum of 30 days prior to a hydraulic fracturing operation:

1. Baseline water quality analyses for all USDWs within the area of review;
2. Proposed source, volume, geochemistry, and timing of withdrawal of all base fluids; and
3. Proposed chemical additives (including proppant coating), reported by their type, chemical compound or constituents, and Chemical Abstracts Service (“CAS”) number, and the proposed concentration or rate and volume percentage of all additives.

The following must be made publically available on a well-by-well basis through an online, geographically based reporting system, a maximum of 30 days subsequent to a hydraulic fracturing operation:

1. Actual source, volume, geochemistry and timing of withdrawal of all base fluids;
2. Actual chemical additives used, reported by their type, chemical compound or constituents, CAS number, and the actual concentration or rate and volume percentage of all additives; and
3. Geochemical analysis of flowback and produced water, with samples taken at appropriate intervals to determine changes in chemical composition with time and sampled until such time as chemical composition stabilizes.

ix. Emergency and Remedial Response

Operators must develop, submit, and implement an emergency response and remedial action plan. The plan must describe the actions the operator will take in response to any emergency that may endanger human life or the environment – including USDWs – such as blowouts, fires, explosions, or leaks and spills of toxic or hazardous chemicals. The plan must include an evaluation of the ability of local resources to respond to such emergencies and, if found insufficient, how emergency response personnel and equipment will be supplemented. Operators should detail what steps they will take to respond to cases of suspected or known water contamination, including notification of users of the water source. The plan must describe what actions will be taken to replace the water supplies of affected individuals in the case of the contamination of a USDW.

x. Plugging and Abandonment

Prior to plugging and abandoning a well, operators should determine bottom hole pressure and perform a mechanical integrity test to verify that no remedial action is required. Operators should develop and implement a well plugging plan. The plugging plan should be submitted with the permit application and should include the methods that will be used to: determine bottom hole pressure and mechanical integrity; the number and type of plugs that will be used; plug setting depths; the type, grade, and quantity of plugging material that will be used; the method for setting the plugs; and, a complete wellbore diagram showing all casing setting depths and the location of cement and any perforations.

Plugging procedures must ensure that hydrocarbons and fluids will not migrate between zones, into USDWs, or to the surface. A cement plug should be placed at the surface casing shoe and extend at least 100 feet above and below the shoe. All hydrocarbon-bearing zones should be permanently sealed with a plug that extends at least 100 feet above and below the top and base of

all hydrocarbon-bearing zones. Plugging of a well must include effective segregation of uncased and cased portions of the wellbore to prevent vertical movement of fluid within the wellbore. A continuous cement plug must be placed from at least 100 feet below to 100 feet above the casing shoe. In the case of an open hole completion, any hydrocarbon or fluid-bearing zones shall be isolated by cement plugs set at the top and bottom of such formations, and that extend at least 100 feet above the top and 100 feet below the bottom of the formation.

At least 60-days prior to plugging, operators must submit a notice of intent to plug and abandon. If any changes have been made to the previously approved plugging plan the operator must also submit a revised plugging plan. No later than 60-days after a plugging operation has been completed, operators must submit a plugging report, certified by the operator and person who performed the plugging operation.

After plugging and abandonment, operators must continue to conduct monitoring and provide financial assurance for an adequate time period, as determined by the regulator, that takes into account site-specific characteristics including but not limited to:

- The results of hydrologic and reservoir modeling that assess the potential for movement of contaminants into USDWs over long time scales; and
- Models and data that assess the potential degradation of well components (e.g. casing, cement) over time and implications for mechanical integrity and risks to USDWs.

D. The BLM Must Take a “Hard Look” at Impacts to Water Resources.

a. Groundwater Impacts

The oil and gas development authorized through the RMPA/EIS could result in significant potential to contaminate groundwater resources in the planning area. Such contamination may result during the following processes: (1) the state of chemical mixing due to spills, leaks, and transportation accidents; (2) during the fracking process due to well malfunctions, migration of fracking fluids or fluids from the fractured formation to aquifers, and mobilization of subsurface materials to aquifers; (3) during flowback due to releases, leakage of on-site storage, and spills from pits (caused by improper construction, maintenance, or closure); and (4) during wastewater disposal due to discharges of wastewater into groundwater, incomplete treatment, and transportation accidents.¹⁴⁶ Fracking chemicals and wastewater may also contaminate groundwater supplies as a result of illegal dumping.¹⁴⁷ As further discussed below, not all chemical used in fracking have been fully disclosed, but many of those that have been disclosed or discovered are toxic, hazardous, or harmful to human health or welfare.

¹⁴⁶ See U.S. Environmental Protection Agency, *Draft Plan to Study the Potential Impacts of Hydraulic Fracturing on Drinking Water Resources* (Feb. 2011) (attached as Exhibit 110).

¹⁴⁷ Nicholas Kusnetz, *North Dakota’s Oil Boom Brings Damage Along with Prosperity*, PROPUBLICA, July 7, 2012, available at: <http://www.propublica.org/article/the-other-fracking-north-dakotas-oil-boom-brings-damage-along-with-prosperi#>.

Despite a general lack of adequate oversight of fracking operations, various instances of water pollution from fracking operations have been documented.¹⁴⁸

Groundwater contamination is among the most serious and consequential impacts of the oil and gas drilling industry, especially where hydraulic fracturing (“fracking”) is anticipated, as discussed above. Due to the existing and projected application of fracking to virtually all oil and gas recovery within the Mancos Shale planning area, careful impact analysis within the RMPA/EIS is critical to ensure the agency’s decision-making is reflective of these new environmental challenges.

Evidence of groundwater contamination from oil and gas operations must be fully analyzed in the RMPA/EIS. For example, based on the Denver Post account of the Windsor, Colorado spill, mentioned further below, the company responsible for that spill, PDC, reported *two other* spills near Greeley within weeks of the Windsor incident. Both spills contaminated groundwater, according to a state database of spills. A January 22, 2013 spill by PDC released 2,880 gallons of oil and covered 3,900 square feet, leaving groundwater contaminated with benzene at a concentration 128 times higher than the state limit along with toluene and xylene chemicals. About 17 percent of 2,078 oil and gas spills that companies reported in Colorado since January 2008 have contaminated groundwater. Fracking wastewater is one of the most common substances spilled.¹⁴⁹

BLM must also consider the potential fracking impacts to groundwater from existing models. For example, *see* T. Myers, *Potential Contaminant Pathways from Hydraulically Fractured Shale to Aquifers*, GROUND WATER (April 17, 2012) (attached as Exhibit 153):

Fracking can release fluids and contaminants from the shale either by changing the shale and overburden hydrogeology or simply by the injected fluid forcing other fluids out of the shale. The complexities of contaminant transport from hydraulically fractured shale to near- surface aquifers render estimates uncertain, but a range of interpretative simulations suggest that transport times could be decreased from geologic time scales to as few as tens of years. Preferential flow through natural fractures fracking-induced fractures could further decrease the travel times to as little as just a few years. *Id.* at 9.

And see, N.R. Warner, *Geochemical evidence for possible natural migration of Marcellus Formation brine to shallow aquifers in Pennsylvania*, PROCEEDINGS OF THE NATIONAL ACADEMY OF SCIENCES, vol. 109, iss. 30. (July 9, 2012) (attached as Exhibit 154):

¹⁴⁸ *See, e.g., id.* (reporting on lack of oversight); Western Organization of Resource Councils, *Gone for Good: Fracking and Water Loss in the West* (2013) at 17-18, 31 (attached as Exhibit 111) (noting lack of state oversight).

¹⁴⁹ *See* Bruce Finely, *Water fouled with fracking chemicals spews near Windsor*, THE DENVER POST (Feb. 14, 2013), available at: http://www.denverpost.com/ci_22586154/water-fouled-fracking-chemicals-spews-near-windsor#ixzz2zpeQUnhK (attached as Exhibit 150).

This study shows that some areas of elevated salinity with type D composition in NE PA were present prior to shale-gas development and most likely are unrelated to the most recent shale gas drilling; however, the coincidence of elevated salinity in shallow groundwater with a geochemical signature similar to produced water from the Marcellus Formation suggests that these areas could be at greater risk of contamination from shale gas development because of a preexisting network of cross-formational pathways that has enhanced hydraulic connectivity to deeper geological formations. *Id.* at 5.

But BLM consistently asserted that there are no documented linkages between hydraulic fracturing and water wells. This overlooks the studies that link the two, and BLM must recognize these and analyze these risks and impacts in the RMPA/EIS. In addition to the studies cited in Conservation Groups' comments, *see, e.g.,* S.G. Osborn, *et al., Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing*, PROCEEDINGS OF THE NATIONAL ACADEMY OF SCIENCES, vol. 108, iss. 20. (May 17, 2011) (attached as Exhibit 155):

Methane concentrations were detected generally in 51 of 60 drinking-water wells (85%) across the region, regardless of gas industry operations, but concentrations were substantially higher closer to natural-gas wells. Methane concentrations were 17-times higher on average in shallow wells from active drilling and extraction areas than in wells from non-active areas. *Id.* at 8173.

Although dissolved methane in drinking water is not currently classified as a health hazard for ingestion, it is an asphyxiant in enclosed spaces and an explosion and fire hazard. *Id.* at 8173.

More research is also needed on the mechanism of methane contamination, the potential health consequences of methane, and establishment of baseline methane data in other locations. *Id.* at 8176.

In addition, *see also*, U.S. EPA, Draft Report, *Investigation of ground water contamination near Pavillion, Wyoming* (December 2011) (attached above as Exhibit 87):

The presence of synthetic compounds such as glycol ethers, along with enrichments in K, Cl, pH, and the assortment of other organic components is explained as the result of direct mixing of hydraulic fracturing fluids with ground water in the Pavillion gas field. *Id.* at 27.

And, *see also*, U.S. EPA, Report to Congress, *Management of wastes from the exploration, development, and production of crude oil, natural gas and geothermal energy*. Vol. 1. (December 1987) (attached as Exhibit 156):

During the fracturing process, fractures can be produced, allowing migration of native brine, fracturing fluid, and hydrocarbons from the oil or gas well to a nearby water well. When this happens, the water well can be permanently damaged and new well must be drilled or an alternative source of drinking water found. *Id.* at IV-22.

In 1982, Kaiser Gas Co. drilled a gas well on the property of Mr. James Parsons. The well was fractured using a typical fracturing fluid or gel. The residual fracturing fluid migrated into Mr. Parson's water well (which was drilled to a depth of 416 feet), according to an analysis by the West Virginia Environmental Health Services Lab of well water samples taken from the property. Dark and light gelatinous material (fracturing fluid) was found, along with white fibers. (The gas well is located less than 1,000 feet from the water well.) The chief of the laboratory advised that the water well was contaminated and unfit for domestic use, and that an alternative source of domestic water had to be found. *Id.* at IV-22.

Moreover, one of the most significant risks of water resources contamination results from pit impoundments. New Mexico acknowledged the risks to groundwater quality associated with fluid waste when the state's Oil Conservation Division ("OCD") signed the Oil and Gas Waste Pit Rule in 2008. The rule was a response to the thousands of documented cases of groundwater contamination recorded by the OCD's Environmental Bureau,¹⁵⁰ and the nearly 400 that were directly associated with oil and gas waste pits.¹⁵¹

At a minimum, the RMPA/EIS should include alternatives that contain stipulations and COAs that mirror the protections afforded by the original Pit Rule, not the 2013 revised pit rule which rolls back many of the key protections. These protections include adequate livestock fencing around the pit, wildlife netting above the pit, increased requirements for liner integrity, requirements for leak detection systems, and a prohibition of siting pits within 50 feet of groundwater, among others.

However, in many cases, 2008 Pit Rule provisions are not sufficient and closed-loop drilling systems are preferable. In all alternatives of the EIS, BLM should require that *all* future APDs include the following analysis. Where pits are preferable, they should be constructed under the 2008 Pit Rule provisions:

- BLM should consider total surface disturbance as a key factor in determining whether or not pits should be allowed.
- As part of the APD process, BLM should require applicants to submit carbon emissions estimates under pit and closed loop scenarios. These estimates should include emissions associated with pit construction, fluid waste trucking requirements, and solid waste trucking requirements.

¹⁵⁰ See Earthworks, *New Mexico Pit Rule*, available at: http://www.earthworksaction.org/issues/detail/new_mexico_pit_rule#.U3pUvK1dVy4.

¹⁵¹ See New Mexico, Energy Minerals and Natural Resources Department, available at: http://www.emnrd.state.nm.us/oed/documents/GW_Impact_updTbl_000.xls (identifying contamination associated with oil and gas waste pits).

- All other impacts being equal, BLM should place emphasis on the least-polluting method of development.
- Should a pit be allowed, BLM should require that solid waste collected after evaporation report only to hazardous waste treatment centers or repositories, not municipal landfills.

BLM should make all these analyses publicly available on a per-well basis, as mandated by the RMPA. This information should be posted online where it is easy to navigate by affected stakeholders. The public should be allowed to comment on an APD and BLM should allow for legal protests to any APD.

Other fluid waste management issues include:

- Water consumption: through stipulations and COAs, BLM should require process and flowback water recycling to the maximum extent practicable to reduce freshwater consumption and reduce carbon emissions associated with trucking of fluid waste to injection wells. BLM should require operators to disclose freshwater requirements on a per-well basis, and the data should be publicly available.
- Given the amount of toxins associated with fracking flowback and process water,¹⁵² BLM should require full disclosure of all chemicals contained in pits or in tanks destined for injection wells. This may require additional mandates for water testing on a periodic basis. The testing data should be publicly available online on a per-well basis.
- Naturally occurring radioactive fluids should be assessed and quantified when first encountered, before more fluids are produced. If the projected amounts of radioactive materials would cause management problems and violations of radiation control laws, the drilling operation should cease until the problem is corrected.
- Airborne gasses originating from storage tanks or pit impoundments should be monitored periodically, and data should be made available to the public. If air emissions associated with fluid waste exceed air quality control laws, the operation should cease until the problem is corrected.

The bulk of pit contamination is associated with seeps into shallow groundwater – of the sort that can readily flow into drinking water wells, as the New Mexico data demonstrates – or as

¹⁵² See Earthworks, Oil & Gas Accountability Project, *The Pit Rule – Good Questions and Honest Answers*, Available at: http://www.earthworksaction.org/files/publications/FS_NM-PitRule-GoodQuestions-webres.pdf (attached as Exhibit 163).

spills and runoff. Similar incidents are occurring across the country.¹⁵³ For example, in Pennsylvania, state authorities were forced to quarantine cattle after a pit leaked into their field, leaking into a smelly pool that killed the grass.¹⁵⁴ In Colorado, leaky pits with torn liners spilled more than 6,000 barrels of waste.¹⁵⁵ And in Ohio, compromised pit liners and pit wall failures have sent pollution spilling out into the environment.¹⁵⁶

Here, in preparing its NEPA analysis for the RMPA/EIS, BLM must address the direct, indirect, and cumulative impacts to groundwater, 40 C.F.R. § 1508.25(c), giving particular scrutiny to the potential for contamination of groundwater supplies.

b. Surface Water Impacts

Likewise, the BLM must quantify and address the risk of potentially catastrophic spills and blowouts at well sites, which could impact and degrade surface waters. This is a serious concern because such major spills are not uncommon in natural gas drilling. For instance, a major well blowout in Pennsylvania recently sent thousands of gallons of contaminated fluid coursing into a stream feeding the Susquehanna River.¹⁵⁷ In February of 2013, a major spill occurred in Windsor, Colorado where at least 84,000 gallons of water contaminated with oil and chemicals used in hydraulic fracturing spilled from a broken wellhead and into a field.¹⁵⁸ The BLM has failed to demonstrate that such incidents could not occur on the leases that will be approved under this RMP. In 2013, there were 495 spills related to oil and gas activities in Colorado, with 71 spills impacting groundwater and 41 impacting surface water. Forty-one spills occurred between 50 and 100 feet from groundwater.¹⁵⁹

¹⁵³ See, e.g., Natural Resources Defense Council, *Petition for Rulemaking to Regulate Oil and Gas Waste* (Sept. 8, 2010) (collecting these incidents) [hereinafter “NRDC Petition”] (attached as Exhibit 147).

¹⁵⁴ Nicolas Kusnetz, *A Fracking First in Pennsylvania: Cattle Quarantine*, PRO PUBLICA (July 2, 2010), available at: <http://www.propublica.org/article/a-fracking-first-in-pennsylvania-cattle-quarantine> (attached as Exhibit 148).

¹⁵⁵ See Colorado Oil and Gas Conservation Commission, *Inspection/Incident Inquiry, Spill Reports* Doc. Nos. 1630424, 1630436, 1630427, 1630428, 1630429, 1630430.

¹⁵⁶ See NRDC Petition at 20.

¹⁵⁷ Associated Press, *Crews Stop Flow of Drilling Fluid from PA Well* (Apr. 22, 2011) (attached as Exhibit 149).

¹⁵⁸ See Finely (attached above as Exhibit 150).

¹⁵⁹ Center for Western Priorities, *Colorado Toxic Release Tracker 2013 Summary*, available at: <http://westernpriorities.org/colorado-toxic-release-tracker-2013-summary/>.

Other data confirms the risk to surface waters from fracking and fracking-related activities.¹⁶⁰

Gas well development of any type creates surface disturbances as a result of land clearing, infrastructure development, and release of contaminants produced from deep groundwater (e.g., brines). However, the use of hydraulic fracturing poses additional environmental threats due to water withdrawals and contamination from fracking fluid chemicals. *Id.* at 504.

Elevated sediment runoff into streams, reductions in stream flow, contamination of streams from accidental spills, and inadequate treatment practices for recovered wastewaters are realistic threats. *Id.* at 510.

In addition, portions of the FFO planning area underlies large forested areas, notably in the Santa Fe National Forest. Fracking and fracking-related activities pose special threats to such areas and the surface waters contained therein.¹⁶¹

The fragmentation of forestland, especially northern core forest, places headwater streams, and their larger downstream waterways, at risk of pollution. *Id.* at 1073.

Drilling-related land disturbance occurs due to road development or expansion of existing roads; drill pad and associated stormwater system development; gathering-line placement to move extracted gas to main transmission lines; compressor station development to pump gas to transmission lines; freshwater storage pond creation for hydraulic fracturing (also known as fracking); flowback water storage ponds and treatment facilities; and development of staging areas for equipment storage. *Id.* at 1062.

The concentration of existing core forest in the northern part of the state, and the focus of drilling in this area (largely on private land), lead us to conclude that remaining areas of public land are key refuges for the protection of wildlife, ecosystems, and their associated ecosystem services, and that these areas should receive further protection. *Id.* at 1073.

i. Antidegradation

Moreover, Section 303 of the Clean Water Act (“CWA”), 33 U.S.C. § 1313, requires each State to institute comprehensive standards establishing water quality goals for all intrastate

¹⁶⁰ See, e.g., Sally Entrekin, *et al.*, *Rapid expansion of natural gas development poses a threat to surface waters*, FRONTIERS IN ECOLOGY, vol. 9, iss. 9. (October 2011) at 503 (attached as Exhibit 151).

¹⁶¹ See, e.g., P.J. Drohan, *et al.*, *Early Trends in Landcover Change and Forest Fragmentation Due to Shale-Gas Development in Pennsylvania: A Potential Outcome for the Northcentral Appalachians*, ENVIRONMENTAL MANAGEMENT, vol. 49, iss. 5. (May 2012) at 1061-75 (attached as Exhibit 152).

waters, and requires that such standards “consist of the designated uses of the navigable waters involved and the water quality criteria for such waters based upon such uses.” 33 U.S.C. § 1313(c)(2)(A). A 1987 amendment to the CWA makes clear that section 303 also contains an “antidegradation policy” – that is, a policy requiring that state standards be sufficient to maintain existing beneficial uses of navigable waters, preventing their further degradation. 33 U.S.C. § 1313 (d)(4)(B); *see also PUD No. 1 of Jefferson County v. Washington Dept. of Ecology*, 511 U.S. 700, 705 (1994). Accordingly, EPA’s regulations implementing the CWA require that state water quality standards include “a statewide antidegradation policy” to ensure that “[e]xisting instream water uses and the level of water quality necessary to protect [those] uses [are] maintained and protected.” 40 C.F.R. § 131.12(a)(1). At a minimum, state water quality standards must satisfy these conditions. The CWA also allows States to impose more stringent water quality controls. *See* 33 U.S.C. §§ 1311(b)(1)(C), 1370; *see also* 40 CFR § 131.4(a) (“As recognized by section 510 of the Clean Water Act [33 U.S.C. § 1370], States may develop water quality standards more stringent than required by this regulation”). BLM also holds independent authority to protect water quality above and beyond what the CWA may require or authorize. 43 U.S.C. §§ 1701(a)(8), 1702(c), 1732(b).

The water quality standards that Congress required the States to develop must include three elements: (1) first, each water body must be given a “designated use,” such as recreation or the protection of aquatic life; (2) second, the standards must specify for each body of water the amounts of various pollutants or pollutant parameters that may be present without impairing the designated use; and (3) third, each state must adopt an antidegradation review policy which will allow the State to assess activities that may lower the water quality of the water body. *See American Wildlands v. Browner*, 260 F.3d 1192, 1194 (10th Cir. 2001) (citing 33 U.S.C. § 1313(c)(2)(A) and 40 C.F.R. §§ 130.3, 130.10(d)(4), 131.6, 131.10, 131.11).

In its NEPA analysis, BLM must address whether the development of oil and gas resources in the FFO will affect any high quality waters or whether it will degrade any existing uses. BLM may not evade its NEPA duty to consider these impacts by asserting that other agencies may issue discharge permits. 40 C.F.R. §§ 1502.14(f), 1502.16(h). “A non-NEPA document – let alone one prepared and adopted by a state government – cannot satisfy a federal agency’s obligations under NEPA.” *South Fork Band Council of Western Shoshone of Nevada v. U.S. Department of Interior*, 588 F.3d 718, 726 (9th Cir. 2009) (citing *Klamath-Siskiyou Wildlands Center v. BLM*, 387 F.3d 989, 998 (9th Cir. 2004)) (BLM’s argument that it need not consider impacts because a facility operated under a state permit issued pursuant to the Clean Air Act is “without merit”); *Southern Or. Citizens Against Toxic Sprays, Inc. v. Clark*, 720 F.2d 1475 (9th Cir. 1983) (another agency’s consideration of environmental impacts does not relieve BLM of its duty to consider effects; “BLM must assess independently [the impacts]”); *see also Calvert Cliffs’ Coordinating Comm., Inc. v. U. S. Atomic Energy Comm’n*, 449 F.2d 1109, 1123 (D.C. Cir. 1971) (“Certification by another agency that its own environmental standards are satisfied involves an entirely different kind of judgment.”).

ii. Water Quality Standards

Pursuant to CWA section 303(d)(1), 33 U.S.C. § 1313(d)(1), each state is further required to identify those waters that do not meet water quality standards – called the “303(d)(1) list.” For

impaired waters identified in the § 303(d)(1) list, the states must establish a total maximum daily load (“TMDL”) for pollutants identified by the EPA. A TMDL specifies the maximum amount of pollutant that can be discharged or loaded into the waters from all combined sources, so as to comply with the subject water quality standards.

CWA section 1323(a) requires federal agencies to comply with state and local water-quality requirements “in the same manner, and to the same extent as any nongovernmental entity.” Congress intended this section to ensure that federal agencies were required to “meet all [water pollution] control requirements as if they were private citizens.” S. REP. NO. 92-414 (1971), *as reprinted in* 1972 U.S.C.C.A.N. 3668, 3734. This provision applies to activities resulting in either “discharge or runoff of pollutants.” 33 U.S.C. § 1323(a).

Accordingly, any activity undertaken by BLM FFO in this area – including the leasing and development of public lands for oil and gas, as contemplated in the RMPA/EIS – may degrade potential “outstanding waters.” Not only is BLM FFO mandated to follow antidegradation and water quality standards under the CWA and state law, but it must also take a NEPA “hard look” at any impacts that may be related to these water quality standards as well.

c. Water Quantity

In addition to impacts on water quality, oil and gas development processes, and particularly fracking, may result in significant impacts on water quantity. To frack a single well one time requires 2-8 million gallons.¹⁶² Annually, the EPA estimates that 70-140 billion gallons of water are used to frack wells in the United States – enough to supply drinking water to 40-80 cities of 50,000.¹⁶³ This massive use of water is of particular concern in states in the interior west, like New Mexico, where water supplies are scarce and already stretched.¹⁶⁴ Indeed, as the Department of Energy has recognized, “[a]vailable surface water supplies have not increased in 20 years, and groundwater tables and supplies are dropping at an alarming rate.”¹⁶⁵ Because of the chemicals that are added to fracking water, the water may not be reused.¹⁶⁶ Removing water for fracking can stress existing water supplies by lower water tables and dewatering aquifers, decreasing stream flows, and reducing water in surface reservoirs.¹⁶⁷ This can result in changes

¹⁶² J. David Hughes, *Will Natural Gas Fuel America in the 21st Century?*, May 2011, at 23 (attached as Exhibit 112).

¹⁶³ See EPA Draft Plan at 20 (attached above as Exhibit 110).

¹⁶⁴ See WORC, *Gone for Good*, at 7-8 (noting water scarcity in west and significant water demands of fracking) (attached above as Exhibit 111)

¹⁶⁵ U.S. Dep’t of Energy, *Energy Demands on Water Resources: Report to Congress on the Interdependency of Energy and Water*, Dec. 2012, at 12 (attached as Exhibit 113).

¹⁶⁶ See EPA Draft Plan at 20 (attached above as Exhibit 110).

¹⁶⁷ *Id.*

to water quality, and it can also alter the hydrology of water systems, and it can increase concentrations of pollutants in the water.

There is also potential for the reductions in water quantity to impacts aquatic and riverine species and habitat by affecting water flows and natural river processes: this, in turn, could lead to fish declines, changes to riparian plant communities, and alterations to sediment.¹⁶⁸ Further, because water resources in New Mexico are in many locations stressed or over-allocated, and oil and gas development has already lead to unpermitted and illegal water withdrawals.¹⁶⁹

Here, in its NEPA analysis BLM must closely assess the direct, indirect, and cumulative impacts of lease development on water supplies. 40 C.F.R. §§ 1508.7, 1508.8. This analysis must consider the potential sources of water in the FFO that would be used for oil and gas development, and the impacts of these water withdrawals on water availability for drinking, agriculture, and wildlife. The analysis must further address the impacts to water quantity at different annual, seasonal, monthly, and daily time scales because the impacts of such water withdrawals could be more acute during times, months, and seasons of scarcity. For example, increased withdrawal and irretrievable contamination of waters will be particularly harmful during times – like the present – when much of the state is experiencing drought conditions.¹⁷⁰

E. The BLM Must Take a “Hard Look” at Impacts to Human Health.

As introduced above, emissions from oil and gas development are not limited only to combustion, rather they occur throughout the chain of production – with some of the greatest emissions occurring at the point of extraction. These impacts are a consequence of various stages of oil and gas development – from the drilling and fracking of oil and gas wells, to air quality impacts and the release of hazardous emissions. The FFO must sufficiently address and analyze these impacts in its NEPA analysis.

The implementation of methane waste mitigation technologies, as discussed above, can not only help spur economic benefit, but they can also allay some of the harmful health effects of oil and gas development by reducing emissions of NOX, VOCs and other criteria pollutants. Aside from the direct health impacts of these emissions,¹⁷¹ they can also result in significant increases in ground-level ozone (i.e., ozone precursors), and, consequently, can have a dramatic

¹⁶⁸ Nat'l Parks Conservation Ass'n, *National Parks and Hydraulic Fracturing: Balancing Energy Needs, Nature, and America's National Heritage* (2013) at 23 (attached as Exhibit 114).

¹⁶⁹ See WORC, *Gone for Good* at 21 (attached above as Exhibit 111).

¹⁷⁰ See WORC, *Gone for Good* at 8 (attached above as Exhibit 111).

¹⁷¹ See, e.g., Colorado Department of Public Health and Environment, *2010 Air Quality Data Report* (2010) (attached as Exhibit 93).

impact on human health.¹⁷² For example, ozone has been shown to decrease lung function – particularly in adolescents and young adults – as well as increase the risk of death from respiratory causes.¹⁷³

The EPA is currently proposing standards to reduce air pollution from oil and natural gas drilling operations. According to the EPA, the oil and gas industry is “the largest industrial source of emissions of volatile organic compounds (VOCs), a group of chemicals that contribute to the formation of ground-level ozone (smog).”¹⁷⁴ Moreover, “[e]xposure to ozone is linked to a wide range of health effects, including aggravated asthma, increased emergency room visits and hospital admissions, and premature death.”¹⁷⁵ The oil and natural gas industry is also “a significant source of emission of methane,” as well as an emitter of “air toxics such as benzene, ethylbenzene, and n-hexane,” which are “pollutants known, or suspected of causing cancer and other serious health effects.”¹⁷⁶ The EPA reports that the oil and gas industry:

emits 2.2 million tons of VOCs, 130,000 tons of air toxics, and 16 million tons of greenhouse gases (methane) each year (40% of all methane emission in the U.S.). The industry is one of the largest sources of VOCs and sulfur dioxide emissions in

¹⁷² See, e.g., GAO Report, *Oil and Gas: Information on Shale Resources, Development, and Environmental and Public Health Risks* (Sept. 2012) (attached as Exhibit 94); GAO Report, *Unconventional Oil and Gas Development: Key Environmental and Public Health Requirements* (Sept. 2012) (attached as Exhibit 95); Earthworks, *Natural Gas Flowback: How the Texas Natural Gas Boom Affects Health and Safety* (April 2012) (attached as Exhibit 96); Green River Alliance, *Healthy Air Questionnaire Final Report: Clean Air and Healthy Communities* (2011) (attached as Exhibit 97); Lisa McKenzie, Ph.D., et. al., *Human health and risk assessment of air emissions from development of unconventional natural gas resources* (Feb. 2012) (attached as Exhibit 98); Lisa McKenzie, Ph.D., Testimony on: *Federal Regulation: Economic, job, and energy security implications of federal hydraulic fracturing regulation*, May 2, 2012 (attached as Exhibit 99); Earthworks, *Gas Patch Roulette: How Shale Gas Development Risks Public Health in Pennsylvania*, October 2012 (attached as Exhibit 100).

¹⁷³ See Ira B. Tager, et. al., *Chronic Exposure to Ambient Ozone and Lung Function in Young Adults*, EPIDEMIOLOGY, Vol. 16, No. 6 (Nov. 2005) (attached as Exhibit 101); Michael Jarrett, Ph.D., et. al., *Long-Term Ozone Exposure and Mortality*, THE NEW ENGLAND JOURNAL OF MEDICINE, 360: 1085-95 (2009) (attached as Exhibit 102).

¹⁷⁴ EPA, *Oil and Natural Gas Pollution Standards: Basic Information, Emissions from the Oil & Natural Gas Industry* (2011), available at: <http://www.epa.gov/airquality/oilandgas/basic.html>; see also Cally Carswell, *Cracking the ozone code – Utah’s gas fields*, HIGH COUNTRY NEWS, Sept. 4, 2012 (attached as Exhibit 103).

¹⁷⁵ See *id.*, EPA, *Pollution Standards*.

¹⁷⁶ *Id.*

the United States.¹⁷⁷

The rapid development of high volume/horizontal drilling in conjunction with hydraulic fracturing has driven expansion of new sources resulting in increased emissions – a change that requires consideration in the FFO’s RMPA/EIS.

Many of the impacts to human health have already been documented in communities subject to industrial scale oil and gas development. For example, in Garfield County, Colorado, residents there have experienced health effects they believe to be caused from oil and gas development. “Community concerns range from mild complaints such as dizziness, nausea, respiratory problems, and eye and skin irritation to more severe concerns including cancer.”¹⁷⁸ Additionally, the community has “environmental concerns related to noise, odors, dust, and ‘toxic’ chemicals in water and air.”¹⁷⁹ After a thorough review of ambient air data across Garfield County, ATSDR determined that, “considering both theoretical cancer risks as well as non-cancer health effects and the uncertainties associated with the available data, it is concluded that the exposures to air pollution in Garfield County pose an indeterminate public health hazard for current exposures.”¹⁸⁰ ATSDR further provided that “estimated theoretical cancer risks and non-cancer hazards for benzene [in the community], which is within the oil and gas development area, appear significantly higher than those in typical urban and rural area, causing some potential concern,” and later concluded that “[t]hese elevated levels are an indicator of the increased potential for health effects related to benzene exposure ... in the oil and gas development area.”¹⁸¹

Unfortunately, impacts to human health are not limited only to shale gas emissions, but can result from exposure to chemicals necessary for gas extraction – namely, the hundreds of chemicals used in hydraulic fracturing.¹⁸² Indeed, “[b]etween 2005 and 2009, the 14 oil and gas

¹⁷⁷ Letter from American Lung Association, American Public Health Association, American Thoracic Society, Asthma and Allergy Foundation of America, and Trust for America’s Health to Lisa Jackson, Administrator, U.S. Environmental Protection Agency (Nov. 30, 2011), at 4 (attached as Exhibit 104).

¹⁷⁸ U.S. Department of Health and Human Services, Agency for Toxic Substances and Disease Registry (“ATSDR”), *Health Consultation: Garfield County, Public Health Implications of Ambient Air Exposures to Volatile Organic Compounds as Measured in Rural, Urban, and Oil & Gas Development Areas* (2008), at 1 (attached as Exhibit 105).

¹⁷⁹ *Id.*

¹⁸⁰ *Id.*

¹⁸¹ *Id.*

¹⁸² See Theo Colborn, et. al., *Comments to the Bureau of Land Management, Uncompahgre Field Office*, THE ENDOCRINE DISRUPTION EXCHANGE, April 20, 2012 (attached as Exhibit 106); Theo

service companies [analyzed by Congress] used more than 2,500 hydraulic fracturing products containing 750 chemicals and other components. Overall, these companies used 780 million gallons of hydraulic fracturing products – not including water added at the well site – between 2005 and 2009.”¹⁸³ Chemical components include BTEX compounds – benzene, toluene, xylene, and ethylbenzene – which are hazardous air pollutants and known human carcinogens. As BLM proceeds with the October 2014 lease sale, it must consider the human health impacts associated with these extractive practices.

Leading doctors and scientists studying these issues recognize the unknown risks inherent to fracking. “We don’t know the chemicals that are involved, really; we sort of generally know,” Vikas Kapil, chief medical officer at National Center for Environmental Health, part of the U.S. Centers for Disease Control and Prevention, said at a conference on hydraulic fracturing.¹⁸⁴ “We don’t have a great handle on the toxicology of fracking chemicals.”¹⁸⁵ Christopher Portier, director of the CDC’s National Center for Environmental Health and Agency for Toxic Substances and Disease Registry further provided that “additional studies should examine whether wastewater from wells can harm people or the animals and vegetables they eat.”¹⁸⁶ “We do not have enough information to say with certainty whether shale gas drilling poses a threat to public health.”¹⁸⁷

The Endocrine Disruption Exchange (“TEDX”) has, however, documented nearly 1,000 products and chemicals that energy companies use in drilling, fracturing (frac’ing, or stimulation), recovery and delivery of natural gas. Many of these products contain chemicals that are harmful to human health. On its website, TEDX says this:

To facilitate the release of natural gas after drilling, approximately a million or more gallons of fluids, loaded with toxic chemicals, are injected underground under high

Colborn, et. al., *Natural Gas Operations from a Public Health Perspective*, HUMAN AND ECOLOGICAL RISK ASSESSMENT, 17: 1039-1056 (2011) (attached as Exhibit 107).

¹⁸³ UNITED STATES HOUSE OF REPRESENTATIVES, COMMITTEE ON ENERGY AND COMMERCE, *Chemicals Used in Hydraulic Fracturing* (April 2011) (attached as Exhibit 108).

¹⁸⁴ Alex Wayne, *Fracking Moratorium Urged by U.S. Doctors Until Health Studies Conducted*, BLOOMBERG NEWS, January 9, 2012, available at: <http://www.bloomberg.com/news/2012-01-09/fracking-moratorium-urged-by-u-s-doctors-until-health-studies-conducted.html>.

¹⁸⁵ *Id.*

¹⁸⁶ Alex Wayne and Katarzyna Klimasinska, *Health Effects of Fracking for Natural Gas Need Study, Says CDC Scientist*, BLOOMBERG NEWS, January 4, 2012, available at: <http://www.bloomberg.com/news/2012-01-04/health-effects-of-fracking-for-natural-gas-need-study-says-cdc-scientist.html>.

¹⁸⁷ *Id.*

pressure. This process, called fracturing (frac'ing or stimulation), uses diesel-powered heavy equipment that runs continuously during the operation. One well can be frac'ed 10 or more times and there can be up to 28 wells on one well pad. An estimated 30% to 70% of the frac'ing fluid will resurface, bringing back with it toxic substances that are naturally present in underground oil and gas deposits, as well as the chemicals used in the frac'ing fluid. Under some circumstances, nothing is recovered.¹⁸⁸

According to TEDX:

In the 980 products identified...[for use during natural gas operations], there were a total of 649 chemicals. Specific chemical names and CAS numbers could not be determined for 286 (44%) of the chemicals, therefore, the health effects summary is based on the remaining 362 chemicals with CAS numbers...Over 78% of the chemicals are associated with skin, eye or sensory organ effects, respiratory effects, and gastrointestinal or liver effects. The brain and nervous system can be harmed by 55% of the chemicals. These four health effect categories...are likely to appear immediately or soon after exposure. They include symptoms such as burning eyes, rashes, coughs, sore throats, asthma-like effects, nausea, vomiting, headaches, dizziness, tremors, and convulsions. Other effects, including cancer, organ damage, and harm to the endocrine system, may not appear for months or years later. Between 22% and 47% of the chemicals were associated with these possibly longer-term health effects. Forty-eight percent of the chemicals have health effects in the category labeled 'Other.' The 'Other' category includes such effects as changes in weight, or effects on teeth or bones, for example, *but the most often cited effect in this category is the ability of the chemical to cause death.*¹⁸⁹ (emphasis added)

Christopher Portier, director of the CDC's National Center for Environmental Health and Agency for Toxic Substances and Disease Registry further provided that "additional studies should examine whether wastewater from wells can harm people or the animals and vegetables they eat."¹⁹⁰ "We do not have enough information to say with certainty whether shale gas drilling poses a threat to public health."¹⁹¹

¹⁸⁸ See TEDX webpage describing "Chemicals in Natural Gas Operations," available at: <http://endocrinedisruption.org/chemicals-in-natural-gas-operations/introduction>.

¹⁸⁹ TEDX, *Chemicals In Natural Gas Operations* (attached above as Exhibit 3).

¹⁹⁰ Alex Wayne and Katarzyna Klimasinska, *Health Effects of Fracking for Natural Gas Need Study, Says CDC Scientist*, BLOOMBERG NEWS, January 4, 2012, available at: <http://www.bloomberg.com/news/2012-01-04/health-effects-of-fracking-for-natural-gas-need-study-says-cdc-scientist.html>.

¹⁹¹ *Id.*

Indeed, a new study demonstrates that animals, especially livestock, are sensitive to the contaminants released into the environment by drilling and by its cumulative impacts.¹⁹² Because animals often are exposed continually to air, soil, and groundwater and have more frequent reproductive cycles, animals can be used to monitor potential impacts to human health – they are shale gas drilling’s “canary in the coalmine.” The study evaluated all available fracking-related reports on sick or dying animals. Although secrecy surrounds the fracking industry, “a few ‘natural experiments’ have provided powerful evidence that fracking can harm animals.”¹⁹³ For example:

Two cases involving beef cattle farms inadvertently provided control and experimental groups. In one case, a creek into which wastewater was allegedly dumped was the source of water for 60 head, with the remaining 36 head in the herd kept in other pastures without access to the creek. Of the 60 head that were exposed to the creek water, 21 died and 16 failed to produce calves the following spring. Of the 36 that were not exposed, no health problems were observed, and only one cow failed to breed. At another farm, 140 head were exposed when the liner of a wastewater impoundment was allegedly slit, as reported by the farmer, and the fluid drained into the pasture and the pond used as a source of water for the cows. Of those 140 head exposed to the wastewater, approximately 70 died and there was a high incidence of stillborn and stunted calves. The remainder of the herd (60 head) was held in another pasture and did not have access to the wastewater; they showed no health or growth problems. These cases approach the design of a controlled experiment, and strongly implicate wastewater exposure in the death, failure to breed, and reduced growth rate of cattle.¹⁹⁴

The health problems and uncertainties that proliferate in communities where oil and gas development takes place warrants the further collection of data and research, as contemplated under NEPA, before such development can be made possible through the authorization of development through the October 2014 lease sale. NEPA requires a hard look at these impacts.

F. The BLM Must Take a “Hard Look” at Social Impacts and Living Communities.

The FFO attempts to avoid taking a hard look while at the same time acknowledging impacts to human communities, providing: “While the act of leasing federal minerals itself would result in no social impacts, subsequent development of a lease may generate impacts to

¹⁹² Michelle Bamberger and Robert E. Oswald, *Impacts of Gas Drilling on Human and Animal Health*, NEW SOLUTIONS, VOL. 22(1) 51-77 (2012) (attached as Exhibit 109).

¹⁹³ See Peter Montague, *Why Fracking and Other Disasters Are So Hard to Stop*, HUFFINGTON POST, Jan. 20, 2012, available at: http://www.huffingtonpost.com/peter-montague/why-fracking-and-other-di_b_1218889.html (last visited Jan. 23, 2012).

¹⁹⁴ See Bamberger at 60 (attached above as Exhibit 109).

people living near or using the area in the vicinity of the lease.” EA at 37. The agency recognizes a number of different impacts to local residents, including: “Oil and gas exploration, drilling, or production could create a disruption to these people due to increased traffic and traffic delays, air pollution, noise and visual impacts[;]” and that “nearby residents may be disturbed while hydraulic fracturing or other completion and stimulation operations are occurring, as these activities involve many vehicles, heavy equipment, and a workover rig[;]” and that “[c]reation of new access roads into an area could allow increased public access and exposure of private property to vandalism.” *Id.* Yet, the agency is dismissive of all these concerns, concluding that “[f]or leases where the surface is privately owned and the subsurface is BLM managed, surface owner agreements, standard lease stipulations, and BMPs could address many of the concerns of private surface owners.” *Id.* Not only does BLM’s vague reference to non-specific mitigation measures fail to satisfy the agency’s NEPA obligations for these identified impacts to communities, but the agency also ignores whole host of foreseeable impacts, the consideration of which should be fundamental to the agency’s decision-making process for the subject lease sale – considerations that are particularly critical, here, given the Navajo allotted lands included in the sale.

There are excellent sources the FFO should consider in their assessment and consideration of impacts to human communities and, particularly, native communities, many of which are outlined in a recent article in THE ATLANTIC.¹⁹⁵ Among the concerns and impacts to native communities raised in this article – and in particular the social and cultural impacts experienced on the Fort Berthold Indian Reservation, located in the heart of North Dakota’s Bakken formation – include:

[North Dakota’s U.S. Attorney] noticed a peculiar pattern emerging from Fort Berthold. Many of his filings – a surprising number of them – involved non-Indian perpetrators. “We had five or six in a month,” he told me. “Why was this? We realized it’s non-enrolled folks moving to the oil patch.”

The immediate side-effects are the obvious ones, and they come with any boom: limited jail space, an overworked police force, a glut of men with cash in their pockets. In 2012, the tribal police department reported more murders, fatal accidents, sexual assaults, domestic disputes, drug busts, gun threats, and human trafficking cases than in any year before. The surrounding counties offer similar reports.

But there is one essential difference between Fort Berthold and the rest of North Dakota: The reservation’s population has more than doubled with an influx of non-Indian oil workers – over whom the tribe has little legal control.

In 2011, the U.S. Justice Department did not prosecute 65 percent of rape cases

¹⁹⁵ Sierra Crane-Murdoch, *On Indian Land, Criminals Can Get Away With Almost Anything*, THE ATLANTIC (Feb. 22, 2013), available at: <http://www.theatlantic.com/national/archive/2013/02/on-indian-land-criminals-can-get-away-with-almost-anything/273391/> (attached as Exhibit 161).

reported on reservations. According to department records, one in three Native American women are raped during their lifetimes – two-and-a-half times the likelihood for an average American woman – and in 86 percent of these cases, the assailant is non-Indian.

Between 2009 and 2011, federal case filings on North Dakota reservations rose 70 percent.

With oil and gas industry predicting a new oil boom for the San Juan Basin¹⁹⁶ – with an estimated 30 billion barrels of oil trapped in the Mancos Shale – the impacts described above threaten to compound those already experienced by the native and non-native communities in the planning area. BLM’s failure to articulate and analyze such impacts represents a fundamental deficiency of the EA, and overlooks critical information weighing on the conclusions reached therein, in violation of NEPA.

IV. The BLM Must Sufficiently Analyze All Reasonable Alternatives.

Through the RMPA/EIS process, the FFO required to “estimate and display the physical, biological, economic, and social effects of implementing each alternative considered in detail. The estimation of effects shall be guided by the planning criteria and procedures implementing [NEPA].” 43 C.F.R. § 1610.4-6. Incumbent to any NEPA process is a robust analysis of alternatives to the proposed action. Consideration of reasonable alternatives is necessary to ensure that the agency has before it and takes into account all possible approaches to, and potential environmental impacts of, a particular project. NEPA’s alternatives requirement, therefore, ensures that the “most intelligent, optimally beneficial decision will ultimately be made.” *Calvert Cliffs’ Coordinating Comm., Inc. v. U.S. Atomic Energy Comm’n*, 449 F.2d 1109, 1114 (D.C. Cir. 1971).

“[T]he heart” of an environmental analysis under NEPA is the analysis of alternatives to the proposed project, and agencies must evaluate all reasonable alternatives to a proposed action.” *Colorado Environmental Coalition*, 185 F.3d at 1174 (quoting 40 C.F.R. § 1502.14). An agency must gather “information sufficient to permit a reasoned choice of alternatives as far as environmental aspects are concerned.” *Greater Yellowstone*, 359 F.3d at 1277 (citing *Colorado Environmental Coalition*, 185 F.3d at 1174); *see also Holy Cross Wilderness Fund v. Madigan*, 960 F.2d 1515, 1528 (10th Cir. 1992). Thus, agencies must “ensure that the statement contains sufficient discussion of the relevant issues and opposing viewpoints to enable the decisionmaker to take a ‘hard look’ at environmental factors, and to make a reasoned decision.” *Izaak Walton League of America v. Marsh*, 655 F.2d 346, 371 (D.C. Cir.1981) (citing *Kleppe v. Sierra Club*, 427 U.S. 390, 410 n. 21 (1976)).

Of critical importance is that the agency considers an alternative that properly balances

¹⁹⁶ Staci Matlock, *New oil boom coming to San Juan Basin*, The New Mexican (March 13, 2014), available at: http://www.santafenewmexican.com/news/local_news/new-oil-boom-coming-to-san-juan-basin/article_665ff2f2-bd6c-54fd-9dd8-238092c73917.html (attached as Exhibit 158).

the permanent protection of certain critical areas from the pressures of oil and gas development by industry proponents.

The FFO is uniquely empowered to make this determination and, as codified in BLM's organic act, the Federal Land and Policy Management Act ("FLPMA") of 1976, 43 U.S.C. § 1701 *et. seq.*, taking such action is part of its mandate. FLPMA's congressional declaration states:

It is the policy of the United States that ... the public lands be managed in a manner that will protect the quality of scientific, scenic, historical, ecological, environmental, air and atmospheric, water resource, and archeological values; that, where appropriate, will preserve and protect certain public lands in their natural condition; that will provide food and habitat for fish and wildlife and domestic animals; and that will provide for outdoor recreation and human occupancy and use;

43 U.S.C. § 1701(a)(8) (emphasis added).

Indeed, BLM is duty bound to develop and revise land use plans according to this congressional mandate, so as to "observe the principles of multiple use." 43 U.S.C. § 1712(c)(1). "Multiple use" means "a combination of balanced and diverse resource uses that takes into account the long-term needs of future generations for renewable and nonrenewable resources, including, but not limited to, recreation, range, timber, minerals, watershed, wildlife and fish, and natural scenic, scientific and historical values." *Id.* at § 1702(c).

The oil and gas leasing process, undertaken pursuant to FLPMA, requires BLM to engage in the type of planning that is intended to give context to the agency's multiple use mandate. Accordingly, FLPMA provides specific criteria for land use plan revisions, requiring consideration of things such as: observation of the principles of multiple use and sustained yield; integrated consideration of physical, biological, economic, and other sciences; reliance on public lands resources and other values; consideration of present and future uses of the public lands; consideration of the relative scarcity of resource values; and weighing the long-term benefits to the public against the short-term benefits. *See* 43 U.S.C. § 1712(c)(1)-(9). Consideration of these criteria must drive the agency's NEPA analysis.

FLPMA does not mandate that every use be accommodated on every piece of land; rather, delicate balancing is required. *See Norton v. S. Utah Wilderness Alliance*, 542 U.S. 55, 58 (2004). "Multiple use' requires management of the public lands and their numerous natural resources so that they can be used for economic, recreational, and scientific purposes without the infliction of permanent damage." *Public Lands Council v. Babbitt*, 167 F.3d 1287, 1290 (10th Cir. 1999) (citing 43 U.S.C. § 1702 (c)). As held by the Tenth Circuit, "[i]f all the competing demands reflected in FLPMA were focused on one particular piece of public land, in many instances only one set of demands could be satisfied. A parcel of land cannot both be preserved in its natural character and mined." *Rocky Mtn. Oil & Gas Ass'n v. Watt*, 696 F.2d 734, 738 n. 4 (10th Cir.1982) (quoting *Utah v. Andrus*, 486 F.Supp. 995, 1003 (D.Utah 1979)); *see also* 43

U.S.C. § 1701(a)(8) (stating, as a goal of FLPMA, the necessity to “preserve and protect certain public lands in their natural condition”); *Pub. Lands Council*, 167 F.3d at 1299 (citing § 1701(a)(8)). As further provided by the Tenth Circuit:

BLM’s obligation to manage for multiple use does not mean that development *must* be allowed on [a particular piece of public lands]. Development is a *possible* use, which BLM must weigh against other possible uses – including conservation to protect environmental values, which are best assessed through the NEPA process. Thus, an alternative that closes the [proposed public lands] to development does not necessarily violate the principle of multiple use, and the multiple use provision of FLPMA is not a sufficient reason to exclude more protective alternatives from consideration.

Otero Mesa, 565 F.3d at 710.

This type of analysis has been absent from the FFO’s analysis of oil and gas leasing and development, which failed to consider, on equal footing, the value of permanent protection and preservation of public lands, along with industry pressure to lease and develop these lands for oil and gas resources. Given current industry pressure to open critical public lands to oil and gas development, it may be appropriate to revisit this decision-making in light of the new information and circumstances that BLM is now aware of. *See* 40 C.F.R. § 1502.9 (c).

While certain lands may indeed be appropriate for responsible fossil fuel resource development, it is equally evident that there are lands where other resource values should prevail. FLPMA affords BLM great authority to appropriately balance these competing interests, which expressly includes the responsibility to “preserve and protect certain public lands in their natural condition.” 43 U.S.C. § 1701(a)(8). Moreover, FLPMA further delegates BLM authority to permanently withdraw lands from consideration. *See* 43 U.S.C. § 1714. This ability authorizes the Secretary to “make, modify, extend, or revoke withdrawals.” *Id.* In either event, the FFO cannot management public lands in a manner that prioritizes oil and gas development above the other resource values at stake.

V. The RMPA/EIS Must Consider Potential Fracking Impacts to Landscape-Level Historic Properties, such as Chaco Canyon National Historical Park, Pursuant to the NHPA and NEPA

The National Historic Preservation Act (“NHPA”) imposes the requirement on federal agencies to “take into account the effect[s] of [their] undertaking[s] on any district, site, building, structure, or object that is included in or eligible for inclusion in the National Register.” 16 U.S.C. § 470f (“Section 106”). *The RMPA is a federal undertaking subject to NHPA compliance.* The regulations implementing Section 106 of the NHPA prescribe the steps agencies must follow to adequately evaluate the effects of undertakings on historic properties. These steps include identifying historic properties in the area of potential effect, assessing whether the undertaking will adversely affect eligible historic properties, and resolving any adverse effects to historic properties from the undertaking. 36 C.F.R. §§ 800.4, 800.5, 800.6. Throughout this process, federal agencies must consult with appropriate parties including the State Historic Preservation

Officer (“SHPO”) and or Tribal Historic Preservation Officer (“THPO”), Native American Tribes, and the public. 36 C.F.R. § 800.2(c).

Section 106 has been characterized as a “stop, look, and listen” statute. *Muckleshoot Indian Tribe v. U.S. Forest Service*, 177 F.3d 800, 805 (9th Cir. 1999). Section 106 consultation must be performed at a time when the full range of avoidance and mitigation measures is still available to a federal agency proposing an undertaking. 36 C.F.R. § 800.1(c). “[P]roject planning activities” that “restrict the subsequent consideration of alternatives to avoid, minimize or mitigate the undertaking’s adverse effects on historic properties” can occur only after the Section 106 consultation is complete. *Id.* Therefore, BLM must conduct a Section 106 consultation concerning the effects of Mancos shale development on the Greater Chaco Landscape¹⁹⁷ at a time when the full range of development options, including withdrawing certain lands from leasing, are still available to BLM. *See Montana Wilderness Ass’n v. Fry*, 310 F. Supp. 2d 1127, 1152-3 (D. Mont. 2004).

Chaco Culture National Historical Park (“CCNHP” or “the Park”) is located within the planning area covered by the RMP Amendment. The Park is listed on the National Register of Historic Places and is designated a World Heritage Site. The National Park Service has identified a variety of fundamental values associated with the Park that also apply to the Chaco Outliers¹⁹⁸ and other cultural sites within the Greater Chaco Landscape, including:

- The physical surroundings that enfold the visitor, conveying both the vast immensity of the San Juan Basin and the dense core of Chacoan culture.
- Solitude, natural sounds, sandstone cliffs, natural events, landscape, and remote sites that are integral for visitor understanding of Chaco Canyon.
- The ability to view the seasonal patterns in the dark night sky including the stars, moon, and other celestial bodies – and the sun in the daytime sky.
- Unpolluted air is an important aspect of the biotic landscape.

NPS, Chaco Culture National Historical Park: Foundation for Planning and Management (Sept. 2007) (attached as Exhibit 164).

¹⁹⁷ The “Greater Chaco Landscape” includes the Park, most of the Chaco Culture World Heritage Site, several of the satellite villages (known as Chacoan Great House Communities), other resources affiliated with Chaco Canyon that have been formally designated by either Congress or BLM, and the Great North Road, which once linked Chaco Canyon with a settlement approximately 55 miles to the north known today as Aztec Ruin. The World Heritage Site designation is not limited to the Park but also includes four Chacoan Outliers (Pierre’s Site, Halfway House, Twin Angels, and Aztec Pueblo) located along the North Road and two Outliers (Kin Nizhoni and Casamero) along the South Road.

¹⁹⁸ The same legislation that created the Park also designated 33 sites outside the Park boundaries as “Chaco Cultural Archaeological Protection Sites” that were to be jointly managed by the National Park Service, BLM, Bureau of Indian Affairs, and the Governor of New Mexico for preservation and interpretation purposes. 16 U.S.C. § 410ii-1(b). Of the 33 sites on the list, 13 of them are on BLM lands and have been designated as ACECs.

Recently, the International Dark-Sky Association (“IDA”) designated the Chaco Culture National Historical Park as the newest “Dark Sky Park” for “its commitment to preserving its near-pristine night skies.” IDA has conferred this designation on only eleven other parks scattered around the world.

Air and light pollution, noise, and vehicle traffic from Mancos shale development authorized by BLM all have the potential to adversely affect the fundamental values of the Greater Chaco Landscape, including the Park and Outliers. As part of the EIS for the RMPA, BLM must analyze whether and to what extent the Park, World Heritage Site, Chaco Outliers, and the North Road will be impacted by Mancos shale development. Such a “landscape level” impacts analysis is required before BLM can authorize Mancos shale development, and should be done at the earliest possible phase in the process of authorizing this development, which is the RMP Amendment stage.

The Section 106 regulations dictate how BLM must assess adverse effects to historic properties from Mancos shale development. The regulations define an “adverse effect” as:

when an undertaking may alter, directly or indirectly, any of the characteristics of a historic property that qualify the property for inclusion in the National Register in a manner that would diminish the integrity of the property’s location, design, setting, materials, workmanship, feeling, or association.

36 C.F.R. § 800.5(a)(1). This definition includes not only direct effects from the undertaking, but also “reasonably foreseeable effects caused by the undertaking that may occur later in time, be farther removed in distance or be cumulative.” *Id.* Adverse effects to historic properties are not limited to direct effects which result in physical destruction or alteration of a property, but also include the following:

(iv) Change of the character of the property’s use or of physical features within the property’s setting that contribute to its historic significance; [and]

(v) Introduction of visual, atmospheric or audible elements that diminish the integrity of the property’s significant historic features

Id. at § 800.5(a)(2). Mancos shale development has the potential to cause these types of adverse effects to the Park, World Heritage Site, Outliers, and the North Road. The attached “Petition to Designate the Greater Chaco Landscape as an ACEC” (attached as Exhibit 165) summarizes the air quality, visual, noise, and seismic effects that Mancos shale development could have on these fragile historic properties. BLM must consider all of these impacts in its EIS and determine whether they will adversely affect landscape-level historic properties that are part of the Greater Chaco Landscape.

As discussed above, BLM cannot defer this analysis until the APD stage of development because that stage will be too late to adequately protect a landscape-level historic properties located within the Greater Chaco Landscape. In *New Mexico ex. rel. Richardson v. Bureau of*

Land Mgmt., 459 F. Supp. 2d 1102 (D.N.M. 2006), the court explicitly recognized that evaluating impacts to landscape-level historic properties cannot be put off until the APD stage:

[Landscape-level cultural properties] may not be able to be adequately protected if the Section 106 consultation process is delayed until the APD stage, after land has already been leased for oil and gas development. BLM's argument focuses on historical sites covering relatively small areas, such as discrete archaeological sites. For such sites, mitigation of impacts can be accomplished simply by moving the proposed drill site to a different location on the lease parcel. For landscape-level [properties] that may or may not be located on the leased parcel itself, however, such movement may not be adequate mitigation.

Id. at 1124-25. Given that the Park, World Heritage Site, Chaco Outliers, and the North Road are landscape-level historic properties, evaluation of impacts to these properties at the APD stage comes too late to afford any substantive protection. *New Mexico ex. rel. Richardson* stands for the principle that BLM cannot defer historic property impacts analysis to the APD stage and limit it only to historic properties (or portions of landscape-level historic properties) present on a proposed lease parcel.

VI. FLPMA: Unnecessary and Undue Degradation

Pursuant to the Federal Land Policy and Management Act ("FLPMA"), 43 U.S.C. § 1701 *et seq.*, "[i]n managing the public lands," the agency "shall, by regulation or otherwise, take any action necessary to prevent unnecessary or undue degradation of the lands." 43 U.S.C. § 1732(b). Written in the disjunctive, BLM must prevent degradation that is "unnecessary" and degradation that is "undue." *Mineral Policy Ctr. v. Norton*, 292 F.Supp.2d 30, 41-43 (D. D.C. 2003). This protective mandate applies to agencies planning and management decisions, and should be considered in light of its overarching mandate that the FFO employ "principles of multiple use and sustained yield." 43 U.S.C. § 1732(a); *see also, Utah Shared Access Alliance v. Carpenter*, 463 F.3d 1125, 1136 (10th Cir. 2006) (finding that BLM's authority to prevent degradation is not limited to the RMP planning process). While these obligations are distinct, they are interrelated and highly correlated. The BLM must balance multiple uses in its management of public lands, including "recreation, range, timber, minerals, watershed, wildlife and fish, and [uses serving] natural scenic, scientific and historical values." 43 U.S.C. § 1702(c). It must also plan for sustained yield – "control [of] depleting uses over time, so as to ensure a high level of valuable uses in the future." *Norton v. S. Utah Wilderness Alliance*, 542 U.S. 55, 58, 124 S.Ct. 2373, 159 L.Ed.2d 137 (2004).

"Application of this standard is necessarily context-specific; the words 'unnecessary' and 'undue' are modifiers requiring nouns to give them meaning, and by the plain terms of the statute, that noun in each case must be whatever actions are causing 'degradation.'" *Theodore Roosevelt Conservation Partnership v. Salazar*, 661 F.3d 66, 76 (D.C. Cir. 2011) (citing *Utah v. Andrus*, 486 F.Supp. 995, 1005 n. 13 (D. Utah 1979) (defining "unnecessary" in the mining context as "that which is not necessary for mining" – or, in this context, "for oil and gas development" – and "undue" as "that which is excessive, improper, immoderate or unwarranted.")); *see also Colorado Env't Coalition*, 165 IBLA 221, 229 (2005) (concluding that

in the oil and gas context, a finding of “unnecessary or undue degradation” requires a showing “that a lessee’s operations are or were conducted in a manner that does not comply with applicable law or regulations, prudent management and practice, or reasonably available technology, such that the lessee could not undertake the action pursuant to a valid existing right.”).

Here, that action is oil and gas leasing and development authorized by the RMPA. The inquiry, then, is whether the agency has taken sufficient measures to prevent degradation unnecessary to, or undue in proportion to, the development the proposed action permits. *See Theodore Roosevelt Conservation Partnership*, 661 F.3d at 76. For example, methane waste and pollution may cause “undue” degradation, even if the activity causing the degradation is “necessary.” Where methane waste and pollution is avoidable, even if in the process of avoiding such emissions lessees or operators incur reasonable economic costs that are consistent with conferred lease rights, it is “unnecessary” degradation. 43 U.S.C. § 1732(b).

Therefore, drilling activities may only go forward as long as unnecessary and undue environmental degradation does not occur. This is a *substantive* requirement, and one that the BLM must define and apply in the context of oil and gas development authorized through the lease sale. In other words, the FFO must define and apply the substantive UUD requirements in the context of the specific resource values at stake.

Further, these UUD requirements are distinct from requirements under NEPA. “A finding that there will not be significant impact [under NEPA] does not mean either that the project has been reviewed for unnecessary and undue degradation or that unnecessary or undue degradation will not occur.” *Ctr. for Biological Diversity*, 623 F.3d at 645 (quoting *Kendall's Concerned Area Residents*, 129 I.B.L.A. 130, 140 (1994)). In the instant case, BLM must specifically account for UUD in its NEPA analysis for RMPA/EIS, which is distinct from its compliance under NEPA, and is also actionable on procedural grounds.

VII. Conclusion

The Conservation Groups appreciate your consideration of the information and concerns addressed herein, as well as the information included in the attached exhibits. This information is critical and must be reflected in the agency’s analysis for the Mancos Shale RMPA/EIS. Conservation Groups reserve the right to supplement these comments, pursuant to 40 C.F.R. § 1502.9.

Should you have any questions, please do not hesitate to contact me.

Sincerely,



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