



January 11, 2012

Hon. Joe Martens, Commissioner
New York State Department of Environmental Conservation
625 Broadway
Albany, New York 12233-1010
RE: Comments of Environmental Defense Fund on the NYSDEC rdSGEIS, Proposed
Regulations and SPDES Stormwater Permit on Shale Gas Fracturing

Dear Commissioner Martens:

We are writing to you on behalf of the Environmental Defense Fund (EDF). EDF is an environmental advocacy organization with over 700,000 members nationwide, and over 70,000 in New York State. Since our founding on Long Island in 1967, EDF has linked science, economics and law to create innovative, equitable and cost-effective solutions to society's most urgent and difficult environmental problems.

An internal EDF team of toxicologists, attorneys, and energy policy specialists has reviewed the New York Department of Environmental Conservation (DEC)'s Revised Draft Supplemental Environmental Impact Statement (rdSGEIS) on the Oil, Gas and Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and other Low-Permeability Gas Reservoirs, and related proposed regulations and SPDES Stormwater permit. We commend the DEC for its efforts to update the regulatory framework for natural gas development in New York. The proposals address many important issues and in a number of cases does so adequately. Nevertheless, implementing the following recommendations would make New York State a leader in environmentally sound high-volume hydraulic fracturing (HVHF) and related activities – the state's permitting processes and regulations could serve as a model for the rest of the country and the world. By properly managing both the immediate and cumulative impacts of HVHF on New York's communities and ecosystems, the DEC can help minimize HVHF's potential negative effects.

Modern shale gas production is a major industrial and quasi-mining operation. It is characterized by large-scale surface infrastructure, intensive truck traffic, movement and injection of chemicals (many of them toxic) in close proximity to public water supplies, large demands on water supply systems, air pollution, and the production and transport of waste water with significant potential, long-term impacts on groundwater and surface water supplies, terrestrial ecosystems and communities. Improperly managed HVHF can negate both the economic and environmental benefits from the use of natural gas. Thus, EDF is working on a variety of model regulations and policies on HVHF that reflect the true risks and costs of drilling and ensure that the work is done safely and effectively. Our comments below reflect years of research and experience in over a dozen states across the country.

In 2009, we submitted comments on the NYSDEC dSGEIS on Shale Gas Fracturing. A copy of that comment letter is enclosed for inclusion as part of these comments. In addition to the matters raised previously, our major suggestions include:

- On implementation of appropriate regulations, we urge a **phase-in** approach, region by region, to build the DEC's capacity to implement its regulations, incentives for technical innovation, and the ability of local communities to plan for and mitigate development activities. Permitting should be limited to a single region for a minimum of three-years, and expanded to other regions subsequently, consistent with sound science and the necessary regulatory and enforcement resources to support expansion.
- On hydraulic fracturing chemicals, ensuring that **chemical disclosure** is not limited to those chemicals required to appear on Material Safety Data Sheets but instead covers *all* chemicals used in an HVHF operation, on a well-by-well basis, made available on a user-friendly website that allows the public to search and sort data.
- On **Greenhouse Gas (GHG) emissions**, requiring stricter reduced emissions completion standards, instituting explicit emission control requirements for well operators instead of merely requiring that operators submit a list of BMPs they plan to implement, and enumerating explicit mitigation targets.
- On **air emissions**, ensuring that the monitoring plan is effective and fully-funded. We propose a stakeholder group be assembled to assist the DEC in designing an optimal program for the essential task of rigorously quantifying emission releases.

- On **well construction**, improving certain provisions that represent safety hazards and elaborating others to conform to industry standards.
- On **waste management and water resource protection**, increasing the optimization and transparency of wastewater recycling and calling for a ban on fluid discharges to Publicly-Owned Treatment Works and private treatment facilities that use current technology other than thermal distillation.
- On **ecosystem fragmentation**, endangered species management and areas off-limits to surface drilling for natural gas using HVHF technology, New York's plans are largely laudable, with a few minor suggestions below. However, we feel that a conservation credit trading framework would be the most efficient and effective way to offset forest and grassland fragmentation and endangered species disturbances.
- On **cumulative impacts**, giving adequate authority and resources to counties and other local governments so they can 1) plan ahead on issues like zoning, noise, light, and visual impacts, and especially road use agreements; 2) track the impact of drilling over time and make changes to drilling practices as needed; 3) respond immediately and effectively to emergencies.
- On **emergency response plans**, operators should be required to submit their emergency response plans as part of their permit application.
- On **enforcement mechanisms**, instituting procedures to ensure consistent, effective, and prompt response to regulatory violations (including establishing a public database listing violations by well owner, operator and subcontractor); and instituting a strict liability penalty for any spills or leaks, whether or not they cause immediate economic damage.

Additional comments are included after exploring each of the above issues, followed by several annexes for reference.

As a general matter, we urge the DEC to consider the 90-day report generated by the Secretary of Energy Advisory Board (SEAB) Natural Gas Subcommittee, convened by U.S. Energy Secretary Steven Chu to make recommendations and outline immediate steps that can be taken to improve the safety and environmental performance of HVHF from shale formations. The Natural Gas Subcommittee was composed of leading experts with extensive experience in natural gas development from the government, academia and environmental groups, and their report has been widely hailed as balanced and authoritative. The report contains an important set of recommendations that set a

baseline for strong regulations. We respectfully request that the DEC affirmatively assess and publicly explain how the proposed rdSGEIS, regulations and permitting conditions achieve the recommendations made by SEAB. The comments that follow are informed by the work and conclusions of the SEAB committee. The report is included in these comments as an annex.

Phase-In Approach to Permitting

A safe, clean HVHF regime has two components: excellent rules and faithful implementation. Both are critical to create a successful regulatory system. New York's proposed rules are credible, and will be improved by incorporating comments submitted by members of the interested public. But even a perfect set of rules will not protect the environment without proportionate implementation, and we are concerned that the DEC's current capacity to regulate a new, pervasive and decentralized extractive industry falls short of the state's ambition in both financing and staffing. Further, the DEC's lack of experience administering a drilling program of this magnitude facing widespread public opposition in parts of the state suggest caution in immediately moving forward with permitting on a statewide basis.

Certain best practices, including chemical disclosure laws, have been honed in other states and should apply smoothly in New York. Many other aspects of the HVHF regulatory framework, however, will face unique conditions in the state, and in any case the implementation of these rules and regulations will be an entirely new experience for the DEC and related agencies.

With those factors in mind, we suggest that, once the EIS and regulations have been finalized, New York adopts a phase-in/capacity building process that concentrates permitting to a particular geographic area (possibly corresponding to a DEC Region) for a period of three years or more.¹ We suggest beginning in a region with relatively strong local political support for HVHF, high shale gas development potential, and fewer sensitive environmental resources like forest preserves, critical surface and groundwater watersheds, and endangered species habitats. By focusing its personnel and resources on a smaller area, the DEC can iron out the kinks and gain experience in the various phases of permitting, inspection and enforcement; test out the efficacy of its regulations; and pursue opportunities for innovative technologies that improve safety and reduce impacts. Experienced personnel from this region may go on to train DEC staff to activate other regions. With resources and ability fully in place, the DEC may implement

¹ The DEC can find authority to pursue a phase-in approach from SEQRA and elsewhere.

its regulatory scheme in areas of the state that are deemed appropriate for shale gas development.

Section 7.11.3 of the rdSGEIS, discussing transportation plans, provides a good argument for a phase-in: "Due to the generic nature of this analysis and the unknown road segments where these heavy- and light-trucks would travel, it is not possible at this time to identify specific operational and safety impacts, nor is it possible to identify operational or safety mitigation strategies for specific locations."

The discussion of potential roadway damage and challenges in setting up roadway damage and cost recovery systems is an excellent example supporting our phase-in proposal. If we do not have good answers to important problems then the state should proceed with a large-scale demonstration phase-in specifically designed to collect data and answers these questions.

Unconventional natural gas represents a potential pathway away from the dirtiest hydrocarbon fuels toward a sustainable energy mix. But since the health and safety of New Yorkers is at stake, it is imperative that we take the time to get the process right. For the credibility of the state and the good of the citizenry, New York should phase in natural gas development, region by region, gaining experience, capability, and trust along the way.

Chemical Disclosure

New York State has rightly recognized that many of the chemicals used in HVHF fluids pose a potential danger to human health and the environment if released. The DEC proposes that project sponsors disclose all *additive products* proposed to be used in hydraulic fracturing, including the product identity, proposed volumes and concentrations, and copies of Material Safety Data Sheets (MSDS) for the products if not already on file.² The proposed rules also require documentation that the additives proposed for use exhibit reduced aquatic toxicity and pose a lower potential risk to water resources and the environment than available alternatives— or documentation that available alternatives are not equally effective or feasible.

EDF commends the DEC for proposing that consideration of additive toxicity be incorporated into the disclosure requirements and recommends that the DEC consider tightening up the drafting of this language to make clear that project sponsors would be required to document the aquatic toxicity and risk to water resources and the

² See especially 6 NYCRR 560.3(c)

environment from the additives proposed for use – even if the project sponsor claims that alternatives are not as effective or feasible as the additives proposed for use.

Problematic elements of the current proposal

First, the proposed rules only require disclosure of the additive products *proposed* to be used in hydraulic fracturing. They do not require project sponsors to disclose what is *actually* used in a hydraulic fracturing treatment. Under current agency practice (though not required by current rule), project sponsors are asked to list the “type and volume of materials” used in well stimulation on their well completion reports.³ This falls well short of the level of specificity required in order to meet public expectations for hydraulic fracturing chemical disclosure. The proposed rules should clearly require public reporting of all chemicals *actually* used in hydraulic fracturing treatments on a well-by-well basis.

Second, the proposed rules limit disclosure to trade-name *additives* and to only those chemicals found on MSDS. According to industry experts, perhaps half or more of the chemicals used in hydraulic fracturing aren’t required to be listed on MSDS. Leaving out half of the chemicals used in hydraulic fracturing is inadequate and falls well short of disclosure policies that have been adopted in other states.

It is important to recognize that even though a chemical may not be considered “hazardous” under the OSHA rules that require MSDS listing, it may still be dangerous to human health and the environment. Chemical disclosure on MSDS is required under OSHA’s Hazard Communication Standard when scientific studies indicate that that exposure can be hazardous to workers in an *occupational* setting. The requirements for MSDS listing do not consider whether public health or the environment could be endangered when exposure occurs through *environmental* pathways – such as through contamination of groundwater, surface water or soil, or through such mechanisms as bioaccumulation, or in settings where exposure may be chronic.

Several states have recognized that many of the chemicals used in HVHF fluids may in fact be dangerous to public health and the environment, even though they aren’t defined by OSHA as being “hazardous” in the context of worker safety. Arkansas, Colorado, Montana, Texas and Wyoming have all adopted rules requiring the disclosure of each chemical used in hydraulic fracturing fluids – not merely those that appear on MSDS.⁴

³ See the DEC’s Well Drilling and Completion Report, *available at* http://www.dec.ny.gov/docs/materials_minerals_pdf/comp_rpt.pdf

⁴ See, e.g., David O. Williams, *Colorado oil and gas regulators impose new hydraulic fracturing chemical disclosure rule*, Colorado Independent, Dec. 13, 2011, *available at* <http://coloradoindependent.com/107883/colorado-oil-and-gas-regulators-impose-new-hydraulic-fracturing-chemical-disclosure-rule>

Likewise, the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission have recognized the importance of disclosing all chemicals and have passed resolutions to require such disclosure by companies utilizing Frac Focus, their voluntary reporting website that many states are beginning to use to mandate disclosure to the public.⁵

EDF's recommendation

In order for New York's disclosure policy to be at least on par with those in other states, EDF recommends that operators be required to disclose the following information on a well-by-well basis:

1. Operator name; HVHF treatment date; county; API well number; longitude and latitude of the wellhead; true vertical depth of the well.
2. Total volume of water used as the base fluid in a HVHF treatment, or total volume and type of base fluid if something other than water.
3. The identify of each additive used in the HVHF treatment, including trade name, vendor and a brief descriptor of the intended function or purpose of the additive.
4. The identity of each chemical used in the HVHF treatment, including the Chemical Abstract Service (CAS) registry number.
5. The maximum concentration, in percent by mass, of each chemical used in the HVHF treatment – as a percentage of the total HVHF fluid.

Disclosure provisions should include requirements for service companies and vendors/suppliers to provide operators any information necessary for compliance with the disclosure policy, subject to protections for legitimate trade secrets. EDF believes a high bar should be set for trade secret protections, in keeping with the recommendation made by the U.S. Department of Energy, Secretary of Energy Advisory Board Shale Gas Production Subcommittee, which reads:

“The Subcommittee believes that the high level of public concern about the nature of fracturing chemicals suggests that the benefit of immediate and complete disclosure of all chemical components and composition of fracturing fluid completely outweighs the restriction on company action, the cost of reporting, and any intellectual property value of proprietary chemicals. The subcommittee believes that public confidence in the safety of fracturing would

⁵ FracFocus, <http://fracfocus.org/>

be significantly improved by complete disclosure and that the barrier to shield chemicals based on trade secret should be set very high.”⁶

If a vendor/supplier, service company or operator claims trade secret protection for a chemical identity or chemical concentration, that entity should be required to disclose the chemical family name or other similar descriptor associated with the chemical as well as the chemical concentration, if applicable.

Trade secret claims should be accompanied by information substantiating the legitimacy of the trade secret assertion, and meaningful provisions should be put in place to allow citizens to challenge trade secret claims. In cases where chemical information for which a trade secret claim has been made is needed for medical diagnosis or treatment, emergency response or for regulatory investigation, the entity that has asserted the trade secret claim should be required to immediately provide that information, on a confidential basis, to the relevant medical professional, emergency responder or state agency.

Well-by-well reporting should be posted on a publicly accessible website that allows the public to search, sort and aggregate data by company, by chemical, by well and by geographic area. If the DEC website or another website acceptable to the DEC, such as FracFocus.org, does not immediately allow for searching, sorting and aggregating data by the above criteria, the DEC may wish to utilize Master Lists – providing aggregated views of chemicals used in HVHF treatments in New York – as a temporary alternative until such search and sort functions can be implemented on the DEC website or another website designated by rule as the disclosure platform for the state.

GHG Emissions

EDF feels very strongly that limiting methane leakage is a critically important component to environmentally sound management of hydraulic fracturing and natural gas delivery. The Secretary of Energy Advisory Board (SEAB) Natural Gas Subcommittee’s 90 day report, outlining best practices and providing an overarching framework protective development of shale gas, recommends the standards of performance:

Methane leakage and uncontrolled venting of methane and other air contaminants in the shale gas production should be eliminated except in cases where operators demonstrate capture is technically infeasible, or where venting is

⁶ See SEAB 90 Day Report, *available at* http://www.shalegas.energy.gov/resources/081811_90_day_report_final.pdf, at 24. This report is also included in the Annex.

necessary for safety reasons and where there is no alternative for capturing emissions. When methane emissions cannot be captured, they should be flared whenever volumes are sufficient to do so.⁷

Adhering to this standard, while stringent, would ensure that New York's development and production of natural gas minimizes GHG and other emissions per unit of energy. Currently, the rdSGEIS requires only that "[a]reduced emissions completion, with minimal flaring (if any), would be performed whenever a sales line is available during completion at any individual well or the multiwall pad." As suggested by the SEAB 90 day report, operators should be required to use "green" completion unless the DEC certifies that it is technically infeasible to do so or it otherwise poses a threat to safety. Flaring should only be used when it is not possible to capture the gas, and venting should be strenuously avoided. At a minimum, New York's standards should be no less stringent than those of Colorado and Wyoming requiring oil and gas operators to utilize reduced emission completions or green completions when completing or re-completing gas wells.⁸ Oil and gas companies tout green completions as one of the most highly cost-effective ways to maximize gas production and profits as green completions capture valuable gas that is otherwise vented or flared to the atmosphere.⁹

Other aspects of the rdSGEIS GHG emission mitigation proposal can be strengthened as well. In Section 7.6, the rdSGEIS proposes to require, as a permit condition, that HVHF operators submit a Greenhouse Gas Emissions Impacts Mitigation Plan incorporating a list of GHG-related BMPs planned for implementation at the permitted well site, a Leak Detection and Repair Program, required use of the EPA's Natural Gas STAR BMP for equipment located from the wellhead to the onsite separator's outlet, and a statement of conformity with the EPA's GHG reporting rule.

While the Best Management Practices described by the EIS have the potential to lower GHG emissions from HVHF operations, there is no requirement about the number of actions operators must undertake or the amount of reductions, relative or absolute, which must be achieved. Further, no particular emissions control requirements are made explicitly mandatory. Thus, the EIS does not provide incentives for operators to

⁷ See SEAB 90 Day Report, *available at*

http://www.shalegas.energy.gov/resources/o81811_90_day_report_final.pdf, at 18.

⁸ Colorado Oil and Gas Conservation Commission Rule 805(b)(3)(A); Wyoming Oil and Gas Production Facilities Permitting Guidelines at 15, 20 (March 2010), *available at*

<http://deq.state.wy.us/aqd/Oil%20and%20Gas/March%202010%20FINAL%20O&G%20GUIDANCE.pdf>.

⁹ EPA, *Reduced Emissions Completions: Lessons Learned from Natural Gas STAR Partners* at 1 (2010), *available at* http://www.epa.gov/gasstar/documents/reduced_emissions_completions.pdf. *See also* April 18, 2011 presentation to the Oil and Gas Task Force of the North Texas Clean Air Steering Committee; *available at* <http://nctcog.org/trans/committees/ntcasc/OGTF/041811/Items3BC.pdf>.

employ the most protective practices nor metrics for evaluation, and allows too much discretion for operators to choose which mitigation practices to adopt.

In order to reliably and quantifiably reduce GHG emissions, the DEC should identify specific measures to be used, explicitly require them, and then incentivize further reduction measures beyond a baseline. EDF is currently studying methane emissions throughout the shale gas supply chain, and would be happy to work with the DEC to establish environmentally responsible and commercially viable GHG emissions limits. As for reduction measures beyond these baseline limits, the DEC could pursue an offset requirement, potentially tied into a sectoral emissions reduction program like RGGI. Furthermore, given the significant global warming potential of methane emissions, and the real possibility of significant increase in methane emissions associated with natural gas production, transportation, and use in New York State, the DEC should consider whether it is appropriate to expand the RGGI program to include oil and natural gas operations in New York State within the RGGI program. Among other things, including methane emissions from oil and gas operations underneath the RGGI cap would create a powerful incentive for producers to minimize these emissions.

Air Emissions

The DEC describes a variety of explicit restrictions to be imposed on operators that would mitigate adverse air quality impacts from well drilling, completion, and production phases. The DEC also conceives of an air monitoring program at the regional and near-field/local levels, but leaves open the question of whether the program will be implemented by the industry or the DEC itself, and how the program will be funded.¹⁰

While the control measures are fairly comprehensive, they do not address fugitive emissions from storage tanks. In Texas, infrared video footage has shown extensive hydrocarbon emissions from storage tanks that appear to have contributed to local ecological damage.¹¹

Further, the rdSGEIS notes that information about the VOC content of emissions is lacking, but the plan to determine VOC levels is insufficiently specific.¹² Hexane and other VOCs are missing from the list of near-field pollutants of concern for inclusion in the near-field monitoring program (see Table 6.23).

Finally, the air quality monitoring program runs the risk of leading to false negatives if not conducted carefully. The rdSGEIS rightly points out the pitfalls of having the

¹⁰ See rdSGEIS Section 6.5.4

¹¹ <http://www.frackalert.org/index.asp?page=2>

¹² See, e.g. rdSGEIS Sections 6.5.1.5 and 6.5.2.3

industry conduct the monitoring program in a piecemeal manner when true rigor would run against the industry's interests. The rdSGEIS calls for funding for the state to run the monitoring program rather than industry, but does not make this a requirement or describe how the funding could be sourced.¹³ Also, there appears to be no opportunity for civil society input into the details of how an air quality monitoring program would be designed.

EDF recommends a suite of adjustments to strengthen the DEC's air quality mitigation proposals. First, fugitive emissions from storage tanks should be controlled through the use of vapor recovery units when VOC emissions from individual tanks or tank batteries exceed 5 tpy. Second, operators should be required to submit raw gas composition data to the DEC on a semi-annual basis. This data will vastly increase the state's ability to accurately determine the amount and speciation of VOC emissions. Third, the air quality monitoring program should be run by the DEC and funded by a commensurate fees paid by industry. The DEC should not issue permits until a funding arrangement for a DEC monitoring program is established – utilizing a phase-in period as discussed above could facilitate this process. Further, the DEC should assemble a stakeholder group to guide the design of an effective program. Such a group would include DEC staff, representatives from community groups, local government officials, ENGOs, and industry. Fourth and finally, hexane and other VOCs should be added to the list of near-field pollutants of concern for inclusion in the near-field monitoring program (see Table 6.23) for the activities where they are not already tagged for concern.¹⁴

Well Construction

EDF appreciates the DEC's efforts to create a safe and effective well construction regulatory scheme. However, we respectfully submit that certain provisions of Part 560 should be amended to reflect best practices; other provisions would benefit from additional specificity; and there is a provision which may represent a serious safety hazard and requires alteration. This section of the comments will explore these issues in some detail. We make reference throughout to the Model Regulatory Framework for Hydraulically Fractured Hydrocarbon Production Wells (the "MRF"). The MRF is not a finished document, but it represents a joint effort by several gas companies and several environmental NGOs to develop requirements for the construction and operation of hydraulically fractured oil and gas production wells that are as protective of the environment as reasonably possible. While a work in progress that has not been

¹³ See rdSGEIS Section 6.5.4

¹⁴ For justification and reference, please see Elizabeth Paranhos, *Protecting Human Health and the Environment through Rigorous, Cost-Effective Emission Standards for the Oil and Gas Industry*, Environmental Defense Fund & Wyoming Outdoor Council, Sep. 2010, available at http://www.whitehouse.gov/sites/default/files/omb/assets/oira_2060/2060_07222011-2.pdf

endorsed by EDF or any other organization, we submit a slightly redacted version of the current MRF draft as an annex to these comments for the DEC's consideration.

First and most importantly, it is critical that the DEC amend the following the following provision that poses a safety hazard.

§ 560.6(c)(19) of the Rule states as follows:

“Under no circumstances should the annulus between the surface casing and the next casing string be shut-in, except during a pressure test.”

This requirement is not good practice and is in fact a safety and environmental hazard, as it could lead to surface pollution, fire or a blowout. A better general rule would be to require an appropriate gauge and release valve.

Second, there are a series of provisions in Part 560 describing ambiguous or vague standards and requirements. For example, § 560.6(c)(1) mandates that a required “well prognosis” be revised by the operator if drilling reveals “significant” variation between anticipated and actual geology/formation pressures, but no clarification or guidance is given as to the interpretation of “significant” in that context. To cite another example, Part 560 uses the word “adequate” without any clarification or guidance a total of eight times (e.g., “...pit sidewalls and bottoms must be adequately cushioned...”)(See § 560.6(a)(4)(iii)). This loose phrasing increases regulatory uncertainty and decreases the likelihood that all operators will follow appropriate procedures and observe the intent of Part 560. Along the same lines, in order to clarify operator obligations and ensure appropriate practices, Part 560 should enshrine specific operational standards and API standards wherever possible and appropriate, including in place of the term “industry standards” in §§ 560.6(c)(3),¹⁵ (4)¹⁶ and (10).¹⁷

Third, some of the provisions in Part 560 call for blanket technology solutions that may not be appropriate for all wells. For example, § 560.6(c)(13) sets forth the blanket rule that “Intermediate casing must be installed in the well.” EDF believes that intermediate casing should be used more often than it is used currently, and we are open to the possibility that in New York all wells that undergo large volume hydraulic fracturing should have intermediate casing, but we are not certain that this is the case and we therefore encourage DEC to consider whether it may be desirable to set forth clear guidelines describing the circumstances where intermediate casing is and is not required.

¹⁵ Blowout preventer testing requirements.

¹⁶ Requirements for operations in wells where hydrogen sulfide is present.

¹⁷ Casing and cementing requirements.

Fourth, Part 560 contains several provisions for on-site pits that should be re-examined.

1. § 560.6(a)(4)(iv) of the Rule states as follows:

“Any reserve pit, drilling pit or mud pit on the well pad which will be used for more than one well [that is] constructed in unconsolidated sediments must have beveled walls (45 degrees or less)[.]”

All earthen pits should meet this requirement, not just those constructed in “unconsolidated sediments.”

2. § 560.6(b)(2) of the Rule states as follows:

“Except for freshwater storage, fluids must be removed from any on-site pit prior to any 45-day gap in use and the pit must be inspected by the department prior to resuming use.”

This requirement could limit water re-use and recycling to the extent that multi-use pits are utilized. The DEC should consider adding a narrowly drawn exception provision.

Fifth and finally, we believe that Part 560 should place greater emphasis on well-bore integrity and certain operational issues. The draft Model Regulatory Framework goes into great detail on these topics. In particular, although we do not endorse the MRF draft in all respects, we feel that Part 560 should be revised to the extent necessary to cover adequately those operational issues addressed in Articles IV through VI of the MRF, including but not limited to the following MRF topics:

- The casing strength and composition requirements set forth in Section 2(a) of Article IV;
- The well-head assembly and blowout preventer requirements set forth in Sections 2(b) and (c) of Article IV;
- The mud and drilling fluid requirements set forth in Sections 2(d), (e) and (f) of Article IV;
- The surface, intermediate and production casing requirements set forth in Sections 4 through 6 of Article IV;
- The cement-quality requirements of Section 4(d) of Article IV;

- The use of only state-approved cementers and service companies pursuant to Section 7 of Article IV and Section 4 of Article V, respectively;
- The pre-hydraulic fracturing pressure, cement-integrity and surface equipment testing requirements of Section 2 of Article V;
- The frac job monitoring and reporting requirements of Section 3 of Article V;
- The production and well monitoring requirements of Article VI; and
- The additional requirements for operations involving “close proximity wells” set forth in Sections 4(h) and 6(h) of Article IV and Section 2(d) of Article V. Rather than conceiving of “close proximity wells” as those that are 500 feet beneath the base of protected water, as is done in the current MRF draft, EDF suggests that DEC consider using 1000 feet.

With the adjustments and calls for further consideration described above, the rules laid out in Part 560 for well construction would ensure the safety of well pad crews and the state’s drinking water. New York has the opportunity to implement the most technically sophisticated and modern well construction framework in the nation, and EDF encourages the DEC toward this end.

Waste Management/Water Resource Protection

The salient features of New York’s waste management program for HVHF include covered watertight tank storage for flowback fluids and a requirement that operators submit a fluid disposal plan in their EAF Addendum demonstrating sufficient capacity to handle the waste with information on the planned disposition of the waste materials and permits where necessary. The fluid disposal plan also correctly requires operators to perform and report a chemical characterization of the waste¹⁸ (though we recommend that the waste characterization information be posted on a publicly accessible website that allows users to search and sort data).

The rdSGEIS indicates that current capacity in New York State to process HVHF wastewater is minimal.¹⁹ Publicly owned wastewater treatment plants are not designed for the volume or chemical constituency of frac fluids; privately owned wastewater treatment plants are few in number and can take years to come online; and deep well injection is largely unavailable in New York. We appreciate the DEC’s desire for

¹⁸ See 6 NYCRR Part 750-3.12

¹⁹ See sections 6.1.8.1 and 6.1.8.2 of the rdSGEIS

stringent standards and requirements governing the use of POTWs to process HVHF wastewater, but we are not persuaded they are strong enough. Further, we agree with the DEC's finding that the majority of wastewater will be recycled by operators, largely due to advances in recycling technology and its low cost compared to readily available alternatives. However, we are concerned that New York is failing to regulate wastewater recycling properly over the lifetime of the process.

Public and Private Wastewater Treatment Facilities

POTWs are not designed to handle the sort of wastewater produced by HVHF. Very few potential POTWs are willing and able to attempt to do so, and the significant requirements that operators must meet in order to allow wastewater processing at POTWs may prove an insurmountable barrier to permitting. Much the same can be said for private wastewater treatment facilities.

Recognizing that there is scientific uncertainty regarding what would constitute proper treatment of HVHF waste other than distillation, the DEC should ban the practice until the technology develops for safe processing of HVHF wastewater. Specifically, the ban should apply to discharges to facilities that use current technology other than thermal distillation. Such a ban would not have a significant practical effect on how wastewater gets treated because operators likely will not elect to dispose of their wastewater through POTWs and private treatment facilities for reasons listed above, but it would eliminate a lengthy regulatory process and send a message about the importance of keeping New York's waterways clean and healthy.

Wastewater Recycling

Given New York's existing water treatment and deep well infrastructure, we agree with the rdSGEIS that the vast majority of wastewater likely will be recycled. Wastewater recycling technologies are developing rapidly, and the technique is in increasing use throughout the country's shale gas deposits. The cost of recycling the wastewater generated by each well (which involves chemical or physical filtration processes and dilution with freshwater before reinjection into a new well) is far less than distillation in order to achieve safe drinking levels (the only treatment method of which EDF is aware that may be adequate) or trucking to deep well injection sites. Wastewater recycling, then, is a case where an environmentally sound methodology will in many cases also be the most cost-effective.

Recycling technologies are evolving rapidly, and it would be counterproductive to mandate the use of a particular recycling technique. However, in order to monitor and react to new recycling technologies and their consequences as they come on line, the

DEC should require operators to describe the recycling technologies they are using on their wells as part of the permitting process, and to file addenda if and when they change technologies. This will also facilitate the development of best management practices and allow knowledge-sharing between operators. Ultimately, the wastewater disposition for each well should be described in the comprehensive online database outlined elsewhere in the comments.

In addition to describing the proposed recycling technology, operators should report how many times the wastewater is reused before it is ultimately disposed, whether in a deep injection well or through thorough treatment (as well as the intended final destination). Because wastewater can become increasingly toxic with each reuse, it is critical to follow its lifecycle, and the DEC should be aware of the current and potential future toxicity of wastewater when it approves a disposition.

We are also quite concerned about the residuals resulting from each wastewater reuse cycle. Operators are removing increasing volumes of solids and fluids as part of their recycling program, as those solids and fluids impair total gas recovery. Proposed rule 730-3.12(d)(3) requires on-site facilities constructed specifically for the treatment and reuse of HVHF wastewater to demonstrate an approved method of residual disposal in compliance with 6 NYCRR Parts 360 and 364. However, not all wastewater recycling will take place on site. Further, since recycling residuals are potentially both toxic and radioactive, it is imperative that the DEC ensure their safe and prompt removal to appropriate disposal sites. The DEC should strengthen the regulation of HVHF wastewater recycling waste regardless of where it is produced.

With respect to the above recommendation, it is worth noting that the economics of wastewater recycling is different for large operators (who can move wastewater from one well to another at will) from those of small operators (which may not have ready access to a market for its wastewater). In Pennsylvania, wastewater brokers have emerged to help direct recycled wastewater where it is needed for small operators who might otherwise have difficulty coordinating such transactions. The DEC should monitor this industry as it emerges in New York, to decrease the costs and increase the efficiency of wastewater recycling for small operators and to ensure that the handling of wastewater bound for recycling is environmentally sound. The DEC should ensure that residuals from this type of wastewater recycling are tightly regulated.

Wastewater Definitions

We also urge the DEC to keep in mind that operators do not necessarily make a clear distinction between flowback water and production brine, and the rdSGEIS and proposed rules should be careful in creating one. When the distinction is used to make a

policy decision, like whether to allow for road-spreading and other arguably beneficial uses, the DEC runs the risk of differentiating between fluids that differ only by time of surfacing and have no fixed delineation between them. Production brine, although likely minimal because Marcellus is a particularly dry formation, may be even more toxic than the flowback water. As such, the DEC should not treat it less cautiously than the flowback water.²⁰

Further, we strongly suggest a clarification of what's meant by flowback fluids. The term is defined in 560.2(b)(7) as "liquids produced following drilling and initial completion and clean-up of the well or clean-up of a well following a re-fracture or workover." The term is used in 750-3.4(b)(3), requiring certification that HVHF flowback fluids will not be directed to or stored in a pit or impoundment. The DEC should specify if this is intended to include only the production brine that comes out of the well immediately after completion or re-fracture, or if production brine surfacing long after the initial completion or re-fracture is included as well. We can read the definition either way and we suggest the DEC clarify, because this ambiguity could lead to operator uncertainty.

Ecosystem Fragmentation and Endangered Species

Large tracts of grasslands and forests are an immensely important habitat for a large number of bird and other wildlife species. Many of these species depend on large, undisturbed interior tracts of forest or grasslands. A large amount of information about the dependence of various wildlife species on interior forests with significant buffers in the 500 to 1000 foot range was assembled in connection with the initiative to preserve Sterling Forest in the mid-1990's and provided to the DEC in comments by the Public Private Partnership to Protect Sterling Forest on the master development plan EIS.

The rdSGEIS does an excellent job of recognizing the ecological importance of such forests and grasslands. It recognizes that shale gas development in a particular location brings with it many types of disturbances that can effectively fragment these forested and grass land landscapes, reduce their undisturbed interior areas and thus have impacts on the viability of many species of wildlife. These fragmenting features include wells and well pads, roads, truck traffic, storage tanks, pipelines and impoundments. All can fragment a grassland or forest landscape. The rdSGEIS also prescribes a number of very useful measures to reduce the impacts of proposed shale gas fracturing with BMPs for reducing well site direct impacts at 7.4.1.1 and specific mitigation measures to reduce impacts to grasslands and forest lands at page 7-82 and 7-86. Similarly, the mitigation measures to avoid impacts on the habitat of endangered and threatened species in section 7.4.3 at 7-98 are good on the whole.

²⁰ See 7.1.7.2 in the rdSGEIS and 6 NYCRR 750-3.12(d)(6).

We have some specific comments relating to: 1) the minimum size threshold of 15,000 acres for qualifying Forest Focus Areas; 2) the lack of specificity as to what a permit applicant would have to provide by way of a mitigation plan if fragmenting impacts encompassed by the proposed rule cannot be avoided; and 3) the lack of inclusion of State Park land in the prohibition of surface disturbance associated with hydraulic fracturing in the class of protected state lands described in section 7.4.4.

Minimum Forest Matrix Block size threshold

The minimum forest matrix block size threshold for determining when special protections apply is too large, and the DEC should reduce it significantly. The identification of Forest Focus Areas as depicted in Figure 7.2 is based on forest matrix blocks developed by The Nature Conservancy (TNC) in 2003. This analysis identified, as we understand it, 26 forest matrix blocks ranging from 17,000 to 176,000 acres, for a total of 1.3 million acres, in the High Allegheny Plateau eco-region, with the minimum block size of 15,000 acres (p. 7-85). TNC, for purposes of its 2003 study, focused on acquisition and preservation priorities in the northeast, and therefore had reasons to use a 15,000-acre minimum size threshold in the selection of forest matrix blocks. It is not clear from the rdSGEIS or its discussion why this size threshold should be used for purposes of determining when shale gas fracturing landscape fragmentation impacts in forests underlain by the Marcellus Shale is significant so as to trigger application of the BMPs, mitigation measures and baseline assessments described.

If we use the 15,000-acre threshold, even the Sterling Forest tract of 17,500 acres in the NY Highlands in Orange County would have barely qualified. Indeed, within that tract, fragmenting roads and development did occur such that the largest tract of unfragmented forest was 13,000 acres, a tract that would not have qualified as a forest matrix block as we understand the proposed threshold. In our view, the threshold size for qualifying forest matrix blocks should be significantly lower. Even an unfragmented forested tract of one square mile to 1000 acres could have productive interior forest areas if interior forest areas had a buffer of 500 to 1000 feet from any kind of fragmentation. Forested tracts of at least 5,000 acres obviously have very considerable interiors. We would urge the DEC to consider a 1000 acre or no larger than 5,000 acre threshold insofar as the purpose is to preserve significant interior forests.

Indeed, the whole discussion of minimum forested patch sizes of 150 acres at pp. 7-86 to 87 suggests that the minimum size of forest matrix blocks should be much less than 15,000 acres. Similarly, the statement that only 2% of the Marcellus Shale subsurface areas would be the subject of the surface disturbance provisions described in section 7.4 suggests that the matrix block minimum size threshold is unnecessarily stringent and

carves out considerable, valuable interior forest areas. It would be useful to have an assessment of the percentage of subsurface areas that could be subject to the surface disturbance rules if the matrix block minimum size was reduced to 5,000 or 1000 acres.

Mitigation plan requirements

The rdSGEIS and associated rule should provide more specificity as to what kind of compensatory mitigation would be required if the kinds of grassland, forest or endangered and threatened species habitat fragmentation impacts described were unavoidable. Section 7.4.1.2 on grasslands at 7-82 and forest lands at 7-86 describes "supplemental mitigation measures" that an applicant would have to take if impacts were unavoidable, but does not appear to require any kind of compensatory mitigation program. The discussion relating to the protection of endangered and threatened species goes further in accordance with 6 NYCRR Part 182 by requiring development of a "mitigation plan" and implementation agreement if the proposed fracturing operation would require a Take Permit.

A threshold condition for developing a sufficient impact mitigation plan is starting with detailed baseline information about the affected area. In addition to compiling historical information on grassland and forest bird use of the proposed well site and conducting a minimum one year of field surveys at the site to determine the current extent of bird use as required by section 7.4.1.2, the biologists should document a complete picture of the baseline conditions at the site. This would include documentation of the current vegetation/habitat conditions (structure and composition), current management, landscape context (the surrounding land condition and uses), as well as bird use. By gathering baseline conditions it will then be possible to better measure the impacts of future land uses. Well-established baselines will also increase the usefulness of the DEC's required monitoring efforts (section 7.4.1.3).

Further, the DEC should develop up-front grassland and forest conservation plans that identify how and where mitigation is to be conducted for use by applicants whose pre-disturbance studies meet Departmental approval. This way, applicants will not be required to generate these conservation plans on a case-by-case basis, and instead will know beforehand what the mitigation responsibility will be for various actions in various locations.

Even the best mitigation plans, however, cannot eliminate the reduction in intact forest and grassland areas. Given the extraordinary value of interior grasslands and forest lands, the rdSGEIS and proposed rule should require development of a compensatory mitigation plan to offset the "unavoidable" impacts of shale gas fracturing operations on designated grasslands and forests. An initial requirement is that the applicant through

preservation or restoration measures would have to provide additional interior grassland or forest areas of comparable value as an offset for any impacts on such interior areas.²¹ In general, a 1:1 offset is unlikely to be sufficiently protection; a 2:1 offset would be more justifiable with qualifying interior areas having buffers of 1000 feet from any kind of human encroachment that scientific studies show have deleterious effects on specific species of birds or other wildlife.

Beyond that, we would urge the State that is demonstrating real leadership in terms of formulating a meaningful program regarding grassland and forest land fragmentation to consider establishing interior grassland and forest land as well as endangered species habitat recovery credit systems. Such systems could achieve the goals of assuring maintenance of or even an increase in grassland and forest land interior areas and endangered and threatened species habitat and providing for reasonable flexibility in the siting of shale gas operations.

We attach to these comments as an annex a copy of EDF's "Fort Hood (Texas) Recovery Credit System" by David Wolfe, Texas Regional Wildlife Director for EDF. While this memo describes the development of such a credit system for an endangered bird habitat at Fort Hood, this kind of methodology could apply to any kind of forest or grassland as well as specific endangered species habitat fragmentation. The memo describes the science of developing "metrics" for the system in terms of habitat values applicable both to the area to be impacted and the compensatory resource and baseline studies on the private land to be used for the compensatory measures.

While the development of such credit systems for different kinds of habitats has to be scientifically rigorous, we would welcome an opportunity to work with the DEC and other interested parties in the development of credit systems that could allow permit applicants to purchase the requisite number of grassland, forest land or endangered species habitat credits when DEC determines that all possible measures to avoid or minimize impacts have been exhausted, and yet issuance of permits is still justified.

State lands

Section 7.4.4 at p. 7-100 sets forth policies restricting shale gas fracturing and associated landscape surface disturbances on State-owned land. This section very briefly describes the high value of State Forests, Wildlife Management Areas and State Parks that justified the purchase of those lands in the first place and their public uses that justify their status as State lands. The section also points out that shale gas operations would have forest and grassland fragmentation impacts and impacts on recreational and

²¹ See section 7.9.4 in the rdSGEIS, which provides a similar proposal for visual offsets.

wildlife resources if those operations could proceed on these kinds of State land resources. The Section furthermore emphasizes that State Forests, WMAs and State Parks "comprise less than 6% of the area underlain by the Marcellus Shale" in NYS. In other words, a prohibition on shale gas operations within these State lands should not have significant implications for shale gas development in the State.

Inexplicably, in the final paragraph of this section at 7-101, the draft SGEIS declines to include State Parkland in the prohibition that applies to State Forests and State WMAs. While the rdSGEIS notes that the New York State Office of Parks, Recreation and Historical Preservation policy would impose a similar restriction on State Parks in 7.4.4 and elsewhere, all three types of protected lands should be addressed together. Section 3.02 of the Park, Recreation and Historic Preservation Law provides a mandate for the state to "operate and maintain the state park, recreation and historic site system to conserve, protect and enhance the natural, ecological, historic, cultural and recreational resources contained therein and to provide for the public enjoyment of and access to these resources in a manner which will protect them for future generations." This guiding principle of state law on management of State Parks does not envisage resource extraction; the rdSGEIS should recognize this law and include State Parkland in the prohibition as well. If there is reason for delineation between State Parks, State Forests and State WMAs, then the rdSGEIS should clearly state what it is and set forth specific protection and mitigation measures that would apply. It is unnecessary and inappropriate that any part of the State's parkland, in particular a state land resource as important to the NY metropolitan area as the Catskill State Park, would be open for shale gas development. Indeed, in the case of the Catskill State Park, some 85% to 90% of the Park would be off-limits either because the land is part of the Catskill State Forest or the NYC watershed, and reasonable buffers between any kind of encroachment associated with shale gas development and those specific, protected resources would justify a prohibition on shale gas development throughout that Park.

Reclamation

As a final point, we applaud the DEC for considering the importance of reclaiming and restoring land used for hydraulic fracturing once production has ceased. Returning the land to its original state provides significant environmental as well as aesthetic benefits to the lands' users and neighbors. To ensure that reclamation and restoration occur as proposed, we recommend that the DEC establish a bonding requirement for operators to reimburse the state for costs incurred in making the site whole. A bonding requirement would protect against operator inaction or bankruptcy.

Cumulative and Local Impacts

Much of the rdSGEIS, proposed regulations and permitting conditions focus on the potential impact of a given well over that well's lifetime. However, it is critical that the DEC take into account the likelihood that thousands of wells will be drilled in the Marcellus Shale region, especially in areas that overlie other unconventional natural gas-producing shales, for a potentially indefinite period of time. Even with the best air/water/waste management in place, the lowest impact system multiplied over space and time will still have considerable impact. With densities of two pads per square mile or more, the zone of impact of each well will inevitably overlap. These impacts are difficult to predict, quantify and address; many will not be known for years or even decades. Nevertheless, the DEC has a responsibility to minimize not just the immediately apparent but also the full cumulative impact of HVHF activities.

Local and cumulative impacts may best be mitigated through a combination of increased community input in permitting and more regulatory cognition of the cumulative effects of increased well pad operations over time and space. The current permitting approach has operators, on a well by well basis, submitting mitigation plans for transportation, noise, light, visual impact and other quality of life issues, all of which the DEC properly requires. However, the operators are not required to involve communities and local governments in formulating these plans, and should a plan violate a local land use ordinance, the DEC maintains that it is not required to abide by that ordinance in issuing a permit to operate.²² At the same time, even if operators *were* required to meet local government or community approval as a permitting condition, such community involvement would not necessarily mitigate the cumulative impacts of many such agreements made over time. So while local and cumulative impacts should be addressed more forcefully, we recognize that designing a program to do so can run quickly into complications, and no single program can address the entire problem.

With these concerns in mind, the DEC should take several steps to strengthen its program on cumulative and local impacts. First, to increase community involvement in mitigation planning – and thus a sense of agency and stakeholdership among community members – the DEC could combine the required transportation mitigation plan with the various quality-of-life mitigation plans on noise, light, and visual impacts into one plan and direct operators to consult with local governments and to incorporate their feedback as a prerequisite to DEC approval of the plans. The rdSGEIS already requires a mechanism like this for Road Use Agreements (7.11.1.3), which require owners to attempt to obtain such an agreement with the appropriate local municipality or document why it was not obtained. Colorado has adopted a Comprehensive Drilling Plan regulation²³ that opens development of a drilling plan to input from local governments and community groups before the state's Oil and Gas Conservation

²² See section 8.1.1.5 of the rdSGEIS

²³ COGCC Rule 216, available at http://cogcc.state.co.us/rr_docs_new/rules/200.htm

Commission makes a decision on the permit. Colorado's program is voluntary and covers many aspects of drilling practices, including proposed waste disposal plans and wildlife resources at the site. New York should consider adopting a similar program with a narrower scope of operational aspects covered while making participation mandatory. Further consideration should be given to whom operators should consult in each geographic area and what weight to give community opposition to a proposed mitigation plan. But in any case, giving local governments and communities more of a role in shaping HVHF development in their areas will likely increase environmental integrity of the practice, and is critical to earning public trust in the production process.

Second, the state needs to manage more carefully the rollout of permitting to limit the total cumulative impact of all permitted wells over time. Ultimately, the DEC is the only authority that may fully control the total number, density and intensity of well pas operations around the state. Despite the studies undertaken in the EIS and the experiences that other states have had, there is no way to know how large-scale HVHF will impact New York's communities and environment in the long term. Thus, by following our earlier recommendation that New York phase in HVHF permitting by starting with a single region, the state can develop a keen sense of the impacts of many wells in a particular area over a period of years. Such experience should inform the DEC's permitting decisions and make them more sensitive to the realities of HVHF operations. Further, the DEC could consider commissioning periodic environmental impact assessments to get a full, scientific perspective on the impacts of HVHF so far and recommendations on how to improve practices going forward.

Transportation Planning

In 7.11 the rdSGEIS discusses in a forthright manner the impacts of truck traffic related to fracturing operations on local, county, state and interstate roadways and associated transportation mitigation measures. It recognizes that the incremental heavy truck traffic associated with these operations could be significant in terms of added damage to roadways, added maintenance and repair costs and response planning costs. Interruption of otherwise normal traffic flows could be another issue. The rdSGEIS provides a mechanism for addressing these issues through the mandatory preparation of a transportation plan by each permit applicant, a process for applicants and local governments to enter into road use agreements that could potentially address these cost burdens and a role for NYSDOT and DEC to assure the adequacy of Transportation Plans as a condition of permit issuance. A strong transportation mitigation program is not only important in terms of avoiding damage road repair cost imposition on local taxpayers who otherwise may not benefit from fracturing operations but also in terms of creating incentives for operators to recycle return flows and thus reduce use of water

and production of wastewater and demand for virgin fracturing chemicals and thus minimize truck traffic and their associated impacts (7.11.4).

Since the rdSGEIS at 7.11.1.1 states that DEC would require that an applicant submit a transportation plan that would provide the kind of information described in this section, the submittal of such a plan with the required information and process for DEC and DOT review and approval should be included as part of the rule. While SEQRA provides a statutory basis for full mitigation, the rule more than the text of the EIS itself should incorporate information concerning all permit conditions.

Second, it is unclear if many town governments in rural areas and even counties would have the technical expertise on staff to conduct the kind of baseline assessments of local and county roads prior to commencement of fracturing operations. Further, even with good baselines, the ascription of damage responsibility to individual applicants may be problematic in a town or county with two or more operators. This is not discussed in the rdSGEIS. If such methodologies are readily available, the rdSGEIS should describe them. Local or county government could presumably retain expert consultants to conduct these baseline and periodic damage assessments, but that could cost a considerable amount of money. Without such an assessment, it may be unlikely that an applicant would be inclined to enter into a roadway agreement that specifies the amount that it would “pay for the work required to repair or prevent the road deterioration” (7.11.1.1 last sentence). If the local unit of government or a county does not have the funds, the baseline survey would be conducted by the operator in accordance with NYS traffic survey methods manual. However, it is unclear without some solid experience how valid this process would be where the local governments may be unable to conduct an in-depth review of the operator’s assessment. The rdSGEIS points out that counties have a means of seeking reimbursement for costs associated with road work under Highway Law 136(2) (7.11.1.4); it is unclear whether this procedure could be used to reimburse local town governments as well.

In its discussion of mitigating incremental damage to the State System of Roads (7.11.2), the rdSGEIS portrays a much more robust method for NYSDOT to assure that it is left whole in terms of dealing with fracturing operated associated roadway damage. We support the proposal that State permit regulations provide for an assessment of mitigation fees as a permit condition. Further, the State should not condone fracturing operators imposing “an additional financial burden on the state” as an impact that “may not be fully mitigated.” (7.11.2) The regulations should require that all such impacts be fully mitigated. However, the challenge that the state may counter in this regard underscores the challenge that local and county units of governments may face even more acutely. This suggests that NYSDOT with DEC should play a more aggressive role both in terms of providing technical assistance and funding, providing first response

training and cost reimbursement absent assurance that applicants are doing so and reviewing roadway agreements to assure that local and county governments and their taxpayers are treated fairly.

Emergency Response Planning

As the DEC has already recognized, emergency response planning is essential to the responsible exploration and development of natural gas resources in the Marcellus Shale formation. Although Section 560.5 of the proposed rules and regulations would require the well operator to develop and provide an emergency response plan (“ERP”) to the DEC at least three days prior to well spud, we feel that the ERP, or at least a preliminary ERP, should be submitted and evaluated with the initial application for a permit to drill. In particular, the ERP should include a detailed methodology for coordinating and training private, local, and state response teams to ensure that community safety, public health and water quality are adequately protected. Without adequate planning, coordination and training first responders, especially those in rural or small communities, will be ill-prepared for spills or catastrophic events relating to shale gas production. These events are not uncommon. In the first half of 2010 alone, there were at least 47 incidents at natural gas operations in Pennsylvania that required an emergency response by the state’s Department of Environmental Protection.²⁴

Although not suggested as an exhaustive list, the emergency response procedures that Sen. Casey proposed in the Faster Action Team Emergency Response (FASTER) Act are good benchmarks against which to judge the adequacy of ERPs. Requiring well operators to adhere to similar planning criteria would ensure that well operators have an employee knowledgeable in responding to emergency situations present at the well as necessary during the exploration, drilling and production phases. The presence of a person knowledgeable in emergency planning and response is essential to the early detection of emergency situations as well as the timely initiation and coordination of the emergency response.

Furthermore, to ensure the adequacy of ERPs, we urge the DEC to require well operators to have access to emergency response teams that can be on scene no later than three hours after being requested. Response teams must be comprised of individuals who are familiar with the well operations and equipment and its members must participate in well emergency training at least annually. Well operators would decide whether they would meet this requirement through the use of multi-employer composite response teams, commercial response teams provided through contract, or state-

²⁴ Steve Mocarisky, *Casey Seeks Input on Shale Gas Bill*, THE TIMES LEADER, Oct. 28, 2010, available at http://www.timesleader.com/news/hottopics/shale/Casey_seeks_input_on_shale_bill_07-26-2010.html

sponsored response teams. On an annual basis the DEC should require operators to provide the DEC with a report containing detailed information on the response team or teams assigned to each of the operator's wells. This report should include the qualifications and training histories for individual response team members along with a detailed inventory and location of the emergency response equipment that is available to each team. On an annual basis well operators must also provide an affirmative statement that the operator is in compliance with the DEC's emergency response requirements.

Recognizing the fact that accidental releases and gas well emergencies are dynamic and highly time sensitive events, we urge the DEC to require operators to inform it within one hour and to contact local first responders no more than two hours after the discovery of an emergency situation. This requirement would be in addition to existing requirements to notify the DEC of the occurrence of any non-routine incident. We fear that in the absence of timely notification and involvement of first responders emergency situations may quickly escalate in severity, and the size and impact of spills and accidental releases may increase dramatically. Because many well sites are likely to be located in remote areas that are outside the normal and reliable range of cell phone or radio coverage, we urge the DEC to require that well operators provide communications technology within a reasonable distance of the well site that will enable well operators to comply with the notification requirements discussed above.

Notification requirements and access to specially trained well incident response teams will be of limited benefit, however, if well operators are not required to provide first responders with appropriate training and equipment. The first couple of hours of an incident are often the most critical, and first responders will often be the only personnel on scene during the early stages of any emergency. Gas well emergencies or spills will likely present new and unique challenges that local first responders may not be equipped or prepared to handle without proper funding, training, and coordination. Furthermore, large scale incidents such as regional or state-wide flooding may quickly overwhelm the limited resources of the teams specially trained in well emergency response. For these reasons we recommend that well operators be required to provide annual training to local first responders on well hazards and proper emergency response techniques. Such training and information sharing will allow local fire departments and other first responders to incorporate well pads into their organization's pre-plans and will significantly improve emergency preparedness and response effectiveness.

Finally, the DEC should require well operators to include in their ERPs detailed assessments of the equipment and resources available to local first responders. Assessments of these local resources should then be compared against the scale of local well development and the types of hazards presented by the wells within given response

districts. If first responders on the local and county level are not adequately equipped to respond to the types of leaks, spills, tanker truck accidents, or other emergencies that may be expected to occur as a result of well development, then well operators must bear the additional cost of adequately outfitting departments.

Enforcement and Penalties

EDF has been generally pleased and encouraged by the DEC's proposed methods of enforcing permit conditions for high-volume hydraulic fracturing, as well as ensuring operator compliance with DEC regulations. As the DEC has noted, the Oil, Gas, & Solution Mining Laws vest the DEC with the authority to regulate the development, production, and utilization of the state's natural energy resources. ECL 23 grants the DEC broad authority to prevent or remedy such conditions as seepages, pollution of fresh water supplies, or the migration of oil, gas, brine or water into surrounding strata. Further authority for the DEC's ability to enforce its oil and gas well regulations is found in 6 NYCRR Part 550 and through the Division of Mineral Resources permitting conditions. ECL 71 makes it unlawful for any person to fail to perform a duty imposed by ECL 23 or otherwise violate any order or permit condition issued by the Department.

Although the rdGEIS provides generally robust enforcement mechanisms, the challenge is in ensuring that the accompanying monitoring, reporting, and penalty provisions are adequate to identify existing violations and discourage future ones. For example, despite similarly robust enforcement provisions, it has been the general experience of other states that fines and penalties are rarely assessed against well operators for permit violations. Of the 80,000 violations by oil and gas drillers operating in Texas in 2009, only 4% resulted in penalty action. Similarly low penalty rates are common in a number of states, and in Wyoming, the center of Rocky Mountain energy, a mere \$15,500 in fines were collected in 2010.²⁵

Such paltry penalty rates and amounts send incorrect signals to oil and gas well operators and may encourage lax adherence to permitting requirements. If the economic risks of cutting corners are perceived to be less than those of strict compliance, then operators will have limited incentive to comply with all of the necessary requirements the DEC has put in place. For these reasons, we would encourage the DEC to put into place mechanisms that will ensure that penalties are sought in a significant number of cases, especially those involving violations that cause or may reasonably result in spills, seepage, or the contamination of water resources. Furthermore, it is essential that the DEC maintain a detailed database that is readily accessible to the public, that shows each complaint and violation, and that allows for

²⁵ Mike Soraghan, *Puny Fines, scant enforcement leave drilling violators with little to fear*, E&E Publishing, Nov. 14, 2011, available at <http://www.eenews.net/public/Greenwire/2011/11/14/1>

tracking of each complaint and violation all the way through resolution and the imposition of any fines or penalties. By tracking violations, enforcement and the number of penalties assessed against individual gas producers the state will be given another tool to help determine and ensure effective and consistent enforcement across the state. This resource would also provide field personnel and regulators with important information on individual operators, and would assist in levying appropriate fines or penalties against operators that are chronic or particularly egregious offenders. Additionally, the transparency and public nature of the reporting tool would give well operators an added incentive to avoid violations and correct them in a timely fashion.

Even with the most robust enforcement mechanisms in place, unintended or unlawful releases or spills will undoubtedly occur. While these releases may be dealt with, in part, through the means of existing administrative, civil or criminal actions, we urge the DEC to impose mandatory fines for any release in violation of the ECL or any permit provision. These penalties should be based on the amount of the release, and would be in addition to, and independent of, any penalties or fines that require evidence of damage. Assessing the damage caused by any release, especially one involving the seepage or migration of fracturing fluid may require the expenditure of substantial amounts of time and money, therefore, mandatory penalties assessed solely on the basis of amount of the release are an essential element to the state's enforcement policy.

While we leave it to the DEC to decide how best to implement mandatory penalty provisions, one suggested method would be to add per gallon penalties to the penalty calculations included in the DEE-1, Civil Penalty Policy. We would suggest that these penalty calculations should be modeled after Section 311 of the Clean Water Act, and would impose a maximum penalty of \$1000 per gallon of hydraulic fracturing fluid released. Upon a finding of gross negligence, the maximum penalty may be four times that amount. The cumulative impact of even small releases may prove great, therefore, we urge the Department to include in the penalty calculations a minimum penalty of \$5000 for any release, regardless of amount. We believe that the addition of these mandatory penalty provisions will encourage compliance and will serve as a financial deterrent against lax adherence to permitting conditions and regulations.

Other Comments

Public Disclosure

EDF feels strongly that public disclosure of operating practices and other details on a well-by-well basis would improve environmental integrity and help educate the public on risks and mitigation options for hydraulic fracturing and gas extraction operations. As we have mentioned elsewhere in the comments, we advocate that the DEC expand its

Oil & Gas Database (<http://www.dec.ny.gov/cfm/xtapps/GasOil/>) or use a similar website to catalogue, make searchable and easily display important information related to shale gas wells. At a minimum, we would hope the website would display a well's permits; its owner, operator and subcontractors; waste disposal and water management plans, including tracking water and waste on a lifecycle, cradle-to-grave basis; a list of chemicals used on site; use of open pits; inspection records; and any sort of regulatory or permitting violations by type, date, and party at fault. To the extent that this information is already publicly accessible, organizing it onto a website should not place a serious additional burden on the state, and would greatly assist in emergency response and enforcement of regulatory violations.

Resources for Implementation

It is essential that the State of New York secure and commit sufficient financial resources to administer the proposed HVHF regulations and permitting conditions before approving any permit applications. Regardless of how the resources are raised and distributed, it is critical that they meet Departmental needs for the necessary studies, inspections and investigations associated with permitting and managing a distributed well network. Our phase-in proposal would allow the DEC to gain a more accurate understanding of the true costs of administering a hydraulic fracturing program before rolling it out statewide.

Adopting Permitting Conditions as Regulations

It is difficult not to see the proposed governing scheme for HVHF in New York as a hodgepodge of permitting conditions, environmental assessments, mitigation plans and regulations. Operators may benefit from a conversion of many of these soft requirements to hard ones. If all of the rules governing HVHF were regulations, operators would gain a certainty that their duties are a matter of law and unlikely to change suddenly. We urge the DEC to codify into regulation as many of the permitting conditions as feasible. While not every permitting condition would benefit by codification – for example, certain air quality standards are already memorialized in broader state and federal legislation – other requirements presented in the rdSGEIS such as the transportation plan are not governed elsewhere. In the alternative, the DEC could add a preamble to the regulations explicating how the agency plans on interpreting and implementing the permitting conditions – such a gesture would promote administrative efficiency and effectiveness without the complication of adopting permitting conditions as regulations.

Respectfully Submitted,

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Annexes

Annex 1: Comments of Environmental Defense Fund on the NYSDEC DSGEIS on Shale Gas Fracturing, December 31, 2009

Annex 2: Secretary of Energy Advisory Board Shale Gas Production Subcommittee 90-Day Report, August 18, 2011

Annex 3: Draft Model Regulatory Framework for Hydraulically Fractured Hydrocarbon Production Wells, January 11, 2012

Annex 4: Fort Hood Recovery Credit System, Environmental Defense Fund, December 2011



December 31, 2009

Hon. Pete Grannis, Commissioner
New York State Department of Environmental Conservation
625 Broadway
Albany, New York 12233-1010
RE: Comments of Environmental Defense Fund on the NYSDEC DSGEIS on
Shale Gas Fracturing

Dear Commissioner Grannis:

We are writing to you on behalf of the Environmental Defense Fund (EDF). EDF is an environmental advocacy organization with over 700,000 members nationwide, over 70,000 in New York State. Since our founding on Long Island in 1967, EDF has linked science, economics and law to create innovative, equitable and cost-effective solutions to society's most urgent and difficult environmental problems.

An internal EDF team of toxicologists, attorneys, and energy policy specialists has reviewed the New York Department of Environmental Conservation (DEC)'s Draft Supplemental Environmental Impact Statement (DSGEIS) on the Oil, Gas and Solution Mining Regulatory Program Well Permit Issuance for Horizontal Drilling and High-Volume Hydraulic Fracturing to Develop the Marcellus Shale and other Low-Permeability Gas Reservoirs. We commend the DEC for its efforts to update the regulatory framework for natural gas development in New York. The DSGEIS addresses many important issues and in a number of cases does so adequately. On balance, however, we find the DSGEIS inadequate both as matter of law and a matter of policy.

Natural gas is a relatively clean, low-carbon fuel compared to other fossil fuels. Nationally, shale gas represents a potentially large new domestic supply of natural gas that could contribute to a significant near-term reduction in carbon

dioxide pollution from the U.S. power sector. The Marcellus shale is acknowledged to be the largest of these potential new reserves.

In New York, the economic benefits of shale gas development could be considerable. New York is the fourth largest natural gas consuming state in the nation. Over 50 percent of all homes in New York State are heated with natural gas, and nearly 30 percent of the electricity consumed in New York is generated through the combustion of natural gas in New York State. Today, the vast majority of dollars used to purchase natural gas for New York's needs flow out of state. Proper development of Marcellus shale gas could have significant potential economic benefits for New York State and certainly for the economic reinvigoration of parts of the State underlain by this formation, such as the southern tier.

The caveat, and it is a big caveat, is that development of the Marcellus shale natural gas reserves in New York State must be accomplished in a manner that protects the environment of the State and the health of its residents, not only over the next few years, but for years and decades into the future. This is a tall order since today's shale gas production is a major industrial and quasi-mining operation characterized by large-scale surface infrastructure, trucking, movement and injection of chemicals, many of them toxic, demands on water supply systems, increased air pollution and the production and transport of waste water with significant potential, long-term impacts on groundwater and surface water supplies, terrestrial ecosystems and communities. In general, if the State wants to see responsible shale gas development proceed in the near-term, it should set about developing the regulatory system that will be protective of public health and the environment in the long-term. The State lacks this comprehensive regulatory system today.

A year ago we submitted comments on the Draft Scope for the DSGEIS. A copy of that comment letter is enclosed for inclusion as part of these comments. In addition to the matters raised previously, our major concerns are:

Disclosing and evaluating the toxicity of fracwater and return flow chemicals. DSGEIS Table 6-1 provides a long list of chemicals in fracwater and return flows. Some of the chemicals in the return flows are not in the fracwater. At least twenty-six chemicals are known or suspected carcinogens. Fifteen are well-established neurotoxicants, and 42 are known or suspected developmental or reproductive toxicants. At least 46 chemicals are likely to be toxic to ecological receptors. Most chemicals on this list have not undergone comprehensive toxicity testing to evaluate risks to human health or the environment. Neither EPA nor the State Department of Health has developed drinking water standards for most of these chemicals.

We have attached as part of today's comments a spreadsheet titled, "EDF Review of Toxicity of Compounds Found in Frac and Flowback Fluids." The

spreadsheet presents the known health effects and other characteristics for each substance on DSGEIS Table 6-1 as these characteristics have been portrayed in a number of lists and databases (i.e., the TEDX database maintained by the Endocrine Disruption Exchange and 30 other lists and databases monitored by EDF). The spreadsheet also identifies 2 additional toxic chemicals from Table 6-1 that are targeted for regulation as Substances of Very High Concern by the European Union pursuant to their Regulation, Evaluation, Authorization, and Restriction of Chemical Substances (REACH) program.

The toxicity status of these chemicals needs to be characterized by the EPA or the State to allow for proper assessment of the potential impact of the use of these chemicals on surface and ground water, as well as effective storage, treatment and disposal methods. If EPA or the State has not made a specific finding for a specific chemical regarding its toxicity, it should not be assumed to be without adverse risk to public health. Indeed, absent a Maximum Contaminant Level (MCL), Maximum Contaminant Level Goal (MCLG), or state standard, the concentration determined not to result in adverse effects on public health in surface or groundwaters with total dissolved solids (TDS) below 10,000 ppm should be assumed to be zero.

If the State is serious about large-scale industrial development of Marcellus shale natural gas, then, ideally with EPA and perhaps neighboring states such as Pennsylvania, it should embark on a comprehensive program of characterizing and setting standards for injection fluid and flowback water chemicals. Until that task is well underway, the State should allow such shale gas development only in areas where the accidental or permitted release of such chemicals would pose virtually no risk of harm to surface or groundwater supplies or ecologically sensitive areas.

Given that many of the chemicals used in hydraulic fracturing are extremely toxic and are known to result in adverse health effects such as cancer, and that the available information regarding many other constituents is inadequate, EDF urges:

- (1) that operators be required to disclose to the state all frac fluid constituents actually used at particular sites;
- (2) that this information be released to the public except to the extent that release would constitute disclosure of a trade secret;
- (3) that information entitled to trade secret protection nevertheless be provided on a confidential basis to qualified medical personnel who ask to see it;
- (4) that DEC devote substantial resources to helping to characterize the health effects of those frac fluid constituents that have not been well characterized;

- (5) that DEC encourage to the maximum extent practicable the disposal of waste into deep geologic formations pursuant to the Underground Injection Control Program;
- (6) that DEC minimize to the extent practicable practices that result in release of pollutants into the atmosphere; and
- (7) that DEC proceed with extreme caution before authorizing waste disposal methods other than deep well injection. If the State selects surface discharge as an option, then we recommend that appropriate steps be taken to ensure proper treatment of the waste water to prevent harm to human and ecological receptors. Specifically, surface discharge permits must require a robust evaluation of each individual chemical that is or could be present in the discharge fluid. Such evaluation must include a toxicity assessment for each chemical component to demonstrate that the residual contamination level will not pose a significant risk to human health or the environment. Additionally, this evaluation must consider potential cumulative impacts by grouping potential risks for each individual chemical by hazard endpoint (e.g., cancer, reproductive harm, developmental harm, neurotoxicity, etc.) Proven conservative methodologies should be used to accomplish these tasks, to guarantee that vulnerable populations, be they human or ecological, will be adequately protected.

Designation of areas off-limits for any shale gas development. Concern about the release of frac chemicals and the inadequacies of their assessments as well as cumulative impacts of drilling waste handling and transportation infrastructure underscore the need to block all shale gas development where determinations are made that surface and groundwater watersheds are especially critical, airsheds are especially vulnerable, or ecosystems are especially sensitive. Perhaps the best example of a municipal water supply watershed that should be excluded from any shale gas development for the foreseeable future is the NYC Catskill-Delaware watershed, an extraordinarily sensitive and critical watershed. No development should occur in such a critical area unless: 1) the State and/or EPA has completed the comprehensive review of the toxicity status of all chemicals used or produced in the fracturing extraction process; 2) reliable flowback water storage, transport and disposal techniques are readily available; and 3) experience and technology would provide a basis for a credible assessment of no risk of long-term damage to such vital resources. The justification for such a designation includes but is not limited to uncertainties about the toxicity and fate of injection fluids and flowback waters, the potential for and impacts of spills and unintended accidents, and impacts of transportation of materials and gas. Moreover, prohibiting development in this watershed at this time is appropriate given the commitments made by New York City to preserve land in exchange for not having to build water filtration facilities and the fact that the Filtration Avoidance Determination does not expressly allow for such activities.

In addition to designating the NYC Catskill-Delaware watershed as off-limits, the State needs to establish a process, whether by petition or otherwise, for designating additional watersheds and sensitive areas where development is not in the public interest and should be prohibited. Such designations would prevent the creation of expectations on the part of landowners or leasing companies that they might be able to embark on development. Conversely, the State should establish a regional land use process for designating areas with shale gas potential that can be safely developed with supporting transportation, chemical transport and waste handling infrastructure in the absence of a completed assessment of the toxicity of chemicals in frac injection fluids and flowback water, adoption of surface, groundwater and drinking water standards for such chemicals and implementation of regulatory programs that will assure compliance with such standards.

The status of EIS described standards and cumulative impact assessments.

The DSGEIS describes a wide range of potential impacts of shale gas operations on public health and the environment and suggests standards that could apply to manage or minimize those impacts, such as the proposed supplementary permit conditions for high-volume hydraulic fracturing describing in Appendix 10. The description of a standard or supplementary permit condition in an EIS, such as a visual, noise or greenhouse gas (GHG) impact mitigation plan consistent with the SGEIS, does not make that standard or condition operative or enforceable. That happens through a regulatory program that authorizes DEC or the State Department of Health to impose and compel compliance with such a standard or condition. Thus, the SGEIS should specify the statutory or regulatory basis for the imposition of any standard or proposed permit condition described in the DSGEIS.

A generic EIS is a very useful setting in which to address the cumulative impacts of a category of activities that might occur in a designated geographic area. The general categories of groundwater, surface water, air and land resource ecological impacts associated with fracturing operations and the use of fracturing fluids include:

1. Spills at the surface at the wellhead or associated with surface tank or impoundment storage or transportation of injection chemicals and flow back fluids;
2. Permitted discharges pursuant to poorly designed/managed NPDES permits or at WWTPs that are not equipped to handle and treat the TDSs and/or chemicals found in flowback fluids;
3. Air emissions from centralized flowback fluid impoundments;
4. Leaks due to poor well construction and/or operation. By requiring surface casing that only protects 1,000 TDS water, rather than 10,000 TDS water, New York may be sanctioning poor construction;

5. Leaks due to migration through transmissive faults or fractures, or unplugged wellbores that penetrate the injection zone that would be very hard to substantiate;
6. Transportation impacts associated with the conveyance of water, chemicals, flowback waste water fluids, equipment or otherwise by truck or pipeline, including land use, congestion, highway expansion, air, noise, visual and vegetation land cover changes impacts.

While these impacts may be described and assessed individually or generically, their cumulative impacts in particular geographic settings may be highly significant. A concentration of wells in a particular town or county will have very different local or county-wide truck or other infrastructure impacts from those associated with a small number or scattered well operations. The likelihood of accidents or spills in a particular geographic area may increase with intensification of fracturing operations. The cumulative land use, visual, noise, ecological, land cover change impacts associated with a large number of wells, pads, storage tanks, pipelines, surface storage impoundments and truck movements in a region, such as a county, may be highly significant and not well understood by the affected populations and businesses. It may not be possible to foresee exactly where such concentrations of fracturing activities may occur or their sequencing. However, perhaps triggered by the timing and geographic location of fracturing operations described in applications, DEC should undertake cumulative impact assessments at a regional i.e., county or town, level in region-specific EISs.

Major industrial operations are often allowed only in areas zoned for those purposes. They are typically kept away from areas dedicated to residential, retail or office commercial, school, park and recreation and other such land use purposes, as well as critical surface and groundwater watersheds or important terrestrial ecosystems and public land resources. From a land use impact perspective, conducting land use planning at a regional level that entails designation of appropriate areas for potentially concentrated fracturing operations may be the best strategy for minimizing land use, transportation and infrastructure impacts. Absent such a regional planning framework, the location and pace of specific operations could be dictated by specific landowners who are willing to enter into lease arrangements with private fracturing firms or by those firms seeking out particular resources. However, the “spillover” effects of such private decisions on other land owners and communities are so immense that private decisions should not compel either the location or pace of development.

DEC could periodically invite firms engaged in Marcellus shale gas development to indicate general geographic areas in towns or counties where they would like to initiate development activities. In conjunction with the affected towns and counties, DEC could initiative a process to designate specific areas suitable for shale gas operations based on local or county land use and zoning-type considerations.

Pilot projects and best practices. For the same reason that DEC should designate critical resource areas as off-limits for shale gas development, it should, working with local governments, designate productive areas that can host pilot-type development of this resource. To gain experience with these new shale gas extraction technologies and to help it refine an effective regulatory and economic management framework, the State, working with the industry and other stakeholders, should identify a small number of pilot project areas that would be prime candidates for near-term investment in shale gas infrastructure and development, and not otherwise off-limits as a sensitive or critical watershed, airshed, or ecological area. Industry best practices should be demonstrated in these pilot development areas. Such a set of pilot test areas would allow for near-term projects of significant size with postponement of development elsewhere pending completion of the comprehensive regulatory framework.

Shortcomings of regulatory framework and need to strengthen it. Current State oil and gas and solid waste regulations were not written with large-scale shale gas fracwater injection and flowback water management in mind. As important as the SEIS process is, it is not a substitute for updating the regulations. Accordingly, EDF calls on the DEC to initiate a thorough review of its underlying rules in the near future. New York needs a regulatory regime that is specifically designed to address the full range of environmental issues that shale gas development raises. We anticipate that a formal rulemaking process will address both issues that have been raised in the DSGEIS and other issues.

Centralized Surface Flowback Impoundments. The DSGEIS acknowledges that above ground storage tanks have some advantages over surface impoundments and that the DEC's experience is that "landfill owners prefer above ground storage tanks over surface impoundments for storage of landfill leachate (which the DSGEIS compares flowback water to). There is good reason for this preference, since the risk of spills and underground seepage is much greater from pits than from tanks and uncovered storage facilities can lead to substantial air emissions. Given this information, the DSGEIS should firmly encourage use of storage tanks for flowback water (and produced water) and only limited use of centralized impoundments.

In the current draft SGEIS, centralized surface flowback impoundments appear to be authorized without a site-specific environmental assessment or environmental impact statement as long as they comply with setback distances from reservoirs, streams, wetlands, storm drains, lakes, ponds or private or public water supply well. This is not adequate for several reasons, but a single reason will make the point – consideration of site-specific topology is clearly necessary if setback distances are to be reasonable, but the draft SGEIS proposes uniform setback distances that fail to take account of this critical factor. All centralized impoundments must be considered on a case-by-case basis so that permitting

decisions can be informed by a site-specific environmental assessment or environmental impact statement.

The proposed oversight of centralized impoundments also needs to be modified in order to assure that these facilities cannot be used as a way around proper waste disposal. Long-term storage of waste in impoundments creates increased risks of leakage to land and water and certain increases in emissions of chemicals into the atmosphere. Additionally, long-term storage could lead to huge financial and environmental problems for the state if operators disappear from the scene before fulfilling their disposal responsibilities. Centralized impoundments cannot be allowed to short-circuit requirements that operators demonstrate viable waste disposal plans prior to drilling and implementation of those plans in a timely manner once fracturing is completed. It is important to impose two different time limits – one applying to the length of time the impoundment itself can operate and another that governs the length of time waste can remain in the impoundment. We suspect that in most cases it will be reasonable to permit the impoundments themselves to operate for two or three years and to require that waste stored in impoundments (or its equivalent in kind) remain in the facility for only 30 to 60 days. Establishing these time limits should be done by rule and/or through permit conditions, rather than in the SGEIS, since the limits should be based in part on industry needs and the needs will vary through time and from location to location and perhaps over the life of operations at particular locations.

Evaluation of generic methods of ultimate disposal of shale gas waste water. The DSGEIS generally provides no discussion of alternative methods of ultimate disposal of flowback water referring to the 1992 GEIS and State rules. While applicants will have to propose specific disposal plans, the rules and DSGEIS also should require that the disposal option “planned” for particular sites must be in place prior to drilling or that there is good reason to expect that the option planned for a particular site will be operational within a few weeks after fracturing operations are completed. Moreover, the rules and DSGEIS should discuss and assess general types of disposal, and the State’s overall capacity for such disposal, including underground injection of waste water, treatment in municipal or private sewage treatment plants and reuse with treatment, as well as management of any residuals following treatment and out-of-state industrial treatment plants. In states like Texas and Louisiana, underground injection of gas extraction wastes is routine. It is unlikely that this will become as common in New York given the challenging geology and the virtual absence of existing disposal well infrastructure.

In Pennsylvania gas drillers are generating contaminated water faster than the state’s treatment plants can handle it. One result of this rush to develop Marcellus shale gas in Pennsylvania is that the Monongahela River has been contaminated by the increased amounts of TDS. There are many other contaminants of concern as well. As noted below, Pennsylvania is now rushing to

amend its Wastewater Treatment Requirements in order to reflect the new and different contaminants being handled by their systems. Similar to Pennsylvania, it appears that industry in New York may be tempted to rely largely on municipal or private waste treatment plants and that New York is no better prepared than Pennsylvania for the influx of new and undefined TDS and chemicals.

There should be no drilling in the Marcellus shale in the absence of overall waste disposal capacity that is adequate to cope with the extent of development and site-specific disposal plans that are tied to capacity that already exists at the time the plans are approved.

Ground Water Protection. The risk of harm and probability of contamination of New York State's water resources is a reasonable concern in light of the ground water contamination that has occurred in Pennsylvania due to Marcellus shale gas drilling in that state. It is pertinent to note that the Pennsylvania Environmental Quality Board has proposed amendments to its Wastewater Treatment Requirements in order to establish new effluent standards for new sources of wastewaters containing high TDS concentrations. In light of these developments and the serious risks involved, there is a need for revamping the regulations applicable to water resources in order to obtain stronger regulations to protect ground water resources in New York State. Towards this end, we recommend that the New York State regulations defining what groundwater needs to be protected (through the length of surface casing for example) be amended to reflect the 10,000 mg/l standard used in the Federal Underground Injection Control Program. Other states use this standard for both UIC and non-UIC wells and if states desire the continuation of the SDWA exemption for hydraulic fracturing they will be wise to upgrade their own regulations to be as protective as the federal program.

Under Federal law, an "*underground source of drinking water*" (USDW) is defined as an aquifer or its portion:

1. Which supplies any public water system; or which contains a sufficient quantity of ground water to supply a public water system; and
 - (A) Currently supplies drinking water for human consumption; or
 - (B) Contains fewer than 10,000 mg/l total dissolved solids; and
2. Which is not an exempted aquifer. 40 C.F.R. § 146.3.

Under New York State law, for oil and gas regulatory purposes, "potable fresh water" is defined as any water containing less than 250 parts per million of sodium chloride or 1,000 parts per million of total dissolved solids. 6 N.Y.C.R.R. §550.3. Water containing sodium chloride or total dissolved solids exceeding these standards is defined as "salt water". 6 N.Y.C.R.R. §550.3. Similarly in relation to water quality and purity standards, "Fresh groundwaters" are defined as those groundwaters having a chloride concentration equal to or less than 250 mg/L or a total dissolved solids concentration equal to or less than 1,000 mg/L. 6 N.Y.C.R.R. §700.1. "Saline groundwater" is defined as groundwater having a

chloride concentration of more than 250 mg/L or a total dissolved solids concentration of more than 1,000 mg/L.

Thus, under Federal law ground water containing up to 10,000 mg/l of total dissolved solids (TDS) is protected however, on the other hand, under New York State law, the scope of protection of ground water is much narrower, wherein only ground water with a TDS concentration of up to 1,000 mg/l is protected.

Cement Casing. The DSGEIS requires or may require running cement bond logs and/or other logs to be run for evaluation purposes.

We suggest that references to “cement bond logs” be eliminated from the regulations and that the language below be used instead. This language has been proposed by EPA in its pending rulemaking on geologic sequestration of carbon dioxide and it has been endorsed by the Ground Water Protection Council (GWPC). Very similar language is being supported in the EPA rulemaking docket by the Interstate Oil and Gas Compact Commission (IOGCC), the American Petroleum Institute and a number of individual oil and gas companies.

“The integrity and location of the cement shall be verified using technology capable of evaluating cement radially and identifying the location of channels to ensure that USDWs are not endangered.”

As EPA, GWPC, IOGCC and many in industry have recognized, cement bond logs are no longer state-of-the-art and it is reasonable to require radial surveys capable of identifying the location of channels. We are confident that DEC recognizes the importance of this issue and urge the agency to modernize its requirements for cement job evaluation.

Damage mitigation fund and bonding requirements. Even with the most thorough regulatory framework in place, the introduction of toxic chemicals into the environment as shale gas development takes place will carry risks of damage in the event of spills, accidents or leaks at the surface, unintended migration of fluids through improperly constructed or maintained wellbores, and even unintended migration through faults and fractures in geological formations. State law and regulations must provide for the funding of a dedicated damage mitigation fund that DEC should manage with automatic contributions from private developers based on production, coupled with long-term bonding requirements and provisions for complete removal of infrastructure associated with a particular well or set of wells once production has effectively terminated.

Severance taxes and revenues. In addition to damage mitigation fund payments, the State should have in place a system of meaningful severance taxes based on production and value of extracted gas with the first dollars raised

from such a tax dedicated to fully fund a comprehensive state regulatory and enforcement program focused on the life cycle of shale gas production.

Yours very truly,

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Secretary of Energy Advisory Board



Shale Gas Production Subcommittee 90-Day Report

August 18, 2011



U.S. DEPARTMENT OF
ENERGY

***The SEAB Shale Gas Production Subcommittee
Ninety-Day Report – August 18, 2011***

Executive Summary

The Shale Gas Subcommittee of the Secretary of Energy Advisory Board is charged with identifying measures that can be taken to reduce the environmental impact and improve the safety of shale gas production.

Natural gas is a cornerstone of the U.S. economy, providing a quarter of the country's total energy. Owing to breakthroughs in technology, production from shale formations has gone from a negligible amount just a few years ago to being almost 30 percent of total U.S. natural gas production. This has brought lower prices, domestic jobs, and the prospect of enhanced national security due to the potential of substantial production growth. But the growth has also brought questions about whether both current and future production can be done in an environmentally sound fashion that meets the needs of public trust.

This 90-day report presents recommendations that if implemented will reduce the environmental impacts from shale gas production. The Subcommittee stresses the importance of a process of continuous improvement in the various aspects of shale gas production that relies on best practices and is tied to measurement and disclosure. While many companies are following such a process, much-broader and more extensive adoption is warranted. The approach benefits all parties in shale gas production: regulators will have more complete and accurate information; industry will achieve more efficient operations; and the public will see continuous, measurable improvement in shale gas activities.

A list of the Subcommittee's findings and recommendations follows.

- Improve public information about shale gas operations: Create a portal for access to a wide range of public information on shale gas development, to include current data available from state and federal regulatory agencies. The portal should be open to the public for use to study and analyze shale gas operations and results.

- Improve communication among state and federal regulators: Provide continuing annual support to STRONGER (the State Review of Oil and Natural Gas Environmental Regulation) and to the Ground Water Protection Council for expansion of the *Risk Based Data Management System* and similar projects that can be extended to all phases of shale gas development.

- Improve air quality: Measures should be taken to reduce emissions of air pollutants, ozone precursors, and methane as quickly as practicable. The Subcommittee supports adoption of rigorous standards for new and existing sources of methane, air toxics, ozone precursors and other air pollutants from shale gas operations. The Subcommittee recommends:
 - (1) Enlisting a subset of producers in different basins to design and rapidly implement measurement systems to collect comprehensive methane and other air emissions data from shale gas operations and make these data publically available;
 - (2) Immediately launching a federal interagency planning effort to acquire data and analyze the overall greenhouse gas footprint of shale gas operations throughout the lifecycle of natural gas use in comparison to other fuels; and
 - (3) Encouraging shale-gas production companies and regulators to expand immediately efforts to reduce air emissions using proven technologies and practices.

- Protection of water quality: The Subcommittee urges adoption of a systems approach to water management based on consistent measurement and public disclosure of the flow and composition of water at every stage of the shale gas production process. The Subcommittee recommends the following actions by shale gas companies and regulators – to the extent that such actions have not already been undertaken by particular companies and regulatory agencies:
 - (1) Measure and publicly report the composition of water stocks and flow throughout the fracturing and clean-up process.
 - (2) Manifest all transfers of water among different locations.
 - (3) Adopt best practices in well development and construction, especially casing, cementing, and pressure management. Pressure testing of cemented casing and state-of-the-art cement bond logs should be used to confirm formation isolation. Microseismic surveys should be carried out to assure that hydraulic fracture growth is limited to the gas producing formations. Regulations and inspections are needed to confirm that operators

have taken prompt action to repair defective cementing jobs. The regulation of shale gas development should include inspections at safety-critical stages of well construction and hydraulic fracturing.

(4) Additional field studies on possible methane leakage from shale gas wells to water reservoirs.

(5) Adopt requirements for background water quality measurements (e.g., existing methane levels in nearby water wells prior to drilling for gas) and report in advance of shale gas production activity.

(6) Agencies should review field experience and modernize rules and enforcement practices to ensure protection of drinking and surface waters.

- Disclosure of fracturing fluid composition: The Subcommittee shares the prevailing view that the risk of fracturing fluid leakage into drinking water sources through fractures made in deep shale reservoirs is remote. Nevertheless the Subcommittee believes there is no economic or technical reason to prevent public disclosure of all chemicals in fracturing fluids, with an exception for genuinely proprietary information. While companies and regulators are moving in this direction, progress needs to be accelerated in light of public concern.
- Reduction in the use of diesel fuel: The Subcommittee believes there is no technical or economic reason to use diesel in shale gas production and recommends reducing the use of diesel engines for surface power in favor of natural gas engines or electricity where available.
- Managing short-term and cumulative impacts on communities, land use, wildlife, and ecologies. Each relevant jurisdiction should pay greater attention to the combination of impacts from multiple drilling, production and delivery activities (e.g., impacts on air quality, traffic on roads, noise, visual pollution), and make efforts to plan for shale development impacts on a regional scale. Possible mechanisms include:
 - (1) Use of multi-well drilling pads to minimize transport traffic and need for new road construction.
 - (2) Evaluation of water use at the scale of affected watersheds.
 - (3) Formal notification by regulated entities of anticipated environmental and community impacts.

(4) Preservation of unique and/or sensitive areas as off-limits to drilling and support infrastructure as determined through an appropriate science-based process.

(5) Undertaking science-based characterization of important landscapes, habitats and corridors to inform planning, prevention, mitigation and reclamation of surface impacts.

(6) Establishment of effective field monitoring and enforcement to inform on-going assessment of cumulative community and land use impacts.

The process for addressing these issues must afford opportunities for affected communities to participate and respect for the rights of surface and mineral rights owners.

- Organizing for best practice: The Subcommittee believes the creation of a shale gas industry production organization dedicated to continuous improvement of best practice, defined as improvements in techniques and methods that rely on measurement and field experience, is needed to improve operational and environmental outcomes. The Subcommittee favors a national approach including regional mechanisms that recognize differences in geology, land use, water resources, and regulation. The Subcommittee is aware that several different models for such efforts are under discussion and the Subcommittee will monitor progress during its next ninety days. The Subcommittee has identified several activities that deserve priority attention for developing best practices:

Air: (a) Reduction of pollutants and methane emissions from all shale gas production/delivery activity. (b) Establishment of an emission measurement and reporting system at various points in the production chain.

Water: (a) Well completion – casing and cementing including use of cement bond and other completion logging tools. (b) Minimizing water use and limiting vertical fracture growth.

- Research and Development needs. The public should expect significant technical advances associated with shale gas production that will significantly improve the efficiency of shale gas production and that will reduce environmental impact. The move from single well to multiple-well pad drilling is one clear example. Given the economic incentive for technical advances, much of the R&D will be performed by the oil and gas industry. Nevertheless the federal government has a role especially in basic R&D, environment protection, and

safety. The current level of federal support for unconventional gas R&D is small, and the Subcommittee recommends that the Administration and the Congress set an appropriate mission for R&D and level funding.

The Subcommittee believes that these recommendations, combined with a continuing focus on and clear commitment to measurable progress in implementation of best practices based on technical innovation and field experience, represent important steps toward meeting public concerns and ensuring that the nation’s resources are responsibly being responsibly developed.

Introduction

On March 31, 2011, President Barack Obama declared that “recent innovations have given us the opportunity to tap large reserves – perhaps a century’s worth” of shale gas. In order to facilitate this development, ensure environmental protection, and meet public concerns, he instructed Secretary of Energy Steven Chu to form a subcommittee of the Secretary of Energy Advisory Board (SEAB) to make recommendations to address the safety and environmental performance of shale gas production.¹ The Secretary’s charge to the Subcommittee, included in Annex A, requested that:

Within 90 days of its first meeting, the Subcommittee will report to SEAB on the “immediate steps that can be taken to improve the safety and environmental performance of fracturing.

This is the 90-day report submitted by the Subcommittee to SEAB in fulfillment of its charge. There will be a second report of the Subcommittee after 180 days. Members of the Subcommittee are given in Annex B.

Context for the Subcommittee’s deliberations

The Subcommittee believes that the U.S. shale gas resource has enormous potential to provide economic and environmental benefits for the country. Shale gas is a widely distributed resource in North America that can be relatively cheaply produced, creating jobs across the country. Natural gas – if properly produced and transported – also offers climate change advantages because of its low carbon content compared to coal.

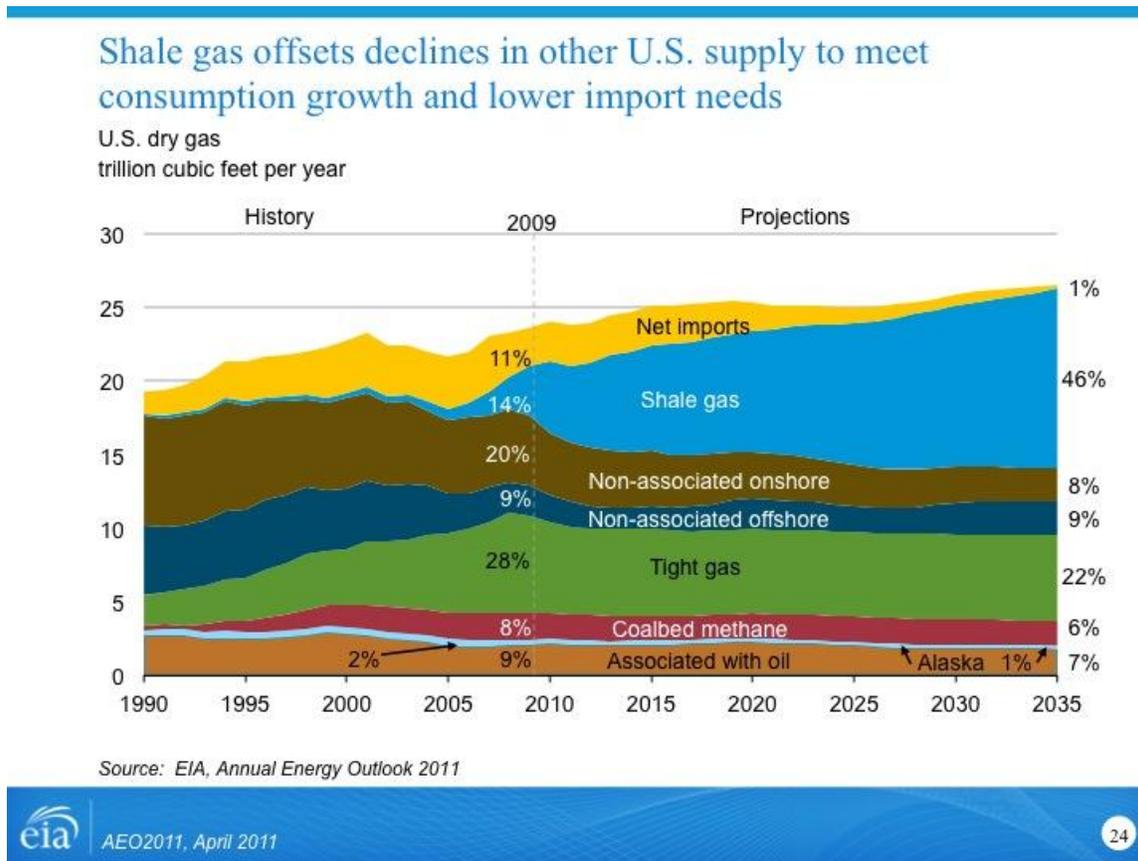


Source: U.S. Energy Information Administration based on data from various published studies. Canada and Mexico plays from ARI. Updated: May 9, 2011

Domestic production of shale gas also has the potential over time to reduce dependence on imported oil for the United States. International shale gas production will increase the diversity of supply for other nations. Both these developments offer important national security benefits.²

The development of shale gas in the United States has been very rapid. Natural gas from all sources is one of America’s major fuels, providing about 25 percent of total U.S. energy. Shale gas, in turn, was less than two percent of total U.S. natural gas production in 2001. Today, it is approaching 30 percent.³ But it was only around 2008 that the significance of shale gas began to be widely recognized. Since then, output has increased four-fold. It has brought new regions into the supply mix. Output from the Haynesville shale, mostly in Louisiana, for example, was negligible in 2008; today, the Haynesville shale alone produces eight percent of total U.S. natural gas output. According to the U.S. Energy Information Administration (EIA), the rapid expansion of shale gas production is expected to continue in the future. The EIA projects shale gas to

be 46 percent of domestic production by 2035. The following figure shows the stunning change.



The economic significance is potentially very large. While estimates vary, well over 200,000 of jobs (direct, indirect, and induced) have been created over the last several years by the development of domestic production of shale gas, and tens of thousands more will be created in the future.⁴ As late as 2007, before the impact of the shale gas revolution, it was assumed that the United States would be importing large amounts of liquefied natural gas from the Middle East and other areas. Today, the United States is essentially self-sufficient in natural gas, with the only notable imports being from Canada, and expected to remain so for many decades. The price of natural gas has fallen by more than a factor of two since 2008, benefiting consumers in the lower cost of home heating and electricity.

The rapid expansion of production is rooted in change in applications of technology and field practice. It had long been recognized that substantial supplies of natural gas were embedded in shale rock. But it was only in 2002 and 2003 that the combination of two technologies working together – hydraulic fracturing and horizontal drilling – made shale gas commercial.

These factors have brought new regions into the supply mix. Parts of the country, such as regions of the Appalachian mountain states where the Marcellus Shale is located, which have not experienced significant oil and gas development for decades, are now undergoing significant development pressure. Pennsylvania, for example, which produced only one percent of total dry gas production in 2009, is one of the most active new areas of development. Even states with a history of oil and gas development, such as Wyoming and Colorado, have experienced significant development pressures in new areas of the state where unconventional gas is now technically and economically accessible due to changes in drilling and development technologies.

The urgency of addressing environmental consequences

As with all energy use, shale gas must be produced in a manner that prevents, minimizes and mitigates environmental damage and the risk of accidents and protects public health and safety. Public concern and debate about the production of shale gas has grown as shale gas output has expanded.

The Subcommittee identifies four major areas of concern: (1) Possible pollution of drinking water from methane and chemicals used in fracturing fluids; (2) Air pollution; (3) Community disruption during shale gas production; and (4) Cumulative adverse impacts that intensive shale production can have on communities and ecosystems.

There are serious environmental impacts underlying these concerns and these adverse environmental impacts need to be prevented, reduced and, where possible, eliminated as soon as possible. Absent effective control, public opposition will grow, thus putting continued production at risk. Moreover, with anticipated increase in U.S. hydraulically fractured wells, if effective environmental action is not taken today, the potential environmental consequences will grow to a point that the country will be faced a more

serious problem. Effective action requires both strong regulation and a shale gas industry in which all participating companies are committed to continuous improvement.

The rapid expansion of production and rapid change in technology and field practice, requires federal and state agencies to adapt and evolve their regulations. Industry's pursuit of more efficient operations often has environmental as well as economic benefits, including waste minimization, greater gas recovery, less water usage, and a reduced operating footprint. So there are many reasons to be optimistic that continuous improvement of shale gas production in reducing existing and potential undesirable impacts can be a cooperative effort among the public, companies in the industry, and regulators.

Subcommittee scope, procedure and outline of this report

Scope: The Subcommittee has focused exclusively on production of natural gas (and some liquid hydrocarbons) from shale formations with hydraulic fracturing stimulation in either vertical or horizontal wells. The Subcommittee is aware that some of the observations and recommendations in this report could lead to extension of its findings to other oil and gas operations, but our intention is to focus singularly on issues related to shale gas development. We caution against applying our findings to other areas, because the Subcommittee has not considered the different development practices and other types of geology, technology, regulation and industry practice.

These shale plays in different basins have different geological characteristics and occur in areas with very different water resources. In the Eagle Ford, in Texas, there is almost no flow-back water from an operating well following hydraulic fracturing, while in the Marcellus, primarily in Ohio, New York, Pennsylvania and West Virginia, the flow-back water is between 20 and 40 percent of the injected volume. This geological diversity means that engineering practice and regulatory oversight will differ widely among regions of the country.

The Subcommittee describes in this report a comprehensive and collaborative approach to managing risk in shale gas production. The Subcommittee believes that a more systematic commitment to a process of *continuous improvement* to identify and

implement best practices is needed, and should be embraced by all companies in the shale gas industry. Many companies already demonstrate their commitment to the kind of process we describe here, but the public should be confident that this is the practice across the industry.

This process should involve discussions and other collaborative efforts among companies involved in shale gas production (including service companies), state and federal regulators, and affected communities and public interests groups. The process should identify best practices that evolve as operational experience increases, knowledge of environmental effects and effective mitigation grows, and know-how and technology changes. It should also be supported by technology peer reviews that report on individual companies' performance and should be seen as a compliment to, not a substitute for, strong regulation and effective enforcement. There will be three benefits:

- For industry: As all firms move to adopt identified best practices, continuous improvement has the potential to both enhance production efficiency and reduce environmental impacts over time.
- For regulators: Sharing data and best practices will better inform regulators and help them craft policies and regulations that will lead to sounder and more efficient environmental practices than are now in place.
- For the public: Continuous improvement coupled with rigorous regulatory oversight can provide confidence that processes are in place that will result in improved safety and less environmental and community impact.

The realities of regional diversity of shale gas resources and rapid change in production practices and technology mean that a single best engineering practice cannot set for all locations and for all time. Rather, the appropriate starting point is to understand what are regarded as “best practices” today, how the current regulatory system works in the context of those operating in different parts of the country, and establishing a culture of continuous improvement.

The Subcommittee has considered the safety and environmental impact of all steps in shale gas production, not just hydraulic fracturing.⁵ Shale gas production consists of

several steps, from well design and surface preparation, to drilling and cementing steel casing at multiple stages of well construction, to well completion. The various steps include perforation, water and fracturing fluid preparation, multistage hydraulic fracturing, collection and handling of flow-back and produced water, gas collection, processing and pipeline transmission, and site remediation.⁶ Each of these activities has safety and environmental risks that are addressed by operators and by regulators in different ways according to location. In light of these processes, the Subcommittee interprets its charge to assess this entire system, rather than just hydraulic fracturing.

The Subcommittee's charge is not to assess the balance of the benefits of shale gas use against these environmental costs. Rather, the Subcommittee's charge is to identify steps that can be taken to reduce the environmental and safety risks associated with shale gas development and, importantly, give the public concrete reason to believe that environmental impacts will be reduced and well managed on an ongoing basis, and that problems will be mitigated and rapidly corrected, if and when they occur.

It is not within the scope of the Subcommittee's 90-day report to make recommendations about the proper regulatory roles for state and federal governments. However, the Subcommittee emphasizes that effective and capable regulation is essential to protect the public interest. The challenges of protecting human health and the environment in light of the anticipated rapid expansion of shale gas production require the joint efforts of state and federal regulators. This means that resources dedicated to oversight of the industry must be sufficient to do the job and that there is adequate regulatory staff at the state and federal level with the technical expertise to issue, inspect, and enforce regulations. Fees, royalty payments and severance taxes are appropriate sources of funds to finance these needed regulatory activities.

The nation has important work to do in strengthening the design of a regulatory system that sets the policy and technical foundation to provide for continuous improvement in the protection of human health and the environment. While many states and several federal agencies regulate aspects of these operations, the efficacy of the regulations is far from clear. Raw statistics about enforcement actions and compliance are not sufficient to draw conclusions about regulatory effectiveness. Informed conclusions about the state of shale gas operations require analysis of the vast amount of data that

is publically available, but there are surprisingly few published studies of this publically available data. Benchmarking is needed for the efficacy of existing regulations and consideration of additional mechanisms for assuring compliance such as disclosure of company performance and enforcement history, and operator certification of performance subject to stringent fines, if violated.

Subcommittee Procedure: In the ninety days since its first meeting, the Subcommittee met with representatives of industry, the environmental community, state regulators, officials of the Environmental Protection Agency, the Department of Energy, the Department of the Interior, both the United States Geologic Survey (USGS) and the Bureau of Land Management (BLM), which has responsibility for public land regulation,⁷ and a number of individuals from industry and not-for-profit groups with relevant expertise and interest. The Subcommittee held a public meeting attended by over four hundred citizens in Washington County, PA, and visited several Marcellus shale gas sites. The Subcommittee strove to hold all of its meeting in public although the Subcommittee held several private working sessions to review what it had learned and to deliberate on its course of action. A website is available that contains the Subcommittee meeting agendas, material presented to the Subcommittee, and numerous public comments.⁸

Outline of this report: The Subcommittee findings and recommendations are organized in four sections:

- Making information about shale gas production operations more accessible to the public – an immediate action.
- Immediate and longer term actions to reduce environmental and safety risks of shale gas operations
- Creation of a Shale Gas Industry Operation organization, on national and/or regional basis, committed to continuous improvement of best operating practices.
- R&D needs to improve safety and environmental performance – immediate and long term opportunities for government and industry.

The common thread in all these recommendations is that measurement and disclosure are fundamental elements of good practice and policy for all parties. Data enables companies to identify changes that improve efficiency and environmental performance and to benchmark against the performance of different companies. Disclosure of data permits regulators to identify cost/effective regulatory measures that better protect the environment and public safety, and disclosure gives the public a way to measure progress on reducing risks.

Making shale gas information available to the public

The Subcommittee has been struck by the enormous difference in perception about the consequences of shale gas activities. Advocates state that fracturing has been performed safely without significant incident for over 60 years, although modern shale gas fracturing of two mile long laterals has only been done for something less than a decade. Opponents point to failures and accidents and other environmental impacts, but these incidents are typically unrelated to hydraulic fracturing *per se* and sometimes lack supporting data about the relationship of shale gas development to incidence and consequences.⁹ An industry response that hydraulic fracturing has been performed safely for decades rather than engaging the range of issues concerning the public will not succeed.

Some of this difference in perception can be attributed to communication issues. Many in the concerned public use the word “fracking” to describe all activities associated with shale gas development, rather than just the hydraulic fracturing process itself. Public concerns extend to accidents and failures associated with poor well construction and operation, surface spills, leaks at pits and impoundments, truck traffic, and the cumulative impacts of air pollution, land disturbance and community disruption.

The Subcommittee believes there is great merit to creating a national database to link as many sources of public information as possible with respect to shale gas development and production. Much information has been generated over the past ten years by state and federal regulatory agencies. Providing ways to link various databases and, where possible, assemble data in a comparable format, which are now in perhaps a hundred different locations, would permit easier access to data sets by interested parties.

Members of the public would be able to assess the current state of environmental protection and safety and inform the public of these trends. Regulatory bodies would be better able to assess and monitor the trends in enforcement activities. Industry would be able to analyze data on production trends and comparative performance in order to identify effective practices.

The Subcommittee recommends creation of this national database. A rough estimate for the initial cost is \$20 million to structure and construct the linkages necessary for assembling this virtual database, and about \$5 million annual cost to maintain it. This recommendation is not aimed at establishing new reporting requirements. Rather, it focuses on creating linkages among information and data that is currently collected and technically and legally capable of being made available to the public. What analysis of the data should be done is left entirely for users to decide.¹⁰

There are other important mechanisms for improving the availability and usefulness of shale gas information among various constituencies. The Subcommittee believes two such mechanisms to be exceptionally meritorious (and would be relatively inexpensive to expand).

The first is an existing organization known as STRONGER – the State Review of Oil and Natural Gas Environmental Regulation. STRONGER is a not-for-profit organization whose purpose is to accomplish genuine peer review of state regulatory activities. The peer reviews (conducted by a panel of state regulators, industry representatives, and environmental organization representatives with respect to the processes and policies of the state under review) are published publicly, and provide a means to share information about environmental protection strategies, techniques, regulations, and measures for program improvement. Too few states participate in STRONGER’s voluntary review of state regulatory programs. The reviews allow for learning to be shared by states and the expansion of the STRONGER process should be encouraged. The Department of Energy, the Environmental Protection Agency, and the American Petroleum Institute have supported STRONGER over time.¹¹

The second is the Ground Water Protection Council’s project to extend and expand the *Risk Based Data Management System*, which allows states to exchange information about defined parameters of importance to hydraulic fracturing operations.¹²

The Subcommittee recommends that these two activities be funded at the level of \$5 million per year beginning in FY2012. Encouraging these multi-stakeholder mechanisms will help provide greater information to the public, enhancing regulation and improving the efficiency of shale gas production. It will also provide support for STRONGER to expand its activities into other areas such as air quality, something that the Subcommittee encourages the states to do as part of the scope of STRONGER peer reviews.

Recommendations for immediate and longer term actions to reduce environmental and safety risks of shale gas operations

1. Improvement in air quality by reducing emissions of regulated pollutants and methane.

Shale gas production, including exploration, drilling, venting/flaring, equipment operation, gathering, accompanying vehicular traffic, results in the emission of ozone precursors (volatile organic compounds (VOCs), and nitrogen oxides), particulates from diesel exhaust, toxic air pollutants and greenhouse gases (GHG), such as methane.

As shale gas operations expand across the nation these air emissions have become an increasing matter of concern at the local, regional and national level. Significant air quality impacts from oil and gas operations in Wyoming, Colorado, Utah and Texas are well documented, and air quality issues are of increasing concern in the Marcellus region (in parts of Ohio, Pennsylvania, West Virginia and New York).¹³

The Environmental Protection Agency has the responsibility to regulate air emissions and in many cases delegate its authority to states. On July 28, 2011, EPA proposed amendments to its regulations for air emissions for oil and gas operations. If finalized and fully implemented, its proposal will reduce emissions of VOCs, air toxics and, collaterally, methane. EPA's proposal does not address many existing types of sources in the natural gas production sector, with the notable exception of hydraulically fractured well re-completions, at which "green" completions must be used. ("Green" completions use equipment that will capture methane and other air contaminants, avoiding its release.) EPA is under court order to take final action on these clean air measures in 2012. In addition, a number of states – notably, Wyoming and Colorado – have taken proactive steps to address air emissions from oil and gas activities.

The Subcommittee supports adoption of emission standards for both new and existing sources for methane, air toxics, ozone-forming pollutants, and other major airborne contaminants resulting from natural gas exploration, production, transportation and distribution activities. The Subcommittee also believes that companies should be required, as soon as practicable, to measure and disclose air pollution emissions, including greenhouse gases, air toxics, ozone precursors and other pollutants. Such disclosure should include direct measurements wherever feasible; include characterization of chemical composition of the natural gas measured; and be reported on a publically accessible website that allows for searching and aggregating by pollutant, company, production activity and geography.

Methane emissions from shale gas drilling, production, gas processing, transmission and storage are of particular concern because methane is a potent greenhouse gas: 25 to 72 times greater warming potential than carbon dioxide on 100-year and 20-year time scales respectively.¹⁴ Currently, there is great uncertainty about the scale of methane emissions.

The Subcommittee recommends three actions to address the air emissions issue.

First, inadequate data are available about how much methane and other air pollutants are emitted by the consolidated production activities of a shale gas operator in a given area, with such activities encompassing drilling, fracturing, production, gathering, processing of gas and liquids, flaring, storage, and dispatch into the pipeline transmission and distribution network. Industry reporting of greenhouse gas emissions in 2012 pursuant to EPA's reporting rule will provide new insights, but will not eliminate key uncertainties about the actual amount and variability in emissions.

The Subcommittee recommends enlisting a subset of producers in different basins, on a voluntary basis, to immediately launch projects to design and rapidly implement measurement systems to collect comprehensive methane and other air emissions data.

These pioneering data sets will be useful to regulators and industry in setting benchmarks for air emissions from this category of oil and gas production, identifying cost-effective procedures and equipment changes that will reduce emissions; and guiding practical regulation and potentially avoid burdensome and contentious regulatory

procedures. Each project should be conducted in a transparent manner and the results should be publicly disclosed.

There needs to be common definitions of the emissions and other parameters that should be measured and measurement techniques, so that comparison is possible between the data collected from the various projects. Provision should be made for an independent technical review of the methodology and results to establish their credibility. The Subcommittee will report progress on this proposal during its next phase.

The second recommendation regarding air emissions concerns the need for a thorough assessment of the greenhouse gas footprint for cradle-to-grave use of natural gas. This effort is important in light of the expectation that natural gas use will expand and substitute for other fuels. There have been relatively few analyses done of the question of the greenhouse gas footprint over the entire fuel-cycle of natural gas production, delivery and use, and little data are available that bear on the question. A recent peer-reviewed article reaches a pessimistic conclusion about the greenhouse gas footprint of shale gas production and use – a conclusion not widely accepted.¹⁵ DOE's National Energy Technology Laboratory has given an alternative analysis.¹⁶ Work has also been done for electric power, where natural gas is anticipated increasingly to substitute for coal generation, reaching a more favorable conclusion that natural gas results in about one-half the equivalent carbon dioxide emissions.¹⁷

The Subcommittee believes that additional work is needed to establish the extent of the footprint of the natural gas fuel cycle in comparison to other fuels used for electric power and transportation because it is an important factor that will be considered when formulating policies and regulations affecting shale gas development. These data will help answer key policy questions such as the time scale on which natural gas fuel switching strategies would produce real climate benefits through the full fuel cycle and the level of methane emission reductions that may be necessary to ensure such climate benefits are meaningful.

The greenhouse footprint of the natural gas fuel cycle can be either estimated indirectly by using surrogate measures or preferably by collecting actual data where it is practicable to do so. In the selection of methods to determine actual emissions,

preference should be given to direct measurement wherever feasible, augmented by emissions factors that have been empirically validated. Designing and executing a comprehensive greenhouse gas footprint study based on actual data – the Subcommittee’s recommended approach -- is a major project. It requires agreement on measurement equipment, measurement protocols, tools for integrating and analyzing data from different regions, over a multiyear period. Since producer, transmission and distribution pipelines, end-use storage and natural gas many different companies will necessarily be involved. A project of this scale will be expensive. Much of the cost will be borne by firms in the natural gas enterprise that are or will be required to collect and report air emissions. These measurements should be made as rapidly as practicable. Aggregating, assuring quality control and analyzing these data is a substantial task involving significant costs that should be underwritten by the federal government.

It is not clear which government agency would be best equipped to manage such a project. The Subcommittee recommends that planning for this project should begin immediately and that the Office of Science and Technology Policy, should be asked to coordinate an interagency effort to identify sources of funding and lead agency responsibility. This is a pressing question so a clear blueprint and project timetable should be produced within a year.

Third, the Subcommittee recommends that industry and regulators immediately expand efforts to reduce air emissions using proven technologies and practices. Both methane and ozone precursors are of concern. Methane leakage and uncontrolled venting of methane and other air contaminants in the shale gas production should be eliminated except in cases where operators demonstrate capture is technically infeasible, or where venting is necessary for safety reasons and where there is no alternative for capturing emissions. When methane emissions cannot be captured, they should be flared whenever volumes are sufficient to do so.

Ozone precursors should be reduced by using cleaner engine fuel, deploying vapor recovery and other control technologies effective on relevant equipment." Wyoming’s emissions rules represent a good starting point for establishing regulatory frameworks and for encouraging industry best practices.

2. Protecting water supply and water quality.

The public understandably wants implementation of standards to ensure shale gas production does not risk polluting drinking water or lakes and streams. The challenge to proper understanding and regulation of the water impacts of shale production is the great diversity of water use in different regional shale gas plays and the different pattern of state and federal regulation of water resources across the country. The U.S. EPA has certain authorities to regulate water resources and it is currently undertaking a two-year study under congressional direction to investigate the potential impacts of hydraulic fracturing on drinking water resources.¹⁸

Water use in shale gas production passes through the following stages: (1) water acquisition, (2) drilling and hydraulic fracturing (surface formulation of water, fracturing chemicals and sand followed by injection into the shale producing formation at various locations), (3) collection of return water, (4) water storage and processing, and (5) water treatment and disposal.

The Subcommittee offers the following observations with regard to these water issues:

- (1) Hydraulic fracturing stimulation of a shale gas well requires between 1 and 5 million gallons of water. While water availability varies across the country, in most regions water used in hydraulic fracturing represents a small fraction of total water consumption. Nonetheless, in some regions and localities there are significant concerns about consumptive water use for shale gas development.¹⁹ There is considerable debate about the water intensity of natural gas compared to other fuels for particular applications such as electric power production.²⁰

One of the commonly perceived risks from hydraulic fracturing is the possibility of leakage of fracturing fluid through fractures into drinking water. Regulators and geophysical experts agree that the likelihood of properly injected fracturing fluid reaching drinking water through fractures is remote where there is a large depth separation between drinking water sources and the producing zone. In the great majority of regions where shale gas is being produced, such separation exists and there are few, if any, documented examples of such migration. An improperly executed fracturing fluid injection can, of course, lead to surface spills

and leakage into surrounding shallow drinking water formations. Similarly, a well with poorly cemented casing could potentially leak, regardless of whether the well has been hydraulically fractured.

With respect to stopping surface spills and leakage of contaminated water, the Subcommittee observes that extra measures are now being taken by some operators and regulators to address the public's concern that water be protected. The use of mats, catchments and groundwater monitors as well as the establishment of buffers around surface water resources help ensure against water pollution and should be adopted.

Methane leakage from producing wells into surrounding drinking water wells, exploratory wells, production wells, abandoned wells, underground mines, and natural migration is a greater source of concern. The presence of methane in wells surrounding a shale gas production site is not *ipso facto* evidence of methane leakage from the fractured producing well since methane may be present in surrounding shallow methane deposits or the result of past conventional drilling activity.

However, a recent, credible, peer-reviewed study documented the higher concentration of methane originating in shale gas deposits (through isotopic abundance of C-13 and the presence of trace amounts of higher hydrocarbons) into wells surrounding a producing shale production site in northern Pennsylvania.²¹ The Subcommittee recommends several studies be commissioned to confirm the validity of this study and the extent of methane migration that may take place in this and other regions.

- (2) Industry experts believe that methane migration from shale gas production, when it occurs, is due to one or another factors: drilling a well in a geological unstable location; loss of well integrity as a result of poor well completion (cementing or casing) or poor production pressure management. Best practice can reduce the risk of this failure mechanism (as discussed in the following section). Pressure tests of the casing and state-of-the-art cement bond logs should be performed to confirm that the methods being used achieve the desired degree of

formation isolation. Similarly, frequent microseismic surveys should be carried out to assure operators and service companies that hydraulic fracture growth is limited to the gas-producing formations. Regulations and inspections are needed to confirm that operators have taken prompt action to repair defective cementing (squeeze jobs).

- (3) A producing shale gas well yields flow-back and other produced water. The flow-back water is returned fracturing water that occurs in the early life of the well (up to a few months) and includes residual fracturing fluid as well as some solid material from the formation. Produced water is the water displaced from the formation and therefore contains substances that are found in the formation, and may include brine, gases (e.g. methane, ethane), trace metals, naturally occurring radioactive elements (e.g. radium, uranium) and organic compounds. Both the amount and the composition of the flow-back and produced water vary substantially among shale gas plays – for example, in the Eagle Ford area, there is very little returned water after hydraulic fracturing whereas, in the Marcellus, 20 to 40 percent of the fracturing fluid is produced as flow-back water. In the Barnett, there can significant amounts of saline water produced with shale gas if hydraulic fractures propagate downward into the Ellenburger formation.
- (4) The return water (flow-back + produced) is collected (frequently from more than a single well), processed to remove commercially viable gas and stored in tanks or an impoundment pond (lined or unlined). For pond storage evaporation will change the composition. Full evaporation would ultimately leave precipitated solids that must be disposed in a landfill. Measurement of the composition of the stored return water should be a routine industry practice.
- (5) There are four possibilities for disposal of return water: reuse as fracturing fluid in a new well (several companies, operating in the Marcellus are recycling over 90 percent of the return water); underground injection into disposal wells (this mode of disposal is regulated by the EPA); waste water treatment to produce clean water (though at present, most waste water treatment plants are not equipped with the capability to treat many of the contaminants associated with shale gas waste water); and surface runoff which is forbidden.

Currently, the approach to water management by regulators and industry is not on a “systems basis” where all aspect of activities involving water use is planned, analyzed, and managed on an integrated basis. The difference in water use and regulation in different shale plays means that there will not be a single water management integrated system applicable in all locations. Nevertheless, the Subcommittee believes certain common principles should guide the development of integrated water management and identifies three that are especially important:

- Adoption of a life cycle approach to water management from the beginning of the production process (acquisition) to the end (disposal): all water flows should be tracked and reported quantitatively throughout the process.
- Measurement and public reporting of the composition of water stocks and flow throughout the process (for example, flow-back and produced water, in water ponds and collection tanks).
- Manifesting of all transfers of water among locations.

Early case studies of integrated water management are desirable so as to provide better bases for understanding water use and disposition and opportunities for reduction of risks related to water use. The Subcommittee supports EPA’s retrospective and prospective case studies that will be part of the EPA study of hydraulic fracturing impacts on drinking water resources, but these case studies focus on identification of possible consequences rather than the definition of an integrated water management system, including the measurement needs to support it. The Subcommittee believes that development and use of an integrated water management system has the potential for greatly reducing the environmental footprint and risk of water use in shale gas production and recommends that regulators begin working with industry and other stakeholders to develop and implement such systems in their jurisdictions and regionally.

Additionally, agencies should review field experience and modernize rules and enforcement practices – especially regarding well construction/operation, management of flow back and produced water, and prevention of blowouts and surface spills – to ensure robust protection of drinking and surface waters. Specific best practice matters that should receive priority attention from regulators and industry are described below.

3. Background water quality measurements.

At present there are widely different practices for measuring the water quality of wells in the vicinity of a shale gas production site. Availability of measurements in advance of drilling would provide an objective baseline for determining if the drilling and hydraulic fracturing activity introduced any contaminants in surrounding drinking water wells.

The Subcommittee is aware there is great variation among states with respect to their statutory authority to require measurement of water quality of private wells, and that the process of adopting practical regulations that would be broadly acceptable to the public would be difficult. Nevertheless, the value of these measurements for reassuring communities about the impact of drilling on their community water supplies leads the Subcommittee to recommend that states and localities adopt systems for measurement and reporting of background water quality in advance of shale gas production activity.

These baseline measurements should be publicly disclosed, while protecting landowner's privacy.

4. Disclosure of the composition of fracturing fluids.

There has been considerable debate about requirements for reporting all chemicals (both composition and concentrations) used in fracturing fluids. Fracturing fluid refers to the slurry prepared from water, sand, and some added chemicals for high pressure injection into a formation in order to create fractures that open a pathway for release of the oil and gases in the shale. Some states (such as Wyoming, Arkansas and Texas) have adopted disclosure regulations for the chemicals that are added to fracturing fluid, and the U.S. Department of Interior has recently indicated an interest in requiring disclosure for fracturing fluids used on federal lands.

The DOE has supported the establishment and maintenance of a relatively new website, FracFocus.org (operated jointly by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission) to serve as a voluntary chemical registry for individual companies to report all chemicals that would appear on Material Safety Data Sheets (MSDS) subject to certain provisions to protect "trade secrets." While FracFocus is off to a good start with voluntary reporting growing rapidly, the restriction to MSDS data means that a large universe of chemicals frequently used in hydraulic

fracturing treatments goes unreported. MSDS only report chemicals that have been deemed to be hazardous in an occupational setting under standards adopted by OSHA (the Occupational Safety and Health Administration); MSDA reporting does not include other chemicals that might be hazardous if human exposure occurs through environmental pathways. Another limitation of FracFocus is that the information is not maintained as a database. As a result, the ability to search for data is limited and there are no tools for aggregating data.

The Subcommittee believes that the high level of public concern about the nature of fracturing chemicals suggests that the benefit of immediate and complete disclosure of all chemical components and composition of fracturing fluid completely outweighs the restriction on company action, the cost of reporting, and any intellectual property value of proprietary chemicals. The Subcommittee believes that public confidence in the safety of fracturing would be significantly improved by complete disclosure and that the barrier to shield chemicals based on trade secret should be set very high. Therefore the Subcommittee recommends that regulatory entities immediately develop rules to require disclosure of all chemicals used in hydraulic fracturing fluids on both public and private lands. Disclosure should include all chemicals, not just those that appear on MSDS. It should be reported on a well-by-well basis and posted on a publicly available website that includes tools for searching and aggregating data by chemical, well, by company, and by geography.

5. Reducing the use of diesel in shale gas development

Replacing diesel with natural gas or electric power for oil field equipment will decrease harmful air emissions and improve air quality. Although fuel substitution will likely happen over time because of the lower cost of natural gas compared diesel and because of likely future emission restrictions, the Subcommittee recommends conversion from diesel to natural gas for equipment fuel or to electric power where available, as soon as practicable. The process of conversion may be slowed because manufacturers of compression ignition or spark ignition engines may not have certified the engine operating with natural gas fuel for off-road use as required by EPA air emission regulations.²²

Eliminating the use of diesel as an additive to hydraulic fracturing fluid. The Subcommittee believes there is no technical or economic reason to use diesel as a stimulating fluid. Diesel is a refinery product that consists of several components possibly including some toxic impurities such as benzene and other aromatics. (EPA is currently considering permitting restrictions of the use of diesel fuels in hydraulic fracturing under Safe Drinking Water Act (SDWA) Underground Injection Control (UIC) Class II.) Diesel is convenient to use in the oil field because it is present for use fuel for generators and compressors.

Diesel has two uses in hydraulic fracturing and stimulation. In modest quantities diesel is used to solubilize other fracturing chemical such as guar. Mineral oil (a synthetic mixture of C-10 to C-40 hydrocarbons) is as effective at comparable cost. Infrequently, diesel is use as a fracturing fluid in water sensitive clay and shale reservoirs. In these cases, light crude oil that is free of aromatic impurities picked up in the refining process, can be used as a substitute of equal effectiveness and lower cost compared to diesel, as a non-aqueous fracturing fluid.

6. Managing short-term and cumulative impacts on communities, land use, wildlife and ecologies.

Intensive shale gas development can potentially have serious impacts on public health, the environment and quality of life – even when individual operators conduct their activities in ways that meet and exceed regulatory requirements. The combination of impacts from multiple drilling and production operations, support infrastructure (pipelines, road networks, etc.) and related activities can overwhelm ecosystems and communities.

The Subcommittee believes that federal, regional, state and local jurisdictions need to place greater effort on examining these cumulative impacts in a more holistic manner; discrete permitting activity that focuses narrowly on individual activities does not reach to these issues. Rather than suggesting a simple prescription that every jurisdiction should follow to assure adequate consideration of these impacts, the Subcommittee believes that each relevant jurisdiction should develop and implement processes for community engagement and for preventing, mitigating and remediating surface impacts and

community impacts from production activities. There are a number of threshold mechanisms that should be considered:

- Optimize use of multi-well drilling pads to minimize transport traffic and needs for new road construction.
- Evaluate water use at the scale of affected watersheds.
- Provide formal notification by regulated entities of anticipated environmental and community impacts.
- Declare unique and/or sensitive areas off-limits to drilling and support infrastructure as determined through an appropriate science-based process.
- Undertake science-based characterization of important landscapes, habitats and corridors to inform planning, prevention, mitigation and reclamation of surface impacts.
- Establish effective field monitoring and enforcement to inform on-going assessment of cumulative community and land use impacts.
- Mitigate noise, air and visual pollution.

The process for addressing these issues must afford opportunities for affected communities to participate and respect for the rights of mineral rights owners.

Organizing for continuous improvement of “best practice”

In this report, the term “Best Practice” refers to industry techniques or methods that have proven over time to accomplish given tasks and objectives in a manner that most acceptably balances desired outcomes and avoids undesirable consequences. Continuous best practice in an industry refers to the evolution of best practice by adopting process improvements as they are identified, thus progressively improving the level and narrowing the distribution of performance of firms in the industry. Best practice is a particularly helpful management approach in a field that is growing rapidly, where technology is changing rapidly, and involves many firms of different size and technical capacity.

Best practice does not necessarily imply a single process or procedure; it allows for a range of practice that is believed to be equally effective at achieving desired outcomes. This flexibility is important because it acknowledges the possibility that different operators in different regions will select different solutions.

The Subcommittee believes the creation of a shale gas industry production organization dedicated to continuous improvement of best practice through development of standards, diffusion of these standards, and assessing compliance among its members can be an important mechanism for improving shale gas companies' commitment to safety and environmental protection as it carries out its business. The Subcommittee envisions that the industry organization would be governed by a board of directors composed of member companies, on a rotating basis, along with external members, for example from non-governmental organizations and academic institutions, as determined by the board.

Strong regulations and robust enforcement resources and practices are a prerequisite to protecting health, safety and the environment, but the job is easier where companies are motivated and committed to adopting best engineering and environmental practice. Companies have economic incentives to adopt best practice, because it improves operational efficiency and, if done properly, improves safety and environmental protection.

Achievement of best practice requires management commitment, adoption and dissemination of standards that are widely disseminated and periodically updated on the basis of field experience and measurements. A trained work force, motivated to adopt best practice, is also necessary. Creation of an industry organization dedicated to excellence in shale gas operations intended to advance knowledge about best practice and improve the interactions among companies, regulators and the public would be a major step forward.

The Subcommittee is aware that shale gas producers and other groups recognize the value of a best practice management approach and that industry is considering creating a mechanism for encouraging best practice. The design of such a mechanism involves many considerations including the differences in the shale production and regulations in different basins, making most effective use of mechanisms that are currently in place, and respecting the different capabilities of large and smaller operators. The Subcommittee will monitor progress on this important matter and continue to make its views known about the characteristics that such a mechanism and supporting organization should possess to maximize its effectiveness.

It should be stressed that any industry best practice mechanism would need to comply with anti-trust laws and would not replace any existing state or federal regulatory authority.

Priority best practice topics

Air

- **Measurement and disclosure of air emissions** including VOCs, methane, air toxics, and other pollutants.
- Reduction of methane emission from all shale gas operations

Water

- Integrated water management systems
- Well completion – casing and cementing
- Characterization and disclosure of flow back and other produced water

The Subcommittee has identified a number of promising best practice opportunities. Five examples are given in the call-out box. Two examples are discussed below to give a sense of the opportunities that presented by best practice focus.

Well integrity: an example. Well integrity is an example of the potential power of best practice for shale gas production. Well integrity encompasses the planning, design and execution of a well completion (cementing, casing and well head placement). It is fundamental to good outcomes in drilling oil and gas wells.

Methane leakage to water reservoirs is widely believed to be due to poor well completion, especially poor casing and cementing. Casing and cementing programs should be designed to provide optimal isolation of the gas-producing zone from overlaying formations. The number of cemented casings and the depth ranges covered will depend on local geologic and hydrologic conditions. However, there need to be multiple engineered barriers to prevent communication between hydrocarbons and potable aquifers. In addition, the casing program needs to be designed to optimize the potential success of cementing operations. Poorly cemented cased wells offer pathways for leakage; properly cemented and cased wells do not.

Well integrity is an ideal example of where a best practice approach, adopted by the industry, can stress best practice and collect data to validate continuous improvement. The American Petroleum Institute, for example, has focused on well completion in its standards activity for shale gas production.²³

At present, however, there is a wide range in procedures followed in the field with regard to casing placement and cementing for shale gas drilling. There are different practices with regard to completion testing and different regulations for monitoring possible gas leakage from the annulus at the wellhead. In some jurisdictions, regulators insist that gas leakage can be vented; others insist on containment with periodic pressure testing. There are no common leakage criteria for intervention in a well that exhibits damage or on the nature of the intervention. It is very likely that over time a focus on best practice in well completion will result in safer operations and greater environmental protection. The best practice will also avoid costly interruptions to normal operations. The regulation of shale gas development should also include inspections at safety-critical stages of well construction and hydraulic fracturing.

Limiting water use by controlling vertical fracture growth: – a second example. While the vertical growth of hydraulic fractures does not appear to have been a causative factor in reported cases where methane from shale gas formations has migrated to the near surface, it is in the best interest of operators and the public to limit the vertical extent of hydraulic fractures to the gas bearing shale formation being exploited. By improving the efficiency of hydraulic fractures, more gas will be produced using less water for fracturing – which has economic value to operators and environmental value for the public.

The vertical propagation of hydraulic fractures results from the variation of earth stress with depth and the pumping pressure during fracturing. The variation of earth stress with depth is difficult to predict, but easy to measure in advance of hydraulic fracturing operations. Operators and service companies should assure that through periodic direct measurement of earth stresses and microseismic monitoring of hydraulic fracturing operations, everything possible is being done to limit the amount of water and additives used in hydraulic fracturing operations.

Evolving best practices must be accompanied by metrics that permit tracking of the progress in improving shale gas operations performance and environmental impacts. The Subcommittee has the impression that the current standard-setting processes do not utilize metrics. Without such metrics and the collection of relevant measured data,

operators lack the ability to track objectively the progress of the extensive process of setting and updating standards.

Research and development needs

The profitability, rapid expansion, and the growing recognition of the scale of the resource mean that oil and gas companies will mount significant R&D efforts to improve performance and lower cost of shale gas exploration and production. In general the oil and gas industry is a technology-focused and technology-driven industry, and it is safe to assume that there will be a steady advance of technology over the coming years.

In these circumstances the federal government has a limited role in supporting R&D. The proper focus should be on sponsoring R&D and analytic studies that address topics that benefit the public or the industry but which do not permit individual firms to attain a proprietary position. Examples are environmental and safety studies, risk assessments, resource assessments, and longer-term R&D (such as research on methane hydrates). Across many administrations, the Office of Management and Budget (OMB) has been skeptical of any federal support for oil and gas R&D, and many Presidents' budget have not included any request for R&D for oil and gas. Nonetheless Congress has typically put money into the budget for oil & gas R&D.

The following table summarizes the R&D outlays of the DOE, EPA, and USGS for unconventional gas:

Unconventional Gas R&D Outlays for Various Federal Agencies (\$ millions)					
	FY2008	FY2009	FY2010	FY2011	FY2012 request
DOE Unconventional Gas					
<u>EPAct Section 999 Program Funds</u>					
RPSEA Administered	\$14	\$14	\$14	\$14	0
NETL Complementary	\$9	\$9	\$9	\$4	0
<u>Annual Appropriated Program Funds</u>					
Environmental	\$2	\$4	\$2	0	0
Unconventional Fossil Energy	0	0	\$6	0	0
Methane Hydrate projects	\$15	\$15	\$15	\$5	\$10
Total Department of Energy	\$40	\$42	\$46	\$23	\$10
Environmental Protection Agency	\$0	\$0	\$1.9	\$4.3	\$6.1
USGS	\$4.5	\$4.6	\$5.9	\$7.4	\$7.6
Total Federal R&D	\$44.5	\$46.6	\$53.8	\$34.7	\$23.7

Near Term Actions:

The Subcommittee believes that given the scale and rapid growth of the shale gas resource in the nation’s energy mix, the federal government should sponsor some R&D for unconventional gas, focusing on areas that have public and industry wide benefit and addresses public concern. The Subcommittee, at this point, is only in a position to offer some initial recommendations, not funding levels or to assignment of responsibility to particular government agencies. The DOE, EPA, the USGS, and DOI Bureau of Land Management all have mission responsibility that justify a continuing, tailored, federal R&D effort.

RPSEA is the Research Partnership to Secure Energy for America, a public/private research partnership authorized by the 2005 Energy Policy Act at a level of \$50 million from offshore royalties. Since 2007, the RPSEA program has focused on unconventional gas. The Subcommittee strongly supports the RPSEA program at its authorized level.²⁴

The Subcommittee recommends that the relevant agencies, the Office of Science and Technology Policy (OSTP), and OMB discuss and agree on an appropriate mission and level of funding for unconventional natural gas R&D. If requested, the Subcommittee, in the second phase of its work, could consider this matter in greater detail and make recommendations for the Administration's consideration.

In addition to the studies mentioned in the body of the report, the Subcommittee mentions several additional R&D projects where results could reduce safety risk and environmental damage for shale gas operations:

1. Basic research on the relationship of fracturing and micro-seismic signaling.
2. Determination of the chemical interactions between fracturing fluids and different shale rocks – both experimental and predictive.
3. Understanding induced seismicity triggered by hydraulic fracturing and injection well disposal.²⁵
4. Development of “green” drilling and fracturing fluids.
5. Development of improved cement evaluation and pressure testing wireline tools assuring casing and cementing integrity.

Longer term prospects for technical advance

The public should expect significant technical advance on shale gas production that will substantially improve the efficiency of shale gas production and that will in turn reduce environmental impact. The expectation of significant production expansion in the future offers a tremendous incentive for companies to undertake R&D to improve efficiency and profitability. The history of the oil and gas industry supports such innovation, in particular greater extraction of the oil and gas in place and reduction in the unit cost of drilling and production.

The original innovations of directional drilling and formation fracturing plausibly will be extended by much more accurate placement of fracturing fluid guided by improved interpretation of micro-seismic signals and improved techniques of reservoir testing. As

an example, oil services firms are already offering services that provide near-real-time monitoring to avoid excessive vertical fracturing growth, thus affording better control of fracturing fluid placement. Members of the Subcommittee estimate that an improvement in efficiency of water use could be between a factor of two and four. There will be countless other innovations as well.

There has already been a major technical innovation – the switch from single well to pad-based drilling and production of multiple wells (up to twenty wells per pad have been drilled). The multi-well pad system allows for enhanced efficiency because of repeating operations at the same site and a much smaller footprint (e.g. concentrated gas gathering systems; many fewer truck trips associated with drilling and completion, especially related to equipment transport; decreased needs for road and pipeline constructions, etc.). It is worth noting that these efficiencies may require pooling acreage into large blocks.

Conclusion

The public deserves assurance that the full economic, environmental and energy security benefits of shale gas development will be realized without sacrificing public health, environmental protection and safety. Nonetheless, accidents and incidents have occurred with shale gas development, and uncertainties about impacts need to be quantified and clarified. Therefore the Subcommittee has highlighted important steps for more thorough information, implementation of best practices that make use of technical innovation and field experience, regulatory enhancement, and focused R&D, to ensure that shale operations proceed in the safest way possible, with enhanced efficiency and minimized adverse impact. If implemented these measures will give the public reason to believe that the nation's considerable shale gas resources are being developed in a way that is most beneficial to the nation.

ANNEX A – CHARGE TO THE SUBCOMMITTEE

From: Secretary Chu

To: William J. Perry, Chairman, Secretary's Energy Advisory Board (SEAB)

On March 30, 2011, President Obama announced a plan for U.S. energy security, in which he instructed me to work with other agencies, the natural gas industry, states, and environmental experts to improve the safety of shale gas development. The President also issued the Blueprint for a Secure Energy Future ("Energy Blueprint"), which included the following charge:

"Setting the Bar for Safety and Responsibility: To provide recommendations from a range of independent experts, the Secretary of Energy, in consultation with the EPA Administrator and Secretary of Interior, should task the Secretary of Energy Advisory Board (SEAB) with establishing a subcommittee to examine fracking issues. The subcommittee will be supported by DOE, EPA and DOI, and its membership will extend beyond SEAB members to include leaders from industry, the environmental community, and states. The subcommittee will work to identify, within 90 days, any immediate steps that can be taken to improve the safety and environmental performance of fracking and to develop, within six months, consensus recommended advice to the agencies on practices for shale extraction to ensure the protection of public health and the environment." *Energy Blueprint (page 13).*

The President has charged us with a complex and urgent responsibility. I have asked SEAB and the Natural Gas Subcommittee, specifically, to begin work on this assignment immediately and to give it the highest priority.

This memorandum defines the task before the Subcommittee and the process to be used.

Membership:

In January of 2011, the SEAB created a Natural Gas Subcommittee to evaluate what role natural gas might play in the clean energy economy of the future. Members of the Subcommittee include John Deutch (chair), Susan Tierney, and Dan Yergin. Following consultation with the Environmental Protection Agency and the Department of the Interior, I have appointed the following additional members to the Subcommittee: Stephen Holditch, Fred Krupp, Kathleen McGinty, and Mark Zoback.

The varied backgrounds of these members satisfies the President's charge to include individuals with industry, environmental community, and state expertise. To facilitate an expeditious start, the Subcommittee will consist of this small group, but additional members may be added as appropriate.

Consultation with other Agencies:

The President has instructed DOE to work in consultation with EPA and DOI, and has instructed all three agencies to provide support and expertise to the Subcommittee. Both agencies have independent regulatory authority over certain aspects of natural gas production, and considerable expertise that can inform the Subcommittee's work.

- The Secretary and Department staff will manage an interagency working group to be available to consult and provide information upon request of the Subcommittee.
- The Subcommittee will ensure that opportunities are available for EPA and DOI to present information to the Subcommittee.
- The Subcommittee should identify and request any resources or expertise that lies within the agencies that is needed to support its work.
- The Subcommittee's work should at all times remain independent and based on sound science and other expertise held from members of the Subcommittee.
- The Subcommittee's deliberations will involve only the members of the Subcommittee.
- The Subcommittee will present its final report/recommendations to the full SEAB Committee.

Public input:

In arriving at its recommendations, the Subcommittee will seek timely expert and other advice from industry, state and federal regulators, environmental groups, and other stakeholders.

- To assist the Subcommittee, DOE's Office of Fossil Energy will create a website to describe the initiative and to solicit public input on the subject.
- The Subcommittee will meet with representatives from state and federal regulatory agencies to receive expert information on subjects as the Subcommittee deems necessary.
- The Subcommittee or the DOE (in conjunction with the other agencies) may hold one or more public meetings when appropriate to gather input on the subject.

Scope of work of the Subcommittee:

The Subcommittee will provide the SEAB with recommendations as to actions that can be taken to improve the safety and environmental performance of shale gas extraction processes, and other steps to ensure protection of public health and safety, on topics such as:

- well design, siting, construction and completion;
- controls for field scale development;
- operational approaches related to drilling and hydraulic fracturing;
- risk management approaches;
- well sealing and closure;
- surface operations;
- waste water reuse and disposal, water quality impacts, and storm water runoff;

- protocols for transparent public disclosure of hydraulic fracturing chemicals and other information of interest to local communities;
- optimum environmentally sound composition of hydraulic fracturing chemicals, reduced water consumption, reduced waste generation, and lower greenhouse gas emissions;
- emergency management and response systems;
- metrics for performance assessment; and
- mechanisms to assess performance relating to safety, public health and the environment.

The Subcommittee should identify, at a high level, the best practices and additional steps that could enhance companies' safety and environmental performance with respect to a variety of aspects of natural gas extraction. Such steps may include, but not be limited to principles to assure best practices by the industry, including companies' adherence to these best practices. Additionally, the Subcommittee may identify high-priority research and technological issues to support prudent shale gas development.

Delivery of Recommendations and Advice:

- Within 90 days of its first meeting, the Subcommittee will report to SEAB on the "immediate steps that can be taken to improve the safety and environmental performance of fracking."
- Within 180 days of its first meeting, the Subcommittee will report to SEAB "consensus recommended advice to the agencies on practices for shale extraction to ensure the protection of public health and the environment."
- At each stage, the Subcommittee will report its findings to the full Committee and the SEAB will review the findings.
- The Secretary will consult with the Administrator of EPA and the Secretary of the Interior, regarding the recommendations from SEAB.

Other:

- The Department will provide staff support to the Subcommittee for the purposes of meeting the requirements of the Subcommittee charge. The Department will also engage the services of other agency Federal employees or contractors to provide staff services to the Subcommittee, as it may request.
- DOE has identified \$700k from the Office of Fossil Energy to fund this effort, which will support relevant studies or assessments, report writing, and other costs related to the Subcommittee's process.
- The Subcommittee will avoid activity that creates or gives the impression of giving undue influence or financial advantage or disadvantage for particular companies involved in shale gas exploration and development.
- The President's request specifically recognizes the unique technical expertise and scientific role of the Department and the SEAB. As an agency not engaged in regulating this activity, DOE is expected to provide a sound, highly credible evaluation of the best practices and best ideas for employing these practices safely that can be made available to companies and relevant regulators for appropriate action. Our task does not include making decisions about regulatory policy.

ANNEX B – MEMBERS OF THE SUBCOMMITTEE

John Deutch, Institute Professor at MIT (Chair) - John Deutch served as Director of Energy Research, Acting Assistant Secretary for Energy Technology and Under Secretary of Energy for the U.S. Department of Energy in the Carter Administration and Undersecretary of Acquisition & Technology, Deputy Secretary of Defense and Director of Central Intelligence during the first Clinton Administration. Dr. Deutch also currently serves on the Board of Directors of Raytheon and Cheniere Energy and is a past director of Citigroup, Cummins Engine Company and Schlumberger. A chemist who has published more than 140 technical papers in physical chemistry, he has been a member of the MIT faculty since 1970, and has served as Chairman of the Department of Chemistry, Dean of Science and Provost. He is a member of the Secretary of Energy Advisory Board.

Stephen Holditch, Head of the Department of Petroleum Engineering at Texas A&M University and has been on the faculty since 1976 - Stephen Holditch, who is a member of the National Academy of Engineering, serves on the Boards of Directors of Triangle Petroleum Corporation and Matador Resources Corporation. In 1977, Dr. Holditch founded S.A. Holditch & Associates, a petroleum engineering consulting firm that specialized in the analysis of unconventional gas reservoirs. Dr. Holditch was the 2002 President of the Society of Petroleum Engineers. He was the Editor of an SPE Monograph on hydraulic fracturing treatments, and he has taught short courses for 30 years on the design of hydraulic fracturing treatments and the analyses of unconventional gas reservoirs. Dr. Holditch worked for Shell Oil Company prior to joining the faculty at Texas A&M University.

Fred Krupp, President, Environmental Defense Fund - Fred Krupp has overseen the growth of EDF into a recognized worldwide leader in the environmental movement. Krupp is widely acknowledged as the foremost champion of harnessing market forces for environmental ends. He also helped launch a corporate coalition, the U.S. Climate Action Partnership, whose Fortune 500 members - Alcoa, GE, DuPont and dozens more - have called for strict limits on global warming pollution. Mr. Krupp is coauthor, with Miriam Horn, of New York Times Best Seller, *Earth: The Sequel*. Educated at Yale and the University of Michigan Law School, Krupp was among 16 people named as America's Best Leaders by U.S. News and World Report in 2007.

Kathleen McGinty, Kathleen McGinty is a respected environmental leader, having served as President Clinton's Chair of the White House Council on Environmental Quality and Legislative Assistant and Environment Advisor to then-Senator Al Gore.

More recently, she served as Secretary of the Pennsylvania Department of Environmental Protection. Ms. McGinty also has a strong background in energy. She is Senior Vice President of Weston Solutions where she leads the company's clean energy development business. She also is an Operating Partner at Element Partners, an investor in efficiency and renewables. Previously, Ms. McGinty was Chair of the Pennsylvania Energy Development Authority, and currently she is a Director at NRG Energy and Iberdrola USA.

Susan Tierney, Managing Principal, Analysis Group - Susan Tierney is a consultant on energy and environmental issues to public agencies, energy companies, environmental organizations, energy consumers, and tribes. She chairs the Board of the Energy Foundation, and serves on the Boards of Directors of the World Resources Institute, the Clean Air Task Force, among others. She recently, co-chaired the National Commission on Energy Policy, and chairs the Policy Subgroup of the National Petroleum Council's study of North American natural gas and oil resources. Dr. Tierney served as Assistant Secretary for Policy at the U.S. Department of Energy during the Clinton Administration. In Massachusetts, she served as Secretary of Environmental Affairs, Chair of the Board of the Massachusetts Water Resources Agency, Commissioner of the Massachusetts Department of Public Utilities and executive director of the Massachusetts Energy Facilities Siting Council.

Daniel Yergin, Chairman, IHS Cambridge Energy Research Associates - Daniel Yergin is the co-founder and chairman of IHS Cambridge Energy Research Associates. He is a member of the U.S. Secretary of Energy Advisory Board, a board member of the Board of the United States Energy Association and a member of the U.S. National Petroleum Council. He was vice chair of the 2007 National Petroleum Council study, *Hard Truths* and is vice chair of the new National Petroleum Council study of North American natural gas and oil resources. He chaired the U.S. Department of Energy's Task Force on Strategic Energy Research and Development. Dr. Yergin currently chairs the Energy Security Roundtable at the Brookings Institution, where he is a trustee, and is member of the advisory board of the MIT Energy Initiative. Dr. Yergin is also CNBC's Global Energy Expert. He is the author of the Pulitzer Prize-winning book, *The Prize: The Epic Quest for Oil, Money and Power*. His new book – *The Quest: Energy, Security, and the Remaking of the Modern World* – will be published in September 2011..

Mark Zoback, Professor of Geophysics, Stanford University - Mark Zoback is the Benjamin M. Page Professor of Geophysics at Stanford University. He is the author of a textbook, *Reservoir Geomechanics*, and author or co-author of over 300 technical research papers. He was co-principal investigator of the San Andreas Fault Observatory at Depth project (SAFOD) and has been serving on a National Academy of Engineering committee investigating the Deepwater Horizon accident. He was the chairman and co-founder of GeoMechanics International and serves as a senior adviser to Baker Hughes,

Inc. Prior to joining Stanford University, he served as chief of the Tectonophysics Branch of the U.S. Geological Survey Earthquake Hazards Reduction Program.

ENDNOTES

¹ http://www.whitehouse.gov/sites/default/files/blueprint_secure_energy_future.pdf

² The James Baker III Institute for Public Policy at Rice University has recently released a report on *Shale Gas and U.S. National Security*, Available at: <http://bakerinstitute.org/publications/EF-pub-DOEShaleGas-07192011.pdf>.

³ As a share of total dry gas production in the “lower ’48”, shale gas was 6 percent in 2006, 8 percent in 2007, at which time its share began to grow rapidly – reaching 12 percent in 2008, 16 percent in 2009, and 24 percent in 2010. In June 2011, it reached 29 percent. Source: Energy Information Administration and Lippman Consulting.

⁴ Timothy Considine, Robert W. Watson, and Nicholas B. Considine, “The Economy Opportunities of Shale Energy Development,” Manhattan Institute, May 2011, Table 2, page 6.

⁵ Essentially all fracturing currently uses water as the working fluid. The possibility exists of using other fluids, such as nitrogen, carbon dioxide or foams as the working fluid.

⁶ The Department of Energy has a shale gas technology primer available on the web at: http://www.netl.doe.gov/technologies/oil-gas/publications/brochures/Shale_Gas_March_2011.pdf

⁷ See the Bureau of Land Management *Gold Book* for a summary description of the DOI’s approach: http://www.blm.gov/pgdata/etc/medialib/blm/wo/MINERALS_REALTY_AND_RESOURCE_PROTECTION/_energy/oil_and_gas.Par.18714.File.dat/OILgas.pdf

⁸ <http://www.shalegas.energy.gov/>

⁹ The 2011 *MIT Study on the Future of Natural Gas*, gives an estimate of about 50 widely reported incidents between 2005 and 2009 involving groundwater contamination, surface spills, off-site disposal issues, water issues, air quality and blow outs, Table 2.3 and Appendix 2E. <http://web.mit.edu/mitei/research/studies/naturalgas.html>

¹⁰ The Ground Water Protection Council and the Interstate Oil and Gas Compact Commission are considering a project to create a *National Oil and Gas Data Portal* with similar a objective, but broader scope to encompass all oil and gas activities.

¹¹ Information about STRONGER can be found at: <http://www.strongerinc.org/>

¹² The RBMS project is supported by the DOE Office of Fossil Energy, DOE grant #DE-FE0000880 at a cost of \$1.029 million. The project is described at: http://www.netl.doe.gov/technologies/oil-gas/publications/ENVreports/FE0000880_GWPC_Kickoff.pdf

¹³ See, for example: John Corra, “Emissions from Hydrofracking Operations and General Oversight Information for Wyoming,” presented to the U.S. Department of Energy Natural Gas Subcommittee of the Secretary of Energy Advisory Board, July 13, 2011; Al Armendariz, “Emissions from Natural Gas Production in the Barnett Shale Area and Opportunities for Cost-Effective Improvements,” Southern Methodist University, January 2009; Colorado Air Quality Control Commission, “Denver Metro Area & North Front Range Ozone Action Plan,” December 12, 2008; Utah Department of Environmental Quality, “2005 Uintah Basin Oil and Gas Emissions Inventory,” 2005.

¹⁴ IPCC 2007 –The Physical Science Basis, Section 2.10.2).

¹⁵ Robert W. Howarth, Renee Santoro, and Anthony Ingraffea, *Methane and the greenhouse-gas*

footprint of natural gas from shale formations, *Climate Change*, The online version of this article (doi:10.1007/s10584-011-0061-5) contains supplementary material.

¹⁶ Timothy J. Skone, *Life Cycle Greenhouse Gas Analysis of Natural Gas Extraction & Delivery in the United States*, DOE, NETL, May 2011, available at: http://www.netl.doe.gov/energy-analyses/pubs/NG_LC_GHG_PRES_12MAY11.pdf

¹⁷ Paulina Jaramillo, W. Michael Griffin, and H. Scott Mathews, *Comparative Life-Cycle Air Emissions of Coal, Domestic Natural Gas, LNG, and SNG for Electricity Generation*, *Environmental Science & Technology*, 41, 6290-6296 (2007).

¹⁸ The EPA draft hydraulic fracturing study plan is available along with other information about EPA hydraulic fracturing activity at: <http://water.epa.gov/type/groundwater/uic/class2/hydraulicfracturing/index.cfm>

¹⁹ See, for example, “South Texas worries over gas industry’s water use during drought,” *Platts*, July 5, 2011, found at:

<http://www.platts.com/RSSFeedDetailedNews/RSSFeed/NaturalGas/3555776>; “Railroad Commission, Halliburton officials say amount of water used for fracking is problematic,” *Abeline Reporter News*, July 15, 2011, found at: <http://www.reporternews.com/news/2011/jul/15/railroad-commission-halliburton-officials-say-of/?print=1>; “Water Use in the Barnett Shale,” *Texas Railroad Commission Website*, updated January 24, 2011, found at:

http://www.rrc.state.tx.us/barnettshale/wateruse_barnettshale.php.

²⁰ See, for example, *Energy Demands on Water Resources, DOE Report to Congress*, Dec 2006, <http://www.sandia.gov/energy-water/docs/121-RptToCongress-EWwEIAcomments-FINAL.pdf>

²¹ Stephen G. Osborna, Avner Vengoshb, Nathaniel R. Warnerb, and Robert B. Jackson, *Methane contamination of drinking water accompanying gas-well drilling and hydraulic fracturing*, *Proceedings of the National Academy of Science*, 108, 8172-8176, (2011).

²² See EPA Certification Guidance for Engines Regulated Under: 40 CFR Part 86 (On-Highway Heavy-Duty Engines) and 40 CFR Part 89 (Nonroad CI Engines); available at: <http://www.epa.gov/oms/regs/nonroad/equip-hd/420b98002.pdf>

²³ API standards documents addressing hydraulic fracturing are: API HF1, *Hydraulic Fracturing Operations-Well Construction and Integrity Guidelines*, First Edition/October 2009, API HF2, *Water Management Associated with Hydraulic Fracturing*, First Edition/June 2010, API HF3, *Practices for Mitigating Surface Impacts Associated with Hydraulic Fracturing*, First Edition/January 2011, available at:

<http://www.api.org/policy/exploration/hydraulicfracturing/index.cfm>

²⁴ Professor Steven Holditch, one of the Subcommittee members, is chair of the RPSEA governing committee.

²⁵ Extremely small microearthquakes are triggered as an integral part of shale gas development. While essentially all of these earthquakes are so small as to pose no hazard to the public or facilities (they release energy roughly equivalent to a gallon of milk falling off a kitchen counter), earthquakes of larger (but still small) magnitude have been triggered during hydraulic fracturing operations and by the injection of flow-back water after hydraulic fracturing. It is important to develop a hazard assessment and remediation protocol for triggered earthquakes to allow operators and regulators to know what steps need to be taken to assess risk and modify, as required, planned field operations.

| CONFIDENTIAL

Deliberative -Draft of January 11, 2012

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**DRAFT MODEL REGULATORY
FRAMEWORK
FOR
HYDRAULICALLY FRACTURED
~~ONSHORE~~-HYDROCARBON ~~EXPLORATION~~
~~AND~~ PRODUCTION WELLS**

For Discussion

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INTRODUCTION

ARTICLE I – Utilizing the Model Regulatory Framework

1.1. Scope of Model Regulatory Framework. This Model Regulatory Framework for Hydraulically Fractured Hydrocarbon Production Wells (the “Model Framework”) is intended to be utilized by state governments in implementing a distinct regulatory regime governing the drilling, completion and production of onshore hydrocarbon exploration and production wells that are stimulated by hydraulic fracturing. The Model Framework applies to all hydraulically fractured hydrocarbon exploration and production wells, regardless of depth or trajectory, but is not intended to govern any aspect of injection wells, storage wells or any other type of wells that may also be stimulated by hydraulic fracturing. The Model Framework addresses ~~all critical~~those regulatory and operational issues ~~pertaining to wellhead control and subsurface wells~~that are critical to ensuring the integrity of a hydraulically fractured hydrocarbon production well throughout its full life-cycle, beginning with the permitting process and ending with plugging and abandonment. The Model Framework does not address surface issues such as impoundment construction standards, spill control, release notification, interagency coordination, surface containment of any well return fluids (including flowback, swabbing or other produced fluids), off-site transport, recycling or disposal of well return fluids. The Model Framework does not include specific provisions requiring financial security because it is presumed that states will already have such provisions in place, but it is necessary for any required cost estimates used under any state financial security requirements to include the costs of any additional incremental requirements that are imposed on hydraulically fractured wells by the Model Framework. In addition, the Model Framework is not intended to address or affect other regulatory or common law issues such as well spacing, correlative rights of mineral owners or lease rights.

2.2. Purpose of Model Regulatory Framework. The Model Framework is based on numerous “best-in-class” state rules and regulations, and incorporates industry “best practices” with regard to safety, efficiency and environmental protection. The Model Framework is meant to give state governments a road-map to implement hydraulic fracturing regulation that (i) utilizes the structure of effective state laws and regulations, (ii) makes effective operational industry practices mandatory, (iii) encourages technological advances and innovation to continually improve industry practices and (iv) ensures the protection of human health and safety and the environment. Articles III through VIII of the Model Framework contain the substance of the Model Framework’s requirements, and are chronologically organized based on the life-cycle of a hydraulically fractured hydrocarbon production well. These are:

(a) ARTICLE I - Definitions

~~a. (b) ARTICLE II – Definitions~~ Well Planning (Permitting);

~~b. ARTICLE III – Well Planning (Permitting);~~

~~e. ARTICLE IV – Well Planning (c) ARTICLE III – PRE-DRILLING WATER SAMPLING Well Planning (Financial Security Requirements);~~

~~(d) ARTICLE IV – Well Construction (Drilling);~~

~~d. (e) ARTICLE V – Well Construction (Drilling Completion);~~

~~e. ARTICLE VI – Well Construction (Completion);~~

~~f. (f) ARTICLE ~~VH~~VI – Production and Well Monitoring; and~~

~~g. (g) ARTICLE ~~VH~~VII – Well Abandonment and Plugging.~~

~~3. How to Utilize the Model Regulatory Framework-~~

~~(h) ARTICLE VIII – Additional Requirements~~

~~a. General. 3. Utilizing the Model Regulatory Framework.~~ It is important to note that while the Model Framework is written in statutory form, it is not meant to be an exhaustive statutory scheme ~~that can be adopted directly~~, but instead is a working structure that sets forth key substantive components for effective regulation. The reason for this is to allow state governments and regulators adequate flexibility in the manner in which they are able to integrate the substantive provisions of the Model Framework into existing state law. Accordingly, it is expected that in implementing the Model Framework, state regulators may utilize different terminology, add or expound upon certain procedural requirements, or otherwise deviate from the Model Framework in certain non-substantive aspects. ~~However, a state should address all substantive requirements of the Model Framework. Deviations shall be considered to be “non-substantive” in nature if such deviation is merely procedural or stylistic in nature. A deviation would also be deemed acceptable if it is an additional requirement that (i) is in excess of what the Model Framework requires, or (ii) otherwise does not conflict with the Model Framework. On the other hand, a deviation shall be considered to be unacceptable to the extent that it conflicts with a provision of the Model Framework that is integral to (a) protection and maintenance of well bore integrity, (b) protection of natural resources (including sources of protected water), and (c) the ability of the operator and the applicable state regulatory authority to adequately monitor hydraulic fracturing activities so as to achieve the objectives of (a) and (b). As a practical matter, deviations from the well construction, production/well monitoring and well abandonment and plugging provisions of the Model Framework (Articles IV through VII) shall be the most likely to be deemed as substantive.~~ In implementing the Model Framework, due consideration should be given to encouraging operators to pursue technological advancements and innovative solutions to better achieve the goals of the Model Framework.

~~ARTICLE II – Definitions~~ ARTICLE I - DEFINITIONS

~~a. — Use of Certain Terms.~~ As used in the Model Framework, the following terms shall have the meanings ascribed to them below, unless the context clearly indicates otherwise:

~~i. (1) “Active operation” — Regular~~ shall mean regular and continuing activities related to the exploration, development or production of hydrocarbons for which the operator has all necessary permits.

(2) “Additive” shall mean any substance or combination of substances found in a hydraulic fracturing fluid, including a proppant, that is added to a base fluid in the context of a hydraulic fracturing treatment, whether or not the function of any such substance or combination of substances is to create fractures in a formation.

~~ii. (3) “Annular overpressurization” — Annular overpressurization.” shall mean the wellbore condition that~~ occurs when (i) fluids in the annulus between the surface casing and the intermediate/production casing are pressurized to such an extent so as to potentially allow for the migration of confined fluids or gases at the surface casing shoe or (ii) fluids in the annulus between any intermediate casing (if intermediate casing is set) and the production casing are pressurized to such an extent so as to potentially allow for the migration of confined fluids or gases at the intermediate casing shoe.

~~iii. — “Application” — A formal request by an operator made with [STATE REGULATOR] for a permit to drill, deepen, plug back, reenter, fracture or refracture any well for the purpose of exploring for, developing and producing hydrocarbons through the use of hydraulic fracturing operations.~~

(4) “Base Fluid” shall mean the base fluid type, such as water, including fresh water and recycled water, or nitrogen foam, used in a particular hydraulic fracturing treatment.

~~i. (5) “Bond” — A~~ shall mean a surety instrument issued:

~~(1) (i)~~ on a [STATE REGULATOR]- approved form;

~~(2) (ii)~~ by and drawn on a third party corporate surety authorized under [STATE] law to issue surety bonds in [STATE]; and

~~(3) (iii)~~ renewed and continued in effect until the conditions of the bond have been met or its release is approved by [STATE REGULATOR].

~~iv. (6) “Chemical Abstract Abstracts Service” or “CAS” — shall mean~~ the chemical registry that is the most authoritative collection of disclosed chemical substance information, containing more than 52 million organic and inorganic substances and 61 million sequences.

(7) “Chemical ingredient” shall mean a discrete chemical constituent with its own specific name or identity, such as a CAS number, that is contained in an additive.

~~v.~~ (8) “Close proximity well” shall ~~refer to a hydrocarbon production~~mean a well that will be completed with a hydraulic ~~fracture stimulation~~fracturing treatment in a productive horizon that (i) has less than 500 vertical feet of intervening zone, or (ii) has more than 500 vertical feet of intervening zone, but which [STATE REGULATOR] determines should nevertheless be classified as a close proximity well because the intervening zone does not contain an adequate confining layer. Notwithstanding the foregoing, an operator may be granted an exemption from the “close proximity well” classification when there is less than 500 vertical feet of intervening zone if the [STATE REGULATOR] determines that such intervening zone contains an adequate confining layer.

~~vi.~~ (9) “Completion” shall ~~refer to mean~~ the collective operational ~~actions taken and methods employed~~activities that are conducted following drilling operations to prepare a well for production, ~~unless the context clearly indicates otherwise. Completion activities include, but are~~including, but not limited to, installation of surface and downhole equipment in the wellbore, perforating, testing and well stimulation ~~and testing~~ to facilitate hydrocarbon production.

~~vii.~~ (10) “Conductor casing” ~~is that shall mean the~~ pipe ordinarily used ~~for the purpose of supporting to support~~ unconsolidated surface deposits and to prevent the subsurface infiltration of surface water or fluids into the wellbore.

~~viii.~~ (11) “Confining layer” shall ~~refer to mean~~ that portion of an intervening zone that acts as an effective barrier to the vertical migration of fluids into one or more strata or zones that contain protected water. In determining whether an intervening zone contains an adequate confining layer, the [STATE REGULATOR] shall review the operator’s analysis of the intervening zone, which shall include an assessment of the mechanical rock properties (including permeability, relative hardness (using Young’s Modulus), and relative elasticity (using Poisson’s Ratio)) and other relevant characteristics of the formation(s) that comprise the intervening zone to determine whether such intervening zone contains one or more formation(s) that will have sufficient areal extent and integrity to ensure proper containment of the hydraulically induced fracture and act as an effective barrier to the vertical migration of fluids into one or more strata or zones that contain protected water.

~~ix.~~ (12) “Delinquent inactive well” ~~—An shall mean an~~ unplugged well that has had no reported production, disposal, injection, or other permitted activity for a period of greater than 12 months and for which, after notice and opportunity for hearing, [STATE REGULATOR] has not extended the plugging deadline.

~~x.~~ (13) “Financial security” ~~—An shall mean an~~ individual performance bond, blanket performance bond, letter of credit, ~~or~~ cash deposit filed with [STATE REGULATOR] or any other authorized means of meeting state financial security requirements. Any required cost estimates developed to comply with state financial security requirements shall include the costs of any additional incremental requirements that are imposed on hydraulically fractured wells by this Model Framework.

~~xi.~~ (14) “Funnel viscosity” — ~~Viscosity~~ shall mean viscosity as measured by the Marsh funnel, based on the number of seconds required for 1,000 cubic centimeters of fluid to flow through the funnel.

~~xii.~~ (16) “Good faith claim” — ~~A~~ shall mean a factually supported claim based on a recognized legal theory to a continuing possessory right in a mineral estate, such as evidence of a currently valid hydrocarbon lease or a recorded deed conveying a fee interest in the mineral estate.

~~xiii.~~ (16) “Hydraulic fracturing” or “Hydraulic fracturing treatment” shall ~~refer to mean~~ the stimulation ~~action~~ of stimulating a well by the application of fluids (which may contain proppant such as sand or man-made ~~inert~~ material) with force in order to create artificial fractures in the formation for the purpose of improving the capacity to produce the flow of hydrocarbons up the well; provided, however, the term “hydraulic fracturing” shall not include any activities or operations that are not designed to generate new fractures in the zone(s) of interest.

~~xiv.~~ — “Hydraulic fracturing treatment” — ~~the action of stimulating a well by the application of fluids with force in order to create artificial fractures in the formation for the purpose of improving the capacity to produce the flow of hydrocarbons up the well. The fluids may contain proppant (such as sand or man made inert material) for the purpose of preventing the artificially created fractures from closing once the~~

(17) “Hydraulic fracturing fluid” shall mean the fluid used to perform a particular hydraulic fracturing treatment ~~is complete~~ and includes the applicable base fluid and all additives.

~~xv.~~ (18) “Hydrocarbon” shall mean a naturally occurring organic compound comprised of hydrogen and carbon and may include oil, gas and other liquid and gaseous hydrocarbons. ~~{4-28-11}~~

~~xvi.~~ (19) “Hydrocarbon strata” shall refer to any stratum encountered in a well that is known to contain hydrocarbons.

~~xvii.~~ (20) “Intervening zone” shall refer to those geological formations (or part of a formation) located between the top boundary of the productive horizon that is being hydraulically fractured and the base of the deepest stratum or zone that contains protected water.

~~xviii.~~ (21) “Letter of credit” — ~~An~~ shall mean an irrevocable letter of credit issued:

- (~~1~~) on a [STATE REGULATOR]- approved form;
- (~~2~~) by and drawn on a third party bank authorized under state or federal law to do business in [STATE]; and
- (~~3~~) renewed and continued in effect until the conditions of the letter of credit have been met or its release is approved by [STATE REGULATOR].

~~xix.~~ (22) “Logging” ~~shall mean~~ to run any of a number of ~~various~~ measurement instruments into a well to measure the mechanical or physical properties of the well casing and/or cement, or the mechanical or petrophysical properties within of the wellbore, or rock geological formations immediately adjacent to the wellbore.

~~xx.~~ (23) “MSDS” ~~shall mean~~ a standardized Material Safety Data Sheet, ~~which that~~ contains key information regarding ~~its applicable subject~~ the substance(s) described therein, including the chemical make-up of ~~the subject~~ such substance(s) and certain other relevant health, safety and environmental data.

~~xxi.~~ (24) “Operator” shall ~~refer to an operator of a hydraulically fractured well that~~ mean the party designated to conduct operations on a well and ~~is~~ subject to state regulation as an operator, ~~unless the context clearly indicates otherwise.~~

~~xxii.~~ (25) “Perforating” ~~shall mean~~ to penetrate the casing wall and cement of a wellbore in order to provide holes through which ~~formation fluids may enter or to provide holes in the casing so that~~ hydraulic fracturing ~~treatments may be introduced into the formation~~ fluids may enter the formation and formation fluids may enter the wellbore.

(26) “Permit Application” shall mean a formal request by an operator made with [STATE REGULATOR] for a permit to drill, deepen, plug back, reenter, or refracture any well for the purpose of exploring for, developing and producing hydrocarbons through the use of hydraulic fracturing operations.

~~xxiii.~~ (27) “Productive horizon” shall mean any hydrocarbon strata determined to contain commercial quantities of hydrocarbons.

(28) “Proppant” shall mean sand or another natural or man-made material that is used in a hydraulic fracturing treatment to prevent artificially created or enhanced fractures from closing once the treatment is completed.

~~xxiv.~~ (29) “Protected water” shall ~~refer to mean~~ water that is classified as either (i) usable-quality water or (ii) treatable-quality water that (a) is currently being used as a supply of drinking water for human consumption or (b) the [STATE REGULATOR] has determined is sourced from an aquifer or portion thereof that is reasonably expected to supply any public water system and does not meet exemption standards as listed in 40 CFR 146 of the UIC Program.

~~xxv.~~ (30) “Protection depth” ~~The~~ shall mean the depth to which protected water must be protected, as determined by [STATE REGULATOR], which may include zones that contain brackish or saltwater if such zones are correlative and/or hydrologically connected to zones that contain protected water.

(31) “Purpose” shall mean a brief descriptor of the intended use or function of an additive in a hydraulic fracturing fluid, such as acid, biocide, breaker, corrosion inhibitor, crosslinker, demulsifier, friction reducer, gel, iron control, oxygen scavenger, ph adjusting agent, proppant, scale inhibitor or surfactant.

Comment [r1]: We need to revise the definition of “protected water” to reflect our decision to leave this to the states.

(32) “Refracture” shall mean the action of restimulating a well through a hydraulic fracturing treatment at a later date after the initial hydraulic fracturing treatment and some period of producing the well.

~~xxvi.~~ (33) “Related piping” ~~—The~~shall mean the surface piping and subsurface piping that is less than three feet beneath the ground surface between pieces of equipment located at any collection or treatment facility. Such piping would include piping between and among headers, manifolds, separators, storage tanks, gun barrels, heater treaters, dehydrators, and any other equipment located at a collection or treatment facility. The term ~~is not intended to refer to~~ “related piping” does not include lines, such as flowlines, gathering lines, and injection lines that lead up to and away from any such collection or treatment facility.

~~xxvii.~~ (34) “Reported production” ~~—Production of hydrocarbons, excluding~~shall mean those quantities of hydrocarbon production that are reported to [STATE REGULATOR] and specifically excludes hydrocarbon production attributable to well tests, ~~that is accurately reported to [STATE REGULATOR]~~ and flow back operations.

~~xxviii.~~ (35) “Serve notice” ~~—To serve notice on~~with respect to the notification of a surface owner or resident ~~pursuant to this Article is to hand deliver~~of plugging operations, shall mean (i) the hand delivery of a written notice identifying the well or wells to be plugged, and the projected date the well or wells will be plugged, ~~to the surface owner (or resident if the owner is absent)~~ at least three days prior to the day of plugging, or ~~to mail~~ (ii) the mailing of such notice by first class mail, postage pre-paid, to the last known address of the surface owner or resident at least seven days prior to the day of plugging.

(36) “Service company” shall mean a person that performs hydraulic fracturing treatments in this state for an operator.

~~xxix.~~ (37) “Source of protected water” shall ~~refer to~~mean any water well or surface water which is used as a source of ~~usable quality water~~water protected under state law.

~~xxx.~~ (38) “Stand under pressure” ~~—To~~shall mean to leave the hydrostatic column pressure in a well acting as the natural force without adding any external pump pressure. The provisions are complied with if float equipment is used and found to be holding at the completion of the cement job.

~~xxxi.~~ ~~—[STATE REGULATOR] shall not have fixed meaning, but instead shall be a “place holder” that refers to the applicable state regulatory body, authority, office or duly authorized person, given the context.~~

(39) “Supplier” shall mean a person, including an operator but excluding a service company, that sells or otherwise provides an additive used in hydraulic fracturing treatments.

~~xxxii.~~ (40) “Surface Casing” shall ~~refer to a~~mean a steel or steel alloy string of pipe set and cemented, or otherwise anchored, in the well to a depth sufficient to isolate

and seal off all zones containing protected ~~waters~~water, and which supports the installation of well control equipment that can be fully shut in and otherwise maintain proper pressure control of the well while drilling to a deeper depth.

(41) “Trade name” shall mean the name under which an additive is sold or marketed.

(42) “Trade secret” shall mean any confidential formula, pattern, process, device, information, or compilation of information that is used in a person’s business and that gives the person an opportunity to obtain an advantage over competitors that do not know or use it.

~~xxxiii. (43) “Treatable quality water” shall refer to mean water with more than 3,000 ppm and up to 10,000 ppm of total dissolved solids (TDS), provided that if the [STATE REGULATOR] determines that an aquifer or portion thereof contains water with greater than 10,000 ppm of TDS and such aquifer or portion thereof is reasonably determined to be likely to supply any public water system based on the technical and economic viability thereof, then such water may be classified by the [STATE REGULATOR] as treatable quality water.~~

~~xxxiv. (4443) “Usable-quality water” shall refer to mean~~ water with a maximum of 3,000 ppm total dissolved solids (TDS).

~~xxxv. (4544) “Well” shall refer to mean~~ a hydrocarbon production well that will be or has been hydraulically fractured, ~~unless the context clearly indicates otherwise.~~

~~xxxvi. (4645) “Zone of critical cement” — For shall mean (i) for~~ surface casing strings ~~greater than 300 feet in length, the zone of critical cement shall be~~ the bottom 20% of the casing string, but in no event shall it be more than 1,000 feet or less than 300 feet. ~~For and (ii) for~~ surface casing strings of 300 feet or less ~~in length,~~ the zone of critical cement ~~extends shall extend~~ to the land surface.

[Note: Sections 5, 6 and 7 were moved to new Article VIII.]

~~ARTICLE III – Well Planning (Permitting II) – WELL PLANNING (PERMITTING)~~

~~1. — General~~ 1. Scope of Article. This Article governs the process whereby an operator must apply for and obtain from [STATE REGULATOR] a permit to drill, deepen, plug back, reenter, ~~fracture~~ or refracture a well for the purpose of exploring for, developing and producing hydrocarbons from oil and gas bearing strata through the use of hydraulic fracturing operations.

~~2. 2. Permitting- Process.~~

~~a. — An application for a permit to drill, deepen, plug back, reenter, fracture or refracture any well for the purpose of exploring for, developing and producing hydrocarbons~~

~~through the use of hydraulic fracturing operations~~ (a) A permit application shall be made pursuant to and in accordance with any and all applicable laws, rules and regulations of [STATE REGULATOR] governing the permitting of hydrocarbon wells in the state of [STATE], and filed with [STATE REGULATOR] on a form approved by [STATE REGULATOR]. Each ~~permit~~ application ~~must~~shall be accompanied by all applicable information, forms, and certifications more particularly described in ~~this~~ Section 2.3 below.

~~b. (b)~~ Operations for the drilling, deepening, plugging back, reentering, ~~fracturing~~ or refracturing of a well for the purpose of exploring for, developing and producing hydrocarbons through the use of hydraulic fracturing operations shall not be commenced until the relevant permit or other authorization has been granted by [STATE REGULATOR] and the waiting period to commence such operations, if any, has terminated.

3. Permit Application Requirements.

~~e. (a)~~ A permit application ~~to drill, deepen, plug back, reenter, fracture or refracture~~ shall provide a well construction plan that contains the following information:

~~i. (i)~~ the operator name;

~~ii. (ii)~~ the lease, pooled unit or unitized tract name;

~~iii. (iii)~~ the lease, pooled unit or unitized tract number or gas identification number;

~~iv. (iv)~~ well number;

~~v. (v)~~ county, parish or other appropriate geographic subdivision;

~~vi. (vi)~~ field name;

~~vii. (vii)~~ a list of all productive horizon(s) intended to be tested;

~~viii. (viii)~~ the planned casing setting depth(s), cement top(s) and the anticipated depth of the deepest productive horizon intended to be tested;

(ix) a statement whether or not the well is to be completed as a Close Proximity Well.

~~ix. (x)~~ a plat showing the well location;

~~x. (xi)~~ a statement as to how the well location would comply with any applicable spacing rule ~~of [STATE REGULATOR] if completed~~ and how the surface location would comply with any applicable set-back rules to structures and public sites such as schools and hospitals.

~~xi.~~ (xii) a statement indicating that the well will be hydraulically fractured;

~~xii.~~ (xiii) the identification and anticipated true vertical depth(s) of the formation(s) to be hydraulically fractured and the anticipated surface treating pressure range for the proposed hydraulic fracturing treatment(s); and

~~xiii.~~ (xiv) an explanation of the steps to be taken to comply with the requirements for close proximity wells in Article V.6.e and Article VI.3.c;

~~xiv.~~ (xv) identification of the source(s) type of ~~all water~~ base fluid to be used for hydraulic fracturing operations, including specific identification of the sources of any water to be used as base fluid; ~~and~~

(xvi) a hydraulic fracturing waste disposal and treatment plan, including identification of where recovered water from the hydraulic fracturing operation will be sent;

~~xv.~~ (xvi) a statement that ~~recorded~~ existing or permitted wells of record within a specified radius of the ~~proposed~~ well that is the subject of the permit application have been evaluated to determine whether ~~the~~ any such well may be a conduit for movement of fluids into a source of protected water; and

~~xvi.~~ (xvii) such other information as [STATE REGULATOR] shall require.

~~d.~~ (b) With each permit application or materially amended permit application, the applicant shall submit to [STATE REGULATOR] a refundable fee as determined by the applicable financial security requirements of [STATE REGULATOR].

~~e.~~ Any permit to drill, deepen, plug back, reenter, fracture or refracture granted by [STATE REGULATOR] shall expire no later than two years after the date of original approval.

~~f.~~ (c) A permit application ~~to drill, deepen, plug back, reenter, fracture or refracture~~ shall be accompanied by a legible, accurate plat, with a scale of one inch equals 500 feet or such other scale as determined by [STATE REGULATOR]. The plat for the initial well on the lease, pooled unit, or unitized tract shall show the entire lease, pooled unit, or unitized tract, including all tracts being pooled or unitized. The boundary of the lease, pooled unit or unitized tract shall be outlined on the plat using either a heavy line or crosshatching. If necessary to show the entire lease, pooled unit or unitized tract, the scale may be one inch equals 2,000 feet or such other scale as determined by [STATE REGULATOR]. Plats for subsequent wells on a lease, pooled unit or unitized tract shall show at least the lease, pooled unit or unitized tract boundary line nearest the proposed location and the nearest permanent geographic subdivision boundary. [STATE REGULATOR] may approve plats with other scales upon request. The plat shall include the following:

~~i.~~ The boundary of the lease, pooled unit or unitized tract shall be outlined on the plat using either a heavy line or crosshatching.

~~ii. The plat is to include the following:~~

~~(1)-(i)~~ the surface location of the proposed drilling site, the proposed horizontal well and the proposed path, penetration point and terminus location for the well;

~~(2)-(ii)~~ perpendicular lines providing the distance in feet from the two nearest non-parallel permanent geographic subdivision boundaries to the surface location;

~~(3)-(iii)~~ perpendicular lines providing the distance in feet from two nearest non-parallel lease or unit boundary lines to the surface location;

~~(4)-(iv)~~ a line providing the distance in feet from the surface location to the nearest point on the lease or unit line, pooled unit line, or unitized tract line. If there is an unleased interest in a tract of the pooled unit that is nearer than the pooled unit line, the nearest point on that unleased tract boundary shall be used;

~~(5)-(v)~~ a line providing the distance in feet from the surface location to the nearest well identified by number either applied for, permitted, or completed in the same lease, pooled unit, or unitized tract and in the same field and reservoir;

~~(6)-(vi)~~ the geographic location information in plane coordinates meeting [STATE] GPS standards;

~~(7)-(vii)~~ a labeled scale bar; and

~~(8)-(viii)~~ northerly direction.

(d) For directional or horizontal wells, the plat attached to the permit application shall contain the following additional information:

(i) the lease, pooled unit, or unitized tract, showing the acreage assigned to the drilling unit for the proposed well and the acreage assigned to the drilling units for all current applied for, permitted, or completed oil, gas, or oil and gas wells on the lease, pooled unit, or unitized tract;

(ii) the surface location of the proposed well, and the proposed path, penetration points, and terminus locations of all wells to be drilled in the wellbore;

(iii) two perpendicular lines from the nearest point on the lease line, pooled unit line, or any unleased interest in a tract of the pooled unit, depicting the distance(s) to:

(1) the penetration point(s); and

(2) the terminus location(s);

(iv) perpendicular lines providing the distance in feet from the two nearest non-parallel survey lines to the terminus location(s);

(v) a line providing the distance in feet from the closest point along the course(s) of the well(s) to the nearest point on the lease line, pooled unit line, or unitized tract line. If there is an unleased interest in a tract of the pooled unit that is nearer than the pooled unit line, the nearest point on that unleased tract boundary shall be used; and

(vi) lines from the nearest oil, gas, or oil and gas well, applied for, permitted or completed in the same lease or pooled unit and in the same field and reservoir depicting the distance to:

(1) the penetration point(s);

(2) the closest point along the course(s) of the well(s); and

(3) the terminus location(s).

4. Term of Permit. Any permit to drill, deepen, plug back, reenter, or refracture granted by [STATE REGULATOR] shall expire no later than two years after the date of original approval.

~~iii.—Other applicable requirements of [STATE REGULATOR] governing plats may supplement or replace the plat requirements set out above.~~

5. Well Database.

~~g.~~(a) [STATE REGULATOR] shall be responsible for the creation and maintenance of a public database that depicts the official surface and bottom-hole locations of all hydrocarbon, disposal, injection and geothermal wells, and all sources of protected water constructed within [STATE].

~~h.~~(b) [STATE REGULATOR] shall determine or approve the location-specific surface casing depth for the permitted well based upon a review of its database(s) or based upon a contour map showing the basal elevation of the lowermost aquifer containing protected water.

~~ARTICLE IV—Well Planning (Financial Security Requirements)~~

~~ARTICLE III – PRE-DRILLING WATER SAMPLINGWELL-PLANNING (FINANCIAL SECURITY REQUIREMENTS)~~

~~2.—General~~1. Scope of Article.

2. Requirements for Wells Adjacent to Sources of Protected Water. When an operator is conducting well construction operations on wells located within the following distances of a source of protected water (including public and permitted private sources): (i) 1,000 radial feet from the edge of the pad for wells that are not classified as a close proximity well, (ii) 2,650

radial feet for close proximity wells, or (iii) such other distance as determined by [STATE REGULATOR]. ~~[STATE REGULATOR] may require that operator shall:~~

~~(4)(i) Through an independent third party contractor, obtain and test the composition of water samples from the relevant source of protected water sufficient to establish representative baseline characteristics for the area. Such testing will comply with any applicable requirements set forth by [STATE REGULATOR], and the third party contractor shall be certified by or otherwise approved as being acceptable to [STATE REGULATOR]. After representative baseline characteristics have been established for the area, additional testing may be required by [STATE REGULATOR];~~

~~This Article governs the process whereby sets forth the provisions that require an operator must to provide the state [STATE REGULATOR] with financial security in connection with the operator's hydraulic fracturing activities such. The purpose of the financial security requirements is to ensure that the state is adequately protected against certain costs the state it might incur as a result of (i) the improper abandonment of one or more wells drilled by the operator, or (ii) pollution or other any environmental damaged damages stemming from the operator's hydraulic fracturing activities. Except as otherwise provided in Section 4.3(a)(i)(3) below with respect to close proximity wells, nothing in this Article shall be construed to require additional financial security from an operator for any wells or activity to the extent that the operator has already posted adequate security with [STATE REGULATOR] for its other operations.~~

~~3. 2. Form of Financial Security Required.~~

~~a. (a) All operators undertaking hydraulic fracturing operations in [STATE] must, in addition to any other applicable filing obligations, file financial security with [STATE REGULATOR] in one of the following forms:~~

~~i. (i) an individual performance bond;~~

~~ii. (ii) a blanket performance bond; or~~

~~iii. (iii) a letter of credit or cash deposit in the same amount as required for an individual performance bond or blanket performance bond.~~

~~b. (b) Operators shall submit bonds and letters of credit on forms prescribed by [STATE REGULATOR] subject to any applicable deadlines and procedures governing such submissions.~~

~~4. 3. Required Amount and Conditions of Financial Security.~~

~~a. (a) An operator required to file financial security shall file financial security as described in this Section 4.a. hereunder shall meet the following requirements:~~

~~i. (i) Types and amounts of financial security required.~~

~~(1) A person operating one or more wells(1) An operator may file an individual performance bond, letter of credit, or cash deposit in an amount~~

equal to the sum of \$_____ per foot for each foot of total true vertical depth for each well operated~~the operator operates~~.

~~(2) — A person operating one or more wells(2) — An operator may file a blanket bond, letter of credit, or cash deposit to cover all wells for which a bond, letter of credit, or cash deposit is required in an amount equal to the greater of (i) the base amount determined in accordance with the last sentence of this Section 4.3(a)(i)(2) or (ii) \$_____. The base amount is determined as follows: (i) the base amount for a person operating 10 or fewer wells or performing other operations shall be \$_____;~~ (ii) the base amount for a person operating more than 10 but fewer than 100 wells shall be \$_____; (iii) the base amount for a person operating 100 or more wells shall be \$_____.

~~(3) (3) In addition to the financial security required under subparagraphs (1) and (2) of this Section 4.3(a)(i), a person an operator operating one or more close proximity wells shall be required to file an individual performance bond, letter of credit or cash deposit in an amount equal to the sum of \$_____ for each foot of total true vertical depth for each such well operated. In lieu of providing an individual performance bond, letter of credit or cash deposit for each such close proximity well, the operator may increase the amount of any blanket bond, letter of credit or cash deposit under Section 4.3(a)(i)(2) by an amount determined in accordance with the immediately preceding sentence.~~

~~ii. (ii) If a person is engaged in more than one activity or operation, including well operation, for which financial security is required, the person is shall not be required to file financial security for each activity or operation in which the person is engaged. The person is shall be required to file financial security only in the greatest amount required for any activity or operation in which the person engages. The and the financial security filed covers by such person shall cover all of the activities and operations for which financial security is required.~~

~~iii. (iii) Financial security amounts required herein are the minimum amounts required to be filed. A person may file a greater amount if desired.~~

~~b. (b) Any bond, letter of credit, or cash deposit required under this Article is subject to the conditions that the operator will plug and abandon all wells and control, abate, and clean-up pollution associated with the surface oil and gas operations and activities covered under the required financial security in accordance with applicable state law and permits, rules, and orders of [STATE REGULATOR].~~

~~e. (e) Operators shall tender cash deposits in United States currency or certified cashiers check only, and shall make such deposit in accordance with any and all applicable rules and regulations governing such cash deposits. [STATE REGULATOR] will not refund a cash deposit until either financial security is accepted by [STATE REGULATOR] as provided hereunder or an operator ceases all activity.~~

~~5. 4 Well or Lease Transfer.~~

a. ~~(a)~~ [STATE REGULATOR] shall not approve a transfer of operatorship submitted for any well or lease unless the operator acquiring the well or lease has on file with [STATE REGULATOR] financial security in an amount sufficient to cover both its current operations and the wells or leases being transferred.

b. ~~(b)~~ Any existing financial security covering the well or lease proposed for transfer shall remain in effect and the prior operator of the well remains ~~shall remain~~ responsible for compliance with all laws and [STATE REGULATOR] rules covering the transferred well until [STATE REGULATOR] approves the transfer.

e. ~~A(c)~~ The transfer of a well or lease from one entity to another entity under common ownership is ~~shall be deemed~~ a transfer for the purposes of this Article.

ARTICLE ~~V~~ – Well Construction (Drilling) ~~IV~~ – WELL CONSTRUCTION (DRILLING)

~~1.~~ **General**, **1. Scope of Article**. It is the intent of all provisions of this Article that (i) all well casing shall meet appropriate API standards and be sufficiently cemented or otherwise anchored in the hole in order to effectively control the well at all times, (ii) all zones containing protected water ~~zones~~ shall be isolated and sealed off to effectively prevent contamination or harm to any water therein, and (iii) all potentially productive zones, zones capable of ~~over-~~ pressurizing the surface casing annulus causing annular overpressurization, or corrosive zones shall be isolated and sealed off to the extent that such isolation is necessary to prevent vertical migration of fluids or gases behind the casing. When this Article does not detail specific methods to achieve these objectives, the operator shall make every effort to follow the intent of this Article, using good engineering and effective industry practices.

2. General Requirements.

a. ~~(a)~~ All casing cemented in any well shall be steel or steel alloy casing that has been hydrostatically pressure tested with an applied pressure that exceeds by a minimum safety factor approved by [STATE REGULATOR] the maximum pressure to which the pipe will be subjected in the well ~~and meet API 5C as determined by electromagnetic, ultrasonic or thickness measurements. For new pipe, the mill test pressure may be used to fulfill this requirement. All such pressure tests shall be conducted pursuant to applicable.~~ Any casing that will be utilized by the operator in conducting hydraulic fracturing operations shall meet API standards, including but not limited to, API 5CT, API Spec 5CT, and API casing specifications and recommended practices shall govern the design, manufacturing, testing and transportation of such casing. Casing manufactured to API specifications must meet strict requirements for compression, tension, collapse and burst resistance. All casing used in a well should be designed to withstand the anticipated hydraulic fracturing pressure to which it will be subjected, production pressures, corrosive conditions and all other conditions that may be reasonably anticipated. If used or reconditioned casing is installed, it shall be tested to ensure that it meets API performance requirements for new casing.

~~b.~~(b) Wellhead assemblies shall be used on all wells to maintain surface control of the well. Each component of the wellhead shall have a pressure rating ~~that exceeds by a minimum safety factor approved by [STATE REGULATOR]~~ greater than the anticipated pressure to which that particular component might be exposed during the course of drilling, testing, completing or producing the well. All wellhead connections shall be assembled and tested prior to installation by a pressure equal to the test pressure of the fitting employed.

~~e.~~(c) A blowout preventer or control head and other connections to keep the well under control at all times shall be installed and tested as soon as practicable, but no later than prior to drilling out of the surface casing. ~~This~~ All such well control equipment shall be of such construction and capable of such operation as to satisfy any reasonable test which may be required by [STATE REGULATOR] or its duly accredited agent. All blowout prevention equipment shall be installed, operated, tested and maintained in accordance with API RP 53: Recommended Practices for Blowout Prevention Equipment Systems. The required working pressure rating of all blowout preventers and related equipment shall be based on known or anticipated subsurface pressure, geologic conditions, or accepted engineering practices, and shall exceed ~~by a minimum safety factor approved by [STATE REGULATOR]~~ the maximum anticipated pressure to be contained at the surface. In the absence of better data, the maximum anticipated surface pressure shall be determined by using a normal pressure gradient of 0.44 psi per foot and assuming a partially evacuated hole. During drilling operations, the ram-type blowout preventers shall be tested by closing at least once each trip and the annular-type preventer shall be tested by closing on the drill pipe at least once each week.

(d) For balanced and overbalanced operations the characteristics, use, and testing of drilling mud and related drilling procedures shall be designed to maintain control of the well. Adequate supplies of mud of sufficient weight and other acceptable characteristics shall be maintained at the well location. Mud tests shall be made at least once per day. The wellbore shall be kept full of mud at all times. When pulling drill pipe, the mud volume required to keep the wellbore full shall be measured to assure that it corresponds with the displacement of pipe pulled. A careful watch for swabbing action shall be maintained when pulling out of the hole.

(e) All drilling fluids shall be properly conditioned so that the fluid properties are the most advantageous, as reasonably possible, to effect proper cement isolation. The wellbore shall be stable with respect to formation influx prior to placing the cement, and shall be kept stable after the cement is placed. When cementing any string of casing more than 200 feet long, before drilling the cement plug the operator shall test the casing ~~at to a pump surface~~ pressure, in pounds per square inch (psi) ~~calculated by multiplying the length of the casing string by 0.2. The, of at least the maximum anticipated pressure to be contained at the surface by the casing string, as calculated by the method in c. above; provided, however, the maximum test pressure required; however, unless otherwise ordered by [STATE REGULATOR], shall not exceed 1,500 psi. 80% of API rated minimum internal yield of the casing.~~ If, at the end of 30 minutes of such testing, the pressure shows a drop of 10% or more from the original test pressure, the applicable casing shall be condemned until the condition is corrected. For purposes of the foregoing sentence, a pressure test demonstrating less than a 10% pressure drop after 30 minutes is evidence that the condition has been corrected.

~~e.~~ (f) To allow for air drilling or underbalanced drilling, all wells being drilled to formations where the expected reservoir pressure exceeds the weight of the drilling fluid column shall be equipped to divert any wellbore fluids away from the rig floor to a flare pit a safe distance from the well. All diverter systems shall be maintained in ~~an~~ effective working condition and shall be function tested when installed and at regular intervals during drilling operations. No well shall continue drilling operations if a test or other information indicates the diverter system is unable to function or operate as designed.

(g) Minimum requirements for accumulator testing shall include precharge of accumulator bottle, accumulator response time and the capability of closing on the minimum size drill pipe being used.

~~f.~~ (h) All hole intervals drilled prior to reaching the base of the protection depth must be drilled with air, fresh water or a fresh water based drilling fluid ~~and without toxic additives~~. The [STATE REGULATOR] may exclude particular drilling fluid constituents based on regional knowledge of protected water conditions.

~~g.~~ (i) Operator must notify [STATE REGULATOR] at least 24 hours prior to commencing any casing cementing operations pursuant to this Article IV.

~~h.~~ (j) Upon completion of ~~the~~each well, a casing and cementing report ~~must~~shall be filed with [STATE REGULATOR] furnishing complete data concerning the casing string(s) set and the cementing of all casing in the well, as specified on a form furnished by [STATE REGULATOR]. The operator ~~of the well~~ or hisits duly authorized agent having personal knowledge of the facts, and representatives of the cementing company performing the cementing job, ~~must~~shall sign the form attesting to compliance with the cementing requirements of [STATE REGULATOR].

~~3. — Conductor casing.~~

~~a.~~ 3. — Conductor Casing. An operator shall drive or set and cement conductor casing to the surface as necessary to maintain a stable borehole or to divert gas and include a mechanical or cement seal to prevent the subsurface infiltration of surface water or fluids into the well.

~~4.~~ 4. Surface Casing.

~~a.~~ (a) An operator shall set and cement sufficient surface casing, using new pipe casing, to a minimum depth of at least 100 feet below the base of the ~~lowest~~deepest strata containing protected water ~~strata~~, but above any hydrocarbon strata, or at an alternative depth determined by [STATE REGULATOR]. Before drilling ~~any~~a well in any field or area in which no rules regarding the protection of protected water supplies (with regard to drilling depth) are in effect, or in which surface casing requirements are not specified in the applicable field rules, an operator shall obtain a letter from [STATE REGULATOR] stating the applicable protection depth. ~~The outside diameter of the surface casing coupling shall be at least one inch less than the drilled diameter of the borehole.~~

~~b.~~ (b) Cementing shall be by the pump and plug method. The outside diameter of the surface casing coupling shall be at least one inch less than the drilled diameter of the borehole. Sufficient cement shall be used to fill the annular space outside the casing from the shoe to the ground surface or to the bottom of the cellar. If cement is not circulated to the ground surface or the bottom of the cellar, the operator shall run a temperature survey, cement bond log or other appropriate evaluation tools to identify the top of cement. [STATE REGULATOR] shall be notified prior to running the required temperature survey, cement bond log or other appropriate evaluation tool. After the top of cement outside the casing is determined, the operator shall contact [STATE REGULATOR] and obtain approval for the procedures to be used to perform any required additional cementing operations.

~~e.~~ (c) Surface casing shall not be used as the production string in the well in which it is installed. An additional casing string shall be used as the production casing.

~~d.~~ (d) Cement quality.

~~i.~~ (i) Surface casing strings must be allowed to stand under pressure until the cement has reached a 24-hour compressive strength of at least 500 psi in the zone of critical cement before drilling out the plug, or initiating a test. The cement mixture in the zone of critical cement shall have a 72-hour compressive strength of at least 1,200 psi.

~~ii.~~ (ii) An operator may use cement with volume extenders above the zone of critical cement to cement the casing from that point to the ground surface, but in no case shall the cement have a compressive strength of less than 100 psi at the time of drill out nor less than 250 psi 24 hours after being placed. If the surface casing string is not set on the bottom of the well, then the casing string shall remain undisturbed ~~for a period of~~ until the earlier to occur of (i) 24 hours after the cement is in place or ~~until~~ (ii) the point in time when the compressive strength in the zone of critical cement has reached at least 500 psi, whichever occurs soonest.

~~iii.~~ (iii) In addition to the minimum compressive strength of the cement, the API free water separation shall average no more than six milliliters per 250 milliliters of cement tested in accordance with the current API RP 10B within the zone of critical cement.

~~iv.~~ (iv) [STATE REGULATOR] may require a better quality of cement mixture to be used in any well or any area if evidence of local conditions indicates a better quality of cement is necessary to prevent pollution, prevent vertical migration of fluids in the wellbore, or ~~to~~ provide safer conditions in the well or area.

~~v.~~ (v) An operator shall ensure that the cement mix water chemistry is proper for the cement slurry designs. An operator's representative shall be on site observing the cement mixing equipment for the entire duration of the cement mixing and placement to ensure that cement slurry design parameters are followed as close as possible.

~~vi.~~ (vi) Unless [STATE REGULATOR] determines, based on depth and site-specific circumstances, to waive this requirement, [STATE REGULATOR] shall require a formation integrity test after drilling out below the surface casing shoe in order to verify the integrity of the cement in the surface casing annulus at the surface casing shoe. If test results are inadequate to verify the following, remedial measures may be required:

(1) Pressure containment to ensure that no flow path exists to formations above the casing shoe; or

(2) The casing shoe is competent to handle an influx of formation fluid or gas without breaking down.

~~e.~~ (e) Compressive strength test requirements.

~~i.~~ (i) Cement mixtures for which published performance data are not available must be tested by the operator or ~~service~~the company providing the cementing services. Tests shall be made on representative samples of the basic mixture of cement and additives used, using distilled water or potable tap water for preparing the slurry. The tests must be conducted using the equipment and procedures adopted by the American Petroleum Institute, as published in the current API RP 10B. Test data showing competency of a proposed cement mixture to meet the above requirements must be furnished [STATE REGULATOR] prior to the cementing operation. To determine that the minimum compressive strength has been obtained, operators shall use the typical performance data for the particular cement used in the well (containing all the additives, including any accelerators used in the slurry) at the following temperatures and at atmospheric pressure:

~~(+)~~ (1) For the cement in the zone of critical cement, the test temperature shall be within 10 degrees Fahrenheit of the formation equilibrium temperature at the top of the zone of critical cement; and

~~(-)~~ (2) For the filler cement, the test temperature shall be the temperature found 100 feet below the ground surface level, or 60 degrees Fahrenheit, whichever is greater.

~~f.~~ ~~Surface~~ (f) Centralizers. At a minimum, surface casing shall be ~~at a minimum~~ centralized at the top, at the shoe, above and below a stage collar or diverting tool, if run, and through all protected water zones. In nondeviated holes, ~~pipe centralization as follows is required;~~ a centralizer shall be placed every fourth joint from the cement shoe to the ground surface or to the bottom of the cellar. ~~All centralizers shall meet API spec 10D specifications.~~ In deviated holes, [STATE REGULATOR] may require the operator ~~shall~~to provide additional centralization. All centralizers shall meet API spec 10D specifications.

~~g.~~ (g) Alternative surface casing depth requirements.

~~i.-(i)~~ (i) An alternative method ~~of fresh water protection~~ for protecting strata containing protected water may be approved upon written application to [STATE REGULATOR]. The operator shall outline the alternate program for casing and cementing through the protection depth ~~for strata containing protected water~~, and shall demonstrate to the satisfaction of [STATE REGULATOR] the need (economics, well control, etc.) for, and how protection of protected water will be achieved by, the alternative fresh water protection method. Alternative programs for setting more than specified amounts of surface casing ~~for well control purposes~~ may be requested on a field or area basis. Alternative programs for setting less than specified amounts of surface casing will be authorized on an individual well basis only. [STATE REGULATOR] may approve, modify, or reject the proposed program. If the proposal is modified or rejected, the operator may request a review by [STATE REGULATOR]. If the proposal is not approved administratively, the operator may request a hearing in the appropriate forum, as determined by the [STATE REGULATOR]. An operator shall obtain approval of any alternative program before commencing operations.

~~ii.-(ii)~~ (ii) Any alternate casing program shall require the first string of casing set through the protection depth to be cemented in a manner that will effectively prevent the migration of any fluid to or from any stratum exposed to the wellbore outside ~~this~~ the string of casing. The casing shall be cemented from the shoe to ground surface in a single stage, if feasible, or by a multi-stage process with the stage tool set at least 50 feet below the protection depth.

~~iii.-(iii)~~ (iii) Any alternate casing program shall include pumping sufficient cement to fill the annular space from the shoe or multi-stage tool to the ground surface. If cement is not circulated to the ground surface or the bottom of the cellar, the operator shall run a temperature survey, cement bond log or other appropriate evaluation tools ~~to identify the top of cement~~. [STATE REGULATOR] shall be notified prior to running the required temperature survey, cement bond log or other appropriate evaluation tools. After the top of cement outside the casing is determined, the operator or his representative shall contact [STATE REGULATOR] and obtain approval for the procedures to be used to perform any required additional cementing operations. Upon completion of the well, a cementing report shall be filed with [STATE REGULATOR] on the prescribed form.

~~iv.-(iv)~~ (iv) Before parallel (nonconcentric) strings of production casing are cemented in a well, surface or intermediate casing must be set and cemented through the protection depth.

~~h. Additional Requirements for Wells Adjacent to Sources of Protected Water.~~

(h) Additional Requirements for Wells Adjacent to Sources of Protected Water. When an operator is conducting well construction operations on wells located within the following distances of a source of protected water (including public and permitted private sources): (i) 1,000 radial feet from the edge of the pad for wells that are not classified as a close proximity well, (ii) 2,650 radial feet for close proximity wells, or (iii) such other distance as determined by [STATE REGULATOR], ~~[STATE REGULATOR] may require that~~ operator shall:

~~(1) (i) Through an independent third party contractor, obtain and test the composition of water samples from the relevant source of protected water sufficient to establish representative baseline characteristics for the area. Such testing will comply with any applicable requirements set forth by [STATE REGULATOR], and the third party contractor shall be certified by or otherwise approved as being acceptable to [STATE REGULATOR]. After representative baseline characteristics have been established for the area, additional testing may be required by [STATE REGULATOR];~~
and

~~(2) (ii) e~~Evaluate the necessity of an additional string of casing to be set no more than 100 subsea depth adjusted feet below the deepest water well within the applicable distance set forth above.

5.5. Intermediate Casing.

~~a. (a)~~ Each intermediate string of casing that is less than 1,000 feet in depth shall be cemented to surface. All other intermediate casing strings shall be cemented from the shoe to a point at least 600 true vertical feet above the shoe. If any productive horizon, any hydrocarbon strata or any strata containing protected water is open to the wellbore above the casing shoe, the casing shall be cemented from the shoe up to a point at least 600 true vertical feet above the top of the shallowest such productive horizon, hydrocarbon strata or strata containing protected water ~~strata~~, or to a point at least 200 feet above the shoe of the next shallower casing string that was set and cemented in the well. Liners may be set and cemented as intermediate casing provided that the cemented liner has a minimum of 200 true vertical depth feet of cemented lap within the next larger casing, and the liner top is pressure tested to a level equal to or higher than the maximum anticipated pressure to be encountered in the interval to be drilled below the liner. The intermediate casing string or liner must be centralized in a manner that will provide for proper zonal isolation by the cement. All centralizers shall meet API spec 10D specifications.

(b) An operator shall ensure that the cement mixture for the intermediate casing shall achieve a minimum compressive strength of 500 psi after 24 hours and 1200 psi after 72 hours.

(c) Prior to drilling out below the intermediate casing shoe, the intermediate casing shall be pressure tested to a minimum of 1,500 psi and/or at a pressure that will determine if the casing integrity is adequate to meet the well design and construction objectives.

(d) Immediately after drilling out below the intermediate casing shoe, a formation pressure integrity test shall be performed to determine that formation integrity at the casing shoe is adequate to meet the maximum anticipated well bore pressure at total depth.

~~b. (e)~~ In the event the distance from the casing shoe to the top of the shallowest ~~such~~ productive horizon, hydrocarbon strata or strata containing protected water ~~strata~~, ~~make~~makes cementing, as specified above, impossible or impractical, ~~the~~ multi-stage ~~process~~cementing operations may be used to cement the casing in a manner that will effectively seal off all such possible horizons or strata and prevent fluid migration to or from such horizons or strata within the wellbore.

~~e.-(f)~~ If operations ~~indicate~~ ~~(e.g. fluid returns, lift pressure)~~ and displacement indicate inadequate coverage of any productive horizon, any hydrocarbon strata or any strata containing protected water, operator shall obtain approval of [STATE REGULATOR] for operator's proposed plan for determining top of cement and/or performing additional cementing operations: prior to continuing drilling operations.

~~d. — If during the setting and cementing of production and/or any intermediate casings the cement program does not occur as submitted in the application, and would cause a reasonably prudent operator to question the integrity of the cementing program with respect to isolating the zone of hydraulic fracturing treatment from movement of fracture fluids up hole into the various casing or well bore annuli, the operator shall immediately notify the [STATE REGULATOR] in writing as soon as practicable, but not more than twenty four (24) hours after the event. In reviewing the report, the [STATE REGULATOR] may require a bond log or other cement evaluation tool to document cement integrity and require additional cementing operations or other appropriate well workover efforts necessary to correct any cement deficiencies prior to initiating any hydraulic fracturing treatments in the well.~~

6.6. Production Casing.

~~a.-(a)~~ The producing string of casing shall be cemented by the pump and plug method, or another method approved by [STATE REGULATOR], with sufficient cement to fill the annular space back of the casing to the surface, or to a point at least 600 true vertical feet above (i) the production casing shoe or the uppermost perforation in a vertical well (whichever is higher), or (ii) the ~~heel of point where~~ a horizontal well first penetrates the zone to be hydraulically fractured. If any productive ~~horizons~~horizon or hydrocarbon strata are open to the wellbore above the production casing shoe, the production casing shall be cemented in a manner that effectively seals off all such horizons or strata by one of the methods specified for intermediate casing in Section 5 of this Article. Liners may be set and cemented as production casing provided that the cemented liner has a minimum of 200 true vertical depth feet of cemented lap within the next larger casing, and the liner top is pressure tested to a level that is at least 500 psi higher than the maximum anticipated pressure to be encountered by the wellbore during completion and production operations. The production casing string or liner must be centralized in a manner that will provide for proper zonal isolation by the cement. All centralizers shall meet API spec 10D specifications.

(b) Prior to cementing the production casing, the operator shall circulate and condition the drilling fluid with a minimum of two hole volumes and shall adjust drilling fluid rheology to optimize conditions for displacement of the drilling fluid and to ensure that the wellbore is static.

(c) Throughout the cementing process operator shall monitor cement mixing in accordance with cement design and cement densities during the mixing and pumping. During placement of the cement, operator shall monitor pump rates to verify they are within design parameters so as to ensure proper displacement efficiency.

(d) An operator shall ensure that the cement mixture for the production casing shall achieve a minimum compressive strength of 500 psi after 24 hours and 1200 psi after 72 hours.

~~b.-(e)~~ The identification of the productive horizon(s) shall be determined by coring, electric log, mud-logging, testing or sufficient regional knowledge. For cemented non-horizontal well completions, the producing string shall be landed and cemented into or below the productive horizon(s). For open-hole well completions, the producing string shall be landed and cemented into or above the productive horizon(s).

~~e.-(f)~~ If operations ~~indicate ((e.g. fluid returns, lift pressure) inadequate coverage, operator shall obtain approval of [STATE REGULATOR] for procedures to determine TOC and/or perform~~ and displacement) indicate inadequate cement coverage and would cause a reasonably prudent operator to question the integrity of the cementing program with respect to the isolation of the zone to be hydraulically fractured so as to prevent the movement of hydraulic fracturing fluids up the wellbore into the various casing or wellbore annuli, the operator shall notify [STATE REGULATOR] in writing as soon as practicable, but not more than twenty-four (24) hours after the event. In reviewing the notification from the operator, [STATE REGULATOR] may require a bond log or other cement evaluation tool to document cement integrity and require additional cementing operations or other appropriate well workover efforts necessary to correct any cement deficiencies prior to initiating any hydraulic fracturing operations on the well.

~~d.-(g)~~ Open hole, open hole packer or other non-cemented completions may be used in the place of cemented completions. If intermediate casing is run with this type of completion, the cementing of the intermediate casing ~~cementing~~ must meet the cementing guidelines set forth in Section ~~6.5.(a-)~~ hereof. If intermediate casing is not run, a multi-stage cementing tool must be run above the top external packer and cemented to fill the annular space ~~back of~~outside the casing to the surface or to a point at least 600 feet above the packer or casing shoe. Alternatively, when no zones containing protected water exist in the open hole, two additional open hole packers may be installed in the casing string above the production zone.

~~e.-(h)~~ Close proximity wells.

~~i.-(i)~~ Close proximity wells may not utilize open hole, open hole packer or other non-cemented completions.

~~ii.-(ii)~~ Cementing of the producing string of casing for a close proximity well shall be by the pump and plug method. Sufficient cement shall be used to fill the annular space outside the casing from the casing shoe to the ground surface or to the bottom of the cellar. If cement is not circulated to the ground surface or the bottom of the cellar, the operator shall run a temperature survey, cement bond log or other appropriate evaluation tools: to identify the top of cement. [STATE REGULATOR] shall be notified prior to running the required temperature survey, cement bond log or other appropriate evaluation tools. After the top of cement outside the casing is determined, the operator or his representative shall contact [STATE REGULATOR] and obtain approval for the procedures to be used to perform any required additional cementing operations.

~~iii.-(iii)~~ The producing string of casing for any close proximity well shall not be disturbed for a minimum of 4 hours after cement is in place.

~~7.7. Approved Cementers Only.~~

~~a.-(a)~~ In order to comply with the provisions of this Article, when conducting well construction operations which require cementing, operators shall utilize only those cementers approved by [STATE REGULATOR]. Cementing companies, service companies, or operators may apply with [STATE REGULATOR] for designation as approved cementers. Such approval will be granted by [STATE REGULATOR] upon a showing by the applicant of its ability to mix and pump cement or other alternate materials as approved by [STATE REGULATOR] in compliance with this rule.

~~i.-(b)~~ A cementing company, service company, or operator seeking designation as an approved cementer by [STATE REGULATOR] shall file a request of such designation with [STATE REGULATOR] in accordance with all applicable procedures governing such requests. The request shall contain such information as the [STATE REGULATOR] shall reasonably require to assess the applicant's ability to competently perform cementing operations in compliance with this rule.

~~ii.-(c)~~ [STATE REGULATOR] shall either approve or deny the application to be designated as an approved cementer. If [STATE REGULATOR] does not recommend approval, or denies the application, the applicant may request a hearing on its application.

~~8.8. Inclination and Directional Surveys Required.~~

~~a.-(a)~~ Nothing in this Section 8 shall be construed to permit the drilling of any well in such a manner that the wellbore crosses lease, unit boundary and/or property lines without special permission from [STATE REGULATOR].

~~b.-(b)~~ Certain inclination survey requirements are as follows:

~~i.-(i)~~ An inclination survey made by persons or concerns approved by [STATE REGULATOR] shall be filed on a form prescribed by [STATE REGULATOR] for each well drilled or deepened with rotary tools, except as hereinafter provided, or when, as a result of any operation, the course of the well is changed. The first shot point of such inclination survey shall be made at a depth not greater than 500 feet below the surface of the ground, and succeeding shot points shall be made either at 500-foot intervals or at the nearest drill bit change thereto, but not to exceed 1,000 feet apart.

~~ii.-(ii)~~ Inclination surveys conforming to these requirements may be made either during the normal course of drilling or after the well has reached total depth. Acceptable directional surveys may be filed in lieu of inclination surveys.

~~iii.-(iii)~~ Copies of all directional or inclination surveys, regardless of the reason for which they are run, shall be filed as a part of or in addition to the inclination surveys otherwise required. If computations are made from dipmeter surveys to determine the

course of the wellbore in any portion of the surveyed interval, a report of such computations shall be required.

~~iv.~~ (iv) Inclination surveys shall not be required in any well drilled to a total depth of 2,000 feet or less on a regular location at least 150 feet from the nearest lease or unit line, provided the well is not intentionally deviated from the vertical in any manner whatsoever.

~~v.~~ (v) Inclination surveys shall not be required on wells deepened with rotary tools if the well is deepened no more than 300 feet or the distance from the surface location to the nearest lease or boundary line, whichever is the lesser, and provided that the well was not intentionally deviated from the vertical at any time before or after the beginning of deepening operations.

~~vi.~~ (vi) Inclination surveys will not be required on wells that are drilled as dry holes and are permanently plugged and abandoned. If such wells are reentered at a later date and completed as producers or injection or disposal wells, inclination reports will be required and must be filed with the appropriate completion form for the well.

~~vii.~~ (vii) Inclination survey filings will not be required on wells that are reentries within casing of previously producing wells if inclination data are already on file with [STATE REGULATOR]. If such data are not on file with [STATE REGULATOR], the results of an inclination survey must be reported on the appropriate form and filed pursuant to the applicable rules of [STATE REGULATOR], except as otherwise provided in this Section 8.

~~e.~~ (c) Certain survey report requirements are as follows:

~~i.~~ (i) The report form shall be signed and certified by a party having personal knowledge of the facts therein contained. The report shall include a tabulation of the maximum drifts which could occur between the surface and the first shot point, and each two successive shot points, assuming that all of the unsurveyed hole between any two shot points has the same inclination as that measured at the lowest shot point, and the total possible accumulative drift, assuming that all measured angles of inclination are in the same direction.

~~ii.~~ (ii) In addition, the report shall be accompanied by a certified statement of the operator, or of someone acting at his direction on his behalf, either:

~~(1)~~ (1) that the well was not intentionally deviated from vertical; or

~~(2)~~ (2) that the well was deviated at random, with an explanation of the circumstances.

~~iii.~~ (iii) The report shall be filed with [STATE REGULATOR] by attaching one copy to each appropriate completion form for the well. [STATE REGULATOR] may require the submittal of the original charts, graphs, or discs resulting from the surveys.

~~d.~~ (d) Certain requirements governing directional surveys are as follows:

~~i.~~ (i) When the maximum displacement indicated by an inclination survey is greater than the actual distance from the surface location to the nearest lease line or unit boundary, it will be considered to be a violating well subject to plugging and to penalty action. However, an operator may submit a directional survey, run at his own expense by an approved surveying company, to show the true bottom hole location of the well to be within the prescribed limits. When such directional survey shows the well to be bottomed within the confines of the lease, but nearer to a well or lease line or unit boundary than allowed by applicable rules, or by the permit for the well if the well has been granted an exception to applicable statewide spacing rules, a new permit will be required if it is established that the bottom hole location or completion location is not a reasonable location.

~~ii.~~ (ii) Directional surveys shall be required on each well drilled under the directional deviation provisions of this Section 8.

~~iii.~~ (iii) No hydrocarbon allowable shall be assigned any well on which a directional survey is required until a directional survey has been filed with and accepted by [STATE REGULATOR].

~~iv.~~ (iv) Directional surveys shall be required for each horizontal drainhole, from the surface to the farthest point drilled in the applicable horizontal drainhole.

~~e.~~ (e) Directional surveys required under this Section 8 must be run by competent surveying companies, approved by [STATE REGULATOR], signed and certified by a person having actual knowledge of the facts, in the manner prescribed by [STATE REGULATOR].

~~f.~~ (f) All directional surveys, unless otherwise specified by [STATE REGULATOR], shall be either single shot surveys or multi-shot surveys with the shot points not more than 200 feet apart, beginning within 200 feet of the surface, and the bottom hole location must be oriented both to the surface location and to the lease or unit lines.

~~g.~~ (g) If more than 200 feet of surface casing has been run, the operator may begin the directional survey immediately below the surface casing depth. However, if such method is used, the inclination drifts from the surface of the ground to the surface casing depth must be added cumulatively and reported on the appropriate form. This total shall be assumed to be in the direction least favorable to the operator, and such point shall be considered the starting point of the directional survey.

~~h.~~ (h) Intentional deviation of wells.

~~i.~~ (i) Definitions.

~~(1)~~ (1) "Directional deviation" -- The intentional deviation of a well from vertical in a predetermined compass direction.

~~(2)~~ (2) “Random deviation” -- The intentional deviation of a well without regard to compass direction for one of the following reasons:

~~(a)~~ (A) to straighten a hole which has become crooked in the normal course of drilling; or

~~(b)~~ (B) to sidetrack a portion of a hole because of mechanical difficulty in drilling.

~~ii.~~ (ii) A permit for directionally deviating a well may be granted:

~~(1)~~ (1) for the purpose of seeking to reach and control another well which is out of control or threatens to evade control;

~~(2)~~ (2) where conditions on the surface of the ground prevent or unduly complicate the drilling of a well at a regular location;

~~(3)~~ (3) where conditions are encountered underground which prevent or unduly hinder the normal completion of the well;

~~(4)~~ (4) where it can be shown to be advantageous from the standpoint of mechanical operation to drill more than one well from the same surface location to reach the productive horizon at essentially the same positions as would be reached if the several wells were normally drilled from regular locations prescribed by the well spacing rules in effect;

~~(5)~~ (5) for the purpose of drilling a horizontal well-bore; or

~~(6)~~ (6) for other reasons found by [STATE REGULATOR] to be sufficient after notice and hearing.

~~iii.~~ (iii) Permission for the random deviation of a well may be granted whenever the necessity for such deviation is shown, as prescribed in this Section 8.

~~iv.~~ (iv) Applications for deviation.

~~(1)~~ (1) Applications for wells to be directionally deviated must specify on the application to drill both the surface location of the well and the projected bottom hole location of the well. On the plat, in addition to the plat requirements provided for in the applicable permitting rules, the following shall be included:

~~(a)~~ (A) two perpendicular lines providing the distance in feet from the projected bottomhole location, rather than the surface location, to the nearest points on the lease, pooled unit, or unitized tract line. If there is an unleased interest in a tract of the pooled unit or unitized tract that is nearer than the pooled unit or unitized tract line, the nearest point on that unleased tract boundary shall be used;

~~(b)~~ (B) a line providing the distance in feet from the projected bottomhole location to the nearest point on the lease line, pooled unit line, or unitized tract line. If there is an unleased interest in a tract of the pooled unit that is nearer than the pooled unit line, the nearest point on that unleased tract boundary shall be used;

~~(c)~~ (C) a line providing the distance in feet from the projected bottomhole location, rather than the surface location, to the nearest oil, gas, or oil and gas well, identified by number, applied for, permitted, or completed in the same lease, pooled unit, or unitized tract and in the same field and reservoir; and

~~(d)~~ (D) perpendicular lines providing the distance in feet from the two nearest non-parallel survey/section lines to the projected bottomhole location.

~~(2)~~ (2) If the necessity for directional deviation arises unexpectedly after drilling has begun, the operator shall give written notice of such necessity to [STATE REGULATOR], and upon giving such notice, the operator may proceed with the directional deviation. If the operator proceeds with the drilling of a deviated well under such circumstances, he proceeds at his own risk. Before any allowable shall be assigned to such well, a permit for the subsurface location of each completion interval shall be obtained from [STATE REGULATOR] under the applicable rules governing such permits. However, should the operator fail to show good and sufficient cause for such deviation, no permit will be granted for the well.

~~(3)~~ (3) If the necessity for random deviation arises unexpectedly after the drilling has begun, the operator shall give written notice of such necessity to [STATE REGULATOR], and, upon giving such notice, the operator may proceed with the random deviation, subject to compliance with the provisions of this Section 8 on inclination surveys.

~~(i)~~ (i) [STATE REGULATOR], at the written request of any operator in a field, shall determine whether a directional survey, an inclination survey, or any other type of approved survey, shall be made in regard to a well complained of in the same field.

~~(i)~~ (i) The complaining party must show probable cause to suspect that the well complained of is not bottomed within its own lease or unit boundary lines.

~~(ii)~~ (ii) The complaining party must agree to pay all costs and expenses of such survey, shall assume all liability, and shall be required to post bond in a sufficient sum as determined by [STATE REGULATOR] as security against all costs and risks associated with the survey.

~~(iii)~~ (iii) The complaining party and [STATE REGULATOR] shall agree upon the selection of the well surveying company to conduct the survey, which shall be a surveying company approved by [STATE REGULATOR].

~~iv. (iv)~~ The survey shall be witnessed by [STATE REGULATOR], and may be witnessed by any party, or his agent, who has an interest in the field.

~~v. (v)~~ Nothing in these rules shall be construed to prevent or limit [STATE REGULATOR], acting on its own authority, from conducting spot checks and surveys at any time and place for the purpose of determining compliance with applicable rules and regulations.

~~j. (j)~~ Directional Survey Company Report - For each well drilled for hydrocarbons for which a directional survey report is required by rule, regulation, or order, the surveying company shall prepare and file the following information. The information shall be certified by the person having personal knowledge of the facts, by execution and dating of the data compiled:

~~i. (i)~~ the name of the surveying company;

~~ii. (ii)~~ the name of the individual performing the survey for the surveying company;

~~iii. (iii)~~ the title or position the individual holds with the surveying company;

~~iv. (iv)~~ the date on which the individual performed the survey;

~~v. (v)~~ the type of survey conducted and whether the survey was multishot;

~~vi. (vi)~~ complete identification of the well, including any applicable identifying information required by [STATE REGULATOR];

~~vii. (vii)~~ a notation that the survey was conducted from a depth of ____ feet to ____ feet; and

~~viii. Each (viii)~~ For each well drilled a directional survey, with its accompanying certification and a certified plat on which the bottom hole location is oriented both to the surface location and to the lease or unit boundary lines shall be mailed by registered, certified, or overnight mail direct to [STATE REGULATOR] by the surveying company making the survey.

~~ARTICLE VI – Well Construction (Completion)~~ **V – WELL CONSTRUCTION (COMPLETION)**

~~1. — General~~ **1. Scope of Article.** It is the intent of all provisions of this Article that, during initial completion, recompletion, reentry, or refracturing, (i) the well shall be stimulated in such a manner that all injected fluids be directed into the zone(s) of interest to be hydraulically fractured, which ~~includes~~ shall include an evaluation of the intervening layers zone and transmissive faults, (ii) the wellbore’s mechanical integrity shall be positively assessed, tested and maintained, (iii) ~~the chemicals~~ all chemical additives injected into the wellbore ~~are~~ shall be of known quantity and description, and (iv) operator ~~conducts~~ shall conduct and ~~monitors~~ monitor completion operations in accordance with this rule so as to ensure that the objectives described in

sub-clauses (i), (ii) and (iii) if this paragraph are achieved. When this Article does not detail specific methods to achieve these objectives, the operator shall make every effort to follow the intent of this Article, using good engineering and effective industry practices.

~~2.~~ 2. Before Hydraulic Fracturing Treatment.

~~a.~~ (a) Prior to beginning ~~a formation's~~ completion operations, all cemented casing strings and all tubing strings to be utilized by an operator in hydraulic fracturing operations shall be tested to a pressure not less than 500 psi greater than the anticipated maximum surface pressure to be experienced during either the completion operations or the life of the completion. If, at the end of 30 minutes of such testing, the pressure shows a drop of 10% or more from the original test pressure, the well shall be taken out of service until the relevant condition is corrected. The condition of a casing removed from service in accordance with the preceding sentence shall be deemed to be corrected once the casing demonstrates less than a 10% drop in pressure after being subjected to a 30 minute pressure test of the type described in this Section ~~3-2(a)~~. Non-cemented production completions shall be tested to 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.

~~b.~~ (b) Prior to beginning ~~a formation's~~ completion operations, all cemented casing strings shall have cement integrity verified by cement records ~~and documentation of prior logging and testing~~ or by conducting running a cement ~~integrity~~ evaluation log ~~or test~~.

~~c.~~ (c) Prior to beginning a hydraulic fracturing treatment, any surface equipment to be utilized by operator in such hydraulic fracturing treatment must be rigged up as designed. At a minimum, the downhole pressure pump and all equipment downstream of same shall be tested to 110% of the maximum allowable surface treating pressure to ensure appropriate safety factor and to prevent fluid losses.

~~d.~~ Additionally, prior (d) Prior to beginning a hydraulic fracturing treatment on a close proximity well, an operator must perform the following additional actions and provide the results thereof to the [STATE REGULATOR]:

~~i.~~ (i) The operator shall undertake an analysis of the intervening zone to determine the ability of the intervening zone to contain the hydraulic fracturing treatment and prevent the vertical migration of the fracturing fluids or hydrocarbons to a strata that contains protected water. In performing its analysis of the intervening zone, the operator shall utilize a 3D model approved by [STATE REGULATOR] that will simulate the projected frac height growth within the design limits submitted to the [STATE REGULATOR]. The operator's analysis of the intervening zone must include a review of abandoned hydrocarbon production wells, water wells and known geologic faults and natural fracture zones in the area of the close proximity well to verify that such wells, faults and natural fracture zones will not permit the vertical migration of the fracturing fluids or hydrocarbons into a strata that contains protected water.

~~ii.~~ (ii) Using the results of the analysis described in (i) above, the operator shall design

the hydraulic fracturing treatment so as to ensure that the fracturing fluids or hydrocarbons do not migrate vertically and come in contact with any strata that contains protected water;

~~iii-~~ (iii) The operator shall run a radial cement evaluation log or such other cement evaluation tool capable of identifying a cement channel as may be approved by the [STATE REGULATOR] to determine the quality of the cement outside of the production casing. If the quality of the cement outside of the production casing is not sufficient to isolate strata containing protected water, then the operator must develop a plan of remediation and receive approval from the [STATE REGULATOR] for the plan of remediation before the operator may proceed; ~~and~~

~~iv-~~ (iv) In the event that (a) the productive horizon to be hydraulically fractured is within a protected water interval, or (b) the results of the analysis in Section ~~3.e.2(d)(i)~~ above indicate that the intervening zone does not contain an adequate confining layer, the operator shall take measures to ensure that all fluids and materials pumped outside of the casing during the relevant completion operations are not of a nature or composition that could endanger an underground source of protected water by introducing chemical additives that may result in the presence of contaminants that exceed national primary drinking water standards, or may otherwise adversely affect the health of persons.

~~e-~~ (e) At least 24 hours prior to commencing a hydraulic fracturing treatment, an operator must notify [STATE REGULATOR] that operator is going to begin such hydraulic fracturing treatment.

~~3.~~ 3. During Hydraulic Fracturing Treatment.

~~a-~~ (a) The operator must monitor all wellbore annuli during the hydraulic fracturing treatment ~~of a well~~, and must report (i) any surface casing change that is 20% or greater than the calculated pressure increase due to pressure and/or temperature expansion; or (ii) a pressure that exceeds 80% of API rated minimum internal yield on any casing string in communication with the hydraulic fracturing treatment.

~~b-~~ (b) The operator must continuously monitor the following parameters during ~~each stage of~~ any hydraulic fracturing treatment:

~~i-~~ (i) surface injection pressure (psi);

~~ii-~~ (ii) slurry rate (bpm);

~~iii-~~ (iii) proppant concentration (ppa);

~~iv-~~ (iv) fluid rate (bpm); and

~~v-~~ (v) all annuli pressures.

With regard to the monitoring of the surface casing annulus, when possible, the surface casing annulus should be open to atmospheric pressure and visually monitored throughout the hydraulic fracturing treatment. The hydraulic fracturing treatment should be terminated if a volume of fluid circulates to surface that is in excess of a volume that could reasonably be expected due to pressure and/or temperature expansion. If the fracturing treatment design does not allow the surface casing annulus to be open to atmospheric pressure, then the surface casing pressures shall be monitored with a gauge and pressure relief device. The maximum set pressure on the relief device shall be the lower of (i) a pressure equal to: 0.70 times 0.433 times the true vertical depth of the surface casing shoe (expressed in feet), (ii) 70% of the API rated minimum internal yield for the surface casing or (iii) a pressure change that is 20% or greater than the calculated pressure increase due to pressure and/or temperature expansion. The hydraulic fracturing treatment shall be terminated if any of these excessive pressures are observed in the surface casing annulus. Pressures on any casing string other than the surface casing should not be allowed to exceed 80% of the API rated minimum internal yield pressure for such casing string throughout the hydraulic fracturing treatment.

~~e.-(c)~~ If during a hydraulic fracturing treatment, an operator has reason to suspect any potential ~~breach in failure of~~ the production casing, ~~the~~ production casing cement, or ~~the~~ isolation of any sources of protected water due to excessive ~~fracture~~ height growth or ~~the~~ intersection of ~~the hydraulically induced fracture~~ with ~~a~~ transmissive ~~conduits, such as faults, fractures or wellbores~~ fault or offset wellbore, then the operator must ~~immediately~~ discontinue ~~the~~ hydraulic fracturing treatment ~~and~~, notify [STATE REGULATOR] within 24 hours ~~of the occurrence of any such event~~ and perform diagnostic testing on the well as is necessary to determine whether ~~such a breach failure~~ has actually occurred. ~~Such~~ ~~The diagnostic~~ testing shall be done as soon as is reasonably practical after operator has reasonable cause to suspect ~~a breach~~ ~~any such failure~~, and if the testing reveals that a ~~breach failure~~ has occurred, then operator shall shut-in the well and isolate the perforated interval as soon as is reasonably practical and notify [STATE REGULATOR] ~~of same~~.

~~4. — Approved Hydraulic Fracturing, Perforation and/or Logging Contractors.~~

~~a. —~~ 4. Approved Hydraulic Fracturing, Perforation and/or Logging Contractors. In order to comply with this Article, when utilizing ~~a service company or other~~ contractors to perform hydraulic fracturing, perforation and/or logging services in connection with the completion of a well, operators shall utilize only those contractors approved by [STATE REGULATOR]. ~~Contractors~~ Service companies or contractors who seek to perform hydraulic fracturing, perforation and/or logging services or operators may apply with [STATE REGULATOR] for designation as approved contractors. Such approval will be granted by [STATE REGULATOR] upon a showing by the applicant of its ability to perform hydraulic fracturing, perforating and/or logging services (as the case may be) in accordance with the standards required by [STATE REGULATOR] in compliance with this rule. The list of approved contractors will be reviewed by ~~(state)~~ [STATE REGULATOR] on a regular basis, but in no event less frequently than once per year, to ~~insure~~ ensure said contractors remain capable of competently performing the required work involved with completion operations.

~~i-~~ (i) A contractor, service company, or operator seeking designation as an approved contractor by [STATE REGULATOR] shall file a request of such designation with [STATE REGULATOR] in accordance with all applicable procedures governing such requests. The request shall contain such information as the [STATE REGULATOR] shall reasonably require to assess the applicant's ability to competently perform such hydraulic fracturing, perforating and/or logging services in compliance with this rule.

~~ii-~~ (ii) In addition to the other requirements of this Section ~~5.4~~, if ~~the contractor,~~ a service company or operator seeking designation as an approved contractor by [STATE REGULATOR] seeks to perform hydraulic fracturing ~~services,~~ treatments in the contractor state, the service company or operator (as the case may be) shall submit to [STATE REGULATOR], along with its request for approved contractor designation ~~a full list of the chemical components of all hydraulic fracturing fluids it would utilize in performing the relevant hydraulic fracturing services, along with a corresponding Material Safety Data Sheet and Chemical Abstract Service information for each such chemical to [STATE REGULATOR],~~ the following additional information:

(1) A list of all base fluids that are to be used in any hydraulic fracturing treatment performed in the state;

(2) A list of all additives that are to be used in any hydraulic fracturing treatment performed in the state; and

(3) A list of all chemical ingredients, and their associated CAS numbers, that are to be used in any hydraulic fracturing treatment performed in the state; provided, however, in those limited situations where the identity of any such chemical ingredient, and its associated CAS number, is entitled to be withheld as a trade secret under the criteria set forth in 40 C.F.R. Section 350.13(a), then (i) the requesting party shall supply both the identity of such chemical ingredient and the chemical family associated with such chemical ingredient, (ii) [STATE REGULATOR] shall protect and hold confidential the identity of such chemical ingredient and its associated CAS number and (iii) [STATE REGULATOR] shall disclose the chemical family associated with such chemical ingredient on any report or list that [STATE REGULATOR] makes available to the public.

~~iii-~~ (iii) [STATE REGULATOR] shall either approve or deny the application to be designated as an approved contractor. If [STATE REGULATOR] does not recommend approval, or denies the application, the applicant may request a hearing on its application.

5.5. Post-Completion Report.

~~a-~~ (a) Within 30 days of completion activities on a well, the operator must prepare and submit to [STATE REGULATOR] a report, in accordance with the rules and requirements of [STATE REGULATOR], containing:

~~i-~~ (i) The casing and cement report described in ~~section 3.h~~ Section 2(j) of Article IV, that shall include the determined depth of the top of cement for each casing string,

hole size, the amount and location of centralizers and the method used to make the determinations;

~~ii.~~ (ii) Inclination and directional surveys;

~~iii.~~ (iii) Applicable depths and thicknesses of the geologic formations penetrated, complete with the relevant well log, mud log and/or other data known about the intervening zone above the ~~stimulated reservoir~~ zone(s) that received the hydraulic fracturing treatment;

~~iv.~~ (iv) A perforation report;

~~v.~~ (v) A hydraulic fracturing treatment report prepared by each applicable [STATE REGULATOR] approved contractor who performed a hydraulic fracturing treatment on the well that includes the following:

~~(1) — By stage, the~~ (1) The treatment data ~~required to be monitored in subsection 3(b) of~~ referenced in this section;

~~(2) — Total~~ (2) The total hydraulic fracturing fluid and proppant volumes used in ~~each stage~~ the well, expressed in gallons and pounds or other units approved by [STATE REGULATOR] and the maximum surface treating pressure observed during the hydraulic fracturing treatment; and

~~(3) — Chemical disclosure for each stage:~~ (3) Chemical disclosure

(A) The type of base fluid used in the hydraulic fracturing treatment;

(B) The trade name and supplier of each additive used in the hydraulic fracturing fluid;

(C) The purpose of each additive described in Subdivision (3)(B) above, provided that if the additives used in the hydraulic fracturing fluid are commercially available as a total system fluid, the operator may satisfy the requirements of this Subdivision (3)(C) by briefly describing the intended purposes of the fluid additive system;

~~(a) — Base hydraulic fracturing fluid type; and~~

(D) A list of all chemical ingredients that are contained in the additives described in Subdivision (3)(B) and their associated CAS numbers, excluding any chemical ingredients entitled to trade secret protection under the criteria set forth in 40 C.F.R. Section 350.13(a); and

⋮

~~(b) — Chemical additives used in hydraulic fracturing fluids utilized by contractor, and the relevant concentration, including the main chemical component.~~ (E) The actual or maximum concentration of each chemical ingredient listed under Subdivision (3)(D), expressed as a percent by mass of the total volume of hydraulic fracturing fluid used.

(4) The estimated maximum fracture height and estimated true vertical depth to the top of the fracture achieved during the hydraulic fracturing treatment, as determined by a three dimensional model approved by [STATE REGULATOR];

A copy of the contractor's hydraulic fracturing treatment field ticket or the operator representative's hydraulic fracture treatment job log providing the above required information ~~by stage~~ is acceptable;

~~vi. — (vi) Initial well test~~ information recording daily gas, oil and water rate, tubing and casing pressure;

~~vii. — (vii) Initial gas and water~~ analysis, performed by a lab approved by [STATE REGULATOR] for such purpose; and

~~viii. — A post hydraulic fracture treatment analysis using the same realistic model as used under Section 3.e.ii of this Article V and actual data from the hydraulic fracturing treatment, including the calculated fracture length and fracture height for the hydraulic fracture treatment.~~

(viii) The results of the water testing described in Article IV.4.(h).

~~b. — (b)~~ In addition to the information provided in Section ~~6.5(a)~~ (i)-(viii) above, for close proximity wells, the operator shall also submit:

~~(i.)~~ The results of the intervening zone analysis undertaken pursuant to Section ~~3.e.2(d)~~ (i) of this Article V;

~~(ii.)~~ The results of the hydraulic fracture treatment design analysis undertaken pursuant to Section ~~3.e.2(d)~~ (ii) of this Article V;

~~(iii.)~~ A post hydraulic ~~fracture~~ fracturing treatment analysis using the same realistic model as used under Section ~~3.e.ii2(d)~~ (i) of this Article V and actual data from the hydraulic fracturing treatment, including the calculated fracture length and fracture height for the hydraulic fracture treatment;

~~(iv.)~~ If the operator is required to take the measures described in Section ~~3.e.2(d)~~ (iv) of this Article V, an affidavit signed by an authorized representative of operator that certifies that no fluids or materials pumped outside of the casing during the completion operations were of a nature or composition that could endanger an underground source of protected water by introducing chemical additives that may result

in the presence of contaminants that exceed national primary drinking water standards or that may otherwise adversely affect the health of persons; ~~and~~

(v-) Results of the cement evaluation log run pursuant to Section ~~3.e.2(d)(iii)~~ of this Article V.

~~ARTICLE VII – Production and Well Monitoring~~ VI – PRODUCTION AND WELL MONITORING

~~1. — General~~ 1. Scope of Article. It is the intent of all provisions of this Article that an operator monitor each producing well to the degree necessary to enable operator to identify any potential problems with a well which could endanger any underground source of protected water. When this Article does not detail specific methods to achieve these objectives, the operator shall make every effort to follow the intent of this Article, using good engineering and effective industry practices.

~~2. —~~ 2. Production and Well Monitoring.

~~a. —~~ General Requirements.

~~i. —~~ (a) An operator shall be obligated to monitor each producing well and measure the performance of same to the extent necessary to produce regular monthly and annual production reports. [For the first thirty days of operation, the operator shall monitor each producing well on a daily basis.] Such reports shall include the amount of gas, oil and water produced and all pressures from the applicable well for the relevant monthly or annual period, as the case may be, and shall be submitted to [STATE REGULATOR] as required. Operator shall keep these records for a minimum of five (5) years after they are produced.

~~ii. —~~ (b) An operator shall conduct regular periodic tests of each producing well. Such tests ~~will~~shall record daily gas produced, the applicable oil and water rate, and tubing and casing pressures.

~~iii. —~~ (c) An operator shall report annular pressures to [STATE REGULATOR] on an annual basis, and upon observation shall report as soon as reasonably practical (i) any annular pressures in excess of 70% of the API rated minimum internal yield or collapse strength of casing ~~or, and (ii)~~ any surface casing pressures that exceed a pressure equal to: 0.70 times 0.433 times the true vertical depth of the surface casing shoe (expressed in feet). All annular valves shall be accessible from the surface or shall be left open and be plumbed to the surface with working pressure gauges. [STATE REGULATOR] shall require installation of a properly functioning pressure relief device on any casing annulus [unless the operator can demonstrate, or [STATE REGULATOR] ~~determine~~determines, that this is unnecessary based on {objective} evidence and/or operating experience in the area]. The maximum set pressure of a surface casing pressure relief device shall be determined in accordance with Article V. ~~4.3(b.)~~ above. The operator shall

report all pressure releases from required pressure relief devices to [STATE REGULATOR] within 24 hours of detection.

~~iv-~~ (d) An operator ~~is obligated to~~ shall monitor its producing wells for any abnormal corrosion, equipment deterioration, or changes in well characteristics that could potentially indicate a deficiency in the production casing, intermediate casing, surface casing, cement, packers or any other aspect of well integrity necessary to ensure isolation of any underground sources of protected water. If operator has cause to suspect such a deficiency, then operator must ~~immediately~~ perform, to the extent possible, ~~such~~ diagnostic testing on the well as is necessary to determine whether a deficiency has actually occurred and must notify [STATE REGULATOR] ~~of the as soon as reasonably practical of any~~ deficiency ~~unless the testing shows that no~~ deficiency has occurred. ~~If~~ Such testing shall be done as soon as is reasonably practical after operator has cause to suspect a deficiency, and if the testing reveals that a deficiency has occurred then operator shall (i) promptly take all appropriate measures to prevent contamination of protected water and otherwise protect the environment, and (ii) promptly commence remedial operations that are designed to repair the deficiency. If the operator is not able to effectively repair the deficiency so as to ensure the protection of all underground sources of protected water and the environment, the operator shall be required to plug and abandon the well in accordance with the requirements of Article VII below.

~~ARTICLE VIII – Plugging and Well Abandonment~~ VII – PLUGGING AND WELL ABANDONMENT

~~1. —~~ General 1. Scope of Article. This Article governs the process of plugging and abandoning hydraulically fractured wells, with the intent of this Article being to ensure that operators plug wells in an effective manner that adequately protects groundwater and other natural resources.

~~2. —~~ 2. Application to Plug an Abandoned Well.

~~a-~~ (a) The operator shall give [STATE REGULATOR] notice, in the form appropriate in the state of [STATE], of its intention to plug any well or wells drilled for hydrocarbons or for any other purpose over which [STATE REGULATOR] has jurisdiction prior to plugging. The operator's notice shall be delivered to [STATE REGULATOR] prior to the beginning of plugging operations, in accordance with applicable [STATE] laws, rule and procedures governing such plugging operations. The notice must set out the proposed plugging procedure as well as the complete casing record. The operator shall not commence the work of plugging the well or wells until the proposed procedure has been approved by [STATE REGULATOR], and then shall proceed in accordance with applicable [STATE REGULATOR] notice and other requirements governing such plugging operations. Operations shall not be suspended prior to plugging the well unless the hole is cased and the casing is cemented in place in compliance with all the requirements of [STATE REGULATOR].

~~i-~~ (i) The duty of the operator to properly plug ends only when:

~~(+)~~ (1) the operator has properly plugged the well in accordance with [STATE REGULATOR] requirements up to the base of the protected water stratum;

~~(2)~~ (2) the surface owner has registered the well, or has obtained appropriate permitting for, the relevant groundwater protection or similar program, if applicable; and

~~(3)~~ (3) [STATE REGULATOR] has approved the application of surface owner to condition an abandoned well for fresh water production.

~~b.~~ (b) The operator of a well shall serve notice on the surface owner of the well site tract, or the resident if the owner is absent, before the scheduled date for beginning the plugging operations, and a representative of the surface owner may be present to witness the plugging of the well. Plugging shall not be delayed because of the lack of actual notice to the surface owner or resident if the operator has served notice as required by this paragraph.

~~3.~~ 3. **Commencement of Plugging Operations, Extensions, and Testing.**

~~a.~~ (a) The operator shall complete and file with [STATE REGULATOR] a duly verified plugging record, in duplicate, on the appropriate form within 30 days after plugging operations are completed. A cementing report made by the party cementing the well shall be attached to, or made a part of, the plugging report. If the well the operator is plugging is a dry hole, an electric log status report shall be filed with the plugging record.

~~b.~~ (b) Plugging operations on each dry or inactive well shall be commenced within a period of one year after drilling or operations cease and shall proceed with due diligence until completed. Plugging operations on delinquent inactive wells shall be commenced immediately, unless the well is restored to active operation.

~~i.~~ (i) Plugging of inactive wells. An operator will be granted a one-year plugging extension for each well it operates that has been inactive for 12 months or more at the time its [annual organizational report or other similar state report] is approved by [STATE REGULATOR] if the following criteria are met:

~~(+)~~ (1) The well and associated facilities are in compliance with all laws and [STATE REGULATOR] rules; and,

~~(2)~~ (2) The operator has and can evidence a good faith claim to a continuing right to operate the well.

~~ii.~~ (ii) Revocation or denial of plugging extension.

~~(+)~~ (1) [STATE REGULATOR] may revoke a plugging extension if the operator of the well that is the subject of the extension fails to maintain the well and all associated facilities in compliance with applicable rules of [STATE

REGULATOR]; fails to maintain a current and accurate organizational report or other similar filing on file with [STATE REGULATOR]; fails to provide [STATE REGULATOR], upon request, with evidence of a continuing good faith claim to operate the well; or fails to obtain or maintain required financial security as required by [STATE REGULATOR].

~~(2)~~ (2) If [STATE REGULATOR] or its delegate declines to grant or continue a plugging extension or revokes a previously granted extension, the operator shall either return the well to active operation or, within 30 days, plug the well or request a hearing on the matter.

~~e.~~ (c) [STATE REGULATOR] may plug or replug any dry or inactive well as follows:

~~i.~~ (i) After notice and hearing, if the well is causing or is likely to cause the pollution of surface or subsurface water or if liquid or gaseous hydrocarbons or other formation fluid is leaking from the well, and:

~~(+)~~ (1) Neither the operator nor any other entity responsible for plugging the well can be found; or

~~(2)~~ (2) Neither the operator nor any other entity responsible for plugging the well has assets with which to plug the well.

~~ii.~~ (ii) Without a hearing if the well is a delinquent inactive well and:

~~(+)~~ (1) [STATE REGULATOR] has sent notice of its intention to plug the well as may be required; and

~~(2)~~ (2) the operator did not request a hearing within the applicable period specified in the notice.

~~iii.~~ (iii) Without notice or hearing, if:

~~(+)~~ (1) [STATE REGULATOR] has issued a final order requiring that the operator plug the well and the order has not been complied with; or

~~(2)~~ (2) The well poses an immediate threat of pollution of surface or subsurface waters or of injury to the public health and the operator has failed to timely remediate the problem.

~~e.~~ (d) [STATE REGULATOR] may seek reimbursement from the operator and any other entity responsible for plugging the well for state funds expended pursuant to section 4.c. of this Article.

~~4.~~ 4. Designated Operator Responsible for Proper Plugging. The entity that is the most recent [STATE REGULATOR]-approved operator of a well is presumed to be responsible for properly

plugging the well. An operator may rebut this presumption of responsibility at a hearing called by [STATE REGULATOR] for purposes of determining plugging responsibility.

~~5.~~ 5. General Plugging Requirements.

~~a.~~ (a) Wells shall be plugged to insure that all formations bearing protected water, hydrocarbons, or geothermal resources are protected. All cementing operations during plugging shall be performed under the direct supervision of the operator or his authorized representative, who shall be independent of the applicable service or cementing company hired to plug the well. The operator and the cementer are both responsible for complying with general plugging requirements and for plugging the well in conformity with the procedure set forth in the approved notice of intention to plug and abandon for the well being plugged.

~~b.~~ (b) Cement plugs shall be set to isolate each hydrocarbon strata and the lowermost protected water strata. Plugs shall be set as necessary to separate multiple protected water strata by placing the required plug at each depth as determined by [STATE REGULATOR]. The operator shall verify the placement of the plug required at the base of the deepest protected water stratum by tagging with tubing or drill pipe or by an alternate method approved by [STATE REGULATOR].

~~c.~~ (c) Cement plugs shall be placed by the circulation or squeeze method through tubing or drill pipe, subject to approved exceptions by [STATE REGULATOR].

~~d.~~ (d) All cement used for plugging shall be of a composition approved by [STATE REGULATOR], and [STATE REGULATOR] may require that specific cement compositions be used in certain situations. [STATE REGULATOR] may approve the use of alternate materials if [STATE REGULATOR] deems it appropriate, but [STATE REGULATOR] shall approve a request to use alternate materials only if the proposed alternate material and plugging method will ensure that the well does not pose a potential threat of harm to natural resources.

~~e.~~ (e) [STATE REGULATOR] may require additional cement plugs to cover and contain any hydrocarbon stratum or to separate any water stratum from any other water stratum if the water qualities or hydrostatic pressures differ sufficiently to justify separation. The tagging and/or pressure testing of any such plugs, or any other plugs, and re-spotting may be required if necessary to ensure that the well does not pose a potential threat of harm to natural resources.

~~f.~~ (f) A 50-foot cement plug shall be placed in the top of the well, and casing shall be cut off at least three feet below the ground surface or at such other depth as required by [STATE REGULATOR].

~~g.~~ (g) Mud-laden fluid of at least 9-1/2 pounds per gallon with a minimum funnel viscosity of 40 seconds shall be placed in all portions of the well not filled with cement or other alternate material as approved by [STATE REGULATOR]. The hole shall be in static condition at the time the cement plugs are placed. [STATE REGULATOR] may grant exceptions to the requirements of this paragraph if a deviation from the prescribed minimums for fluid weight or viscosity will insure that the well does not pose a potential threat of harm to natural resources.

[STATE REGULATOR] may approve the use of alternate fluid if [STATE REGULATOR] deems it appropriate, but [STATE REGULATOR] shall approve a request to use alternate materials only if the proposed alternate material and plugging method will ensure that the well does not pose a potential threat of harm to natural resources.

~~h-~~(h) Non-drillable material that would hamper or prevent reentry of a well shall not be placed in any wellbore during plugging operations, except as may be otherwise expressly permitted under law. Pipe and unretrievable junk shall not be cemented in the hole during plugging operations without prior approval by [STATE REGULATOR].

~~i-~~(i) All cement plugs, except the top plug, shall have sufficient slurry volume to fill 100 feet of hole, plus 10% for each 1,000 feet of depth from the ground surface to the bottom of the plug.

~~j-~~(j) The operator shall fill the rathole, mouse hole, and cellar, and shall empty all tanks, vessels, related piping and flowlines that will not be actively used in the continuing operation of the lease within 120 days after plugging work is completed. Within the same 120 day period, the operator shall remove all such tanks, vessels, and related piping, re-move all loose junk and trash from the location, and contour the location to discourage pooling of surface water at or around the facility site. The operator shall close all pits as is appropriate. [STATE REGULATOR] may grant a reasonable extension of time of not more than an additional 120 days for the removal of tanks, vessels and related piping.

~~k-~~(k) Operator must notify [STATE REGULATOR] at least 24 hours prior to commencing plugging and well abandonment operations.

6.6. Plugging Requirements for Wells with Surface Casing.

~~a-~~(a) When insufficient surface casing is set to protect all protected water strata and all hydrocarbon strata, and such strata are exposed to the wellbore when production or intermediate casing is pulled from the well or as a result of such casing not being run, a cement plug or plugs shall be placed centered opposite the top of each hydrocarbon stratum and the base of the deepest protected water stratum. Each plug shall be a minimum of 200 feet in length and shall extend at least 100 feet below and 100 feet above the top of each hydrocarbon stratum and the base of the deepest protected water stratum. The plug across the deepest protected water stratum shall be evidenced by tagging with tubing or drill pipe. The plug shall be respotted if it has not been properly placed. In addition, a cement plug or plugs shall be set across the shoe of the surface casing and any multi-stage cementing tool. Each such plug shall be a minimum of 200 feet in length and shall extend at least 100 feet above and below the shoe or multi-stage cementing tool.

~~b-~~(b) When sufficient surface casing has been set and cemented to protect all hydrocarbon strata and all protected water strata, a cement plug shall be placed across the shoe of the surface casing and across any multi-stage cementing tool. Each plug shall be a minimum of 200 feet in length and shall extend at least 100 feet above the shoe and at least 100 feet below the shoe.

~~e.~~(c) If surface casing has been set deeper than 200 feet below the base of the deepest protected water stratum, an additional cement plug shall be placed inside the surface casing across the base of the deepest protected water stratum. This plug shall be a minimum of 200 feet in length and shall extend at least 100 feet below and 100 feet above the base of the deepest protected water stratum.

~~e.~~(d) Plugs shall be set as necessary to separate multiple protected quality water strata by placing the required plug at each depth as determined by [STATE REGULATOR].

7.7. Plugging Requirements for Wells with Intermediate Casing.

~~a.~~(a) For wells in which the intermediate casing has been cemented through all protected water strata and all hydrocarbon strata, a cement plug or plugs meeting the requirements of Section ~~5.6.i.~~ of this Article shall be placed inside the casing and centered opposite the base of the deepest protected quality water stratum, but extend no less than 50 feet above and below the base of the deepest protected water stratum. Each plug shall be a minimum of 100 feet in length and shall extend at least 50 feet below and 50 feet above the base of the deepest protected water stratum. In addition, a cement plug or plugs shall be set across the shoe of the intermediate casing, if it is open to the wellbore, and any multi-stage cementing tool. Each plug shall be a minimum of 100 feet in length and shall extend at least 50 feet above and below the shoe or multi-stage cementing tool, as applicable.

~~b.~~(b) For wells in which intermediate casing is not cemented through all protected water strata and all hydrocarbon strata, and if the casing will not be pulled, the intermediate casing shall be perforated at the required depths as described in 8.a. above to place cement outside of the casing by squeeze cementing through casing perforations.

~~e.~~(c) Additionally, plugs shall be set as necessary to separate multiple protected water strata by placing the required plug at each depth as determined by [STATE REGULATOR].

8.8. Plugging Requirements for Wells with Production Casing.

~~a.~~(a) For wells in which the production casing has been cemented through all protected water strata and all hydrocarbon strata, a cement plug meeting the requirements of Section 6.i. of this Article VII shall be placed inside the casing and centered opposite the top or the uppermost hydrocarbon stratum and the base of the deepest protected water stratum and across any multi-stage cementing tool. Each plug shall be a minimum of 100 feet in length and shall extend at least 50 feet below and 50 feet above the top of the uppermost hydrocarbon stratum and the base of the deepest protected water stratum.

~~b.~~(b) For wells in which the production casing has not been cemented through all protected water strata and all hydrocarbon strata and if the casing will not be pulled, the production casing shall be perforated at the required depths as described in Section 9.a. above to place cement outside of the casing by squeeze cementing through the casing perforations.

~~e.~~(c) [STATE REGULATOR] may approve a cast iron bridge plug to be placed immediately above each perforated interval, provided at least 20 feet of cement is placed on top of each bridge plug. A bridge plug shall not be set in any well at a depth where the pressure or temperature exceeds the ratings recommended by the bridge plug manufacturer.

~~e.~~(d) Additionally, plugs shall be set as necessary to separate multiple protected water strata by placing the required plug at each depth as determined by [STATE REGULATOR].

9.9. Plugging Requirements for Wells with Screen or Liner.

~~a.~~(a) If practical, the screen or liner shall be removed from the well.

~~b.~~(b) If the screen or liner is not removed, a cement plug in accordance with Section 6.i. of this Article shall be placed at the top of the screen or liner.

10.10. Plugging Requirements for Wells Without Production Casing and Open-Hole Completions.

~~a.~~(a) Any productive horizon or any formation in which a pressure or formation water problem is known to exist shall be isolated by cement plugs centered at the top and bottom of the formation. Each cement plug shall have sufficient slurry volume to fill a calculated height as specified in Section 6.i. of this Article.

~~b.~~(b) If the gross thickness of any such formation is less than 100 feet, the tubing or drill pipe shall be suspended 50 feet below the base of the formation. Sufficient slurry volume shall be pumped to fill the calculated height from the bottom of the tubing or drill pipe up to a point at least 50 feet above the top of the formation, plus 10% for each 1,000 feet of depth from the ground surface to the bottom of the plug.

~~11.~~**11. Review of Plugging Applications.** [STATE REGULATOR] shall review and approve the notification of intention to plug in a manner so as to accomplish the purposes of this Article. [STATE REGULATOR] may approve, modify, or reject the operator's notification of intention to plug. If the proposal is modified or rejected, the operator may request a review by [STATE REGULATOR]. If the proposal is not administratively approved, the operator may request a hearing on the matter. After hearing, the [STATE REGULATOR] shall recommend final action by [STATE REGULATOR].

~~12.~~**12. Plugging Horizontal Wells.** All plugs in horizontal wells shall be set in accordance with Section ~~5.6~~i. of this Article. The productive horizon isolation plug shall be set from a depth of 50 feet (measured depth) below the top of the productive horizon to a depth of either (i) 50 true vertical feet above the top of the productive horizon, or (ii) if the production casing is set above the top of the productive horizon, 50 true vertical feet above the production casing shoe. In accordance with Section 6.e. of this Article, [STATE REGULATOR] may require additional plugs.

~~13.~~ **13. Plugging of Close Proximity Wells.** In addition to the plugging requirements for wells that are not classified as close proximity wells, for close proximity wells a plug must be set extending 50 feet below the top of the productive horizon to 50 true vertical feet above the top of the intervening zone. The plug shall be evidenced by tagging with tubing or drill pipe.

~~14.~~ **14. Approved Cementers Only.**

~~a.~~ **(a)** In order to comply with this Article, when conducting plugging operations which require cementing, operators shall utilize only those cementers approved by [STATE REGULATOR]. Cementing companies, service companies, or operators may apply with [STATE REGULATOR] for designation as approved cementers. Such approval will be granted by [STATE REGULATOR] upon a showing by the applicant of its ability to mix and pump cement or other alternate materials as approved by [STATE REGULATOR] in compliance with this rule.

~~i.~~ **(b)** A cementing company, service company, or operator seeking designation as an approved cementer by [STATE REGULATOR] shall file a request of such designation with [STATE REGULATOR] in accordance with all applicable procedures governing such requests. The request shall contain such information as the [STATE REGULATOR] shall reasonably require to assess the applicant's ability to competently perform cementing operations in compliance with this rule, which may include, but not limited to, the following:

(i) A list of the applicant's qualifications, including qualifications of the personnel that will supervise the mixing and pumping operations; and

(ii) An inventory of the type of equipment to be used to mix and pump cement.

~~ii.~~ **(c)** [STATE REGULATOR] shall either approve or deny the application to be designated as an approved cementer. If [STATE REGULATOR] does not recommend approval, or denies the application, the applicant may request a hearing on its application.

ARTICLE VIII – ADDITIONAL REQUIREMENTS

1. Health, Safety and Environmental Management System. Each operator shall have a structured system and approach for managing health, safety, environmental and regulatory responsibilities to improve overall health, safety and environmental performance and stewardship.

2. Emergency Response Plan. Each operator shall have a functioning emergency response plan that provides for the efficient management of emergency situations in operations covered by this regulation. At a minimum, emergency situations addressed shall include: spills, natural disasters, uncontrolled wells, explosion or fires, fatalities or serious injuries, and threats or acts of terrorism.

~~3. [STATE REGULATOR] Audit and Enforcement. [STATE REGULATOR] shall have the right to audit operator's activities and compliance with these regulations upon sixty (60) days prior written notice to operator. [STATE REGULATOR] shall have the right to visit and inspect operator's well sites and operations in order to enforce these regulations. Should operator be found not to be in compliance with these regulations, [STATE REGULATOR] may issue a Notice of Violation to operator, and may issue a fine related to said violation(s). Operator shall have the right to a hearing to contest any such Notice of Violation and/or fine(s).~~

Fort Hood Recovery Credit System

A description of how the system was developed and implemented, results achieved, lessons learned and implications for the expansion of habitat credit trading markets.

David Wolfe
Texas Regional Wildlife Director
Environmental Defense Fund

Executive Summary

In December 2005 Environmental Defense Fund (EDF) and key partners initiated development of the first recovery credit system (RCS) for an endangered species in the United States. This system, developed on behalf of Fort Hood and the Department of Defense (DOD), is designed to invest DOD funds in habitat protection and management activities that benefit the endangered Golden-cheeked Warbler (warbler) on private lands¹ in central Texas. In return, Fort Hood receives credits commensurate with the amount and quality of habitat that is managed and protected. These credits are available for use by Fort Hood to offset impacts (i.e., "debits") to habitat on the installation that may result from training exercises. During the three-year proof of concept, which extended from July 2006 through July 2009, participation was limited to landowners in a six-county area around Fort Hood (Bell, Bosque, Coryell, Hamilton, Lampasas and McLennan counties) so as to facilitate program and results monitoring and evaluation.

Insert map of Fort Hood and six county area

Key results from the three-year proof of concept include:

- 2,200 acres of warbler habitat have been protected on participating ranches whereas only 200 acres have been impacted² on Fort Hood;
- The known population of the warbler has nearly doubled, increasing from about 5,000 to 9,000 individuals;
- Cost of credits purchased was about one-eighth of what the cost would be if credits were purchased through a typical conservation bank;
- An independent review of the Fort Hood RCS by Robertson Consulting Group, Inc. found that the stated goals were achieved (see attached RCS Evaluation Executive Summary).

The success of the Fort Hood RCS proof of concept was such that EDF is now expanding the concept by developing a habitat credit trading market that will encompass the entire 34 county

¹ At least 85% of Golden-cheeked Warbler habitat is estimated to occur on private lands.

² The impact on Fort Hood resulted from thinning of understory brush in warbler habitat so as to enable foot soldiers to conduct training exercises in these areas. Results from subsequent monitoring of these areas by Texas A&M university indicate that, so far, warbler productivity has actually increased, rather than being negatively impacted.

range of the warbler in central Texas. Credits generated on private lands through protection and management of warbler habitat will be available for sale to energy transmission companies, DoD and other private and public entities that need to mitigate impacts to warbler habitat. Landowners are eager to participate in the generation and sale of credits: We currently have a list of 25 landowners representing over 5,000 acres of warbler habitat who are waiting to participate.

Insert map of 34 county area

Development of the RCS

To create the RCS EDF and other members of an advisory committee assembled three stakeholder committees; science, economics and policy, and tasked them with building the components and processes necessary to (a) create a functioning habitat credit trading market for the warbler and (b) develop USFWS policy guidance to support this innovative approach to mitigating impacts to habitat on public land and creating a net benefit to the species. These committees initiated work in December 2005 and a draft of the RCS was established in June 2006. Implementation of the three-year proof of concept began in July 2006.

The science committee was tasked with developing metrics for the system (i.e., the "commodity" of habitat that was to be valued and traded), as well as guidelines for habitat management and monitoring. This committee, which was composed of scientists (including several warbler experts) defined 20 acres as a conservation unit (roughly the average size of a territory for a pair of warblers) and assigned this conservation unit a credit value of 1. This credit value was then given additional value (with multipliers) if it was part of a relatively large block of habitat, if it was near other populations of the warbler and if it was in an area of high priority for recovery of the species. The committee also developed management and monitoring guidelines that were applied to each participating ranch.

Debits, which quantified the "value" of adverse impacts to habitat on Fort Hood, were calculated in a manner similar to credits with the following exception:

When calculating the number of conservation units on a private ranch acreage is rounded down to the nearest multiple of 20 acres. So, if a landowner had between 20 and 39 acres of habitat, then they received one credit (defined as 20 acres). If they had between 40 and 59 acres, then they received two credits, and so on. Conversely, on Fort Hood, the acreage of impacts was rounded up to the nearest conservation unit. An impact of from one to 20 acres resulted in one debit, an impact on 21 to 40 acres resulted in two debits, etc.

The economics committee was tasked with creating a market-based approach to the purchase of credits and to identify ways of creating a net benefit for the warbler. For the purposes of the proof of concept, landowners were able to sign performance contracts for periods ranging from 10 - 25 years as these terms were deemed sufficient by the advisory committee to offset anticipated temporary adverse impacts to warbler habitat on Fort Hood. The committee

recommended that qualified landowners sell their credits through a reverse-auction process, (i.e., all else being equal the low bidder "wins" the auction). The actual commodity that was bid by the landowners was recovery credit years (credits multiplied by the term of their performance contract). As a result of the reverse auction process Fort Hood was able to maximize the number of credits received per dollar invested: In other words, both cost efficiency and conservation effectiveness were maximized.

The policy committee was tasked with developing a contract template for landowner participation, identifying how RCS would fit within the framework of the Endangered Species Act, working with the USFWS to develop new policy as needed, and addressing the issue of private landowner confidentiality concerns. This committee, working in collaboration with USFWS, deemed it important to gain experience with RCS implementation so as to inform the development of specific RCS guidance. During the second year of the proof of concept USFWS staff took a lead role in drafting this guidance, which was published as a draft in the Federal Register on November 2, 2007 and as final guidance on July 31, 2008. The guidance:

- enables federal agencies to utilize RCS as a means to offset their impacts to endangered species through conservation actions on private lands that results in a net-benefit to the species;
- promotes the use of habitat credit trading systems for this purpose and
- allows for term agreements to offset temporary impacts and permanent agreements to offset permanent impacts.

Confidentiality of information is a significant issue to many private landowners who are considering participation in a program to benefit an endangered species. The policy committee was keenly aware of this landowner concern and the fact that lack of confidentiality assurances would likely preclude participation of a large percentage of landowners. On the other hand, it is essential for species and habitat data to be made available from participating ranches in order to verify that net benefits are being achieved and funds are being spent as intended. To create a balance between these two competing concerns the policy committee decided that all data related to habitat assessments, habitat maps, credit calculations and management plans for landowners' ranches would be made available to the USFWS (essentially public information), but the landowner and ranch name would remain confidential. This approach was facilitated through execution of an agreement between the landowner and TPWD and supported by Texas state law.

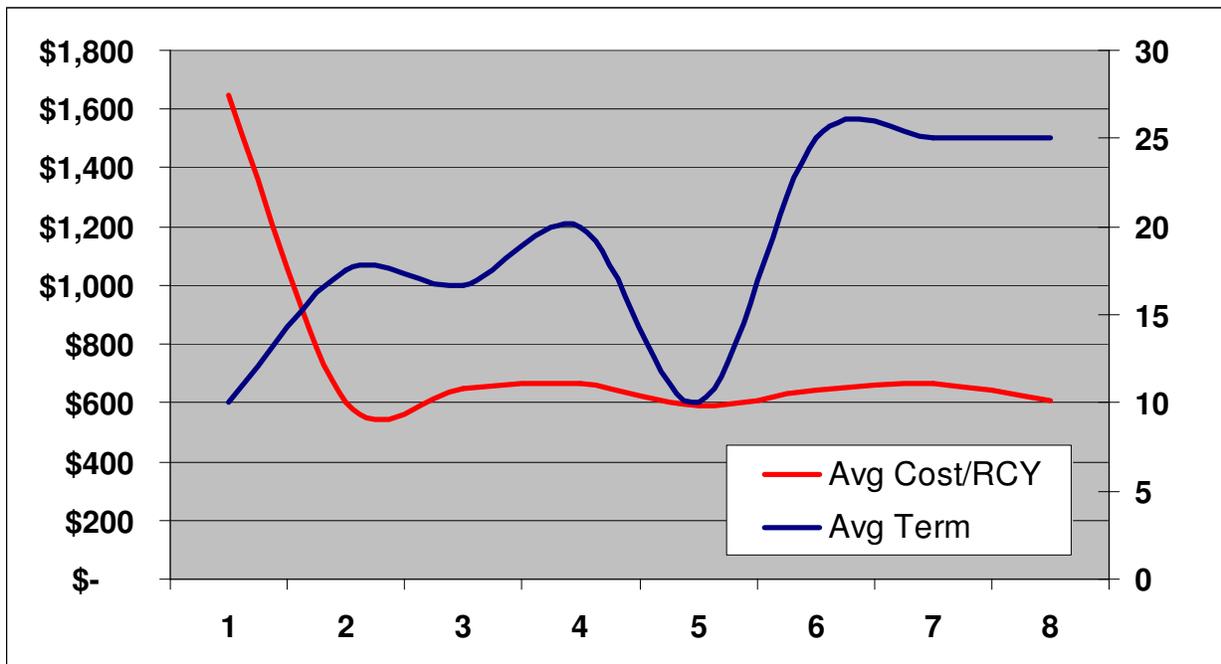
Net benefits for the warbler were insured in two ways. As previously described, acreage was rounded down to calculate credits and rounded up to calculate debits. In addition to this method of insuring a surplus of acres on the credit side, Fort Hood was also required to retire ten percent of the credits accrued each year as a contribution to net benefit for the species.

Implementation of the RCS

Texas A&M IRNR was contracted by DoD to implement a three-year proof of concept phase in July 2006 and to monitor the results. IRNR sub-contracted with various entities to conduct various RCS activities:

- Texas Watershed Management Foundation (TWMF), a non-profit organization, served as the overall program administrator and manager. TWMF staff conducted landowner outreach, met with landowners to describe the system, coordinated site visits for the purpose of determining credit score and conducting management plan development, executed contracts with landowners, conducted prescribed management activities and performed yearly compliance monitoring.
- EDF staff assessed habitat on private ranches, determined associated credit score and developed warbler-specific management plans for each ranch.
- TPWD staff developed overall ranch management plans.

A total of approximately 40 landowners participated in eight bid rounds over the course of the three-year proof of concept. A total of 20 contracts were awarded representing 2,201 acres of warbler habitat. Since the reverse auction process rewarded the bidder offering the lowest cost recovery credit-year (RCY) landowners quickly discovered that they could increase the competitiveness of their bid by increasing the term in years: At the first bid round the majority of landowners chose the 10-year term; by the final bid round **all** of the landowners chose the 25-year term. Over the eight bid rounds the cost per recovery credit-year went down while the term of agreement went up:



Texas A&M graduate students have conducted, and are continuing to conduct surveys of warblers and their habitats on participating private ranches both pre and post-implementation of prescribed management activities. In this way, changes from baseline conditions can be

measured and a determination made as to increases in abundance and/or productivity. Similar surveys have been conducted and are ongoing on Fort Hood both pre and post-implementation of training exercises so as to determine detrimental effects to warblers, if any. In this way, overall net benefits to the warbler resulting from credit - debit transactions could be determined. Initial results from surveys are currently being analyzed and we can expect to see publications beginning in 2012.

Lessons Learned

See Appendix A.

Development of a General Conservation Plan and Associated Habitat Credit Trading Market for the Golden-Cheeked Warbler and Black-Capped Vireo

Given the success of the Fort Hood RCS, the interest in program participation from landowners across central Texas, and the need for mitigation options by energy transmission companies and other entities, EDF is now working with Texas A&M University Institute of Renewable Natural Resources and other partners to create a General Conservation Plan (GCP) and associated range-wide habitat credit trading market for the golden-cheeked warbler and another endangered songbird; the black-capped vireo. A GCP is a USFWS regulatory document that defines conservation actions to benefit the target species, identifies likely adverse impacts to habitat from development and describes how mitigation will be conducted so as to offset adverse impacts and create a net benefit to the species. A habitat credit trading market will serve as the primary means for mitigation. The GCP and associated market will encompass 34 counties in central Texas and will facilitate protection and management of warbler and vireo habitats across vast landscapes on private lands. It will also enable energy transmission companies and other entities to mitigate their impacts to these habitats in a much more efficient and effective way.

EDF and IRNR organized and conducted the first stakeholder committee meetings for the GCP in December 2011. These committees will develop the elements of the GCP and the associated market over the next several months. Our goal is to have a draft plan and market design completed by September 2012. A National Environmental Policy Act (NEPA) review will be conducted on the draft plan immediately thereafter and full implementation of the plan and associated market is scheduled for June 2013.

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Appendix A

Lessons Learned

Benefits of RCS

We have observed a number of benefits to the warbler during the proof of concept phase. In our opinion the most tangible benefits have been realized in our improved knowledge of the status of this species, expansion of habitat, and building of relationships with private landowners for ongoing conservation purposes:

1. **Adding to the Baseline:** As a result of RCS contracts Texas A&M researchers are gaining access to ranches that have previously been off-limits for warbler surveys. These surveys are increasing the known population of warblers. This information is extremely important in terms of assessing the status of the species and in determining progress toward recovery. This type of information is needed from private lands in all eight recovery regions: a range-wide RCS would facilitate the process of gathering this information.
2. **Management to expand and link habitats:** The plans for many, if not most of the participating ranches include management actions that will expand and link warbler habitats. The primary management action that is prescribed for this objective is allowing re-forestation of (previously cleared or thinned) areas in such a way as to expand and link existing habitat patches.
3. **Relationship building with landowners:** Staff of EDF, Texas Watershed Management Foundation and Texas A&M University have been able to build relationships with many of the private landowners participating in RCS. The primary benefit of these relationships is the opportunity to educate landowners about warblers and their habitat and to build a sense of ownership and pride in the landowners regarding this unique component of Texas' natural heritage.

We believe there to be a number of potential benefits (benefits that we have not yet observed or experienced, but we believe to have excellent potential) that will result from RCS participation:

1. **Potential to increase productivity of existing populations:** As part of RCS participation a variety of management practices are being prescribed that are expected to result in increased productivity of warblers on participating ranches. These practices include management of white-tailed deer populations, control of Brown-headed Cowbirds and selective thinning of Ashe juniper so as to increase the deciduous cover within forests and woodlands.
2. **Potential to build longer-term relationships with a sub-set of landowners:** Based on our experience with other private lands conservation efforts, we expect a number of the RCS-

landowner relationships to result in an increased interest in (and associated level of comfort with) other conservation options (e.g., easements) that they would otherwise not consider.

3. Ability to change priority focus areas over time: Warbler habitat can be destroyed, degraded or otherwise altered due to events such as disease outbreaks or wildfire. In addition, warbler habitat is going to change in as yet unknown ways as a result of human-induced climate change. RCS term agreements provide a means of shifting priority areas for warbler conservation over time in order to respond and adapt to the aforementioned events.

Challenges/Weaknesses

We believe that the greatest weakness of the RCS is the uncertainty regarding the conservation status of lands that are not currently enrolled in RCS, but are adjacent to RCS participants and are used to meet the (minimum) 250-acre block of warbler habitat screening criterion. Uncertainty lays in the fact that warbler habitat on these un-enrolled lands could at some future point be destroyed or degraded, thereby reducing the habitat patch size below the 250-acre criterion. This concern is identified in a March 3, 2009 Biological Opinion issued by the USFWS to Fort Hood.

We suggest addressing this concern by restricting RCS participation to the highest priority (250-acre or larger) landscapes for warbler conservation across the breeding range. This range-wide landscape prioritization approach would not necessarily guarantee that the entire landscape will be conserved and remain free from threat, however it will place a high priority on RCS participation in landscapes where warbler conservation is already in place or planned by other partner organizations (e.g., Wildlife Management Areas, State Parks, conservation easements, etc.). The highest priority patches would likely need to be re-evaluated on a regular basis, perhaps annually.

A second weakness is that the current longest-term contract may not be of sufficient duration to offset certain unanticipated events such as wildfire. The longest term available to RCS participants during the pilot project was 25 years, which is substantially shorter than the duration of impact predicted by some experts for intense wildfire. That being the case we suggest that the RCS working group consider increasing contract terms beyond the current 25 years. Indeed, toward the end of the proof of concept period a number of landowners expressed interest in the potential to participate in longer term contracts.

Confidentiality of participating landowners has been a major concern for some critics of RCS. Given this concern and the fact that the Fort Hood RCS has been driven primarily by federal funds we believe that the current policy on confidentiality should be reviewed and perhaps revised or abolished. The growing level of interest on the part of private landowners in RCS indicates the potential for achieving a sufficient level of program participation in the absence of confidentiality. Alternatively, if RCS participation is limited to the highest priority landscapes for warbler conservation, then it may be reasonable to maintain a certain level of confidentiality in return for sharing a few key components of information (e.g., habitat acreage, prescribed

management practices, priority landscape within which project is located) with all concerned parties.

Specific Issues Related to On-the-Ground Implementation of the Fort Hood RCS

As a result of participating in the implementation of the program we have encountered a number of specific issues related to the design of the program that need additional thought, consideration and, perhaps adaptive modification in order to more fully and effectively achieve the goals of the RCS.

The two primary issues that we encountered relate to the 250-acre screening criteria for participation in the RCS. These two issues can be framed as questions: (1) What constitutes fragmentation of a landscape of warbler habitat? and (2) What constitutes continuity of this same habitat?

Almost every 250-acre (or larger) warbler habitat landscape that we encountered in the proof of concept area is fragmented to some degree. In other words, we did not locate any completely contiguous, totally un-fragmented patches of warbler habitat that are 250 acres or larger on private lands within the proof-of-concept area. Every warbler landscape patch that we encountered had some form of opening: fence line access, ranch road, artificial openings for hunting lanes, or other form of discontinuity in the forest canopy. Relatively narrow openings may not necessarily constitute a discontinuity from the perspective of a warbler, but the question arises as to how much fragmentation is allowable when considering the screening criterion of 250 acres? How wide of an opening (fence line, road, etc.) is too wide? How do we measure the amount of fragmentation and at what point do we decide that a particular landscape is too fragmented to qualify?

(1) What constitutes fragmentation of a landscape of warbler habitat?

We subjectively assessed whether a particular opening constituted a discontinuity in habitat. For example, we typically decided that fence line access lanes and single-lane ranch roads within warbler habitat do not constitute a discontinuity, whereas a paved two-lane highway does. We need a more rigorous, standardized means of measuring landscape fragmentation and related criteria for deciding whether or not a particular landscape is too fragmented to qualify for the RCS.

(2) What constitutes continuity of this same habitat?

We frequently encountered landscapes of GCWA habitat that are linked by habitat types that do not necessarily meet the Texas Parks and Wildlife Department Guidelines for areas that are likely to be inhabited by warblers, but which we believe serve as travel corridors between areas that are suitable for breeding. The two types of habitat that we most frequently encountered were riparian forests and juniper woodlands with less than ten percent deciduous canopy. When determining landscape size we considered areas of warbler habitat as contiguous if they were connected by these two habitat types. For example, if a 125-acre patch of warbler habitat was connected to another 125-acre patch of warbler habitat by a riparian forest, then we considered the warbler landscape size to be 250 acres. Of course in making this determination

we faced the question of “How much separation is too much in order for the warbler landscape to be considered contiguous?” Obviously, two patches that are separated by several miles of riparian forest would likely be considered separate, whereas two patches separated by 50 feet might be considered contiguous. This matter of separation is also relevant to conservation units.

Recovery Credit Ranking System – Recovery Region Multiplier

On one particular ranch we encountered a situation that underscores a shortcoming in the current ranking system. This particular ranch included qualifying warbler habitat that spanned the Coryell County – Bosque County line. In the current ranking system warbler habitat in Coryell County (Recovery Region 3) gets a 1.0 (i.e., no additional value) multiplier, while warbler habitat in Bosque County (Recovery Region 2) gets a 2.0 multiplier. For the purpose of calculating recovery credit value we artificially “separated” the warbler habitat into a Coryell County portion and a Bosque County portion in order to apply the Recovery Region multipliers. Obviously, the value of this habitat to the species does not change at this location just because it is bisected by a county boundary. This situation points out the need for a review of the application of the Recovery Region multiplier. Certainly there is merit to the concept of giving more value to habitat patches in locations that will have a greater impact on recovery, but we should perhaps consider a more ecologically based system of assigning this value.

Recovery Credit Ranking System – Landscape Size Multiplier

Bigger is better when it comes to habitat patch size: this is an accepted principle of conservation biology. Obviously there is likely to be some threshold (as one looks at increasingly large patch sizes) above which there are no additional benefits to the species. For example the productivity of warblers in a 100,000 acre patch of contiguous habitat is unlikely to increase (on the original 100,000 acres) if another 1,000 acres of habitat are added to the patch.

One of the primary concerns raised during the development of the debiting component of the RCS is that the current ranking system has a single multiplier for landscapes greater than 650 acres, whereas many of the warbler landscapes on Fort Hood are in the range of several thousand acres. The concern is that these multi-thousand acre landscapes are not adequately valued by the current ranking system. One way to address this issue might be to simply provide additional multipliers above and beyond 650 acres (>1,000 acres, >2,000 acres, >5,000 acres, etc.). There may well be increased productivity benefits in patches of this size and, if this is the case, then intuitively (at least initially) it makes sense to provide additional value for these larger landscapes. However, in considering this matter in light of the debiting process, it occurred to us that, for a given acreage of adverse impact, there may actually be a relatively greater detrimental impact to the species in a small landscape as compared to a large landscape. For example, if 100 acres of a 250-acre patch of warbler habitat are adversely impacted by a fire, then the entire patch may be negatively affected in terms of overall productivity. In contrast, if 100 acres of a 2,500-acre patch of GCWA habitat are adversely impacted by a fire, then impacts on the overall productivity of the patch are likely to be relatively smaller. If this is the case, then it may not make sense to attribute a greater “negative” (i.e., debit) value to a 100-acre impact area within the 2,500-acre patch as compared to a 100-acre area within a 250-acre patch.

A Potential Solution

All of the on-the-ground issues that we have encountered (with the possible exception of the landscape size issue) can potentially be resolved by using the range-wide landscape prioritization process described earlier. This approach could potentially eliminate the screening process altogether: warbler landscapes would be pre-screened for participation. It would also simplify the credit calculation process to number of conservation units and associated multiplier for number of units. All of the other ranking criteria (landscape size, proximity to known populations, recovery region) could be incorporated into the prioritization process.

We believe that the tools and expertise to accomplish a scientifically-supported prioritization of warbler landscapes across the breeding range are currently available. Many, if not most states routinely bring together species and habitat experts to review the status of species and habitats of concern and to assess the priority and conservation status of associated landscapes. This approach builds consensus on conservation priorities and maximizes the efficiency and effectiveness of conservation actions by multiple partners.

Habitat Management Practices

We suggest that the practice of planting deciduous trees (e.g., Spanish oak) be included as a management practice that is available to participating landowners. While landowners do not typically clear warbler habitat on steep slopes, there is evidence at some sites of historical clearing of shallow to moderate slopes to facilitate grazing. Some of these areas are of vital importance for the expansion and linkage of warbler habitat patches. We currently have the ability to prescribe these areas as “no-clearing” areas; however, this is a benign-neglect approach that leads, at least initially, to establishment of cedar-breaks. A more active and more effective means of habitat creation would include actual planting and protection of desirable deciduous trees.