New York State

DEC

# Appendix 4

## Application Form for
## Permit to Drill, Deepen, Plug Back or Convert
## A Well Subject to the Oil, Gas and Solution
## Mining Regulatory Program

Revised Draft
Supplemental Generic Environmental Impact Statement

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NEW YORK STATE DEPARTMENT OF ENVIRONMENTAL CONSERVATION
DIVISION OF MINERAL RESOURCES

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# APPLICATION FOR PERMIT TO DRILL, DEEPEN, PLUG BACK OR CONVERT A WELL SUBJECT TO THE OIL, GAS AND SOLUTION MINING LAW

THIS APPLICATION IS A LEGAL DOCUMENT. READ THE APPLICABLE AFFIRMATION AND ACKNOWLEDGMENT CAREFULLY BEFORE SIGNING.
For instructions on completing this form, visit the Division's website at www.dec.ny.gov/energy/205.html or contact your local Regional office.

PLANNED OPERATION: (Check one)
☐ Drill ☐ Deepen ☐ Plug Back ☐ Convert

TYPE OF WELL: (Check one)
☐ New ☐ Existing

**Existing API Well Identification Number**
31- | | | - | | | | | - | | | - | | |

TYPE OF WELL BORE: (Check one)
☐ Vertical ☐ Directional ☐ Horizontal

| NAME OF OWNER (Full Name of Organization or Individual as registered with the Division) | TELEPHONE NUMBER (include area code) |
|---|---|
| ADDRESS (P.O. Box or Street Address, City, State, Zip Code) | |
| NAME AND TITLE OF LOCAL REPRESENTATIVE WHO CAN BE CONTACTED WHILE OPERATIONS ARE IN PROGRESS | |
| ADDRESS–Business (P.O. Box or Street Address, City, State, Zip Code) | TELEPHONE NUMBER (include area code) |
| ADDRESS–Night, Weekend and Holiday (P.O. Box or Street Address, City, State, Zip Code) | TELEPHONE NUMBER (include area code) |

**WELL LOCATION DATA (attach plat)**

| COUNTY | TOWN | FIELD/POOL NAME (or "Wildcat") |
|---|---|---|

| WELL NAME | WELL NUMBER | NUMBER OF ACRES IN UNIT |
|---|---|---|

| 7½ MINUTE QUAD NAME | QUAD SECTION | PROPOSED TARGET FORMATION |
|---|---|---|

LOCATION DESCRIPTION

| | TVD | TMD | Decimal Latitude (NAD83) | Decimal Longitude (NAD83) |
|---|---|---|---|---|
| Surface | 0' | 0 | __.______ | __.______ |
| Top of Target Interval | | | __.______ | __.______ |
| Bottom of Target Interval | | | __.______ | __.______ |
| Bottom Hole | | | __.______ | __.______ |

**PROPOSED WELL DATA**

WELL TYPE (check one)
☐ Oil Production ☐ Gas Production ☐ Brine ☐ Storage
☐ Injection ☐ Brine Disposal ☐ Geothermal ☐ Stratigraphic
☐ Other ______

PLANNED TOTAL DEPTH
TVD ______ ft.
TMD ______ ft.
Kickoff ______ TMD

PLANNED DATE OF COMMENCEMENT OF OPERATIONS

SURFACE ELEVATION (check how obtained)
______ ft. ☐ Surveyed ☐ Topo Map ☐ Other ______

TYPE TOOLS
☐ Cable ☐ Rotary

PLANNED DRILLING FLUID
☐ Air ☐ Water ☐ Mud

| NAME OF PLANNED DRILLING CONTRACTOR (as registered with the Division) | TELEPHONE NUMBER (include area code) |
|---|---|

ON ATTACHED SHEET GIVE DETAILS FOR EACH PROPOSED CASING STRING AND CEMENT JOB INCLUDING BUT NOT LIMITED TO: Bit size, casing size, casing weight and grade, TVD and TMD of casing set, scratchers, centralizers, cement baskets, sacks of cement, class of cement, cement additives with percentages or pounds per sack, estimated TVD and TMD of the top of cement, estimated amount of excess cement and waiting-on-cement time.

FOR DIRECTIONAL OR SIDETRACK WELLS ALSO INCLUDE A WELL BORE DIAGRAM SHOWING THE LOCATION OF THE ITEMS INCLUDED IN THE ABOVE REFERENCED DETAILS.

**DEPARTMENT USE ONLY**

BOND NUMBER

API WELL IDENTIFICATION NUMBER
31-

RECEIPT NUMBER

DATE ISSUED

# APPLICATION FOR PERMIT TO DRILL, DEEPEN, PLUG BACK OR CONVERT



| WELL NAME | WELL NUMBER | NAME OF OWNER |
|---|---|---|
| | | |

COMMENTS:

## AFFIRMATION AND ACKNOWLEDGMENT

### A. For use by individual:

By the act of signing this application:

(1) I affirm under penalty that the information provided in this application is true to the best of my knowledge and belief; and that I possess the right to access property, and drill and/or extract oil, gas, or salt, by deed or lease, from the lands and site described in the well location data section of this application. I am aware that any false statement made in this application is punishable as a Class A Misdemeanor under Section 210.45 of the Penal Law.

(2) I acknowledge that if the permit requested to be issued in consideration of the information and affirmations contained in this application is issued, as a condition to the issuance of that permit, I accept full legal responsibility for all damage, direct or indirect, of whatever nature and by whomever suffered, arising out of the activity conducted under authority of that permit; and agree to indemnify and hold harmless the State, its representatives, employees, agents, and assigns for all claims, suits, actions, damages, and costs of every name and description, arising out of or resulting from the permittee's undertaking of activities or operation and maintenance of the facility or facilities authorized by the permit in compliance or non-compliance with the terms and conditions of the permit.

______________________________
Printed or Typed Name of Individual

______________________________ ______________
Signature of Individual Date

### B. For use by organizations other than an individual:

By the act of signing this application:

(1) I affirm under penalty of perjury that I am ______________________________ (title) of ______________________________ (organization); that I am authorized by that organization to make this application; that this application was prepared by me or under my supervision and direction; and that the aforenamed organization possesses the right to access property, and drill and/or extract oil, gas, or salt by deed or lease, from the lands and site described in the well location data section of this application. I am aware that any false statement made in this application is punishable as a Class A Misdemeanor under Section 210.45 of the Penal Law.

(2) ______________________________ (organization); acknowledges that if the permit requested to be issued in consideration of the information and affirmations contained in this application is issued, as a condition to the issuance of that permit, it accepts full legal responsibility for all damage, direct or indirect, of whatever nature and by whomever suffered, arising out of the activity conducted under authority of that permit; and agrees to indemnify and hold harmless the State, its representatives, employees, agents, and assigns for all claims, from suits, actions, damages, and costs of every name and description, arising out of or resulting from the permittee's undertaking of activities or operation and maintenance of the facility or facilities authorized by the permit in compliance or non-compliance with the terms and conditions of the permit.

______________________________
Printed or Typed Name of Authorized Representative

______________________________ ______________
Signature of Authorized Representative Date

New York State

DEC

# Appendix 5

## Environmental Assessment Form (EAF)
## For Well Permitting

Revised Draft
Supplemental Generic Environmental Impact Statement

85-16-5 (1/07)--10b

NEW YORK STATE DEPARTMENT OF ENVIRONMENTAL CONSERVATION
DIVISION OF MINERAL RESOURCES

# ENVIRONMENTAL ASSESSMENT FORM

Attachment to Drilling Permit Application

WELL NAME AND NUMBER

NAME OF APPLICANT | BUSINESS TELEPHONE NUMBER ( )

ADDRESS OF APPLICANT

CITY/P.O. | STATE | ZIP CODE

DESCRIPTION OF PROJECT (Briefly describe type of project or action)

**PROJECT SITE IS THE WELL SITE AND SURROUNDING AREA WHICH WILL BE DISTURBED DURING CONSTRUCTION OF SITE, ACCESS ROAD, and PIT AND ACTIVITIES DURING DRILLING AND COMPLETION AT WELLHEAD.**

(PLEASE COMPLETE EACH QUESTION--Indicate N.A., if not applicable)

LAND USE AND PROJECT SITE

1. Project Dimensions. Total Area of Project Site ____________ sq. ft.
   Approximate square footage for items below:

| | | During Construction (sq. ft.) | After Construction (sq. ft.) |
|---|---|---|---|
| a. Access Road | (length x width) | ____________ | ____________ |
| b. Well Site | (length x width) | ____________ | ____________ |

2. Characterize Project Site Vegetation and Estimate Percentage of Each Type Before Construction:

   ______ % Agricultural (cropland, hayland, pasture, vineyard, etc.) ______ % Forested ______ % Wetlands

   ______ % Meadow or Brushland (non agricultural) ______ % Non vegetated (rock, soil, fill)

3. Present Land Use(s) Within ¼ Mile of Project (Check all that apply)

   ☐ Rural ☐ Suburban ☐ Forest ☐ Urban ☐ Agricultural ☐ Commercial ☐ Park/Recreation
   ☐ Industrial ☐ Other ____________

4. How close is the nearest residence, building, or outdoor facility of any type routinely occupied by people at least part of the day? ____________ ft.

   Describe ____________

ENVIRONMENTAL RESOURCES ON/NEAR PROJECT SITE

5. The presence of certain environmental resources on or near the project site may require additional permits, approvals or mitigation measures--Is any part of the well site or access road located:

| | | | |
|---|---|---|---|
| a. Over a primary or principal aquifer? | ☐ Yes | ☐ No | ☐ Not Known |
| b. Within 2,640 feet of a public water supply well? | ☐ Yes | ☐ No | ☐ Not Known |
| c. Within 150 feet of a surface municipal water supply? | ☐ Yes | ☐ No | ☐ Not Known |
| d. Within 150 feet of a lake, stream, or other public surface water body? | ☐ Yes | ☐ No | ☐ Not Known |
| e. Within an Agricultural District? | ☐ Yes | ☐ No | ☐ Not Known |
| f. Within a land parcel having a Soil and Water Conservation Plan? | ☐ Yes | ☐ No | ☐ Not Known |
| g. In a 100 year flood plain? | ☐ Yes | ☐ No | ☐ Not Known |
| h. In a regulated wetland or its 100 foot buffer zone? | ☐ Yes | ☐ No | ☐ Not Known |
| i. In a coastal zone management area? | ☐ Yes | ☐ No | ☐ Not Known |
| j. In a Critical Environmental Area? | ☐ Yes | ☐ No | ☐ Not Known |
| k. Does the project site contain any species of animal life that are listed as threatened or endangered? | ☐ Yes | ☐ No | ☐ Not Known |

   If yes, identify the species and source of information ____________

| | | | |
|---|---|---|---|
| l. Will proposed project significantly impact visual resources of statewide significance? | ☐ Yes | ☐ No | ☐ Not Known |

   If yes, identify the visual resource and source of information ____________

CULTURAL RESOURCES

6. Are there any known archeological and/or historical resources which will be affected by drilling operations? ☐ Yes ☐ No ☐ Not Known

7. Has the land within the project area been previously disturbed or altered (excavated, landscaped, filled, utilities installed)? ☐ Yes ☐ No ☐ Not Known

If answer to Number 6 or 7 is yes, briefly descrbe ________________________________

________________________________

EROSION AND RECLAMATION PLANS

8. Indicate percentage of project site within: 0-10% slope ______ % 10-15% slope ______ % greater than 15% slope ______ %

9. Are erosion control measures needed during construction of the access road and well site? ☐ Yes ☐ No ☐ Not Known

If yes, describe and/or sketch on attached photocopy of plat ________________________________

________________________________

________________________________

10. Will the topsoil which is disturbed be stockpiled for reclamation use? ☐ Yes ☐ No

11. Does the reclamation plan include revegetation? ☐ Yes ☐ No

If yes, what plant materials will be used? ________________________________

________________________________

12. Does the reclamation plan include restoration or installation of surface or subsurface drainage features to prevent erosion or conform to a Soil and Water Conservation Plan? ☐ Yes ☐ No

If yes, describe ________________________________

________________________________

ACCESS ROAD SITING AND CONSTRUCTION

13. Are you going to use existing or common corridors when building the access road? ☐ Yes ☐ No

Locate access road on attached photocopy of plat.

DRILLING

14. Anticipated length of drilling operations? ________ days.

WASTE STORAGE AND DISPOSAL

15. How will drilling fluids and stimulation fluids:

a. Be contained? ________________________________

b. Be disposed of? ________________________________

16. Will production brine be stored on site? ☐ Yes ☐ No

If yes:
How will it be stored? ________________________________

How will it be disposed of? ________________________________

17. Will the drill cuttings and pit liner be disposed of on site? ☐ Yes ☐ No

If yes, expected burial depth? ____________ feet

ADDITIONAL PERMITS

18. Are any additional State, Local or Federal permits or approvals required for this project? ☐ Yes ☐ No

| | Date Application Submitted | Date Application Received |
|---|---|---|
| Stream Disturbance Permit (DEC) | | |
| Wetlands Permit (DEC or Local) | | |
| Floodplain Permit (DEC or Local) | | |
| Other ________________ | | |
| ________________ | | |
| ________________ | | |
| ________________ | | |

| | |
|---|---|
| PREPARER'S SIGNATURE | DATE |
| NAME/TITLE (Please print) | |
| REPRESENTING | |

## Suggested Sources of Information for Division of Mineral Resources Environmental Assessment Form

3. LAND USE

Sources: Local Planning Office
Town Supervisor's Office
Town Clerk's Office

5a. PRIMARY OR PRINCIPAL AQUIFER

Sources: Local unit of government
NYS Department of Health
NYSDEC, Division of Water--Regional Office
*Availability of Water from Aquifers in New York State*--United States Geological Survey
*Availability of Water from Unconsolidated Deposits in Upstate New York*--United States Geological Survey

5b. PUBLIC WATER SUPPLY

Sources: Local unit of government
NYS Department of Health
*NYS Atlas of Community Water Systems Sources,* NYS Department of Health, 1982
*Atlas of Eleven Selected Aquifers in New York State,* United States Geological Survey, 1982

5c. AGRICULTURAL DISTRICT INFORMATION

Sources: Cooperative Extension
DEC, Division of Lands and Forests
NYS Department of Agriculture and Markets
DEC, Division of Environmental Permits--Regional Office
DEC, Division of Mineral Resources--Regional Office

5f. SOIL AND WATER CONSERVATION PLAN

Sources: Landowner
County Soil and Water Conservation District Office

5g. 100 YEAR FLOOD PLAIN

Sources: DEC Division of Water
DEC, Division of Environmental Permits--Regional Office
DEC, Division of Mineral Resources--Regional Office

5h. WETLANDS

Sources: DEC, Division of Fish and Wildlife--Regional Office
DEC, Division of Mineral Resources--Regional Office

5i. COASTAL ZONE MANAGEMENT AREAS

Sources: Local unit of government
NYS Department of State, Coastal Management Program
DEC, Division of Water (maps)
DEC, Division of Environmental Permits--Regional Office

5k. THREATENED OR ENDANGERED SPECIES

Sources: DEC, Natural Heritage Program--Albany
DEC, Division of Environmental Permits--Regional Office

6. ARCHEOLOGICAL OR HISTORIC RESOURCES

Sources: NYS Office of Parks, Recreation and Historic Preservation circles and squares map
DEC, Division of Environmental Permits--Regional Office

18. ADDITIONAL PERMITS NEEDED

Sources: DEC, Division of Environmental Permits--Regional Office
DEC, Division of Mineral Resources--Regional Office
NYS Office of Business Permits

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New York State

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# Appendix 6

## PROPOSED
## Environmental Assessment Form
## Addendum

Updated August 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

PROPOSED EAF ADDENDUM REQUIREMENTS
FOR HIGH-VOLUME HYDRAULIC FRACTURING

**REQUIRED INFORMATION**

- Minimum depth and elevation of top of objective formation or zone for entire length of wellbore
- Estimated maximum depth and elevation of bottom of potential fresh water, and basis for estimate (water well information, other well information, previous drilling at pad, published or private reports, etc.)
- Identification of proposed fracturing service company and additive products, by product name and purpose/type
    - Documentation of the applicant's evaluation of available alternatives for the proposed additive products that are efficacious but which exhibit reduced aquatic toxicity and pose less risk to water resources and the environment
- Proposed volume of water and each additive product to be used in hydraulic fracturing
- Proposed % by weight of water, proppants and each additive
- Water source for hydraulic fracturing
    - If a newly proposed surface water source (not previously approved by the Department as part of a well permit application):
        - Type of withdrawal (stream, lake, pond, groundwater, etc.)
        - Location of water withdrawal point, status of RBC approval if applicable
        - List and location of all private water wells within 500 feet of the proposed water withdrawal point
        - For proposed withdrawals from lakes and ponds:
            - Estimates of the maximum change in storage resulting from the proposed withdrawals, including estimates of inflow into the water body, precipitation onto water surface, existing and proposed water withdrawals, evaporation from water surface, and releases from water body
        - For proposed groundwater withdrawals:
            - Identification of and shortest distance to any wetland within 500 feet of the proposed withdrawal point
            - Results of pump testing as referenced in the SGEIS, including evaluation of any potential influence on wetland(s) within 500 feet
        - Indicate if an Article 15 permit is required and status
        - Size of drainage area above withdrawal point (in $mi^2$)
        - Indicate whether there is a USGS gage on the stream; if yes:
            - Distance to stream gage
            - Upstream or downstream of stream gage
            - Changes in stream flow (e.g., other withdrawals, diversions, tributary input) between gage and withdrawal point
            - Years of stream gage data available and period of record
    - If a previously proposed or Department-approved surface water source:
        - API # of well permit application associated with previous proposal or approval

- Scaled distance from surface location of well and closest edge of well pad to:
  - Any known water supply reservoir, river or stream intake, water well or domestic-supply spring within 2,640 feet, including public or private wells, community or non-community systems
  - Any primary or principal aquifer boundary, perennial or intermittent stream, wetland, storm drain, lake or pond within 660 feet
  - All residences, occupied structures or places of assembly within 1,320 feet
- Capacity of rig fueling tank(s) and distance to:
  - Any public or private water well, domestic-supply spring, reservoir, perennial or intermittent stream, storm drain, wetland, lake or pond within 500 feet of the planned location(s) of the fueling tank(s)
- Available information about water wells and domestic-supply springs within 2,640 feet
  - Well name and location
  - Distance from proposed surface location of well
  - Shortest distance from proposed well pad
  - Shortest distance from proposed centralized flowback water impoundment
  - Well depth
  - Well's completed interval
  - Public or private supply
  - Community or non-community system (see NYSDOH definitions)
  - Type of facility or establishment if not a residence
- Identification of any well listed in Department's Oil & Gas Database, or any other abandoned well identified by property owners or tenants, within the spacing unit of the proposed well and/or within 1 mile (5,280 feet) of the proposed well location. For each well identified, provide the following information:
  - Well name and API Number
  - Distance from proposed surface location of well to surface location of existing well
  - Well Type
  - Well Status
  - Well Orientation
  - Quantity and type of any freshwater, brine, oil or gas encountered during drilling, as recorded on the Department's Well Drilling and Completion Report
- Information about the planned construction and capacity of the reserve pit, if any, and an indication of the timing of the use of a closed-loop tank system (e.g., surface, intermediate and/or production hole)
- Information about the number and individual and total capacity of receiving tanks for flowback water
- If proposed flowback vent/flare stack height is less than 30 feet, then documentation that previous drilling at the pad did not encounter $H_2S$ is required
- Description of planned public access restrictions, including physical barriers and distance to edge of well pad
- Identify the EPA Tiers of the drilling and hydraulic fracturing engines used, if these use gasoline or diesel fuel. If particulate traps or Selective Catalytic Reduction (SCR) are not used, provide a description of other control measures planned to reduce particulate matter and $NO_x$ emissions during the drilling and hydraulic fracturing processes

- If condensate tanks are to be used, provide their capacity and the vapor recovery system to be used
- If a wellhead compressor is used, provide its size in horsepower. Describe the control equipment used for $NO_x$
- If a glycol dehydrator is to be used at the well pad, provide its stack height and the capacity of glycol to be used on an annual basis
- Information on the status of a sales line and interconnecting gathering line to the well or multi-well pad (i.e., is there currently a line in place or is one expected to be in place prior to conducting hydraulic fracturing operations to facilitate a Reduced Emissions Completion [REC])
    - If REC will not be used, the following must be provided
        - an estimate of how much total gas (MMcf) will be vented and flared during flowback
        - an estimate of how much total gas (MMcf) was previously vented and flared during flowback on the same well pad in the previous 12 months
- Well information with respect to local planning documents
    - Identify whether the location of the well pad, or any other activity under the jurisdiction of the Department, conflicts with local land use laws or regulations, plans or policies
    - Identify whether the well pad is located in an area where the affected community has adopted a comprehensive plan or other local land use plan and whether the proposed action is inconsistent with such plan(s)

**REQUIRED ATTACHMENTS**

- Scaled, stamped well plat showing the following:
    - Plan view of wellbore including surface and bottom-hole locations
    - Well pad close-up showing placement of fueling tank(s), reserve pit and receiving tanks for flowback water
    - Vertical section of wellbore showing the land surface elevation and wellbore elevation with an indication of the minimum depth of the wellbore within the objective formation or zone as required above
- A Material Safety Data Sheet (MSDS) for each additive product proposed for use in hydraulic fracturing, if not already on file with the Department
- Topographic map of area within at least 2,640 feet of surface location showing:
    - above features and scaled distances
    - location and orientation of well pad
    - location of access road
    - location of any flowback water pipelines or conveyances
- Evidence of diligent efforts by the well operator to determine the existence of public or private water wells and domestic-supply springs within one half-mile (2,640 feet) of any proposed drilling location or centralized flowback water impoundment if proposed
    - List of municipal officials contacted for water well information and printed copies of responses
    - List of property owners and tenants contacted for water well information
    - List of adjacent lessees contacted for water well information

- Printed results of EPA SDWIS search (http://oaspub.epa.gov/enviro/sdw_form_v2.create_page?state_abbr=NY)
- Printed results of Department Water Well search (http://www.dec.ny.gov/cfmx/extapps/WaterWell/index.cfm?view=searchByCounty)

- Evidence of diligent efforts by the well operator to determine the existence and condition of abandoned wells within the proposed spacing unit and/or within one mile of the proposed well location
  - Printed results of Department Oil & Gas database search
  - List of property owners and tenants contacted for abandoned well information
- For a newly proposed water withdrawal, topographic map showing:
  - The location of the proposed withdrawal
  - All private water wells within 500 feet of the proposed water withdrawal point
  - For proposed surface water withdrawals:
    - Drainage area above the withdrawal point
  - For proposed groundwater withdrawals:
    - Identification of and shortest distance to any Department-regulated wetland within 500 feet of the proposed withdrawal point
- Invasive Species Management Plan that includes:
  - Survey of the entire well site, documenting the presence, location, and identity of any invasive plant species;
  - Specific protocols or best management practices for preventing the spread or introduction of invasive species at the site;
  - Specific protocols for the restoration of native plant cover on the site; and
  - Identification of any Certified Pesticide Applicator, if applicable.
- A Partial Site Reclamation Plan that describes the methods for partially reclaiming the site after well completion. Partial reclamation shall be compatible with sound environmental management practices and minimize negative environmental impacts.
- A description of methods for final reclamation of the well site following plugging of all the wells on the well pad. Reclamation methods shall be compatible with sound environmental management practices and minimize negative environmental impacts from the well pad.
- Proposed fluid disposal plan, pursuant to 6 NYCRR 554.1(c)(1)
  - Planned transport of flowback water and production brine off of well pad – trucking or piping
    - If piping, describe construction including size, materials, leak prevention and spill control measures
  - Planned disposition of flowback water and production brine – treatment facility, disposal well, reuse on same well pad, reuse on another well pad, centralized flowback surface water impoundment, centralized tank facility, or other (describe)
    - If a treatment facility in NY:
      - Name, owner/operator, location
      - SPDES permit # and date if applicable
      - If a POTW, date of Department approval to receive flowback water (attach a copy of approval notification)
      - Brief description of facility and treatment if not a POTW

        - If a disposal well in NY:
            - SPDES permit # and date
            - EPA UIC permit # and date
        - If a centralized tank facility in New York:
            - Location, affirmation of ownership or permission
            - Certification of compliance with 360-6.3
- Proposed cuttings disposal plan for any drilling requiring cuttings to be disposed of off-site including at a landfill.
    - Planned disposition of cuttings – landfill or other (describe)
        - If a landfill in NY:
            - Name, owner/operator, location
            - Part 360 permit # and date if applicable
- Proposed blow-out preventer (BOP) use and test plan for all drilling and completion operations including:
    - Pressure rating of any:
        - Annular preventer
        - Rams including a description of type and number of rams
        - Choke manifold and connecting line (from BOP to choke manifold)
    - Timing and frequency of testing and/or visual inspection of BOP and related equipment including any scheduled retesting of equipment. Test pressure(s) and duration of test(s) including an explanation as to how the test pressure was determined
    - Test pressure(s) and timing for any internal pressure testing of surface, intermediate and production casing strings, and duration of test including an explanation as to how the test pressure was determined
    - Test pressure (psi/ft) and anticipated depth (TVD-ft) of any surface and/or intermediate casing seat integrity tests
        - If a casing seat integrity test will not be conducted on a casing string with a BOP installed on it, an explanation must be provided why such a test is not required and how any flow will be managed
    - System for recording, documenting and retaining the results of all pressure tests and inspections, and making such available to the Department
    - Copy of the operator's well control barrier policythat identifies acceptable barriers to be used during identified operations
    - Minimum distance from well for remote actuator (powered by a source other than rig hydraulics)
- Transportation plan developed by a NYS-licensed Professional Engineer, that specifies proposed routes and includes a road condition assessment.
- Noise mitigation plan, including any proposed mitigation measures for any occupied structure within 1,000 feet.
- If a new well pad is proposed in a Forest or Grassland Focus Area and involves disturbance in a contiguous forest patch of 150 acres or more in size or a contiguous grassland patch of 30 acres or more in size, then the Applicant should not submit this EAF or a well permit application prior to conducting a site-specific ecological assessment in accordance with a

detailed study plan that has been approved by the Department. The need and plan for an ecological assessment should be determined in consultation with the Department and will consider information such as existing site conditions, existing covertype and ongoing and historical land management activities. The completed ecological assessment must be attached to this EAF and must include, at a minimum:

- a compilation of historical information on use of the area by forest interior birds or grassland birds;
- results of pre-disturbance biological studies, including a minimum of one year of field surveys at the site to determine the current extent, if any, of use of the site by forest interior birds or grassland birds;
- an evaluation of potential impacts on forest interior or grassland birds from the project;
- additional mitigation measures proposed by the applicant; and
- protocols for monitoring of forest interior or grassland birds during the construction phase of the project and for a minimum of two years following well completion.

**REQUIRED AFFIRMATIONS**

- Any surface water withdrawal associated with this well pad will only occur when flow is above the appropriate threshold as described in the SGEIS
- Applicable FIRM and Flood Boundary and Floodway maps consulted, and proposed well pad and access road are not within a mapped100-year floodplain
- Baseline residential well sampling, analysis and ongoing monitoring will be conducted and results shared with property owner as described in SGEIS and permit conditions
- Unless otherwise required by private lease agreement, the access road will be located as far as practical from occupied structures, places of assembly and unleased property
- HVHF GP authorization for stormwater discharges will be obtained prior to site disturbance
- Operator will prepare and adhere to the following site plans, which will be available to the Department upon request and available on-site to Department inspector while activities addressed by the plan are occurring:
    - a visual impacts mitigation plan consistent with the SGEIS
    - a noise impacts mitigation plan consistent with the SGEIS
    - a greenhouse gas impacts mitigation plan consistent with the SGEIS
    - an invasive species mitigation plan which includes:
        - -the best management practices listed in the SGEIS and
        - seasonally appropriate site-specific and species-specific physical and chemical control methods (e.g., digging to remove all roots, cutting to the ground, applying herbicides to specific plant parts such as stems or foliage, etc.) based on the invasive species survey submitted with the EAF Addendum
    - an acid rock drainage (ARD) mitigation plan consistent with the SGEIS for on-site burial of Marcellus Shale cuttings from horizontal drilling in the Marcellus Shale if the operator elects to bury these cuttings
- Operator will utilize alternative hydraulic fracturing additive products that exhibit reduced aquatic toxicity and pose less risk to water resources and the environment, unless demonstrated to DMN's satisfaction that they are not equally effective or feasible

- Operator will prepare and adhere to an emergency response plan (ERP) consistent with the SGEIS that will be available on-site during any operation from well spud (i.e., first instance of driving pipe or drilling) through well completion. -A list of emergency contact numbers for the area in which the well site is located must be included in the ERP and the list must be prominently displayed at the well site during operations conducted under this permit
- Operator will adhere to all well permit conditions and approved plans, including requirement for Department approval prior to making any change
- Operator will adhere to best management practices for reducing direct impacts to terrestrial habitats and wildlife consistent with the SGEIS (see Section 7.4.1.1)

**ADDITIONAL SUBMISSION REQUIRED PRIOR TO SITE DISTURBANCE**
- Copy of any road use agreement between the operator and local municipality

**ADDITIONAL SUBMISSION REQUIRED AT LEAST 48 HOURS PRIOR TO WELL SPUD**
- Copy of the ERP in electronic form

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New York State

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# Appendix 7

## Sample Drilling Rig Specifications

Provided by Chesapeake Energy

Revised Draft
Supplemental Generic Environmental Impact Statement

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## ATTACHMENT A
## RIG SPECIFICATIONS
## Example #1

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## National Cabot 900
## Working Depth: 12,000'

| | |
|---|---|
| **DRAWWORKS:** | National Model 2346 – Mechanical – Grooved for 1 1/8'' drilling line.<br>Air operated, water cooled Eaton Assist Brake |
| **ENGINES:** | 2 - Cat C-15 (475HP ea.) with Allison Transmissions |
| **MAST:** | NOV - 117' - 350,000 SHL on 8 lines |
| **SUBSTRUCTURE:** | NOV - 18' Floor Height /15' Working Height |
| **TRAVELING EQUIPMENT:** | IDECO UTB – 265 Ton Block and Hook |
| **ROTARY TABLE:** | 27 ½'' with 440,000# capacity |
| **TUBULARS:** | 12,000' - S-135 - 4 1/2''x 16.60# per foot w/ XH connections<br>18 - 6 ½'' collars with NC46 connections |
| **MUD PUMPS:** | 2 – National 9-P-100 with Cat 3508 Mechanicals (935HP ea.) |
| **MUD SYSTEM:** | 3 - Tank, 900 BBL total |
| **SOLIDS CONTROL EQUIPMENT:** | Shakers: 2 – NOV D285P-LP<br>Desander: Brandt - 2 - 10" Cones<br>Desilter: Brandt - 12 - 4" Cones<br>Agitators: 6 – Brandt with 36'' Impellers |
| **BOP EQUIPMENT:** | 1 - Shaffer LXT - 11" 5M - Double Ram<br>1 – Shaffer Spherical - 11" 5M - Annular |
| **CLOSING UNIT:** | Koomey - 6 Station - 160 Gallon; 3000 psi |
| **CHOKE MANIFOLD:** | 3'' x 4'' - 5M, 1 Hydraulic Choke and 1 Manual Choke |
| **GENERATORS:** | 2 - Caterpillar 545 kW, Powered by 2 Cat C-18's |
| **AUXILARY EQUIPMENT:** | Water Tank: 400 BBL<br>Fuel Tank: 10,000 Gallons |
| **SPECIAL TOOLS:** | 2 - Braden PD12C Hydraulic Hoist<br>Hydraulic Pipe Spinner<br>Oil Works OWI-1000 Wire line with 12,000' of wire |

# Rig Specifications
# Example #2

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## 610 Mechanical 750 HP
## Working Depth: 14,000'

| | |
|---|---|
| **DRAWWORKS:** | National 610 Mechanical<br>Wichita 325 Air Brake |
| **ENGINES:** | 2 – Caterpillar C-18's, 600 HP Each |
| **MAST:** | Dreco 142' 550,000 SHL on 10 Lines |
| **SUBSTRUCTURE:** | Dreco 20' Box on Box |
| **TRAVELING EQUIPMENT:** | Block-Hook: Ideco UTB-265-5-36 |
| **ROTARY TABLE:** | National C-275 |
| **COMPOUND:** | National 2 Engines |
| **TORQUE CONVERTERS:** | 2 – National C195 |
| **MUD PUMPS:** | 2 – National 9-P-100, Independent Drive Cummins QSK38, 920 HP |
| **MUD SYSTEM:** | 2 – Tank, 750 BBL total w/100 BBL Premix |
| **SOLIDS CONTROL EQUIPMENT:** | Shakers: 2 – National Model DLMS-285P<br>Desander: National with 2 - 10" Cones<br>Desilter: National with 16 - 4" Cones |
| **BOP EQUIPMENT:** | 1 – Shaffer LWS Type 11" 5M<br>1 – Shaffer Spherical Type 11: 5M |
| **CLOSING UNIT:** | Koomey 6 Station 180 Gallon; 1 Air and 1 Electrical Pump |
| **CHOKE MANIFOLD:** | 4'' x 3'' 5M, 2 Adjustable Chokes |
| **GENERATORS:** | 2 – Cat 545 kW, Powered by 2 Cat C-18's |
| **AUXILARY EQUIPMENT:** | Water Tank: 500 BBL<br>Fuel Tank: 12,000 Gallons |
| **SPECIAL TOOLS:** | ST-80 Iron Roughneck<br>Pipe Spinner: Hydraulic<br>Auto Driller: Satellite<br>Totco EDR (Rental)<br>Separator/Trip Tank Combo (Rental)<br>Hoists: 1 – Thern 2.5A Air Hoist<br>1 - Braden PD12C Hydraulic Hoist |

# Rig Specifications
# Example #3

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## SpeedStar 185K -- 515 HP
## Working Depth:  8,000’

**ENGINE:** 1 – Caterpillar C-15 with Allison Transmission

**MAST:** SpeedStar – 61’ – 185,000 LB SHL
Setback Capacity of 7,000’ – 3.5” Drill Pipe

**SUBSTRUCTURE:** Box Type – 7’6” Working Height

**MUD PUMP:** 1 – MP5

**MUD SYSTEM:** 2 – Tank, 600 BBL

**BOP EQUIPMENT:** 11” x 3M Annular

**CLOSING UNIT:** Townsend 4 Station, 80 Gallon

**CHOKE MANIFOLD:** 3’’ x 3’’ 5K with 1 Hydraulic Choke

**GENERATORS:** 2 – Onan 320 kW with Cummins Engines

**DRILL PIPE:** 7,500’ OF 3.5” 13.30 LB/FT with IF Connections

**DRILL COLLARS:** 12 – 6 ½”

**AIR SYSTEM:** 3 – Ingersoll Rand 1170/350 Air Compressors
2 – Single Stage Boosters

**AUXILARY EQUIPMENT:** Water Tank:  250 BBL
Fuel Tank:    3,500 Gallons

**SPECIAL TOOLS:** 2 – Braden PD12C Hydraulic Tub Winches
Myers 35GPM Soap Pump
Martin Decker Geolograph
Wireline Unit with 10,000’ of Line

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# Appendix 8

## Casing & Cementing Practices Required for All Wells in NY

Revised Draft
Supplemental Generic Environmental Impact Statement

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New York State Department of Environmental Conservation
Casing and Cementing Practices

## SURFACE CASING

1. The diameter of the drilled surface casing hole shall be large enough to allow the running of centralizers in recommended hole sizes.

| RECOMMENDED CENTRALIZER-HOLE SIZE COMBINATIONS | | |
|---|---|---|
| **Centralizer Size Inches** | **Minimum Hole Sizes Inches** | **Minimum Clearance Inches** |
| 4-1/2 | 6-1/8 | 1-5/8 |
| 5-1/2 | 7-3/8 | 1-7/8 |
| 6-5/8 | 8-1/2 | 1-7/8 |
| 7 | 8-3/4 | 1-3/4 |
| 8-5/8 | 10-5/8 | 2 |
| 9-5/8 | 12-1/4 | 2-5/8 |
| 13-3/8 | 17-1/2 | 4-1/8 |

**NOTE:** (1) If a manufacturer's specifications call for a larger hole size than indicated in the above table, then the manufacturer's specs take precedence.

(2) Check with the appropriate regional office for sizes not listed above.

2. Surface casing shall extend at least 75 feet beyond the deepest fresh water zone encountered or 75 feet into competent rock (bedrock), whichever is deeper, unless otherwise approved by the Department. However, the surface pipe must be set deeply enough to allow the BOP stack to contain any formation pressures that may be encountered before the next casing is run.

3. Surface casing shall not extend into zones known to contain measurable quantities of shallow gas. In the event that such a zone is encountered before the fresh water is cased off, the operator shall notify the Department and, with the Department's approval, take whatever actions are necessary to protect the fresh water zone(s).

4. All surface casing shall be a string of new pipe with a mill test of at least 1,100 pounds per square inch (psi), unless otherwise approved. Used casing may be approved for use, but must be pressure tested before drilling out the casing shoe or, if there is no casing shoe, before drilling out the cement in the bottom joint of casing. If plain end pipe is welded together for use, it too must be pressure tested. The minimum pressure for testing used casing or casing joined together by welding, shall be determined by the Department at the time of permit application. The appropriate Regional Mineral Resources office staff will be notified six hours prior to making the test. The results will be entered on the drilling log.

5. Centralizers shall be spaced at least one per every 120 feet; a minimum of two centralizers shall be run on surface casing. Cement baskets shall be installed appropriately above major lost circulation zones.

6. Prior to cementing any casing strings, all gas flows shall be killed and the operator shall attempt to establish circulation by pumping the calculated volume necessary to circulate. If the hole is dry, the calculated volume would include the pipe volume and 125% of the annular volume. Circulation is deemed to have been established once fluid reaches the surface. A flush, spacer or extra cement shall be used to separate the cement from the bore hole spacer or extra cement shall be used to separate the cement from the bore hole fluids to prevent dilution. If cement returns are not present at the surface, the operator may be required to run a log to determine the top of the cement.

7. The pump and plug method shall be used to cement surface casing, unless approved otherwise by the Department. The amount of cement will be determined on a site-specific basis and a minimum of 25% excess cement shall be used, with appropriate lost circulation materials, unless other amounts of excesses are approved or specified by the Department.

8. The operator shall test or require the cementing contractor to test the mixing water for pH and temperature prior to mixing the cement and to record the results on the cementing ticket.

9. The cement slurry shall be prepared according to the manufacturer's or contractor's specifications to minimize free water content in the cement.

10. After the cement is placed and the cementing equipment is disconnected, the operator shall wait until the cement achieves a calculated compressive strength of 500 psi before the casing is disturbed in any way. The waiting-on-cement (WOC) time shall be recorded on the drilling log.

11. When drive pipe (conductor casing) is left in the ground, a pad of cement shall be placed around the well bore to block the downward migration of surface pollutants. The pad shall be three feet square or, if circular, three feet in diameter and shall be crowned up to the drive pipe (conductor casing), unless otherwise approved by the Department.

WHEN REQUESTED BY THE DEPARTMENT IN WRITING, EACH OPERATOR MUST SUBMIT CEMENT TICKETS AND/OR OTHER DOCUMENTS THAT INDICATE THE ABOVE SPECIFICATIONS HAVE BEEN FOLLOWED.

THE CASING AND CEMENTING PRACTICES ABOVE ARE DESIGNED FOR TYPICAL SURFACE CASING CEMENTING. THE DEPARTMENT WILL REQUIRE ADDITIONAL MEASURES FOR WELLS DRILLED IN ENVIRONMENTALLY OR TECHNICALLY SENSITIVE AREAS (i.e., PRIMARY OR PRINCIPAL AQUIFERS).

THE DEPARTMENT RECOGNIZES THAT VARIATIONS TO THE ABOVE PROCEDURES MAY BE INDICATED IN SITE SPECIFIC INSTANCES. SUCH VARIATIONS WILL REQUIRE THE PRIOR APPROVAL OF THE REGIONAL MINERAL RESOURCES OFFICE STAFF.

## **INTERMEDIATE CASING**

Intermediate casing string(s) and the cementing requirements for that casing string(s) will be reviewed and approved by Regional Mineral Resources office staff on an individual well basis.

## **PRODUCTION CASING**

12. The production casing cement shall extend at least 500 feet above the casing shoe or tie into the previous casing string, whichever is less. If any oil or gas shows are encountered or known to be present in the area, as determined by the Department at the time of permit application, or subsequently encountered during drilling, the production casing cement shall extend at least 100 feet above any such shows. The Department may allow the use of a weighted fluid in the annulus to prevent gas migration in specific instances when the weight of the cement column could be a problem.

13. Centralizers shall be placed at the base and at the top of the production interval if casing is run and extends through that interval, with one additional centralizer every 300 feet of the cemented interval. A minimum of 25% excess cement shall be used. When caliper logs are run, a 10% excess will suffice. Additional excesses may be required by the Department in certain areas.

14. The pump and plug method shall be used for all production casing cement jobs deeper than 1500 feet. If the pump and plug technique is not used (less than 1500 feet), the operator shall not displace the cement closer than 35 feet above the bottom of the casing. If plugs are used, the plug catcher shall be placed at the top of the

lowest (deepest) full joint of casing.

15. The casing shall be of sufficient strength to contain any expected formation or stimulation pressures.

16. Following cementing and removal of cementing equipment, the operator shall wait until a compressive strength of 500 psi is achieved before the casing is disturbed in any way. The operator shall test or require the cementing contractor to test the mixing water for pH and temperature prior to mixing the cement and to record the results on the cementing tickets and/or the drilling log. WOC time shall be adjusted based on the results of the test.

17. The annular space between the surface casing and the production string shall be vented at all times. If the annular gas is to be produced, a pressure relief valve shall be installed in an appropriate manner and set at a pressure approved by the Regional Mineral Resources office.

WHEN REQUESTED BY THE DEPARTMENT IN WRITING, EACH OPERATOR MUST SUBMIT CEMENT TICKETS AND/OR OTHER DOCUMENTS THAT INDICATE THE ABOVE SPECIFICATIONS HAVE BEEN FOLLOWED.

THE CASING AND CEMENTING PRACTICES ABOVE ARE DESIGNED FOR TYPICAL PRODUCTION CASING/ CEMENTING. THE DEPARTMENT WILL REQUIRE ADDITIONAL MEASURES FOR WELLS DRILLED IN ENVIRONMENTALLY OR TECHNICALLY SENSITIVE AREAS (i.e., PRIMARY OR PRINCIPAL AQUIFERS).

THE DEPARTMENT RECOGNIZES THAT VARIATIONS TO THE ABOVE PROCEDURES MAY BE INDICATED IN SITE SPECIFIC INSTANCES. SUCH VARIATIONS WILL REQUIRE THE PRIOR APPROVAL OF THE REGIONAL MINERAL RESOURCES OFFICE.

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# Appendix 9

# EXISTING
## Fresh Water Aquifer Supplementary Permit Conditions Required for Wells Drilled in Primary and Principal Aquifers

Revised Draft
Supplemental Generic Environmental Impact Statement

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# FRESH WATER AQUIFER SUPPLEMENTARY PERMIT CONDITIONS

Operator: Well Name:
API Number:

1. All pits must be lined and sized to fully contain all drilling, cementing and stimulation fluids plus any fluids as a result of natural precipitation. Use of these pits for any other purpose is prohibited.

2. All fluids must be contained on the site and properly disposed. If operations are suspended and the site is left unattended at any time, pit fluids must be removed from the site immediately. After the cessation of drilling and/or stimulation operations, pit fluids must be removed within 7 days. Disposal of fluids must be undertaken by a waste transporter with an approved 6 NYCRR Part 364 permit.

3. Any hole drilled for conductor or surface casing (i.e., "water string") must be drilled on air, fresh water, or fresh water mud. For any holes drilled with mud, techniques for removal of filter cake (e.g., spacers, additional cement, appropriate flow regimes) must be considered when designing any primary cement job on conductor and surface casing.

4. If conductor pipe is used, it must be run in a drilled hole and it must be cemented back to surface by circulation down the inside of the pipe and up the annulus, or installed by another procedure approved by this office. Lost circulation materials must be added to the cement to ensure satisfactory results. Additionally, at least two centralizers must be run with one each at the shoe and at the middle of the string. In the event that cement circulation is not achieved, cement must be grouted (or squeezed) down from the surface to ensure a complete cement bond. In lieu of or in combination with such grouting or squeezing from the surface, this office may require perforation of the conductor casing and squeeze cementing of perforations. This office must be notified _______ hours prior to cementing operations and cementing cannot commence until a state inspector is present.

5. A surface casing string must be set at least 100' below the deepest fresh water zone and at least 100' into bedrock. If shallow gas is known to exist or is anticipated in this bedrock interval, the casing setting depth may be adjusted based on site-specific conditions provided it is approved by this office. There must be at least a 2½" difference between the diameters of the hole and the casing (excluding couplings) or the clearance specified in the Department's Casing and Cementing Practices, whichever is greater. Cement must be circulated back to the surface with a minimum calculated 50% excess. Lost circulation materials must be added to the cement to ensure satisfactory results. Additionally, cement baskets and centralizers must be run at appropriate intervals with centralizers run at least every 120'. Pipe must be either new API graded pipe with a minimum internal yield pressure of 1,800 psi or reconditioned pipe that has been tested internally to a minimum of 2,700 psi. If reconditioned pipe is used, an affidavit that the pipe has been tested must be submitted to this office before the pipe is run. This office must be notified _______ hours prior to cementing operations and cementing cannot commence until a state inspector is present.

6. If multiple fresh water zones are known to exist or are found or if shallow gas is present, this office may require multiple strings of surface casing to prevent gas intrusion and/or preserve the hydraulic characteristics and water quality of each fresh water zone. The permittee must immediately inform this office of the occurrence of any fresh water or shallow gas zones not noted on the permittee's drilling application and prognosis. This office may require changes to the casing and cementing plan in response to unexpected occurrences of fresh water or shallow gas, and may also require the immediate, temporary cessation of operations while such alterations are developed by the permittee and evaluated by the Department for approval.

7. In the event that cement circulation is not achieved on any surface casing cement job, cement must be grouted (or squeezed) down from the surface to ensure a complete cement bond. This office must be notified _______ hours prior to cementing operations and cementing cannot commence until a state inspector is present. In lieu of or in combination with such grouting or squeezing from the surface, this office may require perforation of the surface casing and squeeze cementing of perforations. This office may also require that a cement bond log and/or other logs be run for evaluation purposes. In addition, drilling out of and below surface casing cannot commence if there is any evidence or indication of flow behind the surface casing until remedial action has occurred. Alternative remedial actions from those described above may be approved by this office on a case-by-case basis provided site-specific conditions form the basis for such proposals.

8. This office must be notified _______ hours prior to any stimulation operation. Stimulation may commence without the state inspector if the inspector is not on location at the time specified during the notification.

9. The operator must complete the "Record of Formations Penetrated" on the Well Drilling and Completion Report providing a log of formations, both unconsolidated and consolidated, and all water and gas producing zones.

10. If the well is a producer, holding tanks with water-tight diking capable of retaining 1½ times the capacity of the tank must be installed for the containment of oil, brine and other production fluids. Disposal of fluids must only be undertaken by a waste transporter with an approved 6 NYCRR Part 364 permit.

11. **Any deviation from the above conditions must be approved by the Department prior to making a change.**

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# Appendix 10

## PROPOSED
## Supplementary Permit Conditions
## For High-Volume Hydraulic Fracturing

Updated August 2011

Revised Draft
Supplemental Generic Environmental Impact Statement

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## PROPOSED Supplementary Permit Conditions for High-Volume Hydraulic Fracturing

**Note:** The operator must comply with all provisions of Attachment A and Attachment B as noted at the end of this document, along with Attachment C when applicable.

### Planning and Local Coordination

1) All operations authorized by this permit must be conducted in accordance with the following site-specific plans prepared by the operator, available to the Department upon request, and available on-site to a Department inspector while activities addressed by the plan are taking place:

   a) a visual impacts mitigation plan consistent with the SGEIS; and

   b) a greenhouse gas emissions impacts mitigation plan consistent with the SGEIS.

2) An emergency response plan (ERP) consistent with the SGEIS must be prepared by the well operator and be available on-site during any operation from well spud (i.e., first instance of driving pipe or drilling) through well completion. A list of emergency contact numbers for the area in which the well site is located must be included in the ERP and the list must be prominently displayed at the well site during operations conducted under this permit. Further, a copy of the ERP in electronic form must be provided to this office at least 3 days prior to well spud.

3) The county emergency management office (EMO) must be notified of the well's location including latitude and longitude (NAD 83) as follows:

   a) prior to spudding the well;

   b) first occurrence of flaring while drilling;

   c) prior to high-volume hydraulic fracturing, and;

   d) prior to flaring for well clean-up, treatment or testing. A flare permit from the Department is required prior to any flaring operation for well clean-up, treatment or testing.

   A record of the type, date and time of any notification provided to the EMO must be maintained by the operator and made available to the Department upon request. In counties without an EMO, the local fire department must be notified as described above.

4) The operator shall adhere to the Department-approved transportation plan which shall be incorporated by reference into this permit. In addition, issuance of this permit does not provide relief from any local requirements authorized by or enacted pursuant to the New York State Vehicle and Traffic Law. Prior to site disturbance, the operator shall submit to the Department a copy of any road use agreement between the operator and municipality.

5) Prior to site disturbance (for a new well pad) or spud (for an existing pad), the operator must sample and test residential water wells within 1,000 feet of the well pad as described by the SGEIS, and provide results to the property owner within 30 days of the operator's receipt of

laboratory results. If no residential water wells are available for sampling within 1,000 feet, either because there are none of record or because the property owner denies permission, then wells within 2,000 feet must be sampled and tested with the property owner's permission.

6) Ongoing water well monitoring and testing must continue as described by the SGEIS until one year after hydraulic fracturing at the last well on the pad. More frequent or additional monitoring and testing may be required by the Department in response to complaints or for other reasonable cause.

7) Water well analysis must be performed by an ELAP-certified laboratory. Analyses and documentation that all test results were provided to the property owner must be maintained by the operator. The results of the analyses (data) and delivery documentation must be made available to the Department and local health department upon Department request at any time during the period up to and including five years after the permitted hydrocarbon well is permanently plugged and abandoned under a Department permit. If the permitted hydrocarbon well is located on a multi-well pad, all residential water well data and delivery documentation must be maintained and made available during the period up to and including five years after the last permitted hydrocarbon well on the pad is permanently plugged and abandoned under a Department permit.

**Site Preparation**

8) Unless otherwise required by private lease agreement and in consideration of avoiding bisection of agricultural fields, to the extent practical the access road must be located as far away as possible from occupied structures, places of assembly and unleased property.

9) Unless otherwise approved or directed by the Department, all of the topsoil in the project area stripped to facilitate the construction of well pads and access roads must be stockpiled, stabilized and remain on site for use in final reclamation.

10) Authorization under the Department's General Permit for Stormwater Discharges Associated with High-Volume Hydraulic Fracturing (HVHF GP) must be obtained prior to any disturbance at the site.

11) Piping, conveyances, valves and tanks in contact with flowback water must be constructed of materials compatible with flowback water composition, and in accordance with the fluid disposal plan approved by the Department pursuant to 6 NYCRR 554.1(c)(1).

12) Any reserve pit, drilling pit or mud pit on the well pad which will be used for more than one well must be constructed as follows:

    a) Surface water and stormwater runoff must be diverted away from the pit;

    b) Pit volume may not exceed 250,000 gallons, or 500,000 gallons for multiple pits on one tract or related tracts of land;

    c) Pit sidewalls and bottoms must adequately cushioned and free of objects capable of puncturing and ripping the liner;

    d) Pits constructed in unconsolidated sediments must have beveled walls (45 degrees or less);

e) The pit liner must be sized and placed with sufficient slack to accommodate stretching;

f) Liner thickness must be at least 30 mils, and;

g) Seams must be factory installed or field seamed in accordance with the manufacturer's recommendations.

**Site Maintenance**

13) Secondary containment consistent with the Department's Spill Prevention Operations Technology Series 10, Secondary Containment Systems for Aboveground Storage Tanks, (SPOTS 10) is required for all fueling tanks;

14) To the extent practical, fueling tanks must not be placed within 500 feet of a public or private water-well, a domestic-supply spring, a reservoir, a perennial or intermittent stream, a storm drain, a wetland, a lake or a pond;

15) Fueling tank filling operations must be manned at the fueling truck and at the tank if the tank is not visible to the fueling operator from the truck, and;

16)Troughs, drip pads or drip pans are required beneath the fill port of a fueling tank during filling operations if the fill port is not within the secondary containment.

17) A copy of the SWPPP must be available on-site and available to Department inspectors while HVHF GP coverage is in effect. HVHF GP coverage may be terminated upon the plugging and abandonment of all wells on the well pad in accordance with Department-issued permits.

18) Two feet of freeboard must be maintained at all times for any on-site pit.

19) Except for freshwater storage pits, fluids must be removed from an on-site pit prior to any 45-day gap in use (i.e., from the completion date of the well) and the pit must be inspected by a Department inspector prior to resumed use.

**Drilling, Stimulation and Flowback**

**NOTE: Wildcat Supplementary Conditions may be separately imposed in addition to these. Unless superseded by more stringent conditions below, the Department's Casing and Cementing Practices also remain in effect.**

20) Lighting and noise mitigation measures as deemed necessary by the Department may be required at any time.

21) The operator must provide the drilling company with a well prognosis indicating anticipated formation top depths with appropriate warning comments prior to spud. The prognosis must be reviewed by all crew members and posted in a prominent location in the doghouse. The operator must revise the prognosis and inform the drilling company in a timely manner if

drilling reveals significant variation between the anticipated and actual geology and/or formation pressures.

22) Individual crew member's responsibilities for blowout control must be posted in the doghouse or other appropriate location and each crew member must be made aware of such responsibilities prior to spud of any well being drilled or when another rig is moved on a previously spudded well and/or prior to the commencement of any rig, snubbing unit or coiled tubing unit performing completion work. During all drilling and/or completion operations when a BOP is installed, tested or in use, the operator or operator's designated representative must be present at the wellsite and such person or personnel must have a current well control certification from an accredited training program that is acceptable to the Department (e.g., International Association of Drilling Contractors). Such certification must be available at the wellsite and provided to the Department upon request.

23) Appropriate pressure control procedures and equipment in proper working order must be properly installed and employed while conducting drilling and/or completion operations including tripping, logging, running casing into the well, and drilling out solid-core stage plugs. Unless otherwise approved by the Department, a snubbing unit and/or coiled tubing unit with a BOP must be used to enter any well with pressure and/or to drill out one or more solid-core stage plugs.

24) Pressure testing of the blow-out preventer (BOP) and related equipment for any drilling and/or completion operation must be performed in accordance with the approved BOP use and test plan, and any deviation from the approved plan must be approved by the Department. Testing must be conducted in accordance with American Petroleum Institute (API) Recommended Practice (RP) 53, RP for Blowout Prevention Systems for Drilling Wells, or other procedures approved by the Department. Unless otherwise approved by the Department, the BOP use and test plan must include the following provisions:

    a) A system for recording, documenting and retaining the results of all pressure tests and inspections conducted during drilling and/or completion operations. The results must be available to the Department at the wellsite during the corresponding operation, and to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all pressure testing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit. The record for each pressure test, at a minimum, must identify the equipment or casing being tested, the date of the test, the minimum and maximum test pressures in psig, the test medium (e.g., water, brine, mud, air, nitrogen) including its density, test duration, and the results of the test including any pressure drop;

    b) A well control barrier policy developed by the operator that identifies acceptable barriers to be used during identified operations. Such policy must employ, at a minimum, two mechanical barriers capable of being tested when conducting any drilling and/or completion operation below the surface casing. In no event shall a stripper rubber or a stripper head be considered an acceptable barrier;

    c) BOP testing prior to being put into service. Such testing must include testing after the BOP is installed on the well but prior to use. Pressure control equipment, including the BOP, that fails any pressure test must not be used until it is repaired and passes the pressure test, and;

d) A remote BOP actuator which is powered by a source other than rig hydraulics that is located at least 50 feet from the wellhead. All lines, valves and fittings between the BOP and the remote actuator and any other actuator must be flame resistant and have an appropriate rated working pressure.

25) The operator must detect, if practical, and document all naturally occurring methane in the conductor hole, if drilled, and the surface hole. Further, in accordance with 6 NYCRR 554.7(b), all freshwater, brine, oil and gas shows must be documented on the Department's *Well Drilling and Completion Report*. In the event $H_2S$ is encountered in any portion of the well, all regulated activities must be conducted by the operator in conformance with American Petroleum Institute Publication API RP49, "Recommended Practices For Safe Drilling of Wells Containing Hydrogen Sulfide."

26) Annular disposal of drill cuttings or fluid is prohibited.

27) All fluids must be contained on the site until properly removed in compliance with the fluid disposal plan approved in accordance with 6 NYCRR 554.1(c)(1) and applicable conditions of this permit.

28) A closed-loop tank system must be used instead of a reserve pit to manage and contain drilling fluids and cuttings for any of the following:

a) horizontal drilling in the Marcellus Shale without an acid rock drainage mitigation plan for on-site burial of such cuttings, and;

b) any drilling requiring cuttings to be disposed of off-site including at a landfill.

29) With respect to the closed-loop tank system, cuttings may be removed from the site in the primary capture container (e.g., tank or bin) or transferred onsite via a transfer area to a secondary container or truck for offsite disposal. If a cuttings transfer area is employed, it must be lined with a material acceptable to the department. Transfer of cuttings to an onsite stock pile is prohibited, regardless of any liner under the stock pile. Offsite transport of all cuttings must be undertaken by a waste transporter with an approved 6 NYCRR Part 364 permit. The *Drilling and Production Waste Tracking Form* must be completed and retained for three years by the generator, transporter and destination facility, and made available to the Department upon request during this period. If requested, the generator is responsible for producing its originating copy of the *Drilling and Production Waste Tracking Form* and the completed form with the original signatures of the generator, transporter and destination facility.

30) Only biocides with current registration for use in New York may be used for any operation at the wellsite. Products must be properly labeled, and the label must be kept on-site during application and storage.

31) With respect to all surface, intermediate and production casing run in the well, and in addition to the requirements of the Department's "Casing and Cementing Practices" and any approved centralizer plan for intermediate casing, the following shall apply:

a) Casing must be new and conform to American Petroleum Institute (API) Specification 5CT, Specifications for Casing and Tubing (April 2002), and welded connections are prohibited;

b) casing thread compound and its use must conform to API Recommended Practice (RP) 5A3, RP on Thread Compounds for Casing, Tubing, Line Pipe, and Drill Stem Elements (November 2009);

c) at least two centralizers (one in the middle and one at the top) must be installed on the first joint of casing (except production casing) and all bow-spring style centralizers must conform to API Specification 10D for Bow-Spring Casing Centralizers (March 2002);

d) cement must conform to API Specification 10A, Specifications for Cement and Material for Well Cementing (April 2002 and January 2005 Addendum). Further, the cement slurry must be prepared to minimize its free water content in accordance with the same API specification and it must contain a gas-block additive;

e) prior to cementing any casing string, the borehole must be circulated and conditioned to ensure an adequate cement bond;

f) a spacer of adequate volume, makeup and consistency must be pumped ahead of the cement;

g) the cement must be pumped at a rate and in a flow regime that inhibits channeling of the cement in the annulus;

h) after the cement is pumped, the operator must wait on cement (WOC):
1. until the cement achieves a calculated (e.g., performance chart) compressive strength of at least 500 psig, and
2. a minimum WOC time of 8 hours before the casing is disturbed in any way, including installation of a blow-out preventer (BOP). The operator may request a waiver from the Department from the required WOC time if the operator has bench tested the actual cement batch and blend using mix water from the actual source for the job, and determined that 8 hours is not required to reach a compressive strength of 500 psig, and;

i) A copy of the cement job log for any cemented casing in the well must be available to the Department at the wellsite during drilling operations, and thereafter available to the Department upon request. The operator must provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all cementing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit.

32) The surface casing must be run and cemented immediately after the hole has been adequately circulated and conditioned. This office must be notified _______ hours prior to surface

casing cementing operations. *(Blank to be filled in based on well's location and Regional Minerals Manager's direction.)*

33) Intermediate casing must be installed in the well. The setting depth and design of the casing must consider all applicable drilling, geologic and well control factors. Additionally, the setting depth must consider the cementing requirements for the intermediate casing and the production casing as noted below. Any request to waive the intermediate casing requirement must be made in writing with supporting documentation and is subject to the Department's approval. Information gathered from operations conducted on any single well or the first well drilled on a multi-well pad may serve to form the basis for the Department waiving the intermediate casing requirement on subsequent wells in the vicinity of the single well or subsequent wells on the same multi-well pad.

34) This office must be notified ______ hours prior to intermediate casing cementing operations. Intermediate casing must be fully cemented to surface with excess cement. Cementing must be by the pump and plug method with a minimum of 25% excess cement unless caliper logs are run, in which case 10% excess will suffice. *(Blank to be filled in based on well's location and Regional Minerals Manager's direction.)*

35) The operator must run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the intermediate casing. The quality and effectiveness of the cement job shall be evaluated by the operator using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 "Other Testing and Information" under the heading of "Well Logging and Other Testing" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009). Remedial cementing is required if the cement bond is not adequate for drilling ahead (i.e., diversion or shut-in for well control).

36) Production casing must be run to the surface. This office must be notified _______ hours prior to production casing cementing operations. If installation of the intermediate casing is waived by the Department, then production casing must be fully cemented to surface. If intermediate casing is installed, the production casing cement must be tied into the intermediate casing string with at least 500 feet of cement measured using True Vertical Depth (TVD). Any request to waive any of the preceding cementing requirements must be made in writing with supporting documentation and is subject to the Department's approval. The Department will only consider a request for a waiver if the open-hole wireline logs including a narrative analysis of such and all other information collected during drilling from the same well pad or offsetting wells verify that migration of oil, gas or other fluids from one pool or stratum to another will be prevented. *(Blank to be filled in based on well's location and Regional Minerals Manager's direction.)*

37) The operator must run a radial cement bond evaluation log or other evaluation approved by the Department to verify the cement bond on the production casing. The quality and effectiveness of the cement job shall be evaluated by the operator using the above required evaluation in conjunction with appropriate supporting data per Section 6.4 "Other Testing and Information" under the heading of "Well Logging and Other Testing" of American Petroleum Institute (API) Guidance Document HF1 (First Edition, October 2009). Remedial cementing is required if the cement bond is not adequate to effectively isolate hydraulic fracturing operations.

38) The installation of an additional cemented casing string or strings in the well as deemed necessary by the Department for environmental and/or public safety reasons may be required at any time.

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

40) If hydraulic fracturing operations are performed down casing, prior to introducing hydraulic fracturing fluid into the well the casing extending from the surface of the well to the top of the treatment interval must be tested with fresh water, mud or brine to at least the maximum anticipated treatment pressure for at least 30 minutes with less than a 5% pressure loss. This pressure test may not commence for at least 7 days after the primary cementing operations are completed on this casing string. A record of the pressure test must be maintained by the operator and made available to the Department upon request. The actual hydraulic fracturing treatment pressure must not exceed the test pressure at any time during hydraulic fracturing operations.

41) Prior to commencing hydraulic fracturing and pumping of hydraulic fracturing fluid, the injection lines and manifold, associated valves, frac head or tree and any other wellhead component or connection not previously tested must be tested with fresh water, mud or brine to at least the maximum anticipated treatment pressure for at least 30 minutes with less than a 5% pressure loss. A record of the pressure test must be maintained by the operator and made available to the Department upon request. The actual hydraulic fracturing treatment pressure must not exceed the test pressure at any time during hydraulic fracturing operations.

42) The operator must record the depths and estimated flow rates where fresh water, brine, oil and/or gas were encountered or circulation was lost during drilling operations. This information and the Department's *Pre-Frac Checklist and Certification* form including a treatment plan, must be submitted to and received by the regional office at least 3 days prior to commencement of high-volume hydraulic fracturing operations. The treatment plan must include a profile showing anticipated pressures and volumes of fluid for pumping the first stage. It must also include a description of the planned treatment interval for the well [i.e., top and bottom of perforations expressed in both True Vertical Depth (TVD) and True Measured Depth (TMD)].

43) Fracturing products other than those identified in the well permit application materials may not be used without specific approval from this office.

44) This permit does not authorize the use of diesel as the primary carrier fluid (i.e., diesel-based hydraulic fracturing).

45) The operator may conduct hydraulic fracturing operations provided 1) all items on the checklist are affirmed by a response of "Yes," 2) the *Pre-Frac Checklist And Certification* and treatment plan are received by the Department at least 3 days prior to hydraulic fracturing, and 3) all other pre-frac notification requirements are met as specified elsewhere. The operator is prohibited from conducting hydraulic fracturing operations on the well without additional Department review and approval if a response of "No" is provided to any of the items in the *Pre-Frac Checklist and Certification*.

46) Hydraulic fracturing operations must be conducted as follows:

a) Secondary containment for fracturing additive containers and additive staging areas, and flowback tanks is required. Secondary containment measures may include, as deemed appropriate by the Department, one or a combination of the following; dikes, liners, pads, impoundments, curbs, sumps or other structures or equipment capable of containing the substance. Any such secondary containment must be sufficient to contain 110% of the total capacity of the single largest container or tank within a common containment area. No more than one hour before initiating any hydraulic fracturing stage, all secondary containment must be visually inspected to ensure all structures and equipment are in place and in proper working order. The results of this inspection must be recorded and documented by the operator, and available to the Department upon request;

b) At least two vacuum trucks must be on standby at the wellsite during the pumping of hydraulic fracturing fluid and during any subsequent flowback phases;

c) Hydraulic fracturing additives must be removed from the site if the site will be unattended;

d) Any hydraulic fracturing string, if used, must be either stung into a production liner or run with a packer set at least 100 feet below the deepest cement top. An adequately sized, function tested relief valve and an adequately sized diversion line must be installed and used to divert flow from the hydraulic fracturing string-casing annulus to a covered watertight steel tank or covered watertight tank made of another material approved by the Department in case of hydraulic fracturing string failure. The relief valve must be set to limit the annular pressure to no more than 95% of the working pressure rating of the casings forming the annulus. The annulus between the hydraulic fracturing string and casing must be pressurized to at least 250 psig and monitored;

e) The pressure exerted on treating equipment including valves, lines, manifolds, hydraulic fracturing head or tree, casing and hydraulic fracturing string, if used, must not exceed 95% of the working pressure rating of the weakest component;

f) The hydraulic fracturing treatment pressure must not exceed the test pressure of any given component at any time during hydraulic fracturing operations;

g) All annuli available at the surface must be continuously observed or monitored in order to detect pressure or flow, and the records of such maintained by the operator and made available to the Department upon request, and;

h) Hydraulic fracturing pumping operations must be immediately suspended if any anomalous pressure and/or flow condition is indicated or occurring including a significant deviation from the treatment plan (i.e., profile showing anticipated pressures and volume of fluid for pumping the first stage) provided to the Department with the *Pre-Frac Checklist and Certification* or any other anticipated pressure and/or flow condition. Suspension of operations due to an anomalous pressure and/or flow condition is considered a non-routine incident which must be reported in accordance with the General Provisions of these supplementary permit conditions. In the case of suspended hydraulic fracturing pumping operations and non-routine incident reporting of such, the operator must receive Department approval prior to recommencing hydraulic fracturing activities in the same well.

47) The operator must make and maintain a complete record of its hydraulic fracturing operation including the flowback phase, and provide such to the Department upon request at any time during the period up to and including five years after the well is permanently plugged and abandoned under a Department permit. If the well is located on a multi-well pad, all hydraulic fracturing records must be maintained and made available during the period up to and including five years after the last well on the pad is permanently plugged and abandoned under a Department permit. The record for each well must include all types and volumes of materials, including additives, pumped into the well, flowback rates, and the daily and total volumes of fluid recovered during the first 30 days of flow from well. The record must also include a complete description of pressures exhibited throughout the hydraulic fracturing operation and must include pressure recordings, charts and/or a pressure profile. A synopsis of the hydraulic fracturing operation must be provided in the appropriate section of the Department's *Well Drilling and Completion Report* which must be provided to the Department within 30 days after completing the well in accordance with 6 NYCRR 554.7.

48) Flowback water is prohibited from being directed to or stored in any on-site pit. Covered watertight steel tanks or covered watertight tanks constructed of another material approved by the Department are required for flowback handling and containment on the well pad. Flowback water tanks, piping and conveyances, including valves, must be constructed of suitable materials, be of sufficient pressure rating and be maintained in a leak-free condition. Fluid transfer operations from tanks to tanker trucks must be manned at the truck and at the tank if the tank is not visible to the truck operator from the truck. Additionally, during transfer operations, all interconnecting piping must be manned if not visible to transfer personnel at the truck and tank.

49) The venting of any gas originating from the target formation during the flowback phase must be through a flare stack at least 30 feet in height, unless the absence of $H_2S$ has been demonstrated at a previous well on the same pad. Gas vented through the flare stack must be ignited whenever possible. The stack must be equipped with a self-ignition device.

50) A reduced emissions completion, with minimal flaring (if any), must be performed whenever a sales line and interconnecting gathering line are available during completion at any individual well or a multi-well pad.

51) This permit authorizes a one-time single-stage or multi-stage high-volume hydraulic fracturing operation as described in the well permit application materials, subject to the *Pre-Frac Checklist and Certification* and any modifications required by the Department. Any subsequent high-volume re-fracturing operations are subject to the Department's approval after:
    a) review of the planned fracturing procedures and products, water source, proposed site disturbance and layout, and fluid disposal plans;

    b) a site inspection by Department staff, and;

    c) a determination of whether any other Department permits are required.

**Reclamation**

52) Fluids must be removed from any on-site pit and the pit reclaimed no later than 45 days after completion of drilling and stimulation operations at the last well on the pad, unless the

Department grants an extension pursuant to 6 NYCRR 554.1(c)(3). Flowback water must be removed from on-site tanks within the same time frame.

53) Removed pit fluids must be disposed, recycled or reused as described in the approved fluid disposal plan submitted pursuant to 6 NYCRR 554.1(c)(1). Transport of all waste fluids by vehicle must be undertaken by a waste transporter with an approved 6 NYCRR Part 364 permit. The *Drilling and Production Waste Tracking Form* must be completed and retained for three years by the generator, transporter and destination facility, and made available to the Department upon request during this period. If requested, the generator is responsible for producing its originating copy of the *Drilling and Production Waste Tracking Form* and the completed form with the original signatures of the generator, transporter and destination facility.

54) If any fluid or other waste material is moved off site by pipeline or other piping, the operator must maintain a record of the date and time the fluid or other material left the site, the quantity of fluid or other material, and its intended disposition and use at that destination or receiving facility.

55) Cuttings contaminated with oil-based mud and polymer-based muds must be contained and managed in a closed-loop tank system and not be buried on site, and must be removed from the site for disposal in a 6 NYCRR Part 360 solid waste facility. Consultation with the Department's Division of Materials Management (DMM) is required prior to disposal of any cuttings associated with water-based mud-drilling and pit liner associated with water-based mud-drilling where the water-based mud contains chemical additives. Any sampling and analysis directed by DMM must be by an ELAP-certified laboratory. Disposal must conform to all applicable Department regulations. The pit liner must be ripped and perforated prior to any permitted burial on-site and to the extent practical, excess pit liner material must be removed and disposed of properly. Permission of the surface owner is required for any on-site burial of cuttings and pit liner, regardless of type of drilling and fluids used. Burial of any other trash on-site is specifically prohibited and all such trash must be removed from the site and properly disposed. Transport of all cuttings and pit liner off-site, if required by the Department or otherwise performed, must be undertaken by a waste transporter with an approved 6 NYCRR Part 364 permit. The *Drilling and Production Waste Tracking Form* must be completed and retained for three years by the generator, transporter and destination facility, and made available to the Department upon request during this period. If requested, the generator is responsible for producing its originating copy of the *Drilling and Production Waste Tracking Form* and the completed form with the original signatures of the generator, transporter and destination facility.

56) A site-specific acid rock drainage (ARD) mitigation plan consistent with the SGEIS must be prepared by the operator and followed for on-site burial of Marcellus Shale cuttings from horizontal drilling in the Marcellus Shale if the operator elects to bury these cuttings. The plan must be available to the Department upon request, and available on-site to a Department inspector while activities addressed by the plan are taking place.

57) The operator must fully implement the Partial Site Reclamation Plan described in the approved application materials.

58) Final reclamation of the wellsite must be approved by the Department. Unless otherwise approved by this office, well pads and access roads constructed for drilling and production operations must be scarified or ripped to alleviate compaction prior to replacement of topsoil.

Reclaimed areas must be seeded and mulched after topsoil replacement. Any proposal by the operator to waive these reclamation requirements must be accompanied by documentation of the landowner's written request to keep the access road and/or well pad.

**General**

59) The operator must follow applicable best management practices (BMPs) for reducing direct impacts at individual well pads described in Section 7.4.1.1 of the SGEIS.

60) The operator must fully implement the Invasive Species Management Plan described in the approved application materials.

61) The operator must follow applicable best management practices (BMPs) for reducing the potential for transfer and introduction of invasive species described in Section 7.4.2.2 of the SGEIS.

62) The operator must complete the "Record of Formations Penetrated" on the *Well Drilling and Completion Report* providing a log of formations, both unconsolidated and consolidated, and depths and estimated flow rates of any fresh water, brine, oil and/or gas. In accordance with 6 NYCRR 554.7, the well operator must provide the Department with the *Well Drilling and Completion Report* within 30 days after completing the well.

63) Any non-routine incident of potential environmental and/or public safety significance must be verbally reported to the Department within two hours of the incident's known occurrence or discovery, with a written report detailing the non-routine incident to follow within twenty-four hours of the incident's known occurrence or discovery. Non-routine incidents may include, but are not limited to: -casing, drill pipe or hydraulic fracturing equipment failures, cement failures, fishing jobs, fires, seepages, blowouts, surface chemical spills, observed leaks in surface equipment, observed pit liner failure, surface effects at previously plugged or other wells, observed effects at water wells or at the surface, complaints of water well contamination, anomalous pressure and/or flow conditions indicated or occurring during hydraulic fracturing operations, or other potentially polluting non-routine incident or incident that may affect the health, safety, welfare, or property of any person. Provided the environment and public safety would not be further endangered, any action and/or condition known or suspected of causing and/or contributing to a non-routine incident must cease immediately upon known occurrence or discovery of the incident, and appropriate initial remedial actions commenced. The required written non-routine incident report noted above must provide details of the incident and include, as necessary, a proposed remedial plan for Department review and approval. In the case of suspended hydraulic fracturing pumping operations and non-routine incident reporting of such, the operator must receive Department approval prior to recommencing hydraulic fracturing activities in the same well.

64) Flowback water recovered after high-volume hydraulic fracturing operations must be tested for NORM prior to removal from the site. Fluids recovered during the production phase (i.e., production brine) must be tested for NORM prior to removal.

65) Periodic radiation surveys must be conducted at specified time intervals during the production phase for Marcellus wells developed by high-volume hydraulic fracturing completion methods. Such surveys must be performed on all accessible well piping, tanks, or equipment that could contain NORM scale buildup. The surveys must be conducted for as long as the facility remains in active use. If piping, tanks, or equipment is to be removed,

radiation surveys must be performed to ensure their appropriate disposal. All surveys must be conducted in accordance with NYSDOH protocols.

66) Production brine is prohibited from being directed to or stored in any on-site pit. Covered watertight steel, fiberglass or plastic tanks, or covered watertight tanks constructed of another material approved by the Department, are required for production brine handling and containment on the well pad. Production brine tanks, piping and conveyances, including valves, must be constructed of suitable materials, be of sufficient pressure rating and be maintained in a leak-free condition.

67) Production brine which is removed from the site must be disposed, recycled or reused as described by the well permit application materials. Transport of all waste fluids must be undertaken by a waste transporter with an approved 6 NYCRR Part 364 permit. The *Drilling and Production Waste Tracking Form* must be completed and retained for three years by the generator, transporter and destination facility, and made available to the Department upon request during this period. If requested, the generator is responsible for producing its originating copy of the *Drilling and Production Waste Tracking Form* and the completed form with the original signatures of the generator, transporter and destination facility.

**Any deviation from the above conditions must be approved by the Department prior to making a change.**

## ATTACHMENT A

To avoid or mitigate adverse air quality impacts from the well drilling, completion and production operations, the following restrictions are imposed:

1. The diesel fuel used in drilling and completion equipment engines will be limited to Ultra Low Sulfur Fuel (ULSF) with a maximum sulfur content of 15 ppm.

2. There will not be any simultaneous operations of the drilling and completion equipment engines at the single well pad.

3. The maximum number of wells to be drilled and completed annually or during any consecutive 12--month period at a single pad will be limited to four.

4. The emissions of benzene at any glycol dehydrator to be used at the well pad will be limited to one ton/year as determined by calculations with the GRI-GlyCalc program. If wet gas is encountered, then the dehydrator will have a minimum stack height of 30 feet (9.1m) and will be equipped with a control devise to limit the benzene emissions to 1 Tpy.

5. Condensate tanks used at the well pad shall be equipped with vapor recovery systems to minimize fugitive VOC emissions.

6. During the flowback phase, the venting of gas from each well pad will be limited to a maximum of 5 MMscf during any consecutive 12--month period. If “sour” gas is encountered with detected $H_2S$ emissions, the height at which the gas will be vented will be a minimum of 30 feet (9.1m).

7. During the flowback phase, flaring of gas at each well pad will be limited to a maximum of 120 MMscf during any consecutive 12--month period.

8. Wellhead compressor will be equipped with NSCR controls.

9. No uncertified (i.e., EPA Tier 0) drilling or completion equipment engines will be used for any activity at the well sites.

10. The drilling engines and drilling air compressors will be limited to EPA Tier 2 or newer equipment. If Tier 1 drilling equipment is to be used, these will be equipped with both

particulate traps (CRDPF) and SCR controls. During operations, this equipment will be positioned as close to the center of the well pad as practicable. If industry deviates from the control requirements or proposes alternate mitigation and/or control measures to demonstrate ambient standard compliance, site specific information will be provided to the Department for review and concurrence.

11. The completion equipment engines will be limited to EPA Tier 2 or newer equipment. Particulate traps will be required for all Tier 2 engines. SCR control will be required on all completion equipment engines regardless of the emission Tier. During operations, this equipment will be positioned as close to the center of the well pad as practicable. If industry deviates from this requirement or proposes mitigation and/or alternate control measures to demonstrate ambient standard compliance, site specific information will be provided to the Department for review and concurrence.

# ATTACHMENT B

## PASSBY FLOW IMPLEMENTATION AND ENFORCEMENT

1. Monitoring and Reporting**.** Passby flows must be maintained instantaneously. Determinations of allowable removal rates will be made based on comparisons with instantaneous flow data.

2. Description of Gage Types

***Tier I-*** Gage data in this category is collected by the permitee immediately downstream of the water withdrawal location using streamflow gage equipment capable of accurately measuring instantaneous flow rates as approved at the discretion of the Department.

***Tier II-*** Gage data in this category is obtained from acceptable USGS gages that must be located at a point in the same watershed where the drainage area at the gage is from 0.5x to 2.0x the size of the drainage area as measured at the withdrawal point. The catchment area must not have altered flows unless the instantaneous flow measurements can take into account the alterations.

***Tier III-*** Gage data in this category is obtained from USGS gages that are either outside the acceptable distance within the same watershed or are in adjacent watersheds that possess similar basin characteristics. The use of these "surrogate" watersheds are the most inaccurate account of stream flow and should be used only as approved at the discretion of the Department.

3. All streamflow records used in determining the instantaneous passby flow rates should be measured to the nearest 0.1 cfs at 15-minute increments. Water withdrawal rates must be reported as instantaneous measurements to the nearest 0.1 cfs at 5-minute increments. Reporting is required annually to Department in Microsoft Excel or similar electronic spreadsheet/database formats.

4. Violations and Suspension of Operations. Water withdrawal operations will be suspended immediately upon determination that the required passby flow has not been maintained. The Department has the right to modify passby flow requirements if water quality standards are not being met within a watercourse as the result of a water withdrawal. Failure to submit annual reports, filing of inaccurate reports on water withdrawals, and continuing to withdraw water after a determination that the required passby flow has not been maintained, are all considered separate violations of this permit and the Environmental Conservation Law Article 71-1305(2).

## ATTACHMENT C

## FOREST AND GRASSLAND FOCUS AREAS

Operators developing well sites in Forest and Grassland Focus Areas that involve disturbance in a contiguous forest patch of 150 acres or more in size or in a contiguous grassland patch of 30 acres or more in size must:

1) Implement mitigation measures identified as part of the Department-approved ecological assessment;

2) Monitor the effects of disturbance as active development proceeds and for a minimum of two years following well completion; and

3) Practice adaptive management as previously unknown effects are documented.

New York State

DEC

# Appendix 11

## Analysis of Subsurface Mobility of Fracturing Fluids

Excerpted from ICF International, Task 1, 2009

Revised Draft
Supplemental Generic Environmental Impact Statement

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### *1.2.4 Principles governing fracturing fluid flow*

The mobility of hydraulic fracturing fluid depends on the same physical and chemical principles that dictate all fluid transport phenomena. Frac fluid will flow through the well, the fractures, and the porous media based on pressure differentials and hydraulic conductivities. In addition to the overall flow of the frac fluids, additives may experience greater or lesser movement due to diffusion and adsorption. The concentrations of the fluids and additives may change due to dilution in formation waters and possibly by biological or chemical degradation.

#### 1.2.4.1 Limiting conditions

The analyses below present flow calculations for a range of parameters, with the intent to define reasonable bounds for the conditions likely to be encountered in New York State. Although one or more conditions at some future well sites may lie outside of the ranges analyzed, it is considered unlikely that the combination of conditions at any site would produce environmental impacts that are significantly more adverse than the worst case scenarios analyzed. The equations used in the analyses are presented below to facilitate the assessment of additional scenarios.

The analyses consider potentially useful aquifers with lower limits at depths up to 1,000 feet, somewhat deeper than the maximum aquifer depth reported in Table 3 for the Marcellus Shale. Similarly, the minimum depth to the top of the shale is taken as 2,000 ft, well above the minimum depth reported in Table 3 for the Marcellus Shale. The 2,000 ft. depth has been postulated as the probable upper limit for economic development of the New York shales.

The analyses include an additional conservative assumption. Even for deep aquifers, the analyses consider the pore pressure at the bottom of the aquifer to be zero as if a deep well or well field was operating at maximum drawdown. This assumption maximizes the potential for upward flow of fracturing fluid or its components from the fracture zone to the aquifer.

[134] U.S. EPA, 2004. *Evaluation of Impacts to Underground Sources of Drinking Water by Hydraulic Fracturing of Coalbed Methane Reservoirs*, Report number: EPA 816-R-04-003.

### 1.2.4.2 Gradient

For a fracturing fluid or its additives to have a negative impact on a groundwater aquifer, some deleterious component of the fracturing fluid would need to travel from the target fracture zone to the aquifer. In order for fluid to flow from the fracture zone to an aquifer, the *total head*[135] must be greater in the fracture zone than at the well. We can estimate the *gradient*[136] that might exist between a fracture zone in the shale and a potable water aquifer as follows:

$$i = \frac{h_{t1} - h_{t2}}{L} \tag{1}$$

where $i$ = gradient
$h_{tn}$ = total head at Point n
$L$ = length of flow path from Point 1 to Point 2

Since the total head is the sum of the elevation head and the pressure head,

$$h_t = h_e + h_p \tag{2}$$

The gradient can be restated as

$$i = \frac{(h_{e1} + h_{p1}) - (h_{e2} + h_{p2})}{L} \tag{3}$$

where $h_{en}$ = elevation head at Point n
$h_{pn}$ = pressure head at Point n

If the ground surface is taken as the elevation datum, we can express the elevation head in terms of depth.

$$d_n = -h_{en} \tag{4}$$

Restating the gradient yields

$$i = \frac{(h_{e1} + h_{p1}) - (h_{e2} + h_{p2})}{L} = \frac{(-d_1 + h_{p1}) - (-d_2 + h_{p2})}{L} = \frac{(d_2 - d_1) + (h_{p1} - h_{p2})}{L} \tag{5}$$

where $d_n$ = depth at Point n

We can estimate the maximum likely gradient by considering the combination of parameters which would be most favorable to flow from the hydraulically fractured zone to a potential groundwater aquifer. These include assuming the minimum possible pressure head in the aquifer and the shortest possible flow path, i.e. setting $h_{p2}$ to zero to simulate a well pumped to the maximum aquifer drawdown and setting $L$ to the vertical distance between the fracture zone and the aquifer, $d_1 - d_2$.

[135] Total head at a point is the sum of the elevation at the point plus the pore pressure expressed as the height of a vertical column of water.
[136] The groundwater gradient is the difference in total head between two points divided by the distance between the points.

The gradient now becomes

$$i = \frac{(d_2 - d_1) + h_{p1}}{|d_1 - d_2|} \tag{6}$$

The total vertical stress in the fracture zone equals

$$\sigma_v = d_1 \times \gamma_R \tag{7}$$

where $\sigma_v$ = total vertical stress
$d_1$ = depth at Point 1, in the fracture zone
$\gamma_R$ = average total unit weight of the overlying rock

The effective vertical stress, or the stress transmitted through the mineral matrix, equals the total unit weight minus the pore pressure. For the purposes of this analysis, the pore pressure is taken to be equivalent to that of a vertical water column from the fracture zone to the surface. The effective vertical stress is given by

$$\sigma'_v = \sigma_v - (d_1 \times \gamma_W) \tag{8}$$

where $\sigma'_v$ = effective vertical stress
$\gamma_W$ = unit weight of water

The effective horizontal stress and the total horizontal stress therefore equal

$$\sigma'_h = K \times \sigma'_v \tag{9}$$

$$\sigma_h = \sigma'_h + (d_1 \times \gamma_W) \tag{10}$$

where $\sigma'_h$ = effective horizontal stress
$K$ = ratio of horizontal to vertical stress
$\sigma_h$ = total horizontal stress

The hydraulic fracturing pressure needs to exceed the minimum total horizontal stress. Allowing for some loss of pressure from the wellbore to the fracture tip, the pressure head in the fracture zone equals

$$h_{p1} = c \times \sigma_h = \frac{c \times d_1 \times [K(\gamma_R - \gamma_W) + \gamma_W]}{\gamma_W} \tag{11}$$

where $h_{p1}$ = pressure head at Point 1, in the fracture zone
$c$ = coefficient to allow for some loss of pressure from the wellbore to the fracture tip

Since the horizontal stress is typically in the range of 0.5 to 1.0 times the vertical stress, the fracturing pressure will equal the depth to the fracture zone times, say, 0.75 times the density of the geologic materials (estimated at 150 pcf average), times the depth.[137] To allow for some loss of pressure from the wellbore to the fracture tip, the calculations assume a fracturing pressure 10% higher than the horizontal stress, yielding

$$h_{p1} = \frac{110\% \times d_1 \times \left[0.75\left(150\,pcf - 62.4\,pcf\right) + 62.4\,pcf\right]}{62.4\,pcf} = 2.26 d_1 \qquad (12)$$

Equation (6) thus becomes

$$i = \frac{\left(d_2 - d_1\right) + 2.26 d_1}{\left|d_1 - d_2\right|} = \frac{d_2 + 1.26 d_1}{\left|d_1 - d_2\right|} \qquad (13)$$

Figure 1 shows the variation in the average hydraulic gradient between the fracture zone and an overlying aquifer during hydraulic fracturing for a variety of aquifer and shale depths. The gradient has a maximum of about 3.5, and is less than 2.0 for most depth combinations.

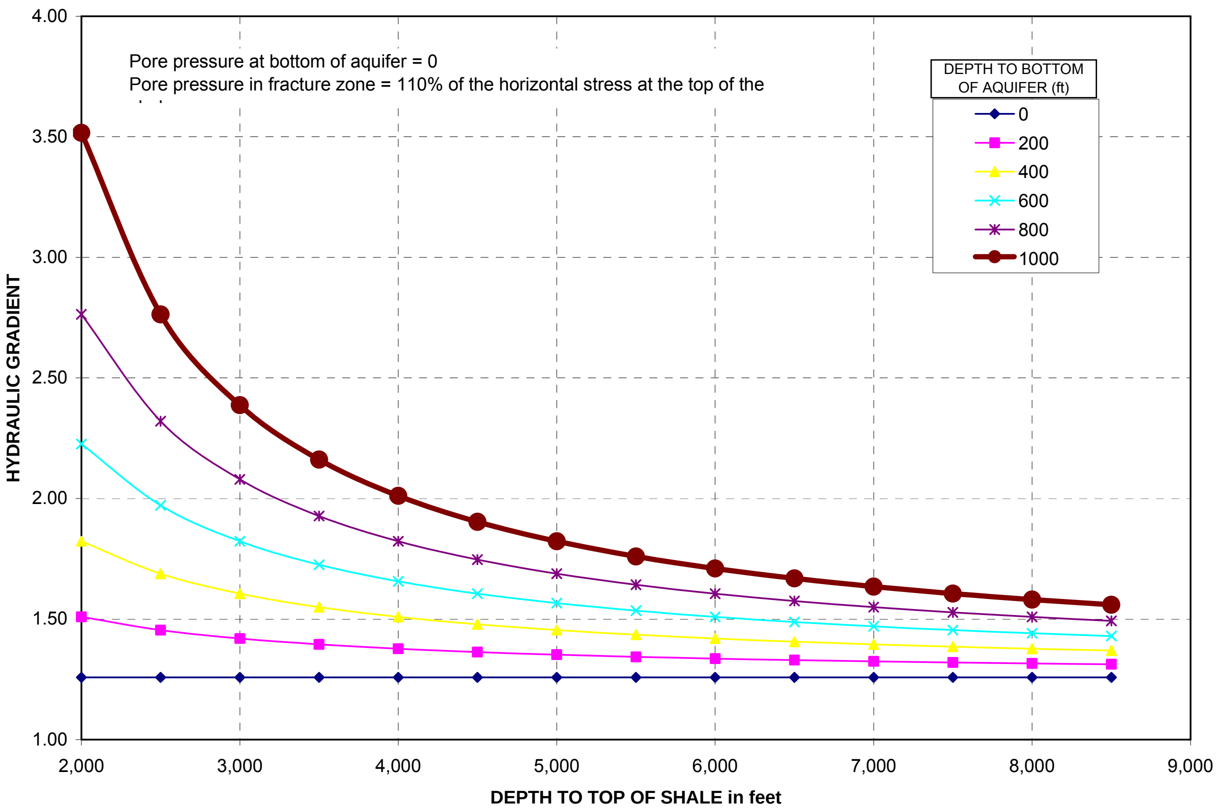


**Figure 1: Average hydraulic gradient during fracturing**

In an actual fracturing situation, non-steady state conditions will prevail during the limited time of application of the fracturing pressures, and the gradients will be higher than the average closer

[137] Zhang, Lianyang, 2005. *Engineering Properties of Rocks*, Elsevier Geo-Engineering Book Series, Volume 4, Amsterdam.

to the fracture zone and lower than the average closer to the aquifer. It is important to note that these gradients only apply while fracturing pressures are being applied.

Once fracturing pressures are removed, the total head in the reservoir will fall to near its original value, which may be higher or lower than the total head in the aquifer. Evidence suggests that the permeabilities of the Devonian shales are too low for any meaningful hydrological connection with the post-Devonian formations. The high dissolved solid content near 300,000 ppm in pre-Late Devonian formations supports the concept that these formations are hydrologically discontinuous, i.e. not well-connected to other formations.[138] During production, the pressure in the shale would decrease as gas is extracted, further reducing any potential for upward flow.

#### 1.2.4.3 Seepage velocity

The second aspect to consider with regards to flow is the time required for a particle of fluid to flow from the fracture zone to the well. Using Darcy's law, the seepage velocity would equal

$$v = \frac{ki}{n} \tag{10}$$

where $v$ = seepage velocity
$k$ = hydraulic conductivity
$n$ = porosity

The average hydraulic conductivity between a fracture zone and an aquifer would depend on the hydraulic conductivity of each intervening stratum, which in turn would depend on the type of material and whether it was intact or fractured. The rock types overlying the Marcellus Shale are primarily sandstones and other shales.[139] Table 4 lists the range of hydraulic conductivities for sandstone and shale rock masses. The hydraulic conductivity of rock masses tends to decrease with depth as higher stress levels close or prevent fractures. Vertical flow across a horizontally layered system of geologic strata is controlled primarily by the less permeable strata, so the average vertical hydraulic conductivity of all the strata lying above the target shale would be expected to be no greater than 1E-5 cm/sec and could be substantially lower.

**Table 4: Hydraulic conductivity of rock masses[140]**

| Material | Minimum k | Maximum k |
|---|---|---|
| Intact Sandstone | 1E-8 cm/sec | 1E-5 cm/sec |
| Sandstone rock mass | 1E-9 cm/sec | 1E-1 cm/sec |
| Intact Shale | 1E-11 cm/sec | 1E-9 cm/sec |
| Shale rock mass | 1E-9 cm/sec | 1E-4 cm/sec |

Figure 2 shows the seepage velocity from the fracture zone to an overlying aquifer based on the average gradients shown in Figure 1 over a range of hydraulic conductivity values and for the maximum aquifer depth of 1000 feet. For all lesser aquifer depths, the seepage velocity would

[138] Russell, William L., 1972, "Pressure-Depth Relations in Appalachian Region", *AAPG Bulletin*, March 1972, v. 56, No. 3, p. 528-536.
[139] Arthur, J.D., et al, 2008. "Hydraulic Fracturing Considerations for Natural Gas Wells of the Marcellus Shale," Presented at Ground Water Protection Council 2008 Annual Forum, September 21-24, 2008, Cincinnati, Ohio.
[140] Zhang, Lianyang, 2005. *Engineering Properties of Rocks*, Elsevier Geo-Engineering Book Series, Volume 4, Amsterdam.

be lower. For all of the analyses presented in this report, the porosity is taken as 10%, the reported total porosity for the Marcellus Shale.[141] Total porosity equals the contribution from both micro-pores within the intact rock and void space due to fractures. For the overlying strata, the analyses also use the same value for total porosity of 10% which is in the lower range of the typical values for sandstones and shales. This may result in a slight overestimation of the calculated seepage velocity, and an underestimation of the required travel time and available pore storage volume.

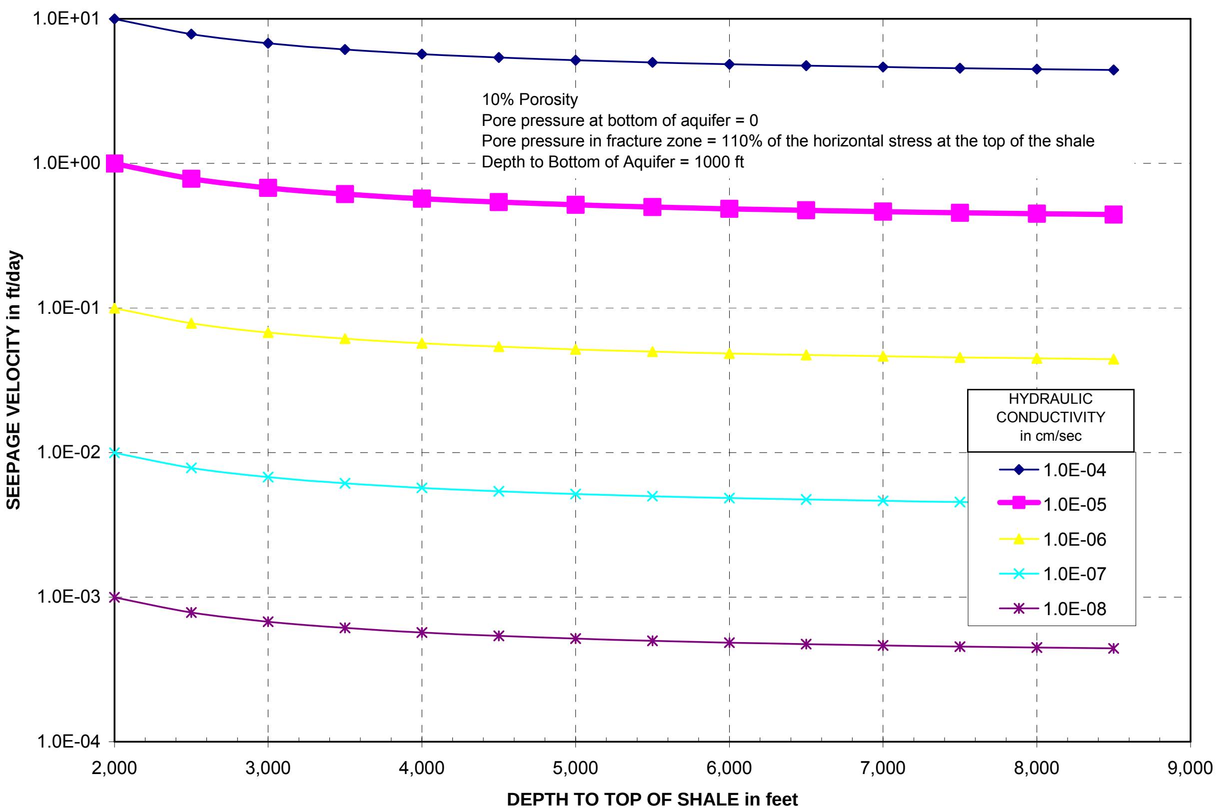


**Figure 2: Seepage velocity as a function of hydraulic conductivity**

Figure 2 shows that the seepage of hydraulic fracturing fluid would be limited to no more than 10 feet per day, and would be substantially less under most conditions. Since the cumulative amount of time that the fracturing pressure would be applied for all steps of a typical fracture stage is less than one day, the corresponding seepage distance would be similarly limited.

It is important to note that the seepage velocities shown in Figure 2 are based on average gradients between the fracture zone and the overlying aquifer. The actual gradients and seepage velocities will be influenced by non-steady state conditions and by variations in the hydraulic conductivities of the various strata.

[141] DOE, Office of Fossil Energy, 2009. *State Oil and National Gas Regulations Designed to Protect Water Resources*, May 2009.

### 1.2.4.4 Required travel time

The time that the fracturing pressure would need to be maintained for the fracturing fluid to flow from the fracture zone to an overlying aquifer is given by

$$t = \frac{|d_2 - d_1|}{v} \tag{11}$$

where $t$ = required travel time

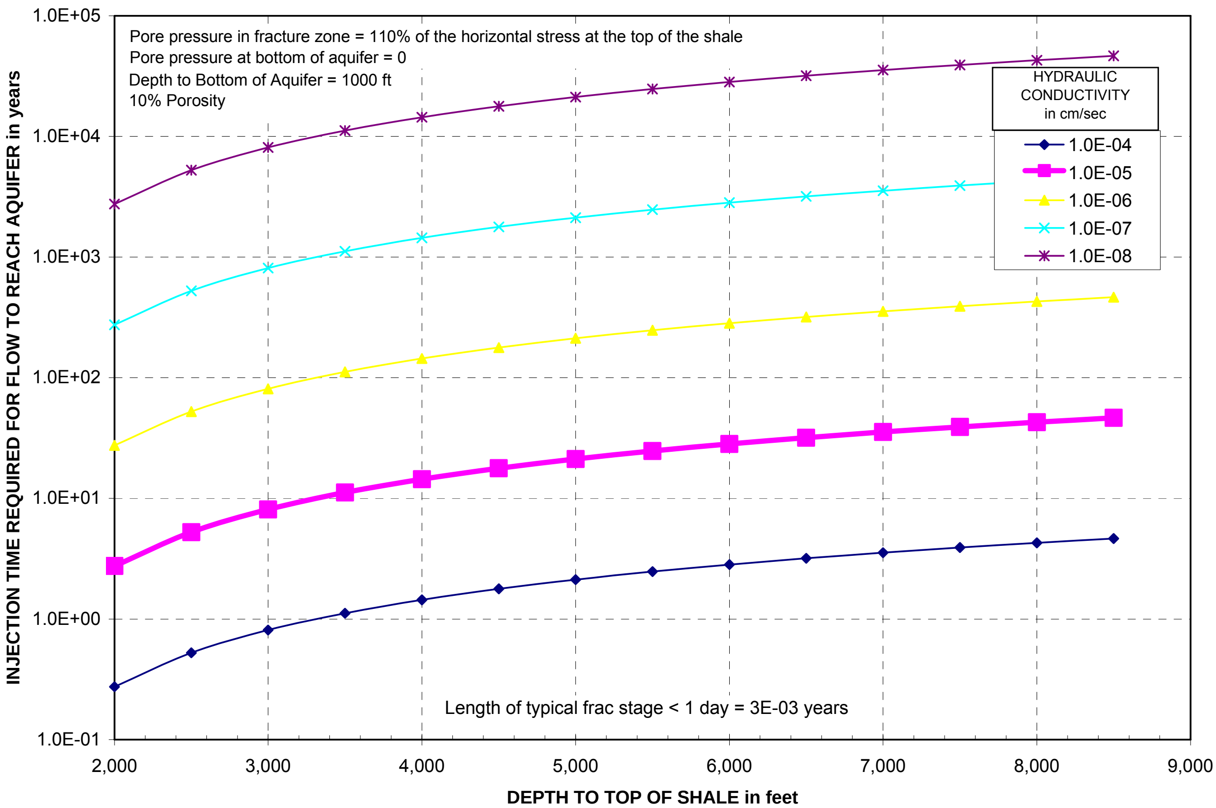


**Figure 3: Injection time required for fracture fluid to reach aquifer as a function of hydraulic conductivity**

Figure 3 shows the required travel time based on the average gradients shown in Figure 1 over a range of hydraulic conductivity values and for the maximum aquifer depth of 1000 feet. For all lesser aquifer depths, the required flow time would be longer. The required flow times under the fracturing pressure is several orders of magnitude greater than the duration over which the fracturing pressure would be applied.

Figure 4 presents the results of a similar analysis, but with the hydraulic conductivity held at 1E-5 cm/sec and considering various depths to the bottom of the aquifer. Compared to a 1000 ft. deep aquifer, 10 to 20 more years of sustained fracturing pressure would be required for the fracturing fluid to reach an aquifer that was only 200 ft. deep.

The required travel times shown relate to the movement of the groundwater. Dissolved chemicals would move at a slower rate due to retardation. The retardation factor, which is the ratio of the chemical movement rate compared to the water movement rate, is always between 0.0 and 1.0, so the required travel times for any dissolved chemical would be greater than those shown in Figures 3 and 4.

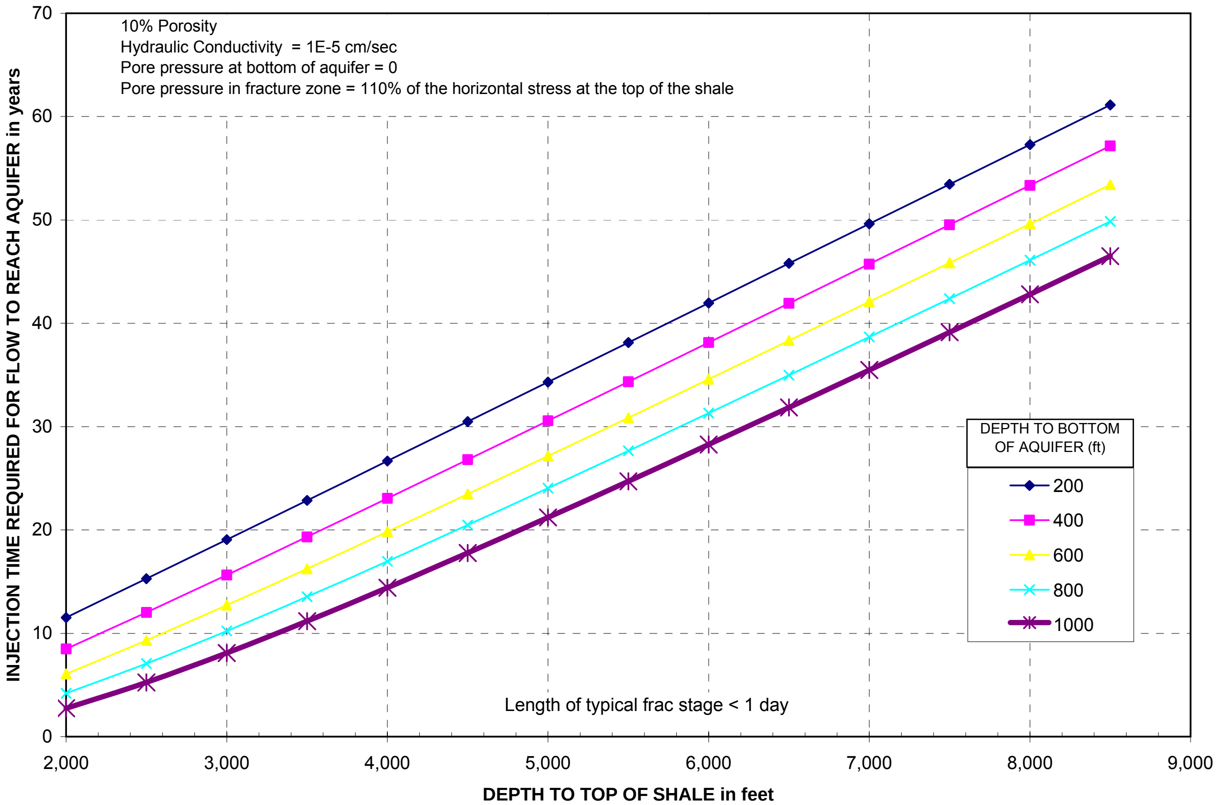


**Figure 4: Injection time required for flow to reach aquifer as a function of aquifer depth**

### 1.2.4.5 Pore storage volume

The fourth aspect to consider in evaluating the potential for adverse impacts to overlying aquifers is the volume of fluid injected compared to the volume of the void spaces and fractures that the fluid would need to fill in order to flow from the fracture zone to the aquifer. Figure 5 shows the void volume based on 10% total porosity for the geologic materials for various combinations of depths for the bottom of an aquifer and for the top of the shale, calculated as follows:

$$V = \left| d_1 - d_2 \right| \times n \times \frac{43{,}560\, ft^2}{acre} \times \frac{7.48 gal}{ft^3} \qquad (12)$$

where $V$ = volume of void spaces and fractures

A typical slickwater fracturing treatment in a horizontal well would use less than 4 million gallons of fracturing fluid, and some portion of this fluid would be recovered as flowback. The void volume, based on 10% total porosity, for the geologic materials between the bottom of an aquifer at 1,000 ft. depth and the top of the shale at a 2,000 ft. depth is greater than 32 million gallons per acre. Since the expected area of a well spacing unit is no less than the equivalent of

40 acres per well,[142,143,144,145] the fracturing fluid could only fill about 0.3% of the overall void space. Alternatively, if the fracturing fluid were to uniformly fill the overall void space, it would be diluted by a factor of over 300. As shown in Figure 5, for shallower aquifers and deeper shales, the void volume per acre is significantly greater.

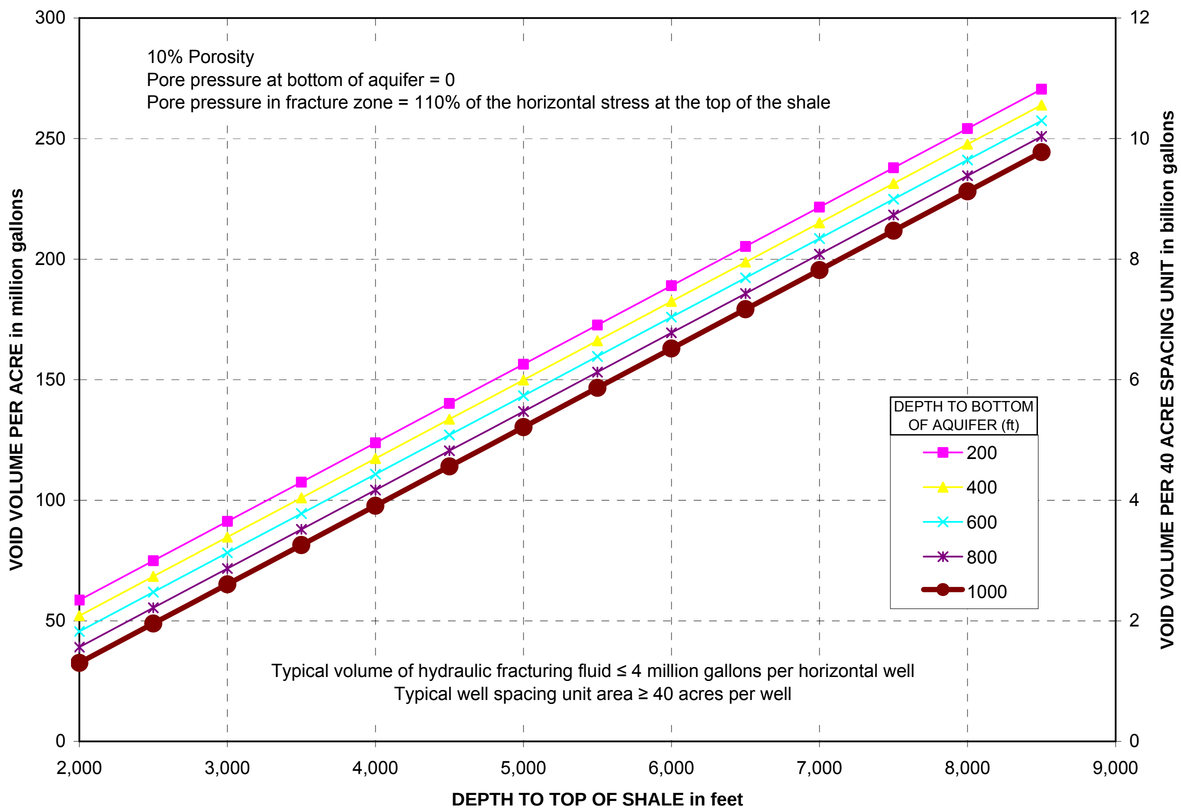


**Figure 5: Comparison of void volume to frac fluid volume**

### *1.2.5 Flow through fractures, faults, or unplugged borings*

It is theoretically possible but extremely unlikely that a flow path such as a network of open fractures, an open fault, or an undetected and unplugged wellbore could exist that directly connects the hydraulically fractured zone to an aquifer. The open flow path would have a much smaller area of flow leading to the aquifer and the resistance to flow would be lower. In such an improbable case, the flow velocity would be greater, the time required for the fracturing fluid to reach the aquifer would be shorter, and the storage volume between the fracture zone and the aquifer would be less than in the scenarios described above. The probability of such a combination of unlikely conditions occurring simultaneously (deep aquifer, shallow fracture

[142] Infill wells could result in local increases in well density.
[143] New York regulations (Part 553.1 Statewide spacing) require a minimum spacing of 1320 ft. from other oil and gas wells in the same pool. This spacing equals 40 acres per well for wells in a rectangular grid.
[144] New York Codes, Rules, and Regulations, Title 6 Department of Environmental Conservation, Chapter V Resource Management Services, Subchapter B Mineral Resources, 6 NYCRR Part 553.1 Statewide spacing, (as of 5 April 2009).
[145] NYSDEC, 2009, “Final Scope for Draft Supplemental Generic 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”, February 2009.

zone, and open flow path) is very small. The fracturing contractor would notice an anomaly if these conditions led to the inability to develop or maintain the predicted fracturing pressure.

During flowback, the same conditions would result in a high rate of recapture of the frac fluid from the open flow path, decreasing the potential for any significant adverse environmental impacts. Moreover, during production the gradients along the open flow path would be toward the production zone, flushing any stranded fracturing fluid in the fracture or unplugged wellbore back toward the production well.

### *1.2.6 Geochemistry*

The ability of the chemical constituents of the additives in fracturing fluids to migrate from the fracture zone are influenced not just by the forces governing the flow of groundwater, but also by the properties of the chemicals and their interaction with the subterranean environment. In addition to direct flow to an aquifer, the constituents of fracturing fluid would be affected by limitations on solubility, adsorption and diffusion.

#### 1.2.6.1 Solubility

The solubility of a substance indicates the propensity of the substance to dissolve in a solvent, in this case, groundwater. The substance can continue to dissolve up to its saturation concentration, i.e. its solubility. Substances with high solubilities in water have a higher likelihood of moving with the groundwater flow at high concentrations, whereas substances with low solubilities may act as longer term sources at low level concentrations. The solubilities of many chemicals proposed for use in hydraulic fracturing in New York State are not well established or are not available in standard databases such as the IUPAC-NIST Solubility Database.[146]

The solubility of a chemical determines the maximum concentration of the chemical that is likely to exist in groundwater. Solubility is temperature dependent, generally increasing with temperature. Since the temperature at the depths of the gas shales is higher than the temperature closer to the surface where a usable aquifer may lie, the solubility in the aquifer will be lower than in the shale formation.

Given the depth of the New York gas shales and the distance between the shales and any overlying aquifer, chemicals with high solubilities would be more likely to reach an aquifer at higher concentrations than chemicals of low solubility. Based on the previously presented fluid flow calculations, the concentrations would be significantly lower than the initial solubilities due to dilution.

#### 1.2.6.2 Adsorption

Adsorption occurs when molecules of a substance bind to the surface of another material. As chemicals pass through porous media or narrow fractures, some of the chemical molecules may adsorb onto the mineral surface. The adsorption will retard the flow of the chemical constituents relative to the rate of fluid flow. The retardation factor, expressed as the ratio of the fluid flow velocity to the chemical movement velocity, generally is higher in fine grained materials and in materials with high organic content. The Marcellus shale is both fine grained and of high organic content, so the expected retardation factors are high. The gray shales overlying the Marcellus

[146] IUPAC-NIST Solubility Database, Version 1.0, NIST Standard Reference Database 106, URL: http://srdata.nist.gov/solubility/index.aspx.

shale would also be expected to substantially retard any upward movement of fracturing chemicals.

The octanol-water partition coefficient, commonly expressed as $K_{ow}$, is often used in environmental engineering to estimate the adsorption of chemicals to geologic materials, especially those containing organic materials. Chemicals with high partition coefficients are more likely to adsorb onto organic solids and become locked in the shale, and less likely to remain in the dissolve phase than are chemicals with low partition coefficients.

The partition coefficients of many chemicals proposed for use in hydraulic fracturing in New York State are not well established or are not available in standard databases. The partition coefficient is inversely proportional to solubility, and can be estimated from the following equation[147]

$$\log K_{ow} = -0.862 \log S_w + 0.710 \qquad (13)$$

where $K_{ow}$ = octanol-water partition coefficient
$S_w$ = solubility in water at 20ºC in mol/liter

Adsorption in the target black shales or the overlying gray shales would effectively remove some percentage of the chemical mass from the groundwater for long periods of time, although as the concentration in the water decreased some of the adsorbed chemicals could repartition back into the water. The effect of adsorption could be to lower the concentration of dissolved chemicals in any groundwater migrating from the shale formation.

### 1.2.6.3 Diffusion

Through diffusion, chemicals in fracturing fluids would move from locations with higher concentrations to locations with lower concentrations. Diffusion may cause the transport of chemicals even in the absence of or in a direction opposed to the gradient driving fluid flow. Diffusion is a slow process, but may continue for a very long time. As diffusion occurs, the concentration necessarily decreases. If all diffusion were to occur in an upward direction (an unlikely, worst-case scenario) from the fracture zone to an overlying freshwater aquifer, the diffused chemical would be dispersed within the intervening void volume and be diluted by at least an average factor of 160 based on the calculated pore volumes in Section 1.2.4.5. Since a concentration gradient would exist from the fracture zone to the aquifer, the concentration at the aquifer would be significantly lower than the calculated average. Increased vertical distance between the aquifer and the fracture zone due to shallower aquifers and deeper shales would further increase the dilution and reduce the concentration reaching the aquifer.

### 1.2.6.4 Chemical interactions

Mixtures of chemicals in a geologic formation will behave differently than pure chemicals analyzed in a laboratory environment, so any estimates based on the solubility, adsorption, or diffusion properties of individual chemicals or chemical compounds should only be used as a guide to how they might behave when injected with other additives into the shale. Co-solubilities can change the migration properties of the chemicals and chemical reactions can create new compounds.

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[147] Chiou, Cary T., *Partition and adsorption of organic contaminants in environmental systems*, John Wiley & Sons, New York, 2002, p.57.

### *1.2.7 Conclusions*

Analyses of flow conditions during hydraulic fracturing of New York shales help explain why hydraulic fracturing does not present a reasonably foreseeable risk of significant adverse environmental impacts to potential freshwater aquifers. Specific conditions or analytical results supporting this conclusion include:

- The developable shale formations are separated from potential freshwater aquifers by at least 1,000 feet of sandstones and shales of moderate to low permeability.
- The fracturing pressures which could potentially drive fluid from the target shale formation toward the aquifer are applied for short periods of time, typically less than one day per stage, while the required travel time for fluid to flow from the shale to the aquifer under those pressures is measured in years.
- The volume of fluid used to fracture a well could only fill a small percentage of the void space between the shale and the aquifer.
- Some of the chemicals in the additives used in hydraulic fracturing fluids would be adsorbed by and bound to the organic-rich shales.
- Diffusion of the chemicals throughout the pore volume between the shale and an aquifer would dilute the concentrations of the chemicals by several orders of magnitude.
- Any flow of frac fluid toward an aquifer through open fractures or an unplugged wellbore would be reversed during flowback, with any residual fluid further flushed by flow toward the production zone as pressures decline in the reservoir during production.

The historical experience of hydraulic fracturing in tens of thousands of wells is consistent with the analytical conclusion. There are no known incidents of groundwater contamination due to hydraulic fracturing.

New York State

DEC

# Appendix 12

## Beneficial Use Determination (BUD) Notification Regarding Road Spreading

Revised Draft
Supplemental Generic Environmental Impact Statement

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**New York State Department of Environmental Conservation**
**Division of Solid and Hazardous Materials**
**Bureau of Solid Waste, Reduction and Recycling, 9th Floor**
625 Broadway, Albany, New York 12233-7253
**Phone:** (518) 402-8704 • **FAX:** (518) 402-9024
**Website:** www.dec.ny.gov

Alexander B. Grannis
Commissioner

January 2009

# NOTICE TO GAS AND OIL WELL & LPG STORAGE FLUID HAULERS

All gas or oil well drilling and production fluids including but not limited to brine and fracturing fluids, and brine from liquefied petroleum gas (LPG) well storage operations, transported for disposal, road spreading, reuse in another gas or oil well, or recycling must be specifically identified in Part C and D of the New York State Waste Transporter Permit Application Form. Transporters must identify the type of fluid proposed to be transported in Section C in the Non-Hazardous Industrial/Commercial box and the Disposal or Destination Facility (or Use) in Part D.

Fracture fluids obtained during flowback operations may not be spread on roads and must be disposed at facilities authorized by the Department. Such disposal facilities must be identified in Part D of the permit application. If fluids are to be transported for use or reuse at another gas or oil well, that location must be identified in Part D of the permit application.

With respect to fluids transported under a Waste Transporter Permit, only production brines or brine from LPG storage operations may be used for road spreading. Drilling, fracing, and plugging fluids are not acceptable for road spreading.

Any person, including any government entity, applying for a Part 364 permit or permit modification to use production brine from oil or gas wells or brine from LPG well storage operations for road spreading purposes (i.e. road de-icing, dust suppression, or road stabilization) must submit a petition for a beneficial use determination (BUD). If a contract hauler is applying for a Part 364 permit or permit modification to deliver brine to a government agency for road spreading purposes, that government agency must submit the BUD petition. The BUD must be granted and the Part 364 permit/modification must be issued before brine can be removed from the well or LPG storage site for road spreading purposes or storage at an offsite facility.

The BUD petition must include:

1. An original letter signed and dated by the government agency representative or other property owner authorizing the use of brine on the locations identified in below item 3.

2. The name, address and telephone number of the person, company or government official seeking the approval.

3. An identification (or map) of the specific roads or other areas that are to receive the brine and any brine storage locations, excluding the well site storage locations.

4. The physical address of the brine storage locations from which the brine is hauled.

5. For each well field or LPG storage facility, a chemical analysis of a representative sample of the brine performed by a NYSDOH approved laboratory for the following parameters: calcium, sodium, chloride, magnesium, total dissolved solids, pH, iron, barium, lead, sulfate, oil & grease, benzene, ethylbenzene, toluene, and xylene. Depending upon the analytical results, the Department may require additional analyses. (This analysis is not required for brine from a LPG well operation with a valid New York State SPDES permit.)

6. A road spreading plan that includes a description of the procedures to prevent the brine from flowing or running off into streams, creeks, lakes and other bodies of water. The plan should include:

- a description of how the brine will be applied, including the equipment to be used and the method for controlling the rate of application. In general this should indicate that the brine is applied by use of a spreader bar or similar spray device with shut-off controls in the cab of the truck; and with vehicular equipment that is dedicated to this use or cleaned of previously transported waste materials prior to this use;
- the proposed rate and frequency of application;
- a description of application restrictions. For dust control and road stabilization use this description should indicate that the brine is not applied: after daylight hours; within 50 feet of a stream, creek, lake or other body of water; on sections of road having a grade exceeding 10 percent; or on wet roads, during rain, or when rain is imminent. For road deicing use, this description should indicate that the brine is applied in accordance NYSDOT Guidelines for Anit-Icing with Liquids and include any other restrictions.

7. Where applicable, a brine storage plan that includes:

- a description of the type, material, size, and number of storage tanks and the maximum anticipated storage;
- procedures for run off and run-on control;
- provisions for secondary containment; and
- a contingency plan.

If you have any questions concerning your permit, please feel free to call this office at (518) 402-8707. You may also visit our public website at the address above for information and forms to download or print.

Waste Transporter Permit Program

New York State

DEC

# Appendix 13

## Radiological Data - Production Brine from NYS Marcellus Wells

Revised Draft
Supplemental Generic Environmental Impact Statement

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# NYS Marcellus Radiological Data from Production Brine

| Well | API # | Date Collected | Town (County) | Parameter | Result +/- Uncertainty |
|---|---|---|---|---|---|
| Maxwell 1C | 31-101-22963-03-01 | 10/7/2008 | Caton (Steuben) | Gross Alpha | 17,940 +/- 8,634 pCi/L |
| | | | | Gross Beta | 4,765 +/- 3,829 pCi/L |
| | | | | Cesium-137 | -2.26 +/- 5.09 pCi/L |
| | | | | Cobalt-60 | -0.748 +/- 4.46 pCi/L |
| | | | | Ruthenium-106 | 9.27 +/- 46.8 pCi/L |
| | | | | Zirconium-95 | 37.8 +/- 21.4 pCi/L |
| | | | | Radium-226 | 2,472 +/- 484 pCi/L |
| | | | | Radium-228 | 874 +/- 174 pCi/L |
| | | | | Thorium-228 | 53.778 +/- 8.084 pCi/L |
| | | | | Thorium-230 | 0.359 +/- 0.221 pCi/L |
| | | | | Thorium-232 | 0.065 +/- 0.103 pCi/L |
| | | | | Uranium-234 | 0.383 +/- 0.349 pCi/L |
| | | | | Uranium-235 | 0.077 +/- 0.168 pCi/L |
| | | | | Uranium-238 | 0.077 +/- 0.151 pCi/L |
| Frost 2 | 31-097-23856-00-00 | 10/8/2008 | Orange (Schuyler) | Gross Alpha | 14,530 +/-3,792 pCi/L |
| | | | | Gross Beta | 4,561 +/- 1,634 pCi/L |
| | | | | Cesium-137 | 2.54 +/- 4.64 pCi/L |
| | | | | Cobalt-60 | -1.36 +/- 3.59 pCi/L |
| | | | | Ruthenium-106 | -9.03 +/- 36.3 pCi/L |
| | | | | Zirconium-95 | 31.6 +/- 14.6 pCi/L |
| | | | | Radium-226 | 2,647 +/- 494 pCi/L |
| | | | | Radium-228 | 782 +/- 157 pCi/L |
| | | | | Thorium-228 | 47.855 +/- 9.140 pCi/L |
| | | | | Thorium-230 | 0.859 +/- 0.587 pCi/L |
| | | | | Thorium-232 | 0.286 +/- 0.328 pCi/L |
| | | | | Uranium-234 | 0.770 +/- 0.600 pCi/L |
| | | | | Uranium-235 | 0.113 +/- 0.222 pCi/L |
| | | | | Uranium-238 | 0.431 +/- 0.449 pCi/L |
| Webster T1 | 31-097-23831-00-00 | 10/8/2008 | Orange (Schuyler) | Gross Alpha | 123,000 +/- 23,480 pCi/L |
| | | | | Gross Beta | 12,000 +/- 2,903 pCi/L |
| | | | | Cesium-137 | 1.32 +/- 5.76 pCi/L |
| | | | | Cobalt-60 | -2.42 +/- 4.76 pCi/L |
| | | | | Ruthenium-106 | -18.3 +/- 44.6 pCi/L |
| | | | | Zirconium-95 | 34.5 +/- 15.6 pCi/L |
| | | | | Radium-226 | 16,030 +/- 2,995 pCi/L |
| | | | | Radium-228 | 912 +/- 177 pCi/L |
| | | | | Thorium-228 | 63.603 +/- 9.415 pCi/L |
| | | | | Thorium-230 | 0.783 +/- 0.286 pCi/L |
| | | | | Thorium-232 | 0.444 +/- 0.213 pCi/L |
| | | | | Uranium-234 | 0.232 +/- 0.301 pCi/L |
| | | | | Uranium-235 | 0.160 +/- 0.245 pCi/L |
| | | | | Uranium-238 | -0.016 +/- 0.015 pCi/L |

| Well | API # | Date Collected | Town (County) | Parameter | Result +/- Uncertainty |
|---|---|---|---|---|---|
| Calabro T1 | 31-097-23836-00-00 | 3/26/2009 | Orange (Schuyler) | Gross Alpha | 18,330 +/- 3,694 pCi/L |
| | | | | Gross Beta | -324.533 +/- 654 pCi/L |
| | | | | Cesium-137 | 3.14 +/- 7.19 pCi/L |
| | | | | Cobalt-60 | 0.016 +/- 5.87 pCi/L |
| | | | | Ruthenium-106 | 17.0 +/- 51.9 pCi/L |
| | | | | Zirconium-95 | 24.2 +/- 13.6 pCi/L |
| | | | | Radium-226 | 13,510 +/- 2,655 pCi/L |
| | | | | Radium-228 | 929 +/- 179 pCi/L |
| | | | | Thorium-228 | 45.0 +/- 8.41 pCi/L |
| | | | | Thorium-230 | 2.80 +/- 1.44 pCi/L |
| | | | | Thorium-232 | -0.147 +/- 0.645 pCi/L |
| | | | | Uranium-234 | 1.91 +/- 1.82 pCi/L |
| | | | | Uranium-235 | 0.337 +/- 0.962 pCi/L |
| | | | | Uranium-238 | 0.765 +/- 1.07 pCi/L |
| Maxwell 1C | 31-101-22963-03-01 | 4/1/2009 | Caton (Steuben) | Gross Alpha | 3,968 +/- 1,102 pCi/L |
| | | | | Gross Beta | 618 +/- 599 pCi/L |
| | | | | Cesium-137 | -0.443 +/- 3.61 pCi/L |
| | | | | Cobalt-60 | -1.840 +/- 2.81 pCi/L |
| | | | | Ruthenium-106 | 17.1 +/- 29.4 pCi/L |
| | | | | Zirconium-95 | 26.4 +/- 8.38 pCi/L |
| | | | | Radium-226 | 7,885 +/- 1,568 pCi/L |
| | | | | Radium-228 | 234 +/- 50.5 pCi/L |
| | | | | Thorium-228 | 147 +/- 23.2 pCi/L |
| | | | | Thorium-230 | 1.37 +/- 0.918 pCi/L |
| | | | | Thorium-232 | 0.305 +/- 0.425 pCi/L |
| | | | | Uranium-234 | 1.40 +/- 1.25 pCi/L |
| | | | | Uranium-235 | 0.254 +/- 0.499 pCi/L |
| | | | | Uranium-238 | 0.508 +/- 0.708 pCi/L |
| Haines 1 | 31-101-14872-00-00 | 4/1/2009 | Avoca (Steuben) | Gross Alpha | 54.6 +/- 37.4 pCi/L |
| | | | | Gross Beta | 59.3 +/- 58.4 pCi/L |
| | | | | Cesium-137 | 0.476 +/- 2.19 pCi/L |
| | | | | Cobalt-60 | -0.166 +/- 2.28 pCi/L |
| | | | | Ruthenium-106 | 7.15 +/- 19.8 pCi/L |
| | | | | Zirconium-95 | 0.982 +/- 4.32 pCi/L |
| | | | | Radium-226 | 0.195 +/- 0.162 pCi/L |
| | | | | Radium-228 | 0.428 +/- 0.335 pCi/L |
| | | | | Thorium-228 | 0.051 +/- 0.036 pCi/L |
| | | | | Thorium-230 | 0.028 +/- 0.019 pCi/L |
| | | | | Thorium-232 | 0.000 +/- 0.007 pCi/L |
| | | | | Uranium-234 | 0.000 +/- 0.014 pCi/L |
| | | | | Uranium-235 | 0.000 +/- 0.005 pCi/L |
| | | | | Uranium-238 | -0.007 +/- 0.006 pCi/L |

| Well | API # | Date Collected | Town (County) | Parameter | Result +/- Uncertainty |
|---|---|---|---|---|---|
| Haines 2 | 31-101-16167-00-00 | 4/1/2009 | Avoca (Steuben) | Gross Alpha | 70.0 +/- 47.8 pCi/L |
| | | | | Gross Beta | 6.79 +/- 54.4 pCi/L |
| | | | | Cesium-137 | 2.21 +/- 1.64 pCi/L |
| | | | | Cobalt-60 | 1.42 +/- 2.83 pCi/L |
| | | | | Ruthenium-106 | 5.77 +/- 15.2 pCi/L |
| | | | | Zirconium-95 | 2.43 +/- 3.25 pCi/L |
| | | | | Radium-226 | 0.163 +/- 0.198 pCi/L |
| | | | | Radium-228 | 0.0286 +/- 0.220 pCi/L |
| | | | | Thorium-228 | 0.048 +/- 0.038 pCi/L |
| | | | | Thorium-230 | 0.040 +/- 0.022 pCi/L |
| | | | | Thorium-232 | -0.006 +/- 0.011 pCi/L |
| | | | | Uranium-234 | 0.006 +/- 0.019 pCi/L |
| | | | | Uranium-235 | 0.006 +/- 0.013 pCi/L |
| | | | | Uranium-238 | -0.013 +/- 0.009 pCi/L |
| Carpenter 1 | 31-101-26014-00-00 | 4/1/2009 | Troupsburg (Steuben) | Gross Alpha | 7,974 +/- 1,800 pCi/L |
| | | | | Gross Beta | 1,627 +/- 736 pCi/L |
| | | | | Cesium-137 | 2.26 +/- 4.97 pCi/L |
| | | | | Cobalt-60 | -0.500 +/- 3.84 pCi/L |
| | | | | Ruthenium-106 | 49.3 +/- 38.1 pCi/L |
| | | | | Zirconium-95 | 30.4 +/- 11.0 pCi/L |
| | | | | Radium-226 | 5,352 +/- 1,051 pCi/L |
| | | | | Radium-228 | 138 +/- 37.3 pCi/L |
| | | | | Thorium-228 | 94.1 +/- 14.9 pCi/L |
| | | | | Thorium-230 | 1.80 +/- 0.946 pCi/L |
| | | | | Thorium-232 | 0.240 +/- 0.472 pCi/L |
| | | | | Uranium-234 | 0.000 +/- 0.005 pCi/L |
| | | | | Uranium-235 | 0.000 +/- 0.005 pCi/L |
| | | | | Uranium-238 | -0.184 +/- 0.257 pCi/L |
| Zinck 1 | 31-101-26015-00-00 | 4/1/2009 | Woodhull (Steuben) | Gross Alpha | 9,426 +/- 2,065 pCi/L |
| | | | | Gross Beta | 2,780 +/- 879 pCi/L |
| | | | | Cesium-137 | 5.47 +/- 5.66 pCi/L |
| | | | | Cobalt-60 | 0.547 +/- 4.40 pCi/L |
| | | | | Ruthenium-106 | -16.600 +/- 42.8 pCi/L |
| | | | | Zirconium-95 | 48.0 +/- 15.1 pCi/L |
| | | | | Radium-226 | 4,049 +/- 807 pCi/L |
| | | | | Radium-228 | 826 +/- 160 pCi/L |
| | | | | Thorium-228 | 89.1 +/- 14.7 pCi/L |
| | | | | Thorium-230 | 0.880 +/- 1.23 pCi/L |
| | | | | Thorium-232 | 0.000 +/- 0.705 pCi/L |
| | | | | Uranium-234 | -0.813 +/- 0.881 pCi/L |
| | | | | Uranium-235 | -0.325 +/- 0.323 pCi/L |
| | | | | Uranium-238 | -0.488 +/- 0.816 pCi/L |

| Well | API # | Date Collected | Town (County) | Parameter | Result +/- Uncertainty |
|---|---|---|---|---|---|
| Schiavone 2 | 31-097-23226-00-01 | 4/6/2009 | Reading (Schuyler) | Gross Alpha | 16,550 +/- 3,355 pCi/L |
| | | | | Gross Beta | 1,323 +/- 711 pCi/L |
| | | | | Cesium-137 | 1.46 +/- 5.67 pCi/L |
| | | | | Cobalt-60 | -2.550 +/- 5.11 pCi/L |
| | | | | Ruthenium-106 | 20.6 +/- 42.7 pCi/L |
| | | | | Zirconium-95 | 30.6 +/- 12.1 pCi/L |
| | | | | Radium-226 | 15,140 +/- 2,989 pCi/L |
| | | | | Radium-228 | 957 +/- 181 pCi/L |
| | | | | Thorium-228 | 38.7 +/- 7.45 pCi/L |
| | | | | Thorium-230 | 1.68 +/- 1.19 pCi/L |
| | | | | Thorium-232 | 0.153 +/- 0.301 pCi/L |
| | | | | Uranium-234 | 3.82 +/- 2.48 pCi/L |
| | | | | Uranium-235 | 0.354 +/- 0.779 pCi/L |
| | | | | Uranium-238 | 0.354 +/- 0.923 pCi/L |
| Parker 1 | 31-017-26117-00-00 | 4/2/2009 | Oxford (Chenango) | Gross Alpha | 3,914 +/- 813 pCi/L |
| | | | | Gross Beta | 715 +/- 202 pCi/L |
| | | | | Cesium-137 | 4.12 +/- 3.29 pCi/L |
| | | | | Cobalt-60 | -1.320 +/- 2.80 pCi/L |
| | | | | Ruthenium-106 | -9.520 +/- 24.5 pCi/L |
| | | | | Zirconium-95 | 1.39 +/- 6.35 pCi/L |
| | | | | Radium-226 | 1,779 +/- 343 pCi/L |
| | | | | Radium-228 | 201 +/- 38.9 pCi/L |
| | | | | Thorium-228 | 15.4 +/- 3.75 pCi/L |
| | | | | Thorium-230 | 1.25 +/- 0.835 pCi/L |
| | | | | Thorium-232 | 0.000 +/- 0.385 pCi/L |
| | | | | Uranium-234 | 1.82 +/- 1.58 pCi/L |
| | | | | Uranium-235 | 0.304 +/- 0.732 pCi/L |
| | | | | Uranium-238 | 0.304 +/- 0.732 pCi/L |
| WGI 10 | 31-097-23930-00-00 | 4/6/2009 | Dix (Schuyler) | Gross Alpha | 10,970 +/- 2,363 pCi/L |
| | | | | Gross Beta | 1,170 +/- 701 pCi/L |
| | | | | Cesium-137 | 1.27 +/- 5.17 pCi/L |
| | | | | Cobalt-60 | 0.960 +/- 4.49 pCi/L |
| | | | | Ruthenium-106 | 14.5 +/- 37.5 pCi/L |
| | | | | Zirconium-95 | 15.2 +/- 8.66 pCi/L |
| | | | | Radium-226 | 6,125 +/- 1,225 pCi/L |
| | | | | Radium-228 | 516 +/- 99.1 pCi/L |
| | | | | Thorium-228 | 130 +/- 20.4 pCi/L |
| | | | | Thorium-230 | 2.63 +/- 1.39 pCi/L |
| | | | | Thorium-232 | 0.444 +/- 0.213 pCi/L |
| | | | | Uranium-234 | 0.000 +/- 0.702 pCi/L |
| | | | | Uranium-235 | 1.17 +/- 1.39 pCi/L |
| | | | | Uranium-238 | 0.389 +/- 1.01 pCi/L |

| Well | API # | Date Collected | Town (County) | Parameter | Result +/- Uncertainty |
|---|---|---|---|---|---|
| WGI 11 | 31-097-23949-00-00 | 4/6/2009 | Dix (Schuyler) | Gross Alpha | 20,750 +/- 4,117 pCi/L |
| | | | | Gross Beta | 2,389 +/- 861 pCi/L |
| | | | | Cesium-137 | 4.78 +/- 6.95 pCi/L |
| | | | | Cobalt-60 | -0.919 +/- 5.79 pCi/L |
| | | | | Ruthenium-106 | -19.700 +/- 49.8 pCi/L |
| | | | | Zirconium-95 | 9.53 +/- 11.8 pCi/L |
| | | | | Radium-226 | 10,160 +/- 2,026 pCi/L |
| | | | | Radium-228 | 1,252 +/- 237 pCi/L |
| | | | | Thorium-228 | 47.5 +/- 8.64 pCi/L |
| | | | | Thorium-230 | 1.55 +/- 1.16 pCi/L |
| | | | | Thorium-232 | -0.141 +/- 0.278 pCi/L |
| | | | | Uranium-234 | 0.493 +/- 0.874 pCi/L |
| | | | | Uranium-235 | 0.000 +/- 0.540 pCi/L |
| | | | | Uranium-238 | -0.123 +/- 0.172 pCi/L |

New York State

DEC

# Appendix 14

## Department of Public Service Environmental Management & Construction Standards and Practices – Pipelines

Revised Draft
Supplemental Generic Environmental Impact Statement

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**ENVIRONMENTAL MANAGEMENT AND CONSTRUCTION**

**STANDARDS AND PRACTICES**

**CHECK-OFF LIST: PART III**

**PIPELINE**

New York State

DEC

# Appendix 15

## Hydraulic Fracturing –
## 15 Statements from Regulatory Officials

Revised Draft
Supplemental Generic Environmental Impact Statement

# Part A

# GWPC's Congressional Testimony

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STATEMENT OF
SCOTT KELL
ON BEHALF OF THE
GROUND WATER PROTECTION COUNCIL

HOUSE COMMITTEE ON NATURAL RESOURCES
SUBCOMMITTEE ON ENERGY AND MINERAL RESOURCES
WASHINGTON, D.C.
JUNE 4, 2009

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Mr. Chairman, thank you for the opportunity to testify today. My name is Scott Kell. I am President of the Ground Water Protection Council (GWPC) and appear here today on its behalf. I am also Deputy Chief of the Ohio Department of Natural Resources Division of Mineral Resources Management. With me today are Mike Paque, Executive Director of the GWPC, Dave Bolin, Assistant Director of the Alabama Oil and Gas Board, and Lori Wrotenbery, Director of the Oklahoma Corporation Commission's Oil and Gas Conservation Division. Within our respective States, we are responsible for implementing the state regulations governing the exploration and development of oil and natural gas resources. First and foremost, we are resource protection professionals committed to stewardship of water resources in the exercise of our authority.

The GWPC is a non-profit association of state agencies responsible for environmental safeguards related to ground water. The members of the association consist of state ground water and underground injection control regulators. The GWPC provides a forum through which its state members work with federal scientists and regulators, environmental groups, industry, and other stakeholders to advance protection of ground water resources through development of policy and regulation that is based on sound science. I have included a list of the GWPC Board of Directors in our written submission.

The GWPC understands that our nation's water and energy needs are intertwined, and that demand for both resources is increasing. Smart energy policy will consider and minimize impacts to water resources.

With respect to the protection of water resources, the GWPC recently published two reports of note. The first of these reports is called *Modern Shale Gas Development in the United States: A Primer (http://www.gwpc.org/e-library/documents/general/Shale%20Gas%20Primer%202009.pdf)*. The primer discusses the regulatory framework, policy issues, and technical aspects of developing unconventional shale gas resources. As you know, there are numerous deep shale gas basins in the United States, which contain trillions of cubic feet of natural gas. The environmentally responsible development of these resources is of critical importance to the energy security of the U.S. Recently, however, there has been concern raised about the methods used to tap these valuable resources. Technologies such as hydraulic fracturing have been characterized as being environmentally risky and inadequately regulated. The primer is designed to provide accurate technical information to assist policy makers in their understanding of these issues.

In recent months, the states have become aware of press reports and websites alleging that six states have documented over one thousand incidents of ground water contamination resulting from the practice of hydraulic fracturing. Such reports are not accurate. Attached to my testimony are signed statements from state officials representing Ohio, Pennsylvania, New Mexico, Alabama, and Texas, responding to these allegations.

From the standpoint of the GWPC, the most critical issue is protection of water resources. As such, our goal is to ensure that oil and gas development is managed in a way that does not create unnecessary and unwarranted risks to water. As a state regulatory official, I can assure you that our regulations are focused on this task. This leads me to the second report the GWPC has recently published.

This report, entitled *State Oil and Gas Regulations Designed to Protect Water Resources,* (http://www.gwpc.org/e-library/documents/general/Oil%20and%20Gas%20Regulation%20Report%20Final%20with%20Cover%205-27-2009.pdf) evaluates regulations implemented by state oil and gas regulatory agencies as they relate to the protection of water. To prepare this report, the GWPC reviewed the regulations of the twenty-seven states that, when combined, account for more than 99.8% of all the oil and natural gas extracted in the U.S. annually. To prepare this report, each state's regulatory requirements were studied with respect to their water protection capacity. The study evaluated regulated processes such as well drilling, construction, and plugging, above-ground storage tanks, pits and a number of other topics. The report also contains a statistical analysis of state regulations. As a result of our regulatory review and analysis, the GWPC concluded that state oil and gas regulations are adequately designed to directly protect water resources through the application of specific programmatic elements such as permitting, well construction, hydraulic fracturing, waste handling, and well plugging requirements. While State regulations are generally adequate, the GWPC report makes the following recommendations.

First, a study of effective hydraulic fracturing practices should be considered for the purpose of developing Best Management Practices (BMPs) that can be adjusted to fit the specific conditions of individual states. A one-size-fits-all federal program is not the most effective way to regulate in this area. BMPs related to hydraulic fracturing would assist states and operators in ensuring the safety of the practice. Of special concern are zones in close proximity to underground sources of drinking water, as determined by the state regulatory authority.

Second, the state review process conducted by the national non-profit organization State Review of Oil and Natural Gas Environmental Regulations (STRONGER) is an effective tool in assessing the capability of state programs to manage exploration and production waste and in measuring program improvement over time. This process should be expanded, where appropriate, to include state oil and gas programmatic elements not covered by the current state review guidelines. STRONGER is currently convening a stakeholder workgroup to consider drafting guidelines for state regulation of hydraulic fracturing.

Finally, the GWPC concludes that implementation and advancement of electronic data management systems has enhanced state regulatory capacity and focus. However, further work is needed in the areas of paper-to-digital data conversion and inclusion of more environmental, or water related data. States should continue to develop comprehensive electronic data management systems and incorporate widely scattered environmental data as expeditiously as possible. Federal agencies should provide financial assistance to states in these efforts.

In conclusion, Mr. Chairman and Committee Members, we believe that state regulations are designed to provide the level of water protection needed to assure water resources remain both viable and available. The states are continuously striving to improve both the regulatory language and the programmatic tools used to implement that language. In this regard, the GWPC will continue to assist states with their regulatory needs for the purpose of protecting water, our most vital natural resource.

Thank you.

**DISCLOSURE REQUIREMENT**
**Required by House Rule XI, clause 2(g)**
**and Rules of the Committee on Resources**

1. Name: **Scott R. Kell**

2. Business Address: **2045 Morse Rd., Columbus, OH 43229-6605**

3. Business Phone Number: **614-265-7058**

4. Organization you are representing: **The Ground Water Protection Council**

5. Any training or educational certificates, diplomas or degrees or other educational experiences which add to your qualifications to testify on or knowledge of the subject matter of the hearing: **Bachelor's Degree in Geology from Mount Union College and a Masters Degree in Geology from Kent State University.**

6. Any professional licenses, certifications, or affiliations held which are relevant to your qualifications to testify on or knowledge of the subject matter of the hearing:

7. Any employment, occupation, ownership in a firm or business, or work-related experiences which relate to your qualifications to testify on or knowledge of the subject matter of the hearing:

8. Any offices, elected positions, or representational capacity held in the organization on whose behalf you are testifying: **Chief of the Ohio Department of Natural Resources, Division of Mineral Resources Management; President of the Ground Water Protection Council**

9. Any federal grants or contracts (including subgrants or subcontracts) from the Department of the Interior (and /or other agencies invited) which **you** have received in the last three years, including the source and the amount of each grant or contract: **Office of Surface Mining, 2008 National Technology Transfer Grant, RBDMS-W, $200,000**

10. Any federal grants or contracts (including subgrants or subcontracts) the Department of the Interior (and /or other agencies invited) which were received in the last three years by the **organization(s) which you represent** at this hearing, including the source and amount of each grant or contract: **Office of Surface Mining, 2008 National Technology Transfer Grant, RBDMS-W, $200,000**

11. Any other information you wish to convey which might aid the members of the Committee to better understand the context of your testimony:

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*Attachment 1 – GWPC Testimony to the House Committee on Natural Resources, Subcommittee on energy and Mineral Resources, June 4, 2009*

# State Oil and Natural Gas Regulations Designed to Protect Water Resources

## EXECUTIVE SUMMARY

Over the past several years the GWPC has been asked, "Do state oil and gas regulations protect water?" How do their rules apply? Are they adequate? The first step in answering these questions is to evaluate the regulatory frameworks within which programs operate. That is the purpose of this report.

State regulation of oil and natural gas exploration and production activities are approved under state laws that typically include a prohibition against causing harm to the environment. This premise is at the heart of the regulatory process. The regulation of oil and gas field activities is managed best at the state level where regional and local conditions are understood and where regulations can be tailored to fit the needs of the local environment. Hence, the experience, knowledge and information necessary to regulate effectively most commonly rests with state regulatory agencies. Many state agencies use programmatic tools and documents to apply state laws including regulations, formal and informal guidance, field rules, and Best Management Practices (BMPs). They are also equipped to conduct field inspections, enforcement/oversight, and witnessing of specific operations like well construction, testing and plugging.

Regulations alone cannot convey the full measure of a regulatory program. To gain a more complete understanding of how regulatory programs actually function, one has to evaluate the use of state guides, manuals, environmental policy processes, environmental impact statements, requirements established by permit and many other practices. However, that is not the purpose of this study. This study evaluates the language of state oil and gas regulations as they relate to the direct protection of water resources. It is not an evaluation of state programs.

To conduct the study, state oil and gas regulations were reviewed in the following areas: 1) permitting, 2) well construction, 3) hydraulic fracturing, 4) temporary abandonment, 5) well plugging, 6) tanks, 7) pits, and 8) waste handling and spills. Within each area specific sub-areas were included to broaden the scope of this review. For example, in the area of pits, a review was conducted of sub-areas such as pit liners, siting, construction, use, duration and closure. The selection of the twenty-seven states for this study was based upon the last full-year list (2007) of producing states compiled by the U.S. Energy Information Administration.

In the area of well construction, state regulations were evaluated to determine whether the setting of surface casing below ground water zones was required, whether cement circulation on surface casing was also required, and whether the state utilized recognized cement standards. Attachment 3 is a listing of the programmatic areas and sub-areas reviewed.

After evaluation, each state was given the opportunity to review and comment on the findings and to provide updated information concerning their regulations. Thirteen states responded. These responses were incorporated into the study.

One of the most important accomplishments of the study was the development of a regulations reference document (Addendum). This document contains excerpted language from each state's oil and gas regulations related to the programmatic areas included in the study. Hyperlinks to web versions of each

state's oil and gas regulations are included as well as some of the forms used by state agencies to implement those regulations. A web enabled version of the study (to be completed by September, 2009) will also contain numerous hyperlinked text segments designed to provide the reader with an easy and effective way to review references and regulations.

**Key Messages and Suggested Actions:**

Key Message 1: State oil and gas regulations are adequately designed to directly protect water resources through the application of specific programmatic elements such as permitting, well construction, well plugging, and temporary abandonment requirements.

Suggested Action 1: States should review current regulations in several programmatic areas to determine whether or not they meet an appropriate level of specificity (e.g. use of standard cements, plugging materials, pit liners, siting criteria, and tank construction standards etc…)

Key Message 2: Experience suggests that state oil and gas regulations related to well construction are designed to be protective of ground water resources relative to the potential effects of hydraulic fracturing. However, development of Best Management Practices (BMPs) related to hydraulic fracturing would assist states and operators in insuring continued safety of the practice; especially as it relates to hydraulic fracturing of zones in close proximity to ground water, as determined by the regulatory authority.

Suggested Action 2: A study of effective hydraulic fracturing practices should be considered for the purpose of developing (BMPs); which can be adjusted to fit the specific conditions of individual states.

Key Message 3: Many states divide jurisdiction over certain elements of oil and gas regulation between the oil and gas agency and other state water protection agencies. This is particularly evident in the areas of waste handling and spill management.

Suggested Action 3: States with split jurisdiction of programs should insure that formal memorandums of agreement (MOAs) between agencies exist and that these MOAs are maintained to provide more effective and efficient implementation of regulations.

Key Message 4: The state review process conducted by the national non-profit organization State Review of Oil and Natural Gas Environmental Regulations (STRONGER) is an effective tool in assessing the capability of state programs to manage exploration and production waste and in measuring program improvement over time.

Suggested Action 4: The state review process should be continued and, where appropriate, expanded to include state oil and gas programmatic elements not covered by the current state review guidelines.

Key Message 5: The implementation and advancement of electronic data management systems has enhanced regulatory capacity and focus. However, further work is needed in the areas of paper-to-digital data conversion and inclusion of more environmental data.

Suggested Action 5: States should continue to develop and install comprehensive electronic data management systems, convert paper records to electronic formats and incorporate widely scattered environmental data as expeditiously as possible. Federal agencies should provide financial assistance to states in these efforts.

*Attachment 2 – GWPC Testimony to the House Committee on Natural Resources, Subcommittee on energy and Mineral Resources, June 4, 2009*

# Modern Shale Gas Development in the United States: A Primer

## EXECUTIVE SUMMARY

Natural gas production from hydrocarbon rich shale formations, known as "shale gas," is one of the most rapidly expanding trends in onshore domestic oil and gas exploration and production today. In some areas, this has included bringing drilling and production to regions of the country that have seen little or no activity in the past. New oil and gas developments bring change to the environmental and socio-economic landscape, particularly in those areas where gas development is a new activity. With these changes have come questions about the nature of shale gas development, the potential environmental impacts, and the ability of the current regulatory structure to deal with this development. Regulators, policy makers, and the public need an objective source of information on which to base answers to these questions and decisions about how to manage the challenges that may accompany shale gas development.

Natural gas plays a key role in meeting U.S. energy demands. Natural gas, coal and oil supply about 85% of the nation's energy, with natural gas supplying about 22% of the total. The percent contribution of natural gas to the U.S. energy supply is expected to remain fairly constant for the next 20 years.

The United States has abundant natural gas resources. The Energy Information Administration estimates that the U.S. has more than 1,744 trillion cubic feet (tcf) of technically recoverable natural gas, including 211 tcf of proved reserves (the discovered, economically recoverable fraction of the original gas-in-place). Technically recoverable unconventional gas (shale gas, tight sands, and coalbed methane) accounts for 60% of the onshore recoverable resource. At the U.S. production rates for 2007, about 19.3 tcf, the current recoverable resource estimate provides enough natural gas to supply the U.S. for the next 90 years. Separate estimates of the shale gas resource extend this supply to 116 years.

Natural gas use is distributed across several sectors of the economy. It is an important energy source for the industrial, commercial and electrical generation sectors, and also serves a vital role in residential heating. Although forecasts vary in their outlook for future demand for natural gas, they all have one thing in common: natural gas will continue to play a significant role in the U.S. energy picture for some time to come.

The lower 48 states have a wide distribution of highly organic shales containing vast resources of natural gas. Already, the fledgling Barnett Shale play in Texas produces 6% of all natural gas produced in the lower 48 States. Three factors have come together in recent years to make shale gas production economically viable: 1) advances in horizontal drilling, 2) advances in hydraulic fracturing, and, perhaps most importantly, 3) rapid increases in natural gas prices in the last several years as a result of significant supply and demand pressures. Analysts have estimated that by 2011 most new reserves growth (50% to 60%, or approximately 3 bcf/day) will come from unconventional shale gas reservoirs. The total recoverable gas resources in four new shale gas plays (the Haynesville, Fayetteville, Marcellus, and Woodford) may be over 550 tcf. Total annual production volumes of 3 to 4 tcf may be sustainable for decades. This potential for production in the known onshore shale basins, coupled with other unconventional gas plays, is predicted to contribute significantly to the U.S.'s domestic energy outlook.

Shale gas is present across much of the lower 48 States. The most active shales to date are the Barnett Shale, the Haynesville/Bossier Shale, the Antrim Shale, the Fayetteville Shale, the Marcellus Shale, and the New Albany Shale. Each of these gas shale basins is different and each has a unique set of exploration criteria and operational challenges. Because of these differences, the development of shale gas resources in each of these areas faces potentially unique opportunities and challenges.

The development and production of oil and gas in the U.S., including shale gas, are regulated under a complex set of federal, state, and local laws that address every aspect of exploration and operation. All of the laws, regulations, and permits that apply to conventional oil and gas exploration and production activities also apply to shale gas development. The U.S. Environmental Protection Agency administers most of the federal laws, although development on federally-owned land is managed primarily by the Bureau of Land Management (part of the Department of the Interior) and the U.S. Forest Service (part of the Department of Agriculture). In addition, each state in which oil and gas is produced has one or more regulatory agencies that permit wells, including their design, location, spacing, operation, and abandonment, as well as environmental activities and discharges, including water management and disposal, waste management and disposal, air emissions, underground injection, wildlife impacts, surface disturbance, and worker health and safety. Many of the federal laws are implemented by the states under agreements and plans approved by the appropriate federal agencies.

A series of federal laws governs most environmental aspects of shale gas development. For example, the Clean Water Act regulates surface discharges of water associated with shale gas drilling and production, as well as storm water runoff from production sites. The Safe Drinking Water Act regulates the underground injection of fluids from shale gas activities. The Clean Air Act limits air emissions from engines, gas processing equipment, and other sources associated with drilling and production. The National Environmental Policy Act (NEPA) requires that exploration and production on federal lands be thoroughly analyzed for environmental impacts. Most of these federal laws have provisions for granting "primacy" to the states (i.e., state agencies implement the programs with federal oversight).

State agencies not only implement and enforce federal laws; they also have their own sets of state laws to administer. The states have broad powers to regulate, permit, and enforce all shale gas development activities—the drilling and fracture of the well, production operations, management and disposal of wastes, and abandonment and plugging of the well. State regulation of the environmental practices related to shale gas development, usually with federal oversight, can more effectively address the regional and state-specific character of the activities, compared to one-sizefits-all regulation at the federal level. Some of these specific factors include: geology, hydrology, climate, topography, industry characteristics, development history, state legal structures, population density, and local economics. State laws often add additional levels of environmental protection and requirements. Also, several states have their own versions of the federal NEPA law, requiring environmental assessments and reviews at the state level and extending those reviews beyond federal lands to state and private lands.

A key element in the emergence of shale gas production has been the refinement of cost-effective horizontal drilling and hydraulic fracturing technologies. These two processes, along with the implementation of protective environmental management practices, have allowed shale gas development to move into areas that previously would have been inaccessible. Accordingly, it is important to understand the technologies and practices employed by the industry and their ability to prevent or minimize the potential effects of shale gas development on human health and the environment and on the quality of life in the communities in which shale gas production is located.

Modern shale gas development is a technologically driven process for the production of natural gas resources. Currently, the drilling and completion of shale gas wells includes both vertical and horizontal wells. In both kinds of wells, casing and cement are installed to protect fresh and treatable water aquifers. The emerging shale gas basins are expected to follow a trend similar to the Barnett Shale play with increasing numbers of horizontal wells as the plays mature. Shale gas operators are increasingly relying on horizontal well completions to optimize recovery and well economics. Horizontal drilling provides more exposure to a formation than does a vertical well. This increase in reservoir exposure creates a number of advantages over vertical wells drilling. Six to eight horizontal wells drilled from only one well pad can access the same reservoir volume as sixteen vertical wells. Using multi-well pads can also significantly reduce the overall number of well pads, access roads, pipeline routes, and production facilities required, thus minimizing habitat disturbance, impacts to the public, and the overall environmental footprint.

The other technological key to the economic recovery of shale gas is hydraulic fracturing, which involves the pumping of a fracturing fluid under high pressure into a shale formation to generate fractures or cracks in the target rock formation. This allows the natural gas to flow out of the shale to the well in economic quantities. Ground water is protected during the shale gas fracturing process by a combination of the casing and cement that is installed when the well is drilled and the thousands of feet of rock between the fracture zone and any fresh or treatable aquifers. For shale gas development, fracture fluids are primarily water based fluids mixed with additives that help the water to carry sand proppant into the fractures. Water and sand make up over 98% of the fracture fluid, with the rest consisting of various chemical additives that improve the effectiveness of the fracture job. Each hydraulic fracture treatment is a highly controlled process designed to the specific conditions of the target formation.

The amount of water needed to drill and fracture a horizontal shale gas well generally ranges from about 2 million to 4 million gallons, depending on the basin and formation characteristics. While these volumes may seem very large, they are small by comparison to some other uses of water, such as agriculture, electric power generation, and municipalities, and generally represent a small percentage of the total water resource use in each shale gas area. Calculations indicate that water use for shale gas development will range from less than 0.1% to 0.8% of total water use by basin. Because the development of shale gas is new in some areas, these water needs may still challenge supplies and infrastructure. As operators look to develop new shale gas plays, communication with local water planning agencies, state agencies, and regional water basin commissions can help operators and communities to coexist and effectively manage local water resources. One key to the successful development of shale gas is the identification of water supplies capable of meeting the needs of a development company for drilling and fracturing water without interfering with community needs. While a variety of options exist, the conditions of obtaining water are complex and vary by region.

After the drilling and fracturing of the well are completed, water is produced along with the natural gas. Some of this water is returned fracture fluid and some is natural formation water. Regardless of the source, these produced waters that move back through the wellhead with the gas represent a stream that must be managed. States, local governments, and shale gas operators seek to manage produced water in a way that protects surface and ground water resources and, if possible, reduces future demands for fresh water. By pursuing the pollution prevention hierarchy of "Reduce, Re-use, and Recycle" these groups are examining both traditional and innovative approaches to managing shale gas produced water. This water is currently managed through a variety of mechanisms, including underground injection, treatment and discharge, and recycling. New water treatment technologies and new applications of existing technologies are being developed and used to treat shale gas produced water for reuse in a variety of applications. This allows shale gas-associated produced water to be viewed as a potential resource in its own right.

Some soils and geologic formations contain low levels of naturally occurring radioactive material (NORM). When NORM is brought to the surface during shale gas drilling and production operations, it remains in the rock pieces of the drill cuttings, remains in solution with produced water, or, under certain conditions, precipitates out in scales or sludges. The radiation from this NORM is weak and cannot penetrate dense materials such as the steel used in pipes and tanks.

Because the general public does not come into contact with gas field equipment for extended periods, there is very little exposure risk from gas field NORM. To protect gas field workers, OSHA requires employers to evaluate radiation hazards, post caution signs and provide personal protection equipment when radiation doses could exceed regulatory standards. Although regulations vary by state, in general, if NORM concentrations are less than regulatory standards, operators are allowed to dispose of the material by methods approved for standard gas field waste. Conversely, if NORM concentrations are above regulatory limits, the material must be disposed of at a licensed facility. These regulations, standards, and practices ensure that shale gas operations present negligible risk to the general public and to workers with respect to potential NORM exposure.

Although natural gas offers a number of environmental benefits over other sources of energy, particularly other fossil fuels, some air emissions commonly occur during exploration and production activities. Emissions may include $NO_x$, volatile organic compounds, particulate matter, $SO_2$, and methane. EPA sets standards, monitors the ambient air across the U.S., and has an active enforcement program to control air emissions from all sources, including the shale gas industry. Gas field emissions are controlled and minimized through a combination of government regulation and voluntary avoidance, minimization, and mitigation strategies.

The primary differences between modern shale gas development and conventional natural gas development are the extensive uses of horizontal drilling and high-volume hydraulic fracturing. The use of horizontal drilling has not introduced any new environmental concerns. In fact, the reduced number of horizontal wells needed coupled with the ability to drill multiple wells from a single pad has significantly reduced surface disturbances and associated impacts to wildlife, dust , noise, and traffic. Where shale gas development has intersected with urban and industrial settings, regulators and industry have developed special practices to alleviate nuisance impacts, impacts to sensitive environmental resources, and interference with existing businesses. Hydraulic fracturing has been a key technology in making shale gas an affordable addition to the Nation's energy supply, and the technology has proved to be an effective stimulation technique. While some challenges exist with water availability and water management, innovative regional solutions are emerging that allow shale gas development to continue while ensuring that the water needs of other users are not affected and that surface and ground water quality is protected. Taken together, state and federal requirements along with the technologies and practices developed by industry serve to reduce environmental impacts from shale gas operations.

***John F. Husted, Chief***
*Division of Mineral Resources Management*
*2045 Morse Road, Building H-3*
*Columbus, OH 43229-6693*
*Phone: (614) 265-6633 Fax: (614) 265-7999*


May 27, 2009

Mike Paque
Executive Director
Ground Water Protection Council
13309 North MacArthur Boulevard
Oklahoma City, Oklahoma 73142

Dear Mike:

In recent months, the Ohio Department of Natural Resources, Division of Mineral Resources Management (DMRM) has become aware of website and media releases reporting that the State of Ohio has documented cases of ground water contamination caused by the standard industry practice of hydraulic fracturing. Such reports are not accurate. For example, some articles inaccurately portrayed hydraulic fracturing as the cause of a natural gas incident in Bainbridge Township of Geauga County that resulted in an in-home explosion in December 2007. This portrayal is not consistent with the findings or conclusions of the DMRM.

DMRM completed a thorough investigation into the cause of a natural gas invasion into fresh water aquifers in Bainbridge Township. The DMRM investigation found that this incident was caused by a <u>defective primary cement job</u> on the production casing, which was further <u>complicated by operator error</u>. As a consequence of this finding, the operator corrected the construction problem by completing remedial cementing operations. The findings and conclusions of this investigation are available on the web at <u>http://www.dnr.state.oh.us/bainbridge/tabid/20484/default.aspx</u>.

While an explosion significantly damaged one house, the investigation did not find any evidence to support the claim "that pressure caused by hydraulic fracturing pushed the gas...through a system of cracks into the ground water aquifer" as reported by some media accounts. In actuality, the team of geologists who completed the evaluation of the gas invasion incident in Bainbridge Township concluded that the problem would have occurred even if the well had never been stimulated by hydraulic fracturing.

After 25 years of investigating citizen complaints of contamination, DMRM geologists have not documented a single incident involving contamination of ground water attributed to hydraulic fracturing. Over this time, the Ohio DMRM has consistently taken decisive action to address oil and gas exploration and production practices that have caused documented incidents of ground water contamination. The DMRM has initiated amendments to statutes and rules, designed permit conditions, refined standards operating procedures, and developed best management practices to improve protection of ground water resources. These actions resulted in substantive changes including:

1. elimination of tens of thousands of earthen pits for produced water storage;
2. development of a model Class II brine injection well program;
3. development of technical standards for synthetic liners used in pits during drilling operations;
4. tighter standards for construction and mechanical integrity testing for annular disposal wells;
5. detailed plugging regulations; and,
6. establishment of an orphaned well plugging program funded by a severance tax on oil and gas production.

The Ohio DMRM will continue to assign the highest priority to improving protection of water resources and public health and safety.

In conclusion, the Ohio DMRM has not identified hydraulic fracturing as a significant threat to ground water resources.

Sincerely,

Scott R. Kell

Scott R. Kell, Deputy Chief

SRK/csc

Enclosure

cc: Cathryn Loucas, Deputy Director, ODNR
Mike Shelton, Chief, Legislative Services, ODNR
John Husted, Chief, DMRM

Pennsylvania Department of Environmental Protection

**Rachel Carson State Office Building**
**P.O. Box 8555**
**Harrisburg, PA 17105-8555**

June 1, 2009

**Bureau of Watershed Management** 717-772-4048

Michael Paque, Executive Director
Ground Water Protection Council
13308 North MacArthur Boulevard
Oklahoma City, OK 73142

Dear Mr. Paque:

I am the program manager for Pennsylvania's Ground Water Protection Program in the Pennsylvania Department of Environmental Protection (DEP). I have been concerned about press reports stating extensive groundwater pollution and contamination of underground sources of drinking water in Pennsylvania, as a result of hydraulic fracturing to stimulate gas production from deep, gas bearing rock formations. DEP has not concluded that the activity of hydraulic fracturing of these formations has caused wide-spread groundwater contamination.

After review of DEP's complaint database and interviews with regional staff that investigate groundwater contamination related to oil and gas activities, no groundwater pollution or disruption of underground sources of drinking water has been attributed to hydraulic fracturing of deep gas formations. All investigated cases that have found pollution, which are less then 80 in over 15 years of records, have been primarily related to physical drilling through the aquifers, improper design or setting of upper and middle well casings, or operator negligence.

If you have any questions or concerns, you may contact me by e-mail at josless@state.pa.us or by telephone at 717-772-4048.

Sincerely,

Joseph J. Lee, Jr., P.G., chief
Source Protection Section
Division of Water Use Planning

New Mexico Energy, Minerals and Natural Resources Department

Mark Fesmire
Division Director
Oil Conservation Division

May 29, 2009

Mr. Michael Paque, Executive Director
Ground Water Protection Council
13308 N. MacArthur Blvd.
Oklahoma City, OK 73142

Dear Mike:

As per your request, I have reviewed the New Mexico Oil Conservation Division Data concerning water contamination caused by Hydraulic Fracturing in New Mexico.

While we do currently list approximately 421 ground water contamination cases caused by pits and approximately an equal number caused by other contamination mechanisms, we have found no example of contamination of usable water where the cause was claimed to be hydraulic fracturing.

Sincerely,

Mark E. Fesmire, PE
Director, New Mexico Oil Conservation Division

# *STATE OIL AND GAS BOARD OF ALABAMA*



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***Berry H. (Nick) Tew, Jr.***
*Oil and Gas Supervisor*

May 27, 2009

Mr. Michel Paque, Executive Director
Ground Water Protection Council
13308 N. MacArthur Blvd.
Oklahoma City, OK 73142

Dear Mr. Paque:

This letter is in response to your recent inquiry regarding any cases of drinking water contamination that have resulted from hydraulic fracturing operations to stimulate oil and gas wells in Alabama. I can state with authority that there have been no documented cases of drinking water contamination caused by such hydraulic fracturing operations in our State.

The U.S. Environmental Protection Agency (EPA) approved the State Oil and Gas Board's (Board) Class II Underground Injection Control (UIC) Program in August 1982, pursuant to Section 1425 of the Safe Drinking Water Act (SDWA). This approval was made after EPA determined that the Board's program accomplished the objectives of the SDWA, that being to protect underground sources of drinking water. Obtaining primacy for the Class II UIC Program, however, was not the beginning of the Board's ground-water protection programs. These programs, to include the regulation and approval of hydraulic fracturing operations, have been actively implemented continually since the Board was established in 1945, pursuant to its legislative mandates.

The point to be made here is that the State of Alabama has a vested interest in protecting its drinking water sources and has adequate rules and regulations, as well as statutory mandates, to protect those sources from all oil and gas operations. The fact that there has been no documented case of contamination from these operations, to include hydraulic fracturing, is a testament to the proactive regulation of the industry by the Board. Additional federal regulations will not provide any greater level of protection for our drinking water sources than is currently being provided.

If we can be of further assistance in this matter, please let me know.

Sincerely,

David E. Bolin

David E. Bolin
Deputy Director

*Mobile Regional Office, 4173 Commanders Drive, Mobile, AL 36615-1421, Phone (251) 438-4848*

# RAILROAD COMMISSION OF TEXAS
**CHAIRMAN VICTOR G. CARRILLO**

May 29, 2009

Mike Paque, Executive Director
Ground Water Protection Agency
13308 N. MacArthur Blvd.
Oklahoma City, OK 73142

Re: Hydraulic Fracturing of Gas Wells in Texas

Dear Mr. Paque:

I am pleased that representatives of the Ground Water Protection Council will be appearing before the U.S. House Committee on Natural Resources next week on the issue of hydraulic fracturing. I was asked to participate but had a longstanding commitment to tour energy projects in Canada that prevented me from personally participating.

I sincerely hope that you will clear up the misconception that there are "thousands" of contamination cases in Texas and other states resulting from hydraulic fracturing. The Railroad Commission of Texas is the chief regulatory agency over oil and gas activities in this state. Though hydraulic fracturing has been used for over 50 years in Texas, our records do not indicate a single documented contamination case associated with hydraulic fracturing.

The Texas Groundwater Protection Committee (TGPC) tracks groundwater pollution in Texas. All Texas water protection agencies, including the Railroad Commission, are members. Each year, the TGPC publishes a Joint Groundwater Monitoring and Contamination Report, which can be found at http://www.tceq.state.tx.us/comm_exec/forms_pubs/pubs/sfr/056_07_index.html. The 2007 report cites a total of 354 active groundwater cases attributed to oil and gas activity – this in a state with over 255,000 active oil and gas wells. The majority of these cases are associated with previous practices that are no longer allowed, or result from activity now prohibited by our existing regulations. A few cases were due to blowouts that primarily occur during drilling activity. *Not one of these cases was caused by hydraulic fracturing activity.*

Hydraulic fracturing plays a key role in the development of virtually all unconventional gas resources in Texas. As of this year, over 11,000 gas wells have been completed (and hydraulically fractured) in the Barnett Shale reservoir, one of the nation's most active and largest natural gas fields. Since 2000, over five trillion cubic feet of gas has been produced from this one reservoir and the Barnett Shale production currently contributes over 20% of Texas' total natural gas production. While the volume of gas-in-place in the Barnett Shale is estimated to be over 27 trillion cubic feet, recovery of the gas is difficult because of the shale's low permeability. The remarkable success of the Barnett Shale results in large part from the use of horizontal drilling coupled with hydraulic fracturing. Even with this intense activity, there are no known instances of ongoing groundwater contamination in the Barnett Shale play.

P.O. Box 12967 ★ Austin, Texas 78711-2967 ★ Phone (512) 463-7131 ★ Fax (512) 463-7161

Regulation of oil and gas exploration and production activities, including hydraulic fracturing, has traditionally been the province of the states. Most oil and gas producing state have had effective programs in place for decades. Regulating hydraulic fracturing as underground injection under the federal Safe Drinking Water Act would impose significant additional costs and regulatory burdens and could ultimately reverse the significant U.S. domestic unconventional gas reserve additions of recent years – harming domestic energy security. I urge the U.S. Congress to leave the regulatory authority over hydraulic fraturing and other oil and gas activities where it belongs – at the state level.

Sincerely,

vg Carrillo

Victor G. Carrillo, Chairman
Railroad Commission of Texas

cc: Commissioner Michael Williams
Commissioner Elizabeth Ames Jones
John J. Tintera, Executive Director

# Part B

# IOGCC's Statements from
# Oil & Gas Regulators from 12 Member States

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# REGULATORY STATEMENTS ON HYDRAULIC FRACTURING SUBMITTED BY THE STATES JUNE 2009

The following statements were issued by state regulators for the record related to hydraulic fracturing in their states. Statements have been compiled for this document.

## ALABAMA:

**Nick Tew, Ph.D., P.G.**
**Alabama State Geologist & Oil and Gas Supervisor**
**President, Association of American State Geologists**

There have been no documented cases of drinking water contamination that have resulted from hydraulic fracturing operations to stimulate oil and gas wells in the State of Alabama.

The U.S. Environmental Protection Agency (EPA) approved the State Oil and Gas Board of Alabama's (Board) Class II Underground Injection Control (UIC) Program in August 1982, pursuant to Section 1425 of the Safe Drinking Water Act (SDWA). This approval was made after EPA determined that the Board's program accomplished the objectives of the SDWA, that is, the protection of underground sources of drinking water. Obtaining primacy for the Class II UIC Program, however, was not the beginning of the Board's ground-water protection programs. These programs, which include the regulation and approval of hydraulic fracturing operations, have been continuously and actively implemented since the Board was established in 1945, pursuant to its mission and legislative mandates.

The State of Alabama, acting through the Board, has a vested interest in protecting its drinking water sources and has adequate rules and regulations, as well as statutory mandates, to protect these sources from all oil and gas operations, including hydraulic fracturing. The fact that there has been no documented case of contamination from these operations, including hydraulic fracturing, is strong evidence of effective regulation of the industry by the Board. In our view, additional federal regulations will not provide any greater level of protection for our drinking water sources than is currently being provided.

## ALASKA:

**Cathy Foerster**
**Commissioner**
**Alaska Oil and Gas Conservation Commission**

There have been no verified cases of harm to ground water in the State of Alaska as a result of hydraulic fracturing.

State regulations already exist in Alaska to protect fresh water sources. Current well construction standards used in Alaska (as required by Alaska Oil and Gas Conservation Commission statutes